Canadian Natural

JACKFISH IN SITU PROJECT DIRECTIVE 54 ANNUAL PERFORMANCE PRESENTATION

Commercial Scheme Approval 10097 (as amended)

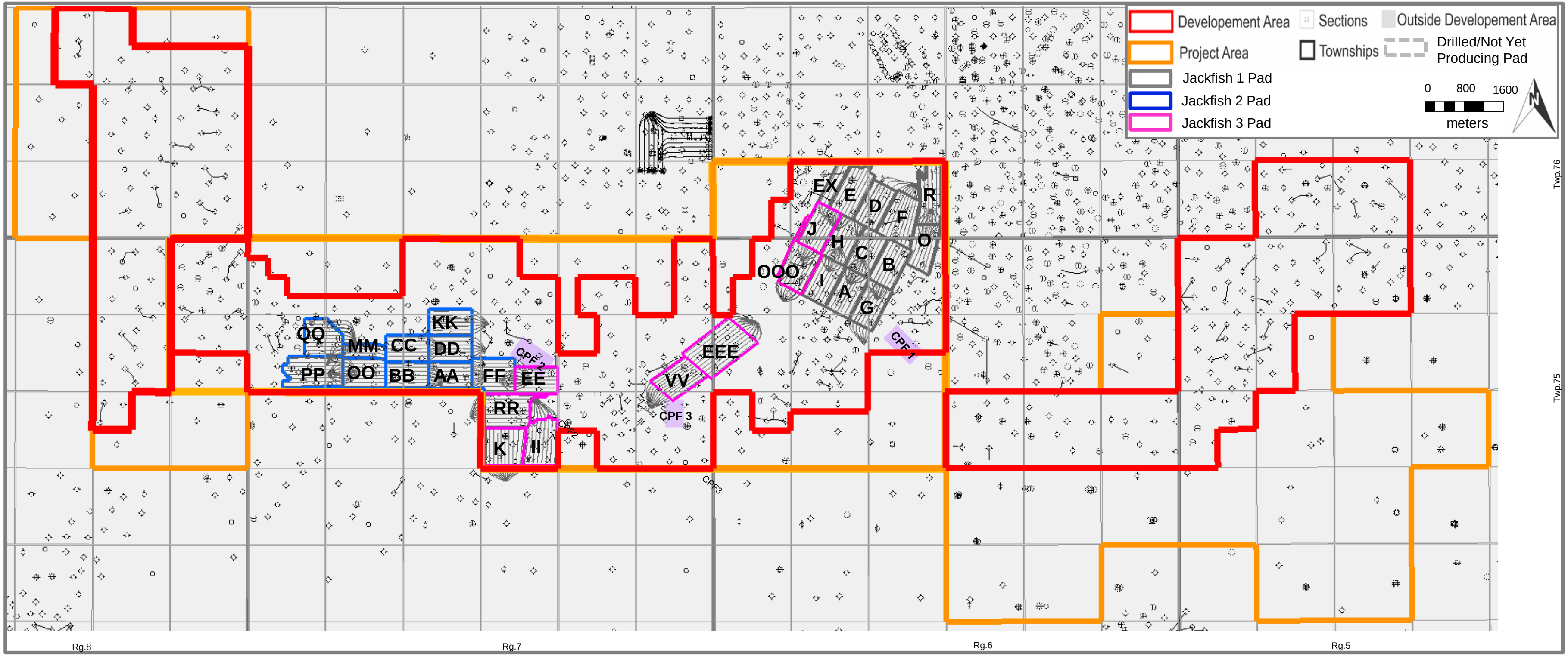
June 30, 2022

4.1
Introduction

4.1, 1) Scheme Setting and Background

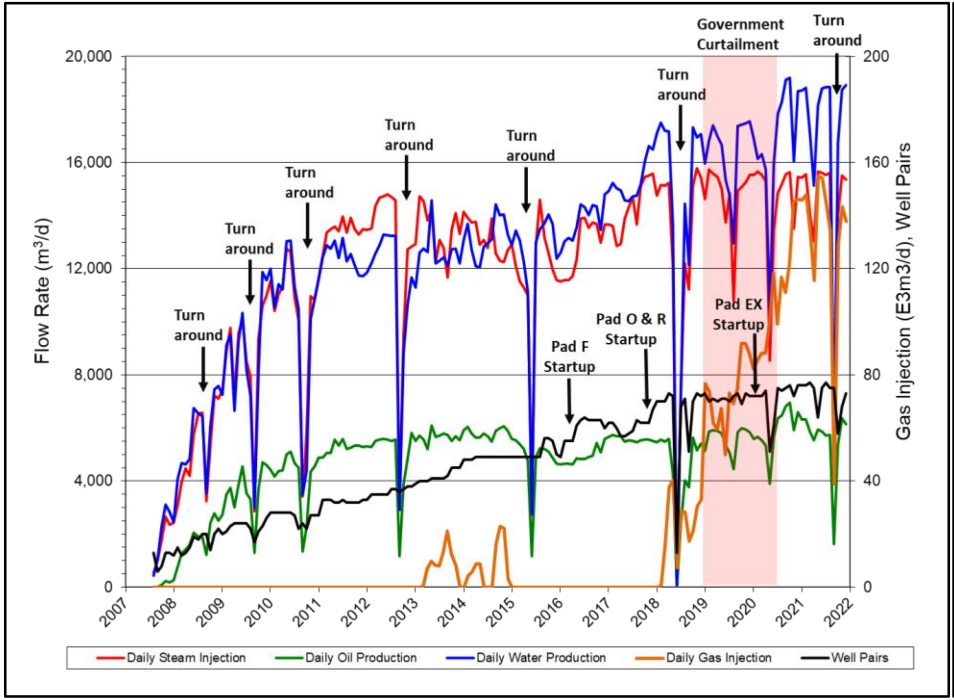
- Jackfish 1, 2, and 3 utilize steam-assisted gravity drainage (SAGD) to recover bitumen from the McMurray formation
- Located 150 km south of Fort McMurray
- Jackfish 1 scheme approval granted August 2006; first steam August 2007
- Jackfish 2 scheme approval granted August 2008; first steam May 2011
- Amalgamation of Jackfish approvals (including Jackfish 3) November 2011; first steam July 2014
- Jackfish expansion approvals granted in 2018 & 2019

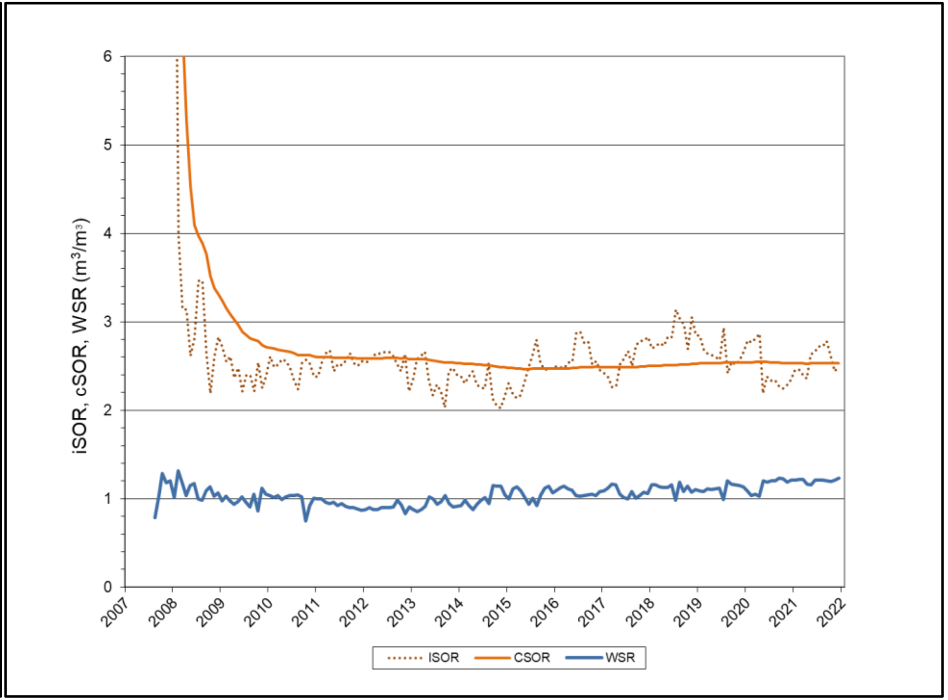
4.1, 1) Scheme Setting and Background (cont'd)



4.2 Subsurface

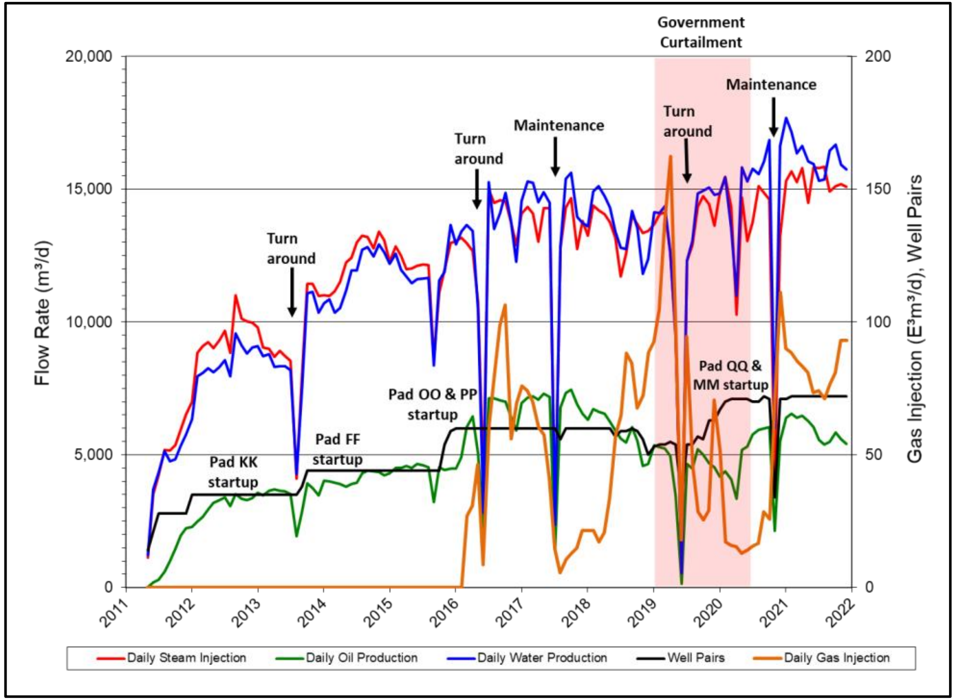
4.2, 2) Production Plot – Jackfish 1

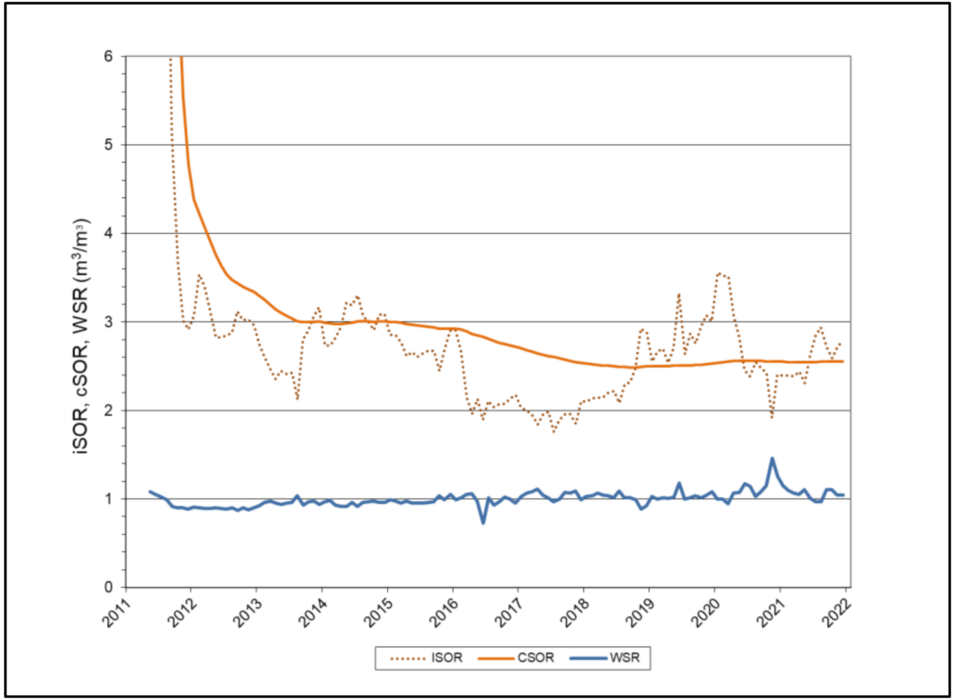




Well pairs represent producing well counts

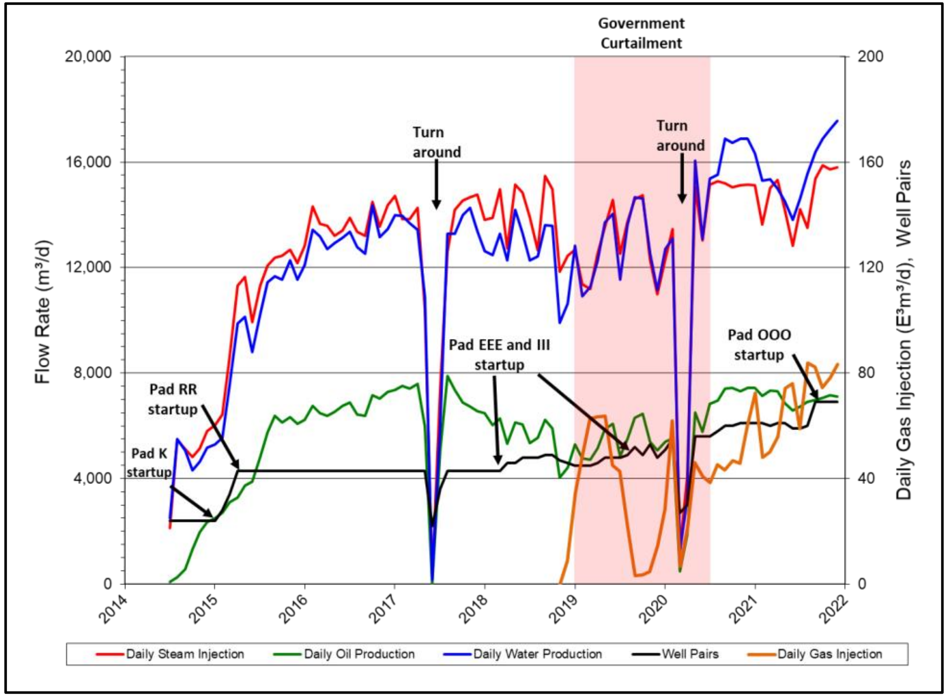
4.2, 2) Production Plot – Jackfish 2

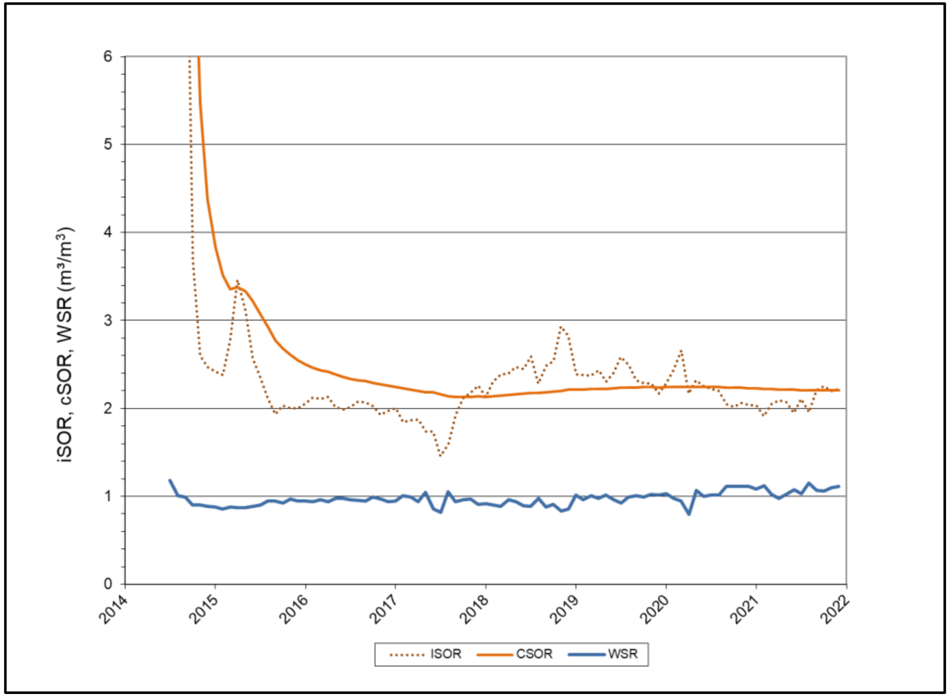




Well pairs represent producing well counts

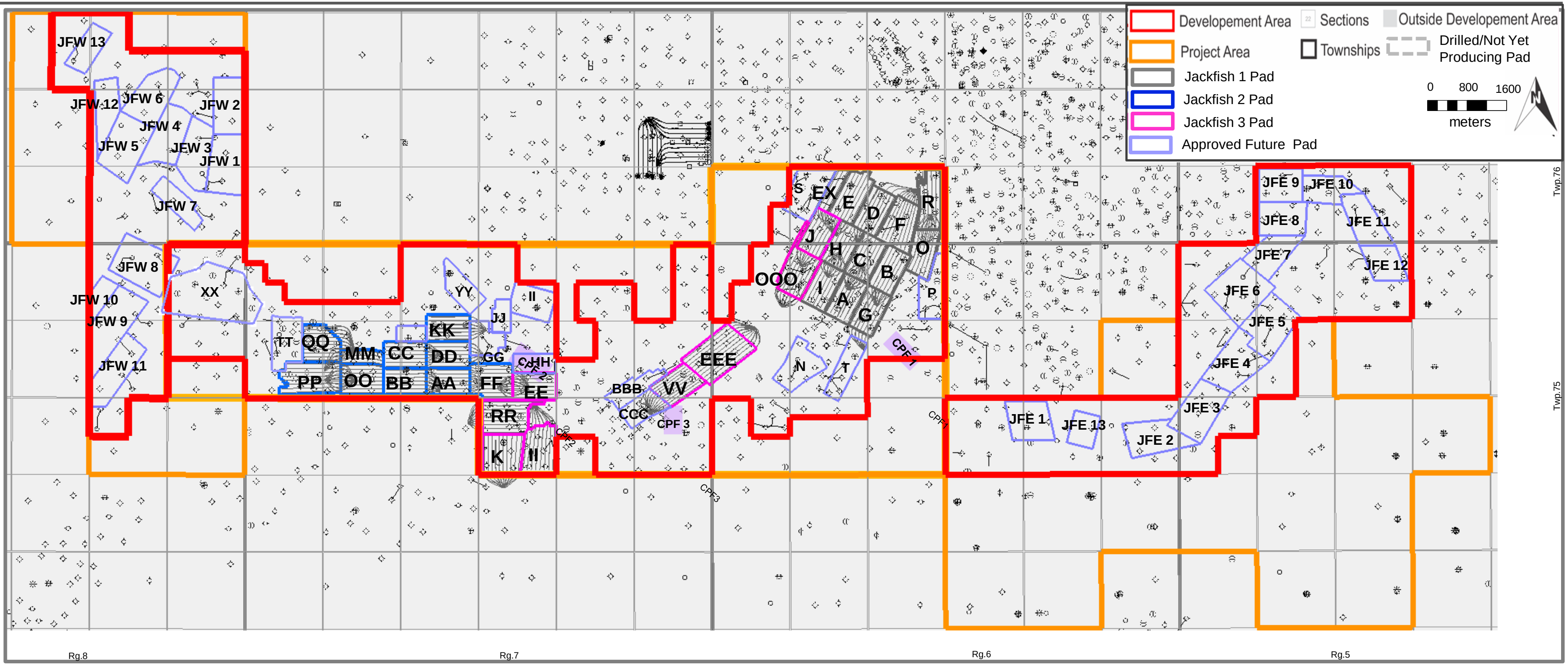
4.2, 2) Production Plot – Jackfish 3





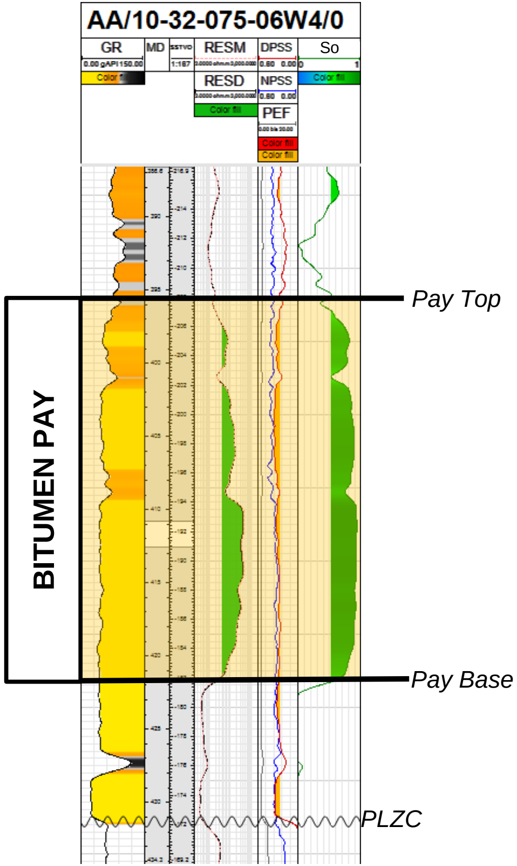
Well pairs represent producing well counts

4.2, 3 a) Drilled and Approved Drainage Boxes



4.2, 3 b) Resource Cut-off

Jackfish Bitumen Pay Definition

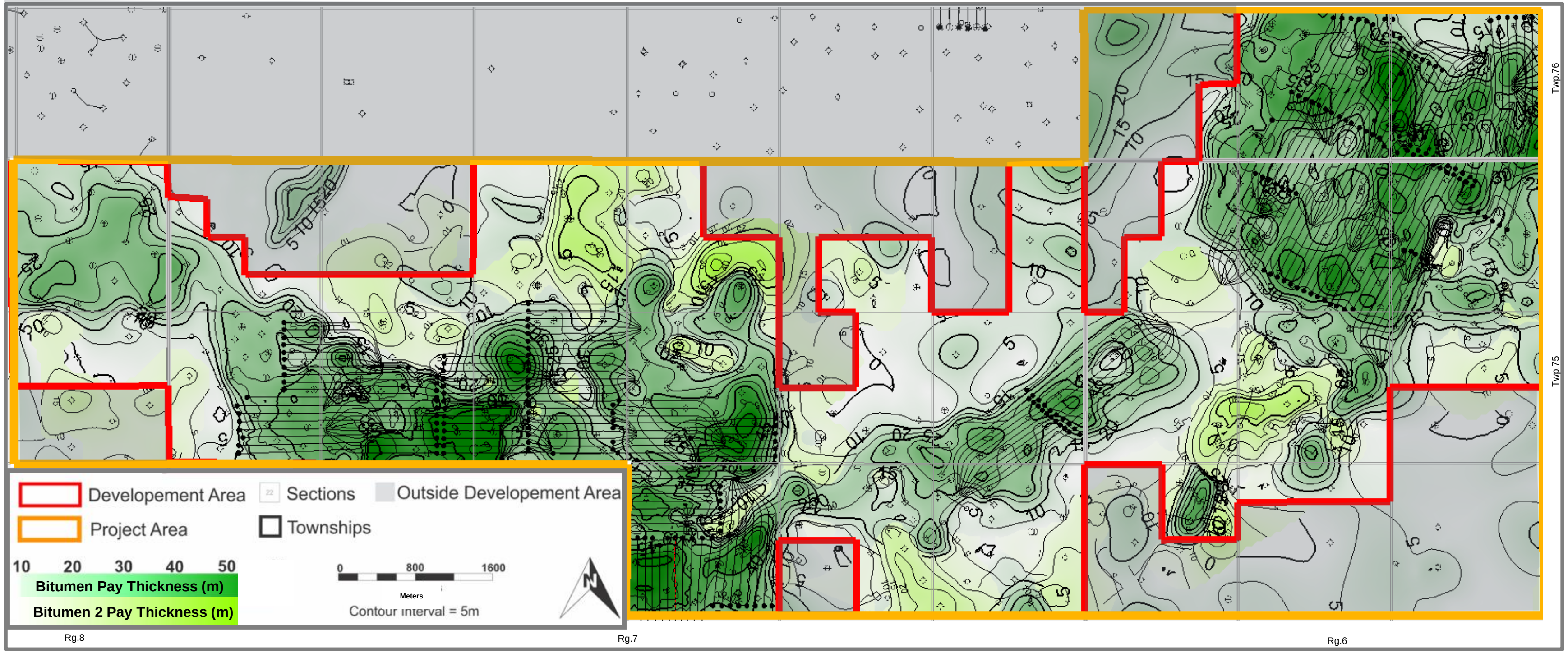


Bitumen Pay

- Characterizes the complete package accessible through SAGD. In Jackfish Project area Bitumen Pay is segregated into two separate pay zones if substantial IHS is present in between.
- Defined by:
    - S_o > 50%
    - Encompasses all brecciated intervals
    - May include minimal IHS
- S_o is a standard petrophysical curve calculated from resistivity and porosity logs, and correlated to core data

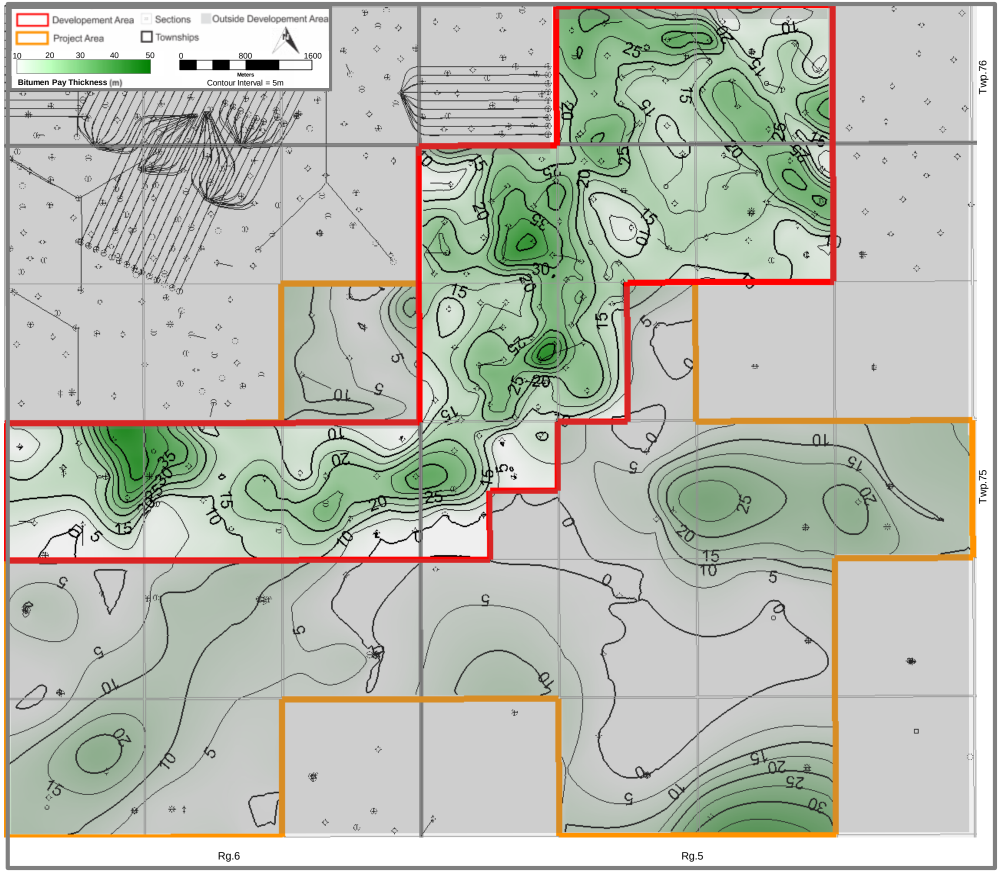
4.2, 3 b) Pay Isopach

Jackfish McMurray Formation Bitumen Pay Thickness



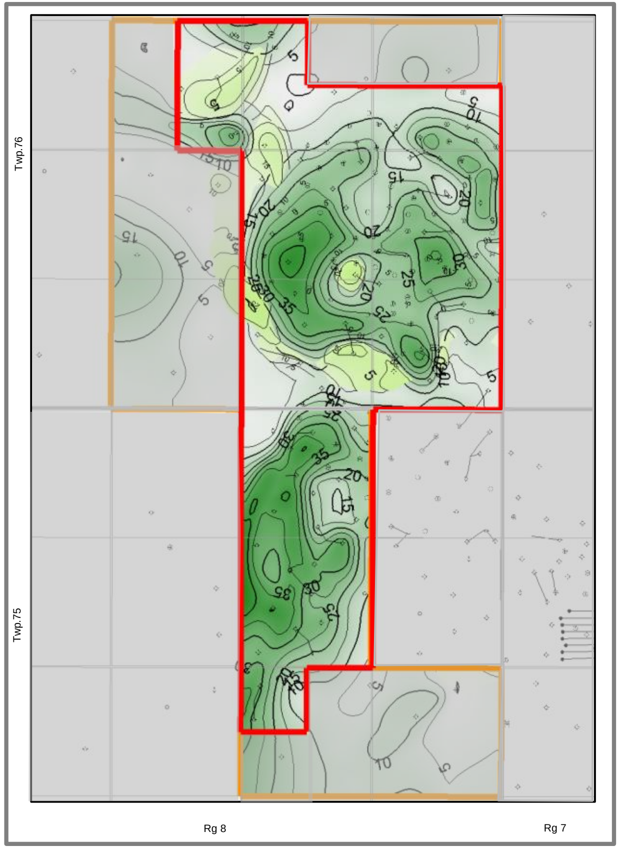
4.2, 3 b) Pay Isopach

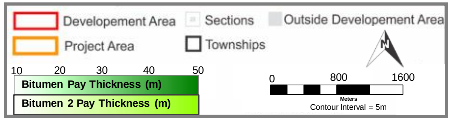
Jackfish Expansion East McMurray Formation Bitumen Pay Thickness



4.2, 3 b) Pay Isopach

Jackfish Expansion West McMurray Formation Bitumen Pay Thickness





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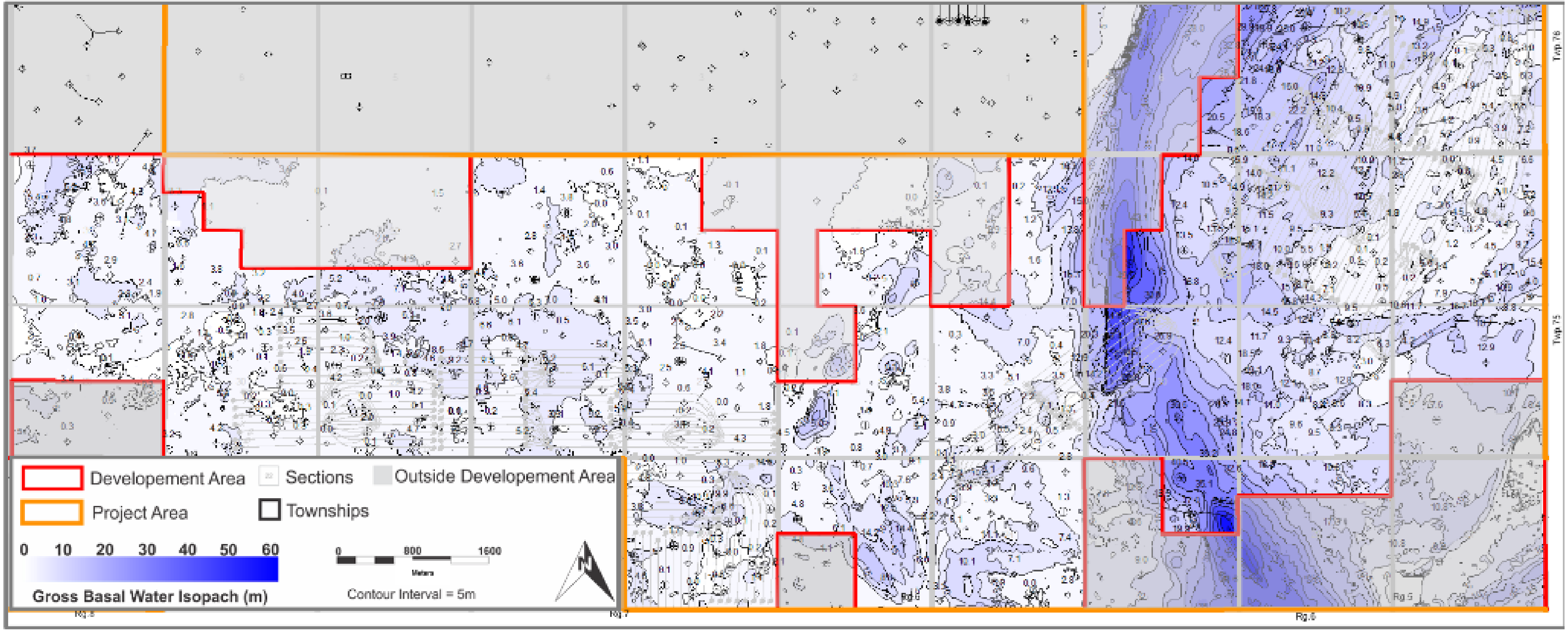
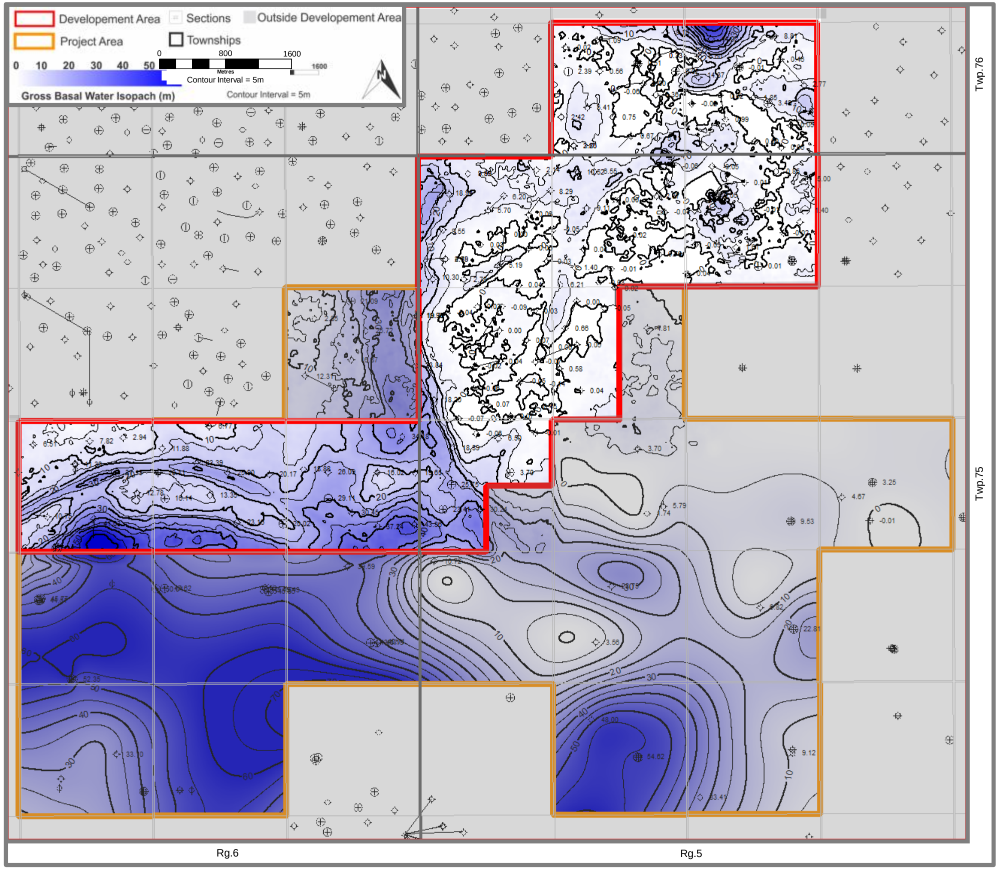
4.2, 3 c) Major Gas and Water Intervals

Jackfish McMurray Formation Water Contact to Paleozoic Isopach



4.2, 3 c) Major Gas and Water Intervals

Jackfish Expansion East McMurray Formation Water Contact to Paleozoic Isopach



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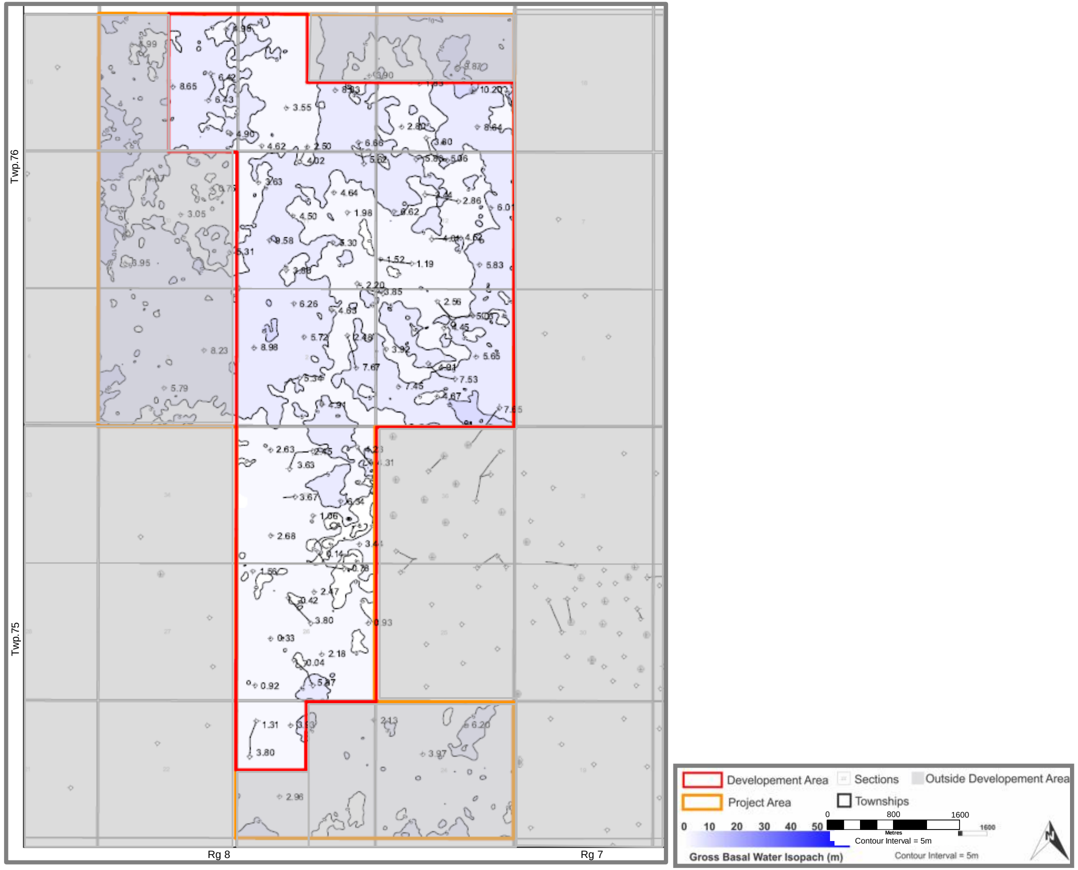


4.2, 3 c) Major Gas and Water Intervals

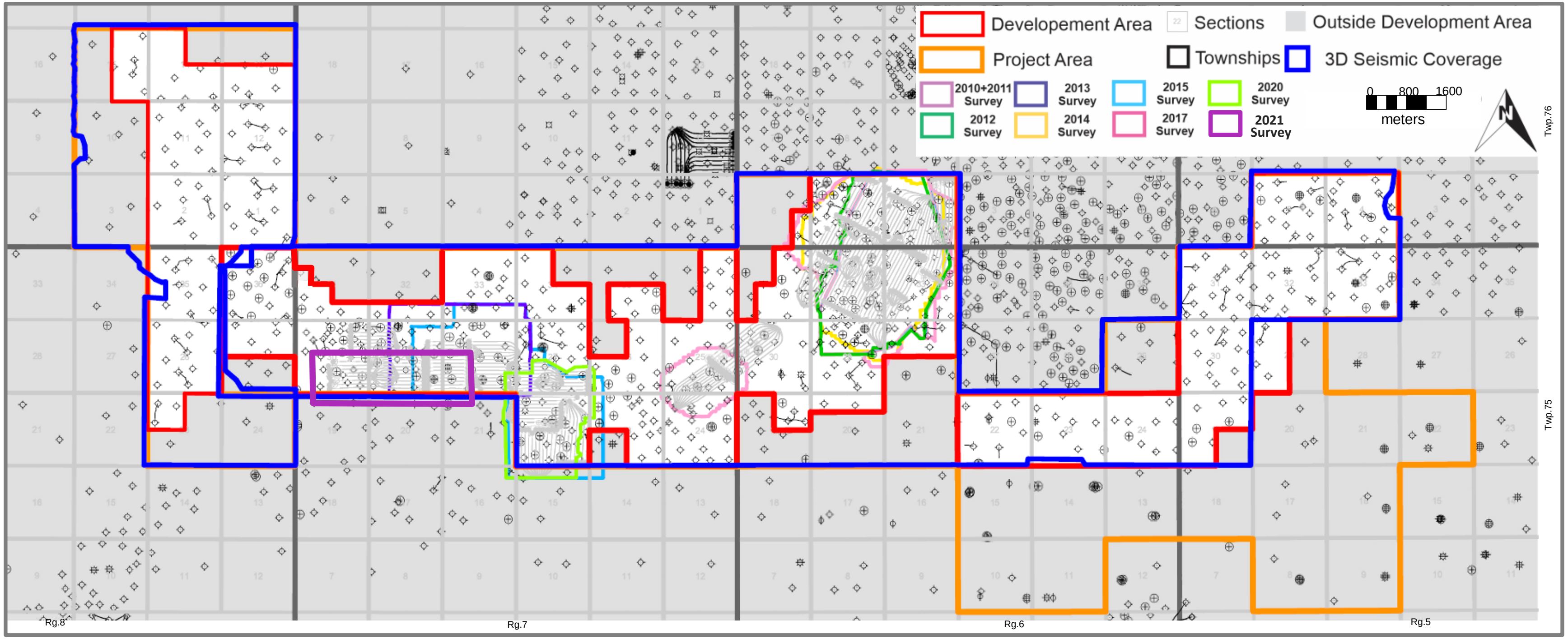
- No major gas intervals in communication with pay at Jackfish

4.2, 3 d) Geomechanical Anomalies

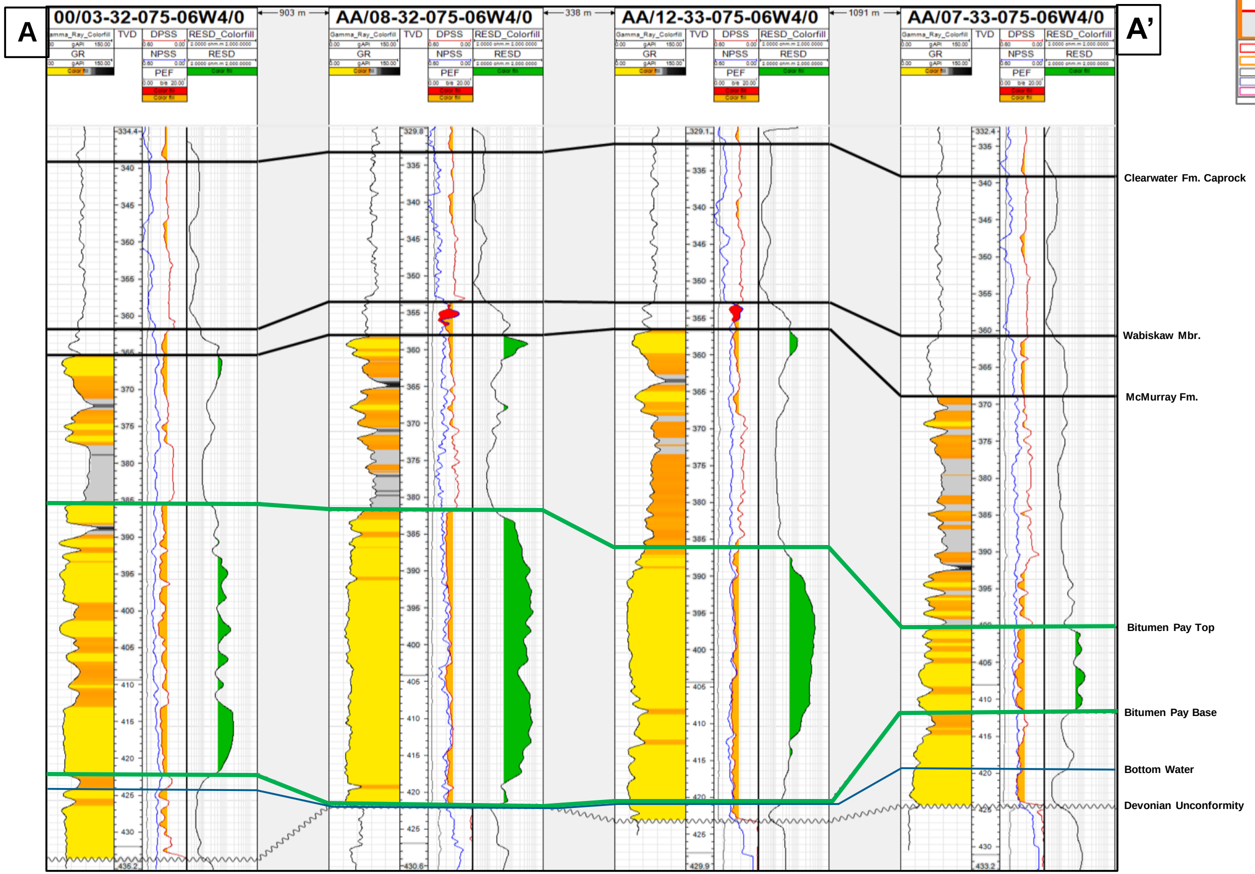
- No known geomechanical anomalies at Jackfish

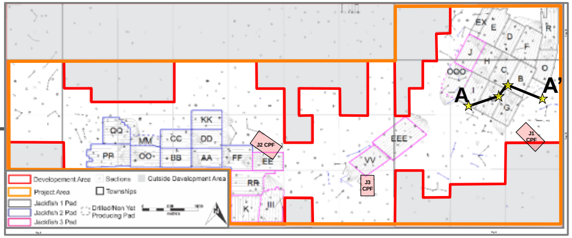
4.2, 3 e) Seismic

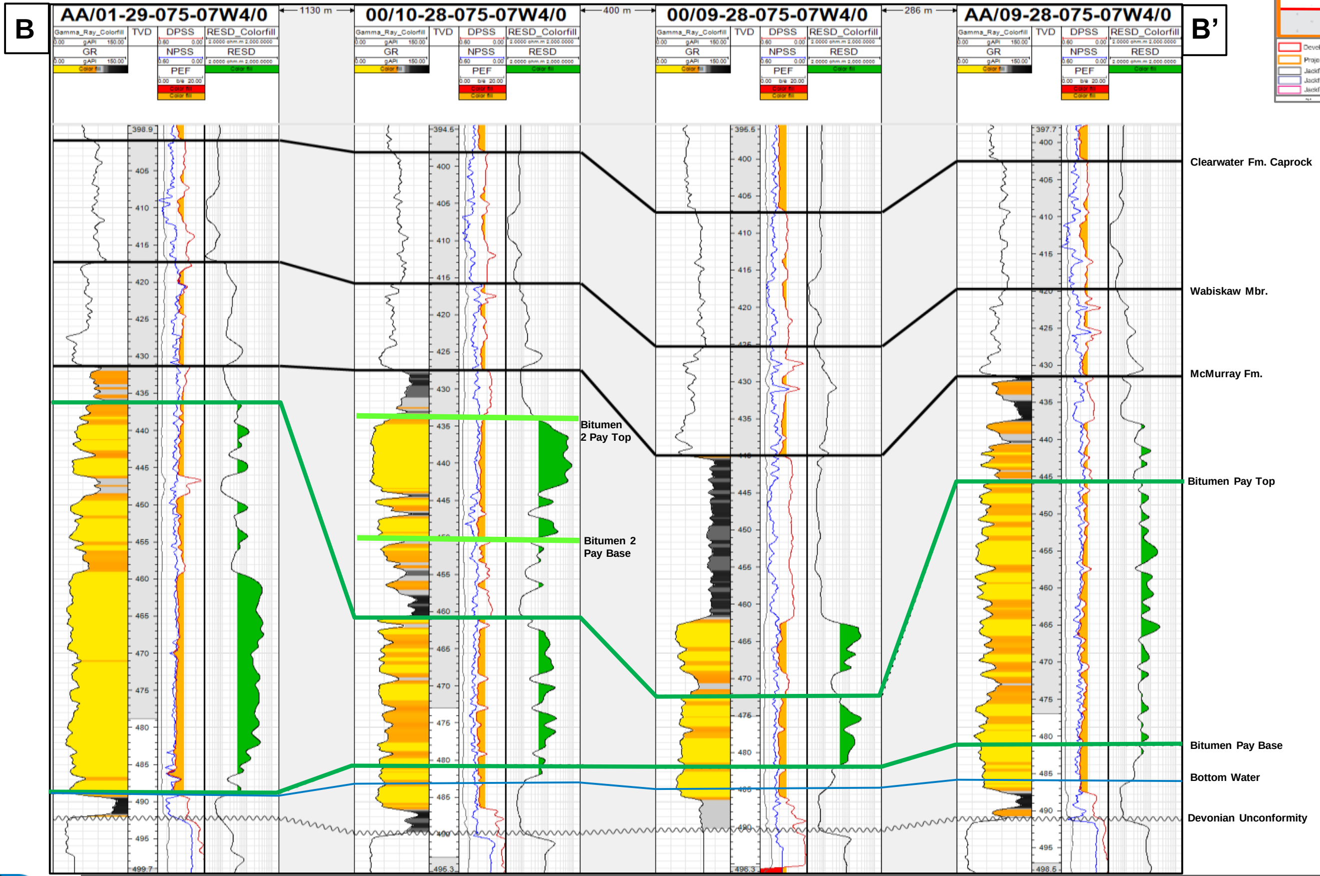
Jackfish Historical Surveys

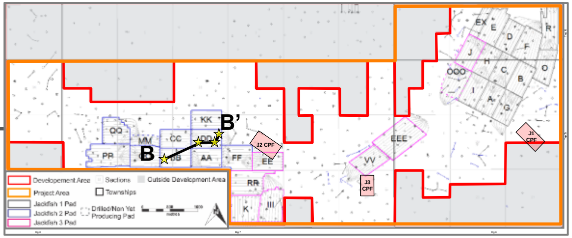


- 4D seismic was acquired in 2021


A
A'
00/03-32-075-06W4/0
903 m
AA/08-32-075-06W4/0
338 m
AA/12-33-075-06W4/0
1091 m
AA/07-33-075-06W4/0
GR
TVD
DPSS
NPSS
PEF
RESD
Clearwater Fm. Caprock
Wabiskaw Mbr.
McMurray Fm.
Bitumen Pay Top
Bitumen Pay Base
Bottom Water
Devonian Unconformity


A
A'
Development Area
Project Area
Jackfish 1 Pad
Jackfish 2 Pad
Jackfish 3 Pad
Sections
Townships
Outside Development Area
Drilled/Non Yet Producing Pad





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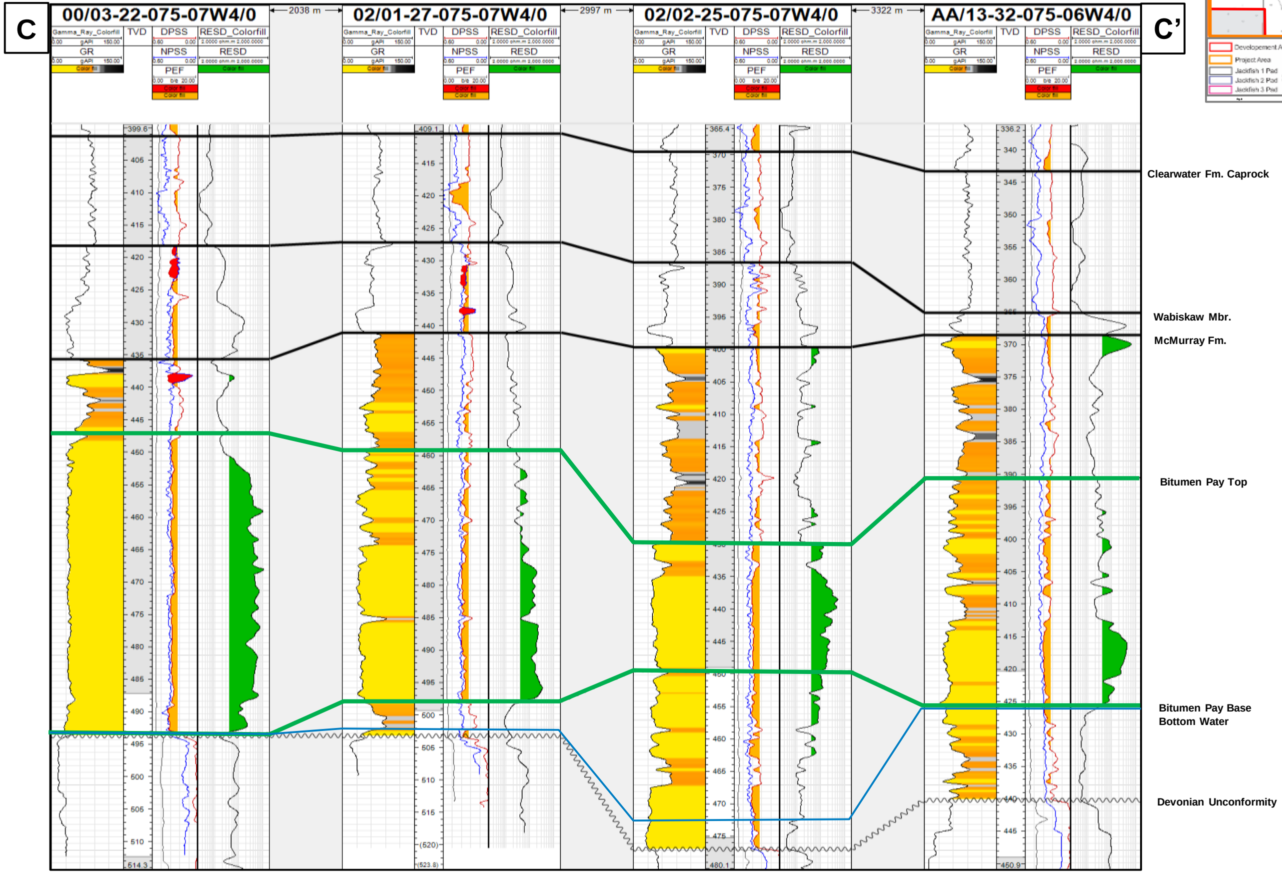
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00/03-22-075-07W4/0
2038 m
02/01-27-075-07W4/0
2997 m
02/02-25-075-07W4/0
3322 m
AA/13-32-075-06W4/0
C'
Clearwater Fm. Caprock
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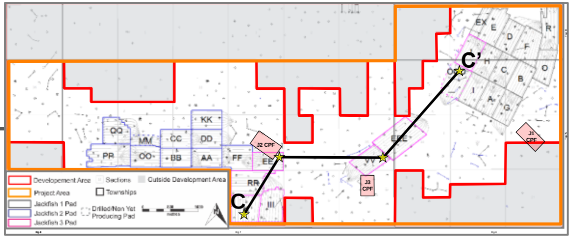
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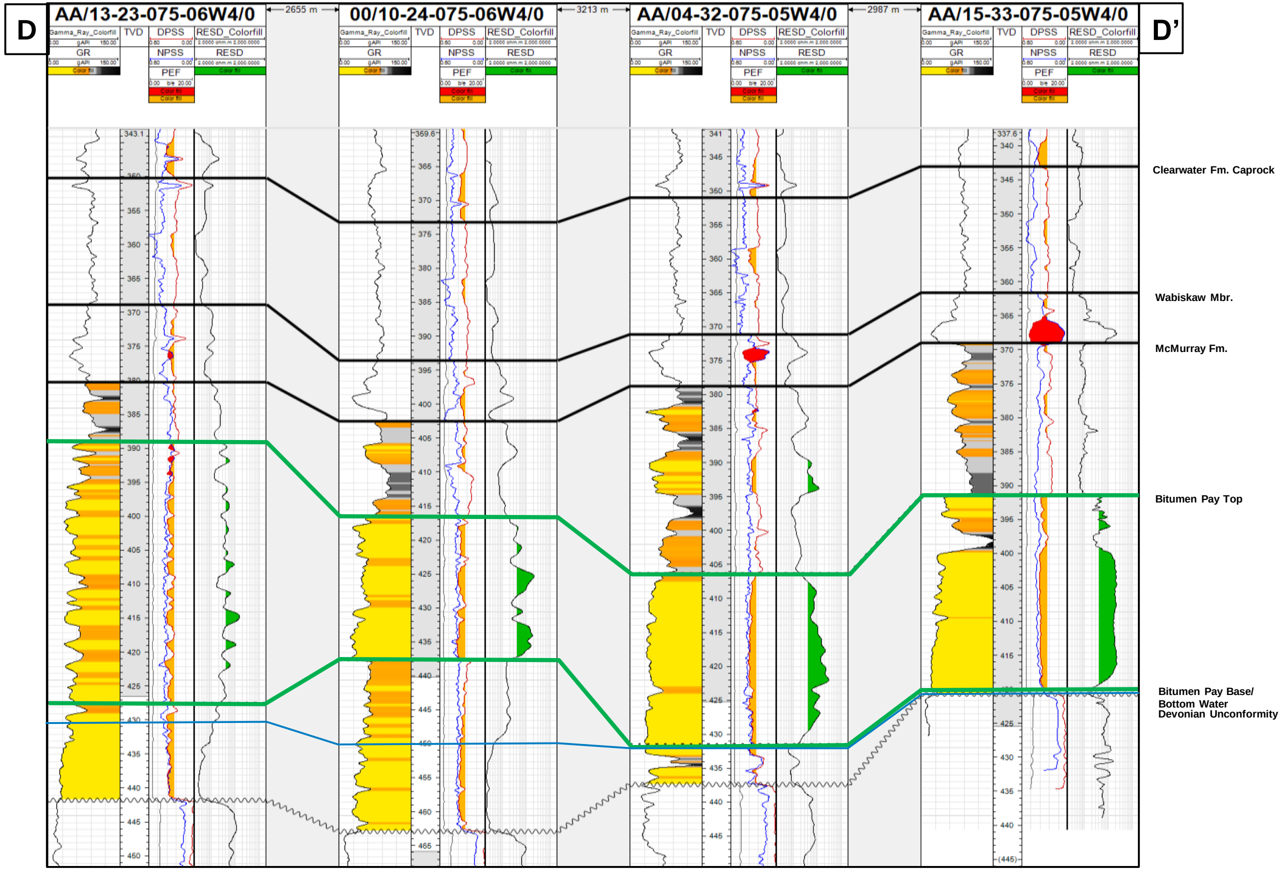

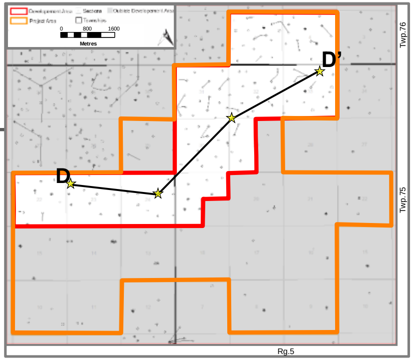

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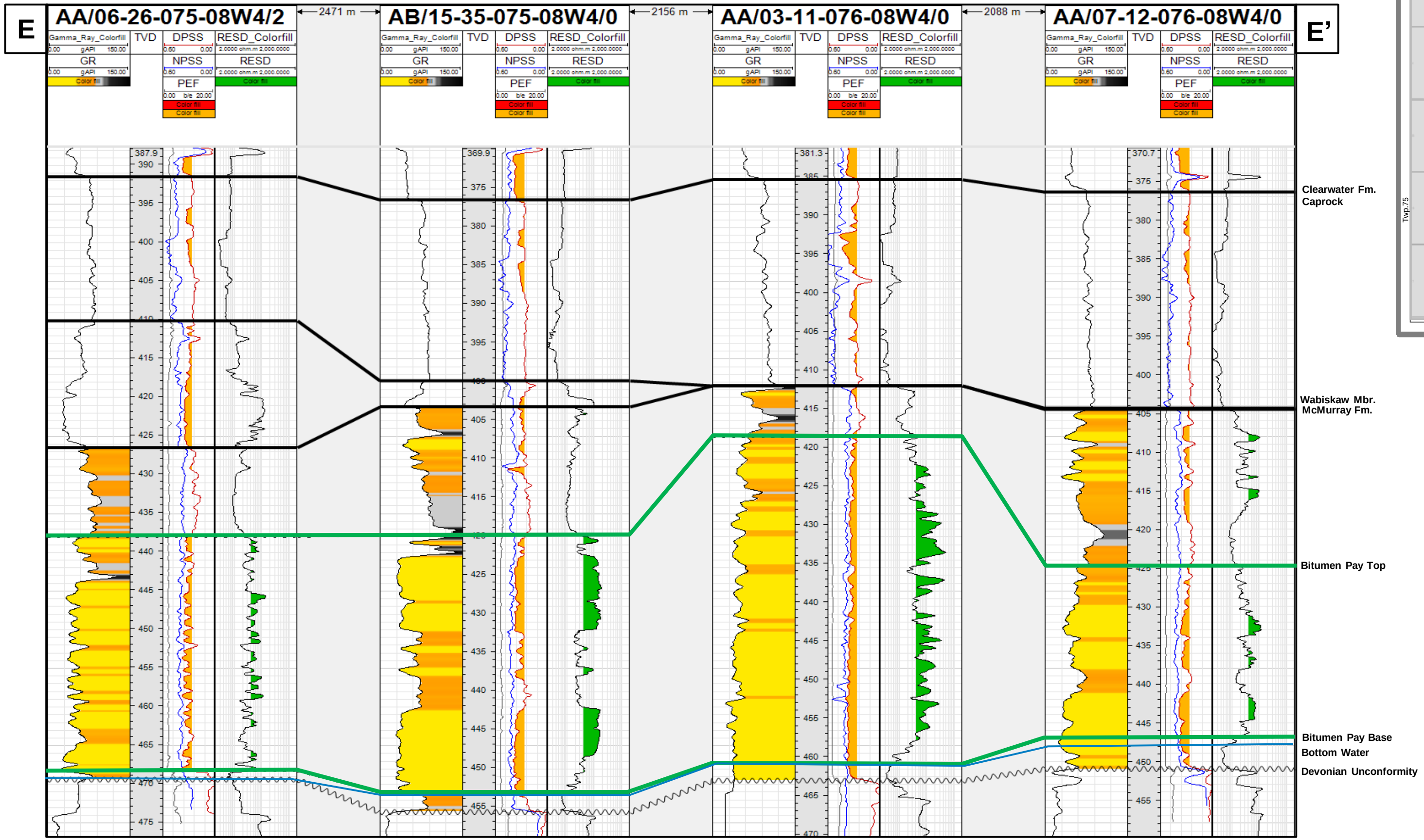

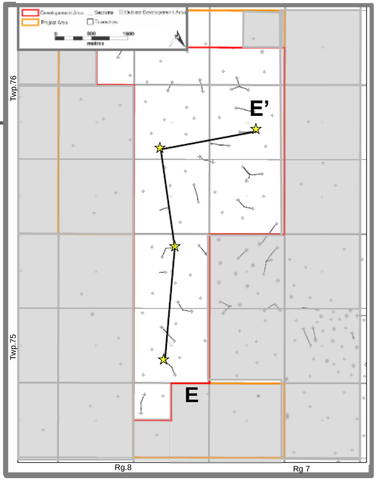

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4.2, 5) Project, Development and Combined Active Well Pattern Volumetrics

	Area (Ha)	Average Thickness (m)	Average Oil Saturation (%)	Average Porosity (%)	OBIP/PBIP ($10^6 m^3$)	OBIP/PBIP ($10^6 m^3$) (Bitumen 2 Inclusive)	Cumulative Oil ($10^6 m^3$)	Cumulative Recovery (%)
Project Area	17,094	13.5	74	33	569	75	-	-
Development Area	10,300	17.6	75	34	462	63	-	-
Active Well Patterns	1,712	31.2	80	34	147	-	58	39

Averages listed above for Bitumen Pay Zone 1
Area = Hydrocarbon area within boundary
OBIP = Original Bitumen in Place; PBIP = Producible Bitumen In Place; PBIP = OBIP
Volumetric calculation = Area within boundary x Bitumen Pay thickness x avg. oil saturation x avg. porosity

Reservoir Characteristics	Jackfish
Average Permeability (Kmax, md)	5400
Average Permeability (Kv, md)	1,200-2,000

4.2, 6) Well Patterns Volumetrics – Jackfish 1

Pad	Area (m^2)	Average Thickness (m)	Average Oil Saturation (%)	Average Porosity (%)	Average Kh Permeability (D)*	OBIP/PBIP ($10^6 m^3$)	Ultimate Recovery Factor (%)	Recovery Factor (%) to Date of OBIP/PBIP
A	529,788	38	83	33	7.7	5.5	85 - 90	85
B	532,736	30	78	35	5.1	4.3	65 - 75	64
C	530,374	38	83	35	6.3	5.7	55 - 75	52
D	531,192	41	82	35	6.0	6.2	55 - 75	44
E	603,919	36	80	34	6.0	6.0	55 - 75	37
EX	246,699	33	80	34	4.7	2.2		
F	675,933	35	80	35	4.9	6.5	55 - 75	44
G	525,388	33	81	34	8.0	4.8	50 - 70	22
H	530,352	26	78	34	4.5	3.7	55 - 75	55
I	530,093	34	79	34	4.0	4.8	50 - 70	28
O	509,016	32	77	34	5.5	4.3	50 - 70	19
R	587,459	27	78	34	6.3	4.2	50 - 70	14

Area = Hydrocarbon area within boundary
OBIP = Original Bitumen in Place; PBIP = Producible Bitumen In Place; PBIP = OBIP
Volumetric calculation = Area within drainage box boundary x Bitumen Pay thickness x avg. oil saturation x avg. porosity
*Permeability values are directly from core analysis and are highly variable across Jackfish

4.2, 6) Well Patterns Volumetrics – Jackfish 2

Pad	Area (m^2)	Average Thickness (m)	Average Oil Saturation (%)	Average Porosity (%)	Average Kh Permeability (D)*	OBIP/PBIP ($10^6 m^3$)	Ultimate Recovery Factor (%)	Recovery Factor (%) to Date of OBIP/PBIP
AA	501,959	27	80	35	5.1	3.7	50 - 70	48
BB	505,878	48	79	34	6.2	6.3	70 - 80	69
CC	506,800	28	75	34	4.6	3.6	50 - 70	26
DD	506,800	24	79	34	3.7	3.2	50 - 70	35
FF	653,881	27	81	34	5.9	4.8	50 - 70	41
KK	506,800	17	76	33	5.0	2.2	50 - 70	54
MM	341,961	30	85	35	4.9	2.4	50 - 70	16
OO	581,971	38	82	34	4.3	6.2	50 - 70	35
PP	802,645	30	80	35	5.6	6.6	60 - 80	54
QQ	577,134	25	80	35	4.6	4.0	50 - 70	13

Area = Hydrocarbon area within boundary
OBIP = Original Bitumen in Place; PBIP = Producible Bitumen In Place; PBIP = OBIP
Volumetric calculation = Area within drainage box boundary x Bitumen Pay thickness x avg. oil saturation x avg. porosity
*Permeability values are directly from core analysis and are highly variable across Jackfish

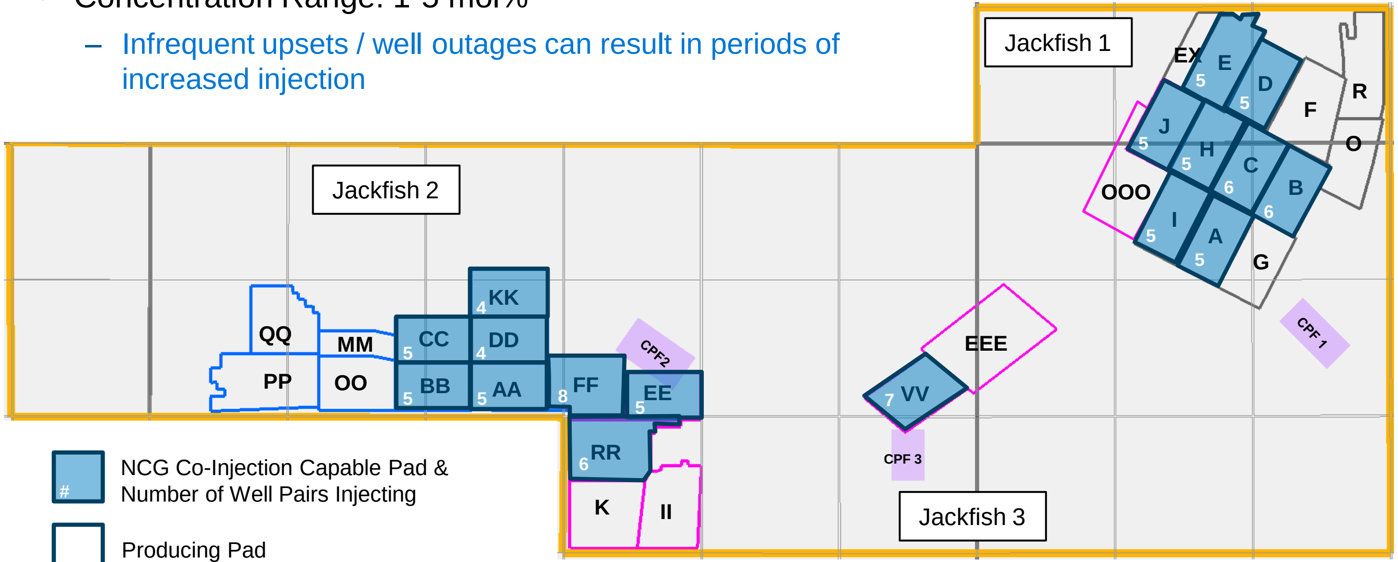
4.2, 6) Well Patterns Volumetrics – Jackfish 3

Pad	Area (m^2)	Average Thickness (m)	Average Oil Saturation (%)	Average Porosity (%)	Average Kh Permeability (D)*	OBIP/PBIP ($10^6 m^3$)	Ultimate Recovery Factor (%)	Recovery Factor (%) to Date of OBIP/PBIP
EE	506,800	41	81	34	6.0	5.6	50 - 70	47
EEE	1,001,408	24	79	34	5.7	6.5	50 - 70	15
III	658,102	31	84	34	4.1	6.0	60 - 80	16
J	530,754	31	84	34	4.5	4.2	50 - 70	37
K	676,312	41	87	34	6.3	8.2	60 - 80	56
RR	720,253	30	82	34	6.7	6.1	50 - 70	42
VV	558,761	26	82	35	5.6	4.1	50 - 70	50
OOO	649,524	30	72	34	5.3	4.7	50 – 70	0

Area = Hydrocarbon area within boundary
OBIP = Original Bitumen in Place; PBIP = Producible Bitumen In Place; PBIP = OBIP
Volumetric calculation = Area within drainage box boundary x Bitumen Pay thickness x avg. oil saturation x avg. porosity
*Permeability values are directly from core analysis and are highly variable across Jackfish

4.2, 7) Co-Injection

- Co-Injection: none other than NCG – fuel gas, predominantly methane.
- Total Pads: 17
- Timing: Late life / decline / higher recovery factor
- Target Steam Re-allocation: 20%
- Concentration Range: 1-5 mol%
  - Infrequent upsets / well outages can result in periods of increased injection
- NCG Recovery: Current estimation of NCG recycle rates is between 30 – 70%
  - As observed throughout industry, the recovery of injected NCG is difficult to differentiate from steam, solution gas and lift gas where applicable.



NCG Co-Injection Capable Pad & Number of Well Pairs Injecting

Producing Pad

Asset	Pads	Co-Injection Start Date
JF1	A, B, C, D, E, H, I	2018
JF2	AA, BB, CC	2018
	DD, FF, KK	2016
JF3	EE, RR, VV	2019
	J	2021

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4.2, 7) Co-Injection (cont'd)

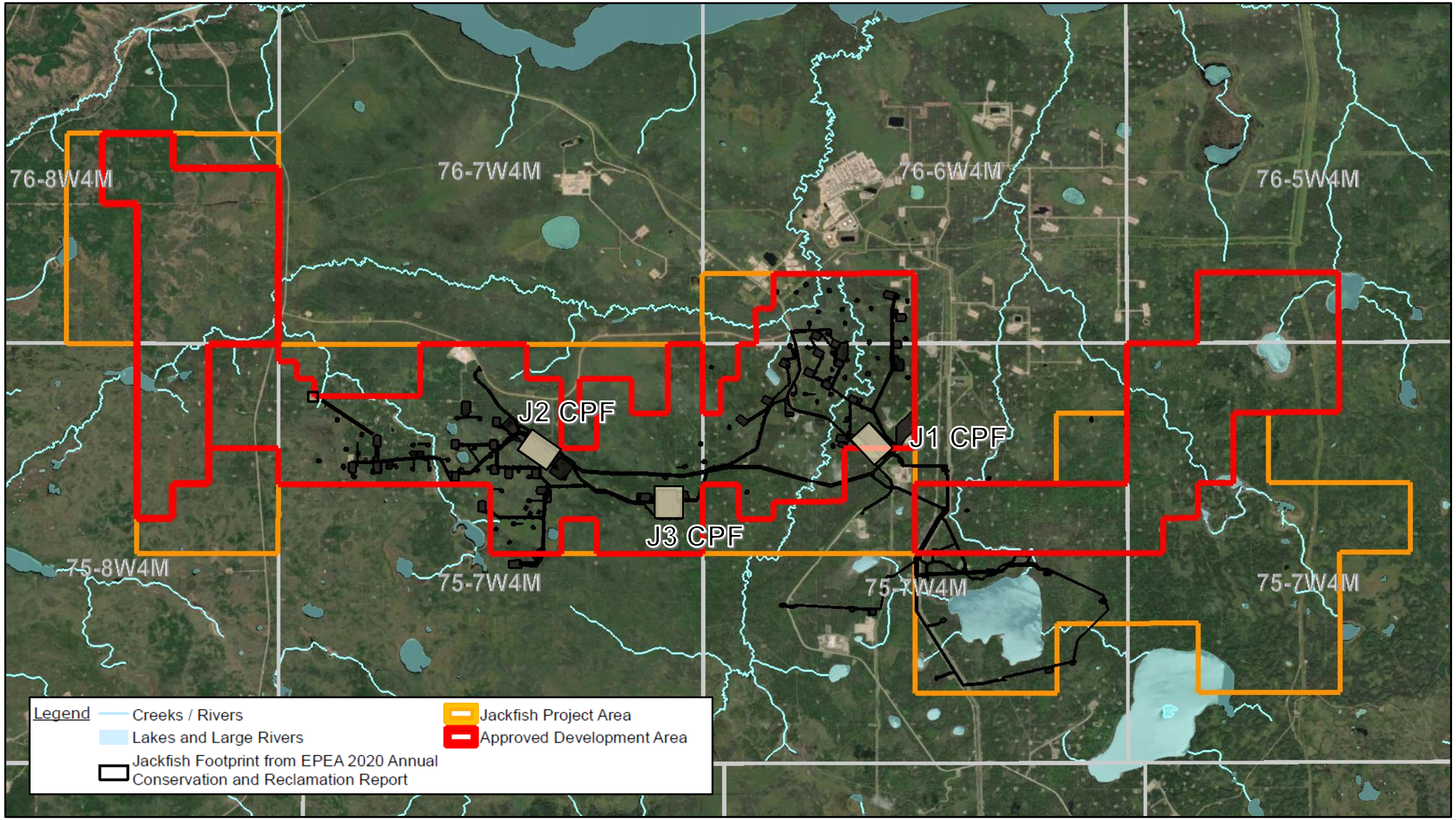
- Discussion:
  - Primarily used for steam re-allocation and reservoir pressure management

- Learnings to date:
  - NCG injection rates within expected range
  - NCG successful in maintaining chamber pressure with reduced steam
  - No negative impact to resource recovery observed in late life NCG co-injection
  - Improved SOR observed
  - No McMurray aquifer or well integrity impacts evident to date

- Go Forward Plan:
  - Continue to monitor and evaluate NCG utilization and performance
  - Add NCG co-injection capability on pad K

4.3
Surface

4.3, 8 a) Built and Planned Surface Infrastructure Map



4.3, 8 b) Modifications to the Central Processing Facility

- Permanent Butane Injection at Custody Transfer Station
  - A Canadian Natural owned, Wolf Midstream operated facility located at Jackfish Tank Farm.
  - Butane is injected into production blend on a continual basis to meet pipeline specification.
  - Optimized operation of this facility throughout 2021.

- Temporary Diesel Pump at Jackfish 2 Facility
  - Additional pump utilized to prevent solids build up in the blowdown pond.

4.3, 8 c) Annual Operational Bitumen and Steam Rates

- A comparison of the annual operational bitumen and steam rates to the design throughputs.

January – December 2021	CPF	Actual Operational	Design Throughput
Bitumen (m^3/d)	Jackfish 1	5,887	6,757
	Jackfish 2	5,947	7,950
	Jackfish 3	7,070	7,950
Steam (sm^3/d)	Jackfish 1	14,168	15,971
	Jackfish 2	15,356	15,971
	Jackfish 3	14,721	15,990

4.4
Historical & Upcoming Activity

4.4, 9) Suspension and Abandonment Activity

- No wells suspended or abandoned during the reporting period.

- No wells in active blow-down or ramp-down during the reporting period.

4.4, 10 a) Regulatory Approvals

Application Description	Application Number	Submission Date	Approval Date
Temporary Diesel Pump Testing	1931960	01/19/2021	01/28/2021
Sulphur Management Compliance Assurance Plan	1932193	02/09/2021	03/31/2021
Pad OOO Temporary MOP Increase	1932802	04/14/2021	07/8/2021
Pad XX Development Amendment	1933199	06/03/2021	09/07/2021
Permanent Butane Injection at District Tank Farm	1933363	06/16/2021	06/16/2021
Pad OOO Warm Hydrocarbon Agent-Assisted Start-up	1934636	10/19/2021	11/29/2021

4.4, 10 a) Regulatory Approvals (cont'd)

Application Description	Application Number	Submission Date	Approval Date
Pad C Producer Re-drill Wells	1934704	10/26/2021	11/22/2021
Pad D Producer Re-drill Well	1934881	11/15/2021	11/23/2021
Pad B Producer Re-drill Wells	1934882	11/15/2021	11/24/2021
Pad DD Producer Re-drill Well	1935263	12/16/2021	02/17/2022

4.4, 10 b) Events with Potential to Impact to Scheme Performance

- Scheme Performance:
  - Pad OOO circulation start October 2021
  - Start up of 2 re-drilled producers on Pad A
  - NCG Co-Injection allowing for steam allocation to new pad developments
    - Primarily used for steam re-allocation and reservoir pressure management, improved SOR observed
    - Continue to monitor and evaluate performance

4.4, 10 c) Jackfish Learnings

- Lessons Learned:
  - In-Flow Control Devices ICDs
    - ICD evaluation ongoing at several pads
    - No tangible learnings to end 2021
  - Fiber vs TCs
    - 120 producer wells have had fiber installed, 102 of those are interrogated fiber.
    - DTS fiber optics were installed in the producer of 15 well-pairs in Q4 2021.
    - DTS plus DAS fiber optic trial is ongoing at Pad III at 3 well-pairs. Pilot showed good conceptual inflow identification in 2021, further focused work is ongoing in 2022.
    - Canadian Natural's preferred monitoring approach to preserve well integrity and optimize production

4.4, 10 d) Regulatory and Operational Changes

- There have been no pilots or major technical innovations conducted at the Jackfish Project associated with Scheme Approval No. 10097 during 2021.

4.4, 11) Compliance History

- Reportable Incidents – Facility Releases:
  - 6 total release incidents with a volume of 70 m^3
- All facility releases contained and controlled on lease; the majority of volumes were into secondary containment and all remained on lease. All were cleaned up and met criteria as per Tier 1 Guidelines (industrial).
  - March 1, 2021 - Ref. # 20210484
  - September 9, 2021 - Ref. # 20212009
  - September 14, 2021- Ref: # 20212041
  - September 24, 2021- Ref: # 20212125
  - December 3, 2021 - Ref: # 20212755
  - December 8, 2021- Ref: # 202112801

4.4, 11) Compliance History (cont’d)

- Reportable Incidents – Pipeline Releases:
  - 2 total release events from pipelines/liner failure of a volume of 0.3 m3
- All releases were cleaned up and required remediation activities were completed
  - February 21, 2021 - Ref. # 20210410
  - April 18th, 2021 - Ref: # 20210898

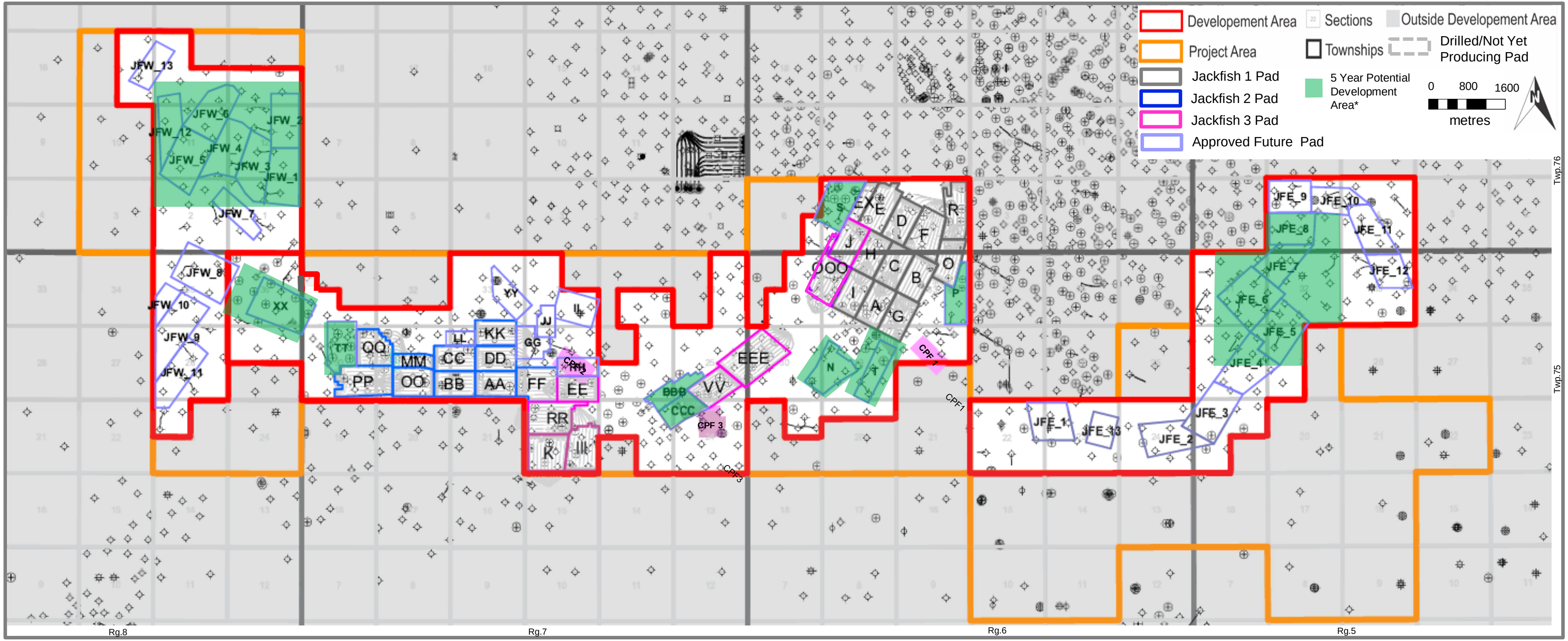
4.4, 11) Compliance History (cont'd)

- Voluntary Self-Disclosures:
  - Non-reporting of HLS - Submitted December 2, 2021
    - Reporting amendment of associated vent volumes resulting in exceedance of OVG.
    - Modifications will be made to Jackfish CPFs 2 and 3 to capture HLS vent, and continue to monitor vent at CPF 1 to ensure compliance. Action items to be completed June 1, 2022.
- Contraventions – Air
  - February 28, 2021: 0 m3
    - Contravention occurred for CEMS unit failing to meet 90% uptime (air), by Alleged Contravention-Approval Requirement. (Ref. # 20210700)
- Contraventions – Water
  - None

4.4, 12 a) Future Plans: Upcoming 12 Month Activity

- Pending favorable economic conditions, the following potential future plans are under evaluation for 2022:
  - Re-drilling of up to 14 producers across district (9 at JF1, 5 at JF2)
  - 4-D seismic acquisition
  - Pad XX drilling

4.4, 12 b) 5-Year Potential Development Plan



- 5 Year Development Area defines area where delineation, seismic and well patterns **MAY** be developed within the next 5 years based on internal capital sanctions and market conditions
- May drill new delineation and/or production wells on existing pads

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4.4, 12 c) Future Plans: Upcoming 12 Month Applications

Application Description	Application Number	Submission Date	Approval Date
Temporary Diesel Pump	1935567	01/21/2022	01/24/2022
Flow Test Production	1935704	02/01/2022	02/11/2022
Pad S Development Amendment		Q3 2022	

Advisory

Special Note Regarding Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed", "aspiration" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, production expenses, capital expenditures, income tax expenses and other targets provided throughout this presentation and the Company's Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of the Company, constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including, without limitation, those in relation to the Company's assets at Horizon Oil Sands ("Horizon"), the Athabasca Oil Sands Project ("AOSP"), Primrose thermal oil projects, the Pelican Lake water and polymer flood projects, the Kirby Thermal Oil Sands Project, the Jackfish Thermal Oil Sands Project, the North West Redwater bitumen upgrader and refinery, construction by third parties of new, or expansion of existing, pipeline capacity or other means of transportation of bitumen, crude oil, natural gas, natural gas liquids ("NGLs") or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market, the development and deployment of technology and technological innovations, and the financial capacity of the Company to complete its growth projects and responsibly and sustainably grow in the long term also constitute forward-looking statements. These forward-looking statements are based on annual budgets and multi-year forecasts, and are reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil, natural gas and NGLs reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserves and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the earlier of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions (including as a result of effects of the novel coronavirus ("COVID-19") pandemic and the actions of the Organization of the Petroleum Exporting Countries Plus ("OPEC+") which may impact, among other things, demand and supply for and market prices of the Company's products, and the availability and cost of resources required by the Company's operations; volatility of and assumptions regarding crude oil and natural gas and NGLs prices including due to actions of OPEC+ taken in response to COVID-19 or otherwise; fluctuations in currency and interest rates; assumptions on which the Company's current targets are based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build, maintain, and operate its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; the Company's ability to meet its targeted production levels; timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities (including production curtailments mandated by the Government of Alberta); government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital expenditures and production expenses); asset retirement obligations; the sufficiency of the Company's liquidity to support its growth strategy and to sustain its operations in the short, medium, and long term; the strength of the Company's balance sheet; the flexibility of the Company's capital structure; the adequacy of the Company's provision for taxes; the continued availability of the Canada Emergency Wage Subsidy ("CEWS") or other subsidies; and other circumstances affecting revenues and expenses.

The Company's operations have been, and in the future may be, affected by political developments and by national, federal, provincial, state and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this presentation or the Company's MD&A could also have adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by applicable law, the Company assumes no obligation to update forward-looking statements in this presentation or the Company's MD&A, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or the Company's estimates or opinions change.

Reporting Disclosures

Special Note Regarding non-GAAP and Other Financial Measures

This presentation includes references to financial measures commonly used in the crude oil and natural gas industry, such as: adjusted net earnings (loss) from operations, adjusted funds flow and net capital expenditures. These financial measures are not defined by International Financial Reporting Standards ("IFRS") and therefore are referred to as non-GAAP financial measures. The non-GAAP financial measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP financial measures to evaluate its performance. The non-GAAP financial measures should not be considered an alternative to or more meaningful than net earnings (loss), cash flows from operating activities, and cash flows used in investing activities as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP financial measure adjusted net earnings (loss) from operations is reconciled to net earnings (loss), as determined in accordance with IFRS, in the "Financial Highlights" section of the Company's MD&A. Additionally, the non-GAAP financial measure adjusted funds flow is reconciled to cash flows from operating activities, as determined in accordance with IFRS, in the "Financial Highlights" section of the Company's MD&A. The non-GAAP financial measure net capital expenditures is reconciled to cash flows used in investing activities, as determined in accordance with IFRS, in the "Net Capital Expenditures" section of the Company's MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of the Company's MD&A.

Adjusted net earnings (loss) from operations is a non-GAAP financial measure that represents net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for the after-tax effects of certain items of a non-operational nature. The Company considers adjusted net earnings (loss) from operations a key measure in evaluating its performance, as it demonstrates the Company’s ability to generate after-tax operating earnings from its core business areas. Adjusted net earnings (loss) from operations may not be comparable to similar measures presented by other companies.

Adjusted funds flow is a non-GAAP financial measure that represents cash flows from operating activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, abandonment expenditures excluding the impact of government grant income under the provincial well-site rehabilitation programs, and movements in other long-term assets, including the unamortized cost of the share bonus program, accrued interest on subordinated debt advances to North West Redwater Partnership ("NWRP"), and prepaid cost of service tolls. The Company considers adjusted funds flow a key measure in evaluating its performance, as it demonstrates the Company’s ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. Adjusted funds flow may not be comparable to similar measures presented by other companies.

Net capital expenditures is a non-GAAP financial measure that represents cash flows used in investing activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, the repayment of NWRP subordinated debt advances, abandonment expenditures including the impact of government grant income under the provincial well-site rehabilitation programs, and the settlement of long-term debt assumed in acquisitions. The Company considers net capital expenditures a key measure in evaluating its performance, as it provides an understanding of the Company’s capital spending activities in comparison to the Company's annual capital budget. Net capital expenditures may not be comparable to similar measures presented by other companies.

Free cash flow is a non-GAAP measure that represents cash flows from operating activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital from operating activities, abandonment, certain movements in other long-term assets, less net capital expenditures and dividends on common shares. The Company considers free cash flow a key measure in demonstrating the Company’s ability to generate cash flow to fund future growth through capital investment, pay returns to shareholders, and to repay debt.

Adjusted EBITDA is a non-GAAP measure that represents net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for interest, taxes, depletion, depreciation and amortization, stock based compensation expense (recovery), unrealized risk management gains (losses), unrealized foreign exchange gains (losses), and accretion of the Company’s asset retirement obligation. The Company considers adjusted EBITDA a key measure in evaluating its operating profitability by excluding non-cash items.

Long-term debt, net and net debt are other financial measures that are calculated as net current and long-term debt less cash and cash equivalents.

Debt to adjusted EBITDA is a non-GAAP measure that is derived as the current and long-term portions of long-term debt, divided by the 12 month trailing Adjusted EBITDA, as defined above. The Company considers this ratio to be a key measure in evaluating the Company's ability to pay off its debt.

Debt to book capitalization is a non-GAAP measure that is derived as net current and long-term debt, divided by the book value of common shareholders' equity plus net current and long-term debt. The Company considers this ratio to be a key measure in evaluating the Company's ability to pay off its debt.

Available liquidity is a non-GAAP measure that is derived as cash and cash equivalents, total bank and term credit facilities and short term investments, less amounts drawn on the bank and credit facilities including under the commercial paper program. The Company considers available liquidity a key measure in evaluating the sustainability of the Company’s operations and ability to fund future growth. See note 8 - Long-term Debt in the Company’s consolidated financial statements.

Special Note Regarding Currency, Financial Information and Production

This presentation should be read in conjunction with the unaudited interim consolidated financial statements for the three months ended March 31, 2021 and the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2020. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company’s unaudited interim consolidated financial statements for the three months ended March 31, 2021 and the Company's MD&A have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB").

Production volumes and per unit statistics are presented throughout the Company's MD&A on a "before royalties" or "company gross" basis, and realized prices are net of blending and feedstock costs and exclude the effect of risk management activities. In addition, reference is made to crude oil and natural gas in common units called barrel of oil equivalent ("BOE"). A BOE is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value. In addition, for the purposes of the Company's MD&A, crude oil is defined to include the following commodities: light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and SCO. Production on an "after royalties" or "company net" basis is also presented for information purposes only.

The Company's 2021 targeted annual adjusted funds flow, free cash flow and net debt are based upon forecasted commodity prices of US$60.47 WTI/bbl, WCS discount of US$11.95/bbl, AECO price of C$2.74/GJ and FX of US$1.00 to C$1.26. Forecasted net debt reflects estimated timing of cash receipts and expenditures.

Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2020, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. Information on the Company's website does not form part of and is not incorporated by reference in the Company's MD&A.

Canadian Natural

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