Energy Research
Angus Energy plc*

27 July 2026

David Mirzai

Source: Company presentation

Energy Initiation Report

Angus Energy*

ANGS LN **BUY – TP 0.37p**

Non-Independent Research

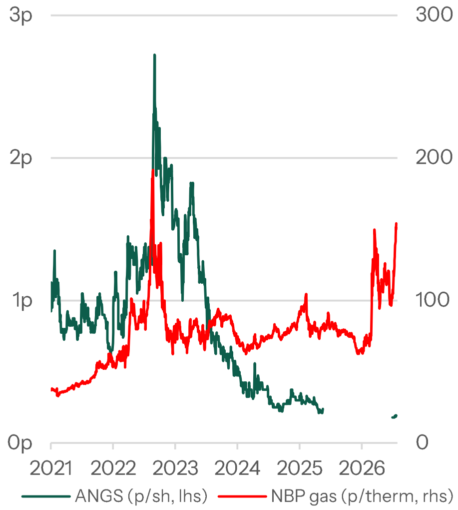
*SP Angel acts as Nomad and Corporate Broker

MiFID II Exempt

27 July 2026

Stock Data	
Ticker	ANGS LN
Share Price	0.1925p
Market Cap.	£15.4m

Share Price and Volume



Source: Bloomberg

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UK gas player emerges from financial restructuring

Angus Energy is an AIM-listed E&P with operated onshore UK oil and gas production, which has resumed trading after a financial restructuring and targets growing the business through organic and inorganic opportunities. We initiate with a BUY rating and 0.37p/sh 12-month target price based on the Core NAV, but recognise significant upside potential in monetising the 2C contingent resources if the UK Government revises its energy policy.

Exposure to the UK's largest onshore gas producer

Angus has a 100% interest in the Saltfleetby gas field that reported average 2Q26 production of ~5.85mmcf/d and 111b/d of condensate (~1.1kboe/d), reflecting 91% operational efficiency during the period. The Company now plans to focus near-term operational activity on increasing production by drilling a new development well at Saltfleetby and a well activation at Brockham to grow both sales volumes and cash flows from its operated UK portfolio.

Refinancing provides relief from unsustainable legacy debt facilities

Angus has completed a financial restructuring with its three key creditor groups (Trafigura, the Royalty Holders and Forum Energy Services), which materially strengthens the balance sheet, enhances liquidity and establishes a more sustainable long-term capital structure. This represents a major milestone for the Company, demonstrating strong stakeholder support and providing a cleaner financial platform for its next phase of development.

Excess free cash flow generation provides optionality

Angus emerges as a cash-generative, gas-weighted producer with a clear value proposition to unlock an estimated £50m NPV10 value from its 2P reserve base. We expect completion of a fourth development well at Saltfleetby to maintain annual revenues above £22m to 2030 based on the 2P production profile. While the majority of free cash flows will be initially directed towards amortising Trafigura's restructured £26m loan facility, we estimate the Company will also generate excess free cash flow to accelerate debt repayment and to recycle into low risk organic growth opportunities at Saltfleetby and Brockham.

Initiate with a BUY rating and a 12-month TP of 0.37p/sh

We initiate coverage on Angus as a BUY with a 0.37p/share 12M target price based on the Core NAV of its producing assets, which offers 92% potential share price upside. The Company benefits from hedged pricing on c.50% of its output out to mid-2027 at c.100p/therm, as well as spot prices on the remainder that currently exceed 150p/therm ($20/mmBtu). In addition, Angus has refined its acquisition strategy to target UK-based additions that would potentially double the size of the Company and accelerate the value of its tax losses.

Blue sky upside: global LNG price spikes and Government policy

NBP gas prices are strongly linked to international LNG prices, as the UK currently imports over half of its natural gas requirements. This means that whenever there is an impact to global supply (e.g. Strait of Hormuz closure) or a surge in global demand (e.g. weak rains hit hydropower output), the relative inelasticity of LNG demand often leads to a price spike. In our view, maintaining a large unhedged position enables gas producers to capture real option value from these periodic trading events. In addition, the new UK Prime Minister could have a material impact on the oil and gas sector if he signals support for approving existing gas projects like Jackdaw, future indigenous developments and / or accelerating the introduction of the Oil and Gas Revenue Levy.

UK gas player emerges from financial restructuring

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EXECUTIVE SUMMARY

Investment case

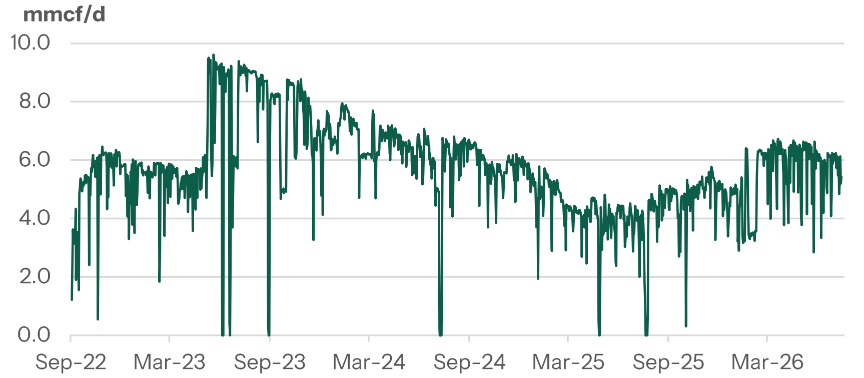
- **Onshore UK gas producer:** average production of over 1.2kboe/d (88% gas) in 2Q26, mainly from the Saltfleetby gas field (100% WI)
- **Strong cash flow generation:** generated £12.8m of net revenues in 1H26 due to higher gas prices and gas output following well workovers
- **Financial restructuring reschedules debt:** first quarterly amortisation payment made on the new 5-year loan facility at a lower interest rate
- **More favourable hedge position:** the legacy hedge book has expired with c.50% of the next 12M production now hedged at c.100p/therm.
- **Near term activity to boost output:** growth expected from facility optimisation, the Brockham workover and a fourth Saltfleetby well.
- **Scaling through M&A opportunities:** targets value-accretive non-operated acquisitions to spread G&A cost over a larger production base

Saltfleetby production provides a solid foundation

In our view, Angus offers investors exposure to a profitable and cash flow positive onshore conventional oil and gas company, with an ambitious growth-orientated management. The shares have recently returned from suspension, during which period the Company stabilised production operations at the Saltfleetby field, completed a financial restructuring to strengthen the balance sheet and reset the M&A strategy to focus on smaller opportunities that are more executable.

Angus' key asset is the onshore UK Saltfleetby gas field (100%), which had been in gradual decline since a third production well was brought online in mid-2023. Installation of a compressor booster in 2025 and workovers on two of the three wells at the start of 2026 has restored volumes back above 1kboe/d (90% gas). The Company now plans to focus operational activity on increasing production further by drilling a new Saltfleetby development well and reactivating a well on Brockham in the next 12M to drive growth from its operated UK portfolio.

Historic Saltfleetby gas production



Source: SP Angel

Roughly 50% of production volumes for the next 12M are already hedged at prices of c.100p/therm

Angus generated over £7m in sales revenues during 2Q26, up 37% q/q, driven primarily by higher realised gas prices, increased production volumes and an improved hedging position. Around half of the production volumes for the next 12M are already hedged at prices of c.100p/therm, which is above our 90p/therm assumption. This underpins a strong revenue and cash flow stream to pay down the Company's senior debt facility with Trafigura, which has reduced to £24.7m outstanding following the first principal repayment of £1.29m in 2Q26.

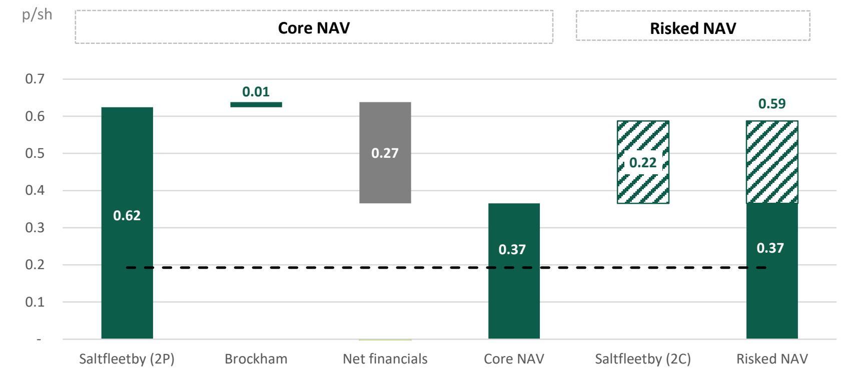
The remaining 50% of the gas attracts spot gas prices that are currently in excess of 150p/therm due to the ongoing disruption impacting LNG supply coming out of the Strait of Hormuz region. While the majority of free cash flows will initially be directed towards amortising Trafigura's restructured 5-Year term loan, we estimate the Company will also generate excess free cash flow at gas prices above 70p/therm to accelerate debt repayment via the cash sweep and recycle into low risk growth opportunities at Saltfleetby (100% WI) and Brockham (80%).

SP Angel valuation

Our valuation of Angus' Core assets produces a Target Price of 0.37p/share

Our valuation of Angus' Core assets produces a Target Price of 0.37p/share (£29.3m mkt cap.), implying that the Company offers 92% potential upside to SPA Core NAV. In our view, the current share price is more than underpinned by the 2P reserves on the producing Saltfleetby field, offset by the Company's net financial assets and liabilities. This includes completion of a fourth development well at Saltfleetby in early 2027, funded by operating cash flow, which is expected to sustain annual revenues above £22m for the rest of this decade.

NAV waterfall for Angus Energy valuation

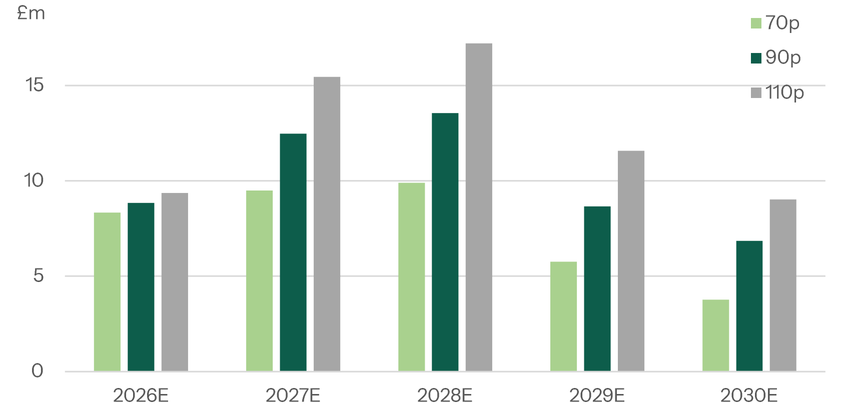


Source: SP Angel estimates

However, redeploying capital back into developing the existing 2C resource base to boost output has the effect of driving over 40% growth in estimated cash flows from the field to more than £60m over the next four years, when compared to the estimated cash flow from only producing the 2P reserves with no additional drilling after the fourth well. We estimate a 0.59p/sh Risked NAV for the Company based on the risked upside potential of the contingent resources at Saltfleetby, with a Total Unrisked NAV of 0.92p/sh (£78m mkt cap.).

Angus has emerged from the trading suspension as a cash-generative, gas-weighted producer with a clear value proposition to unlock an estimated £51m NPV10 value from the 2P reserve base. The next phase of the Company's evolution will be to pay down debt and recycle part of the positive free cash flow into developing the existing asset base. We think the current share price does not reflect the cash flow growth profile of the business, while also offering investors potential exposure to a step change in scale though M&A.

Operating cash flow sensitivity to average gas price scenario (flat from 1 July 2026)



Source: SP Angel estimates

This has created an attractive entry point for investors looking to gain exposure to a UK gas-focussed portfolio that also offers potential upside value not captured in our Core NAV. This is likely to derive from recurring periods of high gas prices due to demand/supply events and/or a change in UK policy that enables Angus to drill additional wells to target its 2C contingent resources. We expect that the improving visibility on production, cash flow and capital allocation policy over the next 12 months will provide greater clarity on the Company's value proposition and the upside optionality offered by the stock.

Strengths and opportunities

Gas is seen as a transition fuel in the UK

The UK currently imports more than half of its natural gas needs for power, industry and domestic use.

With petroleum sources still making up ~75% of the UK's energy mix, the country remains critically dependent upon oil and gas as transitional energy sources until we can produce sufficient quantities of green energy to power the economy. Natural gas, in particular, is widely acknowledged as a lower carbon transition fuel, which is helping to drive the global demand outlook such that both Qatar and the USA plan to effectively double their respective LNG export capacity this decade. Approximately 45% of the UK's energy supply is currently imported, according to Offshore Energies UK, which includes more than half of our current natural gas requirements for power, industry and domestic use. Notwithstanding the energy transition, the medium-term market outlook also remains strongly positive given the mandatory volume targets imposed by the EU to ensure sufficient gas in store ahead of the winter heating season, which is driven by economic sanctions against Russia following its invasion of the Ukraine in 2022.

Management team offers strength in depth

While the original executive team at Angus was able to identify the opportunity presented by the asset in a rising gas price environment to acquire the field for redevelopment, the Company was unable to deliver the technical skills required to bring the project into operation on time or budget. Following the drilling issues on the new B7T sidetrack in 2023, the shareholders effected a change at the top. This has elevated Krzysztof Zielicki (interim Chairman), Carlos Fernandes (CFO) and Ross Pearson (COO) to the executive team, who have put in place more robust operational procedures and oversight that has increased facility uptime. The management team has since stabilised production from the Saltfleetby field and has got the compressors and wells working with greater reliability levels, thereby boosting the reported field uptime and reducing the frequency and ongoing cost of maintenance shutdowns. The current management team has also been successful in negotiating the restructure of the Company's debt with its legacy creditors, which was approved by shareholders in July 2026.

M&A activity in the sector is accelerating

The UK remains a fragmented sector for oil and gas production and we certainly think that investors would respond positively to further consolidation in the small-cap sector, given the potential to cut corporate overheads such as G&A and regulatory costs. The rational for an acquisition of similar UK-focused E&P assets is also straight forward, bringing portfolio diversity, tax synergies and the required scale and motivation to invest in larger and more long-term development projects to make use of EPL offsets for new investments. The larger entity's financial strength would be improved from independent ongoing cashflows, which should support further M&A, organic investments and potentially returns to shareholders. Angus is not alone in pursuing this plan, with several peers targeting similar strategies to increase production via both organic and inorganic means to accelerate the realisation of tax synergies.

Organic investment projects are low risk and quick return

The impact of UK fiscal and political uncertainty on investment decisions has seen a shift towards short-cycle opportunities located close to existing production infrastructure that defer decommissioning and/or offer tax synergies. An updated Saltfleetby field reservoir model with reprocessed and reinterpreted seismic data has identified multiple drilling opportunities to accelerate production of the estimated 38bcf of remaining gas reserves and resources. Angus is now progressing a number of low-risk projects to accelerate production from the Saltfleetby field, which includes a fourth development well on the field targeted for early 2027. The Company also expects to restart output from the BRX4z well on the producing Brockham field, which targets undrained oil volumes in the Portland reservoir.

Weaknesses and risks

Legislation changes increase uncertainty

The UK oil and gas sector is undergoing a period of unprecedented uncertainty characterised by the energy transition, evolving investor sentiment, and energy security concerns. In 2019, the UK Government committed to reduce the 2050 share of fossil energy to 0% and replace it with nuclear and wind, despite concerns that energy security will be sacrificed before non-carbon alternatives are in place. The landmark 'Finch' Supreme Court decision in 2024 means the environmental impact of emissions from burning fossil fuels (Scope 3 emissions) must be considered in planning applications for extraction projects, rather than only the emissions produced in extraction (Scope 1+2 emissions). This resulted in the Jackdaw gas and Rosebank oil development projects having to undergo a further regulatory review. The UK Offshore Petroleum Regulator for Environment and Decommissioning (OPRED) is currently running a public consultation on both fields, which marks another step in the regulatory approval process before either of these North Sea projects can commence production.

Current UK fiscal regime hinders investment

The new OGPL mechanism is designed to improve the future UK oil and gas fiscal regime

The UK government introduced the Energy Profit Levy (EPL) as a windfall tax in response to high prices caused by sanctions against Russia following its invasion of Ukraine. The resultant effective tax rate is 78% on ring-fenced profits and will be in place to March 2030 unless the Energy Security Investment Mechanism (ESIM) triggers removal, with current thresholds at $78.65/bbl for Brent oil prices and at 61p/therm for NBP gas prices. However, the UK government announced plans in November 2025 to replace the windfall tax on oil & gas producers with the Oil and Gas Price Levy (OGPL). This will apply separately to oil and to gas and will tax only the proportion of revenue earned above new CPI-linked OGPL trigger levels of $90/bbl and 90p/therm, while the underlying headline tax rate returns to 40%. The new OGPL mechanism is designed to boost tax revenues during periods of higher prices, while also ensuring that the industry has the clarity it needs regarding the future fiscal landscape. In mitigation, Angus has over £100m of ring fence tax cover and EPL tax losses that we estimate will likely keep the Company in a non-tax paying position until 2H28.

ESG concerns impact financing

A key risk to the development of oil and gas resources has arisen from the public's negative perception of the industry, as well as differing views regarding government commitments to reaching net zero emissions by 2050 and the zeal with which some larger institutional investors and banks have elected to support ESG principles. Access to finance is an issue that has grown in importance following public pressure on certain financial institutions to change their investment policies to avoid funding fossil fuel extraction. As a result, completing bank debt finance or public-market credit instruments in the E&P sector has become far more difficult on the back of new ESG policies and low carbon transition commitments by bank lenders, despite the IPCC and Net Zero both recognising that there will be a need for oil and gas throughout the transition. In addition, bank financing for the sector is typically based on the value of reserves, which drops when there is an increase in the tax rate, as with the EPL. We identify dwindling pools of liquidity and appetite from credit providers to the oil and gas sector, especially at the more junior end, which will likely increase the hurdle rate for new projects and the cost of debt facilities.

Low pressure reservoir needs to be managed

A key operational challenge for the Company is to manage a liquid rich reservoir with depleting gas pressure, as lifting condensate from the wellbore become more challenging as gas velocities decrease with lower reservoir pressure. This is thought to cause the variable gas productivity on well B7T, alongside a possible carbonate build-up close to the well bore due to legacy drilling fluids. Angus expects to continue managing these issues through the utilisation of modern production optimisation techniques, compression, and/or artificial lift.

FINANCIAL OVERVIEW

Valuation Methodology

We assume flat 90p/therm NBP gas price and a $75/bbl Brent oil price

In formulating our valuation assumptions, we have forecast long-term constant benchmarks and apply these inputs into our DCF model. Our near-term assumptions estimate a $75/bbl long term flat Brent oil price from 1 July 2026, as well as a long-term UK natural gas price of 90p/therm and a US$1.35:£1.00 FX rate, discounted to 30 September 2026. We apply a standard 10% discount rate to the assets and incorporate the following assumptions into our financial model:

Assumptions table

Potential shares in issue (diluted millions)	8,011.9
LT exchange US$/£	US$1.35
LT NBP gas price	90p/therm
LT Brent oil price	$75/bbl
Gas conversion ratio	11.075 therms to 1 mcf
Gas shrinkage ratio	0.935
NPV discount rate	10%
Discount date	30/09/2026

Source: SP Angel estimates

We value Angus using a similar approach to all of our E&P companies, with risk-adjusted net asset value (Risked NAV) of the asset portfolio as the primary valuation methodology. We typically do this by modelling a Discounted Cash Flow (DCF) of the key assets in detail, taking the Company's net effective working interest and applying a risk factor. We think that it is useful for investors to think of the Company's asset base in terms of what can already be considered as commercial (e.g. producing 2P reserves at Saltfleetby) and what still has to be de-risked by further development or planning activity (e.g. contingent 2C resources at Saltfleetby). This gives us greater flexibility to 'upgrade' the individual risk factors on news flow and the delivery of commercial milestones, and so better reflect the market's evolving view on the "worth" of the asset base.

Summary Valuation

Asset	Region	Resource (mboe)	Stage	Net WI	Net resource (mboe)	NPV ($/boe)	Unrisked value (pps)	Risk factor	Net risked resources (mboe)	Net risked value ($m)	Net risked value (£m)	Net risked value (pps)
Saltfleetby (2P)	Onshore UK	3.2	P	100.0%	3.2	21.4	0.62	100%	3.2	67.5	50.0	0.62
Brockham	Onshore UK	0.1	P	80.0%	0.1	16.0	0.01	100%	0.1	1.5	1.1	0.01
Production assets		**3.3**			**3.2**	21	**0.64**		**3.2**	**69.0**	**51.1**	**0.64**
Development assets		**0.0**			**0.0**	**0.0**	**0.00**		**0.0**	**0.0**	**0.0**	**0.00**
Net cash / (debt) @ FYE26							-0.22			-23.9	-17.7	-0.22
G&A (2Yr)							-0.05			-5.4	-4.0	-0.05
2026 adj							0.00			-0.1	-0.1	0.00
Core NAV		**3.3**			**3.2**		**0.37**		**3.2**	**39.5**	**29.3**	**0.37**
Saltfleetby (2C)	Onshore UK	3.1	A	100.0%	3.1	19.1	0.55	40%	1.3	24.0	17.8	0.22
Contingent NAV		**3.1**			**3.1**		**0.55**		**1.3**	**24.0**	**17.8**	**0.22**
Lidsey	Onshore UK	0.0	E	80.0%	0.0	0.0	0.00	0%	0.0	0.0	0.0	0.00
Exploration NAV		**0.0**			**0.0**		**0.00**		**0.0**	**0.0**	**0.0**	**0.00**
Total Risked NAV		**6.4**					**0.92**		**4.5**	**63.5**	**47.0**	**0.59**

Source: SP Angel estimates

The above Risked NAV reflects Angus' existing portfolio with SPA estimates that are broadly in line with current internal estimates and the prior independently assessed reserves and contingent resources on the Saltfleetby structure, which were reported in a third-party engineer's Competent Persons Report (CPR) from 2023. We do not ascribe any resources or value in our Risked NAV to the Lidsey field, which is currently suspended due to high water disposal costs. However, the Company has submitted a planning application for disposal of the produced water offsite and to contribute to pressure support at Brockham field.

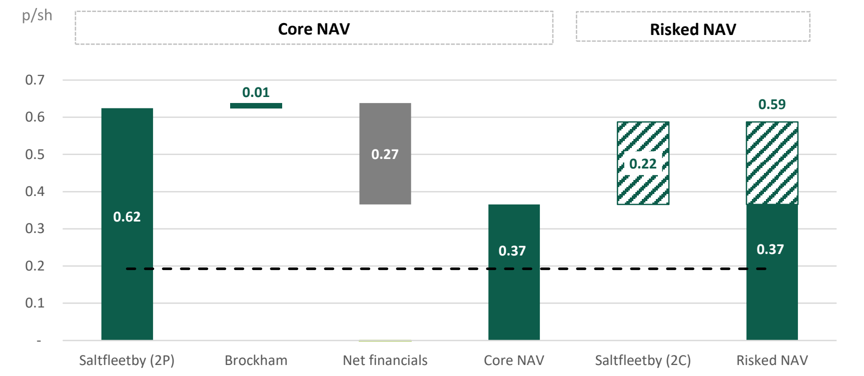
Recommendation and target price

We calculate a £50m NPV10 for the 2P reserves on the producing Saltfleetby field, which we estimate has remaining recoverable volumes of ~19bcf. Angus reported the senior debt facility with Trafigura had reduced to £24.7m as at June 30. Following completion of the financial restructuring in July 2026 we estimate that Angus will end the financial year on September 30 with £17.7m net debt, which includes £1.95m junior debt owed to the former overriding royalty interest holders. The net financials in our Core NAV also include two years of discounted G&A expenses, which are estimated at a run-rate of £2.3m per annum.

We estimate a Core NAV of £29.3m, or 37p/sh based on 90p/therm gas

Our valuation of Angus' Core assets produces a Target Price of 0.37p/share (£29.3m mkt cap.), implying that the Company offers 92% potential upside to SPA Core NAV. In our view, the current share price is more than underpinned by the 2P reserves on the producing Saltfleetby field, offset by the Company's financial assets and liabilities. We estimate a 0.59p/sh Risked NAV (£47m mkt cap.) for the Company based on the upside potential of the contingent resources at Saltfleetby, with a Total Unrisked NAV of 0.92p/sh (£77.8m mkt cap.).

NAV waterfall for Angus Energy valuation



Source: SP Angel estimates

Angus guides that natural gas production from the Saltfleetby field (100% WI) should increase by 25% y/y from 1.6bcf in 2025 to 2bcf in the 2026 financial year to September 30, with condensate production targeted to increase from 30kb to 35kb. Production from the Brockham field (80% WI) is also targeted to increase by 90% y/y from 11kb in 2025 to 21kb in 2026. We expect the Company to more than double y/y revenues to £22.8m for FY26 and maintain this level or higher over the next few years based only on the 2P production profile.

We think that Angus offers UK investors unique exposure to gas-based production and cash flow growth from the Company's key Saltfleetby gas field. Approximately 50% of forecast gas production volumes over the next 12M have been hedged at an average price of c.100p/therm, with the remaining 50% exposed to spot gas prices that have mostly traded above 100p/therm since the closure of the Strait of Hormuz at the end of February.

Angus plans to use £1m from the recent fund raise to prepare and acquire long lead items to drill the fourth development well at Saltfleetby in early 2027, funding the rest of the drilling costs from operating cash flow. A typical Saltfleetby development well costs ~£6m and adds incremental production of over 3mmcf/d across a largely fixed cost base. The wells are anticipated to achieve payback in under 12 months and then generates long-life free cash flow with occasional low cost well workovers required to maintain output levels.

Given the volatility of energy prices in recent years, we estimate that a 10p/them change in natural gas prices will result in a c.£1.5m impact on annual operating cash flows and a ~0.09p/sh (26%) impact on the SP Angel Core NAV.

NAV sensitivity matrix

NBP gas price	Core NAV	2027 operating cash flow	2027 net debt
70p/therm	0.17p	£9.5m	£16.4m
90p/therm	**0.37p**	**£12.5m**	**£12.9m**
110p/therm	0.52p	£15.5m	£9.3m

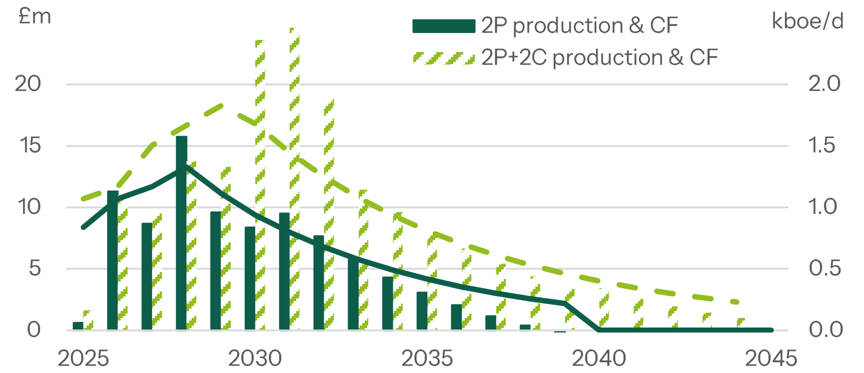
Source: SP Angel estimates

Capital allocation scenario analysis

We estimate Angus can boost cash flows by over 40% out to 2030 by developing the 2C resources

We base our financial estimates on a 90p/therm NBP gas price and the 2P reserves production profile, which assumes drilling of a fourth development well at Saltfleetby. However, redeploying capital back into developing the existing 2C resource base over the next few years to boost output has the effect of driving over 40% growth in estimated cash flows from the field to more than £60m over the next four years, when compared to the estimated field cash flow from only producing the 2P reserves with no additional drilling after the fourth well.

Saltfleetby production and field net cash flows for 2P reserves and 2P+2C resources

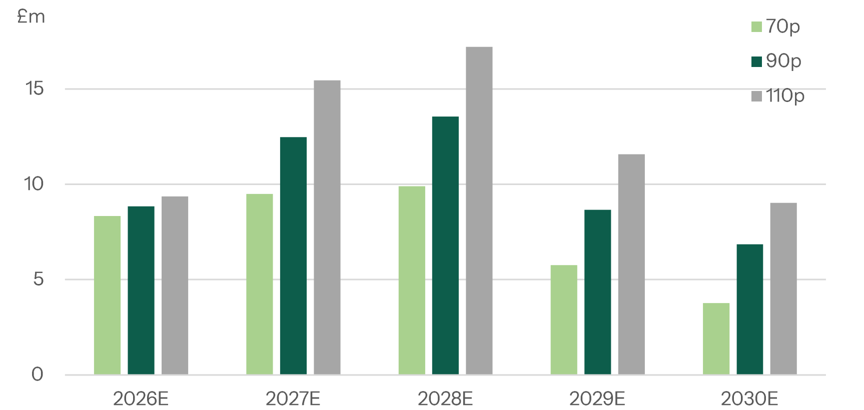


Source: SP Angel

However, we continue to take a prudent approach to risking Angus' onshore UK development portfolio given the exacting regulatory environment, attributing a 40% chance of success to Saltfleetby's 17bcf of 2C contingent resources. This captures not only geological and funding risk, but also balances the above ground risks in securing regulatory approval for new wells with the longer-term optionality that the development of these contingent resources offer.

While Angus is required under the Trafigura facility to retain hedges on part of its production going forward, these hedges will be at current market prices rather than the ~40p/therm legacy hedges that it previously held. Importantly, the Company's economics remain robust even if gas prices fall back to 70p/therm, which is due to low operating costs of 20-30p/therm and the large corporate tax pool available. In addition, the Company can exert control over its discretionary spending as the operator on its UK licences, which provides good portfolio and balance sheet resilience to any potential period of lower prices.

Operating cash flow sensitivity to average gas price scenario (flat from 1 July 2026)



Source: SP Angel estimates

More importantly, we recognise that NBP prices are strongly linked to international LNG prices as the UK currently imports over half of its natural gas requirements. This means that whenever there is an impact to global supply (e.g. Strait of Hormuz closure) or a surge in global demand (e.g. weak rains hit hydropower output), the relative inelasticity of LNG demand often leads to a global price spike. In our view, maintaining a material unhedged position enables UK gas producers to capture real option value from these periodic trading events, which currently includes the mandatory volume targets imposed by the EU to ensure sufficient gas in store ahead of the winter heating season.

Financial restructuring strengthens balance sheet

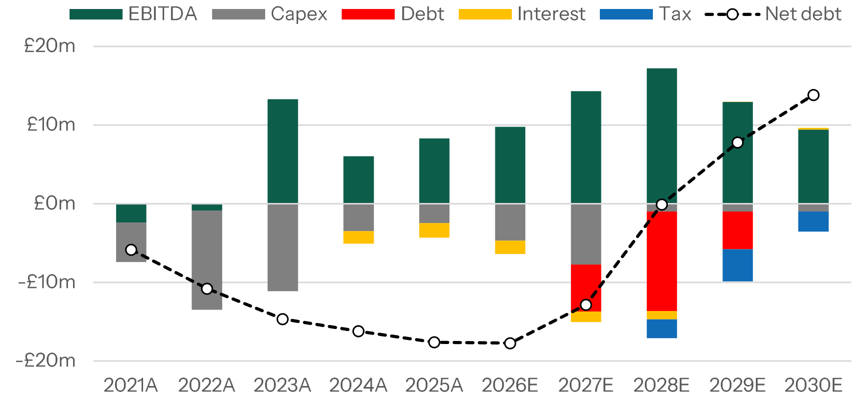
As part of its financial restructuring, Angus consolidated its debts to Trafigura into a single £26m facility agreement that is repaid over a period of five years commencing in 2Q26, with even quarterly repayments up to and including 31 March 2031. The Company also terminated the revenue sharing agreement with the overriding royalty (ORRI) holders in favour of an £2.5m aggregate settlement, of which £0.55m has been settled in new shares. The remaining £1.95m will be settled via a cash sweep mechanism, as described below.

The cash sweep mechanism applies: (i) 50% of Angus' revenues from any asset (after deducting all Company costs, including financing charges) bi-annually to redeem the Trafigura loan; and (ii) the remaining 50% of such revenues shall be applied in repayment of the ORRI cash amount. The cash sweep will only apply to funds in excess of £2m, such that Angus shall be entitled to retain a minimum cash balance of £2m to meet its projected operational and capital expenditure requirements for each following 12 months.

We estimate Angus can payback its Trafigura facility by 2H29 at 90p/therm via the cash sweep

We estimate that the majority of Angus' medium-term free cash flow will be used to amortise the Trafigura's restructured £26m debt facility, which has already received its first quarterly principal repayment of £1.29m in 2Q26 to reduce outstanding borrowings to £24.7m. However, our current modelling at 90p/therm suggests that the Company will be able to accelerate payback to clear all of its debt obligations by 2H29 via the cash sweep agreement.

Cash generation vs outgoings (including cash sweep mechanism)



Source: SP Angel estimates

The Trafigura facility carries an interest rate of SONIA plus 8% per annum. At the Company's sole discretion, an amount of interest equivalent to 4% per annum on the outstanding Trafigura facility amount may also be satisfied by granting warrants to Trafigura that have a five-year maturity period. The number of warrants to be granted shall be derived from an agreed-form Black-Scholes valuation model with an exercise price at the higher of: (i) 150% of the 15-day VWAP and (ii) 0.20p (being the nominal value of an ordinary share).

The final part of the financial restructuring was to amend the terms of the Forum deferred consideration agreement, which was originally entered into regarding the sale of Saltfleetby Energy Limited's 49% interest in the Saltfleetby gas field to Angus in 2022. The remaining deferred consideration amount due to Forum was agreed at £2.5m, which has been settled in full by the issue of 1,250m new shares. These shares are subject to a lock-in for up to the earlier of six months and the completion of the further funding condition, with Forum now holding ~25.69% of the Company's issued shares making it the largest shareholder.

The completion of the financial restructuring in July 2026 demonstrated the strong support of the key stakeholders to improve Angus' financial position. The conversion of liabilities into equity, the crystallisation of the royalty, and the improved terms with Trafigura together create a simpler, stronger and more flexible balance sheet. This marks a clear turning point for the Company and enables the executive team to focus on delivering the operational programme and to establish long-term value for shareholders.

GBP financial projection for Angus (fiscal year ending 30 September)

In GBP (unless stated)		2023A	2024A	2025A	2026E	2027E	2028E	2029E	2030E
Avshare price (p)		**0.63**	**0.28**	**0.24**	**0.19**	**0.19**	**0.19**	**0.19**	**0.19**
Basic YE NOSH (m)		**3,627**	**4,422**	**4,987**	**8,012**	**8,012**	**8,012**	**8,012**	**8,012**
YE $/£		**1.22**	**1.34**	**1.41**	**1.35**	**1.35**	**1.35**	**1.35**	**1.35**
Market cap (£m)		**23**	**12**	**12**	**15.4**	**15.4**	**15.4**	**15.4**	**15.4**
Market cap (US$m)		**28**	**16**	**17**	**20.8**	**20.8**	**20.8**	**20.8**	**20.8**
EV (£m)		**37**	**28**	**30**	**33.2**	**28.3**	**15.5**	**7.7**	**1.6**
Income Statement		**2023A**	**2024A**	**2025A**	**2026E**	**2027E**	**2028E**	**2029E**	**2030E**
Brent	US$/bbl	83.6	83.0	71.0	78.0	75.0	75.0	75.0	75.0
NBP natural gas	p/therm	152.1	99.3	96.2	90.0	90.0	90.0	90.0	90.0
Revenue	£m	28.2	21.8	18.0	22.8	24.1	27.2	22.8	19.2
Opex	£m	-6.9	-7.3	-6.4	-7.4	-7.5	-7.7	-7.4	-7.2
EBITDAX	£m	17.0	10.8	8.3	12.8	14.3	17.2	12.9	9.4
Exploration W/O	£m	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EBITDA	£m	13.3	6.0	8.3	9.8	14.3	17.2	12.9	9.4
DDA	£m	-8.5	-8.7	-6.3	-7.6	-8.4	-9.5	-7.9	-6.7
EBIT	£m	4.8	-2.7	2.0	2.1	5.9	7.7	5.0	2.7
Exceptionals	£m	-3.7	-4.8	0.0	-3.0	0.0	0.0	0.0	0.0
Net finance income	£m	113.0	-1.6	-1.8	-1.7	-1.4	-1.0	0.0	0.2
EBT	£m	117.8	-4.3	0.1	0.4	4.5	6.7	5.0	2.9
Tax	£m	0.0	0.0	0.0	0.0	0.0	-2.4	-4.1	-2.6
Net income	£m	**117.8**	**-4.3**	**0.1**	**0.4**	**4.5**	**4.3**	**0.9**	**0.4**
EPS (basic)	pence	3.48	-0.10	0.00	0.01	0.06	0.05	0.01	0.00
EPS (diluted)	pence	3.48	-0.10	0.00	0.01	0.06	0.05	0.01	0.00
Balance Sheet		**2023A**	**2024A**	**2025A**	**2026E**	**2027E**	**2028E**	**2029E**	**2030E**
Cash	£m	2.2	2.2	1.1	7.7	6.2	4.7	7.8	13.8
Debt	£m	16.8	18.4	18.7	25.4	19.1	4.8	0.0	0.0
Net debt/(cash) BV	£m	14.7	16.2	17.6	17.7	12.9	0.1	-7.8	-13.8
Total Assets	£m	91.1	82.0	77.2	86.7	84.8	75.2	70.7	70.6
Total Liabilities	£m	53.8	43.3	36.4	42.7	36.2	22.3	16.9	16.5
Net Assets	£m	37.3	38.7	40.8	44.1	48.6	52.9	53.8	54.2
Equity	£m	37.3	38.7	40.8	44.1	48.6	52.9	53.8	54.2
Cash Flow		**2023A**	**2024A**	**2025A**	**2026E**	**2027E**	**2028E**	**2029E**	**2030E**
Cash flow from Operations	£m	1.2	3.1	3.0	8.8	12.5	13.6	8.7	6.8
Cash used in Investing	£m	-11.6	-5.9	-2.5	-4.7	-7.6	-0.8	-0.8	-0.8
Cash used in Financing	£m	11.8	2.7	-1.6	2.4	-6.4	-14.3	-4.8	0.0
Change in cash	£m	1.4	0.0	-1.0	6.6	-1.5	-1.5	3.1	6.1
FCF	£m	-9.9	-0.4	0.5	4.2	-1.2	-0.1	2.9	5.8
DACF	£m	-0.1	0.4	1.4	7.9	12.5	13.6	8.7	6.8
Production (WI)									
Oil production	kbo/d	0.09	0.13	0.11	0.14	0.16	0.17	0.14	0.12
Gas production	mmcf/d	6.44	6.50	4.53	5.42	5.96	6.77	5.69	4.79
HC production	kboe/d	1.16	1.21	0.86	1.05	1.15	1.29	1.09	0.92
Production growth	%	1901%	4%	-29%	22%	10%	12%	-16%	-16%
2P reserves	mboe	4.6							
Valuation									
Share price	(p)	0.63	0.28	0.24	0.19	0.19	0.19	0.19	0.19
Market cap	£m	22.7	12.2	12.0	15.4	15.4	15.4	15.4	15.4
EV	£m	37.3	28.4	29.6	33.2	28.3	15.5	7.7	1.6
P/E	(x)	0.2	-2.8	80.0	25.6	3.4	3.6	16.8	40.0
EV/DACF	(x)	-254.0	74.6	20.6	4.2	2.3	1.1	0.9	0.2
EV/2P	(£/boe)	8.1	nm	nm	nm	nm	nm	nm	nm
EV/boe/d	£/boe/d	32.2	23.4	34.4	31.7	24.5	12.0	7.0	1.7
Div yield	(%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
FCF yield	(%)	-44%	-3%	5%	27%	-8%	-1%	19%	38%
Net debt/EBITDA	(x)	1.1	2.7	2.1	1.8	0.9	0.0	-0.6	-1.5
Net debt/Equity	(%)	39%	42%	43%	40%	26%	0%	-14%	-26%
Net debt/EBITDAX	(x)	0.9	1.5	2.1	1.4	0.9	0.0	-0.6	-1.5
EBITDAX/interest	(x)	-0.2	6.7	4.5	7.5	10.6	16.7	-1065.0	-43.3
Interest cover	(x)	0.0	-1.7	1.1	1.3	4.3	7.5	-411.3	-12.6
ROACE	(%)	23%	-5%	4%	4%	11%	14%	9%	5%
EV/EBITDAX	(x)	2.2	2.6	3.6	2.6	2.0	0.9	0.6	0.2

Source: SP Angel estimates

USD financial projection for Angus (fiscal year ending 30 September)

In US$ (unless stated)		**2023A**	**2024A**	**2025A**	**2026E**	**2027E**	**2028E**	**2029E**	**2030E**
Avshare price (p)		**0.63**	**0.28**	**0.24**	**0.19**	**0.19**	**0.19**	**0.19**	**0.19**
Basic YE NOSH (m)		**3,627**	**4,422**	**4,987**	**8,012**	**8,012**	**8,012**	**8,012**	**8,012**
Av $/GBP		**1.23**	**1.27**	**1.32**	**1.35**	**1.35**	**1.35**	**1.35**	**1.35**
YE $/£		**1.22**	**1.34**	**1.41**	**1.35**	**1.35**	**1.35**	**1.35**	**1.35**
Market cap (£m)		**23**	**12**	**12**	**15.4**	**15.4**	**15.4**	**15.4**	**15.4**
Market cap ($m)		**28**	**16**	**17**	**20.8**	**20.8**	**20.8**	**20.8**	**20.8**
EV ($m)		**46**	**37**	**40**	**44.8**	**38.2**	**20.9**	**10.3**	**2.1**
Income Statement		**2023A**	**2024A**	**2025A**	**2026E**	**2027E**	**2028E**	**2029E**	**2030E**
Brent	$/bbl	83.6	83.0	71.0	78.0	75.0	75.0	75.0	75.0
NBP natural gas	$/mmBtu	16.9	11.4	11.5	11.0	11.0	11.0	11.0	11.0
Revenue	$m	34.6	27.6	23.8	30.8	32.6	36.7	30.8	25.9
Opex	$m	-8.5	-9.3	-8.4	-10.0	-10.2	-10.4	-10.0	-9.8
EBITDAX	$m	20.9	13.7	10.9	17.2	19.3	23.2	17.5	12.7
Exploration W/O	$m	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EBITDA	$m	16.3	7.7	10.9	13.2	19.3	23.2	17.5	12.7
DDA	$m	-10.4	-11.1	-8.3	-10.3	-11.4	-12.8	-10.7	-9.0
EBIT	$m	5.9	-3.4	2.6	2.9	7.9	10.4	6.7	3.7
Exceptionals	$m	-4.6	-6.0	0.0	-4.1	0.0	0.0	0.0	0.0
Net finance income	$m	138.7	-2.0	-2.4	-2.3	-1.8	-1.4	0.0	0.3
EBT	$m	144.6	-5.5	0.2	0.6	6.1	9.0	6.8	4.0
Tax	$m	0.0	0.0	0.0	0.0	0.0	-3.3	-5.5	-3.5
Net income	$m	**144.6**	**-5.5**	**0.2**	**0.6**	**6.1**	**5.8**	**1.2**	**0.5**
EPS (basic)	Cents	4.27	-0.13	0.00	0.01	0.08	0.07	0.02	0.01
EPS (diluted)	Cents	4.27	-0.13	0.00	0.01	0.08	0.07	0.02	0.01
Balance Sheet		**2023A**	**2024A**	**2025A**	**2026E**	**2027E**	**2028E**	**2029E**	**2030E**
Cash	$m	2.7	2.7	1.5	10.4	8.4	6.4	10.5	18.7
Debt	$m	20.7	23.3	24.7	34.3	25.7	6.5	0.0	0.0
Net debt/(cash) BV	$m	18.0	20.5	23.3	23.9	17.4	0.1	-10.5	-18.7
Total Assets	$m	111.8	103.9	102.0	117.1	114.4	101.5	95.5	95.4
Total Liabilities	$m	66.1	54.9	48.1	57.6	48.9	30.2	22.9	22.2
Net Assets	$m	45.7	49.1	53.9	59.5	65.6	71.4	72.6	73.1
Equity	$m	45.7	49.1	53.9	59.5	65.6	71.4	72.6	73.1
Cash Flow		**2023A**	**2024A**	**2025A**	**2026E**	**2027E**	**2028E**	**2029E**	**2030E**
Cash flow from Operations	$m	1.5	4.0	4.0	11.9	16.8	18.3	11.7	9.2
Cash used in Investing	$m	-14.2	-7.4	-3.3	-6.3	-10.3	-1.1	-1.1	-1.1
Cash used in Financing	$m	14.5	3.4	-2.1	3.2	-8.6	-19.2	-6.5	0.0
Change in cash	$m	1.7	0.0	-1.4	8.9	-2.0	-2.0	4.1	8.2
FCF	$m	-12.1	-0.5	0.7	5.6	-1.7	-0.1	3.9	7.9
DACF	$m	-0.2	0.5	1.9	10.6	16.8	18.3	11.7	9.2
Production (WI)									
Oil production	kbo/d	0.09	0.13	0.11	0.14	0.16	0.17	0.14	0.12
Gas production	mmcf/d	6.44	6.50	4.53	5.42	5.96	6.77	5.69	4.79
HC production	kboe/d	1.16	1.21	0.86	1.05	1.15	1.29	1.09	0.92
Production growth	%	1901%	4%	-29%	22%	10%	12%	-16%	-16%
2P reserves	mboe	4.6							
Valuation									
Share price	(p)	0.63	0.28	0.24	0.19	0.19	0.19	0.19	0.19
Market cap	$m	27.7	16.3	16.9	20.8	20.8	20.8	20.8	20.8
EV	$m	45.7	36.8	40.2	44.8	38.2	20.9	10.3	2.1
P/E	(x)	0.2	-2.8	80.0	25.6	3.4	3.6	16.8	40.0
EV/DACF	(x)	-253.1	76.5	21.2	4.2	2.3	1.1	0.9	0.2
EV/2P	($/boe)	10.0	nm	nm	nm	nm	nm	nm	nm
EV/boe/d	$/bo/d	39.3	30.4	46.7	42.8	33.1	16.2	9.5	2.3
Div yield	(%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
FCF yield	(%)	-44%	-3%	4%	27%	-8%	-1%	19%	38%
Net debt/EBITDA	(x)	1.1	2.7	2.1	1.8	0.9	0.0	-0.6	-1.5
Net debt/Equity	(%)	39%	42%	43%	40%	26%	0%	-14%	-26%
Net debt/EBITDAX	(x)	0.9	1.5	2.1	1.4	0.9	0.0	-0.6	-1.5
EBITDAX/interest	(x)	-0.2	6.7	4.5	7.5	10.6	16.7	-1065.0	-43.3
Interest cover	(x)	0.0	-1.7	1.1	1.3	4.3	7.5	-411.3	-12.6
ROACE	(%)	23%	-5%	4%	4%	11%	14%	9%	5%
EV/EBITDAX	(x)	2.2	2.7	3.7	2.6	2.0	0.9	0.6	0.2

Source: SP Angel estimates

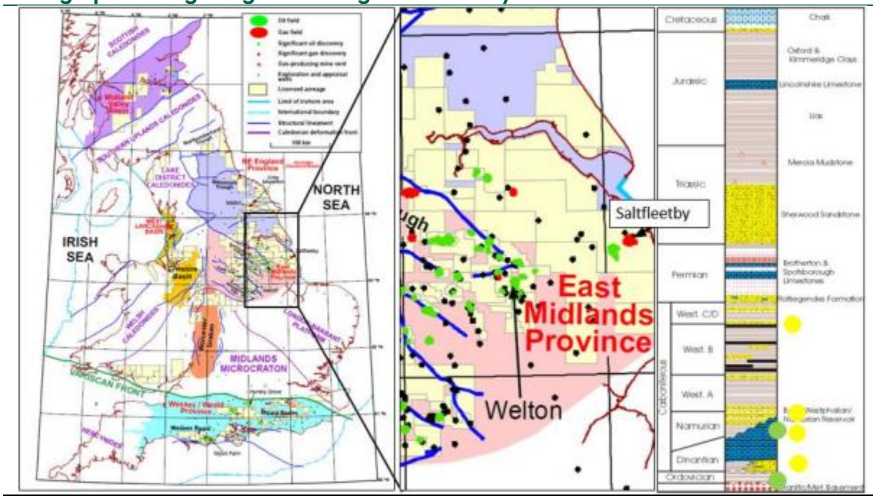
ASSET OVERVIEW

Saltfleetby has a long production history

Following Saltfleetby's discovery in 1996, the field initially produced gas and condensate from 1999 and 2017

The onshore Saltfleetby gas discovery well was drilled in 1996 at the western extent of the Humber Basin on UK licence PEDL005, before being brought into production in December 1999 by Roc Oil. In 2000, the Saltfleetby gas field achieved peak production of 54mmcf/d and 1.1kb/d of condensate from four wells targeting the main Carboniferous-age Early Westphalian sandstone reservoir at a depth of 2,300m. The produced gas and liquids were transported to ConocoPhillips' Theddlethorpe Gas Terminal (TGT) by a single pipeline for processing, separation, stabilisation, compression and sale to the grid.

Geographic and geological Setting of Saltfleetby field

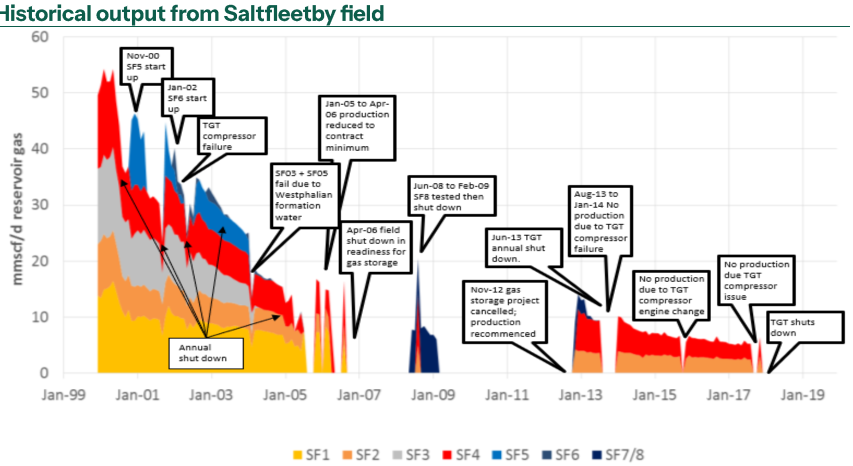


Source: Oilfield International CPR (2023)

Following a period of steady natural production decline, Roc Oil sold the Saltfleetby gas field for £44m in 2004 to Wingas Storage (UK), a joint venture between Wintershall and Gazprom. Wingas shut down the field in 2006 in readiness for conversion to a gas storage facility, but the project was cancelled in 2012 and production restarted. Following a very sudden decision by ConocoPhillips to shut down the TGT facility, one of only four major offshore pipeline systems in the UK Southern North Sea Basin, the owners then spent over £30m on a feasibility study on potentially redeveloping the Saltfleetby field.

However, with UK natural gas prices in 2016 stuck in a range of just 20-30p/them, Gazprom and its partner deemed the project uncommercial. The TGT facility was decommissioned by ConocoPhillips in 2018, which left the Saltfleetby field stranded with nowhere to process the produced gas and liquids and no direct export route. In total, 68bcf of raw gas and 1.1mb of condensate were originally produced from the Saltfleetby gas field (57% recovery factor), which recorded a final aggregate flowrate of 6.5mmcf/d from wells SF2 and SF4 in December 2017.

Historical output from Saltfleetby field

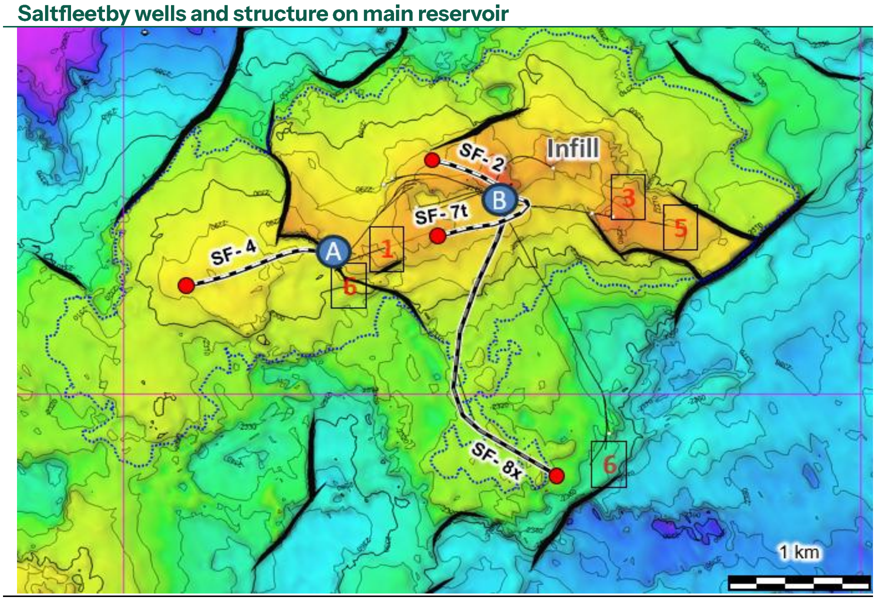


Source: Company presentation

Angus redevelopment of Saltfleetby

In 2019, Angus acquired a 51% working interest and operatorship of the licence from Wingas (renamed Saltfleetby Energy) for a nominal consideration, then a redevelopment plan was approved in 2021 to target the remaining recoverable natural gas still in place in the Westphalian reservoirs. Sadly, the Saltfleetby development experienced significant project delays and cost escalation during the construction process that required multiple equity financings. During 2022, Angus acquired the remaining 49% equity stake from Forum Energy Services, thereby taking its interest to 100% in the field, ahead of the Company finally announcing first gas from the Saltfleetby field in 3Q22.

Saltfleetby wells and structure on main reservoir

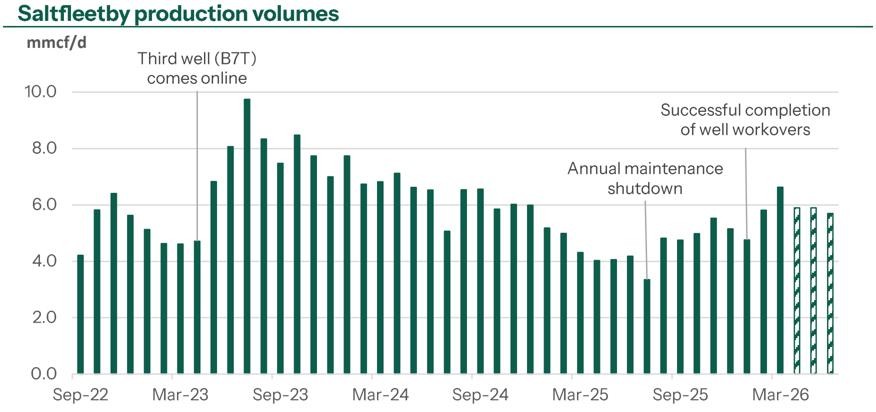


Source: Company presentation

Saltfleetby production peaked at over 10mmcf/d in 2H23 with efforts ongoing to return output to this level

The Saltfleetby field achieved initial average daily production rates of 5.2mmcf/d from the existing B2 and A4 wells, which were constrained by the single compressor on the field. Production peaked at rates of over 10mmcf/d in 2023 following the installation of a second compressor and tie-in of the delayed third well, B7T, which was a sidetrack of an existing wellbore drilled alongside what was previously the best producing well in the field. Production was then stabilised above 6mmcf/d until early 2025, when a new booster compressor was commissioned to improve and stabilise gas flow rates from the field.

Saltfleetby production volumes



Source: Company presentation

The new compressor operated at a lower suction pressure than the two existing compressors at the field, helping to alleviate the impact of liquid loading and allowing more pressure drawdown of the wells to optimise long term production and reduce the flowing wellhead pressure constraint from 17.5bar to 11bar. Saltfleetby's average 4Q25 production increased 19% q/q to 4.85mmcf/d due to optimisation of the booster compressor operations. This led to a significant jump in volumes and revenues that reflected increased equipment uptime, improved well performance and better well management.

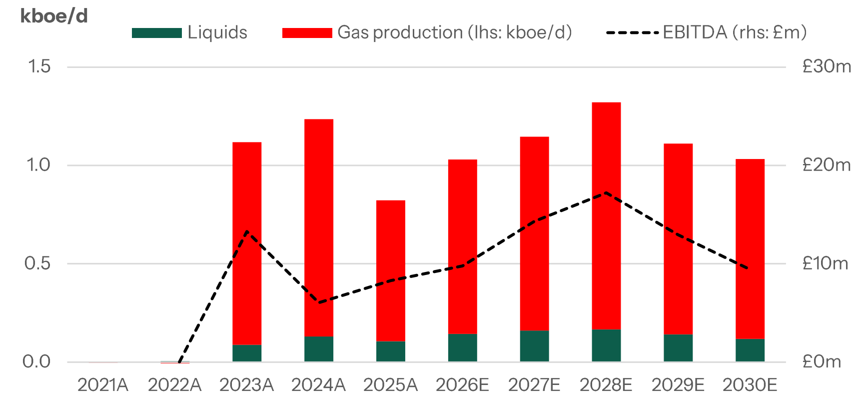
Operational focus to maximise production

In early 2026, Angus completed workover operations as part of the Saltfleetby well intervention programme, which used coil tubing to clean out two of the production wells with acid and with a mutual solvent. This had the effect of increasing aggregate production rates by ~30% compared to pre-workover levels, raising average 1H26 output to 5.55mmcf/d and current flow rates above 6mmcf/d, with operational efficiency of over 90% reported in the last quarter.

A fourth Saltfleetby production well is fully permitted, with plans to start drilling in the 1Q27 period

An updated Saltfleetby field reservoir model with reprocessed and reinterpreted seismic data has identified multiple drilling opportunities to accelerate production of the SPA estimated ~19bcf of remaining 2P gas reserves. Part of the net proceeds from the equity raise will be used for surface upgrades at Saltfleetby and ordering the long leads in preparation for a fourth well at the field. The well is fully permitted, with both planning approval and environmental approval already in-place and plans to commence drilling by 1Q27.

2P reserves' production and EBITDA forecast



Source: SP Angel estimates

There is also 17bcf of gross 2C contingent resource upside attributed to the Saltfleetby field, mostly from a potentially disconnected or poorly connected sections of the Westphalian reservoir, with added potential in the deeper Namurian sandstone reservoir. The updated reservoir model will support the placement and optimisation of potential infill well locations. Subject to planning permission, additional wells could be funded later this decade from operating cash flow at a cost of ~£6m per well, which the Company estimates would add initial incremental volumes of at least 3mmcf/d per well and payback in under 12M. We currently include the contingent resources in the Risked NAV with a chance of success of just 40%, which reflects both the below ground geological risk, and the above ground risk in securing planning approval for new drilling.

We note that there is an also an MOU in place with Trafigura to evaluate storage and low-carbon applications at Saltfleetby, which has the potential to deliver additional long-term value potential on top of the natural gas depletion.

The Brockham field (80% WI)

Also in the portfolio, the onshore Brockham field in Southern England was first discovered by BP in the late 1980's and oil was produced from the Portland Sandstone reservoir right up until 2018. The field underwent a steady decline in production rate as the asset matured, but the BRX-2Y well was finally shut-in due to integrity issues with the production tubing. Angus, as operator (80% WI), performed a workover to acid wash the well, install new tubing and a new pump in the BRX-2Y well and was able to reinstate production from the field in 2Q24.

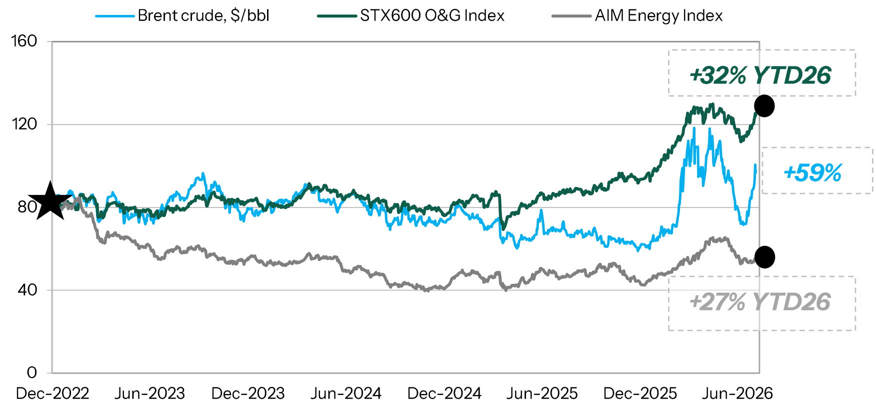
Following a programme of operational optimisation, production performance at the Brockham field has improved significantly over the last twelve months, with average production rates almost doubling from levels achieved in early 2025. The Company is now preparing for the planned return of the BRX4z well to production from the Portland reservoir, which the Board believes has the potential to restore oil production and further enhance aggregate volumes and cash flow from the field. The Company estimates the well workover in 2H26 will cost ~£0.3m and is expected to achieve payback within six months.

Corporate focus is to scale business

Large and mid-cap oil and gas production companies have largely tracked Brent oil prices over the last few years, which has determined their ability to generate free cash flow to deleverage and make shareholder returns. Brent is up ~59% in YTD26, with share prices more measured in their response to rising oil prices as investors were wary of the long-term impact from the Strait of Hormuz closure. However, we note that sentiment in the sector has significantly improved overall, with large-cap oil & gas shares appreciating 21% in 2025 and 32% in YTD26.

The energy transition paradigm triggered a reallocation of capital away from the traditional small-cap E&P model that favoured longer cycle and higher risk exploration and appraisal value proposition. However, small-cap E&Ps have come back into favour during 1H26, as the market has seen positive investment signals from the Majors. This has validated the view that junior oil and gas portfolios can offer an accelerated runway to the exploration, appraisal and development assets required to shore up the declining reserves of larger players.

Oil & Gas Index stock performance relative to Brent oil price

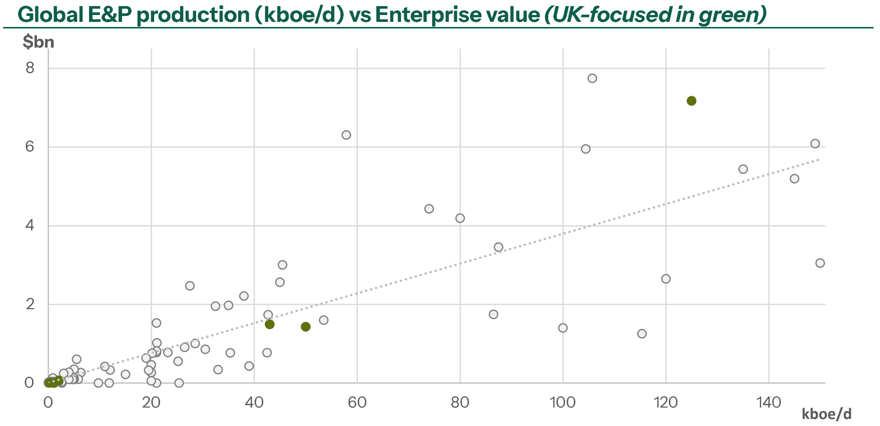


Source: Bloomberg data

E&Ps that can scale their production and cash flows are rewarded with higher market capitalisations

The management team at Angus has talked quite openly regarding inorganic growth opportunities in the last few years. Business combinations represent a strategic opportunity to reduce corporate overheads on a pro forma combined basis and deliver enhanced scale, balance sheet strength, and growth opportunities from the more diversified portfolio. E&Ps that deliver scaling of their production and cash flows have been rewarded with higher market capitalisations, which is essential to maintain institutional relevance, improve balance sheet strength and to boost trading liquidity.

Global E&P production (kboe/d) vs Enterprise value *(UK-focused in green)*



Source: Bloomberg data (correct as of market close 3 July 2026)

The UK oil and gas sector remains a fragmented market and we think investors would respond positively to further consolidation in the small-cap sector, given the potential to cut corporate overheads such as G&A and regulatory costs. However, we do acknowledge that continued UK fiscal and regulatory uncertainty makes cash-based deals more difficult than relative value trades, especially in the current higher commodity price environment.

APPENDICES

Appendix 1: Directors and senior management

Carlos Fernandes, Finance Director

Carlos has been part of the Angus team since 2013 and has seen the Company's transition from private to public. Prior to his appointment as Finance Director, he was the Chief Financial Officer of the group.

Carlos has over 18 years commercial experience working in the Mining and Oil & Gas sectors, with particular expertise in capital management, asset development and operational financial control.

Ross Pearson, Chief Operating Officer and Executive Director

Ross has over 25 years' experience in the Oil & Gas sector, which includes experience working across Schlumberger, Devon Energy, Origin, Senex and IGas (now Star Energy).

Ross leads all operational execution, ensuring drilling, workovers and production growth are delivered safely on time and on budget.

Krzysztof Zielicki, Interim Chairman

Krzysztof has over four decades of experience in the global oil and gas industry. He has held senior leadership positions in several energy Majors, including BP, TNK/BP and Rosneft, where he was Vice President for M&A and Strategy.

Krzysztof brings deep experience in corporate strategy, asset transactions and large-scale energy projects, providing the Board with strong strategic and commercial leadership.

Antoine Valyner, Non-Executive Director

Antoine joined the board of Angus in June 2024, representing Kemexon, one of the Company's largest shareholder. He has extensive experience in origination and execution of transactions in the energy and natural resources sector.

Antoine previously worked for St James's Wealth Management, the Mirabaud Group, and IDCM (Finance/M&A advisory) in London, before taking a position in strategy and business development of the investment arm of Kemexon.

Alexander Craig, Non-Executive Director

Alexander is a Partner of Aleph Commodities, with expertise in commodities, infrastructure and asset management. He has significant experience in investment, trading and the redevelopment of complex and distressed assets.

Previously, Alexander was a founding partner at Omikron Partners and Liberty Street Partners, and a portfolio manager at Tiverton Trading, as well as serving on the advisory board of Taurus Investment Holdings.

Richard Glass, Non-Executive Director

Richard has over 25 years' experience in investment, development and the leadership of complex, multi-disciplinary projects. An entrepreneur with a strong track record in mergers and acquisitions, he has founded and partnered with institutional investors across a number of successful businesses.

Richard has previously held senior roles with an international bank and continues to advise selected financial institutions.

Appendix 2: Major shareholders

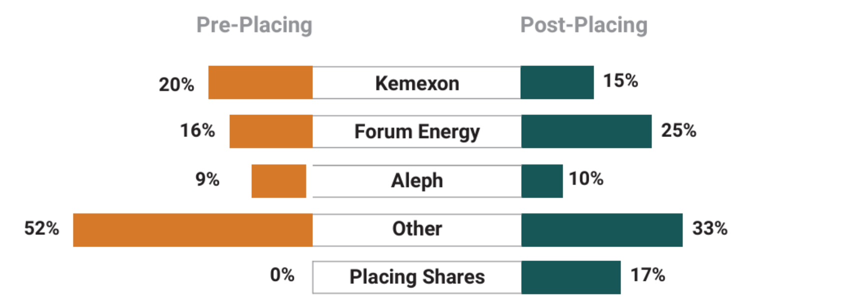
Angus was first admitted to trading on AIM (London Stock Exchange) in 2016, at which point the company was producing oil from the Brockham and Lidsey fields in southern England. The Company acquired an interest in the Balcombe field in early 2018 and applied for planning permission for an extended well test at the site in 2019 but was then hampered by planning objections.

Instead, the Company was recapitalised in 2021 to fund the Saltfleetby gas redevelopment, which achieved first gas in 3Q22. While the stock initially performed well following first production into an unusually high gas price environment, the shares subsequently declined due to operational issues and the introduction of the EPL windfall tax. This share price decline accelerated as the full extent of Angus' liquidity issues became known, which were a result of over £25m worth of accumulated development cost overruns and hedges.

The prior management team were replaced in mid-2023, since when Board control has been exerted by the financiers and original owners of the Saltfleetby project. In 2Q25, Angus proposed a reverse takeover transaction of certain US assets, and accordingly, the Company's shares were suspended from trading. Although the proposed acquisition was later abandoned, the Company remained suspended from trading while it completed a financial restructuring.

In late 2Q26, Angus signed conditional restructuring agreements with all of its key creditor groups (Trafigura, the Royalty Holders and Forum Energy Services). Following shareholder approval of the financial restructuring and a £3m equity fund raise at 0.2p/sh, the shares returned to trading on AIM in July 2026.

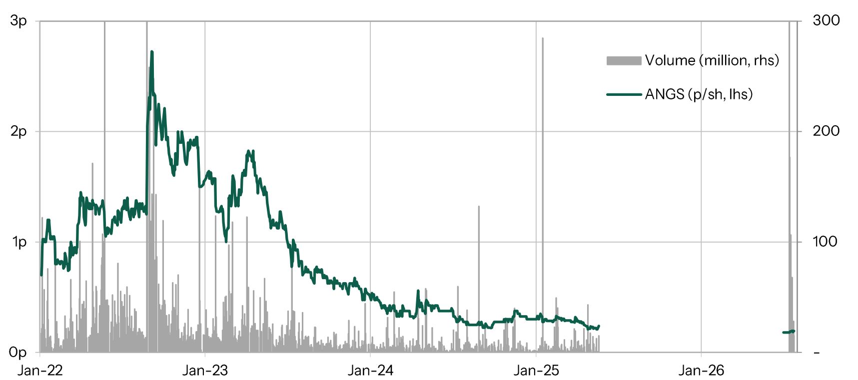
Pre- and post-equity placing share structure



Source: Company

The shares have now resumed trading on AIM and we estimate that roughly half of the issued ordinary shares of Angus are now held by the public. We expect trading in the Company's shares to now exhibit a relatively strong liquidity and turnover position on the AIM market.

Historic stock price and trading volumes

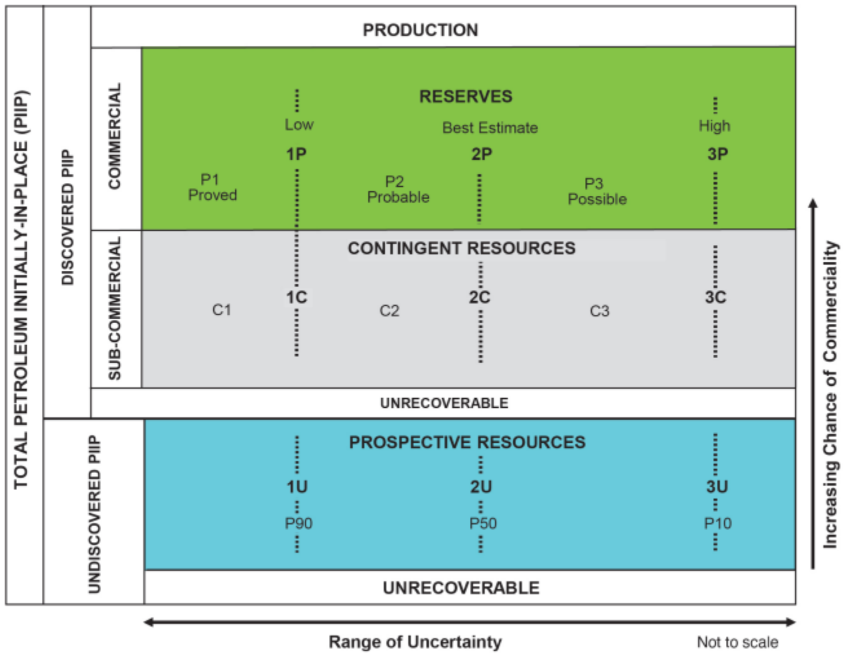


Source: Bloomberg

Appendix 3: SPE Petroleum Resources Management System (PRMS)

The figure below graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Resources. The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality (Pc), which is the chance that a project will be committed for development and reach commercial producing status.

Resources classification framework (SPE-PRMS)



Source: SPE

The following definitions apply to the major subdivisions within the resources classification:

- **Total Petroleum Initially-In-Place (PIIP)** is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.
- **Discovered PIIP** is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.
- **Production** is the cumulative quantities of petroleum that have been recovered at a given date.

When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

- There should be at least a 90% probability (**P90**) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (**P50**) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10 probability (**P10**) that the quantities actually recovered will equal or exceed the high estimate.

Multiple development projects may be applied to each known or unknown accumulation, and each project will be forecast to recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into commercial, sub-commercial, and undiscovered, with the estimated recoverable quantities being classified as reserves, contingent resources, or prospective resources respectively, as defined below.

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied. Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from reserves. Reserves are further categorized in accordance with the range of uncertainty and should be sub classified based on project maturity and/or characterized by development / production status.

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the range of uncertainty associated with the estimates and should be sub-classified based on project maturity and/or economic status.

Undiscovered PIIP is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of geologic discovery and a chance of development. Prospective Resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.

Unrecoverable Resources are that portion of either discovered or undiscovered PIIP evaluated, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered because of physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

The sum of reserves, contingent resources, and prospective resources may be referred to as "**remaining recoverable resources**." Importantly, these quantities should not be aggregated without due consideration of the technical and commercial risk involved with their classification. When such terms are used, each classification component of the summation must be provided. Other terms used in resource assessments include the following:

Estimated Ultimate Recovery (EUR) is not a resources category or class, but a term that can be applied to an accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities already produced from the accumulation or group of accumulations. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.

Technically Recoverable Resources (TRR) are those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations. TRR may be used for specific projects or for groups of projects, or can be an undifferentiated estimate within an area (often basin-wide) of recovery potential.

Appendix 4: Key risks

Exploration and production risks

There is no assurance that Angus' development and appraisal activities will be successful or, if they are successful, that commercial quantities of oil or gas can be recovered from the targeted areas. No assurance can be given that of the commercial reserves proven, that the Company will be able to realise such reserves as intended. Negative results from drilling programmes may result in downgrading their prospectivity. An area may therefore be considered not to merit further investment and licences could be surrendered (subject to the approval of the licensing authority) prior to a potential development.

Regulatory changes

The Company's strategy has been formulated in the light of the current UK regulatory environment and likely future changes. The regulatory environment has changed considerably in the past decade and may change again in the future, and such changes may have a material adverse effect on Angus.

Licences and contractual risks

Angus' activities are dependent upon the grant and maintenance of appropriate licence concessions, leases, permits and regulatory consents which may not be granted or may be withdrawn or made subject to limitations. Unforeseen circumstances or circumstances beyond the control of the Company may lead to commitments given to licensing authorities not being discharged on time. Although the Company believes that the authorisations will be renewed following expiry or grant (as the case may be), there can be no assurance that such authorisations will be renewed or granted or as to the terms of such grants or renewals.

Operational and environmental risks

Drilling, appraisal, exploration, construction, development and production activities may involve significant risks and operational hazards and environmental, technical and logistical difficulties. These include, inter alia, the possibility of uncontrolled hydrocarbon emissions, fires, earthquake activity, extreme weather conditions, coastal erosion, explosions, blowouts, cratering, over-pressurised formations, unusual or unexpected geological conditions, unpredictable drilling-related problems, equipment failure, labour disputes and the absence of economically viable reserves. These hazards may result in delays or interruption to production, cost overruns, substantial losses and/or exposure to substantial environmental and other liabilities. Existing and possible future environmental legislation, regulations and actions could cause additional expense, capital expenditures, restrictions and delays in the activities of the Company, the extent of which cannot be predicted. No assurance can be given that new rules and regulations will not be enacted or that existing rules and regulations will not be applied in a manner, which could limit or curtail production or development.

Non-achievement of anticipated timetables

Drilling rigs or other equipment may not be available at the time envisaged (due to, for example, delays in making appropriate modifications, adverse weather conditions, insolvency of the owners or total loss) or may fail to perform in accordance with the Board's expectations in regard to the timetable. There is no guarantee that replacement equipment will be available on reasonable commercial terms or at all. Failure to meet the expected timetables may result in the Company being unable to generate cash from those assets. This would have a material adverse effect on the Company's business, prospects, financial condition and operations. If the timetable estimates prove to be wrong or the operators or any of them do not take the actions in relation to maintaining or developing the assets then it may lead to delays or further problems which may have a material adverse effect on the Company's business, prospects, financial condition and operations.

Early-stage licence development with no proven reserves

Part of the portfolio in which Angus holds an interest is in the pre-production stage of development and future success will depend on the Company's ability to successfully manage the Lidsey field and to take advantage of further opportunities which may arise. There can be no guarantee that the Company can or will be able to, or that it will be commercially advantageous for the Company to, develop any acreage subject to any tenement, permits or licences in which the Company has or may acquire an interest.

Reserve and resource estimates

Any future reserve and/or resource figures for projects in which the Company may invest, or may acquire, will be estimates and there can be no assurance that the oil, gas and hydrocarbons are present, will be recovered or that they can be brought into profitable production. Reserves and resources estimates may require revisions based on actual production experience. Furthermore, a decline in the market price for oil and gas that may be discovered could render oil and gas reserves containing relatively low volumes of hydrocarbons uneconomic to recover and may ultimately result in a restatement of reserves.

Environmental regulation

Environmental and safety legislation in jurisdictions in which the Company operates may change in a manner that may require stricter or additional standards than those now in effect, a heightened degree of responsibility for companies and their directors and employees, and more stringent enforcement of existing laws and regulations. There may also be unforeseen environmental liabilities resulting from oil and gas activities, which may be costly to remedy. In particular, the acceptable level of pollution and the potential clean-up costs and obligations and liability for hazardous substances for which the Company may become liable as a result of its activities, may be impossible to assess against the current legal framework and enforcement practices of the various jurisdictions in which the Company operates, or in which it may operate in the future.

Market risk

In the event of successful exploration and development of oil and gas reserves, the marketing of the Company's prospective production of oil and gas from such reserves will be dependent on market fluctuations and the availability of processing and refining facilities and transportation infrastructure, including access to ports, shipping facilities, pipelines and pipeline capacity at economic tariff rates, over which the Company may have limited or no control. Pipelines may be inadequately maintained and subject to capacity constraints and economic tariff rates may be increased with little or no notice.

Increase in drilling and production costs, and availability of equipment

The oil and gas industry historically has experienced periods of rapid cost increases. Increases in the cost of exploration, production and development would affect the Company's ability to invest in prospects and to purchase or hire equipment, supplies and services. In addition, the availability of drilling rigs and services is affected by the level and location of drilling activity around the world.

Volatility of commodity prices

The demand for, and price of, oil and gas are highly dependent on a variety of factors, including international supply and demand, weather conditions, the price and availability of alternative fuels, actions taken by governments and international cartels, and global economic and political developments. International oil and gas prices have fluctuated widely in recent years and may continue to fluctuate significantly in the future.

Funding

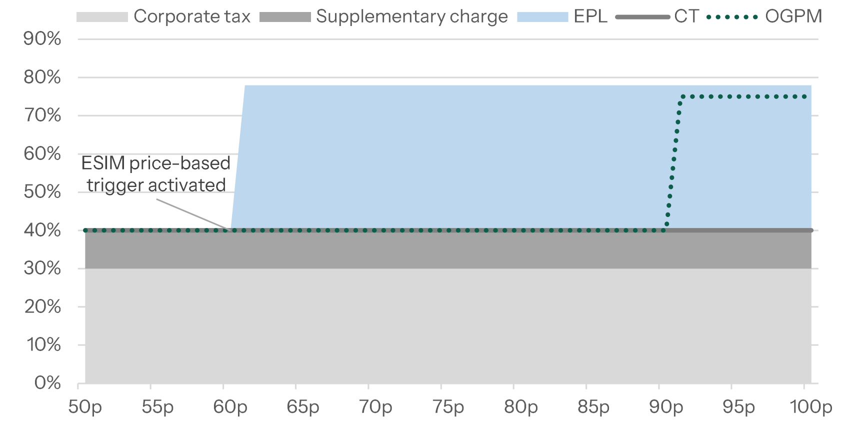
Angus expects to generate sufficient cash flows from its operations to pay for its ongoing costs but may require equity raisings and debt funding, as well as asset sales or farmouts, to fund additional long-term commitments. The Company's listing on the London AIM market also provides Angus with a form of potential consideration to vendors of acquisition opportunities.

Appendix 5: UK fiscal and regulatory regime

With the corporate income tax rate on oil and gas companies already at 40%, the UK government introduced the Energy Profit Levy (EPL) as a windfall tax in May 2022 in response to high prices. This was increased from 25% to 35% in January 2023 and again to 38% in November 2024, which has lifted the effective tax rate to 78% on ring-fenced profits with a maximum relief rate of 84.25% for companies in a tax-paying position. The EPL is in place to March 2030 unless the Energy Security Investment Mechanism (ESIM) triggers removal, with current thresholds at $78.65/bbl for Brent oil prices and at 61p/therm for NBP gas prices.

However, the UK government announced plans in November 2025 to overhaul the windfall tax on oil & gas producers once the current levy expires in 2030, or earlier if the ESIM price-based triggers are activated. The Oil and Gas Price Mechanism (OGPL) will subsequently replace the EPL, will apply separately to oil and to gas and will tax only the proportion of revenue earned above new CPI-linked OGPL trigger levels of $90/bbl and 90p/therm, while the underlying headline tax rate returns to 40%. The new OGPL mechanism is designed to boost tax revenues during periods of higher prices, while also ensuring that the industry has the clarity it needs regarding the future fiscal landscape.

UKCS tax rates (%) at various natural gas prices (p/therm)



Source: SP Angel

In Spring 2025, the UK government launched a consultation on the future of North Sea exploration licensing, following its pledge to end new licence awards. The review aimed to balance climate goals with energy security and investor confidence, ensuring a managed production decline. The result in late 2025 was the North Sea Future Plan (NSFP), which reconfirmed the government's commitment that all existing licences will be honoured, and licence extensions can be granted, but that no new exploration licences would be issued. However, the government's NSFP did introduce a new concept of Transitional Energy Certificates (TECs), which are designed to support further development in currently unlicensed areas adjacent to existing licensed blocks.

The NSFP envisages an ongoing and enhanced role for the North Sea Transition Authority (NSTA), the UK oil and gas regulator, including three objectives which the government stated it would introduce in forthcoming legislation:

- to maximise economic value to the UK
- to support the Energy Secretary in meeting net zero goals
- to consider the impact [of activities] for North Sea workers, communities, and supply chains

The NSTA will have a balancing requirement set out in law to weigh up and balance these three objectives as it best sees fit. These measures are subject to government introducing new legislation in the Energy Independence Bill, which is intended to deliver the government's promise of protecting existing jobs and creating the next generation of good jobs in sectors such as clean energy. In the future, the UK may adopt an approach similar to Norway's APA rounds (new licences located near existing infrastructure), reverse the licence ban like New Zealand or continue the current pivot to phase out the sector like Denmark.

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