crew energy inc.

# 2021 ANNUAL REPORT

## THE BEST VIEWS COME AFTER THE HARDEST CLIMBS

**MARCH 8, 2022**

# ABOUT CREW


Crew Energy Inc. ("Crew" or the "Company") is a liquids-rich natural gas producer committed to pursuing sustainable per share growth through a balanced mix of financially responsible exploration and development, complemented by strategic acquisitions. The Company's operations are focused in northeast British Columbia ('NE BC") and include a large contiguous land base with a vast Montney formation resource. Crew's liquids-rich natural gas areas of Septimus and West Septimus ("Greater Septimus") and Groundbirch offer significant development potential over the long-term. The Company has access to diversified markets with operated infrastructure and access to multiple pipeline egress options. Crew adheres to safe and environmentally responsible operations while remaining committed to sound environmental, social and governance practices which underpin Crew's fundamental business tenets. Crew's common shares are listed for trading on the Toronto Stock Exchange ("TSX") under the symbol "CR".

## CORPORATE INFORMATION

**AUDITORS**
KPMG LLP

**LEGAL COUNSEL**
Burnet, Duckworth & Palmer LLP

**RESERVE ENGINEERS**
Sproule Associates Ltd.

**TRANSFER AGENT**
Odyssey Trust Company

**BANKERS**
Toronto-Dominion Bank
Alberta Treasury Branches
National Bank of Canada
Canadian Western Bank
Business Development Bank of Canada

## CONTACT INFORMATION

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# CREW ENERGY INC. 2021 ANNUAL REPORT

Crew Energy Inc. (TSX: CR, OTCQB: CWEGF) ("Crew" or the "Company") is a growth-oriented natural gas weighted producer operating exclusively in the world-class Montney play in northeast British Columbia ("NEBC"). The Company is pleased to announce our operating and financial results for the three and twelve month periods ended December 31, 2021. Crew's audited consolidated Financial Statements and Notes, as well as Management's Discussion and Analysis ("MD&A") are available on Crew's website and filed on SEDAR at www.sedar.com.

"Crew is excited to advance the Company's previously announced two-year asset development plan (the "Plan") as we further reduce unit costs, increase production and optimize pricing to expand margins. Building on the significant progress achieved towards this Plan during 2021, our objectives through 2022 include increasing production by 20% and generating Free Adjusted Funds Flow[3] ("Free AFF") to significantly reduce debt, with a goal of transferring enterprise value to our shareholders," said Dale Shwed, President and CEO of Crew. "Underpinning our Plan is a steadfast commitment to meeting or exceeding environmental, social and governance ("ESG") goals and upholding our track record as a safe and responsible operator."

## HIGHLIGHTS

- **29,142 boe per day**[1] (174.9 mmcfe per day) average production in Q4/21, 35% higher than Q4/20 and above guidance of 28,000 to 29,000 boe per day[1], while average production in the month of December marked a new record high of 32,766 boe per day[1]. Annual average production in 2021 was 26,443 boe per day[1], a 20% increase over the prior year.
- **$46.8 million of Adjusted Funds Flow**[2] ("AFF") ($0.29 per fully diluted share) was generated in Q4/21, a 201% increase over Q4/20, driven by significant production growth and strong operating netbacks[3] of $20.70 per boe. AFF[2] in 2021 totaled $132.9 million ($0.82 per fully diluted share), 223% higher than 2020.
- **Before tax total proved plus probable reserve value per share of $11.95**[4], and total proved reserve value of $5.85 per share[5], net of debt, discounted at 10% before tax and based on Sproule's December 31, 2021 escalated price forecast; the details of the associated reserves evaluation were outlined in Crew's press release dated February 8, 2022.
- **20% reduction in net operating costs**[3] per boe in 2021, totaling $4.47 per boe compared to $5.61 per boe in 2020, reflecting the advancement of our Plan which aims to reduce per unit costs by over 25% from 2020 to 2022. Net operating costs[3] per boe in Q4/21 were $3.49 per boe, 34% lower than Q4/20.
- **55% improvement in annualized Q4/21 net debt**[2] **to EBITDA ratio**[6] **which improved to 1.9x,** compared to 4.2x at the end of 2020, while net debt[2] to Q4/21 production declined 16% to $13,900 per boe, in-line with the Company's Plan. Net debt[2] at year-end 2021 was $406.0 million.
- **$169.6 million of net capital expenditures**[3] in 2021**,** directed to an active exploration and development program that was largely focused on developing the Company's Montney assets in NEBC, and resulted in Crew drilling 26 (24.7 net) wells and completing 24 (22.7 net) wells. The 2021 capital program realized continued cost and operational improvements, driving reduced drill times, strong capital efficiencies and enhanced returns. Q4/21 net capital expenditures[3] totaled $41.9 million and were focused on the completion of eight (8.0 net) liquids rich wells at Greater Septimus.

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[1] See table in the Advisories for production breakdown by product type as defined in NI 51-101.

[2] Capital management measure that does not have any standardized meaning as prescribed by International Financial Reporting Standards, and therefore, may not be comparable with the calculations of similar measures for other entities. See "Advisories - Non-IFRS and Other Financial Measures" contained within this report.

[3] Non-IFRS financial measure or ratio that does not have any standardized meaning as prescribed by International Financial Reporting Standards, and therefore, may not be comparable with calculations of similar measures or ratios for other entities. See "Advisories - Non-IFRS and Other Financial Measures" contained within this report.

[4] Calculated based on estimated future net revenues of 2P reserves of $2,228.8 million, as reflected in the Crew's year-ended 2021 reserves report prepared by Sproule Associates Ltd, discounted at 10%, less net debt of $406.0 million as at December 31, 2021, divided by total outstanding shares of 152.5 million as at December 31, 2021.

[5] Calculated based on estimated future net revenues of 1P reserves of $1,299.0 million, as reflected in the Crew's year-ended 2021 reserves report prepared by Sproule Associates Ltd, discounted at 10%, less net debt of $406.0 million as at December 31, 2021, divided by total outstanding shares of 152.5 million as at December 31, 2021.

[6] Supplementary measure that does not have any standardized meaning as prescribed by International Financial Reporting Standards, and therefore, may not be comparable with the calculations of similar measures for other entities. See "Advisories - Non-IFRS and Other Financial Measures" contained within this report.

## FINANCIAL & OPERATING HIGHLIGHTS

| FINANCIAL ($ thousands, except per share amounts) | **Three months ended Dec. 31, 2021** | Three months ended Dec. 31, 2020 | **Year ended Dec. 31, 2021** | Year ended Dec. 31, 2020 |
|---|---|---|---|---|
| **Petroleum and natural gas sales** | **103,153** | 42,604 | **332,848** | 137,931 |
| **Cash provided by operating activities** | **45,747** | 14,774 | **119,156** | 37,989 |
| **Adjusted funds flow**[1] | **46,833** | 15,568 | **132,869** | 41,150 |
| Per share – basic | **0.31** | 0.10 | **0.87** | 0.27 |
| - diluted | **0.29** | 0.10 | **0.82** | 0.27 |
| **Net Income (loss)** | **50,901** | 34,668 | **205,299** | (203,180) |
| Per share – basic | **0.33** | 0.23 | **1.34** | (1.34) |
| - diluted | **0.31** | 0.22 | **1.27** | (1.34) |
| **Property, plant and equipment expenditures** | **42,341** | 41,007 | **177,924** | 86,260 |
| **Property acquisitions** (net of dispositions)[2] | **(460)** | (23,219) | **(8,276)** | (58,150) |
| **Net capital expenditures**[2] | **41,881** | 17,788 | **169,648** | 28,110 |

| Capital Structure ($ thousands) | **As at Dec. 31, 2021** | As at Dec. 31, 2020 |
|---|---|---|
| Working capital deficiency[1] | **33,068** | 24,361 |
| Bank loan | **75,067** | 35,994 |
| | **108,135** | 60,355 |
| Senior unsecured notes | **297,834** | 296,851 |
| **Net debt**[1] | **405,969** | 357,206 |
| **Common shares outstanding** (thousands) | **152,480** | 151,182 |

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2) Non-IFRS financial measure that does not have any standardized meaning as prescribed by International Financial Reporting Standards, and therefore, may not be comparable with the calculations of similar measures for other entities. See "Advisories – Non-IFRS and Other Financial Measures" contained within this report.

| OPERATIONAL | **Three months ended Dec. 31, 2021** | Three months ended Dec. 31, 2020 | **Year ended Dec. 31, 2021** | Year ended Dec. 31, 2020 |
|---|---|---|---|---|
| **Daily production** | | | | |
| Light crude oil (bbl/d)[1] | **157** | 182 | **158** | 187 |
| Heavy crude oil (bbl/d) | **-** | 1,281 | **802** | 1,362 |
| Natural gas liquids ("ngl")[2] (bbl/d) | **2,458** | 1,953 | **2,446** | 2,070 |
| Condensate (bbl/d) | **2,596** | 2,121 | **2,667** | 2,583 |
| Conventional natural gas (mcf/d) | **143,584** | 96,771 | **122,217** | 94,519 |
| Total (boe/d @ 6:1) | **29,142** | 21,666 | **26,443** | 21,955 |
| **Average realized**[3] | | | | |
| Light crude oil price ($/bbl) | **89.98** | 47.38 | **75.95** | 39.97 |
| Heavy crude oil price ($/bbl) | **-** | 38.79 | **59.41** | 28.86 |
| Natural gas liquids price ($/bbl) | **34.50** | 13.20 | **20.75** | 9.01 |
| Condensate price ($/bbl) | **93.90** | 47.68 | **79.86** | 42.99 |
| Natural gas price ($/mcf) | **5.42** | 2.87 | **4.82** | 2.12 |
| Commodity price ($/boe) | **38.47** | 21.37 | **34.49** | 17.17 |

1) The Company does not have any medium crude oil as defined by NI 51-101.

2) Throughout this report, NGLs comprise all natural gas liquids as defined in National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities ("NI 51-101"), other than condensate, which is disclosed separately, and natural gas means conventional natural gas by NI 51-101 product type.

3) Supplementary measure that does not have any standardized meaning as prescribed by International Financial Reporting Standards, and therefore, may not be comparable with calculations of similar measures for other entities. See "Advisories – Non-IFRS and Other Financial Measures" contained within this report.

| | **Three months ended Dec. 31, 2021** | Three months ended Dec. 31, 2020 | **Year ended Dec. 31, 2021** | Year ended Dec. 31, 2020 |
|---|---|---|---|---|
| **Netback** ($/boe) | | | | |
| Petroleum and natural gas sales | **38.47** | 21.37 | **34.49** | 17.17 |
| Royalties | **(2.70)** | (0.99) | **(2.39)** | (0.81) |
| Realized commodity hedging (loss) gain | **(8.06)** | 1.27 | **(6.31)** | 2.06 |
| Marketing loss | **-** | (0.04) | **-** | (0.11) |
| Net operating costs[1] | **(3.49)** | (5.30) | **(4.47)** | (5.61) |
| Transportation costs | **(3.52)** | (4.23) | **(4.07)** | (3.67) |
| Operating netback[1] | **20.70** | 12.08 | **17.25** | 9.03 |
| General and administrative ("G&A") | **(0.91)** | (1.30) | **(0.95)** | (1.01) |
| Financing costs on debt[1] | **(2.31)** | (2.97) | **(2.53)** | (2.90) |
| Adjusted funds flow[2] | **17.48** | 7.81 | **13.77** | 5.12 |

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## TWO-YEAR PLAN ON TRACK

In Q4/21 and into 2022, Crew continued to advance our Plan that was launched in late 2020:

- **Continued Production Expansion** – Production volumes in January 2022, based on field estimates, averaged over 32,500 boe per day[7], supporting the forecast Q1/22 average production of between 31,000 to 33,000 boe per day[7]. Q4/21 production averaged 29,142 boe per day[7] (174.9 mmcfe per day), 35% higher than Q4/20.
- **AFF Propelled Higher** – AFF[8] of $46.8 million in Q4/21 was augmented by reduced unit costs, steadily improving netbacks and production growth. Our full year 2022 AFF[8] is forecast between $190 to $210 million, while 2022 Free AFF[9] is now targeted at the high end or above the range of $95 million to $130 million, depending on commodity prices and other underlying assumptions which are outlined in the Outlook section herein.
- **Capital Program on Course –** An active first quarter capital program is driving full year 2022 annual production guidance between 31,000 to 33,000 boe per day[7] based on annual capital expenditures of $80 to $95 million, which has been refined from $70 to $95 million, a result of inflationary factors partially offset by capital program efficiency gains.
- **Leverage Metrics Improving** – Crew has ample liquidity to execute our two-year plan, with leverage metrics expected to improve as the Company plans to reduce indebtedness through 2022. Crew's net debt[8] to the last twelve-months' ("LTM") EBITDA[10] ratio is forecast to improve to below 1.5 times at the end of 2022 at current strip commodity prices, declining from 2.6 times at the end of 2021 and 1.9 times Q4/21 annualized EBITDA.
- **Improved Efficiencies** – Crew's plan to reduce per unit costs by over 25% from 2020 to 2022 is largely based on increasing production volumes into existing infrastructure and transportation capacity, as over 50% of the Company's expenses are fixed. As production has increased, cash costs per boe[9] associated with operating, transportation, G&A and interest expenses have already declined to $10.23 per boe as of Q4/21, representing a decrease of 26% from $13.80 per boe in Q4/20. Net operating costs[9] were reduced to $3.49 per boe in Q4/21, down from $5.30 per boe in Q4/20, supported in

7 See table in the Advisories for production breakdown by product type as defined in NI 51-101.

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10 Supplementary measure that does not have any standardized meaning as prescribed by International Financial Reporting Standards, and therefore, may not be comparable with calculations of similar measures for other entities. See "Advisories – Non-IFRS and Other Financial Measures" contained within this report..

large part by the planned increase in Montney production from West Septimus and Groundbirch, along with optimized field operations and the previously announced sale of Crew's heavy oil assets which carried higher net operating costs per boe.

## OPERATIONS & AREA OVERVIEW

**NE BC Montney (Greater Septimus)**

- Eight wells were completed across two different benches within the Montney in Q4/21, including three extended reach horizontal ("ERH") wells on the 10 well 4-14 pad, which were drilled to an average lateral length of 4,140 meters.
- After an average of 32 days on production, the three ERH wells on the 4-14 pad were flowing at an average per well sales rate of 2,588 boe per day, comprised of 9,602 mcf per day of natural gas, 847 bbls per day of condensate and 140 bbls per day of NGL's[11]. Comparative type curves for this pad are available within Crew's February 2022 investor presentation on the Company's website. The remaining seven wells on our 4-14 pads are currently being completed with initial production expected late in Q1/22.

**Groundbirch**

- Crew had one drilling rig in operation during Q1/22, which recently finished drilling the five-well 4-17 Groundbirch pad following the success of our first three wells that were drilled and completed in the area in 2021. The first three wells at Groundbirch are exceeding Crew's internal type curve with an average raw gas production rate after 120 days ("IP120") of 9,410 mcf per day.
- Crew owns over 70,000 net acres of contiguous land in the Greater Groundbirch area. The Upper Montney at Groundbirch is approximately 470 feet in thickness and has four prospective zones; two of these zones were tested on the initial three well pad, and the other two zones are planned to be tested on Crew's follow-up five well pad.

**Other NE BC Montney**

- We continue to evaluate encouraging offset operator activity in the Tower, Attachie and Oak/Flatrock areas.

## SUSTAINABILITY AND ESG INITIATIVES

Crew's ESG initiatives continue to be a prime focus as we uphold our unwavering commitment to safe and responsible energy production. During 2021, Crew released our inaugural ESG report in an environmentally conscious online format, outlining our efforts to promote operational innovation, reduce our environmental footprint, support stakeholders and protect our employees' health and safety. Please visit https://esg.crewenergy.com to learn more.

- With the sale of our Lloydminster assets in September of 2021, which represented Crew's most emission-intensive asset, approximately 46% of Crew's direct 2020 greenhouse gas ("GHG") emissions (Scope 1) have been removed and we anticipate the Company's total GHG emissions intensity will be reduced significantly, putting Crew on a path to reach our emissions reduction goals earlier than anticipated.
- Divesting of these assets sets the stage for Crew to streamline operations and improve efficiencies while also reducing our overall decommissioning obligations by a targeted 40%, representing approximately $34.5 million associated with 609 gross (539 net) wellbores.
- In 2021, the Company maintained our strong regulatory compliance record, achieving a 94% compliance rating with 284 regulatory inspections completed.
- The Company recorded no spills of significance, no lost time injuries and no employee injuries in 2021.

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[11] Excludes condensate volumes which have been reported separately.

- Crew successfully participated in the provincially funded dormant well programs in 2021, having abandoned 68 (62 net) wells and completed 145 site assessments throughout the year across three different provinces.
- Crew continued to use next generation, spoolable surface pipelines for produced water transfer, which removes trucks from the road, reduces $CO_2$ emissions, and affirms Crew's commitment to improving efficiencies and reducing our environmental impact. The Company's spoolable pipeline resulted in the removal of 24,237 two-way truckloads from the road during 2021, which is the equivalent distance of approximately 4.5 trips around the globe.

## OUTLOOK

- **Full Year 2022 Guidance Reaffirmed** – Forecast full year 2022 average volumes are expected to remain within our previously announced guidance range of 31,000 to 33,000 boe per day[12] with full year net capital expenditures[13] refined to between $80 and $95 million from $70 to $95 million, a result of inflationary factors partially offset by capital program efficiency gains. At current forward strip commodity prices, Free AFF[14] is expected to be at the high end or above our guidance range of $95 to $130 million.

| | 2022 Guidance and Assumptions[1,4] |
|---|---|
| Net capital expenditures[2] ($MM) | **80-95** |
| Annual average production (boe/d) | **31,000-33,000** |
| AFF[3] ($MM) | **190-210** |
| Free AFF[2] | **95-130** |
| EBITDA[2] ($MM) | **214-234** |
| Oil price (WTI)($US per bbl) | **$65.00** |
| Natural gas price (AECO 5A) ($C per mcf) | **$3.50** |
| Natural gas price (NYMEX) ($US per mmbtu) | **$4.00** |
| Natural gas price (Crew est. wellhead) ($C per mcf) | **$4.00** |
| Foreign exchange ($US/$CAD) | **$0.78** |
| Royalties | **5-7%** |
| Net operating costs[2] ($ per boe) | **$3.50-$4.00** |
| Transportation ($ per boe) | **$2.75-$3.25** |
| G&A ($ per boe) | **$0.80-$1.00** |
| Effective interest rate on long-term debt | **6.0-6.5%** |

1) The actual results of operations of Crew and the resulting financial results will likely vary from the estimates and material underlying assumptions set forth in this guidance by the Company and such variation may be material. The guidance and material underlying assumptions have been prepared on a reasonable basis, reflecting management's best estimates and judgments.

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4) Consistent with prior guidance except for (i) net capital expenditures range tightened from prior guidance of $70-95 MM, (ii) addition of Free AFF, (iii) transportation costs per boe increased from $2.50-3.00 per boe, and (iv) royalty rate increased from 4-6%.

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12 See table in the Advisories for production breakdown by product type as defined in NI 51-101.

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- **2022 Guidance Sensitivities**

| | AFF ($MM) | AFF/Share | FD AFF/Share |
|---|---|---|---|
| 100 bbl per day Condensate[1] | $3.6 | $0.02 | $0.02 |
| C$1.00 per bbl WTI | $1.0 | $0.01 | $0.01 |
| US $0.10 NYMEX (per mmbtu) | $3.5 | $0.02 | $0.02 |
| 1 mmcf per day natural gas | $1.8 | $0.01 | $0.01 |
| $0.10 AECO 5A (per GJ) | $2.0 | $0.01 | $0.01 |
| $0.01 FX CAD/US | $1.9 | $0.01 | $0.01 |

1) Condensate is defined as a mixture of pentanes and heavier hydrocarbons recovered as a liquid at the inlet of a gas processing plant before the gas is processed and pentanes and heavier hydrocarbons obtained from the processing of raw natural gas.

- **Active Q1/22 Capital Program** - Crew's first quarter capital expenditures are expected to constitute approximately 60% of the program's full year total, with the remainder to be directed to projects with superior returns at Greater Septimus or Groundbirch in the second half of 2022.
- **Near Term Initiatives**
    - Use forecasted Free AFF in 2022 to reduce debt and improve leverage metrics;
    - Invest in capital projects with strong rates of return and payouts under 12 months, which can be supported by an active hedging program;
    - Continue to optimize transportation and facilities throughput to drive lower unit costs; and
    - Actively monitor service industry efficiencies, cost trends and commodity prices to assess potential capital budget adjustments as market conditions change throughout the year.

In 2022, we will continue executing on our plan to increase production to expand margins and AFF, ultimately reducing leverage metrics to drive enhanced financial flexibility and corporate growth. We would like to thank our employees, Board of Directors, contractors and suppliers for their contribution and commitment to Crew, as well as our extended stakeholders for their ongoing support.

## ADVISORIES

### Forward-Looking Information and Statements

This report contains certain forward–looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "project", "should", "believe", "plans", "intends" "forecast" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this report contains forward-looking information and statements pertaining to the following: the ability to execute on its two-year development plan and underlying strategy and targets as described herein; as to our plan to optimize and increase production and infrastructure utilization, reduce unit and net operating costs and enhance margins, streamline operations and improve efficiencies; our 2022 annual capital budget range, associated drilling and completion plans and all associated near term initiatives and targets, guidance and underlying assumptions; production estimates including forecast 2022 annual, January 2022 and Q1 2022 production averages; our target to reduce unit costs by over 25% from 2020 to 2022; 2022 AFF estimates and targeted 2022 Free AFF and improvement in debt metrics; commodity price expectations including Crew's estimates of natural gas pricing exposure; Crew's commodity risk management programs and future hedging opportunities; well abandonment plans; marketing and transportation and processing plans and requirements; estimates of processing capacity and requirements; anticipated reductions in GHG emissions and decommissioning obligations; future liquidity and financial capacity; future results from operations and operating and leverage metrics; our targeted Net Debt to LTM EBITDA ratio of below 1.5x by the end of 2022; world supply and demand projections and long-term impact on pricing; future development, exploration, acquisition and disposition activities (including drilling and completion plans, anticipated on-stream dates and associated development timing and cost estimates); the potential of our Groundbirch area to be a core area of future development and the number of potential prospective zones to be drilled; infrastructure investment plans; the successful implementation of our ESG initiatives, and significant emissions intensity improvements going forward; the amount and timing of capital projects; and anticipated improvement in our long-term sustainability and the expected positive attributes discussed herein attributable to our two-year development plan.

The internal projections, expectations, or beliefs underlying our Board approved 2022 capital budget and associated guidance are subject to change in light of the impact of the COVID-19 pandemic, and any related actions taken by businesses and governments, ongoing results, prevailing economic circumstances, commodity prices, and industry conditions and regulations. Crew's financial outlook and guidance provides shareholders with relevant information on management's expectations for results of operations, excluding any potential acquisitions or dispositions, for such time periods based upon the key assumptions outlined herein. Such information reflects internal targets used by management for the purposes of making capital investment decisions and for internal long-range planning and budget preparation. Readers are cautioned that events or circumstances could cause capital plans and associated results to differ materially from those predicted and Crew's guidance for 2022 and may not be appropriate for other purposes. Accordingly, undue reliance should not be placed on same.

In addition, forward-looking statements or information are based on a number of material factors, expectations or assumptions of Crew which have been used to develop such statements and information but which may prove to be incorrect. Although Crew believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because Crew can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified herein, assumptions have been made regarding, among other things: that Crew will continue to conduct its operations in a manner consistent with past operations; results from drilling and development activities consistent with past operations; the quality of the reservoirs in which Crew operates and continued performance from existing wells; the continued and timely development of infrastructure in areas of new production; the accuracy of the estimates of Crew’s reserve volumes; certain commodity price and other cost assumptions; continued availability of debt and equity financing and cash flow to fund Crew’s current and future plans and expenditures; the impact of increasing competition; the general stability of the economic and political environment in which Crew operates; that future business, regulatory and industry conditions will be within the parameters expected by Crew; the general continuance of current industry conditions; the timely receipt of any required regulatory approvals; the ability of Crew to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects in which Crew has an interest in to operate the field in a safe, efficient and effective manner; the ability of Crew to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; the timing and cost of pipeline, storage and facility construction and expansion and the ability of Crew to secure adequate product transportation; future commodity prices; currency, exchange and interest rates; regulatory framework regarding royalties, taxes, environmental and indigenous matters in the jurisdictions in which Crew operates; that regulatory authorities in British Columbia will resume granting approvals for oil and gas activities on time frames, and on terms and conditions, consistent with past practices; and the ability of Crew to successfully market its oil and natural gas products.

The forward-looking information and statements included in this news release are not guarantees of future performance and should not be unduly relied upon. Such information and statements, including the assumptions made in respect thereof, involve known and unknown risks, uncertainties and other factors that may cause actual results or events to defer materially from those anticipated in such forward-looking information or statements including, without limitation: the continuing and uncertain impact of COVID-19; changes in commodity prices; changes in the demand for or supply of Crew's products, the early stage of development of some of the evaluated areas and zones the potential for variation in the quality of the Montney formation; interruptions, unanticipated operating results or production declines; changes in tax or environmental laws, royalty rates; climate change regulations, or other regulatory matters; changes in development plans of Crew or by third party operators of Crew's properties, increased debt levels or debt service requirements; inaccurate estimation of Crew's oil and gas reserve volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; and certain other risks detailed from time-to-time in Crew's public disclosure documents (including, without limitation, those risks identified in this news release and Crew's Annual Information Form).

This report contains future-oriented financial information and financial outlook information (collectively, "FOFI") about Crew's prospective capital expenditures, all of which are subject to the same assumptions, risk factors, limitations, and qualifications as set forth in the above paragraphs. The actual results of operations of Crew and the resulting financial results will likely vary from the amounts set forth in this report and such variation may be material. Crew and its management believe that the FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments. However, because this information is subjective and subject to numerous risks, it should not be relied on as necessarily indicative of future results. Except as required by applicable securities laws, Crew undertakes no obligation to update such FOFI. FOFI contained in this report was made as of the date of this report and was provided for the purpose of providing further information about Crew's anticipated future business operations. Readers are cautioned that the FOFI contained in this report should not be used for purposes other than for which it is disclosed herein.

The forward-looking information and statements contained in this news release speak only as of the date of this news release, and Crew does not assume any obligation to publicly update or revise any of the included forward-looking statements or information, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

**Information Regarding Disclosure on Oil and Gas Reserves and Operational Information**

All amounts in this news release are stated in Canadian dollars unless otherwise specified. All reserves information in this report is derived from our independent reserves evaluation effective December 31, 2021, the details of which were announced in our February 8, 2022 press release (the "Reserves Press Release"). Our oil and gas reserves statement for the year ended December 31, 2021, which includes complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101, is contained within our Annual Information Form which is available on our SEDAR profile at www.sedar.com. The reserve estimates and reserves values contained herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Unless otherwise specified all reserves volumes (and information derived therefrom) in this report are based on company gross reserves using forecast prices and costs.

This report contains metrics commonly used in the oil and natural gas industry. Each of these metrics are determined by Crew as specifically set forth in this report. These terms do not have standardized meanings or standardized methods of calculation and therefore may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Such metrics have been included to provide readers with additional information to evaluate the Company's performance however, such metrics are not reliable indicators of future performance and therefore should not be unduly relied upon for investment or other purposes. See "Non-IFRS and Other Financial Measures" below for additional disclosures.

**BOE Conversions**

Barrel of oil equivalents or BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 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 that the value ratio based on the current price of crude oil as compared to natural gas is significantly different than the energy equivalency of 6:1, utilizing the 6:1 conversion ratio may be misleading as an indication of value.

**Non-IFRS and Other Financial Measures**

Throughout this report and other materials disclosed by the Company, Crew uses certain measures to analyze financial performance, financial position and cash flow. These non-IFRS and other financial measures do not have any standardized meaning prescribed under IFRS and therefore may not be comparable to similar measures presented by other entities. The non-IFRS and other financial measures should not be considered alternatives to, or more meaningful than, financial measures that are determined in accordance with IFRS as indicators of Crew's performance. Management believes that the presentation of these non-IFRS and other financial measures provides useful information to shareholders and investors in understanding and evaluating the Company's ongoing operating performance, and the measures provide increased transparency and the ability to better analyze Crew's business performance against prior periods on a comparable basis.

***Capital Management Measures***

**a) Funds from Operations and Adjusted Funds Flow ("AFF")**

Funds from operations represents cash provided by operating activities before changes in operating non-cash working capital, accretion of deferred financing costs and transaction costs on property dispositions. Adjusted funds flow represents funds from operations before decommissioning obligations settled. The Company considers these metrics as key measures that demonstrate the ability of the Company's continuing operations to generate the cash flow necessary to maintain production at current levels and fund future growth through capital investment and to service and repay debt. Management believes that such measures provide an insightful assessment of the Company's operations on a continuing basis by eliminating certain non-cash charges, actual settlements of decommissioning obligations and transaction costs on property dispositions, the timing of which is discretionary. Funds from operations and adjusted funds flow should not be considered as an alternative to or more meaningful than cash provided by operating activities as determined in accordance with IFRS as an indicator of the Company's performance. Crew's determination of funds from operations and adjusted funds flow may not be comparable to that reported by other companies. Crew also presents adjusted funds flow per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of income per share.

**b) Net debt and Working Capital Deficiency (Surplus)**

Crew closely monitors its capital structure with a goal of maintaining a strong balance sheet to fund the future growth of the Company. The Company monitors net debt as part of its capital structure. The Company uses net debt (bank debt plus working capital deficiency or surplus, excluding the current portion of the fair value of financial instruments) as an alternative measure of outstanding debt. Management considers net debt and working capital deficiency (surplus) an important measure to assist in assessing the liquidity of the Company.

***Non-IFRS Financial Measures and Ratios***

**a) Net Property Acquisitions (Dispositions)**

Net property acquisitions (dispositions) equals property acquisitions less property dispositions and transaction costs on property dispositions. Crew uses net property acquisitions (dispositions) to measure its total capital investment compared to the Company's annual capital budgeted expenditures. The most directly comparable IFRS measures to net property acquisitions (dispositions) are property acquisitions and property dispositions.

| ($ thousands) | **Three months ended December 31, 2021** | Three months ended December 31, 2020 | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|---|---|
| Property acquisitions | **-** | 11,733 | **-** | 11,790 |
| Property dispositions | **(460)** | (34,952) | **(10,781)** | (69,940) |
| Transaction costs on property dispositions | **-** | - | **2,505** | - |
| Net property (dispositions) acquisitions | **(460)** | (23,219) | **(8,276)** | (58,150) |

**b) Net Capital Expenditures**

Net capital expenditures equals exploration and development expenditures less net property acquisitions (dispositions). Crew uses net capital expenditures to measure its total capital investment compared to the Company's annual capital budgeted expenditures. The most directly comparable IFRS measure to net capital expenditures is property, plant and equipment expenditures.

**c) EBITDA**

EBITDA is calculated as consolidated net income (loss) before interest and financing expenses, income taxes, depletion, depreciation and amortization, adjusted for certain non-cash, extraordinary and non-recurring items primarily relating to unrealized gains and losses on financial instruments and impairment losses. The Company considers this metric as key measures that demonstrate the ability of the Company's continuing operations to generate the cash flow necessary to maintain production at current levels and fund future growth through capital investment and to service and repay debt. The most directly comparable IFRS measure to EBITDA is cash provided by operating activities.

| ($ thousands) | **Three months ended December 31, 2021** | Three months ended December 31, 2020 | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|---|---|
| Cash provided by operating activities | **45,747** | 14,774 | **119,156** | 37,989 |
| Change in operating non-cash working capital | **(668)** | 19 | **8,844** | 2,170 |
| Accretion of deferred financing costs | **(246)** | (246) | **(983)** | (983) |
| Transaction costs on property dispositions | **-** | - | **2,505** | - |
| Funds from operations | **44,833** | 14,547 | **129,522** | 39,176 |
| Decommissioning obligations settled excluding government grants | **2,000** | 1,021 | **3,347** | 1,974 |
| Adjusted funds flow | **46,833** | 15,568 | **132,869** | 41,150 |
| Interest | **6,199** | 5,903 | **24,399** | 23,210 |
| EBITDA | **53,032** | 21,471 | **157,268** | 64,360 |

**d) Free Adjusted Funds Flow**

Free adjusted funds flow represents adjusted funds flow less capital expenditures, excluding acquisitions and dispositions. The Company considers this metric a key measure that demonstrates the ability of the Company's continuing operations to fund future growth through capital investment and to service and repay debt. The most directly comparable IFRS measure to free adjusted funds flow is cash provided by operating activities.

| ($ thousands) | Three months ended December 31, 2021 | Three months ended December 31, 2020 | Year ended December 31, 2021 | Year ended December 31, 2020 |
|---|---|---|---|---|
| Cash provided by operating activities | **45,747** | 14,774 | **119,156** | 37,989 |
| Change in operating non-cash working capital | **(668)** | 19 | **8,844** | 2,170 |
| Accretion of deferred financing costs | **(246)** | (246) | **(983)** | (983) |
| Transaction costs on property dispositions | **-** | - | **2,505** | - |
| Funds from operations | **44,833** | 14,547 | **129,522** | 39,176 |
| Decommissioning obligations settled excluding government grants | **2,000** | 1,021 | **3,347** | 1,974 |
| Adjusted funds flow | **46,833** | 15,568 | **132,869** | 41,150 |
| Less: capital expenditures | **42,341** | 41,007 | **177,924** | 86,260 |
| Free adjusted funds flow | **4,541** | (25,439) | **(45,055)** | (45,110) |

**e) Net Operating Costs**

Net operating costs equals operating costs net of processing revenue. Management views net operating costs as an important measure to evaluate its operational performance. The most directly comparable IFRS measure for net operating costs is operating costs.

| ($ thousands, except per boe) | Three months ended December 31, 2021 | Three months ended December 31, 2020 | Year ended December 31, 2021 | Year ended December 31, 2020 |
|---|---|---|---|---|
| Operating costs | **10,287** | 11,149 | **45,828** | 47,527 |
| Processing revenue | **(934)** | (576) | **(2,720)** | (2,416) |
| Net operating costs | **9,353** | 10,573 | **43,108** | 45,111 |
| Per boe | **3.49** | 5.30 | **4.47** | 5.61 |

**f) Net Operating Costs per boe**

Net operating costs per boe equals net operating costs divided by production. Management views net operating costs per boe as an important measure to evaluate its operational performance. The calculation of Crew's net operating costs per boe can be seen in the non-IFRS measure entitled "Net Operating Costs" above.

**g) Operating Netback per boe**

Operating netback per boe equals petroleum and natural gas sales including realized gains and losses on commodity related derivative financial instruments, marketing income, less royalties, net operating costs and transportation costs calculated on a boe basis. Management considers operating netback per boe an important measure to evaluate its operational performance as it demonstrates its field level profitability relative to current commodity prices.

**h) Cash costs per boe**

Cash costs per boe is comprised of net operating, transportation, general and administrative and financing costs on debt calculated on a boe basis. Management views cash costs per boe as an important measure to evaluate its operational performance.

**i) Financing costs on debt per boe**

Financing costs on debt per boe is comprised of the sum of interest on bank loan and other, interest on senior notes and accretion of deferred financing charges, divided by production. Management views financing costs on debt per boe as an important measure to evaluate its cost of debt financing.

***Supplementary Financial Measures***

**"Adjusted funds flow per basic share"** is comprised of adjusted funds flow divided by the basic weighted average common shares.

**"Adjusted funds flow per diluted share"** is comprised of adjusted funds flow divided by the diluted weighted average common shares.

**"Average realized commodity price"** is comprised of commodity sales from production, as determined in accordance with IFRS, divided by the Company's production. Average prices are before deduction of transportation costs and do not include gains and losses on financial instruments.

**"Average realized light crude oil price"** is comprised of light crude oil commodity sales from production, as determined in accordance with IFRS, divided by the Company's light crude oil production. Average prices are before deduction of transportation costs and do not include gains and losses on financial instruments.

**"Average realized heavy crude oil price"** is comprised of heavy crude oil commodity sales from production, as determined in accordance with IFRS, divided by the Company's heavy crude oil production. Average prices are before deduction of transportation costs and do not include gains and losses on financial instruments.

**"Average realized ngl price"** is comprised of ngl commodity sales from production, as determined in accordance with IFRS, divided by the Company's ngl production. Average prices are before deduction of transportation costs and do not include gains and losses on financial instruments.

**"Average realized condensate price"** is comprised of condensate commodity sales from production, as determined in accordance with IFRS, divided by the Company's condensate production. Average prices are before deduction of transportation costs and do not include gains and losses on financial instruments.

**"Average realized natural gas price"** is comprised of natural gas commodity sales from production, as determined in accordance with IFRS, divided by the Company's natural gas production. Average prices are before deduction of transportation costs and do not include gains and losses on financial instruments.

"**Net Debt to Last Twelve Months ("LTM") EBITDA Ratio**" is calculated as net debt at a point in time divided by EBITDA earned from that point back for the trailing twelve months.

**Supplemental Information Regarding Product Types**

References to gas or natural gas and NGLs in this report refer to conventional natural gas and natural gas liquids product types, respectively, as defined in National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities ("NI 51-101"), except where specifically noted otherwise.

The following is intended to provide the product type composition for each of the production figures provided herein, where not already disclosed within tables above:

| | Crude Oil | Natural Gas Liquids[2] | Condensate | Conventional Natural Gas | Total (boe/d) |
|---|---|---|---|---|---|
| **December 2021 Average** | 160 bbls/d | 2,698 bbls/d | 3,077 bbls/d | 26,831 bbls/d | 32,766 |
| **Q4 2021 Average** | 157 bbls/d | 2,454 bbls/d | 2,592 bbls/d | 143,379 mcf/d | 29,142 |
| **2021 Annual Average** | 960 bbls/d | 2,442 bbls/d | 2,663 bbls/d | 122,021 mcf/d | 26,443 |
| **January 2022 Average** | 0% | 8% | 11% | 81% | >32,500 |
| **Q1 2022 Average**[1] | 0% | 8% | 11% | 81% | 31,000-33,000 |
| **2022 Annual Average**[1] | 0% | 8% | 10% | 82% | 31,000-33,000 |

Notes:
1) With respect to forward looking production guidance, given the potential for variability in actual product type results, the issuer approximates percentages for budget planning purposes based on management's reasonable assumptions including, without limitation, historical well results.
2) Excludes condensate volumes which have been reported separately.

**Test Results and Initial Production Rates**

A pressure transient analysis or well-test interpretation has not been carried out and thus certain of the test results provided herein should be considered to be preliminary until such analysis or interpretation has been completed. Test results and initial production rates disclosed herein, particularly those short in duration, may not necessarily be indicative of long-term performance or of ultimate recovery.

Crew is a growth-oriented oil and natural gas producer, committed to pursuing sustainable per share growth through a balanced mix of financially and socially responsible exploration and development complemented by strategic acquisitions. The Company's operations are primarily focused in the vast Montney resource, situated in northeast British Columbia, and include a large contiguous land base. Greater Septimus along with Groundbirch and the light oil area at Tower in British Columbia offer significant development potential over the long-term. The Company has access to diversified markets with operated infrastructure and access to multiple pipeline egress options. Crew's common shares are listed for trading on the Toronto Stock Exchange ("TSX") under the symbol "CR".

# YEAR END 2021

Management's Discussion and Analysis

&

Consolidated Financial Statements

# MANAGEMENT'S DISCUSSION AND ANALYSIS

## ABOUT CREW

Crew Energy Inc. ("Crew" or the "Company") is a liquids-rich natural gas producer committed to pursuing sustainable per share growth through a balanced mix of financially responsible exploration and development, complemented by strategic acquisitions. The Company's operations are focused in northeast British Columbia ('NE BC") and include a large contiguous land base with a vast Montney formation resource. Crew's liquids-rich natural gas areas of Septimus and West Septimus ("Greater Septimus") and Groundbirch offer significant development potential over the long-term. The Company has access to diversified markets with operated infrastructure and access to multiple pipeline egress options. Crew adheres to safe and environmentally responsible operations while remaining committed to sound environmental, social and governance practices which underpin Crew's fundamental business tenets. Crew's common shares are listed for trading on the Toronto Stock Exchange ("TSX") under the symbol "CR".

## BASIS OF PRESENTATION

Management's discussion and analysis ("MD&A") is the explanation of the financial performance for the period covered by the consolidated financial statements along with an analysis of the financial position of the Company. Comments relate to and should be read in conjunction with the audited consolidated financial statements of the Company for the years ended December 31, 2021 and 2020. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). All figures provided herein and in the December 31, 2021 and 2020 audited consolidated financial statements are reported in Canadian dollars ("CDN"). The Company uses certain non-IFRS measures and ratios, as well as capital management measures in this MD&A. For a discussion of these measures and ratios, including the method of calculation, please refer to the section titled "Non-IFRS and Other Financial Measures" contained within this MD&A. This MD&A is dated March 8, 2022.

## FINANCIAL HIGHLIGHTS

| Financial<br>($ thousands, except per share amounts) | **Three months ended December 31, 2021** | Three months ended December 31, 2020 | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|---|---|
| **Petroleum and natural gas sales** | **103,153** | 42,604 | **332,848** | 137,931 |
| **Cash provided by operating activities** | **45,747** | 14,774 | **119,156** | 37,989 |
| **Adjusted funds flow** | **46,833** | 15,568 | **132,869** | 41,150 |
| Per share[1] -basic | **0.31** | 0.10 | **0.87** | 0.27 |
| -diluted | **0.29** | 0.10 | **0.82** | 0.27 |
| **Net income (loss)** | **50,901** | 34,668 | **205,299** | (203,180) |
| Per share -basic | **0.33** | 0.23 | **1.34** | (1.34) |
| -diluted | **0.31** | 0.22 | **1.27** | (1.34) |
| Property, plant and equipment expenditures | **42,341** | 41,007 | **177,924** | 86,260 |
| Net property (dispositions) acquisitions[2] | **(460)** | (23,219) | **(8,276)** | (58,150) |
| **Net capital expenditures[2]** | **41,881** | 17,788 | **169,648** | 28,110 |

| Capital structure<br>($ thousands) | **As at December 31, 2021** | As at December 31, 2020 |
|---|---|---|
| Working capital deficiency | **33,068** | 24,361 |
| Bank loan | **75,067** | 35,994 |
| | **108,135** | 60,355 |
| Senior unsecured notes | **297,834** | 296,851 |
| **Net debt** | **405,969** | 357,206 |
| | | |
| **Common shares outstanding** (thousands) | **152,480** | 151,182 |

Notes:
(1) Supplementary measure. See "Non-IFRS and Other Financial Measures" contained within this MD&A.
(2) Non-IFRS measure or ratio that does not have any standardized meaning as prescribed by International Financial Reporting Standards, and therefore, may not be comparable with the calculations of similar measures or ratios for other entities. See "Non-IFRS and Other Financial Measures" contained within this MD&A.

## OPERATING HIGHLIGHTS

| Operations | **Three months ended December 31, 2021** | Three months ended December 31, 2020 | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|---|---|
| **Daily production(1)** | | | | |
| Light crude oil (bbl/d) | **157** | 182 | **158** | 187 |
| Heavy crude oil (bbl/d) | **-** | 1,281 | **802** | 1,362 |
| Natural gas liquids (bbl/d) | **2,458** | 1,953 | **2,446** | 2,070 |
| Condensate (bbl/d) | **2,596** | 2,121 | **2,667** | 2,583 |
| Natural gas (mcf/d) | **143,584** | 96,771 | **122,217** | 94,519 |
| Oil equivalent (boe/d @ 6:1) | **29,142** | 21,666 | **26,443** | 21,955 |
| **Average realized(2)** | | | | |
| Light crude oil price ($/bbl) | **89.98** | 47.38 | **75.95** | 39.97 |
| Heavy crude oil price ($/bbl) | **-** | 38.79 | **59.41** | 28.86 |
| Natural gas liquids price ($/bbl) | **34.50** | 13.20 | **20.75** | 9.01 |
| Condensate price ($/bbl) | **93.90** | 47.68 | **79.86** | 42.99 |
| Natural gas price ($/mcf) | **5.42** | 2.87 | **4.82** | 2.12 |
| Commodity price ($/boe) | **38.47** | 21.37 | **34.49** | 17.17 |
| **Netback** ($/boe) | | | | |
| Operating netback(3) | **20.70** | 12.08 | **17.25** | 9.03 |
| General and administrative | **(0.91)** | (1.30) | **(0.95)** | (1.01) |
| Financing costs on debt(3) | **(2.31)** | (2.97) | **(2.53)** | (2.90) |
| Adjusted funds flow per boe(2) | **17.48** | 7.81 | **13.77** | 5.12 |
| **Drilling activity** | | | | |
| Gross wells | **2** | 5 | **26** | 15 |
| Working interest wells | **2** | 5 | **24.7** | 15 |
| **Completion activity** | | | | |
| Gross wells | **8** | 7 | **24** | 10 |
| Working interest wells | **8** | 7 | **22.7** | 10 |

Notes:

(1) Throughout this MD&A, light crude oil refers to light and medium crude oil product type as defined by National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Condensate is a natural gas liquid as defined by NI 51-101. Throughout this MD&A, references to other natural gas liquids or ngls comprise all natural gas liquids as defined by NI 51-101 other than condensate, which is disclosed separately. Throughout this MD&A, references to natural gas comprise all conventional natural gas as defined by NI 51-101.

(2) Supplementary measure. See "Non-IFRS and Other Financial Measures" contained within this MD&A.

(3) Non-IFRS measure or ratio that does not have any standardized meaning as prescribed by International Financial Reporting Standards, and therefore, may not be comparable with the calculations of similar measures or ratios for other entities. See "Non-IFRS and Other Financial Measures" contained within this MD&A.

## RESULTS OF OPERATIONS

### Annual Overview

Over the past year we have continued to endure the impact of the novel coronavirus ("COVID-19") on our every day lives and its impact on economies around the world. The rolling waves of COVID-19 strains have resulted in governments across the globe continuing to cycle through lockdowns, extend travel restrictions and implement other actions to limit the spread of the virus and to protect their citizens and healthcare systems. These actions have continued to impact global commercial activity and put a strain on supply chains.

Despite these challenges, commodity prices through 2021 continued to recover from their lows in the first half of 2020. Oil prices increased significantly over the prior year as demand for oil in 2021 recovered to pre-pandemic levels. Supply was restrained by the OPEC+ nation's disciplined production quotas and North American producers chose to limit production growth in exchange for the distribution of windfall profits to their stakeholders. North American natural gas also benefited from a return to pre-pandemic demand levels, combined with the growing globalization of natural gas pricing through the increased export of liquified natural gas ("LNG") out of the United States ('U.S."). A cold European 2020/2021 winter, tightened European natural gas storage levels and lower Russian imports increased Europe's reliance on LNG to refill those low storage levels, driving up the global price for LNG. The U.S. LNG market has grown dramatically over the last 10 years, increasing from zero to now drawing almost 13 bcf per day of production out of North American supply. This combined with the increase in global LNG prices elevated North American natural gas prices in 2021 to levels rarely seen over the past decade.

The significant improvement in oil and natural gas prices over the last 18 months have complemented Crew's two-year development plan established in late 2020. The plan was designed to expand the Company's netbacks and significantly improve leverage metrics through increased production volumes that match firm take or pay infrastructure and transportation commitments. In conjunction with this plan, Crew executed on a hedging program locking in value from stronger commodity prices for a portion of our 2020 through 2022 production.

Crew executed an expanded capital program in 2021 as part of its production growth plan. Spending on exploration and development activities totaled $178 million, focused on continued development of the Company's Montney assets in northeast British Columbia with the drilling of 26 (24.7 net) wells and the completion of 24 (22.7 net) wells. The program included the drilling of 22 wells in the Greater Septimus area, targeting liquids rich and ultra-condensate rich ("UCR") natural gas targets, three lease retention and play defining natural gas wells in the Groundbirch area and one lease retention well in the Attachie area. Completions were split with 21 (19.7 net) wells in the Greater Septimus area and three (3.0 net) wells at Groundbirch. The Company's 2021 program continued to realize cost and operational improvements with reduced drill times, contributing to strong capital efficiencies and enhanced returns.

In September of 2021, the Company disposed of its Lloydminster heavy crude oil operations making the Company a pure-play Montney natural gas focused producer. Crew received proceeds from the disposition of $10.7 million, that were offset by costs associated with the disposition that predominantly included a $2.5 million loss incurred on the wind-up of all outstanding Western Canadian Select ("WCS") crude oil hedges, that were being held to protect future cash flow from the disposed Lloydminster operations.

**Fourth Quarter Overview**

Crew's fourth quarter 2021 operations, built on the momentum generated from a busy summer program, growing production to average 29,142 boe per day, including record December production of 32,766 boe per day. Fourth quarter production exceeded the Company's guidance of 28,000 to 29,000 boe per day and was 23% greater than third quarter 2021 production, benefitting from higher than forecast production from the Company's three new wells on the 4-17 pad at Groundbirch, and the 1-8 pad at West Septimus. Exploration and Development expenditures totaled $42.3 million, which included the drilling of the final two (2.0 net) wells on the 10 (10.0 net) well 4-14 pad at Septimus and the completion of 8 (8.0 net) wells, including 5 (5.0 net) on the liquids rich 4-21 pad at West Septimus and 3 (3.0 net) wells on the UCR 4-14 pad at Septimus.

Commodity prices were strong in the fourth quarter, improving over the third quarter, a result of improved oil and gas fundamentals and the belief that we are moving towards the end of COVID-19 related lock downs and restrictions. Oil prices continued to strengthen during the quarter as global demand continued to grow while OPEC+ nations remained disciplined in returning spare capacity to the market and North American producers continued to return capital to shareholders over production growth. Fourth quarter natural gas prices were bolstered by the anticipation of an oncoming cold winter in North America and significant demand for natural gas from the growing U.S. Gulf Coast LNG complex to supply strong demand from Europe and Asia. Crew's fourth quarter average realized commodity price was $38.47 per boe, an 11% increase over the third quarter of 2021. Natural gas production made up 82% of the Company's total production in the fourth quarter, increasing from 76% in the previous quarter, the result of the sale of the Company's heavy oil assets in September and the addition of dry gas production from prolific new dry gas wells at Groundbirch. The Company's combined liquids pricing, including crude oil, condensate and natural gas liquids ("ngl"), increased 17% in the quarter, while Crew's natural gas price also increased by 17%.

Adjusted funds flow ("AFF") for the fourth quarter totaled $46.8 million, a 77% increase over the third quarter of 2021 and exceeding AFF for all of 2020 by 14%, the result of increased production and improved commodity prices. Crew's cash costs per boe[1] decreased by 25% in the fourth quarter. This decrease was in-line with the Company's two-year plan to decrease cash costs per boe[1] through increasing production to match committed transportation and processing capacity.

Note:
(1) Non-IFRS measure or ratio that does not have any standardized meaning as prescribed by International Financial Reporting Standards, and therefore, may not be comparable with the calculations of similar measures or ratios for other entities. See "Non-IFRS and Other Financial Measures" contained within this MD&A.

Crew's financial position remains strong at the end of 2021 with 50% drawn on the Company's $150 million revolving bank facility. The $300 million, 6.5%, unsecured notes remain outstanding with a maturity in March of 2024. The Company has also retained the option to sell an additional 11.43% interest in the Septimus gas processing facility and West Septimus gas processing facility ("Greater Septimus Processing Complex") for an additional $37.5 million in potential proceeds prior to June 2023.

**Responding to COVID-19**

Crew continues to respond and adapt our COVID-19 policies and procedures to the measures recommended by the various levels of Government in the areas in which we operate. Over the past year, the Company's business and operations have not been materially impacted by the COVID-19 pandemic. The impact of the pandemic on the Company's operations and future financial performance is currently unknown. The future impact on Crew will depend on developments that are uncertain and unpredictable, including the duration and spread of COVID-19, its continued impact on financial markets on a macro-scale and any new information that may emerge concerning the effectiveness of available vaccines and the severity and spread of the virus' variants. The pandemic presents uncertainty and risk with respect to the Company, its performance, and the estimates and assumptions used by management in the preparation of its financial results. Crew believes the measures it has taken will provide it with the financial capability to execute on its business plan, deliver safe and reliable operations and continue to build its sustainable business.

**Production**

| | **Three months ended December 31, 2021** | Three months ended September 30, 2021 |
|---|---|---|
| Crude oil (bbl/d) | **157** | 1,157 |
| Condensate (bbl/d) | **2,596** | 2,350 |
| Ngl (bbl/d) | **2,458** | 2,242 |
| Natural gas (mcf/d) | **143,584** | 107,459 |
| Total (boe/d) | **29,142** | 23,659 |

Production during the fourth quarter of 2021 increased 23% over the third quarter of 2021, as a result of the addition of new natural gas and liquids-rich natural gas wells brought on production in the fourth quarter of 2021 at Groundbirch and West Septimus combined with a reduction in shut-in production due to offsetting completion operations in the Greater Septimus field as compared to the previous quarter. This was partially offset by the reduction in crude oil production as a result of the heavy oil asset disposition in Lloydminster in the third quarter of 2021.

| | **Three months ended December 31, 2021** | | | | | Three months ended December 31, 2020 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **Crude oil (bbl/d)** | **Condensate (bbl/d)** | **Ngl (bbl/d)** | **Nat. gas (mcf/d)** | **Total (boe/d)** | Crude oil (bbl/d) | Condensate (bbl/d) | Ngl (bbl/d) | Nat. gas (mcf/d) | Total (boe/d) |
| NE BC | **157** | **2,596** | **2,458** | **143,584** | **29,142** | 182 | 2,121 | 1,953 | 96,651 | 20,365 |
| Lloydminster | **-** | **-** | **-** | **-** | **-** | 1,281 | - | - | 120 | 1,301 |
| Total | **157** | **2,596** | **2,458** | **143,584** | **29,142** | 1,463 | 2,121 | 1,953 | 96,771 | 21,666 |

Production during the fourth quarter of 2021 increased 35% over the same period in 2020, as a result of the successful execution of the Company's strategic two-year development plan that included the drilling and completion of wells in the Greater Septimus and Groundbirch areas adding new natural gas, condensate and ngl production over the past twelve months. This was partially offset by the sale of the Company's Lloydminster heavy oil assets in the third quarter of 2021.

| | **Year ended December 31, 2021** | | | | | Year ended December 31, 2020 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **Crude oil (bbl/d)** | **Condensate (bbl/d)** | **Ngl (bbl/d)** | **Nat. gas (mcf/d)** | **Total (boe/d)** | Crude oil (bbl/d) | Condensate (bbl/d) | Ngl (bbl/d) | Nat. gas (mcf/d) | Total (boe/d) |
| NE BC | **158** | **2,667** | **2,446** | **122,097** | **25,621** | 187 | 2,583 | 2,070 | 94,453 | 20,582 |
| Lloydminster | **802** | **-** | **-** | **120** | **822** | 1,362 | - | - | 66 | 1,373 |
| Total | **960** | **2,667** | **2,446** | **122,217** | **26,443** | 1,549 | 2,583 | 2,070 | 94,519 | 21,955 |

Production in 2021 increased 20% when compared to the same period in 2020 as a result of increased production in NE BC due to the success of the Company's strategic two-year development plan. Production increases stemmed from the addition of new liquids-rich natural gas wells brought on production during the year. Production increases were partially offset by the disposition of the Lloydminster heavy oil assets in the third quarter of 2021.

**Petroleum and Natural Gas Sales**

| | **Three months ended December 31, 2021** | Three months ended September 30, 2021 | Three months ended December 31, 2020 | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|---|---|---|
| **Petroleum and natural gas sales ($ thousands)** | | | | | |
| Light crude oil | **1,301** | 1,065 | 794 | **4,375** | 2,732 |
| Heavy crude oil | **-** | 6,086 | 4,571 | **17,388** | 14,384 |
| Natural gas liquids | **7,801** | 4,900 | 2,371 | **18,528** | 6,827 |
| Condensate | **22,427** | 17,611 | 9,305 | **77,738** | 40,646 |
| Natural gas | **71,624** | 45,966 | 25,563 | **214,819** | 73,342 |
| Total | **103,153** | 75,628 | 42,604 | **332,848** | 137,931 |
| **Average realized** | | | | | |
| Light crude oil price ($/bbl) | **89.98** | 78.29 | 47.38 | **75.95** | 39.97 |
| Heavy crude oil price ($/bbl) | **-** | 65.59 | 38.79 | **59.41** | 28.86 |
| Natural gas liquids price ($/bbl) | **34.50** | 23.76 | 13.20 | **20.75** | 9.01 |
| Condensate price ($/bbl) | **93.90** | 81.47 | 47.68 | **79.86** | 42.99 |
| Natural gas price ($/mcf) | **5.42** | 4.65 | 2.87 | **4.82** | 2.12 |
| Commodity price ($/boe) | **38.47** | 34.75 | 21.37 | **34.49** | 17.17 |
| **Benchmark pricing** | | | | | |
| Light crude oil – WTI (Cdn $/bbl) | **97.13** | 88.91 | 55.53 | **85.09** | 52.52 |
| Heavy crude oil – WCS (Cdn $/bbl) | **79.08** | 71.80 | 43.52 | **68.84** | 35.63 |
| Condensate – Condensate @ Edmonton (Cdn $/bbl) | **99.61** | 87.24 | 55.28 | **85.45** | 49.43 |
| Natural Gas: | | | | | |
| AECO 5A daily index (Cdn $/mcf) | **4.66** | 3.60 | 2.64 | **3.62** | 2.23 |
| AECO 7A monthly index (Cdn $/mcf) | **4.94** | 3.54 | 2.77 | **3.56** | 2.24 |
| Alliance 5A (Cdn $/mcf) | **5.00** | 4.23 | 2.76 | **4.25** | 2.24 |
| Chicago City Gate at ATP (Cdn $/mcf) | **5.03** | 4.43 | 2.29 | **4.93** | 1.78 |
| Henry Hub Close (Cdn $/mcf) | **7.34** | 5.06 | 3.47 | **4.82** | 2.77 |
| Station 2 (Cdn $/mcf) | **3.70** | 3.39 | 2.54 | **3.29** | 2.19 |
| **Natural gas sales portfolio** | | | | | |
| AECO 5A | **61%** | 32% | 22% | **42%** | 7% |
| Alliance 5A | **15%** | 23% | 21% | **20%** | 21% |
| Chicago Interstates at ATP | **10%** | 38% | 44% | **29%** | 51% |
| Henry Hub | **-** | - | 6% | **-** | 14% |
| Station 2 | **14%** | 7% | 7% | **9%** | 7% |

*Fourth quarter 2021 compared to third quarter 2021:*

In the fourth quarter of 2021, the Company's petroleum and natural gas sales increased 36% as compared to the third quarter of 2021, as a result of a 23% increase in production combined with an increase in the average realized commodity price during the quarter.

The Company's fourth quarter realized light crude oil price increased 15% over the third quarter of 2021, which is consistent with the Company's WTI benchmark increase of 9% compared to the previous quarter.

Crew's average realized ngl price increased 45% in the fourth quarter as compared to the third quarter of 2021, due to the Company shifting to trucking a larger portion of its ngl volumes to local Canadian markets starting November 1, 2021. This compared to the previous practice of transporting the ngl volumes in the gas stream via the Alliance Pipeline. The Company's fourth quarter average realized condensate price increased 15% over the third quarter of 2021, which was consistent with the 14% increase in the Condensate at Edmonton benchmark price.

Crew's average realized natural gas price increased by 17% in the fourth quarter of 2021, which is consistent with the 14% increase in the Company's natural gas sales portfolio weighted benchmark price.

*Fourth quarter 2021 compared to fourth quarter 2020:*

The fourth quarter 2021 petroleum and natural gas sales increased 142% as compared to the same period in 2020, as a result of an 80% increase in average realized commodity price, supported by the global commodity price recovery combined with an increase in production.

The Company's fourth quarter average realized light crude oil price increased 90% over the fourth quarter of 2020, which was higher than the Company's WTI benchmark increase of 75%, largely due to a narrowing of the sweet differential between realized Canadian crude oil prices and the Company's WTI benchmark.

Crew's average realized ngl price increased 161% in the fourth quarter as compared to the same period in 2020, due to an increase in the value of component pricing, in particular large increases in realized propane and butane pricing across North America, and the Company shifting to trucking a larger portion of its ngl volumes to local Canadian markets starting November 1, 2021. This compared to the previous practice of transporting the ngl volumes in the gas stream via the Alliance Pipeline. The Company's fourth quarter average realized condensate price increased 97% over the same period in 2020, which was higher than the 80% increase in the Condensate at Edmonton benchmark price, largely stemming from proportionately lower pipeline costs embedded in the 2021 price and lower product differential impacts, relative to the benchmark price.

Crew's average realized natural gas price increased by 89% in the fourth quarter of 2021, which is higher than the 83% increase in the Company's natural gas sales portfolio weighted benchmark price. The greater corporate increase was the result of the expiry of a Chicago fixed price physical delivery contract that negatively impacted the Company's realized natural gas price for most of 2020.

*Year ended 2021 compared to year ended 2020:*

For 2021, the Company's petroleum and natural gas sales increased 141% as compared to the prior year as a result of a 101% increase in the average realized commodity price combined with an increase in production.

The Company's average realized light crude oil price increased 90%, which was higher compared to the 62% increase in the WTI benchmark, largely a result from a narrowing of the differential between Canadian crude oil prices and the Company's WTI benchmark price. Crew's average realized heavy crude oil price for 2021 increased 106% as compared to the same period last year, which was higher than the 93% increase in the Company's WCS benchmark, due to a decrease in blending costs and lower pricing differentials against the benchmark.

For 2021, the Company's average realized ngl price increased 130% over the same period in 2020, due to increases in product pricing for butane and pentane across North America. The Company's average realized condensate price increased 86%, which was higher than the 73% increase in the Condensate at Edmonton benchmark price as compared to the prior year, primarily a result of proportionately lower pipeline costs embedded in the 2021 price and decreases in the product differentials relative to the product benchmark price.

The Company's average realized natural gas price increased 127% over 2020, which is higher than the Company's natural gas sales portfolio weighted benchmark price increase of 105%. The greater corporate increase was the result of the expiry of a Chicago fixed price physical delivery contract that negatively impacted the Company's realized natural gas price for most of 2020.

**Royalties**

| ($ thousands, except per boe) | **Three months ended December 31, 2021** | Three months ended September 30, 2021 | Three months ended December 31, 2020 | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|---|---|---|
| Royalties | **7,250** | 5,961 | 1,969 | **23,068** | 6,469 |
| Per boe | **2.70** | 2.74 | 0.99 | **2.39** | 0.81 |
| Percentage of petroleum and natural gas sales | **7.0%** | 7.9% | 4.6% | **6.9%** | 4.7% |

For the fourth quarter of 2021 and year ended December 31, 2021, royalties per boe and as a percentage of petroleum and natural gas sales increased over the same periods in 2020 due to increases in production and commodity pricing leading to higher royalty rates. Royalty rates fluctuate on a sliding scale with increases and decreases in the underlying commodity price. The rate increases were partially offset by lower royalty rates on new wells drilled and completed in NE BC, that attract lower royalty rates.

**Derivative Financial Instruments**

Commodities

The Company enters into derivative and physical risk management contracts in order to reduce volatility in financial results and to ensure a certain level of cash flow to fund planned capital projects. Crew's strategy focuses on the use of puts, costless collars, swaps and fixed price contracts to limit exposure to fluctuations in commodity prices, interest rates and foreign exchange rates, while allowing for participation in spot commodity prices. The Company's financial derivative trading activities are conducted pursuant to the Company's Risk Management Policy, approved by the Board of Directors.

These contracts had the following impact on the consolidated statements of income (loss) and comprehensive income (loss):

| ($ thousands) | **Three months ended December 31, 2021** | Three months ended September 30, 2021 | Three months ended December 31, 2020 | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|---|---|---|
| Realized (loss) gain on derivative financial instruments | **(21,620)** | (13,545) | 2,536 | **(60,916)** | 16,588 |
| Per boe | **(8.06)** | (6.22) | 1.27 | **(6.31)** | 2.06 |
| Unrealized gain (loss) on financial instruments | **43,388** | (21,817) | 11,649 | **(24,098)** | 4,503 |

As at December 31, 2021, the Company held derivative commodity contracts as follows:

| Notional Quantity | Term | Strike Price | Option Traded | Fair Value |
|---|---|---|---|---|
| *Natural Gas – AECO Daily Index:* | | | | |
| 35,000 gj/day | January 1, 2022 - March 31, 2022 | $2.91/gj | Swap | $ (2,658) |
| 15,000 gj/day | January 1, 2022 - December 31, 2022 | $2.42/gj | Swap | (4,171) |
| 27,000 gj/day | April 1, 2022 - June 30, 2022 | $2.54/gj | Swap | (967) |
| 20,000 gj/day | April 1, 2022 - October 31, 2022 | $3.04/gj | Swap | 577 |
| 2,500 gj/day | April 1, 2022 – December 31, 2022 | $3.43/gj | Swap | 293 |
| 27,500 gj/day | July 1, 2022 - September 30, 2022 | $2.53/gj | Swap | (819) |
| 27,500 gj/day | October 1, 2022 - December 31, 2022 | $2.81/gj | Swap | (1,012) |
| 5,000 gj/day | November 1, 2022 - March 31, 2023 | $3.76/gj | Swap | 278 |
| 2,500 gj/day | January 1, 2023 - March 31, 2023 | $3.75/gj | Swap | 78 |
| 2,500 gj/day | April 1, 2023 - June 30, 2023 | $2.70/gj | Swap | 13 |
| 2,500 gj/day | July 1, 2023 - September 30, 2023 | $2.70/gj | Swap | 9 |
| 2,500 gj/day | October 1, 2023 - December 31, 2023 | $3.05/gj | Swap | 7 |

| Notional Quantity | Term | Strike Price | Option Traded | Fair Value |
|---|---|---|---|---|
| *(continued)* | | | | |
| *Natural Gas – AECO Monthly Index:* | | | | |
| 7,500 gj/day | January 1, 2022 - March 31, 2022 | $2.68 - $3.03/gj | Collar[(1)] | (497) |
| 15,000 gj/day | January 1, 2022 - March 31, 2022 | $3.01/gj | Swap | (989) |
| 7,500 gj/day | January 1, 2022 - December 31, 2022 | $2.36/gj | Swap | (2,265) |
| 10,000 gj/day | April 1, 2022 - June 30, 2022 | $2.20/gj | Swap | (666) |
| 10,000 gj/day | July 1, 2022 - September 30, 2022 | $2.22/gj | Swap | (565) |
| 10,000 gj/day | October 1, 2022 - December 31, 2022 | $2.48/gj | Swap | (691) |
| *CDN$ Edmonton C5 Blended Index:* | | | | |
| 1,000 bbl/day | January 1, 2022 - June 30, 2022 | $81.44/bbl | Swap | (2,370) |
| **Total** | | | | **$ (16,415)** |

Note:
(1) The referenced contract is a costless collar whereby the Company receives $2.68/gj when the market price is below $2.68/gj, and receives $3.03/gj when the market price is above $3.03/gj.

Subsequent to December 31, 2021, the Company entered into the following derivative commodity contracts:

| Notional Quantity | Term | Strike Price | Option Traded |
|---|---|---|---|
| *Natural Gas – AECO Daily Index:* | | | |
| 2,500 gj/day | April 1, 2022 - June 30, 2022 | $3.57/gj | Swap |
| 7,500 gj/day | April 1, 2022 - December 31, 2022 | $3.53/gj | Swap |
| 2,500 gj/day | October 1, 2022 - December 31, 2022 | $3.90/gj | Swap |
| 5,000 gj/day | November 1, 2022 - March 31, 2023 | $3.61/gj | Swap |
| 5,000 gj/day | January 1, 2023 - March 31, 2023 | $4.13/gj | Swap |
| 5,000 gj/day | April 1, 2023 - June 30, 2023 | $2.83/gj | Swap |
| 5,000 gj/day | July 1, 2023 - September 30, 2023 | $2.84/gj | Swap |
| 5,000 gj/day | October 1, 2023 - December 31, 2023 | $3.21/gj | Swap |
| *Natural Gas – AECO Monthly Index:* | | | |
| 5,000 gj/day | January 1, 2023 - December 31, 2023 | $3.13 - $4.35/gj | Collar[(1)] |
| *CDN$ Edmonton C5 Blended Index:* | | | |
| 250 bbl/day | April 1, 2022 - June 30, 2022 | $100.00/bbl | Swap |
| 1,000 bbl/day | July 1, 2022 - December 31, 2022 | $97.06/bbl | Swap |

Note:
(1) The referenced contract is a costless collar whereby the Company receives $3.13/gj when the market price is below $3.13/gj, and receives $4.35/gj when the market price is above $4.35/gj.

## Net Operating Costs[(1)]

| ($ thousands, except per boe) | **Three months ended December 31, 2021** | Three months ended September 30, 2021 | Three months ended December 31, 2020 | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|---|---|---|
| Operating costs | **10,287** | 11,866 | 11,149 | **45,828** | 47,527 |
| Processing revenue | **(934)** | (750) | (576) | **(2,720)** | (2,416) |
| Net operating costs[(1)] | **9,353** | 11,116 | 10,573 | **43,108** | 45,111 |
| Per boe[(1)] | **3.49** | 5.11 | 5.30 | **4.47** | 5.61 |

Note:
(1) Non-IFRS measure or ratio that does not have any standardized meaning as prescribed by International Financial Reporting Standards, and therefore, may not be comparable with the calculations of similar measures or ratios for other entities. See "Non-IFRS and Other Financial Measures" contained within this MD&A.

During the fourth quarter of 2021 and year ended December 31, 2021, net operating costs and net operating costs per boe decreased as compared to the previous quarter and same periods in 2020, as a result of new added production in West Septimus and Groundbirch, which yield lower incremental per unit operating costs, in combination with efforts by the Company to optimize field operations resulting in reduced costs across all operating areas. This was coupled with the disposition of the heavy oil assets in the third quarter of 2021, where net operating costs per boe are higher than the corporate average.

**Transportation Costs**

| ($ thousands, except per boe) | **Three months ended December 31, 2021** | Three months ended September 30, 2021 | Three months ended December 31, 2020 | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|---|---|---|
| Transportation costs | **9,447** | 10,035 | 8,435 | **39,305** | 29,504 |
| Per boe | **3.52** | 4.61 | 4.23 | **4.07** | 3.67 |

For the fourth quarter of 2021, transportation costs and transportation costs per boe decreased when compared to the previous quarter, as a result of the November 1st reduction in the Company's Alliance firm transport service from 65 mmcf per day to 20 mmcf per day. The fourth quarter transportation costs per boe were also reduced by higher natural gas production during the fourth quarter better aligning with the Company's firm transport obligations and reducing the amount of unused demand charges ("UDCs") incurred. The reductions were partially offset by higher trucking charges for the Company's increased sale of ngl volumes into Canadian markets.

During the fourth quarter 2021 and year ended December 31, 2021, transportation costs and transportation costs per boe increased, as compared to the same periods in 2020 as a result of the natural gas pipeline transportation rate increases that commenced in November 2020 and 2021, the Company's ability to mitigate UDCs as compared to the same periods in 2020 and added ngl trucking charges related to the Company's increased sale of ngl volumes into Canadian markets.

**Operating Netbacks(1)**

| *($/boe)* | **Greater Septimus** | **Other NE BC** | **Three months ended December 31, 2021** | Three months ended September 30, 2021 | Three months ended December 31, 2020 |
|---|---|---|---|---|---|
| Petroleum and natural gas sales | **38.98** | **32.63** | **38.47** | 34.75 | 21.37 |
| Royalties | **(2.39)** | **(6.31)** | **(2.70)** | (2.74) | (0.99) |
| Realized (loss) gain on derivative financial instruments | **(8.13)** | **(7.27)** | **(8.06)** | (6.22) | 1.27 |
| Marketing loss | **-** | **-** | **-** | - | (0.04) |
| Net operating costs(1) | **(3.14)** | **(7.46)** | **(3.49)** | (5.11) | (5.30) |
| Transportation costs | **(3.34)** | **(5.59)** | **(3.52)** | (4.61) | (4.23) |
| Operating netbacks(1) | **21.98** | **6.00** | **20.70** | 16.07 | 12.08 |
| Production (boe/d) | **26,802** | **2,340** | **29,142** | 23,659 | 21,666 |

Note:
(1) Non-IFRS measure or ratio that does not have any standardized meaning as prescribed by International Financial Reporting Standards, and therefore, may not be comparable with the calculations of similar measures or ratios for other entities. See "Non-IFRS and Other Financial Measures" contained within this MD&A.

Operating netbacks for the fourth quarter of 2021 increased by 29% when compared to the third quarter of 2021, primarily as a result of higher petroleum and natural gas sales, lower transportation costs, and lower net operating costs, partially offset by higher realized commodity hedging losses.

Operating netbacks for the fourth quarter of 2021 increased 71% when compared to same period in 2020 as a result of higher petroleum and natural gas sales and lower transportation and operating costs, partially offset by an increase in royalties and realized commodity hedging losses.

| ($/boe) | Greater Septimus | Lloydminster Heavy Crude Oil | Other NE BC | Year ended December 31, 2021 | Year ended December 31, 2020 |
|---|---|---|---|---|---|
| Petroleum and natural gas sales | **34.30** | **58.41** | **27.84** | **34.49** | 17.17 |
| Royalties | **(2.05)** | **(9.17)** | **(3.44)** | **(2.39)** | (0.81) |
| Realized (loss) gain on derivative financial instruments | **(6.18)** | **(12.47)** | **(5.49)** | **(6.31)** | 2.06 |
| Marketing loss | **-** | **-** | **-** | **-** | (0.11) |
| Net operating costs(1) | **(3.75)** | **(20.07)** | **(6.14)** | **(4.47)** | (5.61) |
| Transportation costs | **(4.05)** | **(0.32)** | **(5.61)** | **(4.07)** | (3.67) |
| Operating netbacks(1) | **18.27** | **16.38** | **7.16** | **17.25** | 9.03 |
| Production (boe/d) | **23,309** | **822** | **2,312** | **26,443** | 21,955 |

Note:
(1) Non-IFRS measure or ratio that does not have any standardized meaning as prescribed by International Financial Reporting Standards, and therefore, may not be comparable with the calculations of similar measures or ratios for other entities. See "Non-IFRS and Other Financial Measures" contained within this MD&A.

For the year ended December 31, 2021, operating netbacks increased 91% as compared to the same period in 2020 due to significant increases in petroleum and natural gas sales combined with lower net operating costs. These increases were partially offset by higher transportation costs, increased product royalties, and increased realized hedging losses.

## General and Administrative Costs

| ($ thousands, except per boe) | Three months ended December 31, 2021 | Three months ended September 30, 2021 | Three months ended December 31, 2020 | Year ended December 31, 2021 | Year ended December 31, 2020 |
|---|---|---|---|---|---|
| Gross costs | **4,275** | 4,015 | 3,762 | **15,744** | 12,424 |
| Operator's recoveries | **(382)** | (265) | (16) | **(986)** | (332) |
| Capitalized costs | **(1,442)** | (1,473) | (1,154) | **(5,575)** | (4,009) |
| General and administrative expenses | **2,451** | 2,277 | 2,592 | **9,183** | 8,083 |
| Per boe | **0.91** | 1.05 | 1.30 | **0.95** | 1.01 |

Gross general and administrative ("G&A") costs increased in the fourth quarter of 2021 and year ended December 31, 2021 as compared to the previous quarter and same periods in 2020, due to the reversal of compensation rollbacks that were in place through most of 2020 and a reduction in receipts of the government provided COVID-19 related Canada Emergency Wage Subsidy in 2020 as compared to 2021. G&A per boe decreased in the fourth quarter and year ended December 31, 2021 as compared to the same periods in 2020 as a result of an increase in production, partially offset by the increase in G&A costs.

## Share-Based Compensation

| ($ thousands) | Three months ended December 31, 2021 | Three months ended September 30, 2021 | Three months ended December 31, 2020 | Year ended December 31, 2021 | Year ended December 31, 2020 |
|---|---|---|---|---|---|
| Gross costs | **1,088** | 1,162 | 533 | **4,855** | 4,458 |
| Capitalized costs | **(540)** | (574) | (258) | **(2,373)** | (2,186) |
| Total share-based compensation | **548** | 588 | 275 | **2,482** | 2,272 |

In the fourth quarter of 2021 and year ended December 31, 2021, the Company's total share-based compensation expense increased as compared to the same periods in 2020, as a result of a higher annual grant value in 2021 as compared to 2020, partially offset by a decrease in share-based compensation expense from a reduction in staff.

**Depletion and Depreciation**

| ($ thousands, except per boe) | **Three months ended December 31, 2021** | Three months ended September 30, 2021 | Three months ended December 31, 2020 | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|---|---|---|
| Depletion and depreciation | **22,223** | 15,993 | 16,072 | **73,207** | 71,054 |
| Per boe | **8.29** | 7.35 | 8.06 | **7.58** | 8.84 |

In the fourth quarter of 2021, depletion and depreciation costs per boe increased when compared to the previous quarter and same period in 2020, due to an increase in the capital cost base as a result of the impairment reversal recorded in the third quarter of 2021. For the year ended December 31, 2021, depletion and depreciation costs per boe decreased as compared to the same period in 2020, due to a decrease in future development costs associated with reserves bookings at the end of 2020, a decrease to the per boe depletion rate for Tower production due to higher Tower reserve bookings at December 31, 2020 and lower land expiries. This decrease was partially offset by the aforementioned increase in the capital cost base in the fourth quarter of 2021.

**Impairment Reversal**

At December 31, 2021, the Company did not identify any indicators of impairment, and therefore an impairment test was not performed.

The Company identified an indicator of impairment reversal at September 30, 2021 for the northeast British Columbia cash-generating unit ("CGU) and performed an impairment reversal test to estimate its recoverable amount. It was determined that the $1,664.1 million recoverable amount of the northeast British Columbia CGU exceeded its carrying value, resulting in all previous impairment, net of depletion, of $228.5 million being reversed. The indicator of impairment reversal existed as a result of increases in forecasted oil and gas commodity prices, along with an increase in the Company's market capitalization. The Company disposed of its Lloydminster CGU in the third quarter of 2021.

**Finance Expenses**

| ($ thousands, except per boe) | **Three months ended December 31, 2021** | Three months ended September 30, 2021 | Three months ended December 31, 2020 | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|---|---|---|
| Interest on bank loan and other | **1,038** | 1,023 | 742 | **3,916** | 2,727 |
| Interest on senior notes | **4,915** | 4,915 | 4,915 | **19,500** | 19,500 |
| Interest on lease obligations | **26** | 27 | 25 | **105** | 102 |
| Accretion of deferred financing charges | **246** | 245 | 246 | **983** | 983 |
| Accretion of the decommissioning obligation | **264** | 410 | 230 | **1,376** | 1,221 |
| Total finance expense | **6,489** | 6,620 | 6,158 | **25,880** | 24,533 |
| Average long-term debt level(1) | **373,055** | 361,866 | 329,597 | **358,727** | 335,073 |
| Average drawings on bank loan(1) | **73,055** | 61,866 | 29,597 | **58,727** | 35,073 |
| Average senior unsecured notes outstanding(1) | **300,000** | 300,000 | 300,000 | **300,000** | 300,000 |
| Effective interest rate on senior unsecured notes | **6.5%** | 6.5% | 6.5% | **6.5%** | 6.5% |
| Effective interest rate on long-term debt | **6.0%** | 6.1% | 6.3% | **6.1%** | 6.2% |
| Financing costs on debt per boe(2) | **2.31** | 2.84 | 2.97 | **2.53** | 2.90 |

Notes:
(1) Supplementary measure. See "Non-IFRS and Other Financial Measures" contained within this MD&A.
(2) Non-IFRS measure or ratio that does not have any standardized meaning as prescribed by International Financial Reporting Standards, and therefore, may not be comparable with the calculations of similar measures or ratios for other entities. See "Non-IFRS and Other Financial Measures" contained within this MD&A.

The Company's total finance expense and average long-term debt levels increased in the fourth quarter and year ended 2021 as compared to the same periods in 2020, due to increased capital expenditures in 2021 and an increase in borrowing margins. In addition, the Company's corporate effective interest rate decreased as compared to the same periods in 2020 due to a decrease in standby fees as the Company's drawings on its bank facility increased.

**Loss on Divestitures of Property, Plants and Equipment**

During the third quarter of 2021, the Company disposed of its Lloydminster heavy crude oil operations for cash proceeds of $10.7 million and incurred $2.5 million of related transaction costs. The disposition consisted of petroleum and natural gas properties and undeveloped land with a net book value of $45.8 million and associated decommissioning obligations of $34.5 million, resulting in a loss of $3.1 million on closing of the disposition.

During the third quarter of 2021, the Company entered into a swap of petroleum and natural gas properties and undeveloped land with a total net book value of $3.6 million for undeveloped land with a fair value of $1.4 million, resulting in a loss of $2.2 million.

During the year ended 2021, the Company also disposed of various non-core petroleum and natural gas properties with a net book value of $2.7 million and associated decommissioning obligations of $1.7 million, resulting in a loss of $1.0 million.

**Deferred Income Taxes**

In the fourth quarter of 2021 and year ended December 31, 2021, the provision for deferred income taxes was an expense of $16.9 million and $50.0 million, respectively, as compared to a nil provision for deferred income taxes in the fourth quarter of 2020 and a deferred tax recovery of $53.6 million in the year ended December 31, 2020. The deferred tax expense in the fourth quarter and year ended December 31, 2021 was due to net income in these periods, resulting from the increase in petroleum and natural gas sales and for the year ended December 31, 2021, the reversal of impairment charges previously booked against the Company's property, plant and equipment.

A summary of the Company's estimated income tax pools is outlined below:

| ($ thousands) | **December 31, 2021** | December 31, 2020 |
|---|---|---|
| Cumulative Canadian Exploration Expense | **267,200** | 259,200 |
| Cumulative Canadian Development Expense | **275,000** | 412,200 |
| Undepreciated Capital Cost | **192,500** | 176,500 |
| Non-capital losses | **414,500** | 253,200 |
| Share issue costs | **-** | 1,400 |
| Other | **17,700** | 3,400 |
| | **1,166,900** | 1,105,900 |

**Cash Provided by Operating Activities, Adjusted Funds Flow and Net Income (Loss)**

| ($ thousands, except per share amounts) | **Three months ended December 31, 2021** | Three months ended September 30, 2021 | Three months ended December 31, 2020 | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|---|---|---|
| Cash provided by operating activities | **45,747** | 18,072 | 14,774 | **119,156** | 37,989 |
| Adjusted funds flow | **46,833** | 26,511 | 15,568 | **132,869** | 41,150 |
| Per share[(1)] -basic | **0.31** | 0.17 | 0.10 | **0.87** | 0.27 |
| -diluted | **0.29** | 0.17 | 0.10 | **0.82** | 0.27 |
| Net income (loss) | **50,901** | 176,183 | 34,668 | **205,299** | (203,180) |
| Per share -basic | **0.33** | 1.14 | 0.23 | **1.34** | (1.34) |
| -diluted | **0.31** | 1.12 | 0.22 | **1.27** | (1.34) |

Note:
(1) Supplementary measure. See "Non-IFRS and Other Financial Measures" contained within this MD&A.

Cash provided by operating activities and adjusted funds flow increased in both the fourth quarter and year ended December 31, 2021 as compared to the previous quarter and the same periods in 2020, predominantly due to higher petroleum and natural gas sales. Net income in the year ended December 31, 2021 was impacted by the $228.5 million impairment reversal recorded in the third quarter of 2021, whereas net income in the same period in 2020 was impacted by a $267.3 million impairment charge.

**Capital Expenditures, Property Acquisitions and Dispositions**

| ($ thousands) | **Three months ended December 31, 2021** | Three months ended September 30, 2021 | Three months ended December 31, 2020 | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|---|---|---|
| Land | **503** | 787 | 994 | **2,674** | 3,235 |
| Seismic | **96** | 103 | 210 | **492** | 1,007 |
| Drilling and completions | **34,112** | 45,907 | 31,523 | **132,729** | 58,375 |
| Facilities, equipment and pipelines | **6,169** | 15,901 | 7,126 | **36,156** | 19,575 |
| Other | **1,461** | 1,597 | 1,154 | **5,873** | 4,068 |
| Total property, plant and equipment expenditures | **42,341** | 64,295 | 41,007 | **177,924** | 86,260 |
| Net property dispositions(1) | **(460)** | (7,816) | (23,219) | **(8,276)** | (58,150) |
| Net capital expenditures(1) | **41,881** | 56,479 | 17,788 | **169,648** | 28,110 |

Note:
(1) Non-IFRS measure or ratio that does not have any standardized meaning as prescribed by International Financial Reporting Standards, and therefore, may not be comparable with the calculations of similar measures or ratios for other entities. See "Non-IFRS and Other Financial measures" contained within this MD&A.

In the fourth quarter of 2021, the Company spent a total of $42.3 million on exploration and development expenditures. The majority of this amount was spent on the continued development of the Montney assets. During the quarter, $34.1 million was spent on drilling and completion activities, $6.2 million on facilities, equipment and pipelines and $2.0 million on land, seismic and other miscellaneous amounts. The Company completed eight (8.0 net) natural gas wells in NE BC.

In 2021, the Company drilled a total of 26 (24.7 net) natural gas wells and completed 24 (22.7 net) wells. The Company's spending focus in 2021 was on drilling and completions activity in the West Septimus area and Groundbirch area. During the year, the Company disposed of its Lloydminster heavy crude oil operations for cash proceeds of $10.7 million and incurred $2.5 million of related transaction costs, resulting in net proceeds of $8.2 million.

## GUIDANCE

As global markets recover from the impact of the COVID-19 pandemic and demand for energy increases, Crew anticipates that Canadian natural gas will play an increasingly important global energy role as governments seek to diversify energy sources to achieve meaningful emissions reductions. With this reaffirmation, the Company is excited to continue executing on its 2022 plan and strategy to expand on the production of responsible energy, while leveraging a positive operating environment in which it can strive to create value and generate profitable and sustainable growth.

The following table sets forth Crew's guidance and underlying material assumptions for 2021 and 2022 and a review of the 2021 actual results to guidance:

| | 2021 guidance and assumptions[(1)] | 2021 actuals | 2022 guidance and assumptions[(1)] |
|---|---|---|---|
| Net capital expenditures ($Millions)[(2)] | 150–170 | 170 | 80–95 |
| Annual average production (boe/d) | 26,000–28,000 | 26,443 | 31,000–33,000 |
| Adjusted funds flow ($Millions) | 120–140 | 133 | 190–210 |
| Free adjusted funds flow[(2)] ($Millions) | - | - | 95–130 |
| EBITDA[(2)] ($Millions) | 145–165 | 157 | 214–234 |
| Oil price (WTI)($US per bbl) | $66.00 | $67.91 | $65.00 |
| Natural gas price (AECO 5A) ($C per mcf) | $3.40 | $3.62 | $3.50 |
| Natural gas price (NYMEX) ($US per mmbtu) | $3.35 | $3.83 | $4.00 |
| Natural gas price (Crew est. wellhead) ($C per mcf) | $4.60 | $4.82 | $4.00 |
| Foreign exchange ($US/$CAD) | $0.80 | $0.80 | $0.78 |
| Royalties | 5–7% | 6.9% | 5–7% |
| Net operating costs[(2)] ($ per boe) | $4.75–$5.25 | $4.47 | $3.50–$4.00 |
| Transportation ($ per boe) | $3.50–$4.00 | $4.07 | $2.75–$3.25 |
| G&A ($ per boe) | $0.90–$1.10 | $0.95 | $0.80–$1.00 |
| Effective interest rate on long-term debt | 6.0–6.5% | 6.1% | 6.0–6.5% |

Notes:
(1) The actual results of operations of Crew and the resulting financial results will likely vary from the estimates and material underlying assumptions set forth in this guidance by the Company and such variation may be material. The guidance and material underlying assumptions have been prepared on a reasonable basis, reflecting management's best estimates and judgments.
(2) Non-IFRS measure or ratio that does not have any standardized meaning as prescribed by International Financial Reporting Standards, and therefore, may not be comparable with the calculations of similar measures or ratios for other entities. See "Non-IFRS Measures" contained within this MD&A.

Crew's 2021 actuals for capital expenditures, annual average production, adjusted funds flow, EBITDA, royalties, G&A and the interest rate on long-term debt were within the guidance range. The Company's net operating costs came in below the guidance range as a result of the continued efforts to rationalize field operations to reduce net operating costs and the third quarter sale of the Company's Lloydminster heavy oil assets, which carried a higher per unit cost of operation, the impact of which was not reflected in the guidance. Transportation costs came in slightly above guidance as a result of incremental costs incurred in the fourth quarter to truck ngl volumes and increased natural gas pipeline rates that were announced and enacted in November 2021.

The 2022 guidance and underlying material assumptions are consistent with prior guidance except for net capital expenditures with an increased floor of $80 million, up from $70 million due to inflationary pressures experienced early in 2022 and an increase in the royalty rate range to 5% to 7%, from 4% to 6% due to increasing commodity prices that are driving up the sliding scale royalty rates. Additionally, guidance for transportation costs per unit has increased to $2.75 to $3.25 from $2.50 to $3.00 due to increased natural gas pipeline rates that were confirmed late in 2021 and added trucking costs related to the sale of ngl volumes into Canadian markets.

## LIQUIDITY AND CAPITAL RESOURCES

### Capital Management

The Company considers its capital structure to include working capital, long-term debt (including the bank loan and senior unsecured notes) and shareholders' equity. Crew's primary capital management objective is to maintain a strong financial position in order to continue to fund the Company's sustainability. Crew monitors its capital structure and makes adjustments on an ongoing basis in order to maintain the flexibility needed to achieve the Company's long-term objectives. To manage its capital structure, the Company may adjust capital spending, hedge future revenue through commodity contracts, issue new equity, issue new debt or raise funds through asset sales.

With only 50% drawn on the Company's $150 million Facility and the senior unsecured notes termed out to 2024, the Company's financial position remains strong, with sufficient liquidity to fund the Company's on-going operations. The Company will continue to monitor debt levels and, if necessary, it will consider divesting of non-core properties, adjust its annual capital expenditure program or may consider other forms of financing to improve its financial position.

Capital Management includes the monitoring of net debt as part of the Company's capital structure.

The following tables outline Crew's calculation of working capital and net debt:

| ($ thousands) | **December 31, 2021** | December 31, 2020 |
|---|---|---|
| Accounts receivable | **41,861** | 22,135 |
| Accounts payable and accrued liabilities | **(74,929)** | (46,496) |
| Working capital deficiency | **(33,068)** | (24,361) |

| ($ thousands) | **December 31, 2021** | December 31, 2020 |
|---|---|---|
| Bank loan | **(75,067)** | (35,994) |
| Senior unsecured notes | **(297,834)** | (296,851) |
| Working capital deficiency | **(33,068)** | (24,361) |
| Net debt | **(405,969)** | (357,206) |

### Working Capital

The capital intensive nature of Crew's activities generally results in the Company carrying a working capital deficit. Working capital includes cash and cash equivalents and accounts receivable less accounts payable and accrued liabilities.

The Company ensures that sufficient drawings are available from its Facility to satisfy working capital requirements. At December 31, 2021, the Company's working capital deficit totaled $33.1 million, when combined with the drawings on its bank loan, represents drawings of 72% on its $150 million Facility described below.

### Bank Loan

As at December 31, 2021, the Company's bank facility consists of a revolving line of credit of $120 million and an operating line of credit of $30 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 3, 2022. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 per cent and all outstanding advances thereunder will become repayable in one year from the extension date. The available lending limits of the Facility (the "Borrowing Base") are reviewed semi-annually and are based on the bank syndicate's interpretation of the Company's reserves and future commodity prices. The Facility requires the Company to maintain a Liability Management Rating ("LMR") of greater than 1.2:1 in the province of Alberta and Saskatchewan, and greater than 2.0:1 in the province of British Columbia, if the uninflated, undiscounted abandonment and reclamation liabilities ("Decommissioning Obligations"), as determined by the individual province, is greater than $20 million. If the LMR falls below the required level in any province, the lenders have the option to re-determine the Borrowing Base. As at December 31, 2021, the Company's Decommissioning Obligations exceeded $20 million in the province of British Columbia, which carried an LMR of 8.7:1. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled Borrowing Base review on or before June 3, 2022. The Facility is secured by a floating charge debenture and a general securities agreement on all of the assets of the Company.

**Senior Unsecured Notes**

On March 14, 2017, the Company issued $300 million of 6.5% senior unsecured notes, due March 14, 2024 (the "2024 Notes"). The 2024 Notes are guaranteed, jointly and severally, on an unsecured basis, by each of the Company's current and future restricted subsidiaries. Interest on the 2024 Notes accrues at the rate of 6.5% per year and is payable semi-annually.

The Company may redeem, on any one or more occasions, all or part of the 2024 Notes at the redemption prices set forth below, plus any accrued and unpaid interest:

| Year[(1)] | Percentage |
|---|---|
| 2021 | 102.145% |
| 2022 | 101.040% |
| 2023 and thereafter | 100.000% |

(1) For the 12 month period beginning on March 14 of each year.

Upon the occurrence of a change of control, the Company will be required to offer to repurchase each holder's notes at a price equal to not less than 101% of the principal amount, plus any accrued and unpaid interest.

The Company will continue to fund its on-going operations from a combination of cash flow, debt, non-core asset dispositions and equity financings as needed. As the majority of our on-going capital expenditure program is directed to the maintenance and growth of reserves and production volumes, the Company is readily able to adjust its budgeted capital expenditures should the need arise.

**Share Capital**

Crew is authorized to issue an unlimited number of common shares. As at March 8, 2022, there were 156,622,800 common shares of the Company issued and outstanding, which includes 5,004,496 of common shares held in trust for the potential future settlement of awards issued under the Company's Restricted and Performance Award Incentive Plan. In addition, there were 3,444,284 restricted awards and 4,575,528 performance awards outstanding.

The Company provides funds to an independent trustee to acquire common shares in the open market, which are held in trust for the potential future settlement of Restricted and Performance award values. The common shares held in trust are netted out of share capital, including the cumulative purchase cost, until they are distributed for future settlements. For the year ended December 31, 2021, the trustee purchased 4,721,000 common shares for a total cost of $8.4 million. At December 31, 2021, 4,143,000 common shares are held in trust.

**Related-Party and Off-Balance-Sheet Transactions**

Crew was not involved in any off-balance-sheet transactions or related party transactions during the year ended December 31, 2021.

**Contractual Obligations**

Throughout the course of its ongoing business, the Company enters into various contractual obligations such as credit agreements, purchase of services, royalty agreements, operating agreements, transportation agreements, processing agreements, right of way agreements and lease obligations for office space. All such contractual obligations reflect market conditions prevailing at the time of contract and none are with related parties. The Company believes it has adequate sources of capital to fund all contractual obligations as they come due. The following table lists the Company's obligations with a fixed term.

| ($ thousands) | 2022 | 2023 | 2024 | 2025 | 2026 | Thereafter |
|---|---|---|---|---|---|---|
| Bank Loan (note 1) | - | 75,067 | - | - | - | - |
| Senior unsecured notes (note 2) | - | - | 300,000 | - | - | - |
| Lease obligations | 244 | 731 | 731 | 731 | 244 | 352 |
| Firm transportation agreements | 34,071 | 34,005 | 30,022 | 29,373 | 22,678 | 23,994 |
| Firm processing agreement | 18,718 | 18,718 | 18,752 | 18,718 | 18,718 | 87,835 |
| **Total** | **53,033** | **128,521** | **349,505** | **48,822** | **41,640** | **112,181** |

Notes:
(1) Based on the existing terms of the Company's Facility the first possible repayment date may come in 2022. However, it is expected that the Facility will be extended and no repayment will be required in the near term.
(2) Matures on March 14, 2024.

Lease obligations relate primarily to the Company's commitment to a third party for the lease of office space.

Firm transportation agreements include commitments to third parties to transport condensate, ngl and natural gas from gas processing facilities in northeast British Columbia.

Firm processing agreements include commitments to process natural gas through the Greater Septimus Processing Complex in northeast British Columbia.

## ADDITIONAL DISCLOSURES

**Risks and Uncertainties**

Crew's activities expose it to a variety of financial and operational risks and uncertainties that arise as a result of its exploration, development, production, and financing activities. Crew's business could also be affected by additional risks and uncertainties not currently known to the Company or that it currently deems to be immaterial. If any of these risks actually occur, it could materially harm Crew's business, financial condition, results of operations, cash flows or impair the Company's ability to implement business plans or complete development activities as scheduled. While the following sections discuss some of these risks, they should not be construed as exhaustive. For additional information on the risks relating to Crew's business, see "Risk Factors" identified in Crew's most recent Annual Information Form.

**a) Weakness and Volatility in the Oil and Natural Gas Industry**

Weakness and volatility of the oil and natural gas industry may affect petroleum and natural gas sales, the value of Crew's reserves, and restrict its cash flow and ability to access capital to fund the development of its properties.

Market events and conditions, including global excess oil and natural gas supply, aggression by Russia towards Ukraine and other neighboring nations and the actions, including sanctions, taken by NATO nations against this aggression, actions or inaction taken by the Organization of the OPEC+ nations, announcements by Saudi Arabia to relax quotas, sanctions against Iran and Venezuela, slowing growth in China and emerging economies, weakened global relationships, conflict between the U.S. and Iran, isolationist and punitive trade policies, U.S. shale production, sovereign debt levels and political upheavals in various countries including a growing anti-fossil fuel sentiment and the continuing impact of COVID-19 and travel bans, have caused significant weakness and volatility in commodity prices. These events and conditions have caused significant variability in the valuation of Crew's reserves and a decrease in confidence in the oil and natural gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes, Indigenous land claims and environmental regulation. In addition, the difficulties encountered by midstream proponents to obtain on a timely basis or continue to maintain the necessary approvals to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and natural gas industry in Western Canada has led to additional downward price pressure on crude oil, ngl and natural gas produced in Western Canada.

Lower commodity prices may also affect the volume and value of Crew's reserves. In addition, lower commodity prices restrict the Company's cash flow resulting in less funds from operations being available to fund Crew's capital expenditure budget. Any decrease in value of Crew's reserves may reduce the Borrowing Base under its Facility, which, depending on the level of the Company's indebtedness, could result in Crew having to repay a portion of its indebtedness. In addition to possibly decreasing the value of the Company's economically recoverable reserves, lower commodity prices may also result in a decrease in the value of Crew's infrastructure and facilities, all of which could also have the effect of requiring a write down of the carrying value of the Company's crude oil and gas assets on its balance sheet and the recognition of an impairment charge in its income statement. Given the current market conditions and the lack of confidence in the Canadian oil and natural gas industry, the Company may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and highly dilutive terms. If these conditions persist, Crew's cash flow may not be sufficient to continue to fund its operations and to satisfy its obligations when due, particularly its 2024 Notes, and the Company's ability to continue as a going concern and discharge its obligations will require additional equity or debt financing or proceeds or reduction in liabilities from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory to Crew or at all. Similarly, there can be no assurance that the Company will be able to realize any or sufficient proceeds or reduction in liabilities from asset sales to discharge its obligations and continue as a going concern.

**b) Impact of the COVID-19 Pandemic**

The emergence of the COVID-19 pandemic has resulted in emergency actions by governments worldwide, and has impacted Crew's results, business, financial and operating conditions, and has negatively impacted the Canadian, U.S., and global economies; disrupted Canadian, U.S., and global supply chains; disrupted financial markets; contributed to a decrease in interest rates; resulted in ratings downgrades, credit deterioration and defaults in many industries; forced the closure of many businesses, led to loss of revenues, increased unemployment and bankruptcies; and necessitated the imposition of quarantines, physical distancing, business closures, travel restrictions, and sheltering-in-place requirements in Canada, the U.S., and other countries. If the pandemic is prolonged, including through subsequent waves, or if additional variants of COVID-19 emerge which are more transmissible or cause more severe disease, or if other diseases emerge with similar effects, the adverse impact on the economy could worsen. Moreover, it remains uncertain how the macroeconomic environment, and societal and business norms will be impacted following this COVID-19 pandemic. As a result, the Company's business, financial and operational conditions, AFF, EBITDA, reputation, access to capital, cost of borrowing, access to liquidity, and/or business plans may, in particular, and without limitation, be adversely impacted as a result of the pandemic and/or decline in commodity prices.

The full extent of the risks surrounding the severity and timing of the COVID-19 pandemic is continually evolving and is not fully known at this time. Therefore, there is significant risk and uncertainty which may have a material and adverse effect on the Company's operations.

**c) Indigenous Claims**

Indigenous peoples have claimed Indigenous rights and title in portions of western Canada. Any claims made against land where the Company leases the mineral or surface rights may have an adverse effect on the Company's business, financial condition and results of operations. Some Indigenous groups have established or asserted Indigenous treaty, title, and rights to portions of Canada. There are outstanding Indigenous and treaty rights claims, which may include Indigenous title claims, on lands where Crew operates, and such claims, if successful, could have a material adverse impact on its operations or pace of growth. No certainty exists that any lands currently unaffected by claims brought by Indigenous groups will remain unaffected by future claims. At this time, it is not reasonably expected that claims will materially affect the Company's planned activity in 2022 or 2023, however, its longer term effects on the Company's business and operations are unknown. In addition, the process of addressing such claims, regardless of the outcome, could be extensive and time-consuming and could result in delays in drilling, completions, construction of infrastructure systems and facilities which may have a material effect on the Company's business and financial results.

Opposition by Indigenous groups to the conduct of the Company's operations, development or exploratory activities may negatively impact the Company. Opposition by Indigenous groups to the conduct our operations, development or exploratory activities in any of the jurisdictions in which the Company conducts business may negatively impact it in terms of public perception, diversion of management's time and resources, legal and other advisory expenses, and could adversely impact the Company's progress and ability to explore and develop properties.

Some Indigenous groups have established or asserted Indigenous treaty, title and rights to portions of Canada. There are outstanding Indigenous and treaty rights claims, which may include Indigenous title claims, on lands where the Company operates, and such claims, if successful, could have a material adverse impact on its operations or pace of growth. No certainty exists that any lands currently unaffected by claims brought by Indigenous groups will remain unaffected by future claims.

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous or treaty rights and, in certain circumstances, accommodate their concerns. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of ongoing litigation. The fulfillment of the duty to consult Indigenous people and any associated accommodations may adversely affect the Company's ability to, or increase the timeline to, obtain or renew, permits, leases, licences and other approvals, or to meet the terms and conditions of those approvals. For example, regulatory authorities in British Columbia recently ceased granting approvals and, in some cases, revoked existing approvals, for, among other things, crude oil and natural gas activities relating to drilling, completions, testing, production and transportation infrastructure following a recent British Columbia Supreme Court decision that the cumulative impacts of government sanctioned industrial development on the traditional territories of a First Nations group in northeast British Columbia breached that group's treaty rights. While Crew believes that the regulatory authorities will resume granting and reinstate approvals for crude oil and natural gas activities on time frames and terms and conditions consistent with past practice, the long-term impacts of, and associated risks with, the decision on the Canadian crude oil and natural gas industry and Crew remain uncertain.

In addition, the federal government has introduced legislation to implement the UNDRIP. Other Canadian jurisdictions, including British Columbia, have also introduced or passed similar legislation, or begun considering the principles and objectives of UNDRIP, or may do so in the future. The means and timelines associated with UNDRIP's implementation by government is uncertain; additional processes may be created or legislation amended or introduced associated with project development and operations, further increasing uncertainty with respect to project regulatory approval timelines and requirements.

**d) Operational Risks**

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long term commercial success of Crew depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the Company's existing reserves, and the production from them, will decline over time as the Company produces from such reserves.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Crew maintains diligent oversight and maintenance over operations to mitigate these risks, including responsible well supervision, effective maintenance operations and the development of enhanced recovery technologies that contribute to maximizing production rates over time. It is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment and cause personal injury or threaten wildlife.

Oil and natural gas production operations are also subject to geological and seismic risks, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on Crew's business, financial condition, results of operations and prospects.

As part of Crew's rigorous risk assessment, insurance is obtained to protect against major asset destruction or business interruptions. Although the Company maintains liability insurance and business interruption insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, the Company could incur significant costs.

The COVID-19 pandemic has also created additional operational risks for Crew, including the need to provide enhanced safety measures for its employees and customers; comply with rapidly changing regulatory guidance; address the risk of, attempted fraudulent activity and cybersecurity threat behavior; and protect the integrity and functionality of the Company's systems, networks, and data as a larger number of employees work remotely. The Company is also exposed to human capital risks due to issues related to health and safety matters, and other environmental stressors as a result of measures implemented in response to the COVID-19 pandemic, as well as the potential for a significant proportion of the Company's employees, including key executives, to be unable to work effectively, because of illness, quarantines, sheltering-in-place arrangements, government actions or other restrictions in connection with the pandemic.

**e) Financial Risks**

Volatile oil, ngl and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil, ngl and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for, and project the return on, acquisitions and development and exploitation projects. As a result, the Company hedges future revenue through commodity contracts to lock-in value and mitigate financial risk. From time to time, the Company's may enter into agreements to receive fixed prices on its oil, ngl and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Company engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk.

**f) Changing Regulation**

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. With respect to environmental, social and governance ("ESG") and climate reporting, the International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the Canadian Securities Administrators have issued a proposed National Instrument 51-107 Disclosure of Climate-related Matters. The cost to comply with these standards, and others that may be developed or evolve over time, is not quantifiable at this time.

Changes to royalty regimes may also negatively impact the Company's cash flows. There can be no assurance that the governments in the jurisdictions in which the Company has assets will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Company's projects. An increase in royalties would reduce the Company's earnings and could make future capital investments, or the Company's operations, less economic.

**g) Physical Risk of Climate Change**

Based on the Company's current understanding, the potential physical risks resulting from climate change are long-term in nature and associated with a high degree of uncertainty regarding timing, scope, and severity of potential impacts. Many experts believe global climate change could increase extreme variability in weather patterns such as increased frequency of severe weather, rising mean temperature and sea levels, and long-term changes in precipitation patterns. Extreme hot and cold weather, heavy snowfall, heavy rainfall, and wildfires may restrict the Company's ability to access its properties and cause operational difficulties, including damage to equipment and infrastructure. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of the Company's assets are located in locations that are proximate to forests and rivers and a wildfire or flood may lead to significant downtime and/or damage to the Company's assets or cause disruptions to the production and transport of its products or the delivery of goods and services in its supply chain.

**h) Gathering and Processing Facilities, Pipeline Systems, Trucking and Rail**

Lack of capacity and/or regulatory constraints on gathering and processing facilities, pipeline systems and railway lines may have a negative impact on the Company's ability to produce and sell its oil, ngl and natural gas.

The Company delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by truck and rail. The amount of oil, ngl and natural gas that the Company can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems, trucking and railway lines. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Company's production, operations and financial results.

A portion of the Company's production may, from time to time, be processed through facilities owned by third parties and over which the Company does not have control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a material adverse effect on the Company's ability to process its production and deliver the same to market. Midstream and pipeline companies may take actions to maximize their return on investment, which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

## Historical Analysis

The following table summarizes Crew's key quarterly financial results for the past eight financial quarters:

| *($ thousands, except per share amounts)* | **Dec. 31 2021** | Sep. 30 2021 | June 30 2021 | Mar. 31 2021 | Dec. 31 2020 | Sep. 30 2020 | June 30 2020 | Mar. 31 2020 |
|---|---|---|---|---|---|---|---|---|
| Total daily production (boe/d) | **29,142** | 23,659 | 26,712 | 26,258 | 21,666 | 20,207 | 22,074 | 23,894 |
| Exploration and development expenditures | **42,341** | 64,295 | 21,198 | 50,090 | 41,007 | 21,876 | 5,348 | 18,029 |
| Net property (dispositions)/acquisitions[(1)] | **(460)** | (7,816) | - | - | (23,219) | (35) | 44 | (34,940) |
| Average realized commodity price ($/boe) | **38.47** | 34.75 | 28.20 | 36.19 | 21.37 | 17.40 | 12.39 | 17.52 |
| Petroleum and natural gas sales | **103,153** | 75,628 | 68,550 | 85,517 | 42,604 | 32,344 | 24,889 | 38,094 |
| Cash provided by operating activities | **45,747** | 18,072 | 24,890 | 30,447 | 14,774 | 5,121 | 8,175 | 9,919 |
| Adjusted funds flow | **46,833** | 26,511 | 25,530 | 33,995 | 15,568 | 8,549 | 4,633 | 12,400 |
| Per share[(2)] – basic | **0.31** | 0.17 | 0.17 | 0.23 | 0.10 | 0.06 | 0.03 | 0.08 |
| – diluted | **0.29** | 0.17 | 0.16 | 0.22 | 0.10 | 0.06 | 0.03 | 0.08 |
| Net income (loss) | **50,901** | 176,183 | (23,138) | 1,353 | 34,668 | (21,136) | (24,803) | (191,909) |
| Per share – basic | **0.33** | 1.14 | (0.15) | 0.01 | 0.23 | (0.14) | (0.16) | (1.27) |
| – diluted | **0.31** | 1.12 | (0.15) | 0.01 | 0.22 | (0.14) | (0.16) | (1.27) |

Notes:
(1) Non-IFRS measure or ratio that does not have any standardized meaning as prescribed by International Financial Reporting Standards, and therefore, may not be comparable with the calculations of similar measures or ratios for other entities. See "Non-IFRS Measures" contained within this MD&A.
(2) Supplementary measure. See "Non-IFRS and Other Financial Measures" contained within this MD&A.

The global outbreak of COVID-19 in early 2020 and subsequent measures intended to limit the pandemic contributed to significant volatility in the global financial markets. The pandemic adversely impacted global commercial activity and has significantly reduced worldwide demand for commodities including crude oil, natural gas and ngl. The result was significant volatility and a decline in the price of crude oil and gas during the first three quarters of 2020. During this time, the Company conservatively managed capital spending in order to sustain production levels and protect the Company's financial integrity.

Towards the end of 2020, in conjunction with the recovery of oil and gas prices, Crew developed a strategic two-year development plan to enhance long-term sustainability and create meaningful value. The strategic plan included increased capital expenditures beginning in the fourth quarter of 2020, continuing through 2021 into early 2022 in order to increase production in order to improve net backs and improve the Company's overall sustainability.

The decline in crude oil and natural gas prices in the first quarter of 2020 resulted in a March 31, 2020 pre-tax impairment charge of $267.3 million. The prospect of a global vaccination campaign against COVID-19 emerged in the latter part of 2020 resulting in a recovery in global markets including an improvement in global commodity prices. The recovery extended into 2021 with global crude oil, ngl and natural gas prices significantly outperforming those seen throughout 2020, resulting in a September 30, 2021 pre-tax impairment reversal of $228.5 million.

Significant volatility in commodity prices has historically impacted cash provided by operating activities, adjusted funds flow and net income (loss) throughout the past eight quarters. The Company has reduced the financial impact of volatile commodity prices by entering into derivative and physical risk management contracts which can cause significant fluctuations in income due to unrealized gains and losses recognized on a quarterly basis.

The following table summarizes Crew's key financial results over the past three years:

| ($ thousands, except per share amounts) | | **Year ended Dec. 31, 2021** | Year ended Dec. 31, 2020 | Year ended Dec. 31, 2019 |
|---|---|---|---|---|
| Petroleum and natural gas sales | | **332,848** | 137,931 | 193,532 |
| Cash provided by operating activities | | **119,156** | 37,989 | 81,395 |
| Adjusted funds flow | | **132,869** | 41,150 | 81,034 |
| Per share[(1)] | -basic | **0.87** | 0.27 | 0.53 |
| | -diluted | **0.82** | 0.27 | 0.53 |
| Net income (loss) | | **205,299** | (203,180) | 12,071 |
| Per share | -basic | **1.34** | (1.34) | 0.08 |
| | -diluted | **1.27** | (1.34) | 0.08 |
| Daily production (boe/d) | | **26,443** | 21,955 | 22,837 |
| Average realized commodity price ($/boe) | | **34.49** | 17.17 | 23.22 |
| Total assets | | **1,490,658** | 1,189,566 | 1,451,647 |
| Working capital (deficiency) surplus | | **(33,068)** | (24,361) | 149 |
| Bank loan | | **75,067** | 35,994 | 52,136 |
| Senior unsecured notes | | **297,834** | 296,851 | 295,868 |
| Total other long-term liabilities | | **105,597** | 95,992 | 143,295 |

Note:
(1) Supplementary measure. See "Non-IFRS and Other Financial Measures" contained within this MD&A

Over the last three years, a volatile commodity price environment has had a significant impact on revenue, cash provided by operating activities, adjusted funds flow and net income. The recovery of oil and natural gas prices in the second half of 2020, after an extended period of poor fundamentals for oil and gas pricing and the initial impact of COVID-19, provided Crew with the opportunity to strategically increase capital spending to grow production and improve the Company's sustainability. The increased production combined with a continued strengthening of oil and gas prices has had a positive impact on petroleum and natural gas sales, cash provided by operating activists, adjusted funds flow and net income in 2021.

The significant decline in forecasted future commodity prices that occurred in early 2020 due to COVID-19 and other market dynamics led to the assessment and realization of impairment charges on the Company's CGUs in 2020. The subsequent recovery in oil and gas prices in the second half of 2020 carrying into 2021 led to the reversal of the impairment charges in 2021.

**Application of Critical Accounting Estimates**

Crew's significant accounting policies are disclosed in note 4 to the December 31, 2021 consolidated financial statements. 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. Crew continuously refines its management and reporting systems to ensure that accurate, timely and useful information is gathered and disseminated. Crew's financial and operating results incorporate certain estimates including the following:

- Estimated accruals for revenues, royalties, operating expenses and general administrative expenses where actual revenues and costs have not been received;
- Estimated capital expenditures where actual costs have not been received or for projects that are in progress;
- Estimated depletion, depreciation and amortization charges are based on estimates of proved and probable oil and gas reserves that Crew expects to recover in the future. As a key component in the depletion, depreciation and amortization calculation, the reserve estimates have a significant impact on net earnings and the Company's financial results could differ if there is a revision in our estimate of reserve quantities;
- Estimated future recoverable value of property, plant and equipment and any related impairment charges or recoveries are assessed for impairment when circumstances suggest the carrying amount may exceed its recoverable amount. The recoverable amount calculation requires the use of estimates which are subject to change as new information becomes

available. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets;

- Estimated fair values of derivative contracts, which are used to manage commodity price, foreign currency and interest rate swaps, are determined using valuation models which require assumptions regarding the amount and timing of future cash flows and discount rates. As the Company's assumptions rely on external market data, the resulting fair value estimates may not be indicative of the amounts realized or settled and are therefore subject to market uncertainty;
- Decommissioning obligations are based on assumptions which take into consideration current economic factors and experience to date which Crew believes are reasonable. The actual cost of the Company's decommissioning obligations may change in response to numerous factors;
- Estimated deferred income tax assets and liabilities are based on current tax interpretations, regulations and legislation which are subject to change. As a result, there are usually a number of tax matters under review and therefore income taxes are subject to measurement uncertainty.

Crew hires employees and engages consultants who have the expertise to ensure these estimates are accurate and ensures departments with the most knowledge of the activity are responsible for the estimates. Past estimates are reviewed and analyzed regularly to ensure future estimates continue to track actuals. The emergence of new information and changed circumstances may result in actual results or changes to estimate amounts that differ materially from current estimates.

**Disclosure Controls and Procedures and Internal Controls over Financial Reporting**

The Company's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures, as defined in national Instrument 52-109 Certification of Disclosures in Issuers' Annual and Interim Filings ("NI 52-109"), to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's disclosure controls and procedures at the financial year end of the Company and have concluded that the Company's disclosure controls and procedures are effective at the financial year end of the Company.

The Company's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting, as defined in NI 52-109, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Utilizing the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") Internal Control – Integrated Framework (2013), such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal controls over financial reporting at the financial year end of the Company and concluded that the Company's internal controls over financial reporting are effective, at the financial year end of the Company. The Company is required to disclose herein any change in the Company's internal controls over financial reporting that occurred during the period beginning on October 1, 2021 and ended on December 31, 2021 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes in the Company's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

## ADVISORIES

### Conversions

The oil and gas industry commonly expresses production volumes and reserves on a "barrel of oil equivalent" basis ("boe"), whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum crude oil, condensate, other ngl and natural gas measurement units into one basis for improved analysis of results and comparisons with other industry participants.

Throughout this MD&A, Crew has used the 6:1 boe measure which is the approximate energy equivalency of the two commodities at the burner tip. Boe does not represent a value equivalency at the wellhead nor at the plant gate which is where Crew sells its production volumes and therefore may be a misleading measure, particularly if used in isolation. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a 6:1 conversion may be misleading as an indication of value.

### Non-IFRS and Other Financial Measures

Throughout this MD&A and other materials disclosed by the Company, Crew uses certain measures to analyze financial performance, financial position and cash flow. These non-IFRS and other financial measures do not have any standardized meaning prescribed under IFRS and therefore may not be comparable to similar measures presented by other entities. The non-IFRS and other financial measures should not be considered alternatives to, or more meaningful than, financial measures that are determined in accordance with IFRS as indicators of Crew's performance. Management believes that the presentation of these non-IFRS and other financial measures provides useful information to shareholders and investors in understanding and evaluating the Company's ongoing operating performance, and the measures provide increased transparency and the ability to better analyze Crew's business performance against prior periods on a comparable basis.

***Capital Management Measures***

**a) Funds from Operations and Adjusted Funds Flow**

Funds from operations represents cash provided by operating activities before changes in operating non-cash working capital, accretion of deferred financing costs and transaction costs on property dispositions. Adjusted funds flow represents funds from operations before decommissioning obligations settled. The Company considers these metrics as key measures that demonstrate the ability of the Company's continuing operations to generate the cash flow necessary to maintain production at current levels and fund future growth through capital investment and to service and repay debt. Management believes that such measures provide an insightful assessment of the Company's operations on a continuing basis by eliminating certain non-cash charges, actual settlements of decommissioning obligations and transaction costs on property dispositions, the timing of which is discretionary. Funds from operations and adjusted funds flow should not be considered as an alternative to or more meaningful than cash provided by operating activities as determined in accordance with IFRS as an indicator of the Company's performance. Crew's determination of funds from operations and adjusted funds flow may not be comparable to that reported by other companies. Crew also presents adjusted funds flow per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of income per share.

**b) Net debt and Working Capital Deficiency (Surplus)**

Crew closely monitors its capital structure with a goal of maintaining a strong balance sheet to fund the future growth of the Company. The Company monitors net debt as part of its capital structure. The Company uses net debt (bank debt plus working capital deficiency or surplus, excluding the current portion of the fair value of financial instruments) as an alternative measure of outstanding debt. Management considers net debt and working capital deficiency (surplus) an important measure to assist in assessing the liquidity of the Company.

***Non-IFRS Measures and Ratios***

### a) Net Property (Dispositions) Acquisitions

Net property acquisitions (dispositions) equals property acquisitions less property dispositions and transaction costs on property dispositions. Crew uses net property acquisitions (dispositions) to measure its total capital investment compared to the Company's annual capital budgeted expenditures. The most directly comparable IFRS measures to net property acquisitions (dispositions) are property acquisitions and property dispositions.

| ($ thousands) | **Three months ended December 31, 2021** | Three months ended September 30, 2021 | Three months ended December 31, 2020 | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|---|---|---|
| Property acquisitions | **-** | - | 11,733 | **-** | 11,790 |
| Property dispositions | **(460)** | (10,321) | (34,952) | **(10,781)** | (69,940) |
| Transaction costs on property dispositions | **-** | 2,505 | - | **2,505** | - |
| Net property dispositions | **(460)** | (7,816) | (23,219) | **(8,276)** | (58,150) |

### b) Net Capital Expenditures

Net capital expenditures equals exploration and development expenditures less net property acquisitions (dispositions). Crew uses net capital expenditures to measure its total capital investment compared to the Company's annual capital budgeted expenditures. The most directly comparable IFRS measure to net capital expenditures is property, plant and equipment expenditures.

| ($ thousands) | **Three months ended December 31, 2021** | Three months ended September 30, 2021 | Three months ended December 31, 2020 | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|---|---|---|
| Property, plant and equipment expenditures | **42,341** | 64,295 | 41,007 | **177,924** | 86,260 |
| Less: net property (dispositions) acquisitions | **(460)** | (7,816) | (23,219) | **(8,276)** | (58,150) |
| Net capital expenditures | **41,881** | 56,479 | 17,788 | **169,648** | 28,110 |

### c) EBITDA

EBITDA is calculated as consolidated net income (loss) before interest and financing expenses, income taxes, depletion, depreciation and amortization, adjusted for certain non-cash, extraordinary and non-recurring items primarily relating to unrealized gains and losses on financial instruments and impairment losses. The Company considers this metric as key measures that demonstrate the ability of the Company's continuing operations to generate the cash flow necessary to maintain production at current levels and fund future growth through capital investment and to service and repay debt. The most directly comparable IFRS measure to EBITDA is cash provided by operating activities.

| ($ thousands) | **Three months ended December 31, 2021** | Three months ended September 30, 2021 | Three months ended December 31, 2020 | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|---|---|---|
| Cash provided by operating activities | **45,747** | 18,072 | 14,774 | **119,156** | 37,989 |
| Change in operating non-cash working capital | **(668)** | 5,707 | 19 | **8,844** | 2,170 |
| Accretion of deferred financing costs | **(246)** | (245) | (246) | **(983)** | (983) |
| Transaction costs on property dispositions | **-** | 2,505 | - | **2,505** | - |
| Funds from operations | **44,833** | 26,039 | 14,547 | **129,522** | 39,176 |
| Decommissioning obligations settled excluding government grants | **2,000** | 472 | 1,021 | **3,347** | 1,974 |
| Adjusted funds flow | **46,833** | 26,511 | 15,568 | **132,869** | 41,150 |
| Interest | **6,199** | 6,183 | 5,903 | **24,399** | 23,210 |
| EBITDA | **53,032** | 32,694 | 21,471 | **157,268** | 64,360 |

**d) Free Adjusted Funds Flow**

Free adjusted funds flow represents adjusted funds flow less property, plant and equipment expenditures. The Company considers this metric a key measure that demonstrates the ability of the Company's continuing operations to fund future growth through capital investment and to service and repay debt. The most directly comparable IFRS measure to free adjusted funds flow is cash provided by operating activities.

| ($ thousands) | **Three months ended December 31, 2021** | Three months ended September 30, 2021 | Three months ended December 31, 2020 | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|---|---|---|
| Cash provided by operating activities | **45,747** | 18,072 | 14,774 | **119,156** | 37,989 |
| Change in operating non-cash working capital | **(668)** | 5,707 | 19 | **8,844** | 2,170 |
| Accretion of deferred financing costs | **(246)** | (245) | (246) | **(983)** | (983) |
| Transaction costs on property dispositions | **-** | 2,505 | - | **2,505** | - |
| Funds from operations | **44,833** | 26,039 | 14,547 | **129,522** | 39,176 |
| Decommissioning obligations settled excluding government grants | **2,000** | 472 | 1,021 | **3,347** | 1,974 |
| Adjusted funds flow | **46,833** | 26,511 | 15,568 | **132,869** | 41,150 |
| Less: property, plant and equipment expenditures | **42,341** | 64,295 | 41,007 | **177,924** | 86,260 |
| Free adjusted funds flow | **4,541** | (37,784) | (25,439) | **(45,055)** | (45,110) |

**e) Net Operating Costs**

Net operating costs equals operating costs net of processing revenue. Management views net operating costs as an important measure to evaluate its operational performance. The most directly comparable IFRS measure for net operating costs is operating costs. The calculation of Crew's net operating costs can be seen in the section entitled "Net Operating Costs" of this MD&A.

**f) Net Operating Costs per boe**

Net operating costs per boe equals net operating costs divided by production. Management views net operating costs per boe as an important measure to evaluate its operational performance.

**g) Operating Netback per boe**

Operating netback per boe equals petroleum and natural gas sales including realized gains and losses on commodity related derivative financial instruments, marketing income, less royalties, net operating costs and transportation costs calculated on a boe basis. Management considers operating netback per boe an important measure to evaluate its operational performance as it demonstrates its field level profitability relative to current commodity prices. The calculation of Crew's operating netbacks per boe can be seen in the section entitled "Operating Netbacks" of this MD&A.

**h) Cash costs per boe**

Cash costs per boe is comprised of net operating, transportation, general and administrative and financing costs on debt calculated on a boe basis. Management views cash costs per boe as an important measure to evaluate its operational performance.

| ($/boe) | **Three months ended December 31, 2021** | Three months ended September 30, 2021 | Three months ended December 31, 2020 | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|---|---|---|
| Net operating costs | **3.49** | 5.11 | 5.30 | **4.47** | 5.61 |
| Transportation costs | **3.52** | 4.61 | 4.23 | **4.07** | 3.67 |
| General and administrative expenses | **0.91** | 1.05 | 1.30 | **0.95** | 1.01 |
| Financing costs on debt | **2.31** | 2.84 | 2.97 | **2.53** | 2.90 |
| Cash costs | **10.23** | 13.61 | 13.80 | **12.02** | 13.19 |

### i) Financing costs on debt per boe

Financing costs on debt per boe is comprised of the sum of interest on bank loan and other, interest on senior notes and accretion of deferred financing charges, divided by production. Management views financing costs on debt per boe as an important measure to evaluate its cost of debt financing.

| ($ thousands, except per boe) | **Three months ended December 31, 2021** | Three months ended September 30, 2021 | Three months ended December 31, 2020 | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|---|---|---|
| Interest on bank loan and other | **1,038** | 1,023 | 742 | **3,916** | 2,727 |
| Interest on senior notes | **4,915** | 4,915 | 4,915 | **19,500** | 19,500 |
| Accretion of deferred financing charges | **246** | 245 | 246 | **983** | 983 |
| Financing costs on debt | **6,199** | 6,183 | 5,903 | **24,399** | 23,210 |
| Production (boe/d) | **29,142** | 23,659 | 21,666 | **26,443** | 21,955 |
| Financing costs on debt per boe | **2.31** | 2.84 | 2.97 | **2.53** | 2.90 |

***Supplementary Measures***

**"Adjusted funds flow per basic share"** is comprised of adjusted funds flow divided by the basic weighted average common shares.

**"Adjusted funds flow per diluted share"** is comprised of adjusted funds flow divided by the diluted weighted average common shares.

**"Average realized commodity price"** is comprised of commodity sales from production, as determined in accordance with IFRS, divided by the Company's production. Average prices are before deduction of transportation costs and do not include gains and losses on financial instruments.

**"Average realized light crude oil price"** is comprised of light crude oil commodity sales from production, as determined in accordance with IFRS, divided by the Company's light crude oil production. Average prices are before deduction of transportation costs and do not include gains and losses on financial instruments.

**"Average realized heavy crude oil price"** is comprised of heavy crude oil commodity sales from production, as determined in accordance with IFRS, divided by the Company's heavy crude oil production. Average prices are before deduction of transportation costs and do not include gains and losses on financial instruments.

**"Average realized ngl price"** is comprised of ngl commodity sales from production, as determined in accordance with IFRS, divided by the Company's ngl production. Average prices are before deduction of transportation costs and do not include gains and losses on financial instruments.

**"Average realized condensate price"** is comprised of condensate commodity sales from production, as determined in accordance with IFRS, divided by the Company's condensate production. Average prices are before deduction of transportation costs and do not include gains and losses on financial instruments.

**"Average realized natural gas price"** is comprised of natural gas commodity sales from production, as determined in accordance with IFRS, divided by the Company's natural gas production. Average prices are before deduction of transportation costs and do not include gains and losses on financial instruments.

**"Average drawings on bank loan"** is calculated as the average daily bank loan balance for the selected period.

**"Average senior unsecured notes outstanding"** is calculated as the average daily senior unsecured notes outstanding balance for the selected period.

**"Average long-term debt level"** is comprised of the sum of the average drawings on bank loan and average senior unsecured notes outstanding.

**"Adjusted funds flow per boe"** is comprised of adjusted funds flow divided by total production.

**Forward Looking Statements**

This MD&A contains certain forward looking informational statements within the meaning of applicable securities laws. In particular, management's assessment of the potential and uncertain impact of COVID-19 on the Company's operations and results, future plans and operations, including the Company's two year development plan and the associated guidance and material underlying assumptions contained in the section titled "Guidance" herein, capital spending plans and budget estimates, drilling plans and the timing thereof, plans for the completion and tie-in of wells and anticipated on-stream dates, facility and pipeline construction, expansion, commissioning and the timing thereof, capital expenditures, timing of capital expenditures and methods of financing capital expenditures and the ability to fund financial liabilities, production estimates, expected commodity mix and prices, future net operating costs, future transportation costs, expected royalty rates, expected interest rates and other financing charges, debt levels and expected debt levels, funds from operations and the timing of and impact of implementing accounting policies, expectations in regards to the Company's credit facilities, estimates regarding undeveloped land position and estimated future drilling, recompletion or reactivation locations, the potential for further property or infrastructure divestures and the anticipated impact of potential future transactions may constitute forward looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, regulatory risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, the inability to fully realize the benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and inability to access sufficient capital from internal and external sources. As a consequence, the Company's actual results may differ materially from those expressed in, or implied by, the forward looking statements.

Forward looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Crew believes that the expectations reflected in such forward looking statements or information are reasonable, undue reliance should not be placed on forward looking statements because the Company can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document and other documents filed by the Company, assumptions have been made regarding, among other things: the impact measures taken to protect citizens from COVID-19 will have on global energy demand and global economies; the potential impact of government programs associated with COVID-19; the general stability of the economic and political environment in which Crew operates; that future business, regulatory and industry conditions will be within the parameters expected by Crew; the impact of increasing competition; the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; potential changes in the Company's two year development plan; the ability of the operator of the projects which the Company has an interest in to operate the field in a safe, efficient and effective manner; Crew's ability to obtain financing on acceptable terms; changes in the Company's banking facility; field production rates and decline rates; the ability to reduce net operating costs; the ability to replace and expand oil and natural gas reserves through acquisition, development or exploration; the timing and costs of pipeline, storage and facility construction and expansion; the ability of the Company to secure adequate product transportation; future petroleum and natural gas prices; currency exchange and interest rates; the regulatory framework regarding royalties, taxes, environmental and indigenous matters in the jurisdictions in which the Company operates; that regulatory authorities in BC will resume granting approvals for oil and gas activities on time frames, and on terms and conditions, consistent with past practices; and Crew's ability to successfully market its petroleum and natural gas products. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) or at the Company's website (www.crewenergy.com).

The internal projections, expectations or beliefs underlying the Company's 2022 capital expenditure plans, budgets and associated guidance and corporate outlook for 2022 and beyond are subject to change in light of ongoing results, prevailing economic circumstances, commodity prices and industry conditions and regulations. Crew's outlook for 2022 and beyond provides shareholders with relevant information on Management's expectations for results of operations, excluding any potential acquisitions, dispositions or strategic transactions that may be completed in 2022 and beyond. Accordingly, readers are cautioned that events or circumstances could cause results to differ materially from those predicted and Crew's 2022 guidance and outlook may not be appropriate for other purposes. Furthermore, the forward looking statements contained in this document are made as at the date of this document and the Company does not undertake any obligation to update publicly or to revise any of the included forward looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

**Dated as of March 8, 2022**

# MANAGEMENT'S REPORT

Management, in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board, has prepared the accompanying consolidated financial statements of Crew Energy Inc. ("Crew" or the "Company"). Financial and operating information presented throughout this report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

KPMG LLP were appointed by the Company's Board of Directors to conduct an audit of the consolidated financial statements. Their examination included a review and evaluation, including tests and procedures, of Crew's internal control systems as they considered necessary, to provide reasonable assurance that the consolidated financial statements are presented fairly in accordance with IFRS.

The Board of Directors are responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit Committee, with assistance from the Reserves Committee regarding the annual evaluation of our oil and gas reserves. The Audit Committee meets regularly with management and the independent auditors to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of the external auditors and reviews their fees. The external auditors have access to the Audit Committee without the presence of management.

*(signed)*

Dale O. Shwed

President and Chief Executive Officer

*(signed)*

John G. Leach

Executive Vice-President and Chief Financial Officer

March 8, 2022

KPMG LLP
205 5th Avenue SW
Suite 3100
Calgary AB T2P 4B9
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# INDEPENDENT AUDITORS' REPORT

To the Shareholders of Crew Energy Inc.

## *Opinion*

We have audited the consolidated financial statements of Crew Energy Inc. (the "Company"), which comprise:

- the consolidated statements of financial position as at December 31, 2021 and December 31, 2020
- the consolidated statements income (loss) and comprehensive income (loss) for the years then ended
- the consolidated statements of changes in shareholders' equity for the years then ended
- the consolidated statements of cash flows for the years then ended
- and notes to the consolidated financial statements, including a summary of significant accounting policies

Hereinafter referred to as the "financial statements".

In our opinion, the accompanying financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2021 and December 31, 2020, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB).

## *Basis for Opinion*

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "***Auditors' Responsibilities for the Audit of the Financial Statements***" section of our auditors' report.

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

### *Key Audit Matters*

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the financial statements for the year ended December 31, 2021. These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

***Assessment of the recoverable amount of the northeast British Columbia cash-generating unit ("CGU")***

***Description of the matter***

We draw attention to note 4(f) and note 8 to the financial statements. The carrying amounts of the Company's non-financial assets are reviewed at each reporting date to determine whether there are any internal or external indicators of impairment or impairment reversal. If any such indicator exists, then the recoverable amount is estimated. The Company identified an indicator of impairment reversal at September 30, 2021 for the northeast British Columbia CGU and performed an impairment reversal test to estimate its recoverable amount. It was determined that the recoverable amount of the northeast British Columbia CGU exceeded its carrying value, resulting in all previous impairment, net of depletion, of $228.5 million being reversed.

The estimated recoverable amount of the northeast British Columbia CGU involves significant estimates including:

- The estimate of proved and probable oil and gas reserves and the related cash flows
- The discount rates
- The sales value of the undeveloped lands.

The estimate of proved and probable oil and gas reserves and the related cash flows includes significant assumptions related to:

- Forecasted oil and gas commodity prices
- Forecasted production
- Forecasted operating costs
- Forecasted royalty costs
- Forecasted future development costs.

***Why the matter is a key audit matter***

We identified the assessment of the recoverable amount of the northeast British Columbia cash generating unit as a key audit matter. Significant auditor judgment was required in evaluating the results of our audit procedures regarding the estimate of proved and probable oil and gas reserves and the related cash flows, the discount rates, and the sales value of the undeveloped lands.

***How the matter was addressed in the audit***

The following are the primary procedures we performed to address this key audit matter:

We independently developed the estimated recoverable amount of northeast British Columbia CGU as at December 31, 2021 and compared it to the carrying value to assess that the reversal of all previous impairments, net of depletion, recognized during the year ended December 31, 2021 was appropriate.

With respect to the estimate of proved and probable oil and gas reserves and the related cash flows as at December 31, 2021:

- We evaluated the competence, capabilities and objectivity of the independent third party reserve evaluator engaged by the Company
- We compared the forecasted oil and gas commodity prices to those published by other independent third party reserve evaluators
- We compared the 2021 actual production and actual operating costs, royalty costs and development costs to those estimates used in the prior year's estimate of proved oil and gas reserves and the related cash flows to assess the Company's ability to accurately forecast
- We evaluated the appropriateness of forecasted production and forecasted operating costs, royalty costs and future development costs assumptions by comparing to 2021 historical results. We took into account changes in conditions and events affecting the Company to assess the adjustments or lack of adjustments made by the Company in arriving at the assumptions.

We involved valuation professionals with specialized skills and knowledge, who assisted in:

- Developing an independent estimate of the recoverable amount as at December 31, 2021 using proved and probable oil and gas reserves and related cash flows evaluated by independent third party reserve evaluators as at December 31, 2021 with an independently developed discount rate and including an independently developed sales value of the undeveloped lands.

### *Other Information*

Management is responsible for the other information. Other information comprises:

- the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions.
- the information, other than the financial statements and the auditors' report thereon, included in a document likely to be entitled "2021 Annual Report".

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions as at the date of this auditors' report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditors' report.

We have nothing to report in this regard.

The information, other than the financial statements and the auditors' report thereon, included in a document likely to be entitled "2021 Annual Report" is expected to be made available to us after the date of this auditors' report. If, based on the work we will perform on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact to those charged with governance.

### *Responsibilities of Management and Those Charged with Governance for the Financial Statements*

Management is responsible for the preparation and fair presentation of the financial statements in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB), and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

### *Auditors' Responsibilities for the Audit of the Financial Statements*

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Company to cease to continue as a going concern.

– Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

– Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

– Provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

– Determine, from the matters communicated with those charged with governance, those matters that were of most significance in the audit of the financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditors' report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our auditors' report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

The engagement partner on the audit resulting in this auditors' report is Gregory Ronald Caldwell.

KPMG LLP

Chartered Professional Accountants

Calgary, Canada
March 8, 2022

# CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

| (thousands) | December 31, 2021 | December 31, 2020 |
|---|---|---|
| **Assets** | | |
| Current Assets: | | |
| Accounts receivable | **$ 41,861** | $ 22,135 |
| Derivative financial instruments (note 6) | **-** | 4,718 |
| | **41,861** | 26,853 |
| Derivative financial instruments (note 6) | **275** | 3,681 |
| Property, plant and equipment (note 7) | **1,448,522** | 1,159,032 |
| | **$ 1,490,658** | $ 1,189,566 |
| **Liabilities and Shareholders' Equity** | | |
| Current Liabilities: | | |
| Accounts payable and accrued liabilities | **$ 74,929** | $ 46,496 |
| Derivative financial instruments (note 6) | **16,690** | 716 |
| Decommissioning obligations (note 12) | **1,386** | - |
| | **93,005** | 47,212 |
| Bank loan (note 9) | **75,067** | 35,994 |
| Senior unsecured notes (note 10) | **297,834** | 296,851 |
| Lease obligations (note 11) | **2,620** | 2,814 |
| Decommissioning obligations (note 12) | **56,828** | 93,178 |
| Deferred tax liability (note 13) | **46,150** | - |
| **Shareholders' Equity** | | |
| Share capital (note 14) | **1,481,450** | 1,482,925 |
| Contributed surplus | **71,865** | 70,052 |
| Deficit | **(634,161)** | (839,460) |
| | **919,154** | 713,517 |
| Commitments (note 15) | | |
| Subsequent event (note 6) | | |
| | **$ 1,490,658** | $ 1,189,566 |

*See accompanying notes to the consolidated financial statements.*

On behalf of the Board of Directors:

*(signed)*

Ryan A. Shay

Director

*(signed)*

Gail A. Hannon

Director

# CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

| *(thousands, except per share amounts)* | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|
| **Revenue** | | |
| Petroleum and natural gas sales (note 16) | **$ 332,848** | $ 137,931 |
| Royalties | **(23,068)** | (6,469) |
| Realized (loss) gain on derivative financial instruments | **(60,916)** | 16,588 |
| Unrealized (loss) gain on derivative financial instruments | **(24,098)** | 4,503 |
| Processing and marketing revenue (note 16) | **2,720** | 1,526 |
| | **227,486** | 154,079 |
| **Expenses** | | |
| Operating | **45,828** | 47,527 |
| Transportation | **39,305** | 29,504 |
| General and administrative | **9,183** | 8,083 |
| Share-based compensation | **2,482** | 2,272 |
| Depletion and depreciation (note 7) | **73,207** | 71,054 |
| | **170,005** | 158,440 |
| Income (loss) from operations | **57,481** | (4,361) |
| Financing (note 17) | **25,880** | 24,533 |
| Impairment (reversal) on property, plant and equipment (note 8) | **(228,549)** | 267,334 |
| Loss (gain) on divestiture of property, plant and equipment (note 7) | **6,318** | (38,344) |
| Other income | **(1,497)** | (1,141) |
| Income (loss) before income taxes | **255,329** | (256,743) |
| Deferred income tax expense (recovery) (note 13) | **50,030** | (53,563) |
| Net income (loss) and comprehensive income (loss) | **$ 205,299** | $ (203,180) |
| Net income (loss) per share (note 14) | | |
| Basic | **$ 1.34** | $ (1.34) |
| Diluted | **$ 1.27** | $ (1.34) |

*See accompanying notes to the consolidated financial statements.*

# CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

| *(thousands)* | Number of shares, net of shares in trust | Share capital | Contributed surplus | Deficit | Total Shareholders' equity |
|---|---|---|---|---|---|
| Balance January 1, 2021 | 151,182 | $1,482,925 | $ 70,052 | $ (839,460) | $ 713,517 |
| Net income for the year | - | - | - | 205,299 | 205,299 |
| Share-based compensation expensed | - | - | 2,482 | - | 2,482 |
| Share-based compensation capitalized | - | - | 2,373 | - | 2,373 |
| Issued from treasury on vesting of share awards | 174 | 324 | (324) | - | - |
| Released from trust on vesting of share awards | 5,845 | 6,598 | (6,598) | - | - |
| Purchase of shares held in trust (note 14) | (4,721) | (8,397) | - | - | (8,397) |
| Tax deduction on excess value of share awards | - | - | 3,880 | - | 3,880 |
| **Balance, December 31, 2021** | **152,480** | **$1,481,450** | **$ 71,865** | **$ (634,161)** | **$ 919,154** |

| *(thousands)* | Number of shares, net of shares in trust | Share capital | Contributed surplus | Deficit | Total Shareholders' equity |
|---|---|---|---|---|---|
| Balance January 1, 2020 | 151,534 | $1,478,294 | $ 71,644 | $ (636,280) | $ 913,658 |
| Net loss for the year | - | - | - | (203,180) | (203,180) |
| Share-based compensation expensed | - | - | 2,272 | - | 2,272 |
| Share-based compensation capitalized | - | - | 2,186 | - | 2,186 |
| Issued from treasury on vesting of share awards | 177 | 3,693 | (4,112) | - | (419) |
| Released from trust on vesting of share awards | 2,431 | 1,938 | (1,938) | - | - |
| Purchase of shares held in trust (note 14) | (2,960) | (1,000) | - | - | (1,000) |
| **Balance, December 31, 2020** | **151,182** | **$1,482,925** | **$ 70,052** | **$ (839,460)** | **$ 713,517** |

*See accompanying notes to the consolidated financial statements.*

# CONSOLIDATED STATEMENTS OF CASH FLOWS

| *(thousands)* | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|
| **Cash provided by (used in):** | | |
| **Operating activities:** | | |
| Net income (loss) | **$ 205,299** | $ (203,180) |
| Adjustments: | | |
| Unrealized loss (gain) loss on derivative financial instruments | **24,098** | (4,503) |
| Share-based compensation | **2,482** | 2,272 |
| Depletion and depreciation (note 7) | **73,207** | 71,054 |
| Financing expenses (note 17) | **25,880** | 24,533 |
| Interest expense (note 17) | **(23,416)** | (22,329) |
| Impairment (reversal) on property, plant and equipment (note 8) | **(228,549)** | 267,334 |
| Loss (gain) on divestiture of property, plant and equipment (note 7) | **6,318** | (38,344) |
| Transaction costs on property dispositions (note 7) | **(2,505)** | - |
| Deferred income tax expense (recovery) (note 13) | **50,030** | (53,563) |
| Decommissioning obligations settled (note 12) | **(4,844)** | (3,115) |
| Change in non-cash working capital (note 19) | **(8,844)** | (2,170) |
| | **119,156** | 37,989 |
| **Financing activities:** | | |
| Increase (decrease) in bank loan | **39,073** | (16,142) |
| Payments on lease obligations (note 11) | **-** | (187) |
| Shares purchased and held in trust (note 14) | **(8,397)** | (1,000) |
| Settlement of restricted and performance awards | **-** | (419) |
| | **30,676** | (17,748) |
| **Investing activities:** | | |
| Property, plant and equipment expenditures (note 7) | **(177,924)** | (86,260) |
| Property acquisitions (note 7) | **-** | (11,790) |
| Property dispositions (note 7) | **10,781** | 69,940 |
| Change in non-cash working capital (note 19) | **17,311** | 7,869 |
| | **(149,832)** | (20,241) |
| Change in cash and cash equivalents | **-** | - |
| Cash and cash equivalents, beginning of year | **-** | - |
| Cash and cash equivalents, end of year | **$ -** | $ - |

*See accompanying notes to the consolidated financial statements.*

# NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2021 and 2020

*(Tabular amounts in thousands)*

**1. Reporting entity:**

Crew Energy Inc. ("Crew" or the "Company") is an oil and gas exploration, development and production company based in Calgary, Alberta, Canada. Crew conducts its operations in the Western Canada Sedimentary basin, focused in the province of British Columbia. The consolidated financial statements (the "financial statements") of the Company are comprised of the accounts of Crew and its wholly owned subsidiary, Crew Oil and Gas Inc. which is incorporated in Canada, and two partnerships, Crew Energy Partnership and Crew Heavy Oil Partnership. Crew's principal place of business is located at Suite 800, 250 – 5th Street SW, Calgary, Alberta, Canada, T2P 0R4.

**2. Basis of preparation:**

These financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. A summary of the significant accounting policies and method of computation is presented in note 4.

The financial statements have been prepared on the historical cost basis except for derivative financial instruments which are measured at fair value. The methods used to measure fair values are discussed in note 5.

These financial statements are presented in Canadian dollars ("CDN"), which is the functional currency of the Company, its subsidiary and partnerships.

Expenses in the consolidated statements of income (loss) ("statements of income") are presented as a combination of function and nature in conformity with industry practice. Share-based compensation and depletion and depreciation expenses are presented on separate lines by their nature, while operating, transportation, marketing and general and administrative expenses are presented on a functional basis.

The financial statements were authorized for issuance by Crew's Board of Directors on March 8, 2022.

**3. COVID-19 estimation uncertainty:**

In March 2020, the World Health Organization declared a global pandemic following the emergence and rapid spread of a novel strain of the coronavirus ("COVID-19"). The pandemic and measures taken to limit its spread have contributed to significant volatility in global financial markets. The pandemic has adversely impacted global commercial activity creating economic uncertainty and volatility in commodity markets.

The full extent of the impact of COVID-19 on the Company's operations and future financial performance is unknown. It will depend on future developments that are uncertain and unpredictable, including the duration and the continued spread of COVID-19, its continued impact on financial markets on a macro-scale and any new information that may emerge concerning the effectiveness of available vaccines and the severity and spread of the virus. The pandemic presents uncertainty and risk with respect to the Company, its performance, and estimates and assumptions used by management in the preparation of its financial results.

The Company's financial performance, operations and business are particularly sensitive to a reduction in the demand for and prices of crude oil and natural gas. The potential direct and indirect economic impact of COVID-19 have been considered in management's estimates and assumptions at period end and have been reflected in the Company's results with any significant changes described in the relevant financial statements note.

The COVID-19 pandemic is an evolving situation that will continue to have widespread implications for the Company's business environment, operations and financial condition. Management cannot reasonably estimate the length or severity of this pandemic, or the extent to which the disruption may materially impact the Company's financial statements in fiscal 2022 and beyond.

A full list of the key sources of estimation uncertainty can be found in note 4 of these financial statements.

**4. Significant accounting policies:**

(a) Basis of consolidation:

(i) Subsidiaries:

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, substantive potential voting rights are taken into account. The financial statements of subsidiaries are included in the financial statements from the date that control commences until the date that control ceases. The acquisition method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the cost of acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognized immediately in the statements of income.

(ii) Jointly owned assets:

Some of the Company's oil and natural gas activities involve jointly owned assets. The financial statements include the Company's share of these jointly owned assets and its proportionate share of the relevant revenue and related costs.

(iii) Transactions eliminated on consolidation:

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the financial statements.

(b) Foreign currency:

Transactions in foreign currencies are translated to Canadian dollars at exchange rates at the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at the period end exchange rate. Non-monetary assets and liabilities denominated in foreign currencies that are measured at fair value are translated to the functional currency at the exchange rate at the date that the fair value was determined. Foreign currency differences arising on translation are recognized in the statements of income.

(c) Financial instruments:

(i) Non-derivative financial instruments:

Non-derivative financial instruments are comprised of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, the bank loan and the senior unsecured notes. Non-derivative financial instruments are recognized initially at fair value plus, for instruments not at fair value through the statements of income, any directly attributable transaction costs. Subsequent to initial recognition, non-derivative financial instruments are measured as described below.

Cash and cash equivalents is comprised of cash on hand, term deposits held with banks and other short-term highly liquid investments with original maturities of three months or less. Bank overdrafts that are repayable on demand and form an integral part of the Company's cash management, whereby management has the ability and intent to net bank overdrafts against cash, are included as a component of cash and cash equivalents for the purpose of the statement of cash flows.

Other non-derivative financial instruments, such as accounts receivable, the bank loan, the senior unsecured notes and accounts payable and accrued liabilities, are measured at amortized cost using the effective interest method, less any impairment losses.

(ii) Derivative financial instruments:

The Company enters into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices, interest rates and the exchange rate between Canadian and United States dollars. These instruments are not used for trading or speculative purposes. The Company has not designated its financial derivative contracts as effective accounting hedges, and thus has not applied hedge accounting, even though the Company considers all financial derivative contracts to be economic hedges. As a result, all financial derivative contracts are classified at fair value through the statements of income and are recorded on the statement of financial position at fair value. Transaction costs are recognized in the statements of income when incurred.

(iii) Share capital:

Common shares are classified as equity. Incremental costs directly attributable to the issuance of common shares and restricted and performance awards are recognized as a deduction from equity, net of any tax effects.

(d) Property, plant and equipment and intangible exploration assets:

(i) Recognition and measurement:

Exploration and evaluation ("E&E") expenditures:

Pre-license costs are recognized in the statements of income as incurred.

E&E costs, including the costs of acquiring leases and licenses initially are capitalized as E&E assets. The costs are accumulated in cost centers by well, field or exploration area pending determination of technical feasibility and commercial viability.

E&E assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, E&E assets are allocated to the related CGU.

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved and/or probable oil and gas reserves are determined to exist. A review of each exploration license or field is carried out, at least annually, to ascertain whether proved and/or probable oil and gas reserves have been discovered. Upon determination of proved and/or probable oil and gas reserves, intangible E&E assets attributable to those reserves are first tested for impairment and then reclassified from E&E assets to a separate category within tangible assets referred to as oil and natural gas interests.

Development and production costs:

Items of property, plant and equipment, which include oil and gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development and production assets are grouped into CGUs for impairment testing. When significant parts of an item of property, plant and equipment, including oil and natural gas interests, have different useful lives they are accounted for as separate items (major components).

Gains and losses on disposal of property, plant and equipment, property swaps and farm-outs, are determined by comparing the proceeds or fair value of the asset received or given up with the carrying amount of property, plant and equipment and are recognized in the statements of income.

(ii) Subsequent costs:

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in the statements of income as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing on or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in the statements of income as operating costs as incurred.

(iii) Depletion and depreciation:

The net carrying value of development or production assets is depleted using the unit of production method by reference to the ratio of production in the year to the related proved and probable oil and gas reserves, taking into account estimated forecasted future development costs necessary to bring those reserves into production and excludes salvage value and undeveloped land related to future development acreage with no associated reserves. Relative volumes of reserves and production are converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil. Forecasted future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent third party reserve evaluators at least annually.

The estimated useful lives for certain production assets for the current and comparative years are as follows:

| | |
|---|---|
| Gas processing plants | Unit of production |
| Pipeline facilities | Unit of production |
| Turnaround and workover costs | 2 years straight line |

For other assets, depreciation is recognized in the statements of income on a straight-line basis over the estimated useful lives of each part of an item of property, plant and equipment.

The estimated useful lives for other assets for the current and comparative years are as follows:

| | |
|---|---|
| Office equipment | 5 years |

Depreciation methods, useful lives and residual values are reviewed at each reporting date.

(iv) Assets held for sale:

Non-current assets, or disposal groups consisting of assets and liabilities, are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is met when the sale is highly probable and the asset is available for immediate sale in its present condition.

Non-current assets classified as held for sale are measured at the lower of the carrying amount and fair value less costs to sell, with impairments recognized in the statements of income in the period measured. Non-current assets and disposal groups held for sale are presented in current assets and liabilities on the statement of financial position.

(e) Leased assets:

When Crew is party to a lease arrangement as the lessee, it recognizes a right-of-use asset ("ROU asset") and a corresponding lease obligation on the balance sheets on the date that a leased asset becomes available for use. Interest associated with the lease obligation is recognized over the lease period with a corresponding increase to the underlying lease obligation. ROU assets are depreciated on a straight-line basis over the shorter of the asset’s useful life and the lease term.  Depreciation on ROU assets is recognized in depletion and depreciation.  ROU assets and lease obligations are initially measured on a present value basis.  Lease obligations are measured as the net present value of the lease payments which may include: fixed lease payments, variable lease payments based on an index or a rate, and amounts expected to be payable under residual value guarantees and payments to exercise an extension or termination option, if Crew is reasonably certain to exercise either of those options.  ROU assets are measured at cost, which is composed of the amount of the initial measurement of the lease obligation, less any incentives received, plus any lease payments made at, or before, the commencement date and initial direct costs and asset restoration costs, if any.  The rate implicit in the lease is used to determine the present value of the liability and ROU asset arising from a lease, unless this rate is not readily determinable, in which case the Company's incremental borrowing rate is used.

In cases where the leased asset is used in the Company's jointly controlled operations, Crew, as the operator, is the obligor to the lessor and presents the full amount of the lease obligation and ROU asset at the commencement date of the lease.  Certain payments relating to the Company's lease obligation may be recovered over time in accordance with billings for each partner's proportionate interest in the joint operation and are recognized in other income.

Short-term leases and leases of low-value assets are not recognized on the statement of financial position and lease payments are instead recognized in the financial statements as incurred.  For certain classes of leases, Crew does not separate lease and non-lease components, accounting for these leases as a single lease component.

(f) Impairment:

(i) Financial assets:

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired by measuring the asset's expected credit loss ("ECL").  Accounts receivable are due within one year or less; therefore, these financial assets are not considered to have a significant financing component and a lifetime ECL is measured at the date of initial recognition of the accounts receivable.

The ECL pertaining to accounts receivable is assessed at initial recognition and this provision is re-assessed at each reporting date.  ECLs are a probability-weighted estimate of all possible default events related to the financial asset (over the lifetime or within 12 months after the reporting period, as applicable) and are measured as the difference between the present value of the cash flows due to Crew and the cash flows the Company expects to receive.  In making an assessment as to whether financial assets are credit-impaired, the Company considers historically realized bad debts, evidence of a debtor's present financial condition and whether a debtor has breached certain contracts, the probability that a debtor will enter bankruptcy or other financial reorganization, changes in economic conditions that correlate to increased levels of default, the number of days a debtor is past due in making a contractual payment, and the term to maturity of the specified receivable.  The carrying amounts of financial assets are reduced by the amount of the ECL through an allowance account and losses are recognized in the statements of income.

Individually significant financial assets are tested for impairment on an individual basis.  The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in the statements of income.  An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

(ii) Non-financial assets:

The carrying amounts of the Company's non-financial assets are reviewed at each reporting date to determine whether there are any internal or external indicators of impairment or impairment reversal.  If any such indicator exists, then the recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets or CGUs. The estimated recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

Impairment reversals are recognized to the extent that impairment had been previously recorded, but are limited to the net book value that would exist had the original impairment never been recorded, including estimates for depletion.

The estimated recoverable amount involves significant estimates including the estimate of proved and probable oil and gas reserves and the related cash flows, the discount rates and the sales value of the undeveloped lands. The estimate of proved and probable oil and gas reserves and the related cash flows is sensitive to the significant assumptions regarding forecasted oil and gas commodity prices, forecasted production, forecasted operating costs, forecasted royalty costs and forecasted future development costs.

In assessing the value in use, the estimated future cash flows from proved and probable oil and gas reserves are discounted to their present value using a pre-tax discount rate that reflects current market assessment of the time value of money. Fair value is determined as the amount that would be obtained from the sale of the asset in an arm's length transaction between knowledgeable and willing parties. The forecasted oil and gas commodity prices used in the impairment test are based on period-end forecasted oil and gas commodity prices estimated by the Company's independent third party reserve evaluators. The Company also estimates the sales value of undeveloped lands which is based on relevant industry sales value data.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in the statements of income.

An impairment loss in respect of property, plant and equipment, recognized in prior years, is assessed at each reporting date for any internal or external indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized.

(g) Share based payments:

The grant date fair value of restricted and performance awards granted to employees is recognized as compensation expense, with a corresponding increase in contributed surplus over the vesting period. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of restricted and performance awards that are expected to vest. A performance multiplier is estimated on the grant date for performance awards and adjusted to reflect the number of performance awards that are expected to vest.

(h) Provisions:

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

(i) Decommissioning obligations:

The Company's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value using a risk-free rate of interest and management's best estimate of expenditure required to settle the present obligation at the statement of financial position date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as a finance cost whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

(i) Revenue:

Revenue from the sale of crude oil, natural gas, condensate and natural gas liquids is recorded when control of the product is transferred to the buyer based on the consideration specified in the contracts with customers. This usually occurs when the product is physically transferred at the delivery point agreed upon in the contract and legal title to the product passes to the customer.

The Company evaluates its arrangements with third parties and partners to determine if the Company acts as the principal or as an agent. In making this evaluation, the Company considers if it obtains control of the product delivered or services provided, which is indicated by the Company having the primary responsibility for the delivery of the product or rendering of the service, having the ability to establish prices or having inventory risk. If the Company acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net-basis, only reflecting the fee, if any, realized by the Company from the transaction.

Tariffs, tolls and other fees charged to other entities for use of pipelines and facilities owned by the Company are evaluated by management to determine if these originate from contracts with customers or from incidental or collaborative arrangements. Fees charged to other entities that are from contracts with customers are recognized in revenue when the related services are provided.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

(j) Finance income and expenses:

Finance expense comprises interest expense on borrowings and leases, accretion of the discount on provisions, accretion of deferred financing costs, impairment losses recognized on financial assets and corporate acquisition costs.

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use or sale. All other borrowing costs are recognized in the statements of income using the effective interest method. The capitalization rate used to determine the amount of borrowing costs to be capitalized is the weighted average interest rate applicable to the Company's outstanding borrowings during the period.

Interest income is recognized as it accrues in the statements of income, using the effective interest method.

(k) Income tax:

Income tax expense comprises current and deferred tax. Income tax expense is recognized in the statements of income except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(l) Earnings per share:

Basic earnings per share is calculated by dividing the profit or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted earnings per share is determined by adjusting the profit or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as restricted and performance awards granted to employees.

(m) Inventory:

The Company evaluates the carrying value of its inventory at the lower of cost and net realizable value. The net realizable value is estimated based on anticipated current market prices that the Company would expect to receive from the sale of its inventory.

(n) Government grants:

Government grants are recognized when there is reasonable assurance that the grant will be received and all attached conditions will be met. If a grant is received but compliance with any attached condition is not achieved, the grant is recognized as a deferred liability until such conditions are fulfilled. When the grant relates to an income or expense item, it is recognized as income or a reduction of the related expense item in the period in which the income is earned or costs are incurred. Where the grant relates to an asset, it is recognized as a reduction to the net book value of the related asset and then subsequently in the statements of income over the expected useful life of the related asset through lower charges to impairment and/or depletion and depreciation.

(o) Critical accounting judgments and key sources of estimation uncertainty:

The timely preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments made by management in the preparation of these financial statements are outlined below.

*Critical judgments in applying accounting policies:*

The following are the critical judgments that management has made in the process of applying the Company's accounting policies and that have the most significant effect on the amounts recognized in these consolidated financial statements:

*(i) Identification of CGUs*

Crew's assets are aggregated into CGUs, for the purpose of calculating impairment, based on their ability to generate largely independent cash inflows. By their nature, these estimates and assumptions are subject to measurement uncertainty and may impact the carrying value of the Company's assets in future periods. The Company has one CGU as of December 31, 2021.

*(ii) Impairment of petroleum and natural gas assets*

Judgments are required to assess when internal or external indicators of impairment or impairment reversal exist and impairment testing is required. Management considers internal and external sources of information including forecasted oil and gas commodity prices, forecasted production volumes, estimated recoverable quantities of proved and probable oil and gas reserves and rates used to discount the related future cash flow estimates. Judgement is required to assess these factors when determining if the carrying amount of an asset or CGU is impaired, or in the case of a previously impaired asset or CGU, whether the carrying amount of the asset or CGU has been restored.

*(iii) Deferred income taxes*

Judgments are made by management to determine the likelihood of whether deferred income tax assets at the end of the reporting period will be realized from future taxable earnings. To the extent that assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amounts recognized in the statements of income in the period in which the change occurs.

*(iv) Leased assets*

The Company is required to make judgements and assumptions on incremental borrowing rates and lease terms. The carrying amount of the ROU assets, lease obligations, interest and depreciation expense may differ due to changes in market conditions and expected lease terms. Incremental borrowing rates are based on the Company's borrowing rate at the commencement date of the lease, the security of the asset and market conditions. Lease terms are based on management's assumptions of future market conditions and operational decisions.

*Key sources of estimation uncertainty:*

The following are the key assumptions concerning the sources of estimation uncertainty at the end of the reporting period, that have a significant risk of causing adjustments to the carrying amounts of assets and liabilities.

*(i) Reserves*

Proved and probable oil and gas reserves and the related cash flows requires estimation and are subject to assumptions regarding forecasted production, forecasted oil and gas commodity prices, forecasted operating costs, forecasted royalty costs and forecasted future development costs. It also requires interpretation of geological and geophysical models in order to make an assessment of the size, shape, depth and quality of reservoirs, and their anticipated recoveries. The economical, geological and technical factors used to estimate proved and probable oil and gas reserves may change from period to period. Changes in reported proved and probable oil and gas reserves can impact the carrying values of the Company's property, plant and equipment, the calculation of depletion and depreciation, the provision for decommissioning obligations, and the recognition of deferred tax assets due to changes in expected future cash flows. The estimated proved and probable oil and gas reserves and the related cash flows from the Company's property, plant and equipment are evaluated by independent third party reserve evaluators at least annually. The Company's proved and probable oil and gas reserves represent the estimated quantities of oil, natural gas and natural gas liquids ("ngl") which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be economically recoverable in future years from known reservoirs and which are considered commercially producible. Such proved and probable oil and gas reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon (i) a reasonable assessment of the future economics of such production; (ii) a reasonable expectation that there is a market for all or substantially all the expected petroleum and natural gas production; and (iii) evidence that the necessary production, transmission and transportation facilities are available or can be made available. Reserves may only be considered proved and probable if producibility is supported by either production or conclusive formation tests. Crew's proved and probable oil and gas reserves are determined in accordance with the standards contained in National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities and the Canadian Oil and Gas Evaluation Handbook.

The Company is also required to estimate the sales value of undeveloped lands, which is based on industry sales value data.

*(ii) Decommissioning obligations*

The Company estimates future remediation costs of production facilities, wells and pipelines at different stages of development and construction of assets or facilities. In most instances, removal of assets occurs many years into the future. This requires assumptions regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and liability-specific discount rates to determine the present value of these cash flows.

*(iii) Business combinations*

In a business combination, management makes estimates of the fair value of assets acquired and liabilities assumed which includes assessing the value of oil and gas properties based upon the estimated proved and probable oil and gas reserves and the related cash flows acquired.

*(iv) Share-based payments*

All equity-settled, share-based awards issued by the Company are recorded at fair value. The fair value of restricted and performance awards are valued based on the closing stock price at grant date. In assessing the fair value of equity-based compensation, estimates have to be made regarding the performance multiplier for performance awards.

*(v) Income taxes*

Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in the statements of income both in the period of change, which would include any impact on cumulative provisions, and in future periods. Deferred tax assets, if any, are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse.

*(vi) Financial instruments*

The estimated fair value of financial instruments is reliant upon a number of estimated variables including forward curves for commodity prices, foreign exchange rates and interest rates, as well as volatility curves, and risk of non-performance. A change in any one of these factors could result in a change to the overall estimated valuation of the instrument. Additionally, estimates must be made with respect to impairment of financial assets and the provision of ECL recognized. In making an assessment as to whether financial assets are credit-impaired, the Company considers historically realized bad debts, any applicable public credit ratings, evidence of a debtor’s present financial condition and whether a debtor has breached certain contracts, the probability that a debtor will, or has entered bankruptcy or other financial reorganization, changes in economic conditions that correlate to increased levels of default, the number of days a debtor is past due in making a contractual payment, and the term to maturity of the specified receivable.

*(vii) Changing regulation*

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. With respect to environmental, social and governance ("ESG") and climate reporting, the International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the Canadian Securities Administrators have issued a proposed National Instrument 51-107 Disclosure of Climate-related Matters. The cost to comply with these standards, and others that may be developed or evolve over time, has not yet been quantified.

**5. Determination of fair values:**

A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

(i) Property, plant and equipment and exploration assets:

The fair value of property, plant and equipment recognized in an acquisition is based on market values. The market value of property, plant and equipment is the estimated amount for which property, plant and equipment could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The market value of oil and natural gas interests (included in property, plant and equipment) and intangible exploration assets is estimated with reference to the discounted cash flows expected to be derived from proved and probable oil and gas reserves and the related cash flows estimated by the Company's independent third party reserve evaluators. The risk-adjusted discount rate is specific to the asset with reference to general market conditions.

The market value of other items of property, plant and equipment is based on the quoted market prices for similar items.

(ii) Cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, bank loans and the senior unsecured notes:

The fair value of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, bank loans and the senior unsecured notes are estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At December 31, 2021 and December 31, 2020, the fair value of accounts receivable and accounts payable and accrued liabilities approximated their carrying value due to their short term to maturity. Bank loans bear a floating rate of interest and the margins charged by the lenders are indicative of current credit spreads and therefore carrying value approximates fair value. The fair value of the senior unsecured notes fluctuates in response to changes in the market rates of interest payable on similar instruments. At December 31, 2021, the carrying value of the unsecured notes approximated their fair value.

(iii) Derivatives:

The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and published forward price curves as at the statement of financial position date, using the remaining contracted volumes and a credit adjusted interest rate. The fair value of options and costless collars is based on option models that use published information with respect to volatility, prices and interest rates.

(iv) Restricted and performance awards:

The fair value of restricted and performance awards is measured at the grant date using the closing price of the common shares.

## 6. Financial risk management:

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, and financing activities such as:

- Credit risk;
- Market risk; and
- Liquidity risk.

This note presents information about the Company's exposure to each of the above risks, the Company's objectives, policies and processes for measuring and managing risk and the Company's management of capital. Further quantitative disclosures are included throughout these financial statements.

The Board of Directors oversees management's establishment and execution of the Company's risk management framework. Management has implemented and monitors compliance with risk management policies. The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities.

(a) Credit risk:

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations and arises principally from the Company's receivables from partners within jointly owned assets and operations, oil and natural gas marketers and counterparties to derivative financial assets. The maximum exposure to credit risk at year-end is as follows:

| | **December 31, 2021** | December 31, 2020 |
|---|---|---|
| Accounts receivable | **$ 41,861** | $ 22,135 |
| Derivative financial assets | **275** | 8,399 |
| | **$ 42,136** | $ 30,534 |

Accounts receivable:

Substantially all of the Company's petroleum and natural gas production is marketed under standard industry terms. Receivables from petroleum and natural gas marketers are normally collected on the 25th day of the month following production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large credit worthy purchasers and to sell through multiple purchasers. During 2021, the Company had three investment-grade customers that individually accounted for 10% or more of the Company's total revenues. The Company historically has not experienced any collection issues with its petroleum and natural gas marketers. Receivables from partners within jointly owned assets and operations are typically collected within one to three months of the bill being issued to the partner. The Company attempts to mitigate the risk from these receivables by obtaining partner approval of significant capital expenditures prior to the expenditure. However, the receivables are from participants in the petroleum and natural gas sector and collection of the outstanding balances can be impacted by industry factors such as commodity price fluctuations, limited capital availability and unsuccessful drilling programs. The Company does not typically obtain collateral from petroleum and natural gas marketers or joint asset partners; however, the Company can cash call for major projects and does have the ability, in some cases, to withhold production from joint asset partners in the event of non-payment.

Derivative financial assets:

Derivative financial assets can consist of commodity, interest rate and foreign exchange contracts used to manage the Company's exposure to fluctuations in commodity prices, interest rates and the exchange rate between United States and Canadian dollars. The Company manages the credit risk exposure related to derivative financial assets by selecting investment grade counterparties and by not entering into contracts for trading or speculative purposes.

The carrying amount of accounts receivable and derivative financial assets, when outstanding, represents the maximum credit exposure. As at December 31, 2021, the Company's receivables consisted of $39.2 million (December 31, 2020 - $18.5 million) of receivables from petroleum and natural gas marketers, of which all have been subsequently collected, $0.5 million (December 31, 2020 - $0.4 million) from partners with jointly owned assets and operations, none of which has been subsequently collected, and $2.2 million (December 31, 2020 - $3.2 million) of deposits, prepaids and other accounts receivable. The Company does not consider any of its receivables to be past due.

(b) Market risk:

Market risk is the risk that changes in market conditions, such as commodity prices, foreign exchange rates and interest rates, will affect the Company's cash flow, income or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while maximizing the Company's return.

The Company utilizes both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted in accordance with the Company's risk management policy that has been approved by the Board of Directors.

Foreign currency exchange rate risk:

Foreign currency exchange rate risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. The majority of the Company's petroleum and natural gas sales are conducted in Canada and are denominated in Canadian dollars; however, Canadian commodity prices are influenced by fluctuations in the Canadian to U.S. dollar exchange rate.

Interest rate risk:

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate fluctuations on its bank loan which bears a floating rate of interest. Average bank debt outstanding during the year ending December 31, 2021 was $58.7 million (December 31, 2020 - $35.1 million). For the year ended December 31, 2021, a 1.0 percent change to the effective interest rate would have had a $0.5 million impact on net income (loss) (December 31, 2020 - $0.4 million). The interest rate on the senior unsecured notes is fixed and is not subject to interest rate risk.

Commodity price risk:

Commodity price risk is the risk that future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted by not only the relationship between the Canadian and United States dollar, but also regional, North American and global economic events that dictate the levels of crude oil, natural gas and natural gas liquids supply and demand. The Company has attempted to mitigate a portion of the commodity price risk through the use of a diversified portfolio of market pricing points and the use of various financial derivative and physical delivery sales contracts as outlined below. The Company's policy is to only enter into commodity price contracts when considered appropriate to a maximum of 50% of forecasted gross production volumes for a period of not more than two years. Any contracts for volumes greater than 50% of forecasted gross production or extending beyond two years require approval from the Board of Directors.

Derivative assets:

Derivatives are recorded on the statement of financial position at fair value at each reporting period with the change in fair value being recognized as an unrealized gain or loss on the statements of income.

The Company's derivatives are measured in accordance with a three level hierarchy. The hierarchy groups financial assets and liabilities into three levels based on the significance of inputs used in measuring the fair value of the financial assets and liabilities. The fair value hierarchy has the following levels:

a) Level 1: fair value is based on quoted prices (unadjusted) in active markets for identical assets or liabilities;

b) Level 2: fair value is based on inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (ie. as prices) or indirectly (ie. derived from prices); and

c) Level 3: fair value is based on inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The Company's derivative contracts are valued using Level 2 of the hierarchy.

At December 31, 2021, the Company held derivative commodity contracts as follows:

| Notional Quantity | Term | Strike Price | Option Traded | Fair Value |
|---|---|---|---|---|
| *Natural Gas – AECO Daily Index:* | | | | |
| 35,000 gj/day | January 1, 2022 - March 31, 2022 | $2.91/gj | Swap | $ (2,658) |
| 15,000 gj/day | January 1, 2022 - December 31, 2022 | $2.42/gj | Swap | (4,171) |
| 27,500 gj/day | April 1, 2022 - June 30, 2022 | $2.54/gj | Swap | (967) |
| 20,000 gj/day | April 1, 2022 - October 31, 2022 | $3.04/gj | Swap | 577 |
| 2,500 gj/day | April 1, 2022 - December 31, 2022 | $3.43/gj | Swap | 293 |
| 27,500 gj/day | July 1, 2022 - September 30, 2022 | $2.53/gj | Swap | (819) |
| 27,500 gj/day | October 1, 2022 - December 31, 2022 | $2.81/gj | Swap | (1,012) |
| 5,000 gj/day | November 1, 2022 - March 31, 2023 | $3.76/gj | Swap | 278 |
| 2,500 gj/day | January 1, 2023 - March 31, 2023 | $3.75/gj | Swap | 78 |
| 2,500 gj/day | April 1, 2023 - June 30, 2023 | $2.70/gj | Swap | 13 |
| 2,500 gj/day | July 1, 2023 - September 30, 2023 | $2.70/gj | Swap | 9 |
| 2,500 gj/day | October 1, 2023 - December 31, 2023 | $3.05/gj | Swap | 7 |
| *Natural Gas – AECO Monthly Index:* | | | | |
| 7,500 gj/day | January 1, 2022 - March 31, 2022 | $2.68 - $3.03/gj | Collar(1) | (497) |
| 15,000 gj/day | January 1, 2022 - March 31, 2022 | $3.01/gj | Swap | (989) |
| 7,500 gj/day | January 1, 2022 - December 31, 2022 | $2.36/gj | Swap | (2,265) |
| 10,000 gj/day | April 1, 2022 - June 30, 2022 | $2.20/gj | Swap | (666) |
| 10,000 gj/day | July 1, 2022 - September 30, 2022 | $2.22/gj | Swap | (565) |
| 10,000 gj/day | October 1, 2022 - December 31, 2022 | $2.48/gj | Swap | (691) |
| *CDN$ Edmonton C5 Blended Index:* | | | | |
| 1,000 bbl/day | January 1, 2022 - June 30, 2022 | $81.44/bbl | Swap | (2,370) |
| **Total** | | | | **$ (16,415)** |

(1) The referenced contract is a costless collar whereby the Company receives $2.68/gj when the market price is below $2.68/gj, and receives $3.03/gj when the market price is above $3.03/gj.

As at December 31, 2021, a 10% change in future commodity prices applied against these contracts would have a $8.5 million (December 31, 2020 – $10.5 million) impact on net income (loss).

Subsequent to December 31, 2021, the Company entered into the following derivative commodity contracts:

| Notional Quantity | Term | Strike Price | Option Traded |
|---|---|---|---|
| *Natural Gas – AECO Daily Index:* | | | |
| 2,500 gj/day | April 1, 2022 - June 30, 2022 | $3.57/gj | Swap |
| 7,500 gj/day | April 1, 2022 - December 31, 2022 | $3.53/gj | Swap |
| 2,500 gj/day | October 1, 2022 - December 31, 2022 | $3.90/gj | Swap |
| 5,000 gj/day | November 1, 2022 - March 31, 2023 | $3.61/gj | Swap |
| 5,000 gj/day | January 1, 2023 - March 31, 2023 | $4.13/gj | Swap |
| 5,000 gj/day | April 1, 2023 - June 30, 2023 | $2.83/gj | Swap |
| 5,000 gj/day | July 1, 2023 - September 30, 2023 | $2.84/gj | Swap |
| 5,000 gj/day | October 1, 2023 - December 31, 2023 | $3.21/gj | Swap |
| *Natural Gas – AECO Monthly Index:* | | | |
| 5,000 gj/day | January 1, 2023 – December 31, 2023 | $3.13 - $4.35/gj | Collar(1) |
| *CDN$ Edmonton C5 Blended Index:* | | | |
| 250 bbl/day | April 1, 2022 - June 30, 2022 | $100.00/bbl | Swap |
| 1,000 bbl/day | July 1, 2022 - December 31, 2022 | $97.06/bbl | Swap |

(1) The referenced contract is a costless collar whereby the Company receives $3.13/gj when the market price is below $3.13/gj, and receives $4.35/gj when the market price is above $4.35/gj.

(c) Liquidity risk:

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with the financial liabilities. The Company's financial liabilities consist of accounts payable and accrued liabilities, financial instruments, the bank loan and the senior unsecured notes and lease obligations. Accounts payable and accrued liabilities consists of invoices payable to trade suppliers for office, field operating activities and capital expenditures. The Company processes invoices within a normal payment period. Accounts payable and accrued liabilities and financial instruments have contractual maturities of less than one year. To meet these obligations, the Company maintains a revolving credit facility, as outlined in note 9, which is subject to annual renewal by the lenders and has a contractual maturity in 2023 if not extended. The Company maintains and monitors cash flow which is used to partially finance operating and capital expenditures. The Company does not pay dividends. In addition, the Company issued $300 million in senior unsecured notes in 2017 that are scheduled to mature in 2024, as discussed in note 10.

Capital management:

The Company considers its capital structure to include working capital, long-term debt (including the bank loan and senior unsecured notes) and shareholders' equity. Crew's primary capital management objective is to maintain a strong financial position in order to continue to fund the Company's sustainability. Crew monitors its capital structure and makes adjustments on an ongoing basis in order to maintain the flexibility needed to achieve the Company's long-term objectives. To manage its capital structure, the Company may adjust capital spending, hedge future revenue through commodity contracts, issue new equity, issue new debt or raise funds through asset sales.

With 50% drawn on the Company's $150 million Facility and the senior unsecured notes termed out to 2024, the Company's financial position remains strong, with sufficient liquidity to fund the Company's on-going operations. The Company will continue to monitor debt levels and, if necessary, it will consider divesting of non-core properties, adjust its annual capital expenditure program or may consider other forms of financing to improve its financial position.

Net debt:

Capital Management includes the monitoring of net debt as part of the Company's capital structure.

The following table outline Crew's calculation of net debt:

| | December 31, 2021 | December 31, 2020 |
|---|---|---|
| Accounts receivable | **$ 41,861** | $ 22,135 |
| Accounts payable and accrued liabilities | **(74,929)** | (46,496) |
| Working capital deficiency | **(33,068)** | (24,361) |
| Bank loan | **(75,067)** | (35,994) |
| Senior unsecured notes | **(297,834)** | (296,851) |
| Net debt | **$ (405,969)** | $ (357,206) |

Neither the Company nor any of its subsidiaries are subject to externally imposed capital requirements. The bank loan is subject to a semi-annual review of its Borrowing Base, which is directly impacted by the value of the Company's oil and gas reserves (Bank loan – note 9).

Funds from operations and adjusted funds flow:

The benchmarks Crew uses to evaluate its capital management are funds from operations and adjusted funds flow. Funds from operations represents cash provided by operating activities before changes in operating non-cash working capital, accretion of deferred financing costs and transaction costs on property dispositions. Adjusted funds flow represents funds from operations before decommissioning obligations settled excluding government grants. The Company considers these metrics as key measures that demonstrate the ability of the Company's continuing operations to generate the cash flow necessary to maintain production at current levels and fund future growth through capital investment and to service and repay debt. Management believes that such measures provide an insightful assessment of the Company's operations on a continuing basis by eliminating certain non-cash charges, actual settlements of decommissioning obligations and transaction costs on property dispositions, the timing of which is discretionary.

| | Year ended December 31, 2021 | Year ended December 31, 2020 |
|---|---|---|
| Cash provided by operating activities | **$ 119,156** | $ 37,989 |
| Change in operating non-cash working capital | **8,844** | 2,170 |
| Accretion of deferred financing costs (note 17) | **(983)** | (983) |
| Transaction costs on property dispositions (note 7) | **2,505** | - |
| Funds from operations | **129,522** | 39,176 |
| Decommissioning obligations settled net of government grants (note 12) | **3,347** | 1,974 |
| Adjusted funds flow | **$ 132,869** | $ 41,150 |

## 7. Property, plant and equipment:

| Cost | | Total |
|---|---|---|
| Balance, January 1, 2020 | $ | 2,626,078 |
| Additions | | 86,260 |
| Acquisitions | | 13,019 |
| Divestitures | | (16,061) |
| Change in decommissioning obligations | | 8,512 |
| Capitalized share-based compensation | | 2,186 |
| Balance, December 31, 2020 | $ | 2,719,994 |
| Additions | | 177,924 |
| Acquisitions | | 1,400 |
| Divestitures | | (605,355) |
| Change in right-of-use assets | | (59) |
| Change in decommissioning obligations | | 4,717 |
| Capitalized share-based compensation | | 2,373 |
| **Balance, December 31, 2021** | **$** | **2,300,994** |

| Accumulated depletion and depreciation | | Total |
|---|---|---|
| Balance, January 1, 2020 | $ | 1,224,450 |
| Depletion and depreciation expense | | 71,054 |
| Divestitures | | (1,876) |
| Impairment (note 8) | | 267,334 |
| Balance, December 31, 2020 | $ | 1,560,962 |
| Depletion and depreciation expense | | 73,207 |
| Divestitures | | (553,148) |
| Impairment reversal (note 8) | | (228,549) |
| **Balance, December 31, 2021** | **$** | **852,472** |

| Net book value | | Total |
|---|---|---|
| **Balance, December 31, 2021** | **$** | **1,448,522** |
| Balance, December 31, 2020 | $ | 1,159,032 |

The calculation of depletion for the three months ended December 31, 2021 included estimated future development costs of $1,599.0 million (December 31, 2020 - $1,616.0 million) associated with the development of the Company's proved plus probable oil and gas reserves and excludes salvage value of $41.3 million (December 31, 2020 - $70.5 million) and undeveloped land of $142.5 million (December 31, 2020 - $148.0 million) related to future development acreage, with no associated reserves.

Included in depletion and depreciation expense for the year ended December 31, 2021, is $0.4 million (December 31, 2020 - $0.4 million) related to the right-of-use assets for the Company's leases. As at December 31, 2021, the net book value of these right-of-use assets is $2.1 million (December 31, 2020 - $2.6 million).

During the third quarter of 2021, the Company disposed of its Lloydminster heavy crude oil operations for cash proceeds of $10.7 million and incurred $2.5 million of related transaction costs. The disposition consisted of petroleum and natural gas properties and undeveloped land with a net book value of $45.8 million and associated decommissioning obligations of $34.5 million, resulting in a loss of $3.1 million on closing of the disposition.

During the third quarter of 2021, the Company entered into a swap of petroleum and natural gas properties and undeveloped land with a total net book value of $3.6 million for undeveloped land with a fair value of $1.4 million, resulting in a loss of $2.2 million.

During the year ended 2021, the Company also disposed of various non-core petroleum and natural gas properties with a net book value of $2.7 million and associated decommissioning obligations of $1.7 million, resulting in a loss of $1.0 million.

During the first quarter of 2020, the Company disposed of an 11% net working interest in each of its Septimus gas processing facility and West Septimus gas processing facility (“Greater Septimus Processing Complex”) located in Northeast British Columbia for net proceeds of $34.8 million, after transaction costs. This interest in the facilities was classified as held for sale as at December 31, 2019, with a net book value of $19.8 million and associated decommissioning obligations of $0.7 million, resulting in a gain of $15.7 million.

During the fourth quarter of 2020, the Company disposed of an additional 11% net working interest in its Greater Septimus Processing Complex for net proceeds of $34.9 million, after transaction costs. This interest in the facilities had a net book value of $13.0 million and associated decommissioning obligations of $0.9 million, resulting in a gain of $22.8 million. In an unrelated transaction, the Company exercised and closed its option with another third party for the acquisition of an approximate 16% interest in the Greater Septimus Processing Complex for $11.7 million.

## 8. Impairment (reversal) on property, plant and equipment:

| | **Year Ended December 31, 2021** | Year Ended December 31, 2020 |
|---|---|---|
| Impairment (reversal) on property, plant and equipment | **$ (228,549)** | $ 267,334 |
| | **$ (228,549)** | $ 267,334 |

2021 assessment:

At December 31, 2021, the Company did not identify any indicators of impairment, and therefore an impairment test was not performed.

The Company identified an indicator of impairment reversal at September 30, 2021 for the northeast British Columbia CGU and performed an impairment reversal test to estimate its recoverable amount. It was determined that the recoverable amount of the northeast British Columbia CGU exceeded its carrying value, resulting in all previous impairment, net of depletion, of $228.5 million being reversed. The indicator of impairment reversal existed as a result of increases in forecasted oil and gas commodity prices, along with an increase in the Company's market capitalization. The Company disposed of its Lloydminster CGU in the third quarter of 2021.

For the purpose of impairment testing, the recoverable amount of the northeast British Columbia CGU is the greater of its value in use and its fair value less costs to sell. Value in use was used by the Company and derived from proved and probable oil and gas reserves estimated by the Company’s third party reserve evaluators at December 31, 2020, and updated by the Company's internal reserve evaluators, including additional value determined for undeveloped lands. The Company used pre-tax discount rates between 10% and 20% dependent on the risk profile of the reserve category and determined a recoverable amount of $1,664.1 million.

Impairment reversals are recognized to the extent that impairment had been previously recorded, but are limited to the net book value that would exist had the original impairment never been recorded, including estimates for depletion.

The following forecasted oil and gas commodity prices were used in determining the estimated recoverable amount of the northeast British Columbia CGU at September 30, 2021:

| | WTI Oil (US$/bbl)[(1)] | AECO Gas ($CDN/mmbtu)[(1)] | $US/$CDN)[(1)] |
|---|---|---|---|
| 2021 | 76.00 | 5.00 | 0.80 |
| 2022 | 71.00 | 4.00 | 0.80 |
| 2023 | 68.00 | 3.36 | 0.80 |
| 2024 | 66.00 | 3.02 | 0.80 |
| 2025 | 67.32 | 3.08 | 0.80 |
| 2026 | 68.67 | 3.14 | 0.80 |
| 2027 | 70.04 | 3.21 | 0.80 |
| 2028 | 71.44 | 3.27 | 0.80 |
| 2029 | 72.87 | 3.34 | 0.80 |
| 2030 | 74.33 | 3.40 | 0.80 |
| 2031 | 75.81 | 3.47 | 0.80 |
| Remainder | +2.0%/yr | +2.0%/yr | 0.80 thereafter |

(1) Source: Sproule Associates forecasts, effective October 1, 2021.

The Company's independent third party reserve evaluators also assess many other financial assumptions regarding forecasted royalty rates, forecasted operating costs and forecasted future development costs along with several other non-financial assumptions that affect reserve volumes. Management considered these assumptions for the impairment reversal test at September 30, 2021, however, it should be noted that all estimates are subject to uncertainty.

As at September 30, 2021, a one percent increase or decrease in the discount rate or a five percent increase or decrease in forward commodity prices would not change the impairment reversal recorded for the northeast British Columbia CGU.

2020 assessment:

At December 31, 2020, due to strengthening commodity prices, the Company completed an assessment of the indicators of reversal of impairment, and as a result tested its northeast British Columbia CGU and Lloydminster CGU for impairment reversal. It was determined that the recoverable amounts of the northeast British Columbia CGU and Lloydminster CGU approximated their carrying value and impairment reversal was not recorded.

The following forecasted oil and gas commodity prices were used in determining whether an impairment or reversal to the carrying value of the Company's CGUs existed at December 31, 2020:

| | WTI Oil (US$/bbl)[(1)] | WCS ($CDN/bbl)[(1)] | AECO Gas ($CDN/mmbtu)[(1)] | $US/$CDN |
|---|---|---|---|---|
| 2021 | 46.88 | 44.19 | 2.75 | 0.77 |
| 2022 | 51.14 | 48.55 | 2.70 | 0.77 |
| 2023 | 54.83 | 52.90 | 2.65 | 0.77 |
| 2024 | 56.48 | 54.68 | 2.69 | 0.77 |
| 2025 | 57.62 | 55.78 | 2.74 | 0.77 |
| 2026 | 58.77 | 56.89 | 2.79 | 0.77 |
| 2027 | 59.94 | 58.03 | 2.86 | 0.77 |
| 2028 | 61.14 | 59.19 | 2.91 | 0.77 |
| 2029 | 62.36 | 60.37 | 2.97 | 0.77 |
| 2030 | 63.60 | 61.57 | 3.02 | 0.77 |
| Remainder | +2.0%/yr | +2.0%/yr | +2.0%/yr | 0.77 thereafter |

(1) Source: 4 Consultants' average, GLJ Ltd., McDaniel & Associates Consultants, Sproule Associates and Deloitte Resource Evaluation & Advisory price forecasts, effective January 1, 2021.

The external reserve evaluators also assess many other financial assumptions regarding royalty rates, operating costs and future development costs along with several other non-financial assumptions that affect reserve volumes. Management considered these assumptions for the impairment test at December 31, 2020, however, it should be noted that all estimates are subject to uncertainty.

At March 31, 2020, the Company determined that indicators of impairment existed as a result of; the COVID-19 pandemic and its impact on global commodity demand due to the measures taken to limit the spread of the pandemic, the rapid fall in crude oil prices due to increased supply brought on by a price war between OPEC and non-OPEC members and the impact that these events had on the Company's equity and debt values. As a result, the Company tested its northeast British Columbia CGU and Lloydminster CGU for impairment. It was determined that the carrying value of the northeast British Columbia CGU and Lloydminster CGU exceeded their estimated recoverable amounts and impairment charges of $237.5 million and $29.8 million, respectively, were recorded for the CGUs.

**9. Bank loan:**

As at December 31, 2021, the Company's bank facility consists of a revolving line of credit of $120 million and an operating line of credit of $30 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 3, 2022. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 per cent and all outstanding advances thereunder will become repayable in one year from the extension date. The available lending limits of the Facility (the "Borrowing Base") are reviewed semi-annually and are based on the bank syndicate's interpretation of the Company's reserves and future commodity prices. The Facility requires the Company to maintain a Liability Management Rating ("LMR") of greater than 1.2:1 in the province of Alberta and Saskatchewan, and greater than 2.0:1 in the province of British Columbia, if the uninflated, undiscounted abandonment and reclamation liabilities ("Decommissioning Obligations"), as determined by the individual province, is greater than $20 million. If the LMR falls below the required level in any province, the lenders have the option to re-determine the Borrowing Base. As at December 31, 2021, the Company's Decommissioning Obligations exceeded $20 million in the province of British Columbia, which carried an LMR of 8.7:1. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled Borrowing Base review on or before June 3, 2022. The Facility is secured by a floating charge debenture and a general securities agreement on all the assets of the Company.

Advances under the Facility are available by way of prime rate loans with interest rates between 2.00 percent and 5.50 percent over the bank's prime lending rate and bankers' acceptances and LIBOR loans, which are subject to stamping fees and margins ranging from 3.00 percent to 6.50 percent depending upon the secured debt to EBITDA ratio of the Company calculated at the Company's previous quarter end. Standby fees are charged on the undrawn Facility at rates ranging from 0.75 percent to 1.63 percent depending upon the secured debt to EBITDA ratio. As at December 31, 2021, the Company's applicable pricing included a 2.25 percent margin on prime lending, a 3.25 percent stamping fee and margin on bankers' acceptances and LIBOR loans along with a 0.81 percent per annum standby fee on the portion of the Facility that is not drawn. Borrowing margins and fees are reviewed annually as part of the bank syndicate's annual renewal.

At December 31, 2021, the Company had issued letters of credit totaling $7.9 million (December 31, 2020 - $9.4 million).

## 10. Senior unsecured notes:

On March 14, 2017, the Company issued $300 million of 6.5% senior unsecured notes, due March 14, 2024 (the "2024 Notes"). The 2024 Notes are guaranteed, jointly and severally, on an unsecured basis, by each of the Company's current and future restricted subsidiaries. Interest on the 2024 Notes accrues at the rate of 6.5% per year and is payable semi-annually.

The Company may redeem, on any one or more occasions, all or part of the 2024 Notes at the redemption prices set forth below, plus any accrued and unpaid interest:

| Year[1] | Percentage |
|---|---|
| 2021 | 102.145% |
| 2022 | 101.040% |
| 2023 and thereafter | 100.000% |

(1) For the 12 month period beginning on March 14 of each year.

Upon the occurrence of a change of control, the Company will be required to offer to repurchase each holder's notes at a price equal to not less than 101% of the principal amount, plus any accrued and unpaid interest.

At December 31, 2021, the carrying value of the 2024 Notes was net of deferred financing costs of $2.2 million (December 31, 2020 – $3.1 million).

## 11. Lease obligations:

| | **As at December 31, 2021** | As at December 31, 2020 |
|---|---|---|
| Less than 1 year | **$ 244** | $ - |
| 1 – 3 years | **1,461** | 974 |
| After 3 years | **1,328** | 2,117 |
| Total undiscounted future lease payments | **$ 3,033** | $ 3,091 |
| Total undiscounted future interest payments | **(278)** | (382) |
| Present value of lease obligations | **$ 2,755** | $ 2,709 |
| Current portion of lease obligations, included in accounts payable and accrued liabilities | **(135)** | 105 |
| Long-term portion of lease obligations | **$ 2,620** | $ 2,814 |

| | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|
| Principal payments | **$ -** | $ 187 |
| Interest payments | **-** | 102 |
| Total cash outflow | **$ -** | $ 289 |

The Company's total undiscounted future lease payments of $3.0 million (December 31, 2020 – $3.1 million) equate to future lease obligations. This amount excludes commitments for firm transportation and processing agreements, as disclosed in note 15, as they do not meet the definition of a lease as the Company does not control the asset or receive substantially all of the asset's economic benefits.

## 12. Decommissioning obligations:

| | As at December 31, 2021 | As at December 31, 2020 |
|---|---|---|
| Decommissioning obligations, beginning of year | **$ 93,178** | $ 87,024 |
| Obligations incurred | **4,340** | 2,275 |
| Obligations acquired | **-** | 1,229 |
| Obligations settled | **(4,844)** | (3,115) |
| Obligations divested | **(36,213)** | (1,693) |
| Change in estimated future cash outflows | **377** | 6,237 |
| Accretion of decommissioning obligations | **1,376** | 1,221 |
| Decommissioning obligations, end of year | **$ 58,214** | $ 93,178 |

| | Year ended December 31, 2021 | Year ended December 31, 2020 |
|---|---|---|
| Current decommissioning obligations | **$ 1,386** | $ - |
| Long-term decommissioning obligations | **56,828** | 93,178 |
| | **$ 58,214** | $ 93,178 |

The Company's decommissioning obligations result from its ownership interest in oil and natural gas assets including well sites and facilities. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning obligations to be $58.2 million as at December 31, 2021 (December 31, 2020 - $93.2 million) based on an inflation adjusted undiscounted total future liability of $92.2 million (December 31, 2020 - $108.6 million). These payments are expected to be made over the next 40 years with the majority of costs to be incurred between 2029 and 2057. The inflation rate applied to the liability is 1.81% (December 31, 2020 – 1.38%). The discount factor, being the risk-free rate related to the liability, is 1.70% (December 31, 2020 – 1.10%). The $0.4 million (December 31, 2020 - $6.2 million) change in estimated future cash outflows is a result of a change in the inflation rate, discount factor and estimated future abandonment costs.

During the year-end December 31, 2021 the Company received $1.5 million (December 31, 2020 - $1.1 million) of government grants earned for well site rehabilitation. These amounts are recognized in the statements of income as Other Income.

## 13. Income taxes:

(a) Deferred income tax expense (recovery):

The deferred income tax expense (recovery) in the financial statements differs from the result which would have been obtained by applying the combined federal and provincial income tax rate to the Company's income (loss) before income taxes. This difference results from the following items:

| | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|
| Income (loss) before income taxes | **$ 255,329** | $ (256,743) |
| Combined federal and provincial income tax rate | **24.80%** | 25.35% |
| Computed "expected" income tax expense (recovery) | **$ 63,322** | $ (65,084) |
| Increase (decrease) in income taxes resulting from: | | |
| Change in income tax rates | **-** | 1,412 |
| Non-deductible expenses and other | **466** | 662 |
| Change in share-based compensation estimate | **(707)** | 353 |
| Non-taxable portion of capital gain | **-** | (3,957) |
| Unrecognized deferred income tax asset | **(13,051)** | 13,051 |
| Deferred income tax expense (recovery) | **$ 50,030** | $ (53,563) |

(b) Deferred income tax liability:

The components of the Company's deferred income tax liability are as follows:

| | **December 31, 2021** | December 31, 2020 |
|---|---|---|
| Deferred tax liabilities: | | |
| Property, plant and equipment | **$ 162,440** | $ 62,811 |
| Derivative financial instruments | **-** | 1,905 |
| Other | **5,014** | 8,145 |
| Deferred tax assets: | | |
| Derivative financial instruments | **$ (4,071)** | $ - |
| Decommissioning obligations | **(14,437)** | (23,109) |
| Non-capital losses | **(102,796)** | (49,752) |
| Deferred income tax liability | **$ 46,150** | $ - |

As at December 31, 2020, the Company did not recognize a deferred income tax asset due to the uncertainty of future commodity prices and cash flows.

The following tables provide a continuity of the deferred income tax liability:

| | January 1, 2021 | Recognized in equity | Recognized in other | Recognized in statements of income | December 31, 2021 |
|---|---|---|---|---|---|
| Property, plant and equipment | $ 62,811 | $ - | $ - | $ 99,629 | $ 162,440 |
| Decommissioning obligations | (23,109) | - | - | 8,671 | (14,438) |
| Derivative financial instruments | 1,905 | - | - | (5,976) | (4,071) |
| Non-capital losses | (49,752) | - | - | (53,044) | (102,796) |
| Other | 8,145 | (3,880) | - | 750 | 5,015 |
| | **$ -** | **$ (3,880)** | **$ -** | **$ 50,030** | **$ 46,150** |

| | January 1, 2020 | Recognized in equity | Recognized in other | Recognized in statements of income | December 31, 2020 |
|---|---|---|---|---|---|
| Property, plant and equipment | $ 144,436 | $ - | $ - | $ (81,625) | $ 62,811 |
| Decommissioning obligations | (21,766) | - | - | (1,343) | (23,109) |
| Derivative financial instruments | 788 | - | - | 1,117 | 1,905 |
| Non-capital losses | (77,265) | - | - | 27,513 | (49,752) |
| Other | 7,370 | - | - | 775 | 8,145 |
| | **$ 53,563** | **$ -** | **$ -** | **$ (53,563)** | **$ -** |

The Company's assets have an approximate tax basis of $1,166.9 million at December 31, 2021 (December 31, 2020 - $1,105.9 million) available for deduction against future taxable income. The following table summarizes the tax pools:

| | **December 31, 2021** | December 31, 2020 |
|---|---|---|
| Cumulative Canadian Exploration Expense | **$ 267,200** | $ 259,200 |
| Cumulative Canadian Development Expense | **275,000** | 412,200 |
| Undepreciated Capital Costs | **192,500** | 176,500 |
| Non-capital losses | **414,500** | 253,200 |
| Share issue costs | **-** | 1,400 |
| Other | **17,700** | 3,400 |
| Estimated tax basis | **$ 1,166,900** | $ 1,105,900 |

Non-capital losses will begin expiring in 2036. The estimated income tax pools for 2021 have been reduced by the estimated deferred partnership income for 2021.

## 14. Share capital:

At December 31, 2021, the Company was authorized to issue an unlimited number of common shares with the holders of common shares entitled to one vote per share.

*Restricted and Performance Award Incentive Plan:*

The Company has a Restricted and Performance Award Incentive Plan ("RPAP") which authorizes the Board of Directors to grant restricted awards ("RAs") and performance awards ("PAs") to directors, officers, employees, consultants or other service providers of Crew and its affiliates.

Subject to terms and conditions of the RPAP, each RA and PA entitles the holder to an award value typically vesting as to one-third on each of the first, second and third anniversaries of the date of grant. For the purpose of calculating share-based compensation, the fair value of each award is determined at the grant date using the closing price of the common shares. In the case of PAs, the award value is adjusted for a payout multiplier which can range from 0.0 to 2.0 and is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period. On the settlement date, the Company has the option of settling the award value in cash or common shares of the Company.

For RAs and PAs granted prior to May 20, 2021, the Company is eligible to settle the award value for any such grants either in cash or in common shares acquired by an independent trustee in the open market for such purposes. For RAs and PAs granted subsequent to May 20, 2021, the Company is again, following shareholder approval, eligible to settle the award value of such grants either in common shares issued from treasury subject to the treasury share maximum provided in the RPAP or in common shares acquired by an independent trustee in the open market for such purposes. The Company is no longer eligible to settle awards granted after May 20, 2021 with cash.

Common shares are acquired in the open market by an independent trustee and are held in trust for the potential future settlement of award values and are netted out of share capital, including the cumulative purchase cost, until they are distributed for future settlements. For the year ended December 31, 2021, the trustee purchased 4,721,000 (December 31, 2020 – 2,960,000) common shares for a total cost of $8.4 million (December 31, 2020 – $1.0 million) and as at December 31, 2021 the trustee holds 4,143,000 (December 31, 2020 – 5,267,000) common shares in trust.

Upon the vesting of 2,034,000 (December 31, 2020 – 1,690,000) RAs and 2,204,000 (December 31, 2020 – 1,837,000) PAs, when taking into account the earned multipliers for PAs, 174,000 (December 31, 2020 – 177,000) common shares of the Company were issued from treasury, 5,845,000 (December 31, 2020 – 2,431,000) common shares were released from trust and nil in cash (December 31, 2020 – $0.4 million) was paid out in settlement of such awards for the year ended December 31, 2021.

The number of RAs and PAs outstanding are as follows:

| | Number of RAs | Number of PAs |
|---|---|---|
| Balance January 1, 2020 | 3,613 | 4,172 |
| Granted | 2,259 | 2,407 |
| Vested | (1,690) | (1,837) |
| Forfeited | (436) | (307) |
| Balance December 31, 2020 | 3,746 | 4,435 |
| Granted | 2,236 | 2,564 |
| Vested | (2,034) | (2,204) |
| Forfeited | (288) | (219) |
| **Balance December 31, 2021** | **3,660** | **4,576** |

*Per share amounts:*

Per share amounts have been calculated on the weighted average number of shares outstanding. The weighted average shares outstanding for the year ended December 31, 2021 was 153,012,000 (December 31, 2020 – 152,145,000).

In computing diluted earnings per share, the Company considers the dilutive impact of RAs and PAs. For the year ended December 31, 2021, 8,651,000 (December 31, 2020 – nil) shares were added to the basic weighted average common shares outstanding to account for the dilution of RAs and PAs. There were 13,000 (December 31, 2020 – 8,181,000) RAs and PAs that were not included in the diluted earnings per share calculation because they were anti-dilutive.

The volume weighted average trading price of the Company's common shares was $2.22 during the year ended December 31, 2021 (December 31, 2020 - $0.34).

## 15. Commitments:

| | 2022 | 2023 | 2024 | 2025 | 2026 | Thereafter |
|---|---|---|---|---|---|---|
| Firm transportation agreements | $ 34,071 | $34,005 | $30,022 | $29,373 | $22,678 | $ 23,994 |
| Firm processing agreement | 18,718 | 18,718 | 18,752 | 18,718 | 18,718 | 87,835 |
| **Total** | **$52,789** | **$52,723** | **$48,774** | **$48,091** | **$41,396** | **$ 111,829** |

Firm transportation agreements include commitments to third parties to transport natural gas and natural gas liquids from gas processing facilities in northeast British Columbia.

Firm processing agreements include commitments to process natural gas through the Greater Septimus Processing Complex gas processing facilities in northeast British Columbia.

## 16. Revenue:

*Petroleum and natural gas sales:*

Crew sells its production pursuant to fixed or variable-price contracts. The transaction price for variable priced contracts is based on the commodity price, adjusted for quality, location or other factors, whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Under the contracts, the Company is required to deliver a fixed or variable volume of crude oil, condensate, other ngl or natural gas to the customer. Revenue is recognized when a unit of production is delivered to the customer. The amount of revenue recognized is based on the agreed transaction price, whereby any variability in revenue relates specifically to the Company's efforts to transfer production, and therefore the resulting revenue is allocated to the production delivered in the period during which the variability occurs. As a result, none of the variable revenue is considered constrained.

Crude oil, condensate and ngl are sold under contracts of varying terms of up to one year. The Company's natural gas is sold through a combination of spot sales, month ahead physical sales, short term and multi-year contracts. Revenues are typically collected on the 25th day of the month following production.

The following table summarizes the Company's petroleum and natural gas sales, all of which are from revenue with contracts with customers:

| | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|
| Light crude oil | **$ 4,375** | $ 2,732 |
| Heavy crude oil | **17,388** | 14,384 |
| Natural gas liquids | **18,528** | 6,827 |
| Condensate | **77,738** | 40,646 |
| Natural gas | **214,819** | 73,342 |
| | **$ 332,848** | $ 137,931 |

*Marketing and processing revenue:*

The following table summarizes the Company's marketing and processing revenue:

| | **Year ended December 31, 2021** | Year ended December 31, 2020 |
|---|---|---|
| Processing revenue | **$ 2,720** | $ 2,416 |
| Marketing revenue | **-** | (890) |
| | **$ 2,720** | $ 1,526 |

**17. Financing:**

| | Year ended December 31, 2021 | Year ended December 31, 2020 |
|---|---|---|
| Interest expense | **$ 23,416** | $ 22,227 |
| Interest on lease obligations | **105** | 102 |
| Accretion of deferred financing costs | **983** | 983 |
| Accretion of decommissioning obligations | **1,376** | 1,221 |
| | **$ 25,880** | $ 24,533 |

**18. Key personnel expenses:**

The aggregate payroll expense of key personnel was as follows:

| | Year ended December 31, 2021 | Year ended December 31, 2020 |
|---|---|---|
| Short-term benefits | **$ 4,460** | $ 2,532 |
| Long-term benefits | **3,001** | 2,762 |
| | **$ 7,461** | $ 5,294 |

Crew has determined that its key personnel include both officers and the Company's Board of Directors. Short-term benefits are comprised of salaries and directors fees, annual bonuses and other benefits. Long-term benefits include share-based compensation expense from share awards under Crew's long-term incentive plans. Short-term employee benefits and share-based compensation include the capitalized and non-capitalized portion of these expenditures recorded in the financial statements during the respective periods.

**19. Supplemental cash flow information:**

Changes in non-cash working capital is comprised of:

| | Year ended December 31, 2021 | Year ended December 31, 2020 |
|---|---|---|
| Changes in non-cash working capital: | | |
| Accounts receivable | **$ (19,726)** | $ 4,859 |
| Accounts payable and accrued liabilities | **28,433** | 547 |
| | **$ 8,707** | $ 5,406 |
| Operating activities | **$ (8,844)** | $ (2,170) |
| Investing activities | **17,311** | 7,869 |
| Change in current portion of lease obligations, included in accounts payable and accrued liabilities | **240** | (293) |
| | **$ 8,707** | $ 5,406 |
| Interest paid | **$ (23,424)** | $ (22,251) |

# DIRECTORS & OFFICERS

## OFFICERS

Dale O. Shwed
*President and Chief Executive Officer*

John G. Leach, CPA, CA
*Executive Vice President and Chief Financial Officer*

James Taylor
*Chief Operating Officer*

Jamie L. Bowman
*Senior Vice President, Marketing & Originations*

Kurtis Fischer
*Vice President, Planning & Development*

Paul Dever
*Vice President, Government & Stakeholder Relations*

Kevin G. Evers, P. Geol.
*Vice President, Geosciences*

Mark Miller
*Vice President, Land and Negotiations*

Craig Turchak, CPA, CGA
*Vice President, Finance & Controller*

## BOARD OF DIRECTORS

John A. Brussa
*Chairman Independent Director*

Karen Nielsen, ICD.D
*Independent Director*

Ryan Shay, CPA, CA
*Independent Director*

Gail Hannon
*Independent Director*

Dale O. Shwed
*President, Crew Energy Inc.*

## CORPORATE SECRETARY

Michael D. Sandrelli
Partner, Burnet, Duckworth & Palmer LLP

# ABBREVIATIONS

bbl barrels
bbl/d barrels per day
bcf billion cubic feet
boe barrels of oil equivalent (6 mcf: 1 bbl)
bopd barrels of oil per day
mboe thousand barrels of oil equivalent (6 mcf: 1 bbl)
mmboe million barrels of oil equivalent (6 mcf: 1 bbl)
mcf thousand cubic feet
mcf/d thousand cubic feet per day
mmcf million cubic feet
mmcf/d million cubic feet per day
ngl natural gas liquids