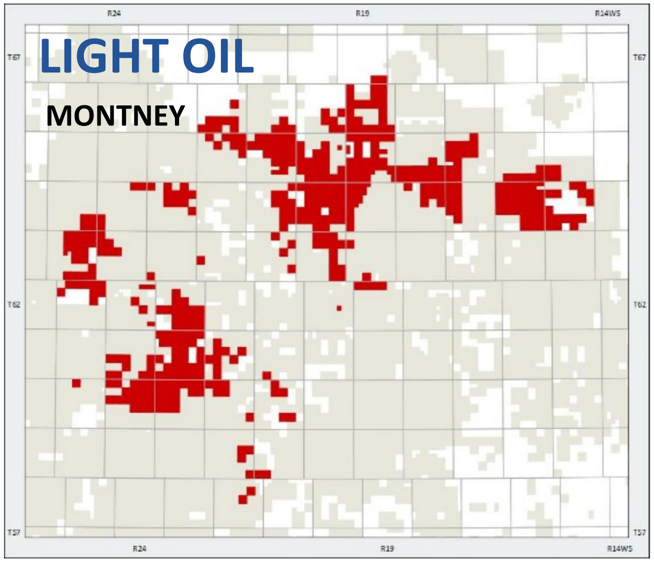
ATHABASCA OIL CORPORATION

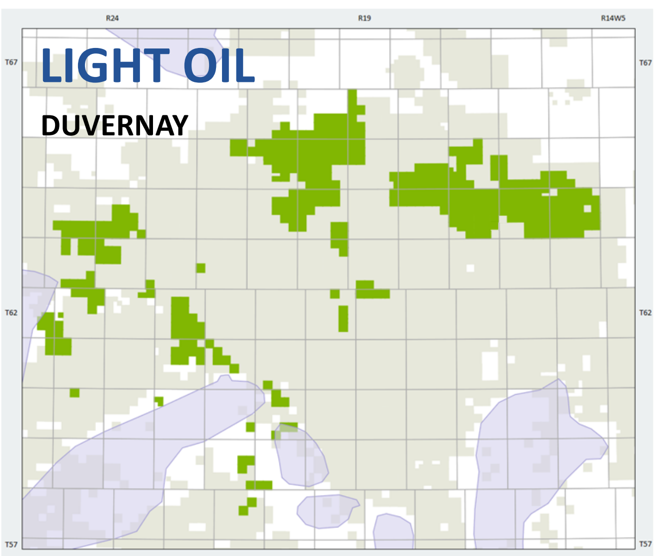
FOCUSED | EXECUTING | DELIVERING

JULY 2021

ATHABASCA OIL CORPORATION

PREMIER RESOURCE EXPOSURE

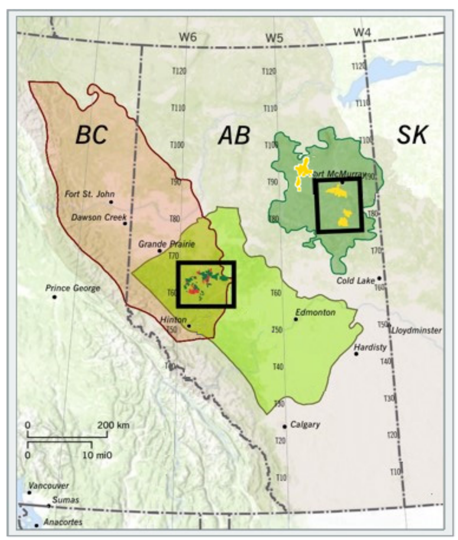


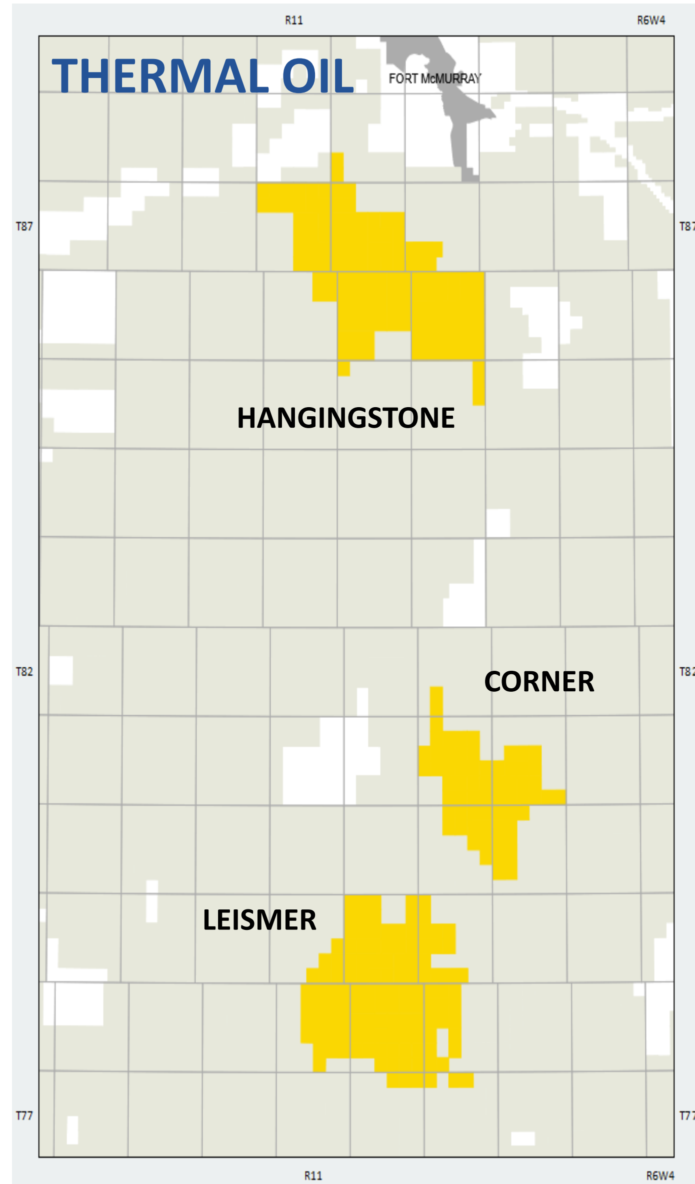


~35,000 boe/d
~90% liquids

~$800MM EV
$153MM Cash

~90 year 2P RLI
1,150 MMboe 2P
400 MMboe Proved





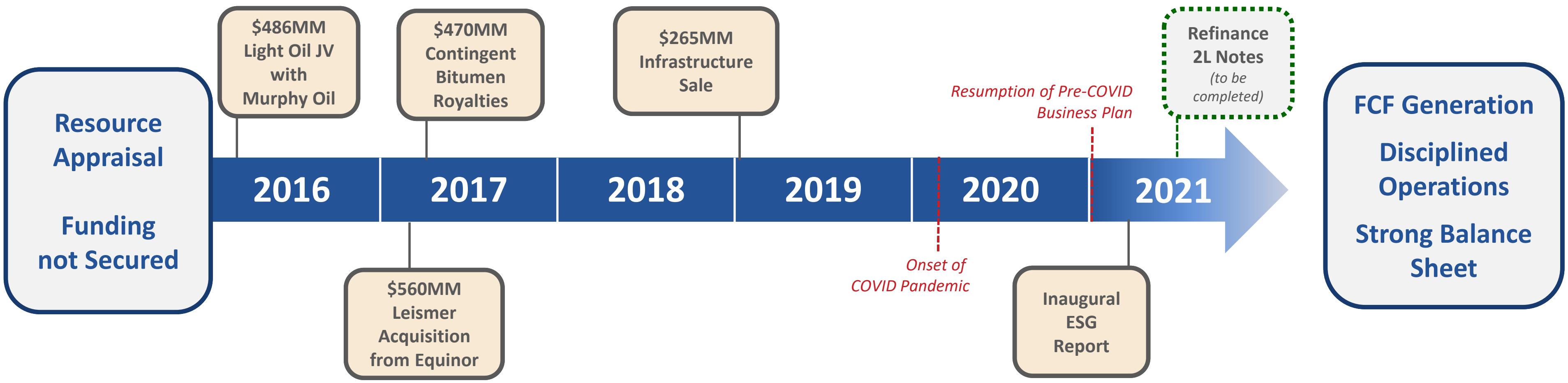
Q2 2021 HIGHLIGHTS & 2021 GUIDANCE

	Q2 2021	2021e
Production	34,659 boe/d *90% liquids*	32,000 - 34,000 boe/d *90% liquids*
Operating Income & Netback	$93MM *~$34/boe Light Oil & ~$32/bbl Leismer*	~$375MM* *~$34/boe Light Oil & ~$31/bbl Leismer*
Adjusted Funds Flow	$50MM *$0.09/share*	~$175MM* *$0.33/share*
Capex	$23MM *95% Thermal Oil*	$100MM *~95% Thermal Oil*
Free Cash Flow	$28MM *~25% FCF yield (annualized)*	~$75MM* *~20% FCF yield*
Cash	$153MM unrestricted cash *+$134MM restricted cash + deposits*	~$210MM* unrestricted *+$134MM restricted cash + deposits*
Net Debt	$383MM	$315MM
Net Debt / 2021e Adj. EBITDA	1.6x	1.3x

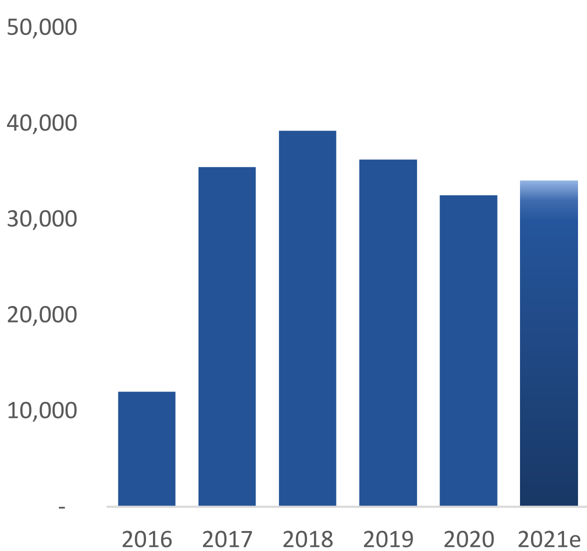
 Footnotes and additional information included in the back as endnotes and reader advisories

* July 5, 2021 strip pricing, see endnotes for additional detail

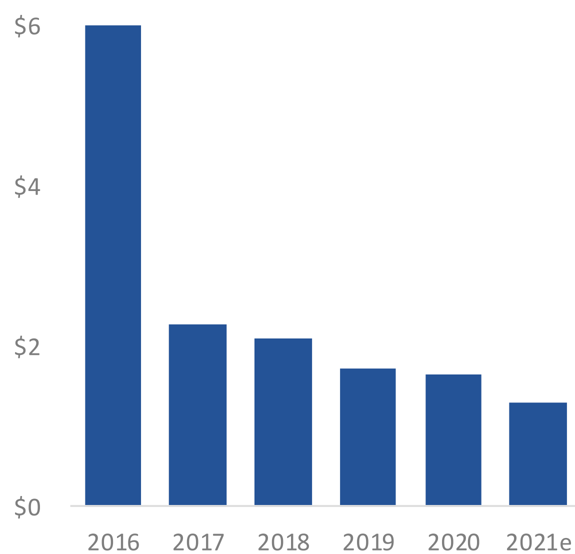
HISTORICAL TRANSFORMATION OF ATH



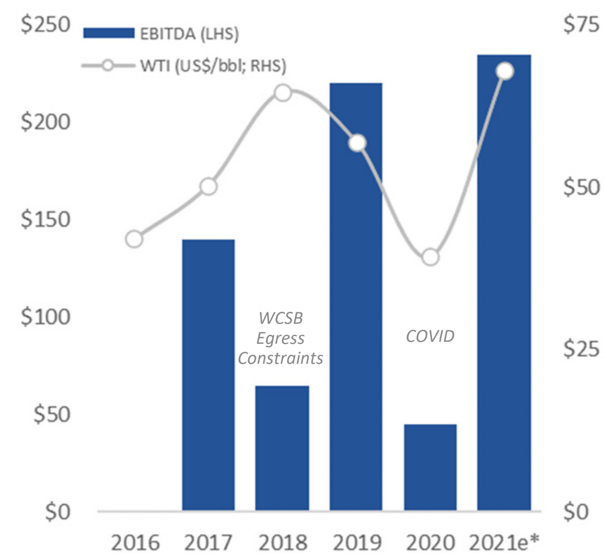
PRODUCTION (BOE/D)



EXPENSED G&A ($/BOE)



EBITDA ($MM)



* 2021e includes $113MM in hedging losses

* July 5, 2021 strip pricing, see endnotes for additional detail

MACRO BUSINESS ENVIRONMENT

GLOBAL DEMAND BACK TO PRE-COVID LEVELS

- Global demand rose to ~97 MMbbl/d in mid-June
- Goldman Sachs forecasting ~99 MMbbl/d demand by Q3/21

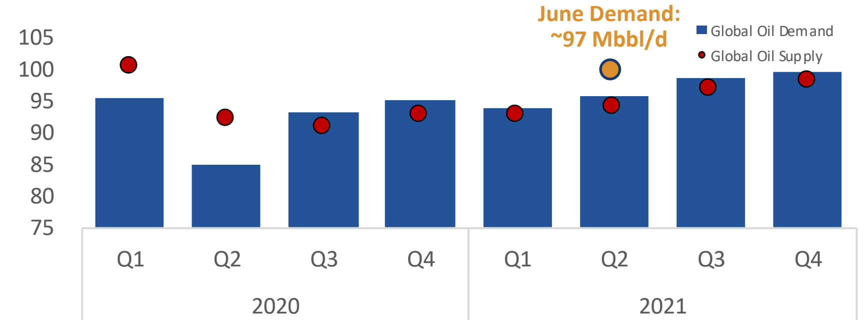
GLOBAL SUPPLY DEFICIT PERSISTS

- U.S. crude inventories have drawn rapidly over 2021
  - Inventories now ~30 MMbbl below 5-Yr Average
- Market expected to remain in deficit until mid 2022

CANADIAN PIPELINE EGRESS RISK NORMALIZED

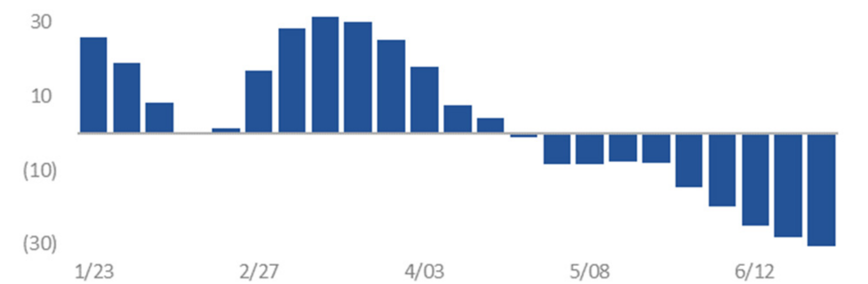
- Lower WCSB supply growth expectations
  - Limited new oil sands projects/expansions
  - Producers focused on return of capital vs. growth model
  - Local inventories falling
- Expectation of excess pipeline capacity for foreseeable future
  - Enbridge Line 3 Replacement: +270 Mbbl/d in late 2021
  - TMX: +590 Mbbl/d in late 2022
- Heavy oil in high demand globally

Global Oil Supply / Demand Outlook (MMbbl/d)



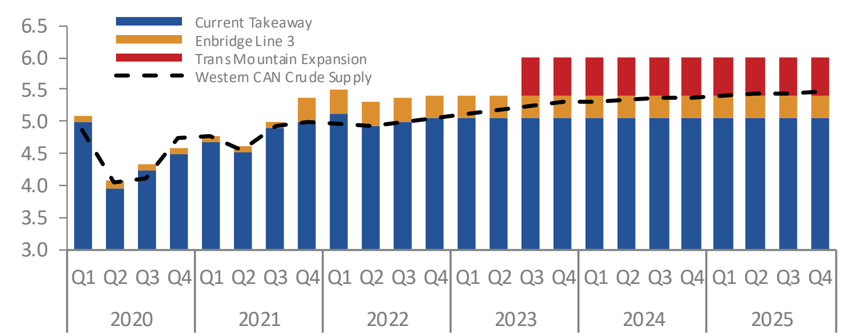
Source: Goldman Sachs

U.S. Crude Inventories Surplus (Deficit) to 5-Yr Avg



Source: RBC Capital Markets

Canadian Egress Outlook (MMbbl/d)



Source: Tudor, Pickering, Holt & Co., BMO, CAPP

BALANCE SHEET & REFINANCING OBJECTIVES

FINANCIAL SNAPSHOT (Q2 2021)

- $153MM unrestricted cash
- $134MM restricted cash and deposits for long-term obligations
- US$450MM Second Lien Notes mature Feb. 2022

2021 OUTLOOK (JULY 5 STRIP PRICING*)

- ~$235MM Adj. EBITDA & ~$175MM Adj. Funds Flow
- $100MM sustaining capital maintains 32,000 – 34,000 boe/d
- ~$75MM Free Cash Flow
- 1.6x Q2 Net Debt to Adj. 2021e EBITDA

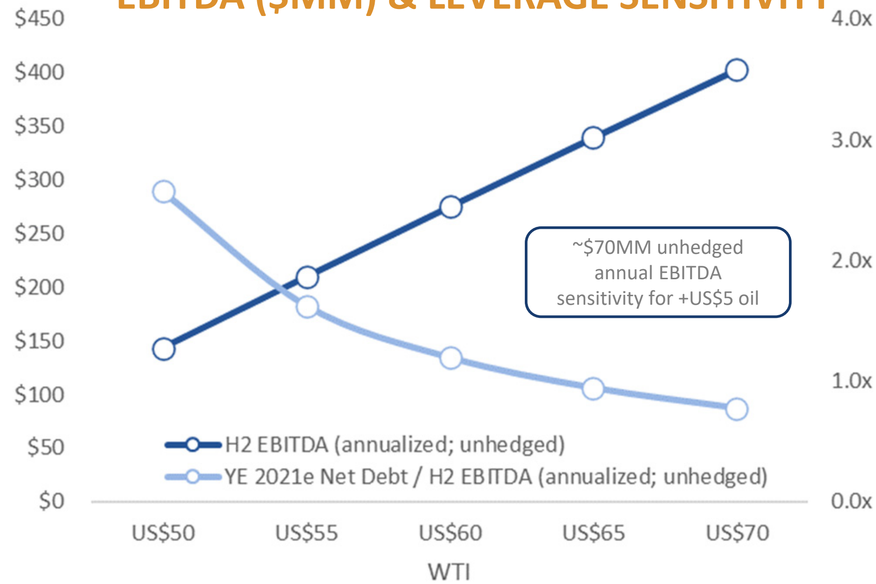
RISK MANAGEMENT

- Robust hedge policy targeting up to 50% of production
- Secure cash flow to protect sustaining capital program

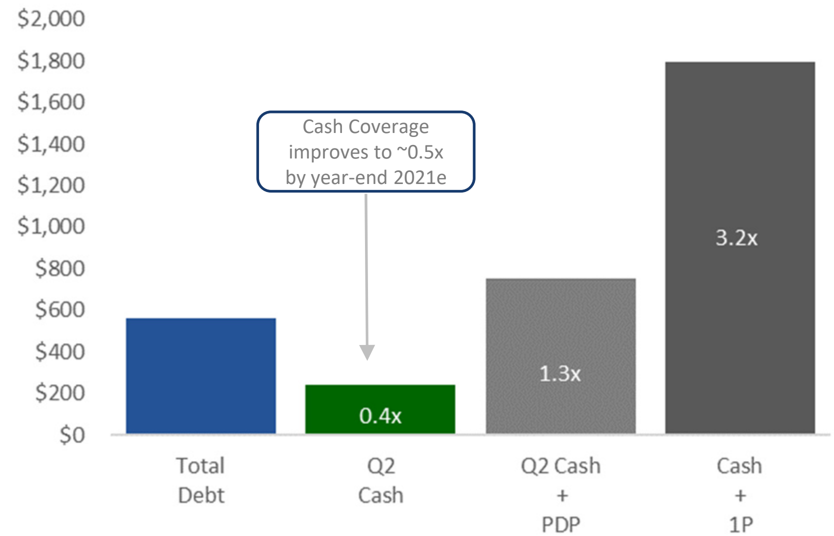
REFINANCING ATTRIBUTES & OBJECTIVES

- Multi-year funding certainty to align with long life assets
- Lower quantum of debt and interest costs
- Long-term leverage target of <1.5x ND/EBITDA at US$55 WTI
- Unlock restricted cash for LCs with secured 1L/LC facilities

EBITDA ($MM) & LEVERAGE SENSITIVITY



STRONG ASSET COVERAGE ($MM)



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ESG – 2020 HIGHLIGHTS

20% Decrease in GHG Emissions Intensity since 2015
Athabasca optimized facilities and applied technology throughout our operations to mitigate emissions.

Zero Reportable Spills
No hydrocarbon reportable spill in 2019 and 2020.

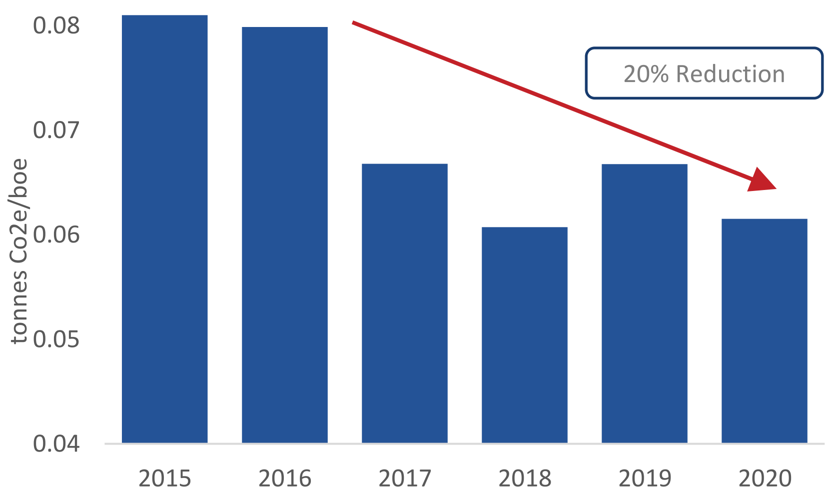
0.1 Total Recordable Injury Frequency (TRIF)
Best in class safety excellence. No lost time injuries.

Exceeded Voluntary Closure Spend by 50%
We actively participated in the Alberta-Based Closure program by reclaiming inactive sites in 2020.

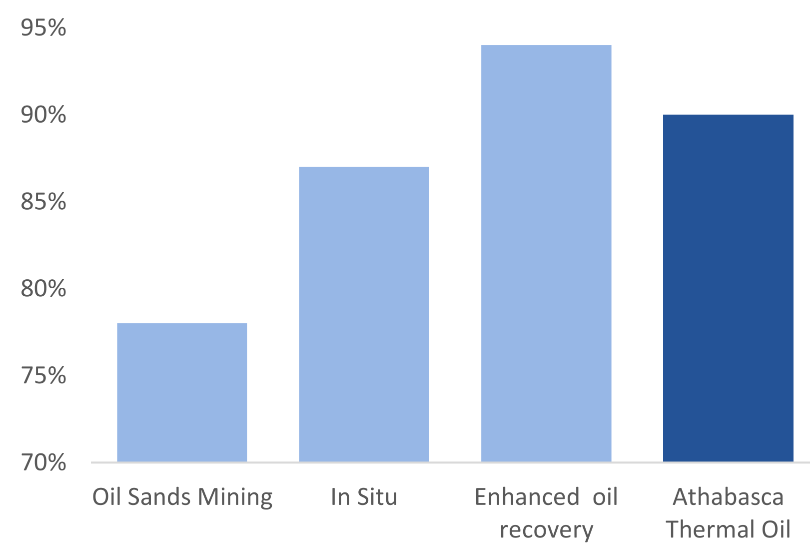
86% Corporate Water Recycle Rate
90% water recycle rate in Thermal Oil.

Contributed 66% of the Provincial Park Expansion Lands to Create the World's Largest Boreal Forest
Expanded the ecologically and culturally significant Kitaskino Nuwenëné Wildland Provincial Park by relinquishing 235,000 acres of mineral rights.

NET GHG EMISSIONS INTENSITY



WATER RECYCLE RATIO



Athabasca has a longstanding history of consistently measuring, tracking and reporting on ESG metrics

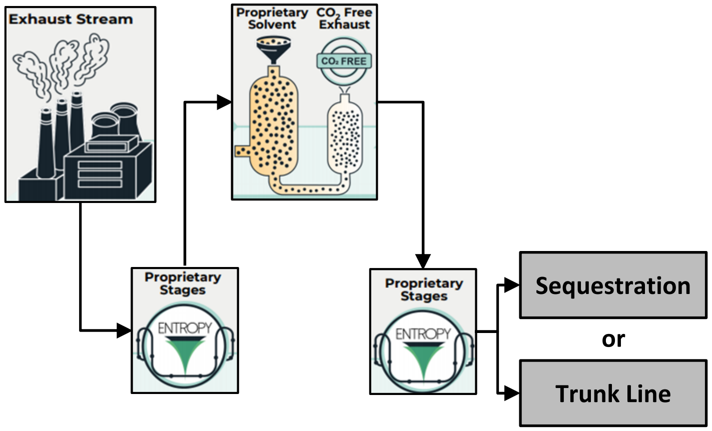
ESG – CARBON CAPTURE

Athabasca Stated ESG Goal (May 2021)
"Prepare a technology roadmap for a lower carbon future evaluating carbon capture use and storage, cogeneration, solvent injection, and renewable energy"

CARBON CAPTURE – AOC'S ROAD MAP TO NET-ZERO

- Entropy Inc. ("Entropy") modular carbon capture technology
  - Athabasca signed an MOU with Entropy in April 2021
  - The goal to produce a "net-zero" barrel at Leismer
- Technology evaluation underway with a focus on application
- Exploring sequestration options for captured carbon into either regional disposal zones or participation in industry carbon trunk line projects

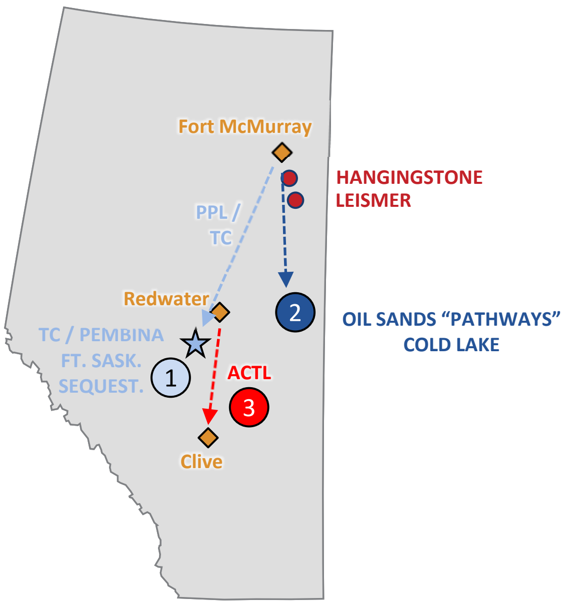
TECHNOLOGY OVERVIEW



ALBERTA BASED INDUSTRY & GOVERNMENT INITIATIVES

- Open access pipeline systems and developments:
- (1) Carbon Grid – multi-sector solution targeting >20MM T CO_2 annually
  - TC Energy and Pembina Pipelines announced a partnership in June
  - Developing a world scale carbon transportation & sequestration
  - Newly developed sequestration hub in the Ft. Saskatchewan region
- (2) Oil Sands "Pathways" – energy industry alliance
  - Consortium of major oil sands producers targeting Net Zero
  - Develop an open access carbon trunk line to a sequestration hub near Cold Lake
  - Deploy existing and emerging GHG reduction technologies
- (3) Alberta Carbon Trunk Line – ~15MM T CO_2 annually into Clive oil reservoir
  - Partnership between Enhance Energy, Wolf Midstream, North West Refining Partnership and Nutrien

PROJECT MAP



ATHABASCA VALUE PROPOSITION & STRATEGY

Low Decline Thermal Oil

- ✓ <10% decline rate
- ✓ ~1 billion bbl reserves at Leismer/Corner
- ✓ US$29/bbl WCS break-even

High Margin Light Oil

- ✓ Peer leading netback (~$34/boe Q2 2021)
- ✓ ~850 gross locations
- ✓ Flexible development plans

Unparalleled Exposure to Oil Prices

- ✓ ~90% liquids weighting
- ✓ +US$5 WTI generates ~$70MM EBITDA (unhedged)
- ✓ ~US$43 WTI operating break-even*

Strong Financial Capacity

- ✓ $153MM cash growing to ~$210MM at year-end
- ✓ 1.6x Q2 Net Debt to Adj. 2021e EBITDA
- ✓ 1.3x Cash + PDP Coverage

STATEGICALLY POSITIONED TO MAXIMIZE VALUE

Disciplined Operations

- ✓ Setting firm targets and work plans for ESG responsibility
- ✓ Maintain production and continually improve margins

Next Step: Refinancing

- ✓ Refinance and deleverage the balance sheet in 2021
- ✓ <1.5x Net Debt to EBITDA at US$55 WTI long-term

AOC is a compelling oil weighted investment with unparalleled free cash flow positioning

Footnotes and additional information included in the back as endnotes and reader advisories
* 2021e operating break-even assumes US$12.50 WCS diff and 0.80 FX

ASSET OVERVIEW

LEISMER OVERVIEW

ASSET OVERVIEW

- Located ~100 km south of Fort McMurray
- Central Processing Facility (CPF); approved capacity of 40,000 bbl/d
- On site lodge with ~500 person capacity; owned Aerodrome

SUBSURFACE DATA & WELLS

- 500+ delineation wells; 100% seismic coverage
- First steam September 2010
- 7 producing pads (40 well pairs & 13 infill wells)

TOP TIER OIL SANDS PROJECT

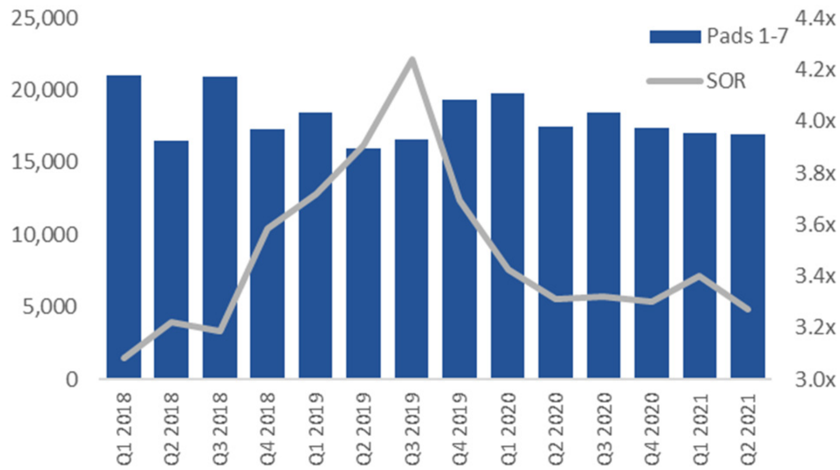
- ~20,000 bbl/d productive capacity
- 694 mmbbl 2P reserves; ~90 year 2P RLI
- ~$35/bbl operating netback (June 2021)
- US$28 WCS operating break-even (US$12.50 WCS diff)

INFRASTRUCTURE

- Dilbit pipe connected to Enbridge Cheecham Terminal
- Diluent pipe connected from Enbridge Cheecham Terminal
- Fuel gas from TransCanada Pipeline

LEISMER CENTRAL PROCESSING FACILITY

PRODUCTION HISTORY (BBL/D; X)



LEISMER SUSTAINING PROJECTS

NEAR-TERM INFILL WELLS

- Pad L7 sustaining well pair; first oil in July
- Two Pad L6 infills; first oil July

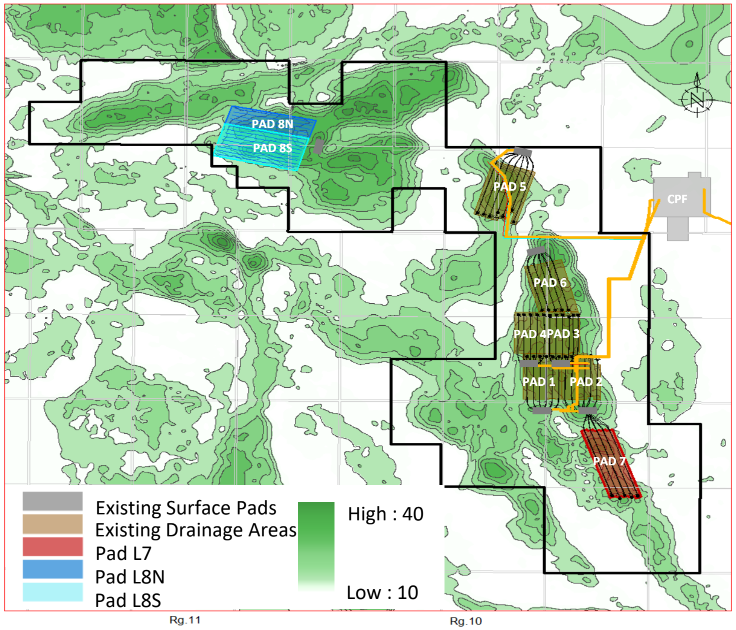
PAD L8 PROJECT

- D&C complete; facility construction commenced
- Highest quality reservoir drilled to date at Leismer
- First steam Q4/21 and first oil early 2022
- Expected to add >5,000 bbl/d with a multi-year plateau
- 9 future well pairs will leverage off existing infrastructure

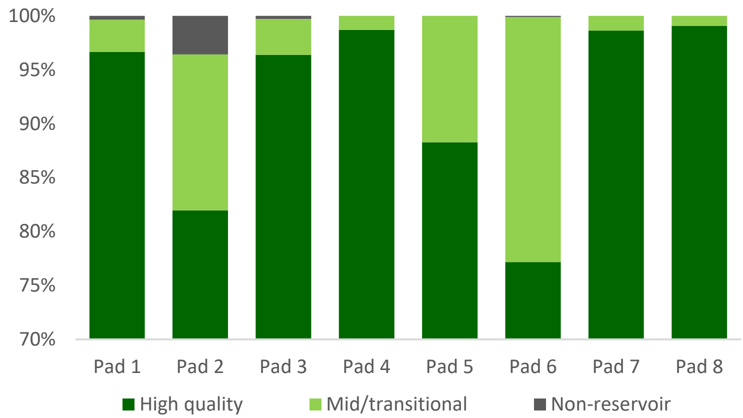
TOP TIER PROJECT ECONOMICS*

- ~110% IRR for 2021 projects
- Pad L8 ~$310MM NPV10; 6.3x P/I
- ~$9,000/bbl/d capital efficiencies
- Support corporate PDP bookings into 2022

DEVELOPMENT MAP



PAD RESERVOIR QUALITY



* Flat long-term commodity price assumptions: US$60 WTI, US$12.50 WCS diff, US$0 C5+ diff, C$2.90 AECO, 0.8 FX
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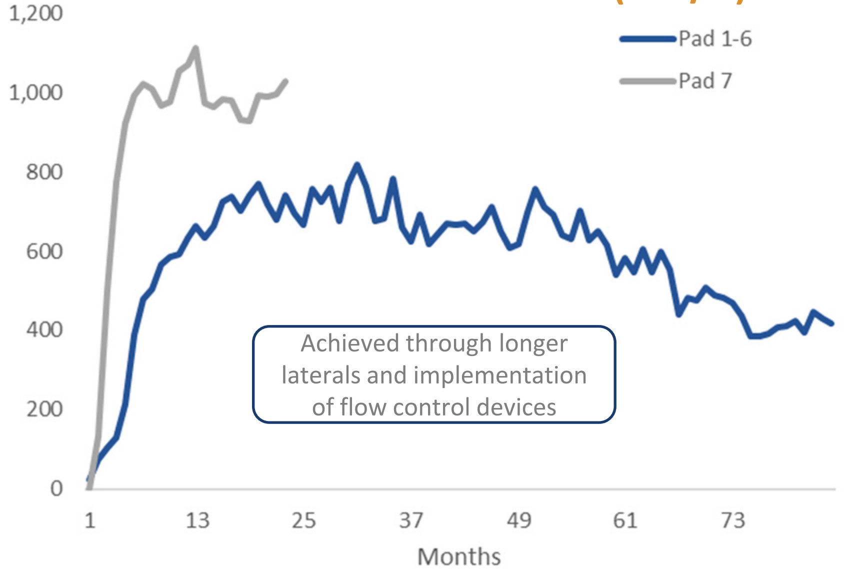
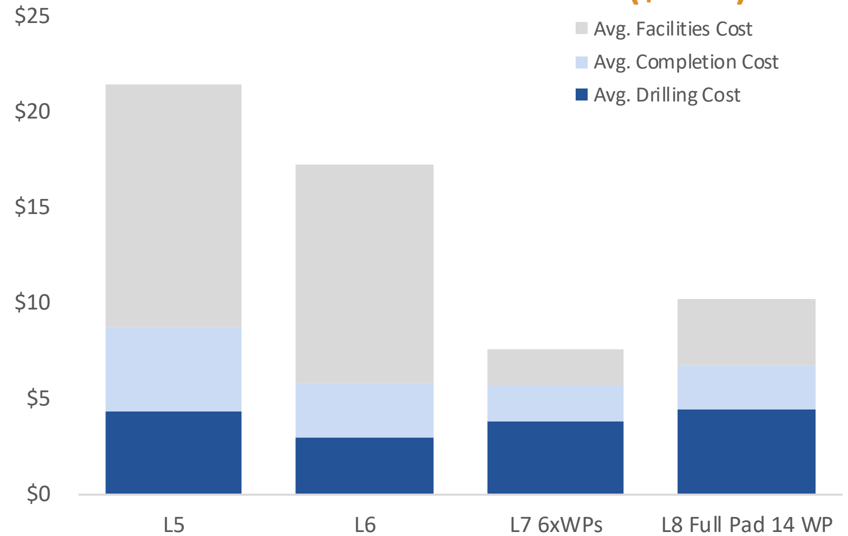
LEISMER IMPROVEMENTS

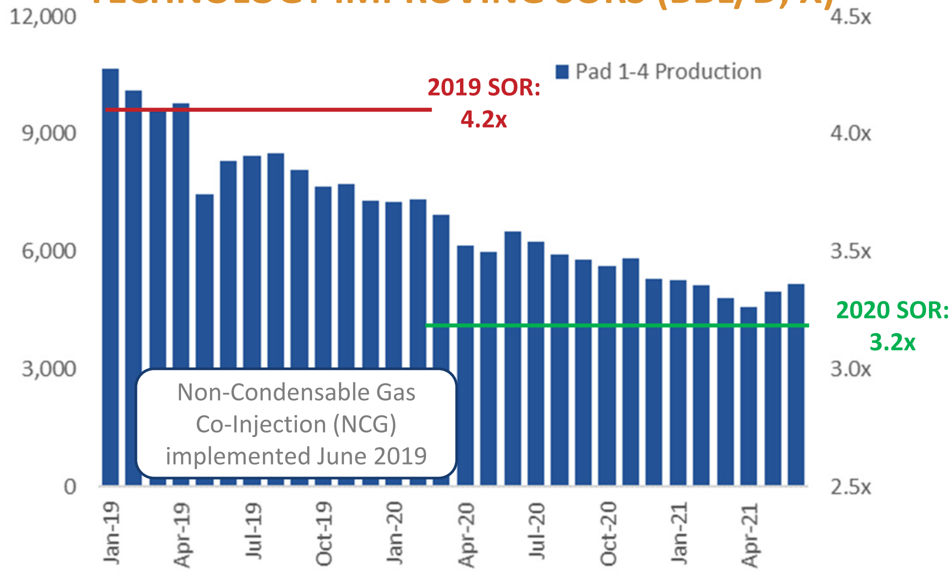
TECHNOLOGY DRIVING RATES (BBL/D)



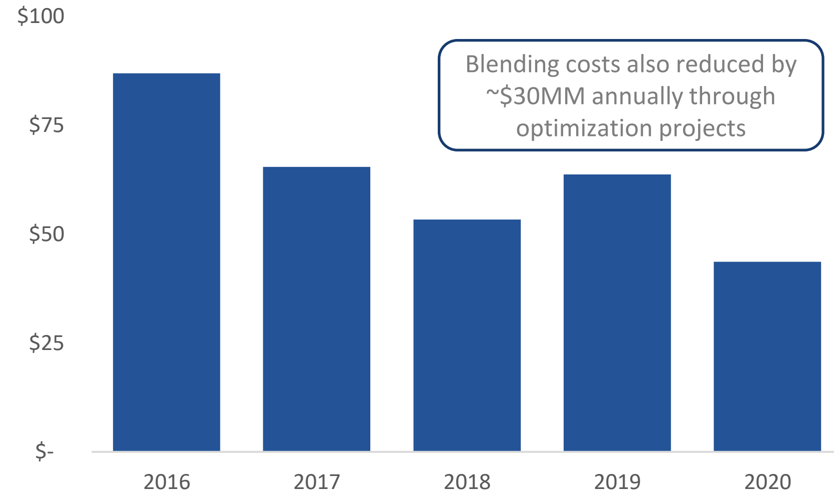
LOWER WELL PAIR COSTS ($MM)



TECHNOLOGY IMPROVING SORS (BBL/D; X)



NON-ENERGY OPEX ($MM)



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LEISMER FUTURE OPPORTUNITIES

STRATEGY

- Maximize free cashflow and deliver strong netbacks
- Focus on projects that improve the SOR
- Maintain agility and execution readiness

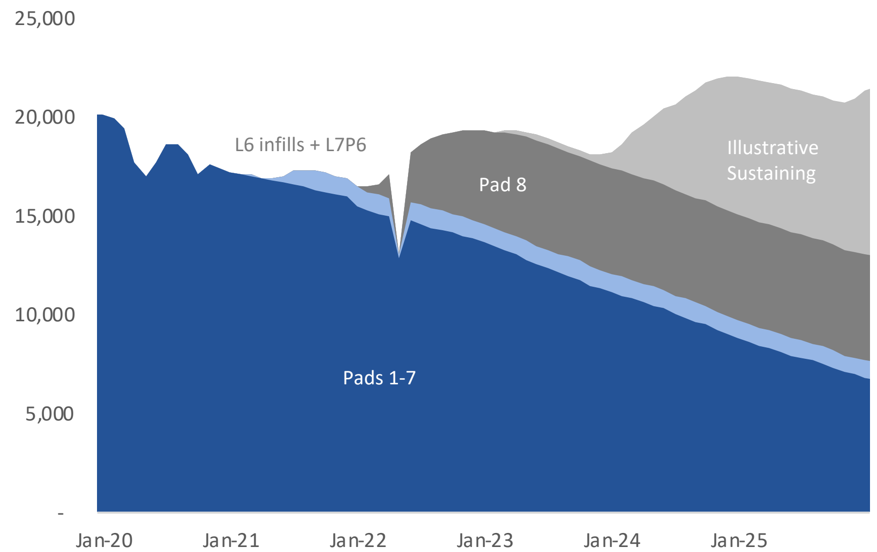
2021 BASE CAPITAL

- L7P6 and L6 Infills on production July 2021
- Pad L8 pipeline
- Pad L8 D&C and facility construction; on production early 2022

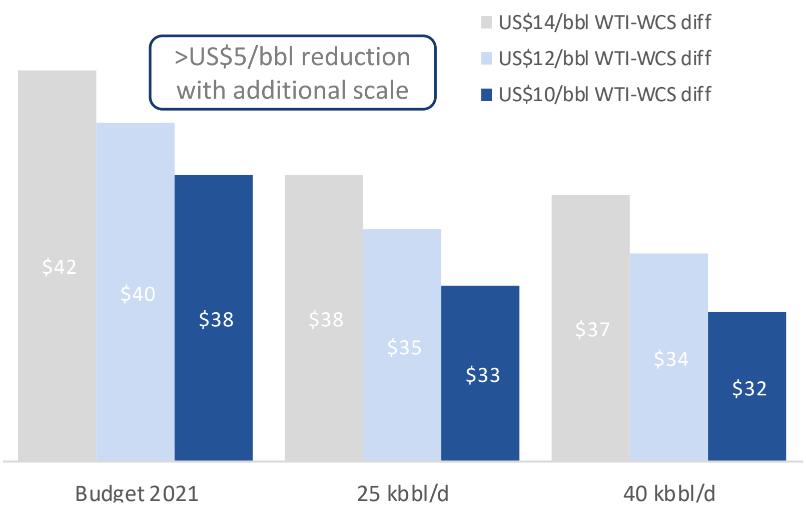
FUTURE CAPITAL FLEXIBILITY

- 9 additional well pair locations on Pad L8

LEISMER DEVELOPMENT (BBL/D)



WTI BREAKEVEN (US$/BBL)



ILLUSTRATIVE PROJECT ECONOMICS (US$60 WTI)

		L8 North	L6 infills	L7P6
Capital (lease edge)	*$MM*	$49	$8	$7
Plateau Rate per project	*bbl/d*	5,400	360	630
EUR per project	*mbbl*	13,400	1,000	2,000
IRR	*%*	109%	101%	320%
NPV10	*$MM*	$310	$17	$44
F&D	*$/bbl*	$3.65	$8.00	$3.25
Recycle Ratio	*x*	6.3x	2.9x	7.1x
Capital Efficiency	*$/bbl/d*	$9,000	$22,000	$11,000
P/I	*x*	6.3x	2.1x	6.3x

Flat long-term commodity price assumptions: US$60 WTI, US$12.50 WCS diff, US$0 C5+ diff, C$2.90 AECO, 0.80 C$/US$ FX

HANGINGSTONE OVERVIEW

ASSET HIGHLIGHTS

- Located ~20 km south of Fort McMurray
- Central Processing Facility (CPF); approved capacity of 12,000 bbl/d
- No camp; proximal to Fort McMurray

SUBSURFACE DATA & WELLS

- >250 delineation wells with good seismic coverage
- First steam March 2015
- 5 producing pads (25 well pairs)

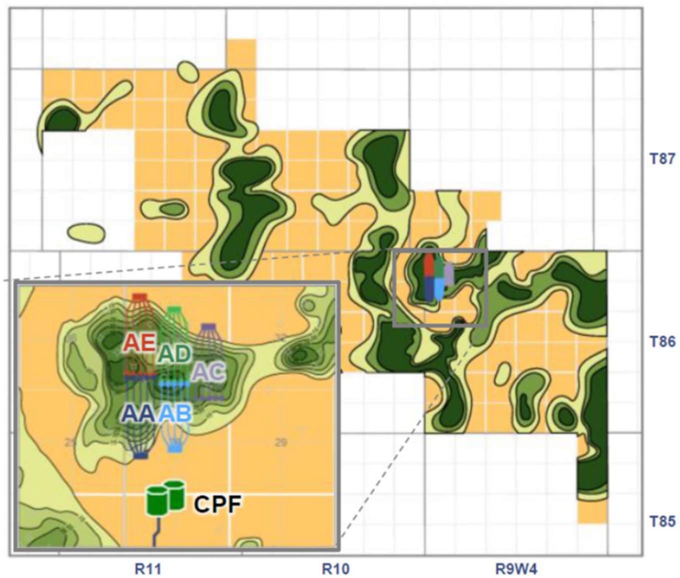
HANGINGSTONE PROJECT

- ~9,500 bbl/d productive capacity (~4.5x SOR)
- 36 mmbbl 2P reserves
- ~$32/bbl operating netback (June 2021)
- US$31 WCS operating break-even (US$12.50 WCS diff)

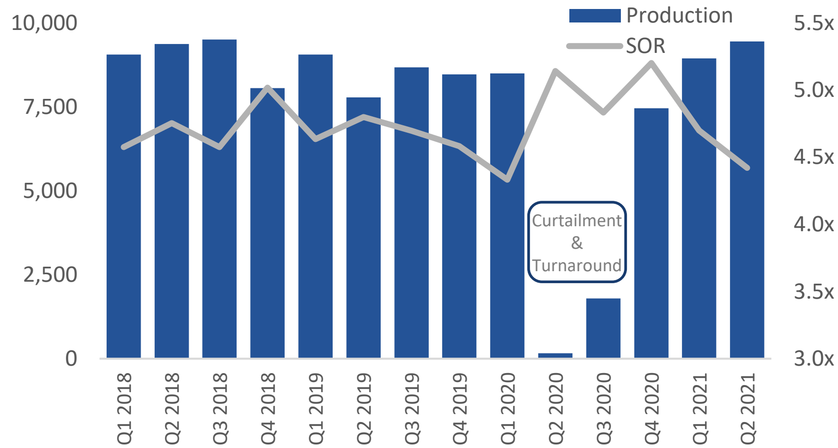
INFRASTRUCTURE

- Dilbit export to Enbridge Cheecham Terminal
- Diluent from Inter Pipeline
- Fuel gas from TransCanada Pipeline

DEVELOPMENT MAP



PRODUCTION HISTORY (BBL/D; X)



HANGINGSTONE RECENT INITIATIVES

STRONG RESERVOIR RESPONSE

- Excellent facility run-time following Summer 2020 turnaround
- Current production ~9,400 bbl/d (June)
- NCG aiding in pressure build-up and energy usage
- Start-up of standing well pair underway (AA03)

TRUCK RACK OPTIMIZATION

- Partnered with industry leading marketing company
- Truck terminal commenced in July at no capital cost to AOC
- Up to 5,000 bbl/d of third-party industry volumes
- Estimated ~$5MM in additional annual cash flow through processing fees and leveraging existing volume commitments

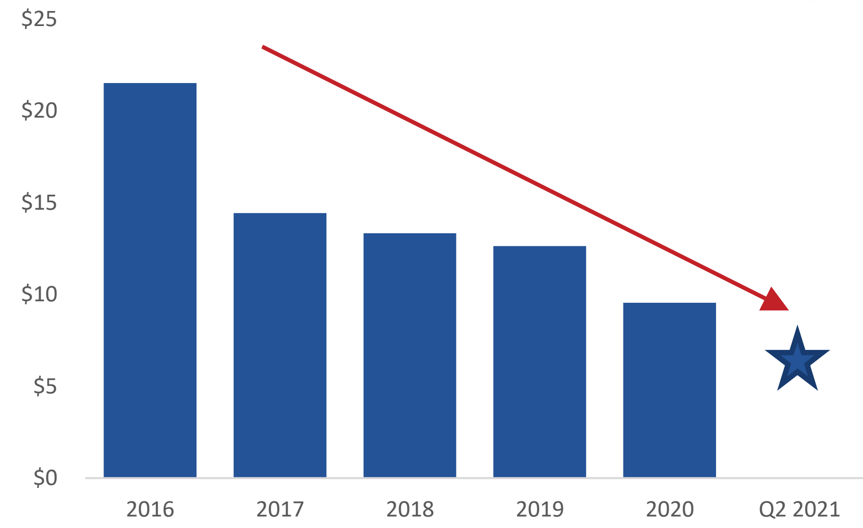
AMENDED TRANSPORTATION CONTRACT

- ~$5MM reduction to annual tolls
- ~$44MM reduction in financial assurances unlocked restricted cash
- Unlocked cash used to fund a $44MM amending prepayment

CAPITAL OUTLOOK

- Minimal sustaining capital required in the medium term

REDUCING NON-ENERGY OPEX ($/BBL)



TRUCK RACK

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LIGHT OIL PORTFOLIO

PLACID MONTNEY – 70% WORKING INTEREST

- ~80,000 gross acres; ~150 gross future locations
- Q2 production ~4,350 boe/d (43% liquids)
- ~$30/boe operating netback (June 2021)
- Declines moderated with flexible future development

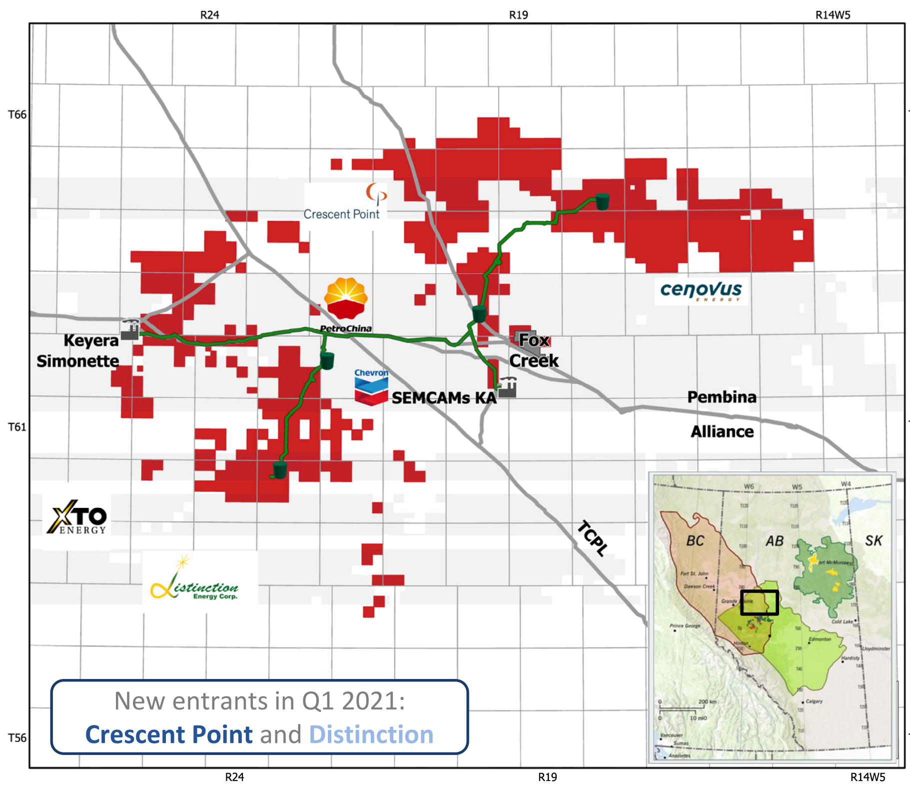
KAYBOB DUVERNAY – 30% WORKING INTEREST

- ~220,000 gross acres; ~700 gross future locations
- Q2 production ~3,500 boe/d (74% liquids)
- ~$44/boe operating netback (June 2021)
- Resource de-risked with $1B+ JV investment to date
- Spending governed by strong Joint Development Agreement

OWNED AND OPERATED INFRASTRUCTURE

- Located in a major development corridor
- Four batteries servicing the Montney and Duvernay
- Gas dually connected to Keyera Simonette & SEMCAMs KA
- Liquids pipeline connected to Pembina

AOC LIGHT OIL PROPERTIES



PLACID FUTURE OPPORTUNITIES

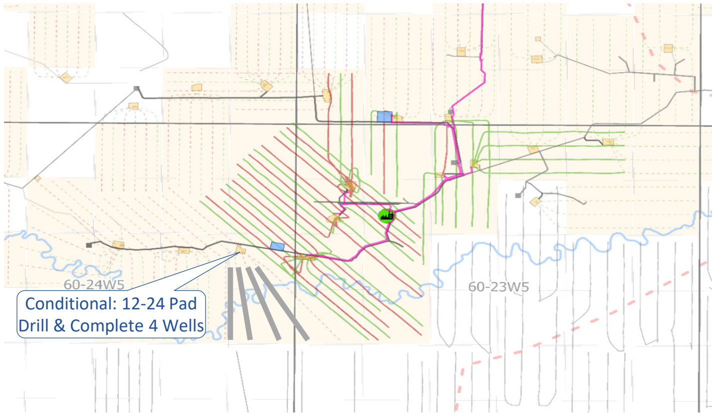
STRATEGIC OBJECTIVES

- Continued development flexibility and readiness
- Focus on free cash flow generation

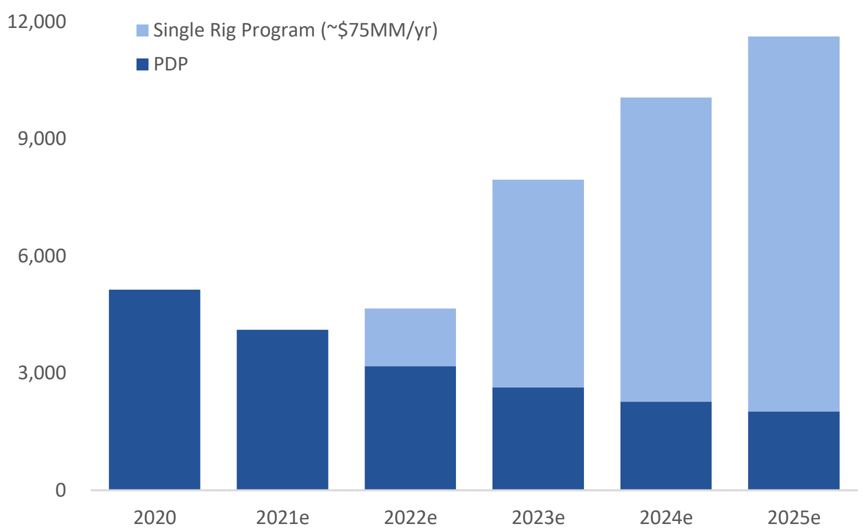
FUTURE ACTIVITY

- Minimal 2021 budget focused on maintenance capital to support base production
- Operational readiness to drill and complete 4 well pad

2021 CONDITIONAL DEVELOPMENT



ILLUSTRATIVE FIVE YEAR PRODUCTION* (BOE/D)



ILLUSTRATIVE MULTI WELL PAD ECONOMICS (US$60 WTI)

Capital (4 wells)	*$MM*	$28.3
IP365 per well	*boe/d*	475
EUR per well	*mboe*	500
IRR	*%*	47%
NPV10	*$MM*	$17.0
F&D	*$/boe*	$14.50
Recycle Ratio	*x*	2.5x
Capital Efficiency	*$/boe/d*	$15,500
P/I	*x*	0.6x

Flat long term price assumptions: C$2.90/mcf AECO, $0/bbl C5+ diff, US$6/bbl Ed Par diff, 0.80 C$/US$ FX

* Athabasca internal illustrative development scenario
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DUVERNAY FUTURE OPPORTUNITIES

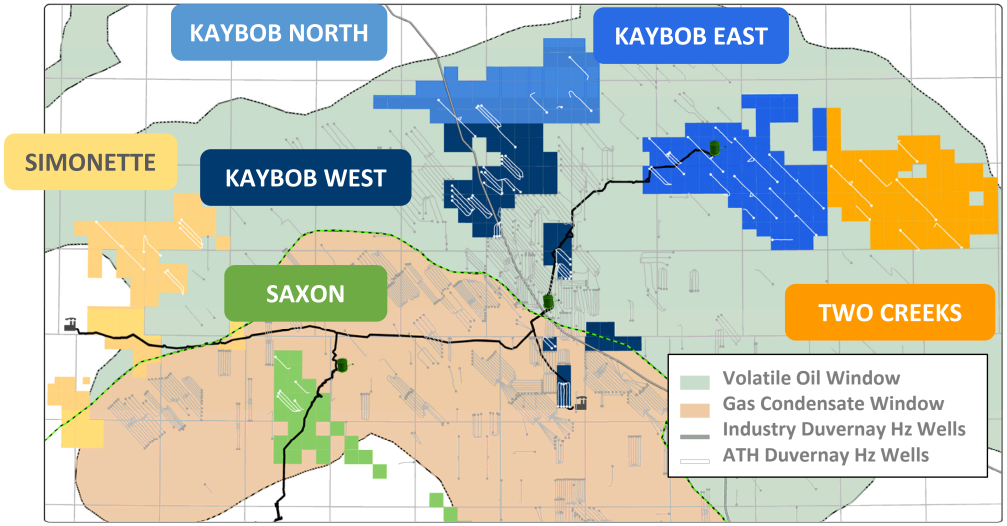
STRATEGIC OBJECTIVES

- Continued development flexibility and readiness
- Focus on free cash flow generation

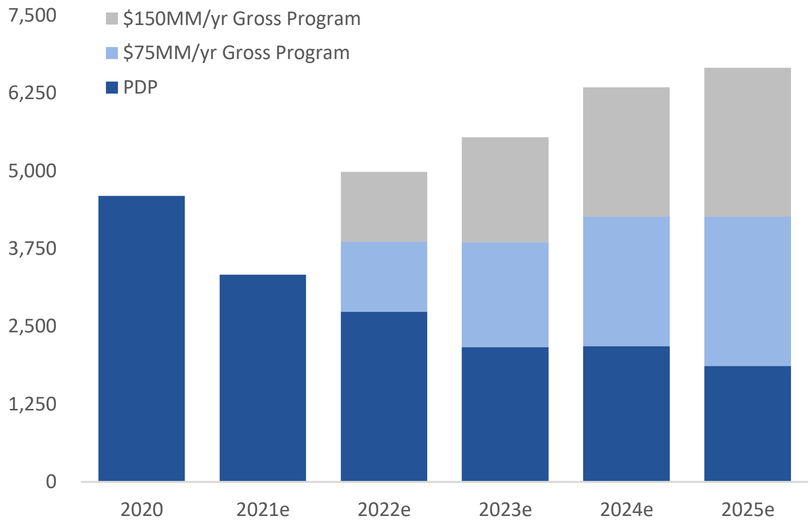
FUTURE DEVELOPMENT

- Minimal 2021 budget focused on maintenance capital to support base production
- Several future development scenarios dependent on commodity prices
- Spending governed by a strong Joint Development Agreement (JDA)

KAYBOB DUVERNAY



ILLUSTRATIVE FIVE YEAR PRODUCTION* (BOE/D)



ILLUSTRATIVE SINGLE WELL KAYBOB EAST ECONOMICS (US$60 WTI)

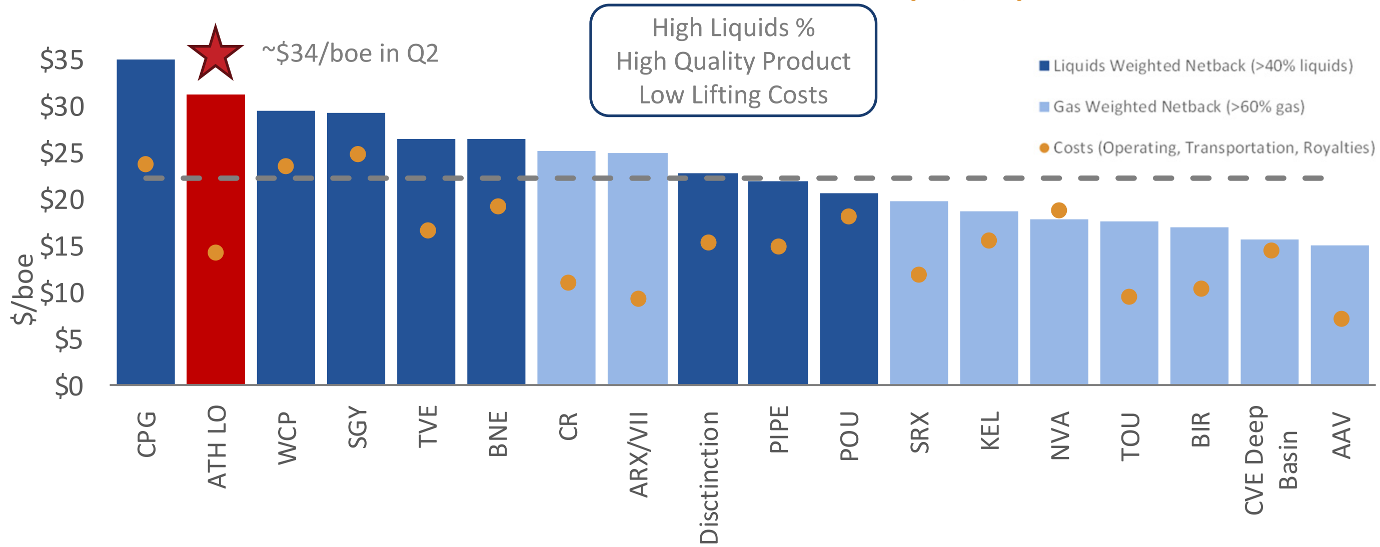
Capital	*$MM*	$8.0
IP365	*boe/d*	425
EUR	*mboe*	675
IRR	*%*	56%
NPV10	*$MM*	$7.6
F&D	*$/boe*	$11.75
Recycle Ratio	*x*	3.8x
Capital Efficiency	*$/boe/d*	$19,000
P/I	*x*	1.0x

Flat long term price assumptions: C$2.90/mcf AECO, $0/bbl C5+ diff, 0.80 C$/US$ FX

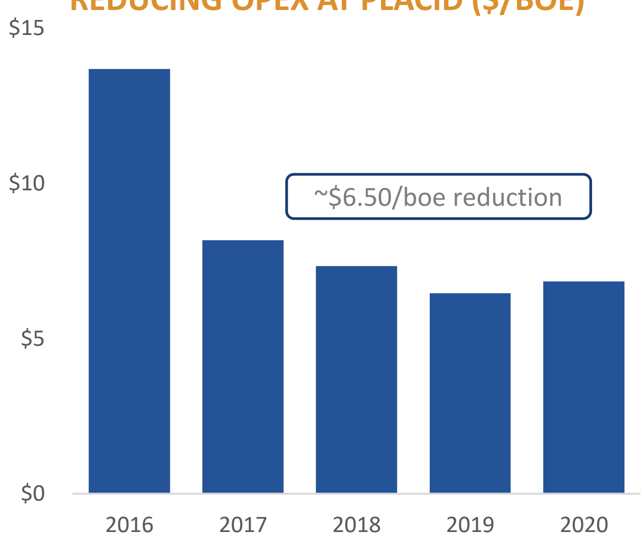
* Athabasca internal illustrative growth scenarios
Footnotes and additional information included in the back as endnotes and reader advisories

LIGHT OIL IMPROVEMENTS

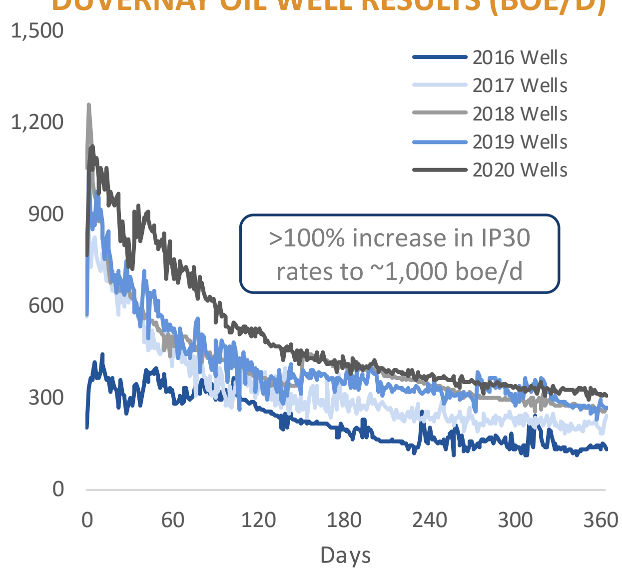
INDUSTRY LEADING NETBACK (Q1/21)



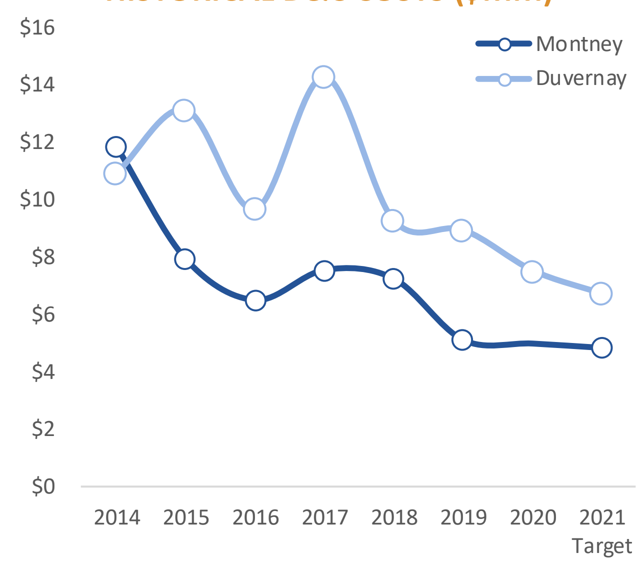
REDUCING OPEX AT PLACID ($/BOE)



DUVERNAY OIL WELL RESULTS (BOE/D)



HISTORICAL D&C COSTS ($MM)*



Footnotes and additional information included in the back as endnotes and reader advisories

* 2021 does not have any approved operations for the Duvernay; 2021 target D&C costs reflect Q1/20 pace setter well results

ESG OVERVIEW

ESG – INAUGURAL 2021 REPORT

We believe that the responsible energy we produce here in Alberta makes people's lives better.

Our inaugural ESG report is an opportunity for us to showcase the positive impacts we have made and explain how sustainability and responsibility are being embedded into every decision we make.

"Our commitment to ESG responsibility and sustainability is part of our long-term strategy and an ongoing process."

Inaugural ESG Report available on our website & SEDAR

1.0 Message from our President & CEO | 2.0 Our Business and Corporate 2020 Highlights | 3.0 Our Approach to Sustainability | 4.0 Health and Safety | 5.0 Environment | 6.0 Kitaskino Nuwenëné Wildland Provincial Park | 7.0 Social | 8.0 Governance | 9.0 Data and Advisories

ATHABASCA OIL CORPORATION

1.0 Message from our President & CEO

At Athabasca, we believe that the responsible energy we produce here in Alberta makes people's lives better.

We have a longstanding commitment to Environmental, Social, and Governance (ESG) initiatives and we are proud of the work we do to take care of the environment and the communities where we operate. We believe that measurement is key to evaluating our work, setting goals, and making year over year progress.

This inaugural ESG report is an opportunity for us to showcase the positive impacts we have made and explain how sustainability and responsibility are being embedded into every decision we make. It highlights the many initiatives and commitments we have made to support our communities, enhance our business and profitability, and create long-term value for all our stakeholders.

Environmental Leadership

Athabasca has made significant progress in reducing our carbon footprint through investment in lower GHG intensity resources where new technology can also be deployed. We have reduced our GHG emissions intensity by 20% since 2015 and are targeting a total 30% reduction by 2025. Canada has some of the most stringent environmental and regulatory regulations in the world and we acknowledge that Canada has committed to lowering its emissions through the Paris Agreement, most recently with an increased commitment to reduce emissions 40-45% below 2005 levels, by 2030. Athabasca is doing our part in this effort and believes the world would greatly benefit from more Canadian energy.

Technology

Investment in new technologies is integral to sustainable energy production. We continue to invest in technologies that increase energy efficiency and reduce land disturbance. An example is the application of non-condensable gas (NCG) co-injection at our thermal assets where we have seen up to 50% reduction in GHG emissions at some older well pads. Over the next year, we intend to advance our roadmap of technologies that will help us transition to a lower carbon future. Technologies under consideration include carbon capture use and storage, cogeneration, solvent injection, and incremental renewable energy. Technology is the cornerstone to improving our environmental footprint and we look forward to engaging with industry and government to push boundaries and find innovative solutions that improve both emissions intensity and lower overall emissions.

Safety & Our People

One year into the COVID-19 pandemic, health and safety have never been more important. Our 2020 Health Safety and Environment (HSE) performance clearly demonstrates our excellent safety culture, with an industry-leading Total Recordable Injury Frequency (TRIF) of 0.1 and zero recordable spills.

This past year also pushed us to connect with our staff in new and meaningful ways, as we pivoted to use technology to virtually host meetings and town halls. We have also made strides integrating new employee offerings that foster Diversity & Inclusion within the organization.

Community & Environmental Stewardship

Earlier this year, we played an important role in returning ecologically and culturally sensitive land back to wildlife and Indigenous communities in our province, a project of which I am particularly proud. We partnered with the Mikisew Cree First Nation and the Government of Alberta to create the world's largest contiguous protected boreal forest in Kitaskino Nuwenëné Wildland Provincial Park.

The last 12 months have been challenging for everyone, but our employees, like all Albertans, have proven their resiliency and generosity. During this difficult time, we have not lost sight of the importance of taking care of those who need it the most. We have continued to give back to our local communities through initiatives like #3things4neighbours, charitable donations, and post secondary scholarships and endowments.

Looking Ahead

Our commitment to ESG responsibility and sustainability is part of our long-term strategy and an ongoing process. Each year we plan to measure, improve, and progress as an organization. Our goal is to supply responsibly developed energy to help meet ongoing global demand, while also creating a positive and long-lasting impact on the communities where we operate.

Our ESG strategy and performance is reviewed, considered, and fully integrated at Board level. Our management team and Board are committed to incorporating ESG considerations and the application of technology in all our capital allocation decisions. HSE targets currently make up 20% of our annual corporate performance scorecard and will reflect the importance of our broader ESG performance in years to come.

As we progress, I can promise you a focus on transparency and continuous advancement as we deliver on our commitments to our stakeholders, communities, and employees. We invite you to join us on our ESG journey as we continue to grow and responsibly produce energy in Alberta.

Sincerely,

Robert Broen, President & Chief Executive Officer

2021 Athabasca Environmental, Social, Governance Report 2

ESG – 2020 HIGHLIGHTS

20% Decrease in GHG Emissions Intensity since 2015
Athabasca optimized facilities and applied technology throughout our operations to mitigate emissions.

Zero Reportable Spills
No hydrocarbon reportable spill in 2019 and 2020.

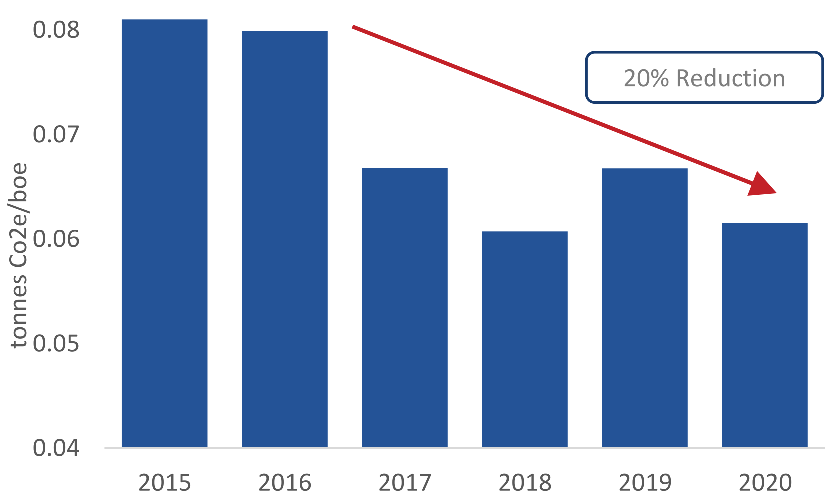
0.1 Total Recordable Injury Frequency (TRIF)
Best in class safety excellence. No lost time injuries.

Exceeded Voluntary Closure Spend by 50%
We actively participated in the Alberta-Based Closure program by reclaiming inactive sites in 2020.

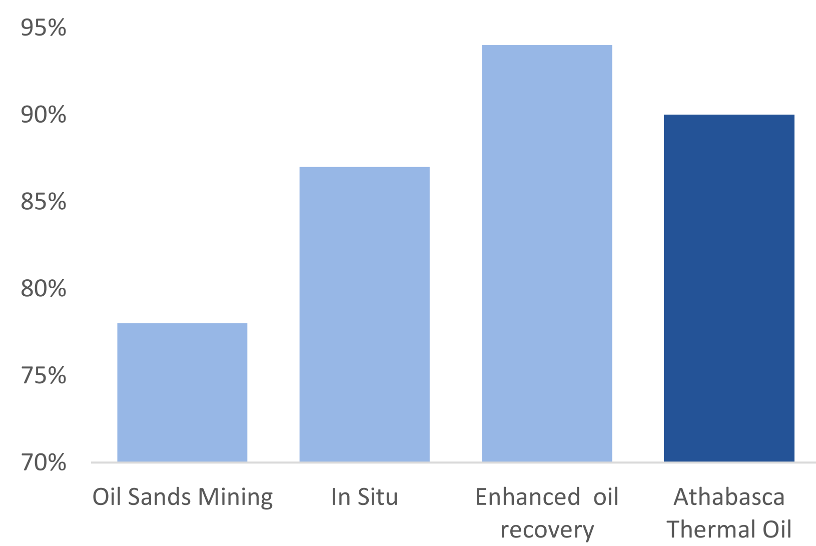
86% Corporate Water Recycle Rate
90% water recycle rate in Thermal Oil.

Contributed 66% of the Provincial Park Expansion Lands to Create the World's Largest Boreal Forest
Expanded the ecologically and culturally significant Kitaskino Nuwenëné Wildland Provincial Park by relinquishing 235,000 acres of mineral rights.

NET GHG EMISSIONS INTENSITY



WATER RECYCLE RATIO



Athabasca has a longstanding history of consistently measuring, tracking and reporting on ESG metrics

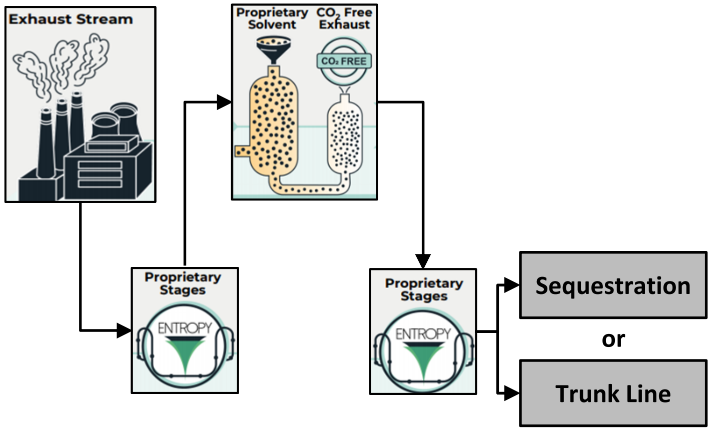
ESG – CARBON CAPTURE

Athabasca Stated ESG Goal (May 2021)
"Prepare a technology roadmap for a lower carbon future evaluating carbon capture use and storage, cogeneration, solvent injection, and renewable energy"

CARBON CAPTURE – AOC'S ROAD MAP TO NET-ZERO

- Entropy Inc. ("Entropy") modular carbon capture technology
  - Athabasca signed an MOU with Entropy in April 2021
  - The goal to produce a "net-zero" barrel at Leismer
- Technology evaluation underway with a focus on application
- Exploring sequestration options for captured carbon into either regional disposal zones or participation in industry carbon trunk line projects

TECHNOLOGY OVERVIEW

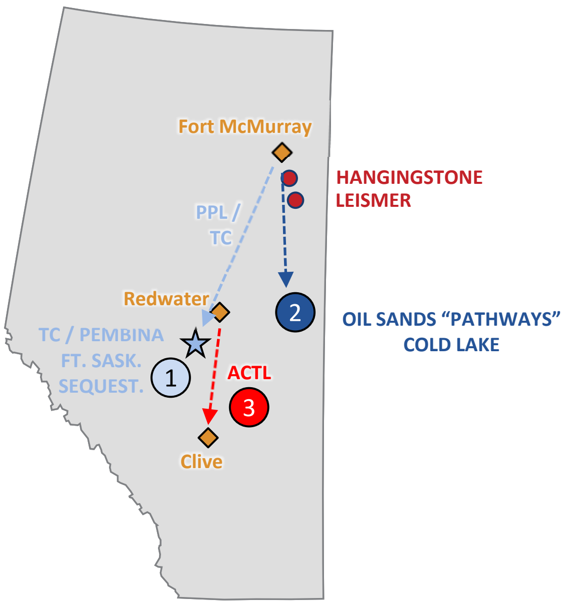


ALBERTA BASED INDUSTRY & GOVERNMENT INITIATIVES

- Open access pipeline systems and developments:

1. Carbon Grid – multi-sector solution targeting >20MM T CO_2 annually
   - TC Energy and Pembina Pipelines announced a partnership in June
   - Developing a world scale carbon transportation & sequestration
   - Newly developed sequestration hub in the Ft. Saskatchewan region
2. Oil Sands "Pathways" – energy industry alliance
   - Consortium of major oil sands producers targeting Net Zero
   - Develop an open access carbon trunk line to a sequestration hub near Cold Lake
   - Deploy existing and emerging GHG reduction technologies
3. Alberta Carbon Trunk Line – ~15MM T CO_2 annually into Clive oil reservoir
   - Partnership between Enhance Energy, Wolf Midstream, North West Refining Partnership and Nutrien

PROJECT MAP



ESG – ENVIRONMENTAL HIGHLIGHTS

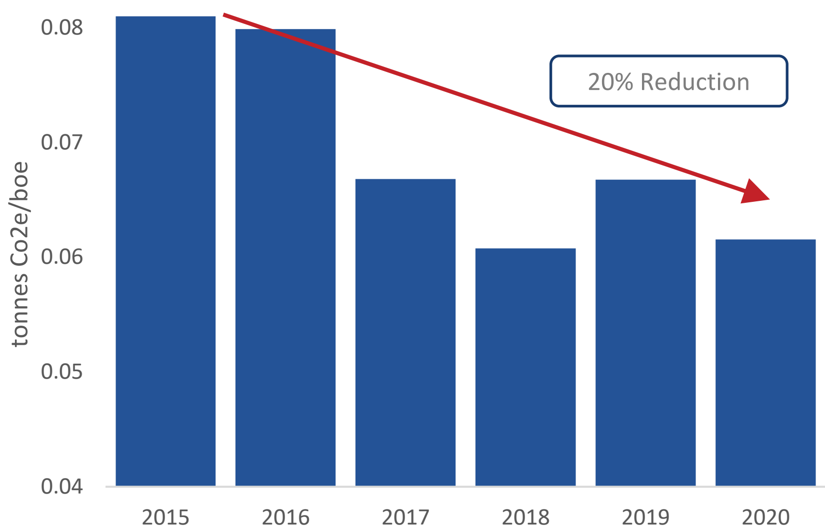
GREEN HOUSE GAS EMISSIONS

- Tracking our performance and setting targets
  - *20% reduction in emission intensity since 2015*
  - *30% total reduction target by 2025*
- New technologies integral to reducing emissions
  - *$45MM+ investment in technology since 2015*
  - *Mitigated GHG emissions by ~250,000 tCO_2e/year*
- Preparing a roadmap for a lower carbon future
  - *MOU with Entropy Inc.*

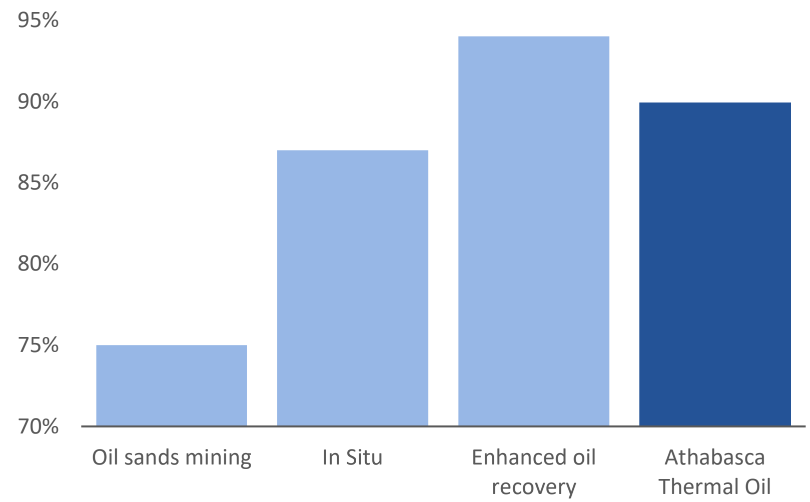
WATER USE

- Minimize water use across our operations
- 86% Corporate Water Recycle Rate (2020)
  - *90% Water Recycle Rate in Thermal Oil*

NET GHG EMISSIONS INTENSITY



WATER RECYCLE RATIO



ESG – SOCIAL & GOVERNANCE HIGHLIGHTS

MEANINGFUL SOCIAL IMPACT

- Accountability for ensuring a safe working environment
  - *2020 0.1 TRIF, no lost time injuries & 0 reportable spills*
- ~$500,000 donations to AOC's communities (2015-20)
- Meaningful engagement with Indigenous People
- Culture of diversity, authenticity, growth and inclusion

STRONG GOVERNANCE IS CORE TO OUR BUSINESS

- Independent Board oversight for long-term strategy
- Board oversight to ESG targets and goals
- Set meaningful ESG goals & have real plans to achieve them
- Robust corporate policies govern day-to day operations

In 2021, AOC partnered with the Mikisew Cree First Nation and the Government of Alberta to establish the Kitaskino Nuwenëné Wildland Provincial Park Expansion, creating the largest protected boreal forest in the world

ESG – COMMITMENT TO RESPONSIBILITY

GOALS

- Reduce emission intensity by 30% (2015 → 2025)
- Top tier safety results (<0.5 TRIF in 2021); aspiration of no harm to people and no hydrocarbon spills
- ESG to be a formal consideration in all capital allocation decisions
- Prepare a roadmap for lower carbon future including carbon capture use & storage, cogeneration, solvent injection and renewables
- Maintain and continually improve disclosure with best-in-class standards (GRI, SASB, TCFD)

ACCOUNTABILITY & GOVERANCE

- ESG goals have been incorporated in AOC's annual compensation scorecard
- Independent Board provides oversight to the Company's ESG performance

"As we progress, Athabasca will focus on transparency and continuous advancement as we deliver on our commitments to our stakeholders, communities, and employees. We invite you to join us on our ESG journey as we continue to grow and responsibly produce energy in Alberta"

APPENDIX

MANAGEMENT TEAM

Rob Broen, P.Eng.
President & Chief Executive Officer

- Joined Athabasca in 2012 as Senior Vice President Light Oil. Promoted to Chief Operating Officer in 2013 and President and Chief Executive Officer in 2015
- 30 years of exploration and production experience including 18 years with Talisman Energy in various technical and management capacities (President, Talisman Energy USA Inc. and Senior Vice President, North American Shale). At Talisman, managed capital budgets over $1 billion and a 120,000 boe/d North American shale portfolio (Montney, Duvernay, Marcellus and Eagle Ford)
- Bachelor of Science in chemical engineering from the University of Alberta and a graduate of the Ivey Executive Program at the Richard Ivey School of Business

Matt Taylor, CFA
Chief Financial Officer

- Joined Athabasca 2014 as Vice President Capital Markets & Communications. Promoted to Chief Financial Officer in 2019
- Over 15 years of financial, corporate and capital markets experience including equity research and investment banking at National Bank Financial, GMP Securities and CIBC World Markets. Most recently Director of Energy Equity Research at National Bank
- Bachelor of Commerce with a specialization in finance from UBC Sauder School of Business and holds a Chartered Financial Analyst designation

Karla Ingoldsby, P.Eng.
Vice President, Thermal Oil

- Joined Athabasca in 2010 as a Senior Reservoir Engineer and has been progressively appointed into more senior roles including Development Manager in the Joint Venture with PetroChina Canada and Director positions for Geoscience Reservoir and Development, Ventures & Land, and Thermal Oil Production
- 20 years of Oil and Gas experience, including reservoir engineering roles at Royal Dutch Shell overseeing thermal oil assets and conventional oil and gas assets
- Bachelor of Science in Mechanical Engineering from the University of Alberta

Mike Wojcichowsky, P.Eng.
Vice President, Light Oil

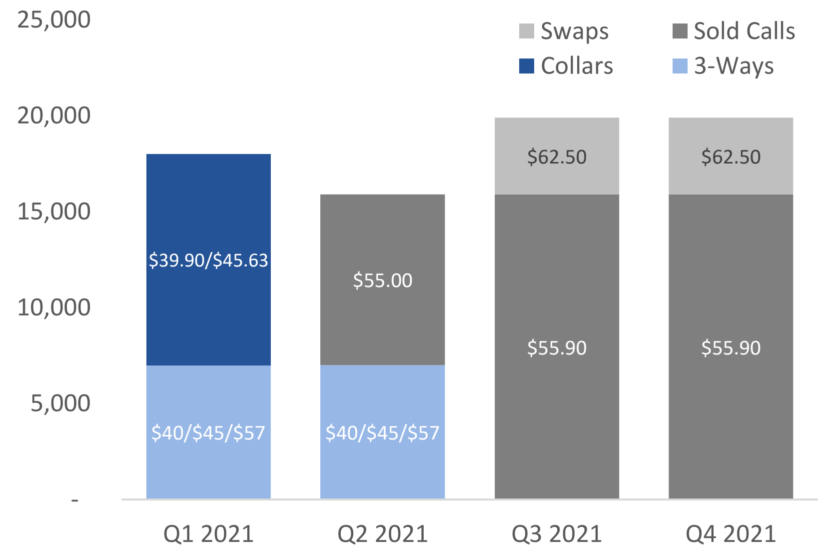
- Joined Athabasca in 2013 as the Thermal Drilling Manager. Progressively appointed to more senior roles including Director of Drilling & Completions Services and Director of Light Oil
- 20 years of Oil and Gas experience in both Canada and the North Sea. Former Drilling & Engineering Manager at Talisman Energy for their Montney and Duvernay assets
- Bachelor of Science and Master of Science degrees in Mechanical Engineering from the University of Alberta

CAPITALIZATION & HEDGING

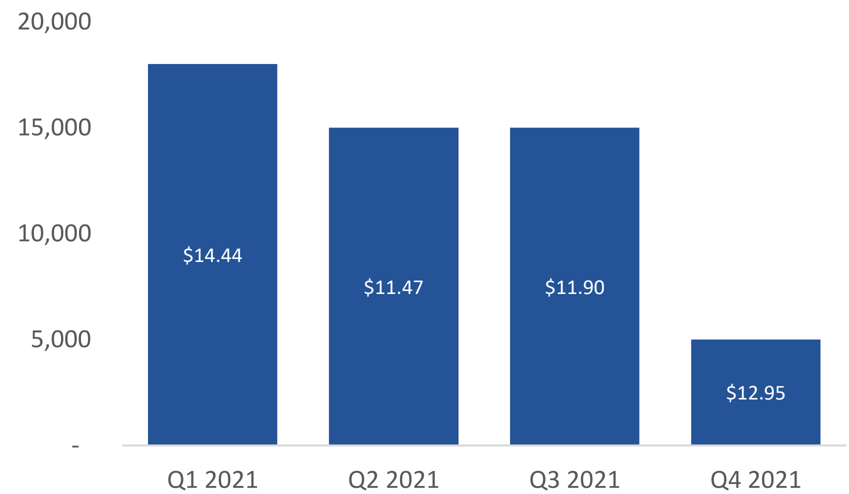
CAPITALIZATION OVERVIEW (ATH-TSX)

Basic Shares Outstanding	531	MM
Market Capitalization ($0.80/sh)	**$425**	**MM**
Q2/21 Net Debt	$383	MM
Total Enterprise Value	**$807**	**MM**
Term Debt (9.875% due Feb 2022)	US$450	MM
Q2/21 Cash *(Unrestricted / Restricted)*	$153 / $90	MM
Tax Pools *(total / NCL & CEE)*	$3.3 / $2.4	billion

WTI HEDGES (BBL/D; US$/BBL)



WCS DIFF HEDGES (BBL/D; US$/BBL)



Q2/21 Net debt = FV term debt + Working Capital Deficit (adj. for risk management contracts)

ENDNOTES

Slide	Endnotes

1 (1) 2021 guidance product breakdown provided below:

Product	2021 Production Split
Bitumen	78%
Natural Gas*	10%
Condensate NGLs	4%
Other NGLs	2%
Oil**	6%

** comprised of 99% or greater of shale gas, with the remaining being conventional natural gas*

*** comprised of 99% or greater of tight oil, with the remaining being light and medium crude oil*

(2) Cash = unrestricted cash & equivalents as of June 30, 2021.

(3) Consolidated reserves as of December 31, 2020. Reserves referred to throughout presentation were evaluated by McDaniel & Associates Consultants Ltd.

(4) Reserve life index (RLI) calculated on corporate 2P reserves of 1,156 mmboe and ~34,000 boe/d production. Please see reader advisory “Additional Oil and Gas Information” for more information.

(5) For additional information regarding Athabasca’s reserves and resources estimates, please see “Independent Reserve and Resource Evaluations” in the Company’s 2020 Annual Information Form which is available on Company’s website or on SEDAR www.sedar.com.

2 (1) Q2 production volumes by product:

Product		Q2/2021
Bitumen	*bbl/d*	26,433
Natural Gas*	*mcf/d*	21,290
Condensate NGLs	*bbl/d*	1,439
Other NGLs	*bbl/d*	953
Oil**	*bbl/d*	2,285
Total	***boe/d***	**34,659**

** comprised of 99% or greater of shale gas, with the remaining being conventional natural gas*

*** comprised of 99% or greater of tight oil, with the remaining being light and medium crude oil*

Product	2021 Production Split
Bitumen	78%
Natural Gas*	10%
Condensate NGLs	4%
Other NGLs	2%
Oil**	6%

** comprised of 99% or greater of shale gas, with the remaining being conventional natural gas*

*** comprised of 99% or greater of tight oil, with the remaining being light and medium crude oil*

(2) Operating Income is calculated by subtracting royalties, the cost of diluent blending, operating expenses and transportation & marketing expenses from petroleum and natural gas sales.

(3) Adjusted Funds Flow is a non-GAPP measures that equals cash flow from operating activities + restructuring fees + changes in non-cash working capital + settlement of provisions. Please see reader advisory “Non-GAAP Financial Information” for more information.

(4) Cash = unrestricted cash & equivalents as of June 30, 2021.

(5) Operating Netback is a non-GAPP measure that equals operating netbacks prior to realized hedging gains (losses) and other income. Please see reader advisory “Non-GAAP Financial Information” for more information.

(6) Net Debt is a non-GAPP measure and is defined as face value of term debt plus accounts payable and accrued liabilities plus current portion of provisions and other liabilities. Please see reader advisory “Non-GAAP Financial Information” for more information.

(7) FCF is a non-GAAP measure that equals adjusted funds flow – capital expenditures. FCF yield equals FCF / market capitalization. Please see reader advisory “Non-GAAP Financial Information” for more information.

(8) Adjusted EBITDA is a non-GAPP measure that is defined as Net income (loss) and comprehensive income (loss) before financing and interest expense, depreciation, depletion, impairment and taxation (recovery) expense adjusted for unrealized foreign exchange gain (loss), unrealized gain (loss) on risk management contracts, gain (loss) on revaluation of provisions and other, gain (loss) on sale of assets and non-cash settled stock-based compensation. Please see reader advisory “Non-GAAP Financial Information” for more information.

ENDNOTES

Slide	Endnotes

3

(1) Historical annual and 2021e Corporate volumes by product are provided below:

Product		2016	2017	2018	2019	2020
Bitumen	*bbl/d*	7,384	27,900	27,900	26,058	22,745
Natural Gas	*mcf/d*	13,858	20,890	33,104	28,281	23,229
Condensate NGLs	*bbl/d*	788	2,687	2,793	2,009	1,964
Other NGLs	*bbl/d*	383	505	1,049	918	785
Light & Medium Crude Oil	*bbl/d*	331	104	98	27	2
Tight Oil	*bbl/d*	784	758	1,823	2,471	3,116
Total	***boe/d***	**11,980**	**35,435**	**39,180**	**36,196**	**32,483**

Product	2021 Production Split
Bitumen	78%
Natural Gas*	10%
Condensate NGLs	4%
Other NGLs	2%
Oil**	6%

** comprised of 99% or greater of shale gas, with the remaining being conventional natural gas*

*** comprised of 99% or greater of tight oil, with the remaining being light and medium crude oil*

(2) Adjusted EBITDA is a non-GAPP measure that is defined as Net income (loss) and comprehensive income (loss) before financing and interest expense, depreciation, depletion, impairment and taxation (recovery) expense adjusted for unrealized foreign exchange gain (loss), unrealized gain (loss) on risk management contracts, gain (loss) on revaluation of provisions and other, gain (loss) on sale of assets and non-cash settled stock-based compensation. Please see reader advisory "Non-GAAP Financial Information" for more information.

(3) Historical financial and operating results found on Company's website or on SEDAR www.sedar.com

5

(1) 2021 production guidance product breakdown:

Product	2021 Production Split
Bitumen	78%
Natural Gas*	10%
Condensate NGLs	4%
Other NGLs	2%
Oil**	6%

** comprised of 99% or greater of shale gas, with the remaining being conventional natural gas*

*** comprised of 99% or greater of tight oil, with the remaining being light and medium crude oil*

(2) Adjusted funds flow is a non-GAPP measures that equals cash flow from operating activities + restructuring fees + changes in non-cash working capital + settlement of provisions. Please see reader advisory "Non-GAAP Financial Information" for more information.

(3) Adjusted EBITDA is a non-GAPP measure that is defined as Net income (loss) and comprehensive income (loss) before financing and interest expense, depreciation, depletion, impairment and taxation (recovery) expense adjusted for unrealized foreign exchange gain (loss), unrealized gain (loss) on risk management contracts, gain (loss) on revaluation of provisions and other, gain (loss) on sale of assets and non-cash settled stock-based compensation. Please see reader advisory "Non-GAAP Financial Information" for more information.

(4) Unrestricted cash, restricted cash and deposits as of June 30, 2021.

(5) Net Debt is a non-GAPP measure and is defined as face value of term debt plus accounts payable and accrued liabilities plus current portion of provisions and other liabilities. Please see reader advisory "Non-GAAP Financial Information" for more information.

(6) Cash Asset Coverage ratios = unrestricted and restricted cash as of June 30, 2021 divided by the face value of the outstanding second lien notes (US$450MM)

(7) Reserves Asset Coverage ratios = McDaniel NPV10 before tax for PDP and PUD (proved undeveloped) divided by the face value of the outstanding Senior Secured Second Lien Notes (US$450MM).

ENDNOTES

Slide	Endnotes	
8	(1)	Break-evens economics based on 2021 forecasted production and 0.8FX, 0% C5 diff and C$2.90 AECO pricing assumptions. Break-even reflects the estimated WCS oil price per barrel required to generate an asset level operating income of Cdn $0. Break-even is used to assess the impact of changes in WCS oil prices on operating income of an asset and could impact future investment decisions. Break-even does not have any standardized meaning and therefore should not be used to make comparisons to similar measures presented by other issuers
	(2)	Consolidated reserves as of December 31, 2020. Reserves referred to throughout presentation were evaluated by McDaniel & Associates Consultants Ltd.
	(3)	Gross Montney inventory based on management estimate of 4 wells per section. Gross Duvernay acres and inventories based on management estimate of 4-6 wells per section and ~2,750m laterals. See reader advisory “Drilling Locations” for more detail
	(4)	Adjusted EBITDA is a non-GAPP measure that is defined as Net income (loss) and comprehensive income (loss) before foreign exchange gain (loss), gain (loss) on foreign exchange risk management contracts, gain (loss) on revaluation of provisions and other, gain (loss) on sale of assets, financing and interest expense, depreciation, depletion, impairment and taxation (recovery) expense. Please see reader advisory “Non-GAAP Financial Information” for more information
	(5)	Cash = unrestricted cash & equivalents as of June 30, 2021
	(6)	Net Debt is a non-GAPP measure and is defined as face value of term debt plus accounts payable and accrued liabilities plus current portion of provisions and other liabilities. Please see reader advisory “Non-GAAP Financial Information” for more information.
	(7)	Coverage = Unrestricted and restricted cash as of June 30, 2021 plus McDaniel NPV10 before tax for PDP divided by the face value of the outstanding Senior Secured Second Lien Notes (US$450MM)
10-15	(1)	Leismer reserve life index calculated on 694 mmbbl 2P reserves and 20,000 bbl/d production. Please see reader advisory “Additional Oil and Gas Information” for more information
	(2)	For additional information regarding Athabasca’s reserves and resources estimates, please see “Independent Reserve and Resource Evaluations” in the Company’s 2020 Annual Information Form which is available on Company’s website or on SEDAR www.sedar.com
	(3)	Operating Netback is a non-GAAP measure calculated that is prior to realized hedging gains (losses) and other income. Please see reader advisory “Non-GAAP Financial Information” for more information
	(4)	Break-evens economics based on 2021 forecasted production and 0.8FX, 0% C5 diff and C$2.90 AECO pricing assumptions. Break-even reflects the estimated WCS oil price per barrel required to generate an asset level operating income of Cdn $0. Break-even is used to assess the impact of changes in WCS oil prices on operating income of an asset and could impact future investment decisions. Break-even does not have any standardized meaning and therefore should not be used to make comparisons to similar measures presented by other issuers
	(5)	All bbl/d, bbl, mbbl and mmbbl references are bitumen
16, 19	(1)	Gross Duvernay acres and inventories. Well inventory based on management estimate of 4-6 wells per section and ~2,750m laterals See reader advisory “Drilling Locations” for more detail
	(2)	Gross Montney inventory based on management estimate of 4 wells per section. See reader advisory “Drilling Locations” for more detail
	(3)	Operating Netback is a non-GAAP measure calculated that is prior to realized hedging gains (losses) and other income. Please see reader advisory “Non-GAAP Financial Information” for more information
	(4)	Montney Q2 production of 4,538 boe/d comprises of 1,439 bbl/d of Condensate NGLs, 570 bbl/d Other NGLs and 15 mmcf/d of Natural Gas (99% shale gas)
	(5)	Duvernay Q2 production of 3,688 boe/d comprises of 2,285 bbl/d of Oil, 384 bbl/d of Other NGLs and 6 mmcf/d of Natural Gas (99% shale gas)

ENDNOTES

Slide	Endnotes	
17-18	(1)	Placid Montney future production forecasts are ~50-55% shale gas, ~35-40% condensate NGLs and ~10% other NGLs
	(2)	Placid Montney IP365 rates are ~40% shale gas, ~50% condensate NGLs and ~10% other NGLs; EURs are ~50% shale gas, ~40% condensate NGLs and ~10% other NGLs
	(3)	Kaybob Duvernay future production forecasts are ~75% tight oil, ~25% shale gas and ~10% NGLs
	(4)	Kaybob East IP365 rates are ~25% shale gas, ~70% tight oil and ~5% NGLs; EURs are ~30% shale gas, ~65% tight oil and ~5% NGLs
29	(1)	Net Debt is a non-GAPP measure and is defined as face value of term debt plus accounts payable and accrued liabilities plus current portion of provisions and other liabilities. Please see reader advisory "Non-GAAP Financial Information" for more information.
	(2)	Enterprise value is calculated as market capitalization plus net debt.

READER ADVISORY

Forward Looking Statements

This Presentation contains forward-looking information that involves various risks, uncertainties and other factors. All information other than statements of historical fact is forward-looking information. The use of any of the words "anticipate", "plan", "forecast", "continue", "estimate", "expect", "may", "will", "project", "target", "should", "believe", "predict", "pursue", "potential", "view" and "contemplate" and similar expressions are intended to identify forward-looking information. The forward-looking information is not historical fact, but rather is based on the Company's current plans, objectives, goals, strategies, estimates, assumptions and projections about the Company's industry, business and future operating and financial results. This information involves 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 information. No assurance can be given that these expectations will prove to be correct and such forward-looking information included in this Presentation should not be unduly relied upon. This information speaks only as of the date of this Presentation and, except as required by applicable securities laws, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. In particular, this Presentation contains forward-looking information pertaining to, but not limited to, the following: our strategic plans and free cash flow potential; the Company's 2021 Outlook; including expected unrestricted cash, EBITDA, funds flow, net debt, production outlook, capital budget and operating income for Thermal Oil and Light Oil; EBITDA sensitivity; refinancing of its US$450 million Senior Secured Second Lien Notes and potential support for a first lien credit facility; future debt levels and composition; Trans Mountain and Keystone in-service dates; timing of Leismer well on stream dates and expected benefits therefrom; our drilling plans in Leismer and L8 project economics; timing for NCG to be operational; expected operating cost savings at Hangingstone and timing for first oil from new well pair; expected costs savings resulting from the Hangingstone truck-in terminal; type well economic metrics; expectations for WCS heavy oil to be amongst the most valuable global crude benchmarks; emissions reductions target; target net debt to EBITDA; and other matters.

In addition, information and statements in this Presentation relating to "Reserves" are deemed to be forward-looking information, 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 and resources described can be profitably produced in the future.

With respect to forward-looking information contained in this Presentation, assumptions have been made regarding, among other things: commodity prices; the regulatory framework governing royalties, taxes and environmental matters in the jurisdictions in which the Company conducts and will conduct business and the effects that such regulatory framework will have on the Company, including on the Company's financial condition and results of operations; the Company's financial and operational flexibility; the Company's financial sustainability; Athabasca's cash flow break-even commodity price; the Company's ability to obtain qualified staff and equipment in a timely and cost-efficient manner; the applicability of technologies for the recovery and production of the Company's reserves and resources; future capital expenditures to be made by the Company; future sources of funding for the Company's capital programs; the Company's future debt levels; future production levels; the Company's ability to obtain financing and/or enter into joint venture arrangements, on acceptable terms; operating costs; compliance of counterparties with the terms of contractual arrangements; impact of increasing competition globally; collection risk of outstanding accounts receivable from third parties; geological and engineering estimates in respect of the Company's reserves and resources; recoverability of reserves and resources; the geography of the areas in which the Company is conducting exploration and development activities and the quality of its assets. Certain other assumptions related to the Company's Reserves are contained in the report of McDaniel & Associates Consultants Ltd. ("McDaniel") evaluating Athabasca's Proved Reserves, Probable Reserves and Contingent Resources as at December 31, 2020 (which is respectively referred to herein as the "McDaniel Report").

Actual results could differ materially from those anticipated in this forward-looking information as a result of the risk factors set forth in the Company's Annual Information Form ("AIF") dated March 3, 2021 and Management's Discussion and Analysis dated July 28, 2021 available on SEDAR at www.sedar.com, including, but not limited to: weakness in the oil and gas industry; exploration, development and production risks; prices, markets and marketing; market conditions; continued impact of the COVID-19 pandemic; ability to finance capital requirements; climate change and carbon pricing risk; regulatory environment and changes in applicable law; gathering and processing facilities, pipeline systems and rail; statutes and regulations regarding the environment; political uncertainty; state of capital markets; anticipated benefits of acquisitions and dispositions; abandonment and reclamation costs; changing demand for oil and natural gas products; royalty regimes; foreign exchange rates and interest rates; reserves; hedging; operational dependence; operating costs; project risks; financial assurances; diluent supply; third party credit risk; indigenous claims; reliance on key personnel and operators; income tax; cybersecurity; advanced technologies; hydraulic fracturing; liability management; seasonality and weather conditions; unexpected events; internal controls; insurance; litigation; natural gas overlying bitumen resources; competition; chain of title and expiration of licenses and leases; breaches of confidentiality; new industry related activities or new geographical areas; and risks related to our debt and securities.

Also included in this Presentation are estimates of Athabasca's 2021 Outlook which are based on the various assumptions as to production levels, commodity prices, currency exchange rates and other assumptions disclosed in this Presentation. To the extent any such estimate constitutes a financial outlook, it was approved by management and the Board of Directors of Athabasca, and is included to provide readers with an understanding of the Company's outlook. Management does not have firm commitments for all of the costs, expenditures, prices or other financial assumptions used to prepare the financial outlook or assurance that such operating results will be achieved and, accordingly, the complete financial effects of all of those costs, expenditures, prices and operating results are not objectively determinable. The actual results of operations of the Company and the resulting financial results may vary from the amounts set forth herein, and such variations may be material. The financial outlook contained in this Presentation was made as of the date of this Presentation and the Company disclaims any intention or obligations to update or revise such financial outlook, whether as a result of new information, future events or otherwise, unless required pursuant to applicable law.

Drilling Locations

"BOEs" may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (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. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Initial Production Rates

Test Results and Initial Production Rates: The well test results and initial production rates provided in this presentation should be considered to be preliminary, except as otherwise indicated. Test results and initial production rates disclosed herein may not necessarily be indicative of long-term performance or of ultimate recovery.

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Additional Oil and Gas Information:

Other Oil and Gas terms: This presentation contains certain other oil and gas metrics, including D&C (drilling and completion costs), F&D, steam oil ratio (or SOR), reserves life index, recycle ratio, capital efficiency and P/I, which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included herein to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the future performance and future performance may not compare to the performance in previous periods and therefore such metrics should not be unduly relied upon. D&C includes all capital spent to drill, complete, equip and tie-in a well. The calculation of F&D costs includes all exploration and development capital for the year plus the change in future development capital for the year. Steam oil ratio, or SOR, measures the average volume of steam required to produce a barrel of oil. The Company's reserves life index for a given period is determined by taking the Company's total proved plus probable reserves at the end of that period divided by the Company's gross production for the same period. Recycle ratio is calculated by dividing operating netback by F&D per boe. Capital efficiency is a measure of how effective projects are at adding production. Lower capital efficiencies indicate a more productive investment for adding production. For Light Oil capital efficiency is calculated by dividing Capital and IP365 rates and for Thermal Oil is calculated by dividing Capital and plateau rates. P/I is a measure of a projects net value relative to its capital investment and is calculated by dividing a project's NVP10 value by its Capital. All Thermal Oil production and volumes are bitumen. Light Oil % liquids include oil, condensate and NGLs as liquids. Consolidated % liquids include bitumen, oil, condensate and NGLs as liquids. Natural Gas volumes include both Conventional and Shale Gas, however most gas volumes are Shale Gas.

Reserves Information

The McDaniel Report was prepared using the assumptions and methodology guidelines outlined in the COGE Handbook and in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities, effective December 31, 2020. There are numerous uncertainties inherent in estimating quantities of bitumen, light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth above are estimates only. In general, estimates of economically recoverable reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For those reasons, estimates of the economically recoverable reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. Reserves figures described herein have been rounded to the nearest MMbbl or MMboe. For additional information regarding the consolidated reserves and information concerning the resources of the Company as evaluated by McDaniel in the McDaniel Report, please refer to the Company's AIF.

Reserve Values (i.e. Net Asset Value) is calculated using the estimated net present value of all future net revenue from our reserves, before income taxes discounted at 10%, as estimated by McDaniel effective December 31, 2020 and based on average pricing of McDaniel, Sproule and GLJ as of January 1, 2021.

The 700 Duvernay drilling locations referenced include: 7 proved undeveloped locations and 78 probable undeveloped locations for a total of 85 booked locations with the balance being unbooked locations. The 150 Montney drilling locations referenced include: 63 proved undeveloped locations and 35 probable undeveloped locations for a total of 98 booked locations with the balance being unbooked locations. Proved undeveloped locations and probable undeveloped locations are booked and derived from the Company's most recent independent reserves evaluation as prepared by McDaniel as of December 31, 2020 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal management estimates. Unbooked locations do not have attributed reserves or resources (including contingent or prospective). Unbooked locations have been identified by management as an estimation of Athabasca's multi-year drilling activities expected to occur over the next two decades based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, commodity prices, provincial fiscal and royalty policies, costs, actual drilling results, additional reservoir information that is obtained and other factors.

Non-GAAP Financial Measures and Production Disclosure

The "Adjusted Funds Flow", "Light Oil Operating Income", "Light Oil Operating Netback", "Light Oil Capital Expenditures Net of Capital-Carry", "Thermal Oil Operating Income (Loss)", "Thermal Oil Operating Netback", "Consolidated Operating Income", "Consolidated Operating Netback", "Consolidated Capital Expenditures Net of Capital-Carry", "Adjusted EBITDA", and "Free Cash Flow" financial measures contained in this Presentation do not have standardized meanings which are prescribed by IFRS and they are considered to be non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers and should not be considered in isolation with measures that are prepared in accordance with IFRS. The "Advisories and Other Guidance" section within the Company's Q2 2021 MD&A includes reconciliations of these measures, where applicable, to the nearest IFRS measures.

Adjusted Funds Flow is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS. Adjusted Funds Flow is calculated by adjusting for changes in non-cash working capital, restructuring expenses and settlement of provisions from cash flow from operating activities. The Adjusted Funds Flow measure allows management and others to evaluate the Company's ability to fund its capital programs and meet its ongoing financial obligations using cash flow internally generated from ongoing operating related activities. Adjusted Funds Flow per share is calculated as Adjusted Funds Flow divided by the applicable number of weighted average shares outstanding.

The Operating Income (Loss) measures in Presentation are calculated by subtracting royalties, diluent expenses, operating expenses and cash transportation & marketing expenses from petroleum and natural gas sales and adjusting for the impacts of inventory write-downs within the Thermal Oil division. The Operating Netback measures are calculated by dividing the Operating Income (Loss) by the total sales volumes and is presented on a per boe basis. The Operating Income (Loss) and the Operating Netback measures allow management and others to evaluate the production results from the Company's assets. The Consolidated Operating Income (Loss) Net of Realized Hedging measure in this Presentation is calculated by adding or subtracting realized gains (losses) on commodity risk management contracts, royalties, the cost of diluent blending, operating expenses and cash transportation & marketing expenses from petroleum and natural gas sales and adjusting for the impacts of inventory write-downs. The Consolidated Operating Netback Net of Realized Hedging measure is calculated by dividing Consolidated Operating Income (Loss) Net of Realized Hedging by the total sales volumes and is presented on a per boe basis. The Consolidated Operating Income (Loss) Net of Realized Hedging and the Consolidated Operating Netback Net of Realized Hedging measures allow management and others to evaluate the production results from the Company's Light Oil and Thermal Oil assets combined together including the impact of realized commodity risk management gains or losses.

The Consolidated Capital Expenditures Net of Capital-Carry and Light Oil Capital Expenditures Net of Capital-Carry measures in this Presentation are outlined in the Company's Q2 2021 MD&A. These measures allow management and others to evaluate the true net cash outflow related to Athabasca's capital expenditures.

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Non-GAAP Financial Measures and Production Disclosure Cont'd

Net Debt is a non-GAPP measure and is defined as face value of term debt plus accounts payable and accrued liabilities plus current portion of provisions and other liabilities.

Adjusted EBITDA is defined as Net income (loss) and comprehensive income (loss) before financing and interest expense, depreciation, depletion, impairment and taxation (recovery) expense adjusted for unrealized foreign exchange gain (loss), unrealized gain (loss) on risk management contracts, gain (loss) on revaluation of provisions and other, gain (loss) on sale of assets and non-cash settled stock-based compensation.

Free Cash Flow is defined as Adjusted Funds Flow less Consolidated Capital Expenditures.

Liquidity is defined as cash and cash equivalents plus available credit capacity.

ATHABASCA
OIL CORPORATION