Press release

20 August 2025

ITHACA ENERGY PLC
("Ithaca Energy", the "Company" or the "Group")
First Half Results for the Six Months to 30 June 2025

Excellent H1 performance
Guidance upgrade for the full year reflects improved organic production performance and value-driven capital investment across the portfolio

Ithaca Energy today announced its unaudited financial results for the six months ended 30 June 2025.

Key H1 2025 highlights– Strong production and adjusted EBITDAX supporting investment in value-accretive growth and shareholder distributions:

- Materially transformed business delivering consistently robust performance:
  - Significant improvements in safety and environmental performance, with >50% reduction in incident frequency and emissions
  - H1 2025 average production of 123.6 kboe/d (H1 2024: 53.0 kboe/d)
  - Adjusted H1 2025 EBITDAX over $1.1 billion (H1 2024: $533.0 million)
  - Material reduction in opex per barrel to $17.5/boe in H1 2025 from $27.3/boe in H1 2024
  - Low pro forma leverage position of 0.32x with available liquidity of over $1.2 bn
  - Additional 9 mmboe of oil hedges added in Q2 providing material cash flow protection
- Continuing to deliver highly attractive shareholder returns
  - First interim 2025 dividend of $167 million declared today, representing dividend per share of $0.101, supporting the reaffirmation of the Group's FY 2025 dividend target of $500 million
  - Expected acceleration of second interim 2025 dividend to December 2025, of $133 million, due to strong year-to-date performance and cash generation totalling $500 million of cash distributions in 2025
- Increased and targeted organic investment supporting production upside, reliability enhancement and efficiency focus alongside incremental investment in high return wells in the year
- Significant progress towards unlocking long-term value creation in West of Shetland area through targeted value-led investment:
  - Rosebank project execution progressing on all work fronts. Full project update to be completed Q4 2025
  - 18-month Cambo licence extension and completion of technical refresh provides a clear pathway towards FID and potential farm-down
  - Tornado gas discovery prospect advancing through FEED towards FID, with NSTA no-objection to the concept secured
- Execution of UKCS growth strategy, increasing interests in high-quality, well-understood assets:
  - Japex UK E&P acquisition completed 7 July 2025 demonstrating deal execution capability
  - Acquisition of a further 46.25% stake in the Cygnus Field from Spirit Energy expected to complete 1 October 2025, following receipt of NSTA approval

FY 2025: An improving outlook driven by excellent delivery

- Strong first half performance and ongoing investment supporting upgrade to FY guidance:
  - FY production guidance range upgraded to 119–125 kboe/d from 109-119 kboe/d, (representing a 8 kboe/d increase at the mid-point)
  - Strong cost control with FY net operating cost guidance range reduced to $790–840 million (representing an Opex per barrel cost of between $17/boe to $19/boe) with cost reductions outweighing FX headwinds
  - Modest increase in net producing asset cost capital guidance to $630-670 million reflecting non-cash FX headwinds and decisions to increase investments in support of production upside potential in the J Area by sanctioning additional well activity
  - Net Rosebank capital cost guidance range increased to $230-270 million with additional spend towards end of 2025 as the Floating Production Storage and Offloading vessel (FPSO) nears yard work completion and targeted sail-away date and reflecting non-cash FX headwinds

Executive Chairman, Yaniv Friedman, commented: "Our first-half results demonstrate the strength and resilience of our transformed business. With production more than doubling year-on-year and adjusted EBITDAX exceeding $1.1 billion, we are delivering on our strategy of disciplined investment and operational excellence. As we adjust our guidance upwards for the remainder of the year, we continue to remain focused on maximising long-term value creation and returns for our shareholders. The declaration of a $167 million interim dividend and expected acceleration of a second interim dividend of $133 million to December 2025, underscores our commitment to delivering sustainable value to shareholders, reaffirming our full-year dividend target of $500 million. Strategic progress across our West of Shetland developments and recent acquisitions executing on our UKCS growth strategy, further position us for long-term growth."

Financial key performance indicators (KPIs)

	H1 2025	H1 2024
Adjusted EBITDAX[1] ($m)	**1,117.0**	533.0
Profit before tax ($m)	**513.4**	189.4
Adjusted net income[1] ($m)	**128.7**	124.7
(Loss)/profit for the period[2] ($m)	**(217.5)**	105.7
Basic EPS (cents)	**(13.2)**	10.5
Net cash flow from operating activities ($m)	**1,004.6**	559.8
Unit operating expenditure[1] ($/boe)	**17.5**	27.3

	H1 2025	Q4 2024
Available liquidity[1] ($m)	**1,228.6**	1,015.1
Adjusted net debt[1] ($m)	**671.4**	884.9
Pro forma leverage ratio[1]	**0.32x**	0.45x

Other KPIs

	H1 2025	H1 2024
Total production (boe/d)	**123,566**	53,046
Tier 1 & Tier 2 process safety events	**0**	0
Serious injury and fatality frequency	**0**	0

[1] Non-GAAP measure as set out on pages 48 to 51

[2] Reflects one-off, non-cash deferred tax charge in Q1 2025 of $327.6 million due to the two-year extension of EPL to 31 March 2030

H1 2025 Strategic Highlights

Successfully executing the Group's organic and inorganic value-orientated growth strategy, with a clear vision for further scale, stability and strength as we seek to maximise long-term value creation and returns for our shareholders.

Organic growth: Investing to sustain and optimise production

- Significant ongoing investment and well activity at Captain in H1 with progression of the 13th drilling campaign, including a work over on well C47, and successful drilling, completion and production start-up of wells C73 and C74. Enhanced Oil Recovery (EOR) phase II well response remains in line with expectations
- The Safe Caledonia flotel arrived at the Captain field in June to support backlog reduction and optimisation activities throughout the remainder of 2025
- Cygnus infill well campaign commenced with the first of the two firm wells spud in H1 2025, with first production from the first well expected in October, and a second well scheduled for Q4
- Value-led investment in J Area focused on high-return opportunities with additional well activity sanctioned at Judy East Flank and investment in Joanne well stimulation activity, based on continued strong performance in the area
- Final planned Seagull well currently being completed, with first production expected in Q4
- Summer shutdown activity progressing well to plan, with significant activity delivered in line with schedule during Q3

Organic Growth: Unlocking value creation opportunities in the West of Shetland area

- Improved regulatory and fiscal clarity:
  - Publication of the UK Government's Scope 3 Environmental Impact Assessment guidance in June 2025 welcomed, supporting the reopening of OPREDs consenting process and unlocking the Group's high-value, long-life resource base, particularly in the West of Shetland, that will support UK energy security for decades to come
  - Active participant in the UK Government's EPL successor regime consultation that seeks to establish an oil and gas price mechanism for future price shock scenarios, with outcome of consultation expected in Q4 2025
- Rosebank development project activity ramping up in preparation for key project milestones towards first production timeline of 2026/27
  - Additional 2025 capital spend forecast on FPSO modifications to maintain sail-away date
  - Critical subsea installation scopes well-advanced with drilling scheduled for Q1 2026
  - Application for refreshed consents proceeding in tandem, with OPRED formally requesting a revised submission following the publication of the Scope 3 assessment guidelines
- Cambo licence extended by 18 months from 31 March 2026 to 30 September 2027, confirming the regulator's trust in the Group's ability to continue progressing the project towards the licence milestones
- Cambo project technical refresh delivered in H1 2025, leveraging the technical capabilities of Eni to challenge and optimise the development concept, with the aim of maximising project value and mitigating risks. During H2, the Field Development Plan and Environmental Statement will be updated to reflect the project optimisations, supporting the progression towards a Final Investment Decision (FID) and potential farm-down, subject to fiscal and regulatory clarity
- Significant progression towards unlocking material organic growth opportunities across the Group's resource base in H1:
  - NSTA approval of the Fotla and Tornado Development Concepts
  - Environmental Statements submission for both Fotla and Tornado projects is the next key milestone

Inorganic growth: Pursuing consolidation strategy in UKCS, increasing stakes in key assets

- M&A activity in H1 aligned with Group's strategy to pursue low-risk consolidation in its core UKCS basin. The bolt-on acquisitions have increased the Group's ownership stakes in key assets across the portfolio, at attractive investment metrics, where the Group believes additional upside potential exists
- The Group continues to maintain an active but patient pursuit of M&A opportunities both in the UKCS and globally, in line with its focused international expansion strategy, as set out at the Capital Markets Day earlier this year

Acquisition of JUK completed 7 July 2025 demonstrating execution capabilities:

- Increased stake in well-understood, high-quality, long-life Seagull field from 35% to 50%, adding pro forma 2025 production of approximately 4 - 4.5 kboe/d
- Transaction includes JUK's material tax losses of approximately $215 million in both ring fence corporation tax (RFCT) and supplementary charge (SC) as well as approximately $105 million EPL losses as at the effective date of 1 January 2024, reflecting JUK's material investment in the field
- Completion payment of $136 million reflecting economic effective date of 1 January 2024 and completion adjustments (Transaction consideration of US$193 million)
- Acquisition equates to a valuation of ~$10/boe (excluding tax losses)

Acquisition of 46.25% stake in the Group's operated Cygnus Field from Spirit Energy:

- Increased stake in high-margin, low-emission operated Cygnus gas field, adding additional gas production to the portfolio
- Attractive investment metrics achieved, equating to a valuation of < $7/boe per 2P Reserves (circa $10/boe including decommissioning costs net of tax)
- Ongoing infill drilling in area, with further upside potential
- Adding circa 12.5 – 13.5 kboe/d net production on a pro forma basis, and circa 4 kboe/d net annualised increase assuming a targeted completion date of 1 October 2025, with NSTA approval received

Value creation and shareholder returns: Continued delivery of dividend commitments

- First interim 2025 dividend of $167 million declared today and payable in September, representing a dividend per share of $0.101
- Expected acceleration of second interim 2025 dividend to December 2025 of $133 million, due to strong year-to-date performance and cash generation
- Reaffirming dividend policy for 2025, of 30% post-tax cash flow from operations (CFFO), at the top end of our capital allocation policy range of 15-30% post-tax CFFO, with today's dividend announcement supporting the Group's FY 2025 dividend target of $500 million

H1 2025 Operational Update

- Consistently improved performance across all operational metrics
- Strong process safety performance with zero Tier 1 or Tier 2 events recorded in the first half of the year and a material reduction in Total Recordable Injury rate (TRIR) of over 50% from 2024, with 1.14 cases per million hours from 2.6 in H1 2024
- Significant reduction in Greenhouse Gas (GHG) emission intensity of the Group's portfolio, bringing our gross operated emissions intensity to 16.9 $kgCO_2e$/boe from 33.9 $kgCO_2e$/boe in H1 2024
- Average H1 production of 123.6 kboe/d (H1 2024: 53.0 kboe/d), reflecting record quarterly production in Q1, the operating capacity of the Group's diversified and enlarged portfolio, and consistently strong operational performance
  - H1 2025 production split 59% liquids, 41% gas and 40% operated, 60% non-operated

- Improved operational performance highlighted by material improvement in production efficiency in H1 across the Group's operated asset base (consistently achieving higher than 2024 average of 80% and 2024 industry average of 75%)
- H1 2025 production reflects:
  - Planned summer shutdown activity commenced in June across the portfolio including Cygnus and the Greater Stella Area, ahead of significant turnaround activity in Q3
  - Production efficiency consistently above basin average and 2024 actual during H1, with strong delivery at the Group's operated Captain and Cygnus assets as well as the non-operated Elgin Franklin, J Area, Seagull, GBA, Schiehallion and Mariner assets

H1 2025 Financial Highlights

- H1 2025 adjusted EBITDAX of $1,117.0 million (H1 2024: $533.0 million), following record quarterly adjusted EBITDAX performance in Q1 of $653.2 million
- Realised prices of $71/boe for oil and $71/boe for gas before hedging results and $73/boe for oil and $71/boe for gas after hedging results (H1 2024: $87/boe for oil and $57/boe for gas before hedging results and $86/boe for oil and $92/boe for gas after hedging results)
- H1 2025 operating costs of $391.3 million (H1 2024: $263.3 million) and unit operating expenditure of $17.5/boe (H1 2024: $27.3/boe) demonstrating operational efficiencies and the high netback capability of the portfolio
- H1 2025 profit before tax of $513.4 million (H1 2024: $189.4 million)
- H1 loss for the period of $217.5 million (H1 2024: profit of $105.7 million) reflecting primarily a one-off, non-cash deferred tax charge in Q1 2025 of $327.6 million due to the two-year extension of EPL to 31 March 2030. H1 2025 adjusted net income of $128.7 million (H1 2024: $124.7 million)
- H1 2025 producing assets capex of $290 million (H1 2024: $178 million) and Rosebank capex of $130 million (H1 2024: $90 million)
- Net cash flow from operating activities of $1,004.6 million (H1 2024: $559.8 million) includes an increase in underlift during H1 of $99.1 million, substantively all of which is expected to reverse through the remainder of FY 2025
- Reduction in adjusted net debt at 30 June 2025 to $671.4 million (31 December 2024: $884.9 million)
- Pro forma leverage ratio at 30 June 2025 of 0.32x (31 December 2024: 0.45x)
- Material available liquidity at 30 June 2025 of $1,228.6 million (31 December 2024: $1,015.1 million) reflecting reduction in net debt and providing a solid financial foundation for growth with additional available accordion of over $700 million providing incremental liquidity potential of up to circa $2bn
- Material build on hedge position during Q2, with 9 million barrels of positions traded at attractive hedge prices during the higher commodity price window in June, to complement existing gas hedge book, providing strong cash flow cover in 2025 and 2026. As at 30 June 2025, the Group had 38.9 million barrels of oil equivalent (47% oil) hedged from Q3 2025 into 2027 at an average floor price of $69/bbl for oil swaps, $68/bbl for oil puts/collar floors and 99p/therm for gas swaps, and 81p/therm for gas puts/collar floors

FY 2025 Management Guidance

- Management provides the following updates to guidance ranges for full year 2025 (updated from 21 May 2025), reflecting excellent operational performance in the first half of the year and continued organic value-driven capital investment supporting production upside with increased investment in high-return wells in the year:
  - FY 2025 **production guidance range upgraded to 119–125 kboe/d** from 109-119 kboe/d, driven by core asset production performance in H1 (acquisition production unchanged from previous guidance) and reflecting planned summer turnaround activity
  - FY 2025 **net operating cost guidance range reduced to $790–840 million** from $780–860 million (representing an Opex per barrel cost of between $17/boe to $19/boe) with cost reductions outweighing FX headwinds
  - FY 2025 **net producing asset capital cost guidance range increased to $630-670 million** from $580-640 million (excluding pre-FID projects and Rosebank development) reflecting non-cash FX headwinds and decisions to increase investments to support production upside potential in the J Area by sanctioning additional well activity
  - FY 2025 **net Rosebank project capital cost guidance range increased to $230-270 million** from $190-230 million due to additional capital spend expected towards the end of 2025 as the FPSO nears yard work completion and targeted sail-away date and reflecting non-cash FX headwinds
  - FY 2025 **cash tax guidance increased to $270-300 million** from $235-265 million mainly due to increased production and profits in newly integrated entities
- Management guidance includes the acquisition of Japex UK E&P from the completion date of 7 July (previous guidance assumed 1 July completion) and the acquisition of an additional 46.25% stake in the Cygnus gas field based on an estimated completion date for the transaction of 1 October 2025 (on the same basis as previously provided guidance)
- Management updates the Group's expected production exit rate at the end of 2025 to circa 140 kboe/d
- Management reaffirms the dividend target of $500 million for 2025 and due to excellent operational performance anticipates being able to accelerate the timing of payments with $133 million targeted for payment in December and $200 million targeted for payment in April 2026, resulting in $500 million dividend for 2025 and $500 million cash dividend paid in 2025 including the final interim 2024 dividend of $200 million in April 2025

Webcast and Conference call

Ithaca Energy will host a virtual presentation and Q&A session for investors and analysts at 09:00 (BST) today, 20 August 2025. Details are accessible via our website.

Investors and Analysts – Webcast link

https://www.investis-live.com/ithaca-energy/6865342c1efae0000ed06921/grefc

Investors and Analysts – Conference call

Operator Assisted Dial-In: United Kingdom (Local): +44 20 3936 2999 United Kingdom (Toll-Free): +44 800 358 1035 Global Dial-In Numbers Access Code: 841877

Half Year 2025 performance in review

Delivering production and reserves growth through targeted investment and optimisation

The Group delivered a strong first half performance strategically, operationally and financially, highlighted by record quarterly production and adjusted EBITDAX in Q1. Our H1 2025 results reflect the continued and reliable execution across all pillars of our strategy delivering further scale, stability and strength as we seek to maximise long-term value creation and returns for our shareholders.

In H1 2025, the Group has delivered production and reserves growth both organically and inorganically. Our focus on optimising production to deliver organic growth has resulted in a strong H1 operational performance supporting an improved and upgraded production outlook for the full year. With a focus on targeted and increased investment, the Group is well positioned to deliver on short-return investment opportunities while continuing to make material progress to advance its high-value, long-life resource base, primarily in the West of Shetland, towards final investment decisions that will be linked to the fiscal and regulatory environment following the recent government consultations.

Improved H1 operational performance across all key metrics

The Group's commitment to responsible operations and sustainable value creation, driven by a relentless focus on operational excellence to sustain and optimise production performance, has led to improvements across all key operational metrics in the first half of the year. This has delivered improvements in safety and environmental performance, higher production efficiency, and a reduction in operating cost per barrel. These metrics are embedded across the organisation with a consistent focus on achieving the 'perfect day' operationally.

The Group achieved a significantly improved safety performance in H1 2025, recording zero Tier 1 and Tier 2 process safety events and a material reduction in the Group's Total Recordable Injury Rate (TRIR) to 1.14. This represents a reduction in TRIR of over 50% compared to the Group's 2024 TRIR of 2.3, and continues the positive safety trend from 2023, where the TRIR stood at 3.31.

The Group also delivered a significant improvement in its environmental performance, reflecting changes in portfolio composition with the portfolio benefitting from low-intensity assets such as Cygnus and Seagull, alongside continued investment in value-led decarbonisation activity. The Group's gross operated emissions intensity decreased to 16.9 $kgCO_2e$/boe in H1 2025 from 23.9 $kgCO_2e$/boe in 2024 (H1 2024: 33.9 $kgCO_2e$/boe), marking material progress towards its decarbonisation objectives and comparing favourably against the latest basin average of approximately 24 $kgCO_2e$/boe. In addition, the number of reportable releases to sea (spills) fell by circa 70% in H1 2025, in comparison to H1 2024, reflecting asset and operational integrity improvements.

The Group achieved record production in Q1 2025, averaging 127.4 kboe/d in the period, with this strong production performance continuing through April and May ahead of planned summer turnaround activity commencing in June. As a result, Q2 production averaged 119.8 kboe/d, delivering H1 2025 average production of 123.6 kboe/d (H1 2024: 53.0 kboe/d). Production in the six-month period was split 59% oil and 41% gas, reflecting a significant increase in gas weighting in the portfolio from H1 2024 (H1 2024 split 69% oil and 31% gas).

Production performance in H1 2025 reflects the enhanced operating capacity of the enlarged and diversified portfolio and is underpinned by operational improvements and optimisation across the Group's portfolio and consistent reliable delivery. Production efficiency performance in H1 2025 has consistently exceeded the Group's 2024 average production efficiency of 80% and the industry average of 75% in 2024, with strong operational delivery at the Group's operated Captain and Cygnus assets as well as the non-operated Elgin

Franklin, J Area, Seagull, MonArb, Schiehallion and Mariner assets, and extended plateau of the Talbot field brought online in November 2024.

Operating costs, net of tanker expenses and tariff income, totalled $391.3 million in H1 2025, in line with management's full-year guidance, reflecting the increased scale of the Group's portfolio and continued strict cost control offsetting the foreign exchange impact of a stronger GBP (H1 2024: $263.3 million). Unit operating expenditure for the period was $17.5/boe, representing a decrease of 36% from $27.3/boe in H1 2024, demonstrating improved operational efficiency and the high netback capability of the enlarged portfolio.

Total net producing asset capital expenditure (excluding decommissioning) in H1 2025 of $290 million (H1 2024: $178 million) reflects material capital spend primarily focused on infill well campaigns at Captain (13^{th} well campaign) and Cygnus (12^{th} well ongoing), and development well activities at Seagull and the J Area as well as the costs of delivering the Captain Flotel campaign focusing on life extension and optimisation activities. Net capex of $130 million in support of the Rosebank development reflects increased activity in the ongoing modification of the FPSO and material activity across subsea project scopes.

Building further Scale. Stability. Strength.

The Group has successfully executed across its organic and inorganic value-orientated growth strategy in the first half of the year, with a clear vision for further scale, stability and strength.

Organic growth – investing in long-term growth

The Group continues to deliver significant activity across its producing asset base with a strong focus on sustaining and optimising production. With a clear ambition to be the basin's top-performing operator, the Group is targeting investment toward new tie-in opportunities, asset optimisation and life extension initiatives, and infill drilling campaigns that unlock and maximise the organic value of its portfolio.

At the Group's Captain field, material investment in the field continues in support of the 13^{th} well campaign and backlog reduction and optimisation activities. In H1, the Group successfully delivered the drilling, completion and production start-up of wells C73 and C74, the work over of well C47 and responses from four out of seven EOR phase II patterns with a target of achieving full EOR II well response by the end of 2026. The Safe Caledonia flotel arrived at the Captain field in June to support backlog reduction, optimisation activities and decarbonisation scopes throughout the remainder of the year, ensuring that the facility remains safe and reliable through to the end of the field's life.

Drilling activities continued at the Group's Cygnus and Seagull assets in the period with the first of the two firm Cygnus wells commencing in H1 2025, with first production expected in October, and the second well scheduled for Q4. At Seagull, the final planned well is currently being completed, following some operational issues experienced in the period, with additional production from the field now expected in Q4.

At the non-operated J Area, value-led investment has focused on short-cycle, high-return opportunities following the successful tie-in of the Talbot and Jocelyn South fields and continued strong operational performance in the area. Additional investment activity has been sanctioned in 2025 to support the development of Judy East Flank and well stimulation activity at Joanne later in the year, highlighting both Ithaca Energy's and the operator's belief in the future for the area.

The Group continues to make strong progress in unlocking material value across its long-life, high-value resource base, predominantly in the West of Shetland. The publication of the UK Government's Scope 3 guidance in June 2025, in response to the Finch case, has provided long-awaited regulatory clarity to support the progression of key UKCS developments in alignment with the UK's energy security objectives. With fiscal certainty for long-term projects expected later this year, the Group is actively advancing key projects through its internal investment stage gates to support final investment decisions, once full regulatory and fiscal clarity is achieved.

At Rosebank, project activity is ramping up in preparation for key project milestones across its multi-year development programme towards first production timeline of 2026/27, with the application for refreshed consents proceeding in tandem with project execution. Following the publication of the Scope 3 Assessment Guidelines, OPRED has formally requested a revised submission for consent from the JV partnership with Equinor, as operator, preparing to submit the updated application in the second half of the year, with a view to securing revised consents in 2026.

From a project execution perspective, the Group is forecasting additional capital spend in 2025, predominantly in relation to increased activity to support the delivery of FPSO modifications ahead of the vessel sail-away date and expects a full project cost update from the operator in Q4. Strong progress has been made across other key scopes including subsea installation activities, ahead of planned drilling activity scheduled for Q1 2026.

In the first half of the year, the regulator granted an extension to the Cambo licence of 18 months, from 31 March 2026 to 30 September 2027, supporting the continued progression of the project towards its licence milestones. A technical refresh of the Cambo project was completed in H1 2025, leveraging the technical capabilities of Eni to challenge and optimise the development concept, with the aim of maximising project value and mitigating risks. In the second half of the year, updates to the Field Development Plan and Environmental Statement will incorporate these project optimisations, supporting the progression towards a FID and a potential farm-out, subject to fiscal and regulatory clarity, following the recent government consultations.

Across the resource base, the Group continued to make strong progress during H1 across a number of projects achieving key regulatory milestones with NSTA approval secured for the Fotla and Tornado Development Concepts. Environmental Statements submission for both projects is the next key milestone.

Inorganic growth – targeted consolidation in key assets in core UKCS basin

The Group successfully executed against its inorganic growth strategy in H1, pursuing low-risk consolidation in its core UKCS basin through the acquisitions of JUK and an additional 46.25% interest in the operated Cygnus Field from Spirit Energy. The bolt-on transactions enhanced the Group's stakes in well-understood, high-quality, long-life assets delivering near-term production growth and cash flow generation, increasing pro forma 2025 production by an estimated 16.5-18 kboe/d and adding 44 mmboe of 2P Reserves and 2C Resources as at 1 January 2025.

The Cygnus acquisition enhances the Group's stake in the UKCS's largest producing gas field, adding additional operated high-margin, low-emission gas production to its portfolio and strengthening the Group's position as a leading UKCS gas producer, delivering critical energy security to the UK.

With the successful completion of the JUK acquisition on 7 July and the Cygnus acquisition remaining on track to complete by 1 October 2025, with NSTA consent received, the Group continues to demonstrate its strong execution capabilities. Both transactions met all of the Group's stated investment criteria and were transacted at attractive valuations of ~$10/boe (excluding tax losses) and $7/boe per 2P reserves for the JUK and Cygnus acquisitions respectively. These strategic bolt-on acquisitions position the Group as a lead consolidator in the UKCS basin, delivering growth through value-accretive acquisitions in its core market that offer additional upside potential.

Robust financial position supports capital allocation priorities

Maintaining a strong and flexible balance sheet remains fundamental to delivering our capital allocation priorities. Our solid financial position supports our continued commitment to **invest** to sustain our base production, **protect** our financial position through maintaining a low leverage position and proactively hedging through the cycle to support the delivery of material **returns** to our shareholders, while retaining the financial agility to **evolve** our business through investing in organic and inorganic growth opportunities.

The Group continues to have material available liquidity, strengthening its available liquidity position in the quarter to $1,228.6 million from year end (31 December 2024: $1,015.1 million) with a reduction in the Group's adjusted net debt position of 24% at 30 June 2025 to $671.4 million (31 December 2024: $884.9 million). The Group's low pro forma leverage position of 0.32x at 30 June (31 December 2024: 0.45x) provides a solid financial foundation for future growth. The Group's Reserves Based Lending (RBL) unused accordion facility of over $700 million, secured during the 2024 refinancing, remains available to be utilised, providing incremental liquidity potential of up to circa $2bn.

In the first half of 2025, our enlarged portfolio delivered adjusted EBITDAX of $1.1 billion (H1 2024: $533.0 million) including a record quarterly EBITDAX performance in Q1 (Q1 2025 adjusted EBITDAX of $653.2 million). The Group's strong financial performance reflects not only the impact of the transformational Business Combination which created a diversified portfolio of scale, but also the optimisations being delivered to achieve a sustained period of strong operational efficiency and optimisation performance.

The Group delivered net cash flow from operating activities of $1,004.6 million (H1 2024: $559.8 million) including an increase in the Group's under lift position during H1 of $99.1 million, substantively all of which is expected to reverse through the remainder of FY 2025.

The Group recorded a profit before tax of $513.4 million in the first half of the year (H1 2024: $189.4 million), however the impact primarily of a one-off non-cash deferred tax charge in Q1 2025 of $327.6 million due to the two-year extension of EPL to 31 March 2030, results in the Group recording a loss for the six-month period of $217.5 million (H1 2024: profit of $105.7 million). The Group delivered adjusted net income of $128.7 million in the period (H1 2024: $124.7 million).

The Group continues to engage constructively with the UK Government in relation to future oil and gas fiscal policy and was an active participant in the EPL successor regime consultation that seeks to establish an oil and gas price mechanism for future price shock scenarios. It is our expectation, that the outcome of the UK Government's consultation will be shared during the Chancellor's Autumn Statement later this year, providing much-needed fiscal certainty to operators in the UK. In the interim period, we will continue to engage with His Majesty's Treasury and Revenue & Customs both as a Group and as part of industry's collective response led by Offshore Energies UK.

In the first half of the year, the Group has continued to place significant importance on protecting cash flows through its proactive hedging policy, building a material hedge position during H1, with 9 million barrels of oil positions traded at attractive hedge prices during the higher commodity price window in June, to complement its existing strong gas hedge book, to provide strong cash flow cover in 2025 and 2026. As at 30 June 2025, the Group had 38.9 million barrels of oil equivalent (47% oil) hedged from Q3 2025 into 2027 at an average floor price of $69/bbl for oil swaps, $68/bbl for oil puts/collar floors and 99p/therm for gas swaps, and 81p/therm for gas puts/collar floors.

Ithaca Energy's commitment and track record for delivering attractive and sustainable returns continues into 2025, with the Group reaffirming its commitment to its dividend policy for 2025, targeting a dividend of 30% post-tax CFFO, at the top end of our capital allocation policy range of 15-30% post-tax CFFO, with a target of $500 million for FY 2025. In line with this policy, the Group has declared its first interim 2025 dividend of $167 million payable in September 2025. This follows the payment of the third interim 2024 dividend of $200 million paid in April 2025, delivering total 2024 dividends of $500 million, in line with the Group's 2024 target. Due to excellent operational performance in year we anticipate being able to accelerate the timing of remaining 2025 dividend payments with $133 million targeted for payment in December and the remaining $200 million targeted for payment in April 2026, resulting in $500 million cash dividend in total during 2025.

FY 2025 outlook

We enter the second half of the year in a position of significant strength, with a clear vision for further scale, stability and strength as we seek to invest across our range of growth opportunities to maximise long-term value creation and returns for our shareholders. The Group's successful execution across its strategic pillars in H1 2025, has further strengthened our foundations for future growth, demonstrated by top quartile production performance, operational excellence and further value-accretive consolidation activities in our core UKCS basin, building scale in assets where we see long-term value.

The Group's excellent H1 performance and 2025 outlook reflects robust operations in the first half of the year and continued organic investment, including increased value-led capital allocation to high-return wells supporting future production upside. Management guidance for the full year incorporates the acquisition of JUK from its completion date of 7 July, and the acquisition of an additional 46.25% interest in the Cygnus gas field, with completion expected and on course for 1 October 2025.

Against this backdrop, management provides updates to its previously provided guidance ranges for full year 2025:

Upgrade in 2025 **production guidance to 119–125 kboe/d from 109-119 kboe/d**, driven by core asset production performance in H1 (acquisition production unchanged from previous guidance), and reflecting planned summer turnaround activity.

Following completion of the acquisition of JUK and the planned completion of the acquisition of an additional 46.25% stake in the Cygnus field, targeted for 1 October 2025, the Group expects to exit the year with a production rate of circa 140 kboe/d, positioning Ithaca Energy as the largest producer in the UKCS basin, providing a platform for material cash generation and growth.

Our net operating cost guidance for 2025 of $790–840 million reflects a reduction of the Group's guidance range from $780–860 million, representing an Opex per barrel cost of between $17/boe to $19/boe, with cost reductions outweighing FX headwinds.

Our net producing asset capital cost guidance range for 2025 of $630-670 million (excluding pre-FID projects and Rosebank development) reflects an increase from previously provided guidance of $580-640 million reflecting non-cash FX headwinds and decisions to increase investments to support production upside potential in the J Area by sanctioning additional well activity.

Our net Rosebank project capital cost guidance range for 2025 is expected to increase to $230-270 million from $190-230 million due to additional capital spend expected towards the end of 2025 as the FPSO nears yard work completion and targeted sail-away date and reflecting non-cash FX headwinds.

Estimated cash tax payments in 2025 are expected to increase to $270-300 million from $235-265 million due to increased production and profits in newly integrated entities.

Enquiries

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Notes:

[1] Non-GAAP measure

About Ithaca Energy plc

Ithaca Energy is a leading UK independent exploration and production company with a strong track record of material value creation. In recent years, the Company has been focused on growing its portfolio of assets through both organic investment programmes and acquisitions and has seen a period of significant M&A driven growth centred upon three transformational acquisitions in recent years, including the recent Business Combination with Eni UK. Today, Ithaca Energy is one of the largest independent oil and gas companies in the United Kingdom Continental Shelf (the "UKCS"), ranking second largest independent by production with the largest resource base.

With stakes in six of the ten largest fields in the UKCS and two of UKCS's largest pre-development fields, and with energy security currently being a key focus of the UK Government, the Group believes it can utilise its significant reserves and operational capabilities to play a key role in delivering security of domestic energy supply from the UKCS.

Ithaca Energy serves today's needs for domestic energy through operating sustainably. The Group achieves this by harnessing Ithaca Energy's deep operational expertise and innovative minds to collectively challenge the norm, continually seeking better ways to meet evolving demands.

Ithaca Energy's commitment to delivering attractive and sustainable returns is supported by a well-defined emissions-reduction strategy with a target of achieving net zero ahead of targets set out in the North Sea Transition Deal.

Ithaca Energy plc was admitted to trading on the London Stock Exchange (LON: ITH) on 14 November 2022.

-ENDS-

Financial performance: (loss)/profit for the period, revenue, costs and adjusted EBITDAX

The loss for the period was $217.5 million (H1 2024: profit of $105.7 million) reflecting principally a one-off, non-cash deferred tax charge of $327.6 million due to the two-year extension of the 38% EPL rate to 31 March 2030.

Adjusted EBITDAX[2] is a key measure of operational performance delivery in the business and amounted to $1,117.0 million (H1 2024: $533.0 million) mainly reflecting the higher production, resulting primarily from the Eni UK Business Combination, as well as improved operational performance partly offet by a lower level of hedging gains compared to H1 2024. After a record Q1 2025 EBITDAX of $653.2 million, Q2 2025 EBITDAX was $463.8 million with the reduction mainly due to lower production and lower realised commodity prices.

Average realised oil prices for H1 2025 were $71/boe before hedging and $73/boe after hedging (H1 2024: $87/boe before hedging and $86/boe after hedging). Average realised gas prices for H1 2024 were $71/boe both before and after hedging (H1 2024: $57/boe before hedging and $92/boe after hedging).

During the period, operating costs net of restructuring costs, tanker costs and tariff income were $391.3 million (H1 2024: $263.3 million). The reduction in unit operating expenditure to $17.5/boe from $27.3/boe in H1 2024 reflects the combined impact of improved operational efficiency, the impact of the higher production on a substantial fixed operational spend level and the addition of the Eni UK assets which have a significantly lower operating expenditure per boe.

Adjusted EBITDAX analysis

	H1 2025		H1 2024		FY 2024	
Production	**kboe/d**	**mmboe**	kboe/d	mmboe	kboe/d	mmboe
Oil	67	12	34	6	41	15
Gas	51	9	16	3	25	9
Condensate	6	1	3	1	3	1
Total production	**124**	**22**	53	10	69	25
Revenues[1]	**$/boe**	**$m**	$/boe	$m	$/boe	$m
Oil revenue	71	756	87	546	81	1,176
Gas revenue	71	611	57	170	64	599
Condensate revenue	48	47	45	18	48	47
Oil and gas hedging gains	1	23	10	98	5	135
Total	**64**	**1,437**	86	832	77	1,957
Movement in oil and gas inventory	4	99	–	(5)	3	84
Tanker costs	–	(11)	(1)	(10)	(1)	(18)
Stella royalties	–	(1)	–	(1)	–	(2)
Total value from production	**68**	**1,524**	85	816	79	2,021
Costs						
Operating costs excluding tanker costs and net of tariff income	(17)	(391)	(27)	(263)	(22)	(570)
Administration expenses excluding restructuring costs (H1 2025) and Business Combination costs (FY 2024)	(1)	(19)	(3)	(20)	(2)	(41)
Foreign exchange gains/(losses)	–	3	–	–	–	(5)
Other operating costs in arriving at adjusted EBITDAX	**(18)**	**(407)**	(30)	(283)	(24)	(616)
Adjusted EBITDAX[2]	**50**	**1,117**	55	533	55	1,405

1 Revenues in the above table exclude principally other income and premium payments on oil and gas derivative instruments.
2 Non-GAAP measure.

Adjusted EBITDAX to profit before taxation

	H1 2025 $m	H1 2024 $m
Adjusted EBITDAX	**1,117.0**	533.0
Depletion, depreciation and amortisation (DDA)	**(438.9)**	(252.9)
Impairment charges on development and production assets	**(30.2)**	(35.5)
Exploration and evaluation expenses	**(0.1)**	(1.5)
Finance income	**2.7**	4.5
Finance costs	**(129.8)**	(84.8)
Oil and gas put premiums	**(0.1)**	(1.6)
Restructuring costs	**(6.9)**	–
Fair value remeasurements of contingent consideration	**(14.6)**	27.4
Revaluation of derivative contracts	**14.3**	0.8
Profit before taxation	**513.4**	189.4

DDA charges were $438.9 million (H1 2024: $252.9 million). The period-on-period increase was principally due to the higher production. DDA per barrel was $20 (H1 2024: $26) with the reduction on H1 2024 primarily due to the new Eni UK assets which have a relatively lower DDA per boe.

Impairment charges on development and production assets of $30.2 million (H1 2024: $35.5 million) principally reflects revisions to decommissioning cost estimates on assets which have either been fully written-off or have ceased production.

Exploration and evaluation expenses amounted to $0.1 million (H1 2024: $1.5 million) and principally relate to licence relinquishments during the period.

Finance costs were $129.8 million (H1 2024: $84.8 million) with the increase due to higher accretion charges as a result of the Eni UK Business Combination as well as additional finance charges from higher RBL borrowings and an increase in the level of Senior Notes compared to H1 2024.

Restructuring costs of $6.9 million (H1 2024: $nil) were incurred on reorganising and streamlining the organisational structure following the Eni UK Business Combination and comprise operational costs of $3.9 million and administrative expenses of $3.0 million.

Fair value remeasurements of contingent consideration was a charge of $14.6 million (H1 2024: credit of $27.4 million), mainly due to the results of a regular reassessment by management of the likelihood of certain milestones being achieved.

Revaluation of derivative financial instruments was a credit of $14.3 million (H1 2024: credit of $0.8 million) principally reflecting the revaluation of foreign exchange forward contracts and collars during the period.

Financial performance: (loss)/profit for the period and adjusted net income

	H1 2025 $m	H1 2024 $m
Profit before taxation	**513.4**	189.4
Taxation charge	**(730.9)**	(83.7)
(Loss)/profit for the period	**(217.5)**	105.7
Impairment charges on development and production assets	**30.2**	35.5
Tax credit on impairment charges	**(13.1)**	(16.5)
Restructuring costs	**6.9**	–
Tax credit on restructuring costs	**(5.4)**	–
One-off, non-cash deferred tax charge on two-year extension of the 38% EPL tax rate to 31 March 2030	**327.6**	–
Adjusted net income[1]	**128.7**	124.7

1 Non-GAAP measure.

Taxation charge
The taxation charge for the period was $730.9 million (H1 2024: $83.7 million) with the increase mainly due to the deferred tax charge for the extension of EPL to 31 March 2030 and higher taxable profits compared to H1 2024.

Earnings per share (EPS)
Basic EPS was a loss of 13.2 cents (H1 2024: earnings of 10.5 cents) and adjusted basic EPS was 7.8 cents (H1 2024: 12.4 cents). Adjusted basic EPS eliminates items which distort period-on-period comparisons such as impairment charges on development and production assets and the tax effect of such items.

Shares in issue
As at 30 June 2025, there were 1,653.7 million (H1 2024: 1,014.4 million) shares in issue. The weighted average number of shares during the period for EPS calculations, excluding shares held by the Employee Benefit Trust, was 1,648.1 million (H1 2024: 1,006.6 million).

Dividends
A third interim dividend for 2024 of $199.3 million was paid during the period (H1 2024: third interim dividend for 2023 of $133.6 million).

Financial position: assets/liabilities/equity

	30 June 2025 $m	31 December 2024 $m
Total assets	**8,286.6**	8,275.0
Total liabilities	**(5,578.9)**	(5,234.6)
Net assets and shareholders' equity	**2,707.7**	3,040.4

Assets
At 30 June 2025, total assets amounted to $8,286.6 million (31 December 2024: $8,275.0 million), and comprised current assets of $1,457.8 million (31 December 2024: $976.2 million) and non-currents assets of $6,828.8 million (31 December 2024: $7,298.8 million). The decrease in total assets was primarily due to a reduction in the net deferred tax asset by $699.4 million due to the tax charge for the two-year extension of EPL, tax on cash flow hedges which go through the statement of comprehensive income as well as the utilisation of historic tax losses. This was partly offset by higher cash balances of $273.5 million reflecting the strong H1 2025 cash flows, increased derivatives financial instruments of $252.0 million representing principally gas trades which have moved from a liability position due to lower than previously forecast future prices, and higher inventories of $87.5 million due to the Q1 2025 build up of underlift which partially reversed during Q2 2025.

Liabilities
At 30 June 2025, total liabilities amounted to $5,578.9 million (31 December 2024: $5,234.6 million) including decommissioning provisions of $2,715.4 million (31 December 2024: $2,655.1 million) and gross borrowings of $1,096.3 million (31 December 2024: $1,024.9 million). The increase in total liabilities during the period was primarily because of higher current tax payable of $296.1 million due to EPL and higher trade and other payables of $162.6 million due to higher capital expenditure accruals and higher deferred income balances at J Area and Elgin Franklin. In addition, gross borrowings increased by $71.4 million due mainly to additional drawings on the RBL and decommissioning liabilities were $60.4 million higher following reassessments of cost estimates. These were partly offset by lower contingent and deferred consideration of $92.3 million due to payments during the period and a reduction in derivative financial instrument liabilities of $135.5 million reflecting the gas trades which, as noted above, have moved to asset positions at the end of H1 2025.

Equity and reserves
At 30 June 2025, total equity and reserves amounted to $2,707.7 million (31 December 2024: $3,040.4 million). The reduction in equity and reserves during the period was primarily due to dividends paid of $199.3 million and the loss for H1 2025 of $217.5 million partly offset by favourable movements on hedging reserves of $81.3 million.

Financial position: cash

	H1 2025 $m	H1 2024 $m
Opening cash	**165.1**	153.2
Operating cash flows	**1,004.6**	559.8
Investing cash flows	**(539.5)**	(229.4)
Financing cash flows	**(198.8)**	(196.2)
Foreign exchange	**7.2**	0.3
Net cash flow	**273.5**	134.5
Closing cash	**438.6**	287.7
Undrawn borrowing facilities	**790.0**	740.3
Available liquidity	**1,228.6**	1,028.0

Operating cash flows
Net cash from operating activities amounted to $1,004.6 million (H1 2024: $559.8 million), with the increase mainly due to the impact of the Business Combination and in particular the higher production in the period compared to H1 2024.

Investing cash flows
Cash flow used in investing activities amounted to $539.5 million (H1 2024: $229.4 million), reflecting capital expenditure of $364.1 million (H1 2024: $210.3 million) driven mainly by drilling and workover activities at Captain, FPSO modifications and subsurface scopes on Rosebank and well work on Judy/Joanne and Seagull. In addition, payments of contingent and deferred consideration amounted to $131.6 million (H1 2024 $19.1 million), reflecting mainly payments to Eni S.p.A., and other acquisition and investing payments amounted to $43.8 million (H1 2024: $nil),

Financing cash flows
Cash outflow from financing activities of $198.8 million (H1 2024: $196.2 million) with interest costs and lease payments of $59.5 million (H1 2024: $62.6 million) and the payment of the third interim dividend for 2024 of $199.3 million (H1 2024: third interim dividend for 2023 of $133.6 million) partly offset by a net drawdown of principal debt of $60.0 million (H1 2024: net movement on debt of $nil).

Cash balances were $438.6 million (H1 2024: $287.7 million) at the end of H1 2025 and available liquidity was $1,228.6 million (H1 2024: $1,028.0 million).

Going concern
Based on their assessment of the Group's financial position over the period to 30 September 2026, the Directors believe that the Group will be able to continue in operational existence for the foreseeable future. Accordingly, they continue to adopt the going concern basis of accounting in preparing the condensed consolidated financial statements. Further details are set out in note 3.

Derivative financial instruments

Derivative financial instruments are utilised to manage commodity price risk in a substantive financial hedging programme for future oil and gas production volumes. As at 30 June 2025, the following hedges were in place:

	H2 2025	2026	2027
Oil			
Volume hedged (mmboe)	**8.1**	7.2	3.1
Weighted average floor hedged price ($/bbl)	**71**	67	66
Gas			
Volume hedged (mmboe)	**7.4**	11.8	1.4
Weighted average floor hedged price (p/therm)	**88**	86	85

Principal risks and uncertainties

The Group faces various risks that could result in events or circumstances that might threaten our business model, future performance, liquidity, solvency or reputation. Not all of these risks are completely within the control of the business and the Group may be affected by risks that have yet to manifest themselves or are not reasonably foreseeable at the present time.

For those identified risks, the Group has mitigation strategies to minimise the likelihood of the risk and reduce the impact as far as is practicable. Depending on the nature of the risk, the Group may elect to take or tolerate risk, treat risk with mitigating actions, transfer risk to third parties, or eliminate risk by ceasing certain operations or activities.

The Directors have reviewed the principal risks and uncertainties facing the Group and have concluded that those facing the Group for the remaining six months of the current financial year are unchanged from the risks set out in the 2024 Annual Report and Accounts. In reaching this conclusion, the Directors considered changes in the internal and external environment during the intervening period which could threaten the Group's business model, future performance, liquidity, solvency or reputation.

The principal risks and uncertainties are as follows:
- Major HSE incident
- Cyber security breach
- Access to capital
- Capital project execution
- Commodity price volatility
- Production delivery issues
- Energy transition and Net Zero delivery
- Workforce recruitment and retention
- Supply chain capacity and capability
- Governmental regulatory, political and fiscal
- Major compliance breach
- Integration of Eni UK upstream assets

Details of these principal risks and how they are being managed are set out on pages 101 to 108 of the 2024 Annual Report and Accounts.

Subsequent events

The acquisition of 100% of the issued share capital of JAPEX UK E&P Limited ('JUK') completed on 7 July 2025 for a total consideration of $156.4 million, thereby increasing the Group's working interest in the Seagull field from 35% to 50%. The quantification of the fair value of the acquired JUK assets and liabilities is ongoing.

Statement of Directors' responsibilities

The Directors confirm that, to the best of their knowledge:

- Condensed consolidated financial statements have been prepared in accordance with IAS 34 *Interim Financial Reporting* as contained within United Kingdom adopted IFRS;
- Half-yearly results statement includes a fair review of the information required by DTR 4.2.7R (indication of important events during the first six months and description of principal risks and uncertainties for the remaining six months of the year); and
- Half-yearly results statement includes a fair review of the information required by DTR 4.2.8R (disclosure of material related parties' transactions and changes therein) as set out in note 18.

By order of the Board,

Iain C S Lewis
Director
19 August 2025

Independent review report to Ithaca Energy plc

Conclusion

We have been engaged by the Company to review the condensed set of financial statements in the half-yearly financial report for the six months ended 30 June 2025 which comprises:

- the condensed consolidated statement of profit or loss;
- the condensed consolidated statement of comprehensive income;
- the condensed consolidated statement of financial position;
- the condensed consolidated statement of changes in equity;
- the condensed consolidated statement of cash flows; and
- the related notes 1 to 19 to the condensed consolidated financial statements.

Based on our review, nothing has come to our attention that causes us to believe that the condensed set of financial statements in the half-yearly financial report for the six months ended 30 June 2025 is not prepared, in all material respects, in accordance with United Kingdom adopted International Accounting Standard 34 and the Disclosure Guidance and Transparency Rules of the United Kingdom's Financial Conduct Authority.

Basis for Conclusion

We conducted our review in accordance with International Standard on Review Engagements (UK) 2410 'Review of Interim Financial Information Performed by the Independent Auditor of the Entity' issued by the Financial Reporting Council for use in the United Kingdom (ISRE (UK) 2410). A review of interim financial information consists of making inquiries, primarily of persons responsible for financial and accounting matters, and applying analytical and other review procedures. A review is substantially less in scope than an audit conducted in accordance with International Standards on Auditing (UK) and consequently does not enable us to obtain assurance that we would become aware of all significant matters that might be identified in an audit. Accordingly, we do not express an audit opinion.

As disclosed in note 2, the annual financial statements of the Group are prepared in accordance with United Kingdom adopted international accounting standards. The condensed set of financial statements included in this half-yearly financial report has been prepared in accordance with United Kingdom adopted International Accounting Standard 34 'Interim Financial Reporting'.

Conclusion Relating to Going Concern

Based on our review procedures, which are less extensive than those performed in an audit as described in the basis for conclusion section of this report, nothing has come to our attention to suggest that the Directors have inappropriately adopted the going concern basis of accounting or that the Directors have identified material uncertainties relating to going concern that are not appropriately disclosed.

This Conclusion is based on the review procedures performed in accordance with ISRE (UK) 2410; however, future events or conditions may cause the entity to cease to continue as a going concern.

Responsibilities of the Directors

The Directors are responsible for preparing the half-yearly financial report in accordance with the Disclosure Guidance and Transparency Rules of the United Kingdom's Financial Conduct Authority.

In preparing the half-yearly financial report, the Directors are responsible for assessing the Group's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless the Directors either intend to liquidate the Company or to cease operations, or have no realistic alternative but to do so.

Auditor's Responsibilities for the review of the financial information

In reviewing the half-yearly financial report, we are responsible for expressing to the Company a conclusion on the condensed set of financial statements in the half-yearly financial report. Our Conclusion, including our Conclusion Relating to Going Concern, are based on procedures that are less extensive than audit procedures, as described in the Basis for Conclusion paragraph of this report.

Use of our report

This report is made solely to the Company in accordance with ISRE (UK) 2410. Our work has been undertaken so that we might state to the Company those matters we are required to state to it in an independent review report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the Company, for our review work, for this report, or for the conclusions we have formed.

Deloitte LLP
Statutory Auditor
Glasgow, United Kingdom
19 August 2025

Unaudited condensed consolidated statement of profit or loss

For the three and six months ended 30 June

	Note	Three months ended 30 June 2025 $m	Three months ended 30 June 2024 $m	Six months ended 30 June 2025 $m	Six months ended 30 June 2024 $m
Revenue	4	**746.4**	361.6	**1,454.0**	841.9
Cost of sales	5	**(496.9)**	(262.3)	**(762.2)**	(541.4)
Gross profit		**249.5**	99.3	**691.8**	300.5
Impairment charges on development and production assets		**(29.2)**	(30.9)	**(30.2)**	(35.5)
Exploration and evaluation expenses	10	**–**	(1.5)	**(0.1)**	(1.5)
Administrative expenses		**(11.8)**	(12.1)	**(21.9)**	(20.0)
Other gains	6	**1.1**	37.5	**0.9**	26.2
Profit from operations before taxation, finance income and finance costs		**209.6**	92.3	**640.5**	269.7
Finance income	7	**1.0**	2.5	**2.7**	4.5
Finance costs	7	**(64.4)**	(41.9)	**(129.8)**	(84.8)
Profit before taxation		**146.2**	52.9	**513.4**	189.4
Taxation	12	**(105.1)**	10.1	**(730.9)**	(83.7)
(Loss)/profit for the period		**41.1**	63.0	**(217.5)**	105.7

Earnings per share (EPS)	Note	Three months ended 30 June 2025 Cents	Three months ended 30 June 2024 Cents	Six months ended 30 June 2025 Cents	Six months ended 30 June 2024 Cents
Basic	8	**2.5**	6.3	**(13.2)**	10.5
Diluted	8	**2.5**	6.2	**(13.2)**	10.4

The results above are entirely derived from continuing operations.

The accompanying notes on pages 27 to 47 are an integral part of the condensed consolidated financial statements.

Unaudited condensed consolidated statement of comprehensive income

For the three and six months ended 30 June

	Note	Three months ended 30 June		Six months ended 30 June	
		2025 $m	2024 $m	**2025 $m**	2024 $m
(Loss)/profit for the period		**41.1**	63.0	**(217.5)**	105.7
Items that may be reclassified to profit and loss					
Fair value gains/(losses) on cash flow hedges	16	**156.4**	(47.2)	**282.5**	(113.7)
Fair value gains/(losses) on cost of hedging	16	**39.3**	(4.3)	**87.2**	(15.2)
Deferred tax (charge)/credit on cash flow hedges and cost of hedging	12	**(152.6)**	32.7	**(288.4)**	90.7
Other comprehensive income/(expense)		**43.1**	(18.8)	**81.3**	(38.2)
Total comprehensive (expense)/income for the period		**84.2**	44.2	**(136.2)**	67.5

The accompanying notes on pages 27 to 47 are an integral part of the financial statements.

Unaudited condensed consolidated statement of financial position

As at 30 June 2025 and 31 December 2024

	Note	2025 $m	2024 $m
Assets			
Current assets			
Inventories		**371.3**	283.8
Other financial assets		**11.3**	11.3
Trade and other receivables	9	**437.9**	417.6
Decommissioning reimbursements	9	**25.8**	23.2
Prepayments		**53.0**	42.2
Derivative financial instruments	17	**119.9**	33.0
Cash and cash equivalents		**438.6**	165.1
		1,457.8	976.2
Non-current assets			
Goodwill		**1,139.1**	1,129.5
Exploration and evaluation assets	10	**608.1**	612.5
Property, plant and equipment	11	**4,228.0**	4,188.4
Deferred tax assets	12	**524.7**	1,224.2
Investments		**23.5**	–
Decommissioning reimbursements	9	**140.3**	144.2
Derivative financial instruments	17	**165.1**	–
		6,828.8	7,298.8
Total assets		**8,286.6**	8,275.0
Liabilities and equity			
Current liabilities			
Borrowings	13	**(9.1)**	(13.0)
Trade and other payables		**(729.1)**	(566.5)
Current tax payable		**(543.2)**	(247.1)
Decommissioning liabilities	14	**(138.1)**	(152.7)
Lease liabilities		**(22.7)**	(19.4)
Contingent and deferred consideration	15	**(177.8)**	(303.5)
Derivative financial instruments	17	**(4.6)**	(130.5)
		(1,624.6)	(1,432.7)

Unaudited condensed consolidated statement of financial position continued
As at 30 June 2025 and 31 December 2024

	Note	**2025 $m**	2024 $m
Non-current liabilities			
Borrowings	13	**(1,087.2)**	(1,011.9)
Decommissioning liabilities	14	**(2,577.3)**	(2,502.4)
Lease liabilities		**(13.7)**	(20.7)
Other provisions		**(35.0)**	(36.2)
Contingent and deferred consideration	15	**(229.7)**	(209.7)
Derivative financial instruments	17	**(11.4)**	(21.0)
		(3,954.3)	(3,801.9)
Total liabilities		**(5,578.9)**	(5,234.6)
Net assets		**2,707.7**	3,040.4
Shareholders' equity			
Share capital		**20.0**	20.0
Share premium		**1,161.6**	1,161.6
Capital contribution reserve		**181.9**	181.9
Own shares		**(7.6)**	(9.6)
Share-based payment reserve		**19.6**	18.8
Cash flow hedge reserve		**46.4**	(15.7)
Cost of hedging reserve		**10.1**	(9.1)
Retained earnings		**1,275.7**	1,692.5
Total equity		**2,707.7**	3,040.4

The accompanying notes on pages 27 to 47 are an integral part of the financial statements.

Approved on behalf of the Board on 19 August 2025:

Iain C S Lewis
Director

Unaudited condensed consolidated statement of changes in equity
For the six months ended 30 June

	Share capital $m	Share premium $m	Capital contribution reserve $m	Own shares $m	Share-based payment reserve $m	Cash flow hedge reserve $m	Cost of hedging reserve $m	Retained earnings $m	Total $m
Balance at 1 January 2024	11.6	308.9	181.9	(12.4)	15.5	39.8	4.1	1,972.0	2,521.4
Dividends paid	–	–	–	–	–	–	–	(133.6)	(133.6)
Share-based payments	–	–	–	1.8	1.1	–	–	–	2.9
Comprehensive income/(expense) for the period:									
Profit for the period	–	–	–	–	–	–	–	105.7	105.7
Other comprehensive expense	–	–	–	–	–	(32.6)	(5.6)	–	(38.2)
Total comprehensive income/(expense) for the period	–	–	–	–	–	(32.6)	(5.6)	105.7	67.5
Balance at 30 June 2024	11.6	308.9	181.9	(10.6)	16.6	7.2	(1.5)	1,944.1	2,458.2
Balance at 1 January 2025	20.0	1,161.6	181.9	(9.6)	18.8	(15.7)	(9.1)	1,692.5	3,040.4
Dividends paid	–	–	–	–	–	–	–	**(199.3)**	**(199.3)**
Share-based payments	**–**	**–**	**–**	**2.0**	**0.8**	**–**	**–**	**–**	**2.8**
Comprehensive (expense)/income for the period:									
Loss for the period	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**(217.5)**	**(217.5)**
Other comprehensive income	**–**	**–**	**–**	**–**	**–**	**62.1**	**19.2**	**–**	**81.3**
Total comprehensive (expense)/income for the period	–	–	–	–	–	**62.1**	**19.2**	**(217.5)**	**(136.2)**
Balance at 30 June 2025	**20.0**	**1,161.6**	**181.9**	**(7.6)**	**19.6**	**46.4**	**10.1**	**1,275.7**	**2,707.7**

The accompanying notes on pages 27 to 47 are an integral part of the financial statements.

Unaudited condensed consolidated statement of cash flows
For the three and six months ended 30 June

	Note	Three months ended 30 June		Six months ended 30 June	
		2025 $m	2024 $m	**2025 $m**	2024 $m
Cash provided by/(used in) operating activities:					
Profit before tax		**146.2**	52.9	**513.4**	189.4
Adjustments for:					
Depletion, depreciation and amortisation	11	**216.3**	107.9	**438.9**	252.9
Exploration and evaluation expenses	10	**–**	1.5	**0.1**	1.5
Impairment charges on development and production assets		**29.2**	30.9	**30.2**	35.5
Fair value remeasurements of contingent consideration	15	**10.6**	(31.1)	**14.6**	(27.8)
Loan fee amortisation	7	**2.6**	1.1	**5.3**	2.2
Fair value gains on financial instruments	16	**(8.9)**	(9.2)	**(14.3)**	(0.8)
Accretion on deferred consideration and decommissioning liabilities less accretion on decommissioning reimbursements	7	**30.3**	18.8	**65.5**	37.5
Finance costs	7	**31.5**	22.0	**59.0**	45.1
Finance income	7	**(1.0)**	(2.5)	**(2.7)**	(4.5)
Unrealised foreign exchange on cash and cash equivalents		**(6.2)**	(0.8)	**(7.2)**	(0.3)
Share-based payment expenses		**1.5**	1.3	**2.8**	2.9
Decommissioning expenditure		**(26.4)**	(19.6)	**(54.8)**	(31.3)
Operating cash flows before movements in working capital		**425.7**	173.2	**1,050.8**	502.3
(Increase)/decrease in inventories		**52.6**	20.3	**(87.5)**	9.9
(Increase)/decrease in trade and other receivables		**12.9**	51.9	**(2.4)**	82.4
Increase/(decrease) in trade and other payables		**75.6**	(18.0)	**66.2**	(8.1)
Operating cash flows		**566.8**	227.4	**1,027.1**	586.5
Taxation paid		**0.1**	–	**(21.7)**	(25.0)
Settlements of foreign exchange and commodity derivative financial instruments		**1.4**	16.1	**(3.5)**	(6.2)
Finance income	7	**1.0**	2.5	**2.7**	4.5
Net cash from operating activities		**569.3**	246.0	**1,004.6**	559.8

Unaudited condensed consolidated statement of cash flows continued
For the three and six months ended 30 June

	Three months ended 30 June		Six months ended 30 June	
	2025 $m	2024 $m	**2025 $m**	2024 $m
Cash used in investing activities:				
Capital expenditure	**(185.7)**	(97.2)	**(364.1)**	(210.3)
Deposit for JAPEX UK E&P Limited acquisition	**–**	–	**(20.3)**	–
Other investment in listed oil and gas shares	**(23.5)**	–	**(23.5)**	–
Deferred consideration payments	**–**	–	**(130.0)**	–
Contingent consideration payments	**(0.3)**	(2.4)	**(1.6)**	(19.1)
Net cash used in investing activities	**(209.5)**	(99.6)	**(539.5)**	(229.4)
Cash used in financing activities:				
Dividends paid	**(199.3)**	(133.6)	**(199.3)**	(133.6)
Payments for lease liabilities (principal)	**(5.4)**	(6.5)	**(10.6)**	(20.1)
Drawdown of RBL loan	**60.0**	–	**60.0**	–
Bank interest and charges	**(40.3)**	(4.7)	**(48.9)**	(41.9)
Interest rate swaps	**–**	–	**–**	(0.6)
Net cash used in financing activities	**(185.0)**	(144.8)	**(198.8)**	(196.2)
Currency translation differences relating to cash	**6.2**	0.9	**7.2**	0.3
Increase in cash and cash equivalents	**181.0**	2.5	**273.5**	134.5
Cash and cash equivalents, beginning of period	**257.6**	285.2	**165.1**	153.2
Cash and cash equivalents, end of period	**438.6**	287.7	**438.6**	287.7

The accompanying notes on pages 27 to 47 are an integral part of the condensed consolidated financial statements.

Notes to the condensed consolidated financial statements

1. General information
Ithaca Energy plc (the Group or Ithaca Energy), is a public Company, limited by shares, incorporated and domiciled in the UK and is a Group involved in the development and production of oil and gas in the North Sea. The Group's registered office is 33 Cavendish Square, London, United Kingdom, W1G 0PP.

2. Basis of preparation
The condensed consolidated financial statements are prepared in accordance with United Kingdom adopted International Accounting Standard 34 *Interim Financial Reporting*.

The condensed consolidated financial statements for the three and six months ended 30 June 2025 do not include all the information required for a full annual report and do not constitute statutory accounts within the meaning of section 434(3) of the Companies Act 2006. The condensed consolidated financial statements for the three and six months ended 30 June 2025 are not audited but have been reviewed by the auditor whose audit review report is set out on page 19. The accounting policies adopted in the preparation of the H1 2025 condensed consolidated financial statements are consistent with those adopted and disclosed in the Group's 2024 Annual Report and Accounts. Comparative information for the year ended 31 December 2024 has been taken from the statutory accounts for that year, a copy of which has been delivered to the Registrar of Companies. The auditor's report on those accounts was not qualified, did not include a reference to any matters to which the auditors drew attention by way of emphasis and did not contain any statements under section 498(2) or (3) of the Companies Act 2006. A number of amendments to existing standards and interpretations were effective from 1 January 2025 but there was no impact on the H1 2025 condensed consolidated financial statements. The Group has not early adopted any standard, interpretation or amendment that has been issued but is not yet effective.

The condensed consolidated financial statements are presented in US Dollars as this is the functional currency of the business. All values are presented in millions ($m) rounded to one decimal place, except when otherwise indicated.

In terms of segmental reporting, the Group currently operates a single class of business being oil and gas exploration, development and production and related activities in a single geographical area, being presently the North Sea. The Group's segmental reporting structure remained in place for all periods presented and is consistent with the way in which the Group's activities are reported to the Board and to the Chief Decision Making Officer. The Group's activities are considered to represent an individual operating segment due to the to the activities of the group being homogenous and such operations existing in a single geographical area that is governed by the same regulations.

These H1 2025 condensed consolidated financial statements are to be read in conjunction with Ithaca Energy's Annual Report and Accounts for the year ended 31 December 2024, which contains additional accounting policy disclosures.

3. Accounting policies
Basis of measurement
The condensed consolidated financial statements have been prepared on a going concern basis using the historical cost convention, except for the revaluation of certain financial assets and financial liabilities (under IFRS) to fair value, including derivative instruments. Historical cost is generally based on the fair value consideration given in exchange for the assets or liabilities.

Going concern
Management closely monitors the funding position of the Group including monitoring compliance with covenants and available facilities to ensure sufficient headroom is maintained to fund operations. Management have considered a number of risks applicable to the Group that may have an impact on the Group's ability to continue as a going concern. Short-term and long-term cash forecasts are prepared on a weekly and quarterly basis respectively along with any related sensitivity analysis. This allows proactive management of any business risk including liquidity risk.

The Directors consider the preparation of the condensed consolidated financial statements on a going concern basis to be appropriate. This is due to the following key factors:
- Continuing robust commodity price backdrop and a well hedged portfolio over the next 12 months;
- Reserves Based Lending (RBL) liquidity headroom of $650 million ($350 million drawn compared to $1.0 billion available), plus $450 million of cash at the end of July 2025; and
- Strong operational performance and well-diversified portfolio.

Cash flow forecast – base case assumptions:		H2 2025	Q1 to Q3 2026
Average oil price	$/bbl	70	68
Average gas price	p/th	91	90
Average hedged oil price (including floor price for zero cost collars)	$/bbl	71	67
Average hedged gas price (including floor price for zero cost collars)	p/th	88	86

3. Accounting policies continued

Going concern continued

Owing to the ongoing fluctuations in commodity demand and price volatility, management prepared sensitivity analysis to the forecasts and applied a number of plausible downside scenarios, including decreases in production of 10%, reduced sales prices of 20% and increases in operating and capital expenditures of 10%. Management aggregated these scenarios to create a reasonable combined worst-case scenario. The sensitivity analysis showed that, without any consideration of the mitigation strategies within management's control, there was no reasonably possible scenario that would result in the business being unable to meet its liabilities as they fell due. Further mitigation strategies within the control of management include the reduction in uncommitted capital expenditure and variable operating cost savings in the low production scenario. The analysis demonstrated that the Group would still continue to comply with financial covenants and have sufficient liquidity to continue trading throughout the period to 30 September 2026.

Notwithstanding the Group having net current liabilities at 30 June 2025 of $166.8 million (31 December 2024: $456.5 million) , there are sufficient undrawn facilities available to enable current liabilities to be settled as they fall due.

Based on their assessment of the Group's financial position in the period to 30 September 2026, the Directors believe that the Group will be able to continue in operational existence for the foreseeable future. Accordingly, they continue to adopt the going concern basis of accounting in preparing the condensed consolidated financial statements.

Use of judgements and estimates

In preparing these H1 2025 condensed consolidated financial statements, management has made judgements and estimates that affect the application of accounting policies and the reported amounts of assets and liabilities and income and expenses. Actual results may differ from these estimates.

The significant judgements made by management in applying the Group's accounting policies, and the key sources of estimation uncertainty are the same as those described on pages 197 to 200 of the Group's 2024 Annual Report and Accounts. Judgements and estimates made in assessing the impact of climate change and the energy transition have not changed for the H1 2025 consolidated condensed financial statements. Details of these are set out on pages 188 and 189 of the 2024 Annual Report and Accounts.

The critical accounting judgements applied in the preparation of the H1 2025 condensed consolidated financial statements are impairment charges on oil and gas assets, and whether or not there have been indications of impairment in respect of the Rosebank field.

Impairment charges on development and production assets for the period ended 30 June 2025 were $30.2 million (H1 2024: $35.5 million) and comprised a charge of $27.3 million in relation to decommissioning cost estimate changes on assets which have either been fully written off or have ceased production and a charge of $2.9 million in relation to fixed asset additions during the period on assets which have been fully written off. With all other assumptions held constant, a 20% decrease in the forecast revenues, illustrating a 20% decrease in commodity prices, would result at 30 June 2025 in an additional post-tax impairment to PP&E of $401 million. In addition, under this scenario, goodwill would be fully impaired with an impairment charge of $1,139 million.

Management has reviewed the pre-tax carrying value of the Rosebank field of $756 million or post-tax $373 million (31 December 2024: pre-tax $617 million or post-tax $304 million). Although the first phase of the Rosebank development had been sanctioned by the NSTA, it was subject to Judicial Review proceedings. On 30 January 2025, the Court of Session ruled that this consent had been unlawfully given in relation to the sanctioning of the Rosebank field development and that a new consent application would be required, which included Scope 3 emissions. It did, however, permit the project to progress as planned whilst this new consent is sought from the Regulators but that no oil could be extracted without this new consent. The Scope 3 guidance has been issued and the Offshore Petroleum Regulator for Environment and Decommissioning have requested the Rosebank Joint Venture to submit a revised Environmental Statement, which is currently being prepared. Whilst the outcome of the Judicial Review could be construed as an indicator of impairment, management has no reason to believe that this further consent will not be forthcoming, and further management believe that the most likely outcome will be that the further consent will be granted and that the project will continue progressing as planned with first oil anticipated in 2026/27. As a result, no impairment charge is required.

4. Revenue

	Three months ended 30 June		Six months ended 30 June	
	2025 $m	2024 $m	**2025 $m**	2024 $m
Oil sales	**436.8**	243.7	**756.2**	546.5
Gas sales	**256.3**	81.5	**610.6**	170.4
Condensate sales	**14.2**	8.3	**47.4**	18.7
Other income	**7.6**	4.2	**16.7**	9.7
Realised gains/(losses) on oil derivative contracts	**16.4**	(4.2)	**20.9**	(6.7)
Premium payments on oil derivative contracts	**–**	(0.3)	**–**	(0.6)
Realised gains on gas derivative contracts	**15.2**	29.6	**2.3**	105.1
Premium payments on gas derivative contracts	**(0.1)**	(1.2)	**(0.1)**	(1.2)
	746.4	361.6	**1,454.0**	841.9

The majority of payment terms are on a specified monthly date, as detailed in the initial contract. Otherwise, payment is due within 30 days of the invoice date. No significant judgements have been made in determining the timing of satisfaction of performance obligations, the transactions price and the amounts allocated to performance obligations. Other income relates to tariff income receivable in the period.

Revenue from two customers (30 June 2024: two customers) exceeds 10% of the Group's consolidated revenue arising from hydrocarbon sales for the six months ended 30 June 2025, representing $952.7 million and $434.7 million respectively (six months ended 30 June 2024: $601.2 million and $85.4 million respectively).

Revenue from contracts with customers derives largely from customers within a single geographical region, being the United Kingdom. Revenue from contracts with customers outwith the United Kingdom is immaterial and is therefore not disclosed separately.

5. Cost of sales

	Three months ended 30 June 2025 $m	Three months ended 30 June 2024 $m	Six months ended 30 June 2025 $m	Six months ended 30 June 2024 $m
Movement in oil and gas inventory	**(61.6)**	(3.7)	**99.1**	(5.1)
Operating costs of hydrocarbon activities	**(218.6)**	(150.3)	**(421.4)**	(282.2)
Royalties	**(0.4)**	(0.4)	**(1.0)**	(1.2)
Depreciation on right-of-use assets (note 11)	**(6.1)**	(6.0)	**(11.2)**	(18.7)
Depletion, depreciation and amortisation (note 11)	**(210.2)**	(101.9)	**(427.7)**	(234.2)
	(496.9)	(262.3)	**(762.2)**	(541.4)

Royalty costs represent 3.34% of Stella and Harrier field revenue paid to the original licence holders. Ithaca Energy holds a 100% interest in the Stella and Harrier fields.

6. Other gains and losses

	Three months ended 30 June 2025 $m	Three months ended 30 June 2024 $m	Six months ended 30 June 2025 $m	Six months ended 30 June 2024 $m
Gains/(losses) on financial instruments (note 16)	**8.8**	6.6	**12.4**	(1.7)
Fair value remeasurements of contingent consideration	**(10.6)**	30.7	**(14.6)**	27.4
Net foreign exchange gains	**2.9**	0.2	**3.1**	0.5
	1.1	37.5	**0.9**	26.2

7. Finance costs and finance income

	Three months ended 30 June 2025 $m	Three months ended 30 June 2024 $m	Six months ended 30 June 2025 $m	Six months ended 30 June 2024 $m
Loan interest and charges	**(15.7)**	(7.7)	**(27.7)**	(16.6)
Senior notes interest	**(15.1)**	(14.0)	**(30.1)**	(27.8)
Loan fee amortisation	**(2.6)**	(1.1)	**(5.3)**	(2.2)
Interest on lease liabilities	**(0.7)**	(0.3)	**(1.2)**	(0.7)
Accretion on deferred consideration and decommissioning liabilities less accretion on decommissioning reimbursements	**(30.3)**	(18.8)	**(65.5)**	(37.5)
Total finance costs	**(64.4)**	(41.9)	**(129.8)**	(84.8)
Finance income	**1.0**	2.5	**2.7**	4.5

During the six months to 30 June 2025, $4.9 million of interest was capitalised into qualifying assets (six months to 30 June 2024: $0.5 million).

8. Earnings per share

The calculation of basic earnings per share is based on the profit after tax and the weighted average number of ordinary shares in issue during the period. Basic and diluted earnings per share are calculated as follows:

	Three months ended 30 June		Six months ended 30 June	
	2025 $m	2024 $m	**2025 $m**	2024 $m
Earnings for the period				
Earnings for the purpose of basic and diluted earnings per share	**41.1**	63.0	**(217.5)**	105.7
Number of shares (million)				
Weighted average number of ordinary shares for the purpose of basic earnings per share	**1,648.1**	1,006.6	**1,648.1**	1,006.6
Dilutive potential ordinary shares	**13.9**	9.2	**13.9**	9.2
Weighted average number of ordinary shares for the purpose of diluted earnings per share	**1,662.0**	1,015.8	**1,662.0**	1,015.8
Earnings per share (cents)				
Basic	**2.5**	6.3	**(13.2)**	10.5
Diluted	**2.5**	6.2	**(13.2)**	10.4

9. Trade and other receivables and decommissioning reimbursements

Current	**30 June 2025 $m**	31 December 2024 $m
Trade receivables	**8.8**	19.0
Other receivables	**10.5**	23.0
Joint operations receivables	**162.2**	106.0
Accrued income	**256.4**	269.6
	437.9	417.6

Materially all trade and other receivables, including receivables from joint operations are not overdue by more than 90 days. The credit risk associated with trade receivables, joint operations receivables, accrued income and other receivables is considered to be insignificant. No ECL has been recognised in the current or prior year.

Accrued income mainly comprises amounts due, but not yet invoiced, for the sale of oil and gas.

Non-current	**30 June 2025 $m**	31 December 2024 $m
Decommissioning reimbursements	**140.3**	144.2

Current	**30 June 2025 $m**	31 December 2024 $m
Decommissioning reimbursements	**25.8**	23.2

9. Trade and other receivables and decommissioning reimbursements continued

Movements on decommissioning reimbursements were as follows:

	30 June 2025 $m	31 December 2024 $m
At beginning of period	**167.4**	195.5
Accretion net of tax at 30%	**3.3**	7.4
Reimbursements received	**(9.8)**	(22.5)
Change in reimbursement estimates	**5.2**	(13.0)
At end of period	**166.1**	167.4

The decommissioning reimbursements represent the equal and opposite of decommissioning liabilities, net of tax, associated with the Heather and Strathspey fields, and relates to a contractual agreement as part of the CNSL acquisition. As part of the terms of the acquisition of what is now Ithaca Oil and Gas Limited (IOGL), Chevron have the obligation to provide the security and remain financially responsible for the decommissioning obligations of IOGL in relation to these interests. The Group pays the liabilities in respect of Heather and Strathspey, and then receives full reimbursement from Chevron.

As these payments are virtually certain, they have been accounted for under IAS 37 as a reimbursement asset.

10. Exploration and evaluation assets

	$m
At 1 January 2024	548.4
Additions	36.3
Change in decommissioning estimates	4.4
Business combinations	48.0
Write-offs/relinquishments	(24.6)
At 31 December 2024 and 1 January 2025	612.5
Additions	**19.6**
Change in decommissioning estimates	**0.3**
Transfers to development and production assets (note 11)	**(24.2)**
Write-offs/relinquishments	**(0.1)**
At 30 June 2025	**608.1**

Following completion of geotechnical evaluation activity, certain North Sea licences were declared unsuccessful and certain prospects were declared non-commercial. This resulted in the carrying value of these licences being fully written off to $nil with $0.1 million being expensed in the period to 30 June 2025 (year to 31 December 2024: $24.6 million).

The transfer to development and production assets during the six months to 30 June 2025 relates to the successful commencement of production on Jocelyn South.

The principal component of exploration and evaluation assets at 30 June 2025 is the Cambo field with a pre-tax carrying value of $403 million (31 December 2024: $391 million).

11. Property, plant and equipment

	Right-of-use operating assets $m	Development and production assets $m	Other fixed assets $m	Total $m
Cost				
At 1 January 2024	156.2	7,976.8	47.6	8,180.6
Additions	136.2	483.5	0.5	620.2
Business combinations	18.7	997.9	–	1,016.6
Change in decommissioning estimates	–	54.6	–	54.6
At 31 December 2024 and 1 January 2025	311.1	9,512.8	48.1	9,872.0
Additions	**70.2**	**356.2**	**5.2**	**431.6**
Change in decommissioning estimates	**–**	**22.7**	**–**	**22.7**
Transfers from exploration and evaluation assets (note 10)	**–**	**24.2**	**–**	**24.2**
At 30 June 2025	**381.3**	**9,915.9**	**53.3**	**10,350.5**
Depletion, depreciation, amortisation and impairment				
At 1 January 2024	(85.5)	(4,808.7)	(28.1)	(4,922.3)
Depletion, depreciation and amortisation charge for the year	(26.8)	(568.1)	(5.3)	(600.2)
Impairment charge	–	(161.1)	–	(161.1)
At 31 December 2024 and 1 January 2025	(112.3)	(5,537.9)	(33.4)	(5,683.6)
Depletion, depreciation and amortisation charge for the period	**(11.2)**	**(424.3)**	**(3.4)**	**(438.9)**
At 30 June 2025	**(123.5)**	**(5,962.2)**	**(36.8)**	**(6,122.5)**
Net book value at 31 December 2024	198.8	3,974.9	14.7	4,188.4
Net book value at 30 June 2025	**257.8**	**3,953.7**	**16.5**	**4,228.0**

Additions to right-of-use assets in the period to 30 June 2025 and the year to 31 December 2024 principally relate to modifications to the Rosebank FPSO and will begin to be depreciated on commencement of production. The related lease will commence on delivery of the FPSO to the joint venture partners at first oil, which is currently anticipated to be 2026/27. The Rosebank field development is still subject to further approvals from the Regulators and further details are set out in note 3.

Other fixed assets include buildings, computer equipment, office equipment and furniture and fittings.

12. Taxation

	Three months ended 30 June		Six months ended 30 June	
	2025 $m	2024 $m	**2025 $m**	2024 $m
Current tax				
Current corporation tax (charge)/credit	**(6.6)**	(0.5)	**(55.7)**	3.0
True-up in respect of prior years	**(0.7)**	84.9	**(0.7)**	76.3
Current EPL tax charge	**(72.8)**	(14.7)	**(261.4)**	(72.8)
Total current tax (charge)/credit	**(80.1)**	69.7	**(317.8)**	6.5
Deferred tax				
True-up in respect of prior years	**18.0**	(59.1)	**18.0**	(59.1)
Group tax charge in the condensed consolidated statement of profit or loss	**(60.8)**	(13.0)	**(448.9)**	(43.6)
Group tax (charge)/credit in the condensed consolidated statement of other comprehensive income	**(152.6)**	32.7	**(288.4)**	90.7
Total deferred tax charge	**(195.4)**	(39.4)	**(719.3)**	(12.0)
Deferred PRT credit in the condensed consolidated statement of profit or loss	**17.8**	12.5	**17.8**	12.5
Total tax (charge)/credit through the condensed consolidated statement of profit or loss	**(105.1)**	10.1	**(730.9)**	(83.7)

12. Taxation continued

The tax on the Group's profit before tax differs from the theoretical amount that would arise using the 40% statutory rate of tax applicable for UK ring fence oil and gas activities as follows:

	Three months ended 30 June		Six months ended 30 June	
	2025 $m	2024 $m	**2025 $m**	2024 $m
Accounting profit before tax	**146.2**	52.9	**513.4**	189.4
At tax rate of 40% (2024: 40%)	**(58.5)**	(21.2)	**(205.4)**	(75.8)
Non-deductible (expense)/income	**(8.2)**	5.7	**(12.7)**	(5.0)
Financing costs not allowed for SCT	**(1.8)**	(0.2)	**(5.1)**	(0.5)
Ring Fence Expenditure Supplement	**5.8**	4.3	**8.3**	8.8
Deferred tax effect of investment allowance	**11.1**	3.6	**22.0**	(0.1)
True-up in respect of prior years	**17.4**	25.8	**17.4**	17.2
Deferred tax on EPL	**3.3**	3.8	**(291.6)**	42.9
Current tax on EPL	**(72.8)**	(14.6)	**(261.4)**	(72.8)
Net deferred tax PRT	**10.6**	7.5	**10.6**	7.5
Share schemes	**–**	(2.1)	**–**	(2.1)
Income taxed at different rates	**(12.0)**	–	**(13.0)**	–
Unrecognised tax losses	**–**	(2.5)	**–**	(3.8)
Total tax (charge)/credit recorded in the condensed consolidated statement of profit or loss	**(105.1)**	10.1	**(730.9)**	(83.7)

The Company is UK tax resident. The effective rate of tax applicable for UK ring fence oil and gas activities in both 2025 and 2024 was 40% (excluding the Energy Profits Levy), consisting of a Ring Fence Corporation Tax rate of 30% and the supplementary charge of 10%. Items affecting the tax charge include interest income taxed at non-oil and gas tax rate of 25%, true-ups in respect of prior years resulting from filing of prior year tax returns, a 10% uplift on ring fence losses, Ring Fence Expenditure Supplement increasing the losses available to offset future profits subject to Ring Fence Corporation Tax and Supplementary Charge. In addition, investment allowance, a 62.5% uplift on capital expenditure, is available reducing the profits subject to the supplementary charge only. Petroleum Revenue Tax (PRT) is applied at 0% on certain oil and gas fields in the UK, however, deferred PRT assets are recognised reflecting the expected carry back of losses to periods in which PRT was payable at 50%. The Energy Profits Levy was enacted on 14 July 2022 with further changes announced on 17 November 2022 such that the Levy was increased to 35% from 1 January 2023 until 31 March 2028 increasing the effective UK ring fence oil and gas tax rate to 75%. On 6 March 2024, it was announced that EPL will be extended by one year to 31 March 2029 and on 29 July 2024, it was announced that there would be a further extension to March 2030 and that the rate would increase from 35% to 38% from 1 November 2024. The impact of this was a charge to the consolidated statement of profit or loss of $58.1 million in the year to 31 December 2024. The extension to 31 March 2030 was substantively enacted on 3 March 2025 and had an impact of $327.6 million on the tax charge for the period ended 31 March 2025.

12. Taxation continued

Deferred tax at 30 June 2025 and 31 December 2024 relates to the following:

	30 June 2025 $m	31 December 2024 $m
Deferred corporation tax liability	**(2,698.7)**	(2,197.5)
Deferred corporation tax asset	**3,063.5**	3,279.6
Deferred PRT asset	**159.9**	142.1
Net deferred tax asset	**524.7**	1,224.2

Deferred tax assets primarily relate to decommissioning liabilities, brought-forward tax losses and accumulated losses and profits related to derivative contracts. Deferred tax liabilities primarily relate to accelerated capital allowances on property, plant and equipment, and accumulated losses and profits related to derivative contracts. Deferred tax balances are presented net as they arise in the same jurisdiction and the Group has a legally-enforceable right to offset as well as an intention to settle on a net basis. There are unrecognised allowances of up to circa $178 million (31 December 2024: circa $147 million) that have no expiry date and could be recognised in future periods if future revenue from oil and gas activities increases and/or further actions are undertaken. Non-oil and gas losses of $256 million (31 December 2024: $217 million), of which there is no expiry date, have not been recognised for deferred tax purposes as it is not sufficiently certain that there will be future non-oil and gas profits to offset these losses.

The net movement on deferred tax in the condensed consolidated statement of financial position, including deferred PRT, is as follows:

	30 June 2025 $m	31 December 2024 $m
At beginning of period	**1,224.2**	704.7
Profit or loss (charge)/credit	**(413.1)**	27.4
Other comprehensive income (charge)/credit	**(288.4)**	195.7
Deferred tax on decommissioning reimbursements	**2.0**	(0.9)
Business combinations	**–**	297.3
At end of period	**524.7**	1,224.2

12. Taxation continued

The net movement on deferred tax through the condensed consolidated statement of profit or loss and condensed consolidated statement of comprehensive income, excluding PRT, relates to the following:

	6 months ended 30 June	
	2025 $m	2024 $m
Accelerated capital allowances	**(315.0)**	41.5
Tax losses	**(147.8)**	(166.0)
Decommissioning provision	**23.5**	23.2
Deferred PRT	**(7.2)**	(5.0)
Hedging[1]	**(299.1)**	95.9
Share schemes	**–**	(2.0)
Other timing differences	**(3.8)**	–
Investment allowances	**30.1**	0.4
	(719.3)	(12.0)

1 Hedging relates to deferred tax on derivatives designated as cash flow hedges and used for economic hedges.

Gross deferred corporation tax liabilities	Hedges $m	Other timing differences $m	Deferred corporation tax on deferred PRT $m	Accelerated tax depreciation $m	Total $m
At 1 January 2024	(107.7)	–	(36.7)	(1,723.6)	(1,868.0)
Business combinations	–	–	–	(549.1)	(549.1)
True-up in respect of prior years	–	–	–	(16.0)	(16.0)
Origination and reversal of temporary differences	201.5	–	(20.1)	148.0	329.4
Reclassification to deferred corporation tax assets	(93.8)	–	–	–	(93.8)
At 31 December 2024 and 1 January 2025	–	–	(56.8)	(2,140.7)	(2,197.5)
True-up in respect of prior years	–	**(3.8)**	–	**19.0**	**15.2**
Origination and reversal of temporary differences	**(299.1)**	–	**(7.2)**	**(303.9)**	**(610.2)**
Reclassification from deferred corporation tax assets	**93.8**	–	–	–	**93.8**
At 30 June 2025	**(205.3)**	**(3.8)**	**(64.0)**	**(2,425.6)**	**(2,698.7)**

12. Taxation continued

Gross deferred corporation tax assets	Share schemes $m	Decommissioning provision $m	Other provisions $m	Tax losses $m	Hedges $m	Total $m
At 1 January 2024	4.0	721.7	–	1,755.2	–	2,480.9
Business combinations	–	257.4	21.4	567.6	–	846.4
True-up in respect of prior years	–	–	–	(5.0)	–	(5.0)
Origination and reversal of temporary differences	0.9	60.8	–	(198.2)	–	(136.5)
Reclassification from deferred corporation tax liabilities	–	–	–	–	93.8	93.8
At 31 December 2024 and 1 January 2025	4.9	1,039.9	21.4	2,119.6	93.8	3,279.6
True-up in respect of prior years	–	–	–	**2.8**	**–**	**2.8**
Origination and reversal of temporary differences	–	**25.5**	–	**(150.6)**	–	**(125.1)**
Reclassification to deferred corporation tax liabilities	–	–	–	–	**(93.8)**	**(93.8)**
At 30 June 2025	**4.9**	**1,065.4**	**21.4**	**1,971.8**	–	**3,063.5**

Deferred PRT asset	Total $m
At 1 January 2024	91.7
Origination and reversal of temporary differences	50.4
At 31 December 2024 and 1 January 2025	**142.1**
Origination and reversal of temporary differences	17.8
At 30 June 2025	**159.9**

The carrying value of the net deferred tax asset (DTA) and the deferred PRT asset at 30 June 2025 of $365 million and $160 million, respectively (31 December 2024: $1,082 million and $142 million, respectively) are supported by estimates of the Group's future taxable income, based on the same price and cost assumptions as used for impairment testing. The Group has undertaken and will undertake further restructuring exercises to move certain assets between Group entities. Existing restructuring exercises have now been substantially completed. The recoverability of the deferred corporation tax asset is supported by this restructuring. The DTA relating to losses within the Group are expected to unwind against taxable profits before the end of 2029.

An EPL (or Levy) was enacted on 14 July 2022, applying a Levy of 25% to the profits of oil and gas companies until 31 December 2025 or earlier if prices return to normalised levels. On 17 November 2022, the Levy was increased to 35% and extended to 31 March 2028 regardless of oil and gas prices. The Levy is charged on oil and gas profits calculated on the same basis as Ring Fence Corporation Tax (RFCT), however, excludes relief for decommissioning and finance costs. RFCT losses and investment allowance are not available to offset the EPL. On 9 June 2023 an Energy Security Investment Mechanism price floor was announced which would remove the EPL if both average oil and gas prices fall to, or below, $71.40 per barrel for oil and £0.54 per therm for gas, for two consecutive quarters. It is not currently forecast that this price floor will be met for both oil and gas prices and, therefore, there is currently no impact from this on tax carrying values. On 6 March 2024, an extension of the Levy until 31 March 2029 was announced and on 29 July 2024, it was announced that there would be a further extension to March 2030 and that the rate would increase from 35% to 38% from 1 November 2024, of which only the rate increase had been enacted at 31 December 2024. The two-year extension to 31 March 2030 was substantively enacted on 3 March 2025 and resulted in a deferred tax charge of $327.6 million in the condensed consolidated statement of profit or loss in Q1 2025.

On 20 June 2023, Finance (No. 2) Act 2023 was substantially enacted in the UK, introducing a global minimum effective tax rate of 15%. The legislation implements a domestic top-up tax and a multinational top-up tax, effective for all accounting periods starting on or after 31 December 2023. The adoption of this has not had a material impact as the prevailing rate of tax in the United Kingdom is in excess of the 15% minimum rate. The Group has applied the exemption under IAS 12 to recognising and disclosing information about deferred tax assets and liabilities related to top-up income taxes and, therefore, there is no impact on the tax values reported.

13. Borrowings

	30 June 2025 $m	31 December 2024 $m
Current		
Accrued interest costs on borrowings	**(19.3)**	(23.2)
Unamortised short-term bank fees	**6.6**	6.6
Unamortised short-term senior notes fees	**3.6**	3.6
Total current borrowings	**(9.1)**	(13.0)
Non-current		
Accrued interest costs on borrowings	**(10.7)**	–
RBL facility	**(210.0)**	(150.0)
Senior unsecured notes	**(750.0)**	(750.0)
Project capital expenditure facility	**(150.0)**	(150.0)
Unamortised long-term bank fees	**21.5**	24.6
Unamortised long-term senior notes fees	**12.0**	13.5
Total non-current borrowings	**(1,087.2)**	(1,011.9)

Details of covenants under the RBL are set out in note 20 to the 2024 Annual Report and Accounts. The Group was in compliance with all financial covenants relating to the RBL facility in all periods presented.

14. Decommissioning liabilities

	30 June 2025 $m	31 December 2024 $m
Balance at beginning of period	**(2,655.1)**	(1,859.7)
Business combination additions	–	(651.0)
Accretion	**(62.5)**	(93.4)
Additions and revisions to estimates	**(52.6)**	(145.1)
Decommissioning provision utilised	**54.8**	94.1
Balance at end of period	**(2,715.4)**	(2,655.1)
Current		
Balance at beginning of period	**(152.7)**	(107.0)
Balance at end of period	**(138.1)**	(152.7)
Non-current		
Balance at beginning of period	**(2,502.4)**	(1,752.7)
Balance at end of period	**(2,577.3)**	(2,502.4)

The total future decommissioning liability represents the estimated cost to decommission, in situ or by removal, the Group's net ownership interest in all wells, infrastructure and facilities, based upon forecast timing in future periods. The Group uses a nominal discount rate of 3.79% for the first five years and 4.79% thereafter (31 December 2024: 4.38% for the first five years and 4.86% thereafter) and an inflation rate of 2.0% (31 December 2024: 2.0%) over the varying lives of the assets to calculate the present value of the decommissioning liabilities. Revisions to estimates in the six months ended 30 June 2025 and the year ended 31 December 2024 were due to changes in both cost estimates and discount rate assumptions.

The estimated H2 2025 and H1 2026 decommissioning spend of $138 million (31 December 2024: estimated 2025 decommissioning spend of $153 million) has been treated as a current liability as at 30 June 2025. Although the Group currently expects to incur decommissioning costs over the next 40 years, it is estimated that approximately 38% (31 December 2024: 40%) of the decommissioning liability relates to assets which are expected to cease production in the next five years and includes spend for assets that will be reimbursed (see note 11 for further details).

A reduction or an increase in the nominal discount rate used of 1% would increase or decrease the decommissioning liabilities by approximately $286 million and $246 million respectively (31 December 2024: $288 million and $247 million respectively).

15. Contingent and deferred consideration

Current	30 June 2025 $m	31 December 2024 $m
Contingent consideration	**(74.5)**	(75.0)
Deferred consideration payable to related party for business combination	**(33.3)**	(160.2)
Marubeni deferred consideration	**(70.0)**	(68.3)
	(177.8)	(303.5)

Non-current	30 June 2025 $m	31 December 2024 $m
Contingent consideration	**(182.5)**	(165.5)
Deferred consideration payable to related party for business combination	**(47.2)**	(44.2)
	(229.7)	(209.7)

	30 June 2025 $m	31 December 2024 $m
Cash flows relating to contingent and deferred considerations	**(131.6)**	(23.0)

Movement in contingent consideration is as follows:

	30 June 2025 $m	31 December 2024 $m
At beginning of period	**(240.5)**	(296.4)
Payments made	**1.6**	23.0
Fair value remeasurements	**(18.1)**	32.9
At end of period	**(257.0)**	(240.5)

Movement in deferred consideration is as follows:

	30 June 2025 $m	31 December 2024 $m
At beginning of period	**(272.7)**	(63.9)
Additions	**–**	(204.5)
Payments made	**130.0**	–
Accretion	**(7.8)**	(4.3)
At end of period	**(150.5)**	(272.7)

15. Contingent and deferred consideration continued

Cash outflows in the six months ended 30 June 2025 were $131.6 million (year to 31 December 2024: $23.0 million) and comprised mainly an Eni UK deferred consideration payment of $130.0 million.

Changes in fair value of contingent consideration in the six months ended 30 June 2025 relate principally to management's regular reassessment of the likelihood of certain milestones and other events occurring.

16. Financial instruments

Details of valuation methodologies are set out on page 229 of the 2024 Annual Report and Accounts.

All of the Group's assets are pledged as security against borrowings.

The accounting classification of each category of financial instruments and their carrying amounts as at 30 June 2025 are set out below:

	Measured at amortised cost $m	Mandatorily measured at fair value through profit or loss $m	Measured at fair value through other comprehensive income $m	Derivatives designated in hedge relationships $m	Total carrying amount $m
Financial assets					
Cash and cash equivalents	**438.6**	–	–	–	**438.6**
Other financial assets	**11.3**	–	–	–	**11.3**
Trade and other receivables	**437.9**	–	–	–	**437.9**
Investments	–	–	**23.5**	–	**23.5**
Derivative financial instruments	–	**7.2**	–	**277.9**	**285.1**
Financial liabilities					
Borrowings	**(1,096.3)**	–	–	–	**(1,096.3)**
Trade and other payables – excluding deferred income, inventory overlift and bonus/holiday pay accruals	**(588.5)**	–	–	–	**(588.5)**
Lease liability	**(36.3)**	–	–	–	**(36.3)**
Contingent and deferred consideration	**(150.5)**	**(257.0)**	–	–	**(407.5)**
Derivative financial instruments	–	**(0.3)**	–	**(15.7)**	**(16.0)**
					(948.2)

16. Financial instruments continued

The accounting classification of each category of financial instruments and their carrying amounts as at 31 December 2024 are set out below:

	Measured at amortised cost $m	Mandatorily measured at fair value through profit or loss $m	Derivatives designated in hedge relationships $m	Total carrying amount $m
Financial assets				
Cash and cash equivalents	165.1	–	–	165.1
Other financial assets	11.3	–	–	11.3
Trade and other receivables – excluding VAT receivable	411.1	–	–	411.1
Derivative financial instruments	–	–	33.0	33.0
Financial liabilities				
Borrowings	(1,024.9)	–	–	(1,024.9)
Trade and other payables – excluding deferred income, inventory overlift and bonus/holiday pay accruals	(439.7)	–	–	(439.7)
Lease liability	(40.2)	–	–	(40.2)
Contingent and deferred consideration	(272.7)	(240.5)	–	(513.2)
Derivative financial instruments	–	(7.5)	(144.0)	(151.5)
				(1,549.0)

The following table presents the Group's material financial instruments measured at fair value for each hierarchy level as at 30 June 2025:

	Level 1 $m	**Level 2 $m**	**Level 3 $m**	**Total fair value $m**
Contingent consideration	–	–	**(257.0)**	**(257.0)**
Derivative financial instrument asset	–	**285.0**	–	**285.0**
Derivative financial instrument liability	–	**(16.0)**	–	**(16.0)**

Movements in level 3 financial instruments in the six months to 30 June 2025 were as follows:

	$m
At 1 January 2025	(239.3)
Fair value remeasurements	**(17.7)**
At 30 June 2025	**(257.0)**

16. Financial instruments continued

The following table presents the Group's material financial instruments measured at fair value for each hierarchy level as at 31 December 2024:

	Level 1 $m	Level 2 $m	Level 3 $m	Total fair value $m
Contingent consideration	–	(1.2)	(239.3)	(240.5)
Derivative financial instrument asset	–	33.0	–	33.0
Derivative financial instrument liability	–	(151.5)	–	(151.5)

Movements in level 3 financial instruments in the 12 months to 31 December 2024 were as follows:

	$m
At 1 January 2024	(272.3)
Cash settlements	15.0
Fair value remeasurements	18.0
At 31 December 2024	(239.3)

Level 3 contingent consideration is valued on a discounted cash flow basis with the key inputs being commodity prices, the probability of certain future events occurring ('trigger events') and the discount rate.

The forecast cash flows are discounted at a rate of 6.39% (31 December 2024: 6.33%).

Management has considered alternative scenarios to assess the valuation of the contingent consideration including, but not limited to, the key accounting estimate relating to the oil price. A reduction or increase in the price assumptions of 20% are considered to be reasonably possible changes. A 20% reduction in the oil price would result in a decrease in contingent consideration of $nil (31 December 2024: $nil) as the forecast price is already at a level which is lower than the trigger price. A 20% increase in the oil price would lead to an increase in contingent consideration of $6.3 million (31 December 2024: $21.7 million).

The following table summarises the sensitivity of the Group's profit before tax due to changes in the carrying value of level 3 financial instruments at the reporting date resulting from a 20% change in the probability of a trigger event occurring, risking of project and conditions being met for payment of contingent consideration, with all other variables held constant. The impact on equity is the same as the impact on profit before tax.

Change in probability	**30 June 2025 $m**	31 December 2024 $m
20% decrease in probability	**78.4**	84.2
20% increase in probability	**(62.4)**	(77.1)

The following table summarises the sensitivity of the Group's profit before tax due to changes in the carrying value of level 3 financial instruments at the reporting date resulting from a 1% decrease in discount rate, with all other variables held constant. The impact on equity is the same as the impact on profit before tax.

Change in discount rate	**30 June 2025 $m**	31 December 2024 $m
1% decrease in discount rate	**(5.0)**	(5.7)

A 1% increase in discount rate would broadly have the equal but opposite effect to the amounts shown above, on the basis that all other variables remain constant.

16. Financial instruments continued

The table below presents the gains or losses on financial instruments that have been recognised in the condensed consolidated statement of profit or loss as disclosed in note 6.

	Three months ended 30 June		Six months ended 30 June	
	2025 $m	2024 $m	**2025 $m**	2024 $m
Revaluation of forex forward contracts	**8.9**	8.3	**14.3**	(0.8)
Revaluation of interest rate swaps	–	–	–	(0.7)
Revaluation of commodity hedges	–	0.9	–	2.3
Total revaluation gains on financial instruments	**8.9**	9.2	**14.3**	0.8
Realised losses on forex forward contracts	**(0.1)**	(1.6)	**(1.9)**	(1.5)
Realised gains on interest rate swaps	–	–	–	0.6
Realised losses on commodity hedges	–	(1.0)	–	(1.6)
Total gains/(losses) on financial instruments	**8.8**	6.6	**12.4**	(1.7)

Cash flow hedge reserve

The table below presents the movements in financial instruments that have been recognised through the condensed consolidated statement of comprehensive income relating to the cash flow hedge reserve:

	Three months ended 30 June		Six months ended 30 June	
Cash flow hedge reserve	**2025 $m**	2024 $m	**2025 $m**	2024 $m
At beginning of period	**12.0**	23.2	**(15.7)**	39.8
Change in fair value of derivative instruments	**196.0**	(20.3)	**313.0**	(14.0)
Amounts recycled to revenue	**(31.0)**	(24.5)	**(22.6)**	(97.2)
Amounts recycled to operating costs	**(4.5)**	(2.4)	**(3.8)**	(2.5)
Amounts recycled to dividends	**(4.1)**	–	**(4.1)**	–
Amount per the condensed consolidated statement of comprehensive income	**156.4**	(47.2)	**282.5**	(113.7)
Deferred tax on movement in period	**(122.0)**	31.2	**(220.4)**	81.1
Cash flow hedge reserve at 30 June	**46.4**	7.2	**46.4**	7.2

16. Financial instruments continued

Cost of hedging reserve

The table below presents the movements in financial instruments that have been disclosed through the condensed consolidated statement of comprehensive income relating to the cost of hedging reserve:

Cost of hedging reserve	Three months ended 30 June 2025 $m	Three months ended 30 June 2024 $m	Six months ended 30 June 2025 $m	Six months ended 30 June 2024 $m
At beginning of period	**1.4**	1.3	**(9.1)**	4.1
Change in fair value of the intrinsic value of derivative instruments	**39.2**	(5.7)	**87.1**	(17.0)
Amounts recycled to revenue – premium payments on oil derivative contracts	**–**	0.3	**–**	0.6
Amounts recycled to revenue – premium payments on gas derivative contracts	**0.1**	1.1	**0.1**	1.2
Amount per the condensed consolidated statement of comprehensive income	**39.3**	(4.3)	**87.2**	(15.2)
Deferred tax on movement in period	**(30.6)**	1.5	**(68.0)**	9.6
Cost of hedging reserve at 30 June	**10.1**	(1.5)	**10.1**	(1.5)

17. Derivative financial instruments

The net carrying amount of each category of derivative is set out below:

	30 June 2025 $m	31 December 2024 $m
Oil swaps – cash flow hedge	**47.3**	19.8
Oil collars – cash flow hedge	**19.0**	6.6
Gas swaps – cash flow hedge	**64.3**	(49.5)
Gas collars – cash flow hedge	**52.2**	(81.2)
FX forwards – cash flow hedge	**18.1**	0.2
FX forwards – non-cash flow hedge	**1.2**	(7.5)
FX collars – cash flow hedge	**66.9**	(6.9)
	269.0	(118.5)

Maturity analysis of derivative financial instruments	30 June 2025 $m	31 December 2024 $m
Non-current assets	**165.1**	–
Current assets	**119.9**	33.0
Non-current liabilities	**(11.4)**	(21.0)
Current liabilities	**(4.6)**	(130.5)
	269.0	(118.5)

Derivative financial instruments that are with counterparties included within the RBL are subject to Master Netting Agreements, this includes the majority of the Group's derivative financial instruments as at 30 June 2025 and 31 December 2024.

17. Derivative financial instruments continued

The terms of the Master Netting Arrangements create a legally enforceable right of offset that comes into effect only on the occurrence of a specified event of default or termination event or other events not expected to happen in the normal course of business. Although the Group has the ability to net settle certain transactions with certain counterparties where an election has been made, this is not considered to be significant at 30 June 2025 or 31 December 2024. Accordingly, the Group has not offset any derivatives balances in the statement of financial position in any of the periods presented.

18. Related-party transactions

The immediate parent undertaking is DKL Energy Limited (incorporated in Jersey), which owns 52.2% (31 December 2024: 52.2%) of the issued share capital of Ithaca Energy plc. The registered office address of DKL Energy Limited is 47 Esplanade, St Helier, JE1 0BD, Jersey.

Eni UK Limited, an indirect wholly owned subsidiary of Eni S.p.A., owns 37.2% (31 December 2024: 37.2%) of the issued share capital of Ithaca Energy plc.

Transactions between the company and its subsidiaries, which are related parties, have been eliminated on consolidation and are not disclosed in this note. There have been no significant changes to related party transactions since 31 December 2024, with the exception of:

- Amounts owed to related parties decreased, on an undiscounted basis, by $130.0 million of deferred consideration payments made in Q1 2025; and
- Sales to related parties in the six months to 30 June 2025 amounted to $434.7 million.

Further details of related-party transactions are set out in note 32 of the 2024 Annual Report and Accounts.

The ultimate parent of the Group is Delek Group Limited (incorporated in Israel), an independent E&P Company listed on the Tel Aviv Stock Exchange. The Group and Delek's ultimate controlling party is Mr Itshak Sharon Tshuva.

There were no related-party transactions with Delek Group Limited or Mr Tshuva in either the period ended 30 June 2025 or the period ended 30 June 2024.

19. Subsequent events

The acquisition of 100% of the issued share capital of JAPEX UK E&P Limited ('JUK') completed on 7 July 2025 for a total consideration of $156.4 million, thereby increasing the Group's working interest in the Seagull field from 35% to 50%. The quantification of the fair value of the acquired JUK assets and liabilities is ongoing.

Alternative performance measures

Non-GAAP measures

The Group uses certain performance metrics that are not specifically defined under United Kingdom-adopted International Financial Reporting Standards or other generally accepted accounting principles. These measures are considered to be important as they track both operational and financial performance, and are used to manage the business and to provide an objective comparison to Ithaca Energy's peer group. These non-GAAP measures, which are presented in the H1 2025 condensed consolidated financial statements, are set out below.

Adjusted EBITDAX: earnings before finance income, finance costs, taxation charges, premium payments on oil and gas derivative contracts, restructuring costs, revaluation gains or losses on financial instruments, depletion depreciation and amortisation, impairment charges on development and production assets, exploration and evaluation expenses and fair value remeasurements of contingent consideration. The Group believes that adjusted EBITDAX is a useful measure for stakeholders because it is a measure closely tracked by management to evaluate the Group's operating performance and to make financial, strategic and operating decisions, and because it may help stakeholders to better understand and evaluate, in the same manner as management, the underlying trends in the Group's operational performance on a comparable basis, period-on-period.

Adjusted EBITDAX is reconciled to (loss)/profit for the period as follows:

	Six months ended 30 June	
	2025 $m	2024 $m
(Loss)/profit for the period	**(217.5)**	105.7
Taxation charge (note 12)	**730.9**	83.7
Depletion, depreciation and amortisation (note 5)	**438.9**	252.9
Impairment charges on development and production assets	**30.2**	35.5
Finance income (note 7)	**(2.7)**	(4.5)
Finance costs (note 7)	**129.8**	84.8
Premium payments on oil and gas derivative contracts (note 4)	**0.1**	1.6
Restructuring costs	**6.9**	–
Revaluation gains on financial instruments (note 16)	**(14.3)**	(0.8)
Exploration and evaluation expenses (note 10)	**0.1**	1.5
Fair value remeasurements of contingent consideration (note 6)	**14.6**	(27.4)
Adjusted EBITDAX	**1,117.0**	533.0

Adjusted net income: profit after tax excluding non-cash impairment charges and restructuring costs, the tax effect of these items and one-off, non-cash deferred tax charges arising on changes to EPL. Adjusted net income, which is presented as it eliminates items which distort period-on-period comparisons, is reconciled to (loss)/profit for the period as follows:

	Six months ended 30 June	
	2025 $m	2024 $m
(Loss)/profit for the period	**(217.5)**	105.7
Impairment charges on development and production assets	**30.2**	35.5
Tax credit on impairment charges	**(13.1)**	(16.5)
Restructuring costs	**6.9**	–
Tax credit on restructuring costs	**(5.4)**	–
One-off, non-cash deferred tax charge for two-year extension of the 38% EPL rate to 31 March 2030	**327.6**	–
Adjusted net income	**128.7**	124.7

Adjusted basic earnings per share (EPS): Adjusted net income divided by average shares for the period of 1,648.1 million (H1 2024: 1,006.6 million).

	Six months ended 30 June	
	2025	2024
Adjusted basic EPS (cents)	**7.8**	12.4

Adjusted net debt: consists of amounts outstanding under RBL facility, senior unsecured loan notes and project capital expenditure facility less cash and cash equivalents, and excludes intragroup debt arrangements or liabilities represented by letters of credit and surety bonds. Adjusted net debt, which excludes accrued interest on borrowings, lease liabilities and unamortised fees, comprises:

	30 June 2025 $m	31 December 2024 $m
RBL drawn facility	**(210.0)**	(150.0)
Senior unsecured notes	**(750.0)**	(750.0)
Project capital expenditure facility	**(150.0)**	(150.0)
Cash and cash equivalents	**438.6**	165.1
Adjusted net debt	**(671.4)**	(884.9)

Pro forma leverage ratio: adjusted net debt at the end of the period divided by pro forma adjusted EBITDAX for the preceding 12 months including $130.1 million of adjusted EBITDAX generated by the Eni UK businesses from 1 July 2024 to 2 October 2024 (year to 31 December 2024: including $580.3 million of adjusted EBITDAX from the Eni UK businesses from 1 January 2024 to 2 October 2024). The pro forma leverage ratio is considered to be an important measure as it is indicative of the borrowing potential of the Group. The calculations are as follows:

	30 June 2025 $m	31 December 2024 $m
Adjusted net debt ($m)	**671.4**	884.9
Pro forma adjusted EBITDAX ($m)	**2,119.1**	1,985.3
Pro forma leverage ratio	**0.32x**	0.45x

Pro forma EBITDAX comprises:

	30 June 2025 $m	31 December 2024 $m
EBITDAX year ended 31 December 2024	**1,405.0**	1,405.0
EBITDAX H1 2025	**1,117.0**	–
EBITDAX H1 2024	**(533.0)**	–
Eni UK EBITDAX	**130.1**	580.3
	2,119.1	1,985.3

Available liquidity: the sum of cash and cash equivalents on the balance sheet and the undrawn amounts available to the Group using existing approved third-party facilities, excluding letters of credit. Available liquidity is regarded as a key measure as it is indicative of the financial capacity of the Group. Available liquidity comprises:

	30 June 2025 $m	31 December 2024 $m
Cash and cash equivalents	**438.6**	165.1
Undrawn borrowing facilities	**790.0**	850.0
Available liquidity	**1,228.6**	1,015.1

Group free cash flow: net cash flow from operating activities less cash used in investing activities, adjusting for cash acquired through business combinations, less bank interest and charges and interest rate swaps. This measure is considered a useful indicator of the Group's ability to make strategic investments, repay the Group's debt and meet other payment obligations. Group free cash flow reconciles to net cash flow from operating activities as follows:

	Six months ended 30 June	
	2025 $m	2024 $m
Net cash flow from operating activities	**1,004.6**	559.8
Net cash used in investing activities	**(539.6)**	(229.4)
Bank interest and charges	**(48.9)**	(41.9)
Interest rate swaps	–	(0.6)
Group free cash flow	**416.1**	287.9

Unit operating expenditure: operating costs (excluding over/underlift) including tariff expense but excluding restructuring costs and tanker costs and net of tariff income, divided by net production for the period. This measure is considered a useful indicator of ongoing operating costs and is also used to compare performance between assets. Operating costs for this calculation are as follows:

	Six months ended 30 June	
	2025	2024
Operating costs of hydrocarbon activities per note 5 ($m)	**421.4**	282.2
Less restructuring costs ($m)	**(3.9)**	–
Less tanker costs included within operating costs of hydrocarbon activities ($m)	**(10.6)**	(9.1)
Less tariff income ($m)	**(15.6)**	(9.8)
Operating costs used to calculate unit operating expenditure ($m)	**391.3**	263.3
Production (mmboe)	**22.37**	9.65
Unit operating expenditure ($/boe)	**17.5**	27.3

Other key performance indicators

DDA rate per barrel: depletion, depreciation and amortisation charge for the period divided by net production for the period. DDA per barrel was:

	Six months ended 30 June	
	2025	2024
Depletion, depreciation and amortisation ($m)	**438.9**	252.9
Production (mmboe)	**22.37**	9.65
DDA ($/boe)	**19.6**	26.2

Production: total hydrocarbons produced related to Ithaca Energy's equity in operated and non-operated fields divided by the number of days in the period. Production in H1 2025 was 123,566 boe/d (H1 2024: 53,046 boe/d).

Tier 1 and 2 process safety events: process safety incidents as defined by API 465 Process Safety-Recommended Practice On Key Performance Indicators. There were no Tier 1 or 2 process safety events recorded in H1 2025 (H1 2024: 0).

Serious injury and fatality frequency: the number of serious injuries resulting in permanent impairment, as defined by IOGP, per million hours worked. There were no such incidents in H1 2025 (H1 2024: 0).