ITHACA ENERGY

Year to 31 December 2021 Financial Results

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HIGHLIGHTS

56 kboe/d
Q4 YTD Production

$18/boe
Q4 YTD 2021 Unit Opex

$1,036M
Q4 YTD EBITDAX

$930M
31 December 2021 Net Debt

Financial highlights

- Production of 56.5 thousand barrels of oil equivalent per day ("kboe/d"), 65% liquids for the year. Fourth quarter production improved following the Forties Pipeline System shutdown in Q2 and other planned maintenance activities in Q3.
- Unit operating costs of $18/boe
- EBITDAX of $1,036 million including realised gains of $115 million on the commodity hedging instruments that were reset in 2020
- $275 million was repaid against the Reserves Based Lending facility during Q4 taking net debt down to $930 million
- 22 million barrels of oil equivalent (73% oil) hedged from Q1 2022 into 2023 at an average price floor of $61/bbl oil and 92p/therm gas

Operational highlights

- Development consent for the Abigail field was received from the North Sea Transition Authority (formerly the Oil and Gas Authority) in January 2022, first oil is still expected to be achieved in Q3 2022

Corporate highlights

- The agreement to acquire 13.3% additional equity interest in the Alba field from Mitsui E&P UK Limited completed on 30 November. This takes Ithaca's interest in the Alba field to 36.7%
- As reported in Q3, on 2 November an agreement was signed to acquire 100% of the share capital of Marubeni Oil & Gas UK Limited for $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 in the future should certain milestones be achieved related to future development activities. The sale and purchase agreement completed on 4 February 2022 and gives Ithaca non operated working interests in the Repsol Sinopec operated MonArb assets and CNR operated Columba assets which will contribute approx. 7 kboe/d to production in 2022.
- On 28 February a further agreement was signed to acquire 100% of the share capital of Summit Exploration and Production Limited. The agreement has an economic date of 1 January 2021 and is subject to normal completion activities including consent from the North Sea Transition Authority

SUMMARY STATEMENT OF INCOME

		YTD Q4 2021	YTD Q4 2020
Average Production	kboe/d	56	66
Average Realised Oil Price [1]	S/bbl	70	44
Revenue [2]	M$	1,418	1,144
Revenue [2]		**1,418**	**1,144**
Opex [3]	M$	(371)	(389)
G&A and Foreign Exchange	M$	(11)	(10)
EBITDAX	**M$**	**1,036**	**745**
Non-recurring Cash Costs	M$	-	(21)
DD&A	M$	(455)	(373)
Impairment reversal/(charge)	M$	465	(682)
Gain on acquisition	M$	10	-
Finance Costs	M$	(244)	(233)
Other Non-Cash Costs [4]	M$	-	3
Taxation	M$	(337)	159
Earnings	**M$**	**475**	**(402)**
Fair value (loss)/gain on hedges	M$	(487)	28
Taxation	M$	195	(11)
Total comprehensive income / (expense)	**M$**	**183**	**(385)**

(1) Average realised oil price before hedging
(2) Revenue, realised hedging gains/losses and inventory movements net of royalty costs and tanker costs
(3) Opex costs net of tariff income and exclude tanker costs
(4) Revluation of FX hedging and contingent consideration

SUMMARY BALANCE SHEET

M$	31 Dec 2021	31 Dec 2020
Cash and Cash Equivalents	45	1
Other Current Assets	422	258
PP&E	3,075	2,655
Goodwill	722	722
Deferred Tax Asset	221	382
Other Non-Current Assets	247	250
Total Assets	**4,732**	**4,265**
Current Liabilities	(1,035)	(368)
Borrowings	(955)	(1,437)
Asset Retirement Obligations	(1,547)	(1,416)
Other Non-Current Liabilities	(66)	(83)
Total Liabilities	**(3,603)**	**(3,304)**
Net Assets	**1,129**	**961**
Share Capital	1,250	1,250
Cashflow Hedge Reserve	(248)	44
Retained earnings	127	(333)
Shareholders' Equity	**1,129**	**961**

OPERATIONAL REVIEW

Full year 2021 production was 56.5 kboe/d compared to 66.4 kboe/d for 2020.

		2021 Full Year Production	2020 Full Year Production
Daily Production	***kboe/d***	**56.5**	**66.4**
▪ Liquids	*kbbl/d*	35.9	40.8
▪ Gas	*kboe/d*	20.6	25.6
Total Production	***MMboe***	**20.6**	**24.3**

Daily Production	***kboe/d***	**56.5**	**66.4**
▪ Captain	*kboe/d*	17.4	21.7
▪ GSA	*kboe/d*	12.4	9.1
▪ Other Operated[1]	*kboe/d*	9.2	11.5
▪ Britannia & Satellites[2]	*kboe/d*	11.6	15.6
▪ Other Non-Operated[3]	*kboe/d*	5.9	8.5

1. Other-operated assets comprises Erskine, Cook and Alba
2. Includes the Ithaca Energy-operated Alder field subsea tie-back to the Britannia platform
3. Other non-operated assets comprises Elgin / Franklin, Jade, Pierce and the Dons

The producing asset portfolio has performed well during 2021 although average production of 56.5 kboe/d (63% liquids – 58% oil / 5% NGL) is lower than the equivalent period in 2020. This was due to a number of fields in the portfolio being shut in for planned maintenance over Q2 and Q3 2021.

2021 results also see the impact of production from the Vorlich field (34% working interest) in the Greater Stella Area following start up in November 2020, and the impact of the well drilled on the Harbour-operated Callanish field (16.5% working interest) at the end of 2020.

As previously reported, production operations from the Enquest operated Dons Area ceased in March 2021. The Dons contributed approximately 0.8 kboe/d to the Group's total production in 2020.

ACTIVITY OVERVIEW

Developments

Captain Enhanced Oil Recovery ("EOR") Programme

Based on the performance and incremental production achieved as a result of the Stage I polymer EOR programme on the Captain field (85% working interest), work is progressing on extending this to a second stage of activities. The "Stage II" programme involves the drilling of up to ten additional wells (four producers and six injectors) to optimise oil recovery from the area of the Upper Captain Sands reservoir that is produced using subsea wells. The overall work programme involves the installation of approximately six kilometre subsea pipelines and umbilicals to the two subsea areas of the field in order to provide polymer injection capacity and the installation of additional polymer storage tanks and pumps on the Captain platform and floating production, storage and offloading ("FPSO") vessel.

Following attainment of North Sea Transition Authority FDPa approval and full sanction in Q1 2021, the project continues to focus on maturing topside engineering and procurement, commencing topsides construction and developing subsea infrastructure design and manufacture. Emphasis has been placed on preparations for rig arrival mid 2022. Significant milestones have been achieved despite the challenges facing the industry because of Covid-19. The development involves a multi-year programme of drilling activities aimed at maximising oil recovery from the field into the 2030s.

GSA Satellite Field Developments

Engineering and procurement activities are progressing for the Abigail (formerly known as Hurricane) field. Preparations are in place for rig arrival in March 2022. Key long lead items (christmas tree, flowbase, wellhead etc) are on schedule for delivery ahead of drilling commencement.

FDP consent was granted in January 2022 and first oil is expected in Q3 2022.

With respect to the other subsequent GSA satellite fields, Austen and Courageous, various subsurface and engineering studies are being progressed to advance the necessary development plans. These studies will continue into 2022, along with the evaluation of additional development opportunities across the portfolio.

Fotla

The Fotla Prospect is within licence P2373 and is located ~12km south of the Ithaca operated Alba North Platform. The licence and the well are operated by Ithaca on behalf of the joint venture which comprises ourselves and Spirit Energy. Exploratory drilling began on 5 August using the Awilco WilPhoenix semisubmersible rig, successfully drilling two appraisal sidetrack wells that also encountered hydrocarbons in the remobilized sands of the Eocene Caran Formation. A comprehensive dataset has been gathered across the three well bores which includes obtaining a full suite of LWD and wireline logs, retrieving 120ft of core, collecting gas, light oil, and water samples, and obtaining pressure data and sidewall cores. Technical work is underway to evaluate the discovery.

Elgin Franklin

The Operator, Total Energies, completed the development well EIG-B5 in the Elgin reservoir and commenced production during Q4 2021. Production volumes are in line with expectation.

Pierce

The Operator, Shell Oil UK, began a life extension project on the Haewene Brim to allow for reservoir depressurisation on the asset. The vessel was disconnected from the field infrastructure and towed to Haugesund, Norway during Q4 2021. Production is anticipated to recommence in summer 2022.

Exploration and Appraisal

Jade South

During Q4 2021, the Operator (Harbour) completed the majority of drilling activity on exploration well 30/2c-J13 which was delivered ahead of schedule and under budget. The well completed in early 2022 and has confirmed a productive Jade reservoir in this previously unexplored section of the block.

Decommissioning

Jacky

The Jacky field, which ceased production in 2014, is located in the Inner Moray Firth area of the UK North Sea (Block 12/21c). Following the significant milestone of removal of the suction-piled, monopole unmanned platform attained during Q3 2021, the removed platform structures were transported to Hoondert in the Netherlands where they have been dismantled and recycled. Final documentation will be completed in early 2022. A final phase will take place in 2023 to remove the remaining subsea equipment, mattresses, pipeline ends / spools and umbilicals.

Dons

Following the cessation of production operations in March 2021, the Northern Producer floating production facility that served the Enquest operated Dons Area has sailed to Kishorn where the owner prepares the vessel for future plans.

HEALTH, SAFETY & ENVIRONMENT

The Company monitors and manages the Lost Time Injury Frequency (“LTIF”) and Total Recordable Injury Frequency (“TRIF”) associated with its operated assets, as a means of evaluating the health and safety performance of the Company and the third parties who are working on the assets. The number of injuries and near misses are also tracked and investigated, where appropriate.

	2021 Goal	Q4-2021		Q3-2021		Q2-2021		Q1-2021	
		Quarter	12month rolling	Quarter	12month rolling	Quarter	12month rolling	Quarter	12month rolling
Health & Safety KPIs									
Lost Time Injury Frequency (LTIF) per million-man hours	0	**1.33**	**0.36**	0	**0.36**	0	**1.12**	0	**1.08**
Number of recordable injuries	0	**3**	**3**	0		0		0	
Total Recordable Injury Frequency (TRIF) per million-man hours	< 1.0	**3.99**	**1.09**	0	**0.36**	0	**1.49**		**1.45**

The three recordable injuries during Q4 occurred on two offshore installations and at our Aberdeen office. These events have been investigated to ensure appropriate lessons are identified, actions assigned, plus audit and assurance plans are adjusted to ensure appropriate verification steps are taken.

The Company's environmental stewardship plan for 2021 includes a commitment to execute various emissions reduction projects to realise Ithaca's goal of reducing emissions by 25% by 2025 from the 2019 benchmark.

The atmospheric emissions are reported on a carbon intensity basis for Ithaca's operated assets for both carbon dioxide (CO2) and carbon dioxide equivalent (CO2e) per million boe produced. Note that the component of CO2e due to diesel use is provisional as it is based on diesel delivered to the installations rather than utilised.

	Full year 2021	Q4-2021	Q3-2021	Q2-2021	Q1-2021
Environmental KPIs					
Carbon intensity of operated assets (ktonnes of CO_2 per million boe produced)	22.89	22.29	25.38	25.75	19.81
Carbon intensity of operated assets (ktonnes of CO_2e per million boe equivalent)	25.29	24.38	28.05	28.68	21.92

Q4 2021 FINANCIAL REVIEW

REVENUE

Revenues for 2021 were $1,418 million, increasing by $274 million year on year (Q4 YTD 2020: $1,144 million). Total 2021 production was 21 MMboe, down 13% on 2020 production of 24 MMboe. Over the summer months scheduled annual maintenance programs resulted in prolonged shutdowns on Forties Pipeline System, FPF1 and Erskine. Water injection on Captain was constrained during Q3 2021 and overall natural field decline is also being seen across the portfolio. This has been offset by production from the Vorlich field which came online in November 2020.

Commodity prices have increased compared to 2020 which has generated higher oil and gas revenues. Average realised gas prices have risen steeply from an average of 23p/therm in 2020 to 119p/therm in 2021. Average realised oil prices also increased to $70/bbl in 2021 from $44/bbl in 2020. The impact of increased commodity prices has been offset by losses in relation to the Group hedging portfolio which have reduced from a $373 million gain 2020 to a $196 million loss in 2021.

OPERATING COSTS

Operating costs decreased to $371 million in 2021 (Q4 YTD 2020: $389 million) as the focus is on continuing to carefully control costs. The corresponding unit cost of $18/boe in the period is up on $16/boe in 2020. This increase is largely driven by lower production volumes in 2021 as noted above.

DEPRECIATION, DEPLETION and AMORTISATION ("DD&A")

Total DD&A expense for the period was $455 million (Q4 YTD 2020: $373 million) with the DD&A rate increasing from $15/boe in 2020 to $22/boe in 2021. This increase was driven by the impact of the impairment reversals recognised in Q2 and Q3 2021.

IMPAIRMENT

An annual impairment review was carried out at the end of 2021. This resulted in a further impairment reversal of $57 million in addition to the previously reported reversals of $234 million at the end of Q3 2021 and $174 million at the end of Q2 2021. The year end 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%. The reversals in Q2 and Q3 2021 were calculated on the same basis but using a discount rate of 9.75%.

GAIN ON ACQUISITION

The Group acquired an additional 13.3% equity share in the Alba field from Mitsui when the Sale and Purchase Agreement completed on 30 November 2021. The headline reverse consideration was $56m. Following recognition of the assets and liabilities acquired on completion, a gain of $10m was taken to the Income Statement.

FINANCIAL INSTRUMENTS

The Company cash flow hedge accounts for both commodities and interest rate instruments, while accounting for foreign exchange instruments is on a mark-to-market basis. This effectively means that the accounting impact relating to financial instruments is split between the Income Statement and the Statement of Other Comprehensive Income (SOCI). The Company executed an oil hedging re-set programme 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 period H1 2020. All the hedges that were re-set were replaced with new positions at the forward curve prices prevailing at the time. $115 million of hedging gains were recognised in the income statement in relation to these re-sets in 2021. Offsetting hedging losses of $311 million reported in the period are primarily driven by realised oil and gas swaps which are hedged at an average of $39/bbl and 48p/therm respectively.

		2021 IS gain/(loss)	2021 Cash in/(out)	2020 IS gain/(loss)	2020 Cash in/(out)
Realised hedging gains/(losses)					
▪ Hedging instruments realised in the period	*$ million*	($311)	($311)	$373	$373
▪ 2020 resets	*$ million*	$115	-	-	$155

CAPITAL INVESTMENTS

Capital investment for the year was $237 million (2020 YTD $109 million), of which $191 million relates to Development and Production and $46 million relates to Exploration and Evaluation assets. The 2021 capital expenditure programme continued to focus on the Captain Enhanced Oil Recovery project and GSA satellite investment on the Abigail field along with the exploration activity on the Fotla and Jade South licences.

2021 CASH FLOW MOVEMENTS

During the year ended 2021 there was a cash inflow from operating, investing and financing activities of approximately $44 million (Q4 2020 outflow of $14 million).

Cash flow from operating activities was $932 million. Revenues from the producing asset portfolio have been supported by carefully controlled operating costs. Movements in working capital resulted in an inflow of cash totalling $6 million in the period. This was primarily driven by timing of receipt of payments for oil and gas hedges.

Cash spend on capital expenditure in the period was $248 million, with the key contributors being on Captain, Abigail and Fotla. Consideration of $56m was received from Mitsui on the acquisition of 13.3% interest in Alba and a deposit of $7m was paid to Marubeni on signing the Sale and Purchase Agreement in November 2021.

The Company aims to maintain minimal cash on hand and prioritises repayment of the RBL facility with excess cash. During Q3 the refinancing program completed resulting in amending and extending the RBL and putting in place a new $625 million bond (senior notes). As part of the refinancing, the $250 million Subordinated Shareholder Loan was repaid to Delek Group Ltd. The completion of the refinancing resulted in a Q3 YTD inflow of $30 million in relation to the RBL and senior notes. During Q4, $275m was repaid to the RBL.

During the year, the Company paid finance costs totalling $170 million. This was split $121 million in interest paid to lenders and $49 million paid in premiums on oil and gas put options.

SUBSEQUENT EVENTS

Marubeni

The Sale and Purchase Agreement for the acquisition of Marubeni Oil & Gas UK Limited completed on 4 February 2022 for $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 in the future should certain milestones be achieved related to future development activities. The transaction has an economic date of 1 January 2021.

Summit

The Group signed a Sale and Purchase Agreement for the acquisition of Summit Exploration & Production Limited which was based on an enterprise value of $148 million. Taking into account cash of $70m and other adjustments, headline consideration is $224m. The transaction has an economic date of 1 January 2021 and is subject to normal completion activities including gaining consent from the North Sea Transition Authority.

ADDITIONAL READER ADVISORIES

The information in this MD&A is provided as of 29 March 2022. The Q4 2021 year to date results have been compared to the results for the same period in 2020. This Management Discussion and Analysis should be read in conjunction with the Company's audited consolidated financial statements as at 31 December 2021 together with the accompanying notes.

CRITICAL ACCOUNTING ESTIMATES

Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. These accounting policies are discussed below and are included to aid the reader in assessing the critical accounting policies and practices of the Company and the likelihood of materially different results being reported. Ithaca Energy's management reviews these estimates regularly. The emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates.

The following assessment of significant accounting policies and associated estimates is not meant to be exhaustive. The Company might realise different results from the application of new accounting standards promulgated, from time to time, by various rule-making bodies.

Capitalised costs relating to the exploration and development of oil and gas reserves, along with estimated future capital expenditures required to develop proved and probable reserves are depreciated on a unit-of-production basis, by asset, using estimated proved and probable reserves as adjusted for production.

A review is carried out at each reporting date for any indication that the carrying value of the Company's D&P and E&E assets may be impaired. For assets where there are such indications, an impairment test is carried out on the Cash Generating Unit ("CGU"). Each CGU is identified in accordance with IAS 36. The Company's CGUs are those assets which generate largely independent cash flows and are normally, but not always, single developments or production areas. 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 of disposal and value in use, where the value in use is determined from estimated future net cash flows. Any additional depreciation resulting from the impairment testing is charged to the Statement of Income.

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 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.

Recognition of decommissioning liabilities associated with oil and gas wells are determined using estimated costs discounted based on the estimated life of the asset. In periods following recognition, the liability and associated asset are adjusted for any changes in the estimated amount or timing of the settlement of the obligations. The liability is accreted up to the actual expected cash outlay to perform the abandonment and reclamation. 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.

All financial instruments are initially recognised at fair value on the balance sheet. The Company's financial instruments consist of cash, accounts receivable, deposits, derivatives, accounts payable, accrued liabilities, contingent consideration and borrowings. Measurement in subsequent periods is dependent on the classification of the respective financial instrument.

The determination of the Company's income and other tax liabilities / assets requires interpretation of complex laws and regulations. Tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded on the financial statements.

The accrual method of accounting will require management to incorporate certain estimates of revenues, production costs and other costs as at a specific reporting date. In addition, the Company must estimate capital expenditures on capital projects that are in progress or recently completed where actual costs have not been received as of the reporting date.

ADDITIONAL INFORMATION

Non-IFRS measures

"EBITDAX" referred to in this MD&A is not prescribed by IFRS. EBITDAX includes Earnings Before Interest, Taxes, Depreciation (or Depletion), Amortization, and Exploration Expense. EBITDAX may not be comparable to other similarly titled measures of other companies, and accordingly EBITDAX may not be comparable to measures used by other companies.

"Cashflow from operations" referred to in this MD&A are not prescribed by IFRS. This non-IFRS financial measure does not have any standardised meaning and therefore are unlikely to be comparable to similar measures presented by other companies. As an indicator of the Company's performance, cashflow from operations should not be considered as an alternative to, or more meaningful than, net cash from operating activities as determined in accordance with IFRS. Cashflow from operations is determined by adding back changes in non-cash operating working capital to cash from operating activities.

"Net working capital" referred to in this MD&A is not prescribed by IFRS. Net working capital includes total current assets less trade and other payables. Net working capital may not be comparable to other similarly titled measures of other companies, and accordingly Net working capital may not be comparable to measures used by other companies.

"Net debt" referred to in this MD&A is not prescribed by IFRS. The Company uses net drawn debt as a measure to assess its financial position. Net drawn debt includes amounts outstanding under the Company's debt facilities and senior notes, less cash and cash equivalents. Subordinated debt of $250m from Delek Group Limited which was repaid on 3 August 2021 was ranked with equity.

BOE Presentation

The calculation of boe is based on a conversion rate of 5.8 thousand cubic feet of natural gas ("mcf") to one barrel of crude oil ("bbl"). The term boe may be misleading, particularly if used in isolation. A boe conversion ratio of 5.8 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 5.8 mcf: 1 bbl, utilising a conversion ratio at 5.8 mcf: 1 bbl may be misleading as an indication of value.

Reserves

The Company's reserves and resources as of 31 December 2021 were independently evaluated by Netherland Sewell & Associates Inc. ("NSAI"), a qualified reserves evaluator, in accordance with the definitions and guidelines set forth in the 2018 Petroleum Resource Management System (PRMS) approved by the Society of Petroleum Engineers (SPE). The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation.

Well Test Results

Well test results represent short-term results, which may not necessarily be indicative of long-term well performance or ultimate hydrocarbon recovery therefrom. Full pressure transient and well test interpretation analyses may not have been completed and as such flow test results should be considered preliminary until such analyses have been completed.

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