Ministry of Indigenous Relations and Reconciliation

CLIFF XXXXX

MEETING BULLETS

DATE: November 12, 2021

PREPARED FOR: Honourable Murray Rankin, Minister of Indigenous Relations and Reconciliation

REGARDING: Explorers and Producers Association of Canada, regarding the Province's response to the Yahey Decision.

SUMMARY:

- The BC Supreme Court, in its decision in *Yahey vs. BC*, declared that the Province has unjustifiably infringed Blueberry River First Nation's (BRFN) treaty rights and that the Province must not authorize further activities that unjustifiably infringe BRFN's exercise of its treaty rights.

- Members of the Explorers and Producers Association of Canada (EPAC) comprise a significant proportion of petroleum and natural gas (PNG) holdings in the BRFN civil claim area, which overlies the Montney oil and gas formation[1]. (See Appendix 1 for more information about EPAC and expected meeting attendees). Several of the expected EPAC attendees were implicated by the 12 deferrals as a result of the Initial Agreement with BRFN announced on October 7 – s.16
s.16

- EPAC wishes to confirm the Province's commitment towards natural gas development and discuss how industry can support government on a path forward for PNG development in the Northeast, given the Yahey Decision.

- EPAC members have expressed significant concerns regarding economic impacts to their sector from authorization delays. EPAC has indicated that even short-term delays will impact capital and operational spending and put jobs at risk and the resulting uncertainty has led member companies to review their investment decisions.

- The Province shares the concern about the PNG sector, as continued access to PNG resources is important for Crown revenue, regional employment, and the socio-economic health of resource dependent communities in the northeast region.

TALKING POINTS FOR MINISTER:

- We recognize that this is a significant decision with major implications for industry on how the Province authorizes activities in BRFN territory and we are committed to keeping our industry partners informed throughout, and to involve you in bringing new ideas to the table.
- While BRFN has stated that this judgement will not "turn off the taps" for development, the ruling will mean a change in how, when and where the Province authorizes development in Treaty 8 territory.
- The ruling made it clear that the ability of BRFN, and correspondingly, other members of Treaty 8, to practice their way of life has been impacted by the way we have managed development to this point. We cannot proceed as we have in the past and a new collaborative

[1] More than 90% of oil and gas activity and close to 30% of Canada's natural gas production is within the Claim Area.

management framework is required that properly considers cumulative impacts and Treaty rights.

- I recognize the strain this uncertainty is putting on business and industry you represent. We know you are concerned, as are we, about the potential impacts to capital and jobs as we navigate a solution over the coming months. And while we believe our work with BRFN and Treaty 8 First Nations is ultimately the right path towards reconciliation, we are committed to ensuring that path includes stable oil and gas activity and employment in the region.
- Healing the land through restoration is an essential element of the path forward. We need to work with BRFN and other Treaty 8 Nations in repairing historical disturbances and restoring the health of the land.

Negotiations Update (if asked)

- As you are aware, on October 7th the Province and BRFN signed an initial agreement. This agreement provided the space to get to the crucial next stage of negotiations that will provide some certainty of what new authorizations and development can proceed within the context of cumulative effects.
- We are actively continuing negotiations with BRFN, and have had some productive discussions. We also seek to develop a regional approach working with the other Treaty 8 Nations on how to address some of the tough, and shared, issues in front of us. We will need to ensure all Treaty 8 Nations are involved in any discussions needed to achieve regional solutions.
- The Province is placing a priority on establishing an authorizations framework for new authorizations as part of the next stage of negotiations with BRFN. We hope to reach agreement on low impact authorizations on crown and private land as soon as possible, while a framework for other “higher impact” authorizations will take more time.
- As negotiations proceed, we are committed to keeping the lines of communication open between the Province and your organizations, and the industry you represent.

How the PNG Sector Can Support

- The Courts have clearly declared that development interests and treaty rights need to be better balanced. I would therefore encourage EPAC, and the sector it represents, to see the ruling as an opportunity to show the rest of Canada that we can set the stage for an oil and gas sector in BC that advances “lasting and meaningful reconciliation” as well as inclusive, sustainable growth in Treaty 8 territory.
- We welcome any ideas you may have on how we can achieve that balance, and appreciate that EPAC would like to be involved in supporting creative solutions.
- A Strategic Solutions Team has been established with representatives from the Forestry and Oil and Gas sectors. This Team will provide an industry lens informing the development of new and collaborative methods of development and restoration. The first meeting is planned for this Wednesday (November 17).

PREPARED BY:

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Appendix 1: EPAC Member Attendees

The Explorers and Producers Association of Canada (EPAC) represents 170 PNG companies, comprising roughly 35% of natural gas production in Canada.

EPAC members expected to attend the November 15th meeting with Honourable Murray Rankin, Minister of Indigenous Relations and Reconciliation, and Honourable Bruce Ralston, Minister of Energy, Mines and Low Carbon Innovation include:

- David Holy: President & Chief Executive Officer (CEO), Aduro Resources
- Terry Anderson: President & CEO, ARC Resources
- Jordan Kevol: CEO, Calima Energy
- Tim McKay: President & CEO, Canadian Natural
- Dale Shwed: President & CEO, Crew Energy
- David Wilson: President & CEO, Kelt Exploration
- Stacy Knull: President & CEO, Saguaro Resources
- Brian Lavergne: President, CEO & Director, Storm Resources
- Rob Morgan: President & CEO, Strathcona Resources
- Michael Jones: Chief Operating Officer, Todd Energy
- Mike Rose: President & CEO, Tourmaline Oil
- Brendan McCracken: President & CEO, Ovintiv
- Grant Fagerheim: President & CEO, Whitecap Resources
- Don Parker: President & CEO, Yoho Resources

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Withheld pursuant to/removed as

s.16

BC GOVERNMENT ROYALTY STUDY METHODOLOGY

Review of Royalty Options

November 2021

Ground up resource methodology run on multiple regimes and pricing scenarios

01	Process Overview and Area Definition	• Methodology Overview • Area Segmentation • Process Highlights • Summary of Regional Activity – Key areas of focus & changes • Machine Learning Insights and Recent Development Trends
02	Inventory Rationalization	• Operator Activity, XDA, Benches
03	Economic Input Summary	
04	Resource Summary	
05	Methodology – Caribou South Example	
06	Economic Royalty Regime Results	

Process Overview and Area Definition

- Methodology Overview
- Area Segmentation
- Process Highlights
- Regional Activity Summaries
- Machine Learning Insights and Development Trends

Methodology comprised of type curve creation and economic royalty sensitivities

Type Curve Methodology

Area and Reservoir Segmentation

Geological Analysis

Dataset Overview

Production Performance Review

Type Curve Creation

- 10 – 15 year development prospects were key focus
- Inactive area prospects assessed leveraging broader regional dataset

Finalize Inventory Analysis

Royalty Regime Analysis

Economic comparisons were generated for all development areas utilizing the provided fiscal regimes

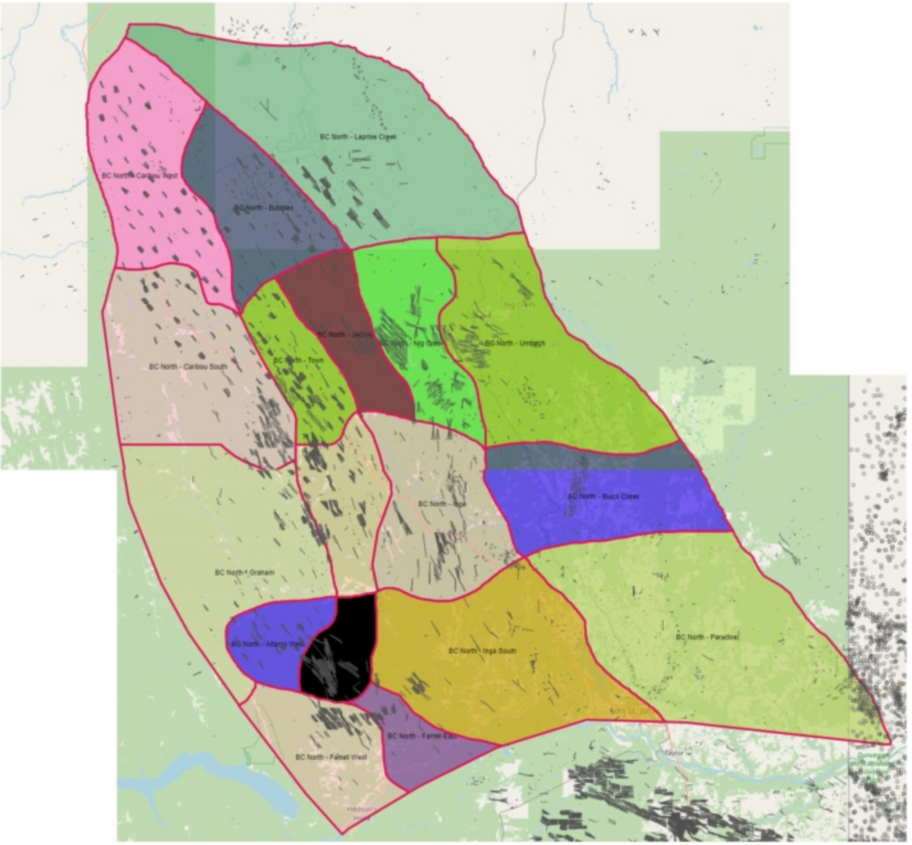
Run economic results through multiple pricing scenarios

- Half-Cycle Rate of Return
- Net Present Value
- Profitability Index
- Half-Cycle Well Payout

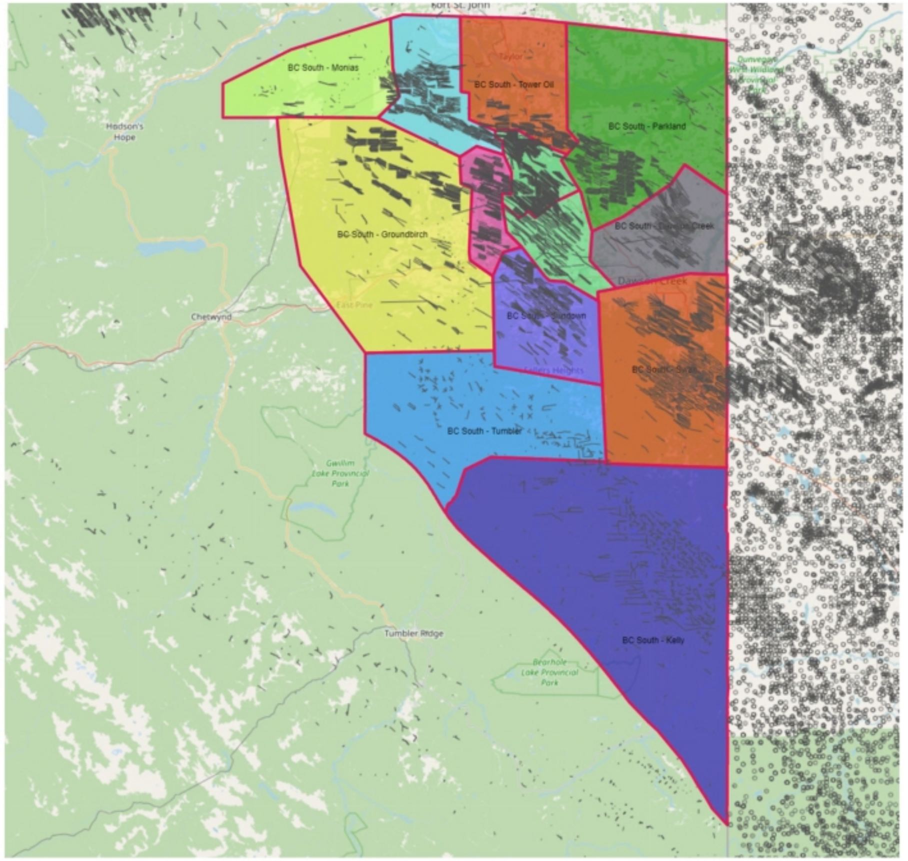
AREA SEGMENTATION

Boundaries provided by BC Gov. and updated based on geological parameters and information

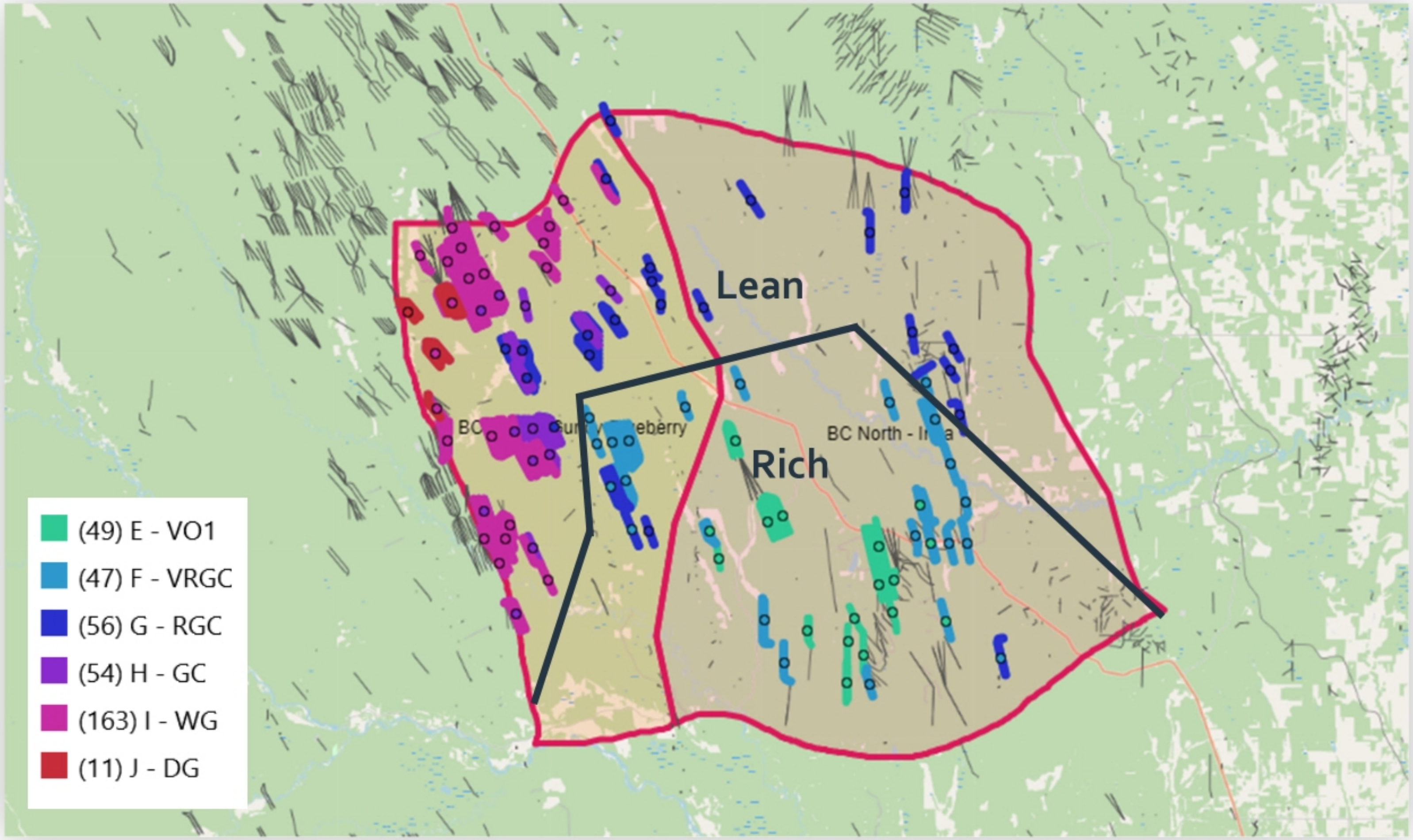
North Peace



South Peace



Gundy-Blueberry and Inga were split into lean and rich areas to better represent the fluids



- Due to geological variation, the southern area for Gundy-Blueberry and Inga are more liquids rich
- To better represent this variation in fluid maturity, the areas were split into a lean and rich section
- Total of 4 areas:
    - Gundy-Blueberry Rich
    - Gundy-Blueberry Lean
    - Inga Rich
    - Inga Lean

Type Curve Process Highlights

Provide a reasonable interpretation on drilling inventory with consideration given to:

- Recent operator activity i.e. areas of significant focus
- Emerging liquids rich regions that show material potential
- Operator development trends i.e. development spacing, bench or cube style development
- Reservoir quality and other geological considerations
  - Additional considerations such as high water saturations, reservoir faulting, seismicity related completion limitations assessed where feasible

Type curve methodology incorporates

- Regional geological mapping and fluids
- Recent operator development practices and completion approach
- Machine Learning models generated using the entire Montney Data Set
  - Completion upscaling in areas where limited activity has occurred in the last 5 years

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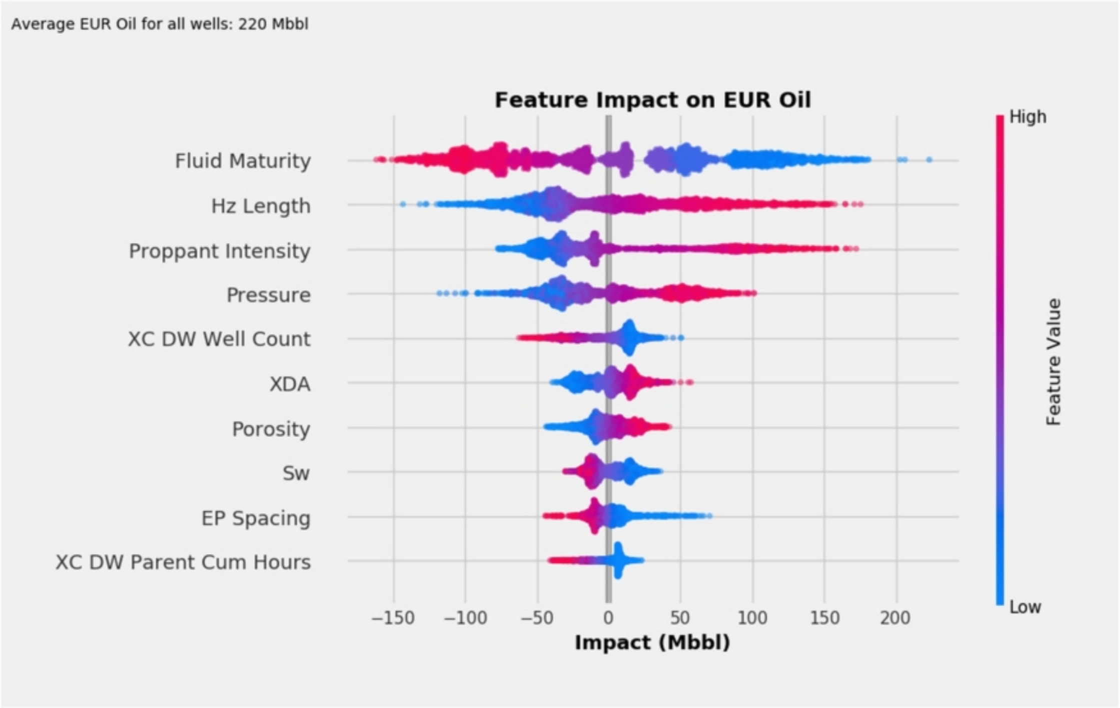
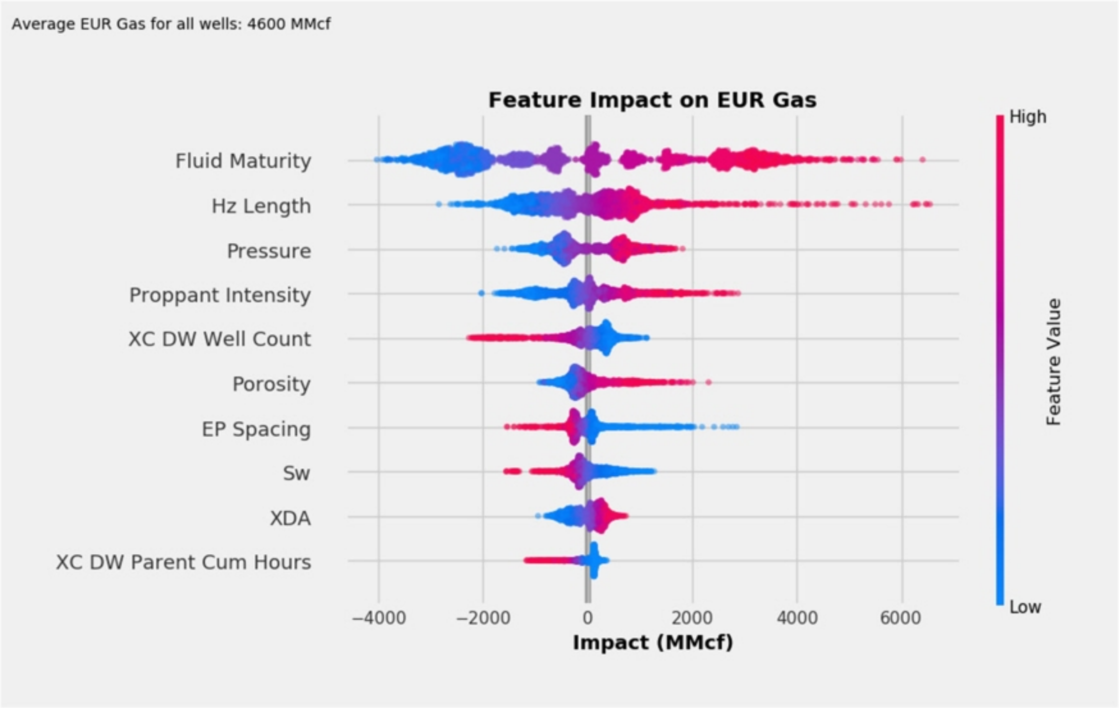
Average Feature Impact: Broad Liquids-Rich Montney

Differences exist between gas and condensate.

Condensate/Oil



Gas



Reservoir parameters have material influence on performance. Parameters like lateral length, proppant intensity and well density are the most impactful controllable features.

*Relative parameter importance changes depending on time sequence (i.e. IP30 vs EUR)

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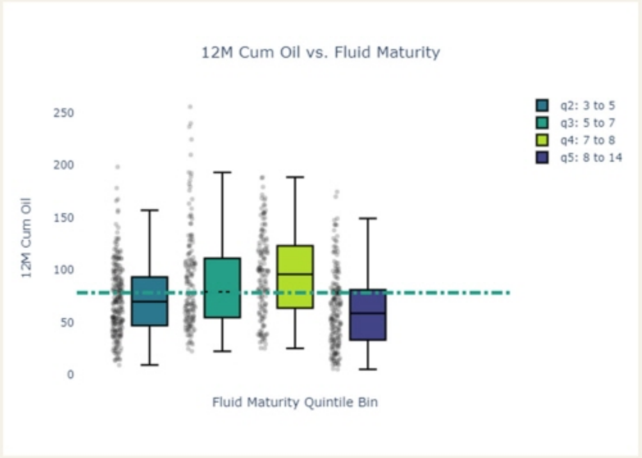
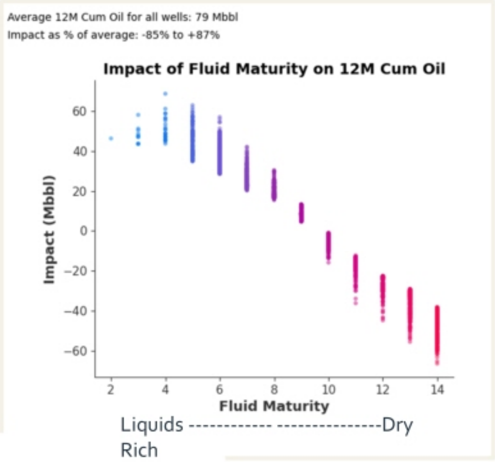
All else equal, wells with lower fluid maturity (higher CGR) produce more oil/condensate

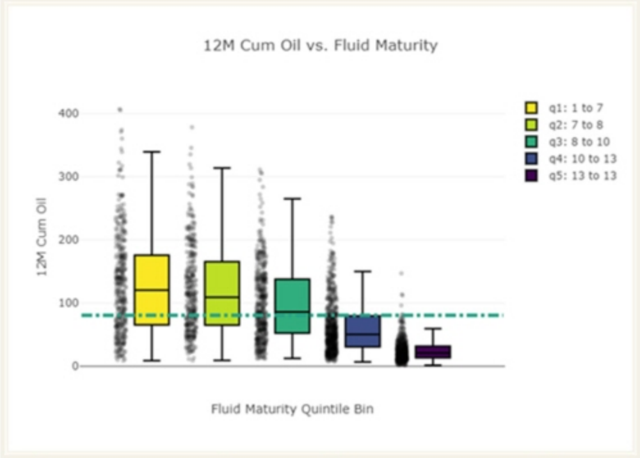


Montney

Raw Data

ML Model

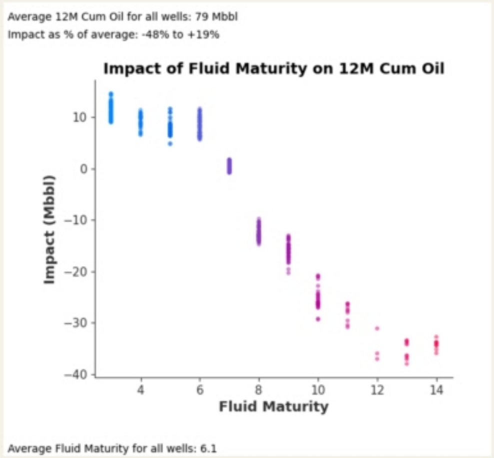




Duvernay

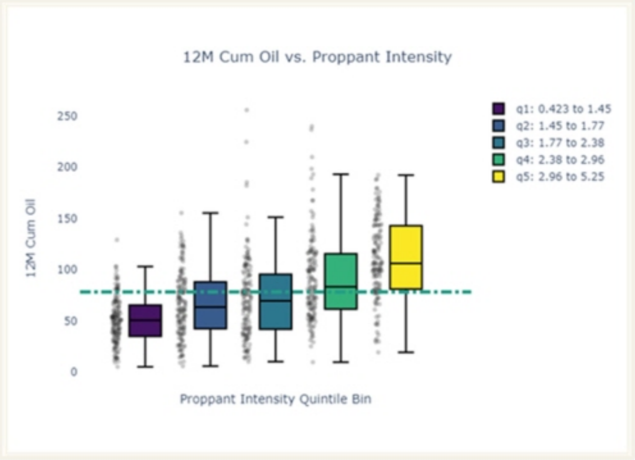
Raw Data

ML Model



Duvernay shown for comparative purposes

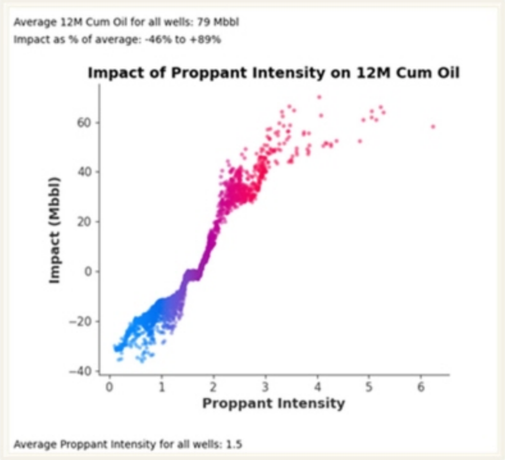
Completion intensity is the strongest and most consistent completion design feature we've studied

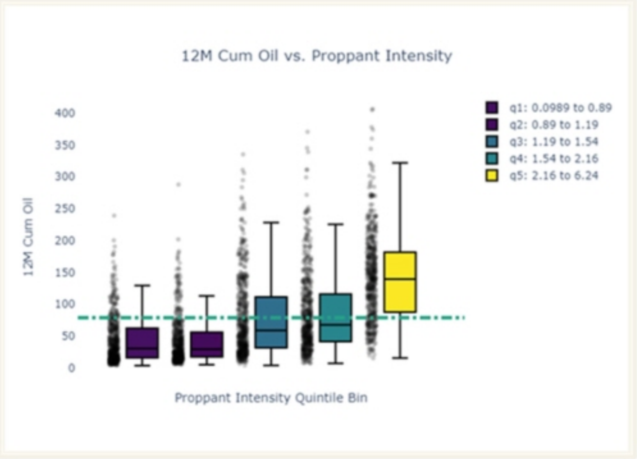


Montney

Raw Data

ML Model

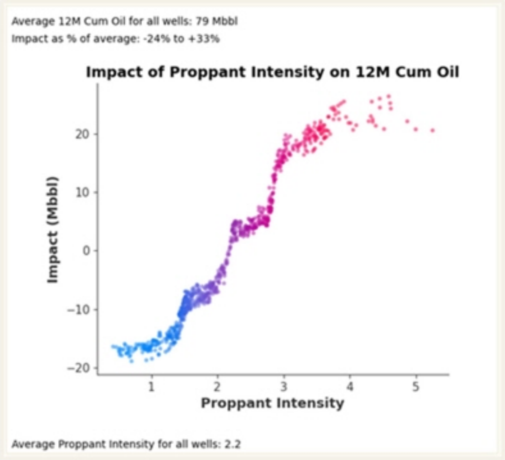




Duvernay

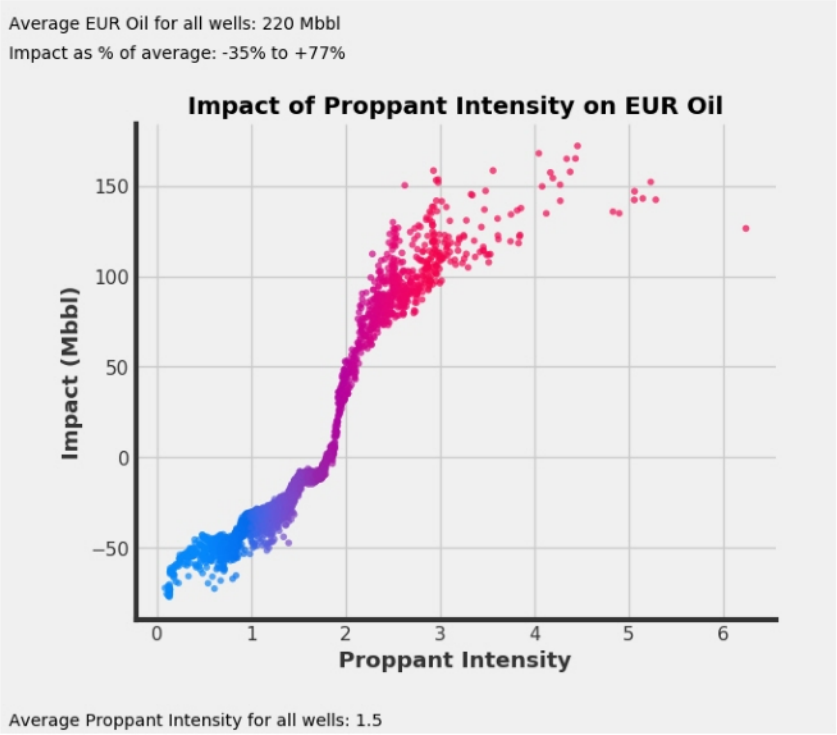
Raw Data

ML Model

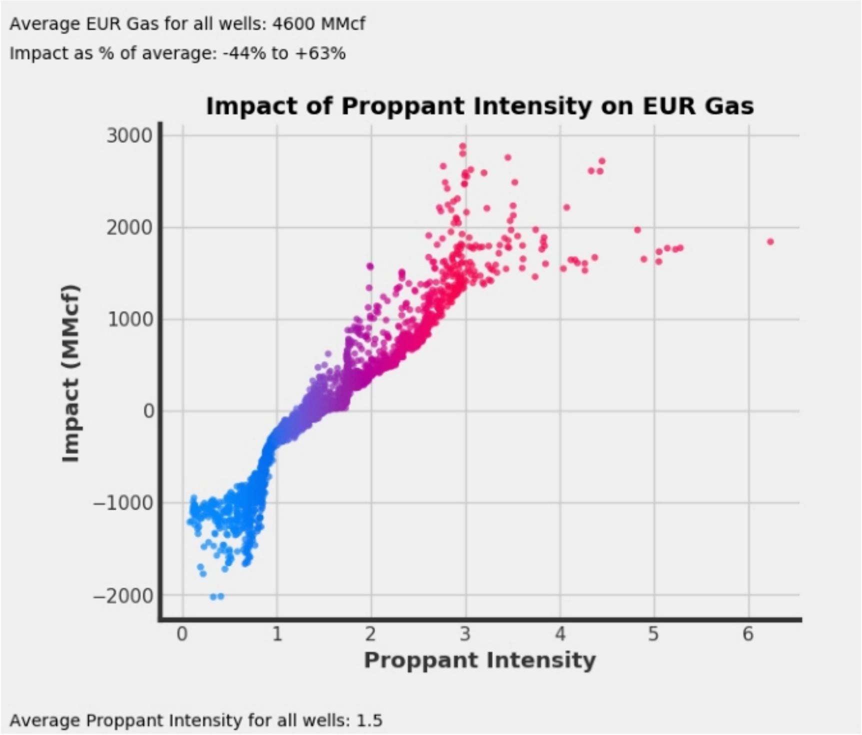


Performance scales strongly with proppant intensity up until 3.0 t/m

Condensate/Oil

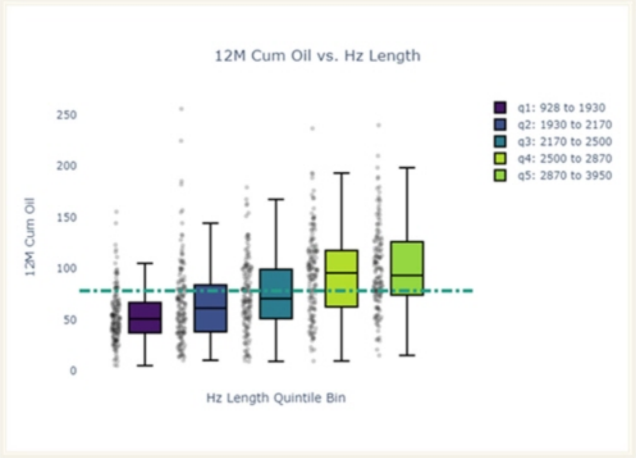


Gas



Relative impact of proppant intensity (i.e. slope) changes depending on reservoir parameters and other controllable factors.

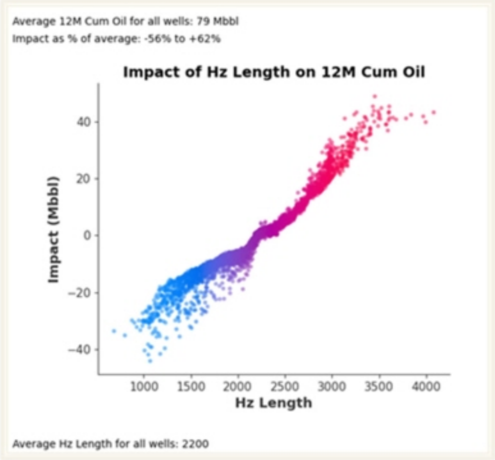
Performance tends to scale nearly 1:1 to wellbore length, especially for EUR

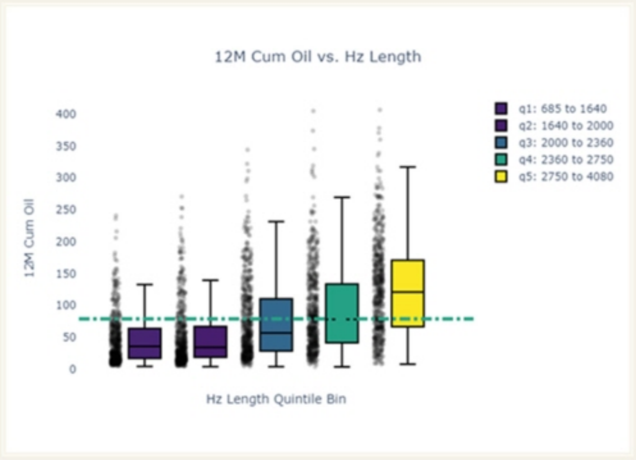


Montney

Raw Data

ML Model

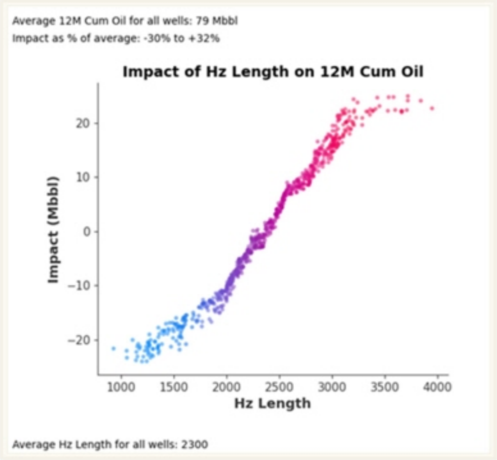




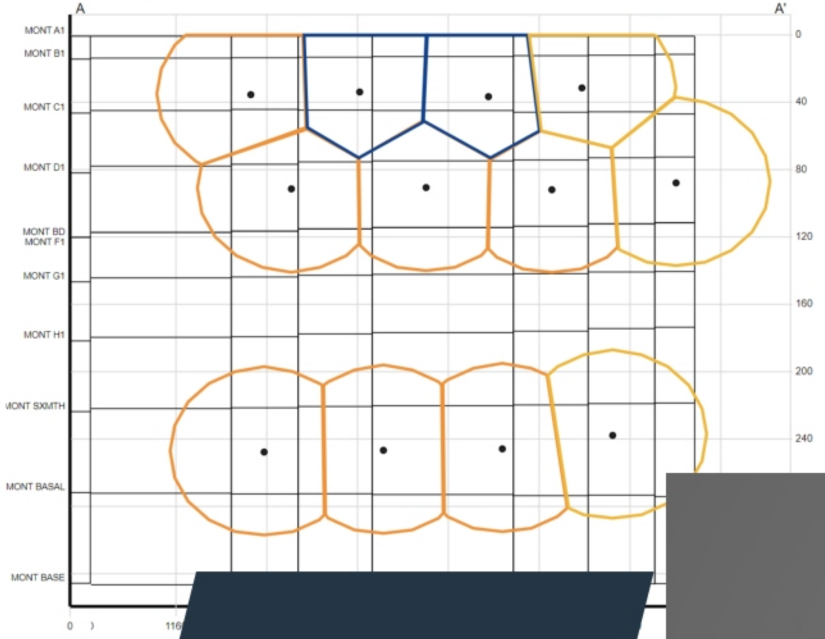
Duvernay

Raw Data

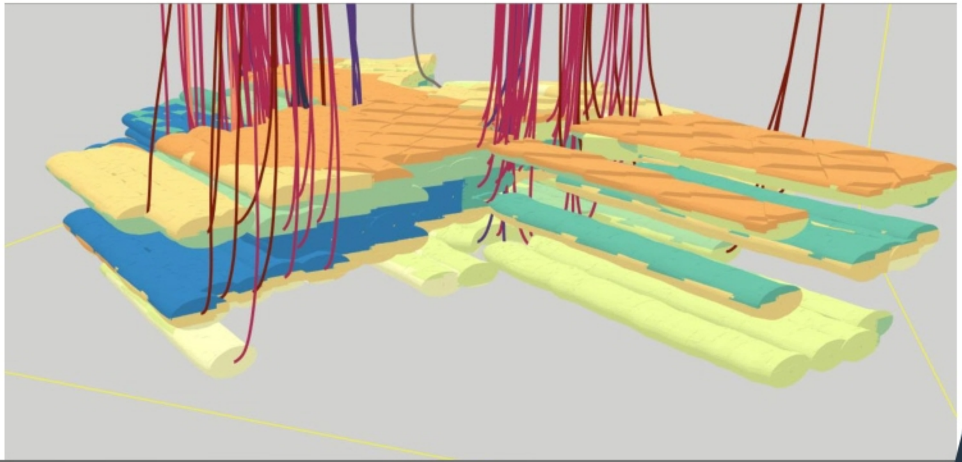
ML Model



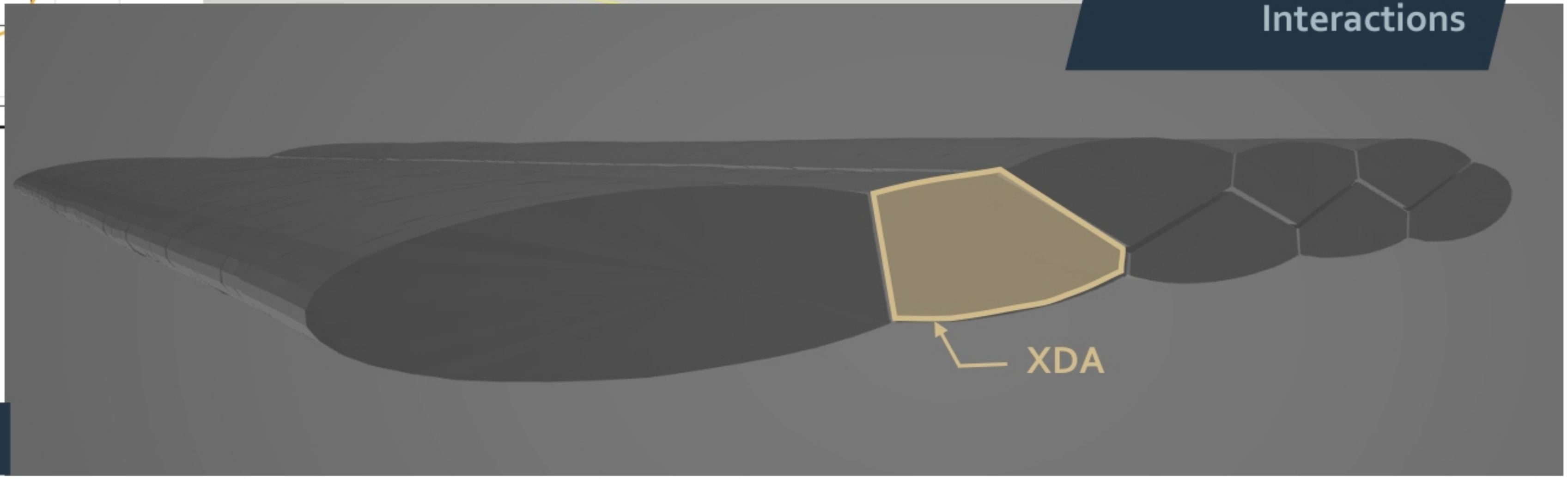
Understanding Cube Design requires a different perspective on spacing



Cross-Section
& 3D Reveals the
Development
Pattern



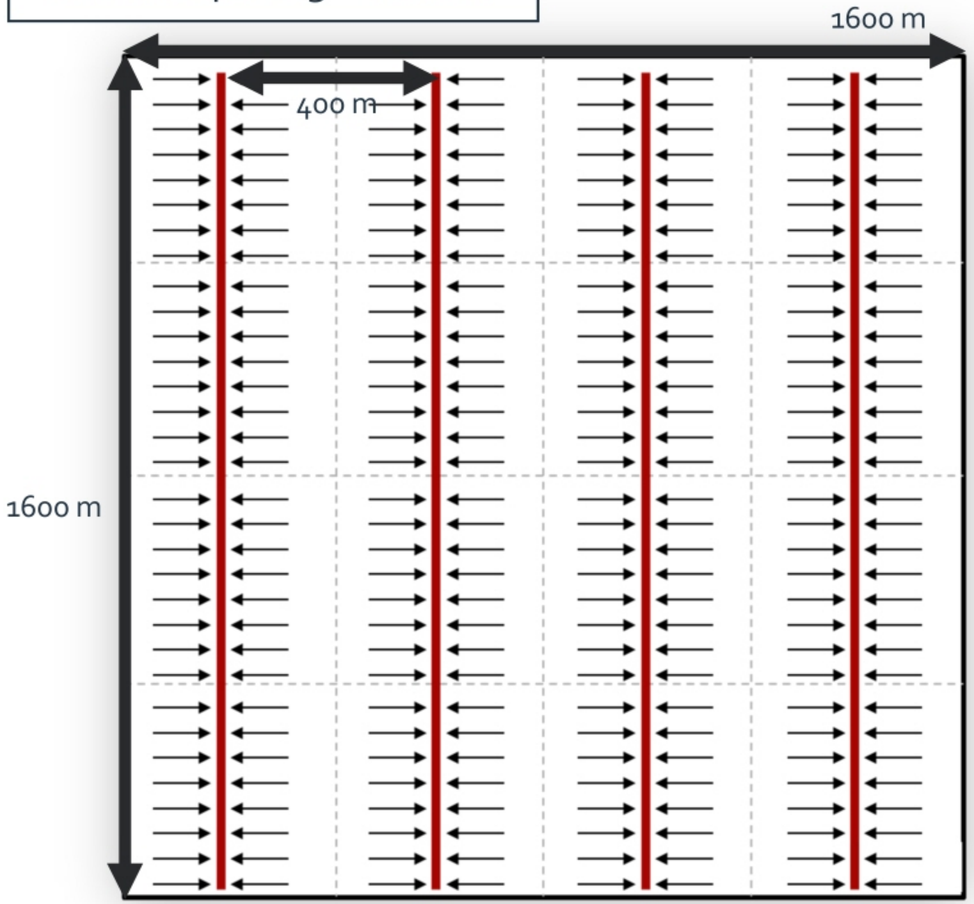
High-Res 3D
Volumetrics,
Interference &
Parent-Child
Interactions



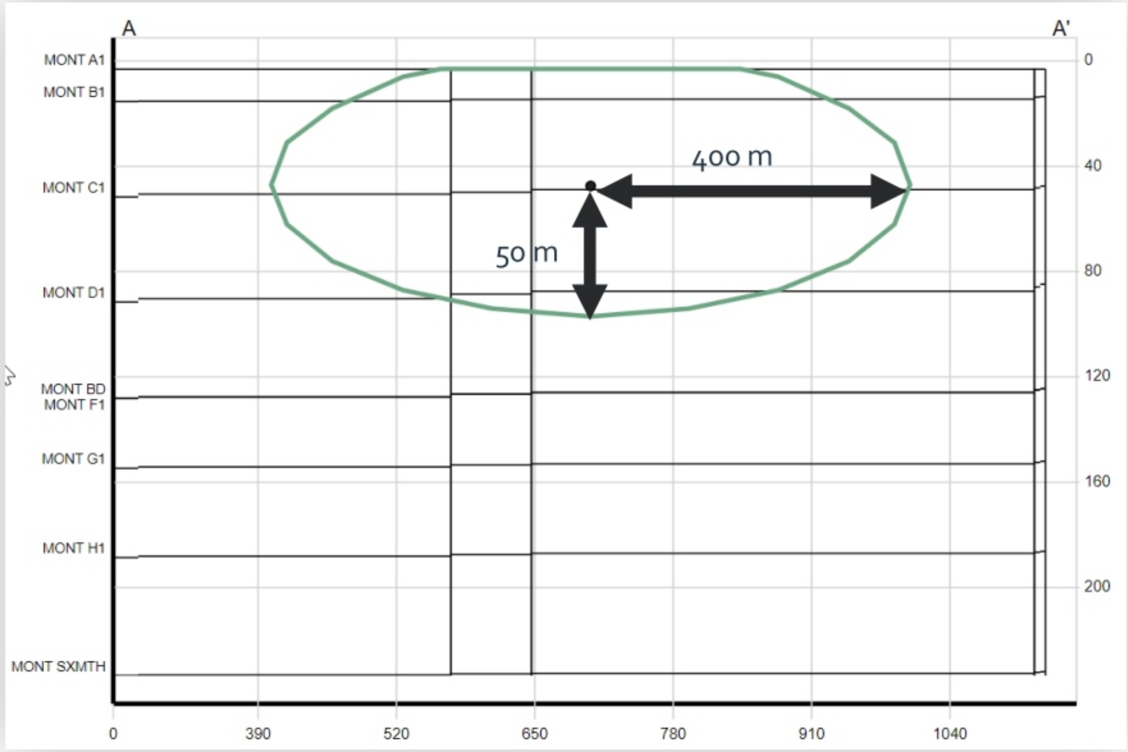
SPE Paper: 195985-MS

Lateral spacing on left, McDaniel XDA metric on right

Lateral Spacing – Meters

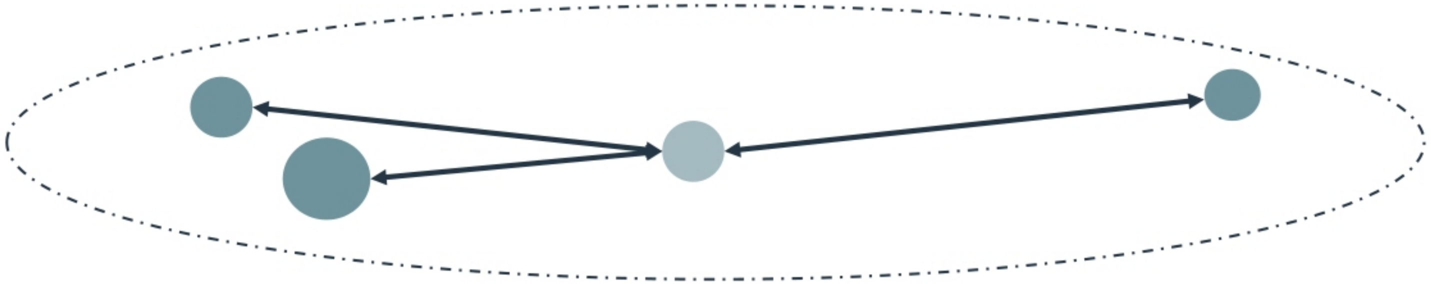


Cross Sectional Drainage (XDA) – Sq. Meters



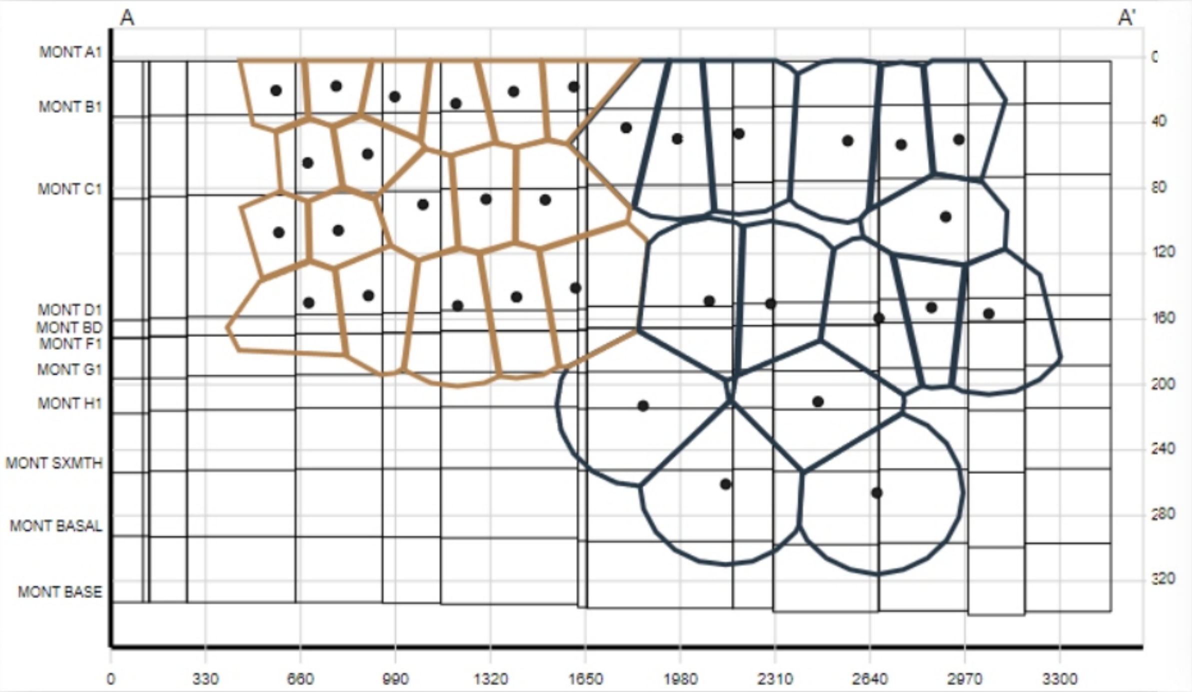
The larger the DW well count is, the more densely spaced the wells are

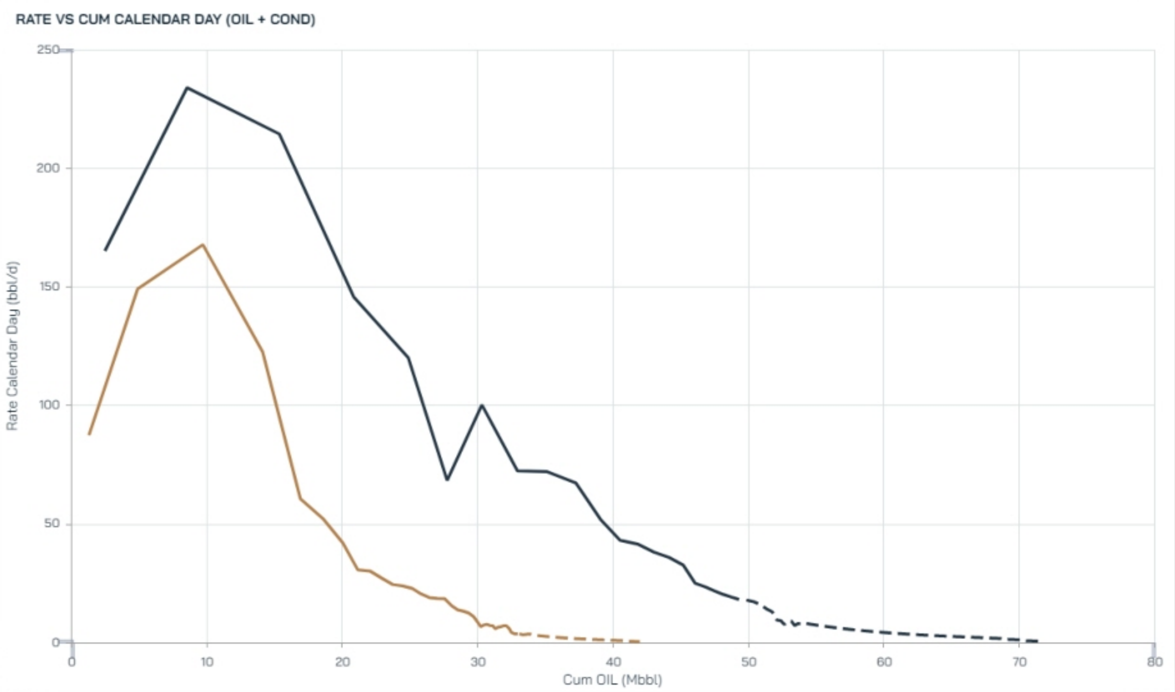
- Distance weighted well count is a metric that measures the normalized distance for a particular well given the surrounding wells proximity
- A large DW well count indicates that there are multiple wells in proximity to the target well, with each additional well within proximity summing to a larger number
  - Indication of the density for the target well
- Montney average DW well count is 3.4 for all wells



$$Distance\ Weighted\ Well\ Count = \sum_{n=1}^{n} \frac{800m\ - (Distance\ from\ well)}{800m}, n = number\ of\ wells$$

Example of high/low XDA and DW well count pads within the Montney





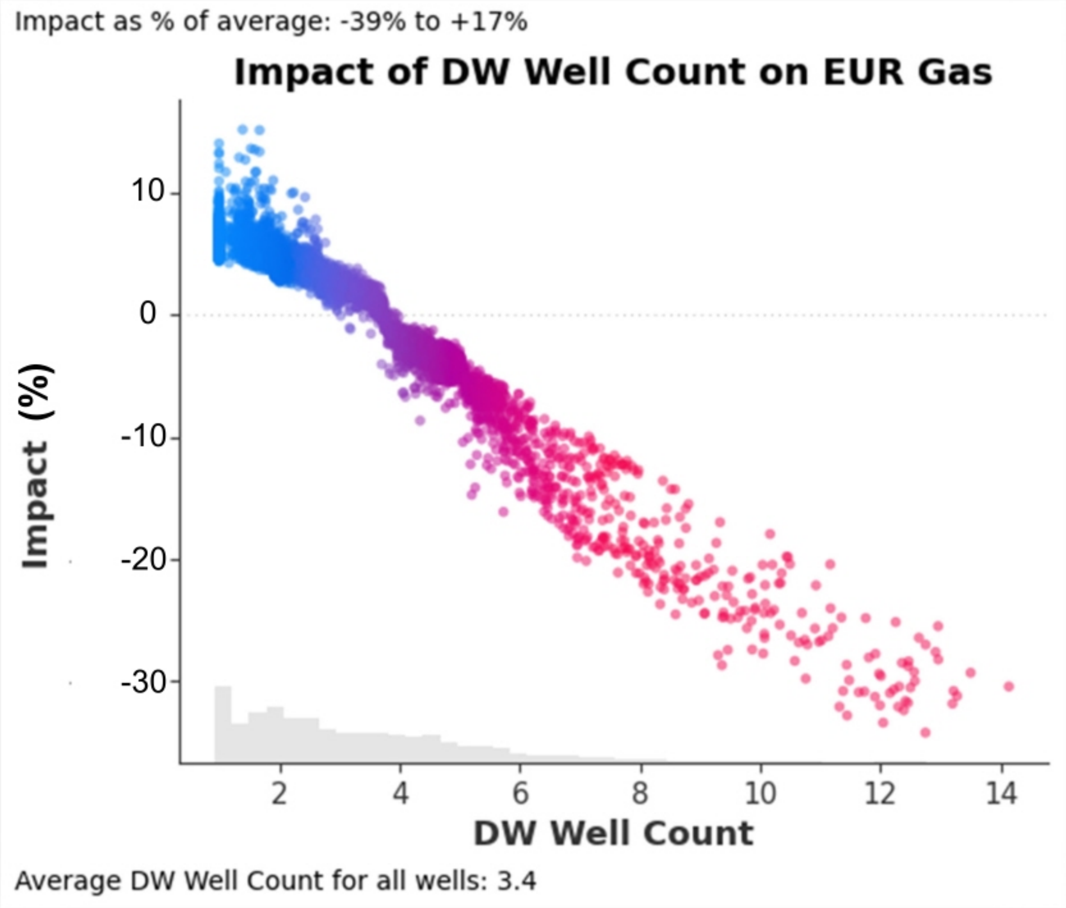
Brown

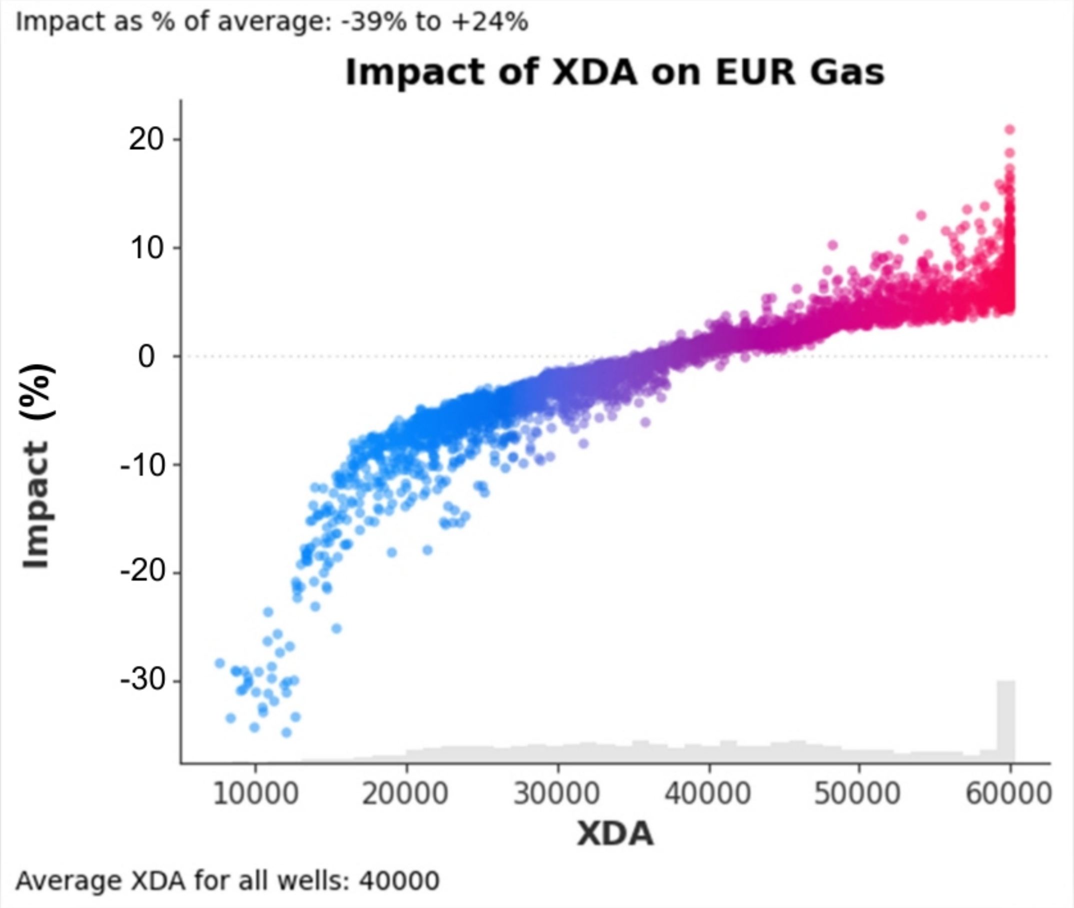
- Triple/quad stack drilled in Upper Montney (~24WPS)
- XDA/well 4.0 ac (16,000 m²)
- Distance Weighted Well Count: 8.5

Navy

- Double stack drilled in Upper Montney 2018/2019 (Lower Montney Drilled in 2021) (12 WPS)
- XDA/well 8.4 ac (34,000 m²)
- Distance Weighted Well Count: 4.8

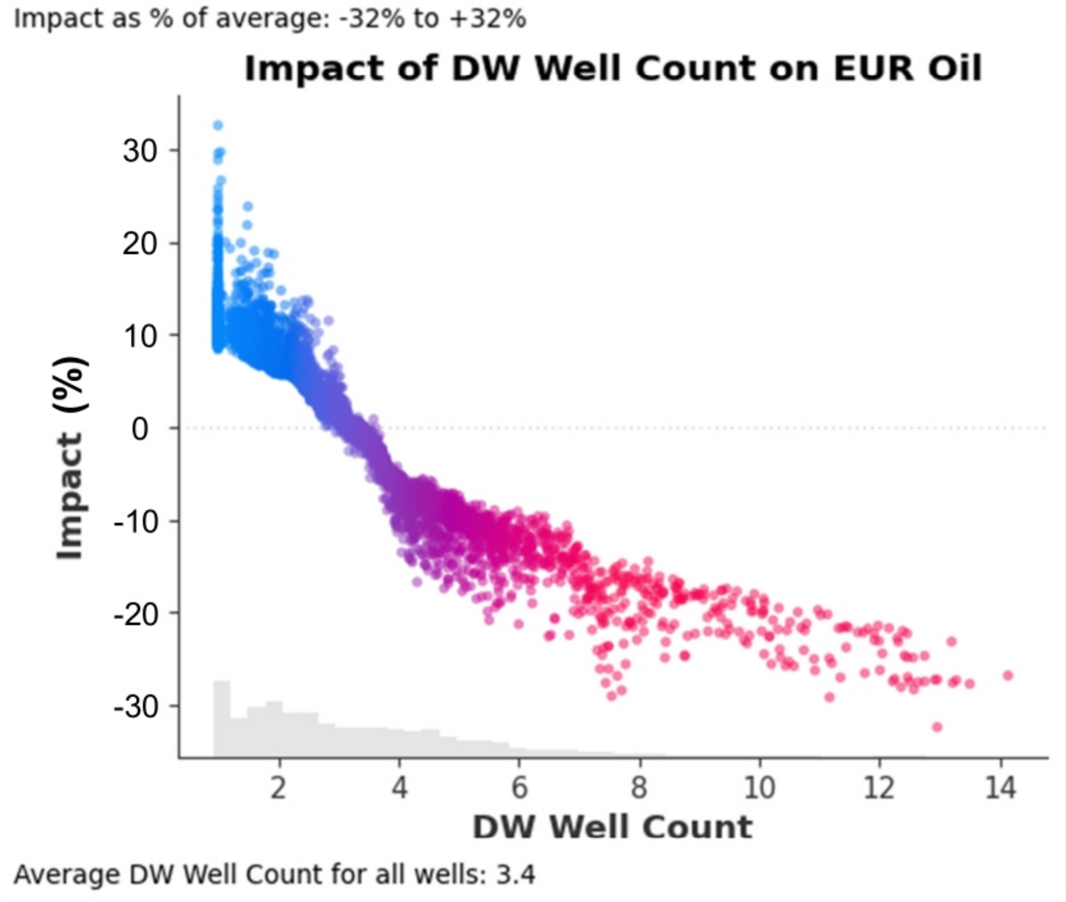
Clear trend for DW well count & XDA effects on gas EUR within the Montney

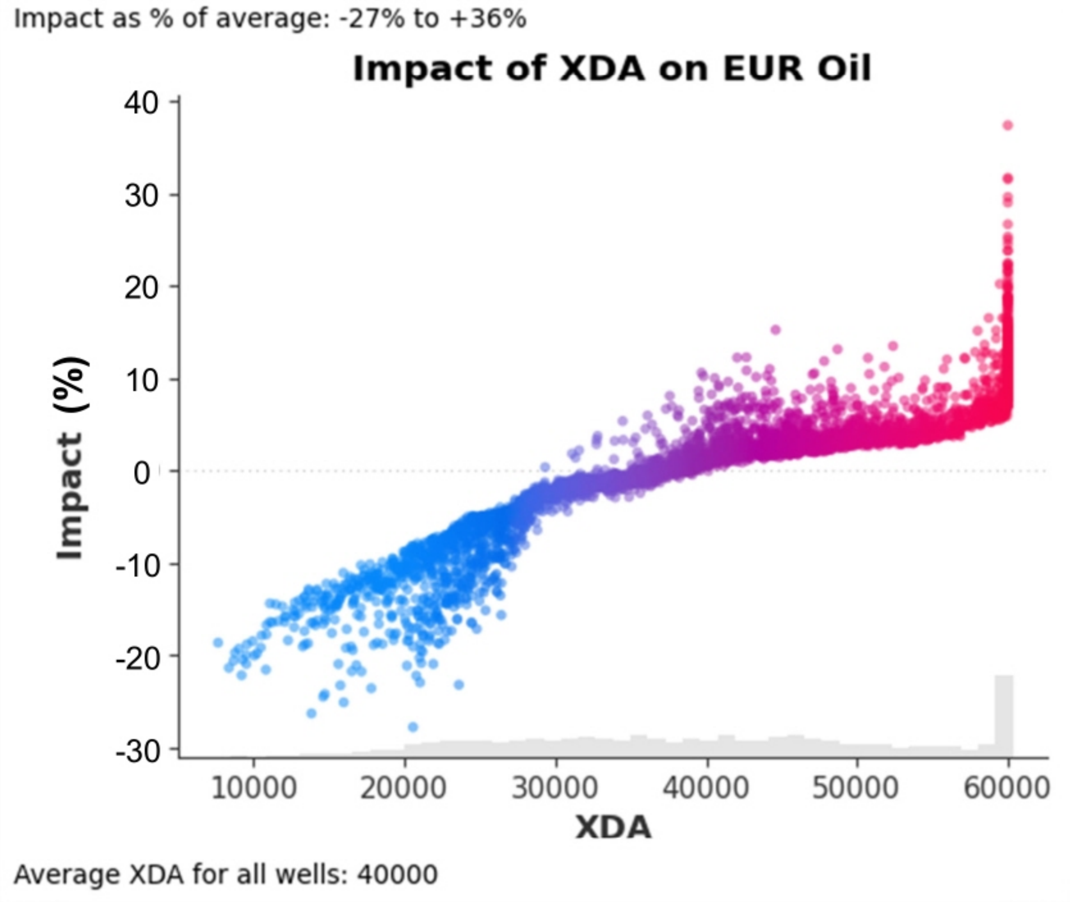




The impact of DW well count and XDA are additive

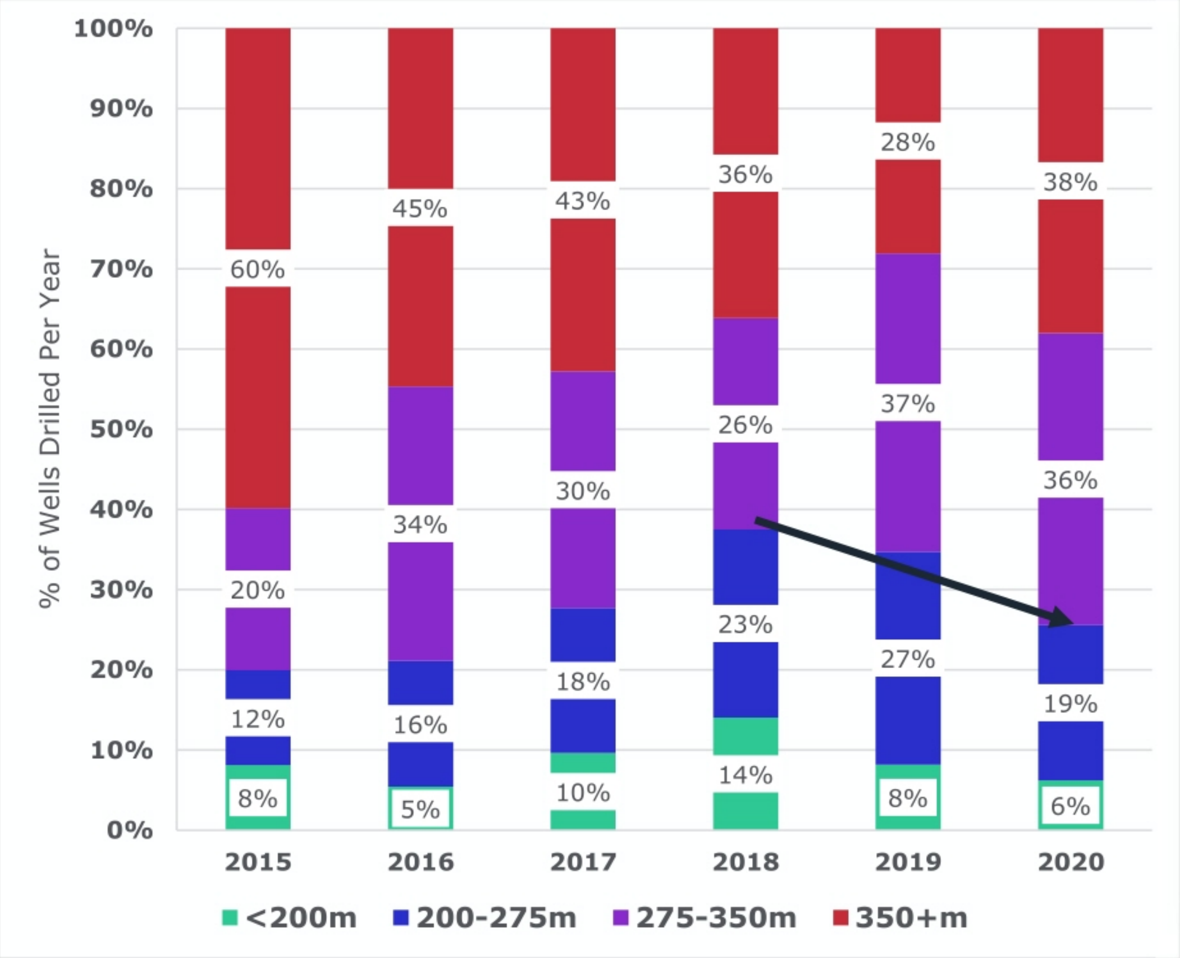
Similar density trends on oil EUR as gas EUR in Montney

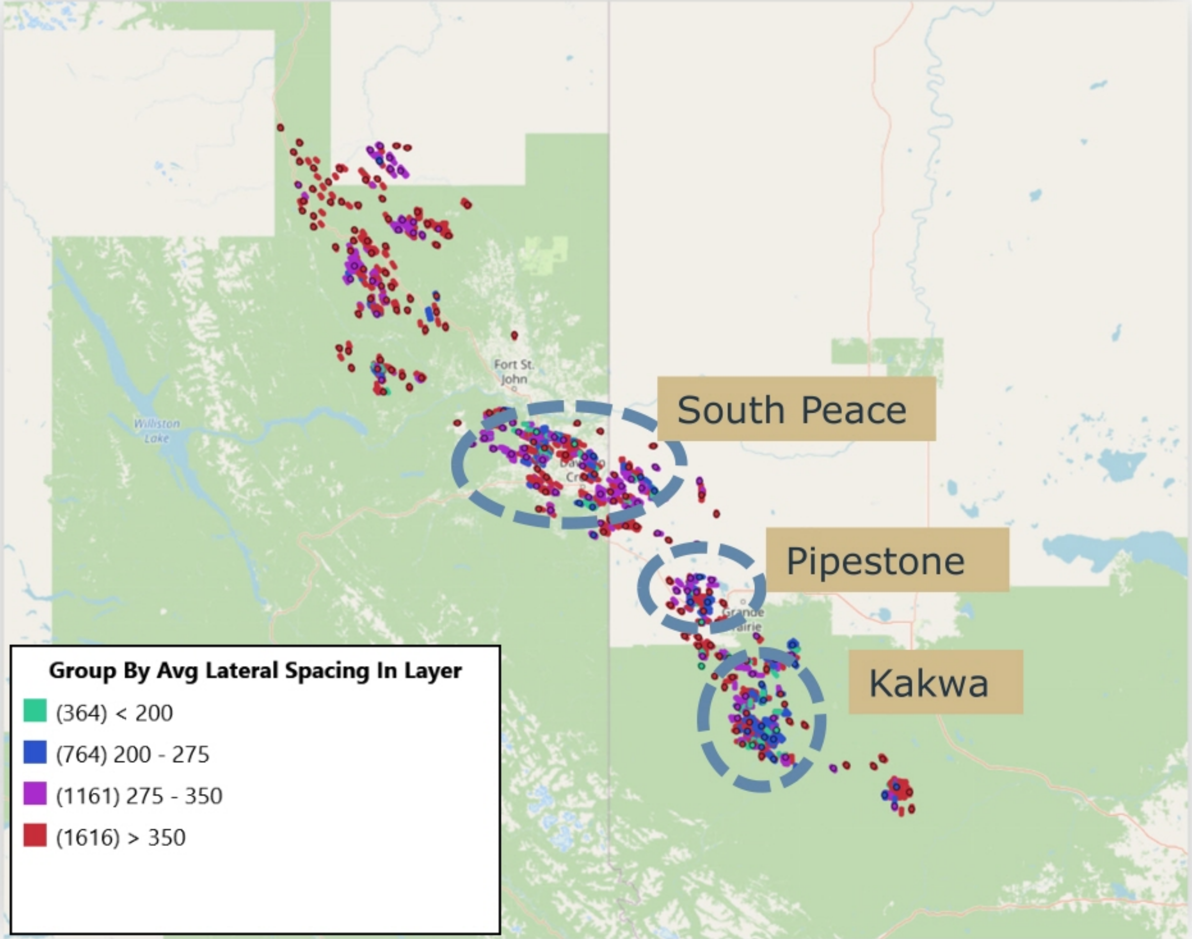




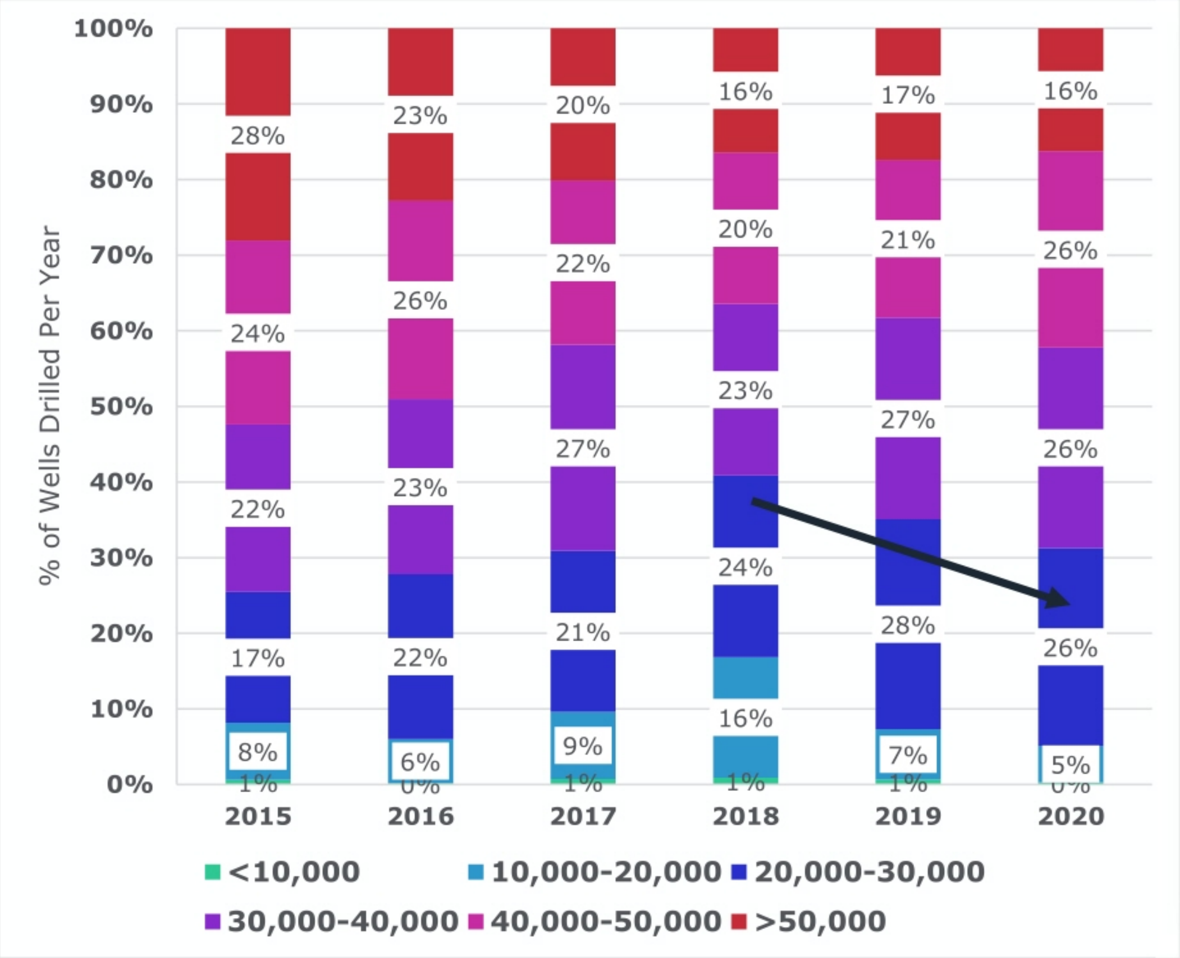
The impact of DW well count and XDA are additive

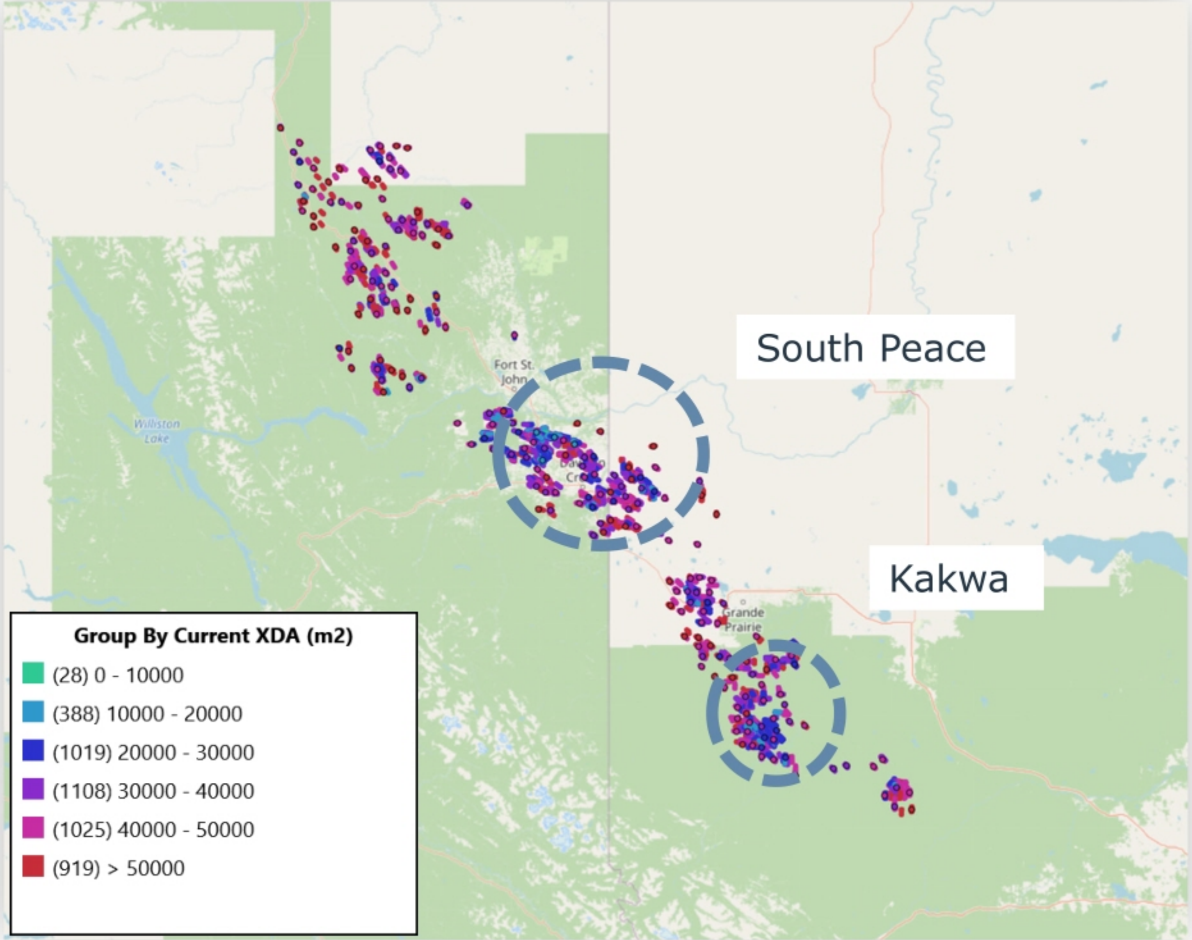
Tighter well spacing peaked in 2018 and has gradually widened in recent years





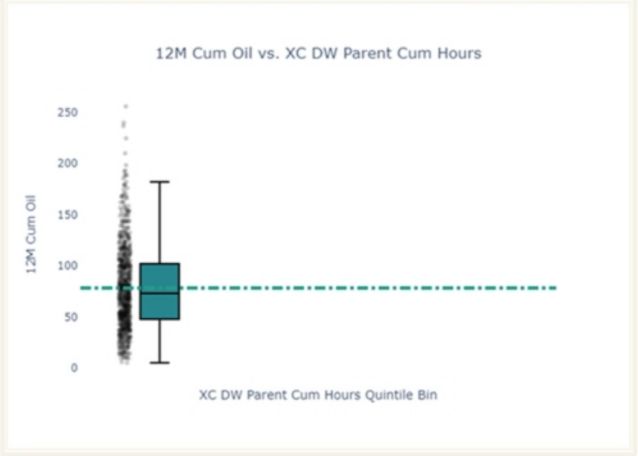
Average density peaked in 2018 and has decreased in years since





Parent-child effects are usually negative and can be material

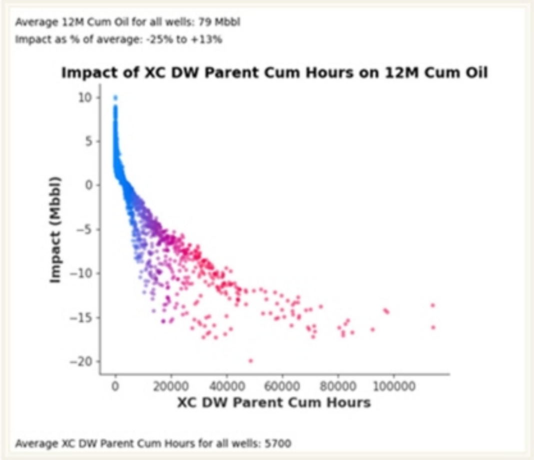
Cross-Sectional Distance-Weighted Cum Hours



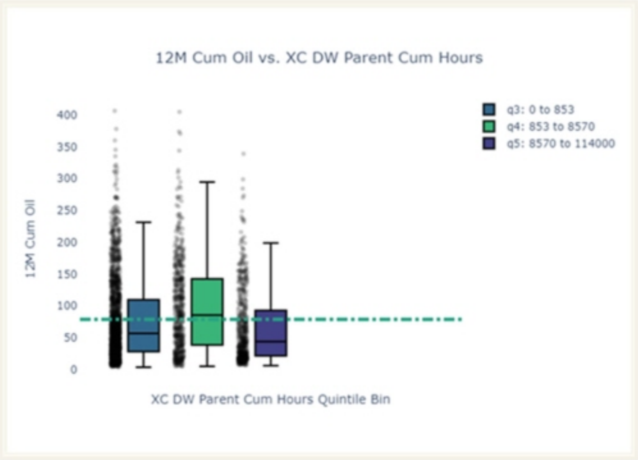
Montney

Raw Data

ML Model



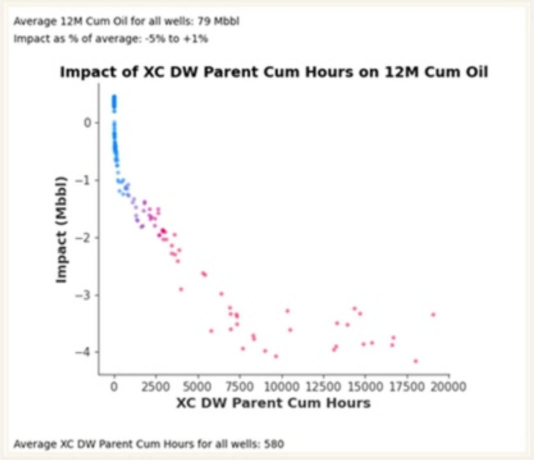
Few notable parent-child examples exist in the Duvernay



Duvernay

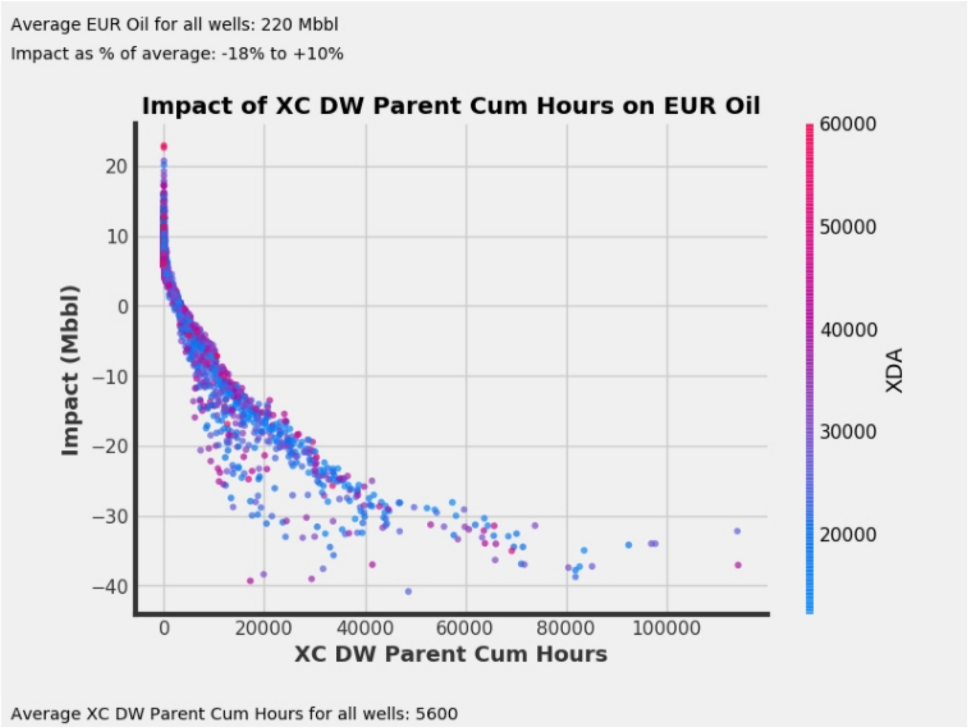
Raw Data

ML Model

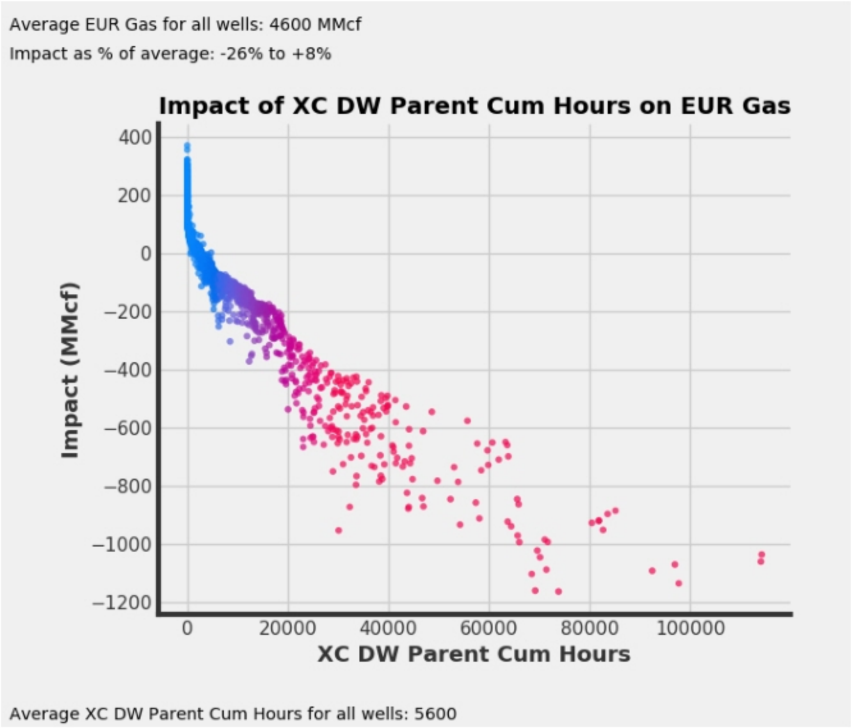


The more hours a parent has produced at a closer distance to a child, the more detrimental the effect

Condensate/Oil



Gas



When considering parent-child effects a distance weighted metric can be used. The more hours a parent well has produced at a closer distance to the child, the more detrimental the parent-child effect will be.

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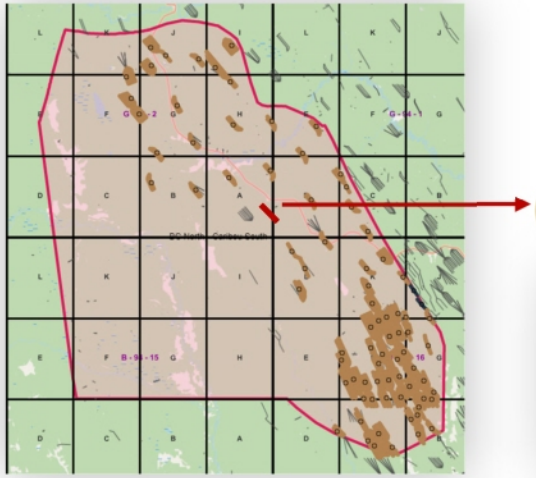
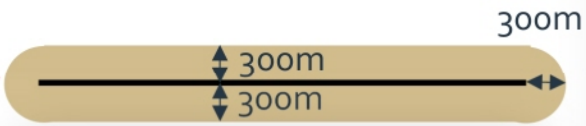
Inventory Rationalization

Inventory calculated assuming a well length of 3,000m, and well spacing of 400m

Assumptions

- Well length: 3,000m
- Well spacing: 400m for lean, 300m for rich
- Proppant intensity: 1.5 t/m (DG), 2.0 t/m (WG/GC), 2.5 t/m (RGC+)





A buffer of 300m from every well was removed /sterilized account for parent-child risks

For each development area, the total acreage was determined and compared to geological and proximity based cut-offs

The total inventory is estimated based on reasonable well length and drilling density for a given development layer (upper, middle or lower)

Remaining inventory is calculated after removing area from producing wells and the sterilized buffer for parent child considerations

Industry Inventory Rationalization

Given the 5 year sustained lower price environment, operators are increasingly shifting to lower density development either via wider inter-well spacing, reduced bench development or both

- Operators who have historically drilled at very high density have recently moved towards removal of development benches and wider spacing
- The move to less "cube" style development today and returning later will result in more significant parent-child interactions in the future
  - Lower EURs on long-term inventory

Despite a recently improved pricing environment, operators appear more focused on rate of return, profitability index and investor returns

- It is McDaniel's opinion that operators will further rationalize inventory in the coming years as their focus shifts to profitability over BOEs
  - McDaniel is currently providing guidance to operators who are considering inventory reductions in order to improve economic viability of their asset

It is McDaniel's opinion that a sustained high price environment coupled with more aggressive investor sentiment will be required in order to "bring back" stranded benches

- Certain stranded benches may not be feasible in the future due to parent depletion

Bench development stacks, total of 82 layers

Area	Development Layer	# of Wells Stacked
Altares	Upper	1
Altares	Middle	1
Altares	Lower	1
Altares West	Upper	1
Altares West	Middle	1
Altares West	Lower	2
Bubbles	Upper	1
Bubbles	Middle	1
Bubbles	Lower	1
Buick Creek	Upper	0
Buick Creek	Middle	0
Buick Creek	Lower	0
Caribou South	Upper	1
Caribou South	Middle	1
Caribou South	Lower	1
Caribou West	Upper	1
Caribou West	Middle	1
Caribou West	Lower	1
Farrell Creek (E)	Upper	1
Farrell Creek (E)	Middle	1
Farrell Creek (E)	Lower	1
Farrell Creek (W)	Upper	1
Farrell Creek (W)	Middle	1
Farrell Creek (W)	Lower	1
Graham	Upper	1
Graham	Middle	0
Graham	Lower	1
Gundy-Blueberry Lean	Upper	1
Gundy-Blueberry Lean	Middle	2
Gundy-Blueberry Lean	Lower	1

Area	Development Layer	# of Wells Stacked
Gundy-Blueberry Rich	Upper	1
Gundy-Blueberry Rich	Middle	2
Gundy-Blueberry Rich	Lower	1
Inga Lean	Upper	1
Inga Lean	Middle	1
Inga Lean	Lower	1
Inga Rich	Upper	1
Inga Rich	Middle	1
Inga Rich	Lower	1
Inga South	Upper	1
Inga South	Middle	1
Inga South	Lower	1
Jedney	Upper	1
Jedney	Middle	1
Jedney	Lower	1
Laprise Creek	Upper	0
Laprise Creek	Middle	1
Laprise Creek	Lower	1
Nig Creek	Upper	1
Nig Creek	Middle	0
Nig Creek	Lower	0
Paradise	Upper	0
Paradise	Middle	0
Paradise	Lower	0
Town	Upper	1
Town	Middle	1
Town	Lower	1
Umbach	Upper	1
Umbach	Middle	0
Umbach	Lower	0

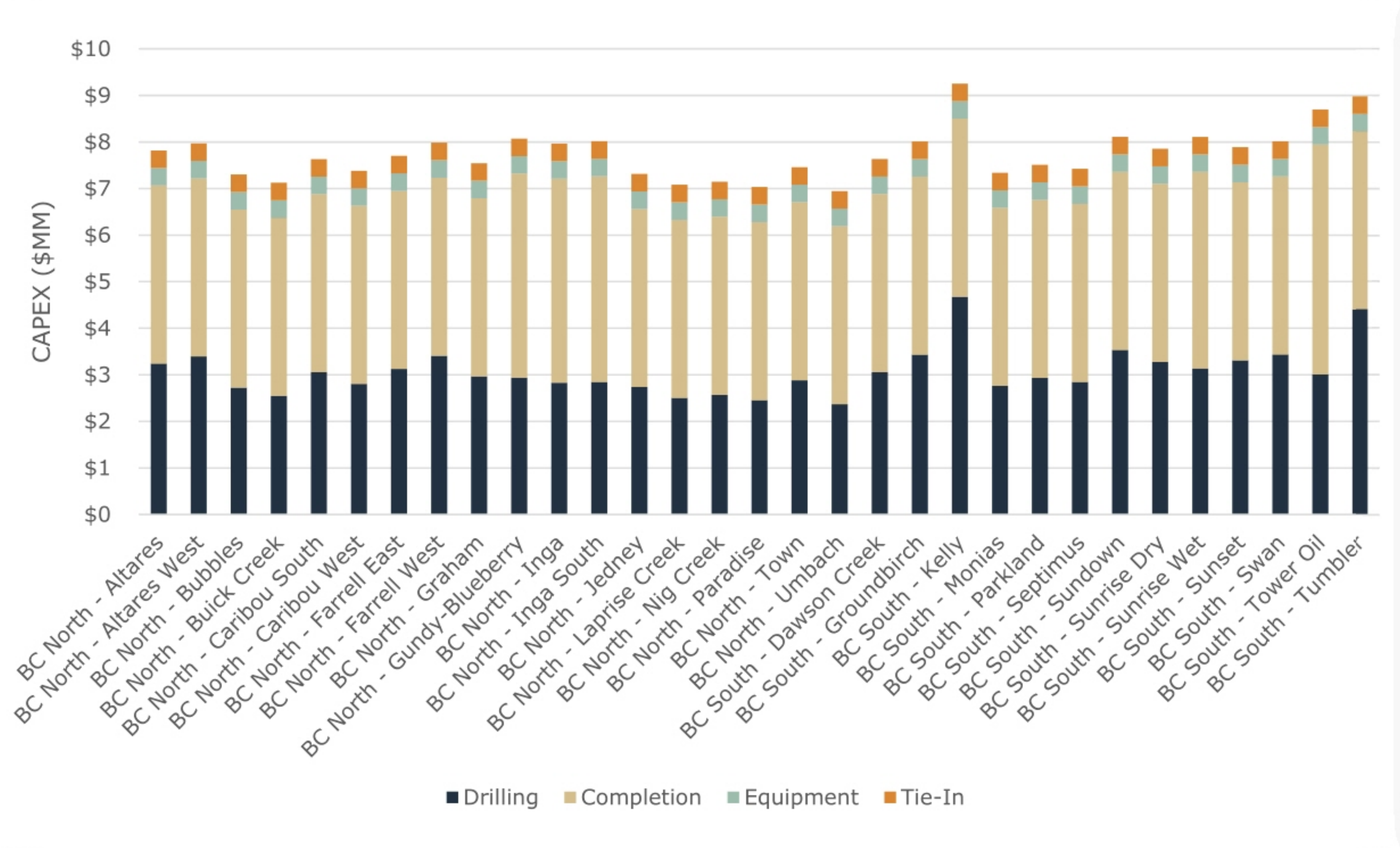
Area	Development Layer	# of Wells Stacked
Dawson Creek	Upper	1
Dawson Creek	Middle	0
Dawson Creek	Lower	1
Groundbirch	Upper	2
Groundbirch	Middle	0
Groundbirch	Lower	0
Kelly	Upper	0
Kelly	Middle	0
Kelly	Lower	0
Monais	Upper	2
Monais	Middle	0
Monais	Lower	0
Parkland	Upper	1
Parkland	Middle	0
Parkland	Lower	1
Septimus	Upper	2
Septimus	Middle	0
Septimus	Lower	0
Sundown	Upper	2
Sundown	Middle	1
Sundown	Lower	1
Sunrise Dry	Upper	2
Sunrise Dry	Middle	0
Sunrise Dry	Lower	1
Sunrise Wet	Upper	1
Sunrise Wet	Middle	1
Sunrise Wet	Lower	1
Sunset	Upper	2
Sunset	Middle	0
Sunset	Lower	1
Swan	Upper	2
Swan	Middle	0
Swan	Lower	1
Tower	Upper	1
Tower	Middle	1
Tower	Lower	1
Tumbler	Upper	0
Tumbler	Middle	0
Tumbler	Lower	0

25-30% of total potential benches not being currently developed

- *McD has still given benefit of the doubt to strong underdeveloped reservoir*
- ***Actual development by operators likely to vary in certain areas due to sub-regional reservoir trends and operator intent***

Economic Inputs

Capital cost model uses proppant intensity, TVD, #wells in pad, and stage spacing as variables



- Average $/tonne = ~$825
- Average $/Hz meter = ~$1000

Constants

- Horizontal Length = 3000m
- Equipment Cost = $375,000
- Tie-in Cost = $375,000

Variables

- Proppant Intensity
- TVD
- # Wells in Pad
- Equipment Cost
- Tie-In Cost
- CAPEX = Drilling cost + Completion cost + Equipment cost + Tie-in cost

OPEX and product yield assumptions by CGR band

Input	Unit	DG	WG/GC	RGC1+
Gas Shrinkage	%	3	7	15
C2 Ratio	bbl/mmcf	0	0	0
C3 Ratio	bbl/mmcf	3	15	25
C4 Ratio	bbl/mmcf	3	15	25
C5+ Ratio	bbl/mmcf	3	8	10
Heating Value	Btu/cf	1075	1100	1175
Variable Gas	$/mcf	0.35	1.25	2.5
Variable Condensate/Oil	$/bbl	3.5	3.5	3.5
Fixed Cost	$/WM	3000	9000	12000
Approximate Total OPEX	$/BOE	3	6	9

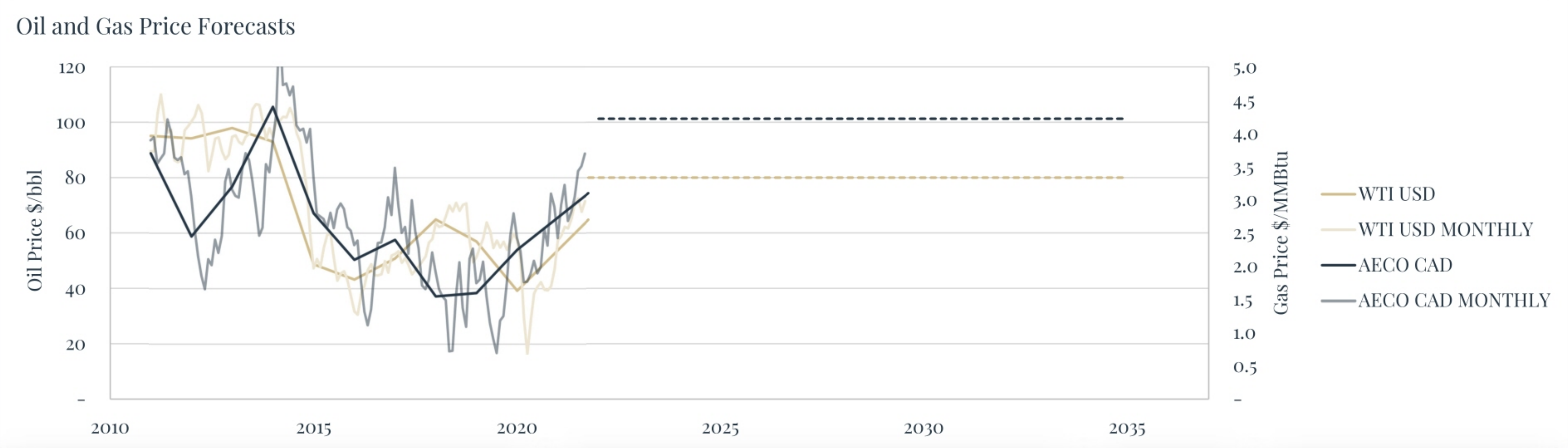
Generalized opex used for comparative purposes

Model is based on observed historical and forward-looking expectations for operating costs in the Montney

Public OPEX data collected from operators in the region

Inputs were varied based on CGR band to best represent OPEX for each area given liquids processing costs

Flat Price Deck: $80WTI & $4.22AECO (~Current)



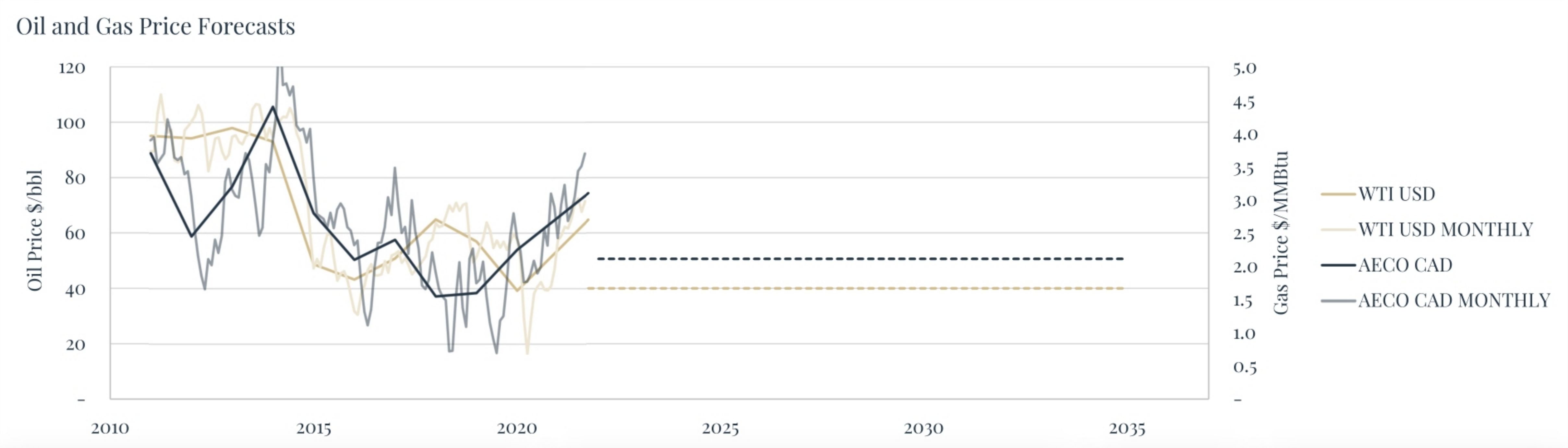
Flat
80 $US/bbl
WTI

Flat
4.22 $C/MMBtu
AECO

No Inflation

Pricing scenario in current environment (October 20, 2021)

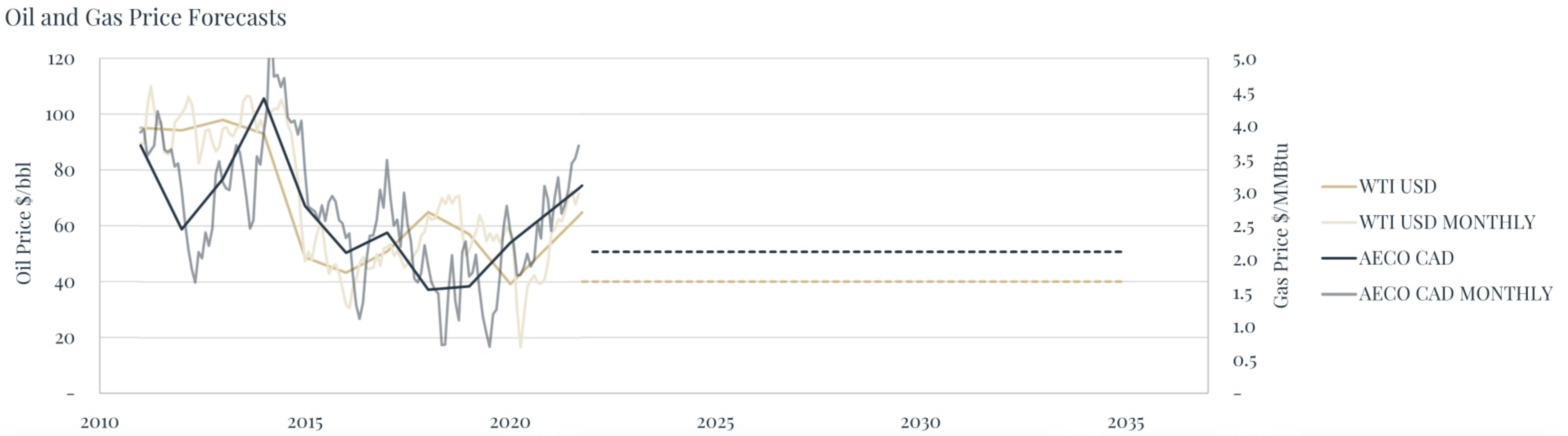
Flat Price Deck: $40WTI & $2.11AECO - Low



Flat	Flat		
40 $US/bbl	2.11 $C/MMBtu	No Inflation	Low pricing scenario
WTI	**AECO**		

PRICING SUMMARY

Flat Price Deck: $50WTI & $2.64AECO - Medium



Flat

50 $US/bbl

WTI

Flat

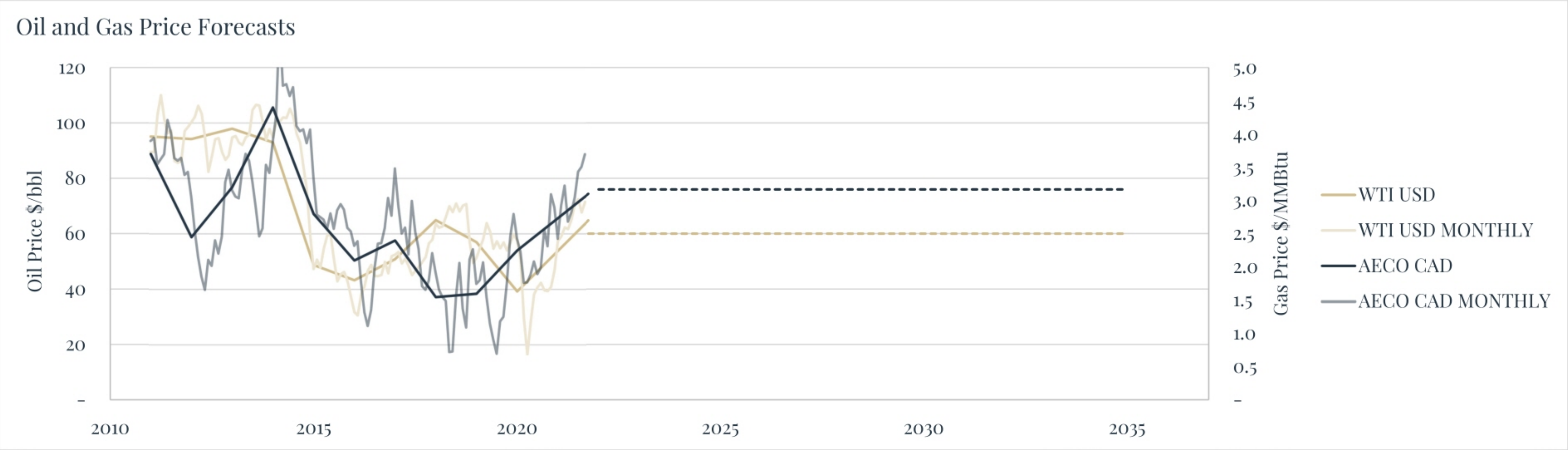
2.64 $C/MMBtu

AECO

No Inflation

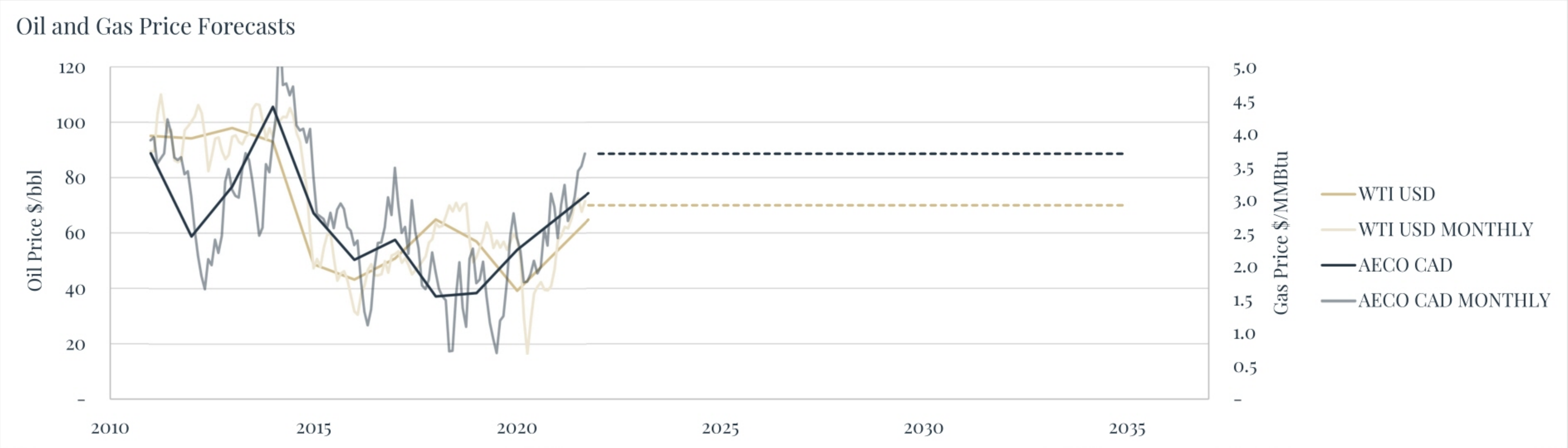
Medium pricing scenario

Flat Price Deck: 60WTI & 3.17 AECO – Medium High



Flat 60 $US/bbl **WTI**	Flat 3.17 $C/MMBtu **AECO**	No Inflation	Medium High pricing scenario

Flat Price Deck: $70WTI & $3.69 AECO – High



Flat

70 $US/bbl

WTI

Flat

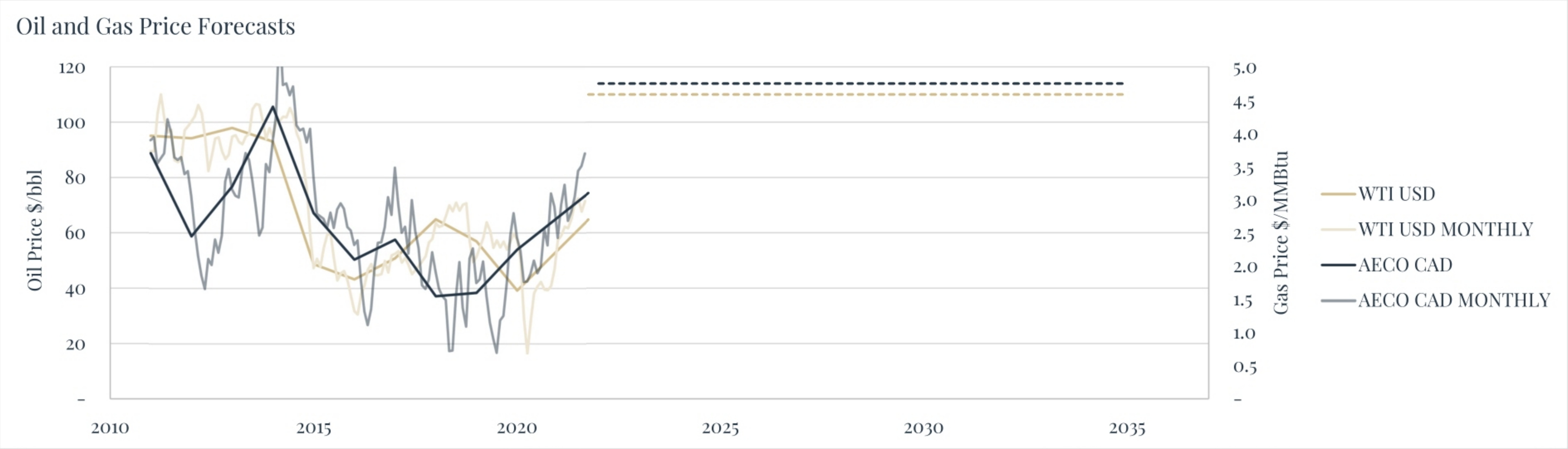
3.69 $C/MMBtu

AECO

No Inflation

High pricing scenario

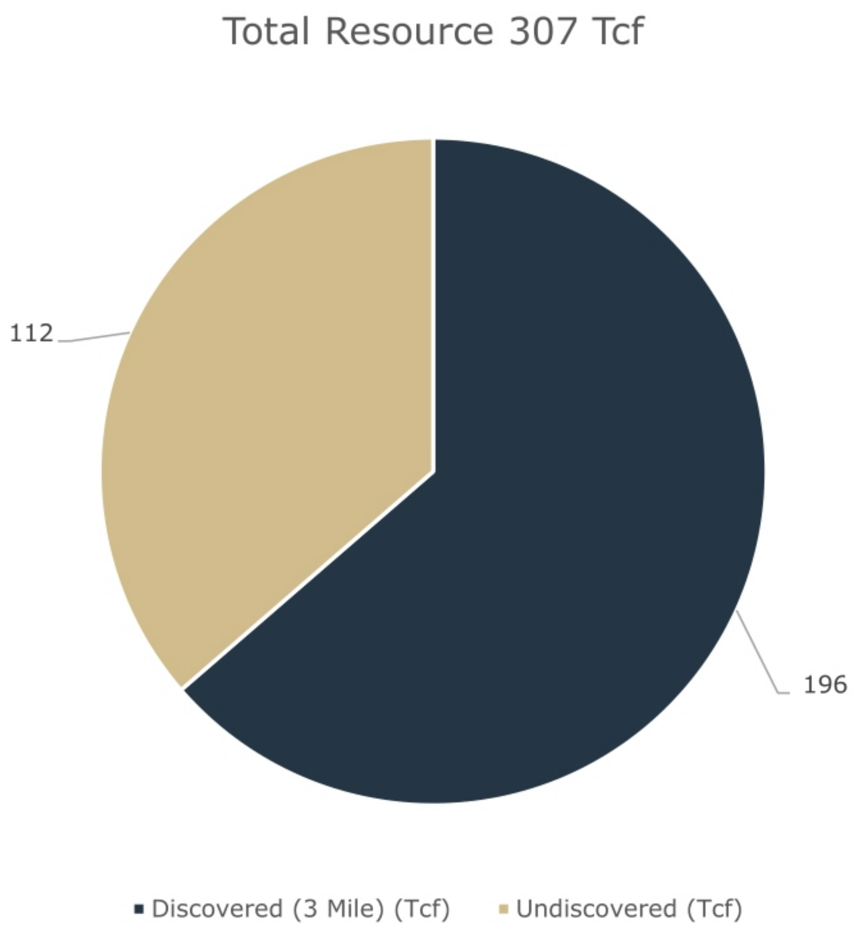
Flat Price Deck: $110WTI & $4.75 AECO – Stretch

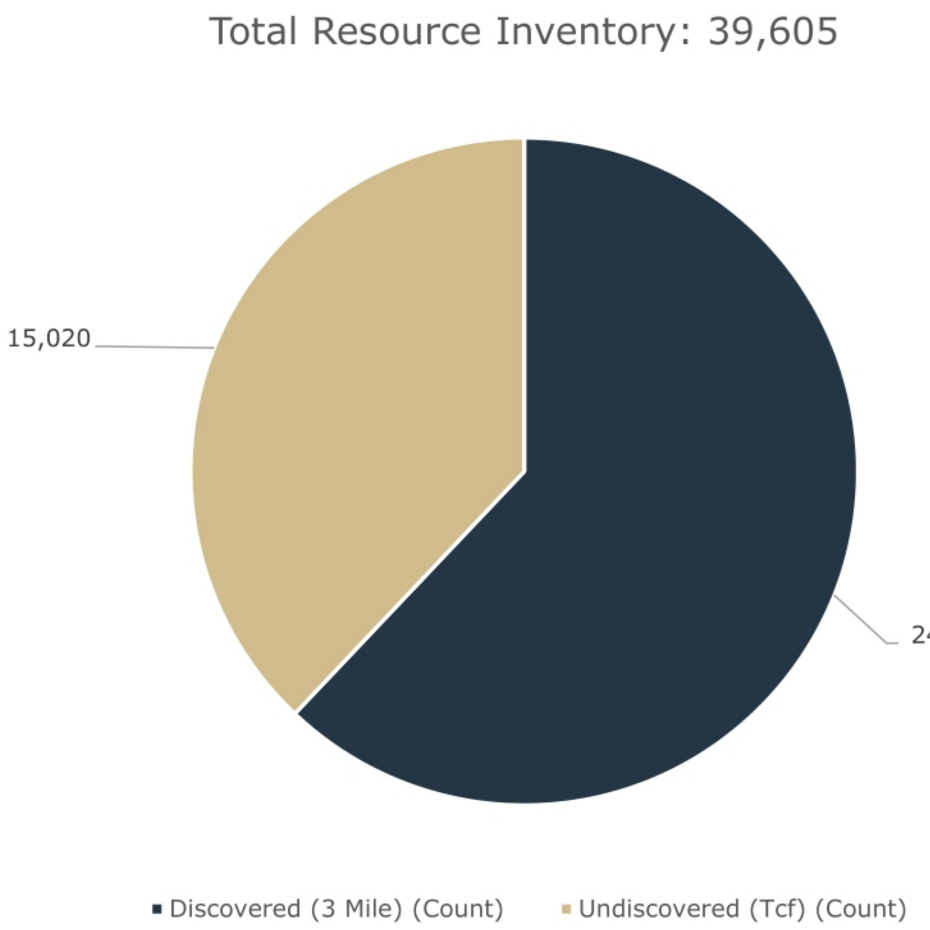


Flat 110 $US/bbl **WTI**	Flat 4.75 $C/MMBtu **AECO**	No Inflation	Stretch pricing scenario

Resource Summary

Approximately 2/3 of resource is 'discovered'

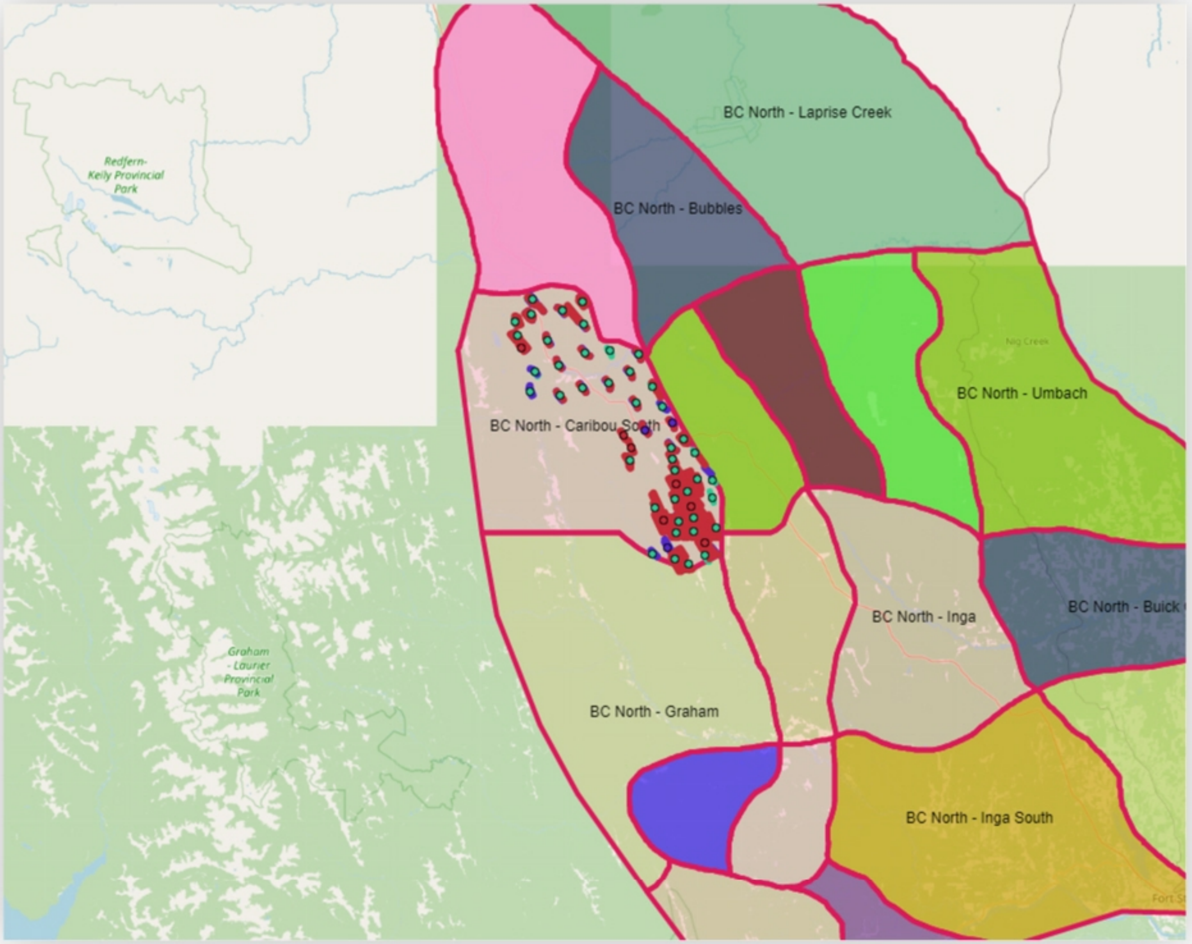




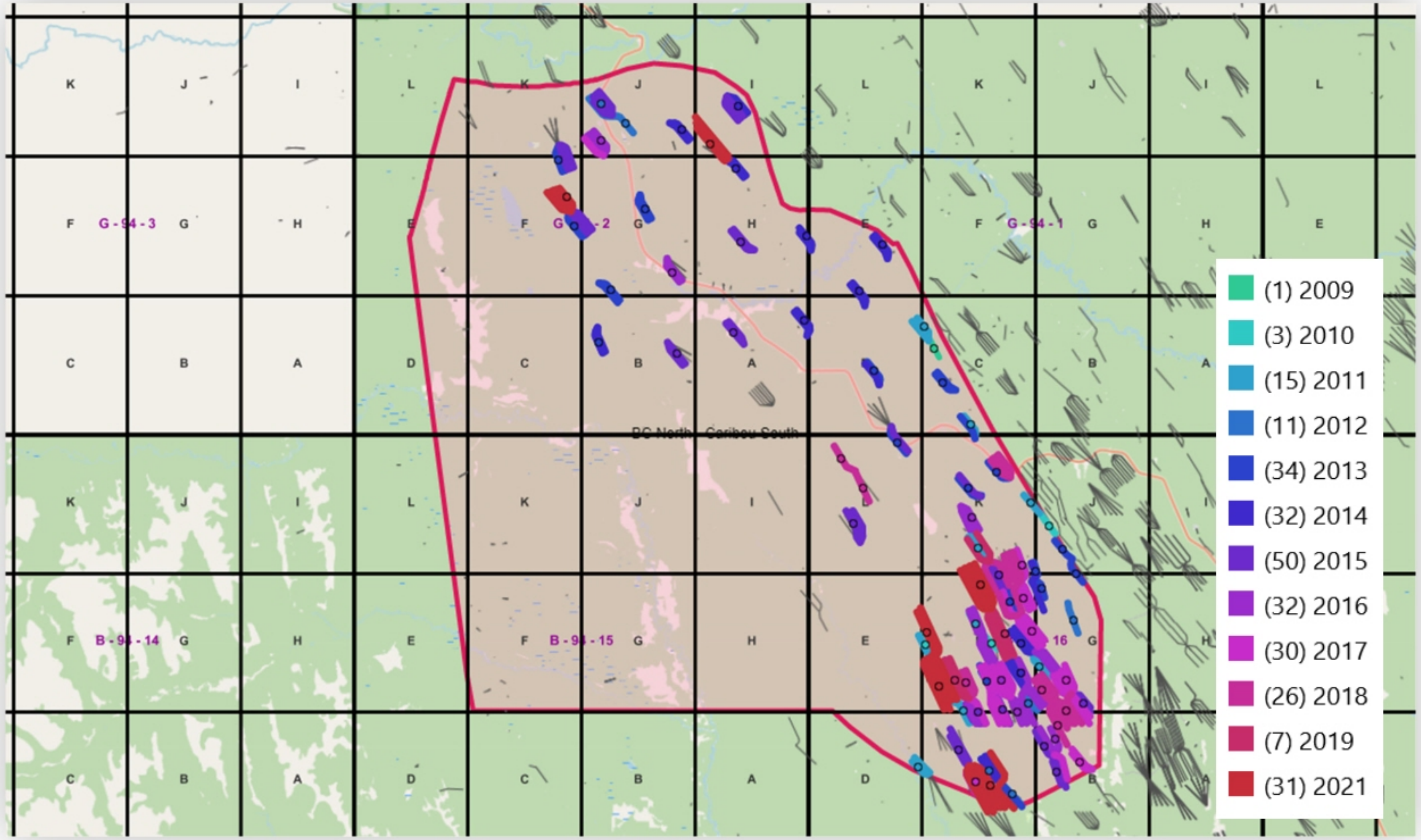
Methodology – Caribou South Example

McDaniel methodology for area type curve assignment presented for Caribou South

- The following process outlined was followed for all the study areas in North and South Peace
- An overall methodology review is presented for Caribou South, this will go through the process and key points such as:
  - Area/bench performance
  - Operator development strategies
  - CGR/fluid maturity
  - Proppant intensity
  - Type curve creation

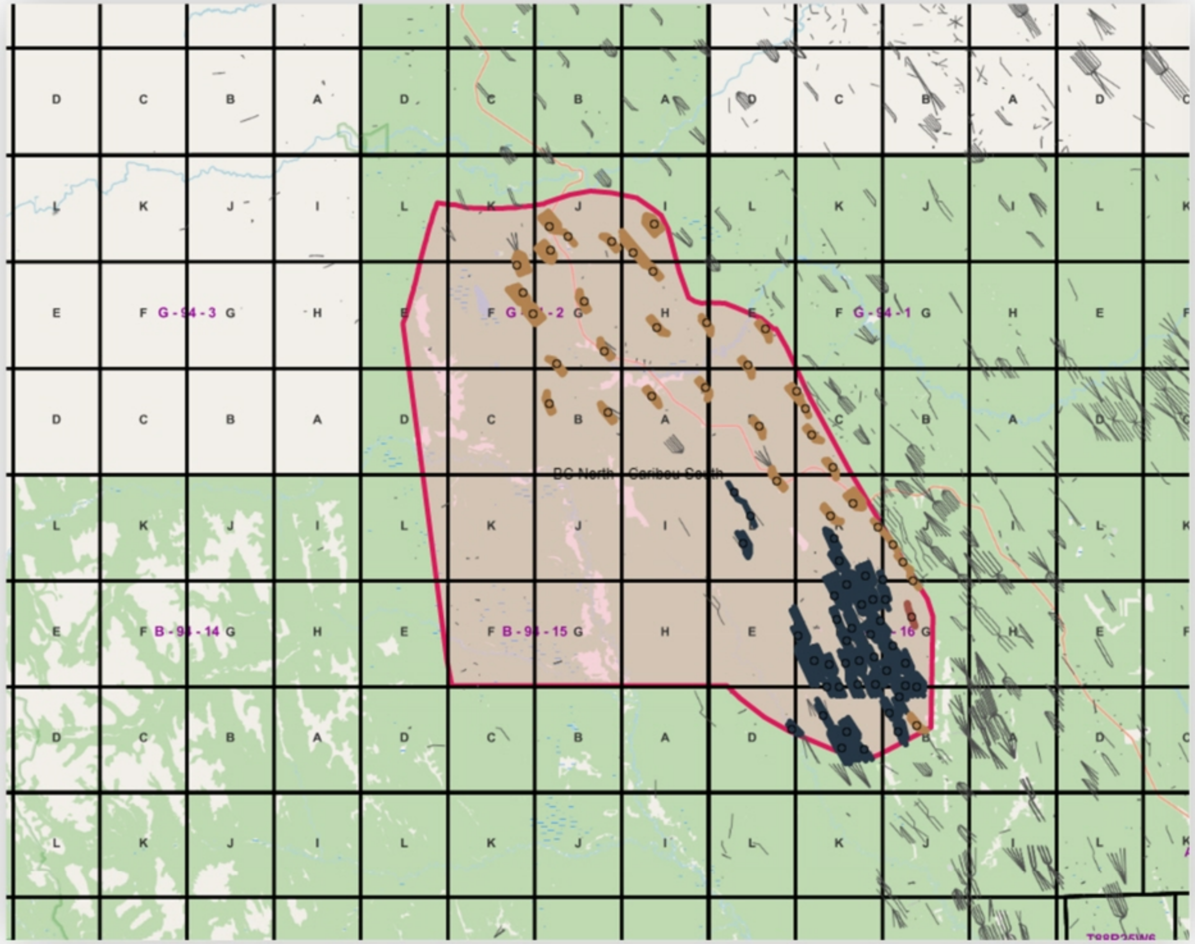


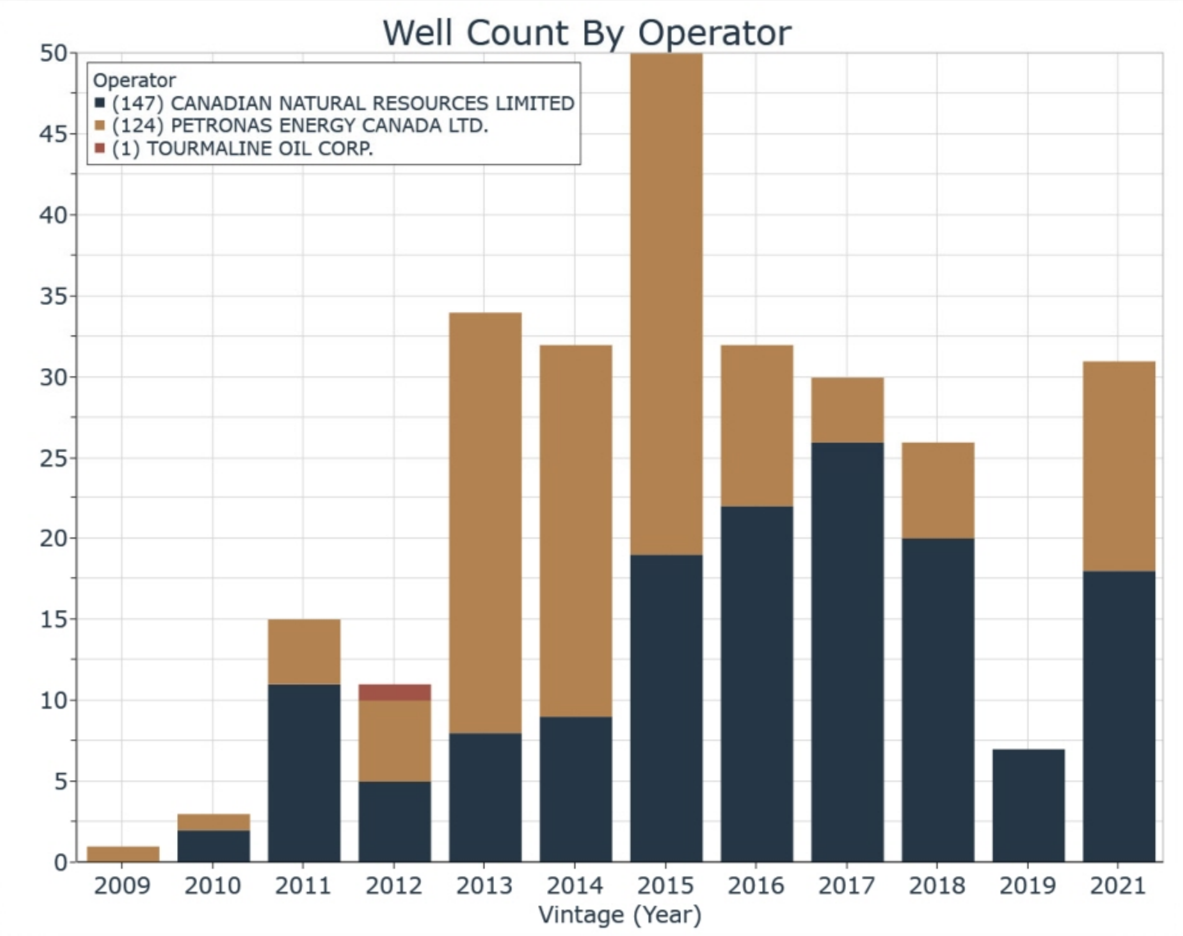
There are ~270 wells within Caribou South as of September 2021



- Both CNRL and Petronas have drilled new wells within 2021
- Caribou South was first drilled in 2009 by Petronas, who have since continued to develop the area
- 2015 had the greatest number of new wells at 50 within the Caribou South

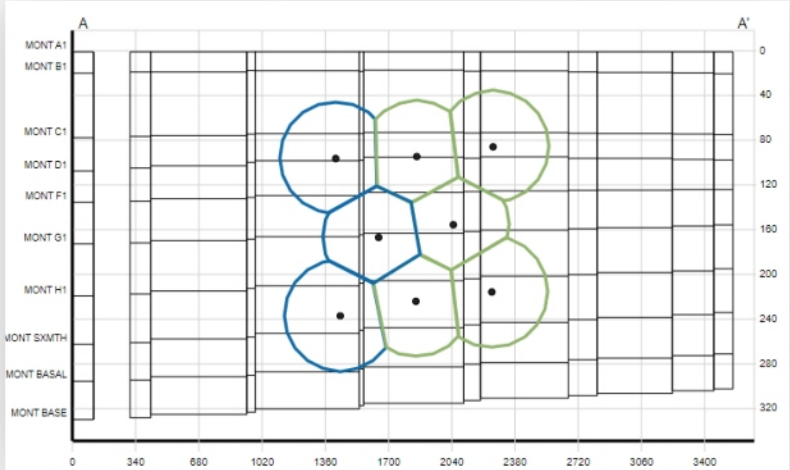
CNRL development in South, while Petronas covers the North

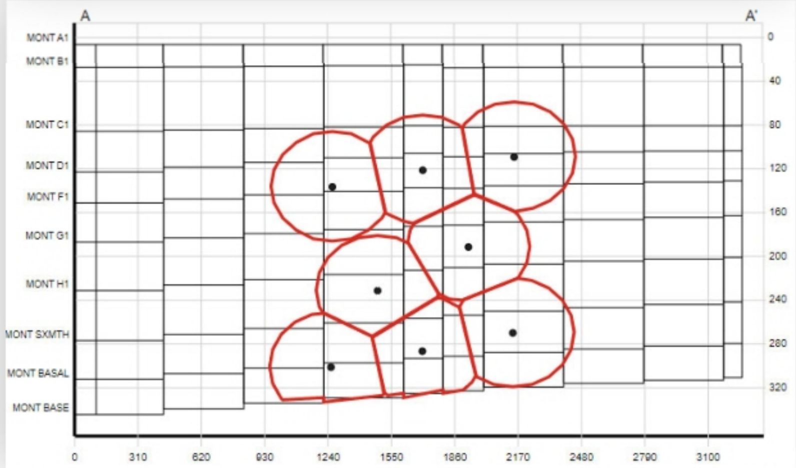




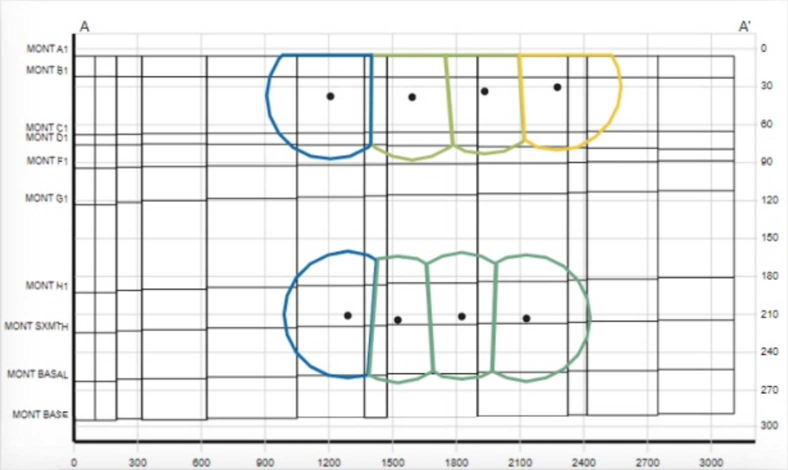
Varying operator development strategies throughout

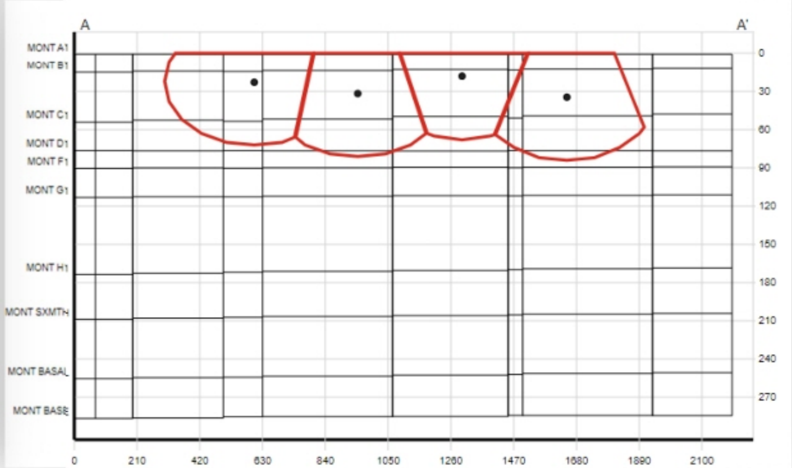
Petronas (top – 2015, bottom – 2021)





CNRL (top – 2015, bottom – 2021)

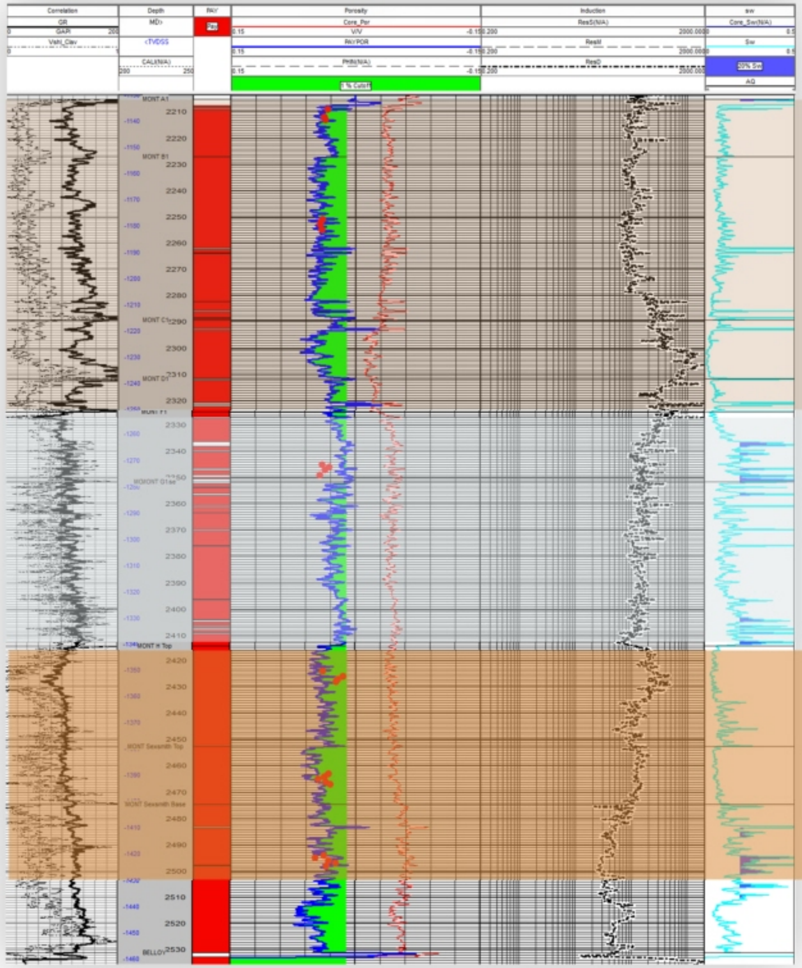




- Petronas in 2015 had highly dense multi-layer stacks drilled within Caribou South
- CNRL had a more restricted approach at the time, drilling double layer stacks in the upper and lower
- In 2021, Petronas continues to drill triple layer stacks targeting all three layers within the Montney
- In contrast, CNRL is following steps with other operators within Montney towards a single layer stack for the best economics and capital savings

Thick stack of continuous resource in Caribou South

Caribou South Type Log (200/A-005-B/094-G-02)



Caribou South Reservoir Parameters

Upper
(MONT A,B,C &D)

Zone	Pay (m)	Porosity (%)	Sw (%)	Z	Depth (TVD)	Gradient	Pressure (kPa)	Temp (C)	BCF/Square Mile
Upper	108.3	3.8	11.5	0.69	2110	11.6	24534	68	98.8

Middle
(MONT F & G)

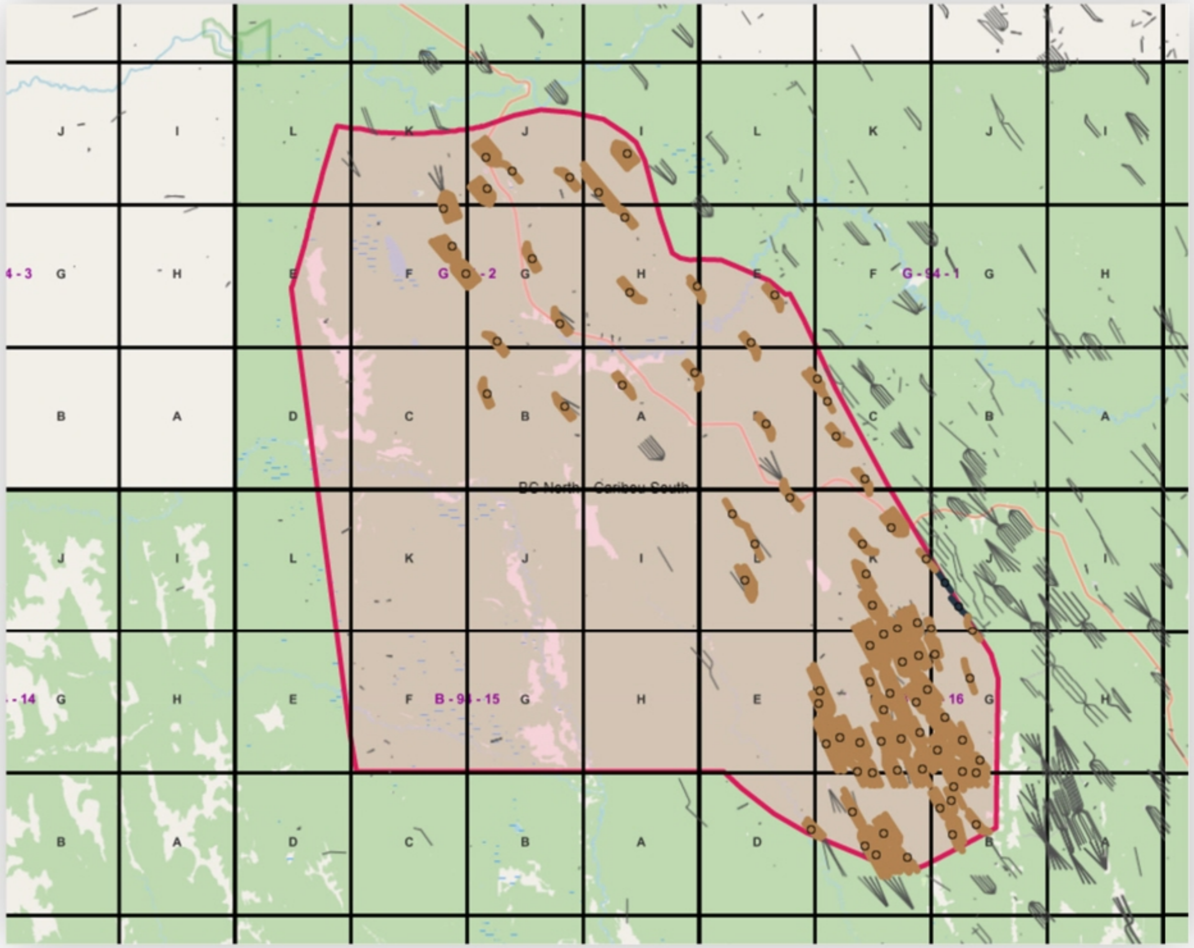
Zone	Pay (m)	Porosity (%)	Sw (%)	Z	Depth (TVD)	Gradient	Pressure (kPa)	Temp (C)	BCF/Square Mile
Middle	77.1	2.8	16.2	0.7	2166	11.6	25176	69	49.8

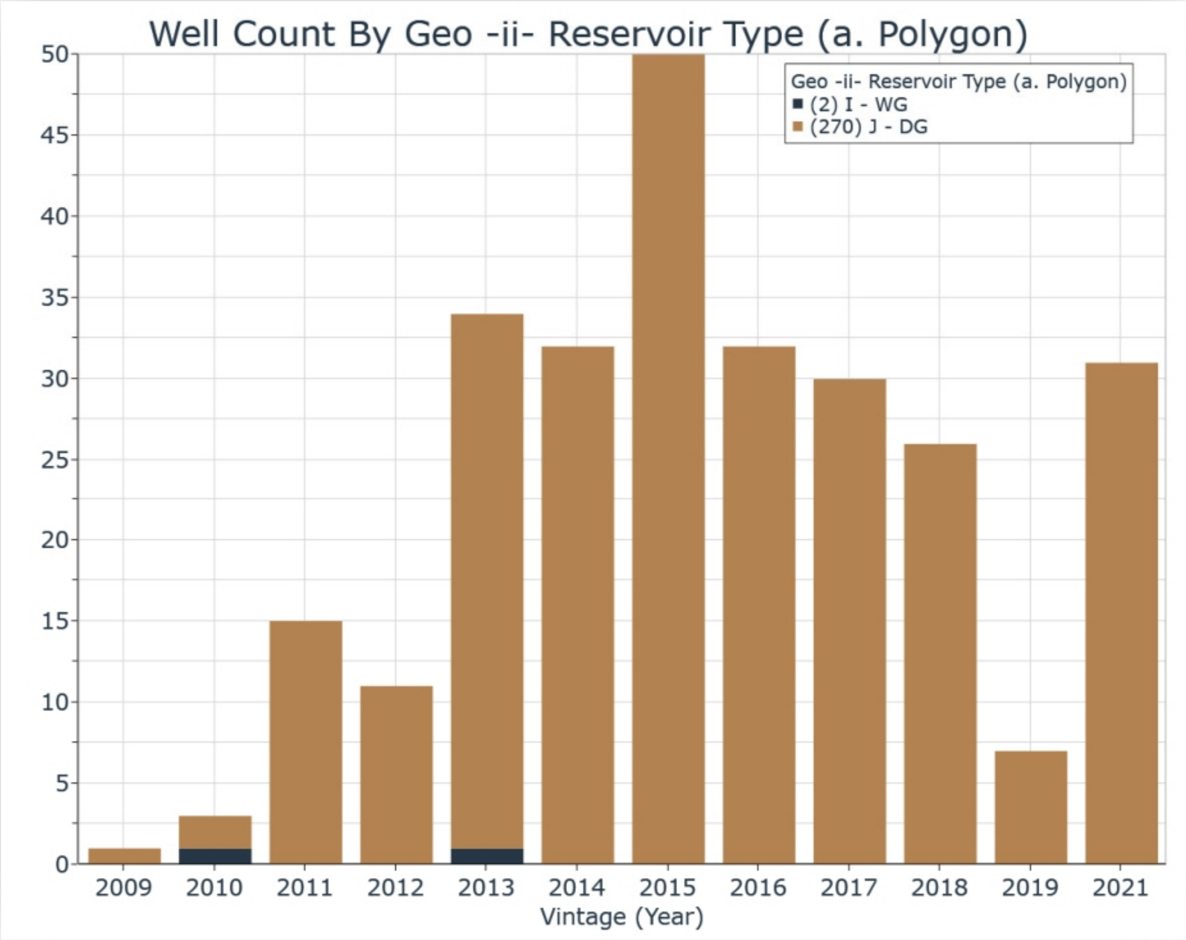
Lower
(MONT H, Basal, Sxmth)

Zone	Pay (m)	Porosity (%)	Sw (%)	Z	Depth (TVD)	Gradient	Pressure (kPa)	Temp (C)	BCF/Square Mile
Lower	63.5	4.3	12.7	0.78	2246	12.5	28112	72	64.2

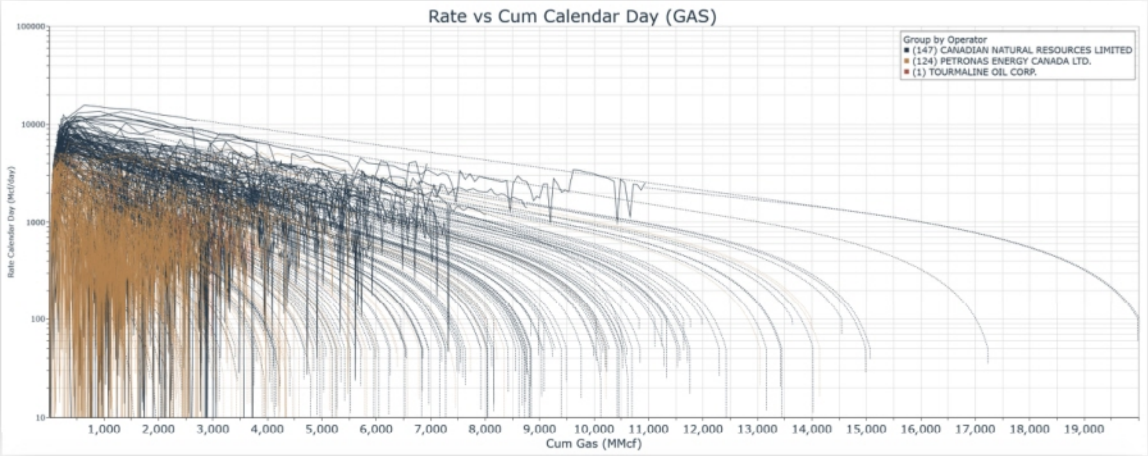
Geological parameters based on McDaniel multi-phase interpretation – SPE -

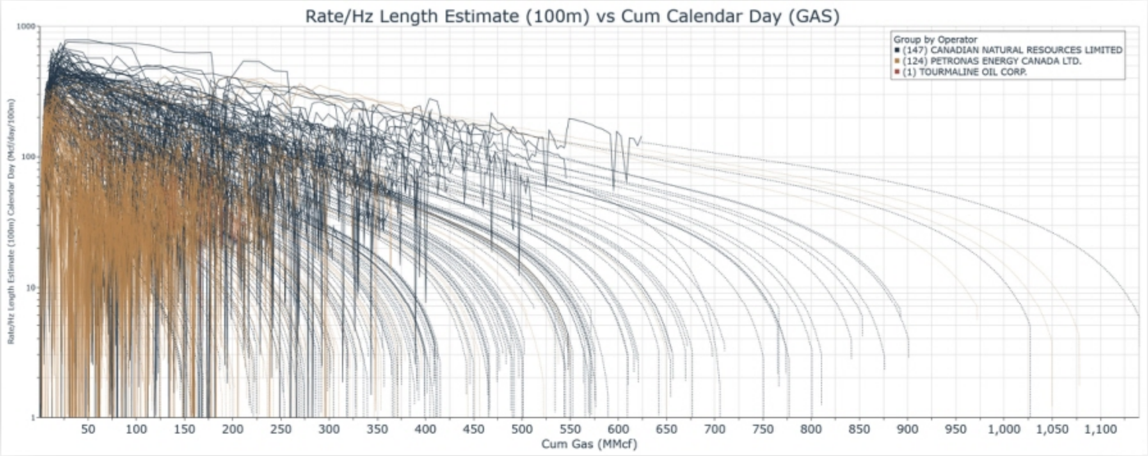
Caribou South is entirely dry gas, except for 2 wet Petronas wells that boarder the boundary with Town

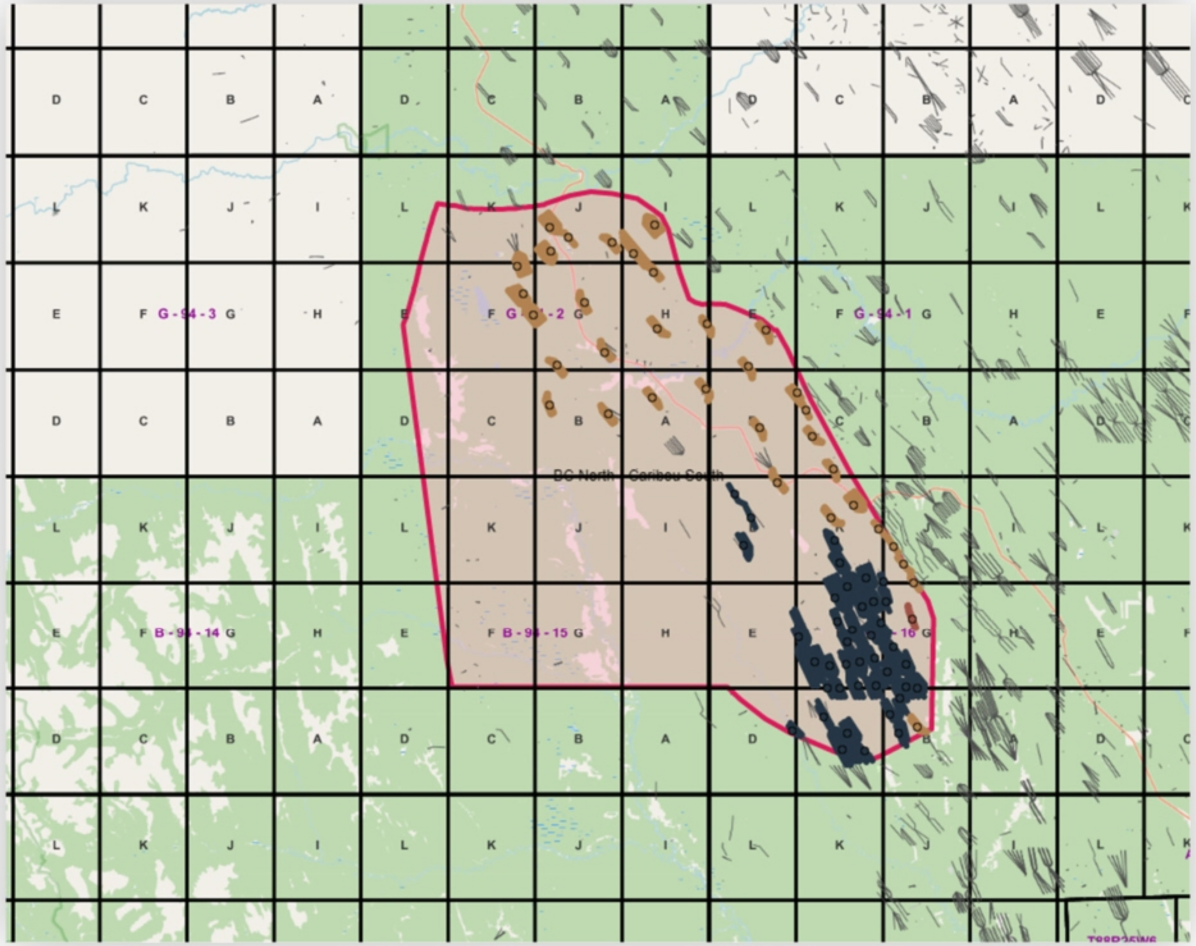




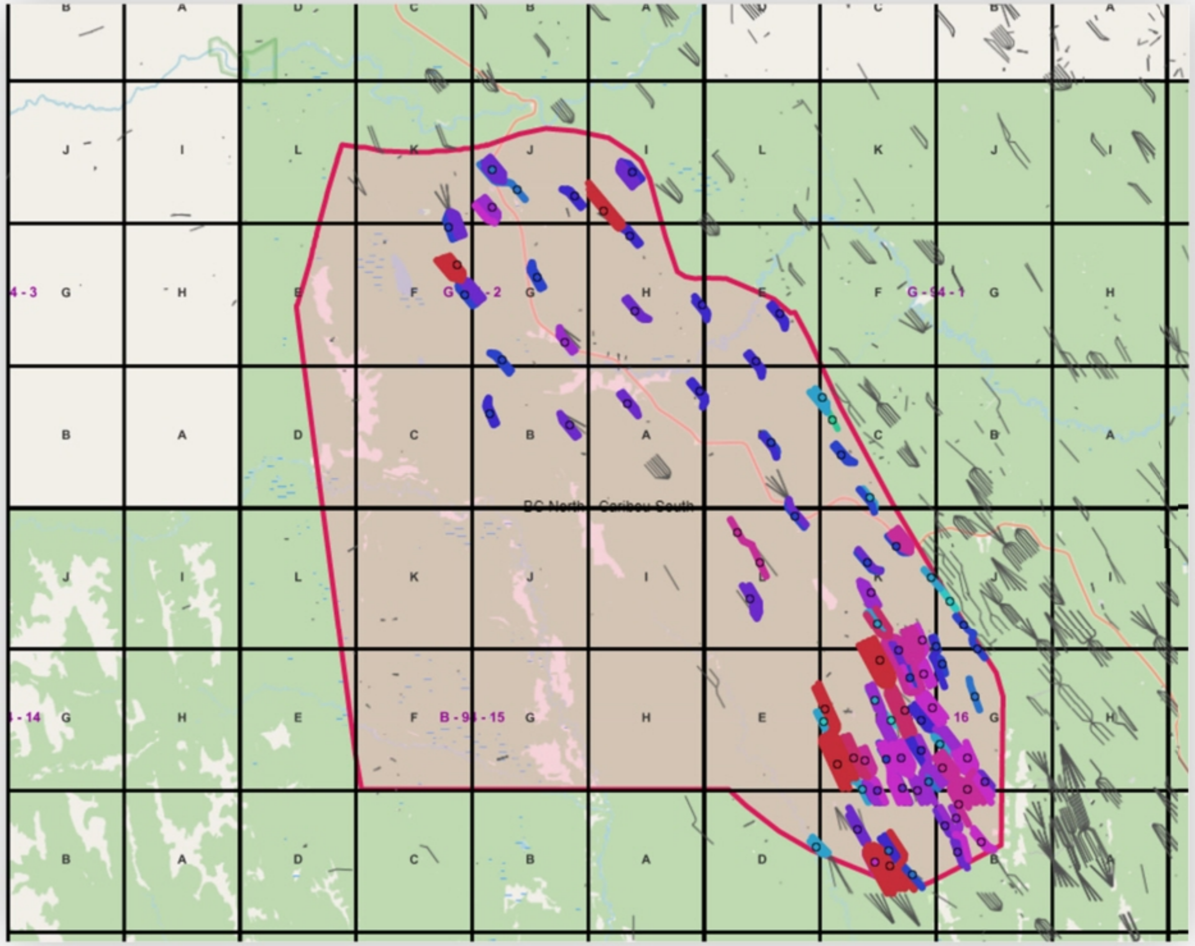
Each individual horizontal well across the area is individually forecast

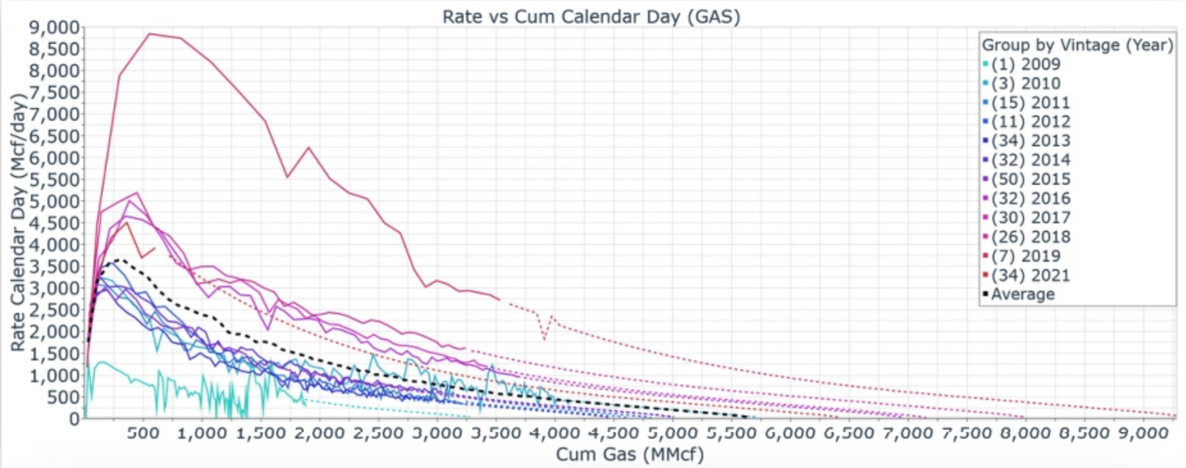


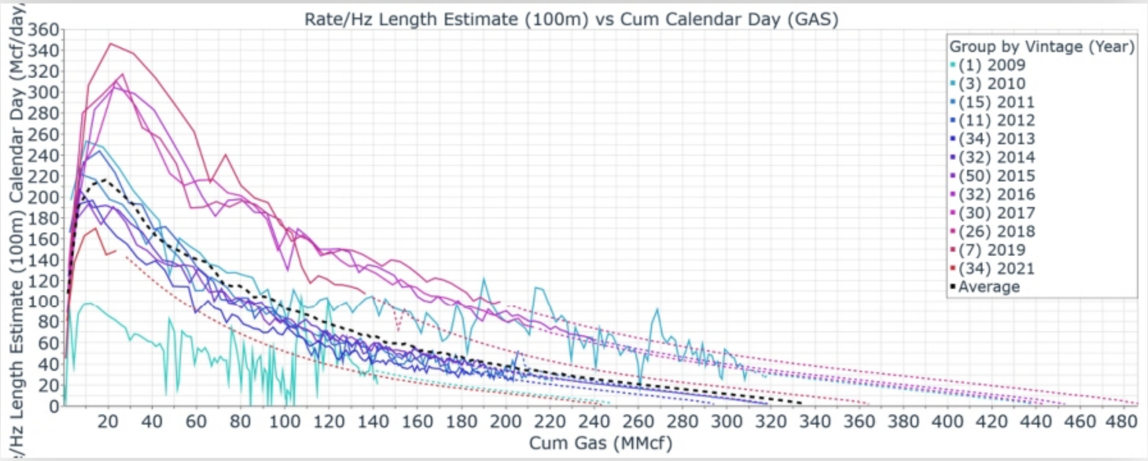




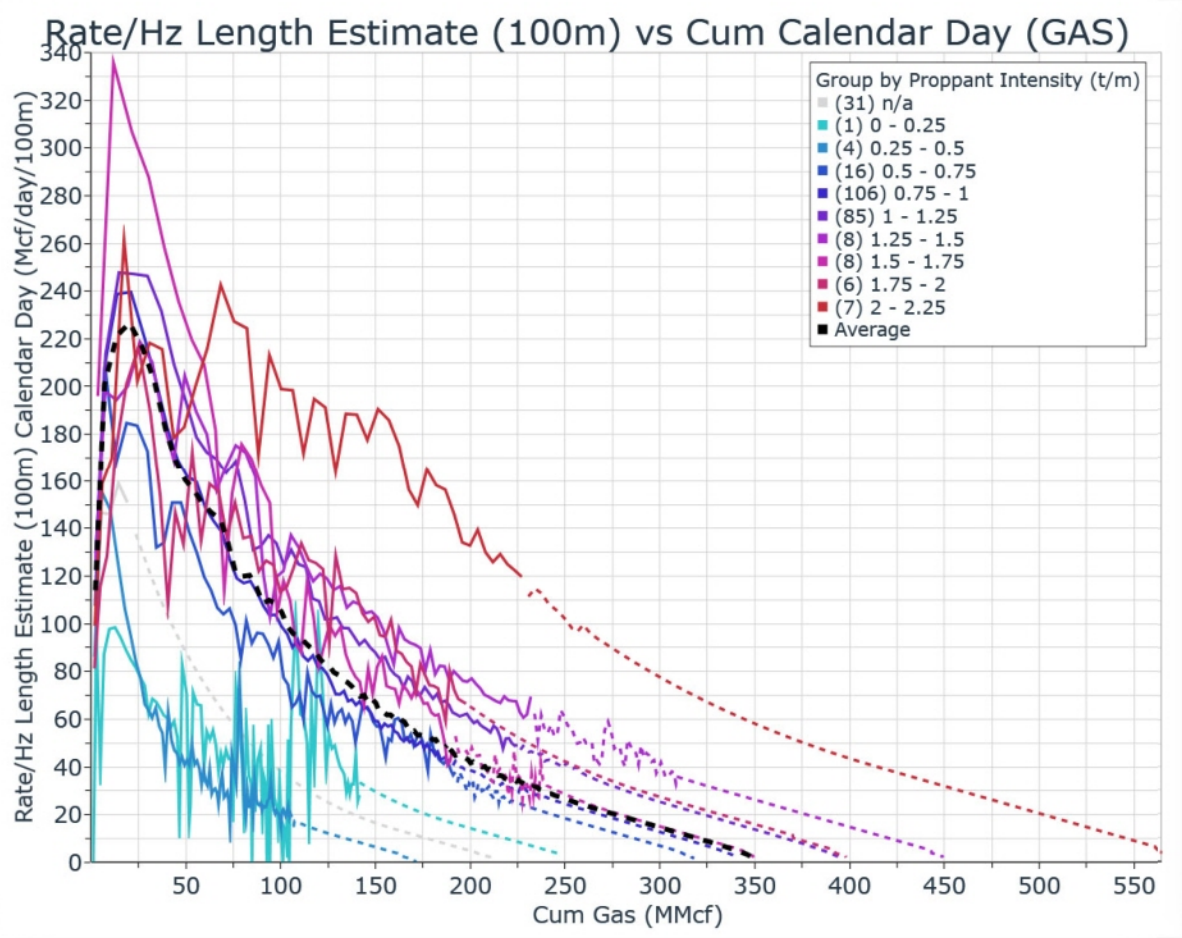
Caribou South trends to an average of 5.75 Bcf, 350MMcf/100m, better performance in recent years

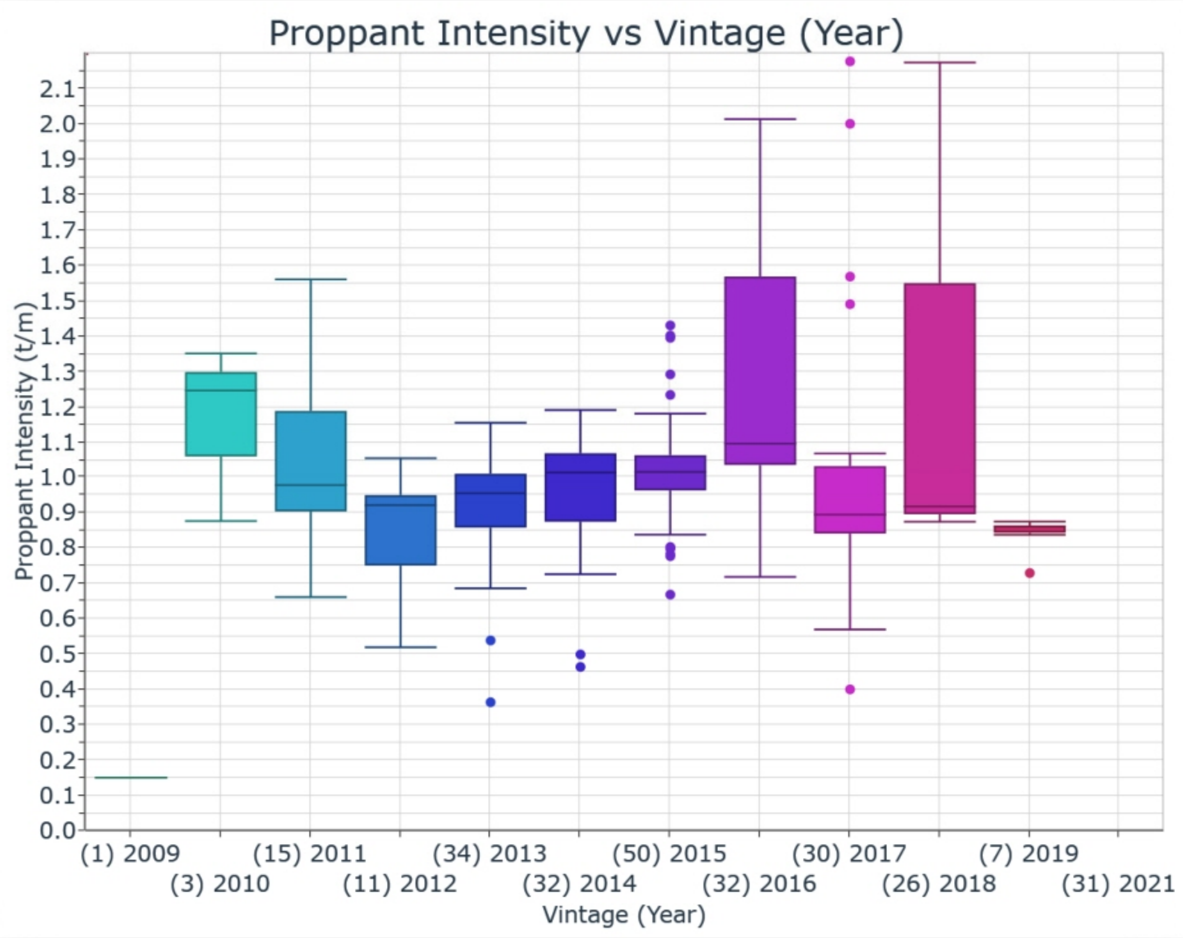






High proppant intensity resulting in better overall performance within the area, average of 1.0 t/m

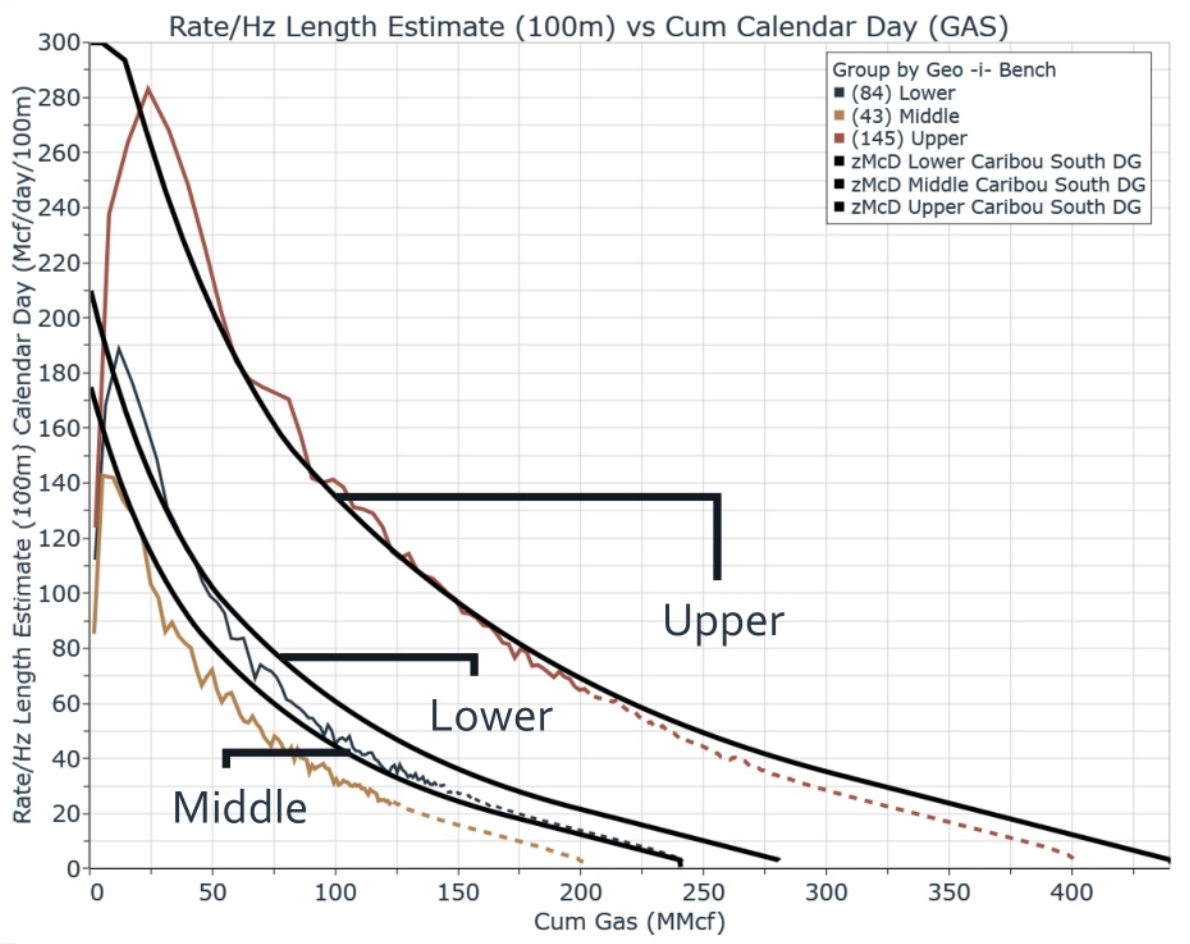




Confidential @ McDaniel 2021

McDaniel created type curves based on operator and regional trends for this area

- Taking into consideration the performance of the area, vintage, geology, the technology available and operator trends, type curves were generated for Caribou South
- Type curves were assigned based on bench (Upper, Middle and Lower) for each area
- The type curve EURs assigned for Caribou South:
  Upper – 13 Bcf
  Middle – 7 Bcf
  Lower – 8.5 Bcf
- Assigned all dry gas (CGR is zero) as the entire area contains no wet fluids, none of the wells producing any material condensate



Go forward expectations are stronger than historical averages due to more modern completion strategy

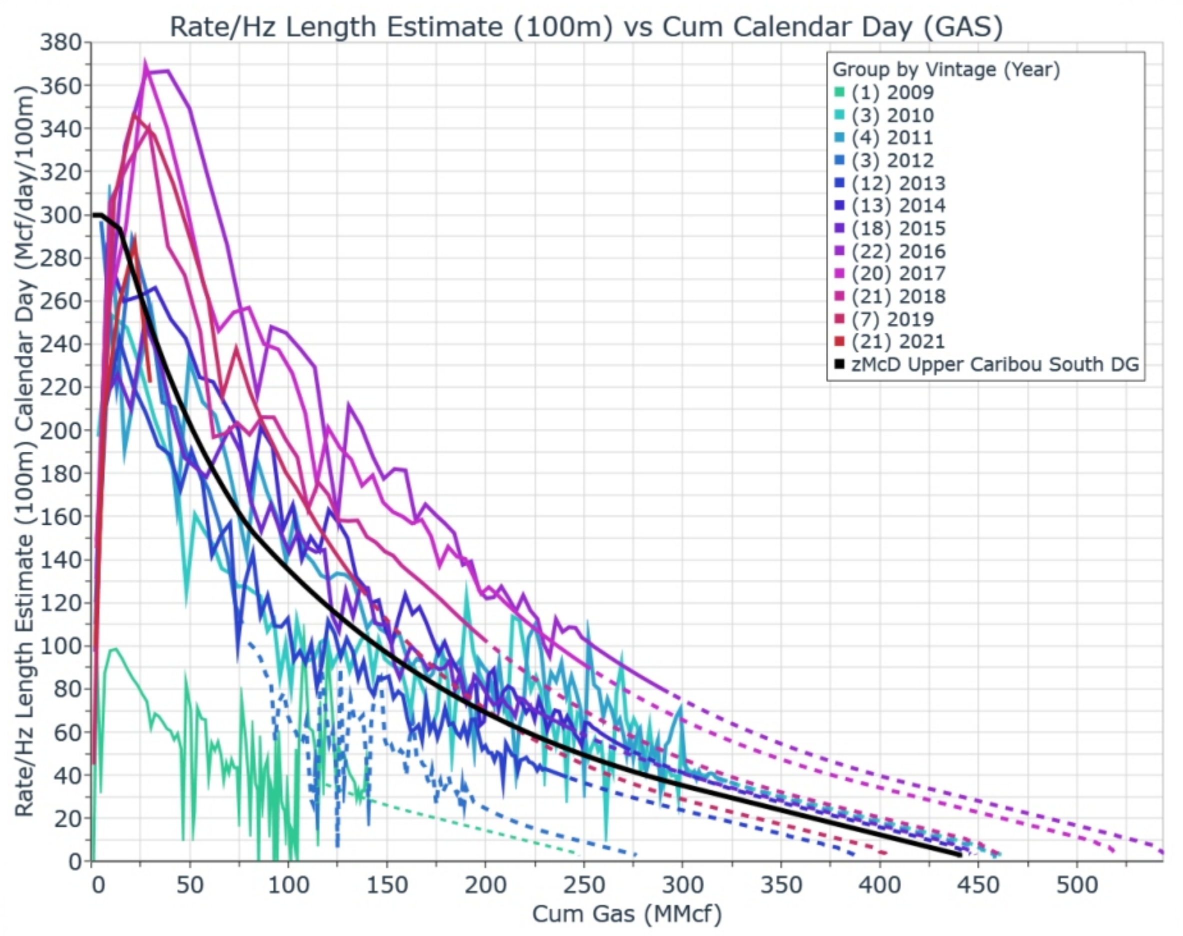
~575 locations forecast for upper type curve

Economic Metrics

	$58/bbl WTI $2.75/MMBTU AECO
NPV10% (C$M)	$7,615
NPV40% (C$M)	$1,396
IRR (%)	69 %
Payout (yrs)	1.42
PIR 20%	+0.55

Technical Inputs & Economic Assumptions

Type Curve EUR	Oil EUR (Mbbl)	0 (Dry Gas)
	Gas EUR (Bcf)	13.012
Well Design	Well Lateral Length (m)	3,000
	Proppant Intensity (t/m)	1.5
Economic Inputs	Total CAPEX	$7,545M
	Total Opex ($/BOE)	$2.12/BOE
Plant Inputs	Combined NGL Yield	9 bbl/MMcf
	Gas Heating Value (Btu/scf)	1075
	Shrinkage (%)	3%



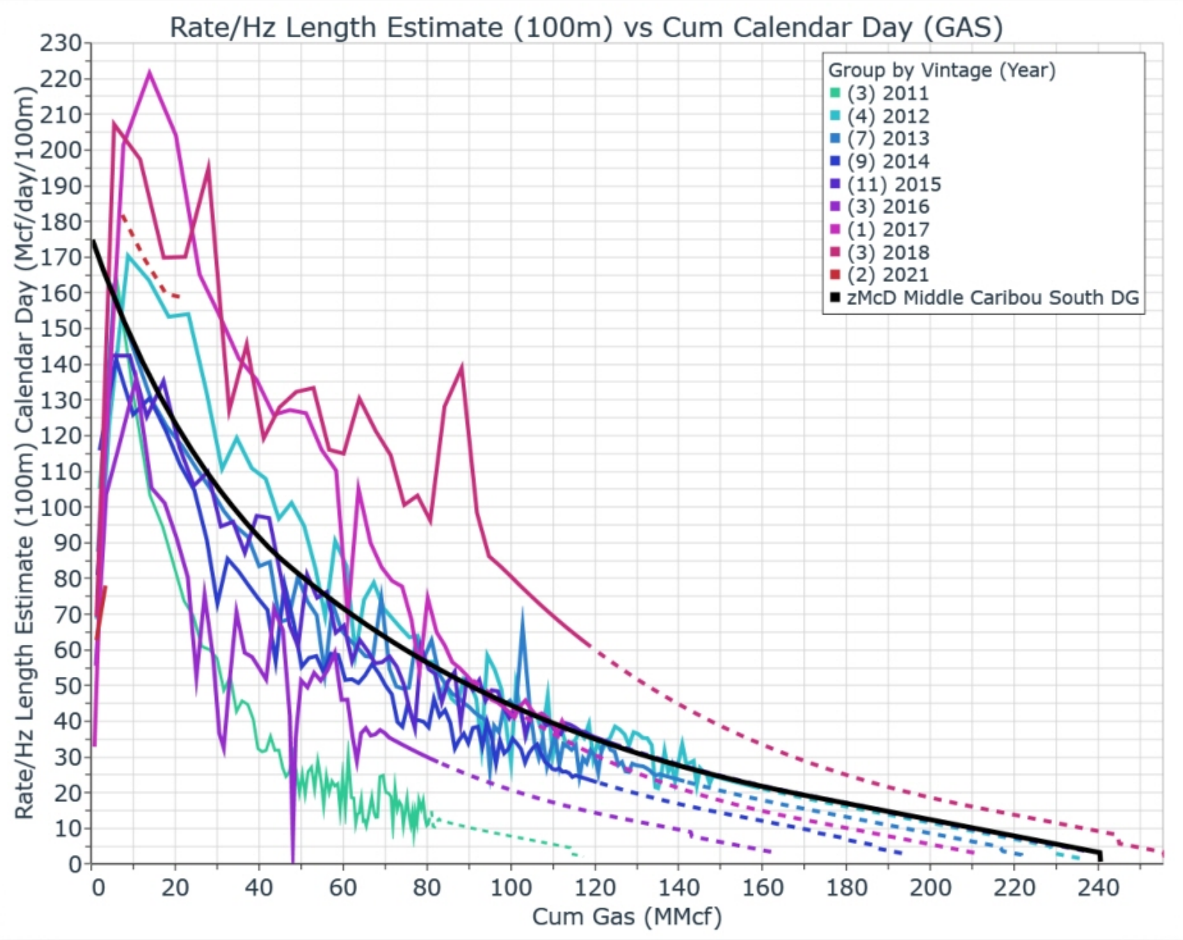
~590 locations forecast for middle type curve

Economic Metrics

	$58/bbl WTI $2.75/MMBTU AECO
NPV10% (C$M)	$863
NPV40% (C$M)	$-1,818
IRR (%)	14%
Payout (yrs)	4.88
PIR 20%	-0.10

Technical Inputs & Economic Assumptions

Type Curve EUR	Oil EUR (Mbbl)	0 (Dry Gas)
	Gas EUR (Bcf)	7.034
Well Design	Well Lateral Length (m)	3,000
	Proppant Intensity (t/m)	1.5
Economic Inputs	Total CAPEX	$7,643M
	Total Opex ($/BOE)	$2.41/BOE
Plant Inputs	Combined NGL Yield	9 bbl/MMcf
	Gas Heating Value (Btu/scf)	1075
	Shrinkage (%)	3%



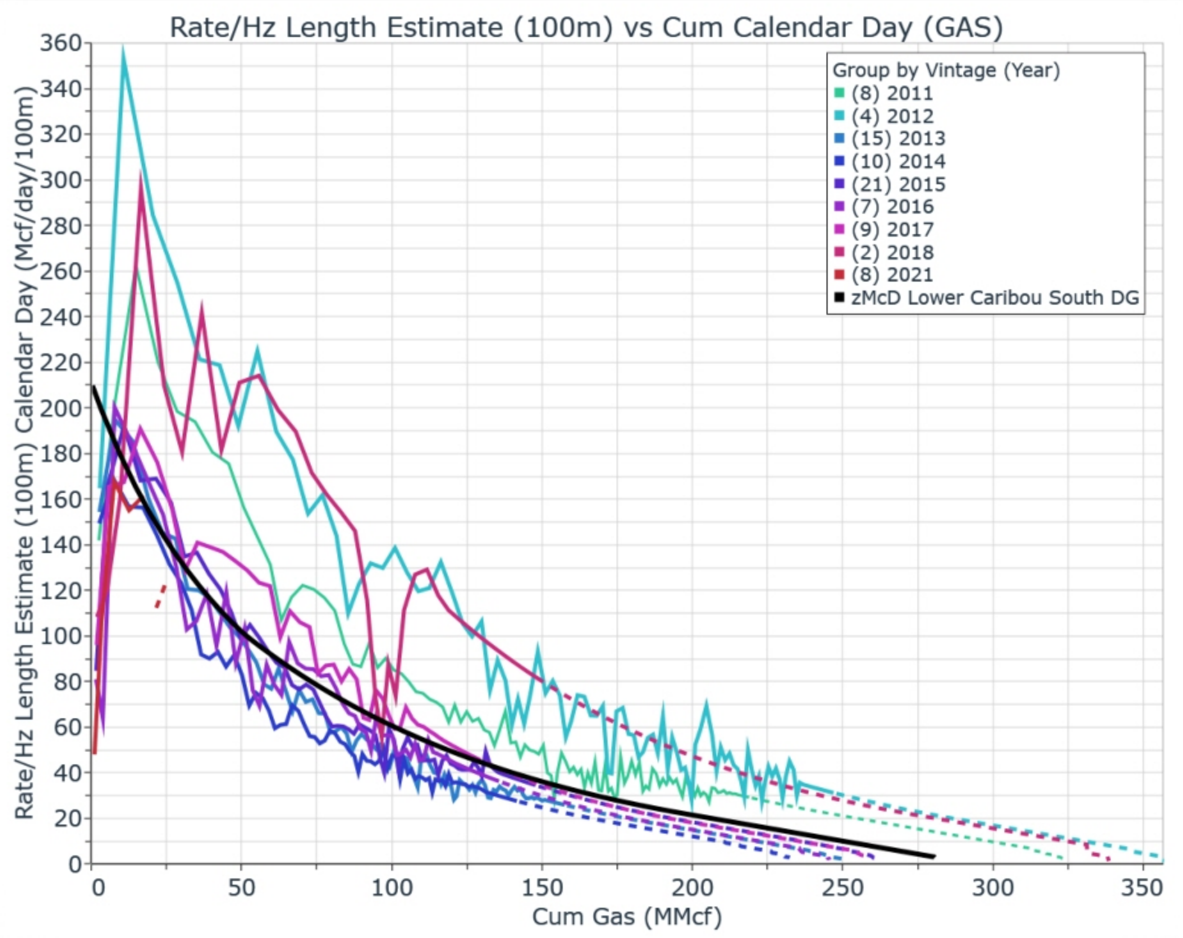
~590 locations forecast for lower type curve

Economic Metrics

	$58/bbl WTI $2.75/MMBTU AECO
NPV10% (C$M)	$2,430
NPV40% (C$M)	$-1,410
IRR (%)	20%
Payout (yrs)	3.3
PIR 20%	0.05

Technical Inputs & Economic Assumptions

Type Curve EUR	Oil EUR (Mbbl)	0 (Dry Gas)
	Gas EUR (Bcf)	8.513
Well Design	Well Lateral Length (m)	3,000
	Proppant Intensity (t/m)	1.5
Economic Inputs	Total CAPEX	$7,705M
	Total Opex ($/BOE)	$2.32/BOE
Plant Inputs	Combined NGL Yield	9 bbl/MMcf
	Gas Heating Value (Btu/scf)	1075
	Shrinkage (%)	3%



Economic Royalty Regime Results

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Withheld pursuant to/removed as

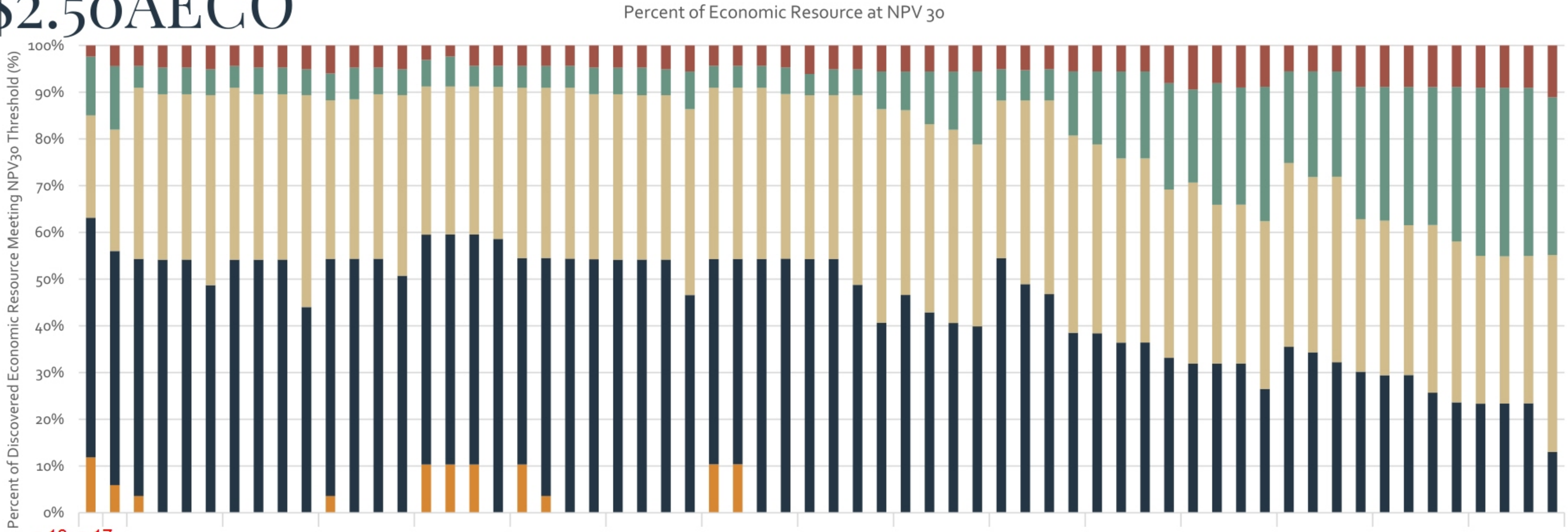
s.13 ; s.17

Half cycle economics must be robust for continued development

- Half Cycle Economics: economic return of the next development well (well level opex approach)
- Does not typically consider
  - Overhead & G&A
  - Assume upfront investment is sunk
  - Capital
- Requires material rate of return to cover unattributed cost centers such as staff and cost of capital
  - G&A – is typically $1.50/BOE for an average Montney producer
  - Cost of Capital in excess of 5%
- Half Cycle threshold for development ranges from approximately 30%-60%
- BC Government requested several half cycle economic thresholds to be run. The following slides represent the 30% ROR threshold

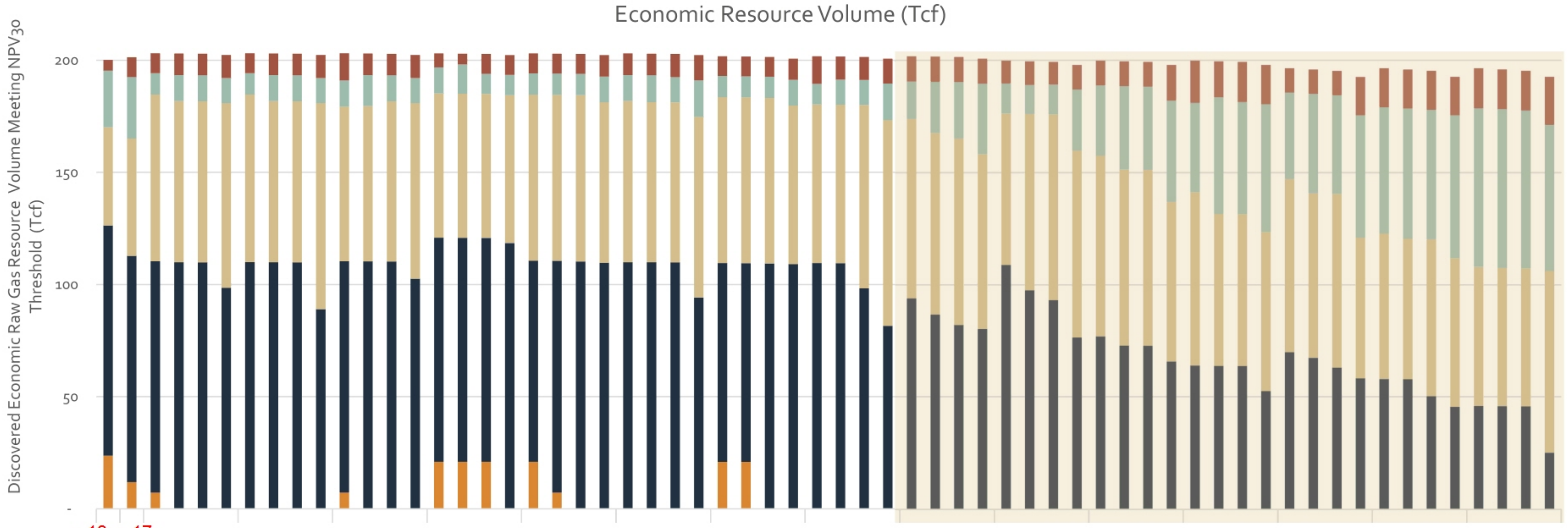
Half Cycle Economics – NPV30

Minimal economic resource volume at $2 AECO, majority of regimes support ~50% development at $2.50AECO



s.13; s.17

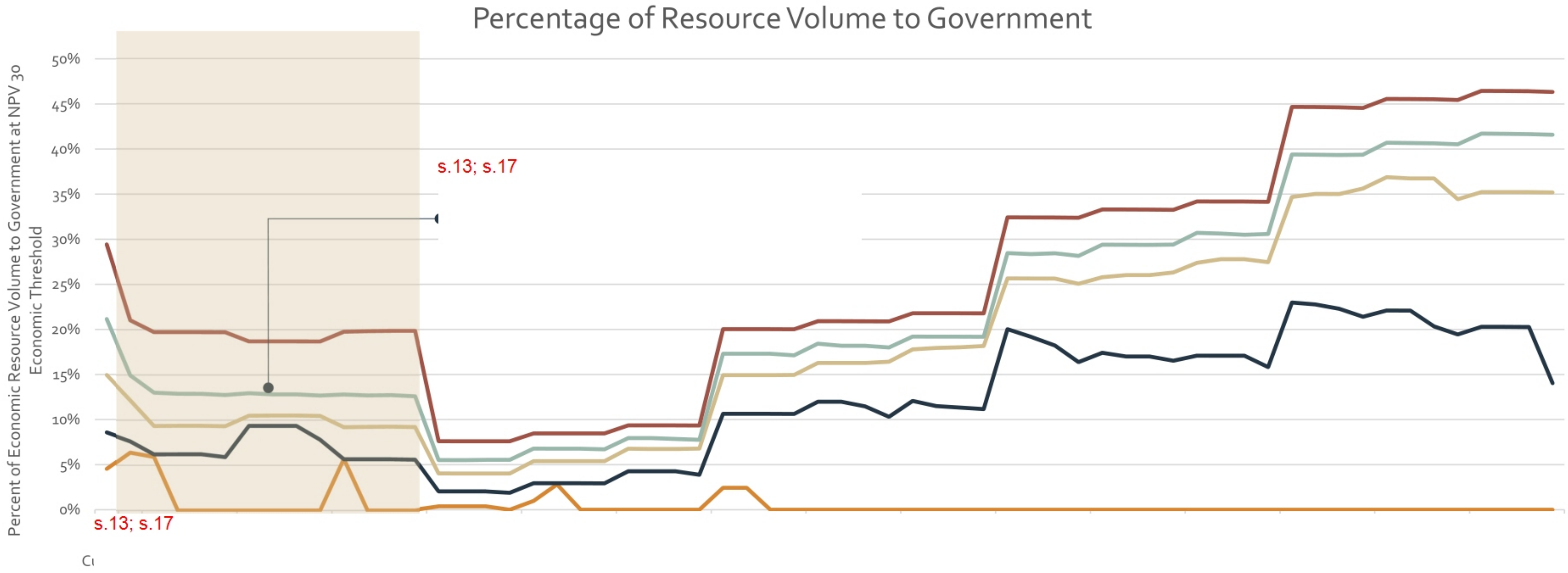
s.13; s.17



s.13; s.17

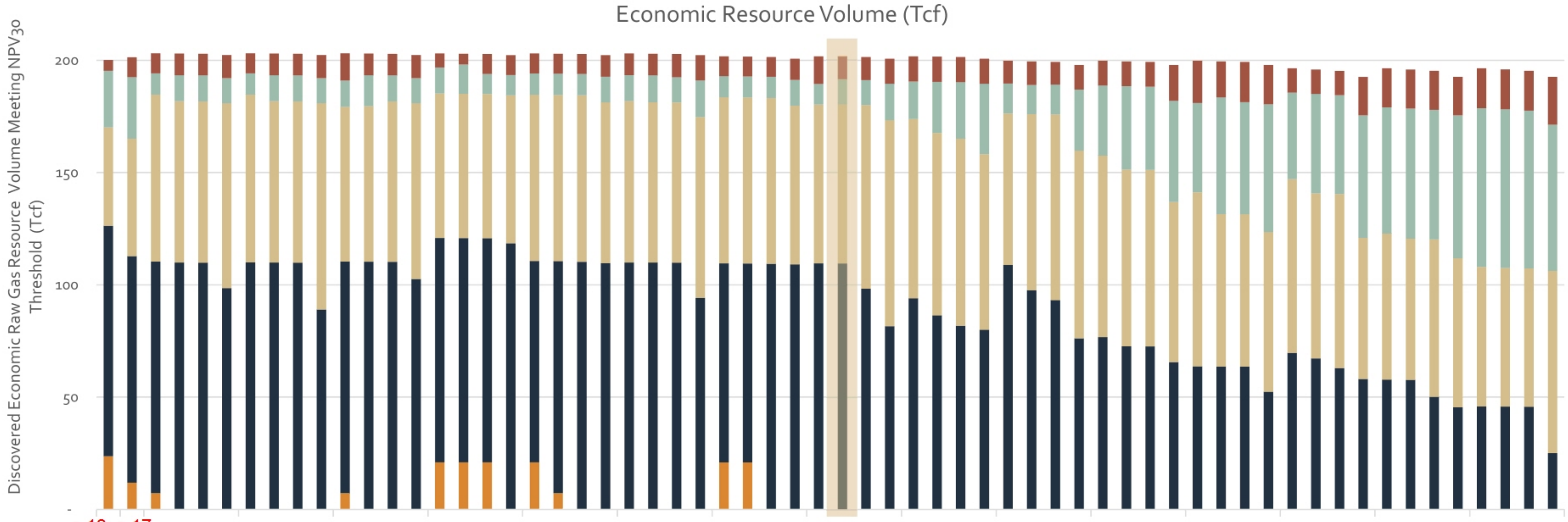
NPV 30% EFFECTIVE ROYALTY RATE BASED ON VOLUME – s.13

Percentage of government volume take rolls off at lower pricing environments



Selecting one regime to review in detail:

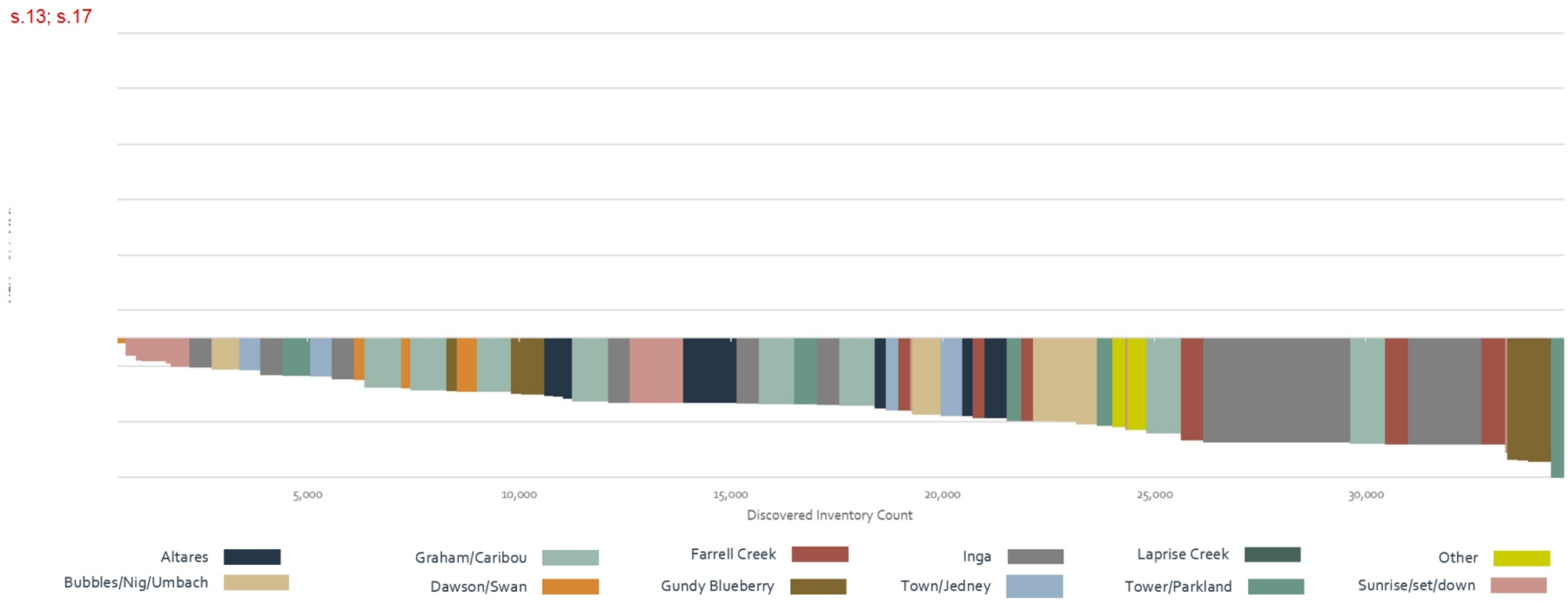
s.13; s.17



s.13; s.17

s.13; s.17

s.13; s.17

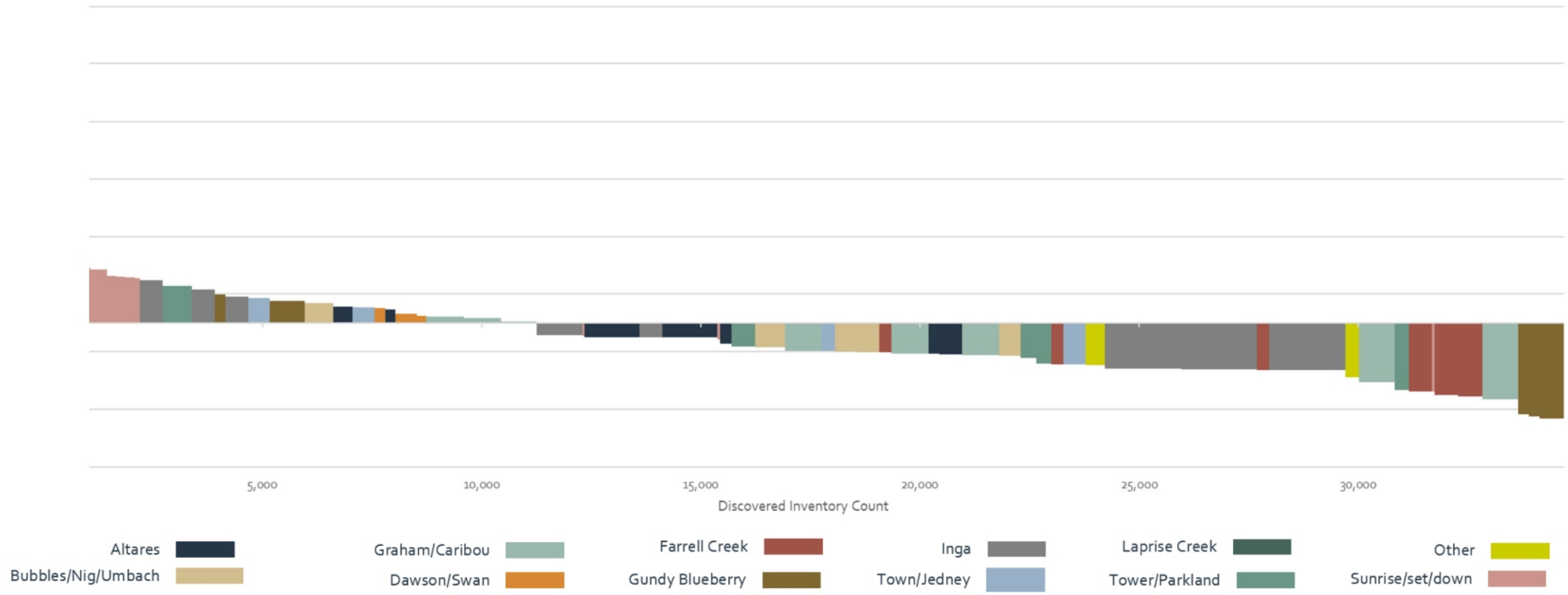


Inventory represents discovered and undiscovered resource

s.13; s.17

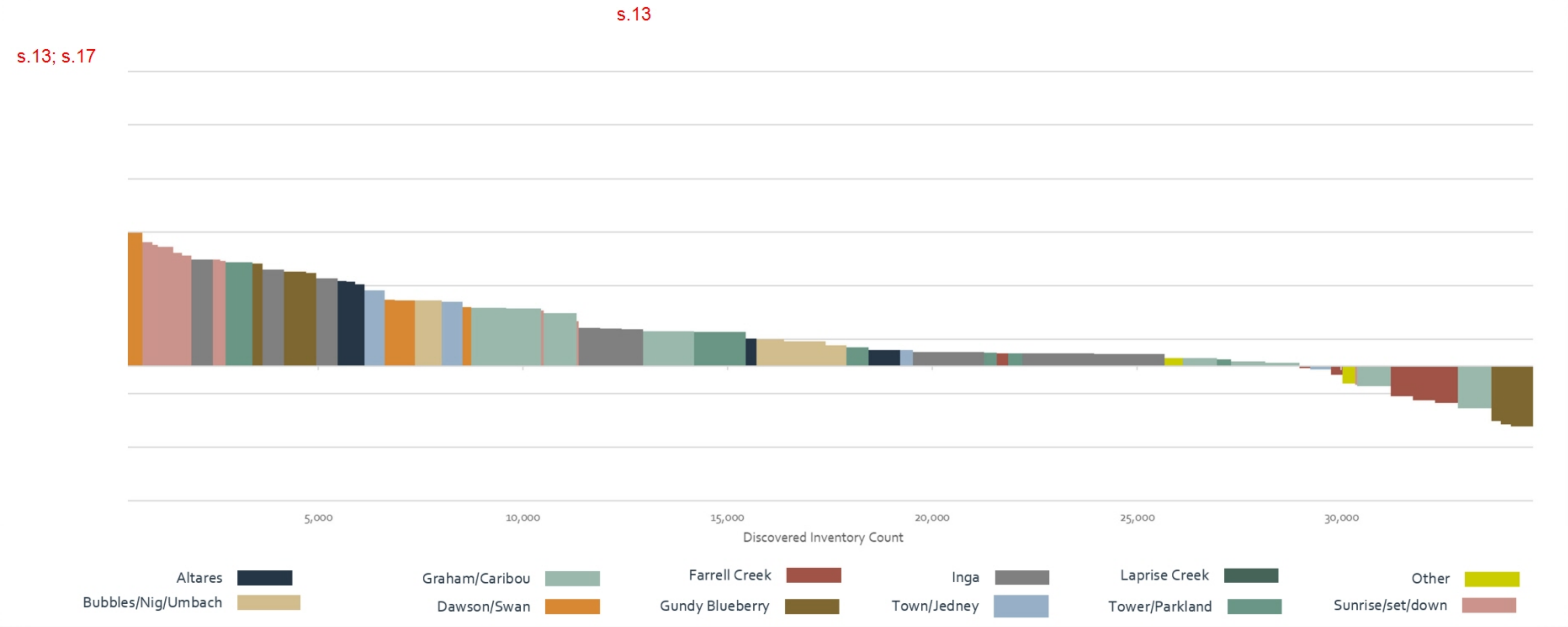
s.13

s.13; s.17



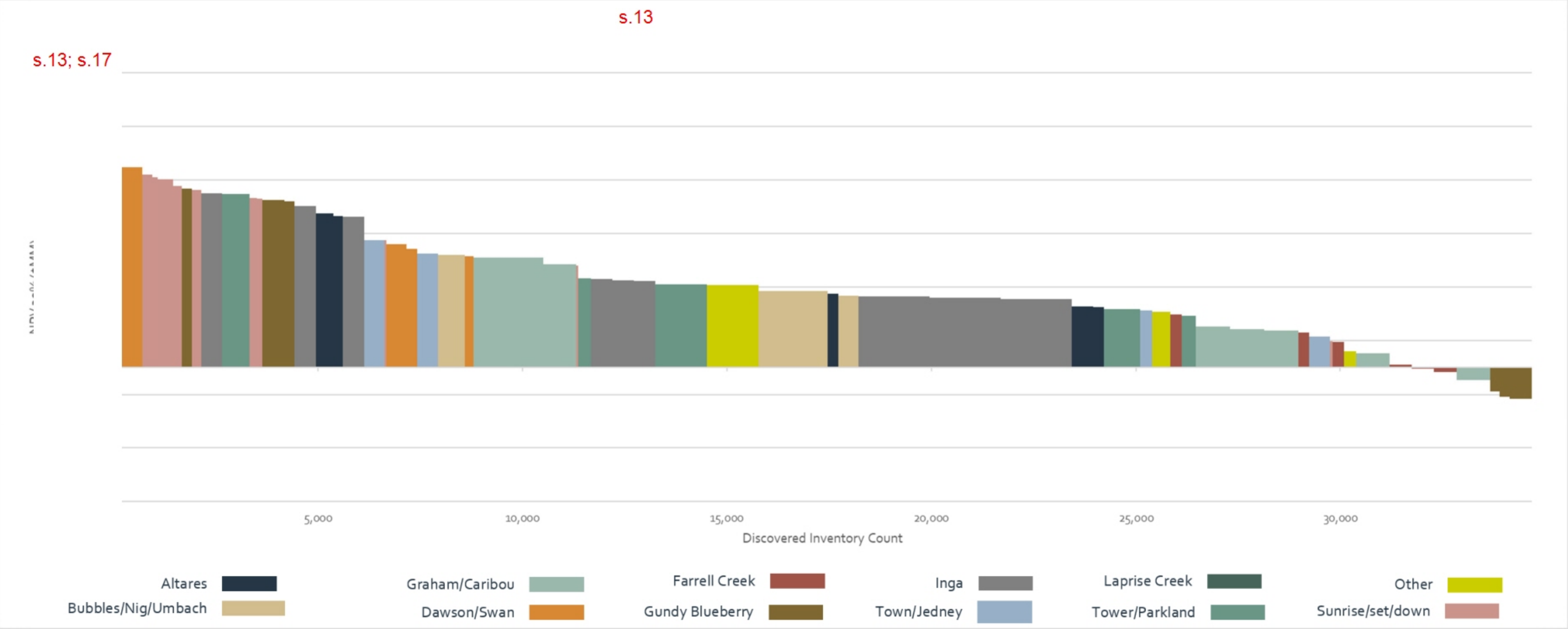
Inventory represents discovered and undiscovered resource

s.13; s.17



Inventory represents discovered and undiscovered resource

s.13; s.17

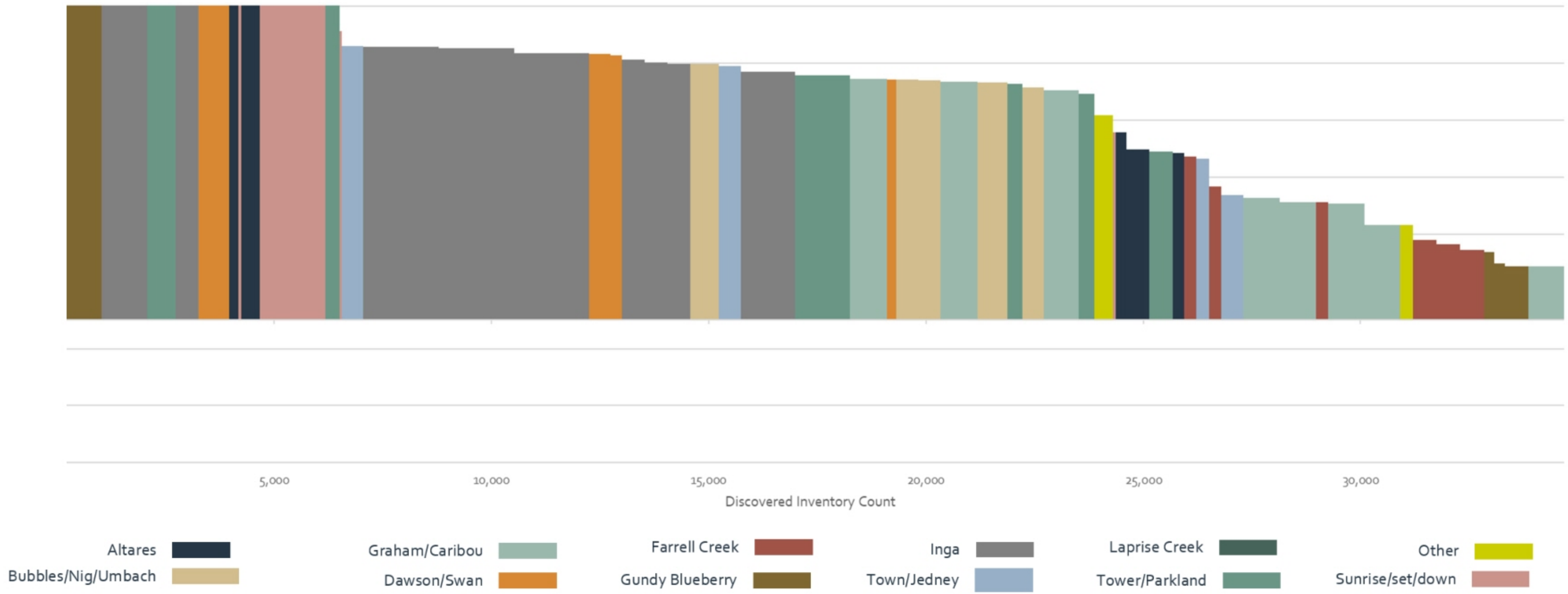


Inventory represents discovered and undiscovered resource

s.13; s.17

s.13

s.13; s.17



Note that y-axis was constrained to show comparison between graphs however in at $110 WTI & $4.50 AECO, certain NPV30s well exceed $11MM

s.13; s.17

s.13; s.17

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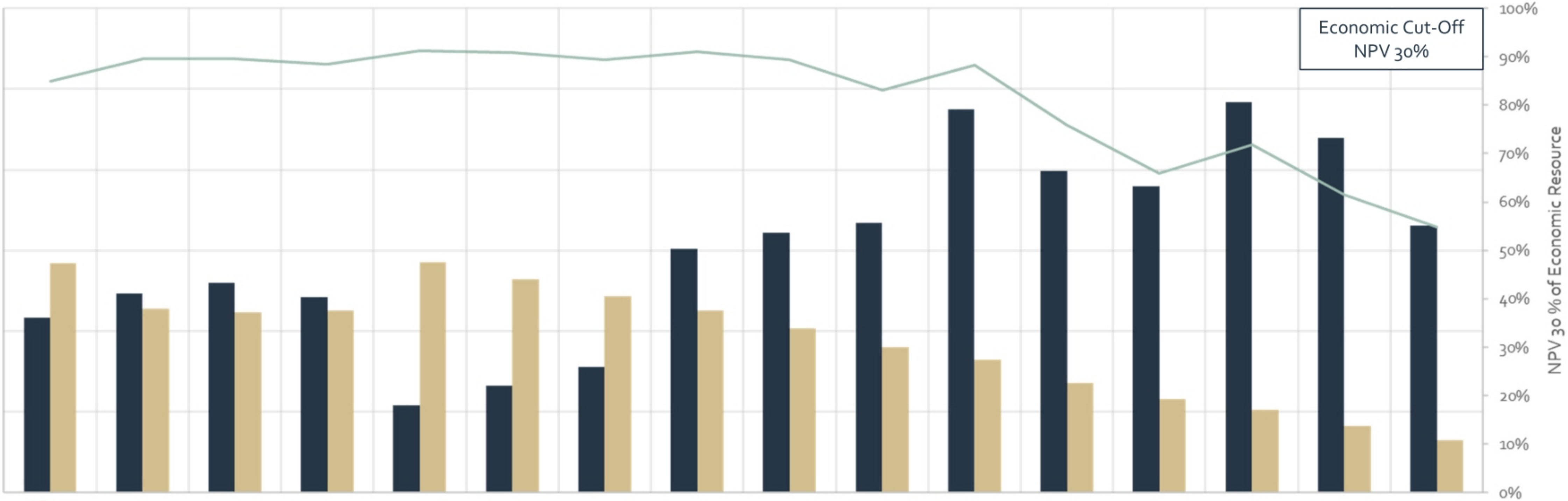

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McDANIEL

Ministry of Energy, Mines and Low Carbon Innovation

Oil and Gas Royalty Review – Economic Competitiveness Evaluation

Executive Presentation – November 30th, 2021

Wood Mackenzie
A Verisk Business

Trusted Intelligence

woodmac.com

British Columbia

Introduction

The report follows 4 main sections

Report structure

Section1: Supply Assessment	Section 2: Sub-plays benchmarking	Section 3: Fiscal Benchmarking	Other Sections: Complementary Information

Key questions
• What is the cost of liquids and gas supply for 9 jurisdictions?
  • Canada: BC, AB, and SK
  • US: TX, NM, ND, OK, OH, and PA
• What is the production outlook under different price scenarios?
 	
Scope
• Includes resources and production of all plays and sub-plays within the 9 jurisdictions
	Key questions
	• How do BC sub-plays compare to competing sub-plays in the 9 jurisdictions?
	• Includes well attributes such as EUR, TVD, lateral lengths, and economic performance pre and post government share
	
	Scope
	• Provides a deep-dive on a subset of competing sub-plays
		Key questions
		• How do the fiscal terms compare for all jurisdictions?
		• How do prices and discount rates affect government share?
		• What is the impact of different carbon tax scenarios on BC's competitiveness?
		
		Scope
		• Compares the fiscal terms of the 9 jurisdictions using 4 BC-like type wells
		  • Same costs, EURs and production profiles
			Topics
			• WoodMac information of other plays in North America
			• WoodMac Financial Health Index

A total of 27 type wells have been selected to expand the jurisdiction competitiveness assessment

The analysis compares sub-plays attributes, costs, and economics

Summary

Available Information

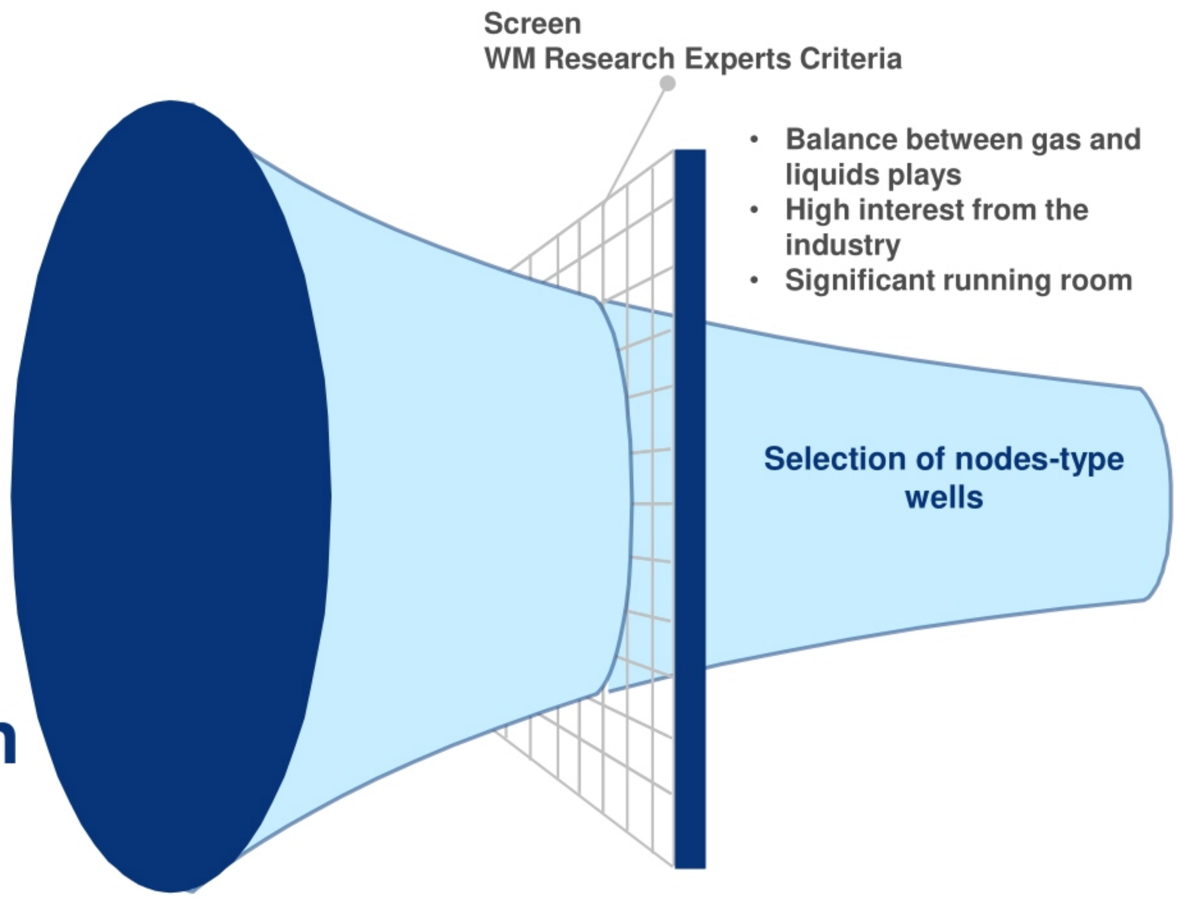
9 Jurisdictions

59 Plays

194 Sub-plays

318 Nodes/ type wells

>1.2 million potential locations



Shortlisted nodes for deep-dive analysis

9 Jurisdictions

14 Plays

27 Sub-plays

27 Nodes/ type wells

>57 thousand potential locations

Source: Wood Mackenzie

Oil and gas production from the benchmarked jurisdiction is assessed using type-well breakevens and different commodities scenarios

Price scenarios

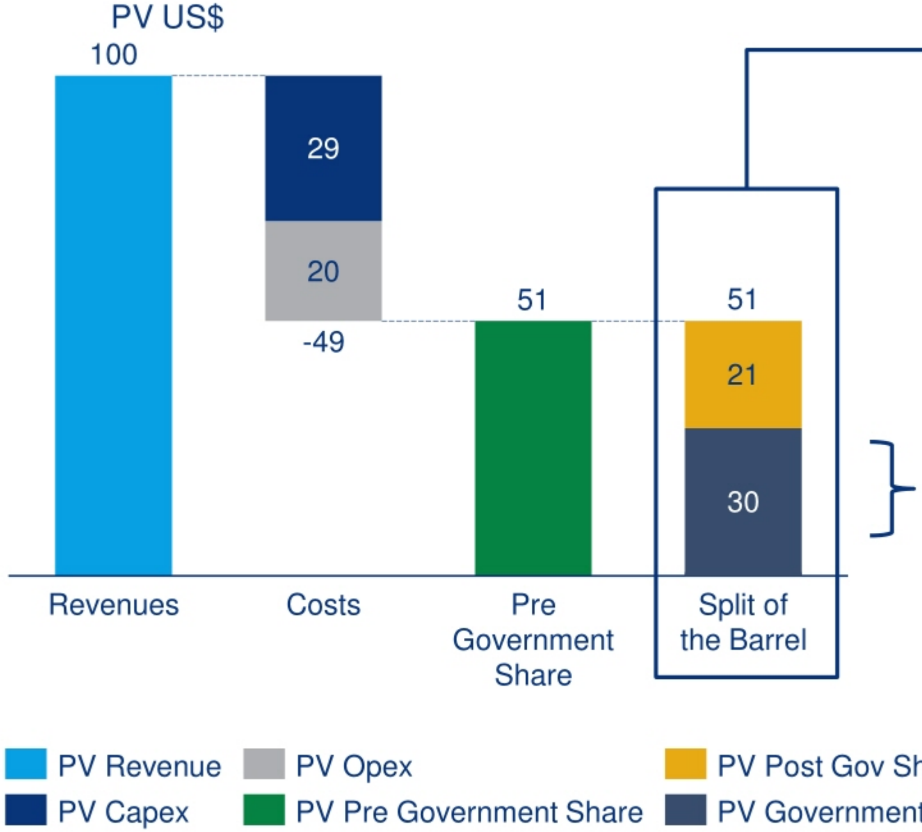
	Average Prices in 2021 real terms	Brent US$/bbl[1]	Henry Hub US$/mcf	AECO US$/mcf
Price Assumptions (How the Industry approves new investments)	Base	50 US$/bbl	2.75 US$/mcf	1.90 US$/mcf
	Low	30 US$/bbl	1.85 US$/mcf	1.00 US$/mcf
	High	70 US$/bbl	3.05 US$/mcf	2.20 US$/mcf
Bespoke Gas Forecasts (Supply and demand forecast)	British Columbia LNG Build Out	50 US$/bbl	3.50 US$/mcf	3.01 US$/mcf
	Restricted British Columbia LNG Expansion	50 US$/bbl	3.50 US$/mcf	2.90 US$/mcf

Notes: 1 Assumed long term differential: WTI = Brent – 4%

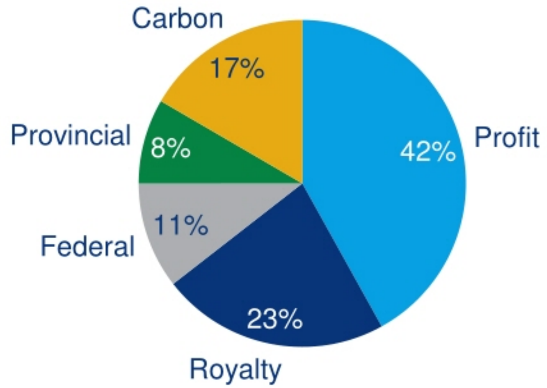
The benchmarking allows an evaluation of the impact of the different taxes applicable to each regime

Calculation framework

Illustrative Example



$$Government\ Share = \frac{30}{51} = 58\%$$

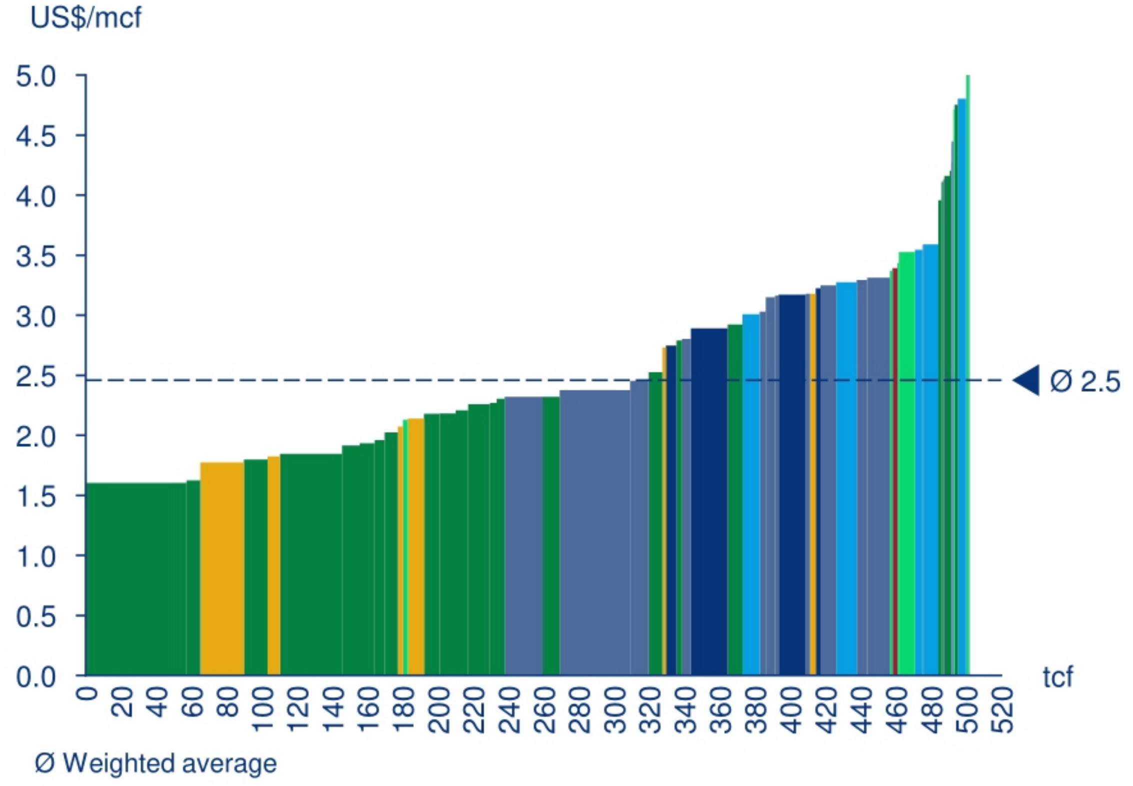


- **Focus on Government Share analysis under different price and discount rates scenarios**
- **Sensitivities to BC's carbon taxes**

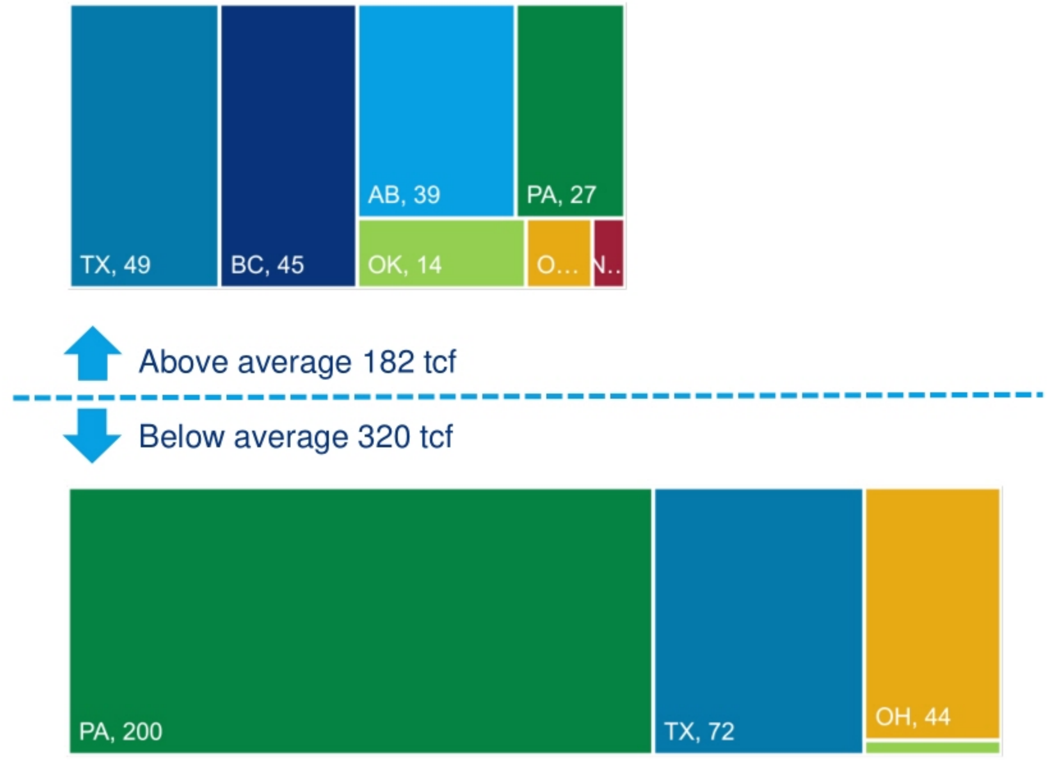
Executive Summary

BC has around 45 tcf of undrilled dry gas that has a higher breakeven than the benchmarked jurisdictions

Undeveloped resources at HH cost of supply[1] at 15% nominal



Share of undeveloped resources by price[1]



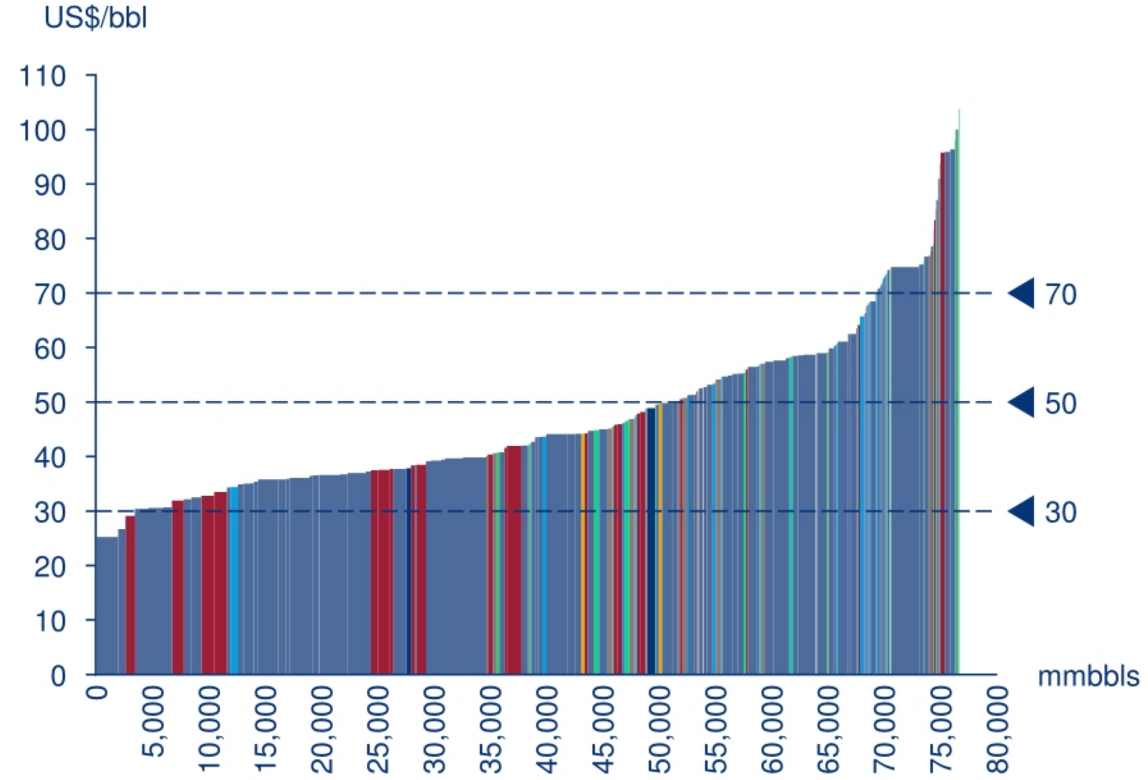
AB BC NM OH OK PA TX

1- Includes only undeveloped resources to be produced from 2021 to 2050

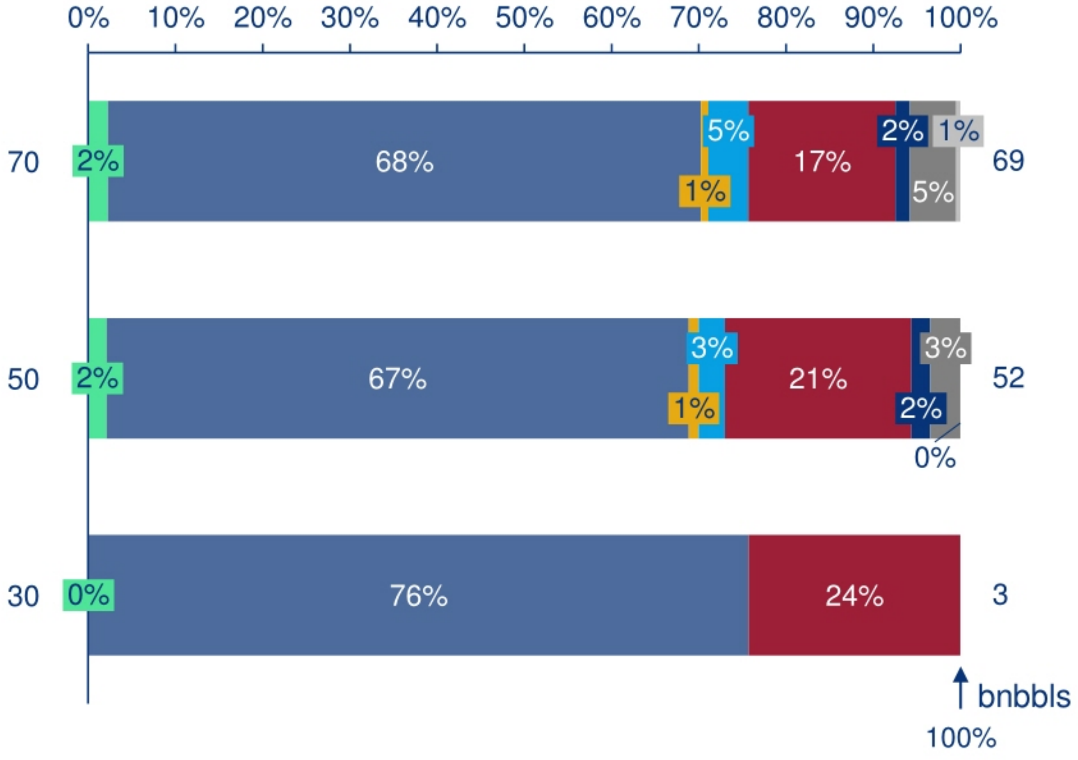
Texas and New Mexico have the most resilient liquid resources out of the selected jurisdictions

BC has ~1.1 bnbbls with a Brent breakeven below 50 US$/bbl

Undeveloped resources Brent cost of supply[1] at 15% nominal



Share of undeveloped resources by price scenario[1]

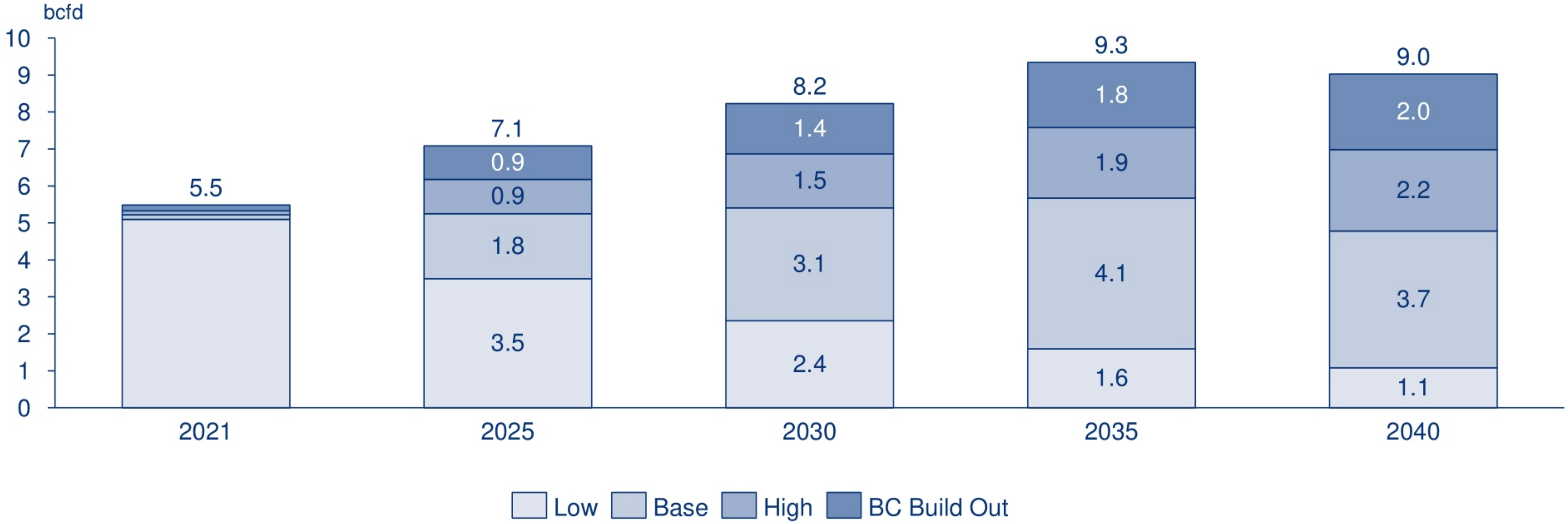


AB BC ND NM OH OK PA SK TX

1- Includes only undeveloped resources to be produced from 2021 to 2050

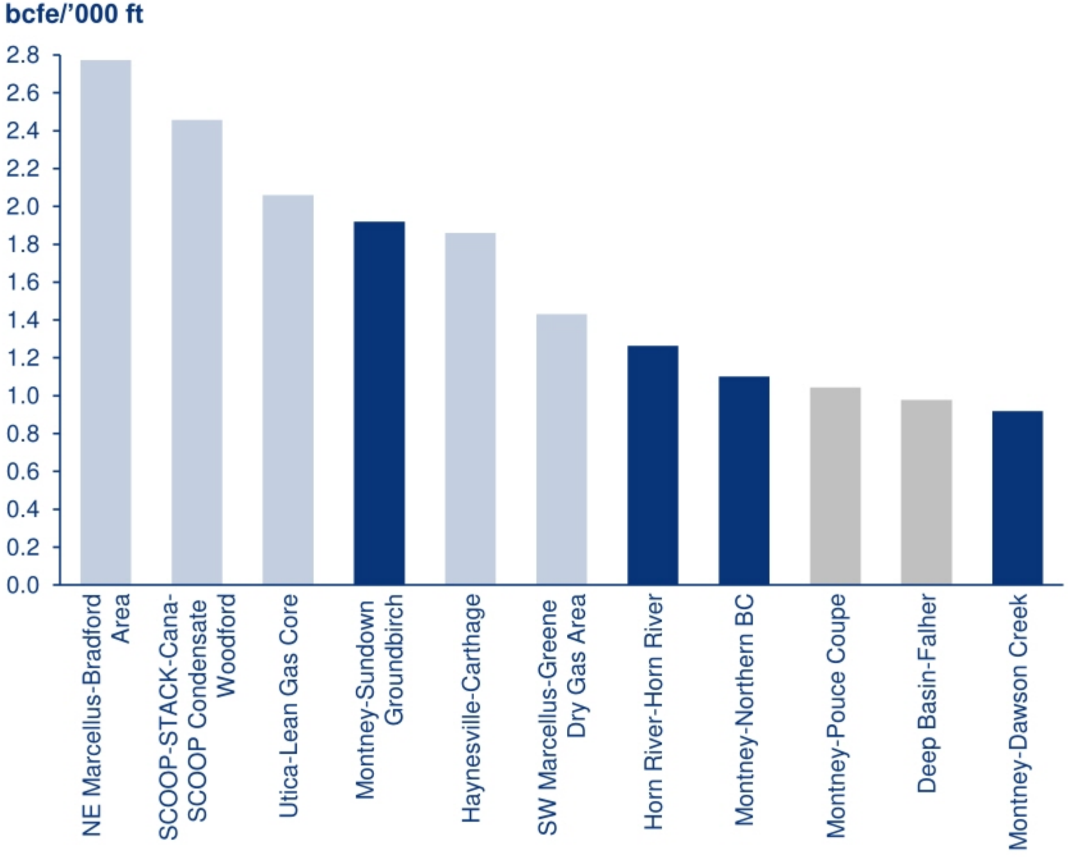
Under the forecast scenarios, BC gas production could reach 9 bcfd by the 2030s

British Columbia gas production comparison for forecast scenarios

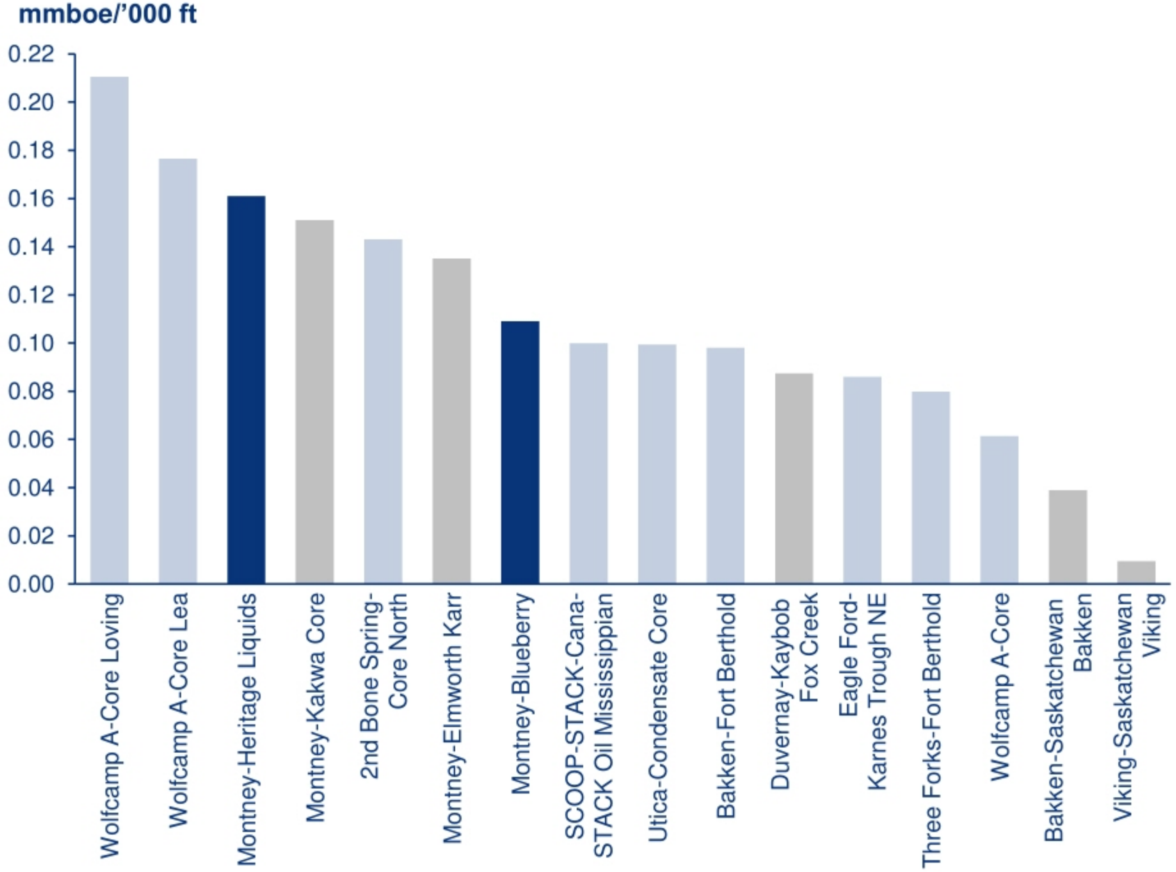


Geology is attractive, and the sub-plays rank high among selected jurisdictions

Normalized EUR/ft – Gas Drive Wells



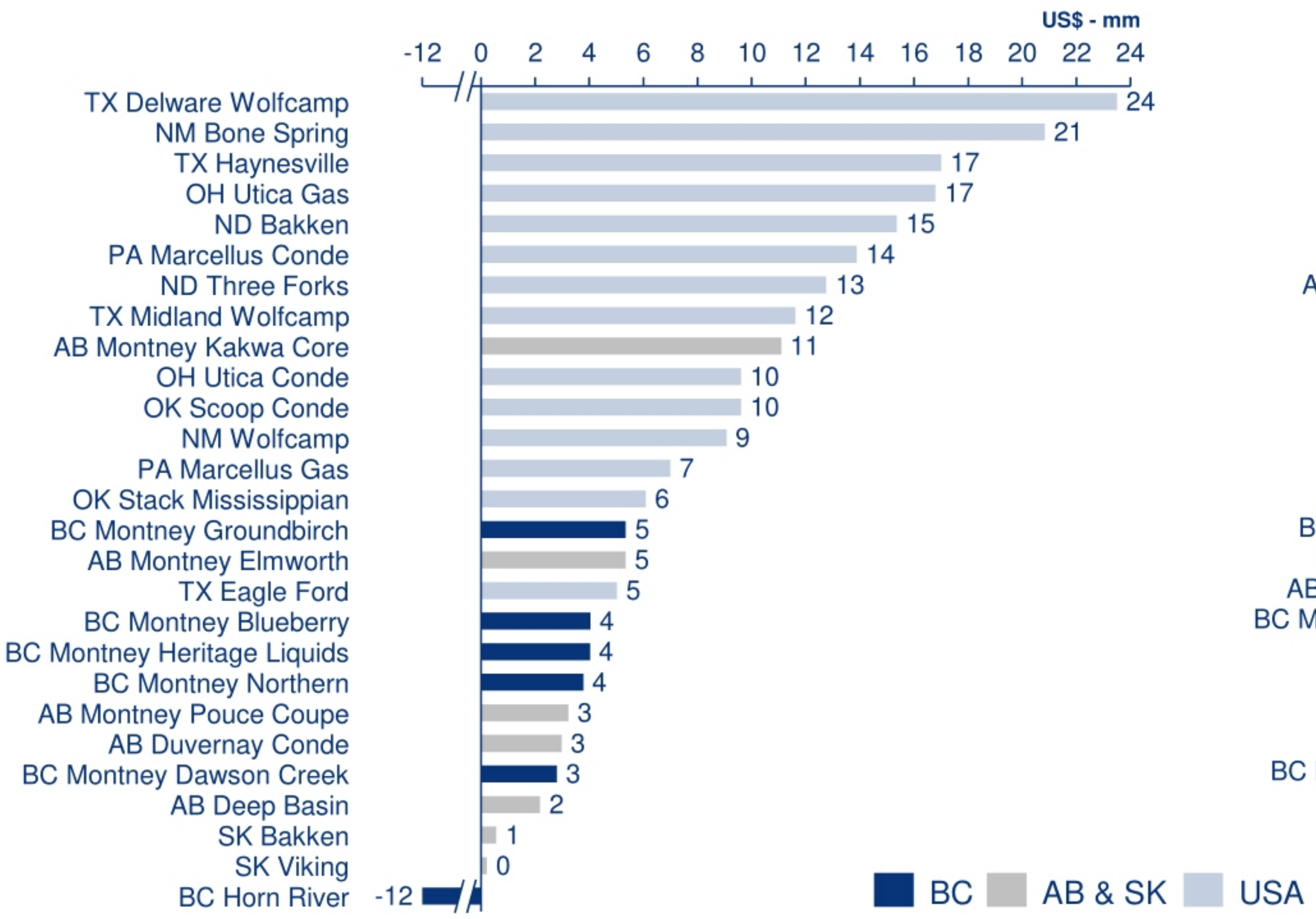
Normalized EUR/ft – Liquids Drive Wells



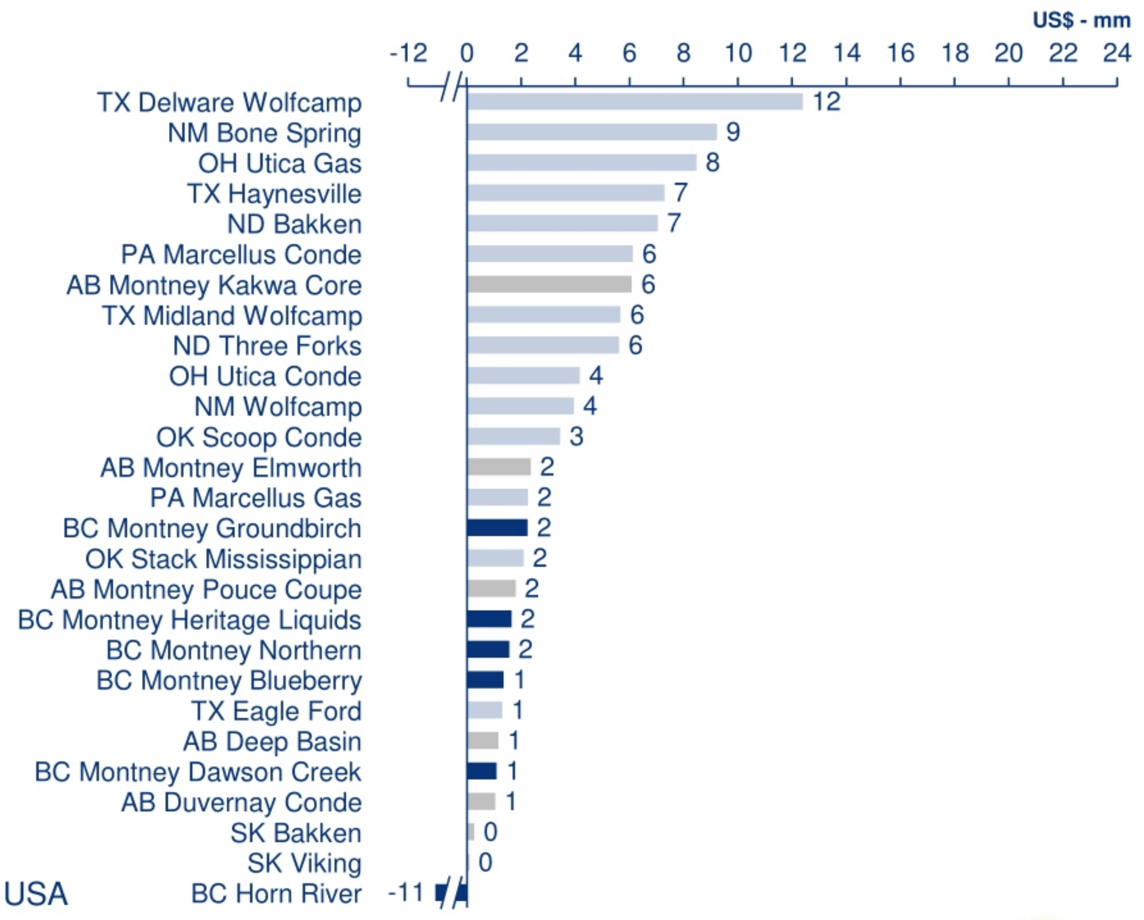
BC AB & SK US

British Columbia's benchmarked wells rank low on value generation on a pre and post government share basis

Pre-Government Share PV15



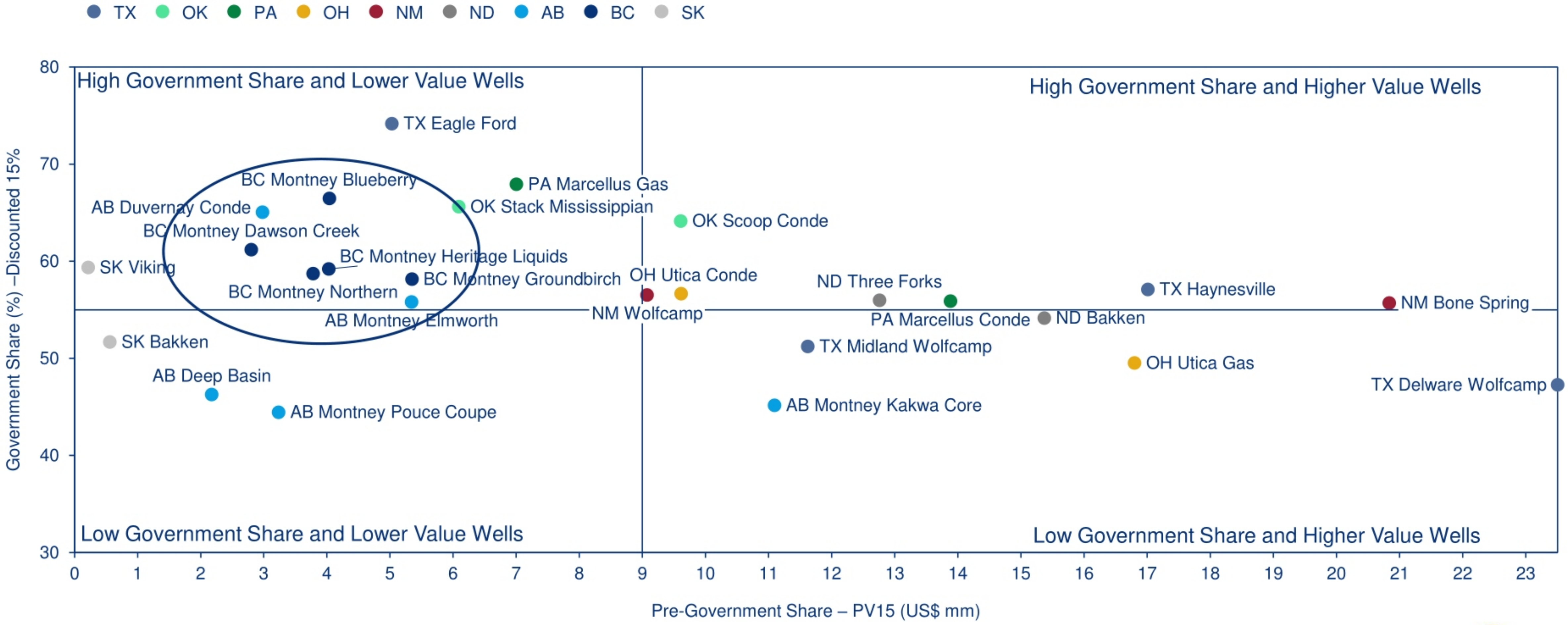
Post-Government Share PV15



Source: Woodmac GEM H1 2021

British Columbia wells are in the top left quadrant with higher government share and lower pre-government value

Pre-Government share comparison of type wells versus Government Share at Woodmac base prices[1]

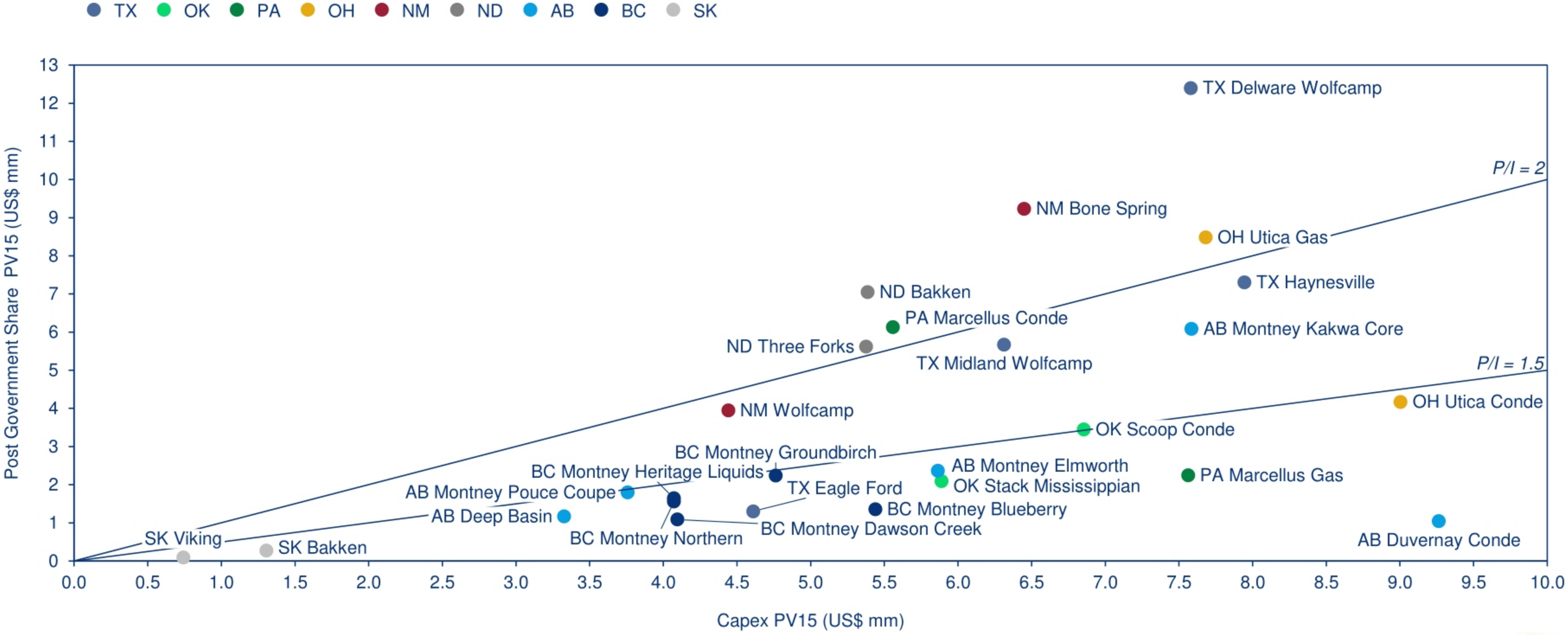


Source: Woodmac GEM H1 2021 – Base prices
Notes: 1. Government Share includes landowner royalty, and not including Horn River

US type wells tend to generate more post government share value for each dollar invested than Canadian wells

Six wells manage to achieve a PI ratio above 2

Capex vs Post Government Share NPV15 at Woodmac base prices



Source: Woodmac GEM H1 2021 – Base prices
Note: P/I = Post Government Share PV / Capex PV + 1

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Q&A

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Appendix

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