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An energy transition driven by climate policy and technological change creates uncertainty for oil producers. Many Latin American and Caribbean (LAC) governments rely on oil for fiscal revenues. Here, we explore prospects for oil production, public revenues, and unused oil reserves in LAC across hundreds of scenarios. We use the BUEGO (Bottom-Up Economic and Geological Oil field production) model to simulate field development and production decisions globally. LAC competes depending on global oil prices and domestic fiscal regimes. We find that 66-81% of 3P oil reserves in LAC will remain unused by 2035. Stringent global climate action could reduce fiscal revenues in LAC to $1.3-2.6 trillion, compared to $2.7-6.8 trillion if reserves were strongly exploited. Global demand and OPEC quotas drive production and fiscal returns in LAC; domestic fiscal management has limited potential to increase revenues. Governments may therefore need to diversify their fiscal revenues away from oil production.

Many countries in Latin America and the Caribbean (LAC) have large oil production sectors or emerging prospects for generating revenues from oil resources. The region holds one fifth of the global proven reserves, distributed in Venezuela (91% of LAC reserves), Brazil (3.8%), Mexico (2.3%), Ecuador (1%), Argentina (0.7%), and Colombia (0.5%)[1].

At the country level, dependence on oil is particularly pronounced for Venezuela, Trinidad & Tobago, Mexico and Ecuador[2,3]. In Venezuela, oil represented 98% of export earnings in 2017[4], while in Trinidad and Tobago, the oil and gas sector represents nearly 10% of GDP. Looking forward, countries like Argentina, Brazil and Mexico have ambitious plans to increase their production, and others, like Guyana, to start exploitation at a transformative scale for their economies[5].

But future oil production prospects are highly uncertain[6]. As alternative technologies become cheaper and measures to address climate change and implement the Paris Agreement take hold, oil demand is expected to slow down[2,3]. Electricity generation is expected to increasingly switch to renewable sources globally, and road transport to move to electric vehicles[7–13]. Such shifts are already occurring, with some countries experiencing large renewable energy growth[14], and others increasing sales of electric vehicles[15] whilst in parallel proposing the future banning of sales of diesel and gasoline vehicles.

If global action is ratcheted, oil demand will decline sharply, leading to *unburnable carbon*, that is fossil fuels which cannot be extracted and used if the world is to adhere to a given carbon budget[16,17]. McGlade and Ekins quantified this prospect, estimating that almost 40% of oil reserves in Latin America (33%

globally) would remain unburnable in 2050 in a world where the global temperature increase was limited to 2°C[18].

Here, we assess the prospects for production, unburnable reserves and fiscal revenues for LAC oil producers, given three key areas of uncertainty: i) global oil demand, sensitive to climate policy and technological change, ii) geo-political uncertainty, reflected in changes of production by the Organization of the Petroleum Exporting Countries (OPEC), and iii) how the type and stringency of fiscal regimes in LAC countries change the competitiveness of fields in the region.

We run 480 scenarios using a global oil field model to explore the relative impact of external uncertainties and domestic policy choices. We find that while the choice of fiscal regimes has some impact on fiscal returns from oil production, those are mainly driven by the level of global demand and the ability of OPEC to limit production. Our results reinforce previous findings that the ongoing energy transition results in a financial risk for oil producers,[6,16,19] suggesting that diversification of fiscal revenues away from oil may be required for exporting countries to ensure sustainable income.

Exploring drivers of regional oil production pathways

To explore a range of possible global oil demand trajectories, we use a large ensemble of scenarios from a peer-reviewed IPCC scenario database[20]. Those reflect assessment from the integrated assessment modelling community, modelling that is focused on exploring the implications of different climate futures under different narratives and assumptions. The scenarios represent futures that would lead to a range of different global temperature increases, and they incorporate different assumptions around demographic change, economic growth, and technological change[21].

For this assessment, we have taken the median oil production trajectory from four groups of representative scenarios, according to the temperature increase in 2100, which range from 1.5°C to above 2°C, with lower and higher 2°C categories in between (Supplementary Figure 1).

A second driver of prospects for oil production in LAC is how other key global producers act. To explore this, we focus on the role the OPEC, which is home to 82% of the world's proven oil reserves[4]. The OPEC uses production quotas to ensure revenue stability for its members by controlling oil price, therefore impacting on the attractiveness of LAC oil. We consider two contrasting cases by either imposing a cap on annual production for each OPEC member (including Venezuela and Ecuador), which we set at the maximum historical annual production level since 2000 (Table 1 in Methods); or imposing no caps at all.

Finally, we model the choice of LAC governments around fiscal regimes. Fiscal regimes impact profitability for investors and producers, influencing which oil field development projects they decide to fund. Most countries in LAC currently use either *production-sharing contracts* or *concessions*, with different levels of fiscal pressure on producers (Supplementary Table 2). We model the current fiscal regimes, we systematically test the impact of switching from one scheme to the other, and we test high and low levels of fiscal pressure (Methods).

To assess the implications of these uncertainties and policy choices on oil production and government tax take, we use the BUEGO (Bottom-Up Economic and Geological Oil field production) simulation model. BUEGO incorporates both economic and geological characteristics of 7,000 global oil fields, to assess the profitability of investing in specific oil field projects under the endogenously

derived global price[22,23] (Methods). In BUEGO, lower cost resources are produced first, hence providing insights into the competitiveness of LAC oil fields.

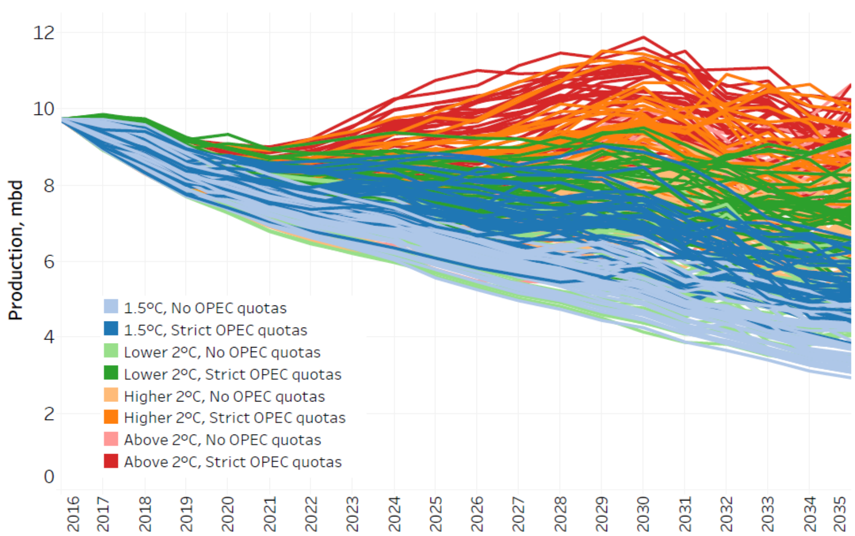
We generate 480 simulations of the global oil markets. Each simulation explores one different fiscal configuration for LAC oil producing countries (varied independently for each LAC country and from five options of *concession* or *production sharing* scheme, with low or high overall pressure, and the current tax regime), one global demand scenario (chosen from 4 representative demand scenarios) and one OPEC quota system (with our without quotas).

Oil production prospects in LAC

Figure 1a shows resulting oil production profiles in LAC from the simulations run. In all scenarios, production declines out to 2021, reflecting increasing production levels in USA and by some Middle Eastern producers, and recent declines in Venezuelan and Mexican production that more than compensate increases in Brazilian output[24]. Post-2025, the widening range highlights the risk that climate policy and technological change casts on producers and investors.

The main driver of future production turns out to be global demand. Under Above 2°C-consistent demand scenarios, production increases during the mid-2020s. For demands consistent with more stringent temperature limits, production continues to decline to 35-70% of 2016 levels by 2035, with the median global price at $50/bbl. A 1.5°C world suggests cumulative production in LAC of 47-56 billion barrels by 2035 compared to 57-70 billion barrels in a 3°C world, based on the interquartile range with large variation around the median level (Supplementary Figure 4a). The role of OPEC quotas is also important. Under the OPEC-constrained variants, production is higher in LAC in all cases, from Above 2°C to 1.5°C cases for the major regional producers (Figure 1b, lower left).

a)



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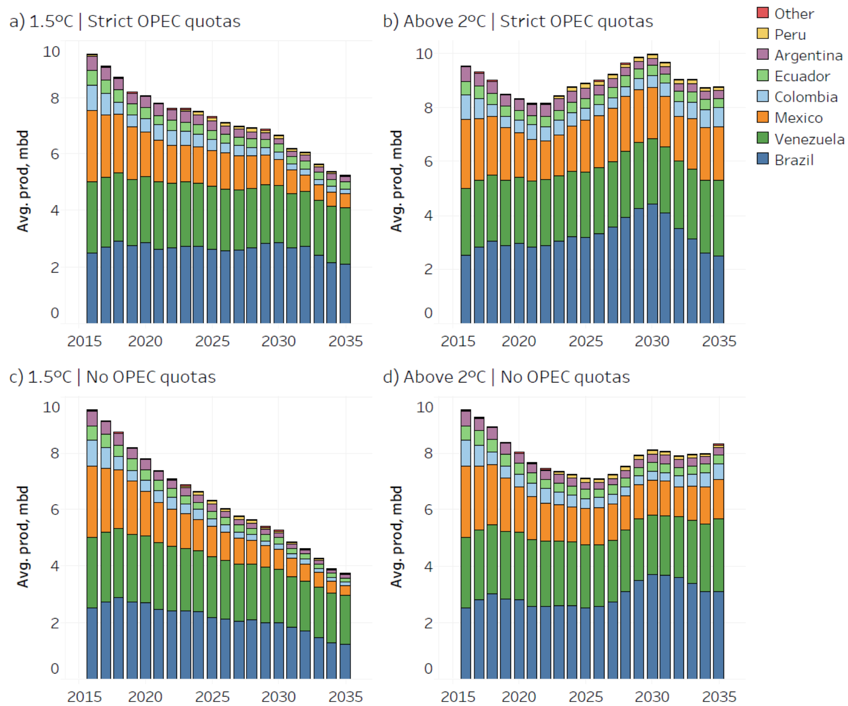


Figure 1. Oil production in LAC under different global demand and OPEC production scenarios, 2016-2035. a) aggregated production for the LAC region under all simulations. b) average oil production by LAC country for selected scenarios.

The production outlook varies considerably at the country level. Figure 2 shows production trajectories for the three top producers in the region: Brazil, Mexico and Venezuela. Across all three countries, global oil demand and OPEC's production are the main drivers of production, although the variability within these groups highlights the impact of different fiscal regimes. Despite Venezuela being part of OPEC, the cases with strict quotas result in higher oil prices globally and pushes production up to the cap, while in the cases without quotas, Venezuelan production sits well below the capped level.

Brazil shows the highest variability in production; from nearly doubling its 2016 oil production (2.5 million barrels day, *mbd*) in the most optimistic Above 2°C scenario (red group), to almost halving production under the least optimistic 1.5°C scenario (light blue group). Production in Mexico declines from 2016 until the early- to mid-2020s, at which point oil field development increases, especially under Higher 2°C and Above 2°C demand scenarios. The impact of large global producers is also clearly shown for both countries by observing the different trajectories for the strict and no OPEC constraint cases under the 1.5°C oil demand.

In Venezuela, the outlook depends less on global oil demand than for other producers in the region, suggesting that their choice of fiscal regime (not highlighted in the figure) and those of other producers in the region play a significant role (see below). For instance, under the most optimistic Lower 2°C scenario, Venezuela could produce 3.1 mbd by 2035; in the least optimistic case for the same global demand and OPEC behaviour, it only produces 1.4 mbd.

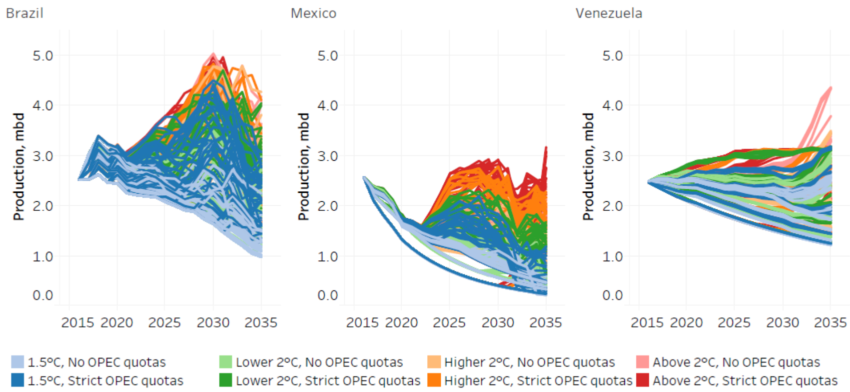


Figure 2. Oil production in Brazil, Mexico and Venezuela, by demand scenario, 2016-2035. Each line corresponds to one of our 480 simulations. In the legend, the numbers refer to the global demand under different temperature targets.

Government revenues from oil production

Production profiles are important for driving future revenues for government budgets. Figure 3 shows cumulative tax take (over the period 2016-2035) by country for the main regional producers. The range in total revenues is large and, like production, is driven by global demand and OPEC production quotas (or lack thereof). For instance, the interquartile range of tax take for Brazil goes from \$550bn to \$1,250bn. The scenarios above the interquartile range primarily correspond to Above 2°C OPEC-constrained cases (red coloured markers), where prices increase towards the end of the period (up to a \$350/bbl mean in 2035). Variability within the clusters is driven by differences in fiscal regimes across LAC (see below).

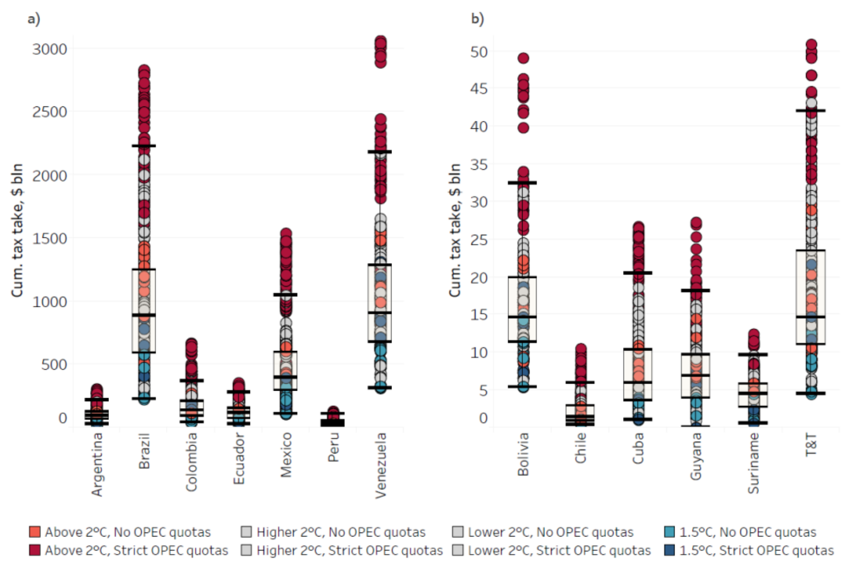


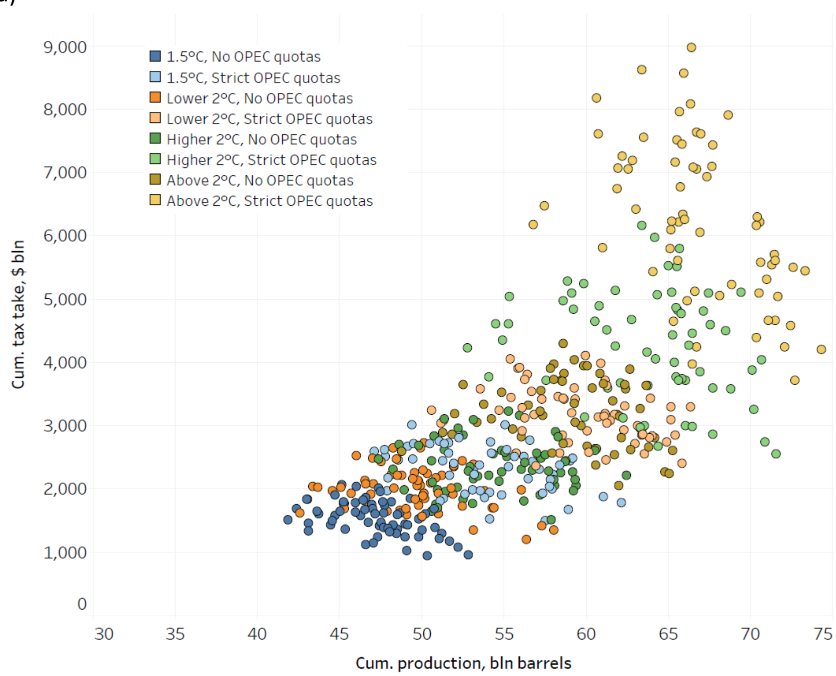
Figure 3. Cumulative government tax take by country and demand scenario (2016-2035). Each dot represents one of the 480 simulations. In box-and-whiskers plot, median and interquartile (IQ) range are shown. Whiskers extend to 1.5 times the IQ range. a) Large oil producers in LAC; b) Small oil producers in LAC. The abbreviation T&T refers to Trinidad and Tobago.

When the cumulative production for LAC is plotted against revenues for government, we observe a positive correlation, with higher tax take associated

with higher production (Figure 4a). Figure 4a shows the impact of different global demand levels on regional production, ranging from 42 to 74 billion barrels; and on tax take, with governments receiving between $1,000 and $9,000 bn. Of interest is that there are wide variations in tax take at similar levels of production (and vice versa), and that it is global demand and OPEC behaviour that largely drives this variation.

The Above 2°C OPEC-constrained scenarios (brown markers) see the highest tax take and production levels, whilst the 1.5°C OPEC-unconstrained (light blue) see the lowest. The difference in tax take between brown and yellow markers reflects the impact on oil price of constrained production from OPEC countries under the highest demand case. For any given combination of global demand and OPEC production, the variability is driven by the choices of fiscal regimes by LAC governments (see below).

a)



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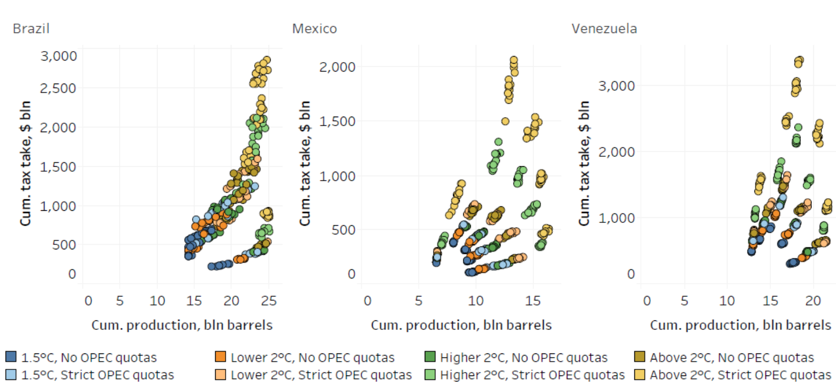


Figure 4. Cumulative production (billion barrels) versus cumulative tax take ($bn) for a) LAC and b) selected countries, 2016-2035. Each dot represents one of the 480 simulations. Colour denotes demand case, colour shade the OPEC production scenario.

For the largest producers, Brazil, Mexico and Venezuela, it is again global oil demand that is a key driver for government tax take (Figure 4b). The highest tax take and production are observed in Above 2°C scenarios, although not in all simulations. In Brazil, tax take ranges from $500 bn to $3,000bn and production from 14 to 25 billion barrels by 2035 in the Above 2°C scenarios; for Mexico, these demand scenarios range from $7 to $16 bn barrels of cumulative production in 2035, with a tax take range of $100-$2000 bn. Similarly, Above 2°C scenarios in Venezuela can lead to a tax take between $300 and $3,300 bn and production between 13 and 23 bn barrels. This variation for a given global demand is linked to fiscal regime sensitivities for these three producers, as well as to the tax configuration in the rest of LAC. Argentina, Ecuador and Colombia see a similar distribution to that observed for the top regional producers, showing a correlation between production, demand level, and fiscal regime and intensities; albeit at much lower levels of production and tax take (Supplementary Figure 5).

The influence of fiscal regimes

To highlight the impact of fiscal regimes, Figure 5 shows production versus government tax take in Brazil, Mexico, and Venezuela, in scenarios with no OPEC quotas, and 1.5°C and Above 2°C demands. The choice of tax rates and regime type have an impact on production and tax take, and therefore indicate possible levers to maximise revenues, particularly in cases of reduced demand; however, fiscal scheme choices may also decrease revenues. For example, in Brazil, a high rate under production sharing contracts, in the Above 2°C demand case could increase the revenue take up to 30% at a production level that is 20% lower than the low rate case; but an alternative low rate concessionary regime could potentially halve the current tax regime revenue. In the 1.5°C demand case, the difference in cumulative tax take between the current rate case and its low and high rate variants is smaller, but following a similar pattern to the Above 2°C demand case; higher tax rate scenarios show 15% less cumulative production than low rate ones, but with higher tax take.

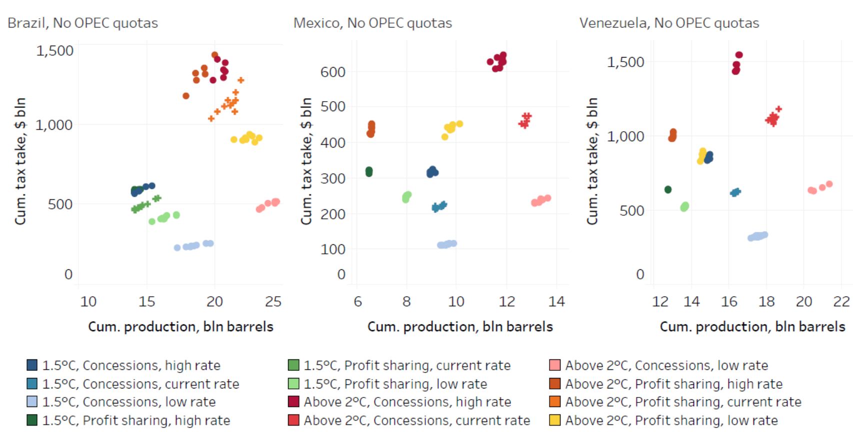


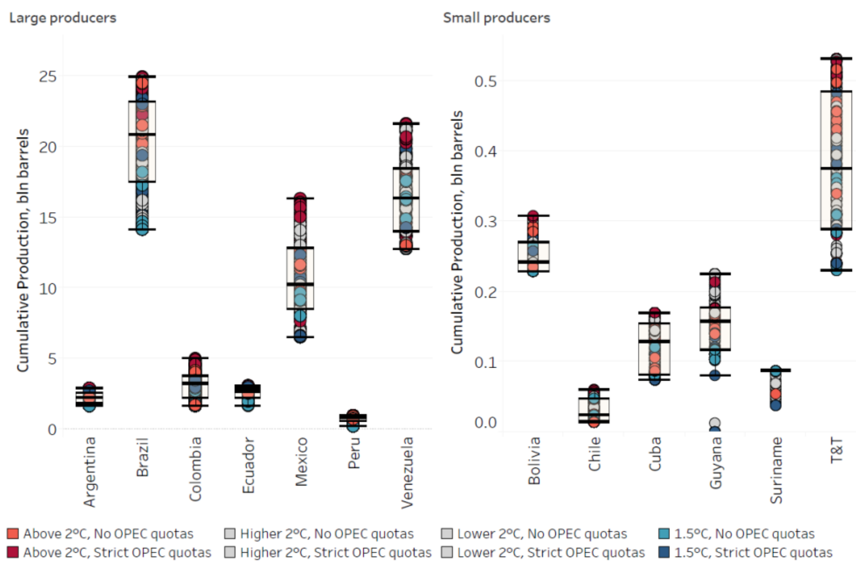
Figure 5. Cumulative tax take and production under 1.5°C and Above 2°C demand scenarios with no OPEC quotas in Brazil, Mexico and Venezuela, 2016-2035. Each dot represents the high and low tax rate simulations, with crosses representing current tax regime scenarios. Colour denotes demand case, colour shade the tax rate scenario. These simulations highlight that tax take under current tax regimes is nearly halved in 1.5°C compared to Above 2°C scenarios; alternative tax regimes as revenue levers are not sufficient to compensate losses in cases of reduced demand.

With production sharing contracts, the change in tax rates (doubling or halving of profit oil share) has less impact on tax take, resulting in slightly higher revenue in the higher tax rate scenarios despite having, in many cases, a reduced production level. In comparison, with concessions, a higher tax take can be achieved, but also a lower tax take at increased production levels. These differences are more significant in higher demand scenarios; tax regimes have less impact on production and tax take in lower demand cases. Overall, profit sharing contracts appear to be more attractive across most scenarios, since they can achieve competitive levels of revenue with less production.

Cumulative production and unused reserves

Figure 6a shows cumulative production by country. The outlook is dominated by Brazil, Venezuela and Mexico with between a 10 to 22 billion cumulative barrels median production. A second set of mid-sized producers includes Argentina, Colombia, Ecuador and Peru, in the 1-3 billion barrels range. All see large ranges in potential cumulative production. Finally, smaller producers are those with a cumulative production of less than 500 million barrels. Interestingly, a few countries experience almost no production at all, including Barbados, Belize, Costa Rica, Guatemala, Nicaragua, Paraguay and Uruguay, but are not presented.

a)



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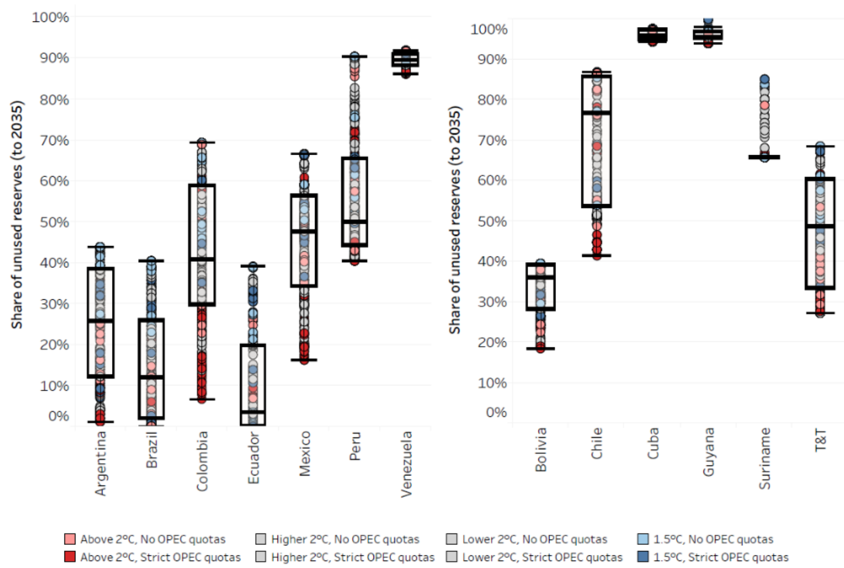

Figure 6. a) Cumulative production range per country under all demand cases, and b) unused reserve range, both for the period 2016-2035. Note that this plot estimates the shares of unused 3P reserves. Larger producers are in the left panel plots, and smaller producers in the right panel plots. The abbreviation T&T refers to Trinidad and Tobago.

Figure 6b compares cumulative production with 3P reserves (proved, probable and possible as of 2016, Supplementary Table 1), to derive unused or unburned reserves in 2035 — except for Venezuela, most LAC producers are exploiting most of their 2P reserves (proved and probable reserves) by 2035 in our modelled scenarios. We find that 66-81% of 3P reserves in LAC are unburnable; excluding Venezuela which dominates, this range is 16-56%.

The range of estimates of unused reserves reflects the high uncertainty of production over the next 20 years. They raise questions about prospect for use after 2035, if and when climate targets will set stronger limits on oil demand. Specific mid-range producing countries such as Argentina and Ecuador show a higher proportion of their reserves used while some of the countries with much larger reserves, notably Venezuela, have high shares of unused reserves. Some of the smaller producers, notably Chile, Peru, Guyana and Trinidad & Tobago, are particularly at risk given their relatively small reserve base, production costs and apparent sensitivity to wider regional production patterns.

The challenge of future uncertainty for LAC oil producers

This analysis highlights that LAC producers face tremendous uncertainty on production and tax receipts returns over coming decades, driven by climate policy and technological change reducing demand for oil, and by the production output of major producers in OPEC. These uncertainties reinforce the message that all reserves may not be bankable today[16,18,19]; they do not necessarily translate into production, nor revenues to government. There is considerable uncertainty as to what future production levels might be – and therefore planning taking account of this uncertainty is critical.

After 2035, with oil demand dropping to very low levels by the middle of the century under the most ambitious climate scenarios, unused reserves will be more difficult to exploit, as the global price of oil continues to fall. For some countries, the range of estimates is very wide (e.g. Colombia, Chile, Trinidad and

Tobago), suggesting that the production is sensitive to the changes in market conditions, driven by changing prices and production levels in other countries. Some countries see much stronger use of reserves, notably Brazil, Argentina and Ecuador, implying a more cost-effective resource base. Other countries, such as Guyana and Venezuela, see much higher unused shares.

The extent to which LAC producers will be able to compete after 2035 for a diminishing market will require further analysis. What is clear is that market conditions could become tighter, and higher cost reserves may struggle to attract investment. In our 1.5°C scenarios, the price is around $50 in 2035, meaning many projects will remain uneconomic. The lack of control across these global sources of uncertainties suggests that a robust approach would be to ensure that LAC public budgets were not heavily dependent on oil revenues, and that increasing diversification across the economy is critical; in particular for countries where the importance of oil has increased in recent years, such as Bolivia, Colombia or Ecuador.

As countries undertake domestic planning around infrastructure and the broader economy, and feed into the Paris Agreement process via reporting on emission-reduction strategies, consideration of global oil demand will be crucial. Research has considered such prospects in a low carbon world, but more needs to be done to reflect the uncertainty, and the implications of different outlooks for government oil revenues.

In summary, this analysis highlights the need for consideration of uncertainty, to highlight not only the potential prospects for developing oil reserves, and the benefits to public revenues, but also the worst-case outcome. To illustrate, by 2035, Chile could have exploited 50% of its reserves, or only 15%. This has major implications for the long-term budgetary planning, the questions of economic diversification, and the types of incentives and fiscal regimes governments might want to consider.

Methods

This paper uses a scenario-based approach, based on the XLRM framework[25], to explore the implications of uncertainty on LAC oil producers, and the production outlook to 2035. We use the model BUEGO as the ‘scenario generator’ in which to simulate the effect of different sources of uncertainty. The XLRM framework helps to organize the relevant data and assumptions that are required to feed into the modelling. The different elements of the framework are as follows –

X: Exogenous uncertainties.

These are the multiple uncertainties that effect global demand for oil, including economic growth, demographic change, environmental constraints reflected through policy and societal shifts, and geo-political factors influencing oil markets. In BUEGO, these uncertainties include global oil demand, and the behaviour of the OPEC group in setting production quotas.

L: Policy levers.

There are a range of policy levers that could be considered for addressing the uncertainty for oil producers, including incentives to make production more profitable, and the fiscal regime in place that determines the share of profits returned to government. Other policies may relate to diversification away from oil, or indeed a moratorium on exploration (as in Costa Rica and Belize), with a focus on driving foreign investment and growth through other sectors of the

economy. In this analysis, we explore this by varying the type of fiscal regime in place over the modelling time horizon, and the level of tax rate assumed.

R: Relationships.

This reflects the outcomes of the uncertainties (X) and policy interventions (L) on the future outlook for oil production. These relationships are represented in and simulated using the BUEGO model, leading to multiple states of the world as reflected by the resulting scenario ensemble. Below we describe BUEGO, its underlying formulation, including how it simulates resulting production trajectories.

M: Measures. These are the performance standards (or criteria) against which future states of the world are judged to be desirable or not. For the purposes of this analysis, we use a criteria based on revenues generated for public budgets, to identify scenarios producing the largest tax take.

Scenario definition

To explore the uncertainty of future production for LAC, we have developed a range of scenarios to be simulated by BUEGO, which include the following dimensions -

1. Four global demand levels based on the median from scenarios of oil production under different temperature targets, including Above 2°C, Higher 2°C, Lower 2°C, and 1.5°C. These scenarios are sourced from the IAM database used to inform the IPCC SR1.5 report (see Supplementary Figure 1)[20].
2. OPEC countries being subject to strict production constraints or not. The production constraints are shown in Table 1. The methodology used to simulate OPEC behaviour is the one used by McGlade, 2013[22]. Caps have been imposed on annual production, which are set at the maximum historical annual production levels since 2000.
3. Three fiscal regime cases have been used: the regime in place for each LAC producer with its current tax rate and two fiscal regimes with low and high rate variants. These production based regimes, namely concession-based and production sharing contract (PSC), have been selected as scenario variants due to their current widespread use in the region.
4. Two tax rate levels, high and low, under each of the regime variants, estimated by simply doubling or halving the current regime level. The current regime levels can be found in Table 4 of the Supplementary Information. For those LAC countries without a PSC regime in place, a fixed contractor share of 25% has been assumed for a high tax take rate and 75% for the low case. For those producers without a concession regime, a royalty of 30% and a tax rate of 37.5% have been assumed for the high rates case, while a royalty of 10% and a tax rate of 12.5% have been assumed for the low rates case. This value range has been considered to be representative of what other countries in the region have in place.

Table 1. OPEC production constraints assumed over the period 2017-2035

Country	Maximum daily production rate (mbbl/d)
Algeria	1.7
Angola	2.0
Libya	1.7
Nigeria	3.0
Ecuador	0.5
Venezuela	3.1
Kuwait	2.3
Iran	4.0
Iraq[2]	5-10.0
Qatar	1.0
Saudi Arabia[1]	11.1
UAE	2.9
Total	38-43

[1] Production from the Neutral Zone is split equally between Kuwait and Saudi Arabia
[2] Iraq is subject to a 4.5 mbbl/d cap up to 2019; and a 7 mbbl/d from 2020.

To derive our uncertainty combinations, we use Latin hypercube sampling (LHS), which allows us to minimise the number of runs necessary to accurately represent the variability of our uncertainty space[26]. This draws from the following options in Table 2, to construct 480 combinations. Therefore, for each simulation, a single global demand and OPEC production variant is chosen, alongside fiscal regime type and rate for each LAC country. Note that the 'Other' category includes all LAC countries not individually listed; for those countries, all of which are smaller producers, they take the same fiscal regime type and level in each simulation.

Table 2. Uncertain variables by region for LHS combinations.

	Uncertain variable [choice of assumption]			
Region	Global oil demand [Above 2°C, Higher 2°C, Lower 2°C, 1.5°C]	OPEC constraint [Yes, No]	Fiscal regime type [Current, Concession, PSC]	Fiscal regime level [Current, High, Low]
Global				
Argentina				
Bolivia				
Brazil				
Colombia				
Ecuador				
Mexico				
Peru				
Trinidad and Tobago				
Venezuela				
Other				

The BUEGO model

The Bottom Up Economic and Geological Oil field production model (BUEGO) is a medium term model that incorporates both economic and geological characteristics of oil production[22,23]. Characteristics include reserve levels, decline rates, capacity expansion potential, water depths, and capital and operating costs for over 7,000 producing, undiscovered and discovered but undeveloped oil fields globally. In addition, the fiscal regime of the country in which a field is located is represented. For a given global demand for oil, the model simulates the production capacity required to meet the production level for each future year iteratively. This is done by increasing the global price until sufficient existing production capacity is utilised and new capacity invested in, based on the economics of different field level project (including fiscal regime). Projects come on line where a positive net present value is realized. Equation 1 presents the NPV calculation used in BUEGO.

$$NPV = \sum_{t=0}^{N} \frac{p_t q_t - tax_t(p) - cost_t}{(1+\delta)^t} \quad (1)$$

where N is the lifetime of the project (assumed to be 30 years), p_t is the oil price, q_t is the grow number of barrels produced in that year, tax_t the taxes paid in that year, δ is the project specific discount rate and $cost_t$ the capital and operational costs at time t.

Therefore, for each year out to 2035, the model provides the minimum oil price required to meet global demand. It also provides the production at a field and country level, the necessary investment level, and the tax take by national governments.

The oilfield database in BUEGO is largely based on the model by Miller, as described in Bentley et al[27]. BUEGO includes all existing and prospective producers in LAC, as listed in Appendix 1. A range of updates have been made to BUEGO since (McGlade and Ekins, 2014)[23], including recalibration of current production to 2016 (from 2009), a review of reserve estimates and costs, and review of the fiscal regimes in each country. This was a large-scale effort, whereby country production totals were matched to IEA estimates[5]. A particular focus was given to updating production and reserves for LAC countries; for large and medium LAC producers, these were informed by national statistics[30-35], when publicly available.

The supply cost curves used in the BUEGO model illustrate the resource uncertainty existing at different cost for a given country, region, resource category, or any combination of these. A detailed description of how these supply cost curves were generated can be found in (McGlade and Ekins, 2014) [23]. Within these oil cost curves there is predominance of certain regions at given cost levels. Middle Eastern OPEC countries dominate the low-cost resource, holding nearly 50% of the resource available below \$40/bbl. Canada and Venezuela control 25% and 20% respectively of the resource available at \$40-70/bbl while the US controls nearly 45% of the resource available over \$70/bbl.

Long, medium and short-term price elasticities of demand are used in BUEGO; a short-term elasticity of -0.05 and a medium and long-term elasticity of -0.15 are assumed by McGlade, 2013[22] This explains why the oil production profile in our Above 2°C scenarios is not higher and declines post-2030, in response to rising oil prices; in particular under OPEC-constrained scenarios (Supplementary Figure 2). It is also worth noting that some categories of oil are not included within

BUEGO, namely natural gas liquids (NGL), biofuels, kerogen oil and other Fischer-Tropsch liquids. While this is a limitation of the model, these oil categories are expected to play a relatively small role to 2035[22].

As described, the project economics in BUEGO are impacted by the fiscal regime of each country. Most of the countries in LAC fit into two main types of fiscal regime, as listed in Supplementary Table 3. Concession regimes involve taking a certain percentage of gross revenues (the royalty), and then levying a tax on profits. Other important factors in the regime design include the depreciation scale (capital allowance) for offsetting capital costs against future profits, and the number of years for which a tax loss can be carried forward.

Production sharing contracts incorporate the features of a concession regime but also include additional terms. The first is 'cost oil', a volume of production initially allocated to an oil company to cover its capital and operating expenditure, and is generally permitted to a maximum percentage of gross revenues, termed the 'cost recovery limit'. Cost oil allows for repayment of the costs associated with the project and is usually levied after any royalties have been subtracted ('royalty oil'). Oil remaining after royalty and cost oil is subtracted is termed 'profit oil', which is split between company and Government, and then typically taxed. Payments may be differentiated (using a sliding scale) based on the level of production or an R-factor. The R-factor is the ratio of revenue to expenses; revenues earned by the IOC from cost recovery and profit oil are divided by the cumulative expenses incurred during a specified period.

Each of the LAC countries has an associated fiscal regime, recently updated based on the latest information[28]. The types of regimes used in LAC are summarized in Supplementary Table 2. Service-based contracts are less prevalent in LAC. Such contracts pay a fee to the IOC for each barrel of oil produced above the total costs of the project, meaning the national oil company retains the ownership of the oil production. This differs to the concessionary model, where the IOC has ownership, or the production-sharing model, where joint ownership is in place[29].

As shown in McGlade, 2013[22], a given fiscal regime can have a serious impact on the tax take depending on the global oil price and project costs. The spread of tax take is enormous, from 40-90%. For the same illustrative project, the tax take in China increases by 15% as the oil price increases by $40/bbl, while India's tax take for example decreases by 6% as the project's capital costs increase. This shows the huge variability in tax take depending on regime set-up – and then exogenous price uncertainty.

The model typically holds the fiscal regime the same across all projects in a given country, and retains the same regime in the future. However, regime terms can change depending on the production of oil. To overcome this relatively static view of regimes, our scenario design builds in fiscal regime type and terms as key sensitivities.

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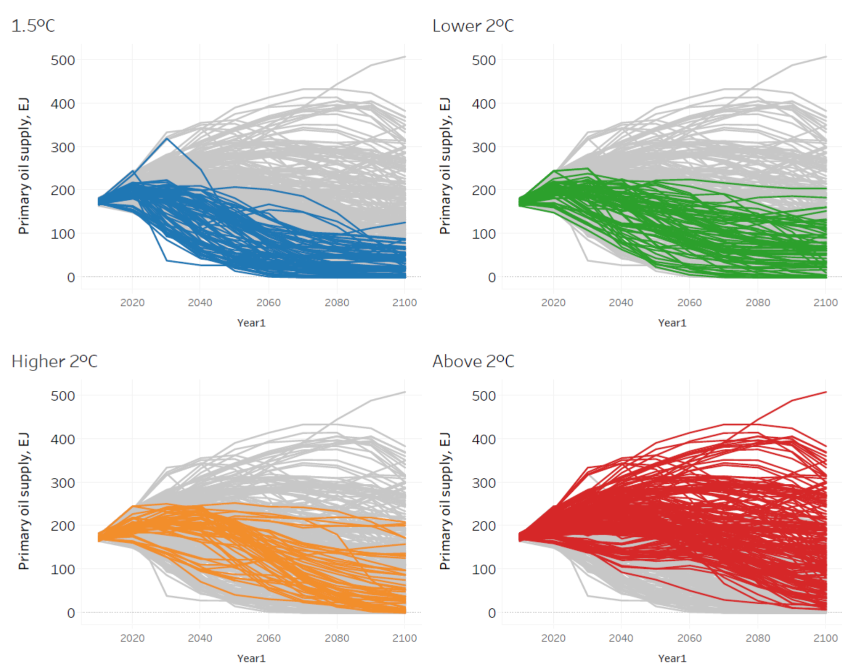
Supplementary Information

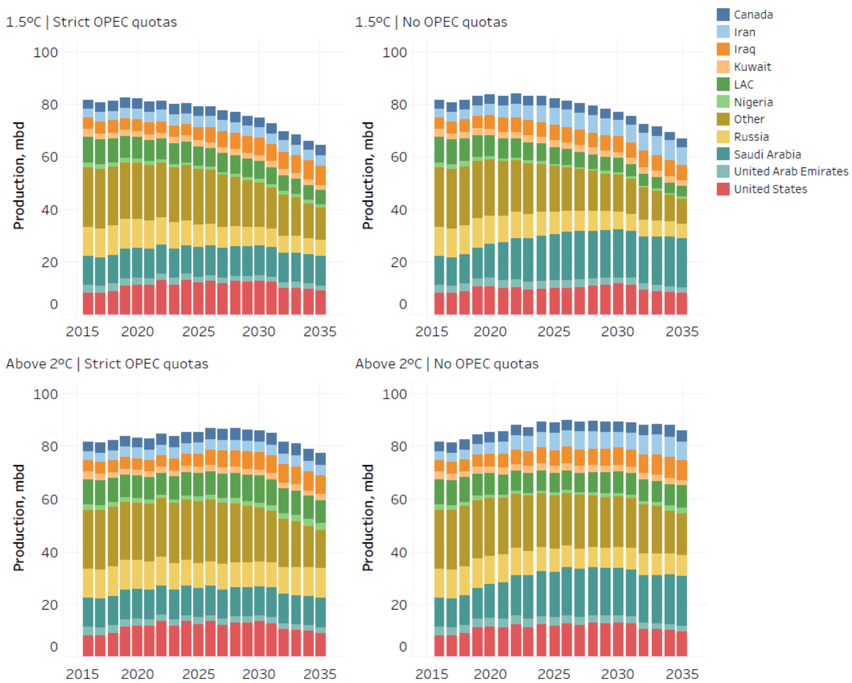
SI1. Global production outlook

The global oil supply trajectories that we use originate from the integrated assessment modelling community[20]. Four global demand levels based on the median from scenarios of oil production under different temperature targets, including Above 2°C, Higher 2°C, Lower 2°C, and 1.5°C.



Supplementary Figure 1. Global oil production trajectories across integrated assessment model scenarios[20]. Scenario groups under different climate objectives include a) 1.5°C, b) Lower 2°C c) Higher 2°C, and d) Above 2°C .

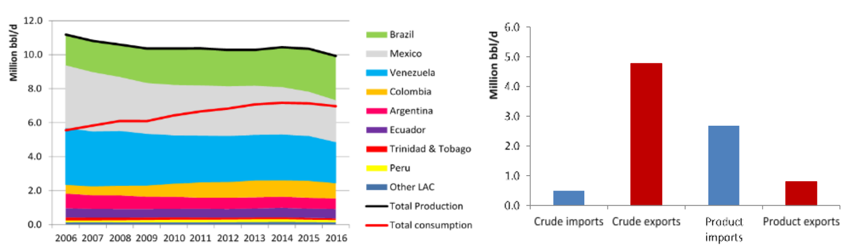
Supplementary Figure 2 shows the average global production in the lowest and highest global demand cases, showing the breakdown by region. The OPEC constrained cases illustrate the impact of constraints on the large producing countries, compared to when non constraints are assumed.



Supplementary Figure 2. Average global production by region under low demand (1.5°C, upper panels) and high demand (Above 2°C, lower panels) cases.

SI2. Oil reserve estimates, production and consumption in LAC

Production in the region accounts for 10% of global supply, at just over 9.9 million bbl/day, nearly half of which is exported[24]. Domestic consumption shows an upward trend, increasing over 1 million bbl/d in the last 10 years. A continued increase in regional consumption may allow LAC national oil companies to allocate new production to their own consumers, although at the expense of potential export gains.



Supplementary Figure 3. Left: Oil production and consumption in LAC (2006-2016). Right: Oil trade in LAC (average over 2006-2016). Source: BP Statistical Review of World Energy 2017.

Global reserves in BUEGO are informed by a range of sources that provide oil and gas data. These include the German Federal Institute for Geosciences and Natural Resources (BGR), the Energy Watch Group (EWG), IHS CERA, and

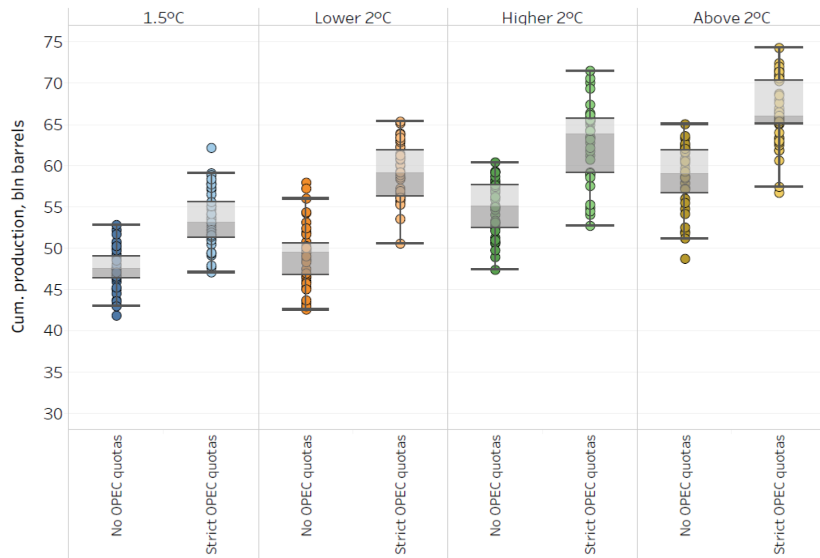
Deutsche Bank. Additionally, LAC reserves have been informed by national statistics[30-35] when publicly available. Supplementary Table 1 shows the 3P reserve values assumed to estimate unused oil shares in LAC.

Supplementary Table 1. 3P oil reserves for LAC countries

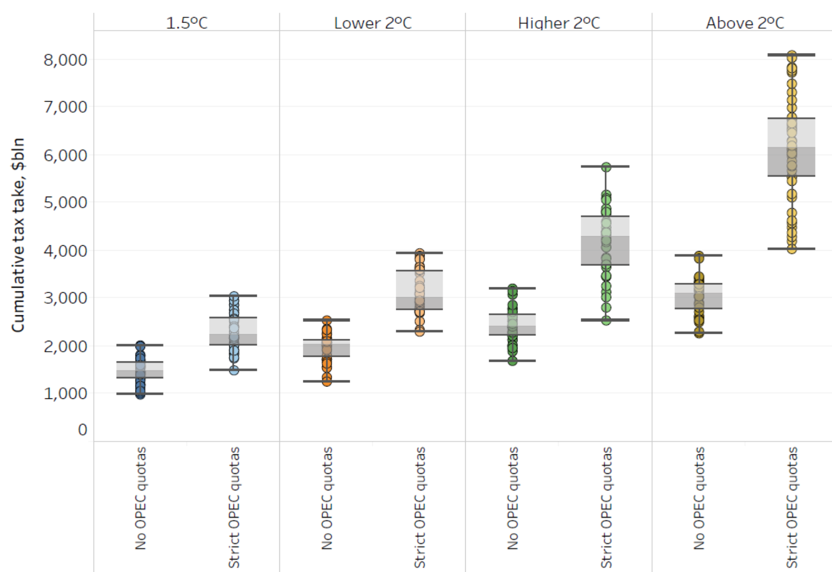
Country	3P reserves (Mbbl)
Argentina	2921.7
Barbados	1.6
Belize	16.8
Bolivia	376.1
Brazil	23630.1
Chile	102.6
Colombia	5321.0
Costa Rica	9.8
Cuba	2970.9
Ecuador	2695.2
French Guiana	403.7
Guatemala	89.4
Guyana	3558.6
Mexico	19455.0
Nicaragua	31.5
Paraguay	2.6
Peru	1526.4
Suriname	250.4
Trinidad & Tobago	728.0
Uruguay	3.7
Venezuela	155671.4
Total LAC	218893.5

SI3. LAC production and tax take estimates

Supplementary Figure 4a shows cumulative LAC production distribution by oil demand, highlighting the impact of OPEC quotas on regional oil production. Having OPEC quotas results in higher LAC production, while at higher global oil demand level OPEC quotas have a larger impact on regional production. This is reflected on oil revenue, as shown in Supplementary Figure 4b. The impact of OPEC quotas is larger on Above 2°C scenarios, reflecting higher LAC production and oil prices.

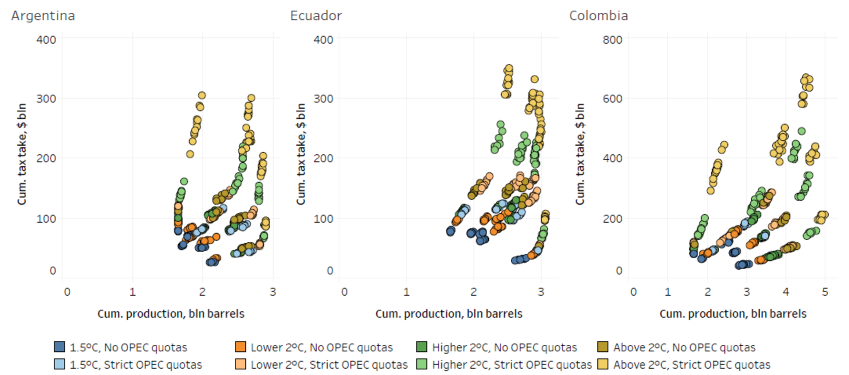


Supplementary Figure 4a. Cumulative LAC production distribution by oil demand level. The box plot shows the interquartile range (IQR), with whiskers extending 1.5 times the IQR.



Supplementary Figure 4b. Cumulative LAC tax take distribution by oil demand level. The box plot shows the interquartile range (IQR), with whiskers extending 1.5 times the IQR.

Global oil demand drives oil production for all LAC producers, including medium and small-sized ones. To illustrate this, Supplementary Figure 5 shows the variation in tax take and production under different global oil demand cases for Argentina, Ecuador and Colombia. For instance, in Argentina tax take ranges from $50 bn to $300 bn and production from 1.6 to 2.9 billion barrels by 2035 in the Above 2°C scenarios; for the 1.5°C scenarios, under a similar production range, revenue ranges from $30 bn to $120 bn.



Supplementary Figure 5. Cumulative production (bbl) versus cumulative tax take ($bln) for selected countries, 2016-2035. Each dot represents one of the 480 simulations. Colour denotes demand case, colour shade the OPEC production scenario.

SI4. Characterization of fiscal regimes in BUEGO

BUEGO (Bottom-Up Economic and Geological Oil field production model) determines the choice of oil field development and production across 7,000 fields, based on the global oil demand and the project NPV. The model works as follows; in each year, BUEGO iteratively increases the oil price to ensure there is sufficient production capacity, based on projects with positive net present value, to meet global demand. The oil price level at which production equals demand is the minimum price required to bring on the marginal project to meet global demand in a given year.

The NPV calculation used in BUEGO is as follows –

$$NPV = \sum_{t=0}^{N} \frac{p_t q_t - tax_t(p) - cost_t}{(1+\delta)^t}$$

where N is the lifetime of the project (assumed to be 30 years), p_t is the oil price, q_t is the grow number of barrels produced in that year, tax_t the taxes paid in that year, δ is the project specific discount rate and $cost_t$ the capital and operational costs at time t.

The cash flow for each project is standard across all fields. Each project has a lifetime of 30 years, with initial capital expenditure in year one and first oil produced in year three. Capital expenditure is spread over the first four years, with an assumption that 50% of capital is spent before production commences. The proportions are as follows: 20% in year one, 30% in year two, 40% in year three (when production starts), and 10% in year four.

Production between years three and thirty declines annually at the field specific decline rate. When calculating the NPV, a project takes the current oil price as constant over its lifetime. Discount rates are in the range of 11-15%, from OECD countries to higher risk non-OECD countries. The exception is capital intensive mining and in situ projects in Canada, which are assumed to require a 15% discount rate to provide additional security for the large investment necessary.

A key element of the NPV calculation is the tax charged by countries. All tax regimes in BUEGO can be classified into one of three categories: concession regimes, production sharing contracts ('PSC'), and service contracts. The

characteristics of the regime will have a strong impact on the level of tax take, such as the 'trigger points' (or project milestones) e.g. levels of gross annual production, internal rates of return, or the 'r-factor' (the ratio of cumulative receipts by a company to its cumulative expenditure). In general, as a project becomes more profitable, the host country will see increased taxes, royalties, or its share of profit oil (or a combination of all three).

Fiscal terms (royalties, taxes, and profit oil) vary significantly between these three categories and between individual countries. Terms also depend upon certain project milestones being achieved or exceeded. Such 'trigger points' include levels of gross annual production, internal rates of return, or the 'r-factor' (generally defined as the ratio of cumulative receipts by a company to its cumulative expenditure). In general, as a project becomes more profitable, the host country will increase taxes, royalties, or its share of profit oil (or all three).

The exact fiscal terms (e.g. the tax rate) were individually specified for all 133 countries within BUEGO. Six classifications were constructed that aided specification and identification of similar models of taxation. These are: concession terms that change with differing production levels (Concession/production), concession terms that change with differing r-factors (Concession/Rfac)), PSC terms that vary with production levels (PSC/production), PSC terms that vary with the r-factor (PSC/Rfac), PSC terms that vary with the internal rate of return (PSC/IRR), and service contracts. Obviously a country could also have tax terms that are static i.e. do not vary by production, r-factor etc. In these cases they are simply assigned to the relevant 'production' classification but with terms kept constant.

Twelve countries were also identified that impose specific or unique taxes or vary their share of profit oil in a manner unlike any other country and so do not fit neatly into these six classifications. Russia, for example, imposes an export tax, China applies an extra tax called the 'Petroleum Special Revenue Charge', Libya requires the oil company to undertake 50% of the capital expenditure but receive a maximum 15% of the production (with this percentage varying on a unique combination of annual production and the r-factor).

In Supplementary Table 2, the regime for each of LAC countries is shown. Four countries – Mexico, Argentina, Ecuador and Trinidad and Tobago – have country-specific regimes, while the rest can be categorised as described above, with most fitting into the 'Concession/production' category.

Supplementary Table 2. Overview of IDB member countries included in the BUEGO model

IDB borrowing country (plus Cuba)	Represented in BUEGO?	Individual fields	2016 production (000 tonnes)	Fiscal regime
Brazil	Yes	122	159400	Concession based on production
Venezuela	Yes	50	132974	Concession based on production
Mexico	Yes	80	120486	Country-specific
Colombia	Yes	72	45778	Concession based on production
Argentina	Yes	80	31996	Concession based on production
Ecuador	Yes	60	28045	Concession based on production
Peru	Yes	35	6519	Concession based on production
Trinidad and Tobago	Yes	25	4550	Country-specific
Bolivia	Yes	20	3204	Concession based on production
Cuba*	Yes	10	3201	Production sharing contracts based on production
Guatemala	Yes	10	492	Production sharing contracts based on production
Chile	Yes	25	245	Concession based on production
Barbados	Yes	3		Production sharing contracts based on production
Suriname	Yes	3		Production sharing contracts based on r-factor
Nicaragua	Yes	2		Concession based on r-factor
Belize	Yes	1		Production sharing contracts based on production
Paraguay	Yes	0		Concession based on production
Costa Rica	Yes	0		Concession based on production
Guyana	Yes	0		Production sharing contracts based on production
Uruguay	Yes	0		Production sharing contracts based on r-factor
Other non-OECD America			1233	

The parameters across these different regimes are provided in Table 4 and Table 5 below. Table 3 provides an overview of the parameters used in the different regimes.

Supplementary Table 3. Parameters considered in BUEGO characterisation of fiscal regimes

Fiscal regime	Parameters considered	Process
Concession based on production	a) Royalties, b) depreciation scale, e) profit tax rate, f) TLCF	Royalty rate is levied on total revenue, and dependent on production capacity. Profit tax levied on income, which is in turn offset by capex cost recovery over time (based on depreciation scale). TLCF is the tax loss carried forward (in years), allowing a company to only carry over losses occurred in a given year for X years, at which point if insufficient revenue is available to cover capital expenditures, then tax breaks are lost.
Concession based on r-factor	a) Royalties, b) depreciation scale, e) profit tax rate, f) TLCF	As per "concession based on production", except that tax rate dependent on r-factor. The r-factor is the ratio of cumulative revenue to cumulative expenditures. An r-factor of less than 1 means that costs have not been fully recovered yet: total expenditures exceed total revenue.
Production sharing contracts based on production	All inputs	After royalties determined (based on production capacity), cost oil is estimated, using c) max recovery factor. This is the maximum share of revenues net of royalties to cover expenditure. The remaining profit oil (Revenue-Royalty-Cost oil) is then split according to production capacity, and subsequently taxed.
Production sharing contracts based on r-factor	All inputs	As per "production shared contracts based on production", but royalties, profit oil share and taxes on profits based on r-factor.
Trinidad and Tobago	a) Royalties, b) depreciation scale, e) profit tax rate, f) TLCF	As per "concession based on production", but with an additional supplemental petroleum taxation (SPT) tax on taxable income, depending on oil price. SPT rates are as follows: 0% on <\$50; 33% on >\$50 to <\$90; 33% to 55% on >\$90 to <\$200; 55% on >\$200

Supplementary Table 4. Assumptions for current LAC country fiscal regimes: Royalty rates, depreciation, and maximum recovery

		a) Royalties (tax rate % for production up to level, 0000 bbl/day, or R-factors)								
Country	Tax regime type	Tax rate 1	Production level/R-factor 1	Tax rate 2	Production level/R-factor 2	Tax rate 3	Production level/R-factor 3	Final tax rate	b) Depreciation scale (years)	c) Max. recovery (%)
Argentina	Concession based on production	12	0	12	100	12	200	12	3	
Barbados	Production shared contracts based on	13	0	13	100	13	200	13	5	65
Belize	Production shared contracts based on	8	0	8	100	8	200	8	5	65
Bolivia	Concession based on production	50	0	50	100	50	200	50	5	
Brazil	Concession based on production	10	0	10	100	10	200	10	10	
Chile	Concession based on production	50	0	50	100	50	200	50	10	
Colombia	Concession based on production	8	5	10	400	23	600	25	5	
Costa Rica	Concession based on production	1	20	6	50	10	100	15	5	
Cuba	Production shared contracts based on	0	0	0	50	0	100	0	5	65
Ecuador	Concession based on production	12.5	30	14	60	18.5	100	18.5	10	
French Guiana	Concession based on production	0	1	6	2	9	6	12	5	
Guatemala	Production shared contracts based on	20	0	20	100	20	200	20	5	0
Guyana	Production shared contracts based on	0	0	0	100	0	200	0	10	75
Mexico	Country-specific									
Nicaragua	Concession based on r-factor	3	1	8	3	13	4	15	5	
Paraguay	Concession based on production	10	0	10	100	10	200	10	1	
Peru	Concession based on production	5	5	10	50	20	100	20	5	
Suriname	Production shared contracts based on r-	6	0	6	1	6	2	6	5	70
Trinidad & Tobago	Country-specific (close to concession based on production)	13	0	13	100	13	200	13	5	
Uruguay	Production shared contracts based on r-	0	0	0	1	0	2	0	10	60
Venezuela	Concession based on production	20	0	20	100	20	200	20	6	

Royalties: Royalty rates are percentage of gross revenues paid to Government. The rate depends on the level of production hit e.g. rate 1 is applied up to the production threshold of 'Production Level 1' (mbbl/day). Production above 'Production Level 3' is subject to 'Final tax rate'. For many countries, the tax rate does not vary by production.

Depreciation scale: no. of years over which a company claims back its development costs.

Supplementary Table 5. Assumptions for LAC country fiscal regimes: Profit oil split, tax rate, and tax loss carried forward (TLCF)

		d) Profit oil split (share to contractor, at thresholds based on production (000 barrels/day) or R-factors								
Country	Tax regime type	contractor share	stage 1	contractor share	stage 2	contractor share	stage 3	final share	e) Profit tax rate (%)	f) TLCF (tax loss carried forward, years)
Argentina	Concession based on production								35	5
Barbados	Production shared contracts based on production	50	25	43.3	50	36.7	100	30	0	
Belize	Production shared contracts based on production	95	25	91.6	50	88.3	100	85	25	
Bolivia	Concession based on production								25	3
Brazil	Concession based on production								34	30
Chile	Concession based on production								25	30
Colombia	Concession based on production								33	30
Costa Rica	Concession based on production								30	30
Cuba	Production shared contracts based on production	60	20	50	30	40	40	30	22.5	
Ecuador	Concession based on production								25	5
French Guiana	Concession based on production								23	5
Guatemala	Production shared contracts based on production	70	20	55	55	42.5	90	30	30	
Guyana	Production shared contracts based on production	50	0	50	100	50	200	50	0	
Mexico	Country-specific								30	
Nicaragua	Concession based on r-factor								30	3
Paraguay	Concession based on production								40	30
Peru	Concession based on production								31.5	4
Suriname	Production shared contracts based on r-factor	80	1	52.5	1.5	20	2	10	36	
Trinidad & Tobago	Country-specific (close to concession based on production)								35	30
Uruguay	Production shared contracts based on r-factor	38	1	45	1.5	50	2	60	25	5
Venezuela	Concession based on production								50	10