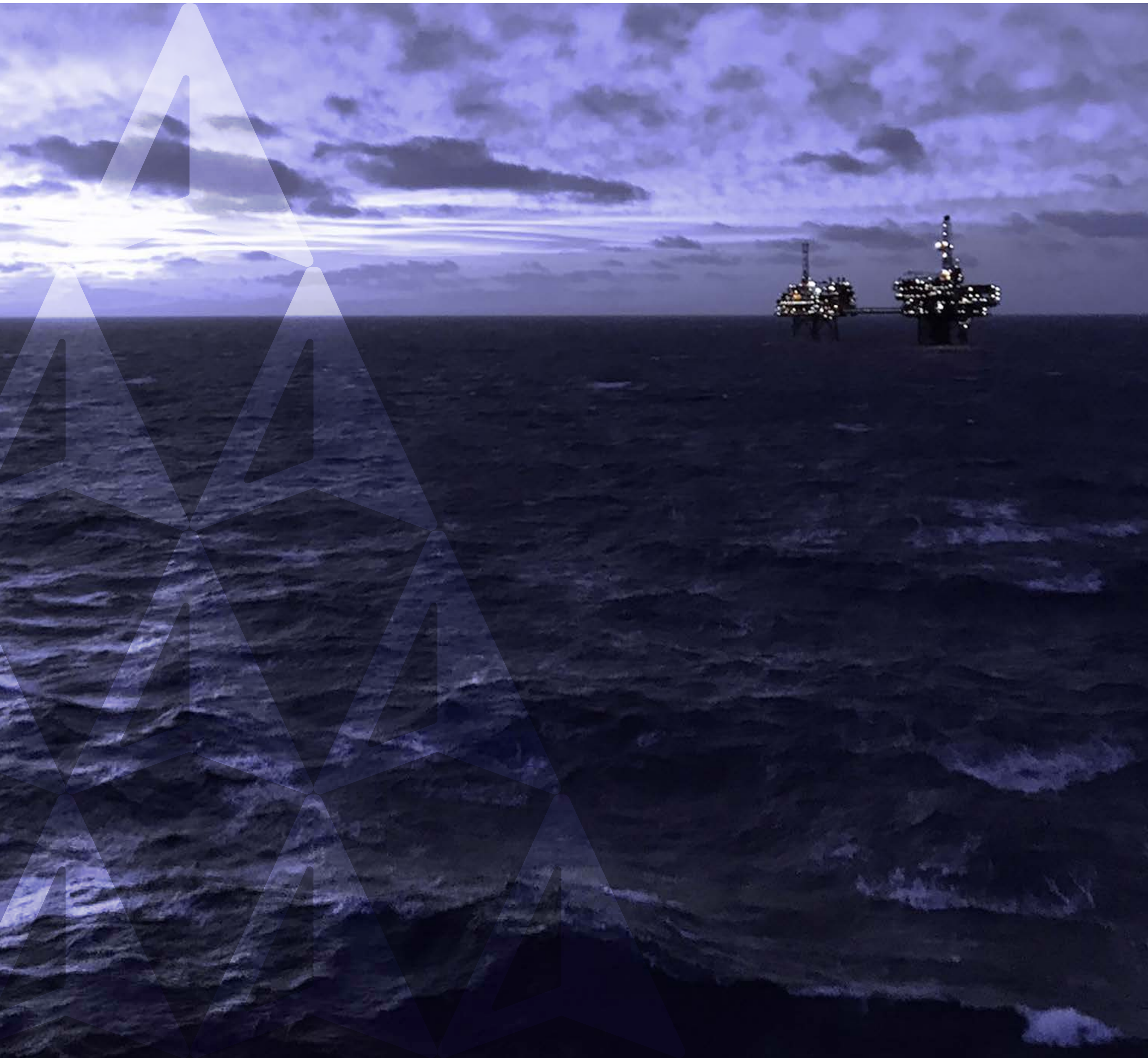
THE STRENGTH OF
THE NORTH SEA

IPO PROSPECTUS
2022

Ithaca Energy plc (ITH)



This document constitutes a prospectus (the "**Prospectus**") for the purposes of the UK version of Regulation (EU) 2017/1129, which is part of UK law by virtue of the European Union (Withdrawal) Act 2018 (as amended and supplemented from time to time (including, but not limited to, by the EU (Withdrawal) Act 2020 and the UK version of commission delegated regulation (EU) 2019/980) (the "**EUWA**")), (the "**UK Prospectus Regulation**"), relating to Ithaca Energy plc (the "**Company**") prepared in accordance with the prospectus regulation rules of the Financial Conduct Authority (the "**FCA**") made under section 73A of the Financial Services and Markets Act 2000 (as amended) ("**FSMA**") (the "**Prospectus Regulation Rules**"). A copy of this Prospectus has been filed with, and approved on 9 November 2022 by, the FCA as competent authority under the UK Prospectus Regulation. The FCA only approves this document as meeting the standards of completeness, comprehensibility and consistency imposed by the UK Prospectus Regulation in respect of a prospectus. Such approval should not be considered as an endorsement of the Company that is, or the quality of the securities that are, the subject of this document. Investors should make their own assessment as to the suitability of investing in the securities. The Prospectus will be made available to the public in accordance with Rule 3.2 of the Prospectus Regulation Rules. Capitalised terms used in this document which are not otherwise defined have the meanings given to them in Part 21 (*Definitions*) and Part 22 (*Glossary of Technical Terms*).

Application will be made (i) to the FCA for all of the ordinary shares of £0.01 each of the Company (the "**Ordinary Shares**"), issued and to be issued pursuant to the Global Offering, to be admitted to the premium listing segment of the Official List maintained by the FCA (the "**Official List**") and (ii) to London Stock Exchange plc (the "**London Stock Exchange**") for such Ordinary Shares to be admitted to trading on its main market for listed securities (the "**Main Market**") ("**Admission**"). Conditional dealings in the Ordinary Shares are expected to commence on the Main Market at 8.00 am (London time) on 9 November 2022. It is expected that Admission will become effective and that unconditional dealings will commence in the Ordinary Shares on the Main Market at 8.00 am (London time) on 14 November 2022. **All dealings in Ordinary Shares prior to the commencement of unconditional dealings will be on a "when issued" basis and of no effect if Admission does not take place and will be at the sole risk of the parties concerned. No application has been, or is currently intended to be, made for the Ordinary Shares to be admitted to listing or trading on any other stock exchange. Prior to the Global Offering, there has been no public market for the Ordinary Shares.**

The Company and its directors, whose names appear on page 67 of this Prospectus (the "**Directors**"), accept responsibility for the information contained in this Prospectus. To the best of the knowledge of the Company and the Directors, the information contained in this Prospectus is in accordance with the facts and makes no omission likely to affect its import.

Prospective investors should read the entirety of this Prospectus and, in particular, Part 2 (*Risk Factors*) beginning on page 8, for a discussion of certain risks and other factors that should be considered in connection with any investment in the Ordinary Shares. The Ordinary Shares are only being offered, and this Prospectus is only being distributed, to those eligible investors who are permitted to purchase or subscribe for Ordinary Shares under applicable law as set out in this Prospectus.

ITHACA ENERGY PLC

(Incorporated under the Companies Act 2006 and registered in England and Wales with registered number 12263719)

Prospectus

Global Offering of 105,000,000 Ordinary Shares at an Offer Price of 250 pence per Ordinary Share

Admission of the Ordinary Shares to the premium listing segment of the Official List and to trading on the Main Market of the London Stock Exchange

The Company is offering 105,000,000 new Ordinary Shares (the "**Offer Shares**") (the "**Global Offering**"). The Global Offering includes 105,000,000 Offer Shares and, if the Over-allotment Option (as defined below) is exercised, up to 15,000,000 additional existing Ordinary Shares may be sold by DKL Energy Limited (the "**Selling Shareholder**"). The Company will not receive any of the net proceeds from the Global Offering, all of which will ultimately be received by Delek Group Ltd. ("**Delek**"). The Selling Shareholder has granted the Stabilising Manager an over-allotment option (the "**Over-allotment Option**") to purchase up to a maximum of 14.3% of the total number of Offer Shares (before exercise of the Over-allotment Option) during the period commencing on the date of commencement of conditional dealings of the Ordinary Shares on the London Stock Exchange and ending no later than 30 calendar days thereafter at the Offer Price to cover over-allotments, if any, made in connection with the Global Offering and to cover any short positions resulting from stabilisation transactions.

The Ordinary Shares have not been, and will not be, registered under the US Securities Act of 1933, as amended (the "**US Securities Act**"), or with any securities regulatory authority of any state or other jurisdiction of the United States, and may not be offered or sold in the United States except pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the US Securities Act and in compliance with any applicable state securities laws. The Global Offering comprises an offering of Ordinary Shares: (a) in the United States to qualified institutional buyers (each a "**QIB**") as defined in, and in reliance on, Rule 144A ("**Rule 144A**") under the US Securities Act or another exemption from, or in a transaction not subject to, the registration requirements of the US Securities Act; and (b) outside the United States in offshore transactions as defined in, and in reliance on, Regulation S ("**Regulation S**") under the US Securities Act.

Joint Sponsors, Joint Global Co-ordinators and Joint Bookrunners

Goldman Sachs International | **Morgan Stanley**

Joint Bookrunners

BofA Securities | **HSBC** | **Jefferies**

Co-lead Manager

ING

ISSUED AND FULLY PAID ORDINARY SHARE CAPITAL IMMEDIATELY FOLLOWING ADMISSION

Number	Nominal value
1,005,162,217	**£0.01 per Ordinary Share**

This Prospectus does not constitute or form part of any offer or invitation to sell or issue, or any solicitation of any offer to purchase or subscribe for, any securities other than the securities to which it relates or any offer or invitation to sell or issue, or any solicitation of any offer to purchase or subscribe for, such securities by any person in any circumstances in which such offer or solicitation is unlawful.

Recipients of this Prospectus are authorised solely to use this Prospectus for the purpose of considering the subscription or acquisition of the Ordinary Shares, and may not reproduce or distribute this Prospectus, in whole or in part, and may not disclose any of the contents of this Prospectus or use any information herein for any purpose other than considering an investment in the Ordinary Shares. Such recipients of this Prospectus agree to the foregoing by accepting delivery of this Prospectus.

Prospective investors should read the entirety of this Prospectus and, in particular, the section entitled "Risk Factors" beginning on page 8, for a discussion of certain risks and other factors that should be considered in connection with any investment in the Ordinary Shares. Prospective investors should be aware that an investment in the Ordinary Shares involves a degree of risk and that, if some or all of the risks described in the Part 2 (*Risk Factors*) occur, investors may find their investment materially adversely affected. Accordingly, an investment in the Ordinary Shares is only suitable for investors who are particularly knowledgeable in investment matters and who are able to bear the loss of the whole or part of their investment. In making an investment decision, each investor must rely on its own examination, analysis and enquiry of the Company, its Subsidiaries (together with Company, the "**Group**"), and the terms of the Global Offering, including the merits and risks involved. The investors also acknowledge that: (a) they have not relied on Goldman Sachs International ("**Goldman Sachs International**"), Morgan Stanley & Co International plc ("**Morgan Stanley**" and, together with Goldman Sachs International, the "**Joint Global Co-ordinators**" or the "**JGCs**"), Merrill Lynch International ("**BofA Securities**"), HSBC Bank plc ("**HSBC**"), Jefferies International Limited and Jefferies GmbH ("**Jefferies**"), ING Bank N.V. ("**ING**" and, together with the Joint Global Co-ordinators, BofA Securities, HSBC and Jefferies, the "**Underwriters**") or any person affiliated with any of the Underwriters, in connection with any investigation of the accuracy of any information contained in this Prospectus or their investment decision; (b) they have relied only on the information contained in this Prospectus; and (c) that no person has been authorised to give any information or make any representation other than those contained in this Prospectus and, if given or made, such information or representation must not be relied upon as having been so authorised by the Company or the Underwriters. Without prejudice to any legal or regulatory obligation of the Company to publish a supplementary prospectus pursuant to Article 23 of the UK Prospectus Regulation and Rule 3.4 of the Prospectus Regulation Rules, neither the delivery of this Prospectus nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in the affairs of the Company since the date of this Prospectus or that the information in this Prospectus is correct as at any subsequent time.

None of the Company, the Underwriters or any of their respective affiliates or representatives is making any representation to any prospective investor in the Ordinary Shares regarding the legality of an investment in the Ordinary Shares by such prospective investor under the laws applicable to such prospective investor. The contents of this Prospectus should not be construed as legal, financial or tax advice. Each prospective investor should consult his, her or its own legal, business, financial or tax adviser for legal, business, financial or tax advice applicable to an investment in the Ordinary Shares.

None of the Company, the Selling Shareholder, the Underwriters or any of their respective affiliates or representatives accept any responsibility for the accuracy or completeness of any information reported by the press or other media, nor the fairness or appropriateness of any forecasts, views or opinions expressed by the press or other media, regarding the Global Offering or the Company. None of the Company, the Selling Shareholder, the Underwriters or any of their respective affiliates or representatives make any representation as to the appropriateness, accuracy, completeness or reliability of any such information or publication, and no such information or publication is, or shall be relied upon as, a promise or representation in this respect, whether as to the past or the future.

Goldman Sachs International and Morgan Stanley have been appointed as joint sponsors, joint global co-ordinators and joint bookrunners in connection with Admission and the Global Offering. BofA Securities, HSBC and Jefferies have been appointed as joint bookrunners and ING has been appointed as a co-lead manager in connection with the Global Offering. Each of Goldman Sachs International, Morgan Stanley, BofA Securities and HSBC is authorised by the Prudential Regulatory Authority and regulated by the FCA and the Prudential Regulatory Authority in the United Kingdom. Jefferies International Limited is authorised and regulated by the FCA in the United Kingdom and Jefferies GmbH is authorised and regulated by Bundesanstalt für Finanzdienstleistungsaufsicht. ING is directly supervised by the European Central Bank as part of the Single Supervisory Mechanism and regulated by De Nederlandsche Bank and the Dutch Autoriteit Financiële Markten. Each of the Underwriters is acting exclusively for the Company and no one else in connection with the Global Offering and will not regard any other person (whether or not a recipient of this Prospectus) as a client in relation to the Global Offering and will not be responsible to anyone other than the Company for providing the protections afforded to their respective clients nor for giving advice in relation to the Global Offering or any transaction or arrangement referred to in this Prospectus. The Underwriters and their respective affiliates may have engaged in transactions with, and provided various investment banking, financial advisory and other services to, the Company for which they would have received customary fees. The Underwriters and any of their respective affiliates may provide such services to the Company and/or the Selling Shareholder and/or any of their respective affiliates in the future. In addition, the Underwriters and any of their respective affiliates may also provide risk management products to the Company and/or the Selling Shareholder or any parties related to any of them in connection with the Global Offering for which they could receive payment(s), earn a profit and/or suffer or avoid a loss contingent on the closing of the Global Offering (and the quantum of such amounts may potentially be significantly in excess of the fees earned by the relevant Underwriter for its services acting as a joint sponsor, Joint Global Co-ordinator, Joint Bookrunner or Co-Lead Manager, as applicable in connection with the Global Offering).

In connection with the Global Offering, each of the Underwriters and their respective affiliates may take up a portion of the Ordinary Shares as a principal position, and in that capacity may retain, purchase, sell, offer to sell or otherwise deal for their own accounts in such Ordinary Shares and other securities of the Company or related investments in connection with the Global Offering or otherwise. Accordingly, references in this Prospectus to the Ordinary Shares being issued, offered, acquired, placed or otherwise dealt in should be read as including any issue or offer to, or acquisition, dealing or placing by, any of the Underwriters and any of their respective affiliates acting as investors for their own accounts. In addition, the Underwriters or certain of their respective affiliates may enter into financing arrangements (including swaps, warrants or contracts for differences) with investors in connection with which the Underwriters (or their respective affiliates) may from time to time acquire, hold or dispose of Ordinary Shares. None of the Underwriters intends to disclose the extent of any such investments or transactions otherwise than in accordance with any legal or regulatory obligations to do so.

Apart from the responsibilities and liabilities, if any, that may be imposed on the Underwriters by FSMA or the regulatory regime established thereunder, or under the regulatory regime of any jurisdiction where the exclusion of liability under the relevant regulatory regime would be illegal, void or unenforceable, none of the Underwriters, nor any of their respective affiliates, accept any responsibility whatsoever for, and makes no representation or warranty, express or implied, as to the contents of, this Prospectus including its accuracy, completeness and verification or for any other statement made or purported to be made by it, or on its behalf, in connection with the Company, the Ordinary Shares or the Global Offering and nothing in this Prospectus will be relied upon as a promise or representation in this respect, whether or not to the past or future. The Underwriters and each of their respective affiliates accordingly disclaim, to the fullest extent permitted by applicable law, all and any liability whether arising in tort, contract or otherwise (save as referred to above) which they might otherwise have in respect of this Prospectus or any such statement. Nothing in this Prospectus excludes, or attempts to exclude, any responsibilities or liabilities which the Underwriters may have under FSMA or the regulatory regime established thereunder. The Underwriters have given and not withdrawn their consent to the issue of this Prospectus with the inclusion of the references to their name in the form and context in which they are included.

In connection with the Global Offering, the Stabilising Manager may (but will be under no obligation to), to the extent permitted by applicable law, over-allot Ordinary Shares up to a maximum of 14.3% of the total number of the Offer Shares (prior to any exercise of the Over-allotment Option) or effect other transactions with a view to supporting the market price of the Ordinary Shares at a level higher than that which might otherwise prevail in the open market for a period of no more than 30 calendar days after the date of commencement of conditional dealings of the Ordinary Shares on the London Stock Exchange. Such transactions may be effected on the London Stock Exchange, in the over-the-counter markets or otherwise. There is no obligation on the Stabilising Manager to undertake stabilisation transactions. Such transactions, if commenced, may be discontinued at any time without prior notice and must be brought to an end no later than 30 calendar days after the date of commencement of conditional dealings of the Ordinary Shares on the London Stock Exchange (the "**Stabilisation Period**"). In no event will measures be taken to stabilise the market price of the Ordinary Shares above the Offer Price. Save as required by law, the Stabilising Manager does not intend to disclose the extent of any stabilisation transactions under the Global Offering.

For the purposes of allowing the Stabilising Manager to cover short positions resulting from any such over-allocations and/or from sales of Ordinary Shares effected by it during the Stabilisation Period, the Selling Shareholder has granted to it the Over-allotment Option, pursuant to which the Stabilising Manager may purchase or procure purchasers for up to a maximum of 14.3% of the total number of Offer Shares at the Offer Price. The Over-allotment Option is exercisable in whole or in part, upon notice by the Stabilising Manager, at any time on or before the 30th calendar day after the commencement of conditional dealings in the Ordinary Shares on the London Stock Exchange. Any Over-allotment Shares made available pursuant to the Over-allotment Option will rank pari passu in all respects with the Ordinary Shares, including for all dividends and other distributions declared, made or paid on the Ordinary Shares, will be purchased on the same terms and conditions as the Ordinary Shares in the Global Offering and will form a single class for all purposes with the other Ordinary Shares.

NOTICE TO INVESTORS

The Ordinary Shares are subject to transfer restrictions in certain jurisdictions. Prospective purchasers or subscribers should read paragraph 1.12 (*Selling Restrictions*) in Part 18 (*Details, Terms and Conditions of the Global Offering*). Each purchaser or subscriber of the Ordinary Shares will be deemed to have made the relevant representations described therein.

The distribution of this Prospectus and the offer of the Ordinary Shares in certain jurisdictions may be restricted by law. No action has been or will be taken by the Company, the Selling Shareholder or any of the Underwriters to permit a public offering of the Ordinary Shares or to permit the possession or distribution of this Prospectus (or any other offering or publicity materials relating to the Ordinary Shares) in any jurisdiction where action for that purpose may be required, other than the United Kingdom. Accordingly, neither this Prospectus nor any advertisement or any other offering material may be distributed or published in any jurisdiction except under circumstances that will result in compliance with any applicable laws and regulations. Persons into whose possession this Prospectus comes should inform themselves about and observe any such restrictions. Any failure to comply with these restrictions may constitute a violation of the securities laws of any such jurisdiction.

In particular, save for the United Kingdom, no actions have been taken to allow for a public offering of the Ordinary Shares under the applicable securities laws of any other jurisdiction, including Canada, Japan or the United States. This Prospectus does not constitute an offer of, or the solicitation of an offer to subscribe for or buy any of, the Ordinary Shares in any jurisdiction where it is unlawful to make such offer or solicitation.

NOTICE TO PROSPECTIVE INVESTORS IN THE UNITED STATES

The Ordinary Shares have not been, and will not be, registered under the US Securities Act or the securities laws of any state or other jurisdiction of the United States, and may not be offered or sold, directly or indirectly, in the United States absent registration under the US Securities Act or an available exemption from the registration requirements of the US Securities Act and in compliance with any applicable securities laws of any state or other jurisdiction of the United States. The Ordinary Shares are being offered and sold outside the United States in reliance on Regulation S. The Underwriters, through their respective selling agents, may arrange for the Global Offering and resale of the Ordinary Shares in the United States only to persons reasonably believed to be QIBs, as defined in, and in reliance on, the exemption from the registration requirements of the US Securities Act provided by Rule 144A, or another exemption from, or in a transaction not subject to, the registration requirements of the Securities Act. Prospective purchasers or subscribers are hereby notified that sellers of the Ordinary Shares may be relying on the exemption from the provisions of Section 5 of the US Securities Act provided by Rule 144A. For a description of these and certain further restrictions on offers, sales and transfers of the Ordinary Shares and the distribution of this Prospectus, see paragraph 1.12 (*Selling Restrictions*) paragraph 1.15 (*United States of America*) and paragraph 1.16 (*Rule 144A*) of Part 18 (*Details, Terms and Conditions of the Global Offering*).

For so long as any of the Ordinary Shares are in issue and are “restricted securities” within the meaning of Rule 144(a)(3) under the US Securities Act, the Company will, during any period in which it is not subject to section 13 or 15(d) under the US Securities Exchange Act of 1934, as amended (the “**US Exchange Act**”), nor exempt from reporting under the US Exchange Act pursuant to Rule 12g3-2(b) thereunder, make available to any holder or beneficial owner of an Ordinary Share, or to any prospective purchaser or subscriber of an Ordinary Share designated by such holder or beneficial owner, the information specified in, and meeting the requirements of, Rule 144A(d)(4) under the US Securities Act.

The Ordinary Shares offered by this Prospectus have not been approved or disapproved by the United States Securities and Exchange Commission, any state securities commission or any other regulatory authority in the United States, nor have the foregoing authorities passed upon, determined or endorsed the merits of the Global Offering or the accuracy or adequacy of the information contained in this Prospectus. Any representation to the contrary is a criminal offence in the United States. No public offer of the Ordinary Shares is being made in the United States.

NOTICE TO PROSPECTIVE INVESTORS IN CANADA

Subject to limited exceptions, this document is not for distribution in or into Canada. No prospectus has been filed with any securities commission or similar regulatory authority in Canada in connection with the offer and sale of the Ordinary Shares. Accordingly, purchasers or subscribers of Ordinary Shares offered by this Prospectus do not receive the benefits associated with a subscription for securities issued pursuant to a prospectus, including the review of offering materials by any securities regulatory authority in Canada. No securities commission or similar regulatory authority in Canada has reviewed or in any way passed upon this document or on the merits of the Ordinary Shares and any representation to the contrary is an offence. The offer and sale of the Offer Shares in Canada is being made on a private placement basis only and is exempt from the requirement that the issuer prepares and files a prospectus under applicable Canadian securities laws. Any resale of Ordinary Shares acquired by a Canadian investor in this offering must be made in accordance with applicable Canadian securities laws and, because the Company is not a reporting issuer in any province or territory of Canada, such resale restrictions may never expire. If no further statutory exemption may be relied upon and if no discretionary order is obtained, the resale restrictions could result in a Canadian investor who purchases or subscribes for the Ordinary Shares having to hold the Ordinary Shares for an indefinite period of time. The resale restrictions may under certain circumstances apply to resales of the Ordinary Shares outside of Canada.

Each Canadian investor who purchases or subscribes for the Ordinary Shares will be deemed to have represented to the issuer, the Underwriters and to each dealer from whom a purchase confirmation is received, as applicable, that the investor (i) is purchasing as principal, or is deemed to be purchasing as principal in accordance with applicable Canadian securities laws, for investment only and not with a view to resale or redistribution; (ii) is an "accredited investor" as such term is defined in section 1.1 of National Instrument 45-106 Prospectus Exemptions ("**NI 45-106**") or, in Ontario, as such term is defined in section 73.3(1) of the Securities Act (Ontario) that is not created or used solely to purchase or hold the Ordinary Shares; (iii) is a "permitted client" as such term is defined in section 1.1 of National Instrument 31-103 Registration Requirements, Exemptions and Ongoing Registrant Obligations ("**NI 31-103**"); and (iv) is located in, and subject to, the securities laws of Alberta, British Columbia, Manitoba, Ontario or Quebec.

Securities legislation in certain provinces or territories of Canada may provide a purchaser or subscriber with remedies for rescission or damages if this Prospectus (including any amendment thereto) contains a misrepresentation (as defined under applicable Canadian securities laws), provided that the remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by securities legislation of the purchaser's province or territory. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for particulars of these rights or consult with a legal advisor.

Canadian investors are advised that, pursuant to section 3A.3 of National Instrument 33-105 Underwriting Conflicts ("**NI 33-105**"), the Underwriters are, in connection with this offering, relying on the exemption from the requirement to provide Canadian investors with certain disclosure required by NI 33-105 regarding underwriter conflicts of interest pertaining to "connected issuer" and/or "related issuer" relationships. By purchasing the Ordinary Shares offered under this Prospectus, each Canadian investor is deemed to acknowledge that its express wish is that all documents evidencing or relating in any way to the sale of the Ordinary Shares be drafted in the English language only. *En souscrivant des valeurs mobilières en vertu de la présente notice d'offre, chaque souscripteur est réputé reconnaître avoir exigé que tous les documents faisant foi de ou relatifs à la vente des valeurs mobilières soient rédigés uniquement en anglais.*

NOTICE TO PROSPECTIVE INVESTORS IN ISRAEL

This document does not constitute a prospectus under the Israeli Securities Law, 5728-1968, and has not been filed with or approved by the Israel Securities Authority. In Israel, as set forth in Section 15A(B)(1) of the Israeli Securities Law, this Prospectus may be distributed only to, and be directed only at, investors listed in the first addendum to the Israeli Securities Law (the "**Addendum**"), consisting primarily of joint investment in trust funds; provident funds; insurance companies; banks; portfolio managers, investment advisers, members of the Tel Aviv Stock Exchange Ltd., underwriters, each purchasing for their own account; venture capital funds; entities with equity in excess of ILS 50 million and "qualified individuals," each as defined in the Addendum (as it may be amended from time to time), collectively referred to as "**Qualified Israeli Investors**". Qualified Israeli Investors shall be required to provide the Company with written declarations and ancillary certificates confirming that they fall within the scope of the Addendum, as deemed necessary by the Company.

NOTICE TO DISTRIBUTORS

UK Product Governance

Solely for the purposes of the product governance requirements of Chapter 3 of the FCA Handbook Product Intervention and Product Governance Sourcebook (the "**UK Product Governance Rules**"), and disclaiming all and any liability, whether arising in tort, contract or otherwise, which any "manufacturer" (for the purposes of the UK Product Governance Rules) may otherwise have with respect thereto, the Ordinary Shares have been subject to a product approval process which has determined that the Ordinary Shares are: (i) compatible with an end target market of retail investors and investors who meet the criteria of professional clients as defined in Regulation (EU) No 600/2014 as it forms part of domestic law by virtue of the EUWA and eligible counterparties as defined in the FCA Handbook Conduct of Business Sourcebook ("**COBS**"); and (ii) eligible for distribution through all permitted distribution channels (the "**UK Target Market Assessment**"). Notwithstanding the UK Target Market Assessment, "distributors" (for the purposes of the UK Product Governance Rules) should note that: the price of the Ordinary Shares may decline and investors could lose all or part of their investment; the Ordinary Shares offer no guaranteed income and no capital protection; and an investment in the Ordinary Shares is compatible only with investors who do not need a guaranteed income or capital protection, who (either alone or in conjunction with an appropriate financial or other adviser) are capable of evaluating the merits and risks of such an investment and who have sufficient resources to be able to bear any losses that may result therefrom. The UK Target Market Assessment is without prejudice to the requirements of any contractual, legal or regulatory selling restrictions in relation to the Global Offering. Furthermore, it is noted that, notwithstanding the UK Target Market Assessment, the Underwriters will only procure investors who meet the criteria of professional clients and eligible counterparties.

For the avoidance of doubt, the UK Target Market Assessment does not constitute: (a) an assessment of suitability or appropriateness for the purposes of Chapter 9A or 10A respectively of COBS; or (b) a recommendation to any investor or group of investors to invest in, or purchase, or take any other action whatsoever with respect to the Ordinary Shares.

Each distributor is responsible for undertaking its own target market assessment in respect of the Ordinary Shares and determining appropriate distribution channels.

EEA Product Governance

Solely for the purposes of the product governance requirements contained within: (a) EU Directive 2014/65/EU on markets in financial instruments, as amended ("**MiFID II**"); (b) Articles 9 and 10 of Commission Delegated Directive (EU) 2017/593 supplementing MiFID II; and (c) local implementing measures in the European Economic Area and in the United Kingdom (together, the "**MiFID II Product Governance Requirements**"), and disclaiming all and any liability, whether arising in tort, contract or otherwise, which any "manufacturer" (for the purposes of the MiFID II Product Governance Requirements) may otherwise have with respect thereto, the Ordinary Shares have been subject to a product approval process, which has determined that the Ordinary Shares are: (i) compatible with an end target market of retail investors and investors who meet the criteria of professional clients and eligible counterparties, each as defined in MiFID II; and (ii) eligible for distribution through all distribution channels as are permitted by MiFID II (the "**Target Market Assessment**"). Notwithstanding the Target Market Assessment, "distributors" (for the purposes of the MiFID II Product Governance Requirements) should note that: the price of the Ordinary Shares may decline and investors could lose all or part of their investment; the Ordinary Shares offer no guaranteed income and no capital protection; and an investment in the Ordinary Shares is compatible only with investors who do not need a guaranteed income or capital protection, who (either alone or in conjunction with an appropriate financial or other adviser) are capable of evaluating the merits and risks of such an investment and who have sufficient resources to be able to bear any losses that may result therefrom. The Target Market Assessment is without prejudice to the requirements of any contractual, legal or regulatory selling restrictions in relation to the Global Offering. Furthermore, it is noted that, notwithstanding the Target Market Assessment, the Underwriters will only procure investors who meet the criteria of professional clients and eligible counterparties.

For the avoidance of doubt, the Target Market Assessment does not constitute: (a) an assessment of suitability or appropriateness for the purposes of the MiFID II Product Governance Requirements; or (b) a recommendation to any investor or group of investors to invest in, or purchase, or take any other action whatsoever with respect to the Ordinary Shares.

Each distributor is responsible for undertaking its own target market assessment in respect of the Ordinary Shares and determining appropriate distribution channels.

PROFIT FORECASTS

Information in relation to the Profit Forecasts is included in Part 15 (*Profit Forecasts*). Other than the Profit Forecasts, no statement in this Prospectus is intended as a profit forecast or estimate and no statement in this Prospectus should be interpreted as a profit forecast or estimate.

INTERPRETATION

Certain terms used in this Prospectus are defined in Part 21 (*Definitions*) and Part 22 (*Glossary of Technical Terms*).

All references to time in this Prospectus are to London time unless otherwise stated.

WEBSITES

Save for the copies of the documents listed in paragraph 24 (*Documents available for inspection*) of Part 20 (*Additional Information*) that are extracts from this Prospectus and will be available for inspection on the Group's website at www.ithacaenergy.com for a period of 12 months following Admission, information contained on the Group's website or the contents of any website accessible from hyperlinks on the Group's website are not incorporated into and do not form part of this Prospectus.

This Prospectus is dated 9 November 2022.

CONTENTS

PART 1

SUMMARY

1. INTRODUCTION AND WARNINGS

1.1 *Details of the issuer*

The legal and commercial name of the Company is Ithaca Energy plc, a public limited company incorporated in England and Wales with registered number 12263719. The Company's registered office is at 23 College Hill, London, EC4R 2RP and head office is at Hill of Rubislaw, Aberdeen, AB15 6XL, United Kingdom. The telephone number of the Company's head office is +44 (0) 1224 638 582. The Company's legal entity identifier number ("**LEI**") is 21380057TNFLXPXBIP34.

1.2 *Details of the securities*

On Admission, the Ordinary Shares will be registered with an ISIN of GB00BPJHV584 and SEDOL of BPJHV58. It is expected that the Ordinary Shares will be traded on the main market for listed securities of the London Stock Exchange under the ticker symbol "ITH".

1.3 *Details of the competent authority*

The head office of the FCA is at 12 Endeavour Square, London, E20 1JN. The telephone number of the FCA is +44 (0)20 7066 1000. This Prospectus was approved by the FCA on 9 November 2022.

1.4 *Warnings*

This summary has been prepared in accordance with Article 7 of the UK Prospectus Regulation and should be read as an introduction to the Prospectus.

This Prospectus should be read in its entirety. Any decision to invest in the securities should be based on a consideration of the Prospectus as a whole by the investor. An investor acquiring Ordinary Shares may lose all or part of their invested capital. Where an investor's liability is not limited to the amount of its investment, an investor may lose more than the invested capital. Where a claim relating to the information contained in this Prospectus is brought before a court a plaintiff might, under national law, have to bear the costs of translating this Prospectus before the legal proceedings are initiated.

Civil liability attaches only to those persons who are responsible for this summary including any translation thereof, but only if this summary is misleading, inaccurate or inconsistent when read together with the other parts of this Prospectus or if it does not provide, when read together with the other parts of this Prospectus, key information in order to aid investors when considering whether to invest in the Ordinary Shares.

2. KEY INFORMATION ON THE ISSUER

2.1 *Who is the issuer of the securities?*

The Company was incorporated in England and Wales with registered number 12263719 on 15 October 2019 as "Delek North Sea Limited". It changed its name to "Ithaca Energy Limited" on 7 October 2022 and to "Ithaca Energy plc" on 1 November 2022 when it was re-registered as a public limited company. The Company's LEI is 21380057TNFLXPXBIP34.

2.2 *Principal activity*

Ithaca Energy is a leading UK independent exploration and production company with production and development activities on the United Kingdom Continental Shelf (the "**UKCS**"). The Group was founded in 2004 and has been an active UK offshore operator and producer since 2008, 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 two transformational acquisitions in recent years.

The Group's portfolio consists of 35 fields, 29 of which are producing field interests, which predominantly lie in the Central North Sea and West of Shetland areas of the UKCS. The Group operates eight of these producing fields and a majority (approximately 63%) of its 2P reserves and 2C resources as at 30 June 2022, providing significant control and flexibility over execution of the business's strategic, operational and financial priorities. The Group had approximately 516 employees as at 30 June 2022, of which around 251 normally work offshore on Group-operated assets. The principal legislation under which the Company operates is the Companies Act and regulations made thereunder.

2.3 *Major shareholders*

As at the Latest Practicable Date, the controlling shareholder of the Company is Delek. Insofar as it is known to the Company as at the date of this Prospectus, the following person is, and immediately following Admission will be, directly or indirectly interested (within the meaning of the Companies Act) in 3% or more of the Company's issued share capital (being the threshold for notification of interests that will apply to Shareholders as at Admission pursuant to Chapter 5 of the Disclosure Guidance and Transparency Rules), assuming no exercise of the Over-allotment Option:

Name of Shareholder	Immediately prior to Admission: Number of Ordinary Shares	Immediately prior to Admission: Percentage (%)	Immediately following Admission: Number of Ordinary Shares	Immediately following Admission: Percentage (%)
DKL Energy[(1)]	898,219,931	99.8	898,219,931	89.4

(1) DKL Energy is an indirect wholly owned subsidiary of DGL (TASE:DLEKG)

2.4 ***Key managing directors***

The Executive Directors of the Company are: (1) Gilad Myerson—Executive Chairman, (2) Alan Bruce—Chief Executive Officer and (3) Iain Lewis—Chief Financial Officer.

2.5 ***Statutory auditors***

Deloitte LLP, whose office is at 1 New Street Square, London, EC4A 3HQ, has provided an accountant's report on the historical financial information of the Group for the six months ended 30 June 2022 and for each of the years ended 31 December 2019, 2020 and 2021. Deloitte LLP is registered to carry on audit work in the UK and Ireland by the Institute of Chartered Accountants in England and Wales and has no material interest in the Group.

Ernst & Young LLP, whose office is at 1 More London Place, London, SE1 2AF, has provided an accountant's report on (i) the historical financial information of the Siccar Point Group for the six months ended 30 June 2022 and for each of the years ended 31 December 2019, 2020 and 2021 and (ii) the historical financial information of IOG (formerly Chevron North Sea Limited) for the year ended 31 December 2019. Ernst & Young LLP is registered to carry on audit work in the UK and Ireland by the Institute of Chartered Accountants in England and Wales and has no material interest in the Group.

Deloitte LLP, whose address is at 1 New Street Square, London, EC4A 3HQ will be appointed the statutory auditor of the Company.

2.6 ***What is the key financial information regarding the issuer?***

2.6.1 **Selected historical key financial information**

The tables below set out selected key financial information for the Group for the six month periods ended 30 June 2021 and 2022 and each of the years ended 31 December 2019, 2020 and 2021.

	Year ended 31 December			Six months ended 30 June	
(in millions of $)	**2019**	**2020**	**2021**	**2021 (unaudited)**	**2022**
Table 1: Income Statement					
Revenue	537.9	1,107.6	1,428.2	619.0	1,337.6
Gross profit	100.4	311.5	549.1	156.4	585.6
(Loss) / profit before tax	(147.6)	(614.7)	763.1	228.3	1,741.3
(Loss) / profit attributable to owners of the parent	(23.6)	(455.7)	426.0	117.0	1,557.7
Table 2: Balance Sheet					
Total assets	4,995.8	4,265.0	4,731.8	4,329.3	7,758.5
Net assets	981.1	542.5	676.5	494.9	2,074.0
Total equity	981.1	542.5	676.5	494.9	2,074.0
Table 3: Cash flow statement					
Cashflow from operations	295.3	789.6	848.5	280.5	832.4
Net cash from operating activities	284.2	735.3	912.7	393.3	989.0
Net cash used in investing activities	(1,900.8)	(199.0)	(220.2)	(85.7)	(1,203.7)
Net cash provided / (used) in financing activities	1,612.8	(549.9)	(650.7)	(301.8)	332.7
(Decrease) / Increase in cash & cash equivalents	(2.4)	(13.9)	43.6	7.1	115.5

The tables below set out selected key financial information for the Siccar Point Group for the six month periods ended 30 June 2021 and 2022 and for each of the years ended 31 December 2019, 2020 and 2021.

(in millions of $)	Year ended 31 December 2019	2020	2021	Six months ended 30 June 2021 (unaudited)	2022
Table 1: Income Statement					
Revenue	223.8	142.3	234.6	107.3	153.2
Gross profit	73.2	14.1	96.8	42.0	80.5
Profit / (loss) before tax	(176.5)	(330.6)	196.8	(100.5)	(217.3)
Profit / (loss) after tax	(27.1)	(173.2)	(148.2)	(100.5)	253.4
Table 2: Balance Sheet					
Total assets	2,591.4	2,347.9	2,176.7	2,182.0	2,418.9
Total liabilities	(1,864.4)	(1,794.0)	(1,771.1)	(1,728.7)	(1,711.2)
Net assets	727.0	553.8	405.6	453.3	707.7
Total equity	727.0	553.8	405.6	453.3	707.7
Table 3: Cash flow statement					
Cash flow from operations	153.8	155.6	127.3	72.1	56.8
Net cash from operating activities	154.9	144.0	145.9	70.0	47.4
Net cash used in investing activities	(80.8)	(82.6)	(86.6)	(35.6)	(27.2)
Net cash flows from / (used in) financing activities	52.4	(172.8)	(173.9)	(160.8)	20.6
Increase / (decrease) in cash and cash equivalents	128.0	(111.9)	(114.8)	(126.2)	39.6

The tables below set out selected key financial information for IOG (formerly Chevron North Sea Limited) for the year ended 31 December 2019.

(in millions of £)	Year ended 31 December 2019
Table 1: Income Statement	
Revenue	794.4
Gross profit	390.6
Profit before tax	1,350.5
Profit attributable to owners	1,455.6
Table 2: Balance Sheet	
Total assets	2,205.3
Net assets	1,826.2
Total equity	1,826.2
Table 3: Cash flow statement	
Cashflow from operations	516.7
Net cash from operating activities	125.5
Net cash used in investing activities	(116.1)
Net cash used in financing activities	(2.8)
Increase in cash and cash equivalents	4.4

2.6.2 **Selected pro forma key financial information**

The unaudited pro forma income statements for the six months ended 30 June 2022 and the year ended 31 December 2021 have been prepared to illustrate the effect on the consolidated earnings of the Group for the six month period ended 30 June 2022 and for the year ended 31 December 2021 as if the Siccar Point Acquisition had taken place on 1 January 2022 and 1 January 2021 respectively. The unaudited pro forma income statements have been prepared for illustrative purposes only. The hypothetical financial position or results included in the Unaudited Pro Forma Condensed Combined Financial Information may differ from the Group's actual financial position or results.

The Unaudited Pro Forma Condensed Combined Financial Information has been prepared in a manner consistent with the accounting policies that will be applied by the Group for the year ending 31 December 2022 and in accordance with the requirements of Annex 20 of the UK Prospectus Regulation.

The unaudited pro forma profit before net finance costs and tax for the year ended 31 December 2021 is $2,025.3 million and for the six months ended 30 June 2022 is $1,679.7 million.

2.6.3 **Accountant's report qualifications**

There are no qualifications in the accountant's reports on the Historical Financial Information.

2.7 ***What are the key risks that are specific to the issuer?***

Any investment in the Ordinary Shares involves a high degree of risk and numerous risks and uncertainties related to the Company. The Company believes that the following risks are the key risks that relate to the Company, based on the probability of their occurrence and the expected magnitude of their negative impact. The occurrence of one or more of these risks, alone or in combination with other events or circumstances, may materially adversely affect the Company's business, financial condition and operating results. In that event, the trading price of the Company's securities could decline and investors could lose all or part of their investment.

- The Group's business depends significantly on the level of oil and gas prices, which are volatile and have fluctuated significantly over recent years and in particular in response to recent global macroeconomic and political developments.
- The levels, quality and production volumes of the Group's oil and gas reserves and resources may be lower than estimated or expected.
- The Group may be affected by the general global economic and financial market situation.
- The Group may be adversely affected by changes to tax legislation or its interpretation or increases in effective tax rates in the tax jurisdictions in which the Group does business.
- The Group's production is entirely concentrated in UKCS offshore fields, making the Group vulnerable to risks associated with having all of its production in one region, such as the effect of fiscal and regulatory factors, regional supply and demand factors, operational cluster concentration and adverse weather conditions.
- The Group may not be able to sanction development projects, including the Rosebank and Cambo fields, required to convert their resources into production and may face delays or cost overruns in executing sanctioned development projects.
- The Group's ability to operate depends on satisfying licensing and other regulatory requirements.
- The effects of climate change, abatement legislation, changes to carbon pricing systems and political and societal perception of the production and use of fossil fuels may have a material adverse effect on the hydrocarbon industry.
- The Group faces inherent uncertainty as to the success of highly capital-intensive appraisal and development activities; in particular, in connection with the development of the Cambo and Rosebank fields
- The Group's ability to grow has depended and will continue to depend on its ability to identify and acquire suitable oil and gas assets or businesses, as well as on the success and integration of such assets or business with the Group, which is subject to a number of risks.
- The Group has presented indicative management estimates in respect of certain future production and related costs. The Group's ability to achieve these estimates is dependent upon the accuracy of a series of assumptions involving factors that are beyond the Group's control.
- The Group faces drilling and production risks and hazards that may affect its ability to produce oil and gas at expected levels, quality and costs and that may result in additional liabilities to the Group.
- The Group could incur material costs to comply with, or as a result of liabilities under, health and safety and environmental regulations.

2.8 ***Profit Forecasts***

Information in relation to the Profit Forecasts is included in this Prospectus. Other than the Profit Forecasts, no statement in this Prospectus is intended as a profit forecast or estimate and no statement in this Prospectus should be interpreted as a profit forecast or estimate.

3. **KEY INFORMATION ON THE SECURITIES**

3.1 ***What are the main features of the securities?***

3.1.1 **Type, class and ISIN of the securities**

The Ordinary Shares are fully paid ordinary shares with a nominal value of £0.01 each. The Company has and, on Admission will have, one class of ordinary shares, comprising the entire issued share capital of the Company. On Admission, the Ordinary Shares will be registered with an ISIN of GB00BPJHV584 and SEDOL of BPJHV58. It is expected that the Ordinary

Shares will be traded on the main market for listed securities of the London Stock Exchange under the ticker symbol "ITH".

3.1.2 **Currency, denomination, par value, number of securities issued and term of the securities**

The Ordinary Shares are currently denominated in GBP. On Admission, the number of Ordinary Shares in issue will be 1,005,162,217. The Ordinary Shares have a nominal value of £0.01 each and will be fully paid.

3.1.3 **Rights attaching to the securities**

All Ordinary Shares will rank pari passu in all respects, there being no conversion or exchange rights attaching thereto, and all Ordinary Shares will have equal rights to participate in capital, dividend and profit distributions by the Company.

On a show of hands every Shareholder who is present in person and every person holding a valid proxy shall have one vote per Ordinary Share and on a poll every Shareholder present in person or by proxy shall have one vote per Ordinary Share. Resolutions put to a meeting will generally be decided on a poll.

3.1.4 **Rank of securities in the issuer's capital structure in the event of insolvency**

In the event of insolvency, the Ordinary Shares will rank behind any creditors or prior ranking capital of the Company and therefore any return for Shareholders will depend on the Company's assets being sufficient to meet prior entitlements of creditors.

3.1.5 **Description of restrictions on free transferability of the securities**

Save as otherwise described in this Prospectus in relation to certain Ordinary Shares held by the Selling Shareholder, Directors and Senior Managers, the Ordinary Shares are freely transferable and there are no restrictions on transfer.

3.1.6 **Dividend policy**

The Company is committed to creating long-term value for its Shareholders through an increase in value of the Ordinary Shares over time, combined with dividend payments (or share buybacks). The Company is targeting annualised dividends of 15-30% of post-tax net cash from operating activities through the cycle. In the near-term, the Company has a firm expectation of a dividend in respect of the year ending 31 December 2023, of $400 million with an ambition of an annual dividend of $420 million for the year ending 31 December 2024. The Company expects to pay dividends to Shareholders semi-annually in the ordinary course of business, specifically: (i) a third of any yearly dividend will be paid to Shareholders following the end of the first half of the relevant financial year; and (ii) two-thirds of any yearly dividend will be paid to Shareholders following the end of the relevant financial year. However, for the year ending 31 December 2023, the Company expects to pay an initial dividend in the first quarter of 2023 followed by two further dividend payments following the first half of the financial year and end of the financial year. The dividend is expected to be paid in cash. Any decision to declare and pay a dividend in any year will be made at the discretion of the Directors and subject to restrictions in the Company's borrowing arrangements (including presently the terms of the 2026 Notes and the liquidity tests in the RBL Facility), the success of the Company's development activities across its asset base, available distributable profits and other factors that the Directors deem significant from time to time.

3.1.7 **Where will the securities be traded?**

Application will be made for all of the Ordinary Shares to be admitted to the Official List maintained by the FCA (by way of a premium listing under Chapter 6 of the Listing Rules) and to trading on the London Stock Exchange's main market for listed securities. No application has been made or is currently intended to be made for Ordinary Shares to be admitted to listing or trading on any other exchange.

3.1.8 **What are the key risks that are specific to the securities?**

- On Admission, Delek will retain a significant interest in, and continue to exert substantial influence over the Group following the Global Offering and its interests may differ from or conflict with those of other Shareholders.
- The Company's ability to pay dividends in the future depends, among other things, on the Group's financial performance and capital requirements and compliance with the terms of the Group's financing arrangements and is therefore not guaranteed.
- The market price of the Ordinary Shares could be negatively affected by sales of substantial amounts of such Ordinary Shares in the public markets, including a sale by Delek.
- Changes in the approach by investors to companies with exposure to the oil and gas industry could have a negative impact on investor demand for the Ordinary Shares.

- The Ordinary Shares will be subject to market price volatility and the market price of the Ordinary Shares may decline disproportionately in response to developments that are unrelated to the Group's operating performance.

4. KEY INFORMATION ON THE GLOBAL OFFERING AND ADMISSION

4.1 *Under which conditions and timetable can I invest in this security?*

4.1.1 General terms and conditions

The Company is offering an aggregate of 105,000,000 new Ordinary Shares (the "**Offer Shares**") to certain institutional investors under the Global Offering and at an Offer Price of 250 pence per Offer Share. The Offer Shares have been underwritten, subject to certain conditions, by the Underwriters. Allocations under the Global Offering will be determined at the discretion of the Company and the Selling Shareholder following consultation with the Joint Global Co-ordinators. The Company will not receive any of the net proceeds from the Global Offering, all of which will ultimately be received by Delek.

The Offer Shares will be (a) offered and sold to certain institutional and qualified professional investors in the United Kingdom and elsewhere outside the United States in offshore transactions as defined in, and in reliance, on Regulation S, and (b) offered and sold in the United States only to persons reasonably believed to be QIBs in reliance on Rule 144A or another exemption from, or in a transaction not subject to, the registration requirements of the US Securities Act.

An investor applying for Offer Shares may elect to receive such shares in uncertificated form if such investor is a system-member in relation to CREST. Where applicable, definitive certificates in respect of the Offer Shares are expected to be despatched by post to the relevant holders within 10 Business Days of Admission.

The Ordinary Shares are not being offered to the public.

4.1.2 Expected timetable of Principal Events

Each of the following times and dates in the table below is indicative only and subject to change without further notice.

All references to times in this Prospectus are to London times unless otherwise stated.

Commencement of conditional dealings in Ordinary Shares on the London Stock Exchange(1)	8.00 am on 9 November 2022
Admission and commencement of unconditional dealings in Ordinary Shares on the London Stock Exchange	8.00 am on 14 November 2022
CREST accounts credited with uncertificated shares	14 November 2022
Despatch of definitive share certificates (where applicable)(2)	Within 10 Business Days of Admission

Notes:

(1) It should be noted that if Admission does not occur, all conditional dealings will be of no effect and any such dealings will be at the sole risk of the parties concerned.

(2) No temporary documents of title will be issued.

4.1.3 Details of admission to trading on a regulated market

Applications have been made for all the Ordinary Shares issued and to be issued pursuant to the Global Offering, to be admitted to trading on the London Stock Exchange's main market for listed securities and admitted to the premium listing segment of the Official List. No application has or is currently intended to be made for the Ordinary Shares to be admitted to listing elsewhere or to be traded on any other exchange.

4.1.4 Plan for distribution

On 9 November 2022, the Company, the Selling Shareholder, the Directors and the Underwriters entered into an underwriting agreement (the "**Underwriting and Sponsors' Agreement**") pursuant to which the Underwriters have severally agreed, on the terms and subject to the conditions contained therein, to use reasonable endeavours to procure subscribers for, and, failing which, to subscribe for themselves (in their relevant proportions) the Offer Shares subject to the Global Offering.

4.1.5 Amount and percentage of immediate dilution resulting from the issue

Pursuant to the Global Offering, the Selling Shareholder will experience a 10.4 per cent. dilution from the issue of 105,000,000 Offer Shares (assuming no exercise of the Over-allotment Option) (*i.e.*, its proportionate interest in the Company will drop by 10.4 per cent.).

4.1.6 Estimate of the total expenses of the Global Offering

The base underwriting commissions in respect of the Offer Shares and the Underwriters' legal fees and expenses are estimated to be £6.7 million (including VAT) (the "**Underwriters'**

Expenses"). The Company will pay the Underwriters' Expenses from the gross proceeds of the Global Offering. The Selling Shareholder's legal fees (including VAT), the Underwriters' advisory fees, the base underwriting commissions in respect of the Over-allotment Shares (if any) and any transfer duty (the "**Selling Shareholder's Expenses**") are estimated to be £3.6 million (including VAT). In consideration of the Selling Shareholder waiving an amount equal to the Selling Shareholder's Expenses under the Capital Note, the Company will pay the Selling Shareholder's Expenses. The other costs and expenses of, and incidental to, Admission and the Global Offering including, amongst others, the FCA fees, the Company's professional fees (including accounting, legal and those of the Competent Person) and the costs of printing and distribution of the documents are estimated to be £13.3 million (including VAT) (the "**IPO Expenses**"). The Company will pay the IPO Expenses and the Selling Shareholder's Expenses with amounts received from payments from IEEPL and/ or certain Subsidiaries. This will require IEEPL and/ or certain Subsidiaries to make payments to the Company, which is not permitted under the RBL Facility Agreement unless agreed by the majority of lenders. It is expected that IEUK will obtain the consent of the majority of lenders under the RBL Facility Agreement. However, if the consent is not received, the Selling Shareholder will pay all the IPO Expenses. The total costs and expenses of, and incidental to, Admission and the Global Offering are £23.7 million (including VAT) (being the aggregate of the Underwriters' Expenses, the Selling Shareholder's Expenses, the IPO Expenses and any discretionary commission). Any discretionary commission on the Offer Shares and the Over-allotment Shares will be payable by the Selling Shareholder within 30 days of Admission in its sole discretion. The Company will not receive any of the net proceeds from the Global Offering, all of which will ultimately be received by Delek.

No expenses will be charged by the Company to any subscribers of Offer Shares pursuant to the Global Offering.

4.1.7 **Joint Sponsors, Joint Global Co-ordinators, Joint Bookrunners and Co-Lead Manager**

Goldman Sachs International and Morgan Stanley are acting as joint sponsors, joint global co-ordinators and joint bookrunners to the Global Offering. BofA Securities, HSBC and Jefferies are acting as joint bookrunners and ING is acting as a co-lead manager to the Global Offering.

4.2 ***Why is this Prospectus being produced?***

4.2.1 **Reasons for the Global Offering**

The Prospectus is being produced in connection with Admission of the Ordinary Shares to trading on the London Stock Exchange's main market for listed securities and to the premium segment of the Official List.

The Directors believe the Global Offering and Admission is a natural progression for the Company and will:

- allow the Group to have an independent capital allocation policy that is beneficial to the Group;
- allow the Group to grow organically, return capital to shareholders and pursue a value accretive M&A strategy;
- provide the Company with sufficient liquidity to repay the Capital Note and amounts outstanding under the Tracker Loan (in each case, in full or in part);
- create a liquid market in the Ordinary Shares for all Shareholders; and
- provide the Company access to a wider range of capital-raising options which may be of use in the future.

The Global Offering comprises an offer of 105,000,000 Offer Shares at the Offer Price, raising gross proceeds of £262.5 million. The Company will use the gross proceeds of the issue of the Offer Shares pursuant to the Global Offering to (i) pay the Underwriters' Expenses; and (ii) first, repay $77.3 million of outstanding principal and accrued interest under the Tracker Loan and, second, $214 million of the Capital Note. DKL Energy has agreed to waive all remaining amounts (if any) outstanding under each of the Tracker Loan and Capital Note. Following such payment and/or waiver (if any), DKL Energy will provide a confirmation that such payment and/ or waiver (if any) is in full and final settlement of any amounts due or payable by the Company in respect of each of the Capital Note and Tracker Loan. The Company will not receive any of the net proceeds from the Global Offering, all of which will ultimately be received by Delek.

4.2.2 **Offer subject to an underwriting agreement on a firm commitment basis**

Under the terms of, and subject to the conditions contained in, the Underwriting and Sponsors' Agreement, each of the Underwriters has agreed to use its reasonable endeavours to procure subscribers for, or, failing which, itself to subscribe for the Offer Shares at the Offer Price.

4.2.3 **Material conflicts of interest**

Not applicable; there are no conflicts of interest that are material to the Global Offering.

PART 2

RISK FACTORS

Investing in and holding Ordinary Shares involves a number of risks. Prior to investing in the Ordinary Shares, prospective investors should carefully consider the factors and risks associated with any such investment in the Ordinary Shares, the Group's business and the industry in which it operates, together with all other information contained in this Prospectus (including, in particular, the risk factors described below).

Prospective investors should note that the risks relating to the Group, its business and industry and the Ordinary Shares summarised in Part 1 (Summary) are the risks that the Directors believe to be the most essential to an assessment by a prospective investor of whether to consider an investment in the Ordinary Shares. However, as the risks which the Group faces relate to events, and depend on circumstances, that may or may not occur in the future, prospective investors should consider not only the information on the key risks summarised in Part 1 (Summary) but also, among other things, the risks and uncertainties described below.

The risks and uncertainties described below represent those that are known to the Directors and which they consider to be material as at the date of this Prospectus. However, the risks and uncertainties described below do not comprise an exhaustive list and do not necessarily include or explain all of the risks associated with the Group, its business and the industry within which it operates and should be used as guidance only. The order in which risks are presented is not necessarily an indication of the likelihood of the risks actually materialising or of the scope of any potential harm to the Group's business, prospects, results of operation, reputation and brand and/or financial position.

Additional risks and uncertainties not presently known to the Directors, or that the Directors currently consider to be immaterial, may individually or cumulatively also have a material adverse effect on the Group's business, prospects, results of operations, reputation and brand financial position and/or the price of the Ordinary Shares. If any or a combination of these risks actually occurs, the business, prospects, results of operations, reputation and brand and/or financial position of the Group's business could be materially and adversely affected. In such case, the market price of the Ordinary Shares could decline and investors may lose all or part of their investment. Investors should consider carefully whether an investment in the Ordinary Shares is suitable for them in the light of the information in this Prospectus and their personal circumstances.

1. RISKS RELATING TO THE GROUP'S BUSINESS AND INDUSTRY

1.1 The Group's business depends significantly on the level of oil and gas prices, which are volatile and have fluctuated significantly over recent years and in particular in response to recent global macroeconomic and political developments.

The Group's operating results, financial condition and prospects depend significantly upon prevailing oil and gas prices, which are impacted by geopolitical and global, regional and national macroeconomic conditions. Oil and gas are commodities for which prices are determined based on world demand, supply and other factors, all of which are beyond the Group's control. As is the case with its peers, the Group is a "price taker", meaning it must accept the prevailing market prices for oil and gas and is unable to control the prices it receives for the oil and gas it produces. The Group's oil sales are priced using Brent, Forties and Ekofisk benchmarks. The Group's gas sales are priced using various benchmarks, with the UK National Balancing Point ("**UK NBP**") being the Group's most widely used benchmark. In aggregate, and taking into account hedging, the Group's realised commodity prices are broadly in line with the benchmark reference prices.

Oil and gas prices are currently subject to heightened levels of uncertainty resulting from a variety of factors, including Russia's full-scale invasion of Ukraine (and associated sanctions and private sector boycotts of Russian oil), a sharp decline in forecasted global GDP growth, the current hyper inflationary environment and a range of potential macroeconomic outcomes that could affect energy markets. Factors driving energy supply uncertainty include how sanctions affect Russia's oil and gas production, the production decisions of Organisation of Petroleum Exporting Countries ("**OPEC**") and/or OPEC+ (including, in particular, the production cuts announced by OPEC+ in September and October 2022), and the rate at which oil and gas producers increase investment and supply. Current oil and gas inventory levels are low, which amplifies the potential for oil and gas price volatility. Low inventory levels are in part due to a lack of investment during 2020 and 2021 (in response to the slowdowns in the demand for oil and gas caused by the COVID-19 pandemic) resulting in maintenance and capacity constraints. Actual price outcomes will largely depend on the degree to which existing sanctions imposed on Russia, any potential future sanctions, and independent corporate and governmental actions affect Russia's oil and gas production or the sale of Russia's oil and gas in the global market. These sanctions or other potential future sanctions, and any Russian export ban, together with positive sentiment surrounding increasing the United Kingdom's energy independence through the energy transition, have and may continue to result in much higher prices for oil and gas based on increased demand. However, there is no way to predict whether the increase in oil and gas prices will be sustained or whether slower-than-forecast economic growth or the factors driving the imbalance in supply and demand will stabilise or improve, resulting in a decline in oil and gas prices. In October 2022, the US Energy Information Administration forecasted oil production in the Organisation for Economic Cooperation and Development ("**OECD**") to increase and oil prices to decline from the multi-year highs in 2022, to average $95 per stock tank barrel ("**BBL**") in 2023. It is impossible to predict the ultimate effect actions to ban oil and gas imports and exports from and to Russia will have on the global economy and commodity prices in general.

Oil and gas prices are volatile and, in addition to the recent impacts on oil and gas prices resulting from those factors summarised above, the prices for oil and gas have fluctuated widely for many reasons, including:

1.1.1 global and regional supply and demand, and expectations regarding future supply and demand, for oil products and gas;

1.1.2 threats or acts of terrorism, cyber security attacks, war or threat of war or resolution of war, the imposition of sanctions or export controls, which may affect supply, transportation or demand, including potential future sanctions (the scope and extent of which are currently unclear) and any Russian export ban in response to the continuing conflict in Ukraine;

1.1.3 political, economic and military developments in oil and gas producing regions generally;

1.1.4 economic disruptions, volatility or slowdowns or fluctuations in the demand for oil and gas caused by the COVID-19 pandemic, the resurgence of existing or the emergence of new COVID strains, or similar outbreaks or pandemics (including the implementation of measures intended to contain the spread of such outbreaks or pandemics), whether localised in a specific region which on its own can impact commodity prices or a widespread global health crisis;

1.1.5 global and regional economic and social conditions, including disruptions to or slowdowns in the global economy as a result of natural disasters or trade-wars;

1.1.6 the ability and willingness of OPEC, and other oil and gas-producing nations (including, for example, OPEC+), to set and maintain specified levels of production and prices, or decisions to reduce such specified levels of production and prices, (e.g., the recent decision of OPEC+ on 5 October 2022 to reduce crude oil production by 2 million barrels per day);

1.1.7 evolution of stocks of oil and gas and related products;

1.1.8 increased production due to new extraction developments and improved extraction and production methods;

1.1.9 geopolitical uncertainty;

1.1.10 weather conditions, natural disasters and environmental incidents;

1.1.11 access to pipelines, storage platforms, shipping vessels and other means of transporting and storing and refining oil and gas changes in availability of, and access to, pipeline ullage;

1.1.12 work stoppages or other labour disturbances, such as industrial action;

1.1.13 prices and availability of alternative fuels;

1.1.14 prices and availability of new technologies;

1.1.15 increasing competition from alternative energy sources, such as nuclear, solar, wind, hydrogen, and coal;

1.1.16 increasing governmental regulations and actions and international treaties and agreements, including the imposition of export restrictions and taxes and environmental requirements and restrictions which aim to reduce the environmental impact of oil and gas exploration, development and production activities;

1.1.17 trading activities by market participants and others either seeking to secure access to oil and gas and natural gas liquids or to hedge against commercial risks, or as part of an investment portfolio; and

1.1.18 market uncertainty, including fluctuations in currency exchange rates and speculative activities by those who buy and sell oil and gas on the world markets.

It is impossible to predict accurately future oil and gas price movements. Historically, crude oil prices have been highly volatile and subject to large fluctuations in response to relatively minor changes in the demand for oil and gas, or subject to sharp price movements, such as that which coincided with the onset of the COVID-19 pandemic. The COVID-19 pandemic had a significant negative impact on the level of global economic activity. Government support and economic stimulus measures in response to the COVID-19 pandemic often featured “net zero” requirements which had a negative impact on financial support for, and consequently investment in, the oil and gas sector. In addition, prices of oil and gas were also impacted by geopolitical developments between key oil producing nations, including market competition between Saudi Arabia and Russia, and the decision taken in April 2020 by OPEC and its allies to cut oil supply. These factors contributed to a substantial decline in demand for hydrocarbons, which contributed to a steep decline in crude oil prices during 2020 with dated Brent crude oil reaching a low of $9.1/BBL on 21 April 2020. In the second half of 2020 and during 2021, oil prices experienced significant recovery, with dated Brent crude averaging $70.8/BBL in 2021, with a low of $50.4/BBL on 4 January 2021 and a high of $85.8/BBL on 26 October 2021, compared to an average of $64.2/BBL and $43.2/BBL in 2019 and 2020, respectively. UK NBP averaged 117 pence per therm in 2021, with a low of 39 pence per therm on 22 February 2021 and a high of 450 pence per therm on 21 December 2021, compared to an average of 35 pence per therm and 25 pence per therm in 2019 and 2020, respectively. In the first half of 2022, oil and gas prices were then subject to sharp increases as markets priced in geopolitical risk premiums relating primarily to Russia’s invasion of Ukraine, exacerbating market uncertainty and energy market volatility; Brent crude oil reaching a high of $128.0/BBL in March 2022 and UK NBP reaching a multi-year high of 633.1 pence per therm in September 2022. See paragraph 1.7 *(The ongoing military action between Russia and Ukraine could adversely affect the Group’s business, financial condition and results of operations.*) of this Part 2 (*Risk Factors*).

Oil and gas prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of this commodity due to the current state of the world’s economies, actions of OPEC (including, in particular, the production cuts announced by OPEC+ in September and October 2022), ongoing geopolitical uncertainty and related economic impacts, ongoing global credit and liquidity concerns slower-than-forecast economic growth and any further spread of COVID-19 (or any further regional or global epidemics or pandemics). It is also expected that the increased focus of governments, regulators and consumers on the impact of climate change and reducing carbon emissions could reduce demand for hydrocarbons and suppress commodity prices in the medium to longer term. There can be no assurances as to the level of oil and gas prices that will be achievable in the future.

A reduction in the price of oil and gas may also result in a reduction in the volumes of the Group’s reserves which can be produced commercially, resulting in decreases to the Group’s reported reserves and resources. The Group might also elect not to continue production from certain fields at lower prices, or its licence partners may not want to continue production regardless of the Group’s position. All of these factors could result in a material decrease in the Group’s net production revenue, causing a reduction in its oil and gas exploration and development activities and its ability to produce remaining reserves and resources. Certain development projects could become unprofitable as a result of a decline in price and could result in the Group having to postpone or cancel a planned project, or if it is not possible to cancel the project, carry out the project with negative economic impact on the Group. Further, a reduction in oil and gas prices may lead to the Group's producing fields reaching cessation of production and entering into the decommissioning phase earlier than estimated.

The Group's revenues, operating results, profitability, future rate of growth and the carrying value of the Group's oil and gas assets depend heavily on the prices the Group receives for oil and gas sales. Oil and gas prices also affect the Group's capital investments and other items, including the value of the Group's oil and gas reserves. In addition, the Group may face oil and gas property impairments if prices fall. No assurance can be given that oil or gas prices will remain at levels which enable the Group to do business profitably or at levels that make it economically viable to produce from certain wells and any material decline in such prices could result in a reduction of the Group's net production volumes and revenue and a decrease in the valuation of the Group's appraisal, development and production properties.

The occurrence of any of the foregoing could have a material adverse impact on the Group's business, financial condition, results of operations or prospects.

1.2 **The levels, quality and production volumes of the Group's oil and gas reserves and resources may be lower than estimated or expected.**

The reserves and resources information set forth in this Prospectus represent estimates only and are based on reserve reports prepared by independent petroleum engineers. The standards utilised to prepare the reserves and resources information that has been extracted in this Prospectus are different from the standards of reporting adopted in the United States and other jurisdictions. Investors, therefore, should not assume that the data found in the reserves and resources information set forth in this Prospectus is directly comparable to similar information that has been prepared in accordance with the reserves and resources reporting standards of other jurisdictions or reported by other companies.

In general, estimates of economically recoverable oil and gas reserves and resources are based on a number of factors and assumptions made as at the date on which the reserves and resources estimates were determined, such as geological, geophysical and engineering estimates (which have inherent uncertainties), historical production from the properties or analogous reserves, the assumed effects of regulation by governmental agencies and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results.

Further, different reserve engineers categorise reserves and resources differently. In 2020, the Group changed its reserve engineer from Sproule to NSAI. This change led to the reserves in respect of two of the GSA fields, Austen (which has subsequently been relinquished by the Group) and Courageous (which was relinquished by the Group with an effective date of 30 September 2022) being reclassified in the NSAI Report as 2C resources from 2P reserves. Ultimately the Group's combined 2P reserves and 2C resources figure for the financial year ended 31 December 2019 as set out in the NSAI Report was in line with the Group's *pro forma* combined 2P reserves and 2C resources figure for the Group and the Chevron Acquired Assets for the year ended 31 December 2018 although the level of 2P reserves decreased.

Underground accumulations of hydrocarbons cannot be measured in an exact manner and estimates thereof are a subjective process aimed at understanding the statistical probabilities of recovery. Estimates of the quantity of economically recoverable oil and gas reserves and resources, rates of production and the timing of development expenditures depend upon several variables and assumptions, including the following:

1.2.1 production history compared with production from other comparable producing areas;

1.2.2 quality and quantity of available data;

1.2.3 interpretation of the available geological and geophysical data;

1.2.4 effects of regulations adopted by governmental agencies;

1.2.5 future percentages of sales;

1.2.6 future oil and gas prices;

1.2.7 capital investments;

1.2.8 effectiveness of the applied technologies and equipment;

1.2.9 future operating costs, tax on the extraction of commercial minerals, development costs and workover and remedial costs; and

1.2.10 the judgment of the persons preparing the estimate.

As all reserves estimates are subjective, each of the following items may differ materially from those assumed in estimating reserves:

1.2.11 the quantities and qualities that are ultimately recovered;

1.2.12 the timing of the recovery of oil and gas reserves;

1.2.13 the production and operating costs incurred;

1.2.14 the amount and timing of development expenditures;

1.2.15 future hydrocarbon sales prices; and

1.2.16 decommissioning costs.

Many of the factors in respect of which assumptions are made when estimating reserves and resources are beyond the Group's control and therefore these estimates may prove to be incorrect over time. Evaluations of reserves necessarily involve multiple uncertainties. The accuracy of any reserves or resources evaluation depends on the quality of available information and oil and gas engineering and geological interpretation. Exploration drilling, interpretation, testing and production after the date of the estimates may require substantial upward or downward revisions in the Group's reserves and resources data. Moreover, different reserve engineers may make different estimates of reserves, resources and cash flows based on the same available data. Actual production, revenues and expenditures with respect to reserves and resources will vary from estimates and the variances may be material.

If the assumptions upon which the estimates of the Group's oil and gas reserves have been based prove to be incorrect or if the actual reserves or recoverable resources available to the Group are otherwise less than the current estimates or of lesser quality than expected, the Group may be unable to recover and produce the estimated levels or quality of oil and other hydrocarbons set out in this Prospectus and this may materially and adversely affect the Group's business, prospects, financial condition and results of operations.

1.3 **The Group may be affected by the general global economic and financial market situation.**

The Group may be affected by the general state of the economy and business conditions, including but not limited to, the occurrence of recessions and inflation, unstable or adverse credit markets, fluctuations in operating expenses, technical problems, work stoppages or other labour difficulties, property or casualty losses which are not adequately covered by insurance, changes in governmental regulations (such as increased taxation or the introduction of new regulations) increasing operating costs and capital expenditure, which may materially and adversely affect the Group's business, operating results, cash flow and financial conditions.

In September 2022, the OECD projected GDP in the United Kingdom to increase by 3.4% in 2022, before stagnating in 2023 due to depressed demand. Headline inflation is expected to keep rising to around 10% in late 2022 due to continuing high energy prices following Russia's invasion of Ukraine and labour and supply shortages, before gradually declining to just under 6% by the end of 2023. The OECD has also projected private consumption to slow as rising prices erode households' income, while, investment by oil & gas companies is expected to weaken in 2022 as supply bottlenecks hamper the implementation of planned investment. Spillovers from economic sanctions and higher than expected energy prices as the Ukraine war drags on, and a deterioration in the public health situation due to new COVID strains are significant downside risks. Higher than expected goods and energy prices are expected to weigh on consumption and further lower growth, as well as place increased pressure on the Company's expenditures, especially with respect to the cost of transport, fuel, diesel and emission allowances. The weak global or regional economic conditions may negatively impact the Group's business in ways that the Group cannot predict.

Global financial markets and economic conditions have been severely disrupted and volatile in recent years and remain subject to significant vulnerabilities, such as the deterioration of fiscal balances and the rapid accumulation of public debt, continued deleveraging in the banking sector and a limited supply of credit. Credit markets as well as the equity and debt capital markets were exceedingly distressed during 2008 and 2009 and have been volatile since that time. Additionally, any substantial and extended decline in the price of oil or natural gas could have an adverse effect on the Group's borrowing capacity, its ability to obtain additional capital, and its revenues, profitability and cash flows. These issues, along with the re-pricing of credit risk and the difficulties currently experienced by financial institutions have made, and will likely continue to make, it difficult to obtain financing. As a result of the disruptions in the credit markets and higher capital requirements, many lenders have increased margins on lending rates, enacted tighter lending standards, required more restrictive terms (including higher collateral ratios for advances, shorter maturities and smaller loan amounts), or have refused to refinance existing debt at all. See paragraph 1.2 *(The levels, quality and production volumes of the Group's oil and gas reserves and resources may be lower than estimated or expected.)* of this Part 2 (*Risk Factors*).

Additional tightening of capital requirements, and the resulting policies adopted by lenders, could further reduce lending activities. The Group may experience difficulties obtaining financing commitments or be unable to fully draw on the capacity under committed loans it arranges in the future if its lenders are unwilling to extend financing to the Group or are unable to meet their funding obligations due to their own liquidity, capital or solvency issues. The Group cannot be certain that financing will be available on acceptable terms or at all. If financing is not available when needed, or is available only on unfavourable terms, the Group may face difficulties in meeting its future longer-term obligations.

1.4 **The Group's production is entirely concentrated in UKCS offshore fields, making the Group vulnerable to risks associated with having all of its production in one region, such as the effect of fiscal and regulatory factors, regional supply and demand factors, operational cluster concentration and adverse weather conditions.**

The Group's entire production in the year ended 31 December 2021 and the six months ended 30 June 2022 has come from offshore fields within the UKCS. From 1 January 2021 to 31 December 2021 and 1 January 2022 to 30 June 2022, the Group's net average daily production was 56,500 BOEPD, and 66,685 BOEPD respectively, from its 29 producing fields located primarily in the Central North Sea and West of Shetland areas of the UKCS.

As the Group's production is located solely in the United Kingdom, significant changes to governmental regulation could adversely affect the Group's business. For example, on 14 July 2022, the Energy Profits Act was enacted to introduce the Energy Profits Levy, a new 25% surcharge on profits made by companies in the oil and gas sector as a result of rises in commodity prices, in addition to the existing 30% Ring Fence Corporation Tax and 10% Supplementary Charge, together with an enhanced investment allowance to incentivise new investment in the UKCS. See paragraph 3.1 *(The Group may be adversely affected by changes to tax legislation or its interpretation or increases in effective tax rates in the tax jurisdictions in which the Group does business.)* of this Part 2 (*Risk Factors*). Further significant changes to the governmental regulation of oil and gas production could still occur as a result of the United Kingdom's withdrawal from the European Union in 2020 (the longer-term nature and extent of which remain unknown at this stage). In addition, a substantial number of the Group's assets are located in what might be considered to be the territorial waters of any future Scottish state. Scotland held a referendum on 18 September 2014 to determine whether it should remain a part of the United Kingdom or become an independent state. While Scotland voted to remain part of the United Kingdom at that time, the Scottish Government announced on 28 June 2022 that it is proposing that a further referendum on Scottish independence be held on 19 October 2023. Should Scotland become an independent state, there may be, among other things, changes in rules and regulations that could result in increased costs for the Group's production or changes in the Group's operating standards. See also paragraph 3.2 *(The Group must comply with licensing and other regulatory requirements in the United*

Kingdom, which may become more challenging following any amendments or reform.) and paragraph 3.4 (*The United Kingdom's withdrawal from the European Union may have a negative effect on global economic conditions and/or financial markets, thereby adversely affecting the Group's business.)* of this Part 2 (*Risk Factors*) below.

As a result of the Group's concentration in the UKCS, the Group may be disproportionately exposed to the effect of regional supply and demand factors, delays or interruptions of production from wells in this area caused by processing or transportation capacity constraints, access restrictions, governmental regulation, availability of equipment, equipment failure, facilities, personnel or services market limitations, terrorist attacks, sabotage or other acts of war, weather events or interruption of the processing or transportation of oil.

Mechanical problems, accidents, oil and gas leaks or other events at any of the Group's installations, FPSOs or the related pipelines or subsea infrastructure or third-party operated-infrastructure on which the Group relies, including with respect to export routes, may cause a widespread, unexpected production shut-down of the Group's operations in the UKCS. Production from multiple fields in the Group's portfolio is co-dependent on the same infrastructure, which magnifies the impact of any unexpected shutdowns at the Group's infrastructure. For instance, production from the GSA Portfolio is exported from the FPF-1 and, along with production from the Jade field, is transported via the Central Area Transmission System ("**CATS**") and the Teesside Gas and Liquids Processing terminal ("**TGLPT**") together with the Norpipe oil pipeline. Crude oil from the Captain field, Alba field, Mariner field and Schiehallion field is exported from the FPSOs / FPU via shuttle tankers. Related equipment such as tanker export hoses, hose recovery winches and green line telemetry systems are at a significant risk of failure. Gas from the Captain field is exported via subsea pipelines to the Frigg UK gas transportation system and then on the St Fergus Terminal and gas from the Schiehallion field is exported through WOSPS. Production from the Erskine field is exported via CATS together with the Forties Pipeline System ("**FPS**"). Production from the Greater Britannia Area is exported via a dedicated pipeline to the Scottish Area Gas Evacuation ("**SAGE**") terminal at St Fergus (gas) and through the FPS (oil) and production from the Elgin-Franklin fields is exported via the Shearwater Elgin Area Line pipeline ("**SEAL**") (gas) and FPS (oil). Any unplanned production shut-down of the Group's facilities or those third-party facilities on which the Group's production is reliant could have a material adverse effect on the Group's business, financial condition and results of operations and if the shut-down impairs the Group's ability to produce or export oil or gas from connected fields. For example, a planned shutdown of the FPS for essential maintenance work took place in the second quarter of 2021, having been postponed from the second quarter of 2020 due to COVID-19.

In September 2022, leaks were reported on the Nord Stream 1 and Nord Stream 2 pipelines, the result of what certain leaders have called acts of "sabotage". Although the Group does not rely on either the Nord Stream 1 or Nord Stream 2 pipelines, any terrorist attacks, sabotage, acts of war or similar incidents affecting pipelines or other infrastructure that the Group does rely on could severely affect the Group's results of operations and financial condition.

The UKCS is prone to difficult weather conditions that can in some cases prevent the Group from continuously operating offshore installations and transporting supplies, personnel and fuel to its facilities, each of which can cause production shutdowns or slowdowns. Unusually difficult weather conditions may lead to a heightened risk of floating facilities detaching from their moorings, and difficulties in supplying these facilities with fuel. For example, during the winter of 2018, sub-zero temperatures and snowfall across Europe caused UK gas outages at British sites supplying gas from the North Sea, including the Group's Stella field. If mechanical problems, storms or other events curtail the Group's production or cause damage to any of its facilities, it may have unpredictable and materially adverse impacts on the Group's results of operations and financial condition.

1.5 **The Group may not be able to sanction development projects, including the Rosebank and Cambo fields, required to convert their resources into production and may face delays or cost overruns in executing sanctioned development projects.**

The Group has development projects that are in various phases of development without current production, including the Cambo field and Rosebank field in the UKCS. In particular, the Group's business strategy depends significantly on the successful development of the

Cambo field and the Rosebank field. However, as at the date of this Prospectus, these fields remain at a preliminary stage of development, with substantial cooperation still required from third parties, including joint venture partners or, in respect of non-operated developments, the operators and require, following sanction by the joint venture partners, regulatory approvals, in particular from the UK North Sea Transition Authority ("**NSTA**"). On 11 August 2022, Shell launched a sale process for its 30% stake in the Cambo field. On the completion of any such sale, the Group will have a new (or, in the event of any partial sale, an additional) joint venture partner in the Cambo field and will be required to cooperate with such partner on the development of the Cambo field. Cambo has also been the focus of significant opposition by environmental groups who have petitioned the UK Government to not sanction development of the field. In addition, Sembcorp Marine, the parent company of Sevan SSP the proposed provider of the FPSO for the Cambo field, announced that it had agreed a merger with Keppel Corporation's offshore and marine division in April 2022. The merger could result in a delay to the Cambo contract award, affect the construction of the Cambo FPSO, or present other execution complexities, each of which could result in delays to first oil on the project. Further, Altera Infrastructure ("**Altera**"), the owner of the Petrojarl Knarr FPSO that is to be redeployed on the Rosebank field development, filed for Chapter 11 bankruptcy protection in the US Bankruptcy Court for the Southern District of Texas on 15 August 2022 as it seeks to agree a restructuring plan with its creditors. The Rosebank partners are in negotiations with Altera in relation to the Petrojarl Knarr FPSO. If Altera was unable to agree a plan with its creditors and successfully exit bankruptcy proceedings, this could impact its ability to deploy the Petrojarl Knarr FPSO on the Rosebank field or present other execution complexities, which could result in delays to first oil from the project.

The process for obtaining the necessary regulatory approvals for such developments may be negatively impacted by public sentiment towards the hydrocarbon industry and, even if such regulatory approvals are obtained, they may be subject to judicial review proceedings or otherwise challenged by, amongst others, groups campaigning against fossil fuel extraction. For example, on 15 May 2020, Greenpeace Limited appealed to the Court of Session against the decisions of the Secretary of State to agree to the grant of consent for the Vorlich field development and of the decision of the NSTA to grant consent to BP Exploration Operating Company Limited (then operator of the Vorlich field) for the Vorlich field development. Greenpeace Limited sought an order quashing the decisions of the Secretary of State and the NSTA in respect of the Vorlich field development and their judicial costs. The appeal was unsuccessful. Following a hearing in September 2021 the Inner House of the Court of Session refused Greenpeace Limited's appeal on 7 October 2021. Greenpeace Limited sought permission to appeal the Inner House of the Court of Session's decision to the Supreme Court of the United Kingdom. Permission to appeal was refused by the Inner House of the Court of Session on 14 January 2022 and by the Supreme Court of the United Kingdom on 25 August 2022 (Greenpeace Limited having sought said permission directly). IEUK, as a partner in the Vorlich field, was an interested party in relation to the Court of Session proceedings. As permission to appeal has been refused, the appeal process comes to an end and the consents remain unaffected.

Failure to sanction or execute development projects or successful challenges being raised in respect of field developments which had already been approved would mean that the Group will be unable to realise the value of their resources by converting them into production. This could result in the Group's failing to replace reserves which could have a negative impact on the Group's reserve replacement ratio and materially and adversely affect the Group's business, prospects, financial condition and results of operations. See paragraph 1.15 (*If the Group is unable to replace its reserves, the Group's reserves, production and revenues will decline*) of this Part 2 (*Risk Factors*). Development projects may also be subject to delays or cost overruns (including as a result of factors outside of the Group's control, such as those relating to increases in the cost of transport, fuel, diesel and emissions allowances) that could result in them being less profitable than forecast, generating cash later than expected or requiring additional expenditure. In the case of projects that are expected to result in significant production, delays in completing the project could have a material adverse effect on the Group's business, operating results, financial condition or prospects.

1.6 **The Group's ability to operate depends on satisfying licensing and other regulatory requirements.**

Oil and gas activities in the United Kingdom where the Group currently operates are subject to licences, regulations and approvals of governmental authorities. These include those relating to the exploration, development, operation, production, marketing, pricing, transportation and storage of oil and gas, taxation, environmental, and health and safety matters (including with regard to eventual decommissioning of production assets).

The Group has limited control over, among other things: (i) whether or not necessary approvals or licences are granted or renewed or extended; (ii) the timing of obtaining (or renewing) such licences or approvals; (iii) the terms on which they are granted; or (iv) the tax regime to which the Group or the relevant assets in which they have interests will be subject. As a result, the Group may have limited control over the nature and timing of exploration and development of oil and gas fields in which they have or seek interests. There can also be no assurance that the Group will not in the future incur decommissioning costs that are currently not anticipated, since OPRED could determine that it will no longer allow derogations to leave certain infrastructure 'in situ' in circumstances where it is anticipated it would currently.

It is possible that, in the future, the Group may be unable or unwilling to comply with the terms or requirements of a licence in circumstances that entitle the NSTA to suspend or revoke the terms of such licence. Moreover, some of the exploration and production licences which are currently held by the Group may expire before the end of what the Group estimates to be the productive life of the licensed fields. There can be no assurance that renewals or extensions will be granted in relation to such licences. Any failure to receive such extensions or any premature termination, suspension or revocation of licences may have a material adverse effect on the Group's reserves, business, operating results, financial condition or prospects.

1.7 **The effects of climate change, abatement legislation, changes to carbon pricing systems and political and societal perception of the production and use of fossil fuels may have a material adverse effect on the hydrocarbon industry.**

The consequences of the effects of global climate change, and the continued political and societal attention afforded to mitigating the effects of climate change, may generate:

1.7.1 longer term reduction in the demand for hydrocarbon products due to the pace of commercial deployment of alternative energy technologies;

1.7.2 longer term reduction in the demand for hydrocarbon products due to shifts in consumer preference for lower greenhouse gas emission products;

1.7.3 longer term disruption to the Group's projects and operations as a result of changing weather patterns and more frequent extreme weather events; and

1.7.4 litigation and challenge by climate activists or others seeking to prevent, constrain or delay the extraction of hydrocarbon products,

any of which may have a material adverse effect on the hydrocarbon industry and on the Group's business, financial condition and results of operations.

Continued political attention to the role of human activity in climate change and potential mitigation through regulation could have a material impact on the hydrocarbon industry and on the Group's business, financial condition and results of operations.

International agreements, national and regional legislation, and regulatory measures to limit greenhouse gas emissions are currently in various stages of discussion or implementation. In the United Kingdom, where a significant proportion of the hydrocarbons produced by the Group are sold and consumed, the UK Parliament passed legislation in June 2019 enshrining in law a target for at least a 100% reduction in greenhouse gas emissions (compared to 1990 levels) in the United Kingdom by 2050 (also known as a "net zero target") and in November 2020 the UK Government announced a ban on sales of new petrol and diesel powered cars and vans from 2030. It is anticipated that the governments of other major economies may introduce similar long-term emissions reduction targets.

Such legislation or regulatory initiatives could have a material adverse effect by increasing the costs associated with complying with climate change related operational regulations and disclosure requirements and/or diminishing the demand for oil, thereby increasing the Group's or industry's cost structure or causing disruption to operations by regulators, and in turn discouraging institutional investment in the industry, which may affect investor demand for securities in companies like the Company. The level of expenditure required to comply with these laws and regulations is difficult to accurately predict and will vary depending on, among other things, the laws enacted by particular countries. Significant liability could be imposed on the Group in the event of environmental damage caused by previous owners of properties purchased or used by the Group or on account of any breaches of environmental laws or regulations. Global efforts to respond to the challenges of climate change may have an impact on the value of the price of oil and gas moving forward, as countries increasingly shift toward alternative energy sources, which may in turn impact the viability of the Group's producing, development and exploration projects.

As part of the United Kingdom's commitment to the Paris Agreement, the Group is in the process of further developing its strategy to reduce gross operated emissions by 25% by 2025 as well as planning to take the Group to net zero by 2040 ("**Net Zero Plan**") based on the Group's equity interest in all of its fields. The Group's plans to reduce its emissions are in part reliant on electrification initiatives in relation to its assets, including for example the Cambo field in the West of Scotland area of the UKCS. There is no existing infrastructure in the West of Shetland area to enable such electrification and the Group is not able to guarantee that electrification of any of its assets will be achieved. In addition, electrification of existing assets presents challenges relating to space and weight capacity for new equipment, the scale and extent of re-wiring work and the integration of new equipment, as well as costs associated with such transition. Failure to achieve the Group's Net Zero Plan could impact its reputation and may also impact the willingness of the NSTA to extend or grant the Group production or exploration licences or sanction developments which could have a material adverse effect on the Group's business, prospects, financial condition and results of operations. In addition, failure to meet the Group's Net Zero Plan, including with respect to potential non-operated emissions reporting, may also impact how investors and other stakeholders, who are increasingly focused on environment, social and governance matters and many of whom now expect climate change commitments, view the Group's business which could, in turn, have an impact on the Group's ability to attract future investment and thus have a material adverse effect on its business, prospects, financial condition and results of operations.

The Group currently participates in the United Kingdom's Emissions Trading System, which replaced the European Union's Emissions Trading System on 1 January 2021 and provides a framework for the trade and transfer between installations of the right to emit greenhouse gases. The four governments of the United Kingdom have established the scheme to increase the climate ambition of the United Kingdom's carbon pricing policy, while protecting the competitiveness of UK business. Emissions trading schemes work on the 'cap and trade' principle, where a cap is set on the total amount of certain greenhouse gases that can be emitted by sectors covered by the scheme. This limits the total amount of carbon that can be emitted and decreases over time. Within this cap, participants receive free allowances and/or buy emissions allowances at auction or on the secondary market which they can trade with other participants as needed.

It is expected that, over time, the price of allowances under the United Kingdom's Emissions Trading System will rise and the number of free allowances allocated is likely to be reduced. This could leave the Group and others in the industry exposed to higher costs for participating in and complying with the United Kingdom's Emissions Trading System. In addition, the cost of mitigation (i.e., reducing, avoiding or capturing emissions) could also be significant and/or some emissions may not be capable of being reduced, avoided or captured, thereby requiring to be accounted for via the purchase of allowances. As such, there could be a material adverse effect on the Group's business, prospects, financial condition and results of operations.

The Paris Agreement sets a goal of limiting the increase in global average temperatures. Different views and interpretations exist as to its feasibility and implementation, as well as its materiality and impact on oil and gas or the wider energy industry. As a result of this, or separately, the Group may be subject to activism from groups campaigning against fossil fuel extraction, which could affect the Group's reputation, negatively impact the process to obtain regulatory approval of field development plans in respect of oil field interests held by the Group (including without limitation Cambo and Rosebank), dissuade investors from investing in the Group's business, persuade Shareholders to sell their holdings, dissuade contractors from working with the Group, disrupt the Group's campaigns or programmes, induce the Group's employees and/or directors to cease working or acting for the Group or otherwise negatively impact the Group's business. Further, non-governmental organisations and shareholder activists are increasing the number of climate change litigations against corporate entitles both in the abstractive industries and in support sectors, such as banks and financial institutions. Such activities seek new arguments and raise new challenges for such industries, and it is difficult to predict what litigation might arise in the future or the prospects of success. One of the most high profile cases recently was *Millieudefensie v Royal Dutch Shell* in the Netherlands. The case resulted in the Court ordering Shell to reduce its global carbon dioxide emissions by 45% by 2030. The case is under appeal. In the UK courts, ClientEarth has brought a claim against Shell, alleging a breach of duties under section 172 and 174 of the Companies Act resulting from a failure to adopt and implement a climate strategy that aligns with the 2015 Paris Agreement. In addition, on 26 July 2022, Greenpeace Limited launched a judicial review of the UK Government's approval of the field development plan for Jackdaw field in the UKCS, operated by Shell. It is expected that such litigations will continue in the future, and that there may be an increase in climate-related litigation and challenges. In examples related to the Group, in June 2019, Greenpeace Limited disrupted the delivery of the Transocean-owned drilling rig, Paul B. Loyd Jr, to the Vorlich field, delaying its delivery by approximately nine days. The rig was leased by Transocean to BP Exploration Operating Company Limited, as then operator, to conduct drilling at the Vorlich field, in which the Group then had a 34% working interest. In addition, in August 2021, Greenpeace Limited sought to disrupt the Siem Day vessel which was preparing construction equipment for the Cambo field. See paragraphs 1.5 (*The Group may not be able to sanction development projects, including the Rosebank and Cambo fields, required to convert their resources into production and may face delays or cost overruns in executing sanctioned development projects.*) and 1.26 (*The Group's operations are subject to the risk of litigation.*) of this Part 2 *(Risk Factors)*.

1.8 **The ongoing military action between Russia and Ukraine could adversely affect the Group's business, financial condition and results of operations.**

In late February 2022, Russian military forces launched a military action against Ukraine, and sustained conflict and disruption in the region is likely. Although the length, impact and outcome of the ongoing military conflict in Ukraine is highly unpredictable, this conflict has led, and could continue to lead, to significant market and other disruptions, including significant volatility in commodity prices, financial markets, supply chain interruptions, changes in consumer or purchaser preferences as well as increase in cyberattacks and espionage. While the Group's operations are exclusively in the UKCS, the Group's business, prospects, financial condition and results of operations depend substantially upon oil and gas prices. See paragraph 1.1 (*The Group's business depends significantly on the level of oil and gas prices, which are volatile and have fluctuated significantly over recent years and in particular in response to recent global macro-economic and political developments.) of* Part 2 (*Risk Factors*). Following the full scale invasion into Ukraine by Russian troops and the imposition of sanctions by the United Kingdom, the United States, the European Union, and other countries against Russia, Belarus, the Crimea Region of Ukraine, the so-called Donetsk People's Republic and the so-called Luhansk People's Republic, Brent oil prices rose sharply reaching a multi-year high of $128.0/BBL in March 2022 and UK NBP rose to 633.1 pence per therm in September 2022. While the increase in Brent oil prices has benefited the Company, there is no way to predict the duration, progress or outcome of the conflict in Ukraine and its effect on oil and gas prices. Although oil prices remain high because of low inventories and the significant geopolitical uncertainty resulting from the military conflict in Ukraine, the oil production in the OECD are forecasted by the US Energy Information Administration to increase and oil prices are forecasted to decline from the multi-year highs in 2022, to average $95/BBL in 2023.

The Group is actively monitoring the situation in Ukraine and assessing its impact on its business, including its impact on oil and gas prices. The Group has no way to predict the progress or outcome of the conflict in Ukraine or its impacts in Ukraine, Russia or Belarus as the conflict, and any resulting government reactions, are rapidly developing and beyond the Group's control. The extent and duration of the military action, sanctions and resulting market disruptions and uncertainty in oil and gas markets could be significant and could potentially have substantial impact on the global economy, oil and gas prices, the willingness of commercial partners to invest in oil and gas developments and the Group's business in each case for an unknown period of time. Any of the abovementioned factors could affect the Group's business, financial condition and results of operations. Any such disruptions may also magnify the impact of other risks described in this Prospectus.

1.9 **The Group faces inherent uncertainty as to the success of highly capital-intensive appraisal and development activities; in particular, in connection with the development of the Cambo and Rosebank fields.**

The Group is dependent on finding, acquiring, developing and producing oil and gas reserves that are economically recoverable, the success of which is subject to significant uncertainty. Oil and gas exploration and production activities are capital intensive and subject to financing limitations and inherent uncertainty in their outcome. There can be no certainty that further commercial quantities of oil and gas will be discovered or acquired by the Group. The Group's existing and future oil and gas appraisal and exploration projects may therefore involve unprofitable efforts, either from dry wells or from wells that are productive but do not produce sufficient net revenues to return a profit after development, operating and other costs.

Even if the Group is able to discover or acquire commercial quantities of oil and gas in the future, there can be no assurance that these will be commercially developed. Few prospects that are explored are ultimately developed into producing oil and gas fields. Development activities may be subjected to unexpected problems and delays and incur significant costs, which can differ significantly from estimates, with no guarantee that such expenditure will result in the recovery of oil and gas in sufficient quantities to justify the Group's investments. The Group may be required to curtail, delay or cancel any development operations because of a variety of factors, including unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, breaches of security, title problems, adverse weather conditions, compliance with governmental requirements or failure to comply with work commitments under any UKCS licence, labour disputes and shortages or delays in the availability of drilling rigs, ancillary support vessels and the delivery of equipment.

Appraisal and development activities involving the drilling of wells across a field may be unpredictable and may not result in the outcome planned, targeted or predicted, as only by extensive testing can the properties of an entire field be more fully understood. The Group may also be required to curtail, delay or cancel any drilling operations because of a variety of factors, including unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, limited access to equipment, breaches of security, adverse weather conditions, compliance with governmental requirements and shortages or delays in the availability of drilling rigs and the delivery of equipment or other factors which may result in drilling operations becoming uneconomic. In addition, commercial partners may not meet their funding obligations, resulting in the curtailing, delay or termination of drilling activities. See paragraph 1.22 (*Some of the Group's producing fields are operated by third parties, and most of the operations conducted by the Group are with commercial partners, which may result in additional costs or increase the risk of delays or the suspension or termination of the licences or the agreements that govern the Group's assets and exposes the Group to the financial capability of these partners.*) of this Part 2 (*Risk Factors*) above.

In addition, much of the Group's success is dependent on it bringing new developments of oil and gas fields to production on budget and on schedule. Any such curtailment, delay or cancellation could delay production or prevent production from taking place, which reduces cash flows and can lead to impairment charges.

Completion of the Group's development plans does not assure a profit on the investment or recovery of drilling, completion and operating costs and drilling hazards and environmental damage can further increase the cost of operations to be recovered. In addition, various field operating conditions may also adversely affect production from successful wells including delays in obtaining governmental approvals, permits, licences, authorisations or consents, shut ins of connected wells, insufficient or uneconomic storage or transportation capacity or other geological and mechanical conditions. For example, the Group's business strategy depends on its ability to successfully develop the Cambo field in line with the Group's expectations. Cambo is a demanding multi-phase development and its successful development is dependent upon, among other factors, substantial cooperation from third parties such as its existing or any future joint venture partners (including at the time of sanctioning the field development and then in respect of its execution), receipt of regulatory approvals which has been the subject of focus from activist groups campaigning against fossil fuel extraction (including approval of the field development from the NSTA), the ability to manage any cost inflation in the supply chain (including with respect to the cost of transport, fuel, diesel and emissions allowances) and to manage the development's capital expenditure spend in line with budget (particularly in the current hyperinflationary environment). There can be no guarantee that the Cambo development will result in the estimated oil and gas production being achieved in line with the Group's expectations, or that the Cambo field will be brought to production on budget and on schedule, which could have a material adverse effect on the Group's business, prospects, financial condition or results of operations.

A proportion of the Group's drilling and development activities are dependent on the Group continuing to have access to financing on commercially acceptable terms such that the activities are commercially viable for the Group to progress. See paragraph 1.11 (*Much of the Group's future growth depends on the successful drilling and other development activities of certain fields in the Group's portfolio, including the polymer enhanced oil recovery programme in the Captain field area.*) of this Part 2 (*Risk Factors*) below.

There can be no assurance that the occurrence of any of the foregoing would not have a material adverse effect on the Group's ability to develop or commercialise the relevant field or more generally on the Group's business, prospects, financial condition or results of operations.

1.10 **The Group's development projects are associated with risks relating to delays and costs.**

The Group's ongoing and future development projects often involve advanced engineering work, extensive procurement activities and complex construction work to be carried out under various contract packages at different locations onshore and offshore. Furthermore, the Group (together with the Group's licence partners) must procure the carrying out of drilling operations, installation, testing and commissioning of offshore installations and obtain governmental approval to take them into use, prior to commencement of production. The complexity of the Group's development projects makes them very sensitive to circumstances which may affect the planned progress or sequence of the various activities and this may result in delays or costs increases. In particular, this applies to Cambo, Rosebank, Marigold and the additional stages of the Captain EOR following the sanction of the second phase in April 2021.

The Group's current or future projected target dates for production to come on stream may be delayed or indicated estimated levels of production may not be consistent with actual performance and significant cost overruns may incur due to delays, changes in any part of the Group's development projects, technical difficulties, project mismanagement, reservoir underperformance, equipment failure, natural disasters, political, economic (including rising inflation and its impact on the cost of goods/services including with respect to transport, fuel, diesel and emission allowances and emission price increases), taxation, legal, regulatory or social uncertainties, piracy, terrorism, visa issues or protests, which again may materially adversely affect the Group's future business, operating results, financial condition and cash flow. Ultimately, there are risks that the rights granted under the Group's licences or agreements with the government may have to be relinquished or could be revoked, which could jeopardise its ability to progress developments, or in the case of the Vorlich field, continue operations.

Going forward, the Group, or the operator of licences in which the Group has an interest, may be unable to explore, appraise or develop hydrocarbon operations, or the development or production of oil and gas may be delayed as a result of, among other things, activities such as the Group's partners' and counterparties' failure to obtain equipment, equipment failure, natural disasters, political, economic (including rising inflation and its impact on the cost of goods/ services, including with respect to fuel price increases), taxation, legal, regulatory or social uncertainties, piracy, terrorism, visa issues or protests. Moreover, the Group's commercial partners and counterparties consist of a diverse base with no single material source of credit risk. A general downturn in financial markets and economic activity may result in a higher volume of late payments and outstanding receivables, which may in turn adversely affect the Group's business, results of operations, cash flows and financial condition.

Furthermore, the Group's estimated exploration costs are subject to a number of assumptions that may not materialise. Any such inability to explore, appraise or develop petroleum operations or non-materialisation of assumptions regarding exploration costs, may have a material adverse effect on the Group's growth ambitions, future business and revenue, operating results, financial condition and cash flow.

1.11 **Much of the Group's future growth depends on the successful drilling and other development activities of certain fields in the Group's portfolio, including the polymer enhanced oil recovery programme in the Captain field area.**

Development activities are capital intensive, and their successful outcome cannot be assured. The Group undertakes exploration and development activities and incurs significant costs with no guarantee that such expenditure will result in the discovery of commercially deliverable oil or natural gas. The Group's oil and gas exploration and development may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenue to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs and drilling hazards and environmental damage can further increase the cost of operations to be recovered. In addition, various field operating conditions may also adversely affect production from successful wells including delays in obtaining governmental approvals, permits, licences, authorisations or consents, shut ins of connected wells, insufficient or uneconomic storage or transportation capacity or other unusual or unexpected geological, oceanographic and mechanical conditions.

The Group also expects that a significant proportion of its near-term future production will be from the Captain field. In 2021, the Captain field (the Group's asset with the highest level of production) accounted for 31% of the Group's total production. Any decrease in future production volumes or reserve estimates from this area would adversely affect the Group's results of operations and financial condition.

A proportion of the future recoverable reserves from the Captain field are dependent on the continued application of the on-going polymer enhanced oil recovery ("**EOR**") programme that commenced in 2010 (the "**Captain EOR**"), the second phase of which was sanctioned in April 2021 following consent from the NSTA ("**Captain EOR II**"). This involves the injection of polymer infused seawater into the field to improve reservoir sweep and thereby enhance production and reserves recovery. The success of Captain EOR II will depend on continued access to sufficient quantities of polymer to support the anticipated expansion of the Captain EOR and application of the appropriate engineering and chemical solutions that may be required to manage polymer returns on the Captain field facilities. It is possible that, over time, the responsiveness of the polymer deteriorates, or that the technologies and infrastructure in which the Group has made significant capital investment for phase two of the programme are less successful than anticipated. The failure of the Captain EOR would result in the premature cessation of production of the Captain field.

The Group is dependent on a small number of polymer suppliers for the Captain EOR. Any inability of the suppliers to provide the volume or quality of polymer required, on timescales that allow the Group to proceed with the Captain EOR, would result in reduced production levels and possible cessation of the programme.

The Group and its commercial partners have made and will continue to make significant capital expenditures in the further development of the Captain field and any cost overruns or delays associated with such development programmes could have a material adverse effect on the Group's business, financial condition and results of operations.

The Group's capital expenditures in the Captain field may not result in the successful production of oil and gas in line with the Group's expectations, which could result in a material adverse effect on the Group's business, results of operations and cash flow. The Group also cannot guarantee that unexpected conditions, such as unexpected drilling conditions, equipment failures or accidents, breaches of security, adverse weather and the unavailability of drilling rigs, among others, will not delay or curtail future production. See paragraph 1.9 (*The Group faces inherent uncertainty as to the success of highly capital intensive appraisal and development activities; in particular, in connection with the development of the Cambo and Rosebank fields*) of this Part 2 (*Risk Factors*) above.

1.12 **The Group faces drilling and production risks and hazards that may affect its ability to produce oil and gas at expected levels, quality and costs and that may result in additional liabilities to the Group.**

The Group's oil and gas drilling and production operations are subject to numerous risks common to the Group's industry, including, but not limited to, premature decline of reservoirs, invasion of water into producing formations, geological uncertainties such as unusual or unexpected rock formations and abnormal geological pressures, oceanographic conditions, low permeability of reservoirs, contamination of oil and gas, blowouts, oil and other chemical spills, explosions, fires, equipment damage or failure, natural disasters, uncontrollable flows of oil, gas or well fluids, adverse weather conditions, shortages of skilled labour, delays in obtaining government approvals or consents, pollution and other environmental risks. For example, the Company believes there has been a misallocation of hydrocarbons to the Vorlich field related to the Stella hub allocation by difference methodology which is being investigated through the use of third party experts. As a further example, in respect of equipment failure, in July 2019, there was an outage in the GSA Portfolio caused by operational issues with subsea water pumps. Any similar operational problems in the future could delay production, resulting in a material adverse effect to the Group's business, financial condition and results of operation.

The Group's facilities and transportation and processing facilities upon which its production is dependent are also subject to hazards inherent in marine operations, such as capsizing, sinking, grounding, vessel collision and damage from natural catastrophes, severe storms or other severe weather or tidal conditions, as well as to any general deterioration in the condition and/or the integrity of such transportation and processing facilities. In particular, the Group utilises a small number of production facilities and operational problems in any one facility could have a materially adverse effect on the Group. The offshore drilling the Group conducts could involve increased risks due to risks inherent in the nature of drilling in complicated and harsh environments and complex geological formations. Such risks include blowouts, encountering formations with unusual or unexpected rock formations and abnormal geological pressures and oil spills, especially as the Group's portfolio includes high pressure, high temperature gas condensate fields (including the Alder field and Jade field).

If any of these events occur, environmental damage, including biodiversity loss or habitat destruction, injury to persons and other species and organisms, loss of life, failure to produce oil in commercial quantities or an inability to fully produce discovered reserves could result. These events could also cause substantial damage to the Group's property and its reputation and put at risk some or all of the Group's interests in licences, which enable the Group to explore and produce, and could result in it incurring fines or penalties, criminal sanctions potentially being enforced against the Group and its management, as well as other governmental and third party claims. Consequent production delays and declines from normal field operating conditions and other adverse actions taken by host governments and third parties may result in revenue and cash flow levels being adversely affected.

Moreover, should any of these risks materialise, the Group could incur legal defence costs, remedial costs and substantial losses (including those due to injury or loss of life, human health risks, severe damage to or destruction of property, natural resources and equipment, environmental damage, unplanned production outages, clean-up responsibilities, regulatory investigations and penalties), increased public interest in the Group's operational performance and suspension of operations, which could have a material adverse effect on the Group's reputation, business, prospects, financial condition or results of operation.

The liability frameworks for offshore oil and gas pollution incidents, including in the United Kingdom, are under continuous scrutiny. Contractual arrangements among various licensees, operators and third-party contractors are under similar scrutiny, and allocation of pollution liability among parties to offshore exploration or production contracts may change as a result. The Group may be exposed to increased liability for offshore incidents or the requirement to procure insurance coverage at higher amounts if these changes occur. Similar hazards and impacts from third-party operations also could result in increased regulatory costs and operational restrictions impacting the Group's operations and those of others in its industry.

1.13 **Failure by the Group, its contractors or primary offtakers or its host infrastructure to obtain access to necessary equipment or transportation systems at a reasonable price could materially and adversely affect the Group's business, prospects, financial condition and results of operations.**

The Group's oil and gas development and exploration activities are dependent upon, among others, the availability of drilling rigs, subsea vessels and related third party equipment or services. High demand for such equipment or services, or access or supply chain restrictions may affect the availability and cost of, and the Group's access to, such equipment and services and may delay the Group's development and exploration activities. Failure by the Group or its contractors to secure necessary equipment or services could materially and adversely affect the Group's business, prospects, financial condition and results of operations. See paragraph 1.11 (*Much of the Group's future growth depends on the successful drilling and other development activities of certain fields in the Group's portfolio, including the polymer enhanced oil recovery programme in the Captain field area.*) of this Part 2 (*Risk Factors*) above. The Group's significantly increased scale following a number of recent acquisitions (including the Siccar Point Acquisition) may mitigate these risks and the Group also seeks to manage such risk by entering into strategic partnerships with suppliers, under which a collection of services is provided, and avoiding reliance on any single provider.

The Group relies on oil and gas field suppliers and contractors to provide materials and services in conducting the Group's exploration, development and production activities. Any competitive pressures on the oil field suppliers and contractors, or substantial increases in the worldwide prices of commodities, such as steel, could result in a material increase of costs for the materials and services required to conduct the Group's business. For example, due to high global demand and a limited number of suppliers, the cost of oil field services and goods has increased significantly in recent years. Such equipment, personnel and services can be scarce and may not be readily available at the times and places required. Future cost increases could have a material adverse effect on the Group's operating income, cash flows and borrowing capacity and may require a reduction in the carrying value of the Group's properties, the Group's planned level of spending for exploration and development and the level of the Group's reserves. Prices for the materials and services on which the Group depends to conduct its business may not be sustained at levels that enable the Group to operate profitably. In certain cases, the Group may extend or provide financing to such parties in connection with the equipment or services they provide, sell or lease to the Group.

The Group and its offtakers rely, and any future offtakers will rely, upon the availability of storage tanks and transportation systems, such as pipelines and oil tankers, including such infrastructure systems that are owned and operated by third parties. The Group may be unable to access the infrastructure and systems which it currently uses or plans to use, or source alternatives or otherwise be subject to interruptions or delays in the availability of infrastructure and systems necessary for the delivery of the Group's oil and gas to commercial markets. Any decrease in the volume transported as the result of unplanned system outages or equipment failures could materially and adversely affect the Group's business, financial condition and results of operations. In addition, such infrastructure may be close to the end of its design life and decisions may be taken to decommission such infrastructure or perform life extension work to maintain continued operations. Any of these events could result in disruptions to the Group's projects, thereby impacting its ability to deliver oil and gas to commercial markets and/or increasing costs associated with the production of oil and gas reliant upon such infrastructure/systems. Further, the Group's offtakers could become subject to increased tariffs imposed by government regulators or the third-party operators or owners of the transportation systems available for the transport of the Group's oil and gas downstream of the delivery point to the offtaker, which could result in decreased offtaker demand and downward pricing pressure.

If the Group is unable to access infrastructure systems facilitating the delivery of its oil and gas to commercial markets, its operations will be materially adversely affected. If the Group is unable to source the most efficient and expedient infrastructure systems for its assets then delivery of its oil and gas to the commercial markets may be negatively impacted, as may the

Group's costs associated with the production of oil and gas that is reliant upon such infrastructure/systems.

1.14 **The Group's ability to grow has depended and will continue to depend on its ability to identify and acquire suitable oil and gas assets or businesses, as well as on the success and integration of such assets or businesses with the Group, which is subject to a number of risks.**

The Group aims to grow its oil and gas reserves through strategic acquisitions of oil and gas businesses or assets. The Group has undertaken a number of acquisitions of oil and gas assets (and of companies holding such assets) including, among others, the Siccar Point Acquisition, the Chevron Acquisition, the GSA Acquisition, the Marubeni Acquisition and the Summit Acquisition. Consistent with its stated strategy, the Group is actively considering strategic acquisitions and may be in discussions regarding and/or in the process of bidding on oil and gas businesses and assets, which could be material to the Group.

The Group's ability to implement its growth through acquisitions requires that suitable oil and gas assets, businesses or licences (or interests in such licences) that allow the Group to leverage the value of its existing infrastructure and that require relatively short development periods to ensure efficient monetisation of reserves are available upon favourable terms, including price. When looking at acquisition opportunities, the Group also competes with oil majors, larger international oil and gas companies and independent operators as well as private equity firms not previously investing in oil and gas, each of whom may possess significantly greater operational and financial resources. Competition may lead to prices for prospective acquisitions being driven up through competing bids and prevent the Group from achieving additional economies of scale.

Once a suitable acquisition target has been identified, successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, the time of recovering reserves, exploration potential, future oil, natural gas liquids and natural gas prices and operating costs in respect of those assets. Such assessments are inexact and based on limited due diligence which the Group focuses on higher valued and material properties or assets, and the Group cannot make these assessments with a high degree of accuracy. Even an in-depth review of all properties and records may not reveal existing or potential problems, nor will it always permit the Group to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Although the Group may receive various warranties, representations and indemnities when it makes an acquisition, including as to good title and validity of the assets and licences acquired, there can be no assurance that the Group will be able to recover any losses it incurs. In addition, changing regulatory and environmental conditions, whether in the United Kingdom or in other countries where the Group may acquire assets, may lead to disputes with other oil and gas companies.

Moreover, the Group may be required to assume pre closing liabilities with respect to an acquisition, including known and unknown environmental and decommissioning liabilities, and may acquire interests in properties on an "as is" basis without recourse to the seller of such interest. In addition, under the terms of the Chevron Acquisition Agreement, the Group is responsible for performing certain functions in respect of decommissioning costs associated with the Retained Decommissioning Liability Fields notwithstanding the fact that these fields will generate no value for the Group. Pursuant to these Retained Decommissioning Liability Arrangements the Group is obliged to satisfy certain decommissioning costs associated with the Retained Decommissioning Liability Fields provided that IEUK is kept wholly indemnified by the Chevron group in respect of such liabilities. See paragraph 1.21 (*The Group may face unanticipated increased or incremental costs in connection with decommissioning obligations*) of this Part 2 (*Risk Factors*) below.

Further, the Group's ability to achieve the anticipated benefits of acquisitions that it enters into will depend in part on whether it can integrate the acquired assets and operations of the target businesses in an efficient and effective manner. Integrating operations, technology, systems, management, personnel and pre- or post-completion costs for future acquisitions may prove more difficult, lengthier or expensive than anticipated, present cultural or internal control challenges or cause other disruptions to the Group's existing operations, thereby rendering the value of any company or assets acquired less than the amount paid. The Group can give no assurance that any acquisition will perform in accordance with its expectations or that its expectations with respect to integration, estimated production capacity or cost savings as a result of any acquisition will materialise.

Any of the foregoing risks could materially and adversely affect the Group's business, prospects, financial condition and results of operations.

1.15 **If the Group is unable to replace its reserves, the Group's reserves, production and revenues will decline.**

The Group's future success depends on its ability to develop or acquire additional reserves that are economically recoverable, which is (although not exclusively) dependent on oil and gas prices. While well supervision and effective maintenance operations can contribute to sustaining production rates over time, production delays and declines from normal field operating conditions cannot be eliminated. Without continued successful appraisal, development and acquisition activities, the Group's reserves and revenues will decline as a result of its current reserves being depleted by production. Future increases in the Group's reserves will depend not only on the Group's ability to appraise, develop, produce and explore its existing assets, but also on its ability to select and acquire suitable assets either through awards at licensing rounds or through acquisitions. Any failure to successfully replace reserves could materially and adversely affect the Group's business, prospects, financial condition and results of operations.

The Group's oil and gas appraisal and development activities include mature producing and/or depleted oil and gas fields which are high risk ventures with uncertain prospects for success. It should be noted that few prospects that are explored are ultimately developed into producing oil and gas fields. Appraisal and development activities may also be subject to delays in obtaining governmental approvals or consents, lender consents, agreeing development plans with joint venture partners, obtaining sufficient access to storage or transportation facilities or other constraints, which could materially adversely affect the Group's replacement of reserves and long-term oil and gas production.

The Group has increased its reserves through acquisitions and intends to continue to do so in the future. Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, upside potential, future oil and gas prices, operating and decommissioning costs and potential environmental and other liabilities. Such assessments are inexact and cannot be made with a high degree of accuracy. While the Group routinely performs due diligence reviews of all potential acquisition targets, such reviews are generally focused on higher value properties and even in-depth reviews of all properties and records will not necessarily reveal all existing or potential problems or liabilities. In addition, the Group's review may not permit the Group to become sufficiently familiar with the assets or properties to fully assess their deficiencies and capabilities prior to an acquisition.

1.16 **The Group has presented indicative management estimates in respect of certain future production and related costs. The Group's ability to achieve these estimates is dependent upon the accuracy of a series of assumptions involving factors that are beyond the Group's control.**

Achieving management estimates (including those contained in or derived from the NSAI CPR) will depend on the accuracy of a series of assumptions involving factors that are beyond the Group's control and are subject to known and unknown risks, uncertainties and other factors that may result in the Group failing to achieve these estimates. These factors include:

1.16.1 the Group's ability to continue to produce or to achieve hydrocarbons at anticipated rates from its producing assets;

1.16.2 the Group's ability to develop its non-producing assets as planned and through the Group's preferred infrastructure;

1.16.3 near-term macroeconomic developments, including the cost of fuel, gas and diesel, and the price of carbon credits;

1.16.4 the market prices of oil and gas products;

1.16.5 the Group's ability to execute its ongoing programme of asset enhancement projects including the Captain EOR;

1.16.6 changes in the political or regulatory framework in which the Group operates (including the Ukraine-Russia conflict); and

1.16.7 macroeconomic or technological trends or conditions.

If one or more of these assumptions is inaccurate, the Group may be unable to achieve one or more of its production targets (or the related estimates in respect of production costs), which may have a material adverse effect on the Group's business, financial condition, results of operations and prospects.

1.17 **The Group relies on its primary offtakers, and any change in relationship or inability to meet their obligations to the Group may adversely affect the Group's financial results.**

On a historical standalone basis, for the years ended 31 December 2019, 2020 and 2021, over 94% of the Group's oil and gas sales have been to Shell, BP Gas Marketing Limited ("**BPGM**") and BP Oil International ("**BPOI**"). In the first half of 2022, most of the Group's oil and gas sales have been to BPOI and BPGM (approximately 86%) to ENI (approximately 10%) and the remaining 4% to Esso, Shell and Gazprom (the offtake contract with Gazprom terminated with effect from 30 September 2022). The inability or failure of the Group's current or future major offtakers to meet their obligations to the Group or their insolvency or liquidation may adversely affect the Group's financial results.

The Group is, therefore, subject to the risk of delayed payment for delivered production volumes or counterparty default. The absence of competitors for the purchase of oil and gas produced by the Group may expose the Group to adverse pricing or other contractual terms. This concentration may impact the Group's overall credit risk in that the Group's current or future major offtakers may be similarly affected by various economic and other conditions. Such delays, defaults, difficulties or adverse pricing or other contractual terms could adversely affect the Group's business, financial condition and results of operations and cash flows.

1.18 **The Group's utilisation of tax losses and tax liability is based on forecasts and subject to estimation.**

The Group's tax provision is subject to estimation. The Group prepares its tax provision before the Group files its UK corporation tax and supplementary charge returns with HMRC and thus the Group must make estimates and judgments on factors in the tax provision process. Such estimates and judgments include those required in calculating the effective tax rate. In considering the tax on exceptional items, the Group applies the appropriate statutory tax rate to each exceptional item to calculate the relevant tax charge. The Group also makes judgments and assumptions regarding the likelihood of future taxable profits and the amount of deferred tax that can be recognised on unused tax losses where it is probable that future taxable profits will be available for utilisation. Inaccurate forecasts or estimates in relation to the Group's tax provision may result in increased tax liability, which could have a material adverse effect on the Group's business, financial condition or results of operations.

On 14 July 2022, the Energy Profits Act was enacted to introduce the Energy Profits Levy, a new 25% surcharge on profits made by companies in the oil and gas sector as a result of rises in commodity prices. Prior to the Energy Profits Levy, companies in the oil and gas sector paid a 40% headline tax rate on profits consisting of 30% Ring Fence Corporation Tax and 10% Supplementary Charge. The Energy Profits Levy takes the combined rate of tax on profits to 65% subject to investment allowances whereby for every £1 invested, businesses are expected to receive a 91 pence tax saving.

The Group has significant tax losses carried forward available to offset future UK taxes due to previous operations and the Siccar Point Acquisition and the Marubeni Acquisition. The Group will benefit from the 'super-deduction' style investment allowance under the Energy Profits Levy, through its planned capital investments program. While the Group anticipates full use of carried forward trading losses to reduce the UK corporation tax payable, such use is dependent on certain factors, notably the level of future profits, the undertaking of intra-group transfer of assets, and that there are no changes in government regulatory tax policies, including adverse changes in tax laws or interpretations of tax laws. The use of the "super-deduction" style investment allowance is dependent on certain factors, including the readiness of the Group's oil and gas assets for qualifying investments and the timing of the investment. There are also tax rules which prevent the use of carried forward losses where, over the course of any period of five years starting up to three years before a change in ownership of a company, there is a major change in the nature or conduct of a trade carried on by that company. Relevant changes in ownership have occurred within the Group, since the Group has in recent years purchased entities that have carried-forward losses, and has previously (and may in future) undertake corporate steps in respect of its structure. Whether there has been a major change in the nature or conduct of a trade depends on all of the specific facts and circumstances of the individual case in question, and may occur if there is a significant change in the property dealt in, the services or facilities provided by, or in customers or markets supplied by, the relevant company. The Group focuses and will continue to focus on oil and gas activities, and whilst HMRC has published guidance indicating that it would generally be unusual for it to take the view that there has been a major change in the nature or conduct of a trade in the context of this industry (that is, in the context of ring-fence trades), the application of these rules cannot be discounted. In the event that the Group were unable to fully utilise its carried forward tax losses or the 'super-deduction' style investment allowance, this would increase the Group's tax burden and therefore negatively impact the Group's cash position, effective tax rate, financial condition and results of operations.

In addition, certain senior employees of Ithaca Energy have received compensation in the form of Ordinary Shares (see paragraph 11 (*Employee Incentive Schemes*) of Part 20 (*Additional Information*)), on which a liability to income tax and National Insurance contributions (for both the relevant employee and the employee's employer company) arose at the date on which the Ordinary Shares were subscribed for. The tax liability arose on the value of the relevant Ordinary Shares at the subscription date, as determined by Ithaca Energy on the basis of valuation advice received from a third-party valuation firm. HMRC may review the value that was attributed to the Ordinary Shares by Ithaca Energy at the subscription date. As a result of that review, HMRC may assess certain additional tax liabilities directly on Ithaca Energy, as well as potential penalties and interest. The relevant employees have provided appropriate indemnities to Ithaca Energy for any additional income tax and employee's National Insurance contributions liabilities arising on Ithaca Energy, although not any employer's National Insurance contributions nor any interest and penalties levied against Ithaca Energy, although practical limitations on Ithaca Energy's ability to enforce the indemnity or fully recover amounts under the indemnity may apply.

1.19 **The Group relies on third party infrastructure that the Group does not control, a significant proportion of which has been in operation for a number of years and requires maintenance and repair to avoid disrupting the Group's operations.**

Almost all of the Group's current production travels through third-party owned and controlled infrastructure at some point before title passes to the customer. For instance, crude oil from the Captain field, Alba field, Mariner field and Schiehallion field is exported from the FPSOs / FPU via shuttle tankers. Gas from the Captain field is exported via subsea pipelines to the Frigg UK gas transportation system and then on the St Fergus Terminal. Production from the GSA Portfolio fields is exported from the FPF-1 and is transported, along with production from the Jade field, via CATS and the TGLPT together with the Norpipe oil pipeline, and production from the Erskine field and MonArb fields are exported via CATS (gas) together with the FPS (oil). Production from the Greater Britannia Area is exported via a dedicated pipeline to the SAGE terminal at St Fergus (gas) and through the FPS (oil) and Elgin-Franklin field production is exported via SEAL (gas) and FPS (oil). If any of these terminals, systems or FPSOs (or any infrastructure connecting to the respective terminal, system or FPSO) experiences mechanical problems, an explosion, adverse weather conditions, a terrorist attack, labour dispute or any other event that causes an interruption in operations or a shut-down, the Group's ability to transport its oil or gas could be severely affected. The Group would not be able to control any response to such an incident and may not be able to find alternative means to transport oil or gas. Any decrease in the Group's ability to transport its oil or gas through third party infrastructure could have a material adverse effect on the Group's business, financial condition and results of operations.

A significant proportion of this infrastructure has been in operation for a number of years. For example, the FPS was constructed in 1975 and has been extensively used roughly 40% of the United Kingdom's oil and gas liquids, and 24% of the Group's production, is transported through it. The FPS requires frequent maintenance and repair to maintain efficiency and may need to be shut down to stop oil and gas leaks. In the second quarter of 2021, a planned shutdown of the FPS for essential maintenance work took place, having been postponed from the second quarter of 2020 due to COVID-19. The Group is also exposed to similar maintenance and repair risks on CATS, a gas transportation and processing system constructed in 1993 and serving more than 30 UK fields, including seven of the Group's fields (Stella, Harrier, Vorlich, Abigail, Erskine, Jade and MonArb).

Erskine production was shut-in from January 2018 to September 2018 due to a stuck pig in the Lomond to Everest condensate export pipeline (part of the Lomond System). The cause of the incident was a wax build up in the pipeline, with resolution of the issue requiring a section of new line to be installed.

If the owners or operators of these pipelines, or any other third-party infrastructure upon which the Group's operations rely, fail to adequately maintain the integrity of or fail to invest into such infrastructure to ensure that uptime levels are maintained, the Group may not be able to efficiently deliver oil and gas to onshore terminals for sale. When pipelines and other key infrastructure is shut-down unexpectedly or planned shut-downs last for longer than anticipated, the Group may not be able to adequately plan for or mitigate the impact of such a shut-down on its production. It may not be able to safely scale back production, which could result in oil spills, explosions or mechanical damage to the Group's assets. A reduction or potential stoppage in the delivery of the Group's oil or gas or the efficiency of its operations could require the Group to source alternative export routes and/or prevent economic production and could, therefore, have a material adverse effect on the Group's results of operations and financial condition.

Furthermore, the third-party infrastructure on which the Group relies could be decommissioned in the future. In the event that any such third-party infrastructure enters the decommissioning phase at a time when the Group still relies upon it or would have intended to use the facilities, the Group may have to provide for alternative means of transportation, which could increase the Group's cost of production and may have a material adverse effect on the Group's business, financial condition and results of operations.

The Group pays charges to export its production through third-party infrastructure to the operator / owners of that infrastructure based in general on the Group's proportionate use of the infrastructure. These charges can be substantial and the per barrel charge is not subject to the Group's direct control. The Group's aggregate tariff charges form a part of its unit operating expenditure of $18.0/BOE for the year ended 31 December 2021 and $19.4/BOE for the six months ended 30 June 2022. The operators of the Sullom Voe terminal, the Britannia facility, the Lomond facility, Anasuria FPSO, J-Block Facility and Norsea Facility set these charges on a cost sharing basis according to the Group's proportionate hydrocarbon through-put of that facility. The Group's exposure to such charges is thus dependent on continued production from assets owned by third parties and may be priced at such a level as to cause production from the Group's assets to no longer be economic and thus have a material adverse effect on the Group's business.

1.20 **A material amount of the Group's equipment has substantial prior use, and significant expenditure may be required to maintain operability and operations integrity and avoid equipment becoming obsolete.**

All fields require ongoing maintenance to ensure continued operational integrity. The Group intends to incur significant planned expenditure on the assets used to service production from the Group's fields but there can be no guarantee that such assets will continue to operate without fault and not suffer material damage through, for example, wear and tear, severe weather conditions, natural disasters or industrial accidents. If the Group's assets or the assets used by it do not operate at or above expected efficiencies, the Group may be required to invest substantial expenditure beyond the amounts budgeted. Any material damage to these assets or significant capital expenditure on these assets for improvement or maintenance may have a material adverse effect on the Group's results of operations and financial condition and, as with planned operating and capital expenditure, there is no guarantee that the amounts expended will ensure continued operation without fault or address the effects of wear and tear, severe weather conditions, natural disasters or industrial accidents.

Whilst the Group has predominantly mid-life assets and developments in the portfolio, some fields (such as the Alba field) are later life in nature. Consequently, some of the equipment used on the facilities to service these fields is less readily available and the Group (or relevant operator) may not carry a substantial quantity of spares. Certain of this equipment may as a result become obsolete and it may be difficult to find appropriate replacements. The Group actively manages the equipment for the assets which it operates to minimise the impact such shortages may have on operations, however there can be no guarantee that spares can be sourced, which could have a material adverse effect on the Group's financial condition and results of operations.

1.21 **The Group may face unanticipated increased or incremental costs in connection with decommissioning obligations.**

The Group is obliged under UK law to dismantle and remove certain equipment, to cap or seal wells and generally to remediate production sites. Under the Petroleum Act, a party incurs liabilities in respect of the decommissioning of installations and pipelines following the service by the Secretary of State, through OPRED, of a section 29 notice on that party. At any time during the life of the relevant field, OPRED can issue a section 29 notice requiring that a costed decommissioning program be provided by, among others, the licence holder, a parent company or associated companies of a licence holder, or the field operator. In addition to the liable parties set out above, under section 34 of the Petroleum Act, OPRED may use a "claw-back" power to impose decommissioning obligations on anyone who, at any time since the issue of the first section 29 notice for the installation or pipeline, could have been served with such a notice, being former licence holders and their affiliates. The parties on whom the notice is served are jointly liable to submit a decommissioning program and, once a decommissioning program has been approved by OPRED, it becomes a joint and several obligation upon the persons who submitted the decommissioning program to ensure that it is carried out. Although the Group has contracted for limited decommissioning liabilities, assuming responsibility only for the Group's working interest, the Group may be liable under regulations for liabilities beyond its working interest. Once a member of the Group is required to submit a decommissioning plan, that Group member will be jointly and severally liable for implementing that plan with former or current commercial partners.

If the Group's commercial partners default on their obligations, the Group will remain liable and could be liable for all decommissioning liabilities related to the relevant field and therefore the Group's decommissioning liabilities could increase significantly. The consequences of such defaults are mitigated by the existence of decommissioning security agreements in relation to certain of the Group's joint venture assets, given that if a commercial partner did default, the Group would be entitled to access security provided by that defaulting party should the Group be made liable for additional decommissioning costs. Further, where the Secretary of State deems that a party with liability for a decommissioning programme is unlikely to be able to fulfil that liability, it is empowered to require the provision of appropriate financial security to cover those decommissioning costs.

In addition, the Group may be liable for decommissioning in respect of assets with which it has been associated with historically (even where it has received limited or no commercial advantage). Although the Group no longer holds certain UK assets (which have been disposed of by the Group or by affiliates whom the Group has subsequently acquired), if the Group is issued with any section 34 notices under the Petroleum Act as a result of the Group formerly holding interests in certain assets, the Group may be subject to significant expenses related to any potential decommissioning of these assets should their owners fail to meet their decommissioning liabilities. Consequently, in connection with the sale or transfer of the Group's assets, the Group may retain or be liable for decommissioning liabilities, even if it has not contractually agreed to accept these liabilities.

Under the Chevron Acquisition Agreement, the Group is responsible for performing certain functions in respect of decommissioning costs associated with the Retained Decommissioning Liability Fields notwithstanding the fact that these fields will generate no value for the Group.

Pursuant to these Retained Decommissioning Liability Arrangements, the Group is obliged to satisfy certain decommissioning costs associated with the Retained Decommissioning Liability Fields provided that IEUK is kept wholly indemnified by the Chevron group in respect of such liabilities. The Chevron group must either reimburse the Group or pay upfront for decommissioning costs in respect of the Retained Decommissioning Liability Fields depending on the value of the relevant cash call. There is a risk that, notwithstanding this contractual framework, Chevron is either delayed in (re)funding the decommissioning costs or fails to do so altogether or IEUK fails to comply with its obligations in respect of such arrangements. Any such delay or failure may result in a material increase in the Group's decommissioning costs depending on the value of the liability arising, which could have a material adverse effect on the Group's business, operating results or financial condition.

The Group's financial statements as at 30 June 2022 include a provision of $1,693.4 million for future decommissioning liabilities, based on internal and third-party estimates taking into account current legal and contractual requirements and current technology and price levels for the removal of facilities and plugging and abandoning of wells. These estimates include the application of annual inflation and discount rates. As at 30 June 2022, the Group has a decommissioning liability of $1,693.4 million calculated using a discount rate of 3.5% and inflation rate of 2% over the varying lives of the assets to determine the pre-tax present value of the decommissioning liabilities. The ultimate costs of decommissioning wells and sites are difficult to accurately predict and may depend on a number of factors. The Group spent $27.9 million on decommissioning in 2021 compared to $25.5 million in 2020 and $8.7 million in 2019.

Under the Group's current decommissioning cost estimates, it is anticipated that the majority of the Group's decommissioning expenditure will be incurred in the 2030s, but any substantial increase in estimated decommissioning liabilities or in the amount of financial security the Group is required to provide under relevant decommissioning security agreements or acceleration in the timing of decommissioning arising out of, for example, a substantial decline in commodity prices or the condition of the infrastructure related to the assets deteriorating quicker than anticipated, could materially and adversely affect the Group's business, prospects, financial condition and results of operations. Additionally, these future decommissioning costs may involve the posting of financial security, such as surety bonds or letters of credit or paying moneys into a decommissioning fund required by the relevant licensees to perform exploration or production activities. The Group has access to a combination of letters of credit available under the RBL Facility and an insurance agreement from third parties, both of which are used to cover required decommissioning security postings. The insurance facility is renewed on an annual basis and there is no guarantee that the facility will be renewed or that the terms offered under the facility will continue to be the same or, if amended, be commercially acceptable. If the insurance facility is not renewed or the terms are not commercially acceptable, the Group will need to provide an alternative form of decommissioning security: either from another provider (which may increase its finance costs), from the RBL Facility (which may reduce the Group's cash available under its facilities), or the Group may need to provide cash as decommissioning security (which may affect its ability to make dividends and other distributions).

The costs of decommissioning are uncertain and may exceed the value of the long-term provision set aside to cover such decommissioning costs. The Group may have to draw on funds from other sources to fund such decommissioning costs. These decommissioning costs could materially and adversely affect the Group's business, prospects, financial condition and results of operations.

1.22 **Some of the Group's producing fields are operated by third parties, and most of the operations conducted by the Group are with commercial partners, which may result in additional costs or increase the risk of delays or the suspension or termination of the licences or the agreements that govern the Group's assets and exposes the Group to the financial capability of these partners.**

The Group has entered into business ventures with commercial partners in respect of substantially all of its assets. While the Group is the operator of a significant number of the

Group's assets, it requires the cooperation of its commercial partners in obtaining approval of field development plans and in funding the development of and production from an asset.

The Group may suffer unexpected costs or other losses, which may or may not be offset by increases in production revenue, if a commercial partner does not meet its obligations under agreements with the Group. For example, other commercial partners who have invested in the Group's properties may default in their funding obligations in relation to such properties. In such circumstances, the Group may be required under the terms of the relevant operating agreement to contribute all or part of any such funding shortfall, regardless of the percentage interests that the Group agreed with such commercial partner under such arrangements. For instance, in January 2016, First Oil (as partner in the Group's West Don field) defaulted in its obligations to pay certain operating costs to EnQuest, the operator of the West Don field. The Group was obliged to make up the shortfall in payments on a pro rata basis with the other non-defaulting party (EnQuest, the operator). First Oil's ensuing insolvency led to the forfeiture of its entire interest in the West Don field, which was assumed along with a corresponding share of field costs, on a pro rata basis by the Group and EnQuest. This led to an unexpected increase in field costs (albeit with a consequential increase in production revenues). Any similar failure of a commercial partner to meet its obligations could materially adversely affect the Group's operations and business. The Group may also be subject to claims itself by the Group's commercial partners regarding potential non-compliance with its own obligations. It is also possible that the Group's interests, on the one hand, and those of its commercial partners, on the other, may not be aligned resulting in possible project delays, additional costs or disagreements.

There is also a risk that a commercial partner may elect not to participate in decisions requiring its consent (including decisions relating to drilling programmes, including the number, identity and sequencing of wells, appraisal and development decisions and decisions relating to production). In these circumstances, it may not be possible for such activities to be undertaken by the Group alone or in conjunction with other commercial partners at the desired time or at all. If such activities are undertaken, the Group may bear a greater proportion of the risks or costs. Conversely, decisions by the Group's partners to engage in certain activities may also be contrary to the Group's desire not to engage in or commence such activities. The Group may nevertheless be required to incur a portion of costs in relation to such projects, which may become significant, or other participants may enforce decisions that will delay or affect the profitability of a project. This is an inherent risk in fields under development where the Group only holds a minority interest and/or does not hold a blocking vote (such as the Elgin-Franklin field), as the management committee in charge of decision-making between the partners makes the decisions on developments, and such decisions may be made regardless of whether or not the Group consents.

Although the Group is the operator of eight of its producing fields, representing 57% of its total production as at 30 June 2022, the Group is dependent on commercial partners operating its remaining producing assets. For example, the Elgin-Franklin field is operated by TotalEnergies E&P UK Limited, the Britannia field and Jade field are operated by Harbour Energy plc, the Pierce field is operated by Shell UK Exploration & Production Limited, the MonArb field is operated by Repsol Sinopec Resources UK Limited, the Schiehallion field is operated by BP Exploration Operating Company Limited and the Mariner field is operated by Equinor UK Limited. For these fields, the Group is not able to direct or control the timing, performance or cost of operations. Further, although the terms of the Group's operating agreements generally impose standards and requirements in relation to the operatorship of the relevant oil or gas field, there can be no assurance that the operator will observe such standards or requirements. In addition, while the Group is the operator of the Cook field, Stella field, Captain field, Alba field, Erskine field, Harrier field, Vorlich field, Alder field and Cambo field, the Group depends on its partners in the field to sanction any improvement or enhancement projects it may have planned, as well as the timing and performance of the Group's planned operations.

Failure by the Group's commercial partners to comply with obligations under the relevant licences or agreements pursuant to which the Group operates may lead to fines, penalties, restrictions or revocation of the licences or agreements under which the Group operates. If any of the Group's commercial partners becomes insolvent or otherwise unable to pay debts as they become due, licences or agreements awarded to them may revert back to the NSTA who will then reallocate the licence. Although the Group anticipates that the NSTA may permit the Group to continue operations at a field during a reallocation process, there can be no assurances that the Group will be able to continue operations pursuant to these reclaimed licences or that any transition related to the reallocation of a licence would not materially disrupt the Group's operations or development and production schedule. The occurrence of any of the situations described above could materially and adversely affect the Group's business, financial condition and results of operations.

Finally, the Group's divestment of a licence interest may also be subject to the prior approval of its commercial partners and the NSTA. The terms of operating agreements often require commercial partners to approve of an incoming participant to the business venture or provide them pre-emption rights with respect to the transfer of the Group's interest, either of which could affect the Group's ability to sell or transfer an interest. If the Group is unable to dispose of an asset on commercially acceptable terms, its business, prospects and financial condition may be materially adversely affected. In certain circumstances, the Group may also be required to consent to new business partners becoming party to its agreements who have a lower financial standing than the outgoing party, which exposes the Group to increased risk of partner default or insolvency.

1.23 **The Group depends on its Board, key members of management, independent experts, technical and operational service providers and on the Group's ability to retain and hire such persons to effectively manage its growing business.**

The Group's future operating results depend in significant part upon the continued contribution of its Board, key senior management and technical, financial and operations personnel. Management of the Group's growth will require, among other things, the ability to attract and retain sufficient numbers of qualified management and other personnel, the continued training of such personnel and the presence of adequate supervision.

The Group's success is dependent on the ability of its Board and key members of management to operate its growing business and to manage the ongoing changes from potential future acquisitions. The loss of services of members of its Board, Senior Managers or other key employees could significantly delay or prevent the achievement of the Group's strategic objectives. From time to time, there may be changes in the Group's senior management team resulting from the hiring or departure of executives, which could disrupt the Group's business. The Group does not maintain key person life insurance policies on any of its employees or Directors. The loss of the services of one or more of the Group's Directors, Senior Managers or other key employees for any reason could require significant amounts of time, training and resources to find suitable replacements and integrate them within the business, could result in meaningful exit payments being required to be made to the departing individual, and could materially and adversely affect the Group's business, prospects, financial condition and results of operations.

The Group uses independent contractors to provide the Group with certain technical, financial, commercial and legal assistance and services. In certain cases, the Group may exercise limited control over the activities and business practices of these providers. Any inability by the Group to maintain satisfactory commercial relationships with them, or their failure to provide quality services, could materially adversely affect the Group's business, prospects, results of operations and financial condition.

Attracting and retaining additional skilled personnel will be fundamental to the continued growth of the Group's business. The Group requires skilled personnel in the areas of exploration and development, operations, engineering, business development, oil marketing, finance and accounting relating to the Group's projects. Personnel costs, including salaries, are increasing as industry-wide demand for suitably qualified personnel increases. There is a scarcity of qualified personnel in the more technical areas in which the Group's business operates, such as in the subsurface and engineering disciplines. Further, over 30% of the Group's offshore workforce is over the age of 50, and it may be difficult to recruit sufficient replacements as current employees retire. See paragraph 1.33 (*The Group's offshore workforce is aging, which may lead to increased injuries, mass retirement of workers, or lack of institutional knowledge*.) of this Part 2 (*Risk Factors*). The Group may not successfully attract new personnel or retain the existing personnel required to continue to expand its business and to successfully execute and implement the Group's business strategy.

The Group undertook a voluntary redundancy programme during 2020 which resulted in approximately 71 onshore employees leaving the Group at a one-off cost to the Group of $19.3 million. In the event that the Directors were in the future to determine it necessary or commercially appropriate to implement any similar such programme, this could entail substantial cost for the Group which, coupled with the loss of experienced and/or key employees, could have a material adverse effect on the Group's operations and prospects (notwithstanding any longer-term cost efficiencies which may be expected to be gained as a result of such exercise).

1.24 **The Group's business reputation is important to its continued viability and any damage to such reputation could materially and adversely affect the Group's business.**

The Group's reputation is fundamental in allowing it to find commercial partners for business ventures, secure licences with the UK Government, obtain debt financing, attract contractors and employees and negotiate favourable terms with suppliers and offtakers, and secure acquisitions to further grow the business, amongst other things.

Any damage to the Group's reputation, whether arising from litigation, regulatory, supervisory or enforcement actions, matters affecting the Group's financial reporting, compliance with administrative agencies, environmental or safety incidents, negative publicity (including from environmental activists), or the conduct of the Group's business or otherwise, could materially and adversely affect the Group's business, financial condition or results of operations.

1.25 **The Group does not insure against certain risks and its insurance coverage may not be adequate for covering losses arising from potential operational hazards and unforeseen interruptions.**

The Group believes that the extent of its insurance cover is reasonable based on the costs of cover, the risks associated with the Group's business, availability of insurance and industry practice. Consistent with insurance coverage generally available to the industry, the Group's insurance currently includes cover for damage to physical assets, operator's extra expense (well control, seepage and pollution clean-up and re drill costs), loss of production income, business interruption insurance and third-party liabilities for the Group's global exploration and production activities, in each case subject to excesses, exclusions and limitations. There can be no assurance that such insurance will be adequate to cover any losses or exposure for liability, or that the Group will continue to be able to obtain insurance to cover such risks.

The Group is not able to guarantee that expenses relating to losses or liabilities will be fully covered by the proceeds of applicable insurance. Consequently, the Group may suffer material losses from uninsurable or uninsured risks or insufficient coverage. The Group is also subject to future risk of unavailability of insurance, increased premiums or excesses and expanded exclusions.

1.26 **The Group's operations are subject to the risk of litigation.**

From time to time, the Group may be subject to or otherwise impacted by litigation or arbitration arising out of its activities or operations, whether or not it is a direct party to those matters. Damages claimed under such proceedings, or the impact on the Group of such proceedings, may be material or may be indeterminate, and the outcome of such litigation or arbitration could materially and adversely affect the Group's business, prospects, reputation, results of operations and financial condition.

For example, IEEPL and the Group's former chief executive officer, Les Thomas, are party to a securities class action lawsuit under the Alberta Securities Act. Initiated in May 2015, the class action alleges that IEEPL published documents and made certain statements containing misrepresentations regarding FPF-1 and the then-development of the Greater Stella Area. Leave to proceed as a class action was granted by the Queen's Bench of Alberta on 24 June 2019. The Company does not anticipate a trial on the merit to occur until late 2024 or 2025 and, accordingly there is a risk that the class action could develop into prolonged litigation. Further, although the class action has not had a material adverse impact on the Group's business to date, any adverse publicity surrounding the claim or similar claims in the future, or any liability that may result from any such similar claims in the future, could have a material adverse effect on the Group's business. The Group may be required to expend significant time and expense in defending against litigation or arbitration and there can be no guarantee that a court or tribunal will find in favour of IEEPL or Mr. Thomas. Any finding against IEEPL or Mr. Thomas, including a finding that either of them made misleading statements to the market, could have a material adverse effect on the Group's reputation or prospects.

In addition, on 15 May 2020, Greenpeace Limited appealed to the Court of Session against the decisions of BEIS to agree to the grant of consent for the Vorlich field development and of the decision of the NSTA to grant consent to BP Exploration Operating Company Limited (then operator of the Vorlich field) for the Vorlich field development. Greenpeace Limited sought an order quashing the decisions of the Secretary of State and the NSTA in respect of the Vorlich field development and their judicial costs. The appeal was unsuccessful. Following a hearing in September 2021 the Inner House of the Court of Session refused Greenpeace Limited's appeal on 7 October 2021. Greenpeace Limited sought permission to appeal the Inner House of the Court of Session's decision to the Supreme Court of the United Kingdom. Permission to appeal was refused by the Inner House of the Court of Session on 14 January 2022 and by the Supreme Court of the United Kingdom on 25 August 2022 (Greenpeace Limited having sought said permission directly).

IEUK, as a partner in the Vorlich field, was an interested party in relation to the Court of Session proceedings. As permission to appeal has been refused, the appeal process comes to an end and the consents remain unaffected.

Separately, on 29 April 2021, IEUK submitted a notice of arbitration on CNSHL in connection with a dispute arising out of the Chevron Acquisition Agreement. The notice requests that a dispute, relating to the condition of the Alba floating storage unit, be referred to arbitration.

While the Group assesses the merits of each lawsuit and raises proceedings or defends accordingly (as applicable), it may be required to incur significant expenses in bringing or defending against such litigation or arbitration and there can be no guarantee that a court or tribunal finds in the Group's favour. Further, although the matters discussed above have not had a material adverse impact on the Group's business to date, any adverse findings or publicity in respect of such claim or similar claims in the future, or any liability that may result from any such similar or related claims in the future, could have a material adverse effect on the Group's business.

1.27 **The Group may be unable to dispose of assets on attractive terms or may be required to retain liabilities for certain matters.**

The Group regularly reviews its asset base to assess the market value versus holding value of existing assets, with a view to optimising deployed capital. The Group's ability to dispose of non-strategic assets could be affected by various factors, including the availability of purchasers willing to purchase such assets at prices and on terms acceptable to the Group. To the extent the Group is not able to monetise such assets (whether in full or in part) on commercially acceptable terms or at all, the Group would be required to continue to meet its funding requirements in relation to such assets. There also can be no guarantee that the value the Group receives on the disposal of an asset will equal or exceed the amount for which it acquired the asset or represent a positive return on all amounts invested in, or spent on or in connection with, such asset for the period of time it has been held.

Sellers typically retain certain liabilities or agree to indemnify buyers for certain matters and, as such, to divest certain assets the Group may provide an indemnity to a buyer. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release the Group from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a sale, the Group may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

1.28 **The Group faces risks with respect to the outbreak of infectious diseases, in particular pandemics such as COVID-19, which can have a long-lasting and far-reaching impact on the global economy.**

Pandemics, epidemics, outbreaks of infectious diseases or any other serious public health concerns, such as the outbreak of COVID-19, together with any measures aimed at mitigating a further expansion thereof, such as restrictions on travel, imposition of quarantines, prolonged closures of workplaces, or curfews or other social distancing measures, may have a material adverse effect on oil and gas prices, the global economy and international financial markets.

The significant shock to oil prices and follow-on volatility driven by COVID-19 and the consequential geopolitical developments between key oil producing nations, had a materially adverse impact on the Group's results of operations and cash flows in financial year ended 31 December 2020 (as further described in paragraph 1.1 (*The Group's business depends significantly on the level of oil and gas prices, which are volatile and have fluctuated significantly over recent years and in particular in response to recent global macroeconomic and political developments.)* of this Part 2 (*Risk Factors))*. The COVID-19 pandemic and the response thereto also materially adversely impacted the Group's business, as well as its employees, customers, users, suppliers, vendors, banking partners and business partners over the same period. Although the growth of the COVID-19 pandemic has been contained in certain countries resulting in a recovery in demand for hydrocarbons to pre-COVID-19 levels, there are continuing concerns over a potential resurgence in COVID-19 cases and the nature of individual, business and government responses. The exact scale and duration of its impact on hydrocarbon prices remains uncertain and it is still too early to predict the full impact that COVID-19 will have on the Group's business.

As a consequence of managing the challenges posed during the COVID-19 pandemic, the volatility in oil prices and proactively preserving the liquidity and cash flow resilience of the Group's business in the face of significantly lower commodity prices, various activities in the 2020 capital programme were stopped and deferred until a more suitable time. This included: the Alba infill drilling campaign that commenced at the end of 2019; the offshore works associated with preparation for the resumption of platform drilling on the Captain field later in 2020; the Abigail development programme; and the Fotla exploration well. In addition, the delay to November 2020 of the completion of the Vorlich field development program, due to restrictions on personnel and equipment, impacted the level of production during the year. To ensure the safety of the personnel on the Group's platforms whilst they were down manned to essential personnel, only critical maintenance or work programmes were undertaken. In total the steps taken across the portfolio resulted in a significant reduction in the capital investments programme that was planned for the year ended 31 December 2020. Such capital investments programme has since recommenced.

As with many other oil and gas companies, the Group has been required to adjust its working practices and scheduling, particularly in offshore roles, to minimise the risk of the spread of COVID-19 among the Group's employees and contractors. The Group undertook a voluntary redundancy programme during the year ended 31 December 2020, which resulted in approximately 71 onshore employees leaving the Group at a one-off cost to the Group of $19.3 million. During the month of April 2020, the Group reduced the number of personnel on its assets from previously approximately 500 to approximately 220 and increased this number to approximately 385 during the month of June 2021. For example, in January 2021, the Group was required to shut down production on the FPF-1 for almost two weeks as a result of a number of crew members having tested positive for the virus resulting in deferred production of 0.5 MMBOE. This was followed by a further outbreak of the virus among workers on the Captain field in February 2021, requiring a number of individuals to remain isolated onboard the asset until they could be returned to shore. Any material or sustained recurrence of such outbreaks on any of the Group's assets could have a material adverse effect upon the Group's results of operations and financial condition.

The extent to which new outbreaks of infectious diseases or the COVID-19 pandemic will continue to impact the Group's business, financial condition, results of operations, prospects and liquidity will depend on numerous factors that are unpredictable, including the duration and scope of the pandemic; governmental, business and individuals' actions that have been and continue to be taken in response to the pandemic; and the impact of the pandemic on global economic activity, unemployment levels and financial markets, including the possibility of a global recession and volatility in the global capital markets which, among other things, may increase the cost of capital and adversely impact the Group's access to capital. Furthermore, the impact of future outbreaks of infectious disease and any further impact of the COVID-19 pandemic on global demand for oil and gas and resulting oil and gas prices could have a material adverse effect on the Group's revenues and profitability.

Any of the foregoing could have a material adverse impact on the Group's business, prospects, financial condition and results of operations. Further, the impact of the COVID-19 pandemic may heighten or exacerbate many of the other risks discussed in this Part 2 *(Risk Factors)*.

1.29 **The Group's website and internal systems may be subject to intentional or unintentional disruption, and the Group's confidential information may be misappropriated, stolen or misused, which could adversely impact the Group's reputation and future sales.**

The Group may face attempted cyber-attacks designed to penetrate the Group's network security or the security of the Group's internal systems, misappropriate proprietary information and/or cause interruptions to the Group's services, and the Group expects to continue to face similar threats in the future. While the Group has successfully prevented attacks faced to date from being successful, the Group cannot guarantee that it will be able to do so in the future. Such future attacks could include hackers obtaining access to the Group's systems, the introduction of malicious computer code or denial-of-service attacks.

Upgrades to incorporate new software and digital solutions are necessary to keep pace with technological change and remain competitive, but they also expose the Group to the risk of cyber-attacks and system hacks. One oil and gas industry survey from 2017 suggested that nearly 70% of oil and gas companies have experienced a cyber compromise. If an attempted, actual or perceived breach of the Group's network security occurs, it could adversely affect the Group's business or reputation, and may expose the Group to the loss of information, litigation and possible monetary liability. Such a security breach could divert the attention of the Group's technical and management personnel. An actual security breach could also impair the Group's ability to operate its business and provide products and services to its customers. Additionally, malicious attacks, including cyber-attacks, may damage the Group's assets, prevent production at its producing assets and otherwise significantly affect corporate activities and, as a consequence, have a material adverse impact on the Group's business, results of operations and financial condition.

In addition, confidential information that the Group maintains may be subject to misappropriation, theft and deliberate or unintentional misuse by current or former employees, third-party contractors or other parties who have had access to such information. Any such misappropriation and/or misuse of the Group's information could result in the Group, among other things, being in breach of certain data protection requirements and related legislation. The Company expects that the Group will need to continue closely monitoring the accessibility and use of confidential information in the Group's business, educate its employees and third-party contractors about the risks and consequences of any misuse of confidential information and, to the extent necessary, pursue legal or other remedies to enforce its policies and deter future misuse.

1.30 **The Group may be subject to work stoppages or other labour disturbances.**

The Group's employees reside in the United Kingdom. Additionally, the Group hires contractors who, in turn, have their own employees. Work stoppages or other labour disturbances, such as industrial action, with the Group's employees or those of its contractors, suppliers and customers may occur in the future. In addition, the Group's employees, and those employed by its contractors, may become members of or represented by labour unions. If this occurs, the Group or its contractors may not be able to negotiate acceptable collective bargaining agreements or future restructuring agreements or may become subject to material cost increases or additional work rules imposed by such agreements. For example, in the UK North Sea, the British Airline Pilots' Association announced on 8 May 2019, that its members had voted for strike action after CHC Helicopters, one of various helicopter service providers that the Group uses, failed to table an acceptable offer on pay deals. Although the strike action was called off on 20 May 2019, future strike actions could adversely affect the business. For example, in May 2022 and 8 September 2022, oil and gas workers across various offshore platforms in the UK North Sea, participated in unofficial strike action across a number of days to demand pay rises against rising costs-of-living. Assets affected by such unofficial strike action included platforms on the Britannia field, Jade field and Elgin-Franklin field. The occurrence of any of the foregoing, or any additional unofficial strike action, could materially and adversely affect the Group's business, prospects, financial condition and results of operations.

1.31 **There are risks related to the determination and redetermination of unitised petroleum deposits.**

In compliance with the Group's licence conditions, certain of the Group's assets are or will become unitised with licence interests held by third parties. The Group has entered, or shall enter into, operating agreements with such third parties governing (amongst other things) the appropriate division of interests in the unitised field. Such divisions are inherently uncertain, and the agreements do, or may, contain redetermination provisions in light of further information regarding the field becoming available. Any such determination or redetermination may not accord with the Group's own analysis and may have a materially adverse effect on the Group's business, financial condition and results of operations.

1.32 **The Group carries out business in a highly competitive environment.**

The oil and gas industry is highly competitive. The key areas in respect of which the Group faces competition include:

1.32.1 engagement of third party service providers whose capacity to provide key services may be limited;

1.32.2 purchasing, leasing, hiring, chartering or other procuring of equipment that may be scarce;

1.32.3 availability of, and access to, specialised equipment, including drilling and related equipment, pipeline ullage and tanker capacity together with other storage, processing and delivery facilities and equipment;

1.32.4 employment and retention of qualified and experienced skilled management and oil and gas professionals; and

1.32.5 access to capital, including bank lending and bond market capacity.

Competition in the Group's markets is intense and depends, among other things, on the number of competitors in the market, their financial power, their degree of geological, geophysical, engineering and management expertise and capabilities, their degree of vertical integration, their pricing policies, their ability to develop oil and gas prospects on time and on budget, their ability to select, acquire and develop reserves and their ability to foster and maintain relationships with host governments of the countries in which they have assets. The Group's competitors include those entities with greater technical, physical and financial resources including those who not only engage in the acquisition, exploration, development and production of oil and gas reserves, but also those who carry out refining operations and the production of market refined items.

In addition, the effects of operating in a competitive industry may include potentially unfair practices including unconscionable pressure on the Group directly or indirectly or the dissemination of false or misleading information or rumours by competitors or third parties. Such pressure can arise out of disparities in the relative bargaining power of the affected parties and includes the stronger party exploiting the weaker party's disadvantage or the stronger party relying on its rights in a harsh or oppressive manner, allowing the weaker party to make an incorrect assumption, failing to disclose a material fact, misrepresentation or otherwise unfairly benefiting from a transaction at the expense of the weaker party.

The oil and gas industry is also characterised by rapid and significant technological advancements and the introduction of new products and services. As others use or develop new technologies, the Group may be placed at a competitive disadvantage or may be forced by competitive pressures to implement those new technologies at substantial costs. In addition, other oil and gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages, which may in the future allow them to implement new technologies before the Group can. The Group may not be able to respond to these competitive pressures or implement new technologies on a timely basis or at an acceptable cost or even at all given the personnel resources available to it. If one or more of the technologies the Group uses now or in the future were to become obsolete, resulting in the Group either falling behind its competitors or being unable to service its infrastructure, the Group's business, prospects, financial condition and results of operations could be materially adversely affected. In addition, any new technology that the Group implements may have unanticipated or unforeseen adverse consequences, either to the Group's business or to the industry as a whole.

If the Group is unsuccessful in competing against other companies, the Group's business, prospects, financial condition and results of operations could be materially adversely affected.

1.33 **The Group's offshore workforce is aging, which may lead to increased injuries, mass retirement of workers or lack of institutional knowledge.**

Over 30% of the Group's offshore workforce is over the age of 50.

A significant number of experienced oil and gas workers are expected to retire in the next decade, a phenomenon referred to in the industry as the "Great Crew Change". As its workforce retires, the Group will need to replace its employees on an increasingly frequent basis, resulting in a higher rate of turnover and additional costs associated with recruitment and hiring. Further, the Group may be unable to recruit new workers on the same terms or with the same skillset as its retiring employees, or at all. An inability to recruit or retain replacement offshore workers could result in production slowdowns and have a material adverse effect on the Group's business, financial condition or results of operations.

In addition, the Group's institutional knowledge retention may suffer as large numbers of its workforce retire, possibly without sufficient overlap between outgoing and incoming workers to allow adequate knowledge sharing. The oil and gas industry requires specialised knowledge, and any difficulties in retaining this knowledge within the Group could result in a material adverse effect to the Group's reputation, business, financial condition or results of operations.

2. RISKS RELATING TO THE GROUP'S FINANCING AND STRUCTURE

2.1 **The Group engages in commodity and interest rate hedging activities that expose the Group to losses should markets move against the Group's hedged position.**

The nature of the Group's operations results in exposure to fluctuations in commodity prices. The Group uses financial instruments and physical delivery contracts to hedge the Group's exposure to these risks and may continue to do so in the future. The Group hedges predominantly through swaps, zero cost collars and puts.

The Group's hedging strategy is linked to its financing arrangements, including certain requirements under the RBL Facility Agreement. These requirements state that the Group may not hedge more than 85% (or lower maximum levels, depending on the time elapsed since the date of the relevant transaction) of the Group's anticipated production as provided in the most recent projection adopted in the RBL Facility Agreement in any given year using instruments with an uncapped contingent credit exposure (i.e., swaps). The Group is thus exposed to credit related losses in the event of non performance by counterparties to the associated financial instruments.

The Group has a commodity hedging strategy designed to satisfy four key objectives: (i) deliver the Group's budget and longer term business plan; (ii) mitigate downside risk of the commodity markets; (iii) allow for benefitting from market upside; and (iv) satisfy a minimum volume rolling cover of 75% (year one), 50% (year two) and 25% (year three). To enable this, a tiered implemented policy is followed with the first 50% of volumes hedged focused on downside protection, the following 25% allowing the capture of market upside while providing downside protection, and the remaining 25% left unhedged. Conventional instruments including puts, swaps and collars are utilised to achieve these objectives. As at 30 June 2022, the Group had approximately 44% of volumes of oil hedged for the remaining two quarters of 2022 at average floor strike prices of $56/BBL and 67% of volumes of gas hedged at average floor strike prices of 114 pence/therm. As at 30 June 2022, the Group currently has 17% of volumes of gas hedged for 2023 at an average floor strike price of 123 pence/therm and 37% of volumes of oil hedged at an average floor strike price of $68/BBL. As at 30 June 2022, the Group currently has 1% of volumes of gas hedged for the first six months of 2024 at an average floor strike price of 46 pence/therm. Although this provides downside commodity price protection, product prices could increase above those levels specified in any future hedging agreements, which would mean the Group would lose the cost of floors or ceilings or a fixed price could limit the Group from receiving the full benefit of commodity price increases. The Group may also suffer financial loss if it is unable to commence operations on schedule or is unable to produce sufficient quantities of oil and gas to fulfil its obligations. In addition, the Group may not be able to find hedging counterparties or pricing for hedging on suitable terms.

If the Group experiences a loss as a result of its hedging activities (for example in the six month period 30 June 2022, the Group incurred losses of $270.2 million on realised hedges) or is unable to hedge its commodity price risk effectively, this could have a material adverse effect on the business, operating results, financial condition or prospects of the Group.

2.2 **The Group's development projects require substantial capital expenditures. The Group may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in the Group's oil and gas reserves.**

The Group makes and expects to continue to make substantial capital expenditures in its business for the development, production and acquisition of oil and gas reserves. The Group anticipates that in order to continue to implement its stated strategy it will need to make substantial capital investments for its operations, exploration, appraisal, development and/or production plans. In particular, the Group estimates that its planned capital, including in relation to any development of the Cambo field and Rosebank field, will amount to approximately $5.5 billion net to the Group over the next 5 years.

The Group may suffer unexpected costs if a commercial partner withdraws from a development project. For example, commercial partners who currently have an interest in the Group's development projects may elect not to continue investing in such projects. In such circumstances, there is no guarantee that the Group will be able to procure a replacement partner. In order to proceed with the development of the project, the Group may be required to proceed on a sole risk basis or bear a greater proportion of the risks, and contribute all, or a greater proportion, of the requisite funding which may materially increase the capital expenditure required. On 11 August 2022, Shell launched a sale process for its 30% stake in the Cambo field. On the completion of any such sale, the Group will have a new (or, in the event of any partial sale, an additional) joint venture partner in the Cambo field and will be required to cooperate with such partner on the development of the Cambo field.

The Group intends to finance the majority of its future capital expenditures with cash flow from operations and, if necessary, borrowings including the RBL Facility Agreement. The Group's cash flows from operations and access to capital are subject to a number of variables which it does not control, including:

2.2.1 the Group's proved reserves;

2.2.2 the level of oil and gas the Group is able to produce from existing wells;

2.2.3 the price at which the Group's oil and gas are sold; and

2.2.4 the Group's ability to acquire, locate and produce new reserves.

If the Group's revenues or the borrowing base under the RBL Facility Agreement decrease as a result of lower oil or gas prices, operating difficulties, declines in reserves or for any other reason, the Group may have limited ability to obtain the capital necessary to sustain its operations at current levels. The RBL Facility Agreement restricts the Group's ability to obtain certain new financing. If additional capital is needed, the Group may not be able to obtain debt or equity financing. If cash generated by operations or cash available under the RBL Facility Agreement is not sufficient to meet the Group's capital requirements, the failure to obtain additional financing could result in a curtailment of the Group's operations relating to the development of its prospects, which in turn could lead to a decline in the Group's oil and gas reserves, or if it is not possible to cancel or stop a project, becoming legally obliged to carry out the project contrary to the Group's desire or with negative economic impact. Further, the Group may fail to make required cash calls and breach licence obligations, which again could lead to adverse consequences. All of the above could adversely affect the Group's production, revenues and results of operations as well as having a material adverse effect on the Group's ability to service its indebtedness.

The Group's ability to sustain planned levels of capital expenditure may also be negatively impacted by the need to reduce costs and preserve capital and liquidity due to unforeseen macroeconomic, geopolitical and other events that are beyond the Group's control. See paragraph 1.28 (*The Group faces risks with respect to the outbreak of infectious diseases, in particular pandemics such as COVID-19, which can have a long-lasting and far-reaching impact on the global economy.)* of this Part 2 *(Risk Factors)* above.

2.3 **The Group is subject to restrictive debt covenants that may limit its ability to pursue future business opportunities and activities.**

The Group has, and will continue to have, outstanding debt and debt service obligations. As at 30 June 2022, the Group's non-current borrowings were $1.4 billion, and the Group's bank interest and charges for the six month period 30 June 2022 were $54.5 million. Under the Indenture and the RBL Facility Agreement, the Group must comply with a number of covenants which may restrict, among other things, the Group's ability to:

2.3.1 incur additional debt and issue guarantees and preferred stock;

2.3.2 make certain payments, including dividends and other distributions to IEEPL and other subsidiaries, with respect to outstanding share capital;

2.3.3 repay or redeem subordinated debt or share capital;

2.3.4 create or incur certain liens;

2.3.5 make certain investments or loans;

2.3.6 sell, lease or transfer certain assets, including shares of any of the Group's restricted subsidiaries;

2.3.7 expand into unrelated businesses;

2.3.8 merge or consolidate with other entities; or

2.3.9 enter into certain transactions with affiliates.

All these limitations are subject to significant exceptions and qualifications. Compliance with these covenants could reduce flexibility in conducting the Group's operations, particularly by:

2.3.10 affecting the Group's ability to react to changes in market conditions, whether by increasing vulnerability in relation to acute economic disruptions or by preventing it from profiting from an improvement in those conditions;

2.3.11 affecting the Group's ability to pursue new business opportunities and activities that may be in its interest;

2.3.12 limiting the Group's ability to obtain certain additional financing to make further investments or acquisitions and carry out refinancing; and

2.3.13 forcing the Group to dedicate a significant portion of its cash flows to payment of the sums due for such loans, thus reducing the ability to utilise such cash flows for other business purposes.

In addition, the Group is subject to affirmative and negative covenants contained in the RBL Facility Agreement, including the requirement to ensure that the amount of utilisations thereunder (together with interests, fees and other amounts accrued in relation thereto) is not in excess of the reserves and resources base value and further, IEUK is required, on certain testing dates, to (i) ensure that the ratio of net debt (excluding obligations to any other member of the Group) to EBITDAX (each as defined in the RBL Facility Agreement) is not less than 3.5.1; and (ii) demonstrate that total corporate sources exceed total corporate uses.

To the extent the Group raises additional debt, the Group may be subject to different or additional covenants or security arrangements. These covenants could limit its ability to finance discretionary business expansion and capital investment in the longer term, which could in turn have a material adverse effect on the Group's business, results of operations and financial condition.

Additional tightening of capital requirements, and the resulting policies adopted by lenders, could further reduce lending activities. The Group may experience difficulties obtaining financing commitments or be unable to fully draw on the capacity under committed loans the Group arrange in the future if the Group's lenders are unwilling to extend financing to the Group or unable to meet their funding obligations due to their own liquidity, capital or solvency issues. The Group cannot be certain that financing will be available on acceptable terms or at all to fund its longer-term growth plans. If financing is not available when needed, or is available only on unfavourable terms, the Group may face difficulties in meeting the Group's future obligations as they become due. The Group's failure to obtain such funds could have a material adverse effect on the Group's business, results of operations and financial condition.

2.4 **Certain of the Group's outstanding borrowings will bear interest at floating rates which could rise significantly, thereby increasing its interest cost and reducing cash flows.**

Interest on borrowings under the RBL Facility Agreement will (depending on the currency of the loan drawn) bear interest on either a term rate basis or compounded rate basis and the applicable reference rate for (i) US dollars will be one of SOFR, (ii) euros will be EURIBOR, and (iii) pounds sterling will be SONIA.

Interest rates could rise significantly in the future, thereby increasing the Group's interest expenses associated with these obligations and reducing cash flows available for capital investments. Although the Group may enter into certain hedging arrangements designed to fix a portion of these rates in compliance with the hedging policy contained in the RBL Facility Agreement, there can be no assurance that hedging will be available or continue to be available on commercially reasonable terms. In addition, hedging itself carries certain risks, including that the Group may need to pay a significant amount (including costs) to terminate any hedging arrangements.

LIBOR, EURIBOR and other interest rates or other types of rates and indices which are deemed to be "benchmarks" are or may be the subject of ongoing national and international regulatory reform, including the implementation of the IOSCO Principles for Financial Market Benchmarks (July 2013) and the European regulation on indices used as benchmarks in financial instruments and financial contracts or to measure the performance of investment funds, which entered into force on 30 June 2016. Following the implementation of any such reforms, the manner of administration of benchmarks may change, with the result that they may perform differently than in the past, or benchmarks could be eliminated entirely, or there could be other consequences which cannot be predicted. For example, on 27 July 2017 and in a subsequent speech by its chief executive on 12 July 2018, the FCA confirmed that it would no longer persuade or compel banks to submit rates for the calculation of the LIBOR benchmark after the end of 2021 and that market participants should not rely on the continued publication of LIBOR after the end of 2021, while on 5 March 2021, the FCA announced the dates that panel bank submissions for all LIBOR settings will cease, after which representative LIBOR rates will no longer be available (together, the "**FCA Announcements**"). The FCA Announcements indicated that the continuation of LIBOR on the current basis cannot and will not be guaranteed after 2021. The potential elimination of the LIBOR benchmark or any other benchmark, changes in the manner of administration or methodology of any benchmark, or actions by regulators or law enforcement agencies could result in changes to the manner in which EURIBOR or LIBOR is determined, which could require an adjustment to the terms and conditions, or result in other consequences, in respect of any debt linked to such benchmark (including but not limited to the RBL Facility). Any such change, as well as manipulative practices or the cessation thereof, may result in a sudden or prolonged increase in reported EURIBOR or LIBOR, which could have an adverse impact on the Group's ability to service debt that bears interest at floating rates of interest. However, the RBL Facility Agreement as amended in July 2021 now caters for the effects of the cessation of LIBOR for pounds sterling and the impending cessation of LIBOR for US dollars after 30 June 2023.

2.5 **The Group is subject to currency exchange and inflation risks, which might adversely affect the Group's financial condition and results of operations.**

The Group receives its gas revenues (which accounted for 37% of production and 45.8% of revenue from oil and gas sales for the year ended 31 December 2021) in UK pounds sterling and its oil revenues (which accounted for 58% of production and 54.2% of revenue from oil and gas sales for the year ended 31 December 2021) in US dollars. Moneys received in US dollars are converted to foreign currencies where necessary to meet payment obligations which are contracted in currencies other than US dollars, such as labour and employee costs that are incurred in UK pounds sterling. Moneys received in UK pounds sterling (including any proceeds received from future primary capital raisings) are converted to foreign currencies where necessary to meet payment obligations which are contracted in currencies other than UK pounds sterling, such as acquisition costs that are incurred in US dollars. Although the Group enters into currency hedging arrangements, it is nevertheless subject to fluctuations in respective currency exchange rates, which may adversely affect the Group's business, results of operations and financial condition. Exchange rates between the UK pound sterling and the US dollar have fluctuated significantly in the past and may do so in the future. See paragraph 3.4 (*The United Kingdom's withdrawal from the European Union may have a negative effect on global economic conditions and/or financial markets, thereby adversely affecting the Group's business.*) of this Part 2 (*Risk Factors*) below. Consequently, construction, exploration, development, operating, acquisition, administration and other costs may be higher in US dollars than the Group anticipates.

2.6 **The Group requires a significant amount of cash to service its debt and sustain its operations, and the ability to generate sufficient cash depends on many factors beyond the Group's control.**

The Group's ability to make payments on, repay or refinance its debt, and to fund longer-term working capital (i.e., outside of the 12 month period from the date of this Prospectus) and capital investments, will depend on future operating performance and ability to generate sufficient cash. This depends on the success of its business strategy and on general economic, financial, competitive, market, legislative, regulatory, technical and other factors as well as the risks discussed in this Part 2 (*Risk Factors*) many of which are beyond the Group's control. In addition, the Group's ability to borrow funds in the future to make payments on its debt will depend on the satisfaction of the covenants in the RBL Facility Agreement and other debt agreements, including the Indenture, and other agreements the Group may enter into in the future. Therefore, it cannot be guaranteed that the business will generate sufficient cash flows from its operations or that future debt and equity financings will be available to the Group in an amount sufficient to enable it to pay debt or to fund other longer-term liquidity needs.

As at 30 June, 2022, the Group had $825 million of unsecured senior indebtedness related to the 2026 Notes and the Siccar Point Bonds (which were subsequently repaid in full) outstanding. Prior to repayment of the 2026 Notes by 2026, the Group may be required to refinance or repay certain other debt, including debt under the RBL Facility Agreement (outstanding principal being $750 million as at 30 June 2022). It cannot be guaranteed that the Group will be able to refinance or repay any of its debt on commercially reasonable terms or at all. Any refinancing of debt could be at higher interest rates than current debt and may require the Group to comply with more onerous covenants, which could further restrict the Group's business operations. Any failure to make payments on debt on a timely basis would likely result in a reduction of credit rating, which could also harm the Group's ability to incur additional indebtedness. In addition, the terms of the debt, including the 2026 Notes and the RBL Facility Agreement, limit, and any future debt may also limit, the Group's ability to pursue any alternative options in the future. If the Group is unsuccessful in any of these efforts, it may not have sufficient cash to meet its longer-term obligations, which could cause an event of default under the debt and result in:

2.6.1 the 2026 Notes holders declaring all outstanding principal and interest to be immediately due and payable;

2.6.2 the lenders under the RBL Facility Agreement being able to terminate their commitments to lend the Group money and foreclose against the assets securing the borrowings thereunder; and

2.6.3 the Group being forced into bankruptcy or liquidation.

Any of these results could have a material adverse effect on the Group's business, prospects, financial condition or results of operation.

3. **RISKS RELATING TO REGULATION AND LEGISLATION**

3.1 **The Group may be adversely affected by changes to tax legislation or its interpretation or increases in effective tax rates in the tax jurisdictions in which the Group does business.**

The Group does business in more than one tax jurisdiction, namely the United Kingdom and Jersey, and its profits are taxed according to the tax laws of such jurisdictions. Jurisdiction by jurisdiction fluctuations in tax rates can have an impact on projects and make certain projects less economically viable. The Group's tax rate, including the Group's effective tax rate and the rate of value added tax ("**VAT**") may be affected by changes in tax laws or interpretations of tax laws in any jurisdiction and in any financial year will reflect a variety of factors that may not be present in succeeding financial years. As a result, the Group's tax rate may increase in future periods, which could have a material adverse effect on the Group's financial results and, specifically, its net income, cash flow and earnings may decrease.

During periods of high profitability in the oil and gas industry, there are often calls for increased or windfall taxes on oil and gas revenues. Taxes have increased or been imposed in the past and may increase or be imposed again in the future. For example, on 14 July 2022, the Energy Profits Act was enacted to introduce the Energy Profits Levy, a new 25% surcharge on profits made by companies in the oil and gas sector as a result of rises in commodity prices, in addition to the existing 30% Ring Fence Corporation Tax and 10% Supplementary Charge. The legislation includes a sunset clause which provides that the Energy Profits Levy will expire on 31 December 2025; however, there is no assurance that the UK Government will not review, change or amend the regulations, rules or policies enacted under the Energy Profits Levy to extend the direction of the levy (including to increase the surcharge, extend the sunset clause or to eliminate or narrow the scope or availability of any investment allowances). Levels of taxation relief may also decrease or no longer be available to the Group due to changes in, or new interpretations of, tax laws. For example, UK Government cabinet ministers have indicated that the new Prime Minister, Rishi Sunak, is considering—among other changes—increasing the Energy Profit Levy above the current 25% surcharge and/or extending the expiration date of the Energy Profit Levy beyond 31 December 2025. In addition, the Labour Party, in opposition to UK government, have proposed to alter the conditions of the Energy Profit Levy, including to backdate its implementation to 1 January 2022 (currently 26 May 2022), and to remove the 80% investment allowance, which serves as an additional tax deduction on capital expenditure. If adopted, any of these changes could have a material adverse effect on the tax payable by the Group. In addition, taxation authorities could review and question the Group's tax returns leading to additional taxes and penalties, which could be material. The Group's cumulative tax loss position could be negatively affected as a result of such inquiry and the Group could potentially become liable to pay tax sooner than anticipated. There are tax rules which prevent the use of carried forward losses where, over the course of any period of five years starting up to three years before a change in ownership of a company, there is a major change in the nature or conduct of a trade carried on by a company, and whilst the Group focuses and will continue to focus on oil and gas activities, and HMRC has published guidance indicating that it would generally be unusual for it to take the view that there has been a major change in the nature or conduct of a trade in the context of this industry (that is, in the context of ring-fence trades), the application of these rules cannot be discounted given that the Group has previously (and may in future) undertake corporate steps in respect of its structure, and the prior acquisition of companies into the Group which have caried forward losses. The tax treatment of decommissioning expenditure (where relevant) (including the ability to carry back decommissioning losses to historical periods of tax payment in the Group entities) could also have a material impact on the economics of the Company's assets.

Tax regimes in certain jurisdictions can be subject to differing interpretations and tax rules in any jurisdiction are subject to legislative change and changes in administrative and regulatory interpretation. The interpretation by the Group's relevant Subsidiaries of applicable tax law as applied to their transactions and activities may not coincide with that of the relevant tax authorities. As a result, transactions may be challenged by tax authorities and any of the Group's profits from activities in those jurisdictions may be subject to additional tax or additional unexpected transactional taxes (e.g., stamp duty, VAT or capital gains tax) may arise, which, in each case, could result in significant legal proceedings and additional taxes, penalties and interest, any of which could have a material adverse impact on the Group's business, prospects, financial condition or results of operations.

In addition, should Scotland become independent from the United Kingdom, tax law and regulations may change so that the tax regime in Scotland diverges further from the tax regime in the remaining parts of the United Kingdom. The Group cannot guarantee that any changes to the tax regime in Scotland would not result in additional tax costs. See paragraph 1.4 *(The Group's production is entirely concentrated in UKCS offshore fields, making the Group vulnerable to risks associated with having all of its production in one region, such as the effect of fiscal and regulatory factors, regional supply and demand factors, operational cluster concentration and adverse weather conditions)* of this Part 2 (*Risk Factors*) above.

3.2 **The Group must comply with licensing and other regulatory requirements in the United Kingdom, which may become more challenging following any amendments or reform.**

The Group's current operations are, and its future operations will be, subject to licences, approvals, authorisations, consents and permits from governmental authorities for exploration, development, construction, operation, production, marketing, pricing, transportation and storage of oil and other hydrocarbons, taxation and environmental and health and safety matters. Relevant legislation currently provides that fines may be imposed and a licence may be suspended or terminated if a licence holder, or party to a related agreement, fails to comply with its obligations under such licence or agreement, or fails to make timely payments of levies and taxes for the licensed activity, provide the required geological information or meet other reporting requirements. It may from time to time be difficult to ascertain whether the Group has complied with obligations under licences as the extent of such obligations may be unclear or ambiguous and regulatory authorities may not be forthcoming with confirmatory statements that work obligations have been fulfilled, which can lead to further operational uncertainty. In addition, the Group and its commercial partners, as applicable, have obligations to develop the fields in accordance with specific requirements under certain licences and related agreements, field development plans, laws and regulations. If the Group or its commercial partners, as applicable, were to fail to satisfy such obligations with respect to a specific field, the licence or related agreements for that field may be suspended, revoked or terminated.

UK authorities are typically authorised to, and do from time to time, inspect in order to verify compliance by the Group or its commercial partners, as applicable, with relevant laws and the licences or the agreements pursuant to which the Group conducts its business. The views of the relevant government agencies regarding the development of the fields that the Group or its commercial partners operate or the compliance with the terms of the licences pursuant to which the Group conducts such operations may not coincide with the Group's views, which might lead to disagreements that may not be resolved. The Group is also reliant on relevant government authorities in order to develop its fields. Should they have a wider area plan or different development strategy then the Group may be unable to develop its fields as it would otherwise intend to and may be forced to use alternative infrastructure or methods.

A small portion of the licences pursuant to which the Group conducts operations are solely exploration licences which have a limited life before the Group is obliged to seek to convert the licence to a production licence, extend the licence term or relinquish the licence area. If commercially viable hydrocarbons are discovered during the exploration licence term, the Group, along with any applicable partners, would be required to apply for a production licence before commencing production. If the Group / partners comply with the terms of the relevant licence, the Group would normally expect that a production licence would be issued; however, no assurance can be given that any necessary production licences will be granted by the NSTA.

The suspension, revocation or termination of any of the licences or related agreements pursuant to which the Group conducts business could materially and adversely affect the Group's business, prospects, financial condition and results of operations. In addition, failure to comply with the obligations under the licences or agreements pursuant to which the Group conducts business may lead to fines, penalties, restrictions or revocations of licences and termination of related agreements, which could materially and adversely affect the Group's business, prospects, financial condition and results of operations.

The Group's oil and gas operations are principally subject to the laws and regulations of the United Kingdom, including those relating to health and safety and the production, pricing and marketing of oil. The grant, continuity and renewal of the necessary approvals, permits, licences and contracts, including the timing of obtaining such licences and the terms on which they are granted, are subject to the discretion of the relevant governmental and local authorities in the United Kingdom. From time to time the Group receives, and may continue to receive, notices and other correspondence from governmental and local authorities, such as the Health and Safety Executive, which the Group aims to resolve in a timely manner. For example, in May 2022, the Group received an improvement notice from the Health and Safety Executive in connection the Alba FSU relating to overdue periodic inspections, with remediation of the inspection of certain cargo tanks required to be completed by May 2023.

Nevertheless, because all of the Group's operations are concentrated in the UKCS, which might be considered to be in Scottish territorial waters, the Group cannot guarantee that current UK laws and regulations regarding licensing and other matters will not change should Scotland become independent from the United Kingdom. The Group cannot guarantee that any changes in the regulatory regime as a result of Scottish independence would not result in increased costs to comply with new regulations or a change in the standards of the Group's operations.

Moreover, the Group is subject to extensive government laws, rules and regulations, including, among others, laws governing prices, taxes, allowable production, waste disposal, pollution control and similar environmental laws, the export of oil and other hydrocarbons, and companies and many other aspects of the oil and gas business. The actions of present or future UK governments, or of governments of other countries in which the Group may acquire assets in the future, may materially adversely affect the Group's business, prospects, financial condition and results of operations.

Failure to comply with applicable laws or regulations, or if the Group is unable to meet or is delayed in meeting applicable regulatory requirements and filings, may lead to civil, administrative or criminal penalties, including but not limited to fines, for example as a result of the delayed filing of statutory accounts or as a result of delayed tax returns of any member of the Group. The Group could also be required to pay damages or civil judgments in respect of third party claims.

Any of these developments, alone or in combination, could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

3.3 The Group could incur material costs to comply with, or as a result of liabilities under, health and safety and environmental regulations.

The Group operates in an industry that is inherently hazardous and consequently subject to comprehensive regulation, including those governing discharges of pollutants to air and water, the management of produced water and wastes and the cleaning of contamination. Failure to adequately mitigate risks may result in loss of life, injury, or adverse impacts on health of employees, contractors and third parties or the environment. Such failure, whether inadvertent or otherwise, by the Group to comply with applicable legal or regulatory requirements may give rise to significant liabilities and/or delays in permitting. Further, health, safety and environment laws and regulations may expose the Group to liability for the conduct of others or for acts that complied with all applicable health, safety and environment laws when they were performed. As a result, the Group could incur material costs, including clean-up costs, civil and criminal fines and sanctions and third-party claims for personal injury, wrongful death and natural resource and property damages, as a result of violations of the Group's obligations under environmental, health and safety requirements.

The terms of licences or permissions necessary for the Group's operations may include more stringent environmental and/or health and safety requirements over time, particularly as the United Kingdom has now left the European Union. Since the Group's operations have the potential to impact air and water quality, biodiversity, ecosystems and human health, obtaining exploration, development or production licences and permits may become more difficult or may be delayed due to governmental, regional or local environmental consultation, scientific studies, approvals or other considerations or requirements.

The Group incurs, and expects to continue to incur, capital and operating costs in an effort to comply with increasingly complex health and safety and environmental laws and regulations and to develop and implement robust health, safety, environment and assurance systems to enable it to ensure compliance with all applicable requirements as licensee and/or operator in respect of the Group's interests.

New laws and regulations, the imposition of tougher requirements in licences, increasingly strict enforcement of, or new interpretations of, existing laws, regulations and licences, or the discovery of previously unknown contamination may require further expenditures to, for example:

3.3.1 modify operations;

3.3.2 install pollution control equipment;

3.3.3 perform site clean ups;

3.3.4 curtail or cease certain operations; or

3.3.5 pay fees or fines or make other payments for pollution, discharges or other breaches of environmental requirements.

Although the costs of the measures taken to comply with environmental regulations have not had a material adverse effect on the Group's business, financial condition or results of operations to date, the costs of such measures and liabilities for any environmental damage caused by the Group's operations in the future may increase. It may also be the case that such future measures place an unmanageable burden on the Group due to the restrictions on personnel resources it faces. Such matters could materially and adversely affect the Group's business, prospects, financial condition and results of operations. In addition, it is not possible to predict with certainty what future environmental regulations will be enacted or how current or future environmental regulations will be applied or enforced in the future. Environmental laws may result in a curtailment of production and a material increase in the cost of production, development or exploration activities.

Controls on the quantities of oil that can be discharged in process waters or via drainage systems in the course of offshore operations have been implemented in the United Kingdom by the OPPC. The OPPC was amended by the Offshore Petroleum Activities (Oil Pollution Prevention and Control) (Amendment) Regulations 2011 which, among other things, extends the scope of the OPPC to apply to all emissions of oil from pipelines used for offshore oil and gas activities and for gas storage and unloading activities. The OPPC requires operators to demonstrate that equipment and processes are "**Best Available Techniques**" ("**BAT**") therefore the Group may incur material expenditure to comply with the OPPC if the Group is required to modify its operations, specifically with regard to the FPF-1 and the Captain FPSO. The PPC have been implemented in the United Kingdom and apply to any installation with an aggregate thermal rating of greater than 50 megawatts (thermal input) and therefore apply to the FPF-1 and the Captain FPSO. Applications for these PPC permits normally contain an energy efficiency survey. Energy efficiency surveys that the Group has conducted as part of the PPC application process have identified potential energy efficiency measures and other upgrades to the installations that may be implemented by the Group, which have been built into the assets' life of field opportunity registers maintained by the Group, for future investment opportunities for improved performance. As with the OPPC, in addition to commitments to improve energy efficiency, the PPC requires operators to demonstrate that equipment and processes are BAT. The costs associated with the PPC permit compliance and other measures to be undertaken are material for the Group.

Should the Group be unable to pay such costs of compliance, its business, prospects, financial condition and results of operations may be materially adversely affected.

3.4 **The United Kingdom's withdrawal from the European Union may have a negative effect on global economic conditions and/or financial markets, thereby adversely affecting the Group's business.**

The Group's operations are conducted wholly within the United Kingdom. On 31 January 2020, the United Kingdom formally withdrew from the European Union ("**Brexit**"), entering into a transition period that ended on 31 December 2020. This process is unprecedented in European Union history and the effects of Brexit are currently uncertain. Although the United Kingdom entered into a trade and cooperation agreement with the European Union on 24 December 2020 that provides for, among other things, the free movement of goods between the United Kingdom and the European Union, continued legal uncertainty and potentially divergent national laws and regulations in relation to financial laws and regulations, tax and free trade agreements, immigration laws and employment laws may adversely affect economic or market conditions in the United Kingdom, the European Union or globally, which could contribute to instability in global financial and foreign exchange markets and could also impair the Group's ability to access capital or transact business and/or to attract and retain qualified personnel. Asset valuations, currency exchange rates and credit ratings have been and may continue to be subject to increased market volatility. Lack of clarity about future UK laws and regulations as the United Kingdom determines which European Union laws to replace or replicate, including financial laws and regulations, tax and free trade agreements, tax and customs laws, intellectual property rights, environmental, health and safety laws and regulations, immigration laws, employment laws and transport laws could decrease foreign direct investment in the United Kingdom, increase costs, disrupt supply chains, depress economic activity and restrict the Group's access to capital. The 'Retained EU Law' bill, announced by the UK Government, under then—Prime Minister Liz Truss, on 22 September 2022, will see retained EU laws disapplied by end 2023 unless the UK Government has legislated to retain or replace them, however there is currently no clarity as to which EU laws will be so retained or replaced.

All or any combination of the foregoing could negatively affect the Group's business, prospects, operations and revenues, and the broader economic environment on which the Group's industry depends.

4. **RISKS RELATING TO THE GLOBAL OFFERING AND THE ORDINARY SHARES**

4.1 **On Admission, Delek will retain a significant interest in, and continue to exert substantial influence over the Group following the Global Offering and its interests may differ from or conflict with those of other Shareholders.**

Immediately following Admission, Delek is expected to beneficially own approximately 89.4% of the issued ordinary share capital of the Company, assuming no exercise of the Over-allotment Option, and if the Over-allotment Option is exercised in full, Delek is expected to beneficially own approximately 87.9% of the issued ordinary share capital of the Company. Due to the size of its shareholding in the Group following Admission, Delek will hold more than 30% of the Ordinary Shares of the Group and will, therefore, be deemed a controlling shareholder for the purposes of the Listing Rules. As a consequence of such, the Company has entered into a relationship agreement with Delek (hereinafter referred to as the "**Relationship Agreement**") to ensure that the Group is capable at all times of carrying on its business independently of Delek and any of its associates.

The Relationship Agreement contains customary undertakings from Delek to, among other things: (i) conduct all transactions and arrangements with any member of the Group at arm's length and on normal commercial terms; (ii) not take any action which would have the effect of preventing the Group from complying with its obligations under the Listing Rules; and (iii) not propose or procure the proposal of any shareholder resolution which is intended or appears to be intended to circumvent the proper application of the Listing Rules. There may be instances when Delek has interests that diverge from those of the other shareholders and the Group cannot assure investors that the interests of Delek will be the same as or align with the interests of subscribers or purchasers of shares in the Global Offering.

The Relationship Agreement will take effect upon Admission and will continue in force unless and until Delek and its affiliates cease to own at least 10% or more of the Ordinary Shares or the voting rights attaching to the Ordinary Shares, save that certain provisions of the

Relationship Agreement relating to requirements of Chapter 6 of the Listing Rules will terminate upon Delek and its affiliates ceasing to own at least 30% of the Ordinary Shares. Delek may terminate the Relationship Agreement in certain circumstances, including where the Ordinary Shares cease to be admitted to the premium segment of the Official List and cease to be admitted to trading to the London Stock Exchange's main market for listed securities.

If and for so long as Delek and its affiliates hold at least 20% of the Ordinary Shares, it will have the right to nominate up to a maximum of two non-executive directors to the Board (such appointment right is subject to the Company's continued compliance with the Governance Code, save as otherwise disclosed in this Prospectus) and, for so long as Delek and its affiliates hold at least 10% of the Ordinary Shares, it will have the right to nominate up to a maximum of one non-executive director to the Board. In addition, if and for so long as Delek and its affiliates hold at least 50% of the Ordinary Shares, it will have the right to appoint one observer to attend and observe the committee meetings of each of the Remuneration Committee and Audit and Risk Committee and the right to nominate one Director to the Nomination and Governance Committee.

While Delek holds more than 25% of the Ordinary Shares, it will have the ability to block special resolutions of the Company proposed by the Board or members of the Company from time to time. Delek, however, will not be entitled to vote on a given shareholder resolution if it would be considered a related party for the purposes of the Listing Rules in respect of that shareholder resolution. As a result, in addition to its right under the Relationship Agreement to nominate up to two non-executive directors to the Board, Delek will possess sufficient voting power to have a significant influence over all matters requiring shareholder approval, including in relation to the election of directors, dividend policy, remuneration policy and approval of significant corporate transactions. As such, Delek may be able to exercise significant influence over the Board and the Company but it will not be under any obligation to act in the best interests of the Company, other Shareholders or other stakeholders.

4.2 **The Company's ability to pay dividends in the future depends, among other things, on the Group's financial performance and capital requirements and compliance with the terms of the Group's financing arrangements and is therefore not guaranteed.**

There can be no guarantee that the Group's historic performance will be repeated in the future, particularly given the competitive nature of the industry in which it operates, and its sales, profit and cash flow may significantly underperform market expectations. The Group is impacted by prices of oil and gas and, if the Group's cash flow deteriorates, then the Company's capacity to pay a dividend will suffer.

The Company is a holding company with no independent operations and is depending on earnings and distributions of funds from its operating subsidiaries for cash, including in order to pay dividends to Shareholders.

The terms of the 2026 Notes include restrictions on the ability of IEEPL, and certain subsidiaries, to make payments (including distribution and dividend payments) to the Company by, amongst other things, limiting the amount of such payments. Certain exceptions to this restriction exist, including, subject to other requirements, permitted payments in an amount equal to $100 million for each twelve months passed since 30 July 2021 or 50% of the consolidated net income of IEEPL for the specified period provided that the consolidated leverage ratio of IEEPL does not exceed 0.6:1. In addition, there are a number of other exceptions available and payments not prohibited by the restrictions contained in the terms of the 2026 Notes. Further, the Company will pay the IPO Expenses and the Selling Shareholder's Expenses with amounts received from payments from IEEPL and/ or certain Subsidiaries. This will reduce the amount of permitted payments available under the terms of the 2026 Notes, which may have otherwise have been available to enable the Company to make dividend payments to Shareholders. However, there can be no assurance that any of the exceptions will be available in order to allow the Company to make the dividend payments which it expects to make, or at all. Consequently, if the Group is unable to successfully refinance its existing capital structure, the terms of the 2026 Notes may restrict the Group's ability to make, or the amount of, any future dividend payments.

The RBL Facility Agreement also includes restrictions on the ability of IEUK, and certain subsidiaries, to make distributions (including dividend payments) to the Company. The right to make a distributions falls at the end of the proceeds account waterfall which requires the payment of various items before an obligor is entitled to make a distributions including (but not limited to) finance party fees, costs and expenses, hedging costs and accrued interest. Such a distribution can then only be made if certain standard conditions (including, but not limited to, there being no continuing event of default and the aggregate US dollar amount of the outstanding utilisations not exceeding the maximum available amount) are met. In addition, on each date on which IEUK intends to make a distributions it must demonstrate that (i) its total corporate sources exceed its total corporate uses in each quarter of the relevant forecast period; and (ii) the obligors have sufficient freely available funds to meet any decommissioning security obligations in respect of the borrowing base assets for the period ending three years from that date, otherwise an event of default will occur.

As a matter of English law, the Company can pay dividends only to the extent that it has sufficient distributable reserves available, which depends upon the Company receiving cash from its operating Subsidiaries in a manner which creates distributable reserves. The Company's ability to pay dividends to Shareholders depends on its future profitability and the ability to distribute or dividend profits from its operating subsidiaries up the Group structure to the Company. The Group's distributable reserves can be affected by reductions in the profitability as well as by impairment of assets.

Any decision to declare and pay dividends will be made at the discretion of the Directors and will depend on, among other things, applicable law, regulation, restrictions, compliance with the terms of the Group's financing arrangements, the Group's financial position, working capital requirements, finance costs, general economic and political conditions, changes in realised oil and gas prices and production, the success of the Company's development activities across its asset base, and other factors the Directors deem significant from time to time.

4.3 **The market price of the Ordinary Shares could be negatively affected by sales of substantial amounts of such Ordinary Shares in the public markets, including a sale by Delek.**

Following Admission, Delek is expected to beneficially own approximately 89.4% of the Group's issued ordinary share capital, assuming no exercise of the Over-allotment Option, and approximately 87.9% if the Over-allotment Option is exercised in full. The Company, the Selling Shareholder, the Directors and certain members of the Company's management team are subject to restrictions on the issue, sale or transfer, as applicable, of their respective holdings in the Group's issued share capital. The issue or sale of a substantial number of Ordinary Shares by the Group, the Selling Shareholder, the Directors or certain members of the Company's management team in the public market after the lock-up restrictions in the Underwriting and Sponsors' Agreement and related arrangements expire (or are waived by the JGCs), or the perception that these sales may occur, may adversely affect the market price of the Ordinary Shares. In particular, the sale or a perception of the likelihood of a sale of a substantial amount of Ordinary Shares directly or indirectly held by Delek may depress the market price of the Ordinary Shares and could impair the Group's ability to raise capital through the sale of additional equity securities which could in turn have an adverse effect on the trading price of the Ordinary Shares.

4.4 **Following Admission, Delek may increase its interest in the Company without incurring any obligation to make a mandatory offer to all Shareholders so long as it retains over 50% voting control.**

From Admission, for so long as Delek and persons acting in concert with Delek continue to be interested in Ordinary Shares carrying over 50% of the Company's voting rights, Delek (and any persons acting in concert with Delek) will be free to acquire further shares in the Company without incurring any obligation under Rule 9 of the Code to make a mandatory offer to all Shareholders (subject to the considerations in Note 4 on Rule 9.1 of the Code, including whether any individual member of Delek's concert party, other than Delek, increases its percentage interest in voting rights through 30%).

4.5 **Changes in the approach by investors to companies with exposure to the oil and gas industry could have a negative impact on investor demand for the Ordinary Shares.**

There have also been efforts in recent years aimed at the investment community, including investment advisors, sovereign wealth funds, public pension funds, universities and other groups, promoting the divestment of equities issued by companies connected to fossil fuels as well as to pressure lenders and other financial services companies to limit or curtail activities with companies similarly connected. If these efforts are successful, and if the Group's business is deemed to be sufficiently tied to the use of fossil fuels by such communities, its ability to access capital markets may be limited and its stock price may be negatively impacted.

Further, members of the investment community have recently increased their focus on sustainability practices with regard to the oil and gas industry, including practices related to greenhouse gas emissions and climate change. An increasing percentage of the investment community considers sustainability factors in making investment decisions and an increasing number of entities consider sustainability factors in awarding business. If the Group is unable to appropriately address sustainability enhancement, it may lose customers, partners, its stock price may be negatively impacted, its reputation may be negatively affected, and it may be more difficult for it to effectively compete.

4.6 **There is no existing market for the Ordinary Shares and an active trading market for the Ordinary Shares may fail to develop or be sustained.**

Prior to the Global Offering and Admission, there has been no public trading market for the Ordinary Shares. There can be no assurance that an active trading market will develop or, if it does develop, that it will be maintained. The Group cannot guarantee that investors will be able to (re)sell their Ordinary Shares at or above the Offer Price, or at all. An inactive market may also impair the Group's ability to raise equity capital in the future by further issues of Ordinary Shares in the long-term. Furthermore, the concentration of ownership in the hands of Delek may reduce the liquidity of the market for Ordinary Shares on the London Stock Exchange. If an active and liquid trading market or market demand does not develop or is not sustained, the liquidity and trading price of the Ordinary Shares could be materially and adversely affected, and investors may have difficulty selling their Ordinary Shares.

4.7 **Admission may fail to occur when expected.**

Admission is subject to the approval (and subject to satisfaction of any conditions on which such approval is expressed) of the FCA and Admission will become effective as soon as a dealing notice has been issued by the FCA and the London Stock Exchange has acknowledged that the Ordinary Shares will be admitted to trading. There can be no guarantee that any conditions to which Admission is subject will be met or that the FCA will issue a dealing notice when anticipated.

4.8 **The Ordinary Shares will be subject to market price volatility and the market price of the Ordinary Shares may decline disproportionately in response to developments that are unrelated to the Group's operating performance.**

The Offer Price is not indicative of the market price of the Ordinary Shares following Admission. The Ordinary Shares will be subject to market price volatility and the market price of the Ordinary Shares may decline in response to developments that are unrelated to the Group's operating performance. The market price of the Ordinary Shares may be volatile and subject to wide fluctuations because of a variety of factors, including but not limited to, those referred to in this Part 2 (*Risk Factors*), as well as period-to-period variations in operating results or changes in revenue or profit estimates by the Group, industry participants or financial analysts. Shareholders may experience fluctuations in the market price of the Ordinary Shares as a result of, amongst other factors, movements in the exchange rate between pounds sterling, the euro and the US dollar.

Markets have, from time to time, experienced significant price and volume fluctuations that have affected market prices for securities and which may be unrelated to the Group's operating performance or prospects. The market price of the Ordinary Shares could also be affected by developments unrelated to the Group's operating performance, such as the operating and share price performance of other companies that investors may consider comparable to the Group, business developments of the Group or the industry, speculation about the Group in the press or the investment community, unfavourable press, strategic actions by competitors (including acquisitions or restructurings) changes in market conditions (particularly in commodity prices), regulatory changes, changes in the UK political environment (particularly regarding the oil and gas industry), litigation against the Group which is commenced or threatened, use of investment strategies by the investment community such as shorting and investor appetite for, or views with regard to, listed equity. Prospective investors should not rely on the Group's results to date as an indication of future performance. Investors may not be able to sell their Ordinary Shares at or above the Offer Price and Shareholders may earn a negative or no return on their investment in the Group.

4.9 **Pre-emptive rights may not be available to Overseas Shareholders.**

Under the Articles (save for certain exceptions set out therein) and pursuant to the Listing Rules, prior to the issue of any new shares, holders of Ordinary Shares generally have pre-emptive rights to subscribe and pay for a sufficient number of Ordinary Shares to maintain their existing ownership percentages, unless such rights are dis-applied by a shareholder resolution.

In connection with the Global Offering, the share capital of the Company will be increased and new Ordinary Shares will be issued. In addition, further share capital increases and share issues may be proposed in the future. Shareholders are entitled to pre-emptive rights in respect of new issues of Ordinary Shares for cash unless those rights are waived by a Shareholders' resolution.

Overseas Shareholders may not be able to exercise their pre-emptive rights as part of a future issue of shares for cash (even if pre-emptive rights were not waived) unless the Company decides to comply with applicable local securities laws and regulations. This is because the securities laws of certain jurisdictions may restrict the Company's ability to allow participation by certain Shareholders in any future issue of shares or offering. In particular, Overseas Shareholders who are located in the United States may not be able to exercise their rights on a future issue of shares, unless either the Ordinary Shares and any other securities that are offered and sold are registered under the US Securities Act, or the Ordinary Shares and such other securities are offered pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the US Securities Act. The Company cannot assure prospective investors that any exemption from such overseas securities law requirements would be available to enable US or other shareholders to exercise their pre-emptive rights or, if available, that the Company would utilise any such exemption. The Ordinary Shares are not and will not be registered under the US Securities Act and the Company may not file any such registration statements for future share issues, and an exemption from the registration requirements of the US Securities Act may not be available. In such an event, Overseas Shareholders who are located in the United States would be unable to participate in such an issue.

4.10 **The ability of Overseas Shareholders to bring actions or enforce judgments against the Group or its directors or officers may be limited.**

The Company is a public limited company incorporated in England and Wales. The rights of holders of the Ordinary Shares are governed by English law and the Articles. Not all rights available to shareholders under US law or other non-UK laws may be available to holders of the Ordinary Shares. Rights afforded to shareholders under English law may differ in certain respects from the rights of shareholders in typical US companies and some other non-UK corporations. In particular, English law currently limits significantly the circumstances under which the shareholders of English companies may bring derivative actions. Under English law, in most cases, only the Company may be the proper plaintiff for the purposes of maintaining proceedings in respect of wrongful acts committed against it and, generally, neither an individual shareholder, nor any group of shareholders, has any right of action in such circumstances. In addition, English law does not afford appraisal rights to dissenting shareholders in the form typically available to shareholders in a US company or other non-UK corporations. Shareholders may not be able to bring or enforce any judgments in civil and commercial matters or any judgments under the securities laws of countries other than the

United Kingdom against the Company and its directors and officers who are residents of the United Kingdom or countries other than those in which judgment is made, and it may not be possible for investors outside the United Kingdom to effect service of process outside the United Kingdom against the Company and its directors and officers.

4.11 **The issuance of additional Ordinary Shares in the Company in connection with future acquisitions or other growth opportunities, any share incentive or share option plan or otherwise may dilute all other shareholdings.**

The Group may seek to raise financing to fund future acquisitions and other growth opportunities. The Group may, for these and other purposes, issue additional equity or convertible equity securities. In addition, the exercise of share options by the Group's employees in the context of existing or future share incentive or share option plans or the issuance of new shares to employees in the context of employee equity programs, such as Ithaca Energy Long Term Incentive Plan, Ithaca Energy Deferred Share Bonus Plan, Ithaca Energy Share Incentive Plan and the MEP for the benefit of Gilad Myerson, could lead to such dilution. In particular, under the MEP for the benefit of Gilad Myerson, subject to certain conditions, Mr Myerson may receive further Ordinary Shares so as to ensure that the aggregate value of Ordinary Shares received by him under such plan is maintained at 1.3% of the value of the Company above a fixed hurdle of $2.5 billion. As a result, existing holders of Ordinary Shares may suffer dilution in their percentage ownership or the market price of the Ordinary Shares may be adversely affected.

4.12 **The ability of Shareholders to sell their Ordinary Shares, particularly in a takeover, may be negatively affected by the UK National Security and Investment Act.**

On 4 January 2022, the UK National Security and Investment Act (the "**UK NS&I Act**") came into force, which, amongst other things, requires that acquisitions of shares or voting rights above certain thresholds in entities in specified sensitive sectors ("**notifiable acquisitions**") will be subject to mandatory notification to BEIS. The list of relevant sectors includes the energy sector and therefore would capture the Group.

Acquisitions of shares or voting rights in qualifying entities within the specified sectors are subject to a mandatory notification requirement where a 'trigger event' takes place: where a person acquires shares or voting rights such that their shareholding or percentage of voting rights in the qualifying entity would increase through certain thresholds, namely 25%, 50% or 75%, or the acquisition would enable that person to either secure or prevent resolutions governing the affairs of the entity. Acquisitions of 'material influence' in an entity (for example a lower shareholding than 25%) can also be reviewed by BEIS. The UK NS&I Act gives BEIS a general power to review transactions which raise national security concerns, and as a result the UK NS&I Act provides that transactions may be voluntarily notified where there is a potential national security concern. Where transactions are notified to BEIS, the Secretary of State has broad information gathering powers, is able to impose interim remedies and where a national security risk is identified, is able to impose remedies to mitigate that risk, which may include prohibiting the transaction or imposing certain conditions.

Such additional regulatory scrutiny could therefore make it more difficult for a buyer, particularly a non-UK person where there may be national security concerns (for example, because of the nationality of such person or its links to persons or entities viewed to be hostile to the UK), to acquire a significant shareholding in the Company or make a successful takeover offer for the Group. This could therefore have an adverse effect on the trading price of the Ordinary Shares, and Shareholders may be unable to sell their Ordinary Shares at a price they may otherwise have been willing to accept.

4.13 **Overseas shareholders may be subject to exchange rate risk.**

The Ordinary Shares are denominated in pounds sterling. Any dividend to be paid in respect of the Ordinary Shares will be denominated in USD. An investment in Ordinary Shares by an investor whose principal currency is not pounds sterling or USD exposes the investor to foreign currency exchange rate risk. Any depreciation of pounds sterling or USD in relation to such foreign currency will reduce the value of the investment in the Ordinary Shares or any dividends in foreign currency terms.

4.14 **US investors may suffer adverse tax consequences if the Company is characterised as a passive foreign investment company ("PFIC").**

In general, a corporation organised or incorporated outside the United States is a PFIC in any taxable year in which either: (a) at least 75% of its gross income is classified as "passive income" (the "**income test**"); or (b) at least 50% of the average quarterly value attributable to its assets produce or are held for the production of passive income (the "**asset test**"). Passive income for this purpose generally includes dividends, interest, royalties, rents and gains from commodities and securities transactions. Passive income generally excludes active business gains arising from the sale of commodities, if substantially all (85% or more) of a foreign corporation's commodities are stock in trade or inventory, real and depreciable property used in a trade or business, or supplies regularly used or consumed in a trade or business, and certain other requirements are satisfied. For the purposes of the above calculations, a non-US corporation that directly or indirectly owns at least 25% by value of the stock of another corporation is treated as if it held its proportionate share of the assets of such other corporation and received directly its proportionate share of the income of such other corporation.

Based on the present nature of its activities, including the Global Offering, and the present composition of its assets and sources of income, the Company does not believe it was a PFIC for the 2021 taxable year or expect to be a PFIC for the current taxable year or for the foreseeable future. There can be no assurances, however, that the Company will not be considered a PFIC for any particular year because PFIC status is factual in nature, generally cannot be determined until the close of the taxable year in question, and will depend on, among other things, the ownership and the composition of the income and assets, as well as the market value of the assets, of the Company and its subsidiaries from time to time. Therefore, there can be no certainty as to the Company's status for any given year and changes in the nature of the Company's income or assets may cause it to be considered a PFIC in the current or any subsequent year. The Company believes that it currently qualifies, and expects to continue to qualify in the future, for the active commodities business exception for purposes of the PFIC asset test and income test. Each US Holder is urged to consult its own tax adviser regarding the applicability of the rules regarding commodities in the PFIC context. If the Company were classified as a PFIC in any year that a US Holder is a shareholder, the Company generally will continue to be treated as a PFIC for that US Holder in all succeeding years, regardless of whether the Company continues to meet the income or asset test described above, unless the holder makes certain elections under PFIC rules.

If the Company were treated as a PFIC for any taxable year during which a US Holder holds Ordinary Shares, certain adverse US federal income tax consequences could apply to such US Holder, including increased tax liability on disposition gains and certain "excess distributions" and additional reporting requirements. See paragraph 2.4 (*Passive Foreign Investment Company Rates*) of Part 19 (*Taxation*) for further information. Each US Holder is urged to consult its own tax advisor concerning the US federal income tax consequences of holding Ordinary Shares if the Company were to be a PFIC in any taxable year during its holding.

PART 3

PRESENTATION OF FINANCIAL AND OTHER INFORMATION

1. GENERAL

Investors should only rely on the information in this Prospectus. No person has been authorised to give any information or to make any representations concerning the Company, the Group, the Global Offering or the Offer Shares (other than those contained in this Prospectus) and, if given or made, such information or representations must not be relied upon as having been authorised by or on behalf of the Company, the Directors, the Selling Shareholder or the Underwriters. No representation or warranty, express or implied, is made by any of the Underwriters or any of their respective representatives or affiliates as to the accuracy, completeness or verification of such information, and nothing contained in this Prospectus is, or shall be relied upon as, a promise or representation by the Underwriters, or any of their respective representatives or affiliates in this respect, whether or not to the past, present or future. The Underwriters assume no responsibility for the accuracy, completeness or verification of the information in this Prospectus and accordingly disclaim, to the fullest extent permitted by applicable law, any and all liability whether arising in tort, contract or otherwise which they might otherwise be found to have in respect of this Prospectus or any such statement. Without prejudice to any obligation of the Company to publish a supplementary prospectus pursuant to Article 23 of the UK Prospectus Regulation and Rule 3.4 of the Prospectus Regulation Rules, neither the delivery of this Prospectus nor any subscription for or sale of Offer Shares pursuant to the Global Offering shall, under any circumstances, create any implication that there has been no change in the business or affairs of the Group since the date of this Prospectus, or that the information contained herein is correct as at any time subsequent to its date.

A copy of this Prospectus has been filed with, and approved by, the FCA and has been made available to the public in accordance with the UK Prospectus Regulation.

The Company will update the information provided in this Prospectus by means of a supplement if a significant new factor that may affect the evaluation by prospective investors of the Global Offering occurs prior to Admission or if this Prospectus contains any material mistake or material inaccuracy. This Prospectus and any supplement will be subject to approval by the FCA and will be made public in accordance with the Prospectus Regulation Rules. If a supplement to this Prospectus is published prior to Admission, investors shall have the right to withdraw their applications for Offer Shares made prior to the publication of the supplement. Such withdrawal must be made within the time limits and in the manner set out in any such supplement (which shall not be shorter than two clear Business Days after publication of the supplement).

The contents of this Prospectus are not to be construed as legal, tax, business and/or financial advice. Each prospective investor should consult his or her or its advisers as to the legal, tax, business, financial and related aspects of subscribing for or purchasing Offer Shares. In making an investment decision, each investor must rely on his or her or its own examination, analysis and enquiry of the Company, the Ordinary Shares and the terms of the Global Offering, including the merits and risks involved.

Prior to making any decision as to whether to subscribe for the Offer Shares, prospective investors should read this Prospectus. Investors should ensure that they read the whole of this Prospectus and not just rely on key information or information summarised within it. Investors who subscribe for Offer Shares in the Global Offering will be deemed to have acknowledged that: (i) they have not relied on the Underwriters, or any person(s) affiliated with any of the Underwriters, in connection with any investigation of the accuracy of any information contained in this Prospectus or their investment decision; (ii) they have relied solely on the information contained in this Prospectus; and (iii) that no person has been authorised to give any information or to make any representation concerning the Company or its Subsidiaries or the Offer Shares (other than as contained in this Prospectus) and, if given or made, any such other information or representation should not be relied upon as having been authorised by the Company or the Underwriters.

None of the Company, the Directors, the Selling Shareholder, the Underwriters, or any of their respective affiliates or representatives is making any representation to any offeree, subscriber or purchaser of the Ordinary Shares regarding the legality of an investment by such offeree, subscriber or purchaser.

In connection with the Global Offering, each of the Underwriters, and/or any of their respective representatives and/or affiliates, may take up a portion of the Offer Shares in the Global Offering as a principal position and in that capacity, may retain, purchase, sell, offer to sell or otherwise deal for its or their own account(s) in such Offer Shares and other securities of the Company or related investments in connection with the Global Offering or otherwise. Accordingly, references in this Prospectus to the Offer Shares being issued, offered, subscribed, acquired, placed or otherwise dealt in should be read as including any issue or offer to, or subscription, acquisition, dealing or placing by, any of the Underwriters and any of their respective representatives and affiliates acting as an investor for its or their own account(s). In addition certain of the Underwriters or their affiliates may enter into financing arrangements (including swaps, warrants or contracts for differences) with investors in connection with which such Underwriters (or their affiliates) may from time to time acquire, hold or dispose of Ordinary Shares. The Underwriters do not intend to disclose the extent of any such investment or transactions otherwise than in accordance with any legal or regulatory obligations to do so.

2. HISTORICAL FINANCIAL INFORMATION

Unless otherwise indicated, the historical financial information, which is Part 16 (*Historical Financial Information*) and is covered by the accountants' reports included in Part A of each of Sections A (*The Group*), B (*The Siccar Point Group*) and C (*IOG*) of Part 16 (*Historical Financial Information*) (the "**Historical Financial Information**"), was prepared in accordance with the International Financial Reporting Standards as adopted by the UK ("**IFRS**"). The basis of preparation is explained in more detail below and in Part 16 (*Historical Financial Information*). The Historical Financial Information has been prepared in accordance with the requirements of the UK Prospectus Regulation.

Each of the Company's, IOG's and Siccar Point's financial year is the calendar year.

None of the financial information used in this Prospectus has been audited in accordance with auditing standards generally accepted in the United States of America ("**US GAAS**") or auditing standards of the Public Company Accounting Oversight Board (United States) ("**PCAOB**"). Accordingly, it would not be possible to express any opinion on the Historical Financial Information in Part 16 (*Historical Financial Information*) under US GAAS or the auditing standards of the PCAOB.

In addition, there are differences between the auditing standards issued by the Auditing Practices Board in the United Kingdom and those required by US GAAS or the auditing standards of the PCAOB. Potential investors should consult their own professional advisers to gain an understanding of the Historical Financial Information in Part 16 (*Historical Financial Information*) and the implications of differences between the auditing standards noted herein.

2.1 *Company*

The Company was incorporated and registered in England and Wales on 15 October 2019 under the 2006 Act as a private company limited by shares under the name "Delek North Sea Limited" with company number 12263719. It changed its name to "Ithaca Energy Limited" on 7 October 2022 and to "Ithaca Energy plc" on 1 November 2022 when it was re-registered as a public limited company. The principal activity of the Company has been to act as a holding company of the Group.

2.2 *The Company and the Group*

Section A (*The Group*) of Part 16 (*Historical Financial Information*) includes audited historical financial information of the Group for the six month period ended 30 June 2022 and for each of the years ended 31 December 2021, 2020 and 2019 (the "**Group Financial Information**"). The word "**Group**" refers to the Company (together with its Subsidiaries) on a consolidated basis.

The consolidated financial data of the Group for the periods and as at the dates presented reflect that: (i) on 8 November 2019, the Group completed the Chevron Acquisition; (ii) on 4 February 2022, the Group completed the Marubeni Acquisition; (iii) on 30 June 2022, the Group completed the Summit Acquisition; and (iv) on 30 June 2022, the Group completed the Siccar Point Acquisition, with relevant assets then being fully consolidated into the consolidated financial data of the Group. As a result, the financial information for such periods and for further periods may not be directly comparable with the Group Financial Information presented in this Prospectus.

2.3 ***Siccar Point Group***

Section B (*The Siccar Point Group*) of Part 16 (*Historical Financial Information*) contains the audited consolidated financial information of the Siccar Point Group for the six month period ended 30 June 2022 and for the years ended 31 December 2019, 2020 and 2021 (the "**Siccar Point Financial Information**").

On 30 June 2022, the Group acquired the entire issued share capital of SPEHL, with the Siccar Point Assets then being fully consolidated into the consolidated financial data of the Group. As a result of the Siccar Point Acquisition, the Group's financial information included in this document, including in Part 9 (*Selected Financial Information*) and Section A (*The Group*) of Part 16 (*Historical Financial Information*), does not include the financial information for the Siccar Point Group for the period from 1 January 2019 through 29 June 2022, which affects the comparability of the Group's results. In order to present in full all material financial results for the businesses now constituting the Group across the entire review period from 1 January 2019 to 30 June 2022, Part 9 (*Selected Financial Information*) and Section B (*The Siccar Point Group*) of Part 16 (*Historical Financial Information*) contains the Siccar Point Financial Information.

2.4 ***IOG***

Section C (*IOG*) of Part 16 (*Historical Financial Information*) includes the financial statements of IOG (formerly Chevron North Sea Limited) as at and for the year ended 31 December 2019 ("**IOG Financial Information**").

On 8 November 2019, the Group acquired the entire issued share capital of IOG with the Chevron Acquired Assets then being fully consolidated into the consolidated financial data of the Group. As a result of the Chevron Acquisition, the Group's Financial Information included in this document, including in Part 9 (*Selected Financial Information*) and Section A (*The Group*) of Part 16 (*Historical Financial Information*), does not include the financial information for IOG for the period from 1 January 2019 through 7 November 2019, which affects the comparability of the Group's results. In order to present in full all material financial results for the business now constituting the Group across the entire review period from 1 January 2019 to 30 June 2022, this document includes the standalone IOG audited financial statements for the year ended 31 December 2019. For the year ended 31 December 2020 and subsequent reporting periods, the financial information of IOG was consolidated in the Historical Financial Information of the Group and presented under IFRS. The financial information and data in respect of IOG included herein are not intended to represent the results had the Chevron Acquired Assets been operated as a standalone business for the period indicated.

The IOG Financial Information included in Section C (*IOG*) of Part 16 (*Historical Financial Information*) and the accompanying notes thereto have been prepared in accordance with the basis of preparation presented in Note 2 thereto.

2.5 ***Marubeni***

On 4 February 2022, the Group acquired the entire issued share capital of MOGL from MNSL with the Marubeni Assets then being fully consolidated into the consolidated financial data of the Group. As a result of the Marubeni Acquisition, the Group's consolidated historical financial information included in this document, including in Part 9 (*Selected Financial Information*) and Section A (*The Group*) of Part 16 (*Historical Financial Information*), does not include the financial information for MOGL for the period from 1 January 2019 through 3 February 2022, which affects the comparability of the Group's results.

2.6 ***Summit***

On 30 June 2022, the Group acquired the entire issued share capital of Summit from Sumitomo, with the Summit Assets then being fully consolidated into the consolidated financial data of the Group. As a result of the Summit Acquisition, the Group's consolidated historical financial information included in this document, including in Part 9 (*Selected Financial Information*) and Section A (*The Group*) of Part 16 (*Historical Financial Information*), does not include the financial information for Summit for the period from 1 January 2019 through 29 June 2022, which affects the comparability of the Group's results.

3. PRO FORMA FINANCIAL INFORMATION

The unaudited pro forma income statements for the six months ended 30 June 2022 and the year ended 31 December 2021 of the Group set out in Part 17 (*Unaudited Pro Forma Condensed Combined Financial Information*) (the "**Unaudited Pro Forma Condensed Combined Financial Information**") have been prepared in accordance with Annex 20 of the UK Prospectus Regulation.

The Unaudited Pro Forma Condensed Combined Financial Information has been prepared to illustrate the effect on the consolidated earnings of the Group for the six month period ended 30 June 2022 and for the year ended 31 December 2021 as if the Siccar Point Acquisition had taken place on 1 January 2022 and 1 January 2021, respectively.

The Unaudited Pro Forma Condensed Combined Financial Information has been prepared for illustrative purposes only. The hypothetical financial position or results included in the Unaudited Pro Forma Condensed Combined Financial Information may differ from the Group's actual results.

The Unaudited Pro Forma Condensed Combined Financial Information has been prepared on the basis set out in the notes in Part 17 (*Unaudited Pro Forma Condensed Combined Financial Information*) and has been prepared in a manner consistent with the accounting policies that will be applied by the Group for the year ending 31 December 2022 and in accordance with the requirements of sections 1 and 2 of Annex 20 of the UK Prospectus Regulation.

The Unaudited Pro Forma Condensed Combined Financial Information does not constitute financial statements within the meaning of section 434 of the 2006 Act. Deloitte LLP's accountant's report on the Unaudited Pro Forma Condensed Combined Financial Information is set out in Part B (*Accountant's Report on the Unaudited pro forma condensed combined financial information*) of Part 17 (*Unaudited Pro Forma Condensed Combined Financial Information*).

4. NON-IFRS FINANCIAL INFORMATION

This Prospectus contains certain financial measures that are not defined or recognised under IFRS, in particular: Adjusted EBITDAX, net debt, net debt to Group Adjusted EBITDAX, net debt to LTM Adjusted EBITDAX, unit operating expenditure, Free Cashflow and Available Liquidity each of which is defined below. The Directors believe that each of these measures provides important supplemental information with respect to the performance of the Group's business and operations.

These non-IFRS financial measures are unaudited and are not measures recognised under IFRS or any other internationally accepted accounting principles, and prospective investors should not consider such measures as an alternative to the IFRS measures included in the Group's Historical Financial Information contained in Part 16 (*Historical Financial Information*). The management of the Group use these measures to calculate operating performance and liquidity, in presentations to the Board and as a basis for strategic planning and forecasting, as well as monitoring certain aspects of the Group's operating cash flow and liquidity. These non-IFRS measures and ratios are presented because management believes that they and similar measures are widely used by certain investors, securities analysts and other interested parties as supplemental measures of performance and liquidity. These non-IFRS measures and ratios may not be comparable to other similarly titled measures of other companies and have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of the Group's operating results as reported under IFRS.

The financial information for the last twelve months ("**LTM**") ended 30 June 2022 set forth in this Prospectus was derived by adding the Company's financial information for the year ended 31 December 2021 to its interim financial information for the six months ended 30 June 2022 and subtracting its financial information for the six months ended 30 June 2021.

The financial information for the LTM ended 30 June 2022 has not been audited or reviewed by the Group's auditors and is not required by, or presented in accordance with, IFRS or any other generally accepted accounting principles and has been prepared for illustrative purposes only. This information is not necessarily representative of the Group's results of operations for such period or any future period or any financial position at any past or future date.

An explanation of the relevance of each of the non-IFRS measures to the most directly comparable measures calculated and presented in accordance with IFRS and a discussion of their limitations is set out below.

- Adjusted EBITDAX is presented for each of the Group and the Siccar Point Group and is calculated for each as set out below:
  - "**Group Adjusted EBITDAX**" consists of profit for the period before income tax, net finance costs, put premiums on oil derivative instruments, put premiums on gas derivative instruments, revaluation of forex forward contracts, revaluation of commodity hedges, depletion, depreciation and amortisation, impairment (charge) / reversal, exploration and evaluation expenses, fair value gain / (losses) on contingent consideration, gain on bargain purchase, transaction costs and employee voluntary redundancy programme. Transaction costs and employee voluntary redundancy programme include costs that are not considered to be representative of underlying operations. This is used as an indicator of underlying financial performance.
  - "**Siccar Point Adjusted EBITDAX**" consists of profit for the period before income tax, net finance costs, unrealised gain / (loss) from hedging, depletion, depreciation and amortisation, impairment charge / reversal, exploration and evaluation expenses and fair value gain / (loss) on contingent consideration.
- "**Net debt**" consists of amounts outstanding under the RBL Facility and the senior unsecured notes less cash and cash equivalents. Net debt does not include intragroup debt arrangements or liabilities represented by letters of credit or surety bonds. This is used as an indicator of the Group's indebtedness and contribution to capital structure.
- The ratio of "**net debt to Group Adjusted EBITDAX**" is calculated as net debt as at the end of the period divided by Group Adjusted EBITDAX as at the end of the corresponding period. This is a useful indicator of the debt capacity of the Group.
- The ratio of "**net debt to LTM Adjusted EBITDAX**" is calculated as net debt at the end of the last twelve month period divided by Group Adjusted EBITDAX for the twelve month period ended 30 June 2022. This is a useful indicator of the debt capacity of the Group.
- "**Unit operating expenditure**" consists of operating costs (excluding over / underlift) including tariff expense, less tariff income and tanker costs, divided by net total production for the period. This is a useful indicator of ongoing operating costs of the Group.
- Free Cashflow is presented for each of the Group and the Siccar Point Group and is calculated for each as set out below:
  - "**Group Free Cashflow**" consists of net cash flow from operating activities less net cash used in investing activities and reverse consideration on acquisitions, plus acquisition of subsidiaries net of cash acquired, less bank interest and charges and interest rate swaps, therefore representing net cash flow of the business before net proceeds of loan repayment, loan drawdown, payment for lease liabilities, bond issue, receipt from issue of equity to Delek, receipt from issue of notes to related company, and acquisition of subsidiaries and reverse consideration on acquisitions. This is a useful indicator of the Group's ability to

make strategic investments, repay the Group's debts and meet other payment obligations.

  - "**Siccar Point Free Cashflow**" consists of net cash flow from operating activities less net cash used in investing activities, less interest paid on long-term loans.

- "**Available Liquidity**" consists of the sum of cash and cash equivalents on the balance sheet less restricted cash and the undrawn amounts available to the Group using existing approved third party facilities. This is a useful indicator of the financial capacity of the Group.

Non-IFRS measures and ratios (including Adjusted EBITDAX, net debt, net debt to Adjusted EBITDAX, net debt to LTM Adjusted EBITDAX, unit operating expenditure, Free Cashflow and Available Liquidity) are not measurements of performance or liquidity under IFRS and do not provide a sufficient basis to compare the Group's performance with that of other companies and should not be considered in isolation or as a substitute or alternative to (i) operating profit, (loss) / profit from operations before tax and net finance costs, profit from continuing activities or (loss) / profit attributable to owners of the parent (as determined in accordance with IFRS) as a measure of the operating performance of the Group, the Company or the Siccar Point Group, (ii) cash flows from operating, investing and financing activities as a measure of the Company's or SPEHL's ability to meet its cash needs or (iii) any other measures of performance under IFRS or other generally accepted accounting principles.

A reconciliation of each of the non-IFRS measures to the most directly comparable measure calculated and presented in accordance with IFRS and discussion of its limitations is provided in Part 9 (*Selected Financial Information*). These measures are alternative performance measures as defined in the guidelines issued by the European Securities and Markets Authority on 5 October 2015 on alternative performance measures, as further described in the "Q&A on Alternative Performance Measures Guidelines" published in 17 April 2020 (together, the "**ESMA Guidelines**"). The Company believes that the presentation of the alternative performance measures included herein complies with the ESMA Guidelines.

Some of the limitations of Adjusted EBITDAX are:

- it does not reflect the Group's cash expenditures or future requirements for capital investments or contractual commitments;
- it does not reflect changes in, or cash requirements for, the Group's working capital needs;
- it does not reflect the significant interest expense, or the cash requirements necessary, to service interest or principal payments on the Group's debt;
- although depletion, depreciation and amortisation are non-cash charges, the assets being depleted, depreciated and amortised will often need to be replaced in the future and Adjusted EBITDAX does not reflect any cash requirements that would be required to make such replacements;
- it does not reflect the impact of certain cash charges resulting from matters the Group consider not to be indicative of the Group's underlying operations;
- it also doesn't include exploration and evaluation costs that are necessary to be incurred for the longer term sustainability of the business; and
- other companies in the Group's industry may calculate these measures differently from the way the Group do, limiting their usefulness as comparative measures.

Because of these limitations, Adjusted EBITDAX should not be considered in isolation or as a substitute or alternative to operating profit, profit from continuing activities or profit / (loss) attributable to owners of the parent (as determined in accordance with IFRS) as a measure of the operating performance of the Group. These limitations should be compensated by relying primarily on the Group's other IFRS results and using these non-IFRS measures only to supplement an evaluation of the Group's performance.

Some of the limitations of Free Cashflow are:

- it does not reflect any restrictions on the transfer of cash and cash equivalents within the Group;
- it does not reflect any requirement to repay the Group's borrowings;
- it does not take into account cash flows that are available from disposals or the issue of shares;
- it does not reflect dividend payments or the cost of acquisitions; and
- other companies in the Group's industry may calculate these measures differently from the way the Group do, limiting their usefulness as comparative measures.

Because of these limitations, Free Cashflow should not be considered as a measure of discretionary cash available to the Group to invest in the growth of the Group's business or as measures of cash that will be available to it to meet its obligations. These limitations should be compensated by relying primarily on the Group's other IFRS results and using these non-IFRS measures only to supplement an evaluation of the Group's performance.

Some of the limitations of unit operating expenditure are:

- it does not reflect the impact of depreciation on assets of the Group;
- it does not reflect the change in inventory of the respective period;
- it does not reflect the complete cost of oil production and additional costs necessary to sustain the output of the Group, which includes selling and distribution expense and administrative expenses; and
- other companies in the Group's industry may calculate these measures differently from the way the Group do, limiting their usefulness as comparative measures.

Because of these limitations, unit operating expenditure should not be considered in isolation or as an alternative to operating costs or cost of sales. These limitations should be compensated by relying primarily on the Group's other IFRS results and using these non-IFRS measures only to supplement an evaluation of the Group's performance.

5. RESERVES AND RESOURCES REPORTING

5.1 Certain Reserves, Contingent Resources and Production Information

Unless otherwise indicated, the oil and gas reserves data of the Group contained in Part 23 (*Competent Person's Report*) has been prepared by NSAI (the "**NSAI CPR**"). The NSAI CPR reflects NSAI's estimates of the Group's oil and gas reserves and resources as at 30 June 2022 and has been prepared in accordance with the recommendations of the FCA and the definitions and guidelines set forth in the 2018 Petroleum Resources Management System ("**2018 PRMS**") approved by the Society of Petroleum Engineers. NSAI has also prepared an estimate of the Group's asset base reserves and resources as at 31 December 2019, 2020 and 2021 (collectively, the "**NSAI Historic Reports**" and together with the NSAI CPR, the "**NSAI Reports**"). NSAI prepared the NSAI Historic Reports in accordance with the definitions and guidelines set forth in the 2018 PRMS and in accordance with internationally recognised standards, as stipulated by the Israel Securities Authority. As presented in the 2018 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources.

References in this Prospectus to "**1P reserves**" are to the Group's proved reserves. Pursuant to the classifications and definitions provided by the 2018 PRMS, "**proved reserves**" are defined as those quantities of petroleum which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. References to "**2P reserves**" are to the sum of the Group's proved reserves plus probable reserves. Pursuant to the classifications and definitions provided by the 2018 PRMS, "**probable reserves**" are defined as those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves. In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P reserves estimate. References to "**3P reserves**" are to the sum of the Group's proved reserves plus probable reserves plus possible reserves. Pursuant to the classifications and definitions provided by the 2018 PRMS, "**possible reserves**" are those additional reserves that analysis of geoscience and engineering data indicates, are less likely to be recoverable than probable reserves. Pursuant to the classifications and definitions provided by the 2018 PRMS, "**contingent resources**" are those quantities of petroleum estimated, as at a given date, to be potentially recoverable from known accumulations by the application of development projects not then considered to be commercial owing to one or more contingencies. Contingent resources have an associated chance of development and may include, for example, projects for which there are currently no viable markets or where commercial recovery is dependent on technology under development. References to "**2C resources**" are to the best estimate contingent resources, for which there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

Unless otherwise indicated, all production figures are presented on a net to the Group's working interest basis. Where gross amounts are indicated, they are presented on a total project basis—i.e., the total interests of all relevant licence holders in the relevant fields and licence areas without deduction for the economic interest of the Group's commercial partners, taxes or royalty interests or otherwise.

Prospective investors should not place undue reliance on the forward-looking statements in the NSAI CPR or on the ability of NSAI to predict actual reserves or resources. Contingent resources relate to undeveloped accumulations and may include non-commercial resources. Prospective resources relate to inferred, undiscovered and/or undeveloped mineral resources and accordingly by their nature are highly speculative. Prospective resources may not result in the successful discovery of economic resources in which case there would be no commercial development. The Group's legal interest and effective working interest in the relevant fields and licence areas are separately disclosed. See paragraph 6 (*Overview of Assets and Operations*) of Part 6 (*Business Overview*).

The information on resources in this Prospectus and in the NSAI CPR is based on economic and other assumptions that may prove to be incorrect. The basis of preparation for the NSAI CPR is set out in more detail in the report as contained in Part 23 (*Competent Person's Report*).

5.2 **Hydrocarbon Data**

The NSAI CPR referenced in this Prospectus uses the following estimates:

- oil and natural gas liquids in thousands of barrels ("**MBBL**") (a barrel being the equivalent of 42 US gallons). Oil volumes include crude oil and condensate; and
- natural gas in millions of cubic feet ("**MMCF**") at standard temperature and pressure bases.

This Prospectus presents certain production and reserves related information on an "equivalency" basis. The conversion of data for tons into barrels and from cubic feet into BOE may differ from that data used by other companies. Oil equivalent volumes showing in the NSAI CPR are expressed in thousands of barrels of oil equivalent ("**MBOE**"), determined using the ratio of 5.8 MCF of gas to 1 BBL of oil. These conversions are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent value equivalencies at the wellhead. Although these conversion factors are an industry accepted convention, they are not reflective of price or market value differentials between product types. Certain reserves figures set out in this Prospectus have been subject to rounding adjustments and, as a result, the totals of such reserves figures may vary slightly from the arithmetic totals of such figures.

There are a number of uncertainties inherent in estimating quantities of reserves and resources, including many factors beyond the Group's control. Such information represents only estimates and such estimates are forward looking statements which are based on judgments regarding future events that may be inaccurate. See paragraph 13 (*Information Regarding Forward-Looking Statements*) of this Part 3 (*Presentation of Financial and Other Information*). Estimation of reserves is a subjective process of estimating underground accumulations of oil and gas and natural gas liquids that cannot be measured in an exact manner. The accuracy of any reserves estimate is a function of a number of factors, many of which are beyond the Group's control, including the quality of available data, and involves engineering and geological interpretation and judgment. As a result, estimates of different engineers may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, due to the inherent uncertainties and the limited nature of reservoir data and the inherently imprecise nature of reserves estimates, the initial reserves estimates are often different from the quantities of oil and gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. In addition, contingent resources relate to undeveloped accumulations and may include non-commercial resources. Prospective resources relate to inferred, undiscovered and/or undeveloped mineral resources and accordingly by their nature are highly speculative. Prospective resources may not result in the successful discovery of economic resources in which case there would be no commercial development. Thus, prospective investors should not place undue reliance on the ability of the reserves reports prepared by NSAI to predict actual reserves or on comparisons of similar reports concerning other companies and this Prospectus should be accepted with the understanding that the Group's financial performance subsequent to the date of the estimates may necessitate revision of the reserves information set forth herein. In addition, except to the extent that the Group acquire additional properties containing reserves or conduct successful exploration and development activities, or both, the Group's reserves will decline as they are produced.

The basis of preparation for the NSAI CPR is set out in more detail in the report as contained in Part 23 (*Competent Person's Report*).

6. PRESENTATION IN NSAI CPR

The NSAI Reports were prepared using oil and gas price and cost parameters specified by the Group, further details of which are set out in the NSAI CPR.

The technical personnel at NSAI primarily responsible for preparing the reserves estimates in the NSAI Reports for each of the years ended 31 December 2019, 2020 and 2021 and as at 30 June 2022 meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the 2007 Standards pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE Society of Petroleum Engineers and referenced in the 2018 PRMS. NSAI personnel are independent petroleum engineers, geologists, geophysicists and petrophysicists. NSAI does not own an interest in the Group's properties and is not employed on a contingent fee basis.

7. CURRENCY PRESENTATION

Unless otherwise indicated, all references in this Prospectus to:

- "Euro" or "€" are to the single currency of the participating member states of the Third Stage of European Economic and Monetary Union of the Treaty Establishing the European Community, as amended from time to time;
- "ILS" are to the Israeli New Shekel, the lawful currency of Israel;
- "UK pounds sterling", "GBP", "£" or "pence" are the lawful currency of the United Kingdom; and
- "US dollars", "USD" or "$" are to the lawful currency of the United States.

8. **ROUNDING**

Certain data in this Prospectus, including financial, statistical and operating information, has been rounded. As a result of the rounding, the totals of data presented in this Prospectus may vary slightly from the actual arithmetic totals of such data. In certain statistical and operating tables contained in this Prospectus, the sum of numbers in a column or a row may not conform to the total figure given for that column or row. Percentages in tables have been rounded and accordingly may not add up to 100%.

9. **MARKET, ECONOMIC AND INDUSTRY DATA**

This Prospectus contains historical market, economic and industry data and forecasts which have been obtained from industry publications, market research and other publicly available information. Certain information regarding market size, market share, market position, growth rates and other industry data pertaining to the Group and its business contained in this Prospectus consists of the Directors' estimates and conclusions based on their review of internal Group data, third party data, multiple third party sources and reports produced by professional organisations and on data from other sources (and the Group's independent analysis of such data), including:

- International Monetary Fund;
- International Energy Agency;
- Offshore Energies UK (formerly Oil & Gas UK, a non-profit organisation whose members comprise oil and gas companies with active operations in the UKCS);
- NSTA (formerly the Oil and Gas Authority);
- bp plc;
- US Department of Energy;
- US Energy Information Administration;
- Rystad Energy;
- HM Treasury;
- Ice Futures Europe; and
- Thomas Reuters;

Industry publications, surveys and forecasts generally state that the information contained therein has been obtained from sources believed to be reliable, but that there can be no assurance as to the accuracy and completeness of such information. The Directors believe that these industry publications, surveys and forecasts are reliable, but none of the data from third party sources has been independently verified. Forecasts and other forward-looking information obtained from these sources are subject to the same qualifications and uncertainties as the other forward-looking statements in this Prospectus.

In some cases, there is no readily available external information to validate market related analyses and estimates, requiring the Group to rely on internally developed estimates. The Group does not intend, and does not assume any obligation, to update industry or market data set forth in this document. Because market behaviour, preferences and trends are subject to change, prospective investors should be aware that market and industry information in this document and estimates based on any data therein may not be reliable indicators of future market performance or the Group's future results of operations.

There can be no assurance that any of the assumptions underlying any statements regarding the oil and gas industry are accurate or correctly reflect the Group's position in the industry. Market data and statistics are inherently predictive and speculative and are not necessarily reflective of actual market conditions. Such statistics are based on market research, which itself is based on sampling and subjective judgments by both the researchers and the respondents, including judgments about what types of products and transactions should be included in the relevant market. In addition, the value of comparisons of statistics for different markets is limited by many factors, including that (i) the markets are defined differently, (ii) the underlying information was gathered by different methods and (iii) different assumptions were applied in compiling the data. Accordingly, the market statistics included in this Prospectus should be viewed with caution and no representation or warranty is given as to their accuracy.

Elsewhere in this Prospectus, statements regarding the oil and gas industry are not based on published statistical data or information obtained from independent third parties, but are based solely on the Group's experience, its internal studies and estimates, and the Group's investigation of market conditions. There can be no assurance that any of these studies or estimates are accurate, and none of the Group's internal surveys or information have been verified by any independent sources. While the Company is not aware of any misstatements regarding the Group's estimates presented herein, the estimates involve risks, assumptions and uncertainties and are subject to change based on various factors, including those discussed in Part 2 (*Risk Factors*).

10. PROFIT FORECASTS

Information in relation to the Profit Forecasts is included in Part 15 (*Profit Forecasts*). Other than the Profit Forecasts, no statement in this Prospectus is intended as a profit forecast or estimate and no statement in this Prospectus should be interpreted as a profit forecast or estimate.

11. REFERENCES TO DEFINED TERMS

This Prospectus refers variously to the "Group" and "Ithaca Energy", which is described and defined in note 1 of Part B (*Consolidated Historical Financial Information of Ithaca Energy*), Section A (*The Group*) of Part 16 (*Historical Financial Information*), and should be understood according to such definitions unless the context requires otherwise.

12. INFORMATION NOT CONTAINED IN THIS PROSPECTUS

No person has been authorised to give any information or make any representations other than those contained in this Prospectus and, if given or made, such information or representations must not be relied upon as having been so authorised. Neither the delivery of this Prospectus nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in the affairs of the Company since the date of this Prospectus or that the information in this Prospectus is correct as at any time subsequent to the date hereof.

13. INFORMATION REGARDING FORWARD-LOOKING STATEMENTS

This Prospectus includes forward-looking statements. These forward-looking statements involve known and unknown risks and uncertainties, many of which are beyond the Group's control and all of which are based on the Directors' current beliefs and expectations about future events. Forward-looking statements are sometimes identified by the use of forward-looking terminology such as "believe", "expects", "targets", "may", "will", "could", "should", "shall", "risk", "intends", "estimates", "aims", "plans", "predicts", "continues", "assumes", "positioned" or "anticipates" or the negative thereof, other variations thereon or comparable terminology. These forward-looking statements include all matters that are not historical facts. They appear in a number of places throughout this Prospectus and include statements regarding the intentions, beliefs or current expectations of the Directors or the Company concerning, among other things, the results of operations, financial condition, prospects, growth, strategies and dividend policy of the Company and the industry in which it operates. In particular, the statements under the headings "*Summary*", "*Risk Factors*", "*Business Overview*", "*Operating and Financial Review relating to the Group*" and "*Operating and Financial Review relating to the Siccar Point Group*" regarding the Company's strategy, targets and expectations in respect of the impact of the Group's production, expected revenue, Adjusted EBITDAX, oil and gas prices, profit, growth, accounting tax rates, operating expenditure, and capital expenditure upon the operating results of the Group as well as other expressions of the Group's targets and expectations and other future events or prospects are forward-looking statements.

The following include some but not all of the factors that could cause actual results or events to differ materially from the anticipated results or events:

- the prices of, and the supply and demand for, oil and gas;
- changes in the general global economic, financial market and business conditions, including, among other things, Russia's invasion of Ukraine, forecasted decline in global GDP, the impact of the current hyper inflationary environment and the potential resurgence of COVID-19 cases;
- production delays or interruptions in operations in the UKCS;
- exposure to regional supply and demand factors, adverse weather conditions, operational difficulties or regulations applicable to the UKCS (being the area in which the Group's business is concentrated);
- a lower level, quality or production volume of crude oil and/or gas reserves than estimated or expected;
- the dependence of the Group's future growth on the successful development of certain key fields in the Group's portfolio, including the Cambo and Rosebank fields;
- the timing and cost of the development of the Group's reserves and resources;
- capital expenditure programs, operating expenditure and other expenditures;
- failure to comply with obligations under contracts, licences, permits, operating agreements and relevant legislation;
- difficulty consummating or successfully integrating acquisitions;
- failure to compete effectively against other oil and gas exploration and production companies or in the domestic UK market;
- changes to, disagreements in respect of or termination of the offtake agreements;
- reliance on third-party pipelines and infrastructure, much of which has been in place for a number of years;
- failure to obtain or access necessary equipment, raw materials, third-party services and transportation systems;
- the occurrence of drilling, exploration and/or production risks or hazards including major pollution events;
- difficulties in retaining or hiring directors, key members of management, technical, exploration, financial and operational service providers;
- failure to replace reserves resulting in a reduction of reserves, production or revenues;
- any inability to fully utilise the Group's carried forward tax losses or the 'super-deduction' style investment allowance introduced by the Energy Profits Act (resulting in additional tax becoming due on ring-fence profits);
- claims or litigation brought against the Group, or any inability of the Group to bring successful claims or litigation against third parties;
- costs relating to compliance with, or liability under, health and safety and environmental regulations and unforeseen changes relating to such regulations;
- climate change abatement legislation, including the costs of complying with such legislation;
- inability to exercise control over certain activities for assets where the Group is not the operator;
- unanticipated increases in decommissioning obligations or the advancement of the anticipated timelines for carrying out such work;
- exposure to foreign exchange and inflation risks;
- changes in the licensing, regulatory and fiscal regimes in the United Kingdom; and

- increased taxes, audits by tax authorities and liabilities in respect of historic tax periods.

For more information regarding these and other uncertainties, please see Part 2 (*Risk Factors*).

These forward-looking statements speak only as at the date of this Prospectus. The information in this Prospectus will be updated as required by the Prospectus Regulation Rules, the Disclosure Guidance and Transparency Rules and the Listing Rules. Except as required by the Prospectus Regulation Rules, the Disclosure Guidance and Transparency Rules and the Listing Rules, or applicable law, the Company explicitly disclaims any obligation or undertaking publicly to release the result of any revisions to any forward-looking statements in this Prospectus that may occur due to any change in the Company's expectations or to reflect events or circumstances after the date of it.

Investors should note that the contents of these paragraphs relating to forward-looking statements are not intended to qualify the statements made as to the sufficiency of working capital in this Prospectus.

14. ADVICE

Prospective investors should not treat the contents of this Prospectus as advice relating to legal, taxation, investment or any other matters. Prospective investors should inform themselves as to: (a) the legal requirements within their own countries for the subscription, purchase, holding, transfer or other disposal of shares; (b) any foreign exchange restrictions applicable to the subscription, purchase, holding, transfer or other disposal of shares which they might encounter; and (c) the income and other tax consequences which may apply in their own countries as a result of the subscription, purchase, holding, transfer or other disposal of shares. Prospective investors must rely upon their own representatives, including their own legal or financial advisers and accountants, as to legal, taxation, investment or any other related matters concerning the Company and an investment therein. Statements made in this Prospectus are based on the law and practice currently in force in England and Wales and are subject to changes therein.

15. NO INCORPORATION OF WEBSITE INFORMATION

The contents of the Group's websites and any other website mentioned in this Prospectus or directly or indirectly linked to these websites do not form part of this Prospectus unless it is expressly incorporated by reference. The information on such websites have not been verified or approved by the FCA and investors should not rely on such information.

PART 4

DIRECTORS, COMPANY SECRETARY, REGISTERED OFFICE AND ADVISERS

Directors	Gilad Myerson	*Executive Chairman*
	Alan Alexander Bruce	*Chief Executive Officer*
	Iain Clifford Scobbie Lewis	*Chief Financial Officer*
	John Mogford	*Senior Independent Director*
	Idan Wallace	*Non-Executive Director*
	Deborah Jane Gudgeon	*Independent Non-Executive Director*
	Lynne Clow	*Independent Non-Executive Director*
	Assaf Ginzburg	*Independent Non-Executive Director*
	David John Blackwood CBE	*Independent Non-Executive Director*
Company Secretary	Julie McAteer	
Head Office Address	Hill of Rubislaw, Aberdeen, AB15 6XL	
Telephone Number	+44 (0) 1224 638 582	
Joint Sponsors, Joint Global Co-ordinators and Joint Bookrunners	Goldman Sachs International Plumtree Court 25 Shoe Lane London EC4A 4AU Morgan Stanley & Co International plc 20 Bank Street Canary Wharf London E14 4AD	
Joint Bookrunners	HSBC Bank PLC 8 Canada Square London E14 5HQ United Kingdom Jefferies International Limited 100 Bishopsgate London EC2N 4JL United Kingdom Jefferies GmbH Bockenheimer Landstrasse 24 60323 Frankfurt am Main Germany Merrill Lynch International 2 King Edward Street London EC1A 1HQ United Kingdom	
Co-lead Manager	ING Bank N.V. Bijlmerdreef 106 1102 CT Amsterdam The Netherlands	

Reporting Accountants	Deloitte LLP 1 New Street Square London EC4A 3HQ Ernst & Young LLP 1 More London Place London SE1 2AF
Auditors to the Company (FY2021 and Current)	Deloitte LLP 1 New Street Square London EC4A 3HQ
Auditors to the Company (FY2019 and FY2020)	Ernst & Young LLP 1 More London Place London SE1 2AF
English and US legal advisers to the Company	Pinsent Masons LLP 30 Crown Place Earl Street London EC2A 4ES
English and US legal advisers to the Underwriters	White & Case LLP 5 Old Broad Street London EC2N 1DW
English and US legal advisers to the Delek Group	Allen & Overy LLP One Bishops Square London E1 6AD
Competent Person	Netherland, Sewell & Associates, Inc. 2100 Ross Avenue Suite 2200 Dallas, Texas 75201 USA
Registrar	Computershare Investor Services plc The Pavilions Bridgewater Road Bristol BS13 8AE

PART 5

EXPECTED TIMETABLE OF PRINCIPAL EVENTS AND OFFER STATISTICS

Each of the times and dates in the table below is indicative only and may be subject to change without further notice. References to time and date are to time and date in London, United Kingdom unless otherwise stated.

Event	Time and date
Latest time and date for receipt of indications of interest under the Global Offering	2:00 pm on 8 November 2022
Announcement of the results of and notification of allocations of Ordinary Shares in the Global Offering	7:00 am on 9 November 2022
Commencement of conditional dealings in Ordinary Shares on the London Stock Exchange	8:00 am on 9 November 2022
Admission and commencement of unconditional dealings in Ordinary Shares on the London Stock Exchange	As soon as possible after 8:00 am on 14 November 2022
CREST accounts credited in respect of Ordinary Shares acquired in the Global Offering in uncertificated form	As soon as possible after 8:00 am on 14 November 2022
Share certificates despatched	Within 10 Business Days of Admission

OFFER STATISTICS

Offer Price (per Ordinary Share)	250 pence
Number of Ordinary Shares in issue immediately prior to Admission(1)	900,042,217
Number of Offer Shares to be issued by the Company in the Global Offering . . .	105,000,000
Number of Ordinary Shares in the Global Offering as a percentage of total number of Ordinary Shares in issue immediately following Admission (assuming no exercise of the Over-allotment Option)(2)	10.4%
Number of Ordinary Shares subject to the Over-allotment Option(2)	15,000,000
Estimated gross proceeds of the Global Offering receivable by the Company . . .	£ 262,500,000
Estimated net proceeds of the Global Offering receivable by the Company(3) . . .	£ 255,800,000
Expected market capitalisation of the Company at the Offer Price(5)	£2,512,905,543
Expenses charged to the subscribers of Ordinary Shares by the Company	£nil

Notes:

(1) Represents the total number of Ordinary Shares in issue following completion of the Share Capital Reorganisation.

(2) The maximum number of Ordinary Shares subject to the Over-allotment Option is, in aggregate, equal to 14.3% of the maximum number of Ordinary Shares comprised in the Global Offering (prior to the utilisation of the Over-allotment Option).

(3) The estimated net proceeds receivable by the Company are stated after deduction of the Underwriters' Expenses, which are currently expected to be £6.7 million. The estimated net proceeds of the Global Offering of approximately £256 million will be used to repay $77.3 million of outstanding principal and accrued interest under the Tracker Loan and $214 million of the Capital Note. DKL Energy has agreed to waive all remaining amounts (if any) outstanding under each of the Tracker Loan and the Capital Note. Following such payment and/or waiver (if any), DKL Energy will provide a confirmation that such payment and/or waiver (if any) is in full and final settlement of any amounts due or payable by the Company in respect of each of the Capital Note and Tracker Loan. The Company will pay the IPO Expenses and the Selling Shareholder's Expenses with amounts received from payments from IEEPL and/ or certain Subsidiaries. This will require IEEPL and/ or certain Subsidiaries to make payments to the Company, which is not permitted under the RBL Facility Agreement unless agreed by the majority of lenders. It is expected that IEUK will obtain the consent of the majority of lenders under the RBL Facility Agreement. However, if the consent is not received, the Selling Shareholder will pay all the IPO Expenses. The Company will not receive any of the net proceeds from the Global Offering, all of which will ultimately be received by Delek.

(4) The market capitalisation of the Company at any given time will depend on the price of the Ordinary Shares at the time. There can be no assurance that the market price of an Ordinary Share will be equal to or exceed the Offer Price.

PART 6

BUSINESS OVERVIEW

In this Prospectus, the term “Group” or “Ithaca Energy” refers to the Company together with its Subsidiaries on a consolidated basis, except where otherwise specified or clear from the context.

Unless otherwise indicated, all production figures are presented on a net to the Group’s working interest basis. Where gross amounts are indicated, they are presented on a total project basis i.e., the total interest of all relevant licence holders in the relevant fields and licence areas without deduction for the economic interest of the Group’s commercial partners, taxes or royalty interests or otherwise. The Group’s legal interest and effective working interest in the relevant fields and licence areas are separately disclosed. See paragraph 14 (Material Contracts) of Part 20 (Additional Information) for a more detailed discussion of the terms of the material contracts governing the Group’s interests. Any projections and other forward-looking statements in this section are not guarantees of future performance and actual results could differ materially from current expectations. Numerous factors could cause or contribute to such differences. See Part 2 (Risk Factors) and paragraph 13 (Information Regarding Forward-Looking Statements) of Part 3 (Presentation of Financial and Other Information).

1. OVERVIEW OF THE GROUP

Ithaca Energy is a leading UK independent exploration and production company with production and development activities on the UKCS. The Group was founded in 2004 and has been an active UK offshore operator and producer since 2008, growing its portfolio of assets through both organic investment programmes and acquisitions. Following Delek’s acquisition of the Group, the Group has seen a period of significant M&A driven growth centred upon two transformational acquisitions: the Chevron Acquisition and the Siccar Point Acquisition. In November 2019, the Group completed the Chevron Acquisition for $1.727 billion and, in June 2022, the Group completed the Siccar Point Acquisition for approximately $1.5 billion. In 2021 and 2022, the Group also completed the Mitsui Acquisition, the Summit Acquisition and the Marubeni Acquisition. These acquisitions delivered a compound annual growth rate in production of approximately 40% between 2017 and 2021. The Chevron Acquisition established Ithaca Energy as one of the largest independent companies in the UKCS and provided a significant operating capability. The Siccar Point Acquisition cemented the Group’s position on the UKCS and critically provided portfolio longevity through interests in two of the UKCS’s largest pre-FID fields: Cambo, which the Group also operates, and Rosebank. Following these acquisitions Ithaca Energy now has stakes in six of the top ten oil and gas assets in the UKCS. They also gave the Group a material, long-life resource base with the second largest resource base of independent oil and gas companies in the UKCS. The Group’s business and employees are located in Aberdeen, Scotland, the primary operational and commercial centre of the UK oil and gas sector.

The Company’s portfolio consists of 29 producing field interests, which predominantly lie in the Central North Sea and West of Shetland areas of the UKCS. The Group operates eight of these producing fields and a majority (approximately 63%) of its 2P reserves and 2C resources as at 30 June 2022, providing significant control and flexibility over execution of the business’s strategic, operational and financial priorities. The Group has approximately 516 employees as at the Latest Practicable Date, of which around 251 normally work offshore on Group-operated assets.

As at 30 June 2022, the Group had 2P reserves of 244 MMBOE (of which approximately 72% were oil), aggregate 2C resources of 302 MMBOE (of which approximately 77% were oil) and delivered a reserves replacement ratio of approximately 230% over the period from 1 January 2019 to 30 June 2022. During the six months ended 30 June 2022, the Group’s average daily production (of oil and gas) on a net working interest basis was 66,685 BOEPD, its revenue was $1,337.6 million, its Group Adjusted EBITDAX was $907.4 million, its profit after tax was $1,557.7 million, and it had net cash from operating activities of $989.0 million.

The Group’s strategy is centred on increasing Ithaca Energy’s value while generating attractive and sustainable shareholder distributions. To do this the Group will focus on: buying value accretive assets across the asset lifecycle, including development and producing assets;

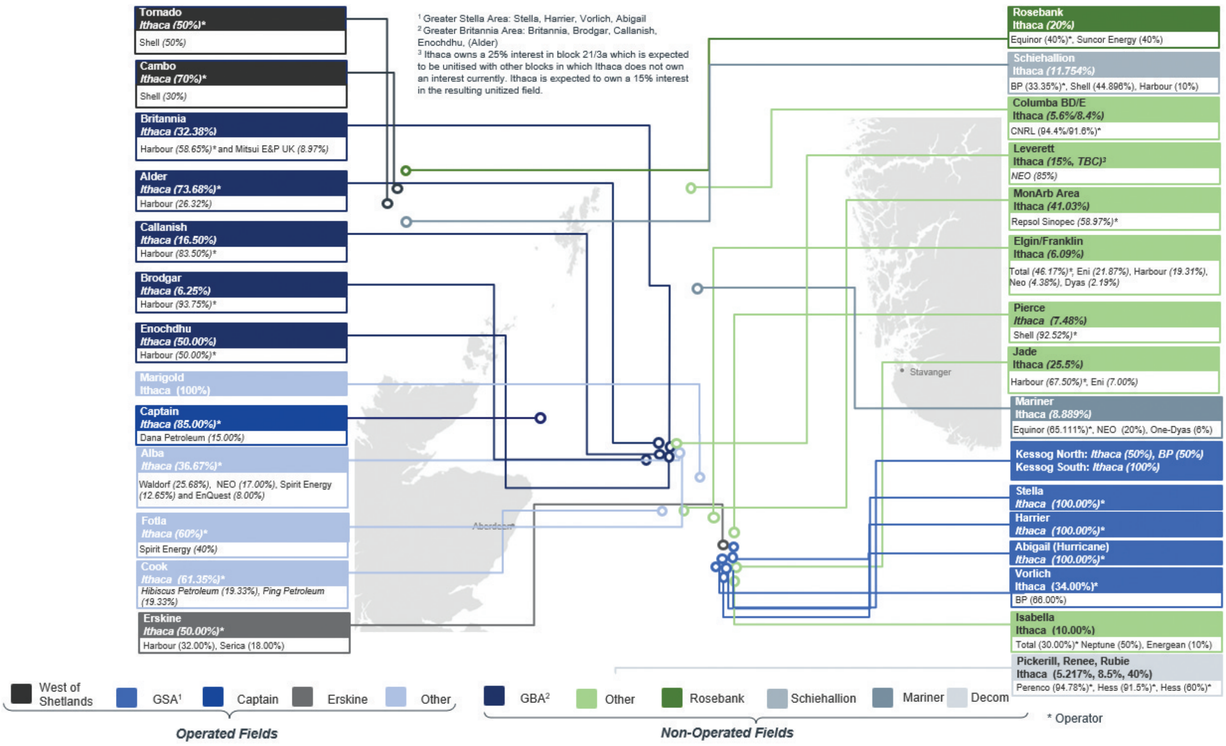
developing projects with strong economics which provide resilience to the Group's portfolio through the commodity price cycle; and optimising existing field performance by maximising recovery, boosting efficiency, emphasising cost control and driving digitalisation. In order to realise this the Group will seek to achieve outstanding performance through operational excellence, maintaining financial discipline and prudence, appropriately incorporating an ESG mindset and by employing an industry leading workforce while always maintaining a staunch focus on safety. The Group believes this strategy has positioned the business to expand the scale and breadth of its production asset base, establish a wider portfolio of development opportunities from which it expects to grow its future cash flows which will enable it to benefit from both the investment allowances under the Energy Profits Levy and accelerate the monetisation of its existing $5.6 billion of RFCT UK tax losses and $4.8 billion of SCT losses, as at 30 June 2022. Energy security has been a key focus of the UK Government, and the Group's management believes the Group can utilise its significant reserves and operational capabilities to play a key role in delivering security of domestic energy supply from the UKCS.

The Group is focused on continued investment in the various development opportunities in its existing portfolio, including the Cambo and Rosebank fields and the ongoing rollout of the Group's innovative Captain EOR II, which is centred around maximising economic recovery of reserves at the Captain field through the injection of polymerised water to achieve a more efficient reservoir sweep. The Captain EOR commenced in 2010 and Captain EOR II was sanctioned in April 2021 following consent from the NSTA. On 22 August 2022, OPRED published an environmental statement for the Captain EOR II, detailing plans for the drilling of seven new wells at the Captain field between the first quarter of 2023 and second quarter of 2024.

The Group also intends to continue leveraging the value of its infrastructure by developing existing discoveries in the catchment area of its facilities. The Group seeks to enhance production and access additional reserves through continued investment in low-cost infill drilling opportunities across its portfolio. In addition, the Group is exploring opportunities in infrastructure and investment business lines to supplement its existing operations.

The Group's Environmental, Social and Governance ("**ESG**") framework is well integrated into its business management and asset operating culture. In 2020, Ithaca Energy set out its ambition for achieving environmental performance in line with or exceeding industry standards and a commitment to reduce greenhouse gas emissions. In support of the global transition to a low carbon economy, and the United Kingdom's net zero targets, the Group has set a goal of reducing its combined scope 1 and scope 2 CO_2 and CO_2e emissions of its operated assets by 25% from 2019 levels in 2025. The Company is also committed to achieving 0.2% methane intensity by 2025, zero routine flaring by 2030, net equity targets set by the North Sea Transition Deal and net zero by 2040 (based on the Group's equity interest in all of its fields). To achieve this goal, the Group established an Energy Transition Team to focus the Group's emission reduction activities and engage with the wider workforce to achieve this reduction. See paragraph 8 (*ESG*) of this Part 6 (*Business Overview)* for further details on the Group's ESG initiatives.

Figure 6.1: Overview of the Group's assets



Source: Company Information

2. KEY STRENGTHS

2.1 *Material scale and longevity*

Ithaca Energy is one of the largest independent oil and gas companies in the UKCS, ranking second by resources and third by production. The Group had an average daily production of 66.7 MBOEPD for the six months ended 30 June 2022, compared to an average daily production of 56 MBOEPD for the twelve months ended 31 December 2021. The Group expects its average daily production for the six month period ending 31 December 2022 to be approximately 77-80 MBOEPD.

Portfolio longevity has been materially enhanced by the Siccar Point Acquisition, as evidenced by a highly competitive 2P reserves and 2C resources to production ("**R/P**") ratio of 19 years, among the highest in the UKCS. The Group believes that it has sufficient development opportunities within its portfolio to enable production to be increased to over 100 MBOEPD in the medium term. This compares favourably to other UKCS participants that are typically characterised by lower R/P ratios and declining production.

The Group believes its portfolio is well balanced with producing, development and near-field exploration assets. It has a diversified portfolio, mitigating concentration risk and providing access to some of the United Kingdom's highest quality fields to drive long-term cash generation and value realisation. This includes interests in six of the top ten assets by reserves on the UKCS, more than any other player, which make up a material portion of the Group's reserves and resource base of 546 MMBOE, with 2P reserves of 244 MMBOE which are supplemented by approximately 302 MMBOE of 2C resources (each as at 30 June 2022), with a 74% oil weighting. This represents approximately an 8x increase in 2P reserves plus 2C resources from 31 December 2017 (when IEEPL was acquired by Delek) to 30 June 2022.

The Group's producing asset portfolio comprises a combination of fields that have a long, stable track record of production and those that have recently come on-stream. The Group benefits from the known production performance characteristics of the established fields, which facilitates the execution of targeted infill drilling programs designed to maximise reserves recovery and develop higher margin incremental volumes.

In addition, the Group has significant interests in the two largest undeveloped discoveries in the UKCS, the Cambo and Rosebank fields, with Rosebank being the single largest undeveloped field in the UKCS. The Group has a 70% operated working interest in the ready-to-develop Cambo field, which has approximately 100 MMBOE of 2C resources as at 30 June 2022. The Group has a 20% non-operated working interest in the Rosebank field, which has approximately 66 MMBOE of 2C resources as at 30 June 2022.

2.2 ***Operating excellence as an established operator focussed on safe and efficient operations***

Safety is at the core of the Group's operating excellence, as demonstrated by the Group's track record for conducting its operations in a safe manner. The Group's Stop Work Authority Initiative enforces safety leadership, and management empowers all employees and contractors to be safety leaders. The Group maintains a strong focus regarding operational safety with particular emphasis on major accident hazard prevention. In support of these objectives, the Group has recently adopted the International Association of Oil and Gas Producers' life-saving rules. Improving operational safety performance, within an open and transparent incident reporting culture, is a continual focus of the business and a combination of leading and lagging indicators are utilised with a view to facilitating this goal. Serious Incident Frequency ("**SIF**"), which is measured by the number of incidents per million hours worked, is a key performance indicator for the Group. SIF has been zero from 2019 to 2022 year to date. In 2022, with increased activity levels across the industry, the Group has seen an increase in the number of first aid cases and recordable injuries. The Group has responded to events by increasing safety leadership focus, supporting its frontline teams with increased HSE resource and completing an independent review of the Group's control of work processes. Actions from this review have been identified for implementation in the remainder of 2022 and Q1 2023.

In addition to operational safety KPI monitoring, the Group reviews key process safety indicators including Process Safety Events as defined by API 456 Process Safety-Recommend Practice on Key Performance Indicators. In the period 2019-2022 there have been zero Tier 1 Process Safety Events.

Ithaca Energy is one of the only independent oil and gas companies in the UKCS with deep expertise across the full four areas of the exploration and production lifecycle. In exploration, the Group employs an infrastructure-led strategy focusing on basin modelling, geoscience interpretation and prospect economic evaluation in the West of Shetland and Central North Sea regions. Such strategies led to the discovery and appraisal of Fotla in 2021 in a single campaign. The Group plans to target approximately two exploration wells per year with near term plans to appraise the Isabella prospect and drill the K2 prospect. The Group also has extensive expertise in greenfield and brownfield developments and well operations through its project development and drilling teams. The Abigail and Captain EOR II projects are currently on schedule and on budget, and the Cambo, Rosebank and Marigold developments are progressing to final investment decisions. In terms of production, the Group is an established operator of producing assets with approximately 630 offshore personnel (including contractors and contractors for services staff). In addition, while the Group has no material near term decommissioning liabilities, it does have the in-house capability to support all aspects of decommissioning, such as with the decommissioning of the Jacky project in early 2022, which was completed safely and on budget, with the recycling target achieved.

The Group maintains a focus on costs and is targeting a continued reduction in unit operating expenditure per barrel in the medium term. The Group reduced average unit operating expenditure per barrel from $18.7/BOE for the year ended 31 December 2019 to $18.0/BOE for the year ended 31 December 2021. The Group's mid-term ambition is to reduce average unit operating expenditure per barrel to approximately $14.0/BOE but this ambition is subject to the impact of higher hydrocarbon fuel prices, medium term inflation rates and will require management of the Group's asset base through a combination of asset decommissioning and successful implementation of the Group's M&A strategy. Given the impact of cost inflation, the base production profiles for ongoing activity and 2P capex development are expected to maintain costs relatively flat in the short term with cost reductions supported by projects with targeted lower cost barrels (including Rosebank which is expected to deliver unit operating expenditure per barrel of $11.8/BOE in the initial years of production). This figure is based on maturity of the Rosebank development and on inflation and hydrocarbon pricing that pre-date 30 June 2022, each of which may be affected by increased hydrocarbon prices and rise in inflation rates since that date and the maturation of the project assumptions. For a discussion of some of the risks and uncertainties related to unit operating expenditure, please refer to Part 2 (*Risk Factors*). In addition, the Group intends to orient its M&A strategy towards assets with strong economics and employ ongoing cost reduction initiatives across the portfolio, such as standardisation of processes and procedures, improving uptime and maintenance optimisation and leveraging digital technology to improve offshore productivity, as the Group is a data driven organisation. In the near term, unit operating expenditure are anticipated to be broadly flat with absolute cost increases associated with inflation and high commodity prices offset by growing production.

The Group has an unwavering focus on the operational value levers within its control. It focuses on value, not just cost, and is prepared to invest to drive operational efficiency and uptime improvements. The Group's operational capabilities are evidenced by the performance track record on the FPF-1 floating production facility which improved from approximately 60% to approximately 95% production efficiency within six months. The Group took the strategic decision to become the duty holder, as it is on other operated installations, to realise greater value. This enabled the Group to drive efficiencies and leverage the Group's in-house operatorship capabilities to focus on reliability and maintenance optimisation. It did so by assigning a new asset manager, conducting a vulnerability study, repairing and upgrading key systems and adopting a condition-based maintenance philosophy. These measures, combined with the new simplified and streamlined arrangements with long standing partner Petrofac, resulted in this significant improvement in production efficiency.

The Group also employs digitalisation initiatives to ensure safe and efficient operations, achieve increased uptime performance and realise cost savings across its operations. For example, the Group has effectively deployed advanced laser-scanning technology to enable digital asset management. This has the potential to reduce repair times from days to hours. In addition, the Group's implementation of onshore-offshore links has enabled real-time connectivity between on-site operators and offshore teams which has boosted intervention efficiency and reduced the requirement for costly site visits.

2.3 ***Development expertise and a strong growth pipeline***

Ithaca Energy has significant development expertise and has undertaken large development programmes focused around its infrastructure hubs, including phase I of the Captain EOR, Captain EOR II, Captain and Alba drilling programmes and initiatives at Abigail, Erskine and Vorlich. These development activities have enabled the Group to further grow its reserves base organically through a balanced blend of investment programs focussed on production enhancement opportunities (infill drilling and continued roll-out of the Captain EOR), satellite field developments and exploration and appraisal activities. With the Group's blend of assets, the Directors believe that it has a strong pipeline ahead with significant opportunities to organically sustain and grow the Group's reserves, including at the Cambo, Rosebank, Marigold, Fotla, MonArb Area, Isabella and Tornado fields.

The Group's development expertise is evidenced by its successful deployment of a pioneering offshore polymer flood technology to maximise recovery rates on its operated Captain field. The first phase of the Captain EOR has resulted in a production response which has tracked or exceeded expectations. The proven effectiveness of the technology supports the Group's investment in phase II of its deployment. The Group's management believe it is the only organisation to deploy offshore polymer flood technology at scale in the UKCS.

The Group is focussed on creating value through high quality developments. The Siccar Point Acquisition in 2022 approximately doubled the Group's recoverable resources providing the Group with portfolio longevity and material growth potential through access to flagship greenfield assets holding material 2C resources, including the two largest undeveloped fields in the UKCS, Cambo and Rosebank, with Rosebank being the single largest undeveloped field in the UKCS, with potential to unlock adjacent upside. The Group also holds interests in lower cost and lower risk brownfield assets such as Marigold, Montrose and Fotla, which are expected to be tied back to existing infrastructure. This attractive development portfolio is complemented by the Group's deep expertise and experience to create potential for material growth and value creation over the next ten years.

Ithaca Energy believes its strong pipeline of development opportunities provide a visible growth trajectory. In addition to its significant greenfield and brownfield developments, the Group intends to undertake infill drilling campaigns at various producing assets which have the potential to deliver net 2P reserves and 2C resources of 61.6 MMBOE and peak production of 20.5 MBOEPD. The robust pipeline of sizeable sanctioned and unsanctioned projects drives portfolio longevity, with the high value growth driven by the Group's development capabilities. As operator of its key assets, the Group is well positioned to effectively manage the nature, timing and amount of capital expenditure invested in its assets including, for example, in relation to the timing of infill drilling programmes. The migration of the Group's contingent resources into reserves is a function of the timing of sanctioning investments. This provides the Group with a degree of control and flexibility over future investment programs, which is a key advantage in light of historic volatility in commodity prices and recent changes in UK tax policy.

2.4 ***Decarbonisation focus with a well-defined emissions-reduction strategy***

Ithaca Energy has a sharp focus on emissions reduction with clear targets and the ambition to have one of the lowest carbon emission intensity portfolios in the UK North Sea. The Group plans to significantly reduce emissions and exceed industry targets by optimising its current portfolio in the short term and fundamentally transitioning the portfolio over the medium to long term.

In the short term, the Group is focussed on operational improvements within its current portfolio. The Group recently reduced emissions on the FPF-1 by 11,500 tonnes CO_2e per annum by performing engineering studies and an offshore trial to prove the feasibility for running only a single gas turbine generator for power generation. The Company's management has a proven track record of implementing sustainability agendas in previous organisations and is fully engaged with the NSTA to support the achievement of the United Kingdom's net zero targets. To this end, the Group has developed an ambitious plan to deliver its short-term target of reducing its scope 1 and 2 carbon dioxide ("**CO_2**") and carbon dioxide equivalent ("**CO_2e**") emissions from its operated assets by 25% in 2025 (against a 2019 baseline), which would exceed the NSTA target of a 10% reduction (against a 2018 baseline). The Company has identified several near term projects and opportunities to reduce CO_2e emissions and help achieve this target, with additional activities planned to deliver further reductions in the longer term. Such plans mean that, subject to incremental investment by the Group beyond its current base capital profiles, and technical feasibility the Group has the potential to reduce emissions by up to 40% by 2025. Further details of these plans are set out in paragraph 8 (*ESG*) of this Part 6 (*Business Overview)*.

The Group's medium-term target is to shift to lower emission intensity assets by ceasing production on, and decommissioning, higher emission intensity assets (such as FPF-1 and Alba which are expected to cease production around 2030) and bringing on stream lower emission intensity assets (such as Rosebank and Cambo, which are expected to commence production in 2026 and 2028, respectively). Captain, FPF-1 and Alba are expected to produce average emissions of approximately 23.2kg CO_2e / BOE across 2022 to 2026. In contrast, the Group's management expects Cambo, by virtue of its FPSO design, and Rosebank to produce average emissions of approximately 7.2kg CO_2e / BOE (which is approximately 80% below the UK average emissions) and 6.8kg CO_2e / BOE respectively across their first five years of production (3.7kg CO_2e/BOE and 3.3kg CO_2e/BOE with partial electrification), which would represent a significant reduction on the average emissions-intensity across the UKCS of 21kg CO_2e/BOE.

In the long term, Ithaca Energy is committed to supporting the North Sea Transition Deal and intends to achieve net zero by 2040 (based on the Group's equity interest in all of its fields), ten years ahead of the NSTD commitments, by adopting low carbon power and carbon offsets.

2.5 ***Return-oriented business with material cash flow generation to drive growth and shareholder return***

Ithaca Energy's diversified, high quality asset base generates strong free cash flow. In the year ended 31 December 2021, the Group generated net cash from operating activities of $912.7 million (or $44.7/BOE) from 56 MBOEPD of production (of which approximately 65% were liquids). In the six months ended 30 June 2022, the Group generated net cash from operating activities of $989.0 million (or $81.7/BOE) from 66.7 MBOEPD of production (of which approximately 64% were liquids).

The Group's strong cash flow generation has supported a rapid deleveraging trajectory. As at 30 June 2022, the Group's net debt to Group Adjusted EBITDAX ratio was 0.9x, compared to 4.1x, 1.6x and 0.9x in the years ended 31 December 2019, 2020 and 2021. As at 30 June 2022, the Group had Available Liquidity of approximately $320.4 million.

The Group's free cash flow significantly exceeds its capital expenditure requirements such that the portfolio has been self-funded with capital expenditure coverage (being net cash from operating activities for the period divided by capital expenditure for the corresponding period) for the six months ended 30 June 2022 of 4.3x, compared to 1.7x, 5.2x and 3.4x in the years ended 31 December 2019, 2020 and 2021, respectively. The Group's capital expenditures for the six months ended 30 June 2022 were $230.3 million, compared with $163.9 million, $142.1 million and $269.6 million in the years ended 31 December 2019, 2020 and 2021, respectively.

The Group has a clear and balanced capital allocation framework which aims to deliver attractive shareholder returns and growth. Subject primarily to production delivery, commodity prices and project execution, the Group expects to continue to generate significant free cash flow from operations after tax. Ithaca Energy expects that such cash flow will satisfy capital expenditure requirements to maintain current production levels, maintenance of leverage of less than 1.5x net debt to Group Adjusted EBITDAX (with levels for the 12 months ended 30 June 2022 at 0.9x net debt), deliver shareholder returns, and provide additional financial flexibility and liquidity headroom to facilitate value-accretive growth projects and incremental distributions.

2.6 ***Experienced management team with proven track record, delivering significant value at pace***

Ithaca Energy has a high-calibre executive leadership team with significant and diverse UK North Sea oil and gas industry experience. The members of the Company's executive team have over 240 years of combined experience and have worked in various management and leadership roles across the spectrum of the international 'supermajors', leading independents and major service contractors. The executive leadership team are supported by a senior leadership team with an extensive array of experience.

The Group has a strong recent track record of identifying, executing and delivering organic growth and value accretive M&A activity having completed four acquisitions in nine months, including the transformative Siccar Point Acquisition. The lean and experienced executive management team, with an execution focus, has enabled the Group to execute complex transactions with both diligence and pace.

Through the Group's M&A activity, it has built and inherited a highly skilled and disciplined operating team, which has added value to acquired assets by safely carrying out incremental investment projects. The team's combined industry and regional expertise enables the Group to clearly understand and effectively manage the inherent risks associated with the business and its assets and provides the required skills and track record to identify new production and development opportunities and targets to continue growing the business. The strong integration capabilities of the Group's management team have also helped to deliver significant synergies and operational improvements from acquired portfolios, as well as in-depth knowledge across the UKCS.

The management team has full-cycle capability with experience and expertise across exploration, development, operations and decommissioning. The team's development expertise is evidenced by the Group's development of the FPF-1 and members of the management team having led the MonArb redevelopment project and the Catcher area development in previous roles. In 2021, the team secured long-term drilling rig contracts for well operations at Abigail and Captain in order to support and protect the drilling programme. The team's operational expertise has supported sustained improvements in the Group's operational efficiency, evidenced by the FPF-1 reaching approximately 95% production efficiency within six months after the Group took back full operational control of the facility having previously operated the asset using a duty holder model with Petrofac.

3. STRATEGY AND OBJECTIVES

Ithaca Energy is a leading UK independent exploration and production company and operates the majority of its production and reserves base. The Group achieved this market positioning through a combination of organic growth and value-accretive acquisitions, including the transformational Chevron Acquisition and then, more recently, through the Siccar Point Acquisition. The Group has a track record of material value creation, having delivered a 5.5x[1] increase in equity value between 2018 and 30 June 2022, and access to flagship assets, including the two largest undeveloped fields in the UKCS, Cambo and Rosebank, to drive organic growth. The Group's goal is to continue to increase Ithaca Energy's value while generating attractive and sustainable Shareholder distributions. The Group's strategy is to evolve its portfolio by: buying value accretive assets across the asset lifecycle, including development and producing assets; developing projects with strong economics which provide resilience to the Group's portfolio through the commodity price cycle; and optimising existing field performance by maximising recovery, boosting efficiency, emphasising cost control and driving digitalisation. In order to realise this the Group will seek to achieve outstanding performance through operational excellence, maintaining financial discipline and prudence, appropriately incorporating an ESG mindset and by employing an industry leading workforce, while always maintaining a staunch focus on safety.

In implementing its strategy, the Group's ambition is to become a key player in providing energy security to the UK and Europe. Energy security is at the forefront of the UK Government's agenda and Ithaca Energy intends to utilise its significant reserves and operational capabilities to play a key role in delivering security of domestic energy supply from the UKCS. The Group's management believes that its strategy is in line with the UK Government's energy security strategy to maximise economic recovery of UKCS resources as part of reducing reliance on imported fossil fuels. This will include Ithaca Energy's operatorship of the Cambo field, one of the largest pre-FID projects in the UKCS.

3.1 *Pursue value accretive acquisitions, consolidating the UK North Sea*

The Group has successfully executed a substantial M&A programme in recent years which has played a key role in transforming its portfolio, completing five acquisitions over the last three years. The Group has also sanctioned three new projects (Captain EOR II, Vorlich and Abigail) in the last three years. It has a track record of executing and integrating acquisitions that complement its existing portfolio, that provide continued reserves and long-term production growth and that enhance cash flows and value. Ithaca Energy intends to continue employing a disciplined approach to evaluating inorganic growth opportunities. The evaluation of the Group's investment programmes and potential acquisition opportunities are rigorously screened based on stringent financial, operational, strategic and technical criteria. It appraises the technical and financial capabilities of any partners in the assets along with the strategic fit of the asset with the Group's existing portfolio. The subsurface quality of the assets, potential infrastructure synergies and the extent of any future decommissioning cost exposures are also thoroughly assessed. The Group structures its acquisitions to optimise value creation at prudent pricing.

The Group's transformative Chevron Acquisition in 2019 led to significant production growth of over 310%, an increase in the 2P reserves of the Group of over 125% and enhanced the Group's operational and technical capabilities. The Siccar Point Acquisition in 2022 provided material long life reserves and flagship producing and development assets, increasing the

1 This multiple is based on (i) the equity value of the Group as at 31 December 2021 (as calculated pursuant to the Kroll Report); plus (ii) gain on bargain purchase (per the Group's Historical Financial Information for the six months ended 30 June 2022) from the Marubeni Acquisition and Siccar Point Acquisition both of which completed during the six months ended 30 June 2022.

Group's recoverable resources by 1.9x, at a cost (estimated by management) of $6.5/BOE, and provided tax losses of $3.0 billion. The Group's M&A strategy has included these transformative acquisitions as well as a series of smaller but highly complementary acquisitions delivered throughout 2021 and 2022, including the Marubeni Acquisition (which provided cash generative assets with a material tax loss position of $1.6 billion (RFCT) and $1.4 billion (SCT), the Summit Acquisition (which augmented gas exposure via an increased stake in the key Elgin-Franklin field) and the Mitsui Acquisition (by which IEUK became the largest partner in the key Alba field with an increased 50% stake). The initial upfront consideration payable by IEUK for the Marubeni Assets was offset by interim period adjustments such that IEUK received the sum of $70.0 million, while the acquisition is expected to generate free cash flows of approximately $100 - $150 million and a material tax loss position of $1.6 billion (RFCT) and $1.4 billion (SCT). The Summit Acquisition consideration is expected to be paid back within two years while providing production up to 2040 and tax synergies. The Mitsui Acquisition featured negative consideration with potential upside from infill drilling and potential decommissioning costs savings.

The Group believes that the UKCS offers various consolidation opportunities through which the Group can continue delivering strategic, high-quality acquisitions which can further enhance its reserves base and maintain the longevity of its business model. These opportunities exist around its core current hubs, providing operational synergies, but also include step-out opportunities into new areas like the Group's recent Siccar Point Acquisition. Oil majors and larger international oil and gas players are increasingly reallocating capital into new energies in order to achieve their ESG targets and also prioritising other regions as they look to satisfy reducing corporate production targets. The Group expects the consolidation trend, driven by portfolio optimisation, energy transition, the ESG agenda and value crystallisation, to deliver a regular pipeline of highly attractive acquisition opportunities, with approximately $11 billion worth of assets currently expected to be brought to market in the UKCS. The Group believes that there are now few independent operators, of both operational and financial strength and supported by proven M&A execution capabilities and integration expertise, focused on the UK North Sea which can acquire assets from these players. The Group believes the balance between the availability of UKCS acquisition opportunities and competition from other operators has moved in the Group's favour and that it is strongly positioned to continue to lead consolidation due to basin expertise, execution capabilities and a strong financial position.

3.2 ***Evolve the portfolio by developing projects in the pipeline with a focus on strong economics***

The Group intends to deliver on its strong growth pipeline by advancing its diversified portfolio of developments and expects this to underpin material growth. The key development assets include Cambo and Rosebank, the two largest undeveloped fields in the UKCS. With gross 2C resources of approximately 148 MMBOE and 336 MMBOE respectively, these flagship assets provide Ithaca Energy with visible production growth trajectory at a lower emissions intensity and lower expected unit operating expenditure per barrel. With the development of Cambo, the NSAI CPR indicates that the Group's 2P reserves plus 2C resources unrisked portfolio has the potential to provide a production plateau of approximately 125 MBOEPD (net) up to 2030, with Cambo having the potential to average unit operating expenditure of $5/BOE over the first five years of production. This figure is based on maturity of the Cambo development and on inflation rates and hydrocarbon pricing that pre-date 30 June 2022, each of which may be affected by increased hydrocarbon prices and the rise in inflation rates since that date and the maturation of the project assumptions. The Group also expects to realise synergies in relation to the Cambo and Rosebank fields through access to common infrastructure in the West of Shetland.

The Group's development opportunities also include the Captain EOR II. Captain is the biggest contributor to the Group's production (contributing approximately 25% of the Group's daily production) with top quartile production. It is a prime adage of the phrase that 'big fields get bigger' and through the ongoing Captain EOR, the Group is driving maximum economic recovery of reserves utilising the Group's proven innovative polymer technology. The Captain EOR II activity is sanctioned, on schedule and on budget with the investment having been supported by phase 1 of the Captain EOR programme being delivered ahead of target. It is expected to double net production at the field to approximately 40 MBOEPD and provide gross

2P reserves of approximately 28 MMBOE. There is a material potential upside with the Captain EOR II activity, with the field having STOIIP of c.1 billion BOE with approximately 36% of volumes recovered.

The Group's pipeline of low-cost developments also includes Marigold and Fotla, with gross 2P reserves plus 2C resources of 29 MMBOE and 16 MMBOE respectively. These represent potential low-cost developments which are expected to be tied back to existing infrastructure. The Group intends to work closely with its supply chain to minimise the risks associated with offshore activities in order to protect its development project returns.

3.3 ***Optimise current asset performance through deep operational expertise***

Leveraging the skills and experience of the Group's geoscience, engineering and commercial teams, Ithaca Energy believes there are further opportunities to optimise the performance of its existing producing assets. Ithaca Energy is the second largest independent operator in the UKCS (on the basis of reserves and resources) and its majority-operated asset portfolio enables the Group to prioritise operational excellence and maintain a value-focus across all activities in order to maximise recovery, boost efficiency and reduce costs.

The Group intends to use established technologies to target increased recovery volumes and maximise the recovery of in-place hydrocarbons. This is evidenced by its use of advanced EOR technology to maximise recovery rates on the operated Captain field. This technology gives Ithaca Energy the potential to enhance resource recovery from the Captain field as well as potentially other fields, while reducing the need for additional infrastructure development and installations.

The Group has a particular focus on maximising production efficiency and uptime initiatives to drive revenue realisation. It has an excellent track record in delivering operational improvements, as evidenced by the improvements in the production efficiency of the FPF-1 facility that increased from approximately 60% to approximately 95% within six months after Ithaca Energy took back control of the facility from Petrofac by becoming duty holder.

The Group maintains a focus on costs and is targeting a reduction in unit operating expenditure per barrel in the medium term. The Group reduced average unit operating expenditure from $18.7/BOE for the year ended 31 December 2019 to $18.0/BOE for the year ended 31 December 2021. The Group's mid-term ambition is to reduce average unit operating expenditure per barrel to approximately $14.0/BOE, but this ambition is subject to the impact of higher hydrocarbon fuel prices, medium term inflation rates and will require management of the Group's asset base through a combination of asset decommissioning and successful implementation of the Group's M&A strategy. Given the impact of cost inflation, the base production profiles for ongoing activity and 2P reserves capex development are expected to maintain costs relatively flat in the short term with cost reductions supported by projects with targeted lower cost barrels (including Rosebank which is expected to deliver unit operating expenditure per barrel of $11.8/BOE in the initial years of production). This figure is based on maturity of the Rosebank development and on inflation and hydrocarbon pricing that pre-date 30 June 2022, each of which may be affected by increased hydrocarbon prices and the rise in inflation rates since that date and the maturation of the project assumptions. For a discussion of some of the risks and uncertainties related to unit operating expenditure, please refer to Part 2 (*Risk Factors*). In addition, the Group intends to orient its M&A strategy towards assets with strong economics and employ ongoing cost reduction initiatives across the portfolio, such as standardisation of processes and procedures, improving uptime and maintenance optimisation and leveraging digital technology to improve offshore productivity. In the near term, unit operating expenditure is anticipated to be broadly flat with absolute cost increases associated with inflation and high commodity prices offset by growing production.

The Group's non-operated assets consist of a diverse portfolio of 24 assets, representing approximately 45% of current production. Ithaca Energy works closely and proactively with the field operators and licence partners to identify and drive the execution of opportunities to increase returns and enhance production across the portfolio.

3.4 ***Maximise the Group's value and deliver attractive and sustainable Shareholder distributions***

The Group's profitable and resilient asset base provides a foundation to deliver value to Shareholders. It generates significant positive free cash flow as a consequence of its material oil and gas production and low unit operating expenditure combined with the self-funded capital expenditures required to sustain and grow production. The Group's performance has been resilient despite volatile market conditions with Group Adjusted EBITDAX of $374.6 million, $742.9 million and $1,035.4 million for the years ended 31 December 2019, 2020 and 2021, respectively, and average unit operating expenditure of $18.7/BOE, $16.1/BOE and $18.0/BOE over the same periods.

3.5 In the near-term, the Company has a firm expectation of a dividend in respect of the year ending 31 December 2023 of $400 million with an ambition of an annual dividend of $420 million for the year ending 31 December 2024. The Group expects to pay dividends to Shareholders semi-annually in the ordinary course of business, specifically: (i) a third of any yearly dividend will be paid to Shareholders following the end of the first half of the relevant financial year; and (ii) two-thirds of any yearly dividend will be paid to Shareholders following the end of the relevant financial year. However, for the year ending 31 December 2023, the Company expects to pay an initial dividend in the first quarter of 2023 followed by two further dividend payments following the first half of the financial year and end of the financial year. The dividend is expected to be paid in cash. Further details of the Company's dividend policy, including details of the restrictions in the Group's borrowing arrangements and the conditions to which the Company's targeted dividend policy is subject, are set out in paragraph 16 (*Dividends and Dividend Policy*) of this Part 6 (*Business Overview*).

4. CORPORATE STRUCTURE, HISTORY AND DEVELOPMENT

4.1 ***Overview***

The Company was incorporated in England and Wales under the 2006 Act on 15 October 2019. IEEPL is a direct wholly-owned subsidiary of the Company.

IEEPL was founded in 2004 and incorporated under the Business Corporations Act in Alberta, Canada. Following its initial public offering on 6 June 2006, the shares in IEEPL were listed and traded on the TSX and AIM.

In H1 2017, IEEPL was the subject of a successful takeover bid by DGL (acting through its subsidiary, DKL Investments). Following completion of the takeover, DKL Investments held 94.2% of the issued and outstanding common shares of IEEPL. DKL Investments then carried out a compulsory acquisition of the remaining shares in IEEPL not held by DKL Investments. The compulsory acquisition completed on 5 June 2017 and the shares in IEEPL were subsequently de-listed from the TSX and AIM on 7 June 2017. Accordingly, since June 2017 IEEPL has been under the indirect sole ownership of DGL.

On 31 July 2018, IEEPL completed its migration from Canada to Jersey.

The Chevron Acquisition, which completed in November 2019, represented a significant step in the growth of the Group. Pursuant to the Chevron Acquisition, IEUK, which is a wholly-owned and controlled subsidiary of IEEPL, acquired 100% of the shares of IOG from CNSHL (a member of the Chevron group). The total cash consideration paid by IEUK in respect of the Chevron Acquisition, following adjustment and including a $200 million deposit paid on signing of the Chevron Acquisition Agreement plus $50 million paid for working capital, was $1.727 billion.

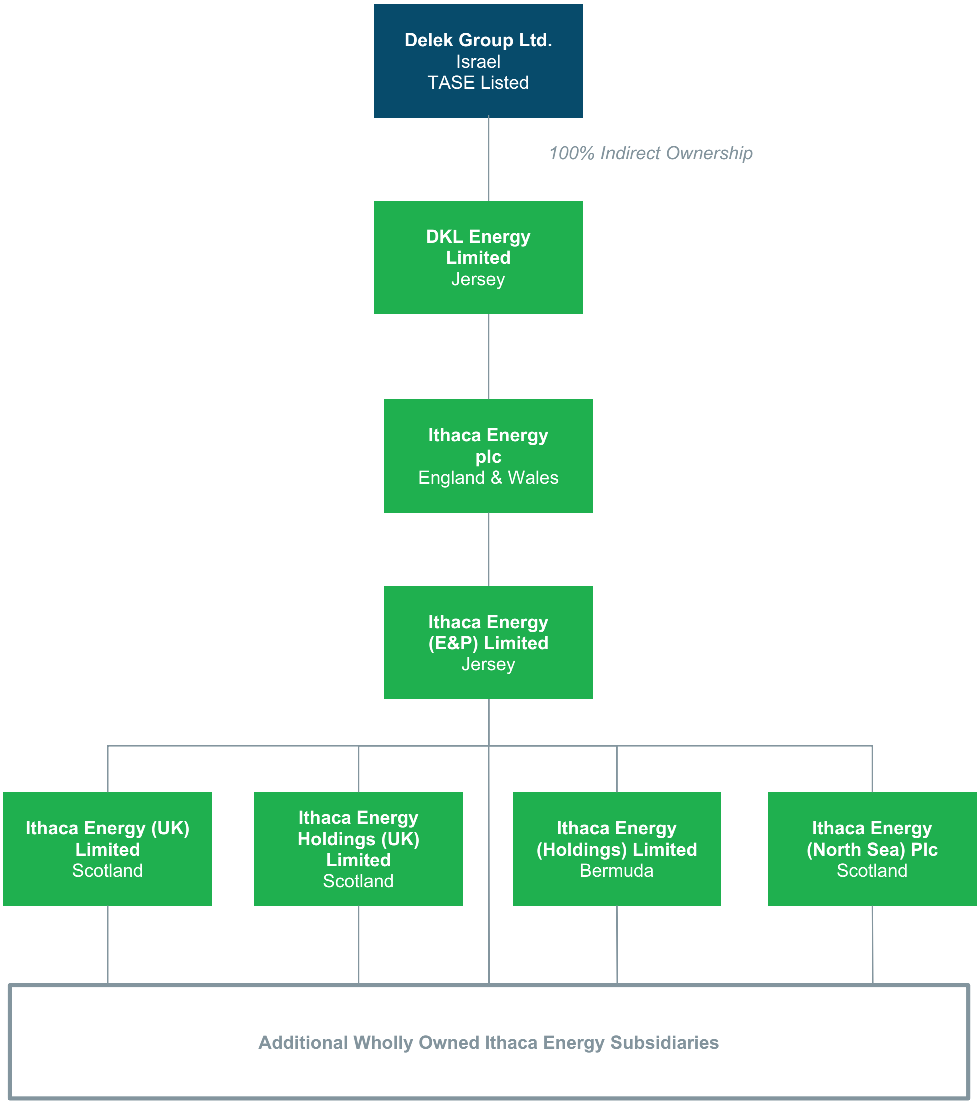
As part of the Chevron Acquisition, approximately 450 employees transferred to the Group, of which approximately 200 work offshore on the operated assets, providing the Group with a highly experienced and knowledgeable workforce that the Company believes has enabled the Group to unlock the full value of the Chevron Acquired Assets.

The Siccar Point Acquisition, which completed in June 2022, represented a further transformational step for the Group. Pursuant to the Siccar Point Acquisition, IEUK acquired 100% of the shares of SPEHL and certain loan notes issued by SPEFL from the Siccar Point Seller. The total initial cash consideration paid by IEUK in respect of the Siccar Point Acquisition, following adjustment was $1.015 billion. Up to a further $360 million of contingent payments is payable by IEUK to the Siccar Point Seller linked to future developments and realised commodity prices.

As part of the Siccar Point Acquisition, the Group acquired significant production, material growth potential and, through Siccar Point Group's interests in Rosebank and Cambo, two of the largest undeveloped discoveries in the UKCS, material long-life cycle to the Group's portfolio.

4.2 ***Structure of the Group***

The following simplified structure chart illustrates the Group's corporate structure as at the date of this Prospectus:



5. RESERVES AND RESOURCES

5.1 ***Reserves and resources information with regard to Ithaca Energy's oil and gas assets***

The Group's oil and gas assets are all located on the UKCS. NSAI has produced the NSAI CPR on the Group's reserves and resources in the UKCS relating to its oil and gas properties. NSAI has prepared its assessment of the Group's asset base as at 30 June 2022 and has reviewed and incorporated field studies and updated data that were available up to that date. In preparing the NSAI CPR, NSAI used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information and property ownership interests. NSAI used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy and reservoir modelling.

The table below provides key information from the NSAI CPR regarding the volume of proved and probable reserves (2P) and the volume of best estimate contingent resources (2C), attributable to the Group's share in all its oil and gas assets, as at 30 June 2022, in terms of thousand barrels of oil equivalent[2].For further information with regard to the reserves and resources attributed to the Group's oil and gas assets, see paragraph 5.2 below and the NSAI CPR contained in Part 23 (*Competent Person's Report*).

From the asset portfolio	**2P reserves (MBOE)**	**2C resources (MBOE)**
Captain Field	79,714.2	13,016.2
Greater Stella Area(1)	21,392.5	12,522.7
Schiehallion Field	24,931.4	7,994.3
Greater Britannia Area(2)	25,487.3	1,015.2
MonArb Area(3)	22,101.2	—
Mariner Area(4)	14,524.3	3,292.5
Jade and Jade South Fields	11,215.3	—
Cook Field	10,568.7	4,118.0
Erskine Field	8,243.4	8,119.9
Elgin-Franklin Field(5)	12,050.4	692.9
Alba Field	7,065.7	—
Pierce Field	6,504.2	468.0
Columba Terraces Area(6)	59.4	—
Cambo Field	—	103,256.7
Rosebank Field	—	65,810.1
Tornado Field	—	33,623.6
Marigold Field	—	28,646.5
Fotla Field	—	9,609.5
Isabella Field	—	6,628.6
Leverett Field	—	2,868.2
Decommissioning Assets(7)	—	—
Total Ithaca Energy Assets	243,858.0	301,682.9

Source: NSAI CPR

(1) Comprising three on-production assets (Stella, Harrier and Vorlich) one field under development (Abigail), and one field classified as contingent resources (Courageous). Licence P.2397 (Courageous) was relinquished by the Group with an effective date of 30 September 2022.

(2) Comprising the Britannia, Alder, Brodgar, Callanish and Enochdhu fields.

(3) Including the hub fields of Montrose and Arbroath and the satellite fields of Arkwright, Brechin, Cayley, Godwin, Shaw and Wood.

(4) Comprising the Mariner, Mariner East and Cadet field.

(5) Comprised of two gas-condensate fields, the Elgin and Franklin fields.

(6) Comprised of three downthrown fault blocks known as the B, D and E Terraces.

(7) Comprised of the Pickerill, Renee and Rubie fields.

5.2 ***Reserves attributed to all of the Group's assets (consolidated)***

The following table contains a breakdown of the volumes of reserves attributable to all of the Group's assets (consolidated) as set out in the NSAI CPR as at 30 June 2022.

	Gross (100%) Reserves		**Working Interest Reserves**			
Development Status/Category	**Oil (MBBL)**	**Gas (MMCF)**	**Oil (MBBL)**	**Gas (MMCF)**	**NGL (MBBL)**	**Equivalent (MBOE)**
DEVELOPED						
Proved Developed	291,180.3	1,249,611.1	57,781.6	203,349.8	5,313.1	98,155.0
Probable Developed	156,379.3	498,506.3	37,860.9	91,934.1	2,549.5	56,261.1

2 Conversion key—the conversion to MBOE was estimated considering the following data: conversion rate of natural gas is 1: 5.8 BOE to mcf, i.e., each 5.8 mcf is equivalent to 1 BOE. The key to the conversion of oil and NGL units is 1:1 bbl to BOE, i.e., every 1 bbl is equivalent to 1 BOE. Caution—MBOE units may be misleading, especially when used without taking into account additional characteristics; the conversion is made according to the energy ratio at the burner and does not represent a value equivalent.

Development Status/Category	Gross (100%) Reserves Oil (MBBL)	Gross (100%) Reserves Gas (MMCF)	Working Interest Reserves Oil (MBBL)	Working Interest Reserves Gas (MMCF)	Working Interest Reserves NGL (MBBL)	Working Interest Reserves Equivalent (MBOE)
Possible Developed	160,125.4	588,300.8	43,559.4	108,110.0	3,091.0	65,290.1
Proved + Probable Developed	447,559.6	1,748,117.4	95,642.5	295,283.9	7,862.6	154,416.1
Proved + Probable + Possible Developed	607,685.0	2,336,418.2	139,201.9	403,393.9	10,953.6	219.706.2
UNDEVELOPED						
Proved Undeveloped	162,635.6	38,726.8	56,665.4	20,504.4	527.6	60,728.3
Probable Undeveloped	86,548.1	37,234.8	24,433.8	21,682.5	541.5	28,713.6
Possible Undeveloped	88,762.0	41,483.3	28,733.1	23,155.7	553.8	33,279.3
Proved + Probable Undeveloped	249,183.7	75,961.6	81,099.2	42,186.9	1,069.1	89.441.9
Proved + Probable + Possible Undeveloped	337,945.7	117,444.9	109,832.3	65,342.6	1,622.9	122,721.2
TOTAL						
Proved (1P)	453,815.9	1,288,337.9	114,446.9	223,854.2	5,840.7	158,883.2
Proved + Probable (2P)	696,743.3	1,824,079.0	176,741.6	337,470.8	8,931.8	243,858.0
Proved + Probable + Possible (3P)	945,630.7	2,453,863.1	249,034.2	468,736.5	12,576.5	342,427.4

Totals may not add because of rounding.

Note: Reserves categorisation conveys the relative degree of certainty; reserves subcategorisation is based on development and production status. The estimates of reserves included in the NSAI CPR have not been adjusted for risk. Estimates may increase or decrease as a result of market conditions, future operations, changes in regulations or actual reservoir performance. In addition to the primary economic assumptions discussed in the NSAI CPR, estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided by the Company, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the volumes and that projections of future production will prove consistent with actual performance. "**Probable**" reserves are those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than proved reserves but more certain to be recovered than Possible reserves. "**Possible**" reserves are those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than probable reserves.

Source: NSAI CPR

5.3 *Management Outlook and Guidance*

Current Trading Update

Key trading and operational updates for the three months ended 30 September 2022 are as follows:

- working interest production during the three months ended 30 September 2022 averaged 71.3 MBOEPD;
- operating costs (as defined below) during the three months ended 30 September 2022 are expected to be approximately $124 million;
- capital costs during the three months ended 30 September 2022 are expected to be approximately $124 million;
- the Group continues to be focused on prudent cost management and full year 2022 guidance for operating and capital costs are now slightly below previous expectations;
- planned shutdowns were completed during the three months ended 30 September 2022 on the Alba field, MonArb area and Cook field;
- the Abigail subsea field tie-back to the FPF-1 infrastructure has now been completed with first production on 20 October 2022—resulting in an update to full year production guidance;
- early production results from Abigail are lower than expected and, while further data gathering and analysis is required to determine any longer-term impact, a prudent

reduction has been applied to the production guidance set forth below for the three months ended 31 December 2022 and the year ended 31 December 2023;

- the Shell operated Pierce field remains shut-in and is undergoing commissioning;
- the relinquishment of the Courageous licence (see paragraph 6.2 (*Greater Stella Area*) of Part 6 (*Business Overview*) on 30 September 2022 is expected to result in a non-cash impairment charge with respect to the associated CGU during the three months ended 30 September 2022;
- the introduction of the Energy Profits Levy, enacted on 14 July 2022, is expected to result in a material non-cash deferred tax charge in the three months ended 30 September 2022;
- during the three months ended 30 September 2022, the amount drawn on the RBL Facility was reduced by $100.0 million to $650.0 million from the principal outstanding as at 30 June 2022 of $750.0 million (see Part 14 (*Capitalisation and Indebtedness)*);
- the $200 million Siccar Point Bonds acquired as part of the Siccar Point Acquisition were redeemed in full between 1 August and 12 October 2022 (see paragraph 14.3.7 (*Siccar Point Bonds*) of Part 20 (*Additional Information*); and
- pre-FID work continues on the Cambo, Rosebank, Marigold and Fotla developments to validate costs, mature engineering and progress commercial and contractual frameworks.

The current trading update provided above is based on management information and has not been audited. All information presented is based on preliminary figures, may be subject to change and should be read as complementary to the NSAI CPR. Operating costs and capital costs are as defined below under Management Outlook and Guidance and, together with production, are subject to the principal assumptions set out below. The current trading update includes forward-looking statements which, although based on assumptions that the Directors consider reasonable, are subject to risks and uncertainties which could cause actual events or conditions to differ from those expressed or implied by the forward-looking statements. For a discussion of some of those risks and uncertainties please refer to Part 2 (*Risk Factors*) and paragraph 13 *(Information regarding Forward-Looking Statements)* in Part 3 *(Presentation of Financial and Other Information)*.

Management Outlook and Guidance

The Company's management has prepared guidance in relation to expected production, operating costs, capital costs, non-development capital expenditure, non-producing assets under decommissioning costs, exploration expenses, general and administrative expenses, net finance costs, hedging impact, tax and contingent and deferred liabilities. Specific management guidance has been provided for assets which are currently producing, along with potential risk around contingent resources (split into three groupings, as noted below).

Operating costs and capital costs are used in the management guidance as set out in the NSAI CPR. Operating costs include the per-well overhead expenses allowed under joint operating agreements along with the estimates of costs to be incurred at and below the area and field levels (which represents the Group's operating costs, less tarrif income, less tanker costs). Capital costs include costs required for new development wells, production equipment, and polymer for the Captain field. For a further description, please see Part 23 *(Competent Person's Report)*. The other terms used in this paragraph 5.3 *(Management Outlook and Guidance)* are as described in this paragraph or, in the case of net finance costs and general and administrative expenses, paragraph 5 (*Description of Key Line Items*) of Part 12 (*Operating and Financial Review Relating to the Group*).

The guidance is based on management information and has not been audited. All information presented is based on preliminary figures, may be subject to change and should be read as complementary to the NSAI CPR. The following discussion includes forward looking statements which, although based on assumptions that the Directors consider reasonable, are subject to risks and uncertainties which could cause actual events or conditions to differ from those expressed or implied by the forward-looking statements. For a discussion of some of those risks and uncertainties please refer to Part 2 (*Risk Factors*) and paragraph 13 *(Information regarding Forward-Looking Statements)* in Part 3 *(Presentation of Financial and Other Information)*.

Production, Operating Costs and Capital Costs for Producing Assets

The Company expects base production to be substantially aligned with the 2P reserves production profiles presented in the NSAI CPR, albeit with some differences in 2022 and 2023 due to near term operational updates. In particular, production in the second half of 2022 is expected to be lower than presented in the NSAI CPR mainly due to certain drilling and project activity taking longer than expected and deferral of base production due to temporarily shut-in wells.

Drilling of new wells at the Captain field has taken longer than planned, due in part to an additional sidetrack to access incremental attic oil volumes, which was not expected in the base case. The water-cut reduction in one of the EOR patterns has also been slower than predicted, leading to an expected production deferral of around 1.8 MBOEPD in the second half of 2022. Two wells in the Erskine field have been shut-in and require remedial intervention work to restart them, leading to an expected production loss of around 1.4 MBOEPD in the second half of 2022. Resumption of production from the Shell operated Pierce FPSO has been delayed due to carryover work from the shipyard to offshore, leading to an expected production loss of around 1.3 MBOEPD in the second half of 2022. Production from the field is expected to commence in the fourth quarter of 2022.

Operating costs are expected to be on average 8–9% higher than the NSAI CPR 2P reserves profiles partly due to further increases in the cost of fuel gas and diesel since the date of the NSAI CPR, general cost inflation and differences in the methodologies of estimation including foreign exchange rate assumptions.

Capital costs in the second half of 2022 are expected to be substantially aligned with the NSAI CPR. Capital costs for 2023 onwards are expected to be higher than the NSAI CPR 2P reserves profiles due partly to the projected impact of market cost inflation and timing of development activities (especially in relation to the Schiehallion, MonArb and Captain fields) which have evolved since the NSAI CPR report was prepared. In addition, the capital costs presented in the NSAI CPR do not include longer term non-development expenditure such as operated asset facilities upgrades, facilities modifications and electrification studies not associated with reserves.

Management guidance ranges for currently producing assets on short-term production, operating costs and capital costs are as follows:

- Production
  - for the three months ending 31 December 2022: 77–80 MBOEPD
  - for the year ended 31 December 2023: 72–80 MBOEPD
- Operating costs
  - for the three months ending 31 December 2022: $130–$150 million
  - for the year ended 31 December 2023: $590–$680 million
- Capital costs
  - for the three months ending 31 December 2022: $100–$120 million
  - for the year ended 31 December 2023: $450–$550 million

The above production figures are presented on a net working interest basis.

The producing assets management production guidance assumes continued production from existing wells using production efficiency in line with historical averages, resumption of production from the Pierce asset (which is currently not producing while undergoing commissioning) and production from new wells (particularly, Abigail and Captain EOR II) being delivered within the range of expected outcomes, some of which are outside the influence or control of the Directors. The Directors believe these assumptions are a reasonable basis upon which to estimate the future production.

The principal assumptions on which the operating and capital costs are based are: historic run rates on base expenditure, market assumptions for commodities, inflation and foreign exchange rates, planned maintenance, capital project contract terms (or anticipated contract terms) and capital project forecast durations, some of which are outside the influence or control of the Directors. The Directors believe these assumptions are a reasonable basis upon which to estimate operating costs and capital costs.

Contingent Production, Operating Costs and Capital Costs

Contingent resources have a varying degree of technical and commercial maturity and consideration should be given to the risks in Part 2 (*Risk Factors*) when an assessment is being made of their value. The Group has a strong pipeline of contingent development projects in currently producing assets, new development assets and early-stage discovery assets. The timing and quantum of 2C resources profile capital costs as well as volume or project sanction related deferred acquisition payments remain contingent upon project maturation and approvals.

The currently producing assets contingent projects consist of future infill wells, facilities upgrades and enhanced recovery projects. These projects are not fully mature and timing, scope and costs are subject to change as more detailed subsurface studies and engineering are undertaken. These projects are expected to mature to reserves around FID subject to satisfactory technical and economic conditions.

The proposed new development assets which are being actively prioritised consist of four projects: Cambo, Rosebank, Marigold and Fotla. These are all discovered, undeveloped fields and FID is being targeted in the near term subject to contingent factors outside of the Group's control including regulatory, financial and joint venture partner related factors. It should be noted that current inflationary conditions may result in cost estimate increases at the point of sanction and phasing of expenditure may change as the projects continue to mature. Typically, such assets are value risked accordingly.

The remaining contingent resources are early-stage discovery assets where hydrocarbons have been discovered but development plans are less mature; Courageous, Tornado, Isabella, Leverett. Since preparation of the NSAI CPR, the Courageous licence was relinquished by the Group with an effective date of 30 September 2022. Feasibility studies continue on Tornado to understand whether this can be developed via the Laggan-Tormore infrastructure. Appraisal wells are planned for Isabella in 2022/2023 to determine the size and commerciality of the field. An appraisal well is planned on Leverett in 2023 and unitisation of the field is still required. Given these projects are less mature compared to others included in the contingent resource category they should be value risked appropriately.

The appraisal and development activities are subject to significant uncertainty, see in particular paragraphs 1.2 (*The levels, quality and production volumes of the Group's oil and gas reserves and resources may be lower than estimated or expected*), 1.5 (*The Group may not be able to sanction development projects, including the Rosebank and Cambo fields, required to convert their resources into production and may face delays or cost overruns in executing sanctioned development projects*), and 1.9 (*The Group faces inherent uncertainty as to the success of highly capital-intensive appraisal and development activities; in particular, in connection with the development of the Cambo and Rosebank fields*) of Part 2 (*Risk Factors*).

Additional Management Guidance

Management guidance in relation to items that are not included within the perimeter of the NSAI CPR including non-development capital expenditure, non-producing assets decommissioning costs, exploration expenses, general and administrative expenses, net finance costs, hedging impact, tax and contingent and deferred liabilities is as follows:

Non-development capital expenditure . . .	Non-development capital expenditure includes capital expenditure on facilities and infrastructure, including upgrades and modifications, that are not directly associated with the development of oil and gas reserves. Estimated to be approximately $33 million in the second half of 2022 and $38 million per annum on average from 2023 through 2033 (and immaterial thereafter). The short-term capital costs management guidance above includes non-development capital expenditure.
Non-producing assets under decommissioning costs	Non-producing assets under decommissioning costs include assets and infrastructure that have ceased production and are in the process of being decommissioned. Estimated to be approximately $155 million in total between the second half of 2022 and 2025 and approximately $30 million in total between 2026 and 2029.
Exploration expenses	Exploration expenses include the costs of maturing exploration prospects including the costs of studies, shooting seismic, reservoir modelling and drilling exploration wells. These costs are not included in the perimeter of the NSAI CPR and they relate to acreage and assets that are pre-discovery. Estimated to be approximately $110–130 million in total until 2025. The short-term capital costs management guidance above excludes exploration expenses.
General & administrative expenses	Estimated to be approximately $25 million net to the Group per annum taking into account inflation in the short-term (excluding fees and expenses incurred in connection with the Global Offering).
Net finance costs	Decommissioning security agreement costs and revolving credit facility costs are estimated to be approximately $10–12 million per annum in the short-term. Longer-term costs will depend on any refinancing and credit capacity. For 2026 Notes and RBL Facility historical interest expense details see Part 16 (*Historical Financial Information*).
Hedging impact	See paragraphs 2.2 (*Hedging*) and 8 (*Qualitative and Quantitative Disclosures about Market Risk*) of Part 12 (*Operating and Financial Review Relating to the Group*).

Tax	The Company expects to pay the Energy Profit Levy rate of 25% on taxable profits after deduction of eligible investment expenditure spent during the period. The timing of the utilisation of the Group's RFCT and SC brought forward loss positions is subject to transfers of assets within the Group and relative profitability within the disparate legal entities. For the purposes of valuation, investors should assume that actual RFCT and SC per annum will be reduced by at least 50% (therefore less than 20% compared to the headline rates of 40%) in the medium term as the Group's brought forward loss positions are utilised. See paragraph 5 (*Taxation*) of Part 11 (*Regulation*) and paragraph 1.18 (*The Group's utilisation of tax losses and tax liability is based on forecasts and subject to estimation*) of Part 2 (*Risk Factors*).
Contingent and deferred liabilities (especially related to past acquisitions)	See paragraph 14 (*Material Contracts*) of Part 20 (*Additional Information*).

The principal assumptions on which the above guidance in relation to non-development capital expenditure, non-producing assets decommissioning costs, exploration expenses, general and administrative expenses, net finance costs, hedging impact, tax and contingent and deferred liabilities are based are: historic annual facility and infrastructure upgrade and modification costs, market rates and historic project timelines for decommissioning activities, the current and historic average costs of maturing exploration prospects, residual general & administrative expenses, the provision of security under decommissioning security agreements, and the ability of the Company to utilise tax losses based on future profits in the Group, some of which are outside the influence of the Directors. The Directors believe these assumptions are a reasonable basis upon which to estimate operating cost and capital cost.

6. OVERVIEW OF ASSETS AND OPERATIONS

The Group's oil and gas assets are divided into 21 main areas, groups and fields (as described in paragraph 5.1 (*Reserves and resources information with regard to Ithaca Energy's oil and gas assets*) above of this Part 6 (*Business Overview*)). The following table provides a summary of the Group's portfolio of assets, all of which are located in the UKCS, as at 30 June 2022.

Field group/area/field	Operator	Licence	Blocks	Ithaca Working Interest (%)	Primary Fluids	Licence Expiry(3)
Captain Field	Ithaca Energy (UK) Limited	P.324	13/22a ALL	85.000	OIL	N/A—until cessation of production
		P.2513	13/21b, 13/22b	100.000		Second Term: 30.11.26 End date: 30.11.44 (Anticipated)
Greater Stella Area						
Stella Field	Ithaca Energy (UK) Limited	P.11	30/6a D, 29/10a C	100.000	GAS	N/A—until cessation of production
Harrier Field	Ithaca Energy (UK) Limited	P.11	30/6a D, 29/10a C	100.000	OIL/GAS	N/A—until cessation of production
Vorlich Field	Ithaca Energy (UK) Limited	P.363	30/1c LOWER 30/1c UPPER	50.000 20.000	OIL	N/A—until cessation of production
		P.1588	30/1f ALL	100.000		End date: 11.02.35 (Anticipated)
Abigail Field	Ithaca Energy (UK) Limited	P.1665	29/10b ALL	100.000	OIL/GAS	End date: 11.02.35 (Anticipated)

Field group/area/field	Operator	Licence	Blocks	Ithaca Working Interest (%)	Primary Fluids	Licence Expiry(3)
Courageous Field(1)	Ithaca Energy (UK) Limited	P.2397	30/1e ALL, 30/2e ALL	55.000	OIL	N/A—licence relinquished, effective 30.09.22
Schiehallion Field	BP Exploration Operating Company Limited	P.556	204/20a,	11.754	OIL	End date: 13.06.33 (Anticipated)
		P.559	204/25a			N/A—until cessation of production
Greater Britannia Area						
Britannia Field .	Harbour Energy plc	P.103	15/30a S-BRI	33.030	GAS	N/A—until cessation of production
			15/30a L-RST	50.634		
		P.119	15/29a AREA B, 15/29a AREA C	75.000		N/A—until cessation of production
		P.213	16/26a B-BRI, 16/26a D-BEL	33.167		N/A—until cessation of production
		P.345	16/27b AREA A, 16/27b AREA B	33.750		N/A—until cessation of production
		P.225	16/27c			N/A—until cessation of production
Alder Field . . .	Ithaca Energy (UK) Limited	P.119	15/29a ALDER, 15/29a AREA A	73.684	GAS	N/A—until cessation of production
Brodgar Field .	Harbour Energy plc	P.118	21/3a ALL	6.250	GAS	N/A—until cessation of production
		P.741	21/3b	—		End Date: 13.06.27 (Anticipated)
		P.2350	21/4c	—		Initial Term: 30.09.24
						Second Term: 30.09.28 End date: 30.09.45 (Anticipated)
Callanish Field .	Harbour Energy plc	P.347	21/4a ALL	13.700	OIL	N/A—until cessation of production
		P.590	15/29b ALL	20.000		End Date: 03.06.23 (Anticipated)
Enochdhu Field	Harbour Energy plc	P.103	21/5a ALL	50.000	OIL	N/A—until cessation of production
MonArb Area						
Montrose Field .	Repsol Sinopec Resources UK	P.19, P.20	22/17n, 22/18n	41.026	OIL	N/A—until cessation of production
Arbroath Field .	Repsol Sinopec Resources UK	P.19, P.291, P.292	22/17n, 22/17s, 22/18a, 22/22a	41.026	OIL	N/A—until cessation of production
Arkwright Field .	Repsol Sinopec Resources UK	P.291	22/23a	41.026	OIL	N/A—until cessation of production
Brechin Field . .	Repsol Sinopec Resources UK	P.291	22/23a	41.026	OIL	N/A—until cessation of production
Cayley Field . .	Repsol Sinopec Resources UK	P.291	22/17s	41.026	GAS	N/A—until cessation of production
Godwin Field . .	Repsol Sinopec Resources UK	P.291, P.19	22/17s, 22/17n	41.026	OIL	N/A—until cessation of production
Shaw Field . . .	Repsol Sinopec Resources UK	P.291	22/22a	41.026	OIL	N/A—until cessation of production
Wood Field . . .	Repsol Sinopec Resources UK	P.292	22/18a	41.026	OIL	N/A—until cessation of production
Mariner Area						
Mariner Field . .	Equinor UK Limited	P.335	9/11a	8.889	OIL	N/A—until cessation of production
		P.979	9/11c,			End Date: 22.12.34 (Anticipated)
		P.2151	9/11g			Second Term: 30.11.22(4)
						End date: 30.11.40 (Anticipated)

Field group/area/field	Operator	Licence	Blocks	Ithaca Working Interest (%)	Primary Fluids	Licence Expiry(3)
Mariner East Field	Equinor UK Limited	P.726	9/11b	8.889	OIL	Second Term: 30.03.23 End date: 13.06.27 (Anticipated)
Cadet Field . . .	Equinor UK Limited	P.1758	8/15a	8.889	OIL	End date: 09.01.37 (Anticipated)
Jade and Jade South Fields . .	Harbour Energy plc	P.672	30/2c JADE,	25.500	GAS	End Date: 19.07.25 (Anticipated)
		P.1589	30/7b ALL			End Date: 11.02.35 (Anticipated)
Cook Field	Ithaca Energy (UK) Limited	P.185	21/20a ALL	61.346	OIL	N/A—until cessation of production
Erskine Field . . .	Ithaca Energy (UK) Limited	P.57	23/26a AREA B, 23/26b AREA B	50.000	GAS	N/A—until cessation of production
		P.264	23/26b AREA C, 23/26d AREA C	50.000		N/A—until cessation of production
Elgin-Franklin Field	TotalEnergies E&P UK Limited	P.188, P.362 P.666	22/30b ELGN, 29/5b ALL, 22/30c ALL, 29/5c ALL	6.088	GAS	N/A—until cessation of production End Date: 19.07.25 (Anticipated)
Alba Field	Ithaca Energy (UK) Limited	P.213	16/26a A-ALB	36.670	OIL	N/A—until cessation of production
			16/26a C-10K	21.850		
		P.2373	22/1b ALL	60.000		Second Term: 30.09.26 End date: 30.09.44 (Anticipated)
Pierce Field	Shell UK Exploration & Production	P.111	23/22a ALL	7.483	OIL/GAS	N/A—until cessation of production
		P.114	23/27a	—		N/A—until cessation of production
Columba Terraces Area						
B/D Terrace . . .	Canadian Natural Resources Limited	P.203, P.199	3/7a, 3/8a	5.600	OIL	N/A—until cessation of production
E Terrace	Canadian Natural Resources Limited	P.203	3/7a	8.400	OIL	N/A—until cessation of production
Cambo Field . . .	Ithaca Energy (UK) Limited	P.1028	204/9a, 204/10a,	70.000	OIL	Second Term: 31.03.24 End date: 31.05.37 (Anticipated)
		P.1189	204/4a, 204/5a			Second Term: 31.03.24 End date: 30.11.30 (Anticipated)
Rosebank Field . .	Equinor UK Limited	P.1026	213/26b, 213/27a,	20.000	OIL	Second Term: 31.05.24 End date: 31.05.37 (Anticipated)
		P.1191,	205/1a			Second Term: 31.05.24 End date: 30.11.30 (Anticipated)
		P1272	205/2a			Second Term: 31.05.24 End date: 21.12.31 (Anticipated)
Tornado Field . . .	Ithaca Energy (UK) Limited	P.2403	204/13,14d	50.000	OIL	Initial Term: 30.09.26 Second Term: 30.09.30 End date: 30.09.48 (Anticipated)
Marigold Field . . .	Ithaca Energy (UK) Limited	P.2158	15/18b ALL	100.000	OIL	Second Term: 31.01.24 End date: 30.11.40 (Anticipated)
Fotla Field	Ithaca Energy (UK) Limited	P.2373	22/1b	60.000	OIL/GAS	Second Term: 30.09.26 End date: 30.09.44 (Anticipated)

Field group/area/field	Operator	Licence	Blocks	Ithaca Working Interest (%)	Primary Fluids	Licence Expiry[3]
Isabella Field . . .	TotalEnergies E&P UK Limited	P.1820	30/11a, 30/12d	10.000	OIL	Second Term: 30.09.25
						End date: 09.01.37 (Anticipated)
Leverett Field . . .	NEO Energy	P.118	21/3a	25.000[2]	OIL/GAS	N/A—until cessation of production
		P.2350	21/2d	—		Initial Term: 30.09.24
						Second Term: 30.09.28 End date: 30.09.45 (Anticipated)
Decommissioning Assets						
Pickerill Field . .	Perenco UK Ltd	N/A	48/11a	5.217	OIL	N/A
Renee Field . .	Hess Corporation	N/A	15/27a	8.500	OIL	N/A
Rubie Field . . .	Hess Corporation	N/A	15/28b	40.000	OIL	N/A

Source: NSAI CPR

(1) Licence P.2397 (Courageous) was relinquished by the Group with an effective date of 30 September 2022.

(2) This block is expected to be unitised with other blocks in which IEUK does not own an interest. IEUK is expected to own a 15.000 percent interest in the resulting unitised field.

(3) Details extracted from the NSTA website (North Sea Transition Authority (NSTA): Licence data—Data downloads and publications—Data centre (nstauthority.co.uk)). Please note: (a) when an 'End Date' is provided for a producing field, this is anticipated only and may be subject to extension; and (b) Licences where the term is stated will only progress to the next term if the applicable work obligations / commitments made to NSTA are met, with the reference to 'End Date' in these circumstances being to the anticipated expiry date if the licence progresses to the next term at the time currently required by the licence.

(4) The Operator of Licence P.2151 has confirmed to NSTA, on behalf of the licensees, that the licensees wish to progress Licence P.2151 to the 'Third Term'.

6.1 *Captain Field*

Captain is an oil field located in Block 13/22a in the UK Sector of the North Sea, approximately 145 km northeast of Aberdeen in a water depth of approximately 370 ft. The field was discovered in 1977 and began producing in March 1997. There are currently 42 active wells: 7 water injection, 4 polymer injection, 17 producing under waterflood, and 14 producing under polymer flood.

Oil at Captain is heavy, with oil gravity ranging from 19 to 21 degrees API; this oil has a relatively low gas-oil ratio ("**GOR**") and an in-situ viscosity between 47 and 150 centipoise ("**cp**") at the mean reservoir temperature of 87°F. However, production is possible because of the high in situ permeability, which averages 7 darcies ("**D**"), the use of horizontal wells with long lateral lengths, and the water injection program, which began at the onset of production in 1997.

Captain produces from four reservoirs: the Upper Captain Sandstone ("**UCS**"), the Lower Captain Sandstone, and the Ross and Burns Sandstones (collectively referred to as Ross). The UCS can be divided into two distinct accumulations. The main accumulation comprises Areas A and B, and the east accumulation comprises Area C.

An EOR polymerised water injection is being deployed in the field. Some initial facilities were included in the original design to facilitate a polymer injection project. The first phase of the EOR programme, with an estimated ultimate recovery of 16 MMBOE, has resulted in a production response which has tracked or exceeded expectations. The first phase of the EOR programme currently contributes approximately 40% of Captain's current production.

In respect of future plans, the Group sanctioned Captain EOR II in April 2021 which is expected to double net production to 40 MBOEPD. Captain EOR II is expected to result in first oil in the fourth quarter of 2022, first injection in the first quarter of 2024, and peak production in 2025.

The table below contains the cumulative production and average daily rate of production for the Captain field in April 2022 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2034.

	Cumulative Production			April 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**355,142**	**70,559**	**1,610,881**	**25,008**	**6,211**	**341,392**

Source: NSAI CPR

A breakdown of the volume of reserves attributed to the Captain field as set out in the NSAI CPR as at 30 June 2022 is as follows:

	Captain Field					
	Oil (MBBL)	Natural gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Gas liquids (NGL) (MBBL)	Equivalent (MBOE)
Reserves Category	Gross reserves		Working interest reserves			
Proved Reserves (1P)	**67,562.5**	**0.0**	**57,428.2**	**0.0**	**0.0**	**57,428.2**
Proved + Probable Reserves (2P)	**93,781.4**	**0.0**	**79,714.2**	**0.0**	**0.0**	**79,714.2**
Proved + Probable + Possible Reserves (3P)	**130,856.9**	**0.0**	**111,228.4**	**0.0**	**0.0**	**111,228.4**

Source: NSAI CPR

IEUK holds an 85% operated interest in the Captain field and its sole partner is Dana Petroleum (15%).

6.2 *Greater Stella Area*

There are five fields that currently make up the Greater Stella Area. Three fields are actively producing (Stella, Harrier and Vorlich), one field is under development (Abigail), and one field was classified as contingent resources (Courageous). Licence P.2397 (Courageous) was relinquished by the Group with an effective date of 30 September 2022.

The Stella, Harrier, and Vorlich fields are tied back to a semi-submersible floating production facility FPF-1. Ithaca Energy's current plans are for the Abigail field to also be tied back to FPF-1.

FPF-1 is 12-point spread moored. It has fixed risers on the hull and flexible risers to the seabed. The facility has two-stage separation. Oil and gas are exported via pipelines. Nameplate processing capacities are 89 million cubic feet of gas per day ("**MMCFD**"), 25,000 barrels of oil per day, and 22,000 barrels of water per day.

An aggregate breakdown of the volume of reserves attributed to the Greater Stella Area as set out in the NSAI CPR as at 30 June 2022 is as follows:

	Greater Stella Area					
	Oil (MBBL)	Natural gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Gas liquids (NGL) (MBBL)	Equivalent (MBOE)
Reserves Category	Gross reserves		Working interest reserves			
Proved Reserves (1P)	**4,115.2**	**62,277.8**	**3,303.5**	**40,112.7**	**1,194.2**	**11,413.7**
Proved + Probable Reserves (2P) . . .	**8,763.9**	**111,940.9**	**6,469.0**	**73,806.6**	**2,198.2**	**21,392.5**
Proved + Probable + Possible Reserves (3P) . . .	**14,352.0**	**173,369.2**	**10,373.0**	**113,706.4**	**3,386.3**	**33,363.9**

Source: NSAI CPR

IEUK holds a 100% operated interest in the Stella, Harrier and Abigail fields, a 34% operated interest in the Vorlich field (with its sole partner as bp (66%)), and held a 55% operated interest in the Courageous field (with its sole partner as NEO Energy (45%)). Licence P.2397 (Courageous) was relinquished by the Group with an effective date of 30 September 2022.

Stella Field

The Stella field, operated by IEUK, lies entirely within Block 30/6a in the UK Sector of the North Sea in a water depth of approximately 330 ft. It is located approximately 260 km east of Aberdeen. The primary reservoir is the Andrew Sand Member ("**ASM**") of the Lista Formation. The second reservoir is the Ekofisk Formation, which is a chalk underlying the ASM. The field is tied back subsea from two drill centres to the Ithaca Energy-operated FPF-1. Following initial processing on the FPF-1, oil is exported via the Norpipe oil pipeline and gas is exported via CATS.

The table below contains the cumulative production and average daily rate of production for the Stella field in March 2022 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2027.

	Cumulative Production			March 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**3,237**	**51,689**	**1,032**	**1,232**	**12,704**	**419**

Source: NSAI CPR

Harrier Field

The Harrier field is a gas-condensate field, operated by IEUK, located within Block 30/6a in the UK Sector of the North Sea in a water depth of approximately 330 ft. It is located approximately 260 km east of Aberdeen. The Harrier field comprises two producing chalk reservoir intervals, the Tor and the Ekofisk Formations, which are at a depth of approximately 10,000 ft true vertical depth sub-sea ("**TVDSS**").

The Harrier field has been developed via a single multi-lateral well, the 30/6a-10Z, which simultaneously produces from the Paleocene Ekofisk Formations and the Cretaceous Tor Formation. The well is tied back to FPF-1 via a 9km pipe-in-pipe flowline connected to the Stella field main subsea manifold.

The Group considers that there is potential to add a further production well in the main reservoir. In addition, the existing well encountered an oil bearing Maureen Sandstone which was not completed and there is an opportunity to appraise and develop this reservoir.

The table below contains the cumulative production and average daily rate of production for the Harrier field in April 2022 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2029.

	Cumulative Production			April 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**910**	**34,470**	**196**	**401**	**15,347**	**230**

Source: NSAI CPR

Vorlich Field

The Vorlich field, operated by IEUK, is a volatile oil field located in Blocks 30/1c and 30/1f in the UK Sector of the North Sea in a water depth of approximately 300 ft. The field, located approximately 260 km east of Aberdeen, was discovered in 1984 with the drilling of the 30/1c-3 well, although only approximately 7 ft of pay was encountered. The field was further appraised by the 30/1f-13A, 30/1f-13Z, and 30/1f-13Y wellbores.

Two production wells have been drilled and completed, and production commenced in November 2020. The wells are tied back via a 9-km pipe-in-pipe flowline to a new dedicated flexible riser and umbilical connecting the subsea infrastructure to the FPF-1. A new natural gas liquids ("**NGL**") processing module on the FPF-1 was installed to maximise liquids production from the field.

The table below contains the cumulative production and average daily rate of production for the Vorlich field in March 2022 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2029.

	Cumulative Production			March 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**4,924**	**22,090**	**255**	**8,694**	**60,130**	**699**

Source: NSAI CPR

Abigail Field

The Abigail field includes both oil and gas-condensate reservoirs and is located in Block 29/10b in the UK Sector of the North Sea in a water depth of approximately 300 ft. The field was discovered in 1995 and further appraised in 2012 with the 29/10b-8 well. Before 2021, the Abigail field was known as the Hurricane field. Abigail is a pre-production discovery and part of the larger GSA development. The Abigail field has been fully sanctioned to proceed with development. A production well has been drilled and completed and subsea infrastructure installed.

The current proposed development plan involves two production wells. The first production well will twin the 29/10-4Z well, and a second well will twin the 29/10b-8 well. The wells will share a flowline back to the Stella Main Drill Centre, which is tied back to FPF-1. First oil is expected in October 2022, ten months after field development plan approval, with the second well scheduled to come online approximately two years later. The Group considers that it has the opportunity to add the second well once production from the existing well begins to decline. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2026.

Courageous Field

The Courageous field, operated by IEUK, is located in Blocks 30/1e and 30/2e of the UK Sector of the North Sea. The field was discovered by the drilling of the 30/2-1 well in 1971. Following the Group's appointment of NSAI as competent person in 2019, NSAI re-evaluated the reserves of the Group and classified the Courageous field reserves as 2C resources. Licence P.2397 (Courageous) was relinquished by the Group with an effective date of 30 September 2022.

6.3 **Schiehallion**

The Schiehallion field, operated by BP, is an oil field located in Blocks 204/20a, 204/25a, 205/16a, and 205/21b in the North Atlantic Ocean in a water depth of approximately 1,300 ft. The Schiehallion field is located approximately 175km west of the Shetland Islands and is the second largest producing field (measured by remaining commercial reserves) currently in production in the UK. Other partners in the field include Shell and Harbour Energy.

The Schiehallion field was discovered by BP in 1993. The final investment decision was secured for the Schiehallion field in 1996, and the field was brought online in 1998. The Schiehallion field was initially developed with 21 production wells and 23 injection wells. A redevelopment program was approved in 2011, and in 2012 the field was shut in. The redevelopment program included the manufacturing of the Glen Lyon FPSO and the drilling of 17 additional wells. Drilling commenced in 2016 and the field was brought back online in 2017. Topsides production design capacity is 130,000 BOPD and 310,000 BWPD, with injection capacity up to 570,000 BWPD. Oil is exported via shuttle tankers, and produced gas is exported via pipeline. The Group considers the STOIIP value for the Schiehallion field to be approximately 2.1 billion BOE, which could enable the field to continue producing into the 2040s and beyond.

First production for the Schiehallion field occurred in July 1998, and the field reached a sustained rate greater than 100,000 BOPD by the early 2000s. The produced oil is a medium crude oil of approximately 25 degrees API, slightly unsaturated. GORs for the producing wells range from 500 to 1,000 standard cubic feet per stock tank barrel, and in situ viscosity ranges from 1.5 to 3.5 cp. The Schiehallion field produces from the Vaila Formation.

In respect of future plans, there are multiple phases of future infill drilling identified. There is a sanctioned phase A program of five additional infill production wells in 2023. In the near term, there is a planned phase B program of six wells to be drilled between 2024 and 2026. Thereafter, a phase C/D program anticipates 15 further wells between 2027 and 2030. There is additional potential upside through a field life extension project to allow an additional seven years of production beyond the year 2047.

The table below contains the cumulative production and average daily rate of production for the Schiehallion field in December 2021 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2047.

	Cumulative Production			December 2021 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**424,522**	**188,353**	**268,056**	**39,503**	**15,353**	**112,944**

Source: NSAI CPR

A breakdown of the volume of reserves attributed to the Schiehallion field as set out in the NSAI CPR as at 30 June 2022 is as follows:

	Schiehallion Area					
	Oil (MBBL)	Natural gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Gas liquids (NGL) (MBBL)	Equivalent (MBOE)
Reserves Category	**Gross reserves**		**Working interest reserves**			
Proved Reserves (1P) . . .	**125,957.6**	**57,343.8**	**14,800.0**	**4,076.4**	**0.0**	**15,502.8**
Proved + Probable Reserves (2P)	**202,530.5**	**92,530.7**	**23,797.3**	**6,577.8**	**0.0**	**24,931.4**
Proved + Probable + Possible Reserves (3P)	**256,962.6**	**116,746.4**	**30,193.1**	**8,299.2**	**0.0**	**31,624.0**

Source: NSAI CPR

IEUK holds a 11.754% non-operated interest in the Schiehallion field, and its partners are Shell (44.896%), bp (operator, 33.35%) and Harbour Energy (10%).

6.4 *Greater Britannia Area*

The Greater Britannia Area consists of the Britannia, Alder, Brodgar, Callanish and Enochdhu fields.

An aggregate breakdown of the volume of reserves attributed to the Greater Britannia Area as set out in the NSAI CPR as at 30 June 2022 is as follows:

	Greater Britannia Area					
	Oil (MBBL)	Natural gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Gas liquids (NGL) (MBBL)	Equivalent (MBOE)
Reserves Category	**Gross reserves**		**Working interest reserves**			
Proved Reserves (1P)	**14,444.0**	**255,541.7**	**4,236.1**	**79,048.0**	**1,290.7**	**19,155.7**
Proved + Probable Reserves (2P)	**22,606.2**	**338,306.7**	**6,326.6**	**101,127.6**	**1,724.9**	**25,487.3**
Proved + Probable + Possible Reserves (3P)	**31,141.9**	**433,133.9**	**8,570.1**	**126,134.8**	**2,223.1**	**32,540.6**

Source: NSAI CPR

IEUK holds a 32.38% non-operated interest in the Britannia field, and its partners are Harbour Energy (operator, 58.65%).and NEO Energy (8.97%). IEUK holds a 73.68% operated interest in the Alder field, and its sole partner is Harbour Energy (26.316%). IEUK holds a 6.25% operated interest in the Brodgar field, and its sole partner is Harbour Energy (93.75%). IEUK holds a 16.5% non-operated interest in the Callanish field, and its sole partner is Harbour Energy (operator, 83.5%). IEUK holds a 50% operated interest in the Enochdhu field, and its sole partner is Harbour Energy (operator, 50%).

Britannia Field

The Britannia field is a gas-condensate field located in Blocks 15/29a, 15/30a, 16/26a, and 16/27b in the UK Sector of the North Sea in a water depth of 480 ft, approximately 225 km northeast of Aberdeen. The field covers approximately 250 square km and is operated by Harbour Energy. The field was discovered in 1975, and field development was approved in 1994 with an agreement to develop Blocks 15/30a and 16/26a as one accumulation. A fixed platform was installed in Block 16/26a, and wells were drilled in Block 15/30a that tie back to the platform via a subsea manifold. Sales gas has been produced from the field since 1998. Dry gas is delivered via the dedicated Britannia Gas Pipeline to the SAGE terminal at St. Fergus. Condensate is exported through the FPS to the Grangemouth oil terminal. There are currently 35 producing wells. The Britannia field produces from a single reservoir, the Britannia Formation.

The table below contains the cumulative production and average daily rate of production for the Britannia field in March 2022 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2035.

	Cumulative Production			March 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**76,138**	**2,114,355**	**—**	**1,358**	**62,118**	**—**

Source: NSAI CPR

Alder Field

The Alder field, operated by IEUK, is a gas-condensate satellite field to Britannia and is located in Block 15/29a in the UK Sector of the North Sea in a water depth of 500 ft. Alder is located 27 km west of Britannia and 199 km northeast of Aberdeen. The field was discovered in 1975, and a single subsea gas well, the 15/29a-A1, began producing in 2016. The production is processed at the Britannia platform, and condensate is exported via the FPS, operated by Ineos FPS Limited, for processing at the Grangemouth oil terminal in Scotland. The gas is exported from the Britannia platform via SAGE, operated by Ancala Midstream, for onshore processing at the St. Fergus gas terminal.

The Alder field has produced from the Galley Formation. The table below contains the cumulative production and average daily rate of production for the Alder field in April 2022 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2026.

	Cumulative Production			April 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**6,126**	**78,863**	**21**	**564**	**11,779**	**—**

Source: NSAI CPR

Brodgar Field

The Brodgar field, operated by Harbour Energy, is a gas-condensate satellite field tied back to Britannia and is located in Blocks 21/3a and 21/3b in the UK Sector of the North Sea in a water depth of 450 ft. The field, located 41 km southwest of Britannia and approximately 185 km northeast of Aberdeen, was discovered in 1985, and first production began in 2008. The Brodgar field currently has two producing wells, the 21/3a-H3Z and 21/3a-H4Z, which tie back to the bridge-linked platform connected to the Britannia platform via a pipeline.

The Brodgar field produces from a single reservoir, the Britannia Formation. The table below contains the cumulative production and average daily rate of production for the Brodgar field in March 2022 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2024.

	Cumulative Production			March 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**10,451**	**198,520**	**196**	**2,097**	**40,828**	**204**

Source: NSAI CPR

Callanish Field

The Callanish field, operated by Harbour Energy, is a saturated oil field with a primary gas cap located in Blocks 15/29b and 21/4a in the UK Sector of the North Sea in a water depth of 490 ft. The Callanish field is located approximately 160 km northeast of Aberdeen and 14 km southwest of Britannia, to which it is a satellite field. The field was discovered in 1999 and began producing in 2008. There are currently four actively producing wells. The Callanish field wells tie back to the bridge-linked platform connected to the Britannia platform via a subsea pipeline.

The Callanish field produces from a single reservoir, the Forties Formation. The table below contains the cumulative production and average daily rate of production for the Callanish field in March 2022 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2035.

	Cumulative Production			March 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**55,738**	**53,029**	**82,302**	**11,351**	**9,949**	**15,051**

Source: NSAI CPR

Enochdhu Field

The Enochdhu field, operated by Harbour Energy, is a satellite oil field to the Britannia field and is located in Block 21/5a in the UK Sector of the North Sea in a water depth of 460 ft. Enochdhu is located 18 km southwest of Britannia and approximately 160 km east of Aberdeen. The field was discovered in 2005 and began producing in 2015. The field currently has one producing well, the 21/5a-6, which is tied back approximately 8 km to the Callanish subsea manifold.

The Enochdhu field produces from a single reservoir, the Forties Formation. The table below contains the cumulative production and average daily rate of production for the Enochdhu field in March 2022 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2033.

	Cumulative Production			March 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**10,306**	**10,652**	**5,988**	**1,140**	**1,001**	**3,258**

Source: NSAI CPR

6.5 ***MonArb Area***

The Montrose-Arbroath (MonArb) Area includes the hub fields of Montrose and Arbroath and the satellite fields of Arkwright, Brechin, Cayley, Godwin, Shaw and Wood.

The Montrose Alpha Platform, commissioned in 1976, is an eight-legged steel jacket structure that has processing, separation, and export facilities for hydrocarbons produced from Montrose, Arbroath, Arkwright, Brechin, Carnoustie, Godwin and Wood fields. The Montrose Alpha Platform was modified in 1990 to receive liquids from the Arbroath Platform, a minimal facilities platform that receives hydrocarbons from Arbroath, Arkwright, Brechin, Carnoustie, and Godwin fields. Gas and liquids are initially separated at this platform, then exported to the Montrose Alpha Platform via a 10-inch liquids pipeline and a 16-inch gas pipeline. Produced liquids from the MonArb Area are exported to the Forties Charlie via a 48km, 14-inch pipeline owned by the MonArb partners. A new platform, the Montrose Bridge Linked Platform ("**BLP**"), was built in 2016 and connected to the Montrose Alpha by a 71 m bridge. The BLP receives hydrocarbons from Cayley and Shaw fields, which are two subsea developed fields, discovered in 2007 and 2009, respectively. Oil is routed over the bridge to the Montrose Alpha Platform and gas is exported via a gas riser into a 6-inch export pipeline in the CATS pipeline.

In respect of future plans, the Group considers that there is exploration upside including the Upside Jurassic Vigne prospect which the Group believes holds up to 27 MMBOE with a 25% geological chance of success.

An aggregate breakdown of the volume of reserves attributed to the MonArb Area as set out in the NSAI CPR as at 30 June 2022 is as follows:

	MonArb Area					
	Oil (MBBL)	Natural gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Gas liquids (NGL) (MBBL)	Equivalent (MBOE)
Reserves Category	Gross reserves		Working interest reserves			
Proved Reserves (1P)	**23,720.2**	**39,950.0**	**9,731.4**	**15,581.8**	**0.0**	**12,417.9**
Proved + Probable Reserves (2P)	**43,450.3**	**63,258.3**	**17,825.8**	**24,797.7**	**0.0**	**22,101.2**
Proved + Probable + Possible Reserves (3P)	**70,277.4**	**94,421.6**	**28,831.7**	**37,135.2**	**0.0**	**35,234.4**

Source: NSAI CPR

IEUK holds a 41.03% non-operated interest in the Monarb Area, and IEUK's sole partner in the Montrose, Arbroath, Arkwright, Brechin, Cayley, Godwin, Shaw and Wood fields is Repsol Sinopec (operator, 58.97%).

Montrose Field

The Montrose field, operated by Repsol Sinopec, is an oil field located in Blocks 22/17n and 22/18n in the UK Sector of the North Sea in a water depth of approximately 289 ft. The field, located approximately 200 km east of Aberdeen, was discovered in 1971 by the drilling of the 22/18-2 well. The field was appraised by the drilling of the 22/17-1 well, and production commenced in June 1976. As at April 2022, 25 production wells and 5 water injection wells have been drilled from the Montrose Alpha platform. Separation, processing, and export of hydrocarbons also occurs on the Montrose Alpha platform. The 22/17-A28Z well is currently the only well online; a number of mechanical failures led to several other wells being prematurely shut in.

In respect of future plans, a proposed infill programme is being processed by the operator, with the final investment decision for phase 1 expected in 2023. Phase 1 includes the drilling of 4 new subsea wells (the MRC, MRG, MRH and MRI) and the purchase of associated production equipment. First oil for the phase 1 wells is expected in 2025. Phase 2 includes the drilling of 2 additional subsea production wells (the MRJ and MRSW) and first oil expected in 2027.

Montrose field produces from a single reservoir, the Forties Sandstone. The table below contains the cumulative production and average daily rate of production for the Montrose field in April 2022 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2033.

	Cumulative Production			April 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**91,263**	**64,265**	**56,634**	**429**	**219**	**1,549**

Source: NSAI CPR

Arbroath Field

The Arbroath field, operated by Repsol Sinopec, is an oil field located in Blocks 22/17n, 22/17s, 22/18a, and 22/22a in the UK Sector of the North Sea in a water depth of approximately 305 ft. The field is located approximately 8km south of Montrose field and was discovered in 1969 by the drilling of the 22/18-1 well. Production commenced in April 1990.

As at April 2022, 26 production wells and 9 water injection wells have been drilled from the Arbroath platform. Arbroath is a minimum facilities platform with gas and liquids separation taking place prior to fluids being exported to the Montrose Alpha platform for further processing and export. There are 5 wells currently producing, and most historical producing wells are shut-in because of water production. Water injection ceased during 2004. The 22/17-T23A well returned to production in 2022 following replacement of an oil choke.

In respect of future plans, 3 additional reinstatements are planned in the near term for the 22/17-T17, 22/17-T20, and 22/17-T25 wells.

The Arbroath field produces from a single reservoir, the Forties Formation. The table below contains the cumulative production and average daily rate of production for the Arbroath field in April 2022 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2033.

	Cumulative Production			April 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**155,756**	**84,569**	**88,253**	**1,138**	**405**	**6,532**

Source: NSAI CPR

Arkwright Field

The Arkwright field, operated by Repsol Sinopec, is an oil field located in Block 22/23a in the UK Sector of the North Sea in a water depth of approximately 308 ft. The field, located approximately 217 km east of Aberdeen, was discovered in 1990 by the drilling of the 22/23a-3 well. Production commenced in November 1996 with the three production wells. A fourth, horizontal well was drilled and brought online in 2007.

The 22/23a-C4 well is the only well currently online. According to Repsol Sinopec, the 22/23a-C3 well is shut-in pending pipeline ullage and the 22/23a-C2 well is infrequently produced.

In respect of future plans, the Group considers that there is potential to increase current production from the return of Arkwright C3 to production.

The Arkwright field produces from a single reservoir, the Forties Formation. The table below contains the cumulative production and average daily rate of production for the Arkwright field in April 2022 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2031.

	Cumulative Production			April 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**23,068**	**13,997**	**6,993**	**763**	**380**	**1,808**

Source: NSAI CPR

Brechin Field

The Brechin field, operated by Repsol Sinopec, is an oil field located in Block 22/23a in the UK Sector of the North Sea in a water depth of approximately 305 ft. The field, located approximately 221km east of Aberdeen, was discovered in 2004 by the drilling of the 22/23a-7 well. Production commenced in June 2005 from the 22/23a-7Z well, a horizontal side-track on the original discovery well.

The Brechin field produces from a single reservoir, the Forties Formation. The table below contains the cumulative production and average daily rate of production for the Brechin field in April 2022 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2033.

	Cumulative Production			April 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**5,469**	**5,919**	**4,331**	**948**	**716**	**2,156**

Source: NSAI CPR

Cayley Field

The Cayley field, operated by Repsol Sinopec, is a gas-condensate field located in Block 22/17s in the UK Sector of the North Sea in a water depth of approximately 298 ft. The field, located approximately 10 km west of the Montrose Alpha platform, was discovered in 2007 by the drilling of the 22/17-3 exploration well. The field was appraised by the drilling of the 22/17-3Z, 22/17-3Y, and 22/22a-7X wells, and production commenced in June 2017. As at April 2022, a single production well has been drilled as a subsea tieback to the Montrose Alpha platform. Separation, processing, and export of hydrocarbons also occurs on the Montrose Alpha platform. The 22/17-J1 well (also known as the CP01 well) started producing in June 2017. The Cayley field produces from the Fulmar Formation.

In respect of future plans, the Group considers that there is potential to increase current production from infill drilling.

The table below contains the cumulative production and average daily rate of production for the Cayley field in April 2022 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2033.

	Cumulative Production			April 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**2,931**	**58,271**	**7**	**850**	**23,743**	**0**

Source: NSAI CPR

Godwin Field

The Godwin field, operated by Repsol Sinopec, is an oil field located in Block 22/17s in the UK Sector of the North Sea in a water depth of approximately 289 ft. The field is located approximately 206km east of Aberdeen, was discovered in 2009 by the drilling of the 22/17-4 well and appraised by the drilling of an updip side-track, the 22/17-4Z well. Production commenced in July 2015 from a single horizontal well, the 22/17-T27, which was drilled as an extended-reach well from the Arbroath platform.

The Godwin field produces from a single reservoir, the Fulmar Formation. The table below contains the cumulative production and average daily rate of production for the Godwin field in April 2022 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2033.

	Cumulative Production			April 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**4,389**	**1,944**	**2,561**	**590**	**258**	**2,366**

Source: NSAI CPR

Shaw Field

The Shaw field, operated by Repsol Sinopec, is an oil field located in Block 22/22a in the UK Sector of the North Sea in a water depth of approximately 313 ft. The field, located approximately 17 km south of the Montrose Alpha platform, was discovered in 2009 by the drilling of the 22/22a-7 exploration well. The field was appraised by the drilling of the 22/22a-7Y wells, and production commenced in May 2017.

As at April 2022, two production wells and one water injection well had been drilled as subsea tiebacks to the Montrose Alpha platform. Separation, processing, and export of hydrocarbons also occurs on the Montrose Alpha platform. The 22/22a-N2 well (also known as the SHA well) started producing in May 2017 and is still producing. The 22/22a-N3 well (also known as the SHB well) started producing in June 2019 and is still producing. Water injection into 22/22a-R1 well (also known as SHD well) started in July 2018. Water injection stopped in May 2020 and recommenced in March 2021.

In respect of future plans, a third production well, the SHC well, has been approved and is expected to be spud in late 2022 or early 2023, with first production expected in 2023. The Group considers that there is potential to increase current production from infill drilling.

The Shaw field produces from a single reservoir, the Fulmar Formation. The table below contains the cumulative production and average daily rate of production for the Shaw field in April 2022 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2033.

	Cumulative Production			April 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**22,678**	**20,419**	**1,601**	**8,660**	**9,097**	**3,165**

Source: NSAI CPR

Wood Field

The Wood field, operated by Repsol Sinopec, is a volatile oil field located in Block 22/18a in the UK Sector of the North Sea in a water depth of approximately 296 ft. The field is located approximately 215 km east of Aberdeen and was discovered in 1996 by the drilling of the 22/18-6 well. Production commenced in December 2007 from a single horizontal subsea well, the 22/18-7 (also known as the W01), which is tied back to the Montrose Alpha platform.

The Wood field produces from a single reservoir, the Fulmar Formation. The table below contains the cumulative production and average daily rate of production for the Wood field in April 2022 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2033.

	Cumulative Production			April 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**4,278**	**9,755**	**1,010**	**684**	**1,626**	**1,020**

Source: NSAI CPR

6.6 *Mariner Area*

The Mariner Area comprises the Mariner, Mariner East, and Cadet fields. The Mariner field is actively producing, and the volumes for Mariner East and Cadet fields are classified as contingent resources. The Mariner and Mariner East fields target the Maureen Formation and Heimdal Sandstone, and Cadet field targets the Heimdal Sandstone. Mariner has had top-tier facilities performance since the start up of the field.

The Mariner Area development is centred on Mariner A, a steel jacket production, drilling, and living quarters platform. The platform has 60 well slots, of which 50 can be concurrently active. Topsides production capacity is 80,000 BOPD and 290,000 BWPD, with injection capacity of 345,000 BWPD. Oil is exported from Mariner A to Mariner B, a fixing floating storage unit, then to shuttle tankers. Oil production began in 2019, and the Mariner A platform has a 40-year design life.

IEUK holds an 8.889% non-operated interest in the Mariner Area, and its partners in the Mariner, Mariner East and Cadet fields are Equinor (operator, 65%), NEO Energy (20%) and ONE-Dyas (6%).

Mariner Field

The Mariner field, operated by Equinor UK Limited, is located in Blocks 9/11a, 9/11b, 9/11c, and 9/11g in the UK Sector of the North Sea in a water depth of approximately 330ft, approximately 150km east of the Shetland Islands. The field was discovered by Union Oil

Company of California (Unocal) in 1981, with the drilling of the 9/11-1 well. Texaco took ownership of the Mariner field in 1984. Unocal had drilled 4 additional appraisal wells by that time, and Texaco drilled 8 appraisal wells from 1995 to 1997. Equinor assumed operatorship in 2007. To date, there are 22 exploration and appraisal wells and 20 development well penetrations, including sidetracks.

First production occurred in August 2019 and the field production rate reached 50,000 BOPD in 2021. The produced oil is heavy, and typical values are 15 degrees API in the Maureen Formation and 11 degrees API in the Heimdal Sandstone. Production is accomplished with the use of the ESPs in every well plus the use of diluent. Diluent was initially used for production from the Maureen Formation but it is understood that this technique has been progressively phased out. It will be used for production of the heavier oil from the Heimdal Sandstone wells. As at the end of February 2022, there were ten wells actively producing from the Maureen Formation and three active water injection wells in the Maureen Formation, one oil well producing from the Heimdal Sandstone with no water injection into the Heimdal Sandstone, and one well returning to production in August 2022 following an ESP replacement.

In respect of future plans, future development of the Maureen Formation includes the drilling of four additional production wells and one additional water injection well in 2022 and 2023. In addition, three production wells and one additional water injection well are further planned from 2026 to 2029. The production wells are a mix of infill locations and step-out locations. Future development of the Heimdal Sandstone includes the drilling of 36 additional production well locations and 19 injection well locations between 2022 and 2031. The Group also considers that the field has a potential uplift from a polymer project which is being matured for decision gate 3 decision and targeted first injection in 2024.

The Mariner field has produced from the Maureen Formation and the Heimdal Sandstone. The table below contains the cumulative production and average daily rate of production for the Mariner field in December 2021 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2041.

	Cumulative Production			**December 2021 Average Daily Rate**		
	Oil (MBBL)	**Gas (MMCF)**	**Water (MBBL)**	**Oil (BOPD)**	**Gas (MCFD)**	**Water (BWPD)**
Total	**21,770**	**4,539**	**63,113**	**22,095**	**4,705**	**101,810**

Source: NSAI CPR

A breakdown of the volume of reserves attributed to the Mariner field as set out in the NSAI CPR as at 30 June 2022 is as follows:

	Mariner Field					
	Oil (MBBL)	**Natural gas (MMCF)**	**Oil (MBBL)**	**Gas (MMCF)**	**Gas liquids (NGL) (MBBL)**	**Equivalent (MBOE)**
Reserves Category	**Gross reserves**		**Working interest reserves**			
Proved Reserves (1P)	**110,697.4**	**0.0**	**9,839.8**	**0.0**	**0.0**	**9,839.8**
Proved + Probable Reserves (2P)	**163,398.4**	**0.0**	**14,524.3**	**0.0**	**0.0**	**14,524.3**
Proved + Probable + Possible Reserves (3P)	**206,961.3**	**0.0**	**18,396.6**	**0.0**	**0.0**	**18,396.6**

Source: NSAI CPR

Mariner East Field

The Mariner East field is located southeast of the Mariner field in Blocks 9/11a and 9/11b in the UK Sector of the North Sea. Mariner East field was discovered by the drilling of the 9/11b-11 well, which penetrated the Maureen Formation and Heimdal Sandstone.

In respect of future plans, the development plan assumes a standalone unmanned wellhead platform tied back to the Mariner A platform that would target both the Maureen Formation and Heimdal Sandstone. The Maureen formation is assumed to be developed with six production wells and two injection wells, and the Heimdal Sandstone is assumed to be developed with three production wells and one injection well.

Cadet Field

The Cadet field is located west of the Mariner field in Block 8/15a in the UK Sector of the North Sea. The Cadet field was discovered by the drilling of the 8/15-1 well, which penetrated the Heimdal Sandstone.

In respect of future plans, the development plan is assumed to be developed with ten production wells and five injection wells.

6.7 *Jade and Jade South Fields*

The Jade and Jade South fields, operated by Harbour Energy, are high pressure, high-temperature gas-condensate fields located in Blocks 30/2c and 30/7b in the UK Sector of the North Sea in a water depth of approximately 260 ft. The Jade field, located approximately 270 km east of Aberdeen, was discovered in 1996 and began producing in 2002 from an NUI. There are currently nine wells producing from a fixed wellhead platform, which is tied back to a dedicated separator on the Judy platform. Two of the nine producing wells produce cyclically. The Judy platform, operated by Harbour Energy, is located approximately 17 km to the southeast and hosts the primary Jade processing facilities. The Jade South field is a southern extension of Jade field. In the subsurface, it is separated from Jade field by a structural saddle.

The Jade South field produces from a single well, which is drilled from the same platform as the Jade field wells. The Jade field produces from the Joanne and Judy Sandstones, and Jade South field produces from the Joanne Sandstone. The single Jade South well came online in January 2022.

In respect of future plans, work on a new development well (JM) commenced in January 2022 in the crestal area of the field. This is targeting the deeper Judy reservoir and has an estimated 2P reserves of 5.3MMBOE (1.4MMBOE net to Ithaca Energy).

The table below contains the cumulative production and average daily rate of production for the Jade and Jade South fields in January 2022 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2035.

	Cumulative Production			January 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**54,969**	**799,577**	**4,745**	**5,434**	**46,530**	**465**

Source: NSAI CPR

An aggregate breakdown of the volume of reserves attributed to the Jade and Jade South fields as set out in the NSAI CPR as at 30 June 2022 is as follows:

	Jade and Jade South Fields					
	Oil (MBBL)	Natural gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Gas liquids (NGL) (MBBL)	Equivalent (MBOE)
Reserves Category	Gross reserves		Working interest reserves			
Proved Reserves (1P)	**6,295.8**	**114,207.3**	**1,605.4**	**26,938.6**	**816.4**	**7,066.5**
Proved + Probable Reserves (2P)	**10,473.5**	**178,694.0**	**2,670.7**	**42,149.4**	**1,277.4**	**11,215.3**
Proved + Probable + Possible Reserves (3P)	**20,350.5**	**286,899.9**	**5,189.4**	**67,672.5**	**2,051**	**18,908**

Source: NSAI CPR

IEUK holds a 25.5% non-operated interest in the Jade and Jade South fields, and its partners are Harbour Energy (operator, 67.5%) and ENI (7%).

6.8 ***Cook Field***

The Cook field, operated by IEUK, is an oil field located in Block 21/20a within the Central Graben Area of the UKCS 195 km east of Aberdeen in a water depth of approximately 310 ft. The field was discovered by the drilling of Amoco's 21/20a-2 well in August 1983 and began commercial production from the 21/20a-P1 well in early 2000.

Oil at Cook is light and under-saturated with oil gravity of approximately 38 degrees API and an in-situ viscosity of approximately 0.3 cp at an average reservoir temperature of 300°F. Fluid expansion and rock compression have been the dominant drive mechanisms as the pressure has depleted nearly 7,000 psi to date. Additionally, there is evidence of aquifer encroachment and pressure support from the formation of a secondary gas cap. The 21/20a-P2 water injection well was drilled to provide additional pressure support and reservoir sweep. The 21/20a-P1 well is a subsea wellhead tied back approximately 12 km to the third-party operated Anasuria FPSO. The Anasuria FPSO is shared with additional subsea tiebacks including the Teal, Teal South, and Guillemot A developments. Oil volumes are offloaded via tanker from the Anasuria FPSO to oil markets. Gas volumes are exported via the subsea Shell-Esso Gas and Liquids ("**SEGAL**") pipeline to the Shell operated gas terminal at St. Fergus. Gas-lift infrastructure is in place and operational in the production well. Successful water injection performance has been realised after the recent installation of water injection infrastructure at the 21/20a-P2 well.

In terms of future plans, the field was developed under depletion drive by the sole producing well until a water injection well, the 21/20a-P2, was drilled in October 2019. The injection well had limited uptime and was repaired in February 2021. A repair is planned for late 2022 to bring the well back into service. An additional water injection well, the Cook West, is planned for 2024.

Cook has produced from a single reservoir, the Fulmar Formation. The table below contains the cumulative production and average daily rate of production for the Cook field in April 2022 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2033.

	Cumulative Production			April 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**53,261**	**76,479**	**221**	**3,502**	**12,019**	**—**

Source: NSAI CPR

A breakdown of the volume of reserves attributed to the Cook field as set out in the NSAI CPR as at 30 June 2022 is as follows:

	Cook Field					
	Oil (MBBL)	Natural gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Gas liquids (NGL) (MBBL)	Equivalent (MBOE)
Reserves Category	Gross reserves		Working interest reserves			
Proved Reserves (1P)	**7,006.7**	**9,288.3**	**4,298.3**	**3,601.1**	**0.0**	**4,919.2**
Proved + Probable Reserves (2P)	**16,096.2**	**10,387.4**	**9,874.3**	**4,027.3**	**0.0**	**10,568.7**
Proved + Probable + Possible Reserves (3P)	**22,861.5**	**11,699.7**	**14,024.6**	**4,536.0**	**0.0**	**14,806.7**

Source: NSAI CPR

IEUK holds a 61.346% operated interest in the Cook field, and its partners are Hibiscus (19.327%) and Ping (19.327%).

6.9 ***Erskine Field***

The Erskine field, operated by IEUK, is a gas-condensate field located in Blocks 23/26a and 23/26b in the UK Sector of the North Sea in a water depth of approximately 300 ft. The field, located approximately 241 km east of Aberdeen, was discovered in 1985 and began producing in 1997 from a NUI operated remotely from the Lomond platform. In January 2018, the field was shut in because of a blockage of the condensate export line from the Lomond platform. Installation of a new line to bypass the blocked segment was completed and production was restarted in October 2018. From the Lomond platform, gas and condensate are exported separately to the North Everest platform, operated by Harbour Energy, before gas is exported via CATS. Condensate is exported through the FPS. There are currently four active producing wells.

In respect of future plans, the W1 well is currently offline because of an issue with scale in tubing with a remedial workover planned in 2022. Future resource opportunities have been identified including a reduction in the arrival pressure at the Lomond processing facility and the possibility of drilling an additional well in the Erskine reservoir.

Erskine has produced from three reservoirs: the Erskine, Kimmeridge, and Pentland Sandstones. The table below contains the cumulative production and average daily rate of production for the Erskine field in April 2022 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2028.

	Cumulative Production			April 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**70,486**	**388,085**	**12,513**	**4,158**	**36,222**	**345**

Source: NSAI CPR

A breakdown of the volume of reserves attributed to the Erskine field as set out in the NSAI CPR as at 30 June 2022 is as follows:

	Erskine Field					
	Oil (MBBL)	Natural gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Gas liquids (NGL) (MBBL)	Equivalent (MBOE)
Reserves Category	**Gross reserves**		**Working interest reserves**			
Proved Reserves (1P)	**2,549.1**	**21,639.6**	**1,274.5**	**10,473.5**	**151.6**	**3,232.0**
Proved + Probable Reserves (2P)	**6,787.3**	**53,614.6**	**3,393.6**	**25,949.4**	**375.7**	**8,243.4**
Proved + Probable + Possible Reserves (3P)	**9,086.1**	**71,474.8**	**4,543.0**	**34,593.8**	**500.9**	**11,008.3**

Source: NSAI CPR

IEUK holds a 50% operated interest in the Erskine field, and its partners are Harbour Energy (32%) and Serica Energy (18%).

6.10 ***Elgin-Franklin Field***

Elgin-Franklin is composed of two gas-condensate fields, the Elgin and Franklin fields, located in Blocks 22/30b, 22/30c, 29/4d, 29/5b, and 29/5c in the UK Sector of the North Sea in a water depth of approximately 330 ft. The fields, operated by TotalEnergies, are located approximately 240 km east of Aberdeen and are produced from a total of four wellhead platforms back to one central processing unit. Gas is exported via the Shearwater Elgin Area Line ("**SEAL**"), and condensate is exported through the FPS. For the purposes of the NSAI CPR, these two fields are combined into Elgin-Franklin field to facilitate the handling of projects impacting the shared infrastructure.

For the purposes of the NSAI CPR, Elgin-Franklin field was split into three separate areas: Elgin, Franklin and West Franklin. The areas combined contribute to Elgin-Franklin being the Group's largest producing field complex on the UKCS[3]. Each area has its own distinct structure and trap. The Elgin, Franklin and West Franklin Areas were discovered in 1991, 1985 and 2003, respectively. All three areas have high pressure, high-temperature fluids and initial pressures over 15,500 pounds per square inch absolute and temperatures over 370°F. There are currently seven active production wells in the Elgin Area, five in the Franklin Area, and four in the West Franklin Area. Elgin-Franklin has a robust operating cash generation with approximately $7.5/BOE operating expenses (including transport) against UK

3 Source: Wood Mackenzie

gas prices of more than $100/BOE. Elgin-Franklin is also a key part of the planning Central North Sea electrification process. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2038.

An aggregate breakdown of the volume of reserves attributed to the Elgin-Franklin field as set out in the NSAI CPR as at 30 June 2022 is as follows:

	Elgin-Franklin Field					
	Oil (MBBL)	Natural gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Gas liquids (NGL) (MBBL)	Equivalent (MBOE)
Reserves Category	Gross reserves		Working interest reserves			
Proved Reserves (1P) . . .	63,706.2	558,387.9	2,404.4	33,482.0	1,139.5	9,316.7
Proved + Probable Reserves (2P)	83,618.5	718,510.6	3,156.0	43,083.2	1,466.3	12,050.4
Proved + Probable + Possible Reserves (3P)	116,726.5	921,538.2	4,405.5	55,257.2	1,880.7	15,813.3

Source: NSAI CPR

IEUK holds a 6.09% non-operated interest in the Elgin-Franklin field, and its partners are TotalEnergies (operator, 46.173%), ENI (21.867%), Harbour Energy (19.31%), NEO Energy (4.375%) and ONE-Dyas (2.188%).

Elgin Area

Wells in the Elgin Area encountered a complex faulted anticline broken into various fault blocks with unique water contacts. The field produces from the Upper Jurassic Fulmar Formation at approximately 17,500ft TVDSS; this formation is a shallow marine, bioturbated sandstone.

In respect of future plans, a further well in Elgin is under consideration.

The table below contains the cumulative production and average daily rate of production for the Elgin Area in April 2022 as set out in the NSAI CPR.

	Cumulative Production			April 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**67,429**	**384,287**	**3,173**	**26,383**	**180,117**	**1,768**

Source: NSAI CPR

Franklin Area

The Franklin Area is a tilted fault block approximately 5 km south of the Elgin Area. Three reservoirs have produced here: the Fulmar Formation at approximately 17,600ft TVDSS, the Middle Jurassic Pentland Formation at approximately 18,050ft TVDSS, and the Triassic Skagerrak Formation at approximately 18,700ft TVDSS.

The table below contains the cumulative production and average daily rate of production for the Franklin Area in April 2022 as set out in the NSAI CPR.

	Cumulative Production			April 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**152,212**	**993,143**	**7,981**	**12,795**	**119,510**	**1,715**

Source: NSAI CPR

West Franklin Area

The West Franklin Area produces from the Fulmar Formation, but at a deeper depth than the Franklin Area, of approximately 18,600ft TVDSS.

The table below contains the cumulative production and average daily rate of production for the West Franklin Area in April 2022 as set out in the NSAI CPR.

	Cumulative Production			April 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**77,195**	**528,697**	**5,114**	**15,391**	**119,519**	**1,536**

Source: NSAI CPR

6.11 ***Alba Field***

The Alba field, operated by IEUK, is an oil field located in Block 16/26a in the UK Sector of the North Sea in a water depth of 440ft, approximately 225 km northeast of Aberdeen. The field was discovered in 1984 with the drilling of the 16/26-5 well, and 16 additional appraisal wells have been drilled. Annex B approval to develop the field was granted in 1991, and production began in 1994. There are 23 active production wells. Oil at Alba has high density, a low GOR, and high in situ viscosity.

Production is possible because of high reservoir permeability, horizontal production wells that are typically 400ft to 2,000ft in lateral length, and bottom-drive water injection to supplement the limited natural aquifer support. The field is developed with long-reach wells from the Alba North Platform ("**ANP**") plus two subsea manifolds: the Alba Extreme South ("**AXS**") for production wells and the SADIE for injection wells. Oil is transported by tanker ship from a floating storage unit. Of the 23 active production wells, 17 are platform wells drilled from the ANP and 6 are subsea wells drilled from the AXS.

In respect of future plans, 14 infill wells have been identified targeting areas of unswept oil. Drilling activities are expected to recommence in the fourth quarter of 2022. The Group also considers that there is tie back potential from nearby prospects.

The Alba field has produced from a single reservoir, the Alba formation. The table below contains the cumulative production and average daily rate of production for the Alba field in April 2022 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2029.

	Cumulative Production			April 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**210,448**	**64,168**	**1,242,736**	**6,806**	**2,871**	**155,412**

Source: NSAI CPR

A breakdown of the volume of reserves attributed to the Alba field as set out in the NSAI CPR as at 30 June 2022 is as follows:

	Alba Field					
	Oil (MBBL)	Natural gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Gas liquids (NGL) (MBBL)	Equivalent (MBOE)
Reserves Category	**Gross reserves**		**Working interest reserves**			
Proved Reserves (1P)	11,863	0.0	4,350.2	0.0	0.0	4,350.2
Proved + Probable Reserves (2P)	19,268.4	0.0	7,065.7	0.0	0.0	7,065.7
Proved + Probable + Possible Reserves (3P)	28,670.9	0.0	10,513.6	0.0	0.0	10,513.6

Source: NSAI CPR

IEUK holds a 36.67% operated interest in the Alba field, and its partners are Waldorf (25.68%), NEO Energy (17%), Spirit Energy (12.65%) and EnQuest (8%).

6.12 ***Pierce Field***

The Pierce field, operated by Shell UK Exploration & Production Limited lies within Blocks 23/22a and 23/27a of the UK Sector of the North Sea approximately 240 km due east of Aberdeen in 280 ft of water. The field is centred around two salt diapirs, both with oil legs containing black oil and respective gas caps. The two parts of the field are referred to as North Pierce and South Pierce. Solution gas drive is the primary drive mechanism. Development wells have been drilled from three subsea wellhead sites: the main drill site centrally located between North and South Pierce, the satellite drill site located on the southwest side of South Pierce, and the C1z wellhead on the north side of North Pierce. Eight production wells and three gas injection wells are currently active. The current production wells have targeted the oil rim with long horizontal producers. Gas has been injected across both diapirs, while water injection has been focused on the southern area where a weaker aquifer is apparent. All wells are connected through subsea manifolds to the Haewene Brim FPSO, which is operated by Bluewater Energy Services BV. The field is operated by Shell. Currently all produced gas, after volumes are consumed in field operations, is injected back into the field.

In respect of future plans, a depressurisation project allowing the export and sale of gas through a subsea tie-in to the Shell-operated SEGAL subsea pipeline is sanctioned. Oil is exported to market via shuttle tankers from the Haewene Brim FPSO. The field was temporarily shut in starting in October 2021 to allow this work to be completed with planned start-up in the fourth quarter of 2022.

The Pierce field produces from a single reservoir, the Forties Formation.

The table below contains the cumulative production and average daily rate of production for the Pierce field in October 2021 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2035.

	Cumulative Production			October 2021 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**81,117**	**402,604**	**5,532**	**7,349**	**70,039**	**191**

Source: NSAI CPR

A breakdown of the volume of reserves attributed to the Pierce field as set out in the NSAI CPR as at 30 June 2022 is as follows:

	Pierce Field					
	Gross reserves		Working interest reserves			
Reserves Category	Oil (MBBL)	Natural gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Gas liquids (NGL) (MBBL)	Equivalent (MBOE)
Proved Reserves (1P)	**15,116.3**	**169,701.6**	**1,131.2**	**10,540.0**	**1,248.3**	**4,196.7**
Proved + Probable Reserves (2P)	**24,918.0**	**256,835.8**	**1,864.6**	**15,951.8**	**1,889.2**	**6,504.2**
Proved + Probable + Possible Reserves (3P)	**35,548.5**	**344,579.4**	**2,660.1**	**21,401.4**	**2,534.7**	**8,884.7**

Source: NSAI CPR

IEUK holds a 7.48% non-operated interest in the Pierce field, and its sole partner is Shell (operator, 92.52%).

6.13 ***Columba Terraces Area***

The Columba Terraces Area, located to the west and southwest of the giant Ninian field, is a complex of three downthrown fault blocks known as the B, D and E Terraces. Both Ninian field and the Columba Terraces Area are operated by Canadian Natural Resources Limited (CNRL).

The Columba Terraces Area is an oil field located in Blocks 3/7a and 3/8a in the UK Sector of the North Sea in a water depth of approximately 476 ft. The complex is located 386 km northeast of Aberdeen. The B, D and E Terraces were discovered in 1976, 1980 and 1875, respectively. Production commenced in 1996 for the B Terrace, 1994 for the F Terrace and 1998 for the E Terrace.

Production has been via long-reach wells drilled from the Ninian South Platform. One injection well has been drilled from the Ninian Central Platform. Currently there are seven producing wells, of which one is a continuous production well, two are cyclic production wells, and four are water injection wells.

The Columba Terraces Area produces from the sandstones of the Middle Jurassic Brent Group. The table below contains the cumulative production and average daily rate of production for the Columba Terraces Area in May 2022 as set out in the NSAI CPR. Based on 2P reserves set out in the NSAI CPR, production is forecast to continue until 2025.

	Cumulative Production			May 2022 Average Daily Rate		
	Oil (MBBL)	Gas (MMCF)	Water (MBBL)	Oil (BOPD)	Gas (MCFD)	Water (BWPD)
Total	**66,454**	**0**	**0**	**798**	**0**	**0**

Source: NSAI CPR

A breakdown of the volume of reserves attributed to the Columba Terraces Area as set out in the NSAI CPR as at 30 June 2022 is as follows:

	Columba Terraces Area					
	Oil (MBBL)	Natural gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Gas liquids (NGL) (MBBL)	Equivalent (MBOE)
Reserves Category	Gross reserves		Working interest reserves			
Proved Reserves (1P)	**782.0**	**0.0**	**44.0**	**0.0**	**0.0**	**44.0**
Proved + Probable Reserves (2P)	**1,050.7**	**0.0**	**59.4**	**0.0**	**0.0**	**59.4**
Proved + Probable + Possible Reserves (3P)	**1,834.7**	**0.0**	**104.9**	**0.0**	**0.0**	**104.9**

Source: NSAI CPR

IEUK holds a 5.60% non-operated interest in the Columba B/D Terrace field, and its sole partner is CNRL (operator, 94.4%), and an 8.40% interest in the Columba E Terrace field and its sole partner is CNRL (operator, 91.60%).

6.14 *Cambo Field*

The Cambo field, operated by the Group, is an undeveloped oil field located in Blocks 204/9a and 204/10a and Blocks 204/4a and 204/5a in the North Atlantic Ocean in a water depth of 3,600ft, approximately 125 km northwest of the Shetland Islands. The field was discovered in 2002, with the drilling of the 204/10-1 well. Between 2002 and 2018, the Cambo field has been appraised with a total of six wells and three sidetracks. The field is also covered by high-resolution Dual Azimuth 3-D seismic data. In 2018, an extended well test was carried out on the most recent 204/10a-5Y well.

The proposed field development will be from two production subsea drill centre manifolds with six slots each and two injection subsea drill centres with up to four injectors. It will be tied back to a new build FPSO specifically designed for harsh water environment around the proven cylindrical Sevan concept which is expected to have a 25 year life with potential for extension. Initial field development is proposed to be carried out in two drilling campaigns. The first campaign is planned to run from 2024 and 2026 with 2C resources of 75.1 MMBOE. This campaign consists of five production wells and two injections wells, with first oil expected in 2028. A gas export pipeline will be installed to West of Shetland Pipeline System as part of Phase 1 (which has sufficient capacity for third-party gas), and oil will be offloaded via tanker to market. After first oil, an additional four production wells and two injection wells will be added. A subsequent field development phase is also being considered to exploit secondary field reservoir targets. The second campaign is expected to have 2C resources of 24.6 MMBOE.

The phase 1 scope is fully defined in a field development plan which has been reviewed by the regulator with no outstanding issues and is awaiting final submission for production consent.

The environmental statement public consultation has been completed. It is a project with a high degree of definition, ready for FID and the procurement cycle is at the Group's option with the same development premise. The licence milestone to finalise applications and gain final approval has been extended until 31 March 2024.

In respect of future plans, the Group is targeting submission of the final field development plan in quarter four of 2022 with NSTA consent targeted to follow in the first half of 2023. FID, along with the supply chain and rig contract award, is targeted by the second quarter of 2023.

IEUK holds a 70% operated interest in the Cambo field, and its sole partner is Shell (30%). On 11 August 2022, Shell launched a sale process for its 30% stake in the Cambo field.

6.15 ***Rosebank Field***

The Rosebank field, operated by Equinor, is located in Blocks 205/1a, 205/2a, 213/26b and 213/27a in the North Atlantic Ocean in a water depth of approximately 3,600 feet, approximately 130 km northwest of the Shetland Islands. The field was discovered by Chevron in 2004, with the drilling of the 213/27-1z well. Chevron drilled an additional five appraisal wells with additional sidetracks, totalling approximately ten well penetrations from 2006 to 2009. Equinor assumed operatorship in 2018 upon purchase of Chevron's interest. Suncor Energy Inc is the other field partner.

The development concept consists of 17 subsea wells (12 production and 5 water injections wells) tied back to the Knarr FPSO. The planned development wells target the Colsay-1, Colsay-3, and Colsay-4 Sands, and these development wells consist of both horizontal wells dedicated to a single sand and nearly vertical wells designed to produce multiple sands simultaneously. Data collected from the field indicate a nearly saturated light oil of approximately 34 degrees API, GOR of approximately 700 standard cubic fee per stock tank barrel and oil viscosity of 0.78 cp. The Knarr FPSO is to be repurposed and has recently been demobilised from the Knarr Field following cessation of production in the third quarter of 2022. The design capacity is approximately 63,000 BOPD. Oil will be exported via shuttle tanker and gas will be exported via pipeline. Altera Infrastructure ("**Altera**"), the owner of the Petrojarl Knarr FPSO, filed for Chapter 11 bankruptcy protection in the US Bankruptcy Court for the Southern District of Texas on 15 August 2022 as it seeks to agree a restructuring plan with its creditors. The Rosebank partners are in negotiations with Altera in relation to the Petrojarl Knarr FPSO. If Altera was unable to agree a plan with its creditors and successfully exit bankruptcy proceedings, this could impact its ability to deploy the Petrojarl Knarr FPSO on the Rosebank field or present other execution complexities, which could result in delays to first oil from the project.

After Equinor assumed operatorship, the joint venture reworked the project, reducing capex by 50% and phasing the development and capex between phase 1 (2023–2026) and phase 2 (2028–2031). Four production wells and three water injectors are planned prior to phase 1; phase 1 targets two reservoir horizons and approximately 693 MMBOE STOIIP; and phase 2 targets three production wells and two water injectors. In January 2022, the Rosebank field partners made concept select decision for the revised development and the NSTA confirmed "no objection" in February 2022. In June 2022, the NSTA granted a licence extension to 31 May 2024.

In respect of future plans, the environment statement public consultation was published in August 2022. SURF FEED was completed in third quarter of 2022 and FPSO FEED is expected to be completed in the fourth quarter of 2022. Final submission of the field development plan is targeted for the first quarter of 2023, with NSTA consent and FID (along with supply chain and rig contract award) targeted for the first half of 2023.

IEUK holds a 20% non-operated interest in the Rosebank field, and its partners are Equinor (operator, 40%) and Suncor (40%).

6.16 ***Tornado Field***

The Tornado field, operated by the Group, is located in Blocks 204/13 and 204/14d in the North Atlantic Ocean in a water depth of 3,445 ft, approximately 160km west of the Shetland Islands. The field was discovered in 2009, with the drilling of the 204/13-1 well. One appraisal sidetrack was subsequently drilled (the 204/13-1Z). Gas at the Tornado field is close to its dew point and its condensate yield is expected to fall with depletion.

In respect of future plans, the Group is targeting FID in 2024 and first production in 2026.

IEUK holds a 50% operated interest in the Tornado field, and its sole partner is Shell (50%).

6.17 ***Marigold Field***

The Marigold field is located in Blocks 15/13a and 15/18b in the UK Sector of the North Sea, approximately 210 km northeast of Aberdeen, in a water depth of approximately 475 ft. The field is divided into two areas: Marigold East and Marigold West. The Marigold East Area is located in Block 15/18b and includes the southern extent of the Marigold discovery. The Marigold West Area is located in Blocks 15/13a (in which IEUK does not currently own an interest) and in Block 15/18B and included the Marigold Discovery. The Group believes there is approximately 180 MMBOE STOIIP across the full field.

The Marigold East Area, operated by IEUK, was discovered in 2011 with the drilling of the 15/18b-11 well by Nexen Petroleum UK Limited. It was further appraised in 2017 with the drilling of the 15/18b-14 well by Maersk Oil North Sea UK Limited. The wells found black oil with a low GOR and moderate viscosity of more than 6.5 cp in the Balmoral Sandstone with various local gas caps.

The Marigold West Area, located immediately west and northwest of the Marigold East Area, is operated by Anasuria Hibiscus and was discovered in July 2008 with the drilling of the 15/13a-10 well by Iranian Oil Company. The discovery well found an undersaturated black oil with a low GOR and moderate viscosity of 12.5 cp in the Balmoral Sandstone with no gas cap.

For the purposes of the NSAI CPR assessment, the development concept consists of a total of six production wells, including two multi-lateral wells, accessing only blocks in which the Group owns an interest and tied back to a host processing facility. For the purpose of the NSAI CPR assessment, the areas to be developed include the Marigold East Area and the portion of the Marigold West Area located in block 15/18b.

In respect of future plans, the Group is targeting a submission of the field development plan during the fourth quarter of 2022 or first quarter of 2023 with NSTA consent, FID, rig contract and supply chain award targeted to follow in the second half of 2023. First oil is expected in 2025, and it is expected to be a low cost development with a tieback to the Piper Bravo field.

IEUK holds a 100% operated interest in Block 15/18b and its share of the Marigold field, which will require to be unitised across Block 15/18b and Block 15/13a, is to be determined.

6.18 ***Fotla Field***

The Fotla field, operated by IEUK, is located in Block 22/1b of the UK Sector of the North Sea in 431 ft of water, approximately 10 km southwest of the Alba field. The field was discovered in August 2021 by the Group's drilling of the 22/1b-12 well. Subsequently, the field was further appraised by two appraisal side-tracks drilled from August to October 2021 in the 22/1b-12Z and 22/1b-12Y wells. Development plans are currently being evaluated, and first oil for the field is expected in 2026. The conceptual field development plan consists of a subsea tieback to the Alba facility of three production wells and one water injection well. Because of the tentative nature and timeline of the development, only contingent resources have been estimated for Fotla field.

In respect of future plans, the Group is targeting FID in 2023 and first production in 2026.

IEUK holds a 60% operated interest in the Fotla field, and its sole partner is Spirit Energy (40%).

6.19 ***Isabella Field***

The Isabella field, operated by TotalEnergies, is a high pressure, high temperature field located in Blocks 30/12d and 30/11a in the UK Sector of the North Sea in a water depth of approximately 263 ft. The field, located approximately 270 km east of Aberdeen, was discovered in early 2020. Gas discoveries were made in the Kimmeridgian Sandstone and the

Joanne Sandstone. Light oil was discovered in the Judy Sandstone. Only the Judy Sandstone was included in the NSAI CPR assessment because it contains the large majority of the discovered resources. An additional appraisal is planned in 2022 to further delineate and test the discovery. The development concept consists of five wells drilled from a wellhead platform tied back to a host processing facility. First oil is expected in the third quarter of 2026.

In respect of future plans, the group is targeting FID in 2024 and first production in 2026.

IEUK holds a 10% non-operated interest in the Isabella field, and its partners are TotalEnergies (operator, 30%), Energean (10%) and Neptune Energy (50%).

6.20 ***Leverett Field***

The Leverett field, operated by NEO Energy, is located in Blocks 21/2d, 21/3a, 21/3b, 21/3d, and 21/4c of the UK Sector of the North Sea approximately 40 km southwest of the Britannia field and approximately 185 km northeast of Aberdeen. The field is spread across multiple licence blocks, with the Group owning a 25% share of Block 21/3a. Unitisation negotiations are ongoing, but the Group estimates its post-unitisation interest in Leverett field to be 15%. Development plans are currently being evaluated, and first oil for the field is expected in 2025. The conceptual field development plan consists of a subsea tieback to the Britannia facility of three to seven wells targeting the western, central, and/or eastern portions of the gas cap region. Because of the tentative nature and timeline of the development, only contingent resources have been estimated for Leverett field.

In respect of future plans, the Group is targeting FID in 2024 and first production in 2025.

IEUK holds a 25% non-operated interest in Block 21/3a, and its sole partner is NEO Energy (operator, 75%). Unitisation negotiations are ongoing, but IEUK estimates its post-unitisation interest in the Leverett field to be 15%.

6.21 ***Decommissioning Assets***

Pickerill, Renee and Rubie fields are referred to as decommissioning assets or post-cessation of production (post-COP) assets. These fields are no longer producing. The remaining abandonment costs for Pickerill, Renee and Rubie fields are scheduled to be incurred from 2022 through 2024.

A key strength of the Group's portfolio is its limited near-term decommissioning commitments as a result of its high-growth, long-life portfolio. The Group also historically delivered top quartile cost performance against the NSTA benchmark for well decommissioning. The Group estimates that it will spend approximately $30 million per annum on average over the next five years on decommissioning costs and expenditure. The key operated projects driving short-term decommissioning expenditure include Athena (H2 2022, 2023), Anglia (H2 2022, 2023, 2024), Causeway and Fionn (2023, 2024, 2025) and Jacky (2023).

6.22 ***Exploration Assets***

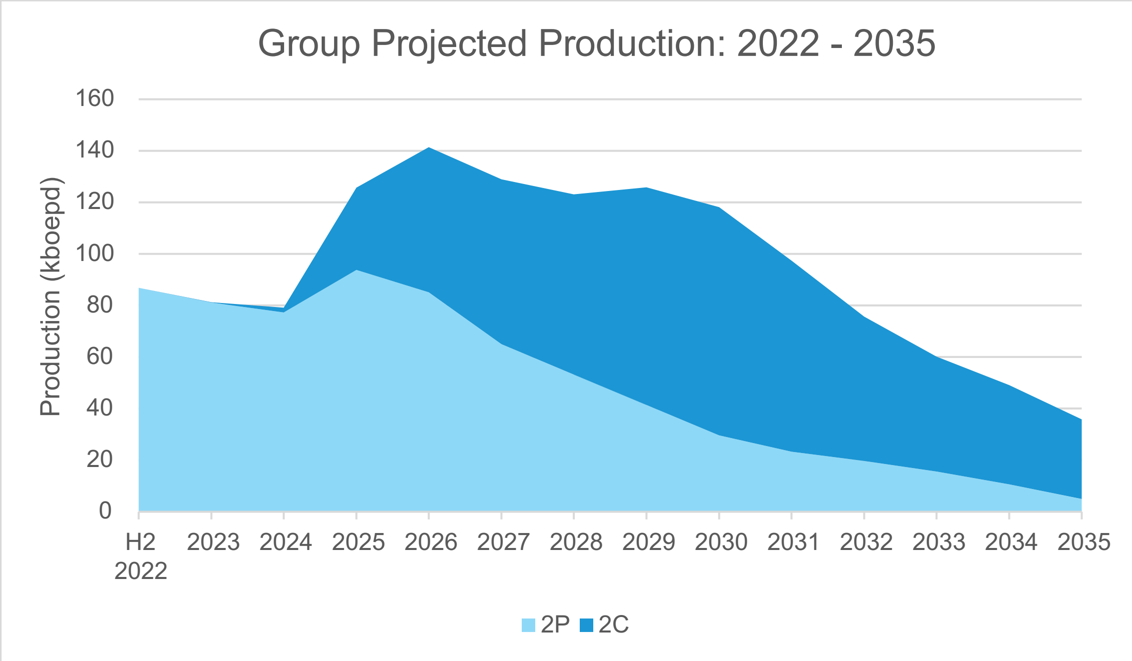
Ithaca Energy has an infrastructure led approach to exploration and ranks opportunities on the basis of prospect size, geological chance of success and likelihood of commercial development. The Group's exploration activities have a hub-driven strategy with a focus on near-field prospects close to existing infrastructure. The Group has an exploration and appraisal funnel of over 150 opportunities which it believes hold approximately 1.9 billion BOE of gross Pmean prospective resources across multiple geographic hub areas. The Group expects near term activity with a target of one to two exploration wells per year and investment of approximately $40 million (on average) in exploration per annum.

7. **PRODUCTION AND DRILLING**

7.1 ***Production Summary***

The graph below sets out the Group's average daily projected production potential (in BOEPD) from all of its fields to 2035 based on data from the NSAI CPR. No risking has been applied to contingent resources in the figure below.

Figure 6.2: The Group's projected production potential from 2022 to 2035



Source: NSAI CPR

7.2 ***Drilling***

The Group has accumulated extensive drilling experience across a number of its assets. 13 wells have been drilled offshore by the Group and its joint venture partners since the Chevron Acquisition in 2019. At the Pierce field, the 23/22a-A14 well was drilled and brought online in Q4 2020. Drilling of the 22/1b-12 well in August 2021 resulted in the discovery of the Fotla field. Callanish 21/04a-F5 well was drilled at the end of 2020 with first production February 2021. Elgin 22/30c-B5 was spudded in December 2020 and handed over to production for first oil in October 2021. Franklin has also drilled and completed two wells in this time 29/5b-F12 and 29/5B-F13 online in 2019 and 2020. Jade South was drilled and developed by well 30/02c-J13 in 2021 with first production in Q1 2022. A further well on Jade, 30/02c-JM14 is now complete and expected online in Q4 2022. In 2022, four additional wells have been drilled and completed on the Captain field, three in the platform area (13/22a-C71Z, 13/22a-C70, 13/22a-C69Z) and a further well in the subsea area of the field (13/22a-A4). The Abigail well was also drilled in 2022, 29/10b-8Z with first production in October 2022.

The Group has extensive experience of safely and efficiently drilling and extracting oil and gas in challenging production conditions including high temperatures, sour gas, scale and complex crudes. The Group's core well engineering team members and well project management service providers have comprehensive experience of drilling operations that includes deep water projects in the West of Shetland.

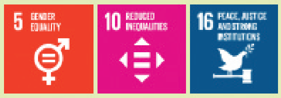
8. **ESG**

The Group is focused on the reduction of greenhouse gases, with clear ambitions and targets as set out in its greenhouse gas emissions policy. The Group is fully engaged with the NSTA and OEUK to champion net zero. To demonstrate the Group's commitment to continual improvement, it is committed to further developing its ISO14001 certified management system, to achieve the global energy management systems standard, ISO50001. The Group has mid-level energy intensity compared to other producers in the UKCS, at 24kt CO_2e/MBOE generating approximately 498kt CO_2e per year over the year ended 31 December 2021 and approximately 258kt CO_2e in the six months ended 30 June 2022.

By Admission, the Group expects to update its ESG policy and strategy in support of both the UN Global Compact and UN Sustainability Goals, respecting human and labour rights, safeguarding the environment and working against corruption in all its forms. From 2023, it will set and report against annual ESG targets. The Group is committed to transparent ESG reporting and will align its reporting to internationally recognised frameworks. The Group is committed to including comprehensive ESG assessments across its business processes and project life cycles. The Company's management has a proven track record of implementing sustainability agendas in previous organisations.

The chart below provides an overview of the Group's sustainability framework including key topics the Group focuses on and how it aligns them with the United Nations Sustainability Development Goals to fulfil its commitment with regard to each of its three strategic pillars.

Figure 6.3: Overview of the Group's sustainability framework

	Environment	Social	Governance
Our Commitment	Responsible operations that protects ecosystems in which we operate	Safe operations that invest in our people and communities	Running our business with integrity and transparency
Key Topics	• **Emissions management** • Water, spills and waste	• Health and Safety • Social investment in staff and communities	• Compliance and anti-corruption • Inclusion and diversity
Sustainable Development Goals (SDG) Alignment			

8.1 ***Environmental***

Operational Excellence Management System

The Group has an Operational Excellence Management System into which is integrated the Environmental Management System ("**EMS**") certified to ISO 14001:2015 standard. The EMS was last verified as meeting the ISO 14001:2015 standard on 26 April 2021, a certification which will remain valid until 4 May 2024. It is designed to implement the Group's environmental policy including its emissions management and environmental stewardship. It demonstrates a commitment to compliance with environmental legislation and the Group's standards, processes, activities and objectives for environmental management of hydrocarbon exploration and production. The Group's vision is to be the highest performing UKCS independent oil and gas company, focused on sustainably growing value.

Emissions Management

The Group seeks to minimise its environmental impact by working to operate in an ever-cleaner manner. The Group aspires to be a low-carbon emissions leader in the North Sea and aims to be an industry leader in its contribution to net zero greenhouse gas emissions by 2040 based on the Group's equity interest in all of its fields. The Group has a commitment to responsible operations that protect the environment in which it operates.

Atmospheric emissions are a significant factor which must be included in the Group's business decisions to allow operation in a sustainable manner and maintenance of the Group's "social licence to operate". The control and management of these issues lies at the centre of the policies and procedures that constitute the health, safety and environmental management system and the culture of the business. Atmospheric emissions management is a core part of the Group's ISO14001 accredited Environmental Management System and Environmental Stewardship programme.

The Group has a Greenhouse Gas Emissions Policy that is endorsed by the executive leadership team and signed by the Chief Executive Officer. The policy sets out the Group's expectations and aligns them with those of the NSTA and OEUK and outlines the key emissions targets of the organisation. The policy includes the following targets:

- reduce scope 1 and 2 carbon dioxide (CO_2) and carbon dioxide equivalent (CO_2e) emissions from its operated assets by 25% from 2019 levels in 2025;
- achieve 0.20% methane intensity of its operated assets by 2025;
- zero routine flaring on its operated assets by 2030;
- reduce scope 1 and 2 CO_2 and CO_2e emissions on the Group's equity interest in all of its fields in line with the North Sea Transition Deal—10% by 2025, 25% by 2027 and 50% by 2030; and
- achieve net zero by 2040 based on the Group's equity interest in all of its fields (ahead of the NSTD commitment of net zero by 2050).

The Group's emissions intensity for its operated assets is in line with other producers in the UKCS, at 24 CO_2e/MBOE generating approximately 498kt CO_2e per year (as per the year ended 31 December 2021). This represents a 10% emissions reduction as compared to its 2019 emissions baseline. The Group is progressing ongoing projects and operational improvement initiatives which could drive further reductions to around 471ktCO_2e per year, representing a 22% emissions reduction as compared to its emissions baseline. The Group is also pursuing projects and operational improvement initiatives, which are currently anticipated to cost more than £100 /t CO_2e, and could lead to further emissions reductions of approximately 24%, as compared to its emissions baseline.

The Group has reduced CO_2e from flaring by 15% and CO_2e from extinguished flaring by 60% for the year ended 31 December 2021 as compared to the year ended 31 December 2019.

The Group is committed to supporting the Oil and Gas UK Roadmap 2035 contribution to the UK Government's mandatory target of net zero greenhouse gas emissions by 2050. In 2023, the Group is planning to work with OEUK to review its approach to methane management. The Group's management has a proven track record of implementing sustainability agendas in previous organisations and is fully engaged with the NSTA to champion net zero.

The Group has in place a strategy targeting an ambitious reduction in scope 1 and scope 2 CO_2e emissions from its operated assets of 25% in 2025. To achieve this target, the Group has implemented several successful projects and operational improvements across the operated assets to reduce emissions, such as unlit flare reduction, FPF-1 single gas turbine operation, Alba flare reduction and FPF-1 flare recovery reinstatement. In addition, as part of the Jacky field late life asset management and associated decommissioning programme, a renewable power module was installed to power the Jacky installation entirely from wind and solar through to the end of the asset life cycle. This eliminated emissions from fuel use and greatly reduced maintenance, having both significant environmental and safety benefits. Future projects include Captain and Alba flare recovery, reinstating a second gas export compressor on Captain, Captain FPSO Cargo Oil Tank vapour recovery, reduction in hydrocarbon purging on FPF-1 and solar panels for the office.

The Group is also actively exploring the potential of electrification to significantly lower emissions. It is engaged in an ongoing project to explore potential future electrification of the Captain field to enable it to meet some or all of its power requirements through nearby wind farms or power from shore via the National Grid. Captain is part of the Outer Moray Firth Electrification (OMFE) Group, which provides opportunities for electrification partnerships, thus potentially reducing capital outlay for greenfield activities.

Longer term, the Group is targeting a shift to lower emission-intensity assets. For example, the Group's management estimates emissions of 27.8kg CO_2/BOE from FPF-1 and 37.0kg CO_2/BOE from the Alba field, in each case over the next five years. FPF-1 and Alba are expected to cease production around 2030. Prior to this Rosebank and Cambo fields are expected to reach first production. Rosebank's emissions are expected by the Group's management to be 3.3-6.8kg CO_2/BOE for the first five years, and Cambo's are expected to be 3.7-7.2kg CO_2/BOE, depending on electrification status. The Group targets emissions levels from Cambo which are significantly lower than the global average, enabled by FPSO design which includes features such as being fully ready for electrification, zero routine flaring, Sevan FPSO hull design reducing power demand and full compliance with strict UK regulations.

Environmental Stewardship

The Group's Environmental Stewardship ("**ES**") process identifies and addresses significant environmental aspects relating to its operations, driving continuous improvement in environmental performance and reducing its environmental impact.

The expectation of the Group's ES process is to strive to continually improve environmental performance and reduce impacts from its operations. It is applied across the life cycle of an asset and is used to identify, assess and manage potential environmental impacts and benefits. To achieve this, the Group has implemented a step-wise process to be followed on an annual basis. First, an inventory of all emissions, releases, wastes and potentially impacted natural resources is prepared. This is followed by a procedure to identify, assess, mitigate and manage any significant risks and impacts to the environment associated with operations, emissions, releases and wastes. The outcome is an annually updated ES plan. The Group's management system is independently certified to the international standard ISO 14001:2015 and requires the Group to engage independent auditors who verify that its onshore and offshore operations meet requirements. A successful independent surveillance audit to assess that the environmental management system is maintained in accordance with the Group's environmental policies, processes and procedures and the requirements of ISO 14001:2015 was conducted in April 2021 and remains valid until 4 May 2024.

The Group's ES plan includes objectives and targets for environmental performance, details of improvement implementation programs and the process for tracking progress in meeting environmental objectives. The Group's ES plan is approved by its senior management and is aligned with other business.

All of the Group's projects have the potential to impact on the environment and they are all subject to strict environmental regulatory controls which require the Group to prepare and submit regulatory applications to gain approval before activities begin and during the ongoing operational activities. The Group monitors and reports its ongoing emissions, discharges and waste streams to ensure it meets regulatory requirements and does not cause significant impact on the environment. In the event of an unplanned release/spill to sea, or a non-compliance with regulatory requirements, notification would be made to the appropriate regulatory authorities and action taken to respond to any threat of or actual pollution. Investigations of incidents are conducted to gain any learnings or actions to prevent recurrence.

The Group's ES process is used to help provide assurance that it is protecting the environment and meeting its internal and regulatory requirements and obligations.

Taskforce on Climate-related Financial Disclosures

The Group recognises the increasing societal, media and investor focus on climate change, and the desire to understand its potential impacts on the oil and gas industry through improved disclosure, utilising mechanisms such as those proposed by the Taskforce on Climate-related Financial Disclosures ("**TCFD**"). The Group provides information relevant to each of the four TCFD recommendations (Governance, Strategy, Risk Management, Metrics and Targets) on its website and annual report and will continue to evolve these disclosures over time.

8.2 ***Social***

Health and Safety

The Group is committed to providing a safe and healthy working environment for all its employees, contractors and other personnel working for the Company, providing a process safety assurance focus, and achieving excellence in Health, Safety and Environmental ("**HS&E**") performance across all of its operations. The Group considers its HS&E performance, prevention of process safety events, and the health, safety and security of those who work for, with and alongside Ithaca Energy as central to its business success.

To achieve this, the Group aims to manage its business in compliance with legislation and industry standards, maintain high quality systems and processes and maintain safe and healthy workplaces. Throughout all of the Group's operations, Ithaca Energy promotes a positive and robust safety culture, ensuring that health and safety standards are not compromised to meet commercial objectives. Ithaca Energy protects people working for the Group and with the Group through the effective identification, understanding and management of risk and the implementation of systems to manage process safety and asset integrity. Ithaca Energy identifies potential areas where its operations could have an impact on the environment and puts measures in place to avoid or minimise such impact. Annual environmental objectives and plans are established to monitor and measure the Group's impact on nature and reduce its risk of causing environmental damage. In addition, Environmental Performance is published annually as part of industry commitments with the Group's regulators, as its Annual Environmental Public Statement.

The Group has developed, and maintains, a Company Management System (the "**CMS**") which implements the Safety Management System (the "**SMS**") and Environmental Management System (the "**EMS**") as documented in the Ithaca Energy HSE policy. The CMS formally describes the environmental responsibilities of the organisation, and individuals within the organisation, and incorporates the Group's EMS and SMS. The EMS complies with the requirements of the OSPAR Recommendations 2003/5 and is certified to the ISO 14001:2015 international standard for environmental management systems which was successfully recertified most recently in April 2021.

The Group also benefits from operating within the well-established health, safety and environmental regime that has been developed and refined by the UK regulatory authorities over many decades of overseeing offshore operations.

The Group monitors and manages the SIF associated with its operated assets as a means of evaluating the health and safety performance of the Group and the suppliers working on the assets. In addition, the Group monitors Process Safety events, monitoring Tier 1 and Tier 2 events for learning. Improving operational and process safety performance, within an open and transparent incident reporting culture, is a continual focus of the business and a combination of targets and specific measures are implemented with a view to facilitating this goal.

Ithaca Energy strives for continuous improvement in its HS&E performance. The Group periodically audits and reviews its HS&E policies to help ensure compliance with all applicable regulations, as well as its policies, principles, processes and procedures, and to identify areas for improvement.

The Group's risk-based audit and assurance program is designed to measure the conformance and effectiveness of HS&E management across its operations, as well as its contractor and supplier organisations, as applicable. Other assurance activities are also periodically conducted to enable the Group to learn from previous challenges and proactively identify opportunities to improve its HS&E performance.

Investment in Staff and Communities

The Group builds relationships that support the economic and social fabric of its local communities. The Group supports community organisations and the development of UK talent through science, technology, engineering and mathematics initiatives and technical apprenticeship programs. In 2021, the Group employed nine interns in a newly launched summer program, and it typically hires six apprentices for offshore roles each year. Each employee is allocated four corporate social responsibility days a year to give back to the community. These investments in people are part of the Group's commitment to growing and developing talent in the communities in which it operates.

In addition, the Group encourages the workforce to participate in local community and charity initiatives including charity donation matching to the DEC Ukraine appeal, food drives for Aberdeen based charity Aberdeen Cyrenians, a giving tree in Christmas 2021 for Instant Neighbour and a school art project with participating local schools. Further, the Group has approved financial assistance to employees supporting local charitable organisations.

8.3 ***Governance***

Inclusion and Diversity

Inclusion and diversity is a focus of the Group, and the Group seeks to provide equal opportunities for all its staff. The Group has engaged external consultants to report on diversity and inclusion best practice, setting targets and embedding diversity and inclusion throughout the Group. The Group measures and reports its gender balance annually, and as at 5 April 2021, recorded a mean gender pay gap of 16.14% between male and female employees, which largely reflects the lower proportion of female staff in more senior positions. Female employees hold around 20% of senior and middle management roles, while holding around 35% of all onshore roles. The Group remains committed to addressing this imbalance through recruitment and promotion as new roles emerge and in the training, mentoring and working arrangements for staff to attract and retain more women into more senior positions. As at 30 June 2022, 98.6% of male employees and 100% of female employees received a bonus.

Compliance

The Company has implemented a series of policies to outline the behaviour which it expects of directors, managers and employees and of suppliers, contractors, agents and partners. The Group is committed to complying with all applicable legal requirements, to upholding the highest ethical standards and to acting with complete integrity at all times.

Anti-Bribery & Corruption Policy

The Group does not tolerate, permit, or engage in bribery or corruption and is firmly against the making of improper payments of any kind in its business dealings anywhere in the world, in either the public or the private sector. The Group is committed to acting professionally, fairly and with integrity in all its business dealings and relationships, wherever it operates, and implementing and enforcing effective systems to counter bribery and corruption.

The Group aims to limit exposure to bribery through the enforcement of its Anti-Bribery and Corruption Policy which requires adherence to relevant anti-bribery and corruption legislation (including without limitation the Bribery Act 2010) and encourages every employee and associated third party to practice and promote ethical and honest business practices at all times.

The Group's Anti-Bribery and Corruption Policy specifically prohibits the offering, giving, solicitation or the acceptance of any bribe (whether in cash or in the form of any other inducement) to or from any person or company, wherever they are situated and whether they are a public official or body or private person or company by any individual employee, agent or other person or body acting on its behalf in order to gain any commercial, contractual or regulatory advantage for the Group in a way which is unethical or in order to gain any personal advantage, pecuniary or otherwise.

The Group attaches the utmost importance to its Anti-Bribery and Corruption Policy and will apply and enforce a strict "zero tolerance" approach to acts of bribery and corruption by any of its employees, contractors or business partners working on its behalf. Any breach of this policy will be regarded as a serious matter and will result in disciplinary action for employees, including, where appropriate, summary dismissal and any third parties associated with the Group who are found to be exposing Ithaca Energy to bribery and corruption risk will be investigated and appropriate action will be taken.

9. PRODUCTS AND SERVICES

The Group's revenues are from the sale of oil, natural gas, condensate and other supplementary petroleum products.

The key nature of the Company's products are: (1) oil is a liquid material consisting essentially of a hydrocarbon compound and its density ranges from 9 degrees to 55 degrees API, indicating the relative density of liquid oil compared to water, and the colour of the oil ranges from yellow to black; (2) natural gas is a compound containing mainly methane, and the difference between wet gas and dry gas is that dry gas does not contain liquid hydrocarbons, and methane accounts for almost all of its composition; and (3) condensate is a natural product of the condensation process of various components in natural gas and is caused due to the pressure and temperature differences in the reservoir and those on the surface.

The distinction between heavy oil and medium and light oil is due to the density of crude oil and the typical amount of distillates that determine its classification as light or heavy. Heavy oil has heavier components, a higher density and higher boiling points than light oil, and heavy crude oil usually needs a thinner added to the pipeline to facilitate its flow. Heavy crude oil products include asphalt, lubricants, waxes and fuel oil. Light crude oil produces large quantities of light fuels (distillates) and small amounts of residual. As noted above, the Group's oil and gas assets generate heavy oil from the Captain and Alba fields as well as light and medium oil from the rest of the on-production assets.

10. CUSTOMERS

The Group provides oil and gas to several large international marketing companies (including BPOI, BPGM and Shell) that operate, among others, in the UKCS region, and which sell the products to the end consumers. The price of oil varies between the fields and is based on several components, including the density and consistency of the oil produced from each field, and payment is made on the basis of an estimated monthly production volume that Ithaca Energy sends to the companies each month. The agreements for selling natural gas set a price calculation that is based on standard UK market prices, as published from time to time, with a discount on the transmission system entry fees and additional discounts in some cases.

The sales agreements between the Group and its customers do not include commitments to purchase or supply minimum or maximum volumes of the energy products produced from its reservoirs. Furthermore, and as aforesaid, the Group's agreements with its customers are based on payment for the estimated volume Ithaca Energy will supply each month and are not based on its customers' utilisation of the actual production rate.

On a historical standalone basis, for the years ended 31 December 2019, 2020 and 2021, over 94% of the Group's oil and gas sales have been to Shell, BPOI and BPGM. In the first half of 2022, most of the Group's oil and gas sales have been to BPOI and BPGM (approximately 86%) to ENI (approximately 10%) and the remaining 4% to Esso, Shell and Gazprom (the offtake contract with Gazprom terminated with effect from 30 September 2022).

As noted above, a significant portion of the Group's offtake arrangements are with various BP entities. The Group is party to five offtake arrangements with these bp entities, with contract terms ranging from two to six years and one arrangement having a rolling contract term.

Pursuant to these offtake arrangements the Group has agreed to sell and bp has agreed to buy the Group's production across the Alba, Alder, Britannia, Brodgar, Callanish, Captain, Cook, Elgin Franklin, Enochdu, Erskine, Harrier, Jade, Loyal, Schiehallion and Stella fields. These arrangements do not provide for any minimum or maximum production volumes (i.e. bp is required to purchase all of the Group's production which is subject to such arrangements, regardless of the level of that production). These arrangements therefore secure sales of a substantial proportion of the Group's production and limit its exposure to offtake risk. The majority of the bp offtake arrangements include mutual termination rights in the event of various insolvency and financial distress related events in respect of either party or in the event that either party has failed to pay undisputed amounts due (subject to notice periods). The bp offtake arrangements were all entered into on arm's length commercial terms and in particular, the arrangements provide that the price payable by bp will be determined by reference to benchmarked prices published by third parties, such as Platts for crude oil.

The Group's key customers, BP (through its trading arms BPOI and BPGM) and ENI, are two of the largest energy companies in the UK market and as at the Latest Practicable Date, Ithaca Energy's contractual relationship with them is stable and to the best of Ithaca Energy's assessment it has the capacity to continue receiving the volumes of oil and gas produced from its oil assets.

In connection with the financing of the Chevron Acquisition, additional agreements were signed with BPOI and BPGM for the sale, purchase and/or marketing of natural gas and crude oil from the Chevron Acquired Assets. These agreements also cover aspects related to the supply of oil recovered from the Group's on-production assets via the Forties Pipeline network and the

Forties reception terminal. Furthermore, the agreements cover aspects related to the supply of oil recovered from the Alba and Captain fields via marine tankers, as well as for the supply of the bulk of the natural gas produced, via onshore natural gas reception terminals in the United Kingdom.

11. DISTRIBUTION

The oil and natural gas produced from the Group's own production assets are supplied via a subsea pipeline to onshore reception terminals in the United Kingdom, and by supplying directly to the end consumers via shuttle tankers and to floating facilities; all as described at paragraph 6 (*Overview of Assets and Operations*) of Part 6 (*Business* Overview).

Some of the subsea pipelines and all of the shuttle tankers through which Group supplies its products, as aforesaid, are owned and operated by third parties.

12. ORDER BACKLOG

As noted in paragraph 10 (*Customers*) of this Part 6 (*Business Overview*) above, the Group's commercial agreements are based on payment for the estimated monthly volumes that the Group intends to supply to its customers every month. Therefore, the Group does not have order backlogs.

13. INSURANCE

The Group maintains the types and amounts of insurance coverage that it believes are consistent with customary industry practices in the United Kingdom being the jurisdiction in which the Group operates. The Group's oil and gas properties and liabilities are insured within an operational energy insurance package. Coverage under the terms of this insurance package includes physical damage, operators' extra expense (including well control, seepage, pollution clean-up and redrill), business interruption and third-party liabilities. Coverage is placed in respect of oil and gas exploration and production activities. The Company believes that the limits and deductibles in force are in line with applicable oil industry insurance standards. The Company also believes that the Group has adequately provisioned for, or otherwise protected the Group's operations against, risks consistent with customary industry practices.

Where applicable, the Group procures construction all risks insurance coverage in respect of development projects. Such coverage generally applies to works executed in performance of contracts wherein the Group is at risk including loss of, or damage to, the pipelines, risers, umbilicals, Christmas trees and completions to be installed and the related liabilities to third parties.

The Group arranges such other insurance from time to time in respect of its other operations as required and in accordance with industry practice and at levels which the Company considers adequately provide for the Group's needs and the risks that it faces. The Group has not had any material claims under its insurance policies that would either make them void or materially increase their premiums. The Company gives no assurance, however, that the Group's insurance coverage will adequately protect the Group from all risks that may arise or in amounts sufficient to prevent any material loss. See paragraph 1.25 (*The Group does not insure against certain risks and its insurance coverage may not be adequate for covering losses arising from potential operational hazards and unforeseen interruptions.*) of Part 2 (*Risk Factors*).

14. EMPLOYEES AND CULTURE

The Company believes that the Group has a strong and established team of highly competent professionals in its core in-house disciplines of subsurface, project management and commercial. Most of the Group's staff began their careers with major oil companies or leading service companies and all have direct experience of working on North Sea assets and field developments. The Group's business model involves using the services of the UKCS' highly developed oil and gas industry supply chain to supplement its in-house capabilities, benefiting from the dedicated and highly experienced resources of its contracting partners for execution of its operational programs. The Company believes that the Group has well established working relationships with these core contracting partners, including FTSE 250 oil and gas services providers and other leading international companies.

As at 1 December 2019, 2020 and 2021 and 30 June 2022, the Group employed 500, 436, 470 and 516 full-time employees, respectively. *See paragraph 7 (Employees) of Part 8 (Directors, Senior Managers and Corporate Governance)*.

The Company believes that the Group has satisfactory working relationships with its employees and has not experienced any significant labour disputes or work stoppages. The Group does not provide a defined benefit pension plan for its employees.

15. RESEARCH AND DEVELOPMENT

The Group does not have any research and development function.

16. DIVIDENDS AND DIVIDEND POLICY

16.1 *Dividend policy*

In deciding whether to propose a dividend and in determining the dividend amount, the Directors must take into account the Company's capital requirements, including capital expenditure requirements, the Company's financial condition, general business conditions and any restrictions under its contractual arrangements in place at the time of the dividend may place on its ability to pay dividends and the maintenance of appropriate financial flexibility.

The Company is committed to creating long-term value for its Shareholders through an increase in value of the Ordinary Shares over time, combined with dividend payments (or share buybacks). The Company is targeting annualised dividends of 15-30% of post-tax net cash from operating activities through the cycle. In the near-term, the Company has a firm expectation of a dividend in respect of the year ending 31 December 2023 of $400 million with an ambition of an annual dividend of $420 million for the year ending 31 December 2024.

The Company expects to pay dividends to shareholders semi-annually in the ordinary course of business, specifically: (i) a third of any yearly dividend will be paid to shareholders following the end of the first half of the relevant financial year; and (ii) two-thirds of any yearly dividend will be paid to shareholders following the end of the relevant financial year. However, for the year ending 31 December 2023, the Group expects to pay an initial dividend in the first quarter of 2023 followed by two further dividend payments following the first half of the financial year and end of the financial year.

The Company is a holding company with no independent operations and is depending on earnings and distributions of funds from its operating Subsidiaries for cash, including in order to pay dividends to Shareholders.

Any decision to declare and pay a dividend in any year will be made at the discretion of the Directors and, in addition to compliance with the terms of Group's borrowing arrangements set out below, will also be subject to the following, together other factors that the Directors deem significant from time to time:

- the success of the Group's development activities across its asset base (including the achievement of certain milestones, e.g., FID, FDP or meeting certain production or other operational targets);
- the ability to distribute or dividend profits from its operating Subsidiaries up the Group structure in a manner which creates sufficient distributable reserves in the Company, which can be effected by reductions in profitability as well as by impairment of assets;
- the Group's financial position, including the existence of sufficient cash in the Group;
- existing prevailing macroeconomic or political conditions;
- changes in realised oil and gas prices or production;
- the Group's working capital requirements; and
- change in legislation or regulatory requirements (including tax regulation).

Further, Shareholders should be aware that the tax legislation of any jurisdiction where a Shareholder is resident or otherwise subject to taxation may have an impact on the tax consequences of an investment in the Ordinary Shares including in respect of any income received from the Ordinary Shares. See Part 19 (*Taxation*).

16.2 ***Limitations on distributions of dividend under the 2026 Notes***

Currently, the 2026 Notes include restrictions on the ability of IEEPL and certain subsidiaries to make payments to the Company (including dividend payments (or to repurchase shares)) by, amongst other things, limiting the value of such payments (subject to specific exceptions).Consequently, if the Group is unable to successfully refinance its existing capital structure, the terms of the 2026 Notes may restrict the Company's ability to make, and the value of, any future dividend payments.

The terms of the 2026 Notes include restrictions on the ability of IEEPL, and certain subsidiaries, to make certain payments including dividend payments to the Company unless at the time of, and after giving effect to, such restricted payment: (i) there is no continuing event of default; (ii) IEEPL would have been permitted to incur at least $1 of additional indebtedness pursuant to the fixed charge cover ratio test set out in the Indenture and/or (for certain exceptions to the restriction on payments) the consolidated leverage ratio of IEEPL will not exceed 1.3:1; and (iii) the restricted payment, together with the aggregate of all other restricted payments following the issue date, is equal to or less than the sum of several factors including, among others (without duplication), either (x) an amount equal to $100 million for each twelve months passed since 30 July 2021 or (y) where the consolidated leverage ratio is 0.6:1, 50% of the consolidated net income of IEEPL for the specified period.

This restriction will not prohibit, amongst other things, dividends payments by IEEPL to the Company to enable the Company to make corresponding dividend payments following the initial public offering provided that there is no continuing event of default and the aggregate amount of all such dividends does not, in a fiscal year, exceed the greater of:

(i) the greater of (A) an amount equal to 5% of the market capitalisation of the Company (being the total number of ordinary shares of the Company at the date a dividend is declared multiplied by the mean closing price per ordinary share for the 30 consecutive trading days prior to that date) and (B) 5% of the IPO market capitalisation of the Company (being an amount equal to the total number of ordinary shares of the Company at the time of the initial public offering multiplied by the price per ordinary share sold in the initial public offering) pursuant to the initial public offering, provided that after giving pro forma effect to the payment of any such dividend, the consolidated leverage ratio of IEEPL would not exceed 1.05:1; and

(ii) the greater of (A) 7% of the market capitalisation of the Company or (B) 7% of the IPO market capitalisation of the Company, provided that after giving pro forma effect to the payment of any such dividend, the consolidated leverage ratio of IEEPL would not exceed 0.8:1.

In addition, so long as no event of default is continuing, the restrictions will not apply in respect of other restricted payments in an amount not exceeding the greater of $135 million over the term of the 2026 Notes ("**Unrestricted Payment Amount**") and 3.2% of the total consolidated assets of IEEPL and its subsidiaries (as shown on the most recent balance sheet). As at the Latest Practicable Date, the amount available under Unrestricted Payment Amount is $105.5 million, following the repayment of in aggregate $29.5 million of accrued interest outstanding under, and costs payable in connection with, the Subordinated Delek Loan, see paragraph 2.1 (*Current trading and prospects*) of Part 12 (*Operating and Financial Review Relating to the Group*). Further, the Company will pay all IPO Expenses with amounts received from payments from IEEPL and/ or certain Subsidiaries. The payment of the IPO Expenses, of approximately $15.4 million, is expected to reduce the Unrestricted Payment Amount to approximately $90 million following Admission.

Consequently, if the Group is unable to successfully refinance its existing capital structure, the terms of the 2026 Notes may restrict or limit the Company's ability to make, or the amount of, any dividend payments. There can be no assurance that any of the exceptions described above will be available in order to allow the Company to make the dividend payments which it expects to make, or at all.

Further details of such restrictions and those under the RBL Facility are set out in paragraph 14 (*Material Contracts*) of Part 20 (*Additional Information*).

16.3 ***Limitations on distributions of dividends under the RBL Facility***

The RBL Facility Agreement includes standard restrictions on the ability of IEUK, and certain subsidiaries, to make distributions including dividend payments to the Company. The right to make a distributions falls at the end of the proceeds account waterfall which requires the payment of various items before an obligor is entitled to make a distributions to the Company including (but not limited to) finance party fees, costs and expenses, hedging costs and accrued interest. Such a distribution can then only be made if certain standard conditions (including, but not limited to, there being no continuing event of default and the aggregate US dollar amount of the outstanding utilisations not exceeding the maximum available amount) are met. In addition, on each date on which IEUK intends to make a distributions to the Company it must demonstrate that (i) its total corporate sources exceed its total corporate uses in each quarter of the relevant forecast period; and (ii) the obligors have sufficient freely available funds to meet any decommissioning security obligations in respect of the borrowing base assets for the period ending three years from that date, otherwise an event of default will occur. Any distributions must be made no later than 30 days after a recalculation date (being 31 May and 30 November of each calendar year, or any interim recalculation date).

16.4 ***Manner of dividend payments***

Any dividends on the Ordinary Shares will be denominated in USD. Any dividends or other distributions on the Ordinary Shares will be prepared and despatched by the Company's Registrar. Dividends and other distributions on the Ordinary Shares will be paid, on a payment date determined by the Company, to Shareholders on the share register as at the record date for the distribution.

PART 7

OVERVIEW OF UK NORTH SEA OIL AND GAS INDUSTRY

Certain projections and other information set forth in this Part 7 (Overview of UK North Sea Oil and Gas Industry) have been derived from external sources including Offshore Energy UK (a non-profit organisation whose members comprise oil and gas companies with active operations in the UKCS), the US Energy Information Administration, the International Energy Agency, the BP Statistical Review of World Energy, the BP Energy Outlook, the UK Government website (www.gov.uk) (the contents of which do not form part of this Prospectus) and NSTA. Industry publications, surveys and forecasts generally state that the information contained therein has been obtained from sources believed to be reliable, but that the accuracy and completeness of such information is not guaranteed. The Company believes that these industry publications, surveys and forecasts are reliable, but has not independently verified them and cannot guarantee their accuracy or completeness. In addition, in many cases there is no readily available external information (whether from trade associations, government bodies or other organisations) to validate market related analyses and estimates, requiring the Company to rely on the review of industry publications, including information made available to the public by the Group's competitors. Further, this Part 7 (Overview of UK North Sea Oil and Gas Industry) does not, nor is it intended to, provide either an exhaustive overview of the industry or analysis of (i) differing projections for global energy markets presented by various industry publications; or (ii) domestic or global policy responses to climate change. Investors should form their own view of the current global energy market and current and projected domestic and international climate change policies. It should further be noted that certain of the referenced external sources were published before Russia's invasion of Ukraine. Where an external source was published following the invasion, it typically included a disclaimer acknowledging that: (1) it had either largely been prepared prior to the invasion; or (2) that it was too soon following the invasion to be able to forecast, with any accuracy, its likely impact on global economics (including commodity prices).

The projections and forward-looking statements in this Part 7 (Overview of UK North Sea Oil and Gas Industry) are not guarantees of future performance and actual events and circumstances could differ materially from current expectations. Numerous factors could cause or contribute to such differences. See Part 2 (*Risk Factors*) *and paragraph 13 (Information regarding Forward-Looking Statements) of* Part 3 (*Presentation of Financial and Other Information*).

1. INTRODUCTION

1.1 *The global energy market*

World energy consumption has increased steadily since the industrial revolution, a trend which is expected to continue in the medium term[4] driven by continued demand from developed economies and increased prosperity and living standards in the emerging world[5]. The International Energy Agency ("**IEA**") forecasts that global energy demand will continue to rise until 2030, and oil and gas is expected to account for over 50% of the total energy mix in 2030 (in 2021 fossil fuels accounted for 82% of primary energy use).[6,7,8] Fossil fuels excluding coal supplied around 55% of the world's primary energy consumption in 2021, with oil accounting for 31% and natural gas accounting for a further 24% of the total[9]. The IEA predicts in its Stated Policies Scenario ("**STEPS**") an increase in global oil and gas demand from today to 2030, and in the STEPS there remains a meaningful proportion of oil and gas demand throughout the forecasting period ending in 2050 (Figure 7.1).[10] BP and the IEA's forecasts in their respective reports provide support for the underlying oil and gas industry fundamentals in

4 Source: IEA (2021 World Energy Outlook 2021). All rights reserved. (Available from: World Energy Outlook 2021—Analysis—IEA).

5 Source: BP (2022) bp Statistical Review of World Energy 2022. All rights reserved (Available from bp.com).

6 Source: IEA (2022) World Energy Investment 2022. All rights reserved (Available from: World Energy Investment 2022).

7 Source: IEA (2022 World Energy Outlook 2022). All right reserved. (Available from: World Energy Outlook 2022—Analysis—IEA). Based on STEPS data and noting that, in the aggregate, growth in global energy demand is met almost entirely almost by renewables and, further, that growth in advanced economies to 2030 are low emission fuels.

8 Source: BP (2022) bp Statistical Review of World Energy 2022. All rights reserved. (Available from: bp.com).

9 Source: IEA (2022 World Energy Outlook 2022). All right reserved. (Available from: World Energy Outlook 2022—Analysis—IEA).

10 Source: IEA (2022 World Energy Outlook 2022). All right reserved. (Available from: World Energy Outlook 2022 – Analysis – IEA).

the next decade.[11] While there is a robust outlook for the consumption of both oil and gas in the next decade, for the first time, the IEA indicated that a scenario based on prevailing policy settings has global demand for each of the fossil fuels exhibiting a peak or plateau. Total demand for fossil fuels declines steadily from the mid-2020s by around 2 exajoules per year on average to 2050, an annual reduction roughly equivalent to the lifetime output of a large oil field. Natural gas demand reaches a plateau by the end of the decade, and oil demand reaches a high point in the mid-2030s before falling slightly. From 80% today – a level that has been constant for decades – the share of fossil fuels in the global energy mix falls to less than 75% by 2030 and to just above 60% by mid-century. In the Announced Pledges Scenario ("**APS**"), the drive to meet climate pledges in full sends demand for all the fossil fuels into decline by 2030. By 2030, fossil fuels account for less than three-quarters of total energy supply, and by 2050 their share falls to just above 60%. These trends are emblematic of a shift in the energy landscape since the Paris Agreement[12]

As a result of the global COVID-19 pandemic, world consumption of primary energy fell by 4.5% in 2020, the first decline since the financial crisis in 2008 and the largest single year decline since 1945[13]. In 2020, global oil consumption decreased by 8.5 million barrels per day ("**MMBBL/d**") or 8.8% according to IEA data from 2021, the largest ever decline in both absolute and relative terms[14]. The transport sector, responsible for approximately 60% of total oil demand, was severely impacted by the mobility restrictions in 2020 and was the main driver for the decrease in oil demand[15]. With the easing of imposed restrictions related to the COVID-19 pandemic, global primary energy demand in 2021 bounced back by almost 6%, more than reversing the sharp fall in energy consumption in 2020 and more than 1% above its 2019 level[16]. In 2021, the IEA estimated oil demand to be back at pre-pandemic levels in 2022 and expected a demand growth of 13.1 million barrels per day to 2026.[17] In 2022, the IEA estimates that oil demand is expected to grow 0.8% per year to 2030, and is expected to reach a peak of 103 million barrels per day in the STEPS, peaking in the mid-2030s.[18] In the STEPS, global oil demand levels off in 2035 at around 103 mb/d and then drops by around 1 mb/d to 2050. In advanced economies, demand falls by 3 mb/d to 2030, mainly because of reductions in road transport, and only a few countries see demand exceed 2019 levels. Demand peaks globally in the mid-2030s as reductions in advanced economies (a drop from 2030 to 2050 of 10 mb/d) just outweigh growth in emerging market and developing economies (6 mb/d increase) and international bunkers (3 mb/d increase). In the APS, oil demand falls by nearly 40% between 2030 and 2050 to 57 mb/d in 2050. In the net zero to emissions by 2050 scenario ("**NZE Scenario**"), strenuous policy efforts to reduce emissions lead to a 6% average annual reduction in oil demand between 2030 and 2050, and demand in 2050 falls to less than 25 mb/d[19]. BP's Energy Outlook 2022 Edition predicts that this will continue to increase to stronger than pre COVID-19 pandemic levels due to the stronger than expected rebound in economic growth[20]. In the STEPS, natural gas demand rises at an average rate of 0.4% per year between 2021 and 2030, well below the 2.2% average rate of growth seen between 2010 and 2021. In the APS, global natural gas demand soon peaks, and by 2030 is nearly 10%

11 Source: IEA (2022 World Energy Outlook 2022). All right reserved. (Available from: World Energy Outlook 2022—Analysis—IEA); BP (2022) bp Statistical Review of World Energy 2022. All rights reserved. (Available from: bp.com).

12 Source: IEA (2022 World Energy Outlook 2022). All right reserved. (Available from: World Energy Outlook 2022—Analysis—IEA).

13 Source: BP Energy Outlook 2021 (November 2021), available from: Full report—Statistical Review of World Energy 2021 (bp.com).

14 Source: IEA (2021 World Energy Outlook 2021). All right reserved. (Available from: World Energy Outlook 2021 – Analysis – IEA).

15 Source: IEA (2021) Global Energy Review. All rights reserved. (Available from: IEA (2021) Global Energy Review).

16 Source: IEA (2021 World Energy Outlook 2021). All right reserved. (Available from: World Energy Outlook 2021—Analysis—IEA).

17 Source: IEA (2021 World Energy Outlook 2021). All right reserved. (Available from: World Energy Outlook 2021 – Analysis – IEA).

18 Source: IEA (2022 World Energy Outlook 2022). All right reserved. (Available from: World Energy Outlook 2022 – Analysis – IEA).

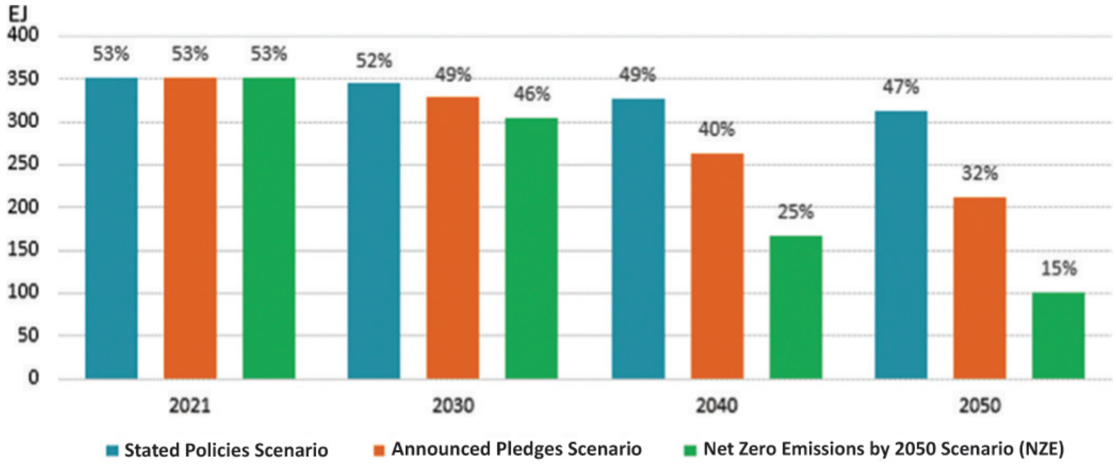
19 Source: IEA (2022 World Energy Outlook 2022). All right reserved. (Available from: World Energy Outlook 2022 – Analysis – IEA).

20 Source: BP Energy Outlook 2022 Edition. All rights reserved. (available from: bp.com).

lower than it was in 2021. In the NZE Scenario, natural gas demand is over 900 bcm lower in 2030 than in 2021, a drop of around 20%[21].

Following Russia's invasion of Ukraine, which resulted in gas supply cuts to Europe as a counter measure for the sanctions imposed on Russia, oil and gas supply security has gained further importance in the world, particularly in Europe. The geopolitical conditions, gas supply cuts (c.75% from January 2022[22]) and desire to reduce reliance on Russian gas have resulted in a 48% increase in oil[23] prices and a 682% increase in gas prices[24].

Figure 7.1 Total global oil and gas supply (in Exajoule) and as percent of total energy supply (%)



Source: IEA (2022 World Energy Outlook 2022). All rights reserved. (Available from: World Energy Outlook 2022 – Analysis – IEA).

1.2 *Oil markets*

1.2.1 Introduction

Crude oil produced from different oil fields varies in composition and the composition and distribution of hydrocarbon components determines the weight of the oil. Lighter oil requires less refinement and is therefore often more valuable than heavier oil.

Oil is well-suited for storage and transportation and is transported across long distances in large crude oil tankers or pipelines. Oil prices are determined on the world's leading commodities exchanges, with the New York Mercantile Exchange in New York and the Intercontinental Exchange in London being the two most important markets for the determination of the global oil prices. Among several reference prices, Brent is considered the leading global price benchmark for Atlantic basin crude oils and is used as a reference for a majority of the world's internationally traded crude oil supplies, including serving as the key reference for most oil production in the North Sea.

1.2.2 Oil Demand

Crude oil is used for a variety of purposes, the most being the production of fuels, with approximately 66% of crude oil being used for the production of gasoline, diesel, jet fuel and other fuel oils[25]. Oil can also be used to heat buildings, produce electricity, and as feedstock for the petrochemical industry to make plastic and other end-user goods[26]. The evolution in oil

[21] Source: IEA (2022 World Energy Outlook 2022). All rights reserved. (Available from: World Energy Outlook 2022 – Analysis – IEA).

[22] Source: IEA Gas Trade Flows as at September 2022—Gas flows from Russia to Germany via Nord Stream.

[23] Refers to the change in Brent prices in the period between 24 February ($66.9/bbl) and 24 February 2022 ($99.1/bbl).

[24] Refers to the change in UK NBP prices in the period between 24 February (GBp0.4/therm) and 24 February 2022 (GBp3.2/therm).

[25] Source: BP Statistical Review of World Energy 2021 (July 2021, available from: BP Statistical Review of World Energy 2021).

[26] Source: EIA (December 2021, Use of oil—US Energy Information Administration (EIA)).

demand has historically been closely linked to global economic growth. Global economic activity, measured in GDP, retracted during 2020, but recovered during 2021[27]. During the 10 years leading up to 2021, global liquids consumption (i.e. crude oil, NGLs and biofuels) grew by 0.8% p.a. on average, reaching 100.3 million barrels per day in 2019[28]. The oil market experienced a material demand shock in 2020 due to the COVID-19 pandemic, with countries globally enforcing lock down measures. This dramatically impacted mobility and economic activity across the world and significantly reduced oil demand. World oil consumption fell by 8.8% to 91.0 million barrels per day in 2020 according to IEA's Oil 2021 report[29]. However, demand recovery has been relatively swift, and world oil demand rose by 5.3 million barrels per day in 2021[30].

As part of the energy transition, the global energy system will gradually experience increased energy supply from renewable sources which will impact the long-term demand outlook for oil. Analysts believe that the 'green shift' is now likely to accelerate in Europe as a result of the Ukraine war and motivation for energy security, whereas an acceleration of US oil output growth is possible for the same reasons[31]. However, in the STEPS, global oil demand surpasses 2019 levels by 2023, undeterred by high oil prices, demand peaks in the mid-2030s at 103 mb/d and then declines slightly to 2050 (Figure 7.2)[32]. According to the IEA, non-member countries of the OECD, such as China and India, are expected to be the primary drivers of oil demand growth in the years ahead, as their economic development will continue to outpace the developed economies. Oil consumption in the industrialised OECD countries was forecast to average 46.1 million barrels per day in 2022[33]. In the APS, stronger policy action leads global oil demand to peak in the mid-2020s, just above the level of demand in 2019, before dropping to 93 mb/d in 2030 (Figure 7.2). Demand then falls by around 40% between 2030 and 2050, with passenger cars, road freight and industry responsible for the largest reductions. In the NZE Scenario, oil demand never returns to its 2019 level (Figure 7.2). Demand falls by 2.5% each year on average between 2021 and 2030, and by just under 6% each year from 2030 to 2050. Reductions in oil use in road transport are particularly significant, and assume that policy makers mandate a strong global push towards cleaner alternatives: no new cars with internal combustion engines are sold after 2035 and nearly all trucks sold from 2040 use electricity or hydrogen. Even with the rapid decline in oil demand in the NZE Scenario, there is a need for continued investment in existing production assets, but the declines are sufficiently steep to avoid the need for any new long lead time conventional fields. The oil price is increasingly set by the operating cost of the marginal project and it falls to around USD 35/barrel in 2030 and to USD 24/barrel in 2050[34].

27 Source: IEA (2021) Global Energy Review. All rights reserved. (Available from: Annual rate of change in world GDP, 1990-2021—Charts—Data & Statistics—IEA).

28 Source: IEA (February 2022) Oil Markets Report 2022.

29 Source: IEA (November 2021) Oil Market Report. All rights reserved.

30 Source: BP Statistical Review of World Energy 2022, (Available from: BP Statistical Review of World Energy 2022).

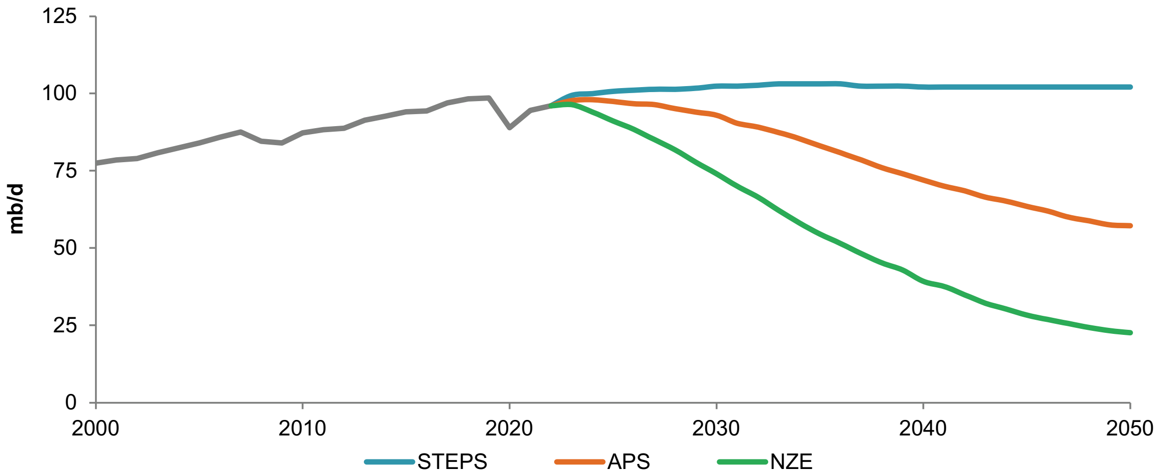
31 Source: Rystad Energy Impact Report, March 2022. All rights reserved. (Available from: Rystad Energy Impact Report, March 2022).

32 Source: IEA (2022 World Energy Outlook 2022). All right reserved. (Available from: World Energy Outlook 2022—Analysis—IEA).

33 Source: IEA (June 2022) Oil Market Report. All rights reserved. (Available from: Oil Market Report—June 2022—Analysis—IEA).

34 Source: IEA (2022 World Energy Outlook 2022). All right reserved. (Available from: World Energy Outlook 2022—Analysis—IEA).

Figure 7.2: Global oil demand forecast (million barrels of oil per day)



Source: IEA (2022 World Energy Outlook 2022). All right reserved. (Available from: World Energy Outlook 2022—Analysis—IEA).

1.2.3 **Oil supply**

Global oil production, including crude oil, condensate and NGLs, reached close to 90 MMBBL/d in 2021[35]. The largest producing countries were the United States of America (16.6 MMBBL/d), Saudi Arabia (11.0 MMBBL/d) and Russia (10.9 MMBBL/d). The OPEC accounted for nearly 35% of global oil supply. OPEC includes the largest Middle East oil producers, namely Iran, Iraq, Kuwait, Saudi Arabia and the UAE, in addition to Algeria, Angola, Congo, Equatorial Guinea, Libya, Nigeria, Gabon, Ecuador, and Venezuela. Historically, OPEC has played the role of swing producer in the global oil market and its decisions have had considerable influence on oil supply and thus international oil prices.

Similar to oil demand, global oil production in 2020 was also heavily impacted by the COVID-19 pandemic, declining by 6.6 MMBBL/d (6.9%) in 2020, largely as a result of production curtailments by OPEC countries and other large producers in response to the large reduction in demand, however global oil production improved in 2021 by 1.6% on 2020 levels[36].

Under the STEPS forecast, oil production in the UK is estimated to reduce from 0.9mb/d in 2021 to 0.6mb/d in 2030, 0.4mb/d in 2040 and 0.3mb/d in 2050. Significant continued upstream investment is required to meet oil demand, both to increase overall global supply and to offset declines from existing fields although the NZE Scenario does not require new oil and gas projects to be developed. Upstream investment is expected to rise by around 10% in 2022, but this remains well below the pre-pandemic level of investment in 2019, and most of the rise stems from cost inflation rather than an increase in activity[37].

Global proven oil reserves stood at an estimated 1,732 billion barrels at the end of 2020[38]. OPEC members represented approximately 70% of these reserves as at 2020 (Figure 7.3). According to the IEA, global proven oil reserves for 2021 stood at 1,752 billion barrels.[39]

[35] Source: IEA (2022 World Energy Outlook 2022). All rights reserved. (Available from: World Energy Outlook 2022—Analysis—IEA).

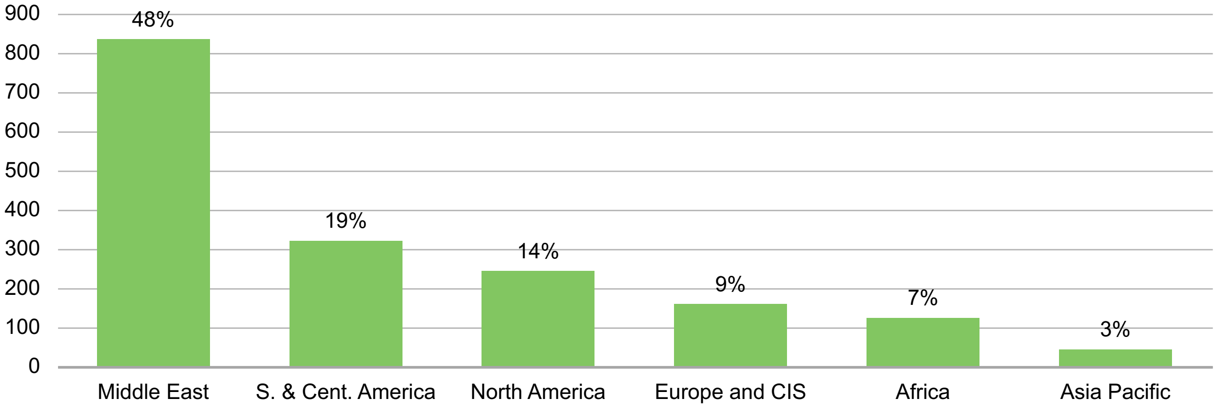
[36] Source: IEA (2022 World Energy Outlook 2022). All rights reserved. (Available from: World Energy Outlook 2022—Analysis—IEA).

[37] Source: IEA (2022 World Energy Outlook 2022). All rights reserved. (Available from: World Energy Outlook 2022—Analysis—IEA).

[38] Source: BP (2021) bp Statistical Review of World Energy 2021. All rights reserved (Available from bp.com).

[39] Source: IEA (2022 World Energy Outlook 2022). All rights reserved. (Available from: World Energy Outlook 2022—Analysis—IEA).

Figure 7.3: Distribution of proven world oil reserves 2020 (in billion barrels) and percent of total (%)



Source: BP Statistical Review of World Energy 2021 (July 2021, available from: BP Statistical Review of World Energy 2021).

As a result of the demand shock created by the COVID-19 pandemic, upstream investments and expansion plans globally were scaled back, with companies looking to bolster their balance sheets during the challenging oil price environment. According to the IEA, in 2020 operators invested one-third less than planned at the start of the year (and 30% less than in 2019)[40].

On forecasts prepared by IEA in 2021, these spending cuts and project delays are beginning to constrain future global supply growth. In the absence of stronger policy action in 2021, the IEA forecasted global oil production would need to rise 10.2 MMBBL/d by 2026 to meet expected demand[41].

With the world re-opening as a result of widespread vaccination programmes and demand for oil increasing going forward, there is currently a constructive backdrop for oil and gas prices. However, external factors including decisions by OPEC+ members, which includes ten non-OPEC crude oil exporting countries, could impact future oil supply. As a result of the reduction in investments during the COVID-19 pandemic, a situation may arise where increasing oil demand is not met by new production, leaving global oil markets undersupplied and pushing prices upwards.

Immediate shortfalls in fossil fuel production from Russia will need to be replaced by production elsewhere—even in a world working towards net zero emissions by 2050. The most suitable near-term substitutes are projects with short lead times that bring oil and gas to market quickly, as well as capturing some of the 260 bcm of gas that is wasted each year through flaring and methane leaks to the atmosphere.[42]

Furthermore, the IEA estimates that if clean energy investment does not accelerate then higher investment in oil and gas would be needed to avoid further fuel price volatility. In the STEPS, an average of almost USD 650 billion per year is spent on upstream oil and natural gas investment to 2030, a rise of more than 50% compared with recent years. This investment comes with risks, both commercial and environmental, including achieving the 1.5°C goal.[43]

1.2.4 The oil price

Oil is a commodity with a well-developed global market. As evidenced by the price changes in recent years, oil prices are highly dependent on current and expected future supply and demand balance. As such, it is influenced by global macroeconomic conditions and may

[40] Source: IEA (November 2021) Oil Market Report. All rights reserved. (Available from: IEA (November 2021) Oil Market Report).

[41] Source: IEA (November 2021) Oil Market Report. All rights reserved. (Available from: IEA (November 2021) Oil Market Report).

[42] Source: IEA (2022 World Energy Outlook 2022). All right reserved. (Available from: World Energy Outlook 2022—Analysis—IEA).

[43] Source: IEA (2022 World Energy Outlook 2022). All right reserved. (Available from: World Energy Outlook 2022—Analysis—IEA).

experience material fluctuations on the basis of economic indicators and material economic events as well as geopolitical events.

Oil prices fell significantly in early 2020 as a consequence of the COVID-19 pandemic, combined with the OPEC+ group's temporary production increase, adding supply to a market experiencing a significant short-term demand reduction. As a result, oil prices dropped significantly with the Brent spot price[44] temporarily trading at approximately $20/BBL, but recovered swiftly on the back of production cuts from OPEC and Russia, combined with a recovery in demand. In the second half of 2020 and during 2021, oil prices experienced a significant recovery, with Brent averaging approximately $70.8/BBL through 2021, ending the year at $77.8/BBL. The impact of the Ukraine war and the desire by many countries to reduce their reliance on Russian oil and gas products has driven prices up even further in 2022 by 48%[45].

1.3 *Gas markets*

1.3.1 Introduction

Natural gas is typically colourless, odourless and non-toxic at ambient temperatures. It can be found in onshore and offshore reservoirs, either as associated gas in crude oil or condensate or alone as non-associated gas. Natural gas is primarily composed of methane, but may also contain ethane, propane and heavier hydrocarbons. It is used both as an energy source and as feedstock for petrochemical production and presents a lower carbon intensity relative to other fossil fuels. As a result, natural gas is consumed for a variety of uses ranging from home and business heating to electric power generation, manufacturing of petrochemical products ranging from plastics to fertilisers and intermediate materials, and as transportation fuel.

1.3.2 Gas demand

According to the IEA, global natural gas demand in 2020 was 3,924 bcm, which represented a reduction of 1.9% compared to 2019 due to a combination of a mild winter in the northern hemisphere and the impact from the COVID-19 pandemic (Figure 7.4)[46]. Following economic recovery from the pandemic. Global demand for natural gas held up better than demand for other fossil fuels and then increased by 5% in 2021, double its average growth rate over the past decade.[47]

The IEA estimates in the STEPS that natural gas demand rises by less than 5% between 2021 and 2030, compared with a 20% rise between 2011 and 2020. It then remains flat from 2030 at around 4,400 billion cubic metres (bcm) through to 2050, with growth in emerging market and developing economies offset by declines in advanced economies.[48] The IEA estimates in APS that natural gas demand will drop by 10% from 2021 to 2030 and in the NZE Scenario that natural gas demand will drop by approximately 20% from 2021 through to 2030. Furthermore, in the NZE Scenario, demand drops rapidly to approximately 3300 bcm in 2030[49].

In the STEPS, natural gas demand is forecast to grow towards 2030 in the IEA World Energy Outlook report for 2022[50]. However, the outlook for gas is dampened by higher near-term prices; more rapid deployment efficiency measures; higher renewables deployment and a faster uptake of other flexibility options in the power sector; and, in some cases, reliance on

[44] Source: Impact of Covid-19 Pandemic on crude oil prices: Evidence from Econophysics approach.

[45] Refers to the change in Brent prices in the period between 24 February 2021 ($66.9/bbl) and 24 February 2022 ($99.1/bbl).

[46] Source: Ice Futures Europe—ICE Brent Index.

[47] Source: IEA (2022 World Energy Outlook 2022). All right reserved. (Available from: World Energy Outlook 2022—Analysis—IEA).

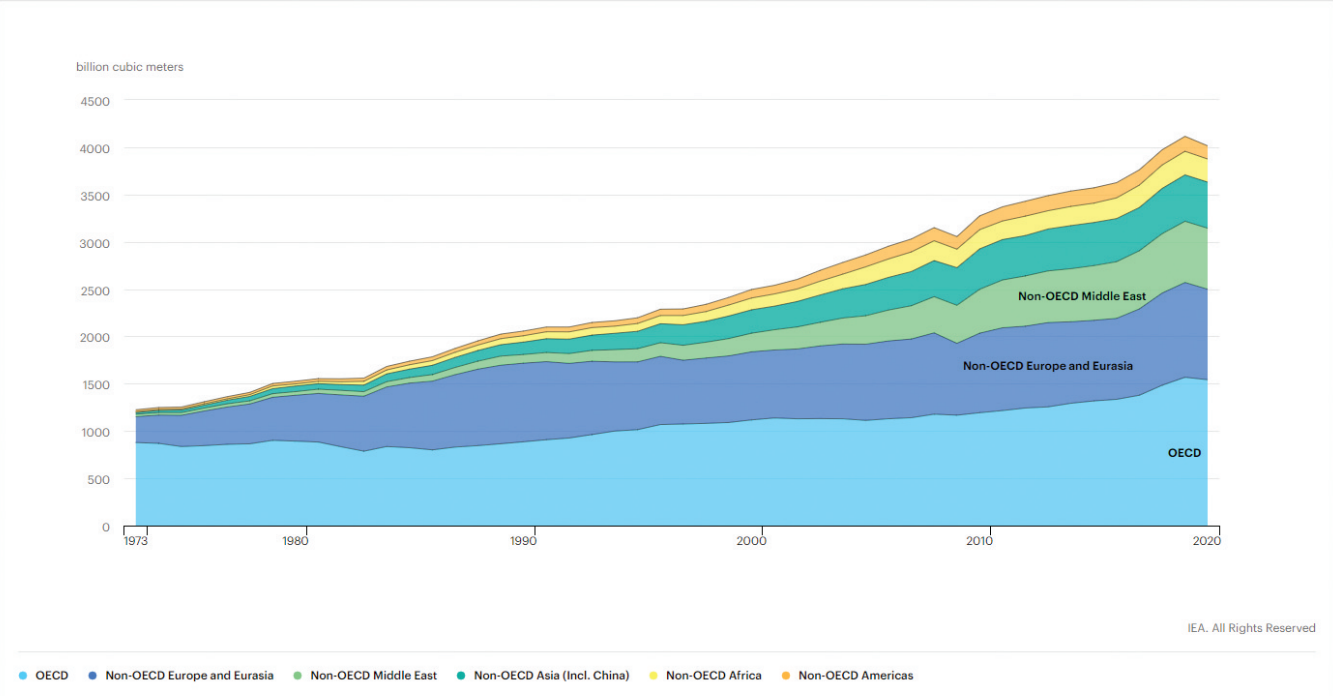
[48] Source: IEA (2022 World Energy Outlook 2022). All right reserved. (Available from: World Energy Outlook 2022—Analysis—IEA).

[49] Source: IEA (2022 World Energy Outlook 2022). All right reserved. (Available from: World Energy Outlook 2022—Analysis—IEA).

[50] Source: IEA (2022 World Energy Outlook 2022). All right reserved. (Available from: World Energy Outlook 2022—Analysis—IEA).

coal for slightly longer. Momentum behind natural gas growth in developing economies has slowed, notably in South and Southeast Asia.[51]

Figure 7.4: Global historical gas demand (bcm per year)



Source: IEA 2021 (available from: iea.org)

1.3.3 Gas supply

The IEA forecast that global natural gas production would fall by approximately 120 bcm in 2020 (-2.9%), a decline larger than in the aftermath of the 2008 global financial crisis (supply fell by 100 bcm in 2009).[52] In the STEPS, the IEA estimates that natural gas production stays flat between 2030 to 2050, with some growth in the Middle East and Central and South America. For the same time period, the IEA forecast in the APS and NZE Scenario that natural gas demand will fall. Global natural gas supply in the APS declines by over 1 200 bcm between 2030 and 2050, to levels seen before the shale gas revolution. In the NZE Scenario, global gas production declines at a rate of 5% per year, and is just under 1 100 bcm by 2050. In the STEPS, global natural gas trade increases at an annual average rate of less than 1% per year from 2021 to 2030, compared to 3% between 2010 and 2021. For the same time period, global gas trade falls slightly in the APS due to faster declines in pipeline gas and slower growth in LNG demand in emerging market and developing economies. LNG rapidly gains market share from long-distance pipeline trade and so grows at a faster rate than overall trade, at more than 2% per year. With Russian pipeline gas to the European Union falling by nearly 90%, or 130 bcm between 2021 and 2030, competition increases between Europe and Asia for LNG. Around 85% of the growth in global LNG supply to 2030 in the STEPS originates in the United States and the Middle East.[53]

1.3.4 Gas price

Due to its characteristics, natural gas is relatively hard to store and transport, and transportation of gas is primarily conducted through pipelines and LNG transportation networks. As a result, gas prices are determined in regional markets, and do not have a global reference price similar to oil prices.

[51] Source: IEA (2022 World Energy Outlook 2022). All right reserved. (Available from: World Energy Outlook 2022—Analysis—IEA).

[52] Source: IEA (2021 World Energy Outlook 2021). All right reserved. (Available from: World Energy Outlook 2021—Analysis—IEA).

[53] Source: IEA (2022 World Energy Outlook 2022). All right reserved. (Available from: World Energy Outlook 2022 – Analysis – IEA).

Three broad pricing mechanisms exist for gas. The first, mostly seen in international trade and in long-term contracts, involves linking gas prices to either crude or petroleum product prices. The second pricing mechanism is regulated pricing in domestic markets, where governments set fixed prices typically reflective of production and transportation costs. The final mechanism is competitive pricing whereby trading points, often called hubs, are established in major markets and prices are determined by supply and demand at these hubs. The gas market in the US is largely deregulated. In Europe, gas has historically been traded under long-term contracts with pricing linked to diesel and heavy fuel. In recent years, however, an increasing share of European gas volumes have shifted from oil-based to hub-based pricing, where gas supply and demand dynamics determine the price. Several trading hubs for gas have been established, with UK NBP and the Transfer Title Facility in the Netherlands being the most active.

Natural gas prices increased dramatically during the second half of 2021, driven by a combination of a robust recovery in demand, particularly in Asia and Europe, extreme weather events and unplanned supply outages, leading to tighter gas markets[54]. While the IEA expects these high prices to be temporary, supply-demand imbalances and price volatility are expected to remain in the market over the medium term. The increase in demand for natural gas, combined with elevated oil prices, puts upward pressure on natural gas prices, underlining the positive sentiment in the gas markets. The impact of Russia's full scale invasion of Ukraine has also significantly affected gas prices as Russia's supply to the rest of the world has been cut. Following Russia's invasion of Ukraine, which resulted in gas supply cuts to Europe as a counter measure for the sanctions imposed on Russia, oil and gas supply security has gained further importance in the world, particularly in Europe. The geopolitical conditions, gas supply cuts of 75% (from January 2022[55]), and desire to reduce reliance on Russian gas have resulted in an increase in gas prices of 682%[56].

1.3.5 **European Gas Dynamics**

Europe has been heavily reliant on gas imports from Russia over the last decade. The share of Russian gas in EU demand increased from 30% in 2009 to 47% in 2019 before falling to 40% in 2020 amid global oversupply. In 2021, Gazprom reduced its supply of gas to the European Union, which contributed to price spikes in 2021/2022. Similarly, the European Union accounted for 60% of Russia's gas exports and 70% in 2021.

Following Russia's invasion of Ukraine, the European Commission published the REPowerEU Plan on 18 May 2022, detailing the measures and investments required by the EU to reduce fossil fuel dependency on Russia to zero by 2027.

According to the IEA, deliveries from Russia to the European Union fell by nearly 40% in the first-half of 2022, with Russia terminating supply contracts for multiple EU countries due to buyer refusal to accept a unilateral change in the payment system. Exports to former subsidiaries of Gazprom in Germany have ceased, and large importers such as Germany and Italy are planning a phase out of Russian gas over the course of the 2020s. With its RePowerEU Plan, the European Union is setting in motion a process to dismantle a structural dependence on energy imports from Russia built over several decades. IEA has indicated that during the winter ahead, the amount of Russian gas supplied to Europe may well be dictated by Russia's own political ends rather than by European policies, raising the risk of possible supply shortfalls and rationing[57]

2. THE UK OIL AND GAS INDUSTRY

2.1 *Introduction*

The UKCS can be broadly divided into five main areas: the Central North Sea, the Northern North Sea, the Southern North Sea Basin, the West of Shetland and the Irish Sea. Amoco

[54] Source: IEA (2021) World Energy Outlook. All rights reserved. (Available from: World Energy Outlook 2021—Analysis—IEA).

[55] Source: IEA Gas Trade Flows as at September 2022—Gas flows from Russia to Germany via Nord Stream.

[56] Refers to the change in UK NBP prices in the period between 24 February (GBp0.4/therm) and 24 February 2022 (GBp3.2/therm).

[57] Source: IEA (2022 World Energy Outlook 2022). All right reserved. (Available from: World Energy Outlook 2022—Analysis—IEA).

discovered the first oil in the UK sector of the North Sea in 1969 in what is now the Arbroath field, with the first UK offshore oil production commenced in June 1975 from the Argyll field. After early exploration success, the surge in activity led to more than 40 billion BOE produced since the beginning of the 1980s.

2.2 ***UKCS outlook***

Oil and gas accounts for approximately 75% of the UK's primary energy demand, with the United Kingdom expected to be a net importer of both by 2050. The NSTA forecasts an estimated 10 to 20 billion BOE remaining in the UKCS, while in its 'Balanced Pathway' scenario, the Climate Change Committee forecasts that the United Kingdom will consume more than 17 billion BOE through to 2050[58,59].

Total oil and gas production from the UKCS was over 800 MMBOE in 2010, before falling to between approximately 500 MMBOE and approximately 550 MMBOE between 2013 and 2014. This preceded the rise through 2018 and 2019 to just over 587 MMBOE in 2020, or 1.61 MBOEPD, equivalent to an estimated 70% of the United Kingdom's total oil and gas demand in 2020 and more than 45% of total energy demand. This was 5% lower than 2019 (just under 616 MMBOE), with oil output falling by 7% (from 403 to 375 MMBOE) and gas remaining stable at a less than 1% decline (from 213 to 212 MMBOE). Oil and gas production declined in 2021, with production levels 20% lower than 2019. This reflects lower levels of recent brownfield and greenfield investments and the impact of increased planned maintenance outages deferred from 2020, including that of the FPS.

The impact of the COVID-19 pandemic on offshore activities in the UKCS resulted in drilling activity falling by half and some of the lowest levels of new project approvals on record, as companies responded to the price collapse and reduced offshore personnel levels by around 20% to help manage COVID-19 exposure risk. Overall, the industry spent 23% less in 2020, representing a fall of approximately £3.4 billion. Nevertheless, the UKCS proved itself to be particularly resilient in the face of the COVID-19 pandemic and periods of low commodity prices. Commodity prices improved steadily through 2021 as the world emerged from the COVID-19 pandemic and competition increased as a result of tighter supply due to lower levels of investment in the previous years. Commodity prices then increased drastically as a result of Russia's invasion of Ukraine in February 2022. It is difficult to predict how prices will develop as this will be dictated by the ongoing geopolitical events, including their impact on global economies, but also ongoing COVID-19 concerns with restrictions in China potentially impacting demand. The IEA has reported that the largest crisis in decades may occur if the disruption to Russian supply is not offset by growth from other producers. Rystad predicts that oil prices will continue to rise and could potentially rise beyond \$130 per barrel[60].

The basin remains globally fiscally competitive (although the impact of the UK Government's 'windfall tax' through the Energy Profits Levy is still unclear). New entrants to the basin continue to invest in assets, with £4.7bn[61] of new acquisitions taking place in 2021 and £4.5bn already this year. In 2019, production efficiency reached a 16 year high of 80%[62], with a key focus for NSTA being the maintenance of the UKCS production efficiency at this level. Operating costs remained stable in 2021 at £11.90/BBL and material new discoveries have demonstrated real prospectivity. Moreover, the totality of reserves and resources being targeted in the UKCS was not undermined by the downturn, despite the challenges faced by the industry and environmental activism targeted at high profile potential developments. The Ukraine war has shone a spotlight on domestic security of supply and it is recognised that fresh investment in UKCS oil and gas developments is needed in the next 12–18 months in order to maintain longer term contributions to security of supply. The UK Government anticipates that the new investment relief, introduced alongside the newly implemented Energy

58 Source: NSTA Overview 2022.

59 Source: NSTA Overview 2022. All rights reserved. Available from: NSTA: NSTA Overview 2022—2022—Publications—News &
publications (nstauthority.co.uk).

60 Source: Rystad Energy Impact Report, March 2022. All rights reserved. (Available from: Rystad Energy Impact Report, March 2022).

61 Source: Thomson Reuters.

62 Source: NSTA, UKCS Production Efficiency Report 2020 (Available from: NSTA, UKCS Production Efficiency Report 2020).

Profits Levy, will encourage companies to invest in the UKCS and to accelerate final investment decisions on near-term developments.

The North Sea Transition Deal is a catalyst for industry's plans to realise its full potential through the energy transition, as set out in the Roadmap 2035. Under a new partnership with the UK Government, it will provide the framework to help unlock new investment, reduce emissions and create new employment and supply chain opportunities, building on the resources of the North Sea. At the same time, NSTA recognises that an orderly transition to net zero requires more domestic oil and gas production to minimise reliance on imports (often with a larger carbon footprint)[63].

2.3 ***Capital investment***

Lower rates of new investment in recent years (albeit from record levels) will result in less production coming on stream in the upcoming period. New fields gaining regulatory approval in 2020 unlocked just under 40 MMBOE of new resources—less than one-third of approvals in 2019 and 85% lower than 2018. This improved in 2021, with 80 MMBOE of new UKCS resources approved (of which 35 MMBOE is gas) and it is expected that 10 fields will start up in 2022. Combined with the fields that started producing in late 2021, these will bring around 450 MMBOE of new reserves (approximately a 50:50 split between oil and gas). The OEUK reports that this would be sufficient to offset the declining production from existing assets, keeping production from the basin relatively stable throughout 2022-2023.

These projects represent a significant opportunity to help manage the basin's production profile and importantly contribute towards domestic energy security, but it will be the middle of the decade before they begin to make a significant contribution to UKCS output. The OEUK estimates that overall there is almost £20bn of possible capital expenditure in the UKCS within company plans between 2022-2026. Alongside the newly introduced Energy Profits Levy, the UK Government has introduced a new 'super-deduction style' investment allowance that, in combination with other reliefs, provides a 91 pence tax saving for every £1 invested[64] in the UKCS (available at the point of the investment), with the hope that this will encourage the acceleration of final investment decisions of near-term development in the basin[65].

2.4 ***Capital Investment versus Brent Crude Price***

The level of capital invested in the basin typically follows commodity price trends, with periods of higher prices associated with the UKCS' ability to attract greater levels of investment. For example, each of 2013 and 2014 saw capital investment reach over £16 billion (in 2020 terms) following annual Brent price highs of between $120/BBL and $140/BBL during the preceding years. During such times companies benefit from greater levels of cash generation and look to sanction projects which may have more challenging economics at lower prices. Declines in investment have generally lagged the onset of price falls by 12 to 24 months. However, the dramatic nature of the 2020 price crash coupled with the relatively low level of new investment approvals in recent years led to a sharper and faster investment decline.

The renewed focus on domestic energy security as a result of the Ukraine war and the 'super-deduction style' investment allowance introduced alongside the Energy Profits Levy are expected to help to slow this decline[66].

2.5 ***Operating expenditure***

Total operating expenditure fell 11% in 2020 to £6.5 billion (compared with £7.3 billion in 2019), as companies deferred some offshore activities and reduced offshore personnel levels by around 20% to reduce COVID-19 exposure risk. Operating expenditure rose 10% in 2021 to

[63] Sources: Oil & Gas UK Business Outlook Report 2019; Oil & Gas UK Business Outlook Report 2021; Offshore Energy UK Business Outlook Report 2022 NSTA; UKCS Production Efficiency Report 2020, International Energy Agency Oil Markets Report 2022, NSTA Overview 2022; Offshore Energy UK Business Outlook 2022; NSTA Corporate Plan 2022.

[64] The investment allowance within the EPL rules plus the standard relief for capex for RFCT, SC and EPL, plus the original SC investment allowance, all taken together combine to provide a 91p tax relief for each £1 invested.

[65] Sources: Oil & Gas UK Business Outlook Report 2021; NSTA Overview 2022; Offshore Energy UK Business Outlook Report 2022, HM Treasury, Policy paper—Energy Profits Levy Factsheet—26 May 2022.

[66] Energy Profits Levy -Factsheet—Gov.uk.

£7.2bn, marking a return to pre COVID-19 levels and going forward it is anticipated that operating expenditure will trend roughly in line with production rates.

Unit operating costs were at their lowest level since 2010 at £11.15/BBL ($14.20/BBL) in 2020. With Brent crude averaging roughly $40/BBL across the year, this is equivalent to over one-third of the per-barrel price, similar to that in 2016 (which followed a decline from a peak of just under £20/BBL (approximately $55/BBL) towards the end of 2014) and significantly higher than the last three years. However, this does represent relatively stable cost efficiency since 2016. Average unit operating cost fell from £11.9/BOE in 2019 to £11.2/BOE in 2020. OEUK expected unit operating costs to see a slight rise or stay flat through 2021 and 2022[67]; 2021 data shows that the average operating cost for 2021 rose back to the 2019 level of £11.9/BOE.

2.6 ***Exploration & appraisal drilling***

Seventy-one wells began drilling on the UKCS in 2020—half the levels seen in 2019—as companies deferred and cancelled activities to preserve cash and reduce operational risk. 2020 was an exceptional year with market conditions driving drilling activity to its lowest levels since the early 1970s. Exploration and appraisal activity was at the lowest level in the basin's history. The activity that took place included seven exploration wells, two appraisal wells and 62 developments wells. In 2021, only 55 wells began drilling on the UKCS. OEUK anticipates approximately a 10% increase in development and exploration drilling for 2022.

Exploration drilling peaked in 1990 at approximately 150 wells, before steadily declining to current levels. Appraisal drilling has seen a gradual decline since 1990, falling steadily over the last decade to current levels. The seven exploration wells drilled in 2020 were the lowest number since 1965. Yet despite the low level of activity, the recent track record of successful finds continued in those which were drilled, including the Isabella well and the Losgann well. OEUK expects to see a modest increase in 2021 and a further potential increase in 2022, with between 10 and 12 exploration wells this year, similar to the levels of exploration drilling seen from 2016 to 2018. This also includes expectations of 70 to 80 development wells and three to five appraisal wells this year again similar to levels seen in 2016 to 2018. These wells include a wide range of exploration prospects, ranging from relatively small infrastructure-led prospects to some potentially high-impact opportunities.

The level of appraisal drilling relies heavily on the amount of exploration activity and number of discoveries. There were two appraisal wells drilled on the UKCS in 2020 and five in 2021[68].

2.7 ***Decommissioning***

The total estimated decommissioning expenditure of £1.1 billion in 2020 accounted for approximately 10% of overall UKCS oil and gas industry expenditure in 2020. Around one-third of well decommissioning plans (representing around £500 million of decommissioning expenditure) previously scheduled for 2020 to 2022 were deferred, with decommissioning not escaping the impact of COVID-19. Whilst a recovery will take time, an increase in these activities is expected through 2022 as companies return to deferred plans. It is possible, however, that companies may look to advance some existing plans which may have been deferred to 2022 to 2023, given the prospect of increased cash generation from improved commodity prices and capacity in the supply chain to complete the work scopes.

Reductions in expenditure have affected the supply chain, and reduced activity is now expected across almost all areas of decommissioning work during the next two to three years. Over the longer term, the impacts of the COVID-19 pandemic, the commodity price volatility on decommissioning plans remains to be seen, with up to £15 billion still expected to be spent over the next ten years. The industry also continues to demonstrate that it is able to manage expenditure effectively, with a 19% reduction in the overall costs of decommissioning over the past three years. This underlines that the industry's concerted efforts to drive progress are having a real impact as it works towards delivering a 35% reduction in decommissioning costs by 2022, from an initial estimate of almost £60 billion set in 2016. The NSTA Overview 2022

[67] Statista—Capital Investment Expenditure 2014-2022; Trading Economic—Brent Oil for the previous 25 years Energy Profits Levy Factsheet -26 May 2022.

[68] Sources: Oil & Gas UK Business Outlook Report 2021; Oil & Gas UK Decommissioning Insight Report 2020; Offshore Energy UK Business Outlook Report 2022.

records that the cost estimate for decommissioning UKCS oil and gas infrastructure has fallen by more than £13 billion to £46 billion at the end of 2020.

Decommissioning expenditure is expected to rise steadily over the next ten years and is expected to amount to an average of approximately £1.5 billion per year during that period, with well decommissioning representing the majority of this. Since 2017, well decommissioning activity has outweighed exploration, development and appraisal activity combined. Decommissioning expenditure typically represents around 10% of overall expenditure, showing that, despite recent challenging market conditions, investment in the basin and expenditure on continued operation of current assets significantly exceeds decommissioning expenditure. OEUK expects a gradual increase in expenditure over the next three years to reach approximately £1.5 billion during 2024 to 2026 before increasing further, although the later years during this timeframe become less certain. While short-term activity remains uncertain, the longer-term view of OEUK is that+ over the next decade the industry is still expected to spend up to £15.1 billion on decommissioning activity[69].

2.8 ***Decommissioning relief deeds ("DRD")***

A decommissioning relief deed ("**DRD**") is a contract between the UK Government and companies operating in the UKCS. It provides companies with certainty as to their entitlement to tax relief on future decommissioning costs. The DRDs provide this certainty if:

- the decommissioning tax relief available is reduced in the future compared to the 2013 position due to a change in tax law (not a change in tax rates); and
- a company has to pick up another company's decommissioning liabilities where that company has defaulted on its own liabilities[70].

2.9 ***Government measures to encourage activities***

The structure of the UKCS fiscal system means that direct tax payments correlate strongly with the cash flow of companies. This is illustrated in the sharp fall in production tax revenues during the recent downturn, from a £2.1 billion net-positive contribution in the tax year 2014 to 2015, to an outflow of $300 million two years later. As cash flows recovered, production tax payments again turned positive, rising to almost £1.2 billion in the tax year 2017 to 2018[71]. The Office for Budget Responsibility forecasts that the upstream oil and gas sector will pay £18.5bn in direct production taxes between 2021 and 2025 and a total of £23.4bn through to 2027 (without taking into account the Energy Profits Levy)[72].

In recent years, HM Treasury had recognised the maturity of the basin and the need to reward investment in the UKCS at all stages of the industry life cycle and that, to maximise investment, the overall tax burden facing the industry needed to be reduced. Since its launch, the Driving Investment Strategy had provided certainty by offering a predictable fiscal environment upon which to base long-term investment decisions. The basin had also seen tax rates fall, helping to ensure that post-tax rewards on the UKCS remain competitive with other investment opportunities around the world.

However, investment in the UKCS has fallen from about £14.8 billion per year in 2014 to £5.5 billion in 2019. While the causes are varied and complex, the threat of the implementation of a windfall tax was believed by Deirdre Michie, former Chief Executive of Offshore Energies UK, to have been one of the factors that may potentially have deterred investment. Now that a windfall tax has been implemented, it is not yet clear what impact will be seen, although it is anticipated that the new 'super-deduction style' investment allowance may encourage an acceleration of final investment decisions for near-term developments[73].

[69] Sources: Oil & Gas UK Decommissioning Insight Report 2020; Oil & Gas UK Business Outlook Report 2021; Oil & Gas UK Decommissioning Insight Report 2021; NSTA Overview 2022.

[70] Source: Oil & Gas UK Economic Report 2018.

[71] Source: Oil & Gas UK Economic Report 2018.

[72] Source: Offshore Energy UK Business Outlook Report 2022.

[73] Source: HM Treasury, Policy paper—Energy Profits Levy Factsheet—26 May 2022.

2.10 ***Energy Transition and ESG in the United Kingdom and UKCS***

Oil and gas will continue to have a key role to play in an increasingly diverse energy mix and it is important that domestic production continues in line with this to support energy security. In addition, the sector will also make a major contribution to the transition to net zero, with many of the skills, expertise and technologies held within the oil and gas industry crucial in the development of net-zero solutions at scale. The NSTA expects that the UKCS can provide solutions to 60% of the UK's net zero emissions abatement needs and suggests that the industry should keep pace on reducing its carbon footprint or risk losing its "social licence to operate".

There has been a growing focus from investors on reporting of ESG metrics and alignment with UN sustainable development goals. In particular, this has centred on environmental impacts of business operations in the context of net zero and the COVID-19 pandemic impact on social risks. Attention to ESG reporting has been driven by changing investor appetite in recent years and is an increasingly common element in many of the industry's financial reports. OEUK expects the focus of both the private and public sectors on sustainable finance to continue to grow.

The oil and gas industry in the United Kingdom was one of the first industrial sectors to welcome the commitments to net zero. For the sector, the focusing of investor expectations particularly regarding environmental factors creates an audience for operators to showcase their ongoing commitments and progress towards emission reduction targets, outlined as part of Roadmap 2035 launched in September 2019, which outlines the contribution the sector can make throughout the transition. The key themes within Roadmap 2035 are:

- helping meet energy needs in the United Kingdom;
- supporting net zero;
- developing people and skills;
- driving technology and innovation; and
- growing the economy and exports.

Whilst securing investment continues to be at the discretion of the investor, industry has been engaging in a cross-sector taskforce to produce a set of guidance on common metrics to suit user and issuer expectations. Good progress has been made since the launch of Roadmap 2035 including but not limited to the development of production emissions targets, launch of the Diversity & Inclusion Task Force, the establishment of the National Decommissioning Centre and the upcoming National Subsea Centre. There are very significant opportunities for oil and gas companies and their supply chain to diversify across the energy landscape. Developments in new technologies are progressing across the United Kingdom, from Shetland to South Wales.

As part of this transition, progress continues on a North Sea Transition Deal which will provide the framework for increased investment and earlier and more coordinated development of these projects. This will help accelerate the energy transition and reduce emissions across the United Kingdom. Alongside this, it will help to open up new markets for the domestic supply chain to service at home and abroad. Proposals include decarbonising oil and gas production, including through electrification, and transforming the oil and gas supply chain so that it underpins the full energy landscape in the United Kingdom and abroad. The discussions around the North Sea Transition Deal have already explored a wide range of policy levers. When combined, these have the potential to release the investment needed to deliver a healthy oil and gas sector that is aligned with the transition to net zero, and which supports emerging new carbon capture and hydrogen technologies. These discussions have continued through 2022 with key themes including carbon pricing policy, offshore electricity infrastructure and supply, investment support for decarbonisation, regulation of carbon dioxide infrastructure and development of the hydrogen market, with much of the investment, technologies and capabilities required being provided by traditionally viewed oil and gas companies[74].

[74] Sources: NSTA Overview 2021; OGA UKCS Energy Integration Final Report; Oil & Gas UK Economic Report 2020; Oil & Gas UK Business Outlook Report 2021.

PART 8

DIRECTORS, SENIOR MANAGERS AND CORPORATE GOVERNANCE

1. **THE DIRECTORS**

1.1 The following table lists the names, ages, positions and dates of appointment of the current members of the Board:

Name	Age	Position	Date of Appointment
Gilad Myerson	46	*Executive Chairman and Chair of the Nomination and Governance Committee*	30 January 2020
Alan Alexander Bruce	40	*Chief Executive Officer*	10 October 2022
Iain Clifford Scobbie Lewis	44	*Chief Financial Officer*	10 October 2022
Idan Wallace	45	*Non-Executive Director*	10 October 2022
John Mogford	69	*Senior Independent Director*	31 October 2022
Deborah Jane Gudgeon	62	*Non-Executive Director and Chair of the Audit and Risk Committee*	31 October 2022
Lynne Clow	51	*Non-Executive Director and Chair of the Remuneration Committee*	31 October 2022
Assaf Ginzburg	47	*Non-Executive Director*	31 October 2022
David John Blackwood CBE . .	68	*Non-Executive Director and Chair of the Health, Safety and Environment Committee*	31 October 2022

1.2 The business address of each Director (in such capacity) is Ithaca Energy plc, 23 College Hill, London, EC4R 2RP. The management expertise and experience of each Director is set out in their biography below:

- **Gilad Myerson**

  Mr Myerson has more than 25 years of extensive experience building businesses and driving value creation initiatives together with private equity funds. He joined the Group after serving as the COO and building Theramex, a global specialty pharmaceutical company dedicated to women and their health operating in over 50 countries, backed by CVC Capital. Prior to Theramex, Mr Myerson was a Partner at McKinsey & Company where he co-led the Private Equity Practice in EMEA, and served many of the leading US and European private equity funds on acquisition, value capture, transformation and exit of companies, achieving returns of 2-6x multiple of money. Mr Myerson started his career serving as a helicopter pilot in the military and the police force where he led aerial and ground operations as a formation and sector leader. Mr Myerson served as the CFO and CEO of Ithaca Energy during the Group's transformation journey. Mr Myerson has a degree in Bioinformatics from the Bar Ilan University, 2005.

- **Alan Bruce**

  Mr Bruce joined the Group in August 2021 as Chief Operating Officer and in January 2022 assumed the role of Chief Executive Officer. He is passionate about ensuring the safe, efficient, and environmentally responsible operation of the business. Mr Bruce has 20 years of oil and gas experience and, prior to joining the Group, he held leadership positions in Subsurface, Operations, Asset Management and Business Planning in the UK, Canada, and Houston with ConocoPhillips. Mr Bruce is a chartered engineer and earned a bachelor's degree in chemical engineering from the University of Edinburgh and a master's degree in petroleum engineering from Imperial College, London.

- **Iain Lewis**

  Mr Lewis joined the Group in July 2022 and has over 20 years of upstream oil and gas finance experience in public practice and the multinational corporate environment. He is a Chartered Accountant who held senior positions with EY in the UK and Canada, leading financial advisory and assurance engagements for upstream oil and gas companies ranging from small cap independents to supermajors. For the past 13 years, Mr Lewis has occupied several executive roles in the Abu Dhabi listed TAQA group including Group Deputy CFO and Europe CFO overseeing the UK and Netherlands upstream and midstream businesses. He has also been accountable for large scale capital programme governance as the Decommissioning Director for TAQA's multibillion-dollar UK decommissioning programme.

- **Idan Wallace**

  Mr Wallace was appointed as CEO of Delek Group in January 2020, after previously serving as CEO of Tshuva Group, a group of private companies owned by Yitzhak Tshuva, the controlling shareholder of Delek Group (through Tashluz Investments and Holdings Ltd.). Mr Wallace also served as a director in a number of leading companies in the energy, real estate and media sectors and currently serves as a director in certain subsidiaries of the Delek Group (including NewMed Energy). Mr Wallace has a degree in law from Tel Aviv University and is a Member of the Israel Bar.

- **John Mogford**

  Mr Mogford has significant global executive experience, including in oil and gas, capital allocation discipline, commodity value chains and health, safety and environment. The majority of his career has been spent in various leadership, technical and operational roles, including Managing Director and an Operating Partner of First Reserve, a large global energy focused private equity firm, from 2009 until 2015, during which he served on the boards of First Reserve's investee companies, including as Chair of Amromco Energy LLC and White Rose Energy Ventures LLP. Mr Mogford is currently an independent non-executive director of BHP Group Limited, an international resources company. Mr Mogford retired from the boards of Weir Group Plc and one of First Reserve's portfolio companies, DOF Subsea AS, in 2018, and was also formerly on the board of ERM Worldwide Group Limited. Mr Mogford is a fellow of the Institute of Mechanical Engineering.

- **Deborah Gudgeon**

  Ms Gudgeon qualified as an ACA accountant at PwC (Coopers & Lybrand) before spending eight years as Finance Executive with the Africa-focused mining and trading group Lonrho plc. Ms Gudgeon subsequently held positions with Deloitte, BDO, Gazelle Corporate Finance and Penfida Limited. Ms Gudgeon has significant experience in acting as an independent non-executive director having held that position at Petra Diamonds Limited, Evraz plc, Highland Gold Mining Limited and Acacia Mining plc. As well as being an independent non-executive director, Ms Gudgeon was also chair of the audit committee for each of these entities.

- **Lynne Clow**

  Ms Clow is an experienced HR and operational director who has worked extensively in the UK and abroad, across a variety of sectors. She is a graduate of Strathclyde and Napier Universities who has most recently worked in the energy sector for KCA Deutag, an Aberdeen based oil and gas company. In February 2022, Ms Clow was appointed by the Minister for Transport, Jenny Gilruth MSP, as a Non-Executive Director of the Board of Highlands and Islands Airports Limited for a three year term. Ms Clow is also a member of the children's panel in Scotland and a member of the Remuneration Committee for Robert Gordons University.

- **Assaf Ginzburg**

  From 2004 until May 2020[70], Mr Ginzburg has held a number of senior positions at Delek US Energy and Delek Logistics Partners LP, including EVP and chief financial officer. Mr Ginzburg is currently the chief financial officer of Ormat Technologies, a global operator and developer of renewable energy electricity projects which offers geothermal, recovered energy, energy management and storage solutions. Prior to this, Mr Ginzburg was a member of the boards of directors for each of Alon USA Energy and Delek Logistics Partners LP. Mr Ginzburg has a B.A in accounting and economics from Tel Aviv university.

- **David Blackwood CBE**

  Mr Blackwood has over 47 years' experience in the oil and gas sector, including seven years in the service sector with Schlumberger in the North Sea and the Middle East, and 27 years in various global roles within BP, including heading up BP's upstream business in the UK and Norway. Since leaving BP in 2009, Mr Blackwood has been a Senior Advisor with Evercore, and has been a non executive director with Valiant Petroleum, Expro, and most recently acting as a non-executive director at Premier Oil plc for four years, from 2017 to 2021. Mr Blackwood has a bachelor's degree in engineering from the University of Glasgow and in 2006 was awarded a CBE for his service to the UK oil and gas industry.

1.3 ***Senior Managers***

In addition to the Executive Directors, each of the following persons is a Senior Manager of the Group:

Name	Age	Position
John Horsburgh	46	*General Manager, Subsurface and Wells*
Julie McAteer	53	*General Counsel and General Manager Business Affairs*
Rachel Stanley	49	*General Manager NOJV, Energy Transition, Technology and Innovation*
Brian Winton	66	*General Manager Operations, Projects and Decommissioning*
Craig Matthew	52	*General Manager, Greenfields Projects*

1.4 The management expertise and experience of each of the Senior Managers listed above is set out below:

- **John Horsburgh**

  Mr Horsburgh has over 20 years of experience in the oil and gas industry. Mr Horsburgh was appointed Chief Technical Officer (since renamed General Manager, Subsurface and Wells) in March 2018 and Subsurface & Growth Director in June 2019 having been the Group's Subsurface Manager and Competent Person responsible for corporate reserves reporting since 2008. Prior to joining Ithaca Energy, Mr Horsburgh worked for ten years at Shell where he held senior technical positions for various field development projects in the North Sea, Africa and the Middle East. Mr Horsburgh holds a MSc in Petroleum Geology from Aberdeen University and a BSc in Geophysics from the University of Edinburgh.

- **Julie McAteer**

  Mrs McAteer joined the Group as Legal and HR Director (since renamed General Counsel and General Manager Business Affairs) in February 2020 and has over 25 years' of experience in the oil and gas sector. Mrs McAteer previously held senior leadership and legal manager/corporate and commercial roles with major operators and independents covering matters in the UKCS and internationally. For the previous eight years Mrs McAteer was Legal Manager and on the leadership team at Premier Oil. Prior to this she occupied legal roles for Dana Petroleum plc, Elf Exploration and TotalEnergies.

[70] Delek Group sold its substantial shareholding (7.5%) in Delek Logistics Partners LP and Delek US Holdings, Inc in 2014 and all remaining shares were sold by the Delek Group in 2017. Delek Logistics Partners LP and Delek US Holdings, Inc. are no longer affiliates of the Delek Group.

Mrs McAteer holds a law degree from the University of Aberdeen and is dual qualified to practice in both Scotland and England.

- **Rachel Stanley**

  Mrs Stanley joined the Group as Transformation Director (since renamed General Manager NOJV, Energy Transition, Technology and Innovation) in November 2019 following the Chevron Acquisition and since then has held positions such as Transformation and HR Director, Technical Services Director and General Manager of NOJV, Energy Transition and Technology Innovation. Prior to this, Mrs Stanley worked for Chevron for over 20 years in various subsurface and operational senior management roles, including holding positions as the Subsurface and Asset Manager for the Chevron operated Alba and Captain fields. Mrs Stanley holds a MSc in Petroleum Engineering from Imperial College, London and BEng in Chemical Engineering from the University of Birmingham.

- **Brian Winton**

  Mr Winton joined the Group in July 2020 as Projects and Decommissioning Director (since renamed General Manager Operations, Projects and Decommissioning) and has 40 years of experience in the oil and gas industry. Mr Winton previously has held senior operational and project leadership roles including offshore field manager. Prior to joining the Group, Mr Winton spent five years on the Repsol Sinopec management team as Vice President of Operations leading the Montrose area asset whilst heading up the MAR project. Prior to Repsol Sinopec, Mr Winton worked at ConocoPhillips for 30 years. During his time at ConocoPhillips he held several senior operations and project management positions and was a member of the UK Management team (Jasmine Project Manager and UK Decommissioning Manager being his last two assignments).

- **Craig Matthew**

  Mr Matthew joined the management team as General Manager, Greenfield Projects in July 2022 after joining the Group in August 2021. Mr Matthew brings more than 30 years of oil and gas industry experience and knowledge including a decade in construction projects in the service sector prior to transitioning into development and asset management roles within a number of oil and gas operators like Premier, EnQuest, Petrofac Energy, Maersk and Kerr-McGee with projects predominantly involving floating production facilities.

2. CORPORATE GOVERNANCE

2.1 *Overview*

The Board is committed to the highest standards of corporate governance and to maintaining a sound framework for the control and management of the Group. As at the date of this Prospectus and on and following Admission, the Company will comply with the provisions of the Governance Code (other than as detailed in this Part 8 (*Directors, Senior Managers and Corporate Governance*)) and will report to its Shareholders on such compliance in accordance with the Listing Rules.

2.2 *The Board*

The Board is responsible for leading and controlling the Company and has overall authority for the management and conduct of the Group's business, strategy and development. The Board is also responsible for ensuring the maintenance of a sound system of internal controls and risk management (including financial, operational and compliance controls) and for reviewing the overall effectiveness of systems in place as well as for the approval of any changes to the capital, corporate and/or management structure of the Group. The Board will meet at such times as are necessary, but not less than four times a year.

2.3 ***Compliance with corporate governance requirements***

2.3.1 **Board and committee independence**

The Governance Code recommends that at least half the board of directors of a UK listed company, excluding the chair, should comprise non-executive directors determined by the Board to be independent in character and judgment and free from relationships or circumstances which may affect, or could appear to affect, their judgment.

The Company has determined that, with the exception of Mr Wallace given his role within Delek, all of the other Non-Executive Directors are free from any business or other relationship that could materially interfere with the exercise of their independent judgment and are considered to be independent in character and judgment and therefore "independent non-executive directors" within the meaning of the Governance Code.

On Admission, the Company will have three Executive Directors (of whom one is the Executive Chairman), one Non-Executive Director who is not deemed independent, and five independent Non-Executive Directors and therefore will comply with the Governance Code in this respect.

Pursuant to the terms of the Relationship Agreement (further details of which are set out in paragraph 14.2 (*Relationship Agreement*) of Part 20 (*Additional Information*)), for so long as Delek holds at least 50% or more of the Ordinary Shares, Delek has the right to appoint an observer to attend and participate in the discussions of the following committees: (i) the audit and risk committee; and (ii) the remuneration committee. The appointed observer, whose identity is subject to the approval in advance by the Board, may be an executive of Delek and need not be a Director of the Company. In addition, for so long as Delek holds at least 50% or more of the Ordinary Shares, Delek has the right to nominate one director to the Nomination and Governance Committee (or failing which, to appoint an observer). This Director's (or observer as the case may be) identity is subject to the approval in advance by the Board.

2.3.2 **Executive Chairman**

The Governance Code recommends that, on appointment, the chairman of a company should be independent when assessed against the circumstances set out in the Governance Code. The Company's Executive Chairman, Mr Myerson, is not considered to be independent and therefore the Company does not comply with the requirements of the Governance Code in relation to the requirement for the chair to be independent on appointment. The Nomination and Governance Committee and the Board consider that the role of an Executive Chairman is in the best interests of the Group in order to utilise the proven leadership qualities and significant experience of Mr Myerson to seek to ensure the ongoing commercial success of the Group.

2.3.3 **Senior independent director**

The Governance Code also recommends that the board of directors of a UK listed company should appoint one of the independent non-executive directors to be the senior independent director to provide a sounding board for the chair and to serve as an intermediary for the other directors and the shareholders when necessary. The senior independent director of the Company has an important role on the Board in leading on corporate governance issues and being available to Shareholders if they have concerns which contact through the normal channels of the chair, Chief Executive Officer or other Executive Directors has failed to resolve or for which such channel of communication is inappropriate. Mr Mogford has been appointed as the senior independent director of the Board.

2.3.4 **Re-election**

The Governance Code recommends that all directors of UK listed companies should be subject to annual re-election. The Directors therefore intend to put themselves up for re-election at the Company's next annual general meeting (expected to be held in the second quarter of 2023). It is also intended that the Directors will continue to put themselves up for annual re-election voluntarily at each further annual general meeting of the Company. In addition, prior to recommending their re-election to Shareholders, the Board intends to carry out an annual reassessment of the ongoing independence of each of the Non-Executive Directors and to make an appropriate statement disclosing their status in the Company's annual report.

3. BOARD COMMITTEES

The Board has established an audit and risk committee, a remuneration committee, a nomination and governance committee, a disclosure committee and a health, safety and environment committee. The members of these committees (other than the disclosure committee) are appointed principally from among the independent non-executive directors and all appointments to these committees shall be for an initial period of up to three years and may be extended by no more than two additional three-year periods. The terms of reference of the committees have been drawn up in accordance with the provisions of the Governance Code and such terms are updated as necessary. A summary of the terms of reference of each of these committees is set out below.

If the need should arise, the Board may set up additional committees as appropriate.

3.1 *Audit and Risk Committee*

The audit and risk committee's role is to assist the Board with the discharge of its responsibilities in relation to financial reporting, including reviewing the Group's annual and half year financial statements and accounting policies, internal and external audits and controls, reviewing and monitoring the scope of the annual audit and the extent of the non-audit work undertaken by external auditors, advising on the appointment of external auditors and reviewing the effectiveness of the internal audit, internal controls, whistleblowing and fraud systems in place within the Group. The audit and risk committee shall additionally oversee and advise the Board on the Group's overall risk appetite, tolerance and strategy, review the Group's capability to identify and manage new types of risk and keep under review the Group's overall risk assessment processes that inform the Board's decision making. The audit and risk committee will meet at such times as are necessary, but not less than four times a year. The audit and risk committee will consider annually how the Group's internal audit requirements shall be satisfied and makes recommendations to the Board accordingly as well as on any area it deems needs improvement or action.

The audit and risk committee is chaired by Ms Gudgeon and its other members are John Mogford and Assaf Ginzburg. It is the opinion of the Directors that Ms Gudgeon has recent and relevant financial experience and is appropriate to chair the audit and risk committee. The Governance Code recommends that the audit and risk committee should consist of at least three independent non-executive directors and that at least one such member has recent and relevant financial experience. The Board considers that the Company complies with the requirements of the Governance Code in this respect.

On Admission, it is intended Tamir Polikar, the Chief Financial Officer of Delek, will be appointed as an observer to the audit and risk committee.

3.2 *Nomination and Governance Committee*

The nomination and governance committee assists the Board in reviewing the structure, size and composition of the Board, including providing advice to the Board on the retirement and appointment of additional and/or replacement Directors. It is also responsible for reviewing succession plans for the Directors, including the Chairman and Chief Executive Officer and other senior executives. The nomination and governance committee will meet at such times as are necessary, and it is intended that the committee meets not less than twice a year.

The nomination and governance committee is chaired by Mr Myerson and its other members are John Mogford, Lynne Clow, Idan Wallace and Assaf Ginzburg. The Governance Code recommends that a majority of the members of the nomination and governance committee be independent non-executive directors and that the chair (other than where the committee is dealing with the appointment of a successor to the chairmanship) or an independent non-executive director should chair the committee. The Board considers that the Company complies with the requirements of the Governance Code in this respect.

3.3 *Remuneration Committee*

The remuneration committee recommends the Group's policy and framework on executive remuneration, determines the levels of remuneration for Executive Directors, the Chairman and other senior executives and prepares an annual remuneration report for approval by the Shareholders at the annual general meeting. The remuneration committee will also review the scale and structure of Executive Directors' remuneration and the terms of their service or employment contracts, including share based schemes, other employee incentive schemes adopted by the Company from time to time and pension contributions and ensure that payments made on termination are fair to the individual and the Company. The remuneration committee will meet at such times as are necessary and it is intended that the committee meets not less than twice a year.

The remuneration committee is chaired by Ms Clow, and its other members are John Mogford, Assaf Ginzburg and Deborah Gudgeon. The Governance Code recommends that the remuneration committee should consist of at least three independent non-executive directors. The Board considers that the Group complies with the requirements of the Governance Code in this respect.

On Admission, it is intended that Mrs Pratt Levin, the General Counsel of Delek and a member of the Delek executive team, will be appointed as an observer to the remuneration committee.

3.4 ***Disclosure Committee***

The Board has established a market disclosure committee in order to ensure timely and accurate disclosure of all information that is required to be so disclosed to the market to meet the legal and regulatory obligations and requirements arising from the listing of the Company's securities on the London Stock Exchange, including the Listing Rules, the Disclosure Guidance and Transparency Rules and UK MAR.

The disclosure committee will meet at such times as shall be necessary or appropriate, as determined by the chair of the market disclosure committee or, in his or her absence, by any other member of the market disclosure committee. The market disclosure committee is chaired by the Company's General Counsel and General Manager Business Affairs, Julie McAteer, and its other members are Iain Lewis, Gilad Myerson, Alan Bruce and Kathryn Reid.

3.5 ***Health, Safety and Environment Committee***

The health, safety and environment committee evaluates the effectiveness of the Group's policies and systems for identifying and managing environmental, health and safety risks within the Group's operations. Additionally, the health, safety and environment committee assesses the performance of the Group with regard to the impact of environmental, health and safety decisions and actions upon employees, communities and other third parties. The health, safety and environment committee will meet at such times as are necessary, and it is intended that the committee meets not less than twice a year.

The health, safety and environment committee is chaired by Mr Blackwood and its other members are John Mogford and Assaf Ginzburg.

4. REMUNERATION AND PENSION BENEFITS

Details regarding remuneration of Directors and Senior Managers are set out in paragraph 10.1 *(Remuneration Policy)* of Part 20 (*Additional Information*).

5. SHARE DEALING CODE

The Company has adopted, with effect from the date of Admission, a code on securities dealings in relation to the Ordinary Shares which is based on the requirements of the UK MAR. The code adopted will apply to the Directors and Senior Managers and other relevant employees of the Group.

6. CONFLICTS OF INTEREST

The Articles contain conflict of interest provisions.

7. **EMPLOYEES**

For each of the years ended 31 December 2019, 2020 and 2021, the Group had at the end of such period 500, 436 and 470 full time equivalent employees, respectively, broken down by operational area as follows:

	2019	2020	2021
Headcount as at 31 December	500	436	470
Alba and Captain Assets	N/A	221	226
Business Services	N/A	40	40
CEO	N/A	12	13
Finance	N/A	29	26
FPF-1 and Erskine Asset	N/A	12	16
HSE and Performance Audit	N/A	10	14
Legal and HR	N/A	11	12
Projects and Decommissioning	N/A	39	62
Reservoir Development & Non Operated Assets	N/A	32	29
Technical Services	N/A	30	32
Total	**500**	**436**	**470**

The Group undertook a voluntary redundancy programme during the year ended 31 December 2020 which resulted in approximately 71 onshore employees leaving the Group at a one-off cost to the Group of $19.3 million.

As at the Latest Practicable Date, the Group had approximately 516 full time equivalent employees.

The average number of temporary employees and contractors retained by the Group in the year ended 31 December 2021 was 101.

PART 9

SELECTED FINANCIAL INFORMATION

SECTION A: THE GROUP

The selected financial information set out below has been extracted without material amendment from Section A (The Group), Part B (*Consolidated Historical Financial Information of the Group*) of Part 16 (*Historical Financial Information*)*, where it is shown with important notes describing some of the line items. Investors should read the whole of this Prospectus (and any prospectus which may be published by the Company) before making an investment decision and not rely solely on the summarised information in this Part 9* (*Selected Financial Information*).

The following tables present the selected consolidated financial data of the Group for the periods and as at the dates presented. The financial statement data presented for the six month period ended 30 June 2022 and for each of the annual periods ended 31 December 2021, 2020, 2019 has been extracted without material amendment from Section A (*The Group*), Part B (*Consolidated Historical Financial Information of the Group*) of Part 16 (*Historical Financial Information*), where it is shown with important notes describing some of the line items.

The selected consolidated financial data of the Group for the periods and as at the dates presented reflect that, on 8 November 2019, the Group completed the Chevron Acquisition, with the relevant assets then being fully consolidated into the consolidated financial data of the Group. As a result of the Chevron Acquisition, the Group Financial Information included below does not include the financial information for IOG for the period from 1 January 2019 through 7 November 2019, which affects the comparability of the Group's results.

The selected consolidated financial data of the Group as at the dates and for the periods presented reflect that, on 4 February 2022, the Group completed the Marubeni Acquisition with the Marubeni Assets then being fully consolidated into the consolidated financial data of the Group. As a result of the Marubeni Acquisition, the Group Financial Information included below, does not include the financial information for MOGL for the period from 1 January 2019 through 3 February 2022, which affects the comparability of the Group's results.

The selected consolidated financial data of the Group as at the dates and for the periods presented reflect that, on 30 June 2022, the Group completed each of the Siccar Point Acquisition and the Summit Acquisition with each of the Siccar Point Asset and the Marubeni Assets then being fully consolidated into the consolidated financial data of the Group. As a result, the Group Financial Information included below, does not include the financial information for either Summit or Siccar Point Group for the period from 1 January 2019 through 29 June 2022, which affects the comparability of the Group's results.

Investors should read the whole of this Prospectus before making an investment decision and not rely solely on the summarised information in this Part 9 (*Selected Financial Information*). Historical results may not necessarily be indicative of results that may be expected or any future period.

1. SELECTED HISTORICAL CONSOLIDATED STATEMENT OF INCOME OF THE GROUP

(in millions of $)	Year ended 31 December			Six months ended 30 June	
	2019	2020	2021	2021	2022
				(unaudited)	
Revenue	**537.9**	**1,107.6**	**1,428.2**	**619.0**	**1,337.6**
Cost of sales	(437.5)	(796.1)	(879.2)	(462.6)	(752.0)
Gross profit	**100.4**	**311.5**	**549.1**	**156.4**	**585.6**
Impairment (charge) / reversal	(106.8)	(681.6)	465.3	173.8	(7.6)
Exploration and evaluation expenses	(0.2)	(1.5)	(0.2)	(0.2)	(9.6)
Fair value gain / (losses) on contingent consideration	—	4.5	8.3	8.3	(14.4)
General and administrative expenses[(a)]	(22.1)	(37.1)	(15.2)	(9.0)	(26.7)
Other gains / (losses)	1.5	7.7	(4.4)	3.0	(13.1)
Gain on bargain purchase[(b)]	—	—	10.5	—	1,324.3
(Loss) / profit from operations before tax and net finance costs	**(27.2)**	**(396.5)**	**1,013.3**	**332.2**	**1,838.4**
Net finance costs	(120.4)	(218.2)	(250.1)	(103.9)	(97.1)
(Loss) / profit before tax	**(147.6)**	**(614.7)**	**763.1**	**228.3**	**1,741.3**
Income tax	124.0	159.0	(337.2)	(111.3)	(183.7)
(Loss) / profit attributable to owners of the parent	**(23.6)**	**(455.7)**	**426.0**	**117.0**	**1,557.7**

(a) "General and administrative expenses" (i) for the six months ended 30 June 2022 included transaction costs relating to each of the Siccar Point Acquisition and Summit Acquisition, (ii) for the year ended 31 December 2020 included certain costs relating to the redundancy costs post an employee voluntary redundancy programme, and (iii) for the year ended 31 December 2019 included fees related to costs associated with the Chevron Acquisition which completed in last quarter of 2019.

(b) "Gain on bargain purchase" (i) for the year ended 31 December 2021 included a recognition of assets and liabilities acquired on completion of the additional 13.3% equity share in the Alba field from Mitsui as part of the Mitsui Acquisition, and (ii) for the six months ended 30 June 2022 is attributable to gains in connection with the Marubeni Acquisition and Siccar Point Acquisition.

2. SELECTED HISTORICAL CONSOLIDATED BALANCE SHEET OF THE GROUP

(in millions of $)	Year ended 31 December			Six months ended 30 June	
	2019	2020	2021	2021	2022
				(unaudited)	
ASSETS					
Current assets					
Cash and cash equivalents	15.1	1.2	44.8	8.3	160.4
Trade and other receivables	158.1	109.2	228.3	139.5	348.7
Decommissioning receivable	10.5	28.8	94.6	32.8	94.6
Deposits, prepaid expenses and other receivables	8.7	10.2	10.5	6.5	5.0
Inventory	100.1	106.7	177.6	124.8	137.5
Derivative financial instruments	46.4	27.9	5.0	5.0	15.1
	338.9	**284.1**	**560.9**	**316.9**	**761.2**
Non-current assets					
Decommissioning receivable	190.5	216.0	152.2	208.1	117.8
Long-term inventory	3.9	2.9	0.5	0.5	0.5
Exploration and evaluation assets	47.4	70.6	116.4	92.5	724.0
Property, plant & equipment	3,196.2	2,583.7	2,958.7	2,610.8	3,813.7
Deferred tax assets	234.1	382.1	220.9	376.6	1,550.5
Derivative financial instruments	55.9	3.5	0.1	1.8	6.8
Goodwill	928.8	722.1	722.1	722.1	783.8
	4,656.9	**3,980.9**	**4,170.9**	**4,012.4**	**6,997.2**
Total assets	**4,995.8**	**4,265.0**	**4,731.8**	**4,329.3**	**7,758.5**
LIABILITIES & EQUITY					
Current liabilities					
Borrowings	—	—	(437.1)	(412.0)	(650.5)
Trade and other payables	(371.0)	(285.7)	(484.3)	(406.1)	(707.0)
Decommissioning liabilities	(10.5)	(28.8)	(94.6)	(32.8)	(94.6)
Lease liability	(5.9)	(6.1)	(3.2)	(3.5)	(21.0)
Contingent and deferred consideration	(8.3)	(8.3)	(49.8)	—	(73.7)
Derivative financial instruments	(35.8)	(78.5)	(438.0)	(217.0)	(672.6)
	(431.5)	**(407.4)**	**(1,507.0)**	**(1,071.4)**	**(2,219.4)**
Non-current Liabilities					
Borrowings	(2,246.0)	(1,840.9)	(954.6)	(1,241.6)	(1,362.1)
Decommissioning liabilities	(1,184.1)	(1,387.4)	(1,546.8)	(1,384.0)	(1,598.8)
Lease liability	(7.2)	(0.9)	(0.3)	(2.5)	(59.2)
Contingent and deferred consideration	(127.4)	(58.9)	(25.3)	(60.2)	(308.1)
Derivative financial instruments	(18.4)	(27.0)	(21.3)	(74.8)	(137.0)
	(3,583.1)	**(3,315.1)**	**(2,548.3)**	**(2,763.0)**	**(3,465.1)**
Net assets	**981.1**	**542.5**	**676.5**	**494.9**	**2,074.0**
Shareholders' equity					
Share capital	1	1	1	1	1
Share premium	634.7	634.7	634.7	634.7	634.7
Capital contribution reserve	114.0	114.0	114.0	114.0	114.0
Hedging reserve	27.2	44.3	(247.7)	(120.2)	(407.9)
Retained earnings / (accumulated loss)	205.2	(250.5)	175.5	(133.5)	1,733.2
Total equity	**981.1**	**542.5**	**676.5**	**494.9**	**2,074.0**

3. SELECTED HISTORICAL CONSOLIDATED STATEMENT OF CASH FLOWS OF THE GROUP

(in millions of $)	Year ended 31 December 2019	2020	2021	Six months ended 30 June 2021 (unaudited)	2022
Cash provided by / (used in):					
Operating activities					
(Loss) / profit before tax	(147.6)	(614.7)	763.1	228.3	1,741.3
Adjustments for:					
Depletion, depreciation and amortisation	235.2	372.8	455.9	208.8	297.4
Exploration and evaluation expenses	0.2	1.5	0.2	0.2	9.6
Impairment (charge) / reversal	106.8	681.6	(465.3)	(173.8)	7.6
Reduction in contingent / deferred consideration	—	(4.5)	(8.3)	(8.3)	14.4
Loan fee amortisation	14.8	9.5	35.3	4.7	2.3
Revaluation of financial instruments	(9.9)	(0.4)	8.3	2.0	18.7
Gain on bargain purchase	—	—	(10.5)	—	(1,324.3)
Hedging resets[(a)]	—	155.0	(115.4)	(65.6)	(20.3)
Accretion	20.4	43.4	38.4	17.9	24.2
Bank interest & charges	76.6	111.8	120.9	50.6	52.9
Interest on related party loan	8.6	53.6	48.3	23.2	17.9
Interest rate swaps	—	5.3	7.3	6.2	(0.3)
Unrealised foreign exchange on cash and cash equivalents	(1.0)	0.3	(1.8)	(1.2)	2.6
Decommissioning expenditure	(8.7)	(25.5)	(27.9)	(12.5)	(11.7)
Cashflow from operations	**295.3**	**789.6**	**848.5**	**280.5**	**832.4**
(Increase) / decrease in inventories	(36.8)	8.0	(65.3)	(27.3)	42.9
(Increase) / decrease in trade and other receivables	(39.6)	131.0	(111.0)	(22.5)	(58.2)
Increase / (decrease) in trade and other payables	65.3	(128.2)	250.5	172.6	172.0
Corporation tax paid	—	(65.2)	(10.0)	(10.0)	—
Net cash from operating activities	**284.2**	**735.3**	**912.7**	**393.3**	**989.0**
Investing activities					
Capital expenditure	(163.9)	(142.1)	(269.6)	(85.7)	(230.3)
Reverse consideration on acquisition[(b)]	—	—	56.5	—	—
Acquisition of subsidiaries net of cash acquired[(c)]	(1,726.9)	—	(7.0)	—	(957.5)
Contingent / deferred consideration payment	(10.0)	(56.9)	—	—	(15.9)
Net cash used in investing activities	**(1,900.8)**	**(199.0)**	**(220.2)**	**(85.7)**	**(1,203.7)**
Financing activities					
Receipt from issue of equity	25.0	—	—	—	—
Bond issue	500.0	—	—	—	—
Payment for lease liabilities	(1.8)	(6.1)	(3.5)	(3.5)	(13.0)
Loan repayment	(477.5)	(1,152.1)	(809.8)	(214.8)	(150.0)
Loan drawdown	1,666.0	700.0	255.0	—	550.0
Bank interest & charges	(99.0)	(86.4)	(85.2)	(77.2)	(54.5)
Interest rate swaps	—	(5.3)	(7.3)	(6.2)	0.3
Net cash provided / (used) in financing activities	**1,612.8**	**(549.9)**	**(650.7)**	**(301.8)**	**332.7**
Currency translation differences relating to cash	1.4	(0.3)	1.9	1.3	(2.6)
(Decrease) / increase in cash & cash equivalents	**(2.4)**	**(13.9)**	**43.6**	**7.1**	**115.5**
Cash and cash equivalents, beginning of the period	17.5	15.1	1.2	1.2	44.8
Cash and cash equivalents, end of period	**15.1**	**1.2**	**44.8**	**8.3**	**160.4**

(a) Hedging resets relate to the armotisation of the deferred reset gains which have been recycled to the current period profit and loss.

(b) "Reverse consideration on acquisition" for the year ended 31 December 2021 includes reverse consideration received in connection with the Mitsui Acquisition.

(c) "Acquisition of subsidiaries net of cash acquired" includes the costs relating to (i) the Chevron Acquisition for the year ended 31 December 2019, (i) a $7 million deposit in connection with the Marubeni Acquisition for the year ended 31 December 2021, and (ii) each of the Marubeni Acquisition, Summit Acquisition and Siccar Point Acquisition for the six months ended 30 June 2022.

4. FINANCIAL AND OPERATIONAL KEY PERFORMANCE INDICATORS

The Directors consider the following metrics to be the financial and operational key performance indicators ("**KPIs**") used by the Group to help evaluate business performance. In addition to the Group's results determined in accordance with IFRS, the Directors believe the KPIs are useful in evaluating the Group's operating performance.

	Year ended 31 December			Six months ended 30 June	
(in millions of $, except where indicated)	**2019**	**2020**	**2021**	**2021**	**2022**
				(unaudited)	
Group Adjusted EBITDAX[(1)]	374.6	742.9	1,035.4	380.1	907.4
Group Free Cashflow[(2)]	11.3	444.6	550.5	224.2	688.6
Available Liquidity[(3)]	181.1	347.2	619.8	313.3	320.4
Total average daily production					
Oil and NGL production (BOPD)[(4)]	16,004	40,763	35,854	37,707	43,214
Natural gas production (Mcfd)[(4)]	73,002	148,484	119,647	108,935	136,134
Total production (BOEPD)[(4)]	28,590	66,360	56,486	56,489	66,685
Unit operating expenditure ($/boe)[(5)]	18.7	16.1	18.0	17.6	19.4
Net debt[(6)]	1,539.9	1,218.8	930.2	1,011.7	1,414.6

				Twelve months ended 30 June 2022
Net debt / Group Adjusted EBITDAX[(7)]	4.1x	1.6x	0.9x	0.9x

(1) Group Adjusted EBITDAX consists of profit for the period before income tax, net finance costs, put premiums on oil derivative instruments, put premiums on gas derivative instruments, revaluation of forex forward contracts, revaluation of commodity hedges, depletion, depreciation and amortisation, impairment (charge) / reversal, exploration and evaluation expenses, fair value gain / (losses) on contingent consideration, gain on bargain purchase, transaction costs and employee voluntary redundancy programme. Transaction costs and employee voluntary redundancy programme include costs that are not considered to be representative of underlying operations. This is used as an indicator of underlying financial performance. Group Adjusted EBITDAX is not a measurement of performance under IFRS and investors should not consider Group Adjusted EBITDAX as an alternative to (i) operating profit or profit from continuing activities or profit / (loss) attributable to owners of the parent (as determined in accordance with IFRS) as a measure of the Group's operating performance, (ii) cash flows from operating, investing and financing activities as a measure of the Group's ability to meet its cash needs or (iii) any other measures of performance under IFRS or other generally accepted accounting principles. See paragraph 4 (*Non-IFRS Financial Information*) of Part 3 (*Presentation of Financial and Other Information*).

The table below presents a reconciliation between the Group's profit / (loss) after tax and Group Adjusted EBITDAX for the periods presented therein:

	Year ended 31 December			Six months ended 30 June		Twelve months ended[(b)]
(in millions of $)	**2019**	**2020**	**2021**	**2021**	**2022**	**2022**
				(unaudited)		
(Loss) / profit attributable to owners of the parent	**(23.6)**	**(455.7)**	**426.0**	**117.0**	**1,557.7**	**1,866.7**
Income tax	(124.0)	(159.0)	337.2	111.3	183.7	409.5
Net finance costs	120.4	218.2	250.1	103.9	97.1	243.3
Put premiums on oil derivative instruments	30.2	52.5	27.2	11.8	7.3	22.6
Put premiums on gas derivative instruments	14.1	16.0	14.6	7.2	17.4	24.9
Revaluation of forex forward contracts	(3.3)	(3.5)	8.3	2.0	18.7	24.9
Revaluation of commodity hedges	1.5	3.7	—	—	—	—
Depletion, depreciation and amortisation	235.2	372.8	455.9	208.8	297.4	544.6
Impairment (charge) / reversal	106.8	681.6	(465.3)	(173.8)	7.6	(283.9)
Exploration & evaluation expenses	0.2	1.5	0.2	0.2	9.6	9.6
Fair value gain / (losses) on contingent consideration	—	(4.5)	(8.3)	(8.3)	14.4	14.4
Transaction costs[(a)]	17.1			—	20.8	20.8
Employee voluntary redundancy programme[(c)]	—	19.3	—	—	—	—
Gain on bargain purchase	—	—	(10.5)	—	(1,324.3)	(1,334.8)
Group Adjusted EBITDAX	**374.6**	**742.9**	**1,035.4**	**380.1**	**907.4**	**1,562.6**

(a) "Transaction costs" for (i) the year ended 31 December 2019 include certain costs relating to the Chevron Acquisition of $17.1 million, and (ii) for the six months ended 30 June 2022 included certain costs relating to each of Siccar Point Acquisition and Summit Acquisition of $20.8 million, and (iii) for the twelve months ended 30 June 2022 also included certain costs relating to each of the Marubeni Acquisition, Siccar Point Acquisition and Summit Acquisition.

(b) The Adjusted EBITDAX for the LTM ended 30 June 2022 was derived by adding the Adjusted EBITDAX for the year ended 31 December 2021 to the Adjusted EBITDAX for the six months ended 30 June 2022 and subtracting the Adjusted EBITDAX for the six months ended 30 June 2021.

(c) "Employee voluntary redundancy programme" for the year ended 31 December 2020 included redundancy costs of $19.3 million.

(2) Group Free Cashflow consists of net cash flow from operating activities less net cash used in investing activities, adding back acquisition of subsidiaries net of cash acquired, and less reverse consideration on acquisitions, bank interest and charges and interest rate swaps, therefore representing net cash flow of the business before net proceeds of loan repayment, loan drawdown, payment for lease liabilities, bond issue, receipt from issue of equity to Delek, receipt from issue of notes to related company, acquisition of subsidiaries and reverse consideration on acquisitions. Group Free Cashflow is not a measurement of performance under IFRS and investors should not consider Free Cashflow as an alternative to cash flows from operating, investing and financing activities as a measure of the Group's ability to invest in the growth of the Group's business or to meet its obligations.

The table below sets forth a reconciliation between the Group's net cashflow from operating activities and Group Free Cashflow for the periods presented therein:

	Year ended 31 December			**Six months ended 30 June**	
(in millions of $)	**2019**	**2020**	**2021**	**2021**	**2022**
				(unaudited)	
Net cash from operating activities	284.2	735.3	912.7	393.3	989.0
Less net cash used in investing activities	(1,900.8)	(199.0)	(220.2)	(85.7)	(1,203.7)
Add back acquisition of subsidiaries net of cash acquired	1,726.9	—	7.0	—	957.5
Less reverse consideration on acquisition	—	—	(56.5)	—	—
Less bank interest & charges	(99.0)	(86.4)	(85.2)	(77.2)	(54.5)
Less interest rate swaps	—	(5.3)	(7.3)	(6.2)	0.3
Group Free Cashflow	**11.3**	**444.6**	**550.5**	**224.2**	**688.6**

(3) Available Liquidity for the Group consists of 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 less restricted cash. Available Liquidity is not a measurement of performance under IFRS and investors should not consider Available Liquidity as an alternative to cash and cash equivalents of the Group.

The table below sets forth a reconciliation of Available Liquidity for periods presented therein:

	as at 31 December			**as at 30 June**	
(in millions of $)	**2019**	**2020**	**2021**	**2021**	**2022**
				(unaudited)	
Cash and cash equivalents	15.1	1.2	44.8	8.3	160.4
Less restricted cash	—	—	—	—	(15.0)
Available RBL facility	1,221.0	1,066.0	925.0	825.0	925.0
Less drawn down amounts	(1,055.0)	(720.0)	(350.0)	(520.0)	(750.0)
Available Liquidity	**181.1**	**347.2**	**619.8**	**313.3**	**320.4**

(4) The Group's historical production volumes for the year ended 31 December 2019 include production volumes from the assets acquired in the Chevron Acquisition for the period from 8 November 2019 to 31 December 2019. The Group's historical production volumes for the six months ended 30 June 2022 include production volumes from the assets acquired in the Marubeni acquisition from 4 February 2022 to 30 June 2022. The provided historical production volumes do not include production volumes for the assets acquired in either the Siccar Point Acquisition or Summit Acquisition, which completed on 30 June 2022.

(5) Unit operating expenditure consists of operating costs (excluding over/underlift) including tariff expense, less tariff income and tanker costs, divided by net total production for the respective period. Unit operating expenditure is not a measurement of performance under IFRS and investors should not consider unit operating expenditure as an alternative to operating costs or cost of sales. See paragraph 4 (*Non-IFRS Financial Information*) of Part 3 (*Presentation of Financial and Other Information*).

(in millions of $, except per mboe and boe information)	Year ended 31 December			Six months ended 30 June	
	2019	2020	2021	2021	2022
				(unaudited)	
Operating costs	198.7	419.0	424.0	204.3	263.2
Less tariff income	(1.7)	(9.6)	(35.4)	(14.1)	(18.7)
Less tanker costs	(2.3)	(18.1)	(17.5)	(10.3)	(10.1)
	194.8	**391.2**	**371.1**	**179.9**	**234.3**
Oil and NGL production (mboe)	5,841	14,919	13,086	6,825	7,822
Natural gas production (mboe)	4,584	9,370	7,530	3,391	4,248
Net total production (mboe)	10,425	24,289	20,616	10,216	12,070
Unit operating expenditure ($/boe)	**18.7**	**16.1**	**18.0**	**17.6**	**19.4**

(6) The following table shows the reconciliation of net debt for the Group, exclusive of all intragroup debt arrangements and liabilities represented by letters of credit or surety bond. Net debt consists of amounts outstanding under RBL Facility and the senior unsecured notes, less cash and cash equivalents (and excludes all intragroup debt arrangements or liabilities represented by letters of credit or surety bonds).

(in millions of $)	as at 31 December			as at 30 June	
	2019	2020	2021	2021	2022
				(unaudited)	
RBL Facility	1,055.0	720.0	350.0	520.0	750.0
Senior unsecured notes[(a)]	500.0	500.0	625.0	500.0	825.0
Less total cash and cash equivalents	15.1	1.2	44.8	8.3	160.4
Net debt	**1,539.9**	**1,218.8**	**930.2**	**1,011.7**	**1,414.6**

(a) Represents (i) the $500.0 million aggregate principal amount of 9 3/8% Senior Notes due 2024 issued on 1 August 2019, which were redeemed in full in connection with the $625.0 million aggregate principal amount of 9.0% Senior Notes due 2026 issued on 30 July 2021; and (ii) the Siccar Point Bonds represents the up to a maximum of $200.0 million aggregate principal amount of 9% senior unsecured callable bonds issued on 4 March 2021.

The net debt to Group Adjusted EBITDAX ratio is calculated as net debt as at the end of the period divided by Group Adjusted EBITDAX for the corresponding period. The net debt to Group Adjusted EBITDAX ratio is not a measurement of financial performance under IFRS and should not be considered as a measure of liquidity or an alternative to operating profit or profit for the period or any other performance measure derived in accordance with IFRS.

The net debt to LTM Adjusted EBITDAX ratio is calculated as net debt at the end of the last twelve-month period divided by Group Adjusted EBITDAX for the twelve-month period ended 30 June 2022. The net debt to LTM Adjusted EBITDAX ratio is not a measurement of financial performance under IFRS and should not be considered as a measure of liquidity or an alternative to operating profit or profit for the period or any other performance measure derived in accordance with IFRS.

(in millions of $)	as at 31 December			as at 30 June
	2019	2020	2021	2022
Net debt	1,539.9	1,218.8	930.2	1,414.6
	Year end 31 December			Twelve months ended 30 June
	2019	2020	2021	2022
Group Adjusted EBITDAX	374.6	742.9	1,035.4	1,562.2[(a)]
Net debt / Group Adjusted EBITDAX[(a)]	**4.1x**	**1.6x**	**0.9x**	**0.9x**

(a) The Adjusted EBITDAX for the LTM ended 30 June 2022 was derived by adding the Adjusted EBITDAX for the year ended 31 December 2021 to the Adjusted EBITDAX for the six months ended 30 June 2022 and subtracting the Adjusted EBITDAX for the six months ended 30 June 2021.

SECTON B: THE SICCAR POINT GROUP

The selected financial information set out below has been extracted without material amendment from Section B *(The Siccar Point Group*), Part B (*Consolidated Financial Information of the Siccar Point Group*) of Part 16 (*Historical Financial Information*)*, where it is shown with important notes describing some of the line items. Investors should read the whole of this Prospectus (and any prospectus which may be published by the Company) before making an investment decision and not rely solely on the summarised information in this Part 9* (*Selected Financial Information*).

The following tables present the selected consolidated financial data of the Siccar Pont Group for the periods and as at the dates presented. The financial statement data presented for the six month period ended 30 June 2022 and for each of the annual periods ended 31 December 2021, 2020, 2019 has been extracted without material amendment from Section B (*The Group*), Part B (*Consolidated Financial Information of the Siccar Point Group*) of Part 16 (*Historical Financial Information*), where it is shown with important notes describing some of the line items.

1. SELECTED HISTORICAL CONSOLIDATED STATEMENT OF INCOME OF THE SICCAR POINT GROUP

	Year ended 31 December			Six months ended 30 June	
(in millions of $)	**2019**	**2020**	**2021**	**2021**	**2022**
				(unaudited)	
Revenue	223.8	142.3	234.6	107.3	153.2
Cost of sales	(150.6)	(128.2)	(137.8)	(65.3)	(72.7)
Gross profit	73.2	14.1	96.8	42.0	80.5
Impairment (charge) / reversal	(99.9)	(304.4)	358.6	—	(191.5)
Exploration and evaluation expenses	(4.3)	(3.4)	(3.9)	(2.4)	(1.9)
General and administrative expenses	(13.0)	(12.0)	(13.5)	(7.2)	(11.6)
Other gains and losses	(17.8)	94.1	(120.5)	(67.7)	(34.3)
Profit / (loss) from operations before tax and finance costs	**(61.8)**	**(211.6)**	**317.5**	**(35.3)**	**(158.9)**
Net finance costs	(114.7)	(119.1)	(120.7)	(65.3)	(58.4)
Profit / (loss) before tax	(176.5)	(330.6)	196.8	(100.5)	(217.3)
Income tax	149.4	157.4	(345.0)	—	470.7
Profit / (loss) after tax	**(27.1)**	**(173.2)**	**(148.2)**	**(100.5)**	**253.4**

2. SELECTED HISTORICAL CONSOLIDATED BALANCE SHEET OF THE SICCAR POINT GROUP

(in millions of $)	Year ended 31 December 2019	2020	2021	Six months ended 30 June 2021 (unaudited)	2022
ASSETS					
Current assets					
Cash and cash equivalents	275.7	163.8	49.0	37.6	88.6
Account receivable	19.4	13.5	19.8	17.8	31.8
Deposit, prepaid expenses and other receivables	13.7	2.6	3.4	1.9	0.8
Inventory	9.4	8.1	10.8	8.9	12.1
Derivative financial instruments	22.2	34.9	3.4	3.6	—
	340.5	222.8	86.4	69.8	133.4
Non-current assets					
Exploration and evaluation assets	352.4	384.1	443.6	407.7	453.7
Property, plant and equipment	1,343.0	1,014.6	1,331.9	992.0	1,058.8
Deferred tax assets	489.9	647.4	302.4	647.4	773.0
Derivative financial instruments	15.7	19.5	2.4	5.1	—
Long-term financial assets	50.0	59.6	10.1	60.2	—
	2,251.0	2,125.1	2,090.3	2,112.3	2,285.5
Total assets	**2,591.4**	**2,347.9**	**2,176.7**	**2,182.0**	**2,418.9**
Liabilities and equity					
Current liabilities					
Borrowings	—	—	—	—	(197.6)
Trade and other payables	(53.8)	(35.8)	(63.6)	(37.3)	(54.0)
Amounts due to parent	—	—	—	—	(323.1)
Contingent consideration	(2.6)	—	—	—	—
Derivative financial instruments	(1.5)	(1.9)	(47.6)	(35.7)	—
	(58.0)	(37.7)	(111.2)	(73.1)	(574.6)
Non-current liabilities					
Borrowings	(1,587.9)	(1,523.7)	(1,454.2)	(1,415.4)	(1,006.6)
Decommissioning liabilities	(169.6)	(179.0)	(180.2)	(181.0)	(129.9)
Other long term liabilities	(0.4)	(0.1)	—	—	—
Contingent consideration	(48.0)	(52.6)	(2.7)	(52.7)	—
Derivative financial instruments	(0.6)	(0.9)	(22.8)	(6.7)	—
	(1,806.5)	(1,756.3)	(1,659.9)	(1,655.7)	(1,136.6)
Total liabilities	**(1,864.4)**	**(1,794.0)**	**(1,771.1)**	**(1,728.7)**	**(1,711.2)**
Net assets	**727.0**	**553.8**	**405.6**	**453.3**	**707.7**
Equity					
Share capital	13.4	13.4	13.4	13.4	13.4
Capital contribution	—	—	—	—	48.6
Retained earnings	713.6	540.5	392.2	439.9	645.7
Total equity	**727.0**	**553.8**	**405.6**	**453.3**	**707.7**

3. SELECTED HISTORICAL CONSOLIDATED STATEMENT OF CASH FLOWS OF THE SICCAR POINT GROUP

(in millions of $)	Year ended 31 December			Six months ended 30 June	
	2019	2020	2021	2021	2022
				(unaudited)	
Operating activities:					
Profit / (loss) before tax	(176.5)	(330.6)	196.8	(100.5)	(217.3)
Adjustments for:					
Finance expense (interest on listed loan notes) and other finance costs	65.6	71.0	76.8	38.1	38.5
Finance expense (interest on RBL and bonds)	44.9	36.8	26.6	13.8	14.3
Depletion, depreciation and amortisation	105.8	80.9	66.5	34.7	47.8
Impairment charge / (reversal)	99.9	304.4	(358.6)	—	191.5
Accretion	3.0	3.3	3.6	1.8	1.8
Decommissioning changes in estimate	1.5	(0.2)	0.3	0	(1.3)
Decommissioning provision utilised	(2.3)	—	(1.1)	—	0
Impact of substantial modification on third party loan	2.5	4.2	—	—	—
Recognition of put option on bonds	—	—	—	—	1.7
Loss / (gain) on derivative financial instruments	9.8	(15.7)	116.2	85.2	(19.5)
Amortisation of bank arrangement fee	0.7	0.4	(0.3)	(0.4)	0.5
Depreciation of office equipment	0	0.1	0.1	—	0
Depreciation of right of use assets	0.2	0.2	0.2	0.1	0
Unrealised net foreign exchange differences	(1.4)	0.9	0.2	(0.7)	(1.3)
Cashflow from operations	**153.8**	**155.6**	**127.3**	**72.1**	**56.8**
Changes in inventory, receivables and payables relating to operating activities	(1.7)	(11.5)	18.6	(2.2)	(9.4)
Corporation tax receipts	2.9	—	—	—	—
Net cash from operating activities	**154.9**	**144.0**	**145.9**	**70.0**	**47.4**
Investing activities:					
Purchase of office equipment	(0.1)	(0.1)	(0)	—	—
Expenditure on development and production assets	(36.7)	(50.8)	(26.4)	(12.0)	(14.3)
Expenditure on exploration and evaluation assets	(43.9)	(31.7)	(60.1)	(23.5)	(12.9)
Net cash used in investing activities	**(80.8)**	**(82.6)**	**(86.6)**	**(35.6)**	**(27.2)**
Financing activities:					
Proceeds from bonds issuance (net of charges)	99.3	—	198.0	198.0	—
Repayment of bonds	—	—	(200.0)	(200.0)	—
Proceeds from borrowings	—	—	—	—	35.0
Repayment of borrowing—third-party (net)	—	(135.0)	(144.0)	(144.0)	—
Interest paid on long-term loans	(47.0)	(37.9)	(27.9)	(14.8)	(14.4)
Net cash flows from / (used in) financing activities	**52.4**	**(172.8)**	**(173.9)**	**(160.8)**	**20.6**
Currency translations differences relating to cash	1.5	(0.6)	(0.3)	0.2	(1.2)
Increase / (decrease) in cash and cash equivalents	128.0	(111.9)	(114.8)	(126.2)	39.6
Cash and cash equivalents at 1 January	147.7	275.7	163.8	163.8	49.0
Cash and cash equivalents, end of period	**275.7**	**163.8**	**49.0**	**37.6**	**88.6**

Non-cash disclosure :

Repayment of borrowing—third-party	—	—	—	—	(277.0)
Settlements of derivative financial instruments	—	—	—	—	(45.2)
Interest and other finance costs on long-term loans	—	—	—	—	(0.9)
Amounts due to parent	—	—	—	—	323.1
Net non-cash flows used in investing activities	—	—	—	—	—

The above reconciliation outlines payments made by IEUK on behalf of the Siccar Point Group as part of the completion mechanism of the acquisition of the Siccar Point Group, completed on 30 June 2022. This mainly represents the mandatory repayment of Siccar Point Energy RBL loan of $277.0 million due to a change of control and the early termination of hedges amounting to $45.0 million which could not be novated to the Group as per mutual agreement with counterparties. Amount due to IEUK of $323.0 million is payable on demand.

4. FINANCIAL AND OPERATIONAL KEY PERFORMANCE INDICATORS

The Directors consider the following KPIs used to help evaluate the Siccar Point Group's operating performance.

(in millions of $, except where indicated)	Year ended 31 December			Six months ended 30 June	
	2019	2020	2021	2021	2022
				(unaudited)	
Siccar Point Adjusted EBITDAX[1]	158.0	161.4	145.4	87.0	82.3
Siccar Point Free Cashflow[2]	27.2	23.6	31.5	19.5	5.8

(1) Siccar Point Adjusted EBITDAX consists of profit for the period before income tax, net finance costs, unrealised gain / (loss) from hedging, depletion, depreciation and amortisation, impairment charge / (reversal), exploration and evaluation expenses and fair value gain / (loss) on contingent consideration. Siccar Point Adjusted EBITDAX is not a measurement of performance under IFRS and investors should not consider Siccar Point Adjusted EBITDAX as an alternative to (i) historical operating profit or profit from continuing activities (as determined in accordance with IFRS) as a measure of the Siccar Point Group's operating performance, (ii) historical cash flows from operating, investing and financing activities as a measure of the Siccar Point Group's historical ability to meet its cash needs or (iii) any other measures of performance under IFRS or other generally accepted accounting principles. See paragraph 4 (*Non-IFRS Financial Information*) of Part 3 (*Presentation of Financial and Other Information*).

The table below presents a reconciliation between the Siccar Point Group's profit / (loss) after tax and Siccar Point Adjusted EBITDAX for the periods presented therein:

(in millions of $)	Year ended 31 December			Six months ended	
	2019	2020	2021	2021	2022
				(unaudited)	
Profit / (Loss) after tax	**(27.1)**	**(173.2)**	**(148.2)**	**(100.5)**	**253.4**
Income tax	(149.4)	(157.4)	345.0	—	(470.7)
Net finance costs	114.7	119.1	120.7	65.3	58.4
Unrealised gain / (loss) from hedging	9.8	(15.7)	116.2	85.2	—
Depletion, depreciation and amortisation	105.8	80.9	66.5	34.7	47.8
Impairment charge / (reversal)	99.9	304.4	(358.6)	—	191.5
Exploration & evaluation expenses	4.3	3.4	3.9	2.4	1.9
Siccar Point Adjusted EBITDAX	**158.0**	**161.4**	**145.4**	**87.0**	**82.3**

(2) Siccar Point Free Cashflow consists of net cash flow from operating activities less net cash used in investing activities, less interest paid on long-term loans. Siccar Point Free Cashflow is not a measurement of performance under IFRS and investors should not consider Siccar Point Free Cashflow as an alternative to cash flows from operating, investing and financing activities. See paragraph 4 (*Non-IFRS Financial Information*) of Part 3 (*Presentation of Financial and Other Information*).

The table below sets forth a reconciliation between the Siccar Point Group's net cashflow from operating activities and Siccar Point Free Cashflow for the periods presented therein:

(in millions of $)	Year ended 31 December			Six months ended 30 June	
	2019	2020	2021	2021	2022
				(unaudited)	
Net cash from operating activities	154.9	144.0	145.9	70.0	47.4
Less net cash used in investing activities	(80.8)	(82.6)	(86.6)	(35.6)	(27.2)
Less interest paid on long-term loans	(47.0)	(37.9)	(27.9)	(14.8)	(14.4)
Siccar Pont Free Cashflow	**27.2**	**23.6**	**31.5**	**19.5**	**5.8**

PART 10

PRINCIPAL SHAREHOLDER AND RELATED PARTY TRANSACTIONS

1. PRINCIPAL SHAREHOLDER

As at the Latest Practicable Date and immediately following Admission, insofar as is known to the Company, the following person held or is expected to directly hold an interest which represents 3% or more of the voting rights attached to the issued share capital of the Company, and the amount of such person's interest is as follows:

	As at the Latest Practicable Date		Immediately following Admission	
Shareholder	**Number of Shares**	**Percentage of issued share capital**	**Number of Shares**	**Percentage of issued share capital**
DKL Energy	898,219,931	99.8[(1)]%	898,219,931	89.4%

(1) On the basis of the aggregate nominal value and voting rights of the shares in the Company held by the relevant shareholder.

Save as described in paragraphs 2.4 (*Related Party Transactions with Directors*) of Part 10 (*Principal Shareholder and Related Party Transactions*) in respect of the B1 Ordinary Shares, B2 Ordinary Shares and MEP Shares held by Mr Myerson (which are to be re-designated as Ordinary Shares prior to Admission), the Selling Shareholder (DKL Energy) detailed above does not have any voting rights which differ in any way from those of the Company's other Shareholders as at the Latest Practicable Date. So far as the Company is aware, save as set out in the table above, no person has an interest which represents 3% or more of the issued share capital or voting rights of the Company as at the Latest Practicable Date.

So far as the Company is aware, as at the Latest Practicable Date, there are no existing arrangements the operation of which may at a later date result in a change of control of the Company.

Save as set out in this Part 10 *(Principal Shareholder and Related Party Transactions)*, the Company is not aware of any other person who as at the Latest Practicable Date exercises, or could exercise, directly or indirectly, control over the Company.

DKL Energy will be a substantial shareholder and controlling shareholder of, a "person exercising significant influence" over, and a "related party" to, the Company for the purposes of the Listing Rules.

DKL Energy is a wholly-owned subsidiary of DKL Investments which is in turn a wholly-owned subsidiary of DGL. DGL's shares are traded on the Tel Aviv Stock Exchange (TASE: DLEKG). The controlling shareholder of DGL is Mr Yitzhak Sharon Tshuva who, as at the Latest Practicable Date, held 50.19% of the voting rights in DGL.

2. RELATED PARTY TRANSACTIONS

The following is a description of the material transactions with related parties to which the Company or its Subsidiaries are a party (or otherwise concern the Company). The Company believes that it has executed all of its transactions with related parties on terms no less favourable to the Group than those it could have obtained from unaffiliated third parties. From Admission, and save for repayment of the Capital Note and principal and interest outstanding under the Tracker Loan (in each case, in full or in part) and the waiver by DKL Energy of all other amounts outstanding (if any) under each of the Capital Note and Tracker Loan, there will be no material commercial arrangements, including financing arrangements, between the Company and the Group and Delek or the Controlling Shareholder and any of its associates and entities connected with its ultimate controlling party. For further details of the Capital Note and Tracker Loan, please see paragraph 14.3.8 (*Capital Note*)and paragraph 14.3.9 (*Tracker Loan*) of Part 20 (*Additional Information*). IEEPL is, and will at Admission be, party to the Bond Subordination Agreement among IEEPL, DGL, BNP Paribas and BNY Mellon Corporate Trustee Services Limited (amongst others). DGL was party to this agreement in its capacity as lender under the Subordinated Shareholder Loan. On 4 October 2022, the Subordinated Shareholder Loan was retired. As at Admission, there will be no amounts outstanding from any member of the Group to DGL. For further information on the Bond Subordination Agreement, please see paragraph 14.3.3 (*Intercreditor Arrangements*) of Part 20 (*Additional Information*).

Save as disclosed below and in paragraph 18 (*Related Third Party Transactions*) of Part 20 (*Additional Information*), there were no related party transactions entered into during the period covered by the Historical Financial Information in this Prospectus and up to the date of this Prospectus.

2.1 *Capital Note*

On 4 November 2019, the Company (as borrower) and DKL Energy (as lender) entered into a $392.0 million capital note agreement ("**Capital Note Agreement**") pursuant to which the Company issued a note in aggregate principal amount of $392.0 million to DKL Energy (the "**Capital Note**"). The Capital Note was originally subordinated against a $200.0 million facility agreement, dated 4 November 2019, among DKL Energy, the Company and BNP Paribas (the "**BNPP Facility Agreement**"), which was discharged on 18 June 2021. The Capital Note does not bear interest and is not linked to the consumer price index. On 2 October 2022, the Capital Note Agreement was amended to provide that repayment of the Capital Note would not occur prior to 1 January 2024 unless from the proceeds of an initial public offering of the Company (in which case, repayment is permitted on notice). The Capital Note Agreement is governed by English law.

Immediately following Admission, the Company will use the net proceeds of the issue of the Offer Shares pursuant to the Global Offering to repay $214 million of the Capital Note. DKL Energy has agreed to waive all remaining amounts (if any) outstanding under the Capital Note. Following such payment and/or waiver (if any), DKL Energy will provide a confirmation that such payment and/or waiver (if any) is in full and final settlement of any amounts due or payable by the Company in respect of the Capital Note.

2.2 *Tracker Loan*

On 4 November 2019, the Company (as borrower) and DKL Energy (as lender) entered into a $198.0 million intragroup loan agreement ("**Tracker Loan**"). The Tracker Loan was put in place as part of the agreed equity funding of the Chevron Acquisition. The Tracker Loan was originally subordinated against the BNPP Facility Agreement, which was discharged on 18 June 2021. The interest payable by the Company to DKL Energy under the Tracker Loan matched the interest payable pursuant to the BNPP Facility Agreement until 4 May 2021, following which the Tracker Loan became interest free.

The rate of interest on the BNPP Facility Agreement for each interest period (each being a 3 month period) was the aggregate of (1) (i) from and including the utilisation date to but excluding the 27 August 2020, 6.5% per annum; (ii) from and including the 27 August 2020 to and including the 12 month anniversary of the utilisation date, 8.5% per annum; (iii) from but excluding the 12 month anniversary of the utilisation date to and including the 15 month anniversary of the utilisation date, 11% per annum; and (iv) from the date following the 15 month anniversary of the utilisation date, 11.5% per annum; and (2) LIBOR. An interest period was not to extend beyond 4 May 2021.

On 3 October 2022, the Tracker Loan was amended to provide that repayment of the Tracker Loan would not occur prior to 1 January 2024 unless from the proceeds of an initial public offering of the Company (in which case, repayment is permitted on notice). As at 30 June 2022, the principal and interest outstanding under the Tracker Loan was $77.3 million.

Immediately following Admission, the Company will use the net proceeds of the issue of the Offer Shares pursuant to the Global Offering to repay $63 million of outstanding principal and $14.3 million of accrued interest under the Tracker Loan. DKL Energy has agreed to waive all remaining amounts (if any) outstanding under the Tracker Loan. Following such payment and/or waiver (if any), DKL Energy will provide a confirmation that such payment and/or waiver (if any) is in full and final settlement of any amounts due or payable by the Company in respect of the Tracker Loan.

2.3 ***Reorganisation immediately prior to Admission***

The Group will implement the Share Capital Reorganisation to take effect prior to Admission. Further details of the Share Capital Reorganisation are set out in paragraph 5.3 (*Share Capital Reorganisation)* of Part 20 (*Additional Information*).

2.4 ***Related Party Transactions with Directors***

2.4.1 The Directors are remunerated for their services on the basis set out in paragraph 10 (*Directors' and Senior Managers' Remuneration and Service Agreements/Letters of Appointment*) of Part 20 (*Additional Information*).

2.4.2 Pursuant to arrangements implemented on 29 September 2022, the Company established a management equity plan for the benefit of Gilad Myerson (the "**MEP**"). Pursuant to the MEP, Mr Myerson has acquired an interest in the MEP Shares. The MEP Shares are subject to restrictions on Mr Myerson's ability to transfer or dispose of such MEP Shares, or to receive any dividends or exercise any voting rights in connection with them, for the duration of a specified vesting period ordinarily expiring in 2026. The terms of the MEP are set out in a management incentive agreement and a share subscription agreement that Mr Myerson has entered into with the Company and DKL Energy. For further details of the MEP arrangements please see paragraph 11.5 (*Management Equity Plan*) of Part 20 (*Additional Information*).

2.4.3 In addition, each of Mr Myerson and Mr Wallace, the CEO of the Delek Group and a Non-Executive Director in the Company, are entitled to separate additional success based compensation linked to the outcome of the arbitration proceedings raised by IEUK, further details of which are set out in paragraph 10.6 (*Additional Success based compensation*) of Part 20 (*Additional Information*).

2.4.4 The Company has been notified by Delek that it intends to establish a management equity plan at the level of DKL Energy for the benefit of Mr Wallace and certain other senior executives within the Delek Group (the "**Delek MEP**"). Further details of these arrangements are set out in paragraph 18.1 (*Ithaca Energy)* of Part 20 (*Additional Information*).

2.4.5 Alan Bruce and Gilad Myerson each have an option over Ordinary Shares (the "**Option**"). The Option represents a right to subscribe for Ordinary Shares (the "**Option Shares**") which have a value which is equal to the higher of (i) 0.2% of the net value of IEEPL's assets less its liabilities as at the date immediately before the initial public offering of the Company's shares; and (ii) 0.2% of the market value of the issued share capital of the Company by reference to the most recent annual valuation of the Company undertaken for audit as at the date immediately before the initial public offering of the Company's shares. For further details of the arrangements please see paragraph 11.6 (*Option Agreements*) of Part 20 (*Additional Information*).

PART 11

REGULATION

1. REGULATORY OVERVIEW

The Group contains a number of entities whose activities and operations are subject to various laws and regulations administered by local, national, supranational and other government entities, and similar agencies in the United Kingdom, in the European Union and in the other countries in which the Group operates. These laws and regulations have a significant impact on oil and gas exploration, development, production and marketing activities, and accordingly can materially affect the Group's operations.

Oil and gas production regulations in the United Kingdom include laws related to:

- location of wells;
- drilling and casing of wells;
- well production limitations;
- spill prevention plans;
- surface use and restoration;
- the calculation and disbursement of royalties;
- platform, facility and equipment removal;
- the plugging and abandonment of wells;
- permits for drilling operations;
- environmental, health and safety matters; and
- production, severance and ad valorem taxes.

The Group's operations are subject to regulations governing operation restrictions and conservation matters, including provisions for the unitisation or pooling of oil and gas properties in straddling fields, the establishment of maximum rates of production from oil wells, and limiting flaring or venting of natural gas. These conservation laws have the effect of limiting the amount of oil the Group can produce from its wells and limiting the number of wells or the locations at which the Group can drill.

This part of the Prospectus is intended to give an overview of the regulatory framework that currently applies to the Group. A description of certain risks associated with the legal and regulatory regime in the jurisdiction under which the Group operates (being the UKCS) is set out in paragraph 3 (*Risks Relating to Regulation and Legislation*) of Part 2 (*Risk Factors*).

2. LICENCE FRAMEWORK

The Crown possesses all title and rights to petroleum located in the United Kingdom, its territorial waters and the UKCS. Consequently, the legal regime established in the United Kingdom for the exploration for, and exploitation of, oil and gas provides for the transfer of the Crown's rights to explore for and exploit oil and gas to licensees.

2.1 *The licensing system*

Oil and gas exploration and production activities in the UKCS are governed primarily by the Petroleum Act. The Petroleum Act vests ownership of the petroleum resources in the UK sectors of the North Sea in the Crown and gives the Secretary of State the authority to grant licences that confer on the licensee for a limited time the right to search for and bore for and get petroleum in the areas governed by the licence. Pursuant to the Energy Act, the authority to grant such licences, together with certain other functions, was transferred from the Secretary of State to the Oil and Gas Authority (now rebranded as the NSTA).

The Energy Act implements a number of recommendations from Sir Ian Wood's UKCS Maximising Recovery Review: Final Report, including one of its key recommendations which was the creation of a new arm's length body to regulate UKCS oil and gas recovery, with this body having a remit (and the necessary powers) to deliver the MER UK Strategy. The principal objective of this strategy is maximising economic recovery of UKCS oil and gas reserves. The NSTA exercises its powers within this context.

Companies are required to obtain a licence prior to commencing any exploration or production activities. Licences are usually awarded through competitive licensing rounds generally held every year or so and conducted by the NSTA, although in exceptional circumstances licences may be granted by the NSTA outside of the ordinary licensing rounds. The NSTA invites applications for each licensing round, which covers specific acreage.

Licences may be awarded to individual companies or to several companies collectively. “Out of round applications” may be made by a prospective licensee to the NSTA with compelling reasons such as urgency, temporary availability of a drilling rig or no prospect of competition. However, certain procedures must still be followed in respect of such applications according to the specified timeframe, including an invitation for applications being published in the London, Edinburgh and Belfast Gazettes at least 90 days in advance of the award of the relevant licence.

The NSTA maintains discretion in the granting of licences, which is exercised to ensure the maximum economic recovery of the resources and considers other factors as well, such as protection of the environment. Each licence carries an annual rental charge due on the anniversary date of the grant of the licence (except pre 20th round seaward production licences, which were only due in their initial year). Rental fees are charged and determined by evaluating the number of square kilometres covered by the licence. In addition, yearly levies are applied against UKCS licences in order to provide the primary funding for the NSTA’s activities. As part of the application process, the NSTA and the licensee agree a work programme of exploration activity for the initial term of the licence.

2.2 ***Offshore Licences***

The NSTA awards different types of offshore licences with the main distinction being seaward exploration licences and seaward production licences. A seaward production licence used to be in the form of either a traditional licence, frontier licence or a promote licence. From the 29th Licensing Round, all new seaward production licences have been classified as Innovate Licences.

Further details regarding each such licence type are set out below.

Seaward Exploration Licence

The NSTA grants seaward exploration licences to enable seismic surveys to be carried out in open acreage that is not covered by a production licence. These licences are non-exclusive in that other parties may also hold a seaward exploration licence in respect of the same area. These licences typically carry an initial three-year term with the possibility of extension for a further three years.

Seaward Production Licence

A seaward production licence is an exclusive licence which enables the licensee(s) to search for, bore for and extract petroleum resources in the UKCS within the licensed area for a defined period of time. Separate consents are required prior to drilling and development. Each seaward production licence runs for a maximum of three successive terms: the initial term, the second term and the third term. The licensees can only move on to the next term if certain requirements are met during the previous term. A seaward production licence usually carries a total term of between 26 years and 31 years, although it can be longer for a frontier licence. The NSTA may allow a licence to continue if the field is still producing at the end of the original term.

The conditions of seaward production licences are predominantly contained in “**model clauses**” applicable at the time of the issue of the licence, although additional restrictions or provisions may also be contained in the particular licence. The model clauses govern matters such as the grant of the rights, the terms and conditions applicable to each of the three periods of a licence and the requirement to relinquish a certain proportion of the licence area, the regulation of work programmes and development plans, measurement, records and access, working methods, pollution and training. The model clauses also give the NSTA the power to direct or restrict certain of the licensee's activities, including prohibiting a licensee from carrying out development or production activities other than with the consent of the NSTA, or in accordance with a government approved development plan. A licence may be revoked by the NSTA for a number of reasons set out in the model clauses, including if the licensee fails to comply with the requirements of the licence.

Under a seaward production licence, the NSTA approves the appointment of an operator. The operator under the licence organises or supervises all the development and production operations associated with the licence. Licensees are also subject to the requirements of the Petroleum Act governing the decommissioning of facilities, including the requirement to produce and agree a decommissioning plan at a future date and, if required, to provide financial security for decommissioning costs.

Depending on the type of licence, licensees in the UKCS are required to relinquish (or give up) a significant section of their licence area after a prescribed period has elapsed. The purpose of this requirement is to ensure that operations conducted in the UKCS are conducted in as efficient and cost effective manner as possible.

As mentioned above, a seaward production licence may be either a traditional licence, frontier licence, a promote licence or innovate licence.

Traditional Licence

A traditional licence has three terms, with the first two terms each lasting four years and the third term lasting 18 years (other than in relation to the 27th and 28th licensing rounds where greater flexibility was introduced for certain licences). At the end of the first four year term, the licence will only move into the second four year term if a specified work programme (which may consist of an agreed combination of acquiring seismic data, processing seismic data, committing to drill a well or conducting other exploration or development activities) is completed and at least 50% of the acreage covered by the licence has been relinquished. During the second four year term, a field development plan must be approved by the NSTA and all acreage outside the development area must be relinquished. If the development plan is not approved, the licence will expire. The 18 year third term covers the producing life of the field. Applicants must prove their technical, environmental and financial capacity before being awarded a traditional licence.

Frontier Licence

A frontier licence usually has a six-year exploration phase and is designed to allow companies to screen large areas that are remote or otherwise difficult to explore. The initial term is split, with a special mandatory relinquishment of 75% of the acreage covered by a frontier licence at the end of year three and a further mandatory relinquishment at the end of the initial term of 50% of the remainder (leaving 12.5% of the original licence area remaining under licence). At the end of the initial term, the licensee must have fully completed the work programme agreed for the licence. This work programme may include a "drill or drop" requirement (that is, if a decision to drill an exploration well is not taken, the licence area must be relinquished). In exceptional circumstances, the NSTA may grant an extension to the initial two-year term, for example, in circumstances where uncharacteristically extreme weather conditions delay seismic acquisition during the first year. There is an additional variant to the frontier licence designed for the West of Shetland environment providing a nine-year initial term.

Promote Licence

The promote licence is designed to allow smaller companies to obtain a production licence before having the necessary operating and financial capacities. Although a promote licence is similar to a traditional licence, the required financial, technical and environmental capacity and a firm commitment to drill a well to undertake an agreed equivalent substantive activity, need only be in place by the end of the second year of the licence. At the end of this two year period, the licensee faces a "drill or drop" decision on the licence where the licensee must either submit a further work programme to retain the licence or relinquish the licence. If the further work programme is approved, the licence continues for the remaining period of the two year initial term, at which point there is a requirement to relinquish 50% of the acreage, and for a second four year term on the same terms as a traditional licence.

Innovate Licence

From the 29th Licensing Round, all new seaward production licences will be Innovate Licences. Innovate Licences retain the initial term of previous licence types, which can be subdivided into up to three phases—Phase A, Phase B and Phase C—with the work for each phase being addressed separately in the licence work programme.

Phase A is a period for carrying out geotechnical studies and geophysical data reprocessing. Phase B is a period for undertaking seismic surveys and acquiring other geophysical data. Phase C is for drilling.

Phases A and B are optional and depend on the plans the applicant has for the licence area. All licences will have a Phase C, except in special cases where an applicant doesn't propose any exploration and goes straight to the second term (e.g., when planning to develop an existing field discovery or redevelop a field where production has ceased).

Licences with a Phase B will expire at the end of this phase if the licensee has not satisfied the NSTA of its technical and financial capability to complete the work programme or if the work required under Phase B has not been completed, and the licensee must also undertake to complete the work required under Phase C.

For licences with a Phase A but no Phase B, the licence will expire at the end of this phase if the licensee has not satisfied the NSTA of its technical and financial capability to complete the work programme or if the work required under Phase A has not been completed, and the licensee must also undertake to complete Phase C.

The existing model clauses enable the NSTA to offer many of the features of an Innovate Licence but not all of the features that the NSTA plans to introduce, so in the 29th Licensing Round, the NSTA offered licences with just the features described above. The NSTA introduced a new set of model clauses for the 30th Licensing Round and subsequent rounds, which offer the full Innovate Licence. Existing pre 29th Licensing Round licences remain unchanged by the introduction of Innovate Licences.

Innovate Licence term length:

Initial term:	Variable with maximum of nine years
Second term:	Four years
Third term:	18 years
Mandatory relinquishment at end of initial term:	50%

2.3 ***Licensing Rounds***

Most seaward production licences are awarded through regular licensing rounds. Licences are awarded pursuant to a review by the NSTA of each applicant's technical understanding of the acreage requested and the applicant's proposed work programme. The 32nd Offshore Licensing Round closed on 12 November 2019 with 113 licence areas over 260 blocks or part-blocks being offered to 65 companies on 3 September 2020. The 33rd Offshore Licensing Round was launched on 7 October 2022.

In exceptional circumstances, the NSTA may formally invite an applicant to apply for a licence outside of the regular licensing rounds. The applicant must convince the NSTA of its case for an out of round licence. A case for an out of round licence generally requires that the applicant show that waiting for the next licensing round would cause unnecessary delay to activities under an existing licence, and that being awarded an out of round licence would avoid that delay, or that broad competition for the licence is not feasible during a licensing round. The NSTA will not award out of round licences for pure exploration or where an applicant simply prefers not to wait for the next licensing round. If the NSTA formally invites an applicant to apply for an out of round licence, the applicant completes the application in the same manner as applying for a licence during a licensing round.

2.4 ***Licence Holders***

A UK Licence may be held by a single licence holder or by a number of entities collectively. The Group holds its interests under the majority of its UK Licences with other parties. However, in such cases, each of these entities' obligations, responsibilities and liabilities under a UK Licence will be joint and several.

There are no restrictions imposed under the Petroleum Act regarding the nationality of private sector companies to whom UK Licences are granted (although certain residency criteria do apply and prospective licensees must satisfy the NSTA that they have a place of business in the United Kingdom). In order to join a licence and take an interest in a producing field a prospective licensee must be registered at Companies House as a UK company or carry on business through a fixed place of business in the United Kingdom.

There is no direct state participation in petroleum operations under UK Licences. UK Licences are designed so as to ensure the most effective and efficient exploitation and exploration of petroleum by the relevant licensees. One of the primary mechanisms used in a UK Licence to focus licensees on efficiently discharging their licence obligations is by way of requiring licensees to relinquish a certain percent of the relevant licence area at the end of the exploration period.

2.5 ***Licence Terms***

As described above, UK Licences are valid for a sequence of periods, called terms. Each licence will expire automatically at the end of the relevant term unless the licensee has satisfied the requisite conditions to allow it to enter into the next subsequent term under the relevant licence. Normally those terms fall into the following categories: the exploration term; the appraisal and development term; and the production term.

The exploration term

The exploration period normally lasts between four and nine years. A UK Licence will expire at the end of the exploration period unless the work programme agreed between the NSTA and the licensee(s) in respect of the exploration period has been completed. At that time, the licensee(s) must also relinquish a prescribed proportion of the relevant licence area.

The appraisal and development term

The appraisal and development period normally lasts between four and six years. The licence expires at the end of this period unless a development plan for the relevant licence area has been submitted by the licensee and approved by the NSTA.

The production term

The production period normally lasts 18 years. However, the NSTA may, acting in its own discretion, extend this term if production is continuing at the date of expiry of the licence.

2.6 ***Transfer of a Licence interest***

A licensee may only transfer their interest in a UK Licence with the prior written approval of the NSTA. If a UK Licence is transferred without such consent the NSTA may revoke the relevant licence or reverse the assignment.

This requirement also applies to assignments between affiliates and related bodies corporate. In order to obtain such consent, the licensee must apply to the NSTA using the NSTA's online e-licence administration system (known as 'PEARS'). The NSTA will then consider the technical and financial capacity of the proposed new licensee, implications of the prospective assignment or decommissioning of relevant facilities and the relevant company's track record and the parent company's provision of any guarantees. However, the NSTA will not provide its consent where the relevant assignment would result in the licence having no approved operator. Any consent granted will be conditional upon the instrument effecting such assignment being substantially in a form approved by the NSTA.

In order to hold a UK Licence, the licensee must demonstrate its financial capacity to meet its expected commitments, liabilities and obligations and must not be insolvent or a company which appears to be in danger of becoming insolvent. The licensee may be required to furnish the NSTA with its latest annual report and accounts together with those of its ultimate parent company in order to demonstrate that it can satisfy these requirements. In addition, a licensee must submit a statement of safety and environmental competence and capability, which evidence (inter alia) that a licensee has the appropriate management and control systems in place to deal with environmental or emergency safety issues arising during the course of activities.

The NSTA may also require trading profit and loss forecasts for the following five years and details, if applicable, of how any deficit may be met by the relevant companies.

Licensees may surrender a UK Licence or part of the acreage covered by it. However, surrendering of all or part of a licence is not allowed where the surrender would be a “nonstandard” surrender, meaning the surrender of irregular shapes or where it leaves a very small, licensed area, or if the surrender would prevent fulfilment of a licence obligation.

2.7 ***Other Consents***

UK Licences also require various approvals from the NSTA, BEIS and other government departments for a number of licence related activities. Failure to procure such approvals may result in the relevant activity being delayed or prevented altogether.

3. DECOMMISSIONING

3.1 ***Decommissioning in the UKCS***

The Petroleum Act (as amended by subsequent Energy Acts) governs decommissioning responsibilities in the UKCS. In addition, the United Kingdom’s international obligations on decommissioning are governed principally by the 1992 Oslo and Paris Convention for the Protection of the Marine Environment of the North East Atlantic (“**OSPAR**”) and the earlier United Nations Convention on the Law of the Sea 1982 (“**UNCLOS**”).

The OSPAR regime is a regional convention and is additional to the United Kingdom’s obligations under international law. Agreement on the regime to be applied to the decommissioning of offshore installations under OSPAR was reached at a meeting of the OSPAR Commission in July 1998 (OSPAR Decision 98/3). The Petroleum Act complies with many of the obligations under the OSPAR regime.

The NSTA works alongside BEIS in assessing decommissioning programmes on the basis of cost, future alternative use and collaboration. BEIS remains the competent authority for decommissioning in the UKCS and is the responsible authority for ensuring that the requirements under OSPAR recommendations or actions are applied to decommissioning programmes.

3.2 ***Decommissioning obligations under the Petroleum Act***

Prior to decommissioning an installation, the Petroleum Act requires that decommissioning programmes be approved by BEIS using best available techniques to achieve best environmental practice.

Under the Petroleum Act, a party will incur liabilities in respect of the decommissioning of installations and pipelines following the service by the Secretary of State, through OPRED, of a section 29 notice on that party under the Petroleum Act. At any time following a submission of a field development plan, BEIS can issue a section 29 notice requiring that a costed decommissioning programme be provided by any of the following parties:

- the licence holder;
- a parent company or associated companies of a licence holder;
- any licensee who transferred an interest in the licence to another party without the consent of the NSTA;
- the field operator;

- the parties to the field joint operating agreement or similar agreement; and
- any person owning an interest in an installation (but generally only where sufficient financial provision has not otherwise been made with regard to decommissioning).

The parties on whom the notice is served are jointly liable to submit a decommissioning programme and once a decommissioning programme has been approved by BEIS, it becomes a joint and several obligation upon the persons who submitted it to ensure that it is carried out. Where the Secretary of State deems that such a party is unlikely to be able to carry out any decommissioning obligations placed upon it, it is empowered to require the provision of appropriate financial security to cover those decommissioning costs.

In addition to the parties set out above, under section 34 of the Petroleum Act, BEIS may use a "claw back" power to impose decommissioning obligations on anyone who, at any time since the issue of the first section 29 notice for the installation, could have been served with such a notice, being former licence holders and their affiliates.

3.3 ***The UK Government's Guiding Principles on Decommissioning***

Installations

The underlying presumption on decommissioning is that, in accordance with OSPAR Decision 98/3:

- all offshore installations will be re used, recycled or disposed of on land;
- all topsides of all installations must be returned to shore;
- all steel installations with a jacket weight of less than 10,000 tonnes must be completely removed for re use, recycling or final disposal on land;
- for steel installations with a jacket weight greater than 10,000 tonnes, it is possible to consider whether the footings of the installation may remain in place but only with a derogation from the OSPAR requirements;
- for concrete installations, it is possible to consider whether they should be left wholly or partially in place but only with a derogation from the OSPAR requirements;
- all installations installed after 9 February 1999 must be completely removed;
- a decommissioning programme is required in respect of all offshore installations;
- any exceptions or exemptions are individually assessed in accordance with the provisions of OSPAR Decision 98/3; and
- each decommissioning programme is subject to full and open consultation and the section 29 notice will contain a list of organisations to be consulted near the time of decommissioning. Such organisations include fishermen's organisations and other interested bodies.

Pipelines

While OSPAR Decision 98/3 does not apply to pipelines and there are no international guidelines relating to decommissioning of pipelines, the Petroleum Act provides for requirements in this regard. In addition, the United Kingdom's guiding principles on decommissioning provide that:

- decommissioning proposals for pipelines will be considered on an individual basis; and
- all feasible decommissioning options should be assessed including removal, burial or trenching to an adequate depth or just leaving in place.

Residual Liability

The parties who own an installation or pipeline at the time of its decommissioning will normally remain the owners of assets and any residual liability remains with those parties in perpetuity. In addition, parties with a duty to secure that the decommissioning programme is carried out will remain liable for any conditions attached to BEIS' approval of the programme. Any remains of installations or pipelines will be subject to monitoring at suitable intervals and may require maintenance or remedial action in the longer term. There will also be a need to ensure that fishing and navigation are not disrupted.

3.4 *The IMO Guidelines*

The International Maritime Organisation (IMO) is the competent international organisation for the purposes of UNCLOS, governing the United Kingdom's international obligations in respect of decommissioning of offshore installations. The IMO Guidelines prescribe the minimum global standards to be applied to decommissioning offshore installations and structures to ensure the safety of navigation. Although the UK Government accepted OSPAR Decision 98/3, certain aspects of the IMO Guidelines remain relevant, particularly in terms of identification, survey and navigational aids.

3.5 *Determination of Decommissioning Timing*

The determination of decommissioning timing is influenced by a number of factors such as increased recovery from existing fields, new exploration and tie back of new fields, the uncertainty about the future fiscal and regulatory regimes, the long term trends in oil and gas prices as well as the reduction of decommissioning costs and future technical innovations.

If a licensee is successful in bringing further reserves into production from both existing and new fields, decommissioning could be delayed by 10 to 15 years in many infrastructure systems. Extending the life of infrastructure allows more reserves to be recovered from both existing fields and any developments arising from new exploration drilling (including fields to which the licensee does not have any direct interest in).

4. ENVIRONMENTAL

4.1 *Overview*

The Group's operations in the UKCS are subject to numerous international national laws, regulations, directives and other requirements relating to environmental and health and safety ("HSE") matters, including those governing discharges of pollutants to air and water, the management of produced water and wastes and the clean-up of contaminated sites. These HSE laws and regulations apply at various stages, including before oil and gas production activities commence, during exploration and production activities and during and after decommissioning, and are subject to change.

Before a UK licensing round begins, the NSTA typically consults with public bodies that have responsibility for the environment. Applications for production licences must include a statement of the general environmental policy of the operator in respect of the contemplated licence activities, a summary of the operator's management systems to implement the environmental policy and confirmation as to how those systems will be applied to the proposed work programme.

Additionally, the Offshore Petroleum Production and Pipelines (Assessment of Environmental Effects) Regulations 1999 (as amended) require the NSTA to exercise its licensing powers under the Petroleum Act in such a way to ensure that an environmental assessment is undertaken and considered before consent is given to certain projects.

4.2 *Applicable Legislation*

The following is a non-exhaustive list which includes some of the main legislation and statutory instruments applicable to the disposal and discharge of substances into the UK environment:

- Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005;
- Offshore Chemicals Regulations 2002;
- Offshore Chemicals (Amendment) Regulations 2011;
- Merchant Shipping (Oil Pollution Preparedness, Response & Cooperation Convention) Regulations 1998;
- Offshore Installations (Emergency Pollution Control) Regulations 2002;

- Food and Environment Protection Act 1985;
- Deposits in the Sea (Exemptions) Order 1985;
- Offshore Combustion Installations (Pollution Prevention and Control) Regulations 2013;
- Offshore Petroleum Activities (Conservation of Habitats) Regulations 2001;
- Energy Acts;
- Fluorinated Greenhouse Gases Regulations 2015;
- Greenhouse Gases Emissions Trading Scheme Order 2020;
- Marine and Coastal Access Act 2009; and
- Conservation of Offshore Marine Habitats and Species Regulations 2017.

Under these statutes and regulations, an offshore operator may require a permit/consent with respect to discharges into the marine environment, subject to a number of exemptions. Both the permits/consents and, if applicable, exemptions, are subject to conditions that must be met for the permit/consent or exemption to continue to operate. Non-compliance with the requirements of the legislation or conditions of a permit/consent may give rise to criminal offences or civil monetary penalties.

In the European Union (and in the United Kingdom from the end of the transition period (31 January 2020) pursuant to the Withdrawal Agreement), the Directive on Environmental Liability with Regard to the Prevention and Remedying of Environmental Damage (2004/35/EC), or the Environmental Liability Directive, imposes strict liability on an operator for environmental damage or imminent threat of environmental damage caused by activities listed in Annex III thereof, which include most offshore oil and gas operations. The Environmental Liability Directive's scope was extended by EU Directive 2013/30/EU on the Safety of Offshore Oil and Gas Operations, or Offshore Directive, to include all marine waters in the EU including the UKCS. The Offshore Directive also requires Member States to ensure that licensees are financially liable for remediation of environmental damage (as defined under the Environmental Liability Directive) caused by offshore oil and gas operations carried out by, or on behalf of, the licensee or operator. In September 2015, the European Commission published a report in furtherance of this directive which analysed (i) parties' liability types of damage and loss in offshore oil and gas accidents; (ii) how to ensure that liable parties have sufficient financial capacity to provide the requisite compensation for the damage and loss they are liable for; and (iii) how compensation should be disbursed so that it reaches legitimate claimants quickly.

5. TAXATION

The following paragraphs are not intended to be exhaustive and are intended as a general guide only. They are based on current UK tax law and HMRC published practice (which is subject to change, possibly with retrospective effect) as at the date of this Prospectus.

Companies engaged in activities relating to the production of oil and gas in the UK and in the UKCS are subject to an oil taxation regime which generally consists of four elements: Ring Fence Corporation Tax; a Supplementary Charge; PRT; and the Energy Profits Levy.

5.1 *Ring Fence Corporation Tax*

With some modifications (for example, relating to capital allowances and losses), this is the normal UK corporation tax applicable to UK companies, but it is subject to a "ring fence" ("**RFCT**"). It is charged at a full rate of 30% (rather than the prevailing full rate of corporation tax of 19% (from 1 April 2017)). This, however, is balanced by 100% first year allowances which are available for almost all capital expenditure. The ring fence prevents taxable profits from oil and gas extraction in the United Kingdom ("**Ring Fenced Profits**") and the UKCS being reduced by losses from other activities or by excessive interest payments by treating ring fenced activities as a separate trade. However, losses from a ring fenced trade ("**Ring Fenced Losses**") can be relieved against profits from a non-ring fenced trade (as well as against ring fenced income), as long as, but for the existence of the ring fence, the non-ring fenced and ring fenced activities would comprise a single trade.

Interest paid by a company is not deductible against Ring Fenced Profits unless it is payable in respect of a loan, the proceeds of which were used in carrying on oil extraction activities or in acquiring oil rights other than from a connected person.

The following activities generally fall within the ring fence:

- hydrocarbon extraction, namely:
- searching for hydrocarbons in the UKCS;
- extracting hydrocarbons at any place in the UKCS under a licence held by the company;
- transporting hydrocarbons to land;
- effecting the initial treatment or storage of hydrocarbons; and
- the acquisition, enjoyment or exploitation of rights to hydrocarbons to be extracted at any place in a designated area in the UKCS.

Aggregated capital gains and losses on material disposals (i.e., disposals of interests in oil to be won from a field and/or field assets) are also confined within the ring fence.

A number of capital allowances may be available to companies engaged in activities relating to oil and gas production in the United Kingdom and the UKCS. These may include research and development allowances, enhanced mineral extraction allowances and enhanced plant and machinery allowances.

Where companies incur ring fence tax losses, ring fence expenditure supplements ("**RFES**") may apply to increase the tax losses at a rate of 10% per annum for up to ten accounting periods. The original legislation restricted this relief to six accounting periods and there are detailed rules which operate to reduce the quantum of losses which can be increased by RFES in the additional four accounting periods.

5.2 ***Supplementary Charge***

Since April 2002 there has been an additional charge on a company's Ring Fenced Profits without deducting costs of debt finance (the "**Supplementary Charge**"). The Supplementary Charge is currently 10% for accounting periods commencing on or after 1 January 2016.

Investment Allowance

The investment allowance in relation to the Supplementary Charge ("**IA**") was introduced in respect of qualifying investment expenditure incurred on or after 1 April 2015. The allowance was introduced with the intention of simplifying the existing field allowance regime (since repealed).

The allowance is equal to 62.5% of qualifying investment expenditure incurred by a company in relation to a field. IA is only activated by reference to field production income. Qualifying investment expenditure includes both capital and operating expenditure which meets the definition of qualifying expenditure in the legislation. The IA reduces the adjusted profits subject to the supplementary charge.

High pressure high temperature (HPHT) cluster area allowance

The HPHT cluster area allowance, which was introduced in respect of qualifying investment expenditure incurred on or after 3 December 2014, is similar to the IA in that it also reduces the adjusted profits subject to the supplementary charge. However, the allowance is available to companies involved in exploration, appraisal and development of oil and gas in high pressure high temperature cluster areas and not confined to a single field. The allowance—which is also at a rate of 62.5% of qualifying investment expenditure—is triggered by reference to production income from the cluster area.

5.3 ***Petroleum Revenue Tax (PRT)***

PRT is an additional level of taxation on profits derived from oil and gas production in the United Kingdom and the UKCS. It is a "field based" tax charged on profits of participants arising from individual oil fields and which were given development consent prior to 16 March

1993 (not on aggregate profits arising from the entire business of the relevant participator's company). In addition, oil fields which have been decommissioned and are subsequently redeveloped are now removed from the charge to PRT.

The rate of PRT prior to 1 January 2016 was 50% but effective from 1 January 2016 the rate was reduced to 0%. It is calculated on a statutory basis set out in the Oil Taxation Act 1975 by reference to the six month periods beginning on 1 July and 1 January of each year rather than by reference to company accounts.

5.4 ***Energy Profits Levy***

The Energy Profits Levy, introduced by the Energy Profits Act, imposes an additional 25% surcharge on a company's Ring Fenced Profits, in addition to the existing 30% Ring Fence Corporation Tax and 10% Supplementary Charge, and applies in respect of Ring Fenced Profits or Ring Fenced Losses arising in accounting periods beginning on or after 26 May 2022 and ending on or before 31 December 2025. Ring Fenced Profits / Ring Fenced Losses for accounting periods which straddle the 26 May 2022 and 31 December 2025 dates are to be apportioned on a just and reasonable basis (except for investment expenditure (see below) which is to be apportioned with reference to when the expenditure was actually incurred).

The Energy Profits Levy is calculated based on a company's Ring Fenced Profit for a period disallowing any deductions for (i) debt financing costs; (ii) Ring Fenced Losses (brought forward or carried back); (iii) corporation tax group relief; or (iv) decommissioning expenditure. The resulting profit or loss is referred to as the "**EPL Profit**" or "**EPL Loss**" (as applicable).

No historic losses are allowed to be carried forward to reduce any EPL Profit or increase any EPL Loss. Further, a company's EPL Loss is not increased by any RFES (see above). However, loss relief will be available within the Energy Profits Levy so that EPL Losses can be carried forward or carried back one year, or surrendered as group relief against EPL profits where relevant conditions are satisfied.

Enhanced investment allowance

A company's EPL Profits can be reduced (or EPL Losses increased) by a new enhanced investment allowance which is equal to 80% of a company's "investment expenditure". Investment expenditure for these purposes includes capital, operating and leasing expenditure which meets the definition of "investment expenditure" in the legislation.

In comparison to the investment allowance within the Supplementary Charge regime, the new enhanced investment allowance in respect of EPL Profits / Losses (i) does not have to relate to a single oil field and (ii) will be available at the point of investment (rather than only being activated when relevant production income is generated).

PART 12

OPERATING AND FINANCIAL REVIEW RELATING TO THE GROUP

The following is a review of the Group*'s operating performance and financial position as at and for the six month periods ended 30 June 2021 and 2022 and as at and for the years ended 31 December 2019, 2020 and 2021. The term "**Group**" refers to the Company together with its Subsidiaries on a consolidated basis. The consolidated financial data of the Group for the periods and as at the dates presented reflect that (i) on 8 November 2019, the Group completed the Chevron Acquisition; (ii) on 4 February 2022, the Group completed the Marubeni Acquisition; (iii) on 30 June 2022, the Group completed the Summit Acquisition; and (iv) on 30 June 2022, the Group completed the Siccar Point Acquisition, in each case with relevant assets then being fully consolidated into the consolidated financial data of the Group. As a result, the financial information for such periods and for further periods may not be directly comparable with the Group Financial Information presented in this Prospectus. The principal activity of the Company has been to act as a holding company of the Group. The following discussion should be read in conjunction with Part 9 (Selected Financial Information), Part 17 (Unaudited Pro Forma Condensed Combined Financial Information), and Part 13 (Operating and Financial Review Relating to the Siccar Point Group), as well as with the consolidated financial statements and the related notes thereto of the Company and the financial statements of Siccar Point included elsewhere in this Prospectus.*

The consolidated financial information referred to in this Part 12 has been prepared in accordance with (i) IFRS as adopted by the United Kingdom; (ii) the requirements of the UK Prospectus Regulation; and (iii) the Listing Rules, and, unless otherwise stated, has been extracted without material adjustment from Section A (The Group), Part B (*Consolidated Historical Financial Information of the Group*) of Part 16 (*Historical Financial Information*).

Unless otherwise indicated, all production figures are presented on a net to the relevant entity's working interest basis. Where gross amounts are indicated, they are presented on a total project basis—i.e., the total interest of all relevant licence holders in the relevant fields and licence areas without deduction for the economic interest of the relevant entity's commercial partners, taxes, royalty interests or otherwise. The relevant entity's legal interest and effective working interest in the relevant fields and licence areas are separately disclosed. See paragraph 14 (Material Contracts) in Part 20 (Additional Information) for a more detailed discussion of the terms of the agreements governing the Group's interests. The following discussion includes forward looking statements which, although based on assumptions that the Directors consider reasonable, are subject to risks and uncertainties which could cause actual events or conditions to differ from those expressed or implied by the forward-looking statements. For a discussion of some of those risks and uncertainties please refer to Part 2 (Risk Factors) and paragraph 13 (Information regarding Forward-Looking Statements) in Part 3 (Presentation of Financial and Other Information). In addition, certain industry issues also affect the Group's results of operations and are described in Part 6 (Business Overview).

1. OVERVIEW

Ithaca Energy is a leading UK independent exploration and production company with production and development activities on the UKCS. The Group was founded in 2004 and has been an active UK offshore operator and producer since 2008, growing its portfolio of assets through both organic investment programmes and acquisitions. Following Delek's acquisition of the Group, the Group has seen a period of significant M&A driven growth centred upon two transformational acquisitions: the Chevron Acquisition and the Siccar Point Acquisition. In November 2019, the Group completed the Chevron Acquisition for $1.727 billion and, in June 2022, the Group completed the Siccar Point Acquisition for approximately $1.5 billion. In 2021 and 2022, the Group also completed the Mitsui Acquisition, the Summit Acquisition and the Marubeni Acquisition. These acquisitions delivered a compound annual growth rate in production of approximately 40% between 2017 and 2021. The Chevron Acquisition established Ithaca Energy as one of the largest independent companies in the UKCS and provided a significant operating capability. The Siccar Point Acquisition cemented the Group's position on the UKCS and critically provided portfolio longevity through interests in two of the UKCS's largest pre-FID fields: Cambo, which the Group also operates, and Rosebank. Following these acquisitions Ithaca Energy now has stakes in six of the top ten oil and gas assets in the UKCS. It also gave the Group a material, long-life resource base with the second largest resource base of independent oil and gas companies in the UKCS. The Group's business and employees are located in Aberdeen, Scotland, the primary operational and commercial centre of the UK oil and gas sector.

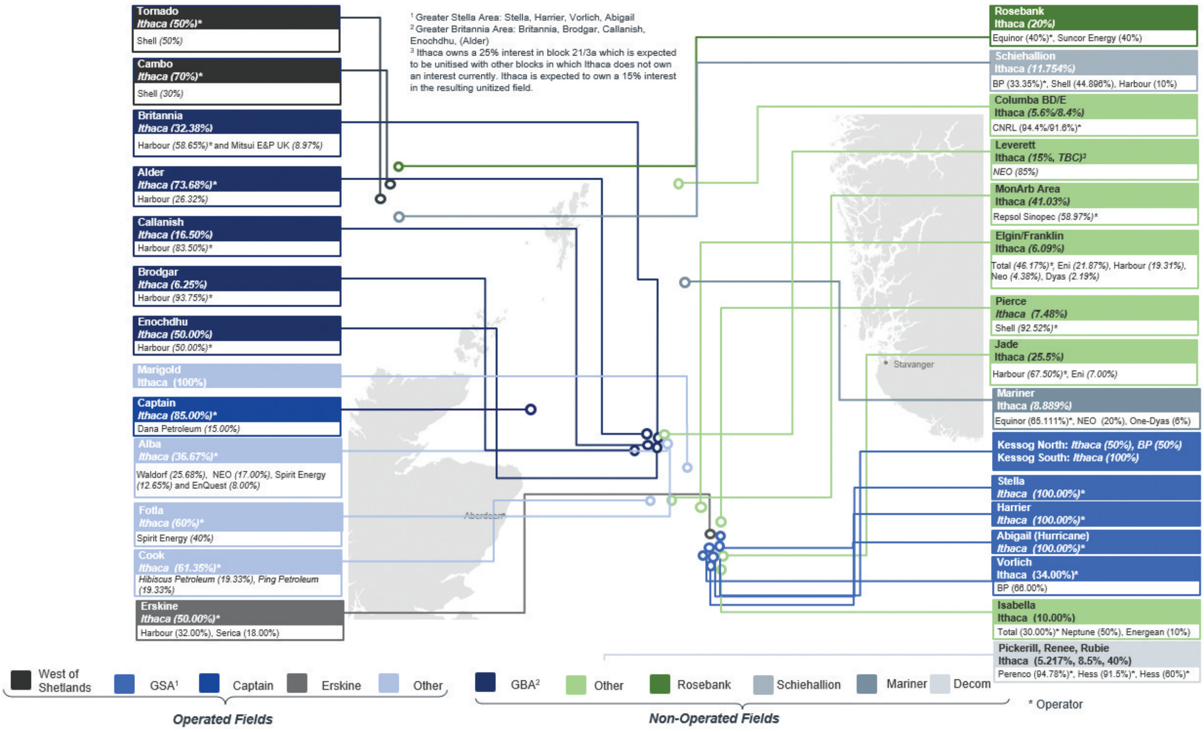
The Group's portfolio consists of 29 producing field interests, which predominantly lie in the Central North Sea and West of Shetland areas of the UKCS. The Group operates eight of these producing fields and a majority (approximately 63%) of its 2P reserves and 2C resources as at 30 June 2022, providing significant control and flexibility over execution of the business's strategic, operational and financial priorities. The Group has approximately 516 employees as at the Latest Practicable Date, of which around 251 normally work offshore on Group-operated assets.

The Group's strategy is centred on increasing Ithaca Energy's value while generating attractive and sustainable shareholder distributions. To do this the Group will focus on: buying value accretive assets across the asset lifecycle, including development and producing assets; developing projects with strong economics which provide resilience to the Group's portfolio through the commodity price cycle; and optimising existing field performance by maximising recovery, boosting efficiency, emphasising cost control and driving digitalisation. In order to realise this, the Group will seek to achieve outstanding performance through operational excellence, maintaining financial discipline and prudence, appropriately incorporating an ESG mindset and by employing an industry leading workforce while always maintaining a staunch focus on safety. The Group believes this strategy has positioned the business to expand the scale and breadth of its production asset base, establish a wider portfolio of development opportunities from which it expects to grow its future cash flows which will enable it to benefit from both the investment allowances under the Energy Profits Levy and accelerate the monetisation of its existing $5.6 billion of RFCT UK tax losses and $4.8 billion of SCT losses, as at 30 June 2022. Energy security has been a key focus of the UK Government, and the Group's management believes the Group can utilise its significant reserves and operational capabilities to play a key role in delivering security of domestic energy supply from the UKCS.

1.1 ***The Group's assets***

The Group's portfolio contains a balanced blend of oil and gas assets predominantly located in the Central North Sea and West of Shetland areas of the UKCS, which benefits from the prevalence of material producing assets, continued strong investment activity and infrastructure, including oil and gas pipelines, that are expected to be utilised by industry participants into the 2040s. These characteristics provide an attractive backdrop to the Group's own operational and investment activities, given the significant accumulated technical knowledge of the area and readily available access to offshore services.

A number of the Group's assets are clustered into production hubs, the key benefit of which is, that by using central infrastructure for multiple fields, the Group is able to minimise both incremental capital costs for satellite feeder field developments and unit operating costs. The Group's key hubs include: the Britannia field infrastructure, which serves as host for the Britannia field and four subsea tiebacks (Alder, Brodgar, Callanish and Enochdhu); and the **FPF-1** floating production facility that serves the GSA fields and the additional future satellite field developments that the Group expects to connect in the coming years. The Group's other fields are either sufficiently large to operate successfully as stand-alone fields with dedicated infrastructure or are individual tiebacks to other hub infrastructure. The following map of the Central North Sea and West of Shetland areas of the UKCS sets forth the locations of the Group's key producing assets, operators, the Group's working interests and the working interests of its field partners as at 30 June 2022.



The following table sets forth the key asset groups in the Group's portfolio and the Group's net working interest in the daily average production from each of the Group's producing key asset groups for the years ended 31 December 2019, 2020, 2021 and the six months ended 30 June 2021 and 2022. The table also sets out the Group's 2P reserves and 2C resources as at 30 June 2022 for each of the key asset groups.

	Production (net BOEPD)(1)						
	Year ended 31 December			Six months ended 30 June		2P reserves (net MMBOE)	2C resources (net MMBOE)
Asset(4)	2019(2)	2020	2021	2021	2022(3)	As at 30 June 2022	
Captain Field	4,843	21,672.06	17,413.73	20,396.93	18,710.14	79.7	13.0
Greater Stella Area(5)	12,508.67	9,117.16	12,364.68	10,824.65	10,907.38	21.4	12.5
Schiehallion Field	—	—	—	—	—	24.9	8.0
Greater Britannia Area(6) . . .	2,917	15,619.17	11,589.69	10,326.63	11,870.90	25.5	1.0
MonArb Area(7)	—	—	—	—	6,364.31	22.1	0
Mariner Area(8)	—	—	—	—	—	14.5	3.3
Jade and Jade South Fields	383	2,084.26	1,560.50	1,548.85	3,654.79	11.2	0
Cook Field	3,074.17	3,368.90	2,767.05	2,719.23	2,790.16	10.6	4.1
Erskine Field	1,253	6,299.64	4,755.65	4,724.02	5,205.58	8.2	8.1
Elgin-Franklin Field(9)	730	4,776.80	3,607.71	3,096.97	4,885.82	12.1	0.7
Alba Field(10)	409	1,820.92	1,682.41	1,648.77	2,227.73	7.1	0
Pierce Field	858.29	813.82	577.82	869.36	0.40	6.5	0.5
Columba Terraces Area(11) .	—	—	—	—	66.35	0.1	0
Cambo Field	—	—	—	—	—	—	103.3
Rosebank Field	—	—	—	—	—	—	65.8
Tornado Field	—	—	—	—	—	—	33.6
Marigold Field	—	—	—	—	—	—	28.6
Fotla Field	—	—	—	—	—	—	9.6
Isabella Field	—	—	—	—	—	—	6.6
Leverett Field	—	—	—	—	—	—	2.9
Decommissioning Assets(12) .	—	—	—	—	—	—	—
Total	**26,976.13**	**65,572.73**	**56,319.24**	**56,155.41**	**66,683.56**	**243.9**	**301.7**

Source: NSAI CPR in respect of 2P reserves and 2C resources; Company information in respect of production.

(1) The table presents historical production volumes for the Group from the completion date of each of the Chevron Acquisition, Marubeni Acquisition and Mitsui Acquisition. The table does not present any historical production volumes from any upstream assets acquired in the Siccar Point Acquisition (being Mariner, Schiehallion, Jade, Cambo, Rosebank, Tornado, and certain exploration assets) or the Summit Acquisition (being an increased working interest in the Elgin-Franklin field and certain exploration assets), each of which completed on 30 June 2022.

(2) The Group's historical production volumes for the year ended 31 December 2019 include production volumes from the Chevron Acquired Assets for the period from 8 November 2019 to 31 December 2019.

(3) The Group's historical production volumes for the six months ended 30 June 2022 include production volumes from the Marubeni Assets for the period from 4 February 2022 to 30 June 2022.

(4) Please refer to paragraph 6 (*Overview of Assets and Operations*) of Part 6 (*Business Overview*) for the Group's working interest in the relevant assets.

(5) Comprising three on-production assets (Stella, Harrier and Vorlich) one field under development (Abigail), and one field classified as contingent resources (Courageous). Licence P.2397 (Courageous) was relinquished by the Group with an effective date of 30 September 2022.

(6) Comprising the Britannia, Alder, Brodgar, Callanish and Enochdhu fields. Figures reflect the reduction in the Group's working interest in the Brodgar field from 12.5% to 6.25% with effect from 1 January 2021.

(7) Including the hub fields of Montrose and Arbroath and the satellite fields of Arkwright, Brechin, Cayley, Godwin, Shaw and Wood.

(8) Comprising the Mariner, Mariner East and Cadet field.

(9) Comprised of two gas-condensate fields, the Elgin and Franklin fields.

(10) The figures reflect the increase in the Group's working interest from 23.37% to 36.67% with effect from 1 December 2021 pursuant to the Mitsui Acquisition.

(11) Comprised of three downthrown fault blocks known as the B, D and E Terraces.

(12) Comprised of the Pickerill, Renee and Rubie Fields.

The Group's combined daily average production for the Group's key producing assets for the year ended 31 December 2021 was approximately 56,320 BOEPD (of which approximately 63% were liquids) compared to daily average production of approximately 65,575 BOEPD (of which approximately 61% were liquids) for year ended 31 December 2020. The Group's combined daily average production for the six months ended 30 June 2022 was approximately 66,685 BOEPD (of which approximately 65% were liquids) compared to daily average production of approximately 56,155 BOEPD (of which approximately 67% were liquids) for the six months ended 30 June 2021.

1.2 *Reserves*

As at 30 June 2022, the Group's 2P reserves were estimated to be 244 MMBOE (of which approximately 76% were liquids).

The Group expects to continue growing its reserve base through continued development of its existing fields and discoveries, near-field exploration around its existing infrastructure, the award of new acreage through participation in UK licence rounds and strategic bolt-on acquisitions around its core assets.

The Group delivered a reserves replacement ratio of approximately 222% over the period from 1 January 2019 to 31 December 2021. The Group achieved this through a combination of positive reserve revisions across its existing assets and expansion of the Group's interests through acquisitions and licence round awards. These revisions along with the formal approval of the Captain EOR II, the sanction of the Abigail field and various new wells in the non-operated portfolio over the period resulted in the conversion of resources into reserves, ensuring the Group's ability to continually maintain its reserves base.

The Group delivered a reserves replacement ratio of approximately 230% over the period from 1 January 2019 to 30 June 2022. The Group achieved this through the acquisition of the Siccar Point Assets which approximately doubled the Group's recoverable reserves and resources.

The following table sets forth a summary of the Group's 1P reserves, 2P reserves and 3P reserves as at 31 December 2019, 2020 and 2021 and 30 June 2022. The table also sets forth a summary of the Group's 2C resources as at 31 December 2019, 2020 and 2021 and 30 June 2022.

Reserves and resources as at 31 December (MMBOE)	1P	2P	3P	2C
2019	134.0	206.3	304.6	66.5
2020	128.3	195.5	273.2	102.1
2021	119.0	183.6	256.4	107.0

Reserves and resources as at 30 June (MMBOE)	1P	2P	3P	2C
2022(1)	158.9	243.9	342.4	301.7

Source: NSAI Reports

(1) Changes in 2022 largely driven by the acquisition of Marubeni Assets, Summit Assets and the Siccar Point Assets, each of which were acquired in the six months ended 30 June 2022.

2. RECENT DEVELOPMENTS

2.1 *Current trading and prospects*

Key trading and operational updates for the three months ended 30 September 2022 are provided below and should be read in conjunction with the guidance prepared by management set forth in paragraph 5.3 (*Management Outlook and Guidance*) of Part 6 (*Business Overview*):

- working interest production during the three months ended 30 September 2022 averaged 71.3 MBOEPD;
- operating costs (as defined below) during the three months ended 30 September 2022 are expected to be approximately $124 million;
- capital costs during the three months ended 30 September 2022 are expected to be approximately $124 million;
- the Group continues to be focused on prudent cost management and full year 2022 guidance for operating and capital costs are now slightly below previous expectations;
- planned shutdowns were completed during the three months ended 30 September 2022 on the Alba field, MonArb area and Cook field;
- the Abigail subsea field tie-back to the FPF-1 infrastructure has now been completed with first production on 20 October 2022—resulting in an update to full year production guidance;
- early production results from Abigail are lower than expected and while further data gathering and analysis is required to determine any longer-term impact, a prudent reduction has been applied to the production guidance set forth below for the three months ended 31 December 2022 and the year ended 31 December 2023;
- the Shell operated Pierce field remains shut-in and is undergoing commissioning;
- the relinquishment of the Courageous licence (see paragraph 6.2 (*Greater Stella Area*) of Part 6 (*Business Overview*) on 30 September 2022 is expected to result in a non-cash impairment charge with respect to the associated CGU during the three months ended 30 September 2022;
- the introduction of the Energy Profits Levy, enacted on 14 July 2022, is expected to result in a material non-cash deferred tax charge in the three months ended 30 September 2022;
- during the three months ended 30 September 2022, the amount drawn on the RBL Facility was reduced by $100.0 million to $650.0 million from the principal outstanding as at 30 June 2022 of $750.0 million (see Part 14 (*Capitalisation and Indebtedness)*);
- the $200 million Siccar Point Bonds acquired as part of the Siccar Point Acquisition were redeemed in full between 1 August and 12 October 2022 (see below and paragraph 14.3.7 (*Siccar Point Bonds*) of Part 20 (*Additional Information*); and
- pre-FID work continues on the Cambo, Rosebank, Marigold and Fotla developments to validate costs, mature engineering and progress commercial and contractual frameworks.

The current trading update provided above is based on preliminary management information, has not been audited and is subject to the assumptions and limitations set forth in paragraph 5.3 (*Management Outlook and Guidance*) or Part 6 (*Business Overview*).

The Company's management has prepared guidance in relation to expected production, operating costs, capital costs, non-development capital expenditure, non-producing assets under decommissioning costs, exploration expenses, general and administrative expenses, net finance costs, hedging impact tax and contingent and deferred liabilities. For further information, see paragraph 5.3 (*Management Outlook and Guidance*) of Part 6 (*Business Overview*).

The Siccar Point Acquisition constituted a change of control event under the terms and conditions of the Siccar Point Bonds. Following completion of the Siccar Point Acquisition on 30 June 2022, Siccar Point issued a put option notice to Nordic Trustee AS at a premium of 1%. Bondholders holding Siccar Point Bonds totalling $166.4 million elected to exercise the put provision and require repayment. The repayment was settled on 1 August 2022. Subsequently, on 22 September 2022, Siccar Point Bonds totalling $25.6 million, were redeemed at a premium of 6% on behalf of SPEB. On 12 October 2022, the remaining Siccar Point Bonds totalling $8 million were redeemed at the make-whole amount of 105.4%. For a description of the Siccar Point Bonds, see paragraph 7.4 (*Debt financing)* of this Part 12 *(Operating and Financial Review Relating to the Group).*

On 4 October 2022, the Group repaid in aggregate $29.5 million of accrued and outstanding interest under, and costs payable in connection with, the Subordinated Delek Loan, thereby retiring the loan. For a description of the Subordinated Delek Loan, see paragraph 7.4 (*Debt financing)* of this Part 12 *(Operating and Financial Review Relating to the Group).*

2.2 ***Hedging***

The Group has a commodity hedging strategy designed to satisfy four key objectives: (i) deliver the Group's budget and longer terms business plan; (ii) mitigate downside risk of the commodity markets; (iii) allow for benefitting from market upside; and (iv) satisfy a minimum volume rolling cover of 75% (year one), 50% (year two) and 25% (year three). To enable this, a tiered implemented strategy is followed with the first 50% of volumes hedged focused on downside protection, the following 25% allowing the capture of market upside while providing downside protection, and the remaining 25% left unhedged. Conventional instruments including puts, swaps and collars are utilised to achieve these objectives.

The Group continues to implement a rolling programme to deliver its hedging objectives and has additionally reacted to improvements in Brent and the UK gas markets to high grade its hedge book. As at 30 June 2022, the Group had approximately 44% of volumes of oil hedged for the remaining two quarters of 2022 at average floor strike prices of $56/BBL and 67% of volumes of gas hedged at average floor strike prices of 114 pence/therm. For 2023, the Group currently has 17% of volumes of gas hedged at an average floor strike price of 123 pence/therm and 37% of volumes of oil hedged at an average floor strike price of $68/BBL. For the first six months of 2024, the Group currently has 3% of volumes of gas hedged at an average floor strike price of 46 pence/therm.

3. **SIGNIFICANT FACTORS AFFECTING THE GROUP'S RESULTS OF OPERATIONS**

The Group's results of operations and financial condition are affected by a variety of factors, a number of which are outside the Group's control. Set out below is a discussion of the principal factors that the Directors believe have affected the Group's operations and financial results during the periods under review and which the Directors currently expect to affect the Group's operations and financial results in the future. Factors other than those presented below could also have a significant impact on the Group's results of operations and financial condition in the future.

3.1 ***Price of oil and gas***

The prevailing price of crude oil and gas significantly affects the Group's operations and also affects the levels of its reserves and, therefore, depreciation. Substantially all of the Group's reserves are constrained by a commercial materiality threshold and therefore are impacted by changes in oil and gas prices. A decrease in oil and gas prices could lead to reduction in the economic life of a field, which will decrease the reserves.

Crude oil and gas prices have historically been volatile, dependent upon the balance between supply and demand and particularly sensitive to OPEC production levels. Commodity prices in the year ended 31 December 2021 significantly improved from historic lows experienced in 2020 as a result of the misalignment of supply and demand caused by COVID-19, combined with the OPEC+ group's temporary production increase and other macroeconomic events.

These factors contributed to a substantial decline in demand for hydrocarbons, which contributed to a steep decline in crude oil prices during 2020 with dated Brent crude oil reaching a low of $9.1/BBL on 21 April 2020. In the nine months of 2022, oil prices experienced significant recovery, with dated Brent crude oil ending the year at $77.8/BBL and UK NBP at 128 pence per therm. In the first nine months of 2022, oil and gas prices have been subject to sharp increases with dated Brent crude oil reaching a high of $120.0/BBL in March 2022 and UK NBP reaching a multi-year high of 633.1 pence per therm in September 2022, with dated Brent crude ending the first nine months of 2022 at $120.0/BBL and UK NBP at 152 pence per therm. Such increases result from a variety of factors, including Russia's full-scale invasion of Ukraine in February 2022 (and associated sanctions and private sector boycotts of Russian oil), a decline in forecasted global GDP growth, inflation and other macroeconomic outcomes that affect energy markets, (including low oil and gas inventory levels due in part to a lack of investment during 2020 and 2021 (in response to the slowdowns in the demand for oil and gas caused by the COVID-19 pandemic) resulting in maintenance and capacity constraints. Given uncertainty surrounding the conflict between Russia and Ukraine, and the potential impacts to global commodity and financial markets, and the continuing dynamic nature of the COVID-19 pandemic and restrictions, the Group expects future benchmark prices for oil and gas to remain volatile for the foreseeable future.

The Group's oil sales are priced against the average price during or following the month of entitlement, according to the Platts Dated Brent crude oil benchmark and the oil sales contract. Premiums or discounts to the benchmark price are negotiated. While realised oil prices for each of the fields in the Group's portfolio do not strictly follow the Brent price pattern, with some fields sold at a discount or premium to Brent and under contracts with differing timescales for pricing, the average realised price for all the fields traded broadly in line with the price of Brent crude oil. The following chart shows the average, highest and lowest Brent crude oil quoted prices for the periods presented:

	Year ended 31 December			Six months ended 30 June	
(in $/BBL)	**2019**	**2020**	**2021**	**2021**	**2022**
Average price for the period	64.2	52.13	70.91	64.98	107.94
Highest price for the period	74.7	69.96	86.12	76.44	137.64
Lowest price for the period	53.2	13.24	50.34	50.34	78.99

Source: Platts

The average Brent crude oil quoted price increased by $42.96/BBL, or 66%, to $107.94/BBL for the six months ended 30 June 2022 from $64.98/BBL for the six months ended 30 June 2021. The average Brent crude oil price increased by $18.78/BBL, or 36%, to $70.91/BBL for the year ended 31 December 2021 from $52.13/BBL for the year ended 31 December 2020. The average Brent crude oil price decreased by $12.1/BBL, or 19%, to $52.13/BBL for the year ended 31 December 2020 from $64.2/BBL for the year ended 31 December 2019. Due to the recovery of Brent crude oil prices in 2021, the Group's average realised oil prices increased to $69.56/BBL in the year ended 31 December 2021 from $43.55/BBL in the year ended 31 December 2020. This is approximately 2% below the average Brent crude oil price for the period, which increased to $70.91/BBL in 2021 from $52.13/BBL in 2020. Due to the sharp increase in Brent crude oil prices in the first half of 2022, average realised oil prices increased to $120/BBL in the six months ended 30 June 2022 from $70.28/BBL in the six months ended 30 June 2021.

The Group's gas sales are priced using various benchmarks with the UK NBP being the Group's most widely used benchmark. The following table sets forth information on UK NBP gas prices for the periods presented:

	Year ended 31 December			Six months ended 30 June	
(in pence/therm)	**2019**	**2020**	**2021**	**2021**	**2022**
Average price for the period	34.7	24.7	117.2	57.4	191.5
Highest price for the period	60.91	57.3	434.2	87.9	583.0
Lowest price for the period	19.2	8.5	40.0	40.0	13.4

Source: Platts

The average UK NBP quoted price increased by 234% from 57.4 pence per therm for the six months ended 30 June 2021 to 191.5 pence per therm for the six months ended 30 June 2022. The average UK NBP quoted price increased by 374% from 24.7 pence per therm for the year ended 31 December 2020 to 117.2 per therm for the year ended 31 December 2021. The average UK NBP quoted price decreased by 29% from 34.7 pence per therm for the year ended 31 December 2019 to 24.7 pence per therm for the year ended 31 December 2020.

UK NBP gas price benchmark had been on a declining trend from late 2018 until mid-2021, with average prices in 2019 and 2020 of 35 pence per therm and 25 pence per therm, respectively. This trend was predominantly driven by an increased flow of North American LNG into the European market. The reduction in industrial gas demand that arose as a consequence of COVID-19 restrictions and the associated economic slowdown also contributed to weakness in gas prices in 2020. The benchmark price showed some signs of recovery in late 2020 and early 2021 and exceeded pre-COVID levels in the second quarter of 2021. In the second half of 2021, the benchmark price began to increase rapidly, and as at 30 June 2022, the UK NBP price was 159.6 pence per therm. The average UK NBP price in the year ended 31 December 2021 was 117.2 pence per therm (compared to 25 pence per therm in the year ended 31 December 2020) and the average UK NBP price in the six months ended 30 June 2022 was 191.5 pence per therm (compared to 57.4 pence per therm in the six months ended 30 June 2021).

3.2 ***Production volumes***

In addition to oil and gas prices, production volumes are a primary revenue driver. The Group's production levels also affect the level of its reserves and depletion charges. The Group's total average daily production for the year ended 31 December 2021 was 56 MBOEPD, compared to a total average daily production of 66 MBOEPD and 29 MBOEPD for the year ended 31 December 2020 and 2019, respectively. The increase in the year ended 31 December 2020 was primarily attributable to the acquisition of the Chevron Acquired Assets that were fully reflected in that year. The subsequent decline in production volumes in the year ended 31 December 2021 was largely the result of planned major maintenance shutdowns. The Group's total average daily production for the six months ended 30 June 2022 was 66 MBOEPD, compared to a total average daily production of 56 MBOEPD for the six months ended 30 June 2021. The acquisition of the Mitsui Assets (which were acquired pursuant to the Mitsui Acquisition on 30 November 2021) and the Marubeni Assets (which were acquired pursuant to the Marubeni Acquisition on 4 February 2022) contributed to the increase in production volumes in the six months ended 30 June 2022. On 30 June 2022, pursuant to the Siccar Point Acquisition and Summit Acquisition, the Group added the Schiehallion and Mariner fields (both currently in the top 10 UK producing fields) and increased the Group's interest in the Jade and Elgin-Franklin fields, each of which are expected to immediately add to production, with an anticipated combined contribution to production of 7 MBOEPD in 2022.

The volume of the Group's oil and gas reserves and production volumes may be lower than estimated or expected. See paragraph 1.2 (*The levels, quality and production volumes of the Group's oil and gas reserves and resources may be lower than estimated or expected*) of Part 2 (*Risk Factors*).

The following table sets forth information on the Group's oil and gas production and sales volumes for the Group for the years ended 31 December 2019, 2020 and 2021 and for the six months ended 30 June 2021 and 2022. The Group's historical production volumes for the year ended 31 December 2019 include production volumes from the assets acquired in the Chevron Acquisition for the period from 8 November 2019 to 31 December 2019 and from the assets acquired in the Marubeni Acquisition for the period from 4 February 2022 to 30 June 2022.

	Year ended December 31			Six months ended 30 June	
	2019	2020	2021	2021	2022
Total average daily oil and NGL production for the period (BOPD)[(a)]	16,004	40,763	35,854	37,707	43,214
Total average daily gas production for the period (Mcfd)	73,002	148,484	119,647	108,935	136,134
Total average daily production for the period (BOEPD)	28,590	66,360	56,483	56,489	66,685
Total average daily sales volume for the period (BOEPD)	28,585	66,024	57,124	58,079	74,491

(a) Total average daily oil and NGL production includes production from the Dons, which ceased production in the first half of 2021.

3.3 ***Reserves***

The Group estimates its reserves using standard recognised evaluation techniques. This estimate is reviewed internally at least annually and is also reviewed annually by independent consultants. The Group estimates future development costs by taking into account the level of development required to produce the reserves it has elected to develop and referencing it to similar operations where applicable, reviews by external engineers and the Group's experience. See paragraph 5 (*Reserves and Resources Reporting*) of Part 3 (*Presentation of Financial and Other Information*).

Separately, the depletion of oil and gas assets charged to the Group's income statement is dependent on the estimate of the Group's oil and gas reserves. An increase in estimated reserves will cause a reduction to the Group's annual income statement charge because a larger base exists on which to depreciate the asset. Correspondingly, a decrease in estimated reserves will cause an increase to the Group's annual income statement charge. The estimate of oil and gas reserves also underpins the net present value of a field used for impairment calculations, and in significant cases a reduction to the reserves estimate can lead to an impairment charge. Similarly, an increase to the reserves estimate can lead to a reversal of a previous impairment charge. These impairment charges or credits would not impact the Group's cash flow or its UK tax charges.

On 30 June 2022, the Group acquired the Siccar Point Assets, which lengthened the life cycle of the Group's portfolio and significantly contributed to the increase in the Group's recoverable reserves, resources and support production to 546 MMBOE (2P reserves + 2C resources) as at 30 June 2022 from 291 MMBOE (2P reserves + 2C resources) as at 31 December 2021, equating to reserves and resources growth of approximately 1.9x since December 2021.

3.4 ***Taxation***

Taxation can have a significant impact on the Group's results of operations. The Group is currently subject to a non-ring-fenced corporation taxation rate of 19%, a ring-fenced corporation taxation rate of 30%, a supplementary charge of 10%, and a 25% surcharge under the Energy Profits Levy.

Corporation tax

The profit and loss tax charge comprises of both current and deferred taxes. The current tax assets and liabilities are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amounts are those that are enacted or substantively enacted at the reporting date.

Deferred tax is recognised on temporary differences and unused tax losses carried forward. Deferred tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled. Deferred tax assets are recognised to the extent that it is probable that future income tax profit will be available against which the temporary differences can be utilised.

The Group's taxation is also affected by tax incentive programmes such as investment allowances. These allowances allow the Group to offset the UK supplementary charge (10% as from 1 January 2016) based on yearly allowances tied to the Group's production and capital expenditures.

Cash taxes paid are based upon the current tax, two-thirds of which is payable in the current year and one-third in the following year.

Energy Profits Levy

On 26 May 2022, the UK Government announced the Energy Profits Levy, a new 25% surcharge on the extraordinary profits made by companies in the oil and gas sector as a result of rises in commodity prices. The Energy (Oil and Gas) Profits Levy Act was enacted on 14 July 2022 and introduced into UK law. Prior to the Energy Profits Levy, companies in the oil and gas sector paid a 40% headline rate of tax on profits consisting of 30% RFCT and 10% SC. The Energy Profits Levy takes the combined rate of tax on profits to 65%. Companies are not able to offset previous losses or decommissioning expenditure against profits subject to the levy.

To encourage the oil and gas sector to reinvest their profits to invest in UK extraction and support the economy, jobs and the United Kingdom's energy security, the Energy Profits Act provides for an enhanced investment allowance. This new investment allowance rate is equal to 80%, which means that, with existing reliefs and allowances for RFCT and SC, for every £1 businesses invest, a 91 pence tax saving will be obtained. This enhanced investment allowance is available in respect of a company's "investment expenditure", which for these purposes includes capital, operating and leasing expenditure which meets the definition of "investment expenditure" in the legislation. In addition, according to NSAI CPR, capital costs (including 2P reserves and 2C reserves capital costs) of approximately $3.7 billion is projected to be spent in the period from 2022 to 2025, which, if utilised for qualifying "investment expenditure", the Company believes may help to reduce the potential impact of the Energy Profits Levy.

See paragraph 5 (*Taxation*) in Part 11 (*Regulation*) for a detailed description of the UK tax laws applicable to the Group and paragraph 3.1. (*The Group may be adversely affected by changes to tax legislation or its interpretation or increases in effective tax rates in the tax jurisdictions in which the Group does business*) of Part 2 (*Risk Factors*).

As at 30 June 2022, the Group had tax losses, mainly from ring fence activities, of $5.6 billion (RFCT) and $4.8 billion (SCT) that may potentially be available for offsetting against future taxable profits in the companies in which the losses arose. These losses include tax losses of approximately $3.0 billion, which the Group acquired as part of the Siccar Point Acquisition, and $1.6 billion (RFCT) and $1.4 billion (SCT), which the Group acquired as part of the Marubeni Acquisition. These tax losses provide a protection for the Group from the payment of the 30% headline corporation tax rate on up to $5.6 billion of taxable profits and 10% headline supplementary charge tax rate on up to $4.8 billion of taxable profits in effect have a cash value of up to approximately $2.1 billion (assuming that the full amount of the tax losses can be offset against the 40% headline tax rate). The Group has recognised a deferred tax asset of $2.1 billion in relation to tax losses only to the extent of anticipated future taxable profits.

As at 31 December 2021, the Group had tax losses, mainly from ring fence activities, of $1.3 billion, that may potentially be available for offset against future taxable profits in the companies in which the losses arose. Included within trade and other receivables is a tax receivable of $14.9 million, relating to an expected refund of RFCT and SCT due to the carry back of decommissioning losses. The Group recognised a net consolidated deferred tax asset of $220.9 million at 31 December 2021, which includes a deferred tax asset of $500.3 million relating to carried forward ring fence losses (both RFCT and SC losses), net decommissioning provision which is expected to give rise to deductible expenditure amounting to $197.7 million and unrealised losses on derivative contracts which should also give rise to deductible expenditure amounting to $179.0 million. The net deferred tax asset is offset by a deferred tax liability recognised on temporary differences relating to fixed assets.

The Group is subject to various tax claims which arise in the ordinary course of its business, including tax claims from tax authorities in the jurisdictions in which it operates. The Group assesses all such claims in the context of the tax laws and, where applicable, makes provision for any settlements which the Group considers to be probable. See paragraph 5 (*Taxation*) of Part 11 (*Regulation*) and paragraph 1.18 (*The Group's utilisation of tax losses and tax liability is based on forecasts and subject to estimation*.) of Part 2 (*Risk Factors*). As at 30 June 2022, the Group held no tax provisions on its balance sheets relating to tax audit risks or other tax contingencies.

The Group may also be affected by how taxes impact its counterparties and contracts.

3.5 ***Development and production success and impairment***

The Group faces inherent risks in connection with its development and production activities. These risks include the difference between estimated and actual reserves, the Group's cost efficiency in development, timing of production activities and its level of production. The Group reviews its development and production projects at least quarterly for indicators of impairment. In the event that such an indicator does exist, the Group compares the expected value of the asset (based on discounted cash flows) with the carrying value on its balance sheet. If the expected value is lower than the carrying value, the Group records any impairment to its income statement.

The Group recorded an impairment charge of $7.6 million for the six months ended 30 June 2022 which related to decommissioning cost estimate increases for fields that have stopped producing. For the years ended 31 December 2019 and 2020, the pre-tax impairment charge in respect of the Group's tangible oil and gas assets and goodwill was $106.8 million and $681.6 million, respectively. Following an impairment review driven by the higher forward curve for both oil and gas prices, the Group recorded a $465.3 million pre-tax impairment reversal on its tangible oil and gas assets, relating primarily to Alba and Stella assets, for the year ended 31 December 2021.

3.6 ***Acquisitions and disposals***

If the Group elects to divest an asset, it could impact several line items in the Group's income statement depending, in part, on the stage of the asset's life during which disposal occurs. For example, a farm-out, which occurs during the development phase is likely to result in a gain or loss. When the Group enters the development phase of a project with a high equity stake and farms out a portion of the equity in that licence in return for cash consideration and a carry of all, or a portion of, the Group's share of development costs, the cash consideration and/or the fair value of the carry will be assessed against the carrying value of the percent of the disposed equity to calculate the gain or loss on disposal. Further, any acquisition of or sale of interests in producing assets will affect the Group's production volumes and revenues.

The Group's results may also be positively affected by successful acquisitions and disposals, although the extent of the impact largely depends on the mix of assets acquired or sold.

Acquisitions and disposals during the periods presented include, among others, those set forth below.

- May 2019: Entered into the Chevron Acquisition Agreement pursuant to which, among other things, IEUK acquired the entire issued share capital of CNSL (now called IOG). Completion of the Chevron Acquisition occurred on 8 November 2019. See paragraph 4.4 *(Chevron Acquisition)* of this Part 12 (*Operating and Financial Review Relating to the Group*).
- February 2020: Entered into a sale and purchase agreement with TotalEnergies E&P UK Limited in respect of an interest in the UKCS Petroleum Production License No. P.2158 Block 15/18b.
- September 2021: Entered into an acquisition agreement with Mitsui pursuant to which IOG acquired a 13.3% additional interest in the Alba field taking its interest in the Alba field to 36.7%. Completion of the Mitsui Acquisition occurred on 30 November 2021.

- November 2021: Entered into the Marubeni Acquisition Agreement with MNSL pursuant to which IEUK acquired the entire issued share capital of MOGL. Completion of the Marubeni Acquisition occurred on 4 February 2022.
- February 2022: Entered into the Summit Acquisition Agreement with Sumitomo pursuant to which IEUK acquired the entire issued share capital of Summit. Completion of the Summit Acquisition occurred on 30 June 2022.
- April 2022: Entered into the Siccar Point Acquisition Agreement pursuant to which IEUK acquired the entire issued share capital of SPEHL and certain loan notes issued by SPEFL. Completion of the Siccar Point Acquisition occurred on 30 June 2022.

See paragraph 14 (*Material Contracts*) of Part 20 (*Additional Information*). As at 30 June 2022, the Group had no appraisal and/or development assets held for sale.

3.7 ***Underlying operating costs***

Underlying operating costs are operating expenses that are either variable or fixed. The variable element of operating costs will increase (or decrease) with the level of production, therefore an increase (or decrease) in production will result in an increase (or decrease) in underlying variable operating costs. The main variable operating costs that affect the Group's results include the costs associated with the use of some infrastructure and production consumables. Fixed operating costs are substantially independent from production levels and therefore do not increase (or decrease) with an increase (or decrease) of the Group's level of production. Fixed operating costs include, for example, routine and non-routine maintenance costs, any element of fixed FPSO lease payments and both offshore and onshore personnel costs. Certain significant maintenance programmes result in the planned shut in of production for a period of time. An increase in fixed operating costs will result in an increase in unit operating expenditure per barrel due to higher costs with no associated increase in production.

The Group's results are affected by its unit operating expenditure per barrel. In 2019, unit operating expenditure per barrel was $18.7/BOE, which decreased to $18.0/BOE in 2021. The Group's mid-term ambition is to reduce average unit operating expenditure per barrel to approximately $14.0/BOE, but this ambition is subject to the impact of higher hydrocarbon fuel prices, medium term inflation rates and will require management of the Group's asset base through a combination of asset decommissioning and successful implementation of the Group's M&A strategy. Given the impact of cost inflation, the base production profiles for ongoing activity and 2P reserves capex development are expected to maintain costs relatively flat in the short term with cost reductions supported by projects with targeted lower cost barrels (including Rosebank which is expected to deliver unit operating expenditure per barrel of $11.8/BOE in the initial years of production). This figure is based on maturity of the Rosebank development and on inflation and hydrocarbon pricing that pre-date 30 June 2022, each of which may be affected by increased hydrocarbon prices and the rise in inflation rates since that date and the maturation of the project assumptions. For a discussion of some of the risks and uncertainties related to unit operating expenditure, please refer to Part 2 (*Risk Factors*), including paragraphs 1.3 (*The Group may be affected by the general global economic and financial market situation*), 1.5 (*The Group may not be able to sanction development projects, including the Rosebank and Cambo fields, required to convert their resources into production and may face delays or cost overruns in executing sanctioned development projects*), and 1.9 (*The Group faces inherent uncertainty as to the success of highly capital-intensive appraisal and development activities; in particular, in connection with the development of the Cambo and Rosebank fields*).

3.8 ***Exploration and appraisal success and exploration costs written off or impaired***

The Group faces inherent risks in connection with the Group's exploration and appraisal activities. The success or failure of the Group's exploration and appraisal activities affect its future development plans for a particular licence area. After the acquisition of an exploration licence, exploration costs (e.g., seismic purchase and evaluation and exploration drilling) are capitalised as intangible assets. The value of the Group's intangible assets is reviewed regularly throughout the year and, when appropriate, values are impaired or written off if the Group does not expect to make a sufficient economic return from the investment (e.g., if an exploration well is dry, has insufficient reserves to be commercial or if a licence has insufficient prospectivity).

The Group's oil and gas assets are analysed into Cash Generating Units ("**CGUs**") for impairment review purposes, in accordance with IAS 36 "Impairment of Assets" accounting standard, with exploration and evaluation ("**E&E**") asset impairment testing being performed at a grouped CGU level. When reviewing E&E assets for impairment, the combined carrying value of the grouped CGU is compared with the grouped CGU's recoverable amount. The recoverable amount of a grouped CGU is determined as the higher of its fair value less costs to sell and value in use. Write-offs and impairments of intangible exploration and evaluation assets are expensed through the exploration and evaluation expenses line of the Group's income statement. The Group accounts for such write-offs using the successful efforts method of accounting. In line with the successful efforts method of accounting, all licence acquisition, exploration and evaluation costs are initially capitalised as intangible oil and gas assets in cost centres by field or exploration area, as appropriate, pending determination of commerciality of the relevant property. Directly attributable administration costs are capitalised insofar as they relate to specific exploration activities. Pre-licence costs and general exploration costs not specific to any particular licence or prospect are expensed as incurred. If prospects are deemed to be impaired or unsuccessful on completion of the evaluation, the associated costs are charged to the income statement. If the field is determined to be commercially viable, the attributable costs are transferred to property, plant and equipment in single field cost centres. These costs are then depreciated on a unit of production basis. All field development costs are capitalised as property, plant and equipment. Property, plant and equipment related to production activities are amortised in accordance with the Group's depletion and amortisation accounting policy. See paragraph 14 (*Property, plant and equipment)* of Part 16 (*Historical Financial Information*).

3.9 ***Derivative financial instruments***

The Group's results are affected by movements in commodity prices and foreign currency exchange. For example, for the year ended 31 December 2020, hedging contributed 50% to the Group Adjusted EBITDAX. The Group currently holds a material hedge position which reduces exposure to price uncertainty: as at 30 June 2022, the Group had (i) approximately 44% of volumes of oil hedged for the remaining two quarters of 2022 at average floor strike prices of $56/BBL and 67% of volumes of gas hedged at average floor strike prices of 114 pence/therm, (ii) approximately 17% of volumes of gas hedged for 2023 at an average floor strike price of 123 pence/therm and 37% of volumes of oil hedged at an average floor strike price of $68/BBL, and (iii) approximately 3% of volumes of gas hedged for the first six months of 2024 at an average floor strike price of 46 pence/therm. The Group's oil and gas hedging strategy is to hedge predominantly by way of swaps, collars and puts. The Group's ability to hedge by way of instruments with an uncapped contingent credit exposure (i.e., swaps) is subject to the following limits (based on a percentage of forecast production from producing assets) contained in the RBL Facility Agreement:

Commodity swap hedging limits	Volume
From the date of the transaction for a period of 12 months	85%
12–24 months from the date of the relevant transaction	65%
24–36 months from the date of the relevant transaction	50%
36–48 months from the date of the relevant transaction	30%
48 months from the date of the relevant transaction	Nil

The Group's foreign currency hedging strategy is to enter into forward contracts or buy options to secure non-US dollar denominated expenditure and to secure pounds sterling at a level sufficient to cover the Group's UK general and administrative costs. See paragraph 8.4 (*Foreign exchange rate risk management*) of this Part 12 (*Operating and Financial Review Relating to the Group*).

3.10 ***Interest rates***

The Group's exposure to the risk of changes in market interest rates relates primarily to the Group's borrowings under the RBL Facility Agreement, which comprise (i) a SONIA-linked interest rate (in the case of loans in pounds sterling), (ii) a SOFR-linked interest rate (in the case of loans in US dollars), or (iii) a EURIBOR-linked interest rate (in the case of loans in euros). The Group may be affected by changes in market interest rates at the time it refinances any of its indebtedness. The Group does not actively pursue interest rate hedging. See paragraph 8.4 (*Foreign exchange rate risk management*) of this Part 12 (*Operating and Financial Review Relating to the Group*).

3.11 ***Currency exchange rates***

The Group's functional and presentational currency is the US dollar, primarily because the Group prices its oil sales in US dollars and the Group's financing is provided in US dollars. However, because a significant amount of the Group's operating, staffing and other administration costs are denominated in pounds sterling, the Group's results are affected by changes in the US dollar/pounds sterling exchange rate. The Group's gas revenues are denominated in UK pounds sterling which provides a natural exchange rate hedge. The Group pursues a case-by-case currency exchange hedging strategy for specific foreign exchange exposures. See paragraph 8.4 (*Foreign exchange rate risk management*) of this Part 12 (*Operating and Financial Review Relating to the Group*).

4. SIGNIFICANT FACTORS AFFECTING COMPARABILITY OF FINANCIAL INFORMATION

4.1 ***Siccar Point Acquisition***

On 7 April 2022, IEEPL (as guarantor), IEUK and the Siccar Point Seller entered into the Siccar Point Acquisition Agreement pursuant to which IEUK agreed to acquire the entire issued share capital of SPEHL and certain loan notes issued by SPEFL. The Siccar Point Acquisition completed on 30 June 2022.

The total consideration comprised an initial payment at completion of $1,015 million (of which approximately $688 million was paid to the Siccar Point Seller and approximately $278 million was in repayment of an existing lending facility), plus contingent payments of (i) up to $300 million in connection with final investment decisions being taken in respect of the Cambo field and the Rosebank field and (ii) up to $60 million linked to realised commodity prices in connection with sales volumes from the Siccar Point Assets over the calendar years 2023 to 2025. The initial payment was funded through a combination of the RBL Facility and existing cash resources of IEUK. The Siccar Point Acquisition included a tax loss of $3 billion.

The following table sets forth the licences acquired in connection with the Siccar Point Acquisition:

License area	License	Block(s)	Working interest
Schiehallion	P.556	204/20a,	11.75%
	P.559	204/25a	11.75%
Jade	P672	30/2c JADE	5.57%
	P.1589	30/7b ALL	5.57%
Rosebank	P1026	213/26b, 213/27a	20.00%
	P1191	205/1a	20.00%
	P1272	205/2a	20.00%
Cambo	P1189	204/4a, 204/5a	70.00%
	P.1028	204/9a, 204/10a	70.00%
Blackrock	P.1830	204/4b, 204/5b	60.00%
Mariner	P335, P.979	9/11a, 9/11c,	8.89%
	P.726	9/11b	8.89%
	P.1758	8/15a	8.89%
	P.2151	9/11g	8.89%
Suilven	P.556	204/19b	50.00%
	P556	204/20b	50.00%
Tornado	P.2403	204/13, 204/14d	50.00%

The acquisition of the Siccar Point Assets is expected to contribute approximately 8 MBOEPD to production in 2022.

The Siccar Point Acquisition was accounted for using the acquisition method of accounting in accordance with IFRS 3, "Business Combinations," which requires recognition and measurement of all identifiable assets acquired and liabilities assumed (with certain limited exceptions) at their full fair value as at the date control is obtained and the estimated purchase price. See Part 3 (*Presentation of Financial and Other Information*).

4.2 ***Summit Acquisition***

On 30 June 2022, the Group completed the Summit Acquisition. By way of the Summit Acquisition, IEUK acquired, through a corporate acquisition of Summit, Sumitomo's entire non-operated working interest in the Elgin-Franklin field and the SEAL and GAEL pipelines. The cash consideration payable on completion was $109 million, with a projected two-year payback period.

The following table sets forth the licences acquired in connection with the Summit Acquisition:

Field	License	Block(s)	Working interest
Elgin Franklin[1]	P.188	22/30b ELGN	2.1875%
	P.362	29/5b ALL	2.1875%
	P.666	22/30c ALL	2.1875%
	P.666	29/5c ALL	2.1875%
K2	P.2382	22/14c	50%

(1) Pursuant to the Summit Acquisition, the Group's working interest in Elgin Franklin increased from 3.9000% to 6.0875%.

The acquisition of the Summit Assets is expected to contribute approximately 1.1 MBOEPD to production in 2022.

The Summit Acquisition was accounted for using the acquisition method of accounting in accordance with IFRS 3, "Business Combinations," which requires recognition and measurement of all identifiable assets acquired and liabilities assumed (with certain limited exceptions) at their full fair value as at the date control is obtained and the estimated purchase price. See Part 3 (*Presentation of Financial and Other Information*).

4.3 ***Marubeni Acquisition***

On 4 February 2022, the Group completed the Marubeni Acquisition. By way of the Marubeni Acquisition, IEUK acquired, through a corporate acquisition of MOGL, MOGL's entire non-operated working interest in the Repsol Sinopec operated MonArb assets and CNR operated Columba assets. The acquisition included a material tax loss position of $1.6 billion (RFCT) and $1.4 billion (SCT). The consideration payable comprised a $140 million base consideration, $70 million (adjusted for interim period cashflows) payable on completion and $70 million of which, is deferred to 2025. There are further contingent payments of up to $255 million in the future should certain milestones be achieved related to future development activities. In respect of the consideration payable on completion, taking into account interim period adjustments, MNSL paid IEUK the sum of $70 million, effectively rendering the Marubeni Acquisition a zero payment acquisition.

The following table sets forth the licences acquired in connection with the Marubeni Acquisition:

Field[(1)]	License	Block(s)	Working interest
Montrose	P.19	22/17n	41.03%
	P.20	22/18n	41.03%
Arbroath	P.19	22/17n	41.03%
	P.291	22/17s	41.03%
	P.292	22/18a	41.03%
	P.291	22/22a	41.03%
Arkwright	P.291	22/23a	41.03%
Brechin	P.291	22/23a	41.03%
Cayley	P.291	22/17s	41.03%
Godwin	P.291	22/17s	41.03%
	P.19	22/17n	41.03%
Shaw	P.291	22/22a	41.03%
Wood	P.292	22/18a	41.03%
Columba B/D	P.203	3/7a	5.6%
	P.199	3/8a	5.6%
Columba E	P.203	3/7a	8.4%

(1) This list does not include Renee, Rubie, or Pickerill fields as these assets do not have active licenses because they are not producing and, so far as the Group is aware, the operators have no plans to produce them in the future.

The acquisition of the Marubeni Assets is expected to contribute approximately 6.5 MBOEPD to production in 2022.

The Marubeni Acquisition was accounted for using the acquisition method of accounting in accordance with IFRS 3, “Business Combinations,” which requires recognition and measurement of all identifiable assets acquired and liabilities assumed (with certain limited exceptions) at their full fair value as at the date control is obtained and the estimated purchase price. See Part 3 (*Presentation of Financial and Other Information*).

4.4 ***Chevron Acquisition***

On 29 May 2019, IEUK, a subsidiary of Ithaca Energy, entered into the Chevron Acquisition Agreement with CNSHL pursuant to which, among other things, IEUK acquired the entire issued share capital of CNSL (now called IOG) on 8 November 2019. The final consideration payable was $1.727 billion.

The following table sets forth the licences acquired in connection with the Chevron Acquisition:

Field	License	Block(s)	Working interest
Alba	P.213(1)	16/26a A-ALB	36.67%
		16/26a C-10K	21.85%(2)
	P.2373(1)	22/1b ALL	60%(3)
Alder	P.119	15/29a ALDER	73.68%
		15/29a AREA A	73.68%
Britannia(4)	P.103	15/30a S-BRI	33.03%
		15/30a L-RST	50.63391%
	P.119	15/29a AREA B	75%
		15/29a AREA C	75%
	P.213	16/26a B-BRI	33.167%
		16/26a D-BEL	33.167%
	P.345	16/27b AREA B	33.75%
		16/27b AREA A	33.75%
Brodgar	P.118	21/3a ALL	6.25%(5)
	P.741	21/3a	—
	P.2350	21/4c	—
Callanish(6)	P.347	21/4a ALL	13.7%
	P.590	15/29b ALL	20%
Captain	P.324	13/22a ALL	85%
	P.2513	13/21b, 13/22b	100%
Elgin-Franklin	P.188	22/30b ELGN	3.9000%
	P.362	29/5b ALL	3.9000%
	P.666	22/30c ALL	3.9000%
		29/5c ALL	3.9000%
Enochdhu	P.103	21/5a ALL	50%
Erskine	P.057	23/26a Area B	50%
	P.264	23/26b Area B	50%
		23/26b Area C	60%
		23/26d Area C	60%
Jade	P.672	30/2c JADE	19.93%
	P.1589	30/7b ALL	19.93%
Thunderball	P.2345	14/23 ALL	50%
		14/24 ALL	50%
		14/28 ALL	50%
		14/29b ALL	50%

(1) P.2373 includes the “Fotla” and “Fortiu” near field exploration targets and P.213 includes the Fortiu near field exploration target, which lie within approximately 20 kilometres of the Alba field facilities and provide potential future satellite field development opportunities for Alba although no final decision has been reached on such future development opportunities.

(2) Related to the Fortiu licence.

(3) Related to the Fotla and Fortiu licences.

(4) CNSL held a 32.38% working interest in Britannia on a unitised basis.

(5) The Brodgar field working interest reduced from 12.5% to 6.25% on 1 November 2018. The working interest increased to 12.5% from 6.25% when the H4 well came online until 10 MMBoe had been recovered, thereafter the working interest reverted to 6.25%.

(6) CNSL held a 16.5% working interest in Callanish on a unitised basis.

Pursuant to the Chevron Acquisition Agreement, IEUK did not acquire certain assets previously owned by CNSL, which were contributed to Chevron Britain Limited pursuant to a pre-completion intragroup asset transfer. These assets included CNSL’s working interest in the Clair field, the Sullom Voe terminal, Ninian pipeline and the SIRGE pipeline system. In addition, cash sums totalling $510 million were extracted from CNSL by CNSHL by way of intercompany loan prior to completion in accordance with the Chevron Acquisition Agreement. Additionally, IEUK did not acquire CNSL’s working interest in the Rosebank field, which had been sold to

Equinor in early 2019. See paragraph 14 (*Material Contracts*) of Part 20 (*Additional Information*) for further details regarding the Chevron Acquisition Agreement.

The Chevron Acquisition was accounted for using the acquisition method of accounting in accordance with IFRS 3, "Business Combinations," which requires recognition and measurement of all identifiable assets acquired and liabilities assumed (with certain limited exceptions) at their full fair value as at the date control is obtained and the estimated purchase price. See Part 3 *(Presentation of Financial and Other Information)*.

5. DESCRIPTION OF KEY LINE ITEMS

The following descriptions of key line items in the income statement are relevant to the discussion of the Group's results of operations.

5.1 *Revenue*

The sale of crude oil, gas and condensate represents a single performance obligation, being the sale of barrels equivalent on collection of a cargo or on delivery of commodity into an infrastructure. Revenue is accordingly recognised for this performance obligation when control over the corresponding commodity is transferred to the customer. This generally occurs when the product is physically transferred into a vessel, pipe or other delivery mechanism. Revenue is measured at fair value of the consideration received or receivable and represents amounts receivable for products in the normal course of business, net of discounts, customs duties and sales tax.

Tariff income is recognised as the underlying commodity is shipped through the pipeline network based on established tariff rates.

Revenue also includes realised gains / (losses) on commodity derivatives which are realised cash gains or losses on financial instruments that have settled in the period.

5.2 *Cost of sales*

The Group's cost of sales consists of operating costs, royalties, movement in oil and gas inventory, depletion, depreciation and amortisation. Operating costs consist of the cost of operations and underlying operating costs such as tariff and transportation expenses charged back to the Group based on its proportionate use of the infrastructure and according to the total costs of the operator of such infrastructure.

The Group includes in movement in inventory an amount for changes in lifting position. Changes in lifting position occur when there has been a change in the Group's cumulative "over lift" or "under lift" for the period ending on a balance sheet date. Over lifts/under lifts occur when there is an imbalance during a given period between the amount of saleable production (which is the Group's interest in gross production less shrinkage, e.g., for fuel use at the terminal or quality adjustments) and the Group's sales.

As multiple production companies share the pipeline and processing infrastructure, any over lift is effectively a sale of another producer's production. Under lifted or over lifted positions are valued at market prices prevailing at the balance sheet date. An under lift of production from a field is included in current receivables and valued at the reporting date spot price or prevailing contract price and an over lift of production from a field is included in current liabilities and valued at the reporting date spot price or prevailing contract price.

Oil and gas assets are depleted, on a field-by-field basis, using the unit of production method based on 2P reserves, taking into account capital expenditures to date as well as an estimate of total future capital expenditure, in each case relating to those reserves.

5.3 *Impairment (charge) / reversal*

At each balance sheet date, the Group reviews the carrying amounts of its investments and its oil and gas assets to assess whether there is an indication that those assets may be impaired. If any such indication exists, the Group makes an estimate of the asset's recoverable amount. An asset's recoverable amount is the higher of an asset's fair value less costs to sell and its value in use, where the value in use is determined from estimated future net cash flows.

If the recoverable amount of an asset is estimated to be less than its carrying amount, the carrying amount of the asset is reduced to its recoverable amount and the Group recognises a non-cash impairment loss.

Where an impairment loss subsequently reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but only so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognised for the asset in prior years.

5.4 ***Exploration and evaluation expenses***

Pre-acquisition costs on oil and gas assets are recognised in the consolidated statement of income when incurred. Costs incurred after rights to explore have been obtained, such as geological and geophysical surveys, drilling and commercial appraisal costs and other directly attributable costs of exploration and evaluation including technical, administrative and share based payment expenses are capitalised as intangible E&E assets. These expenses are not amortised prior to the conclusion of evaluation activities. At completion of evaluation activities, if technical feasibility is demonstrated and commercial reserves are discovered then, following development sanction, the carrying value of the E&E asset is reclassified as a development and production asset, but only after the carrying value is assessed for impairment and where appropriate its carrying value adjusted. If after completion of evaluation activities in an area, it is not possible to determine technical feasibility and commercial viability or if the legal right to explore expires or if the Group decides not to continue E&E activity, then the costs of such unsuccessful exploration and evaluation are written off to the income statement in the period the relevant events occur.

5.5 ***Fair value gain / (charge) on contingent consideration***

Certain agreements that the Group enters into include elements of consideration to be paid to the seller in the event that contingent events happen in the future (e.g., achievement of FDP or milestone production targets being met). Liabilities are recorded for these potential outcomes. When there are changes in the assumptions used to calculate the amount of contingent consideration to be recognised this can result in a change in the amount shown as a liability. Such movements are shown in the income statement as movement in contingent consideration.

5.6 ***General and administrative expenses***

Administrative expenses are comprised of head office staff costs and other general and administration costs that are not allocated to the underlying assets of the business or recharged to commercial partners. With respect to certain of the Group's (as applicable) operated assets, subject to certain conditions the Group's commercial partnership agreements allow it to charge back an allocated portion of its expenses as operator to its partners together with an additional amount up to a specified percentage of the total costs to compensate for parent company overhead.

5.7 ***Other gains / (losses)***

Other gains and losses include unrealised gains / (losses) on financial instruments and net foreign exchange. Fair value unrealised gains / (losses) on commodity and interest rate financial instruments are recognised in other comprehensive income and only unrealised gains / (losses) relating to foreign currency instruments are recognised in the income statement. See paragraph 2.4 (*Certain of the Group's outstanding borrowings will bear interest at floating rates which could rise significantly, thereby increasing the Group's interest cost and reducing cash flows*) of Part 2 (*Risk Factors*).

5.8 ***Gain on bargain purchase***

The cost of an acquisition is measured as the fair value of the consideration provided for the assets acquired, equity instruments issued and liabilities incurred or assumed at the date of completion of the acquisition. Transaction costs incurred are expensed and included in administrative expenses. In the event that the cost of the acquisition is less than the Group's share of the net assets acquired, the difference is recognised directly in the statement of income as gain on bargain purchase.

5.9 ***Net finance costs***

Finance costs include interest and charges attributable to interest bearing loans and borrowings, interest on notes, loan fee amortisation, related party loan interest, accretion, realised losses on interest derivative contracts as well as finance income.

5.10 ***Income tax***

Current income tax

Current income tax assets and liabilities are measured at the amount expected to be recovered from or paid to taxation authorities. The tax rates and tax laws used to compute the amounts are those that are enacted or substantively enacted by the reporting date. Current tax is calculated by applying the applicable statutory tax rate to taxable profits for the year, which is calculated in accordance with UK tax law, and the tax rates applied are those which are enacted or substantively enacted at each balance sheet date. Taxable profit differs from net profit, as reported in the consolidated income statement, because it excludes items of income or expense that are taxable or deductible in other accounting periods and it further excludes items of income or expenses that are never taxable or deductible.

Deferred income tax

Deferred tax is recognised using the liability method, providing for temporary differences arising between the tax bases of assets and liabilities and their carrying amount is in the financial statements. Deferred tax is measured at the tax rates expected to be applied to the temporary differences when they reverse, based on the laws that have been enacted or substantively enacted at each balance sheet date. Deferred tax liabilities are not recognised if they arise from the initial recognition of goodwill and deferred income tax is not accounted for if it arises from initial recognition of an asset or liability in a transaction other than business combination that at the time of the transaction affects neither accounting nor taxable profit or loss. Deferred tax assets are recognised only to the extent that it is probable that future taxable profits will be available against which the temporary differences can be utilised. The carrying value as at the balance sheet date and all available evidence is considered in evaluating the recoverability of these deferred tax assets. Deferred tax assets and liabilities are offset where there is a legally enforceable right to offset current tax assets and liabilities relating to income taxes levied by the same taxation authority on either the same taxable entity or different taxable entities where there is an intention to settle the balances on a net basis.

6. RESULTS OF OPERATIONS

6.1 ***Introduction***

The following tables set forth certain of the Group's historical revenue, expense items and production and operating data for each of the years ended 31 December 2019, 2020 and 2021 and the six months ended 30 June 2021 and 2022.

(in millions of $)	Year ended 31 December 2019	2020	2021	Six months ended 30 June 2021 (unaudited)	2022
Revenue	537.9	1,107.6	1,428.2	619.0	1,337.6
Cost of sales	(437.5)	(796.1)	(879.2)	(462.6)	(752.0)
Gross profit	**100.4**	**311.5**	**549.1**	**156.4**	**585.6**
Impairment (charge) / reversal	(106.8)	(681.6)	465.3	173.8	(7.6)
Exploration and evaluation expenses	(0.2)	(1.5)	(0.2)	(0.2)	(9.6)
Fair value gain / (losses) on contingent consideration	—	4.5	8.3	8.3	(14.4)
General and administrative expenses[(a)]	(22.1)	(37.1)	(15.2)	(9.0)	(26.7)
Other gains / (losses)	1.5	7.7	(4.4)	3.0	(13.1)
Gain on bargain purchase[(b)]	—	—	10.5	—	1,324.3
(Loss) / profit from operations before tax and net finance costs	**(27.2)**	**(396.5)**	**1,013.3**	**332.2**	**1,838.4**
Net finance costs	(120.4)	(218.2)	(250.1)	(103.9)	(97.1)
(Loss) / profit before tax	**(147.6)**	**(614.7)**	**763.1**	**228.3**	**1,741.3**
Income tax	124.0	159.0	(337.2)	(111.3)	(183.7)
(Loss) / profit attributable to owners of the parent	**(23.6)**	**(455.7)**	**426.0**	**117.0**	**1,557.7**

(a) "General and administrative expenses" (i) for the six months ended 30 June 2022 included transaction costs relating to each of the Siccar Point Acquisition and Summit Acquisition, (ii) for the year ended 31 December 2020 included certain costs relating to the redundancy costs post an employee voluntary redundancy programme, and (iii) for the year ended 31 December 2019 included fees related to costs associated with the Chevron Acquisition which completed in last quarter of 2019.

(b) "Gain on bargain purchase" for the year ended 31 December 2021 included a recognition of assets and liabilities acquired on completion of the additional 13.3% equity share in the Alba field from Mitsui as part of the Mitsui Acquisition and for the six months ended 30 June 2022 is attributable to gains in connection with the Marubeni Acquisition and Siccar Point Acquisition.

	Year ended 31 December 2019	2020	2021	Six months ended 30 June 2021	2022
Oil and NGL production (BOPD)[(a)]	16,004	40,763	35,854	37,707	43,214
Natural gas production (Mcfd)	73,002	148,484	119,647	108,935	136,134
Total production (BOEPD)	28,590	66,360	56,483	56,489	66,685
Realised oil price[(a)] ($/BBL)	66.23	43.55	69.56	70.28	107.34
Realised natural gas prices (pence/therm)	31.63	22.56	119.25	52.63	183
Unit operating expenditure[(b)] ($/BOE)	18.7	16.1	18.0	17.6	19.4

(a) Oil and NGL production includes production from Dons, which ceased production in the first half of 2021.

(b) Realised oil prices exclude oil hedging costs.

(c) Operating costs include production and transportation costs but exclude depletion, depreciation and change in lifting position.

Comparison of results of operations for the six months ended 30 June 2021 and 2022

Revenue

Revenue increased by $718.6 million, or 116.1%, to $1,337.6 million for the six months ended 30 June 2022 from $619.0 million for the six months ended 30 June 2021, primarily as a result of the events described below.

Oil sales increased by $502.5 million, or 106.7%, to $973.3 million for the six months ended 30 June 2022 from $470.8 million for the six months ended 30 June 2021. Oil sales volumes for the six months 30 June 2022 amounted 9.1 MMBOE compared to 7.3 MMBOE for the six months ended 30 June 2021.

The average realised oil price for the six months ended 30 June 2022 increased by $37.06/BBL, or 52.7%, to $107.34/BBL for the six months ended 30 June 2022 from $70.28/BBL for the six months ended 30 June 2021.

Gas and NGL volumes and sales increased by $473.3 million, or 283.5%, from a combined revenue of $167.0 million in the six months ended 30 June 2021 to $640.3 million in the six months ended 30 June 2022. These increases are primarily due to the additional production being generated by the Marubeni Assets along with an increase in commodity prices.

The average realised gas price for the six months ended 30 June 2022 was 183.0 pence/therm, an increase from 52.6 pence/therm for the comparable period in 2021, in line with the movement in the UK NBP spot gas price.

Realised losses on derivative contracts of $270.2 million were recorded in the six months ended 30 June 2022 compared to realised losses of $13.9 million in the six months ended 30 June 2021. The loss in the six months ended 30 June 2022 primarily comprised $125.9 million of realised losses on oil derivative contracts attributable to 4.3 MBBL hedged at a strike price of $56/bbl against an average Brent price for the six months of $108/BBL, as well as $144.3 million of realised losses on gas derivative contracts attributable to 185 million therms hedged at a strike price of 91 pence per therm against an average gas price for the six months of 191 pence per therm. The loss in the six months ended 30 June 2021 primarily comprised $4.3 million of realised losses on oil derivative contracts attributable to 5.3 MBBL hedged at a strike price of $47/bbl against an average Brent price for the six months of $65/BBL and $9.6 million of realised losses on gas derivative contracts attributable to 176 million therms hedged at a strike price of 46 pence per therm against an average gas price for the six months of 57 pence per therm.

Cost of sales

Cost of sales increased by $289.5 million, or 62.6%, to $752.0 million for the six months ended 30 June 2022 from $462.6 million for the six months ended 30 June 2021. This was primarily due to increases in operating costs, movement in oil and gas inventory and expenses related to depletion, depreciation and amortisation.

Operating costs increased by $58.9 million, or 28.9%, to $263.2 million for the six months ended 30 June 2022 from $204.3 million for the six months ended 30 June 2021. The increase in operating cost is due to the addition of the Marubeni Assets. The corresponding unit operating expenditure remained consistent at $19.40/BOE for the six months ended 30 June 2022, with tanker costs treated as a revenue offset and net of tariff income, compared to $17.60/BOE for the six months ended 30 June 2021.

A movement in oil and gas inventory charge of $186.1 million was recorded in the six months ended 30 June 2022, compared to a charge of $47.8 million for the six months ended 30 June 2021. Movements in inventory tends to be driven by differences in oil production and liftings, as title for gas production generally passes to the buyer as the gas flows through the pipeline system. This means that there are no significant under- or over-lifts relating to gas sales. In the six months ended 30 June 2022, volumes produced (12.1 MMBBL) exceeded those sold (9.1 MMBBL).

Depletion, depreciation and amortisation increased by $79.2 million, or 38.3%, to $285.9 million for the six months ended 30 June 2022 from $206.7 million for the six months ended 30 June 2021. This increase was driven by the 21.9% increase in production volumes and revisions to the rates driven by the updated reserves volumes reported by NSAI.

Impairment (charge) / reversal

An impairment charge of $7.6 million was recorded in the six months ended 30 June 2022 relating to an increase in the estimate in decommissioning costs for assets that have stopped producing, which resulted in the recognition of a pre-tax impairment loss of $8.7 million relating mainly to Austen. With all other assumptions held constant, a 20% decrease in the forecast revenues used for goodwill impairment testing, illustrating lower commodity prices and/or production volumes, would result in a post-tax impairment of property, plant and equipment of $384 million at 30 June 2022. An increase of 1% in the discount rate assumption would not result in a post-tax impairment of property, plant and equipment. There would be no impairment of goodwill. A decrease in discount rate or an increase in forecast revenues would have no impact on carrying amounts, as there are no remaining impairment provisions to reverse.

Exploration and evaluation expenses

E&E expenses increased by $9.4 million to $9.6 million for the six months ended 30 June 2022 from $0.2 million for the six months ended 30 June 2021. This charge was mainly due to the write-off on the Austen asset subsequent to the relinquishment of the licence.

Fair value gain / (losses) on contingent consideration

A fair value loss on contingent consideration of $14.4 million was recorded for the six months ended 30 June 2022, compared to a fair value gain on contingent consideration of $8.3 million for the six months ended 30 June 2021. This was due to changes in underlying assumptions the fair value calculation, including oil price and discount.

General and administrative expenses

General and administrative expenses increased by $17.7 million, or 195.9% to $26.7 million for the six months ended 30 June 2022 from $9.0 million for the six months ended 30 June 2021, primarily due to transaction costs related to the each of the Siccar Point Acquisition and the Summit Acquisition and other transactions amounting to $20.8 million.

Other gains and (losses)

The Group recognised other losses amounting to $13.1 million in the six months ended 30 June 2022, compared to other gains amounting to $3.0 million in the six months ended 30 June 2021.

Losses on financial instruments amounted to $19.1 million in the six months ended 30 June 2022, compared to gains on financial instruments of $2.0 million in the six months ended 30 June 2021. These losses were primarily due to unrealised losses on a US dollar and Shekel foreign currency exchange rate forward contract.

A net foreign exchange gain of $6.0 million was recorded in the six months ended 30 June 2022, compared to $1.0 million gain for the six months ended 30 June 2021. A significant portion of the Group’s revenue is in US dollars while its expenditures are incurred in pounds sterling, US dollars and Euros. General volatility in the US dollar to pound sterling exchange rate for the six months ended 30 June 2021 and the six months ended 30 June 2022 was the primary driver of the Group’s foreign exchange gains and losses.

Gain on bargain purchase

The Group recorded a gain on bargain purchase amounting to $1,324.3 million in the six months ended 30 June 2022, compared to nil in the six months ended 30 June 2021. This related to gains in connection with the recognition of deferred tax assets in connection with each of the Marubeni Acquisition and the Siccar Point Acquisition.

Net finance costs

Net finance costs decreased by $6.8 million, or 6.6%, to $97.1 million for the six months ended 30 June 2022 from $103.9 million for the six months ended 30 June 2021. This decrease is primarily attributable to interest on related party loans decreasing to $17.9 million in the six months ended 30 June 2022, compared to $23.2 million in the six months ended 30 June 2021, as well as senior notes interest decreasing to $14.0 million in the six months ended 30 June 2022 from $23.2 million in the six months ended 30 June 2021.

Income tax

A total tax charge of $183.7 million was recognised for the six months ended 30 June 2022 compared to a $111.3 million tax charge for the six months ended 30 June 2021. This change is predominately due to an increase in taxable profit at a rate of 40% to $1,741.3 million from $228.3 million, mainly due to the increase in revenue explained above.

<u>Comparison of results of operations for the years ended 31 December 2021 and 2020</u>

Revenue

Revenue increased by $320.7 million, or 29.0%, to $1,428.2 million for the year ended 31 December 2021 from $1,107.6 million for the year ended 31 December 2020, mainly as a result of the events described below.

Oil revenues increased by $271.5 million, or 46.4%, to $856.5 million for the year ended 31 December 2021 from $585.0 million for the year ended 31 December 2020. Oil sales volumes for the year ended 31 December 2021 were 12.3 MMBOE compared to 13.4MMBOE in the year ended 31 December 2020. Oil sales volumes decreased for the year ended 31 December 2021 as a result of constrained water injection on Captain, scheduled shutdowns for major maintenance (deferred from 2020) and annual maintenance programs.

Average realised oil prices increased to $69.56/BBL in the year ended 31 December 2021 from $43.55/BBL in the year ended 31 December 2020. This is approximately 1% below the average Brent price for the period, which increased to $71/BBL in the year ended 31 December 2021 from $52/BBL in the year ended 31 December 2020. While realised oil prices for each of the fields in the Group's portfolio do not strictly follow the Brent price pattern, with some fields sold at a discount or premium to Brent and under contracts with differing timescales for pricing, the average realised price for all the fields traded broadly in line with the price of Brent crude oil.

Gas and NGL volumes decreased, while revenues increased significantly from a combined revenue of $208.4 million in the year ended 31 December 2020 to $777.0 million in the year ended 31 December 2021. In particular, total gas sales decreased from 9.4 MMBOE in the year ended 31 December 2020 to 7.5 MMBOE in the year ended 31 December 2021.

Average realised gas price for the year increased steeply to 119 pence/therm in the year ended 31 December 2021, compared to 23 pence/therm for the year ended 31 December 2020, due to a significant increase in UK NBP spot market prices. Like the Group's oil production, the average realised gas price for gas sales is at or around the UK benchmark price less national grid entry charges.

Other income in the form of tariff income generated by the Britannia and Vorlich fields from third-party fields or partners, increased from $9.6 million in the year ended 31 December 2020 to $32.7 million in the year ended 31 December 2021, owing to full year production from the Vorlich field.

Realised losses on derivative contracts of $196.2 million were recorded in the year ended 31 December 2021 compared to realised gains of $373.2 million in the year ended 31 December 2020.

The realised losses on derivative contracts of $196.2 million in the year ended 31 December 2021 primarily comprised $48.8 million of losses on oil derivative contracts attributable to 10.8 MMBBL realised oil swaps hedged at an average strike price of $48/BBL against an average Brent price for year of $71/BBL and $147.3 million of losses on gas derivative contracts attributable to 341 Mtherms hedged at an average strike price of 48 pence per therm against an average gas price for the year of 117 pence per therm.

The Group executed an oil hedging re-set program in response to the decline in oil prices in March and April 2020. Hedges with a value of $155 million were re-set, which was received in cash during the first half of 2020. All the hedges that were re-set were replaced with new positions at the forward curve prices prevailing at the time. Hedging gains of $115.4 million were recognised in the year ended 31 December 2021 in relation to the 2020 re-sets.

Cost of sales

Cost of sales increased by $83.1 million, or 10.4%, to $879.2 million for the year ended 31 December 2021 from $796.1 million for the year ended 31 December 2020. This was primarily due to increases in operating costs, movement in oil and gas inventory and expenses related to depletion, depreciation and amortisation.

Operating costs increased by $5.1 million, or 1.2%, to $424.0 million for the year ended 31 December 2021 from $419.0 million for the year ended 31 December 2020. The corresponding unit operating expenditure increased to $18.0/BOE for the year ended 31 December 2021, with tanker costs treated as a revenue offset and net of tariff income, from $16.1/BOE for the year ended 31 December 2020. These increases were driven by lower production due to planned shutdowns of FPF-1 and Captain fields and increase in fixed costs (including fuel gas and diesel prices, and emissions and tanker costs) and foreign exchange movements.

An oil and gas inventory credit of $7.0 million was recorded in the year ended 31 December 2021, compared to a charge of $2.3 million for the year ended 31 December 2020. Movements in inventory tends to be driven by differences in oil production and liftings, as title for gas production generally passes to the buyer as the gas flows through the pipeline system. This means that there are no significant under-or over-lifts relating to gas sales. In the year ended 31 December 2021, volumes produced (20.6 MMBBL) were in line with those sold (20.9 MMBBL).

Depletion, depreciation and amortisation increased by $83.7 million, or 22.8%, to $450.3 million for the year ended 31 December 2021 from $366.6 million for the year ended 31 December 2020. This increase in expense was driven by the impact of the impairment reversals recognised in the year ended 31 December 2021.

Impairment (charge) / reversal

An impairment reversal of $465.3 million was recorded in the year ended 31 December 2021, compared to an impairment charge of $681.6 million in the year ended 31 December 2020. Impairment reviews were carried out in the second and third quarters of 2021 driven by the higher forward curve for both oil and gas prices resulting in reversals of $408.1 million, being $397.3 million on Stella and $10.8 million on Alba. In addition, an annual review of all oil and gas assets and goodwill was performed in the fourth quarter of 2021. The review was carried out on a fair value less cost of disposal basis using risk adjusted cash flow projections discounted at a post-tax rate of 10.5%, resulting in pre-tax reversals of $18 million on the Alba CGU and $33 million on the Pierce field. The post-tax recoverable amount as at 31 December 2021 was $77 million for the Alba CGU, $120 million for the Pierce field and $565 million for Stella. The remaining reversal of $6 million relates to revisions to decommissioning estimates for assets which have previously been fully impaired.

Exploration and evaluation expenses

E&E expenses decreased by $1.3 million, or 89.2%, to $0.2 million for the year ended 31 December 2021 from $1.5 million for the year ended 31 December 2020. This charge was mainly due to write-off of expenditure relating to E&E assets that were declared non-commercial in the year ended 31 December 2021.

Fair value gain / (losses) on contingent consideration

A fair value gain on contingent consideration of $8.3 million was recorded for the year ended 31 December 2021, compared to a fair value gain on contingent consideration of $4.5 million for the year ended 31 December 2020. This gain in the year ended 31 December 2021 was due to the release of the contingent consideration relating to the Stella infill well not reaching the given criteria to require payment. The gain in the year ended 31 December 2020 was in relation to a discount given on early settlement of certain deferred consideration liabilities owed to Petrofac in connection with the GSA Acquisition.

General and administrative expenses

General and administrative expenses decreased by $22.0 million, or 59.1% to $15.2 million for the year ended 31 December 2021 from $37.1 million for the year ended 31 December 2020, primarily due to costs in the amount of $19.3 million associated with an employee voluntary redundancy programme undertaken in the year ended 31 December 2020. There was no equivalent programme or expense in the year ended 31 December 2021.

Other gains and losses

The Group recognised other losses amounting to $4.4 million in the year ended 31 December 2021, compared to other gains amounting to $7.7 million in the year ended 31 December 2020.

A net foreign exchange loss of $4.0 million was recorded in the year ended 31 December 2021, compared to $8.2 million gain in the year ended 31 December 2020, mainly due to volatility in the GBP:USD exchange rate, with fluctuations throughout the year from a low of 1.33 to a closing rate of 1.35 on 31 December 2021. A significant portion of the Group's revenue is in US dollars while its expenditures are incurred in pounds sterling, US dollars and euros. General volatility in the US dollar to pound sterling exchange rate for the year ended 31 December 2021 and the year ended 31 December 2020 was the primary driver of the Group's foreign exchange gains and losses, particularly with respect to the revaluation of non-US dollar bank accounts and working capital balances.

Gain on bargain purchase

In connection with the Mitsui Acquisition, after accounting for the acquired decommissioning provision and working capital, a gain on bargain purchase of $10.5 million was recognised in the income statement, which was the difference between the consideration received by the Group and the net liabilities recognised.

Net finance costs

Net finance costs increased by $31.9 million, or 14.6%, to $250.1 million for the year ended 31 December 2021 from $218.2 million for the year ended 31 December 2020. This increase is primarily attributable to the interest and fees paid to holders of the 2024 Notes in connection with the Group's refinancing programme. Loan fee amortisation increased from $9.5 million for the year ended 31 December 2020 to $35.3 million for the year ended 31 December 2021.

Income tax

A total tax charge of $337.2 million was recognised for the year ended 31 December 2021 compared to a $159.0 million tax credit for the year ended 31 December 2020. This change is predominately due to an increase in taxable profit at a rate of 40% to $763.1 million from a taxable loss of $614.7 million, due to an increase in revenue and impairment reversals on oil and gas assets.

Comparison of results of operations for the years ended 31 December 2020 and 2019

Revenue

Revenue increased by $569.6 million, or 105.9%, to $1,107.6 million for the year ended 31 December 2020 from $537.9 million for the year ended 31 December 2019, mainly as a result of the events described below.

Oil revenues increased by $250.5 million, or 74.9%, to $585.0 million for the year ended 31 December 2020 from $334.5 million for the year ended 31 December 2019. Oil sales volumes for the year ended 31 December 2020 were 13.4 MMBOE compared to 5.1 MMBOE in the year ended 31 December 2019, mainly as a result of the Chevron Acquisition as well as the Vorlich field coming onstream.

Average realised oil prices decreased to $43.55/BBL in the year ended 31 December 2020 from $66.23/BBL in the year ended 31 December 2019. This is approximately 5% above the average Brent price for the period, which dropped to $52/BBL in the year ended 31 December 2020 from $64/BBL in the year ended 31 December 2019. While realised oil prices for each of the fields in the Group's portfolio do not strictly follow the Brent price pattern, with some fields sold at a discount or premium to Brent and under contracts with differing timescales for pricing, the average realised price for all the fields traded broadly in line with the price of Brent crude oil. The positive differential for the year ended 31 December 2020 is mainly due to lifting patterns, with significant lifting volumes relating to barrels produced in the months during the period when prices were high (the swing in the Brent benchmark price during the year was between $70/BBL in January 2020 and $13/BBL in April 2020).

Gas and NGL volumes and revenues both increased from a combined revenue of $155.6 million in the year ended 31 December 2019 (which included revenue generated by the Chevron Acquired Assets from 8 November 2019 to 31 December 2019) to $208.4 million in the year ended 31 December 2020, due to the contribution of the assets acquired with the Chevron Acquisition (largely due to the addition of the Britannia and Satellites field interests). In particular, total gas sales increased from 4.6 MMBOE in the year ended 31 December 2019 to 9.4 MMBOE in the year ended 31 December 2020.

Average realised gas price for the year decreased to 22.56 pence/therm in the year ended 31 December 2020 (compared to 31.63 pence/therm for the year ended 31 December 2019) due to a significant drop in UK NBP spot market prices. Like the Group's oil production, the average realised gas price for gas sales is at or around the UK benchmark price less national grid entry charges.

Realised gains on derivative contracts of $373.2 million were recorded in the year ended 31 December 2020 compared to realised gains of $90.5 million in the year ended 31 December 2019. The gain of $373.2 million in the year ended 31 December 2020 primarily comprised $257.6 million of gains on oil derivative contracts attributable to 12.0 MBBL hedged at a strike price of $62.77 against an average Brent price for the year of $52.1/BBL and $115.5 million of gains on gas derivative contracts attributable to 324.8 Mtherms hedged at a strike price of 48.4 pence per therm against an average gas price for the year of 24.7 pence per therm.

The Group executed an oil hedging re-set program in response to the decline in oil prices in March and April 2020. Hedges with a value of $155 million were re-set, which was received in cash during the first half of 2020. All the hedges that were re-set were replaced with new positions at the forward curve prices prevailing at the time.

The gain of $90.5 million in the year ended 31 December 2019 primarily comprised $17.1 million of losses on oil derivative contracts attributable to 5.1 MBBL hedged at a strike price of $67.5 against an average Brent price for the year of $64.2/BBL and $73.5 million of gains on gas derivative contracts attributable to 232.1 Mtherms hedged at a strike price of 59.0 pence per therm against an average gas price for the year of 34.7 pence per therm.

Cost of sales

Cost of sales increased by $358.6 million, or 82.0%, to $796.1 million for the year ended 31 December 2021 from $437.5 million for the year ended 31 December 2020. This was primarily due to increases in operating costs, movement in oil and gas inventory and expenses related to depletion, depreciation and amortisation.

Operating costs increased by $220.3 million, or 110.8%, to $419.0 million for the year ended 31 December 2020 from $198.7 million for the year ended 31 December 2019. The increase in operating cost is due to the increased scale of the producing asset portfolio. The corresponding unit operating expenditure decreased to $16.1/BOE for the year ended 31 December 2020, with tanker costs treated as a revenue offset, from $18.7/BOE for the year ended 31 December 2019. This decrease is driven by an improved mix of lower cost assets within the overall portfolio and various cost reduction initiatives that have been undertaken since acquiring the larger operated asset base.

An oil and gas inventory charge of $2.3 million was recorded in the year ended 31 December 2020, compared to a credit of $2.1 million for the year ended 31 December 2019. Movements in inventory tends to be driven by differences in oil production and liftings, as title for gas production generally passes to the buyer as the gas flows through the pipeline system. This means that there are no significant under or overlifts relating to gas sales. In the year ended 31 December 2020, volumes produced (24.3 MMBBL) were in line with those sold (24.1 MMBBL).

Depletion, depreciation and amortisation increased by $131.8 million, or 56.1%, to $366.6 million for the year ended 31 December 2020 from $234.8 million for the year ended 31 December 2019. This increase in expense was due to higher production volumes, but offsetting this, the unit DD&A rate dropped from $22/BOE to $15/BOE due to a combination of the impact of the post-Chevron Acquisition DD&A rates across the Group's wider portfolio and the asset impairments recognised in the first quarter of the year ended 31 December 2020.

Impairment (charge) / reversal

An impairment charge of $681.6 million were recorded in the year ended 31 December 2020 compared to $106.8 million in the year ended 31 December 2019. The impairment was driven by the lower forward curve for both oil and gas prices resulting in impairments predominantly relating to the Stella and Dons CGUs. The review was carried out on a fair value less cost of disposal basis using risk adjusted cash flow projections discounted at a post-tax rate of 10.5% in the year ended 31 December 2020 and 9.0% in the year ended 31 December 2019.

Exploration and evaluation expenses

E&E expenses increased by $1.3 million to $1.5 million for the year ended 31 December 2020 from $0.2 million for the year ended 31 December 2019. This change was mainly due to write-off of expenditure relating to exploration and evaluation assets made in the year ended 31 December 2020 for non-commercial prospects.

General and administrative expenses

General and administrative expenses increased by $15.0 million, or 67.8% to $37.1 million for the year ended 31 December 2020 from $22.1 million for the year ended 31 December 2019, primarily due to transaction costs in connection with the Chevron Acquisition, alongside the significant upsizing of the business after the Chevron Acquisition.

Other gains and (losses)

Other gains increased by $6.2 million to $7.7 million for the year ended 31 December 2020 from $1.5 million for the year ended 31 December 2019.

Losses on financial instruments amounted to $0.5 million in the year ended 31 December 2020, compared to gains of $0.5 million in the year ended 31 December 2019.

A net foreign exchange gain of $8.2 million was recorded in the year ended 31 December 2020, compared to $1.0 million gain in the year ended 31 December 2019, mainly due to volatility in the GBP:USD exchange rate, with fluctuations throughout the year from a low of 1.23 to a closing rate of 1.36 on 31 December 2020. A significant portion of the Group's revenue is in US dollars while its expenditures are incurred in pounds sterling, US dollars and euros. General volatility in the US dollar to pound sterling exchange rate for the year ended 31 December 2020 and the year ended 31 December 2019 was the primary driver of the Group's foreign exchange gains and losses, particularly with respect to the revaluation of non-US dollar bank accounts and working capital balances.

Net finance costs

Net finance costs increased by $97.8 million, or 81.3%, to $218.2 million for the year ended 31 December 2020 from $120.4 million for the year ended 31 December 2019. This increase is primarily attributable to an increase in interest on related party loan from $8.6 million for the year ended 31 December 2019 to $53.6 million for the year ended 31 December 2020. Accretion also increased due to the additional decommissioning liabilities associated with the Chevron Acquired Assets.

Income tax

A total tax credit of $159.0 million was recognised for the year ended 31 December 2020 compared to a $124.0 million tax credit for the year ended 31 December 2019. This change is predominately due to an increase in taxable loss at a rate of 40% to $614.7 million from $147.6 million. A major driver of this decrease was the goodwill impairment write-off in the three months ended 31 March 2020 (which is non-deductible for tax purposes). In addition, there was a reduction in the RFES in the year ended 31 December 2020 because this relief is only available for a finite period of 10 years. In the year ended 31 December 2019 the Group was unable to claim any additional RFES to uplift its closing losses carried forward.

7. LIQUIDITY AND CAPITAL RESOURCES

7.1 *Liquidity management and resources*

The Group's liquidity requirements arise principally from its capital investment and working capital demands. For the periods presented, the Group met its liquidity requirements primarily from ongoing cash flow generation from its producing assets and debt financing through ongoing drawings under the RBL Facility and the equity investment in IEEPL from DKL Investments.

In addition to amounts available under the Group's debt facilities, the Group also held cash and cash equivalents of $8.3 million and $160.4 million as at 30 June 2021 and 2022, respectively, and $15.1 million, $1.2 million and $44.8 million as at 31 December 2019, 2020 and 2021, respectively. As at 30 June 2022, the Group had Available Liquidity of $320.4 million.

7.2 *Cash flow statement*

The following table sets forth the Group's consolidated cash flow information for the years ended 31 December 2019, 2020 and 2021 and for the six months ended 30 June 2021 and 2022.

	Year ended 31 December			Six months ended 30 June	
(in millions of $)	**2019**	**2020**	**2021**	**2021**	**2022**
				(Unaudited)	
Cash provided by / (used in):					
Operating activities					
(Loss) / profit before tax	(147.6)	(614.7)	763.1	228.3	1,741.3
Adjustments for:					
Depletion, depreciation and amortisation	235.2	372.8	455.9	208.8	297.4
Exploration and evaluation expenses	0.2	1.5	0.2	0.2	9.6
Impairment (charge) / reversal	106.8	681.6	(465.3)	(173.8)	7.6
Reduction in contingent / deferred consideration	—	(4.5)	(8.3)	(8.3)	14.4
Loan fee amortisation	14.8	9.5	35.3	4.7	2.3
Revaluation of financial instruments	(9.9)	(0.4)	8.3	2.0	18.7
Gain on bargain purchase	—	—	(10.5)	—	(1,324.3)
Hedging resets[(a)]	—	155.0	(115.4)	(65.6)	(20.3)
Accretion	20.4	43.4	38.4	17.9	24.2
Bank interest & charges	76.6	111.8	120.9	50.6	52.9
Interest on related party loan	8.6	53.6	48.3	23.2	17.9
Interest rate swaps	—	5.3	7.3	6.2	(0.3)
Unrealised foreign exchange on cash and cash equivalents	(1.0)	0.3	(1.8)	(1.2)	2.6
Decommissioning expenditure	(8.7)	(25.5)	(27.9)	(12.5)	(11.7)
Cashflow from operations	**295.3**	**789.6**	**848.5**	**280.5**	**832.4**
(Increase) / decrease in inventories	(36.8)	8.0	(65.3)	(27.3)	42.9
(Increase) / decrease in trade and other receivables	(39.6)	131.0	(111.0)	(22.5)	(58.2)
Increase / (decrease) in trade and other payables	65.3	(128.2)	250.5	172.6	172.0
Corporation tax paid	—	(65.2)	(10.0)	(10.0)	—
Net cash from operating activities	**284.2**	**735.3**	**912.7**	**393.3**	**989.0**
Investing activities					
Capital expenditure	(163.9)	(142.1)	(269.6)	(85.7)	(230.3)
Reverse consideration on acquisition[(b)]	—	—	56.5	—	—
Acquisition of subsidiaries net of cash acquired[(c)]	(1,726.9)	—	(7.0)	—	(957.5)
Contingent / deferred consideration payment	(10.0)	(56.9)	—	—	(15.9)
Net cash used in investing activities	**(1,900.8)**	**(199.0)**	**(220.2)**	**(85.7)**	**(1,203.7)**
Financing activities					
Receipt from issue of equity	25.0	—	—	—	—
Bond issue	500.0	—	—	—	—
Payment for lease liabilities	(1.8)	(6.1)	(3.5)	(3.5)	(13.0)
Loan repayment	(477.5)	(1,152.1)	(809.8)	(214.8)	(150.0)
Loan drawdown	1,666.0	700.0	255.0	—	550.0
Bank interest & charges	(99.0)	(86.4)	(85.2)	(77.2)	(54.5)
Interest rate swaps	—	(5.3)	(7.3)	(6.2)	0.3

(in millions of $)	Year ended 31 December 2019	2020	2021	Six months ended 30 June 2021	2022
				(Unaudited)	
Net cash provided / (used) in financing activities	**1,612.8**	**(549.9)**	**(650.7)**	**(301.8)**	**332.7**
Currency translation differences relating to cash .	1.4	(0.3)	1.9	1.3	(2.6)
(Decrease) / increase in cash & cash equivalents	**(2.4)**	**(13.9)**	**43.6**	**7.1**	**115.5**
Cash and cash equivalents, beginning of the period	17.5	15.1	1.2	1.2	44.8
Cash and cash equivalents, end of period	**15.1**	**1.2**	**44.8**	**8.3**	**160.4**

(a) Hedging resets relate to the amortisation of the deferred reset gains which have been recycled to the current period profit and loss.

(b) "Reverse consideration on acquisition" for the year ended 31 December includes reverse consideration received in connection with the Mitsui Acquisition.

(c) "Acquisition of subsidiaries net of cash acquired" includes the costs relating to (i) the Chevron Acquisition for the year ended 31 December 2019, (i) a $7 million deposit in connection with the Marubeni Acquisition for the year ended 31 December 2021, and (iii) each of the Marubeni Acquisition, Summit Acquisition and Siccar Point Acquisition for the six months ended 30 June 2022.

Net cash from operating activities

Net cash from operating activities was $989.0 million for the six months ended 30 June 2022, compared to $393.3 million generated for the six months ended 30 June 2021. The difference is primarily attributable to revenues generated from the producing portfolio of assets and carefully controlled operating costs, resulting in an increase in profit before tax from $228.3 million for the six months ended 30 June 2021 to $1,741.3 million for the six months ended 30 June 2022.

Net cash from operating activities was $912.7 million for the year ended 31 December 2021 compared to $735.3 million generated for the year ended 31 December 2020. This change is primarily due to increased revenues from the Group's producing assets and management of operating costs.

Net cash from operating activities was $735.3 million for the year ended 31 December 2020 compared to $284.2 million generated for the year ended 31 December 2019. This change is primarily due to an impairment reversal in the amount of $681.6 million for the year ended 31 December 2020, compared to $106.8 million for the year ended December 2019, as well as hedging resets of $155.0 million for the year ended 31 December 2020.

Net cash used in investing activities

Net cash used in investing activities was $1,203.7 million for the six months ended 30 June 2022, compared to net cash used in investing activities of $85.7 million for the six months ended 30 June 2021. Cash flows for the six months ended 30 June 2022 were due to costs related to the acquisition of subsidiaries net of cash acquired of $957.5 million in connection with each of the Siccar Point Acquisition, Marubeni Acquisition and Summit Acquisitions that completed in the six months ended 30 June 2022, together with an increase in capital expenditure of $144.7 million primarily associated with Captain and Abigail fields and working capital movements.

Net cash used in investing activities was $220.2 million for the year ended 31 December 2021, compared to $199.0 million of net cash used in investing activities for the year ended 31 December 2020. This change is primarily a result of increases in capital expenditure in respect of the drilling on the Capital, Abigail and Fotla fields, partially offset in part by the reverse consideration of $56.5 million received in the year ended 31 December 2021 from Mitsui in connection with the Mitsui Acquisition.

Net cash used in investing activities was $199.0 million for the year ended 31 December 2020, compared to $1,900.8 million of net cash used in investing activities for the year ended 31 December 2019. This change is a result of cash flows for the year ended 31 December 2019 reflecting the Chevron Acquisition at the end of the year which resulted in costs related to the acquisition of subsidiaries net of cash acquired of $1,726.9 million.

For a more detailed description of the Group's recent capital expenditure, see paragraph 7.6 (*Capital expenditure*) of this Part 12 (*Operating and Financial Review Relating to the Group*) below.

Net cash provided / (used) in financing activities

Net cash provided from financing activities for the six months ended 30 June 2022 amounted to $332.7 million, compared to net cash used in financing activities of $301.8 million for the six months ended 30 June 2021. Net cash provided from financing activities for the six months ended 30 June 2022 reflects a $550.0 million loan drawdown, which was partially offset by a $150.0 million loan repayment.

For the year ended 31 December 2021 net cash used in financing activities amounted to $650.7 million, compared to $549.9 million for the year ended 31 December 2020. Cash flow for the year ended 31 December 2021 primarily reflects the Group's refinancing programme, including the repayment of the Subordinated Delek Loan, refinancing of the RBL Facility involving a drawdown of $255.0 million, an inflow in relation to the 2026 Notes (which replaced the 2024 Notes), and associated bank interest and charges.

Net cash used in financing activities amounted to $549.9 million for the year ended 31 December 2020, compared to net cash provided from financing activities amounting to $1,612.8 million for the year ended 31 December 2019. Net cash used in financing activities for the year ended 31 December 2020 primarily reflects repayments under the RBL Facility, together with associated bank interest and charges. Net cash provided from financing activities for the year ended 31 December 2019 primarily reflect a refinancing alongside the completion of the Chevron Acquisition, including the $25.0 million in proceeds from the issuance of equity to Delek, $500.0 million in proceeds from the issuance of the 2024 Notes and a drawdown under the RBL Facility in the amount of $1,666.0 million.

For a more detailed description of the Group's recent financing activities, see paragraph 7.4 (*Debt financing*) below.

7.3 *Capital resources*

The Group's liquidity requirements arise principally from its capital investment and working capital requirements. For the periods presented, the Group met its capital investment and working capital requirements primarily from:

- oil and gas sales revenues;
- the proceeds of debt financing; and
- the equity investment in the Group from DGL and its subsidiaries.

The Group's financing requirements will depend on a number of factors, many of which are beyond the Group's control. See paragraph 2.3 (*The Group is subject to restrictive debt covenants that may limit its ability to pursue future business opportunities and activities.*) of Part 2 (*Risk Factors*). See also paragraph 14 (*Material Contracts*) of Part 20 (*Additional Information*) regarding the Group's third-party and intragroup debt financing arrangements.

In addition to amounts available under the Group's debt facilities, it also held cash and cash equivalents of $160.4 million as at 30 June 2022.

7.4 *Debt financing*

As at 30 June 2022, the Group's total debt (excluding intragroup debt obligations) was $1,575 million, comprising an aggregate principal amount of $750 million of debt outstanding pursuant to the RBL Facility, $625 million of unsecured senior indebtedness represented by the 2026 Notes and $200 million of unsecured senior indebtedness represented by the Siccar Point Bonds.

RBL Facility Agreement

In July 2021, IEUK entered into an amended and restated RBL Facility Agreement comprising (i) an up to $1.076 billion multicurrency revolving borrowing base credit facility with BNP Paribas and eight other banks as lenders and (ii) an up to $149 million US dollar revolving borrowing base credit facility with the same lenders. The maximum amount that can be drawn or outstanding on any date is the lesser of the total commitments (being $1,225 million) and the borrowing base amount, which is calculated by reference to a banking case derived from an agreed financial model prepared by the technical bank prior to each semi-annual redetermination date. The facilities are subject to semi-annual reductions in accordance with an agreed amortisation schedule, with the $1.076 billion facility reducing to $808.0 million on 1 July 2024, $674.0 million on 1 January 2025, $490.0 million on 1 July 2025 and $335.0 million on 1 January 2026, and with the $149.0 million facility reducing to $102 million on 1 July 2024, $61 million on 1 January 2025, $46 million on 1 July 2025 and $31.0 million on 1 January 2026. The facilities will mature on 31 May 2026 (or, if earlier, the last day of the first calculation period in which the aggregate remaining borrowing base reserves for all borrowing base assets are projected in the then-current production to be less than 25% of the initial approved reserves). Under the RBL Facility Agreement, as at 30 June 2022, the principal outstanding was $750.0 million, excluding incremental transaction costs, and $175 million remained available for drawdown.

2026 Notes

In July 2021, IENS plc issued $625 million in aggregate principal amount of 9% senior notes due 2026. Pursuant to the indenture entered into among IENS plc, IEEPL (as guarantor, among other guarantors) and various other parties, IENS plc may issue additional notes in minimum denominations of $200,000 and integral multiples of $1,000 in excess thereof from time to time. Interest on the 2026 Notes will accrue at the rate of 9% per annum and is payable semi-annually in arrears on 15 January and 15 July. Interest on overdue principal and interest (if any) accrues at a rate that is 1.0% higher than the then-applicable interest rate on the 2026 Notes. Payment of interest commenced on 15 January 2022. The 2026 Notes will mature on 15 July 2026. As at 30 June 2022, $625 million of 2026 Notes were outstanding.

Siccar Point Bonds

In March 2021, SPEB issued a series of 9% unsecured callable bonds up to a maximum of $200 million. Payments in relation to the Siccar Point Bonds are made on each payment date, being 4 March and 4 September of each year. Interest on any overdue amounts will accrue at the coupon rate plus 3%. The Siccar Point Bonds mature on 4 March 2026 and must be redeemed by SPEB on such date for 100% of their nominal amount. As at 30 June 2022, $200 million of the Siccar Point Bonds were outstanding. For a description of the Group's recent financing activities relating to the Siccar Point Bonds, see paragraph 2.1 (*Current trading and prospects*) of this Part 12 (*Operating and Financial Review Relating to the Group*).

Intragroup debt arrangements

Subordinated Delek Loan

IEEPL and Delek, as lender, entered into a $250 million unsecured term loan facility, which accrued interest at a rate of 4.75% per annum, on 4 November 2019 (the "**Subordinated Delek Loan**"). The loan was subordinated against the RBL Facility Agreement and the 2026 Notes. On 3 August 2021, as part of the Group's refinancing, the Group repaid the outstanding principle under the facility. On 30 June 2022, there was $28.9 million in accrued and unpaid interest outstanding under the Subordinated Delek Loan. For a description of the Group's recent financing activities relating to the Subordinated Delek Loan, see paragraph 2.1 (*Current trading and prospects*) of this Part 12 (*Operating and Financial Review Relating to the Group*).

Capital Note

On 4 November 2019, the Company (as borrower) and DKL Energy (as lender) entered into a $392.0 million capital note agreement ("**Capital Note Agreement**") pursuant to which the Company issued a note in aggregate principal amount of $392.0 million to DKL Energy (the "**Capital Note**"). The Capital Note was originally subordinated against a $200.0 million facility agreement, dated 4 November 2019, among DKL Energy, the Company and BNP Paribas (the "**BNPP Facility Agreement**"), which was discharged on 18 June 2021. The Capital Note does not bear interest and is not linked to the consumer price index. On initial recognition, in November 2019, the Capital Note was recorded at a fair value of $278.0 million based on an estimated 15% market interest rate. The difference between the two was recorded as a capital contribution on issuance in 2019 and, in subsequent periods, this capital contribution has been unwound to the income statement through imputed interest. As at 30 June 2022, $392.0 million of the Capital Note was outstanding.

On 2 October 2022, the Capital Note Agreement was amended to provide that repayment of the Capital Note would not occur prior to 1 January 2024 unless from the proceeds of an initial public offering of the Company (in which case, repayment is permitted on notice).

Immediately following Admission, the Company will use the net proceeds of the issue of the Offer Shares pursuant to the Global Offering to repay $214 million of the Capital Note. DKL Energy has agreed to waive all remaining amounts (if any) outstanding under the Capital Note. Following such payment and/or waiver (if any), DKL Energy will provide a confirmation that such payment and/or waiver (if any) is in full and final settlement of any amounts due or payable by the Company in respect of the Capital Note.

Tracker Loan

On 4 November 2019, the Company (as borrower) and DKL Energy (as lender) entered into a $198.0 million intragroup loan agreement ("**Tracker Loan**"). The Tracker Loan was put in place as part of the agreed equity funding of the Chevron Acquisition. The Tracker Loan was originally subordinated against the BNPP Facility Agreement, which was discharged on 18 June 2021. The interest payable by the Company to DKL Energy under the Tracker Loan matched the interest payable pursuant to the BNPP Facility Agreement, ranging from 6.5% to 11.5% on LIBOR, until 4 May 2021, following which the Tracker Loan became interest free.

Principal in the amount of $120.0 million and $15.0 million of the Tracker Loan was repaid in 2020 and 2021, respectively. As at 30 June 2022, the principal outstanding under the Tracker Loan was $63 million.

On 3 October 2022, the Tracker Loan was amended to provide that repayment of the Tracker Loan would not occur prior to 1 January 2024 unless from the proceeds of an initial public offering of the Company (in which case, repayment is permitted on notice).

Immediately following Admission, the Company will use the net proceeds of the issue of the Offer Shares pursuant to the Global Offering to repay $63 million of outstanding principal and $14.3 million of accrued interest under the Tracker Loan. DKL Energy has agreed to waive all remaining amounts (if any) outstanding under the Tracker Loan. Following such payment and/or waiver (if any), DKL Energy will provide a confirmation that such payment and/or waiver (if any) is in full and final settlement of any amounts due or payable by the Company in respect of the Tracker Loan.

The following table sets forth information on the Group's total borrowings, as at 30 June 2022.

	As at 31 December			As at 30 June	
(in millions of $)	**2019**	**2020**	**2021**	**2021**	**2022**
RBL Facility	1,055.0	720.0	350.0	520.0	750.0
2026 Notes	500.0	500.0	625.0	500.0	625.0
Siccar Point Bonds	—	—	—	—	200.0
Amounts owed to related parties[(a)]	732.0	654.0	437.1	662.0	455.0
Total debt	**2,287.0**	**1,874.0**	**1,412.1**	**1,682.0**	**2,030.0**

(a) "Amounts owed to related parties" include aggregated amounts outstanding under each of the Subordinated Delek Loan, the Capital Note, and the Tracker Loan for the periods indicated.

The following table sets forth the Group's remaining contractual maturity for debt as at 30 June 2022. The table has been compiled based on the undiscounted cash flows of financial liabilities on the earliest date on which the Group can be required to pay.

(in millions of $)	**As at 30 June 2022**
Due within one year	655.0
Due within one to five years	1,375.0
Total debt	**2,030.0**

For a more detailed description of the Group's financing arrangements, see paragraph 14 (*Material Contracts*) of Part 20 (*Additional Information*).

Restrictions on use of capital resources

The Group is subject to restrictive covenants under the RBL Facility and 2026 Notes, restricting creditors, to, amongst other things: incur additional debt; make certain payments (including, subject to certain exceptions, dividends and other distributions), with respect to outstanding share capital; repay or redeem subordinated debt or share capital; create or incur certain liens; make certain acquisitions and investments or loans; sell, lease or transfer certain assets, including shares of any of the Group's restricted subsidiaries; incur expenditure on exploration and appraisal activities in excess of approved levels; guarantee certain types of the Group's other indebtedness; expand into unrelated businesses; merge or consolidate with other entities; or enter into certain transactions with affiliates. For a more detailed description of the restrictive covenants under the Group's financing arrangements, see paragraph 14 (*Material Contracts*) of Part 20 (*Additional Information*).

7.5 *Letters of credit and surety bonds*

The Group enters into letters of credit and surety bonds to provide security for the Group's obligations under certain field and bi-lateral decommissioning security agreements, or equivalent, Sullom Voe Terminal Tariff Agreements and deferred payment obligations. The instruments are either held by the Law Debenture Trust Corporation P.L.C. under a trust deed or EnQuest Heather Limited, as SVT Terminal Operator. At 31 December 2021 and at 30 June 2022, the Group had £341 million and £383 million, respectively, in letters of credit and surety bonds outstanding relating to security obligations under certain decommissioning and security agreements.

These letters of credit and surety bonds are issued from either the RBL Facility or the Group's surety bond facilities which currently are provided by Liberty Mutual Insurance Europe S.E., Aspen Insurance UK Limited, HCC International Insurance Company plc, Markel International Insurance Company Limited, Everest Insurance (Ireland), DAC and BNP Paribas.

The Group also has a deferred payment on demand bond of $70.0 million issued by a surety syndicate by Liberty Mutual Insurance Europe SE, HCC International Insurance Company plc, Markel International Insurance Company Ltd and Everest Insurance (Ireland) DAC (each with a quarter liability share) in respect of its obligation to furnish the deferred consideration security pursuant to the Marubeni Acquisition Agreement.

7.6 *Capital expenditure*

The primary objective of the Group's capital management is to optimise the return on investment, by managing the Group's capital structure to achieve capital efficiency while maintaining flexibility for future acquisitions. The Group regularly monitors the capital requirements of the business over the short, medium and long term, in order to enable it to better anticipate the timing of requirements for additional capital.

The following table sets forth the Group's capital expenditure for the years ended 31 December 2019, 2020 and 2021 and for the six months ended 30 June 2021 and 2022.

	Year ended 31 December			**Six months ended 30 June**	
(in millions of $)	**2019**	**2020**	**2021**	**2021**	**2022**
				(unaudited)	
Capital expenditure	163.9	142.1	269.6	85.7	230.3

The Group's capital expenditure in the six months ended 30 June 2022 was $230.3 million related primarily to the continuation of the Captain Enhanced Oil Recovery project and Abigail development.

The Group's capital expenditure in the six months ended 30 June 2021 was $85.7 million related primarily to the Captain Enhanced Oil Recovery project and Abigail development.

The Group's capital expenditure in the year ended 31 December 2021 was $269.6 million. The investment programme was centred on topside engineering and procurement and construction activities on the Captain field, drilling and evaluation of discoveries in the Fotla field, engineering and procurement activities in connection with the rig installation on the Abigail field, and the acquisition of the Group's current headquarters.

The Group's capital expenditure in the year ended 31 December 2020 was $142.1 million. The investment programme was centred on activities on the Captain field and activities associated with the expansion of the on-going enhanced oil recovery program, investments on the Vorlich and Abigail fields in the GSA and the acquisition of the Marigold undeveloped discovery licence interest from TotalEnergies E&P UK Limited.

The Group's capital expenditure in the year ended 31 December 2019 of $163.9 million related primarily to activities in the GSA, in particular the execution of the Vorlich field development programme, and the drilling of a water injection well on the Cook field. Post- Chevron Acquisition, the main incremental spend from the CNSL acquired assets was on Captain drilling.

7.7 *Future capital expenditure*

The Group's capital expenditure is driven largely by full phase expenditure on existing producing fields, new development projects and appraisal and development activities. As at 30 June 2022, the Group had commitments for future capital expenditure amounting to $191.0 million. The key components of this relate to AFEs (authorisations for expenditure) signed for activities on Captain EOR and the Abigail field. As at 31 December 2021, the Group had commitments for future capital expenditure amounting to $83.4 million. The key components of this relate to the Captain enhanced oil recovery programme, investments on the Abigail field and upgrade works planned on Jade and Pierce. The Group expects its capital expenditure for the year ended 31 December 2022 to reach up to $479 million.

7.8 *Contractual obligations and contingent liabilities*

The following table sets forth the Group's remaining contractual maturity for its financial liabilities with contractual repayment periods as at 30 June 2022. The table reflects the undiscounted cash flows of financial liabilities based on the earliest date on which the Group could be required to pay.

<u>Contractual obligations</u>

	Payments due by period		
(in millions of $)	**Total**	**Less than 1 year**	**1–5 years**
Trade and other payables[a]	707.0	707.0	—
Borrowings	2,030.0	655.0	1,375.0
Contingent and deferred consideration[b]	381.7	73.7	308.1
Lease liabilities	80.2	21.0	59.2
Derivatives	809.6	672.6	137.0
Total	**4,008.5**	**2,129.3**	**1,879.3**

(a) "Trade or other payables" includes amounts owed due to related parties, including as at 30 June 2022 (i) accrued and outstanding interest in the amount of $28.9 million owed to Delek in respect to the intragroup Subordinated Delek Loan, and (ii) accrued and outstanding interest in the amount of $14.3 million owed to DKL Energy in respect of the Tracker Loan (which is expected to be repaid with the proceeds of the Global Offering).

(b) Includes deferred consideration liabilities in connection with the GSA Acquisition, Marubeni Acquisition and the Siccar Point Acquisition.

<u>Decommissioning liabilities</u>

The Group also has certain liabilities for future decommissioning activities on some of its assets. The Group calculates total future decommissioning liability based on the Group's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon wells and facilities and the estimated timing of the costs to be incurred in future periods. The provisions the Group makes represent the present value of decommissioning costs which are expected to be incurred assuming no further development of the Group's assets. As at 30 June 2022, the Group used a discount rate of 3.5% and an inflation rate of 2% over the varying lives of the assets to calculate a present value of the Group's decommissioning liabilities of $1,693.4 million. These decommissioning costs are expected to be incurred at various intervals over the next 18 years.

These provisions relating to decommissioning liabilities have been created based on internal and third-party estimates. Assumptions based on the current economic environment have been made which the Group believes are a reasonable basis upon which to estimate the future liability. These estimates are reviewed regularly to take into account any material changes to the assumptions. The Group cannot guarantee, however, that actual decommissioning costs will not be materially greater than its estimates. See paragraph 1.21 (*The Group may face unanticipated increased or incremental costs in connection with decommissioning obligations*) of Part 2 (*Risk Factors*).

For further details of the Group's contractual obligations and commitments, see Note 22 to the historical financial information contained in Section A (*The Group*), Part B (*Consolidated Historical Financial Information on the Group*) of Part 16 (*Historical Financial Information*).

Litigation liabilities

The Group may face additional liabilities as a result of pending or future litigation. For further details of legal proceedings affecting the Group, please see paragraph 17 (*Legal and Arbitration Proceedings*) of Part 20 (*Additional Information*) and paragraph 1.26 (*The Group's operations are subject to the risk of litigation*) of Part 2 (*Risk Factors)*.

7.9 ***Off-balance sheet arrangements***

Other than the items described in "Contractual obligations and contingent liabilities", "Contingent Liabilities" and in the notes to the historical financial information contained in Section A (*The Group*), Part B (*Consolidated Historical Financial Information of the Group*) of Part 16 (*Historical Financial Information*), the Group had no off-balance sheet arrangements as at 30 June 2022.

For further details of the Group's contingent liabilities, see the notes to the historical financial information contained in Section A (*The Group*), Part B (*Consolidated Historical Financial Information of the Group*) of Part 16 (*Historical Financial Information*).

8. QUALITATIVE AND QUANTITATIVE DISCLOSURES ABOUT MARKET RISKS

The Board has overall responsibility for identifying and monitoring the principal risks facing the business and ensuring the implementation of appropriate and effective risk management and internal control systems.

8.1 ***Commodity price risk management***

The Group is exposed to the impact of changes in oil and gas prices on its revenue and profits. The Group is also exposed to natural gas price movements on uncontracted gas sales. The Group has a commodity hedging strategy designed to satisfy four key objectives: (i) deliver the Group's budget and longer-term business plan; (ii) mitigate downside risk of the commodity markets; (iii) allow for benefitting from market upside; and (iv) satisfy a minimum volume rolling cover of 75% (year one), 50% (year two) and 25% (year three). To enable this, a tiered implemented strategy is followed with the first 50% of volumes hedged focused on downside protection, the following 25% allowing the capture of market upside while providing downside protection, and the remaining 25% left unhedged. On a rolling 12-month period under the RBL Facility, the Group is required to hedge a minimum of 70% of volumes of net entitlement production expected to be produced in the next 12 months and 50% of volumes of net entitlement produced for the following 12 months on a best effort basis. Conventional instruments including puts, swaps and collars are utilised to achieve these objectives.

The following tables summarise the commodity hedges in place as at 30 June 2022:

Derivative		Q3-2022	Q4-2022	Q1-2023	Q2-2023	Q3-2023	Q4-2023
Oil puts	Average volume (BBL)	524,400	524,400	—	—	—	—
	Put net price ($/BBL)	$57	$57	—	—	—	—
	% of total hedges	21%	23%	0%	0%	0%	0%
Oil swaps	Average volume (BBL)	1,105,396	873,396	955,000	871,500	740,000	460,000
	Average strike price ($/BBL)	$52	$48	$70	$68	$68	$70
	% of total hedges	45%	39%	43%	44%	40%	29%
Oil collars	Average volume (BBL)	851,000	851,000	1,260,000	1,092,000	1,104,000	1,104,000
	Average net floor price ($/BBL)	$61	$61	$68	$67	$67	$67
	Average ceiling price ($/BBL)	$83	$83	$93	$90	$90	$90
	% of total hedges	34%	38%	57%	56%	60%	71%

Derivative		Q3-2022	Q4-2022	Q1-2023	Q2-2023	Q3- 2023	Q4-2023	Q1-2024	Q2-2024
Gas puts	Average volume (therms)	18,400,000	9,200,000	—	—	—	—	—	—
	Put net price (pence/therm)	119	32	—	—	—	—	—	—
	% of total hedges	16%	11%	0%	0%	0%	0%	0%	0%
Gas swaps	Average volume (therms)	55,812,500	54,897,500	41,010,000	14,057,000	14,200,000	7,250,000	2,650,000	2,600,000
	Average strike price (pence/therm)	112	142	191	111m	111	59	51	41
	% of total hedges	48%	65%	86%	76%	76%	100%	100%	100%
Gas collars	Average volume (therms)	41,400,000	20,700,000	6,750,000	4,550,000	4,600,000	—	—	—
	Average net floor price (pence/therm)	113	76	250	140	140	—	—	—
	Average ceiling price (pence/therm)	186	131	492	242	242	—	—	—
	% of total hedges	36%	24%	14%	24%	24%	0%	0%	0%

As at 30 June 2022, a 20% decrease in realised oil prices, with all other variables held constant, would have resulted in a decrease of $194.7 million in profit before tax due to changes in the carrying value of monetary assets and liabilities at the reporting date, and a 20% decrease in realised gas prices would have resulted in a decrease of $137.4 million in profit before tax, in each case with an equivalent impact on equity. A 20% increase in realised commodity prices would have the equal but opposite effect to such amounts, on the basis that all other variables remain constant.

8.2 *Credit risk management*

Credit risk refers to the risk that a counterparty will fail to perform or fail to pay amounts due, resulting in financial loss to the Group. The majority of the Group's accounts receivable balance is with customers and commercial partners in the international oil and gas industry. The Group principally governs the management of credit risk through consideration of the financial strength of customers within offtake contract tendering and award processes, management of commercial partner security arrangements within joint ventures, and assessment of creditworthiness of potential counterparties before entering into supply chain contract awards. The Group trades only with international oil and gas operators and, as at each of 31 December 2019, 2020 and 2021, and 30 June 2022, the Group had no trade receivables past due.

The Group's accounts receivable with customers in the oil and gas industry are subject to normal industry credit risks and are unsecured. On a historical standalone basis, for the years ended 31 December 2019, 2020 and 2021, over 94% of all of the Group's oil and gas sales have been to Shell, BPGM and BPOI. In the first half of 2022, most of the Group's oil and gas sales have been to BPOI and BPGM (approximately 86%), ENI (approximately 10%), with the remaining 4% sold to Esso, Shell and Gazprom (the offtake contract with Gazprom terminated with effect from 30 September 2022). The Group has not experienced any material credit loss in the collection of accounts receivable to date. The maximum financial exposure due to credit risk on the Group's financial assets, representing the sum of cash and cash equivalents, trade and other receivables, deposits, prepaid expenses and other receivables, derivative financial instruments, and decommissioning receivables, as at 31 December 2019, 2020 and 2021 was $485.2 million, $396.9 million, and $535.6 million, respectively, and as at 30 June 2021 and 2022 was $401.9 million and $748.4 million, respectively.

With respect to its decommissioning obligations, the Group does not expect material decommissioning costs in the short to medium term, however, the Group is exposed to the risk of its commercial partners defaulting on their proportionate share of decommissioning costs once such costs became payable.

8.3 *Liquidity risk management*

Liquidity and refinancing risks refer to the risk that the Group will not be able to obtain sufficient financing from lenders and the capital markets to meet its working capital and project financing and refinancing requirements. The Group monitors its liquidity risk by reviewing its cash flow requirements on a regular basis relative to the Group's funding sources, cash flow generation from its producing asset base and its existing bank facilities. Specifically, the Group ensures that it has sufficient liquidity or committed facilities to meet its operational funding requirements and service its debt and adhere to its financial covenants. The Group closely monitors and manages its liquidity requirements through the use of both short term and long-term cash flow projections, supplemented by maintaining debt financing plans and active portfolio management. Cash forecasts are regularly produced and sensitivities run for different scenarios including, but not limited to, changes in commodity prices, different production rates from the Group's portfolio of producing fields and potential delays in development projects. In addition to the Group's operating cash flows, portfolio management opportunities are reviewed to potentially enhance the Group's financial capacity and flexibility. Ultimate responsibility for liquidity risk management rests with the Board, which has built a liquidity risk management framework which the Group believes to be appropriate for the management of all its funding and liquidity management requirements. As at 30 June 2022, the Group was in compliance with all applicable financial covenant ratios.

As at 30 June 2022, the Group had drawings of $750.0 million under the RBL Facility. See paragraph 14 (*Material Contracts—Finance—RBL Facility Agreement with BNP Paribas*) of Part 20 (*Additional Information*). The Group held cash and cash equivalents of $8.3 million and $160.4 million as at 30 June 2021 and 2022, respectively, and $15.1 million, $1.2 million and $44.8 million as at 31 December 2019, 2020 and 2021, respectively.

8.4 *Foreign exchange rate risk management*

The Group generally conducts and manages its business in US dollars and pounds sterling, which are the operating currencies of the industry in the geographic areas where the Group operates. The Group has the ability to draw in US dollars, pounds sterling and euros under the RBL Facility Agreement, which further assists in foreign currency risk management. From time to time, the Group undertakes certain transactions denominated in other currencies. These exposures are managed by executing financial derivatives relating to that currency, typically to manage exposures arising on corporate transactions such as acquisitions and disposals.

The following tables summarise the foreign currency hedges in place as at 30 June 2022:

Derivative	Term	Volume	Average price
Forward Sterling versus USD	July 2022–December 2022	£54 million	1.34
Forward Euro versus USD	July 2022–December 2022	€18 million	1.07
Forward Sterling versus USD	January 2023–December 2023	£20 million	1.27
USD versus ILS zero cost collars	November 2022	$200 million	floor 3.19 ILS; ceiling 3.25 ILS

As at 30 June 2022, the Group's material monetary assets or liabilities that were not denominated in the functional currency of the respective subsidiaries involved were non-US dollar-denominated cash, joint venture billing receivables and third-party suppliers. The carrying amounts of the Group's foreign currency denominated monetary assets and monetary liabilities as at 30 June 2022 was, net of liabilities, $572.9 million. As at 30 June 2022 the Group had an average of £27 million per quarter hedged at an average forward rate of $1.34:£1, and €9 million per quarter at an average rate of $1.07:€1, for the period July to December 2022. The Group also had an average of £5 million per quarter hedged at an average forward rate of $1.27:£1, for the period January to December 2023. The Group also has $200 million of USD-ILS hedges in the form of zero cost collars, with an average floor of 3.19 ILS and an average ceiling of 3.25 ILS, all with an expiry date of 30 November 2022.

The Group is mainly exposed to fluctuations in other currencies against the US dollar, in particular pounds sterling. The Group measures its market risk exposure by running various sensitivity analyses including assessing the impact of reasonably possible movements in key variables. The sensitivity analyses include only outstanding non-US dollar denominated monetary items and adjusts their translation at the period end for a 20% change in such non-

US dollar rates. As at 30 June 2022, a 10% increase in currency exchange rates against the functional currency of the Group's entities would have resulted in a decrease in profit before tax of $66 million, while a 10% decrease would have resulted in an increase of $66 million, with an equivalent impact on equity.

The Group cannot guarantee that its financial condition and results of operations will not be negatively affected by risks related to foreign currency movements. See paragraph 2.5 *(The Group is subject to currency exchange and inflation risks, which might adversely affect the Group's financial condition and results of operations.)* of Part 2 *(Risks Factors)*.

8.5 *Interest rate risk management*

Interest rate risk refers to the risk that market interest rates will increase, resulting in higher borrowing costs under the Group's credit facilities, all of which currently have floating interest rates. The Group manages interest rate risk using interest rate swaps from time to time. The below table represents the interest rate financial instruments in place at 30 June 2022:

Derivative	Term	Value	Rate
Interest rate swap: 3 month USD LIBOR	July 2022–December 2022	$50 million	0.219%
Interest rate swap: 1 month USD LIBOR	July 2022–December 2023	$150 million	0.398%

The Group may be affected by changes in market interest rates at the time it needs to refinance any of its indebtedness. See paragraph 2.4 (*Certain of the Group's outstanding borrowings will bear interest at floating rates which could rise significantly, thereby increasing the Group's interest cost and reducing cash flows*) of Part 2 (*Risk Factors*).

As at 30 June 2022, an increase of 500 basis points in interest rates, with all other variables held constant, would have resulted in a decrease of $3.9 million in profit before tax, with an equivalent impact on equity. A decrease in 500 basis points in interest rates would have the equal but opposite effect, on the basis that all other variables remain constant.

For a detailed description of credit, liquidity, foreign currency, commodity price and interest rate risk, see Note 28 to the historical financial information contained in Section A (*The Group*), Part B (*Consolidated Historical Financial Information of the Group*) of Part 16 (*Historical Financial Information*).

9. SIGNIFICANT ACCOUNTING POLICIES, JUDGEMENTS, AND ESTIMATION UNCERTAINTY

For a full description of the Group's significant accounting policies, judgements and estimation uncertainties, see Note 3 to the historical financial information contained in Section A (*The Group*), Part B (*Consolidated Historical Financial Information of the Group*) of Part 16 (*Historical Financial Information*).

This Part 12 (*Operating and Financial Review Relating to the Group)* discusses the Group's historical financial information, which have been prepared in accordance with IFRS. Accounting estimates are an integral part of the preparation of the financial statements and the financial reporting process and are based upon current judgments. The preparation of financial statements in conformity with IFRS requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. Certain accounting estimates are particularly sensitive because of their complexity and the possibility that future events affecting them may differ materially from the Group's current judgments and estimates. See paragraph 1.18 (*The Group's utilisation of tax losses and tax liability is based on forecasts and subject to estimation.*) of Part 2 (*Risk Factors*).

This listing of critical accounting policies is not intended to be a comprehensive list of all the Group's accounting policies. In many cases, the accounting treatment of a particular transaction is specifically dictated by IFRS, with no need for management's judgment regarding accounting policy. The Group have identified the following areas where significant judgement, estimates and assumptions are required.

9.1 ***Estimates in oil and gas reserves***

The business of the Group is to enhance hydrocarbon recovery and extend the useful lives of mature and underdeveloped assets and associated infrastructure in a profitable and responsible manner. Estimates of oil and gas reserves requires critical judgement, factors such as the availability of geological and engineering data, reservoir performance data, and drilling of new wells all impact on the determination of the Group's estimates of its oil and gas reserves and result in different future production profiles affecting prospectively the discounted cash flows used in impairment testing. These are based on an annual third party expert's view and these volumes are used in the calculations for impairment tests and accounting for depletion and decommissioning. Changes in estimates of oil and gas reserves resulting in different future production profiles will affect the discounted cash flows used in impairment testing, the anticipated date of decommissioning and the depletion charges in accordance with the unit of production method and the recoverability of deferred tax assets. For the purposes of depletion and decommissioning estimates, the Group uses proved and probable reserves and for the purposes of the impairment tests performed and deferredtax asset recoverability, the Group considers the same probable and proved reserves as well as risked resource volumes. These risking adjustments are reflective of the Group's progress of the overall field development and are reflective of a market participant view. See paragraph 5 (*Reserves and Resources Reporting*) of Part 3 (*Presentation of Financial and Other Information*).

9.2 ***Estimates in impairment of oil and gas assets and goodwill***

Determination of whether oil and gas assets or goodwill have suffered any impairment requires an estimation of the fair value less costs to dispose of the CGU to which oil and gas assets and goodwill have been allocated. When performing impairment tests of oil and gas assets, these can be considered on a pre or post tax basis. In respect of the fields where the associated deferred tax liability has been recognised as part of a business combination, this assessment is performed on a pre-tax basis and the associated deferred tax liability is included in the Group's goodwill impairment assessment. Where the associated deferred tax liability has been generated as a result of timing differences, this assessment is performed on a post-tax basis. This includes a review of previously impaired assets (excluding goodwill) for possible reversal of a previous impairment. The calculation requires the Group to estimate the future cash flows expected to arise from the CGU using discounted cash flow models comprising asset-by-asset life of field projections. Key assumptions and estimates in the impairment models relate to: commodity prices that are based on internal view of forward curve prices that are considered to be a best estimate of what a market participant would use; discount rates which reflect management's estimate of a market participant post tax weighted average cost of capital; and commercial reserves. As the production and related cash flows can be estimated from the Group's experience, management believes that the estimated cash flows expected to be generated over the life of each field is the appropriate basis upon which to assess goodwill and individual assets for impairment or an impairment reversal. Furthermore, there is also uncertainty due to climate change and the speed of the energy transition and the likely impact this will have on both oil and gas demand for forecast prices. The Group have considered climate adjusted price curves in their assessment of forecast commodity prices. For further details regarding the estimate value, inputs and assumptions please refer to Notes 14 and 17 to the historical financial information contained in Section A (*The Group*), Part B (*Consolidated Historical Financial Information of the Group*) of Part 16 (*Historical Financial Information*).

9.3 ***Decommissioning provision estimates***

Amounts used in recording a provision for decommissioning are estimates based on current legal and constructive requirements and current technology and price levels for the removal of facilities and plugging and abandoning of wells. Due to changes in relation to these items, the future actual cash outflows in relation to decommissioning are likely to differ in practice. To reflect the effects due to changes in legislation, requirements, technology and price levels, the carrying amounts of decommissioning provisions are reviewed on a regular basis. The effects of changes in estimates do not give rise to prior year adjustments and are dealt with prospectively. While the Group uses its best estimates and judgement, actual results could differ from these estimates. Expected timing of expenditure can also change, for example in response to changes in laws & regulations or their interpretation, and/or due to changes in commodity prices. For further details regarding the estimate value, inputs and assumptions please refer to Note 20 to the historical financial information contained in Section A (*The Group*), Part B (*Consolidated Historical Financial Information of the Group*) of Part 16 (*Historical Financial Information*).

9.4 ***Accounting for business combinations***

The Group has entered into a number of acquisitions and disposals during the periods presented. For further details of these acquisitions and disposals, see paragraph 3.6 (*Acquisitions and disposals*) of this Part 12 (*Operating and Financial Review Relating to the Group*) above.

The acquisition accounting for these transactions is set out in Note 3 to the historical financial information contained in Section A (*The Group*), Part B (*Consolidated Historical Financial Information of the Group*) of Part 16 (*Historical Financial Information*).

In completing the accounting for business combinations, management have been required to make estimates relating to the fair value of the assets and liabilities acquired. In particular, estimates have been made in assessing the valuation of tangible and intangible oil and gas assets, and decommissioning liabilities. The fair value of net assets acquired are primarily determined using discounted cashflow techniques using available data at the time of acquisition. For oil and gas assets, the Group estimates future cash flows from an assessment of economically recoverable reserves and discounts them to present value using a rate reflecting market assessments at the time value of money and risks specific to the asset. Determining the fair value of oil and gas assets requires the Group to apply long term assumptions of commodity prices.

In addition, in accounting for business combinations, the Group have been required to make assumptions in respect of the amount of losses brought forward which will be available to them to offset against future taxable profits of the Group. Specifically, in respect of the Marubeni Acquisition, assumptions have been made with regards to the group relief claims the seller is entitled to make relating to pre-completion periods which would reduce the losses available to the Group, and the quantum of such claims. The provisional deferred tax asset recognised by the Group assumes full utilisation of the losses held in MOGL and therefore a change in this assumption could result in a change in the deferred tax asset recognised on the balance sheet on acquisition, which would in turn change the value of the gain on bargain purchase recognised. Further, in assessing the value of deferred tax assets recognised in each period, the Group has made assumptions regarding future restructuring within the Group, and therefore a change in these assumptions could result in a change in the deferred tax asset recognised.

The Group assesses the fair value of decommissioning liabilities based on the expected timing, extent and amount of expenditure using data available at the time of acquisition. The ultimate decommissioning costs are uncertain and cost estimates can vary in response to many factors including changes to relevant legal requirements, the emergence of new restoration techniques or experience at production sites. The expected timing of expenditure can also change, and as a result there could be significant adjustments to the provisions which could affect future financial results.

9.5 ***Taxation judgements***

The Group's operations are subject to a number of specific tax rules which apply to exploration, development and production. In addition, the tax provision is prepared before the relevant companies have filed their tax returns with the relevant tax authorities and, significantly, before these have been agreed. As a result of these factors, the tax provision process necessarily involves the use of a number of estimates and judgements including those required in calculating the effective tax rate. The Group recognises deferred tax assets on unused tax losses where it is probable that future taxable profits will be available for utilisation. This requires management to make judgements and assumptions regarding the likelihood of future taxable profits and the amount of deferred tax that can be recognised. For further details regarding the estimate value, inputs and assumptions please refer to Note 27 to the historical financial information contained in Section A (*The Group*), Part B (*Consolidated Historical Financial Information of the Group*) of Part 16 (*Historical Financial Information*).

9.6 ***Climate change***

The Group recognises that there may be potential financial implications in the future from climate change risk. The Group expects that climate change policies, legislation and regulation will increase, and likely on accelerating timelines which, although will result in intended benefits, is likely to increase associated costs and administration requirements as well as potentially limiting the investment capital available to the industry. These in due course may well have an impact across a number of areas of accounting including impairment, fair values, increased costs, onerous contracts, contingent liabilities. However, as at 30 June 2022, the Group believes there is no material impact on balance sheet carrying values of assets or liabilities. Although this is an estimate, it is not considered a critical estimate, as management's view is that at the end of the current reporting period there is no significant risk of climate change resulting in a material adjustment to the carrying amounts of assets and liabilities, within the next financial year.

9.7 ***Capital contribution***

In 2019, the Group issued the Capital Note, which was interest free, to its immediate parent company, DKL Energy. The Capital Note was initially measured at fair value, which was estimated by discounting the cash flows payable at 14.7%, being the estimated rate that would have been payable on a similar instrument issued on normal commercial terms. Subsequent to initial recognition, the Capital Note was measured at amortised cost. The difference between the nominal and the fair value of the Capital Note was recorded as a capital contribution.

9.8 ***Recent accounting pronouncements***

Details of the recent accounting pronouncements applied to the Group are set out in Note 3 to the historical financial information contained in Section A (*The Group*), Part B (*Consolidated Historical Financial Information of the Group*) of Part 16 (*Historical Financial Information*).

9.9 ***Other provisions***

The Group is subject to various claims which arise in the ordinary course of its business. The Group assesses all such claims and, where applicable, make provisions for any settlements which it considers probable. Estimating the amount of such claims is inherently uncertain, given the unpredictability of dispute resolution processes and other factors.

PART 13

OPERATING AND FINANCIAL REVIEW RELATING TO THE SICCAR POINT GROUP

The following discussion and analysis is intended to assist in providing an understanding of Siccar Point's financial condition and results of operations as at and for the six month periods ended 30 June 2021 and 2022 and as at and for the years ended 31 December 2019, 2020 and 2021, which, except if stated otherwise, has been extracted without material adjustment from the historical financial information relating to the Siccar Point Group included in Section B (The Siccar Point Group), Part B (*Consolidated Historical Financial Information of the Siccar Point Group*) of Part 16 (*Historical Financial Information*).

Except where noted, the following discussion and analysis of financial condition and results of operation discusses periods prior to the completion of the Siccar Point Acquisition. Accordingly, the following discussion should be read in conjunction with the section entitled "Historical Financial Information Relating to the Siccar Point Group", "Unaudited Pro Forma Condensed Combined Financial Information," and "Operating and Financial Review Relating to the Group" as well as with the consolidated financial statements and the related notes thereto of the Company and the financial statements and the related notes thereto of the Siccar Point Group included elsewhere in this Prospectus. The following discussion includes forward-looking statements which, although based on assumptions that the Company considers reasonable, are subject to risks and uncertainties which could cause actual events or conditions to differ from those expressed or implied by the forward-looking statements. For a discussion of some of those risks and uncertainties, please refer to Part 2 (*Risk Factors*) *and paragraph 13 (Information Regarding Forward-looking Statements) of Part 3* (*Presentation of Financial and Other Information*).

1. OVERVIEW

On 7 April 2022, IEEPL (as guarantor), IEUK and the Siccar Point Seller entered into the Siccar Point Acquisition Agreement, pursuant to which, among other things, IEUK agreed to acquire all of the issued share capital of SPEHL and certain loan notes issued by SPEFL from the Siccar Point Seller. The Siccar Point Acquisition completed on 30 June 2022. By way of the Siccar Point Acquisition, IEUK acquired SPEHL's entire interest in the Siccar Point Assets.

2. SIGNIFICANT FACTORS AFFECTING THE SICCAR POINT GROUP'S RESULTS OF OPERATIONS

The Board considers certain of the significant factors affecting the Siccar Point Group's historical results of operations are comparable to those affecting the Group's results of operations. See paragraph 3.1 (*Price of oil and gas*), paragraph 3.3 (*Reserves*), paragraph 3.4 (*Taxation*), paragraph 3.8 (*Exploration and appraisal success and exploration costs written off or impaired*), and paragraph 3.5 (*Development and production success and impairment*) of Part 12 (*Operating and Financial Review Relating to the Group)*. Set out below is a summary of certain other factors that the Board believes to have affected the Siccar Point Group's operations and financial results during the periods under review. Factors other than those presented below could also have had a significant impact on the Siccar Point Group's results of operations.

2.1 *Production Volumes*

In addition to oil and gas prices, production volumes are a primary revenue driver. The Siccar Point Group's production levels also affect the level of its reserves and depreciation, depletion and amortisation.

The following table sets forth information on the Siccar Point Group's historical oil and gas production for the years ended 31 December 2019, 2020 and 2021:

(BOEPD net to the Siccar Point Group)	Year ended 31 December			Six months ended 30 June	
	2019	2020	2021	2021	2022
Schiehallion	8,809	7,369	5,579	5,814	5,052
Mariner	663	2,060	2,717	3,090	2,160
Jade	459	524	390	402	1,004
Total average daily production for the period	9,931	9,953	8,686	9,306	8,216

2.2 ***Derivative financial instruments***

The Siccar Point Group has used derivative financial instruments as economic hedges to reduce certain exposures to commodity price risk, cash flow interest rate risk and foreign currency exchange risk. These include commodity hedging, forward currency contracts and interest rate swaps. From completion of the Siccar Point Acquisition, all of the Siccar Point Group's hedging arrangements have either been terminated or novated out of the Siccar Point Group and the Group's hedging policies have applied.

3. DESCRIPTION OF KEY LINE ITEMS

3.1 ***Revenue***

The sale of crude oil, gas or condensate represents a single performance obligation, being the sale of barrels equivalent on collection of a cargo or on delivery of commodity into an infrastructure. Revenue is accordingly recognised for this performance obligation when control over the corresponding commodity is transferred to the customer. Revenue is measured at the fair value of the consideration received or receivable and represents amounts receivable for products in the normal course of business, net of discounts, customs duties and sales taxes.

Tariff income is recognised as the underlying commodity is shipped through the pipeline network based on established tariff rates.

3.2 ***Cost of sales***

Includes operating costs, movement in oil and gas inventory and depletion, depreciation and amortisation.

3.3 ***Impairment (charge) / reversal***

At each balance sheet date, the Group reviews the carrying amounts of its investments and its oil and gas assets to assess whether there is an indication that those assets may be impaired. If any such indication exists, the Group makes an estimate of the asset's recoverable amount. An asset's recoverable amount is the higher of an asset's fair value less costs to sell and its value in use, where the value in use is determined from estimated future net cash flows.

If the recoverable amount of an asset is estimated to be less than its carrying amount, the carrying amount of the asset is reduced to its recoverable amount and the Group recognises a non-cash impairment loss.

Where an impairment loss subsequently reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but only so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognised for the asset in prior years.

3.4 ***General and administrative expenses***

General and administrative expenses are comprised of office staff costs and other general and administration costs net of the recharge of costs to joint venture partners. With respect to certain of the Siccar Point Group's operated assets, the Siccar Point Group's joint venture partnership agreements allow it to charge time writing based expenses on a no gain/no loss basis.

3.5 ***Other gains and losses***

Other gains and losses comprise loss/gain on financial instruments which includes gains and losses from hedges, which historically has included Brent swaps and zero cost collars, gas swaps, foreign exchange forward contracts, interest rate swaps and net finance costs.

3.6 ***Net finance costs***

Net finance cost includes bank interest, interest on listed loan notes, interest on third-party loans and bonds and other finance costs and fees.

3.7 ***Income tax***

Income tax expense represents the sum of current tax and deferred tax.

Current income tax

Current income tax assets and liabilities are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amounts are those that are enacted or substantively enacted by the reporting date.

Deferred income tax

Deferred tax is recognised for all deductible temporary differences and the carry-forward of unused tax losses. Deferred tax assets and liabilities are measured using enacted or substantively enacted income tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in rates is included in earnings in the period of the enactment date. Deferred tax assets are recorded in the consolidated financial information if realisation is considered more likely than not.

Deferred tax assets and liabilities are offset only when a legally enforceable right of offset exists, and the deferred tax assets and liabilities arose in the same tax jurisdiction.

4. **RESULTS OF OPERATIONS**

The following table sets forth certain of the Siccar Point Group's historical revenue and expense items for each of the years ended 31 December 2019, 2020 and 2021 and the six months ended 30 June 2021 and 2022:

	Year ended 31 December			**Six months ended 30 June**	
(in millions of $)	**2019**	**2020**	**2021**	**2021**	**2022**
				(unaudited)	
Revenue	223.8	142.3	234.6	107.3	153.2
Cost of sales	(150.6)	(128.2)	(137.8)	(65.3)	(72.7)
Gross profit	73.2	14.1	96.8	42.0	80.5
Impairment (charge) / reversal	(99.9)	(304.4)	358.6	—	(191.5)
Exploration and evaluation expenses	(4.3)	(3.4)	(3.9)	(2.4)	(1.9)
General and administrative expenses	(13.0)	(12.0)	(13.5)	(7.2)	(11.6)
Other gains and losses	(17.8)	94.1	(120.5)	(67.7)	(34.3)
Profit / (loss) from operations before tax and finance costs	**(61.8)**	**(211.6)**	**317.5**	**(35.3)**	**(158.9)**
Net finance costs	(114.7)	(119.1)	(120.7)	(65.3)	(58.4)
Profit / (loss) before tax	(176.5)	(330.6)	196.8	(100.5)	(217.3)
Income tax	149.4	157.4	(345.0)	—	470.7
Profit / (loss) after tax	**(27.1)**	**(173.2)**	**(148.2)**	**(100.5)**	**253.4**

Comparison of results of operations for the six months ended 30 June 2021 and 2022

Revenue

Revenue increased by $45.9 million, or 42.8%, to $153.2 million for the six months ended 30 June 2022 from $107.3 million for the six months ended 30 June 2021. This was primarily due to revenues from oil sales increasing from $102.8 million for the six months ended 30 June 2021 to $132.3 million for the six months ended 30 June 2022, as well as an increase in gas sales from $4.0 million for the six months ended 30 June 2021 to $19.0 million for the six months ended 30 June 2022. The average realised oil price increased by $46.8/BBL, or 71%, to $112.73/BBL for the six months ended 30 June 2022 from $65.93/BBL for the six months ended 30 June 2021, in line with relatively similar Brent crude oil price for the comparative period. The average realised gas price for the six months ended 30 June 2022 was 190 pence/therm, which was an increase of 141 pence/therm from 49 pence/therm in the comparable period in 2021.

Cost of sales

Cost of sales increased by $7.4 million, or 11.3%, to $72.7 million for the six months ended 30 June 2022 from $65.3 million, primarily as a result of an increase of $13.1 million in expenses related to depletion, depreciation and amortisation, which was primarily driven by a reduction in the Group's assumption of future recoverable reserves as at 30 June 2022.

Gross profit

As a result of the foregoing, gross profit increased by $38.5 million, or 91.7%, to $80.5 million for the six months ended 30 June 2022 from $42.0 million for the six months ended 30 June 2021.

Impairment (charge) / reversal

The impairment charge of $191.5 million for the six months ended 30 June 2022 was a pre-tax impairment charge to property, plant and equipment relating to the Schiehallion and Mariner fields. This was largely driven by a reduction in reserves in the Siccar Point Group's assumption of future recoverable reserves based on the reports prepared by independent reserves auditors as at 30 June 2022.

General and administrative expenses

General and administrative expenses increased by $4.4 million, or 60.6%, to $11.6 million for the six months ended 30 June 2022 from $7.2 million for the six months ended 30 June 2021. This was primarily due to accrued transaction bonuses linked to the Siccar Point Acquisition amounting to $5.0 million for the six months ended 30 June 2022.

Other gains and losses

Other gains and losses amounted to $34.3 million for the six months ended 30 June 2022, compared to $67.7 million in the six months ended 30 June 2021. The key driver of the movement between the periods was a decrease in losses on financial instruments to $35.4 million in the six months ended 30 June 2022, compared to $69.2 million in the six months ended 30 June 2021, driven primarily by a loss of $47.1 million from Brent swaps and zero cost collars for the six months ended 30 June 2022, compared to a gain of $16.2 million for the six months ended 30 June 2021, as well as an increase in losses from foreign exchange forward contracts from $0.1 million for the six months ended 30 June 2021 to $15.3 million for the six months ended 30 June 2022 and an increase in losses from interest rate swaps from $1.2 million for the six months ended 30 June 2021 to $1.4 million for the six months ended 30 June 2022. This was partially offset by an increase in gains from gas swaps to $28.3 million for the six months ended 30 June 2022, compared with $1.1 million for the six months ended 30 June 2021.

Net finance costs

Net finance costs amounted to $58.4 million for the six months ended 30 June 2022, compared to $65.3 million for the six months ended 30 June 2021. This decrease in costs was primarily attributed to a decrease in other fees from $12.0 million for the six months ended 30 June 2021 to $2.1 million for the six months ended 30 June 2022, due to finance costs of $5.8 million incurred in March 2021 relating to the issuance of a $200 million senior unsecured bond, the proceeds of which were applied in early repayment of all amounts outstanding under a $200 million bond maturing on 31 January 2023. This was partially offset by a negative impact from a put option on bonds amounting to $1.7 million for the six months ended 30 June 2022, compared to nil for the six months ended 30 June 2021.

Income tax

Income tax was a credit of $470.7 million for the six months ended 30 June 2022. After becoming part of the Group, tax losses of Siccar Point Group were available to be set against the future taxable income of the Group. Hence, an additional deferred tax asset of $470.7 million was credited in six months ended 30 June 2022.

Comparison of results of operations for the years ended 31 December 2021 and 2020

Revenue

Revenue increased by $92.3 million, or 64.9%, to $234.6 million for the year ended 31 December 2021 from $142.3 million for the year ended 31 December 2020. This was primarily due to revenues from oil sales increasing from $137.7 million for the year ended 31 December 2020 to $218.6 million for the year ended 31 December 2021, as well as an increase in revenues from gas sales from $3.9 million for the year ended 31 December 2020 to $15.0 million for the year ended 31 December 2021.

Cost of sales

Cost of sales remained relatively flat at $137.8 million for the year ended 31 December 2021, compared to $128.2 million for the year ended 31 December 2020, an increase of 7.5%. This is mainly due to a decrease of $14.4 million in depletion, depreciation and amortisation for the year ended 31 December 2021, offset by a $6.6 million increase in movement oil and gas inventory charge (net overlift position as at 31 December 2021 increased by 184kbbls compared to 31 December 2020). A lower depreciation charge on Schiehallion and Jade for the year ended 31 December 2021 of $28 million was due to 24% lower production compared to the year ended 31 December 2020, offset by an increased depreciation charge on Mariner of $14 million due to higher production of 35% in the year ended 31 December 2021 compared to the year ended 31 December 2020.

Gross profit

As a result of the foregoing, gross profit increased by $82.7 million, or 585.1%, to $96.8 million for the year ended 31 December 2021, from $14.1 million for the year ended 31 December 2020.

Impairment (charge) / reversal

The reversal of impairment of production assets amounting to $358.6 million in the year ended 31 December 2021 was due to a non-cash pre-tax impairment reversal of property, plant and equipment relating to the Schiehallion field. This was largely driven by an increase in the reserve volumes and improvement in the Siccar Point Group's assumption of future commodity prices. The recoverable amount exceeded the net book value of the asset.

General and administrative expenses

General and administrative expenses increased slightly by $1.5 million, or 12.9%, to $13.5 million for the year ended 31 December 2021 from $12.0 million for the year ended 31 December 2020. This was primarily due to an increase in personnel, insurance and IT expenses by $1 million for the six months ended 30 June 2021.

Other gains and losses

Other gains and losses amounted to $120.5 million for the year ended 31 December 2021, compared to profit of $94.1 million for the year ended 31 December 2020. This was primarily due to a loss on financial instruments amounting to $122.3 million for the year ended 31 December 2021, compared to a gain on financial instruments amounting to $93.7 million for the year ended 31 December 2020. The key drivers of the movement in realised hedges between 2020 and 2021 were a loss of $1.3 million from Brent swaps and zero cost collars for the year ended 31 December 2021, compared to a gain of $73.8 million from Brent swaps and zero cost collars for the year ended 31 December 2020, as well as a loss of $2.2 million from gas swaps in 2021, compared with a gain of $7.1 million from gas swaps in 2020.

Net finance costs

Net finance costs increased by $1.6 million, or 1.4%, from $119.1 million for the year ended 31 December 2020 to $120.7 million for the year ended 31 December 2021. This was primarily due to an increase in other fees to $14.1 million for the year ended 31 December 2021 compared to $2.7 million for the year ended 31 December 2020, which was partially offset by a decrease in interest on third-party loan and bonds in to $26.6 million for the year ended 31 December 2021 compared to $36.8 million for the year ended 31 December 2020.

Income tax

Income tax was a charge of $345.0 million for the year ended 31 December 2021, compared with a credit of $157.4 million for the year ended 31 December 2020. This movement was primarily due to a reduction in the deferred tax asset recognised due to the reclassification of Cambo as 2C resources (included in 2P reserves as at 31 December 2020). The Siccar Point Group used 2P reserves as the basis for recognition of deferred tax assets until December 2021.

Comparison of results of operations for the years ended 31 December 2020 and 2019

Revenue

Revenue decreased by $81.4 million, or 36.4%, to $142.3 million for the year ended 31 December 2020 from $223.8 million for the year ended 31 December 2019. This was mainly due to commodity prices, with revenues from oil sales decreasing from $215.5 million for the year ended 31 December 2019 to $137.7 million for the year ended 31 December 2020, as well as a decrease in revenues from gas sales from $7.3 million for the year ended 31 December 2019 to $3.9 million for the year ended 31 December 2020.

Cost of sales

Cost of sales decreased by $22.4 million, or 14.9%, to $128.2 million for the year ended 31 December 2020 from $150.6 million for the year ended 31 December 2019. This was primarily due to a decrease in depletion, depreciation and amortisation of $24.9 million, or 23.5%, to $80.9 million for the year ended 31 December 2020, compared to $105.8 million for the year ended 31 December 2019. The decrease in depletion, depreciation and amortisation was the result of a $35 million lower depreciation charge on the Schiehallion field in the year ended 31 December 2020. This was offset by an increased depreciation charge on the Mariner field of $10.5 million for the year ended 31 December 2020.

Gross profit

As a result of the foregoing, gross profit decreased by $59.1 million, or 80.7%, to $14.1 million for the year ended 31 December 2020, compared to $73.2 million for the year ended 31 December 2019.

Impairment (charge) / reversal

The impairment charges of $304.4 million and $99.9 million in the years ended 31 December 2020 and 2019, respectively, were due to a pre-tax impairment charge of property, plant and equipment relating to the Schiehallion field. This was largely driven by a reduction in the Siccar Point Group's assumption of future commodity prices.

General and administrative expenses

General and administrative expenses decreased by $1.0 million, or 7.5%, to $12.0 million for the year ended 31 December 2020 from $13.0 million for the year ended 31 December 2019. This was mainly due to higher time writing on projects in the year ended 31 December 2020 compared to the year ended 31 December 2019, which resulted in a $1.0 million higher allocation to projects and less to general and administrative expenses.

Other gains and (losses)

Other gains amounted to $94.1 million for the year ended 31 December 2020, compared to a loss of $17.8 million for the year ended 31 December 2019. The key driver of the movement between 2019 and 2020 was a gain on financial instruments amounting to $93.7 million in the year ended 31 December 2020, compared to a loss amounting to $18.4 million in the year ended 31 December 2019, driven primarily by a gain of $73.8 million from Brent swaps and zero cost collars in the year ended 31 December 2020, compared to a loss of $13.7 million in the year ended 31 December 2019, as well as a gain of $7.1 million from gas swaps in 2020, compared with a gain of $3.7 million from gas swaps in 2019.

Net finance costs

Net finance costs increased by $4.4 million, or 3.8%, to $119.1 million for the year ended 31 December 2020 from $114.7 million for the year ended 31 December 2019. This was primarily due to an increase in the impact of substantial third-party loan modification amounting to $7.2 million for the year ended 31 December 2020, compared to $2.5 million for the year ended 31 December 2019 relating to an extension in December 2020 of a reserve-based lending facility from its previous maturity date of 2025 to 2027, as well as from an increase in interest on listed loan notes and other finance costs from $65.6 million for the year ended 31 December 2019 to $71.0 million for the year ended 31 December 2020.

Income tax

Income tax was a credit of $157.4 million for the year ended 31 December 2020, compared with a $149.4 million credit for the year ended 31 December 2019. This movement was primarily due to an increase deferred tax in the year ended 31 December 2020.

5. LIQUIDITY AND CAPITAL RESOURCES

5.1 *Cash flow statement*

The following table sets forth the Siccar Point Group's consolidated cash flow information for the year ended 31 December 2019, 2020 and 2021 and the six month periods ended 30 June 2021 and 2022:

(in millions of $)	**Year ended 31 December**			**Six months ended 30 June**	
	2019	**2020**	**2021**	**2021**	**2022**
				(unaudited)	
Operating activities:					
Profit / (loss) before tax	(176.5)	(330.6)	196.8	(100.5)	(217.3)
Adjustments for:					
Finance expense (interest on listed loan notes) and other finance costs	65.6	71.0	76.8	38.1	38.5
Finance expense (interest on RBL and bonds)	44.9	36.8	26.6	13.8	14.3
Depletion, depreciation and amortisation	105.8	80.9	66.5	34.7	47.8
Impairment charge / (reversal)	99.9	304.4	(358.6)	—	191.5
Accretion	3.0	3.3	3.6	1.8	1.8
Decommissioning changes in estimate	1.5	(0.2)	0.3	0	(1.3)
Decommissioning provision utilised	(2.3)	—	(1.1)	—	0

(in millions of $)	Year ended 31 December 2019	2020	2021	Six months ended 30 June 2021 (unaudited)	2022
Impact of substantial modification on third party loan	2.5	4.2	—	—	—
Recognition of put option on bonds	—	—	—	—	1.7
Loss / (gain) on derivative financial instruments	9.8	(15.7)	116.2	85.2	(19.5)
Amortisation of bank arrangement fee	0.7	0.4	(0.3)	(0.4)	0.5
Depreciation of office equipment	0	0.1	0.1	—	0
Depreciation of right of use assets	0.2	0.2	0.2	0.1	0
Unrealised net foreign exchange differences	(1.4)	0.9	0.2	(0.7)	(1.3)
Cash flow from operations	**153.8**	**155.6**	**127.3**	**72.1**	**56.8**
Changes in inventory, receivables and payables relating to operating activities	(1.7)	(11.5)	18.6	(2.2)	(9.4)
Corporation tax receipts	2.9	—	—	—	—
Net cash from operating activities	**154.9**	**144.0**	**145.9**	**70.0**	**47.4**
Investing activities:					
Purchase of office equipment	(0.1)	(0.1)	(0)	—	—
Expenditure on development and production assets	(36.7)	(50.8)	(26.4)	(12.0)	(14.3)
Expenditure on exploration and evaluation assets	(43.9)	(31.7)	(60.1)	(23.5)	(12.9)
Net cash used in investing activities	**(80.8)**	**(82.6)**	**(86.6)**	**(35.6)**	**(27.2)**
Financing activities:					
Proceeds from bonds issuance (net of charges)	99.3	—	198.0	198.0	—
Repayment of bonds	—	—	(200.0)	(200.0)	—
Proceeds from borrowings	—	—	—	—	35.0
Repayment of borrowing—third-party (net)	—	(135.0)	(144.0)	(144.0)	—
Interest paid on long-term loans	(47.0)	(37.9)	(27.9)	(14.8)	(14.4)
Net cash flows from / (used in) financing activities	**52.4**	**(172.8)**	**(173.9)**	**(160.8)**	**20.6**
Currency translations differences relating to cash	1.5	(0.6)	(0.3)	0.2	(1.2)
Increase / (decrease) in cash and cash equivalents	128.0	(111.9)	(114.8)	(126.2)	39.6
Cash and cash equivalents at 1 January	147.7	275.7	163.8	163.8	49.0
Cash and cash equivalents, end of period	**275.7**	**163.8**	**49.0**	**37.6**	**88.6**
Non-cash disclosure:					
Repayment of borrowing—third-party	—	—	—	—	(277.0)
Settlements of derivative financial instruments	—	—	—	—	(45.2)
Interest and other finance costs on long-term loans	—	—	—	—	(0.9)
Amounts due to parent	—	—	—	—	323.1
Net non-cash flows used in investing activities	—	—	—	—	—

The above reconciliation outlines payments made by IEUK on behalf of on the Siccar Point Group as part of the completion mechanism of the acquisition of the Siccar Point Group, completed on 30 June 2022. This mainly represents the mandatory repayment of Siccar Point Energy RBL revolving bank loan of $277.0 million due to a change of control and the early termination of hedges amounting to $45.0 million, which could not be novated to the Group as per mutual agreement with counterparties. Amount due to IEUK of $323.0 million is payable on demand.

Net cash from operating activities

Net cash from operating activities was $47.4 million for the six months ended 30 June 2022, compared to $70.0 million for the six months ended 30 June 2021. This change is primarily due to an impairment charge of $191.5 million for the six months ended 30 June 2022, compared to nil for the six months ended 30 June 2021, which was partially offset by an increase in loss before tax to $217.3 million for the six months ended 30 June 2022, from $100.5 million for the six months ended 30 June 2021.

Net cash from operating activities was $145.9 million for the year ended 31 December 2021, compared to $144.0 million for the year ended 31 December 2020. This change is primarily due to a profit before tax of $196.8 million for the year ended 31 December 2021, compared to a loss before tax of $330.6 million for the year ended 31 December 2020, which was partially offset by an impairment reversal of $358.6 million for the year, compared to an impairment charge of $304.4 million for the year ended 31 December 2020.

Net cash from operating activities was $144.0 million for the year ended 31 December 2020, compared to $154.9 million for the year ended 31 December 2019. This change is primarily due to increased losses before tax from continuing operations of $330.6 million for the year ended 31 December 2020, compared to $176.5 million for the year ended 31 December 2019.

Net cash used in investing activities

Net cash used in investing activities was $27.2 million for the six months ended 30 June 2022, compared to $35.6 million for the six months ended 30 June 2021. This change is primarily due to a decrease in expenditure on exploration and evaluation assets from $23.5 million for the six months ended 30 June 2021 to $12.9 million for the six months ended 30 June 2022, which was partially offset by an increase in expenditure on development and production assets from $12.0 million for the six months ended 30 June 2021 to $14.3 million for the six months ended 30 June 2022.

The above reconciliation under non-cash disclosure for the six months ended 30 June 2022 outlines net non-cash flows used in investing activities relating to payments made by IEUK on behalf of the Siccar Point Group as part of the completion mechanism of the Siccar Point Acquisition. This mainly represents the mandatory repayment of Siccar Point's existing revolving bank loan of $277.0 million due to a change of control and the early termination of hedges amounting to $45.0 million, which could not be novated to the Group. Amount due to IEUK of $323.0 million is payable on demand.

Net cash used in investing activities was $86.6 million for the year ended 31 December 2021, compared to $82.6 million for the year ended 31 December 2020. This change is primarily due to an increase in expenditure on exploration and evaluation assets from $31.7 million for the year ended 31 December 2020 to $60.1 million for the year ended 31 December 2021, which was partially offset by a decrease in expenditure on development and production assets from $50.8 million for the year ended 31 December 2020 to $26.4 million for the year ended 31 December 2021.

Net cash used in investing activities was $82.6 million for the year ended 31 December 2020, compared to $80.8 million for the year ended 31 December 2019. This change is primarily due to an increase in expenditure on development and production assets from $36.7 million for the year ended 31 December 2019 to $50.8 million for the year ended 31 December 2020, partially offset by a decrease in expenditure on exploration and evaluation assets from $43.9 million for the year ended 31 December 2019 to $31.7 million for the year ended 31 December 2020.

Net cash flows from / (used in) financing activities

Net cash from financing activities was $20.6 million for the six months ended 30 June 2022, compared to net cash used in financing activities of $160.8 million for the six months ended 30 June 2021. This change is primarily due to repayment of borrowing in the amount of $144.0 million in the six months ended 30 June 2021, which was not repeated in the six months ended 30 June 2022.

Net cash used in financing activities was $173.9 million for the year ended 31 December 2021, compared to $172.8 million for the year ended 31 December 2020.

Net cash used in financing activities was $172.8 million for the year ended 31 December 2020, compared to net cash from financing activities amounting to $52.4 million for the year ended 31 December 2019. This change is primarily due to proceeds received from bond issuance (net of charges) of $99.3 million in the year ended 31 December 2019, which was not repeated in the year ended 31 December 2020, as well as a repayment of third-party borrowings amounting to $135.0 million in the year ended 31 December 2020.

6. **SIGNIFICANT ACCOUNTING JUDGEMENTS, ESTIMATES AND ASSUMPTIONS**

This "*Operating and Financial Review Relating to the Siccar Point Group*" discusses the consolidated financial statements of the Siccar Point Group, which have been prepared in accordance with IFRS as adopted by the United Kingdom. Accounting estimates are an integral part of the preparation of the financial statements and the financial reporting process and are based upon current judgments. The preparation of financial statements in conformity requires management to make judgements, estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. Uncertainty about these assumptions and estimates could result in outcomes that could require a material adjustment to the carrying amount of the asset or liabilities affected in future periods. For a full discussion of the most significant accounting judgements, estimates and assumptions, see Note 3 of the financial statements and the related notes thereto of the Siccar Point Group included in Section B (*The Siccar Point Group*), Part B (*Consolidated Historical Financial Information of the Siccar Point Group*) of Part 16 (*Historical Financial Information*).

PART 14

CAPITALISATION AND INDEBTEDNESS

The tables below set out the Group's total capitalisation and indebtedness as at 31 August 2022. The capitalisation and indebtedness information as at 31 August 2022 is unaudited and has been extracted without material adjustment from the Group's internal accounting records. Investors should read this table together with Part 16 (*Historical Financial Information*) and Part 12 (*Operating and Financial Review Relating to the Group*).

Capitalisation and Indebtedness

The table below sets out the Group's total capitalisation and indebtedness as at 31 August 2022.

	As at 31 August 2022 (in millions of $)
Current debt	
Guaranteed[(1)]	33.6
Secured	—
Unguaranteed / unsecured[(2)]	455.0
Total current debt	**488.6**
Non-current debt	
Guaranteed[(3)]	625.0
Secured[(4)]	650.0
Unguaranteed / unsecured	—
Total non-current debt	**1,275.0**
Total indebtedness	**1,763.6**
Shareholders' equity	
Share capital[(5)]	0.0
Share premium	634.7
Capital contribution reserve	114.0
Hedging reserve	(574.3)
Total shareholders' equity[(6)]	**174.4**

(1) Current guaranteed debt includes the principal outstanding under the Siccar Point Bonds (which are guaranteed by SPEL and certain other of its subsidiaries).

(2) Current unguaranteed / unsecured debt includes (i) the principal in the amount of $392.0 million outstanding in respect of the intragroup Capital Note, and (ii) principal in the amount of $63.0 million outstanding in respect of the intragroup Tracker Loan (the Group repaid $120.0 million under the Tracker Loan in the year ended 2020 and $15.0 million in the year ended 2021).

(3) Non-current guaranteed debt includes the principal outstanding under the 2026 Notes (which are guaranteed by IEEPL and those of IEEPL's subsidiary undertakings that are guarantors under the RBL Facility Agreement).

(4) Non-current secured debt includes the principal outstanding under the RBL Facility (which is secured by substantially all of the assets of the guarantor members of the Group, such security including share pledges, floating charges and/or debentures) available until 31 May 2026.

(5) Share capital was $1,000.

(6) Total shareholders' equity does not include retained earnings.

Indebtedness

The table below sets out the Group's total net financial indebtedness as at 31 August 2022.

		As at 31 August 2022 (in millions of $)
A	Cash[1]	40.9
B	Cash equivalents	—
C	Other Current Financial Assets	—
D	**Liquidity (A+B+C)**	**40.9**
E	Current bank debt	—
F	Current bonds issued[2]	33.6
G	Current portion of non-current debt	—
H	Other current financial debt[3]	455.0
I	**Current financial indebtedness (E)+(F)+(G)+(H)**	**488.6**
J	**Net current financial indebtedness (I)—(D)**	**447.7**
		—
K	Non-current bank loans[4]	650.0
L	Non-current bonds issued[5]	625.0
M	Other non-current debt	—
N	**Non-current financial indebtedness (K)+(L)+(M)**	**1,275.0**
O	**Net financial indebtedness (J)+(N)[6]**	**1,722.7**

(1) Cash includes $15.0 million of restricted cash per the requirements of the Siccar Point Bonds.

(2) Current bonds issued include the principal outstanding under the Siccar Point Bonds (which are guaranteed by SPEL and certain other of its subsidiaries).

(3) Other current financial debt includes (i) the principal in the amount of $392.0 million outstanding in respect of the intragroup Capital Note, and (ii) principal in the amount of $63.0 million outstanding in respect of the intragroup Tracker Loan (the Group repaid $120.0 million under the Tracker Loan in the year ended 2020 and $15.0 million in the year ended 2021).

(4) Non-current bank loans includes the principal outstanding under the RBL Facility (which is secured by substantially all of the assets of the guarantor members of the Group, such security including share pledges, floating charges and/or debentures) available until 31 May 2026.

(5) Non-current bonds issued include the principal outstanding under the 2026 Notes (which are guaranteed by IEEPL and those of IEEPL's subsidiary undertakings that are guarantors under the RBL Facility Agreement).

(6) The Group's letter of credit facilities in respect of future decommissioning obligations are excluded from the indebtedness table above.

On 30 June 2022, in connection with the Siccar Point Acquisition, the Group acquired the $200.0 million Siccar Point Bonds. Following completion of the Siccar Point Acquisition, Siccar Point issued a put option notice to Nordic Trustee AS at a premium of 1%. Bondholders holding Siccar Point Bonds totalling $166.4 million elected to exercise the put provision and require repayment. The repayment was settled on 1 August 2022. Subsequently, on 22 September 2022, Siccar Point Bonds totalling $25.6 million were redeemed at a premium of 6% on behalf of SPEB. On 12 October 2022, the remaining Siccar Point Bonds totalling $8 million were redeemed at the make whole amount of 105.4%.

On 4 October 2022, the Group repaid in aggregate $28.9 million in accrued and outstanding interest, together with $0.6 million in costs payable, under the Subordinated Delek Loan, thereby retiring the loan.

On 30 August 2022, the Company repaid in aggregate $100.0 million of the principal outstanding and the RBL Facility, thereby reducing the principal outstanding to $650.0 million.

Immediately following Admission, the Company will use the net proceeds of the issue of the Offer Shares pursuant to the Global Offering to repay $77.3 million of outstanding principal and accrued interest under the Tracker Loan and $214 million of the Capital Note. DKL Energy has agreed to waive all remaining amounts (if any) outstanding under each of the Capital Note and Tracker Loan.

The Group has contingent liabilities in the form of contingent and deferred consideration. As at 31 August 2022, the Group's current contingent and deferred consideration liabilities amounting to $55.6 million, in connection with the GSA Acquisition, Marubeni Acquisition and Siccar Point Acquisition, and non-current liabilities amounting to $280.9 million mainly in connection with the Marubeni Acquisition and Siccar Point Acquisition.

PART 15

PROFIT FORECASTS

1. CURRENT YEAR PROFIT FORECAST

In the Delek Group Q1 Announcement, the Delek Group made the following EBITDAX forecast for the Company in relation to the current financial year:

"To Ithaca's estimation, subject to the closing of the transaction, considering its production quantities and forecast oil and gas prices, Ithaca's EBITDAX in 2022 is expected to reach a sum of approx. $2 billion."

As at the date of this Prospectus, the Directors have replaced the guidance as a result of their current view on production quantities for the remainder of the year together with the ongoing volatility in oil and gas prices and their current expectation for the year ending 31 December 2022, is that Adjusted EBITDAX of Ithaca Energy is expected to be between $1.7 billion to $2.3 billion.

The statement that the Company is expected to reach an Adjusted EBITDAX for the financial year ended 31 December 2022 constitutes a profit forecast for the purpose of the Prospectus Regulation Rules (the "**Current Year Profit Forecast**").

The Directors confirm that the Current Year Profit Forecast is valid as at the date of this document.

1.1 *Basis of preparation*

The Current Year Profit Forecast has been properly compiled on the basis of the assumptions stated below and on a basis consistent with the accounting policies used in Ithaca Energy's Historical Financial Information for the three years ended 31 December 2021 and the six months ended 30 June 2022, which are prepared in accordance with IFRS and which are those expected by Ithaca Energy to be applicable for the year ending 31 December 2022.

The Directors prepared the Current Year Profit Forecast on the basis of: (i) the audited interim financial statements of Ithaca Energy for the six months ended 30 June 2022; (ii) the unaudited income statement to Adjusted EBITDAX of Ithaca Energy for the six months ended 30 June 2022; and (iii) the projected financial performance of Ithaca Energy for the remaining six months of the year ending 31 December 2022.

"**Adjusted EBITDAX**", as used in the Current Year Profit Forecast, consists of profit for the period before income tax, net finance costs, put premiums on oil derivative instruments, put premiums on gas derivative instruments, revaluation of forex forward contracts, revaluation of commodity hedges, depletion, depreciation and amortisation, impairment (charge) / reversal, exploration and evaluation expenses, fair value gain / (losses) on contingent consideration, gain on bargain purchase, transaction costs and employee voluntary redundancy programme. Transaction costs and employee voluntary redundancy programme include costs that are not considered to be representative of underlying operations.

The Current Year Profit Forecast is expressed in terms of Adjusted EBITDAX rather than profit / (loss) after tax, as the Directors believe this metric is more useful to investors for the following reasons: (i) it is used by management for planning and internal reporting purposes; and (ii) it is in line with peer companies and expectations of the investor community, supporting easier comparison of Ithaca Energy's performance with its peers.

1.2 *Assumptions*

The principal assumptions on which the Current Year Profit Forecast was based, which are outside the influence or control of the Directors are:

- there will be no material change to the existing prevailing macroeconomic or political conditions in the regions in which the Group operates, including the global governmental responses to COVID-19 being materially in line with the level assumed in the Current Year Profit Forecast;

- there will be no material change to the range of oil and gas prices realised by the Group currently assumed in the Current Year Profit Forecast;
- there will be no material change to the range of production volumes delivered across the Group's portfolio of oil and gas assets currently assumed in the Current Year Profit Forecast;
- there will be no material change to the tariffs received relating to third party usage of the Group's owned infrastructure;
- there will be no counterparty default in relation to the hedging contracts that the Group has entered into;
- there will be no deterioration in the Group's customer relationships, contractual terms and no customer default which is material in the context of the Group;
- there will be no material unplanned operating expenditure related to oil and gas infrastructure and assets of the Group;
- there will be no material movements in foreign currency exchange rates compared with the range of foreign currency exchange rates assumed in the Current Year Profit Forecast;
- there will be no material change in legislation or regulatory requirements that impact the Group's operations or its accounting policies;
- there will be no material change in inflation, interest, or tax rates in the Group's principal regions it operates in compared with the Current Year Profit Forecast;
- there will be no business disruptions that materially affect the Group, its customers, or operations, including unplanned shutdowns of producing assets and infrastructure, cyber-attacks, technological issues, and natural disasters; and
- there will be no litigation, contractual dispute, regulatory action or industrial action which is material in the context of the Current Year Profit Forecast.

The principal assumptions on which the Current Year Profit Forecast was based, which are within the influence or control of the Directors are:

- there will be no material change to the Group's existing operational structure and strategy;
- there will be no material change to the Group's production licences;
- there will be no material change to the hedging profile currently assumed in the Current Year Profit Forecast;
- there will be no material change in the current key management of the Group; and
- there will be no material asset acquisitions or disposals.

2. LONG TERM FINANCIAL FORECAST

In accordance with applicable disclosure requirements under Israeli law and the rules of the Tel Aviv Stock Exchange, in its annual report for the year ended 31 December 2021, DGL included a valuation report in connection with impairment testing of the Group under IAS 36 prepared by Kroll Advisory Ltd (the "**Kroll Report**"). The Kroll Report was dated 28 March 2022 and was prepared based on a valuation date of 31 December 2021. The Kroll Report included certain financial projections for the IEEPL, including projected EBITDA for each of the years ending 31 December 2022 to 31 December 2042 (the "**Projected EDITDA Information**").

The Company considers the Projected EBITDA Information in the Kroll Report to constitute in its entirety an outstanding but no longer valid profit forecast in respect of the Group for the following reasons:

2.1.1 the Kroll Report was prepared on a valuation date as at 31 December 2021 and was dated 28 March 2022, therefore the Kroll Report was prepared before IEUK entered into the Siccar Point Acquisition Agreement. The Siccar Point Acquisition was therefore not in contemplation when the Projected EBITDA Information was prepared and the Projected EBITDA Information therefore does not reflect production of oil by the Siccar Point Group or any of the costs and benefits to the Group arising from the Siccar Point Acquisition, which completed on 30 June 2022; and

2.1.2 the Projected EDITDA Information is based on assumptions around forecast Brent oil price and inflation rates as at the 31 December 2021 valuation date. The Kroll Report acknowledges that events subsequent to the 31 December 2021 valuation date, and in particular the Russia-Ukraine conflict, have affected the global economy and the energy sector and resulted in a substantial increase in crude oil and gas prices. The Kroll Report explicitly states that the impact of these subsequent events was not reflected in the Kroll Report and that the analysis and valuation would likely have varied materially had such impact been considered.

The Company considers that, in light of the factors described in (i) and (ii) above, such factors have materially impacted the Projected EBITDA Information for the year ending 31 December 2022, and consequently the longer-term Projected EBITDA Information for the years ending 31 December 2023 to 31 December 2042 are subject to even greater impact. As a result, the Company considers the Projected EDITDA Information to no longer be valid in its entirety.

PART 16

HISTORICAL FINANCIAL INFORMATION

SECTION A: THE GROUP

PART A: ACCOUNTANT'S REPORT ON THE CONSOLIDATED HISTORICAL FINANCIAL INFORMATION OF THE GROUP

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The Board of Directors
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Morgan Stanley & Co. International plc
20 Bank Street
Canary Wharf
London
E14 4AD
United Kingdom

9 November 2022

Dear Sirs/Mesdames

Ithaca Energy plc and, together with its subsidiaries, the "Group"

We report on the financial information of Ithaca Energy plc for the three years ended 31 December 2021 and 6 months ended 30 June 2022 set out in Part 16 (*Historical Financial Information*) of the prospectus dated 9 November 2022 of Ithaca Energy plc (the "**Company**") (the "**Prospectus**"). This report is required by Annex 1 item 18.3.1 of the UK version of the Commission delegated regulation (EU) No 2019/980 (the "**Prospectus Delegated Regulation**) which is part of the law of England and Wales by virtue of the European Union (Withdrawal) Act 2018 and is given for the purpose of complying with that requirement and for no other purpose.

We have not audited or reviewed the financial information for 6 month period ended and as at 30 June 2021 which has been included for comparative purposes only, and accordingly do not express an opinion thereon.

Opinion on financial information

In our opinion, the financial information gives, for the purposes of the Prospectus, a true and fair view of the state of affairs of the Group as at 30 June 2022, 31 December 2021, 31 December 2020 and 31 December 2019 and of its profits and losses, cash flows and changes in equity for the six months ended 30 June 2022 and years ended 31 December 2021, 31 December 2020, 31 December 2019 in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and as adopted in the United Kingdom.

Responsibilities

The Directors of the Company are responsible for preparing the financial information in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (IASB) and as adopted in the United Kingdom.

It is our responsibility to form an opinion on the financial information and to report our opinion to you.

Save for any responsibility arising under Prospectus Regulation Rule 5.3.2R(2)(f) to any person as and to the extent there provided, to the fullest extent permitted by law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report or our statement, required by and given solely for the purposes of complying with Annex 1 item 1.3 of the Prospectus Delegated Regulation, consenting to its inclusion in the Prospectus.

Basis of preparation

This financial information has been prepared for inclusion in the Prospectus on the basis of the accounting policies set out in note 3 to the financial information.

Basis of opinion

We conducted our work in accordance with Standards for Investment Reporting issued by the Financial Reporting Council ("**FRC**") in the United Kingdom. We are independent of the Company and the Group in accordance with the FRC's Ethical Standard as applied to Investment Circular Reporting Engagements, and we have fulfilled our other ethical responsibilities in accordance with these requirements.

Our work included an assessment of evidence relevant to the amounts and disclosures in the financial information. It also included an assessment of significant estimates and judgments made by those responsible for the preparation of the financial information and whether the accounting policies are appropriate to the entity's circumstances, consistently applied and adequately disclosed.

We planned and performed our work so as to obtain all the information and explanations which we considered necessary in order to provide us with sufficient evidence to give reasonable assurance that the financial information is free from material misstatement whether caused by fraud or other irregularity or error.

Our work has not been carried out in accordance with auditing or other standards and practices generally accepted in jurisdictions outside the United Kingdom, including the United States of America, and accordingly should not be relied upon as if it had been carried out in accordance with those standards and practices.

Conclusions Relating to Going Concern

In performing this engagement on the financial information, we have concluded that the Directors' use of the going concern basis of accounting in the preparation of the financial information is appropriate.

Based on the work we have performed, we have not identified any material uncertainties related to events or conditions that, individually or collectively, may cast significant doubt on the Group's ability to continue as a going concern for a period of at least twelve months from the date of this prospectus.

Declaration

For the purposes of Prospectus Regulation Rule 5.3.2R(2)(f), we are responsible for this report as part of the Prospectus and declare that, to the best of our knowledge the information contained in this report is in accordance with the facts and makes no omission likely to affect its import. This declaration is included in the Prospectus in compliance with Annex 1 item 1.2 of the Prospectus Delegated Regulation and for no other purpose.

Yours faithfully

Deloitte LLP

PART B: CONSOLIDATED HISTORICAL FINANCIAL INFORMATION OF ITHACA ENERGY

Consolidated Statement of Income

For the years ended 31 December 2019, 2020 & 2021 and six months ended 30 June 2021 & 2022

Continuing operations

	Note	Audited 31 December 2019 US$'000	Audited 31 December 2020 US$'000	Audited 31 December 2021 US$'000	Unaudited 30 June 2021 US$'000	Audited 30 June 2022 US$'000
Revenue	5	537,921	1,107,568	1,428,240	618,996	1,337,585
Cost of sales	6	(437,515)	(796,111)	(879,181)	(462,576)	(752,035)
Gross profit		100,406	311,457	549,059	156,420	585,550
Impairment (charge)/reversal	18	(106,812)	(681,588)	465,271	173,801	(7,608)
Exploration and evaluation expenses	13	(195)	(1,450)	(156)	(156)	(9,550)
Fair value gain/(losses) on contingent consideration		—	4,484	8,250	8,250	(14,449)
General and administrative expenses	7	(22,132)	(37,134)	(15,180)	(9,040)	(26,746)
Other gains/losses)	8	1,485	7,746	(4,423)	2,970	(13,113)
Gain on bargain purchase		—	—	10,454	—	1,324,342
(Loss)/profit from operations before tax and net finance costs		(27,248)	(396,485)	1,013,275	332,245	1,838,426
Net finance costs	9	(120,372)	(218,214)	(250,136)	(103,913)	(97,081)
(Loss)/profit before tax		(147,620)	(614,699)	763,139	228,332	1,741,345
Income tax	26	124,008	158,970	(337,150)	(111,337)	(183,655)
(Loss)/profit attributable to owners of the parent		(23,612)	(455,729)	425,989	116,995	1,557,690

Earnings per share

The calculation of earnings per share is based on the (loss)/profit after taxation divided by the weighted average number of shares in issue during the year or period.

	Year ended 31 December 2019	Year ended 31 December 2020	Year ended 31 December 2021	6 months ended 30 June 2021	6 months ended 30 June 2022
Weighted average number of ordinary shares for basic and diluted profit/(loss) per share ('000)	1	1	1	1	1
	US$'000	US$'000	US$'000	US$'000	US$'000
Earnings from continuing operations	(23,612)	(455,729)	425,989	116,995	1,557,690
Basic and diluted (loss)/profit per share (cents)	(2,361,232,280)	(45,572,920,263)	42,598,907,147	11,699,500,000	155,769,014,051

Consolidated Statement of Comprehensive Income

For the years ended 31 December 2019, 2020 & 2021 and the six months ended 30 June 2021 & 2022

	Note	Audited Year ended 31 December 2019	Audited Year ended 31 December 2020	Audited Year ended 31 December 2021	Unaudited 6 months ended 30 June 2021	Audited 6 months ended 30 June 2022
		US$'000	US$'000	US$'000	US$'000	US$'000
(Loss)/profit for the period .		(23,612)	(455,729)	425,989	116,995	1,557,690
Fair value gain/(loss) on cash flow hedges	28	4,325	28,420	(486,579)	(274,196)	(267,082)
Deferred tax on cash flow hedges	26	(1,730)	(11,368)	194,632	109,678	106,833
Other comprehensive profit/ (loss)		2,595	17,052	(291,947)	(164,518)	(160,249)
Total comprehensive (loss)/ profit attributable to owners of the parent . . .		(21,017)	(438,677)	134,042	(47,523)	1,397,441

Consolidated Statement of Financial Position

as at 31 December 2019, 2020 and 2021 and 30 June 2021 & 2022

	Note	Audited 31 December 2019	Audited 31 December 2020	Audited 31 December 2021	Unaudited 30 June 2021	Audited 30 June 2022
		US$'000	US$'000	US$'000	US$'000	US$'000
ASSETS						
Current assets						
Cash and cash equivalents		15,059	1,203	44,849	8,311	160,368
Trade and other receivables	10	158,149	109,213	228,290	139,461	348,731
Decommissioning receivable	10	10,472	28,836	94,640	32,778	94,640
Deposits, prepaid expenses and other receivables	11	8,661	10,214	10,536	6,474	4,973
Inventory	12	100,096	106,692	177,619	124,837	137,455
Derivative financial instruments	29	46,419	27,919	4,975	5,042	15,052
		338,856	284,077	560,909	316,903	761,219
Non current assets						
Decommissioning receivable	10	190,514	215,994	152,184	208,088	117,819
Long-term inventory	12	3,933	2,898	532	532	532
Exploration and evaluation assets	13	47,428	70,589	116,355	92,477	724,008
Property, plant & equipment	14	3,196,228	2,583,713	2,958,733	2,610,790	3,813,701
Deferred tax assets	26	234,128	382,114	220,918	376,640	1,550,536
Derivative financial instruments	29	55,890	3,505	133	1,774	6,791
Goodwill	17	928,804	722,075	722,075	722,075	783,848
		4,656,925	3,980,888	4,170,930	4,012,376	6,997,235
Total assets		4,995,781	4,264,965	4,731,839	4,329,279	7,758,454
LIABILITIES AND EQUITY						
Current liabilities						
Borrowings	19	—	—	(437,076)	(412,026)	(650,492)
Trade and other payables	21	(371,036)	(285,672)	(484,268)	(406,056)	(706,984)
Decommissioning liabilities	22	(10,472)	(28,836)	(94,640)	(32,778)	(94,640)
Lease liability	23	(5,942)	(6,080)	(3,211)	(3,543)	(21,006)
Contingent and deferred consideration	24	(8,250)	(8,250)	(49,806)	—	(73,654)
Derivative financial instruments	29	(35,793)	(78,534)	(438,006)	(216,959)	(672,609)
		(431,493)	(407,372)	(1,507,007)	(1,071,362)	(2,219,385)
Non current liabilities						
Borrowings	19	(2,246,018)	(1,840,905)	(954,616)	(1,241,564)	(1,362,058)
Decommissioning liabilities	22	(1,184,135)	(1,387,400)	(1,546,849)	(1,383,972)	(1,598,791)
Lease liability	23	(7,197)	(912)	(278)	(2,479)	(59,182)
Contingent and deferred consideration	24	(127,389)	(58,864)	(25,284)	(60,195)	(308,092)
Derivative financial instruments	29	(18,405)	(27,045)	(21,296)	(74,763)	(136,996)
		(3,583,144)	(3,315,126)	(2,548,323)	(2,762,973)	(3,465,119)
Net Assets		981,144	542,467	676,509	494,944	2,073,950
Shareholders' equity						
Share capital	25	1	1	1	1	1
Share premium	25	634,658	634,658	634,658	634,658	634,658
Capital contribution reserve		114,000	114,000	114,000	114,000	114,000
Hedging reserve		27,242	44,294	(247,653)	(120,224)	(407,902)
Retained earnings/(accumulated loss)		205,243	(250,486)	175,503	(133,491)	1,733,193
Total equity		981,144	542,467	676,509	494,944	2,073,950

Consolidated Statement of Changes in Equity

For the years ended 31 December 2019, 2020 & 2021 and six months ended 30 June 2021 & 2022

	Note	Share Capital	Share premium	Capital Contribution Reserve	Cash Flow Hedge Reserve	Retained Earnings/ Accumulated (Losses)	Total
		US$'000	US$'000	US$'000	US$'000	US$'000	US$'000
Balance, 1 January 2019		635,077	—	—	24,647	203,437	863,161
Loss for the year		—	—	—	—	(23,612)	(23,612)
Other comprehensive income .		—	—	—	2,595	—	2,595
Total comprehensive income/ (expense) for the period . . .		—	—	—	2,595	(23,612)	(21,017)
Share capital issued to original parent		2	24,998	—	—	—	25,000
Group reorganisation	25	(635,079)	(24,998)	—	—	25,418	(634,659)
Share capital issue	25	1	634,658	—	—	—	634,659
Capital contribution	25	—	—	114,000	—	—	114,000
Balance, 31 December 2019 .		1	634,658	114,000	27,242	205,243	981,144
Balance, 1 January 2020 . . .		1	634,658	114,000	27,242	205,243	981,144
Loss for the year		—	—	—	—	(455,729)	(455,729)
Other comprehensive income .		—	—	—	17,052	—	17,052
Total comprehensive income/ (expense) for the period . . .		—	—	—	17,052	(455,729)	(438,677)
Balance, 31 December 2020 .		1	634,658	114,000	44,294	(250,486)	542,467
Balance, 1 January 2021 . . .		1	634,658	114,000	44,294	(250,486)	542,467
Profit for the year		—	—	—	—	425,989	425,989
Other comprehensive expense		—	—	—	(291,947)	—	(291,947)
Total comprehensive (expense)/income for the period		—	—	—	(291,947)	425,989	134,042
Balance, 31 December 2021 .		1	634,658	114,000	(247,653)	175,503	676,509
Balance, 1 January 2022 . . .		1	634,658	114,000	(247,653)	175,503	676,509
Profit for the period		—	—	—	—	1,557,690	1,557,690
Other comprehensive expense		—	—	—	(160,249)	—	(160,249)
Total comprehensive (expense)/income for the period		—	—	—	(160,249)	1,557,690	1,397,441
Balance, 30 June 2022		1	634,658	114,000	(407,902)	1,733,193	2,073,950
Comparison (unaudited):							
Balance, 1 January 2021 . . .		1	634,658	114,000	44,294	(250,486)	542,467
Profit for the period		—	—	—	—	116,995	116,995
Other comprehensive expense		—	—	—	(164,518)	—	(164,518)
Total comprehensive (expense)/income for the period		—	—	—	(164,518)	116,995	(47,523)
Balance, 30 June 2021		1	634,658	114,000	(120,224)	(133,491)	494,944

Consolidated Statement of Cash Flows

For the years ended 31 December 2019, 2020 & 2021 and six months ended 30 June 2021 & 2022

		Audited Year ended 31 December 2019	Audited Year ended 31 December 2020	Audited Year ended 31 December 2021	Unaudited 6 months ended 30 June 2021	Audited 6 months ended 30 June 2022
		US$'000	US$'000	US$'000	US$'000	US$'000
CASH PROVIDED BY/(USED IN):						
Operating activities						
(Loss)/profit before tax		(147,620)	(614,699)	763,139	228,332	1,741,345
Adjustments for:						
Depletion, depreciation and amortisation	14	235,177	372,831	455,913	208,759	297,417
Exploration and evaluation expenses	13	195	1,450	156	156	9,550
Impairment (charge)/reversal	18	106,812	681,588	(465,271)	(173,801)	7,608
Reduction in contingent/deferred consideration		—	(4,484)	(8,250)	(8,251)	14,449
Loan fee amortisation	9	14,751	9,457	35,343	4,683	2,282
Revaluation of financial instruments		(9,931)	(442)	8,261	1,996	18,676
Gain on bargain purchase		—	—	(10,454)	—	(1,324,342)
Hedging resets*		—	155,044	(115,362)	(65,556)	(20,318)
Accretion	9	20,378	43,397	38,348	17,798	24,212
Bank interest & charges		76,640	111,847	120,891	50,628	52,920
Interest on related party loan		8,601	53,552	48,278	23,228	17,924
Interest rate swaps	9	—	5,277	7,276	6,245	(257)
Unrealised foreign exchange on cash and cash equivalents		(1,010)	289	(1,871)	(1,265)	2,585
Decommissioning expenditure		(8,706)	(25,516)	(27,930)	(12,492)	(11,689)
Cashflow from operations		295,287	789,591	848,467	280,460	832,362
(Increase)/decrease in inventories		(36,761)	8,034	(65,302)	(27,259)	42,945
(Increase)/decrease in trade and other receivables		(39,570)	131,018	(110,955)	(22,546)	(58,228)
Increase/(decrease) in trade and other payables		65,270	(128,222)	250,456	172,601	171,956
Corporation tax paid		—	(65,155)	(10,004)	(10,004)	—
Net cash from operating activities		284,226	735,266	912,662	393,252	989,033
Investing activities						
Capital expenditure		(163,884)	(142,061)	(269,606)	(85,660)	(230,338)
Reverse consideration on acquisition		—	—	56,456	—	—
Acquisition of subsidiaries net of cash acquired		(1,726,929)	—	(7,000)	—	(957,452)
Contingent/deferred consideration payment		(10,000)	(56,900)	—	—	(15,864)
Net cash used in investing activities		(1,900,813)	(198,961)	(220,150)	(85,660)	(1,203,654)
Financing activities						
Receipt from issue of equity		25,000	—	—	—	—
Bond issue		500,000	—	—	—	—
Payments for lease liabilities	23	(1,764)	(6,147)	(3,502)	(3,482)	(13,018)
Loan repayment		(477,500)	(1,152,075)	(809,776)	(214,776)	(150,000)
Loan drawdown		1,666,000	700,000	254,999	—	550,000
Bank interest & charges		(98,966)	(86,373)	(85,181)	(77,247)	(54,517)
Interest rate swaps	9	—	(5,277)	(7,276)	(6,245)	257
Net cash provided/(used) in financing activities		1,612,770	(549,872)	(650,736)	(301,750)	332,722
Currency translation differences relating to cash and cash equivalents		1,398	(289)	1,871	1,266	(2,582)
(Decrease)/Increase in cash and cash equivalents		(2,419)	(13,856)	43,646	7,108	115,519
Cash and cash equivalents, beginning of period		17,478	15,059	1,203	1,203	44,849
Cash and cash equivalents, end of period		15,059	1,203	44,849	8,311	160,368

* Hedging resets relate to the amortisation of the deferred reset gains which have been recycled to the current period profit and loss.

Notes to the Consolidated Historical Financial Information

1. NATURE OF OPERATIONS

Ithaca Energy Limited (formerly Delek North Sea Limited (the "Group" or "Ithaca Energy")), is a 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 23 College Hill, London, United Kingdom, EC4R 2RP.

2. BASIS OF PREPARATION

The consolidated Historical Financial Information is prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and in conformity with the requirements of the Companies Act 2006.

The consolidated Historical Financial Information for the three years ended 31 December 2019, 2020, and 2021 and 6 months ended 30 June 2022 (the "consolidated HFI") has been prepared specifically for the purposes of this Prospectus and does not constitute statutory accounts within the meaning of section 434(3) of the Companies Act 2006. The consolidated statement of financial position and statement of equity as at 30 June 2021 and the profit and loss account and statement of cash flows for the 6 month period then ended are not audited and not reviewed.

The consolidated HFI is presented in US dollars as this is the functional currency in which the business trades in the normal course of business. All values are rounded to the nearest thousand (US$'000), except when otherwise indicated.

The principal accounting policies applied in the preparation of the consolidated Historical Financial Information are set out below. These policies have been consistently applied to all the periods presented, unless otherwise stated.

3. SIGNIFICANT ACCOUNTING POLICIES, JUDGEMENTS AND ESTIMATION UNCERTAINTY

Basis of measurement

The consolidated HFI has 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.

Going concern

The Directors consider the preparation of the Consolidated HFI on a going concern basis to be appropriate. This is due to the following key factors:

- Strong commodity markets in 2022 compared with 2021/2020;—Brent has averaged over $105/bbl and NBP has averaged over 211p/therm since December 2021;
- RBL liquidity headroom of almost of $554m ($650m drawn versus $925m available), plus $279m cash as at 4 November 2022;
- Strong operational performance and well-diversified portfolio which has been further strengthened by the acquisitions of Siccar and Summit as at 30 June 2022; and
- A material hedge position which reduces exposure to price uncertainty—over 56% of total H2 2022 production was hedged, and 35% of 2023 production.

The Directors closely monitor the funding position of the Group throughout the year including monitoring continued compliance with covenants as described in the consolidated HFI (note 19), and available facilities to ensure sufficient headroom to fund operations.

The Directors 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 produced on a weekly and quarterly basis respectively along with any related sensitivity analysis. This allows proactive management of any business risks, including liquidity risk discussed below.

The Directors have reviewed the Group's forecasts and projections for the period to 31 December 2023, including forecast covenant compliance. Owing to fluctuations in commodity demand and price volatility, management prepared sensitivity analyses to the forecasts and applied a number of downside plausible scenarios and stress tests including decreases in production, reduced sales prices, increases in operating and capital expenditure assumptions and exchange rate fluctuations. Management aggregated these scenarios to create a reasonable combined worst-case scenario. The sensitivity analysis showed that there was no reasonably possible scenario that would result in the business being unable to meet its obligations as they fall due. The Group would still continue to have sufficient cash headroom throughout the period to 31 December 2023 (the 'going concern period') and still have the necessary liquidity to continue trading.

The Directors have a number of mitigating actions within their control, including the further drawdown on available funds from the RBL facility, the reduction in uncommitted capital expenditure, and the cancellation or deferral of future dividends.

Based on their assessment of the Group's financial position to the period ending 31 December 2023, 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 Consolidated HFI.

Basis of consolidation

The consolidated HFI of the Group includes the financial information of Ithaca and all wholly-owned subsidiaries as listed per note 31. All intergroup transactions and balances have been eliminated on consolidation.

Subsidiaries are all entities, including structured entities, over which the Group has control. The Group controls an entity when the Group is exposed to or has rights to variable returns from its investments with the entity and has the ability to affect those returns through its power over the entity. Subsidiaries are fully consolidated from the date on which control is transferred to the Group. They are deconsolidated on the date that control ceases.

Business reorganisation

In October 2019 the Group undertook a reorganisation process during which the new parent company in the Group, Ithaca was established and all the shares of Ithaca Energy E&P Limited (formerly Ithaca Energy Limited ("IEL")) were transferred to Ithaca from Ithaca's immediate parent company DKL Energy Limited. Based on the terms of the transaction, the Group has concluded that the transaction is a reverse acquisition as defined in IFRS3 and has identified IEL as the acquirer. Accordingly, the consolidated HFI is the continuation of IEL's financial statements with addition of Ithaca's assets and liabilities as from the date of the transaction. The share capital and share premium were adjusted to reflect the share capital and premium of Ithaca which is a legal parent.

Business combinations

Business combinations are accounted for using the acquisition method. The cost of an acquisition is measured as the fair value of the consideration given for the assets acquired, equity instruments issued and liabilities incurred or assumed at the date of completion of the acquisition. Transaction costs incurred are expensed and included in administrative expenses. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the cost of acquisition over the fair value of the Group's share of the identifiable net assets acquired is recorded as goodwill. If the cost of the acquisition is less than the Group's share of the net assets acquired, the difference is recognised directly in the statement of income as gain on bargain purchase.

Goodwill

Capitalisation

Goodwill acquired through business combinations is initially measured at cost. Following initial recognition, goodwill is measured at cost less any accumulated impairment losses.

Impairment

Goodwill is tested annually for impairment and also when circumstances indicate that the carrying value may be at risk of being impaired. Impairment is determined for goodwill by assessing the recoverable amount of each cash generating unit ("CGU") to which the goodwill relates. Where the recoverable amount of the CGU is less than its carrying amount, an impairment loss is recognised in the statement of income. Impairment losses relating to goodwill cannot be reversed in future periods. The CGU for the purposes of the goodwill test is the North Sea ie. the entire Group portfolio of oil and gas assets which is consistent with the operating segment view of the business.

Interest in joint ventures and associates

Under IFRS 11, joint arrangements are those that convey joint control which exists only when decisions about the relevant activities require the unanimous consent of the parties sharing control. Investments in joint arrangements are classified as either joint operations or joint ventures depending on the contractual rights and obligations of each investor. Associates are investments over which the Group has significant influence but not control or joint control, and generally holds between 20% and 50% of the voting rights.

The Group's interest in joint operations (e.g. exploration and production arrangements) are accounted for by recognising its assets (including its share of assets held jointly), its liabilities (including its share of liabilities incurred jointly), its revenue from the sale of its share of the output arising from the joint operation, its share of revenue from the sale of output by the joint operation and its expenses (including its share of any expenses incurred jointly).

Revenue

The sale of crude oil, gas or condensate represents a single performance obligation, being the sale of barrels equivalent on collection of a cargo or on delivery of commodity into an infrastructure. Revenue is accordingly recognised for this performance obligation when control over the corresponding commodity is transferred to the customer. Revenue is measured at the fair value of the consideration received or receivable and represents amounts receivable for products in the normal course of business, net of discounts, customs duties and sales taxes.

Tariff income is recognised as the underlying commodity is shipped through the pipeline network based on established tariff rates.

Foreign currency translation

Items included in this financial information are measured using the currency of the primary economic environment in which the Group and its subsidiaries operate (the 'functional currency'). The consolidated HFI is presented in United States Dollars, which is the Group's presentation currency as well as the functional currency of the parent company and each of its subsidiaries. In preparing the financial information of the parent and its subsidiaries, transactions in currencies other than the entity's functional currency (foreign currencies) are recognised at the rates of exchange prevailing on the dates of the transactions. At each reporting date, monetary assets and liabilities that are denominated in foreign currencies are retranslated at the rates prevailing at that date. Non-monetary items carried at fair value that are denominated in foreign currencies are translated at the rates prevailing at the date when the fair value was determined. Non-monetary items that are measured in terms of historical cost in a foreign currency are not retranslated.

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at year end exchange rates of monetary assets and liabilities denominated in foreign currencies are recognised in the statement of income.

Exchange differences are recognised in profit or loss in the period in which they arise except for:

- exchange differences on foreign currency borrowings relating to assets under construction for future productive use, which are included in the cost of those assets when they are regarded as an adjustment to interest costs on those foreign currency borrowings;
- exchange differences on transactions entered into to hedge certain foreign currency risks (see below under financial instruments/hedge accounting); and
- exchange differences on monetary items receivable from or payable to a foreign operation for which settlement is neither planned nor likely to occur in the foreseeable future (therefore forming part of the net investment in the foreign operation), which are recognised initially in other

comprehensive income and reclassified from equity to profit or loss on disposal or partial disposal of the net investment.

Financial instruments

All financial instruments are initially recognised at fair value on the statement of financial position. The Group's financial instruments consist of cash and cash equivalents, accounts receivable, deposits, contract assets, derivatives, accounts payable, accrued liabilities, contract liabilities, borrowings and contingent and deferred consideration. Under IFRS 9, with the exception of derivatives and contingent and deferred considerations, all financial instruments are recorded at amortised cost based on an analysis of the business model and terms of financial assets. All financial instruments are required to be measured at fair value on initial recognition. Measurement in subsequent periods is dependent on the classification of the respective financial instrument.

IFRS 9 classifications:

Cash and cash equivalents are classified at amortised cost which equates to its fair value. Accounts receivable and long term receivables are classified and carried at amortised cost as they have a business model of held to collect and the terms meet the solely payments of principal and interest criteria. Accounts payable, accrued liabilities, certain other long-term liabilities, and borrowings are classified as other financial liabilities and carried at amortised cost. Although the Group does not intend to trade its derivative financial instruments, they are required to be carried at fair value through other comprehensive income.

Transaction costs that are directly attributable to the acquisition or issue of a financial asset or liability and original issue discounts on long-term debt have been included in the carrying value of the related financial asset or liability and are amortised to consolidated net earnings over the life of the financial instrument using the effective interest method.

Derivative financial instruments

The Group enters into a variety of derivative financial instruments to manage its exposure to commodity risks, interest rate and foreign exchange rate risks. These instruments include commodity swaps, collars and options; foreign exchange forward contracts and collars; and interest rate swaps. Further details of derivative financial instruments are disclosed in note 28 and 29.

Derivatives are recognised initially at fair value at the date a derivative contract is entered into and are subsequently remeasured to their fair value at each reporting date. The resulting gain or loss is recognised in profit or loss immediately unless the derivative is designated and effective as a hedging instrument, in which event the timing of the recognition in profit or loss depends on the nature of the hedge relationship.

A derivative with a positive fair value is recognised as a financial asset whereas a derivative with a negative fair value is recognised as a financial liability. Derivatives are not offset in the financial statements unless the Group has both a legally enforceable right and intention to offset. A derivative is presented as a non-current asset or a non-current liability if the remaining maturity of the instrument is more than 12 months and it is not due to be realised or settled within 12 months. Other derivatives that are maturing in less than 12 months and are expected to be realised or settled in less than 12 months are presented as current assets or current liabilities.

Hedge accounting

The Group designates certain derivatives as hedging instruments in respect of commodity risks in cash flow hedges.

At the inception of the hedge relationship, the Group documents the relationship between the hedging instrument and the hedged item, along with its risk management objectives and its strategy for undertaking various hedge transactions. Furthermore, at the inception of the hedge and on an ongoing basis, the Group documents whether the hedging instrument is highly effective in offsetting changes in fair values or cash flows of the hedged item attributable to the hedged risk, which is when the hedging relationships meet all of the following hedge effectiveness requirements:

- there is an economic relationship between the hedged item and the hedging instrument;

- the effect of credit risk does not dominate the value changes that result from that economic relationship; and
- the hedge ratio of the hedging relationship is the same as that resulting from the quantity of the hedged item that the Group actually hedges and the quantity of the hedging instrument that the Group actually uses to hedge that quantity of hedged item.

If a hedging relationship ceases to meet the hedge effectiveness requirement relating to the hedge ratio but the risk management objective for that designated hedging relationship remains the same, the Group adjusts the hedge ratio of the hedging relationship (i.e. rebalances the hedge) so that it meets the qualifying criteria again.

The Group designates only the intrinsic value of option contracts as a hedged item, i.e. excluding the time value of the option. The changes in the fair value of the aligned time value of the option are recognised in other comprehensive income and accumulated in the hedging reserve. If the hedged item is transaction-related, the time value is reclassified to profit or loss when the hedged item affects profit or loss. If the hedged item is time-period related, then the amount accumulated in the cost of hedging reserve is reclassified to profit or loss on a rational basis—the Group applies straight-line amortisation. Those reclassified amounts are recognised in profit or loss in the same line as the hedged item. If the Group expects that some or all of the loss accumulated in hedging reserve will not be recovered in the future, that amount is immediately reclassified to profit or loss.

Notes 28 and 29 sets out details of the fair values of the derivative instruments used for hedging purposes.

Movements in the hedging reserve in equity are detailed in note 28.

Cash flow hedges

The effective portion of changes in the fair value of derivatives and other qualifying hedging instruments that are designated and qualify as cash flow hedges is recognised in other comprehensive income and accumulated under the heading of hedging reserve, limited to the cumulative change in fair value of the hedged item from inception of the hedge. The gain or loss relating to the ineffective portion is recognised immediately in profit or loss, and is included in the 'Other gains and losses' line item.

Amounts previously recognised in other comprehensive income and accumulated in equity are reclassified to profit or loss in the periods when the hedged item affects profit or loss, in the same revenue line as the recognised hedged item. However, when the hedged forecast transaction results in the recognition of a non-financial asset or a non-financial liability, the gains and losses previously recognised in other comprehensive income and accumulated in equity are removed from equity and included in the initial measurement of the cost of the non-financial asset or non-financial liability. This transfer does not affect other comprehensive income. Furthermore, if the Group expects that some or all of the loss accumulated in the hedging reserve will not be recovered in the future, that amount is immediately reclassified to profit or loss.

The Group discontinues hedge accounting only when the hedging relationship (or a part thereof) ceases to meet the qualifying criteria (after rebalancing, if applicable). This includes instances when the hedging instrument expires or is sold, terminated or exercised. The discontinuation is accounted for prospectively. Any gain or loss recognised in other comprehensive income and accumulated in hedging reserve at that time remains in equity and is reclassified to profit or loss when the forecast transaction occurs. When a forecast transaction is no longer expected to occur, the gain or loss accumulated in the hedging reserve is reclassified immediately to profit or loss.

If a hedge of a transaction related item is discontinued part way through the life of the hedge (e.g. due to early termination of the swap, hedging resets), but the hedged item is still expected to occur, the amounts deferred in equity would remain in equity until the earlier of: (i) the hedged transaction occurring; or (ii) expectation that the amount deferred in equity will not be recovered in the future periods.

Cash and cash equivalents

For the purpose of the statement of cash flow, cash and cash equivalents include investments with an original maturity of three months or less.

Inventories—hydrocarbon and materials

Inventories of materials are stated at the lower of cost and net realisable value. Cost comprises direct materials and, where applicable, direct labour costs and those overheads that have been incurred in bringing the inventories to their present location and condition. Cost is determined on the first-in, first-out method. Current hydrocarbon inventories are stated at net realisable value, which is based on estimated selling price less any further costs expected to be incurred to completion and disposal/sale. Non-current oil and gas inventories are stated at historic cost. Provision is made for obsolete, slow-moving and defective items where appropriate.

Lifting or offtake arrangement for oil and gas produced in certain of the Group's oil and gas properties are such that each participant may not receive and sell its precise share of the overall production in each period. The resulting imbalance between cumulative entitlement and cumulative volume sold less inventory is an "underlift", included within hydrocarbon inventory or "overlift", included within other payables in the Statement of financial position. Both are stated at net realisable value. Movements during an accounting period are adjusted through cost of sales in the statement of income.

Trade and other receivables

Trade receivables are recognised and carried at the original invoiced amount, less any provision for estimated irrecoverable amounts.

For trade receivables, the Group applies a simplified approach in calculating expected credit losses "ECLs". Therefore, the Group does not track changes in credit risk, but instead, recognises any material loss allowance based on lifetime ECLs at each reporting date.

The Group considers a financial asset in default when contractual payments are 90 days past due. However, in certain cases, the Group may also consider a financial asset to be in default when internal or external information indicates that the Group is unlikely to receive the outstanding contractual amounts in full before taking into account any credit enhancements held by the Group. A financial asset is written off when there is no reasonable expectation of recovering the contractual cash flows.

Other receivables are carried at amortised cost using the effective interest method if the time value of money is significant. Gains and losses are recognised in the profit or loss when the assets are derecognised, modified or impaired. The Group's financial assets measured at amortised cost includes trade and other receivables and amounts due from related parties.

Trade and other payables

All other financial liabilities are initially recognised at fair value, net of directly attributable transaction costs. For interest-bearing loans and borrowings this is typically equivalent to the fair value of the proceeds received, net of issue costs associated with the borrowing. After initial recognition, other financial liabilities are subsequently measured at amortised cost using the effective interest method. Amortised cost is calculated by taking into account any issue costs and any discount or premium on settlement. Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognised in interest and other income and finance costs respectively. This category of financial liabilities included trade and other payables and finance debt.

Property, plant and equipment

Oil and gas expenditure—exploration and evaluation assets

Capitalisation

Pre-acquisition costs on oil and gas assets are recognised in the consolidated statement of income when incurred. Costs incurred after rights to explore have been obtained, such as geological and geophysical surveys, drilling and commercial appraisal costs and other directly attributable costs of exploration and evaluation including technical, administrative and share based payment expenses are capitalised as intangible exploration and evaluation ("E&E") assets.

E&E costs are not amortised prior to the conclusion of evaluation activities. At completion of evaluation activities, if technical feasibility is demonstrated and commercial reserves are discovered then, following development sanction, the carrying value of the E&E asset is reclassified as a development and production ("D&P") asset, but only after the carrying value is assessed for impairment and where appropriate its carrying value adjusted. If after completion of evaluation activities in an area, it is not possible to determine technical feasibility and commercial viability or if the legal right to explore expires or if the Group decides not to continue exploration and evaluation activity, then the costs of such unsuccessful exploration and evaluation are written off to the statement of income in the period the relevant events occur.

Oil and gas expenditure—development and production assets

Capitalisation

Costs of bringing a field into production, including the cost of facilities, wells and subsea equipment, direct costs including staff costs together with E&E assets reclassified in accordance with the above policy, are capitalised as a Developing & Producing (D&P) asset. Normally each individual field development will form an individual D&P asset but there may be cases, such as phased developments, or multiple fields around a single production facility when fields are grouped together to form a single D&P asset.

Depreciation

All costs relating to a development are accumulated and not depreciated until the commencement of production. Depreciation is calculated on a unit of production basis based on the proved and probable reserves of the asset generally on a field-by-field basis. Any re-assessment of reserves affects the depreciation rate prospectively. Significant items of plant and equipment will normally be fully depreciated over the life of the field. However, these items are assessed to consider if their useful lives differ from the expected life of the D&P asset.

Impairment

For impairment review purposes the Group's oil and gas assets are aggregated into cash-generating units ("CGUs") as identified in accordance with IAS 36. A review is carried out each reporting date for any indicators that the carrying value of the Group's assets may be impaired or previously impaired assets (excluding goodwill) where a reversal of a previous impairment may arise. For assets where there are such indicators, an impairment test is carried out on the CGU. The impairment test involves comparing the carrying value with the recoverable value of an asset. The recoverable amount of an asset is determined as the higher of its fair value less costs to sell and value in use, where the value in use is determined from estimated future net cash flows. If the recoverable amount of an asset is estimated to be less that its carrying amount, the carrying amount of the asset is reduced to the recoverable amount. The recoverable amount of the CGU is fair value less costs of disposal. The resulting impairment losses are written off to the statement of income. Previously impaired assets (excluding goodwill) are reviewed for possible reversal of previous impairment at each reporting date. The maximum possible reversal is capped at the net book value had the asset not been impaired in the past.

Determination of whether oil and gas assets or goodwill have suffered any impairment requires an estimation of the recoverable amount of the CGU to which oil and gas assets and goodwill have been allocated. When performing impairment tests of oil and gas assets, these can be considered on a pre or post tax basis. In respect of the fields where the associated deferred tax liability has been recognised as part of a business combination, this assessment is performed on a pre-tax basis and the associated deferred tax liability is included in the Group's goodwill impairment assessment. Where the associated deferred tax liability has been generated as a result of timing differences, this assessment is performed per asset on a post-tax basis. This includes a review of previously impaired assets (excluding goodwill) for possible reversal of a previous impairment.

Non oil and natural gas operations

Non oil and gas assets are initially recorded at cost and depreciated over their estimated useful lives on a straight line basis as follows -

Buildings	10 years
Computer and office equipment	3 years
Furniture and fittings	5 years

Borrowings

All interest-bearing loans and other borrowings with banks are initially recognised at fair value net of directly attributable transaction costs. After initial recognition, interest-bearing loans and other borrowings are subsequently measured at amortised cost using the effective interest method. Amortised cost is calculated by taking into account any issue costs, discount or premium.

Interest-free loans from parents are initially recognised at fair value. Any difference between the fair value of the loans and their nominal value is accounted for as a capital contribution and credited to equity. After initial recognition, the loans are measured at amortised cost using implied interest rate of the notes.

Loan origination fees are capitalised and amortised over the term of the loan.

Borrowing costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use or sale, are added to the cost of those assets until such time as the assets are substantially ready for their intended use or sale. All other borrowing costs are expensed as incurred.

Senior notes are measured at amortised cost.

Decommissioning liabilities

The Group records the present value of legal obligations associated with the retirement of long-term tangible assets, such as producing well sites and processing plants, in the period in which they are incurred with a corresponding increase in the carrying amount of the related long-term asset. Liabilities for decommissioning are recognised when the Group has an obligation to plug and abandon a well, dismantle and remove a facility or an item of plant and restore the site on which it is located, and when a reliable estimate can be made. Where the obligation exists for a new facility or well, such as oil & gas production or transportation facilities, the obligation generally arises when the asset is installed or the ground/environment is disturbed at the field location. In subsequent periods, the asset is adjusted for any changes in the estimated amount or timing of the settlement of the obligations. The amount recognised is the present value of the estimated future expenditure determined in accordance with local conditions and requirements. The carrying amounts of the associated decommissioning assets are depleted using the unit of production method, in accordance with the depreciation policy for development and production assets. Actual costs to retire tangible assets are deducted from the liability as incurred. The unwinding of discount in the net present value of the total expected cost is treated as an interest expense. Changes in the estimates are reflected prospectively over the remaining life of the field.

Where some or all of the expenditure required to settle a provision is expected to be reimbursed by another party, a reimbursement asset is recognised when, and only when, it is virtually certain that reimbursement will be received if the entity settles the obligation. The amount recognised for the reimbursement may not exceed the amount of the provision.

Contingent and deferred consideration

Contingent consideration is accounted for as a financial liability and measured at fair value at the date of acquisition with any subsequent remeasurements recognised in profit or loss in accordance with IFRS 9. Deferred consideration is measured at amortised cost.

Taxation

Current income tax

Current income tax assets and liabilities are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amounts are those that are enacted or substantively enacted by the reporting date. Current tax is calculated by applying the applicable statutory tax rate to taxable profits for the year, which is calculated in accordance with UK tax law, and the tax rates applied are those which are enacted or substantively enacted at each balance sheet date. Taxable profit differs from net profit, as reported in the consolidated income statement, because it excludes items of income or expense that are taxable or deductible in other accounting periods and it further excludes items of income or expenses that are never taxable or deductible.

Deferred income tax

Deferred tax is recognised using the liability method, providing for temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the financial statements. Deferred tax is measured at the tax rates that are expected to be applied to the temporary differences when they reverse, based on the laws that have been enacted or substantively enacted at each balance sheet date.

Deferred tax liabilities are not recognised if they arise from the initial recognition of goodwill and deferred income tax is not accounted for if it arises from initial recognition of an asset or liability in a transaction other than business combination that at the time of the transaction affects neither accounting nor taxable profit or loss.

Deferred tax assets are recognised only to the extent that it is probable that future taxable profits will be available against which the temporary differences can be utilised. The carrying amount of deferred tax assets is reviewed at each balance sheet date and all available evidence is considered in evaluating the recoverability of these deferred tax assets.

Deferred tax assets and liabilities are offset where there is a legally enforceable right to offset current tax assets and liabilities relating to income taxes levied by the same taxation authority on either the same taxable entity or different taxable entities where there is an intention to settle the balances on a net basis.

Deferred Petroleum Revenue Tax (PRT) assets are recognised where PRT relief on future decommissioning costs is probable.

Leases

The Group assesses at contract inception all arrangements to determine whether it is, or contains, a lease. That is, if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. The Group is not a lessor in any transactions, it is only a lessee. The Group recognises a right-of-use asset and a corresponding lease liability with respect to all lease arrangements in which it is the lessee, except for short-term leases (defined as leases with a lease term of 12 months or less) and leases of low value assets (such as tablets and personal computers, small items of office furniture and telephones). For these leases, the Group recognises the lease payments as an operating expense on a straight-line basis over the term of the lease unless another systematic basis is more representative of the time pattern in which economic benefits from the leased assets are consumed. The Group applies a single recognition and measurement approach for all leases, except for short-term leases and leases of low-value assets which are recognised in profit or loss on a straight-line basis over the lease term. The Group recognises lease liabilities to make lease payments and right-of-use assets representing the right to use the underlying assets.

Right-of-use assets are measured at cost, less any accumulated depreciation and impairment losses, and adjusted for any remeasurement of lease liabilities. The cost of right-of-use assets includes the amount of lease liabilities recognised, initial direct costs incurred, and lease payments made at or before the commencement date less any lease incentives received. The right-of-use asset is depreciated over the useful life of the asset.

The Group's right-of-use assets are included in Property, Plant and Equipment (Note 14).

At the commencement date of the lease, the Group recognises lease liabilities measured at the present value of lease payments to be made over the lease term. In calculating the present value of lease payments, the Group uses its incremental borrowing rate at the lease commencement date because the interest rate implicit in the lease is generally not readily determinable. After the commencement date, the amount of lease liabilities is increased to reflect the accretion of interest and reduced for the lease payments made. In addition, the carrying amount of lease liabilities is remeasured if there is a modification, a change in the lease term, a change in the lease payments (e.g., changes to future payments resulting from a change in an index or rate used to determine such lease payments) or a change in the assessment of an option to purchase the underlying asset.

Maintenance expenditure

Expenditure on major maintenance refits or repairs is capitalised where it enhances the life or performance of an asset above its originally assessed standard of performance; replaces an asset or part of an asset which was separately depreciated and which is then written off, or restores the economic benefits of an asset which has been fully depreciated. All other maintenance expenditure is charged to the statement of income as incurred.

Changes in accounting pronouncements

The Group has adopted all new and amended IFRS Standards effective in the consolidated HFI period 1 January 2019 to 30 June 2022.

New and revised IFRS Standards in issue but not yet effective

At the date of authorisation of these consolidated HFI, the Group has not applied the following new and revised IFRS Standards that have been issued but are not yet effective.

IFRS 17 (including the June 2020 Amendments to IFRS 17)	Insurance Contracts
Amendments to IFRS 10 and IAS 28	Sale or Contribution of Assets between an Investor and its Associate or Joint Venture
Amendments to IAS 1	Classification of Liabilities as Current or Non-current
Amendments to IFRS 3	Reference to the Conceptual Framework
Amendments to IAS 16	Property, Plant and Equipment—Proceeds before Intended Use
Amendments to IAS 37	Onerous Contracts—Cost of Fulfilling a Contract
Annual Improvements to IFRS Standards 2018-2020 Cycle Amendments to IFRS1 First-time Adoption of International Financial Reporting Standards, IFRS 9 Financial Instruments, and IFRS 16 Leases	Amendments to IFRS 1First-time Adoption of International Financial Reporting Standards, IFRS 9 Financial Instruments, and IFRS 16 Leases
Amendments to IAS 1 and IFRS Practice Statement 2	Disclosure of Accounting Policies
Amendments to IAS 8	Definition of Accounting Estimates
Amendments to IAS 12	Deferred Tax related to Assets and Liabilities arising from a Single Transaction

The Directors do not expect that the adoption of the Standards listed above will have a material impact on the consolidated HFI of the Group in future periods.

Significant accounting judgements and estimation uncertainties

The management of the Group has to make estimates and judgements when preparing the financial statements of the Group. Estimates and judgements could have an impact on the carrying amount of assets and liabilities and the Group's result. Estimation uncertainties could have a material impact on the Group's results in the 12 months following the reporting date. The most important estimates and judgements in relation thereto are:

Key sources of estimation uncertainty

Estimates in oil and gas reserves and contingent resources

The Group's estimates of oil and gas reserves and contingent resources, and the associated production forecasts, are used in the impairment testing of property plant and equipment and goodwill, in the measurement of depletion and decommissioning provisions, and in the determination of whether deferred tax assets are recoverable. The business of the Group is to enhance hydrocarbon recovery and extend the useful lives of mature and underdeveloped assets and associated infrastructure in a profitable and responsible manner. Estimates of oil and gas reserves and contingent resources require critical judgement. Factors such as the availability of geological and engineering data, reservoir performance data, drilling of new wells and estimates of future oil and gas prices all impact on the determination of the Group's estimates of its oil and gas reserves which could result in different future production profiles affecting prospectively the discounted cash flows used in impairment testing. These are based on a bi-annual third party expert's view. For the purposes of depletion and decommissioning estimates, the Group uses proved and probable reserves; and for the purposes of the impairment tests performed and deferred tax asset recoverability, the Group considers the same proved and probable reserves as well as risked resource volumes. These risking adjustments are reflective of management's assessment of the Group's progress of the individual field development and are reflective of a market participant view. Changes in estimates of oil and gas reserves and resources resulting in different future production profiles will affect the discounted cash flows used in impairment testing, the anticipated date of decommissioning, the depletion charges in accordance with the unit of production method and the recoverability of deferred tax assets. The sensitivity of the Group's impairment tests and deferred tax recoverability assessments to key sources of estimation uncertainty including reserves and resources is discussed below.

Estimates in impairment of oil and gas assets and goodwill

Determination of whether the Group's oil and gas assets (note 14) or goodwill (note 17) have suffered any impairment requires an estimation of the recoverable amount of the CGU to which oil and gas assets and goodwill have been allocated. The calculation requires the Group to estimate the future cash flows expected to arise from the CGU using discounted cash flow models comprising asset-by-asset life of field projections.

Key assumptions and estimates in the impairment models relate to: commodity prices that are based on internal view of forward curve prices that are considered to be a best estimate of what a market participant would use; discount rates which reflect management's estimate of a market participant post-tax weighted average cost of capital; and oil and gas reserves and resources on a risked basis as described above.

The sensitivity of the Group's carrying amounts to these assumptions is illustrated by the impairments and reversals disclosed in note 18, and by the sensitivity disclosures in note 18.

Furthermore, there is also uncertainty due to climate change, the speed of the energy transition, and the impact of the recently enacted Energy Profits Levy, and the likely impact these factors will have on both oil and gas demand and forecast prices. The Group recognises that the energy transition is likely to impact the demand, and hence the future prices, of commodities such as oil and natural gas which may, in turn, affect the recoverable amount of the Group's oil and gas assets. The Group also acknowledges that there are a range of possible energy transition scenarios that may indicate different outcomes for oil prices. There are inherent limitations with scenario analysis and it is difficult to predict which, if any, of the scenarios might eventuate. The Group has considered climate adjusted price curves in their assessment of forecast commodity prices and related sensitivity disclosures. In particular, the impact on the carrying amounts of the Group's oil and gas assets at 31 December 2021 and 30 June 2022 of a 20% reduction in forecast revenues is disclosed in note 18, which management considers illustrates the possible effect of the energy transition over the longer term, as well as changes in revenues that could arise from changes in the outlook for commodity prices and oil and gas reserves estimates that are reasonably possible within the next financial year. For further details regarding the estimated value, inputs and assumptions please refer to notes 14 and 18.

Capital contribution estimates

In 2019 the Group issued non-current interest-free capital loan notes to its immediate parent company DKL Energy Limited. The notes were initially measured at fair value, which was estimated by discounting the cash flows payable at 14.7% being the estimated rate that would have been payable on a similar instrument issued on normal commercial terms. Subsequent to initial recognition the notes are measured at amortised cost. The difference between the nominal and the fair value of the notes was recorded as capital contribution.

Decommissioning provision estimates

Amounts used in recording a provision for decommissioning are estimates based on current legal and constructive requirements and current technology and price levels for the removal of facilities and plugging and abandoning of wells. Due to changes in relation to these items, the future actual cash outflows in relation to decommissioning are likely to differ in practice. To reflect the effects due to changes in legislation, requirements, technology and price levels, the carrying amounts of decommissioning provisions are reviewed on a regular basis. The effects of changes in estimates do not give rise to prior year adjustments and are dealt with prospectively.

While the Group uses its best estimates and judgement, actual results could differ from these estimates. Expected timing of expenditure can also change, for example in response to changes in laws and regulations or their interpretation, and/or due to changes in commodity prices. The payment dates are uncertain and depend on the production lives of the respective fields. Management does not expect any reasonable change in the expected timing of decommissioning to have a material effect on the decommissioning provisions, assuming cash flows remain unchanged. A nominal discount rate of 3.5% (2021: 2.5%) is used to discount the estimated costs. The inflation rate applied to discount the estimated costs is 2.0% (2021: 2.0%). Given the long term nature of the Group's decommissioning liabilities and the historic compounded inflation rates in the industry, management do not believe that the current short term inflationary pressures will have a material impact on the decommissioning liabilities of the Group. A variation in this discount rate of 1% would change the decommissioning liabilities by approximately $180 million (2021: $202 million). For further details regarding the estimate value, inputs and assumptions refer to note 22. Management consider that it is not practical to provide sensitivities for the various other individual assumptions.

Taxation estimates

The Group's operations are subject to a number of specific tax rules which apply to exploration, development and production companies. In addition, the tax provision is prepared before the relevant companies have filed their tax returns with the relevant tax authorities and, significantly, before these have been agreed. As a result of these factors, the tax provision process necessarily involves the use of a number of judgements and estimates including those required in calculating the effective tax rate. The Group recognises deferred tax assets on unused tax losses where it is probable that future taxable profits will be available for utilisation. This requires management to make judgements and assumptions regarding the likelihood of future taxable profits and the amount of deferred tax that can be recognised. For further details regarding the estimated value, inputs and assumptions please refer to note 26.

The Group's deferred tax assets are recognised to the extent that taxable profits are expected to arise in the future against which tax losses and allowances in the UK can be utilised, including as a result of group re-organisations and asset transfers. In accordance with IAS 12 Income Taxes, the Group assesses the recoverability of its deferred tax assets at each period end. Consistent with the impairment sensitivity described above, as at 30 June 2022, a 20% reduction in future revenues, with all other assumptions held constant, would result in a deferred tax asset derecognition of $262 million. An increase in future revenues would result in no additional deferred tax asset recognition on the basis that deferred tax assets are already recognised in full.

The above $262m million figure assumes that cash flows are equivalent to taxable profits and that any reorganisation required to utilise certain deferred tax assets does not result in a displacement of other balances.

Contingent consideration

Liabilities for contingent consideration have been recognised on certain business combinations, which are measured at fair value at acquisition and remeasured at fair value through profit and loss at each reporting date. The amounts of contingent consideration ultimately payable depend on several factors, including the progress of certain of the oil and gas properties acquired and the achievement of certain production and commodity price thresholds. Management has estimated the fair value as the aggregate value of each element of the contingent consideration in each case using an appropriate valuation technique, taking into account the likelihood of occurrence of each contingent event and the net present value of the amount potentially payable. Where applicable, risking assumptions applied in the measurement of contingent consideration were consistent with those applied in the fair valuation of the related oil and gas properties.

Further details are provided in note 24, including the estimated fair values recognised at acquisition and at each subsequent period end, and the maximum amounts of consideration payable which defines the range of possible outcomes.

It is not practical to provide sensitivities to specific assumptions given the multiple contingent events and assumptions involved.

Significant judgements

Group reorganisation

In October 2019 the Group undertook a reorganisation process during which the new parent company in the Group, Ithaca was established and all the shares of IEL were transferred to Ithaca from Ithaca's immediate parent company DKL Energy Limited. Based on the terms of the transaction, the Group has concluded that the transaction is a reverse acquisition as defined in IFRS3 and has identified IEL as the acquirer. Accordingly, the consolidated HFI is a continuation of IEL's financial information with the addition of Ithaca's assets and liabilities as from the date of the transaction. The share capital and share premium were adjusted to reflect the share capital and premium of Ithaca which is the legal parent.

Acquisitions

In the periods presented, the Group has made a number of acquisitions, see note 16 for further details of the final/provisional purchase price allocation, including the assets and liabilities acquired, the goodwill/gain on bargain purchase arising on acquisition and details of the contingent consideration payable. The acquisitions were accounted for as business combinations under IFRS 3. The assets and liabilities identified in the purchase price allocation include oil & gas assets, decommissioning liabilities, deferred tax assets and liabilities, derivatives and working capital.

The total consideration payable includes both amounts paid at completion of each of the acquisitions, and in respect of the acquisition of Marubeni Oil & Gas Limited ("MOGL") and the Siccar Point ("Siccar") entities, both acquisitions require judgements to be made regarding the future value of associated contingent consideration, as further described above.

The calculation of the fair value of the oil & gas assets acquired requires the Group to estimate the future cash flows expected to arise from the Cash Generating Units (CGUs) in the acquired business using discounted cash flow models. Key assumptions and estimates include: commodity prices, discount rates and oil and gas reserves estimates. See above estimates in the impairment of oil and gas assets and goodwill sections and estimate in the oil and gas reserves section for further details regarding these assumptions. In addition, the Group has considered the value that a market participant would prescribe to prospective resources in determining both the fair value of the oil & gas assets acquired and the contingent consideration recognised.

In determining the value of the deferred tax asset recognised on acquisition, the Group has made assumptions in respect of the amount of tax losses brought forward which will be available to offset against future taxable profits of the Group. Specifically, in respect of the MOGL acquisition, assumptions have been made with regards to the group relief claims the seller is entitled to make relating to pre-completion periods (pre 4 February 2022) which would reduce the losses available to the Group, and the quantum of such claims. The provisional deferred tax asset recognised by the Group assumes full utilisation of the losses held in MOGL and therefore a change in this assumption could result in a change in the deferred tax asset recognised on the balance sheet on acquisition, which would in turn change the value of the gain on bargain purchase recognised.

Further, in assessing the value of the deferred tax asset recognised in the MOGL and Siccar acquisitions, the Group has made assumptions regarding future restructuring within the Group, therefore a change in these assumptions could result in a change in the deferred tax asset recognised.

4. SEGMENTAL REPORTING

The Group operates a single class of business being oil and gas exploration, development and production and related activities in a single geographical area, presently being 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 / Chief Decision Making Officer. The Group's activities are considered to be an individual operating segment due to the nature of the Group's operations being consistent, and such operations existing in a single geographical region that is covered by the same regulations.

5. REVENUE

	2019	2020	2021	30 June 2021	30 June 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Oil sales	334,482	584,960	856,492	470,789	973,326
Gas sales	126,710	172,153	724,527	145,780	604,996
NGL sales	28,858	36,219	52,466	21,178	35,297
Other income	1,659	9,638	32,742	14,124	18,782
Realised gains/(losses) on oil derivative contracts	17,051	257,623	(48,833)	(4,277)	(125,908)
Put premiums on oil derivative instruments	(30,179)	(52,520)	(27,179)	(11,817)	(7,254)
Realised gains/(losses) on gas derivative contracts	73,480	115,532	(147,348)	(9,623)	(144,265)
Put premiums on gas derivative instruments	(14,140)	(16,037)	(14,627)	(7,158)	(17,389)
	537,921	1,107,568	1,428,240	618,996	1,337,585

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 judgments have been made in determining the timing of satisfaction of performance obligations, the transactions price and the amounts allocated to performance obligations.

Revenue from 2 customers exceeds 10% of the Group's consolidated revenue arising from oil sales for the 6 months ended 30 June 2022 (6 months to 30 June 2021: 2, 12 months to 31 December 2021: 2, 2020: 2 and 2019: 2), with amounts of $836m and $137m per each single customer for the 6 month period ended 30 June 2021 (6 months to 30 June 2021:, $391m and $64m per each single customer, 12 months to 31 December 2021: $678m and $109m, 2020: $492m and $78m, and 2019: $197m and $134m).

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 not disclosed separately.

6. COST OF SALES

	2019	2020	2021	30 June 2021	30 June 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Operating costs	(198,713)	(418,981)	(424,046)	(204,250)	(263,180)
Royalties	(5,749)	(1,999)	(6,192)	(1,725)	(5,362)
Movement in oil and gas inventory	2,124	(2,300)	6,970	(47,842)	(186,076)
Depreciation on right-of-use assets (note 14)	(400)	(6,257)	(5,613)	(2,090)	(11,519)
Depletion, depreciation and amortisation	(234,777)	(366,574)	(450,300)	(206,669)	(285,898)
	(437,515)	(796,111)	(879,181)	(462,576)	(752,035)

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

7. ADMINISTRATIVE EXPENSES

	2019	2020	2021	30 June 2021	30 June 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
General & administrative	(5,077)	(17,833)	(15,180)	(9,040)	(5,911)
Transaction costs	(17,055)	—	—	—	(20,835)
Employee Voluntary Redundancy programme	—	(19,300)	—	—	—
	(22,132)	(37,133)	(15,180)	(9,040)	(26,746)

Transaction costs in 2019 related to acquisition of Chevron North Sea Limited ("CNSL") (now known as Ithaca Oil and Gas Limited). Acquisition costs in 2022 relate to the acquisitions of MOGL, Summit

Exploration and Production Limited ("Summit") and Siccar entities. Further details on these acquisitions can be found in note 16.

The total employee benefit expenses included in cost of sales and administrative expenses are noted below.

	2019	2020	2021	30 June 2021	30 June 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Employee benefit expenses					
Wages and salaries	(9,666)	(46,992)	(33,167)	(11,771)	(13,872)
Social security costs	(7,892)	(32,445)	(23,815)	(14,678)	(12,314)
Pension costs	(1,606)	(14,361)	(10,605)	(5,565)	(6,359)
	(19,164)	(93,798)	(67,587)	(32,014)	(32,545)

8. OTHER GAINS AND LOSSES

	2019	2020	2021	30 June 2021	30 June 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Gain/(loss) on financial instruments	500	(486)	(453)	1,954	(19,131)
Net foreign exchange	985	8,232	(3,970)	1,016	6,018
	1,485	7,746	(4,423)	2,970	(13,113)

9. NET FINANCE COSTS

	2019	2020	2021	30 June 2021	30 June 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Bank interest and charges	(41,856)	(55,133)	(41,372)	(25,619)	(35,202)
Senior notes interest	(35,658)	(47,131)	(74,677)	(23,245)	(14,024)
Loan fee amortisation	(14,751)	(9,457)	(35,343)	(4,683)	(2,282)
Interest on lease liabilities (note 23)	(836)	(587)	(367)	(171)	(1,829)
Interest on related party loan	(8,603)	(53,551)	(48,277)	(23,229)	(17,924)
Accretion	(20,378)	(43,397)	(38,348)	(17,798)	(24,212)
Realised (losses)/gains on interest derivative contracts	—	(5,277)	(7,276)	(6,245)	257
Interest income	1,897	39	11	—	—
Other	(187)	(3,720)	(4,487)	(2,923)	(1,865)
	(120,372)	(218,214)	(250,136)	(103,913)	(97,081)

10. TRADE AND OTHER RECEIVABLES

	2019	2020	2021	30 June 2021	30 June 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Current					
Trade receivables	125,813	6,006	18,918	2,964	20,698
Other	17,114	86,770	105,337	73,271	104,929
Crude oil underlift	—	4,546	45,114	14,569	213,536
Contract asset	15,222	11,891	58,921	48,657	9,568
	158,149	109,213	228,290	139,461	348,731

The Group regularly monitors all customer receivable balances outstanding in excess of 90 days for expected credit losses. Substantially all accounts receivables are current, being defined as less than 90 days. The Group has no Expected Credit Losses ("ECL") as of the current and prior periods as the ECL are immaterial.

Other receivables mainly comprises joint venture receivables relating to operated assets.

	2019 US$'000	2020 US$'000	2021 US$'000	30 June 2021 US$'000	30 June 2022 US$'000
Non-current					
Decommissioning reimbursement	190,514	215,994	152,184	208,088	117,819

	2019 US$'000	2020 US$'000	2021 US$'000	30 June 2021 US$'000	30 June 2022 US$'000
Current					
Decommissioning reimbursement	10,472	28,836	94,640	32,778	94,640

The decommissioning reimbursement represents the equal and opposite of decommissioning liabilities (note 22), 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 CNSL acquisition, Chevron have the obligation to provide the security and remain financially responsible for the decommissioning obligations of CNSL in relation to these interests. As the payment is virtually certain this has been accounted for under IAS 37 as a reimbursement asset.

11. DEPOSITS PREPAID EXPENSES & OTHER RECEIVABLES

	2019 US$'000	2020 US$'000	2021 US$'000	30 June 2021 US$'000	30 June 2022 US$'000
Current					
Prepayments	6,677	6,948	8,524	4,989	3,776
Decommissioning securities	1,984	3,266	2,012	1,485	1,197
	8,661	10,214	10,536	6,474	4,973

The Group enters into letters of credit and surety bonds to provide security for the Group's obligations under certain field and bi-lateral decommissioning security agreements. At 31 December 2021 and at 30 June 2022, the Group had £341 million and £383 million, respectively, in letters of credit and surety bonds outstanding relating to security obligations under certain decommissioning and security agreements.

12. INVENTORY

	2019 US$'000	2020 US$'000	2021 US$'000	30 June 2021 US$'000	30 June 2022 US$'000
Current					
Hydrocarbon inventory	58,989	50,546	115,743	67,133	65,024
Materials inventory	45,403	67,692	89,374	82,480	108,192
Provision for obsolete materials inventory	(4,296)	(11,546)	(27,498)	(24,776)	(35,761)
	100,096	106,692	177,619	124,837	137,455

	2019 US$'000	2020 US$'000	2021 US$'000	30 June 2021 US$'000	30 June 2022 US$'000
Non-current					
Hydrocarbon inventory	3,933	2,898	532	532	532

13. EXPLORATION AND EVALUATION ASSETS

	US$'000
At 1 January 2019	38,746
Additions	8,877
Write offs/relinquishments	(195)
At 31 December 2019 and 1 January 2020	47,428
Additions	19,261
Acquisitions	5,350
Write offs/relinquishments	(1,450)
At 31 December 2020 and 1 January 2021	70,589
Additions	45,922
Write offs/relinquishments	(156)
At 31 December 2021	116,355
Additions	6,191
Acquisitions (note 16)	706,558
Transfer to D&P (note 14)	(95,546)
Write offs/relinquishments	(9,550)
At 30 June 2022	724,008
Comparison:	
At 31 December 2020 and 1 January 2021	70,589
Additions	22,044
Write offs/relinquishments	(156)
At 30 June 2021	92,477

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 $9.6 million being expensed in the period to 30 June 2022 (30 June 2021: $0.2 million, 2021: $0.2 million, 2020: $1.5 million, 2019: $0.2 million).

14. PROPERTY, PLANT & EQUIPMENT

	Right of use operating assets	Development & Producing assets	Other fixed assets	Total
	US$'000	US$'000	US$'000	US$'000
Cost				
At 1 January 2019	—	2,931,978	3,705	2,935,683
Acquisitions (note 16)	13,139	2,145,966	10,064	2,169,169
Additions	—	179,785	8,648	188,433
As at 31 December 2019 and 1 January 2020	13,139	5,257,729	22,417	5,293,285
Additions	—	232,295	2,880	235,175
Reclassification	—	6,441	(6,441)	—
At 31 December 2020 and 1 January 2021	13,139	5,496,465	18,856	5,528,460
Additions	2,512	341,713	21,437	365,662
Disposals	(6,441)	—	—	(6,441)
At 31 December 2021 and 1 January 2022	9,210	5,838,178	40,293	5,887,681
Additions	89,717	180,408	3,322	273,447
Acquisitions (note 16)	—	1,103,423	—	1,103,423
Transfer from E&E (note 13)	—	95,546	—	95,546
Change in decommissioning asset (note 22)	—	(313,016)	—	(313,016)
At 30 June 2022	98,927	6,904,539	43,615	7,047,081

	Right of use operating assets	Development & Producing assets	Other fixed assets	Total
	US$'000	US$'000	US$'000	US$'000
Comparison:				
At 31 December 2020 and 1 January 2021	13,139	5,496,465	18,856	5,528,460
Additions	2,512	59,327	196	62,035
At 30 June 2021	15,651	5,555,792	19,052	5,590,495
DD&A and Impairment				
At 1 January 2019	(6,569)	(1,752,349)	(3,119)	(1,762,037)
DD&A charge for the period	(400)	(233,215)	(1,562)	(235,177)
Derecognition on IFRS 16	6,969	—	—	6,969
Impairment charge (note 18)	—	(106,812)	—	(106,812)
As at 31 December 2019 and 1 January 2020	—	(2,092,376)	(4,681)	(2,097,057)
DD&A charge for the period	(6,257)	(362,980)	(3,594)	(372,831)
Impairment charge (note 18)	—	(474,859)	—	(474,859)
At 31 December 2020 and 1 January 2021	(6,257)	(2,930,215)	(8,275)	(2,944,747)
DD&A charge for the period	(5,613)	(444,751)	(5,549)	(455,913)
Disposals	6,441	—	—	6,441
Impairment reversal (note 18)	—	465,271	—	465,271
At 31 December 2021 and 1 January 2022	(5,429)	(2,909,695)	(13,824)	(2,928,948)
DD&A charge for the period	(11,519)	(280,310)	(5,588)	(297,417)
Impairment (charge)/reversal	—	(8,708)	1,694	(7,014)
At 30 June 2022	(16,948)	(3,198,713)	(17,718)	(3,233,379)
Comparison:				
At 31 December 2020 and 1 January 2021	(6,257)	(2,930,215)	(8,275)	(2,944,747)
DD&A charge for the period	(2,090)	(203,730)	(2,939)	(208,759)
Impairment reversal (note 18)	—	173,801	—	173,801
At 30 June 2021	(8,347)	(2,960,144)	(11,214)	(2,979,705)
NBV at 1 January 2019	25,600	1,179,629	586	1,205,815
NBV at 1 January 2020	13,139	3,165,353	17,736	3,196,228
NBV at 1 January 2021	6,882	2,566,250	10,581	2,583,713
NBV at 1 January 2022	3,781	2,928,484	26,469	2,958,733
NBV at 30 June 2022	81,979	3,705,827	25,898	3,813,701
Comparison:				
NBV at 30 June 2021	7,304	2,595,648	7,838	2,610,790

The transfer from E&E to D&P assets relates to the Abigail, Fotla and Jade South fields.

15. INTEREST IN JOINT OPERATIONS

The Contractual agreements for the license interests in which the Group has an investment do not typically convey control of the underlying joint arrangement to any one party, even where one party has a greater than 50% equity ownership of the area of interest.

The Group's material joint operations as at 30 June 2022 and 31 December 2021 are:

Block	License	Field/Discovery Name	Operator	30 June 2022	Group Net % Interest 31 December 2021
9/11c	P.979	Mariner	Equinor UK Limited	8.89%	0.00%
9/11b	P.726	Mariner	Equinor UK Limited	8.89%	0.00%
30/2c	P.672	Jade*	Chrysaor Petroleum Company U.K. Limited	14.89%	6.64%
22/30c and 29/5c .	P.666	Elgin-Franklin*	TotalEnergies E&P UK Limited	3.04%	1.95%
15/29b	P.590	Callanish*	Chrysaor Production (U.K.) Limited	20.00%	20.00%
204/25a	P.559	Schiehallion	Shell U.K. Limited	35.30%	0.00%
204/19b and 204/20b	P.556	Suilven	Ithaca SP E&P Limited	50.00%	0.00%
30/1c	P.363	Vorlich*	BP Exploration Operating Company Limited	35.00%	35.00%
29/5b	P.362	Elgin-Franklin*	TotalEnergies E&P UK Limited	3.04%	1.95%
21/4a	P.347	Callanish*	Chrysaor Production (U.K.) Limited	13.70%	13.70%
16/27b	P.345	Britannia*	Ithaca Alpha (N.I.) Limited	35.75%	35.75%
9/11a	P.335	Mariner	Equinor UK Limited	8.89%	0.00%
13/22a	P.324	Captain*	Ithaca Energy (UK) Limited	85.00%	85.00%
22/18a	P.292	Arbroath, Arkwright, Carnoustie, Wood	Repsol Sinopec Resources UK Limited	41.03%	0.00%
22/17s, 22/22a and 22/23a . . .	P.291	Arbroath, Arkright, Brechin, Carnoustie, Cayley, Shaw	Repsol Sinopec Resources UK Limited	41.03%	0.00%
23/26b and 23/26d	P.264	Erskine*	Ithaca Energy (UK) Limited	56.67%	56.67%
9/11d and 9/12b .	P.2508	Mariner	Equinor UK Limited	8.89%	0.00%
22/1b	P.2373	F Block (Fotla and Fortriu)*	Ithaca Oil and Gas Limited	60.00%	60.00%
15/18b	P.2158	Marigold	Ithaca Oil and Gas Limited	100.00%	100.00%
9/11g	P.2151	Mariner	Equinor UK Limited	8.89%	0.00%
16/26a	P.213	Alba*	Ithaca Oil and Gas Limited	36.67%	36.67%
16/26a	P.213	Britannia*	Ithaca Alpha (N.I.) Limited	33.17%	33.17%
16/26a	P.213	N/A*	Ithaca Oil and Gas Limited	21.85%	21.85%
3/7a	P.203	Columba E	CNR International (U.K.) Limited	20.00%	0.00%
3/8a and 3/8a . . .	P.199	Columba B/D	CNR International (U.K.) Limited	5.60%	0.00%
22/30b	P.188	Elgin-Franklin*	TotalEnergies E&P UK Limited	3.04%	3.04%
21/20a	P.185	Cook*	Ithaca Energy (UK) Limited	61.35%	61.35%
8/15a	P.1758	Mariner	Equinor UK Limited	8.89%	0.00%
29/10b	P.1665	Abigail*	Ithaca Energy (UK) Limited	50.00%	50.00%
30/7b	P.1589	Jade*	Chrysaor Petroleum Company U.K. Limited	12.75%	9.97%
30/1f	P.1588	Vorlich*	Ithaca Energy (UK) Limited	100.00%	100.00%
205/2a	P.1272	Rosebank	Equinor UK Limited	20.00%	0.00%
205/1a	P.1191	Rosebank	Equinor UK Limited	20.00%	0.00%
15/29a	P.119	Alder*	Ithaca Energy (UK) Limited	73.68%	73.68%
15/29a	P.119	Britannia*	Ithaca Alpha (N.I.) Limited	75.00%	75.00%
204/4a and 204/5a	P.1189	Cambo	Ithaca SP E&P Limited	70.00%	0.00%
21/3a	P.118	Brodgar*	Chrysaor Production (U.K.) Limited	25.00%	25.00%
23/22a	P.111	Pierce*	Enterprise Oil Limited	34.01%	34.01%
15/30a and 21/5a	P.103	Britannia, Enochdhu*	Chrysaor Production (U.K.) Limited	44.55%	44.55%
204/9a and 204/10a	P.1028	Cambo	Ithaca SP E&P Limited	70.00%	0.00%
213/26b and 213/27a	P.1026	Rosebank	Equinor UK Limited	20.00%	0.00%
23/26a	P.057	Erskine*	Ithaca Energy (UK) Limited	50.00%	50.00%
22/18n	P.020	Montrose	Repsol Sinopec Resources UK Limited	41.03%	0.00%
22/17s, 22/22a and 22/23a . . .	P.019	Godwin, Montrose	Repsol Sinopec Resources UK Limited	41.03%	0.00%
30/6a and 29/10a	P.011	Stella*	Ithaca Energy (UK) Limited	100.00%	100.00%

* The Group's material joint operations as at 31 December 2020 and 2019. The beneficial interest for these joint operations have not materially changed throughout the periods presented with the exception of Alba in which an additional 13.3% interest was acquired from Mitsui E&P UK Limited on 17 September 2021.

16. BUSINESS COMBINATION ACCOUNTING

On 4 February 2022, the Group completed the acquisition of 100% of the issued share capital of MOGL. The transaction added a further nine producing field interests (known as 'MonArb') to the existing Ithaca portfolio.

Taking into account the interim period cashflows generated by MOGL since the transaction effective date of 1 January 2021, the $7 million deposit paid at signing of the transaction in November 2021 and conventional working capital adjustments, the price payable at completion of the acquisition was $108 million and contingent and deferred considerations of $203 million has been recognised as at 30 June 2022, resulting in a gain on bargain purchase of $620 million.

On 30 June 2022, the Group completed the acquisition of 100% of the issued share capital of Summit. The transaction added a further 2.1875% ownership of the Elgin Franklin field interest within the existing Ithaca portfolio.

Taking into account the interim period cashflows generated by Summit since the transaction effective date of 1 January 2021, the $10 million deposit paid at signing of the transaction in February 2022 and conventional working capital adjustments, the price payable at completion of the acquisition was $119 million and goodwill of $62 million recognised.

On 30 June 2022, the Group completed the acquisition of 100% of the issued share capital of Siccar Point Energy (Holdings) Limited ("Siccar") and its UK subsidiaries. The transaction added a further two producing assets (Mariner 8.89% and Schiehallion 11.75%), an additional 5.57% increase to Ithaca's existing equity in Jade, and three development prospects (Rosebank 20.00%, Cambo 70.00% and Tornado 50.00%) to the existing Ithaca portfolio.

Taking into account the interim period cashflows generated by Siccar since the transaction effective date of 1 January 2022 and conventional working capital adjustments, the price payable at completion of the acquisition was $1.015 billion and contingent consideration of $102 million is recognised, resulting in a gain on bargain purchase of $704 million being recognised.

The initial accounting for the acquisition of Siccar & Summit has only been provisionally determined at the end of the reporting period. For tax purposes, the tax values of the assets are required to be reset based on market values of the assets. At the date of finalisation of this consolidated HFI, the necessary market valuations and other calculations had not been finalised and they have therefore only been provisionally determined based on the Directors' best estimate of the likely tax values.

On 8 November 2019, the Group completed the acquisition of 100% of the issued share capital of CNSL, now known as Ithaca Oil and Gas Limited. The transaction added a further ten producing field interests to the existing Ithaca portfolio, four of which related to assets operated by the Group, resulting in a marked increase in production and reserves of the Group.

Taking into account the interim period cashflows generated by CNSL from the transaction effective date of 1 January 2019, the $200 million deposit paid at signing of the transaction in May 2019 and conventional working capital adjustments, the price payable at completion of the acquisition was $1.7 billion, resulting in goodwill of $805 million being recognised.

To the extent that the purchase consideration exceeds the aggregate fair value of the identifiable assets and liabilities, including deferred tax, goodwill was recognised on the balance sheet in the period. The goodwill arising from CNSL, driven by the requirement of the accounting standards to book a deferred tax liability against PP&E figures which have been fair valued on a post-tax basis. This deferred tax liability was $868 million. Absent the offset to deferred tax liability a bargain of $63 million would have been recognised.

No contingent liabilities have been acquired on the business combinations detailed above.

The fair values of the identifiable assets and liabilities as at the acquisition date were:

	CNSL 2019	Total 2019	MOGL 2022	Siccar 2022	Summit 2022	Total 2022
	US$'000	US$'000	US$'000	US$'000	US$'000	US$'000
Property, plant and equipment (note 14)	2,169,169	**2,169,169**	332,790	668,700	101,933	**1,103,423**
Exploration and evaluation assets (note 13)	—	**—**	—	706,558	—	**706,558**
Cash	9,782	**9,782**	170,629	88,638	18,799	**278,066**
Inventory	57,020	**57,020**	2,781	—	—	**2,781**
Trade and other receivables	76,294	**76,294**	27,643	32,627	10,513	**70,783**
Other long term receivables	200,300	**200,300**	—	—	—	**—**
	343,396	**343,396**	201,053	121,265	29,312	**351,630**
Trade and other payables	(132,747)	**(132,747)**	(5,436)	(52,616)	(20,407)	**(78,459)**
Oil inventory overlift	—	**—**	—	(2,626)	(2,806)	**(5,432)**
Lease liabilities	(13,139)	**(13,139)**	—	—	—	**—**
Provisions	(953,543)	**(953,543)**	(253,393)	(121,022)	(16,116)	**(390,531)**
Financial instruments	—	**—**	—	(82,899)	—	**(82,899)**
Borrowings	—	**—**	—	(200,000)	—	**(200,000)**
	(1,099,429)	**(1,099,429)**	(258,829)	(459,163)	(39,329)	**(757,321)**
Deferred tax asset	376,291	**376,291**	745,872	1,334,221	6,446	**2,086,539**
Deferred tax liability	(867,668)	**(867,668)**	(90,081)	(550,103)	(40,773)	**(680,957)**
	(491,377)	**(491,377)**	655,791	784,118	(34,327)	**1,405,582**
Total identifiable net assets at fair value	921,759	**921,759**	930,805	1,821,478	57,589	**2,809,873**
Consideration satisfied by cash	(1,727,053)	**(1,727,053)**	(107,811)	(1,015,346)	(119,362)	**(1,242,519)**
Deferred consideration	—	**—**	(68,277)	—	—	**(68,277)**
Contingent consideration	—	**—**	(134,396)	(102,111)	—	**(236,507)**
Consideration	(1,727,053)	**(1,727,053)**	(310,483)	(1,117,457)	(119,362)	**(1,547,303)**
Gain on bargain purchase goodwill/ (goodwill) arising on acquisition	(805,294)	**(805,294)**	620,322	704,021	(61,773)	**1,262,570**

From the date of acquisition, the MOGL assets have contributed $213.1 million of revenue and $93.4 million profit before tax in 2022.

The gain on bargain purchase arising on the MOGL acquisition was principally a result of recognising a deferred tax asset of $746 million as required under IFRS 3 fair value accounting for business combinations. The gain on bargain purchase arising on the Siccar transaction was principally as a result of recognising a deferred tax asset arising from tax losses of $1,334 million which were unable to be utilised by Siccar. The gain on bargain purchase was credited to income in the 6 months to 30 June 2022.

The contingent consideration arrangement on MOGL depends on whether various milestones of the Sale and Purchase Agreement are met as follows: set gross export production volume from Montrose Infill Project Phase 1, set cumulative gross export production volume following Arbroath well reinstatements, set gross export production volume from next new well in the Shaw Field and, an amount payable during the Value Sharing Period (1 January 2022 to 31 December 2024) in relation to sales in excess of a set oil trigger price. The total discounted value of contingent consideration in relation to MOGL as at 30 June 2022 is $175 million. The total undiscounted value is $255 million.

The contingent consideration arrangement on Siccar depends on whether various milestones of the Sale and Purchase Agreement are met as follows: redemption of acquired bond as at repayment date, Final Investment Decision in respect of the Cambo and Rosebank fields and, an amount paid in relation to sales in excess of a set floor oil price. The total discounted value of contingent consideration in relation to Siccar as at 30 June 2022 is $102 million. The total undiscounted value is $360 million.

On acquisition of Siccar the Group acquired a $200 million bond. On 28 July 2022 a group of bondholders exercised their right to redeem and subsequently $166 million was paid to these bondholders. The remaining outstanding balance as at the date of signing these financial statements is $34 million, repayable March 2026.

There was no difference between the fair value of the trade and other receivables as stated above and the contractual amount receivable.

If the combination had taken place at the beginning of 2019, the profit before tax from continuing operations 2019 would have included an additional $240 million of profit related to the CNSL transaction and revenue contribution of the CNSL assets to the continuing operations would have been an additional $916 million.

Both Siccar and Summit acquisitions completed on 30 June 2022 therefore these entities have contributed no revenue or profit before tax in 2022 within the Group.

The goodwill is not tax deductible on all acquisitions.

17. GOODWILL

	2019	2020	2021	30 June 2021	30 June 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Balance at 1 January	123,510	928,804	722,075	722,075	722,075
Additions	805,294	—	—	—	61,773
Impairment	—	(206,729)	—	—	—
Balance at 31 December / 30 June	928,804	722,075	722,075	722,075	783,848

Goodwill of $805.3 million was recognised in 2019 on the acquisition of Ithaca Oil & Gas Limited as detailed in note 16. Absent the goodwill that was recognised related to the deferred tax liability a bargain of $63 million would have been recognised. This goodwill was impaired in 2020 by $206.7 million leaving a remaining balance of goodwill of $598.6 million. The remaining $123.5 million balance of goodwill as at 31 December 2019 relates to the 2014 Summit acquisition.

The goodwill on acquisition in the current period relates to the Summit acquisition, as detailed in note 16.

Annual impairment tests were performed and there were no indicators of impairment in 2022 or throughout the consolidated HFI period. The CGU for the purposes of the goodwill test is the North Sea ie. the entire Ithaca portfolio of oil and gas assets which is consistent with the operating segment view of the business.

18. IMPAIRMENT REVERSAL/(CHARGE) ON OIL & GAS ASSETS

	2019	2020	2021	30 June, 2021	30 June, 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
D&P Assets (note 14)	(106,812)	(474,859)	465,271	173,801	(8,708)
Contingent consideration	—	—	—	—	1,100
Goodwill (note 17)	—	(206,729)	—	—	—
North Sea oil and gas assets	(106,812)	(681,588)	465,271	173,801	(7,608)

2019

During 2019, the Group recorded a $106.8 million pre-tax impairment charge relating to oil and gas assets. The D&P asset impairment was driven partly by the lower forward curve for both oil and gas prices resulting in impairments predominantly relating to the Stella and Dons CGUs. The review was carried out on a fair value less cost of disposal basis using risk adjusted cash flow projections discounted at a post-tax rate of 9.0%.

Applying level 3 fair value measurement techniques, for impairment of property, plant and equipment and intangible oil and gas assets, fair value less costs of disposal are determined by discounting the post-tax cash flows expected to be generated from oil and gas production net of selling costs taking into account assumptions that market participants would typically use in estimating fair values. Applying the same fair value less cost of disposal methodology, goodwill has been tested for impairment by assessing the recoverable amount of the CGU to which the goodwill relates.

The following assumptions were used in developing the cash flow model and applied over the expected life of the respective fields:

	Discount rate assumption	Price assumptions				
		2020	2021	2022	2023	2024
Oil	9%	$61/bbl	$63/bbl	$66/bbl	$71/bbl	$73/bbl

The recoverable amount of the operating segment, being North Sea D&P assets at 31 December 2019, was $3,426 million.

A 10% reduction in the price deck would have resulted in an additional post tax impairment of $432 million to PP&E. This impairment would have been partially mitigated by: i) a reduction in Ithaca's operating cost base, and ii) an increase in value of Ithaca's commodity hedges in place by $155 million.

2020

During 2020, the Group recorded a $475 million pre-tax net impairment charge relating to oil and gas assets.

An impairment review was carried out at the end of 1Q and was driven by the lower forward curve for both oil and gas prices resulting in pre-tax asset impairments of $980.3 million. The review was carried out on a fair value less cost of disposal basis using risk adjusted cash flow projections discounted at a post-tax rate of 10.5%.

A pre-tax impairment charge of $1.2 billion was recorded in the period to 30 September 2020. This impairment was recorded following an impairment review at the end of 1Q 2020 and was driven by the lower forward curve for both oil and gas prices resulting in asset impairments and goodwill impairments. The review was carried out on a fair value less cost of disposal basis using risk adjusted cash flow projections discounted at a post-tax rate of 10.5%. A further impairment of $3.9 million was recorded at the end of 3Q20 as a result of the increased decommissioning costs in relation to Jacky and a change in phasing of spend on Dons. Both fields are no longer producing and have no remaining net book value resulting in the impairment booked.

At 31 December 2020, impairment reversals of $531.2 million have been made. This has been driven by the stronger short term forward curve for both oil and gas prices than earlier in the year. The review was carried out on a fair value less cost of disposal basis using risk adjusted cash flow projections discounted at a post-tax rate of 9.75%. This has been offset by an impairment charge of $21.8 million primarily due to increased decommissioning provisions for assets that have already creased production.

The following assumptions were used at Q120 in developing the cash flow model and applied over the expected life of the respective fields:

	Discount rate assumption	Price assumptions				
		2020	2021	2022	2023	2024
Oil	10.5%	$35/bbl	$45/bbl	$54/bbl	$63/bbl	$68/bbl
Gas	10.5%	24p/therm	33p/therm	39p/therm	42p/therm	43p/therm

A further impairment of $3.9 million was recorded at the end of 3Q as a result of the increased decommissioning costs in relation to Jacky and a change in phasing of decommissioning spend on Dons. Both fields are no longer producing and have no remaining net book value resulting in the impairment during the third quarter.

The following assumptions were used at 4Q20 in developing the cash flow model and applied over the expected life of the respective fields:

	Discount rate assumption	Price assumptions				
		2021	2022	2023	2024	2025
Oil	9.75%	$52/bbl	$57/bbl	$61/bbl	$65/bbl	$68/bbl
Gas	9.75%	47p/therm	44/therm	43p/therm	43p/therm	44p/therm

Applying level 3 fair value measurement techniques, for impairment of property, plant and equipment and intangible oil and gas assets, fair value less costs of disposal are determined by discounting the post-tax cash flows expected to be generated from oil and gas production net of selling costs taking into account assumptions that market participants would typically use in estimating fair values. Applying the same fair value less cost of disposal methodology, goodwill has been tested for impairment by assessing the recoverable amount of the CGU to which the goodwill relates.

The recoverable amount of the operating segment, being North Sea D&P assets, is $4,827 million.

A 10% reduction in the price deck would result in an additional post tax impairment of $48.5 million to PP&E and a $180.5 million post tax reduction to the impairment reversals booked during the final quarter. This additional impairment and lower reversals would be partially mitigated by: i) a reduction in Ithaca's operating cost base, and ii) an increase in value of Ithaca's commodity hedges in place by $72 million. A 10% increase in the price deck would not change the impairment reversals booked and would only result in a post tax impairment reduction of $2.2 million.

2021

During 2021, the Group recorded a $465 million pre-tax impairment reversal relating to oil and gas assets.

An impairment review was carried out at the end of both 2Q and 3Q 2021 driven by the higher forward curve for both oil and gas prices resulting in reversals of $408.1 million, being $397.3m on Stella and $10.8m on Alba. In addition to these impairment reviews performed an annual review of all oil and gas assets and goodwill was performed in 4Q 2021. The review was carried out on a fair value less cost of disposal basis using risk adjusted cash flow projections discounted at a post-tax rate of 9.5%, resulting in pre tax reversals of $18 million on the Alba CGU and $33 million on Pierce. The post tax recoverable amount as at 31 December 2021 was $77 million for the Alba CGU, $120 million for Pierce and $565 million for Stella. The remaining reversal of $6 million relates to revisions to decommissioning estimates for assets which have previously been fully impaired.

The following assumptions were used at 4Q21 in developing the cash flow model and applied over the expected life of the respective fields:

	Discount rate assumption	Price assumptions				
		2022	2023	2024	2025	2026*
Oil	9.50%	$76/bbl	$69/bbl	$71/bbl	$72/bbl	$74/bbl
Gas	9.50%	164p/therm	99p/therm	68p/therm	61p/therm	56p/therm

* post 2026 an annual 2% increase is applied to the price assumption

The following assumptions were used at 3Q21 in developing the cash flow model and applied over the expected life of the respective fields:

	Discount rate assumption	Price assumptions				
		2021	2022	2023	2024	2025
Oil	9.75%	$70/bbl	$70/bbl	$69/bbl	$70/bbl	$71/bbl
Gas	9.75%	204p/therm	119p/therm	71p/therm	65p/therm	65p/therm

The following assumptions were used at Q2 21 in developing the cash flow model and applied over the expected life of the respective fields:

	Discount rate assumption	Price assumptions				
		2021	2022	2023	2024	2025
Oil	9.75%	$65/bbl	$65/bbl	$66/bbl	$68/bbl	$69/bbl
Gas	9.75%	78p/therm	70p/therm	53p/therm	54p/therm	55p/therm

Applying level 3 fair value measurement techniques, for impairment of property, plant and equipment and intangible oil and gas assets, fair value less costs of disposal are determined by discounting the post-tax cash flows expected to be generated from oil and gas production net of selling costs taking into account assumptions that market participants would typically use in estimating fair values. Applying the same fair value less cost of disposal methodology, goodwill has been tested for impairment by assessing the recoverable amount of the CGU to which the goodwill relates.

The recoverable amount of the operating segment, being North Sea D&P assets, is $6,840 million (2020: $4,827 million).

With all other assumptions held constant, a 20% decrease in the forecast revenues used for impairment testing, illustrating lower commodity prices and/or production volumes, would result in a post tax impairment of oil and gas PP&E of $363.1 million. An increase of 1% in the discount rate assumption would have no material impact. There would be no impairment of goodwill. A decrease in discount rate or an increase in forecast revenues would have no impact on carrying amounts, as there were no remaining impairment provisions to reverse.

2022

During the 6 months to 30 June 2022 the decommissioning cost estimates for fields that are no longer producing were reviewed which resulted in the recognition of a pre-tax impairment loss of $8.7 million which mainly relates to Austen.

With all other assumptions held constant, a 20% decrease in the forecast revenues used for goodwill impairment testing, illustrating lower commodity prices and/or production volumes, would result in a post-tax impairment of PP&E of $384 million at 30 June 2022. An increase of 1% in the discount rate assumption would not result in a post-tax impairment of PP&E. There would be no impairment of goodwill. A decrease in discount rate or an increase in forecast revenues would have no impact on carrying amounts, as there are no remaining impairment provisions to reverse.

Estimated production volumes and cash flows used in impairment reviews are considered up to the date of cessation of production on a field-by-field basis, including operating and capital expenditure and are derived from management approved business plans. The following assumptions were used at 2Q 2022 in developing the cash flow model and applied over the expected life of the respective fields:

	Discount rate assumption	Price assumptions				
		2022	2023	2024	2025	2026
Oil	10.40%	$103/bbl	$95/bbl	$85/bbl	$78/bbl	$79/bbl
Gas	10.40%	264p/therm	188p/therm	121p/therm	93p/therm	78p/therm

Estimated production volumes and cash flows up to the date of cessation of production on a field by field basis, including operating and capital expenditure, are derived from the approved business plans.

19. BORROWINGS

	2019	2020	2021	30 June, 2021	30 June, 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Current					
Amounts owed to related parties	—	—	(437,076)	(412,026)	(455,000)
Senior unsecured notes	—	—	—	—	(200,000)
Bank fees	—	—	—	—	3,037
Senior notes fees	—	—	—	—	1,471
	—	—	(437,076)	(412,026)	(650,492)

	2019	2020	2021	30 June, 2021	30 June, 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Non-current					
Amounts owed to related parties	(732,034)	(654,022)	—	(250,000)	—
RBL facility	(1,055,000)	(720,000)	(350,000)	(520,000)	(750,000)
Senior unsecured notes	(500,000)	(500,000)	(625,000)	(500,000)	(625,000)
Long term bank fees	26,691	21,157	13,214	18,130	8,529
Long term senior notes fees	14,325	11,960	7,170	10,306	4,413
Total debt (excluding equity type subordinated debt)	(2,246,018)	(1,840,905)	(954,616)	(1,241,564)	(1,362,058)

Amounts owed to related parties

In November 2019 the Group issued interest-free capital loan notes worth a nominal value of $392 million to a related group undertaking, DKL Energy Limited. At the date of issuance, the capital loan notes were due for repayment no later than May 2022, after which point these are repayable on demand. On initial recognition, in November 2019, the capital loan notes were recorded at a fair value of $278 million estimated based on a 15% market rate of interest rate. The difference between the two was recorded as a capital contribution on issuance in 2019 (see note 25). In subsequent periods this capital contribution has been unwound to the income statement via imputed interest. The full amount of the loan notes remains outstanding at 30 June 2022. Subsequent to the balance sheet date, the maturity date of the loan notes was extended to the earlier of 1 January 2024 or the initial public offering of the Group's shares in the stock exchange.

Subordinated loan

In November 2019, the Group issued a subordinated loan note worth $198 million to the same group undertaking, DKL Energy Limited. The interest terms up to May 2021 matched those of an external loan with BNP Paribas entered into by DKL Energy on which a margin ranging from 6.5% to 11.5% on LIBOR was charged. Subsequent to repayment of the BNP Paribas loan by DKL Energy in May 2021, the tracker loan note was interest free. The tracker loan note was due for repayment at the date of issuance no later than May 2022, after which it was repayable on demand. The Group prepaid $120 million of the tracker loan note in 2020 and $15 million in 2021 and the remaining amount of $63 million and accrued interest remains unpaid at 30 June 2022. Subsequent to the balance sheet date, the maturity date of the loan was extended to the earlier of 1 January 2024 or the initial public offering of the Group's shares in the stock exchange.

Equity and Subordinated Debt

In November 2019, the existing $100 million Subordinated Shareholder Loan with Delek Group Ltd. was increased to $250 million. This loan was repaid to Delek Group Ltd. in August 2021.

RBL Facility

During 2019, the Group's RBL Facility size was increased to $1,650 million and its maturity was extended to April 2024, simultaneously the existing $300 million Term Loan was retired. The effective interest rate of the facility was 4.96%. Loan fees of $26.7 million relating to the RBL were capitalised in 2019 and amortised over the remaining life of the loan. In July 2021, the Group completed a further refinancing to amend and extend the RBL facility.

The RBL availability was approximately $1.225 billion with a maturity to 2026, and subject to interest at a reference rate of SONIA plus 3.5%. At 30 June 2022 $175 million was available for drawdown under the RBL facility.

Loan fees of $13.2 million relating to the RBL were capitalised and will be amortised over the term of the loan, $12.1 million remains to be amortised as at 30 June 2022. Following the refinancing $18.1 million of un-amortised fees were expensed to the income statement, included within loan fee amortisation, relating to the previous RBL facility.

The RBL facilities are secured by the assets of the guarantor members of the Group, such security including share pledges, floating charges and/or debentures.

Senior Notes

During July 2019, the Group issued $500 million 9.375% senior unsecured notes due for repayment in July 2024 with interest payable semi-annually. Loan fees of $14.3 million relating to the senior notes were capitalised on issuance and amortised over the remaining life of the loan. In July 2021, the Group completed the refinancing of its senior unsecured notes with the issuance of $625 million 9% senior unsecured notes due July 2026 and repayment in full of the notes issued during 2019. Loan fees of $7.4 million relating to the new senior notes were capitalised and will be amortised over the life of the loan, $5.8 million remains to be amortised as at 30 June 2022. Following the refinancing, $6 million of un-amortised fees were expensed, to the income statement, included within loan fee amortisation relating to the previous senior notes.

On acquisition of Siccar on 30 June 2022 the Group acquired the existing $200 million 9% senior unsecured notes due March 2026. The Group also acquired $5.8 million of accrued current interest in relation to these senior notes. The acquired senior notes include a voluntary early redemption call option and as such the related borrowings have been classified as current as at 30 June 2022.

On 1 August 2022, a settlement was made as a result of the exercise of the put option on the notes with a combined holding of US$166.4 million exercised the put option. Subsequently, in September 2022, notes totalling US$25.6 million were bought back at a premium of 6% by the Group. The remaining notes totalling US$8 million were redeemed on 12 October 2022. Covenants in relation to these senior notes are detailed below.

Covenants

The Group is subject to financial and operating covenants related to the RBL facility and the acquired senior notes, there are no covenants associated with amounts owed to related parties. Failure to meet the terms of one or more of these covenants may constitute an event of default as defined in the facility agreements, potentially resulting in accelerated repayment of the debt obligations. The Group was in compliance with all its relevant financial and operating covenants during all periods shown for the RBL facility and acquired senior notes. There are no ongoing maintenance or financial covenant tests associated with the $625 million unsecured notes.

In addition to the below financial covenants, the Group is subject to restrictive covenants under the RBL Facility and 2026 Notes, restricting the Group, to, amongst other things: incur additional debt; make certain payments (including, subject to certain exceptions, dividends and other distributions), with respect to outstanding share capital; repay or redeem subordinated debt or share capital; create or incur certain liens; make certain acquisitions and investments or loans; sell, lease or transfer certain assets, including shares of any of the Group's restricted subsidiaries; incur expenditure on exploration and appraisal activities in excess of approved levels; guarantee certain types of the Group's other indebtedness; expand into unrelated businesses; merge or consolidate with other entities; or enter into certain transactions with affiliates.

The key financial covenants in the RBL are:

- The Parent shall ensure that as at the end of each Relevant Period (starting with the Relevant Period ending on 30 November 2021) the ratio of Net Debt to EBITDAX shall be less than 3.5:1 "Net debt" referred to is not an IFRS measure. The Company uses net debt as a measure to assess its financial position. Net debt comprises amounts outstanding under the Company's RBL facility and senior notes, less cash and cash equivalents. Subordinated debt of $250 million from Delek Group Limited which was repaid on 3 August 2021 is a treated as a parent company loan.
- Total projected sources of funds must exceed the total projected uses of funds for the following 12 month period (or a longer period to first production from development, if applicable)
- The ratio of the net present value of cashflows secured under the RBL for the economic life of the fields to the amount drawn under the facility must not fall below 1.15:1
- The ratio of the net present value of cashflows secured under the RBL for the life of the debt facility to the amount drawn under the facility must not fall below 1.05:1

20. CHANGES IN LIABILITIES ARISING FROM FINANCING ACTIVITIES

Interest bearing loans and borrowings (note 19 and 21)

	2019	2020	2021	30 June, 2021	30 June, 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
At 1 January	(723,289)	(2,263,882)	(1,855,773)	(1,855,773)	(1,395,048)
Cash flows	(1,587,770)	544,595	650,736	301,750	(332,722)
Acquisitions	—	—	—	—	(200,000)
Other*	47,177	(136,486)	(190,011)	(106,924)	(158,176)
At 31 December / 30 June	(2,263,882)	(1,855,773)	(1,395,048)	(1,660,947)	(2,085,946)

* other comprises mainly finance costs, capital contribution and related imputed interest, lease liabilities recognised.

Financing cashflows from leasing arrangements disclosed in note 23.

21. TRADE AND OTHER PAYABLES

	2019	2020	2021	30 June, 2021	30 June, 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Trade payables	(23,653)	(17,768)	(13,901)	(10,145)	(17,423)
Amounts owed to parent (note 31)	(13,039)	(28,363)	(43,408)	(43,631)	(44,602)
Current tax payable	(74,414)	(9,964)	—	—	(20,745)
Amounts owed to joint ventures	(4,969)	(3,150)	(42,944)	(62,049)	(180,954)
Other payables	(114,248)	(78,443)	(187,655)	(177,906)	(147,487)
Accruals and deferred income	(140,713)	(147,984)	(196,360)	(112,325)	(295,773)
	(371,036)	(285,672)	(484,268)	(406,056)	(706,984)

The Directors consider the carrying values of trade and other payables to approximate the fair value.

22. DECOMMISSIONING LIABILITIES

	2019	2020	2021	30 June, 2021	30 June, 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Balance, beginning of period	(245,298)	(1,194,607)	(1,416,236)	(1,416,236)	(1,641,489)
Business combination additions (note 16)	(940,728)	—	—	—	(390,530)
Additions	—	—	(55,429)	—	—
Accretion	(16,276)	(47,844)	(42,502)	(21,256)	(23,229)
Revision to estimates	(1,010)	(203,506)	(175,190)	828	313,016
Decommissioning provision utilised	8,705	29,721	47,868	19,914	48,801
Balance, end of period	(1,194,607)	(1,416,236)	(1,641,489)	(1,416,750)	(1,693,431)

	2019	2020	2021	30 June, 2021	30 June, 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Current					
Balance, beginning of period	—	(10,472)	(28,836)	(28,836)	(94,640)
Balance, end of period	(10,472)	(28,836)	(94,640)	(32,778)	(94,640)
Non-current					
Balance, beginning of period	(245,298)	(1,184,135)	(1,387,400)	(1,387,400)	(1,546,849)
Balance, end of period	(1,184,135)	(1,387,400)	(1,546,849)	(1,383,972)	(1,598,791)

The total future decommissioning liability was calculated by management based on its net ownership interest in all wells and facilities, estimated costs to reclaim and abandon wells and facilities and the estimated timing of the costs to be incurred in future periods. The Group uses a discount rate of 3.5 percent (30 June 2021: 3.0 percent, 31 December 2021: 2.5 percent, 31 December 2020: 3.0 percent, 31 December 2019 : 4.0 percent) and an inflation rate of 2.0 percent (30 June 2021: 2.0 percent, 31 December 2021, 2020 & 2019: 2.0 percent) over the varying lives of the assets to calculate the present value of the decommissioning liabilities. The impact of a change in discount rate is included within revision to estimates. These costs are expected to be incurred at various intervals over the next 40 years. Movement in revision in estimates in 2020, 2021 and six months ended 30 June 2022 are mainly due to change in discount and fx rate changes.

The economic life and the timing of the obligations are dependent on commodity price and the future production profiles of the respective production and development facilities and Government legislation.

The estimated 2022 decommissioning spend of $95 million has been treated as a current liability as at 30 June 2022 (30 June 2021: $29 million, 2021: $95 million, 2020: $29 million, 2019: $10 million).

23. LEASE LIABILITIES

	2019	2020	2021	30 June, 2021	30 June, 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Current					
Lease liability	(5,942)	(6,080)	(3,211)	(3,543)	(21,006)

	2019	2020	2021	30 June, 2021	30 June, 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Non-Current					
Lease liability	(7,197)	(912)	(278)	(2,479)	(59,182)

The following table sets out a maturity analysis of lease payments, showing the undiscounted lease payments to be received after the reporting date. All lease liabilities are fully payable within 2 years from 30 June 2022.

	2019	2020	2021	30 June, 2021	30 June, 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Less than one year	(6,762)	(6,360)	(2,094)	(3,555)	(32,593)
One to two years	(6,762)	(877)	(1,617)	(2,383)	(52,503)
Two to three years	(1,370)	—	—	(419)	—
Total undiscounted lease payments	(14,894)	(7,237)	(3,711)	(6,357)	(85,096)
Future finance charges and other adjustments	1,755	245	222	335	4,908
Lease liabilities in the financial statements	(13,139)	(6,992)	(3,489)	(6,022)	(80,188)

	2019	2020	2021	30 June, 2021	30 June, 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
At 1 January	(27,140)	(13,139)	(6,992)	(6,992)	(3,489)
Additions	(13,139)	—	—	—	(85,039)
Interest	(836)	(587)	(367)	(171)	(1,829)
Payments	2,600	6,734	3,870	3,653	10,169
Revision	—	—	—	(2,512)	—
Derecognition of Pierce FPSO lease	25,376	—	—	—	—
At 31 December / 30 June	(13,139)	(6,992)	(3,489)	(6,022)	(80,188)
Current	(5,942)	(6,080)	(3,211)	(3,543)	(21,006)
Non-current	(7,197)	(912)	(278)	(2,479)	(59,182)
	(13,139)	(6,992)	(3,489)	(6,022)	(80,188)

The lease liabilities at 31 December 2019 and 2020 relate to the Captain FPSO and office lease acquired as part of the acquisition of CNSL in 2019. The incremental borrowing rate applied to these leases is 5.83% in all periods presented. The office lease was repaid in full during 2021.

The addition in the 6 month period to 30 June 2022 relates to the Pioneer rig lease currently utilised on the Captain EOR project. The incremental rate applied to the lease is 6.07%. The revision in 2021 relates to a lease extension on the Captain EOR project.

If the Group were to terminate the use of the Pioneer rig early then termination fees would apply, escalating to 75% if within 1 month prior to commencement date of planned works. Remuneration for work performed up to the date of termination, together with costs relating to demobilisation of the drilling unit to the demobilisation port would also be due.

Amounts recognised in profit and loss related to leases is detailed in note 6 and 9.

24. CONTINGENT AND DEFERRED CONSIDERATION

	2019	2020	2021	30 June, 2021	30 June, 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Current					
Contingent consideration	(8,250)	(8,250)	—	—	(28,272)
Petrofac deferred consideration	—	—	(49,806)	—	(45,382)
	(8,250)	(8,250)	(49,806)	—	(73,654)

	2019	2020	2021	30 June, 2021	30 June, 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Non-current					
Contingent consideration	(3,600)	(5,950)	(19,480)	(5,950)	(239,070)
Decommissioning incentive contract	(12,814)	—	—	—	—
Petrofac deferred consideration	(110,975)	(52,914)	(5,804)	(54,245)	—
MOGL deferred consideration	—	—	—	—	(69,022)
	(127,389)	(58,864)	(25,284)	(60,195)	(308,092)

	2019	2020	2021	30 June, 2021	30 June, 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Cashflows relating to contingent and deferred considerations	(10,000)	(56,900)	—	—	(15,864)

The Petrofac deferred consideration relates to the completion of the GSA transaction in December 2018 and is payable over a period from 2020 to 2023 and is discounted to reflect the time value of money. Interest is payable at 5% on $15 million of the consideration.

As part of the GSA transaction, Petrofac had the opportunity to earn up to an additional $25 million dependent on the future performance of the Stella and Harrier fields. At 31 December 2019 and 2020, $8.25 million was recognised to reflect the risk adjusted contingent consideration. $8.25 million was released during 2021 in accordance with the Petrofac SPA.

Cash outflows in the years ended 31 December 2019 and 2020 relate to an interim payments made per the Sale and Purchase Agreement for the Petrofac GSA acquisition in 2018. Cash outlows in the 6 month period ended 30 June 2022 are in relation to the consideration payable on Abigail FDP, and the first quarterly payment in consideration to the MOGL oil price trigger.

During the 6 months ended 30 June 2022 the Group acquired interests in MOGL and Siccar which included elements of consideration that are payable upon certain events occurring and contingent considerations have been recognised to reflect this. Further details regarding these acquisitions and the related contingent terms can be found in note 16.

The MOGL deferred consideration relates to completion of the MOGL transaction in February 2022. It is payable on 1 July 2025 and is discounted to reflect the time value of money.

The decommissioning incentive contract relates to a contractual liability associated with the acquisition of CNSL. Any liability which crystallises is fully recoverable, net of tax, from Chevron and therefore is reflected through the long term receivable included in note 10.

$2.6 million of the non-current contingent consideration balance relates to the acquisition of the Vorlich field, with a remaining amount payable upon Austen FDP submission of $0.6 million and subsequent payment of $3.0 million due upon defined production criteria being met.

$2.4 million relates to Marigold, contingent on achieving FDP and then certain production criteria.

The movement of $13.5 million in 2021 relates to additional consideration payable on Strathspey in accordance with the Sale and Purchase agreement.

25. RESERVES

Authorised share capital	Number of common shares	Amount
		US$'000
At 31 December 2019, 2020 & 2021 and at 30 June 2021 & 2022	1	1

(a) Issued

The issued share capital is as follows:

	Number of common shares	Amount
		US$'000
At 31 December 2019, 2020 & 2021 and at 30 June 2021 & 2022	1	1

(b) Share premium

	Amount
	US$'000
At 31 December 2019, 2020 & 2021 and at 30 June 2021 & 2022	634,658

(c) Capital contribution reserve

	Amount
	US$'000
At 31 December 2019, 2020 & 2021 and at 30 June 2021 & 2022	114,000

26. TAXATION

	2019	2020	2021	30 June, 2021	30 June, 2022
	US$000	US$000	US$000	US$'000	US$'000
Current tax					
Current corporation tax (charge)/credit	(22,921)	(384)	14,863	3,815	—
Current corporation tax credit / (charge)—prior year	—	—	3,815	—	—
Total current tax credit / (charge)	(22,921)	(384)	18,678	3,815	—
Deferred tax					
Adjustment in respect of prior period	38,835	13,646	(1,215)	(2,111)	(1)
Group tax credit/(charge) in Statement of Income	108,094	145,708	(386,767)	(113,041)	(162,112)
Group tax (charge)/credit in Statement of Other Comprehensive Income	(1,730)	(11,368)	194,632	109,678	106,833
Total deferred tax (charge) / credit	145,199	147,986	(193,350)	(5,474)	(55,280)
Deferred Petroleum Revenue Tax					
Deferred PRT credit in Statement of Income	—	—	32,154	—	(21,542)
Total Tax credit/(charge) through Statement of Income	124,008	158,970	(337,150)	(111,337)	(183,655)

Deferred tax	2019	2020	2021	30 June, 2021	30 June, 2022
	US$000	US$000	US$000	US$'000	US$'000
Deferred tax					
Accelerated capital allowances	70,453	242,031	(138,544)	(54,338)	23,129
Tax losses	72,030	(220,182)	(218,174)	(50,111)	(212,316)
Abandonment provision	9,057	77,931	24,214	14,674	5,941
Deferred PRT	—	—	19,293	0	(12,925)
Other	(6,341)	48,206	152,015	84,301	119,349
Total tax credit/(charge)	145,199	147,986	(161,196)	(5,474)	(76,822)

The tax on the Group's (loss)/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:

	2019	2020	2021	30 June, 2021	30 June, 2022
	US$000	US$000	US$000	US$'000	US$'000
Accounting (loss)/profit before tax	(147,620)	(614,698)	763,139	228,332	1,741,345
At tax rate of 40% (2021, 2020 & 2019: 40%)	59,048	245,879	(305,256)	(91,333)	(696,538)
Non-deductible expense	(36,660)	(49,321)	(71,996)	(30,645)	(45,193)
Impairment of goodwill	—	(82,599)	—	—	—
Gain on bargain purchase	—	—	—	—	530,081
Financing costs not allowed for SCT	(2,869)	(1,717)	(2,499)	(867)	(1,015)
Ring Fence Expenditure Supplement	58,700	28,894	11,313	6,301	34,888
Deferred tax effect of investment allowance	8,215	5,783	9,735	3,828	7,253
Over provided in prior years	38,835	13,263	2,602	1,704	(1)
Net deferred PRT	—	—	19,293	—	(12,926)
Unrecognised tax losses	(1,261)	(1,212)	(342)	(325)	(204)
Total tax credit/(charge) recorded in the consolidated statement of income	124,008	158,970	(337,150)	(111,337)	(183,655)

The Company is UK tax resident. The statutory rate of tax applicable for UK ring fence oil and gas activities in 2019, 2020, 2021 and 2022 was 40% consisting of a Ring Fence Corporation Tax Rate of 30% and the Supplementary Charge of 10%. Items affecting the tax charge include 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. Goodwill was impaired in 2020 on the acquisition of Chevron North Sea Limited due to lower oil and gas prices and Goodwill recognised in 2022 on the acquisition of Marubeni, Summit and Siccar Point, both of which are not taxable events. The deferred Petroleum Revenue Tax (PRT) Asset recognised on the Alba field has been partially derecognised in the period from 1 Jan 2022 to 30 June 2022, as the asset is expected to reverse against more profits subject to 0% PRT.

Deferred tax at 31 December / 30 June relates to the following:

	2019	2020	2021	30 June, 2021	30 June, 2022
	US$000	US$000	US$000	US$'000	US$'000
Deferred corporation tax liability	(800,031)	(536,735)	(688,140)	(479,831)	(1,304,135)
Deferred corporation tax asset	1,034,159	918,849	876,904	856,471	2,839,501
Deferred PRT asset	—	—	32,154	—	10,612
Net deferred tax asset	234,128	382,114	220,918	376,640	1,545,978

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 property plant and equipment and accumulated losses and profits related to derivative contracts

The gross movement on the deferred tax account is as follows:

	2019	2020	2021	30 June, 2021	30 June, 2022
	US$000	US$000	US$000	US$'000	US$'000
At 1 January	603,227	234,128	382,114	382,114	220,918
Income statement credit/(charge)	124,008	159,354	(355,828)	(115,152)	(182,797)
Other comprehensive income (charge)/ credit	(1,730)	(11,368)	194,632	109,678	106,833
Business combination (note 16)	(491,377)	—	—	—	1,405,583
At period end	234,128	382,114	220,918	376,640	1,550,536

The gross movement on the deferred tax account through the consolidated statement of income relates to the following:

	2019	2020	2021	30 June, 2021	30 June, 2022
	US$000	US$000	US$000	US$'000	US$'000
Accelerated capital allowances	70,453	242,031	(138,544)	(54,338)	23,129
Tax losses	72,030	(220,182)	(218,174)	(50,111)	(212,316)
Abandonment provision	9,057	77,931	24,214	14,674	5,941
Petroleum revenue tax	—	—	(12,861)	—	8,617
Other	(6,341)	48,206	152,015	84,301	119,349
	145,199	147,986	(193,350)	(5,474)	(55,280)

	Other	Deferred corporation tax on deferred PRT	Accelerated tax depreciation	Total
	US$000	US$000	US$000	US$000
Deferred corporation tax liabilities				
At 1 January 2019	(14,924)	—	(357,842)	(372,766)
Prior year adjustment	88	—	17,491	17,579
Origination and reversal of temporary differences	(6,429)	—	52,962	46,533
Business combination	—	—	(491,377)	(491,377)
At 31 December 2019 and 1 January 2020	(21,265)	—	(778,766)	(800,031)
Prior year adjustment	(700)	—	12,717	12,017
Origination and reversal of temporary differences	48,906	—	229,314	278,220
At 31 December 2020 and 1 January 2021	26,941	—	(536,735)	(509,794)
Reclass to deferred corporation tax assets	(26,941)	—	—	(26,941)
Prior year adjustment	—	—	(15,813)	(15,813)
Origination and reversal of temporary differences	—	(12,861)	(122,731)	(135,592)
At 31 December 2021	—	(12,861)	(675,279)	(688,140)
Prior year adjustment	—	—	—	—
Business combination	—	—	(647,743)	(647,743)
Origination and reversal of temporary differences	—	8,617	23,130	31,747
At 30 June 2022	—	(4,244)	(1,299,892)	(1,304,136)
Comparison:				
At 31 December 2020 and 1 January 2021	(26,941)	—	536,735	509,794
Prior year adjustment	—	—	15,813	15,813
Origination and reversal of temporary differences	(84,301)	—	38,525	(45,776)
At 30 June 2021	(111,242)	—	591,073	479,831

	Abandonment provision	Tax Losses	Other	Total
	US$000	US$000	US$000	US$000
Deferred corporation tax assets				
At 1 January 2019	86,464	866,637	—	953,101
Prior year adjustment	—	21,256	—	21,256
Origination and reversal of temporary differences	9,057	50,745	—	59,802
At 31 December 2019 and 1 January 2020	95,521	938,638	—	1,034,159
Prior year adjustment	—	1,629	—	1,629
Origination and reversal of temporary differences	77,931	(221,811)	—	(143,880)
At 31 December 2020 and 1 January 2021	173,452	718,456	—	891,908
Reclass from deferred corporation tax liabilities	—	—	26,941	26,941
Prior year adjustment	—	14,599	—	14,599
Origination and reversal of temporary differences	24,214	(232,773)	152,015	(56,544)
At 31 December 2021	197,666	500,282	178,956	876,904
Business Combination	156,212	1,858,706	38,406	2,053,324
Prior year adjustment	—	—	(1)	(1)
Origination and reversal of temporary differences	5,941	(212,317)	115,649	(90,727)
At 30 June 2022	359,819	2,146,672	333,010	2,839,500
Comparison:				
At 31 December 2020 and 1 January 2021	173,452	718,456	—	891,908
Prior year adjustment	—	13,702	—	13,702
Origination and reversal of temporary differences	14,674	(63,813)	—	(49,139)
At 30 June 2021	188,126	668,345	—	856,471

Deferred PRT asset	Total
	$000
At 1 January 2019, 2020 and 2021	—
Income statement credit	32,154
At 31 December 2021 and 1 January 2022	32,154
Origination and reversal of temporary differences	(21,541)
At 30 June 2022	10,613

Included within the other deferred tax assets and liabilities are accumulated losses and profits related to derivative contracts.

The carrying value of the net deferred corporation tax asset at 30 June 2022 of $2,800 million (30 June 2021:$856.5 million, 2021: $189 million, 2020: $382 million, 2019: $234 million) is supported by estimates of the Group's future taxable income, based on the same price and cost assumptions as used for impairment testing.

An Energy Profits Levy ("EPL" or "the Levy") was enacted on 14th 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. The Levy is charged upon 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. The impact of the Levy would be to decrease the deferred tax asset by $150.5 million if it was enacted on 30 June 2022.

27. COMMITMENTS AND CONTINGENCIES

	2019	2020	2021	30 June, 2021	30 June, 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Capital commitments					
Capital commitments incurred jointly with other venturers (Group's share)	105,157	65,519	83,368	84,805	191,007

The Group's capital expenditure is driven largely by full phase expenditure on existing producing fields, new development projects and appraisal and development activities. As of 30 June 2022, the Group had commitments for future capital expenditure amounting to $191.0 million. The key components of this relate to AFEs (authorisations for expenditure) signed for activities on Captain EOR and the Abigail field. As of 31 December 2021, the Group had commitments for future capital expenditure amounting to $83.4 million. The key components of this relate to the Captain enhanced oil recovery programme, investments on the Abigail field and upgrade works planned on Jade and Pierce. The Group expects its capital expenditure for the year ended 31 December 2022 to reach up to $479 million.

Contingencies

The Group enters into letters of credit and surety bonds to provide security for the Group's obligations under certain field and bi-lateral decommissioning security agreements, or equivalent, Sullom Voe Terminal Tariff Agreements and deferred payment obligations. The instruments are either held by the Law Debenture Trust Corporation P.L.C. under a trust deed or EnQuest Heather Limited, as SVT Terminal Operator. At 31 December 2021 and at 30 June 2022, the Group had £341 million and £383 million, respectively, in letters of credit and surety bonds outstanding relating to security obligations under certain decommissioning and security agreements.

28. FINANCIAL INSTRUMENTS

To estimate the fair value of financial instruments, the Group uses quoted market prices when available, or industry accepted third-party models and valuation methodologies that utilise observable market data. In addition to market information, the Group incorporates transaction specific details that market participants would utilise in a fair value measurement, including the impact of non-performance risk. The Group characterises inputs used in determining fair value using a hierarchy that prioritises inputs depending on the degree to which they are observable. However, these fair value estimates may not necessarily be indicative of the amounts that could be realised or settled in a current market transaction. The three levels of the fair value hierarchy are as follows:

- Level 1—inputs represent quoted prices in active markets for identical assets or liabilities (for example, exchange-traded commodity derivatives). Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2—inputs other than quoted prices included within Level 1 that are observable, either directly or indirectly, as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, market interest rates, and volatility factors, which can be observed or corroborated in the marketplace. The Group obtains information from sources such as the New York Mercantile Exchange and independent price publications.
- Level 3—inputs that are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value.

In forming estimates, the Group utilises the most observable inputs available for valuation purposes. If a fair value measurement reflects inputs of different levels within the hierarchy, the measurement is categorised based upon the lowest level of input that is significant to the fair value measurement. The valuation of over-the-counter financial swaps and collars is based on similar transactions observable in active markets or industry standard models that primarily rely on market observable inputs. Substantially all of the assumptions for industry standard models are observable in active markets throughout the full term of the instrument. These are categorised as Level 2.

The accounting classification of each category of financial instruments and their carrying amounts as at 31 December 2019 are set out below:

	Measured at amortised cost	Mandatorily measured at fair value through profit or loss	Derivative hedging instruments	Total carrying amount
	$'000	$'000	$'000	$'000
Financial assets				
Cash and cash equivalents	15,059	—	—	15,059
Trade and other receivables	158,149	—	—	158,149
Decommissioning receivable	200,986	—	—	200,986
Derivative financial instruments			102,309	102,309
Financial liabilities				
Borrowings	—	—	—	—
Trade and other payables	—	—	—	—
Lease liability	—	—	—	—
Contingent and deferred consideration	—	—	—	—
Derivative financial instruments	—	—	(54,198)	(54,198)
	374,194		48,111	422,305

The accounting classification of each category of financial instruments and their carrying amounts as at 31 December 2020 are set out below:

	Measured at amortised cost	Mandatorily measured at fair value through profit or loss	Derivative hedging instruments	Total carrying amount
	$'000	$'000	$'000	$'000
Financial assets				
Cash and cash equivalents	1,203	—	—	1,203
Trade and other receivables	109,213	—	—	109,213
Decommissioning receivable	244,830	—	—	244,830
Derivative financial instruments	—	—	31,424	31,424
Financial liabilities				
Borrowings	(1,840,905)	—	—	(1,840,905)
Trade and other payables	(285,672)	—	—	(285,672)
Lease liability	(6,992)	—	—	(6,992)
Contingent and deferred consideration	—	(67,114)	—	(67,114)
Derivative financial instruments			(105,579)	(105,579)
				(1,919,592)

The accounting classification of each category of financial instruments and their carrying amounts as at 31 December 2021 are set out below:

	Measured at amortised cost	Mandatorily measured at fair value through profit or loss	Derivative hedging instruments	Total carrying amount
	$'000	$'000	$'000	$'000
Financial assets				
Cash and cash equivalents	44,849	—	—	44,849
Trade and other receivables	228,290	—	—	228,290
Decommissioning receivable	246,824	—	—	246,824
Derivative financial instruments	—	—	5,108	5,108
Financial liabilities				
Borrowings	(1,391,692)	—	—	(1,391,692)
Trade and other payables	(484,268)	—	—	(484,268)
Lease liability	(3,489)	—	—	(3,489)
Contingent and deferred consideration	—	(75,090)	—	(75,090)
Derivative financial instruments	—	—	(459,302)	(459,302)
				(1,888,770)

The accounting classification of each category of financial instruments and their carrying amounts as at 30 June 2022 are set out below:

	Measured at amortised cost	Mandatorily measured at fair value through profit or loss	Derivative hedging instruments	Total carrying amount
	$'000	$'000	$'000	$'000
Financial assets				
Cash and cash equivalents	160,368	—	—	160,368
Trade and other receivables	348,731	—	—	348,731
Decommissioning receivable	212,459	—	—	212,459
Derivative financial instruments			21,844	21,844
Financial liabilities				
Borrowings	(2,012,550)	—	—	(2,012,550)
Trade and other payables	(706,984)	—	—	(706,984)
Lease liability	(80,188)	—	—	(80,188)
Contingent and deferred consideration	—	(381,746)	—	(381,746)
Derivative financial instruments	—	—	(809,605)	(809,605)
				(3,247,671)

Comparison:

The accounting classification of each category of financial instruments and their carrying amounts as at 30 June 2021 are set out below:

	Measured at amortised cost	Mandatorily measured at fair value through profit or loss	Derivative hedging instruments	Total carrying amount
	$'000	$'000	$'000	$'000
Financial assets				
Cash and cash equivalents	8,311	—	—	8,311
Trade and other receivables	139,461	—	—	139,461
Decommissioning receivable	240,866	—	—	240,866
Derivative financial instruments	—	—	6,815.30	6,815
Financial liabilities				
Borrowings	(1,653,590)	—	—	(1,653,590)
Trade and other payables	(406,056)	—	—	(406,056)
Lease liability	(6,022)	—	—	(6,022)
Contingent and deferred consideration	—	(60,195)	—	(60,195)
Derivative financial instruments	—	—	(291,722)	(291,722)
				(2,022,132)

The following table presents the Group's material financial instruments measured at fair value for each hierarchy level as of 31 December 2019:

	Level 1	Level 2	Level 3	Total Fair Value
	US$'000	US$'000	US$'000	US$'000
Contingent consideration (note 24)	—	—	(11,850)	(11,850)
Derivative financial instrument asset	—	100,956	—	100,956
Derivative financial instrument liability	—	(52,844)	—	(52,844)

There was no movement in level 3 instruments in the 12 months to 31 December 2019.

The following table presents the Group's material financial instruments measured at fair value for each hierarchy level as of 31 December 2020:

	Level 1	Level 2	Level 3	Total Fair Value
	US$'000	US$'000	US$'000	US$'000
Contingent consideration (note 24)	—	—	(14,200)	(14,200)
Derivative financial instrument asset	—	31,748	—	31,748
Derivative financial instrument liability	—	(105,903)	—	(105,903)

Movement in level 3 financial instruments in the 12 months to 31 December 2020 is as follows:

	US$'000
At 1 January 2020	(11,850)
Additions	(2,350)
At 31 December 2020	(14,200)

The following table presents the Group's material financial instruments measured at fair value for each hierarchy level as of 31 December 2021:

	Level 1	Level 2	Level 3	Total Fair Value
	US$'000	US$'000	US$'000	US$'000
Contingent consideration (note 24)	—	—	(19,480)	(19,480)
Derivative financial instrument asset	—	4,949	—	4,949
Derivative financial instrument liability	—	(459,143)	—	(459,143)

Movement in level 3 financial instruments in the 12 months to 31 December 2021 is as follows:

	US$'000
At 1 January 2021	(14,200)
Additions	(13,530)
Changes in fair value	8,250
At 31 December 2021	(19,480)

The following table presents the Group's material financial instruments measured at fair value for each hierarchy level as of 30 June 2022:

	Level 1	Level 2	Level 3	Total Fair Value
	US$'000	US$'000	US$'000	US$'000
Contingent consideration (note 24)	—	—	(273,633)	(273,633)
Derivative financial instrument asset	—	44,959	—	44,959
Derivative financial instrument liability	—	(844,980)	—	(844,980)

Movement in level 3 financial instruments in the 6 months to 30 June 2022 is as follows:

	US$'000
At 1 January 2022	(19,480)
Additions	(249,965)
Changes in fair value	(7,908)
Unwinding of discount rate	(1,617)
Impairment (note 18)	1,100
Utilisation	4,237
At 30 June 2022	(273,633)

Comparison:

The following table presents the Group's material financial instruments measured at fair value for each hierarchy level as of 30 June 2021:

	Level 1	Level 2	Level 3	Total Fair Value
	US$'000	US$'000	US$'000	US$'000
Contingent consideration (note 24)	—	—	(5,950)	(5,950)
Derivative financial instrument asset	—	6,815	—	6,815
Derivative financial instrument liability	—	(291,721)	—	(291,721)

Movement in level 3 financial instruments in the 6 months to 30 June 2021 is as follows:

	US$'000
At 1 January 2021	(14,200)
Additions	8,250
At 30 June 2021	(5,950)

The table below presents the total gain/(loss) on financial instruments that has been disclosed through the statement of income:

	2019	2020	2021	30 June 2021	30 June 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Revaluation of forex forward contracts	3,329	3,504	(8,261)	(1,996)	(18,676)
Revaluation of commodity hedges	(1,505)	(3,696)	—	—	—
	1,824	(192)	(8,261)	(1,996)	(18,676)
Realised loss on forex contracts	(977)	(2,300)	—	3,950	—
Realised gain on commodity hedges	(273)	2,006	7,808	—	—
	(1,250)	(294)	7,808	3,950	—
Ineffectiveness of cashflow hedges	(74)	—	—	—	—
Total gain/(loss) on financial instruments	500	(486)	(453)	1,954	(18,676)

Hedging reserve

The table below presents the total gain/(loss) on financial instruments that has been disclosed through the statement of comprehensive income:

Hedging reserve	2019	2020	2021	30 June 2021	30 June 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Revaluation of derivative contracts	14,322	(125,989)	(371,213)	(208,642)	(249,485)
Realised (loss)/gain on derivative contracts	36,215	459,008	(353,353)	(97,930)	(312,413)
Amounts recycled to revenue	(90,532)	(373,156)	196,181	13,401	270,173
Amounts recycled to revenue—oil put premiums	30,179	52,520	27,179	11,817	7,254
Amounts recycled to revenue—gas put premiums	14,140	16,037	14,627	7,158	17,389
Total gain/(loss)	4,325	28,420	(486,579)	(274,196)	(267,082)

The Group has identified that it is exposed principally to these areas of market risk.

i) Commodity Risk

Commodity price risk related to crude oil prices is the Group's most significant market risk exposure. Crude oil prices and quality differentials are influenced by worldwide factors such as OPEC actions, political events and supply and demand fundamentals. The Group is also exposed to natural gas price movements on uncontracted gas sales. Natural gas prices, in addition to the worldwide factors noted above, can also be influenced by local market conditions. The Group's expenditures are subject to the effects of inflation, and prices received for the product sold are not readily adjustable to cover any increase in expenses from inflation. The Group may periodically use different types of derivative instruments to manage its exposure to price volatility, thus mitigating fluctuations in commodity-related cash flows.

In all periods presented the Group has designated certain commodity options as a cash flow hedge of highly probable purchases. Because the critical terms (i.e. the quantity, maturity and underlying) of the commodity option and their corresponding hedged items are the same, the Group performs a qualitative assessment of effectiveness and it is expected that the intrinsic value of the commodity option and the value of the corresponding hedged items will systematically change in opposite directions in response to movements in the price of underlying commodity if the price of the commodity increases above the strike price of the derivative. The main source of hedge ineffectiveness in these hedge relationships is the effect of the counterparty and the Group's own credit risk on the fair value of the option contracts, which is not reflected in the fair value of the hedged item and if the forecast transaction will happen earlier or later than originally expected.

The Group's policy is to have the ability to hedge oil and gas prices up to a maximum of 75% of the next 12 months' production on a rolling annual basis, up to 50% in the following 12 month period and 25% in the subsequent 12-month period. On a rolling 12 month period under the RBL, the Group is required to hedge a minimum of 70% of volumes of net entitlement production expected to be produced in the next 12 months, 50% of volumes of net entitlement produced for the following 12 months on a best effort basis.

The below represents commodity hedges in place at the 2019 year end:

Derivative	Term	Volume	Average price
Oil puts	Jan 20–Dec 21	13,455,545 bbls	$65/bbl
Oil swaps	Jan 20–Dec 22	8,779,301 bbls	$61/bbl
Gas swaps	Jan 20–Jun 22	299,015,482 therms	51p/therm
Gas puts	Jan 20–Dec 21	264,990,482 therms	53p/therm

The below represents commodity hedges in place at the 2020 year end:

Derivative	Term	Volume	Average price
Oil puts	Jan 21–Dec 21	1,927,750 bbls	$56/bbl
Oil swaps	Jan 21–Dec 22	7,540,238 bbls	$40/bbl
Gas swaps	Jan 21–Mar 23	305,250,000 therms	45p/therm
Gas puts	Jan 21–Dec 22	305,250,000 therms	44p/therm

The below represents commodity hedges in place at the 2021 year end:

Derivative	Term	Volume	Average price
Oil puts	Jan 22–Dec 22	2,080,500 bbls	$64/bbl
Oil swaps	Jan 22–Dec 23	4,851,984 bbls	$56/bbl
Oil collars	Jan 22–Dec 23	3,558,750 bbls	$58/bbl floor–$80/bbl ceiling
Gas swaps	Jan 22–Dec 22	203,900,000 therms	64p/therm
Gas puts	Jan 22–Dec 23	36,500,000 therms	40p/therm
Gas collars	Jan 22–Dec 23	73,000,000 therms	60p/therm floor–94p/therm ceiling

The below represents commodity hedges in place at 30 June 2022:

Derivative	Term	Volume	Average price
Oil puts	Jul 22–Dec 23	5,005,292 bbls	$62/bbl
Oil swaps	Jul 22–Dec 22	1,048,800 bbls	$57/bbl
Oil collars	Jul 22–Dec 23	6,262,000 bbls	$66-$89/bbl
Gas swaps	Jul 22–Dec 23	192,495,000 therms	134p/therm
Gas puts	Jul 22–Dec 22	27,600,000 therms	90p/therm
Gas collars	Jul 22–Sep 23	78,000,000 therms	114p-204p/therm

Comparison:

The below represents commodity hedges in place at 30 June 2021:

Derivative	Term	Volume	Average price
Oil puts	Jul 21–Dec 23	6,559,486 bbls	$47/bbl
Oil swaps	Jul 21–Dec 22	4,750,500 bbls	$60/bbl
Gas swaps	Jul 21–Mar 23	223,700,000 therms	44p/therm
Gas puts	Jul 21–Dec 22	114,700,000 therms	43p/therm

The following table summarises the sensitivity of 20% decrease in realised commodity prices, with all other variables held constant, of the Group's profit before tax due to changes in the carrying value of monetary assets and liabilities at the reporting date. The impact on equity is the same as the impact on profit before tax.

Change in interest rate	2019	2020	2021	30 June 2021	30 June 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
20% decrease in realised oil price	(67,909)	(116,992)	(271,610)	(94,056)	(194,665)
20% decrease in realised gas price	(25,276)	(63,987)	(144,905)	(29,156)	(137,382)
	(93,185)	(180,979)	(416,515)	(123,212)	(332,047)

A 20% increase in realised commodity prices would have the equal but opposite effect to the amounts shown above, on the basis that all other variables remain constant.

ii) Interest Risk

Calculation of interest payments for the RBL Facilities and term loan agreements incorporate SONIA. The Group is therefore exposed to interest rate risk to the extent that SONIA may fluctuate. The Group mitigates the risk of SONIA fluctuations by entering into interest rate swaps on floating rates.

The below represents interest rate financial instruments in place at the 2019 year end:

Derivative	Term	Value	Rate
Interest rate swap (floating to fixed)	Jan 20–Apr 21	$300 million	2.86%

The below represents interest rate financial instruments in place at the 2020 year end:

Derivative	Term	Value	Rate
Interest rate swap (floating to fixed)	Apr 19–Apr 21	$300 million	2.86%
Interest rate swap (floating to fixed)	Oct 20–Dec 21	$200 million	1.44%
Interest rate swap (floating to fixed)	Mar 21–Dec 23	$50 million	0.22%

The below represents interest rate financial instruments in place at the 2021 year end:

Derivative	Term	Value	Rate
Interest rate swap (floating to fixed)	Jan 22–Dec 23	$50 million	0.22%

The below represents interest rate financial instruments in place at 30 June 2022:

Derivative	Term	Value	Rate
Interest rate swap (floating to fixed)	Mar 21–Dec 23	$50 million	0.219%

Comparison:

The below represents interest rate financial instruments in place at 30 June 2021:

Derivative	Term	Value	Rate
Interest rate swap (floating to fixed)	Jan 20–Dec 21	$100 million	1.43%
Interest rate swap (floating to fixed)	Jan 20–Dec 21	$100 million	1.45%
Interest rate swap (floating to fixed)	Mar 21–Dec 23	$50 million	0.22%

The following table summarises the sensitivity of an increase of 500 basis points in interest rate, with all other variables held constant, of the Group's profit before tax due to changes in the carrying value of monetary assets and liabilities at the reporting date. The impact on equity is the same as the impact on profit before tax.

Change in interest rate	2019	2020	2021	June 30, 2021	June 30, 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Increase of 500 basis points	(28,191)	(39,468)	(30,042)	(15,225)	(3,869)

A decrease in 500 basis points in interest rates would have the equal but opposite effect to the amounts shown above, on the basis that all other variables remain constant.

iii) Foreign Exchange Rate Risk

The Group is exposed to foreign exchange risks to the extent it transacts in various currencies, while measuring and reporting its results in US Dollars. Since time passes between the recording of a receivable or payable transaction and its collection or payment, the Group is exposed to gains or losses on non-USD amounts and on balance sheet translation of monetary accounts denominated in non-USD amounts upon spot rate fluctuations from quarter to quarter.

The Group enters into forward contracts as a means of hedging its exposure to foreign exchange rate risks. As at 31 December 2019 the Group had £4 million per quarter hedged at a forward rate of $1.24 : £1 for the period January to September 2020.

As at 31 December 2020 the Group had an average of £25 million per quarter hedged at an average forward rate of $1.30 : £1 for the period January to December 2021.

As at 31 December 2021 the Group had an average of £16 million per quarter hedged at an average forward rate of $1.375 : £1 for the period January to December 2022.

As at 30 June 2022 the Group had an average of £18 million per quarter hedged at an average forward rate of $1.07 : £1 for the period July to December 2022.

Comparison:

As at 30 June 2021 the Group had an average of £28 million per quarter hedged at an average forward rate of $1.30 : £1 for the July to December 2021.

The Group also enters into collar contracts as a means of hedging its exposure to foreign exchange rate risks. The Group holds $200m zero cost foreign exchange collars which mature on 30 November 2022.

The following table summarises the sensitivity to a reasonably possible change in the US Dollar to Sterling foreign exchange rate, with all other variables held constant, of the Group's profit before tax due to changes in the carrying value of monetary assets and liabilities at the reporting date. The impact on equity is the same as the impact on profit before tax. The Group's exposure to foreign currency changes for all other currencies is not material.

Change in GBP foreign exchange rate	2019	2020	2021	30 June 2021	30 June 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
10% weakening of GBP against USD . . .	(7,902)	(44,282)	(33,915)	(50,547)	(66,033)

A 10% strengthening of GBP against USD would have had the equal but opposite effect to the amounts shown above, on the basis that all other variables remain constant.

iv) Credit Risk

The Group's accounts receivable with customers in the oil and gas industry are subject to normal industry credit risks and are unsecured. Oil production from Cook and Dons is sold to Shell Trading International Ltd, Stella and Vorlich to ENI, Captain, Alba and Pierce to BP Oil International. Stella and Vorlich gas is sold to BP Gas Marketing and Gazprom Marketing and Trading. The agreement to sell Vorlich gas to GazProm has been terminated with effect 30 September 2022.

The Group assesses partners' creditworthiness before entering into farm-in or joint venture agreements. In the past, the Group has not experienced credit loss in the collection of accounts receivable. As the Group's exploration, drilling and development activities expand with existing and new joint venture partners, the Group will assess and continuously update its management of associated credit risk and related procedures.

The Group regularly monitors all customer receivable balances outstanding in excess of 90 days for ECLs. As at 30 June 2022, substantially all accounts receivables are current, being defined as less than 90 days. The Group has no allowance for doubtful accounts as at 30 June 2022 (30 June 2021: $Nil, 31 December 2021, 2020 & 2019: $Nil).

The Group may be exposed to certain losses in the event that counterparties to derivative financial instruments are unable to meet the terms of the contracts. The Group's exposure is limited to those counterparties holding derivative contracts with positive fair values at the reporting date. As at 30 June 2022, the Group's exposure is $15.6 million (30 June 2021: $6.8 million, 31 December 2021: $5.0 million, 31 December 2020: $31.7 million, 31 December 2019: $101 million). As derivative instruments are hedged with banks who are counterparties to the Group's RBL agreement the Directors consider there to be a low risk of default and therefore no credit value adjustment (CVA) or credit loss is recognised.

The Group also has credit risk arising from cash and cash equivalents held with banks and financial institutions. The maximum credit exposure associated with financial assets is the carrying values.

v) Liquidity Risk

Liquidity risk includes the risk that as a result of its operational liquidity requirements the Group will not have sufficient funds to settle a transaction on the due date. The Group manages liquidity risk by maintaining adequate cash reserves, banking facilities, and by considering medium and future requirements by continuously monitoring forecast and actual cash flows. The Group considers the maturity profiles of its financial assets and liabilities. As at 31 December 2021, 2020 and 2019, and 30 June 2022 and 2021, substantially all accounts payable are current.

vi) Capital Management

The Group's objectives when managing capital are to safeguard the Group's ability to continue as a going concern in order to provide returns to shareholders and benefits for other stakeholders and to maintain an optimal capital structure to reduce the cost of capital. The Group regularly monitors the capital requirements of the business over the short, medium and long-term, in order to enable it to foresee when additional capital will be required.

The Group has approval from management to hedge external risks, commodity prices, interest rates and foreign exchange risk. This is designed to reduce the risk of adverse movements in market prices, interest rates and exchange rates eroding the Group's financial results.

	2019	2020	2021	30 June 2021	30 June 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Total borrowings	1,163,984	(4,563,117)	329,616	616,564	932,550
Less cash and cash equivalents	(15,059)	(1,203)	(44,849)	(8,311)	(160,368)
Net debt	1,148,925	(4,564,320)	284,767	608,253	772,182
Total equity	(981,144)	(542,467)	(676,509)	(494,944)	(2,073,950)
Total capital	167,781	(5,106,787)	(391,742)	113,309	(1,301,768)

The following table shows the timing of cash outflows relating to liabilities as at 31 December 2019:

	Within 1 year	1 to 5 years
	US$'000	US$'000
Trade and other payables	(371,036)	—
Derivatives	(35,793)	(18,405)
Contingent and deferred consideration	(8,250)	(127,389)
Lease liabilities	(5,942)	(7,197)
Borrowings	—	(2,411,192)
	(421,021)	(2,564,183)

The following table shows the timing of cash outflows relating to liabilities as at 31 December 2020:

	Within 1 year US$'000	1 to 5 years US$'000
Trade and other payables	(28,836)	—
Derivatives	(78,534)	(27,045)
Contingent and deferred consideration	(8,250)	(58,864)
Lease liabilities	(6,080)	(912)
Borrowings	—	(1,908,918)
	(121,700)	(1,995,739)

The following table shows the timing of cash outflows relating to liabilities as at 31 December 2021:

	Within 1 year US$'000	1 to 5 years US$'000
Trade and other payables	(484,268)	—
Derivatives	(438,006)	(21,296)
Contingent and deferred consideration	(49,806)	(25,284)
Lease liabilities	(3,211)	(278)
Borrowings	(437,076)	(1,025,435)
	(1,412,367)	(1,072,293)

The following table shows the timing of cash outflows relating to liabilities as at 30 June 2022:

	Within 1 year US$'000	1 to 5 years US$'000
Trade and other payables	(706,984)	—
Derivatives	(672,609)	(136,996)
Contingent and deferred consideration	(73,654)	(308,092)
Lease liabilities	(21,006)	(59,182)
Borrowings	(655,000)	(1,375,000)
	(2,129,253)	(1,879,270)

Comparison:

The following table shows the timing of cash outflows relating to liabilities as at 30 June 2021:

	Within 1 year US$'000	1 to 5 years US$'000
Trade and other payables	(406,056)	—
Derivatives	(216,959)	(74,763)
Contingent and deferred consideration	—	(60,195)
Lease liabilities	(3,543)	(2,479)
Borrowings	(412,026)	(1,335,149)
	(1,038,584)	(1,472,586)

29. DERIVATIVE FINANCIAL INSTRUMENTS

	2019 US$'000	2020 US$'000	2021 US$'000	30 June, 2021 US$'000	30 June, 2022 US$'000
Oil swaps—cash flow hedge	1,014	(77,081)	(102,704)	(154,532)	(179,683)
Oil collars—cash flow hedge	—	10,804	(6,542)	(14,791)	(110,093)
Oil puts—cash flow hedge	(1,402)	—	(9,402)	(8,436)	(6,487)
Gas swaps—cash flow hedge	47,884	(1,420)	(264,345)	(101,760)	(387,914)
Gas puts—cash flow hedge	1,700	(5,401)	(3,317)	(10,546)	27,775
Gas collars—cash flow hedge	—	—	(66,007)	1,743	(117,792)
Interest rate swaps	(4,725)	(7,877)	133	(1,335)	6,791
FX collars	—	—	—	—	(12,660)
FX forwards	3,640	6,820	(2,010)	4,750	(7,699)
	48,111	(74,155)	(454,194)	(284,907)	(787,762)

Maturity analysis of derivative financial instruments	2019	2020	2021	30 June, 2021	30 June, 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Non-current assets	55,890	3,505	133	1,774	6,791
Current assets	46,419	27,919	4,975	5,042	15,052
Non-current liabilities	(18,405)	(27,045)	(21,296)	(74,763)	(136,996)
Current liabilities	(35,793)	(78,534)	(438,006)	(216,959)	(672,609)
	48,111	(74,155)	(454,194)	(284,906)	(787,762)

30. FAIR VALUES OF FINANCIAL ASSETS AND LIABILITIES

Financial instruments of the Group consist mainly of cash and cash equivalents, receivables, payables, loans and financial derivative contracts, all of which are included in the consolidated HFI. At 31 December the classification of financial instruments and the carrying amounts reported on the balance sheet and their estimated fair values are as follows:

	2019 US$'000		2020 US$'000		2021 US$'000		30 June, 2021 US$'000		30 June, 2022 US$'000	
Classification	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents (held for trading)	15,059	15,059	1,203	1,203	44,849	44,849	8,311	8,311	160,368	160,368
Trade and other receivables	125,813	125,813	6,006	6,006	18,918	18,918	2,964	2,964	20,698	20,698
Derivative financial instruments	102,309	102,309	31,424	31,424	5,108	5,108	6,815	6,815	21,844	21,844
Deposits	8,660	8,660	10,213	10,213	10,536	10,536	6,474	6,474	4,973	4,973
Bank debt (loans and bonds)	(1,746,018)	(1,719,018)	(1,340,905)	(1,340,905)	(329,616)	(312,741)	(741,564)	(594,689)	(737,058)	(776,433)
Trade and other payables	(23,653)	(23,653)	(17,768)	(17,768)	(13,901)	(13,901)	(10,145)	(10,145)	(17,423)	(17,423)
Contingent and deferred consideration	(135,639)	(135,639)	(67,114)	(67,114)	(75,090)	(75,090)	(60,195)	(60,195)	(381,746)	(381,746)
Derivative financial instruments	(54,198)	(54,198)	(105,579)	(105,579)	(459,302)	(459,302)	(291,722)	(291,722)	(809,605)	(809,605)
Other liabilities	(13,139)	(13,139)	(6,992)	(6,992)	(3,489)	(3,489)	(6,022)	(6,022)	(80,188)	(80,188)

31. RELATED PARTY TRANSACTIONS

The Group's immediate parent undertaking is DKL Energy Limited, and the ultimate parent Group is Delek Group Ltd. (incorporated in Israel). The Group's ultimate controlling party is Mr. Yitzhak (Sharon) Tshuva.

The consolidated HFI includes the financial information of the Group and the subsidiaries listed in the following table:

		% equity interest at 31 December			% equity interest at 30 June	
	Country of incorporation	2019	2020	2021	2021	2022
Ithaca Energy (E&P) Limited (formerly Ithaca Energy Inc.)	Jersey	100%	100%	100%	100%	100%
Ithaca Energy (UK) Limited	Scotland	100%	100%	100%	100%	100%
Ithaca Minerals (North Sea) Limited	Scotland	100%	100%	100%	100%	100%
Ithaca Energy (Holdings) Limited	Bermuda	100%	100%	100%	100%	100%
Ithaca Energy Holdings (UK) Limited	Scotland	100%	100%	100%	100%	100%
Ithaca Energy (North Sea) PLC	Scotland	100%	100%	100%	100%	100%
Ithaca Oil and Gas Limited (formerly Chevron North Sea Limited)	England and Wales	100%	100%	100%	100%	100%
Ithaca Petroleum Ltd	England and Wales	100%	100%	100%	100%	100%
Ithaca Causeway Limited	England and Wales	100%	100%	100%	100%	100%
Ithaca Gamma Limited	England and Wales	100%	100%	100%	100%	100%
Ithaca Alpha (NI) Limited	Northern Ireland	100%	100%	100%	100%	100%
Ithaca Epsilon Limited	England and Wales	100%	100%	100%	100%	100%
Ithaca Exploration Limited	England and Wales	100%	100%	100%	100%	100%
Ithaca Petroleum EHF	Iceland	100%	100%	100%	100%	100%
Ithaca SPL Limited***	England and Wales	100%	100%	100%	100%	—
Ithaca Dorset Limited	England and Wales	100%	100%	100%	100%	100%
Ithaca SP UK Limited	England and Wales	100%	100%	100%	100%	100%
Ithaca GSA Holdings Limited	Jersey	100%	100%	100%	100%	100%
Ithaca GSA Limited	Jersey	100%	100%	100%	100%	100%
Ithaca Energy Developments UK Limited	England and Wales	100%	100%	100%	100%	100%
FPF-1 Limited	Jersey	100%	100%	100%	100%	100%
Ithaca MA Limited*	England and Wales	—	—	—	—	100%
Ithaca SP Bonds PLC (formerly Siccar Point Energy Bonds PLC)**	England and Wales	—	—	—	—	100%
Ithaca SP Finance Limited (formerly Siccar Point Energy Finance Limited)**	England and Wales	—	—	—	—	100%
Ithaca SP (Holdings) Limited (formerly Siccar Point Energy (Holdings) Limited)**	England and Wales	—	—	—	—	100%

	Country of incorporation	% equity interest at 31 December 2019	2020	2021	% equity interest at 30 June 2021	2022
Ithaca SP (E&P) Limited (formerly Siccar Point Energy E&P Limited)**	England and Wales	—	—	—	—	100%
Ithaca SP (O&G) Limited (formerly Siccar Point Energy U.K. Limited)**	England and Wales	—	—	—	—	100%
Ithaca SPE Limited (formerly Siccar Point Energy Limited)**	England and Wales	—	—	—	—	100%
Ithaca Zeta Limited (formerly Summit Exploration and Production Limited)**	England and Wales	—	—	—	—	100%

Transactions between subsidiaries are eliminated on consolidation.

* The Group acquired 100% of the share capital of Ithaca MA Limited (formerly Marubeni Oil & Gas (UK) Limited) on 4 February 2022. Further details on the acquisition can be seen in note 16.

** The Group acquired 100% of the share capital of Ithaca SP Bonds PLC, Ithaca SP Finance Limited, Ithaca SP (Holdings Limited), Ithaca SP (E&P) Limited, Ithaca SP (O&G) Limited, Ithaca SP UK Limited, Ithaca SPE Limited and Ithaca Zeta Limited on 30 June 2022. Further details on the acquisitions can be seen in note 16.

*** Ithaca SPL Limited was dissolved on 15 February 2022.

The following table provides the loan balances with related parties as of 31 December

Borrowings—principal amount (note 19)	2019	2020	2021	30 June, 2021	30 June, 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Delek Group Limited	(250,000)	(250,000)	—	(250,000)	—
Subordinated loan due to DKL Energy Limited	(198,000)	(78,000)	(63,000)	(63,000)	(63,000)
Capital Notes issued to DKL Energy Limited	(284,034)	(326,022)	(374,076)	(349,026)	(392,000)
	(732,034)	(654,022)	(437,076)	(662,026)	(455,000)

Amounts due to parent (note 21)	2019	2020	2021	30 June, 2021	30 June, 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Delek Group Limited	(10,465)	(13,896)	(28,941)	(28,941)	(28,941)
Subordinated loan due to DKL Energy Limited	(2,574)	(14,090)	(14,090)	(14,314)	(14,314)
Other amounts owed to parent	—	(377)	(377)	(376)	(1,347)
	(13,039)	(28,363)	(43,408)	(43,631)	(44,602)

The related party loan with Delek Group Limited accrues interest at a rate of 4.75% per annum and is unsecured and repayable on demand.

Movement in capital notes in all periods presented relates to the unwind of the capital contribution (see note 21).

The following table provides remuneration to key management personnel for the periods ended 31 December 2019, 2020, 2021, 30 June 2021 and 30 June 2022:

Key management personnel	2019	2020	2021	30 June, 2021	30 June, 2022
	US$'000	US$'000	US$'000	US$'000	US$'000
Aggregate remuneration	2,913	6,436	3,247	1,539	2,971
Company pension contributions	51	302	155	86	42
	2,964	6,738	3,402	1,625	3,013

32. SUBSEQUENT EVENTS

On 14 July 2022 the UK Government enacted a temporary windfall tax of 25% on the profits of oil and gas companies called the Energy Profits Levy ("EPL" or "the Levy"). The Levy is charged upon 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. The Directors have considered the impact of the Levy at the date of signing these financial statements and it is believed that the Levy will result in a decrease to the net deferred tax asset by $150.5 million.

On 1 August 2022, a settlement was made as a result of the exercise of the put option on the Siccar bond. Given that Siccar Point Group's acquisition by Ithaca Energy (UK) Limited on 30 June 2022, constituted a change of control event under the bond terms, the put option was offered at a premium of 1% and bondholders with a combined holding of US$166.4 million exercised the put option. Subsequently, in September 2022, Siccar Point Bonds totalling US$25.6 million were bought back at a premium of 6% on behalf of Ithaca SP Bonds PLC (formerly Siccar Point Energy Bonds PLC) which were redeemed on 21 September 2022. The remaining Siccar Point Bonds totalling US$8 million were redeemed on 12 October 2022.

SECTION B: THE SICCAR POINT GROUP

PART A: ACCOUNTANT'S REPORT ON THE CONSOLIDATED HISTORICAL FINANCIAL INFORMATION OF THE SICCAR POINT GROUP

The Directors
Ithaca Energy plc
23 College Hill
London
EC4R 2RP

9 November 2022

Dear Ladies and Gentlemen

Ithaca SP (Holdings) Limited

We report on the consolidated financial information of Ithaca SP (Holdings) Limited and its subsidiaries (together, the "**Siccar Point Group**") for the years ended 31 December 2019, 31 December 2020 and 31 December 2021 and for the six-month period ended 30 June 2022 (the "**Siccar Point Group Financial Information**") set out in Part B (*Consolidated Historical Financial Information of the Siccar Point Group*) of Section B (*The Siccar Point Group*) of Part 16 (*Historical Financial Information*) of the prospectus (the "**Prospectus**") dated 9 November 2022 of the Ithaca Energy plc (the "**Company**").

We have not audited or reviewed the financial information for the six-month period ended 30 June 2021 and accordingly do not express an opinion thereon.

This report is required by item 18.3.1 of Annex 1 of the UK version of Commission Delegated Regulation (EU) 2019/980 and is given for the purpose of complying with that item and for no other purpose.

Save for any responsibility arising under Prospectus Regulation Rule 5.3.2R (2)(f) to any person as and to the extent there provided, to the fullest extent permitted by law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report or our statement, required by and given solely for the purposes of complying with item 1.3 of Annex 1 to the UK version of Commission Delegated Regulation (EU) 2019/980, consenting to its inclusion in the Prospectus.

Opinion on the Siccar Point Group Financial Information

In our opinion, the financial information gives, for the purposes of the Prospectus, a true and fair view of the state of affairs of the Siccar Point Group as at the dates stated and of its profits and losses, cash flows and changes in equity for the periods then ended in accordance with the UK-adopted International Accounting Standards.

Responsibilities

The Directors of the Company are responsible for preparing the Siccar Point Group Financial Information in accordance with UK-adopted International Accounting Standards.

It is our responsibility to form an opinion on the Siccar Point Group Financial Information and to report our opinion to you.

Basis of Preparation

The Siccar Point Group Financial Information has been prepared for inclusion in the Prospectus of the Company on the basis of the accounting policies set out in note 3 to the Siccar Point Group Financial Information.

Basis of opinion

We conducted our work in accordance with Standards for Investment Reporting issued by the Financial Reporting Council in the United Kingdom. We are independent in accordance with the FRC's

Ethical Standard as applied to Investment Circular Reporting Engagements, and we have fulfilled our other ethical responsibilities in accordance with these requirements.

Our work included an assessment of evidence relevant to the amounts and disclosures in the Siccar Point Group Financial Information. It also included an assessment of significant estimates and judgments made by those responsible for the preparation of the Siccar Point Group Financial Information and whether the accounting policies are appropriate to the entity's circumstances, consistently applied and adequately disclosed.

We planned and performed our work so as to obtain all the information and explanations which we considered necessary in order to provide us with sufficient evidence to give reasonable assurance that the Siccar Point Group Financial Information is free from material misstatement whether caused by fraud or other irregularity or error.

Our work has not been carried out in accordance with auditing or other standards and practices generally accepted in other jurisdictions and accordingly should not be relied upon as if it had been carried out in accordance with those standards and practices.

Conclusions Relating to Going Concern

We have not identified a material uncertainty related to events or conditions that, individually or collectively, may cast significant doubt on the Siccar Point Group's ability to continue as a going concern for a period of at least twelve months from the date of the Prospectus. We conclude that the Directors' use of the going concern basis of accounting in the preparation of the Siccar Point Group Financial Information is appropriate.

Declaration

For the purposes of Prospectus Regulation Rule 5.3.2R (2)(f) we are responsible for this report as part of the Prospectus and declare that, to the best of our knowledge, the information contained in this report is in accordance with the facts and that the report makes no omission likely to affect its import. This declaration is included in the Prospectus in compliance with item 1.2 of Annex 1 of the UK version of Commission Delegated Regulation (EU) 2019/980.

Yours faithfully

Ernst & Young LLP

PART B: CONSOLIDATED HISTORICAL FINANCIAL INFORMATION OF THE SICCAR POINT GROUP

CONSOLIDATED STATEMENT OF INCOME

For the years ended 31 December 2019, 2020 & 2021 and six month periods ended June 2021 & 2022

		Year ended			Six months ended	
	Note	Audited 31 Dec 2019	Audited 31 Dec 2020	Audited 31 Dec 2021	Unaudited 30 June 2021	Audited 30 June 2022
		US $'000	US $'000	US $'000	US $'000	US $'000
Revenue	5	223,755	142,321	234,642	107,279	153,213
Cost of sales	6	(150,560)	(128,186)	(137,807)	(65,288)	(72,735)
Gross profit		73,195	14,135	96,835	41,991	80,478
Impairment (charge)/reversal	14/15	(99,903)	(304,418)	358,618	—	(191,548)
Exploration and evaluation expenses		(4,333)	(3,412)	(3,850)	(2,369)	(1,924)
Fair value gain/(loss) in contingent consideration		46	10	(31)	—	36
General and administrative expenses		(12,964)	(11,995)	(13,537)	(7,229)	(11,610)
Other gains and losses	7	(17,816)	94,105	(120,503)	(67,678)	(34,297)
Profit/(loss) from operations before tax and finance costs		(61,775)	(211,575)	317,532	(35,285)	(158,865)
Net finance costs	8	(114,697)	(119,059)	(120,748)	(65,258)	(58,397)
Profit/(loss) before tax		(176,472)	(330,634)	196,784	(100,543)	(217,262)
Income tax	9	149,417	157,444	(344,994)	—	470,673
Profit/(loss) after tax		(27,055)	(173,190)	(148,210)	(100,543)	253,411

There is no other income to be reported separately under Statement of comprehensive income.

The consolidated statement of income has been prepared on the basis that all operations are continuing operations.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

As at 31 December 2019, 2020 and 2021 and 30 June 2021 & 2022

		Year ended			Six months ended	
	Note	Audited 31 Dec 2019	Audited 31 Dec 2020	Audited 31 Dec 2021	Unaudited 30 June 2021	Audited 30 June 2022
		US $'000	US $'000	US $'000	US $'000	US $'000
Current assets						
Cash and cash equivalents . . .		275,722	163,778	48,992	37,566	88,638
Account receivable	10	19,434	13,464	19,787	17,774	31,839
Deposit, prepaid expenses and other receivables	11	13,745	2,553	3,441	1,936	834
Inventory	12	9,396	8,128	10,809	8,879	12,055
Derivative financial instruments	23	22,189	34,861	3,352	3.637	—
		340,486	222,784	86,381	69,792	133,366
Non-current assets						
Exploration and evaluation assets	13	352,352	384,097	443,583	407,652	453,717
Property, plant and equipment .	14	1,343,004	1,014,595	1,331,875	991,957	1,058,758
Deferred tax assets	9	489,909	647,353	302,359	647,353	773,032
Derivative financial instruments	23	15,733	19,477	2,399	5,068	—
Long-term financial assets	16	49,964	59,554	10,131	60,221	—
		2,250,962	2,125,076	2,090,347	2,112,251	2,285,507
Total assets		2,591,448	2,347,860	2,176,728	2,182,043	2,418,873
LIABILITIES AND EQUITY						
Current liabilities						
Borrowings	18	—	—	—	—	(197,627)
Trade and other payables	17	(53,818)	(35,806)	(63,616)	(37,339)	(53,954)
Amounts due to parent	25	—	—	—	—	(323,057)
Contingent consideration	20	(2,640)	—	—	—	—
Derivative financial instruments	23	(1,510)	(1,880)	(47,619)	(35,727)	—
		(57,968)	(37,686)	(111,235)	(73,066)	(574,638)
Non-current liabilities						
Borrowings	18	(1,587,850)	(1,523,670)	(1,454,196)	(1,415,371)	(1,006,626)
Decommissioning liabilities	19	(169,613)	(179,001)	(180,202)	(180,963)	(129,931)
Other long term liabilities	21	(355)	(86)	—	—	—
Contingent consideration	20	(48,004)	(52,639)	(2,676)	(52,669)	—
Derivative financial instruments	23	(629)	(939)	(22,790)	(6,678)	—
		(1,806,451)	(1,756,335)	(1,659,864)	(1,655,681)	(1,136,557)
Total liabilities		(1,864,419)	(1,794,021)	(1,771,099)	(1,728,747)	(1,711,195)
Net assets		727,029	553,839	405,629	453,296	707,678
Equity						
Share capital	22	13,385	13,385	13,385	13,385	13,385
Capital contribution	22	—	—	—	—	48,638
Retained earnings		713,644	540,454	392,244	439,911	645,655
Total equity		727,029	553,839	405,629	453,296	707,678

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

For the year ended 31 December 2019, 2020 and 2021 and 30 June 2021 & 2022

	Share capital	Capital contribution	Retained profit	Total equity
	US $'000	US $'000	US $'000	US $'000
Balance at 1 January 2019	13,385	—	740,699	754,084
Loss for the year	—	—	(27,055)	(27,055)
Balance at 31 December 2019	13,385	—	713,644	727,029
Balance at 1 January 2020	13,385	—	713,644	727,029
Loss for the year	—	—	(173,190)	(173,190)
Balance at 31 December 2020	13,385	—	540,454	553,839
Balance at 1 January 2021	13,385	—	540,454	553,839
Loss for the year	—	—	(148,210)	(148,210)
Balance at 31 December 2021	13,385	—	392,244	405,629
Balance at 1 January 2022	13,385	—	392,244	405,629
Capital contribution (note 22)	—	48,638	—	48,638
Profit for the period	—	—	253,411	253,411
Balance at 30 June 2022	13,385	48,638	645,655	707,678
Comparison:				
Balance at 1 January 2021	13,385	—	540,454	553,839
Loss for the period	—	—	(100,543)	(100,543)
Balance at 30 June 2021	13,385	—	439,911	453,296

CONSOLIDATED STATEMENT OF CASH FLOW

For the year ended 31 December 2019, 2020 and 2021 and six month periods ended 30 June 2021 & 2022

		Year ended			Six months ended	
	Note	Audited 31 Dec 2019	Audited 31 Dec 2020	Audited 31 Dec 2021	Unaudited 30 June 2021	Audited 30 June 2022
		US $'000	US $'000	US $'000	US $'000	US $'000
Operating activities						
Profit/(loss) before tax		(176,472)	(330,634)	196,784	(100,543)	(217,262)
Adjustments for:						
Finance expense (interest on listed loan notes) and other finance costs	8	65,642	71,025	76,849	38,109	38,507
Finance expense (interest on RBL and bonds)	8	44,933	36,828	26,596	13,791	14,340
Depletion, depreciation and amortisation	14	105,753	80,877	66,475	34,743	47,757
Impairment charge/(reversal)	14	99,903	304,418	(358,618)	—	191,548
Accretion	8	3,011	3,294	3,597	1,818	1,802
Decommissioning changes in estimate		1,476	(234)	310	4	(1,254)
Decommissioning provision utilised	19	(2,255)	—	(1,078)	—	0
Impact of substantial modification on third party loan		2,525	4,183	—	—	—
Recognition of Put option on bonds	18	—	—	—	—	1,664
Loss/(gain) on derivative financial instruments		9,842	(15,737)	116,178	85,220	(19,508)
Amortisation of bank arrangement fee		732	402	(323)	(407)	524
Depreciation of office equipment	14	37	71	67	—	24
Depreciation of right of use assets	14	159	232	232	72	36
Unrealised net foreign exchange differences		(1,445)	857	212	(682)	(1,326)
(Gain)/loss on long-term receivable/payable remeasurement		(46)	(10)	31	—	(36)
Cashflow from operations		153,795	155,572	127,312	72,125	56,816
Changes in inventory, receivables and payables relating to operating activities		(1,738)	(11,538)	18,579	(2,158)	(9,377)
Corporation tax receipts		2,887	—	—	—	—
Net cash from operating activities		154,944	144,034	145,891	69,967	47,439
Investing activities:						
Purchase of office equipment	14	(105)	(86)	(9)	—	—
Expenditure on development and production assets		(36,745)	(50,848)	(26,439)	(12,044)	(14,297)
Expenditure on exploration and evaluation assets	13	(43,944)	(31,672)	(60,103)	(23,548)	(12,904)
Net cash used in investing activities		(80,794)	(82,606)	(86,551)	(35,592)	(27,201)

	Year ended			Six months ended	
	Audited 31 Dec 2019	Audited 31 Dec 2020	Audited 31 Dec 2021	Unaudited 30 June 2021	Audited 30 June 2022
	US $'000	US $'000	US $'000	US $'000	US $'000
Financing activities:					
Proceeds from bonds issuance (net of charges)	99,307	—	198,000	198,000	—
Repayment of bonds	—	—	(200,000)	(200,000)	—
Proceeds from borrowings	—	—	—	—	35,000
Repayment of borrowing—third-party (net)	—	(135,000)	(144,000)	(144,000)	—
Finance charge on leases	47	35	18	11	1
Interest paid on long-term loans	(46,969)	(37,857)	(27,884)	(14,829)	(14,402)
Net cash flows from/(used in) financing activities	52,385	(172,822)	(173,866)	(160,818)	20,599
Currency translations differences relating to cash	1,505	(550)	(260)	231	(1,191)
Increase/(decrease) in cash and cash equivalents	128,040	(111,944)	(114,786)	(126,212)	39,646
Cash and cash equivalents at 1 January	147,682	275,722	163,778	163,778	48,992
Cash and cash equivalents, end of period	**275,722**	**163,778**	**48,992**	**37,566**	**88,638**
Non-Cash disclosure :					
Repayment of borrowing—third-party	—	—	—	—	(277,000)
Settlements of derivative financial instruments	—	—	—	—	(45,150)
Interest and other finance costs on long-term loans	—	—	—	—	(907)
Amounts due to parent	—	—	—	—	323,057
Net non-cash flows used in financing activities	—	—	—	—	—

The above reconciliation outlines payments made on the Siccar Point Group's behalf by IEUK as part of the completion mechanism of the acquisition of the Siccar Point Group, completed on 30 June 2022. This mainly represents the mandatory repayment of RBL loan of US$277 million due to a change of control and the early termination of hedges amounting to US$45 million which could not be novated to Ithaca Group as per the mutual agreement with counterparties. Amount due to IEUK of US$323 million is payable on demand.

NOTES TO THE HISTORIC FINANCIAL INFORMATION

1. NATURE OF OPERATIONS

Ithaca SP (Holdings) Limited (formerly Siccar Point Energy (Holdings) Limited) ("**the Siccar Point Company**") and its subsidiaries (collectively, "**the Siccar Point Group**") was established in 2014 to build a full cycle, North Sea exploration, development and production business. The registered office address of all members in the Siccar Point Group is 1 Park Row, Leeds, LS1 5AB.

The Siccar Point Company was owned by Siccar Point Energy Luxembourg S.C.A. a Company registered in Luxemburg from the date of its establishment on 25 June 2014 to its eventual sale to IEUK on 30 June 2022.

The Siccar Point Company's immediate parent undertaking is IEUK, a company incorporated in the United Kingdom. The IEUK's immediate parent undertaking is Ithaca Energy (E&P) Limited (collectively with its subsidiaries "**the Ithaca Group**"), a company incorporated in Jersey.

The Siccar Point Company's ultimate parent Group is Delek Group Ltd., a group incorporated in Israel.

2. BASIS OF PREPARATION

The consolidated historical financial information has been prepared in accordance with UK-adopted International Accounting Standards ("**UK-adopted IAS**").

The consolidated historical financial information for the three years ended 31 December 2019, 2020, and 2021 and 6 months ended 30 June 2021 and 30 June 2022 (the "**Consolidated Historical Financial Information**") has been prepared specifically for the purposes of this Prospectus and does not constitute statutory accounts within the meaning of section 434(3) of the Companies Act 2006."

The consolidated financial information is presented in US dollars and all values are rounded to the nearest thousand (US$'000), except when otherwise indicated.

3. SIGNIFICANT ACCOUNTING POLICIES, JUDGEMENTS, AND ESTIMATION UNCERTAINTY

Basis of measurement

The consolidated financial information has been prepared on a going concern basis using the historical cost convention, except for the revaluation of certain financial assets and financial liabilities under International Financial Reporting Standards ("IFRS") to fair value, including derivative instruments. Historical cost is generally based on the fair value consideration given in exchange for the assets.

Going concern

Subsequent to the acquisition of the Siccar Point Group by Ithaca Energy (UK) Limited, as per the Ithaca Group policy, the Siccar Point Group is now under the Ithaca Group's centralised treasury management arrangement and shares banking arrangements with the Ithaca Group of companies and therefore the Siccar Point Group's ability to continue as a going concern is dependent on access to the Ithaca Group's resources.

The Ithaca Group directors consider the preparation of the Consolidated Historical Financial Information on a going concern basis to be appropriate. This is due to the following key factors:

- Commodity market performance. Brent has averaged over $105/bbl and UK Natural Gas has averaged over 211p/therm since 31 December 2021. Oil and gas prices are forecast to remain at high levels through the rest of 2022 and throughout 2023;
- Liquidity headroom. As at 30 June 2022 the Ithaca Group held liquidity of US$335million (US$175 million available to be drawn upon within the Reserves Based Lending ("RBL") facility, plus US$160 million cash) and as at 4 November 2022, the Ithaca Group maintains liquidity of US$554 million (US$275 million available to be drawn upon within the RBL facility, plus US$279 million cash);

- Operational performance and a diversified portfolio, which has been further strengthened by the acquisitions of the Siccar Point Group and Summit E&P as at 30 June 2022; and
- A material hedge position which reduces exposure to price uncertainty—over 56% of total H2 2022 production was hedged, and 35% of 2023 production.

The Ithaca Group directors closely monitor the funding position of the Ithaca Group throughout the year, including monitoring continued compliance with covenants and available facilities to ensure sufficient headroom to fund operations.

The Ithaca Group directors have considered a number of risks applicable to the Ithaca Group that may have an impact on its ability to continue as a going concern. Short-term and long-term cash forecasts are produced on a weekly and quarterly basis respectively along with any related sensitivity analysis. This allows proactive management of any business risks, including liquidity risk discussed below.

The Ithaca Group directors have reviewed the Ithaca Group's forecasts and projections for the period to 31 December 2023, including forecast covenant compliance. Owing to fluctuations in commodity demand and price volatility, management prepared sensitivity analyses to the forecasts and applied a number of downside plausible scenarios and stress tests for the whole Ithaca Group, including decreases in production, reduced sales prices, increases in operating and capital expenditure assumptions and exchange rate fluctuations. Management aggregated these scenarios to create a reasonable combined worst-case scenario.

The sensitivity analysis showed that there was no reasonably possible scenario that would result in the business being unable to meet its obligations as they fall due. The Ithaca Group would still continue to have sufficient cash headroom throughout the period to 31 December 2023 (the 'going concern period') and still have the necessary liquidity to continue trading.

The Ithaca Group directors have a number of mitigating actions within their control, including the further drawdown on its available funds from the RBL facility, the reduction in uncommitted capital expenditure, and the cancellation or deferral of future dividends.

The Siccar Point Group has also obtained a letter of support from both Ithaca Energy (E&P) Limited and Ithaca Energy plc (IEL) (being intermediate parent companies of the Siccar Point Group) to provide financial support for the period up to and including 31 December 2023.

Based on the assessment of the Ithaca Group's financial position for the period to 31 December 2023 and the confirmation of continued parental support, the IEL directors are satisfied that they have a reasonable basis upon which to conclude that the Siccar Point Group is able to continue as a going concern throughout the going concern period. Accordingly, they continue to adopt the going concern basis of accounting in preparing the Consolidated Historical Financial Information.

Basis of consolidation

The consolidated financial information of the Siccar Point Group includes the financial information of Ithaca SP (Holdings) Limited (formerly Siccar Point Energy (Holdings) Limited) and all wholly-owned subsidiaries as listed per note 25. All intergroup transactions and balances have been eliminated on consolidation.

Subsidiaries are all entities, over which the Siccar Point Group has control. The Group controls an entity when the Group is exposed to or has rights to variable returns from its investments with the entity and has the ability to affect those returns through its power over the entity. Subsidiaries are fully consolidated from the date on which control is transferred to the Group. They are deconsolidated on the date that control ceases.

Interest in joint operations

The Siccar Point Group has established a high-quality portfolio of long life, low unit cost, production, development and exploration assets in the UK Continental Shelf.

The Siccar Point Group's exploration, development and production activities are generally conducted in jointly controlled operations with other companies. The Siccar Point Group recognises its share of the jointly controlled assets and liabilities it has incurred, its share of any liabilities jointly incurred with other venturers, income from the sale or use of its share of the joint operations output, together with its share of the expenses incurred by the joint operations, and any expenses it incurs in relation to its interest in the joint operations and a share of production.

Interest in joint operations (continued)

The Siccar Point Group's interests in significant joint arrangements are listed below:

		Ownership interest				
Licence area	**Type**	**2019**	**2020**	**2021**	**30 June 2021**	**30 June 2022**
Schiehallion	Production	11.75%	11.75%	11.75%	11.75%	11.75%
Jade	Production	5.57%	5.57%	5.57%	5.57%	5.57%
Rosebank	Pre sanction development	20%	20%	20%	20%	20%
Cambo*	Pre sanction development	70%	70%	70%	70%	70%
Blackrock*	Exploration & appraisal	52.5%	60%	60%	60%	60%
Mariner	Production	8.89%	8.89%	8.89%	8.89%	8.89%
Suilven*	Exploration & appraisal	75%	75%	75%	75%	75%
Tornado*	Exploration & appraisal	50%	50%	50%	50%	50%

* Operated by the Siccar Point Group

Revenue

The sale of crude oil, gas or natural gas liquids represents a single performance obligation, being the sale of barrels equivalent on collection of a cargo or on delivery of commodity into an infrastructure. Revenue is accordingly recognised for this performance obligation when control over the corresponding commodity is transferred to the customer. Revenue is measured at the fair value of the consideration received or receivable and represents amounts receivable for products in the normal course of business, net of discounts, customs duties and sales taxes.

Foreign currency translation

Items included in this financial information are measured using the currency of the primary economic environment in which the Siccar Point Group operate (the 'functional currency'). The consolidated financial information is presented in US Dollars (note 2), which is the Siccar Point Company's functional and the Siccar Point Group's presentation currency.

Foreign currency transactions are translated into functional currency using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at year end exchange rates of monetary assets and liabilities denominated in foreign currencies are recognised in the statement of income.

Financial Instruments and derivatives

Financial assets are classified, at initial recognition, as subsequently measured at amortised cost, at fair value through other comprehensive income (OCI), and fair value through profit or loss.

The classification of financial assets at initial recognition depends on the financial assets' contractual cash flow characteristics. With the exception of trade receivables that do not contain a significant financing component, the Siccar Point Company initially measures a financial asset at its fair value plus, in the case of a financial asset not at fair value through profit or loss, transaction costs. Trade receivables that do not contain a significant financing component are measured at transaction price.

The Siccar Point Group has used derivative financial instruments as economic hedges to reduce certain exposures to commodity price risk, cash flow interest rate risk and foreign currency exchange risk. These include commodity hedging, forward currency contracts and interest rate swaps. Derivative financial instruments are held at fair value in the Statement of Financial Position with valuation gains or losses shown as operating expenses/income in the Statement of Comprehensive Income.

The Siccar Point Group's valuation strategies for financial instruments utilise, as far as possible, quoted prices on an active market. Valuations fall into 3 levels in the fair value hierarchy:

- Level 1—utilises quoted prices on an active market for an identical asset or liability
- Level 2—utilises quoted prices on an active market for similar products or derives the valuation from other observable inputs
- Level 3—where a market price for similar product is not observable, the valuation uses inputs based on internal models or other valuation techniques

Financial assets and liabilities, other than derivative financial instruments, are held at amortised cost, which approximates their fair value, with the exception of the fixed rate loan notes and bonds.

Impairment of financial assets

The Siccar Point Group will recognise an allowance for expected credit losses (ECLs) for all debt instruments not held at fair value through the income statement. ECLs are based on the difference between the contractual cash flows due in accordance with the contract and all the cash flows that the Siccar Point Group expects to receive.

For trade receivables and contract assets, the Siccar Point Group applies a simplified approach in calculating ECLs. Therefore, the Siccar Point Group does not track changes in credit risk, but instead recognises a loss allowance based on lifetime ECLs at each reporting date. The Siccar Point Group has established a provision matrix, that is based on its historical credit loss experience, adjusted for forward-looking factors specific to the debtors and the economic environment.

For long-term receivables and advances to joint operation partners, ECLs are recognised in two stages. For credit exposures for which there has not been a significant increase in credit risk since initial recognition, ECLs are provided for credit losses that result from default events that are possible within the next 12-months (12-month ECL). For those credit exposures for which there has been a significant increase in credit risk since initial recognition, a loss allowance is required for credit losses expected over the remaining life of the exposure, irrespective of the timing of the default (a lifetime ECL).

The Siccar Point Group considers a financial asset in default when contractual payments are significantly past due date. However, in certain cases, the Siccar Point Group may also consider a financial asset to be in default when internal or external information indicates that the Siccar Point Group is unlikely to receive the outstanding contractual amounts in full. A financial asset is written off when there is no reasonable expectation of recovering the contractual cash flows.

Cash and cash equivalents

For the purpose of the statement of cash flow, cash and cash equivalents include investments with an original maturity of three months or less.

Inventories—hydrocarbon and materials

Inventories of materials and hydrocarbon inventory supplies are stated at the lower of cost and net realisable value. Cost comprises direct materials and, where applicable, direct labour costs and those overheads that have been incurred in bringing the inventories to their present location and condition. Cost is determined on the first-in, first-out method. Current hydrocarbon inventories are stated at net realisable value, which is based on estimated selling price less any further costs expected to be incurred to completion and disposal/sale.

Lifting or offtake arrangements for oil and gas produced in certain of the Siccar Point Group's jointly owned oil and gas operations are such that each participant may not receive and sell its precise share of the overall production in each period. The resulting imbalance between cumulative entitlement and cumulative volume sold less inventory is an "underlift" or "overlift" and are measured at fair value and included within inventories and payables respectively.

Movements during an accounting period are adjusted through cost of sales in the statement of income and is recognised on an entitlement basis.

Trade receivables

Trade receivables are recognised and carried at the original invoiced amount, less any provision for estimated irrecoverable amounts.

For trade receivables, the Siccar Point Group applies a simplified approach in calculating ECLs. Therefore, the Siccar Point Group does not track changes in credit risk, but instead, recognises a loss allowance based on lifetime ECLs at each reporting date.

The Siccar Point Group considers a financial asset in default when contractual payments are 90 days past due. However, in certain cases, the Siccar Point Group may also consider a financial asset to be in default when internal or external information indicates that the Siccar Point Group is unlikely to receive the outstanding contractual amounts in full before taking into account any credit enhancements held by the Siccar Point Group. A financial asset is written off when there is no reasonable expectation of recovering the contractual cash flows.

Financial liabilities measured at amortised cost

All other financial liabilities are initially recognised at fair value, net of directly attributable transaction costs. For interest-bearing loans and borrowings this is typically equivalent to the fair value of the proceeds received, net of issue costs associated with the borrowing. After initial recognition, other financial liabilities are subsequently measured at amortised cost using the effective interest method. Amortised cost is calculated by taking into account any issue costs and any discount or premium on settlement. Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognised in interest and other income and finance costs respectively. This category of financial liabilities includes trade and other payables and finance debt.

Derecognition of financial liabilities

The Siccar Point Group derecognises financial liabilities when, and only when, the Siccar Point Group's obligations are discharged, cancelled or have expired. The difference between the carrying amount of the financial liability derecognised and the consideration paid and payable is recognised in profit or loss.

When the Siccar Point Group exchanges with the existing lender one debt instrument into another one with substantially different terms, such exchange is accounted for as an extinguishment of the original financial liability and the recognition of a new financial liability. Similarly, the Siccar Point Group accounts for substantial modification of terms of an existing liability or part of it as an extinguishment of the original financial liability and the recognition of a new liability.

Property, plant and equipment

Capitalisation

Pre-acquisition costs on oil and gas assets are recognised in the consolidated statement of income when incurred. Costs incurred after rights to explore have been obtained, such as geological and geophysical surveys, drilling and commercial appraisal costs and other directly attributable costs of exploration and evaluation including technical and administrative expenses are capitalised as intangible exploration and evaluation ("E&E") assets.

E&E costs are not amortised prior to the conclusion of evaluation activities. At completion of evaluation activities, if technical feasibility is demonstrated and commercial reserves are discovered then, following approved development sanction, the carrying value of the E&E asset is reclassified as a development and production ("D&P") asset, but only after the carrying value is assessed for impairment and where appropriate its carrying value adjusted. In addition, where the E&E asset forms part of an existing development and production cash-generating units ("CGUs"), such E&E activity is included in the carrying value of the Siccar Point Group's D&P assets. If after completion of evaluation activities in an area, it is not possible to determine technical feasibility and commercial viability or if the legal right to explore expires or if the Siccar Point Group decides not to continue exploration and evaluation activity, then the costs of such unsuccessful exploration and evaluation are written off to the statement of income in the period the relevant events occur.

Oil and gas expenditure—development and production assets

Capitalisation

Costs of bringing a field into production, including the cost of facilities, wells and subsea equipment, direct costs including staff costs together with E&E assets reclassified in accordance with the above policy, are capitalised as a D&P asset.

Depreciation

All costs relating to a development are accumulated and not depreciated until the commencement of production. Depreciation is calculated on a unit of production basis based on the proved and probable reserves of the asset. Any re-assessment of reserves affects the depreciation rate prospectively. Significant items of plant and equipment will normally be fully depreciated over the life of the field. However, these items are assessed to consider if their useful lives differ from the expected life of the D&P asset and should this occur a different depreciation rate would be charged.

Impairment

For impairment review purposes the Siccar Point Group's oil and gas assets are analysed into CGUs as identified in accordance with IAS 36. Individual assets are grouped into CGUs for impairment assessment purposes at the lowest level at which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. This grouping is based on a number of factors which include the infrastructure required to operate the asset, management operating plans (including consideration of hub strategies), internal management reporting, geographic location and operating licences. CGUs are identified consistently from period to period, unless a change is justified. A review is carried out each reporting date for any indicators that the carrying value of the Siccar Point Group's assets may be impaired or previously impaired assets (excluding goodwill) where a reversal of a previous impairment may arise. For assets where there are such indicators, an impairment test is carried out on the CGU.

The impairment test involves comparing the carrying value with the recoverable value of an asset. The recoverable amount of an asset is determined as the higher of its fair value less costs to sell and value in use, where the value in use is determined from estimated future net cash flows. If the recoverable amount of an asset is estimated to be less than its carrying amount, the carrying amount of the asset is reduced to the recoverable amount. The resulting impairment losses are written off to the statement of income. Previously impaired assets (excluding goodwill) are reviewed for possible reversal of the previous impairment at each reporting date.

A previously recognised impairment loss is only reversed if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognised. If this is the case, the carrying amount is increased to the recoverable amount. That increased amount cannot exceed the carrying amount that would have been determined, net of depreciation had no impairment loss been recognised in previous years.

Non-oil and natural gas operations

Non-oil and gas assets are initially recorded at cost and depreciated over their estimated useful lives on a straight line basis as follows—

Computer and office equipment	3 years

Borrowings

All interest-bearing loans and other borrowings with banks are initially recognised at fair value net of directly attributable transaction costs. After initial recognition, interest-bearing loans and other borrowings are subsequently measured at amortised cost using the effective interest method. Amortised cost is calculated by taking into account any issue costs, discount or premium.

Loan origination fees are capitalised and amortised over the term of the loan. Borrowing costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use or sale, are added to the cost of those assets until such time as the assets are substantially ready for their intended use of sale. All other borrowing costs are expensed as incurred.

Decommissioning liabilities

The Siccar Point Group records the present value of legal obligations associated with the retirement of long-term tangible assets, such as producing well sites and processing plants, in the period in which they are incurred with a corresponding increase in the carrying amount of the related long-term asset. Liabilities for decommissioning are recognised when the Siccar Point Group has an obligation to plug & abandon a well, dismantle and remove a facility or an item of plant and restore the site on which it is located, and when a reliable estimate can be made. Where an obligation exists for a new facility or well, such as oil & gas production or transportation facilities, the obligation arises when the asset is installed or the ground/environment is disturbed at the field location and the amount recognised is the present value of the estimated future expenditure determined in accordance with the local regulations and requirements. In subsequent periods, the asset is adjusted for any changes in the estimated amount or timing of the settlement of the obligations. The carrying amounts of the associated assets are depleted using the unit of production method, in accordance with the depreciation policy for development and production assets. Actual costs to retire tangible assets are deducted from the liability as incurred. See note 19 for key assumptions and sensitivity analysis.

Contingent consideration

Contingent consideration is accounted for as a financial liability and measured at fair value at the date of acquisition with any subsequent remeasurements recognised in profit or loss in accordance with IFRS 9.

Taxation

Current income tax

Current income tax assets and liabilities are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amounts are those that are enacted or substantively enacted by the reporting date.

Deferred income tax

Deferred tax is recognised for all deductible temporary differences and the carry-forward of unused tax losses. Deferred tax assets and liabilities are measured using enacted or substantively enacted income tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in rates is included in earnings in the period of the enactment date. Deferred tax assets are recorded in the consolidated financial information if realisation is considered more likely than not.

The carrying amount of deferred tax assets is reviewed at each balance sheet date and reduced to the extent that it is no longer probable that sufficient taxable profits will be available to allow all or part of the asset to be recovered.

Deferred tax assets and liabilities are offset only when a legally enforceable right of offset exists and the deferred tax assets and liabilities arose in the same tax jurisdiction.

Leases

The Siccar Point Group assesses at contract inception all arrangements to determine whether it is, or contains, a lease. That is, if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. The Siccar Point Group is not a lessor in any transactions, it is only a lessee. The Siccar Point Group applies a single recognition and measurement approach for all leases, except for short-term leases and leases of low-value assets. The Siccar Point Group recognises lease liabilities to make lease payments and right-of-use assets representing the right to use the underlying assets.

Right-of-use assets are measured at cost, less any accumulated depreciation and impairment losses, and adjusted for any remeasurement of lease liabilities. The cost of right-of-use assets includes the amount of lease liabilities recognised, initial direct costs incurred, and lease payments made at or before the commencement date less any lease incentives received. The right-of-use asset is depreciated over the useful life of the asset.

The Siccar Point Group's right-of-use assets are included in Property, plant and equipment (note 14).

At the commencement date of the lease, the Siccar Point Group recognises lease liabilities measured at the present value of lease payments to be made over the lease term. In calculating the present value of lease payments, the Siccar Point Group uses its incremental borrowing rate at the lease commencement date because the interest rate implicit in the lease is generally not readily determinable. After the commencement date, the amount of lease liabilities is increased to reflect the accretion of interest and reduced for the lease payments made. In addition, the carrying amount of lease liabilities is remeasured if there is a modification, a change in the lease term, a change in the lease payments (e.g., changes to future payments resulting from a change in an index or rate used to determine such lease payments) or a change in the assessment of an option to purchase the underlying asset.

The Siccar Point Group's lease liabilities are included in net finance costs and long term financial liabilities (notes 8 and 21).

Maintenance expenditure

Expenditure on major maintenance refits or repairs is capitalised where it enhances the life or performance of an asset above its originally assessed standard of performance; replaces an asset or part of an asset which was separately depreciated and which is then written off, or restores the economic benefits of an asset which has been fully depreciated. All other maintenance expenditure is charged to the statement of income as incurred.

3.1 ***Changes in accounting pronouncements***

The Siccar Point Group applied the following standards for the first time for the annual reporting period commencing 1 January 2019:

- IFRS 16 Leases

No new Standards or Interpretations were early adopted by the Siccar Point Group during 2019.

The Siccar Point Group applied the following standards for the first time for the annual reporting period commencing 1 January 2020:

- IFRS 3 Definition of a Business,
- IFRS 7, IFRS 9 and IAS 39 Interest Rate Benchmark Reform, and
- IAS 1 and IAS 8 Definition of Material

The Siccar Point Group applied the following standards for the first time for the annual reporting period commencing 1 January 2021:

- Interest Rate Benchmark Reform—Amendments to IFRS 9/IAS 39 and IFRS 7
- COVID-19 Related Rent Concessions beyond 30 June 2021—Amendment to IFRS 16

The Siccar Point Group applied the following standards for the first time for the annual reporting period commencing 1 January 2022:

- Interest Rate Benchmark Reform—Phase 2—Amendments to IFRS 9, IAS 39, IFRS 7 and IFRS 16

The application of the above standards and amendments did not have any material impact on the Siccar Point Group's financial statements.

International Financial Reporting Standards in issue but not yet effective

At the date of authorisation of the Consolidated Historical Financial information, the IASB and IFRS Interpretations Committee have issued standards, interpretations and amendments which are applicable to the Siccar Point Group. For the next reporting period, applicable IFRS will be those endorsed by the UK Endorsement Board (UKEB).

Whilst these standards and interpretations are not effective for, and have not been applied in the preparation of, this Consolidated Historical Financial Information, the following could potentially have a material impact on the Siccar Point Group's financial statements going forward. The directors are assessing the effect of these standards on the Siccar Point Group financial statements.

All the new standards effective as at 1 January 2023:

- Classification of Liabilities as Current or Non-current—Amendments to IAS 1
- Definition of Accounting Estimates—Amendments to IAS 8
- Disclosure of Accounting Policies—Amendments to IAS 1 and IFRS Practice Statement 2
- Deferred Tax related to Assets and Liabilities arising from a Single Transaction—Amendments to IAS 12

Estimates of oil and gas reserves

Estimates of oil and gas reserves require critical judgement, factors such as the availability of geological and engineering data, reservoir performance data, and drilling of new wells all impact on the determination of the Siccar Point Group's estimates of its oil and gas reserves and result in different future production profiles affecting prospectively the discounted cash flows used in impairment testing. These are based on an annual third party expert's view and these volumes are used in the calculations for impairment tests and accounting for depletion and decommissioning. Changes in estimates of oil and gas reserves resulting in different future production profiles will affect the discounted cash flows used in impairment testing, the anticipated date of decommissioning and the depletion charges in accordance with the unit of production method. For the purposes of depletion and decommissioning estimates the Siccar Point Group use proved and probable reserves and for the purposes of the impairment tests performed, the Siccar Point Group considers the same probable and proved reserves as well as risked resource volumes. These risking adjustments are reflective of the Siccar Point Group's progress of the overall field development and are reflective of a market participant view.

Estimates in impairment of oil and gas assets

The Siccar Point Company assesses assets or groups of assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable, as well as when assets are transferred from exploration and evaluation to D&P assets. Individual assets are grouped for impairment purposes at the lowest level at which there are identifiable cashflows that are largely independent of the cash flows of other groups of assets. If any such indication of impairment exists, the Siccar Point Company makes an estimate of its recoverable amount. A CGUs recoverable amount is the higher of its fair value less cost of disposal and its value in use. When the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount. In assessing its value in use, the estimated future cash flows are adjusted for the risks specific to the CGU and are discounted to their present value using a pre-tax discount rate that reflects the current market assessments of the time value of money.

Any impairment would impact the carrying value of Property, plant and equipment, see notes 14 and 15 for key assumptions and sensitivity analysis.

Decommissioning provision estimates

Amounts used in recording a provision for decommissioning are estimates based on current legal and constructive requirements and current technology and price levels for the removal of facilities and plugging and abandoning of wells. Due to changes in relation to these items, the future actual cash outflows in relation to decommissioning are likely to differ in practice. To reflect the effects due to changes in legislation, requirements, technology and price levels, the carrying amounts of decommissioning provisions are reviewed on a regular basis. The effects of changes in estimates do not give rise to prior year adjustments and are dealt with prospectively.

While the Siccar Point Group uses its best estimates and judgement, actual results could differ from these estimates. Expected timing of expenditure can also change, for example in response to changes in laws & regulations or their interpretation, and/or due to changes in commodity prices. The payment dates are uncertain and depend on the production life of the respective fields. A nominal discount rate of 3.5% (2021, 2020, 2019 and 30 June 2021: 2%) is used to discount the estimated costs. For further details regarding the estimate value, inputs and assumptions please refer to note 19.

Taxation judgement

The Siccar Point Group's operations are subject to a number of specific tax rules which apply to exploration, development and production. In addition, the tax provision is prepared before the relevant companies have filed their tax returns with the relevant tax authorities and, significantly, before these have been agreed. As a result of these factors, the tax provision process necessarily involves the use of a number of estimates and judgements, mainly investment and capital allowance estimates, including others required in calculating the effective tax rate. The Siccar Point Group recognises deferred tax assets on unused tax losses where it is probable that future taxable profits will be available for utilisation. This requires management to make judgements and assumptions regarding the likelihood of future taxable profits and the amount of deferred tax that can be recognised.

Additional deferred tax assets recognised in the 6 month period to 30 June 2022 are dependent on the future transfer of interests in certain oilfield licences from parent undertakings into the Ithaca Group. Management has used judgement in assessing the ability to perform this restructuring, abiding by any applicable regulatory requirements. Were the restructuring to not take place, the impact would lead to a reduction in the deferred tax asset recognised as at 30 June 2022 from US$773 million to US$426 million, with the corresponding entry being a reduction to the income tax credit held on the income statement.

4. SEGMENTAL REPORTING

The Siccar Point Group operates a single class of business being oil and gas exploration, development and production and related activities in a single geographical area presently being the North Sea.

Revenue from one major customer exceeds 10% of the Siccar Point Group's consolidated revenue and amounts to US$83 million for six months ended 30 June 2022 (2019: US$202 million, 2020: US$106 million 2021: US$148 million, and during six months ended 2021: US$66 million) arising from the sale of oil.

All non-current assets of the Siccar Point Group are located in North Sea.

5. REVENUE

	Year ended			Six months ended	
	31 Dec 2019	31 Dec 2020	31 Dec 2021	Unaudited 30 June 2021	30 June 2022
	US $'000	US $'000	US $'000	US $'000	US $'000
Oil sales	215,515	137,660	218,608	102,810	132,270
Gas sales	7,323	3,935	15,034	4,040	19,015
NGL sales	917	726	1,000	429	1,928
	223,755	142,321	234,642	107,279	153,213

6. COST OF SALES

	Year ended			Six months ended	
	31 Dec 2019	31 Dec 2020	31 Dec 2021	Unaudited 30 June 2021	30 June 2022
	US $'000	US $'000	US $'000	US $'000	US $'000
Operating costs	(42,460)	(54,634)	(57,327)	(28,753)	(28,915)
Movement in oil and gas inventory	(2,347)	7,325	(14,005)	(1,792)	3,937
Depletion, depreciation and amortisation (note 14)	(105,753)	(80,877)	(66,475)	(34,743)	(47,757)
	(150,560)	(128,186)	(137,807)	(65,288)	(72,735)

7. OTHER GAINS AND LOSSES

	Year ended			Six months ended	
	31 Dec 2019	31 Dec 2020	31 Dec 2021	Unaudited 30 June 2021	30 June 2022
	US $'000	US $'000	US $'000	US $'000	US $'000
(Loss)/gain on financial instruments (note 23)	(18,417)	93,660	(122,258)	(69,230)	(35,449)
Net foreign exchange	601	445	1,755	1,552	1,152
	(17,816)	94,105	(120,503)	(67,678)	(34,297)

8. NET FINANCE COSTS

	Year ended			Six months ended	
	31 Dec 2019	31 Dec 2020	31 Dec 2021	Unaudited 30 June 2021	30 June 2022
	US $'000	US $'000	US $'000	US $'000	US $'000
Interest on listed loan notes & other finance costs	(65,642)	(71,025)	(76,849)	(38,109)	(38,507)
Interest on third party loan and bonds	(44,933)	(36,828)	(26,596)	(13,791)	(14,340)
Unwinding of decommissioning discount (note 19)	(3,011)	(3,294)	(3,597)	(1,818)	(1,802)
Impact of substantial third party loan modification	(2,525)	(7,212)	—	—	—
Put option on bonds (note 18)	—	—	—	—	(1,664)
Bank interest and other income	5,625	2,015	345	428	61
Other fees	(4,211)	(2,715)	(14,051)	(11,968)	(2,145)
	(114,697)	(119,059)	(120,748)	(65,258)	(58,397)

9. TAX

Tax (credit)/charge to the income statement

	Year ended			Six months ended	
	31 Dec 2019	31 Dec 2020	31 Dec 2021	Unaudited 30 June 2021	30 June 2022
	US $'000	US $'000	US $'000	US $'000	US $'000
Current tax					
Current corporation tax charge/(credit)	—	—	—	—	—
Current corporation tax credit—prior year	3,111	—	—	—	—
Total current tax credit	3,111	—	—	—	—
Deferred tax					
Group tax credit/(charge) in the statement of income	150,680	156,098	(345,378)	—	470,798
Prior year adjustments	(4,374)	1,346	384	—	(125)
Total deferred tax credit/(charge)	146,306	157,444	(344,994)	—	470,673
Total tax credit/(charge) in income statement	149,417	157,444	(344,994)	—	470,673

Reconciliation of total income tax credit/(charge)

The tax on the Siccar Point Group's profit/(loss) before tax differs from the theoretical amount that would arise using the effective rate of tax applicable for UK ring fence oil and gas activities as follows:

	Year ended			Six months ended	
	31 Dec 2019	31 Dec 2020	31 Dec 2021	Unaudited 30 June 2021	30 June 2022
	US $'000	US $'000	US $'000	US $'000	US $'000
Accounting (profit)/loss before tax	176,472	330,634	(196,784)	100,543	217,262
At tax rate of 40% (2021,2020 & 2019 and 30 June 2021: 40%)	70,589	132,254	(78,714)	40,217	86,905
Non-deductible expense	(19,999)	(50,526)	(21,569)	(13,359)	(11,564)
Ring-fenced expenditure supplement	95,907	87,641	96,527	47,783	53,428
Income taxable/expenditure deductible at higher or lower rates	(14,878)	(15,100)	(3,041)	(7,963)	(9,897)
Deferred tax effect of investment allowance	19,771	1,997	1,720	465	894
Prior year adjustments	(1,263)	1,346	384	—	(125)
(Unrecognised)/recognised tax losses	(710)	(168)	(340,301)	(67,143)	351,032
Income tax credit/(charge) to income statement	149,417	157,444	(344,994)	—	470,673

	Year ended			Six months ended	
	31 Dec 2019	31 Dec 2020	31 Dec 2021	Unaudited 30 June 2021	30 June 2022
	US $'000	US $'000	US $'000	US $'000	US $'000
Net deferred tax assets					
Opening balance	343,603	489,909	647,353	647,353	302,359
Income statement credit/(charge)	146,306	157,444	(344,994)	—	470,673
Deferred tax assets at end of period	489,909	647,353	302,359	647,353	773,032
Accelerated capital allowance	(643,691)	(555,719)	(686,278)	(556,057)	(579,180)
Decommissioning provision	67,845	71,601	72,081	72,385	51,972
Investment allowance	47,644	49,641	51,360	50,106	52,254

	Year ended			Six months ended	
	31 Dec 2019	31 Dec 2020	31 Dec 2021	Unaudited 30 June 2021	30 June 2022
	US $'000	US $'000	US $'000	US $'000	US $'000
Derivative financial instruments .	(14,406)	(21,700)	26,406	13,153	—
Tax losses (deferred tax impact) .	1,032,517	1,103,530	838,790	1,067,766	1,247,986
Net deferred tax assets at end of period	489,909	647,353	302,359	647,353	773,032
Status of the Siccar Point Group's ring-fenced trading losses:					
Corporation tax (CT)	2,635,000	2,831,123	3,047,830	2,919,157	3,207,966
Supplementary corporation tax (SCT)	2,388,696	2,540,154	2,716,999	2,580,310	2,855,967

Deferred corporation tax assets are recognised for the carry-forward of unused tax losses and unused tax credits to the extent that it is probable under current tax legislation and using enacted tax rates that taxable profits will be available in the future against which the unused tax losses/credits can be utilised.

The carrying value of the net deferred corporation tax asset at 30 June 2022 of US$773 million (2021: US$302 million 2020: US$647 million, 2019: US$490 million and 30 June 2021: US$647 million) is supported by estimates of the Group's future taxable income, based on the same price and cost assumptions as used for impairment testing.

The reduction from the position at 31 December 2020 US$647 million to US$302 million at 31 December 2021 was mainly due to the reclassification of the Cambo field as 2C resources (included in 2P reserves at 31 December 2020) pending resumption of the project. This deferred tax asset has been re-recognised as at 30 June 2022 due to planned restructuring of assets post acquisition by IEUK allowing for optimisation of profits within the enlarged Ithaca Group. This movement in deferred tax asset recognised has no impact on the quantum of the Siccar Point Group's brought forward trading losses.

The Siccar Point Group also has outside ring fenced tax losses at 30 June 2022 of US$25 million (2021: US$21 million, 2020: US$22 million, 2019: US$25 million and 30 June 2021: US$22 Million) that are available for offset against future taxable profits. Deferred tax assets at 30 June 2022 of US$6 million @25% tax rate (2021: US$5 million @25% tax rate, 2020: US$4 million @19% tax rate, 2019: US$4 million @17% tax rate and 30 June 2021:US$5 million @25% tax rate) in respect of temporary differences relating to tax losses carried forward have not been recognised as there is insufficient evidence that the asset will be recovered.

10. ACCOUNT RECEIVABLE

	Year ended			Six months ended	
	31 Dec 2019	31 Dec 2020	31 Dec 2021	Unaudited 30 June 2021	30 June 2022
	US $'000	US $'000	US $'000	US $'000	US $'000
Accrued income	19,434	13,464	19,787	17,774	31,839
	19,434	13,464	19,787	17,774	31,839

Accrued income relates to revenue recognised as at 30 June 2022 (2021,2020,2019: 31 December and 30 June 2021) to be billed in the subsequent month.

The Siccar Point Group regularly monitors all customer receivable balances outstanding in excess of 90 days for expected credit losses. As at 30 June 2022, substantially all accounts receivables are current, being defined as less than 90 days. The Siccar Point Group has no allowance for doubtful accounts as at 30 June 2022 (31 December 2021, 2020, 2019 and 30 June 2021: US$nil).

11. DEPOSITS, PREPAID EXPENSES AND OTHER RECEIVABLES

	Year ended			Six months ended	
	31 Dec 2019	31 Dec 2020	31 Dec 2021	Unaudited 30 June 2021	30 June 2022
	US $'000	US $'000	US $'000	US $'000	US $'000
VAT	545	208	355	264	77
Deposits and prepayments	5,350	1,333	533	61	—
Advances to joint operation partners	1,911	1,012	2,553	1,611	757
Contingent consideration receivable	5,939	—	—	—	—
	13,745	2,553	3,441	1,936	834

In 2019, the contingent consideration receivable was in relation to the divestment in Jackdaw and was linked to the Final Investment Decision ("FID") to develop the asset in question (note 16).

12. INVENTORY

	Year ended			Six months ended	
	31 Dec 2019	31 Dec 2020	31 Dec 2021	Unaudited 30 June 2021	30 June 2022
	US $'000	US $'000	US $'000	US $'000	US $'000
Material inventory	8,021	6,708	8,644	7,522	7,709
Hydrocarbon inventory	1,375	1,420	2,165	1,357	4,346
	9,396	8,128	10,809	8,879	12,055

13. EXPLORATION AND EVALUATION ASSETS

	US $'000
At 1 January 2019	311,967
Additions	43,944
Change in decommissioning estimate	(3,559)
At 31 December 2019	352,352
Additions	31,672
Change in decommissioning estimate	73
At 31 December 2020	384,097
Additions	60,103
Change in decommissioning estimate	(617)
At 31 December 2021	443,583
Additions	12,904
Change in decommissioning estimate	(2,770)
At 30 June 2022	453,717
Comparison:	
At 31 December 2020	384,097
Additions	23,548
Change in decommissioning estimate	7
At 30 June 2021	407,652

14. PROPERTY, PLANT AND EQUIPMENT

	Right of use operating assets	Other fixed assets	Development & producing assets	Total
	US $'000	US $'000	US $'000	US $'000
Cost:				
At 1 January 2019	—	169	1,666,967	1,667,136
Additions	680	105	36,745	37,530
Decommissioning estimate	—	—	19,111	19,111
At 31 December 2019	680	274	1,722,823	1,723,777
Additions	—	86	50,848	50,934
Decommissioning estimate	—	—	6,255	6,255
At 31 December 2020	680	360	1,779,926	1,780,966
Additions	1	9	27,515	27,525
Decommissioning estimate	—	—	(2,089)	(2,089)
At 31 December 2021	681	369	1,805,352	1,806,402
Additions	—	—	14,297	14,297
Decommissioning estimate	—	—	(48,049)	(48,049)
At 30 June 2022	681	369	1,771,600	1,772,650
Comparison:				
At 31 December 2020	680	360	1,779,926	1,780,966
Additions	—	—	12,044	12,044
Decommissioning estimate	—	—	133	133
At 30 June 2021	680	360	1,792,103	1,793,143
DD&A and Impairment:				
At 1 January 2019	—	(142)	(174,779)	(174,921)
Impairment	—	—	(99,903)	(99,903)
DD&A charge for the year	(159)	(37)	(105,753)	(105,949)
At 31 December 2019	(159)	(179)	(380,435)	(380,773)
Impairment	—	—	(304,418)	(304,418)
DD&A charge for the year	(232)	(71)	(80,877)	(81,180)
At 31 December 2020	(391)	(250)	(765,730)	(766,371)
Impairment reversal	—	—	358,618	358,618
DD&A charge for the year	(232)	(67)	(66,475)	(66,774)
At 31 December 2021	(623)	(317)	(473,587)	(474,527)
Impairment	—	—	(191,548)	(191,548)
DD&A charge for the period	(36)	(24)	(47,757)	(47,817)
At 30 June 2022	(659)	(341)	(712,892)	(713,892)
Comparison:				
At 31 December 2020	(391)	(250)	(765,730)	(766,371)
DD&A Charge for the period	(72)	—	(34,743)	(34,815)
At 30 June 2021	(463)	(250)	(800,473)	(801,186)
NBV at 31 December 2019	521	95	1,342,388	1,343,004
NBV at 31 December 2020	289	110	1,014,196	1,014,595
NBV at 31 December 2021	58	52	1,331,765	1,331,875
NBV at 30 June 2022	22	28	1,058,708	1,058,758
Comparison:				
NBV at 30 June 2021	217	110	991,630	991,957

15. IMPAIRMENT (CHARGE)/REVERSAL

2019:

During 2019, the Siccar Point Group recorded a pre-tax impairment charge of US$99.9 million to Property, plant and equipment relating to the Schiehallion field. This was largely driven by a reduction in the Siccar Point Group's assumption of future commodity prices.

The following assumptions were used in developing the cash flow model and applied over the expected life of the respective field:

	Post-tax discount rate assumption	GBP/USD fx rate	Long term oil price assumption
North Sea	8%	1.30	$68/bbl

The recoverable amount of US$1,547 million of the CGU is value in use. Sensitivity analysis for this asset indicate that if oil price was to fall by 10% then this would lead to a further pre-tax impairment of US$126.5 million. An increase in the discount rate by 1% would lead to a further pre-tax impairment of US$41.6 million.

2020:

During 2020, the Siccar Point Group recorded a pre-tax impairment charge of US$304 million (post-tax: US$182 million) to Property, plant and equipment relating to the Schiehallion field. This was largely driven by a reduction in the Siccar Point Group's assumption of future commodity prices.

The following assumptions were used in developing the cash flow model and applied over the expected life of the respective field:

	Post-tax discount rate assumption	GBP/USD fx rate	Long term oil price assumption
North Sea	8%	1.30	$64/bbl

The recoverable amount of US$1,122 million of the CGU is value in use. Sensitivity analysis for this asset indicate that if oil price was to fall by 10% then this would lead to a further pre-tax impairment of US$156 million. An increase in the discount rate by 1% would lead to a further pre-tax impairment of US$33 million.

2021:

As at 31 December 2021 there was a non-cash pre-tax impairment reversal of US$359 million (post-tax: US$215 million) to Property, plant and equipment relating to Schiehallion field. This was largely driven by an increase in the reserve volumes and improvement in the Siccar Point Group's assumption of future commodity prices. The recoverable amount exceeded the net book value of the asset.

The following assumptions were used in developing the cash flow model and applied over the expected life of the respective field:

	Post-tax discount rate assumption	GBP/USD fx rate	Long term oil price assumption
North Sea	8%	1.30	$75/bbl

The recoverable amount of US$1,837 million of the CGU is value in use. Sensitivity analysis for this asset indicate that if oil price was to fall by 10% then this would lead to a reduction of the non-cash pre-tax impairment reversal of US$117 million (US$70 million post-tax). An increase in the discount rate by 1% would lead to a reduction of non-cash pre-tax impairment reversal of US$53 million (US$32 million post-tax).

2022:

During 2022, the Siccar Point Group recorded a pre-tax impairment charge of US$191.5 million (post-tax: US$115 million) to Property, plant and equipment relating to Schiehallion and Mariner field. This was largely driven by a reduction in reserves in the Siccar Point Group's assumption of future recoverable reserves based on Competent Person's Reports prepared by the independent reserves auditors as at 30 June 2022.

The following assumptions were used in developing the cash flow model and applied over the expected life of the respective field:

	Post-tax discount rate assumption	GBP/USD fx rate	Long term oil price assumption
North Sea	10.4%	1.40	$78/bbl

The recoverable amount of the CGU unit is fair value less costs of disposal.

Applying level 3 fair value measurement techniques, for impairment of Property, plant and equipment and intangible oil and gas assets, fair value less costs of disposal is determined by discounting the post-tax cash flows expected to be generated from oil and gas production net of selling costs taking into account assumptions that market participants would typically use in estimating fair values.

Sensitivity analysis for these assets indicate that if oil price was to fall by 10% then this would lead to a further pre-tax impairment of US$169 million. An increase in the discount rate by 1% would lead to a further pre-tax impairment of US$50 million.

16. LONG-TERM FINANCIAL ASSETS

	Year ended			Six months ended	
	31 Dec 2019	31 Dec 2020	31 Dec 2021	Unaudited 30 June 2021	30 June 2022
	US $'000	US $'000	US $'000	US $'000	US $'000
Contingent consideration receivable	48,004	56,044	6,021	56,111	—
Long-term receivable	1,960	3,510	4,110	4,110	—
	49,964	59,554	10,131	60,221	—

The contingent consideration receivable at 31 December 2021 amounting to US$6 million (2020 & 30 June 2021: US$6 million, 2019: US$6 million presented under note 11) relates to amounts receivable in respect of the divestment of Jackdaw. This was contingent on the FID to develop the asset in question. Subsequent to approval for the development provided by the Secretary of State in June 2022, the Siccar Point Group received the contingent receivable of US$6 million accordingly.

At 30 June 2021, contingent consideration also included US$49.9 million (2020: US$49.9 million, 2019: US$48 million) in respect of the 2016 divestment by OMV (U.K.) Limited (now Ithaca SP E&P Limited) of a 30% working interest in the Rosebank discovery to Suncor. As part of the sale transaction, Suncor agreed to make a cash payment to OMV (U.K.) Limited (now Ithaca SP E&P Limited) upon sanctioning of the Rosebank project. The cash payment is dependent on the timing of the FID approval by 31 December 2022. In 2021, it was determined that the project timeline would not be met so the entire balance of the contingent consideration was reduced to nil at 31 December 2021.

Long-term receivable relates to amounts receivable from Siccar Point Energy Luxembourg S.C.A. The balance was fully repaid in June 2022.

17. TRADE AND OTHER PAYABLES

	Year ended			Six months ended	
	31 Dec 2019	31 Dec 2020	31 Dec 2021	Unaudited 30 June 2021	30 June 2022
	US $'000	US $'000	US $'000	US $'000	US $'000
Trade creditors	(366)	(1,268)	(570)	(1,380)	(2,321)
Accruals	(1,230)	(887)	(1,246)	(207)	(6,439)
Joint operations payable	(13,640)	(10,453)	(8,279)	(5,636)	(9,814)
Oil over-lift	(8,780)	(1,499)	(16,250)	(3,228)	(14,494)
Accrued interest on third-party loan and bond	(8,529)	(7,500)	(6,212)	(6,462)	(5,800)
Joint operations working capital	(21,273)	(14,199)	(31,059)	(20,426)	(15,086)
	(53,818)	(35,806)	(63,616)	(37,339)	(53,954)

18. BORROWINGS

	Year ended			Six months ended	
	31 Dec 2019	31 Dec 2020	31 Dec 2021	Unaudited 30 June 2021	30 June 2022
	US $'000	US $'000	US $'000	US $'000	US $'000
Current:					
Third-Party Bond	—	—	—	—	(197,627)
Non-current:					
Third-Party Bond	(200,693)	(200,488)	(198,165)	(198,081)	—
Listed loan notes	(866,157)	(937,182)	(1,014,031)	(975,290)	(1,006,626)
RBL facility	(521,000)	(386,000)	(242,000)	(242,000)	—
	(1,587,850)	(1,523,670)	(1,454,196)	(1,415,371)	(1,006,626)

The 9.0% unsecured callable 2021/2026 US$200 million bonds are listed on Nordic ABM, a marketplace regulated by Oslo Børs. The accrued interest as at 30 June 2022 is US$5.8 million (2021: US$5.8 million, 2020: US$7.5 million, 2019: US$7.5 million and 30 June 2021: US$5.8 million). Bonds are recorded at fair value less transaction costs at initial recognition and are subsequently measured at amortised cost.

The Siccar Point Acquisition constituted a change of control event under the terms and conditions of Siccar Point's senior unsecured callable bonds up to a maximum of US$200 million. Following completion of the Siccar Point Acquisition on 30 June 2022, the Siccar Point Group issued a put option notice to Nordic Trustee AS at a premium of 1%. Bondholders holding Siccar Point Bonds totalling US$166.40 million elected to exercise the put provision and require repayment. The repayment was settled on 1 August 2022. Subsequently, in September 2022, Siccar Point Bonds totalling US$25.6 million were bought back at a premium of 6% on behalf of Ithaca SP Bonds PLC (formerly Siccar Point Energy Bonds PLC) which were redeemed on 21 September 2022. The remaining Siccar Point Bonds totalling US$8 million were redeemed on 12 October 2022.

The Reserves Based Lending ("RBL") facility provided by a syndicate of banks was fully repaid on 30 June 2022. US$242 million was drawn at 31 December 2021. Accrued interest as at 31 December 2021 was US$0.4million (2020: US$nil, 2019: US$1.0 million and 30 June 2021: US$0.7 million).

Ithaca SP Finance Limited (formerly called Siccar Point Energy Finance Limited (the "Issuer") issued loan notes (the "Notes") carrying an 8.2% per annum interest rate to Siccar Point Energy Luxembourg S.C.A. The Notes were issued in several tranches, and are listed on The International Stock Exchange. The Notes hold maturity dates between 2044 and 2047, with the accrued interest payable at maturity. As at 31 December 2021 the principal amount of the Notes was US$679.2 million and interest accrued on the Notes to that date was US$338.4 million. On 24 June 2022, the holder of the Notes and the Issuer agreed to release the amount of US$31.3 million capital (principal) and interest of US$17.3 million on the Notes. As a consequence of that release, at 30 June 2022, the principal amount of the

Notes was US$647.9 million and interest accrued on the Notes to that date was US$358.7 million. At 30 June 2022, Siccar Point Energy Luxembourg S.C.A. sold these Notes along with accrued interest to IEUK.

19. DECOMMISSIONING LIABILITIES

	Year ended			Six months ended	
	31 Dec 2019	31 Dec 2020	31 Dec 2021	Unaudited 30 June 2021	30 June 2022
	US $'000	US $'000	US $'000	US $'000	US$'000
Balance, beginning of period	(151,831)	(169,613)	(179,001)	(179,001)	(180,202)
Additions	(14,143)	(4,437)	(2,688)	—	(614)
Accretion (note 8)	(3,011)	(3,294)	(3,597)	(1,818)	(1,802)
Revision to estimates	3,437	3,294	2,519	1,818	34,453
Exchange differences	(6,320)	(4,951)	1,487	(1,962)	18,234
Decommissioning provision utilised	2,255	—	1,078	—	—
Balance, end of period	(169,613)	(179,001)	(180,202)	(180,963)	(129,931)

The total future decommissioning liability was calculated by management based on its net ownership interest in all wells and facilities, estimated costs to reclaim and abandon wells and facilities and the estimated timing of the costs to be incurred in future periods. The Siccar Point Group uses a discount rate of 3.5% as at 30 June 2022 (31 December 2021, 2020, 2019 and 30 June 2021: 2.0 percent) and an inflation rate of 2.0 percent (31 December 2021, 2020, 2019 and 30 June 2021: 2.0 percent) over the varying lives of the assets to calculate the present value of the decommissioning liabilities. Of the decommissioning liabilities at 30 June 2022, an estimated US$6.9 million is expected to be utilised within one to ten years and the remainder in later periods up to 2053. Based on the current economic environment, assumptions have been made which are believed to be a reasonable basis upon which to estimate the future liability. These estimates are reviewed regularly to take into account any material changes to the assumptions. However, actual decommissioning costs will ultimately depend upon future market prices for the necessary decommissioning works required, which will reflect market conditions at the relevant time. Furthermore, the timing of decommissioning is likely to depend on when the fields cease to produce at economically viable rates. This in turn will depend upon future oil and gas prices, which are inherently uncertain.

Sensitivity analysis indicate that 10% change in decommissioning cost estimate would lead to increase or decrease of US$13 million (2021: US$18 million, 2020: US$18 million, 2019: US$17 million and 30 June 2021: US$18 million) in decommissioning liabilities.

20. CONTINGENT CONSIDERATION

	Year ended			Six months ended	
	31 Dec 2019	31 Dec 2020	31 Dec 2021	Unaudited 30 June 2021	30 June 2022
	US $'000	US $'000	US $'000	US $'000	US $'000
Balance outstanding—*current*	(2,640)	—	—	—	—
Balance outstanding—*non-current*	(48,004)	(52,639)	(2,676)	(52,669)	—
	(50,644)	(52,639)	(2,676)	(52,669)	—

The contingent consideration as at 31 December 2021 amounting to US$2.7 million (2020: US$2.7 million, 2019: US$2.6 million) relates to amounts payable in respect of the divestment of Jackdaw. This was contingent on the final investment decision to develop the asset in question. Subsequent to approval for the development provided by the Secretary of State in June 2022, the balance is now payable and reclassified under trade creditors in June 2022.

In 2017, the Siccar Point Group acquired OMV (U.K.) Limited (now Ithaca SP E&P Limited). As part of the acquisition, the Siccar Point Group also acquired contingent payment dependent on the timing of FID approval of Rosebank. The payment is dependent on FID approval by 31 December 2022. This consideration has been derecognised as at 31 December 2021

(2020: US$53 million, 2019: US$48 million and 30 June 2021: US$53 million) as it is unlikely that FID approval will be received until 2023.

21. OTHER LONG-TERM LIABILITIES

	Year ended			Six months ended	
	31 Dec 2019	31 Dec 2020	31 Dec 2021	Unaudited 30 June 2021	30 June 2022
	US $'000	US $'000	US $'000	US $'000	US $'000
Leases	(355)	(86)	—	—	
	(355)	(86)	—	—	

22. SHARE CAPITAL

Authorised share capital	Year ended			Six months ended	
	31 Dec 2019	31 Dec 2020	31 Dec 2021	Unaudited 30 June 2021	30 June 2022
	US $'000	US $'000	US $'000	US $'000	US $'000
13,385,052 ordinary shares of US$1 each (2021,2020,2019 and 30 June 2021: 13,385,051 ordinary shares of US$1 each)	13,385	13,385	13,385	13,385	13,385
1 ordinary share of £1 each	—	—	—	—	—
Issued					
13,385,052 ordinary shares of US$1 each (2021,2020,2019 and 30 June 2021: 13,385,051 ordinary shares of US$1 each	13,385	13,385	13,385	13,385	13,385
1 ordinary share of £1 each	—	—	—	—	—
Capital contribution	—	—	—	—	48,638
	13,385	13,385	13,385	13,385	62,023

On 24 June 2022, the Siccar Point Company issued one share of US$1 in exchange for one ordinary share in Ithaca SP Finance Limited (formerly Siccar Point Energy Finance Limited) which is a 100% consolidated subsidiary of the Siccar Point Company.

Under the terms of the Sale Purchase Agreement of the Siccar Point Group signed between Siccar Point Energy Luxembourg S.C.S and IEUK, on 24 June 2022, Siccar Point Energy Luxembourg SCA released Loan Notes amounting to US$48.6 million (including accrued interest of US$17.3 million) (note 18) as capital contribution in exchange for one fully paid ordinary share of US$1 in Ithaca SP Finance Limited (Formerly Siccar Point Energy Finance Limited).

23. FINANCIAL INSTRUMENTS

Commodity risk

Commodity price risk related to crude oil prices is the Siccar Point Group's most significant market risk exposure. Crude oil prices and quality differentials are influenced by worldwide factors such as Opec actions, political events and supply and demand fundamentals. The Siccar Point Group is also exposed to natural gas price movements on uncontracted gas sales. Natural gas prices, in addition to the worldwide factors noted above, can also be influenced by local market conditions. The Siccar Point Group's expenditures are subject to the effects of inflation, and prices received for the product sold are not readily adjustable to cover any increase in expenses from inflation. The Siccar Point Group may periodically use different types of derivative instruments to manage its exposure to price volatility, thus mitigating fluctuations in commodity-related cash flows.

The below represents commodity hedges in place at the 2019 year end:

Derivative	Term	Volume	Average price
Oil swaps	Jan 20–Dec 21	5,610,000 bbls	$66/bbl
Gas swaps	Jan 20–Jun 22	25,941,436 therms	59p/therm

The below represents commodity hedges in place at the 2020 year end:

Derivative	Term	Volume	Average price
Oil swaps	Jan 21–Jun 22	2,799,750 bbls	$60/bbl
Gas swaps	Jan 21–Jun 23	19,220,519 therms	50p/therm

The below represents commodity hedges in place at the 2021 year end:

Derivative	Term	Volume	Average price
Oil swaps	Jan 22–Sep 23	2,247,000 bbls	$67/bbl
Oil Zero Cost Collars	Jan 22–Dec 22	811,500 bbls	$52/bbl Put $60/bbl Call
Gas swaps	Jan 22–Jun 24	26,992,500 therms	45p/therm

The below represents commodity hedges in place at 30 June 2021:

Derivative	Term	Volume	Average price
Oil swaps	Jul 21–Jun 22	1,704,000 bbls	$62/bbl
Oil Zero Cost Collars	Jan 22–Dec 22	811,500 bbls	$52/bbl Put $60/bbl Call
Gas swaps	Jul 21–Jun 24	33,117,451 therms	48p/therm

There were no open derivative positions at 30 June 2022. Prior to closing of the acquisition by IEUK at 30 June 2022 all hedges have either been terminated or novated to IEUK (note 25).

Interest risk

Calculation of interest payments for the RBL facilities incorporate USD LIBOR. The Siccar Point Group is therefore exposed to interest rate risk to the extent that LIBOR may fluctuate.

The below represents interest rate financial instruments in place at the 2019 year end:

Derivative	Term	Value	Rate
Interest rate swap	Jan 20–Dec 21	US$100 million	2.18%
Interest rate swap	Jan 20–Dec 20	US$80 million	1.38%

The below represents interest rate financial instruments in place at the 2020 year end:

Derivative	Term	Value	Rate
Interest rate swap	Jan 21–Dec 21	US$100 million	2.18%
Interest rate swap	Jan 21–Dec 21	US$50 million	0.40%
Interest rate swap	Jan 22–Dec 23	US$150 million	0.40%

The below represents interest rate financial instruments in place at the 2021 year end:

Derivative	Term	Value	Rate
Interest rate swap	Jan 22–Dec 23	US$150 million	0.40%

The below represents interest rate financial instruments in place at 30 June 2021:

Derivative	Term	Value	Rate
Interest rate swap	Jul 21–Dec 21	US$100 million	2.18%
Interest rate swap	Jul 21–Dec 21	US$50 million	0.40%
Interest rate swap	Jan 22–Dec 23	US$150 million	0.40%

The RBL loan was fully repaid on 30 June 2022.

There were no open derivative positions at 30 June 2022. Prior to closing of the acquisition by IEUK at 30 June 2022, all hedges have either been terminated or novated to IEUK (note 25).

Foreign exchange rate risk

The Siccar Point Group is exposed to foreign exchange risks to the extent it transacts in various currencies, while measuring and reporting its results in US Dollars. Since time passes between the recording of a receivable or payable transaction and its collection or payment, the Siccar Point Group is exposed to gains or losses on non-USD amounts and on balance sheet translation of monetary accounts denominated in non-USD amounts upon spot rate fluctuations from quarter to quarter.

The Siccar Point Group enters into forward contracts as a means of hedging its exposure to foreign exchange rate risks.

As at 31 December 2019 the Siccar Point Group had £11.8 million per quarter hedged at a forward rate of $1.27 : £1 for the period January to December 2020 and £11.3 million per quarter hedged at a forward rate of $1.32 : £1 for the period January to December 2021.

As at 31 December 2020 the Siccar Point Group had £11.3 million per quarter hedged at a forward rate of $1.32 : £1 for the period January to December 2021; £9.3 million per quarter hedged at a forward rate of $1.26 : £1 for the period January to December 2022; and £5.4 million per quarter hedged at a forward rate of $1.27 : £1 for the period January to December 2023.

As at 31 December 2021 the Siccar Point Group had £12.0 million per quarter hedged at a forward rate of $1.29 : £1 for the period January to December 2022 and £5.4 million per quarter hedged at a forward rate of $1.27 : £1 for the period January to December 2023.

As at 30 June 2021 the Siccar Point Group had £15.2 million per quarter hedged at a forward rate of $1.35 : £1 for the period July to December 2021; £12.0 million per quarter hedged at a forward rate of $1.29 : £1 for the period January to December 2022 and £5.4 million per quarter hedged at a forward rate of $1.27 : £1 for the period January to December 2023.

There were no open forward contracts positions at 30 June 2022. Following the closing of the acquisition by IEUK all hedges have either been terminated or novated to IEUK (note 25).

The main risks that could adversely affect the Siccar Point Group's financial assets, liabilities or future cash flows are commodity price risk, interest rate risk, foreign currency exchange risk, credit risk and liquidity risk. The Siccar Point Group uses derivatives to reduce certain risk exposures to manage this liquidity risk.

a) Statement of financial position as at 31 December 2019, 2020, 2021 and six months ended 30 June 2021

Type of derivative	31 Dec 2019 US $'000 Current	31 Dec 2019 US $'000 Non-current	31 Dec 2019 US $'000 Total
Foreign exchange ($/£) forward contracts	2,745	579	3,324
Brent swaps and zero cost collars	13,683	11,859	25,542
Gas swaps	5,761	3,295	9,056
Total assets	**22,189**	**15,733**	**37,922**
Brent swaps and zero cost collars	(1,069)	—	(1,069)
Interest rate swaps	(441)	(629)	(1,070)
Total liabilities	**(1,510)**	**(629)**	**(2,139)**
Total	**20,679**	**15,104**	**35,783**

Type of derivative	31 Dec 2020 US $'000 Current	31 Dec 2020 US $'000 Non-current	31 Dec 2020 US $'000 Total
Foreign exchange ($/£) forward contracts	2,004	6,188	8,192
Brent swaps and zero cost collars	30,369	13,289	43,658
Gas swaps	2,488	—	2,488
Total assets	**34,861**	**19,477**	**54,338**
Brent swaps and zero cost collars	—	(90)	(90)
Interest rate swaps	(1,880)	(849)	(2,729)
Total liabilities	**(1,880)**	**(939)**	**(2,819)**
Total	**32,981**	**18,538**	**51,519**

Type of derivative	31 Dec 2021 US $'000 Current	31 Dec 2021 US $'000 Non-current	31 Dec 2021 US $'000 Total
Foreign exchange ($/£) forward contracts	2,749	1,646	4,395
Brent swaps and zero cost collars	—	—	—
Interest rate swaps	603	753	1,356
Total assets	**3,352**	**2,399**	**5,751**
Gas swaps	(16,589)	(14,373)	(30,962)
Brent swaps and zero cost collars	(31,030)	(8,417)	(39,447)
Interest rate swaps	—	—	—
Total liabilities	**(47,619)**	**(22,790)**	**(70,409)**
Total	**(44,267)**	**(20,391)**	**(64,658)**

Type of derivative	Unaudited 30 June 2021 US $'000 Current	Unaudited 30 June 2021 US $'000 Non-current	Unaudited 30 June 2021 US $'000 Total
Foreign exchange ($/£) forward contracts	3,637	4,918	8,555
Interest rate swaps	—	150	150
Brent swaps and zero cost collars	—	—	—
Gas swaps	—	—	—
Total assets	**3,637**	**5,068**	**8,705**
Interest rate swaps	(967)	—	(967)
Brent swaps and zero cost collars	(31,038)	(3,488)	(34,526)
Gas swaps	(3,722)	(3,190)	(6,912)
Total liabilities	**(35,727)**	**(6,678)**	**(42,405)**
Total	**(32,090)**	**1,610**	**(33,700)**

The Siccar Point Group has nil open hedge position as at 30 June 2022.

b) Income statement impact from derivative realised gains and losses

Type of derivative	31 Dec 2019	31 Dec 2020	31 Dec 2021	Unaudited 30 June 2021	30 June 2022
	US $'000	US $'000	US $'000	US $'000	US $'000
Brent swaps and zero cost collars	(13,688)	73,769	(1,314)	16,171	(47,120)
Gas swaps	3,741	7,069	(2,202)	1,056	28,297
Foreign exchange ($/£) forward contracts	1,046	(737)	(245)	(54)	(15,258)
Interest rate swaps	326	(2,178)	(2,319)	(1,183)	(1,368)
Total realised gain/(loss) from hedging	**(8,575)**	**77,923**	**(6,080)**	**15,990**	**(35,449)**

Net Income statement impact from hedging	31 Dec 2019	31 Dec 2020	31 Dec 2021	Unaudited 30 June 2021	30 June 2022
	US $'000	US $'000	US $'000	US $'000	US $'000
Realised gain/(loss) from hedging	(8,575)	77,923	(6,080)	15,990	(35,449)
Unrealised gain/(loss) from hedging	(9,842)	15,737	(116,178)	(85,220)	—
Total net gain/(loss) from hedging	**(18,417)**	**93,660**	**(122,258)**	**(69,230)**	**(35,449)**

24. FAIR VALUES OF FINANCIAL ASSETS AND LIABILITIES

The estimated fair value of the Siccar Point Group's borrowings is shown in the table below with the carrying amount as reflected in the balance sheet.

The carrying amount listed loan notes and RBL facility approximates their fair value. The fair value of a third-party bond is determined using quoted prices in the active market, and so falls within level 1 of the fair value hierarchy.

Classification	31 Dec 2019 US $'000 Carrying value	31 Dec 2019 US $'000 Fair value
Third party bond	(200,693)	(214,000)
Listed loan notes	(866,157)	(866,157)
RBL facility	(521,000)	(521,000)
	(1,587,850)	(1,601,157)

Classification	31 Dec 2020 US $'000 Carrying value	31 Dec 2020 US $'000 Fair value
Third party bond	(200,488)	(194,500)
Listed loan notes	(937,182)	(937,182)
RBL facility	(386,000)	(386,000)
	(1,523,670)	(1,517,682)

Classification	31 Dec 2021 US $'000 Carrying value	31 Dec 2021 US $'000 Fair value
Third party bond	(198,165)	(200,000)
Listed loan notes	(1,014,031)	(1,014,031)
RBL facility	(242,000)	(242,000)
	(1,454,196)	(1,456,031)

Classification	Unaudited 30 June 2021 US $'000 Carrying value	Unaudited 30 June 2021 US $'000 Fair value
Third party bond	(198,081)	(203,500)
Listed loan notes	(975,290)	(975,290)
RBL facility	(242,000)	(242,000)
	(1,415,371)	(1,420,790)

Classification	30 June 2022 US $'000 Carrying value	30 June 2022 US $'000 Fair value
Third party bond—current	(197,627)	(200,600)
Listed loan notes	(1,006,626)	(1,006,626)
	(1,204,253)	(1,207,226)

The only financial assets and liabilities measured at fair value are derivative financial instruments and contingent consideration receivable and payable. Derivatives are deemed to be Level 2 and the contingent consideration is deemed to be Level 3 within the Fair Value hierarchy. There were no transfers between hierarchy levels during the year.

The fair value of the contingent consideration receivable and payable considers the timing of achieving FID and uses a government risk-free discount rate.

Refer to note 15 for the fair value determination for the impairment charge as at 30 June 2022.

The Siccar Point Group uses valuation techniques that are appropriate in the circumstances and for which sufficient data is available to measure fair value, maximising the use of relevant observable inputs and minimising the use of unobservable inputs.

25. RELATED PARTY TRANSACTIONS

The Company was owned by Siccar Point Energy Luxembourg S.C.A. a Company registered in Luxemburg from the date of its establishment on 25 June 2014 to its eventual sale on 30 June 2022 to IEUK, a company registered in the United Kingdom. Sale Purchase Agreement was signed on 7 April 2022 and the transaction completed on 30 June 2022.

The consolidated financial information includes the financial information of the Company and the subsidiaries listed in the following table:

		% Equity interest at				
	Country of incorporation	**31 Dec 2019**	**31 Dec 2020**	**31 Dec 2021**	**30 June 2021**	**30 June 2022**
Ithaca SPE Limited (Formerly Siccar Point Energy Limited)	England	100%	100%	100%	100%	100%
Ithaca SP Finance Limited (Formerly Siccar Point Energy Finance Limited—Direct subsidiary)	England	100%	100%	100%	100%	100%
Ithaca SP O&G Limited (Formerly Siccar Point Energy U.K. Limited)	England	100%	100%	100%	100%	100%
Ithaca SP E&P Limited (Formerly Siccar Point Energy E&P Limited)	England	100%	100%	100%	100%	100%
Ithaca SP Bonds Limited (Formerly Siccar Point Energy Bonds PLC)	England	100%	100%	100%	100%	100%

Transactions between subsidiaries are eliminated on consolidation.

Loans from Siccar Point Energy Luxembourg S.C.A to Ithaca SP Finance Limited (Formerly Siccar Point Energy Finance Limited) (note 18):

	Carrying value as at				
	31 Dec 2019	**31 Dec 2020**	**31 Dec 2021**	**Unaudited 30 June 2021**	**30 June 2022**
	US $'000	**US $'000**	**US '000**	**US $'000**	**US $'000**
Listed loan notes	866,157	937,182	1,014,031	975,290	—

Loans from the Company to Siccar Point Energy Luxembourg S.C.A as at 31 December 2021 totalled US$4.1 million (2020: US$3.5 million, 2019: US$1.9 million). The loans were interest free and fully repaid in June 2022 (note 16).

Loans from IEUK to Ithaca SP Finance Limited (Formerly Siccar Point Energy Finance Limited) (note 18):

	Carrying value as at				
	31 Dec 2019	**31 Dec 2020**	**31 Dec 2021**	**30 June 2021**	**30 June 2022**
	US$ '000	**US $'000**	**US '000**	**US $'000**	**US $'000**
Listed loan notes	—	—	—	—	1,006,626

Amounts due to IEUK amounting to US$323 million and payable on demand as at 30 June 2022. This mainly represents the mandatory repayment of RBL loan of US$277 million due to a change of control and the early termination of hedges amounting to US$45 million which could not be novated to Ithaca Group as per the mutual agreement with counterparties.

On 30 June 2022, the Siccar Point Group entered into an agreement with IEUK to novate a subset of the Siccar Point Group's open hedge positions, other than those terminated as discussed above. As at the date of this agreement, all rights, liabilities, duties and obligations attached to the associated financial instruments were transferred to IEUK. No consideration was paid or received as part of the novation agreement between the parties. As a result of all hedging positions being terminated or novated at the balance sheet date, all gains and losses on these instruments are included within the income statement. Had this transaction not taken place, this would have led to an additional loss of US$73.8 million being present in the income statement for the 6-month period to 30 June 2022, reflecting the total mark to market movement in the 6-month period to the date of novation for these financial instruments.

Directors of the Siccar Point Company are also key management personnel of the Siccar Point Company. Compensation of the Siccar Point Group's directors is disclosed in the key management personnel section of accounts (note 27).

There have been no other transactions with the Board of Directors, Executive Board, Executive Officers, significant shareholders or other related parties of the Siccar Group during the period.

26. COMMITMENTS

	Year ended			Six months ended	
	31 Dec 2019	31 Dec 2020	31 Dec 2021	Unaudited 30 June 2021	30 June 2022
	US $'000	US $'000	US $'000	US $'000	US $'000
Capital commitments					
Capital commitments incurred jointly with other venturers (Siccar Point Group's share)	80,820	75,353	61,191	46,757	39,335

27. KEY MANAGEMENT PERSONNEL

The following table provides remuneration provided to key management personnel:

	Year ended			Six months ended	
	31 Dec 2019	31 Dec 2020	31 Dec 2021	Unaudited 30 June 2021	30 June 2022
	US $'000	US $'000	US $'000	US $'000	US $'000
Aggregate remuneration	1,480	1,545	1,645	1,108	1,168
Employer contributions paid into pension schemes or to the director in lieu of pension scheme contributions	134	139	152	77	76
Accrued bonuses	—	—	—	—	2,304
Compensation for loss of office	—	—	—	—	752
	1,614	1,684	1,797	1,185	4,300

Accrued bonuses were awarded to key management personnel on the completion of the Siccar Point Group acquisition by IEUK as at 30 June 2022. These bonuses were subsequently paid in July 2022 along with Compensation for loss of office payment.

28. CHANGES IN LIABILITIES ARISING FROM FINANCING ACTIVITIES

As at 31 December 2019:

	Opening	Cash flows	Non-cash movements*	Other movements	Closing
	US $000	US $000	US $000	US $000	US $000
Current borrowings (note 17)	(10,565)	46,969	—	(44,933)	(8,529)
Current amounts due to parent	—	—	—	—	—
Non-current borrowings (note 18)	(1,420,454)	(99,307)	—	(68,089)	(1,587,850)
Total liabilities from financing activities	(1,431,019)	(52,338)	—	(113,022)	(1,596,379)

As at 31 December 2020:

	Opening	Cash flows	Non-cash movements*	Other movements	Closing
	US $000	US $000	US $000	US $000	US $000
Current borrowings	(8,529)	37,857	—	(36,828)	(7,500)
Current amounts due to parent	—	—	—	—	—
Non-current borrowings (note 18)	(1,587,850)	135,000	—	(70,820)	(1,523,670)
Total liabilities from financing activities	(1,596,379)	172,857	—	(107,648)	(1,531,170)

As at 31 December 2021:

	Opening	Cash flows	Non-cash movements*	Other movements	Closing
	US $000	US $000	US $000	US $000	US $000
Current borrowings (note 17)	(7,500)	27,884	—	(26,596)	(6,212)
Current amounts due to parent	—	—	—	—	—
Non-current borrowings (note 18)	(1,523,670)	146,000	—	(76,526)	(1,454,196)
Total liabilities from financing activities	(1,531,170)	173,884	—	(103,122)	(1,460,408)

As at 30 June 2021:

	Opening	Cash flows	Non-cash movements*	Other movements	Closing
	US $000	US $000	US $000	US $000	US $000
Current borrowings (note 17)	(7,500)	14,829	—	(13,791)	(6,462)
Current amounts due to parent	—	—	—	—	—
Non-current borrowings (note 18)	(1,523,670)	146,000	—	(37,701)	(1,415,371)
Total liabilities from financing activities	(1,531,170)	160,829	—	(51,492)	(1,421,833)

As at 30 June 2022:

	Opening	Cash flows	Non-cash movements*	Other movements	Closing
	US $000	US $000	US $000	US $000	US $000
Current borrowings	(6,212)	14,402	350	(211,967)	(203,427)
Current amounts due to parent	—	—	(323,057)	—	(323,057)
Non-current borrowings (note 18)	(1,454,196)	(35,000)	277,000	205,570	(1,006,626)
Total liabilities from financing activities	(1,460,408)	(20,598)	(45,707)	(6,397)	(1,533,110)

Non-cash movements relate to payments made on the Siccar Point Group's behalf by IEUK as part of the completion mechanism of the acquisition of the Siccar Point Group, completed on 30 June 2022. This mainly represents the mandatory repayment of RBL loan of US$277 million due to a change of control and the early termination of hedges amounting to US$45 million which could not be novated to Ithaca Group as per the mutual agreement with counterparties. Amount due to IEUK of US$323 million is payable on demand.

* Non-cash movements for current borrowings includes US$350k of accrued interest, paid by IEUK. This amount was held within accruals but has been presented alongside the associated RBL loan for better clarity.

Other movements relate to activities such as interest amounts accruing on listed loan notes, the reclassification of bonds from non-current to current and various other adjustments.

29. SHARE-BASED PAYMENTS

The Siccar Point Group has an equity settled share option scheme in place whereby the Board may grant share options in Siccar Point Energy Luxembourg S.C.A. ("Luxco") to certain employees (all of whom are employed in underlying subsidiaries).

All options granted under the Siccar Point Energy Limited Share Option Scheme, created by rules adopted on 15 March 2018 (the "Rules"), were only exercisable on the occurrence of an exit event under the terms of the Rules and as defined under the articles of association of Luxco and were granted in respect of C ordinary shares in Luxco.

Share options have no expiry date and can only vest upon the completion of an "exit event". This is defined as a sale of the whole share capital of Luxco, the sale or transfer of over ninety percent of the assets, a stock exchange listing, or upon the discretion of the directors.

The option exercise price shall be determined by the directors at the time of granting the option and shall not be less than the nominal value of a share.

The sale by Luxco of the entire issued share capital of Siccar Point Energy (Holdings) Limited to IEUK which was completed on 30th June 2022, was an exit event as so defined, and the options would then have been exercisable, however, the quantum of the initial and contingent consideration received by Luxco on the exit event was insufficient to result in any value being attributable to the C ordinary shares in Luxco the subject of the options. As a consequence, the options were "out of the money" and were simply allowed to lapse unexercised. The option scheme is now closed.

As of the years 31 December 2021, 2020, and 2019 the directors have concluded that there were no indicators of an exit event being probable in the near future and are not likely to use their discretion to determine that an option holder may exercise their option.

As with any award dependent on a non-market performance vesting condition, an expense would be recognised only to the extent that the award is considered likely to vest.

Movement during the period:

The following table illustrates the number and weighted average exercise prices (WAEP) of, and movements in, share options during the period:

	31 Dec 2019	31 Dec 2020	31 Dec 2021	30 June 2021	30 June 2022	WAEP
			Number			US$
Opening balance	19,000	36,444	46,000	46,000	48,888	0.0251
Granted during the period	17,444	9,556	11,216	Nil	Nil	0.0251
Forfeited during the period	Nil	Nil	8,328	Nil	Nil	0.0251
Closing balance	36,444	46,000	48,888	46,000	48,888	0.0251

30. SUBSEQUENT EVENTS

On 1 August 2022, a settlement was made as a result of the exercise of the put option on the bond (note 18). Given that Siccar Point Group's acquisition by IEUK on 30 June 2022, constituted a change of control event under the bond terms, the put option was offered at a premium of 1% and bondholders with a combined holding of US$166.4 million exercised the put option. Subsequently in September 2022, Siccar Point Bonds totalling US$25.6 million were bought back at a premium of 6% on behalf of Ithaca SP Bonds PLC (formerly Siccar Point Energy Bonds PLC) which were redeemed on 21 September 2022. The remaining Siccar Point Bonds totalling US$8 million were redeemed on 12 October 2022.

Ithaca Group has an existing RBL facility in place of US$1.225 billion with maturity to 2026. The RBL facility is secured by the assets of the guarantor members of the Ithaca Group. As per the terms of the RBL arrangement, the companies within the Siccar Point Group formally acceded to become members of the RBL guarantor group within 10 business days after the redemption of the remaining Siccar Point Bonds on 12 October 2022. This arrangement is measured at fair value in accordance with IFRS 9, Financial Instruments at US$nil.

An Energy Profits Levy ("EPL" or "the Levy") was enacted on 14 July 2022 applying a temporary windfall tax of 25% to the profits of oil and gas companies until 31 December 2025 or earlier if prices return to normal levels. The Levy is charged upon 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. The Siccar Point Group directors forecast the impact of that Levy would be to decrease the deferred tax asset by US$75.9 million had it been enacted on 30 June 2022.

SECTION C: IOG

PART A: ACCOUNTANT'S REPORT ON THE HISTORICAL FINANCIAL INFORMATION OF IOG

The Directors
Ithaca Energy plc
23 College Hill
London
EC4R 2RP

9 November 2022

Dear Ladies and Gentlemen

Ithaca Oil and Gas Limited ("IOG")

We report on the financial information of IOG for the year ended 31 December 2019 (the "IOG Financial Information") set out in Part B of Section C (*Consolidated Historical Financial Information of IOG*) of Part 16 (*Historical Financial Information*) of the prospectus (the "**Prospectus**") dated 9 November 2022 of Ithaca Energy plc (the "**Company**").

This report is required by item 18.3.1 of Annex 1 of the UK version of Commission Delegated Regulation (EU) 2019/980 and is given for the purpose of complying with that item and for no other purpose.

Save for any responsibility arising under Prospectus Regulation Rule 5.3.2R (2)(f) to any person as and to the extent there provided, to the fullest extent permitted by law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report or our statement, required by and given solely for the purposes of complying with item 1.3 of Annex 1 to the UK version of Commission Delegated Regulation (EU) 2019/980, consenting to its inclusion in the Prospectus.

Opinion on the IOG Financial Information

In our opinion, the IOG Financial Information gives, for the purposes of the Prospectus, a true and fair view of the state of affairs of IOG as at the date stated and of its profits, cash flows and changes in equity for the year ended 31 December 2019, in accordance with the basis of preparation set out in note 2 to the IOG Financial Information.

Responsibilities

The Directors of the Company are responsible for preparing the IOG Financial Information in accordance with the basis of preparation set out in note 2 to the IOG Financial Information.

It is our responsibility to form an opinion on the IOG Financial Information and to report our opinion to you.

Basis of Preparation

The IOG Financial Information has been prepared for inclusion in the Prospectus of the Company on the basis of the accounting policies set out in note 3 to the IOG Financial Information.

Basis of opinion

We conducted our work in accordance with Standards for Investment Reporting issued by the Financial Reporting Council in the United Kingdom. We are independent in accordance with the FRC's Ethical Standard as applied to Investment Circular Reporting Engagements, and we have fulfilled our other ethical responsibilities in accordance with these requirements.

Our work included an assessment of evidence relevant to the amounts and disclosures in the IOG Financial Information. It also included an assessment of significant estimates and judgments made by those responsible for the preparation of the IOG Financial Information and whether the accounting policies are appropriate to the entity's circumstances, consistently applied and adequately disclosed.

We planned and performed our work so as to obtain all the information and explanations which we considered necessary in order to provide us with sufficient evidence to give reasonable assurance that the IOG Financial Information is free from material misstatement whether caused by fraud or other irregularity or error.

Our work has not been carried out in accordance with auditing or other standards and practices generally accepted in other jurisdictions and accordingly should not be relied upon as if it had been carried out in accordance with those standards and practices.

Conclusions Relating to Going Concern

We have not identified a material uncertainty related to events or conditions that, individually or collectively, may cast significant doubt on IOG's ability to continue as a going concern for a period of at least twelve months from the date of the Prospectus. We conclude that the Directors' use of the going concern basis of accounting in the preparation of the IOG Financial Information is appropriate.

Declaration

For the purposes of Prospectus Regulation Rule 5.3.2R (2)(f) we are responsible for this report as part of the Prospectus and declare that, to the best of our knowledge, the information contained in this report is in accordance with the facts and that the report makes no omission likely to affect its import. This declaration is included in the Prospectus in compliance with item 1.2 of Annex 1 of the UK version of Commission Delegated Regulation (EU) 2019/980.

Yours faithfully

Ernst & Young LLP

PART B: CONSOLIDATED HISTORICAL FINANCIAL INFORMATION OF IOG

STATEMENT OF COMPREHENSIVE INCOME

For the year ended 31 December 2019

	Note	Audited 2019 £'000
Revenue	5	794,399
Cost of sales	6	(403,838)
Gross profit		390,561
General and administrative expenses		(6,331)
Other gains		15,480
Profit on disposal of operations	11	963,878
Profit from operations before tax and finance costs		1,363,588
Net finance costs	7	(13,119)
Profit before tax		1,350,469
Income tax	16	105,168
Profit attributable to owners		1,455,637

A statement of other comprehensive income has not been presented as no items of comprehensive income other than the profit for the financial year were earned during the financial year.

STATEMENT OF FINANCIAL POSITION

As at 31 December 2019

	Note	Audited 2019
		£'000
ASSETS		
Current assets		
Cash and cash equivalents		4,401
Trade and other receivables	8	23,027
Amounts receivable from related parties	20	2,005,938
Deposits, prepaid expenses and other receivables		665
Inventory	9	6,980
		2,041,011
Non current assets		
Long-term receivable		445
Exploration and evaluation assets	10	920
Property, plant & equipment	11	74,452
Deferred tax assets		88,493
		164,310
Total assets		2,205,321
LIABILITIES AND EQUITY		
Current liabilities		
Trade and other payables	12	(68,996)
Decommissioning liabilities	13	(9,237)
		(78,233)
Non current liabilities		
Decommissioning liabilities	13	(290,450)
Other non-current liabilities	14	(10,404)
		(300,854)
Net Assets		**1,826,234**
Shareholders' equity		
Share capital	15	221,000
Share premium	15	119,245
Retained earnings		1,485,989
Total equity		**1,826,234**

STATEMENT OF CHANGES IN EQUITY

For the year ended 31 December 2019

	Share capital	Share Premium	Retained Earnings	Total
	£'000	£'000	£'000	£'000
Balance, 1 January 2019	221,000	119,245	29,020	369,265
Profit for the year			1,455,637	1,455,637
Movement in share based payments			1,332	1,332
Balance, 31 December 2019	**221,000**	**119,245**	**1,485,989**	**1,826,234**

STATEMENT OF CASH FLOW

For the year ended 31 December 2019

	Note	Audited 2019 £'000
Cash provided by (used in)		
Operating activities		
Profit before tax		1,350,469
Adjustment for		
Depletion, depreciation and amortisation	11	131,911
Unwinding of decommissioning discount	7	25,925
Unrealised foreign exchange gains		(15,480)
Profit on sale of non-current assets		(963,878)
Share based payments expense		1,332
Net Interest expense	14	(13,599)
Cashflow from operations		516,680
Decrease in inventories*		10,308
Increase in amounts due from related parties*		(240,529)
Decrease in trade and other receivables, deposits and long term receivables*		25,619
Movement in decommissioning liabilities*		(5,207)
Decrease in trade and other payables*		(3,711)
Corporation tax paid		(177,644)
Net cash from operating activities		125,516
Investing activities		
Capital expenditure		(116,124)
Net cash used in investing activities		(116,124)
Financing activities		
Capital repayments on leases	14	(2,788)
Net cash used in financing activities		(2,788)
Currency translation differences related to cash		(2,149)
Increase in cash & cash equivalents		4,455
Cash and cash equivalents, beginning of period		(54)
Cash and cash equivalents, end of period		4,401

* These movements are presented net of the disposal of assets and liabilities to related parties.

NOTES TO THE HISTORICAL FINANCIAL INFORMATION

1. NATURE OF OPERATIONS

Ithaca Oil and Gas Limited ("IOG") was incorporated in England on 20 February 1981 and is incorporated and domiciled in England. IOG is involved in the development and production of oil and gas in the North Sea. The IOG's registered office is 1 Park Row Leeds LS1 5AB.

On 29 May 2019, IEUK entered into a sale and purchase agreement with Chevron North Sea Holdings Limited to acquire the entire share capital of Ithaca Oil and Gas Limited (previously known as Chevron North Sea Limited). The acquisition was completed on 8 November 2019.

2. BASIS OF PREPARATION

The IOG Historical Financial Information ("HFI"), which has been prepared specifically for the purposes of this document, sets out the Statement of Financial Position as at 31 December 2019 and the results of operations and cash flows for the year then ended and does not constitute statutory accounts within the meaning of section 434(3) of the Companies Act 2006. This historical financial information has been prepared in accordance with the requirements of the Prospectus Directive Regulation, the Listing Rules, and on a basis consistent with the accounting policies adopted in the historical financial information of the Ithaca Group (or Ithaca Energy Limited/PLC), included elsewhere in this document, which were prepared in accordance with UK-adopted International Accounting Standards ("UK-adopted IAS"), except as noted below.

This Historical Financial Information presents only the business that was acquired by Ithaca Group and reflects the assets, liabilities, revenues and expenses of IOG directly attributed to the business acquired. The HFI does not include certain assets, liabilities, revenues and expenses related to the following (the "Carved-out operations"):

- Sale by IOG of its interests in the Rosebank field to Equinor, which completed in January 2019
- Transfer of interests in the following fields and/or former subsidiaries to other Chevron group companies prior to completion of the acquisition of IOG by the Ithaca Group:
  - Clair Licence
  - Ninian pipeline system
  - SIRGE pipeline system
  - Sullom Voe terminal
  - Chevron Europe Limited
  - Chevron Britain Limited
  - Texaco Ireland Limited
  - Oil Spill Response Limited
  - Paloak Limited

UK-adopted IAS does not explicitly provide guidance for the preparation of carve-out historical financial information and therefore certain accounting conventions permitted for the preparation of historical financial information for inclusion in investment circulars, as described in the Standards for Investment Reporting Annexure ("the Annexure" to SIR 2000 (Investment Reporting Standard applicable to public reporting engagements on historical financial information) issued by the Financial Reporting Council, have been applied where UK-adopted IAS does not provide specific accounting treatments.

The HFI has carved out the operations referred to above and therefore does not comply with the requirements of IFRS 10 'Consolidated Financial Statements'. However, the HFI has been prepared on a basis applying the aggregation principles underlying the consolidation procedures of IFRS 10 to the business acquired by the Ithaca Group.

The Prospectus Directive Regulation does not require financial information to be included in this document for any period commencing before 1 January 2019. Accordingly, the directors of

Ithaca Energy Limited have elected not to present comparative information which results in a departure from UK-adopted IAS.

Opening 1 January 2019 and 31 December 2019 Statement of Financial Position

	1 January 2019	31 December 2019
	£'000	£'000
Assets		
Current assets		
Cash and cash equivalents	—	4,401
Trade and other receivables	81,441	23,027
Amounts receivable from related parties	111,356	2,005,938
Deposits, prepaid expenses and other receivables	3,518	665
Inventory	72,346	6,980
	268,661	2,041,011
Non current assets		
Long-term receivable	10	445
Exploration and evaluation assets	—	920
Property, plant & equipment	1,329,916	74,452
Deferred tax assets	—	88,493
	1,329,926	164,310
Total assets	1,598,587	2,205,321
Liabilities And Equity		
Current liabilities		
Trade and other payables	(132,579)	(68,996)
Decommissioning liabilities	(7,494)	(9,237)
Bank overdrafts	(54)	—
	(140,127)	(78,233)
Non current liabilities		
Decommissioning liabilities	(888,088)	(290,450)
Deferred tax liabilities	(184,555)	—
Other non-current liabilities	(16,552)	(10,404)
	(1,089,195)	(300,854)
Net Assets	369,265	1,826,234
Shareholders' equity		
Share capital	221,000	221,000
Share premium	119,245	119,245
Retained earnings	29,020	1,485,989
Total equity	369,265	1,826,234

2.1 ***Changes in accounting pronouncements***

International Financial Reporting Standards in issue but not yet effective.

At the date of authorisation of the historical financial information, the IASB and IFRS Interpretations Committee have issued standards, interpretations and amendments which are applicable to IOG. For the next reporting period, applicable IFRS will be those endorsed by the UK Endorsement Board (UKEB).

Whilst these standards and interpretations are not effective for, and have not been applied in the preparation of, this historical financial information, the following could potentially have a material impact on IOG's historical financial information going forward. The directors are assessing the effect of these standards on IOG's historical financial information.

All the new standards effective as at 1 January 2023:

- Classification of Liabilities as Current or Non-current—Amendments to IAS 1
- Definition of Accounting Estimates—Amendments to IAS 8

- Disclosure of Accounting Policies—Amendments to IAS 1 and IFRS Practice Statement 2
- Deferred Tax related to Assets and Liabilities arising from a Single Transaction—Amendments to IAS 12

Standards adopted as at 1 January 2019: IFRS 16

IOG assessed all contracts existing at 1 January 2019 to determine whether a contract contains a lease based upon the conditions in place as at 1 January 2019.

Lease liabilities were measured at the present value of the remaining lease payments, discounted using the lessee's incremental borrowing rate at 1 January 2019. Right-of-use assets were measured at the amount equal to the lease liabilities, adjusted by the amount of any prepaid or accrued lease payments relating to that lease recognised in the statement of financial position immediately before 1 January 2019. The lease payments associated with leases for which the lease term ends within 12 months of the date of transition to IFRS and leases for which the underlying asset is of low value have been recognised as an expense on either a straight-line basis over the lease term or another systematic basis.

3. SIGNIFICANT ACCOUNTING POLICIES, JUDGEMENTS AND ESTIMATION UNCERTAINTY

Basis of measurement

This HFI has been prepared on a going concern basis using the historical cost convention. Historical cost is generally based on the fair value consideration given in exchange for the assets.

Going Concern

Subsequent to the acquisition of IOG by IEUK, as per the Ithaca Group policy, IOG is under the Ithaca Group's centralised treasury management arrangement and shares banking arrangements with the Ithaca Group of companies and therefore IOG's ability to continue as a going concern is dependent on access to the Ithaca Group's resources. The Ithaca Group directors consider the preparation of the Historical Financial Information on a going concern basis to be appropriate. This is due to the following key factors:

- Commodity market performance. Brent has averaged over $105/bbl and UK Natural Gas has averaged over 211p/therm since 31 December 2021. Oil and gas prices are forecast to remain at high levels through the rest of 2022 and throughout 2023;
- Liquidity headroom. As at 30 June 2022 the Ithaca Group held liquidity of US$335million (US$175 million available to be drawn upon within the Reserves Based Lending ("RBL") facility, plus US$160 million cash) and as at 4 November 2022, the Ithaca Group maintains liquidity of US$554 million (US$275 million available to be drawn upon within the RBL facility, plus US$279 million cash);
- Operational performance and a diversified portfolio, which has been further strengthened by the acquisitions of Siccar Point Group and Summit E&P as at 30 June 2022; and
- A material hedge position which reduces exposure to price uncertainty—over 56% of total H2 2022 production was hedged, and 35% of 2023 production.

The Ithaca Group directors closely monitor the funding position of the Ithaca Group throughout the year, including monitoring continued compliance with covenants and available facilities to ensure sufficient headroom to fund operations.

The Ithaca Group directors have considered a number of risks applicable to the Ithaca Group that may have an impact on its ability to continue as a going concern. Short-term and long-term cash forecasts are produced on a weekly and quarterly basis respectively along with any related sensitivity analysis. This allows proactive management of any business risks, including liquidity risk discussed below.

The Ithaca Group directors have reviewed the Ithaca Group's forecasts and projections for the period to 31 December 2023, including forecast covenant compliance. Owing to fluctuations in commodity demand and price volatility, management prepared sensitivity analyses to the forecasts and applied a number of downside plausible scenarios and stress tests for the whole

Ithaca Group, including decreases in production, reduced sales prices, increases in operating and capital expenditure assumptions and exchange rate fluctuations. Management aggregated these scenarios to create a reasonable combined worst-case scenario.

The sensitivity analysis showed that there was no reasonably possible scenario that would result in the business being unable to meet its obligations as they fall due. The Ithaca Group would still continue to have sufficient cash headroom throughout the period to 31 December 2023 (the 'going concern period') and still have the necessary liquidity to continue trading.

The Ithaca Group directors have a number of mitigating actions within their control, including the further drawdown on its available funds from the RBL facility, the reduction in uncommitted capital expenditure, and the cancellation or deferral of future dividends.

IOG has also obtained a letter of support from both Ithaca Energy (E&P) Limited and Ithaca Energy Limited (being intermediate parent companies of IOG) to provide financial support for the period up to and including 31 December 2023.

Based on the assessment of the Ithaca Group's financial position for the period to 31 December 2023 and the confirmation of continued parental support, the Ithaca Energy Limited directors are satisfied that they have a reasonable basis upon which to conclude that IOG is able to continue as a going concern throughout the going concern period. Accordingly, they continue to adopt the going concern basis of accounting in preparing the consolidated Historical Financial Information.

Interest in joint operations

IOG's interest in joint operations (e.g. exploration and production arrangements) are accounted for by recognising its assets (including its share of assets held jointly), its liabilities (including its share of liabilities incurred jointly), its revenue from the sale of its share of the output arising from the joint operation, its share of revenue from the sale of output by the joint operation and its expenses (including its share of any expenses incurred jointly).

Revenue

The sale of crude oil, gas or condensate represents a single performance obligation, being the sale of barrels equivalent on collection of a cargo or on delivery of commodity into an infrastructure. Revenue is accordingly recognised for this performance obligation when control over the corresponding commodity is transferred to the customer. Revenue is measured at the fair value of the consideration received or receivable and represents amounts receivable for products in the normal course of business, net of discounts, customs duties and sales taxes.

Foreign currency translation

Items included in this financial information are measured using the currency of the primary economic environment in which IOG operates (the 'functional currency'). The financial information is presented in Great British Pounds, which is IOG's functional and presentation currency.

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at year end exchange rates of monetary assets and liabilities denominated in foreign currencies are recognised in the statement of income.

Financial instruments

All financial instruments are initially recognised at fair value on the statement of financial position. IOG's financial instruments consist of cash, trade and other receivables, deposits, amounts receivable from related parties, accounts payable and accrued liabilities. Under IFRS 9 all financial instruments will be recorded at amortised cost based on an analysis of the business model and terms of financial assets. There is no change to the classification of financial liabilities. All financial instruments are required to be measured at fair value on initial recognition. Measurement in subsequent periods is dependent on the classification of the respective financial instrument.

IFRS 9 classifications:

Cash and cash equivalents are classified at amortised cost which equates to its fair value. Trade and other receivables and long term receivables are classified and carried at amortised cost as they have a business model of held to collect and the terms meet the solely payments of principal and interest criteria. Accounts payable, accrued liabilities and certain other long-term liabilities are classified as other financial liabilities.

Cash and cash equivalents

For the purpose of the statement of cash flow, cash and cash equivalents include investments with an original maturity of three months or less.

Inventories—hydrocarbon and materials

Inventories of materials and hydrocarbon inventory supplies are stated at the lower of cost and net realisable value. Cost comprises direct materials and, where applicable, direct labour costs and those overheads that have been incurred in bringing the inventories to their present location and condition. Cost is determined on the first-in, first-out method. Current hydrocarbon inventories are stated at net realisable value, which is based on estimated selling price less any further costs expected to be incurred to completion and disposal/sale. Non-current oil and gas inventories are stated at historic cost.

Lifting or offtake arrangements for oil and gas produced in certain of IOG's oil and gas properties are such that each participant may not receive and sell its precise share of the overall production in each period. The resulting imbalance between cumulative entitlement and cumulative volume sold less inventory is an "underlift" or "overlift" and is measured at fair value. Movements during an accounting period are adjusted through cost of sales in the statement of income.

Trade receivables

Trade receivables are recognised and carried at the original invoiced amount, less any provision for estimated irrecoverable amounts.

For trade receivables, IOG applies a simplified approach in calculating expected credit losses "ECLs". Therefore, IOG does not track changes in credit risk, but instead, recognises a loss allowance based on lifetime ECLs at each reporting date.

IOG considers a financial asset in default when contractual payments are 90 days past due. However, in certain cases, IOG may also consider a financial asset to be in default when internal or external information indicates that IOG is unlikely to receive the outstanding contractual amounts in full before taking into account any credit enhancements held by IOG. A financial asset is written off when there is no reasonable expectation of recovering the contractual cash flows.

Financial liabilities measured at amortised cost

All other financial liabilities are initially recognised at fair value, net of directly attributable transaction costs. For interest-bearing loans and borrowings this is typically equivalent to the fair value of the proceeds received, net of issue costs associated with the borrowing. After initial recognition, other financial liabilities are subsequently measured at amortised cost using the effective interest method. Amortised cost is calculated by taking into account any issue costs and any discount or premium on settlement. Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognised in interest and other income and finance costs respectively. This category of financial liabilities includes trade and other payables and finance debt.

Derecognition of financial liabilities

IOG derecognises financial liabilities when, and only when, IOG's obligations are discharged, cancelled or have expired. The difference between the carrying amount of the financial liability derecognised and the consideration paid and payable is recognised in profit or loss.

Property, plant and equipment

Oil and gas expenditure—exploration and evaluation assets

Capitalisation

Pre-acquisition costs on oil and gas assets are recognised in the statement of income when incurred. Costs incurred after rights to explore have been obtained, such as geological and geophysical surveys, drilling and commercial appraisal costs and other directly attributable costs of exploration and evaluation including technical and administrative expenses are capitalised as intangible exploration and evaluation ("E&E") assets.

E&E costs are not amortised prior to the conclusion of evaluation activities. At completion of evaluation activities, if technical feasibility is demonstrated and commercial reserves are discovered then, following approved development sanction, the carrying value of the E&E asset is reclassified as a development and production ("D&P") asset, but only after the carrying value is assessed for impairment and where appropriate its carrying value adjusted. In addition where the E&E asset forms part of an existing development and production CGU, such E&E activity is included in the carrying value of IOG's D&P assets. If after completion of evaluation activities in an area, it is not possible to determine technical feasibility and commercial viability or if the legal right to explore expires or if IOG decides not to continue exploration and evaluation activity, then the costs of such unsuccessful exploration and evaluation are written off to the statement of income in the period the relevant events occur.

Oil and gas expenditure—development and production assets

Capitalisation

Costs of bringing a field into production, including the cost of facilities, wells and subsea equipment, direct costs including staff costs together with E&E assets reclassified in accordance with the above policy, are capitalised as a D&P asset. Normally each individual field development will form an individual D&P asset but there may be cases, such as phased developments, or multiple fields around a single production facility when fields are grouped together to form a single D&P asset.

Depreciation

All costs relating to a development are accumulated and not depreciated until the commencement of production. Depreciation is calculated on a unit of production basis based on the proved and probable reserves of the asset. Any re-assessment of reserves affects the depreciation rate prospectively. Significant items of plant and equipment will normally be fully depreciated over the life of the field. However, these items are assessed to consider if their useful lives differ from the expected life of the D&P asset and should this occur a different depreciation rate would be charged.

Impairment

For impairment review purposes IOG's oil and gas assets are analysed into cash-generating units ("CGUs") as identified in accordance with IAS 36. Individual assets are grouped into CGUs for impairment assessment purposes at the lowest level at which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. This grouping is based on a number of factors which include the infrastructure required to operate the asset, management operating plans (including consideration of hub strategies), internal management reporting, geographic location and operating licences. CGUs are identified consistently from period to period, unless a change is justified. A review is carried out each reporting date for any indicators that the carrying value of IOG's assets may be impaired or previously impaired assets (excluding goodwill) where a reversal of a previous impairment may arise. For assets where there are such indicators, an impairment test is carried out on the CGU.

The impairment test involves comparing the carrying value with the recoverable value of an asset. The recoverable amount of an asset is determined as the higher of its fair value less costs to sell and value in use, where the value in use is determined from estimated future net cash flows. If the recoverable amount of an asset is estimated to be less that its carrying amount, the carrying amount of the asset is reduced to the recoverable amount. The resulting impairment losses are written off to the statement of income. Previously impaired assets (excluding goodwill) are reviewed for possible reversal of previous impairment at each reporting date. No impairment indicators were identified in the review performed by management for the year ended 31 December 2019. Therefore, no impairment test was performed.

A previously recognised impairment loss is only reversed if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognised. If this is the case, the carrying amount is increased to the recoverable amount. That increased amount cannot exceed the carrying amount that would have been determined, net of depreciation had no impairment loss been recognised in previous years.

Non oil and natural gas operations

Non oil and gas assets are initially recorded at cost and depreciated over their estimated useful lives on a straight line basis as follows—

Buildings	10 years
Computer and office equipment	3 years
Furniture and fittings	5 years

Decommissioning liabilities

IOG records the present value of legal obligations associated with the retirement of long-term tangible assets, such as producing well sites and processing plants, in the period in which they are incurred with a corresponding increase in the carrying amount of the related long-term asset. Liabilities for decommissioning are recognised when IOG has an obligation to plug & abandon a well, dismantle and remove a facility or an item of plant and restore the site on which it is located, and when a reliable estimate can be made. Where an obligation exists for a new facility or well, such as oil & gas production or transportation facilities. The obligation arises when the asset is installed or the ground/environment is disturbed at the field location the amount recognised is the present value of the estimated future expenditure determined in accordance with the local regulations and requirements. In subsequent periods, the asset is adjusted for any changes in the estimated amount or timing of the settlement of the obligations. The carrying amounts of the associated assets are depleted using the unit of production method, in accordance with the depreciation policy for development and production assets. Actual costs to retire tangible assets are deducted from the liability as incurred.

Taxation

Current income tax

Current income tax assets and liabilities are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amounts are those that are enacted or substantively enacted by the reporting date.

Deferred income tax

Deferred tax is recognised for all deductible temporary differences and the carry-forward of unused tax losses. Deferred tax assets and liabilities are measured using enacted or substantively enacted income tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in rates is included in earnings in the period of the enactment date. Deferred tax assets are recorded in the financial information if realisation is considered more likely than not.

The carrying amount of deferred tax assets is reviewed at each balance sheet date and reduced to the extent that it is no longer probable that sufficient taxable profits will be available to allow all or part of the asset to be recovered.

Deferred tax assets and liabilities are offset only when a legally enforceable right of offset exists and the deferred tax assets and liabilities arose in the same tax jurisdiction.

Leases

IOG assesses at contract inception all arrangements to determine whether it is, or contains, a lease. That is, if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. IOG is not a lessor in any transactions, it is only a lessee. IOG applies a single recognition and measurement approach for all leases, except for short-term leases and leases of low-value assets. IOG recognises lease liabilities to make lease payments and right-of-use assets representing the right to use the underlying assets.

Right-of-use assets are measured at cost, less any accumulated depreciation and impairment losses, and adjusted for any remeasurement of lease liabilities. The cost of right-of-use assets includes the amount of lease liabilities recognised, initial direct costs incurred, and lease payments made at or before the commencement date less any lease incentives received. The right-of-use asset is depreciated over the useful life of the asset.

IOG's right-of-use assets are included in Property, Plant and Equipment (Note 11).

At the commencement date of the lease, IOG recognises lease liabilities measured at the present value of lease payments to be made over the lease term. In calculating the present value of lease payments, IOG uses its incremental borrowing rate at the lease commencement date because the interest rate implicit in the lease is generally not readily determinable. After the commencement date, the amount of lease liabilities is increased to reflect the accretion of interest and reduced for the lease payments made. In addition, the carrying amount of lease liabilities is remeasured if there is a modification, a change in the lease term, a change in the lease payments (e.g., changes to future payments resulting from a change in an index or rate used to determine such lease payments) or a change in the assessment of an option to purchase the underlying asset.

IOG's lease liabilities are included in Net finance costs and Other liabilities (Notes 7 and 14).

Significant accounting judgements and estimation uncertainties

The management of IOG has to make estimates and judgements when preparing the financial information of IOG. Uncertainties in the estimates and judgements could have an impact on the carrying amount of assets and liabilities and IOG's result. The most important estimates and judgements in relation thereto are:

Estimates in oil and gas reserves

The business of IOG is to enhance hydrocarbon recovery and extend the useful lives of mature and underdeveloped assets and associated infrastructure in a profitable and responsible manner. Estimates of oil and gas reserves requires critical judgement, factors such as the availability of geological and engineering data, reservoir performance data, and drilling of new wells all impact on the determination of IOG's estimates of its oil and gas reserves and result in different future production profiles affecting prospectively the discounted cash flows used in impairment testing. These are based on an annual third party expert's view and these volumes are used in the calculations for impairment tests and accounting for depletion and decommissioning. Changes in estimates of oil and gas reserves resulting in different future production profiles will affect the discounted cash flows used in impairment testing, the anticipated date of decommissioning and the depletion charges in accordance with the unit of production method. For the purposes of depletion and decommissioning estimates IOG use proved and probable reserves and for the purposes of the impairment tests performed, IOG considers the same probable and proved reserves as well as risked resource volumes. These risking adjustments are reflective of IOG's progress of the overall field development and are reflective of a market participant view.

Estimates in impairment of oil and gas assets

Determination of whether oil and gas assets have suffered any impairment requires an estimation of the fair value less costs to dispose of the CGU to which oil and gas assets have been allocated. When performing impairment tests of oil and gas assets, this assessment is performed on a post-tax basis. This includes a review of previously impaired assets for possible reversal of a previous impairment. The calculation requires IOG to estimate the future cash flows expected to arise from the CGU using discounted cash flow models comprising asset-by-asset life of field projections. Key assumptions and estimates in the impairment models relate to: commodity prices that are based on internal view of forward curve prices that are considered to be a best estimate of what a market participant would use; discount rates which reflect management's estimate of a market participant post-tax weighted average cost of capital; and commercial reserves. As the production and related cash flows can be estimated from IOG's experience, management believes that the estimated cash flows expected to be generated over the life of each field is the appropriate basis upon which to assess individual assets for impairment or an impairment reversal. Furthermore, there is also uncertainty due to climate change and the speed of the energy transition and the likely impact this will have on both oil and gas demand for forecast prices. IOG have considered climate adjusted price curves in their assessment of forecast commodity prices.

Decommissioning provision estimates

Amounts used in recording a provision for decommissioning are estimates based on current legal and constructive requirements and current technology and price levels for the removal of facilities and plugging and abandoning of wells. Due to changes in relation to these items, the future actual cash outflows in relation to decommissioning are likely to differ in practice. To reflect the effects due to changes in legislation, requirements, technology and price levels, the carrying amounts of decommissioning provisions are reviewed on a regular basis. The effects of changes in estimates do not give rise to prior year adjustments and are dealt with prospectively.

While IOG uses its best estimates and judgement, actual results could differ from these estimates. Expected timing of expenditure can also change, for example in response to changes in laws & regulations or their interpretation, and/or due to changes in commodity prices. The payment dates are uncertain and depend on the production life of the respective fields. A nominal discount rate of 4% is used to discount the estimated costs.

Initial recognition of amounts receivables from related parties

To assess the initial measurement of its interest-free and repayable on demand loans to related parties, IOG uses its best estimates and judgement to determine that the right to receive payments are substantive at the inception of the transaction and there are no differences between the face value and fair value of the loan, and take it to account factors like the capacity of the guarantor to repay the loan and the amount of time it would take.

Impairment of financial assets measured at amortised cost

If the credit risk on the financial asset has increased significantly since initial recognition, the loss allowance for the financial asset is measured at an amount equal to the lifetime expected credit losses. In other instances, the loss allowance for the financial asset is measured at an amount equal to the twelve month expected credit losses (ECLs). Changes in loss allowances are recognised in profit and loss. IOG assesses current economic environment and future credit risk outlook to monitor changes in expected credit losses on financial assets measured at amortised cost and no significant impact was determined.

Taxation judgement

IOG's operations are subject to a number of specific tax rules which apply to exploration, development and production. In addition, the tax provision is prepared before the relevant companies have filed their tax returns with the relevant tax authorities and, significantly, before these have been agreed. As a result of these factors, the tax provision process necessarily involves the use of a number of estimates and judgements including those required in calculating the effective tax rate. IOG recognises deferred tax assets on unused tax losses where it is probable that future taxable profits will be available for utilisation. This requires management to make judgements and assumptions regarding the likelihood of future taxable profits and the amount of deferred tax that can be recognised.

4. **SEGMENTAL REPORTING**

IOG operates a single class of business being oil and gas exploration, development and production and related activities in a single geographical area presently being the North Sea. All material revenue from external customers and non-current assets are attributed to/located in the UK, IOG's country of domicile.

5. **REVENUE**

Revenue with external customers	2019
	£'000
Oil sales	635,248
Gas sales	155,289
Other income	3,862
	794,399

Before the acquisition by Ithaca Energy Limited, IOG's largest customers were other entities in the Chevron Corporation—Chevron Products Company (£331m) and Chevron Natural Gas Europe (£112m). The other customer contributing more than 10% of revenue in the year was BP Oil International Limited (£109m).

6. **COST OF SALES**

	2019
	£'000
Operating costs	275,476
Movement in oil and gas inventory	(3,549)
Depletion, depreciation and amortization	131,911
	403,838

7. **NET FINANCE COSTS**

	2019
	£'000
Bank interest and charges	1,154
Interest income	(13,960)
Unwinding of decommissioning discount	25,925
	13,119

8. **TRADE AND OTHER RECEIVABLES**

Current	2019
	£'000
Trade debtors	692
Other current assets	22,335
	23,027

IOG applies the simplified approach for trade receivables and applies a provision matrix taking into account history of default and forward looking factors. There is no history of defaults and no forward looking factors that imply a risk for credit loss, therefore no expected credit loss has been recognised.

Included within other assets are a receivable for reclaimed VAT (£6m) and the partner share of expenditures in joint operations (£10m).

9. **INVENTORY**

Current	2019
	£'000
Hydrocarbon inventory	5,229
Materials inventory	1,751
	6,980

10. EXPLORATION AND EVALUATION ASSETS

	£'000
At 1 January 2019	**—**
Additions	920
At 31 December 2019	920

11. PROPERTY, PLANT AND EQUIPMENT

	Right of use operating assets	Development & Producing assets	Total
	£'000	£'000	£'000
Cost			
At 1 January 2019	7,265	5,266,428	5,273,693
Additions	—	115,204	115,204
Revision to decommissioning liability (Note 13)	—	(35,891)	35,891
Disposals	—	(4,769,397)	(4,769,397)
At 31 December 2019	7,265	576,344	583,609
DD&A and Impairment			
At 1 January 2019	—	3,943,777	3,943,777
Disposals		(3,566,531)	(3,566,531)
DD&A charge for the period	2,564	129,347	131,911
At 31 December 2019	2,564	506,593	509,157
NBV at 1 January 2019	7,265	1,322,651	1,329,916
NBV at 31 December 2019	4,701	69,751	74,452

Equity interests in nine of IOG's assets were transferred to other entities within the Ithaca Group effective 17 December 2019. These assets were transferred through a loan mechanism at fair market value. The aggregate value of the net assets disposed of was approximately £160 million and the non-cash consideration was approximately £1.124 billion, resulting in a gain on sale of £964 million and an associated intercompany receivable balance. The assets transferred were Captain, Erskine, Britannia and satellite fields, Elgin-Franklin and Jade. Alba remains within IOG along with the decommissioning liabilities for Heather and Strathspey.

Security provided against related party facilities

The assets of Ithaca Oil and Gas Limited are included withing the guarantor group for the Reserves Based Lending (RBL) facility of Ithaca Energy (UK) Limited. The RBL availability is approximately $1.225 billion with a maturity to April 2026.

12. TRADE AND OTHER PAYABLES

	2019
	£'000
Trade payables	687
Current tax payable	52,253
Lease liabilities (Note 14)	2,573
Accruals	13,483
	68,996

13. DECOMMISSIONING LIABILITIES

	2019
	£'000
Balance, beginning of period	895,582
Unwinding of discount on provision	25,925
Ithaca group balance transfers on restructure	(580,723)
Utilisation of provision	(5,206)
Revision to estimates	(35,891)
Balance, end of period	299,687

The total future decommissioning liability was calculated based on net ownership interest in all wells and facilities, estimated costs to reclaim and abandon wells and facilities and the estimated timing of the costs to be incurred in future periods. IOG used a risk free rate of 4.0 percent and an inflation rate of 2.0 percent over the varying lives of the assets to calculate the present value of the decommissioning liabilities. These costs are expected to be incurred at various intervals over the next 12 years.

The economic life and the timing of the obligations are dependent on commodity price and the future production profiles of the respective production and development facilities and Government legislation.

As described in Note 11, interests in nine assets were transferred to other Ithaca group entities effective 17 December 2019. Chevron Corporation have the obligation to provide the security and remain financially responsible for the decommissioning obligations of IOG's interest in the Strathspey field and the resulting decommissioning reimbursement is retained by Ithaca Energy Limited.

14. OTHER NON CURRENT LIABILITIES

Other non-current liabilities	2019
	£'000
Lease liability	2,264
Other creditors	8,140
	10,404

On 1 January 2019, IOG adopted IFRS 16, which resulted in the recognition of a right of use asset and associated lease liability. The note below shows the movement in the recognised lease liability throughout 2019. IOG's interest expense related to lease liabilities are included in Net finance costs and the lease liabilities are included in Trade and Other Payables and Other non-current liabilities (Notes 12 and 14).

Other creditors relates to a contingent payable due to Canadian Natural Resources pursuant to IOG's acquisition of their interest in the Strathspey field in 2013, relating to the decommissioning cost, this amount is in addition to the decommissioning liability for Strathspey included in Note 13.

Lease liability	2019
	£'000
At 1 January	7,265
Interest	360
Payments	(2,788)
At 31 December	4,837
Current (Note 12)	2,573
Non-current	2,264
	4,837

The lease liabilities at 31 December 2019 relate to the office lease. The incremental borrowing rate applied to these leases is 5.83%.

15. SHARE CAPITAL

Authorised share capital	Number of common shares	Amount
		£'000
At 31 December 2019	221,000,000	221,000

Issued

The issued share capital is as follows:

Authorised share capital	Number of common shares	Amount
		£'000
At 31 December 2019	221,000,000	221,000

Share premium

Authorised share capital	Number of common shares	Amount
		£'000
At 31 December 2019	221,000,000	221,000

Authorised share capital	Amount
	£'000
At 31 December 2019	119,245

16. TAXATION

	2019
	£'000
Current tax	
Current tax charge	(167,880)
Total current tax charge	(167,880)
Deferred tax	
Deferred tax in Statement of Income	273,048
Total deferred tax credit	273,048
Total tax credit	105,168

Deferred tax

Deferred tax	
Relating to the origination and reversal of temporary differences	273,048
Total tax credit	273,048

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

	2019
	£'000
Accounting profit before tax	1,350,469
At tax rate of 30%	405,141
Deferred tax supplementary charge	(67,912)
Current year supplementary charge	25,683
Non-ringfencing items credit	475
Items not subject to tax	(466,015)
Other	(2,540)
Total tax credit recorded in the statement of income	(105,168)

IOG is UK tax resident. The effective rate of tax applicable for UK ring fence oil and gas activities in 2019 was 40% (2018: 40%) consisting of a corporation tax rate of 30% and the supplementary charge of 10%.

Deferred income tax at 31 December 2019 relates to the following:

	2019
	£'000
Deferred tax liability	(20,893)
Deferred tax asset	109,386
Net deferred tax asset	88,493

The gross movement on the deferred income tax account is as follows:

At 1 January	(184,555)
Income statement credit	273,048
At 31 December	88,493

Deferred tax liability	Other	Accelerated tax depr'n	Total
	£'000	£'000	£'000
At 1 January 2019	18,619	524,169	542,788
Movement	(16,448)	—	(16,448)
Origination and reversal of temporary differences	—	(505,447)	(505,447)
At 31 December 2019	2,171	18,722	20,893

Deferred tax assets	Tax Losses	Total
	£'000	£'000
At 1 January 2019	358,233	358,233
Origination and reversal of temporary differences	(248,847)	(248,847)
At 31 December 2019	109,386	109,386

Deferred income tax assets are recognised for the carry-forward of unused tax losses and unused tax credits to the extent that it is probable under current tax legislation and using enacted tax rates that taxable profits will be available in the future against which the unused tax losses/credits can be utilised.

The carrying value of the net deferred tax asset at 31 December 2019 of $88 million is supported by estimates of IOG's future taxable income.

17. COMMITMENT

Capital commitments	2019
	£'000
Capital commitments incurred jointly with other ventures (Ithaca Energy's share)	3,500

18. FINANCIAL INSTRUMENTS

IOG has identified that it is exposed principally to these areas of market risk.

Commodity Risk

Commodity price risk related to crude oil prices is IOG's most significant market risk exposure. Crude oil prices and quality differentials are influenced by worldwide factors such as Opec actions, political events and supply and demand fundamentals. IOG is also exposed to natural gas price movements on uncontracted gas sales. Natural gas prices, in addition to the worldwide factors noted above, can also be influenced by local market conditions. IOG's expenditures are subject to the effects of inflation, and prices received for the product sold are not readily adjustable to cover any increase in expenses from inflation.

Foreign Exchange Rate Risk

IOG is exposed to foreign exchange risks to the extent it transacts in various currencies, while measuring and reporting its results in GB Pounds. Since time passes between the recording of a receivable or payable transaction and its collection or payment, IOG is exposed to gains or losses on non-GBP amounts and on balance sheet translation of monetary accounts denominated in non-GBP amounts upon spot rate fluctuations from quarter to quarter.

Credit Risk

IOG's accounts receivable with customers in the oil and gas industry are subject to normal industry credit risks and are unsecured.

Prior to the acquisition by IEUK in December 2019, oil production was sold to BP Oil International and gas was sold to Chevron Limited. From December 2019 oil production was sold to BP Oil International and gas production to BP Gas Marketing.

IOG assesses partners' credit worthiness before entering into farm-in or joint venture agreements. In the past, IOG has not experienced credit loss in the collection of accounts receivable. As IOG's exploration, drilling and development activities expand with existing and new joint venture partners, IOG will assess and continuously update its management of associated credit risk and related procedures.

IOG applies the simplified approach for trade receivables and applies a provision matrix taking into account history of default and forward-looking factors. There is no history of defaults and no forward-looking factors that imply a risk for credit loss, therefore no expected credit loss has been recognised. IOG regularly monitors all customer receivable balances outstanding in excess of 90 days. As at 31 December 2019, substantially all accounts receivables are current, being defined as less than 90 days.

For balances due from related parties IOG applies the simplified approach and considers the lifetime expected credit loss at each reporting date. Taking account of currently available information and that the related parties have on parental support and forward-looking data it has been assessed that the companies are profit generating and/or in a net asset position supporting the value of the related party balances.

IOG also has credit risk arising from cash and cash equivalents held with banks and financial institutions. The maximum credit exposure associated with financial assets is the carrying values.

Liquidity Risk

Liquidity risk includes the risk that as a result of its operational liquidity requirements IOG will not have sufficient funds to settle a transaction on the due date. IOG manages liquidity risk by maintaining adequate cash reserves, banking facilities, and by considering medium and future requirements by continuously monitoring forecast and actual cash flows. IOG considers the maturity profiles of its financial assets and liabilities. As at 31 December 2019 substantially all accounts payable were current.

The following table shows the timing of cash outflows relating to trade and other payables as at 31 December 2019:

	Within 1 year	1 to 5 years
	£'000	£'000
Accounts payable and accrued liabilities	14,170	—
Lease liabilities	2,788	2,323
Other liabilities		8,140

19. FAIR VALUES OF FINANCIAL ASSETS AND LIABILITIES

Financial instruments of IOG consist mainly of cash and cash equivalents, receivables, payables, loans and financial derivative contracts, all of which are included in the historical financial information. At 31 December, the classification of financial instruments and the carrying amounts reported on the balance sheet and their estimated fair values are as follows:

		2019
		£'000
Classification	Carrying Amount	Fair Value
Amounts receivable from related parties	2,005,938	2,005,938

20. RELATED PARTY TRANSACTIONS

IOG's immediate parent undertaking is IEUK, and the ultimate parent Company is Delek Group Limited, a company incorporated in Israel. IOG's ultimate controlling party is Mr. Yitzhak (Sharon) Tshuva.

The following table provides the loan balances with related parties as at 31 December:

Amounts receivable from related parties	2019
	£'000
Ithaca Energy UK Limited	1,741,576
Ithaca Minerals (North Sea) Limited	204,456
Ithaca Alpha (NI) Limited	10,617
Ithaca GSA Limited	12,417
Ithaca Energy Limited	25,269
Ithaca Gamma Limited	11,603
	2,005,938

Prior to the acquisition of IOG by IEUK, the remuneration of key management personnel was as follows—

	2019
	£'000
Remuneration	4,018
Long term incentive	363
	4,381

No compensation was payable in respect of loss of office during the financial year.

Following the acquisition by Ithaca Energy (UK) Limited, remuneration to key management personnel was paid by another company in the group, IEUK. It is not practicable to perform an allocation of remuneration between the respective group companies as such amounts are earned in respect of the director's services to the group of companies as a whole. All relevant disclosures are made within the Historical Financial Information of Ithaca Energy Limited.

21. SUBSEQUENT EVENTS

Given the twin challenges that arose in Q1-2020 of Covid-19 and the dramatic fall in oil prices, the main focus of IOG's response to these issues was centered on maintaining the health of the workforce and reducing the risk of spreading the virus, whilst at the same time preserving the operational and financial resilience of the business. To minimise the risks to personnel presented by Covid-19 and simultaneously preserve operational continuity, IOG reduced the number of personnel on each of its operated offshore facilities in March 2020 to the minimum level required to safely maintain production and execute any critical maintenance work scopes.

The planned 2020 investment programme announced at the start of the year involved investments in a range of infill drilling and subsea satellite developments designed to enhance production and reserves over the coming years including on the Alba asset.

As a consequence of managing the Covid-19 situation and proactively preserving the liquidity and cash flow resilience of the business in the face of significantly lower commodity prices, various activities in the 2020 capital programme have been stopped and deferred until a more suitable time. This includes the Alba infill drilling campaign that commenced at the end of 2019 and the Fotla exploration well.

The majority of the amended and deferred capital investment programmes are not specifically centred on activities that are scheduled to materially impact 2020 production. In the short term the reductions in production arising from the deferred infill drilling activities are expected to be largely offset by shorter than originally forecast planned maintenance shutdowns on the platforms and infrastructure serving the producing asset portfolio. The reduced durations are a natural consequence of the measures that need to be taken to manage the prevailing Covid-19 related personnel and equipment restrictions. Though the maintenance activities that had been planned for completion this year will ultimately need to be rescheduled for 2021 and beyond. The exact impact of this on forecast production in future years is being assessed as part of the on-going work being undertaken by IOG and the wider industry to optimise forward work programmes.

As a consequence of the oil price decline, the Alba asset was impaired by $32.9 million in 2020. An impairment review was carried out at the end of both 2Q and 3Q 2021 driven by the higher forward curve for both oil and gas prices resulting in reversals of $10.8m on Alba. In addition to these impairment reviews performed an annual review of all oil and gas assets at 4Q21 resulting in a further reversal of $18m on Alba.

An agreement to acquire 13.3% additional interest in the Alba field from Mitsui E&P UK Limited was signed on 17 September 2021. At completion this took IOG's interest in the Alba field to 36.7%.

On 27 February 2022, a conflict broke out between Russia and Ukraine. Following this, numerous governments around the world have implemented sanctions against Russia and Belarus. The Directors have considered the implications of the ongoing conflict on key assumptions and judgments. This consideration has been made on the recognition and measurement of accounting estimates and the related financial statements disclosure. The assessment included specific review of the supply chain; funding sources; customer; credit risk and cyber security. The Directors do not consider there to be any significant impact on IOG at this stage.

On 14 July 2022 the UK Government enacted a temporary windfall tax of 25% on the profits of oil and gas companies called the Energy Profits Levy ("EPL" or "the Levy"). The Levy is charged upon 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. At the date of this historical financial information the Directors are still assessing the impact for IOG.

PART 17

UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL INFORMATION

PART A: UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL INFORMATION

The unaudited pro forma condensed combined income statement has been prepared in accordance with the requirements of Annex 20, sections 1 and 2 of the UK Prospectus Regulation to illustrate how the Siccar Point Acquisition may have impacted the Group's financial information as follows:

1. the unaudited pro forma condensed combined income statement for the six months ended 30 June 2022 to illustrate the effect that the Siccar Point Acquisition might have had on the Group if it had been completed on 1 January 2022; and
2. the unaudited pro forma condensed combined income statement for the year ended 31 December 2021 to illustrate the effect that the Siccar Point Acquisition might have had on the Group if it had been completed on 1 January 2021.

The unaudited pro forma condensed combined income statements listed above is referred to as the "**Unaudited Pro Forma Condensed Combined Financial Information**".

The Unaudited Pro Forma Condensed Combined Financial Information has been provided for illustrative purposes only. The Unaudited Pro Forma Condensed Combined Financial Information has been extracted without material amendment from the Historical Financial Information of the Group for the year ended 31 December 2021, and for the six months ended 30 June 2022 set forth in Section A (*The Group*) of Part 16 (*Historical Financial Information*), which has been prepared in accordance with IFRS. The Unaudited Pro Forma Condensed Combined Financial Information has also been derived from the Historical Financial Information of the Siccar Point Group for the year ended 31 December 2021, and the six months ended 30 June 2022 set forth in Section B (*The Siccar Point Group*) of Part 16 (*Historical Financial Information*), which has been prepared in accordance with IFRS.

The Unaudited Pro Forma Condensed Combined Financial Information is prepared, unless otherwise specified, on a basis that is consistent with the accounting policies used in the preparation of the Group's and Siccar Point Group's consolidated financial statements, which have been prepared in accordance with IFRS.

The Unaudited Pro Forma Condensed Combined Financial Information set forth in this Prospectus is based on available information and certain assumptions and estimates that the Directors believe are reasonable and may differ materially from the actual amounts that would have been achieved had the Siccar Point Acquisition occurred on the respective dates mentioned above.

The Unaudited Pro Forma Condensed Combined Financial Information does not include all information required for financial statements under IFRS, and should be read in conjunction with the Historical Financial Information of each of the Group and Siccar Point Group for the year ended 31 December 2021, and the six months ended 30 June 2022, and the notes related thereto, included in Part 16 (*Historical Financial Information*).

The Unaudited Pro Forma Condensed Combined Financial Information has not been prepared in accordance with Article 11 of Regulation S-X under the US Securities Act or any generally accepted accounting standards. The Unaudited Pro Forma Condensed Combined Financial Information has been prepared in accordance with the basis of preparation described in Part 3 (*Presentation of Financial and Other Information)*.

The following should be read in conjunction with Part 3 (*Presentation of Financial and Other Information)*, Part 6 (*Business Overview*), Part 9 (*Selected Financial Information)*, Part 12 (*Operating and Financial Review relating to the Group*), Part 13 (*Operating and Financial Review relating to the Siccar Point Group*) as well as the Historical Financial Information of each of the Group and Siccar Point Group included in Part 16 (*Historical Financial Information*).

All unaudited pro forma adjustments and their underlying assumptions are described more fully in the notes to the Unaudited Pro Forma Condensed Combined Financial Information.

Unaudited pro forma condensed combined income statement

In millions of $	Ithaca Energy[(1)]	Siccar Point Group[(2)]	Six months ended 30 June 2022 Pro forma combined total
Revenue	1,337.6	153.2	1,490.8
Cost of sales	(752.0)	(72.7)	(824.7)
Gross profit	**585.6**	**80.5**	**666.1**
Impairment (charge) / reversal	(7.6)	(191.5)	(199.1)
Exploration and evaluation expenses	(9.6)	(1.9)	(11.5)
Fair value gain / (losses) on contingent consideration	(14.4)	0.0	(14.4)
General and administrative expenses[(a)]	(26.7)	(11.6)	(38.3)
Other gains / (losses)	(13.1)	(34.3)	(47.4)
Gain on bargain purchase	1,324.3	—	1,324.3
(Loss) / profit before net finance costs and tax	**1,838.5**	**(158.8)**	**1,679.7**
Net finance costs	(97.1)	(58.4)	(155.5)
Income tax	(183.7)	470.7	287.0
(Loss) / profit after tax	**1,557.7**	**253.5**	**1,811.2**

Unaudited pro forma condensed combined income statement

				Year ended 31 December 2021	
In millions of $	Ithaca Energy[(1)]	Siccar Point Group[(2)]	Transaction costs adjustment[(3)]	Gain on bargain purchase adjustment[(4)]	Pro forma combined total
Revenue	1,428.2	234.6	—	—	1,662.8
Cost of Sales	(879.2)	(137.8)	—	—	(1,017.0)
Gross Profit	**549.0**	**96.8**	—	—	**645.8**
Impairment (charge) / reversal	465.3	358.6	—	—	823.9
Exploration and evaluation expenses	(0.2)	(3.9)	—	—	(4.1)
Fair value gain / (losses) in contingent consideration	8.3	(0.0)	—	—	8.3
General and administrative expenses[(a)]	(15.2)	(13.5)	(9.5)	—	(38.2)
Other gains / (losses)	(4.4)	(120.5)	—	—	(124.9)
Gain on bargain purchase adjustment[(4)]	10.5	—	—	704.0	714.5
(Loss) / profit before net finance costs and tax	**1,013.3**	**317.5**	**(9.5)**	**704.0**	**2,025.3**
Net finance costs	(250.1)	(120.7)	—	—	(370.8)
Income tax	(337.2)	(345.0)	—	—	(682.2)
(Loss) / profit after tax	**426.0**	**(148.2)**	**(9.5)**	**704.0**	**972.3**

(a) "General and administrative expenses" (i) for the six months ended 30 June 2022 included transaction costs relating to each of the Siccar Point Acquisition and Summit Acquisition, (ii) for the year ended 31 December 2020 included certain costs relating to the redundancy costs post an employee voluntary redundancy programme, and (iii) for the year ended 31 December 2019 included fees related to costs associated with the Chevron Acquisition which completed in last quarter of 2019.

Notes to unaudited pro forma condensed combined financial information

(1) ***Ithaca Energy Limited***

The historical financial information of Ithaca Energy for each of the year ended 31 December 2021 and the six months ended 30 June 2022 has been extracted from the Historical Financial Information of Ithaca Energy, without material adjustment, which is prepared in accordance with IFRS and included elsewhere in this Prospectus.

(2) ***Siccar Point Group***

The historical financial information of SPEHL for each of the year ended 31 December 2021 and six months ended 30 June 2022 has been extracted from the Historical Financial Information of Siccar Point Group, without material adjustment, which is prepared in accordance with IFRS and included elsewhere in this Prospectus.

(3) ***Transaction costs adjustment***

The transaction costs adjustment for the year ended 31 December 2021 relates to the Siccar Point Acquisition and mainly includes legal fees, stamp duty, directors & officers insurance and Seismic change of control payments. These costs are payments made directly in relation to the acquisition and no tax benefit has been assumed. These costs will not be incurred on an ongoing basis in the enlarged group. As at 30 June 2022, costs of $9 million had been accrued within the financial information of Delek in respect of Siccar Point Acquisition.

No tax benefit has been assumed for the transaction costs. In addition, no adjustment for financing costs has been illustrated as the acquisition was funded by cash.

(4) ***Gain on bargain purchase adjustment***

The price payable at completion of the Siccar Point Acquisition on 30 June 2022 was $1.015 billion, plus contingent consideration of $102 million. The resulted in a gain on bargain purchase of $704 million being recognised with regards to the Siccar Point Acquisition. This gain is therefore included in the financial information of the Group as at 30 June 2022, and no pro forma adjustment is required to illustrate the impact of the gain.

The gain on bargain purchase of $704 million has been applied to the financial period ended 31 December 2021 with no other adjustments considered.

Other adjustments—taxation

For the purposes of the pro forma we have assumed that there are no tax implications from an earlier tax grouping of Ithaca Energy and Siccar Point. In the event Siccar Point did form part of the Ithaca Energy tax group in 2021, the combined tax charge may be materially different due to different deferred tax asset recognition profiles.

Pro Forma Adjusted EBITDAX

Pro forma Adjusted EBITDAX consists of profit for the period before income tax, net finance costs, put premiums on oil derivative instruments, put premiums on gas derivative instruments, revaluation of forex forward contracts, revaluation of commodity hedges, unrealised gain / (loss) from hedging, depletion, depreciation and amortisation, impairment (charge) / reversal, exploration and evaluation expenses, fair value gain / (losses) on contingent consideration, gain on bargain purchase, transaction costs and employee voluntary redundancy programme on a pro forma basis to give effect to the Siccar Point Acquisition as if it had occurred on 1 January 2021. Transaction costs and employee voluntary redundancy programme for the Group include costs that are not considered to be representative of underlying operations.

These measures are included as the Directors believe that they and similar measures are widely used by certain investors, securities analysts and other interested parties as supplemental measures of performance and liquidity. These measures may not be comparable to other similarly titled measures of other companies and have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of the Group's operating results as reported under IFRS.

The following table sets out the reconciliation from *Pro Forma* profit after tax to *Pro Forma* Adjusted EBITDAX and *Pro Forma* profit for the periods presented. All unaudited pro forma adjustments and their underlying assumptions are described more fully in the notes to the Unaudited Pro Forma Condensed Combined Financial Information set out above or in the accompanying definitions in the table below.

	Year ended 31 December 2021					Six months ended 30 June 2022		
In millions of $	**Ithaca Energy[(1)]**	**SPEHL[(2)]**	**Transaction costs adjustment[(b)]**	**Gain on bargain purchase adjustment[(4)]**	**Pro forma combined total**	**Ithaca Energy[(1)]**	**SPEHL[(2)]**	**Pro forma combined total**
Pro forma (loss) / profit after tax	**426.0**	**(148.2)**	**(9.5)**	**704.0**	**972.3**	**1,557.7**	**253.4**	**1,811.1**
Income tax	337.2	345.0		—	682.2	183.7	(470.7)	(287.0)
Net finance costs	250.1	120.7	—	—	370.9	97.1	58.4	155.5
Put premiums on oil derivative instruments	27.2		—	—	27.2	7.3	—	7.3
Put premiums on gas derivative instruments	14.6	—	—	—	14.6	17.4	—	17.4
Revaluation of forex forward contracts .	8.3	—	—	—	8.3	18.7	—	18.7
Revaluation of commodity hedges	—	—	—	—	—	—	—	—
Unrealised gain/(loss) from hedging . . .	—	116.2	—	—	116.2	—	—	—
Depletion, depreciation and amortisation	455.9	66.5	—	—	522.4	297.4	47.8	345.2
Impairment (charge) / reversal	(465.3)	(358.6)	—	—	(823.9)	7.6	191.6	199.2
Exploration and evaluation expenses . .	0.2	3.9	—	—	4.0	9.6	1.9	11.5
Fair value gain / (losses) on contingent consideration	(8.3)	0.0	—	—	(8.2)	14.4	—	14.4
Gain on bargain purchase	(10.5)	—	—	(704.0)	(714.5)	(1,324.3)	—	(1,324.3)
Transaction costs[(a)]	—	—	9.5	—	9.5	20.8	—	20.8
Employee voluntary redundancy programme	—	—	—	—	—	—	—	—
Proforma Adjusted EBITDAX	**1,035.4**	**145.4**	—	—	**1,180.9**	**907.4**	**82.3**	**989.8**

(a) "Transaction costs" for (i) the year ended 31 December 2019 include certain costs relating to the Chevron Acquisition of $17.1 million, and (ii) for the six months ended 30 June 2022 included certain costs relating to the each of the Siccar Point Acquisition and Summit Acquisition of $20.8 million.

(b) "Transaction cost adjustment" for the year ended 31 December 2021 and six months ended 30 June 2022 relate to the Siccar Point Acquisition. These costs are payments made directly in relation to the acquisition and no tax benefit has been assumed. These costs will not be incurred on an ongoing basis in the enlarged group. As at 30 June 2022, costs of $4 million had been accrued within the financial information of Delek.

PART B: ACCOUNTANT'S REPORT ON THE UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL INFORMATION

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The Board of Directors
on behalf of Ithaca Energy plc
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Goldman Sachs International
Plumtree Court
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United Kingdom

Morgan Stanley & Co. International plc
20 Bank Street
Canary Wharf
London
E14 4AD
United Kingdom

9 November 2022

Dear Sirs/Mesdames,

Ithaca Energy plc (the "Company")

We report on the pro forma financial information (the "**Pro Forma Financial Information**") set out in Part 17 (*Unaudited Pro Forma Condensed Combined Financial Information*) of the prospectus dated 9 November 2022 (the "**Prospectus**"). This report is required by the UK version of the Commission delegated regulation (EU) 2019/980 (the "**Prospectus Delegated Regulation**") which is part of the law of England and Wales by virtue of the European Union (Withdrawal) Act 2018 and is given for the purpose of complying with that regulation and for no other purpose.

Opinion

In our opinion:

(a) the Pro Forma Financial Information has been properly compiled on the basis stated; and

(b) such basis is consistent with the accounting policies of the Company.

Responsibilities

It is the responsibility of the directors of the Company (the "**Directors**") to prepare the Pro Forma Financial Information in accordance with Annex 20 sections 1 and 2 of the Prospectus Delegated Regulation.

It is our responsibility to form an opinion, as to the proper compilation of the Pro Forma Financial Information and to report that opinion to you in accordance with Annex 20 section 3 of the Prospectus Delegated Regulation.

Save for any responsibility arising under Prospectus Regulation Rule 5.3.2R(2)(f) to any person as to and to the extent there provided, to the fullest extent permitted by law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report or our statement, required by and given solely for the purposes of complying with Annex 1 item 1.3 of the Prospectus Delegated Regulation, consenting to its inclusion in the Prospectus.

In providing this opinion we are not updating or refreshing any reports or opinions previously made by us on any financial information used in the compilation of the Pro Forma Financial Information, nor do we accept responsibility for such reports or opinions beyond that owed to those to whom those reports or opinions were addressed at the date of their issue.

Basis of preparation

The Pro Forma Financial Information has been prepared on the basis described in this Part 17 (*Unaudited Pro Forma Condensed Combined Financial Information*), for illustrative purposes only, to provide information about how the transaction might have affected the financial information presented on the basis of the accounting policies adopted by the Company in preparing the financial statements for the year ended 31 December 2021 and the six month period ended 30 June 2022.

Basis of Opinion

We conducted our work in accordance with the Standards for Investment Reporting issued by the Financial Reporting Council in the United Kingdom. We are independent of the Company in accordance with the Financial Reporting Council's Ethical Standard as applied to the Prospectus Reporting Engagements, and we have fulfilled our other ethical responsibilities in accordance with these requirements.

The work that we performed for the purpose of making this report, which involved no independent examination of any of the underlying financial information, consisted primarily of comparing the unadjusted financial information with the source documents, considering the evidence supporting the adjustments and discussing the Pro forma financial information with the Directors.

We planned and performed our work so as to obtain the information and explanations we considered necessary in order to provide us with reasonable assurance that the Pro Forma Financial Information has been properly compiled on the basis stated and that such basis is consistent with the accounting policies of the Company.

Our work has not been carried out in accordance with auditing or other standards and practices generally accepted in jurisdictions outside the United Kingdom, including the United States of America, and accordingly should not be relied upon as if it had been carried out in accordance with those standards or practices.

Declaration

For the purposes of Prospectus Regulation Rule 5.3.2R(2)(f) we are responsible for this report as part of the Prospectus and we declare that to the best of our knowledge, the information contained in this report is, in accordance with the facts and that the report makes no omission likely to affect its import. This declaration is included in the Prospectus in compliance with Annex 1 item 1.2 of the Prospectus Delegated Regulation.

Yours faithfully

Deloitte LLP

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PART 18

DETAILS, TERMS AND CONDITIONS OF THE GLOBAL OFFERING

1. SUMMARY OF THE GLOBAL OFFERING

This Part 18 *(Details, Terms and Conditions of the Global Offering)* should be read in conjunction with Part 5 (*Expected Timetable of Principal Events and Offer Statistics*).

The Global Offering comprises an offer of 105,000,000 Offer Shares by the Company at a price per Offer Share of 250 pence. Up to a maximum of 15,000,000 Ordinary Shares may be sold by the Selling Shareholder pursuant to the Over-allotment Option.

Pursuant to the Global Offering, the Company intends to issue 105,000,000 Offer Shares, raising gross proceeds of approximately £262.5 million. The Company will use the gross proceeds of the issue of the Offer Shares pursuant to the Global Offering to (i) pay the Underwriters' Expenses and (ii) first, repay $77.3 million of outstanding principal and accrued interest under the Tracker Loan and, second, $214 million of the Capital Note. DKL Energy has agreed to waive all remaining amounts (if any) outstanding under each of the Tracker Loan and Capital Note. Following such payment and/or waiver (if any), DKL Energy will provide a confirmation that such payment and/or waiver (if any) is in full and final settlement of any amounts due or payable by the Company in respect of each of the Capital Note and Tracker Loan.

The Offer Shares will represent approximately 10.4 per cent. of the expected issued Ordinary Share capital of the Company immediately following Admission.

Pursuant to the Global Offering, the Selling Shareholder will experience a 10.4 per cent. dilution from the issue of 105,000,000 Offer Shares (i.e. its proportionate interest in the Company will drop by 10.4 per cent.) (assuming no exercise of the Over-allotment Option).

15,000,000 Over-allotment Shares (representing up to 14.3% of the number of Offer Shares (prior to the utilisation of the Over-allotment Option)) will be made available by the Selling Shareholder pursuant to the Over-allotment Option. The Company will not receive any proceeds from the sale of Over-allotment Shares (all of which will be paid to the Selling Shareholder).

Under the Global Offering, all Offer Shares issued pursuant to the Global Offering will be issued, payable in full, at the Offer Price.

On Admission, there will be 1,005,162,217 Ordinary Shares in issue. All Ordinary Shares in issue on Admission will be fully paid.

Immediately following Admission, it is expected that approximately 10.4% of the Company's issued ordinary share capital will be held in public hands (within the meaning of Listing Rule 6.14) assuming no Over-allotment Shares are acquired pursuant to the Over-allotment Option (increasing to approximately 11.9% if the maximum number of Over-allotment Shares are acquired pursuant to the Over-allotment Option).

The aggregate Underwriters' Expenses (being the base underwriting commissions in respect of the Offer Shares and the Underwriters' legal fees) payable by the Company are estimated to be £6.7 million (including VAT). The Company will pay the Underwriters' Expenses from the gross proceeds of the Global Offering. The aggregate Selling Shareholder's Expenses (being the Selling Shareholder's legal fees, the Underwriters' advisory fees, and the base underwriting commissions in respect of the Over-allotment Shares (if any) and any transfer duty) payable by the Company are estimated to be £3.6 million (including VAT). In consideration of the Selling Shareholder waiving an amount equal to the Selling Shareholder's Expenses under the Capital Note, the Company will pay the Selling Shareholder's Expenses. The aggregate IPO Expenses (including, amongst others, FCA fees, the Company's professional fees (including accounting, legal and those of the Competent Person) and the costs of printing and distribution of the documents) are estimated to be £13.3 million (including VAT). The Company will pay the IPO Expenses and the Selling Shareholder's Expenses with amounts received from payments from IEEPL and/ or certain Subsidiaries. This will require IEEPL and/ or certain Subsidiaries to make payments to the Company, which is not permitted under the RBL Facility Agreement unless agreed by the majority of lenders. It is expected that IEUK will obtain the consent of the majority of lenders under the RBL Facility. However, if the consent is not received, the Selling Shareholder will pay all the IPO Expenses. Any discretionary commission on the Offer Shares and the Over-allotment Shares will be payable by the Selling Shareholder within 30 days of Admission in its sole discretion. The Company will not receive any of the net proceeds from the Global Offering, all of which will ultimately be received by Delek.

Under the Global Offering, the Offer Shares are being offered to (i) certain institutional and professional investors in the United Kingdom and elsewhere outside the United States in reliance on Regulation S and (ii) in the United States only to QIBs in reliance on Rule 144A or another exemption from, or in a transaction not subject to, the registration requirements of the US Securities Act.

Certain restrictions that apply to the distribution of this Prospectus and the offer and sale of Ordinary Shares in jurisdictions outside the United Kingdom are described in paragraphs 1.12 to 1.25 (inclusive) of this Part 18 (*Details, Terms and Conditions of the Global Offering*) below.

The Global Offering is subject to the satisfaction of conditions, which are customary for transactions of this type, contained in the Underwriting and Sponsors' Agreement (subject only to Admission, and save for those steps which are to be completed after Admission). Admission becoming effective no later than 8:00 am on 14 November 2022 (or such later date and time, not being later than the fourteenth calendar day after the date of the Underwriting and Sponsors' Agreement, as the Joint Global Co-ordinators may agree with the Company and the Selling Shareholder) and the Underwriting and Sponsors' Agreement not having been terminated prior to Admission.

Admission is expected to become effective and unconditional dealings in the Ordinary Shares are expected to commence on the London Stock Exchange at 8:00 am on 14 November 2022. All dealings in Ordinary Shares prior to the commencement of unconditional dealings will be on a "when issued" basis, will be of no effect if Admission does not take place and will be at the sole risk of the parties concerned. The earliest date for settlement of such dealings will be 14 November 2022.

When admitted to trading, the Ordinary Shares will be registered with ISIN GB00BPJHV584, SEDOL BPJHV58 and LEI 21380057TNFLXPXBIP34, and it is expected that the Ordinary Shares will be traded under ticker symbol "ITH".

The Offer Shares (including any Ordinary Shares sold pursuant to the Over-allotment Option) will, upon Admission, rank equally in all respects with all other Ordinary Shares, including for all dividends and other distributions declared, made or paid on the Ordinary Shares after Admission. The Ordinary Shares will, immediately on and from Admission, be freely transferable, subject to the applicable law, the Articles and any contractual obligations of a Shareholder.

The Company expressly reserves the right to determine, at any time prior to Admission, not to proceed with the Global Offering. If such right is exercised, the Global Offering (and the arrangements associated with it) will lapse and any money received in respect of the Global Offering will be returned to investors without interest.

The Company further reserves the right to extend or shorten the timetable, or any aspect of the timetable, for the Global Offering.

1.1 *Reasons for the Global Offering*

The Directors believe the Global Offering and Admission is a natural progression for the Company and will:

- allow the Group to have an independent capital allocation policy that is beneficial to the Group;
- allow the Group to grow organically, return capital toShareholders and pursue a value accretive M&A strategy;
- provide the Company with sufficient liquidity to repay (in part) the Capital Note and amounts outstanding under the Tracker Loan (in each case, in whole or in part);
- create a liquid market in the Ordinary Shares for all Shareholders; and

- provide the Company access to a wider range of capital-raising options which may be of use in the future.

1.2 ***Use of Proceeds***

Pursuant to the Global Offering, the Company intends to issue 105,000,000 Offer Shares, raising gross proceeds of approximately £262.5 million. The Company will use the gross proceeds of the issue of the Offer Shares pursuant to the Global Offering to (i) pay the Underwriters' Expenses and (ii) first, repay $77.3 million of outstanding principal and accrued interest under the Tracker Loan and, second, $214 million of the Capital Note. DKL Energy has agreed to waive all remaining amounts (if any) outstanding under each of the Tracker Loan and Capital Note. Following such payment and/or waiver (if any), DKL Energy will provide a confirmation that such payment and/or waiver (if any) is in full and final settlement of any amounts due or payable by the Company in respect of each of the Capital Note and Tracker Loan. The Company will pay the IPO Expenses and Selling Shareholder's Expenses with amounts received from payments from IEEPL and/ or certain Subsidiaries. This will require IEEPL and/ or certain Subsidiaries to make payments to the Company, which is not permitted under the RBL Facility Agreement unless agreed by the majority of lenders. It is expected that IEUK will obtain the consent of the majority of lenders under the RBL Facility Agreement. However, if the consent is not received, the Selling Shareholder will pay all the IPO Expenses. The Company will not receive any of the net proceeds from the Global Offering, all of which will ultimately be received by Delek.

No expenses will be charged to investors in connection with Admission or the Global Offering by the Company or the Selling Shareholder.

1.3 ***Related Party Transactions***

Save as disclosed in paragraph 2 (*Related Party Transactions*) of Part 10 (*Principal Shareholder and Related Party Transactions*) neither the Company nor any other member of the Group has entered into any related party transactions (which for these purposes are those set out in the standards adopted according to the Regulation (EC) No 1606/2002) with any related party during the period covered by the Historical Financial Information and up to the Latest Practicable Date. All the transactions set out therein are entered into at fair value and on arm's-length terms.

1.4 ***Selling Shareholder***

The following table sets forth the Selling Shareholder's holding of Ordinary Shares: (i) immediately prior to Admission; and (ii) immediately following the Global Offering, assuming no exercise of the Over-allotment Option:

	Immediately prior to Admission		**Immediately following Admission**	
Selling Shareholder	**Number of Ordinary Shares**	**Percentage (%)**	**Number of Ordinary Shares**	**Percentage (%)**
DKL Energy	898,219,931	99.8	898,219,931	89.4

1.5 ***Underwriting Arrangements***

Underwriting and Sponsors' Agreement

The Underwriters have entered into commitments under the Underwriting and Sponsors' Agreement pursuant to which they have agreed, subject to certain conditions, to procure subscribers for the Offer Shares to be issued by the Company in the Global Offering or, failing which, themselves to subscribe for or purchase such Offer Shares at the Offer Price. The Underwriting and Sponsors' Agreement contains provisions entitling the Joint Global Co-ordinators (for themselves and on behalf of the other Underwriters) to terminate the Global Offering (and the arrangements associated with it) at any time prior to Admission in certain circumstances. If this right is exercised, the Global Offering and these arrangements will lapse and any moneys received in respect of the Global Offering will be returned to applicants without interest. The Underwriting and Sponsors' Agreement provides for the Underwriters to be paid commissions in respect of the Offer Shares issued by the Company together with any Over-allotment Shares sold following exercise of the Over-allotment Option. Pursuant to the terms of the Underwriting and Sponsors' Agreement, any commissions received by the Underwriters may be retained, and any Offer Shares acquired by them may be retained or dealt in, by them, for their own behalf. The Company and the Joint Global Co-ordinators (for themselves and on behalf of the other Underwriters) expressly reserve the right to determine, at any time prior to Admission, not to proceed with the Global Offering. If such right is exercised, the Global Offering will lapse and any moneys received in respect of the Global Offering will be returned to applicants without interest.

Further details of the terms of the Underwriting and Sponsors' Agreement are set out in paragraph 14.1 (*Underwriting and Sponsors' Agreement*) of Part 20 (*Additional Information*). Certain selling and transfer restrictions are set out below.

1.6 ***Lock-up Arrangements and Exceptions***

Pursuant to the Underwriting and Sponsors' Agreement:

- the Company has agreed that during the period of 180 days from (but not including) the date of Admission, it will not, without the prior written consent of the Joint Global Co-ordinators, subject to certain customary exceptions, issue, offer, sell or contract to sell, or otherwise transfer or dispose of, directly or indirectly, or announce an offer of any Ordinary Shares (or any interest therein or in respect thereof) or enter into any transaction with the same economic effect as any of the foregoing;
- the Selling Shareholder has agreed that during the period of 180 days from (but not including) the date of Admission, it will not, without the prior written consent of the Joint Global Co-ordinators, subject to certain customary exceptions, issue, offer, sell or contract to sell, or otherwise transfer or dispose of, directly or indirectly, or announce an offer of any Ordinary Shares (or any interest therein or in respect thereof) or enter into any transaction with the same economic effect as any of the foregoing; and
- the Directors have agreed that during the period of 360 days from (but not including) the date of Admission they will not, without the prior written consent of the Joint Global Co-ordinators, subject to certain customary exceptions, offer, sell or contract to sell, or otherwise transfer or dispose of, directly or indirectly, or announce an offer of any Ordinary Shares (or any interest therein in respect thereof) or enter into any transaction with the same economic effect as any of the foregoing.

1.7 ***Stabilisation and Over-allotment Option***

In connection with the Global Offering, Goldman Sachs International (the "**Stabilising Manager**"), or any of its agents, may (but will be under no obligation to), to the extent permitted by applicable law, over-allot Ordinary Shares and effect other transactions to maintain the market price of the Ordinary Shares at a level other than that which might otherwise prevail in the open market (the "**Over-allotment Option**"). Such transactions may include short sales, stabilising transactions and purchases to cover positions created by short sales. Short sales involve the sale by the Stabilising Manager of a greater number of Ordinary Shares than the JGCs are required to procure purchasers for, or failing which, the Underwriters are required to purchase in the Global Offering. Stabilising transactions consist of bids or purchases made for the purpose of preventing or retarding a decline in the market price of the Ordinary Shares while the Global Offering is in progress. Such transactions shall be carried out in accordance with applicable rules and regulations. Such stabilisation activities may be effected on any securities market, over-the-counter market, stock exchange or otherwise and may be undertaken at any time during the period from the date of the commencement of conditional dealings of the Ordinary Shares on the London Stock Exchange and ending no later than 30 calendar days thereafter.

However, there will be no obligation on the Stabilising Manager or any of its agents to effect stabilising transactions and there is no assurance that stabilising transactions will be undertaken. Stabilisation, if commenced, may be discontinued at any time without prior notice. In no event will measures be taken with the intention of stabilising the market price of the Ordinary Shares above the Offer Price. Except as required by law or regulation, neither the

Stabilising Manager nor any of its agents intends to disclose the extent of any over-allotments made and/or stabilisation transactions conducted in relation to the Global Offering.

In connection with the Global Offering, the Stabilising Manager may, for stabilisation purposes, over-allot Ordinary Shares up to a maximum of 14.3% of the total number of Offer Shares (prior to any exercise of the Over-allotment Option). The Stabilising Manager has entered into the Over-allotment Option with the Selling Shareholder pursuant to which the Stabilising Manager may require the Selling Shareholder to transfer at the Offer Price additional Ordinary Shares representing up to 14.3% of the total number of Offer Shares (prior to any exercise of the Over-allotment Option), to allow it to cover short positions arising from over-allotments and/or stabilising transactions. The Over-allotment Option may be exercised in whole or in part, upon notice by the Stabilising Manager, at any time on or before the 30th calendar day after the commencement of conditional dealings of the Ordinary Shares on the London Stock Exchange. The Over-allotment Shares made available pursuant to the Over-allotment Option will be sold on the same terms and conditions as, and will rank equally with, the other Ordinary Shares, including for all dividends and other distributions declared, made or paid on the Ordinary Shares after Admission and will form a single class for all purposes with the other Ordinary Shares.

1.8 ***Stock Lending Arrangements***

In connection with settlement and stabilisation, the Stabilising Manager has, on the date of this Prospectus, entered into a stock lending agreement (the "**Stock Lending Agreement**") with the Selling Shareholder pursuant to which the Stabilising Manager will be able to borrow from the Selling Shareholder a number of Ordinary Shares equal in aggregate up to 14.3% of the total number of Offer Shares (prior to any exercise of the Over-allotment Option) for the purposes, among other things, of allowing the Stabilising Manager to settle, at Admission, over-allotments, if any, made in connection with the Global Offering.

If the Stabilising Manager borrows any Ordinary Shares pursuant to the Stock Lending Agreement, it will be obliged to return equivalent shares to the Selling Shareholder in accordance with the terms of the Stock Lending Agreement.

1.9 ***Dealing Arrangements***

Applications have been made to the FCA for all of the Ordinary Shares to be admitted to the premium listing segment of the Official List and to the London Stock Exchange for those Ordinary Shares to be admitted to trading on the main market for listed securities of the London Stock Exchange. It is expected that dealings in the Ordinary Shares will commence on a conditional basis on the London Stock Exchange at 8:00 am on 9 November 2022. The earliest date for settlement of such dealings will be 14 November 2022. It is expected that Admission will become effective and that unconditional dealings in the Ordinary Shares will commence on the London Stock Exchange at 8:00 am on 14 November 2022. All dealings in Ordinary Shares prior to the commencement of unconditional dealings will be on a "when issued" basis, will be of no effect if Admission does not take place and will be at the sole risk of the parties concerned. The above-mentioned dates and times may be changed without further notice.

Each investor will be required to undertake to pay the Offer Price for the Ordinary Shares issued and allotted or sold to such investor in such manner as shall be directed by the Joint Global Co-ordinators.

It is intended that, where applicable, definitive share certificates in respect of the Ordinary Shares will be despatched within 10 Business Days of Admission or as soon thereafter as is practicable. Temporary documents of title will not be issued. Dealings in advance of crediting of the relevant CREST stock account(s) shall be at the sole risk of the persons concerned.

Following Admission, the Ordinary Shares held by the Selling Shareholder and the Directors will be subject to the lock-up arrangements described in paragraph 1.6 (*Lock-up Arrangements and Exceptions*) of this Part 18 (*Details, Terms and Conditions of the Global Offering*) above.

1.10 ***Other Relationships***

Subject to the terms and conditions of the Underwriting and Sponsors' Agreement, each of the Underwriters and any affiliate, acting as an investor for its own account, in connection with the Global Offering, may take up Ordinary Shares and in that capacity may retain, purchase or sell for its own account such Ordinary Shares and any related investments and may offer or sell such Ordinary Shares or other investments otherwise than in connection with the Global Offering. Accordingly, references in this Prospectus to the Ordinary Shares being offered or placed should be read as including any offering or placement of Ordinary Shares to the Underwriters and any affiliate acting as an investor for its own account.

None of the Underwriters intend to disclose the extent of any such investment or transactions otherwise than to the Company and the Selling Shareholder and in accordance with any legal or regulatory obligation to do so. In addition, in connection with the Global Offering, certain of the Underwriters may enter into financing arrangements with investors, such as share-swap arrangements or lending arrangements where securities are used as collateral, that could result in such Underwriters acquiring shareholdings in the Company.

1.11 ***CREST***

CREST is a paperless settlement system enabling securities to be transferred from one CREST account to another without the need to use share certificates or written instruments of transfer. The Company has applied for the Ordinary Shares to be admitted to CREST with effect from Admission and, also with effect from Admission, the Articles will permit the holding of Ordinary Shares under the CREST system. Accordingly, settlement of transactions in the Ordinary Shares following Admission may take place within the CREST system if any Shareholder so wishes. CREST is a voluntary system and holders of Ordinary Shares who wish to receive and retain share certificates will be able to do so.

1.12 ***Selling Restrictions***

The distribution of this Prospectus and the offer of Offer Shares in certain jurisdictions may be restricted by law and therefore persons into whose possession this Prospectus comes should inform themselves about and observe any restrictions, including those set out in paragraphs 1.13 to 1.25 (inclusive) of this Part 18 (*Details, Terms and Conditions of the Global Offering*). Any failure to comply with these restrictions may constitute a violation of the securities laws of any such jurisdiction.

No action has been or will be taken in any jurisdiction that would permit a public offering of the Offer Shares, or possession or distribution of this Prospectus or any other offering material in any country or jurisdiction where action for that purpose is required. Accordingly, the Offer Shares may not be offered, directly or indirectly, and neither this Prospectus nor any other offering material or advertisement in connection with the Offer Shares may be distributed or published in or from any country or jurisdiction except in circumstances that will result in compliance with any and all applicable rules and regulations of any such country or jurisdiction. Persons into whose possession this Prospectus comes should inform themselves about and observe any restrictions on the distribution of this Prospectus and the offer of Offer Shares contained in this Prospectus. Any failure to comply with these restrictions may constitute a violation of the securities laws of any such jurisdiction. This Prospectus does not constitute an offer to subscribe for any of the Offer Shares to any person in any jurisdiction to whom it is unlawful to make such offer of solicitation in such jurisdiction.

1.13 ***United Kingdom***

In relation to the United Kingdom, no Offer Shares have been offered or will be offered pursuant to the Global Offering to the public in the United Kingdom prior to the publication of the Prospectus which has been approved by the FCA, except that the Offer Shares may be offered to the public in the United Kingdom at any time:

- to any legal entity which is a qualified investor as defined under Article 2 of the UK Prospectus Regulation;

- to fewer than 150 natural or legal persons (other than qualified investors as defined under Article 2 of the UK Prospectus Regulation), subject to obtaining the prior consent of Goldman Sachs International and Morgan Stanley for any such offer; or
- in any other circumstances falling within Section 86 of the FSMA.

Each person in the United Kingdom who subscribed for any Offer Shares in the Global Offering or to whom any offer is made will be deemed to have represented, acknowledged and agreed to and with the Company, the Selling Shareholder and the Underwriters that it is a qualified investor within the meaning of the UK Prospectus Regulation.

In the case of any Offer Shares being offered to a financial intermediary as that term is used in Article 5(1) of the UK Prospectus Regulation, each such financial intermediary will be deemed to have represented, acknowledged and agreed to and with the Company, the Selling Shareholder and the Underwriters that the Offer Shares subscribed for by it in the Global Offering have not been subscribed for on a non-discretionary basis on behalf of, nor have they been subscribed for with a view to their offer or resale to, persons in circumstances which may give rise to an offer to the public other than their offer or resale in the United Kingdom to qualified investors, in circumstances in which the prior consent of the Underwriters has been obtained to each such proposed offer or resale. Neither the Company nor the Underwriters have authorised, nor do they authorise, the making of any offer of Offer Shares through any financial intermediary, other than offers made by the Underwriters which constitute the final placement of Offer Shares contemplated in this Prospectus.

The Company, the Selling Shareholder, the Underwriters and their affiliates will rely upon the truth and accuracy of the foregoing representations, acknowledgements and agreements.

For the purposes of this provision, the expression an “offer to the public” in relation to the Offer Shares in the United Kingdom means the communication in any form and by any means of sufficient information on the terms of the Global Offering and any Offer Shares to be offered so as to enable an investor to decide to subscribe for any Offer Shares.

1.14 *European Economic Area*

In relation to each Member State of the EEA (each a Member State), no Offer Shares have been offered or will be offered pursuant to the Global Offering contemplated by this Prospectus to the public in that Member State prior to the publication of a prospectus in relation to the Offer Shares which has been approved by the competent authority in that Member State or, where appropriate, approved in another Member State and notified to the competent authority in that Member State, all in accordance with the Prospectus Regulation, except that the Offer Shares may be offered to the public in that Member State at any time:

- to any legal entity which is a qualified investor as defined under Article 2 of the Prospectus Regulation;
- to fewer than 150 natural or legal persons (other than qualified investors as defined under Article 2 of the Prospectus Regulation), subject to obtaining the prior consent of the Joint Global Co-ordinators for any such offer; or
- in any other circumstances falling within Article 1(4) of the Prospectus Regulation, provided that no such offer of Offer Shares shall require the Company or any Underwriter to publish a prospectus pursuant to Article 3 of the Prospectus Regulation or supplement a prospectus pursuant to Article 23 of the Prospectus Regulation.

Each person in a Member State who subscribed for any Offer Shares in the Global Offering or to whom any offer is made will be deemed to have represented, acknowledged and agreed to and with the Company, the Selling Shareholder and the Underwriters that it is a qualified investor within the meaning of the Prospectus Regulation.

In the case of any Offer Shares being offered to a financial intermediary as that term is used in Article 5(1) of the Prospectus Regulation, each such financial intermediary will be deemed to have represented, acknowledged and agreed to and with the Company, the Selling Shareholder and the Underwriters that the Offer Shares subscribed for by it in the offer have not been subscribed for on a non-discretionary basis on behalf of, nor have they been subscribed for with a view to their offer or resale to, persons in circumstances which may give rise to an offer to the public other than their offer or resale in a Member State to qualified investors, in circumstances in which the prior consent of the Underwriters has been obtained to each such proposed offer or resale. Neither the Company nor the Underwriters have authorised, nor do they authorise, the making of any offer of Offer Shares through any financial intermediary, other than offers made by the Underwriters which constitute the final placement of Offer Shares contemplated in this Prospectus.

The Company, the Selling Shareholder and the Underwriters and their affiliates will rely upon the truth and accuracy of the foregoing representations, acknowledgements and agreements.

For the purposes of this provision, the expression "an offer to the public" in relation to any Offer Shares in any Member State means the communication in any form and by any means of sufficient information on the terms of the Global Offering and any Offer Shares to be offered so as to enable an investor to decide to subscribe for any Offer Shares and the expression "**Prospectus Regulation**" means Regulation (EU) 2017/1129.

1.15 ***United States of America***

The Ordinary Shares have not been and will not be registered under the US Securities Act or under any applicable securities laws or regulations of any state or other jurisdiction of the United States and, subject to certain exceptions, may not be offered or sold within the United States except to persons reasonably believed to be QIBs in reliance on Rule 144A or another exemption from, or in a transaction not subject to, the registration requirements of the US Securities Act. The Ordinary Shares are being offered and sold outside the United States in offshore transactions in reliance on Regulation S.

In addition, until 40 days after the commencement of the Global Offering of the Ordinary Shares, an offer or sale of Ordinary Shares within the United States by any dealer (whether or not participating in the Global Offering) may violate the registration requirements of the US Securities Act if such offer or sale is made otherwise than in accordance with Rule 144A or another exemption from, or transaction not subject to, the registration requirements of the US Securities Act.

The Underwriting and Sponsors' Agreement provides that the Underwriters may directly or through their respective US broker-dealer affiliates arrange for the offer and resale of Ordinary Shares within the United States only to QIBs in reliance on Rule 144A or another exemption from, or transaction not subject to, the registration requirements of the US Securities Act.

1.16 ***Rule 144A***

Each acquirer of Ordinary Shares within the United States, by accepting delivery of this Prospectus, will be deemed to have represented, agreed and acknowledged that it has received a copy of this Prospectus and such other information as it deems necessary to make an investment decision and that:

- it acknowledges that the Ordinary Shares have not been and will not be registered under the US Securities Act or with any securities regulatory authority of any state of the United States and are subject to significant restrictions on transfer;
- it is: (i) a QIB within the meaning of Rule 144A; (ii) acquiring the Ordinary Shares for its own account or for the account of one or more QIBs with respect to whom it has sole investment discretion with respect to each such account and the authority to make, and does make, the representations and warranties set forth herein on behalf of each such account; (iii) acquiring the Ordinary Shares for investment purposes, and not with a view to further distribution of such Ordinary Shares; and (iv) aware, and each beneficial owner of the Ordinary Shares has been advised, that the sale of the Ordinary Shares to it is being made in reliance on Rule 144A or in reliance on another exemption from, or in a transaction not subject to, the registration requirements of the US Securities Act;
- it understands that the Ordinary Shares are being offered and sold in the United States only in a transaction not involving any public offering within the meaning of the US Securities Act, that the Ordinary Shares have not been and will not be registered under the US Securities Act or with any securities regulatory authority of any state or other jurisdiction of the United States and may not be offered, sold, pledged or otherwise transferred except: (i) to a person that it and any person acting on its behalf reasonably believes is a QIB purchasing for its own account or for the account of a QIB in a

transaction meeting the requirements of Rule 144A, or another exemption from, or in a transaction not subject to, the registration requirements of the US Securities Act; (ii) in an offshore transaction in accordance with Rule 903 or Rule 904 of Regulation S; (iii) pursuant to an exemption from registration under the US Securities Act provided by Rule 144 thereunder (if available); or (iv) pursuant to an effective registration statement under the US Securities Act, in each case in accordance with any applicable securities laws of any state or other jurisdiction of the United States. The purchaser will, and each subsequent holder is required to, notify any subsequent purchaser from it of those Ordinary Shares of the resale restrictions referred to in (i), (ii), (iii) and (iv) above. No representation can be made as to the availability of the exemption provided by Rule 144 for resale of the Ordinary Shares;

- it further: (i) understands that the Ordinary Shares may not be deposited into any unrestricted depositary receipt facility in respect of the Ordinary Shares established or maintained by a depositary bank; (ii) acknowledges that the Ordinary Shares (whether in physical certificated form or in uncertificated form held in CREST) are "restricted securities" within the meaning of Rule 144(a)(3) under the US Securities Act and that no representation is made as to the availability of the exemption provided by Rule 144 for resales of the Ordinary Shares; and (iii) understands that the Company may not recognise any offer, sale, resale, pledge or other transfer of the Ordinary Shares made other than in compliance with the abovementioned restrictions;
- it understands that the Ordinary Shares (to the extent they are in certificated form), unless otherwise determined by the Company in accordance with applicable law, will bear a legend substantially to the following effect:

THE ORDINARY SHARES REPRESENTED HEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE US SECURITIES ACT OF 1933, AS AMENDED (THE "**US SECURITIES ACT**") OR WITH ANY SECURITIES REGULATORY AUTHORITY OF ANY STATE OR OTHER JURISDICTION OF THE UNITED STATES AND MAY NOT BE OFFERED, SOLD, PLEDGED OR OTHERWISE TRANSFERRED EXCEPT (1) IN ACCORDANCE WITH RULE 144A UNDER THE US SECURITIES ACT TO A PERSON THAT THE SELLER AND ANY PERSON ACTING ON ITS BEHALF REASONABLY BELIEVE IS A QUALIFIED INSTITUTIONAL BUYER WITHIN THE MEANING OF RULE 144A UNDER THE US SECURITIES ACT PURCHASING FOR ITS OWN ACCOUNT OR FOR THE ACCOUNT OF A QUALIFIED INSTITUTIONAL BUYER, (2) IN AN OFFSHORE TRANSACTION IN ACCORDANCE WITH RULE 903 OR RULE 904 OF REGULATION S UNDER THE US SECURITIES ACT, (3) PURSUANT TO AN EXEMPTION FROM REGISTRATION UNDER THE US SECURITIES ACT PROVIDED BY RULE 144 THEREUNDER (IF AVAILABLE) OR (4) PURSUANT TO AN EFFECTIVE REGISTRATION STATEMENT UNDER THE US SECURITIES ACT, IN EACH CASE IN ACCORDANCE WITH ANY APPLICABLE SECURITIES LAWS OF ANY STATE OF THE UNITED STATES. NO REPRESENTATION CAN BE MADE AS TO THE AVAILABILITY OF THE EXEMPTION PROVIDED BY RULE 144 UNDER THE US SECURITIES ACT FOR RESALES OF THE ORDINARY SHARES. NOTWITHSTANDING ANYTHING TO THE CONTRARY IN THE FOREGOING, THE ORDINARY SHARES REPRESENTED HEREBY MAY NOT BE DEPOSITED INTO ANY UNRESTRICTED DEPOSITARY RECEIPT FACILITY IN RESPECT OF THE ORDINARY SHARES ESTABLISHED OR MAINTAINED BY A DEPOSITARY BANK. EACH HOLDER, BY ITS ACCEPTANCE OF ORDINARY SHARES, REPRESENTS THAT IT UNDERSTANDS AND AGREES TO THE FOREGOING RESTRICTIONS;

- it represents that if, in the future, it offers, resells, pledges or otherwise transfers such Ordinary Shares while they remain "restricted securities" within the meaning of Rule 144, it shall notify such subsequent transferee of the restrictions set out above; and
- it acknowledges that the Company, the Selling Shareholder, the Underwriters and their affiliates, and others will rely on the truth and accuracy of the foregoing acknowledgements, representations and agreements.

1.17 ***Canada***

No prospectus has been filed with any securities commission or similar regulatory authority in Canada in connection with the offer and sale of the Ordinary Shares, the Ordinary Shares have not been, and will not be, qualified for sale under the securities laws of Canada or any province or territory thereof and no securities commission or similar regulatory authority in Canada has reviewed or in any way passed upon this Prospectus or the merits of the Ordinary Shares and any representation to the contrary is an offence.

The Ordinary Shares may not be offered or sold, directly or indirectly, in Canada or to or for the benefit of any resident of Canada, other than in compliance with applicable securities laws and, without limiting the generality of the foregoing:

- any offer or sale of the Ordinary Shares in Canada will be made only to in, or to persons subject to the securities laws of, the provinces of Alberta, British Columbia, Manitoba, Ontario or Québec and only to purchasers that are "accredited investors"(as such term is defined in section 1.1 of NI 45-106 or, in Ontario, as such term is defined in section 73.3(1) of the Securities Act (Ontario)), that are also "permitted clients" (as such term is defined in section 1.1 of NI 31-103), that are purchasing as principal, or are deemed to be purchasing as principal in accordance with applicable Canadian securities laws, and that are not a person created or used solely to purchase or hold the Ordinary Shares as an "accredited investor" as described in paragraph (m) of the definition of "accredited investor" in section 1.1 of NI 45-106;
- each Underwriter distributing the Ordinary Shares in Canada is (i) appropriately registered under applicable Canadian securities laws in each relevant province or territory to distribute the Offered Shares, or (ii) relying on an exemption from the dealer registration requirements under applicable Canadian securities laws and has complied with the requirements of that exemption; and
- no offering memorandum or any other offering material other than this Prospectus will be distributed or delivered in or to a resident of Canada in connection with the offering of the Ordinary Shares, except in compliance with applicable Canadian securities laws.

1.18 ***Israel***

This document does not constitute a prospectus under the Israeli Securities Law, 5728-1968, and has not been filed with or approved by the Israel Securities Authority. In Israel, as set forth in Section 15A(b)(1) of the Israeli Securities Law, this Prospectus may be distributed only to, and be directed only at, investors listed in the first Addendum, consisting primarily of joint investment in trust funds; provident funds; insurance companies; banks; portfolio managers, investment advisors, members of the Tel Aviv Stock Exchange Ltd., underwriters, each purchasing for their own account; venture capital funds; entities with equity in excess of ILS 50 million and "qualified individuals," each as defined in the Addendum (as it may be amended from time to time), collectively referred to as "**Qualified Israeli Investors**". Qualified Israeli Investors shall be required to provide to the Company a written declaration and ancillary certificates that they fall within the scope of the Addendum, as deemed necessary by the Company.

1.19 ***Singapore***

This Prospectus has not been and will not be registered as a prospectus with the Monetary Authority of Singapore and the securities will be offered pursuant to exemptions under the Securities and Futures Act 2001 of Singapore, as modified or amended from time to time (the "**SFA**"). Accordingly, this Prospectus and any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the securities may not be circulated or distributed, nor may the securities be offered or sold, or be made the subject of an invitation for subscription or purchase, whether directly or indirectly, to persons in Singapore other than (i) to an institutional investor (as defined in Section 4A of the SFA) pursuant to Section 274 of the SFA, (ii) to a relevant person (as defined in Section 275(2) of the SFA) pursuant to Section 275(1) of the SFA, or any person pursuant to Section 275(1A) of the SFA, and in accordance with the conditions specified in Section 275 of the SFA, or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA.

Where the Offer Shares are subscribed under Section 275 of the SFA by a relevant person which is:

(a) a corporation (which is not an accredited investor (as defined in Section 4A of the SFA)) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or

(b) a trust (where the trustee is not an accredited investor) whose sole purpose is to hold investments and each beneficiary of the trust is an individual who is an accredited investor,

securities or securities-based derivatives contracts (each term as defined in Section 2(1) of the SFA) of that corporation or the beneficiaries' rights and interest (howsoever described) in that trust shall not be transferred within six months after that corporation or that trust has acquired the Offer Shares pursuant to an offer made under Section 275 of the SFA except:

(a) to an institutional investor or to a relevant person, or to any person arising from an offer referred to in Section 275(1A) or Section 276(4)(c)(ii) of the SFA;

(b) where no consideration is or will be given for the transfer;

(c) where the transfer is by operation of law;

(d) as specified in Section 276(7) of the SFA; or

(e) as specified in Regulation 37A of the Securities and Futures (Offers of Investments) (Securities and Securities-based Derivatives Contracts) Regulations 2018.

1.20 ***Hong Kong***

This Prospectus has not been and will not be approved by or registered with the Securities and Futures Commission of Hong Kong or the Registrar of Companies of Hong Kong. No person may offer in Hong Kong, by means of any document, any Offer Shares other than (i) to "professional investors" as defined in the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made thereunder, or (ii) in other circumstances which do not result in the document being a "prospectus" as defined in the Companies (Winding Up and Miscellaneous Provisions) Ordinance (Cap. 32, Laws of Hong Kong) (the "**C(WUMP)O**") or which do not constitute an offer to the public within the meaning of the C(WUMP)O. No person may issue or have in its possession for the purposes of issue, in each case whether in Hong Kong or elsewhere, any advertisement, invitation or document relating to the Ordinary Shares which is directed at, or the contents of which are likely to be accessed or read by, the public of Hong Kong (except if permitted to do so under the laws of Hong Kong) other than with respect to Offer Shares which are or are intended to be disposed of only to persons outside Hong Kong or only to "professional investors" as defined in the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made thereunder.

1.21 ***People's Republic of China***

This Prospectus has not been and will not be circulated or distributed in the People's Republic of China, and the Offer Shares may not be offered or sold, and will not be offered or sold, to any person for re-offering or resale, directly or indirectly, to any resident of the People's Republic of China except pursuant to applicable laws and regulations of the People's Republic of China. For the purpose of this paragraph, People's Republic of China does not include Taiwan and the special administrative regions of Hong Kong and Macau.

1.22 ***United Arab Emirates (excluding the Dubai International Financial Centre)***

The Offer Shares have not been and will not be offered, sold or publicly promoted or advertised in the United Arab Emirates (the "**UAE**") other than in compliance with any laws applicable in the UAE governing the issue, offering or sale of securities.

1.23 ***Dubai International Finance Centre***

The Offer Shares to which this Prospectus relates may not be offered or sold to any person in the Dubai International Financial Centre unless such offer is:

(a) an "Exempt Offer" in accordance with the Markets Rules (MKT) Module of the Dubai Financial Services Authority (the "**DFSA**") rulebook; and

(b) made only to persons who meet the Professional Client criteria set out in Rule 2.3.3 of the Conduct of Business (COB) Module of the DFSA rulebook.

1.24 ***Japan***

The Offer Shares have not been and will not be registered under the Financial Instruments and Exchange Law (Law No.25 of 1948, as amended) and, accordingly, will not be offered or sold, directly or indirectly, in Japan, or for the benefit of any Japanese Person or to others for re-offering or resale, directly or indirectly, in Japan or to any Japanese Person, except in compliance with all applicable laws, regulations and ministerial guidelines promulgated by relevant Japanese governmental or regulatory authorities in effect at the relevant time. For the purposes of this paragraph, "Japanese Person" shall mean any person resident in Japan, including any corporation or other entity organised under the laws of Japan.

1.25 ***Switzerland***

The offering of the Offer Shares in Switzerland is exempt from requirement to prepare and publish a prospectus under the Swiss Financial Services Act ("**FinSA**") because the Ordinary Shares are offered to less than 500 investors and the Offer Shares will not be admitted to trading on any trading venue (exchange or multilateral trading facility) in Switzerland. This Prospectus does not constitute a prospectus or a similar document pursuant to FinSA, and no such prospectus has been or will be prepared for or in connection with the offering of the Offer Shares.

PART 19

TAXATION

1. UK TAXATION

The following statements are intended to apply only as a general guide to certain UK tax considerations in relation to the Ordinary Shares. They are based on current UK tax legislation and what is understood to be the current published practice of His Majesty's Revenue and Customs ("**HMRC**") (which may not be binding on HMRC), in each case as at the Latest Practicable Date before the date of this Prospectus, and both of which may change at any time, possibly with retrospective effect.

They relate only to certain limited aspects of the UK taxation treatment of, and are intended to apply only to, Shareholders who are resident and, in the case of individuals, domiciled or deemed domiciled, solely in the United Kingdom for UK tax purposes (except where the position of non-UK resident or non-UK domiciled Shareholders is referred to expressly) and do not apply to Shareholders to whom "split year" treatment applies. They apply only to Shareholders who hold their Ordinary Shares as investments (other than in an individual savings account or a self-invested personal pension) and who are, or are treated as, the absolute beneficial owners of both the Ordinary Shares and any dividends paid on them. The statements may not apply to certain categories of Shareholders, such as (but not limited to) trustees, persons acquiring (or deemed to be acquiring) their Ordinary Shares in connection with an office or employment, persons holding their shares through trust arrangements, dealers in securities, banks, insurance companies and collective investment schemes.

The rates and thresholds included within these statements in respect of UK resident individual Shareholders assume that the rates and thresholds applicable to Shareholders resident in England will apply. Shareholders that are, or may be, resident in a different jurisdiction within the UK should seek their own professional advice.

Shareholders or prospective holders of Ordinary Shares who are unsure as to their tax position or who may be subject to tax in a jurisdiction other than the United Kingdom should seek their own professional advice. In particular, Shareholders should be aware that the tax legislation of any jurisdiction where a Shareholder is resident or otherwise subject to taxation (as well as the jurisdictions discussed below) may have an impact on the tax consequences of an investment in the Ordinary Shares including in respect of any income received from the Ordinary Shares.

1.1 *Taxation of dividends*

1.1.1 Withholding Tax

The Company will not be required to deduct or withhold amounts on account of UK tax at source from dividend payments, irrespective of the residence or particular circumstances of the Shareholder receiving such dividend payments.

1.1.2 Individual Shareholders

Dividends received by a United Kingdom resident individual Shareholder from the Company will generally be subject to tax as dividend income.

A nil rate of income tax will apply for the first £2,000 of dividend income (including any dividends received from the Company) received by individual Shareholders for the tax year running from 6 April 2022 to 5 April 2023 (the "**Nil Rate Amount**"), regardless of what tax rate would otherwise apply to that dividend income.

The rate of tax applicable to dividend income in excess of the Nil Rate Amount will depend on the wider tax position of the Shareholder. Broadly speaking, after taking into account the amount (if any) of a Shareholder's personal allowance and any other allowances, exemptions and reliefs available to a Shareholder, for the tax year running from 6 April 2022 to 5 April 2023, the Shareholder's taxable income up to the basic rate limit will fall within the basic rate band; taxable income between the basic rate limit and the higher rate limit will fall within the higher rate band; and taxable income above the higher rate limit will fall within the additional rate band. For the tax year running from 6 April 2022 to 5 April 2023, the basic rate limit is £50,270 and the higher rate limit is £150,000 (although these limits can be increased in certain circumstances).

The rates of income tax on dividends received above the Nil Rate Amount for the tax year running from 6 April 2022 to 5 April 2023 are:

(a) 8.75% to the extent the dividend income falls in the basic rate band;

(b) 33.75% to the extent the dividend income falls in the higher rate band; and

(c) 39.35% to the extent the dividend income falls in the additional rate band.

In determining the tax band in which any dividend income over the Nil Rate Amount falls, dividend income is treated as the top slice of a Shareholder's income, and dividend income within the Nil Rate Band is still taken into account.

Because dividend income (including income within the Nil Rate Amount) is taken into account in assessing whether a Shareholder's overall income is above the basic, higher or additional rate thresholds, the receipt of such income may also affect the amount of personal allowances and savings allowances to which the Shareholder is entitled.

1.1.3 **Corporate Shareholders**

Shareholders within the charge to UK corporation tax that are "small companies" for the purposes of the UK taxation of dividends legislation in Part 9A of the Corporation Tax Act 2009, will not be subject to UK corporation tax on dividends received from the Company so long as certain conditions are met (including an anti-avoidance condition).

Shareholders within the charge to UK corporation tax that are not "small companies" for the purposes of the UK taxation of dividends legislation in Part 9A of the Corporation Tax Act 2009 will not be subject to UK corporation tax on any dividend received from the Company so long as the dividend falls within an exempt class and certain conditions are met. For example: (i) dividends paid on shares that are not redeemable and which do not carry any present or future preferential rights to dividends or to the Company's assets on its winding-up; and (ii) dividends paid to a person holding less than a 10% interest in the Company, should generally fall within an exempt class. However, the exemptions mentioned above are not comprehensive and are subject to anti-avoidance rules.

If the conditions for exemption are not met or cease to be satisfied, or such a Shareholder elects for an otherwise exempt dividend to be taxable, the Shareholder will be subject to UK corporation tax on dividends received from the Company, at the rate of corporation tax applicable to that Shareholder (the main rate of corporation tax is currently 19% and is expected to rise to 25% from April 2023).

1.2 ***Capital Gains***

A disposal or deemed disposal of Ordinary Shares by a Shareholder who is resident in the United Kingdom for tax purposes or, in the case of individuals, who cease to be resident in the United Kingdom for a period of five years or less, may, depending on the Shareholder's circumstances and subject to any available exemptions or reliefs, give rise to a chargeable gain. For the purposes of UK tax on chargeable gains, the amounts paid by a Shareholder for Ordinary Shares will generally constitute the base cost of the Shareholder's holdings in those Ordinary Shares.

1.2.1 **Individual Shareholders**

For individual Shareholders, the principal factors that will determine the UK capital gains tax position on a disposal or deemed disposal of Ordinary Shares are the extent to which the Shareholder realises any other capital gains in the UK tax year in which the disposal is made, the extent to which the Shareholder has incurred capital losses in that or earlier UK tax years, the UK income tax band into which the Shareholder falls, and the level of the annual allowance of tax-free gains in that UK tax year (the "**Annual Exemption**"). The Annual Exemption for the tax year running from 6 April 2022 to 5 April 2023 is £12,300.

The applicable rate for an individual Shareholder who makes a capital gain on the disposal (or deemed disposal) of Ordinary Shares, which (after taking advantage of the Annual Exemption and deducting any available capital losses) is liable to UK capital gains tax for the tax year running 5 April 2022 to 5 April 2023, is 10% for individuals who are subject to income tax at the basic rate or 20% for individuals who are subject to income tax at the higher or additional rates.

A Shareholder who ceases to be resident in the United Kingdom for tax purposes and then reacquires UK tax residence before five complete tax years have elapsed and who disposes of Ordinary Shares during that period of non-residence may also be liable on their return to the United Kingdom to tax on any capital gain realised, subject to any available exemptions or reliefs.

1.2.2 **Corporate Shareholders**

A disposal or deemed disposal of Ordinary Shares by a Shareholder within the charge to UK corporation tax may give rise to a chargeable gain or allowable loss for the purposes of UK corporation tax, depending on the circumstances and subject to any available exemptions or reliefs. UK corporation tax is charged on chargeable gains at the rate applicable to that company (the main rate of corporation tax is currently 19% and is expected to rise to 25% from April 2023).

1.3 ***Stamp duty and stamp duty reserve tax***

The following statements about UK stamp duty and stamp duty reserve tax ("**SDRT**") apply regardless of whether or not a Shareholder is resident, domiciled or deemed domiciled in the United Kingdom. The statements in this section are intended as a general guide to the current United Kingdom stamp duty and SDRT position. Special rules apply to certain transactions such as transfers of shares to a company connected with the transferor and those rules are not described below. Certain categories of person, including intermediaries, brokers, dealers and persons connected with depositary receipt arrangements and clearance services, may not be liable to stamp duty or SDRT or may be liable at a higher rate or may, although not primarily liable for tax, be required to notify and account for it under the Stamp Duty Reserve Tax Regulations 1986.

1.3.1 **The Global Offering**

No liability to stamp duty or SDRT will arise on the issue of the Ordinary Shares by the Company.

The sale of any Over-allotment Shares by DKL Energy under the Global Offering will generally give rise to a liability to stamp duty and/ or SDRT at a rate of 0.5% of the Offer Price (in the case of stamp duty, rounded up to the nearest multiple of £5). Under the terms of the Underwriting and Sponsors' Agreement, DKL Energy has agreed to indemnify such liability.

Special rules apply to depositary receipt systems and clearance services which are discussed below.

1.3.2 **Clearance Services and Depositary Receipt arrangements**

Subject to the comments in the following paragraphs, where Ordinary Shares are issued or transferred (i) to, or to a nominee for, a person whose business is or includes the provision of clearance services or (ii) to, or to a nominee or agent for, a person whose business is or includes issuing depositary receipts, stamp duty or SDRT may be payable at a rate of 1.5% of the amount or value of the consideration payable or, in certain circumstances, the value of the Ordinary Shares (in the case of stamp duty, rounded up to the nearest multiple of £5). Under the terms of the Underwriting and Sponsor Agreement, the Selling Shareholder will not be required to generally meet such a liability in excess of 0.5%.

However, following litigation, HMRC has confirmed that it will no longer seek to impose the 1.5% SDRT charge on issues of UK shares to depositary receipt issuers and clearance services anywhere in the world on the basis that the charge is not compatible with EU law. (HMRC's published practice states that the 1.5% charge on such issues will remain disapplied under the terms of the EUWA and this will remain the position unless stamp taxes on shares legislation is amended). The 1.5% SDRT and / or stamp duty charge will generally still apply to transfers of shares to depositary receipt issuers or clearance services but may not so apply where the transfers are an integral part of an issue of share capital. Whether a transfer is an integral part of an issue of share capital will depend on the facts and circumstances of any given case and specific professional advice should be sought before paying the 1.5% SDRT or stamp duty charge in any circumstances.

Transfers of Ordinary Shares within a clearance service or transfers of depositary receipts issued in respect of the Ordinary Shares within a depositary receipt system will generally be exempt from SDRT and, provided no instrument of transfer is entered into, will not be subject to stamp duty. However, clearance service providers may elect, in certain circumstances, for the 0.5% rate of SDRT and stamp duty (on the amount or value of the consideration payable for the transfer) to apply to the entry into, and transfers of Ordinary Shares within, the clearance service instead of the 1.5% charges described above.

Any liability for stamp duty or SDRT in respect of a transfer into a clearance service or depositary receipt system, or in respect of a transfer within such a service, which does arise will strictly be accountable by the clearance service or depositary receipt system operator or their nominee, as the case may be, but will, in practice, be payable by the participants in the clearance service or depositary receipt system.

1.3.3 **Deposit of Ordinary Shares in CREST**

Deposits of Ordinary Shares into CREST will generally not be subject to stamp duty or SDRT unless such a transfer is made for a consideration in money or money's worth, in which case, a liability to SDRT will arise usually at the rate of 0.5% of the amount or value of the consideration.

1.3.4 **Subsequent transfers within CREST**

Paperless transfers of Ordinary Shares within CREST are generally liable to SDRT, rather than stamp duty, at the rate of 0.5% of the amount or value of the consideration for the transfer. CREST is obliged to collect SDRT on relevant transactions settled within the system and to account for this to HMRC. In practice, the charge is generally borne by the purchaser or transferee of the Ordinary Shares.

1.3.5 **Subsequent transfers outside of CREST**

The conveyance or transfer on sale of Ordinary Shares outside the CREST system will generally be subject to stamp duty on the instrument of transfer at the rate of 0.5% of the amount or value of the consideration given (rounded up to the nearest £5).

An exemption from stamp duty is available on an instrument transferring Ordinary Shares where the amount or value of the consideration is £1,000 or less, and it is certified on the instrument that the transaction effected by the instrument does not form part of a larger transaction or series of transactions for which the aggregate consideration exceeds £1,000.

An unconditional agreement to transfer Ordinary Shares will normally give rise to a charge to SDRT at the rate of 0.5% of the amount or value of the consideration for the Ordinary Shares. However, where, within six years of the date of the agreement (or, if the agreement is conditional, the date on which it becomes unconditional) an instrument of transfer is executed pursuant to the agreement, and stamp duty is paid on that instrument, any SDRT already paid will generally be refunded (generally, but not necessarily, with interest) provided that a claim for payment is made, and any outstanding liability to SDRT will be cancelled.

The purchaser or transferee of the Ordinary Shares will generally be responsible for paying SDRT. In the absence of contractual agreement, no party is legally responsible for the payment of stamp duty as it is not an assessable tax. However, in practice the purchaser or transferee will usually pay this to ensure that the company register of members can be updated by the registrar to show the transfer.

2. US FEDERAL INCOME TAXATION

2.1 *Summary*

The following is a summary of certain US federal income tax considerations relevant to US Holders (as defined below) acquiring, holding and disposing of the Ordinary Shares. This summary is based on the US Internal Revenue Code of 1986, as amended, its legislative history, final, temporary and proposed US Treasury regulations promulgated thereunder, published rulings and court decisions as in effect or available on the date hereof, as well as the Convention Between the Government of the United States of America and the Government of the United Kingdom of Great Britain and Northern Ireland for the Avoidance of Double Taxation and the Prevention of Fiscal Evasion with Respect to Taxes on Income (the "**Treaty**") and administrative and judicial interpretations thereof, all of which are subject to change, possibly with retroactive effect.

This summary does not discuss all aspects of US federal income taxation that may be relevant to investors in light of their particular circumstances, such as investors subject to special tax rules (including, without limitation):

- financial institutions;
- insurance companies;
- traders or dealers in stocks, securities, currencies or notional principal contracts;
- regulated investment companies;
- real estate investment trusts;
- tax-exempt organisations;
- grantor trusts;
- "dual resident" corporations;
- entities or arrangements that are treated as partnerships or pass-through entities for US federal income tax purposes or persons that hold Ordinary Shares through such entities;
- holders that own (directly, indirectly or constructively) 10% or more of the stock by vote or value of the Company for US federal income tax purposes;
- investors that hold Ordinary Shares as part of a straddle, hedge, conversion, constructive sale or other integrated transaction for US federal income tax purposes;
- persons that generally mark their securities to market for US federal income tax purposes;
- persons required for US federal income tax purposes to accelerate the recognition of any item of gross income with respect to the Ordinary Shares as a result of such income being recognised on an applicable financial statement;
- US Holders that have a functional currency other than the US dollar; and
- US expatriates and former long-term residents of the United States, all of whom may be subject to tax rules that differ significantly from those summarised below.

This summary also does not address tax consequences applicable to holders of equity interests in a holder of the Ordinary Shares, US federal estate, gift, Medicare contribution or alternative minimum tax considerations or non-US, state or local tax considerations. This summary only addresses investors that will acquire Ordinary Shares in the Global Offering, and it assumes that investors will hold their Ordinary Shares as capital assets (generally, property held for investment).

For the purposes of this summary, a "**US Holder**" is a beneficial owner of Ordinary Shares that is for US federal income tax purposes: (i) an individual who is a citizen or resident of the United States; (ii) a corporation or other entity taxable as a corporation created in, or organised under the laws of, the United States or any state thereof, including the District of Columbia; (iii) an estate the income of which is includible in gross income for US federal income tax purposes regardless of its source; or (iv) a trust subject to the control of one or more US persons and under the primary supervision of a US court or that has validly elected to be treated as a domestic trust for US federal income tax purposes.

If a partnership (including any entity or arrangement treated as a partnership for US federal income tax purposes) holds Ordinary Shares, the tax treatment of the partnership and a partner in such partnership generally will depend upon the status of the partner and the activities of the partnership. Any such partner or partnership should consult their tax advisers as to the US federal income tax consequences to them of the acquisition, ownership and disposition of Ordinary Shares.

As described in more detail below, the Company does not expect to be a PFIC for US federal income tax purposes although that is not free from doubt and no assurance can be provided that the Company will not be a PFIC for any particular taxable year.

INVESTORS SHOULD CONSULT THEIR OWN TAX ADVISORS AS TO THE PARTICULAR TAX CONSIDERATIONS APPLICABLE TO THEM RELATING TO THE ACQUISITION, OWNERSHIP AND DISPOSITION OF THE ORDINARY SHARES, INCLUDING THE APPLICABILITY OF US FEDERAL, STATE AND LOCAL TAX LAWS OR NON-US TAX LAWS, ANY CAHNGES IN APPLIABLE TAX LAWS AND ANY PENDING OR PROPOSED LEGISLATION OR REGULATIONS.

2.2 ***Distribution***

Subject to the PFIC rules discussed below, a distribution made by the Company on the Ordinary Shares generally will be treated as a dividend includible in the gross income of a US Holder as ordinary income to the extent of the Company's current and accumulated earnings and profits as determined under US federal income tax principles. To the extent the amount of such distribution exceeds the Company's current and accumulated earnings and profits as so computed, the distribution will be treated first as a non-taxable return of capital to the extent of such US Holder's adjusted tax basis in the Ordinary Shares and, to the extent the amount of such distribution exceeds such adjusted tax basis, will be treated as gain from the sale of such shares. The Company does not expect to maintain calculations of earnings and profits for US federal income tax purposes. Therefore, a US Holder should expect that such distribution will generally be treated as a dividend. In addition, such dividends will not be eligible for the dividends received deduction allowed to US corporations with respect to dividends received from other US corporations.

Dividends received by individuals and certain other non-corporate US Holders will be taxed at the preferential rate applicable to qualified dividend income, provided that (i) the Company qualifies for the benefits of the Treaty, (ii) the Company is not classified as a PFIC (as discussed below) in the year of distribution and was not a PFIC in the preceding year, and (iii) the holder has held the Ordinary Shares for more than 60 days during the 121-day period beginning 60 days before the ex-dividend date. Although it cannot provide assurances to this effect, and its circumstances could change, the Company currently expects to be eligible for the benefits of the Treaty provided the Ordinary Shares are "regularly traded" on a recognised stock exchange. The London Stock Exchange is a recognised stock exchange for these purposes. The Ordinary Shares will be "regularly traded" in a taxable year if the aggregate number of Ordinary Shares traded on one or more recognised stock exchanges during the 12 months ending on the day before the beginning of the taxable year is at least 6% of the average number of Ordinary Shares outstanding during that 12-month period. If, however, the Ordinary Shares are not listed on a recognised stock exchange during such 12-month period, the Ordinary Shares will still be treated as regularly traded so long as the Ordinary Shares meet such aggregate trading requirements for the taxable period in which the income arises. US Holders should consult their own tax advisors regarding the "regularly traded" requirement and whether such dividends will qualify for the reduced rates provided by the qualified dividends rules.

Dividends on the Ordinary Shares generally will constitute income from sources outside the United States for United States foreign tax credit purposes. The amount of any distribution of property other than cash will be the fair market value of the property on the date of the distribution.

The US dollar value of any distribution made by the Company in pound sterling must be calculated by reference to the exchange rate in effect on the date of actual or constructive receipt of such distribution by the US Holder, regardless of whether the pound sterling is in fact converted into US dollars. If the pound sterling so received is converted into US dollars on the date of receipt, such US Holder generally will not recognise foreign currency gain or loss on such conversion. If the pound sterling so received is not converted into US dollars on the date of receipt, such US Holder will have a basis in the pound sterling equal to its US dollar value on the date of receipt. Any gain or loss on a subsequent conversion or other disposition of the pound sterling generally will be treated as ordinary income or loss to such US Holder and generally will be income or loss from sources within the United States for foreign tax credit limitation purposes.

2.3 ***Sale or other Disposition***

Subject to the PFIC rules discussed below, a US Holder generally will recognise gain or loss for US federal income tax purposes upon a sale or other disposition of its Ordinary Shares in an amount equal to the difference between the amount realised from such sale or disposition and the US Holder's adjusted tax basis in such Ordinary Shares, as determined in US dollars. Such gain or loss generally will be capital gain or loss and will be long-term capital gain (taxable at a reduced rate for non-corporate US Holders, such as individuals) or loss if, on the date of sale or disposition, such Ordinary Shares were held by such US Holder for more than one year. The deductibility of capital loss is subject to significant limitations. Such gain or loss realised generally will be treated as derived from US sources.

A US Holder that receives non-US currency from a sale or disposition of Ordinary Shares generally will realise an amount equal to the US dollar value of the non-US currency on the date of sale or disposition or, if such US Holder is a cash basis or electing accrual basis taxpayer and the Ordinary Shares are treated as being traded on an "established securities market" for this purpose, the settlement date. If the Ordinary Shares are so treated and the non-US currency received is converted into US dollars on the settlement date, a cash basis or electing accrual basis US Holder will not recognise foreign currency gain or loss on the conversion. Such an election by an accrual method US Holder must be applied consistently from year to year and cannot be revoked without the consent of the US Internal Revenue Service. A non-electing accrual basis US Holder may be required to recognise foreign currency gain or loss on the conversion attributable to changes in the relevant exchange rate between the date of sale or disposition and the settlement date. If the non-US currency received is not converted into US dollars on the settlement date, the US Holder will have a basis in the non-US currency equal to the US dollar value on the settlement date. Any gain or loss on a subsequent conversion or other disposition of the non-US currency generally will be treated as ordinary income or loss to such US Holder and generally will be income or loss from sources within the United States for foreign tax credit limitation purposes. A US Holder should consult their own tax advisors regarding how to account for payments made or received in a currency other than the US dollar.

2.4 ***Passive Foreign Investment Company Rates***

In general, a corporation organised or incorporated outside the United States is a PFIC in any taxable year in which either: (a) at least 75% of its gross income is classified as "passive income" (the "**income test**"); or (b) at least 50% of the average quarterly value attributable to its assets produce or are held for the production of passive income (the "**asset test**"). Passive income for this purpose generally includes dividends, interest, royalties, rents and gains from commodities and securities transactions. Passive income generally excludes active business gains arising from the sale of commodities, if substantially all (85% or more) of a foreign corporation's commodities are stock in trade or inventory, real and depreciable property used in a trade or business, or supplies regularly used or consumed in a trade or business, and certain other requirements are satisfied. For purposes of the above calculations, a non-US corporation that directly or indirectly owns at least 25% by value of the stock of another corporation is treated as if it held its proportionate share of the assets of such other corporation and received directly its proportionate share of the income of such other corporation.

Based on the present nature of its activities, including the Global Offering, and the present composition of its assets and sources of income, the Company does not believe it was a PFIC for the 2021 taxable year or expect to be a PFIC for the current taxable year or for the foreseeable future. There can be no assurances, however, that the Company will not be considered a PFIC for any particular year because PFIC status is factual in nature, generally cannot be determined until the close of the taxable year in question, and will depend on, among other things, the ownership and the composition of the income and assets, as well as the market value of the assets, of the Company and its subsidiaries from time to time. Therefore, there can be no certainty as to the Company's status for any given year. Changes in the nature of the Company's income or assets may cause it to be considered a PFIC in the current or any subsequent year. The Company believes that it currently qualifies, and expects to continue to qualify in the future, for the active commodities business exception for purposes of the PFIC asset test and income test. Each US Holder is urged to consult its own tax advisor regarding the applicability of the rules regarding commodities in the PFIC context. If the Company were classified as a PFIC in any year that a US Holder is a shareholder, the Company generally will continue to be treated as a PFIC for that US Holder in all succeeding years, regardless of whether the Company continues to meet the income or asset test described above, unless the holder makes certain elections under PFIC rules.

If the Company were a PFIC in any taxable year that a US Holder held the Ordinary Shares, US Holders generally would be subject to special rules with respect to "excess distributions" made by the Company on the Ordinary Shares and with respect to gain from a US Holder's disposition of the Ordinary Shares. An "excess distribution" generally is defined as the excess of the distributions a US Holder receives with respect to the Ordinary Shares in any taxable year over 125% of the average annual distributions a US Holder has received from the Company during the shorter of the three preceding years, or the US Holder's holding period for the Ordinary Shares. Generally, US Holders would be required to allocate any excess distribution or gain from the disposition of the Ordinary Shares rateably over their holding period for the Ordinary Shares. The portion of the excess distribution or gain allocated to a prior taxable year, other than a year prior to the first year in which the Company became a PFIC, would be taxed at the highest US federal income tax rate in effect for individual or corporate taxpayers, as applicable, for such taxable year, and US Holders would be subject to an interest charge on the resulting tax liability, determined as if the tax liability had been due with respect to such particular taxable years. The portion of the excess distribution or gain that is not allocated to prior taxable years, together with the portion allocated to the years prior to the first year in which the Company became a PFIC, would be included in a US Holder's gross income for the taxable year of the excess distribution or disposition and taxed as ordinary income.

If the Company were a PFIC for any taxable year during which a US Holder holds Ordinary Shares and any of the Company's non-US subsidiaries were also a PFIC, such US Holder will be treated as owning a proportionate amount (by value) of the shares of the lower-tier PFIC for purposes of the application of these rules and will be subject to US federal income tax according to the PFIC rules described in the paragraph above on (i) certain distributions by any non-US subsidiaries and (ii) a disposition of shares of any such non-US subsidiaries, in each case as if the US Holder owned such shares directly, even though it has not received the proceeds of those distributions or dispositions directly. US Holders should consult their own tax advisors regarding the application of the PFIC rules to any of the Company's subsidiaries.

US Holders may be eligible to make a market-to-market election with respect to the Ordinary Shares. If a US Holder makes a market-to-market election, such US Holder will generally include as ordinary income the excess, if any, of the fair market value of the Ordinary Shares at the end of each taxable year over the adjusted basis of the Ordinary Shares, and will be permitted an ordinary loss in respect of the excess, if any, of the adjusted basis of the Ordinary Shares over their fair market value at the end of the taxable year (but only to the extent of the net amount of income previously included in income as a result of the mark-to-market election). Any gain recognised on the sale or other disposition of the Ordinary Shares will be treated as ordinary income, and any loss incurred on the sale or other disposition of the Ordinary Shares will be treated as ordinary loss to the extent of any mark-to-market gains for prior years. The mark-to-market election is available only for "marketable stock," which is stock that is traded in other than de minimis quantities on at least 15 days during each calendar quarter on a qualified exchange or other market, as defined in the applicable US Treasury regulations. The London Stock Exchange may constitute a qualified exchange for this purpose provided it meets certain trading volume, listing, financial disclosure and other requirements set forth in applicable US Treasury regulations. However, the Company cannot be certain that the Ordinary Shares will continue to trade on the London Stock Exchange, that the Ordinary Shares will be traded on at least 15 days in each calendar quarter in other than de minimis quantities, or that the other qualifications will be met in a given year. US Holders should be aware, however, that if the Company was determined to be a PFIC, the interest charge regime described above could be applied to indirect distributions or gains deemed to be attributable to US Holders in respect of any of the Company's subsidiaries that also may be determined to be a PFIC, and the mark-to-market election generally would not be effective for such subsidiaries.

A US Holder's adjusted tax basis in the Ordinary Shares will be increased by the amount of any income inclusion and decreased by the amount of any deductions under the mark-to-market rules. If a US Holder makes a mark-to-market election, it will be effective for the taxable year for which the election is made and all subsequent taxable years unless the Ordinary Shares are no longer regularly traded on a qualified exchange or the US Internal Revenue Service (the "**IRS**") consents to the revocation of the election. US Holders are urged to consult their own tax advisors about the availability of the mark-to-market election in the event the Company were to be characterised as a PFIC, and whether making the election would be advisable in their particular circumstances.

In some cases, a shareholder of a PFIC can avoid the interest charge and other adverse PFIC consequences described above by making a "qualified electing fund ("**QEF**") election to be taxed currently on its share of the PFIC's undistributed income. The Company does not, however, expect to provide to US Holders the information regarding this income that would be necessary in order for a US Holder to make a QEF with respect to the Ordinary Shares.

Any US Holder who owns, or who is treated as owning, PFIC stock during any taxable year in which the Company is classified as a PFIC may be required to file IRS Form 8621. The failure to file such form when required could result in substantial penalties.

Each US Holder is urged to consult its own tax advisor concerning the US federal income tax consequences of holding Ordinary Shares if the Company were to be a PFIC in any taxable year during its holding period.

2.5 *Transfer Reporting Requirements*

A US Holder who purchases Ordinary Shares may be required to file Form 926 (or similar form) with the IRS in certain circumstances. A US Holder who fails to file any such required form could be required to pay a penalty equal to 10% of the gross amount paid for the Ordinary Shares (subject to a maximum penalty of $100,000, except in cases of intentional disregard). US Holders should consult their tax advisers with respect to this or any other reporting requirements that may apply to an acquisition of the Ordinary Shares.

2.6 *US Information Reporting and Backup Withholding*

Payments in respect of the Ordinary Shares may be subject to information reporting unless the US Holder establishes, if required, that payments to it are exempt from these rules. Payments that are subject to information reporting may be subject to backup withholding if a US Holder does not provide its taxpayer identification number and otherwise comply with the backup withholding rules. Non-US Holders may be required to comply with applicable certification procedures to establish that they are not US Holders in order to avoid the application of such information reporting requirements and backup withholding. Backup withholding is not an additional tax. Amounts withheld under the backup withholding rules are available to be credited against a US Holder's US federal income tax liability and may be refunded to the extent they exceed such liability, provided a claim is timely filed with the RBS.

Certain US Holders that own "specified foreign financial assets" that meet certain US dollar value thresholds generally are required to file an information report with respect to such assets with their tax returns. The Ordinary Shares generally will constitute specified foreign financial assets subject to these reporting requirements unless the Ordinary Shares are held in an account at certain financial institutions. Penalties can apply if US Holders fail to satisfy such reporting requirements. US Holders are urged to consult their tax advisers regarding the application of these or other disclosure requirements to their ownership of the Ordinary Shares.

THE DISCUSSION ABOVE IS A GENERAL SUMMARY. IT DOES NOT COVER ALL TAX MATTERS THAT MAY BE OF IMPORTANCE TO A PARTICULAR INVESTOR. EACH PROSPECTIVE INVESTOR IS URGED TO CONSULT ITS OWN TAX ADVISER ABOUT THE TAX CONSEQUENCES TO IT OF AN INVESTMENT IN ORDINARY SHARES IN LIGHT OF THE INVESTOR'S OWN CIRCUMSTANCES.

PART 20

ADDITIONAL INFORMATION

1. RESPONSIBILITY

The Directors, whose names appear in Part 8 (*Directors, Senior Managers and Corporate Governance*), and the Company accept responsibility for the information contained in this Prospectus. To the best of the knowledge of the Directors and the Company, the information contained in this Prospectus is in accordance with the facts and makes no omission likely to affect its import.

2. COMPETENT PERSON'S RESPONSIBILITY STATEMENT

The Competent Person accepts responsibility for the NSAI CPR contained in Part 23 (*Competent Person's Report*). To the best of the knowledge of the Competent Person, the information contained in the NSAI CPR, including the estimates of reserves section contained therein, is in accordance with the facts and makes no omission likely to affect its import.

3. THE COMPANY

3.1 The Company was incorporated and registered in England and Wales on 15 October 2019 under the 2006 Act as a private company limited by shares under the name "Delek North Sea Limited" with company number 12263719. It changed its name to "Ithaca Energy Limited" on 7 October 2022 and to "Ithaca Energy plc" on 1 November 2022 when it was re-registered as a public limited company. The Company's LEI is 21380057TNFLXPXBIP34.

3.2 The principal activity of the Company is to act as the holding company of the Group. The principal activity of the Group is the appraisal, development of, and production from, UK North Sea oil and gas properties. The principal legislation under which the Company operates, and under which the Ordinary Shares have been created, is the 2006 Act and regulations made thereunder. The Company is operating in conformity with its constitution.

3.3 The Company is domiciled in the United Kingdom with its registered office at 23 College Hill, London, EC4R 2RP. The head office of the Company is Hill of Rubislaw, Aberdeen, AB15 6XL and its telephone number is +44 (0) 1224 334 000. The Registrar of the Company is Computershare Investor Services plc.

3.4 The Company's accounting reference date is 31 December. For the period covered by the historical financial information contained in Part 16 (*Historical Financial Information*), the Group's auditor for (i) the year ended 31 December 2021 (and the six months ended 30 June 2022) was Deloitte LLP of 1 New Street Square, London, United Kingdom, EC4A 3HQ; and (ii) the years ended 31 December 2019 and 31 December 2020 was Ernst & Young LLP of 1 More London Place, London, SE1 2AF. Both Deloitte LLP and Ernst & Young LLP are registered to carry out audit work by the Institute of Chartered Accountants in England and Wales.

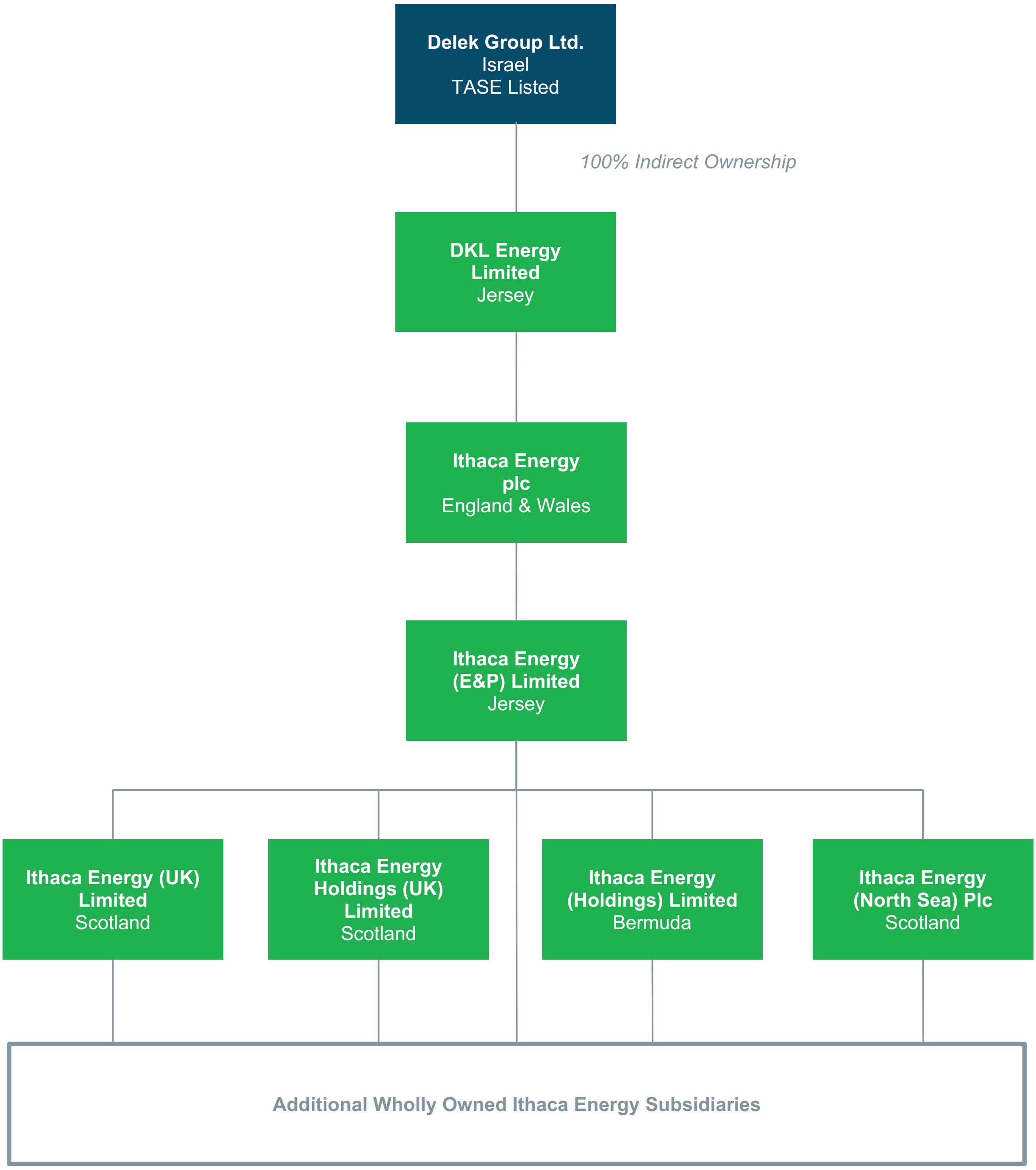
3.5 The Company's website address is www.ithacaenergy.com. The information on the website does not form part of this Prospectus unless that information is incorporated by reference into this Prospectus.

3.6 The Company has all necessary statutory consents in connection with Admission.

4. ORGANISATIONAL STRUCTURE

4.1 The Company is the principal holding company of the Group and a wholly owned subsidiary of DKL Energy. DKL Energy is a wholly owned subsidiary of DKL Investments, which is in turn a wholly owned subsidiary of DGL. DGL's shares are traded on the Tel Aviv Stock Exchange (TASE: DLEKG). The controlling shareholder in DGL is Mr. Yitzhak Sharon Tshuva who, as at the Latest Practicable Date, held 50.19% of the voting rights in DGL. Further details of the share capital structure are set out in Part 10 (*Principal Shareholder and Related Party Transactions*) and paragraph 5 (*Share Capital of the Company*) of this Part 20 (*Additional Information*).

4.2 The diagram below sets out the simplified Group structure as at the date of this Prospectus.



4.3 The following table shows details of the Company's significant subsidiaries, all of which are held 100% (directly or indirectly) by the Company:

Name	Country of Incorporation or Residence	Principal Activity
Ithaca Energy (E&P) Limited . . .	Jersey	Holding company
Ithaca Energy (North Sea) Plc . .	Scotland	Raising of and holding a $625 million Bond listed on The International Stock Exchange
Ithaca Energy (UK) Limited	Scotland	Oil and gas appraisal, development and production and intermediate holding company

Name	Country of Incorporation or Residence	Principal Activity
Ithaca Minerals (North Sea) Limited	Scotland	Oil and gas appraisal, development and production
Ithaca GSA Holdings Limited . . .	Jersey	Intermediate holding company
Ithaca Energy Developments UK Limited	England & Wales	Oil and gas appraisal, development and production
Ithaca GSA Limited	Jersey	Oil and gas appraisal, development and production
Ithaca Oil and Gas Limited	England & Wales	Oil and gas appraisal, development and production
Ithaca Exploration Limited	England & Wales	Dormant
Ithaca MA Limited	England & Wales	Oil and gas appraisal, development and production
Ithaca MA(NS) Limited	England & Wales	Dormant
Ithaca SP UK Limited	England & Wales	Dormant
Ithaca Dorset Limited	England & Wales	Dormant
Ithaca SP (Holdings) Limited . . .	England & Wales	Intermediate holding company
Ithaca SP Finance Limited	England & Wales	Financing vehicle
Ithaca SPE Limited	England & Wales	Intermediate holding company
Ithaca SP (O&G) Limited	England & Wales	Oil and gas appraisal, development and production
Ithaca SP (E&P) Limited	England & Wales	Oil and gas appraisal, development and production
Ithaca SP Bonds plc	England & Wales	Raising of and holding a $200 million Bond listed on Nordic ABM
Ithaca Zeta Limited	England & Wales	Oil and gas appraisal, development and production
Ithaca Energy (Holdings) Limited .	Bermuda	Intermediate holding company
FPF1 Limited	Jersey	Dormant
Ithaca Energy Holdings (UK) Limited	Scotland	Intermediate holding company
Ithaca Petroleum Limited	England & Wales	Intermediate holding company
Ithaca Gamma Limited	England & Wales	Oil and gas appraisal, development and production
Ithaca Alpha (N.I.) Limited	Northern Ireland	Oil and gas appraisal, development and production
Ithaca Epsilon Limited	England & Wales	Oil and gas appraisal, development and production
Ithaca Causeway Limited	England & Wales	Dormant
Ithaca Petroleum EHF	Iceland	Dormant

5. SHARE CAPITAL OF THE COMPANY

5.1 *Issued share capital of the Company*

As at the Latest Practicable Date, the issued share capital of the Company is 900,042,217 comprising 898,219,931 A ordinary shares, 1,401,758 B1 ordinary shares and 420,528 B2 ordinary shares which are fully paid. The issued share capital of the Company immediately after Admission is expected to be £10,051,622.17 comprising 1,005,162,217 Ordinary Shares. The liability of each Shareholder is limited to the amount, if any, unpaid on the shares held by that Shareholder. The Ordinary Shares are fully paid and freely transferable. The Ordinary Shares have a nominal value of £0.01. Since incorporation, the Company's share capital has been issued in conformity with the laws of England and Wales.

The Company has no convertible securities, exchangeable securities or securities with warrants in issue.

On Admission, it is expected that approximately 10.4% of the Ordinary Shares will be held in public hands (within the meaning of the Listing Rules) assuming no Over-allotment Shares are acquired pursuant to the Over-allotment Option (increasing to approximately 11.9% if the maximum number of Over-allotment Shares are acquired pursuant to the Over-allotment Option).

5.2 *History of the Share Capital*

On 15 October 2019, the Company was incorporated as a private limited company with an issued share capital of 1,000 ordinary shares of $1 each held by DKL Energy. On 17 October 2019, one additional ordinary share of $1 was issued to DKL Energy. On 29 September 2022, in connection with the MEP (further details of which are set out in paragraph 11.5 (*Management Equity Plan*) of this Part 20 (*Additional Information*):

- the 1,001 ordinary shares of $1 each in the capital of the Company were reclassified as "A ordinary shares" of $1 each in the capital of the Company ("**A Ordinary Shares**");
- 100 B1 ordinary shares of $0.01 each ("**B1 Ordinary Shares**") were issued to Gilad Myerson;
- 100 B2 ordinary shares of $0.01 each ("**B2 Ordinary Shares**") were issued to Gilad Myerson; and
- the Company adopted new articles of association.

5.3 *Share Capital Reorganisation*

The Group has implemented a share capital reorganisation prior to Admission (the "**Share Capital Reorganisation**"). The principal steps of the Share Capital Reorganisation were as follows:

- the amount standing to the credit of the Company's capital contribution reserve ($114,000,000) was capitalised and such capitalised sum was used to pay up in full 114,000,000 A Ordinary Shares;
- the amount standing to the credit of the Company's share premium account ($634,659,000) and the 114,000,000 A Ordinary Shares were each cancelled in order to create distributable profits of the Company;
- the 100 B1 Ordinary Shares were consolidated into 1 B1 ordinary share of $1 and the 100 B2 Ordinary Shares were consolidated into 1 B2 ordinary share of $1;
- the ordinary share capital of the Company was redenominated from USD to GBP. Each ordinary share of nominal value of $1.00 was converted into a share of nominal value of £0.88 on the basis of being converted at the rate of 1 USD to 0.8804 GBP (being the spot rate for a transaction between USD and GBP as at 17 October 2022 as published by Bloomberg, but with the spot rate being rounded to the nearest whole pence (i.e. £0.88));

- the 1,001 A ordinary shares of £0.88 each, the 1 B1 ordinary share of £0.88 and the 1 B2 ordinary share of £0.88 were then subdivided into shares of £0.01 each, resulting in there being 88,088 A ordinary shares of £0.01 each, 88 B1 ordinary shares of £0.01 each and 88 B2 ordinary shares of £0.01 each; and
- 4,911,736 A ordinary shares of £0.01 each (credited as fully paid up, that is to say as to £49,177.36 in aggregate) were issued to the holder of A ordinary shares of £0.01 each by way of a bonus issue of shares to enable the Company to meet the minimum authorised share capital requirement in order to re-register as a public limited company. Following this bonus issue of shares, the share capital of the Company comprised 4,999,824 A ordinary shares of £0.01 each, 88 B1 ordinary shares of £0.01 each and 88 B2 ordinary shares of £0.01 each.

5.4 ***Confirmations***

As at the date of this Prospectus and save as otherwise disclosed in this Part 20 (*Additional Information*):

- no share or loan capital of the Company has, since its incorporation, been issued or agreed to be issued, or is now proposed to be issued, fully or partly paid, either for cash or for a consideration other than cash, to any person;
- there has been no change in the amount of the issued share or loan capital of the Company since its incorporation;
- no commissions, discounts, brokerages or other special terms have been granted by the Company in connection with the issue or sale of any share or loan capital of the Company, since its incorporation;
- no share or loan capital of the Company is under option or agreed, conditionally or unconditionally, to be put under option; and
- the Company holds no treasury shares (as defined in the 2006 Act).

5.5. ***Authorisations relating to the share capital of the Company***

The Company obtained the following shareholder approvals on 8 November 2022 in connection with Admission:

5.5.1 an ordinary resolution to capitalise and appropriate as capital to DKL Energy the sum of £8,932,201.07 standing to the credit of the Company's profit and loss account and to authorise the directors to apply such sum in paying up in full 893,220,107 A ordinary shares of £0.01 each, and to allot and issue such new shares to DKL Energy;

5.5.2 ordinary resolutions to capitalise and appropriate as capital to Gilad Myerson the sum of £18,221.10 standing to the credit of the Company's profit and loss account and to authorise the directors of the Company to apply such sum in paying up in full 1,401,670 B1 ordinary shares of £0.01 each and 420,440 B2 ordinary shares of £0.01 each, and to allot and issue such new shares to Gilad Myerson in order to give effect to the rights attaching to the B1 ordinary shares and B2 ordinary shares pursuant to clause 7.3 of the Management Incentive Agreement (as set out in paragraph 11.5 (Management Equity Plan) of Part 20 (Additional Information));

5.5.3 an ordinary resolution to re-designate the A ordinary shares of £0.01 each, the B1 ordinary shares of £0.01 each and the B2 ordinary shares of £0.01 each as a single class of ordinary shares of £0.01 each in the capital of the Company;

5.5.4 a special resolution approving the adoption of new articles of association of the Company in a form suitable for the Company as a company whose shares will be admitted to the Official List and to trading on the main market of the London Stock Exchange (as referred to in paragraph 6 (Summary of the Articles) of this Part 20 (Additional Information));

5.5.5 an ordinary resolution approving the allotment by the directors of the Company (pursuant to section 551 of the Companies Act) of new Ordinary Shares:

(a) up to an aggregate nominal amount of £1,200 to be issued in connection with the arrangements referred to in paragraph 10.3.5 of this Part 20 (Additional Information);

(b) up to an aggregate nominal amount of £1,050,000 to be issued in connection with the Global Offering,

such authority to expire on 00:00 on 30 November 2022 if Admission has not occurred by that time;

5.5.6 an ordinary resolution authorising directors of the Company (pursuant to section 551 of the Companies Act) to allot shares in the Company and to grant rights to subscribe for or convert any security into shares in the Company as follows:

(a) up to an aggregate nominal amount representing one third of the Ordinary Shares expected to be in issue immediately following Admission (excluding treasury shares) (such amount to be reduced by any allotments or grants made under paragraph (b) below in excess of such number); and

(b) comprising equity securities (as defined in section 560(1) of the Companies Act) up to an aggregate nominal amount representing two-thirds of the Ordinary Shares expected to be in issue immediately following Admission (excluding treasury shares) (such amount to be reduced by any allotments made under paragraph (a) above) in connection with an offer by way of a rights issue:

(i) to ordinary shareholders in proportion (as nearly as may be practicable) to their existing holdings; and

(ii) to holders of other equity securities as required by the rights of those securities or as the directors otherwise consider necessary,

provided always that the directors of the Company may impose any limits or restrictions and make any arrangements which they consider necessary or appropriate to deal with any treasury shares, fractional entitlements, record dates, legal, regulatory or practical problems in, or under the laws of, any territory or any other matter,

such authority to expire at the earlier of the date which is 15 months from the date of the passing of the resolution and the conclusion of the next annual general meeting of the Company, except that the Company may at any time before such expiry make an offer or agreement which would or might require relevant securities to be allotted after such expiry and the directors may allot relevant securities in pursuance of such an offer or agreement as if this authority had not expired; and

5.5.7 a special resolution approving the disapplication of pre-emption rights (pursuant to section 561 of the Companies Act):

(a) in respect of the new Ordinary Shares to be allotted and issued in connection with the arrangements referred to in paragraph 10.3.5 of this Part 20 (Additional Information);

(b) in respect of the Offer Shares to be allotted and issued in connection with the Global Offering;

(c) in connection with rights issues but taking account of exclusions or other arrangements as the directors may deem necessary or expedient in relation to treasury shares, fractional entitlements or legal or practical problems under the laws of, or the requirements of any recognised regulatory body or any stock exchange in, any territory or any other matter;

(d) up to a nominal amount representing approximately 10 per cent. of the aggregate nominal amount of the share capital of the Company (excluding treasury shares) as it is expected to be immediately following Admission; and

(e) up to a nominal amount representing approximately 10 per cent. of the aggregate nominal amount of the share capital of the Company (excluding treasury shares) as it is expected to be immediately following Admission, such authority to be used only for the purpose of financing (or refinancing, if the authority is to be used within six months after the original transaction) a transaction which the directors of the Company determine to be an acquisition or other capital investment of a kind contemplated by the Statement of Principles on Disapplying Pre-Emption Rights most recently published by the Pre-Emption Group prior to the date on which this resolution was passed,

such authority to expire upon the earlier of the conclusion of the next annual general meeting of the Company and the date which is 15 months from the date of passing of the resolution, except that the Directors can during such period make offers or arrangements which could or might require the allotment of equity securities after the expiry of such period; and

5.5.8 a special resolution to authorise the Company for the purposes of section 701 of the Companies Act to make one or more market purchases (as defined in section 693(4) of the Companies Act) of its ordinary shares of £0.01 each, such power to be limited:

(a) to a maximum number of shares representing approximately 10 per cent. of the Ordinary Shares expected to be in issue immediately following Admission (excluding treasury shares);

(b) by the condition that the minimum price which may be paid for an ordinary share is £0.01 and the maximum price which may be paid for an ordinary share is the highest of:

(i) an amount equal to 105% of the average market value of an ordinary share for the five business days immediately preceding the day on which that ordinary share is contracted to be purchased; and

(ii) the higher of the price of the last independent trade of an ordinary share and the highest current independent bid for an ordinary share on the trading venue where the purchase is carried out,

in each case, exclusive of expenses, such power to apply until the earlier of the date which is 15 months from the date of the passing of the resolution and the conclusion of the next annual general meeting of the Company, but in each case so that the Company may enter into a contract to purchase ordinary shares which will or may be completed or executed wholly or partly after the power ends and the Company may purchase ordinary shares pursuant to any such contract as if the power had not ended.

6. SUMMARY OF THE ARTICLES

6.1 The summary in this section relates to the Articles which will be adopted by the Company immediately prior to Admission. The Articles of the Company shall include provisions to the following effect:

Objects

The Articles contain no restriction on the objects of the Company. Accordingly, pursuant to section 31 of the 2006 Act, the Company's objects are unrestricted.

Capital structure

The share capital of the Company is represented by an unlimited number of Ordinary Shares having the rights described in the Articles.

Voting rights

Subject to any rights or restrictions attached to any shares, on a show of hands every member who (being an individual) is present in person or by proxy or (being a corporation) is present by a duly authorised representative, not being himself a member entitled to vote, shall have one vote, and on a poll every member shall have one vote for every share of which he is the holder. Votes may be given personally or by proxy.

Dividends

Subject to the 2006 Act and as set out in the Articles, the Company may by ordinary resolution declare dividends but no dividend shall exceed the amount recommended by the Board. No dividend may be paid otherwise than in accordance with the 2006 Act. The Board may at any time declare and pay such interim dividends as appears to be justified by the position of the Company.

Except as otherwise provided by the rights attached to the shares, all dividends shall be declared and paid according to the amounts paid up on the nominal amount of the shares on which the dividend is paid but no amount paid on a share in advance of calls shall be treated as paid on the share. All dividends shall be apportioned and paid proportionately to the amounts paid up on the nominal amount of the shares during any portion or portions of the period in respect of which the dividend is paid; but, if any share is issued on terms providing that it shall rank for dividend as from a particular date, that share shall rank for dividend accordingly.

Any dividend or other moneys payable in respect of a share may be paid:

- in cash;
- by cheque or warrant sent by post to the address in the register of members of the Company of the person entitled to the moneys or, if two or more persons are the holders of the share or are jointly entitled to it by reason of the death or bankruptcy of the holder or otherwise by operation of law, to the address in the register of that one of those persons who is first named in the register in respect of the joint holding or to such person and to such address as the person or persons entitled to the moneys may in writing direct. Every such cheque or warrant shall be made payable to the person or persons entitled to the moneys or to such other person as the person or persons so entitled may in writing direct and shall be sent at the risk of the person or persons so entitled. Any such cheque or warrant may be crossed 'account payee' although the Company shall not be obliged to do so;
- by bank transfer to such account (of a type approved by the Board) as the person or persons entitled to the moneys may in writing direct; or
- by such other method of payment approved by the Board as the person or persons entitled to the moneys may in writing agree.

Redemption

Subject to the provisions of the 2006 Act and the Articles, the Company can issue shares which are required to be redeemed and shares which may be redeemed at the option of the Company or the relevant member.

Variation of class rights

Whenever the capital of the Company is divided into different classes of shares, the rights attached to any class of the shares in issue may from time to time be varied or abrogated, whether or not the Company is being wound up, with the sanction of a special resolution passed at a separate meeting of holders of the issued shares of the class held in accordance with the Articles (but not otherwise).

The special rights conferred on the holders of any shares or class of shares shall, unless otherwise provided by the Articles or the terms of issue of the shares concerned, be deemed to be varied by a reduction of capital paid up on those shares but shall be deemed not to be varied by the creation or issue of further shares ranking pari passu with them or subsequent to them. The rights conferred on the holders of shares shall be deemed not to be varied by the creation or issue of any further shares ranking in priority to them nor shall any consent or sanction of the holders of shares be required to any variation or abrogation effected by a resolution on which only the holders of shares are entitled to vote.

Issue of shares

Subject to the provisions of the 2006 Act and without prejudice to any rights attaching to any existing shares, shares may be issued with such rights or restrictions as the Company may, by ordinary resolution, determine or in the absence of such determination, or as far as any such resolution does not make specific provision, as the Board may determine.

Form and transfer of shares

The Board may issue shares as certificated or uncertificated shares, subject to any restrictions on transfers described below.

A share held in certificated form may be transferred by an instrument of transfer in any usual form or in any other form which the Board may approve, which shall be executed by or on behalf of the transferor and, unless the share is fully paid, by or on behalf of the transferee. A share held in uncertificated form may be transferred by means of a relevant system. The transferor shall be deemed to remain the holder of the share until the transferee is entered on the register as its holder.

Every member (other than a person who is not entitled to a certificate under the 2006 Act) is entitled, on becoming a holder of any shares in certificated form and without payment, to a certificate for all shares of each class held by him in certificated form. If a share certificate is worn out, defaced, lost, destroyed or stolen it may be renewed without fee but on such terms as to evidence and indemnity as the Board requires. In the case of loss, theft, or destruction, the person to whom the new certificate is issued may be required to pay any exceptional out of pocket expenses incidental to the investigation of evidence of loss, theft or destruction and the preparation of an appropriate form of indemnity. Every share certificate is sent at the risk of the person entitled thereto.

The Board may, in the case of shares held in certificated form, in its absolute discretion refuse to register the transfer of a share which is not fully paid provided that such discretion may not be exercised in such a way as to prevent dealings in the shares of that class from taking place on an open and proper basis.

The Board may also refuse to register a transfer of any shares held in certificated form unless the instrument of transfer is:

- duly stamped or duly certified or otherwise shown to the satisfaction of the Board to be exempt from stamp duty, lodged at the transfer office or at such other place as the Board may appoint and (save in the case of a transfer by a person to whom no certificate was issued in respect of the shares in question) accompanied by the certificate for the shares to which it relates, and such other evidence as the Board may reasonably require to show the right of the transferor to make the transfer and, if the instrument of transfer is executed by some other person on his behalf, the authority of that person so to do;
- in respect of only one class of shares; and
- in favour of not more than four transferees.

If the Board refuses to register a transfer of shares held in certificated form, it shall (except in the case of suspected fraud) as soon as practicable and in any event within two months after the date on which the transfer was lodged with the Company send to the transferee notice of the refusal together with its reasons for the refusal.

No fee shall be charged for the registration of any instrument of transfer or other document relating to or affecting the title to any share or for making any entry in the register affecting the title to any share.

The Company shall be entitled to retain any instrument of transfer which is registered, but (except in the case of suspected fraud) any instrument of transfer which the Board refuses to register shall be returned to the person lodging it when notice of the refusal is given.

For all purposes of the Articles relating to the registration of transfers of shares, the renunciation of the allotment of any shares by the allottee in favour of some other person shall be deemed to be a transfer and the Board shall have the same powers of refusing to give effect to such a renunciation as if it were a transfer.

If a member dies the survivor or survivors where he was a joint holder, and his personal representatives where he was a sole holder or the only survivor of joint holders, shall be the only persons recognised by the Company as having any title to his interest; but nothing contained in the Articles shall release the estate of a deceased member from any liability in respect of any share which had been held (whether solely or jointly) by him.

Calls

Subject to the terms of allotment, the directors may from time to time make calls upon the members in respect of any moneys unpaid on their shares including any premium and each member shall (subject to being given at least 14 clear days' notice specifying where and when payment is to be made) pay to the Company the specified amount called on his shares. If any sum called in respect of a share is not paid before or on the day appointed for payment thereof, the person from whom it is due and payable shall pay interest on the amount unpaid from the day it became due and payable until it is paid. Interest shall be paid at a rate fixed by the terms of allotment of the share or in the notice of the call; or if no rate is fixed, at the appropriate rate per annum from the day appointed for the payment thereof to the time of the actual payment. Directors may at their discretion waive payment of any such interest in whole or in part.

Forfeiture

If a member fails to pay any call or instalment of a call on the day appointed for payment of such call or instalment, the directors may serve a notice on him requiring payment of so much of the amount unpaid together with any interest which may have accrued and any expenses which have been incurred by the Company due to the default. The notice shall name the place where payment is to be made and shall state that if the notice is not complied with the shares in respect of which the call was made will be liable to be forfeited.

A forfeited share may be sold, re-allotted or otherwise disposed of on such terms and in such manner as the Board determine and at any time before a sale or disposition the forfeiture may be cancelled on such terms as the directors think fit.

A person whose shares have been forfeited shall cease to be a member in respect of the forfeited shares, but shall, notwithstanding such forfeiture, remain liable to pay to the Company all moneys which at the date of forfeiture were payable by him to the Company in respect of the shares, together with all expenses and interest from the date of forfeiture or surrender until payment, but his liability shall cease if and when the Company receives payment in full of the unpaid amount.

A statutory declaration in writing that the declarant is a director or the secretary of the Company, and that the particular share of the Company has been duly forfeited on a date stated in the declaration, shall be conclusive evidence of the facts therein stated as against all persons claiming to be entitled to the forfeited share.

Disclosure of interests

The Company may give notice to any member or any person whom the Company knows or has reasonable cause to believe (a) to be interested in the Company's shares or (b) to have been so interested at any time in the three years immediately preceding the date on which the notice is issued. The notice may require the person (a) to confirm that fact or (as the case may be) to state whether or not it is the case and (b) if he holds, or has during that time held, any such interest, to give such further information as may be required in accordance with section 793 of the 2006 Act (including particulars of the interest (present or past) and the identity of the persons interested in the shares in question).

If the Company has served a disclosure notice on a member or any other person appearing to be interested in shares referred to in the disclosure notice, and the Company has not received the information required in the disclosure notice within 14 days after service of the disclosure notice, the directors may determine that the member holding the specified shares shall be subject to restrictions in respect of those shares (including restrictions as to voting, right to transfer the shares and right to receive dividends).

Directors

Unless otherwise determined by the Board, the number of directors of the Company shall be not less than two.

The directors may be paid all travelling, hotel and other expenses as they may incur in connection with their attendance at meetings of the Board or of committees of the Board or general meetings or separate meetings of the holders of any class of shares or debentures of the Company or otherwise in connection with the discharge of their duties.

The Board may provide benefits, whether by the payment of gratuities or pensions or by insurance or otherwise, for any director, employee or former employee who has held but no longer holds any office or employment with the Company or with any body corporate which is or has been a subsidiary undertaking or a predecessor in business of the Company or of any subsidiary undertaking, and for any member of his family (including a spouse and a former spouse) or any person who is or was dependent on him and may (as well before as after he ceases to hold such office or employment) contribute to any fund and pay premiums for the purchase or provision of any such benefit. The power conferred by the 2006 Act to make provision for the benefit of persons employed or formerly employed by the Company or any of its subsidiaries (other than a director or former director or shadow director), in connection with the cessation or the transfer to any person of the whole or party of the undertaking of the Company or any subsidiary, shall be exercised by the Board.

At each annual general meeting all of the directors shall stand for re-election. Any director may be removed from office by ordinary resolution of the Company. The directors are not subject to a mandatory retirement age.

Directors' interests

A director who to his knowledge is in any way directly or indirectly interested in a contract or arrangement or proposed contract or arrangement with the Company shall disclose the nature of his interest at a meeting of the Board.

A director may not vote (or be counted in the quorum) in respect of any resolution of the directors or committee of the directors concerning a contract, arrangement, transaction or proposal to which the Company is or is to be a party and in which he has an interest which (together with any interest of any person connected with him) is, to his knowledge, a material interest (otherwise than by his interest in shares or debentures or other securities of or otherwise in or through the Company). This is subject to certain exceptions including (i) where the contract, arrangements, transaction or proposal concerns general employee privileges or insurance policies for the benefit of directors or (ii) in circumstances where a director acts in a personal capacity in the giving of a guarantee, security or indemnity for the benefit of the Company or any of its subsidiary undertakings.

Any director may act by himself or his firm in a professional capacity for the Company, other than as auditor, and he or his firm shall be entitled to remuneration for professional services as if he were not a director.

Disclosure of interests

Subject to the provisions of the 2006 Act, and provided that he has disclosed to the Board the nature and extent of any interest of his in accordance with the Articles, a director notwithstanding his office:

- may be a party to or otherwise interested in any transaction or arrangement with the Company or in which the Company is otherwise interested;
- may be a director or other officer of, or employed by or party to any transaction or arrangement with, or otherwise interested in any body corporate promoted by the Company or in which the Company is otherwise interested; and
- shall not be, by reason of his office, accountable to the Company for any benefits derived from any such office or employment or from any transaction or arrangement or from any interest in any such body corporate and no such transaction or arrangement shall be liable to be avoided on the grounds of any such interest or benefit.

Authorisation of interests

The directors may authorise, to the fullest extent permitted by law, any matter proposed to them which would otherwise result in a director infringing his duty under the 2006 Act to avoid a situation in which he has, or can have, a direct or indirect interest that conflicts, or possibly may conflict, with the interests of the Company and which may reasonably be regarded as likely to give rise to a conflict of interest.

Authorisation of a matter is effective only if: (i) the matter has been proposed to the directors at a meeting of the directors or for the authorisation of the directors by resolution in writing and in accordance with the Board's normal procedures or in such other manner as the Board may approve; (ii) any requirement as to quorum at the meeting of the directors at which the matter is considered is met without counting the director in question and any other interested director; and (iii) the matter has been agreed to without the director in question and any other interested Director voting or would have been agreed to if their votes had not been counted.

An interest of a person connected with a director shall be treated as an interest of the director. Section 252 of the 2006 Act shall determine whether a person is connected with a director.

Borrowing powers

The directors may exercise all the powers of the Company to borrow money and to give guarantees, hypothecate, mortgage, charge or pledge the assets, property and undertaking of the Company or any part thereof and to issue debentures and other securities whether outright or as collateral security for any debt, liability or obligation of the Company or of any third party.

Annual General Meetings and General Meetings

An annual general meeting shall be held at such time and place as the Board may determine. The Board may call general meetings and, on the requisition of members pursuant to the provisions of the 2006 Act, shall forthwith convene a general meeting. If there are not sufficient directors capable of acting to call a general meeting, any director may call a general meeting. If there is no director able to act, any two members may call a general meeting for the purpose of appointing directors.

No business shall be transacted at any general meeting unless a quorum is present when the meeting proceeds to business. A quorum is two members present in person or by proxy and entitled to vote upon the business to be transacted at the meeting.

An annual general meeting shall be called by at least 21 days' clear notice in writing. A meeting of the Company other than an annual general meeting shall be called by not less than 14 days' clear notice. The notice shall specify the place, the day and the time of the meeting and the general nature of that business. A notice calling an annual general meeting shall specify the meeting as such and a notice for the passing of a special resolution shall specify the intention to propose the resolution as a special resolution and the terms of the resolution. Every member entitled to attend and vote is entitled to appoint one or more proxies to attend, vote and speak instead of him and that proxy need not be a member.

The accidental omission to give notice of a meeting, or to send an instrument of proxy or invitation to appoint a proxy as provided by the Articles, to any person entitled to receive notice, or the non receipt of notice of a meeting or instrument of proxy or invitation to appoint a proxy by such a person, shall not invalidate the proceedings at that meeting.

Every notice of meeting shall state with reasonable prominence that a member entitled to attend and vote is entitled to appoint one or more proxies to attend, vote and speak instead of him and that a proxy need not be a member.

Annual Accounts and Financial Statements

Save as provided in the Articles, a copy of the annual accounts of the Company together with a copy of the auditors' report and the directors' report thereon and any other documents required to accompany or to be annexed to them shall, not less than 21 clear days before the date of the general meeting at which copies of those documents are to be laid, be sent to every member and to every debenture holder of the Company and to every other person who is entitled to receive notices from the Company of general meetings.

Copies of the documents referred to in the Articles need not be sent to: (a) a person who is not entitled to receive notices of general meetings or of whose address the Company is unaware; or (b) more than one of the joint holders of shares or debentures in respect of those shares or debentures, provided that any member or debenture holder to whom a copy of such documents has not been sent shall be entitled to receive a copy free of charge on application at the registered office.

The Company may send a summary financial statement to any of the persons otherwise entitled to be sent copies of the documents referred to in the Articles instead of or in addition to those documents and, where it does so, the statement shall be delivered or sent to such person not less than 21 clear days before the general meeting at which copies of those documents are to be laid.

Winding up

If the Company is wound up, the liquidator may, with the sanction of a special resolution of the Company and any other sanction required by the 2006 Act, divide among the members in specie the whole or any part of the assets of the Company and may, for that purpose, value any assets and determine how the division shall be carried out as between the members or different classes of members. The liquidator may, with the applicable sanction, vest the whole or any part of the assets in trustees upon such trusts for the benefit of the members as he with the applicable sanction determines, but no member shall be compelled to accept any assets upon which there is a liability.

Untraceable shareholders

The Company shall be entitled to sell at the best price reasonably obtainable any member's shares or the shares to which a person is entitled by virtue of transmission on death or bankruptcy or otherwise by operation of law if:

- for a period of twelve years, no cash dividend payable in respect of the shares has been claimed, no cheque or warrant sent by the Company through the post in a pre-paid envelope addressed to the member or to the person entitled to the shares at his address on the register or (if different) the last known address given by the member or the person so entitled to which cheques and warrants are to be sent has been paid, each attempt to make a payment in respect of the shares by means of bank transfer or other method for the payment of dividends or other moneys in respect of shares has failed and no communication has been received by the Company from the member or the person so entitled (in his capacity as member or person entitled);
- in such period of twelve years at least three dividends (whether interim or final) have become payable on the shares;
- the Company has at the expiration of the said period of twelve years by advertisement in both a national newspaper and in a newspaper circulating in the area in which the address referred to in the Articles is located given notice of its intention to sell such shares; and

- during the period of three months following the publication of the said advertisements the Company has received no communication in respect of such share from such member or person entitled.

If at any time during or after the said period of twelve years further shares have been issued in right of those held at the commencement of that period or of any issued in right during that period and, since the date of issue, the requirements of the Articles have been satisfied in respect of such further shares, the Company may also sell the further shares.

To give effect to such a sale the Board may authorise any person to execute an instrument of transfer or otherwise effect the transfer of the shares to be sold. If the shares concerned are in uncertificated form, in accordance with the CREST Regulations, the Company may issue a written notification to the operator requiring conversion of the shares into certificated form. The purchaser shall not be bound to see to the application of the purchase moneys and the title of the transferee to the shares shall not be affected by any irregularity in or invalidity of the proceedings relating to the sale. The net proceeds of sale shall belong to the Company which shall be obliged to account to the former member or other person previously entitled to the shares for an amount equal to the net proceeds, which shall be a debt of the Company, and shall enter the name of such former member or other person in the books of the Company as a creditor for such amount. No trust shall be created and no interest shall be payable in respect of the debt, and the Company shall not be required to account for any money earned on the net proceeds, which may be employed in the business of the Company or invested in such investments for the benefit of the Company as the Board may from time to time determine.

7. PRINCIPAL SHAREHOLDER

Details of principal shareholder of the Company and material transactions with related parties to which the Company or its Subsidiaries are party are set out in Part 10 (*Principal Shareholder and Related Party Transactions*).

8. MANDATORY BIDS AND COMPULSORY ACQUISITION RULES RELATING TO THE SHARES

8.1 *Takeover bids*

The City Code is issued and administered by the Takeover Panel. At the date of this Prospectus the Company, as a public limited company, is subject to the City Code and therefore its Shareholders will be entitled to the protections afforded by the City Code.

8.2 *Mandatory bid*

Rule 9 of the City Code provides that, except with the consent of the Takeover Panel, when:

- any person acquires, whether by a series of transactions over a period of time or not, an interest in shares which (taken together with shares in which persons acting in concert with him are interested) carry 30% or more of the voting rights of a company; or
- any person, together with persons acting in concert with him, is interested in shares which in the aggregate carry not less than 30% of the voting rights of a company but does not hold shares carrying more than 50% of such voting rights and such person, or any person acting in concert with him, acquires an interest in any other shares which increases the percentage of shares carrying voting rights in which he is interested,

then, in either case, that person, together with the persons acting in concert with him, is normally required to extend offers in cash, at the highest price paid by him (or any persons acting in concert with him) for shares in the Company within the preceding 12 months, to the holders of any class of equity share capital whether voting or non-voting and also to the holders of any other class of transferable securities carrying voting rights in the Company.

Under Note 5 of the Notes on Dispensations from Rule 9, the Panel may waive the requirement for a cash offer under Rule 9 where shares carrying 50% or more of the voting rights of the Company are already held by one person.

If a person (or group of persons acting in concert) already holds shares of the Company carrying more than 50% of the voting rights in the Company, that person (or any person(s) acting in concert with such person) may acquire further shares without incurring any obligation under Rule 9 to make a mandatory offer, although individual members of a concert party will not be able to increase their percentage interest in shares through or between a Rule 9 threshold without Panel consent.

8.3 *Application of Rule 9 while Delek controls more than 50% of the voting rights*

Immediately following Admission, Delek will be interested (directly or indirectly) in approximately 89.4% of the voting rights of the Company.

From Admission, for so long as Delek and persons acting in concert with Delek continue to be interested in Ordinary Shares carrying over 50% of the Company's voting rights, Delek (and any persons acting in concert with Delek) will be free to acquire further shares in the Company without incurring any obligation under Rule 9 of the Code to make a mandatory offer to all Shareholders (subject to the considerations in Note 4 on Rule 9.1 of the Code, including whether any individual member of Delek's concert party, other than Delek, increases their percentage interest in voting rights through 30%).

8.4 *Squeeze-out*

Under the 2006 Act, if an offeror were to make an offer to acquire all of the shares in the Company not already owned by it and were to acquire 90% of the shares to which such offer related it could then compulsorily acquire the remaining 10% of the shares. The offeror would do so by sending a notice to outstanding shareholders telling them that it will compulsorily acquire their shares and then, six weeks later, it would deliver a transfer of the outstanding shares in its favour to the Company which would execute the transfers on behalf of the relevant shareholders, and pay the consideration to the Company which would hold the consideration on trust for outstanding shareholders. The consideration offered to the shareholders whose shares are compulsorily acquired under this procedure must, in general, be the same as the consideration that was available under the original offer unless a shareholder can show that the offer value is unfair.

8.5 *Sell-out*

The 2006 Act also gives minority shareholders a right to be bought out in certain circumstances by an offeror who has made a takeover offer. If a takeover offer related to all the shares in the Company and, at any time before the end of the period within which the offer could be accepted, the offeror held or had agreed to acquire not less than 90% of the shares, any holder of shares to which the offer related who had not accepted the offer could by a written communication to the offeror require it to acquire those shares. The offeror would be required to give any shareholder notice of his/her right to be bought out within one month of that right arising. The offeror may impose a time limit on the rights of minority shareholders to be bought out, but that period cannot end less than three months after the end of the acceptance period or, if later, three months from the date on which notice is served on shareholders notifying them of their sell-out rights. If a shareholder exercises his/her rights, the offeror is entitled and bound to acquire those shares on the terms of the offer or on such other terms as may be agreed.

9. DIRECTORS' AND SENIOR MANAGERS' INTERESTS

9.1 *Directorships and partnerships outside the Group*

The details of those companies and partnerships outside the Group of which the Directors and Senior Managers are currently directors, partners or members of any administrative, management or supervisory body, or have been directors, partners or members of any administrative, management or supervisory body at any time in the five years immediately preceding the date of this Prospectus are as follows:

Name	Current directorships and partnerships	Previous directorships and partnerships
Directors		
Gilad Myerson	N/A	DKL Investments Limited DKL Energy Limited

Name	Current directorships and partnerships	Previous directorships and partnerships
Alan Bruce	N/A	N/A
Iain Lewis	N/A	N/A
Idan Wallace	Delek Group Ltd. NewMed Energy Management Ltd Delek Energy Systems Ltd Wallace Consulting Ltd Wallace Investments (2018) Ltd	Keshet Broadcasting Ltd Israeli Television News Company Tashluz Investments & Holdings Ltd
John Mogford	BHP Group (Aus) Limited Sutton Energy Consultants Limited Mogford Albion Limited	BHP Group (UK) Ltd ERM Worldwide Group Limited Weir Group Plc (The) DOF Subsea AS
Deborah Gudgeon	5 Wolseley Road Limited Petra Diamonds Limited Conan Limited	Evraz Plc Barrick TZ Limited Highland Gold Mining Limited
Lynne Clow	Highlands and Islands Airports Limited Dundee Airports Limited Scottish Prison Service	N/A
Assaf Ginzburg	Alon USA Energy Inc[1] Ormat Technologies inc	Delek Logistics Partners LP Delek Logistics GP LLC[1]
David Blackwood CBE	N/A	Harbour Energy plc (formerly Premier Oil plc) Aberdeen Science Centre Carbon-Elite (Scotland) Limited Christie-Elite Nurseries Limited Fasque Group Limited Fasque Forestry Limited
Senior Managers		
John Horsburgh	N/A	N/A
Julie McAteer	N/A	Premier Oil UK Limited Premier Oil E&P UK Limited Premier Oil E&P UK EU Limited Premier Oil Aberdeen Services Limited Premier Oil E&P UK Energy Trading Limited
Rachel Stanley	N/A	N/A
Brian Winton	BJK Winton Properties Limited B J Winton Consultants Limited	N/A
Craig Matthew	N/A	N/A

(1) Delek sold its substantial shareholding (7.5%) in Delek Logistics Partners LP and Delek US Holdings, Inc in 2014 and all remaining shares were sold by the Delek Group in 2017. Delek Logistics and Delek US are no longer affiliates of the Delek Group

9.2 ***Interests in the ordinary share capital of the Company***

As at the Latest Practicable Date and immediately following Admission, the interests of the Directors and the Senior Managers and (so far as is known to them or could with reasonable diligence be ascertained by them) the persons closely associated with them (within the meaning of UK MAR) in the Ordinary Shares are as follows:

	At the Latest Practicable Date		Immediately following Admission[1]	
Name	Number of Ordinary Shares	Percentage of issued share capital	Number of Ordinary Shares	Percentage of issued share capital
Gilad Myerson[2]	1,822,286	0.2%	1,822,286	0.181%
Alan Bruce[3]	—	—	—	—
Iain Lewis	—	—	—	—
Idan Wallace[4]	—	—	—	—
John Mogford	—	—	40,000	0.004
Deborah Gudgeon	—	—	20,000	0.002

Name	At the Latest Practicable Date		Immediately following Admission[(1)]	
	Number of Ordinary Shares	Percentage of issued share capital	Number of Ordinary Shares	Percentage of issued share capital
Lynne Clow	—	—	20,000	0.002
Assaf Ginzburg	—	—	20,000	0.002
David Blackwood	—	—	20,000	0.002
John Horsburgh	—	—	—	—
Julie McAteer	—	—	—	—
Rachel Stanley	—	—	—	—
Brian Winton	—	—	—	—
Craig Matthew	—	—	—	—

Notes:

(1) Assuming that the Share Capital Reorganisation steps described in paragraph 5.3 (*Share Capital Reorganisation*) of this Part 20 (*Additional Information*) have been completed in full.

(2) Mr Myerson currently holds: (i) an option over shares which have a value equal to 0.2% of IEEPL's assets less its liabilities or 0.2% of the market value of the issued share capital of the Company, as shown in the latest audited accounts (for further details, please see paragraph 11.6 (*Option Agreements*) of Part 20 (*Additional Information*)); and (ii) an entitlement to receive Ordinary Shares which have a value equal to 1.3% of the entire issued share capital of Ithaca Energy above a fixed hurdle of $2.5 billion (for further details, please see paragraph 11.5 (*Management Equity Plan*) of Part 20 (*Additional Information*)). In each case, the value (and, therefore, the number) of Ordinary Shares which Mr Myerson is entitled to receive shall be determined by reference to the Offer Price.

(3) Mr Bruce currently holds an option over shares which have a value equal to 0.2% of IEEPL's assets less its liabilities or 0.2% of the market value of the issued share capital of the Company, as shown in the latest audited accounts (for further details, please see paragraph 11.6 (*Option Agreements*) of Part 20 (*Additional Information*)). The value (and, therefore, the number) of Ordinary Shares which Mr Bruce is entitled to receive shall be determined by reference to the Offer Price.

(4) Idan Wallace is not directly interested in any Ordinary Shares, but acts as a representative of the Controlling Shareholder on the Board, whose interests are set out in paragraph 1 of Part 10 (*Principal Shareholder and Related Party Transactions*).

Save as set out in this paragraph 9.2 (*Interests in the ordinary share capital of the Company*) of this Part 20 (*Additional Information*), no Director or Senior Manager holds, directly or indirectly, any voting rights in respect of the Company or any of its Subsidiaries.

9.3 ***Conflicts of Interest***

There is the following potential conflict of interest between the duties of a Director of the Company and his private interests and/or other duties. This conflict has been authorised by the Board.

Idan Wallace	Mr Wallace was appointed by and represents the Controlling Shareholder, on the Board of the Company.

Each of the Directors has a duty under the Articles to avoid conflicts of interest with the Company and to disclose the nature and extent of any such interest to the Board. Under the Articles, and as permitted by the 2006 Act, the Board may authorise any matter which would otherwise involve a Director breaching this duty to avoid conflicts of interest and may attach to any such authorisation such conditions and/or restrictions as the Board deem appropriate (including in respect of the receipt of information or restrictions on participation at certain Board meetings), in accordance with the Articles.

Save as set out above, there are no actual or potential conflicts of interest between the duties owed by the Directors, the Senior Managers, or members of any administrative, management or supervisory body of the Company to the Group, and the private interests and/or other duties that they may also have.

9.4 ***Directors and Senior Managers' confirmations***

Save as disclosed below in relation to the class action lawsuits against Idan Wallace, as at the date of this Prospectus, no Director or Senior Manager has during the last five years:

- any convictions in relation to fraudulent offences;
- been associated with any bankruptcy, receivership or liquidation, or any company being put into administration, while acting in the capacity of a member of the administrative, management or supervisory body or as senior manager of any company;
- been subject to any official public incrimination and/or sanctions by any statutory or regulatory authority (including any designated professional bodies); or
- been disqualified by a court from acting as a member of the administrative, management or supervisory bodies of a company or from acting in the management or conduct of the affairs of any company.

There are no family relationships between any of the Directors and/or Senior Managers.

There are no outstanding loans or guarantees granted or provided by any member of the Group for the benefit of any of the Directors, Senior Managers or members of any administrative, management or supervisory body of the Company.

Idan Wallace, a Non-Executive Director and chief executive officer of the Delek Group, is party to a number of class action lawsuits filed with the Tel Aviv District Court. On 16 April 2020, a motion for a certification of a class action was filed against Delek, its board of directors and its present and former chief executive officer, alleging a failure to disclose to investors material information about certain terms under a loan agreement. On 16 April 2020, a separate motion for a certification of a class action was filed against Delek, its board of directors and its present and former chief executive officer, alleging a failure to disclose to investors material information about changes to the scope and terms of certain price hedging transactions made by IEEPL. On 23 April 2020, a claim and motion for its certification as a class action was filed against NewMed Energy, its general partner, the board of directors of such general partner, Delek and the controlling shareholder of Delek. On 18 May 2020, a motion was filed against Delek, its board of directors, its chief executive officer and its chief financial officer, alleging misleading information and non-disclosure of material details about Delek's affairs and finances. The claims remain ongoing. Given the uncertainty of litigation, the preliminary stage of the cases, and the legal standards that must be met for, among other things, class certification and success on the merits, the reasonably possible loss or range of loss that may result from these actions cannot be estimated.

10. DIRECTORS' AND SENIOR MANAGERS' REMUNERATION AND SERVICE AGREEMENTS / LETTERS OF APPOINTMENT

10.1 ***Remuneration Policy***

In anticipation of Admission, the Company undertook a review of the Company's remuneration policy for senior employees, including the Executive Directors, to ensure that it is appropriate for the listed company environment. In undertaking this review, the Remuneration Committee sought independent, specialist advice.

The principal objectives of the policy, which shall apply from Admission, are to attract, retain and motivate the Executive Directors and senior employees, incorporating incentives that align with and support the Group's business strategy as it evolves, and which align executives to the creation of long-term shareholder value.

The Remuneration Committee will oversee the implementation of the Company's remuneration policy and, in particular, will seek to ensure that the Executive Directors are properly rewarded for the Group's performance and the delivery of the Group's strategy.

10.2 ***Executive Directors***

Set out below are summary details of the service agreements of each of the Executive Directors to be entered into on Admission:

10.2.1 Gilad Myerson, Alan Bruce and Iain Lewis will enter into a service agreement with the Company, which is conditional on Admission at which point it would take effect. If Admission does not occur by 30 November 2022, each will revert to their current service agreements with IEUK.

10.2.2 Gilad Myerson will receive a base salary of £500,000 per annum, Alan Bruce will receive a base salary of £400,000 per annum and Iain Lewis will receive a base salary of £300,000 per annum. The base salaries are reviewed annually. There is no obligation to increase the relevant Executive Director's salary following a salary review.

10.2.3 Each Executive Director will be eligible for a discretionary annual bonus payment of up to 150% of his base salary. Further information regarding Executive Director remuneration is set out at paragraph 10.5 (*Bonus Arrangements*) of this Part 20 (*Additional Information*).

10.2.4 The Executive Directors will be eligible to participate in the Company's employee incentive schemes, further details of which are set out in paragraph 11 (*Employee Incentive Schemes*) of this Part 20 (*Additional Information*). Gilad Myerson is also entitled to participate in the Management Equity Plan as further set out in paragraph 11.5 (*Management Equity Plan*) of this Part 20 (*Additional Information*).

10.2.5 Each Executive Director will be entitled to receive an amount of up to 15% of his base salary as a contribution to a pension scheme or an equivalent cash allowance. The Executive Directors may also receive other benefits (for example, the provision of life assurance and private medical insurance) and other market standard benefits.

10.2.6 Each Executive Director will also be entitled to reimbursement of reasonable expenses in accordance with the terms of their service agreement.

10.2.7 Each Executive Director's service agreement will be terminable by the Company or the respective Executive Director on 6 months written notice, or by the Company without notice where (i) they become disqualified from holding or cease to hold office as a director by virtue of any court order, under any provision of general law or under any provision of the Articles or (ii) they lose any approval given to them by any statutory or regulatory authority as a result of which they are no longer able to perform their duties.

10.2.8 The Executive Directors are subject to certain restrictive covenants for a period after termination of their executive service contract. This includes a non-competition covenant which applies for 6 months from the date of termination of the relevant executive service contract and non-solicitation covenants in respect of customers, suppliers and employees which apply for 12 months from the date of termination of the relevant executive service contract. The undertaking not to disclose or use confidential information applies during and after employment.

10.2.9 The Executive Directors are not permitted to be directly or indirectly employed, engaged, concerned or interested, whether as a director, employee, sub-contractor, partner, consultant, proprietor, agent or otherwise, in any other business, undertaking or occupation or the setting up of any other business, undertaking or occupation, or accept any other engagement or public office (other than becoming a (i) "Minority Holder", as defined in their service agreements, provided that they disclose this in writing to the board of the Company) or (ii) as agreed in accordance with the terms of their service agreement. The executive service contracts also contain provisions relating to share dealings.

10.2.10 The Executive Directors have the benefit of a qualifying third party indemnity from the Group (the terms of which are in accordance with the 2006 Act) and appropriate directors' and officers' liability insurance.

10.2.11 The Company is entitled to put the Executive Directors on garden leave during their employment. During such period of garden leave, the Executive Directors will be entitled to receive salary and all contractual benefits.

10.2.12 The Company has the ability to terminate the employment of the Executive Directors with immediate effect by making a payment in lieu of notice which shall consist of base salary only.

10.2.13 The Executive Directors are, in certain circumstances, eligible for an enhanced redundancy pay of up to 52 weeks' pay depending on age and service.

10.2.14 In certain defined and time limited circumstances set out in his service agreement, where his employment is terminated, Alan Bruce is entitled to payment equal to 3 times base annual salary for loss of employment subject to him signing a settlement agreement.

10.2.15 In certain defined and time limited circumstances set out in his service agreement, where his employment is terminated, Iain Lewis is entitled to payment equal to 12 months' base salary for loss of employment subject to him signing a settlement agreement.

10.3 ***Non-Executive Directors***

10.3.1 Idan Wallace entered into a letter of appointment with the Company, which lasts for an initial period of three years and is subject to annual re-election.

10.3.2 Each of the independent Non-Executive Directors has entered into a letter of appointment with the Company which terminates in the event that Admission does not occur by 30 November 2022, and lasts for an initial period of three years and are subject to annual re-election.

10.3.3 The Non-Executive Directors' fees will be set at a level to reflect the amount of time and level of involvement required in order to carry out their duties as members of the Board and its committees, and to attract and retain Non-Executive Directors of the highest calibre with relevant commercial and other experience. The Senior Independent Director, John Mogford, will receive an annual fee of £105,000, this fee is inclusive of membership of any Board committee. Each of Deborah Gudgeon, David Blackwood and Lynne Clow will receive an annual fee of £95,000, this fee is inclusive of membership of any Board committee. Assaf Ginzburg will receive an annual fee of £75,000, this fee is inclusive of membership of any Board committee. Idan Wallace, is not initially entitled to receive an annual fee in connection with his appointment pursuant to the terms of the Relationship Agreement as set out in further detail of paragraph 14.2 (*Relationship Agreement*) of this Part 20 (*Additional Information*).

10.3.4 The fees paid to the Senior Independent Director are determined by the Remuneration Committee and the fees of the other Non-Executive Directors are determined by the Board. No Board member may participate in the approval of their own fees.

10.3.5 Each independent Non-Executive Director was due fees from the Company as a result of services undertaken in connection with Admission of an amount equal to £100,000 in respect of the Senior Independent Director and £50,000 in respect of each of the other independent Non-Executive Directors (each being the "**INED IPO Fees**"). Each independent Non-Executive Director signed up to a share subscription agreement on 8 November 2022 for the respective number of shares as set out against their name in paragraph 9.2 (*Interests in the ordinary share capital of the Company*) of this Part 20 (*Additional Information*) with payment for their Ordinary Shares in each case being satisfied by the individual independent Non-Executive Director's release of the liability of the Company to pay them their INED IPO Fees. The Non-Executive Directors will not otherwise be eligible to participate in any of the Company's incentive arrangements and do not receive pension contributions. The Non-Executive Directors are entitled to reimbursement of reasonable and properly incurred expenses (including travel expenses). The Non-Executive Directors will not be entitled to receive any compensation on termination of their appointment.

10.3.6 The Non-Executive Directors will have the benefit of a qualifying third-party indemnity from the Company (the terms of which are in accordance with the 2006 Act) and appropriate directors' and officers' liability insurance.

10.3.7 The appointment of any non-independent Non-Executive Directors is terminable in accordance with the relevant Relationship Agreement. Please refer to paragraph 14.2 (*Relationship Agreement*) of this Part 20 (*Additional Information*).

Save as set out in this paragraph 10 (*Directors' and Senior Managers' Remuneration and Service Agreements/Letters of Appointment*) of this Part 20 (*Additional Information*) (and in the case of one Senior Manager, redundancy and enhanced early retirement benefits connected with a defined benefit pension arrangement), no benefits are payable by any member of the Group to any Director and Senior Manager upon termination of employment.

10.4 ***Directors' and Senior Managers' remuneration***

In the financial year ended 31 December 2021, the aggregate remuneration paid ((including any contingent or deferred compensation) and benefits in kind granted by the Company and its Subsidiaries for services in all capacities to the Company and its Subsidiaries) to the Directors and Senior Managers was approximately £2.6 million, of which approximately £1.3 million comprised salaries/fees, approximately £1 million comprised bonuses, £61,200 comprised car and lunch allowances, approximately £138,500 comprised pension contributions and cash in lieu of pension allowance and £4,530 comprised healthcare benefits.

Set out in the table below is the remuneration paid and benefits in kind granted to the Directors and Senior Managers in the year ended 31 December 2021. The Directors and Senior Managers are categorised in their positions as at the date of this Prospectus for these purposes.

Name	Position	Annual Remuneration Salary (£)	Annual Remuneration Bonus (£)(2)	Other Benefits (£)	Date of joining the Group
Gilad Myerson	Chairman	337,500(1)	763,359	10,200	19 April 2021
Alan Bruce	CEO	113,846(1)	102,500	10,200	16 August 2021
Iain Lewis	CFO	n/a	n/a	n/a	25 July 2022
John Horsburgh	General Manager, Subsurface and Wells	235,100	58,775	10,200	12 May 2008
Julie McAteer	General Counsel and General Manager Business Affairs	190,000	59,375	10,200	24 February 2020
Rachel Stanley	General Manager NOJV, Energy Transition, Technology and Innovation	193,550	36,290	10,200	14 October 1996
Brian Winton	General Manager Operations, Projects and Decommissioning	180,000	45,000	10,200	1 January 2021
Craig Matthew	General Manager, Greenfield Projects	66,349(1)	5,000	n/a	16 August 2021

(1) Denotes pro rata entitlement for the financial year.

(2) The figures in this column reflect bonuses for performance in the year ended 31 December 2021 but which were not paid until March 2022. Bonuses in respect of performance during the financial year ended 31 December 2020 were paid to certain directors and senior managers in the financial year ended 31 December 2021. Given these relate to the financial year ended 31 December 2020, these have not been reflected in this table.

Due to the current structure of the Company's pension arrangements, neither the Company nor any of its Subsidiaries set aside or accrue amounts to provide for pension, retirement or similar benefits of the Directors and Senior Managers. The Company's group personal pension plan is a collection of individual pension plans where each member enters into an individual contract with the pension provider in their own name.

10.5 ***Bonus arrangements***

The Executive Directors and other senior employees are eligible to participate in the Ithaca Energy annual bonus plan. Following Admission, the maximum annual bonus opportunity for

Executive Directors will be 150% of base salary. The annual bonus will be based on stretching financial, strategic and operational targets.

Half of any bonus earned will be subject to bonus deferral. Any bonus subject to deferral will be deferred into an award over Ordinary Shares in accordance with the Ithaca Energy Deferred Share Bonus Plan (summarised at paragraph 11.2 (*Ithaca Energy Deferred Bonus Plan*) of this Part 20 (*Additional Information*) below).

The existing FY2022 annual bonus will continue to operate for the remainder of the year and will be payable in cash following the year end. The current bonus ordinarily has a maximum annual bonus opportunity for the Executive Directors of 50% of salary and is subject to the achievement of a scorecard of measures.

Separately, at Admission, approximately 30 employees (including the Executive Directors) will be awarded a discretionary cash bonus of up to £50,000 each to recognise their exceptional contribution to Admission. Several individuals, none of whom is an Executive Director, are contractually entitled to bonuses in excess of £50,000 each in connection with Admission. In each case these bonuses will not be subject to any further conditions or deferral requirements and will be payable at or following Admission. The total bonus pot available for distribution in connection with such bonuses is approximately £2,300,000.

Additionally, Mr Myerson is entitled to receive a one-off payment for the accounting period ending 30 September 2022, in the amount of $1 million. The payment is due to be paid on 1 April 2023.

The Remuneration Committee will have the discretion to adjust bonus outcomes (including to zero) if it believes that the outcome is not a fair and accurate reflection of business performance. The exercise of this discretion may result in a downward or upward adjustment in the amount of bonus that would otherwise be earned by reference to the applicable bonus targets.

10.6 ***Additional success based compensation***

Pursuant to arrangements agreed with IEEPL on 15 July 2021, Mr Myerson is also entitled to separate additional success based compensation linked to the outcome of the arbitration proceedings raised by IEUK, further details of which are set out in paragraph 17 *(Legal and Arbitration Proceedings*) of this Part 20 (*Additional Information*). In the event that IEUK is successful in the proceedings, either by way of commercial settlement or arbitral award by the arbitration tribunal, Mr Myerson shall be entitled to up to 1.8% of the net proceeds received by IEUK provided at the date of payment he remains employed by the Group and no notice to terminate his employment has been served. The outcome of the claim is uncertain at this stage and the quantum of any proceeds sought by IEUK is subject to expert evidence that is yet to be finalised. As such it is not possible to quantify the amount of any potential success based compensation and consequently it is not possible to quantify the amount of Mr Myerson's potential related additional compensation, although it is IEUK's reasonable expectation that, if it is successful in the proceedings, the level of damages recovered by IEUK will be material and accordingly Mr Myerson's additional compensation could be significant. Further details of the proceedings are set out in paragraph 17 (*Legal and Arbitration Proceedings)* of this Part 20 (*Additional Information*). Mr Wallace, the CEO of the Delek Group and a Non-Executive Director in the Company, is entitled to a payment of up 1% of the net proceeds received by IEUK in respect of the same arbitration proceedings on the same terms as Mr Myerson's additional compensation. Further details of the arrangements for Mr Wallace are set out in paragraph 18 (*Related Third Party* Transactions) of this Part 20 (*Additional Information*).

11. **EMPLOYEE INCENTIVE SCHEMES**

The Group has adopted three employee share schemes immediately prior to Admission: (i) the Ithaca Energy Long Term Incentive Plan; (ii) the Ithaca Energy Deferred Share Bonus Plan; and (iii) a Share Incentive Plan. The Group has also adopted a further employee share scheme—the Management Equity Plan—prior to Admission, and in respect of which awards of Ordinary Shares will continue to vest for a period after Admission. The principal features of each of the employee share schemes are summarised below.

11.1 ***Ithaca Energy Long Term Incentive Plan***

General

The Ithaca Energy Long Term Incentive Plan (the "**LTIP**") will enable Executive Directors and selected employees of the Group to be granted awards over Ordinary Shares ("**LTIP Awards**"). The LTIP has been designed to align with prevailing best practice and the terms of the Directors' Remuneration Policy which is summarised at paragraph 10.1 (*Remuneration Policy*) of this Part 20 (*Additional Information*).

The operation of the LTIP will be overseen by the Remuneration Committee, which consists entirely of non-executive directors.

Eligibility

The LTIP rules provide that all employees of the Group (including Executive Directors) are eligible to participate at the discretion of the Remuneration Committee.

However, for so long as any Ordinary Shares held by Gilad Myerson under the Management Equity Plan (described at paragraph 11.5 (*Management Equity Plan*) of this Part 20 (*Additional Information*) below) remain unvested in accordance with its terms, Mr Myerson shall not be eligible to participate in the LTIP.

Individual Limits

The maximum number of Ordinary Shares that may be awarded to a participant in the form of LTIP Awards (other than the At-IPO Awards, as defined below) in any financial year will be limited so that the market value of such Ordinary Shares on the grant date will not exceed 225% of the participant's base salary or any higher limit that is specified under the Company's prevailing shareholder-approved Directors' Remuneration Policy in force at the time that the relevant LTIP Award is granted.

Market value for the purposes of the above limit shall generally be taken to be either the market value of Ordinary Shares on the dealing day immediately preceding the date on which the LTIP Award is granted or by reference to a short averaging period, or on such other reasonable basis as the Remuneration Committee decides.

Vesting of LTIP Awards and Performance Conditions

LTIP Awards may be subject to stretching performance conditions which will determine the extent to which such LTIP Awards shall be capable of vesting ("**Performance Awards**"). Alternatively, LTIP Awards may be granted which are not subject to performance conditions and which vest solely on the basis of the participant's continued employment with the Group ("**Restricted Share Awards**"). Restricted Share Awards may not be granted to Executive Directors.

Performance Awards will not ordinarily be capable of vesting until the third anniversary of their grant date, except in exceptional circumstances such as corporate events (see further below).

Post-vesting holding period

Executive Directors (and such other participants as the Remuneration Committee determines) shall be required to retain any vested Ordinary Shares acquired under the LTIP until the fifth anniversary of the grant date of the relevant LTIP Award.

In exceptional circumstances, the Remuneration Committee may allow a participant who is subject to the post-vesting holding period to sell, transfer, assign or dispose of some or all of those Ordinary Shares prior to the end of the post-vesting holding period.

Initial Awards

The Company intends to grant an initial set of LTIP Awards to senior employees (excluding Mr Myerson and Mr Bruce) shortly following Admission (the "**At-IPO Awards**"). The At-IPO Awards are intended to recognise effort and performance up to Admission, to provide an incentive and retention mechanism for recipients and also to settle certain obligations of Ithaca Energy under legacy incentive arrangements offered prior to Admission.

The At-IPO Awards will be granted in the form of a Restricted Share Award and will not be subject to any performance conditions. The At-IPO Awards will generally vest in three equal instalments on the first, second and third anniversaries of the date of Admission respectively. The At-IPO Awards will be granted over Ordinary Shares having a market value (determined by reference to the Offer Price) equal to a specified percentage of the participant's base salary, with the percentage depending on the individual's employment grade (and ranging from 50% to 300% of base salary).

Additionally, the Company intends to grant a set of LTIP Awards to senior employees (including the Executive Directors other than Mr Myerson) shortly following Admission (the "**Initial LTIP Awards**"). The Initial LTIP Awards will be granted in the form of either Performance Awards or Restricted Share Awards. Executive Directors receiving Initial LTIP Awards will be granted Performance Awards. The Initial LTIP Awards will ordinarily vest following the later of the end of the applicable performance period (in the case of the Initial LTIP Awards which are granted as Performance Awards) and the third anniversary of the grant date of the Initial LTIP Awards, and in the case of the Initial LTIP Awards which are granted as Performance Awards, the performance measures for the Initial LTIP Awards will be as follows:

- 50% Relative TSR—the Company's TSR to be assessed against a comparator group of companies over the period from 1 December 2022 to 31 December 2025. 25% of the shares vest for achieving Median ranking, rising on a straight-line basis to full vesting for achieving an Upper Quartile ranking.
- 50% a balanced score card of company performance measures—these shall comprise safety & environmental measures, operational measures, growth measures (by reference to total reserves replacement (organic and inorganic)) and financial measures (by reference to unit operating cost).

The Initial LTIP Awards will be granted over Ordinary Shares having a market value (determined by reference to the Offer Price) equal to a specified percentage of the participant's base salary, with the percentage depending on the individual's employment grade (and ranging from 75% to 225% of base salary). For the Executive Directors (other than Mr Myerson), the Initial LTIP Awards will be granted over Ordinary Shares having a market value equal to 225% and 200% of salary for the Chief Executive Officer and Chief Financial Officer respectively.

Performance Awards

Performance conditions applicable to Performance Awards granted after Admission will be kept under review and may be varied in the future years, but may include a combination of financial, value creation, operational or strategic measures.

Details of the performance conditions applicable to LTIP Awards granted to Executive Directors will be fully disclosed in the Company's Annual Report and Accounts which are prepared for the year in which the relevant LTIP Awards were granted and will at all times be subject to the Company's prevailing shareholder-approved Directors' Remuneration Policy.

The Remuneration Committee may vary the performance conditions applying to existing Performance Awards if an event has occurred which causes the Remuneration Committee reasonably to consider that it would be appropriate to amend the performance conditions, provided the Remuneration Committee considers the varied performance conditions are a fairer measure of performance and provide a more effective incentive for the participant and will not be materially less difficult to satisfy than the original conditions would have been but for the event in question.

Adjustment of vesting outcome of LTIP Awards

Other than the At-IPO Awards, the Remuneration Committee retains discretion to adjust the extent of vesting of any LTIP Award that would otherwise result under the LTIP rules. In the case of Performance Awards, such adjustment may be irrespective of the extent to which any performance condition applicable to that Performance Award has been met.

Such discretion would only be used where the Remuneration Committee considers that the extent of vesting but for any adjustment would not produce an appropriate vesting outcome for the relevant participant or the Group, taking into account overall performance of the Group or the participant, or because the vesting outcome is inappropriate in the context of circumstances that were unexpected or unforeseen at the start of the applicable performance period.

Cessation of Employment

If a participant ceases to be employed within the Group, their LTIP Award(s) will normally lapse on the date of termination of employment.

However, if a participant ceases to be employed with the Group due to their: (i) death; (ii) ill-health or disability; (iii) the sale of the Group member or business unit which is the participant's employer company or business unit for which they work out of the Group; or (iv) in any other circumstances at the Remuneration Committee's discretion, then the participant will be treated as a "good leaver", in which case their LTIP Award(s) shall vest subject to:

- in the case of Performance Awards, the extent to which the performance conditions applicable to the Performance Award(s) have, in the opinion of the Remuneration Committee, been satisfied over the original performance period; and
- in the case of all LTIP Awards, a time pro-rata apportionment of the number of Ordinary Shares under the LTIP Award(s) by reference to the length of time between the grant date of the relevant LTIP Award and the date of cessation of the participant's employment, relative to the full length of the original vesting period.

LTIP Awards held by good leavers will normally vest on their normal vesting timetable. Exceptionally and at the Remuneration Committee's discretion, LTIP Awards held by good leavers may vest sooner following the date of the participant's cessation of employment.

In a good leaver scenario, the Remuneration Committee will retain discretion to vary the application of time pro-rating and increase the number of Ordinary Shares which vest (although, in the case of a Performance Award, this may not result in the number of Ordinary Shares which vest being higher than the number of Ordinary Shares which may vest by reference to application of the performance conditions).

Takeover, Reconstruction etc.

In the event of: (i) a takeover of the Company; (ii) a scheme of arrangement (not being an internal corporate re-organisation); (iii) a winding-up of the Company; or (iv) a delisting; or (v) (at the discretion of the Remuneration Committee) other events including a demerger, unvested LTIP Awards shall vest immediately subject to:

- in the case of Performance Awards, the Remuneration Committee's assessment of the extent to which the performance conditions applicable to the LTIP Awards have been met at the date of the relevant corporate event or (at the Remuneration Committee's discretion) the extent to which such performance conditions would, in the opinion of the Remuneration Committee, have been satisfied over the original performance period; and
- in the case of all LTIP Awards, a time pro-rata apportionment of the number of Ordinary Shares under the LTIP Award by reference to the length of time between the grant date of the relevant LTIP Award and the date of the corporate event, relative to the full length of the original vesting period.

Where there is a takeover or other corporate event, the Remuneration Committee will retain discretion to vary the application of time pro-rating and increase the number of Ordinary Shares which vest (although, in the case of a Performance Award, this may not result in the number of Ordinary Shares which vest being higher than the number of Ordinary Shares which may vest by reference to application of the performance conditions).

Alternatively, on the occurrence of a takeover or a scheme or arrangement, the Remuneration Committee may specify that LTIP Awards shall not vest on the occurrence of such event and instead participants shall be required to 'roll-over' their awards into equivalent new awards over shares in a new holding company.

LTIP Awards will be automatically ‘rolled-over’ on the occurrence of an internal reorganisation.

11.2 ***Ithaca Energy Deferred Bonus Plan***

General

The Ithaca Energy Deferred Share Bonus Plan (the “**DSBP**”) is intended to facilitate the deferral of a portion of any annual bonus which is paid to selected employees of the Group into awards over Ordinary Shares (“**DSBP Awards**”). The DSBP has been designed to align with prevailing best practice and the terms of the Directors’ Remuneration Policy which is summarised at paragraph 10.1 (*Remuneration Policy*) of this Part 20 (*Additional Information)*.

The operation of the DSBP will be overseen by the Remuneration Committee, which consists entirely of non-executive directors.

Eligibility

All employees of the Group are eligible to participate in the DSBP and receive DSBP Awards at the discretion of the Remuneration Committee.

The DSBP will primarily be operated to defer the bonuses of Executive Directors. However, the Remuneration Committee may select other employees of the Group to participate in the DSBP at its discretion.

Size of DSBP Awards

DSBP Awards shall be granted over such number of Ordinary Shares as have a market value equal to the value of the portion of the employee’s bonus that the Remuneration Committee has determined is required to be deferred into a DSBP Award.

In the case of Executive Directors, the proportion of their annual bonus which is required to be deferred into a DSBP Award shall be not less than the amount specified in the Company’s prevailing shareholder-approved Directors’ Remuneration Policy in force at the time that the DSBP Award is granted. The Remuneration Committee retains discretion to specify that a higher proportion (including up to 100%) of an Executive Director’s annual bonus shall be required to be deferred into a DSBP Award at its discretion.

Market value for the purposes of the above limit shall generally be taken to be either the market value of Ordinary Shares on the dealing day immediately preceding the date on which the DSBP Award is granted or by reference to a short averaging period, or on such other reasonable basis as the Remuneration Committee decides.

Vesting of DSBP Awards

DSBP Awards granted to Executive Directors will not ordinarily be capable of vesting until the third anniversary of their grant date, except in exceptional circumstances such as corporate events. Shorter vesting periods may apply to DSBP Awards granted to employees who are not Executive Directors.

The vesting of DSBP Awards will not ordinarily be subject to the achievement of any performance conditions.

Leaving employment

If a participant ceases to be employed within the Group due to their dismissal for cause or their voluntary resignation, their DSBP Awards will normally lapse on the date of termination of employment.

If a participant ceases to be employed with the Group for any reason other than their dismissal for cause or their voluntary resignation, their DSBP Award will remain capable of vesting in full on its normal vesting timetable unless the Remuneration Committee determines that any such DSBP Awards held by good leavers shall vest at an earlier date (although it is anticipated that the Remuneration Committee would not ordinarily permit early exercise of DSBP Awards by good leavers).

Corporate events

In the event of: (i) a takeover of the Company; (ii) a scheme of arrangement (not being an internal corporate re-organisation); (iii) a winding-up of the Company; or (iv) (at the discretion of the Remuneration Committee) a demerger, unvested DSBP Awards shall vest immediately and in full.

Alternatively, on the occurrence of a takeover or a scheme or arrangement, the Remuneration Committee may specify that DSBP Awards shall not vest on the occurrence of such event and instead participants shall be required to 'roll-over' their awards into equivalent new awards over shares in a new holding company.

DSBP Awards will be automatically 'rolled-over' on the occurrence of an internal reorganisation.

11.3 ***Terms common to the LTIP and DSBP***

In this paragraph 11.3 (*Terms common to the LTIP and DSBP*), references to "Awards" are to both LTIP Awards and DSBP Awards unless otherwise stated.

Grants of Awards

Awards may be granted:

- in the period of six weeks following Admission;
- in the period of six weeks commencing on the dealing day following the announcement by the Company of its results for any period;
- in the case of the LTIP, within six weeks of a person commencing employment with the Group;
- in the case of the DSBP, as soon as reasonably practicable following the determination of the relevant employee's bonus for any period; and
- subject to any relevant restrictions on dealings in Ordinary Shares, on any other day on which the Remuneration Committee determines that exceptional circumstances exist that justify the grant of an Award.

If regulatory or statutory restrictions prevent Awards from being granted in these periods, Awards may be made in the period immediately after the removal of all such restrictions.

No Awards may be granted under either the LTIP or the DSBP more than 10 years after the date of Admission.

Structure of Awards

Awards may be structured as: (i) conditional awards of Ordinary Shares; or (ii) as nil-cost or nominal-cost options to acquire Ordinary Shares.

The Remuneration Committee may also grant cash-based awards of an equivalent value to share-based awards, or settle share-based awards with cash, although the Remuneration Committee does not currently intend to do so.

Exercise periods (applicable only to options)

Where Awards are granted in the form of options to acquire Ordinary Shares, once vested such options will remain exercisable up until the tenth anniversary of their grant date (or such shorter period that the Remuneration Committee specifies on grant).

Shorter exercise periods apply in the case of Awards held by "good leavers" and/or vesting of Awards in connection with corporate events.

Dilution limits

Awards granted under either the LTIP or the DSBP may be satisfied by the issue of new Ordinary Shares, Ordinary Shares purchased in the market by an employee benefit trust or Ordinary Shares transferred from treasury.

No Award may be granted under either the LTIP or the DSBP if it would cause the number of new Ordinary Shares issued or issuable pursuant to awards and options granted in any rolling 10 year period starting on Admission under any Group share plan (including the LTIP, DSBP and the SIP) to exceed 10% of the Company's issued ordinary share capital at the proposed date of grant.

A similar 5% in 10 years limit applies to awards granted under the Company's discretionary share plans (which would include the LTIP and the DSBP).

For the avoidance of doubt, the At-IPO Awards and the Initial LTIP Awards do not count towards these dilution limits.

As is typical, if Awards are specified as being capable of being satisfied by a transfer of existing Ordinary Shares only (including Ordinary Shares held by or purchased by the Company's employees' share trust), the percentage limits stated above will not apply.

For so long as it is required by institutional investor guidelines, these dilution limits will also apply to Awards satisfied by the transfer of Ordinary Shares from treasury.

Dividend equivalent payments

The Remuneration Committee may determine that a participant is entitled to receive a payment (in cash or shares) when they receive their vested Ordinary Shares of an amount equivalent to any dividends that would have been payable in relation to the vested Ordinary Shares between the date of grant and the vesting date of the Award (or if later, and only whilst an Award which is structured as an option remains unexercised, the expiry of any post-vesting holding period).

Any dividend equivalent payment may exclude the amount of any special dividends or other dividends and/or may assume re-investment of dividends in further Ordinary Shares, in each case at the discretion of the Remuneration Committee.

Post-cessation holding period

Executive Directors (and such other participants as the Remuneration Committee determines) will ordinarily be required to retain a number of Ordinary Shares that vest in connection with any Award until the second anniversary of the date of their cessation of employment with the Group. The number of Ordinary Shares that are required to be retained shall be determined by the Remuneration Committee at the time that the Award vests. The details of the post-cessation holding period, including the specified number or value of Ordinary Shares that an individual is required to retain post-cessation of their employment, will be set out in the Directors' Remuneration Policy.

Exceptionally, the Remuneration Committee may allow participants who are subject to the post-cessation holding period to sell, transfer, assign or dispose of some or all of those Ordinary Shares prior to the end of the post-cessation holding period, subject to such additional terms and conditions as the Remuneration Committee specifies.

Malus and Clawback

The Remuneration Committee may apply the malus and clawback provisions, at any point prior to the third anniversary of the date on which an Award vests, if:

- it is discovered that there has been a material misstatement of the Group's financial results for any period;
- it is discovered that an error of calculation has occurred when assessing the performance conditions;
- the participant has committed fraud or misconduct;
- the behaviour of the participant materially fails to reflect the governance or values of the Company or has caused injury to the reputation of the Group; and/or
- the Company has suffered an instance of material corporate failure.

Any application of malus and clawback may be satisfied by way of a reduction in the amount of any future bonus, subsisting award or future share awards (whether granted under the LTIP, DSBP or any other discretionary share plan adopted by any Group member) and/or a requirement to make a cash payment.

Variations of share capital

If there is: (i) a capitalisation or rights issue; (ii) a sub-division, consolidation or reduction of the Company's ordinary share capital; (iii) a de-merger or payment of a special dividend; or (iv) any variation of the Company's share capital that may (in the opinion of the Remuneration Committee) affect the value of the Company's shares, then the Remuneration Committee may (at its discretion) adjust the number of Ordinary Shares subject to Awards.

Amendments

The Remuneration Committee may amend the LTIP and the DSBP at any time at its discretion.

However, the provisions governing: (i) eligibility requirements; (ii) equity dilution; (iii) individual limits on participation; (iv) the basis for determining participants' rights to acquire shares; and (v) the adjustments that may be made following a rights issue or any other variation of capital, cannot be altered to the advantage of participants without the prior approval of the Company's shareholders in general meeting.

There is an exception for minor amendments to benefit the administration of the LTIP or the DSBP, to take account of a change in legislation affecting the LTIP or the DSBP (as applicable) or to obtain or maintain favourable tax, exchange control or regulatory treatment for participants in the LTIP or DSBP or for any member of the Group.

Rights attaching to shares

Awards which are structured as conditional awards over Ordinary Shares or as options over Ordinary Shares will not confer any shareholder rights, such as the right to vote the Ordinary Shares or to receive any dividend, until a participant has received the Ordinary Shares after vesting or exercise (as applicable).

Ordinary Shares allotted or transferred under the LTIP or the DSBP will rank alongside shares of the same class then in issue.

Miscellaneous

Awards are not transferable (except on death). Benefits received under the LTIP or DSBP are not pensionable benefits.

No payment shall be required for the grant of an Award.

The Remuneration Committee may adopt schedules to, or establish further plans based on, the LTIP and/or the DSBP but which are modified to take account of local tax, exchange control or securities laws in any territory, provided that such further plans are materially similar to the LTIP or DSBP (as applicable) and that any Ordinary Shares made available under such further plans are treated as counting against the limits on individual or overall participation in the LTIP or DSBP (as applicable).

11.4 ***Share Incentive Plan***

General

The Ithaca Energy Share Incentive Plan (the "**SIP**") complies with and will be operated within the requirements of Schedule 2 to the Income Tax (Earnings and Pensions) Act 2003 ("**Schedule 2**") so that the SIP qualifies as a Schedule 2 Share Incentive Plan under the governing legislation.

Types of awards

The SIP comprises the following three elements and the Directors may decide which element (or elements) to offer to eligible employees:

- "***Free Shares***", which are Ordinary Shares which may be allocated to an eligible employee for free.

The maximum market value of Free Shares that may be allocated to any eligible employee in any tax year is £3,600 (or such other limit as may be permitted under Schedule 2).

Free Shares may be allocated to eligible employees equally or on the basis of performance, as permitted by Schedule 2.

- "***Partnership Shares***", which are Ordinary Shares that an eligible employee may purchase out of their pre-tax earnings.

  The market value of Partnership Shares that may be acquired by an eligible employee in any tax year may not exceed £1,800 (or 10% of the eligible employee's salary, if lower), or such other limit as may be permitted by Schedule 2.

- "***Matching Shares***", which are Ordinary Shares which may be allocated for free to an eligible employee who elects to purchase Partnership Shares.

  The Directors may allocate Matching Shares to an eligible employee who purchases Partnership Shares at a ratio of up to two Matching Shares for every one Partnership Share (or such other maximum ratio as may be permitted by Schedule 2).

Eligibility

Any UK-based employee (including any UK-based Executive Director) of the Company or any other participating subsidiary of the Company who has been employed for a qualifying period of such length as the Directors may determine from time to time (but not exceeding 18 months) is eligible to participate in the SIP.

All eligible employees must be invited to participate.

Retention of Shares

Free Shares and Matching Shares will be held by the trustee of the SIP trust ("**Trustee**") on behalf of the participants.

Ordinarily, any Free Shares and Matching Shares must be held by the Trustee for a period of between three and five years after the date that those Free Shares and/or Matching Shares are awarded.

Partnership Shares will be acquired and held by the Trustee on behalf of participants, using the funds contributed by the relevant participant by way of pre-tax salary deductions. Partnership Shares can be withdrawn from the SIP trust at any time.

Leaving employment

The Directors may determine that any Free Shares and/or Matching Shares will be forfeited if a participant ceases to be employed by the Group within three years (or such lesser period as the Directors may determine) from the award of those Free Shares and/or Matching Shares, unless the participant leaves by reason of death, injury, disability, redundancy, retirement, a transfer to which the Transfer of Undertakings (Protection of Employment) Regulations 2006 would apply or if the participant's employer company ceases to be an "associated company" of the Company. In any of those cases, the participant will be required to withdraw their Shares from the SIP trust.

If an employee ceases to be employed by the Group at any time after acquiring Partnership Shares, the employee will be required to withdraw the Partnership Shares from the SIP trust.

Corporate events

In the event of a general offer being made to Shareholders, participants may be able to direct the Trustee how to act in relation to their Ordinary Shares.

In the event of a corporate reorganisation, any Ordinary Shares held by participants may be replaced by equivalent shares in a new holding company.

In the case of a variation of share capital of the Company, Ordinary Shares held in the SIP will be treated in the same way as other Ordinary Shares. In the event of a rights issue, participants may be able to direct the Trustee how to act on their behalf.

Dividends on Ordinary Shares held by the Trustee

Any dividends paid on Ordinary Shares held by the Trustee on behalf of participants may be either distributed to participants or used to acquire additional Ordinary Shares for employees.

If any dividends are used to acquire additional Ordinary Shares, any such additional Ordinary Shares will be held by the Trustee on behalf of the participants on the same basis as the underlying Ordinary Shares on which the dividends were paid.

Rights attaching to Ordinary Shares acquired under the SIP

An employee will be treated as the beneficial owner of Ordinary Shares held on their behalf by the Trustee.

Non-transferability of awards

Grants of Free Shares and Matching Shares are not transferable other than to the participant's personal representatives in the event of their death.

Benefits received under the SIP will not be pensionable.

Satisfaction of awards and dilution limits

Awards of Ordinary Shares in connection with the SIP may be satisfied by the issue of new Ordinary Shares, Ordinary Shares purchased in the market by the SIP trust or Ordinary Shares transferred from treasury.

No award of Ordinary Shares may be made under the SIP if it would cause the number of new Ordinary Shares issued or issuable pursuant to awards and options granted in any rolling 10 year period starting on Admission under any Group share plan (including the LTIP, DSBP and the SIP) to exceed 10% of the Company's issued ordinary share capital at the proposed date of award.

For the avoidance of doubt, the At-IPO Awards and the Initial LTIP Awards (granted under the LTIP) do not count towards these dilution limits.

As is typical, if awards of Ordinary Shares are specified as being capable of being satisfied by a transfer of existing Ordinary Shares only (including Ordinary Shares held by or purchased by the Company's employees' share trust), the percentage limit stated will not apply.

For so long as it is required by institutional investor guidelines, these dilution limits will also apply to awards of Ordinary Shares which are satisfied by the transfer of Ordinary Shares from treasury.

Amendment

The Directors may amend the SIP at any time at their discretion.

However, the provisions governing: (i) eligibility requirements; (ii) equity dilution; (iii) individual limits on participation; (iv) the basis for determining participants' rights to acquire shares; and (v) the adjustments that may be made following a rights issue or any other variation of capital, cannot be altered to the advantage of participants without the prior approval of the Company's shareholders in general meeting.

There is an exception for minor amendments to benefit the administration of the SIP, to take account of a change in the requirements of Schedule 2 or any other legislation affecting the SIP or to obtain or maintain favourable tax, exchange control or regulatory treatment for participants in the SIP or for any member of the Group.

International schedules and sub-plans

The Directors may adopt schedules to, or establish further plans based on, the SIP but which are modified to take account of local tax, exchange control or securities laws in any territory, provided that such further plans are materially similar to the SIP and that any Ordinary Shares made available under such further plans are treated as counting against the limits on individual or overall participation in the SIP.

11.5 ***Management Equity Plan***

Pursuant to arrangements entered into prior to Admission, Ithaca Energy has established a management equity plan for the benefit of Gilad Myerson (the "**MEP**").

The principal purpose of the MEP is to incentivise and align Mr Myerson's interests with those of the Company's shareholders in the realisation of maximum shareholder value following Admission. The MEP is structured such that Mr Myerson is entitled to receive shares in the Company which, on Admission, have a value which is equal to 1.3% of the market value of the Company above a fixed hurdle of $2.5 billion (the "**Hurdle**"). When Mr Myerson joined Ithaca Energy the market value was substantially lower than $2.5 billion, and the MEP is intended to create a structural incentive for Mr Myerson to maximise the value of the share capital of the Company.

Under the MEP, Mr Myerson subscribed for two separate classes of shares (B1 Ordinary Shares and B2 Ordinary Shares) in the Company and which carried limited rights (e.g., no voting rights, and limited rights to transfer the shares).

Immediately prior to Admission, the B1 Ordinary Shares and B2 Ordinary Shares were converted into, respectively, 1,401,758 and 420,528 Ordinary Shares (the "**MEP Shares**"), being such number of Ordinary Shares as have a value (by reference to the Offer Price) equal to, respectively, 1% and 0.3% of the market value of the Company on Admission minus the Hurdle.

The MEP Shares will 'vest' over a five year period starting from 1 October 2021 as follows:

- the B1 Ordinary Shares (or any Ordinary Shares received in respect of those B1 Ordinary Shares): 15% on 1 October 2022, a further 15% on 1 October 2023, a further 15% on 1 October 2024, a further 15% on 1 October 2025, and the remaining 40% on 1 October 2026.
- the B2 Ordinary Shares (or any Ordinary Shares received in respect of those B2 Ordinary Shares): 45% on 1 October 2024, a further 15% on 1 October 2025, and the remaining 40% on 1 October 2026.

Accordingly, from 1 October 2026 the MEP Shares will be fully vested. Whilst any of the MEP Shares remain unvested, Mr Myerson shall not be eligible to participate in, and receive grants of awards under, the Ithaca Energy Long Term Incentive Plan (as described at paragraph 11.1 (*Ithaca Energy Long Term Incentive Plan*) of this Part 20 (*Additional Information*)).

On each vesting date, Mr Myerson may receive further Ordinary Shares so as to ensure that the aggregate value of the MEP Shares is maintained at 1.3% of the value of the Company above the Hurdle.

Whilst the MEP Shares are unvested, they will be held in a nominee account on Mr Myerson's behalf and may not be transferred or sold out of the nominee account (other than with the consent of the Company).

A loan facility of up to $500,000 was provided by IEUK to cover income tax and National Insurance contributions that arose on the share subscription.

The MEP Shares acquired will remain subject to forfeiture provisions in a leaver scenario. If Mr Myerson leaves as a 'Bad Leaver', all of the MEP Shares held by him (whether vested or unvested) shall be subject to compulsory transfer for nominal payment. Mr Myerson will be a 'Bad Leaver' if: (1) his employment is terminated at any time due to fraud, gross misconduct or conviction of a criminal offence; or (2) if Mr Myerson resigns voluntarily at any time prior to 1 September 2023.

If Mr Myerson leaves as a 'Good Leaver' (being any reason other than as a 'Bad Leaver'), any unvested MEP Shares shall be subject to compulsory transfer for nominal payment. However, Mr Myerson shall be entitled to retain any MEP Shares which have vested. For the purposes of determining the number of MEP Shares have vested in a 'Good Leaver' scenario, an accelerated vesting schedule shall apply being 40% of the MEP Shares originally represented by the B1 Ordinary Shares only where cessation occurs prior to 1 October 2024, thereafter increasing to 60%, 80% and 100% of all of the MEP Shares on each anniversary of 1 October 2024.

In certain circumstances where Mr Myerson's employment with the Group ceases as a result of any involvement from an activist minority shareholder, then Mr Myerson shall be entitled to retain any of the MEP Shares which have vested as at the termination date and, additionally, a further 50% of the unvested MEP Shares as at the termination date.

In certain circumstances, such as change of control of the Company, material disposal or termination of employment before 1 October 2023, Mr Myerson shall, in lieu of all of his MEP shares, be entitled to receive (or, in certain circumstances, may elect to receive) a one-time payment of up to $9 million minus any bonuses received after 29 September 2022 (including the one-off payment described below). This payment will be subject to deductions for income tax and National Insurance contributions. This payment is in lieu of all the MEP Shares, which must be transferred by Mr Myerson for nil payment, and is intended to operate as a floor on the value that Mr Myerson may receive in recognition of his contribution to value creation from 2019 onwards and the incentive arrangements forfeited by him on commencing employment with the Group.

As part of the overall terms of the MEP, Mr Myerson is entitled to receive a one-off payment for the accounting period ending 30 September 2022 (as described in paragraph 10.5 (*Bonus Arrangements*) of this Part 20 (*Additional Information*)).

11.6 *Option Agreements*

Option held by Gilad Myerson

Gilad Myerson has an option over Ordinary Shares (the "**GM Option**"). The GM Option represents a right to subscribe for Ordinary Shares (the "**GM Option Shares**") which have a value which is equal to the higher of (i) 0.2% of the net value of IEEPL's assets less its liabilities as at the date immediately before the date of any intial public offering of the Company's shares and (ii) 0.2% of the market value of the issued share capital of the Company by reference to the most recent annual valuation of the Company undertaken for audit as at the date immediately before any initial public offering of the Company's shares. The GM Option may only be exercised on (or in contemplation of) the occurrence of an exit event such as an initial public offering. Where an exit event occurs, the GM Option shall become exercisable immediately and in full and the vesting schedule, otherwise applying to the GM Option (whereby 20% of the GM Option Shares vest on each anniversary of the grant date of the GM Option (21 July 2021)) will cease to apply If Mr Myerson no longer remains employed within the Group, the GM Option will normally lapse. However, if Mr Myerson ceases to be employed as a result of his (i) death; (ii) permanent incapacity; (iii) illness; (iv) unfair dismissal; (v) redundancy; or (vi) voluntary resignation after three years, then he will be treated as a 'good leaver" and entitled to retain and exercise the GM Option over the number of GM Option Shares which have vested as at the leaving date. The GM Option will lapse, to the extent not exercised, at the end of the day before the tenth anniversary of the grant date of the GM Option.

Dividend equivalents will be paid, if the Company declares and pays a cash dividend during a period in which any GM Option Shares have vested but not been exercised, equal to the value of the dividend, net of tax, that the vested GM Option Shares would have received had Mr Myerson exercised the GM Option and acquired the respective GM Option Shares. The GM Option is subject to malus and clawback provisions which will apply at any point prior to the third anniversary of the the Board determining that a number of specified circumstances have occurred as specified in the GM Option agreement (including, but not limited to, Mr Myerson having failed to meet appropriate standards of fitness and propriety or a company in the Group for which Mr Myerson is responsible having suffered a material failure of risk management).

Option held by Alan Bruce

Alan Bruce has an option over Ordinary Shares (the "**AB Option**"). The AB Option represents a right to subscribe for Ordinary Shares (the "**AB Option Shares**") which have a value which is equal to the higher of (i) 0.2% of the net value of IEEPL's assets less its liabilities as at the date immediately before any initial public offering of the Company' shares; and (ii) 0.2% of the market value of the issued share capital of the Company by reference to the most recent annual valuation of the Company undertaken for audit as at the date immediately before any initial public offering of the Company's shares. The AB Option may only be exercised on (or in contemplation of) the occurrence of an exit event such as an initial public offering. Exercise of the AB Option is subject to a vesting schedule, in accordance with which the AB Option, as a result of the initial public offering, will continue to vest and become exercisable over a five year period, as to 20% of the AB Option Shares on each anniversary of the grant date of the AB Option (21 July 2021). If Mr Bruce no longer remains employed within the Group, the AB Option will normally lapse. However, if Mr Bruce ceases to be employed as a result of his (i) death; (ii) permanent incapacity; (iii) illness; (iv) unfair dismissal; (v) redundancy; or (vi) voluntary resignation after three years, then he will be treated as a 'good leaver" and entitled to retain and exercise the AB Option over the AB Option Shares which have vested as at the leaving date. The AB Option will lapse, to the extent not exercised, at the end of the day before the tenth anniversary of the grant date of the AB Option.

Dividend equivalents will be paid, if the Company declares and pays a cash dividend during a period in which any AB Option Shares have vested but not been exercised, equal to the value of the dividend, net of tax, that the vested AB Option Shares would have received had Mr Bruce exercised the AB Option and acquired the respective AB Option Shares. The AB Option is subject to malus and clawback provisions which will apply at any point prior to the third anniversary of the the Board determining that a number of specified circumstances have occurred as specified in the AB Option agreement (including, but not limited to, Mr Bruce having failed to meet appropriate standards of fitness and propriety or a company in the Group for which Mr Bruce is responsible having suffered a material failure of risk management).

12. PENSIONS

The Group operates a defined contribution group personal pension scheme. The employees that wish to participate in the scheme pay a minimum contribution of 3% of their salary, and Ithaca Energy contributes a maximum of 15% of total salary.

13. INVESTMENTS AND PRINCIPAL ESTABLISHMENTS

13.1 The Company has made no material investments since 30 June 2022 being the latest date to which the historical financial information in Part 16 (*Historical Financial Information*) was prepared other than the subsidiary undertakings listed in paragraph 4.3 (*Organisational Structure*) of this Part 20 (*Additional Information*).

13.2 The Company currently has no material investments (in progress or planned for the future on which the Directors have made firm commitments or otherwise).

13.3 The Company is not party to any corporate joint ventures and does not hold a proportion of capital in an undertaking which is likely to have a significant effect on the assessment of its own assets and liabilities, financial position or profits and losses.

13.4 The principal establishments of the Group are as follows:

Location	Tenure
Hill of Rubislaw, Aberdeen, AB15 6XL	Leasehold
23 College Hill, London, EC4R 2RP	Leasehold

14. MATERIAL CONTRACTS

The following contracts (not being contracts entered into in the ordinary course of business) have been entered into by the Company or another member of the Group: (a) within the two years immediately preceding the date of this Prospectus which are, or may be, material to the Company or any member of the Group; and/or (b) at any time and contain provisions under which the Company or any member of the Group has an obligation or entitlement which is, or may be, material to the Company or any member of the Group as at the date of this Prospectus:

14.1 *Underwriting and Sponsors' Agreement*

On 9 November 2022, the Company, the Directors, the Selling Shareholder and the Underwriters entered into the Underwriting and Sponsors' Agreement. Pursuant to the Underwriting and Sponsors' Agreement:

14.1.1 the Company has agreed, subject to certain conditions, to issue Offer Shares in the Global Offering at the Offer Price;

14.1.2 the Underwriters have severally agreed, subject to certain conditions, to procure subscribers (or to subscribe themselves) for the Offer Shares (in such proportions as will be set out in the Underwriting and Sponsors' Agreement);

14.1.3 The Company will pay the Underwriters' Expenses (including the Underwriters' base commission in respect of the Offer Shares) from the gross proceeds of the Global Offering. The Company will pay the IPO Expenses and Selling Shareholder's Expenses with amounts received from payments from IEEPL and/ or certain Subsidiaries. This will require IEEPL and/ or certain Subsidiaries to make payments to the Company, which is not permitted under the RBL Facility Agreement unless agreed by the majority of lenders. It is expected that IEUK will obtain the consent of the majority of lenders under the RBL Facility Agreement. However, if the consent is not received, the Selling Shareholder will pay all the IPO Expenses. The Company will not receive any of the net proceeds from the Global Offering, all of which will ultimately be received by Delek.

14.1.4 the Company has agreed to pay the Underwriters commissions based upon the aggregate of the Offer Price and the number of Over-allotment Shares sold, if any, pursuant to the exercise of the Over-allotment Option;

14.1.5 the obligations of the Underwriters to procure subscribers for or, failing which, themselves to subscribe for the Offer Shares on the terms of the Underwriting and Sponsors' Agreement are subject to certain conditions. These conditions include the absence of any breach of representation or warranty under the Underwriting and Sponsors' Agreement and Admission occurring on or before 8.00 am (London time) on the date of Admission (or such later time and/or date as the Joint Global Co-ordinators and the Company may agree (being not later than the fourteenth calendar day after the date of the Underwriting and Sponsors' Agreement)). In addition, the Joint Global Co-ordinators have the right to terminate the Underwriting and Sponsors' Agreement, exercisable in certain circumstances prior to Admission;

14.1.6 Goldman Sachs International, as Stabilising Manager has been granted the Over-allotment Option by the Selling Shareholder pursuant to which it may purchase, or procure purchasers for, up to 15,000,000 Over-allotment Shares at the Offer Price for the purposes of covering short positions arising from over-allocations, if any, in connection with the Global Offering, and/or any sales of Over-allotment Shares made during the stabilisation period. Save as required by law or regulation, neither the Stabilising Manager, nor any of its agents, intends to disclose the extent of any over-allotments and/or stabilisation transactions under the Global Offering. Settlement of any sale of Over-allotment Shares will take place shortly after such determination (or, if acquired on Admission, at Admission). If any Over-allotment Shares are sold following exercise of the Over-allotment Option, the Stabilising Manager (on behalf of the Underwriters) will be committed to pay to the Selling Shareholder, or procure that payment is made to it of an amount equal to the Offer Price multiplied by the number of Over-allotment Shares purchased from the Selling Shareholder, less commissions and expenses;

14.1.7 the Selling Shareholder has agreed to pay any stamp duty and/or stamp duty reserve tax arising on the sale of the Over-allotment Shares (if any);

14.1.8 to the extent permitted by law, the Company has agreed to pay its share of the costs, charges, fees and expenses of the Global Offering (together with any related VAT);

14.1.9 each of the Company, the Directors and the Selling Shareholder has given certain representations, warranties and undertakings, subject to certain limits, to the Underwriters;

14.1.10 the Company has given an indemnity to the Underwriters on customary terms;

14.1.11 the parties to the Underwriting and Sponsors' Agreement have given certain covenants to each other regarding compliance with laws and regulations affecting the making of the Global Offering in relevant jurisdictions; and

14.1.12 the Underwriting and Sponsors' Agreement contains lock-up provisions described in more detail in paragraph 1.6 (*Lock-up Arrangements and Exceptions*) of Part 18 (*Details, Terms and Conditions of the Global Offering*).

14.2 ***Relationship Agreement***

14.2.1 The Relationship Agreement to be entered into between the Company and Delek will take effect on Admission and will regulate the on-going relationship between the Company and Delek following Admission. The principal purpose of the Relationship Agreement is to ensure that the Company is capable of carrying on its business independently of Delek.

14.2.2 The provisions of the Relationship Agreement imposing obligations on Delek will continue in force, in respect of Delek, for so long as:

(a) Delek and any of its associates own at least 10% or more of the Ordinary Shares; and

(b) the Ordinary Shares are admitted to the premium segment of the Official List and admitted to trading to the London Stock Exchange's main market for listed securities,

save that certain provisions of the Relationship Agreement relating to requirements of Chapter 6 of the Listing Rules will terminate upon Delek and its affiliates ceasing to own at least 30% of the Ordinary Shares.

14.2.3 Under the Relationship Agreement:

(a) Delek undertakes, amongst other things, that it shall not (and shall procure that its associates will not):

(i) take any action that would have the effect of preventing:

(1) the Company from complying with its obligations under the Listing Rules; or

(2) complying with the principles of good governance set out in the Governance Code (save to the extent disclosed in this Prospectus or any annual report of the Company or as otherwise agreed by a majority of the independent Directors); or

(3) any member of the Group from carrying on its business independent of Delek and its associates;

(ii) propose or procure the proposal of any Shareholder resolution which is intended or appears to be intended to circumvent the proper application of the Listing Rules;

(iii) exercise any of its voting rights in the Company or other rights and powers as a Shareholder in a way that would:

(1) adversely impact the Company's ability in accordance with the Listing Rules to carry on its business (including the Company's ability to operate and make decisions) independently of Delek and its associates;

(2) prevent the election of independent directors; or

(3) be inconsistent with, or undermine any of the provisions of, the Relationship Agreement or the Listing Rules; and

(iv) publish, disclose or otherwise announce to the market any information in relation to the Company's affairs, business or matters pertaining to the Group independently of the Company, without in each case providing the Company with reasonable advance notice of any such publication or announcement and to the extent reasonably practicable in the circumstances, consulting with the Company before any such disclosure or publication is made and taking into account the Company's reasonable requests as to the form and content of such disclosure or publication provided that, Delek may, subject to the provisions of the Relationship Agreement, make such announcement where in its opinion (acting in good faith) such publication or disclosure is required pursuant to applicable law and the rules of any stock exchange by which Delek is bound.

(b) Delek undertakes, amongst other things, that it shall:

(i) conduct all transactions and arrangements with members of the Group on an arm's length basis and on normal commercial terms;

(ii) except where approved by the Board, not take any action or omit to take any action which would be reasonably likely to result in the cancellation of Admission; and

(iii) in respect of any transaction with Delek where such transaction is submitted to a vote of the Shareholders, abstain from voting in relation to the Ordinary Shares held by it (or them) or any resolution required by paragraph 11.1.7R(3) of the Listing Rules.

(c) The Company has granted Delek the right to nominate directors to the Board commensurate with the aggregate holdings of the Company as follows:

(i) for so long as Delek and its associates hold, in aggregate, not less than 20% of the Ordinary Shares, Delek will be entitled to appoint (and to remove and reappoint) a maximum of two non-executive Directors on the Board (the "**Nominated Directors**"), by notice in writing to the Company, provided always that Delek's entitlement to appoint the maximum of two non-executive Directors is subject to the Board of the Company being in compliance with the Governance Code (save to the extent disclosed in this Prospectus or any annual report of the Company); or

(ii) for so long as Delek and its associates hold, in aggregate, not less than 10% (but not more than 20%) of the Ordinary Shares, Delek will be entitled to appoint (and to remove and reappoint) a maximum of one non-executive Director on the Board.

On Admission, Delek only intends to nominate one Nominated Director to the Board, Mr Idan Wallace.

(d) In addition to the right to appoint Nominated Directors, for so long as Delek and its associates hold, in aggregate, not less than 50% of the Ordinary Shares:

(i) Delek will be entitled to appoint one observer, whose identity must be approved in advance by the Board, to attend and observe the committee meetings of each of the Remuneration Committee and Audit and Risk Committee; and

(ii) Delek will be entitled to nominate one Director to the Nomination and Governance Committee (or if there are no Nominated Directors appointed to the Board, for an observer to be appointed to attend and observe the committee meetings of the Nomination and Governance Committee, in the case of an observer, whose identity must be approved in advance by the Board).

(e) The Relationship Agreement contains a non-compete obligation, whereby Delek agrees and undertakes that, for a period of up to 1 year following Admission, for so long as the Company holds (directly or indirectly) any material oil and gas assets in the North Sea, Delek will not, and will procure, so far as it is able, that no other member of the Delek's Group will, without the prior written consent of the Company, operate, establish or acquire an undertaking whose business primarily involves the production and/or exploration of oil and gas assets in the North Sea (save in relation to any assets acquired as part of the NewMed Capricorn Transaction).

(f) Subject to the Company's compliance with the requirements of the Listing Rules, and any applicable legal, regulatory or contractual restrictions which apply, Delek is entitled to request the Company to procure that its senior management provide assistance to Delek and its associates in relation to any proposed sale of Ordinary Shares by Delek and their associates.

(g) Subject to applicable law and regulation and certain confidentiality obligations, Delek will have the benefit of certain information rights for the purpose of its tax, accounting and other regulatory requirements and obligations.

(h) The Relationship Agreement is governed by and construed in accordance with English Law.

14.3 ***Finance***

14.3.1 **RBL Facility Agreement with BNP Paribas**

Overview

On 19 July 2021, IEUK as borrower, signed a deed of amendment, restatement and release in relation to its existing borrowing base facility agreement dated 29 May 2019 with, among others, BNP Paribas (in its various capacities) for a $1.225 billion borrowing base facility to, among other things, fund the refinancing of its existing borrowing base facility, existing $500 million senior notes (being the 2024 Notes) and for its lawful general corporate purposes (the "**RBL Facility Agreement**").

The terms and conditions of the RBL Facility Agreement comprise two facilities:

- a multicurrency revolving borrowing base credit facility up to $1.076 billion comprising BNP Paribas, Lloyds Bank plc, Wells Fargo Bank N.A., London Branch, The Royal Bank of Scotland plc, Deutsche Bank AG, Amsterdam Branch, DNB (UK) Limited, ING Belgium S.A./NV, Morgan Stanley and Mizrahi Tefahot Bank Limited, London Branch as lenders ("**Facility A**"); and
- a US dollar revolving borrowing base credit facility up to $149 million comprising the aforementioned lenders as lenders ("**Facility B**" and together with Facility A, the "**Facilities**").

Facility A may be utilised by way of loan or letter of credit and may be utilised in US dollars, pounds sterling or euros. Facility B may be utilised by way of loan only and may only be utilised in US dollars.

Each of IEEPL, Ithaca GSA Limited, Ithaca GSA Holdings Limited, Ithaca Minerals (North Sea) Limited, Ithaca Energy Holdings (UK) Limited, Ithaca Petroleum Limited, Ithaca Causeway Limited, Ithaca Gamma Limited, Ithaca Epsilon Limited, Ithaca Energy Developments UK Limited, Ithaca Exploration Limited, IOG, Ithaca MA Limited and Ithaca Alpha (NI) Limited are guarantors under the RBL Facility Agreement. The entities within the Siccar Point Group will accede to the RBL Facility Agreement as guarantors immediately following Admission. Each obligor subordinates its claims against each other obligor and each guarantor jointly and severally guarantees the obligations of each obligor under the RBL Facility Agreement and related finance documents, in each case, in favour of the lenders and other finance/hedging parties.

The RBL Facility Agreement is drafted on the basis of a customary reducing borrowing base facility arrangement whereby the maximum amount that can be drawn or outstanding on any date shall be the lesser of the total commitments (being $1.225 billion) and the borrowing base amount. The borrowing base amount shall be calculated by reference to a banking case derived from an agreed financial model prepared by the technical bank prior to each semi-annual redetermination date. The borrowing base amount, in relation to any redetermination period (periods of six months), shall be the amount set out in the banking case which is the maximum amount of the loans that could be outstanding in such calculation period whilst ensuring (i) a project life cover ratio of not less than 1.5:1 and a loan life coverage ratio of not less than 1.3:1 in respect of Facility A and (ii) a project life cover ratio of not less than 1.3:1 and a loan life coverage ratio of not less than 1.2:1 in respect of Facility B, in each case for each calculation period until the applicable final repayment date. The borrowing base amount will be approved by the lenders on each redetermination date.

Security

The lenders and other finance/hedging parties also benefit from security over substantially all the assets of IEUK and each guarantor—including security over their bank accounts and all balances and claims arising from such accounts, certain material agreements and certain insurance policies which each is required to maintain, as well as a first priority security over the shares in each obligor (other than IEEPL).

The Facilities will share any proceeds from the enforcement of security pari passu.

Repayment and Maturity

The Facilities will mature on 31 May 2026 (or, if earlier, the last day of the first calculation period in which the aggregate remaining borrowing base reserves for all borrowing base assets are projected in the then current projection to be less than 25% of the initial approved reserves). Each of the Facilities are revolving facilities and subject to semi-annual reductions in accordance with an agreed amortisation schedule. Each of the total commitments shall reduce over the life of the Facilities in accordance with an agreed reduction schedule.

Facility A will reduce to $808 million on 1 July 2024, $674 million on 1 January 2025, $490 million on 1 July 2025 and $335 million on 1 January 2026.

Facility B will reduce to $102 million on 1 July 2024, $61 million on 1 January 2025, $46 million on 1 July 2025 and $31 million on 1 January 2026.

Fees

Commitment Fee: IEUK shall pay commitment fees on a quarterly basis at the rate of 40% of the margin on not utilised but available amounts and 25% of the margin on unavailable amounts.

LC Commission: IEUK shall pay on a quarterly basis:

- a commission equal to 50% of the margin on the daily amount of exposure in respect of each performance letter of credit in respect of which approved cash cover has not been provided:
    - a commission equal to the margin on the daily amount of exposure in respect of each letter of credit which is not a performance letter of credit in respect of which approved cash cover has not been provided; and
    - a commission equal to 0.40% per annum on the daily amount of exposure for which approved cash cover has been provided, provided that no lender is entitled to commission to the extent that its exposure is subject to cash cover provided by a borrower pursuant to the terms of the RBL Facility Agreement.

Interest

The interest rate on Facility A is (i) SOFR (or in relation to any loan in euros, EURIBOR or in relation to any loan in pounds sterling, SONIA) plus a margin of 3.5% per annum until (but excluding) the date falling four years after the date of the RBL Facility Agreement and (ii) SOFR (or in relation to any loan in euro, EURIBOR or in relation to any loan in pounds sterling, SONIA) plus a margin of 3.75% thereafter.

The interest rate on Facility B is (i) SOFR plus a margin of 4.5% per annum until (but excluding) the date falling four years after the date of the RBL Facility Agreement and (ii) SOFR plus a margin of 4.75% thereafter.

Interest periods in respect of the Facilities will be one, three or six months or any other period agreed between IEUK and the majority lenders.

Prepayment and Cancellation

The RBL Facility Agreement contains prepayment and cancellation provisions customary for a facility of this type such as illegality, voluntary prepayment, mandatory prepayment of disposals except for permitted disposals (meaning disposals that are not borrowing base assets), mandatory prepayments of insurance claim proceeds relating to the borrowing base assets except for excluded insurance proceeds (meaning proceeds which are to be promptly applied for the repair, replacement or reinstatement of the relevant asset(s) to which the claim relates) and a mandatory prepayment for a change of control, which shall not be triggered by an initial public offering of the shares in the Company where the ultimate change of control of the Company is less than 50%.

Distributions

Save as otherwise agreed by the majority lenders, no obligor may make or declare payment of any distribution unless:

- (i) such distribution is made from funds available for that purpose pursuant to the RBL Facility Agreement; and (ii) no event of default is continuing or will occur as a result of making such distribution; or
- in relation to any distribution in connection with any bridge facility agreement between IEUK and IEEPL and/or any additional bond financing, such distribution is equal to the amount of any payment in connection with any such bridge facility agreement and/or additional bond financing (including (if applicable) but not limited to, any payment to be made indirectly through IENS or other specific Bond Issuer); or
- it is a distribution which is permitted in connection with specific financings.

The above shall not apply to any distribution by an obligor which is (i) paid to the proceeds account of another obligor or (ii) any distribution required to give effect to any permitted disposal of the RBL Facility Agreement.

The right to make a distribution falls at the end of the proceeds account waterfall. This contains requirements to pay various items before an obligor would be entitled to make a distribution including (but not limited to) finance party fees, costs and expenses; hedging costs and hedging termination payments; accrued interest; principal; gross expenditure. Thereafter, if:

- all amounts payable under the RBL Facility Agreement and certain related documents which have fallen due for payment have been paid;
- the aggregate US dollar amount of the outstanding utilisations does not exceed the maximum available amount;
- no borrowing base deficiency has occurred or will occur as a result of making such payment;
- the forecast which was due to be adopted by the most recent recalculation date has been so adopted;
- no event of default is continuing or will occur as a result of making such payment;

- such payment is contemplated in the most recent corporate cashflow projection and such corporate cashflow projection shows no funding shortfall after such expenditure having been taken into account; and
- payment of such amount is permitted or not prohibited under any additional bridge financing or additional bond financing,

then a distribution may be made provided that (i) such payment is no later than 30 days after a recalculation date being 31 May and 30 November if each calendar year, or any interim calculation; and (ii) the provisions detailed in the paragraph below shall apply in respect of the making of any distributions.

An obligor may withdraw amounts from the proceeds accounts in or towards the making of any distributions in accordance with the proceeds account waterfall (as detailed above), provided that no withdrawal or payment shall be permitted until the earlier of: (a) (i) the first date on which oil is produced from the wells located in the Captain field; and (ii) the date falling on or after the second anniversary of the satisfaction of the conditions precedent under the deed of amendment, restatement and release dated 19 July 2021 provided that IEUK has submitted to BNP Paribas a corporate cashflow projection which demonstrates to its satisfaction (acting on the instruction of the majority lenders (acting reasonably)) that the amount by which the total corporate sources exceeds total corporate uses is more than $150 million in any quarter of the forecast period as at the date of the proposed distribution; and (b) if at least 10% of the share capital of the Company (or any replacement direct shareholder of IEEPL incorporated for the purposes of listing IEEPL) has been listed on a stock exchange, then (a) above shall not apply in respect of the withdrawal for the payment of distributions.

In addition, on each date on which the IEUK intends to make a distribution it must demonstrate that (i) its total corporate sources exceed its total corporate uses in each quarter of the relevant forecast period; and (ii) the obligors have sufficient freely available funds to meet any decommissioning security obligations in respect of the borrowing base assets for the period ending three years from that date, otherwise an event of default will occur.

An obligor may, at any time, transfer amounts from a proceeds account maintained by it which is denominated in any one currency to any other proceeds account maintained by it which is denominated in another currency.

IOG shall procure that all amounts payable to it are paid into a proceeds account or the CNSL retained decommissioning liabilities account (as the case may be). To the extent IOG receives amounts in an account that is not a proceeds account but which would otherwise be required to be credited to a proceeds account, IOG shall transfer the same as soon as reasonably practicable (but in any event within five business days) to a proceeds account.

Covenant Package

The RBL Facility Agreement contains customary representations, including as to status, binding obligations, non-conflict with other obligations, power and authority, borrowing base assets and project documents, environmental compliance, ownership, the accuracy of information, borrowing base projections, anti-bribery, anti-corruption and sanctions and in certain cases are subject to knowledge and materiality qualifications.

The RBL Facility Agreement imposes a number of affirmative and negative covenants on IEEPL and certain of its Subsidiary Undertakings and/or the obligors. Affirmative covenants include compliance with, among other things; environmental matters, hedging policy, applicable laws (including sanctions) and tax rules, its obligations under licences, and the maintenance of certain bank accounts, insurance policies and material agreements.

The RBL Facility Agreement also contains negative covenants, including, among other things, a negative pledge and restrictions (subject to, where appropriate, agreed exceptions) on: capital expenditure, distributions (including shareholder loan payments), additional financial indebtedness, disposals, acquisitions, investments and asset sales, and changes in the entities' business, its constitutional documents or certain material agreements and an event of default for failure to comply with certain financial ratios.

Such financial ratios include a project life cover ratio of not less than 1.15:1 (the project life coverage ratio being, at each calculation date, the ratio of the net present value of projected net revenues (accounting for capital expenditure add back) for the present and subsequent periods to the aggregate amount of the principal outstanding under the RBL Facility Agreement (other than in respect of letters of credit in relation to costs associated with a borrowing base asset which are already counted as gross expenditure in the most recent projection)); a loan life coverage ratio of not less than 1.05:1 (the loan life coverage ratio being, at each calculation date, the ratio of the net present value of projected net revenues (accounting for capital expenditure add back) for the present and subsequent periods arising on or before the earliest of the final repayment date or reserve tail date to the aggregate amount of the principal outstanding under the RBL Facility Agreement); a ratio of net debt (excluding obligations to IEEPL and its subsidiaries) to EBITDAX of not less than 3.5:1; and demonstrating that total corporate sources exceed total corporate uses (which is capable of being rectified by delivery of a rectification plan in form and substance satisfactory to the majority lenders within 30 days of the date on which the relevant projection was due to be delivered).

The RBL Facility Agreement contains customary events of default including breach of financial ratios, non-payment of any amount under the finance documents, insolvency and analogous proceedings, cross-default, misrepresentation, the qualification of accounts, repudiation and effectiveness, litigation and material adverse change. There are additional events of default relating to the material project documents (which are qualified by reference to material adverse effect) and borrowing base assets.

14.3.2 **Indenture**

Overview

On 30 July 2021, IENS plc entered into an indenture among IEEPL (as guarantor) and other guarantors, BNY Mellon Corporate Trustee Services Limited (as trustee), The Bank of New York Mellon, London Branch (as principal paying agent) and The Bank of New York Mellon SA/NV, Dublin Branch (in various capacities) (the "**Indenture**").

The Indenture provides for (i) the issuance of its 9% senior notes due 2026 and any additional notes issued by IENS plc under the Indenture from time to time (the "**2026 Notes**"), and (ii) the issuance by the guarantors (as hereinafter defined) of their respective guarantees of the 2026 Notes.

The proceeds of the initial offering on 30 July 2021 were used, together with drawings under the RBL Facility Agreement, to refinance its existing borrowing base facility and existing $500 million 2024 Notes.

Pursuant to the initial offering on 30 July 2021, IENS plc issued $625.0 million in aggregate principal amount of 2026 Notes. IENS plc may issue additional notes in minimum denominations of $200,000 and integral multiples of $1,000 in excess thereof under the Indenture from time to time.

Listing

The 2026 Notes are admitted to the Official List of The International Stock Exchange.

Interest and Maturity

Interest on the 2026 Notes will accrue at the rate of 9% per annum and is payable semi-annually in arrears on 15 January and 15 July. Payment of interest commenced on 15 January 2022. Interest on overdue principal and interest (if any) accrues at a rate that is 1.0% higher than the then applicable interest rate on the 2026 Notes. IENS plc will make each interest payment to the holders of record on the immediately preceding 1 January and 1 July.

Interest on the 2026 Notes will accrue from the date of original issuance or, if interest has already been paid, from the date it was most recently paid. Interest will be computed on the basis of a 360 day year comprised of twelve 30 day months.

The 2026 Notes will mature on 15 July 2026.

Redemption

The 2026 Notes are only redeemable at IENS plc's option prior to maturity under the following circumstances:

- in connection with any tender offer or other offer to purchase all of the 2026 Notes, if holders of not less than 90% of the aggregate principal amount of the then outstanding 2026 Notes validly tender and do not validly withdraw such 2026 Notes in such tender offer or offer to purchase, all of the noteholders will be deemed to have consented to such tender offer or other offer and, accordingly, IENS plc will have the right to redeem all 2026 Notes that remain outstanding at a price equivalent to the price paid pursuant to such tender offer or offer to purchase; and
- in the event of certain changes in the law of any relevant taxing jurisdiction affecting taxation of the 2026 Notes, IENS plc may redeem the 2026 Notes in whole, but not in part, at any time upon giving prior notice, at a redemption price of 100% of the principal amount, plus accrued and unpaid interest (if any) and additional amounts (if any) due as a result of the withholding or deduction for taxes up to and including the date of redemption.

IEEPL and its restricted subsidiaries may acquire or cause to be acquired, the 2026 Notes by means other than a redemption, whether pursuant to a tender offer, open market purchase or otherwise, so long as the acquisition does not violate the following terms of the Indenture:

- prior to 15 July 2023, IENS plc may redeem all or part of the 2026 Notes at a redemption price equal to 100% of the principal amount of such 2026 Notes redeemed, plus accrued and unpaid interest (if any) to the redemption date plus a "make whole" premium, subject to the rights of the holders on the relevant date to receive interest due on the relevant interest payment date;
- in addition, on or prior to 15 July 2023, IENS plc may redeem up to 40% of the original principal amount of each of the 2026 Notes with the net cash proceeds from specified equity offerings at a redemption price equal to 109.000% of the principal amount thereof plus accrued and unpaid interest (if any) to the redemption date, provided that at least 50% of the original principal amount of the 2026 Notes remain outstanding after the redemption; and
- on or after 15 July 2023, IENS plc may on any one or more occasions redeem all or a part of the 2026 Notes at the following redemption prices (expressed as percentages of principal amount):
  - in 2023, at a redemption price of 104.500%;
  - in 2024, at a redemption price of 102.250%; or
  - in 2025 and thereafter, at a redemption price of 100.000%,

plus accrued and unpaid interest (if any).

Change of Control

Under the terms of the Indenture, a "Change of Control" is deemed to have occurred if: (i) all or substantially all of the properties or assets of IEEPL and its restricted subsidiaries are sold, leased or otherwise disposed of to any person other than a 'permitted holder' (which includes, amongst others, DGL and its Subsidiary Undertakings, and their affiliates); (ii) a plan relating to the liquidation or dissolution of IEEPL is adopted; and (iii) a person, other than a 'permitted holder', becomes the beneficial owner of more than 50% of the voting stock of the IEEPL.

A transaction will not be deemed to involve a "Change of Control" solely as a result of IEEPL becoming a direct or indirect wholly-owned subsidiary of a holding company provided certain conditions as outlined in the Indenture are met.

Upon the occurrence of a "Change of Control", IENS plc will be required to offer to repurchase the 2026 Notes at a purchase price equal to 101% of their aggregate principal amount, plus accrued and unpaid interest (if any) to the date of the purchase.

Distributions

The terms of the 2026 Notes include restrictions on the ability of IEEPL, and certain of its subsidiaries, to, directly or indirectly:

- declare or pay any dividend or make any other payment or distribution (including, without limitation, in connection with any merger, amalgamation or consolidation);
- repurchase (including, without limitation, in connection with any merger, amalgamation or consolidation) any equity interest in IEEPL or its parent;
- make any principal payment on or repurchase any indebtedness of IEEPL or any guarantor that is subordinated to the 2026 Notes (subject to certain exceptions);
- make any payment on or repurchase certain shareholder debt obligations; or
- make any investment not permitted under the terms of the 2026 Notes,

unless at the time of, and after giving effect to, such restricted payment:

- no event of default has occurred or is continuing or would occur as a consequence of such payment;
- IEEPL would have been permitted to incur at least $1 of additional indebtedness pursuant to the fixed charge cover ratio test set out in the 2026 Notes and/or (for certain exceptions to the restriction on payments) the consolidated leverage ratio of IEEPL will not exceed 1.3:1; and
- such payment, together with the aggregate of all other restricted payments following the issue date, is equal to or less than the sum, without duplication, of:
  - either:
    - (x) an amount equal to $100 million for each twelve months passed since 30 July 2021 or (y) where the consolidated leverage ratio is 0.6:1, 50% of the consolidated net income of IEEPL for the specified period; or
    - following a public equity offering of greater than 25% of the issued common stock of IEEPL, 50% of the consolidated net income of IEEPL for the specified period; plus
  - 100% of the aggregate net cash proceeds and fair market value of marketable securities and other property or assets received by IEEPL as a contribution to its common capital or from the issue of certain interests of IEEPL; plus
  - (i) to the extent any restricted investment is (x) sold, the aggregate amount received in cash and the fair market value of the marketable securities and other property received by IEEPL and certain of its subsidiaries, or (y) made in an entity that becomes a restricted subsidiary, 100% of the fair market value of the restricted investment of IEEPL and certain of its subsidiaries; plus (ii) to the extent any subsidiary not designated as restricted is subsequently re-designated as or merged with a restricted subsidiary, or all or substantially all properties or assets of such unrestricted security is transferred to IEEPL or certain of its subsidiaries which are restricted, the fair market value of the property received by IEEPL or its restricted subsidiary or the amount of restricted investment (to the extent such investment reduced the restricted payments capacity under this bullet point and were not previously repaid); plus
  - 100% of distributions received in cash by IEEPL or certain of its subsidiaries from a subsidiary which is not restricted, to the extent such amounts are not otherwise included in the consolidated net income of IEEPL for such period.

The value of all restricted payments made will be the fair market value on the date of such payment (or declaration in the case of dividends).

The restriction on payments under the terms of the 2026 Notes will not prohibit:

- dividend or redemption payments which would have complied with the terms of the 2026 Notes at the date of declaration or notice;

- certain payments which would otherwise be restricted but which are in exchange for certain equity or debt interests of IEEPL;
- the repurchase of debt of IEEPL or any guarantor that is subordinated to the 2026 Notes if paid for using net cash proceeds from a substantially concurrent refinancing for the purpose of such repurchase;
- dividend payments by a restricted subsidiary on no more than a pro rata basis;
- so long as no event of default has occurred and is continuing or would be caused thereby, the repurchase of IEEPL's equity interests held by its current or former officers, directors, employees or consultants pursuant to a stock option or similar agreement, subject to certain requirements;
- the repurchase of IEEPL's equity interests held by its current or former directors or employees in connection with the vesting or any equity compensation in order to satisfy a tax withholding obligation;
- repurchases of certain debt obligations subordinated to the 2026 Notes at a purchase price not greater than (i) in the event of a change of control, 101% of the principal amount and unpaid interest or (ii) in the event of an asset sale, 100% of the principal amount and unpaid interest, subject to certain additional requirements;
- the repurchase of IEEPL capital stock representing fractional shares in connection with a merger or other combination or any other transaction permitted by the terms of the 2026 Notes;
- the repurchase of equity interests representing a portion of the exercise price of stock options or warrants;
- so long as no event of default has occurred and is continuing or would be caused thereby, regularly scheduled or accrued dividends to holders of disqualified stock of IEEPL or certain of its subsidiaries in accordance with the fixed charge coverage ratio test as set out in the terms of the 2026 Notes;
- payment of cash in lieu of the issuance of fractional shares upon the exercise of options or warrants or the conversion or exchange of capital stock;
- so long as no event of default has occurred and is continuing or would be caused thereby, certain advances paid to officers, directors, employees or consultants or in relation to any management equity plan or certain similar arrangements, subject to certain additional restrictions;
- so long as no event of default has occurred and is continuing or would be caused thereby, repurchase of equity interests of IEEPL to be held as treasury stock not exceeding $50 million plus proceeds from the sale of such equity interests from treasury stock;
- dividend payments by IEEPL to the Company to make corresponding dividend payments following the initial public offering provided that there is no continuing event of default and the aggregate amount of all such dividends does not, in a fiscal year, exceed the greater of:
    - 7% per annum of the net cash proceeds received by IEEPL in any public equity offering; and
    - the greater of:
        - the greater of (A) an amount equal to 5% of the market capitalisation of the Company (being the total number of ordinary shares of the Company at the date a dividend is declared multiplied by the mean closing price per ordinary share for the 30 consecutive trading days prior to that date) and (B) 5% of the IPO market capitalisation of the Company (being an amount equal to the total number of ordinary shares of the Company at the time of the initial public offering multiplied by the price per ordinary share sold in the initial public offering) pursuant to the initial public offering, provided that after giving pro forma effect to the payment of any

  - such dividend, the consolidated leverage ratio of IEEPL would not exceed 1.05:1; and
  - the greater of (A) 7% of the market capitalisation of the Company or (B) 7% of the IPO market capitalisation of the Company, provided that after giving pro forma effect to the payment of any such dividend, the consolidated leverage ratio of IEEPL would not exceed 0.8:1,

  provided that in each case, if such public equity offering was of capital stock of a parent, the net proceeds of any such dividend are used to fund a corresponding dividend in equal or greater amount on the capital stock of such parent.

- so long as no event of default has occurred and is continuing or would be caused thereby, an amount not exceeding the greater of $135 million over the term of the 2026 Notes and 3.2% of the total consolidated assets of IEEPL and its subsidiaries (as shown on the most recent balance sheet);
- payments in an aggregate amount not exceeding the aggregate amount of certain capital contributions;
- payments related to a tax sharing agreement, subject to certain additional requirements;
- distributions to any parent by IEEPL or certain of its subsidiaries in amounts not exceeding (without duplication) (a) amounts required for certain expenses of such parent, or (b) amounts constituting payments of fees and expenses in connection with certain transactions with affiliates; and
- payments in connection with the offering of the 2026 Notes, the amendment and restatement of the RBL Facility Agreement and the redemption and repayment of certain existing indebtedness on or about the date of the issuance of the 2026 Notes.

Any dividend payment under the 2026 Notes will be subject to the waterfall provisions in the RBL Facility Agreement and must be made no later than 30 days after a recalculation date (being 31 May and 30 November of each calendar year, or any interim recalculation date).

Guarantees and Security

The 2026 Notes are guaranteed by IEEPL (as senior guarantor) and those of IEEPL's Subsidiary Undertakings (other than IENS plc) that are borrowers and guarantors under the RBL Facility Agreement (as subordinated guarantors) The 2026 Note guarantees are joint and several obligations of the guarantors.

The obligations of the subordinated guarantors under the subordinated note guarantees are subordinated in right of payment to the subordinated guarantors' obligations under the RBL Facility Agreement and may be subordinated in right of payment to the subordinated guarantors' future senior obligations. The 2026 Note guarantee of a guarantor will be automatically and unconditionally released upon the occurrence of certain events outlined in the Indenture.

The 2026 Notes are unsecured.

Ranking

The 2026 Notes:

- constitute general obligations of IENS plc;
- rank pari passu in right of payment with all existing and future obligations of IENS plc that are not expressly contractually subordinated in right of payment to the 2026 Notes;
- rank senior in right of payment to all future obligations of IENS plc that are subordinated in right of payment to the 2026 Notes;
- are effectively subordinated to all existing and future secured obligations of IENS plc to the extent of the value of the property and assets securing such obligations, unless such assets also secure the 2026 Notes on an equal and rateable or senior basis;

- are structurally subordinated to all existing and future obligations of IEEPL's subsidiaries that do not guarantee the 2026 Notes (other than IENS plc); and
- are guaranteed on a senior basis by IEEPL and on a senior subordinated basis by the subordinated guarantors, subject to limitations under applicable law as set out in the Indenture.

Covenants

The Indenture limits, among other things, the ability of IENS plc and its restricted subsidiaries to:

- incur additional debt and issue guarantees and preferred stock;
- make certain payments, including dividends and other distributions, with respect to outstanding share capital;
- repay or redeem subordinated debt or share capital;
- create or incur certain liens;
- impose restrictions on the ability of IEEPL's restricted subsidiaries to pay dividends or other payments to IEEPL or any of its other restricted subsidiaries;
- make certain investments or loans;
- sell, lease or transfer certain assets, including shares of any restricted subsidiary of IEEPL;
- guarantee certain types of other indebtedness of IEEPL or its restricted subsidiaries without also guaranteeing the 2026 Notes;
- expand into unrelated businesses;
- merge or consolidate with other entities; and
- enter into certain transactions with affiliates.

Each of the covenants is subject to a number of important exceptions and qualifications.

In addition, the Indenture also contains certain customary events of default. If any event of default occurs in relation to the bankruptcy or insolvency of IENS plc or IEEPL, all then outstanding 2026 Notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing then the trustee or holders of at least 25% in aggregate principal amount of the then outstanding 2026 Notes may declare all the then outstanding 2026 Notes to be due and payable immediately by notice in writing to IENS plc.

14.3.3 **Intercreditor Arrangements**

In relation to the financing arrangements, there is a Bond Subordination Agreement between, amongst others, IEEPL, DGL, BNP Paribas and BNY Mellon Corporate Trustee Services Limited dated 1 November 2019 (and to which BNY Mellon Corporate Trustee Services Limited in its capacity as Trustee acceded to on 30 July 2021) which sets out the rank and priority of the relevant liabilities owed by the Group as follows: (i) first, the liabilities due under the RBL Facility Agreement and related finance documents (i.e., the senior liabilities), (ii) second, the liabilities due in respect of the 2026 Notes and related bond documents, and (iii) third, the liabilities owed to DGL. On 4 October 2022, the Subordinated Shareholder Loan was retired. As at Admission, there will be no amounts outstanding from any member of the Group to DGL.

There is also a Hedging Intercreditor Agreement between, amongst others, IEEPL, BNP Paribas and IEUK dated 4 November 2019 which governs the relationship of the unsecured hedging counterparties vis a vis the finance parties in respect of the senior liabilities (including the secured hedging liabilities).

Finally, there is a Subordination Agreement between, amongst others, IEUK and BNP Paribas dated 4 November 2019, which subordinates any inter-group obligations owed amongst the members of the Group to the senior liabilities.

14.3.4 **Letters of Credit and Surety Bonds**

IEEPL and certain subsidiaries enters into letters of credit and surety bonds principally to provide security for its decommissioning obligations.

IEEPL and certain subsidiaries has entered into a number of deeds of indemnity in respect of the surety bonds (the "**Deeds of Indemnity**"). These include:

- Deed of indemnity between, amongst others, IEEPL (as lead indemnitor) and HCC International Insurance Company plc ("**HCCI**") dated 28 January 2021 ("**HCCI Deed of Indemnity**");
- Deed of indemnity between, amongst others, IEEPL (as principal indemnitor) and Everest Insurance (Ireland), DAC ("**Everest**") dated 22 January 2022 ("**Everest Deed of Indemnity**");
- Deed of indemnity between, amongst others, IEEPL (as principal indemnitor) and Liberty Mutual Insurance Europe SE ("**Liberty**") dated 26 November 2020 ("**Liberty Deed of Indemnity**");
- Deed of indemnity between, amongst others, IEEPL (as principal indemnitor) and Aspen Insurance UK Limited ("**Aspen**") dated 30 November 2020 ("**Aspen Deed of Indemnity**"); and
- Deed of indemnity between, amongst others, IEEPL (as lead indemnitor) and Markel International Insurance Company Limited ("**MIIC**") dated 21 January 2022 ("**MIIC Deed of Indemnity**").

The Deeds of Indemnity all provide that, in the event of a change of control, the surety will be entitled to make demand for the payment of cash to cover a deposit in an amount equal to an amount the relevant surety determines is the amount of the maximum aggregate liability of the surety in connection with any outstanding bond or bonds. The triggers for a change of control vary between the Deeds of Indemnity and are summarised as follows:

- Under the HCCI Deed of Indemnity, a change of control will occur where IEEPL ceases to control (as defined in sections 449–451 of the Corporation Tax Act 2010) any other indemnitor or bond holder or where any person or group of persons (other than DGL or any subsidiary thereof) acting in concert gain control of IEEPL or other bond holder.
- Under the Everest Deed of Indemnity and Liberty Deed of Indemnity, a change of control will occur where any person or group of persons acting in concert gain control (as defined in section 416 of the Income and Corporation Taxes Act 1988) of IEEPL.
- Under the Aspen Deed of Indemnity, a change of control will occur where there is a change to the persons who: (i) hold the majority of voting rights in IEEPL (or any other indemnitor); or (ii) who are entitled to remove a majority of IEEPL's (or any other indemnitor's) board of directors.
- Under the MIIC Deed of Indemnity, a change of control will occur where a person or group of persons acting in concert gain direct or indirect control of IEEPL by holding more than 50% of its issued share capital or a majority of the voting or director appointment rights.

The notice required to be provided prior to such cash cover being due varies under the Deeds of Indemnity and is as follows:

- Under the HCCI Deed of Indemnity, the indemnitors will pay to HCCI a sum equal to the aggregate bond amounts under all outstanding bonds within 5 business days of HCCI's written demand.
- Under the Everest Deed of Indemnity, the indemnitors will deposit with Everest, in cash or any other form of acceptable security, a sum equal to the face value of any guarantee then outstanding on behalf of any subsidiary of any indemnitor within 5 business days of receipt of written request from Everest.
- Under the Liberty Deed of Indemnity, the indemnitors will deposit with Liberty, in cash or any other form of acceptable security, a sum equal to 101.5% of the face value of any

guarantee then outstanding on behalf of any subsidiary of any indemnitor within 5 business days of receipt of written request from Liberty.

- Under the Aspen Deed of Indemnity, the indemnitors will deposit with Aspen an amount equal to the amount that Aspen determines, in its sole discretion, is its maximum aggregate liability in connection with the outstanding bonds, within 30 days of notice from Aspen.

Under the MIIC Deed of Indemnity, the indemnitors will pay to MIIC, in cash or any other form of acceptable security, a sum equal to 101.5% of the aggregate bond amounts in respect of all outstanding bonds within 5 business days of MIIC's written demand. IEEPL and certain subsidiaries has the following surety bonds and letters of credit issued in respect of its decommissioning activities each issued benefitting the Law Debenture Trust Corporation P.L.C.:

- A letter of credit of £80,163,582 issued by BNP Paribas benefitting the Law Debenture Trust Corporation P.L.C. in respect of decommissioning obligations of Alba;
- An on demand bond of £28,912,554 issued by Aspen benefitting the Law Debenture Trust Corporate P.L.C. in respect of decommissioning obligations of Alder;
- An on demand bond of £8,771,000 issued by HCCI benefitting the Law Debenture Trust Corporate P.L.C. in respect of decommissioning obligations of Anglia;
- An on demand bond of £7,854,000 issued by Liberty benefitting the Law Debenture Trust Corporate P.L.C. in respect of decommissioning obligations of Athena;
- A letter of credit of £9,736,555 issued by BNP Paribas benefitting the Law Debenture Trust Corporate P.L.C. in respect of decommissioning obligations of Brodgar;
- An on demand bond of £25,000,000 issued by Aspen benefitting the Law Debenture Trust Corporate P.L.C. in respect of decommissioning obligations of Britannia;
- A letter of credit of £83,062,170 issued by BNP Paribas benefitting the Law Debenture Trust Corporate P.L.C. in respect of decommissioning obligations of Britannia;
- An on demand bond of £2,047,567 issued by Liberty benefitting the Law Debenture Trust Corporate P.L.C. in respect of decommissioning obligations of Broom;
- An on demand bond of £16,407,138 issued by Liberty benefitting the Law Debenture Trust Corporate P.L.C. in respect of decommissioning obligations of Don South West & Conrie;
- An on demand bond of £6,365,829 issued by HCCI benefitting the Law Debenture Trust Corporate P.L.C. in respect of decommissioning obligations of Enochdhu;
- A letter of credit of £3,244,814 issued by BNP Paribas benefitting the Law Debenture Trust Corporate P.L.C. in respect of decommissioning obligations of Erskine;
- A letter of credit of £3,244,814 issued by BNP Paribas benefitting the Law Debenture Trust Corporate P.L.C. in respect of decommissioning obligations of Erskine.
- An on demand bond of £1,000,000 issued by Liberty benefitting the Law Debenture Trust Corporate P.L.C. in respect of decommissioning obligations of Hurricane;
- An on demand bond of £4,791,250 issued by Liberty benefitting the Law Debenture Trust Corporate P.L.C. in respect of decommissioning obligations of Jacky;
- A letter of credit of £4,302,574 issued by BNP Paribas benefitting the Law Debenture Trust Corporate P.L.C. in respect of decommissioning obligations of West Don;
- An on demand bond of £1,064,411 issued by HCCI benefitting the Law Debenture Trust Corporate P.L.C. in respect of decommissioning obligations of Ythan;
- A letter of credit of $45,000,000 issued by BNP Paribas benefitting the Law Debenture Trust Corporate P.L.C in respect of decommissioning obligations of Elgin Franklin; and
- A letter of credit of £359,291 issued by BNP Paribas benefitting the Law Debenture Trust Corporate P.L.C in respect of bi-lateral decommissioning obligations of Pickerill.

IEEPL and certain subsidiaries also has a deferred payment on demand bond of $70 million issued by a surety syndicate by Liberty, HCCI, MIIC and Everest (each with a quarter liability share) in respect of its obligation to furnish the deferred consideration security pursuant to the Marubeni Acquisition Agreement.

IEEPL and certain subsidiaries has the following letters of credit issued by BNP Paribas in respect of its obligations under the Sullom Voe Terminal Tariff Agreements:

- A letter of credit of £271,068 issued by BNP Paribas benefitting EnQuest Heather Limited in respect of obligations under the Sullom Voe Terminal Tariff Agreement for Columba B & D; and
- A letter of credit of £115,450 issued by BNP Paribas benefitting EnQuest Heather Limited in respect of obligations under the Sullom Voe Terminal Tariff Agreement for Columba E.

As at the Latest Practicable Date, the Group does not have letters of credit or surety bonds in respect of its other assets. See paragraph 1.21 (*The Group may face unanticipated increased or incremental costs in connection with decommissioning obligations*) of Part 2 (*Risk Factors*).

14.3.5 **Hedging Arrangements**

The Group maintains certain commodity hedges to manage its exposure to movements in oil and gas prices. In addition, the Group holds a small portfolio of foreign exchange derivatives. In connection with these activities, the Group has entered into International Swaps and Derivatives Association master agreements (the "**ISDAs**") with several hedging partners.

The ISDAs have been entered into by IEUK with Deutsche Bank AG, J.P. Morgan Securities PLC, Goldman Sachs International, Britannic Energy Trading Limited, ABN AMRO Bank N.V., Royal Bank of Canada, Lloyds Bank Corporate Markets PLC, Skandinaviska Enskilda Banken AB (PUBL), BNP Paribas and Natwest Markets PLC respectively, all on 6 November 2019. These ISDAs contain change of control provisions which give rise to an event of default or a termination right in the case of: (i) a merger without assumption (where a merger, transfer, reorganisation or similar results in the resulting, surviving or transferee entity failing to assume all of the obligations of the previous entity under the ISDA); (ii) a credit event upon merger (which, amongst other things, includes where any person acquires directly or indirectly an ownership interest enabling it to control the party but which results in the creditworthiness of said party becoming materially weaker); or (iii) a notification by the facility agent of a change of control under the RBL Facility Agreement (see paragraph 14.3.1 (*RBL Facility Agreement with BNP Paribas*) of this Part 20 (*Additional Information*) above) (save for in relation to the Goldman Sachs International and Britannic Energy Trading Limited ISDAs). Exercising of the termination rights/events of default under the ISDAs are subject to the intercreditor agreement entered into in respect of the RBL Facility Agreement and/or the prior consent of the security trustee or the majority lenders under the terms of the ISDAs.

14.3.6 **SPEL Facility Agreement with, among others, Natixis**

<u>Overview</u>

On 8 December 2020, SPEL signed an amendment and restatement agreement in relation to their existing borrowing base facility agreement with: (1) Natixis S.A. (as Agent); (2) DNB Bank ASA, London Branch (as Security Agent); and (3) DNB (UK) Limited, ING Bank N.V., Natixis, London Branch, Natixis, ABN AMRO Bank N.V., Commonwealth Bank of Australia, Barclays Bank PLC, BNP Paribas SA, Credit Agricole Corporate and Investment Bank and Nedbank Limited (as lenders), for a $550 million senior secured borrowing base facility to, among other things, finance the acquisition of SPEEPL, for general corporate purposes and for the financing of offshore asset acquisitions in the United Kingdom, Norway, Delek, the Netherlands and/or the Republic of Ireland (the "**SPEL Facility Agreement**").

The terms and conditions of the SPEL Facility Agreement comprises one revolving credit facility up to a total of $550 million (for the purposes of this paragraph 14.3.6 (*SPEL Facility Agreement with, among others, Natixis*) of this Part 20 (*Additional Information*) (the "**SPEL Facility**"). The Facility includes an accordion option for $200 million which SPEL may request by giving written notice provided there is no default continuing at such time and the notice is issued no later than 8 November 2023.

The SPEL Facility may be utilised by way of loan and may be utilised in US dollars, pounds sterling or euros.

Each of SPEUKL and SPEEPL are original guarantors under the SPEL Facility Agreement. Each obligor subordinates its claims against each other obligor and each guarantor jointly and severally guarantees the obligations of each obligor under the SPEL Facility Agreement and related finance documents, in each case, in favour of the lenders and other finance/hedging parties.

The SPEL Facility Agreement is drafted on the basis of a customary reducing borrowing base facility arrangement whereby the maximum amount that can be drawn or outstanding will be recalculated every six months based on the value of the borrowing base assets and certain economic and financial assumptions. The borrowing base amount shall be calculated by reference to a banking case prior to each semi-annual redetermination date. The borrowing base amount, in relation to any calculation period (periods of six months), shall be the lesser of the project life cover ratio amount calculated by dividing the net present value of projected net revenues (accounting for capex add back) for the present and subsequent calculation periods by 1.5 and the loan life cover ratio amount calculated by dividing the net present value of projected net revenues (accounting for capex add back) for the present and subsequent calculation periods by 1.25.

The Siccar Point Acquisition triggered the Change of Control provisions (as set out below) and, as a result, SPEL sought to prepay the outstanding facility. This was repaid in full on 30 June 2022 with all securities being released.

Security

The lenders benefit from first ranking English and Scots law security. The English law security includes several all-asset floating charges as well as security over all of SPEL's and SPEEPL's bank accounts, security over SPEL's shares in SPEUKL and SPEEPL as well as over SPEFL shares in SPEL and the assignments of intercompany loans owed to SPEL and SPEFL. The Scots law security consists of three bonds and floating charges granted by SPEL, SPEUKL and SPEEPL respectively.

Repayment and Maturity

The SPEL Facility will mature on 8 November 2027 (or, if earlier, the date on which the value of the remaining reserves of all borrowing base assets are deemed to have fallen to be less than 25% of the initial approved reserve threshold). The SPEL Facility is a revolving facility and subject to semi-annual reductions in accordance with an agreed amortisation schedule. Each of the total commitments shall reduce over the life of the Facility in accordance with an agreed reduction schedule.

The SPEL Facility will reduce to £495 million on 1 July 2024, $440 million on 1 January 2025, $385 million on 1 July 2025, $330 million on 1 January 2026, $275 million on 1 July 2026, $220 million on 1 January 2027 and $165 million on 1 July 2027.

Fees

SPEL shall pay commitment fees at the rate of 20% of the margin on the daily amount by which the total commitments exceed the borrowing base amount and 40% of the margin on the daily amount by which the borrowing base amount exceeds the amount in USD of all outstanding utilisations.

Interest

The interest rate in respect of the drawn loans under the SPEL Facility Agreement is the sum of the margin and LIBOR (or EURIBOR if drawn in euros). The margin was 3.0% per annum for the period ending 8 November 2021 and 3.5% per annum thereafter provided that the rate will now reduce to 3.25% per annum if the Mariner field exceeds certain production projections.

Interest periods in respect of the SPEL Facility will be one, three or six months or any other period agreed between SPEL and Natixis (acting on the instructions of all of the lenders in relation to the relevant loan).

Prepayment and Cancellation

The SPEL Facility Agreement contains prepayment and cancellation provisions customary for a facility of this type such as illegality, voluntary prepayment and a mandatory prepayment for a change of control, which shall not be triggered by an initial public offering of the shares in the Company where the ultimate change of control of the Company is less than 50%.

Prepayment of a utilisation may be made on giving Natixis no less than 5 business days' notice provided that, where a utilisation is being paid in part, it must reduce the base currency amount of the utilisation by a minimum of $5 million. Similarly, cancellation of the available SPEL Facility may be made on giving Natixis no less than five business days' notice provided that, where the cancellation is in part, it must be for a minimum of $5 million and such cancellation would not demonstrate a funding shortfall in the most recent liquidity and funding statements.

Change of Control

Under the SPEL Facility Agreement, a "Change of Control" is deemed to have occurred if any person or group of persons acting in concert (other than Blackstone Energy Partners II LP, Blackstone Energy Partners (Cayman) II LP, Blackstone Energy Partners (Cayman) II F LP, Blackstone Capital Partners VI LP, Blackstone Capital Partners (Cayman II) VI LP, Blue Water Energy Fund I-A LP, Blue Water Energy Fund I LP and their affiliates) gains direct or indirect control of SPEL. The term "control" means: (1) the power to cast more than 50% of the votes at a general meeting of SPE; (2) the power to appoint or remove the majority of directors of SPEL; (3) the power to give directions to the operating and financial policies of SPEL which the directors of SPEL are obliged to comply with; and (4) the holding of more than 50% of the issued share capital of SPEL.

In the event of a Change of Control (or the sale of all or substantially all of the assets) the SPEL Facility shall be automatically cancelled and all outstanding utilisations, together with accrued interests, shall be immediately due and payable.

Dividends

The obligors are generally prohibited from making any distributions including dividend payments. This, however, is subject to certain exceptions including: (1) where a distribution is made 18 months after the date of the SPEL Facility Agreement, provided such distribution is made within 20 days of a recalculation date and the amount of the distribution has been taken into account in the most recent liquidity statement and funding statement, no default is continuing and no funding shortfall is continuing; (2) where a distribution is made in and among the obligors; (3) where a distribution is made with the prior approval of the majority lenders; and (4) where a distribution is made to a subordinated debt issuer in compliance with the terms of an inter-company loan subordination agreement.

The right to make a distribution falls at the end of the proceeds account waterfall. This contains the usual requirements to pay various items first including fees due under the finance documents, costs and expenses, hedging costs, accrued interests and gross expenditure.

Covenant Package

The SPEL Facility Agreement contains customary representations, including as to status, binding obligations, non-conflict with other obligations, power and authority, insolvency, tax, the banking case, existence of project documents, environmental compliance, title to field interests, the accuracy of information, anti-corruption and sanctions and in certain cases are subject to knowledge and materiality qualifications.

The SPEL Facility Agreement imposes a number of positive and negative covenants on the obligors. Positive covenants include compliance with, among other things, environmental matters, applicable laws (including sanctions) and tax rules and with its obligations under its licences, maintenance of certain bank accounts, insurance policies and project documents.

The SPEL Facility Agreement also contains negative covenants, including, among other things, a negative pledge and restrictions (subject to, where appropriate, agreed exceptions) on distributions (as set out above), additional financial indebtedness, disposals, acquisitions, mergers, and changes in the entities' business, its constitutional documents or certain project documents.

The SPEL Facility Agreement contains customary events of default including breach of non-payment of any amount under the finance documents, insolvency, a funding shortfall, cross-default, misrepresentation, change of ownership, cessation of business, repudiation and recission of agreements, litigation and material adverse change. There are additional events of default relating to the material project documents (which are qualified by reference to material adverse effect) and borrowing base assets.

14.3.7 **Siccar Point Bonds**

Overview

SPEB issued a series of senior unsecured callable bonds up to a maximum of $200 million ("**Siccar Point Bonds**") on 4 March 2021 pursuant to terms and conditions dated 2 March 2021 entered into with Nordic Trustee AS (as bond trustee).

The Siccar Point Bonds rank pari passu between themselves and will at least rank pari passu with all other obligations of SPEB (save for those claims which are preferred by bankruptcy, insolvency, liquidation or similar).

Following completion of the Siccar Point Acquisition on 30 June 2022, SPEB issued a put option notice to Nordic Trustee AS pursuant to the change of control provisions detailed below. Bondholders holding Siccar Point Bonds totalling $166.40 million elected to exercise the put provision and require repayment at a price of 101% of the nominal amount of such bonds. The repayment was settled on 1 August 2022. Subsequently, on 22 September 2022, Siccar Point Bonds totalling $25.6 million were redeemed at a premium of c.6% on behalf of SPEB. On 12 October 2022, the remaining Siccar Point Bonds totalling $8 million were redeemed at the make-whole amount of 105.4%.

Security

Each of SPEL, SPEUKL, SPEEPL and SPEFL are the original guarantors under the Siccar Point Bonds' terms and conditions and have provided Norwegian law guarantees in favour of Nordic Trustee AS. Each of the guarantees (other than the guarantee granted by SPEFL) is subordinated to the SPEL Facility Agreement.

Redemption and maturity

Payments in relation to the Siccar Point Bonds are made on each payment date, being 4 March and 4 September of every year. Interest on any overdue amounts will accrue at the coupon rate (i.e., 9%) plus 3%.

The Siccar Point Bonds have a maturity date of 4 March 2026 and must be redeemed by SPEB on such date for 100% of their nominal amount. SPEB may redeem all of the outstanding Siccar Point Bonds by written notice to Nordic Trustee AS (and bondholders) at least 10 business days, but no more than 20 business days, prior to the intended repayment date. The redemption amount payable will differ depending on the period during which the notice is issued: (1) if the Siccar Point Bonds are redeemed prior to 3 March 2023, then a price equal to the sum of the present value on the prepayment date of 105.4% of the nominal amount of the redeemed Siccar Point Bonds and the remaining interest payment in respect of the redeemed Siccar Point Bonds to 3 March 2023 will be payable; (2) if the Siccar Point Bonds are redeemed between 4 March 2023 and 3 March 2024, a price of 105.4% of the nominal amount for each redeemed bond will be payable; (3) if the Siccar Point Bonds are redeemed between 4 March 2024 and 3 March 2025, a price of 103.6% of the nominal amount of each redeemed bond will be payable; and (4) if the Siccar Point Bonds are redeemed between 4 March 2025 and 4 March 2026, a price of 101.8% of the nominal amount of each redeemed bond will be payable.

In addition, SPEB is entitled to redeem all of the outstanding Siccar Point Bonds at a price of 100% of the nominal amount if it is or will be required to gross up any withheld tax imposed by law from any payment in respect of the Siccar Point Bonds as result of a change in applicable implemented after the date of the Siccar Point Bonds' terms and conditions.

Interest

The Siccar Point Bonds accrue interest at the rate of 9% per annum. The interest periods are the periods between 4 March and 4 September and 4 September and 4 March each year, with the interest payable at the end of each interest period.

Change of Control

Under the Siccar Point Bonds' terms and conditions, a "Change of Control Event" is deemed to have occurred if a person or group of persons (other than Blackstone Group Inc., Blue Water Energy LLP and their affiliates) acting in concert gain decisive influence (i.e. having a direct or indirect majority of the voting rights or a right to elect or remove a majority of the directors in that other person) over SPEB, SPEL or SPEFL.

If a Change of Control Event occurs then each bondholder is entitled to require that SPEB purchases all or some of its Siccar Point Bonds at a price of 101% of the nominal amount of such bonds. If Siccar Point Bonds representing more than 90% of the outstanding Siccar Point Bonds have been purchased as a result of a Change of Control Event then SPEB is entitled to repurchase all the remaining outstanding Siccar Point Bonds at a price of 101% of the nominal amount.

Dividends

In order for SPEL to make distributions (including dividends) and incur further financial indebtedness the net interest bearing debt to EBITDAX ratio must be 3.0x or less (the "Incurrence Test") with such calculation being made no earlier than one month prior to the relevant event. In addition to the Incurrence Test not being met, SPEL is prohibited from making any distribution (including dividends) if: (1) liquidity is less than $35 million; (2) the aggregate amount of all distributions in the relevant year exceeds 50% of the group's consolidated net profit for the previous financial year; or (3) there is a continuing event of default. SPEL is required to ensure that its group companies do not make any distributions other than to SPEL.

SPEB is required to ensure that SPEFL does not make any distributions while an event of default is continuing.

Covenant package

SPEL is required to ensure that at all times the group maintains liquidity of at least $15 million with such covenant being tested on 30 June and 31 December of each year.

More generally, the Siccar Point Bonds' terms and conditions contain a number of positive and negative covenants which apply to both SPEB and SPEL. Positive covenants include compliance with applicable laws and conducting all business transactions on market terms. The negative covenants include a negative pledge and restrictions (subject to, where appropriate, agreed exceptions) on distributions, additional financial indebtedness, disposals, mergers, and changes in the entities' business.

The Siccar Point Bonds' terms and conditions contain customary events of default which, if applicable, will entitle Nordic Trustee AS to declare that all or part of the outstanding Siccar Point Bonds together with accrued interest are payable. The events of default include non-payment of amounts due, misrepresentation, cross-default and insolvency.

14.3.8 **Capital Note**

On 4 November 2019, the Company (as borrower) and DKL Energy (as lender) entered into a $392.0 million capital note agreement ("**Capital Note Agreement**") pursuant to which the Company issued a note in aggregate principal amount of $392.0 million to DKL Energy (the "**Capital Note**"). The Capital Note was originally subordinated against a $200.0 million facility agreement, dated 4 November 2019, among DKL Energy, the Company and BNP Paribas (the "**BNPP Facility Agreement**"), which was discharged on 18 June 2021. The Capital Note does not bear interest and is not linked to the consumer price index. On 2 October 2022, the Capital Note Agreement was amended to provide that repayment of the Capital Note would not occur prior to 1 January 2024 unless from the proceeds of an initial public offering of the Company (in which case, repayment is permitted on notice). The Capital Note Agreement is governed by English law.

Immediately following Admission, the Company will use the net proceeds of the issue of the Offer Shares pursuant to the Global Offering to repay $214 million of the Capital Note. DKL Energy has agreed to waive all remaining amounts (if any) outstanding under the Capital Note. Following such payment and/or waiver (if any), DKL Energy will provide a confirmation that such payment and/or waiver (if any) is in full and final settlement of any amounts due or payable by the Company in respect of the Capital Note.

14.3.9 **Tracker Loan**

On 4 November 2019, the Company (as borrower) and DKL Energy (as lender) entered into a $198 million intragroup loan agreement ("**Tracker Loan**"). The Tracker Loan was put in place as part of the agreed equity funding of the Chevron Acquisition. The Tracker Loan was originally subordinated against the BNPP Facility Agreement, which was discharged on 18 June 2021. The interest payable by the Company to DKL Energy under the Tracker Loan matched the interest payable pursuant to the BNPP Facility Agreement until 4 May 2021, following which the Tracker Loan became interest free.

The rate of interest on the BNPP Facility Agreement for each interest period (each being a 3 month period) was the aggregate of (1) (i) from and including the utilisation date to but excluding the 27 August 2020, 6.5% per annum; (ii) from and including the 27 August 2020 to and including the 12 month anniversary of the utilisation date, 8.5% per annum; (iii) from but excluding the 12 month anniversary of the utilisation date to and including the 15 month anniversary of the utilisation date, 11% per annum; and (iv) from the date following the 15 month anniversary of the utilisation date, 11.5% per annum; and (2) LIBOR. An interest period was not to extend beyond 4 May 2021.

On 3 October 2022, the Tracker Loan was amended to provide that repayment of the Tracker Loan would not occur prior to 1 January 2024 unless from the proceeds of an initial public offering of the Company (in which case, repayment is permitted on notice). Principal in the amount of $120.0 million and $15.0 million under of the Tracker Loan was repaid in 2020 and 2021, respectively. As at 30 June 2022, the outstanding principal and interest under the Tracker Loan was $77.3 million.

Immediately following Admission, the Company will use the net proceeds of the issue of the Offer Shares pursuant to the Global Offering to repay $63 million of outstanding principal and $14.3 million of accrued interest under the Tracker Loan. DKL Energy has agreed to waive all remaining amounts (if any) outstanding under the Tracker Loan. Following such payment and/or waiver (if any), DKL Energy will provide a confirmation that such payment and/or waiver (if any) is in full and final settlement of any amounts due or payable by the Company in respect of the Tracker Loan.

14.4 ***Subordinated Shareholder Loan***

IEEPL (as borrower), IEUK and DGL (as lender) entered into a $250 million unsecured term loan facility on 4 November 2019 (the "**Subordinated Delek Loan**"). The loan is subordinated against the RBL Facility Agreement and the Indenture. Interest accrues on the loan at a rate of 4.75% per annum.

IEEPL is permitted to prepay the loan provided it is in compliance with the terms of the RBL Facility Agreement and the Indenture and the amount of such prepayment is limited to an amount which IEEPL could use to make an equity distribution or a purchase or redemption of its issued share capital. The loan will mature on 15 November 2025. On 3 August 2021, the Group repaid the outstanding principal. As at 30 June 2022, $28.9 million of accrued interest remained outstanding. On 4 October 2022, the Group repaid in aggregate $29.5 million of accrued and outstanding interest under, and costs payable in connection with, the Subordinated Delek Loan, thereby retiring the loan.

14.5 ***Mitsui Acquisition Agreement***

Mitsui and IOG entered into the Mitsui Acquisition Agreement on 17 September 2021 pursuant to which IOG agreed, on the terms and subject to the conditions of the Mitsui Acquisition Agreement to acquire a 13.3% participating interest in UKCS Petroleum Production Licence No. P.213 Block 16/26, Area A—Alba Field Area (the "**Mitsui Interests**") from Mitsui. Completion under the Mitsui Acquisition Agreement was conditional on certain conditions precedent, including NSTA consent to the transfer of the Mitsui Interests. The conditions precedent were satisfied and the Mitsui Acquisition completed on 30 November 2021. By way of the Mitsui Acquisition, IOG acquired a 13.3% additional interest in the Alba field taking its total interest in the Alba field to 36.7%.

The total consideration for the transfer of the Mitsui Interests was the payment by Mitsui to IOG, following adjustment, of $56.4 million.

Pursuant to the terms of the Mitsui Acquisition Agreement, IOG has indemnified Mitsui for certain decommissioning and environmental liabilities relating to any of the Mitsui Interests acquired by IOG, irrespective of when such liabilities are or were incurred.

The Mitsui Acquisition Agreement contains a number of warranties given by Mitsui in favour of IOG in relation to the Mitsui Interests.

Pursuant to the terms of the Mitsui Acquisition Agreement, IEEPL and Mitsui & Co., Ltd, as the respective parent companies of IOG and Mitsui, entered into deeds of guarantee and indemnity. IEEPL agreed to guarantee to Mitsui: (i) the due and punctual payment to Mitsui by IOG of all amounts which IOG is or shall become obliged to pay to Mitsui; and (ii) the due and punctual performance by IOG of all other terms, covenants, stipulations and obligations in the Mitsui Acquisition Agreement. Mitsui & Co., Ltd agreed to give an equivalent guarantee to IOG in respect of payments and obligations of Mitsui.

14.6 ***Marubeni Acquisition Agreement***

IEEPL (as guarantor), IEUK and MNSL entered into the Marubeni Acquisition Agreement on 2 November 2021 pursuant to which IEUK agreed, on the terms and subject to the conditions of the Marubeni Acquisition Agreement, to acquire the issued share capital of MOGL from MNSL. Completion under the Marubeni Acquisition Agreement was conditional on certain conditions precedent, including NSTA approval of the transaction. The conditions precedent were satisfied and the Marubeni Acquisition completed on 4 February 2022. By way of the Marubeni Acquisition, IEUK acquired MOGL's entire interest in the Marubeni Assets.

IEUK paid a $7 million deposit on signing of the Marubeni Acquisition Agreement and, on completion, taking into account interim period adjustments, MNSL paid IEUK the sum of $70 million. In addition, IEUK has agreed to pay a further $70 million in cash on 1 July 2025. IEUK has also agreed to pay further contingent consideration in cash of up to a maximum amount of $255 million consisting of: (i) $75 million following certain cumulative production volumes in relation to Montrose; (ii) $27 million following certain cumulative production volumes in relation to Arbroath wells; (iii) $43 million following certain cumulative production volumes in relation to a certain well at Shaw; (iv) $25 million in connection with commercial discovery from the Vigne exploration well; (v) $25 million in connection with the tie-back of Birgitta; (vi) $15 million following certain cumulative production volumes in relation to a certain well at Shaw; (vii) $15 million following certain cumulative production volumes in relation to a certain well at Cayley; (viii) up to $30 million, dependent on realised oil prices, in connection with sales volumes from the MonArb and Columba fields during the calendar years 2022 to 2024; and (ix) 20% of revenue above a price of $65/BBL capped at $30 million in total over the years 2023 to 2024.

Pursuant to the terms of the Marubeni Acquisition Agreement, IEUK has indemnified MNSL for certain decommissioning and environmental liabilities relating to the entities acquired by IEUK, irrespective of when such liabilities are or were incurred. IEUK's obligations under the Marubeni Acquisition Agreement are guaranteed by IEEPL.

The Marubeni Acquisition Agreement contains a number of warranties given by MNSL in favour of IEUK in relation to MOGL and the Marubeni Assets.

14.7 ***Summit Acquisition Agreement***

IEEPL (as guarantor), IEUK and Sumitomo entered into the Summit Acquisition Agreement on 28 February 2022 pursuant to which IEUK agreed, on the terms and subject to the conditions of the Summit Acquisition Agreement, to acquire the issued share capital of Summit from Sumitomo. Completion under the Summit Acquisition Agreement was conditional on certain conditions precedent, including approval of the transaction by the NSTA and the Ministry of Economic, Trade and Industry of Japan. The conditions precedent were satisfied and the Summit Acquisition completed on 30 June 2022. By way of the Summit Acquisition, IEUK acquired Summit's entire interest in the Summit Assets.

IEUK paid a $10 million deposit on signing of the Summit Acquisition Agreement and total cash consideration on completion, following interim period adjustments, of $109 million. The cash consideration was funded through a combination of the RBL Facility and existing cash resources of IEUK.

Pursuant to the terms of the Summit Acquisition Agreement, IEUK has indemnified Sumitomo for certain decommissioning and environmental liabilities relating to the entities acquired by IEUK, irrespective of when such liabilities are or were incurred. IEUK's obligations under the Summit Acquisition Agreement are guaranteed by IEEPL.

The Summit Acquisition Agreement contains a number of warranties given by Sumitomo in favour of IEUK in relation to Summit and the Summit Assets. The agreement also contains certain indemnities given by Sumitomo in favour of IEUK, including in respect of liabilities deriving from certain out-of-scope assets which were terminated or transferred out of Summit prior to completion of the Summit Acquisition.

14.8 ***Siccar Point Acquisition Agreement***

IEEPL (as guarantor), IEUK and the Siccar Point Seller entered into the Siccar Point Acquisition Agreement on 7 April 2022 pursuant to which IEUK agreed, on the terms and subject to the conditions of the Siccar Point Acquisition Agreement, to acquire the issued share capital of SPEHL and certain loan notes issued by SPEFL from the Siccar Point Seller. Completion under the Siccar Point Acquisition Agreement was conditional on certain conditions precedent, including NSTA approval of the transaction. The conditions precedent were satisfied and the Siccar Point Acquisition completed on 30 June 2022. By way of the Siccar Point Acquisition, IEUK acquired SPEHL's entire interest in the Siccar Point Assets.

The total cash consideration paid by IEUK on completion in respect of the Siccar Point Acquisition, following adjustment, was $1.015 billion (of which approximately $688 million was paid to the Siccar Point Seller and approximately $278 million was in repayment of an existing lending facility). The cash consideration was funded through a combination of the RBL Facility and existing cash resources of IEUK. In addition, IEUK has agreed to pay in cash a further $1.5/BBL of total Rosebank and Cambo P50 reserves in the respective FDPs (up to a maximum of $300 million aggregate) in connection with final investment decisions being taken in respect of the Cambo field and the Rosebank field, with 50% payable at the end of 2024. Shell's share for Cambo FID of $50 million is expected to be received at Cambo FID. IEUK has also agreed to pay up to a further $60 million quarterly in cash, dependent on realised commodity prices, in connection with sales volumes from the Siccar Point Assets over the calendar years 2023 to 2025. The commodity prices will be based on the higher of (i) 50% of sales volumes multiplied by excess Brent price minus hedging losses and (ii) zero, with floor prices set at $85/BBL (2023), $80/BBL (2024) and $75/BBL (2025).

Pursuant to the terms of the Siccar Point Acquisition Agreement, IEUK has indemnified the Siccar Point Seller for certain decommissioning and environmental liabilities relating to the entities acquired by IEUK, irrespective of when such liabilities are or were incurred. IEUK's obligations under the Siccar Point Acquisition Agreement are guaranteed by IEEPL.

Simultaneous with entry into the Siccar Point Acquisition Agreement, IEUK and certain managers of SPEHL entered into a warranty deed which contained certain warranties given by such managers in favour of IEUK in relation to SPEHL and the Siccar Point Assets.

14.9 ***Kemira Contract for the provision of liquid polymer and associated services***

IOG and Kemira entered into the Kemira Contract on 17 June 2016 pursuant to which Kemira shall provide certain services and products in connection with provision of liquid polymer. There is an agreed pricing formula (as revised by the parties on 1 January 2021) and IOG has 30 days following receipt of an invoice to make payment to Kemira for the relevant work order. The relationship between IOG and Kemira is non-exclusive and will expire on 31 December 2027 (unless mutually agreed otherwise).

Pursuant to the Kemira Contract, IOG can terminate the Kemira Contract, any work order or any part of the work undertaken by Kemira without cause at any time by giving Kemira at least 30 days' notice. IOG shall pay Kemira: (i) for the work performed and the portion of the work in manufacturing process; and (ii) any reasonable documented expenses incurred in respect of any portion of the work not yet put into the manufacturing process less any amount that Kemira is able to avoid, mitigate or recover from another source provided such payments will not exceed the agreed purchase agreement under the Kemira Contract.

Pursuant to the Kemira Contract, the parties agree to indemnify and hold each other harmless in respect of certain losses under the Kemira Contract and other consequential or indirect losses arising out of the Kemira Contract. Subject to certain exceptions, Kemira's total liability to IOG arising out of or related to its performance of the work is limited to the purchase price of the relevant product.

14.10 ***Chevron Acquisition Documents***

14.10.1 **Chevron Acquisition Agreement**

IEUK entered into the Chevron Acquisition Agreement with CNSHL on 29 May 2019. The exercise of the put and call option under the Chevron Acquisition Agreement was conditional on a number of conditions precedent, including OGA approval of the transaction and completion by CNSHL of an internal restructuring in order to extract certain out-of-scope assets and liabilities from CNSL prior to completion. The conditions were satisfied and the Chevron Acquisition completed on 8 November 2019.

The total cash consideration paid by IEUK in respect of the Chevron Acquisition, following adjustment and including a $200 million deposit paid on signing of the CSNL Acquisition Agreement, was $1.727 billion. The cash consideration was funded through a combination of the RBL Facility, the proceeds of the 2024 Notes, equity funds advanced to the Group from holding companies of the Company (see paragraphs 14.3.8, 14.3.9 and 14.4 above) and existing cash resources of IEUK.

As part of the consideration for the Chevron Acquisition, IEUK also assumed CNSHL's obligation to make repayment to CNSL in respect of certain intra-group debts (see paragraph 14.10.3 (*Debts owed by IEUK to CNSL (now IOG)* of this Part 20 (*Additional Information*) below).

By way of the Chevron Acquisition, IEUK acquired CNSL's entire interest in the Chevron Acquired Assets. In addition, certain historic interests—being the Retained Decommissioning Liability Fields—have remained in CNSL under IEUK's ownership in accordance with the terms of the Chevron Acquisition Agreement, as described in paragraph 14.10.3 (*Debts owed by IEUK to CNSL (now IOG)*) of this Part 20 (*Additional Information*) below.

The Chevron Acquisition Agreement contains a number of warranties given by CNSHL in favour of IEUK in relation to CNSL and the Chevron Acquired Assets. The agreement also contains certain indemnities given by CNSHL in favour of IEUK, including in respect of any liabilities deriving from out-of-scope assets which were transferred out of CNSL prior to completion of the Chevron Acquisition (as described above) as well as the Retained Decommissioning Liability Arrangements which are summarised in paragraph 14.10.3 *(Debts owed by IEUK to CNSL (now IOG)*) of this Part 20 (*Additional Information*) below. CNSHL's obligations under the Chevron Acquisition Agreement are guaranteed by a parent entity of substance within CNSHL's group.

IEEPL provided a parent company guarantee on 29 May 2019 in favour of CNSHL pursuant to the Chevron Acquisition Agreement. Under this guarantee, IEEPL is prohibited from merging or consolidating without CNSHL's consent (such consent not to be unreasonably withheld) except for any merger carried out as part of an IPO of the shares in IEEPL or one of its holding companies where, after such merger and IPO, DGL holds directly or indirectly 50% or more of the issued share capital or otherwise retains control of IEEPL and such merger does not prejudice IEEPL's ability to discharge the guaranteed obligations under the parent company guarantee.

14.10.2 **Retained Decommissioning Liability Arrangements**

As part of the Chevron Acquisition, CNSL retained the obligations which had been put in place in respect of: (1) Heather; (2) Strathspey; and (3) Cambo (the "**Retained Decommissioning Liability Arrangements**"), notwithstanding the fact that these fields (the "**Retained Decommissioning Liability Fields**") will generate no value for CNSL (now IOG).

Under the Chevron Acquisition Agreement, CNSHL undertakes to: (a) provide the decommissioning security required to be provided to the counter-party by IOG under each of the Retained Decommissioning Liability Arrangements; and (b) pay the IOG share of the costs of decommissioning each of the Retained Decommissioning Liability Fields to IOG. IOG will pre-fund such costs (to be reimbursed by CNSHL) up to $5 million, with any decommissioning payments over $5 million to be transferred by CNSHL to IOG prior to the date for payment. CNSHL's obligations under the Chevron Acquisition Agreement are guaranteed by a parent entity of substance within CNSHL's group.

If the relevant decommissioning costs are increased as a result of IEUK breaching certain material obligations in the Chevron Acquisition Agreement or IEUK's 'wilful misconduct' (the "**Buyer Liabilities**"), CNSHL shall not be obliged to: (i) provide security; or (ii) pay, for such increased costs. CNSHL provides IEUK with an uncapped decommissioning indemnity in respect of the Retained Decommissioning Liability Fields and for any costs / losses that IOG or IEUK or its affiliates incurs as a result of CNSHL not providing the security or paying the sums required for decommissioning costs in time. Conversely, IEUK provides a counter-indemnity for: (a) any increase in liabilities as a result of IOG voluntarily acquiring additional interest in a Retained Decommissioning Liability Field or transferring any interest to another member of the IEUK group; and (b) the Buyer Liabilities.

A short overview of each of the Retained Decommissioning Liability Arrangements is included below for completeness:

(a) **Heather Retained Decommissioning Liability Arrangements**

CNSL (now IOG) transferred its entire interest in Heather to (now) EnQuest Heather Limited but retained liability for paying its share of the decommissioning costs of the existing Heather facilities. IOG remains a party to the joint operating agreement to the extent of decisions related to decommissioning only. As noted under paragraph 14.10.1 (*Chevron Acquisition Agreement*) of this Part 20 (*Additional Information*), CNSHL will provide the required security and pay such decommissioning costs, subject to the terms of the Chevron Acquisition Agreement.

(b) **Strathspey Retained Decommissioning Liability Arrangements**

CNSL (now IOG) transferred its entire interest in Strathspey to CNR International (U.K.) Limited but retained liability for paying decommissioning costs related to the transferred interest up to a cap. As noted under paragraph 14.10.1 (*Chevron Acquisition Agreement*) of this Part 20 (*Additional Information*), CNSHL will provide the required security and pay such decommissioning costs, subject to the terms of the Chevron Acquisition Agreement.

(c) **Cambo exploration well Retained Decommissioning Liability Arrangements**

CNSL (now IOG) withdrew from the Cambo field and transferred its entire interest to SPEEPL, but retained liability for paying decommissioning costs related to the transferred interest if abandonment of the Cambo well occurs by 11 May 2022. As noted under paragraph 14.10.1 (*Chevron Acquisition Agreement*) of this Part 20 (*Additional Information*), CNSHL will provide the required security and pay such decommissioning costs, subject to the terms of the Chevron Acquisition Agreement. The Company understands that abandonment of the Cambo well did not occur by 11 May 2022.

14.10.3 **Debts owed by IEUK to CNSL (now IOG)**

(a) **Pre-Chevron Acquisition Restructuring Loan**

As part of the extraction of the out-of-scope asset and liabilities from CNSL to CNSHL prior to completion of the Chevron Acquisition (as described in paragraph 14.10.1 (*Chevron Acquisition Agreement*) of this Part 20 (*Additional Information*)), a loan was put in place between CNSHL and CNSL (the "**Pre-Chevron Acquisition Restructuring Loan**"). The Pre- Chevron Acquisition Restructuring Loan, which is the form of a non-interest-bearing loan note originally issued by CNSHL in favour of CNSL, represented the consideration owed by CNSHL to CNSL in respect of the transfer of such assets and liabilities.

CNSHL's obligations in respect of the Pre-Chevron Acquisition Restructuring Loan (including the obligation to make repayment in respect of such loan) were novated to IEUK on 8 November 2019 as part of completion of the Chevron Acquisition. The amount outstanding in respect of the Pre-Chevron Acquisition Restructuring Loan is £331,978,471.

(b) **Pre-Chevron Acquisition Cash Extraction Loan**

Prior to completion of the Chevron Acquisition (and in accordance with the Chevron Acquisition Agreement), certain cash sums were extracted from CNSL and transferred to CNSHL by way of an upstream loan (the "**Pre-Chevron Acquisition Cash Extraction Loan**"). The Pre-Chevron Acquisition Cash Extraction Loan is in the form of a non-interest-bearing intra-group term loan originally entered into between CNSL (as lender) and CNSHL (as borrower).

CNSHL's obligations in respect of the Pre-Chevron Acquisition Cash Extraction Loan (including the obligation to make repayment in respect of such loan) were novated to IEUK on 8 November 2019 as part of completion of the Chevron Acquisition. The amount of principal outstanding in respect of the Pre-Chevron Acquisition Cash Extraction Loan is $510 million as at 30 June 2022.

14.10.4 **Captain IP Licence**

Pursuant to the terms of an intellectual property licence between CNSHL (as licensor) and IEUK (as licensee) (as successor to CNSL (now IOG) following the transfer of the operations in respect of the Captain field to IEUK on 6 January 2020) dated 8 November 2019 (the "**Captain IP Licence**"), CNSHL granted to IOG a non-exclusive, royalty-free and sub-licensable licence to use certain intellectual property in the area of the Captain field. The purpose of the Captain IP Licence is to allow IOG to continue exploration and production operations in the Captain field after closing of the Chevron Acquisition Agreement, which is essential for the ongoing Captain EOR (see Part 6 (*Business Overview*)).

The licensed intellectual property includes UK patents resulting from patent applications pertaining to: (i) polymer flooding enhanced oil recovery; (ii) surfactant stimulation; and (iii) produced polymer patents for chemical treatment and heat exchange coating, and certain know how relating to use in the area of the Captain field. CNSHL makes no warranties and disclaims all liabilities in respect of the licensed intellectual property. IOG will indemnify CNSHL if it suffers any loss in connection with IOG's exercise of rights under the Captain IP Licence, use by a third party of the licensed intellectual property disclosed to them by IOG, any breach by IOG of the terms of the Captain IP Licence and third-party claims.

The Captain IP Licence will continue until the cessation of production from the Captain field, unless terminated by CNSHL sooner in accordance with the terms of the Captain IP Licence.

14.10.5 **Master IP Licence**

Pursuant to the terms of a master licence agreement between Chevron USA. Inc (as licensor) and IOG and IEUK (the "**Licensees**") dated 8 November 2019 (the "**Master Licence Agreement**"), Chevron USA has agreed to licence certain valuable and proprietary information and materials that can be used in planning, constructing, operating, maintaining and managing the Interests (as defined in the Chevron Acquisition Agreement) solely for the purposes of allowing the Licensees to continue exploration and production operations within the Interests after closing of the Chevron Acquisition Agreement. Each non-exclusive, royalty-free licence to use certain materials and processes is granted pursuant to, and governed by the terms of, individual Process Licence Agreements to be entered into between Chevron USA and the Licensees in accordance with the Master Licence Agreement.

Other than warranting that it has the right to grant such licences, Chevron USA makes no warranties and disclaims all liabilities in respect of the materials and processes. Subject to certain exceptions, the Licensees will indemnify Chevron USA if it suffers any loss in connection with the Licensees' exercise of rights under the Master Licence Agreement and any Process Licence Agreements, use by a third party of the materials and processes disclosed to them by the Licensees, any breach by the Licensees of the terms of the Master Licence Agreement and third-party claims.

The Master Licence Agreement will continue until the cessation of production from all of the Interests, unless terminated by Chevron USA. sooner in accordance with the terms of the Master Licence Agreement. Each individual Process Licence Agreement has an expiry date specified within its terms.

14.11 ***Technip Contract for the provision of pipelay and subsea construction services (including flexible and umbilical supply) for the Captain EOR II***

IEUK and Technip have entered into the Technip Contract which was signed on 29 April 2021 and 4 May 2021, pursuant to which Technip will perform pipelay and subsea construction services (including flexible and umbilical supply) in relation to the Captain EOR II. The Technip Contract incorporates a schedule of rates and prices which apply to the work. Technip is to be remunerated on a milestone payment basis. IEUK is obliged to make payment of Technip's invoices within 30 days of receipt. The scheduled completion date for completion of all of the work under the Technip Contract is 1 March 2024.

IEUK has the right to terminate the Technip Contract for its convenience on notice to Technip. In the event of such termination, IEUK is obliged to make payment of a cancellation payment to Technip provided that Technip is progressing the work in accordance with the schedule set out in the Technip Contract. Any amounts already paid to Technip by IEUK as part of the milestone payment structure are to be deducted from the cancellation payment. IEUK also has express rights to terminate the Technip Contract in response to any material default on the part of Technip and also if Technip becomes subject to specified insolvency events.

The parties have both agreed to indemnify and hold each other harmless in relation to specified risks (including consequential and indirect losses). The Technip Contract incorporates various financial caps on Technip's liability.

15. SIGNIFICANT CHANGE

There has been no significant change in either the financial performance or financial position of the Group since 30 June 2022, being the end of the last financial period for which the historical financial information in Part 16 (*Historical Financial Information*) relating to the Group was published.

16. WORKING CAPITAL

In the opinion of the Company, taking into account the proceeds of the Global Offering and the facilities available to the Group, the working capital available to the Group is sufficient for the Group's present requirements, that is for at least the next 12 months following the date of this Prospectus.

17. LEGAL AND ARBITRATION PROCEEDINGS

There are no governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which the Company is aware) during the 12 months preceding the date of this Prospectus, which may have, or have had in the recent past, significant effects on the Company's and/or the Group's financial position or profitability, save as described in this paragraph 17 (*Legal and Arbitration Proceedings*).

IEEPL and the Group's former CEO, Les Thomas, are party to a securities class action lawsuit under the Alberta Securities Act. Initiated in May 2015, the class action alleges that IEEPL published documents and made certain statements containing misrepresentations regarding the FPF-1 floating production facility and the then-development of the Greater Stella Area. On 7 March 2019, the plaintiff's application for leave to commence a secondary market claim under the Alberta Securities Act and for certification of such claim as a class action was heard by the Court of Queen's Bench of Alberta. On 24 June 2019, a judgment was issued by the court granting leave to proceed with the claim for a reduced claim period. The dispute remains ongoing, and the Company does not anticipate a trial on the merits to occur until late 2024 or 2025, following mediation expected in 2023 due to Alberta being a mandatory mediation jurisdiction. The Plaintiff's counsel has estimated its damages to be approximately C$30 million (Canadian dollars). However, given the uncertainty of litigation, the preliminary stage of the case, and the legal standards that must be met for, among other things, class certification and success on the merits, the Company cannot estimate the reasonably possible loss or range of loss that may result from this action. IEEPL disputes these claims and intends to defend the matter vigorously.

On 15 May 2020, Greenpeace Limited appealed to the Court of Session against the decisions of the Secretary of State to agree to the grant of consent for the Vorlich field development and of the decision of the NSTA to grant consent to BP Exploration Operating Company Limited (then operator of the Vorlich field) for the Vorlich field development. Greenpeace Limited sought an order quashing the decisions of the Secretary of State and the NSTA in respect of the Vorlich field development and their judicial costs. The appeal was unsuccessful. Following a hearing in September 2021 the Inner House of the Court of Session refused Greenpeace Limited's appeal on 7 October 2021. Greenpeace Limited sought permission to appeal the Inner House of the Court of Session's decision to the Supreme Court of the United Kingdom. Permission to appeal was refused by the Inner House of the Court of Session on 14 January 2022 and by the Supreme Court of the United Kingdom on 25 August 2022 (Greenpeace Limited having sought said permission directly).

IEUK, as a partner in the Vorlich field, was an interested party in relation to the Court of Session proceedings. As the permission to appeal has been refused, the appeal process comes to an end and the consents remain unaffected.

On 29 April 2021, IEUK commenced formal arbitration proceedings against CNSHL. The arbitration is seated in London, UK, governed by the Arbitration Act 1996, and is being conducted under the UNCITRAL Rules. IEUK has brought the claims in relation to CNSHL's alleged misrepresentations and breach of certain provisions of the Chevron Acquisition Agreement in respect of the condition of the Alba floating storage unit. Given the ongoing nature of the proceedings and the possibility of different outcomes, the Group has not made any provision in the Group's accounts in respect of this matter. Whilst the quantum of the damages is subject to expert evidence that is yet to be finalised, it is IEUK's reasonable expectation that, if it is successful in the proceedings, the level of damages recovered will be material. IEUK is not aware of any reason why the counterparty to the arbitration would be unable to satisfy any award. CNSHL has not brought any counterclaims against IEUK, and IEUK's exposure is therefore limited to an adverse costs award (an adverse costs award is unlikely to be material in the context of the Group's operations).

18. RELATED THIRD PARTY TRANSACTIONS

18.1 *The Company*

18.1.1 Save as disclosed below, there are no related party transactions between the Company and its related parties that were entered into during the financial years covered by the historical financial information and up to the Latest Practicable Date.

18.1.2 The Company main related parties comprise members of key management personnel and it's controlling shareholder, DKL Energy, along with affiliated persons and entities. Delek Group is the ultimate holding company of DKL Energy. Transactions with these related parties are disclosed below:

(a) Pursuant to arrangements agreed with IEEPL on 15 July 2021, Mr Wallace, a Non-Executive Director of the Company and the CEO of the Delek Group, is entitled to a success based compensation linked to the outcome of the arbitration proceedings raised by IEUK, further details of which are set out in paragraph 17 *(Legal and Arbitration Proceedings*) of this Part 20 (*Additional Information*). In the event that IEUK is successful in the proceedings, either by way of commercial settlement or arbitral award by the arbitration tribunal, Mr Wallace shall be entitled to up to 1% of the net proceeds received by IEUK provided at the date of payment he remains in employed by the Delek Group and no notice to terminate his employment has been served. The outcome of the claim is uncertain at this stage and the quantum of any proceeds sought by IEUK is subject to expert evidence that is yet to be finalised. As such it is not possible to quantify the amount of any potential additional compensation and consequently it is not possible to quantify Mr Wallace's potential additional compensation, although it is IEUK's reasonable expectation that, if it is successful in the proceedings, the level of damages recovered by IEUK will be material and accordingly Mr Wallace's additional success based compensation could be significant. Further details of the proceedings are set out in paragraph 17 (*Legal and Arbitration Proceedings*) of this Part 20 (*Additional Information*). Mr Myerson, the Executive Chairman of the Company is entitled to a payment of up 1.8% of the net proceeds received by IEUK in respect of the same arbitration proceedings on the same terms as Mr Wallace's additional compensation. Further details of the arrangements for Mr Myerson are set out in paragraph 10.6 (*Additional success based compensation*) of this Part 20 (*Additional Information*).

(b) The Company has been notified by Delek that it intends to establish a management equity plan at the level of DKL Energy for the benefit of Mr Wallace and certain other senior executives within the Delek Group (the "**Delek MEP**"). The Company understands that the terms of the Delek MEP are in the process of being agreed but that the Delek MEP will be satisfied by the transfer by DKL Energy of Ordinary Shares to the particular individual and will be subject to the terms of the lock-up arrangements to which DKL Energy is bound pursuant to the terms of the Underwriting and Sponsors' Agreement which require that Mr Wallace enter into lock-up arrangements on the same terms as the other Directors.

(c) The Company (as borrower) and DKL Energy (as lender) are party to the Capital Note Agreement pursuant to which the Company issued the Capital Note to DKL Energy. Immediately following Admission, the Company will use the net proceeds of the issue of the Offer Shares pursuant to the Global Offering to repay $214 million of the Capital Note. DKL Energy has agreed to waive all remaining amounts (if any) outstanding under the Capital Note. Following such payment and/or waiver (if any), DKL Energy will provide a confirmation that such payment and/or waiver (if any) is in full and final settlement of any amounts due or payable by the Company in respect of the Capital Note. Further details of the Capital Note Agreement and Capital Note are set out in paragraph 2.1 (*Capital Note*) of Part 10 (*Principal Shareholder and Related Party Transactions*).

(d) The Company (as borrower) and DKL Energy (as lender) are party to the Tracker Loan. Principal in the amount of $120.0 million and $15.0 million under the Tracker Loan was repaid in 2020 and 2021, respectively. As at 30 June 2022, the outstanding principal and interest under the Tracker Loan was $77.3 million. Immediately following Admission, the Company will use the net proceeds of the issue of the Offer Shares pursuant to the Global Offering to repay $63 million of outstanding principal and $14.3 million of accrued interest under the Tracker Loan. DKL Energy has agreed to waive all remaining amounts (if any) outstanding under the Tracker Loan. Following such payment and/or waiver (if any), DKL Energy will provide a confirmation that such payment and/or waiver (if any) is in full and final settlement of any amounts due or payable by the Company in respect of the Tracker Loan. Further details of the Tracker Loan are set out in paragraph 2.2 (*Tracker Loan*) of Part 10 (*Principal Shareholder and Related Party Transactions*).

(e) On 29 September 2022, the Company, DKL Energy and Gilad Myerson entered into a management incentive agreement relating to the Company (the "**Management Incentive Agreement**"). Pursuant to the Management Incentive Agreement and a related share subscription agreement, Mr Myerson has acquired an interest in the MEP Shares. The MEP Shares that Mr Myerson has acquired in are subject to restrictions on Mr Myerson's ability to transfer or dispose of such MEP Shares, or to receive any dividends or exercise any voting rights in connection with them, for the duration of a specified vesting period ordinarily expiring in 2026. For further details, please see paragraph 11.5 (*Management Equity Plan*) of Part 20 (*Additional Information*).

(f) Alan Bruce and Gilad Myerson each have an option over Ordinary Shares (the "**Option**"). The Option represents a right to subscribe for Ordinary Shares (the "**Option Shares**") which have a value which is equal to the higher of (i) 0.2% of the net value of IEEPL's assets less its liabilities as at the date immediately before the initial public offering of the Company's shares; and (ii) 0.2% of the market value of the issued share capital of the Company by reference to the most recent annual valuation of the Company's shares undertaken for audit as at the date immediately before the initial public offering of the Company's shares. For further details of the arrangements please see paragraph 11.6 (*Option Agreements*) of Part 20 (*Additional Information*).

19. AUDITORS AND REPORTING ACCOUNTANTS

19.1 Deloitte LLP, whose office is at 1 New Street Square, London, EC4A 3HQ, has provided an accountant's report on the historical financial information of the Group for the three years ended 31 December 2019, 2020 and 2021 and the six months ended 30 June 2022 as set out in Section A (*The Group*) of Part 16 (*Historical Financial Information*). Deloitte LLP is registered to carry on audit work in the UK and Ireland by the Institute of Chartered Accountants in England and Wales.

19.2 Ernst & Young LLP, whose office is at 1 More London Place, London, SE1 2AF, has provided an accountant's report on (i) the historical financial information of the Siccar Point Group for the three years ended 31 December 2019, 2020 and 2021 and the six months ended 30 June 2022 as set out in Section B (*The Siccar Point Group*) of Part 16 (*Historical Financial Information*) and (ii) the historical financial information of IOG (formerly Chevron North Sea Limited) for the year ended 31 December 2019 as set out in Section C (*IOG*) of Part 16 (*Historical Financial Information*). Ernst & Young LLP is registered to carry on audit work in the UK and Ireland by the Institute of Chartered Accountants in England and Wales.

19.3 The financial information contained in this Prospectus which relates to the Company does not constitute full statutory accounts as referred to in section 434(3) of the 2006 Act. Statutory audited accounts of Ithaca Energy, on which the Ithaca Energy's previous auditors, Ernst & Young LLP, have given their unqualified report and which contained no statement under section

498(2) or (3) of the 2006 Act, have been delivered to the Registrar of Companies in respect of the two accounting periods ended 31 December 2019 and 31 December 2020. Statutory audited accounts of Ithaca Energy, on which the Ithaca Energy's auditors, Deloitte LLP, have given their unqualified report and which contained no statement under section 498(2) or (3) of the 2006 Act, have been delivered to the Registrar of Companies in respect of the accounting period ended 31 December 2021.

20. CONSENTS

20.1 Deloitte LLP of 1 New Street Square, London, EC4A 3HQ is registered to carry on audit work in the UK and Ireland by the Institute of Chartered Accountants in England and Wales and has given and has not withdrawn its written consent to the inclusion in this Prospectus of its report in Section A (*The Group*) of Part 16 (*Historical Financial Information*) and Part 17 (*Unaudited Pro Forma Condensed Combined Financial Information*) and references thereto, in the form and context in which they appear and has authorised the contents of its reports for the purposes of item 1.3 of Annex 1 of the UK version of Commission Delegated Regulation (EU) 2019/980, as it forms part of UK law by virtue of the EUWA. A written consent under the Prospectus Regulation Rules is different from a consent filed with the US Securities and Exchange Commission under Section 7 of the US Securities Act. Deloitte LLP has not filed and will not be required to file a consent under Section 7 of the US Securities Act.

20.2 Ernst & Young LLP of 1 More London Place, London, SE1 2AF has given and has not withdrawn its written consent to the inclusion in this Prospectus of its reports in Section B (*The Siccar Point Group*) and Section C (*IOG*) of Part 16 (*Historical Financial Information*) and references thereto, in the form and context in which they appear and has authorised the contents of its reports for the purposes of item 1.3 of Annex 1 of the UK version of Commission Delegated Regulation (EU) 2019/980, as it forms part of UK law by virtue of the EUWA. A written consent under the Prospectus Regulation Rules is different from a consent filed with the US Securities and Exchange Commission under Section 7 of the US Securities Act. Ernst & Young LLP has not filed and will not be required to file a consent under Section 7 of the US Securities Act.

20.3 Netherland, Sewell & Associates, Inc., whose registered office is at 2100 Ross Avenue, Suite 2200, Dallas, Texas 75201, United States of America, are independent petroleum engineers, geologists, geophysicists and petrophysicists and (in its capacity as a competent person), Netherland, Sewell & Associates, Inc., has given and not withdrawn its written consent to the inclusion in this Prospectus of its report which is set out in Part 23 (*Competent Person's Report*) and references thereto in the form and context in which they appear and has authorised the contents of those parts of this Prospectus for the purposes of 5.3.2(2)(f) of the Prospectus Regulation Rules. Netherland, Sewell & Associates, Inc do not have any material interest in the Company. The Company confirms that, between the date of publication of the NSAI CPR and the date of this Prospectus, no material changes have occurred, the omission of which would make the NSAI CPR misleading.

21. THIRD PARTY INFORMATION

21.1 *External Publications*

The Company confirms that all external third-party information included in this Prospectus has been accurately reproduced and, so far as the Company is aware and has been able to ascertain from information published by such third parties, no facts have been omitted which would render the reproduced information inaccurate or misleading. Where third-party information has been used in this Prospectus, the source of such information has been identified. Where the Group has relied upon internally developed estimates, the information is identified as Company estimates or beliefs. Unless otherwise stated, such information has not been audited.

21.2 *NSAI CPR*

There have been no material changes since the effective date of the NSAI CPR (being 30 June 2022), the omission of which would make such report misleading.

22. GENERAL

22.1 The total costs and expenses of, and incidental to, Admission and the Global Offering (being the Underwriters' expenses, Selling Shareholder's Expenses, IPO Expenses and any discretionary fees) are estimated to amount to approximately £23.7 million (including VAT).

22.2 The financial information contained in this Prospectus does not amount to statutory accounts within the meaning of Section 434(3) of the Companies Act 2006.

23. WITHDRAWAL RIGHTS

23.1 In the event that the Company is required to publish a supplementary prospectus, applicants who have applied to subscribe for Offer Shares in the Global Offering will have at least two Business Days following the publication of the supplementary prospectus within which to withdraw their offer to subscribe for Offer Shares in the Global Offering pursuant to Article 23(2) of the UK Prospectus Regulation.

23.2 If the application is not withdrawn within the stipulated period, any offer to apply for Offer Shares in the Global Offering will remain valid and binding.

24. DOCUMENTS AVAILABLE FOR INSPECTION

24.1 Copies of the following documents shall be available for inspection on the Company's website at www.Ithaca'senergy.com for a period of 28 days from the date of publication of this Prospectus:

24.1.1 the Articles;

24.1.2 the historical financial information of the Group as at and for the six months ended 30 June 2022 and the years ended 31 December 2019, 2020 and 2021 and , together with the related accountant's report from Deloitte LLP, which is set out in Part A (*The Group*) of Part 16 (*Historical Financial Information*);

24.1.3 the historical financial information of the Siccar Point Group as at and for the six month period ended 30 June 2022 and the years ended 31 December 2019, 2020 and 2021, together with the related accountant's report from Ernst & Young LLP, which is set out in Section B (*The Siccar Point Group*) of Part 16 (*Historical Financial Information*);

24.1.4 the historical financial information of IOG (formerly Chevron North Sea Limited) as at and for the year ended 31 December 2019, together with the related accountant's report from Ernst & Young LLP, which is set out in Section C (*IOG*) of Part 16 (*Historical Financial Information*);

24.1.5 the report from Deloitte LLP on the unaudited pro forma condensed combined financial information, which is set out in Part 17 (*Unaudited Pro Forma Condensed Combined Financial Information*);

24.1.6 the Competent Person's Report by Netherland, Sewell & Associates, Inc., set out in Part 23 (*Competent Person's Report*);

24.1.7 the consent letters referred to in paragraph 20 (*Consents*) of this Part 20 (*Additional Information*) above; and

24.1.8 a copy of this Prospectus.

PART 21

DEFINITIONS

The following definitions apply throughout this Prospectus unless the context requires otherwise:

"**$**" or "**USD**" or "**US dollars**"	the lawful currency of the United States;
"**£**" or "**GBP**" or "**UK pounds sterling**" or "**pence**"	the lawful currency of the United Kingdom;
"**€**" or "**Euro**"	the single currency of the participating member states of the Third Stage of European Economic and Monetary Union of the Treaty Establishing the European Community, as amended from time to time;
"**2006 Act**" or "**Companies Act**"	the Companies Act 2006, as amended;
"**2024 Notes**"	the $500 million aggregate principal amount of 9.375% senior notes due 2024 issued by the Bond Issuer;
"**2026 Notes**"	the $625 million aggregate principal amount of 9.000% senior notes due 2026 issued by the Bond Issuer;
"**A Ordinary Shares**"	has the meaning given to it in paragraph 5.2 (*History of the Share Capital*) Part 20 (*Additional Information*);
"**AB Option**"	has the meaning given to it in paragraph 11.6 (*Option Agreements*) in Part 20 (*Additional Information*);
"**AB Option Shares**"	has the meaning given to it in paragraph 11.6 (*Option Agreements*) in Part 20 (*Additional Information*);
"**Addendum**"	the first addendum, to the Israeli Securities Law;
"**Adjusted EBITDAX**"	has the meaning given to it in paragraph 1.1 (*Basis of Preparation*) of Part 15 (*Profit Forecasts*);
"**Admission**"	admission of the Ordinary Shares to the premium listing segment of the Official List (under Chapter 6 of the Listing Rules) and the admission of such shares to trading on the Main Market becoming effective in accordance with the Listing Rules and the current edition of the Admission and Disclosure Standards published by the London Stock Exchange;
"**AIM**"	the AIM market operated by the London Stock Exchange;
"**Alberta Securities Act**"	the Securities Act (Alberta), RSA 2000 cS-4 in Canada;
"**Altera**"	Altera Infrastructure;
"**Annual Exemption**"	has the meaning given to it in paragraph 1.2.1 (*Individual Shareholders*) of Part 19 (*Taxation*);
"**Articles**" or **"Articles of Association"**	the articles of association of the Company as amended from time to time;
"**Aspen**"	Aspen Insurance UK Limited;
"**Aspen Deed of Indemnity**"	the deed of indemnity between, amongst others, IEEPL (as principal indemnitor) and Aspen dated 30 November 2020;
"**At-IPO Awards**"	has the meaning given to it in paragraph 11.1 (*Ithaca Energy Long Term Incentive Plan*) of Part 20 (*Additional Information*);
"**Audit and Risk Committee**"	the audit and risk committee of the Board;

"**Available Liquidity**"	has the meaning given to it in paragraph 4 (*Non-IFRS Financial Information*) of Part 3 (*Presentation of Financial and Other Information);*
"**B1 Ordinary Shares**"	has the meaning given to it in paragraph 5.2 (*History of the Share Capital*) Part 20 (*Additional Information*);
"**B2 Ordinary Shares**"	has the meaning given to it in paragraph 5.2 (*History of the Share Capital*) Part 20 (*Additional Information*);
"**BEIS**"	the Department of Business, Energy and Industrial Strategy of the United Kingdom;
"**BNPP Facility Agreement**"	$200.0 million facility agreement dated 4 November 2019 among DKL Energy, the Company and BNP Paribas;
"**Board**"	the board of Directors of the Company;
"**BofA Securities**"	Merrill Lynch International;
"**Bond Subordination Agreement**"	the bond subordination agreement among, amongst others, IEEPL, DGL, BNP Paribas and BNY Mellon Corporate Trustee Services Limited dated 1 November 2019;
"**Brexit**"	the withdrawal of the United Kingdom from the European Union;
"**Business Day**"	a day other than a Saturday or Sunday on which banks are generally open for non-automated business in the City of London;
"**Buyer Liabilities**"	has the meaning given to it in paragraph 14.10.2 (*Retained Decommissioning Liability Arrangements*) of Part 20 (*Additional Information*);
"**C(WUMP)O**"	Companies (Winding Up and Miscellaneous Provisions) Ordinance (Cap. 32, Laws of Hong Kong);
"**Capital Note**"	the capital note in aggregate principal amount of $392,000,000 issued by the Company to DKL Energy pursuant to the Capital Note Agreement;
"**Capital Note Agreement**"	the $392,000,000 capital note agreement between the Company (as borrower) and DKL Energy (as lender) dated 4 November 2019, as amended from time to time;
"**Captain IP Licence**"	has the meaning given to it in paragraph 14.10.4 (*Captain IP Licence*) of Part 20 (*Additional Information*);
"**certificated**" or "**in certificated form**"	a share or other security (as appropriate) not in uncertificated form (that is, not in CREST);
"**Chairman**" or "**Executive Chairman**"	the executive chairman of the Board;
"**Chevron Acquired Assets**"	those assets acquired by the Group by way of the Chevron Acquisition, being Alba, Alder, Britannia, Brodgar, Callanish, Captain, Elgin-Franklin, Enochdhu, Erskine, Jade and Thunderball;
"**Chevron Acquisition Agreement**"	the put and call option agreement entered into between CNSHL and IEUK in respect of the Chevron Acquisition dated 29 May 2019, as amended from time to time;
"**Chevron Acquisition**"	the acquisition by IEUK from CNSHL of the entire issued share capital of CNSL;

"**City Code**" or "**Code**"	the UK City Code on Takeovers and Mergers, as amended, supplemented or replaced from time to time;
"**CNSHL**"	Chevron Eurasia Pacific Limited (formerly named Chevron North Sea Holdings Limited), a company incorporated in England & Wales with registered number 11867122;
"**CNSL**" or "**IOG**"	Ithaca Oil and Gas Limited (formerly named Chevron North Sea Limited), a company incorporated in England & Wales with registered number 01546623;
"**COBS**"	FCA Handbook Conduct of Business Sourcebook;
"**Company**" or "**the Issuer**"	Ithaca Energy plc, a public company limited by shares, incorporated under the 2006 Act and registered in England and Wales with the registered number 12263719;
"**Controlling Shareholder**"	Mr Tshuva, the controlling shareholder of the Delek Group, who as at the Latest Practicable Date, held 50.19% of the voting rights in DGL;
"**CREST**"	the relevant system (as defined in the CREST Regulations) for paperless settlement of sales and purchases of securities and the holding of shares in uncertificated form in respect of which Euroclear is the operator (as defined in the CREST Regulations);
"**CREST Regulations**"	the Uncertificated Securities Regulations 2001 (SI 2001/3755);
"**Current Year Profit Forecast**"	has the meaning given in paragraph 1 (*Current Year Profit Forecast*) of Part 15 (*Profit Forecasts*);
"**Deeds of Indemnity**"	together, the HCCI Deed of Indemnity, Everest Deed of Indemnity, Aspen Deed of Indemnity and MIIC Deed of Indemnity;
"**Delek**" or "**DGL**"	Delek Group Ltd., a company incorporated in Israel with registered number 520044322 and whose securities are admitted to trading on the Tel Aviv Stock Exchange;
"**Delek Group**"	DGL and its subsidiaries;
"**Delek Group Q1 Announcement**"	the announcement released by the Delek Group on 24 May 2022 in relation to the financial results for the Delek Group, including the Group for Q1 2022;
"**Delek MEP**"	has the meaning given to it in paragraph 18.1 (*Ithaca Energy*) of Part 20 (*Additional Information*);
"**DFSA**"	Dubai Financial Services Authority rulebook;
"**Directors**"	the directors of the Company as at the date of this Prospectus, whose details are set out in Part 8 (*Directors, Senior Managers and Corporate Governance*), and "**Director**" means any one of them;
"**Disclosure Guidance and Transparency Rules**"	the disclosure guidance and transparency rules issued by the FCA under Part VI of FSMA;
"**DKL Energy**" or "**Selling Shareholder**"	DKL Energy Limited, a company incorporated in Jersey with registered number 130061;
"**DKL Investments**"	DKL Investments Limited, a company incorporated in Jersey with registered number 116681;
"**DSBP**"	the Ithaca Energy Deferred Share Bonus Plan;

"**DSBP Awards**"	has the meaning given to it in paragraph 11.2 (*Ithaca Energy Deferred Bonus Plan*) of Part 20 (*Additional Information*);
"**EEA**" or "**European Economic Area**"	together, the EU, Iceland, Liechtenstein and Norway;
"**Energy Act**"	the Energy Act 2016 (and "**Energy Acts**" means such Act and other applicable Energy Acts of the United Kingdom from time to time, in each case as amended from time to time);
"**Energy Profits Act**"	Energy (Oil and Gas) Profits Levy Act 2022;
"**Energy Profits Levy**"	the charge referred to as the energy (oil and gas) profits levy within the Energy (Oil and Gas) Profits Levy Act 2022;
"**EnQuest**"	EnQuest PLC;
"**EPL Profit**"	has the meaning given to it in paragraph 5.4 (*Energy Profit Levy*) in Part 11 (*Regulation*);
"**EPL Loss**"	has the meaning given to it in paragraph 5.4 (*Energy Profit Levy*) in Part 11 (*Regulation*);
"**ESG**"	Environmental, Social and Governance;
"**ESMA Guidelines**"	the guidelines issued by the European Securities and Markets Authority on 5 October 2015 on alternative performance measures, as further described in the "Q&A on Alternative Performance Measures Guidelines" published in 17 April 2020;
"**EURIBOR**"	the Euro Inter-bank Offered Rate;
"**Euroclear**"	Euroclear UK & Ireland Limited, the operator (as defined in the CREST Regulations) of CREST;
"**European Union**" or "**EU**"	the European Union, first established by the treaty made at Maastricht on 7 February 1992;
"**EUWA**"	the European Union (Withdrawal) Act 2018 as amended and supplemented from time to time (including, but not limited to, by the EU (Withdrawal) Act 2020);
"**Everest**"	Everest Insurance (Ireland), DAC;
"**Everest Deed of Indemnity**"	the deed of indemnity between, amongst others, IEEPL (as principal indemnitor) and Everest dated 22 January 2022;
"**Executive Directors**"	the executive directors of the Company as at the date of this Prospectus, being Gilad Myerson, Alan Bruce and Iain Lewis, whose details are set out in Part 8 (*Directors, Senior Managers and Corporate Governance*);
"**Facilities**"	together, Facility A and Facility B;
"**Facility A**"	a multicurrency revolving borrowing base credit facility up to $1.076 billion comprising BNP Paribas, Lloyds Bank plc, Wells Fargo Bank N.A., London Branch, The Royal Bank of Scotland plc, Deutsche Bank AG, Amsterdam Branch, DNB (UK) Limited, ING Belgium S.A./NV, Morgan Stanley and Mizrahi Tefahot Bank Limited, London Branch as lenders;
"**Facility B**"	a US dollar revolving borrowing base credit facility up to $149 million comprising BNP Paribas, Lloyds Bank plc, Wells Fargo Bank N.A., London Branch, The Royal Bank of Scotland plc, Deutsche Bank AG, Amsterdam Branch, DNB (UK) Limited, ING Belgium S.A./NV, Morgan Stanley and Mizrahi Tefahot Bank Limited, London Branch as lenders;

"**FCA**"	UK Financial Conduct Authority;
"**FCA Announcements**"	has the meaning given to it in paragraph 2.4 (*Certain of the Group's outstanding borrowings will bear interest at floating rates which could rise significantly, thereby increasing its interest cost and reducing cash flows*) of Part 2 (*Risk Factors*);
"**FDP**"	the field development plan;
"**FID**"	Final investment decision;
"**FinSA**"	the Swiss Financial Services Act;
"**FRC**"	Financial Reporting Council in the United Kingdom;
"**Free Cashflow**"	means Group Free Cashflow or Siccar Point Free Cashflow, as applicable;
"**Free Shares**"	has the meaning given to it in paragraph 11.4. (*Share Incentive Plan*) of Part 20 (*Additional Information*);
"**FSMA**"	the Financial Services and Markets Act 2000, as amended;
"**FY2019**"	the financial year of the Group or IOG or the Siccar Point Group (as applicable) ended 31 December 2019;
"**FY2020**"	the financial year of the Group or IOG or the Siccar Point Group (as applicable) ended 31 December 2020;
"**FY2021**"	the financial year of the Group or IOG or the Siccar Point Group (as applicable) ended 31 December 2021;
"**Global Offering**"	means the Offer Shares being allotted and issued at the Offer Price as described in Part 18 (*Details, Terms and Conditions of the Global Offering)*;
"**GM Option**"	has the meaning given to it in paragraph 11.6 (*Option Agreements*) in Part 20 (*Additional Information*);
"**GM Option Shares**"	has the meaning given to it in paragraph 11.6 (*Option Agreements*) in Part 20 (*Additional Information*);
"**Goldman Sachs International**" . . .	Goldman Sachs International;
"**Governance Code**"	the UK Corporate Governance Code issued by the Financial Reporting Council, as amended from time to time;
"**Group**" or **"Ithaca Energy**"	the Company and its Subsidiaries from time to time;
"**Group Adjusted EBITDAX**"	has the meaning given to it in paragraph 4 (*Non-IFRS Financial Information*) of Part 3 (*Presentation of Financial and Other Information)*;
"**Group Financial Information**" . . .	the audited historical financial information of the Group for the six month period ended 30 June 2022 and for each of the years ended 31 December 2021, 2020 and 2019 included in Section A of Part 16 (*Historical Financial Information*);
"**Group Free Cashflow**"	has the meaning given to it in paragraph 4 (*Non-IFRS Financial Information*) of Part 3 (*Presentation of Financial and Other Information);*
"**GSA Acquisition**"	the acquisition of all of the GSA licences and the associated infrastructure interests of One Dyas E&P Limited (formerly, Dyas UK Limited) and Petrofac Limited, including the acquisition of One Dyas E&P Limited (formerly, Dyas UK Limited), Stella FPF Holdings Limited and Petrofac Limited's interests in FPF1 Limited, the company that owned the FPF-1

	floating production facility that is used on the GSA production hub, which completed in December 2018;
"**Harbour Energy**"	the group of companies of which Harbour Energy plc is the holding company;
"**HCCI**"	HCC International Insurance Company plc;
"**HCCI Deed of Indemnity**"	the Deed of indemnity between, amongst others, IEEPL (as lead indemnitor) and HCCI dated 28 January 2021;
"**Historical Financial Information**" or "**HFI**"	the historical financial information included in Part A of each of Section A (*The Group*), Section B (*The Siccar Point Group*) and Section C (*IOG*) of Part 16 (*Historical Financial Information*);
"**HMRC**"	His Majesty's Revenue and Customs;
"**HS&E**	Health, safety and environmental;
"**HSBC**"	HSBC Bank plc;
"**Hurdle**"	has the meaning given to that term in paragraph 11.5 (*Management Equity Plan*) of Part 20 (*Additional Information*);
"**IA**"	has the meaning given to it in paragraph 5.2 (*Supplementary Charge*) in Part 11 (*Regulation*);
"**IEEPL**"	Ithaca Energy (E&P) Limited, (formerly named Ithaca Energy Limited), a company registered in Jersey with registered number 126983;
"**IENS plc**" or "**Bond Issuer**"	Ithaca Energy (North Sea) plc, a company incorporated in Scotland with registered number SC595124;
"**IEUK**"	Ithaca Energy (UK) Limited, a company incorporated in Scotland with registered number SC272009;
"**IFRS**"	International Financial Reporting Standards as issued by the International Accounting Standards Board;
"**ILS**"	the Israeli New Shekel, the lawful currency of Israel;
"**Incurrence Test**"	has the meaning given to it in paragraph 14.3.7 (*Siccar Point Bonds*) of Part 20 (*Additional Information*);
"**Indenture**"	the indenture under which the 2026 Notes were issued among, inter alios, the Bond Issuer, IEEPL as Senior Guarantor, the Subordinated Guarantors (as defined therein), BNY Mellon Corporate Trustee Services Limited, as trustee and The Bank of New York Mellon, London Branch, as Principal Paying Agent and The Bank of New York Mellon SA/NV, Dublin Branch, as Transfer Agent and Registrar;
"**Initial LTIP Awards**"	has the meaning given to it in paragraph 11.1 (*Ithaca Energy Long Term Incentive Plan*) of Part 20 (*Additional Information*);
"**ING**" or "**Co-lead Manager**"	ING Bank N.V.;
"**IOG Financial Information**"	the financial statements of IOG as at and for the year ended 31 December 2019 included in Section C (*IOG*) of Part 16 *(Historical Financial Information*);
"**IPO Expenses**"	the costs and expenses of, and incidental to, Admission payable by the Company (or the Selling Shareholder, as applicable) excluding the Underwriters' Expenses and Selling Shareholder's Expenses;
"**IRS**"	US Internal Revenue Service;

"**ISDAs**"	International Swaps and Derivatives Association master agreements;
"**ISIN**"	International Securities Identification Number;
"**Israeli Securities Law**"	Israeli Securities Law, 5728 -1968;
"**Jefferies**"	Jefferies International Limited and/or Jefferies GmbH;
"**Joint Bookrunners**"	together, BofA Securities, HSBC and Jefferies;
"**Joint Global Co-ordinators**" or "**JGCs**"	together, Goldman Sachs International and Morgan Stanley;
"**Kemira**"	Kemira OYJ with offices at Porkkalankatu 3, 00180 Helsinki, Finland;
"**Kemira Contract**"	the contract for the provision of liquid polymer entered into between IOG and Kemira on 17 June 2016, as amended from time to time;
"**KPI**"	key performance indicator;
"**Kroll Report**"	a valuation report in connection with impairment testing of the Group under IAS 36 prepared by Kroll Advisory Ltd included in the annual report of Delek Group Limited for the year ended 31 December 2021;
"**Latest Practicable Date**"	8 November 2022, being the latest practicable date before the publication of this Prospectus;
"**LEI**"	legal entity identifier;
"**Liberty**"	Liberty Mutual Insurance Europe SE;
"**Liberty Deed of Indemnity**"	the deed of indemnity between, amongst others, IEEPL (as principal indemnitor) and Liberty dated 26 November 2020;
"**LIBOR**"	the London Inter-bank Offered Rate;
"**Licensees**"	has the meaning given to it in paragraph 14.10.5 (*Master IP Licence*) of Part 20 (*Additional Information*);
"**Listing Rules**"	the listing rules of the FCA made under Part VI of FSMA;
"**Lock-up Arrangements and Exceptions**"	the lock-up agreements entered into between the Selling Shareholder, each of the Directors and the Company and as described in paragraph 1.6 (*Lock-up arrangements and Exceptions*) Part 18 (*Details, Terms and Conditions of the Global Offering*);
"**London Stock Exchange**"	London Stock Exchange plc;
"**Long Term Profit Forecast**"	has the meaning given in paragraph 2 (*Long Term Financial Forecast*) of Part 15 (*Profit Forecasts*);
"**LTIP**"	the Ithaca Energy Long Term Incentive Plan;
"**LTIP Awards**"	awards over Ordinary Shares granted to Executive Directors and selected employees of the Group pursuant to the LTIP;
"**LTM**"	last twelve months;
"**Main Market**"	the London Stock Exchange's main market for listed securities;
"**Management Incentive Agreement**"	the management incentive agreement between the Company, DKL Energy, Gilad Myerson dated 29 September 2022;

"**Marubeni Acquisition**"	the acquisition by IEUK from MNSL of the entire issued share capital of MOGL;
"**Marubeni Acquisition Agreement**"	the sale and purchase agreement entered into between MNSL, IEUK and IEEPL in respect of the Marubeni Acquisition dated 2 November 2021, as amended from time to time;
"**Marubeni Assets**"	those assets acquired by the Group by way of the Marubeni Acquisition, being Monarb and Columba;
"**Master Licence Agreement**"	has the meaning given to it in paragraph 14.10.5 (*Master IP Licence*) of Part 20 (*Additional Information*);
"**Matching Shares**"	has the meaning given to it in paragraph 11.4 (*Share Incentive Plan*) of Part 20 (*Additional Information*);
"**Member State**"	member states of the EEA;
"**MEP**"	the management equity plan for the benefit of Gilad Myerson. further details of which are set out at paragraph 11.5 (*Management Equity Plan*) of Part 20 (*Additional Information*);
"**MEP Shares**"	has the meaning given to that term in paragraph 11.5 (*Management Equity Plan*) of Part 20 (*Additional Information*);
"**MER UK Strategy**"	the Maximising Economic Recovery Strategy for the UK as published by BEIS in 2016;
"**MiFID II**"	EU Directive 2014/65/EU on markets in financial instruments, as amended;
"**MIIC**"	Markel International Insurance Company Limited;
"**MIIC Deed of Indemnity**"	the deed of indemnity between, amongst others, IEEPL (as lead indemnitor) and dated 21 January 2022;
"**Mitsui**"	Mitsui E&P UK Limited a company incorporated in England and Wales with registered number 07652477;
"**Mitsui Acquisition**"	the acquisition by IOG from Mitsui of certain interests in the UKCS Petroleum Production Licence No. P.213 Block 16/26, Area A—Alba Field Area;
"**Mitsui Acquisition Agreement**"	the sale and purchase agreement entered into between Mitsui and IOG in respect of the Mitsui Acquisition dated 17 September 2021;
"**Mitsui Interests**"	has the meaning given to it in paragraph 14.5 (*Mitsui Acquisition Agreement*) of Part 20 (*Additional Information*);
"**MNSL**"	Marubeni North Sea Limited, a company incorporated in England & Wales with registered number 05119283;
"**MOGL**"	Ithaca MA Limited (formerly named Marubeni Oil & Gas (UK) Limited), a company incorporated in England & Wales with registered number 03947050;
"**Morgan Stanley**"	Morgan Stanley & Co International plc;
"**Net debt**"	has the meaning given to it in paragraph 4 (*Non-IFRS Financial Information*) of Part 3 (*Presentation of Financial and Other Information);*
"**net debt to Group Adjusted EBITDAX**"	has the meaning given to it in paragraph 4 (*Non-IFRS Financial Information*) of Part 3 (*Presentation of Financial and Other Information);*

"**net debt to LTM Adjusted EBITDAX**"	has the meaning given to it in paragraph 4 (*Non-IFRS Financial Information*) of Part 3 (*Presentation of Financial and Other Information*);
"**Net Zero Plan**"	has the meaning given to it on page 32 of this Prospectus;
"**NewMed Capricorn Transaction**"	means the proposed combination of Capricorn Energy plc ("**Capricorn**") with NewMed Energy Limited Partnership (formerly Delek Drilling Limited) ("**NewMed**") by way of reverse takeover announced by Capricorn on 29 September 2022, and expected retention of Capricorn's premium listing on the London Stock Exchange, with the combined group trading under the name NewMed Energy plc ("**NewMed Energy**");
"**NI 31-103**"	National Instrument 31-103 Registration Requirements, Exemptions and Ongoing Registrant Obligations;
"**NI 33-105**"	National Instrument 33-105 Underwriting Conflicts;
"**NI 45-106**"	National Instrument 45-106 Prospectus Exemptions;
"**Nil Rate Amount**"	has the meaning given to it in paragraph 1.1.2 (*Individual Shareholders*) of Part 19 (*Taxation*);
"**Nominated Directors**"	has the meaning given to it in paragraph 14.2 (*Relationship Agreement*) of Part 20 (*Additional Information*);
"**Non-Executive Directors**"	the non-executive directors of the Company as at the date of this Prospectus, whose details are set out in paragraph 1 (*The Directors*) of Part 8 (*Directors, Senior Managers and Corporate Governance*);
"**North Sea Transition Deal**"	North Sea Transition Deal published in March 2021 by BEIS and OEUK setting out how the UK Government and the oil and gas industry will work together to support the country's transition to net zero carbon by 2050;
"**notifiable acquisitions**"	has the meaning given to it in paragraph 4.12 (*The ability of Shareholders to sell their Ordinary Shares, particularly in a takeover, may be negatively affected by the UK National Security and Investment Act*) of Part 2 (*Risk Factors*);
"**NSAI**" or "**Competent Person**"	Netherland, Sewell & Associates, Inc., whose registered office is at 2100 Ross Avenue, Suite 2200, Dallas, Texas 75201, United States of America;
"**NSAI CPR**" or "**Competent Person's Report**"	the competent person's report produced by NSAI as contained in Part 23 (*Competent Person's Report*);
"**NSAI Reports**"	(i) the NSAI CPR; and (ii) the NSAI Historic Reports;
"**NSAI Historic Reports**"	the competent person's reports produced by NSAI dated as at (i) 31 December 2021, and (ii) 31 December 2019 and 2020;
"**NSTA**"	the UK North Sea Transition Authority, being a business name of the Oil and Gas Authority, a limited company registered in England and Wales with registered number 09666504, whose registered office is at Sanctuary Buildings, 20 Great Street, London, SW1P 3BT, United Kingdom and whose sole shareholder is the Secretary of State, and any successor in relevant function (formerly known as the "Oil and Gas Authority");
"**OEUK**"	Offshore Energies UK;

"**Offer Price**"	the price at which each Offer Share is to be issued and allotted under the Global Offering;
"**Offer Shares**"	the 105,000,000 new Ordinary Shares to be issued and allotted by the Company;
"**Official List**"	the Official List maintained by the FCA in its capacity as competent authority for the purposes of Part VI of FSMA;
"**Option**"	has the meaning given to it in paragraph 18.1 (*Related Third Party Transactions*) of Part 20 (*Additional Information*);
"**Option Shares**"	has the meaning given to it in paragraph 18.1 (*Related Third Party Transactions*) of Part 20 (*Additional Information*);
"**Ordinary Shares**"	the ordinary shares of £0.01 each in the capital of the Company;
"**Over-allotment Option**"	the over-allotment option granted by the Company to Goldman Sachs International to purchase up to a maximum of 14.3% of the total number of Offer Shares (before exercise of the Over-allotment Option) during the period commencing on the date of commencement of conditional dealings of the Ordinary Shares on the London Stock Exchange and ending no later than 30 calendar days thereafter at the Offer Price to cover over-allotments, if any, made in connection with the Global Offering and to cover any short positions resulting from stabilisation transactions;
"**Over-allotment Shares**"	to be sold by the Selling Shareholder, if any, in the event the Over-Allotment Option is exercised, pursuant to the terms and conditions of the Underwriting and Sponsors Agreement;
"**Overseas Shareholders**"	shareholders who are resident in, ordinarily resident in, or citizens of, jurisdictions outside the United Kingdom, and "**Overseas Shareholder**" shall be construed accordingly;
"**Paris Agreement**"	the Paris Agreement negotiated at the 2015 United Nations Conference on Climate Change and includes a commitment to limiting the increase in global average temperature increase to well below 2°C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels;
"**Partnership Shares**"	has the meaning given to it in paragraph 11.4 (*Share Incentive Plan*) of Part 20 (*Additional Information*);
"**PCAOB**"	the Public Company Accounting Oversight Board (United States);
"**Performance Awards**"	LTIP Awards which are subject to stretching performance conditions which will determine the extent to which such LTIP Awards shall be capable of vesting;
"**PFIC**"	a passive foreign investment company;
"**Pre-Chevron Acquisition Cash Extraction Loan**"	has the meaning given to it in paragraph 14.10.3(b) (*Pre-Chevron Acquisition Cash Extraction Loan*) Part 20 (*Additional Information*);
"**Pre-Chevron Acquisition Restructuring Loan**"	has the meaning given to it in paragraph 14.10.3(a) (*Pre-Chevron Acquisition Restructuring Loan*) Part 20 (*Additional Information*);

"**Profit Forecasts**"	the Current Year Profit Forecast and the Long Term Profit Forecast;
"**Projected EDITDA Information**"	certain financial projections for the Group, including projected EBITDA for each of the years ending 31 December 2022 to 31 December 2042, as included in the Kroll Report;
"**Prospectus**"	this document;
"**Prospectus Regulation Rules**"	the prospectus regulation rules of the FCA made under section 73A of FSMA;
"**Prospectus Regulation**" or **"Prospectus Delegated Regulation"**	the UK version of commission delegated regulation (EU) 2019/980 of the European Parliament and of the Council, supplementing the UK Prospectus Regulation, which is part of UK law by virtue of EUWA;
"**PRT**"	petroleum revenue tax applying in the United Kingdom from time to time;
"**Qualified Israeli Investors**"	has the meaning given to it on page (v);
"**QEF**"	has the meaning given to it in paragraph 2.4 (*Certain of the Group's outstanding borrowings will bear interest at floating rates which could rise significantly, thereby increasing its interest cost and reducing cash flows*) of Part 2 (*Risk Factors*);
"**QIBs**"	qualified institutional buyers as defined in Rule 144A and "**QIB**" will be construed accordingly;
"**RBL Facility**"	the facility made available under the RBL Facility Agreement;
"**RBL Facility Agreement**"	the secured revolving borrowing base facility agreement dated 29 May 2019, as amended from time to time including by a deed of amendment, restatement and release dated 19 July 2021, entered into between, among others, IEUK as borrower, BNP Paribas as facility agent and the lenders thereunder from time to time;
"**Registrar**"	Computershare Investor Services plc of The Pavilions, Bridgewater Road, Bristol, BS13 8AE;
"**Regulation S**"	Regulation S under the US Securities Act;
"**Relationship Agreement**"	the relationship agreement to be entered into between Delek and Ithaca Energy as further described in paragraph 14.2 (*Relationship Agreement*) of Part 20 (*Additional Information*);
"**Remuneration Committee**"	the remuneration committee of the Board;
"**Restricted Share Awards**"	LTIP Awards which are granted which are not subject to performance conditions and which vest solely on the basis of the participant's continued employment with the Group;
"**Retained Decommissioning Liability Arrangements**"	the arrangements pertaining to the Retained Decommissioning Liability Fields pursuant to the Chevron Acquisition Agreement, details of which are set out in paragraph 14.10.2 (*Retained Decommissioning Liability Arrangements*) of Part 20 (*Additional Information*);

"**Retained Decommissioning Liability Field**"	the Cambo field, Heather field or the Strathspey field, and "**Retained Decommissioning Liability Fields**" means all of them;
"**RFCT**"	Ring Fence Corporation Tax;
"**Ring Fence Losses**"	has the meaning given to it in paragraph 5.1 (*Ring Fence Corporation Tax*) in Part 11 (*Regulation*);
"**Ring Fence Profits**"	has the meaning given to it in paragraph 5.1 (*Ring Fence Corporation Tax*) in Part 11 (*Regulation*);
"**Rule 144A**"	Rule 144A under the US Securities Act;
"**Schedule 2**"	Schedule 2 to the Income Tax (Earnings and Pensions) Act 2003;
"**SC**" or "**SCT**"	has the meaning given to it in paragraph 5.2 (*Supplementary Charge*) in Part 11 (*Regulation*);
"**SDRT**"	UK stamp duty reserve tax;
"**Secretary of State**"	means the Secretary of State for Business, Energy and Industrial Strategy;
"**SEDOL**"	Stock Exchange Daily Official List;
"**Selling Shareholder's Expenses**"	the Selling Shareholder's legal fees, the Underwriters' advisory fees, the underwriting commissions in respect of the Over-allotment Shares (if any) and any transfer duty;
"**Senior Independent Director**"	the "**senior independent director**", as referred to in the Governance Code;
"**Senior Managers**"	those persons identified as senior managers of Ithaca Energy in Part 8 (*Directors, Senior Managers and Corporate Governance*);
"**SFA**"	Securities and Futures Act 2001 of Singapore, as modified or amended from time to time;
"**Share Capital Reorganisation**"	the reorganisation of the Group referred to in paragraph 5.3 (*Share Capital Reorganisation*) of Part 20 (*Additional Information*);
"**Share Dealing Code**"	the EU Market Abuse Regulation, any statute, order or regulation on dealing in the Company's securities or the Company's share dealing code from time to time;
"**Shareholders**"	the holders of Ordinary Shares from time to time and "**Shareholder**" shall be construed accordingly;
"**Shell**"	Shell International Trading and Shipping Company Limited;
"**Siccar Point**" or "**SPEHL**" or "**Siccar Point Company**"	Ithaca SP (Holdings) Limited (formerly named Siccar Point Energy (Holdings) Limited), a company incorporated in England & Wales with registered number 09102478;
"**Siccar Point Acquisition Agreement**"	the sale and purchase agreement entered into between the Siccar Point Seller, IEUK and IEEPL in respect of the Siccar Point Acquisition dated 7 April 2022, as amended from time to time;

“**Siccar Point Acquisition**” . . . . . . the acquisition by IEUK from the Siccar Point Seller of the entire issued share capital of SPEHL and certain loan notes issued by SPEFL;

“**Siccar Point Adjusted EBITDAX**” . has the meaning given to it in paragraph 4 (*Non-IFRS Financial Information*) of Part 3 (*Presentation of Financial and Other Information)*;

“**Siccar Point Assets**” . . . . those assets acquired by the Group by way of the Siccar Point Acquisition, being Mariner, Schiehallion, Jade, Cambo, Rosebank, Tornado, Suilven, Blackrock, certain other exploration assets, Glen Lyon FPSO, SIRGE and WOSP;

“**Siccar Point Bonds**” . . . . the $200.0 million 9.00% senior, unsecured, callable bonds 2021/2026 issued by SPEB;

“**Siccar Point Financial Information**” . . . . the audited consolidated financial information of the Siccar Point Group for the six month period ended 30 June 2022 and for the years ended 31 December 2019, 2020 and 2021 included in Section B (*The Siccar Point Group*) of Part 16 (*Historical Financial Information*);

“**Siccar Point Free Cashflow**” . . . . has the meaning given to it in paragraph 4 (*Non-IFRS Financial Information*) of Part 3 (*Presentation of Financial and Other Information);*

“**Siccar Point Group**” . . . . SPEHL and its subsidiaries from time to time;

“**Siccar Point Seller**” . . . . Siccar Point Energy Luxembourg S.C.A., a partnership limited by shares (société en commandite par actions) incorporated and existing under the laws of the Grand Duchy of Luxembourg, registered with the Luxembourg Trade and Companies Register under number B 189091;

“**SIF**” . . . . serious incident frequency;

“**SIP**” . . . . the Ithaca Energy Share Incentive Plan;

“**SOFR**” . . . . the Secured Overnight Financing Rate;

“**SONIA**” . . . . the Sterling Overnight Index Average;

“**SPEB**” . . . . Ithaca SP Bonds plc (formerly named Siccar Point Energy Bonds plc), a company incorporated in England & Wales with registered number 11029537;

“**SPEEPL**” . . . . Ithaca SP E&P Limited (formerly named Siccar Point Energy E&P Limited), a company incorporated in England & Wales with registered number 01504603;

“**SPEFL**” . . . . Ithaca SP Finance Limited (formerly named Siccar Point Energy Finance Limited), a company incorporated in England & Wales with registered number 09102885;

“**SPEL**” . . . . Ithaca SPE Limited (formerly named Siccar Point Energy Limited), a company incorporated in England & Wales with registered number 09103084;

“**SPEL Facility**” . . . . has the meaning given to it in paragraph 14.3.6 (*SPEL Facility Agreement with, among others, Natixis*) of Part 20 (*Additional Information*);

“**SPEL Facility Agreement**” . . . . . . has the meaning given to it in paragraph 14.3.6 (*SPEL Facility Agreement with, among others, Natixis*) of Part 20 (*Additional Information*);

"**SPEUKL**"	Ithaca SP O&G Limited (formerly named Siccar Point Energy U.K. Limited), a company incorporated in England & Wales with registered number 09858988;
"**Sproule**"	Sproule International Limited of 140 - 4th Avenue SW, Suite 900, Calgary, Alberta, Canada T2P 3N3;
"**Stabilisation Period**"	no later than 30 calendar days after the date of commencement of conditional dealings of the Ordinary Shares on the London Stock Exchange;
"**Stabilising Manager**"	Goldman Sachs International;
"**Stock Lending Agreement**"	the stock lending agreement entered into between the Stabilising Manager and the Selling Shareholder;
"**Subordinated Delek Loan**"	the $250,000,000 unsecured term loan facility between IEEPL (as borrower), IEUK and DGL (as lender) dated 4 November 2019;
"**Subsidiary**"	has the meaning given to it in section 1162 of the 2006 Act and includes group companies included in the consolidated financial statements of the Company from time to time (and "**Subsidiaries**" shall be construed accordingly);
"**Subsidiary Undertaking**"	has the meaning given to such term in section 1162 of the 2006 Act (and "**Subsidiary Undertakings**" shall be construed accordingly);
"**Sumitomo**"	Sumitomo Corporation, a company incorporated in Japan with registered number 0100-01-008692;
"**Summit**"	Ithaca Zeta Limited (formerly named Summit Exploration and Production Limited), a company incorporated in England & Wales with registered number 08860426;
"**Summit Acquisition**"	the acquisition by IEUK from Sumitomo of the entire issued share capital of Summit;
"**Summit Acquisition Agreement**"	the sale and purchase agreement entered into between the Sumitomo, IEUK and IEEPL in respect of the Summit Acquisition dated 28 February 2022, as amended from time to time;
"**Summit Assets**"	those assets acquired by the Group by way of the Summit Acquisition, being Elgin-Franklin, certain other exploration assets, SEAL and GAEL;
"**Takeover Panel**" or "**Panel**"	the UK Panel on Takeovers and Mergers;
"**Target Market Assessment**"	has the meaning given to it on page FC(vi) of this Prospectus;
"**Technip**"	Technip UK Limited, a company incorporated in England and Wales with registered number 00200086;
"**Technip Contract**"	the contract between IEUK and Technip for the provision of pipelay and subsea construction services (including flexible and umbilical supply) for the Captain EOR II executed on 29 April 2021 and 05 May 2021;
"**Terms and Conditions of the Global Offering**"	the terms of the Global Offering and the conditions to which the Global Offering is subject, which are set out in Part 18 (*Details, Terms and Conditions of the Global Offering*);
"**Tracker Loan**"	the $198.0 million intercompany loan agreement between the Company (as borrower) and DKL Energy (as lender) dated 4 November 2019, as amended from time to time;

"**Treaty**"	the Convention Between the Government of the United States of America and the Government of the United Kingdom of Great Britain and Northern Ireland for the Avoidance of Double Taxation and the Prevention of Fiscal Evasion with Respect to Taxes on Income;
"**Trustee**"	has the meaning given to it in paragraph 11.4 (*Share Incentive Plan*) of Part 20 (*Additional Information*);
"**TSX**"	the Toronto Stock Exchange;
"**UAE**"	United Arab Emirates;
"**UKCS**"	the United Kingdom Continental Shelf;
"**UK Licence**"	a petroleum exploration and/or production licence in the UK;
"**UK MAR**"	the Market Abuse Regulation (2014/596/EU) to the extent that it forms part of the domestic law of the United Kingdom by virtue of the EUWA;
"**UK NS&I Act**"	the UK National Security and Investment Act;
"**UK Product Governance Rules**"	the product governance requirements of Chapter 3 of the FCA Handbook Product Intervention and Product Governance Sourcebook;
"**UK Prospectus Regulation**"	the UK version of commission delegated regulation (EU) 2017/1129 of the European Parliament and of the Council which is part of UK law by virtue of the EUWA;
"**Unaudited Pro Forma Condensed Combined Financial Information**"	the unaudited pro forma income statements for the six months ended 30 June 2022 and the year ended 31 December 2021 of the Group set out in Part 17 (*Unaudited Pro Forma Condensed Combined Financial Information*);
"**uncertificated**" or "**other in uncertificated form**"	in relation to a share or other security, title to which is recorded in the relevant register of the share or security concerned as being held in uncertificated form in CREST and title to which, by virtue of the CREST Regulations, may be transferred by means of CREST;
"**Underwriters**"	the Joint Global Co-ordinators, the Joint Bookrunners and ING;
"**Underwriters' Expenses**"	the underwriting commissions in respect of the Offer Shares (including the maximum amount of any discretionary commission), the FCA's fees, the Underwriters' legal fees and expenses;
"**Underwriting and Sponsors' Agreement**"	the underwriting and sponsors' agreement entered into between the Company, the Directors, the Selling Shareholder and the Underwriters, details of which are set out in Part 18 (*Details, Terms and Conditions of the Global Offering*) and further described in paragraph 14.1 (*Underwriting and Sponsors' Agreement*) of Part 20 (*Additional Information*);
"**Unit operating expenditure**"	has the meaning given to it in paragraph 4 (*Non-IFRS Financial Information*) of Part 3 (*Presentation of Financial and Other Information)*;
"**United Kingdom**" or "**UK**"	the United Kingdom of Great Britain and Northern Ireland;

"**United States**" or "**US**"	the United States of America, its territories and possessions, any state of the United States of America and the District of Columbia;
"**Unrestricted Payment Amount**" . .	has the meaning given to it in paragraph 16.2 (*Limitations on distributions of dividend under the 2026 Notes*) of Part 6 (*Business Overview*);
"**US Exchange Act**"	the US Securities Exchange Act of 1934, as amended;
"**US GAAS**"	auditing standards generally accepted in the United States;
"**US Holder**"	has the meaning given in paragraph 2 (*US Federal Income Taxation*) of Part 19 (*Taxation*);
"**US Securities Act**"	the US Securities Act 1933, as amended, and the rules and regulations promulgated thereunder;
"**VAT**"	UK value added tax; and
"**Withdrawal Agreement**"	the agreement on the withdrawal of the United Kingdom of Great Britain and Northern Ireland from the European Union 2019/C 384 I/01.

PART 22

GLOSSARY OF TECHNICAL TERMS

The following technical terms or other abbreviations (or variations of them) are used in this Prospectus:

"**1P reserves**"	proved reserves;
"**2018 PRMS**"	the 2018 Petroleum Resources Management System;
"**2C resources**"	best estimate scenario of contingent resources;
"**2P reserves**"	proved plus probable reserves;
"**3P reserves**"	proved plus probable plus possible reserves;
"**Abigail**"	the oil and gas field commonly known as Abigail (formerly known as Hurricane) located in block 29/10b ALL in the UKCS;
"**AFE**"	authorisation for expenditure;
"**Alba**"	the oil field commonly known as the Alba field located in blocks 16/26a A ALB (Area A Alba Field Area), 16/26a C-10k (Area C Above 10,000 Feet) and 22/1b ALL in the UKCS;
"**Alba FSU**"	the floating storage unit that is connected to Alba;
"**Alder**"	the oil field commonly known as the Alder field located in blocks 15/29a ALDER (Alder Field) and 15/29a AREA A (Area Outside Britannia) in the UKCS;
"**Anglia**"	the gas field which was commonly known as the Anglia field and which was located in blocks 48/18b and 48/19b in the UKCS;
"**ANP**"	Alba North Platform;
"**API**"	American Petroleum Institute;
"**Arbroath**"	the oil and gas field commonly known as the Arbroath field located in blocks 22/17n ALL, 22/17s ALL, 22/18a ALL and 22/22a ALL in the UKCS;
"**Arkwright**"	the oil field commonly known as the Arkwright field located in block 22/23a ALL in the UKCS;
"**ASM**"	Andrew Sand Member;
"**Athena**"	the oil field commonly known as the Athena field located in block 14/18b ALL in the UKCS;
"**Austen**"	the discovery commonly known as the Austen field located in block 30/13b ALL in the UKCS;
"**AXS**"	Alba Extreme South;
"**BBL**"	barrels;
"**bcm**"	billion cubic meters;
"**Best Available Techniques**" or "**BAT**"	the available techniques which are the best for preventing or minimising emissions and impacts on the environment;
"**Birgitta**"	the oil and gas field commonly known as the Birgitta field located in block 22/19a ALL in the UKCS;
"**Blackrock**"	the oil and gas field commonly known as the Blackrock field located in blocks 204/4b ALL and 204/5b ALL in the UKCS;

"**BLP**"	Bridge Linked Platform;
"**BOE**"	barrels of oil equivalent;
"**BOEPD**"	barrels of oil equivalent per day;
"**BOPD**"	barrels of oil per day;
"**BPGM**"	BP Gas Marketing Limited;
"**BPOI**"	BP Oil International;
"**Brechin**"	the oil and gas field commonly known as the Brechin field located in block 22/23a ALL in the UKCS;
"**Britannia**"	the gas condensate field commonly known as the Britannia field located in blocks 15/30a S BRI (Area S—Britannia Field), Area 15/30a L-RST (Area L Non-Britannia), 15/29a AREA B (Britannia UOA), 15/29a AREA C (Non-Britannia UOA), 16/26a B BRI (Area B—Britannia Field), 16/26a D BEL, 16/27b AREA B (Britannia Field), 16/27b AREA A (Rest of Block—Excluding Britannia) and 16/27c in the UKCS;
"**Brodgar**"	the oil field commonly known as the Brodgar field located in blocks 21/3a ALL, 21/3b ALL and 21/4c ALL in the UKCS;
"Broom"	the oil field commonly known as the Broom field located in blocks 2/4a (BROOM) and 2/5a (BROOM) in the UKCS;
"BWPD"	barrels of water per day;
"Cadet"	the oil and gas field commonly known as the Cadet field located in block 8/15a ALL in the UKCS;
"Callanish"	the oil field commonly known as the Callanish field located in blocks 21/4a ALL and 15/29b ALL in the UKCS;
"Cambo"	the oil and gas field commonly known as the Cambo field located in blocks 204/9a ALL, 204/10a ALL, 204/4a ALL and 204/5a ALL in the UKCS;
"Captain"	the oil field commonly known as the Captain field located in blocks 13/22a ALL, 13/21b ALL and 13/22b ALL in the UKCS;
"Captain EOR"	the on-going polymer EOR development programme of Captain which commenced in 2010;
"Captain EOR II"	the second phase of the Captain EOR, which was sanctioned in April 2021 following consent from the NSTA;
"Captain FPSO"	the floating production storage and offtake vessel known as the 'Captain FPSO' located in block 13/22a in the UKCS;
"CATS"	the Central Area Transmission System;
"**Cayley**"	the oil and gas field commonly known as the Cayley field located in block 22/17s ALL in the UKCS;
"**CGU"**	a cash generating unit;
"**CMS**"	Company Management System;
"CO_2"	carbon dioxide;
"CO_2e"	carbon dioxide equivalent;
"Columba" or "Columba Terraces Area"	the oil and gas field commonly known as the Columba field located in blocks 3/7a AREA B (Part of Columba B and Columba E Fields), 3/8a COLB (Columba B Reservoir), 3/8a COLD (Columba D Reservoir);

"Conrie"	the oil field commonly known as the Conrie field located in block 211/18a (B) (Don South West Area) in the UKCS;
"contingent resources"	quantities of petroleum estimated, as at a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies;
"**Cook**"	the oil and gas field commonly known as the Cook field located in block 21/20a ALL of the UKCS;
"**Courageous**"	the oil and gas field commonly known as the Courageous field located in blocks 30/1e ALL and 30/2e ALL in the UKCS, which was relinquished by the Group with an effective date of 30 September 2022;
"**cp**"	centipoise;
"**D**"	darcy;
"Dons"	the Don South West, West Don, Conrie and Ythan fields;
"**Don South West**"	the oil field commonly known as the Don South West field located in block 211/18a (Don South West Area) in the UKCS;
"**D&P**"	development and production;
"**DRD**"	decommissioning relief deed;
"**E&E**"	exploration and evaluation;
"**Elgin-Franklin**"	the oil and gas field commonly known as the Elgin-Franklin field located in blocks 22/30b ELGN (Area A—Elgin-Field), 22/30c ALL, 29/5c ALL and 29/5b ALL in the UKCS;
"**EMS**"	environmental management system;
"**Enochdhu**"	the oil field commonly known as Enochdhu field located in block 21/5a ALL in the UKCS;
"**EOR**"	enhanced oil recovery;
"**Erskine**"	the oil field commonly known as Erskine field located in blocks 23/26a AREA B, 23/26b AREA B, 23/26b AREA C and 23/26d AREA C in the UKCS;
"**ES**"	Environmental Stewardship;
"**ESP**"	electric submersible pump;
"**Fotla**"	the oil and gas field commonly known as Fotla located in block 22/1b ALL in the UKCS;
"**FPF-1**"	the offshore floating production facility owned by the Group known as FPF-1;
"**FPS**"	the Forties Pipeline System;
"**FPSO**"	a floating production, storage and offloading vessel used by the offshore oil and gas industry for the processing of hydrocarbons and for storage of oil;
"**FPU**"	a floating production unit used by the offshore oil and gas industry for the processing of hydrocarbons;
"**GAEL"**	the Graben Area Export Line pipeline;
"**Glen Lyon FPSO**"	the floating production storage and offtake vessel known as the 'Glen Lyon' located in block 204/25a (ALL) in the UKCS;

"**Godwin**"	the oil and gas field commonly known as the Godwin field located in blocks 22/17s ALL and 22/17n ALL in the UKCS;
"**GOR**"	gas-oil ratio;
"**Greater Britannia Area**"	the Britannia, Brodgar, Callanish, Enochdhu and Alder fields;
"**Greater Stella Area**", "**GSA**" or "**GSA Portfolio**"	the Stella, Harrier, Abigail, Vorlich, Austen and Courageous fields;
"**Harrier**"	the oil and gas field currently known as Harrier located in blocks 30/6a (D) (Rest of Block (Chalk Layers and Younger)) and 29/10a (C) in the UKCS;
"**Heather**"	the oil and gas field commonly known as the Heather field located in block 2/5a in the UKCS;
"**IEA**"	International Energy Agency;
"**IMO Guidelines**"	the IMO guidelines and standards for the removal of offshore installations and structures on the continental shelf and in the exclusive economic zone;
"**Isabella**"	the oil field commonly known as the Isabella field located in blocks 30/12d ALL and 30/11a ALL in the UKCS;
"**Jacky**"	the oil field commonly known as the Jacky field located in block 12/21c ALL in the UKCS;
"**Jade**"	the oil and gas field commonly known as the Jade field located in blocks 30/2c JADE, 30/2c REST and 30/7b JADE SOUTH in the UKCS;
"**Jade South**"	the oil and gas field commonly known as the Jade South field located in block 30/7b JADE SOUTH in the UKCS;
"**J-Block Facility**"	the Judy Platform and associated pipeline infrastructure commonly known as the J-Block Gas Pipeline and the J-Block Crude Petroleum Pipeline;
"**Leverett**"	the oil and gas field commonly known as the Leverett field located in blocks 21/2d ALL and 21/3a ALL in the UKCS;
"**Marigold**"	the oil field commonly known as the Marigold field located in block 15/13a and 15/18b ALL in the UKCS;
"**Mariner**"	the oil and gas field commonly known as the Mariner field located in blocks 9/11a ALL, 9/11c ALL and 9/11g ALL in the UKCS;
"**Mariner East**"	the oil and gas field commonly known as the Mariner East field located in block 9/11b ALL in the UKCS;
"**MBBL**"	thousands of barrels;
"**MBOE**"	thousands of barrels of oil equivalent;
"**MBOEPD**"	thousands of barrels of oil equivalent per day;
"**MCF**"	thousands of cubic feet;
"**MCFD**"	thousands of cubic feet per day;
"**MMBBL**"	millions of barrels;
"**MMBBL/d**"	million barrels per day;
"**MMBOE**"	millions of barrels of oil equivalent;
"**MMCF**"	millions of cubic feet;

"**MMCFD**"	millions of cubic feet of gas per day;
"**model clauses**"	the model clauses set out in the statutory instruments deriving from the UK Petroleum Act 1998;
"**MonArb**"	the oil and gas field commonly known as the MonArb field located in blocks 22/17n ALL, 22/18A ALL 22/18n ALL, 22/17s ALL, 22/22a ALL, 22/23a ALL and 22/18a ALL in the UKCS;
"**MonArb Area**"	the Montrose field, Arbroath field, Arkwright field, Brechin field, Cayley field, Godwin field, Shaw field and Wood field;
"**Montrose**"	the oil and gas field commonly known as the Montrose field located in blocks 22/17n ALL and 22/18n ALL in the UKCS;
"**NGL**"	natural gas liquids;
"**Norsea Facility**"	the processing and terminal facilities constructed on sites near Teeside, England commonly known as 'Norsea' and operated by ConocoPhillips Petroleum Company UK;
"**NUI**"	normally unattended installation;
"**OECD**"	the Organisation for Economic Cooperation and Development;
"**OPEC**"	the Organisation of Petroleum Exporting Countries;
"**OPEC+**"	OPEC together with eleven non-OEPC members;
"**OPPC**"	the UK Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005;
"**OPRED**"	the Offshore Petroleum Regulator for Environment and Decommissioning;
"**OSPAR**"	the 1992 Oslo and Paris Convention for the Protection of the Marine Environment of the North East Atlantic;
"**Petroleum Act**"	the Petroleum Act 1998, as amended;
"**Pickerill**"	the oil and gas field commonly known as the Pickerill field located in block 48/11a in the UKCS;
"**Pierce**"	the oil field commonly known as the Pierce located field in blocks 23/22a ALL and 23/27a ALL in the UKCS;
"**possible reserves**"	additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than probable reserves;
"**PPC**"	the UK Offshore Combustion Installations (Pollution Prevention and Control) Regulations 2013;
"**probable reserves**"	additional reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves;
"**proved reserves**"	those quantities of petroleum, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations;
"**R/P**"	reserves to production;

“**Renee**”	the oil and gas field commonly known as the Renee field located in block 15/27a in the UKCS;
“**reserves**”	quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under define conditions;
“**RFES**”	ring fence expenditure supplements;
“**Rosebank**”	the oil and gas field commonly known as the Rosebank field located in blocks 213/26b ALL, 213/27a ALL, 205/1a ALL, 205/2a ALL in the UKCS;
“**Rubie**”	the oil and gas field commonly known as the Rubie field located in block 15/28b in the UKCS;
“**SAGE**”	the Scottish Area Gas Evacuation System;
“**Schiehallion**”	the oil and gas field commonly known as the Schiehallion field located in blocks 204/20a and 204/25a ALL in the UKCS;
“**SEAL**”	the Shearwater Elgin Area Line pipeline;
“**SEGAL**”	Shell-Esso Gas and Liquids;
“**Shaw**”	the oil and gas field commonly known as the Shaw field located in block 22/22a ALL in the UKCS;
“**SIRGE**”	the Shetland Islands Regional Gas Export System;
“**SMS**”	Safety Management System;
“**Stella**”	the oil and gas field commonly known as the Stella field located in blocks 30/6a (D) and 29/10a (C) in the UKCS;
“STOIIP”	stock tank oil initially in place;
“**Strathspey**”	the oil and gas field commonly known as the Strathspey field located in blocks 3/4a, AREA B and 3/4D, AREA B in the UKCS;
“**Sulliven**”	the oil and gas field commonly known as the Sulliven field located in blocks 204/19b ALL and 205/20b ALL in the UKCS;
“**TCFD**”	Taskforce on Climate-related Financial Disclosures;
“**TGLPT**”	Teesside Gas and Liquids Processing terminal;
“**Thunderball**”	the oil field commonly known as the Thunderball field located in blocks 14/23 ALL, 14/24 ALL, 14/28 ALL and 14/29b ALL in the UKCS;
“**Tornado**”	the oil and gas field commonly known as the Tornado located in blocks 204/13 ALL and 204/14d ALL in the UKCS;
“**Trustee**”	the trustee of the SIP trust;
“**TVDSS**”	true vertical depth subsea;
“**UCS**”	Upper Captain Sandstone;
“**UK NBP**”	the UK National Balancing Point;
“**ullage**”	the volume of empty space left in a pipeline, container, cargo tank or storage tanks in cargo ships and oil terminal tanks;
“**UNCLOS**”	the United Nations Convention on the Law of the Sea 1982;
“**Vorlich**”	the oil and gas field commonly known as the Vorlich field located in blocks 30/1c LOWER 30/1c UPPER and 30/1f ALL in the UKCS;

"**West Don**" . . . . the oil field commonly known as the West Don field located in blocks 211/18a (West Don Area) and 211/13b in the UKCS;

"**Wood**" . . . . the oil field commonly known as the Wood field located in block 22/18a ALL in the UKCS;

"**WOSPS**" . . . . the West of Shetland Gas Pipeline; and

"**Ythan**" . . . . the oil field commonly known as the Ythan field located in block 211/18e YTHAN in the UKCS.

PART 23

COMPETENT PERSON'S REPORT

ESTIMATES

of

RESERVES AND FUTURE REVENUE AND CONTINGENT RESOURCES AND CASH FLOW

to the

ITHACA ENERGY (UK) LIMITED INTEREST

in

CERTAIN OIL AND GAS PROPERTIES

located in the

UNITED KINGDOM SECTOR OF THE NORTH SEA AND IN THE NORTH ATLANTIC OCEAN

as of

JUNE 30, 2022

COMPETENT PERSON'S REPORT

BASED ON ESCALATED PRICE AND COST PARAMETERS

specified by

ITHACA ENERGY (UK) LIMITED

NETHERLAND, SEWELL & ASSOCIATES, INC.

WORLDWIDE PETROLEUM CONSULTANTS

ENGINEERING • GEOLOGY
GEOPHYSICS • PETROPHYSICS

October 18, 2022

Mr. John Horsburgh
Ithaca Energy (UK) Limited
Hill of Rubislaw
Aberdeen AB15 6XI
United Kingdom

Dear Mr. Horsburgh:

In accordance with your request, we have estimated the proved, probable, and possible reserves and future revenue, as of June 30, 2022, to the Ithaca Energy (UK) Limited (referred to herein as "Ithaca") interest in certain oil and gas properties located in the United Kingdom (UK) Sector of the North Sea and in the North Atlantic Ocean. Also as requested, we have estimated the contingent resources and cash flow, as of June 30, 2022, to the Ithaca interest in certain discoveries located in the UK Sector of the North Sea and in the North Atlantic Ocean. We completed our evaluation on August 15, 2022. This Competent Person's Report (report) has been prepared using escalated price and cost parameters specified by Ithaca, as discussed in subsequent paragraphs of this letter. Monetary values shown in this report are expressed in United States dollars ($) or thousands of United States dollars (M$) using Ithaca's estimated exchange rate, which escalates from $1.28 to 1.00 British pound sterling in 2022 to $1.40 to 1.00 British pound sterling in 2025. Working interest volumes shown in this report are after deductions for shrinkage to account for processing, fuel, and flare.

The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2018 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE) and in accordance with the recommendations of the Financial Conduct Authority (FCA), as set out in Primary Market Technical Note 619.1 – the Guidelines on disclosure requirements under the Prospectus Regulation and Guidance on specialist issuers published by the FCA.

As presented in the 2018 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to quantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors. Definitions are presented immediately following this letter. Following the definitions are certificates of qualification for the primary evaluators who contributed to this report, a list of abbreviations used in this report, and portfolio summary tables. This report has been prepared for use by Ithaca in connection with a proposed initial public offering. In our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable from known accumulations by application of development projects from a given date forward under defined conditions. Reserves must be discovered, recoverable, commercial, and remaining as of the evaluation date based on the planned development projects to be applied. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be commercially recoverable; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves.

We estimate the Ithaca working interest reserves and the future net revenue after UK corporate income taxes to the Ithaca interest in these properties, as of June 30, 2022, to be:

	Working Interest Reserves			Future Net Revenue After UK Corporate Income Taxes (M$)	
Category	Oil (MBBL)	Gas (MMCF)	NGL (MBBL)	Total	Present Worth at 10%
Proved (1P)	114,446.9	223,854.2	5,840.7	4,111,140.2	3,985,975.0
Probable	62,294.7	113,616.6	3,091.0	2,669,142.0	1,841,135.4
Proved + Probable (2P)	176,741.6	337,470.8	8,931.8	6,780,282.2	5,827,110.4
Possible	72,292.6	131,265.7	3,644.8	2,946,963.9	1,812,942.5
Proved + Probable + Possible (3P)	249,034.2	468,736.5	12,576.5	9,727,246.0	7,640,053.0

Totals may not add because of rounding.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases. Oil equivalent volumes shown in this report are expressed in thousands of barrels of oil equivalent (MBOE), determined using the ratio of 5.8 MCF of gas to 1 barrel of oil.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The 1P reserves are inclusive of proved developed producing, proved developed non-producing, and proved undeveloped reserves. The project maturity subclass for these reserves is on production. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Working interest revenue for the reserves is Ithaca's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Ithaca's share of royalties, capital costs, abandonment costs, operating expenses, and estimates of UK corporate income taxes. The UK corporate income taxes have been calculated using a simplified model based on existing tax pools and abandonment tax relief; the values of the tax pools effective June 30, 2022, were provided by Ithaca. The UK corporate income taxes include estimates of the Energy Profits Levy introduced in 2022; it is our understanding that this tax applies to profits earned through 2025. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Ithaca interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Ithaca receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

CONTINGENT RESOURCES

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. The contingent resources shown in this report are contingent upon commitment to develop the resources for all fields; finalization of development plans for Alder, Cadet, Callanish, Cambo, Captain, Elgin-Franklin, Erskine, Fotla, Harrier, Isabella, Leverett, Marigold, Mariner, Mariner East, Pierce, Rosebank, Schiehallion, and Tornado Fields; finalization of commercial terms for subsea tieback for Tornado Field; and confirmation of technical feasibility for polymer injection in Mariner Field. The costs required to resolve these contingencies have not been included in this report; estimates of cash flow are based on the assumption that all contingencies will be successfully addressed. If these contingencies are successfully addressed, some portion of the contingent resources estimated in this report may be reclassified as reserves; our estimates have not been risked to account for the possibility that the contingencies are not successfully addressed. The project maturity subclass for these contingent resources is development pending for Alba, Alder, Callanish, Cambo, Captain, Cook, Courageous, Elgin-Franklin, Erskine, Fotla, Harrier, Isabella, Leverett, Marigold, Pierce, Rosebank, Stella, Tornado, and Vorlich Fields. The project maturity subclass for these contingent resources is development unclarified for Cadet, Mariner, Mariner East, and Schiehallion Fields.

We estimate the Ithaca working interest contingent resources and the net contingent cash flow after UK corporate income taxes to the Ithaca interest in these properties, as of June 30, 2022, to be:

	Working Interest Contingent Resources			Net Contingent Cash Flow After UK Corporate Income Taxes (M$)	
Category	Oil (MBBL)	Gas (MMCF)	NGL (MBBL)	Total	Discounted at 10%
Low Estimate (1C)	125,164.4	253,636.8	723.6	4,401,099.1	1,958,529.3
Best Estimate (2C)	232,174.4	398,268.5	841.5	9,427,221.8	3,994,985.5
High Estimate (3C)	369,382.1	587,234.7	1,324.0	17,723,131.7	6,919,249.3

The oil volumes shown include crude oil and condensate.

The contingent resources shown in this report have been estimated using deterministic methods. Once all contingencies have been successfully addressed, the approximate probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is generally inferred to be 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. For the purposes of this report, the volumes and parameters associated with the low, best, and high estimate scenarios of contingent resources are referred to as 1C, 2C, and 3C, respectively. The estimates of contingent resources included herein have not been adjusted for development risk.

Working interest contingent revenue is Ithaca's share of the gross (100 percent) revenue from the properties prior to any deductions. Net contingent cash flow is after deductions for Ithaca's share of royalties, capital costs, abandonment costs, operating expenses, and estimates of UK corporate income taxes. The UK corporate income taxes have been calculated using a simplified model based on existing tax pools and abandonment tax relief; the values of the tax pools effective June 30, 2022, were provided by Ithaca. The UK corporate income taxes include estimates of the Energy Profits Levy introduced in 2022; it is our understanding that this tax applies to profits earned through 2025. The net contingent cash flow has been discounted at an annual rate of 10 percent to indicate the effect of time on the value of money; the contingent cash flow, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

ECONOMIC PARAMETERS

As requested, this report has been prepared using oil, NGL, and gas price parameters specified by Ithaca. Oil and NGL prices are based on Brent Crude futures prices and are adjusted by field for quality, transportation fees, and market differentials. Gas prices are based on National Balancing Point futures prices and are adjusted by field for energy content, transportation fees, and market differentials. All prices, before adjustments, along with escalation parameters are shown in the following table:

Period Ending	Oil/NGL Price ($/Barrel)	Gas Price ($/MMBTU)	Period Ending	Oil/NGL Price ($/Barrel)	Gas Price ($/MMBTU)
12-31-2022	103.00	33.796	12-31-2033	92.00	12.483
12-31-2023	95.00	25.321	12-31-2034	95.00	12.732
12-31-2024	85.00	16.371	12-31-2035	97.00	12.987
12-31-2025	78.00	13.079	12-31-2036	100.00	13.247
12-31-2026	79.00	10.867	12-31-2037	103.00	13.512
12-31-2027	80.00	11.084	12-31-2038	106.00	13.782
12-31-2028	82.00	11.307	12-31-2039	108.00	14.058
12-31-2029	83.00	11.533	12-31-2040	112.00	14.339
12-31-2030	85.00	11.762			
12-31-2031	87.00	11.998	Thereafter, escalated 2 percent on		
12-31-2032	90.00	12.238	January 1 of each year.		

Operating costs used in this report are based on operating expense records and estimates of Ithaca or the previous operator of the properties. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the area and field levels. Britannia Field and its satellites (Alder, Brodgar, Callanish, and Enochdhu Fields) have a cost sharing agreement to distribute the costs of operating the Britannia platform. Abigail, Courageous, Harrier, Stella, and Vorlich Fields have a cost sharing agreement to distribute the costs of operating FPF-1. Operating costs have been divided into area-level costs, field-level costs, per-well costs, per-unit-of-production costs, and polymer purchase costs for Mariner Field; the cost sharing agreement costs are modeled as field-level costs. Headquarters general and administrative overhead expenses of Ithaca are included to the extent that they are covered under joint operating agreements for the operated properties. As requested, operating costs are escalated 2 percent on January 1 of each year throughout the lives of the properties.

Capital costs used in this report were provided by Ithaca and are based on authorizations for expenditure, internal planning budgets, and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, production equipment, and polymer purchase for Captain Field. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Ithaca's or the operators' estimates of the costs to abandon the wells, platforms, and production facilities, net of any salvage value. As requested, capital costs and abandonment costs are escalated 2 percent on January 1 of each year to the date of expenditure.

GENERAL INFORMATION

As shown in the Table of Contents, this report includes summary projections of reserves and revenue by reserves category and summary projections of resources and cash flow by resources category. Also included are a technical discussion and pertinent figures.

This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves and contingent resources have been estimated. For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

The reserves and contingent resources shown in this report are estimates only and should not be construed as exact quantities. Estimates may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Ithaca, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the volumes, and that our projections of future production will prove consistent with actual performance. If these volumes are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received, and costs incurred may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves and contingent resources in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to classify, categorize, and estimate volumes in accordance with the 2018 PRMS definitions and guidelines. A portion of the reserves shown in this report are for non-producing zones and undeveloped locations, and the contingent resources shown in this report are for undeveloped locations. Such volumes are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

For the purposes of UK Prospectus Regulation Rule 5.3.2R(2)(f), Netherland, Sewell & Associates, Inc. (NSAI) accepts responsibility for the information contained in this report and confirms that, to the best of our knowledge, the information contained in this report is in accordance with the facts and makes no omission likely to affect its import. In connection with our engagement by Ithaca to perform consulting petroleum engineering, geological, geophysical, petrophysical, or property evaluation work, Ithaca indemnifies and holds harmless NSAI, each person who controls it, and each employee of it and each consultant or contractor engaged by it from and against any and all losses, claims, damages, expenses, or liabilities, joint or several, to which they or any of them may become subject in connection with the performance of such consulting work or the preparation of such evaluations or the reliance thereon by Ithaca or any other party. Ithaca does not indemnify NSAI with respect to losses, claims, damages, expenses, or liability arising from the gross negligence or willful misconduct of NSAI.

The data used in our estimates were obtained from Ithaca, public data sources, and the nonconfidential files of NSAI and were accepted as accurate. Supporting work data are on file in our office. We have not examined the contractual rights to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By:
C.H. (Scott) Rees III, P.E.
Executive Chairman

By:
Derek F. Newton, P.E. 97689
Senior Vice President

Date Signed: October 18, 2022

STATE OF TEXAS
D. F. NEWTON
97689
LICENSED
PROFESSIONAL ENGINEER

By:
Shane M. Howell, P.G 11276
Vice President

Date Signed: October 18, 2022

STATE OF TEXAS
S. M. HOWELL
GEOLOGY
11276
LICENSED
PROFESSIONAL GEOSCIENTIST

DFN:NFH

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, June 2018

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the SPE, World Petroleum Council, American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers, Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts, and European Association of Geoscientists & Engineers.

Preamble

Petroleum resources are the quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resources assessments estimate quantities in known and yet-to-be-discovered accumulations. Resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating projects, and presenting results within a comprehensive classification framework.

This updated PRMS provides fundamental principles for the evaluation and classification of petroleum reserves and resources. If there is any conflict with prior SPE and PRMS guidance, approved training, or the Application Guidelines, the current PRMS shall prevail. It is understood that these definitions and guidelines allow flexibility for entities, governments, and regulatory agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein must be clearly identified. The terms "shall" or "must" indicate that a provision herein is mandatory for PRMS compliance, while "should" indicates a recommended practice and "may" indicates that a course of action is permissible. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

1.0 Basic Principles and Definitions

1.0.0.1 A classification system of petroleum resources is a fundamental element that provides a common language for communicating both the confidence of a project's resources maturation status and the range of potential outcomes to the various entities. The PRMS provides transparency by requiring the assessment of various criteria that allow for the classification and categorization of a project's resources. The evaluation elements consider the risk of geologic discovery and the technical uncertainties together with a determination of the chance of achieving the commercial maturation status of a petroleum project.

1.0.0.2 The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

1.0.0.3 The use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios. The application of PRMS must consider both technical and commercial factors that impact the project's feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

1.1.0.1 Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid state. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content can be greater than 50%.

1.1.0.2 The term resources as used herein is intended to encompass all quantities of petroleum naturally occurring within the Earth's crust, both discovered and undiscovered (whether recoverable or unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered as conventional or unconventional resources.

1.1.0.3 Figure 1.1 graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Petroleum.

1.1.0.4 The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality, P_c, which is the chance that a project will be committed for development and reach commercial producing status.

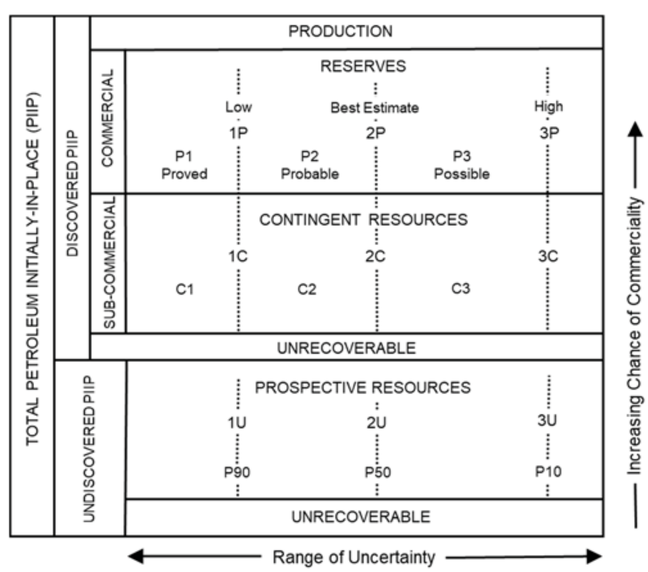


Figure 1.1—Resources classification framework

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, June 2018

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

A. **Total Petroleum Initially-In-Place** (PIIP) is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.

B. **Discovered PIIP** is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.

C. **Production** is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Section 3.2, Production Measurement).

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

A. 1. **Reserves** are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

2. Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) (see Section 3.2.2), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

3. Reserves are further categorized in accordance with the range of uncertainty and should be sub-classified based on project maturity and/or characterized by development and production status.

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

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

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

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

1.1.0.7 The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." Importantly, these quantities should not be aggregated without due consideration of the technical and commercial risk involved with their classification. When such terms are used, each classification component of the summation must be provided.

1.1.0.8 Other terms used in resource assessments include the following:

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

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

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1.2 Project-Based Resources Evaluations

1.2.0.1 The resources evaluation process consists of identifying a recovery project or projects associated with one or more petroleum accumulations, estimating the quantities of PIIP, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on maturity status or chance of commerciality.

1.2.0.2 The concept of a project-based classification system is further clarified by examining the elements contributing to an evaluation of net recoverable resources (see Figure 1.2).

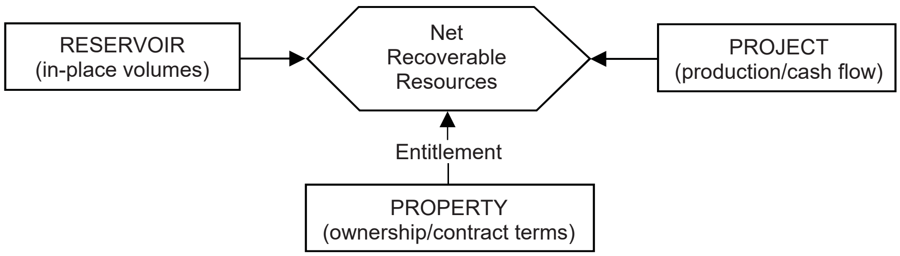

Figure 1.2—Resources evaluation

1.2.0.3 **The reservoir** (contains the petroleum accumulation): Key attributes include the types and quantities of PIIP and the fluid and rock properties that affect petroleum recovery.

1.2.0.4 **The project:** A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty. The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

1.2.0.5 **The property** (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations that may be spatially unrelated to a potential single field designation.

1.2.0.6 An entity's net recoverable resources are the entitlement share of future production legally accruing under the terms of the development and production contract or license.

1.2.0.7 In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See Section 2.1.3.5, Project Maturity Sub-Classes) at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project (See Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

1.2.0.8 An accumulation or potential accumulation of petroleum is often subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resources classes simultaneously.

1.2.0.10 Not all technically feasible development projects will be commercial. The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see Section 3.1, Assessment of Commerciality). Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions (e.g., inflation, market factors, and contingencies), exchange rates, transportation and processing infrastructure, fiscal terms, and taxes.

1.2.0.11 The resources being estimated are those quantities producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Section 3.2.1, Reference Point) and may permit forecasts of CiO quantities (see Section 3.2.2., Consumed in Operations). The cumulative production forecast from the effective date forward to cessation of production is the remaining recoverable resources quantity (see Section 3.1.1, Net Cash-Flow Evaluation).

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1.2.0.12 The supporting data, analytical processes, and assumptions describing the technical and commercial basis used in an evaluation must be documented in sufficient detail to allow, as needed, a qualified reserves evaluator or qualified reserves auditor to clearly understand each project's basis for the estimation, categorization, and classification of recoverable resources quantities and, if appropriate, associated commercial assessment.

2.0 Classification and Categorization Guidelines

2.1 Resources Classification

2.1.0.1 The PRMS classification establishes criteria for the classification of the total PIIP. A determination of a discovery differentiates between discovered and undiscovered PIIP. The application of a project further differentiates the recoverable from unrecoverable resources. The project is then evaluated to determine its maturity status to allow the classification distinction between commercial and sub-commercial projects. PRMS requires the project's recoverable resources quantities to be classified as either Reserves, Contingent Resources, or Prospective Resources.

2.1.1 Determination of Discovery Status

2.1.1.1 A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs (see Section 4.1.1, Analogs). In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.

2.1.1.2 Where a discovery has identified potentially recoverable hydrocarbons, but it is not considered viable to apply a project with established technology or with technology under development, such quantities may be classified as Discovered Unrecoverable with no Contingent Resources. In future evaluations, as appropriate for petroleum resources management purposes, a portion of these unrecoverable quantities may become recoverable resources as either commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

2.1.2.1 Discovered recoverable quantities (Contingent Resources) may be considered commercially mature, and thus attain Reserves classification, if the entity claiming commerciality has demonstrated a firm intention to proceed with development. This means the entity has satisfied the internal decision criteria (typically rate of return at or above the weighted average cost-of-capital or the hurdle rate). Commerciality is achieved with the entity's commitment to the project and all of the following criteria:

A. Evidence of a technically mature, feasible development plan.
B. Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.
C. Evidence to support a reasonable time-frame for development.
D. A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see Section 3.1.1, Net Cash-Flow Evaluation).
E. A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, $CO2$) can be sold, stored, re-injected, or otherwise appropriately disposed.
F. Evidence that the necessary production and transportation facilities are available or can be made available.
G. Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

2.1.2.2 The commerciality test for Reserves determination is applied to the best estimate (P50) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the 2P Reserves. Stricter cases [e.g., low estimate (P90)] may be used for decision purposes or to investigate the range of commerciality (see Section 3.1.2, Economic Criteria). Typically, the low- and high-case project scenarios may be evaluated for sensitivities when considering project risk and upside opportunity.

2.1.2.3 To be included in the Reserves class, a project must be sufficiently defined to establish both its technical and commercial viability as noted in Section 2.1.2.1. There must be a reasonable expectation that all required internal and external approvals will be forthcoming and evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where justifiable; for example, development of economic projects that take longer than five years to be developed or are deferred to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

2.1.2.4 While PRMS guidelines require financial appropriations evidence, they do not require that project financing be confirmed before classifying projects as Reserves. However, this may be another external reporting requirement. In many cases, financing is conditional upon the same criteria as above. In general, if there is not a reasonable expectation that financing or other forms of commitment (e.g., farm-outs) can be arranged so that the development will be initiated within a reasonable time-frame, then the project should be classified as Contingent Resources. If financing is reasonably expected to be in place at the time of the final investment decision (FID), the project's resources may be classified as Reserves.

2.2 Resources Categorization

2.2.0.1 The horizontal axis in the resources classification in Figure 1.1 defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project or group of projects. These estimates include the uncertainty components as follows:

A. The total petroleum remaining within the accumulation (in-place resources).
B. The technical uncertainty in the portion of the total petroleum that can be recovered by applying a defined development project or projects (i.e., the technology applied).
C. Known variations in the commercial terms that may impact the quantities recovered and sold (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) are part of project's scope and are included in the horizontal axis, while the chance of satisfying the commercial terms is reflected in the classification (vertical axis).

2.2.0.2 The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P1), Probable (P2), Possible (P3), 1C, 2C, 3C, C1, C2, and C3; or 1U, 2U, and 3U resources categories. The commercial chance of success is associated with resources classes or sub-classes and not with the resources categories reflecting the range of recoverable quantities.

2.2.1 Range of Uncertainty

2.2.1.1 Uncertainty is inherent in a project's resources estimation and is communicated in PRMS by reporting a range of category outcomes. The range of uncertainty of the recoverable and/or potentially recoverable quantities may be represented by either deterministic scenarios or by a probability distribution (see Section 4.2, Resources Assessment Methods).

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

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

2.2.1.3 In some projects, the range of uncertainty may be limited, and the three scenarios may result in resources estimates that are not significantly different. In these situations, a single value estimate may be appropriate to describe the expected result.

2.2.1.4 When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental method, quantities for each confidence segment are estimated discretely (see Section 2.2.2, Category Definitions and Guidelines).

2.2.1.5 Project resources are initially estimated using the above uncertainty range forecasts that incorporate the subsurface elements together with technical constraints related to wells and facilities. The technical forecasts then have additional commercial criteria applied (e.g., economics and license cutoffs are the most common) to estimate the entitlement quantities attributed and the resources classification status: Reserves, Contingent Resources, and Prospective Resources.

2.2.2 Category Definitions and Guidelines

2.2.2.1 Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental method, the deterministic scenario (cumulative) method, geostatistical methods, or probabilistic methods (see Section 4.2, Resources Assessment Methods). Also, combinations of these methods may be used.

2.2.2.2 Use of consistent terminology (Figures 1.1 and 2.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high forecasts are used to estimate the resulting 1P/2P/3P quantities, respectively. The associated incremental quantities are termed Proved (P1), Probable (P2) and Possible (P3). Reserves are a subset of, and must be viewed within the context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, the criteria can be equally applied to Contingent and Prospective Resources. Upon satisfying the commercial maturity criteria for discovery and/or development, the project quantities will then move to the appropriate resources sub-class. Table 3 provides criteria for the Reserves categories determination.

2.2.2.3 For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.

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2.2.2.4 For Prospective Resources, the general cumulative terms low/best/high estimates also apply and are used to estimate the resulting 1U/2U/3U quantities. No specific terms are defined for incremental quantities within Prospective Resources.

2.2.2.5 Quantities in different classes and sub-classes cannot be aggregated without considering the varying degrees of technical uncertainty and commercial likelihood involved with the classification(s) and without considering the degree of dependency between them (see Section 4.2.1, Aggregating Resources Classes).

2.2.2.6 Without new technical information, there should be no change in the distribution of technically recoverable resources and the categorization boundaries when conditions are satisfied to reclassify a project from Contingent Resources to Reserves.

2.2.2.7 All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Section 3.1, Assessment of Commerciality).

Table 1—Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

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Class/Sub-Class	Definition	Guidelines
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame). There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.

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Class/Sub-Class	Definition	Guidelines
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2—Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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Status	Definition	Guidelines
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3—Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

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Category	Definition	Guidelines
Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

NETHERLAND, SEWELL & ASSOCIATES, INC.

CERTIFICATE OF QUALIFICATION

I, Derek F. Newton, Licensed Professional Engineer, 1301 McKinney Street, Suite 3200, Houston, Texas 77010, hereby certify:

> I am an employee of Netherland, Sewell & Associates, Inc., which prepared a Competent Person's Report for Ithaca Energy (UK) Limited. The effective date of this evaluation is June 30, 2022.
>
> I consider myself to be independent of Ithaca Energy (UK) Limited, its directors, senior management, and other advisers. I do not have at the date of this report, have not had within the previous two years, nor do I expect to receive, any economic or beneficial interest (present or contingent) in the securities of Ithaca Energy (UK) Limited or in any of the assets being evaluated in this report. Additionally, our fees are not contingent upon the results of our evaluation.
>
> I attended University College, Cardiff, Wales, and I graduated in 1983 with a Bachelor of Science Degree in Mechanical Engineering; I attended Strathclyde University, Scotland, and I graduated in 1986 with a Master of Science Degree in Petroleum Engineering; I am a Licensed Professional Engineer in the State of Texas, United States of America; and I have in excess of 39 years of experience in petroleum engineering studies and evaluations.

By: Derek F. Newton

Derek F. Newton, P.E.
Senior Vice President
Texas License No. 97689

STATE OF TEXAS
D. F. NEWTON
97689
LICENSED
PROFESSIONAL ENGINEER

October 18, 2022
Houston, Texas

NETHERLAND, SEWELL
& ASSOCIATES, INC.

CERTIFICATE OF QUALIFICATION

I, Shane M. Howell, Licensed Professional Geoscientist, 1301 McKinney Street, Suite 3200, Houston, Texas 77010, hereby certify:

I am an employee of Netherland, Sewell & Associates, Inc., which prepared a Competent Person's Report for Ithaca Energy (UK) Limited. The effective date of this evaluation is June 30, 2022.

I consider myself to be independent of Ithaca Energy (UK) Limited, its directors, senior management, and other advisers. I do not have at the date of this report, have not had within the previous two years, nor do I expect to receive, any economic or beneficial interest (present or contingent) in the securities of Ithaca Energy (UK) Limited or in any of the assets being evaluated in this report. Additionally, our fees are not contingent upon the results of our evaluation.

I attended San Diego State University, I graduated in 1997 with a Bachelor of Science Degree in Geological Sciences, and I graduated in 1998 with a Master of Science Degree in Geological Sciences; I am a Licensed Professional Geoscientist in the State of Texas, United States of America; and I have in excess of 24 years of experience in geological and geophysical studies and evaluations.

By: Shane M. Howell

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ABBREVIATIONS

$	United States dollars
%	percent
°F	degrees Fahrenheit
1C	low estimate scenario of contingent resources
2C	best estimate scenario of contingent resources
3C	high estimate scenario of contingent resources
1P	proved
2P	proved plus probable
3P	proved plus probable plus possible
AFE	authorization for expenditure
Anasuria Hibiscus	Anasuria Hibiscus Petroleum UK Limited
Ancala	Ancala Midstream Acquisitions Limited
ANP	Alba North Platform
API	American Petroleum Institute
ASM	Andrew Sand Member
AXS	Alba Extreme South
BBL	barrels
BBL/MMCF	barrels per million cubic feet
BBL/mo	barrels per month
BLP	bridge-linked platform
BOE	barrels of oil equivalent
BOPD	barrels of oil per day
BP	British Petroleum
BWPD	barrels of water per day
CATS	Central Area Transmission System
CF/BBL	cubic feet per barrel
CGR	condensate-gas ratio
Chevron	Chevron North Sea Limited
CNRL	Canadian Natural Resources Limited
cP	centipoise
D	darcy
DCA	decline curve analysis
DST	drillstem test
EOR	enhanced oil recovery
EOS	equation of state
Equinor	Equinor UK Limited
ESP	electric submersible pump
EUR	estimated ultimate recovery
FBHP	flowing bottomhole pressure
FCA	Financial Conduct Authority
FDP	field development plan
FID	final investment decision
FPF	floating production facility
FPS	Forties Pipeline System

ABBREVIATIONS

FPSO	floating production storage and offloading
ft	feet
ft^3/ft^3	cubic feet per cubic foot
g/cm^3	grams per cubic centimeter
GBA	Greater Britannia Area
GOC	gas-oil contact
GOR	gas-oil ratio
GRV	gross rock volume
GSA	Greater Stella Area
GWC	gas-water contact
Harbour	Harbour Energy plc
HKO	highest known oil
IHS	IHS Markit
Ithaca	Ithaca Energy (UK) Limited
km	kilometers
LCS	Lower Captain Sandstone
LKO	lowest known oil
LP	Low Pressure
LLP	Low Low Pressure
M$	thousands of United States dollars
MBBL	thousands of barrels
MBOE	thousands of barrels of oil equivalent
MBOPD	thousands of barrels of oil per day
MBWPD	thousands of barrels of water per day
MCF	thousands of cubic feet
MCFD	thousands of cubic feet per day
MCF/mo	thousands of cubic feet per month
mD	millidarcies
MDT	modular dynamics test
MMBTU	millions of British thermal units
MMBTU/MCF	millions of British thermal units per thousands of cubic feet
MMCF	millions of cubic feet
MMCFD	millions of cubic feet of gas per day
MonArb	Montrose-Arbroath
MTR	meters
NGL	natural gas liquids
NRV	net rock volume
NSAI	Netherland, Sewell & Associates, Inc.
NSTA	North Sea Transition Authority
NTG	net-to-gross ratio
NUI	normally unattended installation
ohm-m	ohm-meters
OOIP	original oil-in-place
OWC	oil-water contact

ABBREVIATIONS

P/Z	material balance
PDP	proved developed producing
post-COP	post-cessation of production
PFG	polymer flood group
PRMS	Petroleum Resources Management System
psi	pounds per square inch
psia	pounds per square inch absolute
PVT	pressure-volume-temperature
report	Competent Person's Report
Repsol	Repsol Sinopec Resources UK Limited
RFT	repeat formation test
Ross	Ross and Burns Sandstones
S1b	Sele
SADIE	Southern Area Development Injection Equipment
SAGE	Scottish Area Gas Evacuation
SCF/STB	standard cubic feet per stock tank barrel
SEGAL	Shell-Esso Gas and Liquids
Shell	Shell UK Exploration & Production
Siccar Point	Siccar Point Energy Limited
SMDC	Stella Main Drill Center
SPE	Society of Petroleum Engineers
SPE Standards	Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE
STOIIP	stock tank oil initially in-place
SUCS	Southern Upper Captain Sandstone
S_{wi}	initial water saturation
Total	Total E&P U.K. Limited
TVDSS	true vertical depth subsea
UCS	Upper Captain Sandstone
UK	United Kingdom
Unocal	Union Oil Company of California
UTM	Unitised Template Manifold
WOR	water-oil ratio

SUMMARY OF RESERVES
UNITED KINGDOM SECTOR OF THE NORTH SEA AND THE NORTH ATLANTIC OCEAN
ITHACA ENERGY (UK) LIMITED INTEREST
AS OF JUNE 30, 2022

	Gross (100%) Reserves		Working Interest Reserves(1)			
Development Status/Category	Oil (MBBL)	Gas(2) (MMCF)	Oil (MBBL)	Gas (MMCF)	NGL (MBBL)	Equivalent (MBOE)
DEVELOPED						
Proved Developed	291,180.3	1,249,611.1	57,781.6	203,349.8	5,313.1	98,155.0
Proved + Probable Developed	447,559.6	1,748,117.4	95,642.5	295,283.9	7,862.6	154,416.1
Proved + Probable + Possible Developed	607,685.0	2,336,418.2	139,201.9	403,393.9	10,953.6	219,706.2
UNDEVELOPED						
Proved Undeveloped	162,635.6	38,726.8	56,665.4	20,504.4	527.6	60,728.3
Proved + Probable Undeveloped	249,183.7	75,961.6	81,099.2	42,186.9	1,069.1	89,441.9
Proved + Probable + Possible Undeveloped	337,945.7	117,444.9	109,832.3	65,342.6	1,622.9	122,721.2
TOTAL						
Proved (1P)	453,815.9	1,288,337.9	114,446.9	223,854.2	5,840.7	158,883.2
Proved + Probable (2P)	696,743.3	1,824,079.0	176,741.6	337,470.8	8,931.8	243,858.0
Proved + Probable + Possible (3P)	945,630.7	2,453,863.1	249,034.2	468,736.5	12,576.5	342,427.4

Totals may not add because of rounding.

Note: Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves included herein have not been adjusted for risk.

(1) Working interest volumes are after deductions for shrinkage to account for processing, fuel, and flare.

(2) Gross gas volumes are the wet gas volumes prior to extracting natural gas liquids (NGL) and deducting volumes flared or consumed for fuel; therefore, gross NGL volumes are not shown separately because they would be misleading.

SUMMARY OF CONTINGENT RESOURCES
UNITED KINGDOM SECTOR OF THE NORTH SEA AND THE NORTH ATLANTIC OCEAN
ITHACA ENERGY (UK) LIMITED INTEREST
AS OF JUNE 30, 2022

	Gross (100%) Contingent Resources		Working Interest Contingent Resources[1]			
Category	Oil (MBBL)	Gas[2] (MMCF)	Oil (MBBL)	Gas (MMCF)	NGL (MBBL)	Equivalent (MBOE)
Low Estimate (1C)	347,278.0	641,593.6	125,164.4	253,636.8	723.6	169,618.5
Best Estimate (2C)	676,879.8	1,116,961.6	232,174.4	398,268.5	841.5	301,682.9
High Estimate (3C)	1,153,169.1	1,749,309.9	369,382.1	587,234.7	1,324.0	471,953.4

(1) Working interest volumes are after deductions for shrinkage to account for processing, fuel, and flare.
(2) Gross gas volumes are the wet gas volumes prior to extracting natural gas liquids (NGL) and deducting volumes flared or consumed for fuel; therefore, gross NGL volumes are not shown separately because they would be misleading.

SUMMARY OF FUTURE NET REVENUE AFTER UK CORPORATE INCOME TAXES
UNITED KINGDOM SECTOR OF THE NORTH SEA AND THE NORTH ATLANTIC OCEAN
ITHACA ENERGY (UK) LIMITED INTEREST
AS OF JUNE 30, 2022

	Future Net Revenue After UK Corporate Income Taxes (M$)	
Category	Undiscounted	Present Worth at 10%
Proved (1P)	4,111,140.2	3,985,975.0
Probable	2,669,142.0	1,841,135.4
Proved + Probable (2P)	6,780,282.2	5,827,110.4
Possible	2,946,963.9	1,812,942.5
Proved + Probable + Possible (3P)	9,727,246.0	7,640,053.0

Totals may not add because of rounding.

Note: Reserves categorization conveys the relative degree of certainty. The estimates of future revenue included herein have not been adjusted for risk.

SUMMARY OF NET CONTINGENT CASH FLOW AFTER UK CORPORATE INCOME TAXES
UNITED KINGDOM SECTOR OF THE NORTH SEA AND THE NORTH ATLANTIC OCEAN
ITHACA ENERGY (UK) LIMITED INTEREST
AS OF JUNE 30, 2022

	Net Contingent Cash Flow After UK Corporate Income Taxes (M$)	
Category	Undiscounted	Discounted at 10%
Low Estimate (1C)	4,401,099.1	1,958,529.3
Best Estimate (2C)	9,427,221.8	3,994,985.5
High Estimate (3C)	17,723,131.7	6,919,249.3

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

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