Methodology

2 degrees of separation
Transition risk for oil and gas in a low carbon world

Introduction

This paper provides detail on the methodology to prepare the supply side data and demand scenario used in the accompanying asset level analysis of oil & gas production in a carbon-constrained scenario.

Methodology used is broadly similar to that used in Carbon Tracker's Carbon Supply Cost Curve papers, in particular the November 2015 "Danger Zone" report, with the following key points:

- **A 15% IRR has been used to calculate "breakeven" prices.** This level is closer to that which we believe should be a sanction hurdle rate for new projects than the 10% IRR frequently used for calculating breakeven prices.
- **A production and CO_2 timeframe of 2017-2035 has been used**. The use of 2035 as an end point is consistent with Carbon Tracker's November 2015 "Danger Zone" report.
- **The IEA's 450 scenario has been used as the 2°C demand scenario focus**, rather than the Carbon Tracker estimate of the remaining carbon budget.
- **Capex data has been presented in real terms to 2025.**
- **Rystad's base case has been used for oil & gas production, including uncommercial assets.** Oil and gas figures should be thought of as being more similar in scale to expected production and capex rather than relative to full supply potential.

Further details are provided throughout this document.

Methodology - Key points

All oil and gas data was provided by Rystad Energy from its UCube database

Total identified potential supply under the database's base case has been compared to a demand scenario in order to determine the relative amounts of production that are needed and not needed under that scenario

The demand scenario used is the IEA 450 scenario, which is based on a 50% chance of achieving a 2°C global warming outcome

Needed/unneeded projects have been determined on the basis of their relative costs

The measure of relative cost is the "breakeven price", calculated as the oil or gas price that gives an NPV of a project's future cash flows of 0 using a 15% discount rate/IRR. It can be thought of as the price required to deliver a minimum return including a contingency accounting for possible delays/cost overruns

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1. Breakeven prices and contingency

In this exercise we have reviewed the oil and gas prices required to give a net present value (NPV) of zero using a given discount rate or IRR. A distinction can be drawn between two bases:

1) Breakeven price (typically 10% IRR) – illustrative of the price at which a project is economic, the 10% discount rate intended to represent a company's weighted-average cost of capital; and

2) Breakeven price including contingency (15% IRR) – illustrative of the minimum price that a project would require to generate a 15% IRR, the minimum we see as being satisfactory for sanction given risks such as cost overruns etc[1].

The 15% IRR breakeven price has been used in determining production as either needed or not needed. In previous work we have referred to this as a "sanction price"; in this document we refer to it as the breakeven price for convenience, although it would generally deliver an above breakeven return if the project is executed without delays or cost overruns.

Note that the IRR used has no effect on the volume or relative proportions of needed or unneeded production overall, which is dictated by the demand scenario used (the volume of production that satisfies the demand scenario being "needed", potential identified production above this level being "unneeded").

All prices are presented in real terms. The 10% and 15% IRRs used are stated in nominal terms; long term inflation of 2.5% has been assumed in this study (i.e. IRRs equivalent to 7.8% and 12.7% IRR in real terms).

2. Supply methodology – upstream oil & gas

a) Data Sources: Rystad Energy

Rystad UCube

All oil & gas data has been provided to us as a custom download by Rystad Energy, sourced from their UCube database as at January 2017.

UCube (Upstream Database) is an online, complete and integrated field-by-field database, including reserves, production profiles, financial figures, ownership and other key parameters for all oil and gas fields, discoveries and exploration licenses globally. UCube includes 65,000 oil and gas fields and licenses, portfolios of 3,200 companies, and it covers the time span from 1900 to 2100.

b) Oil and gas categorisation

What's included

The global supply of liquids comprises a number of different hydrocarbons from different sources and of different chemical compositions.

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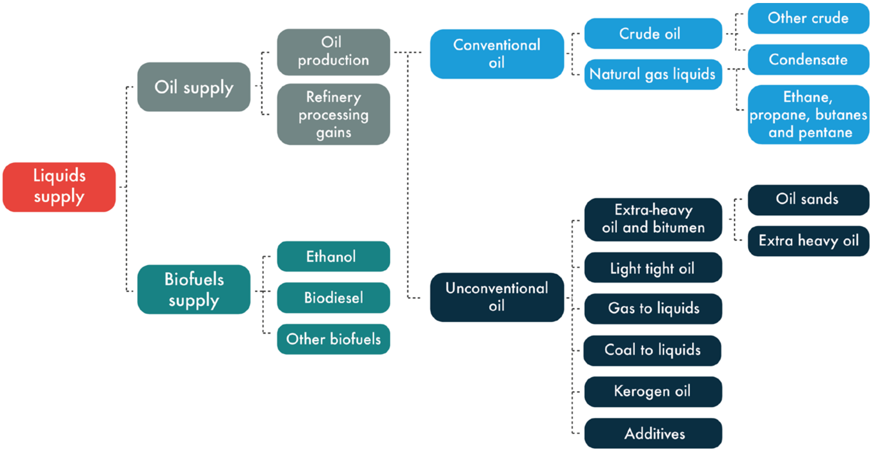
1 We have previously represented an approximation of this concept in oil analysis by adding a fixed $15/bbl "contingency" to the breakeven based on 10% discount rate.

Figure 1: IEA classification of liquid fuel



Source: IEA

In this study, "liquids" or "oil" comprises the following:

• **Crude oil**: Crude oil is oil excluding lease condensate.
• **Condensate**: Condensate is gaseous at reservoir conditions, but a liquid with specific gravity below 0.8 at standard conditions. The UCube includes lease condensate, even when this is blended (spiked) with crude if such data are available, but excludes plant condensate sourced from several fields, which in UCube is considered as NGL.
• **Natural gas liquids (NGLs)**: ethane, propane and butane sold separately from dry gas. Propane and butane can be sold as Liquified Petroleum Gas, i.e. in pressurised bottles.
Other sources of liquids supply, for example coal to liquids, bioethanol and biodiesel, and refinery processing gains have been excluded.

"Gas" is comprised of:

• **Gas**: dry sales gas, primarily made up of methane.
• **LNG**: liquefied natural gas, being gas liquefied by cooling for transport.
Unsold gas, either flared or injected, has not been included in the analysis, which therefore refers exclusively to marketed gas and oil.

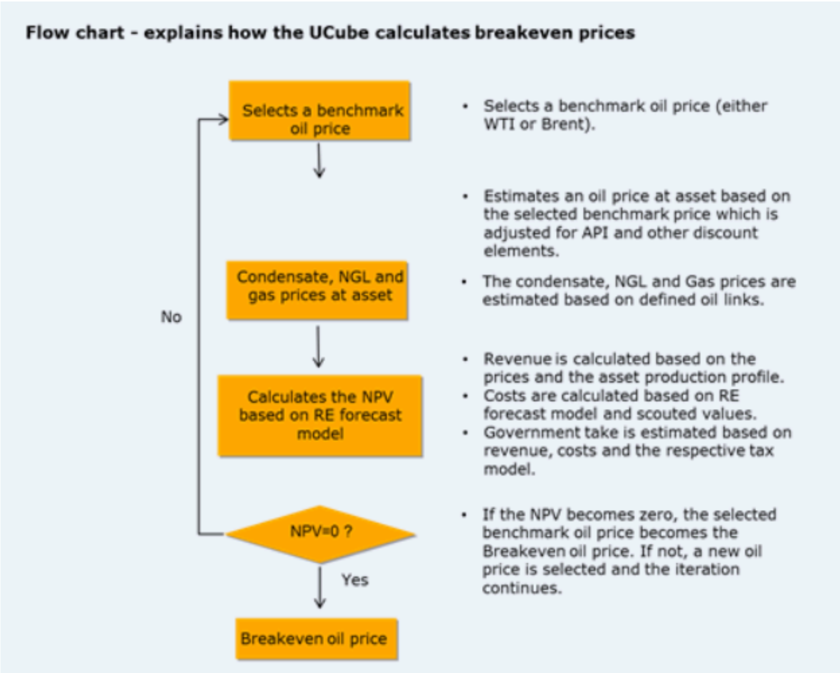
Lifecycle classification

Life cycle describes the current maturity status of the assets. Life cycle is used to identify production from already producing fields, fields under development, discoveries and still to be discovered assets. Production from all lifecycles is included in our analysis unless otherwise noted. In this study, assets categorised as at the discovery and undiscovered stages have been aggregated as "new", and those at the producing and under development stages have been aggregated as "existing".

c) Breakeven oil price (BEOP)/ breakeven gas price (BEGP)

Breakeven oil and gas prices indicate at which oil prices the assets are commercial, i.e. the oil price required for a net present value (NPV) of zero assuming a given discount rate. By default, UCube generates breakeven prices based on a Brent Equivalent Oil Price and 10% discount rate.

Figure 2: Schematic of how Rystad calculates breakeven prices



Source: Rystad Energy

Although Rystad's UCube database does not normally generate prices that give a 0 NPV based on any discount rate other than 10%, Rystad separately provided us with the breakeven prices based on 15% as above for all assets on their database.

d) Production scenarios

Rystad's base price case has been used in estimating future potential supply, including uncommercial assets.

Basis for Forecasting

Forecasting and modeling is used to obtain a complete data set. As UCube is a bottom-up database, all modeling is done on asset level. The value of applying qualified estimates for asset parameters appears when analysing aggregated results. As an example, certainly no one knows how current exploration licenses will be developed in future. By assigning a development type to each license based on analogies to existing fields and industry trends, UCube provides insight into development trends.

Modeling in UCube is generally based on:

- Analogies - The industry is mainly going to continue as it has, thus analyses of industry practices are the starting point for modeling.
- Industry trends - Ongoing shifts in technology or practice are included in the modeling. As new trends usually enhance new business, trends are followed closely.
- Data - All known data points are included in the modeling in order to adapt models to field specifics and to limit the contribution from models.
- Simplicity - Conceptually, simple models are preferred; users prefer, accept, and trust simpler models they understand, despite possibly lower precision.
- Calibration - The bottom-up models are calibrated top-down against benchmarks on aggregated levels.

Forecasting Production

In UCube all assets - fields, awarded and unawarded acreage - have reserves and production profiles. The minimum parameters to provide a production profile are Reserves and Production start year. The resulting generic production profile will show a build-up, plateau, and decline phase, where production stops at economic cut-off. The more information available the more field specific the profile; reserve size, hydrocarbon type, development type, water depth, distance to shore, geography, and previous production all influence the resulting production profile. Licenses are risked with respect to volumes to take into account that not all licenses will result in successful discoveries and developments. Production (and economics) are forecasted on de-risked volumes and then risked to UCube values.

Forecasting Economics

Economic data on developments and operations at asset level are scarce, and Economics in UCube are mainly model-based. As for production the models are based on case studies and analogies. Size of reserves, development type, and water depth determine input parameters to decide development capex levels and timing as well as opex, well capex, and modification capex throughout field life. The models are extensively calibrated to known development cases and are calibrated “top-down”, to benchmarks at aggregated levels. The fields stop producing when operational and well costs exceed revenue from production.

Economic modeling starts by allocating exploration, development, operational costs, and modification costs to the asset. When the asset starts producing the revenue is determined by multiplying production by prices. Oil prices depend on oil quality (API and total acids) and gas prices on local markets or known contracts. Knowing production, revenue, and costs, the government take is calculated and so is the profit (FCF- free cash flow). More than 600 different tax regimes are included to calculate correct government take, comprising a variety of taxes, royalties, PSAs, sliding scales, and bonus schemes. In UCube the Economics variable is identical to the revenue, thus Economics = Revenue = Capex + Opex + Government take + FCF. From the economics time series the Net Present Value, not only of FCF but also of capex, opex, and government take, is calculated in the Economics Present Value (thus, to get the NPV use the Economics Present Value for 2010 with only FCF selected in Economy Type). For the purpose of analysing economics effectively, the calculated fields.

Estimating Yet-to-find Resources

Two different approaches are used to estimate resources in open (unawarded) acreage and licensed (awarded) acreage. In both cases to-be-discovered volumes allocated to specific assets are risked to obtain overall expectancy correct results. When volumes are allocated, production and economics are calculated on de-risked volumes, and the resulting production profiles and economics are risked again before being entered into UCube. The interpretation of risked volumes is that all assets have a probability of becoming discoveries but many will not become so. Thus, it is expected that successful discoveries will show larger volumes than allocated. Since we do not know where discoveries will occur the YTF-volumes are generally low for each asset.

For open (unawarded) acreage volumes are mainly based on USGS surveys and basin estimates. However, resource estimates are reduced by roughly 50% as USGS is assumed to be too optimistic. In order to provide a realistic development of each basin, future licensing rounds are simulated to distribute discoveries and developments on time.

For licenses (awarded acreage) an industrial approach is applied:

• The best indication for the prospectivity of specific license blocks is given at "the moment of truth" when companies make their bids (work commitments and signature bonuses) for the blocks.

• Companies show different track records in finding costs. A company with a track record in finding costs of USD 2/bbl bidding MUSD 100 for a license will find 50 MMbbl; a company with track record USD 5/bbl will find 20 MMbbl. The best track record in the owner group applies.

• Volumes will be risked for probability of discovery, mainly depending on the maturity of a basin and also taking into account the recent discoveries in a license or basin.

• Further, volumes will be risked by probability of drilling. In particular, this applies to offshore deepwater, where committed wells generally exceed exploration rig capacity. Confirmed wells get a pdrilling=1; for other wells pdrilling is reduced to ensure realistic drilling capacity.

• Exploration capex (expex) is based on simulating license commitments (e.g. seismics, number of wells).

When a discovery has been made in a license, a field asset is created and the remaining volumes of the license are reduced. The reserves of the discovery are determined by Rystad Energy's review board, estimating reserves based on published information, context, and industry insight.

e) Calculating CO_2 emissions from oil production

The conversion ratio to calculate carbon emissions from oil production is a crucial feature for estimating the use of the carbon budget and the concept of carbon emissions from oil supply. Simply put, the different categories of oil supply have to be converted to CO_2 emissions, using an oil to carbon conversion factor (or ratio). Combustion-only ratios can be calculated using empirical data and known chemical processes[2].

Because we are doing an analysis that just looks at oil supply outside of a general or comprehensive economic model, we use life cycle emission estimates (instead of combustion-only ratios) which take into account other factors, for example the energy used to produce the oil and gas, and how much of the oil and gas is not combusted. However, the estimates are more difficult to determine and will vary somewhat between locations, depending on extraction type and how the oil and natural gas liquids are used.

2 *See http://www.epa.gov/cleanenergy/energy-resources/refs.html*

The approximate life cycle conversion factors used for oil and gas are shown in the below tables. For simplicity, these have been averaged at the level of resource theme for oil/liquids and market for gas. In practice, each oil category will include varying blends of oils with different characteristics, and differing relative production of products like NGLs and condensate compared to crude oil. The figures below represent a barrel-weighted average of the emissions from the different products over the course of the 2017-2035 period in the two demand scenarios.

Table 1: Life-cycle CO_2 conversion factors for different liquids categories

Oil resource theme	CO_2 produced ($GtCO_2$/mmboe)
Arctic	0.0032
Coalbed methane	0.0030
Conventional (land/shelf)	0.0031
Deep water	0.0032
Extra heavy oil	0.0033
Oil sands	0.0046
Oil shale (kerogen)	0.0046
Tight/shale	0.0031
Ultra deep water	0.0032

Source: Carbon Tracker analysis

Similarly, there are variations in factors used between gas markets; although gas is more homogenous then oil in terms of energy content and CO_2 emissions, there are still variations. For example, LNG is generally more carbon-intensive than piped gas due to energy required during the liquefaction process. For further details please see our gas-specific paper published in July 2015[3]. Further on gas emissions, recent concerns have often related to the leakage or release of the actual natural gas itself, being primarily composed of methane, a potent greenhouse gas ("fugitive emissions"). The emissions examined in this report and previous Carbon Tracker reports relate to CO_2 only, with no additional analysis of the impact of fugitive emissions.

3 *Carbon Tracker, Carbon Supply Cost Curves: Evaluating Financial Risk to Natural Gas Capital Expenditures*
http://www.carbontracker.org/wp-content/uploads/2015/07/GasSupply-finaldraft-06072015-FINAL.pdf

Table 2: Life-cycle CO_2 conversion factors for different gas market

Gas market	CO_2 produced ($GtCO_2$/mmboe)
North America	0.0017
Europe	0.0017
LNG	0.0020
Other	0.0017

Source: Carbon Tracker analysis

This factors give overall CO_2 emissions levels consistent with those in the IEA's 450 Scenario when applied to the 450 demand numbers used in our report, and are consistent with the internal relativities of carbon factors from the Intergovernmental Panel on Climate Change[4].

f) Calculating upstream capital expenditure (capex)

"Capex" for the purposes of this report includes capital expenditures for both exploration and production combined[5].

- Capex includes investment costs incurred related to development of infrastructure, drilling and completion of wells, and modification and maintenance on installed infrastructures.
- Exploration capex are costs incurred to find and prove hydrocarbons: seismic, wildcat and appraisal wells, general engineering costs, based on reports and budgets or modeled.

Capex figures in this report are presented in real US dollars, over the time frame 2017-2025.

3. Demand methodology

In this study we compare the potential supply of oil and gas to a carbon-constrained demand scenario over the period 2017-2035, based as closely as possible on the IEA's 450 Scenario.

The single source of detail on the 450 Scenario used here is the World Energy Outlook 2016, published in November 2016. This document provides a great deal of information on the scenario, including some coverage at a regional level. However, it does not provide the entirety of the detail needed in order to apply a fully comprehensive demand scenario at the asset level, particular in gas markets. Accordingly some reasonable approximations have been made, where necessary, and annual points in between those disclosed by the IEA have been interpolated. Further detail on this scenario is provided below.

4 See IEA, "CO_2 emissions from fuel combustion: Documentation for beyond 2020 files," 2014 Edition, and Intergovernmental Panel on Climate Change (IPCC), "2006 IPCC Guidelines for National Greenhouse Gas Inventories."
5 Rystad Energy, UCube Technical Presentation 2014, 29-33.

Whilst the IEA 450 Scenario has been used on a regional basis in this report, this does not represent any intended apportionment of a carbon budget to specific regions by any political process. We encourage users to apply their own projections of demand levels and carbon constraints on the cost curves to understand the implications of a range of scenarios.

a) The IEA 450 Scenario

The 450 Scenario is one of the three central scenarios published in the IEA's annual World Energy Outlook. It is the "main decarbonisation scenario", and "assumes a set of policies with the objective of limiting the average global temperature increase in 2100 to 2 degrees Celsius (2°C) above pre-industrial levels". Details of these assumed policies can be found in the World Energy Outlook[6].

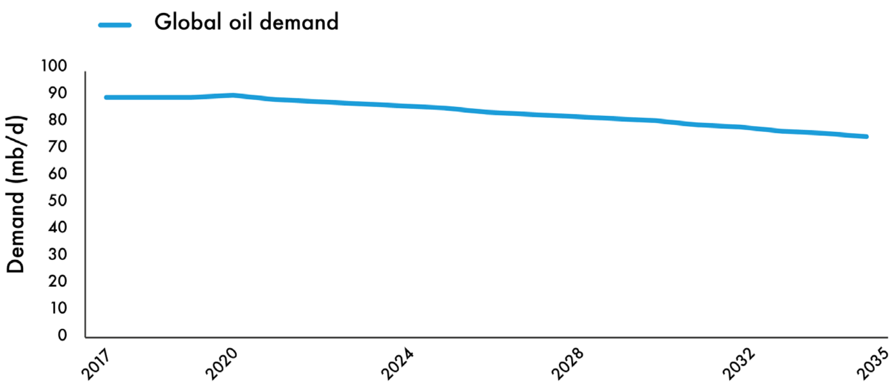
The 2°C global warming outcome in 2100 is based on a 50% chance of success.

b) Oil demand

The world oil supply in the 450 Scenario has been used, with refinery gains, coal to liquids (CTL) and gas to liquids (GTL) excluded.

On this basis, demand for upstream oil peaks in 2020 at slightly under 91 mb/d, before gradually falling to 75 mb/d in 2035 (a decline of 1.2% CAGR from peak).

Figure 3: Global oil demand under the 450 Scenario



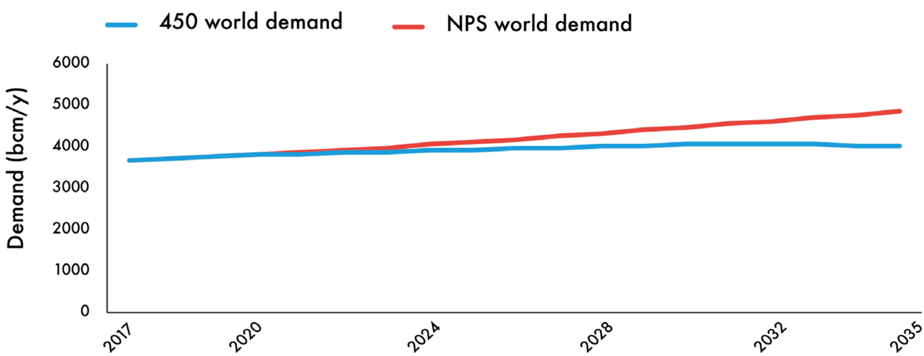
Source: IEA, Carbon Tracker analysis

6 *See IEA, World Energy Outlook 2016, Annex B*

c) Gas demand

Natural gas is unique amongst fossil fuels in that its use increases under the 450 scenario over the period contemplated, albeit modestly (2017-2035 CAGR of 0.6%) and with a peak in 2030 from which there is subsequently a slight decline.

Figure 4: Global gas demand under the 450 and NPS scenarios



Source: IEA, Carbon Tracker analysis

Whereas oil can be approximately treated as a global market where projects all compete with each other (albeit with differing qualities), the difficulty and inflexibility of transporting gas means that it must be looked at on a more regional basis (although the growing importance of the LNG market means that markets are increasingly connected to a degree).

Accordingly, global demand must be broken up into regional markets. In this report, we have looked at three key demand markets for gas, which account for approximately half of global demand in the period 2017-2035 in the carbon-constrained scenario:

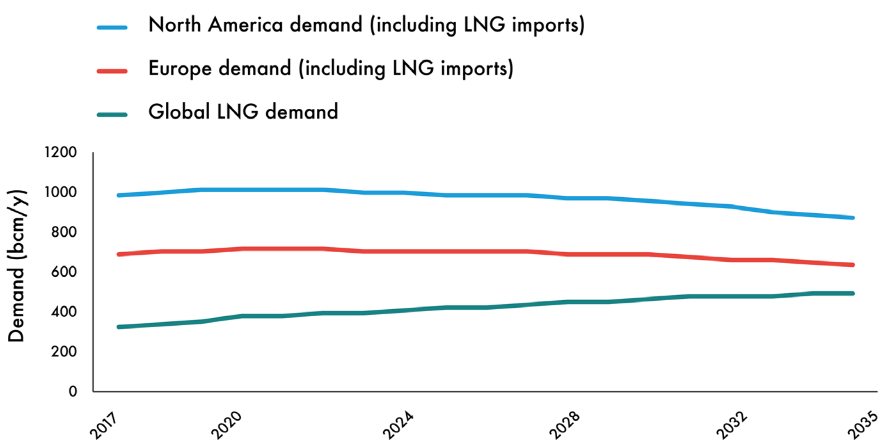
- **Global LNG** – LNG consumed anywhere in the world;
- **North America** – gas consumed in the US, Canada and Mexico; and
- **Europe** – gas consumed by those countries constituting the IEA's World Energy Outlook definitions of OECD Europe and Eastern Europe/Eurasia, excluding Russia.

Much of global gas outside the three focus markets is to a greater or lesser extent not traded in a fully functioning market, and therefore cannot be truly represented in cost curves. Comparing the 450 Scenario demand levels to remaining identified supply in Rystad's database, however, suggests that the substantially all of the expected supply of the "all other gas" outside the key markets will be needed, so we have assumed that 100% will be required for the sake of simplicity for the purpose of this exercise.

The IEA provides detail on gas demand by region in the 450 Scenario. However, detail on LNG demand/supply is only provided for the IEA's central New Policies Scenario (NPS). To solve this issue, when Carbon Tracker produced its gas cost curves report in July 2015[7], consultants Wood Mackenzie were engaged to model 450 Scenario regional gas demand and flows on a dynamic basis using their Global Gas Model. LNG demand as a percentage of global gas demand under the 450 Scenario was found to be approximately equivalent to that under the NPS; accordingly, for the sake of simplicity and transparency, we have assumed that this pattern still holds.

450 Scenario demand trends for North America, Europe and LNG are shown in the below chart.

Figure 5: Gas demand in key markets under the 450 scenario



Source: IEA, Carbon Tracker analysis

Note that the North America and Europe demand numbers are for total demand; in other words, they include LNG imports as well as piped gas, and hence LNG would be double counted in these markets if the three components of the graph were added. Accordingly LNG imports to each market have been estimated and netted out using Rystad's UCube database for the purposes of calculating demand for piped gas alone to these markets.

7 *Carbon Tracker, Carbon Supply Cost Curves: Evaluating Financial Risk to Gas Capital Expenditures. http://www.carbontracker.org/report/gascostcurve/*

4. The marginal supply cost

Intersecting the supply curve with a demand profile enables us to calculate the price needed to make the marginal project profitable under the given parameters – the marginal supply cost, otherwise known as the equilibrium price. This figure is therefore dependent on the demand scenario considered, the available supply, and the discount rate used to calculate the breakeven prices in the supply curve. A higher demand scenario necessitates supply from projects higher up the cost curve. Using a higher discount rate shifts the supply curve upwards and results in a higher marginal cost.

The marginal costs for oil and gas that are produced by intersecting 2D demand with the supply curves in this study are higher than the currently prevailing prices for those fuels. Note, however, that this does not mean that oil and gas prices will reach these levels in the near future. They are not forecasts of price for a point of time. They are the prices needed for the last unit of supply (barrel of oil or cubic metre of gas) to breakeven, over the review period of 2017-35 for the given demand scenario.

In a perfect world where oil and gas markets are efficient, the marginal unit of production would be produced towards the end of the time frame. Logically, the cost of the marginal unit in preceding years would be expected to be lower, as in theory the lowest cost (hence highest return) projects will be favoured for production first. This assumption implies that it would be some time before prices reach a level that would justify investing in high cost projects at the top of the cost curve. The oil market in particular is not completely efficient in reality (for example OPEC have attempted to support the price by restricting their production, allowing some higher cost oil to go ahead at the expense of lower cost oil), but the market collectively still seems to expect oil price increases to be limited for several years at least. At the time of writing, 2024 Brent futures contracts are trading at $58/bbl, a long way short of the prices needed to justify producing the marginal barrel of supply in this analysis. Longer term, the producer of the marginal project needs to be confident that prices can reach significantly higher levels than these, otherwise shareholder returns could suffer.

The above being said, it is worth noting that the derived marginal cost is a function of the current understanding of the market, and the actual oil prices that ultimately do drive investment behaviour will almost certainly differ from this. The multi-decade period under review will include a number of other factors that affect the oil price aside from pure supply and demand, for example cyclical effects of cost inflation and deflation, periods of oversupply and undersupply, geopolitical concerns etc. Accordingly, we do not place significant emphasis on the precise value of the marginal cost; for the purposes of this exercise it merely signifies the dividing point between projects that are needed and unneeded.

Another factor for fossil fuel companies to consider is that it is likely that price volatility for some fossil fuels will increase in a 450 scenario due to falling demand (oil in particular). We believe therefore, that owners of future long-life, capital intensive projects could face progressively more volatile markets. Accordingly, it would be prudent to consider using higher hurdle rates before sanctioning such projects and potentially putting material amounts of shareholder capital in danger.

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