ITHACA ENERGY

H1-2020 Financial Results

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HIGHLIGHTS

73 kboe/d	$15/boe	$398M	$1.3Bn
H1-2020 Production	H1-2020 Unit Opex	H1-2020 EBITDAX	End H1-2020 Net Debt

- Strong operational performance with limited disruption arising from Covid-19 related restrictions
- Production of 73 thousand barrels of oil equivalent per day ("kboe/d"), 61% liquids, during the first six months of 2020 ("H1-2020")
- Forecast 2020 production anticipated to be at the top end of the 63-68 kboe/d guidance range
- Unit operating costs of $15/boe in H1-2020, down from $17/boe pro-forma 2019 unit operating expenditure
- H1-2020 EBITDAX of $398 million, including realised commodity hedging gains of $220 million
- During H1-2020 the company re-set the majority of its 2021/22 oil hedges, maintaining underlying hedge volumes with swaps at the prevailing forward curve – as a result, in addition to EBITDAX of $398 million, $155 million of cash flow has been accelerated into H1-2020
- 23 million barrels of oil equivalent (68% oil) hedged from the start of July 2020 into 2022 at an average price floor of $51/bbl oil and 49p/therm gas after reflecting the impact of the re-set
- Net debt at 30 June 2020 was $1.3 billion, down from $1.55 billion at year-end 2019
- H1-2020 results include the $795 million post-tax non-cash impairment included in the Q1-2020 financial results
- Decisive actions taken at the start of the year to manage the Covid-19 pandemic and sharp fall in oil prices – forecast 2020 capital expenditure halved to approximately $125 million and unit operating expenditure reduced by approximately 15% to $15/boe
- Measures being taken to recommence some of the deferred investment programmes, with capital expenditure forecast to be in the range of $125 to $135 million.
- Taking into account solid year to date operational performance, full year 2020 production is anticipated to be towards the top end of the guidance range of the 63-68 kboe/d issued when the potential impact of Covid-19 restrictions were incorporated into the outlook
- Mid-year independent reserves evaluation completed with proven and probable reserves ("2P") and resources ("2C") broadly unchanged at 258 million barrels of oil equivalent ("MMboe"), after taking into account production in H1-2020, despite a reduction in forecast future commodity prices

SUMMARY STATEMENT OF INCOME

		H1 2020	H1 2019
Average Production	kboe/d	72.8	18.1
Average Realised Oil Price [1]	$/bbl	44	66
Revenue [2]	M$	610	183
Revenue [2]		**610**	**183**
Opex [3]	M$	(192)	(66)
G&A and Foreign Exchange	M$	(19)	(5)
Cashflow from Operations [4]	**M$**	**399**	**112**
DD&A & Impairment	M$	(1,405)	(74)
Finance Costs	M$	(120)	(38)
Other Non-Cash Costs	M$	(6)	(2)
Taxation	M$	362	19
Earnings	**M$**	**(770)**	**17**
Fair value gain/loss on hedges	M$	293	23
Taxation	M$	(117)	(9)
Total Comprehensive Expense/Income	**M$**	(595)	**31**

(1) Average realised oil price before hedging
(2) Revenue net of royalty costs, realised hedging gains/losses, inventory movements and tanker costs;
(3) Opex costs excluding tanker costs
(4) Cashflow from Operations per cashflow statement includes $155m of Hedge resets which will not be recognized in the income statement until the original hedge matures

SUMMARY BALANCE SHEET

M$	30 Jun 2020	31 Dec 2019
Cash and Equivalents	10	15
Other Current Assets	432	327
PP&E	2,089	3,244
Goodwill	722	929
Deferred Tax Asset	479	234
Other Non-Current Assets	256	245
Total Assets	**3,988**	**4,994**
Current Liabilities	(320)	(431)
Borrowings	(1,533)	(1,764)
Asset Retirement Obligations	(1,189)	(1,195)
Other Non-Current Liabilities	(95)	(139)
Total Liabilities	**(3,137)**	**(3,529)**
Net Assets	**851**	**1,465**
Share Capital	1,250	1,250
Cashflow Hedge Reserve	203	27
Retained earnings	(602)	188
Shareholders' Equity	**851**	**1,465**

Note: All references to "pro-forma" in this Management Discussion and Analysis take into account the contribution of the Chevron North Sea Limited ("CNSL") assets from the 1 January 2019 acquisition effective date

CORPORATE STRATEGY

Ithaca Energy is an independent oil and gas company with production, development and exploration operations focused on the UK North Sea. The Company was founded in 2004 and has grown through a combination of acquisitions and new field developments.

The Company's portfolio consists of 18 producing field interests, which predominantly lie in the Central North Sea area of the UK Continental Shelf. The portfolio is heavily weighted towards operated assets, both in terms of production and reserves, providing significant control and flexibility over execution of the business' strategic and operational priorities. The Company has approximately 450 employees, of which around 200 work offshore on Ithaca-operated assets.

Ithaca Energy's corporate strategy is focused on establishing the Company as a leading North Sea operator, delivering sustainable growth in free cash flow generation, underpinned by operational excellence and financial discipline. Execution of this strategy is centred on delivering a balanced blend of investment programmes to sustain and enhance production through continued expansion of the Captain enhanced oil recovery ("EOR") programme, infill drilling on existing producing assets, satellite field developments and near-field exploration and appraisal activities.

The Company has total proven and probable reserves and resources of 258 million barrels of oil equivalent as of 30 June 2020 (as independently evaluated by Netherland Sewell & Associates Inc.)

Ithaca Energy is a wholly owned subsidiary of the Tel Aviv stock exchange listed Delek Group Limited (TASE: DLEKG, US ADR: DGRLY), Israel's leading integrated energy company.

2020 ENVIRONMENT & RESPONSE

Given the twin challenges that arose in March 2020 of Covid-19 and the dramatic fall in oil prices, the main focus of the Company's response to these issues has been centred 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, the Company 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. Forecast expenditure totalled approximately $250 million, with around two-thirds associated with the Ithaca-operated Captain, Greater Stella Area ("GSA") and Alba assets.

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 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 this year, the Hurricane development programme and the Fotla exploration well. In total the steps taken across the portfolio amounted to a forecast halving of the originally planned 2020 capital investments programme to approximately $125 million.

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 taken to manage 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 and expenditure in future years is being assessed as part of the on-going work being undertaken by the Company and the wider industry to optimise forward work programmes.

Although the majority of the capital investments relate to activities designed to increase production in 2021 and beyond, the timing for completion of the Vorlich field development programme (34% working interest) will impact the level of production during the year. Vorlich represents the next satellite field start-up in the Greater Stella Area ("GSA"). As previously reported, the impact of Covid-19 related restrictions on personnel and equipment have resulted in the anticipated start-up of production moving from mid-2020 to the fourth quarter of this year. Strong progress has been made over the recent months in completing the subsea infrastructure installation campaign and advancing the remaining topsides modification works on the “FPF-1” floating production facility and the development remains on-track for start up prior to the end of the year.

In addition to the 2020 capital expenditure reductions, the Company is also targeting an approximately 15% reduction in 2020 operating expenditure. These savings are driven by both work programme changes, being the cancellation or deferral of activities that are not required to specifically maintain safe and stable production operations while Covid-19 restrictions are on-going, and the work being undertaken as part of transforming the business following the CNSL acquisition.

Various initiatives have been taken over the first half of the year to re-set the cost base of the enlarged business and drive forward the underlying transformation principles of process simplification, operational efficiencies and value creation. As previously reported, the Company has reduced the size of the onshore workforce to better match the operational footprint of the business. A voluntary leavers programme was initiated in April 2020 and will be completed during the third quarter of the year. This will result in an approximately 25% reduction in the number of onshore employees as well as reduced contractor utilisation.

2020 OUTLOOK

Taking into account the reductions in offshore work programmes, including reductions to the duration of planned maintenance shutdowns scheduled to take place across the portfolio during the year, it was estimated that 2020 production would be in the region of 63-68 kboe/d, approximately 10% lower than guidance at the start of the year. Production in H1-2020 was 73 kboe/d (61% liquids), following strong operational performance across the portfolio and ultimately limited disruption to date from Covid-19 related restrictions. Taking into account year to date performance, full year production is anticipated to be towards the top end of the guidance range.

With the on-going easing of Covid-19 related restrictions across the economy, steps are being taken to commence increasing offshore manning levels in order to prepare for recommencement of some of the previously deferred investment programmes. Depending on the speed with which such upmanning can progress over the coming months, it is anticipated that a modest increase in the reduced capital work programme could be delivered in the year. This could result in the ultimate 2020 capital expenditure programme being in the range of $125 to $135 million.

As a consequence of the various cost reduction initiatives being implemented across the business, forecast 2020 unit operating expenditure remains at approximately $15/boe, down from guidance at the start of the year of $17/boe.

OPERATIONAL REVIEW

H1-2020 production was 72.8 kboe/d, in line with pro-forma 2019 performance and ahead of the 63-68 kboe/d guidance issued in April 2020 when the potential impact of Covid-19 issues and restrictions were incorporated into the outlook

The production portfolio is weighted towards operated assets, which accounted for approximately 70% of production. This provides the Company with the control and flexibility over the operation of these fields, enabling a sharp focus to be maintained on optimising and maximising the value of production from the assets.

		H1-2020 Production	2019 Pro-Forma Production
Daily Production	**kboe/d**	**72.8**	**74.7**
▪ *Liquids*	*kbbl/d*	*44.3*	*46.8*
▪ *Gas*	*kboe/d*	*28.5*	*28.0*
Total Production	**MMboe**	**13.2**	**27.3**
Daily Production	**kboe/d**	**72.8**	**74.7**
▪ Captain	kboe/d	24.2	23.9
▪ GSA	kboe/d	10.5	12.5
▪ Other Operated[1]	kboe/d	12.0	13.2
▪ Britannia & Satellites[2]	kboe/d	16.7	16.7
▪ Other Non-Operated[3]	kboe/d	9.3	8.4

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 H1-2020. Average production of 72.8 kboe/d (61% liquids – 56% oil / 5% NGL) is in line with expectations and at the same level as annual average production in 2019.

Production during the period benefitted from solid operational uptime performance across the portfolio, with no major impact arising from the move to minimum offshore manning levels in March 2020 as a result of the measures taken to mitigate the potential impact of Covid-19.

Production during H1-2020 has been comparable with full year 2019 volumes as the benefit of the infill drilling programmes that were completed on various assets over the course of last year have mitigated the rate of natural production decline across the portfolio. In particular, infill wells drilled in 2019 on the Captain (85% working interest), Stella (100% working interest), Elgin / Franklin (3.9% working interest) and Brodgar (12.5% working interest) fields have all contributed to sustaining solid production volumes in the first half of 2020.

While infill drilling activities have temporarily been paused on the Company's operated fields, certain wells on the non-operated assets are continuing or forecast to commence in the second half of 2020 and will contribute additional volumes in the later part of 2020 and into 2021, although at a modest level given the Company's relatively low working interest in the fields. These include on-going infill drilling activities on the TOTAL-operated Elgin / Franklin (3.9% working interest) and the Shell-operated Pierce (7.48% working interest) fields, plus a well that is scheduled to commence drilling on the Chrysaor-operated Callanish field (16.5% working interest) later in the year. The next more significant boost to production is anticipated to come from start-up of the Vorlich field (34% working interest) towards the end of this year.

Taking into account the year to date, production to the end of August 2020 is expected to average approximately 70 kboe/d. This performance continues to exceed the revised production guidance of 63-68 kboe/d (down 10% on the range reported at the start of the year) that was issued in April 2020. The guidance took into account the potential impact of Covid-19 issues and restrictions on both operational uptime and and the delay to start-up of the Vorlich field (from mid-2020 to Q4-2020), as well as deferrals and delays associated with the originally planned infill drilling campaigns during the year.

The reduction in average year to date production of approximately 70 kboe/d versus H1-2020 production of 73 kboe/d predominantly reflects the impact of an approximately one month planned shutdown of the FPF-1 floating production facility that serves the GSA fields in August 2020 in order to facilitate construction and tie-in works on the FPF-1 for the forthcoming start-up of the Vorlich field. A reduction in polymer injection to one of the well patterns on the Captain field in order to optimise reservoir performance and reserves recovery has also contributed to a marginal reduction in volumes over the last three months.

As a result of issues arising with the water injection and gas lift capability on the EnQuest-operated Dons Area fields in the second quarter of this year, it has been concluded that the fields being served by the “Northern Producer” floating production facility have reached their economic limit. The Dons Area, which is located in the Northern North Sea, consists of the Don Southwest, Conrie and Ythan fields in Blocks 211/18a & 18c (all 40% working interest) and the West Don field in 211/18b & 211/13b (21.4% working interest). As previously announced, work is on-going to secure the necessary regulatory approvals for cessation of production from the field at the end of Q1 2021. This will enable removal of the Northern Producer ahead of executing the full field decommissioning programme in the years to come. In the first half of 2020, the Dons contributed approximately 1.2 kboe/d or under 2% to the Company’s total production.

DEVELOPMENTS

The Company’s development activities are centred on leveraging the value of existing infrastructure in the portfolio, through infill drilling and developing additional resources in the vicinity of the assets

The Company’s main on-going development activities are focused on execution of the Vorlich field development plan (34% working interest), which represents the third satellite field to be connected to the Ithaca-operated GSA production hub. Development planning activities are also continuing to advance on expansion of the Captain field enhanced oil recovery (“EOR”) programme.

Vorlich Field Development

The bp-operated Vorlich field is being developed as a two well subsea tie-back to the Ithaca-operated FPF-1 floating production facility, which lies approximately 10 kilometres to the south of the field.

The wells were successfully drilled and clean-up flow tested in 2019, along with installation of the mid-water arch and dynamic risers connecting the subsea infrastructure to the FPF-1, as well as installation of the pre-assembled units on the FPF-1 for enhancing the recovery and processing of natural gas liquids (“NGL”) on the vessel.

Since the start of April this year, Technip have completed the majority of the remaining subsea infrastructure installation programme. The 10-kilometre infield pipeline and control umbilical between the wells and the FPF-1 were trenched, installed and backfilled, following which subsea manifolds were installed and tie-ins completed at the wells and the FPF-1 riser base. As such, installation of the subsea infrastructure is over ninety-five percent complete, with only the diving works required to tie-in the pipeline to the FPF-1 riser base and flushing of the production riser needing to be closed out in September 2020.

With the subsea work programme nearing completion, the key remaining work scopes to be completed ahead of start-up of production from the field are the on-going hook-up and commissioning activities associated with the enhanced NGL processing plant facilities that have been installed on the FPF-1. An approximately one month planned shutdown of the vessel was undertaken in August to tie-in of the NGL processing facilities and execute the associated modifications to the integrated control and safety systems (“ICSS”) on the FPF-1. The outstanding activities that are to be undertaken on the vessel over the coming weeks are now centred on the non-shutdown related tie-in of metering systems and finalisation of the mechanical completion, leak testing and commissioning programme for the new NGL processing facilities.

It is anticipated that the Vorlich field will be onstream in the fourth quarter of 2020, slightly later than the mid-2020 start-up expected prior to the delays imposed by the measures taken to manage Covid-19 related restrictions. Following start-up, operatorship of the field will transfer from bp to Ithaca Energy. The project remains under budget.

Captain Enhanced Oil Recovery 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 6 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.

Various supply chain tendering activities are currently on-going for the Stage II work programme, with a view to sanctioning the development in 2020. While the pace of this has been slowed down by the immediate challenges facing the industry as a result of Covid-19, the development involves a multi-year programme of activities aimed at maximising oil recovery from the field into the 2030s.

GSA Satellite Field Developments

In addition to the key Vorlich and Captain field development programmes, engineering and procurement activities are progressing for the Hurricane field in order to maintain flexibility over the timing for execution of future offshore activities. However, as part of preserving the financial resilience of the Company in the face of the prevailing volatile commodity price environment and managing the operational complications associated with contracting for offshore services while the future Covid-19 related restrictions are unclear, commitments have not been made to facilitate the originally anticipated start-up of the field in 2021. The exact timing for the future development of the Hurricane field will be assessed as part of the work completed later in the year to set the work programmes and budgets for 2021 and beyond.

With respect to the other subsequent GSA satellite fields, Austen and Courageous, various subsurface and engineering studies are being progressed in order to advance the necessary development plans. These studies are scheduled to continue in 2020, along with the evaluation of additional development opportunities within the enlarged asset portfolio resulting from the CNSL acquisition.

Exploration and Appraisal

The Company's exploration and appraisal ("E&A") activities are centred on infrastructure-led opportunities, which leverage the value of the existing portfolio and have an efficient route to the timely monetisation of resources

As announced in March 2020, an exploration well drilled on the "Isabella" prospect (10% working interest) identified hydrocarbons in the Upper Jurassic and Triassic sandstone reservoirs. This is an encouraging high-pressure high-temperature gas condensate discovery in a location close to existing infrastructure. Further analysis of the well results are being performed by the licence Operator, TOTAL E&P North Sea UK Limited ("TOTAL"), to determine future appraisal activity and recoverable resource estimates. The well, in which Ithaca Energy had a carried cost interest as a result of prior farm-out agreements with TOTAL and Euroil Exploration Limited, has been plugged and abandoned.

DECOMMISSIONING

With modest near-term decommissioning activities across the portfolio, the Company's focus over the longer term is on capturing the full benefits associated with the growing industry experience of safely and efficiently executing offshore programmes in a highly cost effective manner

The scheduled well abandonment programme on the Ithaca-operated Jacky field (100% working interest) was completed as planned using the Valaris 101 jack-up drilling rig in June 2020. The three well campaign took approximately 50 days to complete, approximately 10 days longer than forecast due primarily to an extended period of waiting on weather during rig demobilisation operations at the end of the programme.

The Jacky field, which ceased production in 2014, is located in the Inner Moray Firth area of the UK North Sea (Block 12/21c). The main decommissioning activities that remain to be completed on the field involve removal and recycling of the suction-piled, monopole unmanned platform. This work had been scheduled to take place in the third quarter of 2020, but given the complication of Covid-19 related restrictions this is now scheduled for 2021.

As part of the Jacky decommissioning programme an "EnergyPod" has been installed on the platform, enabling the full power requirements of the unmanned installation to be provided by wind and solar energy within a single modular system. This represents an "offshore first" for the deployment of this technology and an investment that has the potential to unlock other opportunities to deploy the technology across the portfolio.

In June 2020 approval was received from the Offshore Petroleum Regulator for Environment and Decommissioning ("OPRED") for the Ithaca-operated Anglia field (30% working interest) decommissioning programme. The Anglia field, which ceased production in 2015, is located in Blocks 48/19b and 48/18b in the Southern North Sea. The facilities to be removed consists of a normally unmanned platform and a number of platform and subsea wells. It is anticipated that the offshore work programme will be executed in the mid-2020s.

HEALTH, SAFETY & ENVIRONMENT

Ithaca Energy's objective is to provide a safe and healthy working environment for all its employees, contractors and other personnel working for the Company, while simultaneously minimising the environmental impact of the Company's operations by working in an ever-cleaner manner. The control and management of these issues lies at the centre of the policies and procedures that constitute the "Operational Excellence" health, safety and environmental management system used by the Company and the culture of the business.

As part of proactively managing the response to the Covid-19 situation, measures to safeguard the Company's personnel and contractors were established in the first quarter of the year along with emergency response plans and measures to curtail the spread of the virus and at the same time maintain the safe and reliable continuation of business activities. The mitigating measures, which are supported by a full risk assessment of operational activities, are continuously reviewed and updated as appropriate to ensure they are aligned with industry and government guidelines.

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 suppliers working on the assets. There have been no recordable injuries to date in 2020, resulting in a continuing reduction in both the LTIF and TRIF statistics as at 30 June 2020 (12-month rolling average). The LTIF fell to 0.96 per million manhours worked and the TRIF fell to 1.46. This compares to an LTIF of 1.01 and a TRIF of 1.59 as at the end of 2019.

Improving operational 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. A specific area addressed this year has been the Alba floating storage unit ("FSU"), which was the subject of a Health & Safety Executive ("HSE") Improvement Notice in February 2020. The notice was issued for failing to follow the procedures set out in the Alba FSU Safety Case regarding the control of Major Accident Hazards, specifically the prevention of fire and explosion. There was no immediate threat to the installation and the Company worked with the HSE to implement improvements identified as a result of the HSE inspection and subsequent notice and the Improvement Notice has been closed out by the HSE.

The Company has an excellent record on environmental performance, the importance of which is heightened by the requirements associated with conducting offshore oil loading to shuttle tankers at two operated assets, the Captain and Alba fields. The Company had no hydrocarbon releases to sea in 2019. In 2020 the hydrocarbon spills to sea rate is a modest 0.09 barrels per million barrels of oil production.

The Company's environment stewardship planning for 2020 includes a commitment to analysing and reducing greenhouse gas emissions, both direct and indirect, in order to contribute towards the industry goal of net zero emissions by 2035.

The carbon intensity of Ithaca Energy's operated assets (emissions over which the Company has direct operational control) in 2019 was 26 kilogrammes of carbon dioxide (equivalent) per barrel of oil equivalent produced ("kg CO_2e/boe"). This was marginally higher than the average level for UK North Sea operators of 24 kg CO_2e/boe. Approximately three-quarters of the emissions is driven by platform and operational power requirements.

In H1-2020 the Company's carbon intensity increased to 29 kg CO_2e/boe for 2019. The increased emissions per unit of production was primarily attributable to compressor availability in the early part of the year.

INDEPENDENT RESERVES EVALUATION

An updated independent reserve evaluation was performed as of 30 June 2020 – proven and probable reserves were estimated to be 258 MMboe, implying a reserves and resource life of approximately 10 years

In order to satisfy certain regulatory requirements of Ithaca Energy's parent company, the Delek Group Limited, an updated independent reserves evaluation was completed by Netherland Sewell & Associates Inc. ("NSAI").

Total proved and probable reserves ("2P") and resources ("2C") as at 30 June 2020 have been estimated to be 258 million barrels of oil equivalent ("MMboe"). Taking into account approximately 13 MMboe of production in the first half of 2020, the Company's 2P reserves outlook is essentially unchanged compared to the year-end 2019 evaluation, as is the 2C resource outlook. The total resource base is comprised of 191 MMboe 2P reserves and 67 MMboe 2C resources. This equates to an approximately 10-year reserves and resource life based on forecast 2020 production.

The report summarising the NSAI reserves evaluation is available on the Company's website (www.ithacaenergy.com).

PORTFOLIO ACTIVITIES

Opportunities to augment the Company's existing portfolio and resource base remain a key component of the business plan, with a focus on potential strategic bolt-on acquisitions from which to leverage existing operating capabilities and experience

As part of expanding the portfolio of potential future development opportunities, two previously reported licence acquisitions were completed in the first half of the year. The resources associated with these licence interests have not been included in the independent reserves evaluation completed by NSAI as of 30 June 2020.

In February 2020 the Company signed a Sales and Purchase Agreement with TOTAL E&P UK Limited to acquired the full working interest of licence P.2158 (Block 15/18b). The licence contains the "Yeoman" discovery and southern extent of the Hibiscus Petroleum-operated "Marigold" discovery. The discoveries contain oil and gas within the Palaeocene Balmoral sandstone fairway. Based on Ithaca Energy's Management estimates, it is anticipated that the licence adds resources of around 15 MMboe from the two discoveries. A limited consideration was payable at completion of the acquisition, which took place in the second quarter of 2020, with additional contingent payments at Field Development Plan approval and upon reaching a reserves recovery threshold.

In June 2020 the Company obtained Licence P.2494 (Block 13/22c) from Chrysaor North Sea Limited. The licence contains the "Phoenix" gas discovery, which lies approximately 10km south of the Captain field in a Jurassic reservoir formation. Subsurface and engineering studies are required in order to assess the development potential of the field, with the licence requiring either the submission of a Field Development Plan by July 2022 or relinquishment. It is estimated that the licence adds approximately 10 MMboe of resources (based on Management estimates).

The Company continues to actively engage in the UK Offshore Licencing Rounds conducted by the Oil & Gas Authority ("OGA"). Seven licence applications were submitted in 2019 as part of the 32nd Licence Round. The applications related to a range of undeveloped discoveries and near-field exploration targets in the vicinity of the Company's existing portfolio, with proposed work programmes relating predominantly to the performance of subsurface and technical studies in order to make "drill or drop" decisions within a period of two to four years. An announcement on the results of the licence awards is expected from the OGA in the second half of this year.

FINANCIAL STRATEGY

The Company's strategy is centred on maintaining a conservative financial profile and strong liquidity headroom in order to protect the resilience of the business and enable the delivery of long term growth and value creation

Under the current challenging commodity market conditions, the key financial priority is to maintain the financial strength of the Company. Following the refinancing completed in 2019 as part of the CNSL acquisition, the business has no near term debt maturities and remains fully financed for its prevailing investment plans.

As part of maintaining capital strength, a core component of the Company's financial strategy is to consistently protect the cash flows of the business and underpin investment expenditures and debt obligations through commodity price hedging covering an approximately two to three year time horizon.

The Company has in place hedging arrangements (swaps and puts) for approximately 23 MMboe (68% oil) of production from the start of July 2020 into 2022, at an average price floor of $51/bbl oil and 49p/therm gas.

As previously reported, the Company "reset" a portion of its 2021-22 oil hedges in the second quarter of the year as part of enhancing the liquity position of the business following the dramatic fall in oil prices in March 2020. This enabled the acceleration of $155 million of oil price hedging gains into the second half, equating to approximately $19 per hedged barrel, while maintaining the underlying hedged volumes with swaps at the prevailing forward curve prices at the time of the reset. The cash generated was used to reduce the Company's drawn RBL debt.

As commodity prices continue to recover following the dramatic fall in the first part of this year, the Company expects to continue opportunistically adding further hedging protection over the medium term horizon. Such hedging is typically undertaken via swaps and puts.

In addition to the revenue protection provided by the Company's extensive commodity hedging position, the free cash flow generation of the business is also strengthened by a UK tax allowances pool of approximately $2.0 billion carried forward as of 30 June 2020. Based on current commodity prices, these allowances are forecast to shelter the Company from the payment of tax over the medium term.

The Company's capital allocation priorities are centred on a balanced and proportionate blend of investment to further enhance the value of the business, debt service and shareholder returns. While the capital expenditure programme for 2020 has been significantly reduced in order to manage the Covid-19 situation and maintain financial flexibility, the option remains to reinitiate those investment plans at the appropriate time given the dominance of the Company's operated asset positions across the portfolio.

In terms of shareholder returns, the Company has the flexibility to pay up to a $135 million dividend to its parent company, the Delek Group, subject to the terms of its RBL facility agreement. Any further distributions are subject to the Company not exceeding a 1.3x leverage ratio and distributing no more than 50% of the cumulative net income generated from the start of the fourth quarter 2019, as per the terms governing distributions in the senior notes indenture. In conjunction with completion of the recent six-monthly RBL redetermination, a $20 million dividend was paid to the Delek Group in May 2020.

DEBT FINANCE

In conjunction with completing the Chevron North Sea Limited acquisition, the Company completed a refinancing of its capital structure in 2019. This involved the injection of additional equity capital into the business by the Delek Group and the replacement of existing debt facilities with an enlarged Reserves Based Lending ("RBL") facility and the issuance of senior unsecured notes. As such the business is funded from its existing debt facilities and cash generation from the producing asset portfolio.

As at 30 June 2020, net debt was $1,310 million:

- $820 million drawn under a $1,650 million Reserves Based Lending facility, which matures in May 2024
- $500 million senior notes, paying a 9.375% coupon, maturing in July 2024
- $10 million of cash held on the balance sheet

Based on pro-forma EBITDAX of approximately $840 million for the twelve months ending 30 June 2020, the leverage ratio of the Company as of that date was 1.6x. This is comfortably below the Company's target of maintaining leverage through the cycle of under 2.0x.

In May 2020 the Company completed its scheduled six-monthly RBL facility redetermination process. Following the redetermination, RBL availability was approximately $1.1 billion, resulting in the business retaining liquidity headroom of approximately $300 million as anticipated.

In conjunction with concluding the RBL redetermination, in May 2020 the Company accelerated payment (from October 2020) of a scheduled contingent payment to Petrofac for an annualised discount of over 20% and paid a $20 million dividend to the Delek Group.

While net debt at 30 June 2020 totalled $1.31 billion, it should be noted that the majority of the hedging gains (approximately $70 million) relating to the second quarter of 2020 were not received until mid-July 2020. As such, the Company's strong deleveraging trajectory has continued into the third quarter of the year.

The financial statements also reflect a Subordinated Shareholder Loan due to Ithaca Energy's parent company, Delek Group Limited, of $250 million. Due to its deeply subordinated nature, this is considered equity-like in the Company's external reporting and by the credit rating agencies.

The Company's corporate credit rating as at 26 August 2020 from Moody's, S&P and Fitch are B1 (Outlook Negative), CCC+ (CreditWatch Developing) and B (Rating Watch Negative), respectively.

CORPORATE ACTIVITIES

On 24 August 2020 it was announced that Mr Bill Dunnett was appointed Chief Executive Officer of the Company, taking over the role from his predecessor Mr Les Thomas.

Mr Dunnett is a Chartered Engineer with over 35 years experience in the oil and gas industry, in various engineering, operational and senior management positions in the UK and internationally. For the last five years Mr Dunnett has been the Chief Executive Officer of Repsol-Sinopec Resources UK Limited, during which time he successfully led a large-scale transformation of the business. Prior to this, he worked in various positions at Petrofac, Halliburton, Mobil North Sea and Shell. Mr Dunnett has served as Chair of the MER UK Technology Leadership Board and been a Board Member of both OGUK and The Oil and Gas Technology Centre.

H1-2020 RESULTS OF OPERATIONS

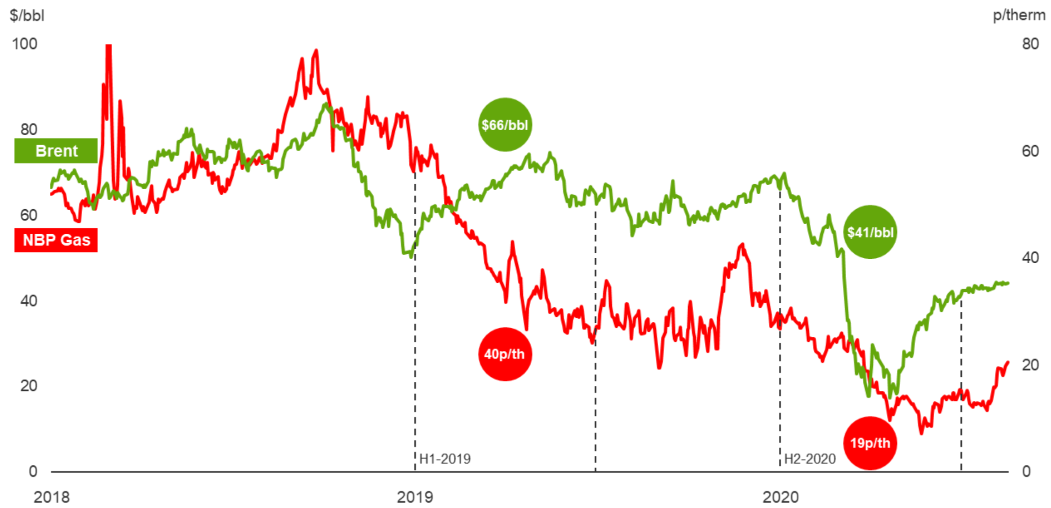
The financial results for H1-2020 reflect the material step-up in the scale of the business following completion of the CNSL acquisition in November 2019

TRADING ENVIRONMENT

The Brent benchmark oil price traded between $50/bbl and $80/bbl over the course of 2018 and 2019, with the average price in each of those years being relatively close at $71/bbl and $64/bbl, respectively.

Over the course of H1-2020, the average Brent benchmark price was $41/bbl, down nearly 40% on the same period in 2019 (2019: $66/bbl). Perhaps more significantly, however, the Brent benchmark price has been extremely volatile during H1-2020 as a result of both over supply following the discord between Saudi Arabia and Russia in March 2020 and massive demand destruction arising from escalation of the Covid-19 pandemic during the period. As a consequence, the Brent benchmark has moved from a high of $70/bbl at the start of the period to a low of $17/bbl in March, following which it has steadily moved upwards to around $40/bbl.

The "NBP" UK gas price benchmark has been on a declining trend since late 2018, with average prices in 2018 and 2019 of 60p/therm and 35p/therm, respectively. This trend has been predominantly driven by an increased flow of North American LNG into the European market. The reduction in industrial gas demand that has arisen as a consequence of Covid-19 restrictions and the associated economic slowdown has also contributed to recent weakness in gas prices, although the benchmark price has shown some signs of strength in recent weeks. The average NBP price in H1-2020 was 19p/therm or $2.4/MMbtu (2019: 40p/therm / $5.2/MMbtu).



REVENUE

$'000	H1 2020	H1 2019
Oil Sales	**315,253**	108,197
Gas Sales	**73,033**	53,354
NGL Sales	**16,522**	13,337
Other Income	**2,291**	261
Cashflow Hedge Accounting	**216,933**	29,670
Total	**624,032**	204,819

Total revenue increased by $419.2 million in H1 2020 to $624.0 million (H1 2019: $204.8 million) driven primarily by increased volumes from the enlarged business resulting from completion of the CNSL acquisition in November 2019. Total production in H1 2020 was 13.2 MMboe, up >300% on H1 2019 production of 3.3 MMboe.

OIL

Oil revenues increased significantly in H1 2020, mainly as a result of the additional contribution from the CNSL assets in the period. Volumes increased by 5.5 MMbbl to 7.1 MMbbl, with 6.3 MMbbl attributable to liftings from the CNSL assets, offset by a decrease of approximately 0.8 MMbbl on the original Ithaca Energy assets. The original Ithaca Energy assets production was down 0.2 mmbl as a result of lower production with the balancing 0.6 mmbls movement was drived by timing on liftings.

Average realised oil prices decreased to $44/bbl in H1 2020 from $66/bbl in H1 2019. This is approximately 10% above the average Brent price for the period, which dropped to $40/bbl in H1 2020 from $66/bbl in H1 2019.

While realised oil prices for each of the fields in the Company's portfolio do not strictly follow Brent prices, 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 trades largely in line with Brent. The strong positive differential for H1 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 first half of the year was between $70/bbl and $17/bbl).

GAS AND NGLS

Gas and NGL revenues increased from $66.7 million in H1 2019 to $89.6 million in H1 2020. Gas and NGL volumes more than doubled between the two periods due to the contribution of the assets acquired with the CNSL transaction (largely due to the addition of the Britannia and Satellite field interests). In particular, total gas sales increased from 1.6 MMboe to 5.2 MMboe. However, the potential increase in gas revenues was tempered as a result of realised gas prices falling from 36 p/therm in H1 2019 to 17p/therm in H1 2020 due to a significant drop in UK NBP spot market prices. Like the Company's oil production, the average realised gas price for gas sales is at or around the UK benchmark price less national grid entry charges of 1.7p.

COST OF SALES

$'000	H1 2020	H1 2019
Operating Expenditure	**(201,553)**	(65,749)
DD&A	**(217,533)**	(73,842)
Movement in Oil and Gas Inventory	**(6,866)**	(18,455)
Royalties	**(1,270)**	(3,136)
Total	**(427,222)**	(161,182)

Cost of sales increased in H1 2020 by approximately 165% to $427.2 million (H1 2019: $161.2 million) primarily driven by the 300% increase in production arising from the addition of the CNSL assets, partly mitigated by other factors as noted below. The overall increase in cost of sales is predominantly associated with two main categories of expenditure, Operating Costs and Depreciation, Depletion and Amortisation ("DD&A") expenses, with both increases naturally due to the acquisition of the CNSL assets.

OPERATING EXPENDITURE

Operating costs increased to $201.6 million in the period (H1 2019: $65.7 million) due to the increased scale of the producing asset portfolio. The corresponding unit cost has fallen to $15/boe in the period, down from the H1 2019 rate of $20/boe. This material 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.

DD&A

Total DD&A expense for the period was $217.5 million (H1 2019: $73.8 million). This increase in expense was due to higher production volumes, but offsetting this, the unit DD&A rate dropped from $23/boe to $16/boe due to a combination of the impact of the post-acquisition DD&A rates across the wider portfolio and the asset impairments recognised in the first quarter of 2020.

MOVEMENT IN INVENTORY

An oil and gas inventory movement of $6.9 million was charged to cost of sales in H1 2020 (H1 2019: charge of $18.5 million). Movements in inventory tend 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 H1 2020 more barrels of oil were produced (7.4 MMbbl) than sold (7.1 MMbbl), which would normally result in a credit to cost of sales. However, a decline in the value of Brent from the year end to 30 June 2020 turned the expected credit into a charge as a result of the negative revaluation of the barrels in inventory.

Movement in Operating Oil and Gas Inventory	Oil (kbbls)	Gas/NGL (kboe)	Total (kboe)
Opening Inventory	721	108	**829**
Production	7,384	5,862	**13,246**
Liftings/Sales	(7,141)	(5,818)	**(12,959)**
Disposals/Transfers/Others	26	(15)	**11**
Closing Volumes	990	137	**1,127**

IMPAIRMENT CHARGES AND EXPLORATION AND EVALUATION EXPENSES

$'000	H1 2020	H1 2019
Exploration and Evaluation Write Off	**-**	(195)
Impairment of Oil and Gas Assets	**(980,328)**	-
Impairment of Goodwill	**(206,729)**	-
Total	**(1,187,057)**	(195)

EXPLORATION AND EVALUATION EXPENSES

Minor write offs of expenditure relating to Exploration and Evaluation (E&E) assets were made during Q1 2019 for non-commercial prospects.

IMPAIRMENT

Pre-tax impairment charges of $1,187 million ($795 million post-tax) reported as part of our Q1 results are included in the period. This was driven by the lower forward curve for both oil and gas prices resulting in impairments across the oil and gas portfolio of $980 million coupled with a write-down of the value of Goodwill by $207million. 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%. The increased value of the Company's hedges are not part of the impairment calculation.

ADMINISTRATION EXPENSES

$'000	H1 2020	H1 2019
General and Administration	**(21,886)**	(5,309)
Total Administration Expenses	**(21,886)**	(5,309)

Total administrative expenses were $21.9 million in the period (H1 2019: $5.3 million, including $2.7 million of non-recurring acquisition fees). G&A costs have increased in the period primarily due to approximately 70 onshore employees taking up the Company's voluntary redundancy programme resulting in a one-off cost to Ithaca of $8.9 million coupled with some residual corporate costs relating to the CNSL acquisition, alongside the significant upsizing of the business post the CNSL acquisition. Underlying G&A costs continue to be subject to disciplined management, totalling approximately $1/boe.

FOREIGN EXCHANGE & FINANCIAL INSTRUMENTS

$'000	H1 2020	H1 2019
Gain on Foreign Exchange	**3,747**	326
Total Gain on Foreign Exchange	**3,747**	326

FOREIGN EXCHANGE

A foreign exchange gain of $3.7 million was recorded in H1 2020 (H1 2019: $0.4 million gain) mainly due to volatility in the GBP:USD exchange rate. The rate at the end of the period was $1.23:£ compared to a rate of $1.31:£ on 31 December 2019. As the majority of the Company's creditors are paid in sterling, this has resulting in a gain on settlement of invoices as expected.

FINANCIAL INSTRUMENTS

The Company cash flow hedge accounts for both commodities and interest rate intruments, while accounting for foreign exchange instruments is done 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) as set out in the following tables.

$'000	H1 2020	H1 2019
Revaluation of commodity hedges	**(1,116)**	(674)
Revaluation of other instruments	**(9,608)**	(461)
Total Revaluation (Loss)	***(10,724)***	*(1,135)*
Realised gain on commodity hedges	**3,463**	-
Realised loss on other instruments	**(1,008)**	(169)
Total Realised Loss	***2,455***	*(169)*
Ineffectiveness on cash flow hedges	**-**	2
Income Statement (Loss) on Financial Instruments	**(8,269)**	(1,302)

$'000	H1 2020	H1 2019
Revaluation of derivative contracts	**138,565**	31,306
Realised gain on derivative contracts	**334,697**	15,094
Amounts recycled to revenue	**(216,933)**	(29,670)
Amounts recycled to finance costs	**36,646**	6,415
Total Cashflow Hedge Gain in SOCI	**292,975**	23,145

In total, the Company recorded a loss of $8.3 million on financial instruments in the Income Statement for the period ended 30 June 2020 (H1 2019: $1.3 million loss). In addition, a gain was recognised in the Statement of Other Comprehensive Income of $293.0 million (H1 2019: $23.1 million gain). The application of cash flow hedge accounting means that revaluation amounts relating to financial instruments are booked to a Cash Flow Hedge Reserve and are only transferred to the Income Statement in the same period as the hedged item impacts the profit or loss.

The Income Statement contains a revaluation loss of $10.7 million relating primarily to foreign exchange instruments, while the Statement of Other Comprehensive Income shows a revaluation gain of $138.6 million relating to commodity instruments. The revaluation is driven by the commodity price forward curve as at the valuation date – as the forward curve falls, the value of the instruments increase and vice versa. Oil spot prices began the period at $67/bbl and ended at $42/bbl with gas moving similarly, beginning the period at 30p/therm and ending at 15p/therm, with the forward curves following these trends. These movements resulted in significant revaluation gains at the end of H1 2020.

The amount recycled to revenue in the period was $216.9 million, reflecting the success of the Company's hedging programme. This represents the instruments crystallising in the period and is partially offset by the related put premiums of $35.1 million which were recycled to finance costs along with the crystallised interest rate hedges.

The Company executed an oil hedging re-set programme in response to the decline in oil prices in March and April 2020. During the six month period, hedges with a value of $155 million were re-set, which was received in cash during the period (and used to reduce the drawn debt under the RBL facility). All the hedges that were re-set were replaced with new positions at the forward curve prevailing at the time.

The following table summarises the commodity hedges in place at 30 June 2020.

Derivative	Term	Volume bbls	Av. Price $/bbl
Oil Puts	Jul 2020 – Dec 2021	5,533,250	61
Oil Swaps	Jul 2020 – Dec 2022	9,933,238	45
Derivative	**Term**	**Volume (therms)**	**Av. Price (p/therm)**
Gas Puts	Jul 2020 – Dec 2021	160,300,000	52
Gas Swaps	Jul 2020 – Dec 2022	248,975,000	49

As of 30 June 2020 the Company's commodity hedges were valued as an asset of $176.8 million based on valuations relative to the respective forward curves. This comprises an oil hedging asset of $112.8 million coupled with a gas hedging asset of $81.6 million, offset by an foreign exchange forward liability of $6.2 million and an interest rate hedge liability of $11.4 million.

FINANCE COSTS

$'000	H1 2020	H1 2019
Bank Interest and Charges	**(53,849)**	(22,706)
Loan Fee Amortisation	**(4,722)**	(1,294)
Accretion	**(22,105)**	(7,572)
Put Premiums	**(35,134)**	(6,415)
Other	**(4,424)**	(327)
Total Finance Costs	**(120,234)**	(38,314)

Finance costs charged to the Income Statement increased to $120.2 million in H1 2020 (H1 2019: $38.3 million). This increase is primarily attributable to changes in financing arrangements associated with the CNSL acquisition, including repayment of the RBL facility that was in place prior to the refinancing completed in 2019, including repayment of a $300 million term loan with JP Morgan. These facilities were replaced with a $1.65 billion RBL facility ($820 million drawn as at 30 June 2020) and $500 million senior unsecured notes.

The extent of the Company's commodity hedging programme means put premiums have increased significantly compared to last year. This is reflected in the significant step up in cash flow hedging gains recognised in revenues. Accretion has also increased due to the additional decommissioning liabilities associated with the CNSL assets.

TAXATION

$'000	H1 2020	H1 2019
Corporation Tax – Current	**(143)**	-
Corporation Tax – Deferred	**362,080**	18,743
Corporation Tax – Other Comprehensive Income	**(117,190)**	(9,258)
Total UK Corporation Tax	**244,747**	9,485

A tax credit of $244.7 million was recognised in the six months ended 30 June 2020 (H1 2019: $9.5 million credit). This is less than the expected credit of 40% of the combined Income Statement and the Statement of Other Comprehensive Income loss due primarily to the goodwill impairment at the end of Q1 2020, which is not tax deductable.

The Company's total carried forward UK tax allowances as at 30 June 2020 were $2.0 billion (31 December 2019 $2.4 billion). Based on current commodity prices, these allowances are forecast to shelter the Company from the payment of tax over the medium term.

CAPITAL INVESTMENTS

$'000	Additions H1 2020
Development and Production (D&P)	39,775
Exploration and Evaluation (E&E)	10,315
Other Fixed Assets	2,222
Total	52,312
Non cash decommissioning revisions	(11,523)
Total capex additions per accounts	40,789

The capital expenditure programme in H1 2020 has been mainly focused on the Captain field and activities associated with the expansion of the on-going enhanced oil recovery programme, investments on the Vorlich and Hurricane fields in the GSA and the acquisition of the "Yeoman" undeveloped discovery licence interest from Total E&P UK Limited.

WORKING CAPITAL

$'000	30 Jun 2020	31 Dec 2019	Increase / (Decrease)
Cash and Cash Equivalents	10,361	15,059	(4,698)
Trade and Other Receivables	161,820	158,149	3,671
Inventory - Hydrocarbon	50,625	47,626	2,999
Inventory – Materials	44,970	52,470	(7,500)
Other Current Assets	2,716	8,660	(5,944)
Trade and Other Payables	(282,671)	(368,462)	85,791
Net Working Capital[1]	(12,179)	(86,498)	74,319

1. Working capital being total current assets less trade and other payables, excluding derivative instruments.

As at 30 June 2020 the Company had a net working capital credit balance of $12.2 million, including an unrestricted cash balance of $10.4 million held in accounts with BNP Paribas.

Substantially all of the Receivables are current, being defined as less than 90 days. The Company regularly monitors all receivable balances outstanding in excess of 90 days. No credit loss has historically been experienced in the collection of accounts receivable.

The significant item driving the movement from year end is payment in the first quarter of 2020 of $65 million relating to the 2019 Corporation Tax due by CNSL prior to the acquisition.

Working capital movements are driven by the timing of receipts and payments of balances, which fluctuate in any given period. Of the Company's $161.8 million accounts receivable balance a significant proportion, $73 million, relate to hedging receipts due. The remainder of the balance is predominantly due from co-ventures in the oil and gas industry and is subject to normal joint venture/industry credit risks.

CAPITAL RESOURCES – DEBT FACILITIES

In November 2019, alongside completion of the CNSL acquisition, the Company completed its process of refinancing the business. The existing Subordinated Shareholder Loan with the Company's parent company, the Delek Group, was increased from $100 million to $250 million, alongside a $590 million increase to the Company's issued and fully paid share capital.

In addition, the existing RBL facilitiy was increased from $400 million to $1,650 million, with the term of the facility extended to April 2024, and the $300 million term loan with JP Morgan that was in place prior to the refinancing being simultaneously retired.

The final part of the refinancing involved the issuance of $500 million 9.375% senior unsecured notes due July 2024, with interest payable semi-annually. The notes offering was completed on 1 August 2019 and the funds were held in escrow until release at completion of the CNSL acquisition on 8 November 2019.

The following table summarises the funds drawn under the debt facilities noted above. This highlights that net debt at 30 June 2020 was $1,310 million (excluding the equity-like Subordinated Shareholder Loan).

Debt Summary (M$)	30 Jun 2020	31 Dec 2019
RBL Facility	820.0	1055.0
Senior Notes	500.0	500.0
Total Debt (excl equity type subordinated debt)	**1,320.0**	**1,555.0**
UK Cash and Cash Equivalents	(10.4)	(15.1)
Net Drawn Debt (excl equity type subordinated debt)	**1,309.6**	**1,539.9**
Equity Type Subordinated Debt	250.0	250.0
Net Drawn Debt	**1,559.6**	**1,789.9**

Note: This table shows debt repayable as opposed to the reported balance sheet debt which nets off capitalised RBL and Term Loan costs.

The key covenants in the RBL facility are as follows:

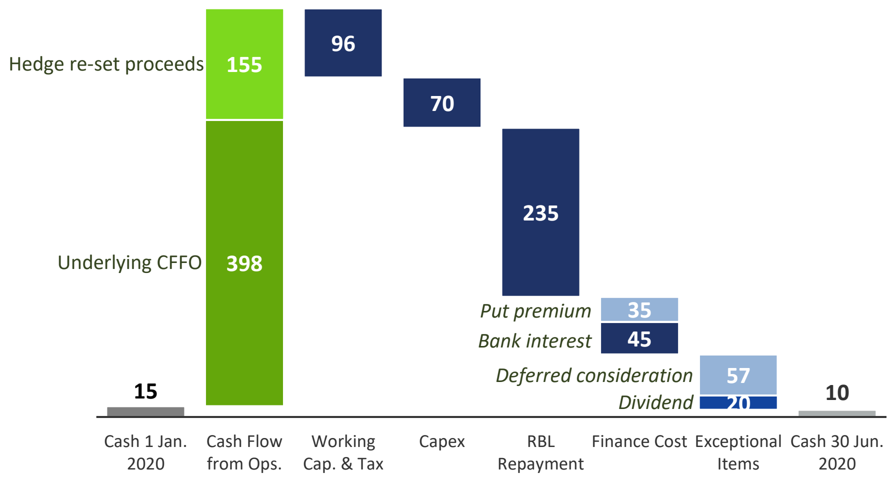
- Total projected sources of funds must exceed the total projected uses of funds for the remaining term of the RBL
- The ratio of the net present value of cashflows secured under the RBL for economic life of the fields to the amount drawn under the facility must not fall below 1.15:1
- The ratio of the 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

The Company was in compliance with all its relevant financial and operating covenants during H1 2020.

There are no historic or maintenance financial covenant tests associated with the senior unsecured notes or the Subordinated Shareholder Loan.

H1-2020 CASH FLOW MOVEMENTS

During the six months ended 30 June 2020 there was a cash outflow from operating, investing and financing activities of approximately $5 million (H1 2019 outflow of $10 million); as set out in the following graph:



Cash flow from operating activities was $553 million. Revenues from the producing asset portfolio have been supported by a successful hedging programme and carefully controlled operating costs resulting in underlying CFFO of $398 million for the period. In addition, funds were received from the hedging re-sets during 1H 2020 totalling $155 million.

Movements in working capital resulted in an outflow of cash totalling $96 million in the period. This was primarily driven by a tax payment of $65m made in Q1 2020 relating to 2019 profits made by CNSL. The remaining balance arises due to a build up in working capital related to timing of receipt of payment for oil and gas hedges.

Cash spend on capital expenditure in the period was $70 million, with the key contributors being the development of the Vorlich field and the abandonment spend on the Jacky field.

The Company aims to maintain minimal cash on hand and prioritises repayment of our RBL facility with excess cash. During the period $235 million of drawn RBL was repaid.

During the first six months of 2020, the Company incurred finance costs totalling $80 million. This was split $45 million in interest paid to lenders and $35 million paid in deferred premiums on oil and gas put options.

The Company accelerated a deferred acquisition payment to Petrofac previously due in Q4 2020 of this year into the second quarter in exchange for a significant discount. A payment of $57 million was made in respect of this liability during the period. Additionally, a dividend of $20 million was distributed in May.

COMMITMENTS

$'000	1 Year
Engineering	79,662
Total	79,662

The Company's operational commitments primarily relate to on-going project and drilling activities across the portfolio.

CONSOLIDATION

The consolidated financial statements of the Company and the financial data contained in this Management Discussion and Analysis are prepared in accordance with IFRS. The consolidated financial statements include the accounts of Ithaca Energy and its wholly-owned subsidiaries, listed below.

Wholly owned subsidiaries:

- Ithaca Energy (Holdings) Limited
- Ithaca Energy (UK) Limited
- Ithaca Minerals (North Sea) Limited
- Ithaca Energy Holdings (UK) Limited
- Ithaca Energy (North Sea) plc
- Ithaca Petroleum Limited
- Ithaca Causeway Limited
- Ithaca Exploration Limited
- Ithaca Alpha (N.I.) Limited
- Ithaca Gamma Limited
- Ithaca Epsilon Limited
- Ithaca Petroleum EHF
- Ithaca SPL Limited
- Ithaca SP UK Limited
- Ithaca Dorset Limited
- Ithaca GSA Holdings Limited
- Ithaca GSA Limited
- Ithaca Energy Developments UK Limited
- FPF1 Limited
- Ithaca Oil & Gas Limited

All inter-company transactions and balances have been eliminated on consolidation. A significant portion of the Company's North Sea oil and gas activities are carried out jointly with others. The consolidated financial statements reflect only the Company's proportionate interest in such activities.

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 in order 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

"Cashflow from operations" and "cashflow per share" referred to in this MD&A are not prescribed by IFRS. These non-IFRS financial measures do not have any standardised meanings and therefore are unlikely to be comparable to similar measures presented by other companies. The Company uses these measures to help evaluate its performance. 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. The Company considers cashflow from operations to be a key measure as it demonstrates the Company's underlying ability to generate the cash necessary to fund operations and support activities related to its major assets. 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.

Off Balance Sheet Arrangements

The Company has certain lease agreements and rig commitments which were entered into in the normal course of operations, all of which are disclosed under the heading "Commitments", above. Leases are accounted for under IFRS 16 and where appropriate, leases are recorded on the balance sheet. As at 30 June 2020 the Company has lease assets of $10.1 million recorded on on the balance sheet.

Related Party Transactions

As at 30 June 2020 the Company had subordinated loans due to its Parent Company, Delek Group Limited, of $250 million (30 June 2019: $150 million).

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 30 June 2020 have been 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 report detailing the reserves evaluation is available on the Company's website (www.ithacaenergy.com). 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.

RISKS & UNCERTAINTIES

The Company and its direct and indirect subsidiaries (together the "Group") are exposed to a variety of risks that can have material strategic, financial and operational impact on the Group's business, performance, prospects, financial condition and reputation. Aside from the general risks that face all businesses, the principal risks to the Group which may materially and adversely affect the Group's business, performance, prospects, financial condition and reputation are outlined below. These risks are not listed in order of magnitude or probability and should not be regarded as a complete and/or comprehensive statement of all potential risks and uncertainties facing the Group. Additional risks not currently known to the Group, or which the Group currently considers immaterial, may also have an adverse effect on the Group's business, performance, prospects, financial condition and reputation.

COMMODITY PRICE VOLATILITY

Risks: The Group's performance is significantly impacted by prevailing hydrocarbon prices, which are primarily driven by supply and demand as well as economic and political factors. The market price of hydrocarbon products has been very volatile and, if the price of oil and gas products should drop significantly, the economic prospects of the projects in which the Group has an interest could be significantly reduced or rendered uneconomic, leading to a reduction in the volume of the Group's oil and natural gas reserves. Also, participants in a well/licence may elect not to produce at lower prices, or not to invest in, explore on or develop certain properties. All of these factors could result in a material decrease in the Group's future net production revenue, causing a reduction in its oil and gas production, development and acquisition activities and an acceleration of abandonment. Early abandonment crystallises liabilities earlier and negatively impacts the Group's cash flow.

In addition bank borrowings available to the Group are in part determined by the borrowing base of the Group. A sustained material decline in prices from historical average prices could limit or reduce the Group's borrowing base, therefore reducing the available bank credit available and could require that a portion of any existing bank debt be repaid

Mitigations: To mitigate the risk of fluctuations in oil and gas prices, the Group routinely executes commodity price derivatives in accordance with its hedging policy, as a means of establishing a floor in realised prices. However, if commodity prices increase beyond the levels set in some of these agreements, the Group may not, or not fully, benefit from such increases. Additionally, the Group uses conventional conservative corporate planning commodity price assumptions and actively evaluates the sensitivity of its plans and significant investment decisions to potential changes in the outlook for commodity prices. The Group's commodity hedging arrangements will typically only cover the relatively short term, leaving the Group exposed to any longer-term decline in commodity prices.

FOREIGN EXCHANGE RISKS

Risks: The Group is exposed to financial risks including financial market volatility and fluctuation in various foreign exchange rates. The Group's revenues are mainly received in US Dollars while its costs are incurred primarily in Pounds Sterling and to a lesser extent in US Dollars and Euros. Exchange rates between the Pound Sterling and the US Dollar have fluctuated significantly in the past and may do so in the future. Such fluctuations affect the cash flows that the Group may realise from its operations.

Mitigations: Given the proportion of operating and expenditures incurred in currencies other than the US Dollar, the Company routinely executes hedges to mitigate foreign exchange rate risk on committed expenditures and/or draws debt in Pounds Sterling to settle sterling costs which will be repaid from surplus sterling generated revenues derived from gas sales.

BANK DEBT FACILITY RISK

Risks: The Group is exposed to borrowing risks relating to drawdown of its bank debt facilities (the "Facilities"). The available debt capacity and ability to drawdown on the Facilities is based on the Group meeting certain covenants including coverage ratio tests, liquidity tests and development funding tests. The available bank debt capacity is redetermined semi-annually, using a detailed economic model of the Group and forward looking assumptions of which future oil and gas prices, costs and production profiles are key components. Movements in any component, including movements in forecast commodity prices, can have a significant impact on available debt capacity and limit the Group's ability to borrow. There can be no assurance that the Group will satisfy such tests in the future in order to have access to adequate Facilities or will have sufficient resources to repay interest and principal amounts drawn thereunder.

Mitigations: The Group routinely produces detailed cashflow forecasts to monitor its compliance with the financial and liquidity tests of the Facilities and maintains the ability to execute proactive debt positive actions such as additional commodity hedging.

INTEREST RATE RISK

Risks: The Group is exposed to fluctuation in interest rates, particularly in relation to its debt facilities.

Mitigations: To mitigate the fluctuations in interest rates, the Group routinely reviews the associated cost exposure and periodically executes hedges to lock in interest rates.

FINANCING RISK

Risks: The Group will require substantial capital expenditures for the development and production of its oil and natural gas reserves and for any potential acquisitions of additional oil and gas properties. The ability to finance firm commitments, participate in the Group's forthcoming developments and generally to continue and develop the Group's business depends largely upon (i) cash flow from the Group's producing assets and (ii) continued access to debt finance facilities.

Cash flow is dependent upon a combination of factors including field performance and operating costs coupled with factors which are substantially outwith the control of the Group such as commodity prices and the fiscal regime. To the extent cash flow from operations, the Group's senior unsecured notes and the Facilities' resources are ever deemed not adequate to fund the Group's cash requirements, external financing may be required. Lack of timely access to such additional financing, or access on unfavourable terms, could limit the Group's ability to make the necessary capital investments to maintain or expand its current business and the Group's ability to make necessary principal or interest payments under the Facilities and / or the senior unsecured notes.

A significant proportion of the Group's production and cashflow is derived from its key assets in the UK Central North Sea making it vulnerable to the risks associated with having production in only one country and from a concentrated number of fields. Also any decrease in future production volumes or reserve estimates of key assets would adversely affect the Group's results of operation and financial condition.

The future revenues generated by the Group may not be sufficient to provide the necessary capital for the Group to replace its reserves or to maintain its production. If the Group's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements on favourable terms or at all. A failure to access adequate capital to continue its expenditure programs may require that the Group meet any liquidity shortfalls through the selected divestment of all or a portion of its portfolio (possibly at undervalue) or by delaying existing work programs. In the event sufficient funds are not available to finance the business and its commitments, it would have a material adverse effect on the Group's financial condition and its ability to conduct operations and ultimately the Group may default on its obligations.

Mitigations: The Group has established a business plan and routinely monitors its detailed cashflow forecasts and sensitivities associated with its forecasts and liquidity requirements over both the short and longer term to ensure it remains fully funded. The Group is focused on maintaining a diversified capital structure with a balanced blend of low cost secured and unsecured debt finance and maintenance of adequate liquidity headroom from cash and undrawn debt. The Group has a solid track record of raising capital in the commercial bank and debt capital markets and has a strong and supportive sole shareholder in the Delek Group Limited.

The Group believes that there are no circumstances that exist at present which require forced divestments, significant value destroying long term delays to existing work programmes or will likely lead to critical defaults relating to the Facilities or senior unsecured notes.

THIRD PARTY CREDIT RISK

Risks: The Group is and may in the future be exposed to third party credit risk through its contractual arrangements with its current and future joint venture partners, marketers of its production, contractors and other parties. Such parties 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 our business, performance, prospects, financial condition and reputation. The Group may extend unsecured credit to these and certain other parties, and therefore, the collection of any receivables may be affected by changes in the economic environment or other conditions affecting such parties.

Mitigations: The Group manages its credit risk by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to do so after transactions have been initiated. Where appropriate, a cash call process is implemented with joint venture partners to cover high levels of anticipated capital expenditure, thereby reducing third party credit risk on such projects.

The majority of the Group's oil and gas production is sold to BP and Shell. Each of these parties has historically demonstrated their ability to pay amounts owing to the Group.

EXPLORATION, DEVELOPMENT AND PRODUCTION RISK

Risks: The business of exploring for, developing and producing oil and natural gas reserves is inherently risky. Also, all of the Group's operations are conducted offshore on the United Kingdom Continental Shelf. The Group is therefore exposed to operational risk associated with weather delays that can result in a material delay or increased costs associated with executing its projects and delay production or restrict production operations from

loss. Health, safety and environment laws and regulations may also expose the Group to liability for the conduct of others. 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 its liabilities under environmental, health and safety requirements. These events could also cause substantial damage to the Group's business and reputation and put at risk some or all of the Group's interests in licenses, which enable it to explore, develop and produce.

Reserves replacement and the efficient delivery of new developments is a key feature of the Group's long term strategy and the development of any hydrocarbon reserves involves an array of complex activities which are often, amongst other things, long term, capital intensive and weather dependent and the outcomes of which are subject to a number of uncertainties. The Group's ability to execute such projects and market any oil and natural gas derived therefrom depends upon numerous factors beyond the Group's control, including the availability of drilling and related equipment; the availability and proximity of pipeline capacity; the availability of processing capacity; the availability and productivity of skilled labour; the effects of inclement weather, unexpected cost increases, currency fluctuations and fluctuations in the supply of and demand for oil and natural gas; the availability of alternative fuel sources; accidental events; and regulation of the oil and natural gas industry by various levels of government and governmental agencies in the countries in which the Group operates. Because of these factors, the Group could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it hopes to produce. Delays in the construction and commissioning of these projects and/or other technical difficulties may also result in the Group's current or future projected target dates for the delivery of development projects and for production being delayed and/or further capital expenditure being required. Licensing authorities may also impose modifications to a development or redevelopment plan, to meet environmental or other objectives that may render such projects uneconomic. Significant unanticipated costs or delays in any of these projects or the failure to recover oil and gas in sufficient quantities to justify the Group's investments may also have an adverse effect on the Group's business, performance,

taking place, which reduces cash flows and can lead to impairment charges.

As a participant in the exploration, development and production of hydrocarbons, the Group may be exposed to material risk in the event of a major safety incident or operational accident occurring or a natural disaster leading to injuries, loss of life, environmental harm, business disruption and financial and reputational

prospects, financial condition and reputation. Additionally, there is no assurance that any exploration activities the Group engages in will be successful and statistically a relatively small number of properties that are explored are ultimately developed into producing hydrocarbon fields.

There are numerous risks inherent in drilling and operating wells, many of which are beyond the Group's control. The Group's operations may be curtailed, delayed or cancelled as a result of weather conditions, environmental hazards, industrial accidents, occupational and health hazards, technical or operational failures, shortage or delays in the delivery of rigs and/or other equipment, labour disputes and compliance with governmental requirements.

Mitigations: The Group acts at all times as a reasonable and prudent operator, with the designated operators of the Group's non-operated assets required to act in the same manner. The Group maintains, in conjunction with its core contractors, a comprehensive programme of HSE, asset integrity and assurance activities. The Group also has a rigorous process for engaging and evaluating contractors to ensure it uses experienced and reputable service providers that are suitably qualified and experienced for the completion of its work programmes. The Group continually assesses the condition of its assets and has procedures in place that are designed to (i) identify potential issues which may result in unplanned shutdowns or which may in other respects have the potential to undermine asset availability and (ii) minimise the risk of any such unplanned shutdowns and associated expenditures. Production efficiency is continually monitored with losses being identified and remedial and improvement actions undertaken as required.

The Group places emphasis on ensuring it attracts and engages with high quality suppliers, subcontractors and partners to enable it to achieve successful project execution. The Group seeks to obtain optimal contractual agreements, including using turnkey and lump sum incentivised contracts where appropriate, when undertaking major project developments so as to limit its financial exposure to the risks associated with project execution. The Group takes potential delays as a result of adverse weather conditions into consideration in preparing budgets and forecasts and seeks to include an appropriate buffer in its all estimates of costs, which could be adversely affected by weather.

The Group also takes out insurance to mitigate many operational, construction and environmental risks in line with recognised industry limits, although the Group cannot guarantee that such insurance will be adequate to cover any losses or exposure for liability or that it will continue to be able to obtain insurance to cover such risks.

PROPERTY AND INFRASTRUCTURE RISK

Risks: The Group's properties will be generally held in the form of licences, concessions, permits and regulatory consents ("Authorisations"). The Group's activities are dependent upon the grant of and maintenance of appropriate Authorisations, which: may not be granted; may be made subject to limitations which, if not met, will result in the termination or withdrawal of the Authorisation; or may be otherwise withdrawn. Also, in the majority of its licences, the Group shares its interest with other third parties over which it has no control. An Authorisation may be revoked by the relevant regulatory authority if the other interest-holder is no longer deemed to be financially credible. There can be no assurance that any of the obligations required to maintain each Authorisation will be met. Although the Group believes that the Authorisations will be renewed following expiry or being granted (as the case may be), there can be no assurance that such authorisations will be renewed or granted or as to the terms of such renewals or grants. The termination or expiration of the Group's Authorisations may have a material adverse effect on the Group's results of operations and business.

A substantial portion of the Group's production passes through some third-party owned and controlled infrastructure. This infrastructure is in turn subject not only to the risk of physical damage, but also has economic longevity thresholds that are a function of a combination of factors, including commodity prices and throughput, often from other producing fields over which the Group has no control. If the third party infrastructure is no longer economic it may lead to cessation of production leaving its satellite fields stranded without a readily available export route. In addition, the Group's use of such third-party infrastructure in general is subject to tariff charges. These charges can be substantial and the per barrel charge is not subject to our direct control and may be set on a cost sharing basis according to our proportionate hydrocarbon throughput of the relevant facility.

A significant proportion of the Group's current and future production is derived from the Captain and GSA fields. Should any of the infrastructure associated with production from these fields be compromised, the Group's future production and cashflow would be adversely affected, which would in turn affect the Group's results of operation and financial condition.

Mitigations: The Group has routine ongoing communications with the UK oil and gas regulatory body and the Department of Business, Energy & Industrial Strategy ("BEIS"). Regular communication allows all parties to an Authorisation to be fully informed as to the status of any Authorisation and ensures the Group remains updated regarding fulfilment of any applicable requirements.

The Group regularly monitors and assesses its exposure to the short and long term risks associated with third party infrastructure costs, availability and economic life, particularly when evaluating investment opportunities and potential asset acquisitions.

ESTIMATION OF RESERVES, RESOURCES AND PRODUCTION PROFILE

Risks: Estimates of oil and gas reserves, anticipated production profiles and expenditures involve subjective judgements and determinations based on available geological, technical, contractual and economic information. These judgements may change based on new information from production or drilling activities or changes in economic factors, as well as from developments such as acquisitions and dispositions, new discoveries and extensions of existing fields and the application of improved recovery techniques. Published reserve estimates are also subject to correction for errors in the application of published rules and guidance.

Many of the factors in respect of which assumptions are made when estimating reserves are beyond the Group's control and therefore any estimates may prove to be incorrect over time. If the assumptions upon which estimates of the Group's hydrocarbon reserves, resources or production profiles have been based prove to be incorrect, the Group may be unable to recover and produce the estimated level or quality of hydrocarbons anticipated and its business, performance, prospects, financial condition and reputation may be adversely affected as a result.

Mitigations: The Group's assessment of reserves is prepared by Netherland Sewell & Associates Inc., an independent reserves evaluator, in accordance with the definitions and guidelines set forth in the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers.

COMPETITION RISK

Risks: In all areas of the Group's business, there is competition with entities that may have greater technical and financial resources. There remains strong competition within the industry for the acquisition of good-quality hydrocarbon assets. The Group competes with other oil and gas companies, many of which have greater financial resources than the Group, for the acquisition of such properties, licences and other interests as well as for the recruitment and retention of skilled personnel. The challenge for the Group is to secure assets and recruit and retain key staff without having to pay excessive premiums. There is also continuing competition for access to pipelines and other infrastructure which may delay the development of a field and thereby its economic value.

The Group's development is also dependent upon the continued services and performance of its senior management and other key personnel. The loss of the services of any of the senior management or key personnel may have an adverse impact on the Group and it is possible that the Group may not be able to attract or retain qualified individuals, or its key personnel, in the future.

Mitigations: In formulating bids to acquire assets, the Group utilises experienced senior professionals within the Group to ensure that any bids are submitted at a competitive price that reflects the potential risked asset value and can generate appropriate returns. Prior to any asset being evaluated, senior management review the target to ensure it fits within the strategic and financial objectives of the Group. The Group seeks to ensure that it maintains a competitive remuneration and benefits package to ensure it is able to attract and retain appropriately qualified and experienced personnel.

REPUTATION RISK

Risks: In the event a major incident were to occur in respect of a property in which the Group has an interest, the Group's reputation could be severely harmed.

Mitigations: The Company's operational activities are conducted in accordance with approved policies, standards and procedures, which are also shared and developed with the Group's subcontractors. In addition, the Group regularly audits its operations and the subcontractors it uses to ensure compliance with established policies, standards and procedures.

CYBER RISK

Risks: The Group is at risk of financial loss, reputational damage and general disruption from a failure of its Information Technology ("IT") systems or an attack for the purposes of espionage, extortion or to cause embarrassment.

Mitigations: The Group has a well-qualified and experienced IT department that ensures the Group's systems are protected in so far as is practicable.

ACQUISITION RISK

Risks: Part of the Group's strategy includes increasing oil and gas reserves and/or production through strategic acquisitions. Although the Group performs a review of the companies, businesses and assets prior to acquiring them consistent with industry practices, such reviews are inherently incomplete. It is often not feasible to review in depth every individual property involved in each acquisition and the Group will generally focus its due diligence efforts on higher valued properties and will sample the remainder. However, even where in-depth reviews of all properties and records are conducted they may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. In order to establish a value and offer price for an acquisition the Group will make certain technical and economic assumptions as regards the continuing performance of the asset and its associated liabilities, particularly as regards decommissioning, and in the event that those assumptions are incorrect the Group risks overpaying for such acquisition which may have a material adverse effect on the business.

Risks commonly associated with acquisitions of companies or businesses include the difficulty of integrating the operations and personnel of the acquired business, problems with minority shareholders in acquired companies, the potential disruption of the Group's own business, the possibility that indemnification agreements with the sellers may be unenforceable or insufficient to cover potential liabilities and difficulties arising out of integration, as well as operational risks relating to the assets acquired. Furthermore, the value of any assets or business the Group acquires or invests in may be less than the amount it pays and there can be no assurance that any acquisition by the Group will be successful.

Mitigations: in formulating bids to acquire assets, the Group utilises experienced senior professionals within the Group and external advisers where appropriate. The Group actively reviews its acquisition evaluation criteria and considers in detail the fit of any potential acquisition in relation to the prevailing criteria. Acquisition opportunities are rigorously screened based on the strategic fit with our existing portfolio, the subsurface quality of the assets and any associated production facilities, the rate of return and speed of payback, the technical and financial capabilities of any partners in the assets, the potential upsides and the extent of any future decommissioning cost exposures.

FORWARD LOOKING INFORMATION

This Management Discussion and Analysis ("MD&A") and any documents incorporated by reference herein contain certain forward-looking statements and forward-looking information which are based on the Company's internal expectations, estimates, projections, assumptions and beliefs as at the date of such statements or information, including, among other things, assumptions with respect to production, future capital expenditures, future acquisitions and dispositions and cash flow. The reader is cautioned that assumptions used in the preparation of such information may prove to be incorrect. The use of any of the words "forecasts", "anticipate", "continue", "estimate", "expect", "may", "will", "project", "plan", "should", "believe", "could", "scheduled", "targeted" and similar expressions are intended to identify forward-looking statements and forward-looking information. These statements are not guarantees of future performance and involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements or information. The Company believes that the expectations reflected in those forward-looking statements and information are reasonable but no assurance can be given that these expectations, or the assumptions underlying these expectations, will prove to be correct and such forward-looking statements and information included in this MD&A and any documents incorporated by reference herein should not be unduly relied upon. Such forward-looking statements and information speak only as of the date of this MD&A and any documents incorporated by reference herein and the Company does not undertake any obligation to publicly update or revise any forward-looking statements or information, except as required by applicable laws.

In particular, this MD&A and any documents incorporated by reference herein, contain specific forward-looking statements and information pertaining to the following:

- Oil, natural gas liquids ("NGLs") and natural gas production rates and targeted production levels;
- The quality of and future net revenues from the Company's reserves;
- Commodity prices, foreign currency exchange rates and interest rates and the expected effect of fluctuations in such prices and rates;
- Capital expenditure programmes and other expenditures;
- Future operating costs;
- The development of certain exploration, appraisal and development properties using third party resources;
- Supply and demand for oil, NGLs and natural gas;
- The Company's ability to raise capital and the potential sources thereof;
- The continued availability of bank debt facilities and senior unsecured notes;
- The sufficiency of the bank debt facilities, senior unsecured notes, cash balances and forecast cash flow to cover anticipated future commitments;
- Expected future net debt and continued deleveraging;
- The anticipated effects on production and cashflow of various operational work programmes;
- The Company's acquisition and divestment strategy, the criteria to be considered in connection therewith and the benefits to be derived therefrom;
- The realisation of anticipated benefits from acquisitions and divestments;
- The anticipated timing for completion of licence acquisitions;
- Expected future payments associated with licence acquisitions and previous asset transactions;
- Statements related to reserves and resources;
- Development plans associated with pending licence acquisitions, including field development plans and the anticipated timing thereof;
- Anticipated benefits of development programmes;
- Anticipated cost to develop portfolio investment opportunities;
- Potential investment opportunities and the expected development costs thereof;
- The Company's ability to continually add reserves and resources;
- Schedules and timing of certain projects and the Company's strategy for growth;
- The Company's future operating and financial results;
- The ability of the Company to optimise operations and reduce operational and capital expenditures;
- Treatment under governmental and other regulatory regimes and tax, environmental and other laws;
- The ability of the Company to continue operating in the face of inclement weather;
- Timing and cost of the development of the Company's reserves and resources;
- Estimates of production volumes and reserves in connection with acquisitions and certain projects;
- Estimated decommissioning liabilities and the timing for execution of decommissioning programmes;
- The timing and effects of planned maintenance shutdowns;
- The expected impact on the Company's financial statements resulting from changes in tax rates;
- The Company's expected tax horizon; and,
- Anticipated cost exposure resulting from third party circumstances.

With respect to forward-looking statements contained in this MD&A and any documents incorporated by reference herein, the Company has made assumptions regarding, among other things:

- The Company's ability to obtain additional drilling rigs and other equipment in a timely manner, as required;
- Ability to negotiate access to third party host facilities and associated pipelines within the expected timeframe;
- Field Development Plan approvals are obtained and operational construction and development activities are completed within expected timeframes, both of the Company, its business partners and regulatory authorities;
- The Company's ability to receive necessary regulatory and partner approvals in connection with acquisitions and divestments;
- The Company's development plan for its properties will be implemented as planned;
- The market for potential opportunities from time to time and the Company's ability to successfully pursue opportunities;
- The Company's ability to keep operating during periods of harsh weather;
- The timing of anticipated shutdowns;
- Reserves and resources volumes assigned to the Company's properties and the ability to recover those volumes;
- Revenues do not decrease significantly below anticipated levels and operating and capital costs do not increase significantly above anticipated levels;
- Future oil, NGL and natural gas production levels from the Company's properties and the prices obtained from the sales of such production;
- The level of future capital expenditure required to exploit and develop reserves;
- The Company's ability to obtain financing on acceptable terms, in particular, the Company's ability to access its debt facilities;
- The continued ability of the Company to collect amounts receivable from third parties that the Company has provided credit to;
- The Company's reliance on partners and their ability to meet commitments under relevant agreements; and,
- The state of capital markets in the current economic environment.

The Company's actual results could differ materially from those anticipated in these forward-looking statements and information as a result of assumptions proving inaccurate and of both known and unknown risks, including the risk factors set forth in this MD&A and the documents incorporated by reference herein, such as:

- Risks associated with the exploration for and development of oil and natural gas reserves in the North Sea;
- Risks associated with offshore development and production including risks of inclement weather and the unavailability of processing and transportation facilities;
- Operational risks and liabilities that are not covered by insurance;
- Volatility in market prices for oil, NGLs and natural gas;
- The ability of the Company to fund its capital requirements and operations and the terms of such funding;
- Risks associated with ensuring title to the Company's properties;
- Changes in environmental, health and safety or other legislation applicable to the Company's operations, and the Company's ability to comply with current and future environmental, health and safety and other laws;
- The accuracy of oil and gas reserve estimates and estimated production levels as they are affected by the Company's exploration and development drilling and estimated decline rates;
- The Company's success at acquisition, exploration, exploitation and development of reserves and resources;
- Risks associated with satisfying conditions to closing acquisitions and divestments;
- Risks associated with realisation of anticipated benefits of acquisitions and divestments;
- Risks related to changes to government policy with regard to offshore drilling and operations;
- The Company's reliance on key operational and management personnel;
- The ability of the Company to obtain and maintain all of its required permits and licences;
- Competition for, among other things, capital, drilling equipment, acquisitions of reserves, undeveloped lands and skilled personnel;
- Changes in general economic, market and business conditions in the United Kingdom, North America and worldwide;
- Actions by governmental or regulatory authorities including changes in income tax laws or changes in tax laws, royalty rates and incentive programmes relating to the oil and gas industry including any increase in UK taxes; and,
- Adverse regulatory or court rulings, orders and decisions.

ADDITIONAL READER ADVISORIES

The information in this MD&A is provided as of 27 August 2020. The H1 2020 results have been compared to the results for the same period in 2019. This Management Discussion and Analysis should be read in conjunction with the Company's audited consolidated financial statements as at 31 December 2019 together with the accompanying notes.

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