Mind the gap: the $1.6 trillion energy transition risk

Carbon Tracker Initiative

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About Carbon Tracker

The Carbon Tracker Initiative is a team of financial specialists making climate risk real in today's financial markets. Our research to date on unburnable carbon and stranded assets has started a new debate on how to align the financial system in the transition to a low carbon economy.

About the authors

Andrew Grant – Senior Analyst
Andrew joined Carbon Tracker in 2014 as a Senior Analyst, leading research on oil & gas and coal mining. He has authored a number of Carbon Tracker's major reports on these sectors, including the Carbon Supply Cost Curves series, scenario analysis of the oil refining industry in Margin Call, and exploring transition risk at the company level in 2 Degrees of Separation. Prior to joining Carbon Tracker, Andrew formerly worked at Barclays Natural Resources Investments, a private equity department of Barclays that committed capital across a range of commodities and related industries. Andrew has a degree in Chemistry & Law from Bristol University.

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This report can be downloaded at:
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MIND THE GAP

Executive Summary

Oil, gas and thermal coal face varying challenges and degrees of risk in a climate-constrained future. This report will look at each of these fuels in turn with a focus on the upstream end of the value chain, comparing potential supply to a selection of different demand scenarios that result in varying global warming outcomes.

The three scenarios used are drawn from those published annually by the International Energy Agency (IEA). These are the Beyond 2 Degrees Scenario (B2DS, aligned with a 1.75°C global warming outcome); the Sustainable Development Scenario (SDS, aligned with 2°C); and the New Policies Scenario (NPS, aligned with 2.7°C). Each of the scenarios assumes a 50% probability of success in achieving its respective level of warming.

Key takeaways:

- Compared to the SDS, the **1.75°C B2DS demand scenario puts a further $0.7tr capex at risk** over the period 2018-2025 for the three fossil fuels (15% of NPS capex). Compared to the NPS, the B2DS requires $1.6tr less capex over the period 2018-2025 (33% of NPS). The SDS requires $0.9tr less (18% of NPS).

- **Meeting demand in any of the three scenarios will still require very significant investment.** Capital expenditure on existing and new projects in the period 2018-2025 amounts to $3.3tr in the B2DS, $4.0tr in the SDS and $4.8tr in the NPS.

- **Coal carries disproportionate danger to the climate, but absolute capex dollars are low compared to oil and gas.** Oil and gas account for over 90% of total investment under each scenario, and of the intervals between each scenario.

- **New oil and gas projects are needed, but not all of them.** Material investment in new oil & gas projects is required even in low demand scenarios - $1.6tr in the B2DS and $2.1tr in the SDS (2018-2025). However, given the multitude of project options available, they also carry the greatest risk. Nearly a quarter of investment dollars in new projects that go ahead in the NPS don't fit in the SDS, and over 40% of potential capex is surplus to requirements in the B2DS.

- **No new thermal coal mines go ahead in the US or China, or to supply the international seaborne export market, in either the SDS or B2DS.** This is consistent with prior findings, despite a diminished outlook for potential production.

- **No investment in new greenfield oil sands projects is required before 2025 in the B2DS or the SDS.**

Scenario analysis – a range of possible futures

In this report, we have used the NPS level of demand as an upper limit to our potential supply curves. This approach in effect assumes that companies are already aligned with this scenario, and focuses on the "surprise" or "misread" differentials down to the SDS and B2DS demand levels – the capital at risk if companies invest to deliver NPS demand but are caught out by a lower level. We would note that disclosures to date do not suggest that all companies expect long-term demand to be as low as NPS, even if capex levels have been curtailed by prices recently.

It is worth remembering that these scenarios are not static reference points either. Increased policy expectation post-Paris COP and rapid advances in technology costs mean that the emissions profile for the NPS has been lowered in recent years. Moreover, the NPS is based on policy that has already been announced; given the direction of travel for the energy transition, it could be expected that a "base case" scenario might assume continuously increasing pressures on fossil fuel demand. This makes it even more relevant to apply the other scenarios to assess a range of future outcomes, as it is likely the NPS will have shifted further in a few years. Beyond that, we would also argue that comparing a portfolio to a scenario that simply reflects current expectations is not informative in terms of properly testing the resilience of a business strategy.

Carbon budgets and temperature outcomes

By applying the IEA's scenarios, this brings in the associated assumptions of the methodologies. The probability of the associated anthropogenic warming outcome is one area of interest. For ease, we highlight here the equivalent warming (in degrees Celsius) at 50% probability and our approximate estimate at 66% probability for the three scenarios analysed.

Scenario	*50% Probability (IEA)*	*66% Probability (estimate)*
B2DS	*1.75°C*	*2°C*
SDS	*2°C*	*2.3°C*
NPS	*2.7°C*	*3°C*

We have written in more detail about the factors which impact carbon budget calculations elsewhere[1]. We would highlight here that using the B2DS may be seen as a stricter constraint on fossil fuel demand, but in terms of climate outcome it could be tightened further in the context of the Paris Agreement to hold warming to "well below 2°C".

1 *See for example Carbon Tracker, "Carbon Budgets Explained", February 2018 https://www.carbontracker.org/carbon-budgets-explained/*

Distribution of risk

The range of competitive positioning along the cost curves within each fossil fuel means that there are strong differences in outcomes between the companies that hold those resources. The majority of oil & gas reserves might be held by state-controlled companies, but we find that private investors have disproportionate exposure to the higher risk portions that might be affected by demand destruction as shown below. We do not go into further detail of ownership in this macro-level report.

Using this note

The charts on the next few pages illustrate key points of the research. While the numbers from these charts should not be used precisely[2], they are representative of the broad themes and illustrative of the relative positioning of future supply options.

We generally see a focus on the general and relative as more instructive than assuming precision that isn't warranted given the nature of multi-decade projections that aren't designed for that purpose. Thermal coal coverage is incomplete globally, and metallurgical coal has been excluded for the purposes of this exercise – see the Appendix for further details on methodology. Potential production figures are presented over the period 2018-2035, and potential capex over the period 2018-2025.

The division of future thermal coal, oil and gas supply by the three supply scenarios applied essentially creates 4 categories of risk. Supply which is under the B2DS is the lowest risk. Then there are tranches between B2DS – SDS, and SDS – NPS, which are higher risk. Beyond the NPS there are further opportunities and potential projects at the higher ends of the cost curve which are not considered here, as they are likely to be more expensive and not under immediate consideration for development.

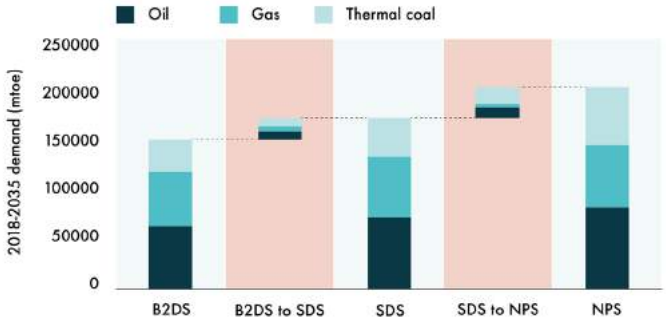
However, if projects move along the cost curve or commodity price changes increase then this could bring these supply options into play, so the category above NPS cannot be ignored completely.

Clearly, thoughts about transition risks in the energy sector have changed considerably in recent years and continue to evolve. Investors are increasingly focusing on aligning with both climate change mitigation efforts and the achievement of an "orderly transition" which minimises financial disruption in the process. Scenario analysis will play a crucial role in improving understanding and preparation.

2 *For example, annual emissions between data points have been interpolated; thermal coal capex is only for selected regions representing >80% of current demand, whereas the CO_2 and demand charts are for global thermal coal; the oil demand and CO_2 charts include coal-to-liquids and gas-to-liquids whereas these are excluded from capex.*

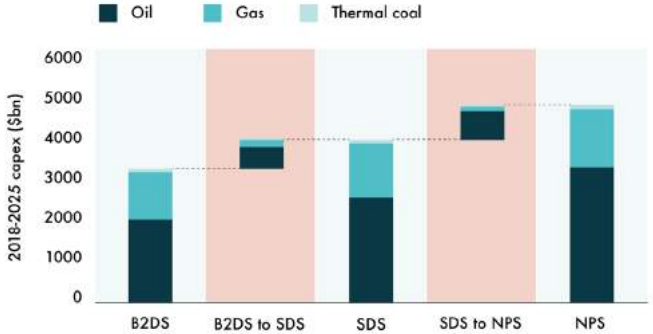
Fossil fuel scenario dynamics in three charts

*Demand under the three scenarios, 2018-2035**



Source: IEA, Carbon Tracker analysis

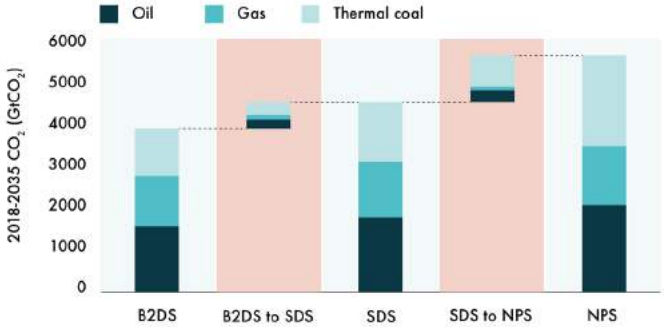
*Capex under the three scenarios, 2018-2025 (coal focus markets only)**



Source: IEA, Rystad Energy, Wood Mackenzie, Carbon Tracker analysis

**Note: Highlighted floating stacks indicate the incremental oil, gas and coal supply that is surplus to requirements in the more ambitious scenarios.*

*CO_2 emissions under the three scenarios, 2018-2035**

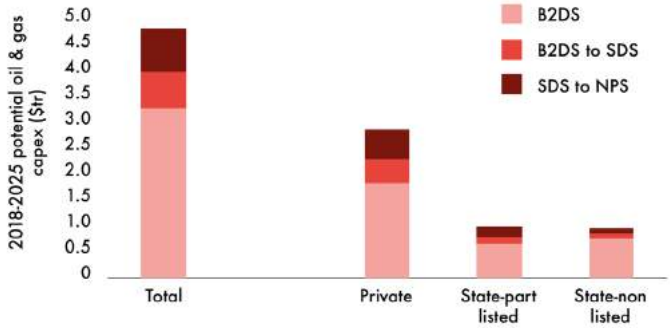


Source: IEA, Carbon Tracker analysis

- **Coal has an outsized influence on CO_2 emissions**, producing around 50% CO_2 per unit of energy more than oil and over 60% more than gas.
- Accordingly, and due to ease of substitution, in the power sector, **thermal coal demand is particularly sensitive to climate outcomes**. The B2DS sees 45% less thermal coal demand globally than the NPS, compared to 14% for gas.
- This effect is amplified when looking at new potential projects - **no new thermal coal mines at all go ahead in the US, China, or seaborne export market**, in either the SDS or B2DS.
- However, **absolute financial risk is dominated by the oil & gas industry** due to its much greater capital intensity – oil & gas accounts for over 90% of the capex in the intervals between the scenarios which are at risk of overinvestment.

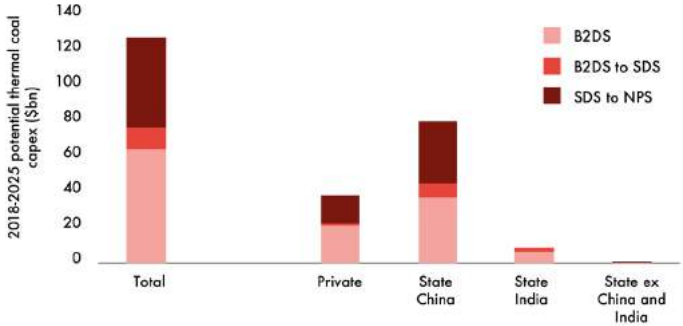
Who owns the risk?

Oil & gas potential capex by ownership, 2018-2025



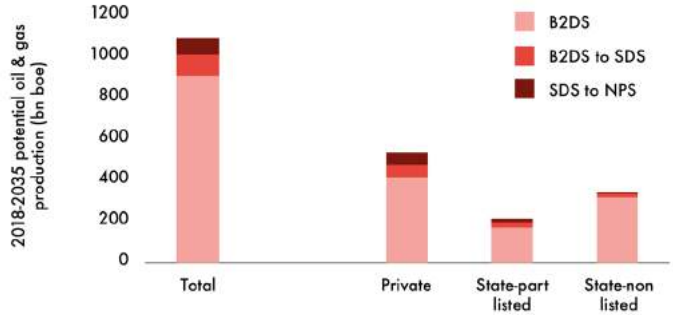
Source: Rystad Energy, IEA, Carbon Tracker analysis

Thermal coal potential capex by ownership, 2018-2025 (coal focus markets only)



Source: Wood Mackenzie, IEA, Carbon Tracker analysis

Oil & gas production by ownership, 2018-2025



Source: Rystad Energy, IEA, Carbon Tracker analysis

- For oil & gas, it is clear that private sector companies and part-listed NOCs have the greatest exposure to the tranches of capex/production lying in the higher risk categories. State-controlled entities that aren't publicly listed account for just 12% of oil & gas capex in the gap between B2DS and NPS. Oil & gas demand destruction is therefore disproportionately an issue for private investors in capex terms, despite the majority of global reserves being held by national oil companies.
- Thermal coal is dominated by state-controlled domestic supply (Chinese and to a lesser degree Indian). However nearly half of the capex of private sector companies falls into the gap between NPS and B2DS demand levels.

1. IEA Demand Scenarios

Image source: Gretar Ivarsson, geologist at Nesjavellir, via Wiki Commons

In this paper we examine the range of outcomes for the potential supply of oil, gas and thermal coal in terms of production and capex required under three different demand scenarios, each of which can be thought of as approximating a "carbon budget" resulting in a different level of global warming.

Our usual focus to date has been on levels of demand that result in 2°C of global warming above pre-industrial times, consistent with prior international targets. However, following the 2015 Paris Agreement to hold "the increase in the global average temperature to well below 2°C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5°C", there has been increased interest in the results of scenarios that assume a higher level of climate ambition.

In this study, we therefore compare potential oil supply to demand levels based as closely as possible on the International Energy Agency's (IEA) 1.75°C Beyond 2 Degrees Scenario (B2DS) as well as the 2°C Sustainable Development Scenario (SDS), and include the 2.7°C New Policies Scenario (NPS) for reference.

A brief description of these three scenarios is provided below. The IEA is explicit that none of them should be taken as a long-term forecast.

- **IEA New Policies Scenario**: The NPS is the central scenario published in the World Energy Outlook. It is "designed to show where existing policies as well as announced policy intentions might lead the energy sector". "It incorporates not just the policies and measures that governments around the world have already put in place, but also the likely effects of announced policies, as expressed in official targets or plans"[3]. As there are no assumptions relating to potential future policies beyond those announced, it may be seen as lagging given the general direction of travel towards greater climate-related regulation. It is consistent with a course that gives a 50% probability of a global temperature rise of roughly **2.7°C**.

- **IEA Sustainable Development Scenario**: The SDS replaces the previous 450 Scenario in the 2017 World Energy Outlook as the main decarbonisation scenario. It is "consistent with the direction needed to achieve the objectives of the Paris Agreement", and further incorporates ambitions relating to universal energy access and improvements in air quality. While the temperature increase that would result from this scenario is dependent on measures that would take place after the period that it covers, it is consistent with a roughly 50% chance of limiting global warming to **2°C** above pre-industrial temperatures. It is therefore at the upper limit of the amount of emissions that can be considered to comply with the Paris Agreement.

- **IEA Beyond 2 Degrees Scenario**: The B2DS was published for the first time in the 2017 Energy Technology Perspectives. Like the SDS, it is driven by outcomes rather than inputs; that is, the demand pathway results from the ultimate goal, in this case limiting global warming to **1.75°C** by 2100, "the midpoint of the Paris Agreement's ambition range"[4]. Again, the associated level of cumulative emissions has a 50% chance of successfully delivering this temperature outcome.

As each of these scenarios ultimately results in a given level of global warming, the modelled resulting aggregate amount of demand for each fossil fuel can be thought of as a "budget" for that fossil fuel to result in that warming outcome.

The documents published by the IEA that describe these scenarios provide a great deal of information on each, including some coverage at a regional level. However, it does not provide the entirety of the detail needed in order to apply a fully comprehensive demand scenario at the asset level, particularly in some gas and coal markets. Accordingly, we have attempted to make some reasonable approximations where necessary, and annual points in between those disclosed by the IEA have been interpolated.

This approach of comparing a single stack of potential supply to three demand scenarios is an extension of previous Carbon Tracker studies, where we have tended to focus on a single

3 *See IEA, World Energy Outlook 2017*
4 *See IEA, Energy Technology Perspectives 2017*

scenario[5]. Providing analysis of additional options allows investors different interpretations of the results depending on their outlook and risk tolerance; for example, allowing them to test against a climate outcome with a higher ambition than the 2°C warming scenario we have used as our main benchmark to date, or allowing them to be more conservative on potential supply by cutting off at the demand attributed to the NPS rather than the full extent of potential supply, for example.

NPS demand used as upper limit of supply

In our "2 Degrees of Separation" report, we noted that the full extent of potential supply of oil and gas was not much higher than NPS levels of demand, and hence felt justified in calling potential supply business-as-usual ("BAU").

However, due in part to an increase in potential supply options on the source databases[6] relative to demand since that analysis was undertaken in January 2017, we have reconsidered this approach. In the current environment of drastically reduced sanction activity and renewed focus on margin rather than volume growth, it is clear that many of the higher cost options are not on the table at the moment. Therefore in this study we will focus on the increments of supply/capex between the B2DS and SDS and an upper limit to potential supply equal to NPS demand.

The report in effect assumes that shareholders are already assuming that projects beyond this level will not get built, and focuses on the "surprise" or "misread" differentials down to the SDS and B2DS demand levels – the capital at risk if companies invest to deliver NPS demand but are caught out by a lower level.

We doubt that there is a single perfect method of determining the extent of potential supply which reflects the full fossil fuel development opportunity set whilst balancing this against a desire to prioritise more immediate projects in a way that will satisfy all interested parties. This approach thus does not capture all the opportunities to destroy value in the industry, indeed it would be well accepted that some initially prospective options would inevitably fail to pass sanction even in higher demand scenarios. However, on balance and reflecting feedback from investors on previous research, in this instance we prefer the conservativeness and greater focus on nearer term, more likely projects that comes with assuming lower levels of potential supply. We continue to consider the most appropriate approach.

5 *See for example Carbon Tracker, "2 Degrees of Separation", June 2017. Available at 2degreeseparation.com*
6 *See Appendix*

2. Oil

Image source: Agência Brasil, via Wiki Commons

Key takeaways:

- **The B2DS puts an additional incremental $0.6tr capex outside the budget and at risk of overinvestment compared to the SDS.**

- **Meeting demand in any of the three scenarios will require very significant investment in oil developments.** Capital expenditure on existing and new projects in the period 2018-2025 amounts to $2tr in the B2DS, $2.6tr in the SDS and $3.3tr in the NPS.

- **New projects are needed, but not all of them.** Material investment in new oil projects is required even in low demand scenarios; $0.9tr in the B2DS and $1.2tr in the SDS (2018-2025). However, given the multitude of project options available, they also carry the greatest risk. Nearly a third of investment dollars in new projects that go ahead in the NPS don't fit in the SDS, and over half of potential capex is surplus to requirements in the B2DS.

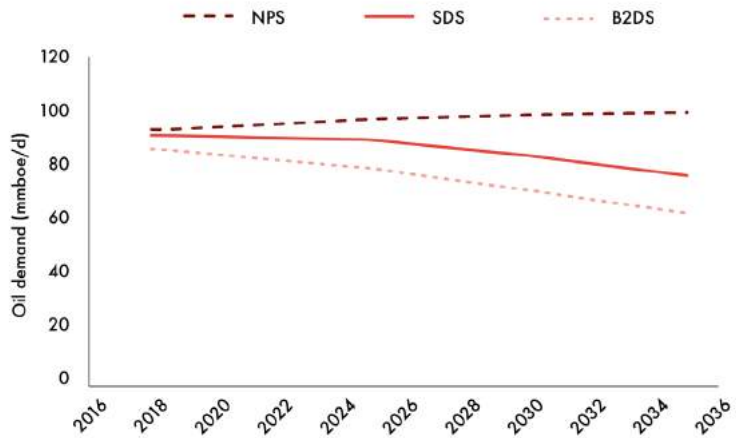
- **No investment in new greenfield oil sands projects is required before 2025 in the B2DS or the SDS.**

Oil demand

Oil has been treated as a single global market, with refinery gains, coal to liquids (CTL) and gas to liquids (GTL) excluded. These have been estimated where not disclosed in the published scenario detail (e.g. in the IEA B2DS).

Over the period 2018-2035, the demand pathways for oil are shown in the below chart.

Figure 1: Global oil demand under the three benchmark scenarios, 2018-2035[7]



Source: IEA, Carbon Tracker analysis

Hence it can be seen that in the NPS, oil demand continues to rise throughout the period whereas the SDS and B2DS require oil demand to fall almost immediately to deliver the required outcomes. 2018-2035 oil demand CAGRs for the NPS, SDS and B2DS are 0.4%, -1.0% and -1.8% respectively.

Although not shown in the above chart as the IEA does not provide data points between 2016 and 2025, in the Sustainable Development Scenario oil demand peaks in 2020 (and the B2DS envisages an even sharper decline). However, we note that in the context of carbon budgets and global warming it is the aggregate amount of CO_2 emissions over the entire period that determines the outcome. The exact trajectory of the demand pathways should therefore not be thought of as all-important; a later peak but higher subsequent rate of decline would give the same result.

7 The three scenarios appear to have different starting points for demand in 2018 – this is a function of the different start dates for the ETP and WEO data (2014 and 2016 respectively), after which respective points the demand pathways immediately begin on different trajectories. As it is the cumulative amount of emissions which ultimately determines the degree of global warming and hence the demand levels modelled here, we have not sought to change the data points for 2015-17 in line with the actual emissions that have transpired. However, we would note that to the extent that emissions in these years were higher than factored into the scenarios, this excess will need to be made up with lower emissions later in the period, and thus our interpretation of the B2DS in particular arguably allows slightly greater future emissions than should be the case. Furthermore, for the same reason (and given that 2018 demand is yet to transpire) we have not attempted to give the scenarios the same 2018 baseline.

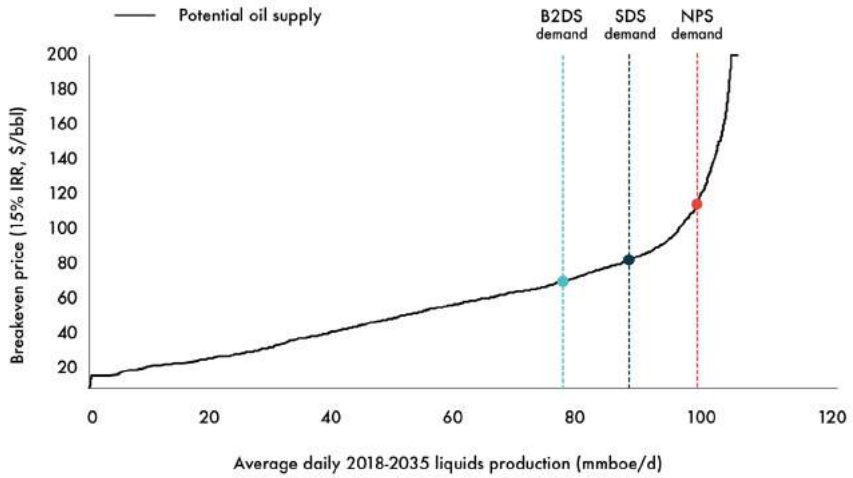
High-level findings

The oil supply cost curve

Sufficient potential supply for every scenario

The cost curve for oil supply, with the three demand scenarios overlaid, is shown below.

Figure 2: Oil production 2018-2035



Source: Rystad Energy, IEA, CTI analysis

Thus it can be seen that the database of potential supply contains sufficient volumes to satisfy demand under all three scenarios in the timeframe under review. However, the supply options over and above those needed in the NPS require very high oil prices (by today's standards) to deliver profitably.

When compared to oil prices seen today, many of the potential supply options on the curve will require a significant price rise in order to go ahead, and are likely to be far from the minds of sanctioning executives. However, in this exercise we are looking out 18 years into the future – in order to satisfy the demand in the given scenarios, these are the projects that will make up the necessary level of production. It may be

Note: A small volume of potential supply is calculated as having a breakeven price above $200/bbl; given the uncertainty inherent in estimating the economics of particular projects, these have been capped at $200/bbl.

that the oil price rises sufficiently to encourage the sanction of these projects, it may be that supply costs fall to the point where they are economic, or a combination of the two.

Equilibrium costs of supply

The intersection between the supply curve and the demand line for each scenario gives an equilibrium cost of supply, the theoretical price which the last marginal unit of supply requires to satisfy demand. A higher demand scenario necessitates supply from projects higher up the cost curve.

However, we would caution against reading these equilibrium costs as price forecasts for each demand scenario. Firstly, as the curve is in aggregate, it does not give the timing of the marginal supply unit and hence the point at which this price would need to be met. While logically one might expect this to be towards the end of the timeframe (as an efficient market would use the lowest cost supply options first), in reality the market is not efficient, and factors such as cyclicality and producer behaviours are likely to mean that this is not the exact route that the market takes. Secondly, these curves are based on present-day knowledge; while assumptions have been made about future inflation etc, as we have seen over the last few years costs can move very significantly in ways that might have been unforeseeable even a year or two previously. The multi-decade period under review will include a number of other factors that affect the oil price and hence supply costs aside from pure supply and demand. These include, for example, cyclical effects of cost inflation and deflation, periods of oversupply and undersupply, and geopolitical concerns. The volumes of supply available will also change with discoveries, outages and political instability.

Accordingly, we do not place significant emphasis on the precise value of the marginal cost. For the purposes of this exercise it merely signifies the dividing point between projects that are within the budget for each scenario and those that are outside. It is the approximate relative positioning of projects that is important for the purposes of this exercise, rather than their precise attributes.

Production in and outside each budget

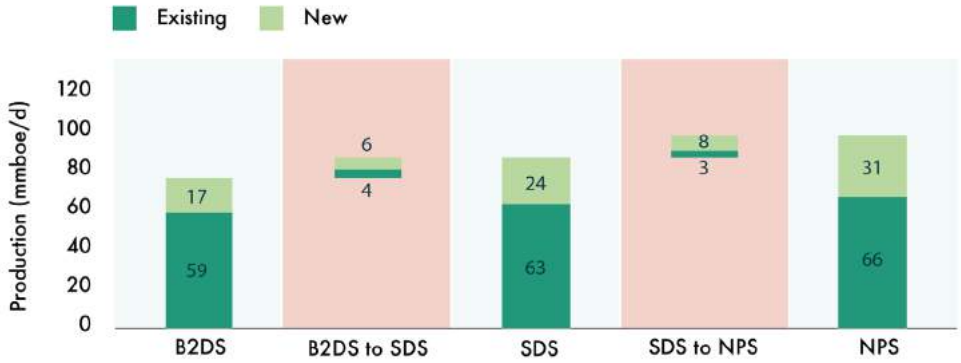
Incremental gains

The average levels of oil demand over the period 2018-2035 in the B2DS, SDS and NPS scenarios are 76, 86 and 97 mmboe/d respectively.

The below chart shows the incremental jumps in production between each scenario. These can be thought of as the amount of production that would be out of the budget in each scenario compared to another one – for example, an industry that collectively (but not necessarily consciously) planned for NPS production but was confronted by B2DS demand would find that an average 21 mmboe/d of production was surplus to requirements.

Of course this is something of a simplification – when it transpires that demand is not going down the higher route, the industry can take steps to cut investment and production (as illustrated clearly since 2014), albeit with a certain amount of pain for investors. Therefore while the industry in this scenario is unlikely to find itself swimming in 21 mmboe/d of excess oil, these numbers are intended to be illustrative of the relative scale of the opportunity to get caught out by shifting trends. We consider the relative outcomes from this analysis more important than the absolute numbers in general, and recommend that this approach be borne in mind throughout. This is also where short-cycle developments afford more flexibility than conventional capital-intensive megaprojects.

Figure 3: Waterfall chart for potential oil production, 2018-2035



Source: Rystad Energy, IEA, CTI analysis

22% of NPS production would be outside the B2DS budget, and 11% outside the SDS budget.

Table 1: Oil production and capex in the B2DS and SDS relative to NPS

	B2DS	SDS	NPS
2018-2035 production	-22%	-11%	0%
2018-2025 capex	-39%	-22%	0%

Source: Rystad Energy, IEA, CTI analysis

Existing outcompetes new

The breakeven prices used here are calculated on a point-forward basis; that is, they only consider future cash flows. Therefore existing sources of supply tend to have lower breakeven prices than future supply sources, as they have sunk their initial capex and the forward looking breakeven is likely to be closer to the project's operating costs, rather than also having to deliver a return on their initial capex like a project undergoing sanction would. This reflects the reality of economic decision-making – once a project has been sanctioned, even if the initial capex has proven to be value-destructive, the project is likely to be able to continue operating at the expense of competing pre-FID (final investment decision) projects provided that it can remain cash flow positive to run.

Accordingly, existing (post-FID) projects disproportionately fit within even the more ambitious budgets – nearly 90% of production from existing projects is within the B2DS level of demand. However, the lower oil demand scenarios leave significantly less space for new production, with 77% of the B2DS budget being satisfied by existing production compared to 68% of the NPS budget.

Taking NPS demand as the upper limit on potential supply, 45% of new potential oil production is outside the B2DS budget, and 25% outside the SDS budget.

Capex in and outside each budget

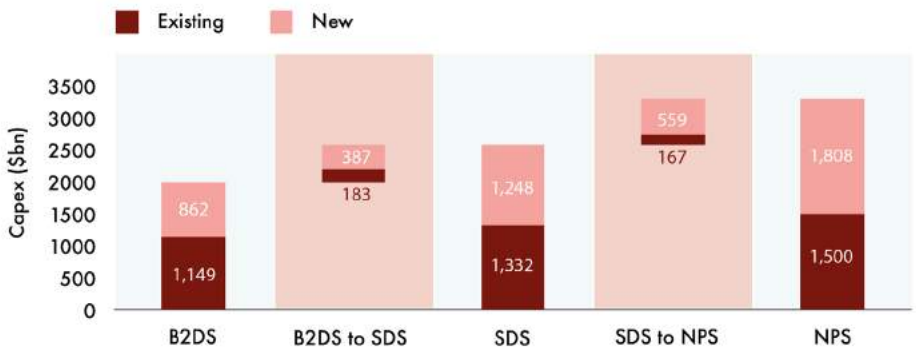
However, project sanctions continue

Despite the above, there remains a need for new oil investment even in the B2DS scenario. This is a consequence of the average demand decline rate over this period of -1.8% being likely to be far less than the global natural decline rate of existing fields, where the rate of oil production falls at a rate normally in the region 4-7% globally.

Therefore, new oil supply will be needed to satisfy demand in any scenario which doesn't envision something dire happening to the global economy; the question is how much. In the NPS, over 80% of new potential oil supply volumes are within the budget. In the B2DS, less than half.

As noted above, even low demand scenarios will require very significant capital investment in oil projects, $2tr in the B2DS and $2.6tr in the SDS. This includes a large amount of investment in new projects, $0.9tr in the B2DS and $1.2tr in the SDS.

Figure 4: Potential oil capex, 2018-2025



Source: Rystad Energy, IEA, Carbon Tracker analysis

As existing projects are more likely to fit within the budget for each scenario, the incremental capex between scenarios – or the investment outside the lower demand scenario budgets, and at risk of overinvestment – is dominated by new projects. Accordingly, the proportion of capex in each scenario accounted for by new projects (43% in the B2DS and 48% in the SDS) increases with higher overall production levels.

Amplified capex

Production at the higher end of the cost curve tends to have more future capex associated with it than at the lower end. This is due to both the type of project that is likely to be at this end (capital intensive projects tend to have higher overall costs), and the fact that these are disproportionately likely to be future project options rather than those that are already producing and with the bulk of their capex in the rear-view mirror.

Accordingly there is something of a multiplier effect, where the proportion of potential capex associated with higher cost projects is greater than their share of production.

Hence, the 11% of potential production volume that is goes ahead in the NPS but not the SDS translates into 22% of potential capex dollars. The 22% of total potential supply that doesn't go ahead in the B2DS translates into 39% of potential capex.

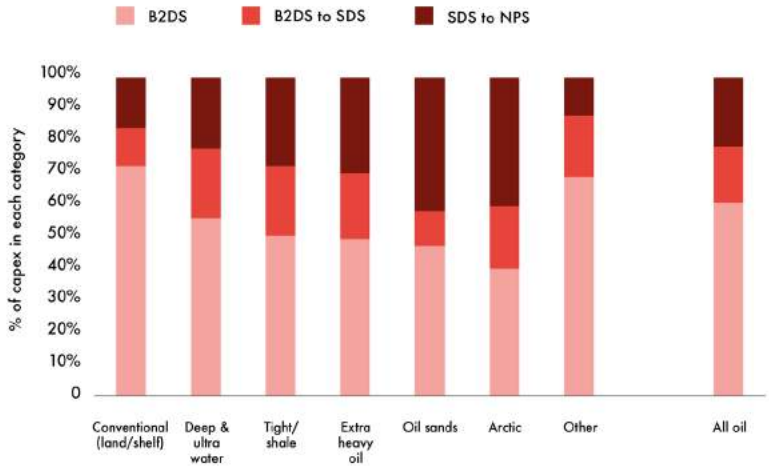
For new projects the effect is even more pronounced – the 25% of new supply that doesn't go ahead in the SDS accounts

for 31% of potential capex on new projects. The 45% of new supply that doesn't go ahead in the B2DS is associated with 52% of potential capex on new projects.

Results by resource theme

As we have highlighted in recent reports[8], the range of different costs and capital intensities between the different types of oil development can mean that particular sectors are more or less exposed than others.

Figure 5: Potential oil capex by resource theme, 2018-2025



Source: Rystad Energy, IEA, Carbon Tracker analysis

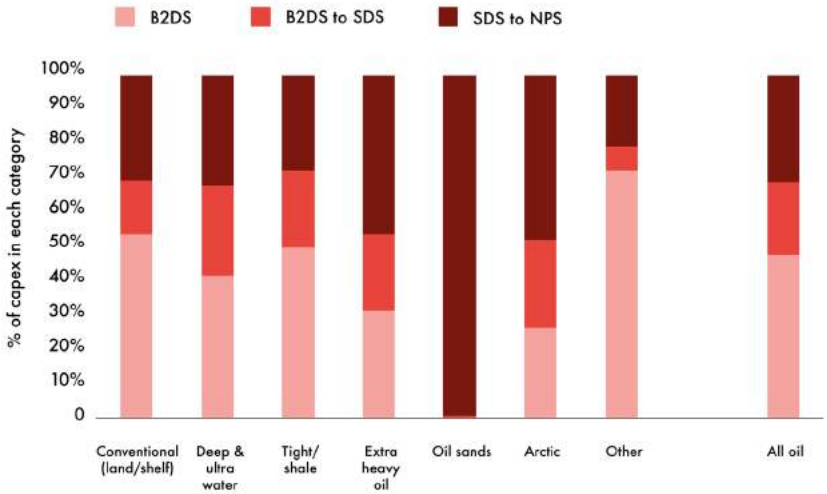
Oil sands and Arctic developments tend to be higher cost than e.g. conventional projects either onshore or in shallow water, and hence are disproportionately less likely to fit into each budget.

These types of development make up a small proportion of future capital expenditure at the industry level. Oil sands and Arctic projects make up $80bn and $47bn respectively of potential capex in the NPS, compared to over $1.5tn for conventional onshore and continental shelf. Hence they pose limited risk to the industry as a whole, but operators that specialise in such themes may represent a concentration of low-demand risk to investors.

8 *See for example "The $2tr Stranded Assets Danger Zone", published November 2015*

This is amplified again when looking at just new projects. Since the oil price collapse that began in mid-2014, a lot of high-cost options have come off the table. Total potential capex for new oil sands projects is $32bn in our data, with $17bn going ahead in the NPS. However, on a relative basis, the higher risk in weak demand scenarios is clear – before 2025, no new oil sands investments at all fit within the B2DS and only a nominal amount (c.$150m) in the SDS. In this context, "new" oil sands includes expansion/debottlenecking of existing projects – there is no spend on greenfield oil sands in the SDS either.

Figure 6: Potential oil capex by resource theme – new projects only, 2018-2025



Source: Rystad Energy, IEA, Carbon Tracker analysis

Country-level analysis

Low cost prducers outperform

The variation in upstream costs internationally means that there is significant variation between countries when it comes to their production resilience to lower demand scenarios. Our recent report "2 Degrees of Separation"[9] showed Saudi Aramco as having materially all its future investment options fitting within a budget consistent with 2°C of global warming. Unsurprisingly, the same applies here at the country level, with Saudi Arabia and other low-cost Middle East producers (Iran, Iraq and Kuwait) having substantially all their capex within not only the SDS, but also the B2DS.

However, note that here we look at only financial resilience and breakeven costs at the upstream level. Large oil exporting countries typically require a certain oil price to balance their governments' budgets – the "fiscal breakeven". We do not attempt to predict oil prices, but suggest that all other things being equal, lower demand is likely to equal lower oil prices on average. Hence while low-cost producers may be able to profitably maintain production from their oil fields even in the low demand scenarios that lead to a relatively good climate outcome,

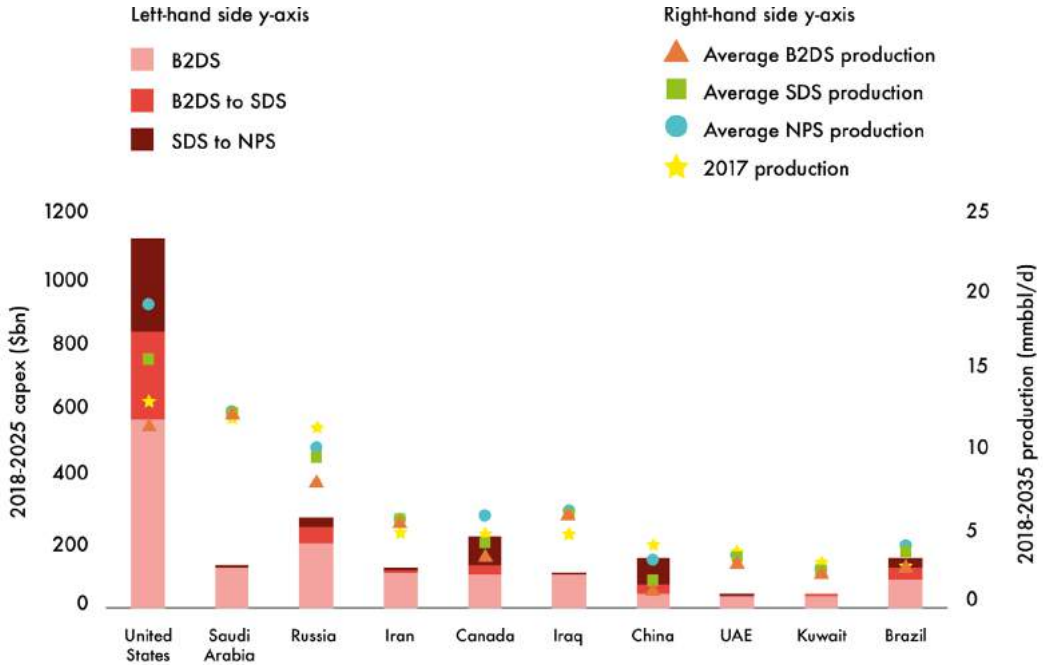
9 See 2degreeseparation.com

that is not to say that those that are more reliant on oil revenues might not have uncomfortable decisions to make.

The below chart shows the breakdown of oil capex by budget for the 10 largest countries producing oil in 2017 (including crude, natural gas liquids and condensate).

In terms of the range of outcomes across the scenarios, the US, Russia, Canada and China see the largest variation in levels of production and capex to 2035.

Figure 7: Potential 2018-2025 oil capex, potential 2018-2035 oil production by country (2017 largest oil producers)



Source: Rystad Energy, IEA, Carbon Tracker analysis

Capex intensity

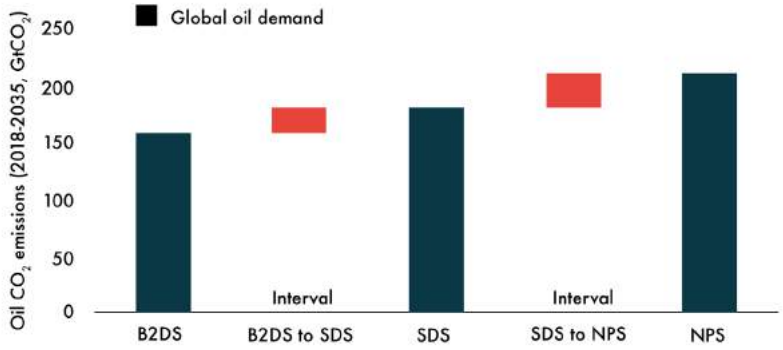
Also noticeable from the chart is the higher capex intensity of some producers than others – the US has much greater level of forward looking potential capex than Russia and Saudi Arabia which are comparable in terms of 2017 production levels; similarly Canada, China and Brazil compared to the other Middle Eastern producers.

While this measure of financial risk holds true in all scenarios, this huge amount of investment can deliver very significant production growth in the US, in the NPS at least. The OPEC members on this list are assumed to maintain production at similar levels to today's in all scenarios, reflecting their commitments to production constraint. Whether this discipline would hold in a scenario of declining demand, and thus an increasingly limited future for the products on which they are largely reliant, is another question.

Carbon budgets for oil

In CO_2 emissions terms, the carbon budgets associated with oil implied for the IEA B2DS, SDS and NPS scenarios are 157 $GtCO_2$, 178 $GtCO_2$ and 207 $GtCO_2$ respectively.

Figure 8: Carbon budgets for oil in the three IEA scenarios, 2018-2035



Source: Rystad Energy, IEA, Carbon Tracker analysis

We would emphasise that these budgets are not an input into our supply/demand analysis, but rather an output that is used for presentation of the results which allows the different fossil fuels to be shown in common units. The basis of the analysis remains the demand numbers provided by the IEA for the various scenarios, typically in energy equivalent units.

3. Natural gas

Image source: Peretz Partensky, USA, via Wiki Commons

Key takeaways:

- **Achieving 1.75°C rather than 2°C puts an additional incremental $130bn capex outside the budget and at risk of overinvestment.**
- **There is less variation in demand between scenarios for gas than other fossil fuels, but each will require very significant investment.** Capital expenditure in the period 2018-2025 amounts to $1.2tr in the B2DS, $1.3tr in the SDS and $1.4tr in the NPS.
- **Gas is proportionately more reliant on new investment than the other fuels, but not all project options go ahead.** Capital investment in new gas projects amounts to $0.8tr in the B2DS and $0.9tr in the SDS (2018-2025). While there is less of a gap to NPS investment than in other fuels (19% of NPS investment doesn't fit in B2DS, and 7% in the SDS), there is a substantial overhang of project options available beyond NPS demand that should not be ignored.
- **LNG demand is covered until the late 2020s by liquefaction capacity that is already producing or under development.** However, some further new capacity may enter the market in this period and attempt to outcompete existing producers.

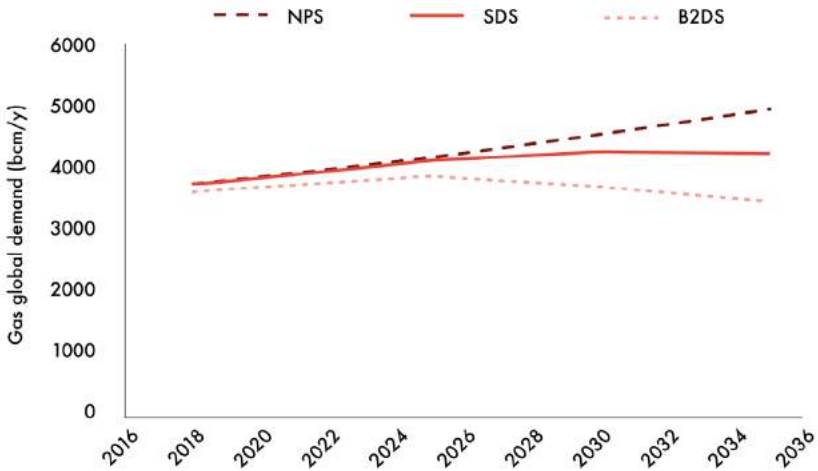
Natural gas demand

Global demand

Natural gas has frequently been called a "bridge" fuel, although time is running out to utilise this bridge. This phrase suggests that, to the extent gas replaces the more carbon-intensive coal in power generation, this can help put economies on the path to decarbonisation as an interim measure while renewables continue to scale up. However, the benefits of this approach are not unqualified. Whilst lower carbon than coal in the combustion phase, there are question marks around "fugitive emissions" or leaks of methane, itself a very strong greenhouse gas. Furthermore, given that gas is still a relatively carbon-intensive source of power compared to others such as nuclear and renewables, there are strict limits to the amount of gas that can be combusted while staying on course for a particular climate outcome. For example, in the SDS, the CO_2 emissions intensity of electricity generation falls to less than 45 gCO_2/kWh in Europe[10] and around 60 gCO_2/kWh in China[11] by 2040, compared to the average emissions intensity today of gas-fired power plants of 440 gCO_2/kWh today[12] and around 350 gCO_2/kWh for a new combined cycle gas turbine plant[13]. In the B2DS, it drops to minus 13 gCO_2/kWh globally by 2060[14], i.e. net negative emissions.

This is illustrated by the progressively lower demand pathways for gas with increasing climate ambition under the three benchmark scenarios in this study, shown in the below chart for the period 2018-2035.

Figure 9: Global gas demand under the three benchmark scenarios, 2018-2035



Source: IEA, Carbon Tracker analysis

10 IEA, World Energy Outlook 2017, p454
11 EA, World Energy Outlook 2017, p622
12 IEA, World Energy Outlook 2017, p264
13 IEA, World Energy Outlook 2017, p444
14 IEA, Energy Technology Perspectives 2017, p173

In the NPS, gas use grows continuously over the period 2018-2035 at an average CAGR of 1.6%. In the SDS gas grows modestly before peaking in 2030 for a CAGR of 0.7%, the only one of the fossil fuels where demand grows in absolute terms in this scenario. In the B2DS, the peak is brought forward to 2025 followed by a steady decline, meaning that overall gas demand is lower at the end of the period than the start, with an end-to-end CAGR of -0.3%.

Regional markets

In contrast to oil, which we have treated as a single global market, gas is broken down into three main markets. These attempt to reflect the reality that gas transport is less flexible and more regional due to infrastructure constraints (although the growing importance of LNG trade means that markets are increasingly connected to a degree and certainly in price terms).

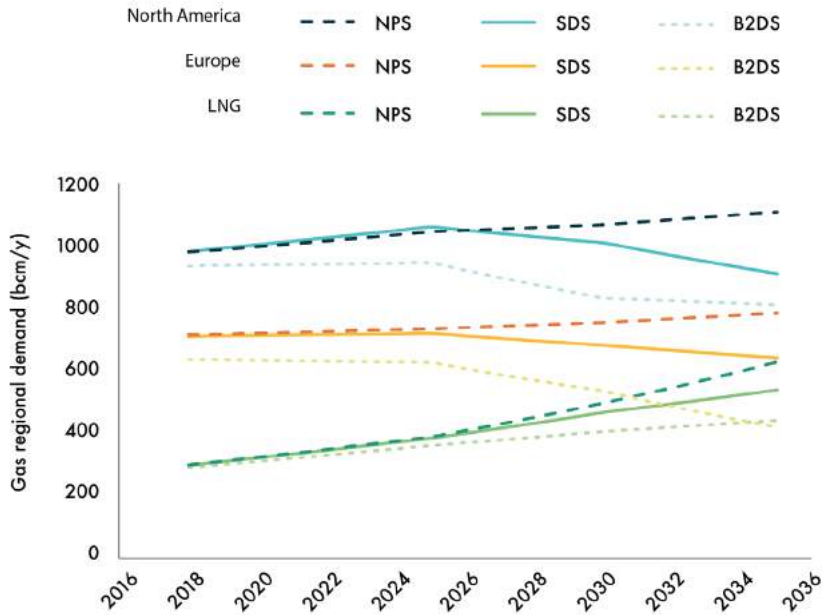
Accordingly, this report examines three key regional demand markets for gas, which account for just under half of demand over the period 2018-2035 under each of the three scenarios:

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

Much of global gas outside the three focus markets is to a greater or lesser extent captive within local markets, and therefore cannot be truly represented in cost curves. Comparing the three scenario demand levels to remaining identified supply in Rystad's database, however, suggests that (purely on an aggregate basis) all of the expected supply of the "other gas" outside the key markets will go ahead, with increasingly significant shortfalls in the higher demand scenarios. Accordingly, for the sake of simplicity we have assumed that 100% will be required for the purpose of this exercise. That is not to say that gas supply in these "other" regions doesn't warrant more detailed attention, and there will no doubt be regional deficits or surpluses that aren't addressed here.

The demand scenarios for the 3 main markets are shown below.

Figure 10: Gas demand in key markets under the three benchmark scenarios, 2018-2035[15]



Source: IEA, Carbon Tracker analysis

Note that the North America and Europe demand numbers in the above chart are for total regional demand; in other words, they include LNG imports as well as piped gas, and hence LNG would be double counted in these markets if the three components of the graph were summed to calculate a total demand level. Accordingly, LNG imports to each market have been estimated and netted out using Rystad's UCube database for the purposes of calculating demand for piped gas alone to these markets. Furthermore, new US LNG liquefaction facilities, which generally buy gas from the hubs, act as an incremental source of demand for North American gas in the NPS.

15 The three scenarios appear to have different starting points for demand in 2018 – this is a function of the different start dates for the ETP and WEO data (2014 and 2016 respectively), after which respective points the demand pathways immediately begin on different trajectories. As it is the cumulative amount of emissions which ultimately determines the degree of global warming and hence the demand levels modelled here, we have not sought to change the data points for 2015-17 in line with the actual emissions that have transpired. However, we would note that to the extent that emissions in these years were higher than factored into the scenarios, this excess will need to be made up with lower emissions later in the period, and thus our interpretation of the B2DS in particular arguably allows slightly greater future emissions than should be the case. Furthermore, for the same reason (and given that 2018 demand is yet to transpire) we have not attempted to give the scenarios the same 2018 baseline.

High-level findings

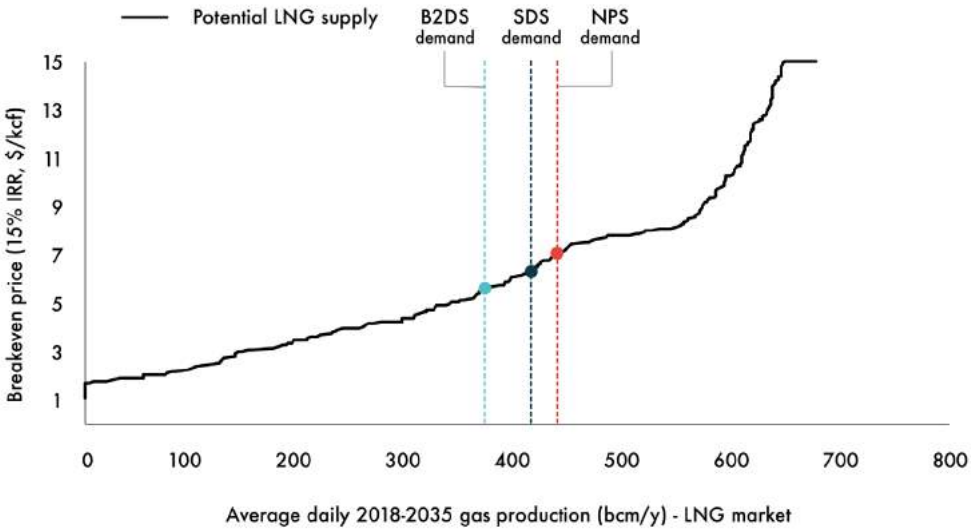
The gas supply cost curves

Variation between markets

The 3 cost curves for gas supply in the focus markets, with the 3 demand scenarios overlaid, are shown below. A small volume of potential supply is calculated as having a breakeven price above $15/kcf; given the uncertainty inherent in estimating the economics of particular projects, these have been capped at $15/kcf.

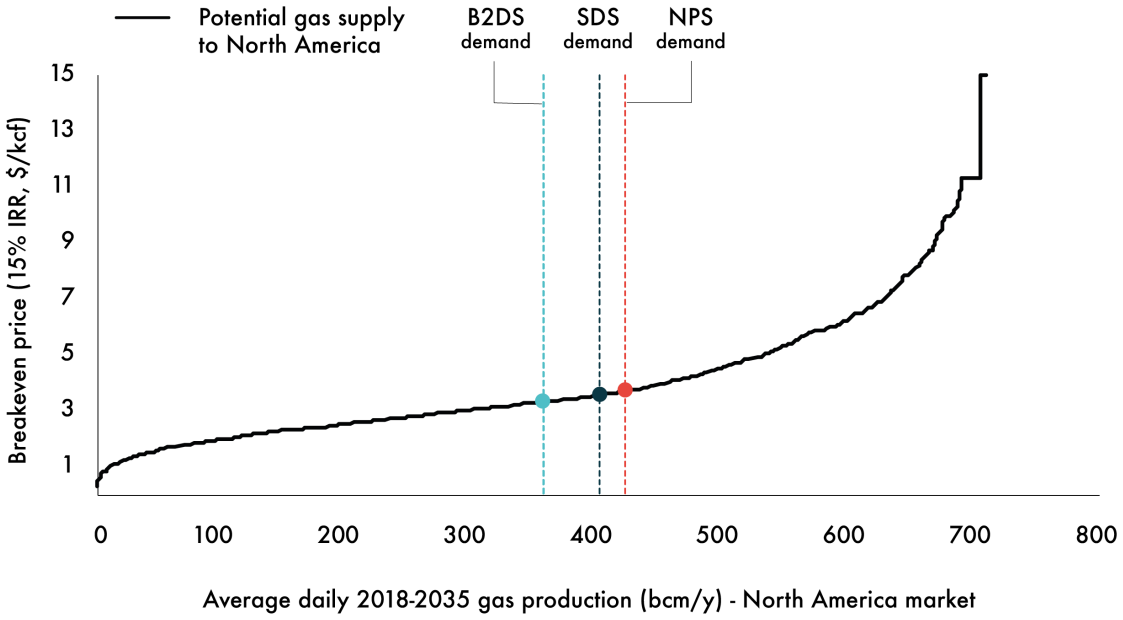
LNG and North American markets can be seen to be well supplied by the options available under each of the scenarios, with a large overhang of potential supply even in the NPS. The European market is much tighter in the SDS and NPS (with supply only just covering demand in the latter), although again well supplied in the B2DS.

Figure 11: Cost curve of global LNG supply 2018-2035



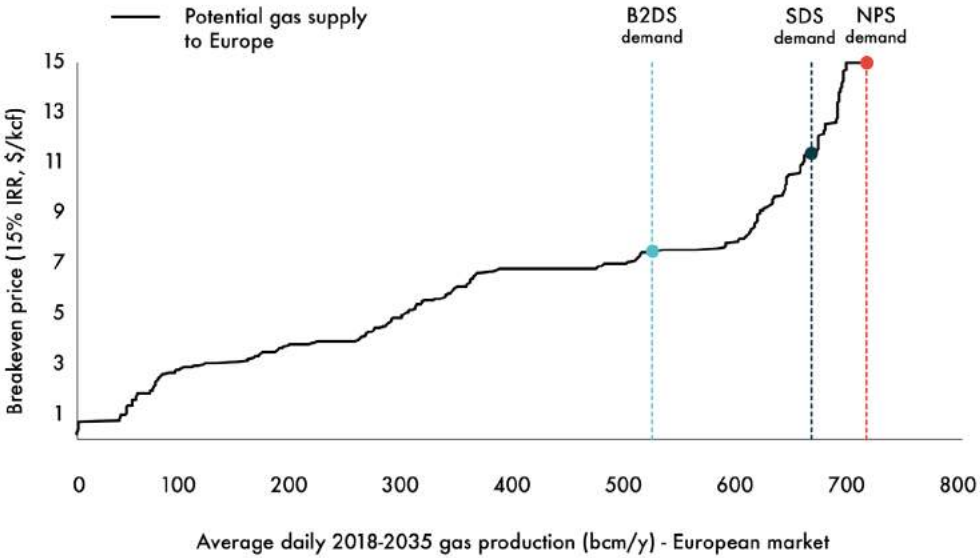
Source: Rystad Energy, IEA, Carbon Tracker analysis

Figure 12: Cost curve of gas supply to North American market, 2018-2035



Source: Rystad Energy, IEA, Carbon Tracker analysis

Figure 13: Cost curve of gas supply to European market, 2018-2035



Source: Rystad Energy, IEA, Carbon Tracker analysis

The table on the side illustrates the sensitivity of demand in the three focus markets – Europe is assumed to have proportionately much lower demand in the B2DS compared to the NPS than the other two.

Table 2: Gas production in the B2DS and SDS relative to NPS, focus markets

2018-2035 production	B2DS	SDS	NPS
LNG	-15%	-6%	0%
North America	-16%	-5%	0%
Europe	-27%	-7%	0%

Source: IEA, Carbon Tracker analysis

Production in and outside each budget

NPS demand shown as upper limit

As noted above, in this study we focus on the increments of supply/capex between the B2DS and SDS and an upper limit of the NPS.

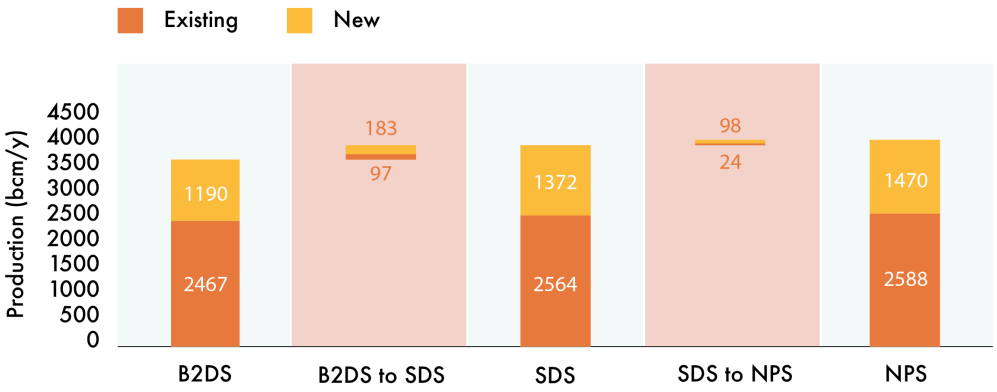
While this approach is more conservative than including supply beyond this level, for gas in particular it raises possibility of understating the risks. There are material amounts of capex in excess of the NPS that are excluded here but which are realistic project options, for example some new LNG liquefaction capacity. As much of this is above even NPS demand it does not factor into the capex here – however, the developers still intend to press ahead.

Relatively low variation between scenarios

The average levels of gas demand over the period 2018-2035 in the B2DS, SDS and NPS scenarios are 3.7, 3.9 and 4.1 tcm/y respectively. These averages are all higher than the current demand of ~3.6 tcm/y - even the B2DS where gas falls below this level by 2035, due to the rise and fall in gas demand in the interim.

The below chart shows the incremental jumps in production between each scenario. These can be thought of as the amount of production that would be out of the budget in each scenario compared to another one. Despite the variation in shape of the three gas demand pathways above, they are much more similar in aggregate demand than those for oil or thermal coal.

Figure 14: Potential gas production, 2018-2035



Source: Rystad Energy, IEA, Carbon Tracker analysis

For oil, NPS demand is 22% lower than B2DS – for gas the difference is only 14%. The increments between the different scenarios are therefore much smaller. As there is insufficient potential supply on the database to cover demand in "other" markets, the NPS level of potential supply is lower than demand, and hence the gap is even lower in our modelling. Just 10% of NPS gas production would be outside the B2DS budget, and only 3% outside the SDS budget.

Table 3: Gas production and capex in the B2DS and SDS relative to NPS

	B2DS	SDS	NPS
2018-2035 production	-10%	-3%	0%
2018-2025 capex	-16%	-7%	0%

Source: Rystad Energy, IEA, Carbon Tracker analysis

Existing outcompetes new

As with oil above, the breakeven prices used here are calculated on future cashflows, hence existing projects tend to be favoured compared to future projects when competing for demand. Accordingly, existing (post-FID) projects disproportionately fit within even the more ambitious budgets. Around 95% of production from existing sources fits within in the B2DS.

Despite this, there remains a need for new gas investment even in the B2DS scenario. While gas fields tend to have lower production decline rates than oil fields on average, this is coupled with a slower demand decline rate in each of the scenarios (and periods of growth in the NPS and SDS), meaning that new production is incentivised to fill the gap. 67% of the B2DS budget is composed of existing production (77% in the case of oil), and 64% in the NPS. However, we would note the long lifetimes of gas infrastructure, which may extend well beyond the demand peaks in the SDS and B2DS.

19% of new production is surplus to requirements in the B2DS, and 7% in the SDS. This compares to 45% and 25% respectively for oil.

Capex in and outside each budget

Significant investment continues to be required

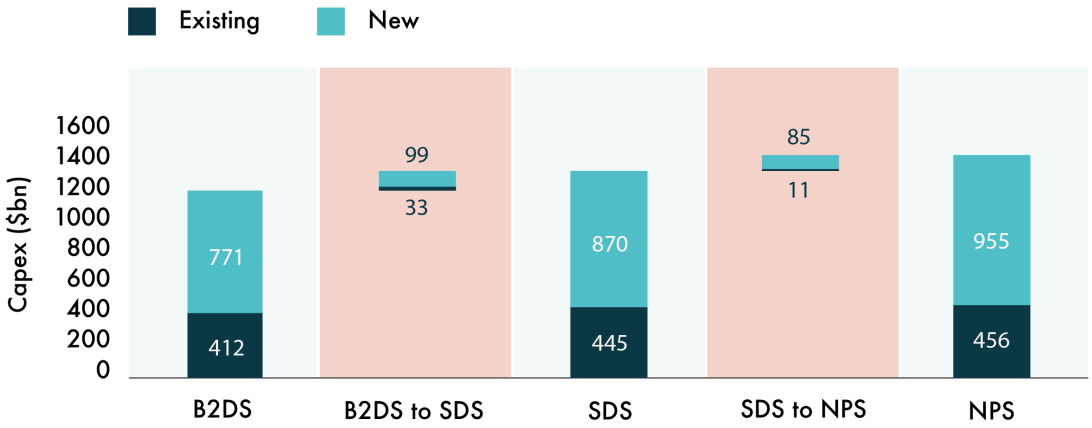
As noted above, even low demand scenarios will require very significant capital investment in gas projects - $1.2tr in the B2DS and $1.3tr in the SDS. This includes a large amount of investment in new projects, $0.8tr in the B2DS and $0.9tr in the SDS.

Figure 15: Potential gas capex, 2018-2025

Satisfying demand for gas is significantly more reliant on new investment than the other fuels – new projects account for a majority of capex in all scenarios, 65% in the B2DS and 66% in the SDS.

The 10% of potential production volume that goes ahead in the NPS but not the B2DS translates into 16% of potential capex dollars. The 3% of total potential supply that doesn't go ahead in the SDS translates into 7% of potential capex.

For new projects, the 19% and 7% of gas production outside the budget in the B2DS and SDS respectively are associated with 19% and 9% of potential capex.



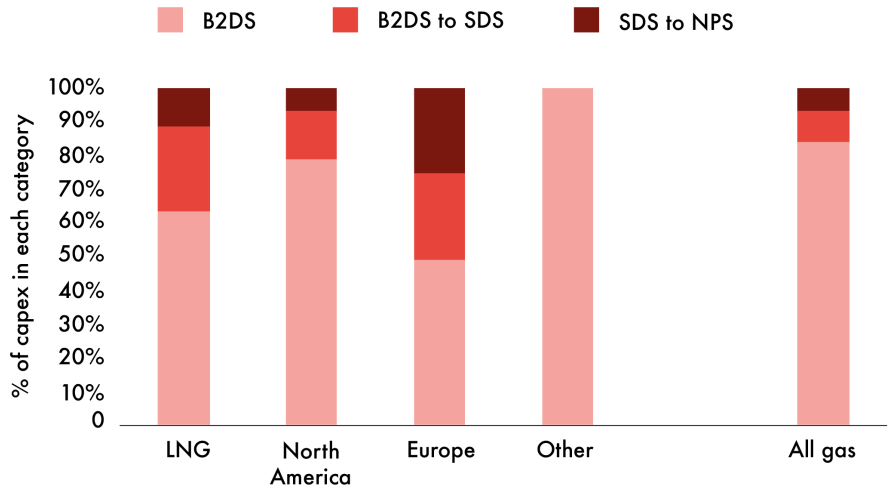
Source: Rystad Energy, IEA, Carbon Tracker analysis

Results by market

The wider differentiation in aggregate demand between the scenarios in Europe rather than the other two main markets is reflected in a greater proportion of potential capex in the increments between them.

Here we can see the influence of excluding projects that don't fit within the NPS budget from the analysis. LNG and North America come across as lower risk than Europe here – however, referring to the full cost curves above, we can see the huge overhang of potential project options above this level in these markets, with associated potential capex.

Figure 16: Potential gas capex by market, 2018-2025



However, we do view the risk in these two markets differently. US/Canadian onshore gas production, produced well-by-well, is more flexible than capital-intensive LNG projects which may take years to pay back. If demand and pricing declines, producers can stop drilling and see production fall off rapidly, albeit with a certain degree of financial pain. Conversely, LNG projects do not tend to attract financing, and hence get built, without a majority of capacity being contracted in advance – the risk to these investors is therefore mainly through the price of their products, rather than the volumes they sell (at least in the early portion of their operation). US LNG, sold on a "Henry Hub plus" basis rather than the traditional linkage to crude oil prices, is different again and flows will be determined based on the differential between US and international gas spot prices.

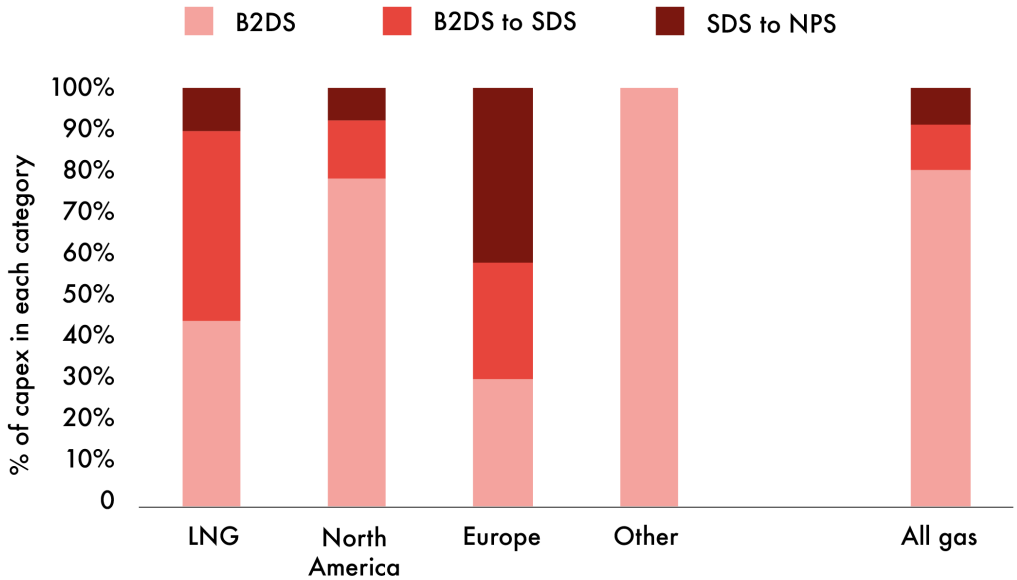
While the overall gas market features less variation in demand between NPS and the lower demand scenarios, for new projects there remain substantial pockets of financial risk. For example, in LNG 55% of NPS investment is outside the B2DS budget, and 70% for Europe.

Source: Rystad Energy, IEA, Carbon Tracker analysis

Our methodology for oil & gas allows new supply to enter the market and attempt to outcompete existing demand for limited supply. However, this raises the risk of continuing oversupply in LNG markets beyond expectations (although we note recent strength in LNG demand growth).

Although our methodology allows some new LNG capex within the budget based on lower modelled supply costs than some existing, production from liquefaction capacity that is already producing or under development is sufficient to cover demand until the mid-late 2020s in all scenarios.

Figure 17: Potential gas capex by market – new projects only, 2018-2025



Source: Rystad Energy, IEA, Carbon Tracker analysis

Country-level analysis

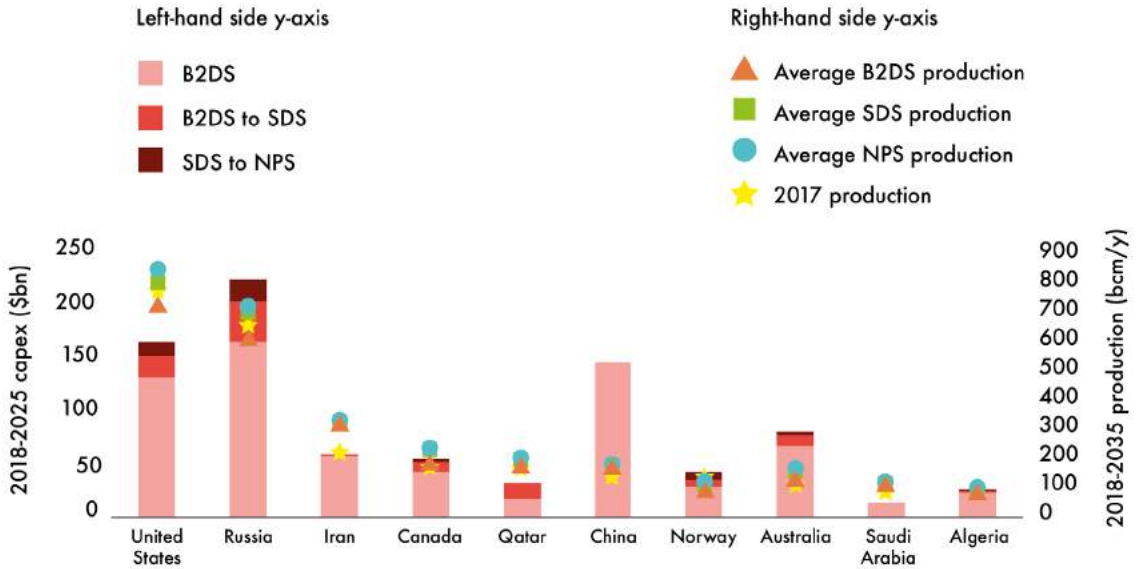
Low cost producers outperform

The below chart shows the breakdown of gas capex by budget for the 10 largest producers of gas in 2017.

Given that all "other" gas is assumed to go ahead in every scenario as above, the incremental details between the three scenarios are limited to North America, projects supplying Europe, and LNG projects around the world.

Again, the similarity in average demand levels between the three scenarios is clear, with the production levels in each scenario being similar for each country.

Figure 18: Potential gas capex by country (2017 largest gas producers), 2018-2025



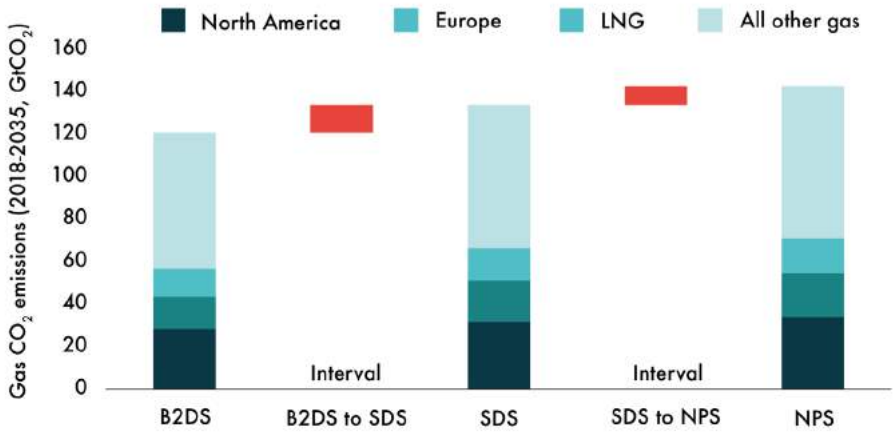
Source: Rystad Energy, IEA, Carbon Tracker analysis

Carbon budgets for gas

In CO_2 emissions terms, the carbon budgets associated with gas implied for the IEA B2DS, SDS and NPS scenarios are 119 $GtCO_2$, 132 $GtCO_2$ and 141 $GtCO_2$ respectively.

We would emphasise that these budgets are not an input into our supply/demand analysis, but rather than output that is used for presentation of the results which allows the different fossil fuels to be shown in common units. The basis of the analysis remains the demand numbers provided by the IEA for the various scenarios, typically in energy equivalent units.

Figure 19: Carbon budgets for gas in the three IEA scenarios, 2018-2035



Source: IEA, Carbon Tracker analysis

4. Thermal coal

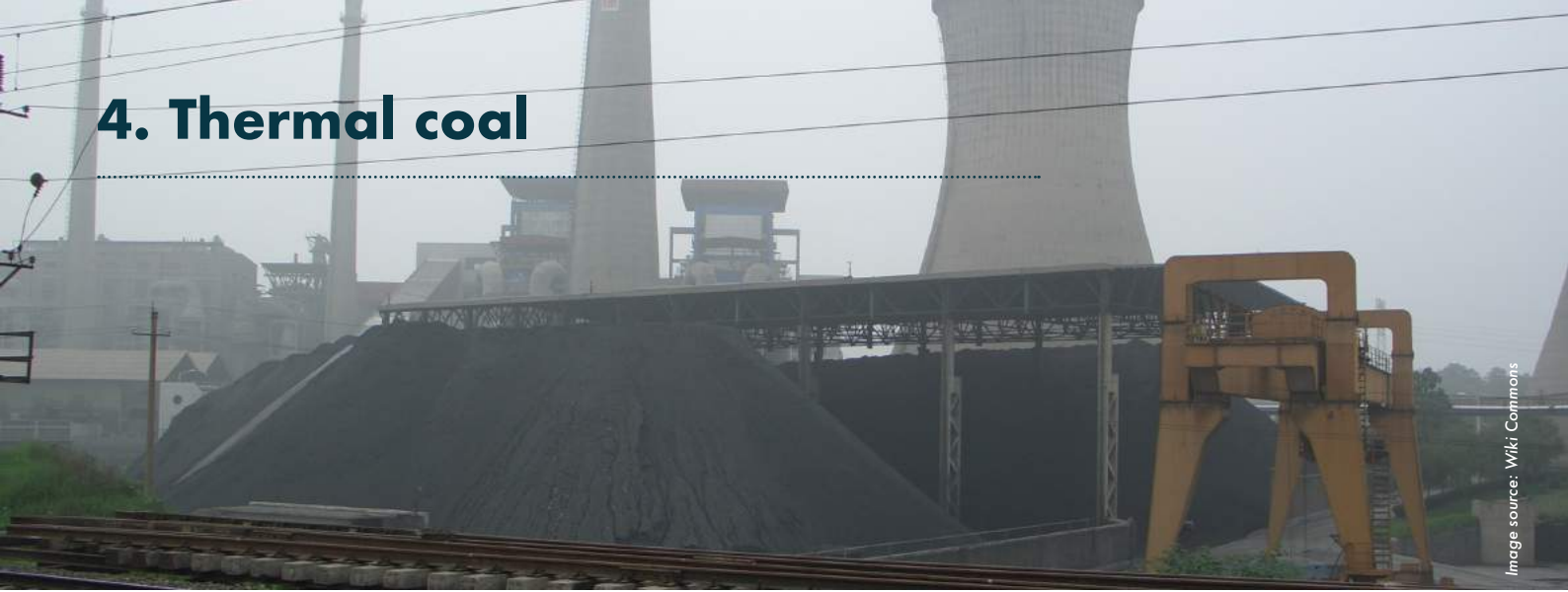


Image source: Wiki Commons

Key takeaways:

- **The B2DS sees an additional incremental $12bn capex outside the budget and at risk of overinvestment compared to the SDS.**
- **In the SDS and B2DS, thermal coal use declines at CAGRs of -3.3% and -5.2% respectively.** This is reflective of thermal coal's status as most carbon-intensive fossil fuel, and significant demand risks primarily related to substitution by other energy sources.
- **Coal carries the greatest danger to the climate, but absolute capex dollars are low compared to oil and gas.** $63bn and $75bn of capex is invested in thermal coal projects in the B2DS and SDS respectively in the period 2018-2025.
- **No new thermal coal mines go ahead in the US or China, or to supply the international seaborne export market, in either the SDS or B2DS.** This is consistent with prior findings, despite a diminished outlook for potential production.
- **$2.6bn (57%) of potential investment in new domestic Indian coal capacity could be required in the B2DS over the period 2018-2025, and $4.6bn (all available projects) in the SDS.** However, assumptions of future Indian thermal coal imports carry considerable uncertainty, and could dry up entirely within the next decade under the B2DS and SDS.

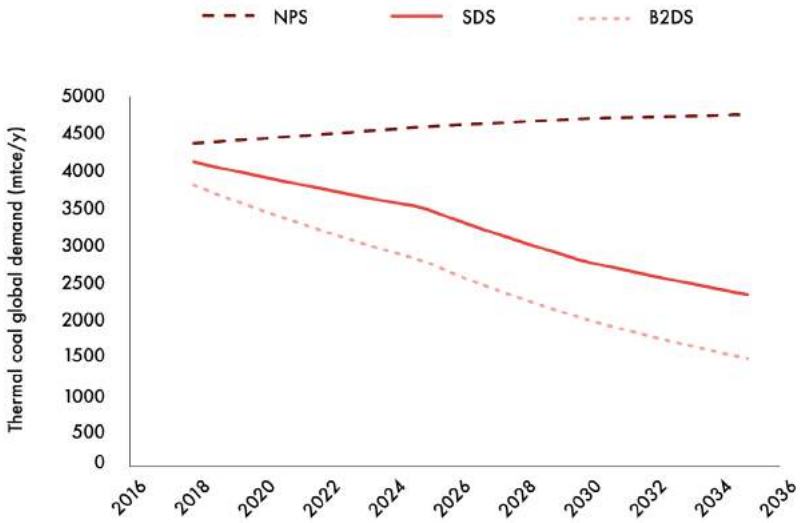
Thermal coal demand

Global demand

Thermal coal is generally accepted to be the most carbon-intensive fuel on average, which is reflected in the stark difference between the demand pathways for the different scenarios.

Whereas the NPS shows thermal coal use growing through the period (at an average CAGR of 0.5%), the climate-constrained scenarios require an immediate and sharp fall in coal use. In the 2°C SDS and 1.75°C B2DS, thermal coal use declines at CAGRs of -3.3% and -5.5% respectively.

Figure 20: Global thermal coal demand under the three benchmark scenarios, 2018-2035[16]



Note: thermal coal includes lignite
Source: IEA, Carbon Tracker analysis

16 *The three scenarios appear to have different starting points for demand in 2018 – this is a function of the different start dates for the ETP and WEO data (2014 and 2016 respectively), after which respective points the demand pathways immediately begin on different trajectories. As it is the cumulative amount of emissions which ultimately determines the degree of global warming and hence the demand levels modelled here, we have not sought to change the data points for 2015-17 in line with the actual emissions that have transpired. However, we would note that to the extent that emissions in these years were higher than factored into the scenarios, this excess will need to be made up with lower emissions later in the period, and thus our interpretation of the B2DS in particular arguably allows slightly greater future emissions than should be the case. Furthermore, for the same reason (and given that 2018 demand is yet to transpire) we have not*

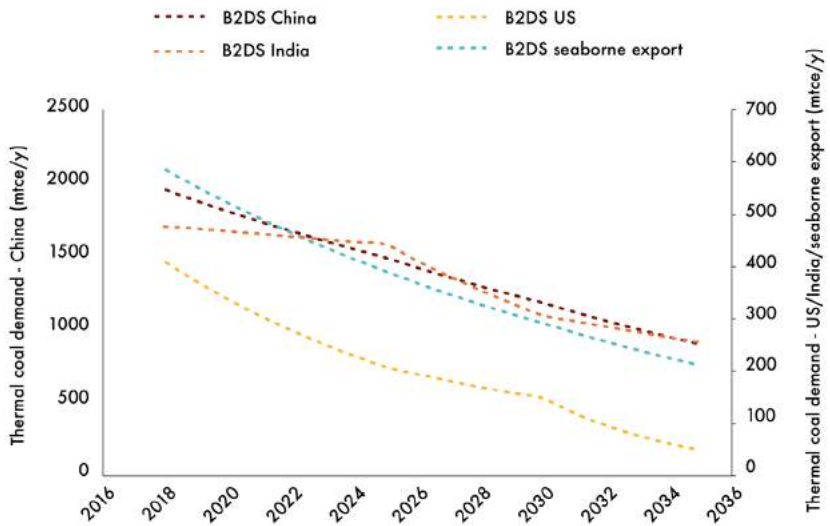
Regional markets

Like gas, thermal coal is a more regionally traded commodity than oil. Accordingly, this report takes a regional approach when looking at thermal coal cost curves. Further, our supply database does not contain all global supply (see methodology in appendix below), hence this paper does not cover the entirety of global coal mining.

We therefore focus on 4 major markets, which account for over 80% of global production at present[17]:

- **Global seaborne export** – coal traded internationally by sea;
- **US domestic** – coal produced in the US for domestic consumption;
- **China domestic** – coal produced in China for domestic consumption;
- **India domestic** – coal produced in India for domestic consumption;

The demand scenarios for the 4 main markets are shown in the Figures 21A, 21B, 21C.



Source: IEA, Carbon Tracker analysis

Figure 21: Thermal coal demand in key markets under the three benchmark scenarios, 2018-2035

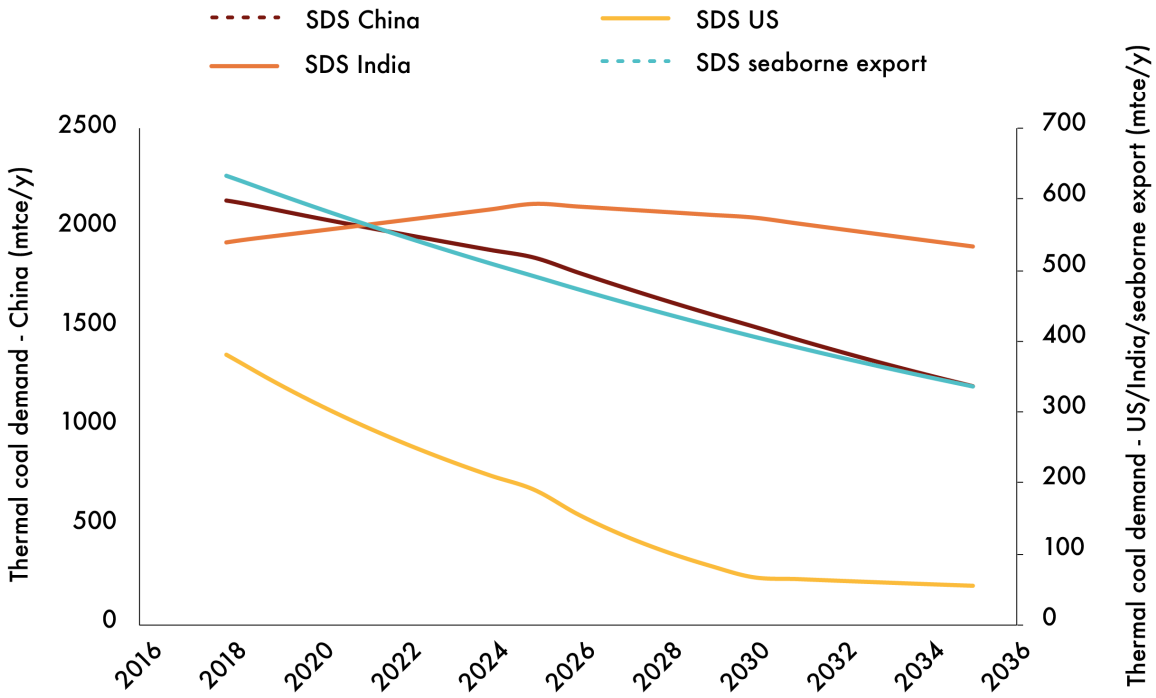
Figure 21A: B2DS

17 *IEA, Medium Term Coal Report 2016*

attempted to give the scenarios the same 2018 baseline.

Figure 21: Thermal coal demand in key markets under the three benchmark scenarios, 2018-2035

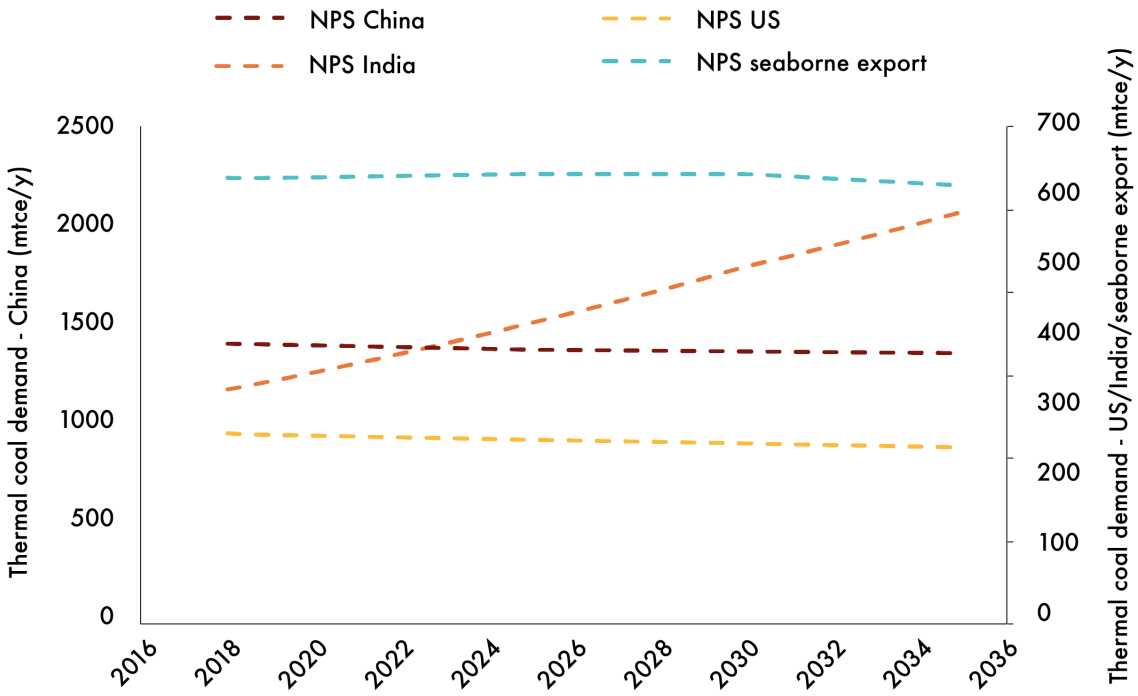
Figure 21B: SDS



Source: IEA, Carbon Tracker analysis

Figure 21: Thermal coal demand in key markets under the three benchmark scenarios, 2018-2035

Figure 21C: NPS



Source: IEA, Carbon Tracker analysis

High-level findings

The thermal coal supply cost curves

Existing production covers B2DS and SDS demand in US, China, and seaborne export markets

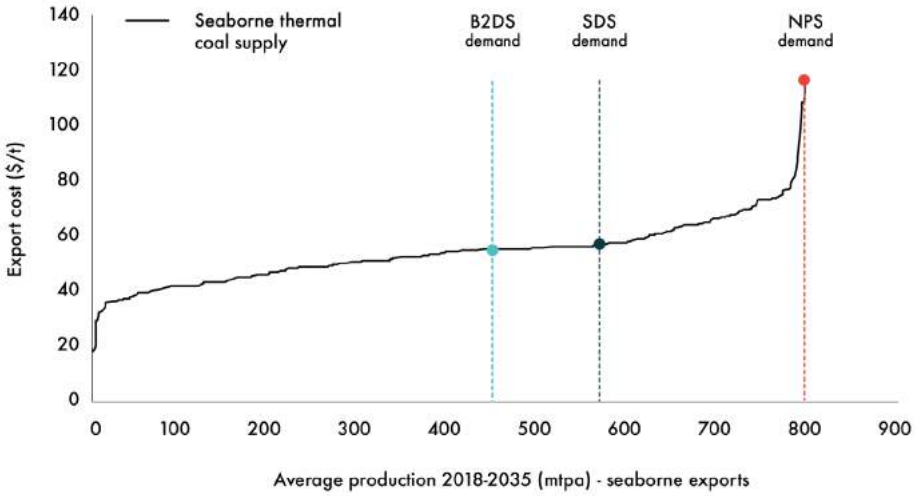
The four cost curves for thermal coal supply in the focus markets, with the 3 demand scenarios overlaid, are shown below[18].

For the seaborne export, US domestic and China domestic markets, the SDS and B2DS levels of demand are comfortably covered by supply from existing mines. Given this large overhang and increasing difficulties in financing new mines, we assume priority for existing mines when it comes to satisfying demand. In other words, new mines will only be required to the extent that demand exceeds supply from existing mines. For these markets therefore, the curves shown are for existing mines only and exclude new supply options. For the Indian market, demand is sufficient to encourage new domestic supply in all three scenarios; the curve for India therefore includes both existing and new supply. Note that the Indian curve is for domestic production only; imports into India will be included in the seaborne export curve (and accordingly satisfied by existing export mines in the SDS and B2DS).

Seaborne exports

The potential supply extent of existing mines supplying the seaborne market can be seen to match NPS demand almost exactly. This does not necessarily mean that the NPS is a

Figure 22: Cost curve of global seaborne export thermal coal supply – existing mines only, 2018-2035



Source: Wood Mackenzie, IEA, Carbon Tracker analysis

18 *Thermal coal supply has been sourced from Wood Mackenzie's Coal GEM database – see Appendix*

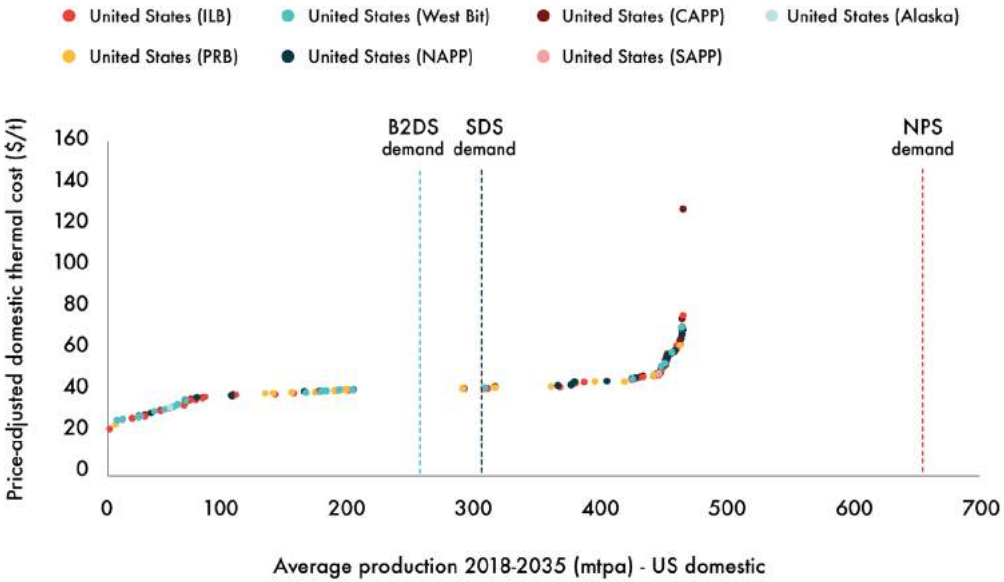
perfect proxy for industry expectations – were potential new mines to be included on this chart, it would allow a further 200 mtpa average supply over 2018-2035. Given the high thermal coal prices that would be required to deliver NPS supply (and bearing in mind the imperfect nature of breakeven calculations), we would anticipate that some new projects may go ahead in this scenario.

However, given the focus of this paper on carbon-constrained scenarios, we note both the B2DS and SDS scenarios are well supplied by existing mines. The geographic breakdown of the seaborne supply is discussed later in the paper.

US domestic – downgraded production estimates

A peculiarity of US thermal coal demand in the scenarios examined here is that the 1.75°C B2DS actually calls for slightly more coal than the 2°C SDS. We note that these scenarios are produced using different IEA models with differing assumptions/parameters. The difference here is primarily due to (a) a greater

Figure 23: Cost curve of US domestic thermal coal production – existing mines only, 2018-2035



Source: Wood Mackenzie, IEA, Carbonz Tracker analysis

emphasis on air pollution concerns in the SDS, which further increases the relative attractiveness of other energy sources over coal; and (b) a greater assumed subsequent deployment of carbon capture and storage (CCS) in the B2DS. Emissions in the power sector are net negative in the B2DS by 2055 due to the use of negative emissions technology at great scale (Bio-energy with CCS, or BECCS), used to offset emissions from other sectors that are more difficult to decarbonise. The SDS assumes a lower degree of negative emissions than the B2DS, requiring the earlier removal of coal from the energy mix.

The middle of the US domestic cost curve is dominated by the Powder River Basin's North Antelope Rochelle, the world's largest coal mine, which is the marginal mine for the SDS curve. The slightly smaller Black Thunder is a little further up the curve, with B2DS demand falling between the two.

NPS demand is not covered by supply from operating mines modelled at Wood Mackenzie's forecast demand levels. Furthermore, even the inclusion of all projects, including those that are highly speculative, from Wood Mackenzie will still not meet NPS demand levels. This is largely due to the difference in demand forecasts.

NPS demand would require the US to continue producing coal at close to 2017 levels throughout the period whereas Wood Mackenzie expects greater renewable penetration, gas displacement, and an eventual carbon tax to erode domestic coal demand. The difference in these demand forecasts has led Wood Mackenzie to remove some 150 mtpa of highly speculative projects from their dataset since our last review of the thermal coal industry in 2015. An additional 70 mtpa of supply at remaining mines and projects has been removed over the forecast period due to the lower demand assumptions. In aggregate, this c.220 mtpa represents a decline in potential supply of 25% from our 2015 analysis.

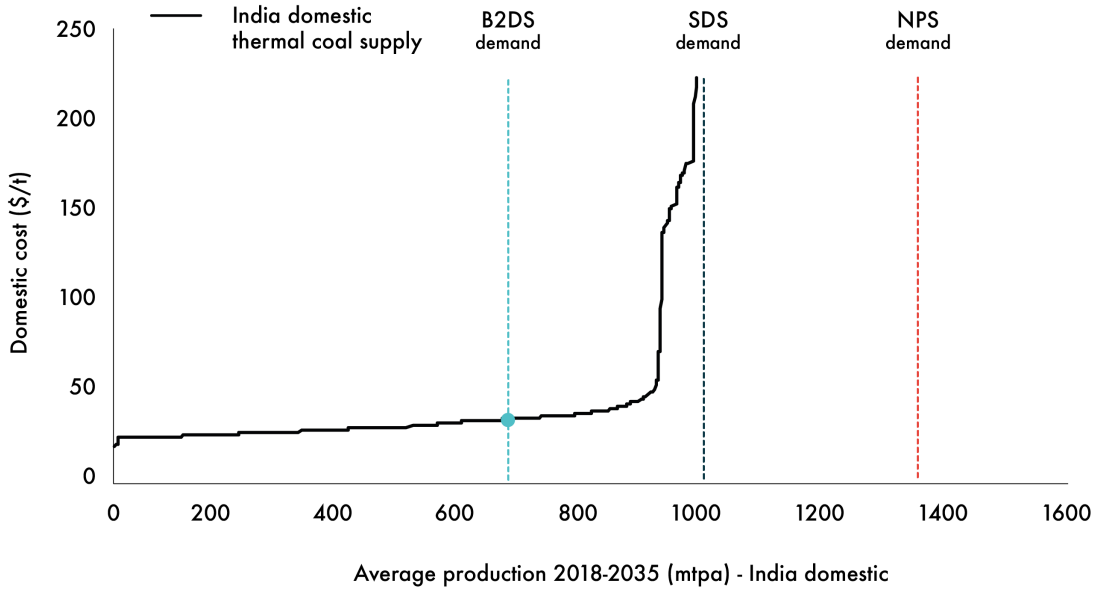
However, this does not mean the US is lacking in coal reserves and resources. If an NPS level of demand were to materialise, existing mines would be able to increase supply and many projects which have been shelved would return to the forefront for development.

India domestic

India's coal demand increases throughout the period in the NPS, and to a peak in 2025 in the SDS (the B2DS requires that demand begin to fall immediately). It is the only supply market covered here in which there is some initial coal demand growth in the SDS, although the demand level ultimately falls over the period considered here. As one of the world's largest importers of thermal coal, the Indian government has announced plans to increase domestic production to meet demand growth and reduce its reliance on imports to the extent that they all but cease by the end of the decade[19]. India therefore is the only one of the focus markets which requires new domestic thermal coal supply in all three scenarios, partly due to the policy ambition to eliminate coal imports.

19 *See IEEFA, India's Electricity Sector Transformation, November 2017* http://ieefa.org/wp-content/uploads/2017/11/India-Electricity-Sector-Transformation_Nov-2017-3.pdf

Figure 24: Cost curve of India domestic thermal coal production – existing and new mines, 2018-2035



Source: Wood Mackenzie, IEA, Carbon Tracker analysis

The above cost curve, for aggregate production and demand over the 2018-2035 period, suggests that domestic production can cover all requirements in the B2DS and virtually all in the SDS. However, this does not tell the whole story due to the time dimension of the supply and demand trajectories, which is not reflected in aggregate calculations.

For example, India is currently reliant on imports of thermal coal. Although production is assumed to increase and demand begins to decline immediately in the B2DS, it still takes some time to close this gap. Therefore imports will still occur initially in the B2DS, despite the aggregate calculation showing that domestic production covers demand once domestic production is ramped up in output later on in the review period.

In the NPS ceiling, thermal coal imports increase throughout the period, albeit gradually. We note that implied NPS demand levels for India (and hence imports) are higher than the IEA's forecasts in its 2017 Medium Term Coal Report, up to 2022 at least. The Indian government's ambitions make future coal demand difficult to forecast. In the WEO, the IEA acknowledges that "the projection of rising steam coal imports from the late 2020s is subject to considerable policy uncertainty". It notes that tax reforms may improve the competitiveness of domestic coal, and the possibility of strengthened support for renewables and/or gas "also raises questions about India's future coal demand and, in turn, its import requirements". "A reversal in the projected trend of rising imports is possible if circumstances change: this would have significant repercussions for coal exporters around the world"[20].

Our research suggests that India would technically be able to cease imports of thermal coal in the early 2020s in the B2DS and the late 2020s in the SDS[21]. That said, we reiterate a lack of precision in the nearer term use of the scenario demand numbers (and for the B2DS in particular), being based on simple interpolations between the data points provided by the IEA. Although for the sake of this research we assume that the reductions in Indian imports are captured in lower demand in the seaborne market, we have not modelled trade flows globally, and Indian demand for imports represents a significant source of downside risk to potential exporters banking on the higher levels of demand that are projected in the NPS.

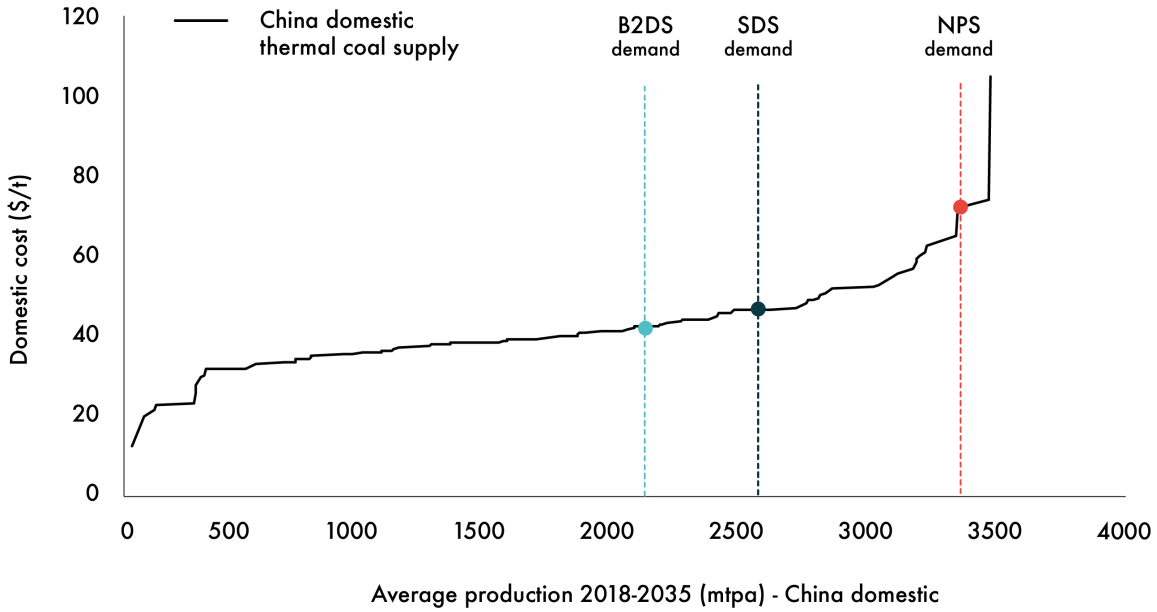
Indian demand for imports is captured in the seaborne export cost curve, and hence covered by existing mines in the SDS and B2DS. Adani's proposed Carmichael mine in Australia's Galilee basin has been pitched with the intent of feeding Indian demand; even in the NPS and allowing new mines to enter and compete with existing capacity, it is a long way behind other would-be suppliers on cost and doesn't make it to market.

China domestic

Like the seaborne market, production from existing mining areas can be seen to be sufficient to cover demand even in the NPS in the below curve. This is influenced by the aggregate nature of the calculation (see India domestic above for further discussion) - China has been a net importer since 2009. Potential production from operating mines falls throughout the period in Wood Mackenzie's data, but to a lesser degree than Chinese demand for thermal coal falls in the NPS, meaning that excess production from later in the period outweighs some nearer term imports.

20 *IEA, World Energy Outlook 2017, p221*
21 *Some imports may continue to be economic after this point; we have not attempted to balance global trade on a cost basis.*

Figure 25: Cost curve of China domestic thermal coal production – existing mines only, 2018-2035



Source: Wood Mackenzie, IEA, Carbon Tracker analysis

It has even been suggested by IEEFA that China may return to being an opportunistic net exporter of thermal coal[22].

22 *See for example IEEFA, Data Bite: January Decline in China's Coal Imports Adds to 30 Percent Slide in 2015, February 2016 Available at http://ieefa.org/data-bite-january-decline-in-chinas-coal-imports-adds-30-percent-slide-in-2015/*

Production in and outside each budget

High sensitivity to climate outcomes

The average levels of thermal coal demand over the period 2018-2035 in the B2DS, SDS and NPS scenarios are c.3,600 mtpa, c.4,400 mtpa and c.5,800 mtpa respectively. This compares to 2017 production in these markets of c.5,000 mtpa, illustrating market growth in the NPS but sharpening contraction in the two climate-constrained scenarios.

The chart on the side shows the incremental jumps in production between each scenario. These can be thought of as the amount of production that would be out of the budget in each scenario compared to another one. As noted above, the only new sources of production that go ahead in the B2DS and SDS are in India, with some new US mines going ahead in the NPS. Thus new mines outside India account for just 1% of total NPS production in the focus markets.

The demand intervals between scenarios are proportionately much greater for coal than oil or gas. Production for the markets covered in this study is 38% lower in the B2DS than the NPS, compared to 22% for oil and 10% for gas. At the global level (including demand outside the focus markets) demand in the B2DS is 45% lower than in the NPS. This reflects both coal's status as the most carbon-intensive fossil fuel, and hence its removal from the energy system being the most effective way to lower emissions, and the greater perceived ease of substitution by other energy sources.

Figure 26: Potential thermal coal production (focus markets only), 2018-2035

Source: Wood Mackenzie, IEA, Carbon Tracker analysis

Table 4: Thermal coal production and capex in the B2DS and SDS relative to NPS (focus markets only)

	B2DS	SDS	NPS
2018-2035 production	-38%	-23%	0%
2018-2025 capex	-50%	-40%	0%

Source: Wood Mackenzie, IEA, CTI analysis

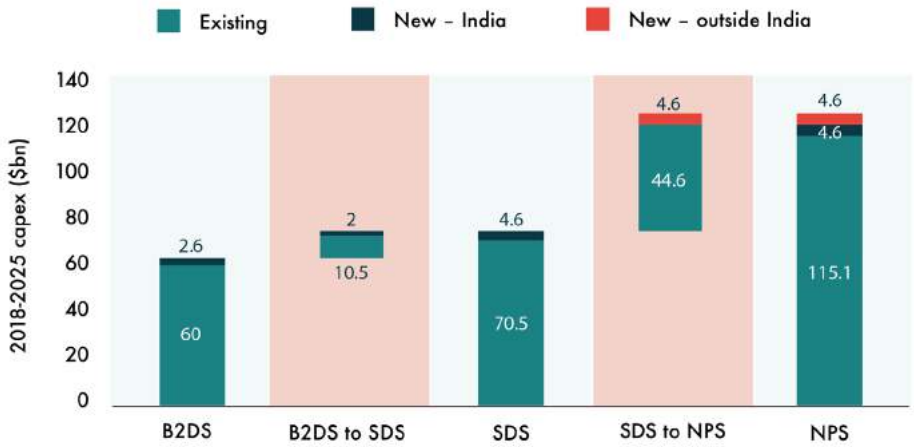
Capex in and outside each budget

Capex relatively low compared to oil & gas

The sums of capex involved in the covered thermal coal markets are a small fraction of those in oil and gas. Capex requirements in the B2DS and SDS are $63bn and $75bn respectively; global gas capex in the B2DS is over a trillion dollars, and global oil capex is over two trillion dollars. Hence while coal carries the greatest risk to the climate of the three fossil fuels, and is the most heavily impacted in demand in scenarios that result in a relatively benign global warming outcome, it doesn't necessarily carry the greatest risk to investors (in absolute terms at least).

As noted above, differences between Wood Mackenzie's demand outlook (which the database of supply is aligned with) and the IEA's NPS means that there is the appearance of a shortfall in supply in the US in the NPS. While in reality, US domestic supply of thermal coal could rise and satisfy demand even if it did reach the levels indicated in the NPS, Wood Mackenzie's lower expectations mean that this additional production potential is not included in the database as it is assumed to be excess to demand. The NPS capex number (and hence the interval from SDS to NPS) therefore underestimates the quantum of capex that would actually go ahead in that scenario, and would be apparent if more possible projects were included on the database.

Figure 27: Waterfall chart for potential thermal coal capex (focus markets only), 2018-2025



Source: Wood Mackenzie, IEA, Carbon Tracker analysis

The only new projects that go ahead in the B2DS and SDS are Indian mines feeding the domestic market, and helping displace imports. They incur $2.6bn of capex over the period 2018-2025 in the B2DS (57% of potential capex on new projects), and $4.6bn (all of the available project options) in the SDS. There is no increase in capex on Indian projects between SDS and NPS due to the entirety of Indian supply options entering production under the SDS.

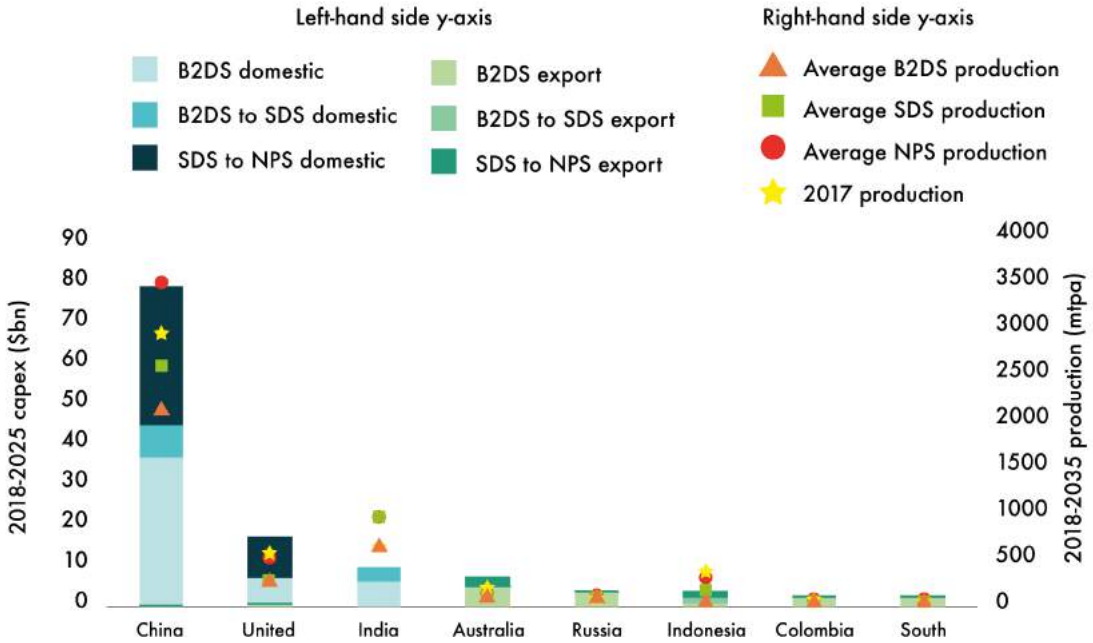
Country-level outcomes

China dominates

The chart on the side shows the breakdown of thermal coal capex by budget for the main countries covered in this study. China is by far the most important country in the thermal coal industry, accounting for just under half of global production (and demand) at present, so it is not surprising to see that it has far greater potential capex than any other country going forward.

While the numbers for China, India and the US incorporate both domestic and any export-oriented capex. Seaborne exports are shown country by country for the main exporters; for these countries, figures relate to seaborne exports only and exclude domestic production.

Figure 28: Potential 2018-2025 thermal coal capex, potential 2018-2035 thermal coal production by country

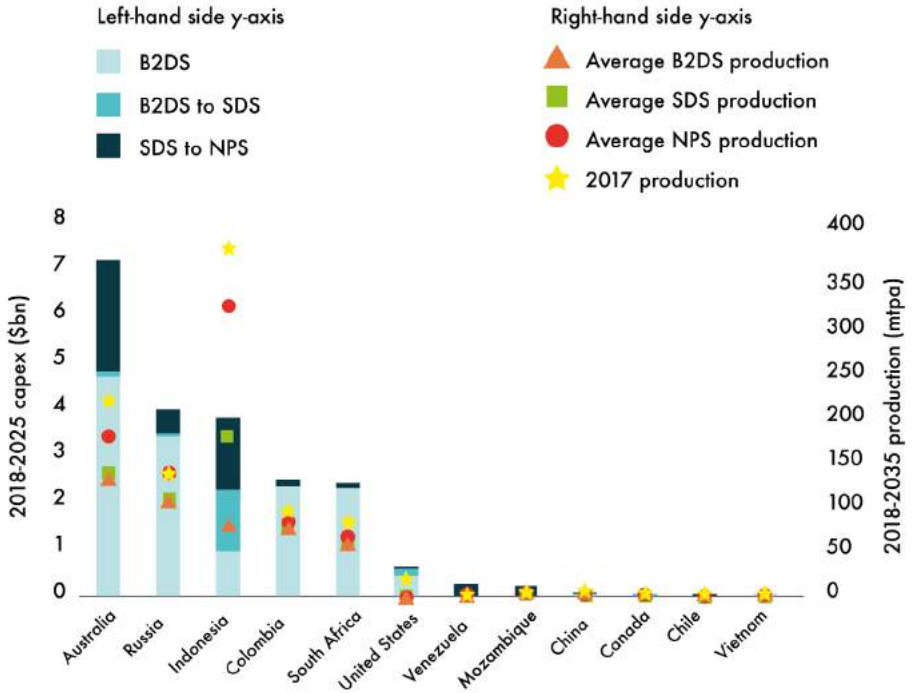


Note: China, US and India include domestic production, other countries refer to export thermal coal production only. Venezuela, Mozambique, Canada, Chile, Vietnam are excluded from the above chart due to small scale
Export refers to seaborne only; landborne exports are excluded
Source: Wood Mackenzie, IEA, Carbon Tracker analysis

Focusing on the seaborne export market (see chart below), most of the variation between the two scenarios occurs in Australia and Indonesia, the latter in particular proving to be particularly levered to coal demand in production terms.

Indonesia, currently the world's largest exporter of thermal coal, produces the highest volume of export coal in the SDS and NPS, but falls below Australia in the B2DS. Other countries, such as Colombia and South Africa, are relatively demand-insensitive in terms of the mines which reach the market, with substantially the same levels of production and capex in all three scenarios.

Figure 29: Potential 2018-2025 thermal coal capex, potential 2018-2035 thermal coal production by country – seaborne export market only



Source: Wood Mackenzie, IEA, Carbon Tracker analysis

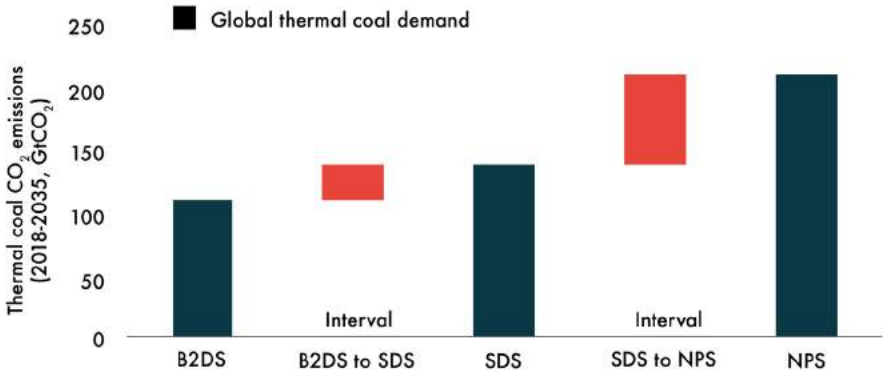
As noted, no new projects go ahead in the seaborne export market in any of the scenarios. New projects are therefore not shown in the above chart, which is limited to NPS demand levels. Of the potential projects that aren't needed even in the NPS, 65% of capex is in Australia, with Colombia and Indonesia accounting for 14% and 10%.

Carbon budgets for thermal coal

In CO_2 emissions terms, the approximate carbon budgets associated with thermal coal are shown in the below chart. As the IEA does not provide a split in CO_2 emissions between thermal and metallurgical coal, these have been estimated and should be considered illustrative only.

We would emphasise that these budgets are not an input into our supply/demand analysis, but rather than output that is used for presentation of the results which allows the different fossil fuels to be shown in common units. The basis of the analysis remains the demand numbers provided by the IEA for the various scenarios, typically in energy equivalent units.

Figure 30: Carbon budgets for thermal coal in the three IEA scenarios, 2018-2035



Source: IEA, Carbon Tracker analysis

5. Appendix: Methodology

Summary of methodology

Methodology used is similar to that used in Carbon Tracker's Carbon Supply Cost Curve papers, in particular the June 2017 "2 Degrees of Separation" report. It is based on the comparison of carbon-constrained demand scenarios (or "budgets") to cost curves of potential supply.

Demand/budgets: We firstly derive demand pathways for the chosen fossil fuel from those provided by the International Energy Agency for the various scenarios that they produce. The aggregate level of demand for each fuel can be thought of as its total "budget" over a given timeframe – here 2018-2035. A carbon budget is the total amount of carbon which can be emitted during that period and to deliver a given climate outcome.

Potential supply cost curves: We then overlay our cost curves of potential supply (based on underlying data sourced from industry databases), to ascertain which potential fossil fuel project options, and their associated investments or capex, would fall outside of the maximum allowed budget. This determination is based on the core assumption that markets are rational, and that the highest cost (or lowest returning) projects would be outcompeted by lower cost supply sources under the demand-constrained scenario we have outlined. Accordingly we have identified which upstream projects appear to be outside the budget in a given demand scenario. Our ranking of projects is based on the breakeven oil/gas/coal price required to meet a 15% IRR hurdle rate.

Key points of the methodology used are summarised in the below tables.

General:

Demand scenarios	*SDS, NPS – IEA World Energy Outlook (published November 2017)* *B2DS – IEA Energy Technology Perspectives (published June 2017)*
Timeframe	*Supply and demand have been compared over the period 2018-2035*
Capex figures	*Presented in real US dollars, over the time frame 2018-2025*
CO_2 budgets	*CO_2 budgets are based on life cycle emission estimates which take into account other factors beyond combustion.* *As these factors are based on the total emissions arising in the scenarios, they therefore incorporate the differing assumptions used in each scenario. For example, the scenarios assume differing degrees of carbon capture and storage (CCS) deployment. Should CCS not live up to these assumptions, then the volume of fossil fuel demand which results in the same level of emissions, and hence global warming outcome, will be lower.* *The emissions examined in this report and previous Carbon Tracker reports relate to CO_2 only, with no additional analysis of the impact of "fugitive" methane emissions or other associated products.*

Oil & gas:

Potential supply	*All oil supply data has been sourced from Rystad Energy UCube, as at September 2017. Potential supply is estimated using Rystad Energy's base case, including uncommercial assets. Fossil fuel supply figures should therefore be thought of as being conceptually closer in scale to contemplated or possible production and capex rather than relative to full supply potential. However, this does not mean that all the projects in this study are planned or even under consideration at this point. Potential supply includes production and capex estimates for discoveries and as yet undiscovered (yet to find) resources.*
Breakeven prices	*Calculated as the Brent-equivalent oil price that gives an NPV of a project's future cash flows of 0 using a 15% discount rate/IRR. The NPV calculation includes exploration costs, development investment, maintenance investments, production costs and the impact of fiscal regime. It can be thought of as the price required to deliver a minimum return including a contingency accounting for possible delays/cost overruns.*
Life-cycle stage	*Assets categorised as at the discovery and undiscovered stages have been aggregated as "new", and those at the producing and under development stages have been aggregated as "existing".*

Thermal coal:

Potential supply	*All coal supply data has been sourced from Wood Mackenzie's Coal Global Economic Model (GEM), as at Q3 2017. Unlike the database we use for oil & gas, GEM's coverage of coal is not global but covers a selection of major producing nations only.* *For India, domestic coal production was provided to us separately by Wood Mackenzie, including estimates of capex.*
Domestic/export	*Mines have been assumed to sell coal into either domestic or export markets (or both) as stipulated by GEM. Chinese coastal volumes have been included in the China domestic market. While India exports c.1-2mt annually to Bangladesh, we have assumed that all coal is domestic for simplicity.*
Focus markets	*As the global coal market is more segmented than that for oil, we have focused on particular markets. In this study we look at (1) the seaborne export market; (2) Chinese domestic production; (3) US domestic production; and (4) India domestic production. Supply outside these segments has not been included in this exercise.*
Thermal coal demand	*Although the IEA provides overall coal demand figures, including at the regional level, it does not always provide the split in demand between thermal and metallurgical coal. Where the IEA has not provided this data, as a proxy we have estimated demand for the different coal types using the available information including approximations where necessary.* *In this paper we focus on thermal coal only.*
Breakeven prices	*Calculated as the coal price that gives an NPV of a project's future cash flows of 0 using a 15% discount rate/IRR. It can be thought of as the price required to deliver a minimum return including a contingency accounting for possible delays/cost overruns.* *In the case of projects that supply both domestic and export markets, for domestic production, breakeven prices have been used unless export production accounts for greater than 10% of production, when cash costs plus average capex has been used as a proxy.* *For mines that produce both metallurgical and thermal coal, breakeven prices have been calculated fixing the ratio of metallurgical coal to 1.7x the thermal coal price.* *In India, cash costs plus average capex has been used as a proxy for breakeven prices.*

Price adjustments	*Prices in different markets have been variously adjusted to provide a comparable basis for showing different coals on the same cost curves.* *For domestic coal production, breakeven prices have been adjusted by energy content to a standard reference energy content of 6,000 kcal/kg net as received (NAR), using the following energy contents outside India (NAR, kcal/kg):* **Coal type** / **Export** / **Domestic** **Anthracite** / 6,690 / 6,690 **Bituminous** / 6,000 / 6,000 **High ash bituminous** / 5,390 / - **Sub-bituminous** / 4,780 / 4,780 **Lignite** / 2,630 / 2,510 *For export coal production, breakeven prices have been adjusted to a 6,000 kcal/kg price benchmark (this energy level is consistent with bituminous coals exported from the Australian port of Newcastle). This approach therefore theoretically takes into account transport differentials as well as coal quality differences.* *Similarly, in US domestic markets, breakeven prices have been standardised to a 11,500 Btu/lb Illinois Basin price benchmark.*
Life-cycle stage	*Coal projects that have production in 2018 have been categorised as "existing", those that enter production after this date have been categorised as "new".* *Due to the overhangs in supply from existing coal in the China domestic, US domestic and seaborne export markets, we have assumed that existing supply is prioritised over new. We further note increasing difficulty in financing new coal projects. In India, where new mines are required, we have assumed competition on costs as normal.*
Coal volumes	*Coal demand volumes are provided in million tonnes of coal equivalent (mtce), standardised to an energy content of 7,000 kcal/kg. Supply numbers are given in million tonnes of coal (mt).*
Thermal coal CO_2 budgets	*The emissions associated with thermal coal have been estimated as those that give emissions levels consistent with those in each IEA scenario when applied to the demand numbers for that scenario used in our report, whilst being consistent with the internal relativities of metallurgical and thermal coal carbon factors from the Intergovernmental Panel on Climate Change.* [23]

23 See IEA, "CO_2 emissions from fuel combustion: Documentation for beyond 2020 files," 2014 Edition, and Intergovernmental Panel on Climate Change (IPCC), "2006 IPCC Guidelines for National Greenhouse Gas Inventories."

Supply databases

Oil & gas data source: Rystad UCube

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

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

Thermal coal data source: Wood Mackenzie Ltd. Global Economic Model

All data for supply cost curves and capital expenditure for thermal coal is mine-based and comes from the Wood Mackenzie Ltd. Global Economic Model (GEM) as of Q3 2017. The exception to this is India, which was provided to us separately by Wood Mackenzie.
Wood Mackenzie Ltd. Global Economic Model is a coal data and discounted cash flow modeling package designed to facilitate coal asset "market valuations, M&A transactions, benchmarking, strategic planning and fiscal analysis.[24]"
GEM contains 15 countries with cost data, so does not cover total world supply/demand. Those countries included are: Australia, New Zealand, Colombia, Venezuela, Chile, Canada, China, Mongolia, Indonesia, Vietnam, Botswana, Mozambique, South Africa, Russia, and the US.

24 *Wood Mackenzie Ltd.: Global Economic Model - Coal (brochure)*

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