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Supplementary information

Unextractable fossil fuels in a 1.5 °C world

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Unextractable fossil fuels in a 1.5°C world

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Supplementary Information

SI section 1. Estimates of unextractable resources under a 1.5°C scenario

Broadening out the 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. Resources include reserves but also a much wider range of the recoverable resource base (see Methods in main paper for definitions). Due to the much larger size of the resource base, the unextractable estimates are considerably higher than those for reserves (Supplementary Table 1). We do not include kerogen oil in our analysis, due to the fact it is not extracted even in lower ambition runs in TIAM-UCL.

For oil, the regions with large resource bases that are more carbon intensive and higher cost see a larger share unused. This includes Canada, where 92% of the Canadian oil resource base is heavy bitumen from oil sands, and Central and South America, where 65% of the resource base is ultra-heavy oil. The higher carbon intensity of production, and additional upgrading stages and energy inputs that lead to higher production costs, see these regions with some of the highest shares of unextractable oil resources.

For fossil methane gas, the FSU region sees the largest volume of unextractable resources out to 2100. This is driven by two main factors. Firstly, the FSU reserve base is sufficiently large to cover the bulk of production given declining demand in our scenarios. Secondly, the FSU region holds huge volumes of undiscovered fossil methane gas in the Arctic, which as mentioned previously, remain largely unextracted.

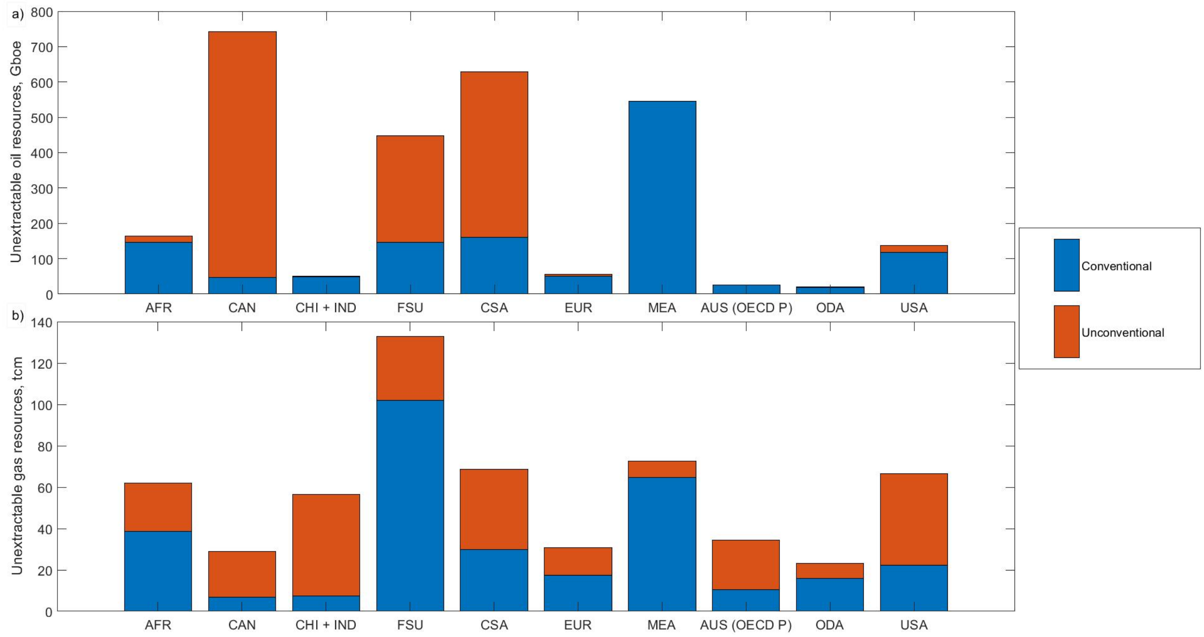
Supplementary Table 1. Unextractable resources of fossil fuels (% and physical units) by region in 1.5°C scenario. Resources refer to technically recoverable resources (see Methods in main paper for additional detail). Units include Gb = billion barrels of oil; Tcm = trillion cubic meters; Gt = billion tons (metric).

Region	**Oil**				**Fossil methane gas**				**Coal**			
	2050		**2100**		**2050**		**2100**		**2050**		**2100**	
	%	***Gb***	**%**	**Gb**	**%**	**Tcm**	**%**	**Tcm**	**%**	**Gt**	**%**	**Gt**
Africa (AFR)	74%	203	59%	164	88%	68	81%	62	91%	41	90%	41
Australia and other OECD PACIFIC (AUS)	86%	26	85%	26	92%	35	91%	34	99%	304	99%	304
Canada (CAN)	98%	739	98%	737	92%	30	89%	29	99%	70	99%	70
China and India (CHI AND IND)	64%	57	57%	50	85%	58	82%	57	95%	1,114	94%	1,109
Russia and former Soviet states (FSU)	82%	520	71%	448	88%	139	84%	133	99%	1,088	99%	1,087
Central and South America (CSA)	90%	665	85%	629	93%	70	92%	69	94%	31	93%	31
Europe (EUR)	74%	66	62%	55	87%	32	84%	31	97%	214	97%	214
Middle East (MEA)	73%	743	54%	546	80%	86	67%	73	100%	13	100%	13
Other Developing Asia (ODA)	50%	26	38%	20	69%	25	65%	23	94%	213	94%	212
USA	61%	200	42%	138	83%	69	81%	66	99%	867	99%	866
Global	81%	3,336	71%	2,905	86%	625	81%	590	97%	3,960	97%	3,952

In fact, across all regions where these are located, we find that Arctic oil and fossil methane gas resources are not developed. This is critical given continued exploration efforts in the Arctic region, despite the high cost, challenging operating conditions, and the threat oil and gas drilling poses to diverse and extremely delicate ecosystems. It is clear that there is an abundance of oil and fossil methane gas remaining across global regions in reserves to meet demand in a 1.5°C (50% probability) scenario, without the development of Arctic resources.

Supplementary Figure 1 breaks down unextractable oil and fossil methane gas resources into more detailed geological categories, namely unconventional and conventional resources. It highlights that unconventional resources account for a much larger share than conventional resources across most regions, with the exception of oil and fossil methane gas in the Middle East and Africa, and fossil methane gas in FSU. 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 fossil methane 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.

We have explored unextractable resource shares because of the dynamic nature of fossil fuel volumes across techno-economic classifications (discussed in detail in the Methods section) and because the growth and decline constraints on production technologies in TIAM-UCL (see SI Section 5) means that not all production out to 2050 (and beyond) will be from designated reserves. However, in our 1.5°C scenario, we find that over 75% of the total oil and fossil methane gas recoverable resource base must remain unextracted, and for coal the figure is even higher at 97%.



Supplementary Figure 1. Unextractable oil (a) and gas (b) resources in each region, 2018-2100. Note that arctic oil and gas is included in conventional resources. Conventional and unconventional oil refers to the density of the liquid found in the oil reservoir, whereas conventional and unconventional fossil methane gas refers to the geological structure of the reservoir (a full discussion, including definitions of conventional and unconventional oil and fossil methane gas can be found in the Methods section).

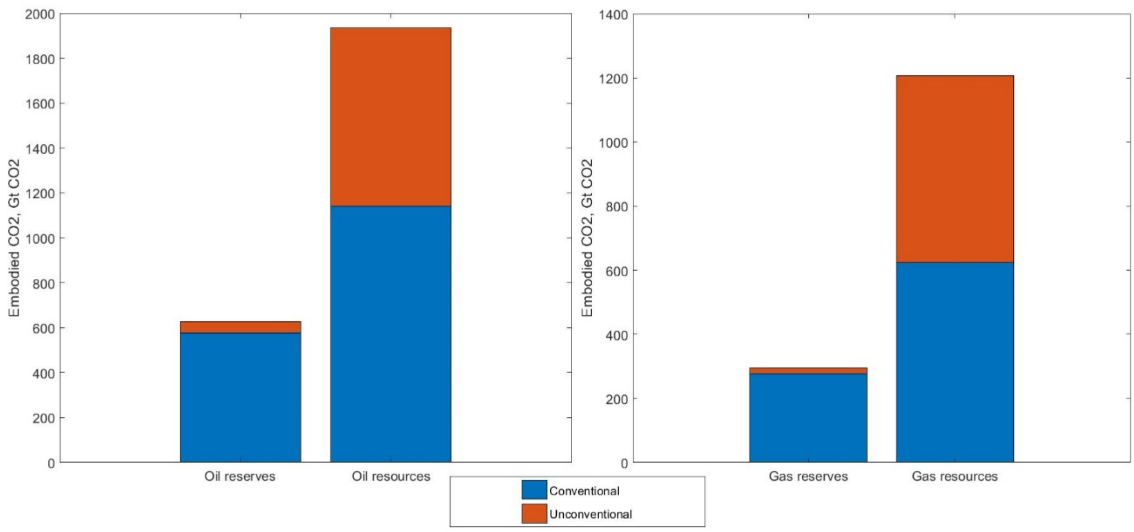
For reference, in terms of combined energy content, our total resource base across all fossil fuels is ~ 126 ZJ, with 9% of this produced in total by 2050, and 12% by 2100.

SI section 2. Embodied carbon in resources estimates, and comparison to McGlade and Ekins (2015) paper

Embodied carbon in resource estimates

To contextualise the unextractable fossil fuels number, we also estimate the total carbon contained in the resource base today. We express this in CO_2 emission terms (assuming the embodied carbon is combusted) to allow for ease of comparison with carbon budget levels. Supplementary Figure 2 shows the embodied CO_2 emissions of a) oil and b) fossil methane gas reserve and resource base in TIAM-UCL from 2018 (i.e. all of the fossil fuel resources shown in the supply cost curves in Figures 7-9 in the main paper). For reference, embodied CO_2 emissions in global coal reserves and resources are 1863 and 7500 Gt CO_2, respectively.

The embodied CO_2 emissions include all emissions through production and consumption, and therefore if the fossil fuel were used as a feedstock then the embodied emissions from combustion would be significantly lower. We can observe that conventional oil reserves alone would account for the entire carbon budget if they were to all be used (i.e. embodied emissions of conventional oil reserves are > 580 Gt CO_2 as seen in Supplementary Figure 2). The (generally) higher cost of unconventional oil vis-à-vis conventional reserves explains why most unconventional resources remain unused under a 1.5˚C budget. Additionally, unconventional oil tends to have a higher carbon intensity of production (due to energy inputs required for extraction and upgrading), although the carbon intensity of conventional crude oil also varies significantly.

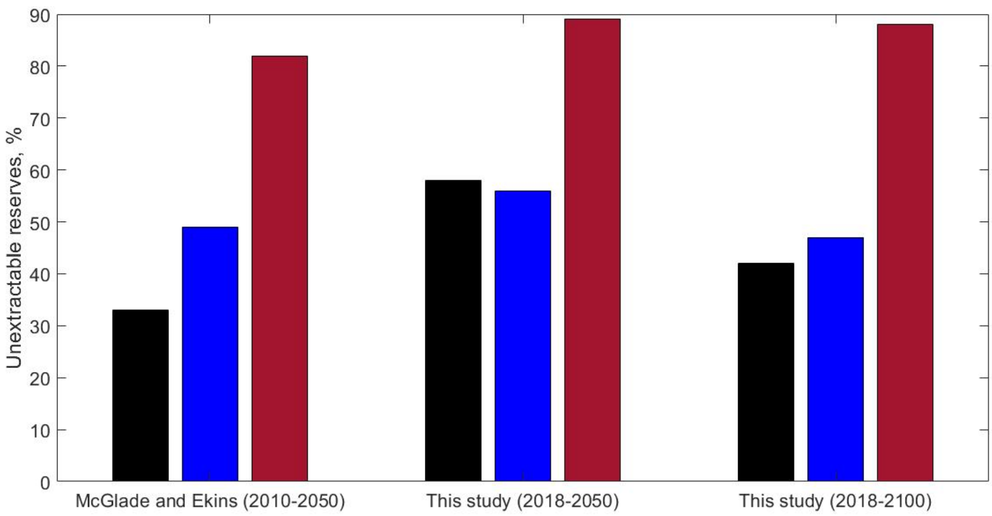


Supplementary Figure 2. Embodied CO_2 in oil (a) and gas (b) reserve and resource base in TIAM-UCL, split by resource type.

Comparison to McGlade and Ekins (2015) paper

In Supplementary Figure 3, we compare the estimates of global unextractable fossil fuel reserves in 2050 in this study with those in McGlade and Ekins[1]. 2050 unextractable oil is at 58%, compared to 33% in the earlier study, fossil methane gas is at 56%, compared to 49%, and coal is at 89%, compared to 82%. The increase in estimates reflects the much smaller carbon budget assumed in this paper, at 580 Gt CO_2 from 2018 onwards, consistent with a 50% probability of limiting average warming to 1.5°C. McGlade and Ekins had an implicit budget of well over 1000 $GtCO_2$.

In addition, this analysis reflects an improved representation of fossil fuels, and major updates to the availability, cost and deployment potential of renewables, zero emission vehicles and options for mitigation in hard-to-abate sectors (Supplementary sections 5 and 6). For renewable generation technologies, future costs were updated based on BNEF projections whilst present day costs were taken from IRENA[2] (see Supplementary Table 21). Additionally, the technical potentials of solar and wind generation have been updated to reflect the significant potential of these technologies. The data for the updated technical potentials was taken from the National Renewable Energy Laboratory (NREL), and applied to each region within TIAM-UCL[3]. In addition to the cost and technical potential of solar and wind generation, the rate at which these technologies can grow has also been updated given rapid growth in recent years. For example, solar PV has grown at an average annual rate of 34% between 2010 and 2019, with our upper annual growth rate for solar PV (30%) reflecting this[4]. For electric vehicles, costs were also updated using data from BNEF.



***Supplementary Figure 3**. Unextractable reserve estimates of fossil fuels from this work using a 1.5°C scenario, compared with earlier estimates for a 2°C scenario in McGlade and Ekins.* McGlade and Ekins[1] fossil reserves are from 2010 onwards, whilst this study is from 2018 onwards. McGlade and Ekins used 2P reserves for both oil (1294 Gb) and fossil methane gas (192 Tcm), and 1P reserves for coal (1004 Gt) whereas this study uses 1P oil (1276 Gb), gas (155 Tcm) and coal (931 Gt) reserves (for further details see the Methods section in the main paper).

In order to directly compare the difference between volumes of unextractable fossil fuel reserves and cumulative production between the two studies, Supplementary Table 2 provides context to the reserve assumptions used in each study, as well as cumulative production from each fossil fuel. It should be noted that the cumulative production data from McGlade and Ekins[1] has been amended to start at 2018 using historical production between 2010 and 2018, to ensure a direct comparison of 2018-2050 cumulative production between this study and the 2015 paper.

Supplementary Table 2** (a)**. Comparison of unextractable reserves and cumulative production between McGlade and Ekins and this study. Note cumulative production includes production from both designated reserves and from non-reserves.

Study	Oil		Fossil methane gas		Coal	
	Unextractable reserves	**Cumulative production (2018-2050)**	***Unextractable reserves***	**Cumulative production (2018-2050)**	***Unextractable reserves***	**Cumulative production (2018-2050)**
	Gb		**Tcm**		**Gt**	
McGlade and Ekins	431	1129	95	136	819	113
This study	740	748	87	100	826	105

Supplementary Table 2 (b). Comparison of unextractable resources and cumulative production between McGlade and Ekins and this study. Note cumulative production includes production from both designated reserves and from non-reserves. Unextractable oil resources from McGlade and Ekins has been altered to remove kerogen oil from the resource base, given no kerogen is produced either in the 2ºC scenarios from McGlade and Ekins, nor the 1.5°C scenarios run in this analysis.

Study	Oil		Fossil methane gas		Coal	
	Unextractable resources	**Cumulative production (2018-2050)**	***Unextractable resources***	**Cumulative production (2018-2050)**	***Unextractable resources***	**Cumulative production (2018-2050)**
	Gb		**Tcm**		**Gt**	
McGlade and Ekins	2783	1129	504	136	3900	113
This study	3331	748	625	100	3960	105

SI Section 3. Additional scenario results, including sensitivity cases

As part of our analysis of unextractable fossil fuels under a 1.5^{o}C compatible carbon budget (50% probability), we undertook a range of other scenarios, including optimistic (1.5D-HighCCS) and less optimistic (1.5D-LowCCS) outlooks for CCS, an important technology for prolonging fossil use, increased biomass availability as an alternative primary energy source (1.5D-HighBio), and lower demands for selected energy services (1.5D-LowDemand). The Methods section of the main paper provides a description of scenarios.

In the '1.5D-LowCCS' (2.5% upper annual growth rate (AGR), compared with 5% upper AGR in central 1.5D scenario) scenario, we find that the model solution is on the margin of infeasibility, with a proxy 'backstop' technology removing ~ 8.8 Gt CO_2 between 2090 and 2100. This represents ~1.5% of the total 1.5^{o}C carbon budget (50% probability) used, and it provides important policy implications that lowering the deployment rate of CCS technologies pushes the energy system to the edge of infeasibility. It should be noted that we did not run a 'No CCS' scenario because the modelling solution would have required significantly more of this 'backstop' technology. Additionally, the developed economies (including the US, the EU, and the UK) deploy more BECCS in the power generation sector in our 'Low CCS' deployment scenario (compared to our central 1.5D scenario), and therefore distributing more of the carbon budget to developing regions.

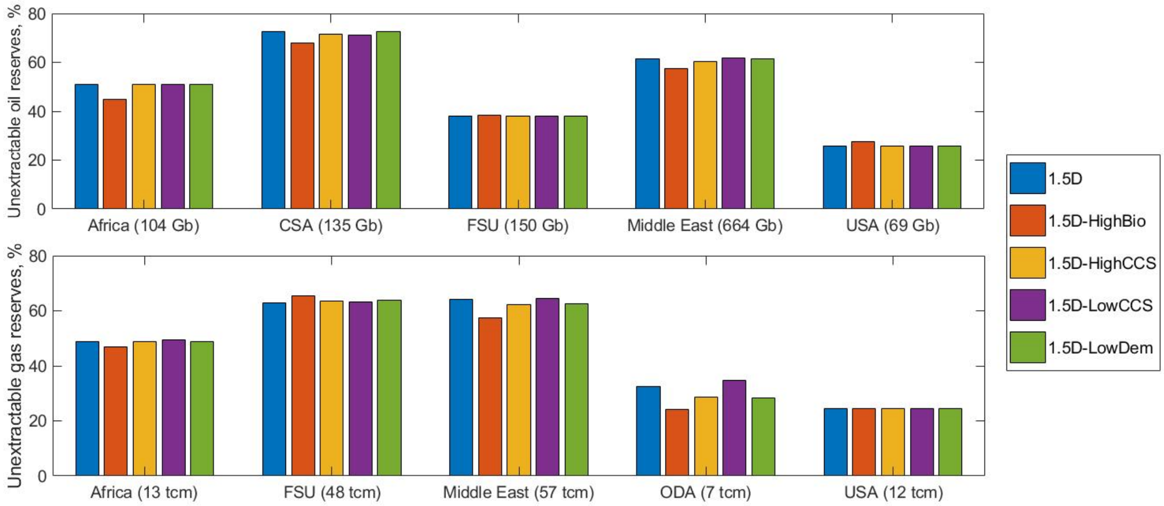
Budinis et al.[5] also explored the implications of various outlooks for CCS on unextractable carbon in a below 2^{o}C world, finding that CCS increases production of the total fossil reserve base from 33% in a case with no CCS to 65% with CCS. In this paper, we have extended the analysis of varying degrees of CCS deployment to regional implications, as well as disaggregating the fossil reserve and resource base significantly further. However, we also find that once the carbon budgets are 1.5^{o}C consistent, the impact CCS can have on unlocking unextractable carbon is much less significant. For example, in Supplementary Table 3, we find unextractable proportions of oil, fossil methane gas and coal are only 2%, 2% and 1% lower in our 'High CCS' deployment scenario compared to our central 1.5D scenario by 2100.

We also find that fossil fuel consumption, and therefore emissions, are higher in the 1.5D-HighBio scenario where, as expected, the higher availability of biomass allows higher deployment of biomass with carbon capture (BECCS) technologies, and therefore more negative emissions. By 2100, unextractable reserves of oil, fossil methane gas and coal are 6%, 7% and 3% lower than our central 1.5D scenario. In terms of the total *resource* base in the 'High Bio' scenario, this is particularly the case moving towards the second half of the century as proved reserves are depleted. The 1.5D-HiBio scenario sees an additional 189 Gb oil, 47 Tcm of fossil methane gas, and 31 Gt of coal resources produced above the central 1.5D scenario by 2100.

Supplementary Table 3. Unextractable global fossil fuel reserves by scenario

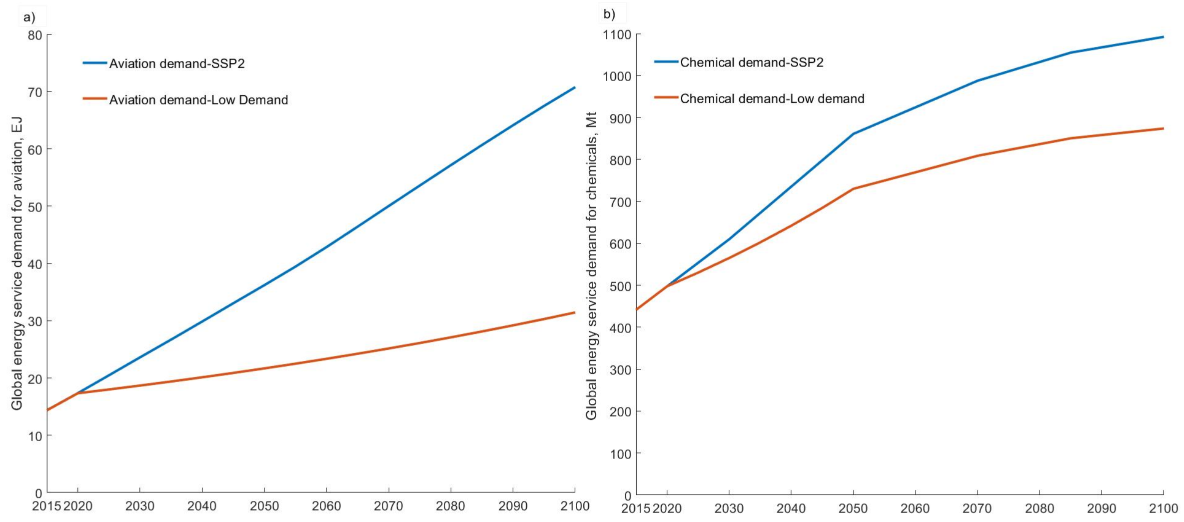
Scenario	Oil				Fossil methane gas				Coal			
	2050		**2100**		**2050**		**2100**		**2050**		**2100**	
	%	***Gb***	**%**	**Gb**	**%**	**Tcm**	**%**	**Tcm**	**%**	**Gt**	**%**	**Gt**
1.5D	58%	740	42%	541	56%	87	47%	73	89%	826	88%	818
1.5D-LowCCS	58%	740	42%	549	57%	88	48%	75	89%	833	89%	826
1.5D-HighCCS	58%	730	40%	513	55%	85	45%	70	88%	819	87%	809
1.5D-HighBio	55%	702	36%	471	53%	82	40%	63	87%	811	85%	787
1.5D-LowDemand	58%	739	42%	549	55%	86	45%	72	88%	822	87%	811

Supplementary Figure 4 shows unextractable fossil fuel reserves by 2050 for oil (a) and fossil methane gas (b) across some key producing regions. Of particular interest to note is the minimal changes between regions across our 1.5°C consistent scenarios, driven by the carbon budget leaving very little room for manoeuvre. The key exception is the Other Developing Asia (ODA) region for fossil methane gas. In the high CCS, high biomass availability, and low demand scenarios, more of ODA's fossil methane gas reserves are developed. Two key caveats should be noted in relation to these scenario results. Firstly, this shows the critical role of widespread CCS deployment to facilitate gas consumption, particularly in regions where it is displacing coal in the industrial sector. Secondly, and as discussed further below, the low demand scenario is interesting as the remaining carbon budget is redistributed (given lower emissions from aviation and the chemicals sector) to developing regions allowing slightly more room to manoeuvre in terms of decarbonisation in the transportation and industrial sectors.



Supplementary Figure 4*. *Unextractable reserves by 2050 in largest reserve holders. Top panel: Unextractable oil reserves for major reserve holders with total proved reserves shown on the x-axis; Bottom panel: Unextractable fossil methane gas reserves for major reserve holders with total proved reserves shown on the x-axis.

Our low demand scenario is of interest in that it frees up some of the carbon budget from slowing demand growth for energy services from the chemical and aviation sectors and redistributes this elsewhere to the transportation sector *in developing countries* (particularly road transport), and hence the same unextractable reserve volumes for oil. In short, a saturation of aviation demand in OECD countries leaves more room for developing regions to transfer their transportation fleets away from oil, whilst remaining consistent with the 1.5°C budget. The altered energy service demand pathways for aviation (b) and chemicals (b) in our low demand scenario (assumed an exponential growth rate for OECD and non-OECD regions derived from Grubler et al.[6] and extrapolated to 2050 and 2100) are shown in Supplementary Figure 5 below.

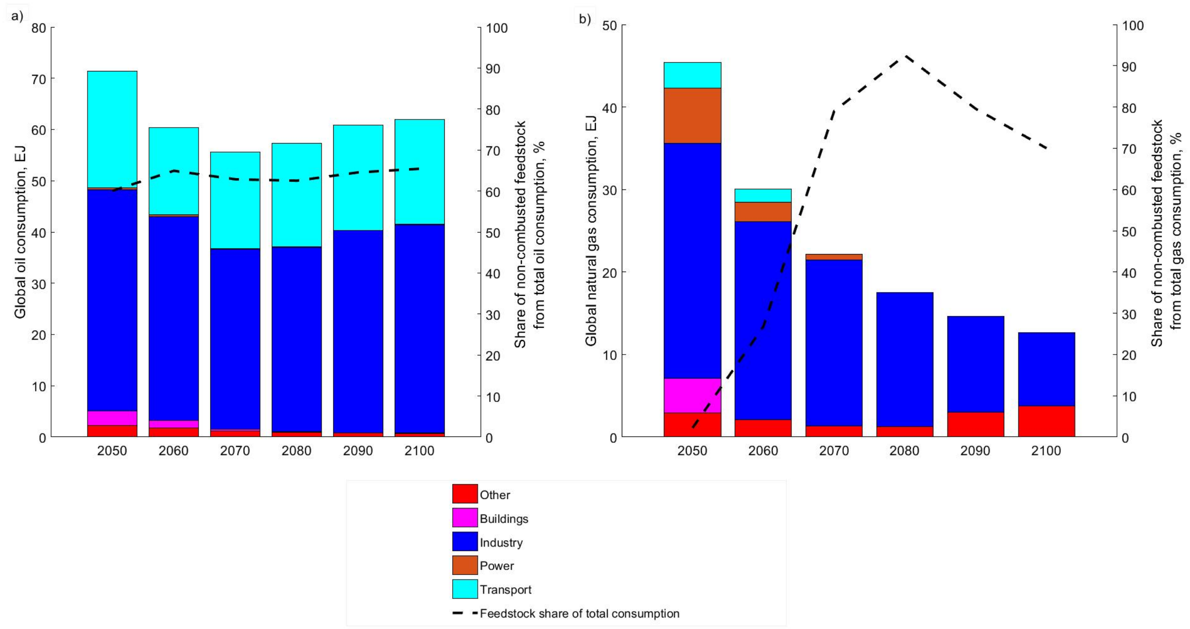


Supplementary Figure 5. Low demand scenario (with growth rates derived from Grubler et. al) departing from baseline SSP2 used in our central 1.5°C scenario for global aviation energy service demand (a) and global chemical demand (b). Note energy service demand for aviation in TIAM is input into the model as an energy unit rather than the more standard passenger kilometres or vehicle kilometres.

Continued use of fossil fuels post-2050

In our discussion of unextractable fossil fuels under a 1.5°C target, we identified that a significant proportion of fossil fuel consumption post-2050 was in the form of feedstock consumption in the petrochemical and non-energy industrial sectors. Supplementary Figure 6 below shows total oil (a) and fossil methane gas consumption (b) by sector and the percentage of consumption in the form of non-combusted feedstocks between 2050 and 2100. Feedstock shares of oil remain relatively static (at around 65%) throughout the 2050-2100 time period, with consumption driven by feedstocks in the petrochemical sector and non-energy sector (e.g. naphtha in the petrochemical sector and asphalt production in the non-energy sector). In contrast, fossil methane gas shows a huge shift from combustion-based consumption to feedstocks post-2050.

The share of fossil methane gas consumption as a feedstock increases from around 5% in 2050 to 70% in 2100, peaking at 90% in 2080. The consumption of gas as a feedstock fluctuates between 2020 and 2050, dropping from around 8% in 2020 to 5% in 2050, before rising again. This is largely because in this period, the rapid need to decarbonise leads to lower emission feedstocks being consumed in the petrochemical sector, before emissions turn net negative in 2060 and gas is then consumed as feedstock (i.e. although crucially it is non-combusted consumption).



Supplementary Figure 6. Oil (a) and gas (b) consumption by sector and percentage of total consumption from non-combusted feedstocks in our central 1.5˚C scenario after 2050

Therefore, as suggested in the main paper, a combination of the development of low carbon alternatives to fossil feedstocks, innovation and efficiency improvements to reduce consumption in the processes themselves, and demand side initiatives to change consumer behaviour would further reduce fossil fuel consumption in these sectors. This is particularly important given the huge uncertainty of the roll out of key technologies required in keeping global temperatures to 1.5^{o}C including carbon capture utilisation and storage (CCUS), and bioenergy with carbon capture and storage (BECCS), particularly given supply chain issues with bioenergy and land competition.

It is also important to identify where residual emissions remain in the 1.5^{o}C scenarios in order to provide relevant direction for policy-makers to target these sectors and/or regions. Supplementary Table 4 shows the proportion of energy system CO_2 emissions from some key sectors across our scenarios. Of particular note is the significantly lower share of CO_2 emissions from transport by 2100 in our lower demand scenario, where energy service demand for aviation in particular reaches a saturation point in developed countries; this could be achieved sooner if specific policies are put in place to discourage aviation demand.

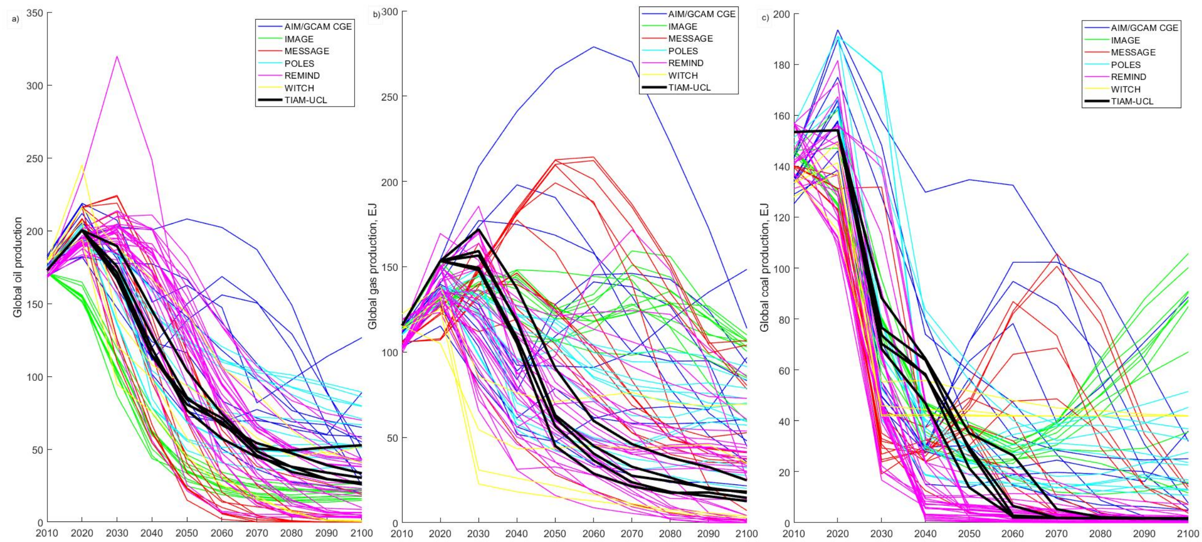
Supplementary Table 4. Percentage of total CO_2 residual emissions by key sectors across our 1.5^{o}C consistent scenarios and cumulative CO_2 capture from BECCS. 'Other' sectors include buildings (residential and commercial), upstream and the agricultural sectors (including land-use change emissions).

Scenario	Cumulative CO_2 capture from BECCS	Transport		Industry		Power		Other	
	2025-2100, CO_2	2050, %	2100, %	2050, %	2100, %	2050, %	2100, %	2050, %	2100, %
1.5D	287	32	56	40	12	7	10	21	22
1.5D-LoCCS	273	29	56	42	12	8	10	21	22
1.5D-HiCCS	278	31	55	38	12	6	10	25	23
1.5D-HiBio	508	39	32	33	8	5	13	23	47
1.5D-LoDem	282	28	38	43	16	6	14	23	32

SI Section 4. Comparison of TIAM-UCL scenarios versus IAM 1.5°C scenarios

In order to put our results in the context of the other estimates of fossil fuel supply in a 1.5°C world, Supplementary Figure 7 shows global primary fossil energy supply from a range of integrated assessment models used in the IPCC's Special Report on 1.5 degrees[7], and the outputs from the 1.5 degree scenarios explored in this work. This provides a significant range of uncertainty across the modelling horizon.

For oil and coal, our scenarios indicate global supply needs to peak now, which has significant implications for oil and coal producers. For fossil methane gas, supply either declines immediately ('1.5D', '1.5D-LowCCS') or sees modest growth (0.2-1.1% annually) out to 2030 ('1.5D-HighCCS', '1.5D-HighBio', '1.5D-LowDem'), before declining. We also see significant sectoral and regional variations in fossil fuel supply and demand. For example, fossil methane gas demand becomes increasingly dominated by the industrial sector, with the proportion of fossil methane gas consumption from power generation and buildings falling constantly from 2020 onwards. Additionally, there is a significant shift in gas consumption towards regions with (currently) very high levels of coal consumption, particularly in the industrial sector. For example, China, Other Developing Asia and India represent ~15% of global gas consumption in 2020, rising to 30-33% across our scenarios in 2030, and 34-49% by 2050.



Supplementary Figure 7. TIAM-UCL time-series of global fossil fuel production compared against IPCC 1.5°C database (Source of non-study scenarios: Huppman et al. 2018[7]). Panel: a) Oil production; b) Fossil methane gas production; c) Coal production. TIAM-UCL 1.5°C scenarios are the black trend lines.

Whilst results are only published out to 2040, we briefly compare cumulative production of each fossil fuel to the IEA Sustainable Development Scenario (SDS). We find that between 2018 and 2040, cumulative production of oil, gas and coal in our central 1.5°C scenario are 4% (-21 Gboe), 6% (-5 tcm) and 17% (- 11 Gtce) lower respectively, compare to the IEA SDS[8].

SI section 5. Approach to modelling fossil fuels in TIAM-UCL

The fossil fuel upstream sector in TIAM-UCL incorporates the availability and costs of primary energy resources, all extraction processes, and any upgrading / processing required to produce and distribute energy products for use in end-use sectors. The representation therefore captures the full system, from getting the resource out of the ground to a form where it can be used in another downstream sector and / or traded to another region. In this section, we describe the following parts of the sector representation –

- Reserve and resource estimates
- Fossil resource extraction
- Primary transformation (upgrading and/or processing)
- Trade
- Specific constraints used in the sector

Reserve and resource estimates

Given the derivation of unextractable volumes of oil, gas, and coal heavily depends on both the availability and cost of different categories of fossil fuels, as well as the overarching climate constraints, we describe in detail how our reserve and resource numbers were derived, as well as comparing these to publicly available reported volumes.

A significant focus of McGlade[9] for oil and gas, and Welsby[10] for gas, was to identify uncertainties in the availability of different categories of oil and gas across the McKelvey matrix, and how these uncertainties could be quantified and if possible, limited. A large part of this was consistency in definitions (which is particularly difficult given transparency is a perennial problem with oil and gas reserve reporting). This Section provides both publicly available estimates of oil and gas reserves and resources, as well as volumes of different categories of oil and gas derived to consider the inherent uncertainty associated with these estimates.

We first consider the issues around oil reserve definition, with aggregated 1P global reserve estimates from publicly reporting sources and this study shown in Supplementary Table 5. The discrepancy between what we have defined as proved reserves and those of the publicly available "1P" country-level databases are predominantly driven by reserve revisions of Venezuela (ultra-heavy oil), Canada (oil sands) and the Middle East. Rystad Energy stated that the reporting of 1P reserves in Venezuela which form the basis of BP Statistical Review (as well as other public reporting sources) contain volumes of undiscovered, prospective resources (i.e. undiscovered, ultimately recoverable oil)[11,12]. Therefore, these contradict the Society of Petroleum Engineers (SPE) definitions (i.e. geologically and economically proven) laid out in our work and we therefore altered those volumes of oil classified as reserves in Venezuela.

Supplementary Table 5. Reported volumes of 'proved' (or 1P) oil reserves and resources in 2018 from publicly available sources. OPEC does not include Canadian oil sands in their proved reserve estimates. Volumes of kerogen oil from shale formations have been subtracted from the IEA and BGR recoverable resource estimates. Whilst TIAM-UCL does represent kerogen oil, none is produced across any of our scenarios due to its cost and high carbon intensity. Therefore, to provide a like-for-like comparison to the resource estimates derived in this work (for example we have not included kerogen in our estimates of unextractable resources), estimates of kerogen (shale oil) have been removed.

Source	Proved reserves, Gb	Recoverable resources, Gb
BP[12]	1735	
EIA[13]	1663	
OPEC[14]	1498	
BGR[15]	1790	3070
IEA[8]	1700	5092
This study estimate	1276	4094

The same is also true for Canadian oil sands, where BP continue to distinguish between total reserves of oil sands and reserves "under active development", reflecting the uncertainty in applying the term "proved reserves" to oil sands. BP indicates that 21 Gb of Canadian oil sands were under active development in 2018. Canadian "proved reserves" jumped from 32 Gb in 2009 to 175 Gb in 2010, and have stayed roughly around the 170-180 Gb level since 2010 (successive releases of the

BP Statistical Review from 2010-2020)[12]. This seems counter-intuitive, particularly given if these are in fact 1P figures, i.e. at least 90% of the quoted volume is commercially and technically recoverable, then this number would likely have increased (above simply reserve replacement to cover annual production) as oil sands development economics have improved significantly over the last decade, with cost reductions between 2014 and 2019 estimated between 25-33%[9,16,17]. For the Middle East, our reserve numbers are generally below the majority of publicly reporting sources (e.g. IEA, BP, OPEC), which in large part can be reconciled with a more detailed exploration of "political reserves", i.e. booking volumes of oil as reserves which in fact do not conform to SPE guidelines but are used to convey a political message of resource abundancy.[9]

An analysis into the uncertainty of recoverable volumes of oil was conducted in detail by McGlade[9] and McGlade and Ekins[1], and we used these uncertainty ranges as guiding principles for this work (albeit updating reserves/resource estimates to 2018 to account for movements between different resource classifications, as well as cumulative production). Estimates are provided in Supplementary Table 6.

Supplementary Table 6. Uncertainty ranges for different categories of oil. The Central estimates were used in this work for volumes of reserves and resources. Some volumes of tight oil, gas liquids and EHOB are included in the proved reserve category. The total volume of proven reserves assumed in this work is 1276 Gb, with the regional distribution shown in Supplementary Table 10. Data is adapted from IEA[8], BGR[15], McGlade and Ekins[1], BP[12], and Gautier and Moore[18].

Category	Low estimate (Gboe)	Central estimate (Gboe)	High estimate (Gboe)
Proved conventional reserves	845	1045	1156
Reserve additions	336	576	926
New discoveries	126	246	526
Tight oil (technically recoverable resources)	286	436	823
Extra heavy oil and bitumen (EHOB) (technically recoverable resources)	830	1518	1870
Arctic	40	66	80
Gas liquids	134	210	585
Total recoverable resources	2597	4094	5966

For gas, a more recent bottom-up assessment of country-level reserves was conducted by Welsby[10], using a field-level database initially available from NETL[19] and significantly expanded. Ranges of country-level conventional non-associated proved gas reserves were applied individual probability distributions and combined into aggregated regional distributions. In general (although not exclusively), the summation of field reserves from the database provided the lower bound input into each country's distribution and amended 1P data from Cedigaz provided the upper bound. The analysis at a field-level allowed for a more robust application of the SPE guidelines for 1P reserves. For example, from 2015 onwards, Cedigaz and the Oil and Gas Journal have quoted Russian 1P gas reserves at around 50 tcm. However, this figure appears to have been derived from Russian government estimates which use "geological reserves", rather than any consideration of project economics. In the Energy Review undertaken by the Government of the Russian Federation[20], Russian "proved reserves" include fields such as Shtokman where field development has consistently been shelved due to extremely high development costs. Therefore, the quoting of 2018 Russian proved (1P) reserves of 48-51 tcm by Cedigaz and the Oil and Gas Journal strongly suggests these refer instead to those quoted by the Russian government using their own ("ABC1") reserve reporting standards, which includes both producing fields, undeveloped fields, contingent reservoirs in producing fields (i.e. reserves, reserve additions, and undiscovered volumes)[21]. For reference, BP quoted 1P Russian gas reserves in 2018 at 38 tcm[12]. These dynamics were reviewed for gas by Welsby[10] with all reserves estimated to a base year of 2018 for this work. A similar bottom-up analysis was used to quantify uncertainty in technically recoverable resources of unconventional gas, including shale gas at a play level. As with all estimates of reserves and resources, huge uncertainty surrounds these estimates, and the application of individual country distributions and aggregation into the regions of TIAM-UCL was deemed the best way to account for such uncertainty. Supplementary Table 7 shows publicly reported global 1P gas reserves from a range of reporting sources as well as the 1P estimate of global fossil methane gas reserves estimated in this work.

Supplementary Table 7. Estimates of global 1P gas reserves in 2018 from publicly available sources

Source	Proved reserves, tcm
BGR[15]	198
BP[12]	197
IEA[8]	225
Cedigaz[21]	198
OGJ[21]	198
EIA[22]	193
OPEC[14]	203
This study estimate	155

Examples of the range of uncertainty for each category of gas generated by Welsby[10] from a range of sources is provided in Supplementary Table 8. As discussed above for oil, the uncertainties around recoverable fossil methane gas resources are often even larger than for reserves, given the relative lack of development of many of these resources and/or lack of technological maturation in certain regions. The method to account for this uncertainty is covered in more detail later in this section, including graphical representations in Supplementary Figure 12 for uncertainty in technically recoverable shale gas resources in the Central and South America region in TIAM-UCL.

Supplementary Table 8. Uncertainty ranges for different categories of gas. The Central estimates were used in this work for volumes of reserves and resources. The low, central and high estimates refer to the 95th, 50th (i.e. median), and 5th percentile outputs from the relevant regional distributions used to explore uncertainty. Ranges have been adapted from Welsby[10], with data sources including IEA[8,23], NETL[19], BP[12], Attanasi and Freeman[24], Klett et. al[25], Brownfield et. al[26], EIA[27,28], Medlock[29], BGR[15], Wang et. al[30], McGlade and Ekins[1], Gautier and Moore[18], and APEC[31].

Category	Low estimate (tcm)	Central estimate (tcm)	High estimate (tcm)
Proved reserves	115	155	176
Reserve additions	75	100	155
New discoveries	68	119	187
Shale (technically recoverable resources)	145	198	225
Tight (technically recoverable resources)	53	72	91
CBM (technically recoverable resources)	42	47	49
Arctic	15	29	37
Total	513	720	881

Given its carbon intensity, coal is rapidly phased-out of the energy system across our 1.5°C scenarios. Whilst less attention was given to uncertainty ranges for coal compared to oil and gas, we have nevertheless ensured that our reserve estimates lie broadly within the ranges given by the BGR[15]. Whilst our proved coal reserves are ~ 13% lower than the BGR, this can be partially explained by the conversion of these numbers to Gtce (i.e. energy content billion tons of coal, equivalent), with lignite (brown coal) and hard coal (anthracite and bituminous) having significantly different energy contents. Therefore, our coal reserves are lower than the BGR (2019) suggests on a metric ton basis, however given these “proved reserve” figures are open to significant uncertainty, and the aforementioned use of Gtce distinguishing between hard and soft coals, these numbers can be reconciled. Additionally, the regional breakdown of reserves shows similar levels in key coal producing/consuming regions. For example, combined hard coal reserves in India and China are 222 Gtce according to the BGR (2019), with our estimates suggesting 226 Gtce.

Supplementary Table 9. Estimates of global coal reserves in 2018 from publicly available sources

Source	Unit	Proved reserves
BGR[15]	Gt	1070
BP[12]	Gt	1070
IEA[8]	Gt	1043
EIA[32]	Gt	1048
This study	Gtce	931

Regional distribution of reserves and resources

Supplementary Table 10 shows the regional distribution of reserves and resources for oil, gas and coal. These were taken from the above discussion of reserves and resource estimates in TIAM-UCL, with uncertainty ranges shown in Supplementary Table 6 and 8.

Supplementary Table 10. Regional distribution of reserves and resources based on central estimates

	Oil, Gboe		**Gas, Tcm**		**Coal, Gtce**	
Region	**Reserves**	**Resources**	**Reserves**	**Resources**	**Reserves**	**Resources**
Africa	104	276	13	77	31	46
Canada	52	756	2	33	5	71
China and India	35	88	5	69	242	1174
Former Soviet Union	150	632	48	158	212	1094
Central and South America	135	741	5	75	13	34
Europe	16	89	4	37	76	221
Middle East	664	1,015	57	108	5	13
OECD Pacific	4	31	2	38	84	312
Other Developing Asia	22	51	7	36	24	226
USA	69	327	11	82	239	873
Global	1,276	4,094	155	720	931	4066

Fossil resource extraction

Primary extraction in TIAM-UCL is represented by a range of ‘mining’ processes, with the costs reflecting a range of factors including:

- Technology maturity (e.g. if a technology has been developed over time in a certain region, and experience has been accrued (learning-by-doing), then the technology can be relatively mature and potential cost reductions/efficiency gains can be experienced. For example, shale gas drilling experience was accrued over decades in the United States, both through learning-by-doing (e.g. multiple wells per drilling pad) and fiscal incentives (tax breaks) which reduced costs, and therefore US shale gas costs are lower than other regions.
- Technical difficulty (generally driven by the geology of the formation in question, i.e. the source rock). Higher mining costs are incurred for fossil resources which require additional stimulation to lead to economic flow rates, such as hydraulic fracturing for tight reservoirs of oil/gas
- Production flow rates linked to the above technical difficulty. Additionally, various source rocks yield different production flow dynamics, e.g. across the lifetime of a well, production characteristics for conventional and unconventional gas vary. Conventional non-associated fossil methane gas would generally exhibit slower growth rates up to peak production, a longer production plateau period, and slower rates of production decline. Unconventional shale gas wells would generally exhibit rapid production growth up to a maximum, a shorter plateau vis-à-vis conventional gas, and faster decline rates.

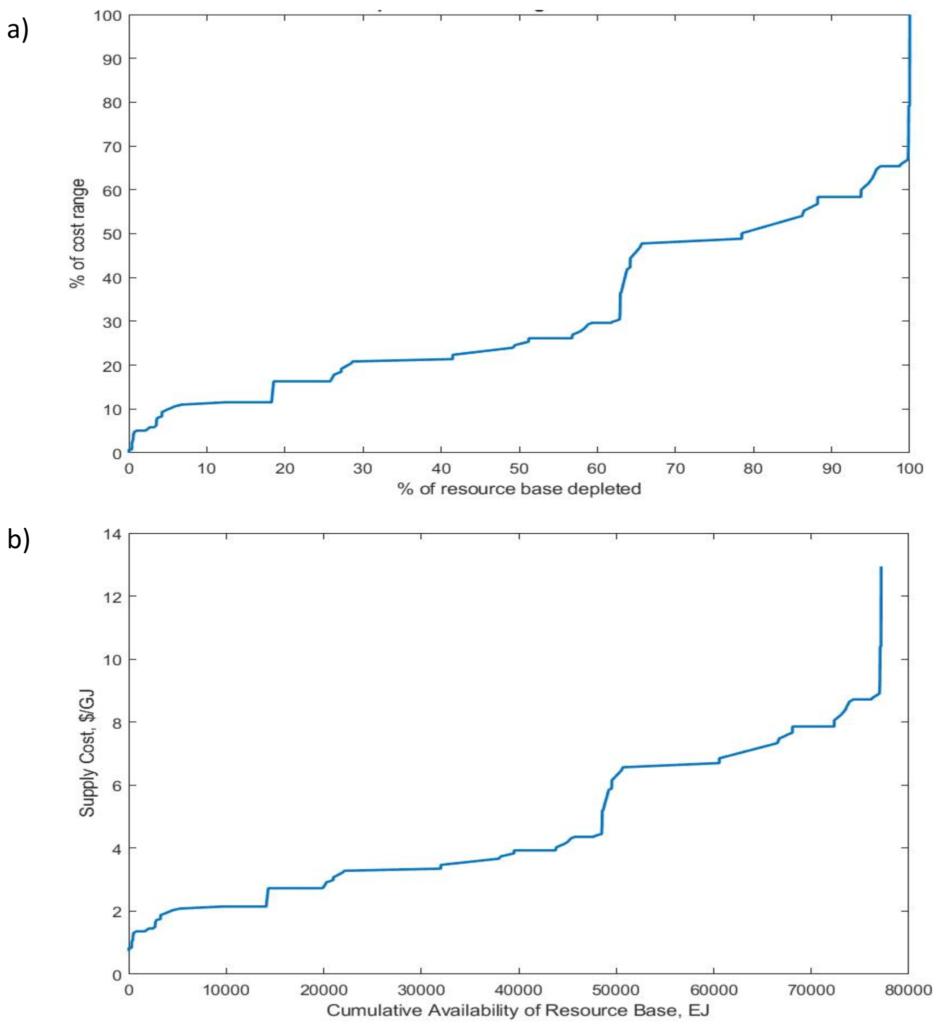
<u>Coal</u>

Primary coal resources in TIAM-UCL are split into two categories, utilizing data collected by Remme et. al.[33] -

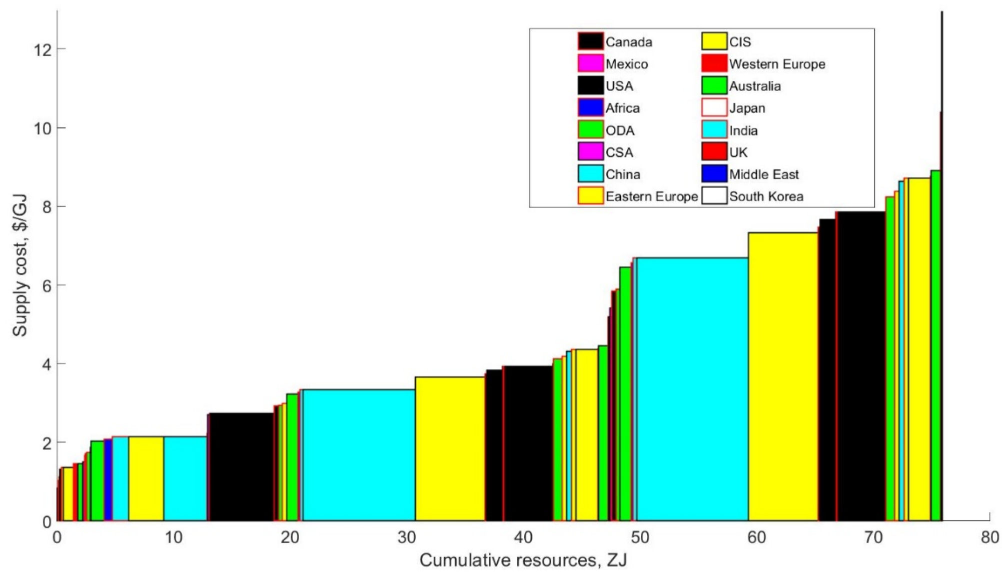
- Brown coal (lignite): lower energy content, with average heating value ranging from 5.57-17 MJ/kg
- Hard coal (sub-bituminous, bituminous and anthracite): higher energy content, with average heating value ranging from 17.58-27.55 MJ/kg

As with oil and fossil methane gas, the extraction technologies for coal split the resource base into cost tranches, in order to reflect (albeit simplistically), cost depletion dynamics. In short, as the more accessible and higher quality resources are depleted, the model must move to more expensive extraction of (potentially) harder to exploit resources. Coal is split into hard coal and brown coal, with the representative mining technologies for both categories split into three cost categories. The distribution of resources/reserves assigned to each cost category varies by region, and is influenced by the proportion of the total resource base which can be considered reserves, with the remainder of resources split between the middle and highest cost categories.

Supplementary Figure 8 shows a cost depletion curve for global coal resources, and the corresponding global supply cost curve constructed from the cost depletion curve. Additionally, Supplementary Figure 9 shows a global supply cost curve broken down into the regions of TIAM-UCL.



Supplementary Figure 8. a) Cost depletion curve derived from TIAM-UCL resources and costs for global coal; b) supply cost curve derived from the cost depletion curve. Source data are provided as a Source Data file.



Supplementary Figure 9. Global supply cost curve for coal disaggregated into TIAM-UCL regions. Source data are provided as a Source Data file.

<u>Fossil methane gas</u>

The underlying availability and cost of fossil methane gas in TIAM-UCL is disaggregated into the following geological categories:

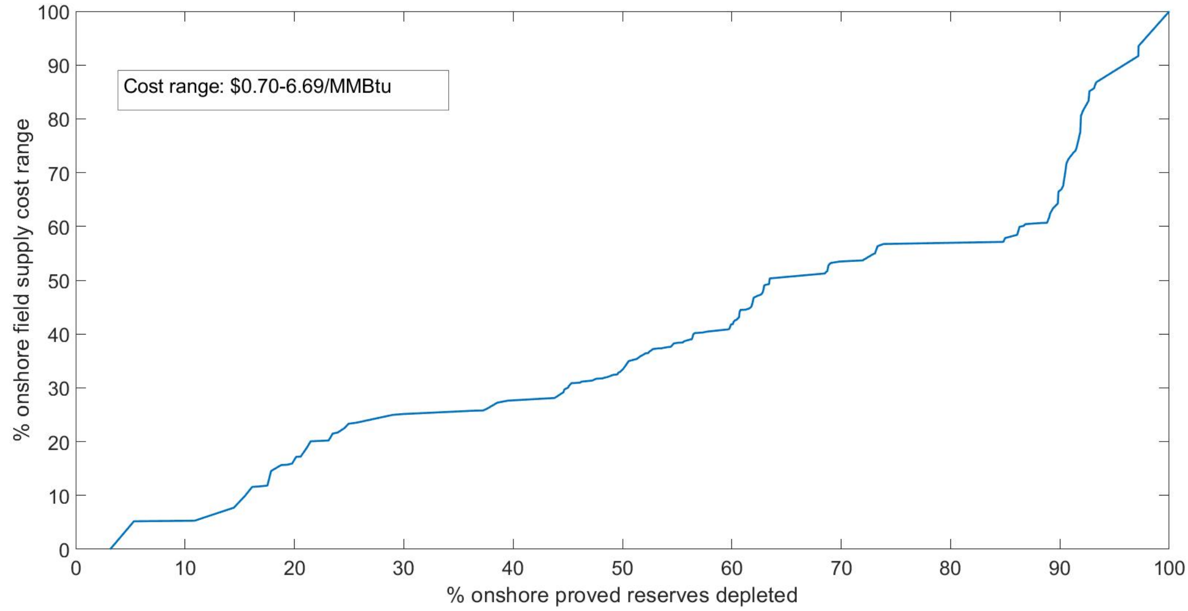
- Non-associated conventional gas proved reserves
- Non-associated conventional gas reserve additions
- Non-associated conventional gas new discoveries
- Associated fossil methane gas
- Arctic conventional fossil methane gas resources
- Shale gas
- Coal bed methane
- Tight fossil methane gas

As with oil, the disaggregation of fossil methane gas in TIAM-UCL is based on McGlade[9]. This analysis has been extended in a forthcoming thesis by Welsby[10], with field-level assessments of resource availabilities and costs. On a regional level, supply cost curves are constructed using an approach developed in Welsby[10]. Resource assessments were generally conducted at disaggregated field-/play-level, and then aggregated into the regions of TIAM-UCL using probability distributions, and taking into account any correlation between discrete estimates etc. These were then applied to depletion curves which were formed from a database of field-/play-level costs where possible. The database was extended to fields for which costs were either not known (i.e. no publicly available indication of field supply costs) or have not yet been developed.

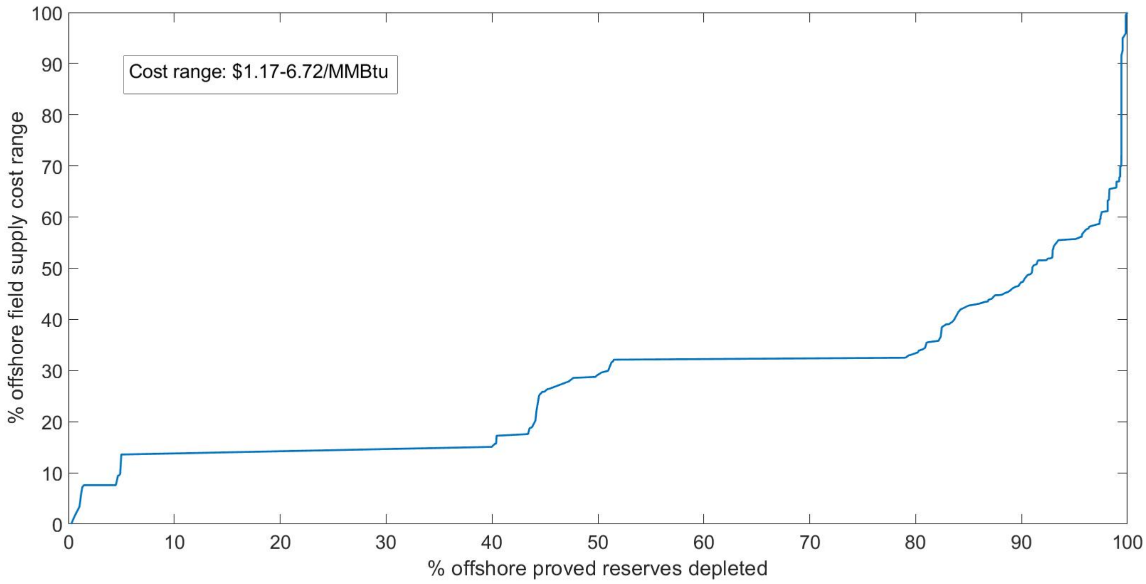
The field database was available from NETL[19], and significantly extended and improved by Welsby, including adding additional geological information such as water depths, reservoir depths (where missing), and concentrations of hydrogen sulphide / CO_2. This includes undiscovered fossil methane gas in TIAM-UCL by applying the field costs derived for potential reserve additions and adding an exploration cost. The application of supply costs to the individual gas fields was done via a linear regression model. A database of field costs was developed by Welsby[10] and a linear regression model fitted to a range of parameters in order to identify statistically significant drivers of field development costs. For conventional fossil methane gas, these include reservoir depth, the presence of hydrogen sulphide and CO_2, water depths, the size of the field, and a binary risk variable. For unconventional fossil methane gas, statistically significant field cost drivers included reservoir depths, accumulated drilling experience, the range of lateral lengths for horizontal drilling, and the thickness of the source rock. This means the representation of fossil methane gas supply costs in TIAM-UCL is driven by statistically significant coefficients of field-/play-level supply costs, aggregated into a representative cost depletion curves.

Supplementary Figure 10 shows an example cost depletion curve for conventional non-associated fossil methane gas reserves (taken from Welsby[10]). Aggregated regional supply cost curves (Supplementary Figure 11) were derived from field-/play-level cost depletion curves shown in Supplementary Figure 10 and have been aggregated into the TIAM-UCL regions. The three-step cost curves in TIAM-UCL mean that costs for each regions are aggregated from field-level data into weighted average costs for each cost step.

a)



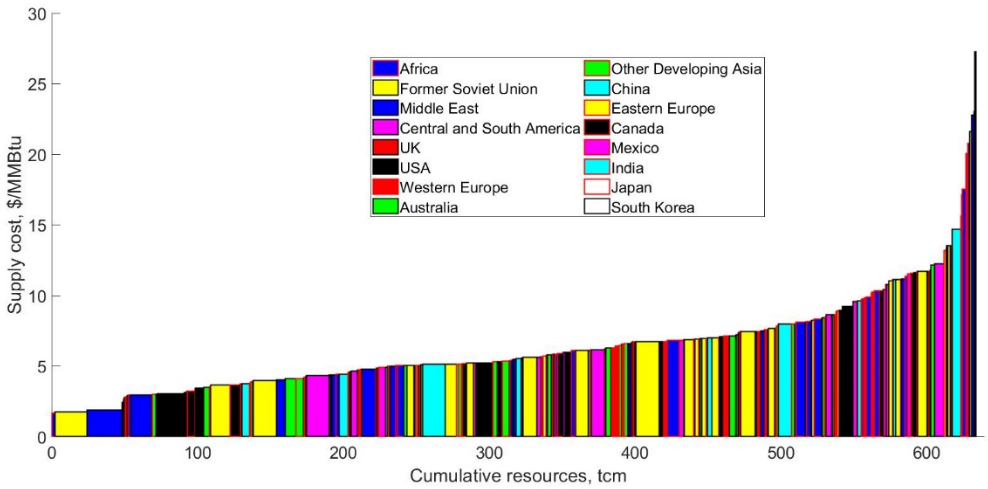
b)



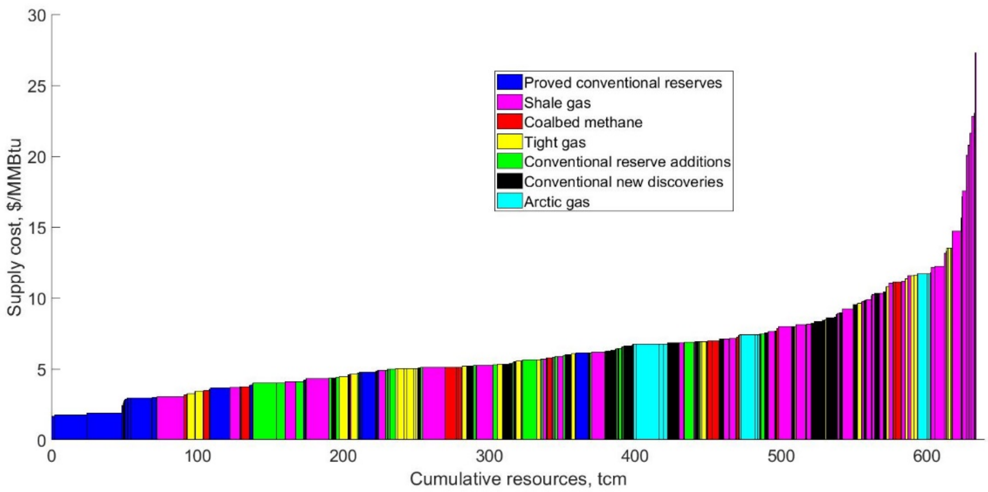
Supplementary Figure 10. Example cost depletion curve constructed by Welsby[10] for proved onshore (a) and offshore (b) non-associated gas reserves. Source data are provided as a Source Data file. Source: Welsby, 2021[10]

Additionally, Supplementary Figure 11 shows a) the regional breakdown of the resource distribution, and b) the supply cost with each resource category identified. For reference, none of the figures in this section include associated fossil methane gas resources in the supply cost curves, as these are calculated separately, with resource availabilities calculated by McGlade[9] and Welsby[10]. Additionally, improvements made by Welsby[10] include an endogenous decision within the model of whether to produce the gas (which requires investment in new capacity if existing capacity is insufficient) or flare/vent it.

a)

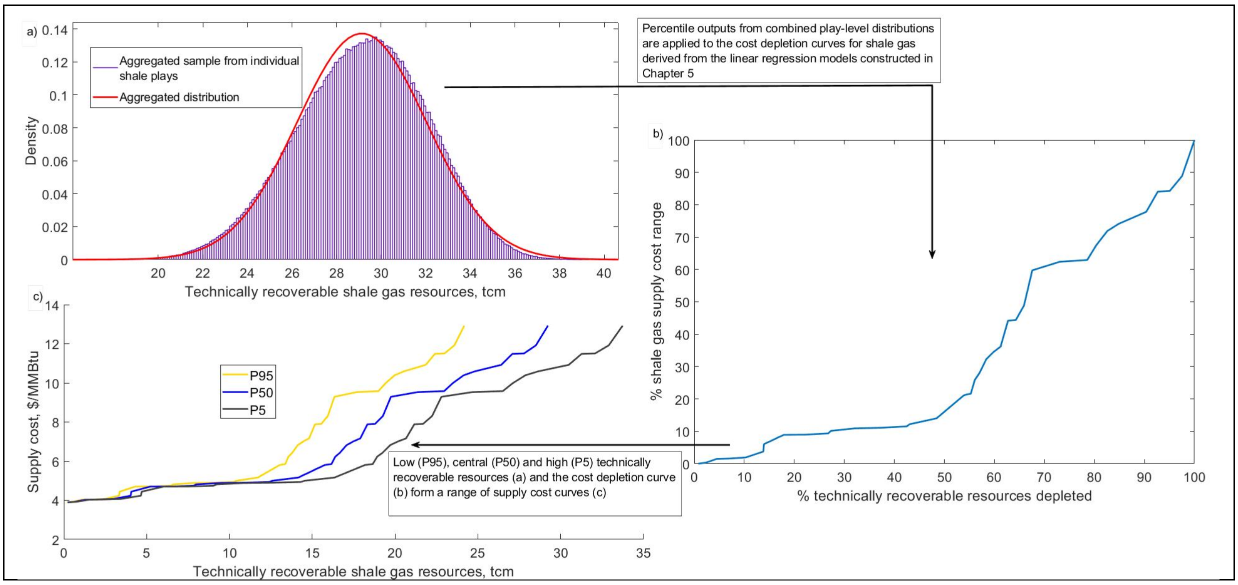


b)



Supplementary Figure 11. Global gas supply cost curve from 2015 by a) region b) resource category. Source data are provided as a Source Data file. Source: Welsby, 2021[10], McGlade, 2013[9]

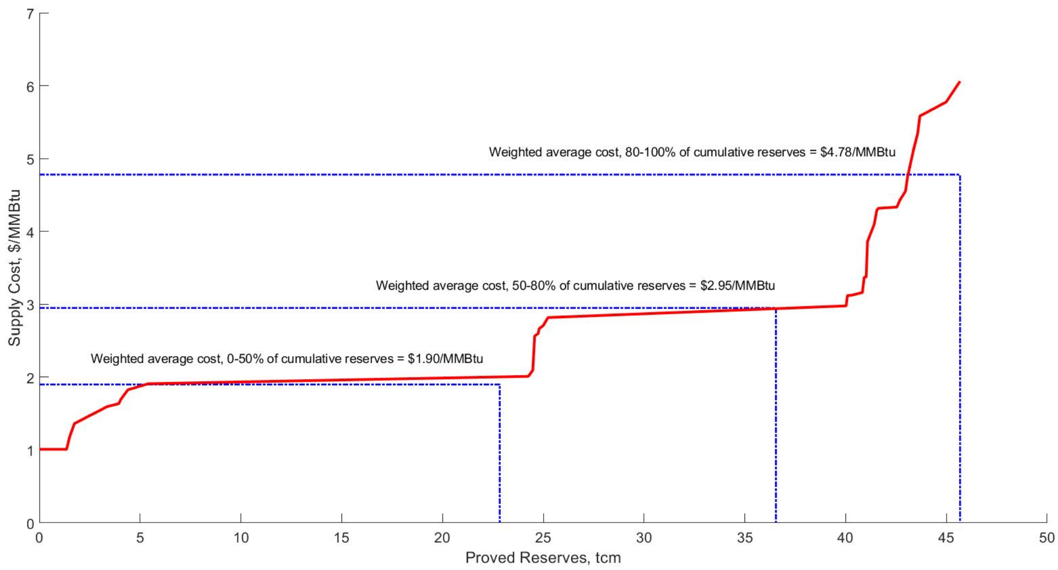
Supplementary Figure 12a shows the aggregated output distribution for combining play-level estimates of shale gas for the Central and South America region in TIAM-UCL, while Supplementary Figure 12b shows the depletion analysis using US shale play cost analogues and linear regression using the geological characteristics of individual plays in South America (e.g. shale reservoir depth, thickness, etc.). These are then combined to form a range of supply cost curves, shown in Supplementary Figure 12c.



Supplementary Figure 12. a) Aggregated distribution for estimates of technically recoverable resources of shale gas in individual plays in Central and South America (CSA) region in TIAM-UCL; b) Cost depletion curve for shale gas in Central and South America, and c) central supply cost curve for technically recoverable resources of shale gas for Central and South America (CSA). Source data are provided as a Source Data file. Source: Welsby, 2021[10]. Play-level technically recoverable resource distribution inputs adapted from IEA[8,23], EIA[34], and Medlock[29].

Primary extraction of fossil methane gas is split by region and into the different geological categories mentioned previously. For each category, the supply cost curves shown above are then disaggregated into a three-step supply cost curve, with the first 50% of the resource base in the lowest cost bracket, then the next 30% in the middle cost category, and finally the last 20% in the highest cost category. The use of a 50-30-20% split was used by McGlade[9] and could be considered somewhat arbitrary. However, in the example shown in Supplementary Figure 13, it can be seen that the distribution of field costs generally follow the pattern that a significant proportion of the reserve base is available at the lower end of the cost range, whilst high cost reserves make up less of the reserve base.

Supplementary Figure 13 is taken from the work conducted on field-level analysis of the drivers of fossil methane gas supply costs undertaken by Welsby[10]. The supply cost curve in Figure 13 represents the median output from the combined distribution of uncertainty in proved (1P) non-associated fossil methane gas reserves for Middle East OPEC countries, with the median estimate of 1P non-associated gas reserves from Welsby[10] ~ 46 Tcm. Additionally, the blue lines shows the low, middle and high cost ranges, and the corresponding quantity of proved non-associated gas reserves which can be extracted at each aggregated cost step. For reference, the higher end of the cost range for the Middle East OPEC region would be sour gas deposits in the UAE and Saudi Arabia, some of which lie at significant reservoir depths but have been developed to limit import dependency (e.g. Shah sour gas field in the UAE).



Supplementary Figure 13. a) Example of three-step supply cost curve for the Middle East OPEC region in TIAM-UCL, for proved non-associated conventional gas reserves. The curve represents the median (P50) estimate from the aggregated regional distribution of non-associated proved gas reserves. Source data are provided as a Source Data file. Source: Welsby, 2021[10]

Supplementary Table 11 shows a cost range for some key fossil methane gas mining technologies, generated using a field-level database and a linear regression model applied to geological parameters to generate cost depletion curves[10].

Supplementary Table 11. Cost range for individual fossil methane gas fields derived from the regression analysis by Welsby[10], and used to construct supply cost curves which were into TIAM-UCL

Resource category	Minimum cost, $/boe	Minimum cost region	Maximum cost, $/boe*	Maximum cost region
Proved non-associated onshore conventional reserves (includes sour)	4	FSU	38	FSU
Proved non-associated offshore shallow conventional reserves	7	Middle East	37	Europe
Proved non-associated offshore deep conventional reserves	16	Central and South America	38	USA
Conventional non-associated reserve additions	10	FSU	45	Middle East
Undiscovered non-associated conventional	24	Middle East	58	Central and South America
Sour fossil methane gas undeveloped	29	FSU	45	MEA_P
Arctic (undeveloped)	36	-	63	-
Shale gas	14	USA	147	MEA_P
Tight fossil methane gas	18	USA/CAN	66	Europe
CBM	17	USA	60	China, FSU

* Fossil methane gas costs here have been expressed in $/boe so they can be directly compared to the oil extraction costs in Table 1.3. Data from Welsby, 2021[10], McGlade, 2013[9].

<u>Oil</u>

The representation of oil in TIAM-UCL is predominantly based on the work by McGlade[9], which focused on quantifying uncertainties in the outlook for oil and fossil methane gas, and in particular their availability and costs. As with fossil methane gas, oil is split into different geological categories, each with specific availabilities and supply cost dynamics:

- Conventional oil proved reserves
- Conventional oil reserve additions
- Conventional oil new discoveries
- Arctic oil
- Mined shale oil
- In-situ shale oil
- Light tight oil
- Mined oil sands
- In-situ oil sands (ultra-heavy oil)

The representation of uncertainty in TIAM-UCL for oil availability and costs differs between conventional and unconventional oil. For conventional oil, adapted country-level estimates of reserve and/or resource availability were taken from the literature and input into probability distributions, with corresponding assumptions on correlation between the estimates. For unconventional oil (e.g. mined bitumen), two parameters were assigned probability distributions: a range of estimates for original oil in-place (OOIP) and a range of estimates of a recovery factor (i.e. between 0 and 1, which determines the proportion of the in-place resource base which is technically recoverable). These two distributions were then combined using random repeated sampling (Monte Carlo simulations) to form regional estimates. The combination is the product of the OOIP and the recovery factor, repeated a large number of times to generate an aggregated distribution. These estimates of the resource base for each category of oil were then combined with cost depletion curves, mostly formed from IEA data on cost ranges, and used to generate supply cost curves. For reference, a detailed discussion around the construction of cost depletion and supply cost curves taking into account the inherent uncertainty in volumetric and cost estimates across different regions and oil resource categories can be found in McGlade[9]. In general, the depletion analysis for unconventional oil exhibits significantly more rapid cost escalation (compared to conventional oil) as the resource base is depleted.

The mining processes for oil and fossil methane gas match the geological categories listed previously. Unconventional oil (tar sands and oil shale) has several more steps in the model to reflect the upgrading required to generate a barrel of crude oil (i.e. to get from bitumen/kerogen, to a barrel of synthetic crude oil). Supplementary Table 12 shows the range of costs in TIAM-UCL for the mining technologies in the upstream sector. Also included is the region in TIAM-UCL containing the minimum and maximum cost for each category. As with fossil methane gas represented in Supplementary Figure 13, the supply cost curves for each category of oil are split into three sections: the first 50% of the resource base considered the lowest cost, then the next 30%, and finally the most expensive oil representing the last 20% of the resource base.

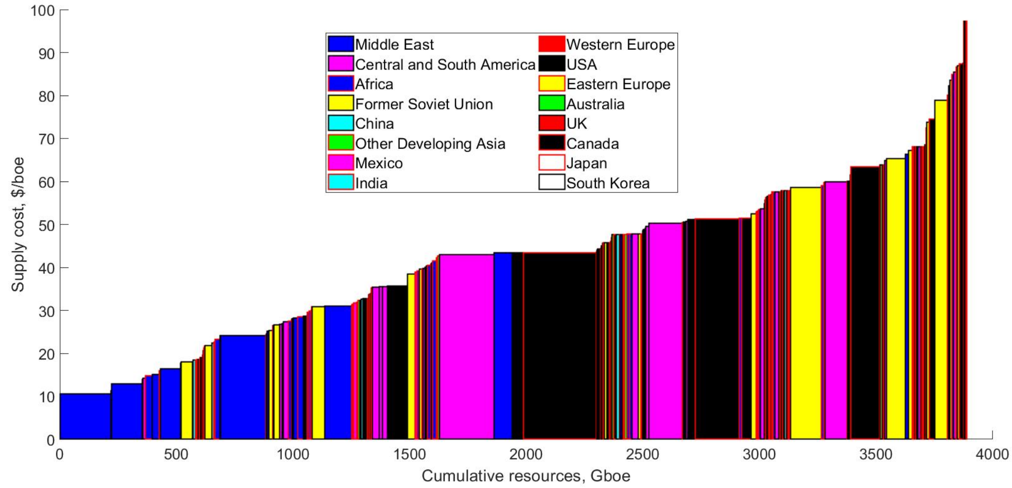
Supplementary Table 12. Cost ranges for oil resources in TIAM-UCL (McGlade, 2013[9])

Resource category	Minimum cost, $/boe	Minimum cost region	Maximum cost, $/boe	Maximum cost region
Proved reserves	11	MEA_OPEC	47	CSA_N
Reserve addition	21	MEA_OPEC	68	CSA_N
New discoveries	16	MEA_OPEC	94	IND
Light tight oil	30	USA	68	Outside North America
Arctic	46	-	97	-
Bitumen (mining)	51	Canada	89	Central and South America
Bitumen (in-situ)	43	Canada	88	Central and South America
Ultra-heavy oil	43	Central and South America	75	Central and South America
Oil shale	54	Europe	124	Middle East

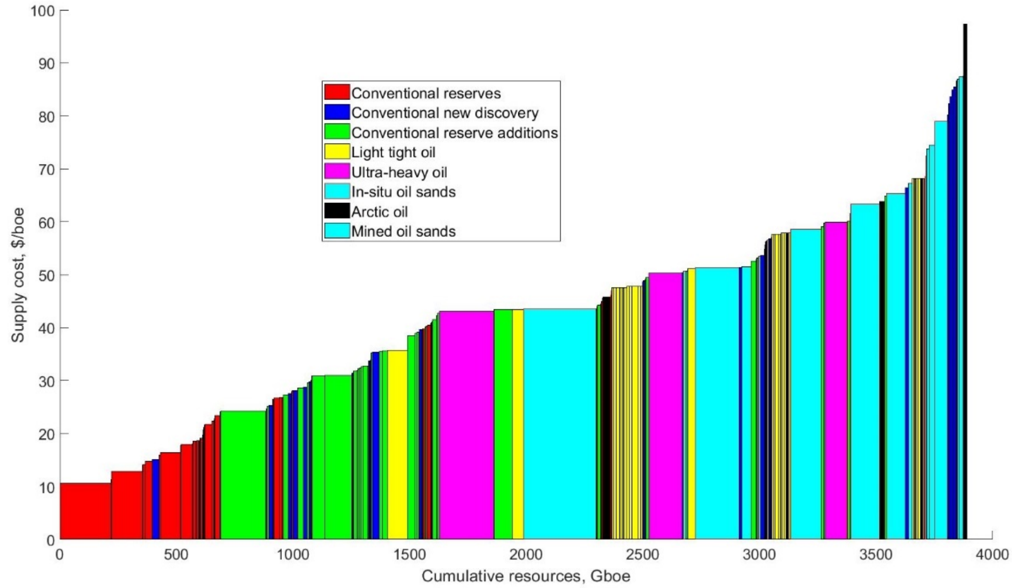
* Sourced from McGlade, 2013[9] with light tight oil updated by Welsby, 2021[10]

Due to limited development outside of certain countries (e.g. Canada for bitumen production), costs have largely been applied homogenously across the relevant TIAM regions. Supplementary Figure 14 shows the global supply cost curve for oil in TIAM-UCL split by region (a) and resource category (b). It should also be noted that unconventional oil is split into three separate cost categories: variable O&M, fixed O&M, and an investment cost (i.e. capital cost). In order to incorporate these into a supply cost curve with conventional oil, a singular supply cost figure was required, therefore the O&M costs were summed, and then a per-unit investment cost was assigned to each category of unconventional oil (derived by dividing cumulative investment and cumulative production from each mining technology) which then yielded a supply cost figure.

a)



b)



Supplementary Figure 14. Global supply cost curve for oil from 2015 by a) TIAM-UCL region and b) oil resource category. Source data are provided as a Source Data file.

Primary transformation (upgrading and/or processing)

In addition to differentiating primary energy resources, TIAM-UCL also accounts for the further upgrading and processing of energy commodities (e.g. heat inputs required for the production of crude oil from the oil sands mining process).

Coal

Coal requires far less upstream upgrading/processing than oil and gas. In general any impurities will result in lower energy content in its end-use, rather than being removed in the upstream as with oil and gas. One main exception is the production of coking coal from hard coal, which requires energy inputs and therefore incurs costs, losses, and emissions across the upstream sector. Coking coal, used predominantly in the production of iron and steel is represented in TIAM-UCL as a product of heating hard coal at very high temperatures (≥ 1000°C), leaving very high concentrations of carbon[35].

Fossil methane gas

Fossil methane gas requires processing to ensure it is of pipeline / liquefaction quality. This involves removing any impurities which could undermine the integrity of transportation / further transformation infrastructure, such as hydrogen sulphide (H_2S) and carbon dioxide (CO_2) corroding gas pipelines, or CO_2 in a liquefaction terminal which would freeze at a much higher temperature than methane liquefies, and therefore lead to blockages/system shutdown at the facility.

After the mining process in the model, fossil methane gas then passes to an upstream process for the collection and processing of fossil methane gas from the well-heads to gas processing plants. Regionalised operation and maintenance costs are associated with this processing technology, as well as historical capacities. Additionally, a distinction is made between the gathering and processing of non-associated conventional fossil methane gas, and unconventional fossil methane gas. This process (taking into account emissions intensities, efficiencies, and any required energy inputs) turns the output gas from the mining process into an energy commodity which can either be traded internationally, via pipeline or LNG, or can be used as 'useful' input downstream (in conversion or end use sectors).

Due to its large regional-scale and intensive data requirements, TIAM-UCL is not able to accurately reflect the techno-economic characteristics of smaller downstream distribution networks for fossil methane gas (e.g. distribution networks in urban areas which transport gas to individual households for cooking and heating service demand) due to the granularity required to effectively model such networks. However, additional user constraints have been added in the model to prevent excessively large and unrealistic uptake of downstream fossil methane gas, particularly for the residential sector, in regions/sub-regions where this is highly unlikely, at least in the near-term.

Additionally, underlying capacities and new capacity costs have been added into TIAM-UCL for associated fossil methane gas[10], in order to reflect the fact that whilst it is produced as a relatively low cost by-product of oil, it still requires infrastructure to be in place, and is therefore a key reason behind large-scale flaring and venting in some regions. Supplementary Table 13 shows a range of investment and O&M costs for associated fossil methane gas projects, which have been incorporated in TIAM-UCL. These improvements led to a more accurate recalibration of actual production volumes of associated fossil methane gas in the near-term. Associated gas is modelled differently, in the sense that the supply cost is the cost of separating and processing the gas to yield 'dry stripped gas' (essentially pure methane). This is because associated gas is based on oil extraction economics, and therefore a field level analysis was not possible. The TIAM-UCL model has been amended to include region-specific operational costs associated with separating and processing, as well as investment costs (CAPEX) for building new associated gas processing capacities if necessary.

Supplementary Table 13. Range of associated fossil methane gas investment and operational costs

Associated gas production field/region	CAPEX, \$/MMBtu	OPEX, \$/MMBtu	Region (Country)	Source
Bakken		0.31-0.67	United States (USA)	EIA (2016)[36]
Grand Rapids Bitumen	11.25	0.62	Canada (Canada)	AER (2018)[37]
Tengiz	2.40		Former Soviet Union (Kazakhstan)	Carbon Limits (2013)[38]

Middle East OPEC		0.8-1.3	Middle East OPEC countries	IPAA (2015)[39]
Utorogu	1.95		Africa (Nigeria)	OGJ (2016)[40]
Nigeria offshore		0.09-0.38	Africa (Nigeria)	Santley et al (2014)[41]
El Merk		0.27	Africa (Algeria)	Aissaoui (2016)[42]
Gassi Touil		0.60	Africa (Algeria)	Aissaoui (2016)[42]
Cantarell		0.18	Mexico (Mexico)	IMCO (2014)[43]
Ku-Maloob-Zaap		0.11	Mexico (Mexico)	IMCO (2014)[43]

* Sourced from Welsby, 2021[10].

Oil

Oil generally requires the most refining, upgrading and processing in the upstream sector prior to being sent further downstream (e.g. crude oil as a traded commodity, or derived naphtha as a feedstock into petrochemical production of plastics etc.). In particular, for some forms of unconventional oil, a huge operation is required to upgrade the oil to 'useful' forms of energy (e.g. crude oil), which requires large-scale investment in upgrading infrastructure and intensive energy inputs into the processes. For example, extra-heavy oil and bitumen oil require significant upgrading to reduce the viscosity of the oil from a tar-like liquid (hence the name tar-sands) to a less viscous compound which can be transported by pipeline. A significant part of the improvements made to the upstream sector of TIAM-UCL was to provide insights into the costs and availability of unconventional oil production[9]. These costs and material flows (including externalities associated with production of oil and gas, such as fugitive emissions, flaring, emissions from the upgrading process, etc.) can be separately assessed in the model prior to the processed product eventually being used downstream. These upstream processes to upgrade and process require energy inputs, which have a range of efficiencies and costs. This is important for ensuring cost and additional energy use, and emissions, are captured, beyond the energy use and emissions associated with the initial extraction phase. This is of particular importance for bitumen and extra-heavy oil, where the upgrading process can account for upwards of 50% of the production cost (i.e. generating synthetic crude).

TIAM-UCL has a detailed representation of the use of upstream energy fuels, whereby an energy commodity output from the upstream sector requires energy commodity inputs to produce a useable commodity downstream. An example of this would be the use of fossil methane gas in in-situ and mined oil sands production, whereby the gas is used to generate steam/heated water, which increases the temperature of the oil in the reservoir or separates the oil from the sand, increasing the viscosity which allows it to flow at sufficient rates[44]. Supplementary Table 14 shows a (simplified) section of the upstream for the production of crude oil from synthetic mined bitumen, as well as the upstream energy requirements (input commodities with subscript UPS_).

Supplementary Table 14. Example of upstream transformation for mined oil sands into synthetic crude oil

Mining process	**Output commodity**	**Primary transformation**	**Input commodity**	**Output commodity (efficiency)**

Oil sands, mined bitumen	Oil sands	Production of synthetic oil from mined bitumen	Oil sands UPS_Fossil methane gas UPS_Electricity UPS_Heat (Steam) UPS_Hydrogen UPS_Biofuels	Crude oil (72%) Heat Flared and vented Fossil methane gas CO_2 CH_4

Energy trade

Once extracted and processed, fossil fuels can then be transported between regions. An underlying trade matrix is used to determine inter-regional trade flow opportunities. For flexible forms of transportation (i.e. by maritime transport), the number of trade links will be higher than more constrictive forms of trading energy commodities (e.g. by pipeline, which are not just restricted by cost but also by geopolitical and geographical constraints). Supplementary Figure 15a shows a representative trade matrix for crude oil, with the number of trade links (represented by the number 1) significantly higher due to the flexibility of ocean tankers over pipelines, with the significantly lower number of trade links for fossil methane gas via pipeline shown in Supplementary Figure 15b. The comments in this figure reflect some of the main uncertainty in pipeline routes, with the several projects stalling over several years and with no final investment decision taken. Therefore, the decision whether to switch these trade links on/off rests with the user.

a)

~TradeLinks

OILCRD	AFR	AUS	CAN	CHI	CSA	EEU	FSU	GBL	IND	JPN	MEA	MEX	ODA	SKO	USA	WEU	UK	MINRNW	IMPEXP
AFR		1		1		1			1	1			1	1	1	1	1		
AUS				1						1									
CAN	1			1		1			1	1	1	1	1	1	1	1	1		
CHI																			
CSA	1			1		1			1	1		1	1	1	1	1	1		
EEU																			
FSU	1	1	1	1	1	1			1	1		1	1	1	1	1	1		
GBL																			
IND																			
JPN																			
MEA	1	1	1	1	1	1	1		1	1		1	1	1	1	1	1		
MEX															1				
ODA		1		1					1	1				1					
SKO																			
USA	1	1	1	1	1	1	1		1	1	1	1	1	1		1	1		
WEU															1		1		
UK			1												1	1			
MINRNW																			
IMPEXP																			

b)

~TradeLinks

GASNGA	AFR	AUS	CAN	CHI	CSA	EEU	FSU	GBL	IND	JPN	MEA	MEX	ODA	SKO	UK	USA	WEU	MINRNW	IMPEXP
AFR																	1		
AUS																			
CAN																1			
CHI														1					
CSA																			
EEU																	1		
FSU				1		1					1		1	1			1		
GBL																			
IND																			
JPN																			
MEA						1	1		1				1						
MEX																1			
ODA				1															
SKO																			
UK																	1		
USA			1									1							
WEU						1									1				
MINRNW																			
IMPEXP																			

Daniel Welsby:
Take out for non-TAPI runs

Daniel Welsby:
Constrain MEA_IND trade and no capacity start until 2025

Daniel Welsby:
Dependent on the Iran Pakistan (India) pipeline being built

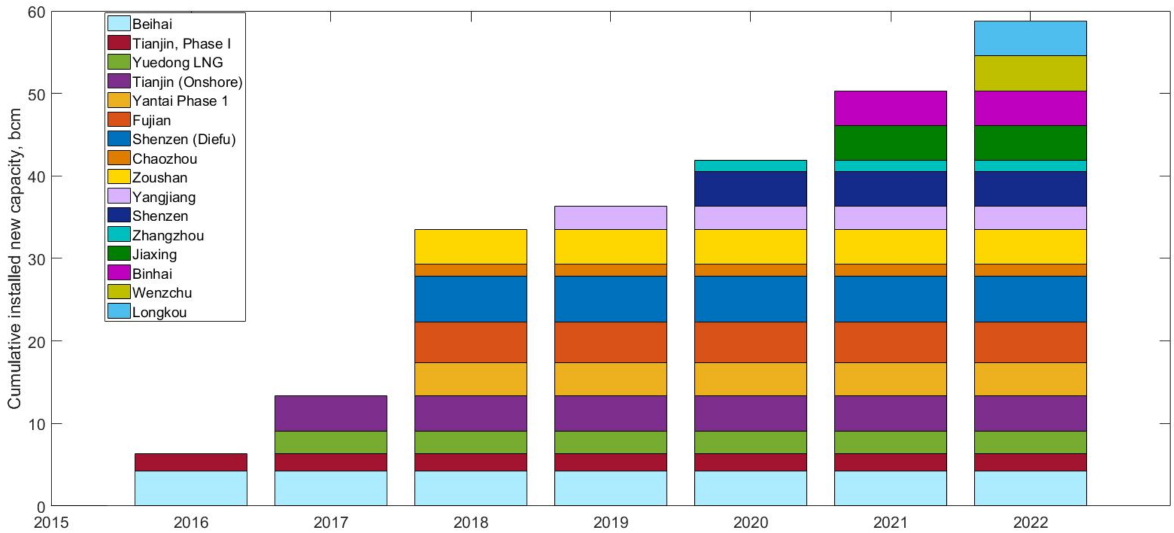
Supplementary Figure 15. Trade links between TIAM-UCL regions for a) crude oil and b) fossil methane gas via pipeline

Coal

It is assumed in TIAM-UCL that only higher-grade coal is traded; i.e. sub-bituminous, bituminous and anthracite. All trade flows for coal have been recalibrated in the model to ensure that 2015-2020 flows of coal around the world are consistent with historical data[45,46]. As with fossil methane gas (and oil) discussed subsequently, the trade of coal incurs costs, namely for its transportation via international shipping or across land-borders (i.e. by rail). The transportation costs, as with fossil methane gas and oil, are determined based on average shipping/train capacities and rental rates, and the distance between the regions. However, unlike fossil methane gas which requires processing, transformation and transportation infrastructure (e.g. liquefaction plants and pipelines), coal can be more easily transported and therefore it is assumed no investment costs are required.

<u>Fossil methane gas</u>

Fossil methane gas trade in TIAM-UCL is split between pipeline gas and liquefied natural gas (LNG). Both are constrained firstly by the underlying trade matrix shown above. Additionally, trade volumes and infrastructure have been calibrated to 2015/2020-2025, with under construction infrastructure (both pipeline and LNG) fixed to come online in the model by 2020/2025, depending on an estimated start-date[21,47]. For example, Supplementary Figure 16 shows under construction regasification capacity for China between 2016 and 2022, which is used to bound the build rates of trade infrastructure capacity.



Supplementary Figure 16. Cumulative installed regasification capacity in China, 2016-2022. Source data are provided as a Source Data file. Source: IGU, 2019[48]

Liquefied fossil methane gas trade in TIAM-UCL includes infrastructural parameters (liquefaction and regasification capacities, and build constraints) and cost parameters (CAPEX on new infrastructure, OPEX on the liquefaction/regasification process, and a shipping cost). Regionalised liquefaction costs have been included based on:

- Representative projects in each region, including the location of the liquefaction terminal and investment costs;
- Competition for E&P in recent years which led to real price inflation on projects built between 2010 and 2020[49];
- Whether the project was a brownfield extension or conversion (e.g. conversion of regasification (import) terminals in the United States into liquefaction (export) facilities), or green-field integrated project (e.g. Yamal LNG field and export facility development in

Russia, and several projects in Australia including Gorgon, Ichthys (floating), and Wheatstone).

Supplementary Table 15 shows a range of investment costs for liquefaction terminals in TIAM-UCL, showing the cost inflation attributed to a large range of projects coming online at the same time, and the corresponding stabilisation of these costs. It clearly shows which regions have the potential to take advantage of cost de-escalation for brownfield conversions/expansions[50], i.e. the USA and the Middle East, before (at least in this example) costs converge across regions for green-field investments. Additionally, the amount of capacity which can be converted / expanded under these lower costs has been limited to existing regasification capacity and/or a maximum upper limit based on proposed brownfield extensions.

Supplementary Table 15. Liquefaction investment costs by region and year in TIAM-UCL, $M/PJ

Year	AFR	AUS	CAN	CHI	CSA	EEU	FSU	IND	JPN	MEA	MEX	ODA	SKO	UK	USA	WEU
2006	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
2010	16	16	16	14	16	18	16	14	16	9	16	14	14	18	9	18
2015	10	20	16	14	16	18	16	14	16	9	16	14	14	18	9	18
2020	10	21	22	20	20	20	20	20	20	10	20	20	20	20	12	20
2025	25	21	22	20	20	20	20	20	20	10	20	20	20	20	12	20
2050	20	21	20	20	20	20	20	20	20	18	20	20	20	20	12	20

* Sourced from Songhurst, 2014; 2018[49,50]; adapted by Welsby, 2021[10]. Note $M refers to million USD per petajoule.

LNG variable O&M (i.e. shipping) costs in TIAM-UCL are calculated based on a range of parameters[10,51]:

- Assumed distance between ports
- Average speed of tanker
- Average capacity of tanker; calculated based on average capacity of tankers which are assigned to fixed routes and/or average size of delivery
- Daily rental rate of tanker which is highly volatile depending on available capacities in each basin and seasonal spikes in LNG demand[52]; however, for a long-term energy systems model a fixed figure is assumed based on McGlade et al.[51].
- Boil-off rate (i.e. efficiency of transportation process translated into losses of fossil methane gas), which in turn is a function of journey time
- Loading/unloading time at each port

A database of LNG transportation costs has been developed[10], with representative average shipping costs between the TIAM-UCL regions used if more than one trade route is used. An example of these shipping costs between individual liquefaction and regasification terminals is shown in Supplementary Table 16 below. For reference, the exporters are in red, and the zeros reflect that a) there is no intra-regional trade in TIAM-UCL and b) some regions are exogenously determined (through the trade link matrix shown) not to be able to trade with each other.

User constraints for fossil methane gas trade through LNG are employed for both the technology which covers overall export capacity (i.e. the liquefaction process technology) and the bilateral trade process itself. In short, this constrains the model from building new capacity too quickly and sending all of the potential output through a single trade link.

Supplementary Table 16. Representative shipping costs for LNG between TIAM-UCL regions, $M/PJ

	AFR	AUS	CAN	CHI	CSA	EEU	FSU	IND	JPN	MEA	MEX	ODA	SKO	UK	USA	WEU
AFR	0	0	0	1.09	0.26	0	0	0.84	1.28	0.63	1.06	1.02	1.19	0.83	0	0.81
AUS	0	0	0	0.75	0	0	0	0.96	0.8	0	0	0.73	0.8	0	0	0
CAN	0	0	0	0.85	0	0	0	1.2	0.81	0	0.62	0.85	0.82	0	0	0
CHI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CSA	0	0	0	1.07	0	0	0	0.97	1.14	0.91	0.78	1.15	1.12	0.81	0	0.8
EEU	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FSU	0	0	0	0.72	0	0	0	1.39	0.59	0	0	1.38	0.66	0.81	0	0.8
IND	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
JPN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MEA	0	0	0	0.83	0.81	1.02	0	0.6	0.94	0	1.28	0.74	0.92	0.97	0	0.85
MEX	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ODA	0	0	0	0.66	0	0	0	0.71	0.73	0	0	0	0.69	0	0	0
SKO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
USA	0	0	0	1.09	0.84	0.91	0	1.21	1.11	0	0.72	1.1	1.09	0.85	0	0.9
WEU	0	0	0	0	0	0.63	0.64	0	0	0	0	0	0	0	0	0

* Sourced from Welsby, 2021[10].

For pipeline investment costs and capacity additions in the near-term, individual project costs and capacity have been added where appropriate (e.g. pipeline cost and maximum volume from Russia to China between 2015 and 2020 are based on the Power of Siberia pipeline, which came online at the end of 2019). Some examples of pipeline investment costs are shown in Supplementary Table 17, with each pipeline at different development stage[10]. However, other factors need to be taken into account including whether the pipeline has to cross challenging physical barriers (e.g. a sea or mountainous territory).

Supplementary Table 17. Pipeline investment costs for a range of representative projects used in TIAM-UCL

Pipeline Name	**Status**	**Investment Cost, $M/PJ**	**Investment Cost, $M/km**
Power of Siberia	Under-construction	10.38-23.02	5.27-11.67
Central Asia-China	Operational	3.51	3.99
TAPI	Proposed	6.66-8.33	7.11-8.89

Additionally, a user constraint has been added as an upper bound on potential gas pipeline trade, with a similar functional form as the upstream constraints discussed in the section that follows. In short, it is assumed that the model can, at a maximum, double capacity across a ten year period for any trade route (e.g. add a new pipeline parallel to an existing one with the same capacity)[10]. Therefore, an exponential growth constraint is set in the following form shown in Equation 1:

$$PipeCap_{a \to b,t} \leq PipeCap_{a \to b,t-1} * PipeGro^{ts} + Seed_{r,t} \qquad (1)$$

Where,

$PipeCap_{a \to b,t}$ = pipeline capacity between exporter *a* and importer *b*, in time period *t*

$PipeCap_{a \to b,t-1}$ = pipeline capacity between exporter *a* and importer *b*, in time period *t-1*, i.e. the preceding time period

$PipeGro^{ts}$ = pipeline growth coefficient, set at ~1.07 (i.e. allows a doubling of capacity over 10 years using the above formulation)

$Seed_{r,t}$ = seed value for region *r* and time-period *t*, which allows growth value to take hold if there is no historical trade link, or adds on to the growth constraint for absolute upper bound (i.e. slackness on the constraint). The seed value is added across the time-slice, rather than in each individual year. As with LNG, this is based on a maximum capacity addition across a time-slice.

For regions where volumes of trade are already well established and there is significant pipeline capacity in place, the seed value has been set to zero from 2020 (e.g. between the UK and Western Europe, and the USA and Canada). A seed value is included in these cases between 2006 and 2015 in case large increases in gas pipeline trade were in evidence, such as between the United States and Mexico after the expansion of shale gas in the Barnett shale play. In short, the seed value allows the model to expand trade up to the upper bounds which have been added for 2015 to calibrate fossil methane gas trade to historical data. However, some trade links have a seed value from 2020 to allow the model to expand pipeline capacity over the growth coefficient alone. For example, the seed value for gas pipeline trade between the Former Soviet Union and China is bounded (upper) by the growth coefficient (1.07/a) and a seed value equivalent to the Power of Siberia pipeline operating between a minimum (70%) and maximum (90%) contracted quantity[10].

<u>Oil</u>

The trade of oil commodities is split into various different products, which are outputs of processing / transformation processes in the upstream: crude oil, heavy fuel oil, naphtha, gas liquids, and diesel. As with fossil methane gas trade via LNG tankers, the variable cost of transporting oil via tankers is assumed to be a function of the distance between ports, the speed of the tanker, and the average capacity of a ship travelling from the exporter to the importer.

Key upstream constraints

<u>Coal</u>

Upstream constraints for coal extraction are not as widely applied for two main reasons. Firstly, the extraction of coal does not follow the same geological production profile of oil and gas extraction; i.e. the growth and decline of production profiles through time and different geological structures. Secondly, for decarbonisation scenarios meeting 2°C and below, coal is rapidly phased out of the energy mix. Traditionally, this decline has not been constrained in previous iterations of TIAM-UCL, however in this paper we have constrained the rate at which coal can be phased out of the energy system.

Oil and fossil methane gas

There are a range of upstream user constraints which control the rate at which production of different categories of oil and gas can grow/decline. In short, these user constraints model the natural growth and decline of oil and fossil methane gas. The predominant form of constraint is an exponential (constant) rate of growth/decline across a time-slice, using seed values if there is no residual (historical) productive capacity. Equation 2 shows the functional form of these growth (a) and decline (b) constraints, for extractive technologies with historical production, while (c) and (d) shows the same equations for technologies which have no historical production and therefore require a seed value.

$$Production_{i,t} \leq (Production_{i,t-1} * Growth^{ts}) + Seed_{i,t} \quad \text{(2 (a))}$$

$$Production_{i,t} \geq (Production_{i,t-1} * Decline^{ts}) + Seed_{i,t} \quad \text{(2 (b))}$$

$$Production_{i,t} \leq Seed_{i,t} * Growth^{ts} \quad \text{(2 (c))}$$

$$Production_{i,t} \geq Seed_{i,t} * Decline^{ts} \quad \text{(2 (d))}$$

Where,
$Production_i$ = production of oil/gas for mining process i
$Seed_i$ = seed value from which growth/decline coefficients are assigned to if no historical (i.e. $t-1$) volumes, and which is added to overall growth/decline constraint across each time-slice
t = time period in the model (therefore $t-1$ is the previous time-slice)
$Growth$ = growth coefficient, where $Growth \geq 1$
$Decline$ = decline coefficient, where $Decline \leq 1$
ts = time-slice length (i.e. $t - (t-1)$)

Therefore, for growth constraints, the production of an oil and/or gas mining technology in time slice t will be bounded (upper) by a maximum of production in time slice $t-1$ multiplied by the growth coefficient to the power of the length of the time-slice. For decline constraints, the inverse applies: production in t will be bounded (lower) by a minimum of production in $t-1$ multiplied by the decline coefficient to the power of the time-slice length. Supplementary Table 18 shows examples of the growth/decline coefficient parameters and seed values used in TIAM-UCL, for a range of oil (a) and gas (b) mining technologies.

For example, shale gas decline rates were calculated using well-level data from the United States (Marcellus)[10]. Over 950 shale gas wells were assessed over a 10 month period; the rate of decline for these wells, when aggregated, best fit a hyperbolic profile. The rate of change between the first year and last year was then calculated to give a constant annual rate of decline. In order to generate a decline parameter which fits the formulation of user constraints in TIAM-UCL (Equations 2 (a-d)), this annual decline rate was then re-calculated to an equivalent rate of decline but as a constant exponential rate of decline. For the shale gas wells examined, this translates as a decline coefficient of ~ 0.83, which when raised to the power of 5 (assuming a five year time-slice), gives a maximum rate of decline of ~ 60% between *t-1* and *t*. Additional constraints have been input as a proxy for controlling the expansion of associated fossil methane gas. Whilst the production itself is a function of oil extraction (and oil economics), the infrastructural issues surrounding associated gas utilisation require some degree of user constraint. Therefore, an upstream constraint is placed on the speed at which associated gas processing and separation capacity can be added.

Supplementary Table 18. a) User constraints for a range of oil mining technologies extraction processes and b) gas extraction processes in TIAM-UCL

a)

Mining technology	**Growth coefficient**	**Decline coefficient**
Conventional proved reserves	1.41 ($\sqrt{2}$)	0.93
Conventional reserve additions	1.41 ($\sqrt{2}$)	0.93
Conventional undiscovered	1.41 ($\sqrt{2}$)	0.93
Shale oil	1.07	0.8
Mined bitumen	1.07	0.8
In-situ bitumen	1.1	0.85

b)

Mining technology	**Growth coefficient**	**Decline coefficient**
Conventional proved reserves	1.41 ($\sqrt{2}$)	0.95
Conventional reserve additions	1.41 ($\sqrt{2}$)	0.92
Conventional undiscovered	1.41 ($\sqrt{2}$)	0.92
Shale gas	1.27	0.83
Tight gas	1.12	0.83
Coal bed methane	1.12	0.83

Note: Regional variations are taken into account; therefore the numbers above may differ between regions. Additionally, the decline rate for conventional oil and gas fields will vary depending on the size of the field, the stage of decline, and the geological structure of the reservoirs (IEA, 2009). For example, larger fields generally exhibit slower rates of production decline, as shown with the value for conventional proved gas reserves which is taken from a representative decline parameter calculated from super-giant gas fields in the Former Soviet Union (e.g. Urengoy)[10].

Supply chain emissions from upstream fossil fuel activity

TIAM-UCL accounts for methane leakage from the gas supply chain, with a user-defined percentage of total fossil methane gas supply being lost into the atmosphere (i.e. direct methane emissions). Distinctions are made between conventional and unconventional fossil methane gas. A central methane leakage rate was derived across a range of literature [10]. The global warming potential of methane in TIAM-UCL is calculated over a 100-year time horizon (GWP-100), therefore where studies reported a different GWP time-period (e.g. 25 years), these were converted to GWP-100. For this study, our global average central leakage rate assumptions were 1.7% for conventional fossil methane gas and 2.1% for unconventional gas.

In addition to gas supply chains, TIAM-UCL also tracks methane emissions from oil and coal supply chains. For oil, fugitive methane emissions or intentional venting of methane is directly related to the presence of associated fossil methane gas. In short, if there is no infrastructure in place and/or demand downstream to absorb associated gas, the methane is either directly released into the atmosphere (venting) or flared (burnt-off) and released as CO_2. TIAM-UCL has various options for mitigating methane emissions from oil supply chains. Firstly, the model can build capacity to utilise rather than flare/vent fossil methane gas produced as a by-product of oil production (see Supplementary Table 13).

Additionally, there is also a dummy option where the model can chose to flare rather than vent the methane if there is no demand for gas downstream/if building capacity is not cost optimal. Therefore, instead of methane being released into the atmosphere, CO_2 is instead emitted. As with oil, there are options available to minimise methane emissions from coal mining. These include an option to gather the methane and inject it into pipelines for use downstream, or a dummy option to flare the gas, therefore releasing CO_2 into the atmosphere rather than methane.

SI section 6. Key assumptions used in TIAM-UCL v4.1.1

This supplementary information describes some of the core assumptions used in this analysis. Additionally, the individual countries making up each region in TIAM-UCL are listed in Supplementary Table 26. Many of the same model assumptions were used in this recent report by Pye et al.[53].

Demand drivers

For most of the scenarios assessed, population and economic growth drivers are based on the SSP2 'Middle of the Road' scenario narrative. These drivers are used to construct the energy service demands across different sectors. Some adjustments have been made to energy service demands to ensure final energy demand globally falls within the SSP2 marker model (MESSAGE) range. As SSPs are independent of climate ambition, defining the socio-economic backdrop that a given climate ambition has to be achieved within, the demands for SSP2 in TIAM have been tuned to match the marker model's base / reference SSP2 run with no climate constraints[54]. Region specific values are used but global values are shown in Supplementary Table 19.

Supplementary Table 19. Demand drivers used in TIAM-UCL scenarios

Category	Assumption	Values				Units
		2030	**2050**	**2080**	**2100**	
SSP2	Population	8.3	9.2	9.4	9.0	billion
	GDP	17	25	42	59	000 US$2005/cap

Bioenergy characterisation and availability

Bioenergy is characterised into first and second generation fuels. First generation fuels are represented as bioliquids (bioethanol and biodiesel from crops which might compete with food crops for land) and biomethane (gas captured from controlled landfill sites). Four types of second-generation bioenergy feedstock distinguished: i) Solid biomass (BIOSLD), comprising woody residues from forestry and agriculture; ii) Energy crops (BIOCRP), comprising second generation purposely grown energy crops (grassy and woody bioenergy crops); iii) Municipal waste (BIOBMU), comprises wastes produced by households, industry, hospitals and the tertiary sector that are collected by local authorities; and iv) Industrial waste (BIOBIN), Solid and liquid products (e.g. tyres, sulphite lyes (black liquor), animal materials/wastes), usually combusted directly in specialised plants to produce heat and/or power. For each of these fractions cost supply curves are specified within the model for each of the 16 regions, i.e. amount of biomass available at different costs in each region. Cost ranges for solid biomass range between 4-16 $/GJ, and for energy crops between 9-15 $/GJ, with zero cost for waste fractions. To avoid competition for land, energy crops are assumed to be grown only on marginal and degraded land. Importantly, only solid biomass and energy crops fractions can be used for BECCS, and traded between regions. Supplementary Table 20 lists the global potentials for each bioenergy type.

Supplementary Table 20. Bioenergy availability (central estimates)

Bioenergy category	**Values by year, EJ potential**				**Source**
	2030	**2050**	**2080**	**2100**	
Solid biomass	43	45	48	50	Daioglou et al. (2016)[55]
Energy crops	17	31	31	31	Marginal land availability and energy crop yields from Ricardo-AEA. (2017)[56]. Biomass Feedstock Availability. Final report for BEIS. Supply cost curves based on Hoogwijk et al. (2009)[57]
MSW	17	27	27	28	TIAM-ETSAP

Conversion technology assumptions

A key input into the TIAM-UCL model is the assumptions on costs and performance of different conversion technologies, which produce low carbon vectors. This section provides an overview of the key assumptions for different technology groups. Supplementary Table 21 provides information regarding the power generation sector. An important constraint for this sector is one that prevent unabated coal generation disappearing at too rapid a speed i.e. no faster than observed in the fastest power generation transition. For this, we use the phase out dates under the Powering Past Coal Alliance (PPCA). This is 2030 for OECD and EU members, and 2050 for others (except the European countries that have already committed to earlier dates).

The assumptions for the suite of BECCS technologies available in the model can be found in Supplementary Table 22. The main 'brake' on this technology set is the bioenergy resource availability. The other negative emission technology in TIAM-UCL is Direct Air Capture (DAC) which draws on heat and electricity inputs to capture CO2 directly from the atmosphere and sequester it. Supplementary Table 23 has the cost and technical lifetime assumptions used for DAC.

On the supply side, hydrogen production technologies are divided into three different scales: centralised large-scale, centralised medium and decentralised small-scale production. Large-scale plants are based on biomass, coal and gas with continuous production of hydrogen. These plants are available with and without CCS technology. Hydrogen produced from centralised plants are transported with two different transportation options: long-distance pipe line transportation (gaseous hydrogen) and liquefaction plus trucks (liquid hydrogen). Hydrogen production data is presented in Supplementary Table 24, and are based on the review by Dodds and McDowall, 2012[58].

Supplementary Table 21. Power generation costs and efficiency assumptions

	CAPEX, $2005 /kW					Efficiency, %			
Technology	**2010**	**2020**	**2030**	**2040**	**2050**	**2010**	**2020**	**2030**	**2050**
MSW combustion	5236	4862	4488		4114	23	27	30	33
Bioenergy combustion	2618	2431	2244		2057	28	31	34	37
Bioenergy combustion (dcn)	2880	2674	2468		2263	28	31	34	37
Bioenergy gasification	3080	2860	2640		2420	31	34	37	40
Bioenergy gasification (dcn)	3388	3146	2904		2662	31	34	37	40
Coal IGCC	2376					44	48	51	54
Coal super critical	1870					41	42	42	42
Coal ultra super critical	2277					46	48	49	50
Gas CCGT	990					56	59	61	63
Oil generation (dcn)	659					31	31	31	31
Oil generation	495					38	39	40	42
Coal IGCC w/CCS		3802	3564		3326		38	43	48
Coal USC w/CCS		3643	3416		3188		39	42	46
Gas CCGT w/CCS		1584	1485		1386		49	53	57
Geothermal shallow	2376	2310	2255	2200	2129				
Geothermal deep	3911	3644	3383	3108	2846				
Geothermal very deep		4978	4510	4015	3564				
Hydro dam	1650-6050	1623-5913	1595-5775	1568-5638	1540-5500				
Solar CSP	5850	3330	2700	2385	2070				
Solar PV	2587	667	437		288				
Tidal	6600	5500	4400		3432				
Offshore wind		3229	2507	1983	1591				
Onshore wind		1110	1011	949	919				
Nuclear Advanced LWR	4166	3939	3849		3623				
Storage	3300	1359	1051	700	510	80	80	80	80

Source: All costs presented above are averages across the 16 regions in TIAM-UCL, however in the model, costs are differentiated across the different regions. Fossil and CCS technologies (Ekins et al. (2017)[59]; Rubin et al. (2015)[60]); CCS is available from 2030, and can see capacity growth of a maximum of 5% per annum. Power generation technologies have capture rates of 90%, which do not improve over time. Future solar PV and wind reductions based on BNEF estimates (unpublished), recent cost estimates based on IRENA[2]. The maximum build rate of new solar PV and wind capacity each year is set at 30% of existing capacity in line with recent solar PV build rates[4]. Range for hydro denotes different resource tranches and cost of exploitation. In the above table, 'dcn' denotes 'decentralised'.

Supplementary Table 22. a) BECCS technology costs and efficiency assumptions and b) other assumptions

a)

Technology Group	Technology Group	Efficiency %		Investment cost $/kW		Fix cost $/kW		Variable cost $/GJ	
	Year	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**
Electricity	Energy Crop Combustion w CCS	26	31	3060	2618	175	131	6.9	6.6
	Energy Crop Gasification w CCS	29	34	3600	3080	206	173	1.7	1.7
	Solid Biomass Combustion w CCS	26	31	3060	2618	175	131	6.9	6.6
	Solid Biomass Gasification w CCS	29	34	3600	3080	206	154	1.7	1.7
Heat	Heat from biomass with CCS	63	65	1671	1419	189			
Hydrogen	Hydrogen from biomass gasification + CCS	42	44	4594	3516	322	246		
Advanced transport fuels	FT process w CCS using solid biomass	34	42	2235	1565	27	27	0.8	0.8
	FT process w CCS using energy crops	34	42	2235	1565	27	27	0.8	0.8

b)

Technology Group	Technology Group	Start time	Life yr	Availability / capacity factor	CO_2 Capture rate %	Build rate %
Electricity	Energy Crop Combustion w CCS	2030	25	0.85	90	5
	Energy Crop Gasification w CCS					
	Solid Biomass Combustion w CCS					
	Solid Biomass Gasification w CCS					
Heat	Heat from biomass with CCS	2030	30	0.6	90	3
Hydrogen	Hydrogen from biomass gasification + CCS	2030	30	0.9	90	5
Advanced transport fuels	FT process w CCS using solid biomass	2030	30	0.9	50	5
	FT process w CCS using energy crops					

Source: Butnar et al. 2020[61]

Supplementary Table 23. Direct Air Capture costs and technical lifetime assumptions

Technology	Life (yr)	Fixed O&M costs ($2005/tCO2/yr)	Capital investment costs ($2005/$tCO_2$)
		2030	**2030**
Direct air capture	20	120	2900

Supplementary Table 24. Hydrogen production technology costs and efficiency assumptions

Technology	Size	Fixed O&M costs (% capital costs)	Capital investment costs ($2005/GJ/y)	
			2025	**2050**
Coal gasification	Large	0.05	27	24
Gas SMR	Large	0.04	7	5
Gas SMR	Small / medium	0.04	17	14
Biomass gasification	Large	0.07	26	26
Biomass gasification	Medium	0.07	34	34
Biomass gasification	Small	0.07	43	43
Waste gasification	Medium	0.07	34	34
Electrolysis	Large	0.04	7.7	2.4
Electrolysis	Medium	0.05	8.8	2.7
Electrolysis	Small	0.05	10	3.1

Other key assumptions

- LULUCF emissions. Land use and forestry (LULUCF) emissions of CO_2 are based on a fixed trajectory, using outputs from the IMAGE model, based on the RCP2.6 SSP2 case. They are net CO_2 emissions from deforestation, and reforestation in line with SSP2 RCP2.6 assumptions (Supplementary Table 25).
- Non-CO_2 GHGs. Some non-energy sector sources of CH_4 and N_2O are not explicitly represented in TIAM-UCL but rather included as an emissions trajectory based on the RCP database. Such sources include CH_4 from landfill and waste water, and agriculture (manure, rice paddies) and N_2O from industry (nitric and adipic acid) and agriculture. In this modelling, the RCP2.6 trajectory is used for climate ambition cases (Supplementary Table 25). Emissions of these gases from the energy sector (e.g. CH_4 leakage from fossil methane gas extraction and transport) are capped under an overall constraint, which includes the sources above.
- Discount rate. The social discount rate used in the calculation of net present value (used as the basis for the objective function) is set at 3.5%.
- Base year. Model is calibrated based on 2005 IEA energy balances. Additional constraints have been introduced in the model to help represent the energy system in 2010 and 2015 - and to reflect projected emissions in 2020.

Supplementary Table 25. LULUCF and non-CO_2 GHG emissions

Emissions	Values by year				Units	Source
	2030	**2050**	**2080**	**2100**		
CO_2 from LULUCF	2.5	1.2	-1.0	-1.5	$GtCO_2$	Trajectory sourced from SSP Public Database (Version 1.1) hosted by IIASA https://tntcat.iiasa.ac.at/SspDb/dsd?Action=htmlpage&page=welcome. Model-Scenario: IMAGE SSP2-26
CH_4	275,467	212,033	178,996	157,291	Kt	
N_2O	9297	8863	8320	7920	Kt	

Additional documentation for TIAM-UCL can be found on the Integrated Assessment Modelling Consortium (IAMC) wiki at https://www.iamcdocumentation.eu/index.php/Model_Documentation_-_TIAM-UCL.

Supplementary Table 26. List of regions and countries in the 16 region TIAM-UCL model

Region	Countries
Africa (AFR)	Algeria, Angola, Benin, Botswana, Burkina Faso, Burundi, Cameroon, Cape Verde, Central African Republic, Chad, Comoros, Congo, Côte d'Ivoire, Democratic Republic of the Congo, Djibouti, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Gambia, Ghana, Guinea, Guinea-Bissau, Kenya, Lesotho, Liberia, Libya, Madagascar, Malawi, Mali, Mauritania, Morocco, Mozambique, Namibia, Niger, Nigeria, Rwanda, Sao Tome and Principe, Senegal, Seychelles, Sierra Leone, Somalia, South Africa, South Sudan, Sudan, Swaziland, Togo, Tunisia, Uganda, United Republic of Tanzania, Zambia, Zimbabwe
Australia (AUS)	Australia, New Zealand
Canada (CAN)	Canada
Central and South America (CSA)	Anguilla, Antigua and Barbuda, Argentina, Aruba, Bahamas, Barbados, Belize, Bermuda, Bolivia, Brazil, Cayman Islands, Chile, Colombia, Costa Rica, Cuba, Dominica, Dominican Republic, Ecuador, El Salvador, Falkland Islands, Grenada, Guatemala, Guyana, Haiti, Honduras, Jamaica, Martinique, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Saint Kitts and Nevis, Saint Lucia, Saint Vincent and the Grenadines, Suriname, Trinidad and Tobago, Uruguay, Venezuela (Bolivarian Republic of)
China (CHI)	China, Taiwan, Tibet
Eastern Europe (EEU)	Bosnia and Herzegovina, Bulgaria, Croatia, Czech Republic, Hungary, Montenegro, Poland, Romania, Serbia, Slovakia, Slovenia, The former Yugoslav Republic of Macedonia
Former Soviet Union (FSU)	Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Republic of Moldova, Russian Federation, Tajikistan, Turkmenistan, Ukraine, Uzbekistan
India (IND)	India
Japan (JAP)	Japan
Mexico (MEX)	Mexico
Middle-east (MEA)	Bahrain, Brunei Darussalam, Cyprus, Iran (Islamic Republic of), Israel, Jordan, Kuwait, Lebanon, Occupied Palestinian Territory, Oman, Qatar, Saudi Arabia, Syrian Arab Republic, Turkey, United Arab Emirates, Yemen
Other Developing Asia (ODA)	Afghanistan, American Samoa, Bangladesh, Bhutan, Cambodia, Democratic People's Republic of Korea, Fiji, French Polynesia, Indonesia, Kiribati, Lao People's Democratic Republic, Malaysia, Maldives, Mauritius, Mongolia, Myanmar, Nepal, New Caledonia, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Thailand, Timor-Leste, Tonga, Vanuatu, Vietnam
South Korea (SKO)	Republic of Korea
United Kingdom (UK)	United Kingdom
USA (USA)	United States of America
Western Europe (WEU)	Albania, Andorra, Austria, Belgium, Denmark, Faroe Islands, Finland, France, Germany, Gibraltar, Greece, Greenland, Iceland, Ireland, Italy, Luxembourg, Malta, Monaco, Netherlands, Norway, Portugal, San Marino, Spain, Sweden, Switzerland, Vatican

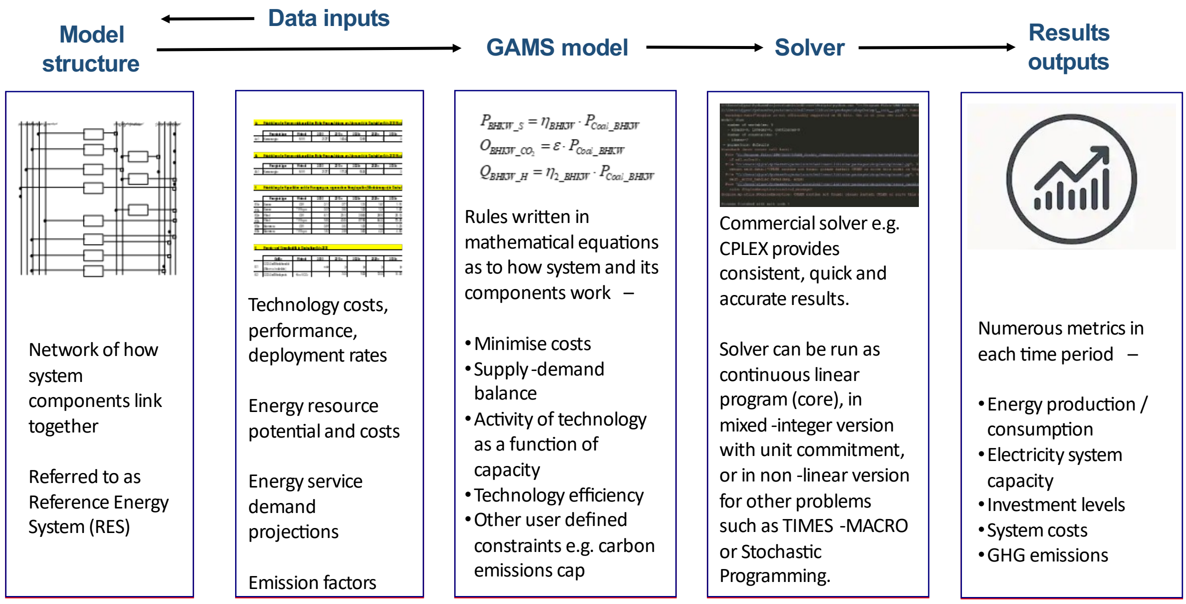
For reference, the following regions were aggregated to provide the regional unextractable shares reported in the main paper and in this supplementary information document: Europe = Eastern Europe, UK and Western Europe; Australia and other OECD Pacific = Australia and New Zealand, Japan, South Korea; China and India = China and India.

SI section 7. TIMES model formulation

TIAM-UCL uses the TIMES (The Integrated MARKAL-EFOM System) framework, a framework developed to explore and assess how energy systems may change over time, particularly in response to different policies e.g. climate or renewable energy targets, and drivers of energy demand e.g. economic growth. It is a partial equilibrium model, so balances supply and demand within the energy system, finding the least-cost solution for an energy system that meets future demand for energy services, such as space heating and cooling, mobility, and industrial production output.

A key feature of the model is that it is constructed from the technology level up, meaning that many of the system components e.g. refineries, vehicles, power stations, can be represented, including their performance and costs. An advantage of TIMES is that is can assess the role of these many different components within an interconnected system, exploring trade-offs, and dependencies, and providing a consistent assessment of the system as a whole. TIMES is also known as an E3 model, meaning that it provides metrics on the physical energy system (technology capacity, system operation, energy use totals), on the economics of the system (investment requirements, energy costs), and on the environmental impacts (GHGs).

TIAM-UCL, as typical of a TIMES model, is made up of five key components, as shown in Supplementary Figure 17. The first stage is the definition of what the system looks like (model structure), including the sectors to be included, typically from primary production through conversion to end use, types of technologies, and available energy resources. A Reference Energy System links all of these components together, allowing for the flow of energy through the system. Structure definition also include the spatio-temporal resolution e.g. number of regions, the number of time periods, and the time horizon over which the model is going to be run.



Supplementary Figure 17. Core components of the TIMES model framework

Each part of the model system is populated with data assumptions, including technology costs and performance, resource availability and cost, the demands that the system needs to meet today and in the future, and the associated emissions of different fuel-technologies.

The model input data are then used to construct a linear programme (using GAMS code), whereby the rules of the system operation and evolution are defined based on a set of mathematical equations. The linear programme is then solved to explore the least-cost energy system required to meet the energy service demands in the future, subject to constraints. A large number of metrics result that describe the emerging energy system, in terms of the physical system (number of vehicles, power system capacity, total bioenergy use), the costs of that system, and the emissions resulting from the system's operation.

This section now focuses on the core equations used in the linear programme. This code is available on Github, with full documentation available on the ETSAP website[62].

In simple terms, an optimisation model such as TIAM-UCL will –

- Minimise the objective function (total system costs)
- whilst satisfying the energy service demand requirements
- and respecting the system constraints

The key equations that set the rules of the model LP (linear programming) problem are summarised below:

- Objective function (EQ_OBJ). The function is to minimise total discounted system costs.

$$Min \quad \sum_{y} disc_{y} \left[\begin{array}{l} \sum_{p}\sum_{ts} \cdot varom_{y,p,ts} \cdot ACT_{y,p,ts} + \sum_{p} crf_{y,p} \cdot invcost_{y,p} \cdot NCAP_{y,p} + \sum_{p} fixom_{y,p} \cdot CAP_{y,p} \\ + \sum_{c}\sum_{ts} impprice_{y,c,ts} \cdot IMP_{y,c,ts} - \sum_{c}\sum_{ts} expprice_{y,c,ts} \cdot EXP_{y,c,ts} + \sum_{c}\sum_{p}\sum_{ts} flocost_{y,p,c,ts} \cdot FLO_{y,p,c,ts} \end{array} \right]$$

  Where *disc* is the global discount rate, *varom* is the variable O&M costs associated with technology activity (*ACT*), *invcost* is the capital expenditure associated with new investment (*NCAP*), discounted using the *crf* (capital recovery factor), *impprice* is the price of imports, multiplied by import level (*IMP*), *expprice* is the price of exports, multiplied by export level (*EXP*), and *flocost* is the cost of other domestic energy commodities (*FLO*).

  Where index *y* is year, *p* is process (technology), *c* is energy commodity, and *ts* is time segment.

- Commodity balance (EQ(l)_COMBAL). This equation ensures that the production of a commodity is equal to it consumption, to balance commodity markets.

$$\sum_{p \in Production} \sum_{ts} FLO_{t,p,c,ts} + \sum_{ts} IMP_{t,c,ts} = \sum_{p \in Consumption} \sum_{ts} FLO_{t,p,c,ts} + \sum_{ts} EXP_{t,c,ts}$$

- Transformation equation (EQ_PTRANS). This establishes the relationship between an input commodity to a technology and an output commodity e.g. technology efficiency

$$\eta_{t,p,cin,cout,ts} \cdot FLO_{t,p,cin,ts} = FLO_{t,p,cout,ts}$$

  Where η is the efficiency factor, and FLO_{cin} and FLO_{cout} represent the input and output commodities of a technology.

- Product allocation constraint (EQ(l)_INSHR/OUTSHR). Allows for the control of different commodity shares, where there are more than one input or output commodities into a technology.

$$\frac{FLO_{t,p,com,ts}}{\sum_{c \in cg} FLO_{t,p,c,ts}} \le (=, \ge) floshar_{t,p,com,cg,ts,bd}$$

  Where *floshar* defines the share of the single commodity (numerator) over the sum of commodities (denominator), or commodity group (index *cg*).

- Activity definition (EQ_ACTFLO). Activity of a technology is a function of the commodity flow, either of inputs but more typically outputs.

$$ACT_{t,p,ts} = FLO_{t,p,c,ts}$$

- Utilization constraint (EQ_CAPACT). Ensures that the activity of a technology is a function of its capacity

$$ACT_{t,p,ts} \le \alpha_{t,p,ts} \cdot CAP_{t,p}$$

While the above equations constitute the key set used in the linear programme, a full listing can be found in Loulou et al. (2016)[62], in Table 24. These include specific equations that bound capacity, activity and commodity production, set the rules for the operation of storage technologies, or ensures capacity exceeds demand for a selected commodity in a given time period (often used to ensure a peak margin for electricity systems).

User defined equations can also be built to provide more control over the model operation. Most are built using the standard LHS form, where the left hand side of the equation includes the variables to be controlled, while the right hand side (RHS) set the rule e.g. must be greater than 10% of total generation (share) or less than 50 GW capacity (absolute). Other user constraints are more dynamic in nature e.g. growth constraints that set % changes on the preceding period levels. For the purpose of modelling fossil fuels in a 1.5^{o}C world, important constraints used to represent production growth and decline were outlined in Section 5 (“Key Upstream Constraints”).

SI section 8. Correction of original unextractable estimates

This section provides a detailed description of the author correction to the original manuscript 'Unextractable fossil fuels in a 1.5°C world'. We provide the source of the off-model calculation error and show the differences between the corrected and original estimates. The vast majority of the original analysis (unextractable reserves for coal, unextractable resource estimates for all fossil fuels, production pathways) remains exactly the same.

We start with the Equations by which our unextractable estimates of reserves (Equation 1) and resources (Equation 2) are calculated. Our *unextractable resource* estimates in the corrected calculation have not changed because total modelled production is the same (Equation 2). It is the volume of production from proved reserves which has been corrected (Equation 1).

$$UnextractableReserves_{2050} = 1 - \left(\frac{\sum_{t=2018}^{2050} Production_{ProvedReserves}}{ProvedReserves_{2018}}\right)$$

(Equation 1)

Where:

$UnextractableReserves_{2050}$ = proportion of the 2018 reserve base which remains unextracted in 2050

$Production_{ProvedReserves}$ = production from the estimated proved reserve base for each geological/resource category in each region

$ProvedReserves_{2018}$ = proved reserves in each region in 2018

Similarly, for unextractable fossil fuel resources, we used the following formula as shown in Equation 2:

$$UnextractableResources_{2050} = 1 - \left(\frac{\sum_{t=2018}^{2050} Production_{Resources}}{Resources_{2018}}\right)$$

(Equation 2)

Where:

$UnextractableResources_{2050}$ = proportion of the 2018 resource base which remains unextracted in 2050

$Production_{Resources}$ = production from the total resource base in each region

$Resources_{2018}$ = total resource base in each region in 2018

Our off model error arose from that fact that, for some categories of oil and gas (as explained further below), our estimate mistakenly reduced the available volume of production from our proved reserve base in 2018. Therefore, whilst total cumulative production from these categories has not changed meaning the results from Equation 2 are unaffected (i.e. in relation to the total resource base), a higher share of this production needed to be assigned to proved reserves. This led to the overestimate of unextractable reserves (Equation 1) in some regions.

Our reserve base year is 2018 and our modelled cumulative production calculation starts in 2018. However, our results sheet, in which we estimate unextractable values, has production results starting in 2010. This is because the TIAM-UCL model, is run for the period 2005-2100, with production up to 2018 calibrated to historical data. Therefore in our off model calculation, we needed to assign production from 2010 to 2018 to the "reserve category", so that our available base reserves in 2018 are the quoted volumes in the paper (1276 Gb for oil, 155 tcm for fossil methane gas, and 931 Gtce for coal).

For conventional oil and gas, proved reserves are explicitly modelled in the supply cost curves and therefore these categories are unaffected. However, for specific categories of oil and gas including light tight oil, shale gas, tight gas and coalbed methane, there is no distinction between reserves and resources for those categories in the supply cost curve used in our model. Instead, reserves are assigned in our off-model calculations. This is due to proved reserves from these categories being limited to a small number of countries, as well as relatively limited data from which to conduct a full uncertainty analysis of the volume of proved reserves. In short, proved reserves from the categories identified above are not explicitly included in the model supply cost curves.

Additionally, the supply cost steps for the specific categories identified above are derived from a detailed bottom-up analysis of cost depletion curves and therefore current production (i.e. reserves) from these categories are implicitly taken into account. However, once cumulative production exceeds the allocated volume of reserves for these categories, production is assigned from the wider resource base. This resulted in lower cumulative production from estimated proved reserves from 2018 onwards, and therefore a higher proportion of reserves estimated to be 'unextractable' (Equation 1) within the carbon budget.

We provide the following example to highlight both the source of the error and correction for proved reserves of non-associated dry shale gas in the US as laid out in Supplementary Table 27.

Supplementary Table 27: Defining and correcting the off-model error in unextractable reserves

Proved shale gas reserves estimate (2018)	5 tcm	This is our starting estimate of proved reserves.
Historical cumulative shale gas production (2010-18)	3.1 tcm	This is historical shale gas production between 2010-2018.
Modelled cumulative shale gas production (2018-2050)	6 tcm	Total cumulative shale gas production (i.e. from shale gas reserves and the wider resource base) for the period 2018-2050 based on our modelling
ERROR IN OUR PUBLISHED ESTIMATES		
Off-model estimate of production from proved shale gas reserves 2018-2050	1.9 tcm	In our published estimates, only 1.9 tcm of cumulative production was from proved reserves with the additional 4.1 tcm from the wider technically recoverable resource base. The error occurred because 2010-2018 production from shale gas reserves of 3.1 tcm was mistakenly netted off the 2018 reserve base (i.e. there was only 1.9 tcm of available production from designated shale gas reserves, instead of the full 5 tcm).
CORRECTION IN NEW ESTIMATES		
Off-model estimate of production from proved shale gas reserves 2018-2050	5 tcm	In the corrected case 5 tcm of cumulative production is from proved reserves with the additional 1 tcm from the wider technically recoverable resource base.

CORRECTED UNEXTRACTABLE ESTIMATE		
Unextractable total US gas reserves, tcm (%)	2.8 (24)	The difference in US unextractable fossil methane gas reserves from the incorrect published estimates (5.9 tcm (52%)) is therefore exactly the difference from higher shale gas production from designated reserves in the corrected version (i.e. an additional 3.1 tcm of cumulative production have been correctly reclassified as from proved shale gas reserves rather than resources).

It should be noted that in both the published and our corrected results, US fossil methane gas production is exactly the same (declining at an annual average rate of ~ 8% per year), but more of this fossil methane gas is assigned to come from proved reserves rather than the wider resource base.

For full transparency, Supplementary Table 28 and 29 below show the percentage and absolute changes in unextractable reserves (regional and global) for oil and gas, respectively. This takes into account the corrections for each of the categories identified: light tight oil, shale gas, tight gas and coalbed methane. The correction follows the exact same steps as the example provided for US shale gas above.

Supplementary Table 28: Regional and global difference in unextractable oil reserves after accounting error has been fixed

Region	Unextractable oil in 2050 (2100), Gb	Unextractable oil in 2050 (2100), %	Change in unextractable oil from original manuscript in 2050, Gb (%)	Change in unextractable oil from original manuscript in 2100, Gb (%)	Category corrected
United States	18 (14)	26 (20)	-3.7 (-5%)	-3.7 (-5%)	Light tight oil
Global	740 (541)	58 (42)	-3.7 (0%)	-3.7 (-1%)	

For gas, the recalibrated allocation of unconventional reserves impacts the following regions where unconventional gas forms a proportion of the reserve base, as shown in Supplementary Table 29 below. Globally for gas, the proportion of reserves which must remain unextracted falls from 59% to 56% by 2050, and from 50% to 47% by 2100.

Supplementary Table 29: Regional and global difference in unextractable gas fossil methane reserves after accounting error has been fixed

Region	Unextractable gas in 2050 (2100), tcm	Unextractable gas in 2050 (2100), %	Change in unextractable gas from original manuscript in 2050, tcm (%)	Change in unextractable gas from original manuscript in 2100, tcm (%)	Category corrected
Australia	0.7 (0.6)	29 (25)	-0.1 (-6%)	-0.1 (-6%)	Coalbed methane
Canada	1.1 (1.1)	56 (56)	-0.5 (-25%)	-0.5 (-25%)	Tight gas
China and India	1.3 (1.1)	29 (24)	-0.4 (-6%)	-0.4 (-8%)	Tight gas
USA	2.8 (2.8)	24 (24)	-3.1 (-28%)	-3.1 (-28%)	Shale, tight and coalbed methane
Global	87 (73)	56 (47)	-4.1 (-3%)	-4.1 (-3%)	

N.B. the negative change reflects lower unextractable volumes and proportions of gas reserves in these regions, i.e. higher production from designated reserves.

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