Unextractable fossil fuels in a 1.5°C world

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The 2015 Paris climate agreement pledged to limit global warming to well below 2 °C and to pursue efforts to limit the temperature increase to 1.5°C relative to pre-industrial times[1]. However, fossil fuels continue to dominate the global energy system and a sharp decline in their use must be realised to limit temperature increase to 1.5°C[2–7]. Here we use a global energy systems model[8] to assess the amount of fossil fuels that would need to be left in the ground, regionally and globally, to allow for a 50% probability of limiting warming to 1.5°C. By 2050, for fossil reserves, we find nearly 60% of oil and fossil methane gas, and 90% of coal must remain unextracted in line with a 1.5°C carbon budget. This is a large increase in the unextractable estimates for a 2°C carbon budget previously published[9], particularly for oil where an additional 25% of reserves remain unextracted. Furthermore, we estimate that, globally, oil and gas production must decline by 3% annually until 2050. This implies that many regions face peak production now or during the next decade, rendering many operational and planned fossil fuel projects unviable. We probably present an underestimate of the production changes required, because a greater than 50% probability of limiting warming to 1.5°C requires more carbon to stay in the ground and because of uncertainties around the timely deployment of negative emission technologies.

In 2015, McGlade and Ekins[9] set out the limits to fossil fuel extraction under stringent climate targets. They estimated that one-third of oil reserves, almost half of fossil methane gas reserves and over 80% of current coal reserves should remain in the ground in 2050 to limit warming to 2°C. They also highlighted that some countries would need to leave much higher proportions of fossil fuel reserves in the ground than others. Since 2015, the Paris Agreement and the Intergovernmental Panel on Climate Change (IPCC) have helped refocus the debate on warming limits of 1.5°C[1,10]. Multiple scenarios have been published, showing the additional effort required to limit global CO_2 emissions to net-zero by around 2050 to meet this target[11]. In this article, we extend the earlier 2015 work to estimate the levels of unextractable fossil fuel reserves out to 2100 based on 1.5°C (50% probability), using a 2018-2100 carbon budget of 580 $GtCO_2$[3]. We also provide insights into the required decline of fossil fuel production at a regional level, which will necessitate a range of policy interventions. We define unextractable fossil fuels to be the volumes which need to stay in the ground, regardless of end-use (i.e. combusted or non-combusted), to keep within our 1.5°C carbon budget.

Paris agreement compliant fossil fuel prospects

Fossil fuels continue to dominate the global energy system, accounting for 81% of primary energy demand[12]. After decades of growth, their rate of production and use will need to reverse and decline rapidly to meet internationally agreed climate goals. There are some promising signs, with global coal production peaking in 2013, and oil output estimated to have peaked in 2019 or be nearing peak demand, even by some industry commentators[13].

The plateauing of production, and subsequent decline, will mean that large amounts of fossil fuel reserves, prospects that are seen today as economic, will never be extracted. This has important implications for producers who may be banking on monetising those reserves in the future, and current and prospective investors. Investments made today in fossil energy therefore risk being stranded[14]. However, there continues to be a disconnect between the production outlook of different countries and corporates and the necessary pathway to limit average temperature increases[2].

A number of analyses have explored how fossil fuels fit into an energy system under a 1.5°C target. The IPCC's Special Report on 1.5°C estimates coal use only representing 1-7% of primary energy use in 2050, while oil and fossil methane gas see declines relative to 2020 levels by 39-77% and 13-62% respectively[3]. Despite strong declines, the use of fossil fuels continues albeit at lower levels, reflecting the assumed inertia in the system and continued use of fossil fuels in hard-to-mitigate sectors. Luderer et al. estimate that despite large scale efforts, CO_2 emissions from fossil fuels are likely to exceed the 1.5°C carbon budget and require high levels of carbon dioxide removals (CDR)[4]. Grubler et al.[5] explored efforts to reduce energy demand, significantly reducing role for fossil fuels, and removing the need for CDR deployment.

The extent of fossil fuel decline in the coming decades remains uncertain, influenced by factors such as the rapidity of the roll out of clean technologies and decisions about the retirement of, and new investment in, fossil fuel infrastructure. Indeed, while dependent on lifetimes and operating patterns, existing fossil fuel infrastructure already places a 1.5°C target at risk due to implied "committed" future CO_2 emissions[6]. The possible extent of CDR further complicates this picture. At high levels, this may allow for more persistent use of fossil fuels, but such assumptions have attracted significant controversy[7].

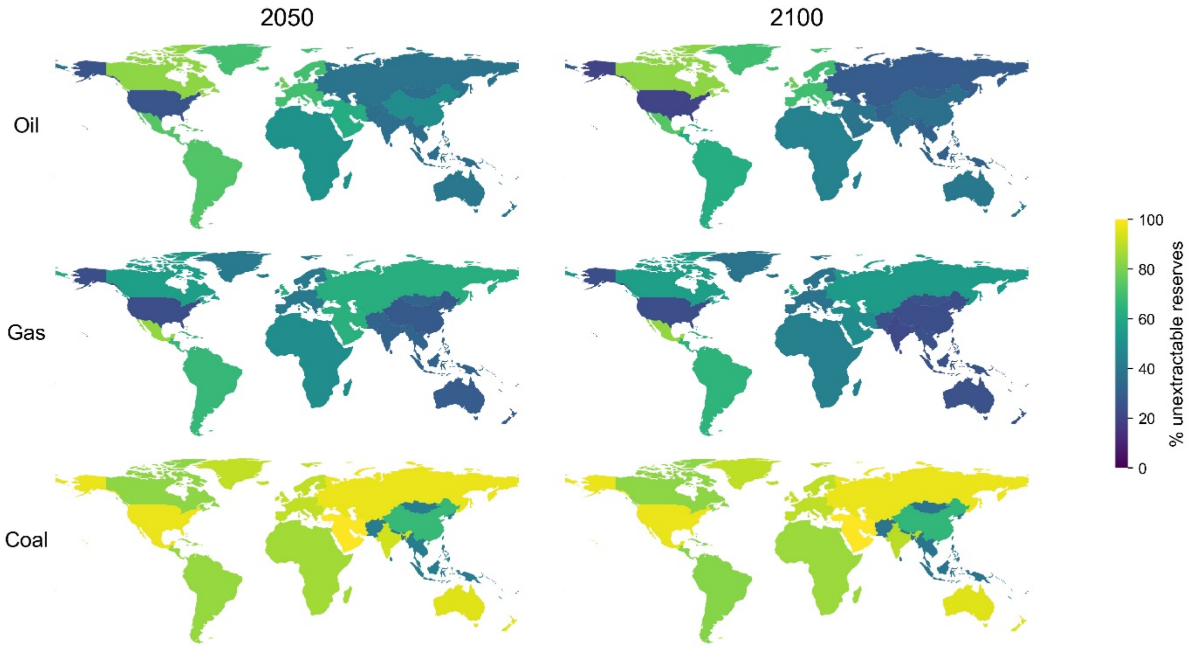
While a number of studies have explored fossil fuel reductions under a 1.5°C target, none have estimated the fossil fuel reserves and resources that have to remain in the ground. Here, using a global energy systems model, TIAM-UCL, we assess the levels of fossil fuels that would remain unextractable in 2050 and 2100.

Unextractable reserves under a 1.5°C target

Unextractable oil, fossil methane gas and coal reserves are estimated as the percentage of the 2018 reserve base that is not extracted, to achieve a 50% probability of keeping global temperature increase to 1.5°C. We estimate this to be 58% for oil, 56% for fossil methane gas, and 89% for coal in 2050. This means that very high shares of reserves considered economic today would not be extracted under a global 1.5°C target. These estimates are considerably higher than those in the McGlade and Ekins paper[9], who estimated unextractable reserves at 33% and 49% for oil and fossil methane gas respectively (Supplementary Figure 3). This reflects the stronger climate ambition assumed in this analysis, plus a more positive outlook for low carbon technology deployment, such as zero emission vehicles and renewable energy.

Continued use of fossil fuels after 2050 see these estimates reduce by 2100. For oil, the global estimate drops to 47% in 2100. The reduction is smaller for fossil methane gas, reducing from 56% to 50%. The majority of fossil fuels extracted post 2050 are used as feedstocks in the petrochemical sector, and as fuel in the aviation sector in the case of oil. Feedstock use, which has a substantially lower carbon intensity than combustion, accounts for 65% and 68% of total oil and fossil methane gas use respectively in 2100 under a 1.5°C carbon budget. However, it also reflects limited consideration of targeted actions to reduce feedstock use, which if available would limit the dependence on CDR.

Unextractable shares vary significantly by region, relative to the global estimates (Figure 1, Table 1). The largest reserve holders, such as Middle East (MEA; for oil and fossil methane gas) and Russia and other former Soviet states (FSU; for fossil methane gas) have the strongest influence on the global picture, and therefore have estimates close to or marginally above the global average. For oil, Canada has much higher unextractable estimates than in other regions, at 83%. This includes 84% of the 49 billion barrels of Canadian oil sands we estimate as proven reserves. In contrast, the FSU region has a relatively low unextractable share of total oil reserves (38% in 2050), reflecting their cost-effectiveness.



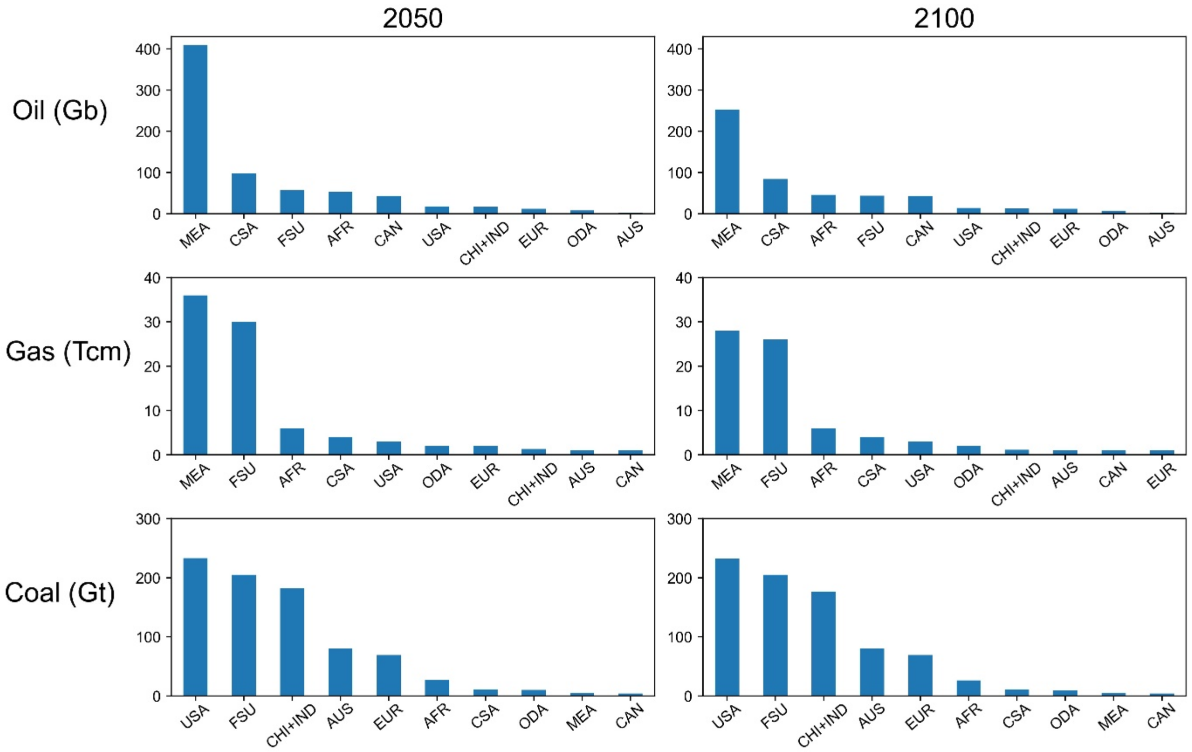


Figure 1. Unextractable reserves of fossil fuels by region in 2050 and 2100 under a 1.5°C scenario. The top panel shows the geographic distribution of the percentage of unextractable reserves broken out into the model regions. Note 13 out of 16 TIAM regions are plotted with Western and Eastern EU aggregated together and South Korea and Japan not shown given their negligible reserves. The bottom panel plots the absolute amount of each fossil fuel reserve that must remain unextractable. Note that, in some cases, the order of regions on the x axis changes between 2050 and 2100. Reserves are defined as both technically and economically proven given current market conditions. They can be further sub-categorised: currently producing, undeveloped but post/pending final investment decision, and undeveloped but sufficient field appraisal to meet SPE definition of technically and economically proven[15]. Additional detail on the definition of reserves in this work is provided in the methods section. Mapping Software: Python Version 3.8 (Python Software Foundation).

Given its role as a key exporter and with the lowest cost reserve base, the Middle East sees unextractable reserves of 62% in 2050, reducing to 38% by 2100. As previously mentioned, oil consumption post-2050 is dominated by non-combustible feedstocks and therefore action to reduce demand for oil-based products, e.g. plastics[16], would substantially change this picture for producers[17], including the Middle East. It is evident that large incumbent producers dominate the production picture going forward, with the vast majority of undeveloped (particularly unconventional) oil remaining unused.

Unextractable estimates for coal show less regional variation, although are lowest in those regions that utilise most coal in the next 30 years, notably India, China and other parts of Asia (ODA). However, even in these regions, coal consumption declines rapidly (see SI Section 6 for additional detail on coal decline).

Table 1. Unextractable reserves of fossil fuels (% and physical units) by region in 1.5°C scenario. Reserves are defined as both technically and economically proven given current market conditions. Additional detail on the definition of reserves in this work is provided in the methods section. For a breakdown of countries included in the aggregated regions of TIAM-UCL, see Supplementary Table 26.

Region	**Oil**				**Fossil methane gas**				**Coal**			
	2050		**2100**		**2050**		**2100**		**2050**		**2100**	
	%	***Gb***	**%**	**Gb**	**%**	**Tcm**	**%**	**Tcm**	**%**	**Gt**	**%**	**Gt**
Africa (AFR)	51%	53	44%	46	49%	6	43%	6	86%	27	85%	26
Australia and other OECD Pacific (AUS)	40%	2	40%	2	29%	1	25%	1	95%	80	95%	80
Canada (CAN)	83%	43	83%	43	56%	1	56%	1	83%	4	83%	4
China and India (CHI + IND)	47%	17	36%	13	29%	1	24%	1	76%	182	73%	177
Russia and former Soviet states (FSU)	38%	57	29%	44	63%	30	55%	26	97%	205	97%	205
Central and South America (CSA)	73%	98	62%	84	67%	4	65%	4	84%	11	82%	11
Europe (EUR)	72%	12	72%	12	43%	2	40%	1	90%	69	90%	69
Middle East (MEA)	62%	409	38%	253	64%	36	49%	28	100%	5	100%	5
Other Developing Asia (ODA)	36%	8	31%	7	32%	2	25%	2	42%	10	39%	9
USA	26%	18	20%	14	24%	3	24%	3	97%	233	97%	232

Global	**58%**	**740**	**42%**	**541**	**56%**	**87**	**47%**	**73**	**89%**	**826**	**88%**	**818**

Sensitivity analysis on key model assumptions was undertaken to explore the impact on unextractable reserve estimates (SI section 3). These include the rate of carbon capture and storage (CCS) deployment, availability of bioenergy, and growth in future energy service demands in aviation and the chemical sector given the challenges in their decarbonisation. We find that the sensitivities do not impact the unextractable estimates substantially, suggesting the headline results are relatively robust to uncertainties across key assumptions. Of the sensitivities, the availability of biomass (and therefore negative emissions potential from BECCS) has the most impact on unextractable estimates. Where higher biomass availability is assumed, unextractable estimates in 2050 for oil, fossil methane gas and coal are 55% (-3%), 56% (-3%), and 87% (-2%) respectively (change relative to central scenario in brackets).

Broadening out unextractable estimates to resources is important because a share of non-reserve resources come online in future years, and contribute to overall production and eventual emissions (SI section 1). For unconventional oil, their large size but also less favourable economics and higher carbon intensity means that 99% of these resources remain unextractable. A higher share of unconventional gas also remains unextractable (86%), relative to conventional resources (74%), again due to higher extractions costs in most regions, with the exception of North America. Across all regions where these are located, Arctic oil and fossil methane gas resources are not developed.

Production decline of major producing regions

Underlying the regional unextractable estimates of both reserves and the wider resource base are regional production trajectories. Figure 2 shows the outlook to 2050 for the five largest oil and fossil methane gas producing regions. The outlook is one of decline, with 2020 marking both global peak oil and fossil methane gas production, with decline thereafter to 2050 of 2.8% and 3.2% respectively (Supplementary Figure 7).

Apart from the US, all oil producing regions see strong declines to 2050 (Figure 2a). The US sees production growth to 2025, peaking at 16.9 mb/d, before constant decline out to 2050. This initial increase is due to several factors including falling imports of oil into the US, and the continued use of oil in the transport sector before strong growth in low emission vehicles, and the flexibility of light tight oil due to its production dynamics (i.e. high production growth and decline rates from tight oil wells).

For CSA, production shows modest decline of 1.1% per year to 2025, before a more rapid rate of decline of 3.5% out to 2050. The early slow decline reflects Brazilian fields with final investment decisions offsetting production decline of mature producing assets[18]. The Middle East, the largest oil producer, sees over a 50% decline by 2050 (relative to 2020). Given the huge reserves in the region, most production to 2050 is from designated reserves (85-91% in any given year). Elsewhere, oil production in Africa and FSU exhibits constant decline from 2020 out to 2050 at rates of 3.5% and 3.1%, respectively, driven by declining domestic demand and oil demand destruction in key importing regions (e.g. Europe).

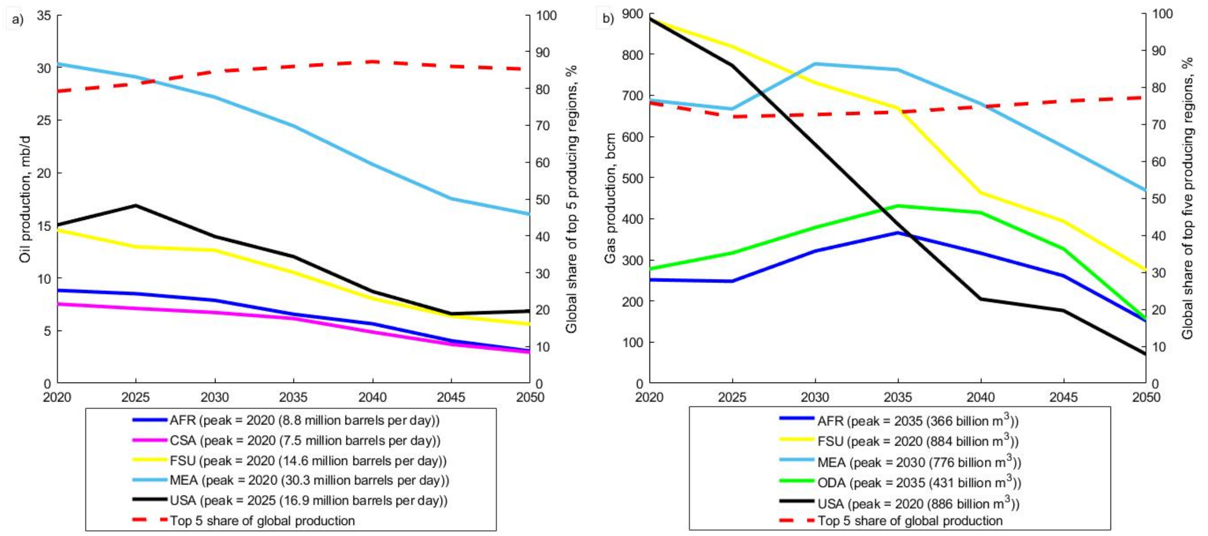


Figure 2. Production profiles for major oil and fossil methane gas producing regions, 2020-2050. a) Total oil production and b) total fossil methane gas production. The left hand y-axis shows the volume of production from each of the five largest a) oil and b) gas producing regions, whilst the right hand y-axis shows the global share captured by these incumbent producers. The legend shows the year and volume of peak production for each region.

Regional fossil methane gas production is a more complex story, due to its use to meet demand growth in emerging markets, and as an alternative to coal use in the industrial sector, notably in China and ODA (Figure 2b). Production in the US peaks in 2020, and sees rapid decline through 2050, with an annual derived decline rate of 8.1%. This mirrors a rapid decline in the domestic market, with complete phase out in use in the power sector by 2040. In addition, the high share of unconventional gas in the production mix exhibits faster decline than for other major producers. This has significant implications for US LNG exports, with prospects of low utilisation rates of infrastructure, and limited prospect for future additional liquefaction capacity. The FSU region sees peak gas production in 2020, but with production decline across legacy gas fields in Western Siberia and Central Asia moderated by the production increases from export projects to predominantly Asian (and particularly Chinese) markets and a shift of production to the Yamal Peninsula and East Siberia.

Three of the regions in Figure 2b see fossil methane gas production growth out to the 2030s, prior to decline. For the Middle East, this reflects the competitiveness of exporters in the region. For Africa, this growth is driven by increased demand for electricity, higher industrial demand (partially displacing oil), as well as modest growth in exports to 2035. For ODA, fossil methane gas gains domestic market share as coal is rapidly phased out of industry. However, there is significant uncertainty around the geological and economic feasibility of undeveloped resources, particularly for the two largest producers in ODA, Indonesia and Malaysia. The profiles for Africa and ODA also suggest significant transition risk, notably as post-2035 production rapidly declines at rates of 5.7% and 6.6%, respectively. This decline is due to the ramp-up in renewables crowding fossil methane gas out of the power sector and increasing electrification of industry. This transition risk also extends to large exporters, given rapidly changing import dynamics in regions like China. For example, Chinese gas demand peaks at 700 bcm (60% of which is imported) in 2035, before reverting to 2018 levels by 2050.

Reassessing fossil fuel production

The need to forego future production means country producers, fossil energy companies, and their investors need to seriously reassess their production outlooks. This is particularly true for countries that are fiscally reliant on fossil fuels, to allow for a managed diversification of their economies. Many regions are facing peak production now or over the next decade, and therefore, the development of new low carbon sectors of their economies that provide employment and revenues will be key. For regions heavily dependent on fossil fuels for fiscal revenue, this analysis echoes that of recent work suggesting huge transition risk unless economies diversify rapidly[19]. For example, Middle Eastern oil production needs to peak in 2020, which in combination with lower oil prices from demand destruction, signifies large reductions in fiscal revenue, with Iraq, Bahrain, Saudi Arabia and Kuwait currently relying on fossil fuels for 65-85% of total government revenues.

Central to pushing this transition forward will be the domestic policy measures required to both restrict production and reduce demand[20]. Increasing attention is being focused on supply-side policies that can complement carbon pricing and regulatory instruments that focus on demand[21]. Such policies act to curtail fossil fuels at the point of production and can include subsidy removal, production taxes, penalties for regulatory non-compliance and bans on new exploration and production[22]. The development of international initiatives, such as the proposed non-proliferation treaty on fossil fuels[23], is also key as they could serve to foster global action, as could existing frameworks like the UNFCCC[24].

The recent downturn in oil and fossil methane gas demand due to Covid-19 provides an opportune moment for governments to shift strategy[2]. The crisis has further exposed the vulnerability of the oil and gas sector in particular, and raised concerns about its profitability in the future[25,26]. With many fossil energy companies revising down their outlooks in 2020, this makes new investments risky. These risks are compounded by the momentum towards low carbon technologies, with continued falls in renewable energy costs and battery technology. Governments who have historically benefited should take the lead, with other countries that have a high dependency on fossil fuels but low capacity for transition or are foregoing extractive activities, needing to be supported to follow this lead[27].

The bleak picture painted by our scenarios for the global fossil fuel industry is very likely an underestimate of what is required and as a result, production would need to be curtailed even faster. This is because our scenarios use a carbon budget associated with a 50% probability of limiting warming to 1.5˚C, which does not consider uncertainties around, for example, earth system feedbacks[3]; therefore, to ensure more certainty of stabilising at this temperature, more carbon needs to stay in the ground. Furthermore, it relies on CDR of approximately 4.4 (5.9) $GtCO_2$ per year by 2050 (2100). Given the substantial uncertainties around the scaling of CDR, this dependency risks underestimating the required rate of emissions reduction.

Methods

In this section, we first describe the TIAM-UCL model, before presenting our approach to modelling scenarios. The remainder of the Methods section focuses on key issues of definition around geological categories and techno-economic classifications of fossil fuels.

Description of TIAM-UCL

To explore the question of unextractable fossil fuel reserves and resources under a 1.5˚C carbon budget, we used the TIMES Integrated Assessment Model at University College London (TIAM-UCL)[8,9,28,29]. This model provides a representation of the global energy system, capturing primary energy sources (oil, fossil methane gas, coal, nuclear, biomass, and renewables) from production through to their conversion (electricity production, hydrogen and biofuel production, oil refining), their transport and distribution, and their eventual use to meet energy service demands across a range of economic sectors. Using a scenario-based approach, the evolution of the system over time to meet future energy service demands can be simulated, driven by a least-cost objective. The model uses the TIMES modelling framework, which is described in detail in SI section 7.

The model represents the countries of the world as 16 regions (Supplementary Table 26), allowing for more detailed characterisation of regional energy sectors, and the trade flows between regions. Upstream sectors within regions that contain members of OPEC are modelled separately, so as an example, the upstream sector in the Central and South America (CSA) region will be split between OPEC (Venezuela) and non-OPEC countries. Regional coal, oil and fossil methane gas prices are generated within the model. These incorporate the marginal cost of production, scarcity rents (e.g. the benefit foregone by using a resource now as opposed to in the future, assuming discount rates), rents arising from other imposed constraints (e.g. depletion rates), and transportation costs but not fiscal regimes. This means full price formation, which includes taxes and subsidies, is not captured in TIAM-UCL, and remains a contested limitation of this type of model[30].

A key strength of TIAM-UCL is the representation of the regional fossil resource base (SI section 5). For oil reserves and resources, these are categorised into current conventional proved (1P) reserves in fields that are in production or are scheduled to be developed, reserve growth, undiscovered oil, Arctic oil, light tight oil, gas liquids, natural bitumen, and extra-heavy oil. The latter two categories represent unconventional oil resources. For fossil methane gas, these resources are categorized into current conventional 1P reserves that are in fields in production or are scheduled to be developed, reserve growth, undiscovered gas, Arctic gas, associated gas, tight gas, coal-bed methane, and shale gas. Categorisation of resources and associated definitions are described later in this Methods section. For oil and fossil methane gas, individual supply cost curves for each of the categories are estimated for each region (Extended Data Figure 1 (a) and (b)). These supply cost curves in TIAM-UCL refer to all CAPEX and OPEX associated with exploration through production, but do not include fiscal regimes or additional transportation costs[31]. Crucially, the upstream emissions associated with the extraction of different fossil fuels are also captured in the model.

The model has various technological options to remove emissions from the atmosphere via negative emissions, including a set of bioenergy with carbon capture and storage (BECCS) technologies, in power generation, industry, and in H_2 and biofuel production. The primary limiting factor on this suite of technologies is the global bioenergy resource potential, set at a maximum 112 EJ per year, in line with the recent UK Committee on Climate Change (CCC) biomass report[32]. This is a lower level than the biomass resource available in many other integrated assessment scenarios for 1.5°C (which can be up to 400 EJ/yr)[33,34], and is more representative of an upper estimate of the global resource of truly low-carbon sustainable biomass based on many ecological studies[35] (Supplementary Table 20). In addition to technological solutions for capturing carbon from the atmosphere, TIAM-UCL also models CO_2 emissions from land use, land use change and forestry (LULUCF) at the regional level based on exogenously defined data from the IMAGE model[36]. Here we use a trajectory based on that model's SSP2 RCP2.6 scenario which leads to global net negative CO_2 emissions from LULUCF from 2060 onwards.

In TIAM-UCL, exogenous future demands for energy services (including mobility, lighting, residential, commercial and industrial heat and cooling) drive the evolution of the system so that energy supply meets the energy service demands across the whole time horizon (i.e. 2005-2100), which have increased through the population and economic growth. For this paper, we use energy service demands derived from Shared Socio-economic Pathway 2 (SSP2)[37]. The model was also run with an elastic demand function, with energy service demands reducing as the marginal price of satisfying the energy service increases. Decisions around what energy sector investments to make across regions are determined based on the cost-effectiveness of investments, taking into account the existing system today, energy resource potential, technology availability, and crucially policy constraints such as emissions reduction targets. The model time horizon runs to 2100, in line with the timescale typically used for climate stabilisation.

In conjunction with a cumulative CO_2 budget, an upper limit is placed on annual CH_4 and N_2O emissions based on pathways from the IPCC's Special Report on 1.5°C scenario database[11] We select all pathways that have a warming at or below 1.5°C in 2100 and take an average across these scenarios to derive a CH_4 and N_2O emissions trajectory that is in line with a 1.5°C world. Further information on key assumptions used in the model is provided in SI section 6. The TIAM-UCL model version used for this analysis was 4.1.1, and was run using TIMES code 4.2.2 with GAMS 27.2. The model solver used was CPLEX 12.9.0.0.

Scenario specification

Extended Data Table 1 describes the scenarios used in this work and some key sensitivities to explore the impact on unextractable fossil fuels under a 1.5°C consistent carbon budget. For a 50% probability, this is estimated at 580 $GtCO_2$ (from 2018)[3]. On sensitivities, three key parameters were varied; i) the rate at which carbon capture and storage technologies can deploy; ii) the availability of bioenergy and therefore the potential for negative emissions through BECCS; and iii) the future energy service demands in aviation and the chemical sector which provide a significant challenge to decarbonise given their current total reliance on fossil fuels.

The lower level of bioenergy on sustainability grounds, compared with other IAM models[38], combined with a constrained role for Direct Air Capture (DAC), puts the global emissions trajectory in our central scenario between the P2 and P3 archetypes set out in the IPCC's Special Report on 1.5°C. Here, in our central case, BECCS sequesters 287 $GtCO_2$ cumulatively out to 2100 compared with 151 and 414 $GtCO_2$ for P2 and P3 scenarios respectively. Annually, BECCS use is 5 $GtCO_2$ in 2100 with a further 0.9 $GtCO_2$ being captured by DAC. This scale of engineered removals mean the central 1.5D scenario is on the edge of what is feasible, i.e. does not require a backstop to remove CO_2, within the current version of TIAM-UCL.

As such, while CDR has an important role to play in our scenarios, aside from 1.5D-HiBio, we do not see cases where global net negative emissions are in the range of 10-20 GtCO2 per year in the second half of the century which would enable a large carbon budget exceedance prior to net-zero. This in turn inherently limits the amount that global surface temperatures can exceed or overshoot 1.5°C prior to 2100 and, to some extent, reduces the exposure to the sizable long term risks associated with reliance on extensive negative emissions post-2050 as envisaged by P3 and P4 type scenarios[39].

For the low demand scenarios we derived an exponential annual growth rate for aviation (domestic and international) and the chemical sector based on Grubler et al.[5], considering regional variation between OECD and non-OECD regions. These growth rates were then applied to the calibrated historical data in TIAM-UCL and extrapolated forward to 2050 and 2100. These two sub-sectors were chosen due to relatively high residual emissions, and because specific policy direction can influence consumer demand (e.g. passenger demand for aviation and demand for plastics). More detail on the low energy service demand trajectories, and how these differ from our central 1.5˚C scenario, can be found in SI Section 3.

Defining geological categories and techno-economic classifications of fossil fuel resources

It is crucial that definitions for reporting are clearly set out, given the regular use of both geological and techno-economic terminology in previous sections, and their differing use in the literature.

Conventional and unconventional oil and fossil methane gas

Conventional oil in TIAM-UCL is defined as having an American Petroleum Institute (API) index greater than 10°; this reflects the 'density' of the oil and therefore its flow characteristics in the hydrocarbon bearing reservoir[31]. Conventional oil also includes light tight oil, gas liquids, and Arctic oil. Unconventional oil, which includes ultra-heavy oil and bitumen, generally has an API < 10° and therefore is extremely viscous with a very high density, typically requiring additional processing and upgrading to produce synthetic crude oil (SCO), which is comparable to conventional crude oil. The additional energy required for upgrading results in a more carbon intensive product and often with higher costs than conventional oils (shown in Extended Data Figure 1 (a)). TIAM-UCL also includes shale oil (kerogen), which we classify as unconventional. However, none of this is produced in any scenario conducted for this work, and therefore we have not included it within our unextractable resource estimates.

Conventional fossil methane gas refers to those resources in well-defined reservoirs, which do not require additional stimulation to recover economical volumes. It can be found in both gas-only reservoirs and associated with oil (associated fossil methane gas, either forming a gas cap or dissolved in the oil stream). Unconventional fossil methane gas refers to the gas-bearing reservoir, and whether additional technologies are required to initiate commercial flow rates e.g. hydraulic fracturing. In TIAM-UCL, this includes shale (low permeability shale source rock), tight (sandstone reservoirs with extremely low permeability), and coal bed methane (absorbed within coal matrices).

Conventional oil and fossil methane gas are split further into four main production categories, with i) providing the bulk of our reserve estimates, and the other three categories (ii-iv) included as resources.

i. Reserves. These include resources technically and economically proven at prevailing market rates. If the field is not developed, sufficient appraisal needs to have occurred to satisfy the condition of technically and economically proven. As described below, oil and gas reserves are considered on a 1P basis.

ii. Reserve additions. These are discovered but undeveloped accumulations which are either sub-economic, abandoned, or reservoirs in producing fields which have not yet been developed due to technical constraints or insufficient geological testing. Therefore, these can become reserves through improved efficiency, technical improvements, fossil fuel price increases, and additional geological testing.

iii. New discoveries. These resources of conventional oil and fossil methane gas can be geologically inferred to be recoverable (usually under different probabilities) without taking into account costs.

iv. Arctic oil and fossil methane gas. These include undiscovered and undeveloped conventional resources in the Arctic region. As discussed by McGlade[31], the categorisation of Arctic resources is based on economic viability (i.e. whether the field has been developed or any interest in development has been indicated), with the geographical extent defined by the USGS[40].

Unconventional oil and gas do not have the same disaggregation in terms of resource steps, with no distinct “proved reserves” step for unconventional oil and gas as with conventional reserves, but rather three different cost steps for the overall resource base. Therefore, we have identified volumes of unconventional oil and gas which we categorise as reserves, with the relevant cumulative production from these steps accounted for in the calculation of unextractable fossil fuel reserves.

Coal

Unlike oil and fossil methane gas production which naturally decline through time, coal is not susceptible to the same geological cost-depletion characteristics. Whilst significantly more attention is paid in this paper to oil and fossil methane gas, coal reserve levels were compared to recent data from the BGR[41]. Given the rapid phase-out of coal across our 1.5°C scenarios, a systematic review of uncertainties in the availability and cost of coal reserves and resources was not undertaken, however as mentioned static reserve and resource numbers were cross-checked with the BGR.

Reserve estimates for oil and fossil methane gas

Oil and fossil methane gas reserves are assumed to be recoverable with current technologies at current market prices or are currently producing. They are typically provided with a given probability of the reported volume being recovered at current market prices: the notation for this is 1P, 2P, and 3P, reflecting proved, probable and possible reserves. 1P reserves would be the most conservative, with a 90% probability of at least the reported volume being recovered. 2P reserves have a 50% probability, while 3P are the most speculative with a 10% probability of the reported volume being recovered.

In this paper, for reserve estimates we use the methods described by Welsby[42] for fossil methane gas and used a combination of publicly available data and the methods set out by McGlade[31] for oil (described in further detail in SI section 5). Both used discrete estimates of proven reserves, and combined these, assuming various degrees of correlation, using Monte Carlo simulations. For fossil methane gas, using a 1P basis, outputs from the reserve uncertainty distributions were then combined with a field level cost database, which was extended to non-producing fields using linear regression models. For oil, we have updated and recalibrated McGlade’s study using 1P estimates from public sources given these are the most up to date available. This allows for us to account for reserves of light tight oil in the United States[43], whilst maintaining the robust assessment of uncertainty conducted by McGlade[31]. The definitions follow SPE guidelines on what constitutes proved reserves to the greatest possible extent[15]. For example, McGlade[31] identified several key examples (the Middle East, Venezuela and Canada) where publicly reported estimates of oil reserves are likely exaggerated, including due to countries booking reserves for political leverage[44], and which provide the bulk of the variation between our 1P estimates and those reported by public sources[12,45–47]. Additionally, Welsby[42] identified the example of Russia where publicly reported 'proved' gas reserves (under an SPE definition) actually seem in reality to refer to Russian reporting standards where field economics are not considered within the definition of reserves[48,49]. The bottom-up assessment of reserves, utilising field-level data and accounting for the inherent volumetric uncertainty using probability distributions, is the main driver behind the systematically lower reserve numbers in this work compared to other publicly reporting sources. A detailed explanation of the method used to estimate reserves is provided in Section 5 of the Supplementary Information.

Resource estimates for oil and fossil methane gas

Resource estimates used in TIAM-UCL are based on the category of technically recoverable resources. These are a subset of ultimately recoverable resources, in that technologies assumed to be used in recovery are relatively static i.e. do not evolve. Oil resources were originally defined on a ultimately recoverable resources basis. Due to the sensitivity of resource estimates to the recovery factor, a Monte Carlo simulation method was used which combined uncertainty distributions of recovery factors with in-place unconventional volumes in order to generate aggregated country- and region-level volumes of ultimately recoverable unconventional oil[9,31]. Since their original estimation, updates have been undertaken to consider historical production (since 2010) and changes in both estimates of recoverable volumes and costs. For example, the revised volumes of ultimately recoverable extra-heavy oil and bitumen (EHOB) have been reconciled with recent technically recoverable resource estimates from the IEA[12].

For unconventional gas, there is a wide range of literature now estimating technically recoverable resources at individual play levels (at least for shale gas). Therefore, play-level uncertainty ranges of technically recoverable shale resources were constructed and combined using a Monte Carlo simulation to generate regional estimates of technically recoverable shale gas[42].These were then combined with cost depletion curves derived from statistically significant drivers of field supply costs for individual shale plays. This process is illustrated in Supplementary Figure 12. For tight gas and coal bed methane, country-level ranges were combined in a similar manner to generate regional estimates of technically recoverable resources.

Estimation approach for unextractable reserves and resources

The representation of fossil fuels in TIAM-UCL is driven by detailed bottom-up analysis of both the cost and availability of different geological categories of oil and fossil methane gas. McGlade[31] and Welsby[42] constructed supply cost curves for each region and resource category in TIAM-UCL using robust statistical methods to estimate the availability and cost of oil and fossil methane gas.

The supply cost curves of different fossil fuel resources in TIAM-UCL are shown in Extended Data Figure 1, with oil, fossil methane gas and coal split into the regions of TIAM-UCL. Additional information is provided in SI section 5. These supply costs represent costs associated with getting the fossil fuels out of the ground, but do not include transportation costs or taxes under different fiscal regimes. Therefore, they should not be considered as breakeven prices. The oil supply cost curve (Extended Data Figure 1 (a)) reflect the supply cost for a representative barrel of oil energy equivalent (boe), as the mining processes yield different energy commodities. For example, conventional oil reserves output a barrel of crude oil, whereas oil sand production processes output a barrel of bitumen, which may then have to be upgraded if it is to be used for certain downstream uses. This requires additional energy inputs and technology processes, the additional costs of which are not included in the supply curve although are captured in the processing sector of TIAM-UCL.

In order to provide full transparency and flexibility across the full hydrocarbon resource base, we extended our analysis in this study to unextractable fossil fuel resources (i.e. not just reserves), taking into account production from across the supply cost curves shown below. Crucially, fossil fuels are not necessarily extracted in cost order along the supply curve because additional constraints (at a region and resource category level) are included which control both the rate of production expansion and decline.

Constraints are based on McGlade[31], McGlade and Ekins[9] and Welsby[42], with each constructed from bottom-up databases of oil and gas fields (and individual wells for US shale gas), and allow TIAM-UCL to provide an empirically robust representation of 'depletion' characteristics of oil and fossil methane gas production. The decline and growth constraints are used to model both geological and techno-economic characteristics of oil and gas mining technologies, as well as some degree of inertia within the system. Additional information on how these constraints function, as well as underlying data assumptions, are provided in SI Section 5.

In this paper, resources beyond reserves are considered when estimating unextractable fossil fuels for a number of reasons. Firstly, the dynamic nature of 'reserves' means that resources can shift across the techno-economic feasibility matrix in either direction (i.e. resources can become reserves and vice versa). Therefore, considering the whole resource base allows us to expand away from the relatively restrictive definition of reserves, albeit necessarily increasing the uncertainty range away from the most certain recoverable volumes. Secondly, not all fossil production, particularly when moving out to 2100, is from the reserves base, due to constraints on production growth and decline, and trade. The full resource base needs consideration to capture non-reserve volumes. Finally, when analysing fossil fuel extraction under a 1.5°C consistent carbon budget, it is not just the supply cost hierarchy of different reserves and resources that drives the regional distribution of production, but the volume of CO_2 (and other GHG's) associated with those resources, and therefore the potential emissions from extraction and consumption.

Extended data figures and tables

Extended data Table 1: Description of scenarios explored in this work

Extended data Figure 1: Supply cost curves for oil (a), fossil methane gas (b) and coal (c) split by region in TIAM-UCL

Supply cost curve for oil (a), fossil methane gas (b) and coal (c) split by region in TIAM-UCL. Costs are on an energy content basis (barrel of oil equivalent for oil, British thermal units for gas, and joules for coal), on a $2005 basis. For oil, different mining processes output different commodities (e.g. oil sands mining initially (pre-upgrading) outputs a barrel of bitumen) hence the use of the energy content cost basis. For gas, associated gas is not included in Extended Data Figure 1 (b) as it is a by-product of oil production.

Data availability

The results data and key source data in the figures (including in the Supplementary Information) are provided in the Zenodo repository (DOI: 10.5281/zenodo.4725672).

Code availability

The underlying code (mathematical equations) for the model is available on GitHub (Link: https://github.com/etsap-TIMES/TIMES_model). The full model database is also available on Zenodo (DOI: 10.5281/zenodo.4725672). Given the complexity of the model, further guidance will be provided on model assumptions upon reasonable request.

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