Managing Peak Oil

Why rising oil prices could create a stranded asset trap as the energy transition accelerates

Analyst Note

January 2022

About Carbon Tracker

The Carbon Tracker Initiative is a team of financial specialists making climate risk real in today's capital 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.

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With thanks to Paul Spedding.

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1 Key Findings

- **Oil demand and pricing are currently rebounding, triggering calls for significantly increased investment into new oil** – a narrative at odds with the immediate global production reductions required within most "well below 2°C" scenarios.
- **Short-term demand growth would see even greater reductions required subsequently to keep the goals of the Paris Agreement alive.** Policy action is likely to strengthen post-COP26, while the rapid adoption of EVs will potentially further weaken demand.
- **Companies basing sanctioning decisions on bullish short-term signals thus risk significant over-investment**, seriously impacting shareholder value. It wouldn't be the first time that the industry has fallen into this trap.
- **This analysis therefore explores the financial implications of such a non-linear scenario, where oil demand grows in the short-term before falling rapidly.** We use the *Inevitable Policy Response* **Forecast Policies Scenario** (FPS, 1.8°C) where oil demand peaks in the mid-2020s.
- **Under a 'high-investment case', companies could waste some $530bn of capex this decade** as demand starts to decline and the oil price falls back to c.$40. This amount would double at $30/bbl.
- **As an alternative, we explore a 'managed' case where companies sanction more conservatively for long-cycle projects, only up to $30/bbl breakeven**. The managed case then assumes companies sanction more liberally for short-cycle projects (which ramp up production quickly), up to $50/bbl breakeven, to meet elevated short-term demand.
- **The key is to avoid locking in high-cost, long-cycle projects.** Our managed case significantly cuts oversupply over the long term and eliminates wasted capex at a $50/bbl long-run oil price. The managed case wastes less capital than the high investment case irrespective of oil price.
- **Managing oil prices in the next few years would be a challenge under a scenario such as the FPS**, even allowing for increased shale production. There is, however, enough oil to meet the short term bump.
- **OPEC needs to deploy its spare capacity much more aggressively to avoid even higher prices than today – up to an extra 2mbd in the managed case**. This is what can stop the oil price spiking beyond $80; without this, higher prices could last for several years. We believe this is in the group's long-term interests.
- **For investors who subscribe to an FPS-like pathway, it's imperative to challenge management on higher cost projects, particularly those with sanction some years hence**.

2 Executive Summary

The world is currently experiencing a strong rebound in oil demand and prices. This raises the question of whether demand through the energy transition will follow a straight downward line, as Paris-aligned energy scenarios often assume, or more of a 'bump' curve of strong initial demand followed by sharp reductions.

With oil investment depressed over the last few years, such a demand pathway could mean increased prices in the run up to the peak. Indeed, there is *concern* currently that oil prices could move substantially higher than the current $80/bbl.

Such a pathway would pose a tricky timing challenge for the oil industry. Strong initial demand and prices would incentivise greater investment, not least to capture additional profit opportunities while they still exist. After the peak, however, prices would likely drop rapidly, and those same investments, many of which would earn most of their cashflows well after demand has peaked, could turn deeply unprofitable later on.

This note explores such a non-linear demand pathway: the *Inevitable Policy Response Forecast Policies Scenario* (FPS, 1.8°C), commissioned by the UN PRI. We explore two different ways forward for the industry in this complex future – one risky and destructive (the 'high investment case'), the other cautious and more tailored to the 'bump' shape of the FPS demand curve (the 'managed case').

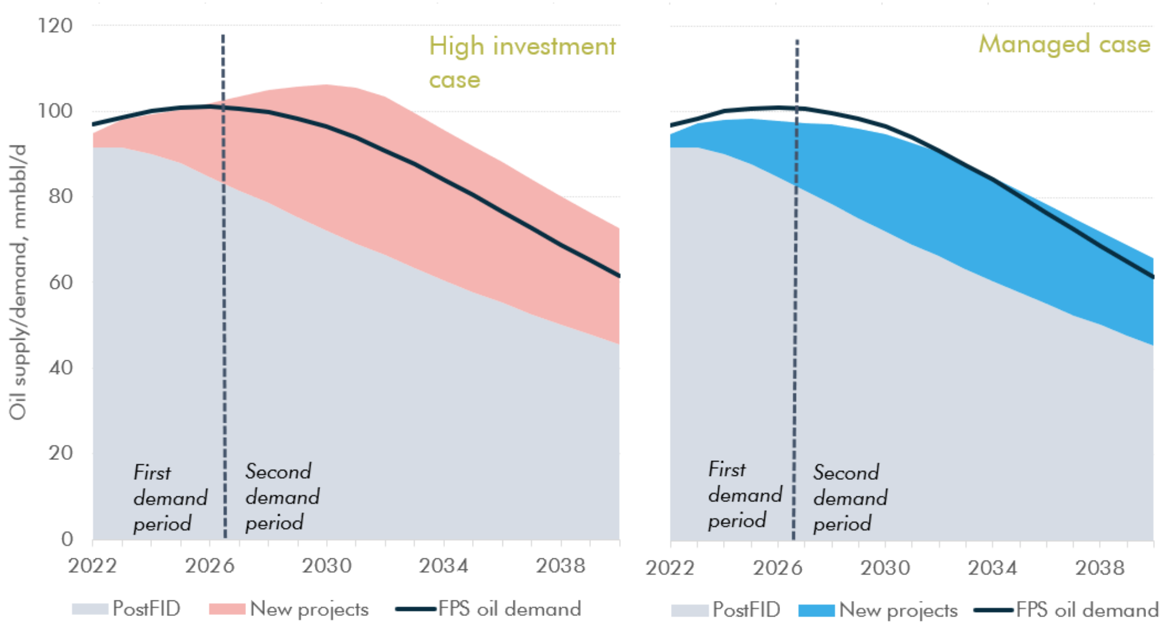
While Carbon Tracker is committed to supporting a rapid decarbonisation of the global energy system, limiting global temperature rise to 1.5°C and averting the worst physical impacts of climate change, we believe it is valuable to explore the implications of other demand scenarios. This is particularly important given the *significant gap* between current policies and those needed for a 1.5°C outcome.

High investment case overestimates initial demand bump, creates stranded assets

In our high investment case, we assume that companies sanction projects in the next five years up to a breakeven price of $60/bbl at a 10% IRR, regardless of how quickly the project can ramp up supply. This succeeds in balancing the market in the higher-demand, pre-peak period (2022-2026, 'period 1'). However, it severely oversupplies the market in the lower-demand, post-peak period (2027-2040, 'period 2') – Figure 1.

FIGURE 1 – HIGH INVESTMENT CASE SEVERELY OVERSUPPLIES MARKET IN PERIOD 2 (2027-2040)

OIL SUPPLY FROM ALREADY-SANCTIONED (POST-FID) PROJECTS AND NEW PROJECTS SANCTIONED IN PERIOD 1 (2022-2026) IN THE HIGH INVESTMENT (LEFT CHART) AND MANAGED (RIGHT CHART) CASES, WITH FPS OIL DEMAND



Note: Includes associated oil supply from gas fields, which we keep constant in both cases.

Source: IPR, Rystad Energy, Carbon Tracker analysis

This oversupply would likely reduce the oil price. In our central high investment case we assume that it falls to $40/bbl long term, roughly halfway between the current marginal cost of supply ($25/bbl) and the highest-cost sanctioned project ($60/bbl). Many projects sanctioned in the high investment case would fail to earn a 10% IRR at this long-run oil price, possibly becoming stranded assets. We estimate that companies using a sanctioning price of $60/bbl would commit $500bn on such uncommercial projects over the five years.

Managed case cuts back on long-cycle supply, reduces value destruction

To mitigate these risks, we explore an alternative supply mix which favours projects that can deliver oil more quickly, without locking in long-term supply that may turn uncommercial later on.

Our managed case sanctions long-cycle projects (mostly conventional fields) up to a breakeven price of $30/bbl at a 10% IRR. This low threshold acts as a safety buffer against approving long-lived, expensive projects. Meanwhile, we assume that short-cycle (shale) projects are sanctioned up to a higher breakeven price of $50/bbl. These ramp up more quickly, and contribute less to long-term oversupply given high decline rates.

The managed case largely balances the market in period 2. It fails to completely meet demand in period 1, leaving an average gap of 2mmbbl/d. This would need to be met by OPEC deploying more of its spare capacity, and possibly other sources such as increased investment to offset declines in mature fields. Analysis indicates OPEC and indeed other producers do have spare capacity and that a surge in oil prices is not inevitable purely because of past investment constraints.

Crucially, the managed case could significantly mitigate value destruction. Assuming that the improved long-run market balance increases the long-run equilibrium oil price up to $50/bbl, wasted capex would theoretically be eliminated (Figure 2). Even if the long-term price were to remain the same under the managed case at $40/bbl (unlikely given the lower locked-in supply), wasted capex is still reduced vs the high investment case.

FIGURE 2 – MANAGED CASE COULD ELIMINATE VALUE DESTRUCTION

CAPEX (2022-2030) ON PROJECTS APPROVED IN 2022-2026 SPLIT BY COMMERCIALITY AT TWO SUPPLY CASES AND THREE LONG-RUN OIL PRICES

Note: Real prices in 2021 dollars.

Source: Rystad Energy, Carbon Tracker analysis

This holds true in fact for any of the long-term prices we studied ($30/$40/$50), which gives rise to this clear conclusion: irrespective of the long-term oil price, the managed case wastes less capex than a high investment case.

The cost of this managed approach could be viewed as the lost profit opportunity (seen as the difference between the blue columns in Figure 2 at a $50/bbl long-run price). Nevertheless, we see such a long-term price as unlikely in the high investment case, as there is significantly more oversupply of oil post the peak than in the managed case. This would make OPEC's task of holding prices up significantly more difficult. The managed case is arguably the less risky approach that the industry needs to take to avoid the catastrophic alternative of the far-left column: high investment and heavy oversupply leading to a $30/bbl price with mass value destruction.

3 Introduction

Surging energy prices send strong signals about oil investment

The world is currently seeing high energy prices across the board, due to several interacting factors – chief among them being a demand resurge after the rolling Covid-19 lockdowns of 2020 and early 2021. As of mid-January 2022, Brent crude was climbing steadily above the $80/bbl mark, compared to mid-$50s a year ago.

This has sparked debate in the markets around the need for significantly increased investment to meet demand and forestall inflationary pressure. For instance, IHS Markit says investment needs to come back to pre-Covid levels and *stay there until 2030*. Goldman Sachs forecasts $85/bbl oil for next several years, saying the *"transition to cleaner energy will take a long time"*. Unsurprisingly, many oil companies agree, saying the world is *moving off oil and gas too fast*. The IEA offers an alternative read, saying the solution is instead *vastly more clean energy investment*.

It's clear that the decarbonisation debate no longer centres around whether people believe in the need for a transition away from fossil fuels – rather, they disagree about its timing and speed. This is evident not least among oil and gas companies, where most admit climate change is a real threat but only a handful (BP, Eni, Shell) concede that their oil production will need to fall this decade.

In this context, it may seem like some companies currently see a huge neon sign pointing towards sanctioning more supply. Meanwhile, the risks of a sudden downward demand shift continue to grow. The speed of the clean energy revolution continues to defy forecasts, particularly for solar energy deployment and electric vehicles sales. At COP26, we have seen how politicians too have realised the need to *promise aggressive policy change*; it is likely that before long they will also realise the need to act on those promises. Combined, these two effects could lead to rapidly falling demand for oil and gas, with significant financial implications for investors in oil and gas.

Inevitable Policy Response sees a clear demand inflection in the mid-2020s

In 2019, the **Inevitable Policy Response** (IPR) project sought to quantify the impacts of this big, sudden switch on the horizon. The **IPR Forecast Policy Scenario** (FPS) expected a world where policy action starts off as gradual in the near term. Towards the mid-2020s however, it accelerates through the 2025 Paris agreement ratchet mechanism as policymakers are forced to address the increasing threats of climate change. It results in a 1.8C temperature outcome, in line with *current government policy pledges*.

In our report *Handbrake Turn* (2020) we tested this scenario on the oil and gas industry. We found that extrapolating the demand trajectory of the first business-as-usual period into the future led to severe value destruction as newly sanctioned projects lived out their producing lives in the second demand period, when demand and prices are both lower. The new 2021 iteration of the IPR is extremely timely in the present context, and has prompted us to renew our earlier analysis.

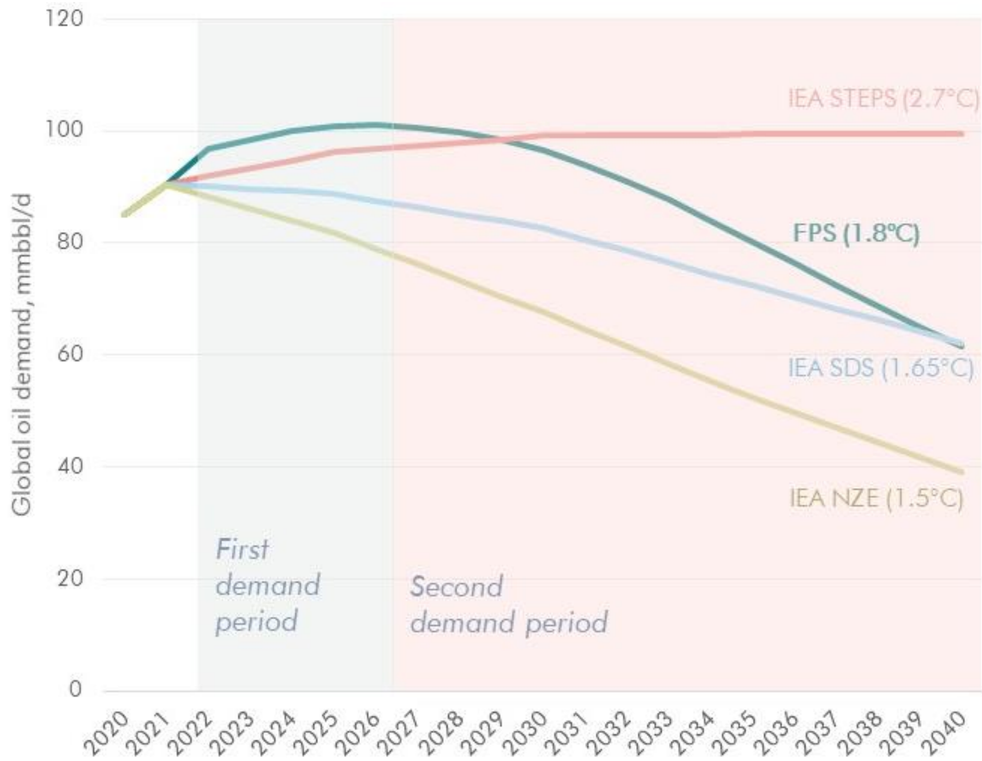
In a sense the FPS is a challenge to the oil industry's belief in a gradual transition that companies are able to manage without value destruction. In this note, we use the updated FPS to once again model upstream oil and gas in a world of two distinct periods – the first featuring rising demand as economies bounce back from Covid-19, the second featuring tough climate policies along with rapid take off in electric vehicle sales which quickly drives down demand for oil.

Future demand pathway determines extent of potential value destruction

To model potential stranded asset risk[1], in the past we have generally used IEA scenarios (principally, the Stated Policies Scenario, STEPS, and the Sustainable Development Scenario, SDS).[2] A common feature of these scenarios, however, is that they assume that demand will follow a smooth, broadly linear trajectory. In other words, if demand is falling at the start of the forecast period, it continues to do so over the long term (Figure 3). By contrast, the FPS follows a non-linear trajectory, with oil demand rising in the next few years before falling sharply around the middle of this decade. The current trend, with fossil fuel demand bouncing back strongly towards pre-Covid levels, suggests this type of pathway could be playing out – making the FPS an important complementary stress testing tool.

FIGURE 3 – FPS SEES STRONG SHORT-TERM OIL DEMAND REBOUND, RAPID DECLINE POST MID-2020S

OIL DEMAND IN THE FORECAST POLICY SCENARIO AND THREE IEA SCENARIOS



Note: STEPS and SDS as of WEO 2020. 2021 data is an IEA estimate.

Source: IPR, IEA, Rystad Energy, Carbon Tracker analysis

We would argue that an FPS-style demand pathway would be far harder for the oil industry to adjust to than the linear IEA scenarios. Companies would be faced with the urge to invest to meet rising short-term demand, knowing that there will be a growing risk of a sharp demand decline thereafter. The nightmare scenario for the industry is to invest heavily in projects which deliver oil around the time that demand starts to decline. That demand decline is likely to drive down oil prices just as the newly sanctioned projects start producing.

[1] *Defined as projects which do not meet their initially promised IRR.*

[2] *For more on this work, see* [Adapt to Survive](#) *(September 2021).*

The oil industry has been here before. It was caught out by price collapses in 1986, 1988, 2014 and 2020. In every case, there was material value destruction evidenced by the level of impairments.

The purpose of this note is to understand the financial risks associated with this nonlinear demand curve, and to offer insights on how a potential energy shortfall in the short term can be met in a way consistent with the longer-term need to avoid oversupplying a declining market, and how companies can avoid value destruction under such a scenario.

Lower-cost projects assumed to be more resilient under weaker demand

Historically, as production from individual oil and gas fields declines naturally over time, new projects are sanctioned on a regular basis to meet demand. The level of project sanctions by company will vary based on a company's view of future demand and prices and the development options it has within its portfolio. As the energy transition gathers pace, future fossil fuel demand will weaken and across the industry there are far more project options than are needed under many scenarios - particularly those that are Paris-aligned.

To identify those projects at risk of becoming stranded – or in other words, those not needed under a given scenario – we assume that the industry takes a rational approach by developing the lowest-cost, and thus most competitive, projects that are available: our "least cost" methodology.

Key focus is on projects due for sanction in the next five years

Under FPS, the simple answer to preserving value is to avoid developing projects that appear commercial during the high demand phase but which prove sub-commercial during the falling demand (falling oil price) phase. Accordingly, our focus here is on upstream oil projects that are on course for sanction over the next five years. These will generally earn their projected cashflows over a long time – according to Rystad Energy's base case, **as a group these projects won't generate positive free cash flow until the late 2020s**. If companies become tempted to sanction projects based on present price signals, they risk destroying value if a sharp policy shift occurs beyond the short term.

To perform this analysis, we need to pay particular attention not just to a project's cost, but also its investment lead time. Trying to meet a short-term rise in demand with projects that have a multi-year lead times is not optimal. Instead, looking to short lead-time projects makes more sense, as they both ramp up faster and have shorter payback periods, and are thus less likely to be caught out than those with longer life-cycles. For example, a deepwater offshore field can have a development lead time of 3-5 years or more whereas smaller onshore projects may be nearer 1-2 years. Shale wells have even shorter lead times, often measured in months.

Sunk capital effect means sanctioned projects likely to keep producing

All of our analysis is based on field-level economics and production data from Rystad Energy UCube.[3] Our analysis assumes that, once approved, a project will continue producing for the remainder of its natural life, even if oil prices fall below the breakeven cost. This is because the sunk capital effect still means it's usually more economic on a point forward basis to do so than to write the asset off.

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[3] *Although the main focus of this note is on oil projects, we also include gas fields in our modelling since these often produce oil as a byproduct. Selected results for gas fields are shown in the note's appendix.*

Of course, if the oil price proves to be lower than expected at the time of sanction, project returns are likely to be lower too. Most companies have a hurdle rate or internal rate of return (IRR) that a project has to meet prior to sanctioning. If that fails to be met because of weak oil prices, the project risks destroying value. We regard capital expended on such projects as potentially 'wasted'; it may well have been a better option to return such capital to shareholders rather than burying it in the ground.

In this note, we use 10% – Rystad's default rate – as our benchmark hurdle rate to stay consistent with the IPR. In our previous work we've used a more conservative 15% rate, mainly to account for the high risk of project delays and cost overruns in oil and gas projects.

4 Supply scenarios for the FPS

Assuming the FPS plays out, then the oil and gas industry stands before a significant challenge in the next few years. Supply may need to be met with a wide array of projects before demand peaks, but with asset lives for new oil and gas assets usually long, this creates a major risk of oversupply and value destruction down the line.

As such, in this note, we approach the issue from a new perspective at Carbon Tracker; in addition to identifying the risks to investors if companies behave recklessly, we want to explore a transition pathway that can help reduce value destruction while keeping demand on a pathway consistent with the goals of the Paris Agreement.

Specifically, our ideal outcome is to find a suite of projects sanctioned in the next five years that meet the heightened demand of the first period (2022-2026) without becoming stranded assets in the second period (2027-2040) when demand is declining. We explore two scenarios:

- **The high investment case:** High sanctioning to meet period 1 demand and reflecting current oil prices, with little regard for project timing.
- **The 'managed' case:** Conservative sanctioning for long-cycle projects to reduce long-term oversupply, with more liberal sanctioning for short-cycle (shale) projects.

4.1 The high investment case

The high investment scenario posits a world in which companies continue to sanction high-cost projects with long production timeframes. In effect, this case describes a situation where companies wrongly extrapolate the near-term demand trend – and thus prices – into the future.

Business as usual leads to greatest value destruction

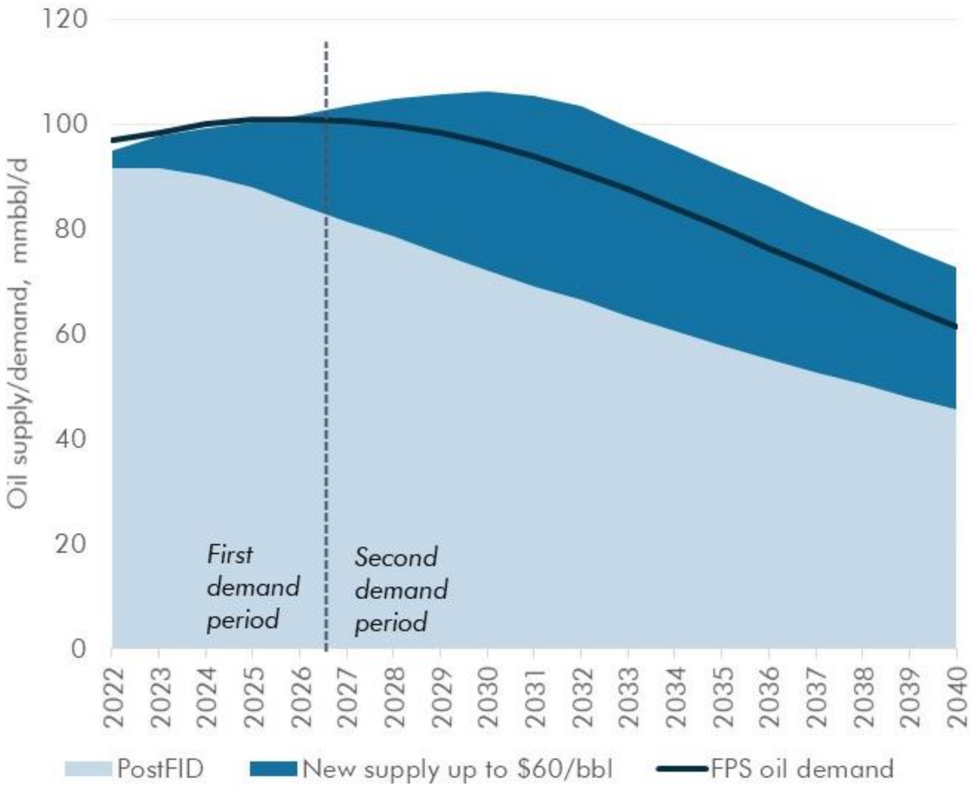
Looking purely at future supply from currently-sanctioned projects (post FID), we identify an average annual oil supply gap of 10mmbbl/d in the first period and 21mmbbl/d in the second under FPS (Figure 4).

Oil companies may thus see an opportunity to accelerate investment in order to fill the period 1 supply gap; to do so, they would need to sanction projects with breakeven prices up to roughly $60/bbl over the next five years. This level is in line with European majors' current price forecasts.

In this high investment case we assume that companies sanction projects without considering whether these can ramp up production quickly – a crucial detail, given that oil demand in the FPS is only growing in the first few years. As a result, while such an investment strategy would succeed in meeting period 1 demand, it creates a massive timing problem in period 2. As projects start to reach their peak output, demand is already starting to decline materially. This leads to an average supply overhang of 10mmbbl/d in period 2, as we can see in Figure 4, which could cause prices in period 2 to plummet. Examples of this sort of price action were seen in 2020 (and several previous periods of falling demand).

FIGURE 4 – HIGH-COST PROJECTS ARE CLEARLY SURPLUS TO REQUIREMENTS IN PERIOD 2

OIL SUPPLY FROM POST-FID (ALREADY-SANCTIONED), 2022-2026 PROJECTS SANCTIONED IN HIGH INVESTMENT CASE, WITH FPS DEMAND



Source: IPR, Rystad Energy, Carbon Tracker analysis

No new oil fields would need to be approved in the second demand period, given that long-term demand is more than adequately covered by projects sanctioned in the first half of the decade. It also goes without saying that there is no need for any new exploration, especially for conventional assets, under this scenario. Any such expenditure would very likely be wasted.

Increased sanctioning activity in period 1 leaves stranded asset hangover in period 2

As a result of the significant oversupply in period 2, new projects become unnecessary, and the oil price could potentially fall to near the marginal cost of supply. The point-forward breakeven price of currently-sanctioned projects[4] puts that figure at around $25/bbl.

This is arguably too low to use as our benchmark price. Although large OPEC producers may be able to break even at the wellhead at $25/bbl, their fiscal dependence on oil revenues means they would likely pull back supply to keep the equilibrium price higher. $25/bbl would also reduce shale production, which is more flexible than conventional oil and thus not as clearly "locked in" once

[4] *Where each asset's breakeven is weighted by its 2021 production.*

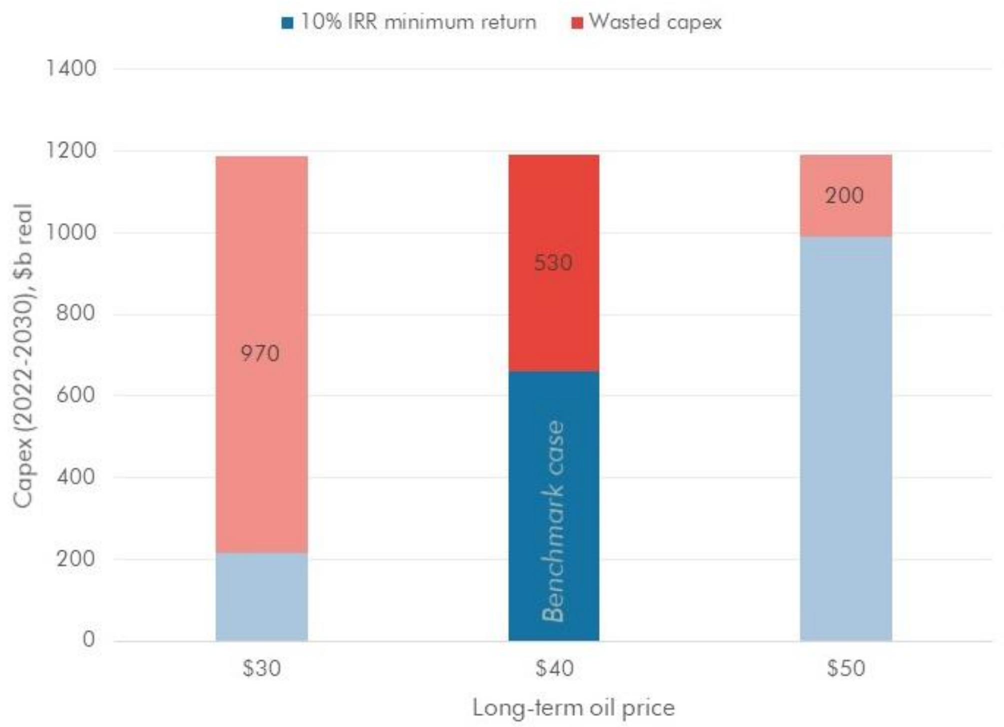
sanctioned – thus cutting future supply and bringing up the equilibrium price. In light of this and OPEC's likely supply response we have chosen not to use the theoretical breakeven price of $25/bbl.

We use $40/bbl as our central cut-off price case for project commerciality; that price keeps over 50% of new shale fields in play, and should be a conservative benchmark.[5] At this price, we find that investment in oil fields with breakeven prices up to $60/bbl that fail to meet a 10% internal rate of return (IRR) could amount to $530bn to the end of the decade. (Recall that $60/bbl is in line with European majors' current price forecasts).

Figure 5 shows this estimate of the amount of capital invested in projects that fail to meet hurdle rates during the second period at our central long term price of $40/bbl, with sensitivity either side.[6] These calculations assume that companies do not discriminate between short- and long-cycle projects – we modify this assumption in the next supply scenario.

FIGURE 5 – HIGH-COST PROJECTS WOULD DESTROY VALUE AS DEMAND FALLS IN PERIOD 2

PERIOD 1 (2022-2026) SANCTIONS: CAPEX (2022-2030) ON OIL FIELDS SANCTIONED IN HIGH INVESTMENT CASE AT DIFFERENT LONG-RUN OIL PRICES



Note: Real prices in 2021 dollars.

Source: Rystad Energy, Carbon Tracker analysis

[5] *$40/bbl as a price ceiling is supported by the fact that the weighted average decline in breakeven prices for projects sanctioned in 2017, five years ago, is $20/bbl. In other words, we can expect that the most expensive project sanctioned today ($60/bbl) would cost around $40/bbl in five years' time on a point forward basis.*

[6] *Our calculations assume the price applies from FID, which may be less accurate for certain shale fields that come online in the next five years when prices are assumed to be higher. However, Rystad data shows that new shale projects would still produce the majority of their reserves in period 2, so our assumption should be valid.*

We use 10% as the key hurdle rate in our analysis to stay consistent with the IPR. This is Rystad's default benchmark IRR, and *research* suggests it's also a common level used by oil companies in their own reporting. We do note, however, that the majors generally have a weighted average cost of capital (WACC) around 10%, so a project that breaks even at this level would have little room for error. We provide results at higher IRRs in Section 4.3 for comparison.

Expensive long-cycle projects are the most destructive

In our view, the highest-risk projects sanctioned in the high-investment case would be those that are both relatively high cost and which deliver oil relatively late. Where these projects are held by public companies, it's important that investors who subscribe to an FPS-like demand pathway press management on these projects, as they are at significant risk of stranding if the FPS plays out.

TABLE 1 – SELECTED HIGH-COST, LONG-CYCLE OIL FIELDS SANCTIONED IN THE HIGH-INVESTMENT CASE

Asset	Location	Capex (2022-2030)	Breakeven price (10% IRR), $/bbl	First oil	Ownership
Lower Fars Heavy Oil (Phase 2)	Kuwait	$7.5bn	High $50s	2028	Kuwait Petroleum Corp (100%)
Bosi	Nigeria	$6.7bn	High $50s	2029	ExxonMobil (56%), Shell (44%)
Tupi (x-Lula)	Brazil	$3.1bn	Low $50s	2030	Petrobras (67%), Shell (23%), Galp (6.5%), Others (3.4%)
Bacalhau (x-Carcara) & Bacalhau Norte Phase 2	Brazil	$3bn	High $50s	2030	Equinor (40%), ExxonMobil (40%), Galp (14%), Sinopec (6%)
Ichalkil Full Field	Mexico	$2.7bn	Mid-$50s	2028	Fieldwood Energy (50%), Petrobal (50%)

Note: Capex data in real 2021 terms.

Source: Rystad Energy, Carbon Tracker analysis

The high investment case: conclusion

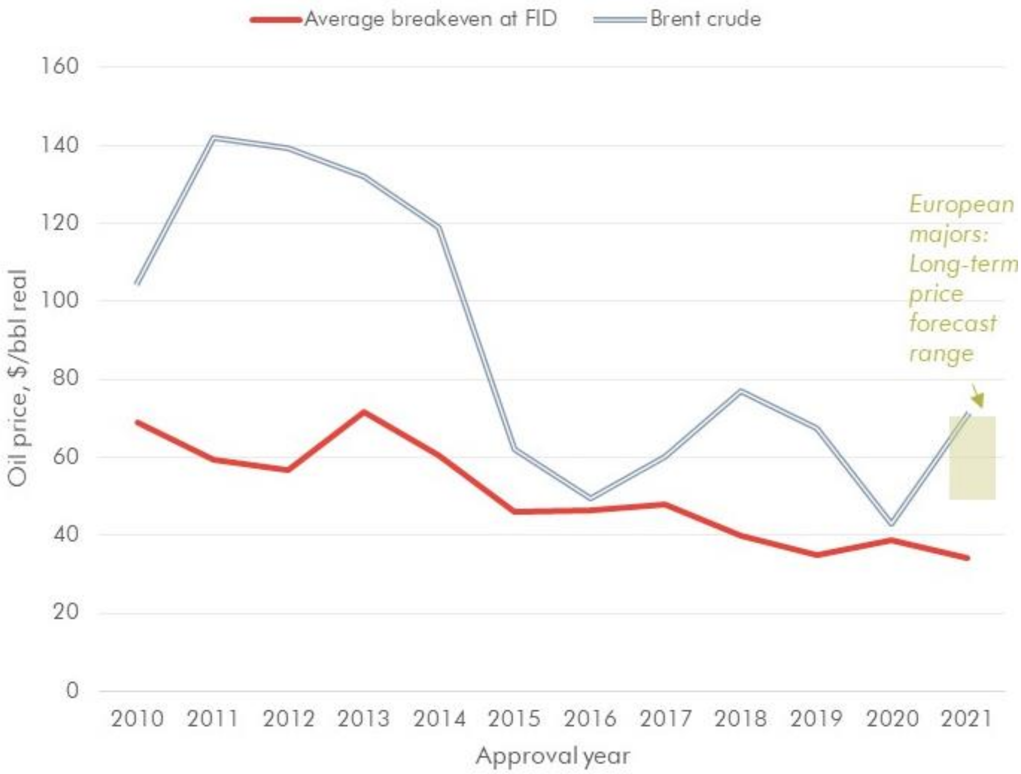
- Sanctioning oil fields at $60/bbl in the next five years would balance the market 2022-2026, but severely oversupply the market in 2027-2040.
- This translates into a significant risk of value destruction as projects fail to earn their initially promised return.
- At $60/bbl sanctioning, we estimate this risk at $530bn over the next ten years, assuming a long-run oil price of $40/bbl.

4.2 The 'managed' case

Over the past decade the industry has started to recognise the challenges of the energy transition, with the average breakeven price for projects sanctioned falling alongside falling Brent crude prices – illustrating clearly how companies have been favouring increasingly low-cost projects since the last commodity price boom (Figure 6).

FIGURE 6 – INDUSTRY APPEARS TO HAVE BECOME PROGRESSIVELY MORE CAUTIOUS

WEIGHTED AVERAGE BREAKEVEN PRICE AT APPROVAL FOR OIL FIELDS, AND BRENT CRUDE PRICE (2021 REAL TERMS)



Note: Breakevens weighted by asset lifecycle capex according to Rystad Energy base case. All data in real 2021 terms.

Source: Rystad Energy, Carbon Tracker analysis

While this might imply the high investment case outlined in the previous section is an increasingly remote possibility, the extended period of higher prices seen through 2021 may encourage a return to more expansionist mindset, despite the value destruction that may result. It's therefore not a foregone conclusion that companies are committed to a more conservative pathway.

In our second supply scenario, the 'managed' case, we describe a case with continued, and deepened, conservative bias in the industry and explore the possibility of a supply pathway that is more tailored to the non-linear pathway outlined in the FPS. Here, industry players foresee demand peaking in the next few years and respond by changing which projects they sanction from now on.

Managed case restrains long-cycle projects

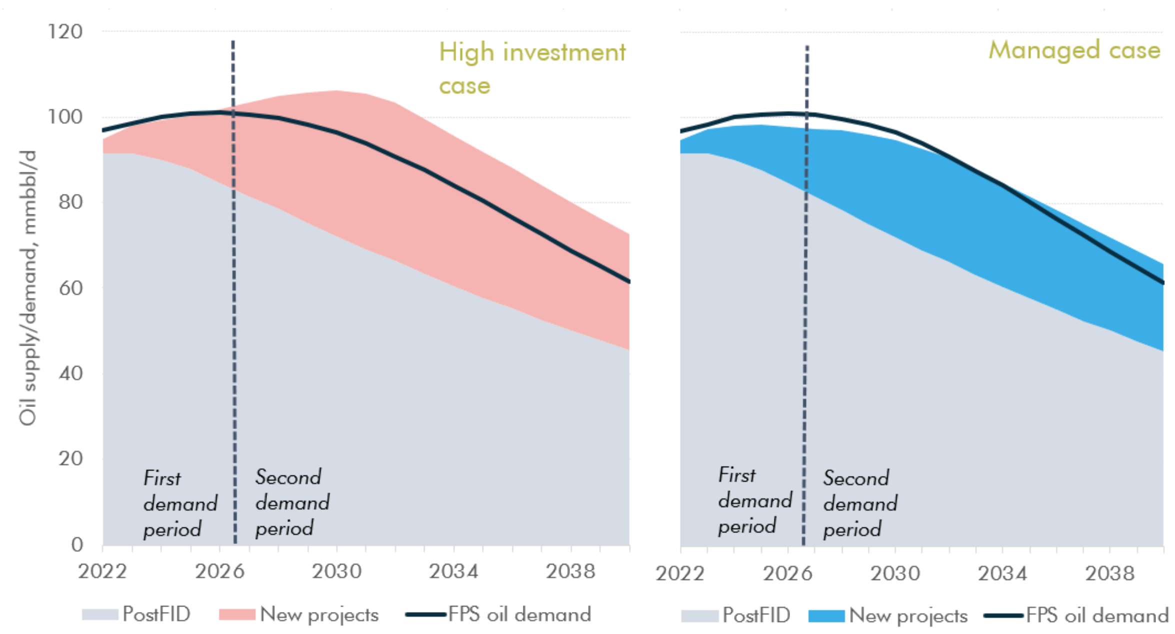
The managed case favours projects that can deliver new production quickly (short-cycle projects). The goal is to find a supply mix that better satisfies the elevated demand in period 1 with as little supply overhang as possible in period 2.

- We continue to assume that already-sanctioned projects are locked in, focusing on the marginal remaining demand in each subperiod of the FPS.
- For additional projects sanctioned over the next five years, we assume that all (long and short cycle) go ahead if their breakeven oil price is up to $30/bbl at a 10% IRR.
- This is justified by the fact that long cycle projects are far less flexible than short cycle projects, and thus need to build in a bigger margin of safety.
- These projects alone cannot fully satisfy demand in period 1, leaving a substantial gap of over 7mmbbl/d on average.
- To clear this gap, we assume that **only** short-cycle projects – defined here simply as shale/tight oil wells – go ahead based on a $50 oil price. Note that this is still quite a conservative price compared to current price levels.

Using this combination of projects we reduce the period 1 supply gap to 2mmbbl/d, still a material amount. However, we now only oversupply the market by an average of less than 1mmbbl/d in period 2.

FIGURE 7 – FOCUS ON SHORT-CYCLE REDUCES PERIOD 2 OVERSUPPLY BUT LEAVES PERIOD 1 GAP

OIL SUPPLY FROM ALREADY-SANCTIONED (POST-FID) PROJECTS AND NEW PROJECTS SANCTIONED IN PERIOD 1 (2022-2026) IN THE HIGH INVESTMENT (LEFT CHART) AND MANAGED (RIGHT CHART) CASES, WITH FPS OIL DEMAND



Note: Includes associated oil supply from gas fields, which we keep constant in both cases.

Source: IPR, Rystad Energy, Carbon Tracker analysis

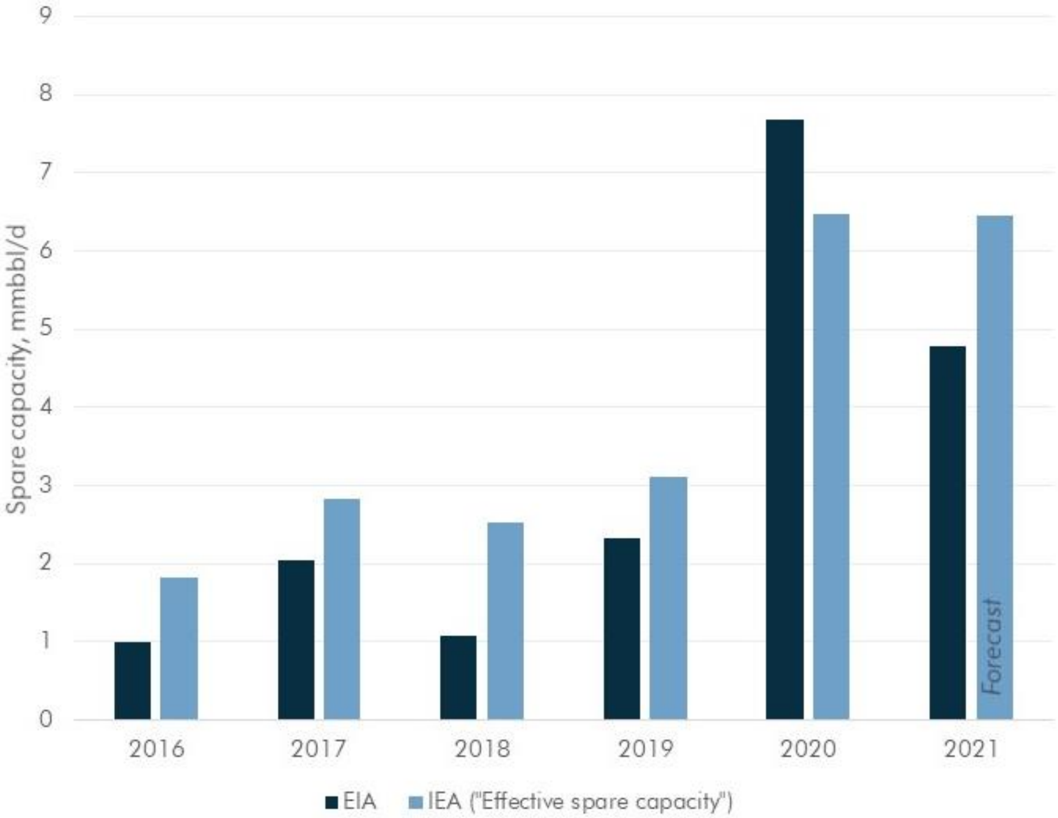
Crucially, our period 2 production mix is now more heavily tilted towards short-cycle projects - on average, 79% shale and 21% conventional, compared to 64/36% in the high investment ($60/bbl) case. This means that there's more flexibility to reduce or increase production to meet shorter-term imbalances.

Managing the short-term will require OPEC to step up to the plate

To be sure, our period 1 supply gap of 2mmbbl/d is still an issue to be reckoned with, and points in the direction of OPEC and its large spare capacity. The group has built up significant excess production capacity since the outbreak of Covid-19, which to date has only been partially unwound. Estimates vary, but official bodies place it in the range of 5-6 mmbbl/d – see Figure 8.

FIGURE 8 – ESTIMATES OF TRUE OPEC SPARE CAPACITY VARY

OPEC SPARE CAPACITY ACCORDING TO EIA AND IEA



Note: IEA "effective spare capacity" excludes Iran.

Source: EIA, Carbon Tracker analysis

We assume that any additional output is subject to the same low decline rates (at least for the next few years) as current onshore Middle Eastern production. As such, remaining spare capacity should be able to cover the period 1 supply gap without exhausting the group's ability to respond to short-term supply variations.

We also think it's in OPEC's interest to play this role, as hanging back to let prices surge would inevitably draw in more shale production. Granted, OPEC has proven it can drive out new shale by flooding the market if it so chooses, but only at the cost of a painful round of low prices like in 2015-2016, which this time may well become permanent. With sovereign debt at multi-year highs, few 'petrostates' are in a position to endure such low revenues again. (For more on this topic, see our report *Beyond Petrostates*, February 2021).

Moreover, letting prices race higher would accelerate demand destruction; this isn't a new threat but it is a fast-growing one, with electric vehicles far more accessible now than during previous periods of high pricing. Although the core OPEC members have a low cost of production, bringing forward peak demand would still drive down pricing, in turn wreaking havoc on oil-related fiscal revenue.

Other supply sources could ease the burden on OPEC

We also note that OPEC's spare capacity wouldn't necessarily need to shoulder the entire burden of the period 1 supply gap. Non-OPEC+ producers may invest more to reduce decline rates from existing assets if the demand environment is sufficiently supportive. The average annual decline rate for producing non-OPEC+ fields in 2022-2026 is 8%; reducing this rate by just one percentage point would unlock 0.3mmbbl/d of additional oil production, covering 15% of the period 1 supply gap.

Shale producers may also accelerate production from already sanctioned fields if prices rise higher – an effect not captured in our data, which is kept static at Rystad base case price assumptions (averging in the high $50s/bbl in period 1). Rystad estimate that moving from a flat $60 to a flat $70 oil price in period 1 would unlock an average 1mmbbl/d of shale oil, purely from additional drilling in sanctioned fields. That said, luring in this production would require that OPEC+ keep prices consistently high – which, as discussed earlier, we don't see as being in their long-term interests. In sum, we would discount this effect somewhat, but could see it easing OPEC's burden to some extent.

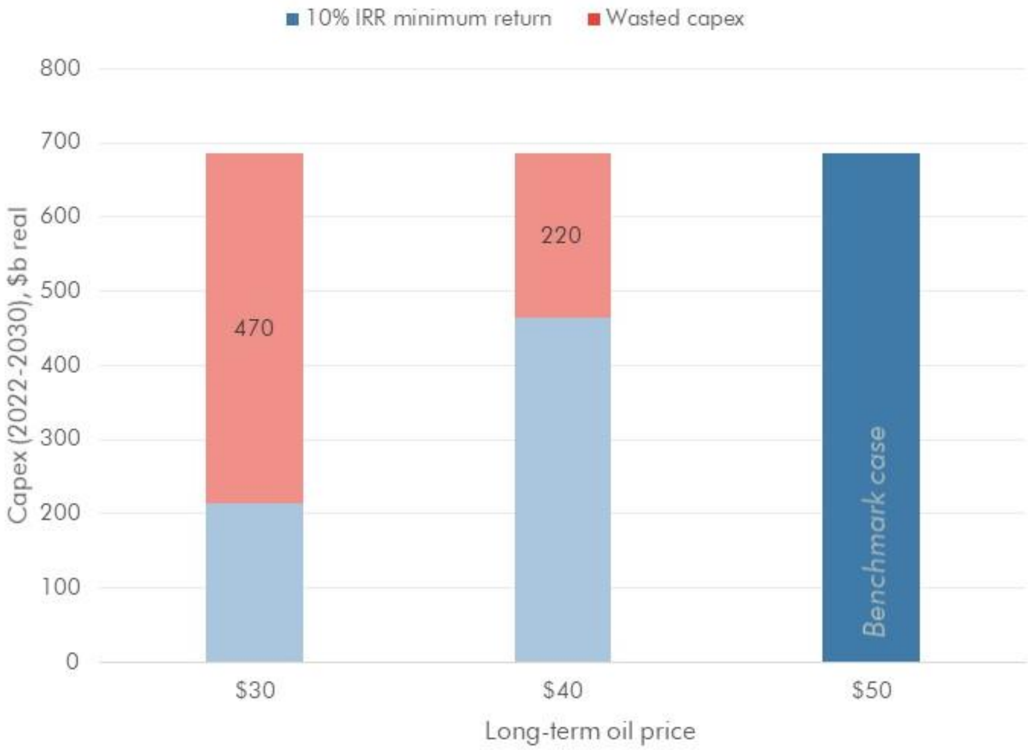
Managed case mitigates value destruction irrespective of price

The managed case significantly reduces the capex spent on projects that fail to earn a 10% IRR. Given that the managed case results in a largely balanced market in period 2, we assume that the equilibrium oil price is also higher than in the high investment case – we therefore take a reference case of $50/bbl for simplicity. At this price, wasted capex is eliminated, as shown in Figure 9 (alongside downside sensitivity).

Some shale projects would also earn cashflows in period 1 when prices are presumably even higher, but this is ultimately a marginal effect: according to Rystad's base case, 87% of our new supply in the managed case happens in period 2.

FIGURE 9 – MANAGED CASE WOULD REDUCE VALUE DESTRUCTION VS HIGH INVESTMENT CASE

CAPEX (2022-2030) ON PROJECTS APPROVED IN 2022-2026 WHICH FAIL TO EARN 10% IRR AT DIFFERENT LONG-TERM OIL PRICES



Note: Real prices in 2021 dollars.

Source: Rystad Energy, Carbon Tracker analysis

In this analysis we have selected central long-term oil prices that we are believe are most appropriate for each case ($40/bbl for high-investment and $50/bbl for managed); under these we find that the high investment case wastes $530bn vs the managed case (Figure 10). We stress, however, that the managed case results in reduced wasted capital compared to the high investment case even if the same oil price is used for both case, and this holds true across a range of long-term prices, as shown in Figure 10.

FIGURE 10 - MANAGED CASE GENERATES LEAST WASTED CAPEX REGARDLESS OF OIL PRICE

CAPEX (2022-2030) ON PROJECTS APPROVED IN 2022-2026 SPLIT BY COMMERCIALITY AT TWO SUPPLY CASES AND THREE LONG-RUN OIL PRICES

Note: Real prices in 2021 dollars.

Source: Rystad Energy, Carbon Tracker analysis

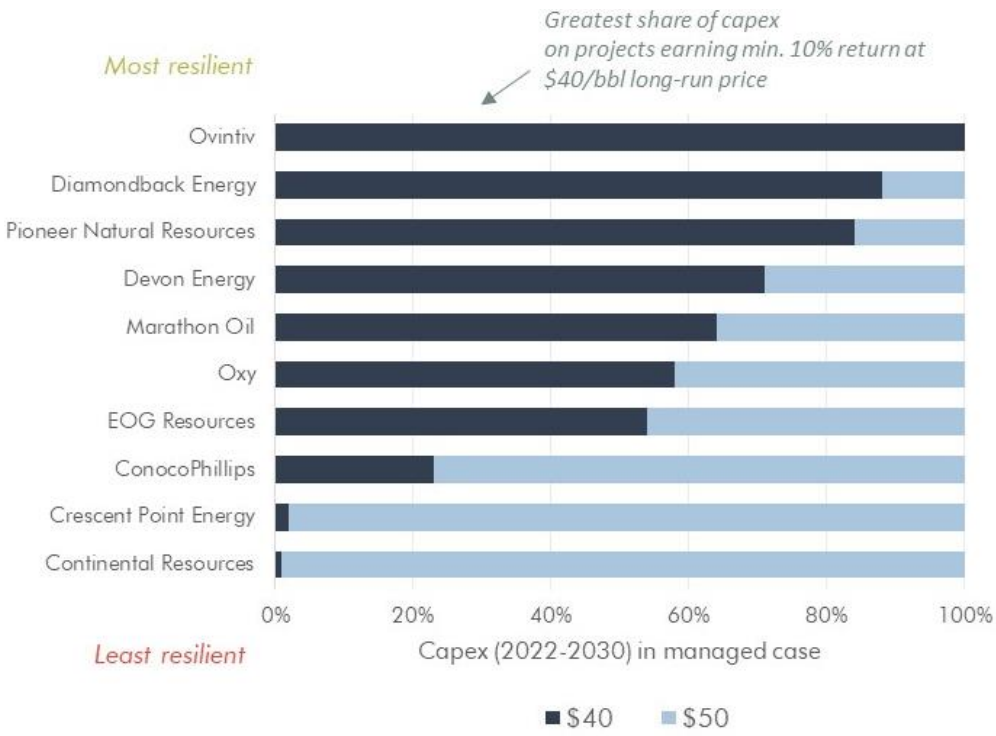
It may seem at first glance like this comes at the cost of 'wasted opportunity', represented by the difference between the blue columns in the $50/bbl section of Figure 10. We see this as a red herring; with markets so heavily oversupplied in the high investment case, a $50/bbl price is far less likely, so this 'wasted opportunity' is probably a mirage. This is precisely the point of the managed case – the industry plays it safe and captures more certain returns.

Not all shale producers can compete for marginal barrels in managed case

It's important to note that a company's relative cost positioning is still important in the managed case, even for shale companies. While many of them may be able to produce profitably at $50/bbl, if the long-run price were to fall even just to $40/bbl, many newly approved fields would no longer make the hurdle rate. Figure 11 shows the 10 largest shale companies and their share of capex on projects sanctioned in the managed case, split by commerciality under our benchmark $50 price and a lower $40 price. The main focus here is relative positioning rather than specific percentages. Bigger bars mean higher-cost production and less resilience in a lower-price outcome.

FIGURE 11 – RESILIENCE TO LOWER PRICE OUTCOMES STILL IMPORTANT IN MANAGED CASE

TOP 10 SHALE COMPANIES[7] - CAPEX ON SHALE OIL FIELDS IN THE MANAGED CASE – SHARE ON PROJECTS EARNING MIN. 10% RETURN AT $40 AND $50 LONG-RUN PRICE



Note: Top 10 largest companies in terms of capex on projects sanctioned in the next five years under the high investment case.

Source: Rystad Energy, Carbon Tracker analysis

We recognise that capital may not be truly sunk for shale fields in the same way that it is for conventional assets, since they tend to be more granular and short-lived. As such, some portion of a shale company's 'wasted' capex may never be put in the ground. But that doesn't change the fact that some shale production will be less competitive – meaning that some companies' reserves won't be produced. That reduces their long-term cashflow potential and by extension should negatively impact terminal equity values. Those companies may also struggle more to meet asset retirement obligations, an important and underplayed challenge for the shale industry (for more on this topic, see *our extensive research on AROs*).

The managed case: Conclusions

- Reducing the amount of long-cycle supply that is sanctioned in the next five years largely eliminates oversupply in 2027-2040. It leaves a supply gap in 2022-2026, but this is likely manageable through OPEC spare capacity and other levers.
- At a long-run oil price of $50/bbl, value destruction is eliminated in the managed case. It is likely that the price would be higher than in the high investment case, given the significantly reduced oversupply in period 2.

[7] *Top 10 companies in terms of projected capex on shale oil fields sanctioned in the next five years under the high investment case. This is mainly to filter out shale gas companies and shale oil companies with little expected capex on unsanctioned assets.*

- Although the managed case hands market share to shale producers, they still need to exercise capital discipline, especially in period 2. Shale projects with a breakeven above $50/bbl Brent would, on average, struggle to earn a sufficient return.

4.3 Sensitivities

We recognise that our results are sensitive to both the long-run oil price and project hurdle rate. Our key benchmarks in this report are a long-run oil price of $40/bbl in the high investment case and $50/bbl in the managed case, in addition to a 10% hurdle rate, but these could be inappropriate for several reasons.

We discussed the sensitivity to long-term price assumptions in the previous section (Figure 10). Irrespective of long-term price, less capital is wasted under the managed case vs the high investment case – but it's worth again considering the role of OPEC in this context.

Our managed case assumes that OPEC will deploy its spare capacity to support the market in the short term, before scaling back in the long-term while letting shale capture market share. But the petrostates, seeing a future of lower revenues and declining market share, may well react differently by seeking to monetise reserves as quickly as possible, content to control the market at a much lower price than they have in the past. *Saudi Arabia still needs about $80/bbl* to balance its state budget, but this could conceivably be brought down through fiscal reform and increased production. The UAE and Kuwait already have fiscal breakevens in the $60s/bbl, and there's nothing like a crisis to push through political barriers to reform. Again, however, investing along the managed case, rather than the high investment case, reduces company exposure to OPEC actions, and the potential for wasted capital as a result.

In terms of the the hurdle rate, Rystad uses 10% as a proxy for the industry standard, and we have used 10% IRRs in this report at the request of the IPR. In past research we've tended to use 15% to build in leeway for cost overruns and project delays, both of which are relatively common in the oil and gas industry, and reflecting rising WACCs for oil and gas projects. Indeed, a resilient project may need more of a financial buffer – especially if fossil fuel companies' *declining access to capital* causes the WACC to rise over time. According to a 2019 *investor survey* conducted by researchers at the Oxford Institute for Energy Studies, investors are already asking for 15% or more for new oil projects.

Table 2 explores these possibilities in a matrix form for our managed case. We see that wasted capex is lower if projects are sanctioned at a 15% IRR. The logic here is simple. If companies (and investors) require a higher return of 15%, then fewer projects will be viable at a given sanctioning price ($30 for long-cycle, $50 for short-cycle in this case), reducing total investment and thus potentially stranded capex.

TABLE 2 – MANAGED CASE: CAPEX (2022-2030) ON OIL FIELDS SANCTIONED IN PERIOD 1 (2022-2026) WHICH FAIL TO MEET A GIVEN HURDLE RATE

	Capex that fails to meet hurdle rate (IRR)	
Long-run oil price	IRR = 10%	IRR = 15%
$50/bbl	$0bn	$0bn
$40/bbl	$220bn	$200bn
$30/bbl	$470bn	$380bn
2022-2026 supply gap	2.1 mmbbl/d	3.4 mmbbl/d

Note: Real prices in 2021 dollars.

Source: Rystad Energy, Carbon Tracker analysis

Note, however, that this also reduces the amount of sanctioned supply, significantly exacerbating the supply gap in period 1. So while requiring 15% may avoid more value destruction at our given sanctioning price, it also exacerbates the fundamental demand problem posed by the FPS. This would put greater pressure on OPEC to deploy spare capacity to forestall price spikes.

5 Appendix: Gas fields

While this note is primarily focused on oil market dynamics, in order to accurately model future oil supply we also need to include assumptions about gas fields since these produce associated oil. Under Rystad's base case projections, oil from gas fields accounts for 15% of global supply to 2040 – a non-neglible amount.

Our approach to gas leans on the methodology used in our previous work on upstream capex analysis, most recently *Adapt to Survive* (September 2021). Methodologically, the fundamental difference against oil fields is that gas (LNG aside) does not move on globally connected markets, being limited by pipeline infrastructure. Each market will have its own price fundamentals. As such, we model piped gas on four distinct markets: Europe, North America, Russia and Australia – other geographies are not explicitly modelled. LNG is modelled globally, using LNG trade demand numbers in IEA scenarios.

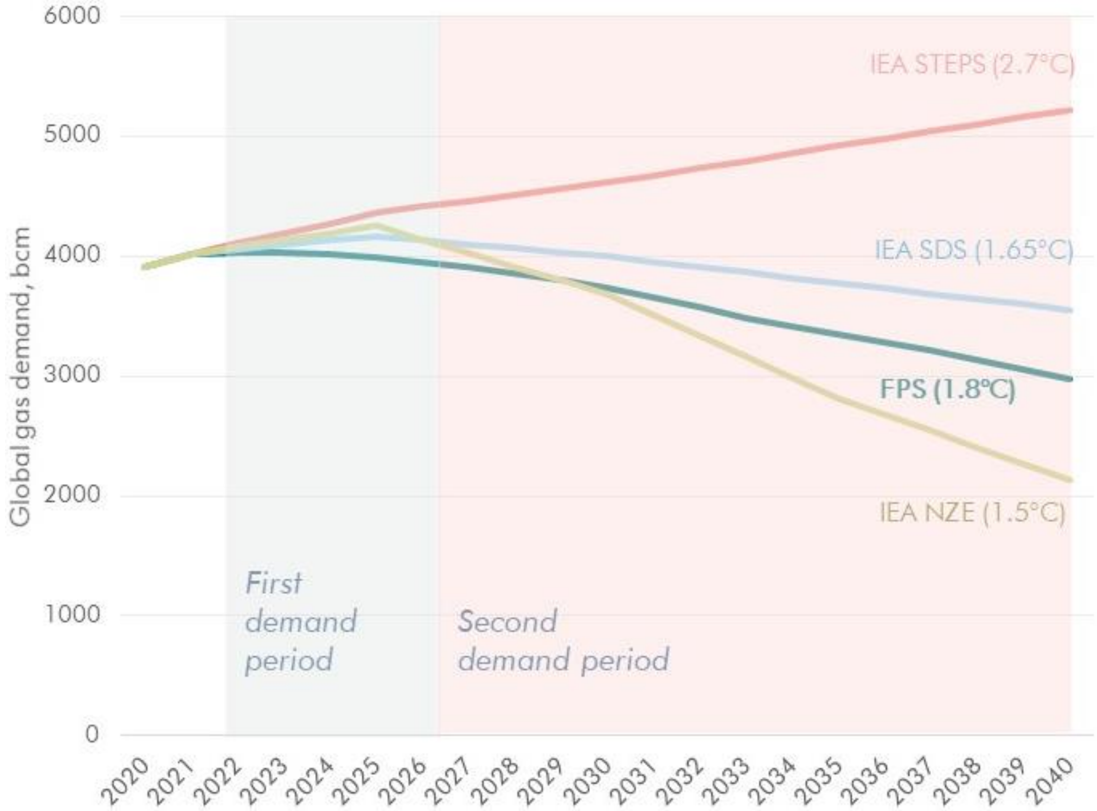
As a simplifying assumption, our model allows all gas fields due for sanction in the next five years to go ahead if they are cost competitive under a demand pathway consistent with the IEA STEPS. Looking at global gas demand, the STEPS is characterised by a steadily upward demand trajectory over the next two decades, as shown in Figure 12.

The STEPS is meant to represent a business-as-usual pathway, similar to the 'high investment' case presented in Section 4.1. We think this assumption is reasonable, given the current unprecedented tightness in gas markets and generally bullish gas demand assumptions among even transition-minded oil companies.

While it may have been desirable to also create a 'managed case' for gas that seeks to eliminate oversupply in each market, we think the complexities of that exercise are best explored in a separate study.

FIGURE 12 – STEPS PATHWAY ASSUMES UPWARD DEMAND TRAJECTORY FOR GAS

GLOBAL GAS DEMAND IN THE FORECAST POLICY SCENARIO AND THREE IEA SCENARIOS



Note: STEPS and SDS as of WEO 2020. 2021 data is an IEA estimate.

Source: IPR, IEA, Rystad Energy, Carbon Tracker analysis

Note that our two demand periods – 2022-2026 and 2027-2040 – are based on the shape of the global oil demand curve, seen in Figure 3. This is perhaps less appropriate for gas where demand trajectories differ for each market, and is something that would need to be improved on in future modelling efforts.

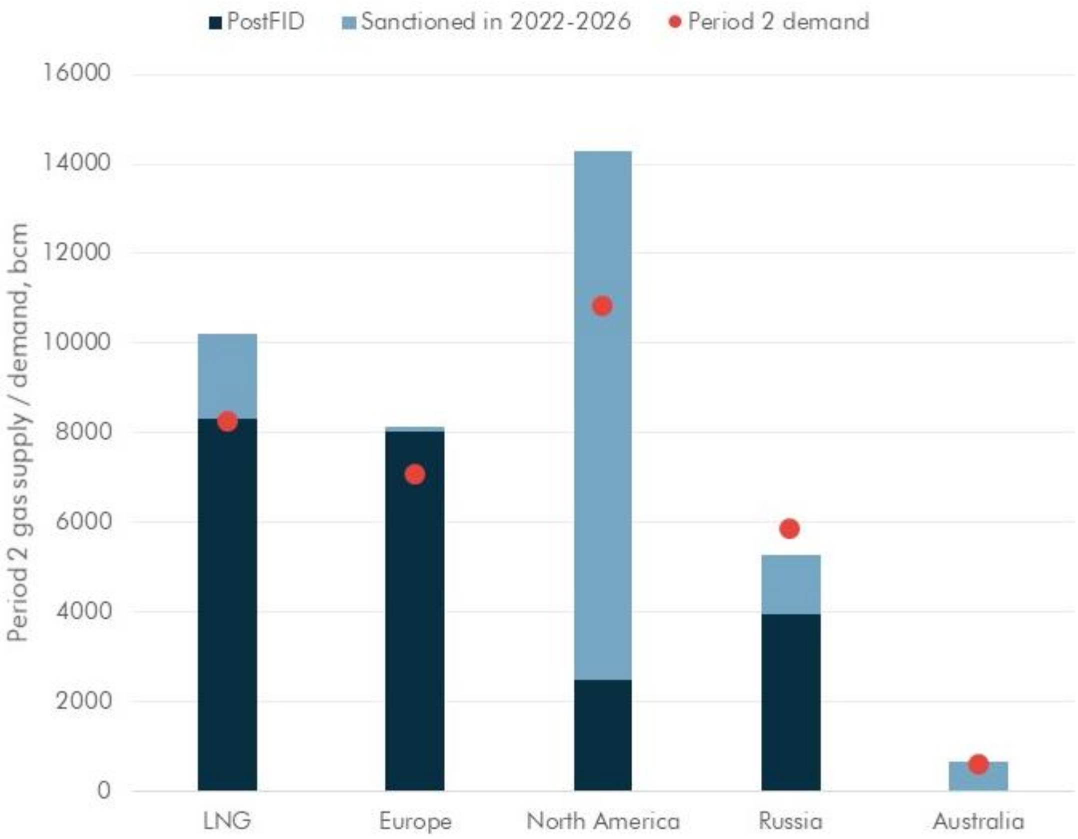
Headline results show high investment pathway would oversupply several gas markets

Figure 13 shows some high-level results for gas fields for our different markets. This is meant to sketch out a future where companies invest heavily in the next few years while the FPS pathway – which features significantly less gas demand - plays out.

For both LNG and the European market, *already sanctioned* gas fields bring on enough long-term supply to meet expected demand in period 2. Only Russia sees a supply gap even when projects sanctioned in period 1 are accounted for, meaning companies would need to draw on higher-cost projects to meet expected demand. In Australia, demand is largely met, leaving little need for new projects beyond 2026.[8] That these two markets stand out clearly reflects their demand trajectories in the FPS: both see gas demand declining by about 20-25% in 2022-2040, compared to nearly 50% in Europe and North America.

FIGURE 13 – MOST GAS MARKETS OVERSUPPLIED IN PERIOD 2 IF COMPANIES CONTINUE WITH BAU

GAS SUPPLY FROM POST-FID, 2022-2026 PROJECTS SANCTIONED AT STEPS, WITH FPS DEMAND



Note: Includes associated gas from oil fields, which we assume here are sanctioned at $60/bbl.

Source: Rystad Energy, Carbon Tracker analysis

[8] *The apparent lack of postFID supply in Australia reflects the offsetting impact of LNG exports.*

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