Department for
Business, Energy
& Industrial Strategy

BEIS FOSSIL FUEL SUPPLY CURVES

Prepared by Rystad Energy

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Any enquiries regarding this publication should be sent to us at:
enquiries@beis.gov.uk

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Introduction and purpose

Disclaimer

This Rystad Energy report presents long-run supply curves for fossil fuels i.e. the resources that would be commercial to produce at varying future prices, given the assumptions and the time horizons in the report. The report does not present assumptions or projections on what the level of future global production of fossil fuels will be. That will depend on future levels of global demand for fossil fuels which is outside the scope of the report. This Rystad Energy report should not be interpreted or presented as representing the views of BEIS.

Introduction

The Department for Business, Energy & Industrial Strategy (BEIS) publishes long-term assumptions for UK fossil fuel prices to be used by the government and other entities for long-term planning. BEIS has engaged Rystad Energy to provide cost of supply curves for oil, gas and coal for the years 2025, 2030, 2035 and 2040.

Future cost and production levels are inherently uncertain, which has resulted in the inclusion of low supply and high supply scenarios, providing a reasonable span of outcomes for the respective fuels. Furthermore, forecasting involves both the use of hard data, analysis and subjective assessments. Whilst all assumptions and choices made in the construction of the curves are believed by Rystad Energy to be reasonable, other assumptions and choices may be equally so. This report seeks to provide transparency on the underlying assumptions and choices made in the construction of the cost of supply curves.

This report contains the following elements:

- A description about the methodology
- A breakdown and explanation of the key assumptions
- A description of assumptions for key resource types and countries/regions
- A presentation and description of the cost of supply curves
- A sensitivity analysis of the key components driving the cost of supply curves

Summary of results and implications

Oil

The global supply potential in the base case expands from 113 million barrels per day in 2025 to around 130 million barrels per day in the period between 2030 and 2040. Currently producing and sanctioned fields are expected to see production decline significantly in the long term, with their contribution dropping from 82 million barrels per day in 2025 (72% of total) to 41 million barrels per day in 2040 (32%).

The Middle East will continue to be an important source of oil, providing the lowest cost source of currently unsanctioned volumes between 2025 and 2040. North America has the largest supply potential going forward, with production potential increasing from 37 million to 43 million barrels per day between 2025 and 2040. The majority of these volumes are also among the low-cost supply groups, implying that even in a low-demand environment, shale will be a key contributor to global supply. Consequently, the cost of shale is also a key factor for the future balancing price for oil.

Gas

Russia remains the key provider of gas to Europe. The majority of the Russian volumes have a forward-looking breakeven price of 3-6 USD/MMBtu in 2025, increasing to 6-9 USD/MMBtu by 2040. The Norwegian and North African pipeline volumes are among the cheapest sources of supply for Europe (delivered to the border) as the majority of the potential volumes have a forward-looking breakeven price below 3 USD/MMBtu in 2025. Since these countries have few alternative markets for their gas, they are expected to continue to be important exporters to Europe.

Qatar has historically been a key supplier of LNG to Europe. Going forward, some volumes will likely be made available for European imports, though strong demand from Asia and increased competition from exports from the US are expected to increase Qatari flows to Asia. From a transportation-cost perspective, Europe is the most attractive market for US LNG, implying that the cost of US LNG is likely to be important for the long-term cost of gas in Europe.

Coal

Colombia and Russia provide the majority of the available volumes for Europe, collectively amounting to 80% of the available volumes in 2025. Both countries have large volumes available, with forward-looking breakevens of between 40 and 80 USD/tonne.

Most of the supply potential stems from existing mines, and the cost of supply is thus driven primarily by operational costs rather than the cost of developing new mines. This is also a key reason for the limited range between the high- and low-cost scenarios.

Fossil fuel methodology and approach

Rystad Energy has developed cost of supply curves for oil, gas and coal in 2025, 2030, 2035 and 2040. Three scenarios are presented: a base case, a high supply case and a low supply case. The cost of supply curves represent volumes that are available to Europe, but the definition of availability is different for each fuel. This is explained further in the fuel-specific methodology chapters.

The methodology used in construction of the cost of supply curves was developed through discussions and collaboration with industry specialists in BEIS and an external expert panel.

Common economic assumptions

The cost of supply curves are based on the forward-looking breakeven price for all assets (field, mine, exploration license, etc.) with available supply for Europe. The breakeven price is defined as the price that results in an NPV of 0, where a real discount rate of 13% has been applied for all assets to ensure consistency across fuels. Annex A includes a further discussion on the choice of discount rate.

The “forward-looking”-element of the breakeven price entails that only the future free cash flow (from 2019) is included in the calculation, while all historic costs are treated as sunk cost. This ensures that the breakeven price only includes the cash flow elements that affect the future decisions.

In the estimation of all future costs, Rystad Energy assumes that the exchange rate for all local currencies to US dollars will equal the average US dollar exchange rate for 2018. This is done to eliminate currency impact on the breakeven prices. The future inflation rate is assumed to equal 2.5% for all countries.

All cost of supply curves are provided in real terms (USD 2019). The transport cost to the European market is included for all assets.

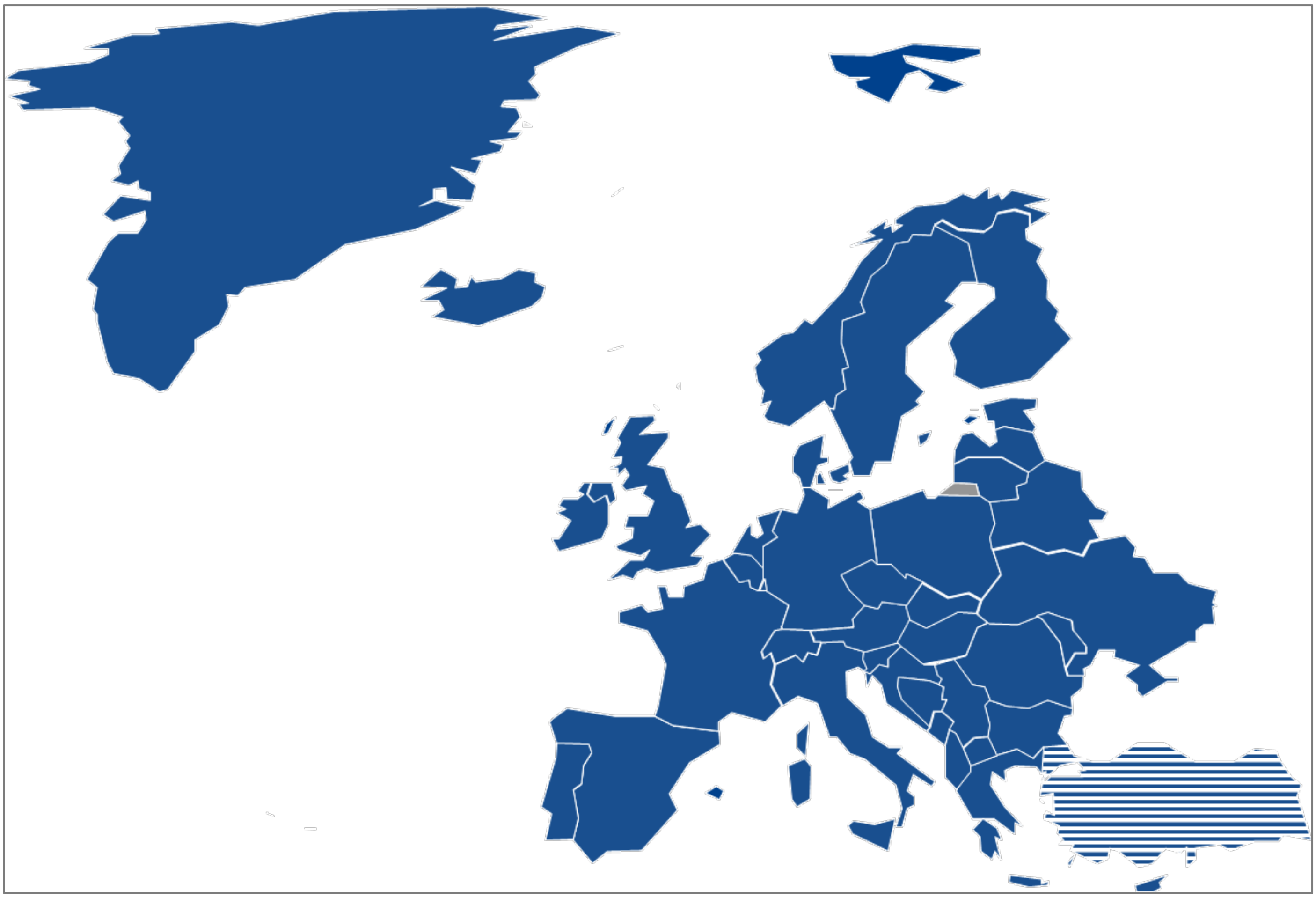
High and low cases

Rystad Energy has developed two additional cases to get a view of the sensitivity in our base-case cost of supply curves. These are the low supply and high supply scenarios. The low supply scenario represents a case where the costs could be higher than in our base case. The high supply scenario represents a case where the costs could be lower than in our base case. Other assumptions in the high and low scenarios are provided in the fuel-specific chapters.

European region

Figure 1 shows the countries that are included in the European region for the coal and gas analysis. The same country classification is applied, with the exception of Turkey, which is included for coal, but not gas.

Figure 1: European region



Oil and gas methodology

Rystad Energy has estimated the cost of supply for global liquids production and the European gas market for the years 2025, 2030, 2035 and 2040. A summary of the assumptions used in construction of these cost of supply curves are listed in table 1-4.

Table 1: Oil and gas methodology assumptions in the base case

Base case
Liquids are defined as crude oil, condensate, NGLs, refinery gains and other liquids (excl. biofuels[1]).
The modelling of conventional assets can be split into three steps. First, a production profile is constructed based on the fields remaining technically recoverable resources and standard profiles (a build-up phase, a plateau phase and a decline phase). Next, the cost profile of the field is estimated, using known field characteristics and historical observations. Lastly, the fiscal terms are taken into account, using the field's appropriate fiscal regime and assuming that all E&P companies are in a positive tax position.
The shale/tight oil production is forecasted bottom up, starting by estimating future drilling locations based on acreage size, well-spacing and utilisation. Then a future drilling schedule is estimated for each acreage position, assuming cash-neutrality. Next, again for each acreage position, a well curve, hydrocarbon split, well cost and number of drilling locations are estimated. Combining these three factors, a production profile and cost profile is generated at acreage level well by well.
Breakeven prices are calculated by finding the NPV equal to zero, excluding all historical costs.
Mid- and downstream costs are excluded except for transportation costs. Midstream costs are included for gas.
Infrastructure capacity constraints are excluded in the forecasting of long-term supply.
All potential assets are included, regardless of commerciality.
Cost levels are forecasted to increase by 5-10% over the next years for conventional assets, but remain flat for American shale/tight oil assets.

[1] Volumes from biofuels are captured by increasing the size of the conventional assets to reflect the volumes from biofuels.

Forecast is based on current technology.
Iranian crude- and condensate production is forecasted to increase to 5-6 million bbl/d in the long term.
Libyan crude- and condensate production is forecasted to remain stable at around 1 million bbl/d in the long term.
Venezuelan crude- and condensate production is forecasted to increase to nearly 3 million bbl/d in the long term.
Saudi Arabian crude production is forecasted to be at 11.5 million bbl/d in the long term.
No production cuts are assumed for OPEC and all countries are forecasted to produce at capacity, except for Saudi Arabia.

Table 2: Oil methodology assumptions in the low and high case

High supply case	**Low supply case**
Well-productivity for shale/tight oil assets are increased by 5%.	Well-productivity for shale/tight oil assets are reduced by 5%.
Overall capex and opex levels are reduced by 15% and 10%, respectively.	Overall capex and opex levels are increased by 15% and 10%, respectively.
Saudi Arabian oil production is raised to 12 million bbl/d.	Saudi Arabian oil production is limited to 10.5 million bbl/d.
Decline rates are lowered.	Decline rates are increased.

Future production and cost estimates are based on Rystad Energy's global upstream field-by-field database, named UCube. The database consists of over 65,000 assets, where an asset can be either a producing field, a field currently under development (not-yet producing field where the final investment decision has been made), a discovered, but not-yet sanctioned project, an exploration license or a not-yet awarded acreage.

The database covers resources, production profiles, economic profiles and valuation for each asset. In addition, it includes a large range of field-specific characteristics, such as ownership, resource type and life cycle.

Fundamental analysis

Three "ingredients" are needed to make a cost of supply curve. These ingredients are: volumes, long-term costs (incl. government take) and field characteristics.

Volumes

Rystad Energy's oil supply curves show the forecasted global production potential for liquids. In the liquids production, Rystad Energy includes crude oil, condensate, natural gas liquids (NGLs), refinery gains and other liquids (e.g. biofuels). With this definition of liquids, the global supply curve can be compared to global liquids demand forecasts prepared by other energy agencies, such as IEA and EIA. The cost of supply is made asset by asset, considering each asset's potential production outlook split by the different hydrocarbons.

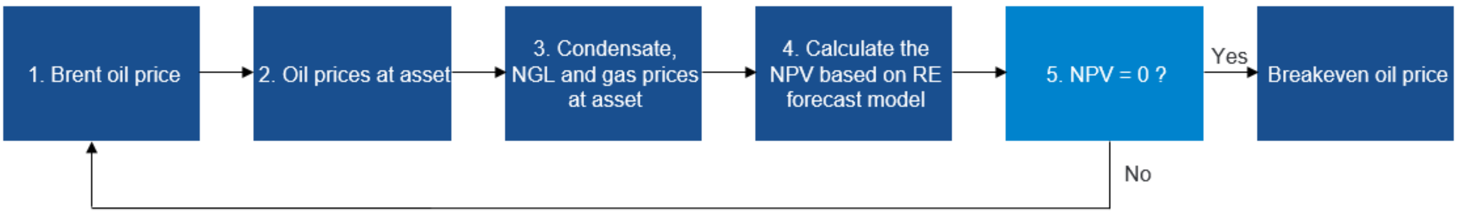
The gas supply curves show the gas supply that is expected to be available for the European market. It includes European production, pipeline imports and LNG imports. Gas production is provided asset by asset. Since the LNG market is a global market, Rystad Energy considers Europe's position in the market to determine the available volumes.

Long-term costs

The key components of the cost estimation are future investment costs, future operational costs and government take.

The breakeven price is defined as the price that results in an NPV equal to zero when only future free cash flow is included and it is given in Brent terms for oil and NBP terms for gas. To calculate the breakeven price, Rystad Energy runs an iterative processes for all assets, to find the price that gives an NPV equal zero. See Figure 2 for more information regarding the calculation.

Figure 2: Illustration of Rystad Energy's breakeven-price calculation



1. Selects a Brent oil price.

2. Estimates an oil price at asset level based on the selected benchmark price, which is adjusted for API and other discount elements.

3. The condensate, NGL and gas prices are estimated based on defined oil links.

4. Calculates NPV:

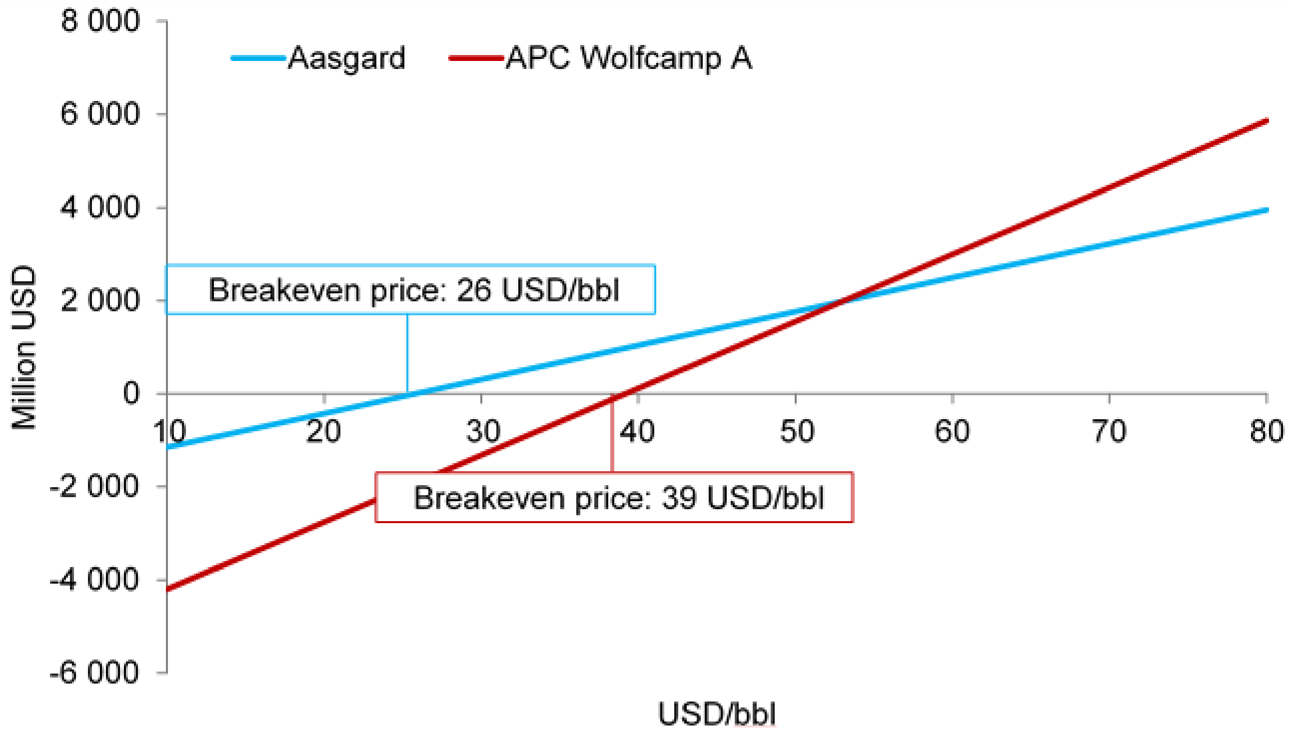
- Revenue is calculated based on the prices and the asset production profile.
- Costs are calculated based on Rystad Energy's forecast model and researched values.

- Government take is estimated based on revenue, costs and the fiscal regime.

5. If the NPV becomes zero, the selected Brent oil price becomes the breakeven oil price. If not, a new Brent oil price is selected and the iteration continues.

Figure 3 shows the NPV for Aasgard and Wolfcamp A for different oil prices.

Figure 3: NPV calculations for different oil prices for Aasgard and Wolfcamp A asset



Field characteristics

The upstream database also includes additional field characteristics for each asset. This is used to construct the various supply groups in the cost of supply curves:

- Country/region.
- Resource type (conventional onshore, shale/tight oil, oil sands, offshore shelf, offshore midwater, offshore deepwater).
- Life cycle (producing, under development, not-yet sanctioned and undiscovered).

Modelling

Rystad Energy has different modelling approaches for conventional assets and shale/tight oil assets due to the large differences in production- and cost profiles.

Production forecasting

Conventional assets

For conventional assets, the following steps are used to estimate the future production profiles:

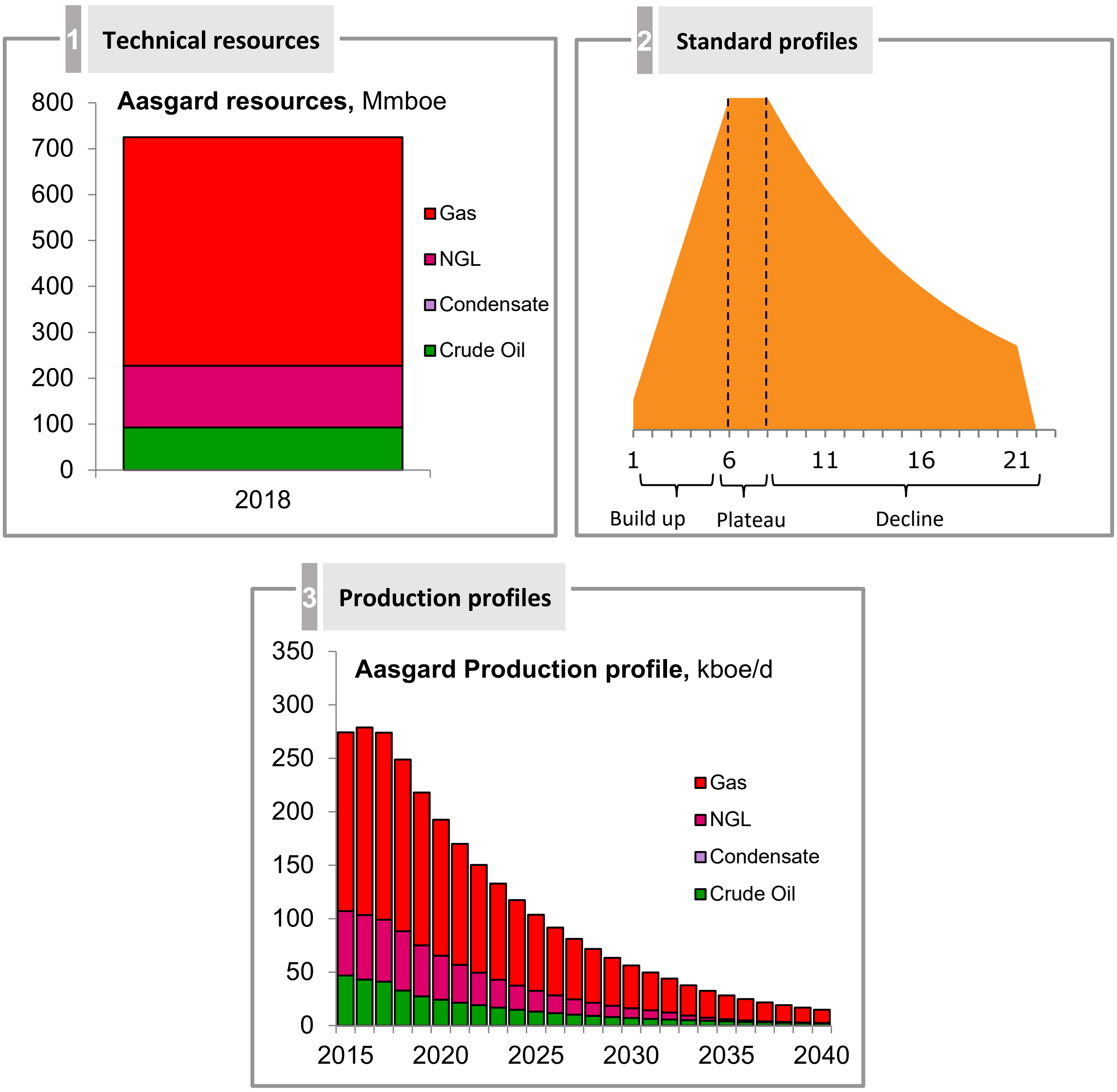
1. The key driver for the forecasted production is the remaining technically-recoverable resources in each field. The remaining resources are based on either:

- Company reported values: Annual reports, quarterly reports and investor presentations, where E&P companies provide information regarding the resources per fields.
- Government data: Some government agencies, such as NPD (Norway) and BOEM (United States), provide resource estimates per field. In these cases Rystad Energy will use this to support the resource estimates.
- If primary sources are not available for the resources, they are estimated.

2. To estimate the asset-level production profile, Rystad Energy assumes the production will follow a standard production profile with a build-up phase, a plateau phase and a decline phase. However, if production numbers are reported on asset level, these will be used to improve the estimates.

3. The production profile is developed based on the resources and the standard profile. For not-yet-producing assets, Rystad Energy will estimate the start-up date. This implies that each asset has potential production in a given year by hydrocarbon.

Figure 4: Illustration on of how the production profile for a conventional asset is generated (Aasgard example)



Shale/tight oil assets

Rystad Energy creates the shale/tight oil production forecast bottom-up by evaluating more than 2,000 acreage positions in North America. The production is estimated based on the following steps:

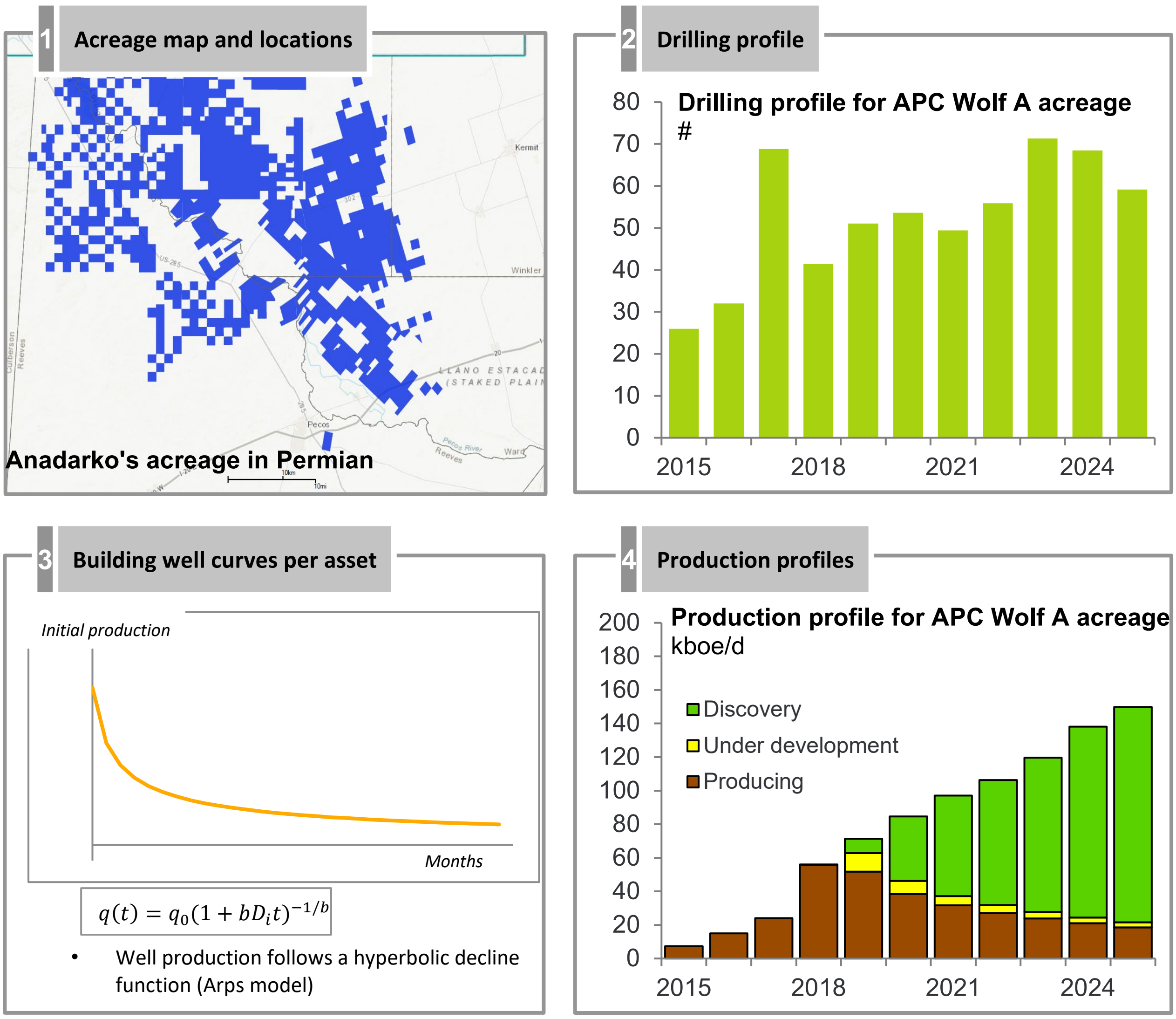
1. The future drilling locations are estimated based on the acreage size, well spacing and utilisation of the acreage.

2. The future drilling schedule is estimated for each acreage position. The short- and long-term activity forecast is based on the assumption that investments will equal cash from operations. This means that the oil price will influence the cash from operations, and consequently the investments. As a result, the cash-neutrality assumption can work as both a driver of activity and a constraint given a certain oil price.

3. A well curve is estimated for each of the acreage positions.

4. The production profile is generated at the acreage level (well by well) by combining the drilling schedule and the well performance for each acreage position.

Figure 5: Illustration of how the production profile for a shale/tight oil asset is generated (Wolfcamp A acreage example)

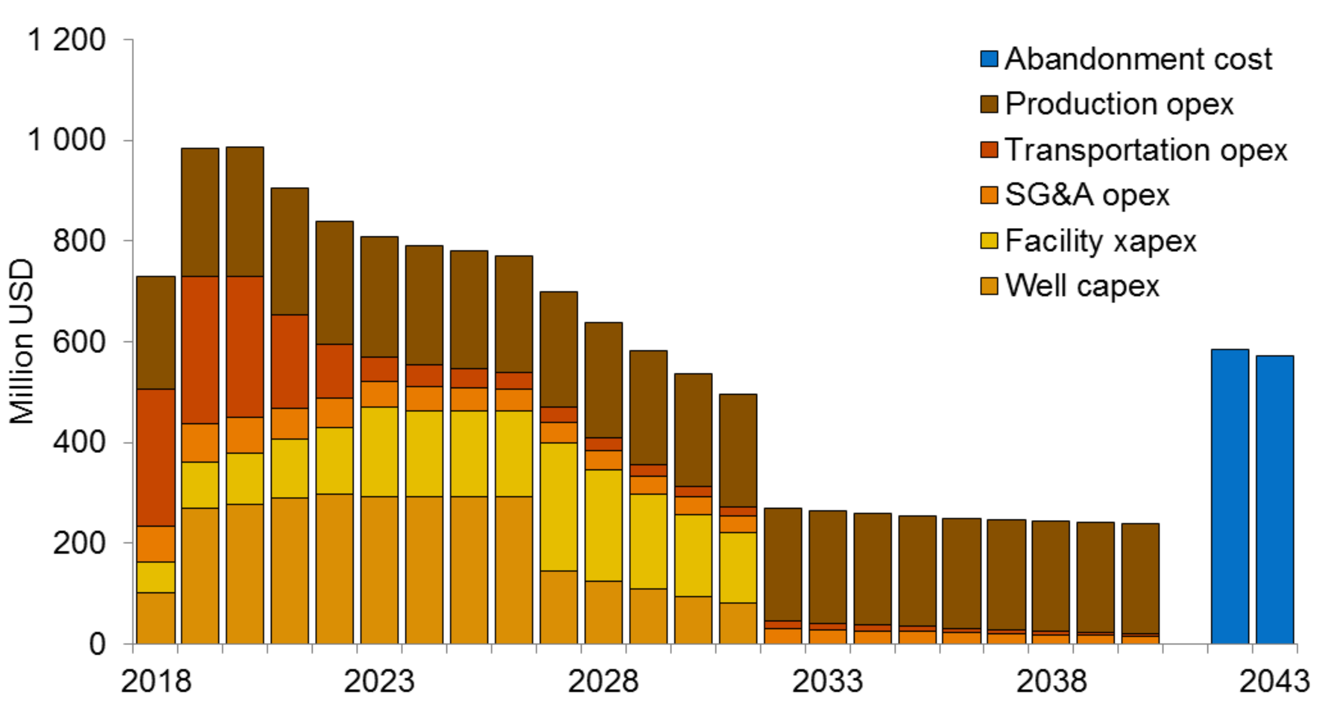


Economic forecasting

Conventional assets

Rystad Energy estimates the cost profile for each asset. The investment profile includes exploration-, well- and facility investments. During the production phase, the production cost, transportation cost and SG&A cost are included. The future cost is based on operator communication and Rystad Energy's own estimates. The cost forecast at asset level is based on historical observations, facility type, installed capacity and other field characteristics.

Figure 6: Cost profile for the Aasgard field



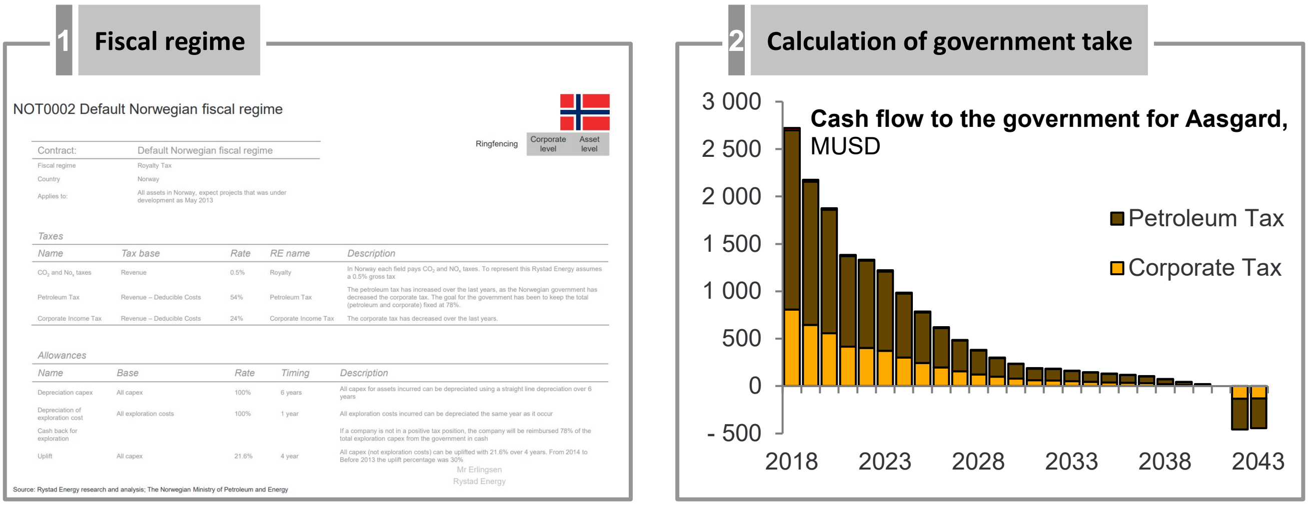
Any price differentials between the realised price at the asset level and benchmark price (Brent) is taken into account. For example, heavy oil assets will realise a discount to the Brent oil price.

The fiscal terms are also considered when estimating the breakeven price seen from the E&P companies' perspective. The calculation of the government take is done by:

1. Information for 600 different fiscal regimes globally has been collected. This includes information regarding royalty rates, export taxes, production taxes, government profit oil, petroleum, corporate taxes and allowances.

2. The government take calculation is done asset by asset, assuming that all E&P companies are in a positive tax position.

Figure 7: Illustration of the fiscal regime in Norway and the estimated government take (Aasgard example)

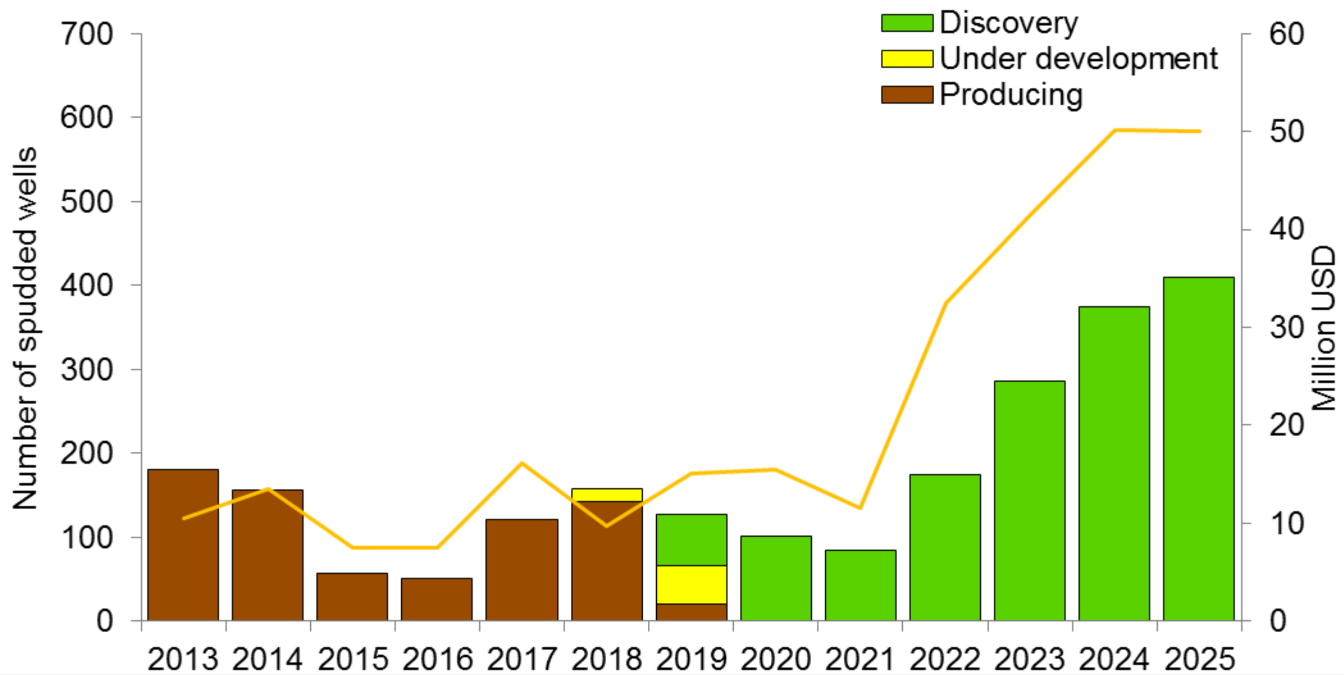


Shale/tight oil assets

Rystad Energy has collected information on the estimated well cost for each of the acreage positions to estimate the future costs for drilling new wells. The data is either collected from E&P companies or estimated by Rystad Energy based on the average well configuration for the wells drilled on that acreage.

Rystad Energy includes the price differentials between the different pricing points in the US, which are based on the infrastructure capacity and the distance to end markets. Assets in, for example, Bakken will have a lower realised oil price compared to an asset located close to the Gulf Coast. This will be reflected in the breakeven-price calculation, which is given in Brent terms.

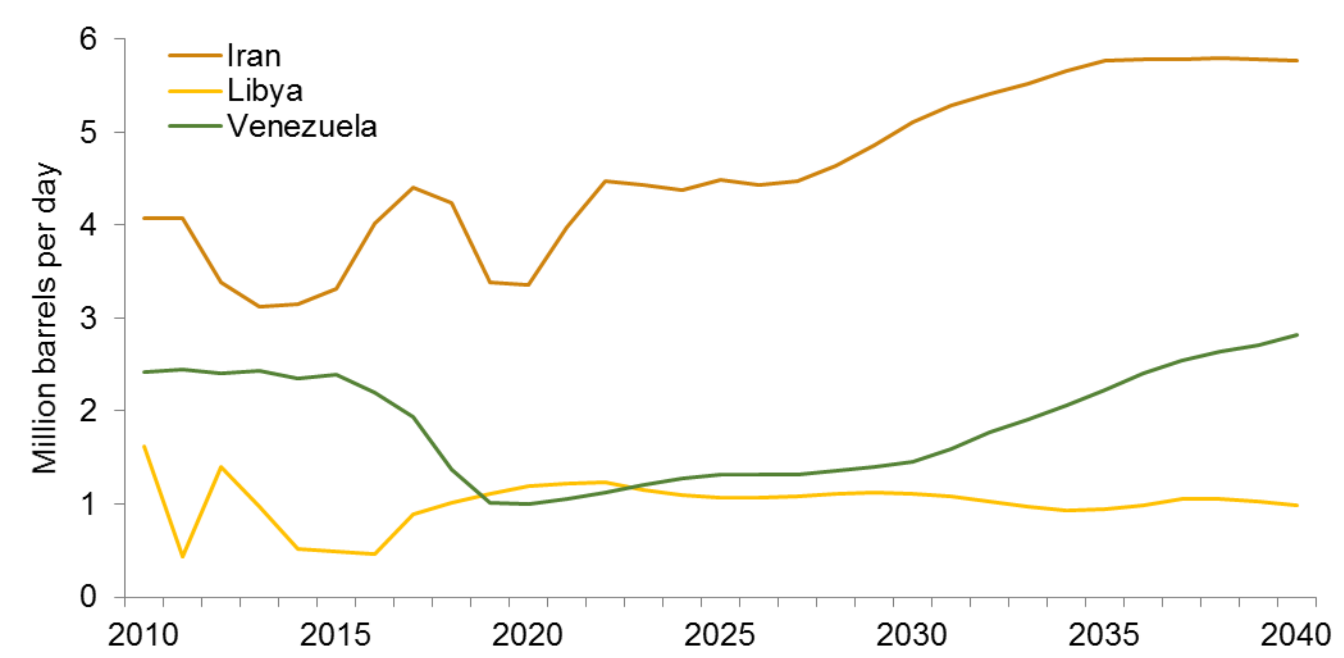
Figure 8: Historical and forecasted investments for APC Wolfcamp A acreage split by the life cycle of the wells and the number of spudded wells



Key global assumptions

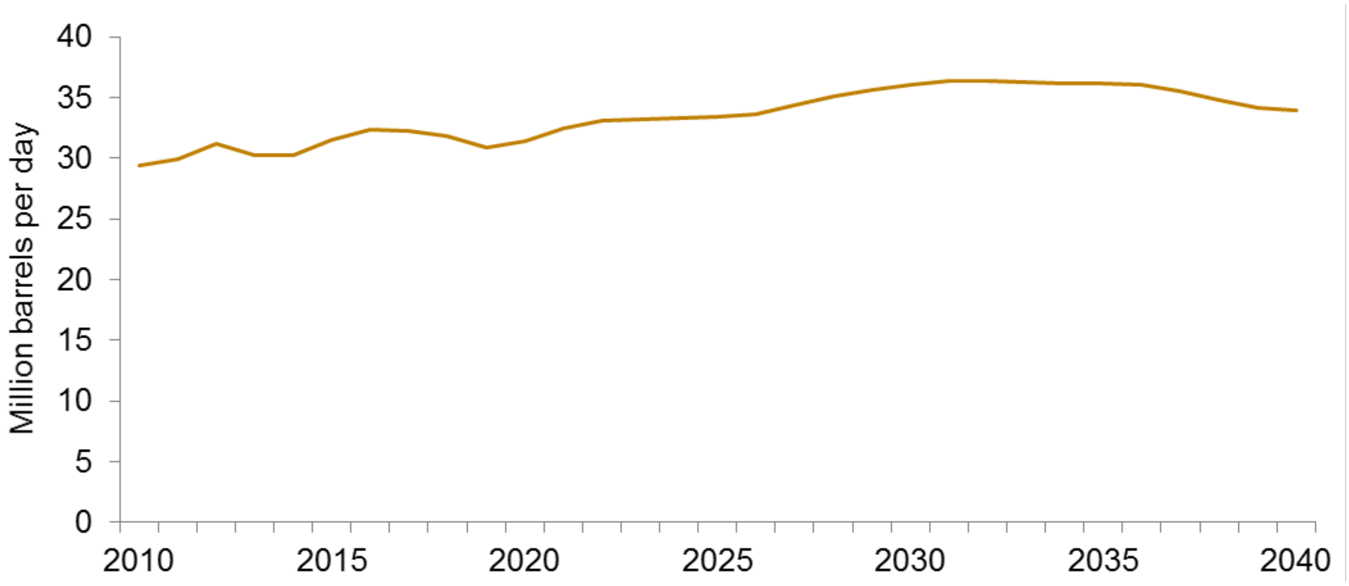
- Rystad Energy only includes costs linked directly to the production of oil and gas. It does not include any mid- or downstream costs except for the transportation cost.
- To predict the long-term potential supply, Rystad Energy does not include any infrastructure capacity constraints. In the forecast, we assume that any short- and medium-term bottlenecks will be resolved.
- To construct the cost of supply curves, we have included all assets, regardless of commerciality, so that they represent the full supply potential. However, uncommercial projects are likely to have a higher breakeven price and could as such fall outside the final supply base.
- For countries with currently large outages, such as Iran, Libya and Venezuela, Rystad Energy assumes that the production will gradually recover. Although the production outlook for these countries are highly uncertain, Rystad does not make any assumptions about future restrictions or turmoil. The crude oil and condensate production in our base case is illustrated in figure 9. The breakeven prices for these volumes range from 10 USD/bbl to more than 100 USD/bbl, but the majority of the volumes have a breakeven price of between 10 USD/bbl and 50 USD/bbl.

Figure 9: Rystad Energy base-case crude and condensate production outlook for Iran, Libya and Venezuela



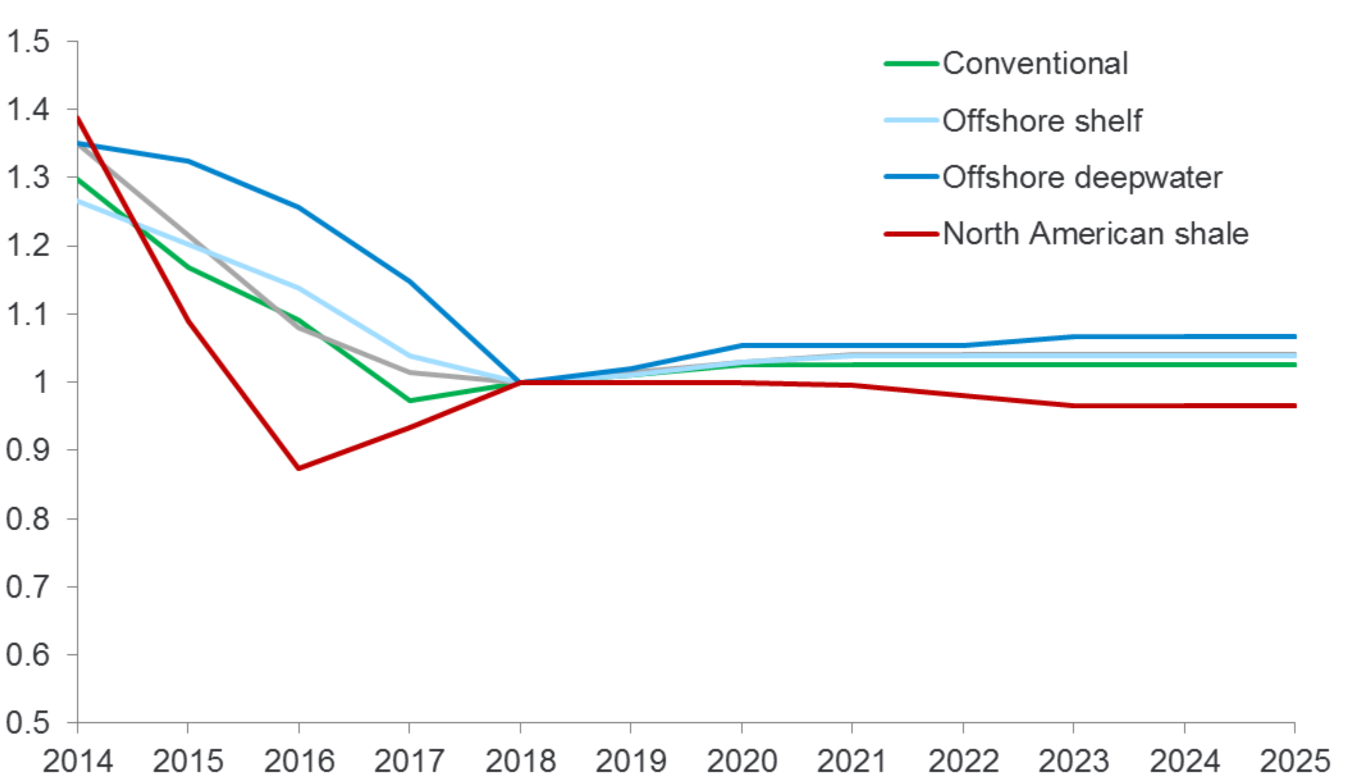
- Rystad Energy does not assume any long-term production cuts for OPEC countries, except Saudi Arabia. The assumption is that in the long run all countries, except Saudi Arabia, will produce at their capacity. For Saudi Arabia, we assume in the base case that its long-term crude production will be around 11.5 million bbl/d, as it is assumed that the country will keep volumes at a certain level to avoid flooding the market.

Figure 10: Rystad Energy base-case crude production outlook for the current OPEC countries



- Rystad Energy expects that the unit costs for conventional sources will increase around 5-10% from the current levels over the next years. This is to reflect that Rystad expects the increased activity within conventional oil and gas will increase unit prices within the industry. Unit prices are assumed to remain stable after 2025. For North American shale/tight oil we are assuming no changes in the unit prices in our costs forecast. The reason for this is that despite a doubling in shale/tight oil activity since 2016, the unit prices have not increased for shale/tight oil.

Figure 11: Base-case cost deflation indexed to 2018



- Rystad Energy is not assuming any improvement in technology in the upstream industry, neither for conventional nor shale/tight oil, since the outlook and the effect of future technology is highly uncertain. The forecast is based on the current technology.

Low and high supply cases

The following assumptions have been included in order to construct the “high cost” (high) and “low cost” (low) oil scenarios. These assumptions apply primarily to the high and low oil scenarios, as other fuels have different assumptions included in the respective scenarios.

Low supply scenario assumptions

US shale/tight oil

The key source of new supply in the medium- to long term is US shale/tight oil and it is uncertain how the future well performances will develop. Rystad Energy’s base case has risked down the well performances for future wells in not-yet drilled acreages.

In the low supply scenario, the future well-productivity for undrilled acreage is reduced by approximately 20%. This implies that the estimated production from future wells is reduced. This will both reduce the potential supply from US shale/tight oil and increase the breakeven prices.

Cost levels

Developments in future costs in the upstream industry are uncertain and historically we have observed large fluctuations in unit prices. Figure 11 shows our base-case assumptions related to development in future unit prices for different segments.

In the low supply case, the future costs are increased compared to the base case. Capital expenditure increases by 15% and operational expenditure by 10%. These percentages correspond to observed changes in historic cost levels. The global average operational costs per barrel produced for conventional fields declined by around 25% between 2014 and 2017 (peak to trough), implying that a cost variation of +/- 10% should cover the likely outcomes in the long term. The cost variation of capital expenditures is expanded to 15%, as certain capex segments (such as drilling rigs) have proven to vary significantly more. An increase in costs will increase the breakeven prices.

Saudi Arabia

In the base case we assume that Saudi Arabia will gradually increase its crude oil production as the market slowly tightens. This will bring the long-term Saudi Arabian crude production to around 11.5 million barrels per day in our base case.

In the low supply scenario, Saudi Arabia is assumed to limit its oil production to 10.5 million barrels per day, close to the same level as the country’s production targets stated in the latest OPEC agreements.

Production decline rates

When forecasting the decline rates from mature assets, Rystad Energy uses its own estimate based on reported remaining resources and historical performance. The decline rate depends on several factors, such as infill drilling EOR projects and abandonment date.

In the low supply scenario, the decline rates for mature assets are increased. This will reduce the future potential supply from currently producing assets.

High supply scenario assumptions

US shale/tight oil

Over recent years, Rystad Energy has observed improvements in the well-productivity for US shale/tight oil. This has resulted in higher production and lower breakeven prices for new wells.

In the high supply scenario, the well performances from US shale/tight oil are assumed to continue to improve. An improvement of 5% is assumed. The higher well-productivity will increase the future potential supply and lower the breakeven prices.

Cost levels

In the high supply case, future costs are decreased compared to the base case. Capital expenditure is decreased by 15% and operational expenditure by 10%. These percentages correspond to observed changes in cost levels historically. A decrease in costs will lower the breakeven prices.

Saudi Arabia

In the high supply scenario, Saudi Arabia is assumed to increase oil production rapidly to around 12 million barrels per day, which is assumed to be the country’s current capacity. Saudi Arabia could increase its oil production if it wants to keep its market share and compete with US shale/tight oil. However, Saudi Arabia is likely to keep volumes lower to avoid flooding the market. In addition, increasing production above the current capacity will require significant investments in new wells and infrastructure.

Production decline rates

In the high suply scenario, the decline rates from mature assets are lowered. This will increase the future potential supply from currently producing assets.

Alternative assumptions not changed in the scenarios

Exploration

The assumptions regarding exploration activity have been left unchanged in the scenarios. However, the potential supply from currently undiscovered fields could have been changed, either as a change in investments into exploration or as a change in the exploration success rate. This has not been implemented in the scenarios as the range of outcomes created by the utilised assumptions were deemed sufficient.

Technology

The cost of supply curve has been constructed assuming the use of current technology going forward. As proven by the recent growth in shale, there is potential for technology to significantly reduce the cost of developing oil and gas resources. It is, however, not likely that the scale and timing of such future improvements can be accurately predicted. Consequently, the potential for such future technology improvements is believed to be best captured through a high supply scenario.

Oil cost of supply

The long-term cost supply for oil has been estimated using the assumptions detailed in the oil methodology section. Curves are presented for 2025, 2030, 2035 and 2040.

Base case

Figure 12: Rystad Energy base-case cost of supply curves for oil in 2025 to 2040

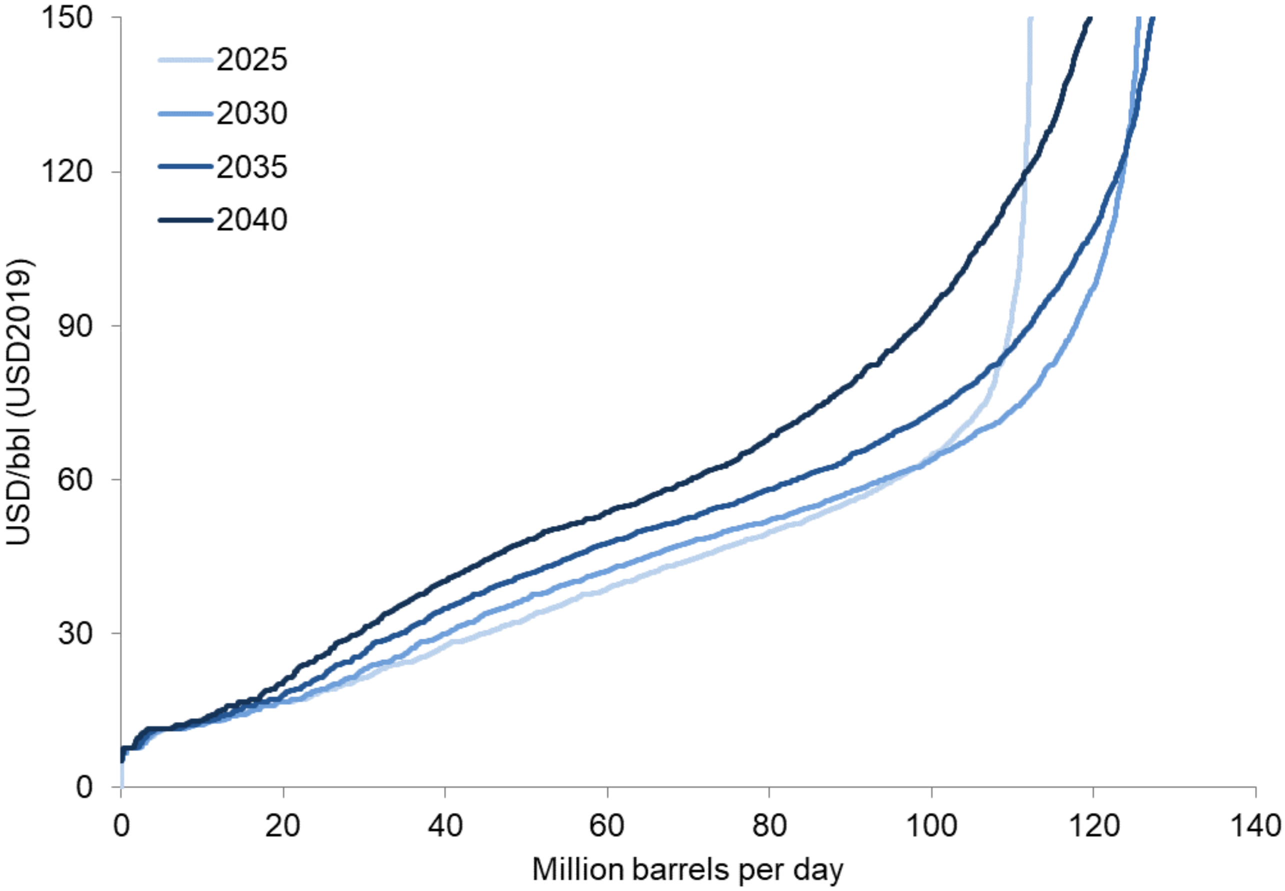


Figure 12 shows the base-case cost of supply curves for oil in 2025, 2030, 2035 and 2040. The maximum available liquids supply accumulates to approximately 113 million barrels per day in 2025, rising to 128 million barrels per day in 2030 and 132 million barrels per day in 2035 as more fields potentially come into production. In 2040, the maximum available supply decrease back to 128 million barrels per day, as the production from new fields in 2040 is not able to combat the natural decline in production from the already-producing fields.

It is evident that the cost of supply is increasing in the long term, as the curves are shifting upwards when moving out in time. In the short term, a large share of potential supply originates from already producing or sanctioned fields plus the most lucrative not-yet-sanctioned projects. However, in order to meet the demand in the longer term, more of the potential supply will come from technically challenging projects and undiscovered assets, which requires exploration. This results in projects with higher breakeven prices, causing the upward shift.

Figures 13 to 20 show the base-case cost of supply curves for oil in 2025, 2030, 2035 and 2040 by different supplier groups. The first chart for each year shows the base-case cost of supply curves for oil, grouped by continent and breakeven-price groups. The breakeven price is further grouped so that fields within the same 20 USD/bbl increment are grouped together. All fields from the same continent with breakeven above 80 USD/bbl have been grouped together.

The second chart for each year shows the base-case cost of supply curves for gas grouped by continents and life cycle groups. The fields within the same continent are split into groups based on whether the field is sanctioned or not sanctioned. All sanctioned fields have been grouped together.

The width of the boxes represents the potential supply, while the height represents the breakeven-price interval, which covers 60% of supply in the group. The breakeven price from the supplies with the highest and lowest breakeven price is not included in the breakeven-price interval. The breakeven price from the upper and lower quartile are excluded in order to give a more representative picture of the breakeven price range for the majority of the supply within the group. And due to the large variations in breakeven price for some of the defined supply groups, the interquartile range is set to 60%.

Figure 13: Rystad Energy base-case cost of supply for oil in 2025 by continent and cost group

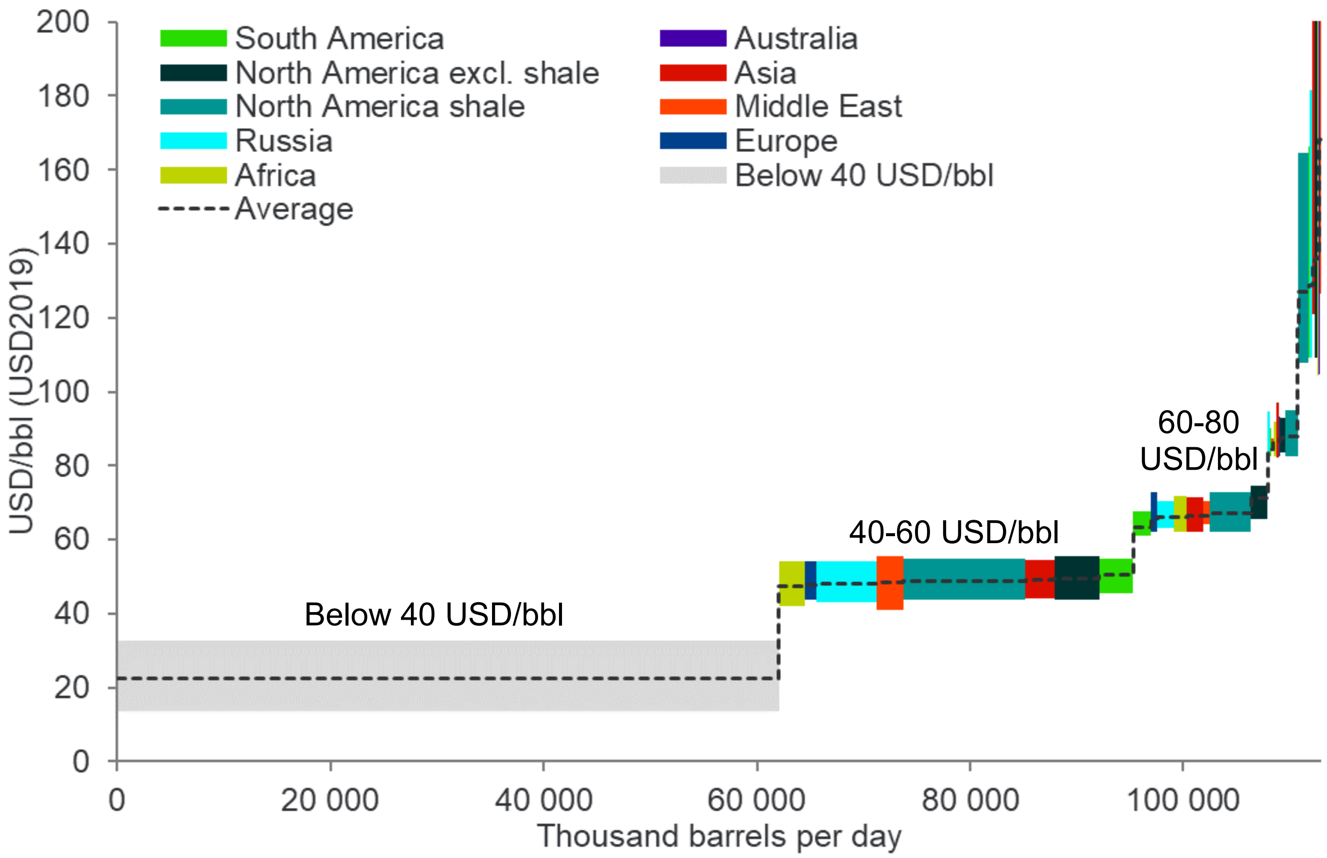


Figure 14: Rystad Energy base-case cost of supply for oil in 2025 by continent and life cycle

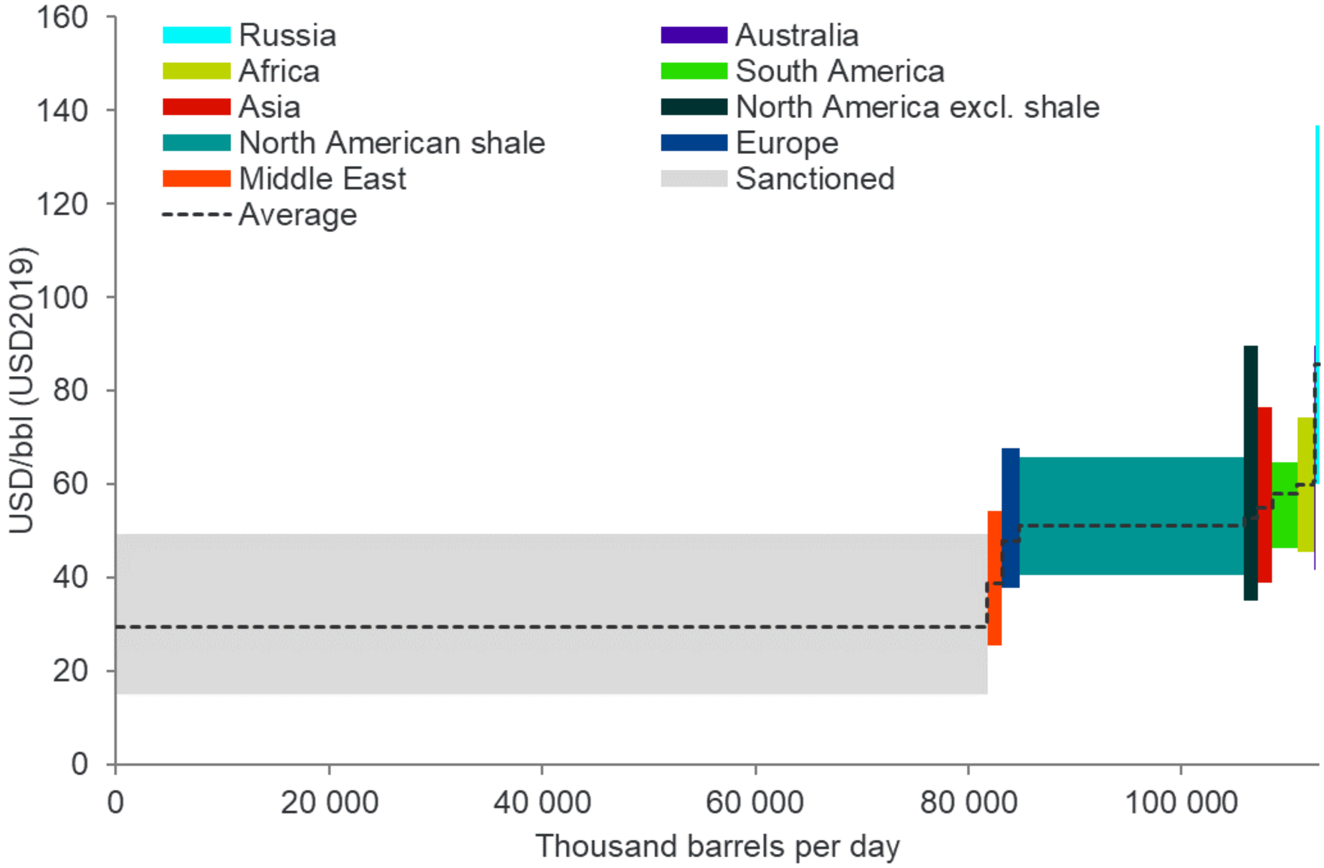


Figure 15: Rystad Energy base-case cost of supply for oil in 2030 by continent and cost group

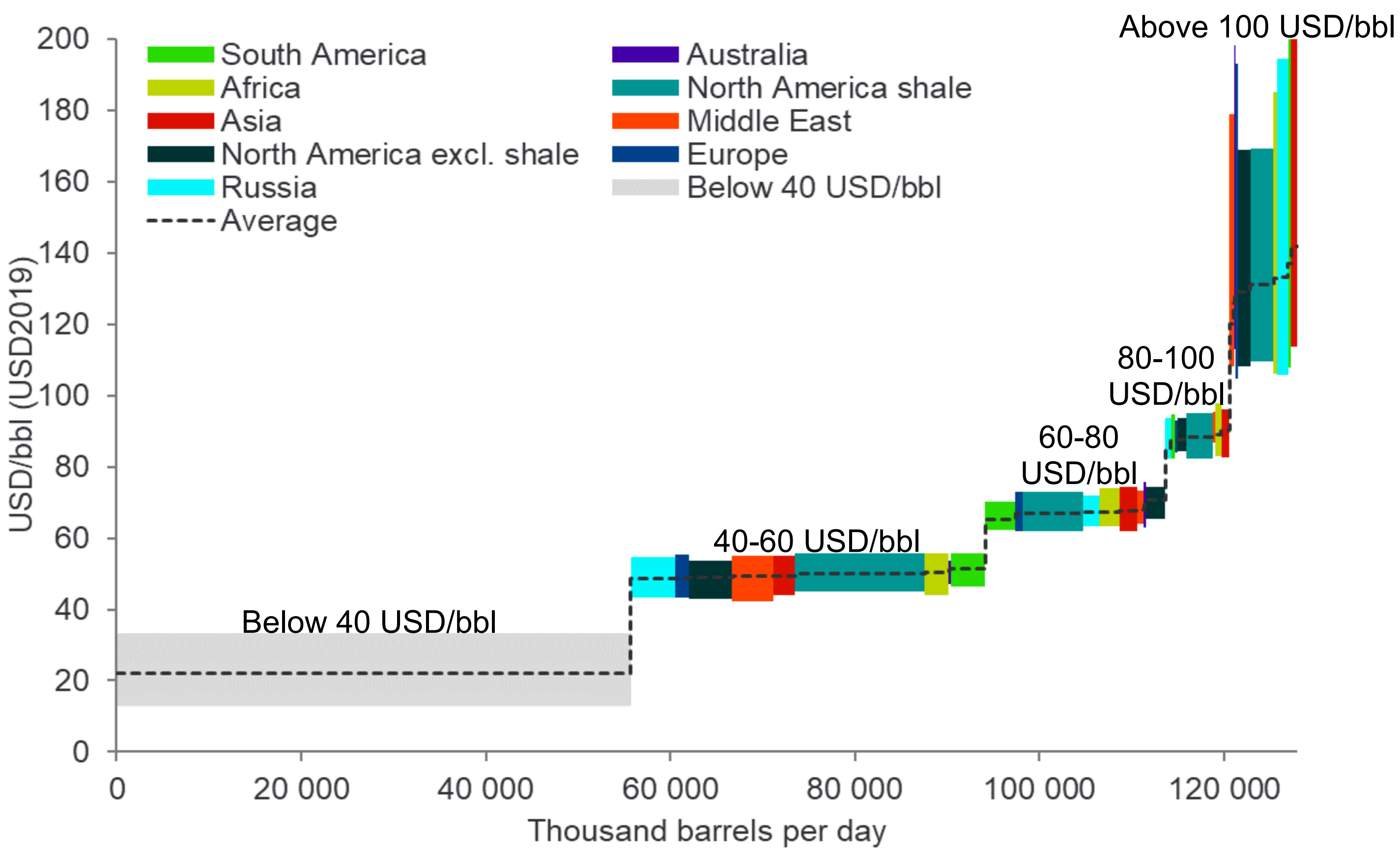


Figure 16: Rystad Energy base-case cost of supply for oil in 2030 by continent and life cycle

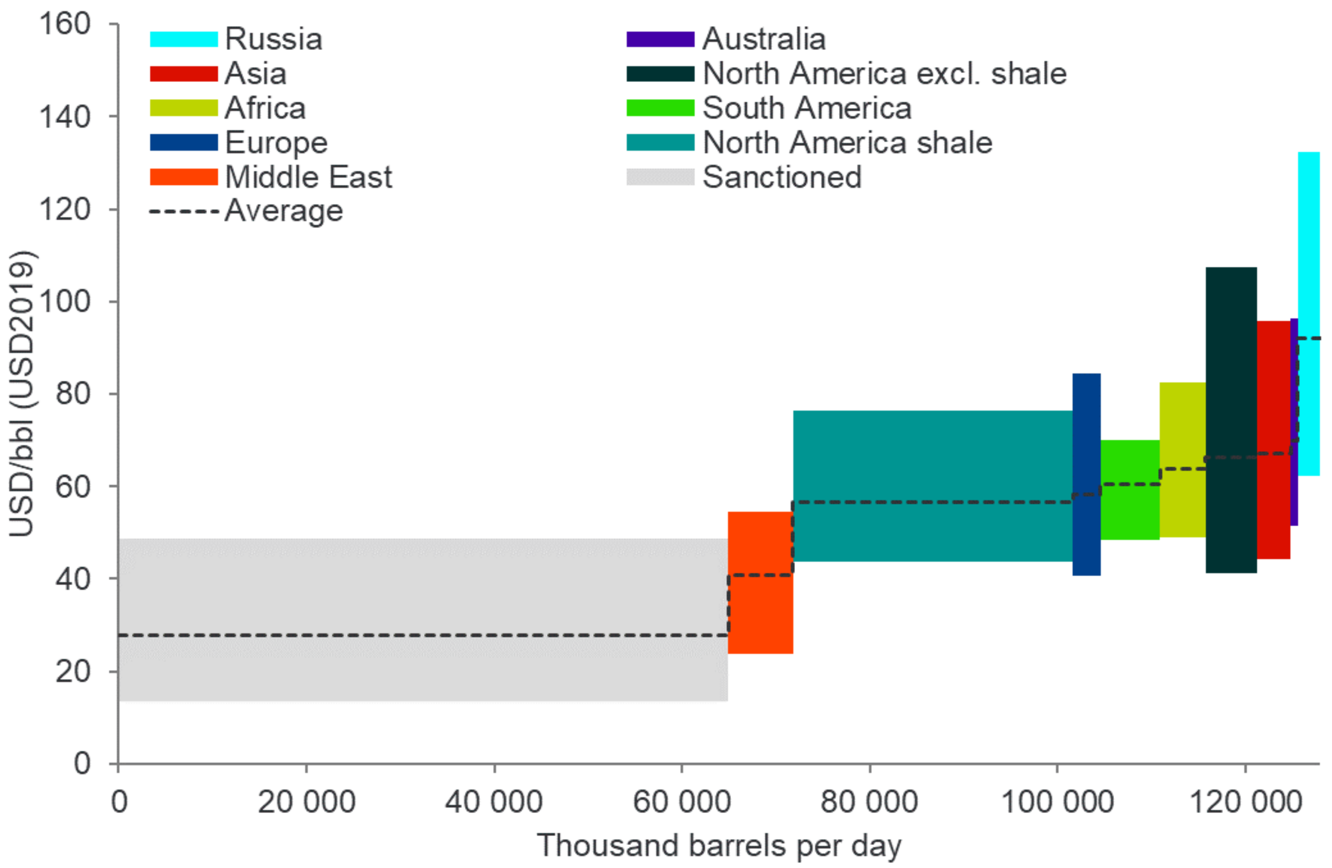


Figure 17: Rystad Energy base-case cost of supply for oil in 2035 by continent and cost group

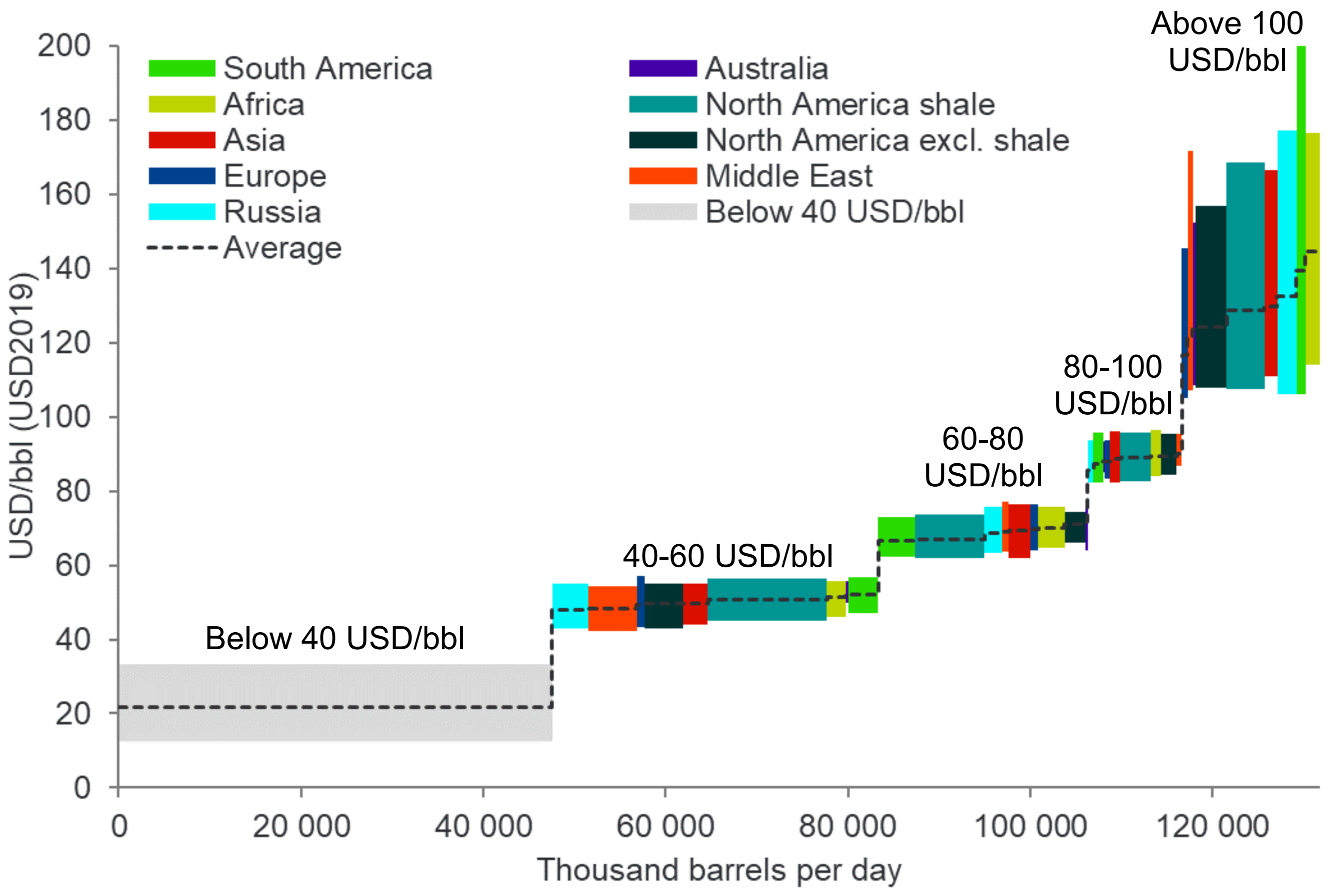


Figure 18: Rystad Energy base-case cost of supply for oil in 2035 by continent and life cycle

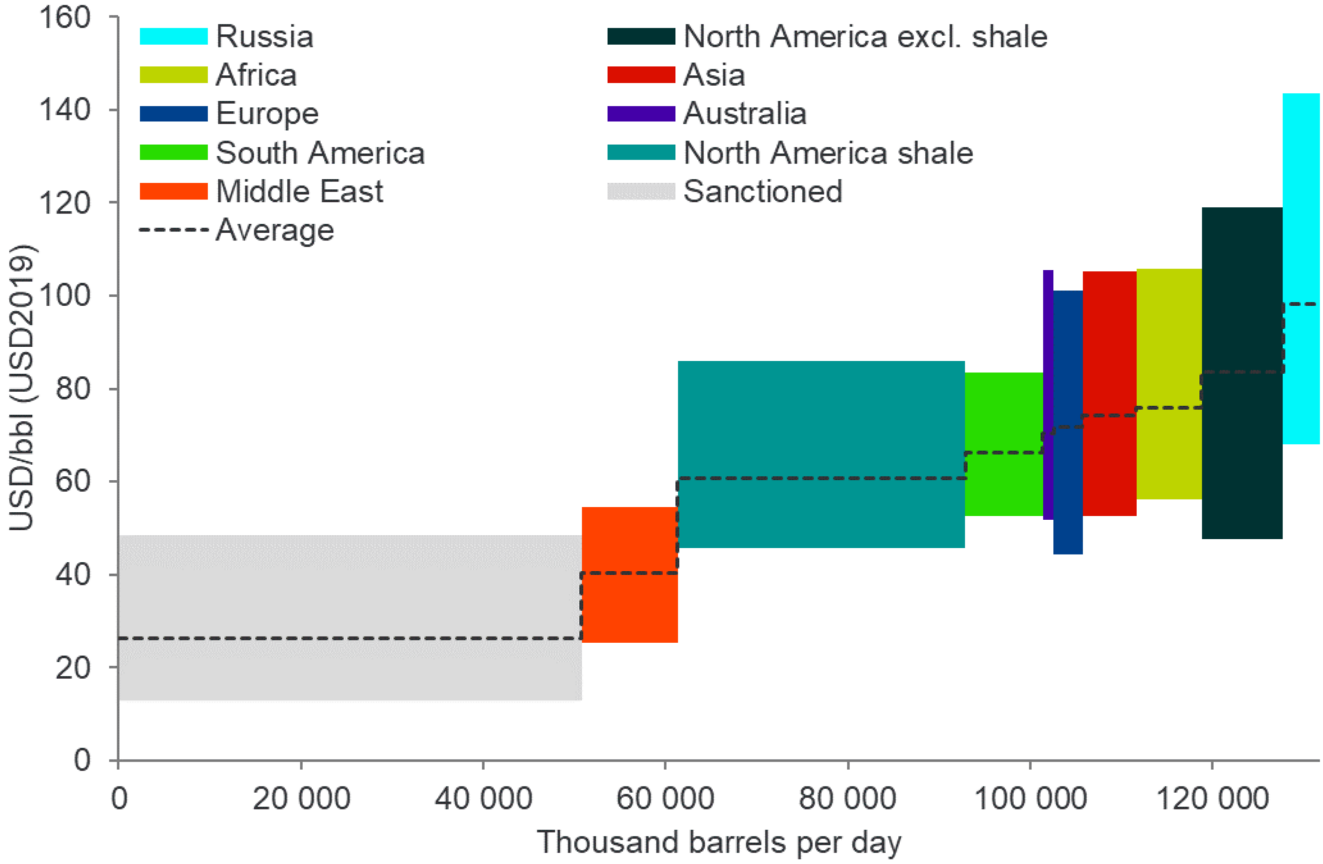


Figure 19: Rystad Energy base-case cost of supply for oil in 2040 by continent and cost group

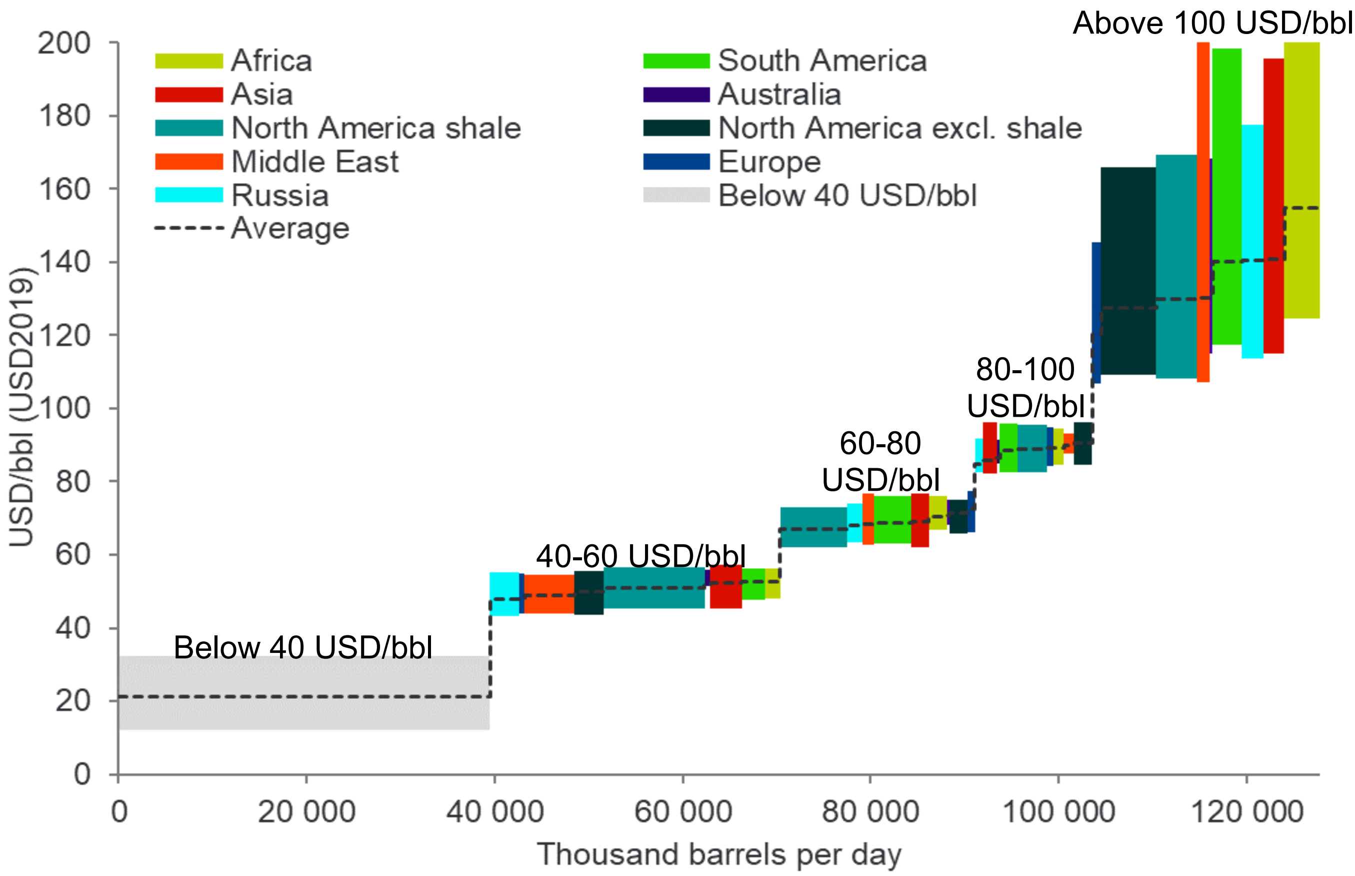
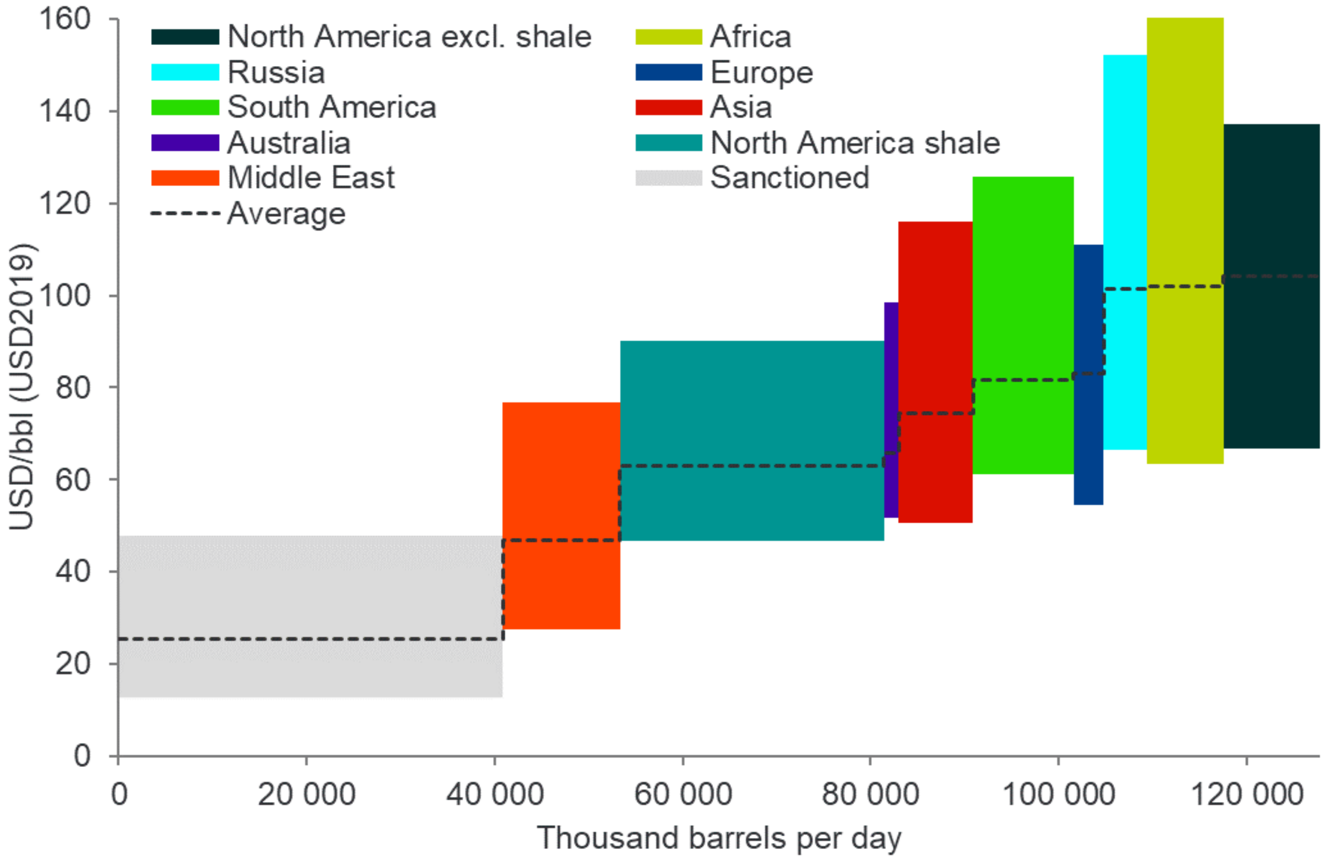


Figure 20: Rystad Energy base-case cost of supply for oil in 2040 by continent and life cycle



A large share of the potential supply in 2025 comes from fields with breakeven below 40 USD/bbl in terms of cost group, or already sanctioned fields in terms of life cycle. Moving out in time, these groups become a smaller part of the potential supply. This underlines the point made previously that in the short term, much of the supply will come from already producing and sanctioned fields with low cost, but as the production from these fields declines, more high-cost fields will need to be sanctioned in order to meet the demand in the longer term.

When it comes to source of supply, both the Middle East (conventional) and North American shale stand out in the charts when it comes to low weighted average breakeven prices and supply potential. This is especially noticeable in the supply potential from not-yet-sanctioned fields, where the two groups combined represent about 50% of the not-yet-sanctioned volumes.

Low and high supply cases

Figure 21: Rystad Energy cost of supply curves in the base, high and low supply case for oil in 2025

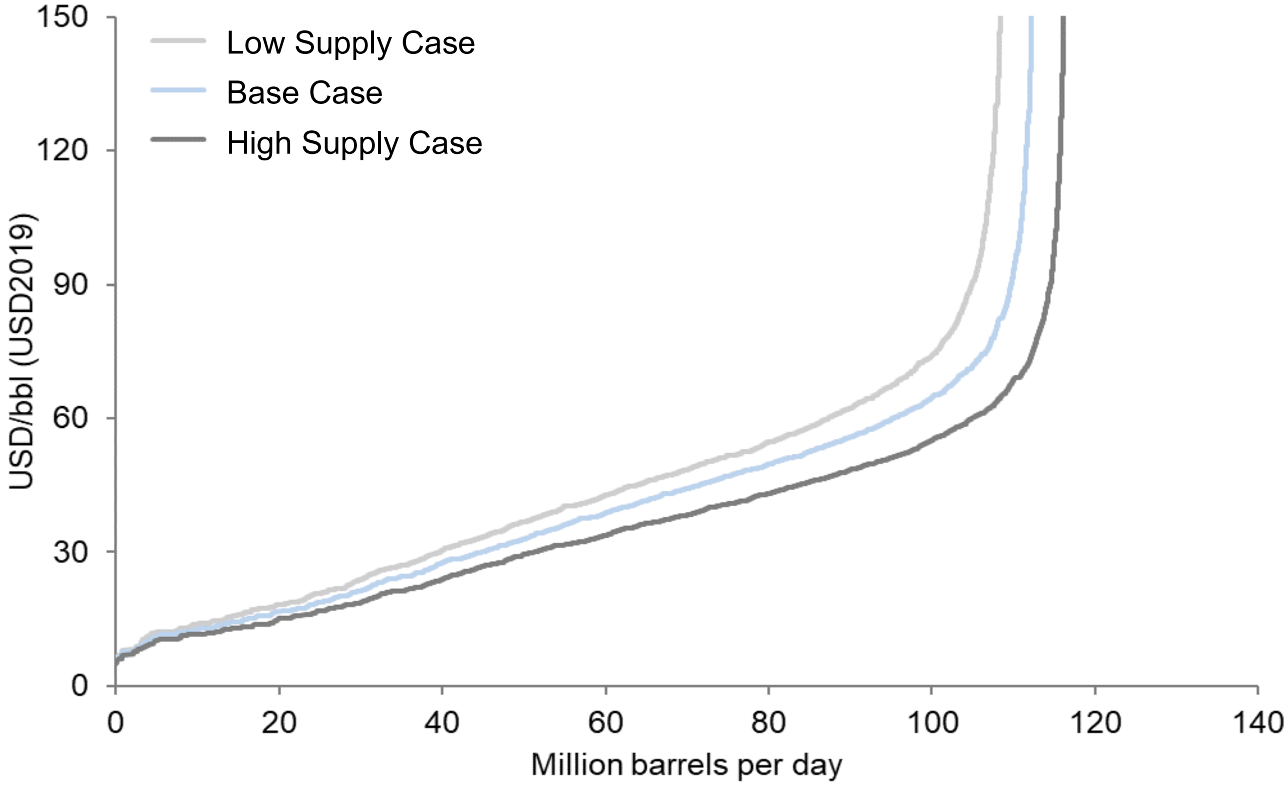


Figure 22: Rystad Energy cost of supply curves in the base, high and low supply case for oil in 2030

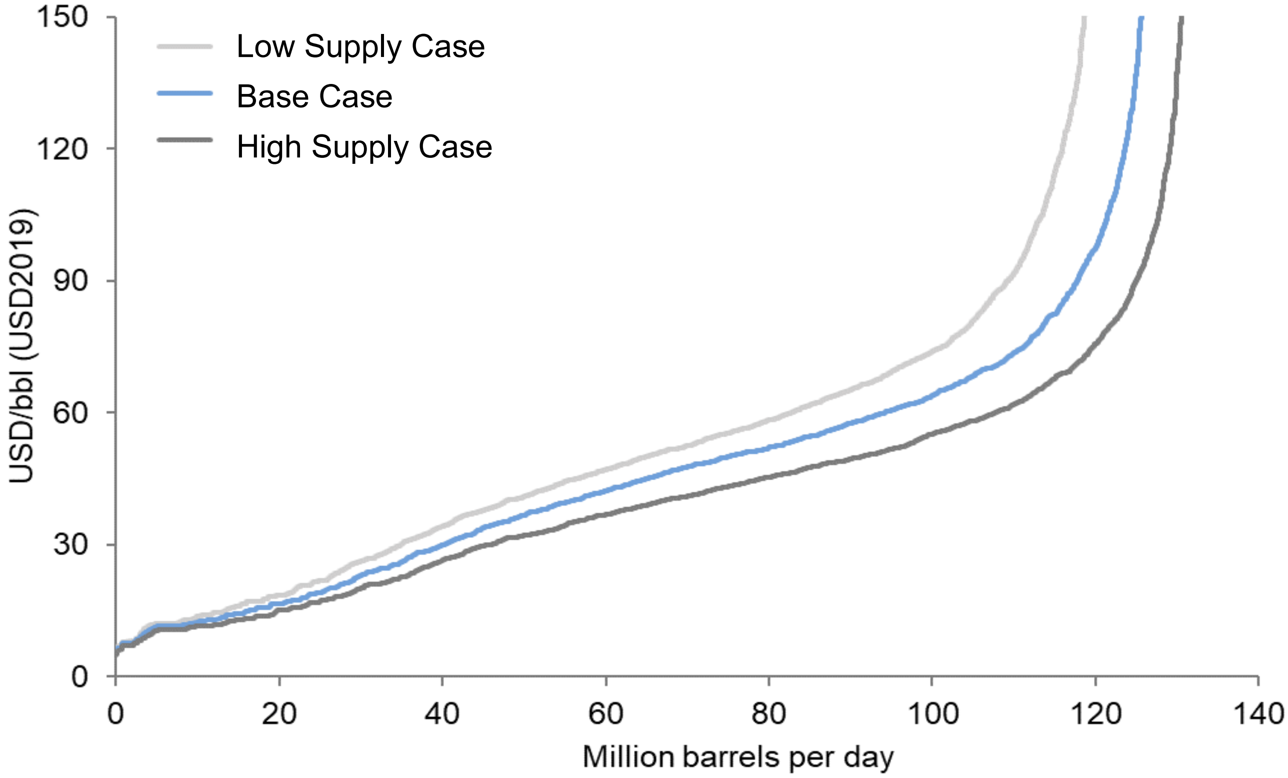


Figure 23: Rystad Energy cost of supply curves in the base, high and low supply case for oil in 2035

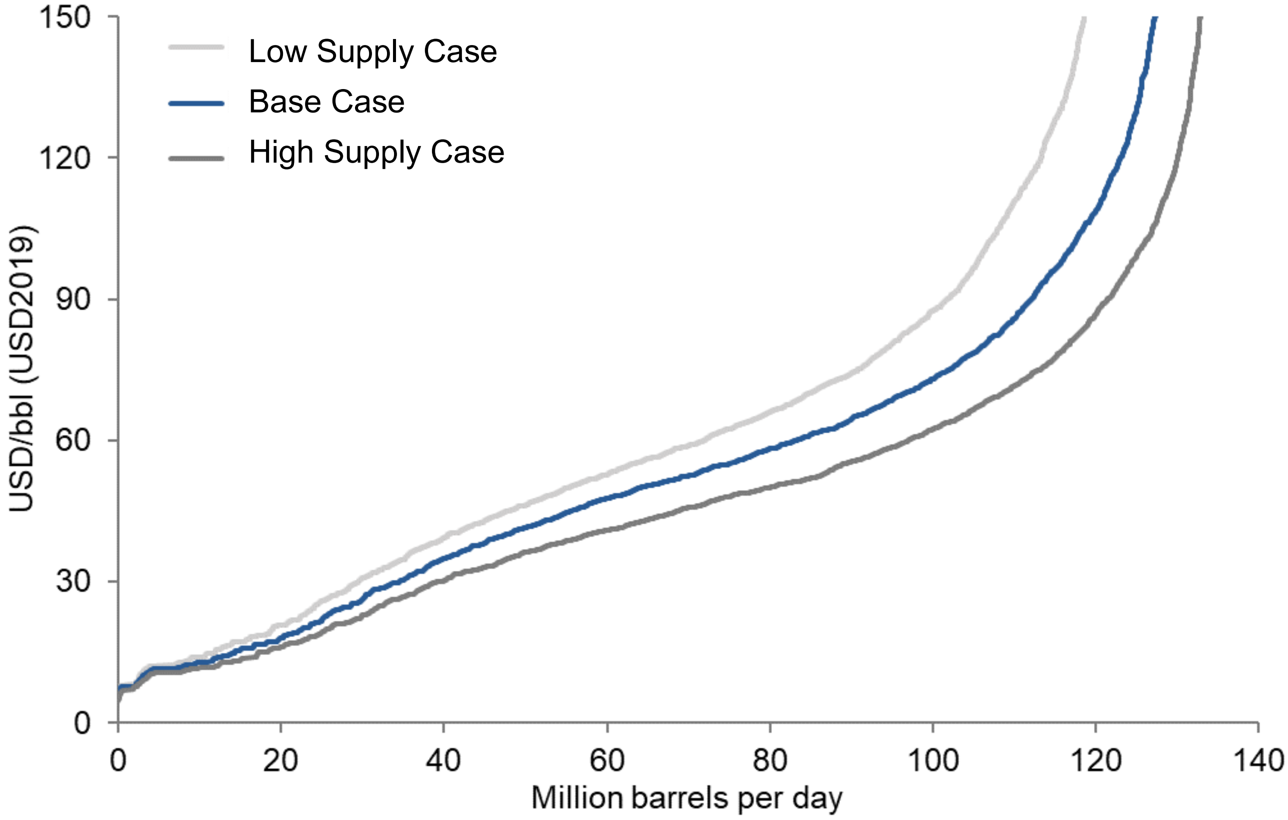
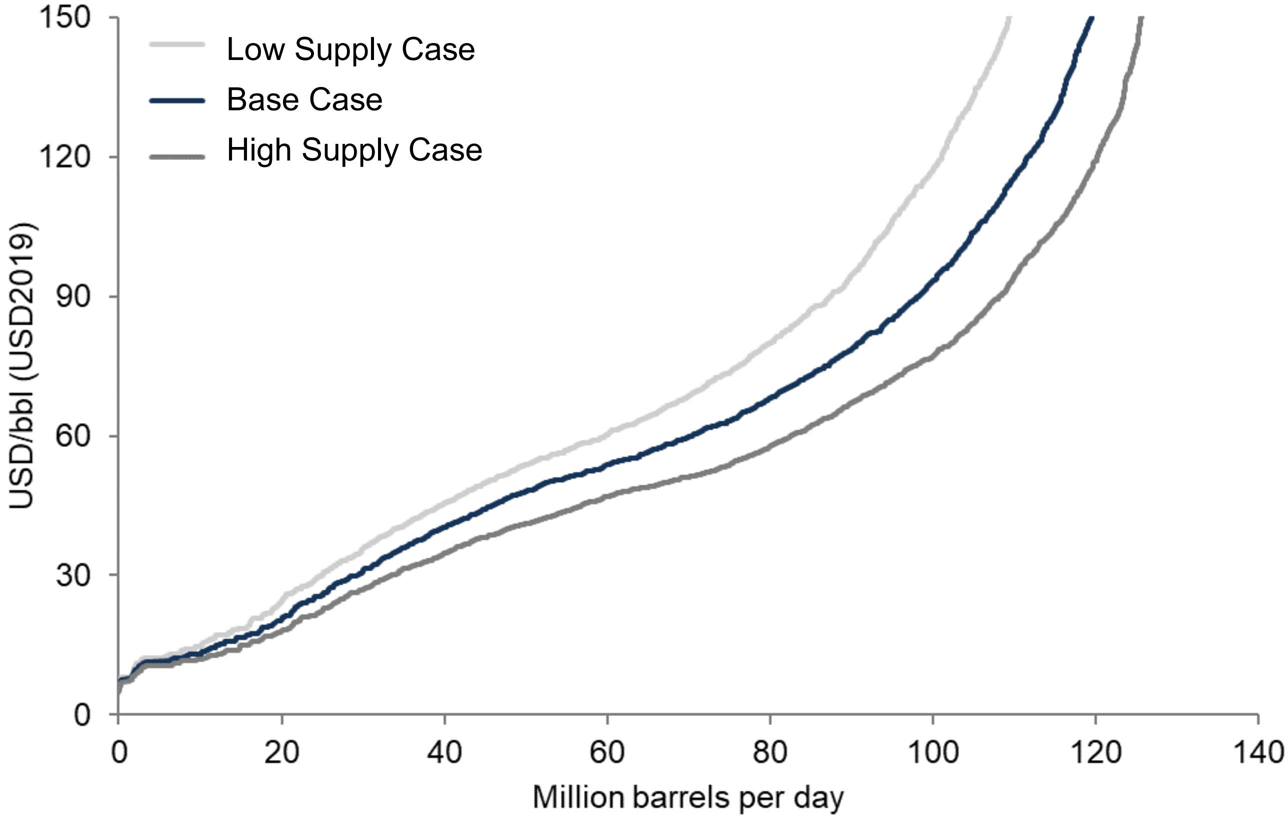


Figure 24: Rystad Energy cost of supply curves in the base, high and low supply case for oil in 2040



The high supply case lies below the base case and allows for higher maximum available volumes in each year, while the low supply case lies above the base case and allows for lower maximum available volumes in each year. The difference between the maximum available volume in the high supply and low supply case ranges from 7 million barrels per day in 2025 to 11 million barrels per day in 2040.

Gas-specific methodology

Rystad Energy has estimated gas supply curves for the European market. A summary of the assumptions used in construction of the cost of supply curves for gas are listed in tables 1, 3 and 4.

Table 3: Additional gas-specific methodology assumptions in the base case

Base case
Europe is defined as the European continent including Greenland, but excluding Turkey.
The energy content for supply volumes to Europe is standardised at 40 MJ/Scm.
The supply volumes that are available to Europe are divided into three categories: - European production: Domestic gas production in European countries. - Pipeline imports: Volumes available to Europe via pipelines from countries outside Europe. - LNG imports: Volumes available to Europe as imported LNG from countries outside Europe.
Transport costs are calculated differently for the different supply groups: - European production: Transportation costs represent the costs of bringing gas from the production site or processing plant to a pricing point, and the cost of gas flowing within Europe is excluded from the calculation of cost curves. - Pipeline imports: Transportation costs for pipeline imports are based on estimates of the existing tariffs and calculated from the exporting country's production site or processing plant to the relevant pricing point in Europe. - LNG imports: The transport cost represents the cost of shipping the LNG from the liquefaction plant to the regasification plant, and is determined by the distance and other costs related to the route between the exporter and importer.
Liquefaction costs consist of liquefaction opex and liquefaction capex. A liquefaction opex between 0.35 USD/MMBtu and 0.7 USD/MMBtu is assumed for all liquefaction plants.
Rystad Energy has used the estimated operational cost of regasification terminals in the UK to represent those in Europe. An average regasification cost of 0.5 USD/MMBtu is used.
Upstream and midstream cost are included up until the first arrival point in Europe.

The cost of storage is excluded from the cost estimation.
The contracted gas volumes are based on currently contracted volumes and no assumptions have been made on future contracts. The contract volumes have been allocated to the relevant import region within the stated contract duration.
All future uncontracted volumes have been allocated based on the forecasted demand for each region and transport-cost optimisation. Since Asia is normally willing to pay a premium, the region has been allocated with all the LNG supplies needed to meet their uncontracted LNG demand. The remaining supplies have been divided between Europe and other regions and it is assumed that these will have to compete to secure the necessary supplies.
The Dutch government has decided to shut down the Groningen field by 2030 and the future production of Groningen is modelled accordingly.
UK gas production potential is forecasted to increase by 2040.
The gas delivered by Russia is assumed to be sourced predominantly from the northwestern part of Russia. It is assumed that parts of the Shtokman volumes will be available to Europe.
The Russian gas price is based purely on the breakeven price of the different assets.
Europe is assumed to take 20% of overall Qatari LNG production, which represents the current share of Qatari LNG volumes taken by Europe.
An average price of 3.64 USD/MMBtu has been used to construct the cost curve for the US. An average utilisation rate of 92% has been used for US liquefaction plants.

Table 4: Gas methodology assumptions in the low and high case

High supply case	**Low supply case**
Overall capex and opex levels are reduced by 15% and 10%, respectively.	Overall capex and opex levels are increased by 15% and 10%, respectively.
Shale output is increased, which results in a reduction in Henry Hub of 1 USD/MMBtu.	Shale output is reduced, which results in an increase in Henry Hub of 1 USD/MMBtu.
LNG demand in Asia and other regions is increased by 15%, which results in lower available volumes for Europe.	LNG demand in Asia and other regions is lowered by 15%, which results in higher available volumes for Europe.
Europe is assumed to take 40% of the currently uncontracted volumes from Qatar in addition to the contracted volumes.	The only available volumes from Qatar are the contracted volumes.

Supply source

The supply volumes that are available to Europe are divided into three categories:

- European production: Domestic gas production in European countries.
- Pipeline imports: Volumes available to Europe via pipelines from countries outside Europe.
- LNG imports: Volumes available to Europe as imported liquefied natural gas (LNG) from countries outside Europe.

Storage

The cost of storage has not been included in the cost base as this cannot accurately be tied to each individual asset and the choice of placing volumes into storage is typically driven by market conditions.

European production

Norway is included as part of the European region, which means that Norwegian natural gas production is considered as domestic production.

The Netherlands

Regulatory decisions are included in Rystad Energy's production forecast. The Dutch government has decided to shut down Groningen field by 2030. Rystad Energy models Groningen's future production profile accordingly.

The United Kingdom

The UK gas production potential is forecasted to increase by 2040. While the production from discovered fields is set to decline from the current level, production from undiscovered fields could potentially increase the maximum available volumes, but at a higher cost.

Transportation costs

The European gas market is regarded as an integrated market. Transportation costs represent the cost of bringing gas from the production site or processing plant to a pricing point. The cost of gas flowing within Europe is not considered, and therefore excluded from the calculation of cost curves.

Pipeline imports

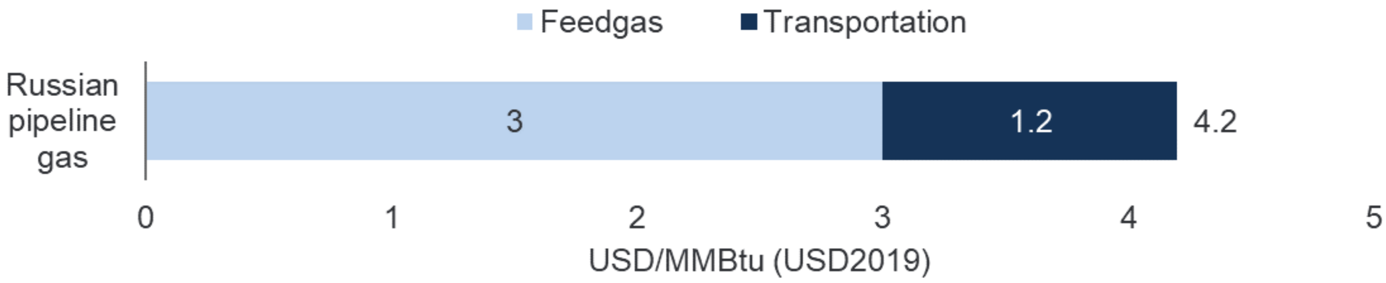
Russia, Algeria and Libya have been and will remain the main pipeline gas suppliers to Europe through 2040. In addition, gas volumes from Azerbaijan and Turkmenistan are available to Europe within the relevant timeframe.

Russia

Russia has a dominant position in the European gas market and is forecasted to remain the largest pipeline gas supplier to Europe in the foreseeable future. Most of the pipeline gas supplied to Europe is produced in the northwestern part of Russia, around the Yamal region. Russia will also become a large gas supplier to China, but these volumes will be sourced from fields located in southeast Russia and will therefore not affect exports to Europe. We expect first gas from Russia's Power of Siberia project to China at the end of 2019, and from the west route of Power of Siberia post 2026. Most of the volumes from the Far East and Eastern Siberia assets have been assigned to China. And although the second Power of Siberia pipeline could source some gas from Yamal this is assumed to be limited to the planned capacity of 30 Bcm. For the Shtokman project, as Russia has no development plan at present, we see potential markets in both Asia and Europe in the long term. Therefore, we assigned parts of the Shtokman volumes to Europe via pipeline.

The cost of supply from Russia is based purely on the estimated breakeven price of the different assets, including the transportation costs to the European market. The included taxes and tariffs contribute to a higher breakeven cost for Russian gas. In practice, Russia may have the flexibility to utilise different pricing strategies for its piped gas to Europe. This means that Russia could apply a market share strategy to maximise its dominant position in the European gas market or it could utilise its geopolitical influence and export its gas at a target price to maximise profits.

Figure 25: Average breakeven price for Russian pipeline gas delivered to Europe in 2025



Transportation costs

Transportation costs for pipeline imports are based on estimates of the existing tariffs and calculated from the exporting country's production site or processing plant to the relevant pricing point in Europe. Transportation costs within Europe are not considered.

LNG imports

LNG imports available to the European market is divided into two groups: Contracted LNG volumes and uncontracted LNG volumes.

Contracted LNG volumes

Rystad Energy has identified all publicly available information on international LNG contracts. The contracts are classified by LNG exporting plant and importing country, and the information includes contract duration, volumes and contract terms. Based on this, contracted LNG volumes from liquefaction plants have been allocated to the importing countries. Although the contracts typically allow for some volume flexibility, which could be affected by higher or lower prices, the full contract volume has been allocated to the buyers unless otherwise specified. The volumes contracted by the different countries have then been aggregated into the following regions: Europe, Asia and Other (the Middle East, North America, South America and Africa).

Uncontracted LNG volumes

Rystad Energy has not made any assumptions regarding potential future contracts, for which there is no information. More specifically, no assumptions have been made on renewal of existing contracts after they expire, and future uncontracted volumes (i.e. volumes that have not been sanctioned) have been considered uncontracted.

All future uncontracted volumes have been allocated to a region based on the forecasted demand for each region and transport-cost optimisation. Given that Asia is normally willing to pay a premium, leaving several exporters with higher netbacks, the region has been allocated with all the LNG supplies needed to meet their uncontracted LNG demand. Thus, the uncontracted gas volumes allocated to Asia equals the part of the total Asian LNG demand that is not covered by contracted volumes. The remaining uncontracted supplies have been divided between Europe and other regions and it is assumed that these will have to compete to secure the necessary supplies.

The allocation of uncontracted volumes followed these steps (see table 5):

1. Assigned the cheapest uncontracted volumes to Asia to meet its uncontracted LNG demand.

2. Assigned 50% to other* continents' uncontracted LNG demand.

The remaining uncontracted LNG would be available to Europe. Please note that the cheapest uncontracted volumes to Asia and other continents may not be the cheapest supplies to Europe, due to different distances between export locations.

Table 5: Asia and other* continent LNG demand and uncontracted LNG allocation

Volume group	2025	2030	2035	2040
Total uncontracted LNG (Bcm)	380	686	948	1032
Total Asia base-case LNG demand (Bcm)	462	576	638	658
Uncontracted LNG allocated to Asia (Bcm)	232	402	532	628
Total other* base-case LNG demand (Bcm)	62	94	115	121
Uncontracted LNG allocated to other* (Bcm)	21	47	57	60
Uncontracted LNG allocated to Europe (Bcm)	127	237	359	344

*Other continents indicate the Middle East, North America, South America and Africa.

Rystad Energy believes that the approach for handling uncontracted LNG volumes described above best reflects the fast-growing LNG market dynamics. We have decided not to use the approach of extending existing contracts, since we believe that both existing and new LNG buyers would keep seeking better contract conditions or source the volumes in the spot market instead.

Qatar

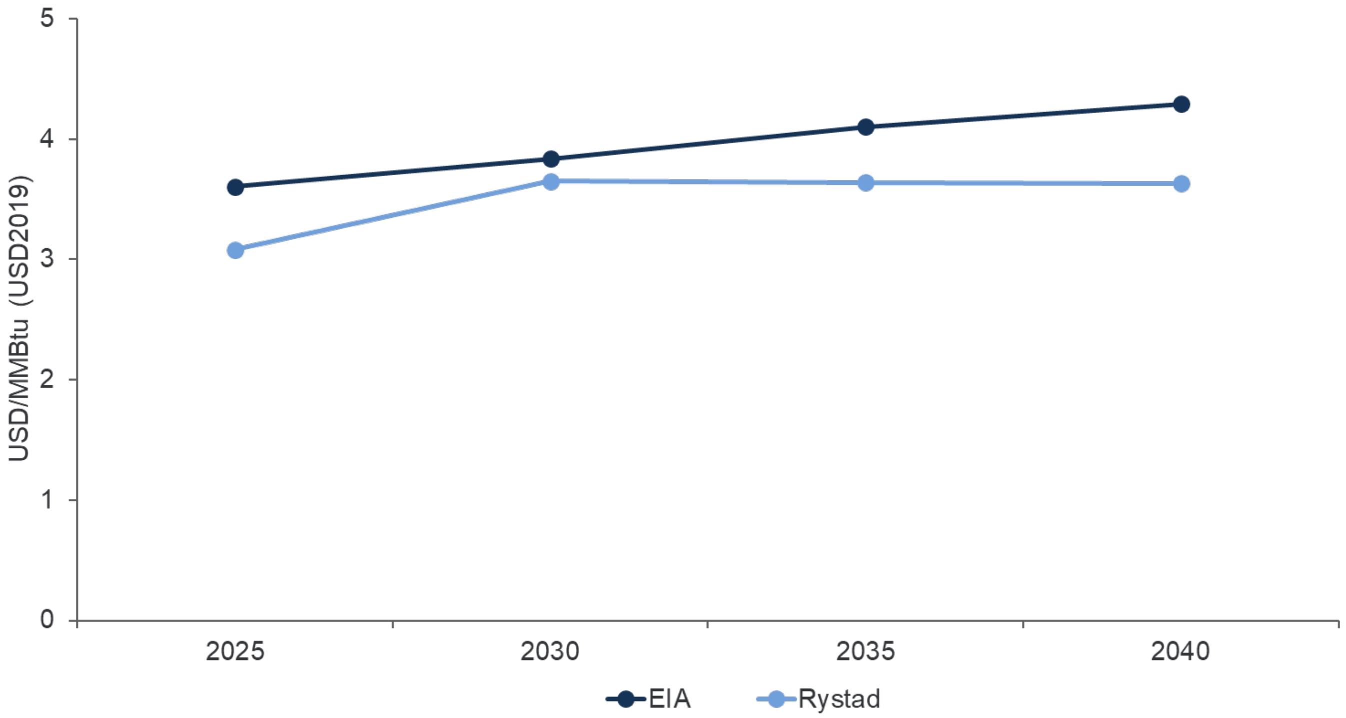
Qatar is currently operating 14 liquefaction trains with a total capacity of 105 Bcm. Rystad Energy believes that Qatar is likely to add another four trains with a total capacity of 42 Bcm post 2024. Qatari production is currently over-contracted, and around 60% of this is contracted to Asia, while the remaining 40% is mainly contracted to Europe. However, during recent years Europe has only taken 50% of its contracted Qatari volumes, which amounts to 20% of total Qatari contracted volumes. In the base case, we assume that Europe will continue to take 20% of Qatari production.

US

The US has the potential to produce a substantial amount of gas over the coming decades due to the abundant resources in its shale plays. Rystad Energy assumes that US LNG production will depend on the country's liquefaction capacity.

Given that US projects source their gas in the market, the forecasted Henry Hub price has been used instead of the breakeven price of upstream production, to form the base for the cost curves. Rystad Energy has forecasted Henry Hub prices in real terms to be: 3.08 USD/MMBtu in 2025, 3.65 USD/MMBtu in 2030, 3.64 USD/MMBtu in 2035 and 3.63 USD/MMBtu in 2040, which is lower than EIA's reference case (see figure 26). More forecasts are available in annex E. An average price of 3.64 USD/MMBtu has been used to construct the cost curve for the US. However, there is a downside risk to the Henry Hub price from 2030 onwards if shale volumes can be developed at a lower cost. This downside risk could result in US LNG being delivered to Europe at a discount of 0.5 USD/MMBtu compared to the current base case, which would be a midpoint between the base case and the low case.

Figure 26: Henry Hub price forecast*



*EIA: 2% inflation rate assumed for 2018-2019

An average utilisation rate of 92% has been used for US liquefaction plants, which reflects the observed utilisation rates for US plants during the last two years and allows for downtime during maintenance.

Liquefaction costs

Liquefaction costs consist of the variable cost to liquefy natural gas (liquefaction opex) and liquefaction facility capital expenditure (liquefaction capex). A liquefaction opex between 0.35 USD/MMBtu and 0.7 USD/MMBtu is assumed for all liquefaction plants. The liquefaction capex for existing liquefaction plants and the plants under development is considered sunk costs, and is therefore not included into the calculation of the cost curves. The liquefaction capex for planned and speculative terminals is used to build the cost curves, and as provided for each individual asset according to planned capital expenditure for the facility. The liquefaction capex differ between assets, but is typically around 3 USD/MMBtu. The capex cost of currently producing US LNG plants have been low compared to the global average, but the capex cost for the many proposed US LNG project varies.

Transportation costs

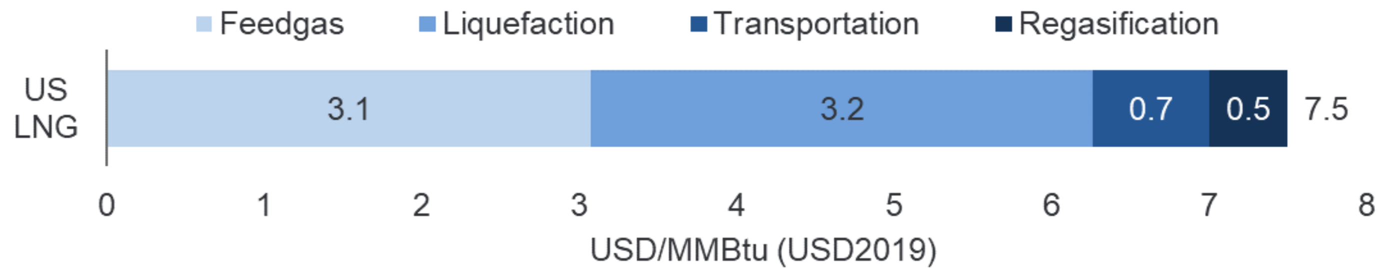
In Rystad Energy's UCube, every LNG asset has been assigned a gas market, which determines the transportation cost. We have modelled cost curves for all LNG assets and made all of the uncontracted volumes potentially available to Asia, Europe and other continents in accordance with the description of allocation of uncontracted LNG volumes provided on page 35 to 36.

The transport cost represents the cost of shipping the LNG from the liquefaction plant to the regasification plant and is determined by the distance and other costs related to the route between the exporter and importer. Transportation costs are based on freight rate of USD 65,000/day (in real terms) for a carrier with a total capacity of 150 000 cubic meters and aggregated to country level. Examples of other costs are tariffs or additional insurance. This results in a transport cost of 0.7 USD/MMBtu between the Gulf Coast in the US and Spain.

Regasification costs

Rystad Energy has used the estimated operational cost of regasification terminals in the UK to represent those in Europe, which is based on the reported cost for European regasification terminals. In this project, an average regasification cost of 0.5 USD/MMBtu is used to build the cost curves.

Figure 27: Average breakeven price for US LNG delivered to Europe in 2025



Low and high supply cases

The following assumptions have been included in order to construct the “low supply” and “high supply” gas scenarios. These assumptions primarily apply to the low and high gas supply scenarios. Other fuels use different assumptions included in the respective scenarios.

Low supply scenario assumptions

Cost levels

Historically we have observed large fluctuations in development costs in the upstream industry per gas unit. In the low supply case, the capital expenditures are increased by 15% compared to the base case and the operational expenditures by 10%. These increases correspond to observed changes in cost levels historically and will increase the breakeven prices.

US shale/tight gas

In the low supply scenario, the estimated future market dynamics in the US would lead to lower production and/or higher demand, resulting in 1 USD/MMBtu increase (in real terms) in Henry Hub prices.

Our Henry Hub price forecast increases to 4.6 USD/MMBtu as this is the breakeven price of some of the most expensive fields in the US. If domestic demand for natural gas increases, more expensive fields might be needed to balance the market.

Uncontracted LNG volumes

In the low supply scenario, a 15% increase in Asia and other continents’ LNG demand could shift more uncontracted LNG volumes to these regions, leaving less volumes available to Europe and volumes at a higher breakeven price.

Qatar

In the low supply scenario, we expect Asia will take all Qatari uncontracted LNG supply, which leaves Europe with only contracted Qatari volumes. With the current signed contracts, this entails that no volumes are assumed to be available for Europe from Qatar from 2035 in the low supply case.

High supply scenario assumptions

Cost levels

Historically, we have observed large fluctuations in development costs in the upstream industry per gas unit. In the high supply- case, the capital expenditures are decreased by 15% compared to the base case and the operational expenditures by 10%. These decreases correspond to observed changes in cost levels and will decrease the breakeven prices.

US shale/tight gas

In the high supply scenario, the estimated future market dynamics in the US would lead to higher production and/or lower demand, resulting in 1 USD/MMBtu decrease (in real terms) in Henry Hub prices.

Our Henry Hub price forecast drops to 2.6 USD/MMBtu, closer to the average breakeven price of some of the largest fields in the US (Marcellus, Permian Delaware and Utica Shale). Henry Hub prices could drop to this level if domestic demand for natural gas drops or if there are cost improvements in production at some of the more expensive fields.

Uncontracted LNG volumes

In the high supply scenario, a 15% decrease in Asia and other continent LNG demand could divert more cheap uncontracted LNG volumes to Europe, resulting in lower breakeven prices to Europe.

Qatar

In the high supply scenario, we expect that Europe will take 40% of the uncontracted Qatari volumes, which reflects its current share of contracted volumes.

Gas cost of supply

The long-term cost supply for gas has been estimated using the assumptions detailed in the oil and gas methodology sections. Curves are presented for 2025, 2030, 2035 and 2040.

Base case

Figure 28: Rystad Energy base-case cost of supply curves for in 2025 to 2040

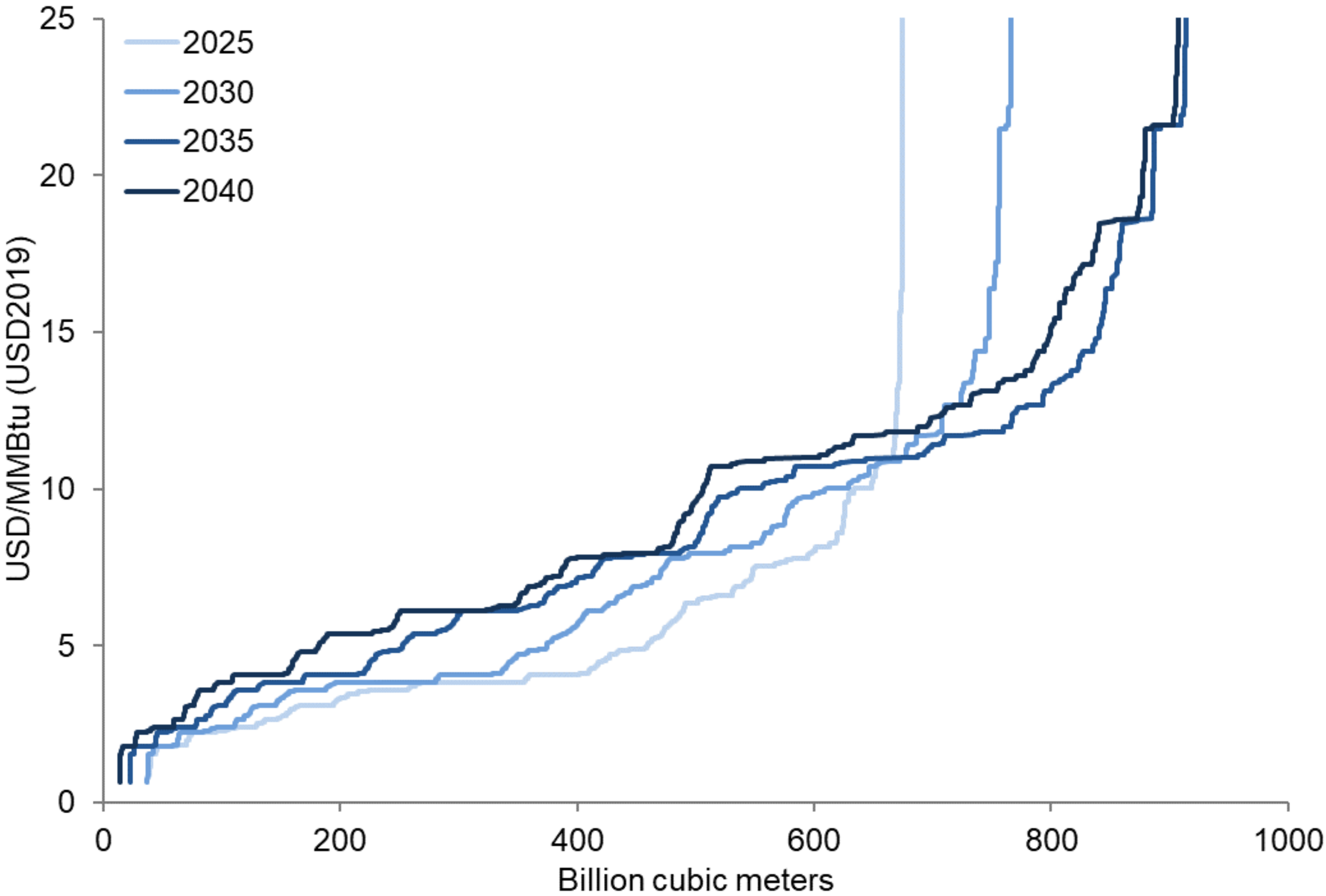


Figure 28 shows the base-case cost of supply curves for gas in 2025, 2030, 2035 and 2040. The maximum available volumes increase from 680 Bcm in 2025 to 920 Bcm in 2035 as the available volumes from not-yet sanctioned fields could increase more than the decline in mature field production. However, from 2035 to 2040, the maximum available volumes will decrease to 917 Bcm, as the mature field decline from currently sanctioned fields starts to offset the potential production growth from newer developments.

The cost curve is shifting upwards with time as a larger share of the volumes in 2025 comes from fields that are already producing or are currently under development to 2040. These sanctioned fields have a significant share of sunk cost, which is removed from the forward-looking breakeven calculation and results in lower overall breakeven prices compared with the not-yet sanctioned fields. Moreover, it is likely that the most lucrative fields that have yet to be sanctioned or are currently undiscovered will be developed first. Thus, the more complex and costly fields would be developed later in time.

Figure 29 to 36 show the base-case cost of supply curves for gas in 2025, 2030, 2035 and 2040 by different supplier groups. The first chart for each year shows the base-case cost of supply curves for gas grouped by major suppliers and breakeven price. The specified suppliers are Norway, Russia, Qatar, North Africa, Europe, the US and other. The suppliers are further split into groups based on breakeven price so that fields within the same 3 USD/MMBtu increment are grouped together.

The second chart for each year shows the base-case cost of supply curves for gas grouped by major suppliers and life cycle groups. The specified suppliers are the same as the ones mentioned above. The suppliers' fields are then split into groups based on whether the field is sanctioned or not sanctioned.

The width of the boxes represents the potential supply, while the height represents the breakeven-price interval, which covers 60% of supply in the group. The breakeven price from the supplies with the highest and lowest breakeven price is not included in the breakeven-price interval. The breakeven prices from the upper and lower quartile are excluded in order to give a more representative picture of the breakeven price range for the majority of the supply within the group. And due to the large variations in breakeven price for some of the defined supply groups, the interquartile range is set to 60%.

Figure 29: Rystad Energy base-case cost of supply for gas in 2025 by supplier and cost group

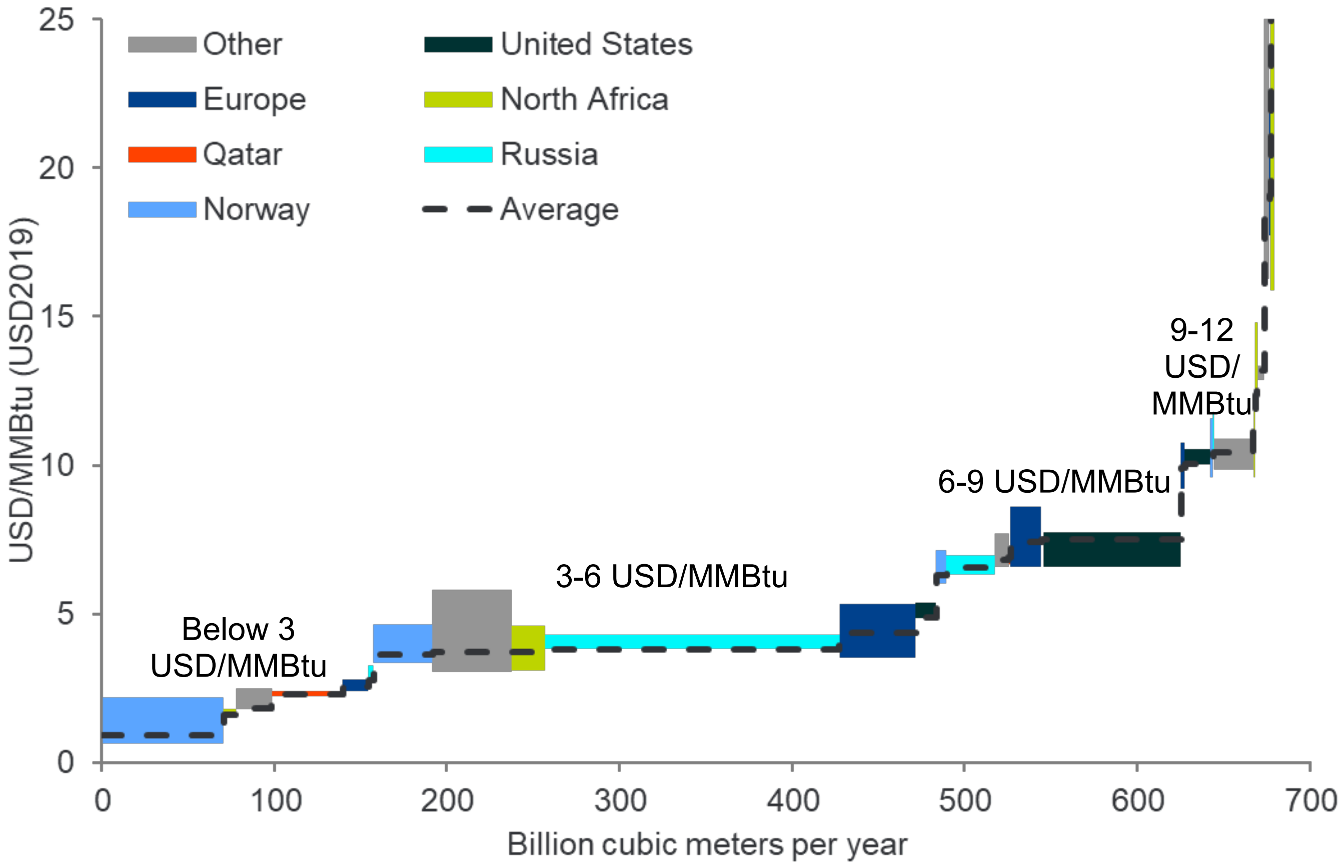


Figure 30: Rystad Energy base-case cost of supply for gas in 2025 by supplier and life cycle

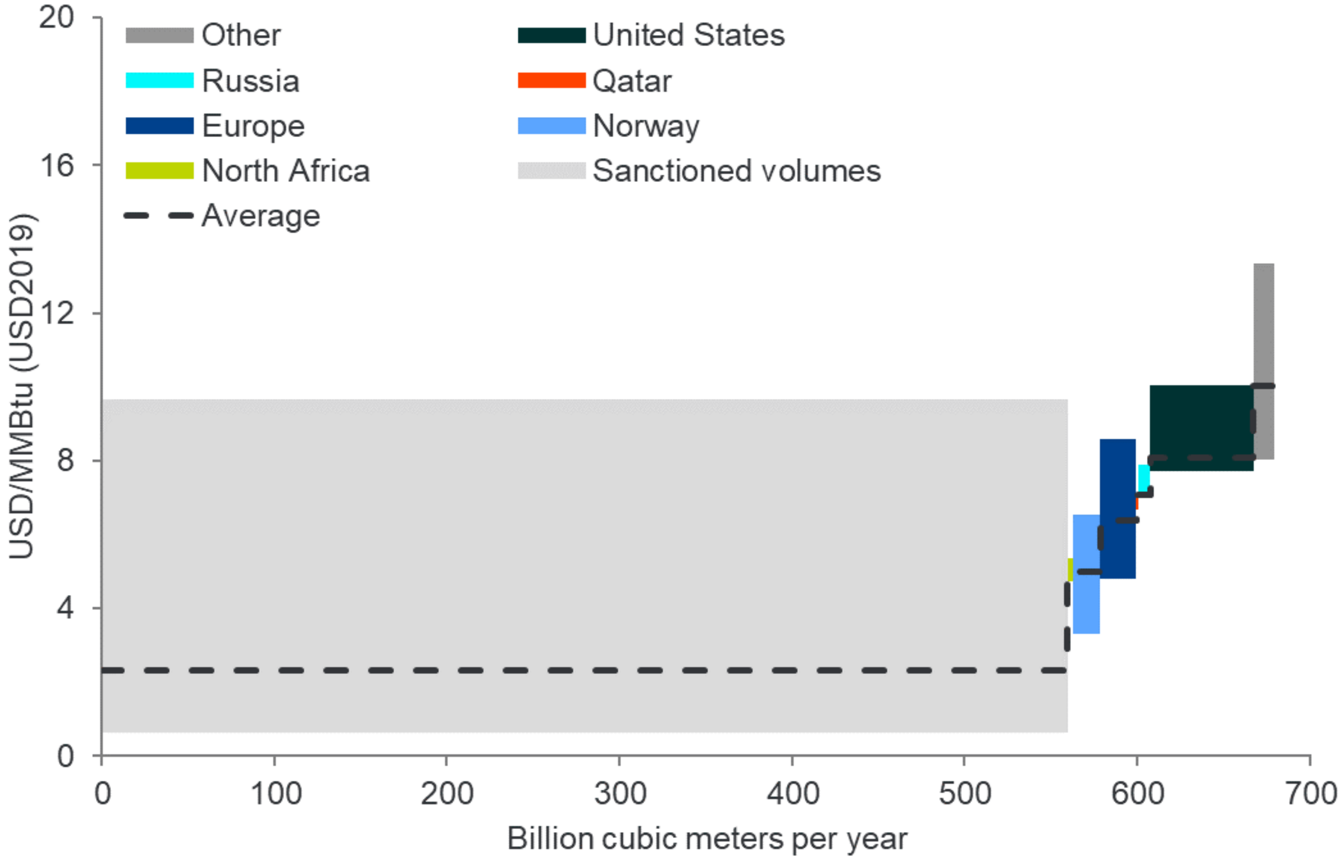


Figure 31: Rystad Energy base-case cost of supply for gas in 2030 by supplier and cost group

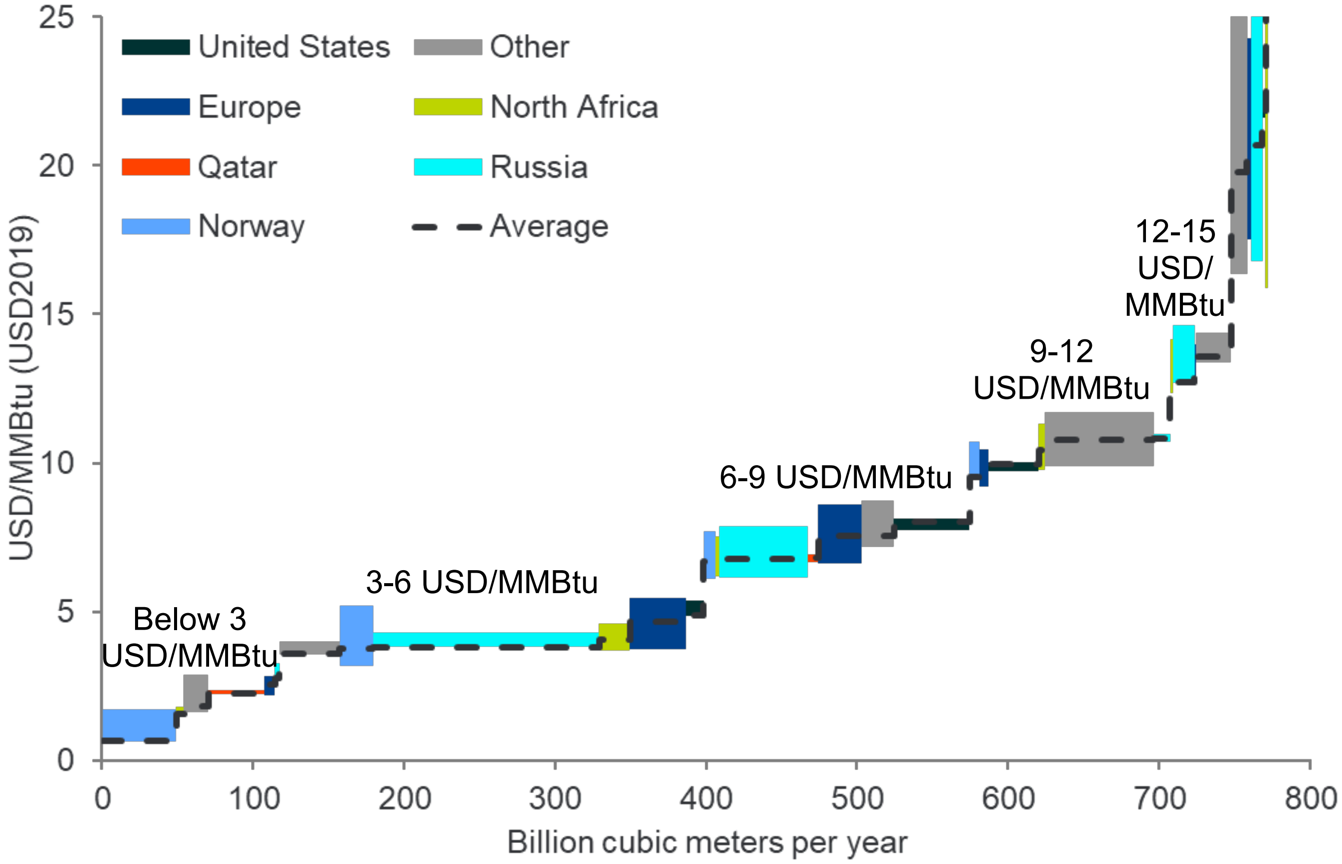


Figure 32: Rystad Energy base-case cost of supply for gas in 2030 by supplier and life cycle

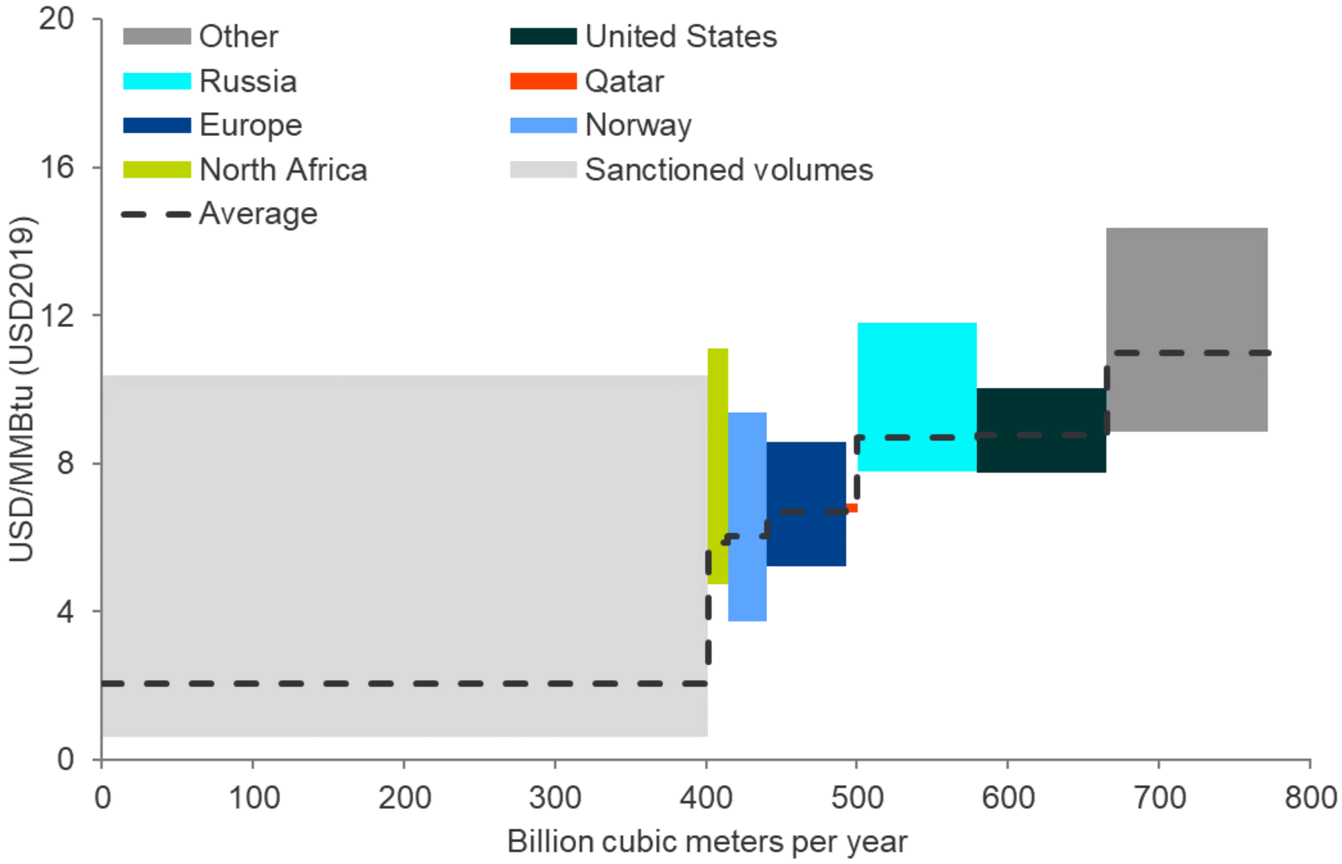


Figure 33: Rystad Energy base-case cost of supply for gas in 2035 by supplier and cost group

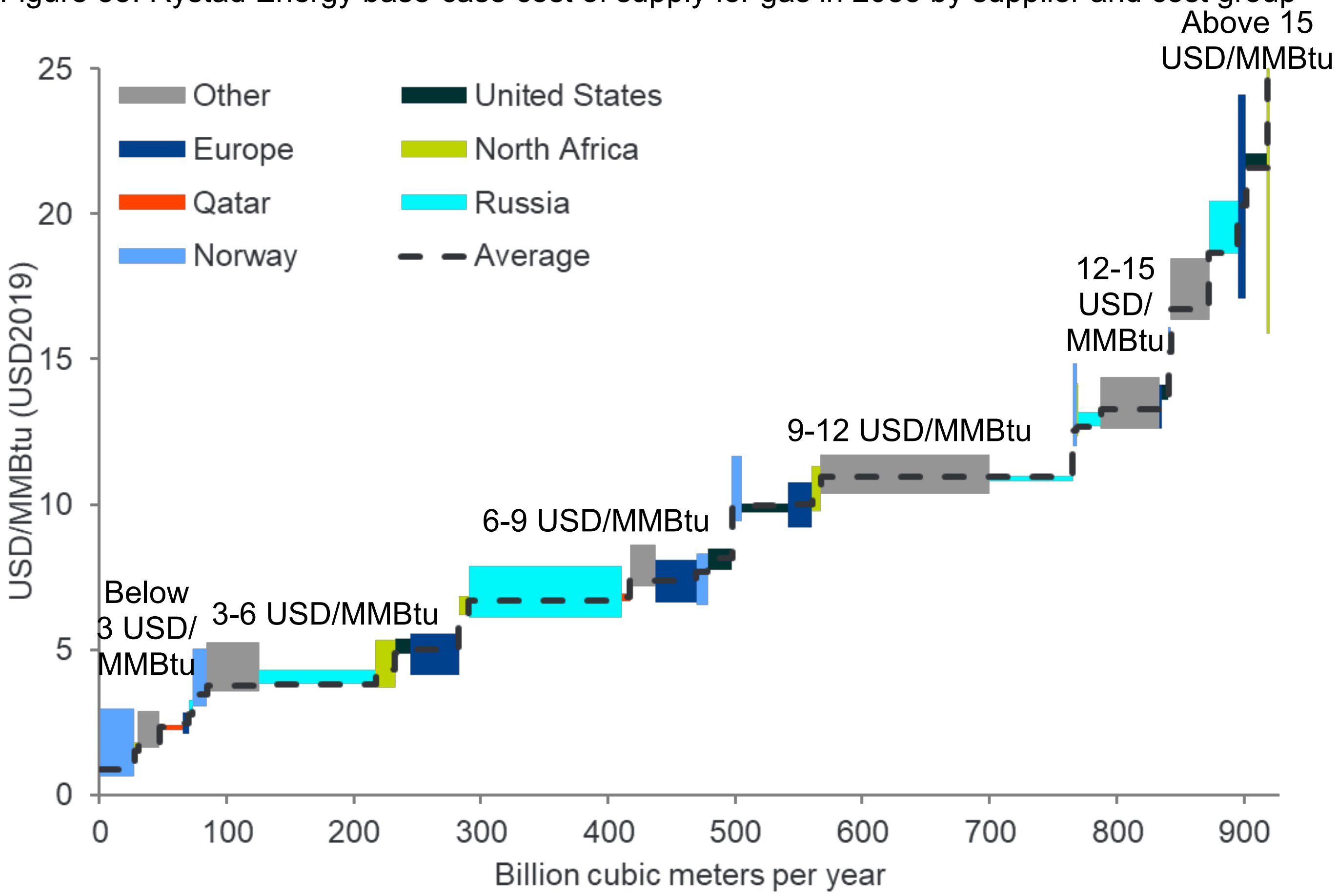


Figure 34: Rystad Energy base-case cost of supply for gas in 2035 by supplier and life cycle

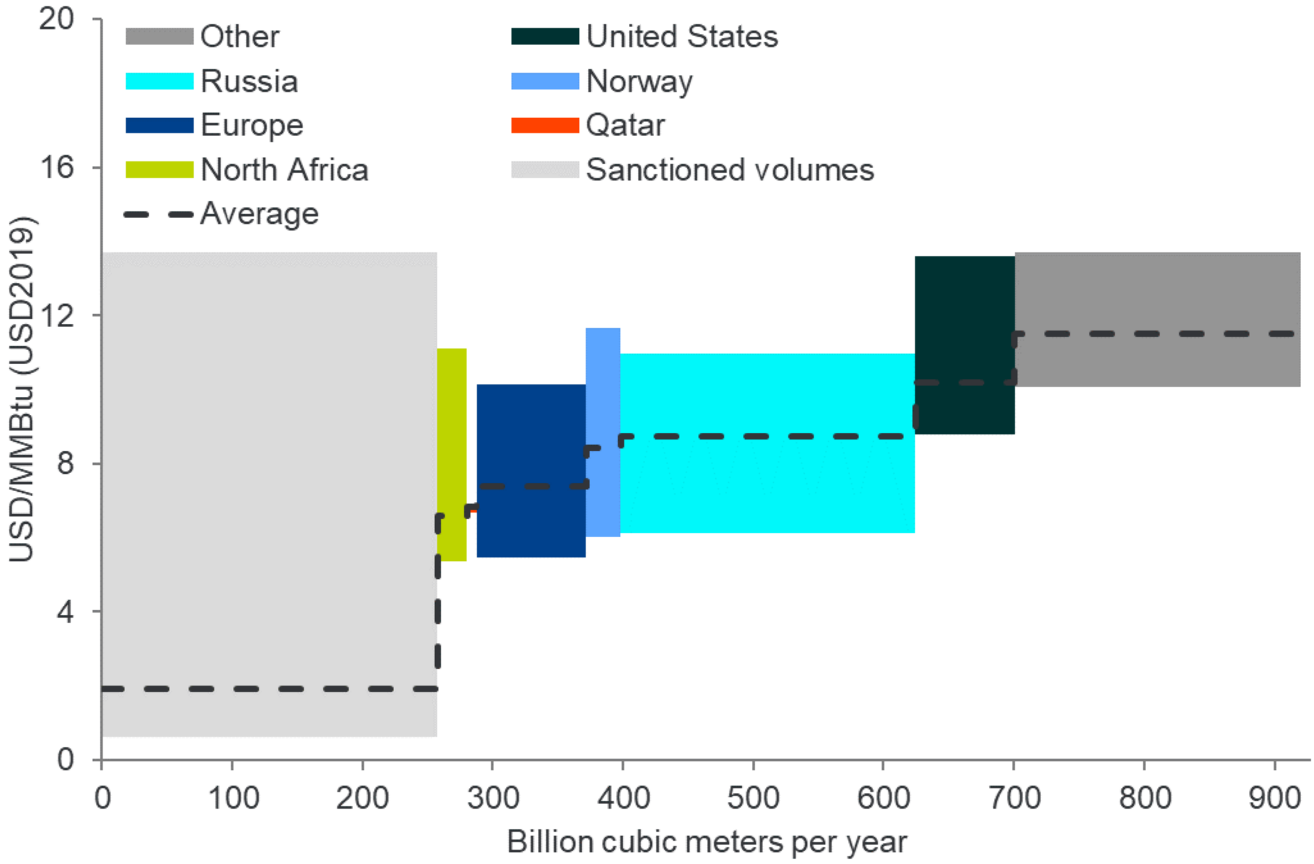


Figure 35: Rystad Energy base-case cost of supply for gas in 2040 by supplier and cost group

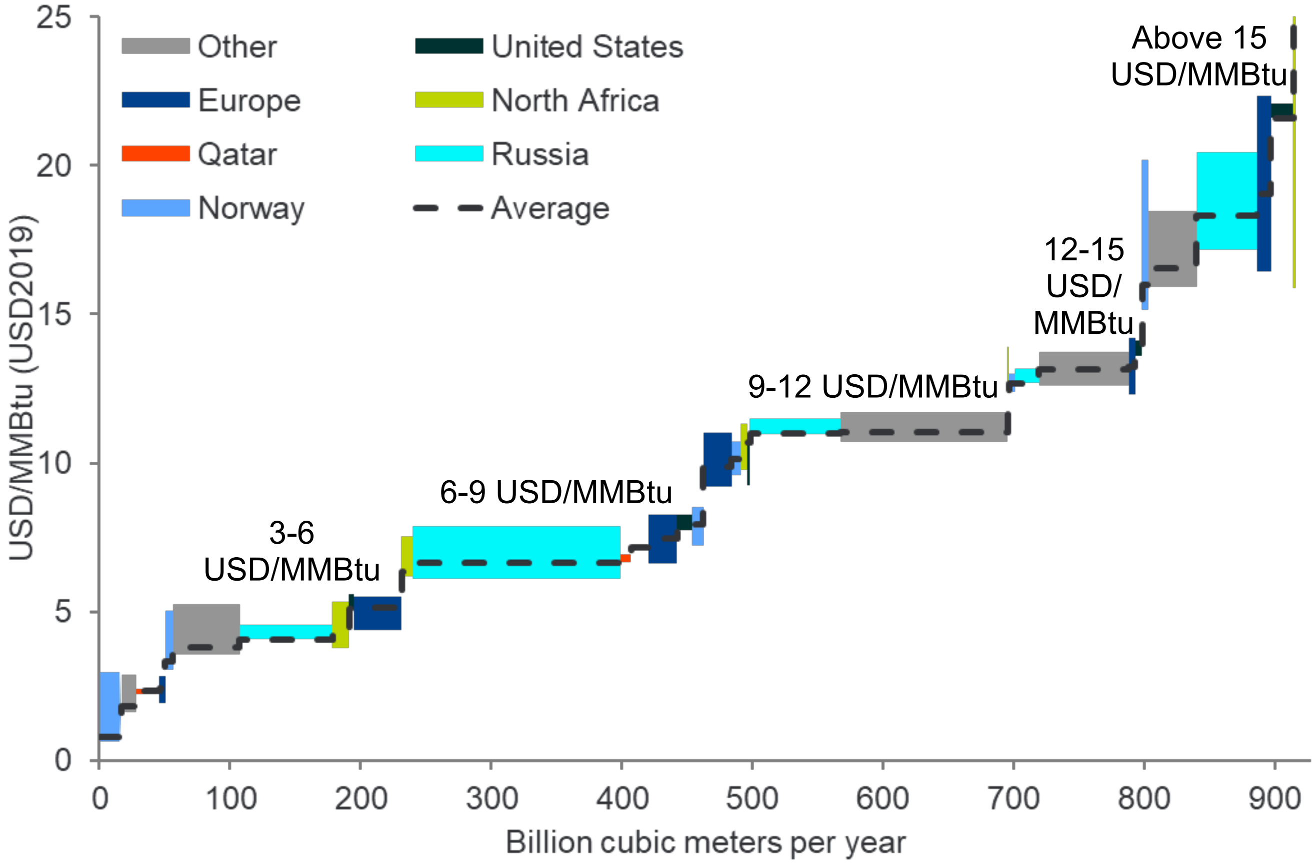
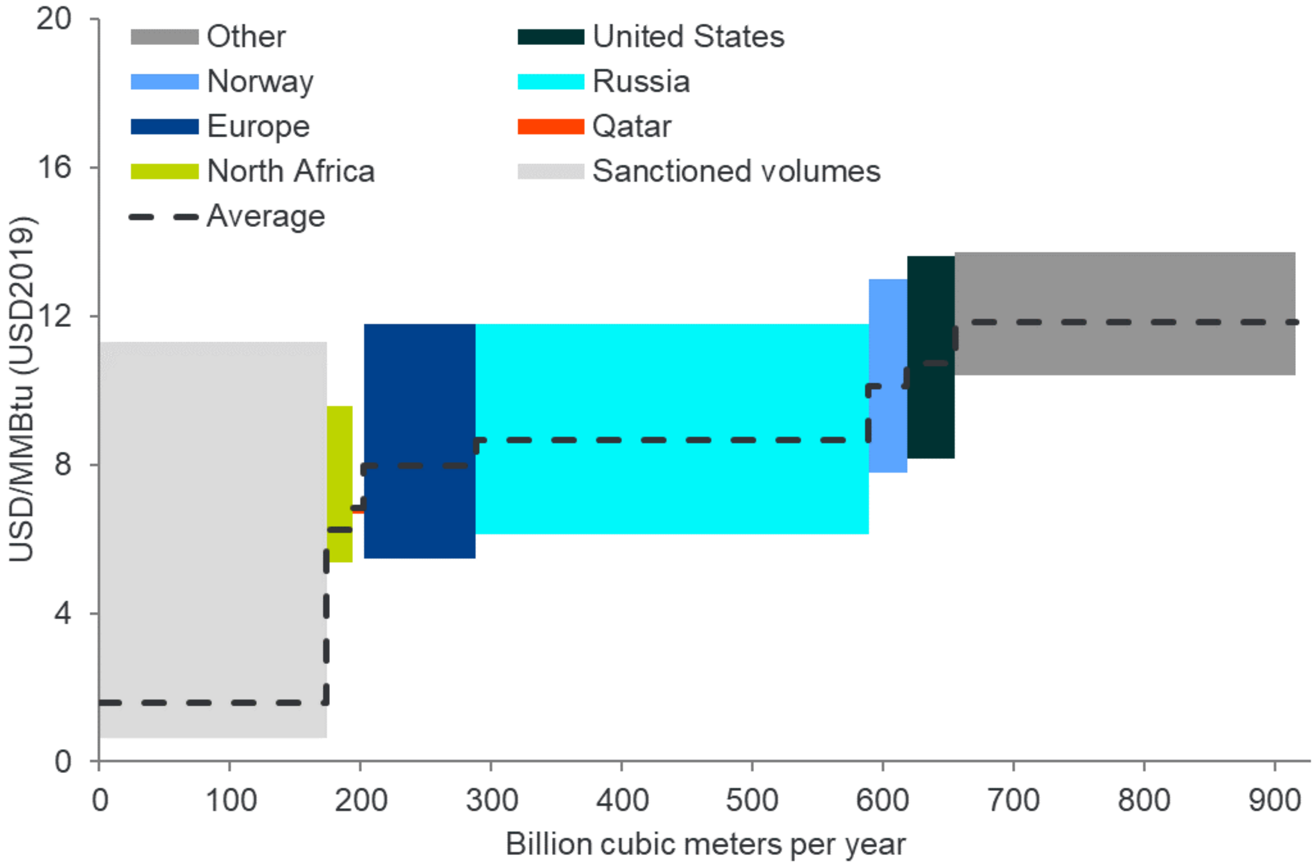


Figure 36: Rystad Energy base-case cost of supply for gas in 2040 by supplier and life cycle



As explained for figure 28, the cost curves shift upwards with time. This results in lower potential supply from the lower cost groups as we move out in time and the available supply with a breakeven below 3 USD/MMBtu declines from 160 Bcm in 2025 to 15 Bcm in 2040.

The largest available supply is in Russia, but Norway, the US and other suppliers could potentially also deliver large volumes. While the potential supply from Russia and other suppliers grows with time, the available volumes from Norway and the US decrease. However, the share of available volumes from non-sanctioned, higher cost fields in Russia and other supply countries will also increase with time.

Low and high supply cases

Figure 37: Rystad Energy cost of supply curves in the base, low and high supply case for gas in 2025

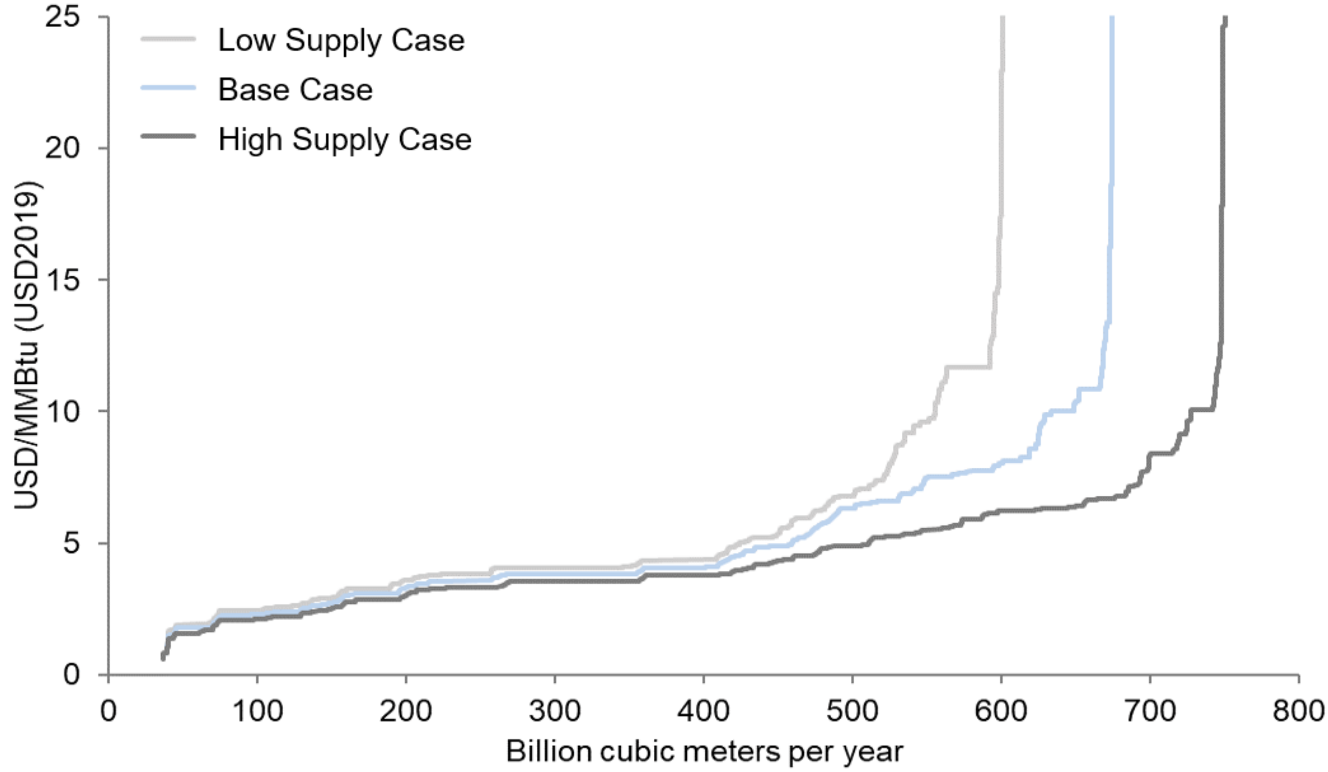


Figure 38: Rystad Energy cost of supply curves in the base, low and high supply case for gas in 2030

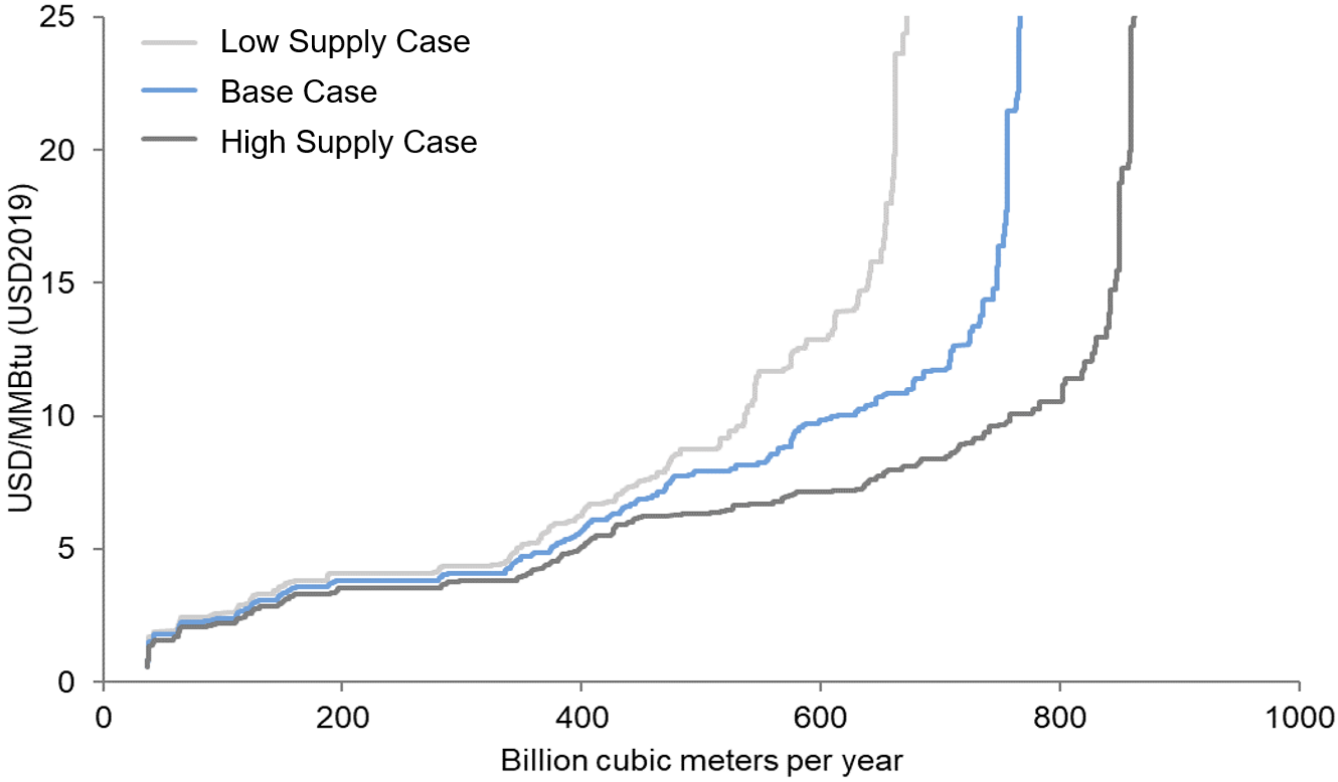


Figure 39: Rystad Energy cost of supply curves in the base, low and high supply case for gas in 2035

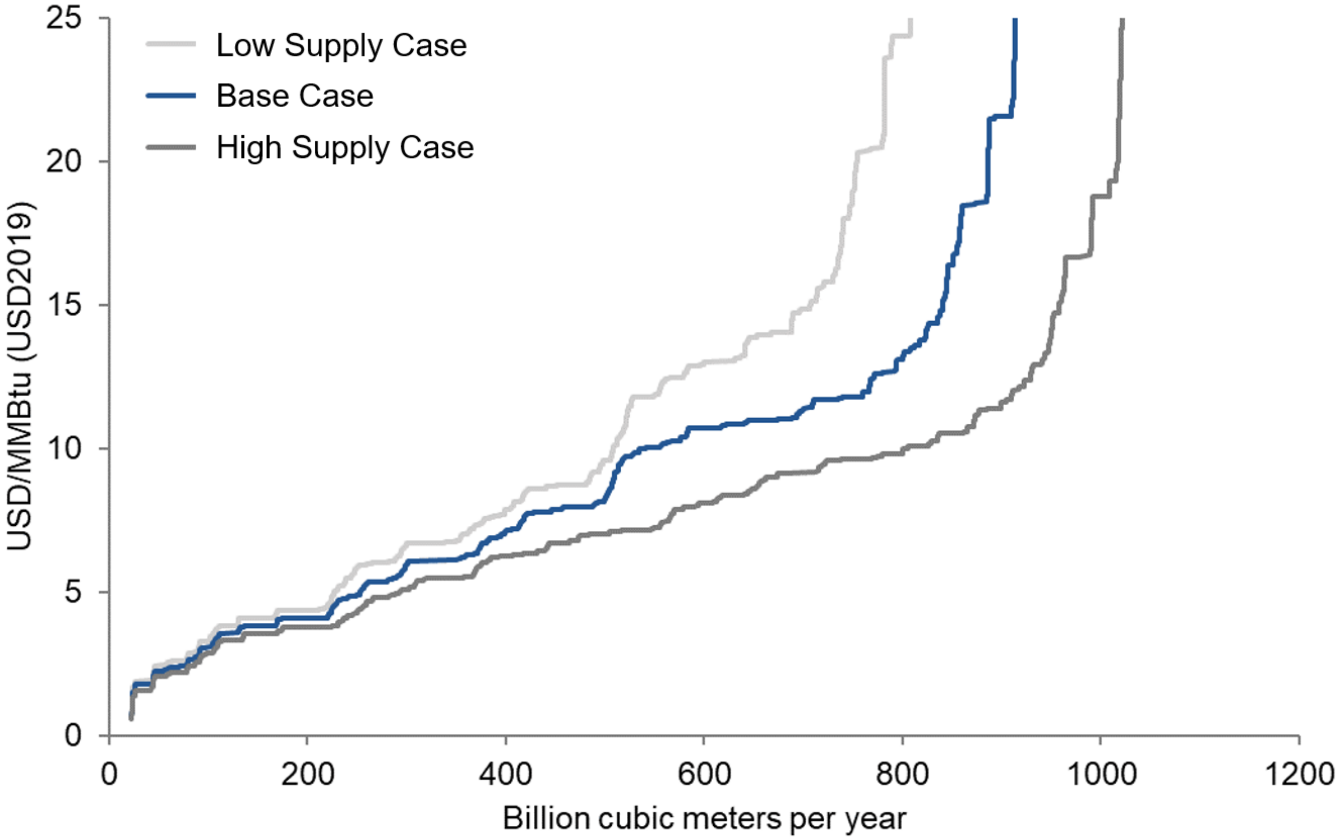
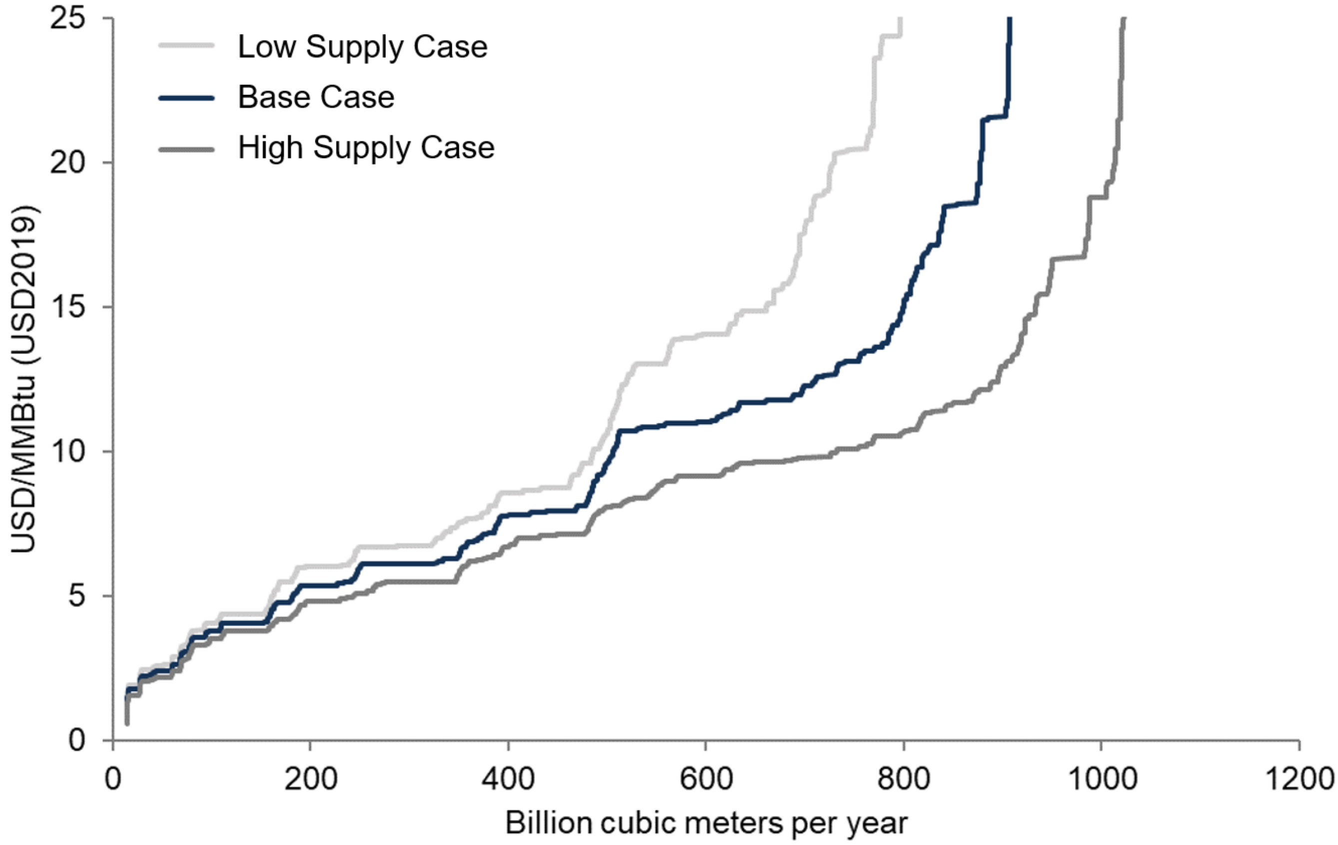


Figure 40: Rystad Energy cost of supply curves in the base, low and high supply case for gas in 2040



The high supply case lies below the base case and allows for higher maximum available volumes in each year, while the low supply case lies above the base case and allows for lower maximum available volumes in each year. The difference between the maximum available volume in the high and low supply case ranges from 150 Bcm in 2025 to 215 Bcm in 2040.

Coal methodology

Rystad Energy has estimated the supply cost of imported seaborne thermal coal into the European market for the years 2025, 2030, 2035 and 2040. A summary of the assumptions used in construction of the cost of supply curves for coal are listed in table 4.

Table 6: Coal methodology assumptions in the base case

Base case
Europe is defined as the entire European continent including Greenland and Turkey.
Breakeven prices are calculated by finding the NPV equal to zero excluding all historical costs.
Future coal mine supply cost estimates on a free-on-board basis. All-in sustaining cash costs per tonne are built up from estimates for mining, preparation, transport, port, royalties & taxes, selling, general & administration, plus sustaining capital.
The average mining cost assumption is that cost will increase by 1.5% p.a. to 2025, before declining to 0.5% p.a. from 2035.
Future sea freight costs estimates are based on an analysis of historical rates from export ports to ARA. Capsize vessel rates are utilised for Colombia and South Africa. Panamax vessel rates are utilised for Russia West and US East coast and US Gulf coast.
Costs per tonne are adjusted to a standard benchmark product to account for the difference in coal qualities and the benchmark used is ARA 6000 kcal/kg net as received basis, with 1% max sulphur.
The analysis is based on current technology, and does not include any major technological improvements in the future.
Mine lives are determined for each operation based on identified reserves with an allowance for extension or expansion in the presence of a substantial additional resource inventory.
The analysis of future mining projects is based on current technology and cost estimates, and does not include any major technological improvements in the future.
Production data only includes thermal coal that is available for export from Colombia, Russia, South Africa and the US. All metallurgical coal, and thermal coal produced for the domestic market, is excluded.

The available volumes to Europe from Colombia are assumed to be 80% of thermal exports from Colombia.
The available volumes to Europe from Russia are assumed to be 80% of Russian production.
The available volumes to Europe from South Africa are assumed to be 30% of South African production.
US coal mining companies will supply into export markets when prices are sufficiently high to cover the additional transport costs incurred, and margins are comparable or better than from domestic sales.

Table 7: Coal methodology assumptions in the low and high case

High supply case	Low supply case
The operating cost is decreased by 10% and the capital cost is decreased by 15%.	The operating cost is increased by 10% and the capital cost is increased by 15%.
The share of exports/production made available to Europe is increased from 80% to 90% for Colombia and Russia and from 30% to 80% for South Africa.	The share of exports/production made available to Europe is reduced from 80% to 70% for Colombia and Russia and from 30% to 15% for South Africa.
US volumes remain unchanged from the base case.	US volumes are increased by between 7 Mt and 14 Mt depending on the year.

Future production and costs estimates are based upon Rystad Energy's coal research database, and deep analytical knowledge and expertise in the sector. Information was obtained from various external sources including mining company reports and presentations, government publications and other regulatory information, industry research agencies and general and industry-specific media publications.

Fundamental analysis

Rystad Energy's coal supply curves show the expected volume of thermal coal to be exported into the European seaborne market from individual production sites. Coal production for domestic consumption or metallurgical export coal is not included in the supply curve volumes. The data is presented on a mine-by-mine level and was derived by examining the current levels of export supply, existing cost structures, known remaining reserves and mine life, and potential new coal mining projects.

The main sources of export thermal coal supply were identified for the European market. The principal countries exporting thermal coal into Europe are Colombia, Russia, South Africa and the US (Illinois and Appalachia basins). Individual mining operations in these locations were modelled to estimate their future production costs, coal production volume and coal qualities.

The final supply cost estimates represent the all-in sustaining unit cash cost in USD/tonne on a delivered basis (i.e. includes shipping transport costs for the coal to be delivered into Europe). As such, the all-in cash cost represents the breakeven price for existing producers, where initial development capital costs are already sunk.

Initially, the total cash cost was calculated at each identified export thermal coal mine inclusive of all relevant mining, processing, transport, port, royalty, selling, general & administration charges to give a total cash cost on a free-on-board (FOB) basis at the relevant export port. An estimate of ongoing capital spend required to keep the mine in operation at the defined production level was then included to give an all-in sustaining cash cost in USD per metric tonne FOB. Finally, a seaborne freight cost from the particular export port to Europe (ARA) was then added to the FOB cost to calculate the overall delivered all-in sustaining cash cost on a CIF (cost-insurance-freight) basis.

For possible future thermal coal mining projects where capital has not yet been spent, the supply costs included an estimate for development capital recovery.

Thermal coal is produced and sold at varying product qualities. The thermal coal products imported by European consumers have varying energy content, ranging approximately from 4,500 kcal/kg to 7,000 kcal/kg, with blending of different coals common before final consumption. The market price received for different thermal coal products varies substantially, depending largely on the energy content of the coal and other quality parameters such as sulphur and ash content. In Rystad Energy's supply curves, the cost estimates have therefore been adjusted to a standard energy value of 6,000 kcal/kg (net as received) basis, in line with specification for the primary Europe thermal coal price benchmark. This is commonly measured by the API2 coal price index, for delivered coal at the receiving ports of Amsterdam, Rotterdam and Antwerp (ARA).

Modelling

Production forecasting

Outside of market conditions, future supply from existing coal mining operations is usually dependent on installed mining, processing and transport capability along with the known coal reserve & resource quantity. In order to construct the future thermal coal cost curves, mine lives were determined for each operation based on identified reserves with an allowance for extension or expansion in the presence of a substantial additional resource inventory (where it was judged likely that the additional resources would be converted into mineable and economic reserves).

Coal resources in the studied supply regions are relatively abundant, though vary considerably basin to basin. There are a large number of possible coal mining projects which could potentially be developed over the longer-term time frame to 2040, given sufficient demand and price support. The lack of detailed information regarding proposed development plans and operating and capital costs makes it difficult to model these new operations with certainty. Accordingly, Rystad Energy has provided best estimates of the likely cost of new projects in different supply regions based on existing operating cost benchmarks and at varying levels of capital intensity. In general terms, the amount of coal supplied by new mining projects is relatively small compared to future production available from existing mining operations.

Economic forecasting

As a significant proportion of production costs for coal mines in Russia, Colombia and South Africa are denominated in local currency, the US dollar exchange rate plays an important role in the relative costs measured in US dollar terms. However, since the average US dollar exchange rate for 2018 is applied to future cost, the currency impact is eliminated.

Outside of currency impacts, future mining costs in real terms will be influenced by various factors but largely depend on changing physical characteristics at individual mining operations. Increasing waste to coal stripping ratios for open pit mining, increasing depth for underground mining, increasing mine haulage distances and changing processing yields based on declining coal quality trends will lead to increasing costs. These changing physical parameters drive up the cost of producing a tonne of saleable coal by increasing the consumption of key cost components including labour, fuel & electricity, consumables (e.g. explosives, tyres, and roof support materials), maintenance & contractors. Offsetting the general trend of higher mining costs with increased mine age, is the potential for future labour and capital productivity gains which will lower unit production costs.

Taking these various different factors into account, Rystad Energy models differential real cost increases for the mining portion of operating costs in the various supply regions. The average mining cost assumption is that cost will increase by 1.5% p.a. to 2025, before declining to 0.5% p.a. from 2035. The rate of mining cost inflation is assumed to decrease as operators adjust to lower prices with greater cost control focus, combined with the effect of older mines closing and being replaced by newer, more efficient, mining projects. Other components of the all-in sustaining cost cash cost build-up are kept constant in real dollar terms, apart from rail costs in Russia where Rystad Energy's analysis predicts a gradual small increase in usage charges above general inflation, as freight subsidies for coal producers are slowly wound back by Russian Railways and investment in rail infrastructure upgrades is repaid.

Key global assumptions

Countries exporting to Europe

Future coal supply for Europe is expected to come predominantly from mines in the following countries/regions:

- Colombia
- Russia: The mines in the far eastern Russian provinces (Khabarovsk, Primorskye, Amur, and Yakutsk) are excluded as export supply goes almost exclusively to Asia.
- South Africa
- US: Export thermal coal from the US for the European market is sourced from the eastern coal basins in the Appalachia, and Illinois Basin. Thermal coal exports from the Powder River Basin are not included as export coal is directed west due to the cheaper transport distance sold into the Asian market.

Potential thermal coal supply to Europe from Mozambique and Venezuela has not been included in Rystad Energy's future supply curves as volumes are likely to be negligible and have no material impact on the supply curve.

Mozambique thermal coal is produced primarily as a by-product of coking coal mining operations. The export thermal coal product, while of a reasonable energy content, contains high ash, with levels of approximately 25 to 30%, well above the normal Europe specification limit maximum of 15 to 17% ash. It is Rystad Energy's view that thermal coal exported from Mozambique is likely to be all consumed in the Pacific market, with India being the natural importer given its geographic proximity allowing low shipping costs, combined with a large domestic power sector and cement industry built around the consumption of relatively high-ash coal.

Venezuela coal production and exports have declined substantially over the last decade and the country is currently exporting only around 200 thousand tonnes of thermal coal to Europe. While Venezuela has substantial resources of relatively shallow, high energy, low-ash bituminous coal, exports are strongly constrained by an ongoing lack of investment in production and transport infrastructure. It is Rystad Energy's view that the lack of investor confidence is unlikely to turn around quickly, even with resolution of the political uncertainty, and consequently no future coal production from the country has been included in the future supply estimates.

Base-case volumes from countries

Colombia

Colombian thermal coal is generally good quality with high energy, low ash and low sulphur. Along with its generally low cost of production, these factors make Colombia a major exporter of thermal coal into the global seaborne traded market. While the majority of export production is sold into Europe, significant amounts of Colombian coal are also imported by Brazil, US and Mexico. Asian power utility consumers also source coal from Colombia for blending and supply source diversification. In the base case, 80% of thermal coal export volume was made available for the Europe supply curve.

Future coal production in Colombia is likely to be around current levels which are close to fully utilising existing rail and port infrastructure capacity. Production and exports are dominated by a small number of large mining companies which are judged likely to continue to invest in new mining projects upon depletion at existing operations in order maintain current production levels.

Russia

The majority of Russian export thermal coal production is mined in the central Kuznetsk Basin (Kuzzbass). Coal is exported from central Russia to both Atlantic and Pacific markets with rail costs forming the majority of the delivered cost due to the long distances involved. The distance to ports in far-eastern Russia ranges from 5,450-6,000 km, and the distance to Murmansk seaport in the northwest is 4,750 km. Having excluded mines located in the Far East due to the uneconomic rail distance to Europe, Rystad Energy has made 80% of Russian production available for the Europe supply base case.

Russia has extensive coal reserves (estimated at more than 160 billion tonnes) and has been investing in increasing port and rail capacity for the export market. Russian coal mining companies have also increasingly investing in processing capacity to enable beneficiation of coal to export specifications. Given the massive reserve base, Russian coal companies are well placed to develop additional export focussed mining projects to meet future international demand.

South Africa

South Africa has historically been a key supplier of export thermal coal to European consumers. Nearly all coal exports from the country are through Richards Bay Coal Terminal situated on the Indian Ocean coast, and coal producers have the ability to ship to both European and Asian markets. In recent years, strong demand growth in Asia has shifted the bulk of exports into this region. In the base-case supply curve, Rystad Energy has assumed that only 30% of export thermal coal production will be available for the Europe market.

Export thermal coal quality in South Africa, which traditionally has been at the specification of 6,000 kcal/kg nar, has been on a declining trend for a number of years and now averages around 5,700 kcal/kg nar. The deteriorating quality trend has been modelled in Rystad Energy’s analysis by assuming a continued general 0.25% annual decrease in the calorific value of South Africa’s thermal coal product.

New South African coal mining projects are being planned as replacements for a number of thermal coal mines that are approaching the end of their planned mine life. However, increases in potential future export supply are constrained by the need to have sufficient domestic thermal supply, as over 70% of the country’s coal production is consumed locally.

United States

The US is a strong swing supplier in the international thermal coal market. The country is the world’s second largest coal producer but a relatively minor exporter due to high internal consumption driven by domestic coal-fired power generation. US coal mining companies will supply into export markets when prices are sufficiently high to cover the additional transport costs incurred, and margins are comparable or better than from domestic sales. For the European market, coal is sourced from mines in northern Appalachia and from the Illinois Basin, utilising coal export terminals on the east and gulf coasts.

US export thermal coal from these basins is generally very high energy, up to 7,000 kcal/kg nar, but often contains elevated sulphur to over 3%, for which it receives a significant price penalty. US mine cost estimates are adjusted where appropriate to reflect the lower value of high sulphur coal products, in order to have all supply costs onto a common comparable basis (6,000 kcal/kg nar with 1% max sulphur basis).

Under high coal demand conditions, thermal coal exports from the US are modelled to increase into Europe as increasingly seaborne coal supply from exporters in Colombia and South Africa is drawn into the Pacific market.

Freight cost assumptions

Ocean bulk freight shipping costs are likely to stay relatively low in historic terms given the large supply of bulk carrier ships and shipbuilding capacity that was left over as a legacy of the commodities boom. Little growth in bulk commodities pricing is expected and while likely to be somewhat cyclical, future freight costs are assumed to be flat in real dollar terms for the base-case supply curve. A potential rise in ship operating costs due to the IMO fuel sulphur regulation starting in 2020 is expected to be reduced over the medium to longer term as bunker fuel markets re-balance and the use of scrubbers increases.

Table 8: Rystad Energy's shipping costs for the various supply locations to ARA Europe.

Country	**Size**	**Port**	**USD/t**
South Africa	Cape	Richards Bay	6
Colombia	Cape	Bolivar	7
US	Panamax	US Gulf	12
US	Panamax	US East	10
Russia	Panamax	Russia West (average)	5.5

Key risks and uncertainties

The thermal coal market is experiencing significant uncertainty with respect to future demand. A number of countries – notably in Europe – have announced their intention to move away from coal combustion for power generation in an effort to reduce carbon emissions in response to the threat of climate change. However, on the other hand, a significant number of other countries – particularly in South East Asia – may require increasing volumes of thermal coal over the period to 2040, due to both energy growth and diversification needs. The changing global pattern of import demand will be key driver with respect to shaping future export supply curves, as there is no fundamental shortage of mineable coal resources in the foreseeable future. New mining projects will only be developed if there is sufficient import demand and prices are high enough for an adequate return on capital for investors. Consequently, some modelled projects may not be brought into production in the identified timeframe if the supply is not required by the market.

Outside of demand-side factors, the main uncertainties impacting on future coal supply costs are geological conditions in proposed mining areas, the real price of cost inputs, plus internal rail transport and bulk shipping freight rates. For Colombia, Russia and South Africa, local currency versus US dollar exchange rates will have a major impact on their future cost competitiveness in US dollar terms. It is also important to recognise that technological advancement in both mining and transport equipment could lead to supply cost reduction over the medium to long term, but this is difficult to predict and is thus covered through the different scenarios within a reasonable range.

A growing area of uncertainty is sourcing investment capital for coal related ventures. The financing of both new coal mines and coal-fired power plants is becoming more difficult as banks and companies that historically provided funding to the coal sector reassess their investment priorities and financial exposure. Equity participation is also changing with several companies (e.g. Rio Tinto, Itochu, Mitsui) with long histories of involvement in coal mining deciding to exit the industry, creating opportunities for new players (e.g. Chinese and Indian backed companies). This changing investment landscape is likely to lead to timing delays in the construction of new coal mines as it takes proponents longer to source debt and/or equity funding. Delays in the construction of new mines could lead to supply tightness in the future as existing operations close, and accordingly is likely to cause greater price-cycle volatility.

Regulatory approval for new coal mines will be more difficult to obtain if government bodies start to take carbon emissions sourced from the final utilisation of the coal into account. With respect to future European import coal supply, this is not considered a highly significant risk as the majority of future coal supply is likely to be sourced from Colombia, Russia and South Africa where (current) government support for the export coal industry is high.

The future supply curves in this study represent estimates of the delivered cost of seaborne coal into the European market from the traditional main supply basins. However, it should be noted that the seaborne coal market is global in nature and coal supply is available to Europe from other regions (e.g. Australia and Indonesia) if market conditions are favourable. While seeking to maximise revenue, coal producers will also maintain a diversified customer portfolio in order to minimise sales risk.

Over recent years, international thermal coal pricing has been largely driven by the arbitrage between Chinese domestic coal prices and imported coal, with regional traded prices then balancing via netbacks and arbitrage opportunities. With thermal coal demand forecast to relatively robust in the region, the Asian market is likely to continue to have a strong influence on European coal prices in the foreseeable future. Strong demand and higher prices in the seaborne Pacific market will support European coal prices, even if Atlantic market import demand is subdued, as producers and coal traders sell to the highest bidder and prices at export ports balance due to arbitrage according to freight differentials.

Low and high supply cases

The following assumptions have been included in order to construct the “low supply” and “high supply” coal scenarios. These assumptions primarily apply to the low and high coal supply scenarios. Other fuels use different assumptions included in the respective scenarios.

Low supply scenario assumptions

In the low supply case, the available thermal coal supply to Europe is restricted from the main exporters due to strong demand pull in Asia, with more coal moving from traditional Atlantic basin suppliers into the Pacific. Colombian and Russian export volumes are reduced from 80% to 70% and South African exports from 30% to 15% of their respective production. In this scenario, US (east/gulf coast) thermal coal exports to Europe increase moderately to taking advantage of market opportunity. In 2025, approximately 180 Mt is assumed to be available, increasing to 198 Mt in 2040.

Combined with the restricted coal supply availability, in this scenario all operating costs, including sea freight, are increased by 10% and capital costs are increased by 15%.

High supply scenario assumptions

In the high supply case, the potentially available thermal coal supply to Europe is significantly higher due to overall weaker import coal demand pull from Asia. Colombian and Russian export volumes are increased from 80% to 90% and South African exports from 30% to 80%. Potential export supply from the US east/gulf coast is maintained at base-case levels. In 2025, approximately 240 Mt is modelled to be available, dropping to 205 Mt in 2040.

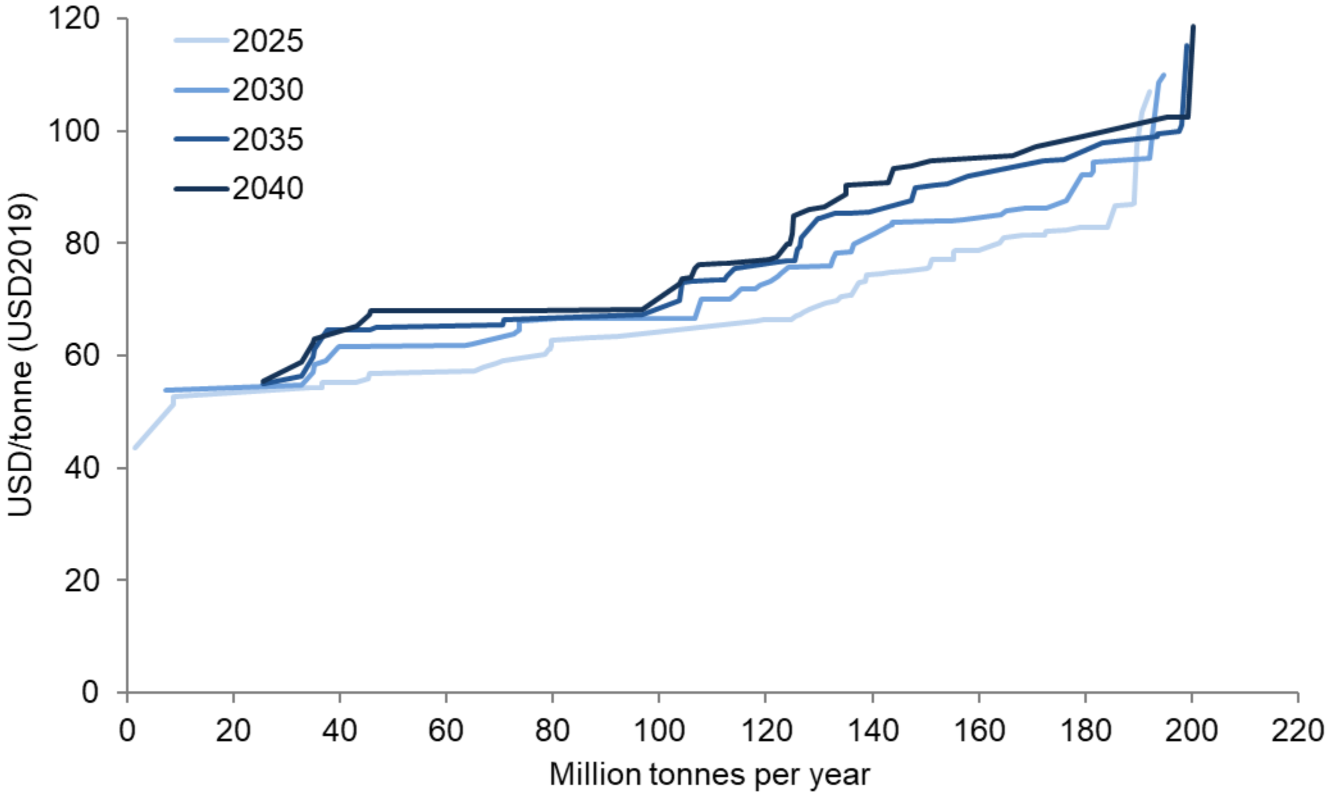
Combined with the increased potential coal supply availability, in this scenario all operating costs, including sea freight, are decreased by 10% and capital costs are decreased by 15%.

Coal cost of supply

The long-term cost of supply for coal has been estimated using the assumptions detailed in the coal methodology section. Curves are presented for 2025, 2030, 2035 and 2040.

Base case

Figure 41: Rystad Energy base-case cost of supply curves for coal in 2025 to 2040



The base case identifies approximately 190 Mt of thermal coal supply in 2025, rising to 200 Mt in 2040, as being available for European import customers. Individual mines located in different countries and basins are spread along the energy adjusted cost curve but there is a broad trend to Colombian supply being the lower cost and US thermal exports being the higher cost supply on a quality-adjusted, delivered basis. The mid-point of the supply curve has a delivered cost level of approximately 70 USD/tonne in 2040.

Small volumes of very high cost coal at the far right of the supply curve represents marginal export supply from predominantly domestic, market-focused operations. This supply would be opportunistically produced and sold only if export market pricing was sufficiently strong to cover the additional transport costs and yield loss. The steepness at the far right end of the supply curve is a result of the modelling assumptions on available supply, which limit the opportunity to source more coal from other regions even at high price levels. In reality, it is likely that very high prices would result in increased supply from global coal producers as they respond to the price signal resulting in a smoother export supply curve.

In 2025, close to 95% of export coal supply is sourced from existing mining operations. By 2040, with reserve exhaustion and subsequent mine closures, close to one third of forecast potential supply is sourced from new coal mining projects. New projects are expected to be developed in all studied supply regions as companies replace lost production and take advantage of existing transport infrastructure, but if demand and price levels are not sufficiently strong, then a number of potential projects may not be developed in this timeframe.

Figure 42 to 45 show the base-case cost of supply curves for coal in 2025, 2030, 2035 and 2040 by different supplier groups. The charts show the base-case cost of supply curves for coal grouped by exporters and breakeven price. The exporters are further split into groups based on breakeven price so that fields within the same 20 USD/tonne increment are grouped together.

The width of the boxes represent the potential supply, while the height represent the breakeven-price interval, which covers 90% of supply in the group. The breakeven price from the supplies with the highest and lowest breakeven price is not included in the breakeven-price interval. The breakeven price from the upper and lower quartile are excluded to give a more representative picture of the breakeven price range for the majority of the supply within the group. Since the breakeven price-variations in the defined supply groups are lower for coal than for oil and gas, the interquartile is set to 90%.

Figure 42: Rystad Energy base-case cost of supply for coal in 2025 by supplier and cost group

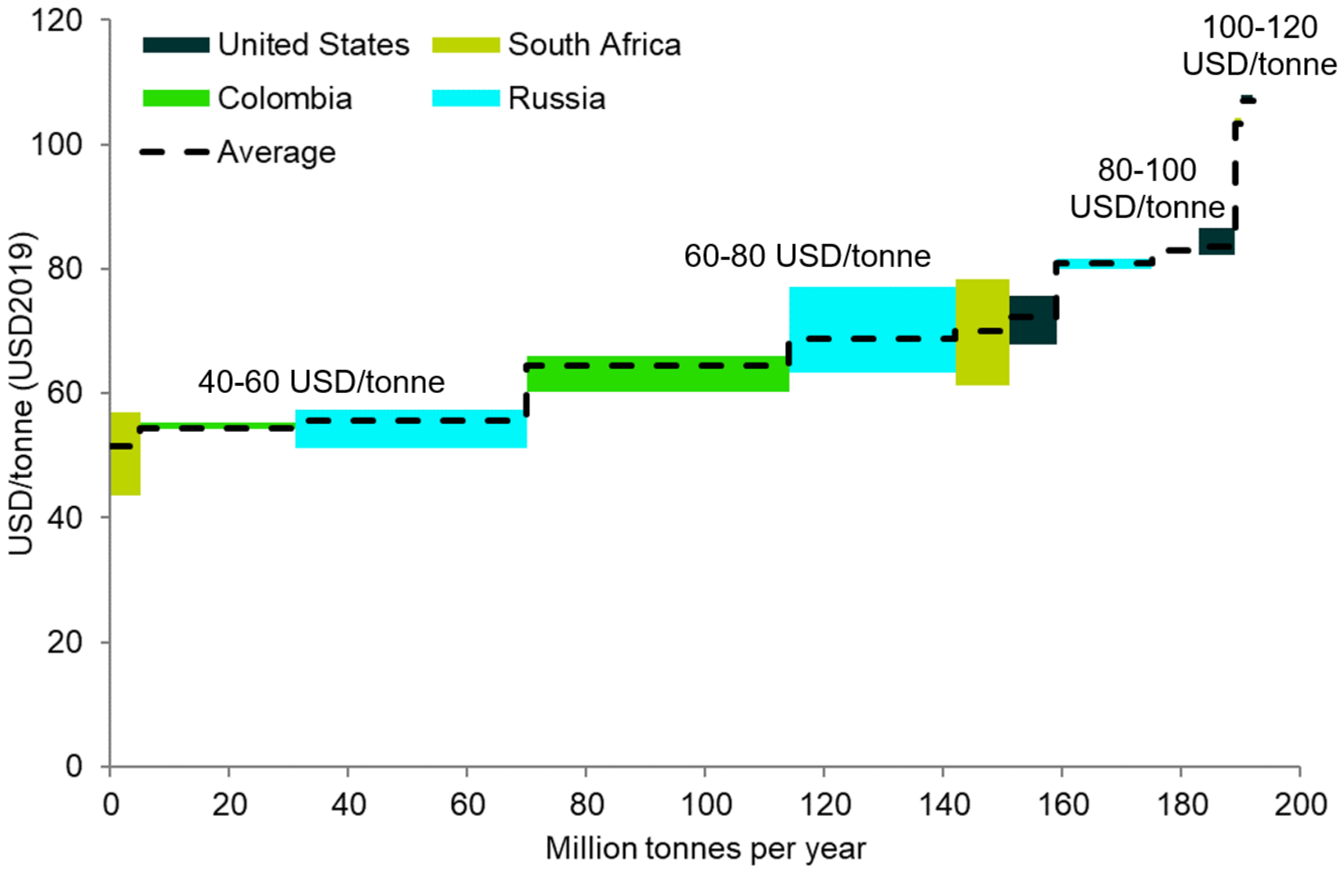


Figure 43: Rystad Energy base-case cost of supply for coal in 2030 by supplier and cost group

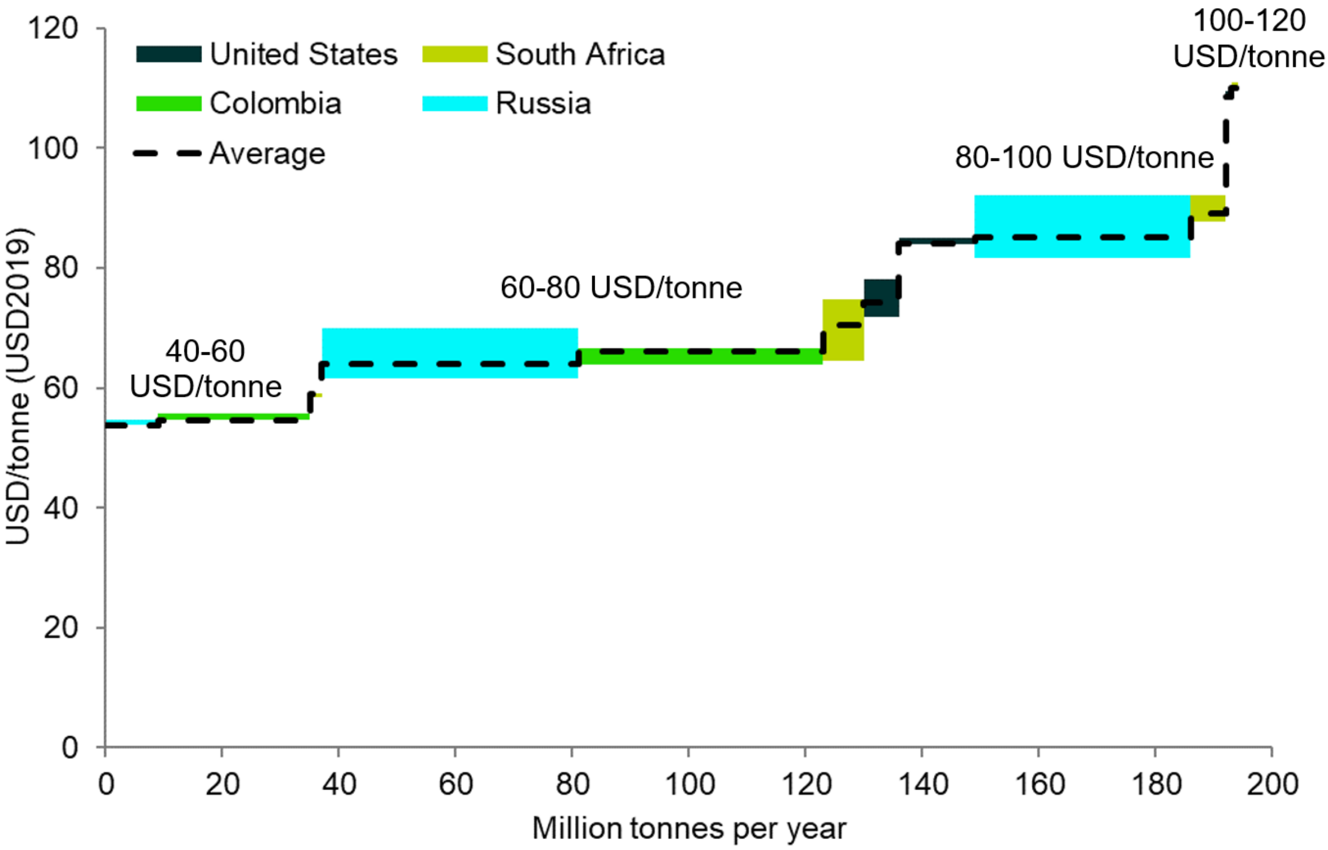


Figure 44: Rystad Energy base-case cost of supply for coal in 2035 by supplier and cost group

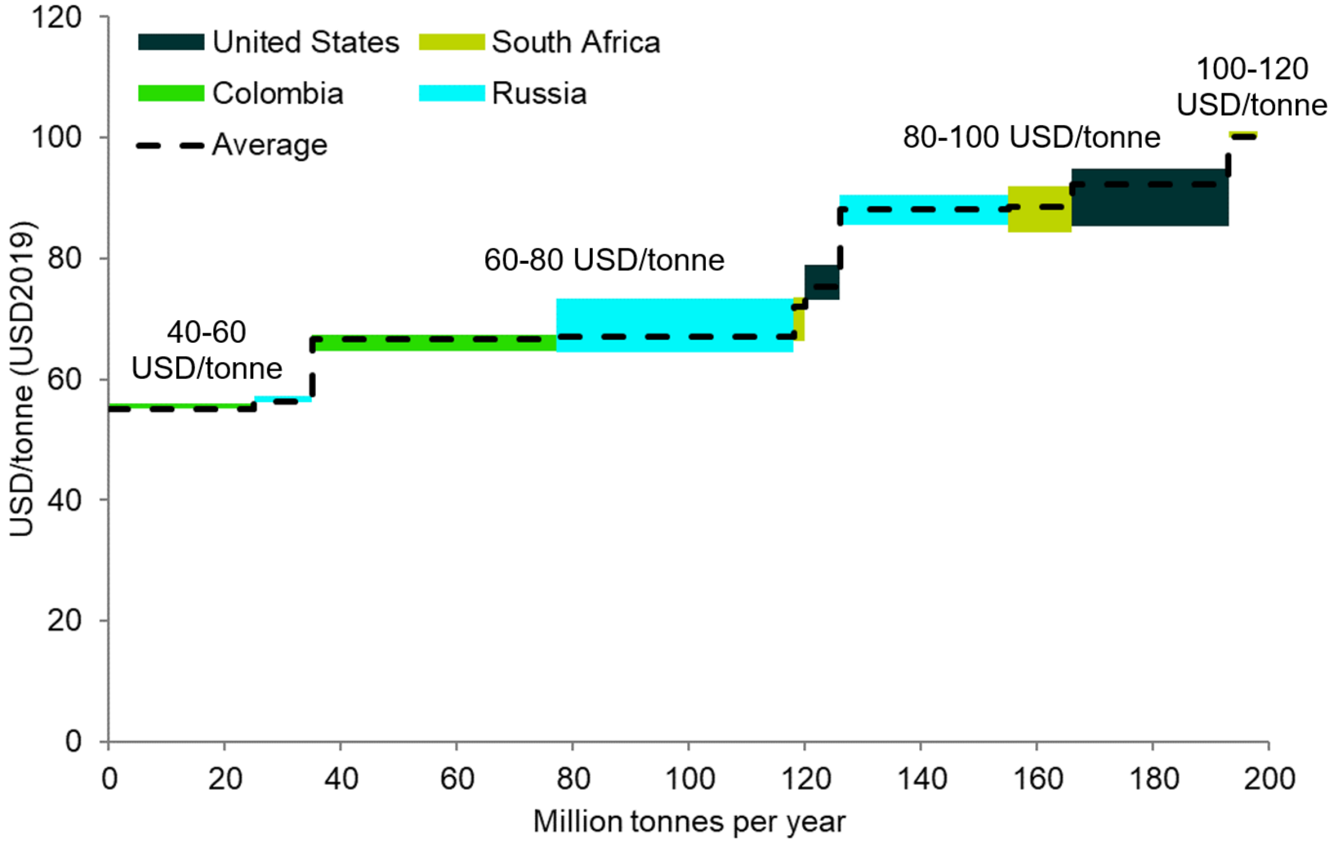
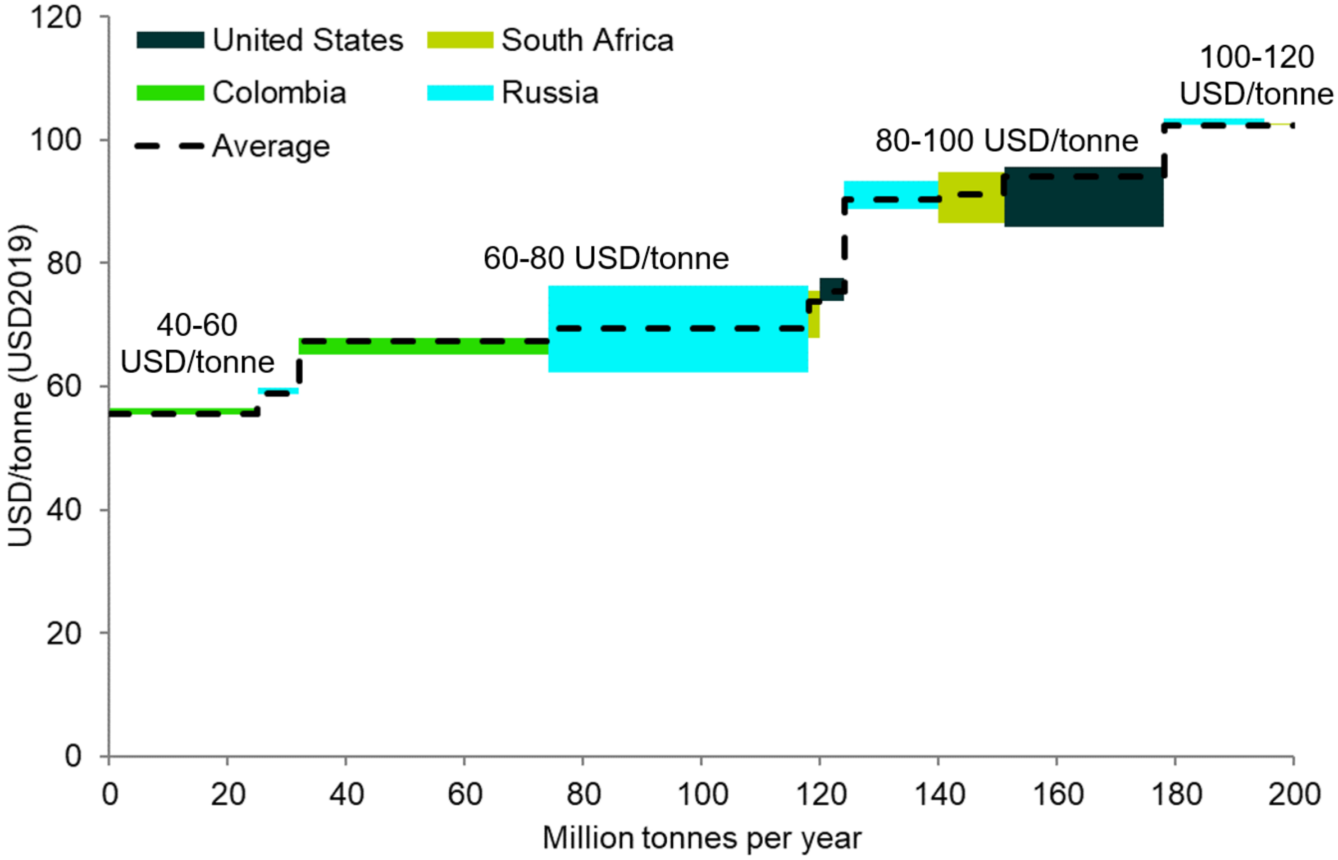


Figure 45: Rystad Energy base-case cost of supply for coal in 2040 by supplier and cost group



Low and high supply cases

Figure 46: Rystad Energy cost of supply curves in the base, low and high supply case for coal in 2025

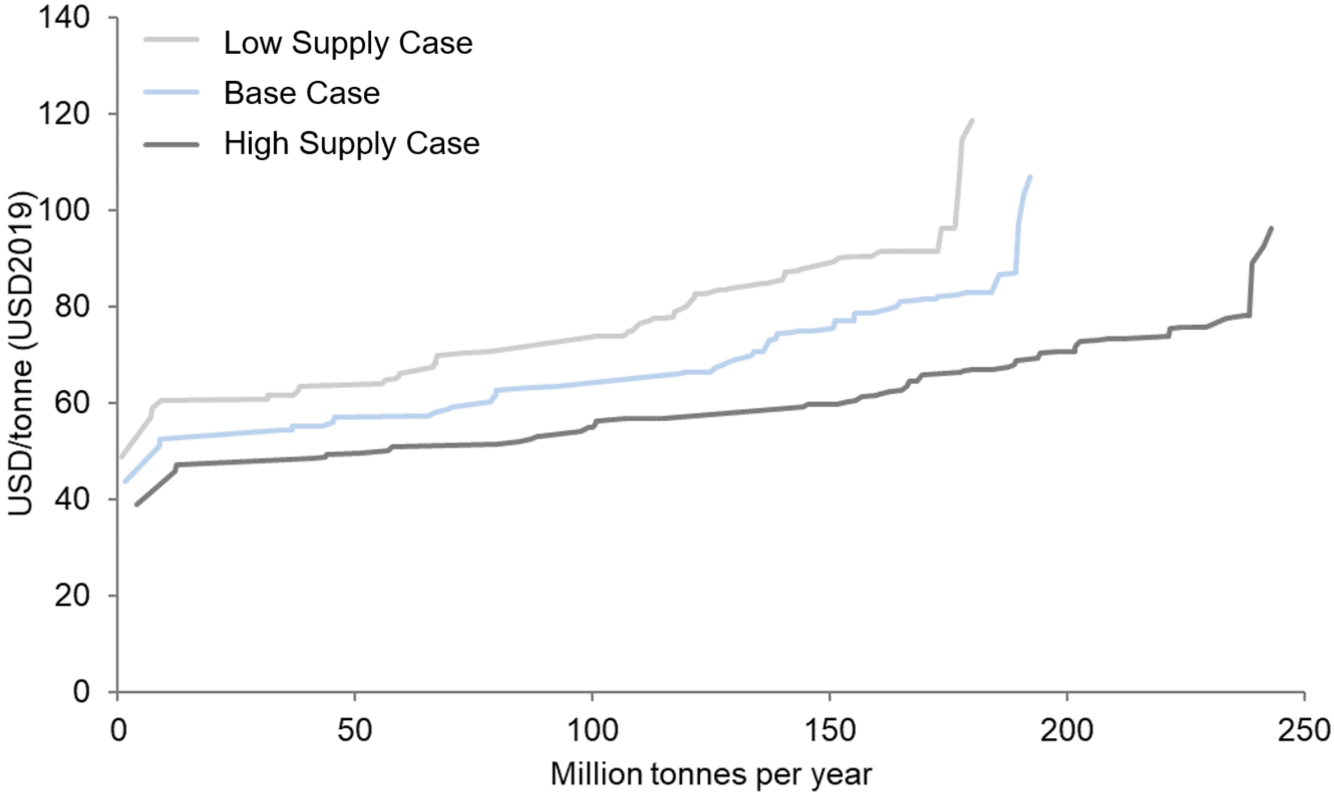


Figure 47: Rystad Energy cost of supply curves in the base, low and high supply case for coal in 2030

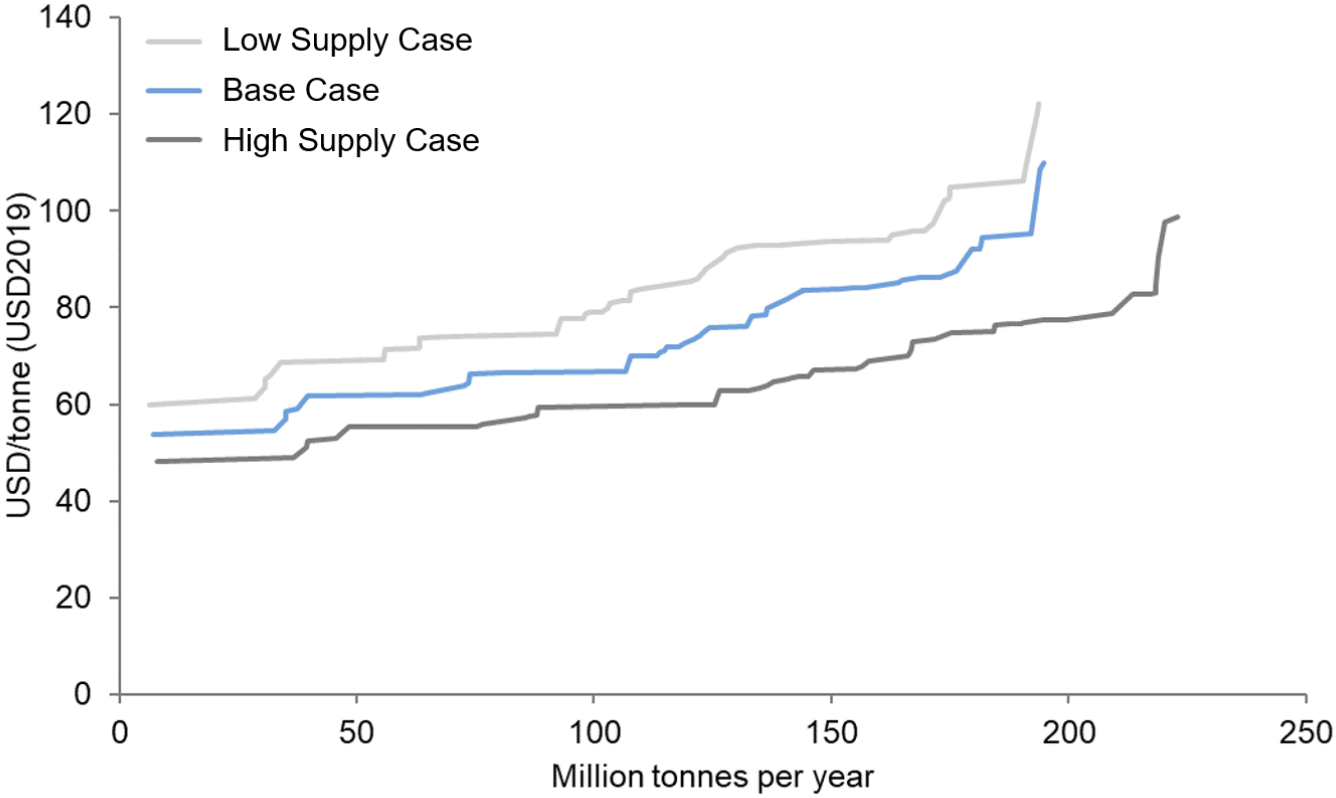


Figure 48: Rystad Energy cost of supply curves in the base, low and high supply case for coal in 2035

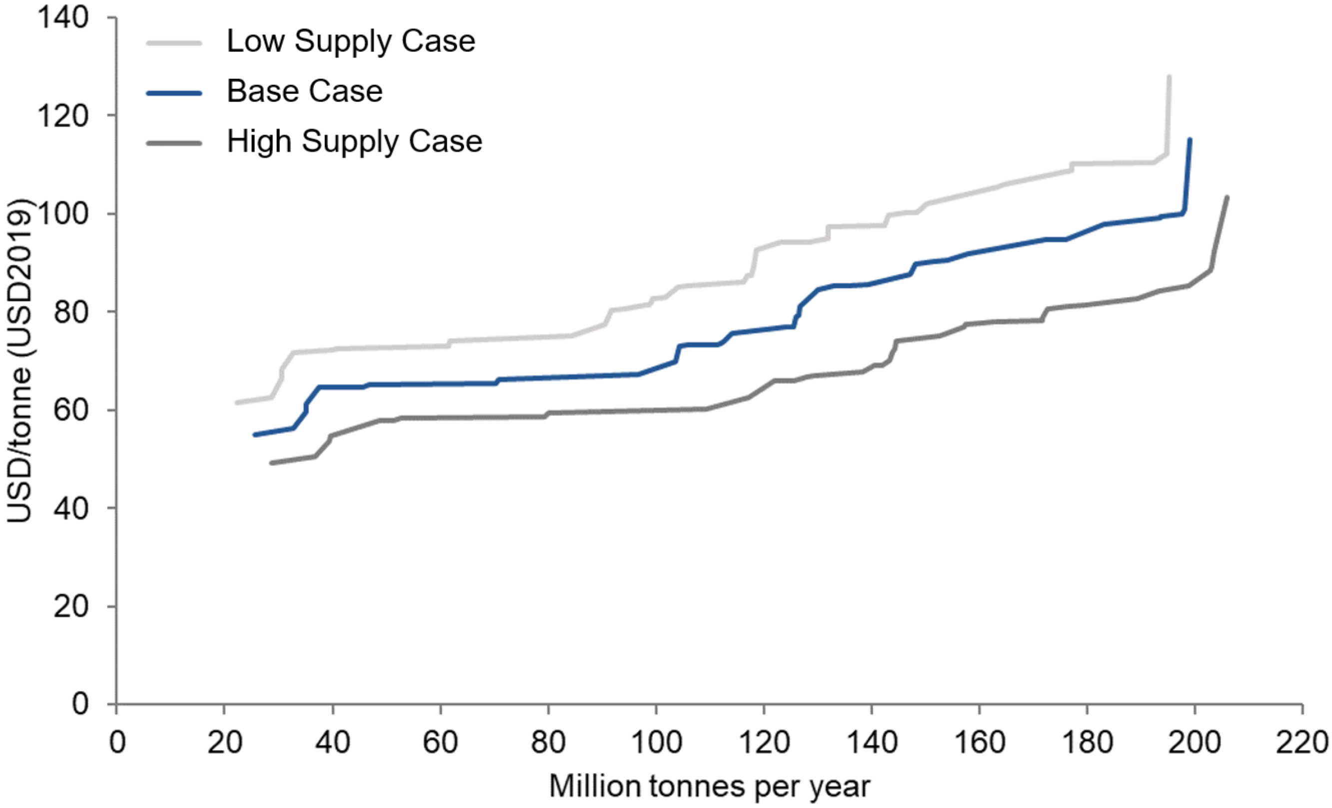
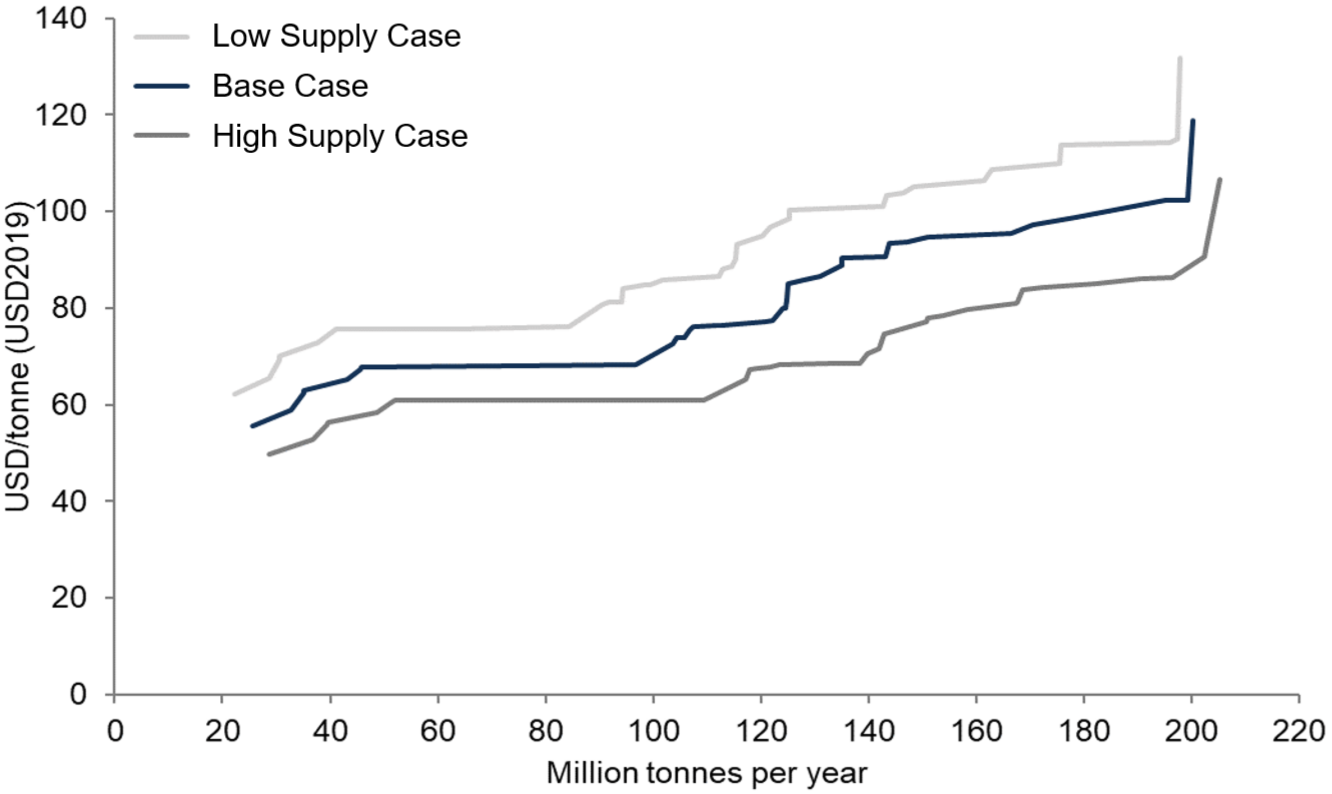


Figure 49: Rystad Energy cost of supply curves in the base, low and high supply case for coal in 2040



Low supply case

The sustained higher demand/price environment incentivises a greater rate of project development starting post-2025 and by 2040, some 40% of modelled supply is from new coal mining projects. Outside of the Atlantic/Pacific market coal flow restriction, no individual supply response changes has been modelled to operating mine production rates with the assumption that operations are fully utilising their export capacity. Additional investment could feasibly overcome existing production constraints and would be more economic for those operations at the lower end of the cost curve. Thus the coal supply curve could actually be flatter than indicated.

High supply case

The lower demand/price environment slows down the rate of project development and in 2040, only 24% of modelled available supply is from new coal mining projects. As per the low supply case case, no individual mine production response is modelled due to the change in price – in this scenario, mines are likely to keep operating at existing installed capacity in order to extract maximum efficiencies.

Annex A – Discount rate

A 13% real discount rate is applied to all assets across fuel types to construct the cost of supply curves provided in the report. Although E&P companies and other players in the upstream industry communicate the use of a range of different discount rates varying from around 7-15%, the 13% real discount rate was set to reflect the current return requirements and the developments in discount rates.

Although in Rystad Energy's experience, the discount rates used have typically been at the lower at end of the range, the energy transition risk and emergence of short-cycle sources of energy (shale) is placing increasing pressure on the required rates of return. A higher future discount rate is therefore reasonable going forward. The rate of return also varies between the different fossil fuels, regions, resource types and so on. However, to ensure consistency across the projects, a single discount has been chosen.

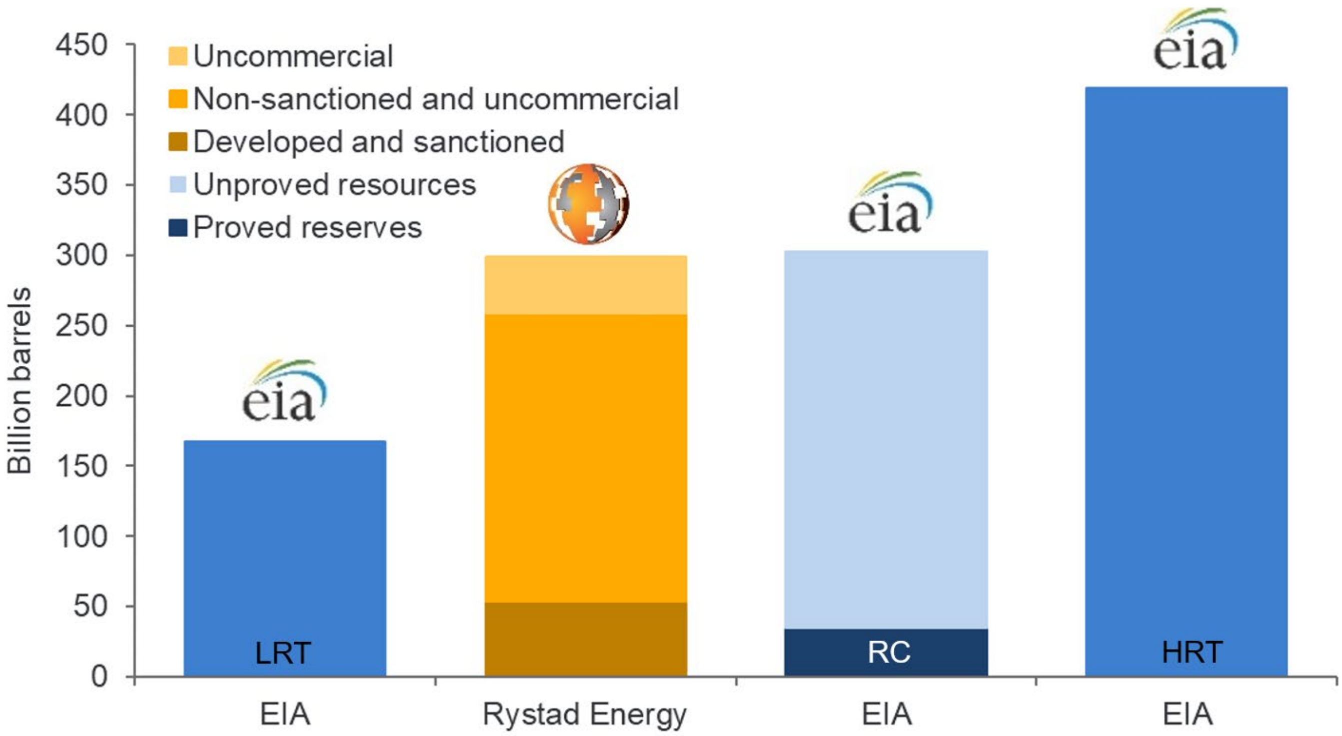
Reducing the discount rate from 13% to 8% (real), would reduce fuel prices by 3-15% in the base case in 2035 given demand assumptions of 107 million barrels per day for oil, 600 billion cubic meters per year for gas and 160 million tonnes per year for coal. The largest impact of a reduced discount rate is seen on oil prices since the cost of supply curves for oil include a large number of non-producing assets with significant future investments. This is also true for gas, however, since initial development cost make up a somewhat smaller share of the breakeven cost for gas, the effect on gas prices is lower. With regards to the coal prices, since most of the supply comes from already producing assets, where the development capex is considered sunk cost, the effect on coal prices is very small.

Annex B – US resources and production

Figure 50 shows the total US resource estimates in January 2017 for crude and condensate from Rystad Energy (orange) and EIA (blue). The EIA Low Oil and Gas Resource and Technology case (LRT) and the EIA High Oil and Gas Resource and Technology case (HRT) are included in addition to the EIA reference case (RC).

The EIA reference case estimate amounts to just over 300 billion bbl, which is close to the Rystad Energy estimate of approximately 280 billion bbl. However, these numbers are not directly comparable since the Rystad Energy resource estimate is determined by what the acreage can and is likely to produce (closer to the economically recoverable resources), while the EIA estimate represents the technically recoverable resources. Thus, Rystad Energy's resources estimate is production-driven, and is likely to be lower than EIA's resource estimate.

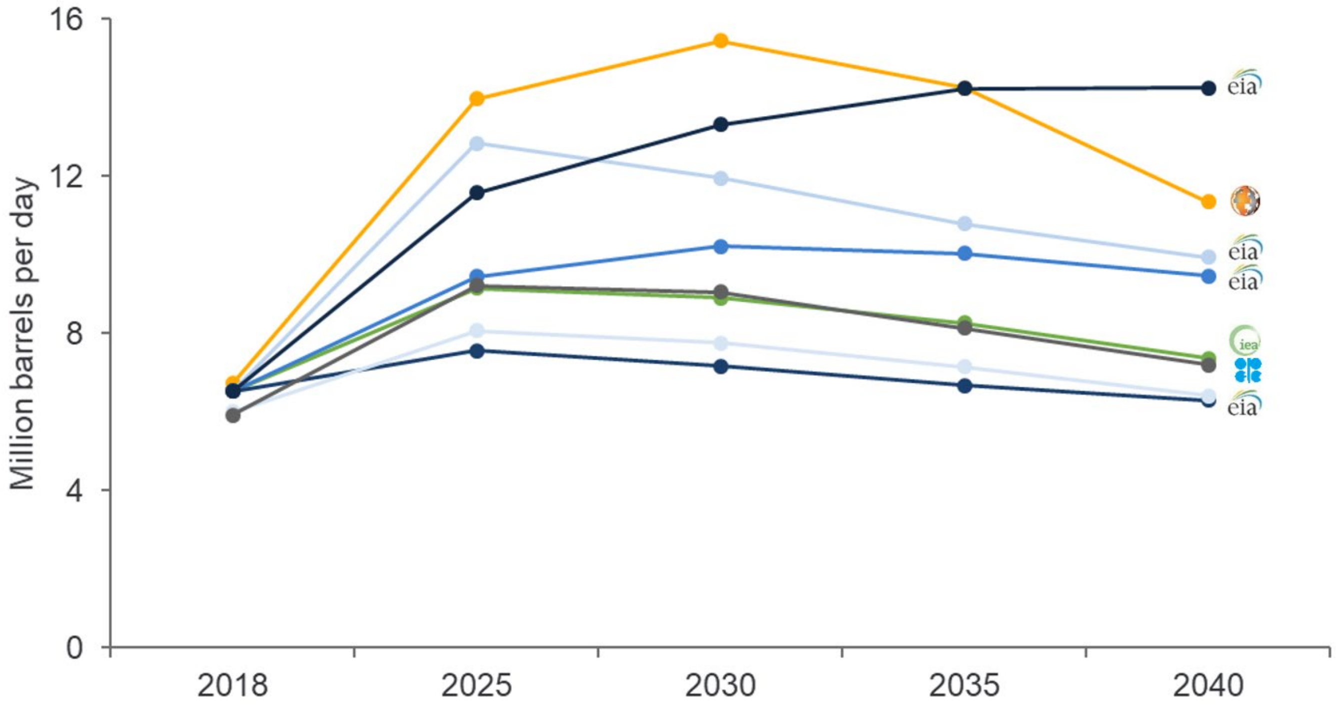
Figure 50: US resource estimates for crude oil and condensate from Rystad Energy and EIA (January 1, 2017)



Source: Rystad Energy research and analysis, EIA AEO 2019, IEA Oil and Gas Supply Module

Figure 51 shows various production forecast for US tight crude oil and condensate production. Rystad Energy forecasts the highest US tight oil production up until 2040 when EIA's High Oil and Gas Resource and Technology case takes a more bullish stance.

Figure 51: Production forecast for US tight crude oil and condensate*



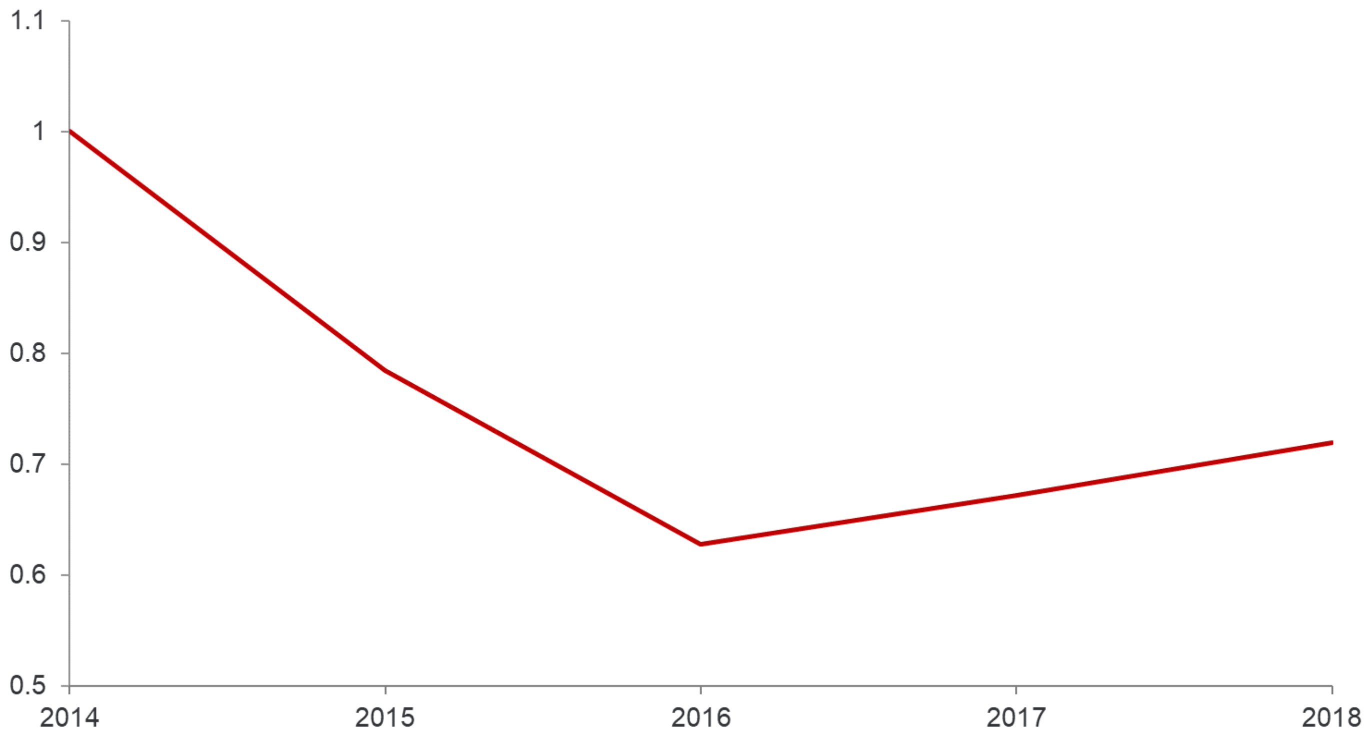
*Condensate is excluded from IEA and OPEC numbers

Source: Rystad Energy research and analysis, IEA WEO 2018, EIA AEO 2019, OPEC WOO 2018

Annex C – North American shale cost developments

The continued growth in shale production has been driven by rapidly declining costs. Figure 52 shows that costs in the shale industry declined by more than 35% between 2014 and 2016, which was a larger cost reduction than what was seen in other onshore and offshore resource types in the same period. The cost improvements were mainly driven by more efficient operations and lower unit prices through the downcycle. From 2016, the rising activity level in the North American shale industry put pressure on the unit prices and resulted in rising costs. However, the cost are still close to 30% below the 2014-cost level.

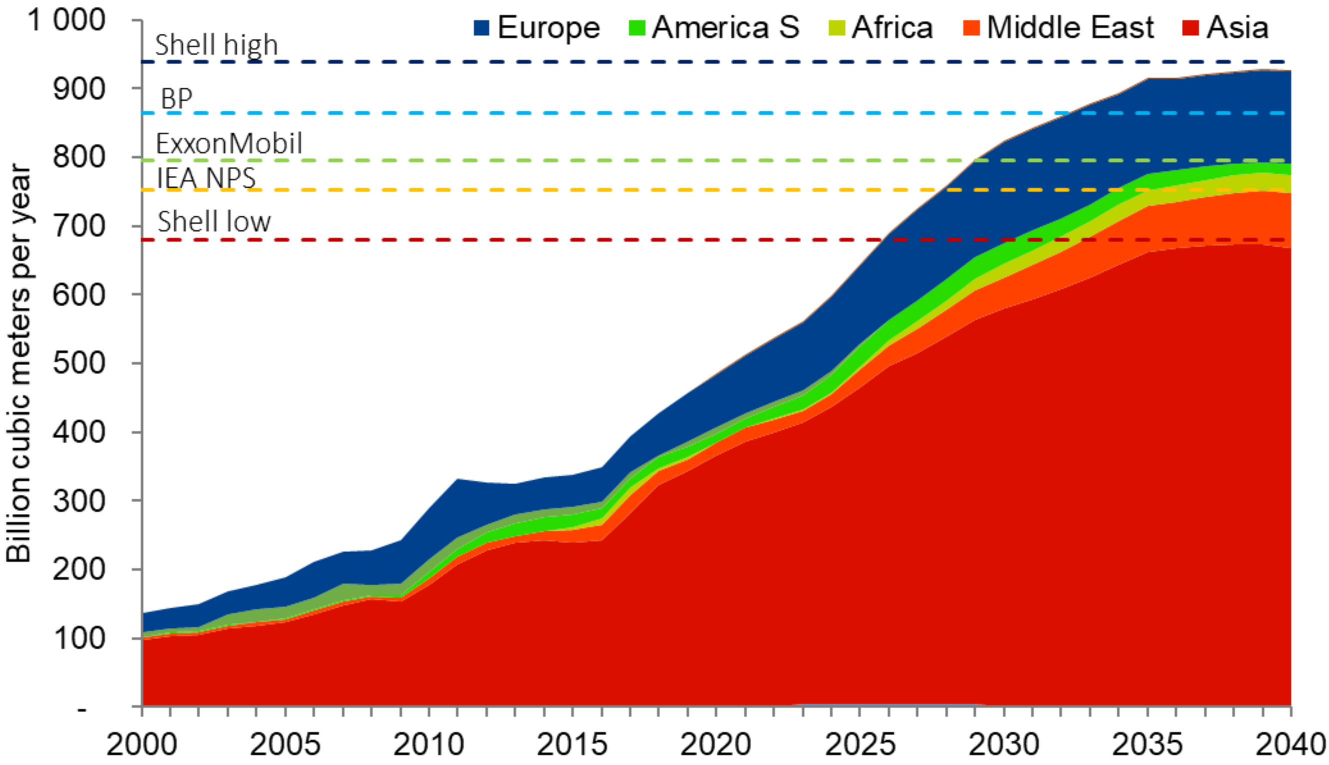
Figure 52: Cost deflation for North American shale indexed to 2014



Annex D – LNG market

Rystad Energy forecasts that the global LNG demand will grow from a level of 430 Bcm in 2018 to 930 Bcm in 2040. Other external sources forecast LNG demand to total between 680 and 940 Bcm in 2040.

Figure 53: Rystad Energy LNG demand forecast by continent vs external forecasts.



Source: Rystad Energy research and analysis, Shell LNG Outlook 2019, IEA WEO 2018, ExxonMobil 2018 Outlook for Energy: A View to 2040, BP Energy Outlook 2019

Annex E – Henry Hub

Figure 54 and 55 shows Rystad Energy's Henry Hub price forecasts in the high, low and base case (orange), in addition to various Henry Hub price forecasts from IEA (green) and EIA (blue). Rystad Energy's price forecast in 2040 range between 2.63-4.63 USD/MMBtu, while the other forecasts range from 3.22-6.84 USD/MMBtu in the same year. Thus, Rystad Energy's base-case and low-case forecasts are among the more bearish forecast in the long term.

Figure 54: Henry Hub forecasts* from Rystad Energy, IEA and EIA

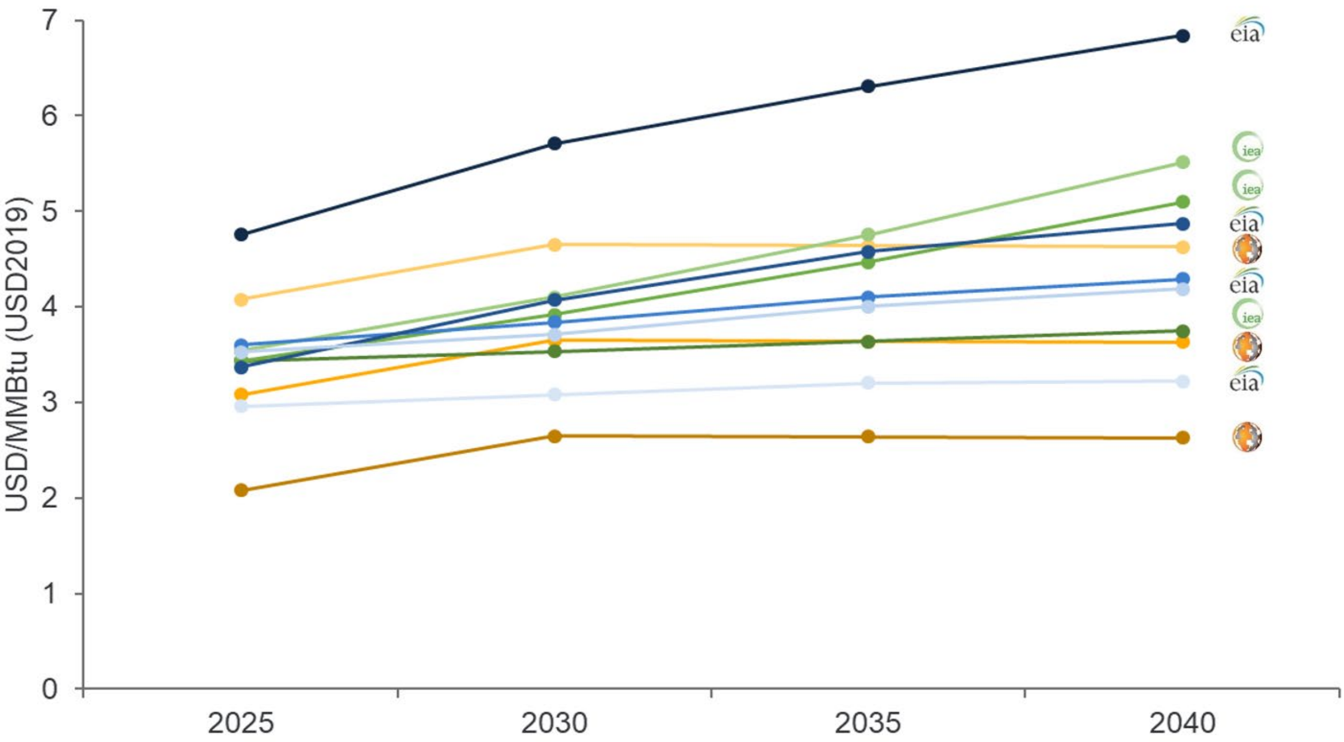
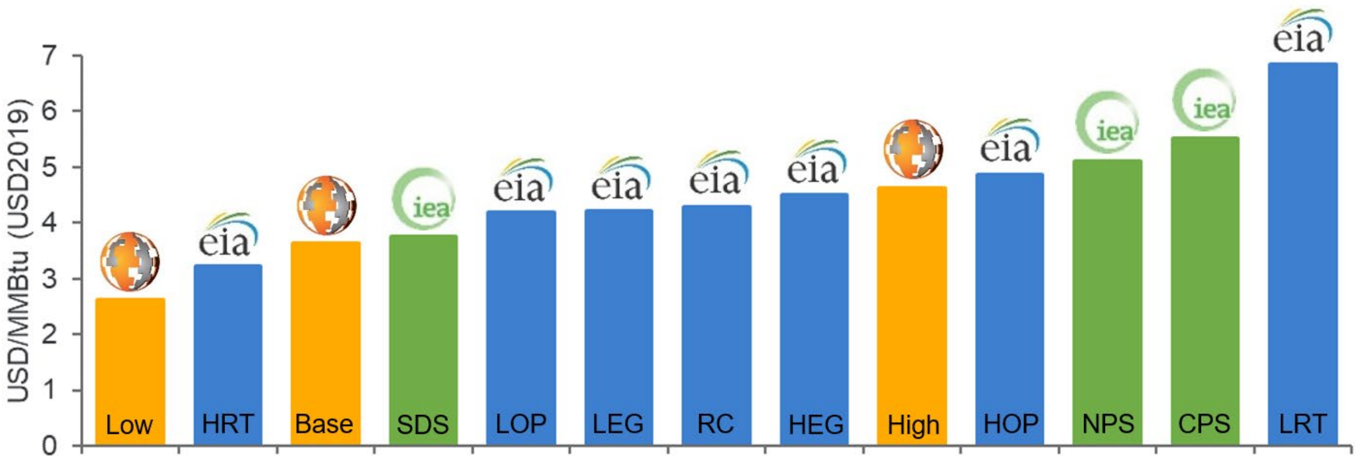


Figure 55: Henry Hub forecasts* from Rystad Energy, IEA and EIA in 2040



*Inflation rate of 2% assumed for the years 2017-2019 (IEA) and 2018-2019 (EIA)

Source: Rystad Energy research and analysis, IEA WEO 2018, EIA AEO 2019

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