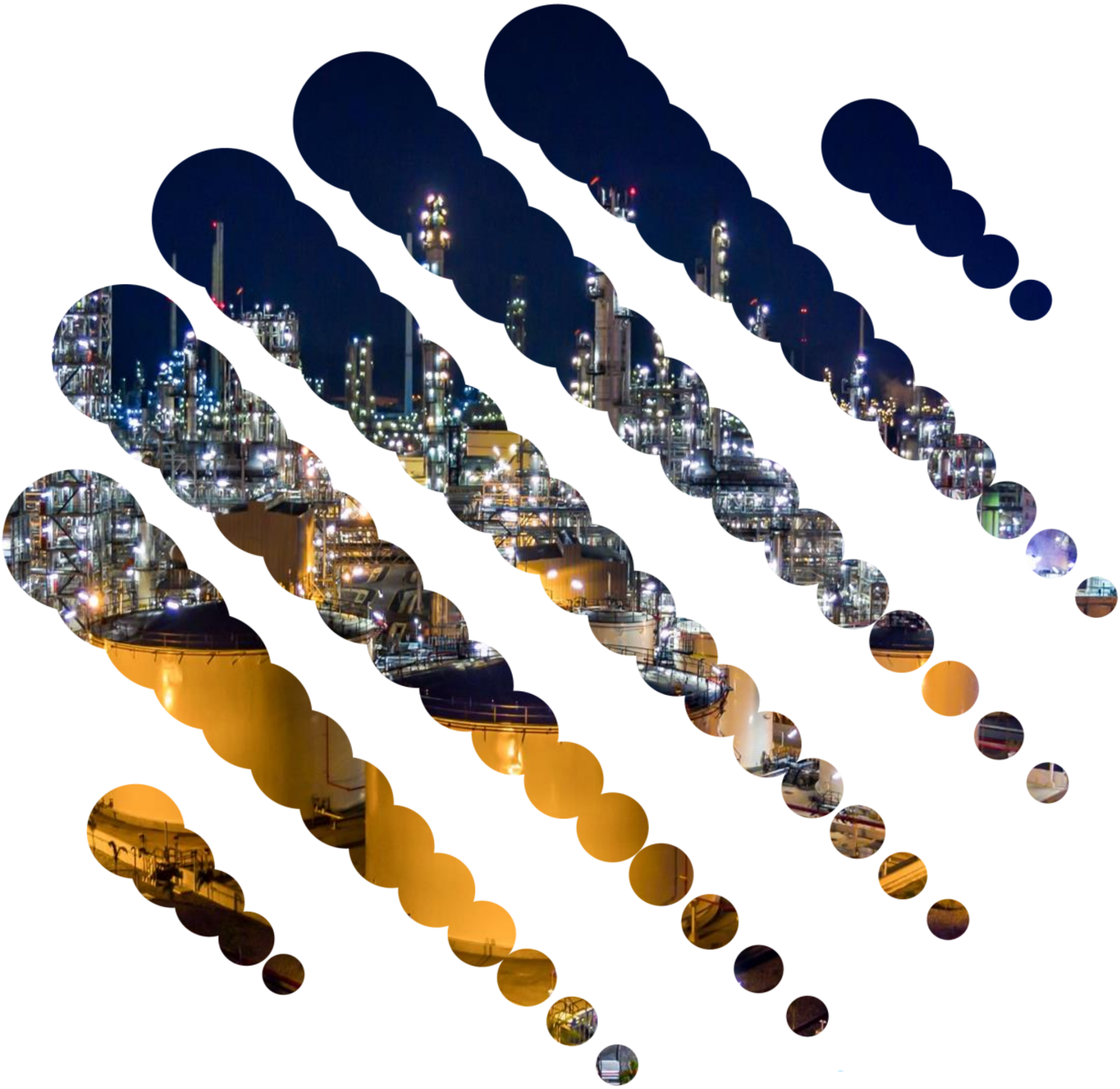
Carbon Performance Assessment of Oil & Gas Producers Methodology Note

October 2020



Simon Dietz, Dan Gardiner,
Valentin Jahn and Jolien Noels

Transition Pathway Initiative

Contents

1. Introduction

The Transition Pathway Initiative (TPI) is a global initiative led by asset owners and supported by asset managers. Established in January 2017, TPI is now supported by over 75 investors globally with over $20 trillion of assets under management.[1]

On an annual basis, TPI assesses how companies are preparing for the transition to a low-carbon economy in terms of their:

- *Management Quality* – all companies are assessed on the quality of their governance/management of greenhouse gas emissions and of risks and opportunities related to the low-carbon transition;
- *Carbon Performance* – in selected sectors, TPI quantitatively benchmarks companies' carbon emissions against international climate targets made as part of the 2015 UN Paris Agreement.

TPI publishes the results of its analysis through an open access online tool hosted by the Grantham Research Institute on Climate Change and the Environment at the London School of Economics (LSE): www.transitionpathwayinitiative.org.

Investors are encouraged to use the data, indicators and online tool to inform their investment research, decision making, engagement with companies, proxy voting and dialogue with fund managers and policy makers, bearing in mind the Disclaimer that can be found in section 6. Further details of how investors can use TPI assessments can be found on our website.

The purpose of this note is to provide an overview of the methodology being followed by TPI in its assessment of the Carbon Performance of oil and gas companies.

[1] As of July 2020.

2. The basis for TPI's Carbon Performance assessment: the Sectoral Decarbonization Approach

TPI's Carbon Performance assessment is based on the Sectoral Decarbonization Approach (SDA).[1] The SDA translates greenhouse gas emissions targets made at the international level (e.g. under the Paris Agreement to the UN Framework Convention on Climate Change) into appropriate benchmarks, against which the performance of individual companies can be compared.[2]

The SDA is built on the principle of recognising that different sectors of the economy (e.g. oil and gas production, electricity generation and automobile manufacturing) face different challenges arising from the low-carbon transition, including where emissions are concentrated in the value chain, and how costly it is to reduce emissions. Other approaches to translating international emissions targets into company benchmarks have applied the same decarbonisation pathway to all sectors, regardless of these differences.[2]

Therefore the SDA takes a sector-by-sector approach, comparing companies within each sector against each other and against sector-specific benchmarks, which establish the performance of an average company that is aligned with international emissions targets.

Applying the SDA can be broken down into the following steps:

- A global carbon budget is established, which is consistent with international emissions targets, for example keeping global warming below 2°C. To do this rigorously, some input from a climate model is required.
- The global carbon budget is allocated across time and to different regions and industrial sectors. This typically requires an integrated economy-energy model, and these models usually allocate emissions reductions by region and by sector according to where it is cheapest to reduce emissions and when (i.e. the allocation is cost-effective). Cost-effectiveness is, however, subject to some constraints, such as political and public preferences, and the availability of capital. This step is therefore driven primarily by economic and engineering considerations, but with some awareness of political and social factors.
- In order to compare companies of different sizes, sectoral emissions are normalised by a relevant measure of sectoral activity (e.g. physical production, economic activity). This results in a benchmark pathway for emissions intensity in each sector:
$$\text{Emissions intensity} = \frac{\text{Emissions}}{\text{Activity}}$$
Assumptions about sectoral activity need to be consistent with the emissions modelled and therefore should be taken from the same economy-energy modelling, where possible.
- Companies' recent and current emissions intensity is calculated and their future emissions intensity can be estimated based on emissions targets they have set (i.e. this assumes companies exactly meet their targets).[3] Together these establish emissions intensity pathways for companies.

[2] Another initiative that is also using the SDA is the Science Based Targets Initiative (http://sciencebasedtargets.org/).
[3] Alternatively, future emissions intensity could be calculated based on other data provided by companies on their business strategy and capital expenditure plans.

- Companies’ emissions intensity pathways are compared with each other and with the relevant sectoral benchmark pathway.

3. How TPI is applying the SDA

3.1. Deriving the benchmark paths

The key inputs to calculating the benchmark paths are:

- A time path for carbon emissions, which is consistent with the delivery of a particular climate target (e.g. limiting global warming to 2°C). Consistency requires that cumulative carbon emissions are within the associated carbon budget.
- A breakdown of this economy-wide emissions path into emissions from key sectors (the numerator of sectoral emissions intensity).
- Consistent estimates of the time path of physical production from, or economic activity in, these key sectors (the denominator of sectoral emissions intensity).

For the oil and gas sector, TPI obtains all three of these inputs from the International Energy Agency (IEA), via its biennial *Energy Technology Perspectives* report [3]. The IEA has established expertise in modelling the cost of achieving international emissions targets. It also provides unprecedented access to the modelling inputs and outputs in a form suitable for applying the SDA.

The IEA's economy-energy model simulates the supply of energy and the path of emissions in different sectors burning fossil fuels, or consuming energy generated by burning fossil fuels, given assumptions about key inputs, such as economic and population growth.

In low-carbon scenarios, the IEA model minimises the cost of adhering to a carbon budget by always allocating emissions reductions to sectors where they can be made most cheaply, subject to some constraints as mentioned above. These scenarios are therefore cost-effective, within some limits of economic, political, social and technological feasibility.

The IEA's work can be used to derive three benchmark emissions paths, against which companies are evaluated by TPI:

1. A **Below 2 Degrees** scenario, which is consistent with the overall aim of the Paris Agreement to hold "the increase in the global average temperature to well below 2°C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels".[4]
2. A **2 Degrees** scenario, which is also consistent with the overall aim of the Paris Agreement to limit warming, albeit at the low end of the range of ambition.
3. A **Paris Pledges** scenario, which is consistent with the global aggregate of emissions reductions pledged by countries as part of the Paris Agreement in the form of Nationally Determined Contributions or NDCs. Several studies have documented that this aggregate is currently insufficient to put the world on a path to limit warming to 2°C, even if it will constitute a departure from a business-as-usual trend.[5]–[7]

For each scenario, IEA modelling output provides estimates of the global primary energy supply. It also provides emissions paths associated with primary energy supply. Emissions from energy supply are then divided by the total supply of energy to derive pathways for the emissions intensity of energy.

Energy supply is defined as the total net calorific energy supply from all energy sources. This includes hydrocarbons, biomass and waste used for energy generation, and energy supplied as electricity generated from fossil fuels, nuclear or renewables. The IEA discloses both primary energy supply and final energy supply. While pure exploration and production (E&P) companies sell primary energy only, TPI recognises that integrated companies provide some of their externally sold energy products in the form of final energy. For some types of final energy, primarily electricity, this distinction is important due to large energy losses in conversion (this issue is addressed in section 4.1). For liquid fuels however, the loss in conversion is small [8].

The aggregate supply of energy products is an appropriate measure of activity to benchmark the oil and gas sector against, because oil and gas companies are primarily engaged in the supply of energy. Indeed, they are mainly involved in the sale of hydrocarbons. Additionally, they increasingly supply both electrical energy, generated from renewables, fossil fuels, and biofuels. Finally, some oil and gas companies are also involved in the sale of hydrocarbons for plastic and petrochemical production, as well as other non-energy uses. Hydrocarbons destined for non-energy use are excluded from the benchmarks, both in terms of primary energy used for non-energy outputs and associated emissions.

Like other modelling groups, IEA foresees a low-carbon transition, where decreasing volumes of oil and gas (and coal) are extracted and are replaced by a steadily rising share of zero-carbon sources of energy (Figure 1). Thus companies can reduce their emissions intensity (Figure 2) by, among other things, diversifying away from fossil fuels and producing more energy from other sources (e.g. biofuels and renewables).

Figure 1 Global primary energy mix 2014-2050 in different scenarios, based on data from IEA ETP2017

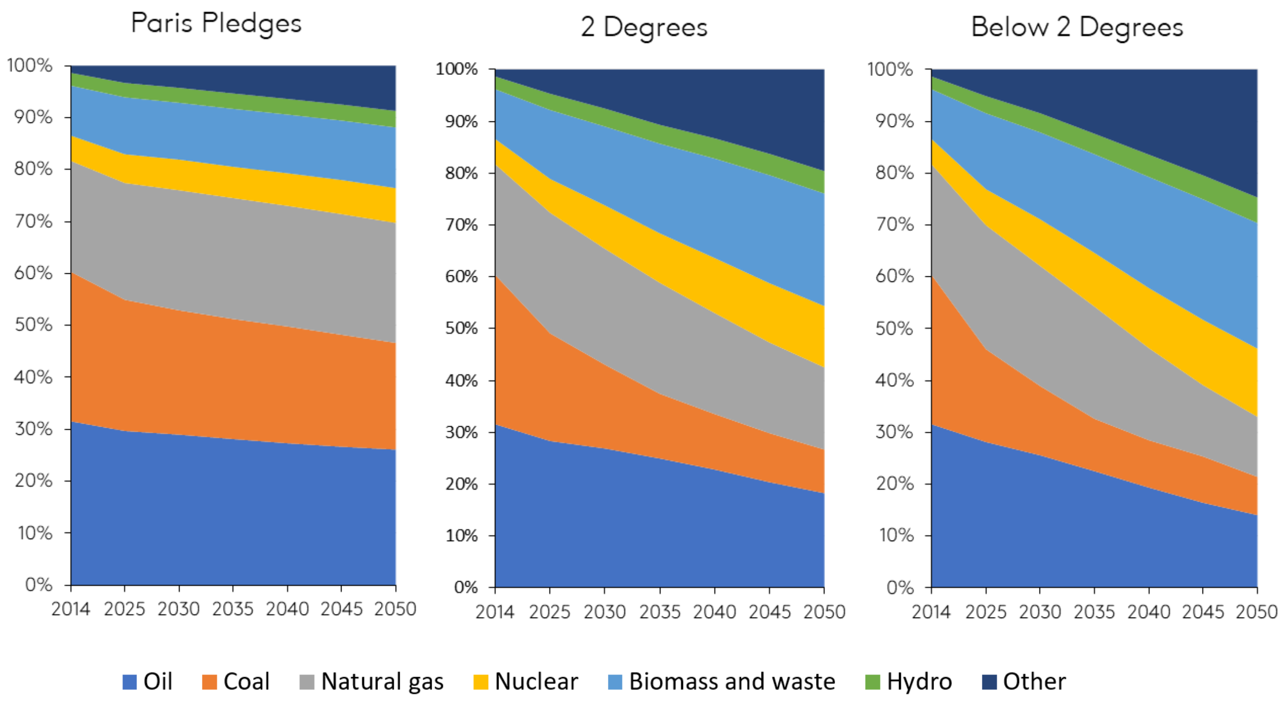


Figure 2. Benchmark global carbon intensity paths for the Oil & Gas sector

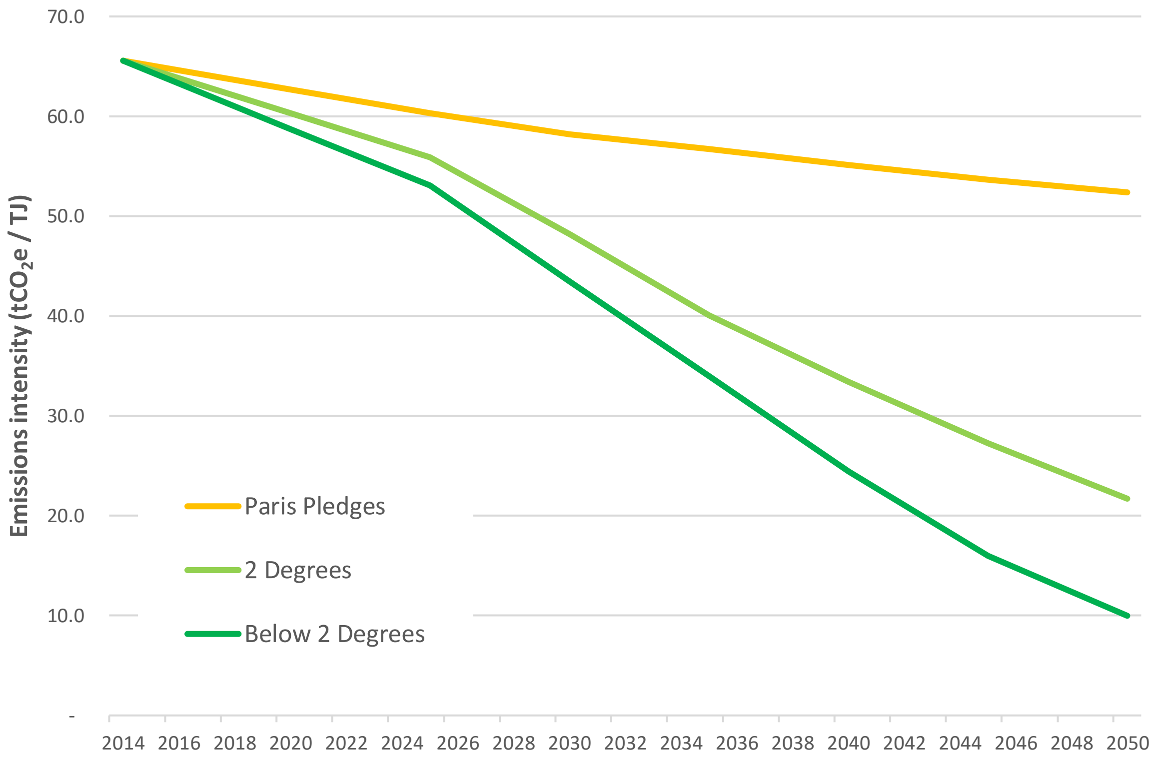


Figure 2 shows the benchmark emissions intensity paths for the oil & gas sector, while Table 1 provides the underlying data on emissions and primary energy supply. For example, under the Paris Pledges scenario in 2025, global direct emissions (excluding process emissions from industry)[4] from the primary energy supply are projected to be 33.98 gigatonnes (Gt) of CO_2. Under the same scenario, total primary energy supply excluding final energy demand for non-energy use is projected to be 602,037 peta joules (PJ) in 2025. Therefore, the average carbon intensity of an oil and gas producer aligned with the Paris Pledges path is 33.98 Gt CO_2/ 602,037 PJ = 56.44 grams of CO_2 per megajoule of energy supplied.

The IEA emissions intensity paths for the oil and gas sector only include CO_2. Additionally, non-CO_2 greenhouse gases, in the form of methane (CH_4)[5] are emitted in the process of supplying energy (e.g. fugitive emissions). In 2010, methane emissions from solid fuels and oil and gas were calculated by the Emissions Database for Global Atmospheric Research (EDGAR) to be 105,108 kilo tonnes of CH_4 [9]. The IPCC provides scenarios for methane emissions from fossil fuels and industry via its Shared Socio-economic Pathways (SSPs) [1]. SSP1-2.6 and SSP1-1.9 are consistent with the IEA's Paris Pledges/2 degrees scenarios and well below 2 degrees scenario respectively. Using EDGAR's 2010 calculation and applying IPCC's pathways, global methane emissions from energy supply are projected to be 0.071 gigatonnes in 2030 in the Paris Pledges scenario. Applying a 100-year global warming potential (GWP) factor of 28 [10], methane emissions will be equivalent to 1.98 gigatonnes of CO_2. Consequently, the average

[4] The IEA's total direct emissions from primary energy include "process emissions from industry". This is defined by the IEA as "the portion of CO_2 emissions that are inherently generated by the reactions taking place in an industrial process, such as CO_2 released during calcination of limestone in cement kilns." [16]. These non-energy emissions are excluded, as well as CO_2 captured from process emissions from industry.

[5] Other non-CO2 greenhouse gases such as SO_2 and HFCs are negligible.

emissions intensity, including CH_4 emissions, of an oil and gas producer aligned with the Paris Pledges in 2030 is (35.09 + 1.98) / 636,804 = 58.22 grams of CO_2e per megajoule of energy supplied.

Table 1 Projections of emissions and primary energy demand used to calculate intensity paths (Sources: IEA, IPCC, EU EDGAR, and own calculations)

	2014*	2020*	2025*	2030	2050
Paris Pledges scenario					
Total direct CO_2 emissions from primary energy, excluding process emissions from industry ($GtCO_2$)	32.20	32.89	33.98	35.09	37.75
Methane emissions from primary energy ($GtCO_2$e)	2.84	2.69	2.34	1.98	1.15
Total primary energy demand, excluding non-energy use (PJ)	534,461	571,321	602,037	636,804	742,636
Carbon intensity (gCO_2 / MJ)	60.25	57.56	56.44	55.11	50.84
Emissions intensity (gCO_2e / MJ)	65.57	62.70	60.32	58.22	52.38
2 Degrees scenario					
Total direct CO_2 emissions from primary energy, excluding process emissions from industry ($GtCO_2$)	32.20	29.88	28.49	24.51	12.31
Methane emissions from primary energy ($GtCO_2$e)	2.84	2.69	2.34	1.98	1.15
Total primary energy demand, excluding non-energy use (PJ)	534,461	543,731	551,456	549,461	619,950
Carbon intensity (gCO_2 / MJ)	60.25	54.96	51.66	44.60	19.85
Emissions intensity ($ktCO_2$e / MJ)	65.57	60.29	55.90	48.21	21.70
Below 2 Degrees scenario					
Total direct emissions from primary energy, excluding process emissions from industry ($GtCO_2$)	32.20	28.02	25.62	20.83	4.68
Methane emissions from primary energy ($GtCO_2$e)	2.84	2.69	2.07	1.45	0.65
Total primary energy demand, excluding non-energy use (PJ)	534,461	527,730	522,121	512,858	534,218
Carbon intensity (gCO_2 / MJ)	60.25	53.10	49.07	40.62	8.77
Emissions intensity (gCO_2e / MJ)	65.57	58.74	53.04	43.45	9.98

* Emissions, primary energy demand and carbon intensities for the year 2020 are estimated by linearly interpolating between 2014 and 2025. Methane emissions and emissions intensities for the years 2014 and 2025 are estimated by linearly interpolating between 2010, 2020 and 2030.

3.2. Calculating company emissions intensities

TPI's Carbon Performance assessments are based on public disclosures by companies. Disclosure that is useful to our assessments tends to come in one of three forms:

1. **Emissions Intensity**. Some companies disclose their recent and current emissions intensity and some companies have also set future emissions targets in intensity terms. Provided these are measured in a way that can be compared with the benchmark scenarios and with other companies (e.g. in terms of scope of emissions covered and measure of activity chosen), these disclosures can be used directly. In some cases, adjustments need to be made to obtain estimates of emissions intensity on a consistent basis. The necessary adjustments will generally involve sector-specific issues (see below).
2. **Absolute emissions.** Some companies disclose their recent and current emissions on an absolute (i.e. un-normalised) basis. Provided emissions are appropriately measured, and an accompanying disclosure of the company's activity can be found that is also in the appropriate metric, recent and current emissions intensity can be calculated by TPI.
3. **Absolute emission targets.** Some companies set future emissions targets in terms of absolute emissions. This raises the particular question of what to assume about those companies' future activity levels. The approach taken in the TPI is to assume company activity increases at the same rate as the sector as a whole (i.e. this amounts to an assumption of constant market share), using sectoral growth rates from the IEA in order to be consistent with the benchmark paths. While companies' market shares are unlikely to remain constant, there is no obvious alternative assumption that can be made, which treats all companies consistently. Sectoral growth rates from the Paris Pledges (IEA RTS) scenario are used. These lie in the middle of the range from the IEA's three scenarios, close to the average of them.

The length of companies' emissions intensity paths will vary depending on how much information companies provide on their emissions since 2013, as well as the time horizon for their emissions targets.

3.3. Emissions reporting boundaries

Companies disclose emissions using different organisational boundaries. There are two high-level approaches: the "equity" approach and the control approach, and within the control approach there is a choice of financial or operational control. Companies are free to choose which organisation boundary to set in their voluntary disclosures and there is variation between companies assessed by TPI.

TPI accepts emissions reported using any of the above approaches to setting organisational boundaries, as long as:

1. The boundary that has been set appears to allow a representative assessment of the company's emissions intensity;
2. The same boundary is used for reporting company emissions and activity, so that a consistent estimate of emissions intensity is obtained.

At this point in time, limiting the assessment to one particular type of organisational boundary would severely restrict the breadth of companies TPI can assess.

When companies report historical emissions or emissions intensities using *both* equity share and control approaches, TPI chooses the reporting boundary based on which method provides the longest available time series of disclosures, or is most consistent with disclosure on activity, and any targets.

3.4. Data sources and validation

All TPI's data is based on companies' own disclosures. The sources for the Carbon Performance assessment include responses to the annual CDP questionnaire, as well as companies' own reports, e.g. sustainability reports.

Given that TPI's Carbon Performance assessment is both comparative and quantitative, it is essential to understand exactly what the data in company disclosures refer to. Company reporting varies not only in terms of what is reported, but also in terms of the level of detail and explanation provided. The following cases can be distinguished:

- Some companies provide data in a suitable form and they provide enough detail on those data for analysts to be confident appropriate measures can be calculated or used. For oil and gas companies, TPI accepts production and sales data in units of weight, volume and energy.
- Some companies also provide enough detail, but from the detail it is clear that their disclosures are not in a suitable form for TPI's Carbon Performance assessment (e.g. they do not report the measure of company activity needed). These companies cannot be included in the assessment.
- Some companies do not provide enough detail on the data disclosed and these companies are also excluded from the assessment (e.g. the company reports an emissions intensity estimate, but does not explain precisely what it refers to).
- Some companies do not disclose their carbon emissions and/or activity.

Once a preliminary Carbon Performance assessment has been made, it is subject to the following procedure to provide quality assurance:

- *Internal review*: the preliminary assessment is reviewed by an analyst that was not involved in the original assessment.
- *Company review*: the reviewed assessment is sent to the company, which then has the opportunity review it and confirm the accuracy of the disclosures used. Only information in the public domain can be accepted as a basis for any change. This review includes all companies including those who provide unsuitable or insufficiently detailed disclosures.
- *Final assessment*: feedback from the company is reviewed and, if it is considered appropriate, incorporated.

3.5. Responding to companies

Allowing companies the opportunity to review their assessments is an integral part of TPI's quality assurance process. Each company receives its draft TPI assessment and the data that underpins the assessment, offering them the opportunity to review and comment on the data and assessment. We also allow companies to contact us at any point to discuss their assessment.

If a company seeks to challenge its result/representation, our process is as follows:

- TPI reviews the information provided by the company. At this point, additional information may be requested.
- If it is concluded that the company's challenge has merit, the assessment is updated and the company is informed.
- If it is concluded that there are insufficient grounds to change the assessment, this decision is explained to the company.
- If a company chooses to further contest the assessment and reverts to legal means to do so, the company's assessment is withheld from the TPI website and the company is identified as having challenged its assessment.

3.6. Presentation of assessment on TPI website

The results of the Carbon Performance assessment are posted on the TPI website, within the TPI tool (https://www.transitionpathwayinitiative.org/tpi/sectors). A company's emissions intensity path is plotted alongside the relevant sector benchmark on a company specific page and different companies can be selected for comparison on the main sector page.

4. Specific considerations in the assessment of oil & gas producers

4.1. Measure of emissions intensity

In applying the SDA to the oil and gas sector, a key consideration is that the vast majority of lifecycle emissions stem from use of companies' sold products, i.e. burning oil and gas to provide energy for buildings, electricity generation, industry and transport. Therefore, the scope of a company assessment should include emissions from use of sold products, as well as the contribution from direct and indirect operational emissions (i.e. Scope 1 and 2).

Hence, in the oil and gas sector, the specific measure of emissions intensity used by TPI is:

- Scope 1, 2 and 3 (use of sold product) greenhouse gas emissions from energy products sold externally in units of grams of CO_2 equivalent (gCO_2e) per mega joule (MJ).

"Energy products sold externally" is defined as the total net calorific energy supply from all fuels including hydrocarbons, biomass and waste, plus energy supplied as electricity generated from fossil fuels, nuclear or renewables.

4.2 The Assessed Product

Companies in the oil and gas sector are active at different levels of the value chain. They range from pure E&P companies focused on extraction of raw hydrocarbons, to more downstream-focused integrated companies that both extract and process these hydrocarbons. They also typically have differing levels of non-energy petrochemical production, processing hydrocarbons into products such as plastics and fertilisers, and diversification into renewable energy.

TPI segments energy products sold externally into five categories (see Figure 5). The relative importance of these categories varies widely according to company structure:

1) Sales of primary, 'unrefined' products. This principally includes crude oil, NGLs (collectively known as liquids) and natural gas, but can also include coal. When only production of primary products is disclosed, as opposed to sales of primary products, further assumptions need to be made to obtain external sales. If an integrated oil and gas producer does not disclose external sales of primary product, we assume all liquid production is consumed internally by their downstream refinery activities, or, if refinery throughput data is available, we assume that the amount of externally sold primary liquids equals the difference between primary liquids production and refinery throughput. Additionally, we assume that all natural gas production is sold externally unless stated otherwise. When a pure E&P company discloses only liquid production numbers and no sales numbers, we assume that all produced liquids are sold externally. Royalty production owned by host governments is excluded from assessed product.

2) Sales of refined products. Liquid production typically must be refined before it can be used as an energy product. Integrated companies refine both their internal, "upstream" production and liquids purchased externally. Some companies exclusively focus on refining. When no explicit sales data is available, we assume that refinery production equals sales.

3) Sales of finished products. Refined liquid products, either internally produced or purchased from external suppliers, are blended and distributed as fuel to end-customers (i.e. at petrol stations).

4) Sales of physically traded products. Some integrated oil and gas companies sell energy products (natural gas and liquids) originally extracted by third parties without transforming them.

5) Sales of other energy products. Some oil and gas companies are diversifying into supplying electricity and heat generated from fossil fuels and low-carbon sources, including biofuels, solar and wind.

The objective is to only measure emissions and supply from energy products sold externally, so that emissions arising from any other activities that companies are engaged in are excluded, otherwise companies' emissions intensity may be mis-estimated. Some oil and gas products have a non-energy use, mainly in the plastics and petrochemicals industry. In excluding emissions and supply from non-energy products, it is important to make a distinction between energy and non-energy use of fuels.

According to Richard Heede [11][6], 8.02% of carbon in produced oil[7] and 1.86% of carbon in gas is permanently stored through non-energy use (measured in energy equivalent units) such as for plastics and petrochemicals. Using carbon storage factors instead of non-energy outputs allows to take into account that some non-energy outputs such as plastics are burned at the end of their lifecycle for energy. This is also reflected in the benchmark, because some non-energy products feed back into primary energy in the form of waste. Hence, when calculating a company's use of sold product emissions and energy content, an adjustment is made to reflect the portion of hydrocarbon output destined for non-energy uses. While companies disclose the production of individual non-energy products, the total is not typically stated and therefore TPI must make an assumption. For companies where the sum of disclosed non-energy products such as naphtha or lubricants is equal to or higher than 10% of liquids sold, no adjustment is made. Where it is less than 10%, an adjustment is made so that a minimum of 10% of liquid production is treated as non-energy. The adjustment is made to the sum of all liquid energy products sold externally by a company.

Companies disclose production/sales outputs in a range of different units which TPI must convert into a consistent measure of energy (MJ). Typically output is disclosed in either:

1) volume: barrels, cubic meters/feet etc. for gas and liquids;
2) weight: tons/tonnes etc.;
3) energy: Boe, BTU, MWh etc. heat, electricity

We convert the amount of product sold into a unit of energy measured in joules predominantly using the IPCC's net calorific values for each energy product category. Assigning an appropriate IPCC category to a company's energy product is relatively straightforward in most cases, but

6 The average carbon storage factors from Richard Heede [11] are based on US-only data. We assume that the US average is representative of the world average.

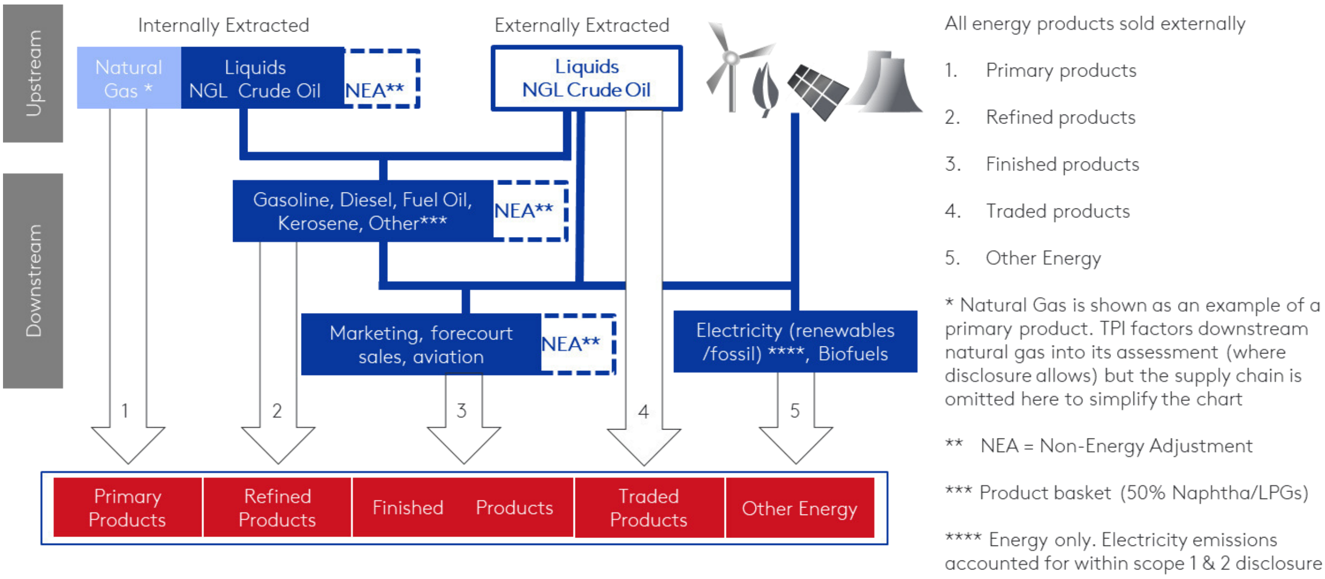
7 This includes crude oil, natural gas liquids, naphtha, liquefied petroleum gases, motor gasoline aviation gasoline, jet kerosene, other kerosene, gas/diesel and fuel oil.

wherever there is some ambiguity, TPI references IPCC's product category definitions to determine the most appropriate classification (see Annex 3).

Typically companies disclose quantities sold in a unit other than weight and therefore the disclosed unit is either converted into weight or straight into joules depending on the original unit of disclosure and fuel type. For volume disclosures TPI uses energy density figures expressed in tonnes per barrel published by the UN [12]. See Annex 1 for more details on the conversion ratios.

Finally, to calculate the assessed product, all categories of energy products sold externally are added together (see figure 4).

Figure 4 Calculating "Assessed Product": all energy products sold externally

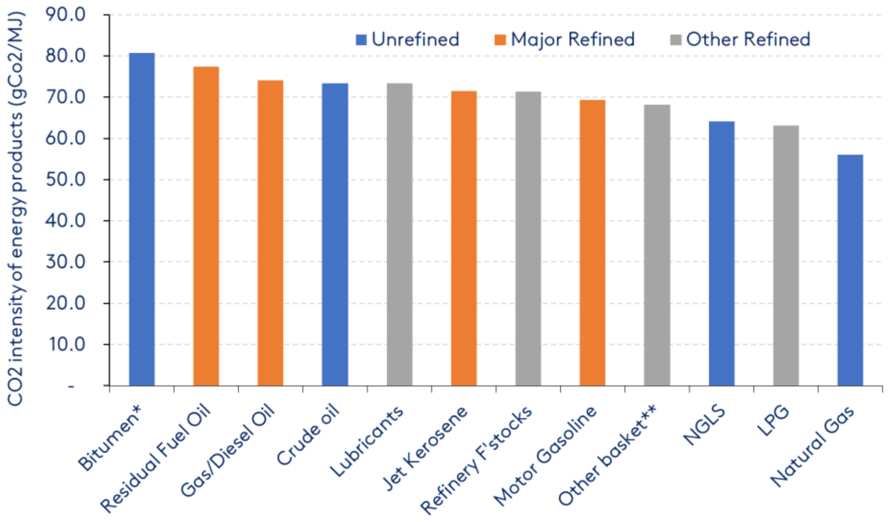


4.3 Estimating Scope 3 emissions from use of sold products

While most oil and gas companies disclose their Scope 1 and 2 emissions, only a few currently disclose their Scope 3 'use of sold product' emissions and none discloses it on a basis consistent with TPI's assessed product methodology. Hence, TPI has developed a methodology to calculate emissions from use of sold products.

The emissions content of fossil fuels varies by product (see Figure 5). TPI analysis uses product CO_2 emissions and energy factors from the 2006 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories (see Annex 1) [7].

Figure 5. The CO_2 intensity of disclosed energy products

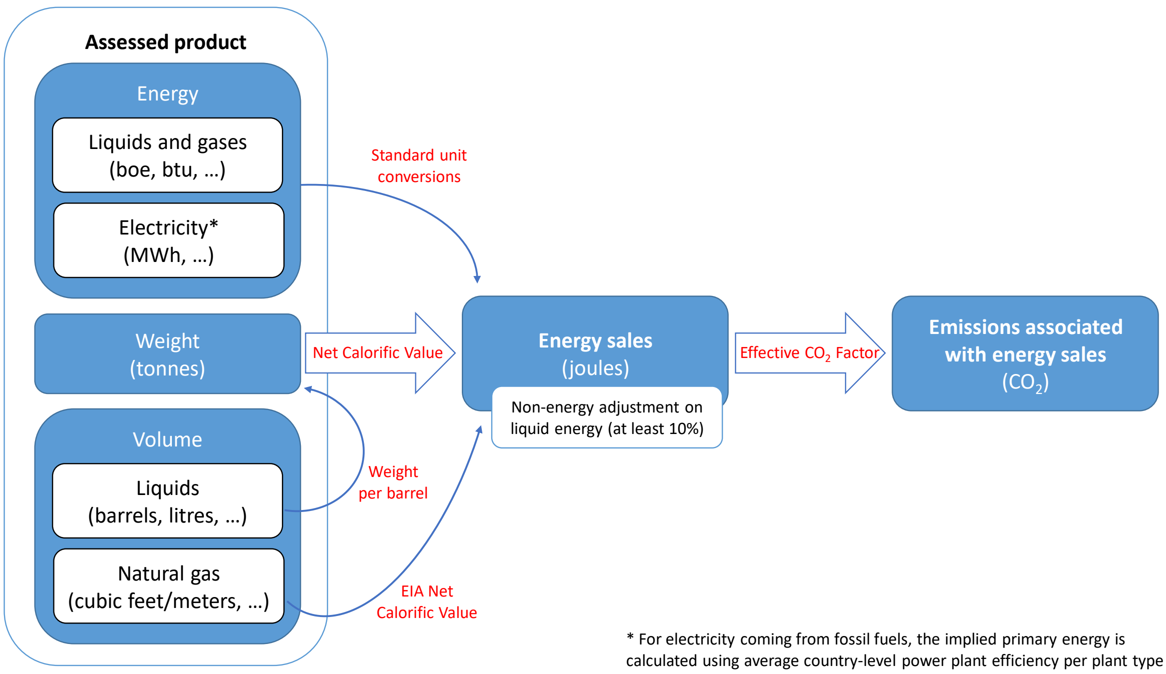


* Bitumen is classified as energy product when it is disclosed as primary product and a non-energy product when it is disclosed as a refined product

** Other basket is 50% naphtha and 50% LPGs based on IEA analysis of residual fuels [8]

After performing any necessary non-energy adjustments on the calculated amounts of energy, the energy of the remaining "assessed product" is converted into emissions by applying each fuel-specific emissions factor published by the IPCC. For a general schematic please refer to Figure 6.

Figure 6 Scope 3 Methodology Schematic



4.4 Other energy

Oil and gas companies also sell other forms of energy, most notably in the form of biofuels and electricity and heat (both from fossil fuels and renewables).

Biofuels can either be sold in their pure form or blended with refined oil products like motor gasoline. When sold in its pure form the energy is calculated based on the appropriate energy density factor (see Annex 2) and Scope 3 emissions from use of sold products are assumed to be zero. Some companies blend their biofuel production into one or more of their finished fuels (typically motor gasoline). In order to obtain an estimate of Scope 3 use of sold product emissions for the company's particular blend, we proceed as follows. First, both the biofuel and the finished fuel are converted into their respective weights[8], if not already disclosed in a weight unit. Second, the amount of biofuel is subtracted from the amount of gasoline sold to obtain the biofuel-based "emissions-free" proportion and the fossil-based "emissions-intensive" proportion. Both weights are then converted into energy using TPI's standard methodology, but Scope 3 emissions from use of sold products are only calculated for the fossil-based proportion.

Electricity sales are usually disclosed in watt-hours. Based on average country-level power plant efficiency per fossil plant type (see Annex 4), the primary energy input implied from electricity output is calculated in joules. The primary energy equivalent from electricity is only calculated for electricity generated from fossil fuels. Electricity from renewables is taken directly, no fossil fuel equivalent is calculated, consistent with IEA methodology and the benchmarks. If a company discloses the primary energy going into electricity generation, we prefer using that data. Associated Scope 3 use of sold products emissions are not calculated, because, regardless of whether the source of the energy is burning fossil fuels or renewables, the emissions will already be accounted for in Scope 1 and 2 disclosure.

4.5 Estimating Scope 2 emissions

In a few cases, only scope 1 emissions are disclosed, not Scope 2. In these cases, we estimate the missing Scope 2 emissions to complete an assessment. We do this using an average ratio of Scope 1 to Scope 2 emissions computed across comparable companies. For E&P companies, the median ratio is 13% (calculated from a sample of 12)[9] and for an integrated company the median ratio is 8% (calculated from a sample of 17)[10].

4.6 Incomplete disclosure

Most oil and gas producers appear to disclose emissions from all their operations, albeit employing different reporting boundaries, but some explicitly do not, or it is unclear whether the disclosure is comprehensive. When it is either explicitly incomplete or unclear, a further assessment is made to determine whether the omission of some facilities would bias the

[8] We use weight for the following reasons:

1. The volume of a mixture of two liquids is different from the volume of the two liquids separately.
2. Because gasoline and biofuels tend to have different energy densities, a blend with a high degree of biofuels can contain significantly less energy compared a blend with a lower biofuel content. Hence, we do not adjust on energy basis either.

[9] As of 5th of June 2019

[10] As of 5th of June 2019

emissions intensity assessment. Ultimately we make a judgement, in line with the principles set out in Section 3.3 above, on whether a reliable Carbon Performance assessment can be made from existing disclosure.

4.7. Coverage of target

There are various types of targets that oil and gas companies disclose, but they can be broadly categorised into emissions intensity targets and absolute emissions targets. Absolute emissions targets are expressed in terms of a decrease in the total amount of emissions a company aims to emit by a certain date. By contrast, emissions intensity targets are expressed in emissions per unit of output and make no direct reference to total emissions. Targets can cover different scopes of emissions and apply only to specific operations, or to the whole organisation.

TPI incorporates different types of target into its Carbon Performance assessment. In particular, we are faced with the following permutations:

- **Absolute targets relating to operational emissions (either Scope 1 or Scope 1 and 2):** as these targets only cover part of total emissions, assumptions are required to calculate how emissions outside the scope of the target evolve. Consistent with the approach used in other TPI sectors, we assume the emissions intensity of activities outside the scope of the target remains constant at the level in the latest disclosure year. To convert an absolute emissions target into an intensity target, we make an assumption about the future growth of energy sold externally by the company. Consistent with the approach adopted in other TPI sectors, we assume that a company's energy sales grow in line with IEA's global forecasts.
- **Absolute Scope 1, 2 & 3 or Scope 3 target:** similar to the above, we make an assumption about the future growth of energy sold externally by the company to convert an absolute emissions target into an intensity target and assume the emissions intensity of activities outside the scope of the target remains constant at the level in the latest disclosure year. If both an absolute and intensity target are disclosed, we verify that both are consistent with/complement each other. If so, we prefer the intensity target to avoid assumptions regarding the company's future energy output, if not, further research is needed to accurately reflect a company's decarbonization pathway.
- **Emissions intensity targets applying to Scope 1 and 2 only:** these are disclosed, or can be expressed as, percentage reductions against a base year. TPI applies the percentage reduction to the Scope 1 and 2 emissions intensity calculated for the designated base year and assumes Scope 3 use of sold products emissions remain constant at the intensity in the latest year of disclosure.
- **Comprehensive intensity targets including Scope 1, 2, and 3 use of sold products emissions:** these are usually expressed as percentage reductions against a base year. We apply the same percentage that is either explicitly or implicitly disclosed and apply it to the TPI-calculated intensity in the designated base year.

As mentioned, some companies set targets that only apply to Scope 1 emissions, or a part of Scope 1 emissions, as opposed to Scope 1 and 2 emissions from energy supply as a whole. In the case of a partial absolute emissions target, the target intensity for the specified part of emissions is calculated by applying the target to the emissions and dividing that by projected energy sales (calculated using the global growth projection of IEA). Further, it is assumed that the intensities of all other relevant emissions remain constant at the level in the latest year of disclosure. In case of a partial Scope 1 emissions intensity target, the total emissions intensity is calculated by applying the target to the intensity of the specified emissions and assuming that the emissions intensity of all other relevant emissions (other Scope 1, 2 and 3 emissions) remains unchanged. Additionally, some companies disclose Scope 3 targets only covering part of their energy sales. In this case we apply the target to the Scope 1, 2 & 3 emissions of those externally sold energy products covered by the target. We assume that the intensity of energy sales not covered by the target remains the same as the level of the latest disclosure, and that the proportion of energy covered by the target compared to that not covered by the target remains constant from the latest disclosure as well (i.e. the energy sales mix remains constant).

Some companies disclose net targets. Unlike gross targets, net targets include emissions offsets and/or negative emissions, either within company boundaries or outside. Currently, TPI accepts both types of targets and does not make an explicit distinction between both. Although we recognise that there are additional risks related to relying heavily on offsetting, in principle it is a cost-effective mechanism to reduce emissions. Moreover, no company currently discloses sufficient detail on the contribution from offsets to their overall targets.

Furthermore, some companies disclose a target range. In this case the midpoint value is used. Finally, most companies express targets relative to emissions in a base year (e.g. 2010). However, some companies disclose targets without disclosing the base year. TPI then assumes that the base year is the latest year of disclosure prior to the publication of the target.

5. Discussion

This note describes the methodology followed by TPI in assessing the Carbon Performance of the oil and gas sector. The approach aims to be easy to both understand and use, while also being robust. However there are inevitably nuances and judgements made in each assessment. Investors may wish to dig deeper to understand these.

5.1. General issues

The methodology builds on the Sectoral Decarbonization Approach (SDA), which compares a companies' emissions intensity with sector-specific benchmarks that are consistent with international targets (i.e. limiting global warming to well below 2°C, no more than 2°C, and the sum of the Paris Pledges).

TPI uses the modelling of the International Energy Agency (IEA) to calculate the benchmark paths. The IEA modelling has a number of advantages, but it is also subject to limitations, like all other economy-energy modelling. In particular, model projections often turn out to be wrong. This would impact the accuracy of the benchmark and potentially lead to investors drawing inaccurate conclusions about a company's alignment. The IEA updates its modelling every two years and TPI plans to update its benchmark calculations accordingly. Nevertheless in such a forward-looking exercise there is no way to avoid the uncertainty created by projecting into the future.

TPI predominantly uses disclosed emissions and activity data to derive emissions intensity paths. While much of this data is audited, the emissions intensity estimates can only be as accurate as the underlying disclosures.

Estimating the recent, current and especially the future emissions intensity of companies involves a number of assumptions. Therefore it is important to bear in mind that, in some cases, the emissions path drawn for each company is an estimate made by TPI, based on information disclosed by companies, rather than the companies' own estimate or target. In other cases, the information disclosed by companies is sufficient on its own to completely characterise the emissions intensity path.

5.2. Issues specific to oil & gas producers

The principal challenge in the oil and gas sector, relative to other sectors whose Carbon Performance TPI is assessing, is the absence of (consistent) disclosures of Scope 3 emissions from use of sold products. Consequently TPI has developed a methodology to calculate Scope 3 emissions based on energy sales. This methodology requires detailed information on externally sold energy in physical/energy units, as well as organisational boundaries and disclosure basis, so that we can match Scope 1 and 2 emissions with Scope 3 emissions associated with energy sales on a consistent basis. But some companies disclose operational emissions and product volumes using different reporting boundaries. TPI accepts both operational control and equity share boundaries in its assessments, but inconsistency between the scope of disclosed operational emissions and product volumes makes it inaccurate to add Scope 3 use of sold products emissions to operational emissions. For these companies, TPI has attempted to adjust for this by scaling operational emissions using the ratio between production stated on an equity basis and on a 100% operational control basis.

Additionally, TPI's assessments are complicated by inconsistent disclosure of energy products. Some companies disclose large quantities of traded products. We believe this activity is widespread among integrated players, but may not be fully disclosed. Without disclosure of an oil trading business, for example, the proportion of oil-based products in the mix is lowered, flattering emissions intensity results. Sales from low-carbon initiatives are also inconsistently disclosed. Several companies highlight initiatives to diversify into lower-carbon energy sources, such as biofuels, solar and wind power generation, within published investor materials. Often these companies only disclose generating capacity values as opposed to sales. However, as the energy produced by these initiatives is a small proportion of the total currently, it is rarely systematically disclosed.

Currently no company explicitly discloses the total proportion of sales destined for non-energy uses and when they do it is often unclear how to estimate their energy content, in particular in the case of chemicals. In the absence of this disclosure, we are forced to assume 10% of liquid sales volume is non-energy across the rest of the sector. In reality, the proportion of sales destined for non-energy uses is likely to vary widely by company.

Finally, some companies do not disclose Scope 1 and 2 emissions from chemicals separately from Scope 1 and 2 emissions associated with the supply of energy products. For companies with a small chemicals business, TPI has assumed that this would have a negligible impact on their overall emissions intensity. However, some companies have a large interest in chemical activities. Hence, for those companies where TPI cannot make an appropriate adjustment, the assessments cannot be finalised.

We believe that these issues, in isolation, do not impact the emissions intensity results sufficiently to undermine the analysis. For example, as operational emissions are a small proportion of oil and gas companies' total emissions, restating them on an equity share basis (to match Scope 3 calculations) would have a modest impact on overall intensity.

Even with consistent and full disclosure of product volumes, there are further, inherent limits to the accuracy of the methodology. Issues include the application of the appropriate IPCC category. Even with much more granular product disclosure, it may not be possible to match IPCC categories exactly. Applying a standard product basket (50% naphtha / 50% LPGs) to all "other" categories can also be problematic. The emissions and energy generated by energy products are inherently variable. The IPPC emissions factors for unrefined products (e.g. crude oil) can range ± 5%.

6. Disclaimer

1. Data and information published in this paper and on the TPI website is intended principally for investor use but, before any such use, you should read the [TPI website](#) terms and conditions to ensure you are complying with some basic requirements which are designed to safeguard the TPI whilst allowing sensible and open use of TPI data. References in these terms and conditions to "data" or "information" on the website shall include the carbon performance data, the management quality indicators or scores, and all related information.
2. By accessing the data and information published in the report and on this website, you acknowledge that you understand and agree to these website terms and conditions. In particular, please read paragraphs 4 and 5 below which details certain data use restrictions
3. The data and information provided by the TPI can be used by you in a variety of ways – such as to inform your investment research, your corporate engagement and proxy-voting, to analyse your portfolios and publish the outcomes to demonstrate to your stakeholders your delivery of climate policy objectives and to support the TPI in its initiative. However, you must make your own decisions on how to use TPI data as the TPI cannot guarantee the accuracy of any data made available, the data and information on the website is not intended to constitute or form the basis of any advice (investment, professional or otherwise), and the TPI does not accept any liability for any claim or loss arising from any use of, or reliance on, the data or information. Furthermore, the TPI does not impose any obligations on supporting organisations to use TPI data in any particular way. It is for individual organisations to determine the most appropriate ways in which TPI can be helpful to their internal processes.
4. Subject to paragraph 3 above, none of the data or information on the website is permitted to be used in connection with the creation, development, exploitation, calculation, dissemination, distribution or publication of financial indices or analytics products or datasets (including any scoring, indicator, metric or model relating to environmental, climate, carbon, sustainability or other similar considerations) or financial products (being exchange traded funds, mutual funds, undertakings collective investment in transferable securities (UCITS), collective investment schemes, separate managed accounts, listed futures and listed options); and you are prohibited from using any data or information on the website in any of such ways and from permitting or purporting to permit any such use.
5. Notwithstanding any other provision of these website terms and conditions, none of the data or information on the website may be reproduced or made available by you to any other person except that you may reproduce an insubstantial amount of the data or information on the website for the uses permitted above.
6. The data and information on the website may not be used in any way other than as permitted above. If you would like to use any such data or information in a manner that is not permitted above, you will need TPI's written permission. In this regard, please email all inquiries to tpi@unpri.org.

7. Bibliography

[1] O. Krabbe *et al.*, “Aligning corporate greenhouse-gas emissions targets with climate goals,” *Nat. Clim. Chang.*, vol. 5, pp. 1057–1060, 2015.

[2] J. Randers, “Greenhouse gas emissions per unit of value added (‘GEVA’): a corporate guide to voluntary climate action,” *Energy Policy*, vol. 48, pp. 46–55, 2012.

[3] International Energy Agency, *Energy Technology Perspectives 2017*. International Energy Agency, 2017.

[4] UNFCCC, “Paris Agreement,” 2015.

[5] UNEP, “The Emissions Gap Report 2015: A UNEP Synthesis Report,” Nairobi, 2015.

[6] R. Boyd, J. Cranston Turner, and B. Ward, “Intended nationally determined contributions: what are the implications for greenhouse gas emissions in 2030?,” London, 2015.

[7] United Nations, “Adoption of the Paris Agreement,” 2015.

[8] International Energy Agency, “Oil Information 2018,” OECD, Sep. 2018.

[9] G. Janssens-Maenhout *et al.*, “EDGAR - Global Greenhouse Gases Emissions EDGAR v4.3.2,” *Global Atlas of the three major Greenhouse Gas Emissions for the period 1970-2012, Earth System Science Data*, 2017. [Online]. Available: http://edgar.jrc.ec.europa.eu/overview.php?v=432_GHG&SECURE=123. [Accessed: 17-Apr-2019].

[10] IPCC, *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovern- mental Panel on Climate Change*. United Kingdom and New York, 2013.

[11] R. Heede, “Carbon Majors : Updating activity data, adding entities, & calculating emissions: A Training Manual,” *Clim. Account. Inst.*, no. September, 2019.

[12] United Nations, “2016 Energy Statistics Yearbook,” 2016.

[13] US Energy Information Administration, “Energy Conversion Calculators - Energy Explained, Your Guide To Understanding Energy - Energy Information Administration,” 2019. [Online]. Available: https://www.eia.gov/energyexplained/index.php?page=about_energy_conversion_calculator. [Accessed: 17-Apr-2019].

[14] General Electric (GE), “GE Global Power Plant Efficiency Analysis,” 2016.

[15] US Energy Information Administration, “Electric Power Annual 2017: Revised December 2018,” 2018.

[16] International Energy Agency, “Energy Technology Perspectives 2017,” OECD, Jun. 2017.

[17] K. e. a. Riahi, The Shared Socioeconomic Pathways and their energy, land use, and greenhouse gas emissions implications: An overview, vol. 42, 2017, pp. 153-168.

Annex 1: The emissions and energy content of fossil fuels varies by product

	Net Calorific value (TJ/Tonnes)	Effective CO_2 emissions factor (Tonnes CO_2/TJ)	Weight of a barrel of specific fuel (tonnes/barrel)	Net Calorific value (MJ/mCF)
Source:	IPCC, 2006	IPCC, 2006	UN, 2016	EIA, 2019
Crude oil	0.042	73.3	0.137	-
Orimulsion	0.028	77.0	-	-
Natural Gas Liquids	0.044	64.2	0.096	-
Motor Gasoline	0.044	69.3	0.118	-
Aviation Gasoline	0.044	70.0	0.116	-
Jet Gasoline	0.044	70.0	0.121	-
Jet Kerosene	0.044	71.5	0.129	-
Other Kerosene	0.044	71.9	0.129	-
Shale Oil	0.038	73.3	-	-
Gas/Diesel Oil	0.043	74.1	0.138	-
Residual Fuel Oil	0.040	77.4	0.151	-
Liquified Petroleum Gases	0.047	63.1	0.086	-
Ethane (used to produce plastics)	0.046	61.6	0.059	-
Naphtha	0.044	73.3	0.114	-
Bitumen	0.040	80.7	0.165	-
Lubricants	0.040	73.3	0.143	-
Petroleum Coke	0.033	97.5	0.181	-
Refinery Feedstocks	0.043	73.3	0.135	-
Other OilRefinery Gas	0.050	57.6	0.125	-
Parafin Wax	0.040	73.3	0.127	-
White Spirit & SBP	0.040	73.3	0.129	-
Other Petroleum Products	0.040	73.3	0.145	-
Anthracite	0.027	98.3	-	-
Coking Coal	0.028	94.6	-	-
Other Bituminous Coal	0.026	94.6	-	-
Sub Bituminous Coal	0.019	96.1	-	-
Lignite	0.012	101.2	-	-

	Net Calorific value (TJ/Tonnes)	Effective CO_2 emissions factor (Tonnes CO_2/TJ)	Weight of a barrel of specific fuel (tonnes/barrel)	Net Calorific value (MJ/mCF)
Oil shale and tar sands	0.009	106.7	-	-
Brown Coal Briquettes	0.021	97.5	-	-
Patent Fuel	0.021	97.5	-	-
Coke Over Coke and Lignite Coke	0.028	107.1	-	-
Gas Coke	0.028	80.7	-	-
Coal Tar	0.028	44.4	-	-
Gas Works Gas	0.029	44.4	-	-
Oil Works Gas	0.039	-	-	-
Blast Furnace Gas	0.002	259.6	-	-
Oxygen Steel Furnace Gas	0.007	181.9	-	-
Natural Gas	0.048	56.1	-	1,094
Municipal Wastes (non-biomass fraction)	0.010	91.7	-	-
Industrial Waste		106.3	-	-
Waste Oils	0.040	73.3	-	-
Peat	0.010	106.0	-	-
Wood/Wood Waste	0.016	111.8	-	-
Sulphite lyes (black liquor)	0.012	95.3	-	-
Other Primary Solid Biomass	0.012	100.1	-	-
Charcoal	0.030	111.8	-	-
Biogasoline	0.027	70.8	-	-
Biodiesels	0.027	70.8	-	-
Other Liquid Biofuels	0.027	79.6	-	-
Landfill Gas	0.050	54.6	-	-
Slude Gas	0.050	54.6	-	-
Other Biogas	0.050	54.6	-	-
Municipal Wastes (biomass fraction)	0.012	100.1	-	-

Annex 2: The energy content of biofuels

	Energy density toe/tonne	Energy density Toe/cubic meter
Source:	European Commission, 2006	European Commission, 2006
Biodiesel	0.86	0.78
(Bio)ethanol	0.64	0.51

Annex 3: IPCC Product Category Definitions

	IPCC definition
Crude oil	Crude oil is a mineral oil consisting of a mixture of hydrocarbons of natural origin, being yellow to black in colour, of variable density and viscosity. It also includes lease condensate (separator liquids) which are recovered from gaseous hydrocarbons in lease separation facilities.
Orimulsion	A tar-like substance that occurs naturally in Venezuela. It can be burned directly or refined into light petroleum products.
Natural Gas Liquids	NGLs are the liquid or liquefied hydrocarbons produced in the manufacture, purification and stabilisation of natural gas. These are those portions of natural gas which are recovered as liquids in separators, field facilities, or gas processing plants. NGLs include but are not limited to ethane, propane, butane, pentane, natural gasoline and condensate. They may also include small quantities of non-hydrocarbons.
Motor Gasoline	This is light hydrocarbon oil for use in internal combustion engines such as motor vehicles, excluding aircraft. Motor gasoline is distilled between 35ºC and 215ºC and is used as a fuel for land based spark ignition engines. Motor gasoline may include additives, oxygenates and octane enhancers, including lead compounds such as TEL (Tetraethyl lead) and TML (Tetramethyl lead).
Aviation Gasoline	Aviation gasoline is motor spirit prepared especially for aviation piston engines, with an octane number suited to the engine, a freezing point of -60ºC, and a distillation range usually within the limits of 30ºC and 180ºC.
Jet Gasoline	This includes all light hydrocarbon oils for use in aviation turbine power units. They distil between 100ºC and 250ºC. It is obtained by blending kerosenes and gasoline or naphthas in such a way that the aromatic content does not exceed 25 percent in volume, and the vapour pressure is between 13.7 kPa and 20.6 kPa. Additives can be included to improve fuel stability and combustibility.
Jet Kerosene	This is medium distillate used for aviation turbine power units. It has the same distillation characteristics and flash point as kerosene (between 150ºC and 300ºC but not generally above 250ºC). In addition, it has particular specifications (such as freezing point) which are established by the International Air Transport Association (IATA).
Other Kerosene	Kerosene comprises refined petroleum distillate intermediate in volatility between gasoline and gas/diesel oil. It is a medium oil distilling between 150ºC and 300ºC.
Shale Oil	A mineral oil extracted from oil shale.
Gas/Diesel Oil	Gas/diesel oil includes heavy gas oils. Gas oils are obtained from the lowest fraction from atmospheric distillation of crude oil, while heavy gas oils are obtained by vacuum redistillation of the residual from atmospheric distillation. Gas/diesel oil distils between 180ºC and 380ºC. Several grades are available depending on uses: diesel oil for diesel compression ignition (cars, trucks, marine, etc.), light

	heating oil for industrial and commercial uses, and other gas oil including heavy gas oils which distil between 380ºC and 540ºC and are used as petrochemical feedstocks.
Residual Fuel Oil	This heading defines oils that make up the distillation residue. It comprises all residual fuel oils, including those obtained by blending. Its kinematic viscosity is above 0.1cm2 (10 cSt) at 80ºC. The flash point is always above 50ºC and the density is always more than 0.90 kg/l.
Liquified Petroleum Gases	These are the light hydrocarbons fraction of the paraffin series, derived from refinery processes, crude oil stabilisation plants and natural gas processing plants comprising propane (C_3H_8) and butane (C_4H_{10}) or a combination of the two. They are normally liquefied under pressure for transportation and storage.
Ethane (used to produce plastics)	Ethane is a naturally gaseous straight-chain hydrocarbon (C_2H_6). It is a colourless paraffinic gas which is extracted from natural gas and refinery gas streams.
Naphtha	Naphtha is a feedstock destined either for the petrochemical industry (e.g. ethylene manufacture or aromatics production) or for gasoline production by reforming or isomerisation within the refinery. Naphtha comprises material in the 30ºC and 210ºC distillation range or part of this range.
Bitumen	Solid, semi-solid or viscous hydrocarbon with a colloidal structure, being brown to black in colour, obtained as a residue in the distillation of crude oil, vacuum distillation of oil residues from atmospheric distillation. Bitumen is often referred to as asphalt and is primarily used for surfacing of roads and for roofing material. This category includes fluidised and cut back bitumen.
Lubricants	Lubricants are hydrocarbons produced from distillate or residue; they are mainly used to reduce friction between bearing surfaces. This category includes all finished grades of lubricating oil, from spindle oil to cylinder oil, and those used in greases, including motor oils and all grades of lubricating oil base stocks.
Petroleum Coke	Petroleum coke is defined as a black solid residue, obtained mainly by cracking and carbonising of petroleum derived feedstocks, vacuum bottoms, tar and pitches in processes such as delayed coking or fluid coking. It consists mainly of carbon (90 to 95 percent) and has a low ash content. It is used as a feedstock in coke ovens for the steel industry, for heating purposes, for electrode manufacture and for production of chemicals. The two most important qualities are "green coke" and "calcinated coke". This category also includes "catalyst coke" deposited on the catalyst during refining processes: this coke is not recoverable and is usually burned as refinery fuel.
Refinery Feedstocks	A refinery feedstock is a product or a combination of products derived from crude oil and destined for further processing other than blending in the refining industry. It is transformed into one or more components and/or finished products. This definition covers those finished products imported for refinery intake and those returned from the petrochemical industry to the refining industry.

Other OilRefinery Gas	Refinery gas is defined as non-condensable gas obtained during distillation of crude oil or treatment of oil products (e.g. cracking) in refineries. It consists mainly of hydrogen, methane, ethane and olefins. It also includes gases which are returned from the petrochemical industry.
Parafin Wax	Saturated aliphatic hydrocarbons (with the general formula CnH2n+2). These waxes are residues extracted when dewaxing lubricant oils, and they have a crystalline structure with carbon number greater than 12. Their main characteristics are that they are colourless, odourless and translucent, with a melting point above 45ºC.
White Spirit & SBP	White spirit and SBP are refined distillate intermediates with a distillation in the naphtha/kerosene range. They are sub-divided as: i) Industrial Spirit (SBP): Light oils distilling between 30ºC and 200ºC, with a temperature difference between 5 percent volume and 90 percent volume distillation points, including losses, of not more than 60ºC. In other words, SBP is a light oil of narrower cut than motor spirit. There are 7 or 8 grades of industrial spirit, depending on the position of the cut in the distillation range defined above. ii) White Spirit: Industrial spirit with a flash point above 30ºC. The distillation range of white spirit is 135ºC to 200ºC.
Other Petroleum Products	Includes the petroleum products not classified above, for example: tar, sulphur, and grease. This category also includes aromatics (e.g. BTX or benzene, toluene and xylene) and olefins (e.g. propylene) produced within refineries.
Anthracite	Anthracite is a high rank coal used for industrial and residential applications. It has generally less than 10 percent volatile matter and a high carbon content (about 90 percent fixed carbon). Its gross calorific value is greater than 23 865 kJ/kg (5 700 kcal/kg) on an ash-free but moist basis.
Coking Coal	Coking coal refers to bituminous coal with a quality that allows the production of a coke suitable to support a blast furnace charge. Its gross calorific value is greater than 23 865 kJ/kg (5 700 kcal/kg) on an ash-free but moist basis.
Other Bituminous Coal	Other bituminous coal is used for steam raising purposes and includes all bituminous coal that is not included under coking coal. It is characterized by higher volatile matter than anthracite (more than 10 percent) and lower carbon content (less than 90 percent fixed carbon). Its gross calorific value is greater than 23 865 kJ/kg (5 700 kcal/kg) on an ash-free but moist basis.
Sub Bituminous Coal	Non-agglomerating coals with a gross calorific value between 17 435 kJ/kg (4 165 kcal/kg) and 23 865 kJ/kg (5 700 kcal/kg) containing more than 31 percent volatile matter on a dry mineral matter free basis.
Lignite	Lignite/brown coal is a non-agglomerating coal with a gross calorific value of less than 17 435 kJ/kg (4 165 kcal/kg), and greater than 31 percent volatile matter on a dry mineral matter free basis.
Oil shale and tar sands	Oil shale is an inorganic, non-porous rock containing various amounts of solid organic material that yields hydrocarbons, along with a variety of solid products, when subjected to pyrolysis (a treatment that consists of heating the rock at high temperature). Tar sands

	refers to sand (or porous carbonate rocks) that are naturally mixed with a viscous form of heavy crude oil sometimes referred to as bitumen. Due to its high viscosity this oil cannot be recovered through conventional recovery methods.
Brown Coal Briquettes	Brown coal briquettes (BKB) are composition fuels manufactured from lignite/brown coal, produced by briquetting under high pressure. These figures include dried lignite fines and dust.
Patent Fuel	Patent fuel is a composition fuel manufactured from hard coal fines with the addition of a binding agent. The amount of patent fuel produced may, therefore, be slightly higher than the actual amount of coal consumed in the transformation process.
Coke Over Coke and Lignite Coke	Coke oven coke is the solid product obtained from the carbonisation of coal, principally coking coal, at high temperature. It is low in moisture content and volatile matter. Also included are semi-coke, a solid product obtained from the carbonisation of coal at a low temperature, lignite coke, semi-coke made from lignite/brown coal, coke breeze and foundry coke. Coke oven coke is also known as metallurgical coke.
Gas Coke	Gas coke is a by-product of hard coal used for the production of town gas in gas works. Gas coke is used for heating purposes.
Coal Tar	The result of the destructive distillation of bituminous coal. Coal tar is the liquid by-product of the distillation of coal to make coke in the coke oven process. Coal tar can be further distilled into different organic products (e.g. benzene, toluene, naphthalene) which normally would be reported as a feedstock to the petrochemical industry.
Gas Works Gas	Gas works gas covers all types of gases produced in public utility or private plants, whose main purpose is manufacture, transport and distribution of gas. It includes gas produced by carbonization (including gas produced by coke ovens and transferred to gas works gas), by total gasification with or without enrichment with oil products (LPG, residual fuel oil, etc.), and by reforming and simple mixing of gases and/or air. It excludes blended natural gas, which is usually distributed through the natural gas grid.
Oil Works Gas	Coke oven gas?
Blast Furnace Gas	Blast furnace gas is produced during the combustion of coke in blast furnaces in the iron and steel industry. It is recovered and used as a fuel partly within the plant and partly in other steel industry processes or in power stations equipped to burn it.
Oxygen Steel Furnace Gas	Oxygen steel furnace gas is obtained as a by-product of the production of steel in an oxygen furnace and is recovered on leaving the furnace. The gas is also known as converter gas, LD gas or BOS gas.
Natural Gas	Natural gas should include blended natural gas (sometimes also referred to as Town Gas or City Gas), a high calorific value gas obtained as a blend of natural gas with other gases derived from other primary products, and usually distributed through the natural gas grid (eg coal seam methane). Blended natural gas should include substitute natural gas, a high calorific value gas, manufactured by chemical conversion of a hydrocarbon fossil fuel, where the main raw materials are: natural gas, coal, oil and oil shale.

Municipal Wastes (non-biomass fraction)	Non-biomass fraction of municipal waste includes waste produced by households, industry, hospitals and the tertiary sector which are incinerated at specific installations and used for energy purposes. Only the fraction of the fuel that is non-biodegradable should be included here.
Industrial Waste	Industrial waste consists of solid and liquid products (e.g. tyres) combusted directly, usually in specialised plants, to produce heat and/or power and that are not reported as biomass.
Waste Oils	Waste oils are used oils (e.g. waste lubricants) that are combusted for heat production.
Peat	Combustible soft, porous or compressed, sedimentary deposit of plant origin including woody material with high water content (up to 90 percent in the raw state), easily cut, can contain harder pieces of light to dark brown colour. Peat used for non-energy purposes is not included.
Wood/Wood Waste	Wood and wood waste combusted directly for energy. This category also includes wood for charcoal production but not the actual production of charcoal (this would be double counting since charcoal is a secondary product).
Sulphite lyes (black liquor)	Sulphite lyes is an alkaline spent liquor from the digesters in the production of sulphate or soda pulp during the manufacture of paper where the energy content derives from the lignin removed from the wood pulp. This fuel in its concentrated form is usually 65-70 percent solid.
Other Primary Solid Biomass	Other primary solid biomass includes plant matter used directly as fuel that is not already included in wood/wood waste or in sulphite lyes. Included are vegetal waste, animal materials/wastes and other solid biomass. This category includes non-wood inputs to charcoal production (e.g. coconut shells) but all other feedstocks for production of biofuels should be excluded.
Charcoal	Charcoal combusted as energy covers the solid residue of the destructive distillation and pyrolysis of wood and other vegetal material.
Biogasoline	Biogasoline should only contain that part of the fuel that relates to the quantities of biofuel and not to the total volume of liquids into which the biofuels are blended. This category includes bioethanol (ethanol produced from biomass and/or the biodegradable fraction of waste), biomethanol (methanol produced from biomass and/or the biodegradable fraction of waste), bioETBE (ethyl-tertio-butyl-ether produced on the basis of bioethanol: the percentage by volume of bioETBE that is calculated as biofuel is 47 percent) and bioMTBE (methyl-tertio-butyl-ether produced on the basis of biomethanol: the percentage by volume of bioMTBE that is calculated as biofuel is 36 percent).
Biodiesels	Biodiesels should only contain that part of the fuel that relates to the quantities of biofuel and not to the total volume of liquids into which the biofuels are blended. This category includes biodiesel (a methyl-ester produced from vegetable or animal oil, of diesel quality), biodimethylether (dimethylether produced from biomass), fischer tropsh (fischer tropsh produced from biomass), cold pressed bio oil

	(oil produced from oil seed through mechanical processing only) and all other liquid biofuels which are added to, blended with or used straight as transport diesel.
Other Liquid Biofuels	Other liquid biofuels not included in biogasoline or biodiesels.
Landfill Gas	Landfill gas is derived from the anaerobic fermentation of biomass and solid wastes in landfills and combusted to produce heat and/or power.
Slude Gas	Sludge gas is derived from the anaerobic fermentation of biomass and solid wastes from sewage and animal slurries and combusted to produce heat and/or power.
Other Biogas	Other biogas not included in landfill gas or sludge gas.
Municipal Wastes (biomass fraction)	Biomass fraction of municipal waste includes waste produced by households, industry, hospitals and the tertiary sector which are incinerated at specific installations and used for energy purposes. Only the fraction of the fuel that is biodegradable should be included here.

Annex 4: Power plant efficiency

A4.1 Coal

Country	Average power plant efficiency (%)
Source:	GE, 2016
World	34%
China	35%
United States	37%
India	27%
Russia	25%
Germany	36%
South Africa	34%
Japan	37%
Korea	35%
Australia	35%
Poland	34%
Ukraine	30%
United Kingdom	38%
Indonesia	31%
Kazakhstan	30%
Taiwan	38%
Czech Republic	28%
Turkey	34%
Canada	38%
Spain	36%
Vietnam	35%

A4.2 Gas

	Average power plant efficiency (%)
Source:	GE, 2016
World	39%
Russian Federation	26%
United States	45%
Japan	45%
Saudi Arabia	32%
Iran	43%
United Arab Emirates	34%
China	39%
Korea	44%
Egypt	45%
India	45%
Uzbekistan	28%
Mexico	45%
Thailand	45%
Turkey	45%
Algeria	38%
Belarus	28%
Italy	45%
Canada	41%
Australia	39%
Turkmenistan	25%

A4.3 Other

Average operating rate for selected energy sources	
Source	EIA, 2018
Btu per KWH (KiloWattHour)	2017
Coal	10465
Petroleum	10834
Natural Gas	7812
Nuclear	10459