

Constellation

Stars aligned, dividends are destined

- Brazil's largest driller
- High contract coverage, dividends around the corner
- Initiate coverage with BUY, TP of NOK 150/sh

Brazil's largest driller with long relationship with Petrobras

Constellation is the largest drilling contractor in Brazil, and its assets include three owned drillships (1x 7th gen, 2x 6th gen), four owned semisubmersible rigs (3x 6th gen, 1x 2nd gen), and two managed units. With more than three decades of operational experience in Brazil's deep- and ultra-deepwater markets, the company has established a leading position supported by long-term relationships with Petrobras, which currently employs all of its rigs.

High contract coverage, dividends around the corner

Across its owned rig fleet, Constellation has robust contract coverage with 94%/60% of our '26e/'27e revenues covered by firm contracts, which provides confidence in an earnings uplift in the medium term. For the open capacity, we believe contract awards with Petrobras and IOCs could be just around the corner, further increasing visibility. After the refinancing in '24, constellation is now deleveraging and closing in on a dividend-paying position. We estimate that it will drop below the NIBD/EBITDA 1.25x dividend covenant in Q3'26, after which we believe it could declare NOK 36/sh (~32% of MCap) in cumulative DPS by YE'27 and become the highest yielding company in our oil service coverage.

Priced below peers: BUY, TP of NOK 150/sh

Although it has amongst the highest contract coverages and best visibilities, COSH is still priced below peers, trading at 3.5x/2.8x divi-adj. EV/EBITDA (peers at 6.1x/4.4x) on '26e/'27e. We think the introduction of dividends from Q3'26 and potential contract awards could be triggers for repricing the share, and we also like COSH's leading position in Brazil and close relationship with Petrobras. We initiate coverage with BUY and a TP of NOK 150/sh, at which COSH would trade at a divi.-adj. EV/EBITDA of 4.4x on '26e.

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USDm	2023	2024	2025e	2026e	2027e
Sales	552	564	561	708	756
EBITDA	151	239	236	353	376
EBITDA margin (%)	27.4	42.4	42.1	49.8	49.7
EBIT adj.	21	-11	14	136	161
EBIT adj. margin (%)	3.7	-1.9	2.6	19.2	21.2
Pretax profit	-26	-47	-33	83	115
EPS	-0.37	-0.50	-0.51	0.77	1.17
EPS adj.	-0.37	-0.50	-0.51	0.77	1.17
Sales growth (%)	35.9	2.1	-0.5	26.3	6.8
EPS growth (%)	nm	35.8	2.5	nm	50.7

Source: ABG Sundal Collier, Company Data

Reason: Initiating coverage

BUY  HOLD  SELL 

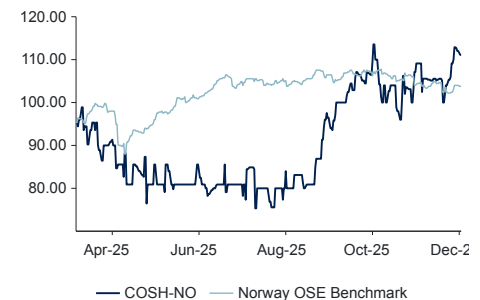
Oil & Oil Services

COSH-NO/COSH NO

Share price (NOK) 1/12/2025 112.50
Target price 150.00

MCap (NOKm) 9,499
MCap (EURm) 809
No. of shares (m) 84.4

Performance



	2025e	2026e	2027e
P/E (x)	nm	14.4	9.5
P/E adj. (x)	nm	14.4	9.5
P/BVPS (x)	0.52	0.52	0.55
EV/EBITDA (x)	6.0	3.7	3.3
EV/EBIT adj. (x)	98.2	9.5	7.8
EV/sales (x)	2.53	1.83	1.65
ROE adj. (%)	-2.4	3.6	5.6
Dividend yield (%)	0.0	10.8	21.6
FCF yield (%)	2.1	18.8	26.1
Le. adj. FCF yld. (%)	2.1	18.8	26.1
Net IB debt/EBITDA (x)	2.0	1.0	0.8
Le. adj. ND/EBITDA (x)	2.0	1.0	0.8

Company description

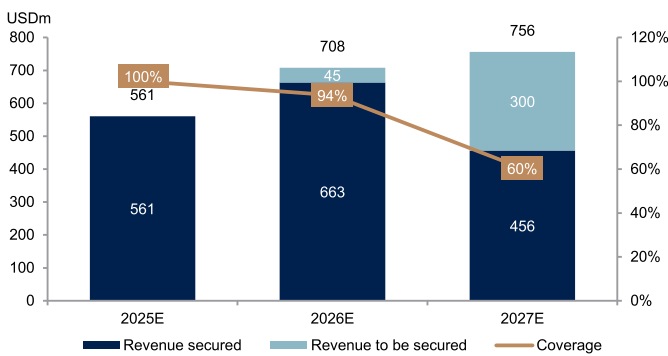
Constellation Oil Services is the largest drilling contractor in Brazil. Its assets include three owned drillships (one 7th gen, two 6th gen), four owned semi-submersible rigs (three 6th gen, one 2nd gen), and two managed units. With more than three decades of operational experience in Brazil’s deep- and ultra-deepwater markets, the company has established a leading position, supported by a long-term relationship with Petrobras. Constellation is headquartered in Luxembourg and listed on Euronext Growth Oslo, while its operations are located in Brazil.

[Sustainability information](#)

Risks

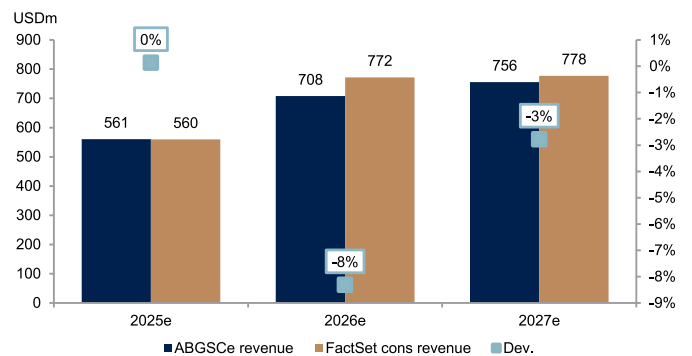
The main risks to the investment case are fluctuations in global oil and gas prices, as they could adversely affect E&P spending. Given that Petrobras is its most important client, changes to Petrobras’ spending could also affect Constellation significantly. There are also operational risks: Constellation owns seven assets and manages two and is therefore sensitive to unexpected events impacting earnings from one rig. Moreover, there is inflation risk on opex and capex, given the tight oil market supply chain and counterparty risk.

COSH: Share of revenue estimate secured



Source: ABG Sundal Collier, Company data

COSH: ABGSCe vs. cons revenue (Factset)



Source: ABG Sundal Collier, Company data, Factset

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Investment case

We initiate coverage of Constellation Oil Services (COSH) with a BUY and a target price of NOK 150/sh, at which the share would trade at a divi.-adj. EV/EBITDA of 4.4x on '26e. We believe COSH offers attractive exposure due to its 1) leading position in Brazil and long-term relationship with Petrobras, 2) high contract coverage with 94%/60% of revenues secured by firm contracts for '26e/'27e, 3) valuation, which is below peers at 3.5x/2.8x the divi.-adj. EV/EBITDA (peers at 6.1x/4.4x) for '26e/'27e, and 14%/23% FCF to divi.-adj. EV yield for '26e/'27e, 4) introduction of dividends from Q3'26e, with NOK 36/sh (32% of MCap) in cumulative DPS by YE'27e.

The largest driller in Brazil with a long-term relationship with Petrobras

Constellation is the largest drilling contractor in Brazil, and its assets include three owned drillships (one 7th gen, two 6th gen), four owned semi-submersible rigs (three 6th gen, one 2nd gen), and two managed units. With more than three decades of operational experience in Brazil's deep- and ultra-deepwater markets, the company has established a leading position supported by long-term relationships with Petrobras, which currently employs all of Constellation's rigs.

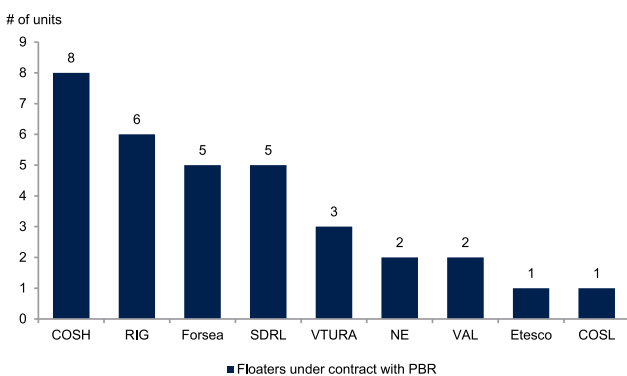
High contract coverage and first dividends from 2026

Across its owned rig fleet, Constellation holds a robust 94%/60% of our '26e/'27e revenue secured by firm contracts, which provides confidence in an earnings uplift in the medium term. For the open capacity, we believe contract awards with Petrobras and IOCs could be just around the corner, further increasing visibility. After the refinancing in '24, constellation is now deleveraging and closing in on a dividend-paying position. We estimate that it will drop below the NIBD/EBITDA of 1.25x dividend covenant in Q3'26, after which we believe COSH could declare NOK 36/sh (~32% of MCap) in cumulative DPS by YE'27 and become the highest yielding company in our oil service coverage.

Priced below peers despite better visibility, we initiate with BUY, TP of 150/sh

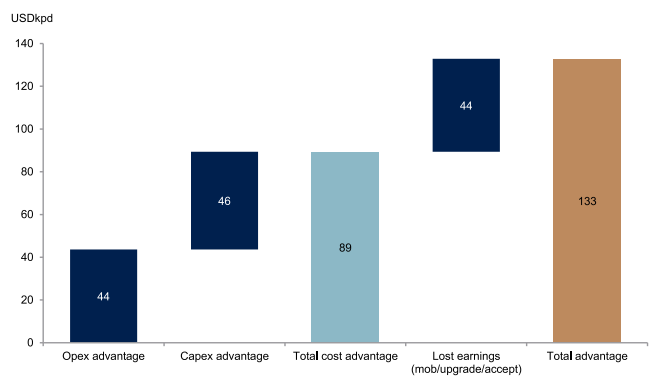
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Floater units under contract in Brazil



Source: ABG Sundal Collier, Company data, S&P

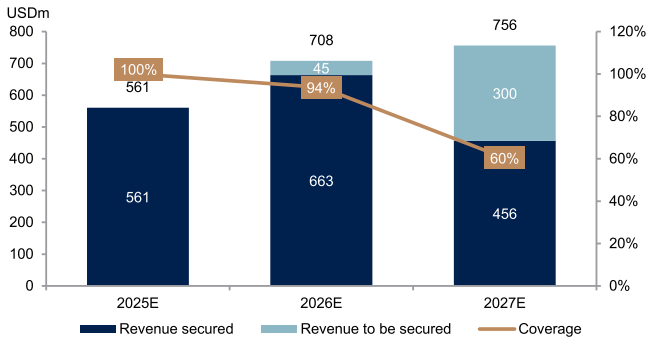
COSH: Cost advantage compared to foreign rigs



Source: ABG Sundal Collier, Company data, S&P

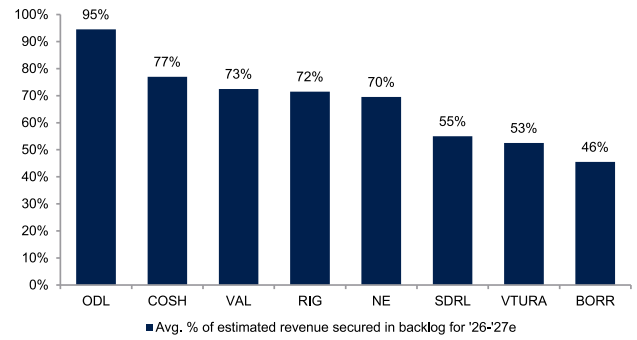
Footnote: Opex advantage based on the average opex for international floaters. Assuming a) capex advantage based on 3Y contract, b) foreign rigs have significantly higher capex related to compliance requirements when commencing work for Petrobras in Brazil, and c) foreign rigs had the opportunity to work elsewhere (for USD 350kpd) during the assumed 9 months it takes to prepare for initial work in Brazil.

COSH: Share of revenue estimate secured



Source: ABG Sundal Collier, Company data

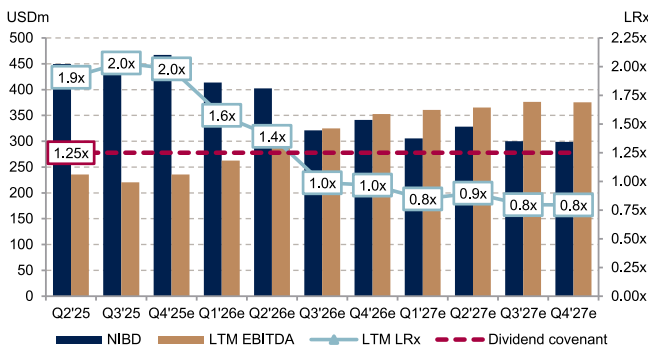
Revenue estimate coverage



Source: ABG Sundal Collier, Company data

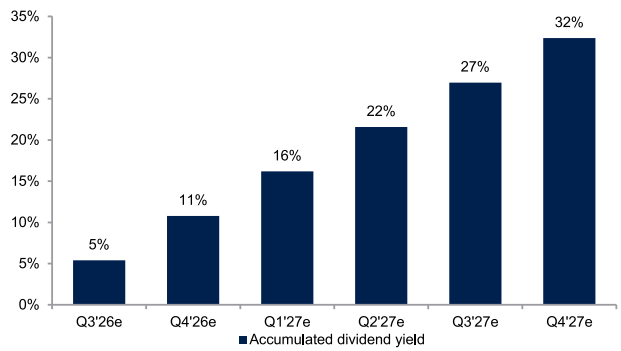
Footnote: Share of revenue estimate covered by firm contracts

COSH: Dividend covenant compliance in Q3'26



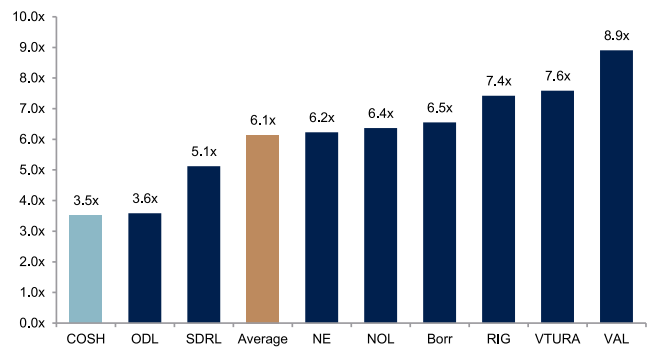
Footnote: ABG Sundal Collier, Company data

COSH: Accumulated dividend yield



Source: ABG Sundal Collier, Company data

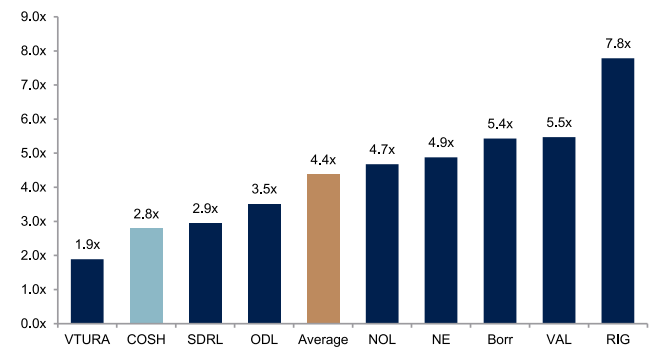
'26e EV/EBITDA dividend-adj.



Source: ABG Sundal Collier, Company data

Footnote: ABGSCe COSH estimate. Factset median consensus for peers.

'27e EV/EBITDA dividend-adj.



Source: ABG Sundal Collier, Company data

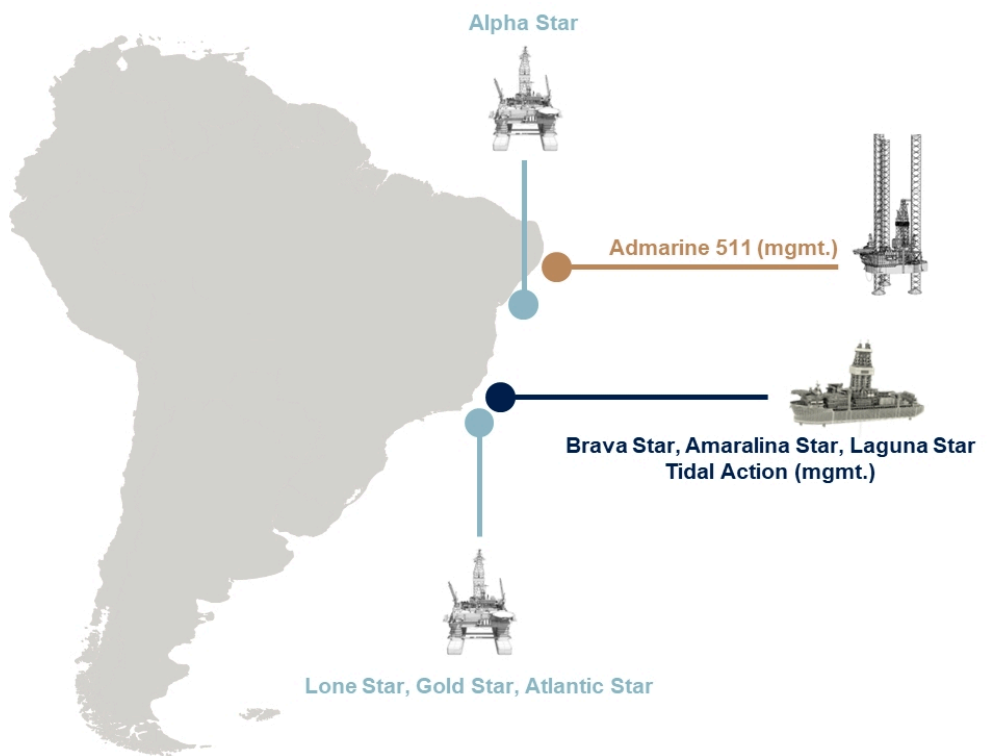
Footnote: ABGSCe COSH estimate. Factset median consensus for peers.

Introduction to Constellation

Company description

Constellation Oil Services is Brazil's largest offshore drilling contractor, operating a fleet of seven owned rigs, plus two under management. With more than three decades of operational experience in Brazil's deep- and ultra-deepwater markets, the company has established a leading position supported by a long-term relationship with Petrobras. Headquartered in Luxembourg and listed on Euronext Growth Oslo, following a USD 1.3bn financial restructuring in 2024, Constellation today operates one of the most advanced fleets in the Brazilian offshore sector. Its assets include three owned drillships (one 7th gen, two 6th gen), four owned semi-submersible rigs (three 6th gen, one 2nd gen), and two managed units, a 7th gen drillship and a premium jack-up, highlighting its technical breadth across rig types.

Pure Brazilian exposure



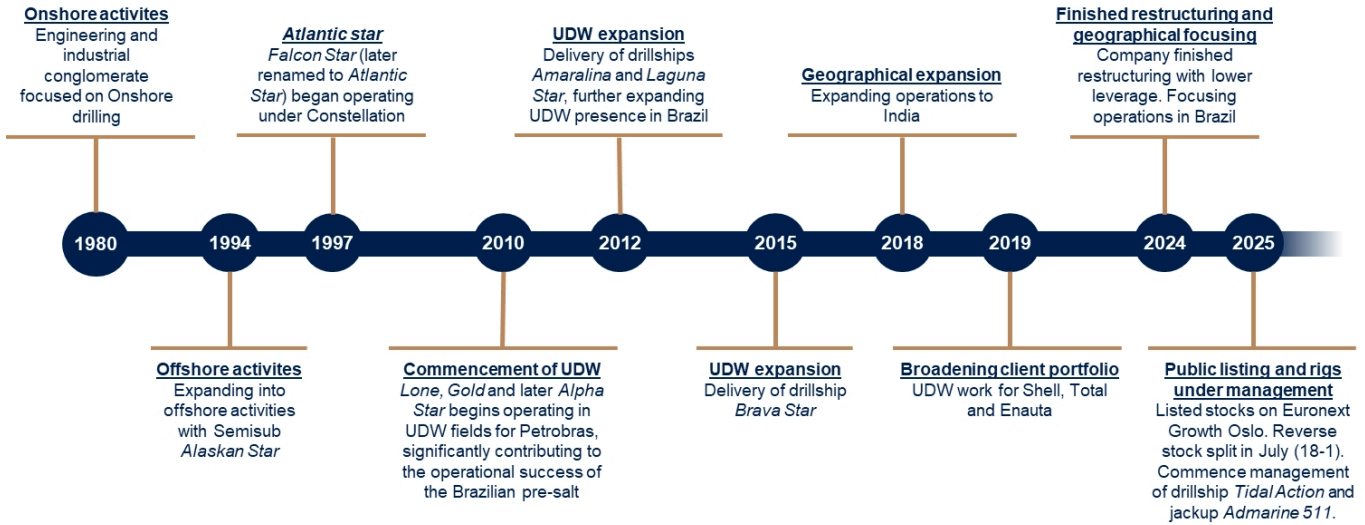
Source: ABG Sundal Collier, Company data, S&P

History

Constellation Oil Services traces its roots back to 1980, when it was established as part of the Queiroz Galvão Group, one of Brazil's leading engineering and industrial conglomerates. Initially focused on onshore drilling, the company gradually expanded into offshore operations during the late 1990s and early 2000s, capitalising on Brazil's rapidly growing deepwater sector driven by Petrobras' exploration successes. Over time, Constellation transformed from a diversified oilfield services provider under the name Queiroz Galvão Óleo e Gás (QGOG) into a pure-play offshore driller, building and acquiring a modern fleet of high-specification rigs tailored for Brazil's pre-salt developments. The company's evolution was marked by several milestones, including the delivery of sixth- and seventh-generation drillships and semi-submersibles, many built under local content initiatives. In 2018, following the financial distress of its parent group, QGOG underwent a court-supervised restructuring and later rebranded as Constellation Oil Services, signalling a new phase of independence and operational refocus. The firm completed a USD 1.3bn balance sheet restructuring in 2024, significantly deleveraging its capital structure and paving the way for its listing on Euronext Growth Oslo. Today, Constellation stands as Brazil's largest

offshore drilling contractor, combining over 30 years of technical expertise with one of the most advanced fleets in Latin America’s offshore oil and gas industry.

Company timeline



Source: ABG Sundal Collier, Company data

Asset overview - The COSH fleet

Constellation owns a fleet of three drillships and four semi-submersibles and manages one drillship and one jackup on behalf of third parties.

The drillship fleet comprises *Brava Star* (7G, 2015-built), *Amaralina Star* (6G, 2012-built) and *Laguna Star* (6G, 2012-built), all operating for Petrobras in Brazil and capable of pre-salt drilling. The company has one Managed Pressure Drilling (MPD) package, now assigned to *Amaralina Star* (previously on *Laguna Star*), while *Brava Star* is MPD-ready. These units mainly perform exploration and development drilling, typically commanding higher day rates than workover or P&A activity. Notably, *Amaralina Star* is approved for drilling in the environmentally sensitive Equatorial Margin, a process requiring lengthy regulatory clearance due to its proximity to the Amazon River delta.

Constellation’s semisubmersible fleet includes *Alpha Star* (6G, 2011-built), *Gold Star* (6G, 2010-built), *Lone Star* (6G, 2010-built) and *Atlantic Star* (2G, 1976-built). All have operated for Petrobras, with *Lone Star* transitioning to work for Brava Energia and *Atlantic* for Karoon Energy. These rigs primarily perform workover and P&A operations where rates are generally lower, but demand is more stable.

The company also manages the 7G drillship *Tidal Action* (2025-built, owned by Hanwha) and premium jackup *Admarine 511* (2019-built, owned by ADES). Operating in Brazil, particularly with Petrobras, requires strong local relationships and detailed procedural expertise, factors that make Constellation a preferred manager for international owners, being the largest rig operator in Brazil, and for Petrobras. With capacity to take on up to five additional rigs without adding notable cost, the company retains notable upside potential through future management additions.

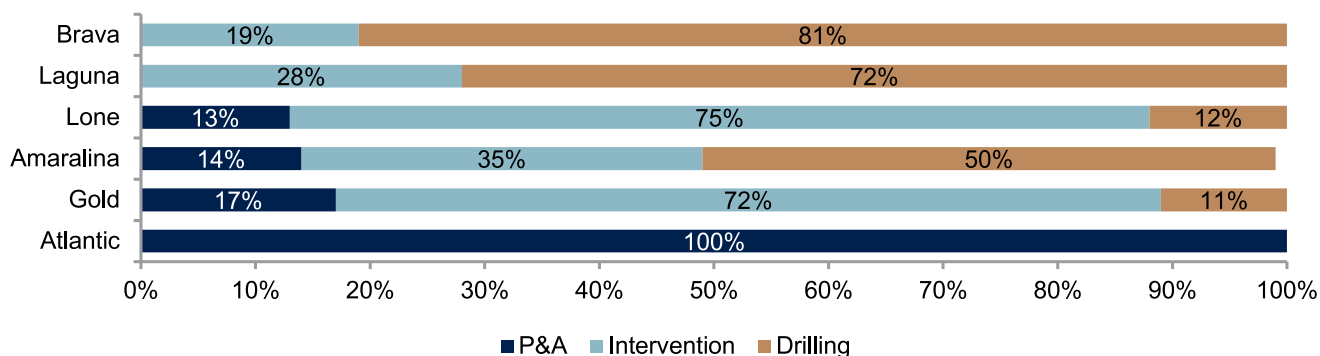
See further rig details below.

Constellation fleet overview

	Owned rigs							Managed rigs	
	Atlantic Star	Lone Star	Gold Star	Alpha Star	Laguna Star	Amaralina Star	Brava Star	Tidal Action	Admarine 511
									
Specification	Standard semisubmersible	Ultra-deepwater semisubmersible	Ultra-deepwater semisubmersible	Ultra-deepwater semisubmersible	Ultra-deepwater drillship	Ultra-deepwater drillship	High-spec ultra-deepwater drillship	High-spec ultra-deepwater drillship	Premium jackup
Type	2G Semi	6G Semi	6G Semi	6G Semi	6G Drillship	6G Drillship	7G Drillship	7G Drillship	Premium JU
Built (age)	1976 (49)	2010 (15)	2010 (15)	2011 (14)	2012 (13)	2012 (13)	2015 (10)	2018/25 (0)	2019 (6)
Water depth (ft)	2,000	8,000	8,000	9,000	10,000	10,000	10,000	12,000	375
Drilling depth (ft)	21,000	24,600	30,000	24,600	40,000	40,000	40,000	37,400	30,000
Derrick hook load (t)	585	900	900	900	900	900	1,125	1,280	675
Variable deck load (t)	2,313	7,131	6,197	10,606	22,046	22,046	22,046	26,455	3,850
BOP stacks	Single	Single	Single	Single	Single	Single	Dual	Dual	Single
BOP rams	4	5	5	5	6	6	7	7	6
Country	Brazil	Brazil	Brazil	Brazil	Brazil	Brazil	Brazil	Brazil	Brazil
MPD	No	No	No	No	No	Yes	No	No	No
Dual derrick	No	No	No	No	Yes	Yes	Yes	Yes	No
DP system	None	DP2	DP2	DP2	DP3	DP3	DP3	DP3	None
Next SPS	Q1'26	Q4'25	Q4'29	Q2'30	Q3'27	Q3'27	Q2'30	Q2'30	Q1'29

Source: ABG Sundal Collier, Company data, S&P, Offshore Intelligence

Activity split with Petrobras, ('22-'24)



Source: ABG Sundal Collier, Company data

Footnote: Intervention includes completion, testing and workover

Contract overview

Atlantic Star: *Atlantic* is currently operating for Petrobras. The contract runs until Jan 26, after which remaining SPS work is scheduled to be carried out prior to commencement of a 77-day contract for Karoon Energy in Q2'26. The rig can potentially secure more work in 2026, most likely linked to decommissioning or workover projects for independent operators.

Lone Star: *Lone Star* is currently operating for Petrobras under a contract set to conclude in Jan 26. The rig will undergo remaining SPS work before starting a new contract with Brava Energia, which will run through Q1'27. The new contract carries materially improved economics, with a dayrate uplift of ~USD 140kpd. The company has secured another 90-day contract with an undisclosed client in direct continuation of the Brava Energia contract, with options potentially extending the contract coverage to YE'27.

Gold Star: Currently operating under an extended contract with Petrobras into Q1'26, while the rig may continue working for Petrobras through H1'26. However, if Petrobras does not agree to rate adjustments closer to current market levels, we believe the company might prioritise securing work with independent operators, who are expected to contribute to incremental demand in 2026. The current contract's economics remain relatively weak, making a shift towards higher-margin opportunities more attractive.

Alpha Star: Currently operating under a new contract with Petrobras running through Q1'28 at a strong rate, the rig also holds a 3-year extension option that could keep her working with Petrobras through 2030.

Laguna Star: Commenced a new contract with Petrobras in Q4'25, running through Q2'28 at strong rates. The agreement includes a 95-day priced option followed by a 930-day extension option, which could keep the rig active with Petrobras into Q1'31.

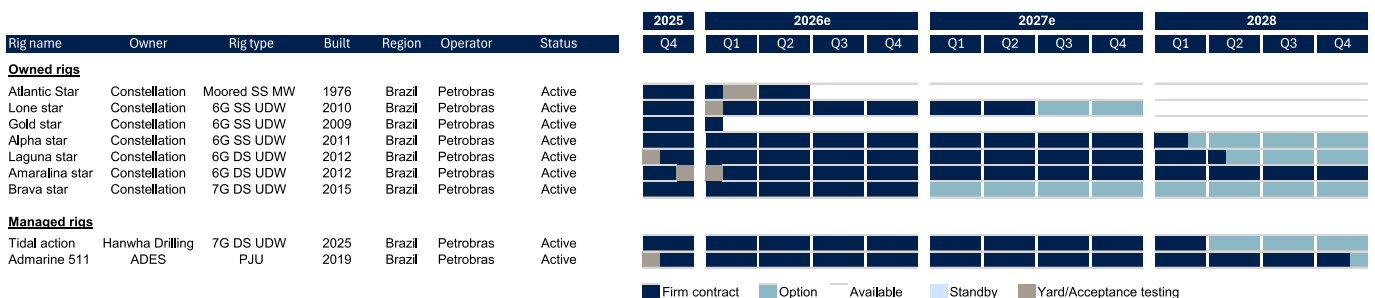
Amaralina Star: Currently operating under a Petrobras contract set to conclude in Q4'25, the rig is expected to undergo remaining SPS work and preparations before starting a new Petrobras campaign in Q1'26 in the Equatorial Margin. The new contract runs into Q1'29 with a significant increase in day rate and includes an option that could keep the rig working through the remainder of 2029.

Brava Star: Currently operating under a Petrobras contract set to conclude in Q4'26, the rig holds a three-year extension option that could keep her active through the end of the decade. The existing contract is secured at a solid rate. *Brava* is well positioned for the Buzios or Mero & Tupi campaigns, both expected to commence in Q1'27. These projects require an MPD system, which the rig currently lacks and would need to lease or acquire. The firm periods for Buzios and Mero & Tupi are ~2.5 and ~3 years (S&P) respectively, each followed by significant optional extensions.

Tidal Action: Currently contracted with Petrobras through Q1'28, providing solid visibility for management revenues.

Admarine 511: Currently contracted with Petrobras into Q4'28, providing solid visibility for management revenues.

Fleet overview



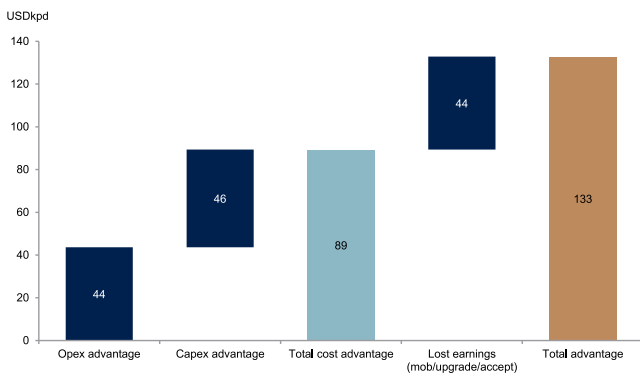
Source: ABG Sundal Collier, Company data, S&P

Leveraging its local setup in Brazil

Constellation has established a leading position in Brazil, with over 25 years of offshore experience and a long-standing partnership with Petrobras, the primary rig demand driver accounting for 33 of the 36 floaters currently active in the country. The two companies have a combined contract history approaching 90 years, giving Constellation deep operational insight into Petrobras’ technical and procedural requirements. This expertise is valuable as new entrants, such as ADES and Hanwha, seek to leverage Constellation’s local experience and operational platform to manage their rigs in Brazil.

Constellation operates from a single hub, providing a structural opex advantage over larger peers with multiple bases. The company also benefits from a pronounced cost edge versus foreign operators, largely stemming from the high capex burden associated with meeting Petrobras’ technical and regulatory requirements. Foreign rigs typically face upfront compliance related costs of up to, and in some cases exceeding, USD 100m when entering Brazil to work for Petrobras. These entry barriers enable Constellation to bid at more competitive rates while maintaining comparable or superior margins. Moreover, the certification process spans several months (typically 6-12), representing a material opportunity cost for new entrants. The effect of these dynamics is reflected in the market structure, where domestic drillers currently contribute a dominant share of Petrobras’ active floater fleet.

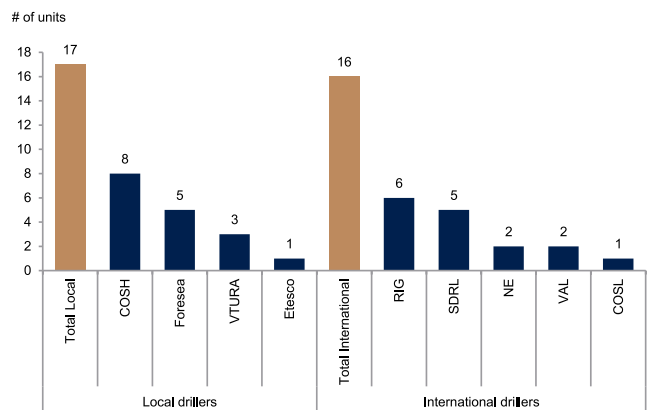
COSH: Cost advantage compared to foreign rigs



Source: ABG Sundal Collier, Company data, S&P

Footnote: Opex advantage based on the average opex for international floaters where several include MPD opex and various add-on services. Assuming a) capex advantage based on 3Y contract, b) foreign rigs have significantly higher capex related to compliance requirements when commencing work for Petrobras in Brazil, and c) foreign rigs had the opportunity to work elsewhere (for USD 350kpd) during the assumed 9 months it takes to prepare for initial work in Brazil.

Petrobras' floater composition, by supplier



Source: ABG Sundal Collier, S&P

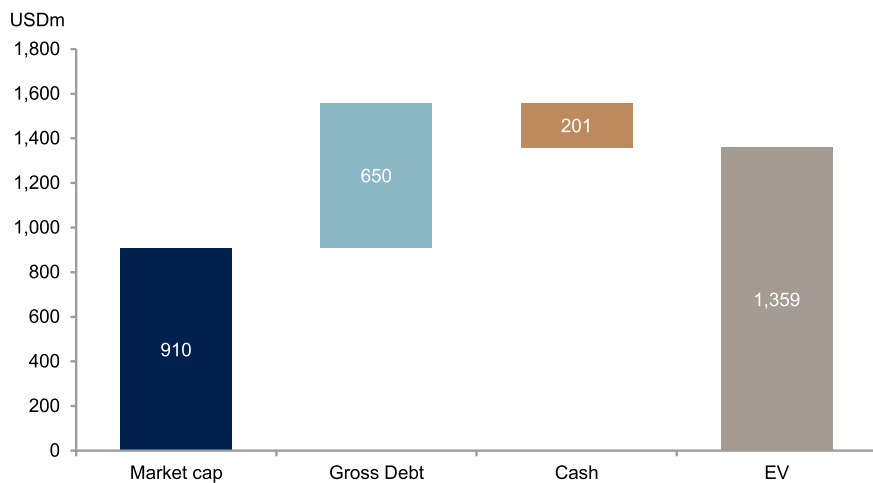
Recent refinancing

In December 2024, Constellation completed a major financial recapitalisation and debt-restructuring that strengthened and simplified its capital structure. As of YE'23, the company's NIBD stood at ~USD 875m, and after the restructure, net debt was reduced to around ~USD 460m by YE'24. The restructuring centred on issuing new senior secured notes of USD 650m due in Q4'29, replacing predecessor debt. As part of the restructuring, the company raised USD 75m in new equity. Post restructuring, Constellation's NIBD/ EBITDA adj. decreased to ~2.0x, from ~4.7 at YE'23. The new debt structure also improved the company's liquidity as cash and short-term investments grew to ~USD183m by end 2024 (~USD 90m YE'23). This transaction stabilised Constellation's financial footing ahead of the listing on Euronext Growth Oslo in Mar'25, giving it a cleaner balance sheet and potential for dividends if LTM leverage dips below 1.25x. The USD 650m has an annual USD 75m amortisation profile, commencing in Nov'26.

As part of the restructuring, certain bondholders opted to redeem their holdings at 95% of par, while others converted debt into equity. Given that several of the converting investors have a credit-oriented mandate, we expect some shareholder rotation ahead. This could increase the stock's free float, which we view positively given the current low trading volume potentially causing a liquidity discount.

The make-whole period on the bond expires within Nov'26, after which we believe the company considers refinancing their bond (Q2 call). On our assumptions, the company should be able to secure a lower coupon on a new bond issue, which would improve cash flow to equity. A refinancing could also introduce more flexible distribution terms, providing additional upside to dividend capacity.

COSH: Capital structure



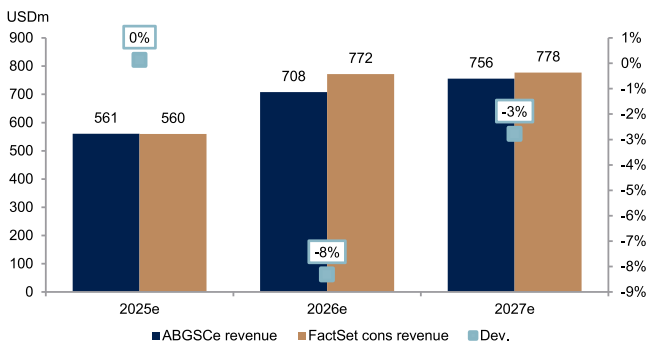
Source: ABG Sundal Collier, Company data

Estimates

ABGSC vs. FactSet consensus

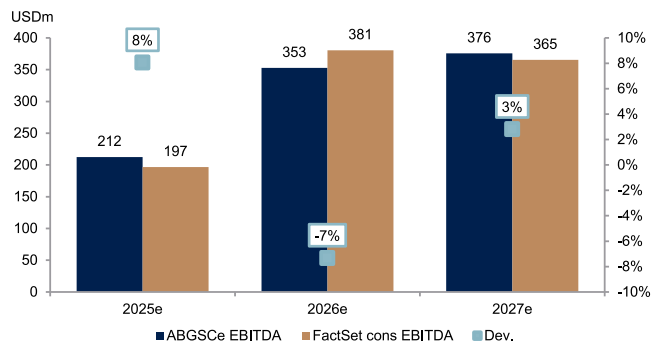
We estimate '25e/'26e/'27e adj. EBITDA of USD 212m/353m/376m. We are 8% above Factset consensus for '25e, although we believe consensus does not fully reflect the updated guidance announced in the Q3 report, when the mid-point was raised by USD 22.5m. We believe the contract schedule has moved in favour of higher activity in '25. Consequently, we have pushed some yard time into Q1'26, reducing the total '26 uptime somewhat, which we believe partly explains why our estimate is 7% below consensus for '26 EBITDA. In addition, we believe a somewhat more cautious estimate for *Gold* mainly explains the remaining deviation. Our '27e deviation is limited as our general market assumption of improving floater markets towards the end of '26/start of '27 is broadly in line with consensus, supported by an increase in outstanding demand requirements, as well as the communication of Constellation, peers, other major oil service players and S&P in Q3'25. Our revenue estimate deviation is partly explained by the above-mentioned factors, while we believe our revenue tax accounting has a negative impact.

COSH: ABGSCe vs. cons revenue (Factset)



Source: ABG Sundal Collier, Company data, Factset

COSH: ABGSCe vs. cons EBITDA (Factset)



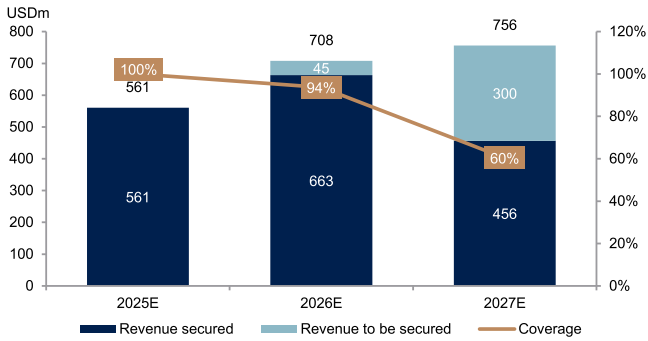
Source: ABG Sundal Collier, Factset

Revenue visibility and deleveraging

Constellation's relatively high share of revenue secured provides confidence in a medium-term earnings uplift, as our '26e revenue is 94% covered by firm contracts. Despite a relatively strong 60% share of revenue secured for '27e, our estimates still rely on firming up available capacity for *Brava*, *Lone*, *Gold* and *Atlantic*. Based on the current pipeline of tenders and the expected work requirements in the region, a strong historical utilisation and the ability to secure contracts offshore Brazil, we believe Constellation is well positioned to secure employment for these rigs in 2027.

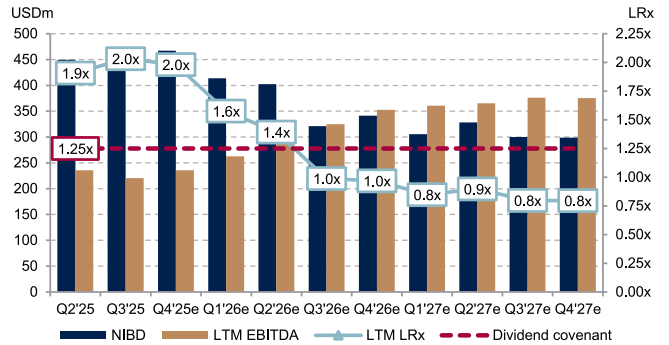
The strong share of revenue secured provides high visibility and confidence in a sharp deleveraging trajectory as rigs roll onto higher day rates and complete maintenance work to lift financial utilisation. The planned commencement of USD 75m in annual amortisation from Q4'26, combined with robust cash generation from improved contract economics, is expected to drive rapid balance sheet strengthening and create room for dividend distribution commencement in H2'26 as LTM NIBD/EBITDA dips below the LR 1.25x incurrence test.

COSH: Share of revenue estimate secured



Source: ABG Sundal Collier, Company data

COSH: Dividend covenant compliance in Q3'26

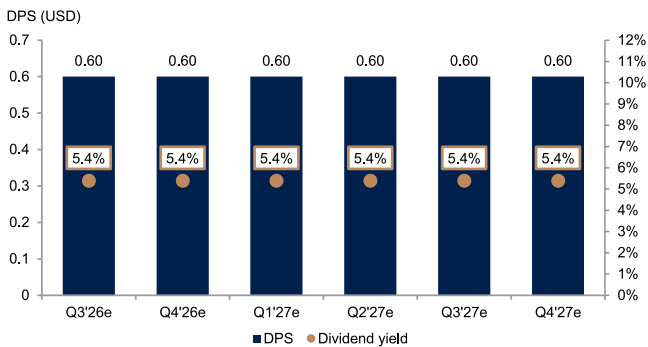


Footnote: ABG Sundal Collier, Company data

Distribution commencement in late 2026

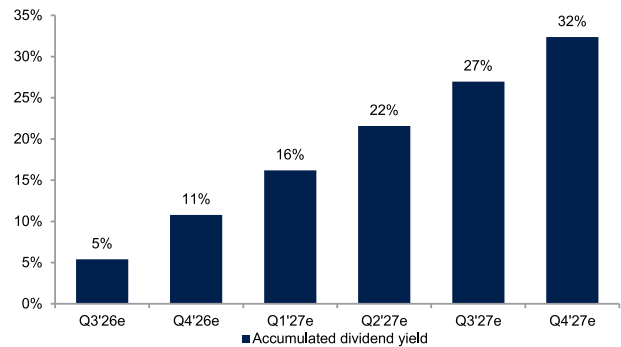
On our estimates, the sharp deleveraging creates room for dividends from Q3'26, with the first payment expected in Q4'26. We estimate DPS of USD 0.60 (~NOK 6.1, ~22% annualised yield) per quarter from Q3'26 through Q4'27, while emphasising the significant upside potential to this estimate as leverage remains low in the 0.8x-0.9x range. This is comfortably below the 1.25x incurrence test while holding a cash balance of ~USD 200m at YE'27 (above its targeted USD 100m minimum liquidity). A potential refinancing in late '26 and potentially more flexible distribution terms provides further upside to our DPS assumption. Based on ~USD 11.1/sh (NOK 112.5/sh), our accumulated DPS estimate indicates 32% of the market cap declared by YE'27.

COSH: DPS and dividend yield



Source: ABG Sundal Collier, Company data

COSH: Accumulated dividend yield



Source: ABG Sundal Collier, Company data

Key assumptions overview

For '25e, the main uncertainty on our estimates relates to the utilisation of *Amaralina* mainly affected by the uncertain timing of yard stay associated with well in progress extensions on existing work, potentially moving a larger part of the stay into '26. Consequently, this aspect also creates uncertainty for our '26e.

In 2026, we have conservatively assumed that *Gold* is inactive for 7 months following the current contract end in Q1'26, succeeded by an assumed day rate of USD 310kpd at 85% utilisation from Nov-26, contributing USD -10m to FY'26e EBITDA. Furthermore, we have assumed that the LOI with Karoon Energy and *Atlantic* is converted into a firm contract, followed by a day rate of USD 250kpd at an average utilisation of 50%. At these assumptions, the rig adds ~USD 15m to FY'26e EBITDA.

In 2027, the main estimate uncertainty relates to *Brava*, *Gold*, *Atlantic* and *Lone*. Our general market view is a strengthening from late '26 / early '27, which leaves our *Brava* rate assumption at USD 390kpd, an increase compared to the current contract, and broadly where we believe the current market for 7G floaters is (market sources suggest high-spec Buzios rates at ~USD 395kpd and Mero/Tupi rates at ~USD 370kpd). Utilisation is assumed at 85% as we believe the rig has several potential opportunities to secure work for the year,

including Buzios, Mero/Tupi, and Gato do Mato. For *Lone* and *Gold*, we have assumed USD 310kpd, leaving the two in line/somewhat below where we believe the current market is for 6G semis performing workover operations in Brazil (we estimate that *Lone* was contracted at ~USD 330kpd in the 90-day contract announced on the Q3 report). For utilisation, we also assume 85%, as we believe demand for the rigs will be driven by required P&A work and more stable workover demand. We have assumed Atlantic at USD 250kpd, although at 50% utilisation. We believe this is conservative given its strong utilisation track record, however a prudent approach is warranted considering the age of the rig.

Our utilisation assumption for contracted rigs is at the long-term historical average of ~92%, and we expect opex to increase at a 3% inflation rate.

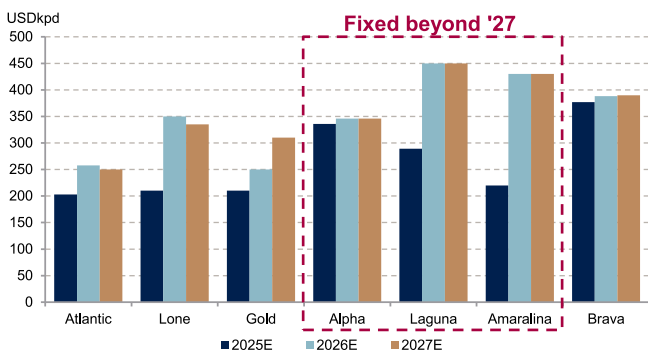
Key assumptions

Key assumptions	2025E	2026E	2027E
Day rates, USDkpd			
Atlantic	203	258	250
Lone	210	350	335
Gold	210	250	310
Alpha	336	346	346
Laguna	289	450	450
Amaralina	220	430	430
Brava	377	388	390
Utilization			
Atlantic	92%	52%	50%
Lone	92%	91%	89%
Gold	92%	86%	85%
Alpha	77%	92%	92%
Laguna	73%	92%	92%
Amaralina	85%	81%	92%
Brava	92%	89%	74%
Opex, USDkpd			
Atlantic	90	93	96
Lone	110	113	118
Gold	115	118	123
Alpha	125	129	134
Laguna	140	139	145
Amaralina	135	149	155
Brava	140	144	150

Source: ABG Sundal Collier, Company data

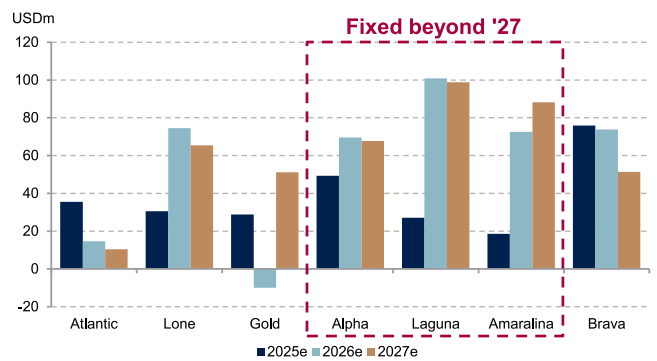
Footnote: Average for the respective year

Rate assumptions



Source: ABG Sundal Collier, Company data, S&P

EBITDA contribution, by rig

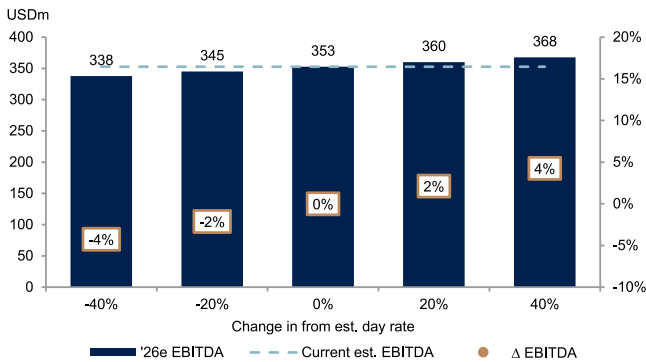


Source: ABG Sundal Collier, Company data

Assumption sensitivity on EBITDA

Our '26e EBITDA has limited sensitivity to day rates given the 94% of revenue secured, while the '27e is more sensitive to changes in the day rate as four rigs remain uncontracted. A 40% lower day rate estimate for open capacity in '27 implies 25% lower EBITDA on our estimates. This is equivalent to assuming ~USD 235kpd for *Brava*, ~USD 185kpd for *Lone* and *Gold*, and USD 150kpd for *Atlantic*.

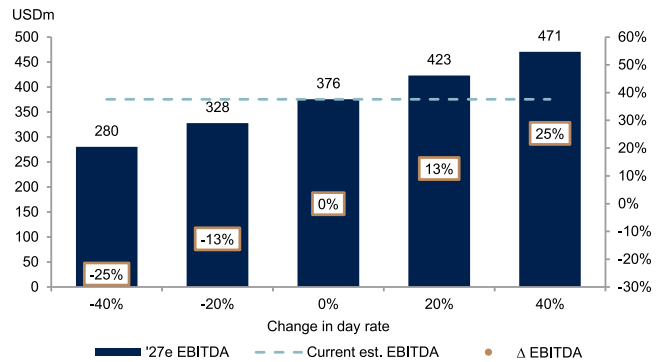
COSH: '26e EBITDA sensitivity to changes in day rates



Source: ABG Sundal Collier, Company data

Footnote: All other model assumptions are fixed.

COSH: '27e EBITDA sensitivity to changes in day rates



Source: ABG Sundal Collier, Company data

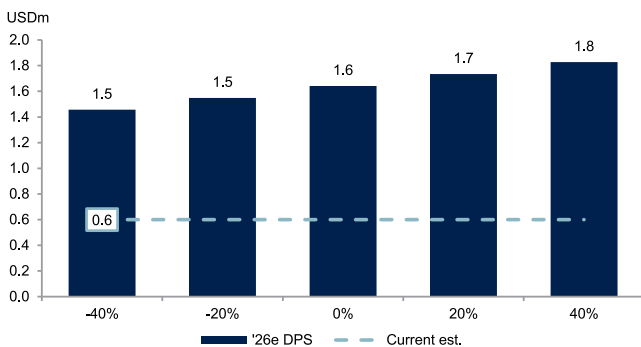
Footnote: All other model assumptions are fixed.

Assumption sensitivity on DPS

Our estimated '26e DPS potential has relatively low sensitivity to day rate assumptions due to 94% of revenue secured. The '27e DPS potential is much more sensitive to day rate assumptions due to the 60% share of revenue secured. Notably, there is still dividend potential in '27e if open capacity is contracted at rates 40% below our already conservative assumptions. Furthermore, our estimated DPS of USD 2.4/sh is possible even at a 20% drop in open capacity day rates.

Note: The bars show the maximum potential DPS at different rate assumptions within the limits of LTM LRx 1.25 and USD 100m in minimum liquidity.

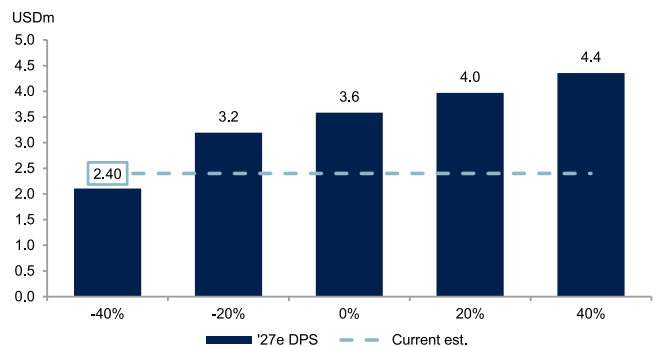
COSH: '26e DPS sensitivity



Source: ABG Sundal Collier, Company data

Footnote: 1) Assuming maximum DPS within LR 1.25x and minimum liquidity = USD 100m. 2) Dividend estimates are based on time of payment, not the quarter to which they relate.

COSH: '27e DPS sensitivity



Source: ABG Sundal Collier, Company data

Footnote: 1) Assuming maximum DPS within LR 1.25x and minimum liquidity = USD 100m. 2) Dividend estimates are based on time of payment, not the quarter to which they relate.

Key estimates

Below we summarise our key estimates.

COSH: Key estimates vs. consensus (Factset)

Constellation Oil Services													Cons.			Cons.			Cons.		
USDm	Q4'24	Q1'25	Q2'25	Q3'25	Q4'25e	Q4'25e	2022	2023	2024	2025e	2026e	2027e	2025e	2026e	2027e	Cons. Dev.	Cons. Dev.	Cons. Dev.			
Income Statement	FactSet						FactSet						FactSet								
Revenue	140	122	139	136	161	152	406	552	564	561	708	756	560	772	778	0%	-8%	-3%			
Opex	-91	-78	-84	-92	-92	-101	-339	-366	-333	-348	-355	-380	-363	-392	-412						
EBITDA adj.	49	44	55	44	70	51	67	185	230	212	353	376	197	381	365	8%	-7%	3%			
EBITDA adj. margins	35%	36%	40%	32%	43%	33%	17%	34%	41%	38%	50%	50%	35%	49%	47%						
EBIT	-45	-9	12	-4	15	-4	994	21	-11	14	136	161	-13	161	151	-212%	-16%	7%			
EBIT margins	n.a.	n.a.	9%	n.a.	9%	n.a.	245%	4%	n.a.	3%	19%	21%	n.a.	21%	19%						
PTP	-36	-23	4	-15	1	-17	861	-26	-47	-33	83	115	-61	111	105	-46%	-25%	9%			
Net profit	-41	-24	0	-14	-6	-22	859	-31	-42	-43	65	98	-77	85	87	-44%	-23%	13%			
EPS	-0.48	-0.28	0.00	-0.16	-0.07	-0.09	10.18	-0.37	-0.50	-0.51	0.77	1.17	-0.91	1.01	1.03	-44%	-23%	13%			
DPS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.20	2.40	0.00	0.92	2.48	na	30%	-3%			
Key BS and CF figures																					
Gross interest bearing debt	642	658	644	660	660		0	964	642	660	585	510									
Gross cash	165	173	195	201	182		0	88	165	182	232	200	173	253	158						
NIBD	477	486	450	459	479	471	0	876	477	479	353	310	465	304	343	3%	16%	-10%			
Operating cash flow	62	33	47	60	-9		36	111	167	130	247	313									
Capex	-39	-36	-26	-47	-42		103	78	122	151	124	120									
Free cash flow	26	6	20	14	-19		-66	33	29	20	176	245	33	200	223	-39%	-12%	10%			
Free cash flow/share	0.3	0.1	0.2	0.2	-0.2		-0.8	0.4	0.3	0.2	2.1	2.9									
							-21.44	27.115	42	20	101	170									
Other key figures																					
NIBD/rig										68	50	44									
NIBD/EBITDA										2.3x	1.0x	0.8x	2.4x	0.8x	0.9x						
NIBD/EV										34%	27%	25%									
Dividend covenant										1.25x	1.25x	1.25x									

Source: ABG Sundal Collier, Company data, Factset

Detailed estimates

COSH: Key P&L estimates

Key figures (USDm)			
P&L	2025E	2026E	2027E
Contract drilling (net of tax)	556	690	738
Mgmt fee	5	18	18
Revenue	561	708	756
Contract drilling	-311	-323	-336
SG&A	-35	-32	-36
Other	21	0	-8
EBITDA	236	353	376
EBIT	14	136	161
PTP	-33	83	115
Net profit	-43	65	98
EPS	-0,51	0,77	1,17
EBITDA%	42%	51%	51%
EBIT%	3%	20%	22%
PTP%	-6%	12%	16%
NF%	-8%	9%	13%

Source: ABG Sundal Collier, Company data

COSH: Key cash flow estimates

Cash Flow	2025E	2026E	2027E
EBITDA	236	353	376
Tax	(7)	(18)	(16)
NWC	(37)	(19)	2
Other	(16)	(16)	(4)
Operating cash flow	176	299	358
Capex	(151)	(124)	(120)
Other	40	53	53
FCFF	66	229	290
Net finances	(46)	(53)	(45)
FCF	20	176	245
Change in debt	0	(75)	(75)
FCFE	20	101	170
Dividends	0	51	203

Source: ABG Sundal Collier, Company data

COSH: Key balance sheet items

Balance sheet	2025E	2026E	2027E
Cash	182	232	200
Other current assets	291	324	334
Rigs and equipment	2190	2044	1896
Other current liabilities	211	208	217
GJBD	660	585	510
Equity	1806	1821	1717
NIBD	479	353	310
NIBD/EBITDA	2,0x	1,0x	0,8x
ICR	5,2x	6,7x	8,3x
NIBD/EV	34%	28%	25%
NIBD/rig	68	50	44
GJBD/rig	94	84	73

Source: ABG Sundal Collier, Company data

Valuation

We initiate coverage of Constellation with a BUY rating and a target price of NOK 150/sh. At our TP, the share would be trading at:

- ~4.4x/3.6x EV/EBITDA (divi-adjusted) multiple on our '26e/'27e, compared to the peer group trading at a median '26e/'27e multiple of 6.4x/4.7x.
- A valuation slightly above our SOTP NAV/sh of NOK 145/sh based on conservative asset values (EV / rig at USD 232m), and in line with our SG&A adjusted '26e-'27e NAV of NOK 140-160/sh.
- ~16% dividend yield on our '26e DPS on an annualised basis, compared to an ODL dividend yield of ~13% and a broader rig space with few companies paying dividends.
- ~11%/18% FCF yield (divi-adjusted) on our '26e/'27e, notably above the peer median of 3%/9% for '26e/'27e.

Multiple and yield valuation

Below we summarise key valuation metrics.

COSH: Valuation overview

Valuation	2025E	2026E	2027E
Mcap	939	939	939
NIBD	479	353	310
EV	1418	1292	1250
EV/EBITDA	6.0x	3.7x	3.3x
P/E	-21.8x	14.4x	9.5x
FCFF yield to EV	5%	18%	23%
FCF yield to EV	1%	14%	20%
FCF yield to Mcap	2%	19%	26%
FCFE yield	2%	11%	18%
Dividend yield	0%	5%	22%
Accumulated FCF	-20	197	442
Accumulated FCF % of YE'25 EV	1%	14%	31%
EV/rig	203	185	179
Dividend adj. multiples			
NIBD divi add back	479	302	108
EV	1418	1242	1047
EV/EBITDA	6.0x	3.5x	2.8x
FCF yield to EV	1%	14%	23%

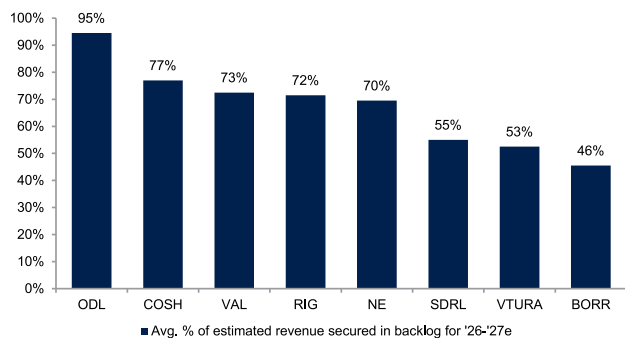
Source: ABG Sundal Collier, Company data

Footnote: Note that dividend yield is based on the timing of dividend payments

Coverage vs. peers

Within our drilling coverage, Constellation has the second-strongest revenue visibility, with an average estimate coverage of ~77% for '26e-'27e at strong day rates. This is above Transocean, Valaris and Noble, but below Odfjell Drilling following its recent contract announcements. However, if Brava secures a contract in any of the large Petrobras tenders, we estimate an average revenue coverage for '26e-'27e of 85%. High coverage adds visibility, de-risks estimates and should arguably achieve a higher valuation. During the recent market downturn, we have favoured RIG and ODL given their strong share of revenue secured at solid economics relative to peers, and we see similar characteristics for Constellation.

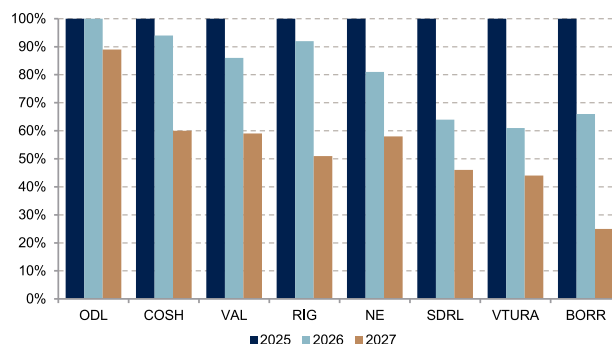
Revenue estimate coverage



Source: ABG Sundal Collier, Company data

Footnote: Share of revenue estimate covered by firm contracts

Revenue estimate coverage, by year



Source: ABG Sundal Collier, Company data

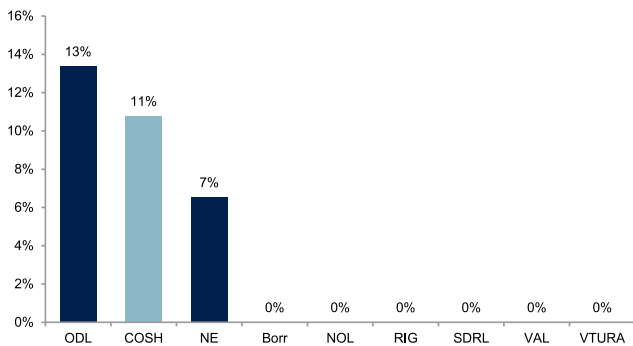
Footnote: Share of revenue estimate covered by firm contracts

Multiple and yield valuation vs peers

We believe Constellation can declare a DPS implying 11%/22% of its market cap in '26e/'27e, amounting to 32% on aggregate. We emphasise that the '27e 22% yield is above the FCFE yield of 19% in '27e, meaning that at our current assumption the high dividend yield is not a long-term sustainable yield. However, the distribution is comfortably within the limiting LRx and target minimum cash. Furthermore, a potential refinancing of the bond after Nov-26 could entail more flexible distribution terms and potential upside to dividend payments.

Most peers are not expected to pay dividends in '26e-'27e, constrained by low contract coverage and elevated leverage. Amid limited short-term demand requirements, drillers with relatively low backlog visibility have suspended distributions, and Borr and Transocean remain focused on deleveraging. Constellation, by contrast, has already completed parts of its deleveraging phase following the restructuring and is expected to continue reducing its leverage while maintaining strong contract coverage and an industry-leading dividend yield. We therefore view the stock as attractively valued relative to peers.

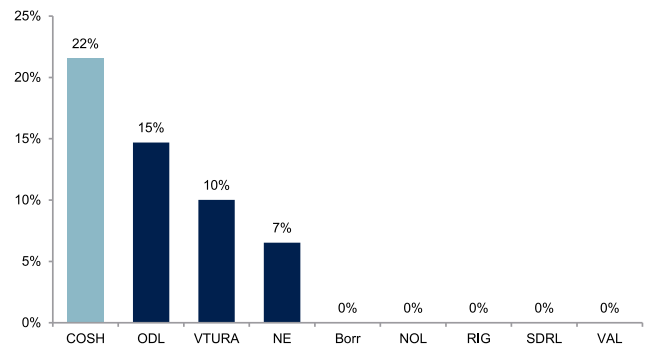
'26e dividend yield



Source: ABG Sundal Collier, Company data

Footnote: ABGSCe COSH estimate. Factset median consensus for peers.

'27e dividend yield

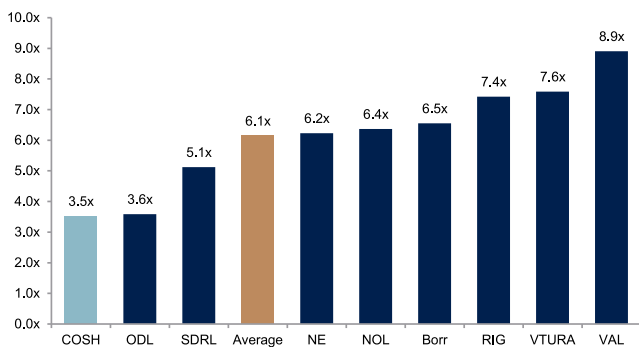


Source: ABG Sundal Collier, Company data

Footnote: ABGSCe COSH estimate. Factset median consensus for peers.

Given that Constellation is one of only three to four peers expected to pay dividends, dividend-adjusted EV/EBITDA offers a clean, capital-structure-neutral comparison across the peer group. The company is trading at 3.5/2.8x dividend-adjusted EV/EBITDA for '26e/'27e, well below the average for peers that have a relatively similar share of revenue secured (RIG, ODL, VAL, NE) of 6.5x/5.4x. Although we believe a discount to the larger drillers is justified given Constellation's higher asset risk and geographic concentration, as well as peers trading closer to mid-cycle earnings and therefore warranting higher multiples, we believe the current valuation gap is too wide.

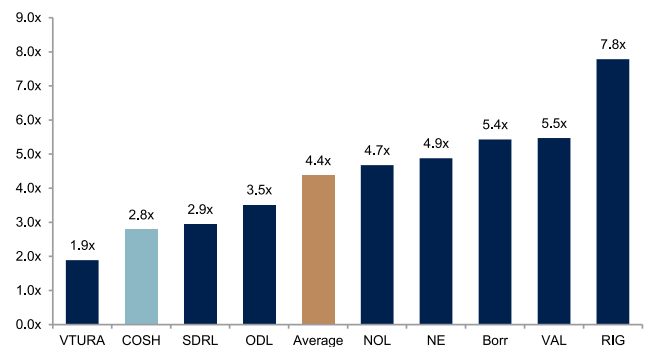
'26e EV/EBITDA dividend-adj.



Source: ABG Sundal Collier, Company data

Footnote: ABGSCe COSH estimate. Factset median consensus for peers.

'27e EV/EBITDA dividend-adj.

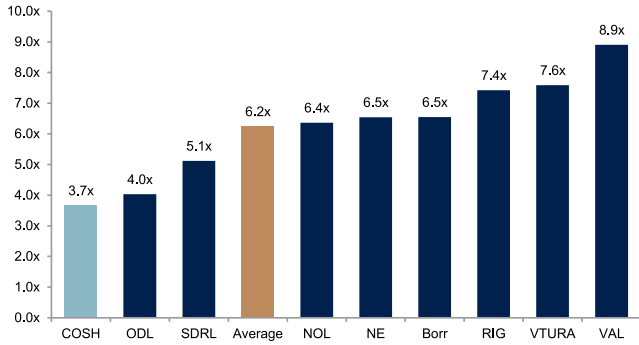


Source: ABG Sundal Collier, Company data

Footnote: ABGSCe COSH estimate. Factset median consensus for peers.

Constellation is trading at EV/EBITDA (not dividend-adjusted) of 3.7x/3.3x on our '26e/'27e, placing it at the lower end of the peer group. The average multiple for RIG, ODL, VAL and NE is 6.7x/5.6x implying significant upside to the current market cap.

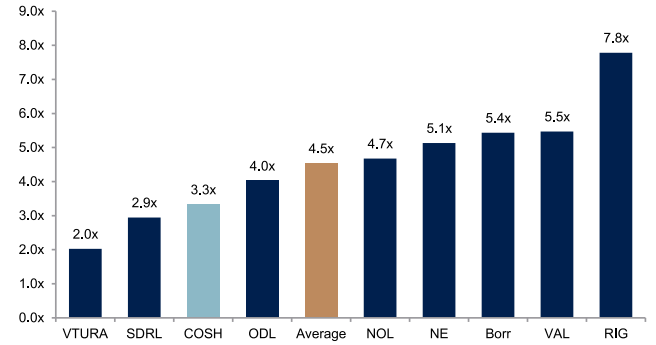
'26e EV/EBITDA



Source: ABG Sundal Collier, Company data

Footnote: ABGSCe COSH estimate. Factset median consensus for peers.

'27e EV/EBITDA



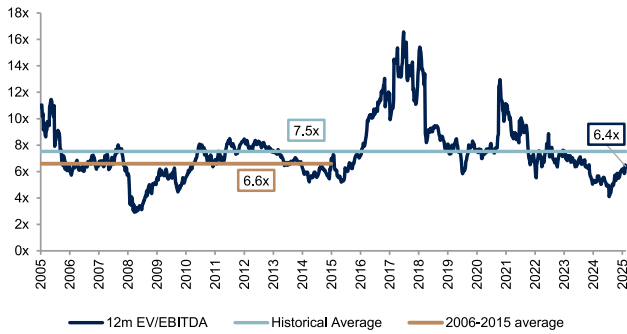
Source: ABG Sundal Collier, Company data

Footnote: ABGSCe COSH estimate. Factset median consensus for peers.

Sector EV/EBITDA

The floater sector currently trades at an EV / EBITDA multiple of 6.4x/5.8x at NTM and the subsequent 12 months, a level close to the last upcycle ('05-'14), while ~1 turn below the through-cycle multiple average of 7.5x/6.9x. The '25 multiple expansion was initially driven by downwards estimate revisions followed by the post-Liberation Day rally in the sector.

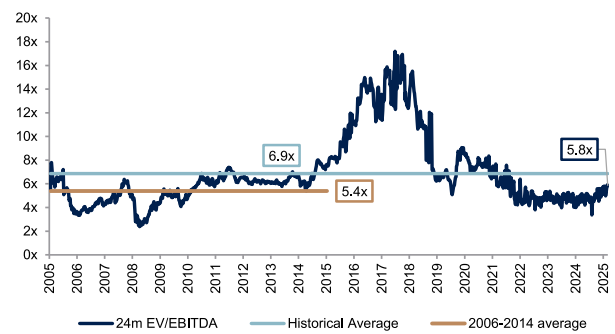
Sector 12m EV/EBITDA



Source: ABG Sundal Collier, FactSet

Footnote: Currently including RIG, NE, VAL, SDRL, ODL

Sector 24m EV/EBITDA



Source: ABG Sundal Collier, FactSet

Footnote: Currently including RIG, NE, VAL, SDRL, ODL

SOTP

In our asset NAV we value the rigs based on a DCF, with asset-specific assumptions until '27e and generic assumptions for each rig based on their asset class for the remaining life of the rig. We assume higher rates for Brava than Amaralina and Laguna, mainly due to the spec difference (7G vs 6G), while we expect Amaralina to achieve somewhat higher rates based on the assumption that Amaralina will be MPD-enabled while Laguna will not. We assume equal rates for the three 6G semis, lower than for the drillships mainly due spec differences, and that the rigs typically perform lower-rate workover and P&A work, while Atlantic achieves the lowest rates due to its lower spec. Furthermore, we adjust current contract economics compared to the assumed current market rates for similar assets, which totals USD 187m. Based on this, we arrive at USD 1,625m in asset GAV, implying an EV / rig at USD 232m and a USD 1,212m NAV, indicating NOK 145/sh as fair value (23% discount). We find our through-cycle rate estimates as fair, supported by historical rates as well as broker quotes of ~USD 158m/350m for 6G/7G floaters.

We note that this is an asset NAV, and that SG&A, a necessity to operate these rigs, is not included in the calculation. Applying a 4.0x multiple on USD 45m annual SG&A and other opex, and looking at the YE'26e/YE'27e NAV when NIBD (dividend-adjusted) has decreased to USD 302m/108m, we arrive at a NAV/sh of NOK 140/160.

COSH: SOTP

SOTP Q3'25e	Asset class	Built	Status	Asset value	Backlog and other adj. (USDm)	Net NPV (USDm)
Floaters						
Atlantic Star	Moored SS MW	1976	Drilling	41	0	41
Lone star	6G SS UDW	2010	Drilling	137	36	173
Gold star	6G SS UDW	2009	Drilling	143	0	143
Alpha star	6G SS UDW	2011	Drilling	139	33	173
Laguna star	6G DS UDW	2012	Drilling	294	62	356
Amaralina star	6G DS UDW	2012	Drilling	320	50	371
Brava star	7G DS UDW	2015	Drilling	362	5	368
Total owned fleet				1,438	187	1,625
Gross fleet value (USDm)						1,625
Mgmt agreements						46
NIBD Q3'25e						459
Net fleet value						1,212
Diluted share count						84
NAV/sh						14.4
NAV/sh (NOK)						145
EV/GAV						0.86x
P/NAV						0.77x
LTV						27%
EV / rig						232

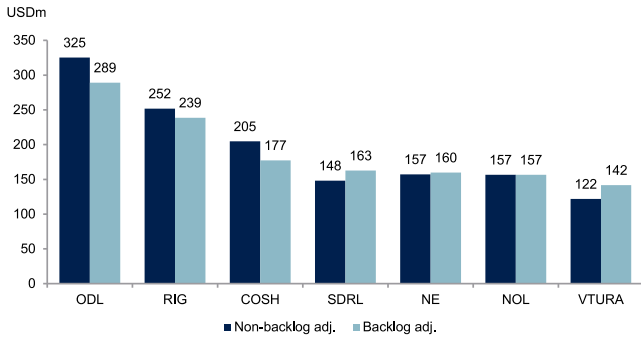
Source: ABG Sundal Collier, Company data

EV / Rig vs peers

COSH is priced at USD 205m per 6G benign rig equivalent, or USD 178m if adjusting for the backlog. This is below the peer average of ~USD 189m. We argue a premium is warranted due to the strong share of revenue secured on solid rates, expected low leverage relative to peers, and an industry-leading near-term distribution yield. Note that several peers have a different fleet composition than COSH, are often more focused towards 7G drillships, making the implied rig calculations subject to some uncertainty related to the conversion factor of different rig types.

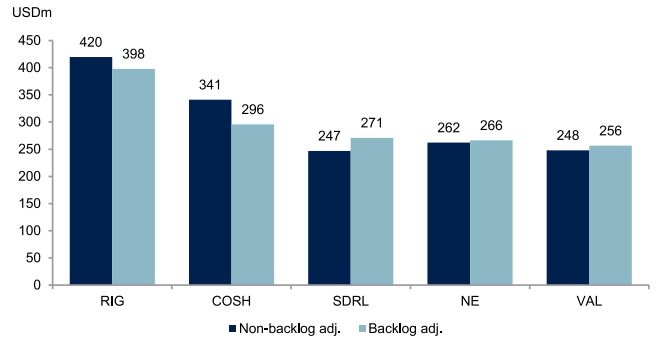
The implied EV/7G pricing of COSH is at USD 341m/296m on non-backlog adj./backlog adj. basis. This is USD 12%/-1% compared to the peer average.

Implied EV/6G benign



Source: ABG Sundal Collier, Company data

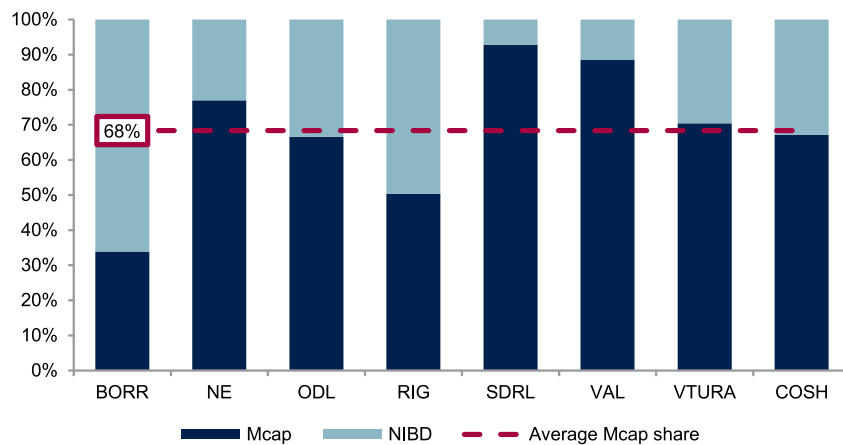
Implied EV / 7G



Source: ABG Sundal Collier, Company data

Constellation's current EV composition implies a NIBD share of EV at ~67%, around the peer average. However, on our estimates, the NIBD will be ~USD 310 by YE'26, increasing the share to ~75%. In order to keep the same EV / rig valuation by YE'26, the market cap would need an equivalent increase as the NIBD decrease (~USD 149m/16% of MCap). Furthermore, we believe a lower NIBD will decrease equity risk, potentially resulting in an equity appreciation above the NIBD decrease, resulting in a EV / rig valuation closer to our SOTP estimate.

EV structure, by peer



Source: ABG Sundal Collier, Company data, Factset

Broader peer valuation comparison

Peer table

FactSet cons	Mcap	EV ^{25E}	EV/EBITDA			EV/EBITDA-net capex			EV/EBIT			P/E			FCF Yield to EV			Distribution yield			NIBD/EBITDA		
	USDm	USDm	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E
Floater	1,985	2,899	6.6x	4.7x	4.6x	9.2x	5.0x	5.0x	11.3x	7.6x	7.6x	11.9x	7.1x	7.3x	-1%	16%	17%	8%	13%	14%	2.1x	1.3x	1.0x
Odyssey drilling	1,904	2,095	6.1x	5.2x	3.4x	48.0x	12.5x	5.2x	17.7x	11.9x	5.1x	-36.6x	19.0x	6.6x	-4%	3%	14%	0%	0%	0%	0.6x	0.3x	0.0x
Northern Ocean	247	763	11.8x	7.0x	5.2x	33.0x	7.9x	5.8x	50.9x	13.7x	8.3x	-5.7x	-35.3x	7.1x	-4%	2%	7%	0%	0%	0%	8.0x	4.7x	3.3x
Ventura	214	315	3.6x	7.8x	2.0x	4.3x	-6.8x	2.2x	5.9x	24.3x	2.4x	10.7x	-23.0x	2.3x	12%	-20%	32%	0%	0%	10%	1.2x	3.5x	0.7x
Valaris	3,925	4,412	7.3x	8.8x	5.4x	20.7x	31.9x	10.1x	9.3x	11.6x	6.5x	14.0x	15.1x	7.6x	4%	1%	7%	0%	0%	0%	0.8x	0.9x	0.3x
Noble	4,864	6,350	5.8x	6.4x	4.9x	9.7x	11.8x	7.4x	12.1x	14.9x	9.1x	34.0x	30.2x	11.9x	9%	4%	8%	7%	7%	7%	1.4x	1.6x	1.1x
Transocean	4,857	9,686	7.1x	6.7x	6.9x	7.8x	7.4x	7.7x	13.8x	11.5x	12.5x	47.6x	19.7x	32.8x	6%	8%	9%	0%	0%	0%	3.5x	3.1x	2.9x
Average	2,571	3,789	6.9x	6.7x	4.6x	19.0x	10.0x	6.2x	17.3x	13.7x	7.3x	10.8x	4.7x	10.8x	3%	2%	13%	2%	3%	4%	2.5x	2.2x	1.3x
Median	1,985	2,899	6.6x	6.7x	4.9x	9.7x	7.9x	5.8x	12.1x	11.9x	7.6x	11.9x	15.1x	7.3x	4%	3%	9%	0%	0%	0%	1.4x	1.6x	1.0x
COSH (ABGScE)	939	1,418	6.0x	3.7x	3.3x	11.3x	4.6x	4.1x	98.2x	9.5x	7.8x	-21.8x	14.4x	9.5x	1%	14%	20%	0%	11%	22%	2.0x	1.0x	0.8x
Premium/(discount) to core peers			-9%	-45%	-32%	16%	-42%	-30%	712%	-20%	3%	-284%	-5%	31%	148%	-76%	-57%	na	-100%	-100%	-33%	56%	26%
Jackups	USDm	USDm	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E
Borr Drilling	946	2,768	6.0x	6.6x	5.4x	7.1x	7.7x	6.2x	8.7x	10.2x	8.0x	22.9x	na	15.3x	7%	4%	7%	11%	0%	0%	3.9x	4.2x	3.4x
Sheff Drilling	469	1,601	4.5x	4.3x	4.2x	6.2x	6.1x	6.6x	8.2x	7.8x	6.6x	18.0x	10.2x	7.4x	5%	3%	3%	0%	0%	0%	3.2x	3.0x	2.8x
Valaris	3,925	4,412	7.3x	8.8x	5.4x	20.7x	31.9x	10.1x	9.3x	11.6x	6.5x	14.0x	15.1x	7.6x	4%	1%	7%	0%	0%	0%	0.8x	0.9x	0.3x
Average	1,780	2,927	5.9x	6.6x	5.0x	11.4x	15.2x	7.7x	8.7x	9.8x	7.0x	18.3x	12.7x	10.1x	5%	3%	6%	4%	0%	0%	2.6x	2.7x	2.2x
Median	946	2,768	6.0x	6.6x	5.4x	7.1x	7.7x	6.6x	8.7x	10.2x	6.6x	18.0x	12.7x	7.6x	5%	3%	7%	0%	0%	0%	3.2x	3.0x	2.8x
MED jackups	USDm	USDm	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E
ADCS	5,107	8,416	9.3x	7.4x	7.2x	17.2x	9.5x	9.2x	16.7x	14.9x	13.3x	24.5x	18.1x	16.7x	2%	5%	7%	2%	3%	4%	3.7x	2.8x	2.6x
ADNOC Drilling	22,783	24,653	11.2x	10.6x	9.8x	14.6x	13.2x	12.7x	14.9x	13.9x	12.8x	16.0x	15.3x	14.0x	5%	7%	8%	4%	5%	5%	0.9x	0.6x	0.4x
Arabian Drilling	2,147	2,795	8.3x	7.2x	6.4x	22.5x	15.6x	11.8x	n.m.	21.3x	15.1x	n.m.	33.3x	18.8x	5%	5%	7%	1%	2%	4%	1.9x	1.5x	1.1x
Average	10,013	11,954	9.6x	8.4x	7.8x	18.1x	12.8x	11.2x	15.8x	16.7x	13.7x	20.3x	22.2x	16.5x	4%	6%	7%	3%	3%	4%	2.1x	1.7x	1.4x
Median	5,107	8,416	9.3x	7.4x	7.2x	17.2x	13.2x	11.8x	15.8x	14.9x	13.3x	20.3x	18.1x	16.7x	5%	5%	7%	2%	3%	4%	1.9x	1.5x	1.1x
Subsea	USDm	USDm	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E
Subsea7	5,780	6,129	4.3x	3.7x	3.4x	5.4x	4.8x	4.4x	8.1x	6.4x	5.9x	13.1x	10.1x	9.6x	10%	12%	15%	6%	5%	5%	0.2x	0.1x	-0.2x
DOF	2,292	3,697	4.9x	4.2x	4.2x	7.9x	5.4x	5.4x	7.3x	6.3x	6.3x	5.7x	5.5x	5.9x	7%	13%	13%	10%	15%	16%	1.9x	1.5x	1.5x
Paratus	736	1,344	5.6x	5.4x	5.3x	6.0x	5.9x	5.8x	23.6x	39.1x	18.6x	10.8x	8.2x	6.9x	15%	10%	9%	20%	20%	20%	2.6x	2.4x	2.4x
Sea1 Offshore	325	537	3.7x	4.4x	4.9x	8.5x	-84.6x	-6.2x	5.6x	7.0x	7.6x	2.9x	5.0x	4.8x	24%	-5%	-22%	29%	2%	7%	1.5x	2.0x	2.8x
Average	2,283	2,927	4.6x	4.4x	4.5x	7.0x	-17.1x	2.4x	11.2x	14.7x	9.6x	8.1x	7.2x	6.8x	14%	8%	4%	16%	11%	12%	1.5x	1.5x	1.6x
Median	1,514	2,521	4.6x	4.3x	4.6x	7.0x	5.1x	4.9x	7.7x	6.7x	7.0x	8.3x	6.9x	6.4x	12%	11%	11%	15%	10%	12%	1.7x	1.8x	1.9x
Oil service majors	USDm	USDm	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E
SLB	54,140	61,994	7.4x	6.9x	6.4x	9.6x	9.3x	8.5x	10.7x	10.2x	9.3x	13.0x	12.4x	11.5x	6%	8%	8%	3%	3%	3%	0.9x	0.8x	0.6x
TechnipFMC	18,309	17,800	9.7x	8.6x	7.9x	12.0x	10.3x	9.5x	13.0x	11.1x	10.0x	19.3x	16.6x	15.0x	8%	7%	7%	0%	0%	0%	-0.3x	-0.3x	-0.4x
Baker Hughes	49,536	51,997	11.0x	9.9x	9.1x	14.7x	13.2x	11.9x	14.5x	12.8x	11.4x	20.0x	19.2x	16.9x	4%	5%	6%	2%	2%	2%	0.5x	-0.1x	-0.2x
Halliburton	22,067	27,342	6.6x	6.6x	5.9x	9.7x	8.8x	8.1x	9.2x	9.3x	7.9x	11.4x	12.2x	10.4x	6%	8%	8%	3%	3%	3%	1.3x	1.1x	0.9x
Average	36,013	39,783	8.7x	8.0x	7.3x	11.5x	10.4x	9.5x	11.8x	10.9x	9.6x	15.9x	15.1x	13.5x	6%	7%	7%	2%	2%	2%	0.6x	0.4x	0.2x
Median	35,802	39,669	8.6x	7.7x	7.1x	10.8x	9.8x	9.0x	11.9x	10.6x	9.6x	16.1x	14.5x	13.2x	6%	7%	8%	2%	2%	2%	0.7x	0.4x	0.2x
Engineering and other	USDm	USDm	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E	2025E	2026E	2027E
Archer	211	636	4.3x	3.9x	3.4x	7.1x	5.9x	4.9x	7.6x	6.4x	5.7x	-17.5x	5.7x	4.5x	0%	8%	12%	18%	10%	11%	2.9x	2.6x	2.2x
Odyssey Technology	218	309	3.9x	3.6x	3.4x	8.4x	5.5x	4.7x	6.1x	5.7x	5.3x	6.5x	6.2x	5.8x	3%	13%	15%	11%	11%	11%	1.2x	1.0x	0.8x
NOV	5,603	6,070	6.0x	6.0x	5.4x	9.4x	9.2x	8.1x	9.3x	9.2x	8.4x	15.7x	14.0x	12.3x	9%	9%	9%	4%	3%	3%	0.5x	0.4x	0.1x
Aker Solutions	1,490	1,287	2.5x	3.4x	3.9x	2.7x	4.0x	4.7x	3.3x	5.1x	6.2x	5.8x	7.2x	8.9x	16%	11%	11%	11%	8%	7%	-0.4x	-0.3x	-0.6x
Weatherford	5,365	5,886	5.6x	5.3x	4.6x	7.1x	6.6x	5.7x	7.7x	7.3x	6.1x	13.4x	13.4x	12.1x	6%	9%	11%	1%	1%	1%	0.5x	0.2x	-0.1x
Expro	1,584	1,478	4.2x	3.9x	3.7x	6.1x	5.8x	5.5x	11.2x	10.4x	9.1x	14.6x	16.5x	14.5x	6%	9%	10%	0%	0%	0%	-0.3x	-0.4x	-0.6x
Hunting	780	741	5.5x	4.8x	3.9x	7.6x	6.3x	5.0x	7.7x	6.5x	5.3x	12.6x	11.1x	9.8x	9%	11%	15%	3%	3%	3%	-0.3x	-0.5x	-0.8x
Average	2,179	2,344	4.6x	4.4x	4.0x	6.9x	6.2x	5.5x	7.6x	7.2x	6.6x	7.3x	10.6x	9.7x	7%	10%	12%	7%	5%	5%	0.6x	0.4x	0.1x
Median	1,490	1,287	4.3x	3.9x	3.9x	7.1x	5.9x	5.0x	7.7x	6.5x	6.1x	12.6x	11.1x	9.8x	6%	9%	11%	4%	3%	3%	0.5x	0.2x	-0.1x

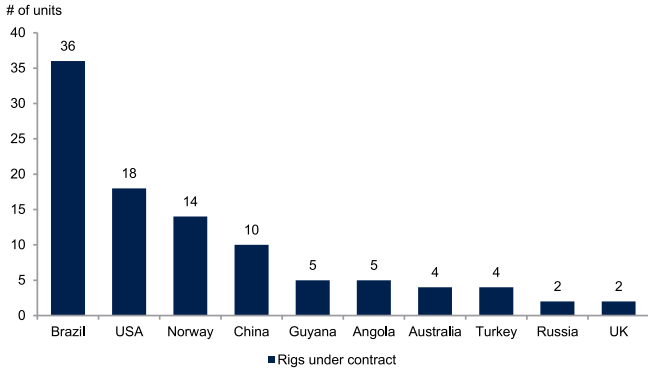
Source: ABG Sundal Collier, Company data, Factset

Rig Market overview

Brazil

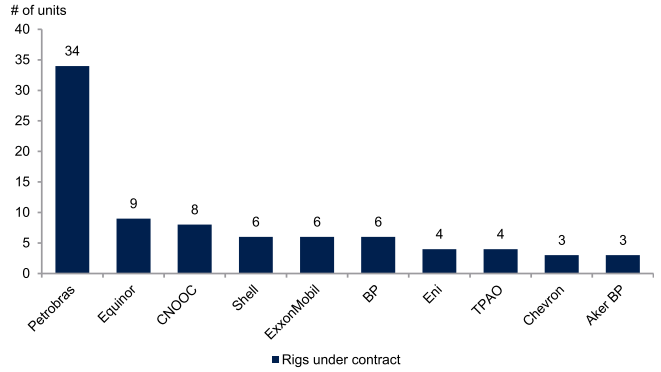
Brazil remains the main market for floaters, with 36 contracted units, including 35 UDW rigs, representing 31% of the global floater fleet (32% of all contracted UDW units). This concentration makes Petrobras the most important operator in the sector. The company controls 34 contracted floaters, equal to roughly 30% of the global total and nearly four times the number operated by the second-largest player, Equinor.

Active floaters by country



Source: ABG Sundal Collier, S&P

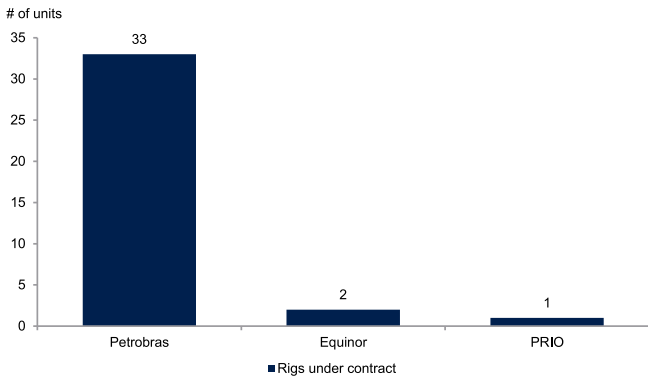
Active floaters by operator



Source: ABG Sundal Collier, S&P

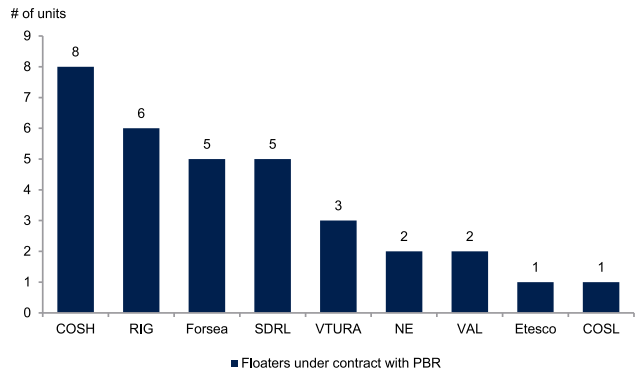
Petrobras dominates the Brazilian floater market, operating 33 of the 36 contracted units, with Equinor and PRIO accounting for the remaining three. Constellation is the largest supplier to Petrobras, providing 7 of its 34 rigs, or ~21%. Once the Lone contract begins with *Brava Energia*, Constellation’s contribution will decrease to 6 units. Petrobras’ floater portfolio is broadly balanced between domestic and international drillers.

Contracted floaters in Brazil per operator



Source: ABG Sundal Collier, S&P

Floaters under contract with Petrobras

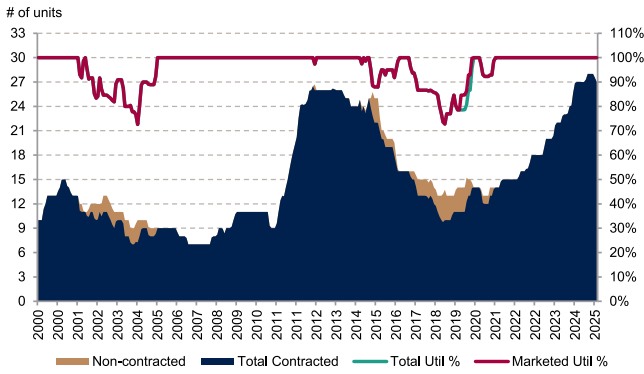


Source: ABG Sundal Collier, Company data, S&P

Brazil: Semi and drillship market

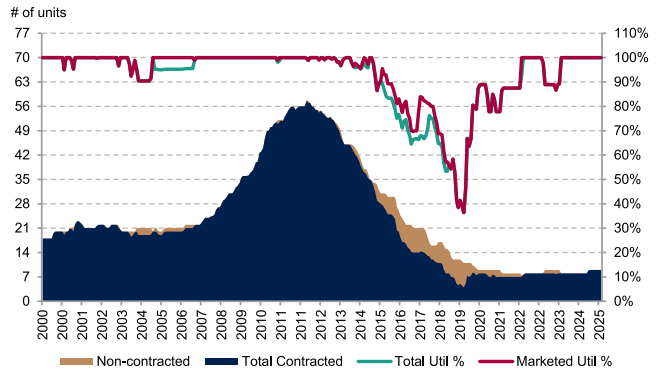
Drillship demand surged during the previous upcycle before falling sharply from 2014 as oil prices weakened and investment slowed, with activity bottoming in 2018. Since then, drillships have driven the gradual recovery as exploration and development drilling picked up, reflected in steadily rising contracted units and tightening marketed utilisation. The semisub market, by contrast, has remained more stable following the market decline in 2014. Semis are now primarily deployed on workover and P&A operations, where activity levels have remained consistent, producing a flatter activity profile. COSH units account for four of 10 semis (including an upcoming newbuild in late 2026), underlining their importance to Petrobras’ workover and P&A requirements.

Drillship: Brazil market balance



Source: ABG Sundal Collier, S&P

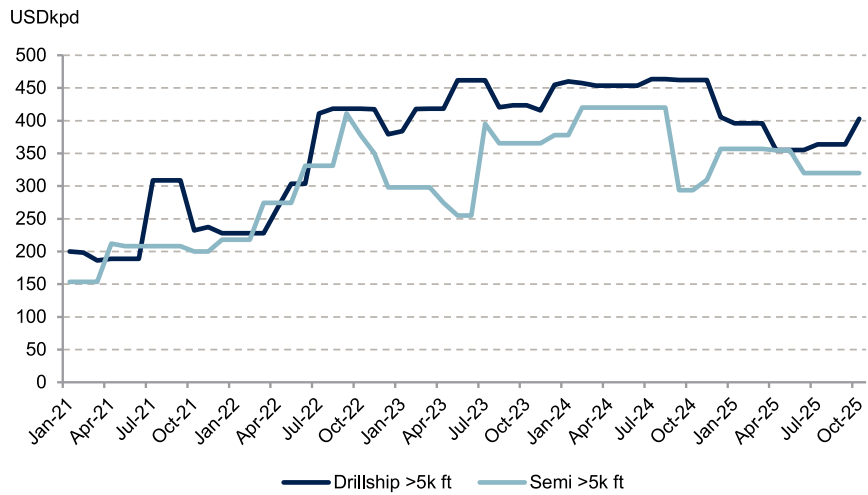
Semisub: Brazil market balance



Source: ABG Sundal Collier, S&P

As utilisation tightened through and after the pandemic, day rates moved sharply higher, peaking in '24 before softening in line with the global utilisation decline from the '24 highs. South American drillship rates reached approximately ~USD 450kpd at peak levels, while semis achieved around ~USD 425kpd. In the second half of 2025, day rates have broadly stabilised in the region. These figures reflect South America as a whole, though the region is mainly driven by the Brazilian market.

Day rates in South America



Source: ABG Sundal Collier, S&P

Below are the most recent fixtures in South America. Activity has been limited in '25, with few new contracts and a higher share of priced options, making headline day rates less representative of underlying market conditions. Several Petrobras-linked options for rigs such as *Laguna*, *Lone* and *Gold* were priced in the low 200s range (USD kpd), reflecting legacy option structures rather than current market rates. *ODN II* was the only rig able to operate in the Equatorial Margin at the time of contracting, which also limits comparability with similar units in the region.

South America floater fixtures

Rig Name	Owner	Type	Fixture	Country	Operator	Days	Start	Contract type	Day Rate
Noble Developer	Noble	SS	Oct-25	Suriname	PETRONAS	70	Jan-26	Priced option	na
ODN II	Foresea	DS	Oct-25	Brazil	Petrobras	150	Oct-25	New mutual	440
Norbe IX	Foresea	DS	Oct-25	Brazil	Petrobras	40	Oct-25	Priced contract	179
Deepwater Mykonos	Transocean	DS	Oct-25	Brazil	Petrobras	30	Dec-25	Priced option	367
Stena Carron	Stena	DS	Aug-25	Guyana	ExxonMobil	180	Dec-25	Priced option	na
Stena Carron	Stena	DS	Aug-25	Guyana	ExxonMobil	186	Jun-26	Priced option	na
Deepwater Mykonos	Transocean	DS	Jun-25	Brazil	Petrobras	79	Oct-25	New mutual	366
Amaralina Star	Constellation	DS	May-25	Brazil	Petrobras	34	Oct-25	Priced option	430
Lone Star	Constellation	SS	May-25	Brazil	Petrobras	88	Sep-25	Priced option	na
Gold Star	Constellation	SS	May-25	Brazil	Petrobras	105	Aug-25	Priced option	na
Laguna Star	Constellation	DS	May-25	Brazil	Petrobras	124	Mar-25	Priced option	na
Noble Developer	Noble	SS	Apr-25	Suriname	TotalEnergies	1060	Dec-26	New mutual	na
Noble Valiant	Noble	DS	Apr-25	Suriname	TotalEnergies	1060	Jan-27	New mutual	na
Noble Discoverer	Noble	SS	Apr-25	Colombia	Petrobras	390	Jul-25	Priced option	na
ODN II	Foresea	DS	Apr-25	Brazil	Petrobras	91	Jul-25	Priced option	440
Valaris DS-15	Valaris	DS	Feb-25	Brazil	BP	105	May-25	Priced sublet	400
Valaris DS-15	Valaris	DS	Jan-25	Brazil	Shell	93	Feb-25	Priced sublet	400
Stena DrillMAX	Stena	DS	Jan-25	Suriname	TotalEnergies	118	May-25	New mutual	na
Noble Developer	Noble	SS	Dec-24	Suriname	PETRONAS	201	Jul-25	New mutual	na
Atlantic Star	Constellation	SS	Dec-24	Brazil	Petrobras	322	Jan-25	New mutual	200
Norbe IX	Foresea	DS	Dec-24	Brazil	Petrobras	1095	Feb-26	New mutual	380
West Tellus	Seadrill Ltd	DS	Dec-24	Brazil	Petrobras	1095	Jun-26	New mutual	455
Carolina	Ventura	DS	Dec-24	Brazil	Petrobras	910	May-26	New mutual	370
West Jupiter	Seadrill Ltd	DS	Dec-24	Brazil	Petrobras	1095	Apr-26	New mutual	450
Etesco Takatsugu J	Etesco	DS	Dec-24	Brazil	Petrobras	1095	Dec-25	New mutual	348
Amaralina Star	Constellation	DS	Dec-24	Brazil	Petrobras	1095	Feb-26	New mutual	429
Lone Star	Constellation	SS	Nov-24	Brazil	Brava Energia	400	Dec-25	New mutual	325
Tidal Action	Hanwha	DS	Sep-24	Brazil	Petrobras	931	Sep-25	New mutual	na
Laguna Star	Constellation	DS	Sep-24	Brazil	Petrobras	931	Oct-25	New mutual	450
Noble Tom Madden	Noble	DS	Sep-24	Guyana	ExxonMobil	427	Jun-27	New mutual	na
Noble Courage	Noble	SS	Sep-24	Brazil	Petrobras	1186	Sep-24	New mutual	294

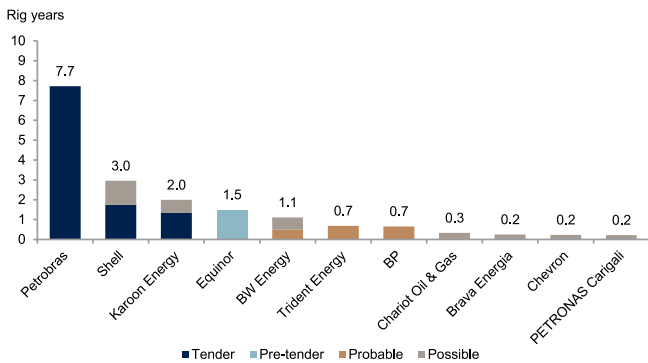
Source: ABG Sundal Collier, S&P

Brazil demand

Tenders and identified opportunities are good proxies for future floater demand. Petrobras remains the dominant source of rig requirements, with an estimated 7.7 rig years in the queue, while international operators such as Shell, Karoon and Equinor also show a more visible presence compared to the current active rig distribution. Aside from tenders and other known potential opportunities, workover and P&A projects are typically bilateral agreements, not covered by the chart below.

S&P expects Brazilian floater demand to continue rising through '27, with the active rig count projected to increase from 30 units in '24 to 35-37 units in '26-'27.

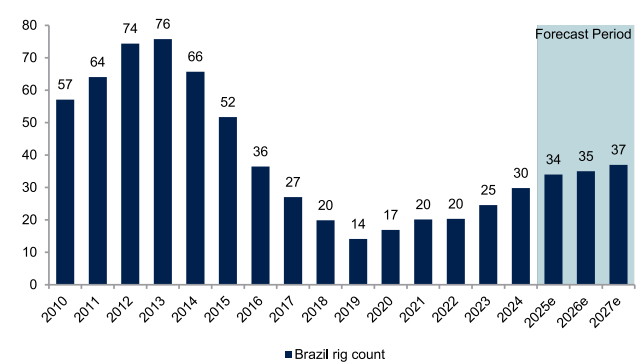
Brazil: Tenders and potential demand, by operator



Source: ABG Sundal Collier, S&P

Footnote: According to S&P, RIG mgmt. stated an estimated firm 23 rig years spread across 6 rigs for Buzios, Mero/Tupi and Gato do Mato.

Brazil rig count, S&P estimate



Source: ABG Sundal Collier, S&P

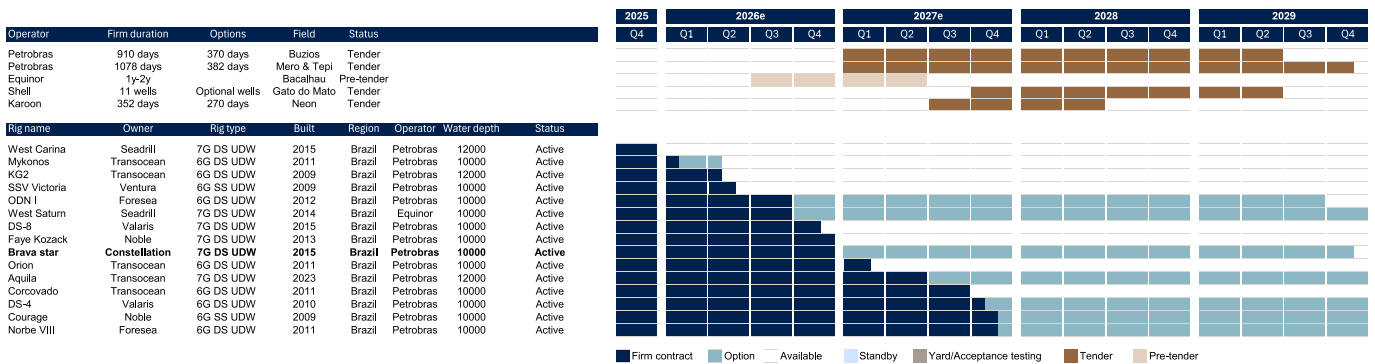
The three major tenders driving demand in Brazil is related to Petrobras' major Buzios and Mero&Tupi fields and Shell's Gato do Mato. The Petrobras fields are at the core of Brazil's production, with Buzios, the world's largest deepwater field, expected to reach 1.5mbpd with four additional FPSOs in '26-'27. Tupi/Iracema, Brazil's largest producing asset, delivers around 1mboe/d, while Mero has an installed capacity of 0.8mbpd. Despite S&Ps estimated tendered rig years, we note that the three tenders are expected to occupy six floaters, implying significant upside to the estimate in the chart above. This is supported by Transocean's expectation for the three tenders to contribute with 23 rig years in aggregate demand.

All major Brazilian floater tenders are now concluded and awaiting final awards. The competitive Buzios tender attracted 14 bids, with indicative rates in the USD 305-395kpd

range for the four prospective winners, depending on how Petrobras classifies the rig, since the company adjusts bid values based on the rig’s technical setup. For example whether it has one or two drilling towers, and how much work it can perform offline. The Mero and Tupi tender saw nine bids, with expected rates of USD 305-370kpd for the single awarded unit. Shell’s Gato do Mato tender has also been finalised, with contract execution pending partner approval. Importantly, the campaigns are expected to be largely, if not fully, covered by rigs that are already in Brazil. Brava Star, which meets all technical requirements, including MPD capability, deepwater specification and availability aligned with the project start dates, is well positioned for an award.

Comparing the tender schedule (see below) with rigs in Brazil assumed to be specification compliant with the three major tenders, and availability matching the commencement of the tenders, it becomes evident that the availability of floaters is expected to exceed demand. This holds true even when assuming the Buzios tender will require four floaters. This supports the reported strong competition in the tenders, and explains the muted day rates expected for the tenders.

Floater tenders vs qualified floaters in Brazil with matching open capacity



Source: ABG Sundal Collier, S&P, Company data

Incremental demand may arise from the expected Brazilian exploration drilling activity, both expected in the Equatorial margin and the South and Southeast margin. The Equatorial margin has significant potential and has achieved increased interest considering its proximity to Guyana and Suriname. The blocks in the margin are located in deepwater, hence drilling demand in the region would be covered by floaters. In the most recent Open Acreage-Concession (Jun-25), Chevron, Petrobras and ExxonMobil acquired several blocks in the Foz do Amazonas basin (the Brazilian basin with the closest proximity to Suriname and Guyana). Exploration drilling performed by ExxonMobil or Chevron on these blocks could imply incremental drilling demand as the operators currently do not have contracted rigs in the country.

Obtaining drilling allowance in Foz do Amazonas requires a comprehensive environmental licence from Ibama. Currently, only ODN II has drilled in the basin. However, Amaralina will commence exploration activity in the Equatorial margin for Petrobras when her new contracts start in early '26, implying that Constellation has experience with obtaining allowance for drilling operations in the region.

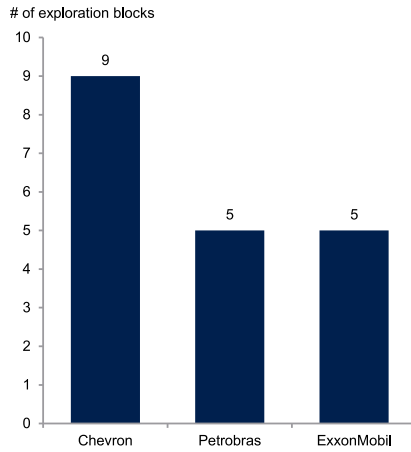
In the June concession round, Karoon, Shell, Equinor and Petrobras acquired blocks in the Santos and Pelotas basin. As Shell and Karoon do not have contracted compliant rigs in Brazil, any investment decisions for exploration drilling would imply incremental drilling demand in the South & Southeast margin as well.

**Jun-25 Open Acreage-
Concessions block awards**



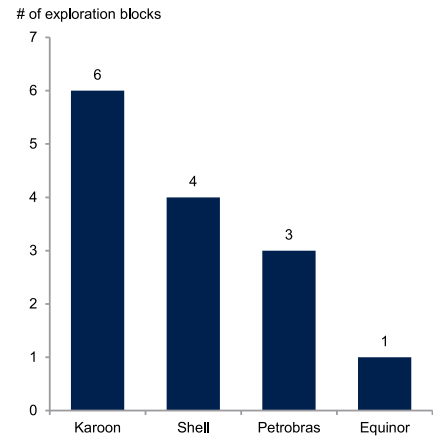
Source: ABG Sundal Collier, Brazilian government

**Equatorial Margin: Exploration
blocks awarded in Jun-25**



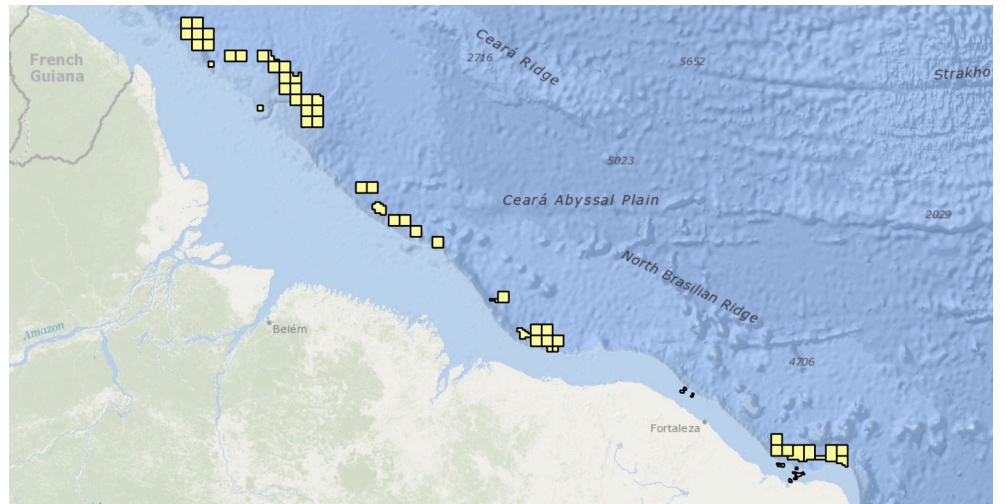
Source: ABG Sundal Collier, Brazilian Government

**South and Southeast Margin:
Exploration blocks awarded in
Jun-25**



Source: ABG Sundal Collier, Brazilian Government

Blocks in the Equatorial margin are located in deepwater

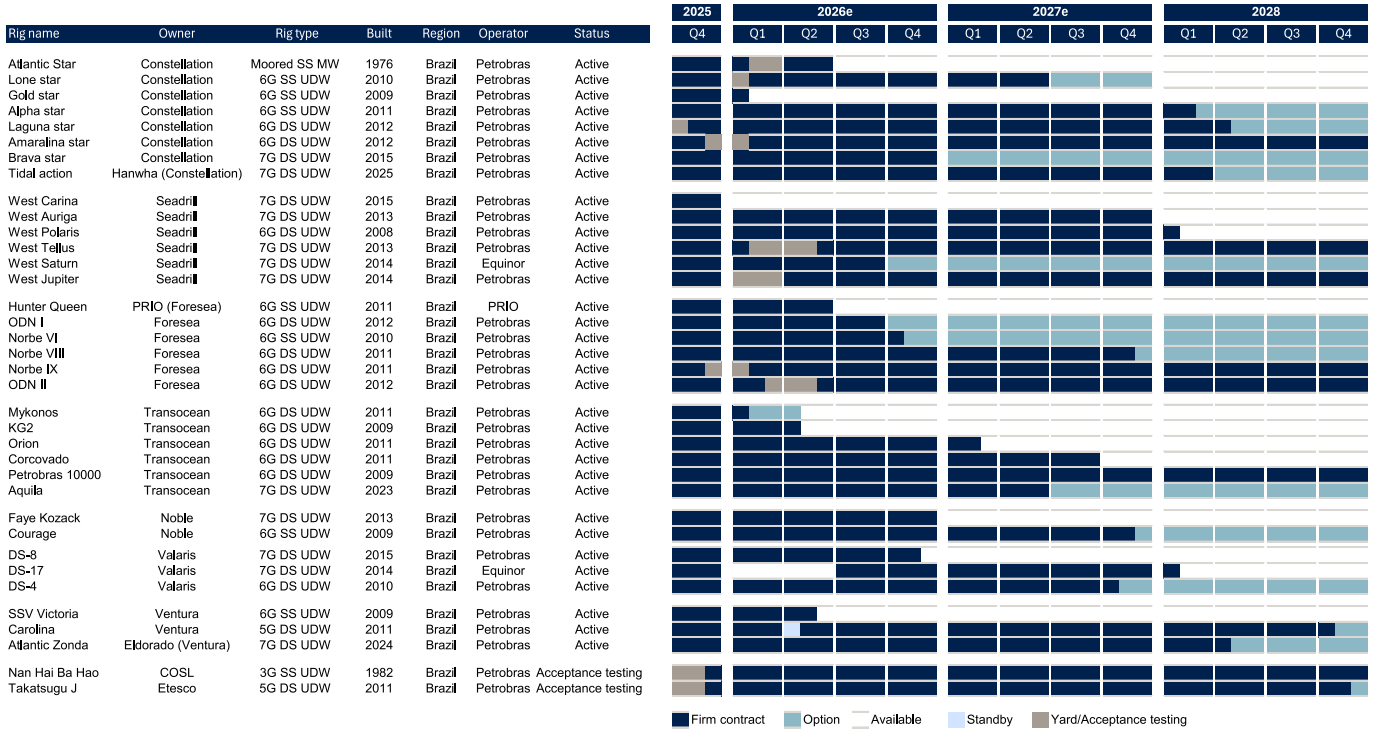


Source: ABG Sundal Collier, S&P

Brazil supply

Below is the Brazilian floater fleet, filtered by drilling company and contract schedule.

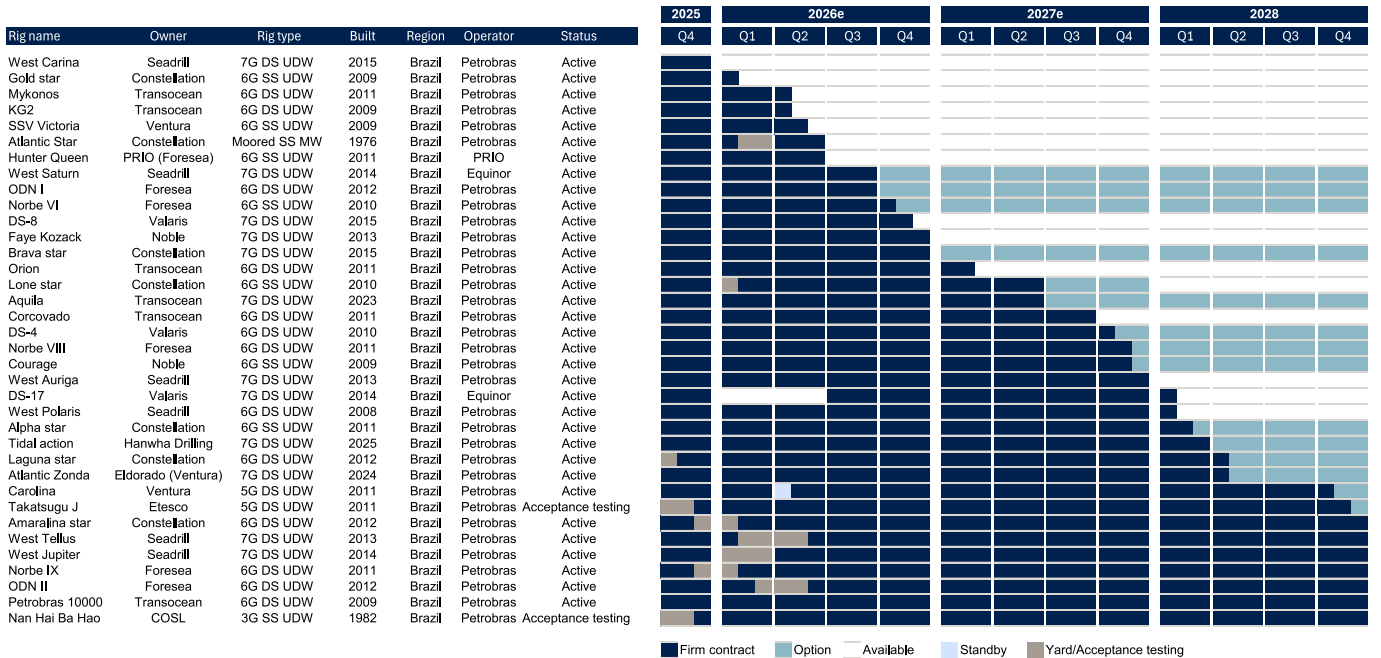
Brazil floater contract schedule



Source: ABG Sundal Collier, S&P, Company data

10 floaters go off contract in 2026, with limited incremental demand in the short term. This might drive short-term fixtures at low rates due to high competition to secure short-term work. Another nine rigs end their contracts during '27 as a floater market recovery is expected in late '26/early '27 driven by several projects in the pipeline and an expected uptick in offshore FID sanctioning from '27.

Ascending contract schedule

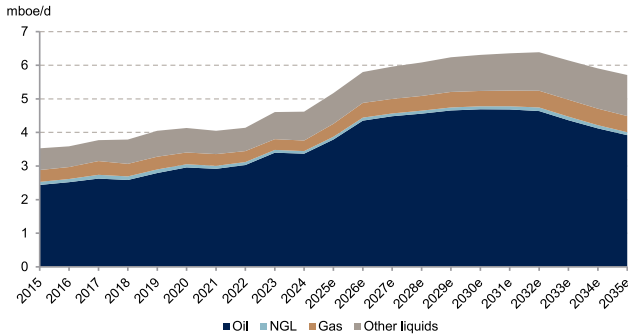


Source: ABG Sundal Collier, S&P, Company data

Brazil production outlook

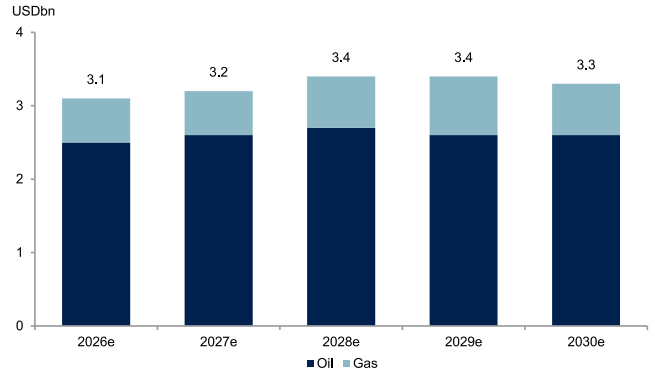
Rystad expects production to increase into the early 2030s, which is supported by Petrobras' growing its production target towards 2030. In order to facilitate for this production growth, drilling activity needs to remain high as both new fields and the depletion of existing operating fields require drilling to sustain and increase production.

Brazilian O&G production



Source: ABG Sundal Collier, Rystad Energy

PBR: '26-'30 production curve (mboe/d)



Source: ABG Sundal Collier, Petrobras

Petrobras spending outlook and rig outlook

Petrobras released its 2026-2030 business plan last week. The proposal outlines total spend of USD 109bn over 2026-2030, of which USD 78bn is E&P. This compares with USD 111bn and USD 77bn, respectively, in the 2025-2029 plan, implying -2% and +1% revisions. Ahead of the update, several media reports had flagged potential capex cuts of -2-7%, mainly in FPSO and platform construction. PBR raised its production trajectory, now peaking at ~3.4mboe/d in 2028 vs. 3.2mboe/d in the prior plan.

PBR's oil price assumption for 2026 is USD 63/bbl, down from USD 83/bbl for 2025 and USD 77/bbl for 2026 in last year's plan. Long-term oil (2029/2030) was nudged up from USD 68/bbl to USD 70/bbl. Mgmt noted during the presentation that potential commodity softness in 2026 is likely to defer part of the global investment cycle, resulting in improving price momentum in 2027. The portfolio remains resilient, with an average breakeven of USD 25/bbl and 92% of projects viable at USD 50/bbl.

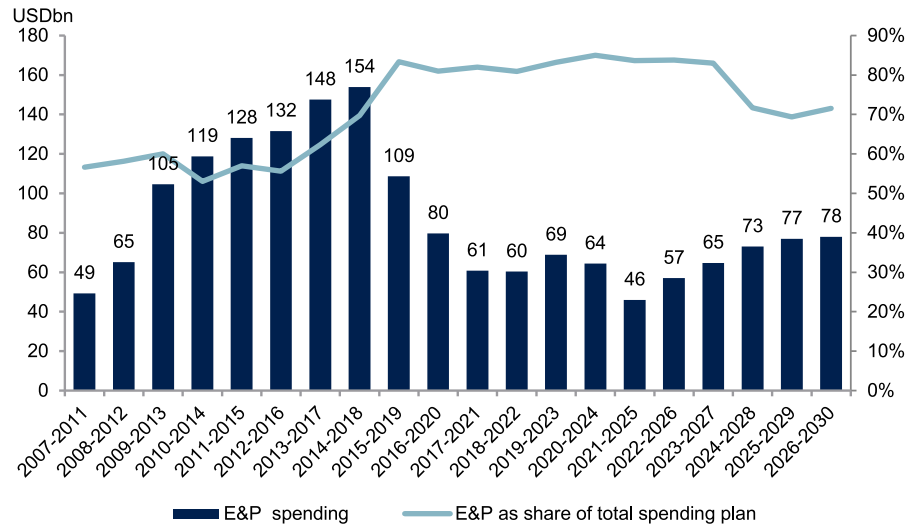
Overall, the spending level is constructive and better than rumours in media reports. However, the share of capex contingent on oil price/under evaluation is higher, giving PBR more flexibility to adjust the plan.

PBR Business Plan: New vs. Old

PBR Business Plan	NEW	OLD
	Business Plan 2026-2030	Business Plan 2025-2029
E&P spending, 5Y plan, USDbn	78	77
E&P spending, 5Y plan under implementation, USDbn	69	76
E&P spending, next year (under implementation), USDbn*	14.8	15.1
Exploration spending, 5Y plan, USDbn	7.1	7.9
Exploration wells, 5Y plan, # of wells	40	51
Oil price, 2026, USD/bbl	63	77
Oil price, long-term, USD/bbl	70	68
E&P prospective portfolio break-even, USD/bbl	25	28
Rig fleet, 5Y plan, # of rigs	23 - 28	25 - 30
FPSOs, to be contracted + under study, # of FPSOs	4 + 6	5 + 6
Rigid, flex and umbilical pipes, 5Y plan, km	6,000	6,000
Subsea x-mas trees, 5Y plan, # of trees	200	200
EPCIs, 5Y plan, # of major contracts	9	6
Subsea vessel fleet*, 5Y plan, # of vessels	75 - 85	80 - 90
EPRDs, 5Y plan, # of major contracts	13	14

Source: ABG Sundal Collier, Petrobras. *Includes AHTS, RSV, PLSV, SDSV, MPSV.

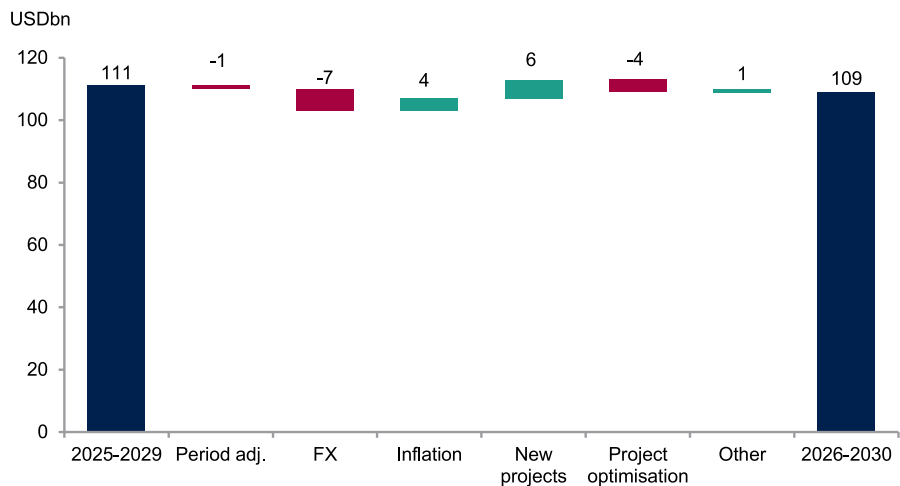
PBR: E&P spending plan



Source: ABG Sundal Collier, Petrobras

Looking at the total spending bridge (E&P, RTM, Gas & Low Carbon, Corporate), FX accounts for USD -7bn, new projects USD +6bn, and project reassessments USD -4bn, implying the underlying total spending scope is marginally higher ex-FX. However, when comparing E&P projects under implementation vs. those under evaluation (pre-FID, no approved budget, and dependent on commodity prices), overall total spending uncertainty has increased vs. last year. E&P spending under evaluation now stands at 12% of the total (USD 9bn), reducing the implementation bucket (under implementation, approved, or short-/medium-term FID) from USD 76.4bn to USD 69.2bn in the new plan. This shift appears primarily in the long tail (2029-2030) and highlights Petrobras' increased flexibility in planned investments. The total spending profile still points to activity at or above current levels across the 5Y horizon.

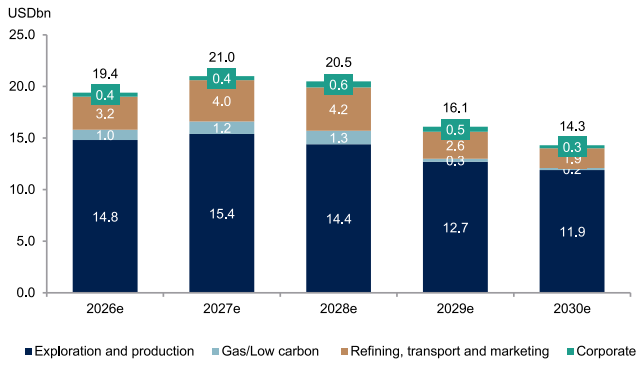
PBR: Total spend plan bridge, old vs. new (USDbn)



Source: ABG Sundal Collier, Petrobras.

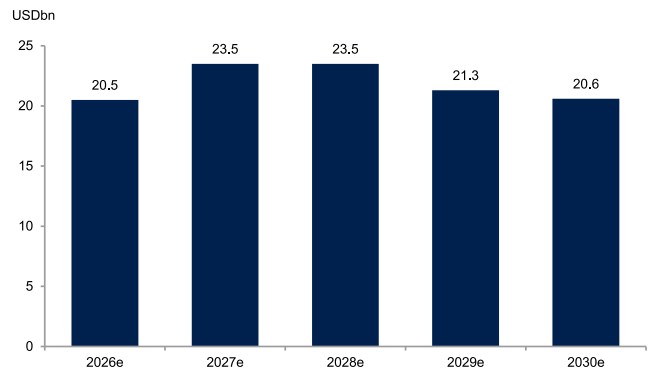
Footnote: *Leased to owned/BOT

PBR: Spending plan (under implementation)



Source: ABG Sundal Collier, Petrobras. Note: Portfolio under implementation only.

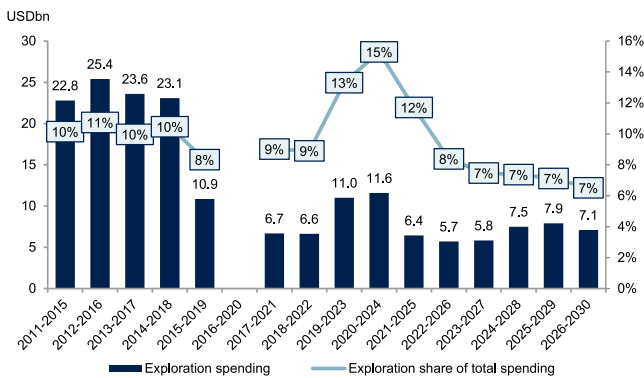
PBR: Total portfolio spending (under implementation + under evaluation)



Source: ABG Sundal Collier, Petrobras

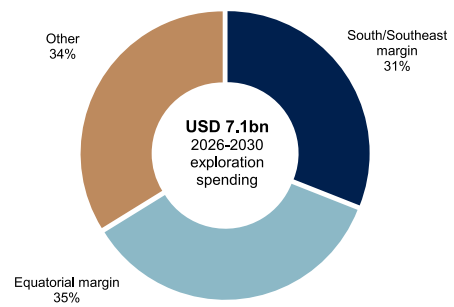
Exploration spend is set at USD 7.1bn, down -10% vs. USD 7.9bn in the previous plan. Of this, 31% is allocated to the South/Southeast margin and 35% to the Equatorial margin. PBR targets 40 exploration wells (15 in the Equatorial margin), down from 51 in last year's plan. Exploration remains <7% of total E&P spend, which is exceptionally low in a historical context.

PBR: Exploration spending



Source: ABG Sundal Collier, Petrobras

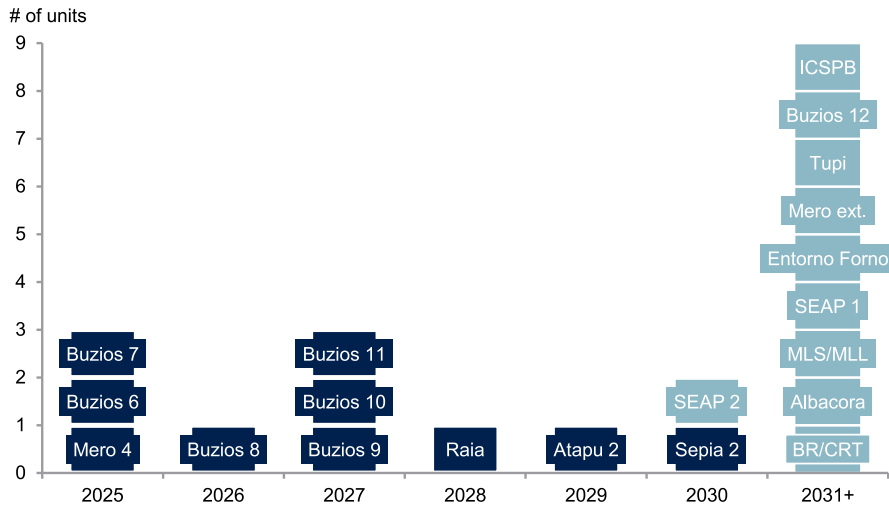
PBR: Exploration plan by region



Source: ABG Sundal Collier, Petrobras

In the FPSO schedule, the Barracuda-Caratinga (BR/CRT) revitalization FPSO was pushed from 2029 to 2031+, while SEAP 2 is expected in 2030 (prev. 2030+). PBR now expects 8 FPSO start-ups over the next 5Y, with another 9 units planned for 2031+, supporting elevated activity in Brazilian waters through the coming decade.

PBR: New FPSO schedule, #

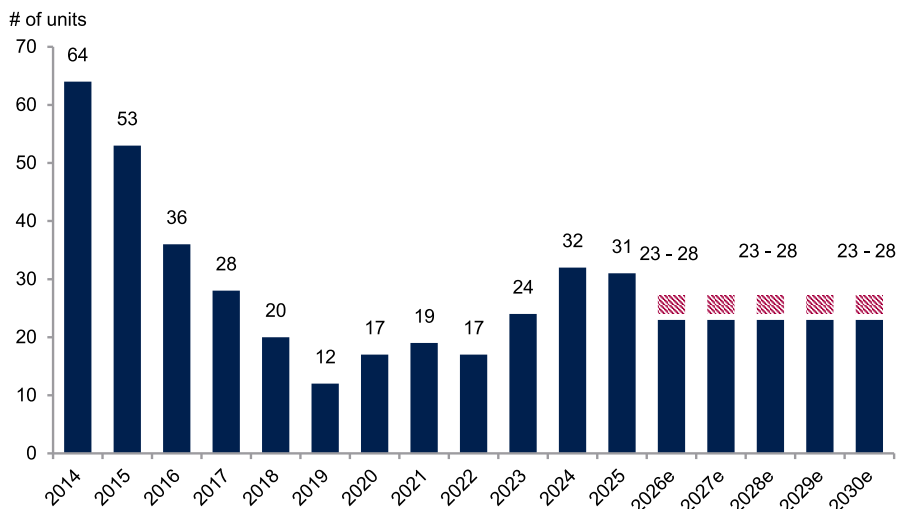


Source: ABG Sundal Collier, Petrobras. Dark blue: Contracted. Light blue: To be contracted.

On rig demand, Petrobras now expects 23-28 rigs over the next 5Y vs. 25-30 in the prior plan. This implies that for Brazil's overall rig demand to hold flat, other operators will need to step up activity. We view the latter as probable as several oil majors/IOCs without contracted drilling rigs in the region have acquired exploration blocks both in the South/Southeast margin and the Equatorial margin. Note that the Buzios' FPSO plans remain unchanged, which is supportive for the timing and scope of the ongoing Buzios rig tender.

Subsea demand remains very strong. PBR is guiding to 9 major EPCIs (prev. 6) over the next 5Y, ~6,000 km of rigid/flexible/umbilical pipe (unch.), and 200 x-mas trees (unch.). The subsea support vessel fleet is expected at 75-85 vs. 80-90 previously. On decommissioning, PBR targets 13 ERPD contracts (prev. 14). Overall, the plan continues to support elevated subsea activity in Brazil for years ahead.

PBR: Rig count

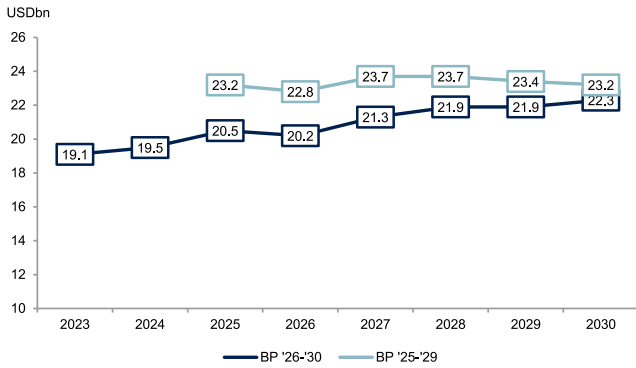


Source: ABG Sundal Collier, Petrobras

There has been considerable discussion around PBR's cost measures and potential blend-and-extend arrangements for service providers. PBR detailed its efficiency levers within manageable operating expenses, which total ~USD 19.5bn annually (with O&G production costs, gas transport tariffs, marine transport, corporate, and non-production E&P costs as the largest sub-categories). The company targets USD 12bn in cumulative cost cuts (USD 0.9-2.7bn/y, including USD 2.7bn in 2026) over the next 5Y vs. the prior plan. On a per-barrel basis, the efficiency targets imply a 12-16% reduction in manageable operating costs per year relative to the 2025-2029 plan. PBR also aims for meaningful efficiency gains on

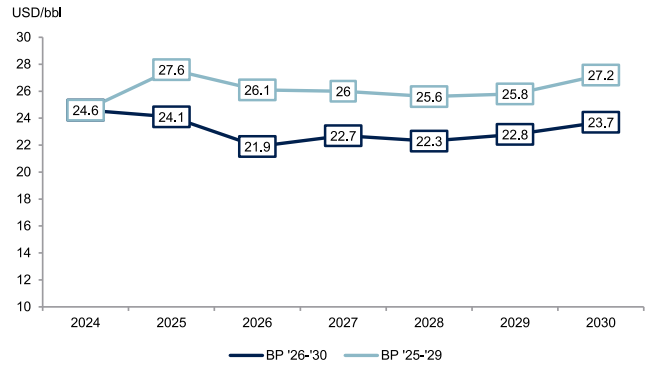
FPSOs/platforms; for example, the new SEAP FPSO was optimized with a 7,500t weight reduction, lowering capex by ~15%.

Manageable operating expenses



Source: ABG Sundal Collier, Petrobras

Manageable operating expenses, per bbl



Source: ABG Sundal Collier, Petrobras

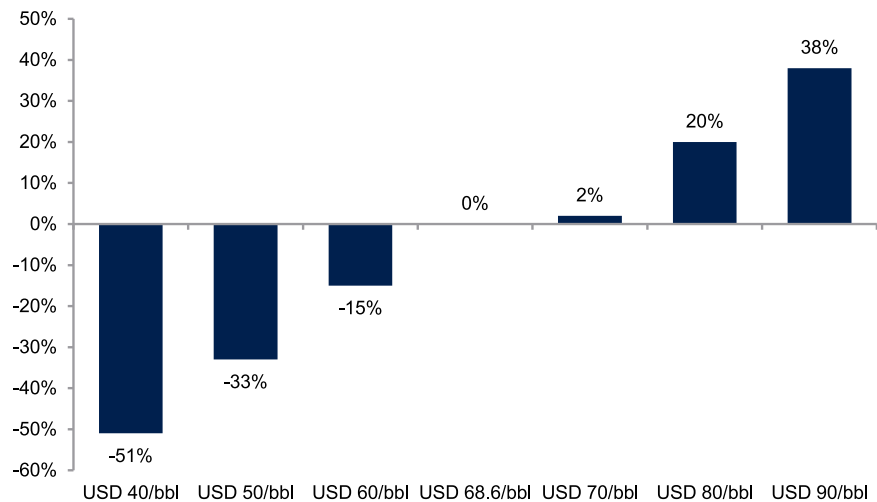
PBR also provided unusually detailed disclosures on its base-case total portfolio, enabling a clearer assessment of dividend/spending sensitivity under different commodity price scenarios. The illustration below reflects base-case portfolio economics (and dividends) using the plan’s USD 63/70/bbl assumptions for 2026/2027-2030. As the sensitivity shows, if oil were to remain at USD 60/bbl through the plan period, allocations to dividends/spending would fall ~15% assuming gross debt is held flat. At USD 80/bbl, base-case economics support a ~20% uplift to dividends/spending over the next 5Y.

Petrobras cash flow forecast

Brent (USD/bbl) Plan assumption	63	70	70	70	70
PBR cash flow forecast (USDbn)	2026e	2027e	2028e	2029e	2030e
OCF	35	40	42	42	42
Cash capex	-18	-20	-21	-17	-17
Leasing	-10	-10	-9	-9	-9
FCFF	7	10	12	16	16
Net finance	-2	-2	-2	-2	-2
Net amort	-1	-1	-1	-1	-1
FCFE	4	7	9	13	13
Business Plan dividend	-10	-10	-10	-10	-10
Cash flow after dividend	-5	-2	0	4	4

Source: ABG Sundal Collier, Petrobras

PBR dividend/spending sensitivity to Brent assumption



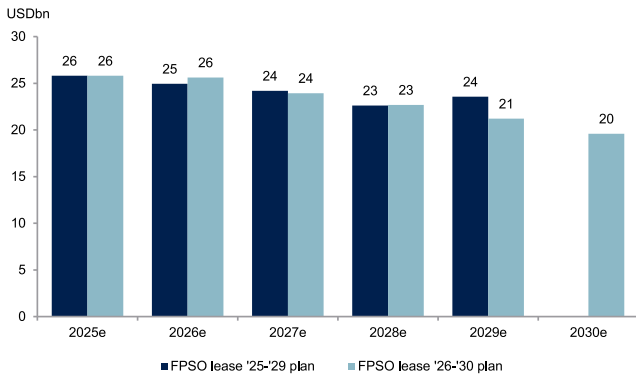
Source: ABG Sundal Collier, Petrobras.

Footnote: Sensitivity in % vs. total plan spending and dividend targets.

Note that the FPSO contracting model drives differences in the spending plans. Leased FPSOs do not appear in capex, while owned/BOT units do; hence FPSO lease spend

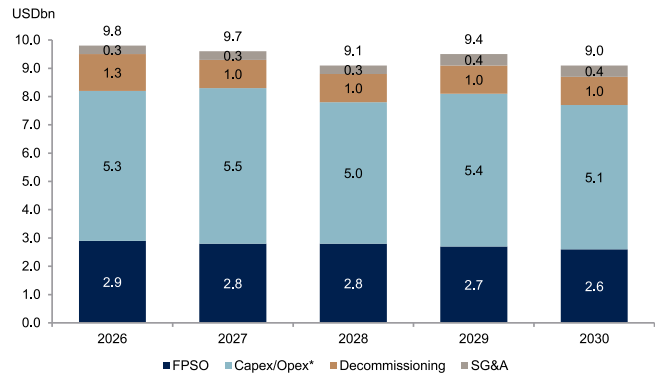
remains a key component of total PBR spending. Total lease spend (FPSOs + all other leases) is budgeted at USD 45-50bn, vs. USD 55-60bn in the 2025-2029 plan. The reduction reflects the deferral of a chartered FPSO from 2029, a shift toward owned/BOT as the dominant contracting model in 2029-2030, and additional cost-efficiency gains.

PBR: Expected FPSO leasing debt (USDbn)



Source: ABG Sundal Collier, Petrobras

PBR: Lease break-down



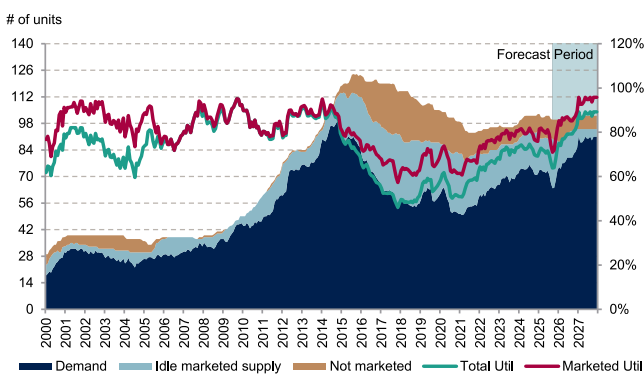
Source: ABG Sundal Collier, Petrobras

Footnote: *Capex/opex lease split is 60/40% in this category

Global floater market

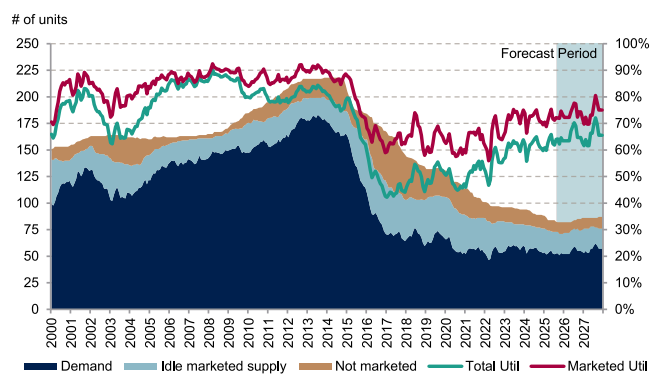
The overall drilling market has gradually improved following the bust of the previous cycle initiated by a sharp drop in the oil price in 2014 as OPEC+ oversupplied the O&G market to capture market share. The resulting long period of lower oil prices led to a significant drop in E&P operators' offshore spending, which impacted the demand for offshore drilling services negatively, shown in the charts below where active floaters dropped from an aggregated high 300s to the low 100s. Accordingly, a large share of the previously demanded floaters were left idle and stacked, leading to a sharp drop in fleet utilisation. Following utilisation growth since 2018, disrupted by a drop during the pandemic, the demand reached a level of ~130 active rigs in 2024. The growth was driven by increasing offshore spending as the industry had experience limited investments since 2014. Decreased demand since Q2'24 has been driven by a drop in offshore spending. The development has made utilisation drop, despite a total marketed rig count decrease of ~10 units in the same period. As we expect a slight decline in offshore spending in '26 before a rebound in '27, drilling demand could be negatively affected in the short-term.

Drillship: Market balance



Source: ABG Sundal Collier, S&P

Semisub: Market balance



Source: ABG Sundal Collier, S&P

On the contrary, S&P expects floater demand to increase sharply from current levels, driven by several projects in the pipeline and an expected uptick in offshore FID sanctioning from '27. According to S&P's forecast, utilisation will increase significantly going forward, which should impact rates positively (as illustrated below).

UDW rates vs. total utilisation

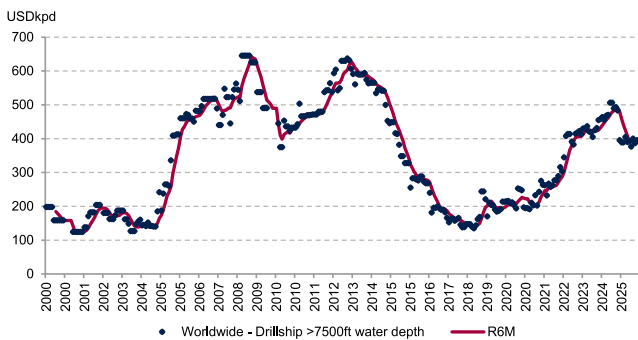


Source: ABG Sundal Collier, S&P

Footnote: Based on data from 2006 and onwards

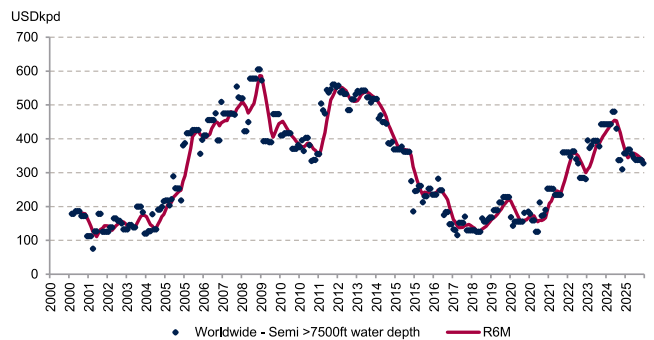
Day rates for drillships and semis has followed the market and utilisation rates explained above. There has been a dip in day rates since the peak in mid-24, while the rate level has stabilised in recent months at ~USD 400kpd for drillships and below USD 350kpd for semis.

Drillship: Global average dayrates



Source: ABG Sundal Collier, S&P

Semisub: Global average dayrates



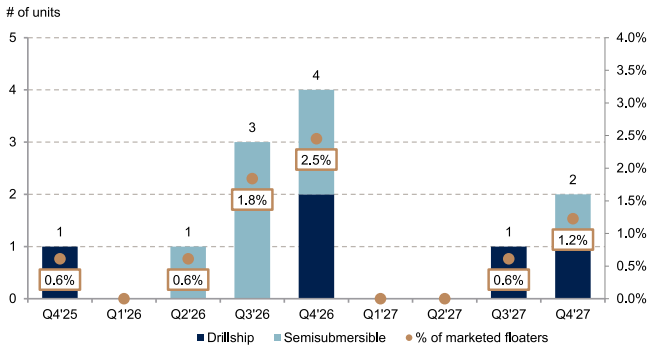
Source: ABG Sundal Collier, S&P

Supply

The floater orderbook (OB) consists of 12 units, 5 drillships and 7 semi-submersibles. In total, the OB accounts for ~7% of the marketed fleet, of which 5% has expected delivery during '26, while the remaining part is expected in late '27. The OB indicates limited supply potential for the floater fleet in the medium term.

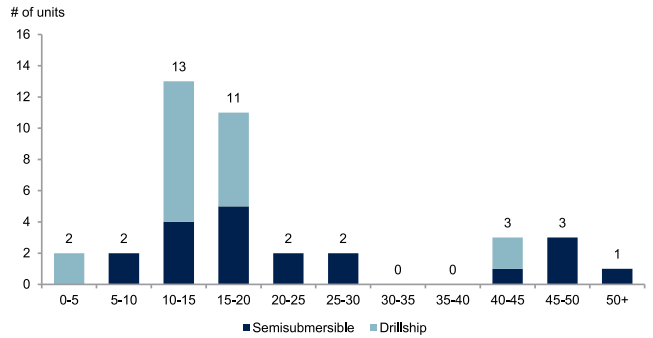
The supply potential from the stacked fleet is ~40 units, implying a notably larger supply potential than the OB. We note that only 16 units are warm stacked, while the remaining 23 units are cold stacked and have been so for an average of ~6 years. We only believe these units would be reactivated and added to supply if the market tightened adequately to justify the significant reactivation capex. We note that seven of the stacked units are more than 40 years old, making them probable scrapping candidates.

Floater orderbook delivery schedule



Source: ABG Sundal Collier, S&P

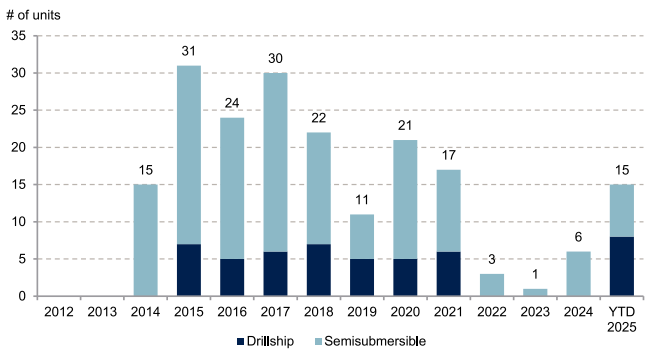
Cold and Warm stacked units, by age



Source: ABG Sundal Collier, S&P

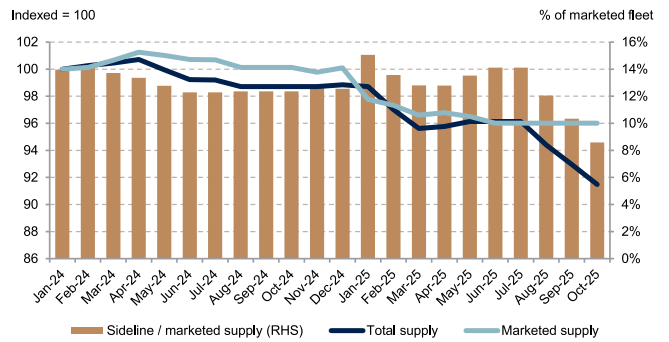
Attrition has rebounded during '25 going from 1 in 2023 to 15 so far in '25, with the first drillship attritions since '21. The increase showcases disciplined rig owners removing supply when the market softens. The increased attrition has contributed to a reduction of sideline floater capacity as a share of the marketed fleet from ~13% to ~8%, reducing the potential for rig owners to reactivate and supply incremental units to the market. In parallel, the marketed and total supply has decreased by 4% and 8% since Jan-24. The current expectations of a near-term soft market could entail more attrition, which would be a positive for the market balance.

Floater attrition, by type



Source: ABG Sundal Collier, S&P

Supply and sideline capacity



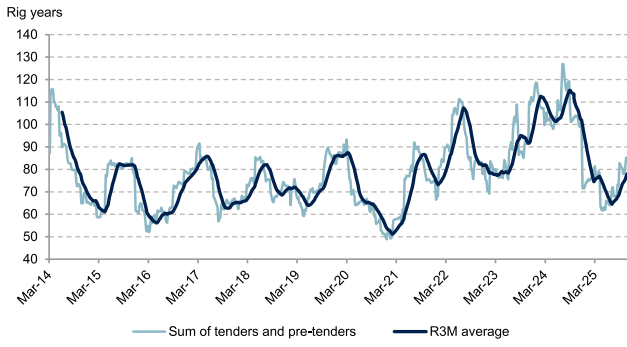
Source: ABG Sundal Collier, S&P

Demand

Outstanding tenders is a good proxy for future rig demand and has followed a similar pattern as the floater market utilisation. The outstanding tender and pre-tender floater years reached a 10Y peak during 2024, before falling sharply from mid-24 to mid-25. Floater rig years has since rebounded, mainly driven by a notable increase in average tender duration, partly offset by a sliding number of tenders which has trended downwards since 2018. The sliding amount of pre-tenders indicates no short-term improvement in the amount of outstanding tenders, meaning average tender duration needs to remain elevated to keep outstanding rig year demand at current levels.

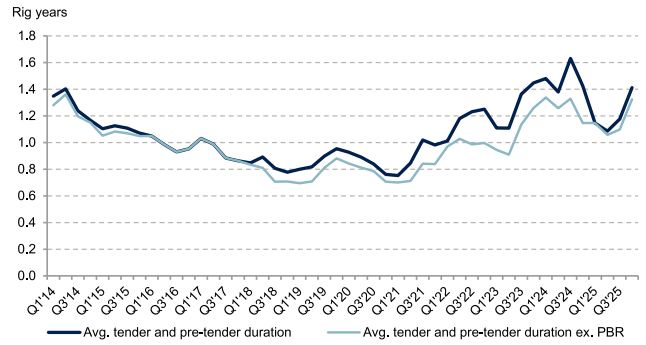
We emphasise that a tender can require multiple rigs despite only being counted as one in the charts below, as is the case for the Buzios, Mero/Tupi and Gato do Mato tenders described previously in the report. Hence, there is upside potential to demand compared to the charts below.

Floater: Sum of tender and pre-tender years rebounding



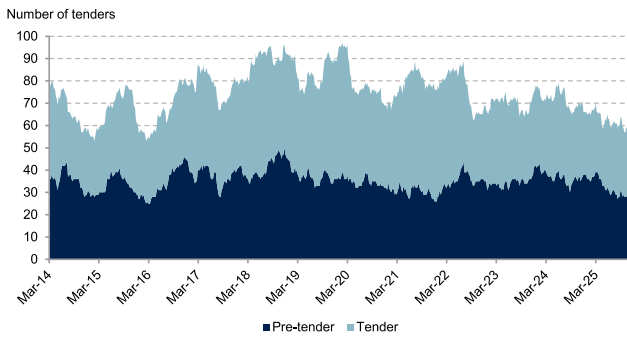
Source: ABG Sundal Collier, S&P

Floater: Avg. tender duration rebounding



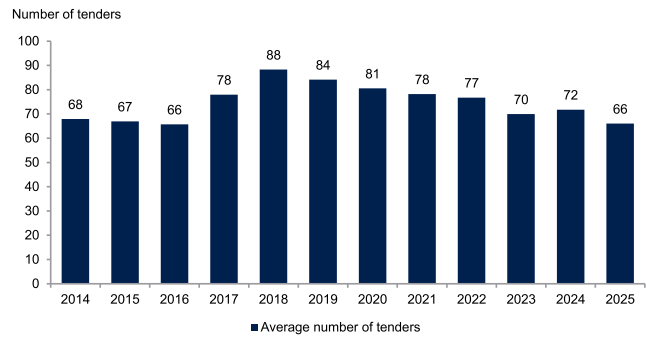
Source: ABG Sundal Collier, S&P

Floater: Tenders and pre-tenders trending down



Source: ABG Sundal Collier, S&P

Floater: Avg. number of tenders per year



Source: ABG Sundal Collier, S&P

The oil market

The following chapter outlines a summary of our oil market view as described in our latest oil market sector report. See the full report for more details: ["Crude Quarterly Q3'25: oil price could be troughing"](#)

Demand estimates too low; non-OPEC production could disappoint

Fear of large inventory builds is probably exaggerated. Global GDP forecasts have been notching up lately, and global oil demand forecasts normally follow. On the non-OPEC production side, it is becoming increasingly clear that the current oil price leads to lower E&P spending (both onshore US and general offshore spending). We forecast an increase in call-on-OPEC of 0.6 mb/d in 2026, which compares to consensus of 0.1 mb/d. Normally, there is high correlation between the direction of consensus call-on-OPEC and the oil price. Lastly, OPEC+ has increased production and sent the oil price lower. However, OPEC+'s capability to massively increase production from here could be limited. For instance, Saudi will produce more than 10 mb/d in October, which is close to its ATH production level of 10.5-11.0 mb/d. All in all, we think oil price sentiment could improve going forward. We therefore stick to our Brent crude oil assumption of USD 70 for Q4'25 and 2026 and USD 80 thereafter.

Stock builds are well known - could fundamentals surprise?

A massive oversupply of oil is expected for the coming three quarters. However, this story is heavily marketed by IEA and other analysts and should be well-known in the market. Actually, the main pushback we get from equity investors is that they fear a lower oil price over the next six months as inventories build. Despite the fear of big inventory builds, though, the oil price has held up pretty well.

Our view in short:

- Oil demand is stronger than the market seems to believe.
- Non-OPEC production estimates will come down if the oil price remains at current levels.
- Consensus call-on-OPEC ("the oil market's EPS") – the most important figure that decides near-term oil prices – will come up over the next months. This normally means a higher oil price.
- We assume Brent crude oil at USD 70 flat to the end of 2026, and USD 80 thereafter.

Main assumptions (key figures highlighted in brown)

Key assumptions	2022	2023	2024	2025e	2026e	2027e	2028e	2029e	2030e
Future price (Brent, USD)				66	65	65	66	67	n.a.
Factset (Brent, USD)				68	64	69	76	n.a.	n.a.
ABGSC (Brent, USD)	100	82	81	71	70	80	80	80	80
Q1	100	81	83	76	70	80	80	80	80
Q2	112	78	85	68	70	80	80	80	80
Q3	101	86	80	69	70	80	80	80	80
Q4	89	84	75	70	70	80	80	80	80
Other key assumptions:									
WTI (USD)	94	78	76	67	66	76	76	76	76
Brent-WTI spread	6.0	4.8	4.8	4.0	4.0	4.0	4.0	4.0	4.0
NOK/USD	9.6	10.5	10.6	10.0	10.0	10.0	10.0	10.0	10.0
Future price (UK gas price, mmBTU, USD)									
ABGSC: UK gas price (USD/mmBTU)	31.0	12.4	10.6	12.4	11.0	10.0	9.0	9.0	9.0
Q1	32.0	16.1	8.8	14.6	13.0	10.5	9.5	9.5	9.5
Q2	23.1	10.9	9.6	11.3	10.0	9.5	8.5	8.5	8.5
Q3	48.6	10.3	10.7	10.8	10.0	9.5	8.5	8.5	8.5
Q4	20.4	12.2	13.5	13.0	11.0	10.5	9.5	9.5	9.5
Offshore E&P spending:									
Development (y/y%)	18%	23%	14%	-3%	-3%	12%	8%	4%	4%
Exploration (y/y%)	15%	12%	3%	-3%	-7%	15%	8%	4%	4%
Total	17%	21%	12%	-3%	-3%	12%	8%	4%	4%

Source: ABG Sundal Collier, FactSet

Call-on-OPEC is the key driver for the oil price

Consensus call-on-OPEC estimates, which have been on a steady decline since mid-2022, have continued on the same path. However, the 2026 call-on-OPEC has stabilised somewhat, while there are wide discrepancies in estimates amongst the four agencies we track. We note that:

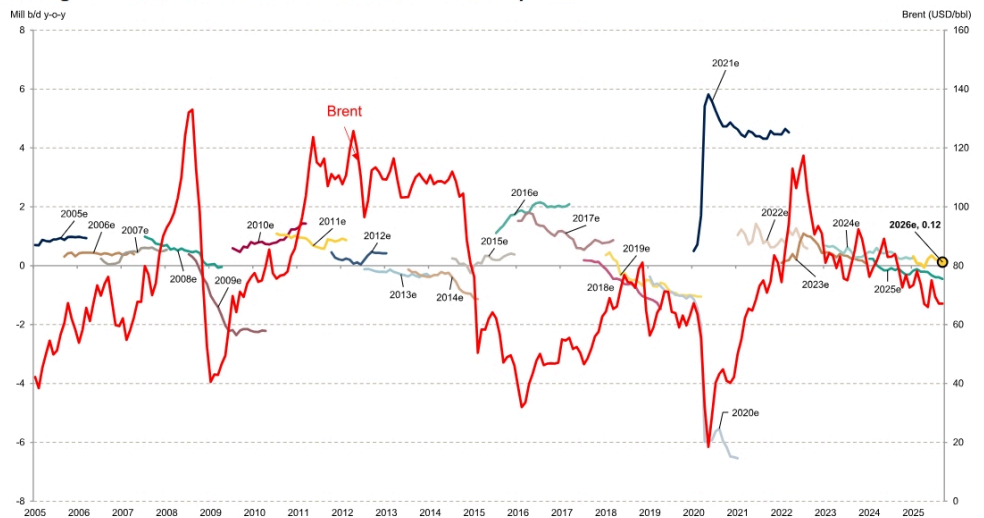
- The main driver of oil demand, global GDP growth, has shown some positive indications of late, as some of the agencies we follow now estimate 3.0/3.1% for '25e and '26e (previously below 3%).
- Expectations for '25 and '26 non-OPEC production growth have increased in recent months, in-line with non-OPEC production growth historically surprising on the upside.

In our view, the single best indicator to look at for predicting the oil price is the change in the “call-on-OPEC”. This figure encompasses both demand and supply. If the number is positive, it means that OPEC will have to increase production. If it is negative, OPEC will have to cut production. As such, the “call-on-OPEC” is the ultimate metric for tightness in the market.

The chart below shows the oil price vs. the change in consensus call-on-OPEC estimates for the last 20 years. Note:

- The oil price is generally high or rising when call-on-OPEC estimates are positive (above zero), and vice versa.
- The direction of consensus call-on-OPEC estimates also moves the oil price, i.e. rising call-on-OPEC estimates are generally associated with a rising oil price.

Changes to consensus call-on-OPEC estimates vs. oil price

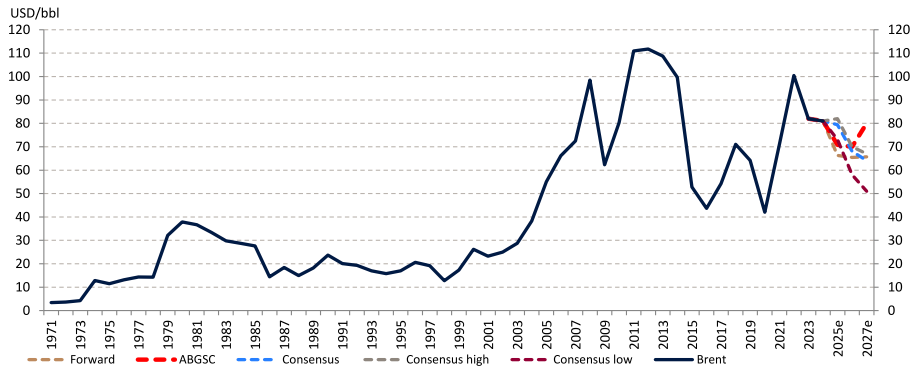


Source: IEA, OPEC, EIA, FGE, ABG Sundal Collier

Our oil price estimate for '26 is above consensus

Our oil price estimates for '25 and '26 are below and above FactSet consensus, respectively. For '25 we are USD 8.6/bbl below consensus (note that consensus is not regularly updated), while for '26 we are somewhat above. However, FactSet consensus is quite thin and has a limited number of participants. Compared to the forward curve for '25e-'26e, we are USD 4.5/bbl and 4.6/bbl above, respectively.

ABGSCe vs. futures and consensus oil price estimates (annual)



Source: ABG Sundal Collier, FactSet

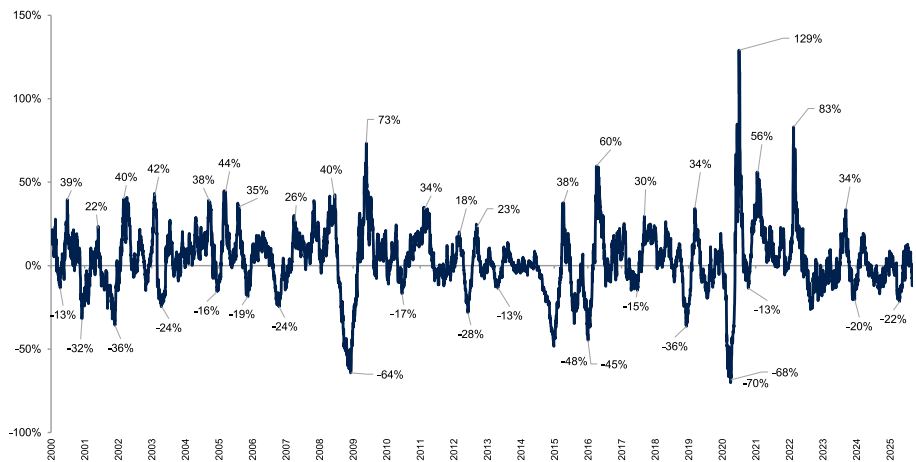
It is important to remember that the oil price is volatile, with movements of +/-30% every eight months.

Oil price estimate range

Oil price (USD/bbl)	2024	2025	2026	2027
Forward	81.0	66.3	65.4	65.7
ABGSCe	81.0	70.8	70.0	80.0
Consensus	81.0	79.4	68.0	64.1
Consensus high	81.0	82.0	70.0	67.0
Consensus low	81.0	73.1	58.0	51.0

Source: ABG Sundal Collier, FactSet

3-month rolling change in the oil price



Source: ABG Sundal Collier, Factset

A closer look at supply and demand

It is difficult to obtain consensus estimates for supply and demand in the oil market, so we follow the monthly forecasts of the IEA (the OECD's energy agency), OPEC (the oil organisation publishes forecasts in its monthly report), EIA (the US Energy Information Administration) and FGE (Facts Global Energy, an independent consultancy). The table below shows the current estimates of these agencies; we refer to the average of their estimates as the "consensus".

In their monthly oil market reports for January, OPEC, EIA and FGE all launched detailed 2026 estimates. Note that IEA's supply/demand forecasts were extended to 2026 in its April oil market report.

Key oil market estimates for 2025

Oil market forecasts 2025e y-o-y change in demand (mb/d), 2025e						
	IEA	OPEC	EIA	FGE	Average/ consensus	ABGSC
Demand:						
North America	0.07	0.16	0.01	0.15	0.10	0.10
Western Europe	0.03	0.03	0.03	-0.02	0.02	0.03
OECD Pacific	-0.13	-0.06	-0.12	-0.12	-0.11	-0.10
Total OECD	-0.03	0.13	-0.08	0.01	0.01	0.03
China	0.07	0.18	0.25	0.56	0.27	0.20
FSU	0.03	0.14	-0.05	0.10	0.05	0.08
Middle East	0.06	0.14	0.17	0.17	0.14	0.15
India	0.10	0.10	0.18	0.17	0.14	0.11
Other non-OECD	0.48	0.61	0.62	-0.07	0.41	0.40
Total non-OECD	0.74	1.17	1.67	0.93	1.00	0.94
Global demand	0.71	1.30	1.08	0.95	1.01	0.97
y-o-y change in production (mb/d), 2025e						
	IEA	OPEC	EIA	FGE	Average/ consensus	ABGSC
Supply:						
US	0.61	0.31	0.56	0.53	0.53	0.48
Canada&Mexico	0.08	0.12	0.11	0.27	0.15	0.20
Western Europe	0.13	0.05	0.15	0.09	0.11	0.10
OECD Pacific	0.00	-0.01	0.13	n.m.	0.04	0.04
China	0.06	0.05	0.14	0.06	0.08	0.07
Brazil	0.38	n.a.	0.19	0.38	0.32	0.33
Guyana	0.10	n.a.	0.13	0.08	0.10	0.11
Other non-OPEC	0.18	0.29	0.26	0.19	0.23	0.11
Non-OPEC excl. FSU	1.55	0.81	1.67	1.70	1.43	1.44
FSU	0.10	0.03	0.24	0.15	0.13	0.12
Total non-OPEC	1.65	0.84	1.91	1.85	1.56	1.56
Call on OPEC	-0.94	0.46	-0.83	-0.90	-0.55	-0.59

Source: ABGSC, IEA, EIA, OPEC, FGE

Key oil market estimates for 2026

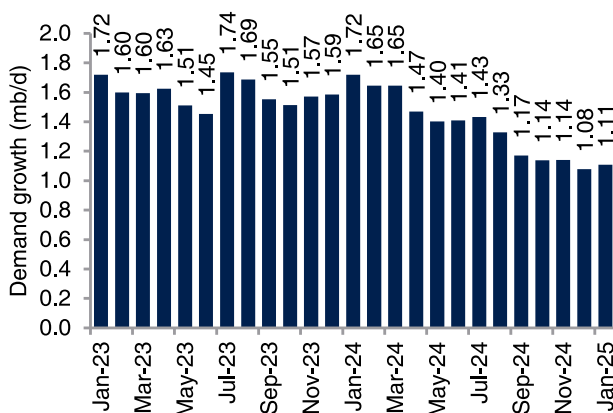
Oil market forecasts 2026e y-o-y change in demand (mb/d), 2026e						
	IEA	OPEC	EIA	FGE	Average/ consensus	ABGSC
Demand:						
North America	0.03	0.12	0.03	0.00	0.05	0.12
Western Europe	-0.07	0.04	0.06	-0.06	-0.01	0.07
OECD Pacific	-0.07	-0.01	0.00	-0.08	-0.04	0.00
Total OECD	-0.11	0.15	0.09	-0.14	0.00	0.19
China	0.14	0.20	0.24	0.38	0.24	0.25
FSU	0.03	0.09	0.03	0.00	0.04	0.07
Middle East	0.06	0.16	0.07	0.20	0.13	0.14
India	0.15	0.22	0.25	0.20	0.21	0.20
Other non-OECD	0.41	0.56	0.43	0.29	0.42	0.50
Total non-OECD	0.81	1.23	1.02	1.07	1.03	1.16
Global demand	0.70	1.38	1.12	0.92	1.03	1.35
y-o-y change in production (mb/d), 2026e						
	IEA	OPEC	EIA	FGE	Average/ consensus	ABGSC
Supply:						
US	0.25	0.10	0.19	0.36	0.23	0.10
Canada&Mexico	0.02	0.11	0.02	-0.01	0.03	0.05
Western Europe	0.06	-0.04	-0.03	0.04	0.01	0.02
OECD Pacific	0.01	-0.01	0.06	n.m.	0.02	0.00
China	0.02	0.00	0.01	-0.03	0.00	0.00
Brazil	0.24	n.a.	0.31	0.15	0.23	0.25
Guyana	0.17	n.a.	0.14	0.16	0.16	0.15
Other non-OPEC	0.35	0.47	0.23	0.64	0.42	0.15
Non-OPEC excl. FSU	1.12	0.83	0.93	1.31	1.00	0.72
FSU	0.10	-0.02	0.16	-0.12	0.03	0.00
Total non-OPEC	1.22	0.82	1.09	1.19	1.03	0.72
Call on OPEC	-0.52	0.77	0.03	-0.27	0.00	0.63

Source: ABGSC, IEA, EIA, OPEC, FGE

A closer look at how 2024 ended

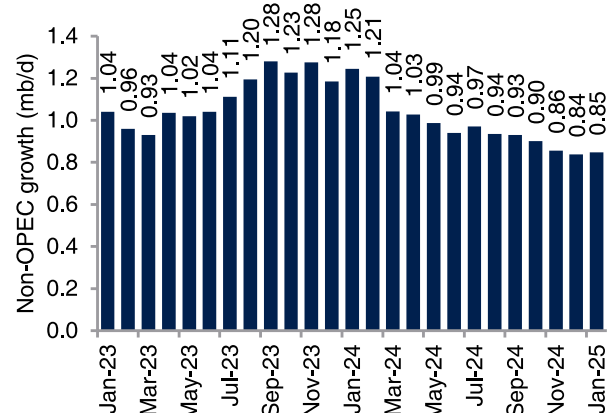
We note that the estimates for 2024 have changed over time. The EIA published detailed estimates in January 2023, FGE in February, the IEA in June and OPEC in July. Throughout the '24 forecast period, China in particular saw its demand growth estimates revised, first from 0.4m b/d in Jan'23 to 0.55m b/d in Jul'23, before falling to the current growth estimate of 0.18m b/d in Jan'25. On the supply side, Russia (FSU) saw lower estimated growth after increasing and extending its production cuts as part of the OPEC+ deal. Estimated call-on-OPEC demand for '24 started at 0.68m b/d in '23 and ended at (Jan '25) at 0.26m b/d for 2024.

2024 oil demand estimates



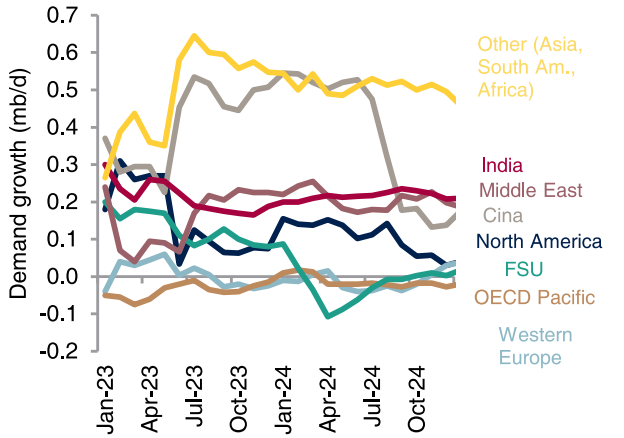
Source: IEA, OPEC, EIA, FGE, ABG Sundal Collier

2024 non-OPEC supply estimates



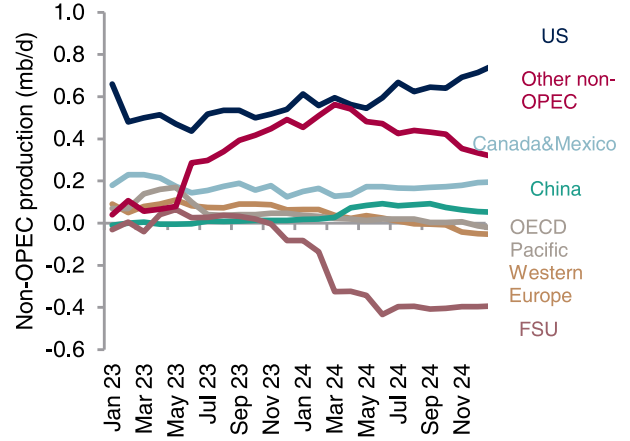
Source: IEA, OPEC, EIA, FGE, ABG Sundal Collier

2024 oil demand estimates



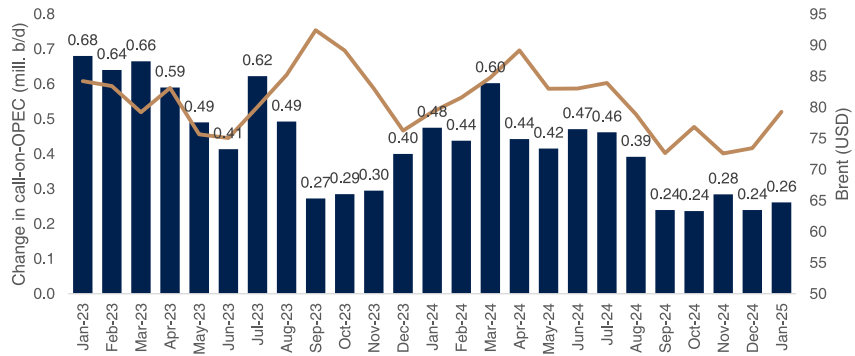
Source: IEA, OPEC, EIA, FGE, ABG Sundal Collier

2024 supply growth details



Source: IEA, OPEC, EIA, FGE, ABG Sundal Collier

2024e consensus call-on-OPEC



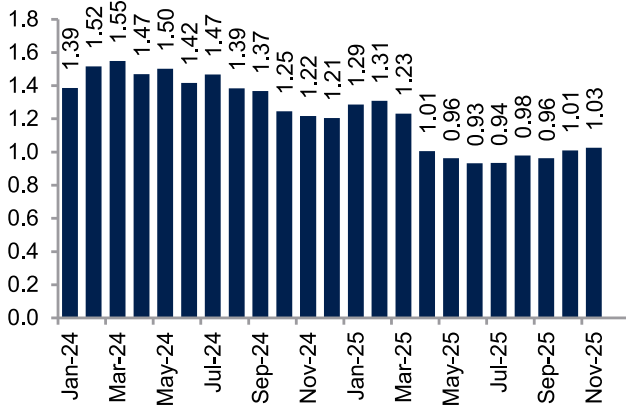
Source: ABGSC, FGE, OPEC, IEA, EIA

How 2025 estimates have evolved over time

We note that the participants in the consensus estimates for 2025 have changed over time, as the EIA, OPEC and FGE published detailed estimates in January 2024, while the IEA published its estimates for '25 in April. The trend in consensus estimates therefore shows a somewhat high volatility when a new agency publishes its outlook and is included in our consensus figures. We note, however, that the call-on-OPEC now stands at -0.64m b/d, compared with +0.23m b/d in Jan '24, showing a steady decline throughout the forecast period, mainly driven by decreasing demand forecasts.

2025 Oil demand estimate

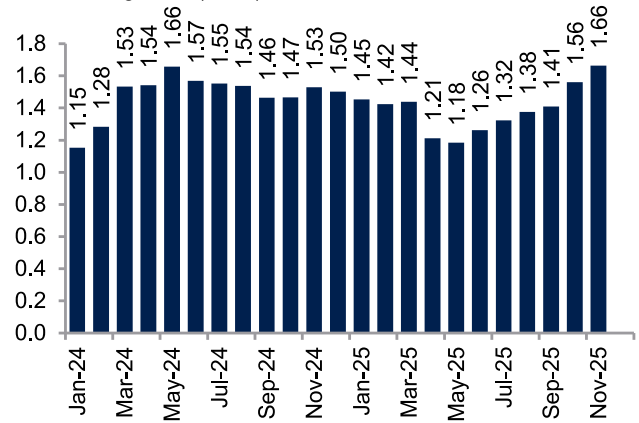
Demand growth (mb/d)



Source: IEA, OPEC, EIA, ABG Sundal Collier

2025 Non-OPEC growth (mb/d)

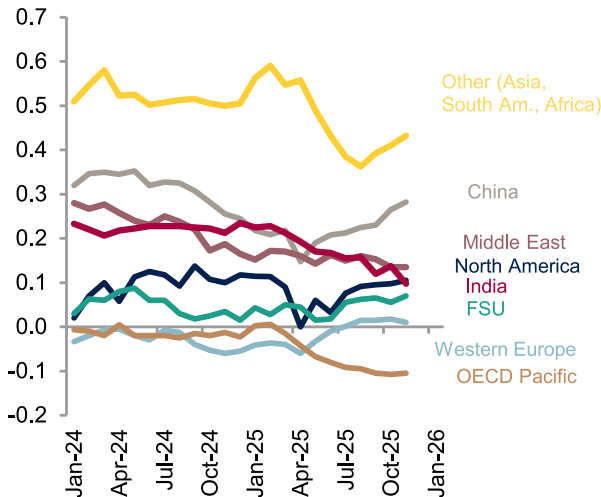
Non-OPEC growth (mb/d)



Source: IEA, OPEC, EIA, ABG Sundal Collier

2025 oil demand growth details

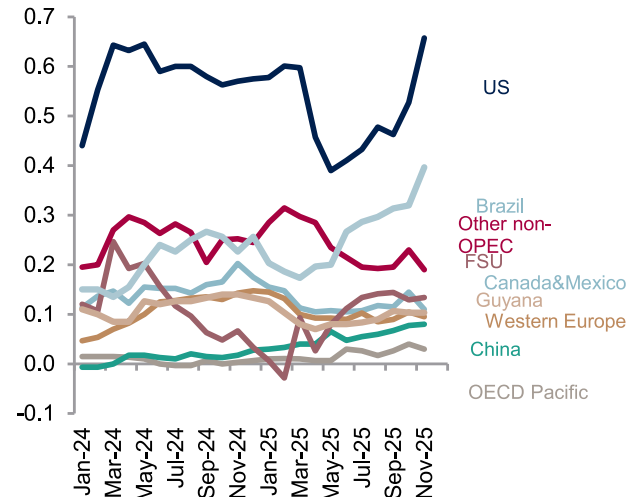
Demand growth (mb/d)



Source: IEA, OPEC, EIA, FGE, ABG Sundal Collier

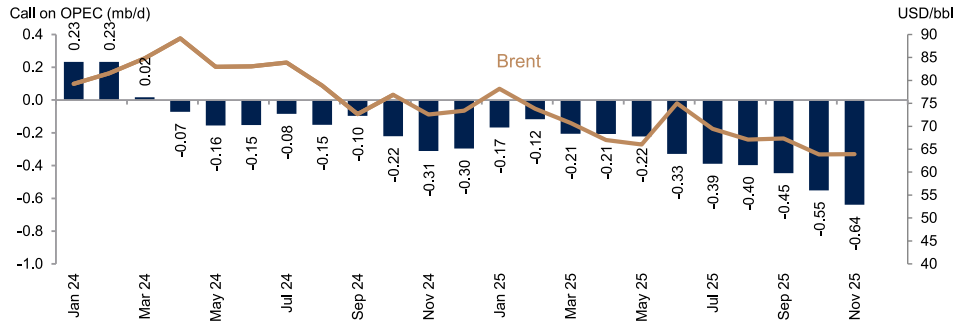
2025 oil supply estimates

Non-OPEC production growth (mb/d)



Source: IEA, OPEC, EIA, FGE, ABG Sundal Collier

2025 Consensus call on OPEC

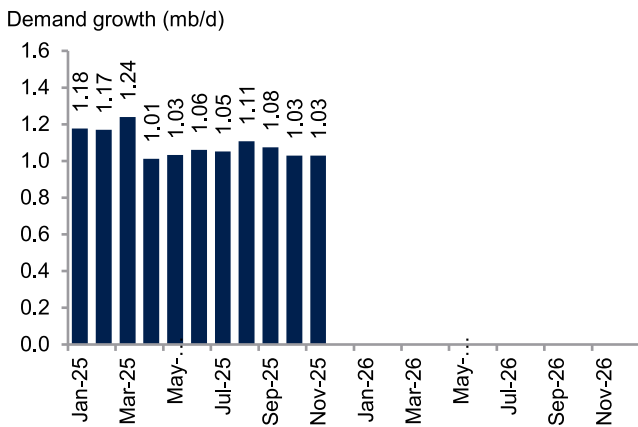


Source: IEA, EIA, FGE, ABG Sundal Collier

A closer look at 2026 estimates

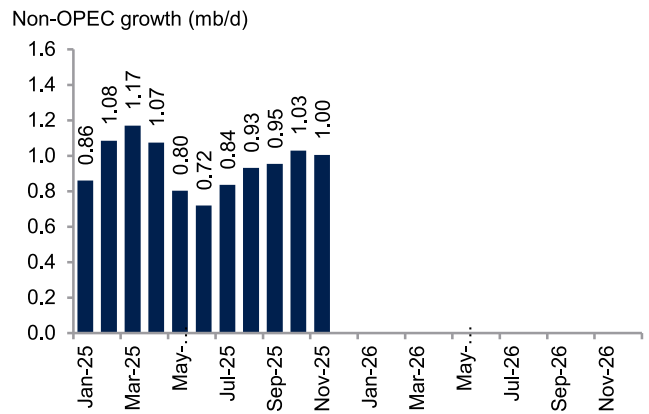
In their monthly oil market reports for January, OPEC, EIA and FGE all launched detailed 2026 estimates. Note that IEA's supply/demand forecasts were extended to 2026 in its April oil market report. The call-on-OPEC in 2026 now stands at +0.03m b/d, down from +0.32m b/d in Jan '25. Estimates have been volatile, driven by changes in non-OPEC production growth estimates which have recently grown after declining in the two months after "Liberation Day".

2026 Oil demand estimate



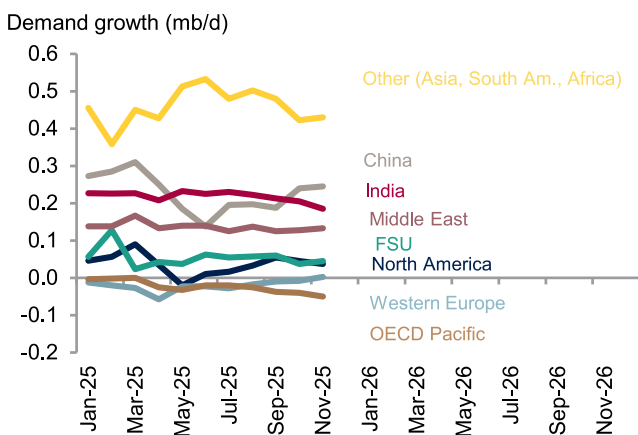
Source: IEA, OPEC, EIA, ABG Sundal Collier

2026 Non-OPEC growth (mb/d)



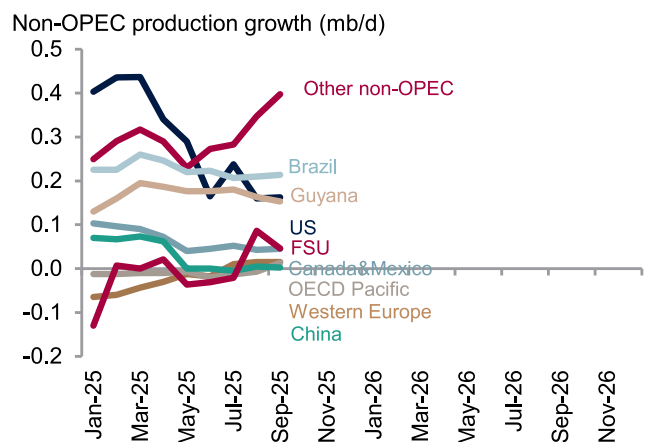
Source: IEA, OPEC, EIA, ABG Sundal Collier

2026 oil demand growth details



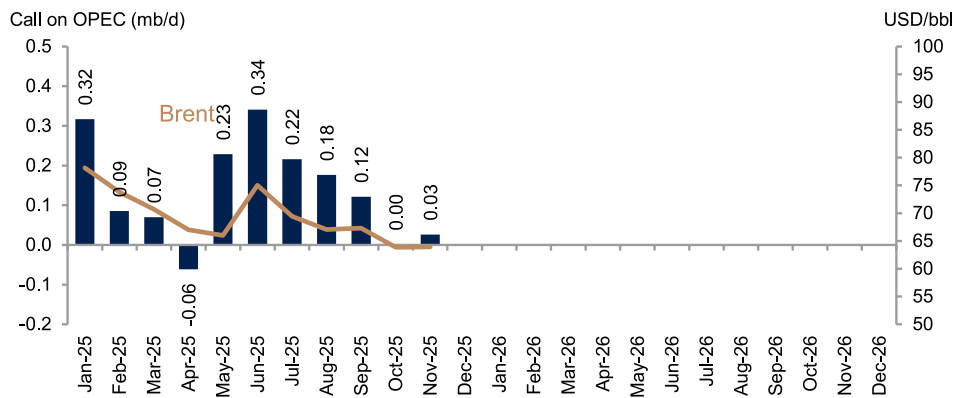
Source: IEA, OPEC, EIA, FGE, ABG Sundal Collier

Changes to consensus call-on-OPEC estimates



Source: IEA, OPEC, EIA, FGE, ABG Sundal Collier

2026 Consensus call on OPEC



Source: EIA, FGE, OPEC, ABG Sundal Collier

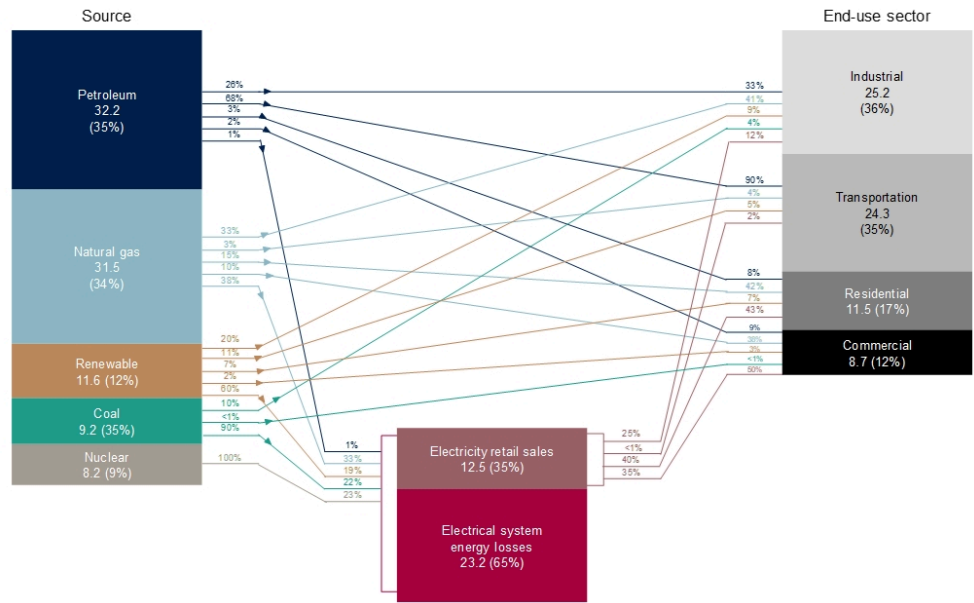
A closer look at demand

The chart below shows the sources and the end-users of energy in the US. The two key takeaways that we find most relevant are:

- 68% of oil production is used for transportation.
- 90% of all energy used for transportation comes from oil.

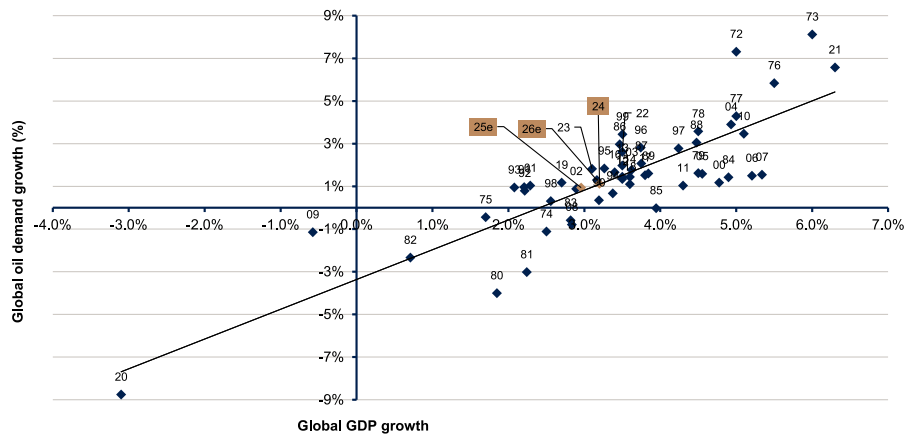
The energy mix is slightly different in other regions/countries. However, oil is basically the only energy source used for transportation in all regions. The point is that transportation (the movement of people and goods) is driven by GDP growth and population growth.

Transportation drives oil consumption (the case of the US from 2020)



Source: ABG Sundal Collier, EIA

GDP growth drives oil demand



Source: ABG Sundal Collier, IEA

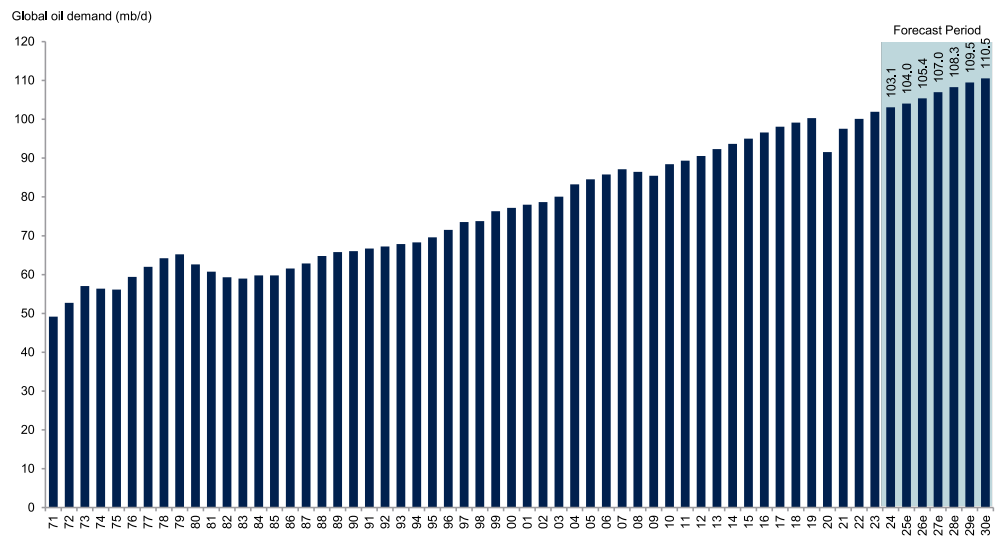
Global macro assumptions

Real GDP Growth	ABGSC			1971-24 mean	Last 10y mean	1971-24 median	Last 10y median	IMF/IEA		OPEC		EIA		Bloomberg	
	2024	2025e	2026e					2025e	2026e	2025e	2026e	2025e	2026e	2025e	2026e
Global (PPP adjusted)	3.2 %	3.0 %	3.2 %	3.4 %	3.0 %	3.5 %	3.5 %	3.0 %	3.1 %	3.0 %	3.1 %	3.0 %	2.9 %	2.8 %	2.9 %
US / North America	2.8 %	1.7 %	2.1 %	2.7 %	2.2 %	2.9 %	2.5 %	1.9 %	2.0 %	1.8 %	2.1 %	1.7 %	2.4 %	1.7 %	1.7 %
Europe	0.8 %	1.3 %	1.5 %	1.9 %	1.3 %	1.9 %	1.9 %	1.0 %	1.2 %	1.2 %	1.2 %	n.a.	n.a.	1.3 %	1.4 %
OECD	1.7 %	1.5 %	1.8 %	2.5 %	1.7 %	2.6 %	2.0 %	1.5 %	1.6 %	1.4 %	1.7 %	1.5 %	1.5 %	1.4 %	1.6 %
Non-OECD	4.2 %	4.2 %	4.3 %	3.8 %	3.9 %	4.2 %	4.3 %	4.1 %	4.0 %	4.1 %	4.1 %	4.2 %	3.9 %	4.1 %	4.0 %
India	6.5 %	6.3 %	6.4 %	5.5 %	5.7 %	6.3 %	7.0 %	6.4 %	6.4 %	6.5 %	6.5 %	n.a.	n.a.	6.4 %	6.4 %
China	4.8 %	4.8 %	4.7 %	8.7 %	5.7 %	8.4 %	6.4 %	4.8 %	4.2 %	4.8 %	4.5 %	n.a.	n.a.	4.8 %	4.2 %

Source: ABG Sundal Collier, IMF, OPEC, IEA, Bloomberg

On our updated estimates, we continue to forecast that oil demand will reach new record levels during 2025 and continue to grow towards 2030.

Global oil demand



Source: ABG Sundal Collier, IEA

More on non-OPEC production

The table below gives an overview of the most significant new fields in non-OPEC countries that are expected to come on-stream in the next few years. The production figures reflect peak production rates over the projects' lifetimes, and not necessarily the initial production rates.

Fields starting up in 2025			
Asset	Country	Operator	Est. Peak production, kboepd
Tengiz FGP	Kazakhstan	Tengizchevroil	95
Buzios VII (Almirante Tamandare)	Brazil	Petrobras	77
Bacalhau (x-Carcara) Phase 1	Brazil	Equinor	75
Johan Castberg	Norway	Equinor	73
Mero 4 (x-Libra NW)(Alexandre de Gusm)	Brazil	Petrobras	61
Yellowtail (ONE GUYANA)	Guyana	ExxonMobil	60
Syncrude Mildred Lake Extension West	Canada	Suncor Energy	51
Whale (AC772)	United States	Shell	35
Agogo full field (Phase 3)	Angola	Azule Energy	30
Redtail	Guyana	ExxonMobil	30
Shenandoah (WR051)	United States	Beacon Offshore	30
Ballymore (MC607)	United States	Chevron	25
Balder Future	Norway	Vaar Energi	24
Ichthys (Phase 2)	Australia	Inpex	16
Leon (KC642)	United States	LLOG	12
Kravtsovskoye (D-33) Phase 1	Russia	Lukoil	12
Ndungu	Angola	Azule Energy	12
Gavrikovskoye	Russia	NZNP Trade	11
Penguins (redevelop)	United Kingdom	Adura	11
CLOV Phase 3	Angola	TotalEnergies	10
Other			633
Total added capacity 2025			1,382

Source: Rystad Energy

Fields starting up in 2026			
Asset	Country	Operator	Est. Peak production, kboepd
Buzios VI (P-78)	Brazil	Petrobras	61
Buzios VIII (P-79)	Brazil	Petrobras	61
Uaru (Errea Wittu)	Guyana	ExxonMobil	54
Ignyalinskoye	Russia	Gazprom Neft (Pl	33
Qatargas T9 (North Field)	Qatar	QatarEnergy LNG	30
Qatargas T8 (North Field)	Qatar	QatarEnergy LNG	30
Pikka (Nanushuk) Phase 1	United States	Santos	27
Mako	Guyana	ExxonMobil	18
Snoek	Guyana	ExxonMobil	18
West White Rose	Canada	Cenovus Energy	16
North Field Sustainability Compression F	Qatar	QatarEnergy LNG	15
Wahoo (1-APL-1-ESS)	Brazil	PRIO	13
Foster Creek Optimization	Canada	Cenovus Energy	11
Blackrod Phase 1	Canada	International Petr	10
Christina Lake MEG Phase 3	Canada	MEG Energy	9
Lorito	Colombia	Ecopetrol	9
Solveig-Phase 2	Norway	Aker BP	8
Quiluma/ Maboqueiro (Northern Gas Cc	Angola	Azule Energy	8
Colt (Buckskin South)	United States	LLOG	8
Monument (WR316)	United States	Beacon Offshore	7
Other			136
Total added capacity 2026			582

Source: Rystad Energy

Fields starting up in 2027			
Asset	Country	Operator	Est. Peak production, kboepd
Buzios X (P-82)	Brazil	Petrobras	77
Buzios IX (P-80)	Brazil	Petrobras	77
Al Shaheen Ruya 3 (Batch 1)	Qatar	North Oil Compar	35
Whiptail	Guyana	ExxonMobil	34
Qatargas T11 (North Field)	Qatar	QatarEnergy LNG	30
Qatargas T10 (North Field)	Qatar	QatarEnergy LNG	30
Pinktail	Guyana	ExxonMobil	30
Tilapia (Jaguar)	Guyana	ExxonMobil	26
Munin (Krafla)	Norway	Aker BP	21
Jobi-Rii (x-Buffalo-Giraffe)	Uganda	TotalEnergies	20
Rosebank (213/27- 1Z)	United Kingdom	Adura	19
Ngiri (x-Warthog)	Uganda	TotalEnergies	15
Kingfisher South	Uganda	CNOOC	13
Pampo-Enchova (redevelop)	Brazil	Trident Energy	12
ISND (Phase V Part 2)	Qatar	QatarEnergy LNG	12
Vito (Waterflood)	United States	Shell	11
Hugin (Frigg Gamma/Delta)	Norway	Aker BP	11
Fenris (King Lear)	Norway	Aker BP	10
Lac Da Vang (Golden Camel)	Vietnam	Murphy Oil	10
Gunya	Uganda	TotalEnergies	10
Other			211
Total added capacity 2027			712

Source: Rystad Energy

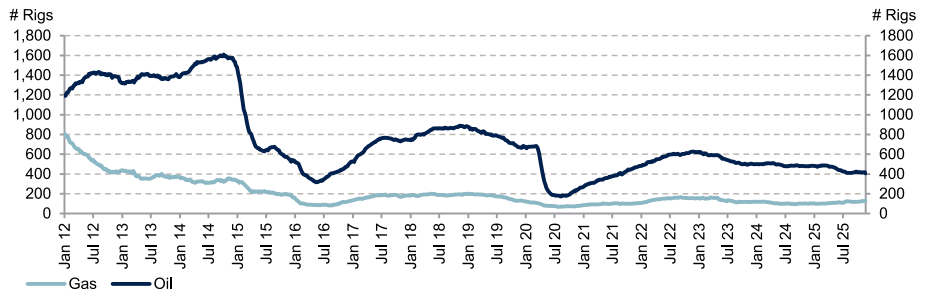
Fields starting up in 2028			
Asset	Country	Operator	Est. Peak production, kboepd
Buzios XI (P-83)	Brazil	Petrobras	77
Gran Morgu (x-Krabdagu)	Suriname	TotalEnergies	44
Trion	Mexico	Woodside	35
Gran Morgu (x-Sapakara South)	Suriname	TotalEnergies	32
Qatargas T12 (North Field)	Qatar	QatarEnergy LNG	31
Qatargas T13 (North Field)	Qatar	QatarEnergy LNG	31
Bul Hanine (Field Life Extension)	Qatar	QatarEnergy LNG	29
Sparta (x-N Platte) (GB959)	United States	Shell	28
Baleine Phase 3	Cote d'Ivoire	Eni	26
Raia Manta (x-Pao de Acucar)	Brazil	Equinor	26
Maromba	Brazil	BW Energy	20
Bovanenkovskoye (Neocomian-Jurassic)	Russia	Gazprom Neft (Pl	17
Cameia	Angola	TotalEnergies	17
Winterfell later phases (GC943/944)	United States	Beacon Offshore	14
North Field Sustainability Compression F	Qatar	QatarEnergy LNG	14
25/2-24 S (Ost Frigg Beta/Epsilon)	Norway	Aker BP	14
Raia Pintada (x-Seat)	Brazil	Equinor	13
Mad Dog West & North Water Injection	United States	BP	12
Ocotillo (MC040)	United States	Occidental Petrol	11
Chenda	Malaysia	PTTEP	11
Other			220
Total added capacity 2027			723

Source: Rystad Energy

US production

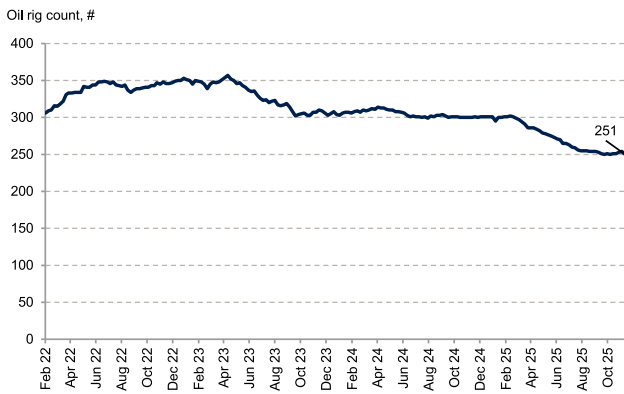
The charts below show the leading indicators (number of rigs, frac crews and wells drilled and completions) for US crude oil production. The number of US oil rigs rose sharply from its post-pandemic low of 172, but has during 2024/2025 flattened out and recently dipped to its current level of ~418, down from ~488 (y-o-y growth of -14.3%). On a general basis, a slowdown in drilling activity leads, with some time lag, to lower production. This dynamic has historically been partly offset by productivity growth, which results in higher production per well.

Baker Hughes US rig count



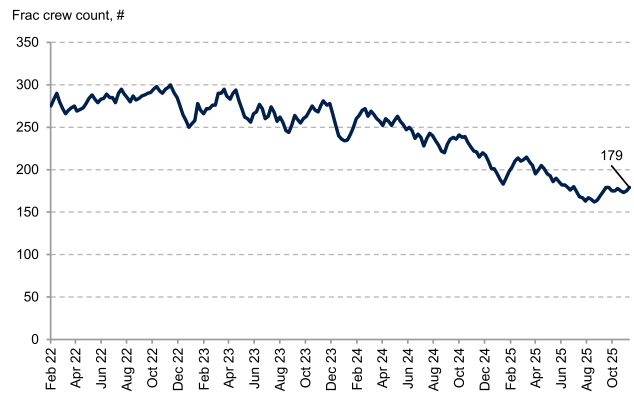
Source: ABGSC & FactSet

Permian oil rig count



Source: Baker Hughes, ABG Sundal Collier

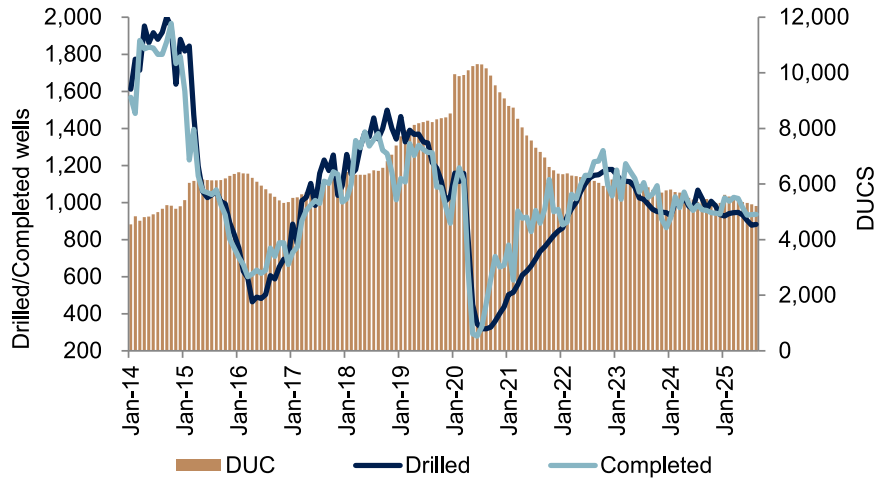
US frac crew count



Source: Bloomberg, ABG Sundal Collier

The inventory of drilled-uncompleted wells (DUCs) increased sharply between 2014 and 2020. During the drop in oil prices following the pandemic, shale producers were able to use the inventory to support production levels (drawing on the DUC inventory). The number of wells drilled per month increased almost every month from the trough in summer 2020 until early 2023, when it started to fall again. The high level of activity also reduced the stock of DUCs from 10,300 in mid-2020 to 5,215 in May '25, and the decline appears set to continue due to the current somewhat higher amount of completions compared to drilled wells. Note that the chart below includes DUC and well data for a selection of shale regions, as the EIA has recently changed its reporting standard and stopped publishing the monthly Drilling Productivity Report.

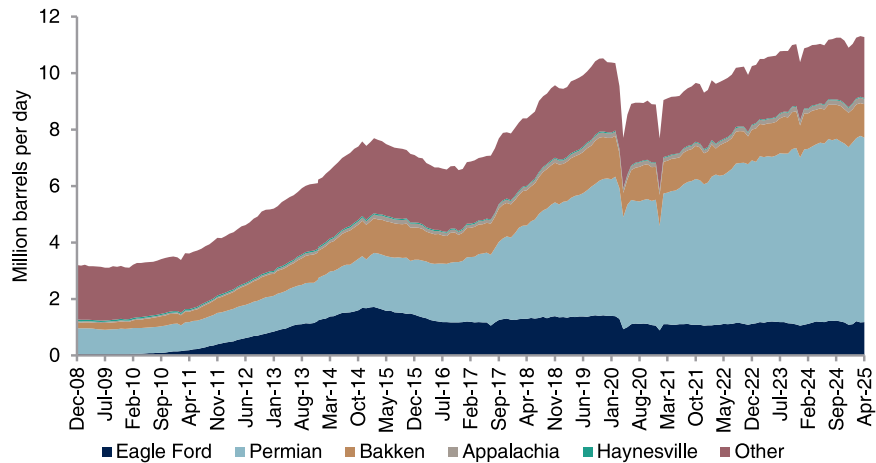
Shale players have been drawing on the DUCs



Source: ABG Sundal Collier, EIA

The growth in shale oil production is dominated by the Permian basin, which still exhibits fairly strong growth compared to other basins. The chart below shows US crude production for some selected basins: Bakken, Appalachia, Eagle Ford, Permian and Haynesville.

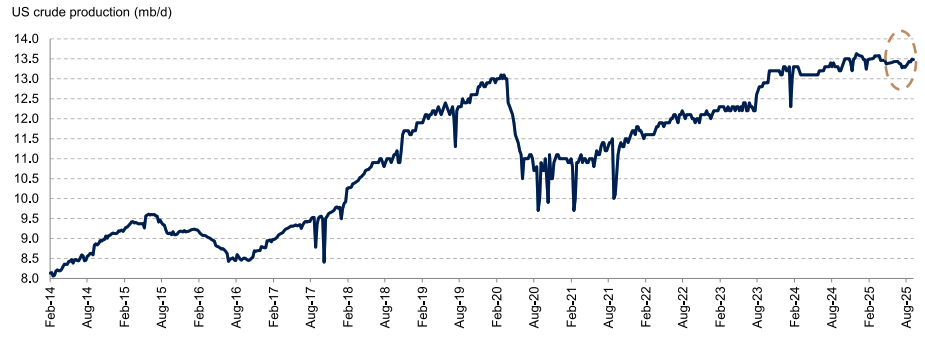
Shale oil production across selected basins



Source: ABG Sundal Collier, EIA

US crude oil production declined following its peak in 2020, prior to the COVID-19 pandemic. It peaked at 13.1m b/d in March 2020, but has increased significantly in recent years and is now hovering around a new all-time high near 13.5m b/d. Note the volatility in 2021 caused by weather disruptions. In addition, the EIA's weekly crude oil production figures have recently been revised sharply upwards, after lagging the monthly figures for some time. This should be seen as a technical adjustment and a correction of previous errors rather than an actual increase in production over the period.

US crude oil production



Source: ABG Sundal Collier, DOE

OPEC production

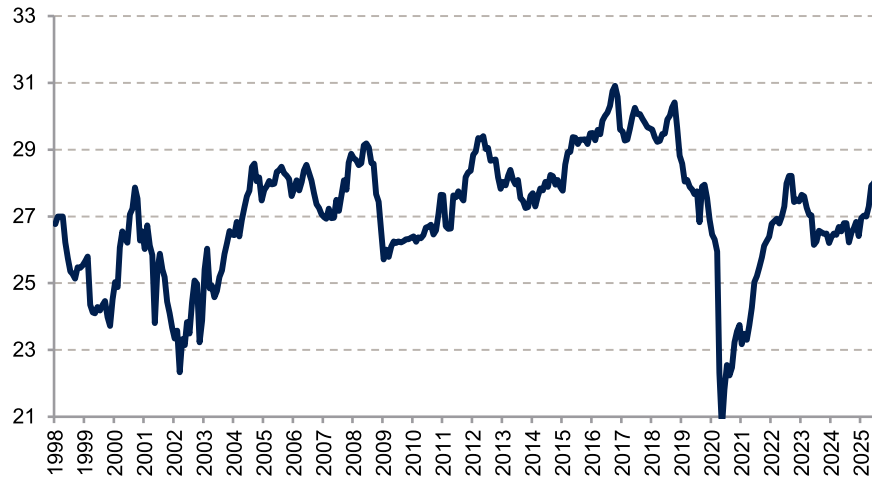
During the COVID-19 pandemic, we saw the largest production cuts in OPEC's history. Subsequently, OPEC gradually returned almost all the cut production to the market before introducing a new round of cuts in late 2022. At its March meeting, it re-affirmed its decision agreed upon on 5 December 2024, to proceed with a gradual and flexible return of the 2.2m b/d voluntary adjustments starting on 1 April 2025. In April through September, OPEC+ unwound 138k, 411k, 411k, 411k, 548k and 547k b/d of voluntary cuts, respectively, fully releasing the first layer of voluntary cuts (in addition to increasing UAE's production target by 300k b/d in line with previous plans). The unwinding accelerated quicker than most analysts had anticipated, and in September, the cartel announced the initiation of a gradual unwinding of the second tranche of voluntary cuts (1.65m b/d), increasing production further by 137k b/d from October.

Questions have been raised regarding whether the actual production will match the announced production unwind. Some OPEC members have produced above their targets for several months, and OPEC has communicated that it will produce below its targets until the aggregate overproduction has been compensated for. However, the absolute amount of reduced supply by this compensation will not impact the total supply picture materially. As shown in the chart below, the organisation's production has, as of August, increased by close to 1.5m b/d since March.

OPEC's decision to unwind quicker than expected has prompted several oil market agencies to forecast a massive build of oil inventories towards the end of 2025 and in the first half of 2026.

OPEC 9 production

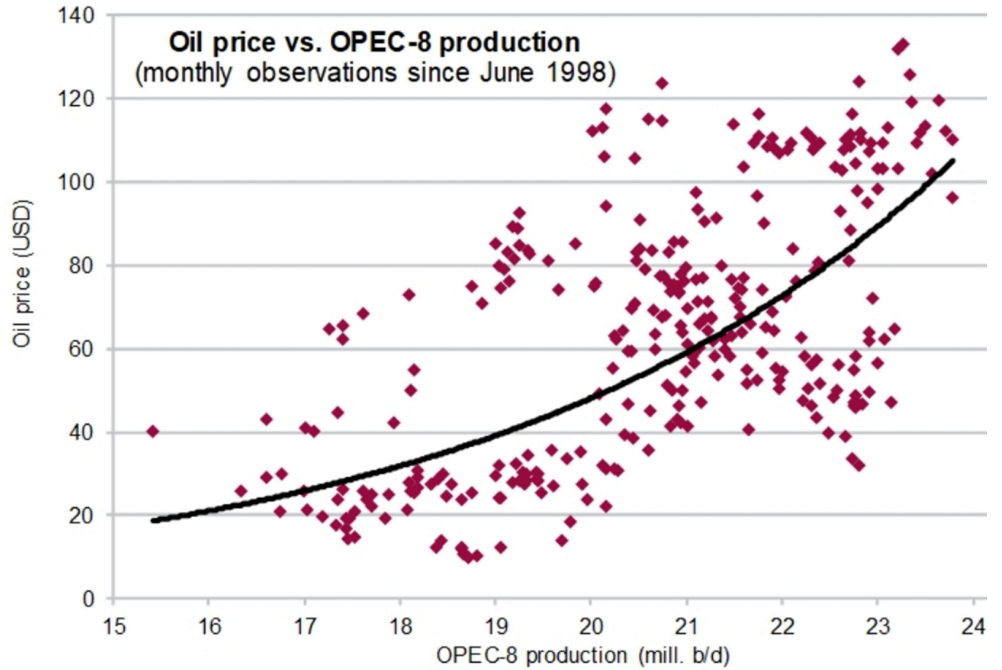
OPEC9 production (mb/d)



Source: ABG Sundal Collier, IEA

However, it is worth noting that the oil price has historically been strong when OPEC's production is high and spare capacity is limited. As such, in order to see even higher prices, we would preferably need to see an increase in the call-on-OPEC, OPEC production and lower global spare capacity.

Oil price vs OPEC-8 production

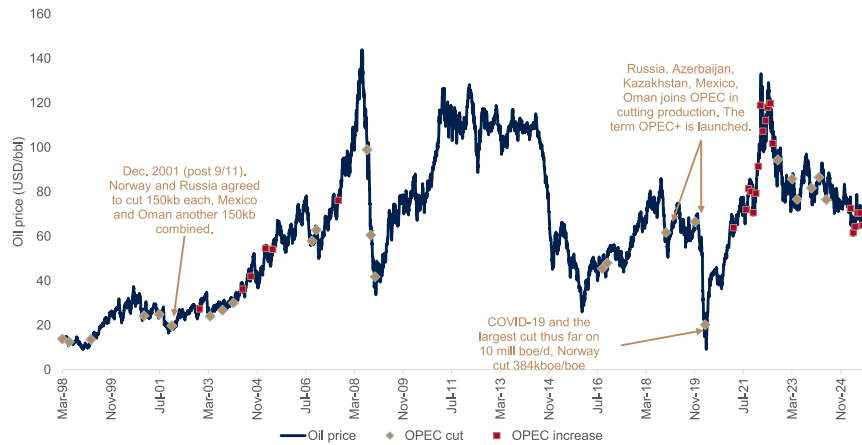


Source: ABG Sundal Collier, IEA

Oil price and historical OPEC cuts

Throughout the history of the oil market, the OPEC group has acted as a swing producer, adjusting its production quotas and output levels to influence the market balance and the oil price. The chart below provides an overview of recent production cuts and increases by the OPEC group and the wider OPEC+ group.

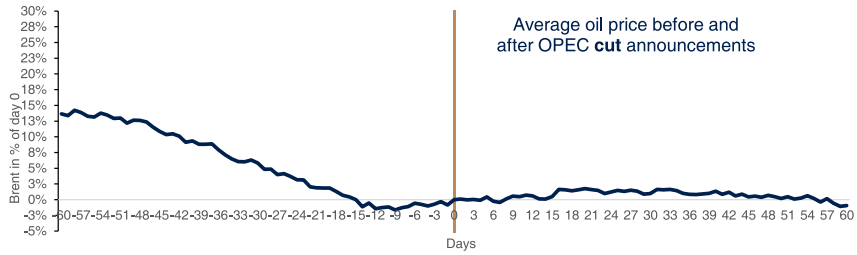
Oil price and changes from OPEC from 1998 to 2024



Source: ABG Sundal Collier, OPEC, FactSet

Historically, the oil price has been weak in the weeks leading up to OPEC meetings at which the group decides to cut production. This could be the result of OPEC deciding to cut production when the oil market balance is weak, in order to support oil prices. Below, we show the average oil price 60 days before and 60 days after OPEC announces a cut, showing that OPEC is often successful in terms of limiting further falls in the oil price.

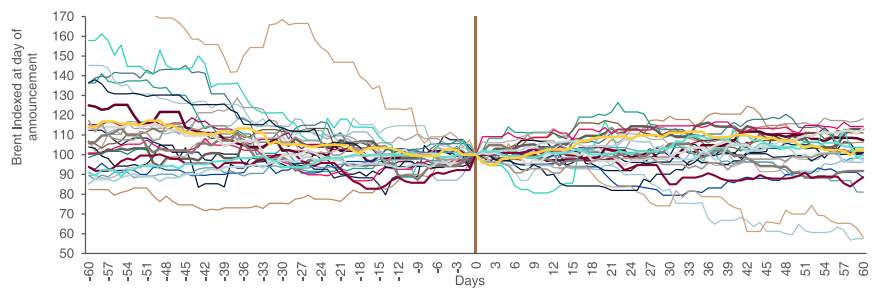
Average oil price before and after OPEC cut announcements



Source: ABG Sundal Collier, company data

The chart above shows that the oil price has usually been weak and falling ahead of situations where OPEC has imposed production cuts. The chart below shows oil price movements before and after OPEC cuts, with the latest OPEC cut highlighted in red (02/06/2024), at which OPEC agreed to extend the 2.2m b/d of voluntary cuts.

Oil price before and after OPEC cuts (recent cut marked in red)



Source: ABG Sundal Collier, FactSet, OPEC

Production vs. October quotas

(millionbarrelsperday)	Sep-25 Supply	Oct-25 Supply	Oct-25 vs Target	Oct-25 Implied Target	Sustainable Capacity	Eff Spare Cap vs Sep
Algeria	0.97	0.96	(0.01)	0.96	1.00	0.00
Congo	0.26	0.27	(0.01)	0.28	0.30	0.00
Equatorial Guinea	0.05	0.04	(0.03)	0.07	0.10	0.00
Gabon	0.26	0.24	0.06	0.18	0.20	0.00
Iraq	4.60	4.65	0.54	4.11	4.90	0.20
Kuwait	2.73	2.65	0.09	2.56	2.90	0.20
Nigeria	1.39	1.37	(0.13)	1.50	1.40	0.00
Saudi Arabia	9.98	9.95	(0.07)	10.02	12.10	2.20
UAE	3.72	3.65	0.27	3.38	4.30	0.60
Total OPEC-9	23.95	23.77	0.72	23.05	27.10	3.30
Iran	3.46	3.40			3.80	
Libya	1.29	1.20			1.20	0.00
Venezuela	1.00	1.01			0.90	0.00
Total OPEC	29.70	29.38			33.10	3.40
Azerbaijan	0.45	0.45	(0.10)	0.55	0.50	0.00
Kazakhstan	1.92	1.68	0.15	1.53	1.80	0.10
Mexico	1.43	1.42			1.50	0.10
Oman	0.76	0.78	(0.02)	0.80	0.80	0.00
Russia	9.28	9.28	(0.20)	9.48	9.40	
Others	0.79	0.78	(0.09)	0.87	0.90	0.10
Total Non-OPEC	14.63	14.40	(0.25)	13.23	14.80	0.30
OPEC+ 18 in Nov 2022 deal	37.14	36.74	0.47	36.28	40.40	3.60
Total OPEC+	44.33	43.78			47.90	3.70

Source: IEA, ABG Sundal Collier

Detailed OPEC production

The table below gives more details on OPEC production and spare capacity:

OPEC production capacity and spare capacity

OPEC production mb/d	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25
Saudi Arabia	8.97	8.99	9.02	9.03	9.03	8.87	9.01	9.01	9.04	9.05	9.02	9.00	9.00	8.96	9.07	8.94	9.09	9.80	9.52	9.69
UAE	3.21	3.22	3.22	3.15	3.25	3.28	3.30	3.30	3.26	3.23	3.25	3.22	3.20	3.28	3.26	3.25	3.35	3.42	3.53	3.43
Kuwait	2.47	2.44	2.47	2.49	2.49	2.48	2.52	2.52	2.50	2.49	2.44	2.48	2.44	2.47	2.62	2.65	2.73	2.76	2.66	2.68
Venezuela	0.83	0.86	0.86	0.86	0.88	0.89	0.92	0.92	0.93	0.93	0.89	0.86	0.86	0.97	0.97	0.83	0.85	0.94	0.86	0.94
Nigeria	1.40	1.36	1.34	1.28	1.35	1.32	1.26	1.36	1.31	1.33	1.37	1.51	1.35	1.44	1.40	1.49	1.45	1.51	1.48	1.50
Libya	1.03	1.16	1.16	1.19	1.19	1.19	1.16	0.98	0.57	0.97	1.17	1.24	1.17	1.24	1.20	1.24	1.26	1.20	1.25	1.27
Algeria	0.91	0.91	0.91	0.91	0.90	0.91	0.92	0.91	0.90	0.91	0.91	0.90	0.88	0.90	0.91	0.93	0.90	0.93	0.89	0.92
Ecuador	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na
OPEC 7	18.82	18.94	18.98	18.91	19.09	18.94	19.09	19.00	18.51	18.91	19.05	19.21	18.90	19.26	19.43	19.33	19.63	20.56	20.19	20.43
Iraq	4.23	4.25	4.26	4.24	4.28	4.26	4.36	4.36	4.30	4.25	4.20	4.24	4.20	4.30	4.23	4.22	4.19	4.28	4.48	4.55
Iran	3.15	3.20	3.25	3.30	3.31	3.35	3.35	3.42	3.41	3.35	3.41	3.39	3.31	3.39	3.36	3.45	3.48	3.08	3.33	3.17
OPEC 9	26.20	26.39	26.49	26.45	26.68	26.55	26.80	26.80	26.22	26.51	26.66	26.84	26.41	26.95	27.02	27.00	27.30	27.92	28.00	28.15
Gabon	0.23	0.22	0.24	0.21	0.22	0.22	0.22	0.23	0.22	0.23	0.24	0.25	0.25	0.23	0.24	0.22	0.25	0.25	0.23	0.24
Qatar	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na
Equatorial Guinea	0.05	0.05	0.06	0.05	0.06	0.05	0.06	0.07	0.06	0.05	0.06	0.08	0.06	0.06	0.06	0.06	0.06	0.05	0.04	0.04
Congo	0.25	0.25	0.26	0.26	0.26	0.26	0.26	0.27	0.26	0.26	0.24	0.25	0.25	0.24	0.24	0.24	0.24	0.26	0.27	0.24
OPEC (all)	26.73	26.91	27.05	26.97	27.22	27.08	27.34	27.37	26.76	27.05	27.20	27.42	26.97	27.48	27.52	27.85	28.48	28.48	28.54	28.67

Total prod. Capacity	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25
Saudi Arabia	12.20	12.10	12.10	12.10	12.10	12.10	12.10	12.10	12.10	12.10	12.10	12.10	12.10	12.10	12.10	12.10	12.10	12.10	12.10	12.10
UAE	4.20	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30
Kuwait	2.80	2.90	2.80	2.80	2.80	2.80	2.80	2.80	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90
Venezuela	0.80	0.80	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Nigeria	1.40	1.40	1.50	1.50	1.50	1.50	1.50	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40
Libya	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
Algeria	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Ecuador	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na
OPEC 8	23.60	23.70	23.80	23.80	23.80	23.80	23.80	23.80	23.80	23.80	23.80	23.80	23.80	23.80	23.80	23.80	23.80	23.80	23.80	23.80
Iraq	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.90	4.90	4.90	4.90	4.90	4.90	4.90	4.90	4.90	4.90	4.90	4.90
Iran	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80
OPEC 10	32.20	32.30	32.40	32.40	32.40	32.40	32.40	32.40	32.50	32.50	32.50	32.50	32.50	32.50	32.50	32.50	32.50	32.50	32.50	32.50
Gabon	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Equatorial Guinea	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Congo	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
OPEC (all)	32.80	32.90	33.00	33.00	33.00	33.00	33.00	33.10	33.10	33.10	33.10	33.10	33.10	33.10	33.10	33.10	33.10	33.10	33.10	33.10

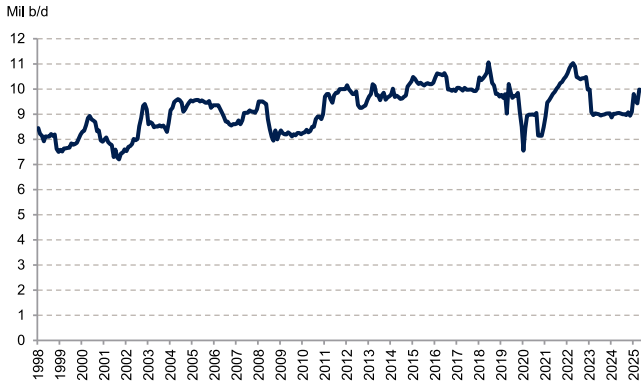
Spare capacity	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25
Saudi Arabia	3.23	3.11	3.08	3.07	3.07	3.23	3.09	3.09	3.06	3.05	3.08	3.10	3.10	3.14	3.03	3.16	3.01	2.30	2.58	2.41
UAE	0.99	1.08	1.08	1.15	1.05	1.02	1.00	1.00	1.04	1.07	1.05	1.08	1.10	1.02	1.04	1.05	0.95	0.88	0.77	0.87
Kuwait	0.33	0.46	0.33	0.31	0.31	0.32	0.28	0.28	0.40	0.41	0.46	0.42	0.46	0.43	0.28	0.25	0.17	0.14	0.24	0.22
Venezuela	-0.03	-0.06	0.04	0.04	0.02	0.01	-0.02	-0.02	-0.03	-0.03	0.01	0.04	0.04	-0.07	-0.07	0.07	0.05	-0.04	0.04	-0.04
Nigeria	0.00	0.04	0.16	0.22	0.15	0.18	0.24	0.14	0.09	0.07	0.03	-0.11	0.05	-0.04	0.00	-0.09	-0.05	-0.11	-0.08	-0.10
Libya	0.17	0.04	0.04	0.01	0.01	0.01	0.04	0.22	0.63	0.23	0.03	-0.04	0.03	-0.04	0.00	-0.04	-0.06	0.00	-0.05	-0.07
Algeria	0.09	0.09	0.09	0.09	0.10	0.09	0.08	0.09	0.10	0.09	0.09	0.10	0.12	0.10	0.09	0.07	0.10	0.07	0.11	0.08
Ecuador	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na
OPEC 8	4.78	4.76	4.82	4.89	4.71	4.86	4.71	4.80	5.29	4.89	4.75	4.59	4.90	4.54	4.37	4.47	4.17	3.24	3.61	3.37
Iraq	0.57	0.55	0.54	0.56	0.52	0.54	0.44	0.42	0.60	0.65	0.70	0.66	0.70	0.60	0.67	0.68	0.71	0.62	0.42	0.35
Iran	0.65	0.60	0.55	0.50	0.49	0.45	0.45	0.38	0.39	0.45	0.39	0.41	0.49	0.41	0.44	0.35	0.32	0.72	0.47	0.63
OPEC 10	6.00	5.91	5.91	5.95	5.72	5.85	5.60	5.60	6.28	5.99	5.84	5.66	6.09	5.55	5.48	5.50	5.20	4.58	4.50	4.35
Gabon	-0.03	-0.02	-0.04	-0.01	-0.02	-0.02	-0.02	-0.03	-0.02	-0.03	-0.04	-0.05	-0.05	-0.03	-0.04	-0.02	-0.05	-0.05	-0.03	-0.04
Equatorial Guinea	0.05	0.05	0.04	0.05	0.04	0.05	0.04	0.03	0.04	0.05	0.04	0.02	0.04	0.04	0.04	0.04	0.04	0.05	0.06	0.06
Congo	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.03	0.04	0.04	0.06	0.05	0.05	0.06	0.06	0.06	0.06	0.04	0.03	0.06
OPEC (all)	6.07	5.99	5.95	6.03	5.78	5.92	5.66	5.63	6.34	6.05	5.90	5.68	6.13	5.62	5.54	5.58	5.25	4.62	4.56	4.43

Source: ABG Sundal Collier, IEA, OPEC

Monthly production data for 10 main OPEC countries

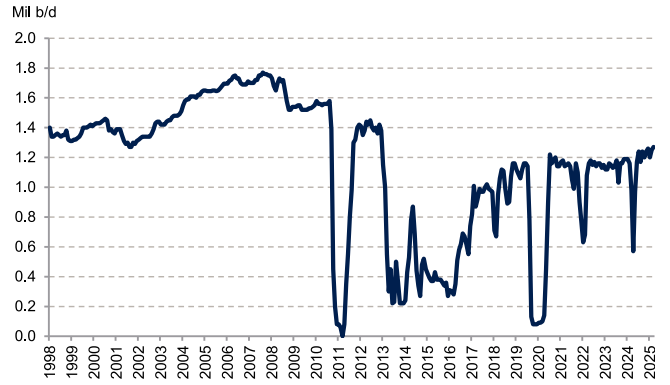
We note that most countries have increased their production since the unwinding of the voluntary cuts (at least for the countries that were involved in the voluntary cuts). However, we also note that the Iranian production has seen a sharp decline recently as the US has ramped up its pressure to curb Iranian oil production. This is somewhat offsetting the unwinding of the voluntary cuts by other OPEC members.

Saudi Arabia production



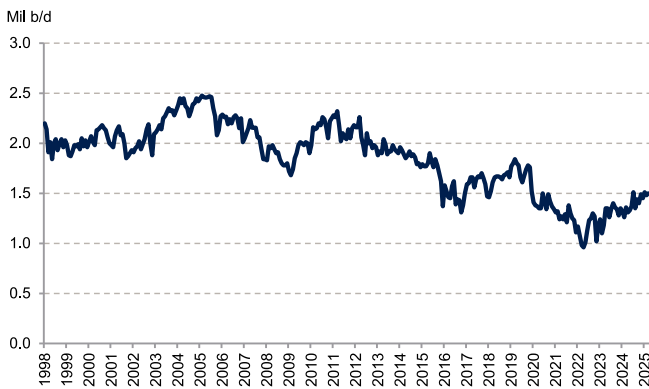
Source: ABG Sundal Collier, IEA

Libya oil production



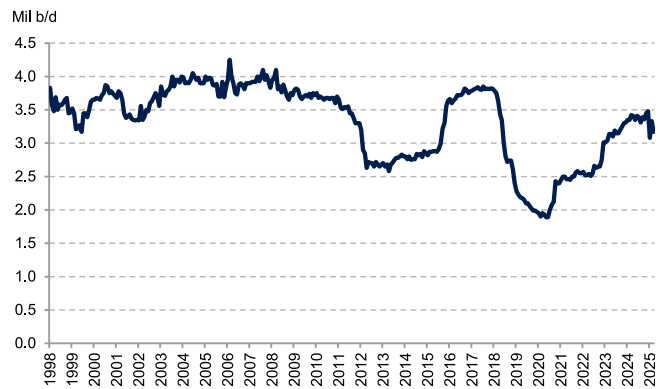
Source: ABG Sundal Collier, IEA

Nigeria oil production



Source: ABG Sundal Collier, IEA

Iran oil production



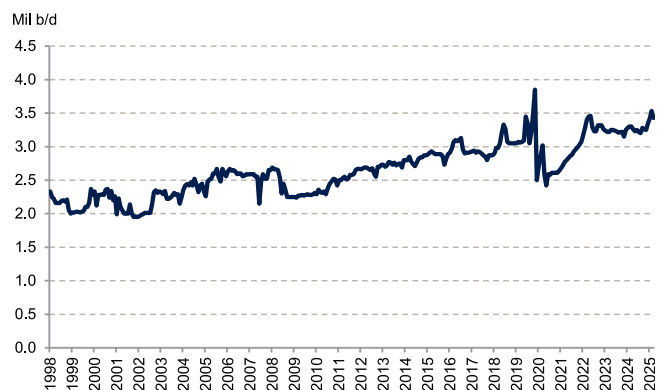
Source: ABG Sundal Collier, IEA

Venezuela oil production



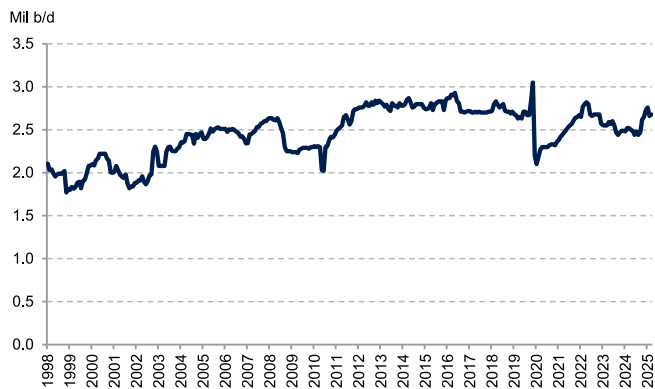
Source: ABG Sundal Collier, IEA

UAE oil production



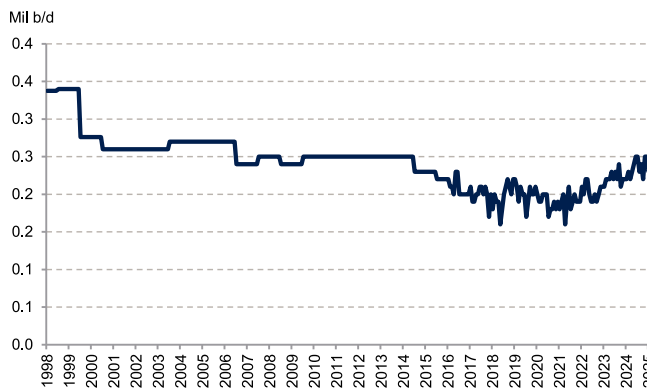
Source: ABG Sundal Collier, IEA

Kuwait oil production



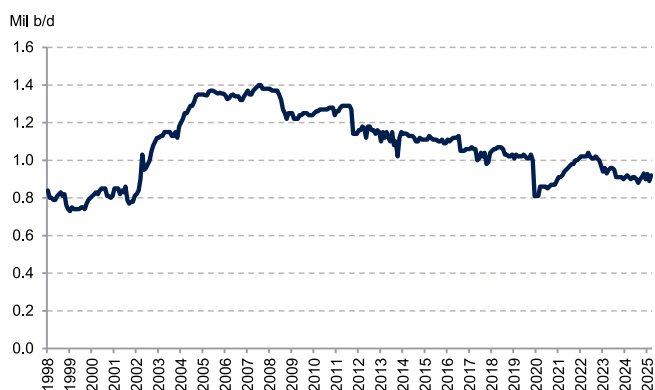
Source: ABG Sundal Collier, IEA

Gabon oil production



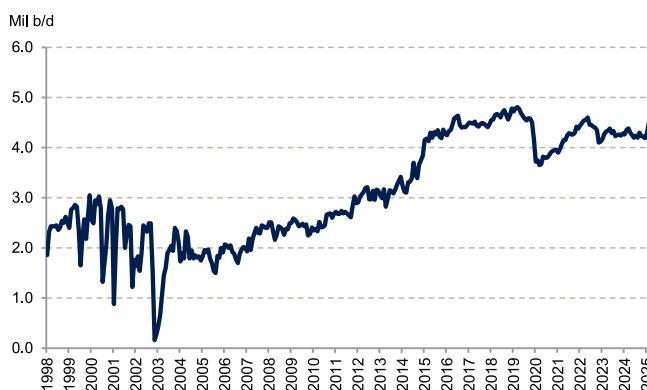
Source: ABG Sundal Collier, IEA

Algeria oil production



Source: ABG Sundal Collier, IEA

Iraq oil production

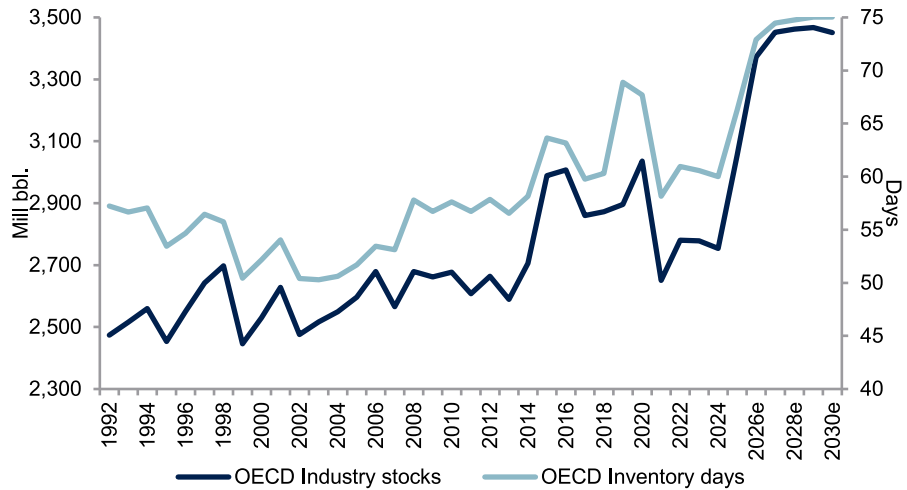


Source: ABG Sundal Collier, IEA

Stock levels

Industry stock levels grew materially in 2020 amid a pandemic-driven demand shock. After a steep decline in 2021, we subsequently saw an increase in OECD industry inventory days during 2022 before a relatively flat trend in 2023-2025. We now estimate that global OECD stocks will increase, reaching ~70 days by the end of 2026. Beyond this, our estimates indicate a flat development in global OECD stocks towards 2030 given our updated market balance.

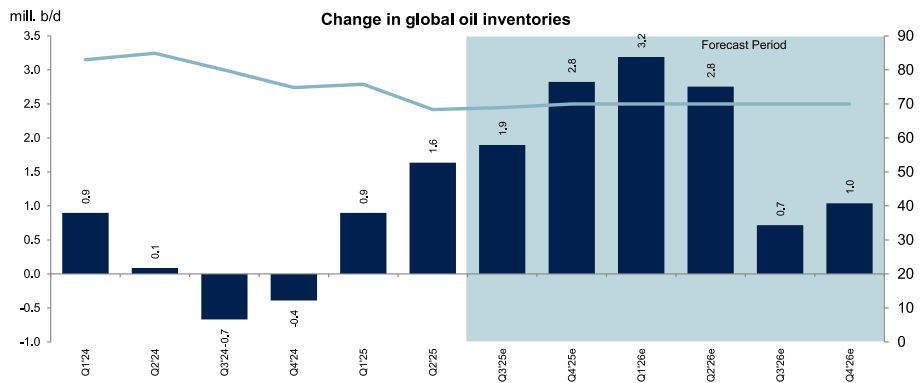
OECD industry stock days expected to increase sharply



Source: ABG Sundal Collier, IEA

The global supply/demand estimates show that we expect heavy inventory builds to continue towards the middle of 2026.

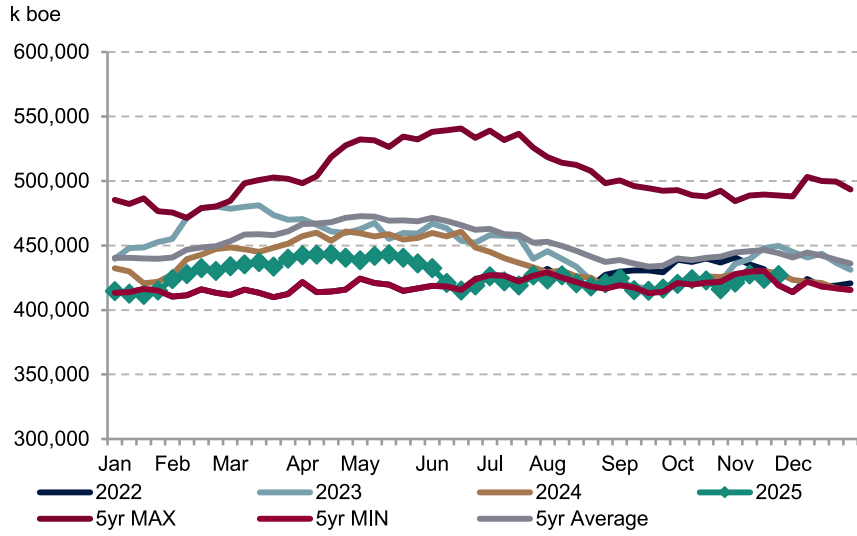
Global oil stocks change and oil price



Source: ABG Sundal Collier, IEA

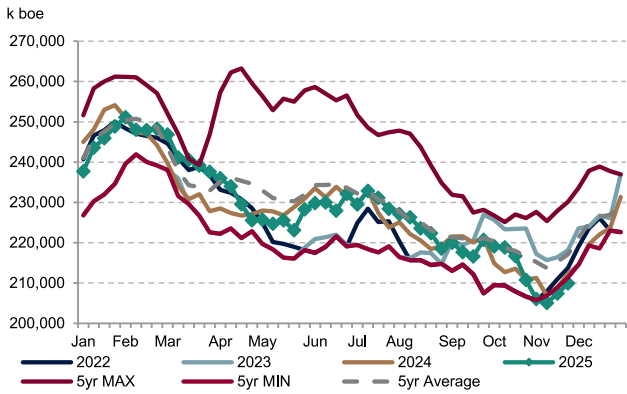
Below, we show selected data on US crude oil and product inventories.

Crude inventory



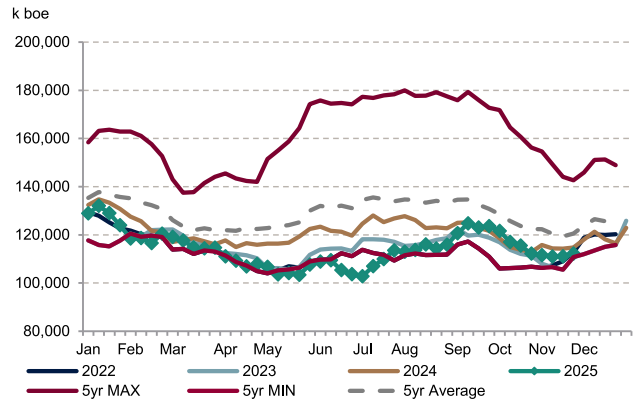
Source: ABG Sundal Collier, Bloomberg

Gasoline inventory



Source: ABG Sundal Collier, Bloomberg

Distillate inventory



Source: ABG Sundal Collier, Bloomberg

Overview of our oil market estimates

Key oil market estimates - annual figures (million barrels/day)

Oil demand (mb/d)	2017	2018	2019	2020	2021	2022	2023	2024	2025e	2026e	2027e	2028e	2029e	2030e
OECD														
US	20.0	20.5	20.5	18.2	19.9	20.0	20.2	20.5	20.5	20.7	20.8	20.8	20.8	20.8
Other America (Canada, Mexico, Chile)	5.1	5.0	5.0	4.3	4.4	4.7	4.7	4.7	4.7	4.7	4.8	4.8	4.8	4.8
Sum Americas	25.1	25.5	25.4	22.5	24.3	24.7	24.9	25.2	25.3	25.4	25.6	25.6	25.6	25.6
Europe	14.4	14.3	14.3	12.4	13.2	13.6	13.5	13.5	13.6	13.6	13.6	13.7	13.6	13.6
Pacific	8.2	8.1	7.9	7.2	7.3	7.3	7.2	7.2	7.1	7.1	7.1	7.1	7.1	7.1
Total OECD	47.6	47.9	47.7	42.9	44.9	45.6	45.0	45.9	46.1	46.1	46.3	46.4	46.3	46.2
Growth Y/Y (%)	1.3%	0.5%	-0.4%	-11.8%	6.7%	1.6%	0.1%	0.5%	0.1%	0.4%	0.4%	0.2%	-0.1%	-0.2%
FSU&Eastern Europe														
FSU	4.5	4.6	4.7	4.6	4.9	4.9	5.0	4.8	4.9	4.9	5.0	5.1	5.2	5.3
Europe	0.8	0.8	0.8	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9
Total Eastern Block	5.3	5.4	5.5	5.3	5.7	5.7	5.8	5.6	5.7	5.8	5.9	6.0	6.1	6.2
Growth Y/Y (%)	-8.0%	2.5%	2.0%	-4.0%	7.2%	1.2%	1.2%	-3.6%	1.6%	1.6%	1.9%	1.9%	1.9%	1.9%
Emerging Economies														
China	12.5	13.0	13.9	14.2	15.1	15.1	16.4	16.5	16.7	16.9	17.2	17.4	17.5	17.7
India	4.7	4.9	5.0	4.6	4.9	5.2	5.4	5.7	5.8	6.0	6.2	6.4	6.6	6.8
Other Asia	9.1	9.2	9.0	8.2	8.6	9.0	9.0	9.2	9.5	9.7	9.9	10.0	10.2	10.4
Latin America	6.3	6.3	6.3	5.5	6.0	6.3	6.4	6.3	6.4	6.6	6.6	6.8	7.0	7.2
Middle East	8.4	8.3	8.7	8.1	8.4	8.9	9.0	9.2	9.3	9.5	9.7	10.0	10.2	10.4
Africa	4.3	4.2	4.3	3.8	4.1	4.3	4.3	4.6	4.8	5.0	5.2	5.3	5.5	5.6
Total Emerging	45.2	45.9	47.2	44.2	47.1	48.8	50.5	51.6	52.5	53.5	54.8	55.9	57.0	58.1
Growth Y/Y (%)	3.0%	1.5%	2.8%	-6.2%	6.4%	3.7%	3.5%	2.2%	1.6%	2.0%	2.4%	2.0%	2.0%	1.8%
Total Non-OECD	50.5	51.3	52.7	49.5	52.7	54.5	56.3	57.2	58.2	59.3	60.7	61.9	63.2	64.3
Growth Y/Y (%)	1.7%	1.6%	2.7%	-6.0%	6.5%	3.5%	3.3%	1.6%	1.6%	2.0%	2.3%	2.0%	2.0%	1.8%
TOTAL DEMAND	98.1	99.2	100.3	91.5	97.6	100.1	101.9	103.1	104.0	105.4	107.0	108.3	109.5	110.5
Growth Y/Y (%)	1.5%	1.1%	1.2%	-8.8%	6.6%	2.6%	1.8%	1.1%	0.9%	1.3%	1.5%	1.2%	1.1%	1.0%
Oil supply (mb/d)														
NON-OPEC														
US	13.2	15.5	17.2	16.6	16.8	17.9	19.5	20.4	20.9	21.0	21.0	21.0	21.0	21.0
Mexico	2.2	2.1	1.9	1.9	2.0	2.0	2.1	1.9	1.9	1.8	1.8	1.8	1.8	1.8
Canada	4.8	5.4	5.5	5.4	5.6	5.8	5.8	6.1	6.3	6.5	6.5	6.6	6.6	6.5
North America	20.3	23.0	24.7	23.8	24.3	25.7	27.5	28.4	29.1	29.3	29.2	29.3	29.3	29.3
Europe	3.5	3.5	3.3	3.6	3.4	3.2	3.2	3.1	3.2	3.2	3.1	2.9	2.7	2.5
Pacific	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total Non-OECD	24.2	26.9	28.6	27.9	28.2	29.4	31.1	31.9	32.7	32.9	32.8	32.7	32.4	32.2
Russia	11.4	11.6	11.6	10.6	10.9	11.1	11.0	10.8	10.7	10.7	10.8	11.0	11.1	11.1
Other FSU	3.0	3.0	3.0	2.8	2.9	2.8	2.9	2.8	3.0	3.0	2.9	2.8	2.7	2.6
China	3.9	3.8	3.9	4.0	4.1	4.2	4.3	4.3	4.4	4.4	4.3	4.2	4.1	4.0
Brazil	2.7	2.7	2.9	3.0	3.0	3.1	3.5	3.4	3.7	4.0	4.1	4.2	4.4	4.4
Guyana	0.0	0.0	0.0	0.1	0.1	0.3	0.4	0.6	0.7	0.9	1.0	1.2	1.4	1.6
Angola	1.6	1.5	1.4	1.3	1.1	1.2	1.1	1.2	1.1	1.2	1.1	1.0	1.0	1.0
Indonesia	0.8	0.8	0.8	0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Ecuador	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4
Other	11.9	12.2	9.3	8.7	8.4	8.4	8.5	8.4	8.5	8.4	8.5	8.6	8.7	8.8
Total non-OECD	35.9	36.1	33.3	31.7	31.6	32.2	32.7	32.6	33.2	33.6	33.7	34.0	34.4	34.5
Processing Gains	2.3	2.1	2.4	2.1	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Global biofuels	0.0	0.0	2.8	2.6	2.8	2.9	3.1	3.4	3.5	3.7	3.9	4.1	4.3	4.5
Total Non-OPEC	62.3	65.1	67.0	64.3	64.9	66.7	69.3	70.3	71.9	72.6	72.7	73.2	73.5	73.6
Growth Y/Y (%)	4.9%	4.4%	2.9%	-4.1%	0.9%	2.9%	3.9%	1.4%	2.2%	1.0%	0.2%	0.6%	0.5%	0.1%
OPEC														
Iraq	4.5	4.6	4.7	4.1	4.0	4.5	4.3	4.3	4.4	4.3	4.4	4.5	4.7	4.8
Iran	3.8	3.0	2.4	2.0	2.4	2.6	3.0	3.4	3.3	3.4	3.4	3.5	3.6	3.8
Gabon	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Saudi Arabia	10.0	10.3	9.8	9.2	9.2	10.5	9.6	9.1	9.5	10.1	10.1	10.4	10.9	11.4
Venezuela	2.0	1.4	0.9	0.5	0.6	0.7	0.8	0.9	0.9	1.0	0.9	0.9	0.9	0.9
Nigeria	1.5	1.6	1.7	1.5	1.3	1.2	1.3	1.5	1.5	1.5	1.5	1.4	1.3	1.2
Libya	0.8	1.0	1.1	0.4	1.2	1.0	1.2	1.1	1.2	1.2	1.2	1.2	1.2	1.2
Algeria	1.1	1.0	1.0	0.9	0.9	1.0	1.0	0.9	0.9	1.0	1.0	1.0	1.0	1.0
UAE	2.9	3.0	3.2	2.9	2.8	3.3	3.3	3.2	3.4	3.4	3.4	3.4	3.4	3.5
Kuwait	2.7	2.8	2.7	2.4	2.4	2.7	2.6	2.5	2.6	2.6	2.6	2.6	2.6	2.6
Other OPEC (Congo, Equatorial Guinea)	0.4	1.0	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2
Total OPEC crude	29.8	29.9	28.1	24.4	25.3	27.9	27.4	27.2	28.4	28.9	28.9	29.3	30.0	30.8
NGLs	5.8	5.5	5.5	5.1	5.2	5.4	5.5	5.6	5.6	5.8	5.9	6.0	6.1	6.2
Total OPEC	35.4	35.4	33.6	29.5	30.5	33.3	32.9	32.8	34.0	34.7	34.8	35.3	36.1	37.0
TOTAL SUPPLY	97.8	100.5	100.5	93.8	95.4	100.0	102.2	103.1	105.9	107.3	107.6	108.5	109.7	110.6
Key figures														
Call on OPEC crude	30.1	28.6	27.9	22.2	27.5	28.0	27.1	27.2	26.6	27.0	28.3	29.1	29.8	30.8
OPEC crude production	29.8	29.9	28.1	24.4	25.3	27.9	27.4	27.2	28.4	28.9	28.9	29.3	30.0	30.8
= Implied stock change	-0.3	1.3	0.2	2.2	-2.2	-0.1	0.3	0.0	1.8	1.9	0.6	0.2	0.2	0.1

Source: ABG Sundal Collier, IEA

Oil market estimates - annual figures (y-o-y growth, million barrels/day)

y-o-y growth Oil supply (mb/d)	2017	2018	2019	2020	2021	2022	2023	2024	2025e	2026e	2027e	2028e	2029e	2030e
OECD														
US	0.0	0.5	0.0	-2.3	1.7	0.1	0.2	0.2	0.1	0.1	0.1	0.0	0.0	0.0
Other America (Canada, Mexi)	0.2	-0.1	-0.1	-0.7	0.2	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sum Americas	0.2	0.5	-0.1	-3.0	1.9	0.4	0.2	0.2	0.1	0.1	0.2	0.1	0.0	-0.1
Europe	0.4	-0.1	0.0	-1.9	0.8	0.4	-0.1	0.1	0.0	0.1	0.0	0.0	0.0	0.0
Pacific	0.0	-0.1	-0.1	-0.8	0.2	0.0	-0.1	-0.1	-0.1	0.0	0.0	0.0	0.0	0.0
Total OECD	0.6	0.3	-0.2	-5.6	2.8	0.7	0.1	0.2	0.0	0.2	0.2	0.1	0.0	-0.1
Growth Y/Y (%)	1.3%	0.5%	-0.4%	-11.8%	6.7%	1.6%	0.1%	0.5%	0.1%	0.4%	0.4%	0.2%	-0.1%	-0.2%
FSU&Eastern Europe														
FSU	-0.5	0.1	0.1	-0.2	0.3	0.0	0.1	-0.2	0.1	0.1	0.1	0.1	0.1	0.1
Europe	0.0	0.0	0.0	-0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Eastern Block	-0.5	0.1	0.1	-0.2	0.4	0.1	0.1	-0.2	0.1	0.1	0.1	0.1	0.1	0.1
Growth Y/Y (%)	-8.0%	2.5%	2.0%	-4.0%	7.2%	1.2%	1.2%	-3.6%	1.6%	1.6%	1.9%	1.9%	1.9%	1.9%
Emerging Economies														
China	0.5	0.5	0.9	0.3	0.9	0.0	1.3	0.1	0.2	0.3	0.3	0.2	0.2	0.2
India	0.2	0.2	0.1	-0.4	0.3	0.3	0.2	0.3	0.1	0.2	0.2	0.2	0.2	0.2
Other Asia	0.7	0.1	-0.2	-0.9	0.5	0.3	0.0	0.2	0.3	0.2	0.2	0.2	0.2	0.2
Latin America	-0.1	0.0	0.0	-0.8	0.6	0.3	0.0	0.1	-0.1	0.1	0.2	0.2	0.2	0.2
Middle East	-0.1	0.0	0.4	-0.6	0.3	0.5	0.1	0.2	0.1	0.1	0.2	0.2	0.2	0.2
Africa	0.0	0.0	0.0	-0.5	0.3	0.3	0.0	0.3	0.2	0.2	0.2	0.2	0.2	0.2
Total Emerging	1.3	0.7	1.3	-2.9	2.8	1.7	1.1	0.8	1.1	1.3	1.1	1.3	1.1	1.0
Growth Y/Y (%)	3.0%	1.5%	2.8%	-6.2%	6.4%	3.7%	3.5%	2.2%	1.6%	2.0%	2.4%	2.0%	2.0%	1.8%
Total Non-OECD	0.8	0.8	1.4	-3.2	3.2	1.8	1.8	0.9	0.9	1.2	1.4	1.2	1.2	1.2
Growth Y/Y (%)	1.7%	1.6%	2.7%	-6.0%	6.5%	3.5%	3.3%	1.6%	1.6%	2.0%	2.3%	2.0%	2.0%	1.8%
TOTAL DEMAND	1.5	1.1	1.2	-8.8	6.0	2.5	1.8	1.1	1.0	1.4	1.6	1.3	1.2	1.1
Growth Y/Y (%)	1.5%	1.1%	1.2%	-8.8%	6.6%	2.6%	1.8%	1.1%	0.9%	1.3%	1.5%	1.2%	1.1%	1.0%
y-o-y growth Oil supply (mb/d)														
NON-OPEC														
US	0.7	2.3	1.7	-0.7	0.2	1.2	1.6	0.9	0.5	0.1	0.0	0.0	0.0	0.0
Mexico	-0.2	-0.2	-0.1	0.0	0.0	0.1	0.1	-0.2	-0.1	-0.1	-0.1	0.0	-0.1	0.1
Canada	0.4	0.6	0.1	-0.2	0.2	0.2	0.1	0.2	0.3	0.1	0.0	0.1	0.0	-0.1
North America	0.8	2.7	1.7	-0.9	0.5	1.4	1.8	1.0	0.7	0.2	-0.1	0.1	-0.1	0.0
Europe	0.0	0.0	-0.1	0.2	-0.2	-0.2	0.0	-0.1	0.1	0.0	-0.1	-0.2	-0.2	-0.2
Pacific	0.0	0.0	0.1	0.0	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	0.0	0.0	0.0
Total OECD	0.8	2.7	1.7	-0.7	0.3	1.2	1.8	0.8	0.8	0.2	-0.2	-0.1	-0.3	-0.2
Russia	0.0	0.2	0.0	-1.0	0.3	0.2	-0.1	-0.2	-0.1	0.0	0.1	0.2	0.1	0.0
Other FSU	-0.1	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	0.2	0.0	-0.1	-0.1	-0.1	-0.1
China	-0.1	-0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.0	-0.1	-0.1	-0.1	-0.1
Brazil	0.1	0.0	0.2	0.1	0.0	0.1	0.4	-0.1	0.3	0.2	0.1	0.1	0.2	0.0
Guyana	0.0	0.0	0.0	0.1	0.0	0.2	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.2
Angola	-0.1	-0.2	-0.1	-0.1	-0.2	0.1	0.0	0.0	-0.1	0.1	-0.1	-0.1	0.0	-0.1
Indonesia	0.0	0.0	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ecuador	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	2.1	0.3	-3.0	-0.6	-0.2	0.0	0.1	-0.1	0.1	-0.1	0.1	0.1	0.2	0.1
Total non-OECD	2.2	0.2	-2.8	-1.6	0.0	0.5	0.5	-0.1	0.6	0.3	0.1	0.4	0.4	0.0
Processing Gains	0.0	-0.2	0.3	-0.2	0.1	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
Global biofuels	0.0	0.0	2.8	-0.2	0.2	0.1	0.2	0.3	0.1	0.2	0.2	0.2	0.2	0.2
Total Non-OPEC	2.9	2.7	1.9	-2.7	0.6	1.9	2.6	1.0	1.6	0.7	0.1	0.5	0.4	0.0
Growth Y/Y (%)	4.9%	4.4%	2.9%	-4.1%	0.9%	2.9%	3.9%	1.4%	2.2%	1.0%	0.2%	0.6%	0.5%	0.1%
OPEC														
Iraq	0.0	0.1	0.1	-0.7	0.0	0.4	-0.2	0.0	0.1	-0.1	0.1	0.1	0.2	0.1
Iran	0.3	-0.8	-0.6	-0.4	0.4	0.1	0.4	0.4	0.0	0.1	0.0	0.1	0.1	0.2
Gabon	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Saudi Arabia	-0.5	0.4	-0.5	-0.6	-0.1	1.4	-0.9	-0.5	0.4	0.6	0.0	0.3	0.5	0.5
Venezuela	-0.3	-0.6	-0.5	-0.3	0.1	0.1	0.1	0.1	0.1	0.1	-0.1	0.0	0.0	0.0
Nigeria	0.1	0.1	0.1	-0.2	-0.2	0.1	0.1	0.1	0.1	0.0	0.0	-0.1	-0.1	-0.1
Libya	0.4	0.1	0.1	-0.7	0.8	-0.2	0.2	-0.1	0.2	0.0	0.0	0.0	0.0	0.0
Algeria	-0.1	0.0	0.0	-0.1	0.0	0.1	0.0	-0.1	0.0	0.0	0.0	0.0	0.0	0.0
UAE	-0.1	0.1	0.2	-0.3	-0.1	0.6	-0.1	0.0	0.2	0.0	0.0	0.0	0.0	0.1
Kuwait	-0.2	0.0	-0.1	-0.3	0.0	0.3	-0.1	-0.1	0.1	0.0	0.0	0.0	0.0	0.0
Other OPEC (Congo, Equator)	0.0	0.7	-0.6	0.0	0.0	-0.1	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	0.0
Total OPEC crude	-0.3	0.1	-1.8	-3.7	0.9	2.6	-0.5	-0.2	1.2	0.6	0.0	0.4	0.7	0.8
NGLs	0.1	-0.1	0.0	-0.4	0.1	0.2	0.1	0.1	0.0	0.2	0.1	0.1	0.1	0.1
Total OPEC	-0.2	-0.1	-1.8	-4.0	1.0	2.8	-0.4	-0.1	1.2	0.7	0.1	0.5	0.8	0.9
TOTAL SUPPLY	2.8	2.7	0.1	-6.8	1.6	4.6	2.2	0.8	2.8	1.5	0.2	1.0	1.2	0.9
Key figures														
Call on OPEC crude	-1.6	-1.6	-0.7	-5.7	5.3	0.5	-0.9	0.1	-0.6	0.4	1.3	0.8	0.7	0.9
OPEC crude production	-0.3	0.1	-1.8	-3.7	0.9	2.6	-0.5	-0.2	1.2	0.6	0.0	0.4	0.7	0.8

Source: ABG Sundal Collier, IEA

Key oil market estimates - quarterly figures (million barrels/day)

Oil demand (mill. b/d)	Q1'24	Q2'24	Q3'24	Q4'24	Q1'25	Q2'25	Q3'25e	Q4'25e	Q1'26e	Q2'26e	Q3'26e	Q4'26e
OECD	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
US	19.9	20.5	20.7	20.8	20.3	20.5	20.7	20.6	20.4	20.6	20.9	20.8
Other America (Canada, Mexico, Chile)	4.7	4.7	4.8	4.7	4.7	4.8	4.8	4.7	4.7	4.7	4.8	4.7
Sum Americas	24.6	25.2	25.5	25.4	25.0	25.3	25.6	25.3	25.1	25.3	25.8	25.5
Europe	12.9	13.7	14.0	13.5	13.0	13.7	14.0	13.5	13.0	13.7	14.2	13.6
Pacific	7.5	6.9	6.9	7.4	7.3	6.8	6.9	7.2	7.3	6.8	6.9	7.2
Total OECD	45.0	45.9	46.3	46.3	45.3	45.7	46.5	46.0	45.4	45.7	46.9	46.3
Growth Y/Y (%)	-0.2%	0.7%	0.8%	0.7%	0.6%	-0.3%	0.5%	-0.5%	0.3%	0.0%	0.7%	0.6%
FSU&Eastern Europe												
FSU	4.6	4.7	4.9	5.0	4.7	4.8	5.0	5.0	4.8	4.8	5.1	5.1
Europe	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9
Total Eastern Block	5.4	5.5	5.7	5.8	5.5	5.6	5.8	5.8	5.6	5.6	5.9	5.9
Growth Y/Y (%)	-5%	-4%	-3%	0%	2%	2%	2%	0%	1%	1%	2%	2%
Emerging Economies												
China	16.4	16.5	16.6	16.5	16.7	16.4	16.9	16.8	16.8	16.8	17.1	17.1
India	5.8	5.8	5.3	5.8	5.9	5.9	5.4	6.0	5.9	6.1	5.7	6.2
Other Asia	9.1	9.3	9.1	9.4	9.6	9.5	9.3	9.6	9.6	9.6	9.6	9.9
Latin America	6.2	6.4	6.5	6.5	6.2	6.3	6.4	6.4	6.3	6.4	6.6	6.5
Middle East	8.8	9.2	9.7	9.1	8.9	9.3	9.9	9.3	9.1	9.5	9.9	9.4
Africa	4.6	4.5	4.7	4.7	4.8	4.8	4.8	5.0	5.0	5.0	5.0	5.1
Total Emerging	50.9	51.7	52.0	52.0	52.1	52.1	52.8	53.0	52.8	53.3	53.9	54.2
Growth Y/Y (%)	2.4%	1.4%	1.2%	2.6%	2.0%	0.9%	1.7%	1.9%	1.5%	2.2%	2.1%	2.3%
Total Non-OECD	56.3	57.1	57.7	57.8	57.5	57.7	58.7	58.8	58.3	58.9	59.9	60.2
Growth Y/Y (%)	1.6%	0.9%	0.8%	2.3%	2.0%	1.0%	1.8%	1.7%	1.5%	2.1%	2.0%	2.3%
TOTAL DEMAND	101.3	103.0	104.0	104.1	102.8	103.4	105.2	104.8	103.8	104.6	106.7	106.5
Growth Y/Y (%)	0.8%	0.8%	0.8%	1.6%	1.4%	0.4%	1.2%	0.7%	1.0%	1.2%	1.4%	1.6%
Oil supply (mill. b/d)	Q1'24	Q2'24	Q3'24	Q4'24	Q1'25	Q2'25	Q3'25e	Q4'25e	Q1'26e	Q2'26e	Q3'26e	Q4'26e
NON-OPEC												
US	19.7	20.5	20.5	20.9	20.4	21.1	21.0	21.2	20.7	21.1	21.0	21.1
Mexico	1.9	1.9	1.9	1.9	1.8	1.9	1.9	1.9	1.9	1.8	1.8	1.7
Canada	6.0	5.8	6.0	6.4	6.4	6.0	6.5	6.5	6.6	6.4	6.4	6.5
North America	27.7	28.3	28.5	29.2	28.6	28.9	29.4	29.5	29.2	29.3	29.2	29.4
Europe	3.1	3.1	3.0	3.1	3.3	3.2	3.1	3.3	3.3	3.3	3.1	3.2
Pacific	0.4	0.4	0.4	0.4	0.4	0.5	0.4	0.4	0.4	0.5	0.4	0.4
Total OECD	31.3	31.8	31.9	32.7	32.3	32.6	32.9	33.2	32.9	33.1	32.7	33.0
Russia	10.9	10.7	10.7	10.8	10.5	10.6	10.8	11.0	10.7	10.7	10.7	10.7
Other FSU	2.9	2.8	2.8	2.7	3.0	3.0	2.9	2.9	3.0	3.0	3.0	3.0
China	4.4	4.4	4.3	4.3	4.5	4.5	4.3	4.3	4.4	4.4	4.4	4.4
Brazil	3.5	3.4	3.4	3.4	3.6	3.8	3.8	3.8	4.0	4.0	4.0	4.0
Guyana	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.9	0.9	0.9	0.9	0.9
Angola	1.2	1.2	1.2	1.1	1.1	1.0	1.1	1.2	1.2	1.2	1.2	1.2
Indonesia	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.6	0.6	0.6	0.6	0.6
Ecuador	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.5	0.4	0.4	0.4	0.4
Other	8.0	8.7	8.6	8.4	8.6	8.5	8.5	8.5	8.4	8.4	8.4	8.4
Total non-OECD	32.6	32.8	32.6	32.4	32.9	33.1	33.3	33.7	33.6	33.5	33.6	33.6
Processing Gains	2.3	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.5
Global biofuels	3.4	3.4	3.5	3.3	2.9	3.5	3.9	3.5	3.2	3.7	4.0	3.7
Total Non-OPEC	69.5	70.4	70.5	70.8	70.5	71.5	72.6	72.9	72.1	72.7	72.7	72.7
Growth Y/Y (%)	1.5%	2.1%	0.8%	0.0%	1.4%	1.6%	2.9%	3.0%	2.4%	1.7%	0.2%	-0.2%
OPEC												
Iraq	4.3	4.3	4.3	4.3	4.3	4.2	4.5	4.6	4.5	4.3	4.3	4.3
Iran	3.3	3.3	3.4	3.4	3.2	3.3	3.3	3.4	3.4	3.4	3.4	3.4
Gabon	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Saudi Arabia	9.3	8.9	9.1	9.0	9.1	9.3	9.6	10.0	10.1	10.1	10.1	10.1
Venezuela	0.8	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0
Nigeria	1.3	1.3	1.3	1.4	1.5	1.5	1.4	1.4	1.4	1.5	1.5	1.5
Libya	1.1	1.2	0.9	1.1	1.2	1.2	1.3	1.2	1.2	1.2	1.2	1.2
Algeria	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0
UAE	3.2	3.3	3.3	3.2	3.2	3.3	3.6	3.6	3.5	3.4	3.4	3.4
Kuwait	2.5	2.6	2.5	2.5	2.5	2.7	2.7	2.6	2.6	2.6	2.6	2.6
Other OPEC (Congo, Equatorial Guinea)	0.3	0.3	0.3	0.3	0.4	0.3	0.3	0.2	0.2	0.2	0.2	0.2
Total OPEC crude	27.2	27.1	27.1	27.3	27.5	27.9	28.9	29.2	29.1	28.9	28.9	28.9
NGLs	5.5	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.7	5.8	5.8	5.9
Total OPEC	32.7	32.7	32.8	32.9	33.2	33.5	34.5	34.8	34.8	34.7	34.7	34.8
TOTAL SUPPLY	102.2	103.1	103.3	103.7	103.6	105.1	107.1	107.7	107.0	107.4	107.4	107.5
Growth Y/Y (%)	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Key figures	Q1'24	Q2'24	Q3'24	Q4'24	Q1'25	Q2'25	Q3'25e	Q4'25e	Q1'26e	Q2'26e	Q3'26e	Q4'26e
Call on OPEC crude	26.3	27.0	27.8	27.7	26.6	26.3	27.0	26.3	25.9	26.1	28.2	27.9
OPEC crude production	27.2	27.1	27.1	27.3	27.5	27.9	28.9	29.2	29.1	28.9	28.9	28.9
= Implied stock change	0.9	0.1	-0.7	-0.4	0.9	1.6	1.9	2.8	3.2	2.8	0.7	1.0

Source: ABG Sundal Collier, IEA

Oil market estimates - quarterly figures (y-o-y growth, million barrels/day)

Growth y-o-y (mill. barrels/day)	Q1'23	Q2'23	Q3'23	Q4'23	Q1'24	Q2'24	Q3'24	Q4'24	Q1'25	Q2'25	Q3'25e	Q4'25e	Q1'26e	Q2'26e	Q3'26e	Q4'26e
OECD																
US	-0.4	0.4	0.2	0.7	0.3	0.2	0.3	0.2	0.4	0.0	0.1	-0.1	0.1	0.0	0.2	0.2
Other America (Canada, Mexico, Ct)	-0.1	-0.1	0.0	-0.3	0.1	0.0	-0.1	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Sum Americas	-0.5	0.2	0.2	0.4	0.4	0.1	0.2	0.3	0.4	0.0	0.1	-0.1	0.1	0.0	0.2	0.2
Europe	-0.1	0.1	-0.3	0.1	-0.2	0.1	0.3	0.1	0.1	0.0	0.1	0.0	0.0	0.0	0.2	0.1
Pacific	0.0	0.0	-0.2	-0.2	-0.3	0.1	-0.1	0.0	-0.2	-0.1	0.1	-0.1	0.0	0.0	0.0	0.0
Total OECD	-0.7	0.3	-0.3	0.2	-0.1	0.3	0.4	0.3	0.3	-0.1	0.2	-0.2	0.1	0.0	0.3	0.3
Growth Y/Y (%)	-1.4 %	0.6 %	-0.6 %	0.4 %	-0.2 %	0.7 %	0.8 %	0.7 %	0.6 %	-0.3 %	0.5 %	-0.5 %	0.3 %	0.0 %	0.7 %	0.6 %
FSU&Eastern Europe																
FSU	0.1	0.1	-0.1	-0.1	-0.3	-0.2	-0.1	0.0	0.1	0.1	0.1	0.0	0.1	0.0	0.1	0.1
Europe	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Eastern Block	0.1	0.1	-0.1	-0.1	-0.3	-0.2	-0.2	0.0	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1
Growth Y/Y (%)	1.6%	2.5%	-0.8%	-1.7%	-5.1%	-3.7%	-2.7%	0.3%	2.2%	1.8%	2.3%	0.2%	1.4%	1.0%	1.6%	2.3%
Emerging Economies																
China	0.7	2.8	2.5	1.5	0.6	-0.3	-0.4	-0.1	0.3	-0.1	0.3	0.3	0.2	0.3	0.2	0.3
India	0.2	0.2	0.2	0.0	0.3	0.3	0.1	0.4	0.0	0.1	0.1	0.2	0.1	0.2	0.3	0.2
Other Asia	0.1	0.1	0.2	0.1	0.2	0.4	0.3	0.4	0.5	0.2	0.2	0.2	0.0	0.1	0.3	0.3
Latin America	0.3	0.3	0.2	0.2	-0.1	0.0	-0.1	0.0	0.0	-0.1	-0.1	-0.1	0.1	0.1	0.2	0.2
Middle East	0.3	0.0	0.1	0.0	0.0	0.2	0.2	0.3	0.0	0.1	0.3	0.2	0.3	0.2	0.0	0.1
Africa	0.1	0.1	0.0	0.0	0.2	0.2	0.4	0.4	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1
Total Emerging	1.8	3.3	3.3	1.9	1.2	0.7	0.6	1.3	1.0	0.5	0.9	1.0	0.8	1.1	1.1	1.2
Growth Y/Y (%)	3.7 %	7.0 %	6.8 %	3.9 %	2.4 %	1.4 %	1.2 %	2.6 %	2.0 %	0.9 %	1.7 %	1.9 %	1.5 %	2.2 %	2.1 %	2.3 %
Total Non-OECD	1.8	3.5	3.2	1.8	0.9	0.5	0.4	1.3	1.2	0.6	1.0	1.0	0.9	1.2	1.2	1.4
Growth Y/Y (%)	3.5 %	6.5 %	6.0 %	3.3 %	1.6 %	0.9 %	0.8 %	2.3 %	2.0 %	1.0 %	1.8 %	1.7 %	1.5 %	2.1 %	2.0 %	2.3 %
TOTAL DEMAND	1.2	3.8	2.9	2.0	0.8	0.8	0.8	1.6	1.4	0.4	1.2	0.8	1.0	1.2	1.5	1.7
Growth Y/Y (%)	1.2 %	3.8 %	2.9 %	2.0 %	0.8 %	0.8 %	0.8 %	1.6 %	1.4 %	0.4 %	1.2 %	0.7 %	1.0 %	1.2 %	1.4 %	1.6 %
Oil supply (mill. b/d)																
NON-OPEC																
US	1.5	1.5	1.4	1.8	1.0	1.3	0.8	0.8	0.7	0.5	0.5	0.2	0.3	0.1	0.0	0.0
Mexico	0.1	0.2	0.1	0.1	-0.2	-0.2	-0.1	-0.1	-0.1	-0.1	0.0	0.0	0.0	0.0	-0.1	-0.1
Canada	-0.1	-0.1	0.1	0.2	0.2	0.4	0.2	0.2	0.3	0.1	0.5	0.1	0.2	0.4	-0.2	0.0
North America	1.6	1.5	1.5	2.0	1.0	1.4	0.8	0.9	0.6	0.9	0.6	0.3	0.6	0.4	-0.2	-0.2
Europe	-0.3	0.2	0.0	0.1	-0.2	-0.1	0.0	-0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.0	-0.1
Pacific	-0.1	-0.1	0.0	-0.1	0.0	-0.1	-0.1	-0.1	0.0	0.1	0.0	0.1	0.0	0.0	0.0	0.0
Total OECD	1.2	1.6	1.6	2.0	0.8	1.3	0.7	1.0	0.8	1.0	0.6	0.7	0.5	0.7	0.5	-0.3
Russia	0.6	-0.3	-0.4	-0.3	-0.3	-0.2	-0.1	-0.1	-0.4	-0.1	0.1	0.2	0.2	0.1	-0.1	-0.3
Other FSU	-0.1	0.6	0.3	-0.1	-0.1	-0.1	0.0	0.0	0.2	0.2	0.1	0.2	0.0	0.0	0.1	0.1
China	0.2	0.1	0.1	0.2	0.0	0.0	0.1	-0.1	0.1	0.1	0.0	0.1	0.0	0.0	0.0	0.0
Brazil	0.1	0.3	0.5	0.5	0.2	0.0	-0.2	-0.3	0.1	0.4	0.4	0.4	0.4	0.2	0.2	0.2
Guyana	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.0	0.0	0.1	0.2	0.2	0.2	0.2	0.0
Angola	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Indonesia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0
Ecuador	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	0.0	-0.1	0.0	0.0
Other	0.2	0.0	0.6	0.0	-0.8	-0.1	-0.1	-0.6	0.6	-0.2	-0.1	0.2	-0.1	-0.1	-0.1	-0.1
Total non-OECD	0.9	0.9	1.2	0.5	-0.5	0.0	-0.2	-0.9	0.4	0.3	0.6	1.3	0.7	0.4	0.3	-0.1
Processing Gains	0.0	0.1	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.1
Global biofuels	-0.4	0.3	0.2	0.3	0.7	0.1	0.0	0.1	-0.4	0.1	0.4	0.3	0.3	0.2	0.0	0.2
Total Non-OPEC	1.8	2.8	3.0	2.8	1.0	1.4	0.6	0.0	1.0	1.1	2.0	2.1	1.7	1.2	0.2	-0.1
Growth Y/Y (%)	2.7%	4.2%	4.5%	4.2%	1.5%	2.1%	0.8%	0.0%	1.4%	1.6%	2.9%	3.0%	2.4%	1.7%	0.2%	-0.2%
OPEC																
Iraq	0.1	-0.3	-0.3	-0.2	-0.1	0.1	0.0	0.0	0.0	0.0	0.1	-0.1	-0.1	0.0	-0.2	0.0
Iran	0.2	0.5	0.6	0.5	0.6	0.3	0.3	0.3	-0.1	0.0	-0.1	0.1	0.3	0.1	0.1	0.0
Gabon	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Saudi Arabia	0.3	-0.3	-1.9	-1.6	-1.1	-1.2	0.1	0.1	-0.2	0.4	0.6	1.0	0.9	0.7	0.3	0.0
Venezuela	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0
Nigeria	0.0	0.0	0.2	0.2	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.1	0.0	0.0	0.0	0.0
Libya	0.1	0.4	0.2	0.0	0.0	0.0	-0.3	-0.1	0.1	0.0	0.4	0.2	0.1	0.0	0.0	0.0
Algeria	0.0	0.0	-0.1	-0.1	-0.1	-0.1	0.0	-0.1	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0
UAE	0.3	-0.1	-0.2	-0.2	-0.3	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.2	0.1	0.0	-0.1
Kuwait	0.1	0.0	-0.2	-0.1	-0.2	0.0	-0.1	0.0	0.1	0.1	0.1	0.0	0.0	-0.2	-0.1	0.0
Other OPEC (Congo, Equatorial Gu)	0.1	0.0	0.0	0.0	0.0	-0.1	0.0	0.0	0.1	0.0	0.0	-0.1	-0.2	-0.1	-0.1	0.0
Total OPEC crude	1.0	0.2	-1.5	-1.3	-1.1	-0.7	0.3	0.3	0.3	0.8	1.5	1.5	1.2	0.8	0.1	0.0
NGLs	0.2	0.2	0.1	0.2	0.0	0.0	0.2	0.1	0.1	0.0	0.0	0.0	0.1	0.2	0.2	0.3
Total OPEC	1.2	0.4	-1.5	-1.1	-1.1	-0.6	0.4	0.4	0.5	0.9	1.5	1.5	1.3	1.0	0.3	0.3
TOTAL SUPPLY	3.0	3.2	1.5	1.7	0.0	0.8	1.0	0.4	1.4	2.0	3.5	3.6	2.9	2.2	0.5	0.1
Growth Y/Y (%)																
Key figures																
Call on OPEC crude	-0.8	0.8	-0.1	-1.0	-0.3	-0.6	0.1	1.5	0.3	-0.7	-0.8	-1.3	-0.7	-0.2	1.1	1.5
OPEC crude production	1.0	0.2	-1.5	-1.3	-1.1	-0.7	0.3	0.3	0.3	0.8	1.5	1.5	1.2	0.8	0.1	0.0

Source: ABG Sundal Collier, IEA

E&P spending

Key E&P spending assumptions

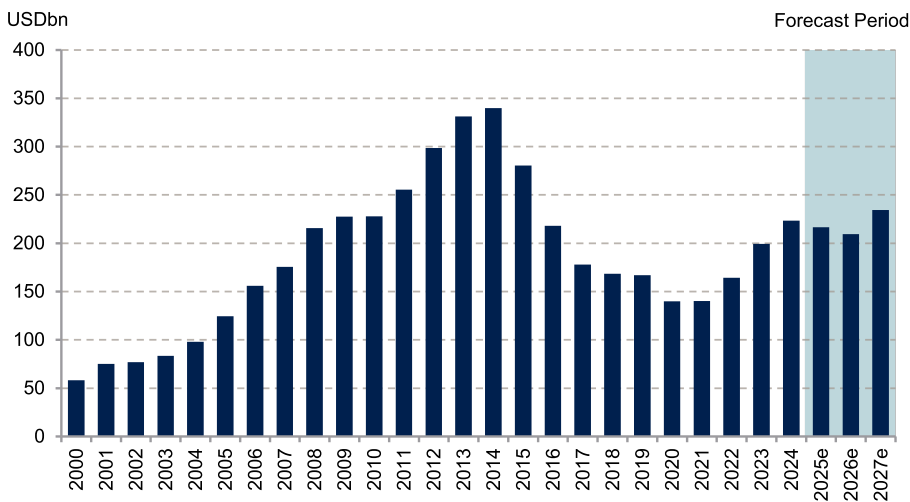
E&P spending	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025e	2026e	2027e
Brent blend	44	54	73	64	42	71	100	83	81	71	70	80
	-17%	24%	35%	-12%	-35%	70%	42%	-18%	-2%	-12%	-1%	14%
E&P spending (USDbn):												
Global	495	520	555	540	391	424	522	597	624	605	582	641
Onshore	277	342	387	373	252	284	358	397	400	388	373	406
US onshore	77	117	149	140	73	86	134	153	149	140	134	147
Offshore	218	178	168	167	140	140	164	199	223	217	209	235
	77	117	149	140	73	86	134	153	149	142	140	143
E&P spending growth:												
Global	-25%	5%	7%	-3%	-28%	8%	23%	14%	4%	-3%	-4%	10%
Onshore	-27%	23%	13%	-3%	-33%	13%	26%	11%	1%	-3%	-4%	9%
US onshore	-38%	51%	28%	-6%	-47%	17%	56%	15%	-3%	-6%	-4%	9%
Offshore	-22%	-18%	-5%	-1%	-16%	0%	17%	21%	12%	-3%	-3%	12%
Offshore E&P spending (USDbn):												
Development	182	146	136	135	116	118	139	171	194	188	182	204
Exploration	36	32	32	32	24	22	26	29	29	29	27	31
Total	218	178	168	167	140	140	164	199	223	217	209	235
Offshore E&P spending (YoY growth):												
Development	-18%	-20%	-6%	-1%	-14%	2%	18%	23%	14%	-3%	-3%	12%
Exploration	-37%	-9%	-1%	0%	-26%	-6%	15%	12%	3%	-3%	-7%	15%
Total	-22%	-18%	-5%	-1%	-16%	0%	17%	21%	12%	-3%	-3%	12%

Source: ABG Sundal Collier, Rystad (historical data)

Spending is flattening amid higher uncertainty

We see spending declining slightly, with offshore activity down ~3% in 2025e and 2026e. From 2027e, we forecast a rebound driven by stronger oil market fundamentals and elevated FID activity.

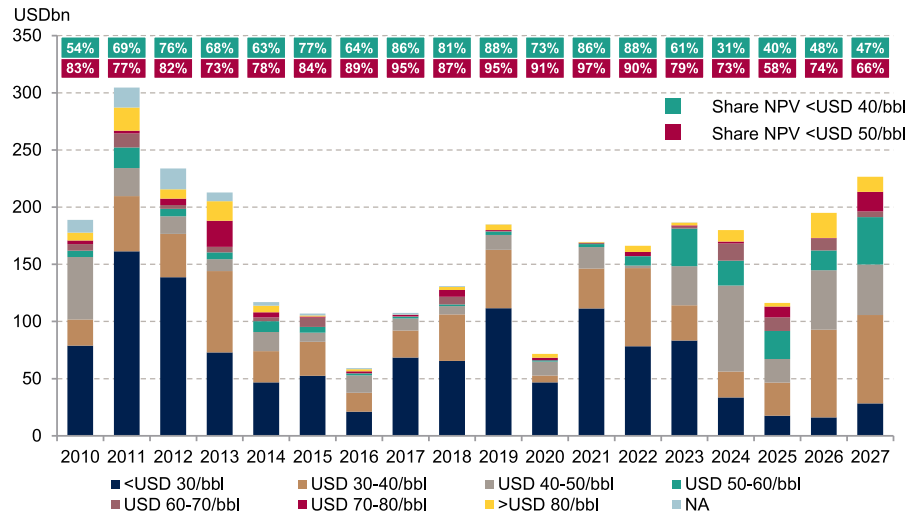
Global offshore spending (USDbn)



Source: ABG Sundal Collier, Rystad (historical data)

Rystad expects weak offshore sanctioning in 2025, at ~35% below both 2024 and the 4Y average. As expected, some FIDs have been delayed on weaker oil market fundamentals and post-Liberation Day uncertainty. There have also been some negative revisions to 2026e FIDs, but the overall outlook for elevated activity in 2026-2027 remains intact. Rystad sees average offshore sanctioning above USD 200bn in 2026-2027, comparable to the last upcycle and ~30% above the 2021-2025e average. Roughly 70% of these projects have break-evens <USD 50/bbl, and ~50% are <USD 40/bbl. However, current uncertainty and a weak oil market balance may keep higher NPV projects on the shelf, meaning that there is still a risk of 2026-2027 FID slippage.

Global offshore sanctioning by NPV break-even oil price



Source: ABG Sundal Collier, Rystad. Note: Sanctioning by approval year. Discount rate 10%.

SLB, Halliburton, and Baker Hughes all expect a negative spending environment for 2025. Halliburton sees international activity down by mid-single digits, while Baker guides for a mid-to-high single-digit decline (both include Mexico). SLB expects negative growth in global upstream investments, with US onshore underperforming. Baker forecasts North America spend down by low double digits, driven by weakness in US land.

Despite minor cuts of 3-6% from EOG, ENI, and Shell, most large E&Ps kept their 2025 budgets unchanged in Q1/Q2. While some near-term flexibility exists, the bulk of 2025 spend is already committed. Petrobras maintained its official targets but flagged a more cautious stance on capex and opex amid a softer oil market, and note that the current 5Y plan is based on long-term oil prices at >USD 80/bbl. There have been rumours in the media that PBR aims to cut spending by ~USD 8bn over the next five years. Saudi Aramco's 2025 budget implies low-single-digit growth.

2025e spending/activity: Selected key players

Company	'25e spending comment	'25e spending growth (international/offshore)
ExxonMobil	+8% y-o-y with an effect from Pioneer acquisition – base capex flat	~0%
Shell	Organic capex up vs. 2024 actual spending	+3%
bp	Cut '25e spending target by -3-5%	-3-5%
PETROBRAS	'25e strategic plan vs. '24 E&P capex	+9%
Chevron	Total upstream spending down -9%, partly driven by Permian	-9%
TotalEnergies	O&G spending growth of 8% in '25e	+8%
equinor	O&G spending flat at ~USD 10bn	~0%
slb	Global upstream investment to decline – int. activity to outperform NA	-3-8%
HALLIBURTON	Int. activity. at mid-single digit decline	-4-6%
Baker Hughes	Int. activity in higher end of mid-high single digit decline	-7-9%

Source: ABG Sundal Collier, Company data

Overall, guidance from major E&P and service companies suggests a muted outlook with plateauing or declining activity. Analyst consensus for major oil companies points to spending growth of ~3% in '25 and ~1% in '26.

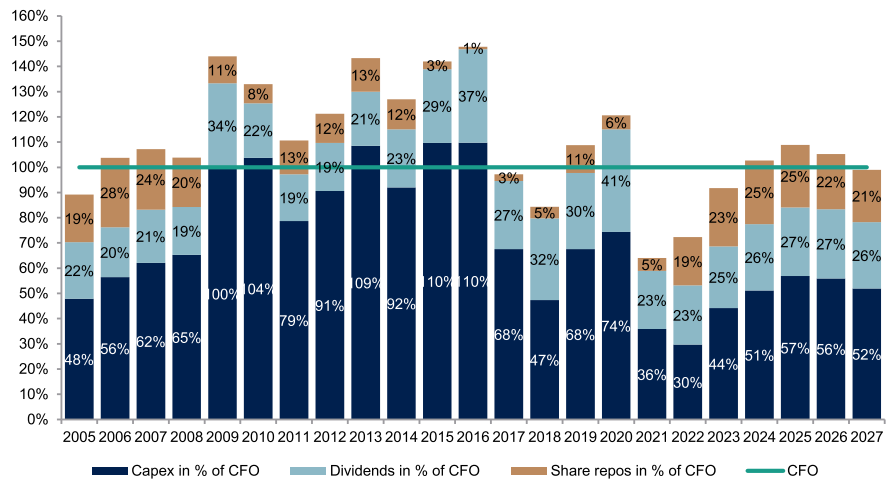
Capex estimates

Capex, US\$M	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025e	2026e	2027e
Exxon	26,490	16,163	15,402	19,574	26,591	21,000	16,595	19,421	21,919	24,306	27,390	29,289	30,097
Shell	26,131	22,116	20,845	23,011	22,971	16,585	19,000	22,600	22,993	19,601	20,168	20,239	20,501
BP	18,648	16,701	16,562	16,707	15,200	12,306	12,848	16,330	16,253	16,237	14,050	14,227	14,460
Petrobras	21,349	14,140	13,661	11,914	18,216	7,010	8,068	9,206	12,557	14,669	16,933	17,313	17,750
Equinor	15,448	12,191	10,755	11,367	10,000	7,800	8,100	8,529	10,575	16,700	12,733	12,867	12,721
Total	25,132	18,106	13,767	17,080	14,716	11,255	12,343	15,690	17,722	14,909	17,681	16,964	17,046
Chevron	28,949	18,055	13,379	13,728	14,100	8,900	8,100	11,955	16,028	16,502	16,601	17,813	17,926
Conoco	10,050	4,869	4,591	6,750	6,636	4,715	5,324	10,200	11,200	12,100	12,433	12,083	12,154
Occidental	5,272	2,717	3,599	4,975	6,355	2,535	2,870	4,411	6,247	6,959	7,211	6,928	6,913
Saudi Aramco			32,518	35,132	32,800	26,939	31,893	37,600	50,000	50,365	52,238	52,633	48,298
ENI	12,533	10,155	9,792	10,758	8,609	6,027	6,594	6,741	9,867	8,835	9,517	9,661	9,916
PetroChina	35,617	28,512	35,069	41,686	41,857	37,686	40,401	37,011	38,490	38,479	32,929	32,926	34,337
CNOOC	10,767	7,729	7,063	7,748	10,584	12,359	14,317	14,980	16,723	18,797	16,497	16,866	16,840
China Pet & Chem	16,340	10,965	10,498	15,568	19,567	19,309	22,980	26,565	22,827	19,610	21,470	20,768	20,506
Suncor	5,211	4,968	5,047	4,171	4,138	3,040	3,504	3,717	4,420	4,494	4,275	4,201	4,063
Cenovus	1,340	780	1,287	1,062	887	661	2,016	2,658	3,228	3,517	3,546	3,165	2,931
Imperial Oil	2,340	810	765	1,150	1,372	681	874	1,144	1,322	1,289	1,433	1,489	1,346
Ecopetrol	5,183	1,912	2,021	2,862	4,331	2,838	3,901	4,595	5,839	5,508	5,896	5,899	5,645
Repsol	3,221	2,216	2,594	3,139	4,112	2,605	3,274	4,688	6,674	7,130	5,895	5,370	5,250
Inpex	4,194	2,773	2,460	#N/A	1,267	1,575	1,476	2,001	1,378	1,978	2,621	3,191	3,218
OMV	3,302	2,237	1,789	3,767	5,397	7,245	3,072	4,596	4,294	4,257	4,359	3,887	3,557
India Oil & Gas	2,497	2,205	3,482	3,645	3,570	2,959	3,277	3,901	4,092	4,289	3,924	3,966	3,709
ONGC	4,601	5,418	6,963	6,118	6,456	5,291	5,269	4,806	6,408	6,394	5,816	6,040	5,211
APA	4,808	1,949	2,760	3,904	2,747	1,274	1,110	1,807	2,333	2,851	2,440	2,450	2,495
Galp	1,098	1,154	826	1,310	924	1,103	595	1,357	1,133	872	1,255	1,133	1,138
EOG	5,013	2,583	4,124	6,076	6,234	3,490	3,909	4,607	6,041	6,226	6,319	6,628	6,861
Devon	6,415	3,688	2,014	2,171	1,910	1,153	1,989	2,542	3,883	3,645	3,707	3,705	3,762
Range	1,110	513	1,213	1,023	728	411	414	492	614	654	661	681	688
SM Energy	1,502	2,814	978	1,336	1,024	548	664	880	989	1,311	1,381	1,327	1,330
Murphy	#N/A	812	#N/A	1,206	1,206	1,206	1,206	1,066	908	1,206	1,205	1,184	1,184
Majors only	194	137	157	173	179	127	133	165	199	206	212	215	213
YoY	(22%)	(29%)	(10%)	10%	3%	(29%)	5%	24%	21%	3%	3%	1%	(1%)

Source: ABG Sundal Collier, Factset

Returns on capital are still solid for the major E&Ps and there is decent FCF generation in the companies at current oil & gas prices and our forward assumptions. We note that oil companies' capital expenditures and shareholder payouts remain below operating cash flow, and that capex to sales is ~50% vs. ~100% in 2010-2015.

Capital allocation, majors

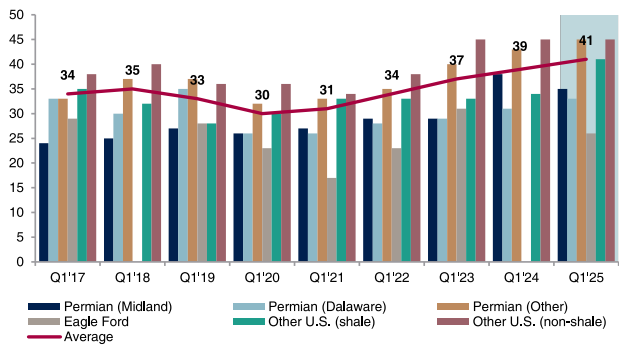


Source: ABG Sundal Collier, Factset

The impact of the new US administration on overall E&P spending growth is negative. While the pro-gas stance supports increased export capacity, tariffs, through general uncertainty, a weaker demand outlook, and direct cost impacts (e.g., steel), are clear headwinds. There is a push to boost domestic activity and production, both onshore and offshore, but we expect operators to remain disciplined and focused on returns.

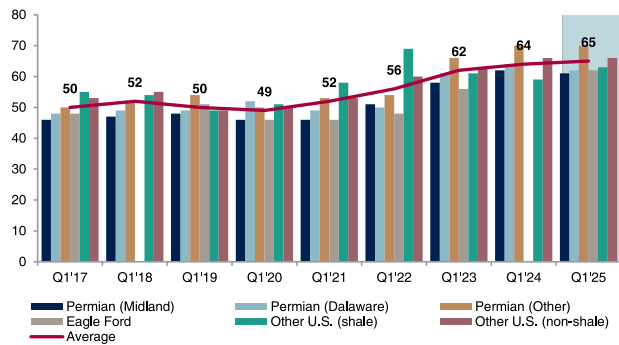
Moreover, the *drill, baby, drill* narrative is not supported by low oil prices, as the average US onshore break-even stands at ~USD 65/bbl WTI and is rising. Given these factors, the administration's realistic policy levers, especially for onshore activity, are limited. As a result, we expect US onshore spending to decline by 6% in '25, which is supported by a plummeting US rig count and frac spreads.

US opex break-evens (USD/bbl, WTI)



Source: ABG Sundal Collier, Dallas Fed

US new well NPV break-evens (USD/bbl, WTI)



Source: ABG Sundal Collier, Dallas Fed

Risks

Oil price & E&P spending

COSH is a supplier of assets to end-users (the oil companies) whose economics are highly dependent on the oil price. Weaker client economics have a significant impact on clients' spending and therefore also on rig demand, and impact COSHs earnings and cash flow.

Asset risk

COSH is a drilling contractor owning 7, and operating 9 drilling rigs, which entails complex operations and demanding conditions. This implies operational risk that could lower utilisation and cause earnings to be lower than expected.

Counterparty risk

COSH charters out rigs on contracts with clients, which means that it is dependent on timely payments from clients. This entails a counterparty risk should a client not be able to meet its agreed commitments with COSH. The company has all its rigs on contracts with Petrobras, as such, the counterparty risk and concentration is particularly high for COSH.

Cost inflation

A large part of COSHs opex is related to labour, and given a tight labour market within the oil service industry, higher than expected inflation could impact COSHs profit margin.

Macroeconomic risk

The oil and gas market is cyclical, and slower macroeconomic growth can result in less consumption of oil, which can reduce the global oil price and again impact E&P spending and the rig market negatively.

Appendix - Management

Rodrigo Ribeiro, Chief Executive Officer

Bachelor degree in Mechanical Engineer, post graduated in Petroleum Eng. and O&G Energy, 26 years of industry experience. Joined Constellation in 2000. Ribeiro has served in several roles in Brazil and abroad, including Chief Operation Officer, Operations Manager, Rig Manager and Site Manager. He also serves as President of ABESPetro (2022- 2023).

Daniel Rachman, Chief Financial Officer

Bachelor degree in Business and Master in Accounting with over 12 years of industry experience. Joined Constellation as CFO in 2023. Served in several finance leadership roles in GE Oil & Gas and Baker Hughes, in Brazil and in the United States, having his last position as Global CFO of the Subsea Production business.

Moniques Fares, Deputy Chief Financial Officer

Bachelor degree in Economics with MBA in Finance and over 12 years of industry experience. Joined Constellation in 2010 as Financial Planning Coordinator. Occupied Financial Planning Manager position since 2016.

Silvia Ruggeri, Chief Administration Officer

Bachelor degree in Business Administration and over 18 years of industry experience. Joined Constellation in 2010. Occupied leadership roles in HR and Deputy CAO position leading HR, Real State, IT, and Communications. Before joining Constellation occupied HR roles, including International HR, HR Systems and Compensation at Halliburton.

Thiago Schimmelpfenning, Chief Commercial Officer

Mechanical Engineer with MBA in Oil & Gas with over 11 years in different areas within Constellation. Joined the company as Operations Engineer in 2009. Later, as Rig Manager, worked in Amazonas, Mato Grosso and Paraguay. Acted as the Deputy COO before joining the Commercial Department in 2018 as Commercial Manager.

Rodrigo Jokubauskas, Chief Operating Officer

Bachelor's degree in Mechanical Engineering with over 20 years of industry experience. Joined Constellation in 2012. Served in various leadership positions, such as Offshore Installation Manager, Corporate QHSE Manager, Base and Operations Manager, and Operations Superintendent.

Luis Senna, Chief Legal Officer

Lawyer with over 11 years of industry experience. Joined Constellation in 2012. He previously served as Compliance Officer from 2017 until 2020. Before joining Constellation worked in recognized law firms in Brazil representing clients in complex commercial deals.

Leonardo Guimaraes, Chief Technical Officer

Bachelor's degree in Mechanical Engineering with over 23 years of industry experience. Joined Constellation in 2022 as Asset Integrity Manager having previously served in operations management positions for ten years and technical and project management for seven years.

Appendix - Board of directors

Maria Gordon, Chair of board and strategy committee

Maria started her career as a reporter for The Washington Post. In 1998, joined Goldman Sachs and spent the next 12 years in the asset management division, being named Managing Director in Oct. 2006. In 2009, Gordon moved to PIMCO to help the firm broaden its outreach beyond debt markets. She was named twice Top 40 under 40 by The Financial News. She is also an explorer and climber, having scaled the highest peaks on every continent and also skied the ultimate north and south poles.

Bruno Serapiao, Board member and chair of sustainability, HSE and Operations committee

Bruno started his career in aviation in 1996, after graduating in aerospace mechanical engineering in ITA. With solid experience in aviation regulations, he further moved to the logistics area. From 2010 to 2020 he founded Hidrovias, a business which today has more than 1,200 direct employees. He is currently Executive Chairman of the Board of Hidrovias do Brasil S/A, and has extensive experience as board member in different companies.

Jorgen Tagle, Board member and chair of compensation and nomination committee

Jorge, throughout his career, held senior executive positions, primarily at the Quiñenco Group. He was Deputy General Manager and Commercial Manager of Banco de Chile, Executive Vice President of Nexans SA, Corporate General Manager of Alusa SA, Corporate Finance Manager of Madeco SA. At Quiñenco SA, meanwhile, he was Manager of M&A and new projects. Earlier in his career, he worked at Citicorp Corporate Finance in different M&A and capital markets transactions. Currently, he is Director and Advisor of Megeve Investments and member of the Board of Constellation Oil Services Holding S.A. He is also Director of Fundación Generación Empresarial and Director of the Institute for Society Studies (IES). Jorge holds a bachelor's in civil Engineer, Pontificia Universidad Católica de Chile and master's in business administration, Wharton School, University of Pennsylvania (Pennsylvania, USA).

Jaap Jan Prins, Board member

Jaap has over 30 years of banking experience at ING Bank, a major European financial institution, where he was Global Head of the Energy, Transport and Infrastructure sectors, responsible for more than EUR 40 billion AUM. His prior roles at ING Bank included positions in risk management and business management. In 2020, he became partner of Bowline Capital Partners, a firm with offices in London and Rotterdam, providing services in capital raising, debt advisory, M&A, and proprietary investments. He also served as expert advisor of the Investment Committee of NN Investment Partners, one of the largest Dutch asset managers.

Bertrand de Fays, Board member

Bertrand is a qualified accountant with extensive experience in accounting and outsourced corporate services in Luxembourg. His fields of experience (non-exhaustive) include: intra-group financing (treasury/cash pool operations) and holding/investment structures, securitisation vehicles for a variety of clients, such as private equity funds and listed multinationals. Over the years, Bertrand has gained vast experience in the energy sector, real estate business, and metal industry.

Nicholas Procopenko, Board member

Mr. Procopenko is a qualified attorney licenced by the California Bar (inactive), holding a Juris Doctor from Golden Gate University, an LL.M. in Public International Law from the University of Leiden in the Netherlands, and a Bachelor's degree in Political Science from the University of California, Irvine. He brings over 15 years of experience in Luxembourg's corporate services sector, having co-founded a corporate service provider in 2014. Earlier in his career, Mr. Procopenko practised as a civil litigation attorney in California. His expertise spans legal advisory, company administration, and compliance, with a strong focus on both client service and internal operations.

Appendix - Shareholders

Below, we show an overview of the top 10 largest shareholders in Constellation, according to Holdings.

COSH - Top 10 largest shareholders

Top 10 largest shareholders	Number of shares	Percentage
Constellation Holdco S.A.	29,530,542	34.97%
Capital Group	10,017,110	11.86%
Lux Oil and Gas International S.A.R.L	7,414,000	8.78%
Caius Capital LLP	5,486,069	6.50%
Export Finance Norway	4,800,623	5.69%
Astaris Capital Management LLP	2,425,680	2.87%
BlueBay Asset management LLP	1,549,246	1.83%
Cobas Asset Management SGIC S.A.	1,333,808	1.58%
South Star Investments Limitada	1,221,740	1.45%
Acasta Partners	1,028,903	1.22%
Total number of shares	64,807,721	76.75%

Source: ABG Sundal Collier, Holdings

Income Statement (USDm)	2018	2019	2020	2021	2022	2023	2024	2025e	2026e	2027e
Sales	0	0	235	387	406	552	564	561	708	756
COGS	0	0	-302	-293	-341	-401	-361	-350	-355	-380
Gross profit	0	0	-67	94	66	150	202	210	353	376
Other operating items	0	0	116	5	516	1	37	25	0	0
EBITDA	0	0	49	99	582	151	239	236	353	376
Depreciation and amortisation	0	0	-221	-150	-149	-186	-202	-221	-217	-215
of which leasing depreciation	0	0	0	0	0	0	0	0	0	0
EBITA	0	0	-172	-51	433	-34	37	14	136	161
EO Items	0	0	0	0	0	0	0	0	0	0
Impairment and PPA amortisation	0	0	-952	180	561	55	-48	0	0	0
EBIT	0	0	-1,124	129	994	21	-11	14	136	161
Net financial items	0	0	-130	-124	-132	-47	-36	-47	-53	-46
Pretax profit	0	0	-1,254	5	861	-26	-47	-33	83	115
Tax	0	0	8	-5	-2	-5	5	-10	-18	-16
Net profit	0	0	-1,246	-0	859	-31	-42	-43	65	98
Minority interest	0	0	0	0	0	0	0	0	0	0
Net profit discontinued	0	0	0	0	0	0	0	0	0	0
Net profit to shareholders	0	0	-1,246	-0	859	-31	-42	-43	65	98
EPS	0.00	0.00	-14.75	-0.01	10.18	-0.37	-0.50	-0.51	0.77	1.17
EPS adj.	0.00	0.00	-14.75	-0.01	10.18	-0.37	-0.50	-0.51	0.77	1.17
Total extraordinary items after tax	0	0	0	0	0	0	0	0	0	0
Leasing payments	0	0	0	0	0	0	0	0	0	0
Tax rate (%)	--	--	0.7	109.2	0.2	-18.7	10.6	-30.9	21.6	14.0
Gross margin (%)	--	--	-28.4	24.2	16.1	27.3	35.9	37.5	49.8	49.7
EBITDA margin (%)	--	--	20.9	25.5	143.3	27.4	42.4	42.1	49.8	49.7
EBITA margin (%)	--	--	-73.1	-13.3	106.6	-6.2	6.6	2.6	19.2	21.2
EBIT margin (%)	--	--	-478.4	33.3	244.7	3.7	-1.9	2.6	19.2	21.2
Pre-tax margin (%)	--	--	-533.7	1.2	212.1	-4.7	-8.3	-5.9	11.8	15.2
Net margin (%)	--	--	-530.2	-0.1	211.6	-5.6	-7.5	-7.7	9.2	13.0
Growth Rates y-o-y	-	-	-	-	-	-	-	-	-	-
Sales growth (%)	--	--	--	64.7	4.9	35.9	2.1	-0.5	26.3	6.8
EBITDA growth (%)	--	--	--	101.0	489.3	-74.0	57.6	-1.2	49.5	6.5
EBITA growth (%)	--	--	--	-70.1	-943.0	-107.9	-209.0	-61.2	840.9	18.1
EBIT growth (%)	--	--	--	-111.5	nm	-97.9	-152.5	-234.0	nm	18.1
Net profit growth (%)	--	--	--	-100.0	-201,337.7	-103.6	35.8	2.5	-251.9	50.7
EPS growth (%)	--	--	--	-100.0	nm	nm	35.8	2.5	nm	50.7
Profitability	-	-	-	-	-	-	-	-	-	-
ROE (%)	--	--	-894.1	-0.2	93.1	-2.0	-2.5	-2.4	3.6	5.6
ROE adj. (%)	--	--	-210.6	-65.2	32.4	-5.5	0.4	-2.4	3.6	5.6
ROCE (%)	--	--	-107.6	6.0	42.2	0.9	-0.1	1.3	6.1	7.5
ROCE adj. (%)	--	--	-16.4	-2.3	18.4	-1.2	1.8	1.3	6.1	7.5
ROIC (%)	--	--	-16.6	0.2	18.8	-1.7	1.4	0.8	4.8	6.6
ROIC adj. (%)	--	--	-16.6	0.2	18.8	-1.7	1.4	0.8	4.8	6.6
Adj. earnings numbers	-	-	-	-	-	-	-	-	-	-
EBITDA adj.	0	0	49	99	582	151	239	236	353	376
EBITDA adj. margin (%)	--	--	20.9	25.5	143.3	27.4	42.4	42.1	49.8	49.7
EBITDA lease adj.	0	0	49	99	582	151	239	236	353	376
EBITDA lease adj. margin (%)	--	--	20.9	25.5	143.3	27.4	42.4	42.1	49.8	49.7
EBITA adj.	0	0	-172	-51	433	-34	37	14	136	161
EBITA adj. margin (%)	--	--	-73.1	-13.3	106.6	-6.2	6.6	2.6	19.2	21.2
EBIT adj.	0	0	-1,124	129	994	21	-11	14	136	161
EBIT adj. margin (%)	--	--	-478.4	33.3	244.7	3.7	-1.9	2.6	19.2	21.2
Pretax profit Adj.	0	0	-302	-175	301	-81	1	-33	83	115
Net profit Adj.	0	0	-293	-181	299	-86	6	-43	65	98
Net profit to shareholders adj.	0	0	-293	-181	299	-86	6	-43	65	98
Net adj. margin (%)	--	--	-124.9	-46.6	73.5	-15.5	1.1	-7.7	9.2	13.0

Source: ABG Sundal Collier, Company Data

Cash Flow (USDm)	2018	2019	2020	2021	2022	2023	2024	2025e	2026e	2027e
EBITDA	0	0	49	99	582	151	239	236	353	376
Net financial items	0	0	-130	-124	-132	-47	-36	-47	-53	-46
Paid tax	0	0	-2	-4	-0	-2	-1	-7	-18	-16
Non-cash items	0	0	-80	-14	-552	31	-45	-16	-16	-4
Cash flow before change in WC	0	0	-163	-43	-103	134	157	165	266	310
Change in working capital	0	0	116	111	139	-23	10	-35	-19	3

Cash Flow (USDm)	2018	2019	2020	2021	2022	2023	2024	2025e	2026e	2027e
Operating cash flow	0	0	-47	68	36	111	167	130	247	313
Capex tangible fixed assets	0	0	-25	-21	-102	-78	-138	-110	-70	-67
Capex intangible fixed assets	0	0	0	0	0	0	0	0	0	0
Acquisitions and Disposals	0	0	0	17	20	1	8	0	0	0
Free cash flow	0	0	-72	64	-46	34	37	20	176	245
Dividend paid	0	0	0	0	0	0	0	0	-51	-203
Share issues and buybacks	0	0	0	0	2	0	75	0	0	0
Leasing liability amortisation	0	0	0	0	0	0	0	0	0	0
Other non-cash items	0	0	-1,710	-146	967	-28	330	-121	0	0
Balance Sheet (USDm)	2018	2019	2020	2021	2022	2023	2024	2025e	2026e	2027e
Goodwill	-	-	-	-	-	-	-	-	-	-
Other intangible assets	0	0	20	16	18	20	19	21	21	21
Tangible fixed assets	0	0	1,868	1,934	2,470	2,416	2,294	2,190	2,044	1,896
Right-of-use asset	-	-	-	-	-	-	-	-	-	-
Total other fixed assets	0	0	126	142	10	9	9	108	108	108
Fixed assets	0	0	2,014	2,092	2,498	2,445	2,322	2,320	2,173	2,025
Inventories	0	0	0	0	0	0	0	0	0	0
Receivables	0	0	98	101	112	155	116	177	193	199
Other current assets	0	0	48	36	18	16	26	115	131	134
Cash and liquid assets	0	0	35	76	59	88	165	182	232	200
Total assets	0	0	2,196	2,306	2,687	2,704	2,630	2,793	2,730	2,559
Shareholders equity	0	0	279	275	1,570	1,544	1,838	1,806	1,821	1,717
Minority	0	0	0	0	0	0	0	0	0	0
Total equity	0	0	279	275	1,570	1,544	1,838	1,806	1,821	1,717
Long-term debt	0	0	1,734	1,817	937	931	637	564	489	414
Pension debt	-	-	-	-	-	-	-	-	-	-
Convertible debt	-	-	-	-	-	-	-	-	-	-
Leasing liability	0	0	0	0	0	0	0	0	0	0
Total other long-term liabilities	0	0	9	7	59	60	16	115	115	115
Short-term debt	0	0	75	117	5	34	6	96	96	96
Accounts payable	0	0	87	80	101	108	92	116	113	121
Other current liabilities	0	0	13	9	15	28	42	95	95	96
Total liabilities and equity	0	0	2,196	2,306	2,687	2,704	2,630	2,793	2,730	2,559
Net IB debt	0	0	1,774	1,858	883	876	477	479	353	310
Net IB debt excl. pension debt	0	0	1,774	1,858	883	876	477	479	353	310
Net IB debt excl. leasing	0	0	1,774	1,858	883	876	477	479	353	310
Capital employed	0	0	2,088	2,209	2,512	2,509	2,480	2,466	2,406	2,227
Capital invested	0	0	2,053	2,133	2,453	2,421	2,315	2,285	2,174	2,027
Working capital	0	0	47	48	14	35	9	80	116	117
EV breakdown	-	-	-	-	-	-	-	-	-	-
Market cap. diluted (m)	0	0	939	939	939	939	939	939	939	939
Net IB debt adj.	0	0	1,774	1,858	883	876	477	479	353	310
Market value of minority	0	0	0	0	0	0	0	0	0	0
Reversal of shares and participations	0	0	0	0	0	0	0	0	0	0
Reversal of conv. debt assumed equity	-	-	-	-	-	-	-	-	-	-
EV	0	0	2,714	2,797	1,822	1,816	1,416	1,418	1,292	1,250
Total assets turnover (%)	--	--	21.4	17.2	16.3	20.5	21.1	20.7	25.6	28.6
Working capital/sales (%)	--	--	10.0	12.3	7.6	4.5	3.9	8.0	13.9	15.4
Financial risk and debt service	-	-	-	-	-	-	-	-	-	-
Net debt/equity (%)	--	--	636.8	674.5	56.2	56.7	25.9	26.5	19.4	18.1
Net debt / market cap (%)	--	--	188.9	197.7	94.0	93.3	50.8	50.9	37.6	33.0
Equity ratio (%)	--	--	12.7	11.9	58.4	57.1	69.9	64.7	66.7	67.1
Net IB debt adj. / equity (%)	--	--	636.8	674.5	56.2	56.7	25.9	26.5	19.4	18.1
Current ratio	--	--	1.04	1.04	1.57	1.53	2.22	1.54	1.83	1.71
EBITDA/net interest	--	--	0.4	0.8	4.4	3.3	6.7	5.0	6.7	8.2
Net IB debt/EBITDA (x)	--	--	36.1	18.8	1.5	5.8	2.0	2.0	1.0	0.8
Net IB debt/EBITDA lease adj. (x)	--	--	36.1	18.8	1.5	5.8	2.0	2.0	1.0	0.8
Interest coverage	--	--	1.3	0.4	3.2	0.6	1.0	0.5	2.3	2.9

Source: ABG Sundal Collier, Company Data

Share Data (USDm)	2018	2019	2020	2021	2022	2023	2024	2025e	2026e	2027e
Actual shares outstanding	0	0	84	84	84	84	84	84	84	84
Actual shares outstanding (avg)	0	0	84	84	84	84	84	84	84	84

Constellation

Share Data (USDm)	2018	2019	2020	2021	2022	2023	2024	2025e	2026e	2027e
All additional shares	0	0	NA	0	0	0	0	0	0	0
Issue month	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Assumed dil. of shares from conv.	0	0	0	0	0	0	0	0	0	0
As. dil. of shares from conv. (avg)	0	0	0	0	0	0	0	0	0	0
Conv. debt not assumed as equity	0	0	0	0	0	0	0	0	0	0
No. of warrants	0	0	0	0	0	0	0	0	0	0
Market value per warrant	0	0	0	0	0	0	0	0	0	0
Dilution from warrants	0	0	0	0	0	0	0	0	0	0
Issue factor	0.0	0.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Actual dividend per share	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.20	2.40
Reported earnings per share	-	-	-	-	-	-	-	-	-	-

Source: ABG Sundal Collier, Company Data

Valuation and Ratios (USDm)	2018	2019	2020	2021	2022	2023	2024	2025e	2026e	2027e
Shares outstanding adj.	0	0	84	84	84	84	84	84	84	84
Diluted shares adj.	0	0	84	84	84	84	84	84	84	84
EPS	0.00	0.00	-14.75	-0.01	10.18	-0.37	-0.50	-0.51	0.77	1.17
Dividend per share	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.20	2.40
EPS adj.	0.00	0.00	-14.75	-0.01	10.18	-0.37	-0.50	-0.51	0.77	1.17
BVPS	0.00	0.00	3.30	3.26	18.59	18.29	21.76	21.39	21.56	20.33
BVPS adj.	0.00	0.00	3.06	3.07	18.38	18.05	21.54	21.14	21.32	20.08
Net IB debt/share	0.00	0.00	21.01	22.00	10.45	10.38	5.65	5.67	4.18	3.67
Share price	112.50	112.50	112.50	112.50	112.50	112.50	112.50	112.50	112.50	112.50
Market cap. (m)	0	0	939	939	939	939	939	939	939	939
Valuation	-	-	-	-	-	-	-	-	-	-
P/E (x)	--	--	nm	nm	1.1	nm	nm	nm	14.4	9.5
EV/sales (x)	--	--	11.6	7.2	4.5	3.3	2.5	2.5	1.8	1.7
EV/EBITDA (x)	--	--	55.2	28.3	3.1	12.0	5.9	6.0	3.7	3.3
EV/EBITA (x)	--	--	-15.8	-54.4	4.2	-53.2	38.1	98.2	9.5	7.8
EV/EBIT (x)	--	--	-2.4	21.7	1.8	88.5	-131.4	98.2	9.5	7.8
Dividend yield (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.8	21.6
FCF yield (%)	0.0	0.0	-7.7	6.8	-4.9	3.6	4.0	2.1	18.8	26.1
Le. adj. FCF yld. (%)	0.0	0.0	-7.7	6.8	-4.9	3.6	4.0	2.1	18.8	26.1
P/BVPS (x)	--	--	3.37	3.41	0.60	0.61	0.51	0.52	0.52	0.55
P/BVPS adj. (x)	11.13	11.13	3.37	3.41	0.60	0.61	0.51	0.52	0.52	0.55
P/E adj. (x)	--	--	nm	nm	1.1	nm	nm	nm	14.4	9.5
EV/EBITDA adj. (x)	--	--	55.2	28.3	3.1	12.0	5.9	6.0	3.7	3.3
EV/EBITA adj. (x)	--	--	-15.8	-54.4	4.2	-53.2	38.1	98.2	9.5	7.8
EV/EBIT adj. (x)	--	--	-2.4	21.7	1.8	88.5	-131.4	98.2	9.5	7.8
EV/CE (x)	--	--	1.3	1.3	0.7	0.7	0.6	0.6	0.5	0.6
Investment ratios	-	-	-	-	-	-	-	-	-	-
Capex/sales (%)	--	--	10.8	5.4	25.2	14.2	24.4	19.7	9.9	8.9
Capex/depreciation	--	--	0.1	0.1	0.7	0.4	0.7	0.5	0.3	0.3
Capex tangibles / tangible fixed assets	--	--	1.4	1.1	4.1	3.2	6.0	5.0	3.4	3.5
Capex intangibles / definite intangibles	--	--	--	--	--	--	--	--	--	--
Depreciation on intang / def. intang	--	--	--	--	--	--	--	--	--	--
Depreciation on tangibles / tangibles	--	--	11.8	7.8	6.0	7.7	8.8	10.1	10.6	11.3

Source: ABG Sundal Collier, Company Data

Analyst Certification

We, ABGSC Oil & Oil Services Research, Martin Mauseth, Lars Trongaard Brattli and Stian Wibstad, analyst(s) with ABG Sundal Collier ASA, ABG Sundal Collier Denmark, filial af ABG Sundal Collier ASA, Norge, ABG Sundal Collier AB and/or ABG Sundal Collier Limited (hereinafter collectively referred to as “ABG Sundal Collier”), and the author(s) of this report, certify that not withstanding the existence of any such potential conflicts of interests referred to below, the views expressed in this report accurately reflect my/our personal view about the companies and securities covered in this report. I/We further certify that I/We has/have not been, nor am/are or will be, receiving direct or indirect compensation related to the specific recommendations or views contained in this report.

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Stock ratings distribution

ABG Sundal Collier Ratings and Investment Banking by 12/2/2025

Total of Rating	Research Coverage	Investment Banking Clients (IBC)	
	% of Total Rating	% of Total IBC	% of Total Rating by Type
BUY	60.50%	25%	10.33%
HOLD	35.25%	7%	4.96%
SELL	3.75%	0%	0.00%

IBC: Companies in respect of which ABG SC or an affiliate has received compensation for investment banking services within the past 12 months.

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BUY = We expect this stock’s total return to exceed the market’s expected total return by 5% or more over the next six months.

HOLD = We expect this stock’s total return to be in line with the market’s expected total return within a range of 4% over the next six months.

SELL = We expect this stock’s total return to underperform the market’s expected total return by 5% or more over the next six months.

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Stock price, company ratings and target price history

Company: Constellation

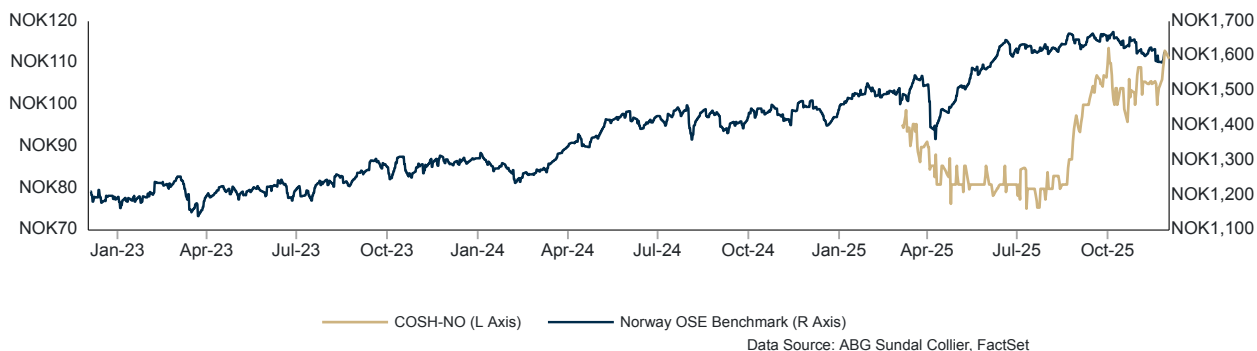
Currency: NOK

Current Recommendation: BUY

Date: 1/12/2025

Current Target price: 150.00

Current Share price: 112.50



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Production of recommendation: 12/2/2025 05:38.

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