Energy in transition

January 2022
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Kiwetinohk today

Kiwetinohk is an Alberta-based energy company with:

1. **15,058 boe/d Q3 2021 production** coming largely from high-netback, liquids-rich gas fields, that include owned processing infrastructure with significant spare processing capacity, with a Proved + Probable Reserve Life Index\(^1\) of 34 years in the Fox Creek region of northwest Alberta

2. **1,800 MW across 5 electrical power generation projects** (2 solar and 3 low-emissions, gas-fired) in early stages of development and sourcing of external project financing

3. Team with skills, experience and the aspiration to consolidate, develop and operate high netback natural gas properties and build a market-leading energy transition company

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\(^1\) Reserve life index refers to the ratio of total proved + probable reserves as per the 2021 Mid-Year McDaniel's Reserve Report using the July 1, 2021 Price Deck divided by annualized Q3 2021 production.
Targeted ten-year vision

Kiwetinohk aspires to finance and position among Alberta’s energy transition leaders, becoming an energy company of significance to the Alberta economy by targeting:

1. Generating **>1,500 MW of electricity** (>10% of Alberta grid capacity) from solar, wind and natural gas

2. Consolidating and developing **>300 MMcf/d of natural gas** production

3. Becoming a **significant producer** in the emerging hydrogen businesses, and

4. Capturing **>90% of the carbon** associated with its gas-fired power and blue hydrogen production operations
The term “Firm Renewable” is a Kiwetinohk-originated term that describes efficient, flexible-output, fast responding, gas-fired, internal reciprocating engine-driven power generation that addresses the need for stability that has been revealed as wind and solar renewable grows to become a significant proportion of a grid’s power supply.

NGCC stands for natural gas combined cycle.

<table>
<thead>
<tr>
<th></th>
<th>Firm Renewable</th>
<th>NGCC</th>
<th>Solar</th>
<th>Wind</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Renewable and non-GHG emitting</strong></td>
<td>✔️</td>
<td></td>
<td>✔️</td>
<td></td>
</tr>
<tr>
<td><strong>Reliable — supply can be controlled</strong></td>
<td>✔️</td>
<td>✔️</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Dispatchable — supply can be adjusted rapidly</strong></td>
<td>✔️</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- **Synergies between gas-fired and renewable power:**
  - Solar and wind minimize emissions but gas-fired power is required for reliability and dispatchability
  - *Firm Renewable* is fast responding gas-fired power generation that can compensate for the erratic output of wind and solar power thereby increasing grid stability as wind and solar renewable capacity grows
  - “Blue” hydrogen, produced from natural gas, offers a foot in the door of the hydrogen economy while “green” hydrogen, produced from water and renewable-sourced electricity, remains too expensive

- **Synergies between gas production operations and power and hydrogen production operations:**
  - Adverse effects of gas price volatility are nullified by balancing gas production with power and hydrogen gas feedstock requirements
  - Gas producers may be able to vary gas production rate to meet variable needs of power generation, eliminating need for storage
  - Gas production operations can be made greener by using clean power for pumps, compressors, space heat and lighting, and
  - CO₂ capture includes equipment and skills proven and in widespread use by gas producers to remove CO₂ from some natural gas (that can be adapted to capture CO₂ from power generation exhaust gas)

- Kiwetinohk aspires to be able to provide customers with reliable, dispatchable, clean electricity and hydrogen

- Transition gone bad: some jurisdictions that have excluded gas-fired power from their energy transition portfolios have suffered from high consumer energy prices and interruptions in grid power supply
Global drive to lower emissions

- International Energy Agency’s (IEA) primary energy projection scenarios all show strong growth in renewables and continued use of oil and gas.
- All 2030 scenarios suggest varying levels of reduction in the use of coal and oil, with further reductions required for net zero.

### Primary energy sources predicted in 2030

#### Four scenarios

- **2020 Actual**
  - Renewables: 5%
  - Oil: 26%
  - Gas: 29%
  - Coal: 24%
  - Nuclear: 5%
  - Biomass: 4%
  - Total: 12% of the natural gas wedge

- **Stated Policies**
  - Renewables: 5%
  - Oil: 22%
  - Gas: 16%
  - Coal: 30%
  - Nuclear: 17%
  - Biomass: 6%
  - Total: 23%

- **Announced Pledges**
  - Renewables: 5%
  - Oil: 23%
  - Gas: 30%
  - Coal: 19%
  - Nuclear: 28%
  - Biomass: 6%
  - Total: 22%

- **Sustainable Development**
  - Renewables: 6%
  - Oil: 23%
  - Gas: 28%
  - Coal: 19%
  - Nuclear: 28%
  - Biomass: 6%
  - Total: 19%

- **Net Zero 2050 Scenario**
  - Renewables: 8%
  - Oil: 24%
  - Gas: 25%
  - Coal: 13%
  - Nuclear: 8%
  - Biomass: 30%
  - Total: 24%

### Increasingly aggressive reduction in greenhouse gas emissions

Demand for energy within Kiwetinohk’s scope of business increases in all IEA scenarios.

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1. Gas includes “Natural Gas with CCUS”, which represents less than 1% of the natural gas wedge in 2020, 2030 and 2050. CCUS is carbon capture utilization and storage.
Kiwetinohk and the energy transition

Kiwetinohk is focussed on profitable, high impact increments toward net zero emissions.
1. Returns are calculated using the assumption that all capital was invested at the original financing dates and prices for original investors, and that all capital was returned based on the dates and pricing at the point of IPO or corporate sale. MOIC: “multiple on invested capital”, calculated as realized value plus unrealized value divided by total investment. IRR: “internal rate of return”, calculated as the discount rate required for the net present value of all cash flows to be zero.

2. Seven Generations original financing return at time of IPO based on $2.50/sh purchase and $18.00/sh IPO price; North American Oil Sands original financing return at time of sale based on $2.43/sh purchase and $20.00/sh sale price; Krang original financing return at time of sale based on $1.00/sh purchase and $3.40/sh sale price; Passage original financing return at time of sale based on $0.60/sh purchase and $2.05/sh sale price.

Pat Carlson’s track record – commercialization of technology

Pat ranks among Canadian energy industry leaders at commercializing and adapting technology as new business opportunities emerge.
Kiwetinohk senior management team

**Pat Carlson** Chief Executive Officer
Technology application and ESG leader, successful executive and entrepreneur. Four previous successful companies, all with a focus in emerging business / technology trends (shale gas, SAGD\(^1\) & upgrading, cold production, enhanced gas recovery)

**Mike Backus** Chief Operating Officer, Upstream Division
Experienced leader in a variety of professions, including operational, engineering, finance, executive leadership and director roles, both domestically and internationally

**Janet Annesley** Chief Sustainability Officer
Extensive experience in private sector and government across large projects leading stakeholder engagement, government and regulatory affairs. Helped establish ESG strategies for Shell Canada and Husky, and managed the Canadian Association of Petroleum Producer’s Responsible Canadian Energy performance reporting program

**Mike Hantzsch** Senior Vice President, Midstream and Market Development
Seasoned midstream executive with extensive experience in the areas of gas gathering, processing, transmission, marketing and joint ventures

**Lisa Wong** Senior Vice President, Business Systems
Extensive energy industry finance and accounting experience in four successful PE start-ups. She currently focuses her efforts on maximizing organizational effectiveness

**Jakub Brogowski** Chief Financial Officer
Experienced executive with global investment banking background in North America, Europe and Asia; completed over 50 advisory and financing transactions with a total value of ~$47 billion

**John Maniawski** President, Green Energy Division
Experienced executive in power, utilities and pipelines including strategy, business development, project execution and operations. Former SVP, Business Development at Evolugen and Head of Power Development, Americas at Enbridge where he led growth of a $4 billion, 2000 MW renewable platform

**Sue Kuethe** Executive Vice President, Land and Community Inclusion
Highly experienced land, community and indigenous relations professional. Previously VP, Land and Community Affairs with subsidiaries of Koch Industries, Inc. Sue has negotiated greater than $1.3 billion in property transactions.

**Kurt Molnar** Senior Vice President, Business Development
Independently ranked as a top three equity energy analyst for five years prior to joining KEC. Highly experienced in all aspects of energy finance including corporate finance, energy credit, institutional equity sales, research and corporate development

**Farid Shirkavand** Vice President, Power Projects
Formerly Drilling Technology Director at Seven Generations. Ph.D. drilling engineer, technical oversight on greater than 400 wells comprising over 1,000 km of lateral length drilled while reducing costs per meter by 67%

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Senior management team has expertise for all aspects of Kiwetinohk's business

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1. Steam-assisted gravity drainage.
Kiwetinohk subject matter experts

**Mike Carlson**  
Vice President, Completions  
Formerly Completions Manager at Seven Generations. Oversight of 10,000 fracture stimulation operations. Dominated top 20 Canadian well lists

**Jim Floyd**  
Senior Vice President, Power, Green Energy Division  
Extensive experience in multiple areas in the power industry. Manager of Engineering - The Western Alberta Tie Line ($1.4B), General Manager of Construction - Heartland Transmission Project ($660M), President - Caltech Group (Acquired by Stantec)

**Craig Parsons**  
Vice President, Economics and Finance, Kiwetinohk Green Energy Division  
Experienced leader in power energy finance funding numerous projects including corporate finance, debt financing and restructuring. Expertise in carbon management including quantification and monetization of carbon offsets

**Tim Stauf**  
Senior Executive, Power, Kiwetinohk Green Energy Division  
Proven industry executive and project developer with extensive infrastructure and marketing experience in the North American energy and petrochemical industries including natural gas, natural gas liquids, olefins, hydrogen and methanol

**Shelin Chugh**  
Director, Reservoir Engineering  
Canadian and international experience in optimizing recovery, with expertise in EOR screening, design and field development for CO₂ and hydrocarbon miscible floods via reservoir simulations

**Mark Friesen**  
Director, Investor Relations  
Experienced sell-side equity research analyst at several Canadian banks and energy boutique firms before pivoting to corporate financial planning. Mark comes to investor relations combining his capital markets and corporate strategy experience

**Tim Alberts**  
Vice President, Production  
Extensive experience in managing gas operations. Co-founder of Seven Generations Grande Prairie operations hub, serving as Production Manager and community liaison with leadership of over 150 personnel

**Dobromir Filip**  
Director of Engineering, Kiwetinohk Green Energy Division  
Expertise in managing power generation project development and design. Expert in evaluation of emerging technologies in power generation, energy storage, CO₂ capture and hydrogen production

**Jim Floyd**  
Senior Vice President, Power, Green Energy Division  
Extensive experience in managing gas operations. Co-founder of Seven Generations Grande Prairie operations hub, serving as Production Manager and community liaison with leadership of over 150 personnel

**Lyle Strom**  
Vice President, Petroleum Marketing  
Broad experience in the management of risk, trading and marketing of energy products throughout North America. Recently, Lyle was instrumental in initiating Canada’s first EO100 Certification of the Kakwa River Project and Canada’s first physical sale of natural gas to an LNG exporter.

**Kevin Nielsen**  
Controller  
Extensive experience providing leadership in public financial reporting, internal controls, treasury, tax, insurance and risk management. Expertise in IFRS, regulatory and security-related filings.

**Depth of technical expertise in required areas for Kiwetinohk’s business**
Culture of stakeholder inclusion

- **Low relative upstream emissions profile** driven by liquids-rich gas focus
- “Firm Renewables,” dispatchable, high-efficiency natural-gas fired power generation **enables more solar and wind**
- **700 MW** renewable power in development, approval and financing
- Anticipated long-term growth in net zero energy systems, including **hydrogen and circular economy**

- Strong leadership representation of **women and people of color**
- **Indigenous engagement** and partnerships to advance economic inclusion
- Developing **low carbon reliable electricity** to support Canada’s energy transition and economy
- Providing skilled, good-paying and long-term jobs in rural communities

- Board accountable for ESG, including climate-related risk oversight
- Board delegation of ESG oversight to board committees, including audit and verification
- Majority independent board directors
- Diverse and inclusive board: 30% women and people of color, with added board recruitment underway

Our team is charged with including stakeholders in planning, building and operating Kiwetinohk’s projects with the objective of building a shared sense of ownership
Growth aspirations and shareholder value realization

Vertically integrating from energy resource to clean energy market to capture added market value resulting from price & market stability and reduced emissions

The varying cost of capital requires a variety of financial structures

- Carried interest / project equity
- Project debt
- Term debt
- Partnership structures

Note: Illustrative EV/EBITDA and D/EBITDA multiples based on Kiwetinohk's review of analyst estimates.
Benchmarking netbacks and integration value
(based on US$70 WTI / US$3.75 HHUB / $70 MWhr)

Operating Netback ($/boe)

- Fox Creek
- Integrated Firm Renewable
- Integrated NGCC

Implied Recycle Ratio (x)

- $36.5
- $50.5
- $52.4

Integration value adds netback and reduces volatility at higher recycle ratio

INTEGRATION ADVANTAGE

- Higher margins & netbacks
- Reduced volatility
- Increased market optionality
- Lower cost of capital
- Carbon accounting

See “Forward-looking statements – future-oriented financial information”.

1. Fox Creek includes Simonette and Placid assets. Sales product pricing differential to benchmarks, royalties, transportation and operating costs based on Q3 2021 results. Capital costs based on July 2021 McDaniel Reserves Report 1P Corporate Reserves forecast 2022-2025. Fox Creek netbacks are at field level and exclude debt servicing charges.

2. Firm Renewable and NGCC facility figures assume 50% and 96% uptime, and 40% premium and 0% premium to 24 by 7 Alberta power pricing, respectively. Netback calculated based on fully integrated gas, associated liquids based on Q3 2021 production split and McDaniel capital costs per boe from Fox Creek. Power plant capital costs based on equity share capital required for each project and include capitalized interest payments during construction. Integrated netbacks are at field level and exclude debt servicing charges.
Asset Overview
Power portfolio strategy

POWER PORTFOLIO STRATEGY: Pursuing three pillars of renewable and low-carbon, natural gas-fired power generation to deliver clean, reliable, dispatchable, and low-cost power through early-stage development and focused deployment of capital.

Renewable: Utility scale solar and wind power
- No emissions, sustainable solar and wind power
- Advancing development of solar projects
- Evaluating acquisitions and partnerships on pre-construction wind and solar projects

Firm Renewable, high efficiency, fast responding, reciprocating engine, gas-fired power
- Bridges supply gaps related to intermittency of renewables and unplanned outages
- Flexibility and fast response enable maximum penetration of solar and wind power
- Evaluating carbon capture, use and storage (CCUS)

Large-scale, natural gas combined cycle (NGCC) power
- Low-emissions, reliable, base load power implementing leading edge technology
- Developing plants with among the highest efficiency baseload power in Alberta
- Evaluating CCUS and hydrogen fueled technology
**Green Energy | $3.0 Bn of Power projects in development**

<table>
<thead>
<tr>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Solar 1</strong></td>
<td><strong>Solar 2</strong></td>
<td><strong>Firm Renewable 1</strong></td>
<td><strong>NGCC 1</strong></td>
<td><strong>NGCC 2</strong></td>
</tr>
<tr>
<td>Capacity (Nameplate, AC)</td>
<td>400 MW</td>
<td>300 MW</td>
<td>101 MW</td>
<td>500 MW</td>
</tr>
<tr>
<td>Capacity (Net to Grid)</td>
<td>400 MW</td>
<td>300 MW</td>
<td>97 MW</td>
<td>460 MW</td>
</tr>
<tr>
<td>Plant Efficiency</td>
<td>47%</td>
<td>60%</td>
<td>60%</td>
<td></td>
</tr>
<tr>
<td>(Adjusted to site conditions)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Capacity Factor</td>
<td>28%¹</td>
<td>28%¹</td>
<td>90%²</td>
<td>90%</td>
</tr>
<tr>
<td>Heat Rate (MJ/kWh: +/-5%)</td>
<td>7.6</td>
<td>6.0</td>
<td>6.0</td>
<td></td>
</tr>
<tr>
<td>Capital Cost ($ MM)</td>
<td>$655 (Class 3)</td>
<td>$492 (Class 3)</td>
<td>$145 (Class 3)³</td>
<td>$875 (Class 4)³</td>
</tr>
<tr>
<td>Carbon Credits Earned</td>
<td>✔</td>
<td>✔</td>
<td>✔</td>
<td>✔</td>
</tr>
</tbody>
</table>

Note: Existing gas-fired generation simple cycle heat rate 9.5, NGCC heat rate 7 as per 2021 Alberta Annual Electric Study, EDC & Associates.

1. Assumes DC/AC ratio of 1.5, and bifacial, single axis tracking design.
2. Designed for intermittent operation. The actual dispatch will be based on market conditions and contracting.
3. Costs exclude CCUS.
# Green Energy | Status of power projects in development

<table>
<thead>
<tr>
<th></th>
<th>1 Solar 1</th>
<th>2 Solar 2</th>
<th>3 Firm Renewable 1</th>
<th>4 NGCC 1</th>
<th>5 NGCC 2</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Capacity</strong> (Nameplate, AC)</td>
<td>400 MW</td>
<td>300 MW</td>
<td>101 MW</td>
<td>500 MW</td>
<td>500 MW</td>
</tr>
<tr>
<td><strong>AESO Stage</strong></td>
<td>2</td>
<td>1</td>
<td>2</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td><strong>Site Control</strong></td>
<td>Options secured</td>
<td>Options secured</td>
<td>Land acquisition in progress</td>
<td>Land acquisition in progress</td>
<td>Land acquisition in progress</td>
</tr>
<tr>
<td><strong>Public Consultation</strong></td>
<td>Underway</td>
<td>Planning underway</td>
<td>Underway</td>
<td>Planning underway</td>
<td>Planning underway</td>
</tr>
<tr>
<td><strong>Regulatory/Environmental</strong></td>
<td>AEP application submitted; AUC Q2</td>
<td>AEP application submitted</td>
<td>AEP and AUC applications Q2</td>
<td>Planning underway</td>
<td>Planning underway</td>
</tr>
<tr>
<td><strong>Engineering</strong></td>
<td>Pre-FEED Complete; FEED underway</td>
<td>BD complete</td>
<td>FEED complete</td>
<td>BD complete; Pre-FEED Q2</td>
<td>BD complete; Pre-FEED Q2</td>
</tr>
<tr>
<td><strong>Targeted FID</strong></td>
<td>Q3 2022</td>
<td>Q2 2023</td>
<td>Q4 2022</td>
<td>Q3 2024</td>
<td>Q1 2023</td>
</tr>
<tr>
<td><strong>Targeted COD</strong></td>
<td>Q4 2024</td>
<td>Q2 2025</td>
<td>Q3 2024</td>
<td>Q3 2027</td>
<td>Q1 2026</td>
</tr>
</tbody>
</table>

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1. Regulatory and environmental applications are filed with the Alberta Environment and Parks (AEP) and Alberta Utilities Commission (AUC)
Green Energy | Hydrogen and other clean energy initiatives

For the long term, Kiwetinohk aspires to be a leading provider of low-to-no emissions, dispatchable, reliable, low-cost energy and related products and services.

The need for carbon accountability and the difficulty shipping hydrogen motivate companies to co-locate with their carbon manager and hydrogen provider; the synergistic conservation of energy and management of waste, resources such as water and by-products advantage clusters of businesses.
## Justifying business development capital: power project financing strategy

<table>
<thead>
<tr>
<th>Project Type</th>
<th>Project Size</th>
<th>Estimated Pre-Construction Business Development Capital Exposure</th>
<th>Illustrative Project Capital Cost</th>
<th>Required Benchmark Annual EBITDA</th>
<th>Illustrative Carried Interest EBITDA Range (10% - 20%)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>(MM)</td>
<td>(MM)</td>
<td>(MM)</td>
<td>(MM)</td>
</tr>
<tr>
<td></td>
<td>400 MW</td>
<td>$3 – $6</td>
<td>$625 – $675</td>
<td>$80 – $90</td>
<td>$8 – $18</td>
</tr>
<tr>
<td></td>
<td>101 MW</td>
<td>$3 – $6</td>
<td>$140 – $160</td>
<td>$20 – $25</td>
<td>$2 – $5</td>
</tr>
<tr>
<td></td>
<td>500 MW</td>
<td>$4 – $8</td>
<td>$850 – $925</td>
<td>$150 – $180</td>
<td>$15 – $36</td>
</tr>
</tbody>
</table>

- Kiwetinohk has allocated capital in 2022 to business development and pre-construction activities for power development projects.
- Due to higher upfront risk involved in identifying and advancing projects prior to construction, Kiwetinohk will seek carried equity interests and/or other incentives in projects it is successful in bringing to a final investment decision stage.
- Earning a carried equity interest in a power project at construction justifies the pre-construction business development costs.

1. See “Forward-looking statements – future-oriented financial information”.
2. See “Green energy project assumptions” and additional details in appendix at the back of this presentation for operating assumptions of power project types.
High quality upstream asset base with running room

UPSTREAM ASSET OVERVIEW

Strategically located assets

- **Superior development area:** strong Montney and Duvernay production base in active greater Kaybob area
- **Growing production base:** Fox Creek core area delivering over 14,000 boe/d (~55% natural gas and 12% NGLs)\(^1\) in Q3 2021
- **Optionality:** dry gas – liquids rich window provides a variety of economic opportunities and flexibility to control the Company's product mix

Established production and reserve base

- **Strong foundation at an attractive price:** 38 mmboe of Proved Developed Producing reserves purchased for <$10/boe (>100 mmboe Total Proved at ~$4/boe)\(^2\)
- **Strong netbacks:** generating >3x recycle ratio on acquired reserves
- **Running room:** 119 Total Proved plus Probable future drilling locations in Fox Creek, and a significant number of unbooked locations and undeveloped land position, and a current corporate Reserve Life Index of 34 years\(^2,3\)

Depth of resilient inventory

- **Capital efficiency:** deploying longer laterals and wider lateral spacing with larger fracs to improve capital efficiency across the asset
- **Scale:** significant upstream asset consolidation opportunities exist in Fox Creek region

Core assets provide large scale owned and controlled upstream resource
Owned and controlled midstream infrastructure

1. Net ownership interest in operated facility raw gas capacities of Kaybob 05-31 38mmcf/d, Simonette 10-29 60mmcf/d, Negus 11-03 15mmcf/d, 07-11 Sour 33.8 mmcf/d and 07-11 Amine 12.8 mmcf/d.

2. As at Q3 2021.

3. Replacement cost represents facilities, gathering systems, and water infrastructure – all net Working Interest amounts.

~$300MM of infrastructure (net replacement cost) underpins superior asset value.
Consolidation opportunities across the Montney, Duvernay and Deep Basin

Opportunity for consolidation of high-quality natural gas

- Focused on superior upstream economics
- Seeking locations with overlapping proximity to owned midstream and potential power development opportunities
- Developing diversified profit sources to reduce cyclical volatility

Each of the Montney, Duvernay and Deep Basin Cretaceous plays possess opportunities to consolidate production and low break-even cost drilling locations
Financial Overview
## Corporate summary

### FINANCIAL AND OPERATING HIGHLIGHTS

<table>
<thead>
<tr>
<th></th>
<th>Q3 2021</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>WTI</strong></td>
<td>$67.60</td>
</tr>
<tr>
<td><strong>Henry Hub</strong></td>
<td>$4.01</td>
</tr>
<tr>
<td><strong>Production</strong></td>
<td>15,058</td>
</tr>
<tr>
<td><strong>Production Split</strong></td>
<td><strong>31%</strong> / <strong>12%</strong> / <strong>57%</strong></td>
</tr>
<tr>
<td><strong>Operating Netback</strong></td>
<td>$31.13</td>
</tr>
<tr>
<td><strong>Capital Expenditures</strong></td>
<td>$14.7</td>
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<tr>
<td><strong>Cash Flow from Operating Activities</strong></td>
<td>$29.6</td>
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<tr>
<td><strong>Adjusted Funds Flow from Operations</strong></td>
<td>$28.2</td>
</tr>
<tr>
<td><strong>Net Debt / Credit Facility Capacity</strong></td>
<td>$37 / $315</td>
</tr>
<tr>
<td><strong>Basic Shares Outstanding</strong></td>
<td>43.6</td>
</tr>
<tr>
<td><strong>Management and Director Ownership</strong></td>
<td>3.5%</td>
</tr>
</tbody>
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### Q3 2021 OPERATING NETBACK (C$/BOE)

**PDP acquisition cost of ~$10.00 per boe**

**1P acquisition cost of ~$4.00 per boe**

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2. Adjusted funds flow from operations is cash flow from operating activities before changes in non-cash working capital, decommissioning expenditures, restructuring costs, acquisition costs and settlement agreement costs.
3. Net debt is loans and borrowings plus working capital deficit adjusted for risk management contract fair values.
4. As of Q3 2021 Kiwetinohk’s credit facility capacity was $225 million. On December 13, 2021, the Company announced an increase in its credit facility to $315 million.
5. See “Non-GAAP Measures”.
2022 full year outlook
An investment year for growth into 2023

PRODUCTION
With continued drilling at about the same pace, we would expect year-over-year growth of about 50% in annual production volumes from 2022 to 2023.

Natural Gas
39 – 45 MMcf/d

13 – 15 Mboe/d

Oil & Liquids
6.5 – 7.5 Mboe/d

Capital spending to be managed according to net debt to last twelve months cash flow target of 1.0x

GROSS WELLS (#)

2 Wells tied-in in H1/22; 10 wells tied-in in H2/22 and Q1 2023

2023 land retention drilling contingent on results

Capital and drilling plans beyond 2022 are not based on a budget or capital expenditures plan approved by the Board of Directors of the Company and such growth is not intended to present a forecast of future performance or a financial outlook. Projections of production growth are highly dependent on individual wells which have shown a significant amount of variability historically.

See “Forward-looking statements – future-oriented financial information”.

1. Graphs based on midpoint of guidance. See appendix for additional details regarding corporate guidance. Simonette working interest 100%. Placid working interest 65%, partner has not yet determined participation.
2. Capital and drilling plans beyond 2022 are not based on a budget or capital expenditures plan approved by the Board of Directors of the Company and such growth is not intended to present a forecast of future performance or a financial outlook. Projections of production growth are highly dependent on individual wells which have shown a significant amount of variability historically.
3. See “Forward-looking statements – future-oriented financial information”.

Green Energy: $10 - $20
Pre-FID costs advancing 5+
projects for 1,800+ MW

Upstream: $200 - $220
Development capital, supporting infrastructure, contingent payment

FINANCIAL OVERVIEW
2022 full year outlook
An investment year for growth into 2023

PRODUCTION

1. Graphs based on midpoint of guidance. See appendix for additional details regarding corporate guidance. Simonette working interest 100%. Placid working interest 65%, partner has not yet determined participation.
2. Capital and drilling plans beyond 2022 are not based on a budget or capital expenditures plan approved by the Board of Directors of the Company and such growth is not intended to present a forecast of future performance or a financial outlook. Projections of production growth are highly dependent on individual wells which have shown a significant amount of variability historically.
3. See “Forward-looking statements – future-oriented financial information”.

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## Q3 2021 Operating netback and production summary

Weighted average sales price at $48.29 (96% Fox Creek)

Q3’21 operating netback\(^6\) $31.13 per boe

Q3’21 royalties ($6.49) per boe

Transportation ($3.98) per boe

Operating cost ($6.69) per boe

---

Kiwetinohk is starting with robust operating netbacks among industry leaders and looking to improve forward margins through continuous field operations and operational effectiveness.

<table>
<thead>
<tr>
<th>Liquids</th>
<th>% of Q3</th>
<th>Production</th>
<th>Realized Price</th>
<th>Benchmark Price</th>
<th>Adjustment</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Production</td>
<td>(bbl/d)</td>
<td>(C$/bbl)</td>
<td>(C$/bbl)</td>
<td>(C$/bbl)</td>
</tr>
<tr>
<td>Condensate (^1)</td>
<td>66%</td>
<td>4,261</td>
<td>$80.70</td>
<td>$83.04</td>
<td>($2.34)</td>
</tr>
<tr>
<td>Light Oil (^1)</td>
<td>5%</td>
<td>308</td>
<td>$81.61</td>
<td>$83.04</td>
<td>($1.43)</td>
</tr>
<tr>
<td>Heavy (^2)</td>
<td>1%</td>
<td>39</td>
<td>$61.90</td>
<td>$72.62</td>
<td>($10.72)</td>
</tr>
<tr>
<td>NGLs (^1)</td>
<td>28%</td>
<td>1,814</td>
<td>$49.74</td>
<td>$83.04</td>
<td>($33.30)</td>
</tr>
<tr>
<td><strong>Total liquids</strong></td>
<td><strong>100%</strong></td>
<td><strong>6,422</strong></td>
<td><strong>$71.88</strong></td>
<td><strong>$82.98</strong></td>
<td><strong>($11.09)</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Natural gas</th>
<th>% of Q3</th>
<th>Production</th>
<th>Realized Price</th>
<th>Benchmark Price</th>
<th>Adjustment</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Production</td>
<td>(mcf/d)</td>
<td>(C$/GJ)</td>
<td>(US$/MMBtu)</td>
<td></td>
</tr>
<tr>
<td>Natural Gas CDA (^3)</td>
<td>22%</td>
<td>11,296</td>
<td>$3.32</td>
<td>$3.41</td>
<td>($0.09)</td>
</tr>
<tr>
<td>Natural Gas US (^4)</td>
<td>78%</td>
<td>40,521</td>
<td>$4.16</td>
<td>$4.10</td>
<td>$0.06</td>
</tr>
<tr>
<td><strong>Total natural gas</strong></td>
<td><strong>100%</strong></td>
<td><strong>51,817</strong></td>
<td><strong>$5.12</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

---

1. Benchmarks off Edmonton Light.
2. Benchmark off Western Canadian Select.
3. Benchmark off AECO 5A.
4. Benchmark off Chicago City Gate DI. Going forward sales could be a combination of DI and MI.
5. Adjustment on Canadian gas pricing includes shrinkage, quality and location differentials, adjustment on US gas pricing includes shrinkage, fuel gas, and adjustment for heat content.
6. Based on Q3 2021 operating results. See “Non-GAAP Measures.”
Capital allocation strategy

GREEN ENERGY DEVELOPMENT
- Green energy project screening, development and FEED capital

TARGET 8% - 10% of spending

GROWTH & CAPITAL RETURN
- Decisions compete for capital based on returns on invested capital

TARGET 50% - 60% of spending

MAINTENANCE AND ASSET OPTIMIZATION
- Decline abatement
- Operational effectiveness
- Inventory / land management

TARGET 30% - 35% of spending

ENVIRONMENTAL & ARO
- Aggressive inactive ARO management
- Methane emissions reduction
- Environmental leadership and technologies

TARGET 3% - 5% of spending
Summary
Kiwininohk: an energy transition toward a sustainable and profitable low-carbon future

1. Leading, Integrated Energy Transition Business Model, Purpose-Built Since Inception
   - Green energy strategy aligned with growing global energy demand
   - Strong synergies in the integrated business model – pairing low supply cost upstream resource with renewable and gas-fired power to generate robust netbacks and recycle ratios

2. High Quality, Low Supply Cost, Upstream Resource
   - Acquired over 38 mmboe of PDP Reserves <$10/boe
   - Significant owned processing capacity reduces operating costs and provides room to grow
   - Attractive liquids-rich production generates high netbacks and recycle ratio of >3x on PDP Reserves
   - Well positioned geographically and financially for further high-quality upstream consolidation

3. Unique Green Energy Project Portfolio with the Potential for Attractive Economics
   - Kiwininohk’s multi-year effort has positioned it to capitalize on a limited number of top tier power projects, with several already underway at various stages of development
   - Advantageously positioned to capture advantaged, developer economics through carried interests or other innovative financing structures

4. Strong Financial Position
   - Q3 2021 net debt of ~$37 million and credit facility capacity of $230 million as of December 2021
   - Manage leverage to remain below 1.0x Debt / LTM EBITDA in 2022
   - Consistent hedging policy to manage exposure to commodity price volatility

5. Experienced Green Energy, Natural Gas and ESG Leadership
   - Proven management team with a track record of successfully implementing new technologies and ESG leadership – led by highly successful energy entrepreneur Pat Carlson
   - Diversified board with large independent representation

---

1. Net debt is loans and borrowings plus working capital deficit adjusted for risk management contract fair values. See “Non-GAAP Measures”
2. Credit facility capacity is the total credit facility available, less amounts drawn, less letters of credit outstanding. Subsequent to September 30, 2021 the Credit Facility was increased to $315 million resulting in a pro-forma credit facility capacity of $230 million as per Kiwininohk’s December 13, 2021 news release. See “Non-GAAP Measures”
CONTACT US:

Kiwetinohk Energy Corp.
Suite 1900, 250 – 2 Street S.W.
Calgary, AB
T2P 0C1

Main line: (587) 392-4224

Mark Friesen, Director, Investor Relations
mfriesen@kiwetinohk.com
Direct line: (587) 392-4414
Capitalization, ownership and board of directors

**CAPITALIZATION (AS AT Q3 2021)**

- **Basic Shares Outstanding**: 43.6 million
- **Dilutive Securities** (avg. exercise price of $16.89/sh): 10.8 million
- **Net Debt**: $37 million
- **Credit Facility**: $315 million

**COMMON SHARE OWNERSHIP (AS AT Q3 2021)**

- **ARC**: 63.0%
- **Luminus**: 12.0%
- **Management and Directors**: 3.5%
- **Other**: 21.5%

**BOARD OF DIRECTORS**

- **Kevin Brown**: Co-Chair and Director, ARC Financial Corp.
- **Nancy Lever**: Advisor, ARC Financial Corp.
- **Steven Sinclair**: Director and Audit Chair of TransGlobe Energy Corp. and of Deltastream Energy Corp.
- **Pat Carlson**: Chief Executive Officer, Kiwetinohk Energy Corp.
- **Beth Reimer-Heck**: Senior Counsel, Borden Ladner Gervais LLP
- **Timothy Schneider**: Chief Investment Officer, LE Capital
- **Leland Corbett**: Partner, Stikeman Elliott LLP
- **Kaush Rakhit**: Owner, Canadian Discovery Ltd.

---

1. Net debt is loans and borrowings plus working capital deficit adjusted for risk management contract fair values. See “Non-GAAP Measures”.
2. As of Q3 2021 Kiwetinohk’s credit facility capacity was $225 million. On December 13, 2021, the Company announced an increase in its credit facility to $315 million on December 13, 2021.
Corporate history

CORPORATE HISTORY / TIMELINE

February 2018
Kwetinohk Resources Corp. (KRC) is founded with Pat Carlson assuming the role of CEO in June 2018.

July 2020
Delphi Energy announced a recapitalization and financing transaction with KRC emerging as majority stakeholder (on a fully diluted basis).

January 2021
KRC announced early exercise of its warrants for $40 million, acquiring an additional 25% stake in Distinction Energy (formerly Delphi Energy).

April 2021
Kwetinohk closed on $104 million of equity proceeds alongside Simonetta Acquisition with a subsequent $33 million of private placements issued to repay outstanding debt.

September 2021
Closed Distinction combination.

2018

August 2019
Strategic joint venture with Journey Energy to develop 140 sections in their East Duvernay shale oil resource.

2020

October 2020
Delphi restructuring transaction is completed with KRC emerging with a 50%+1 stake on a fully diluted basis (~25% ownership on an undiluted basis).

2021

February 2021
Distinction Energy announced 50% participation in KRC’s $335 million acquisition of certain assets in the Simonetta area of Northwest AB from Cenovus (~10 mboe/d).

June 2021
KRC announced acquisition of the remaining 50% stake in Distinction Energy.
### Hedging summary

<table>
<thead>
<tr>
<th></th>
<th>Unit</th>
<th>Q1 2022</th>
<th>Q2 2022</th>
<th>Q3 2022</th>
<th>Q4 2022</th>
<th>Full Year 2023</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Oil</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>WTI Fixed Price bbl/d</td>
<td></td>
<td>750</td>
<td>750</td>
<td>750</td>
<td>750</td>
<td>900</td>
</tr>
<tr>
<td>WTI Buy Put bbl/d</td>
<td></td>
<td>2,367</td>
<td>2,167</td>
<td>2,033</td>
<td>1,883</td>
<td></td>
</tr>
<tr>
<td>WTI Sell Call bbl/d</td>
<td></td>
<td>2,367</td>
<td>2,167</td>
<td>2,033</td>
<td>1,883</td>
<td></td>
</tr>
<tr>
<td>WTI Swap Average C$/bbl</td>
<td></td>
<td>$69.950</td>
<td>$69.950</td>
<td>$69.950</td>
<td>$69.950</td>
<td>$82.600</td>
</tr>
<tr>
<td>WTI Buy Put Average C$/bbl</td>
<td></td>
<td>$65.000</td>
<td>$65.000</td>
<td>$65.000</td>
<td>$65.000</td>
<td></td>
</tr>
<tr>
<td>WTI Sell Call Average C$/bbl</td>
<td></td>
<td>$76.715</td>
<td>$76.692</td>
<td>$76.668</td>
<td>$76.650</td>
<td></td>
</tr>
<tr>
<td><strong>Natural Gas</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NYMEX Henry Hub Fixed Price MMBtu/d</td>
<td></td>
<td>18,900</td>
<td>21,167</td>
<td>20,350</td>
<td>15,350</td>
<td>11,375</td>
</tr>
<tr>
<td>NYMEX Henry Hub Buy Put MMBtu/d</td>
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<td>2,500</td>
<td>2,500</td>
<td>2,500</td>
<td>2,500</td>
<td>2,000</td>
</tr>
<tr>
<td>NYMEX Henry Hub Sell Call MMBtu/d</td>
<td></td>
<td>2,500</td>
<td>2,500</td>
<td>2,500</td>
<td>2,500</td>
<td>2,000</td>
</tr>
<tr>
<td>NGI Chicago Basis to NYMEX Henry Hub MMBtu/d</td>
<td></td>
<td>17,400</td>
<td>19,600</td>
<td>18,450</td>
<td>17,950</td>
<td>9,375</td>
</tr>
<tr>
<td>NYMEX Henry Hub Fixed Price Average US$/MMBtu</td>
<td></td>
<td>$2.806</td>
<td>$2.986</td>
<td>$2.979</td>
<td>$2.697</td>
<td>$3.353</td>
</tr>
<tr>
<td>NYMEX Henry Hub Buy Put Average US$/MMBtu</td>
<td></td>
<td>$3.000</td>
<td>$3.000</td>
<td>$3.000</td>
<td>$3.000</td>
<td>$3.000</td>
</tr>
<tr>
<td>NYMEX Henry Hub Sell Call Average US$/MMBtu</td>
<td></td>
<td>$4.750</td>
<td>$4.750</td>
<td>$4.750</td>
<td>$4.750</td>
<td>$3.805</td>
</tr>
<tr>
<td>NGI Chicago Basis to NYMEX Henry Hub Average US$/MMBtu</td>
<td></td>
<td>$0.194</td>
<td>($0.145)</td>
<td>($0.170)</td>
<td>($0.064)</td>
<td>$0.007</td>
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<tr>
<td>AECO 5A Fixed Price GJ/d</td>
<td></td>
<td>2,250</td>
<td>2,250</td>
<td>2,025</td>
<td>2,025</td>
<td></td>
</tr>
<tr>
<td>AECO 5A Average C$/GJ</td>
<td></td>
<td>$2.262</td>
<td>$2.262</td>
<td>$2.092</td>
<td>$2.092</td>
<td></td>
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<tr>
<td><strong>Other Natural Gas</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Purchase AECO 5A Basis (to NYMEX Henry Hub) MMBtu/d</td>
<td></td>
<td>80,000</td>
<td>30,000</td>
<td>30,000</td>
<td>10,000</td>
<td></td>
</tr>
<tr>
<td>Sell GDD Chicago Basis (to NYMEX Henry Hub) MMBtu/d</td>
<td></td>
<td>(80,000)</td>
<td>(30,000)</td>
<td>(30,000)</td>
<td>(10,000)</td>
<td></td>
</tr>
<tr>
<td>AECO 5A Basis (to NYMEX Henry Hub) Average US$/MMBtu</td>
<td></td>
<td>($0.971)</td>
<td>($1.335)</td>
<td>($1.335)</td>
<td>($1.335)</td>
<td></td>
</tr>
<tr>
<td>GDD Chicago Basis (to NYMEX Henry Hub) Average US$/MMBtu</td>
<td></td>
<td>$0.200</td>
<td>$0.052</td>
<td>$0.052</td>
<td>$0.052</td>
<td></td>
</tr>
<tr>
<td><strong>FX</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sell USD CAD (Monthly Average) US$</td>
<td></td>
<td>$10,000,000</td>
<td>$5,000,000</td>
<td>$5,000,000</td>
<td>$1,666,667</td>
<td></td>
</tr>
<tr>
<td>USD CAD Rate US$</td>
<td></td>
<td>1.2902</td>
<td>1.2901</td>
<td>1.2901</td>
<td>1.2901</td>
<td></td>
</tr>
</tbody>
</table>

---

2. Other natural gas hedges includes financial hedges on replacement gas to fill pipeline take or pay commitments.
### 2022 guidance details

#### OUTLOOK\(^1\)

<table>
<thead>
<tr>
<th>Description</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Fox Creek drilling program</strong></td>
<td><strong>11</strong> wells candidate</td>
</tr>
<tr>
<td>(wells)</td>
<td><strong>Target 6 wells completed in 2022 and 5 wells completed in 2023</strong></td>
</tr>
<tr>
<td><strong>Production (2022 average)</strong></td>
<td><strong>13.0 – 15.0 Mboe/d</strong></td>
</tr>
<tr>
<td>(Mboe/d)</td>
<td><strong>Average annual production for the year</strong></td>
</tr>
<tr>
<td><strong>Oil &amp; liquids</strong></td>
<td><strong>6.5 – 7.5 Mbbl/d</strong></td>
</tr>
<tr>
<td>(Mbbl/d)</td>
<td><strong>Condensate, oil and NGL</strong></td>
</tr>
<tr>
<td><strong>Natural gas</strong></td>
<td><strong>39.0 – 45.0 MMcf/d</strong></td>
</tr>
<tr>
<td>(MMcf/d)</td>
<td><strong>Natural gas volumes sold to Chicago and Alberta</strong></td>
</tr>
<tr>
<td><strong>Royalty rate (Crown)</strong></td>
<td><strong>12% - 15%</strong></td>
</tr>
<tr>
<td>(%)</td>
<td><strong>Royalty rates influenced by new well drilling and commodity pricing</strong></td>
</tr>
<tr>
<td><strong>Operating Expense</strong></td>
<td><strong>$7.5 - $8.5/boe</strong></td>
</tr>
<tr>
<td>($/boe)</td>
<td><strong>Includes a provision for scheduled plant turnarounds at Fox Creek</strong></td>
</tr>
<tr>
<td><strong>Transportation Expense</strong></td>
<td><strong>$5.0 - $6.0/boe</strong></td>
</tr>
<tr>
<td>($/boe)</td>
<td><strong>Excluding marketing activities</strong></td>
</tr>
<tr>
<td><strong>Corporate G&amp;A Expense</strong></td>
<td><strong>$15 - $18/MM</strong></td>
</tr>
<tr>
<td>($MM)</td>
<td><strong>Corporate, Upstream, Green Energy and Business Development</strong></td>
</tr>
<tr>
<td><strong>Cash Taxes</strong></td>
<td><strong>0%</strong></td>
</tr>
<tr>
<td>(%)</td>
<td><strong>Cash tax horizon around 2024</strong></td>
</tr>
<tr>
<td><strong>Capital Expenditures</strong></td>
<td><strong>$210 - $240/MM</strong></td>
</tr>
<tr>
<td>($MM)</td>
<td><strong>Green energy and upstream capital expenditures</strong></td>
</tr>
</tbody>
</table>

---

1. See “Forward-looking information – Future-oriented financial information”. 
# Fox Creek type curves economics

## MCDANIEL’S TYPE CURVES\(^1,2\)

<table>
<thead>
<tr>
<th></th>
<th>Duvernay</th>
<th>Montney</th>
</tr>
</thead>
<tbody>
<tr>
<td>IRR (Before Tax)</td>
<td>214%</td>
<td>96%</td>
</tr>
<tr>
<td>PIR 15(^3) (Before Tax)</td>
<td>1.21x</td>
<td>0.82x</td>
</tr>
</tbody>
</table>

### Investing in well design
- Extending limits on lateral length and optimizing well spacing
- Testing the pumping bigger fracs to enhance recovery

### De-risking the asset base
- With 119 Total Proved plus Probable future drilling locations and a significant number of unbooked locations and undeveloped land position, we have to continue to delineate our asset base and add proved reserves in Fox Creek\(^2\)
- Continue to firm up our geological mapping

### Goal of improved returns over 2021 Mid-Year McDaniel’s Reserve Report
- Type curve improvement driven by our well designs
- Optimize our costs through learnings and continuous operations

---

1. See “Reserves and Resources Disclaimer”.
3. “PIR 15” refers to the ratio required to earn a 15% return on an investment, calculated as expected profits divided by initial investment.
Gas and transportation and marketing

SALES GAS VS COMMITTED GAS TRANSPORTATION (MCF/D)

- Q3 2021 net marketing income\(^3\) of $5.1 million
- 100% of Alliance capacity filled in Q3
- Contracted gas meets heat content requirement for Aux Sable premium
- Additional 2022 future gas purchases to be assessed along with new production additions

1. Contracted gas volumes currently in-place for October 31, 2021 – October 31, 2022 gas year. Contracted gas volumes meet minimum heat content requirements to receive Aux Sable premium at Chicago sales point.
2. Total contracted Alliance capacity of 120 MMcf/d ending October 31, 2025. Aux Sable premium contract applies to 90.3 MMcf/d and available until October 31, 2023. NGTL volume commitment of 20.7 mmcf/d, ending March 31, 2026.
3. Net marketing income (loss) is revenue from the sale of purchased natural gas less original purchase, transportation and any related marketing fees. See “Non-GAAP Measures”
Green Energy project assumptions

Renewable: Utility scale solar and wind power
- Power price EDC Q4 7x24 less 20% solar discount on 25% merchant production, $70/MWh on 75% contracted production
- Capacity factor 28%
- Federal carbon tax under Alberta TIER system

Firm Renewable, high efficiency, fast responding, reciprocating engine, gas-fired power
- Gas at $3.52 / GJ less 10% for integration discount.
- Power price EDC Q4 7x24 plus 40% peak price premium (fully merchant)
- Run time 50%
- Federal carbon tax under Alberta TIER system
- $5/MWh ancillary service revenue

Large-scale, natural gas combined cycle (NGCC) power
- Gas at $3.52 / GJ less 10% for integration discount.
- Power price EDC Q4 7x24 on 25% merchant production, $70/MWh on 75% contracted production
- Run time 96%
- Federal carbon tax under Alberta TIER system
- $5/MWh ancillary service revenue

1. Green Energy project assumptions relate to power project financing strategy as described on slide 17. MWh is megawatt-hour.
2. Construction capital assumes 40% equity and 60% debt financing and no CCUS. Illustrative capital cost based on Class 3 and 4 estimates for Kiwetinohk’s current power portfolio projects.
3. Benchmark EBITDA based on project designs for Alberta-based projects in Kiwetinohk’s power portfolio and EDC Q3 power pricing.
4. Carried interest has been calculated based on illustrative ranges of what Kiwetinohk’s carried interest could possibly be.
Forward-looking statements

Certain statements contained in this presentation constitute "forward-looking statements" or "forward-looking information" within the meaning of applicable securities legislation (collectively, "forward-looking statements"). All statements other than statements of historical fact are forward-looking statements. The use of any of the words "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "should", "would", and "potential" and similar expressions or statements regarding an outlook are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. No assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this presentation should not be unduly relied upon. Events or circumstances may cause actual results to differ materially from those predicted as a result of numerous known and unknown risks, uncertainties and other factors, many of which are beyond the control of the Company. These statements speak only as of the date of this presentation. In addition, this presentation may contain forward-looking statements attributed to third-party industry sources.

Specifically, this presentation contains forward-looking statements pertaining to: the Company's objectives, strategies and competitive strengths and weaknesses; the Company's growth strategy; the Company's plans for developing a low emission power generation business, including development of its natural gas-fired and solar and wind power generation projects and expectations with respect to future opportunities for other renewable energy projects; the Company's ability to achieve its goals, including the Company's ability to: bring its natural gas production into equivalent proportion with its use of natural gas for hydrogen and electricity production; produce and supply desired volumes of power, natural gas and hydrogen; and capture and utilize more than 90% of the carbon dioxide ("CO2") associated with Scope 1 emissions; expectations regarding the further development and operation of the Company's existing upstream properties; the Company's plans for exploration, resource testing, development, exploitation and acquisitions; projections of market prices and costs; access to emerging markets; nature, timing and development of the Company's capital projects, including the expected financial performance thereof following completion of the development and the commencement of operations, as applicable; estimates of EBITDA, carried interest EBITDA and underlying assumptions; the quantity and quality of the Company's inventory of drilling locations and the Company's plans with respect to development and operation of its upstream properties, including estimates of drilling and completion costs and efficiency improvements; expectations with respect to the Company's financial position; the Company's beliefs and expectations with respect to its business model, energy demands, energy transition, the future of energy, distribution of power prices, and the best strategies for the Company to succeed in the Alberta power industry moving forward; future costs; access to third-party infrastructure and the expected limitations, costs and benefits thereof; the use of risk-management techniques, including hedging; the Company's ability to capitalize on certain energy transition opportunities through the use of new, innovative technologies in the market; industry conditions pertaining to the crude oil and natural gas industry and the energy transition and renewable power industries; potential new hydrogen-fueled electricity generation; potential co-location of hydrogen production with the Company's power projects; the Company's access to a unique green energy project portfolio with the potential for attractive economics; the Company's management team as it evolves, including the continuity of employment of any person; the Company's ability to obtain carbon credits for future projects; and anticipated growth in the market share for gas fired power generation and renewable power generation in Alberta.

Statements relating to "reserves" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future. Actual reserve values may be greater than or less than the estimates provided herein.

In addition, this presentation contains certain forward looking information relating to economics for drilling opportunities in the areas that the Company has an interest. Such information includes, but is not limited to, anticipated payout rates, rates of return, profit to investment ratios and recycle ratios which are based on additional various forward-looking information such as production rates, anticipated well performance and type curves, the estimated net present value of the anticipated future net revenue associated with the wells, anticipated reserves, anticipated capital costs, anticipated finding and development costs, anticipated ultimate reserves recoverable, anticipated future realized hedging gains and losses, anticipated future royalties, operating expenses, and transportation expenses.

In addition to other factors and assumptions that may be identified in this document, assumptions have been made regarding, among other things:

- future oil, natural gas liquids ("NGL") and natural gas prices;
- the Company's ability to realize on expectations regarding low supply cost, reliability and efficiency of its power generation portfolio;
- development and completion of the Company's natural gas-fired and solar power generation projects in a timely and cost-efficient manner and the Company's ability to continue to identify and progress projects for its power generation portfolio;
- the Company's ability to successfully integrate its upstream business and assets with the Company's power generation portfolio;
- the Company's ability to obtain qualified staff and equipment in a timely and cost-efficient manner;
- the general stability of the economic and political environment in which the Company operates;
Forward-looking statements (continued)

- the regulatory framework governing royalties, electricity generation, transmission and distribution, taxes and environmental matters in the jurisdictions in which the Company conducts its business and any other jurisdictions in which the Company may conduct its business in the future;
- the Company’s ability to market production of oil, condensate, NGL, natural gas, electricity, low-emissions electricity, hydrogen, CO2 and tax credits and other financial instruments as they emerge and evolve from time to time related to the production of low-emissions electricity and/or hydrogen successfully to customers;
- that the Alberta government carbon credit regime remains favourable to the Company and its projects;
- the Company's ability to buy and sell hydrocarbon gathering and processing services and carbon capture, utilization and storage services to other parties;
- the Company's future production levels;
- the recoverability of the Company's reserves;
- that the Company will have access to solar and other renewable resources in amounts and at the costs consistent with the amounts and costs expected by the Company for the development projects in its power generation portfolio;
- the nature of carbon capture technologies and the benefits of their application, including to the Company's proposed projects;
- future cash flows from production;
- future sources of funding for the Company's capital program and the Company's plans for future capital investments;
- the Company's future debt levels;
- geological and engineering estimates in respect of the Company's reserves;
- the geography of the areas in which the Company is conducting exploration and development activities and the access, economic, regulatory and physical limitations to which the Company may be subject from time to time;
- community and stakeholder commitment to sustainable energy sources, and the Company's positioning within the sustainable energy or energy transition space;
- the impact of competition on the Company;
- currency, exchange and interest rates;
- the Company's ability to obtain the support of stakeholders other than regulators which may affect the Company's ability to efficiently develop its capital projects including the cost or timing thereof; and
- the Company's ability to obtain financing necessary for the advancement of the Company's business plan on acceptable terms.

Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions that have been used. Although the Company believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements as the Company can give no assurance that such expectations will prove to be correct.

Forward-looking statements or information involve a number of risks and uncertainties that could cause actual results to differ materially from those anticipated by the Company and described in the forward-looking statements or information. These risks and uncertainties include, among other things:
- the ability of management to execute its business plan;
- risks associated with developing and operating the power generation and renewable energy business;
- the ability of the Company to achieve its investment and development objectives;
- the ability of the Company to successfully execute its energy transition strategy;
- risks associated with exploration, development and production of crude oil and natural gas, and drilling for unconventional oil, NGL and natural gas;
- the risks and limitations of forecasting reserves data;
- risks associated with operating and integrating a newly-combined business;
- global economic and financial conditions;
- capital markets;
- licences and permits;
- government regulations;
- fluctuations in commodity and power prices, foreign currency exchange rates and interest rates;
- health, safety and environmental risks;
- competition in the crude oil and natural gas industry;
- carbon taxes and environmental compliance costs;
- coronavirus;
- market constraints and access to services and equipment;
Forward-looking statements (continued)

- talent, recruitment and retention of key personnel;
- technology risks;
- seasonality; and
- environmental, health and safety requirements.

Readers are cautioned that the foregoing list is not exhaustive of all possible risks and uncertainties. Additional information on risks, uncertainties and assumptions can be found under "Risk Factors" in the Company's annual information form ("AIF") published on the Company's profile on the System for Electronic Document Analysis and Retrieval ("SEDAR") at www.sedar.com.

The forward-looking statements and information contained in this document speak only as of the date of this document and the Company undertakes no obligation to publicly update or revise any forward-looking statements or information, except as expressly required by applicable securities laws.

This presentation includes information obtained from independent industry publications, government publications, market research reports and other published independent sources. Such publications and reports generally state that the information contained therein has been obtained from sources believed to be reliable. Although the Company believes these publications and reports to be reliable, it has not independently verified any of the data or other statistical information contained therein, nor has it ascertained or validated the underlying economic or other assumptions relied upon by these sources.

**Future-Oriented Financial Information**

Financial outlook and future-oriented financial information contained in this presentation about prospective financial performance, financial position or cash flows is based on assumptions about future events, including economic conditions and proposed courses of action, based on management's assessment of the relevant information currently available. In particular, this presentation contains expected EBITDA ratios, benchmark annual EBITDA, carried interest EBITDA, capital costs and power generation capacity of the Company's proposed power generation capital projects, forecast economics of the Company's oil and gas assets, operating netbacks and implied recycle ratios of the Company's oil and gas assets and proposed power generation capital projects and 2022 financial outlook information for the Company, including expected royalties, operating expenses, transportation expenses, G&A expenses, interest expenses, ARO expenses and cash tax percentage. These projections contain forward-looking statements and are based on a number of material assumptions and factors set out above and are provided to give the reader a better understanding of the potential future performance of the Company in certain areas. Actual results may differ significantly from the projections presented herein. These projections may also be considered to contain future oriented financial information or a financial outlook. The actual results of the Company's operations for any period will likely vary from the amounts set forth in these projections, and such variations may be material. See above and "Risk Factors" in the Company's AIF published on the Company's profile on SEDAR at www.sedar.com for a further discussion of the risks that could cause actual results to vary. The future oriented financial information and financial outlooks contained in this presentation have been approved by management as of the date of this presentation. Readers are cautioned that any such financial outlook and future-oriented financial information contained herein should not be used for purposes other than those for which it is disclosed herein.
Reserves and Resources Disclosure

Independent Reserves Evaluation

Estimates of the company's reserves and the net present value of future net revenue attributable to the company's reserves contained in this presentation are based upon the report prepared McDaniel & Associates Consultants Ltd. ("McDaniel") dated July 16, 2021, evaluating the reserves attributable to certain of the assets of Kiwetinohk and its subsidiaries as at July 1, 2021, assuming completion of the business combination of Kiwetinohk and Distinction Energy Corp. and an effective date of July 1, 2021 (the "2021 Mid Year Reserves Report"). The estimates of reserves contained herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided in this news release and the differences may be material. Estimates of net present value of future net revenue attributable to the company's reserves do not represent the fair market value of the company's reserves and there is uncertainty that the net present value of future net revenue will be realized. There is no assurance that the forecast price and cost assumptions applied by McDaniel in evaluating the Company's reserves will be attained and variances could be material. For important additional information regarding the independent reserves evaluations that were conducted by McDaniel, please refer to the Company's AIF published on the Company's profile on SEDAR at www.sedar.com.

The reserves information contained in this presentation has been prepared in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Complete NI 51-101 reserves disclosure is included in the Company's AIF published on the Company's profile on SEDAR at www.sedar.com.

This presentation contains indicative individual well economics for the Fox Creek Region based on type curves prepared by McDaniel. Type-curves do not have any standardized preparation methodology or meaning and readers are cautioned that the type-curves and forecast development area economics shown in this presentation may not be comparable to similar information that is presented by other companies. Actual results may vary significantly from the Company's forecasts and estimates.

"IRR" is a measure of return used to compare the profitability of an investment and represents a discount rate at which the net present value of costs equals the net present value of the benefits. "PIR 15" refers to the ratio required to earn a 15% return on an investment, calculated as expected profits divided by initial investment.

References herein to initial production rates and other short-term production rates are useful in confirming the presence of hydrocarbons; however, such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long-term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating aggregate production for the Company or the assets for which such rates are provided. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, the Company cautions that the test results should be considered preliminary.

This presentation discloses drilling inventory and potential drilling locations. Drilling inventory and drilling locations refers to the Company's total proved, probable and unbooked locations. Proved locations and probable locations account for drilling locations in our inventory that have associated proved and/or probable reserves. Unbooked locations are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves and are farther away from existing wells and, therefore, there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty whether such wells will result in additional oil and gas reserves, resources or production.

The Company's ability to drill and develop these locations and the drilling locations on which the Company actually drills wells depends on a number of uncertainties and factors, including, but not limited to, the availability of capital, equipment and personnel, oil and natural gas prices, costs, inclement weather, seasonal restrictions, drilling results, additional geological, geophysical and reservoir information that is obtained, production rate recovery, gathering system and transportation constraints, the net price received for commodities produced, regulatory approvals and regulatory changes. As a result of these uncertainties, there can be no assurance that the potential future drilling locations that the Company has identified will ever be drilled and, if drilled, that such locations will result in additional oil, NGLs or natural gas production and, in the case of unbooked locations, additional reserves. As such, the Company's actual drilling activities may differ materially from those presently identified, which could adversely affect the Company's business. While certain of the unbooked drilling locations have been de-risked by drilling existing wells in relatively close proximity to such unbooked drilling locations, some of the other unbooked drilling locations are farther away from existing wells, where management has less information about the characteristics of the reservoir and there is therefore more uncertainty whether wells will be drilled in such locations and, if drilled, there is more uncertainty that such wells will result in additional proved or probable reserves, resources or production.

Reserve life index refers to the ratio of Total Proved + Probable reserves as per the 2021 Mid Year Reserves Report using the July 1, 2021 Price Deck divided by annualized Q3 2021 production. Q3 2021 daily average production rate of 15,058 boe/d was annualized for the reserves life index calculation which is used as a measure of a company’s sustainability.

Recycle ratios are calculated by dividing the average operating netback per boe or adjusted funds flow netback per boe, as the case may be, by finding and development costs and finding, development and acquisition costs, as the case may be. Recycle ratios may be used as a measure of a company’s profitability.
Non-GAAP measures

Certain information set forth in this document contains Non-GAAP measures, including “adjusted funds flow from operations”, “operating netback”, “adjusted working capital” and “net debt”. These performance measures presented in this document should not be considered in isolation or as a substitute for performance measures prepared in accordance with IFRS and should be read in conjunction with the consolidated financial statements. Readers are cautioned that these non-GAAP measures do not have any standardized meanings and should not be used to make comparisons between Kiwetinohk and other companies without also taking into account any differences in the method by which the calculations are prepared.

The Company will use certain measures to analyze operational and financial performance. These non-GAAP measures do not have any standardized meaning prescribed under IFRS and therefore may not be comparable to similar measures presented by other entities nor should it be viewed as an alternative to other possible comparable IFRS measures.

Adjusted Funds Flow from Operations
Adjusted funds flow from operations is cash flow from operating activities before changes in non-cash working capital from operating activities, decommissioning expenditures, restructuring costs, acquisition costs and settlement agreement costs. Management uses funds flow from operations to analyze performance and considers it a key measure as it demonstrates the Company’s ability to generate the cash necessary to fund future capital investments, abandonment obligations and to repay debt.

<table>
<thead>
<tr>
<th>$000s</th>
<th>Three months Q3 2021</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cash flow from (used) in operating activities</td>
<td>29,643</td>
</tr>
<tr>
<td>Change in non-cash operating working capital</td>
<td>(4,087)</td>
</tr>
<tr>
<td>Restructuring costs</td>
<td>1,617</td>
</tr>
<tr>
<td>Acquisition costs</td>
<td>1,048</td>
</tr>
<tr>
<td>Settlement agreement costs</td>
<td>-</td>
</tr>
<tr>
<td>Adjusted funds from operations</td>
<td>28,221</td>
</tr>
</tbody>
</table>

Adjusted Working Capital
Adjusted working capital is comprised of current assets less current liabilities excluding the fair value of risk management contracts. Adjusted working capital is used by management to provide a more complete understanding of the Company’s liquidity. The current fair value of risk management contracts has been excluded as there is no intention to realize these financial instruments and they are also subject to a high degree of volatility prior to ultimate settlement.

<table>
<thead>
<tr>
<th>$000s</th>
<th>Q3 2021</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current assets</td>
<td>40,797</td>
</tr>
<tr>
<td>Current liabilities</td>
<td>(93,280)</td>
</tr>
<tr>
<td>Working capital surplus (deficit)</td>
<td>(52,483)</td>
</tr>
<tr>
<td>Plus current fair value of risk management contract liability</td>
<td>48,167</td>
</tr>
<tr>
<td>Adjusted working capital surplus (deficit)</td>
<td>(4,316)</td>
</tr>
</tbody>
</table>

Credit Facility Capacity
Credit facility capacity is the total credit facility available, less amounts drawn, less letters of credit outstanding

EBITDA
EBITDA is calculated as net income or loss before interest, income taxes, depletion and depreciation, adjusted for certain other non-cash items such as stock-based compensation, unrealized gains and losses on risk management contracts and contingent consideration among other things.
Non-GAAP measures (continued)

**Net Marketing Income (Loss)**
Net marketing income (loss) is revenue from the sale of purchased natural gas less the original commodity purchase, related transportation expense and any related marketing fees. Net marketing income (loss) is used as a key measure of how the Corporation is managing its take or pay pipeline commitments.

**Operating Netback**
Operating Netback is calculated on a per boe basis as petroleum and natural gas revenue from production less royalties, operating and transportation expense. Management believes that operating netback is a key industry benchmark and a measure of performance for the company that provides investors with information that is commonly used by other oil and natural gas producers. The measurement on a per boe basis assists Management with evaluating operating performance on a comparable basis.

**Net Debt**
Net debt is comprised of loans and borrowings plus adjusted working capital deficit (surplus) and represents the Company’s net financing obligations. Net debt is used by management to provide a more complete understanding of the Company’s capital structure and provides a key measure to assess the Company’s liquidity.

<table>
<thead>
<tr>
<th>$000s</th>
<th>Q3 2021</th>
</tr>
</thead>
<tbody>
<tr>
<td>Loans and borrowings</td>
<td>(32,620)</td>
</tr>
<tr>
<td>Adjusted working capital surplus (deficit)</td>
<td>(4,316)</td>
</tr>
<tr>
<td>Net surplus (debt)</td>
<td>(36,936)</td>
</tr>
</tbody>
</table>