THIS ANNOUNCEMENT CONTAINS INSIDE INFORMATION

22 September 2021

IGas Energy plc (AIM: IGAS)

("IGas" or "the Company" or "the Group")

Unaudited Interim results for the six months ended 30 June 2021

IGas announces its unaudited interim results for the six months to 30 June 2021.

Results Summary

	Six months to 30 June 2021 £m	Six months to 30 June 2020 £m
Revenues	**16.6**	10.5
Adjusted EBITDA*	**2.7**	2.2
Loss after tax – continuing activities	**(12.2)**	(30.0)
Operating cash flow before working capital movements and realised hedges*	**6.4**	(1.4)
Net debt* (excluding capitalised fees)	**13.2**	11.2
Cash and cash equivalents	**2.8**	2.6

*these are alternative performance measures which are further detailed in the financial review

Corporate & Financial Summary

- Cash balances as at 30 June 2021 were £2.8 million (H1 2020: £2.6 million) with net debt of £13.2 million (H1 2020: £11.2 million).
- £2.6 million of capex incurred during six months to 30 June 2021. Net cash capex for FY 2021 expected to be £5.6 million, primarily relating to our conventional assets.
- Operating cash flow before working capital movements and realised hedges in H1 2021 of £6.4 million (H1 2020: cash outflow £1.4 million).
- Successful Reserve Based Lending facility (RBL) redetermination in June (a semi-annual recalculation), confirming US$27 million (£19.5 million) of debt capacity and headroom of US$8.8 million (£6.4 million).
- Hedging in place for H2 2021 of 190,800 bbls using swaps and collars. Average price including collar upside of c.$49/bbl. 126,000 bbls are currently hedged in 2022 using swaps at an average price of $63/bbl and 114,000 bbls using puts with an average guaranteed minimum price, net of premiums, of $44/bbl. The RBL requires IGas to hedge c.50% of the next twelve months' production on a rolling basis.

Operational Summary

- Net production averaged 2,005 boepd in H1 2021 (H1 2020: 1,940 boepd) with operations, maintenance and project activities all being directly and indirectly impacted by COVID-19. Excluding the total COVID-19 impact in H1 2021, which averaged c.180 boepd, production in H1 2021 would have been 2,185 boepd.
- Full year net production is now forecast to be c.2,000 boepd, with underlying cash operating costs per boe anticipated to be c.$38/boe (based on an exchange rate of £1:$1.39).
- Material progress on deep geothermal
  - Planning approval received for Stoke-on-Trent and MoU with SSE to deliver the heat network
  - Constructive discussions with Government in respect of downstream financial support. In addition, there has been a geothermal Ministerial roundtable and a Westminster Hall Debate – on 'Opportunities for geothermal energy extraction.'

- MoU signed with CeraPhi to jointly develop geothermal energy projects which repurpose and utilise IGas's existing wells and other infrastructure and use CeraPhi's patented technology, CeraPhiWell, a closed loop downhole heat exchanger.
- The planning applications for the Albury and Bletchingley hydrogen projects have been submitted and validated by Surrey County Council.
- Full CPR published in February 2021: 2P reserves replacement ~ 250% (1P ~275%)
    - 1P NPV10 of $150 million: 2P NPV10 of $204 million*

**based on forward oil curve of: 2021 $53/bbl; 2022 $56/bbl; 2023 $58/bbl; 2024 $59/bbl; 2025 $62/bbl (for full price deck see CPR).*

Commenting today Stephen Bowler, Chief Executive Officer, said:

"The health, safety, societal and economic impacts of the COVID-19 pandemic have presented a unique set of challenges for our production business. Despite these challenges, production remains robust. We continue to focus our technical and operational expertise on offsetting the underlying natural decline in our fields through the execution of incremental production opportunities that demonstrate commercial benefit via our delivery assurance processes.

The Group's existing operational expertise as the UK's largest onshore operator gives us the opportunity to use our existing business platform to play an important role in the UK's transition to net zero. Our sub-surface expertise is relevant both to drilling for geothermal resources, and assessing the potential for carbon capture and storage. We have extensive experience of dealing with onshore regulators and planning authorities. We have predictable operating cash flows to help fund new initiatives and assets to repurpose in a readily accessible onshore environment.

We have progressed our low-carbon projects during the period. We have submitted planning applications to produce hydrogen from two existing sites in Surrey – Albury and Bletchingley. Should we be successful in developing these blue hydrogen projects, IGas is on track to produce the UK's first blue hydrogen ahead of other, refinery scale projects. This demonstrates that small-scale, distributed hydrogen production will allow blue hydrogen to be offered to the market rapidly and will build resilience into new energy networks.

In geothermal, the Stoke-on-Trent project could be the first in a new generation of British-backed heat plants. It will support the decarbonisation of heat, move us along the path to net zero and help tackle climate change. Whilst we await the necessary Government support for the Stoke-on-Trent project, we are receiving an increasing number of enquiries from local councils and other large-scale users of heat.

We believe there is significant commercial potential for geothermal energy production and the development of localised hybrid energy systems generating both heat and power."

A results presentation will be available at http://www.igasplc.com/investors/presentations.

Qualified Person's Statement

Ross Pearson, Technical Director of IGas Energy plc, and a qualified person as defined in the Guidance Note for Mining, Oil and Gas Companies, March 2006, of the London Stock Exchange, has reviewed and approved the technical information contained in this announcement. Mr Pearson has 20 years oil and gas exploration and production experience.

For further information please contact:

IGas Energy plc
Tel: +44 (0)20 7993 9899
Stephen Bowler, Chief Executive Officer

Ann-marie Wilkinson, Director of Corporate Affairs

Investec Bank plc (NOMAD and Joint Corporate Broker)
Tel: +44 (0)20 7597 5970
Sara Hale/Jeremy Ellis/Virginia Bull

Canaccord Genuity (Joint Corporate Broker)
Tel: +44 (0)20 7523 8000
Henry Fitzgerald-O'Connor/James Asensio

Vigo Consulting
Tel: +44 (0)20 7390 0230
Patrick d'Ancona/Chris McMahon/Kendall Hill

Introduction and Market Backdrop

Whilst the rebound in oil prices since the start of the year hitting highs of c.$75/bbl has been driven by a mixture of some early economic recovery and continued production restraint by OPEC+, the spectre of COVID-19 mutations in many major economies and pace of vaccine roll-outs could still impact oil demand growth in the second half of 2021.

Having said that, world demand for crude is stronger than it was last year and the International Energy Agency anticipates that by the end of 2022 consumption will rise by about 5% from 2020 levels. In the longer term, the lack of commitment in investment by the oil majors will also put upward pressure on prices but ultimately the balance between these factors will depend on OPEC's future decisions on output.

Natural gas prices in Europe and the UK have also been very strong recently. In the UK, prices have risen to over 100p/therm, a record for summer months as global supplies have tightened as economies rebound from the COVID-19 pandemic. High prices in Asia also make it harder for Europe to attract cargoes of liquefied natural gas, and Europe's stock levels remain low.

Against this backdrop and the ongoing challenges of the COVID-19 pandemic on our business, we have continued to pursue our strategy of maximising our UK onshore production whilst exposing shareholders to value creating opportunities in the energy transition space, principally through geothermal and hydrogen.

The increase in the oil price in recent months has been a welcome boost to revenue and cash generation and following the cost reduction exercises implemented last year, we have continued to tightly manage our finances. We have also successfully completed the scheduled six-monthly RBL facility redetermination process. The redetermination exercise confirmed US$27.0 million (£19.5 million) of debt capacity and headroom of US$8.8 million (£6.4 million) at 30 June 2021.

Throughout the pandemic, the health and safety of all staff and contractors across our operations has been, and remains, our priority while ensuring that the business continues to operate safely and effectively.

As detailed in our 2020 Annual Report, we are now reporting Scope 1 and 2 emissions under the SECR disclosure and are reviewing our energy consumption with the aim of delivering ongoing reductions in emissions and further reducing our emissions intensity ratio. As part of our efforts to strengthen our ESG performance, IGas continues its commitment to the UN Sustainable Development Goals and has recently committed to the UN Global Compact's 10 Principles on human rights, labour standards, the environment, and anti-corruption. We continue to support the communities in which we operate through investment in local projects.

The Committee on Climate Change (CCC) acknowledges that oil and gas will be important contributors to the UK's energy needs for many years to come and that there will be a structural shortage in supply. In their March 2021 assessment of the compatibility of onshore oil and gas with the UK's net zero target, the CCC stated that UK shale gas production could save up to 11.5 million tonnes of CO_2 equivalent (CO_2e) in the year 2035 alone. Based on analysis of the shortfall between supply and demand using the same method as the CCC, the failure to develop onshore natural gas resources in the UK will add up to 145 million tonnes CO_2e to the UK's fuel supply carbon footprint by 2050.

Production operations

Net production for the period averaged 2,005 boepd. The health, safety, societal and economic impacts of the COVID-19 pandemic have presented a unique set of challenges for our production business. There are both direct and indirect consequences of managing the effects of the virus, some of which have immediate impact and others that are extended over longer periods. We have identified three key drivers to "COVID-19 related" production deferral; Internal Resourcing, External Resourcing & External Supply Chain, and our analysis of the production impact during the period has shown fluctuations on a month-by-month basis. The average impact for the six month period was c.180 boepd and in light of this, we have revised our full year forecast to anticipate net production of c.2,000 boepd. Encouragingly, we have observed an improving downward trend in disruption as the UK pandemic situation has improved, though we recognise that there are still inherent risks ahead and the uncertainty will continue for at least the remainder of the year.

Despite these challenges, we continue to focus our technical and operational expertise on offsetting the underlying natural decline in our fields through the execution of incremental production opportunities that demonstrate commercial benefit via our delivery assurance processes. Artificial lift optimisation remains a key continuous improvement objective in terms of cost management and production enhancement, with routine dynamic optimisation activities and specific intervention works sanctioned. This has included the introduction of innovative scale management technology, artificial lift type conversions, rod string improvements, rod pump deepening plus the expansion of the beam-gas compressor systems across more fields. In addition, we have continued to invest in our facilities to drive operational improvements such as replacing older power generation systems with newer, more efficient versions and the continued expansion and modernisation of our instrumentation systems.

In February 2021, we announced the publication of a CPR by DeGolyer & MacNaughton (D&M), a leading international reserves and resources auditor.

The report comprised an independent evaluation of IGas' conventional oil and gas interests as of 31 December 2020. The full report can be found on the IGas website www.igasplc/investors/publications-and-reports

IGas Group Net Reserves & Contingent Resources as at 31 December 2020 (MMboe)

	1P	**2P**	**2C**
Reserves & Resources as at 31 December 2019	10.55	16.05	19.51
Production during the period	(0.68)	(0.68)	-
Revision of estimates	1.87	1.75	0.84
Reserves & Resources as at 31 December 2020	**11.74**	**17.12**	**20.35**

The report confirms a continuing high reserves replacement of 2P reserves of approximately 250% reflecting the good performance of our production assets and progression of projects demonstrating the significant upside that remains in our conventional portfolio. Some 85% of the 2P is developed meaning it does not require any capital investment to produce.

IGas has a track record of significant reserves replacement with a three-year average of over 200%.

This independent report valued our conventional assets at c.$204 million on a 2P NPV10 basis: 1P NPV10 of $150 million (based on forward oil curve of 2021 $53/bbl; 2022 $56/bbl; 2023 $58/bbl; 2024 $59/bbl; 2025 $62/bbl).

Development assets

Petroleum

The Welton (C-1) waterflood project was brought online in Q2 2021 and completed on budget with good results as anticipated, injecting an average of c.400 bbls/d of water which is expected to increase field recovery by approximately 660 Mbbls adding over 100 bopd incremental production which will be realised in 2022. Scampton North is on the lower end of expectation encountering higher than anticipated injection pressure, injecting c. 90 bbls/d of water. Work is ongoing to resolve the lower injection rates and higher pressure but even at lower than expected results it is still anticipated to increase ultimate field recovery. These projects not only add incremental value but also improve environmental impact by reducing emissions and reducing vehicle movements in water handling.

A permit application has been submitted to convert an existing, suspended well in the Stockbridge field to a water disposal well; this will allow for the resumption of c. 50 bbls/d of suspended production to be brought back on line. The project will also provide more operational flexibility in handling produced water in the Stockbridge area. This work is anticipated to be completed in early 2022.

Energy Diversification

We continue to evaluate the viability of enhancing our UK sites to include renewable energy. It is feasible that a number of our UK sites could become integrated hybrid energy hubs, encompassing combinations of solar, modular hydrogen, Carbon Capture, Utilisation and Storage (CCUS) and battery storage.

Geothermal

Good progress is being made in developing our UK geothermal business. We have now received planning approval for the Stoke-on-Trent project from both Stoke-on-Trent City Council and Newcastle-under-Lyme. We have signed a Memorandum of Understanding (MoU) with SSE Heat Networks Limited (SSE) for roll-out of geothermal district heating project in Stoke. The MoU grants exclusivity to each of SSE and GTE with regard to the project for a period of 12 months with certain milestones including executing a heat offtake agreement in relation to GTE's future geothermal plant. . We are in dialogue with the Government regarding grant funding to support the project - which has public backing from the council and the Staffordshire Chamber of Commerce – to provide renewable heat to the Stoke heat network.

We continue to have positive discussions with the Government regarding future financial support for the UK geothermal industry. A working group with the Department for Business, Energy and Industrial Strategy (BEIS) has been established to look at the policy gap for non-domestic renewable heat and a financial model for the long-term support of deep geothermal heat. We still await publication of the delayed BEIS Heat and Building Strategy.

In April 2021, a new industry report on the economic and environmental importance of UK deep geothermal resources by the ARUP Group and the Association for Renewable Energy and Clean Technology (REA) was published. The Report estimates that, with immediate government support, the UK could deliver 360 geothermal projects by 2050. This would include an estimated 12 projects being operational by 2025 with 1,300 jobs created and c.£100 million of investment flowing into the UK economy. The full report can be found at https://www.igasplc.com/investors/publications-and-reports

The Committee on Climate Change stated that only decarbonisation of heat in the UK could deliver the major reduction in emissions needed to meet the 2050 net zero target. By delivering on average 12 heat projects per year over the next three decades, the UK could expect to generate up to 15,000 GW hours (GWh) of heat from geothermal, annually by 2050.

As local authorities and other large-scale users of heat transition away from fossil fuels we are receiving an increasing number of enquiries looking to geothermal as a solution and through this growing pipeline of development opportunities, IGas is well positioned to deliver a solution to the long-term decarbonisation for heat in the UK.

Hydrogen

Significant work has been undertaken in order to understand the potential for low carbon energy production from our existing asset base. This has resulted in the recent planning applications to produce hydrogen from two existing sites in Surrey – Albury and Bletchingley.

At Albury, we have now submitted a planning application that has been validated by Surrey County Council to install a hydrogen generation system on the existing site. The steam methane reformation (SMR) unit will generate 1000kg/day of hydrogen.

A second application at our existing Bletchingley site was submitted in late August. This is a bigger project involving two SMR units with initial generation of 2000kg/day and a potential of up to 6000kg/day depending on reserves.

The projects are being developed in phases, the first phase being to establish the principle of hydrogen production at the sites. The second, to produce blue hydrogen, is now being accelerated following positive feedback from key regulators and interest from local communities.

Discussions with potential offtakers are taking place for both projects.

Shale

Discussions are ongoing with partners and regulators in respect to the effective moratorium on shale albeit impacted by COVID-19 priorities. We believe we can demonstrate that we can operate safely and environmentally responsibly.

As imports continue to rise and the need for gas and in particular, methane for hydrogen, has been made clear by the Committee on Climate Change, the safe development of shale could play a critical role in the UK's energy transition and in the creation of jobs and wealth to a number of key areas.

The Springs Road well proved that the Gainsborough Trough has a world-class resource and therefore could be part of that solution, producing indigenous gas, providing many skilled jobs and all at lower emissions than imported gas. We still believe the Springs Road site is of national importance and we therefore applied to extend the operational period of the site for a further three years while discussions continue with the UK Government and regulators. In July 2021, despite a recommendation by the Planning Officer, the planning committee at Nottinghamshire County Council voted against the extension. We are considering our options along with our partners including our right to bring forward an appeal.

We still await a decision on our appeal at Ellesmere Port now over two years since the appeal was recovered by the Secretary of State and 50 months since the initial application.

Financial review

The Group generated revenue of £16.6 million in the first six months of 2021 from sales of 330,984 barrels of oil, including sales of third party oil, 7,112 Mwh of electricity and 1,247,946 therms of gas (H1 2020: revenue £10.5 million, sales of 335,687 barrels of oil, 4,411 Mwh of electricity and 966,445 therms of gas). The higher revenue was driven by the improvement in Brent prices, which averaged $64.9/bbl during H1 2021 compared to $39.1/bbl in H1 2020 as a result of OPEC constraining supply and increased demand as economies started to recover from the impacts of the COVID-19 pandemic. This was offset by a strengthening of sterling versus the US dollar with an average USD/GBP rate of $1.39/£1 in H1 2021 compared to $1.28/£1 in H1 2020. The Group incurred a realised loss on oil price hedges with 208,800 bbls hedged for H1 2021 at an average price of $44.5/bbl.

Adjusted EBITDA for H1 2021 was £2.7 million (H1 2020: £2.2 million) and the loss after tax from continuing activities was £12.2 million (H1 2020: loss of £30.0 million). The main factors explaining the movements between H1 2021 and H1 2020 were as follows:

- Revenues of £16.6 million (H1 2020: £10.5 million) were higher than the first half of 2020 due to higher oil prices as described above;
- DD&A decreased to £2.4 million (H1 2020: £3.5 million) mainly due to the lower carrying value of assets in 2021 following the impairment to oil and gas properties in 2020;
- Operating costs decreased to £8.6 million (H1 2020: £9.3 million). The decrease was mainly due to lower transportation costs, lower rates and licence fee costs and reduced staff costs as a result of the cost saving measures implemented in 2020. These savings were partially offset by increased workover activity and an increase in electricity costs;
- Administrative expenses decreased to £2.3 million (H1 2020: £2.8 million) primarily due to a reduction in staff costs as part of cost saving measures implemented in 2020 offset by a lower allocation to capital projects;
- Exploration and evaluation assets of £10.1 million were written off during the year primarily relating to PEDL 200 which was relinquished during the year and the impairment of capitalised decommissioning assets relating to previously written off licences (H1 2020: nil). An impairment of £nil (H1 2020: £34.6 million) was recognised on oil and gas assets during the period;

- A loss was recognised on oil price derivatives of £5.4 million (H1 2020: £4.8 million gain) mainly due to lower hedged prices and an increase in the Brent benchmark;
- Decreased net finance costs of £1.8 million (H1 2020: £3.4 million) due to gains on foreign exchange and a lower unwinding of discount on provisions; and
- A tax credit of £1.9 million (H1 2020: credit £8.1 million) principally due to movement in deferred tax relating to the value of recognised tax losses available for offset against future taxable profits and an increase in the tax rate substantially enacted during the period for non-ring-fenced profits to 25%.

Income statement

The Group recognised revenues of £16.6 million in the period (H1 2020: £10.5 million). Group production in the period averaged 2,005 boepd (H1 2020: 1,940 boepd). Oil sales were 322,199 barrels (excluding third party sales), with 7,112 Mwh of electricity and 1,247,946 therms of gas sold (H1 2020: 318,751 barrels; 4,411 Mwh of electricity and 966,445 therms of gas sold). Revenues for the period also included £0.4 million (H1 2020: £0.5 million) relating to the sale of third party oil, the bulk of which is processed through our gathering centre at Holybourne in the Weald Basin.

The average realised price for the period pre-hedge (excluding third party sales) was $63.4/bbl (H1 2020: $36.7/bbl) and post hedge $51.6/bbl (H1 2020: $50.0/bbl). The average exchange rate for the period was £1:$1.39 (H1 2020: £1:$1.28) which partially offset the positive impact on revenues as a result of increased prices compared to H1 2020.

Cost of sales for the period was £11.0 million (H1 2020: £12.9 million) including depreciation, depletion and amortisation (DD&A) of £2.4 million (H1 2020: £3.5 million), and operating costs of £8.6 million (H1 2020: £9.3 million). Operating costs include £0.4 million (H1 2020: £0.5 million) in relation to processing third party oil. The net contribution received from processing third party oil was £nil (H1 2020: £nil). Operating costs were £0.7 million lower than the prior period, due to lower transportation costs, lower rates and licence fee costs and reduced staff costs as a result of the cost saving measures implemented in 2020. These savings were partially offset by increased workover activity and an increase in electricity costs. Underlying operating costs per boe were £24.8 ($34.4), excluding the cost of third party sales (H1 2020: £27.0 ($34.5)).

Adjusted EBITDA in the period was £2.7 million (H1 2020: £2.2 million). A gross profit of £5.6 million was recognised in the period (H1 2020: loss of £2.4 million).

Administrative costs decreased by £0.5 million to £2.3 million (H1 2020: £2.8 million) principally due to lower staff and office costs as a result of cost savings measures implemented in 2020 partially offset by a lower allocation of costs to capital projects.

Exploration costs written off in H1 2021 were £10.1 million (H1 2020: £nil) primarily relating to PEDL 200 which was relinquished during the year and the impairment of capitalised decommissioning assets relating to previously written off licences. As part of our ongoing active portfolio management we continually review our acreage positions and will relinquish non-core or uneconomic acreage.

Management has not identified any impairment indicators for oil and gas assets for the period to 30 June 2021 (H1 2020: impairment of £34.6 million). See note 10 for further details.

Net finance costs were £1.8 million in the period (H1 2020: £3.4 million), including interest on borrowings of £0.6 million (H1 2020: £0.7 million), unwinding of provisions discount £0.9 million (2020: £2.0 million) and a net foreign exchange gain of £0.1 million (H1 2020: loss of £0.4 million). The net cost also includes £0.3 million (H1 2020: £0.3 million) relating to the finance charge on lease liabilities.

The Group recognised a tax credit of £1.9 million (H1 2020: credit £8.1 million) during the period primarily due to movement in deferred tax relating to the value of recognised tax losses available for offset against future taxable profits and an increase in the tax rate substantially enacted during the period for non-ring fenced profits to 25%.

Cash flow

Net cash generated from operations before working capital movements in the period amounted to £3.7 million (H1 2020: £1.9 million). The Group invested £2.6 million across its asset base in the period (H1 2020: £4.9 million). £1.7 million (H1 2020: £3.5 million) was invested in conventional assets, primarily on the Scampton North waterflood, Welton water injection and other projects to optimise existing facilities and systems, including beam pump installations. £0.8 million (H1 2020: £1.4 million) was invested primarily in working up additional exploration opportunities on conventional assets.

IGas made a net drawdown of £1.4 million ($2.0 million) of principal on borrowings under the RBL facility (H1 2020: net repayment of £1.4 million ($2.0 million)) in accordance with the terms of the facility.

IGas paid £0.5 million ($0.6 million) in interest (H1 2020: £0.5 million ($0.6 million)). Repayment of obligations under leases was £0.8 million (H1 2020: £1.6 million).

Cash and cash equivalents were £2.8 million at the end of the period (31 December 2020: £2.4 million).

Balance sheet

Net assets were £61.9 million at 30 June 2021 (31 December 2020: £73.3 million). The decrease related primarily to the write-off of exploration and evaluation assets.

Shareholder's equity decreased by £11.4 million to £61.9 million (31 December 2020: £73.3 million).

Non-IFRS measures

The Group uses non-IFRS measures of performance that are not specifically defined under IFRS or other generally accepted accounting principles. The non-IFRS measures include net debt, adjusted EBITDA, underlying cash operating costs and operating cash flow before working capital movements and realised hedges, which are considered by the Company to be useful additional measures to help understand underlying performance.

Net Debt

Net debt, being borrowings excluding capitalised fees less cash and cash equivalents, increased to £13.2 million at 30 June 2021 (31 December 2020: £12.2 million; 30 June 2020: £11.2 million). The Group's definition of net debt does not include the Group's lease liabilities.

	Six months ended 30 June 2021	Six months ended 30 June 2020	Year ended 31 December 2020
	£m	£m	£m
Debt (nominal value excluding capitalised expenses)	**(16.0)**	(13.8)	(14.6)
Cash and cash equivalents	**2.8**	2.6	2.4
Net Debt	**(13.2)**	(11.2)	(12.2)

Adjusted EBITDA

Lease costs for the period which have been capitalised under IFRS 16 have been added to underlying cash operating costs and deducted in the calculation of adjusted EBITDA to be consistent with previous periods. Adjusted EBITDA includes adjustments in relation to non-cash items such as share-based payment charges and unrealised gain/loss on hedges along with other one-off exceptional items after deducting lease rentals capitalised under IFRS 16.

	Six months ended 30 June 2021	Six months ended 30 June 2020	Year ended 31 December 2020
	£m	£m	£m
Loss before tax	**(14.2)**	(38.1)	(44.1)
Net finance costs	**1.8**	3.4	2.2
Changes in fair value of contingent consideration	**0.2**	-	0.2

Depletion, depreciation & amortisation	**2.5**	3.7	6.3
Impairments/write-offs	**10.1**	34.6	38.6
EBITDA	**0.4**	3.6	3.2
Lease rentals capitalised under IFRS 16	**(0.8)**	(0.9)	(1.8)
Share-based payment charges	**0.5**	1.3	1.0
Unrealised loss/(gain) on hedges	**2.6**	(1.8)	0.8
Redundancy costs	**-**	-	0.6
Acquisition costs	**-**	-	0.2
Adjusted EBITDA	**2.7**	2.2	4.0

Underlying cash operating costs

	Six months ended 30 June 2021	Six months ended 30 June 2020	Year ended 31 December 2020
	£m	£m	£m
Other cost of sales	**8.6**	9.3	17.6
Lease rentals capitalised under IFRS 16	**0.8**	0.9	1.8
Underlying cash operating costs	**9.4**	10.2	19.4

Operating cash flow before working capital movements and realised hedges

	Six months ended 30 June 2021	Six months ended 30 June 2020	Year ended 31 December 2020
	£m	£m	£m
Operating cash flow before working capital movements	**3.7**	1.9	3.3
Realised (gain)/loss on oil price derivatives	**2.7**	(3.3)	(4.6)
Operating cash flow before working capital movements and realised hedges	**6.4**	(1.4)	(1.3)

Principal risks and uncertainties

The Group constantly monitors the Group's risk exposures and management reports to the Audit Committee and the Board on a regular basis. The Audit Committee receives and reviews these reports and focuses on ensuring that the effective systems of internal financial and non-financial controls including the management of risk are maintained. The results of this work are reported to the Board which in turn performs its own review and assessment.

The principal risks for the Group remain as previously detailed on pages 22-23 of the 2020 Annual Report and Accounts and can be summarised as:

- Political risk such as change in Government or the effect of local or national referendums;
- Strategy fails to meet shareholder expectations;
- Climate change risks that causes changes to laws, regulations, policies, obligations and social attitudes relating to the transition to a lower carbon economy which could have a cost impact or reduced demand for hydrocarbons for the Group and could impact our Strategy;
- Cyber security risk that gives exposure to a serious cyber-attack which could affect the confidentiality of data, the availability of critical business information and cause disruption to our operations;
- Planning, environmental, licensing and other permitting risks associated with its operations and, in particular, with drilling and production operations;
- Oil or gas production, as no guarantee can be given that they can be produced in the anticipated quantities from any or all of the Group's assets or that oil or gas can be delivered economically;
- Development of shale gas resources not successful;
- Loss of key staff;
- Pandemic that impacts the ability to operate the business effectively;

- Oil market price risk through variations in the wholesale price in the context of the production from oil fields it owns and operates;
- Gas and electricity market price risk through variations in the wholesale price in the context of its future unconventional production volumes;
- Exchange rate risk through both its major source of revenue and its major borrowings being priced in US$ while most of the Group's operating and G&A costs are denominated in UK pounds sterling;
- Liquidity risk through its operations; and
- Capital risk resulting from its capital structure, including operating within the covenants of its RBL facility.

Going concern

The Group continues to closely monitor and manage its liquidity risks. Cash flow forecasts for the Group are regularly produced based on, inter alia, the Group's production and expenditure forecasts, management's best estimate of future oil prices, management's best estimate of foreign exchange rates and the Group's available loan facility under the RBL. Sensitivities are run to reflect different scenarios including, but not limited to, possible further reductions in commodity prices, strengthening of sterling and reductions in forecast oil and gas production rates.

The Group's operating cash flows have improved in 2021 as a result of improving commodity prices and we have successfully completed the 2021 half-year redetermination. However, the ability of the Group to operate as a going concern is dependent upon the continued availability of future cash flows and the availability of the monies drawn under its RBL, which is redetermined semi-annually based on various parameters (including oil price and level of reserves) and is also dependent on the Group not breaching its RBL covenants. To mitigate these risks, the Group benefits from its hedging policy with 190,800 bbls hedged for H2 2021 at an average price including collar upside of c.$49/bbl, 126,000 bbls are currently hedged in 2022 using swaps at an average price of $63/bbl and 114,000 bbls using puts with an average price, net of premiums, of $44/bbl.

The international efforts to curtail the COVID-19 pandemic, particularly the increasing vaccination roll-outs has created an improving macroeconomic outlook. The combination of the recovery in oil demand and OPEC+ decision on production levels has resulted in higher oil prices which have increased from c.$54/bbl at the beginning of the year to above $70/bbl in June 2021. Although the oil price has recovered sharply, there remains significant uncertainty as to how COVID-19 and its aftermath will impact economies, oil demand and therefore oil price over the near and mid-term.

Management has also considered the impact of the COVID-19 global crisis on the Group's operations. We have seen some impact on production during 2021 due to supply chain constraints and the need for members of our staff to self-isolate. We continue to monitor the situation closely and act within Government guidelines and have a number of contingency plans in place should our operations be significantly affected by the COVID-19 pandemic. Many of our sites are remotely manned and we are well equipped as a business to ensure we maintain business continuity recognising that our production comes from a large number of wells in a variety of locations and we have flexibility in our off-take arrangements. We continue to liaise and co-operate with all the relevant regulators on guidance relating to the pandemic.

The Group's base case cash flow forecast was run with average oil prices of $68/bbl for Q4 2021 falling to an average of $63/bbl in 2022 based on the forward curve. A foreign exchange rate of $1.39/£1 for Q4 2021 and $1.38/£1 for 2022 was used. Our forecasts show that the Group will have sufficient financial headroom to meet its financial covenants based on the existing RBL facility. However, given the uncertainties described above, the level of Group revenues and the availability of facilities under the RBL are inherently uncertain. As such, management has also prepared a downside case with average oil prices at $58/bbl for Q4 2021 falling to an average of $50/bbl in 2022 and an exchange rate of $1.40/£1.00 for Q4 2021 and $1.42/£1.00 for 2022. Our downside case also included an average reduction in production of 5% over the period. To manage the impact of the downside scenario modelled, management would take mitigating actions, including further commodity hedging, delaying capital expenditure and additional reductions in costs in order to remain within the Group's debt liquidity covenants. All such mitigating actions are within management's control. In the downside case, management has also considered additional cash generating opportunities for the Group. While management acknowledges that these may not be in our control, we have assumed that cash flow from some of these opportunities would be available in 2022. In this downside scenario, our forecast shows that the Group will have sufficient financial headroom to meet its financial covenants for the 12 months from the date of approval of the financial statements. However, should oil price or demand (and therefore revenue) fall further, the Group may not have sufficient funds available for 12 months from the date of approval of these financial statements.

As a result, at the date of approval of these interim financial statements, there continues to be material uncertainties, as described above, arising as a result of the potential impact of COVID-19 on the Group's operational activities and future commodity prices. These material uncertainties cast significant doubt upon the Group's ability to continue as a going concern. Notwithstanding these material uncertainties, the Directors have a reasonable expectation that the Group has adequate resources to continue in existence for the foreseeable future and have concluded it is appropriate to adopt the going concern basis of accounting in the preparation of the interim financial statements. The interim financial statements do not include the adjustments that would result if the Group was unable to continue as a going concern.

Statement of directors' responsibilities

The Directors confirm that these Condensed Interim Consolidated Financial Statements have been prepared in accordance with UK-adopted International Accounting Standard 34, 'Interim Financial Reporting' ("IAS 34") and the AIM Rules for Companies; and these Unaudited Interim results include:

a) a fair review of the information required (i.e., an indication of important events and their impact and a description of the principal risks and uncertainties for the remaining six months of the financial year); and
b) a fair review of the information required on related party transactions.

By order of the Board,

Stephen Bowler
Chief Executive Officer

22 September 2021

Independent review report to IGas Energy plc

Report on the condensed interim consolidated financial statements

Our conclusion
We have reviewed IGas Energy plc's condensed interim consolidated financial statements (the "interim financial statements") in the Unaudited Interim results of IGas Energy plc for the 6-month period ended 30 June 2021 (the "period").

Based on our review, nothing has come to our attention that causes us to believe that the interim financial statements are not prepared, in all material respects, in accordance with UK adopted International Accounting Standard 34, 'Interim Financial Reporting' and the AIM Rules for Companies.

Emphasis of matter
Without modifying our conclusion on the interim financial statements, we have considered the adequacy of the disclosure made in note 2 to the interim financial statements concerning the Group's ability to continue as a going concern. The ability of the Group to operate as a going concern is dependent upon the continued availability of future cash flows, the availability of the monies drawn under its Reserve Based Lending facility ('RBL'), which is redetermined semi-annually based on various parameters (including oil price and level of reserves), and on the Group not breaching its RBL covenants. The Group's cash flows and the ability to meet its covenants could be impacted by a return to lower oil prices, the impact of further COVID-19 restrictions and the ability of management to implement mitigating actions which are not completely within their control. These conditions, along with the other matters explained in note 2 to the interim financial statements, indicate the existence of material uncertainties which may cast significant doubt upon the Group's ability to continue as a going concern. The Group's interim financial statements do not include the adjustments that would result if the Group was unable to continue as a going concern.

What we have reviewed
The interim financial statements comprise:

- the Condensed Interim Consolidated Balance Sheet as at 30 June 2021;
- the Condensed Interim Consolidated Income Statement for the period then ended;
- the Condensed Interim Consolidated Statement of Comprehensive Income for the period then ended;
- the Condensed Interim Consolidated Cash Flow Statement for the period then ended;
- the Condensed Interim Consolidated Statement of Changes in Equity for the period then ended; and
- the explanatory notes to the interim financial statements.

The interim financial statements included in the Unaudited Interim results of IGas Energy plc have been prepared in accordance with UK adopted International Accounting Standard 34, 'Interim Financial Reporting' and the AIM Rules for Companies.

Responsibilities for the interim financial statements and the review

Our responsibilities and those of the directors
The Unaudited Interim results, including the interim financial statements, is the responsibility of, and has been approved by the directors. The directors are responsible for preparing the Unaudited Interim results in accordance with the AIM Rules for Companies which require that the financial information must be presented and prepared in a form consistent with that which will be adopted in the company's annual financial statements.

Our responsibility is to express a conclusion on the interim financial statements in the Unaudited Interim results based on our review. This report, including the conclusion, has been prepared for and only for the Company for the purpose of complying with the AIM Rules for Companies and for no other purpose. We do not, in giving this conclusion, accept or assume responsibility for any other purpose or to any other person to whom this report is shown or into whose hands it may come save where expressly agreed by our prior consent in writing.

What a review of interim financial statements involves

We conducted our review in accordance with International Standard on Review Engagements (UK and Ireland) 2410, 'Review of Interim Financial Information Performed by the Independent Auditor of the Entity' issued by the Auditing Practices Board for use in the United Kingdom. A review of interim financial information consists of making enquiries, 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.

We have read the other information contained in the Unaudited Interim results and considered whether it contains any apparent misstatements or material inconsistencies with the information in the interim financial statements.

PricewaterhouseCoopers LLP
Chartered Accountants
London
22 September 2021

Condensed Interim Consolidated Income Statement

	Notes	**Unaudited 6 months ended 30 June 2021 £000**	Unaudited 6 months ended 30 June 2020 £000	Audited year ended 31 December 2020 £000
Revenue	4	**16,574**	10,476	21,578
Cost of sales				
Depletion, depreciation and amortisation		**(2,379)**	(3,539)	(5,974)
Other costs of sales		**(8,608)**	(9,340)	(17,553)
Total cost of sales		**(10,987)**	(12,879)	(23,527)
Gross profit/(loss)		**5,587**	(2,403)	(1,949)
Administrative expenses		**(2,314)**	(2,793)	(5,331)
Exploration and evaluation assets written off	9	**(10,097)**	(5)	(67)
Oil and gas assets impairment	10	**-**	(34,607)	(38,535)
(Loss)/gain on oil price derivatives		**(5,370)**	4,840	3,520
(Loss)/gain on foreign exchange contracts		**-**	310	229
Operating loss		**(12,194)**	(34,658)	(42,133)
Finance income	5	**135**	7	1,472
Finance costs	5	**(1,893)**	(3,409)	(3,648)
Changes in fair value of contingent consideration	12	**(230)**	-	(180)
Other income		**-**	-	415
Loss from continuing activities before tax		**(14,182)**	(38,060)	(44,074)
Income tax credit	6	**1,942**	8,095	1,985
Loss after tax from continuing operations attributable to shareholders' equity		**(12,240)**	(29,965)	(42,089)
Loss after tax from discontinued operations	7	(106)	(10,896)	(11,060)
Net loss for the period/year attributable to shareholders' equity		**(12,346)**	(40,861)	(53,149)
Loss attributable to equity shareholders from continuing operations:				
Basic loss per share	8	(9.78p)	(24.58p)	(34.35p)
Diluted loss per share	8	(9.78p)	(24.58p)	(34.35p)
Loss attributable to equity shareholders including discontinued operations:				
Basic loss per share	8	(9.87p)	(33.52p)	(43.37p)
Diluted loss per share	8	(9.87p)	(33.52p)	(43.37p)

Condensed Interim Consolidated Statement of Comprehensive Income

	Unaudited 6 months ended 30 June 2021 £000	Unaudited 6 months ended 30 June 2020 £000	Audited year ended 31 December 2020 £000
Loss for the period/year	**(12,346)**	(40,861)	(53,149)
Other comprehensive income/(loss) for the period/year:			
Currency translation adjustments recycled to the income statement (note 7)	**326**	10,781	10,781
Currency translation adjustments	**-**	(67)	(19)
Total comprehensive loss for the period/year	**(12,020)**	(30,147)	(42,387)

Condensed Interim Consolidated Balance Sheet

	Notes	**Unaudited at 30 June 2021 £000**	Unaudited at 30 June 2020 £000	Audited at 31December 2020 £000
Assets				
Non-current assets				
Intangible assets	9	**37,661**	42,399	46,711
Property, plant and equipment	10	**73,264**	69,348	72,439
Right-of-use assets		**7,458**	7,694	7,658
Restricted cash		**410**	410	410
Deferred tax asset	6	**33,888**	38,056	31,945
		152,681	157,907	159,163
Current assets				
Inventories		**1,094**	1,106	1,023
Trade and other receivables		**5,289**	3,973	4,095
Cash and cash equivalents	13	**2,755**	2,592	2,438
Derivative financial instruments		**-**	1,704	314
		9,138	9,375	7,870
Total assets		**161,819**	167,282	167,033
Liabilities				
Current liabilities				
Trade and other payables		**(4,588)**	(5,245)	(5,247)
Derivative financial instruments		**(3,897)**	-	(1,271)
Lease liabilities		**(720)**	(979)	(694)
Provisions	12	**(358)**	-	(293)
		(9,563)	(6,224)	(7,505)
Non-current liabilities				
Borrowings	13	**(15,123)**	(12,650)	(13,695)
Other creditors		**(970)**	(1,358)	(1,160)
Lease liabilities		**(6,667)**	(6,394)	(6,820)
Provisions	12	**(67,591)**	(56,263)	(64,550)
		(90,351)	(76,665)	(86,225)
Total liabilities		**(99,914)**	(82,889)	(93,730)
Net assets		**61,905**	84,393	73,303
Equity				
Capital and reserves				
Called up share capital	14	**30,333**	30,333	30,333
Share premium account	14	**102,969**	102,741	102,906
Foreign currency translation reserve		**3,799**	3,425	3,473
Other reserves		**35,676**	34,150	35,117
Accumulated deficit		**(110,872)**	(86,256)	(98,526)
Total equity		**61,905**	84,393	73,303

Condensed Interim Consolidated Statement of Changes in Equity

	Called up share capital £000	Share premium account £000	Foreign currency translation reserve* £000 £000	Other reserves ** £000	Accumulated deficit £000	Total Equity £000
At 31 December 2019 (audited)	30,333	102,680	(7,289)	32,781	(45,395)	113,110
Loss for the period	-	-	-	-	(40,861)	(40,861)
Share options issued under the employee share plan	-	-	-	1,369	-	1,369
Issue of shares (note 14)	-	61	-	-	-	61
Currency translation adjustments	-	-	10,714	-	-	10,714
At 30 June 2020 (unaudited)	30,333	102,741	3,425	34,150	(86,256)	84,393
Loss for the period	-	-	-	-	(12,288)	(12,288)
Share options issued under the employee share plan	-	-	-	997	-	997
Issue of shares (note 14)	-	165	-	(30)	-	135
Disposal of shares held in EBT	-	-	-	-	18	18
Currency translation adjustments	-	-	48	-	-	48
At 31 December 2020 (audited)	30,333	102,906	3,473	35,117	(98,526)	73,303
Loss for the period	**-**	**-**	**-**	**-**	**(12,346)**	**(12,346)**
Share options issued under the employee share plan	**-**	**-**	**-**	**559**	**-**	**559**
Issue of shares (note 14)	**-**	**63**	**-**	**-**	**-**	**63**
Currency translation adjustments	**-**	**-**	**326**	**-**	**-**	**326**
At 30 June 2021 (unaudited)	**30,333**	**102,969**	**3,799**	**35,676**	**(110,872)**	**61,905**

* The foreign currency translation reserve represents exchange gains and losses arising on translation of foreign currency subsidiaries net assets and results, and on translation of those subsidiaries intercompany balances which form part of the net investment of the Group.

** Other reserves include: 1) EIP/MRP/LTIP/VCP/EDRP reserves which represent the cost of share options issued under the long term incentive plans; 2) share investment plan reserve which represents the cost of the partnership and matching shares; 3) treasury shares reserve which represents the cost of shares in IGas Energy plc purchased in the market and held by the IGas Employee Benefit Trust to satisfy awards held under the Group incentive plans; and 4) capital contribution reserve which arose following the acquisition of IGas Exploration UK Limited.

Condensed Interim Consolidated Cash Flow Statement

	Notes	**Unaudited 6 Months ended 30 June 2021 £000**	Unaudited 6 Months ended 30 June 2020 £000	Audited year ended 31 December 2020 £000
Cash flows from operating activities:				
Loss from continuing activities before tax for the period/year		**(14,182)**	(38,060)	(44,074)
Depletion, depreciation and amortisation		**2,475**	3,702	6,303
Abandonment costs/other provisions utilised		**(122)**	(863)	(1,348)
Share-based payment charge		**467**	921	1,025
Exploration and evaluation assets written-off	9	**10,097**	5	67
Oil and gas assets impairment		**-**	34,607	38,535
Change in unrealised loss/(gain) on oil price derivatives		**2,626**	(1,533)	1,048
Change in unrealised loss(gain) on foreign exchange contracts		**314**	(310)	(229)
Changes in fair value of contingent consideration	12	**230**	-	180
Other income		**-**	-	(415)
Finance income	5	**(135)**	(7)	(1,472)
Finance costs	5	**1,893**	3,409	3,648
Other non-cash adjustments		**(1)**	3	(10)
Operating cash flow before working capital movements		**3,662**	1,874	3,258
(Increase)/decrease in trade and other receivables and other financial assets		**(1,103)**	2,675	1,514
Decrease/(increase) in trade and other payables		**352**	(2,199)	(1,187)
(Increase)/decrease in inventories		**(71)**	87	170
Cash from continuing operating activities		**2,840**	2,437	3,755
Cash used in discontinued operating activities		**(124)**	(168)	(156)
Net cash from operating activities		**2,716**	2,269	3,599
Cash flows from investing activities:				
Purchase of intangible exploration and evaluation assets		**(794)**	(1,407)	(2,314)
Purchase of property, plant and equipment		**(1,743)**	(3,500)	(6,152)
Purchase of intangible development assets		**(35)**	-	(67)
Cash acquired on acquisition of subsidiary		**-**	-	77
Other income received		**-**	-	4
Interest received		**5**	7	11
Cash used in continuing investing activities		**(2,567)**	(4,900)	(8,441)
Net cash used in investing activities		**(2,567)**	(4,900)	(8,441)
Cash flows from financing activities:				
Cash proceeds from issue of ordinary share capital	14	**21**	31	56
Proceeds from disposal of shares held in EBT net of costs		**-**	-	4
Drawdown on Reserves Based Lending facility	13	**1,432**	3,215	5,544
Repayment on Reserves Based Lending facility	13	**-**	(4,645)	(4,645)
Repayment of principal portion of lease liability		**(484)**	(1,265)	(973)
Repayment of interest on lease liabilities		**(340)**	(320)	(795)
Interest paid	13	**(454)**	(477)	(940)
Net cash from/(used in) financing activities		**175**	(3,461)	(1,749)
Net increase/(decrease) in cash and cash equivalents during the period/year		**324**	(6,092)	(6,591)
Net foreign exchange difference		**(7)**	490	835
Cash and cash equivalents at the beginning of the period/year		**2,438**	8,194	8,194
Cash and cash equivalents at the end of the period/year	13	**2,755**	2,592	2,438

Notes to the Condensed Interim Consolidated Financial Statements

1 Corporate information

The condensed interim consolidated financial statements of the Group for the six months ended 30 June 2021, which are unaudited, were authorised for issue in accordance with a resolution of the Directors on 22 September 2021.

IGas Energy plc is a public limited company incorporated and domiciled in England whose shares are publicly traded on the AIM market. The Group's principal activity is exploring for, appraising, developing and producing oil and gas resources in Great Britain. The Group is also diversifying into the wider UK energy markets and is appraising geothermal and hydrogen projects.

2 Accounting policies

Basis of preparation

These condensed interim consolidated financial statements for the six months ended 30 June 2021 have been prepared in accordance with UK-adopted International Accounting Standard 34, 'Interim Financial Reporting' ("IAS 34") and the AIM Rules for Companies. The unaudited condensed interim consolidated financial statements should be read in conjunction with the consolidated financial statements for the year ended 31 December 2020, which have been prepared in accordance with international accounting standards in conformity with the requirements of the Companies Act 2006 and IFRS adopted pursuant to Regulation (EC) No 1606/2002 as it applies in the European Union.

The financial information contained in this document does not constitute statutory accounts as defined by Section 435 of the Companies Act 2006 (England & Wales). The financial information as at 31 December 2020 is based on the statutory accounts for the year ended 31 December 2020. A copy of the statutory accounts for that year, has been delivered to the Register of Companies and is available on the Company's website at www.igasplc.com. The auditors' report in accordance with Chapter 3 Part 16 of the Companies Act 2006 in relation to those accounts was unqualified and did not contain any matters on which the auditors are required to report an exception in accordance with section 498 (2) and (3) of the Companies Act 2006.

The accounting policies adopted are consistent with those of the previous financial year and corresponding interim reporting period, except for the new and amended standards and interpretations discussed below.

In the year to 31 December 2021 the annual financial statements will be prepared in accordance with IFRS as adopted by the UK Endorsement Board and that this change in basis of preparation is required by UK company law for the purposes of financial reporting as a result of the UK's exit from the EU on 31 January 2020 and the cessation of the transition period on 31 December 2020.

This change does not constitute a change in accounting policy but rather a change in framework which is required to ground the use of IFRS in company law. There is no impact on recognition, measurement or disclosure between the two frameworks in the period reported.

Going concern

The Group continues to closely monitor and manage its liquidity risks. Cash flow forecasts for the Group are regularly produced based on, inter alia, the Group's production and expenditure forecasts, management's best estimate of future oil prices, management's best estimate of foreign exchange rates and the Group's available loan facility under the RBL. Sensitivities are run to reflect different scenarios including, but not limited to, possible further reductions in commodity prices, strengthening of sterling and reductions in forecast oil and gas production rates.

The Group's operating cash flows have improved in 2021 as a result of improving commodity prices and we have successfully completed the 2021 half-year redetermination. However, the ability of the Group to operate as a going concern is dependent upon the continued availability of future cash flows and the availability of the monies drawn under its RBL, which is redetermined semi-annually based on various parameters (including oil price and level of reserves) and is also dependent on the Group not breaching its RBL covenants. To mitigate these risks, the Group benefits from its hedging policy with 190,800 bbls hedged for H2 2021 at an average price including collar upside of c.$49/bbl, 126,000 bbls are currently hedged in 2022 using swaps at an average price of $63/bbl and 114,000 bbls using puts with an average price, net of premiums, of $44/bbl.

The international efforts to curtail the COVID-19 pandemic, particularly the increasing vaccination roll-outs has created an improving macroeconomic outlook. The combination of the recovery in oil demand and OPEC+ decision on production levels has resulted in higher oil prices which have increased from c.$54/bbl at the beginning of the year to above $70/bbl in June 2021. Although the oil price has recovered sharply, there remains significant uncertainty as to how COVID-19 and its aftermath will impact economies, oil demand and therefore oil price over the near and mid-term.

Management has also considered the impact of the COVID-19 global crisis on the Group's operations. We have seen some impact on production during 2021 due to supply chain constraints and the need for members of our staff to self-isolate. We continue to monitor the situation closely and act within Government guidelines and have a number of contingency plans in place should our operations be significantly affected by the COVID-19 pandemic. Many of our sites are remotely manned and we are well equipped as a business to ensure we maintain business continuity recognising that our production comes from a large number of wells in a variety of locations and we have flexibility in our off-take arrangements. We continue to liaise and co-operate with all the relevant regulators on guidance relating to the pandemic.

The Group's base case cash flow forecast was run with average oil prices of $68/bbl for Q4 2021 falling to an average of $63/bbl in 2022 based on the forward curve. A foreign exchange rate of $1.39/£1 for Q4 2021 and $1.38/£1 for 2022 was used. Our forecasts show that the Group will have sufficient financial headroom to meet its financial covenants based on the existing RBL facility. However, given the uncertainties described above, the level of Group revenues and the availability of facilities under the RBL are inherently uncertain. As such, management has also prepared a downside case with average oil prices at $58/bbl for Q4 2021 falling to an average of $50/bbl in 2022 and an exchange rate of $1.40/£1.00 for Q4 2021 and $1.42/£1.00 for 2022. Our downside case also included an average reduction in production of 5% over the period. To manage the impact of the downside scenario modelled, management would take mitigating actions, including further commodity hedging, delaying capital expenditure and additional reductions in costs in order to remain within the Group's debt liquidity covenants. All such mitigating actions are within management's control. In the downside case, management has also considered additional cash generating opportunities for the Group. While management acknowledges that these may not be in our control, we have assumed that cash flow from some of these opportunities would be available in 2022. In this downside scenario, our forecast shows that the Group will have sufficient financial headroom to meet its financial covenants for the 12 months from the date of approval of the financial statements. However, should oil price or demand (and therefore revenue) fall further, the Group may not have sufficient funds available for 12 months from the date of approval of these financial statements.

As a result, at the date of approval of these interim financial statements, there continues to be material uncertainties, as described above, arising as a result of the potential impact of COVID-19 on the Group's operational activities and future commodity prices. These material uncertainties cast significant doubt upon the Group's ability to continue as a going concern. Notwithstanding these material uncertainties, the Directors have a reasonable expectation that the Group has adequate resources to continue in existence for the foreseeable future and have concluded it is appropriate to adopt the going concern basis of accounting in the preparation of the interim financial statements. The interim financial statements do not include the adjustments that would result if the Group was unable to continue as a going concern.

New and amended standards and interpretations

During the period, the Group adopted the following new and amended IFRSs for the first time for their reporting period commencing 1 January 2021:

Amendments to IFRS 9, IAS 39, IFRS 7, IFRS 4 and IFRS 16 *Interest Rate Benchmark Reform – Phase 2*

These standards do not have a material impact on the Group in the current or future reporting periods. There are no other standards that are not yet effective and that would be expected to have a material impact on the entity in the current or future reporting periods.

Estimates and judgements

The preparation of the condensed interim consolidated financial statements requires management to make judgements, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets and liabilities, income and expense. Actual results may differ from these estimates.

In preparing these condensed interim consolidated financial statements, the significant judgements made by management in applying the Group's accounting policies and the key sources of estimation uncertainty were the same as those applied to the consolidated financial statements for the year ended 31 December 2020.

Financial risk management

The Group's activities expose it to a variety of financial risks; market risk (including interest rate, commodity price and foreign currency risks), credit risk and liquidity risk.

The condensed interim consolidated financial statements do not include all financial risk management information and disclosures required in the annual financial statements; they should be read in conjunction with the Group's annual financial statements as at 31 December 2020.

3 Basis of consolidation

The condensed interim consolidated financial statements present the results of IGas Energy plc and its subsidiaries as if they formed a single entity. The financial information of subsidiaries used in the preparation of these condensed interim consolidated financial statements are based on consistent accounting policies to those of the parent. All intercompany transactions and balances between Group companies, including unrealised profits/losses arising from them, are eliminated in full. Where shares are issued to an Employee Benefit Trust, and the Company is the sponsoring entity, it is treated as an extension of the entity.

4 Revenue

The Group derives revenue solely within the United Kingdom from the transfer of goods and services to external customers which is recognised at a point in time when the performance obligation has been satisfied by the transfer of goods. The Group's major product lines are:

	Unaudited 6 months ended 30 June 2021	Unaudited 6 months ended 30 June 2020	Audited year ended 31 December 2020
	£000	£000	£000
Oil sales	**15,284**	10,048	20,546
Electricity sales	**550**	181	438
Gas sales	**740**	247	594
Revenue for the period/year	**16,574**	10,476	21,578

5 Finance income and costs

	Unaudited	Unaudited	Audited

	6 months ended 30 June 2021 £000	6 months ended 30 June 2020 £000	year ended 31 December 2020 £000
Finance income:			
Interest on short-term deposits	**1**	7	11
Foreign exchange gains	**134**	-	1,461
Finance income for the period/year	**135**	7	1,472
Finance expense:			
Interest on borrowings	**(448)**	(477)	(940)
Amortisation of finance fees on borrowings	**(165)**	(225)	(387)
Foreign exchange loss	**-**	(361)	-
Unwinding of discount on decommissioning provisions (note 12)	**(811)**	(2,026)	(1,466)
Unwinding of discount on contingent consideration (note 12)	**(129)**	-	(60)
Finance charge on lease liability for assets in use	**(340)**	(320)	(795)
Finance expense for the period/year	**(1,893)**	(3,409)	(3,648)

6 Tax on profit on ordinary activities

The Group calculates the period income tax expense using the UK corporation tax rate that would be applicable to expected total annual earnings (40% for UK ring fenced activities and 19% for all other UK activities). The effective tax rate for the period is 13% (six months ended 30 June 2020: 21%, year ended 31 December 2020: 5%) and the major components of income tax expense in the condensed interim consolidated income statement are:

	Unaudited 6 months ended 30 June 2021 £000	Unaudited 6 months ended 30 June 2020 £000	Audited year ended 31 December 2020 £000
UK corporation tax			
Charge on loss for the period/year	**-**	-	-
Total current tax charge	**-**	-	-
Deferred tax			
Charge/(credit) relating to the origination or reversal of temporary differences	**(1,526)**	(7,998)	1,409
Credit due to tax rate changes	**(416)**	(97)	(99)
Credit in relation to prior periods	**-**	-	(3,295)
Total deferred tax credit	**(1,942)**	(8,095)	(1,985)
Tax credit on loss on ordinary activities for the period/year	**(1,942)**	(8,095)	(1,985)

Changes to the UK corporation tax rates were substantively enacted in the current period where the rate of tax will increase to 25% from 1 April 2023. A deferred tax asset of £33.9 million (30 June 2020: £38.1 million, 31 December 2020: £31.9 million) has been recognised in respect of tax losses and other temporary differences where the Directors believe that it is probable that these assets will be recovered based on estimated taxable profit forecast.

7 Loss after tax from discontinued operations

The divestment of assets acquired as part of the Dart Acquisition, namely the Rest of the World segment, was completed in 2016. The Group still has a presence in a small number of Australian, Indian and Singaporean registered operations and continues to progress its plans to exit all legal jurisdictions in the near future. During the current period, we have commenced the liquidation process for the remaining of these overseas dormant subsidiaries and control over these entities has been transferred to the administrators. The total loss after tax in respect of discontinued operations was £0.1 million primarily due to the recycling of the currency translation reserve on liquidation/strike off (six months ended 30 June 2020: loss after tax of £10.9 million; year ended 31 December 2020: loss after tax of £11.1 million, primarily relating to administration costs).

Effect of liquidation/strike off on the financial statements:

	Unaudited 6 months ended 30 June 2021 £000	Unaudited 6 months ended 30 June 2020 £000	Audited year ended 31 December 2020 £000
Other receivables	**(10)**	(1)	2

Cash and cash equivalents	**(20)**	(9)	(9)
Other payables	**15**	56	56
Net assets and liabilities disposed	**(15)**	46	49
Disposal consideration	**-**	-	-
Translation reserve re-classification to income statement on liquidation/strike off	**(326)**	(10,781)	(10,781)
Loss on liquidation/strike off charged to the income statement	**(341)**	(10,735)	(10,732)

8 Earnings per share (EPS)

Basic EPS amounts are based on the loss for the period after taxation attributable to ordinary equity holders of the parent of £12.2 million (six months ended 30 June 2020: a loss after tax of £30.0 million; year ended 31 December 2020: a loss after tax of £42.1 million) and the weighted average number of ordinary shares outstanding during the period of 125.1 million (six months ended 30 June 2020: 121.9 million; year ended 31 December 2020: 122.5 million).

Diluted EPS amounts are based on the loss for the period after taxation attributable to the ordinary equity holders of the parent and the weighted average number of shares outstanding during the period plus the weighted average number of ordinary shares that would be issued on the conversion of all the potentially dilutive ordinary shares into ordinary shares, except where these are anti-dilutive.

There are 11.7 million potentially dilutive employee share options (six months ended 30 June 2020: 12.0 million, year ended 31 December 2020: 10.9 million) which are not included in the calculation of diluted earnings per share in the current period as their conversion to ordinary shares would have decreased the loss per share.

9 Intangible assets

	Unaudited 6 months ended 30 June 2021 £'000			Unaudited 6 months ended 30 June 2020 £'000			Audited year ended 31 December 2020 £'000		
	Exploration and evaluation assets	**Development costs**	**Total**	Exploration and evaluation assets	Development costs	Total	Exploration and evaluation assets	Development costs	Total
Cost									
At 1 January	**43,421**	**3,290**	**46,711**	41,455	-	41,455	41,455	-	41,455
Acquisitions	**-**	**-**	**-**	-	-	-	-	3,223	3,223
Additions	**621**	**38**	**659**	949	-	949	2,090	67	2,157
Changes in decommissioning (note 12)	**388**	**-**	**388**	-	-	-	(57)	-	(57)
Amounts written off	**(10,097)**	**-**	**(10,097)**	(5)	-	(5)	(67)	-	(67)
At 30 June/31 December	**34,333**	**3,328**	**37,661**	42,399	-	42,399	43,421	3,290	46,711

Exploration and evaluation assets

Exploration costs written off in the period to 30 June 2021 were £10.1 million (6 months to 30 June 2020: £nil, year ended 31 December 2020: £0.1 million) of which £10.0 million related to the PEDL 200 (Tinker Lane) licence and £0.1 million impairment of capitalised decommissioning assets relating to previously written off licences. PEDL 200, the licence in which the basin edge defining well Tinker Lane was drilled, and EXL 288 have been relinquished during the period. This allows the group to focus on its core Gainsborough Trough shale acreage, defined as those licences in which a significant thickness of the Gainsborough shale is, or is predicted, to be present.

Further analysis by location of asset is as follows:

North West: The group has £6.3 million (H1 2020: £6.1 million, year ended 31 December 2020: £6.1 million) of capitalised exploration expenditure relating to Ellesmere Port where IGas has lodged an appeal against the decision made by Cheshire West and Chester Council's Planning and Licensing Committee to refuse planning consent for routine tests on a rock formation encountered in the Ellesmere Port-1 well. The appeal has been recovered by the Secretary of State and we are awaiting the outcome. As the outcome is still undetermined, it is appropriate to keep the carrying value of the asset capitalised.

East Midlands: The group has £23.1 million (H1 2020: £32.3 million, year ended 31 December 2020: £32.8 million) of capitalised exploration expenditure relating to our core area in the Gainsborough Trough which includes PEDLs 12, 139, 140, 169 and 210. The Gainsborough Trough is an area with significant shale potential. Following the moratorium on fracking, we continue to work with the OGA, BEIS and No 10 Policy Unit to demonstrate that we can develop shale in this area in a safe manner. Our discussions have focused on the new science that would be brought forward on a sector wide and site specific basis that would allow the moratorium to be lifted. We are doing this in conjunction with our joint venture partners and the work is ongoing at present. As the work is still ongoing, it is appropriate to keep the carrying value of the asset capitalised.

Conventional assets: The Group has £4.9 million (six months ended 30 June 2020: £4.0 million, year ended 31 December 2020: £4.5 million) of capitalised exploration expenditure which relates to our conventional assets including PEDL 235 and PL 240.

Development costs

The development costs relate to assets acquired as part of the GT Energy acquisition in 2020. The costs relate to the design and development of deep geothermal heat projects in the United Kingdom, with the principal project being at Etruria Valley, Stoke-on-Trent.

The Group reviewed the carrying value of development costs as at 30 June 2021 and assessed it for impairment indicators. Principally due to COVID-19, the development of the Stoke-on-Trent project has taken longer than anticipated. This, however, does not impact the overall economics of the project materially. On this basis, the group has concluded that there are no impairment indicators as at 30 June 2021. No impairment was required for the period (year ended 31 December 2020: £nil).

10 Property, plant and equipment

	Unaudited 6 months ended 30 June 2021 £'000			Unaudited 6 months ended 30 June 2020 £'000			Audited year ended 31 December 2020 £'000		
	Oil and gas assets	**Other fixed assets**	**Total**	Oil and gas assets	Other fixed assets	Total	Oil and gas assets	Other fixed assets	Total
Cost									
At 1 January	**209,225**	**2,951**	**212,176**	197,875	3,660	201,535	197,875	3,660	201,535
Additions	**1,152**	**-**	**1,152**	2,465	3	2,468	5,212	1	5,213
Disposals	**-**	**(518)**	**(518)**	(21)	-	(21)	(117)	(710)	(827)
Changes in decommissioning (note 12)	**1,591**	**-**	**1,591**	-	-	-	6,255	-	6,255
At 30 June/31 December	**211,968**	**2,433**	**214,401**	200,319	3,663	203,982	209,225	2,951	212,176
Depreciation and Impairment									
At 1 January	**138,233**	**1,504**	**139,737**	94,940	2,063	97,003	94,940	2,063	97,003
Charge for the period/year	**1,879**	**39**	**1,918**	2,955	90	3,045	4,875	151	5,026
Disposals	**-**	**(518)**	**(518)**	(21)	-	(21)	(117)	(710)	(827)
Impairment	**-**	**-**	**-**	34,607	-	34,607	38,535	-	38,535
At 30 June/31 December	**140,112**	**1,025**	**141,137**	132,481	2,153	134,634	138,233	1,504	139,737
Net book value at 30 June/31 December	**71,856**	**1,408**	**73,264**	67,838	1,510	69,348	70,992	1,447	72,439

The Group reviewed the carrying value of oil and gas assets as at 30 June 2021 and assessed it for impairment and impairment reversal indicators. The strong pricing along the forward curve and an improving economic outlook has improved the oil price environment and other key assumptions underpinning the recoverable value of oil and gas assets have not moved materially since 31 December 2020. On this basis, the group has concluded that there are no impairment indicators as at 30 June 2021 (six months ended 30 June 2020: £34.6 million impairment; year ended 31 December 2020: £38.5 million impairment). However, continued uncertainty exists as a result of the COVID-19 pandemic and its related impact on the demand for oil, as a result, the group has concluded that there are no impairment reversal indicators as at 30 June 2021.

11 Financial Instruments – fair value disclosure

The Group uses the following hierarchy for determining and disclosing the fair value of the financial instruments by valuation technique:

- Level 1: quoted (unadjusted) prices in active markets for identical assets or liabilities;
- Level 2: other valuation techniques for which all inputs which have a significant effect on the recorded fair value are observable, either directly or indirectly; and
- Level 3: valuation techniques which use inputs which have a significant effect on the recorded fair value that are not based on observable market data.

There are no non-recurring fair value measurements nor have there been any transfers between levels of the fair value hierarchy.

The financial assets and liabilities measured at fair value are categorised into the fair value hierarchy as at the reporting dates as follows:

	Level	**Unaudited 6 months ended 30 June 2021 £'000**	Unaudited 6 months ended 30 June 2020 £'000	Audited year ended 31 December 2020 £'000
Financial assets:				
Derivative financial instruments – oil hedges	2	**-**	1,309	-

Derivative financial instruments – foreign exchange contracts	2	**-**	395	314
At 30 June/31 December		**-**	1,704	314
Financial liabilities:				
Derivative financial instruments – oil hedges	2	**(3,897)**	-	(1,271)
Contingent consideration (note 12)	3	**(3,383)**	-	(3,024)
At 30 June/31 December		**(7,280)**	-	(4,295)

Fair value of derivative financial instruments

Commodity price hedges
The fair values of the commodity price options were provided by counterparties with whom the trades have been entered into. These consist of Asian style put and call options and swaps to sell/buy oil. The options are valued using a Black-Scholes methodology; however, certain adjustments are made to the spot-price volatility of oil prices due to the nature of the options. These adjustments are made either through Monte Carlo simulations or through statistical formulae. The inputs to these valuations include the price of oil, its volatility, and risk free interest rates.

Foreign exchange contracts
The fair values of foreign exchange contracts were provided by counterparties with whom the trades have been entered into.

Fair value of financial assets and financial liabilities
The carrying values of the financial assets and financial liabilities are considered to be materially equivalent to their fair values.

12 Provisions

	Unaudited 6 months ended 30 June 2021 £'000			Unaudited 6 months ended 30 June 2020 £'000			Audited year ended 31 December 2020 £'000		
	Decommissioning provisions	**Contingent consideration**	**Total**	Decommis-sioning provision	Contingent consideration	Total	Decommis-sioning provision	Contingent consideration	Total
At 1 January	**61,819**	**3,024**	**64,843**	55,101	-	55,101	55,101	-	55,101
Acquisitions							-	2,784	2,784
Utilisation of provision	**(43)**	**-**	**(43)**	(864)	-	(864)	(946)	-	(946)
Unwinding of discount (note 5)	**811**	**129**	**940**	2,026	-	2,026	1,466	60	1,526
Reassessment of decommissioning provision (note 9 and 10)	**1,979**	**-**	**1,979**	-	-	-	6,198	-	6,198
Changes in fair value of contingent consideration	**-**	**230**	**230**	-	-	-	-	180	180
At 30 June/31 December	**64,566**	**3,383**	**67,949**	56,263	-	56,263	61,819	3,024	64,843

Decommissioning provision
Provision has been made for the discounted future cost of abandoning wells and restoring sites to a condition acceptable to the relevant authorities. The provisions are based on the Group's internal estimate as at 30 June 2021. Assumptions are based on the current experience from decommissioning wells which management believes is a reasonable basis upon which to estimate the future liability. The estimates are reviewed regularly to take account of any material changes to the assumptions. Actual decommissioning costs will ultimately depend upon future costs for decommissioning which will reflect market conditions and regulations at that time. Furthermore, the timing of decommissioning is uncertain and is likely to depend on when the fields cease to produce at economically viable rates. This, in turn, will depend on factors such as future oil and gas prices, which are inherently uncertain.

A risk free rate range of 1.20% to 3.00% is used in the calculation of the provision as at 30 June 2021 (30 June 2020: Risk free rate range of 1.2% to 3.03%, 31 December 2020: Risk free rate range of 1.20% to 3.00%).

Contingent consideration
The carrying value of contingent consideration relates to the acquisition of GT Energy. The change in fair value is primarily related to the increase in fair value of IGas Energy plc shares between 31 December 2020 and 30 June 2021, as the consideration is payable in shares offset by changes to the anticipated timing of the various milestones being achieved.

13 Cash and cash equivalents and other financial assets

	Unaudited As at 30 June 2021 £000	Unaudited As at 30 June 2020 £000	Audited As at 31 December 2020 £000
Cash and cash equivalents	**2,755**	2,592	2,438
Borrowings – including capitalised fees	**(15,123)**	(12,650)	(13,695)
Net debt	**(12,368)**	(10,058)	(11,257)
Capitalised fees	**(803)**	(1,108)	(937)
Net debt excluding capitalised fees at 30 June/31 December	**(13,171)**	(11,166)	(12,194)

Net debt reconciliation

	Cash and cash equivalents £000	Borrowings £000	Total £000
At 1 January 2020	8,194	(13,071)	(4,877)
Interest paid on borrowings	(477)	-	(477)
Drawdown of RBL	3,215	(3,215)	-
Repayment of RBL	(4,645)	4,645	-
Foreign exchange adjustments	491	(846)	(355)
Other cash flows	(4,186)	-	(4,186)
Other non-cash movements	-	(163)	(163)
At 30 June 2020	2,592	(12,650)	(10,058)
Interest paid on borrowings	(463)	-	(463)
Drawdown of RBL	2,329	(2,329)	-
Foreign exchange adjustments	(1,327)	1,456	129
Other cash flows	(693)	-	(693)
Other non-cash movements	-	(172)	(172)
At 31 December 2020	2,438	(13,695)	(11,257)
Interest paid on borrowings	**(454)**	**-**	**(454)**
Drawdown of RBL	**1,432**	**(1,432)**	**-**
Foreign exchange adjustments	**(7)**	**137**	**130**
Other cash flows	**(654)**	**-**	**(654)**
Other non-cash movements	**-**	**(133)**	**(133)**
At 30 June 2021	**2,755**	**(15,123)**	**(12,368)**

Reserve Based Lending facility

On 3 October 2019, the Company announced that it had signed a $40.0 million RBL facility with BMO Capital Markets (BMO). In addition to the committed $40.0 million RBL, a further $20.0 million is available on an uncommitted basis, and can be used for any future acquisitions or new conventional developments. The RBL has a five-year term, an interest rate of LIBOR plus 4.0%, matures in September 2024 and is secured on the Company's assets. The RBL is subject to a semi-annual redetermination in May and November when the loan availability will be recalculated taking into account forecast commodity prices, remaining field reserves (assessed by an independent reserves auditor annually) and the latest forecast of operating and capital costs. As at 30 June 2021, the Group had successfully completed the May 2021 redetermination which confirmed an available facility limit of $27.0 million. Under the terms of the RBL, the Group is subject to a financial covenant whereby, as at 30 June and 31 December each year, the ratio of Net Debt at the period end to Earnings before Interest, Tax, Depreciation, Amortisation and Exceptional items (EBITDAX as defined in the RBL agreement) for the previous 12 months shall be less than or equal to 3.5:1.

Collateral against borrowing

A Security Agreement was executed between BMO and IGas Energy plc and some of its subsidiaries, namely; Island Gas Limited, Island Gas Operations Limited, Star Energy Weald Basin Limited, Star Energy Group Limited, Star Energy Limited, Island Gas (Singleton) Limited, Dart Energy (East England) Limited, Dart Energy (West England) Limited, IGas Energy Development Limited, IGas Energy Enterprise Limited, Dart Energy (Europe) Limited and IGas Energy Production Limited. Under the terms of this Agreement, BMO have a floating charge over all of the assets of these legal entities, other than property, assets, rights and revenue detailed in a fixed charge. The fixed charge encompasses the Real Property (freehold and/or leasehold property), the specific petroleum licences, all pipelines, plant, machinery, vehicles, fixtures, fittings, computers, office and other equipment, all related property rights, all bank accounts, shares and assigned agreements and rights including related property rights (hedging agreements, all assigned intergroup receivables and each required insurance and the insurance proceeds).

14 Share capital

	Ordinary shares		Deferred shares		Share capital	Share premium
	No.	Nominal value £000	No.	Nominal value £000	Nominal value £000	Value £000
Issued and fully paid						
At 1 January 2020	122,360,175	2	303,305,534	30,331	30,333	102,680
SIP issue partnership	85,036	-	-	-	-	30
SIP issue matching	85,036	-	-	-	-	31
At 30 June 2020	122,530,247	2	303,305,534	30,331	30,333	102,741
SIP issue partnership	203,327	-	-	-	-	26
SIP issue matching	200,326	-	-	-	-	25
Shares issued in respect of salary sacrifice scheme	1,235,168	-	-	-	-	-
Shares issued for acquisitions	377,586	-	-	-	-	84
Shares issued in lieu of Directors' fees	250,515	-	-	-	-	30
At 31 December 2020	124,797,169	2	303,305,534	30,331	30,333	102,906
SIP issue partnership	**185,212**	**-**	**-**	**-**	**-**	**21**
SIP issue matching	**271,971**	**-**	**-**	**-**	**-**	**42**
At 30 June 2021	**125,254,352**	**2**	**303,305,534**	**30,331**	**30,333**	**102,969**

15 Subsequent events

On 17 September 2021, the Group signed a Memorandum of Understanding (MoU) with SSE Heat Networks Limited (SSE) for the development of a geothermal district heating project in Stoke-on-Trent (the Project). The MoU grants exclusivity to each of SSE and GT Energy UK Limited (GTE), a wholly subsidiary of the Group, with regard to the Project for a period of 12 months with certain milestones including executing a heat offtake agreement in relation to GTE's future geothermal plant. This is a non-adjusting subsequent event.

Glossary

£ The lawful currency of the United Kingdom

$ The lawful currency of the United States of America

1P Low estimate of commercially recoverable reserves

2P Best estimate of commercially recoverable reserves

3P High estimate of commercially recoverable reserves

1C Low estimate or low case of Contingent Recoverable Resource quantity

2C Best estimate or mid case of Contingent Recoverable Resource quantity

3C High estimate or high case of Contingent Recoverable Resource quantity

AIM AIM market of the London Stock Exchange

Bbl(s)/d Barrel(s) of oil per day

boepd Barrels of oil equivalent per day

bopd Barrels of oil per day

CCUS Carbon capture usage and storage

Contingent Recoverable Resource - Contingent Recoverable Resource estimates are prepared in accordance with the Petroleum Resources Management System (PRMS), an industry recognised standard. A Contingent Recoverable Resource is defined as discovered potentially recoverable quantities of hydrocarbons where there is no current certainty that it will be commercially viable to produce any portion of the contingent resources evaluated. Contingent Recoverable Resources are further divided into three status groups: marginal, sub-marginal, and undetermined. IGas' Contingent Recoverable Resources all fall into the undetermined group. Undetermined is the status group where it is considered premature to clearly define the ultimate chance of commerciality.

Drill or drop - A drill or drop well carries no commitment to drill. The decision whether or not to drill the well rests entirely with the Licensee being driven by the results of geotechnical analysis. The Licence will, however, still expire at the end of the Initial Term if the well has not been drilled.

Firm well - A firm well is classified as a firm commitment to drill a well. It is not contingent on any further geotechnical evaluation (i.e. it is a fully evaluated Prospect).

GIIP Gas initially in place

m Million

Mbbl Thousands of barrels

MMboe Millions of barrels of oil equivalent

MMscfd Millions of standard cubic feet per day

PEDL United Kingdom petroleum exploration and development licence

PL Production licence

Tcf Trillions of standard cubic feet of gas

UK United Kingdom