[PS]Unconventional Oil Play Assessment in Northeastern British Columbia, Canada*

Brad Hayes[1], Raphael Wust[2], Carlos Salas[3], and Howard Anderson[4]

Search and Discovery Article #80688 (2019)**
Posted July 22, 2019

*Adapted from poster presentation given at AAPG 2019 Annual Convention & Exhibition, San Antonio, Texas, May 19-22, 2019
 DOI:10.1306/80688Hayes2019

[1]Petrel Robertson Consulting Ltd., Calgary, Alberta, Canada (bhayes@petrelrob.com)
[2]AGAT Laboratories, Calgary, Alberta, Canada
[3]Geoscience BC, Vancouver, British Columbia, Canada
[4]Consultant

Abstract

Horizontal drilling and multi-frac completions have greatly augmented British Columbia gas and liquids resources by providing economic access to unconventional (low permeability) reservoirs. However, relatively little new unconventional oil production has been brought on stream in this gas-prone area of the Western Canada Sedimentary Basin. We identified exploration and exploitation fairways for oil in unconventional reservoirs throughout the stratigraphic column, except for the Montney Formation, as it is already an active oil and liquids drilling target. Regional geological assessment of reservoir and production trends identified potential in conventional, tight, and shale reservoirs. We reviewed existing files of analytical data submitted to the Regulator - standard core analysis, geochemistry / maturity, mineralogy, geomechanical properties - and tabulated them to support future detailed analyses. Where analytical data were lacking on promising plays, we sampled cores and completed comprehensive laboratory analyses to fill the gaps. Finally, we analyzed test and production data from a reservoir engineering perspective to better understand the scope and quality of potential resource oil fairways. Of 19 reservoir intervals deemed suitable for analysis, 10 demonstrated little prospectivity for reasons including: lack of extensive low-permeability reservoir facies, poor geomechanical properties (low “frackability”), and lack of viable oil charge. Six demonstrated some resource oil potential based on existing oil shows and favourable geological / geomechanical characteristics, but lacked either substantial horizontal / multi-frac testing, or evidence of substantive resource oil fairways. Only two reservoirs showed potential to be top-priority unconventional oil targets. Cretaceous Chinkeh Formation sandstones are prospective for tight oil across a broad, poorly defined fairway downdip from the existing Maxhamish gas field. The Triassic Halfway Formation presents halo oil potential in limited-permeability shoreface sandstones offsetting conventional production, which has been focused on higher-quality tidal channel sandstones. New Halfway production could be brought on stream quickly using existing infrastructure but developing the Chinkeh would require new processing and pipeline construction in a relatively remote part of the province.

References Cited

Caplan, M.L., and T.F. Moslow, 1997, Tectonic controls on preservation of Middle Triassic Halfway reservoir facies, Peejay Field, northeastern British Columbia: a new hydrocarbon exploration model: Bulletin of Canadian Petroleum Geology, v. 45/4, p. 596-613.

Caplan, M.L., and T.F. Moslow, 1999, Depositional origin and facies variability of a Middle Triassic barrier island complex, Peejay Field, northeastern British Columbia. American Association of Petroleum Geologists Bulletin, v. 83, p. 128-154.

Dixon, J., 2008, Stratigraphic relationships of the Triassic Halfway Formation in the Western Canada Sedimentary Basin. Bulletin of Canadian Petroleum Geology, v. 56/1, p. 62-68.

Ferri, F., and M. Griffiths, 2014, Thermal maturity and regional distribution of the Muskwa Formation, northeastern British Columbia: In Geoscience Reports 2014, British Columbia Ministry of Natural Gas Development, p. 37-45.

Frank, J.H., 2002, Sedimentology, ichnology and stratigraphy of the lowermost Cretaceous, Liard Basin, Canada. M.Sc thesis, University of Alberta.

Jiang, C., A. Mort, M. McMechan and Z. Chen, 2015, Source of Chinkeh oil from Maxhamish Field, Liard Basin, northeastern British Columbia: Geoconvention 2015 Proceedings.

Ross, D.J.K, and R.M. Bustin, 2006, Sediment geochemistry of the Lower Jurassic Gordondale Member, northeastern British Columbia. Bulletin of Canadian Petroleum Geology, v. 54/4, p. 337-365.

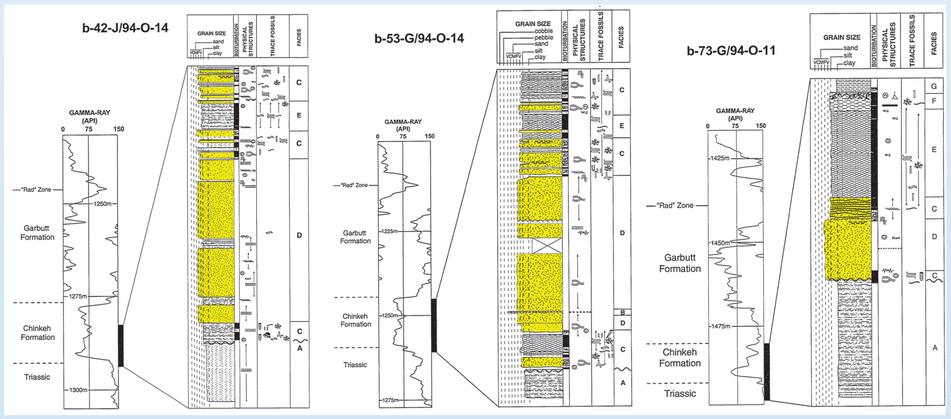
Ross, D.J.K. and R.M. Bustin, 2007, Shale gas potential of the Lower Jurassic Gordondale Member, northeastern British Columbia, Canada. Bulletin of Canadian Petroleum Geology, v. 55/1, p. 51-75.

CHINKEH FORMATION MAXHAMISH FIELD CASE STUDY

The Lower Cretaceous Chinkeh Formation lies on the pre-Cretaceous unconformity, which cuts strata ranging from Mississippian carbonates in the east to Triassic siltstones over most of the Liard Basin. The Chinkeh was deposited in basal fluvial through marine shoreface and shallow shelfal settings, then was transgressed more or less conformably by marine shales of the Garbutt Formation.

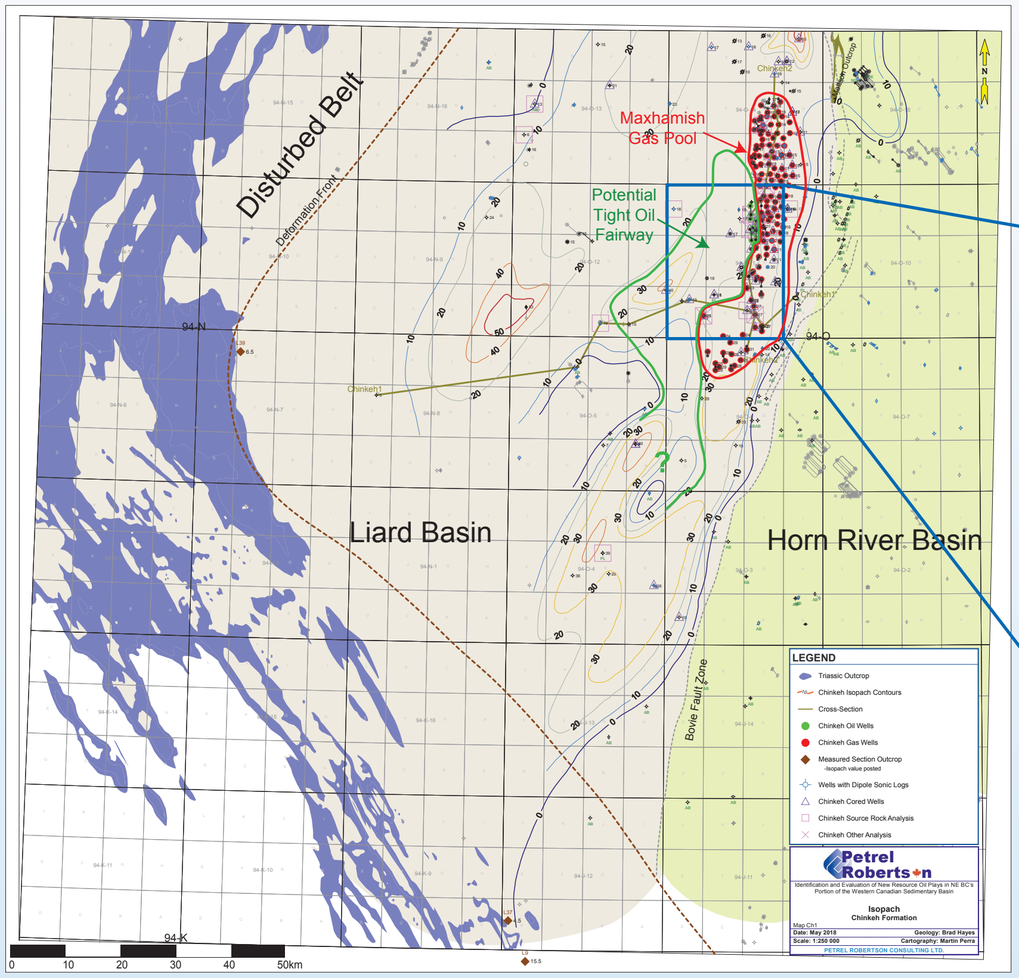
Chinkeh sandstones host a hydrocarbon-saturated (Deep Basin) petroleum system on the eastern flank of the Liard Basin. The large (400 BCF) Maxhamish Chinkeh 'A' gas pool is largely depleted, but nine oil wells on its western (downdip) flank exhibit variable production behaviour, and do not appear to have been drawn down by the updip gas production. Only a small percentage of the oil in place has been produced, and geological mapping suggests reservoir sandstones extend westward and southward to form an areally-extensive, oil-saturated, low-permeability sandstone fairway; Jiang et al. (2015) projected 400-500 million barrels of light oil in place. Production analysis suggests pressure support from downdip hydrocarbons, but no associated aquifer.

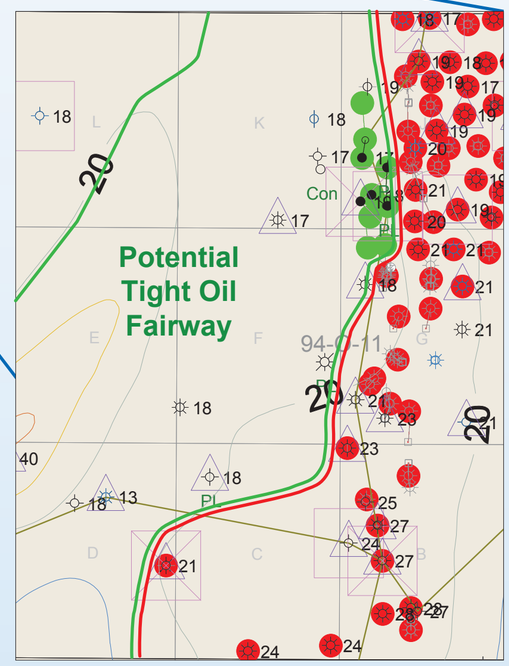
We recommend the western flank of the Chinkeh gas and oil pools be mapped in detail to support new Chinkeh horizontal drilling in the best-quality and thickest sandstones. Well control is very poor, and additional stratigraphic testing may be necessary. Both poorer-quality Chinkeh sandstones above the basal clean sandstone and underlying Toad-Grayling sandstones should be assessed for their potential contribution.



Core logs, typical Chinkeh sections in Maxhamish gas field *(Frank, 2002)*

Typical cored section, Chinkeh Fm (AEC Maxhamish c-95-J/94-O-11)



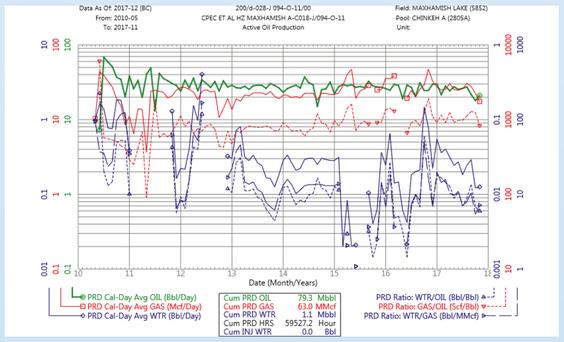


Production Analysis

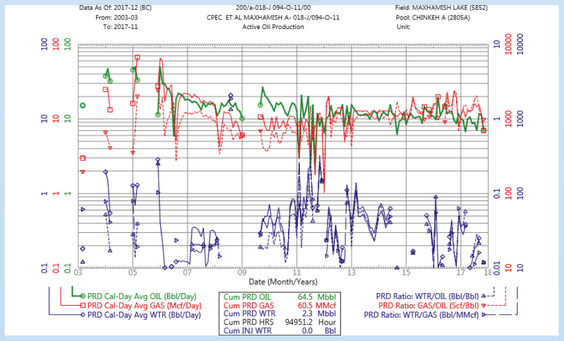
Oil production began in 2003, and as of November 2017 the nine oil wells have produced about 368 MBO. Water production continues to be very low, and there does not appear to be water drive or aquifer support.

BCOGC (2016) assigned 5.6 MMBO oil in place and a recovery factor of 10% to the concurrent production area, which they measured as 325 ha. Looking at the present distribution of oil wells, we estimated a 1250 ha productive area with oil in place of about 30 MMBO, using parameters similar to BCOGC (2016) but with a thicker net pay (3.1m vs OGC 2.1m). Production to date is thus only 1.2% of the oil in place. The oil gravity is 42 API, and at reservoir conditions, industry correlations give a Bo of 1.25 and a saturation pressure (bubble point) of 1200 to 1500 psia. Original reservoir pressure is 1334 psia, indicating that the gas and oil areas were likely originally in pressure and phase equilibrium.

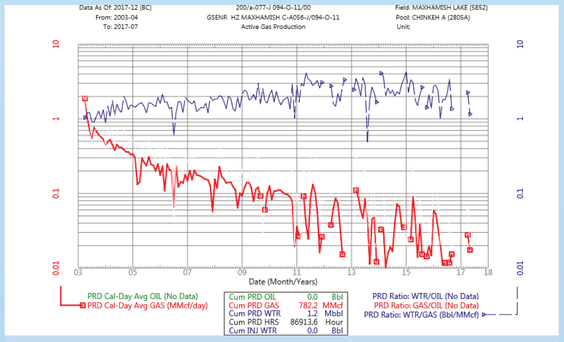
We performed decline analysis on all nine oil wells, and on some gas wells adjacent to the oil leg. Production is extremely flat, and it was difficult in some cases to get the decline analysis routine to converge to an answer. The four horizontal wells averaged initial production of 58 BOPD and estimated ultimate recovery of 192 MBO. Two vertical wells averaged 47 BOPD and EUR 138 MBO. Three deviated, almost-vertical wells performed poorly, with average 17 BOPD and EUR 21 MBO. One additional vertical well is listed as producing, but has never produced. Total EUR for the nine wells is 1.1 MMBO, or 4% of volumetric OOIP, indicating potential for infill drilling.



Production plot, Representative horizontal oil well



Production plot, Representative vertical oil well



Production plot, Representative vertical gas well

UNCONVENTIONAL OIL PLAY ASSESSMENT IN NORTHEASTERN BRITISH COLUMBIA, CANADA

ABSTRACT

Horizontal drilling and multi-frac completions have greatly augmented British Columbia gas and liquids resources by providing economic access to unconventional (low-permeability) reservoirs. However, relatively little new unconventional oil production has been brought on stream in this gas-prone part of the Western Canada Sedimentary Basin.

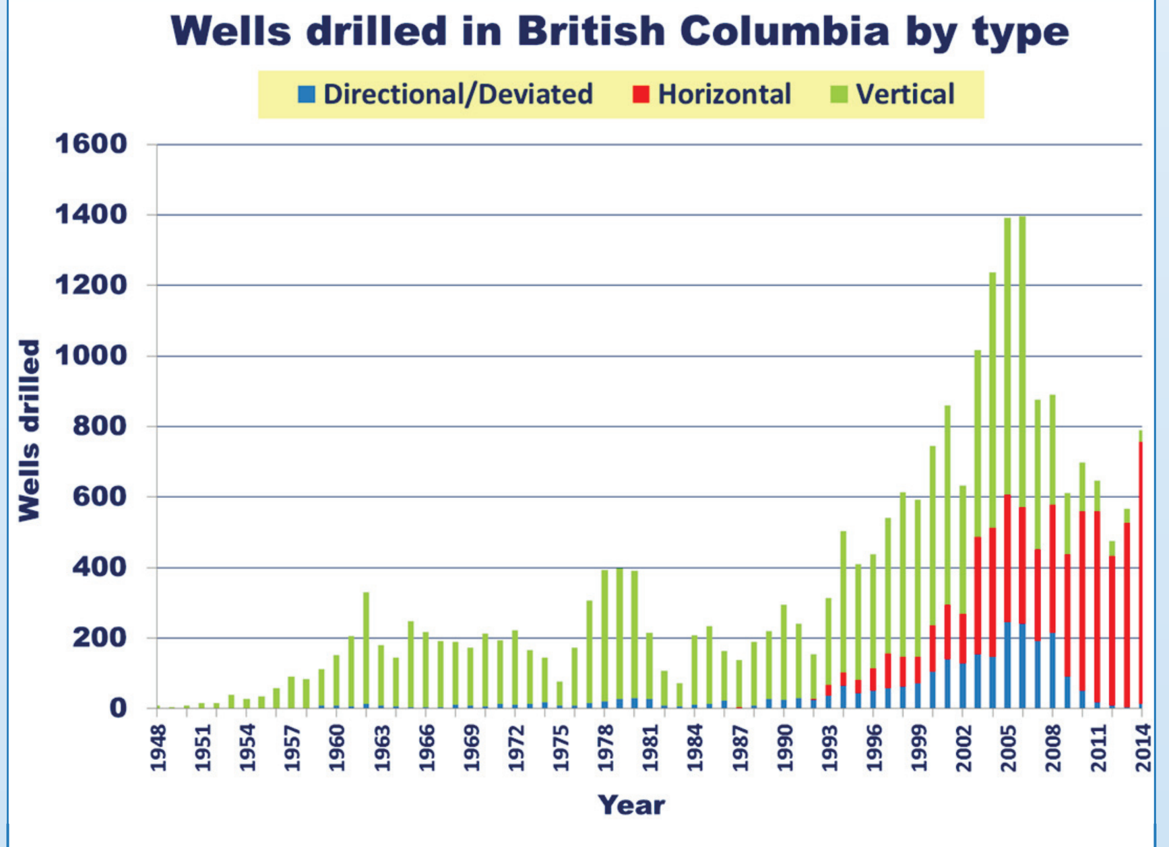
We identified exploration and exploitation fairways for oil in unconventional reservoirs throughout the stratigraphic column, with the exception of the Montney Formation, as it is already an active oil and liquids drilling target.

Of 19 reservoir intervals deemed suitable for analysis, 10 demonstrated little prospectivity for reasons including: lack of extensive low-permeability reservoir facies, poor geomechanical properties (low "frackability"), and lack of viable oil charge. Six demonstrated some resource oil potential based on existing oil shows and favorable geological / geomechanical characteristics, but lacked either substantial horizontal / multi-frac testing, or evidence of substantive resource oil fairways. Three examples of limited resource oil potential are highlighted in this presentation – the Muskwa, Tetcho, and Gordondale units.

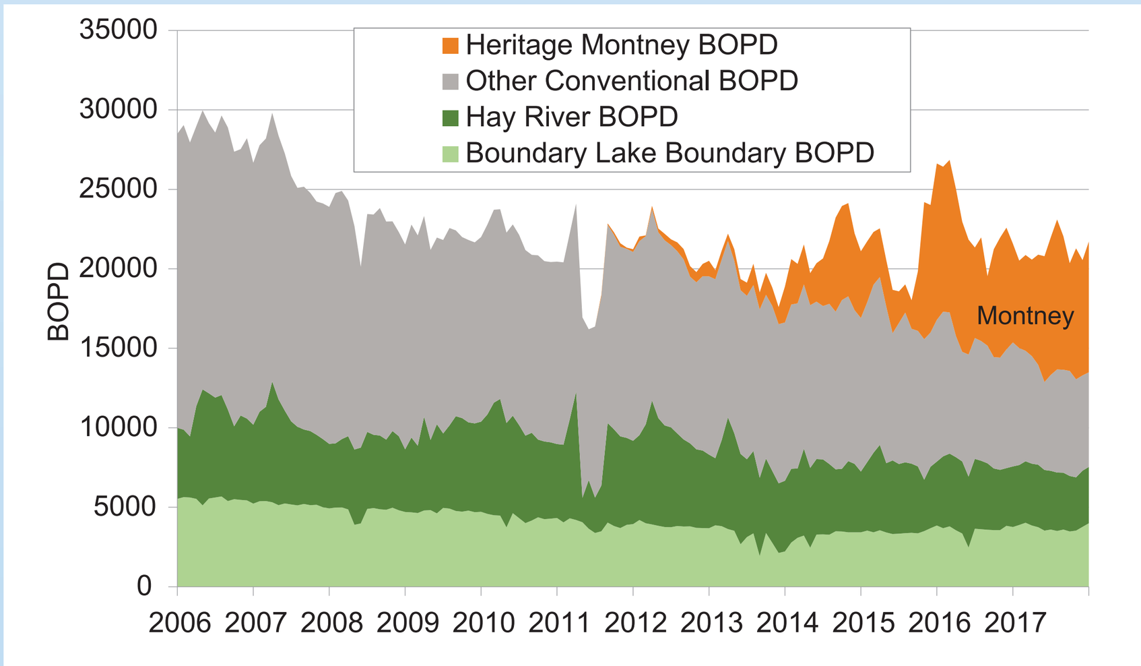
Only two reservoirs showed potential to be top-priority targets, and are highlighted as case studies. Cretaceous Chinkeh Formation sandstones are prospective for tight oil across a broad, poorly-defined fairway downdip from the existing Maxhamish gas field. The Triassic Halfway Formation presents halo oil potential in limited-permeability shoreface sandstones offsetting conventional production, which has been focused on higher-quality tidal channel sandstones.

New Halfway production could be brought on stream quickly using existing infrastructure, but developing the Chinkeh would require new processing and pipeline construction in a relatively remote part of the province.

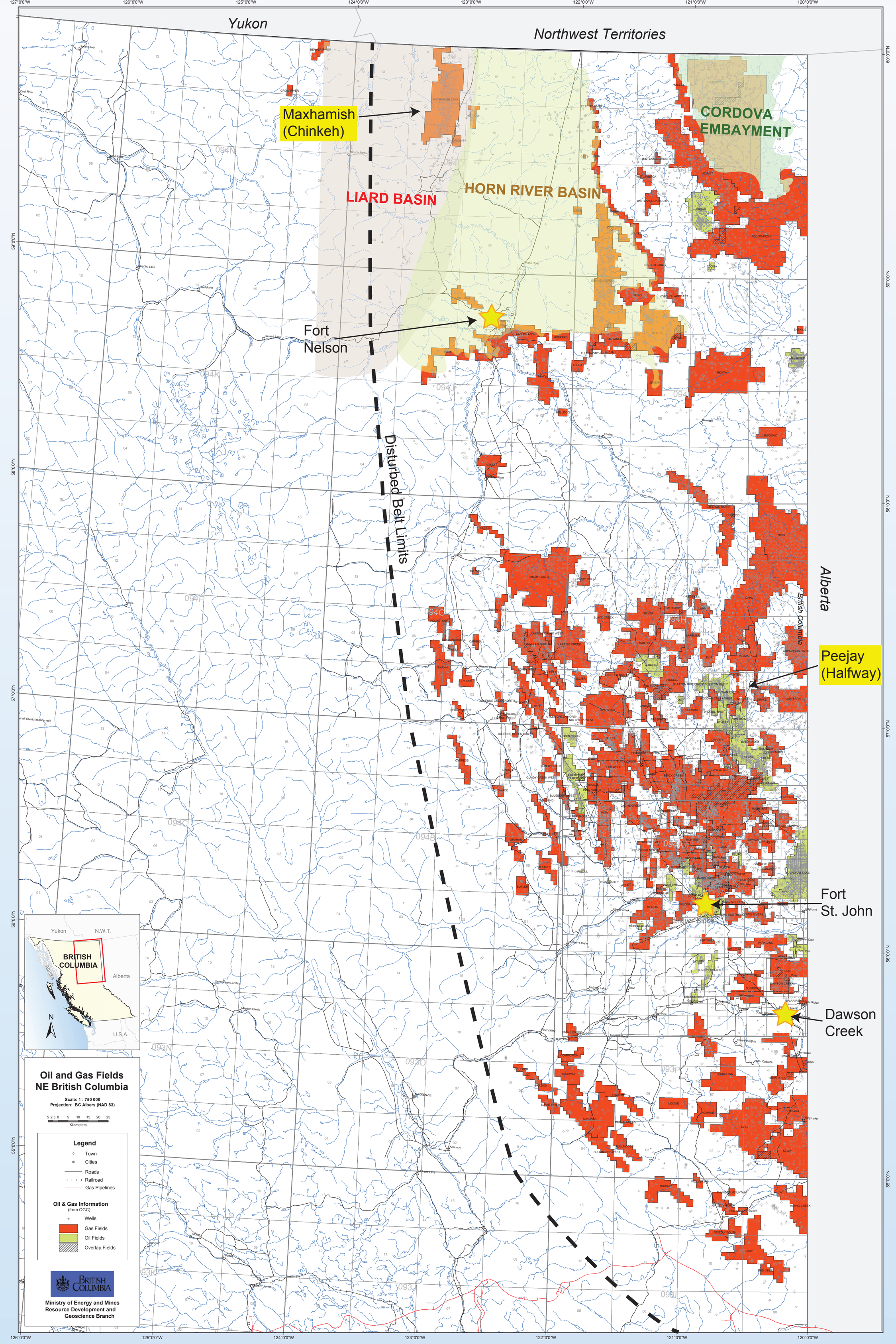
The full report can be viewed on Geoscience BC's website at: http://www.geosciencebc.com/s/2015-021.asp



Unconventional plays and horizontal / multi-frac wells now dominate in northeastern BC.
(BC Ministry of Natural Gas Development, 2016)



Conventional oil production has declined steadily. Only Montney (tight) oil has added substantial volumes.
(BC Oil and Gas Commision, 2018)

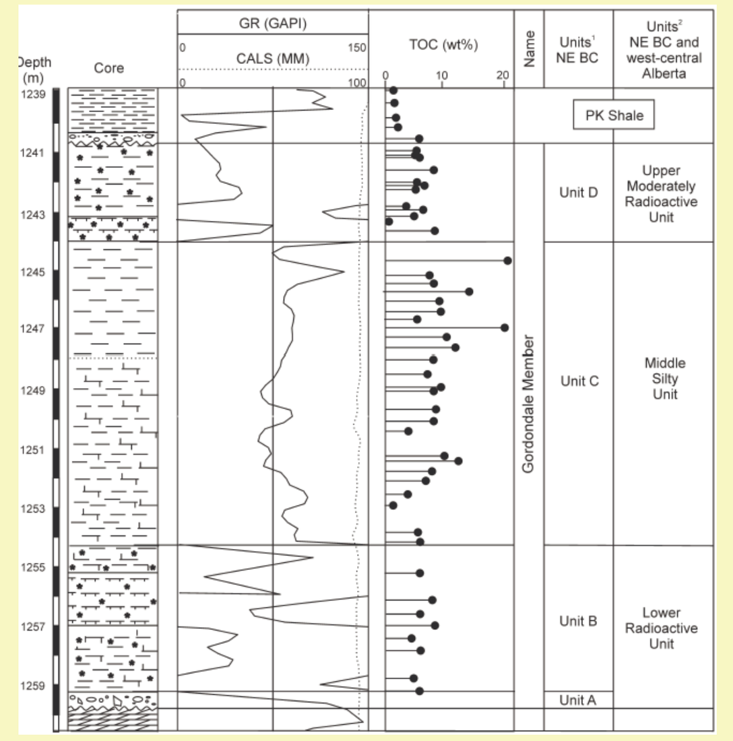


Oil and Gas Fields in NEBC *(BC Ministry of Energy and Mines)*

GORDONDALE ("NORDEGG") SHALE

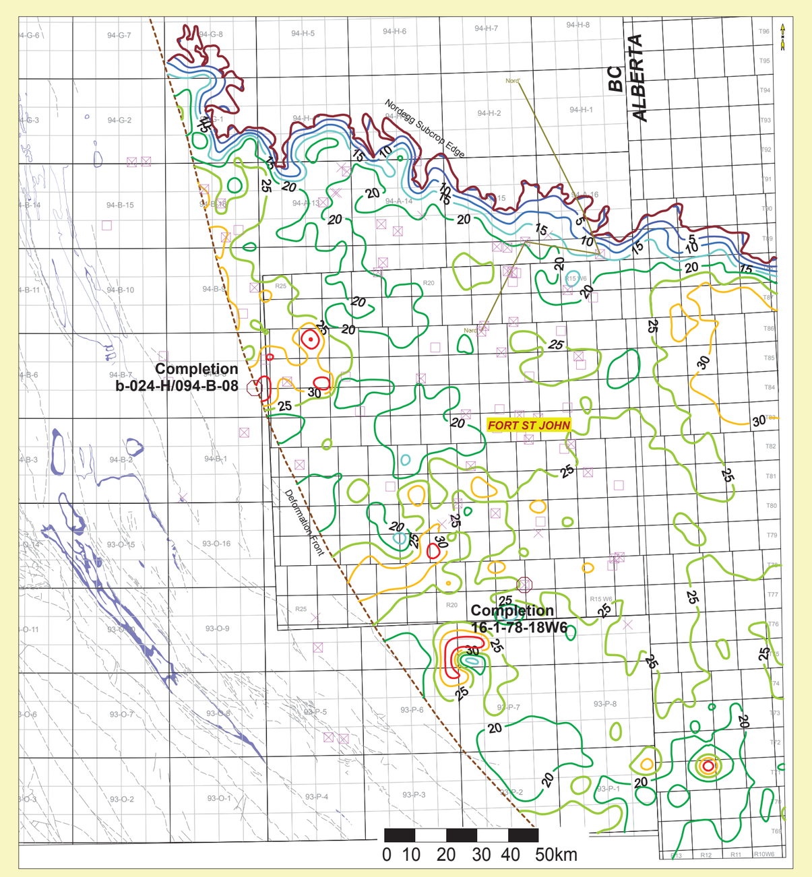
The Gordondale (also called "Nordegg") Member in northwestern Alberta and adjacent British Columbia is a highly-mappable, regionally continuous shale. Ross and Bustin (2006, 2007), described it to consist of mudstones, calcareous mudstones, phosphatic mudstones and phosphatic marlstones. Abundant source rock data show high organic content and oil-prone to gas-prone maturities, and the unit is regarded as an important conventional source rock.

Silica- and carbonate-rich mineralogies and limited geomechanical data suggest that some intervals of the Gordondale should be amenable to hydraulic fracturing. While there has been limited oil production in western Alberta from a few naturally-fractured sections, industry has had little success in fracture stimulating the Nordegg. Two completions in NEBC yielded limited gas flows with some signs of liquids, but operators have not been sufficiently encouraged to pursue the Gordondale further.

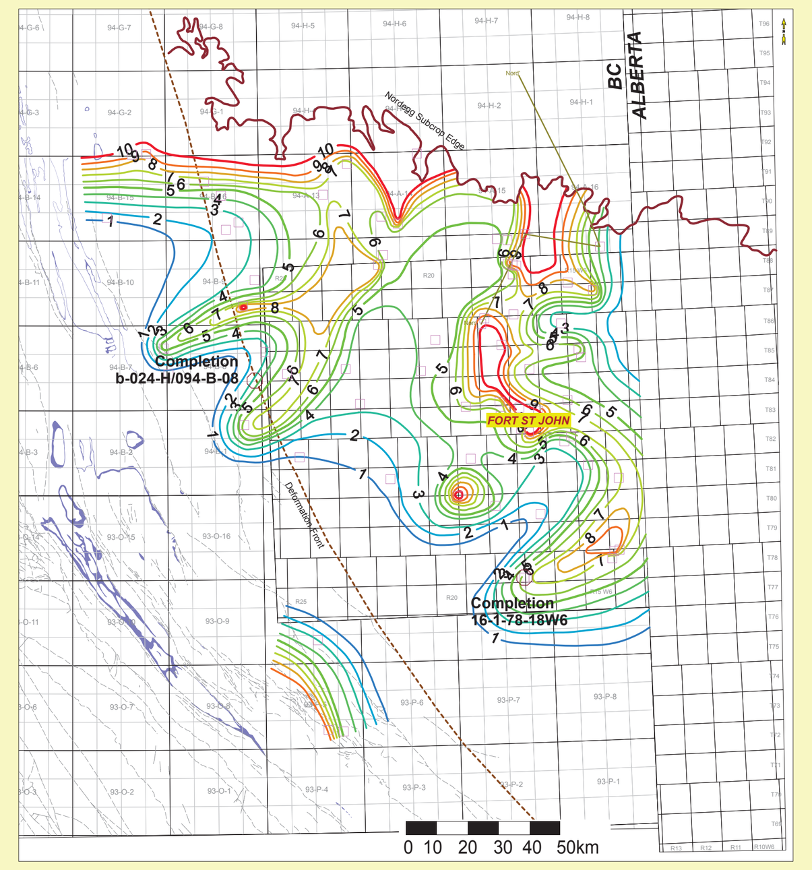


Core description, TOC and stratigraphic subdivision of complete cored Gordondale section, well d-88-H/94-A-13
(Ross and Bustin, 2007)

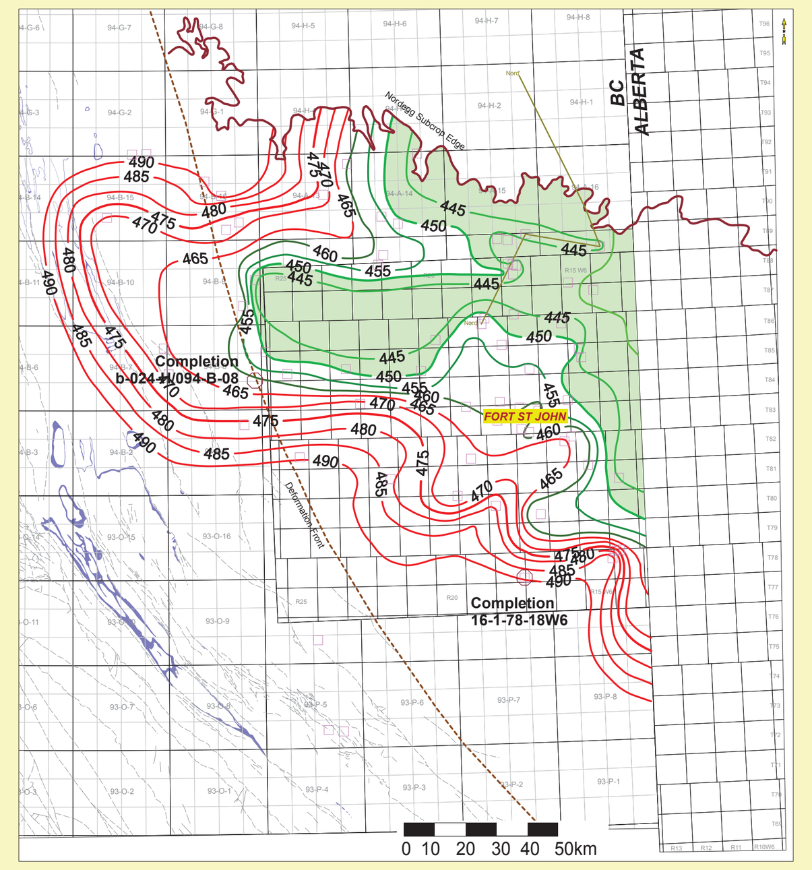
Gordondale - Gross Thickness

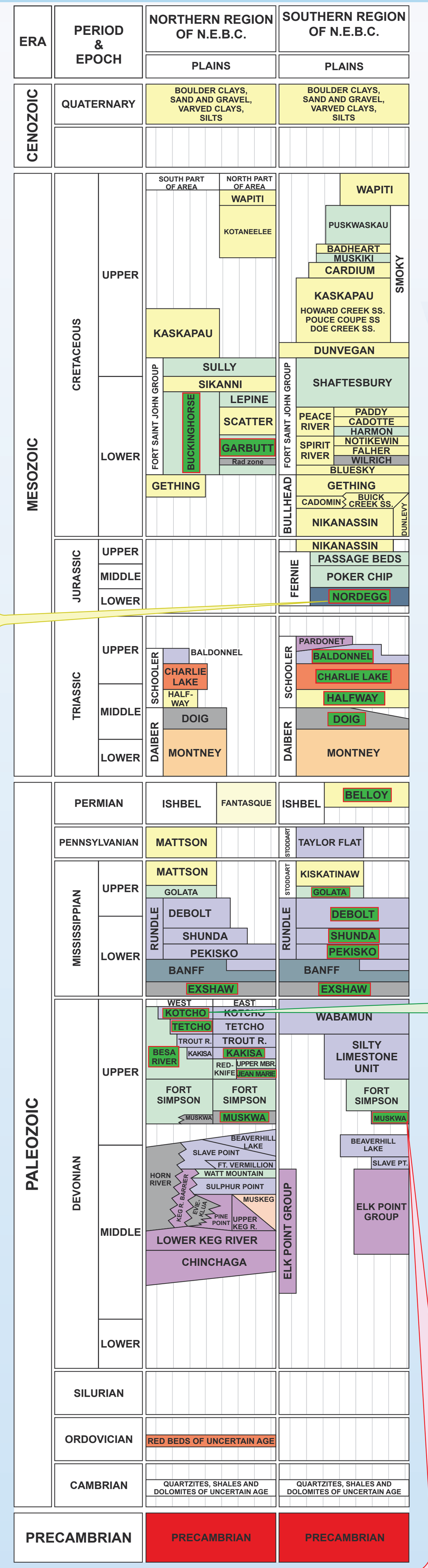


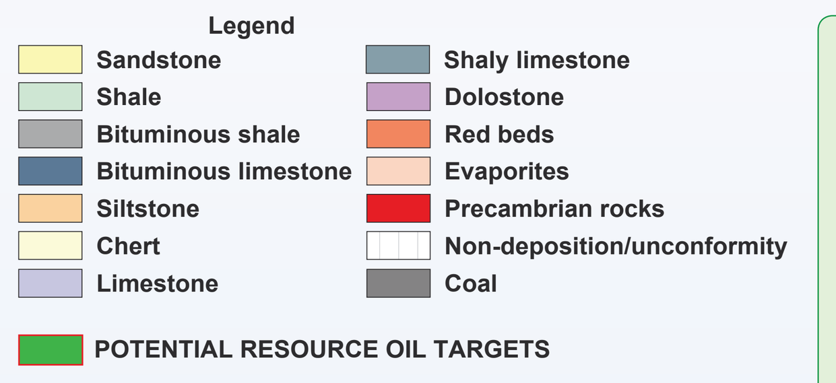
Gordondale - TOC (%)



Gordondale - Tmax (°K)







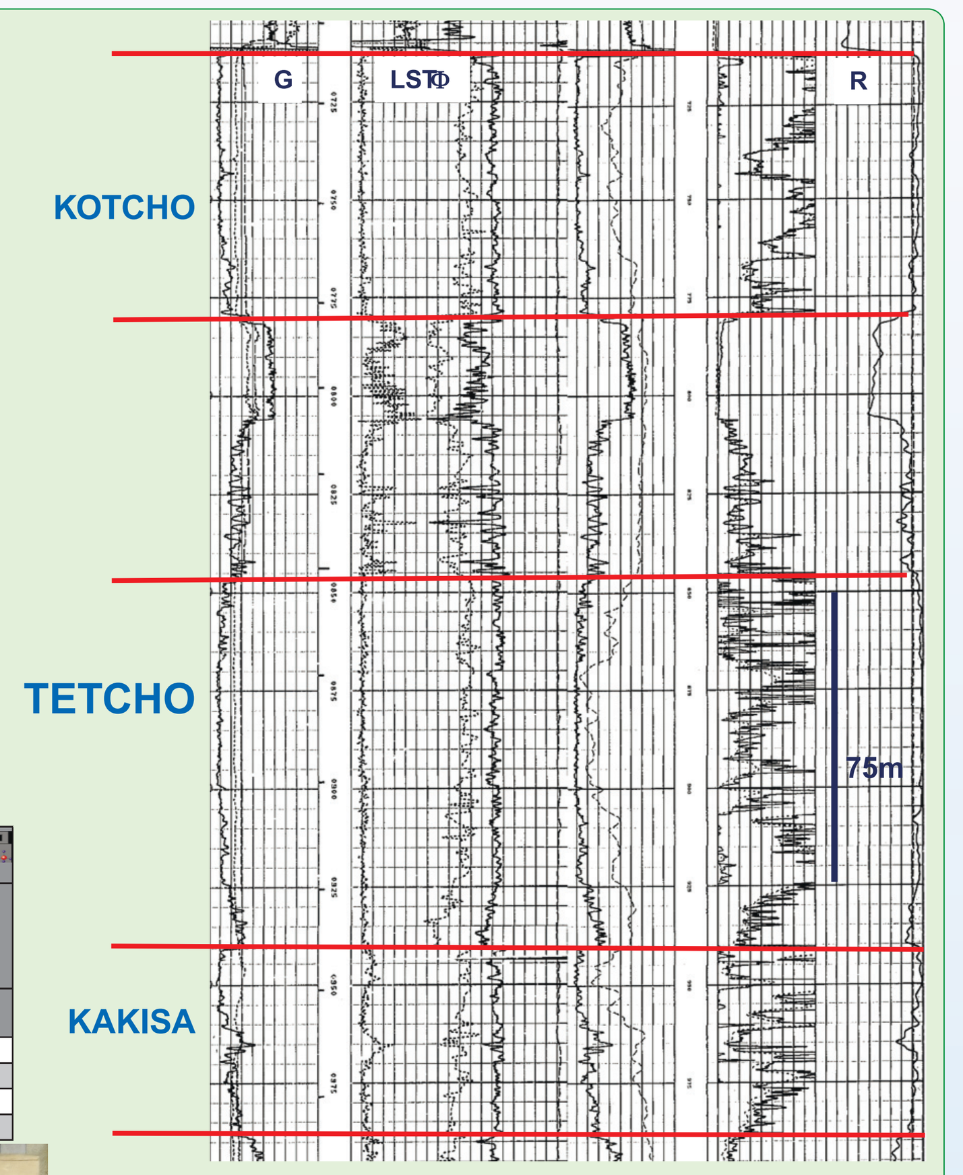
NEBC Stratigraphic Column
(modified from BC Ministry of Natural Gas Development)

TETCHO LIMESTONE

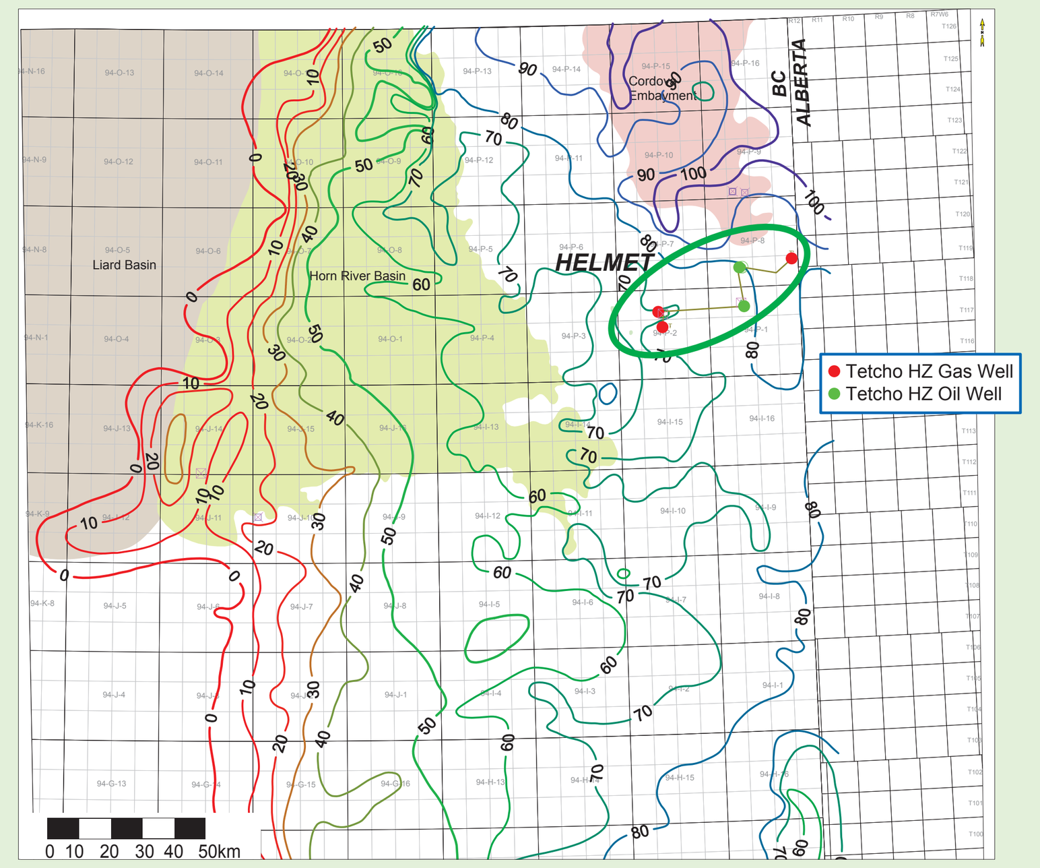
Upper Devonian Tetcho skeletal lime mudstones and wackestones accumulated in a broad open shelfal setting which shaled out westward at the edge of the craton. Unlike many Devonian reservoirs in western Canada, we found no evidence for systematic development of dolomitized or leached reservoirs along specific stratigraphic or structural trends.

Six horizontal wells have been drilled in the Helmet area, three of which were completed for oil. Production rates averaged 73 BOPD, with EUR's around 48 MBO per wellbore. Rock and geomechanical properties suggest a reservoir that can be effectively stimulated, but more work needs to be done to optimize completion methods.

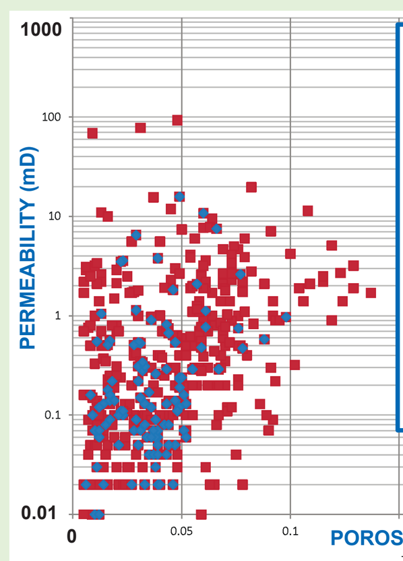
Oil production in the Tetcho and associated Devonian shelfal carbonate reservoirs appears linked to the maturity of the underlying Muskwa source rock, which is in the liquids-rich gas to oil window in the Helmet area.



Tetcho - Gross Thickness



Tetcho - Analytical Data



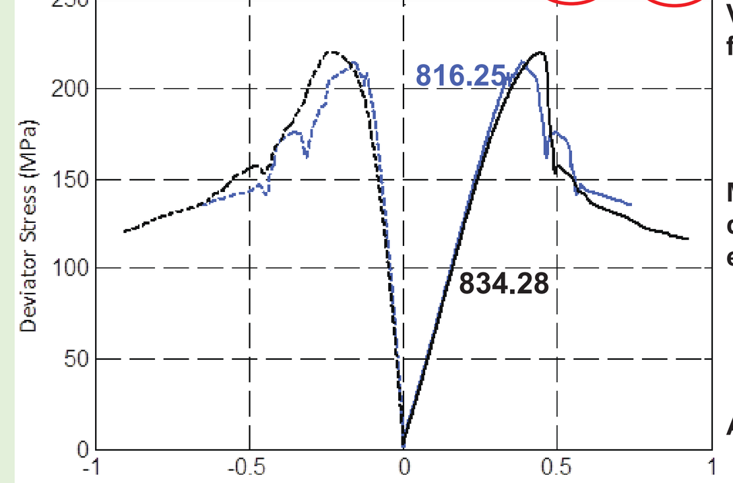
- Standard core analysis data show low porosity and low-moderate permeability
- Seven wells with existing petrographic / geochemical analyses
- New geomechanical data acquired from two cores near oil producers

Tetcho - Analytical Data

Czar Venus d-13-C/94-P-9 Unconfined Porosity and Crushed Permeability									
Sample	Core Depth (m)	Formation	Total Bulk Density (g/cc)	Total Skeletal Density (g/cc)		Total Porosity (%)	GRI Matrix Permeability (mD)		GRI Matrix Permeability (nD)	
			Avg	Avg	Std Dev		Avg	Std Dev	Avg	Std Dev
811.84	811.84	Tetcho	2.66	2.722	0.001	2.34	4.61E-06	3.19E-06	4.61	3.19
822.99	822.99		2.65	2.723	0.001	2.54	4.01E-06	6.69E-07	4.01	0.67
833.53	833.53		2.63	2.719	0.001	3.14	1.26E-05	4.21E-06	12.56	4.21
844.97	844.97		2.67	2.726	0.002	2.00	3.35E-06	5.55E-07	3.35	0.56

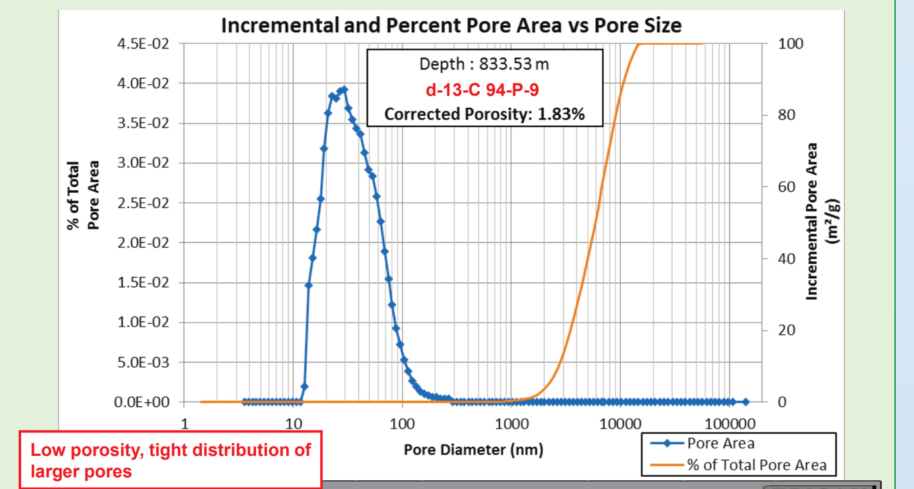
Tetcho - Geomechanics

Czar Venus d-013-C 094-P-09 - Triaxial										
Depth (m)	Confining Pressure (MPa)	Axial Strain at Failure (%)	Compressive Strength (MPa)	Residual Strength (MPa)	Static Young's Modulus (GPa)	Static Poisson's Ratio	Static Bulk Modulus (GPa)	Static Shear Modulus (GPa)	Strain Brittleness	Stress Brittleness
816.25	14.50	0.38	229.15	183.88	63.28	0.30	51.56	24.42	0.88	0.21
834.28	14.50	0.44	234.45	120.65	62.68	0.33	61.75	23.55	0.79	0.52



- Values consistent across formation
  - Very high Young's modulus
  - Average Poisson's ratio
- Moderate plastic deformation, with moderate energy release at failure
  - Spl 816.25 showed drop in stress prior to max load, indicating multiple failure events
- Average compressive strength

Tetcho - Pore Size Distribution

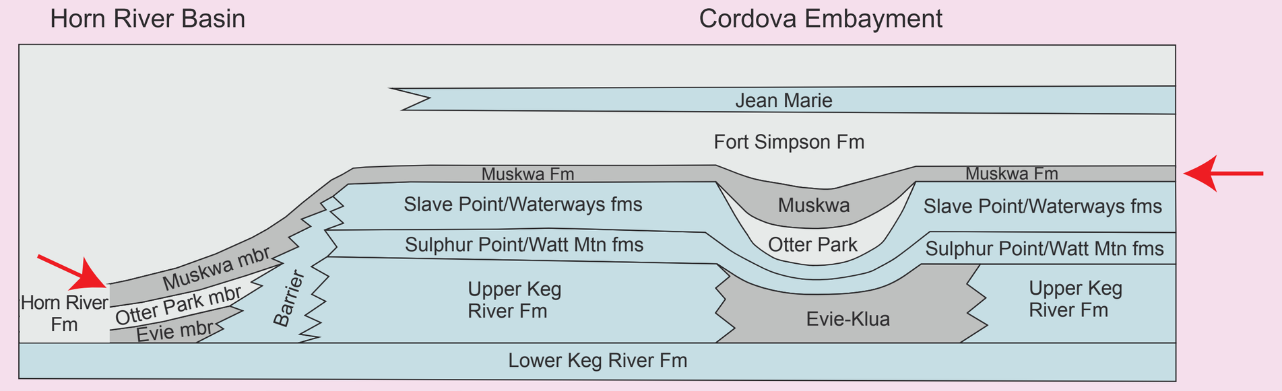


Sample	Core Depth (m)	Density		Porosity (%)	Conformance Corrected Porosity (%)	Peak Range (nm)		Stem Volume Used %
		Bulk (g/cc)	Skeletal (g/cc)			Peak Range	Modal Peak	
811.84	811.84	2.640	2.676	1.59	1.35	4 - 30	12	11
822.99	822.99	2.556	2.626	3.23	2.67	4 - 70	8	41
833.53	833.53	2.631	2.680	2.27	1.83	16 - 200	53	30
844.97	844.97	2.655	2.665	0.63	0.37	10 - 70	23	8

MUSKWA FORMATION

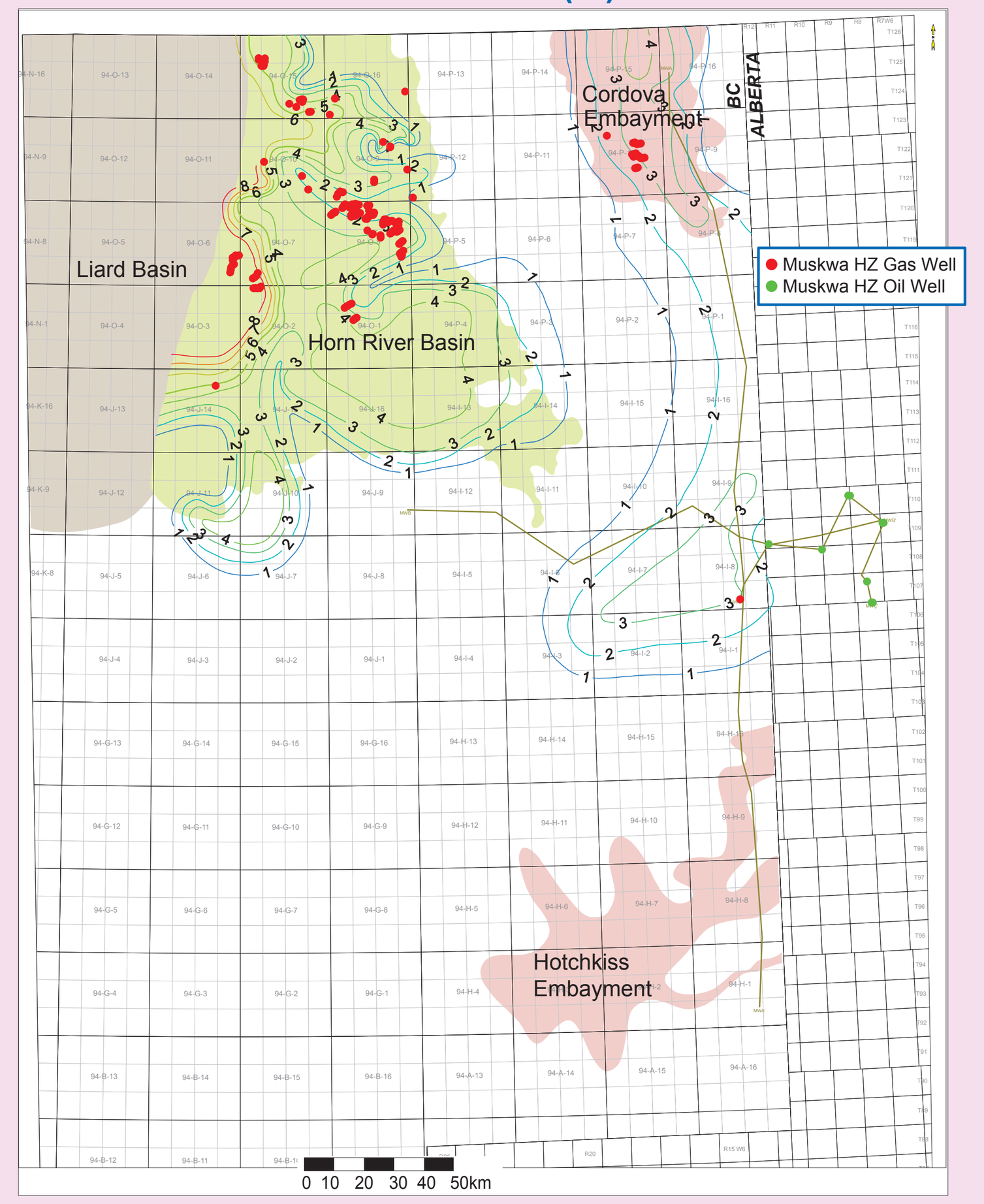
The Muskwa is a pyritic, siliceous, variably calcareous and generally organic-rich dark grey to black shale, and is viewed as a principal source rock in the Western Canada Sedimentary Basin.

In the Horn River Basin, it is a productive shale gas reservoir. Southeastward, along the Alberta / B.C. border, Muskwa maturity levels indicate liquids-rich gas or light liquids generative potential, although reliable maturity data are scarce. Reservoir parameters suggest good productive potential in many sections, with effective drilling and frac stimulation.

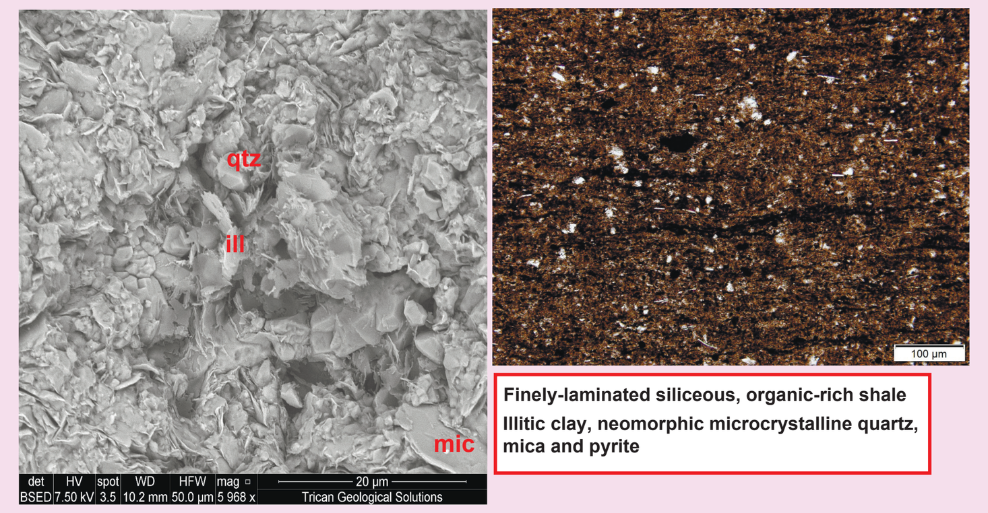


Stratigraphic Relationships, Muskwa Fm, NEBC
(Ferri and Griffiths, 2014)

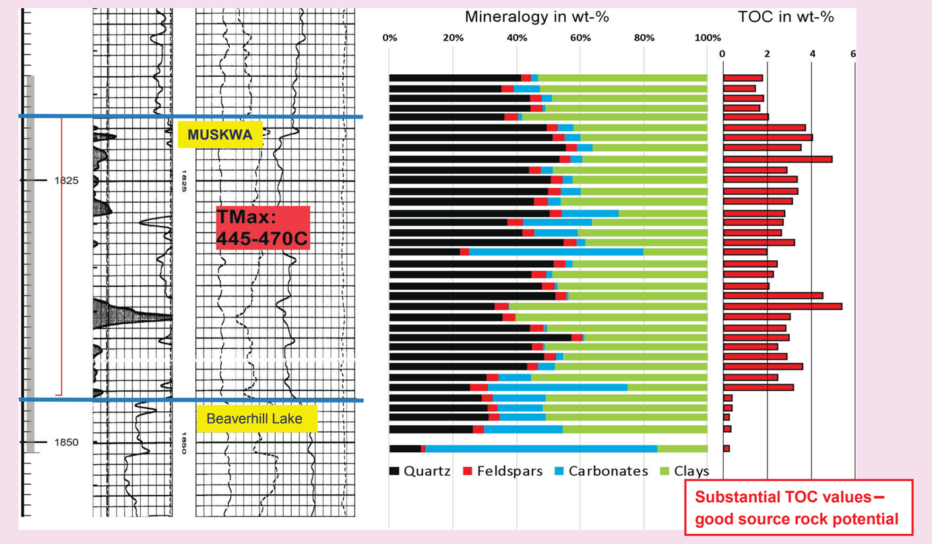
Muskwa - TOC(%)



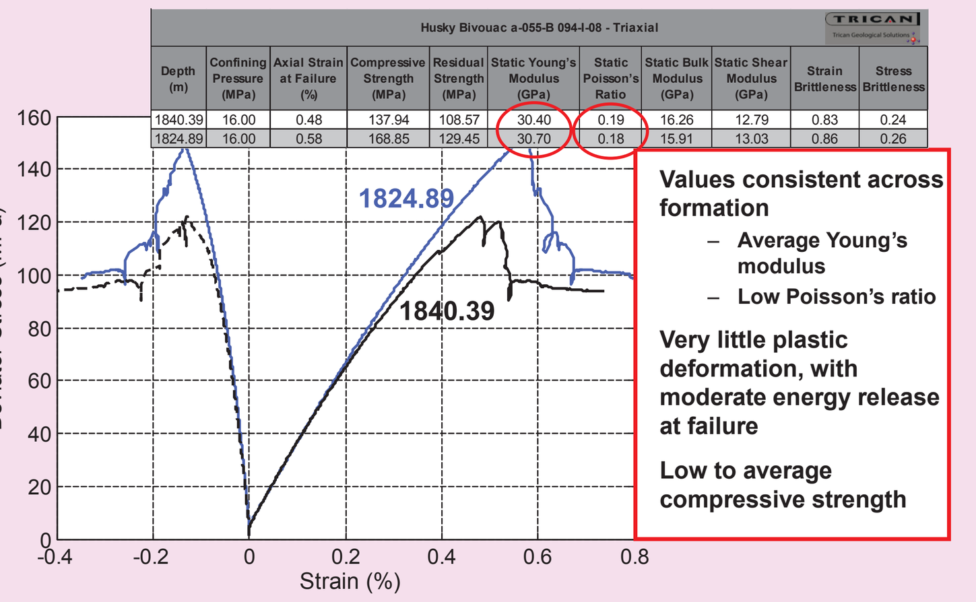
Muskwa - Mineralogy



Muskwa - Mineralogy / Organics

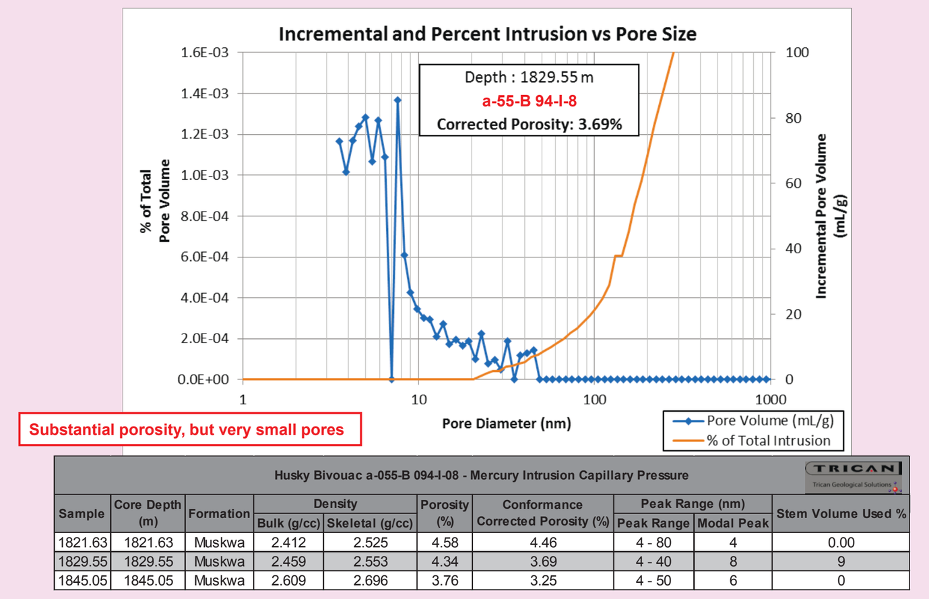


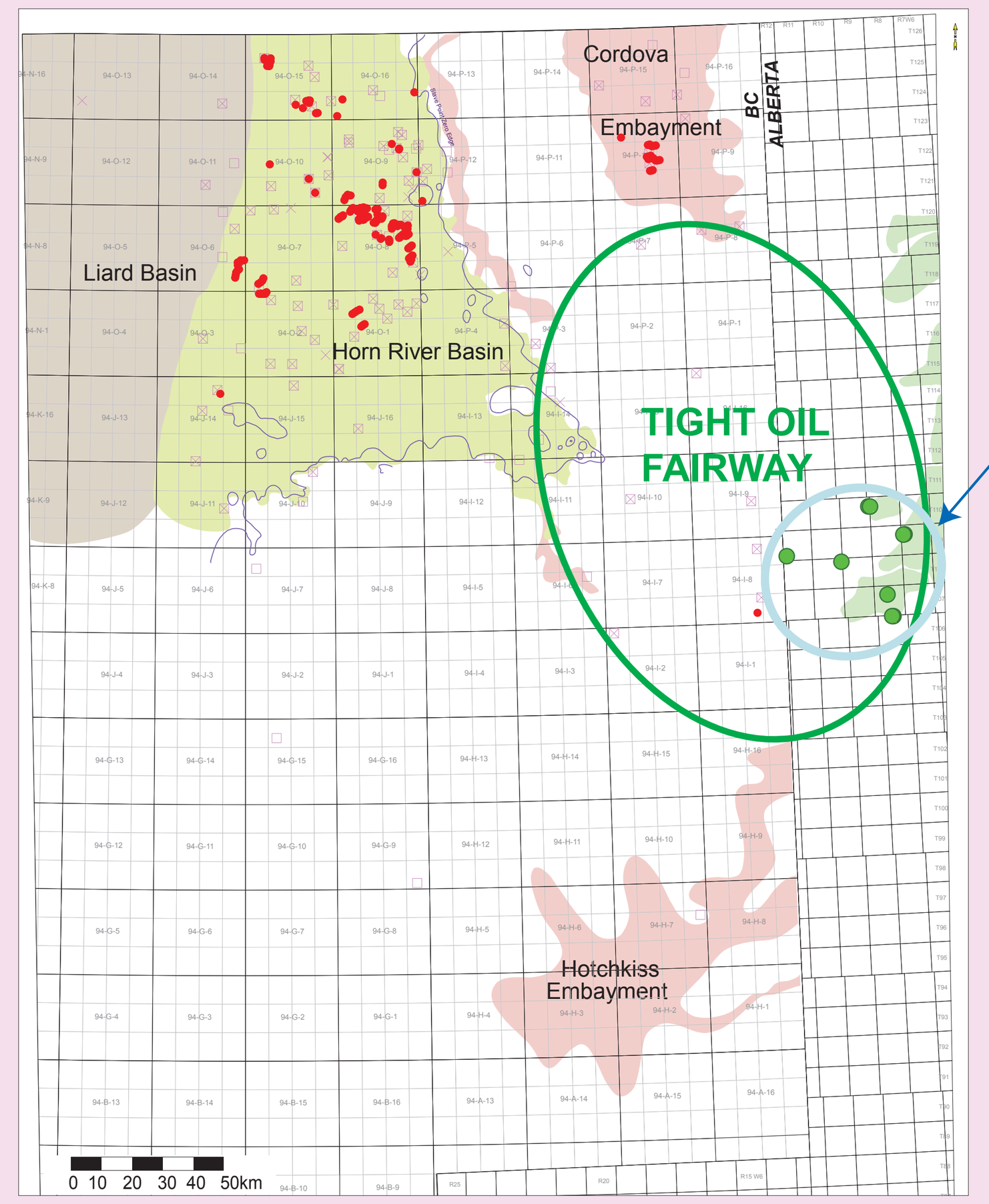
Muskwa - Geomechanics



- Values consistent across formation
  - Average Young's modulus
  - Low Poisson's ratio
- Very little plastic deformation, with moderate energy release at failure
- Low to average compressive strength

Muskwa - Pore Size Distribution





Of 13 wells drilled in the Muskwa, nine were completed as oil wells, and most demonstrated poor to moderate production (Table M1). There is little correlation between performance and drill/complete methodologies, and the nature of reservoir pressures has not been established reliably. As most of this work took place in 2009-2012, we suggest that further completion work using current technology may yield more robust results.

Well	Top Completion	Bottom Completion	Approx HZ Length	Completion Style	No of Fracs	IP bbl/d	EUR bbl
100/16-33-106-09W6/00	2015	3769	1754	Perf, acid, frac	16	54	13232
100/13-34-106-09W6/00	2060	3769	1709	Perf, frac	17	65	9572
100/02-28-107-09W6/02	1858	3179	1321	Perf, frac	3	23	2810
100/08-36-108-11W6/02	1961	3370	1409	Open hole	25	27	3079
100/02-30-109-08W6/00	2219	2990	771	Perf, frac	11	129	116000
100/03-30-109-08W6/00	2115	3120	1005	Open hole	12	51	10870
100/16-06-109-12W6/00	2020	3540	1520	Open hole	14	11	1033
100/04-30-110-09W6/00	2822	3380	558	Open hole	7	31	6993
100/02-25-110-10W6/00	2070	3807	1737	Perf, frac	20	97	55000

Table M1. Horizontal Muskwa oil wells

REFERENCES

Caplan, M.L. and T.F. Moslow, 1997. Tectonic controls on preservation of Middle Triassic Halfway reservoir facies, Peejay Field, northeastern British Columbia: a new hydrocarbon exploration model. Bulletin of Canadian Petroleum Geology, v. 45, no. 4, p. 596-613.

Caplan, M.L. and T.F. Moslow, 1999. Depositional origin and facies variability of a Middle Triassic barrier island complex, Peejay Field, northeastern British Columbia. American Association of Petroleum Geologists Bulletin, v. 83, p. 128-154.

Dixon, J., 2008. Stratigraphic relationships of the Triassic Halfway Formation in the Western Canada Sedimentary Basin. Bulletin of Canadian Petroleum Geology, v. 56, no. 1, p. 62-68.

Ferri, F., and M. Griffiths, 2014. Thermal maturity and regional distribution of the Muskwa Formation, northeastern British Columbia. In Geoscience Reports 2014, British Columbia Ministry of Natural Gas Development, p. 37-45.

Frank, J.H., 2002. Sedimentology, ichnology and stratigraphy of the lowermost Cretaceous, Liard Basin, Canada. M.Sc thesis, University of Alberta.

Jiang, C., A. Mort, M. McMechan and Z. Chen, 2015. Source of Chinkeh oil from Maxhamish Field, Liard Basin, northeastern British Columbia. Geoconvention 2015 Proceedings.

Ross, D.J.K, and R.M. Bustin, 2006. Sediment geochemistry of the Lower Jurassic Gordondale Member, northeastern British Columbia. Bulletin of Canadian Petroleum Geology, v. 54, no. 4, p. 337-365.

Ross, D.J.K. and R.M. Bustin, 2007. Shale gas potential of the Lower Jurassic Gordondale Member, northeastern British Columbia, Canada. Bulletin of Canadian Petroleum Geology, v. 55, no. 1, p. 51-75.

Geoscience BC

Brad J. Hayes, Petrel Robertson Consulting Ltd., bhayes@petrelrob.com

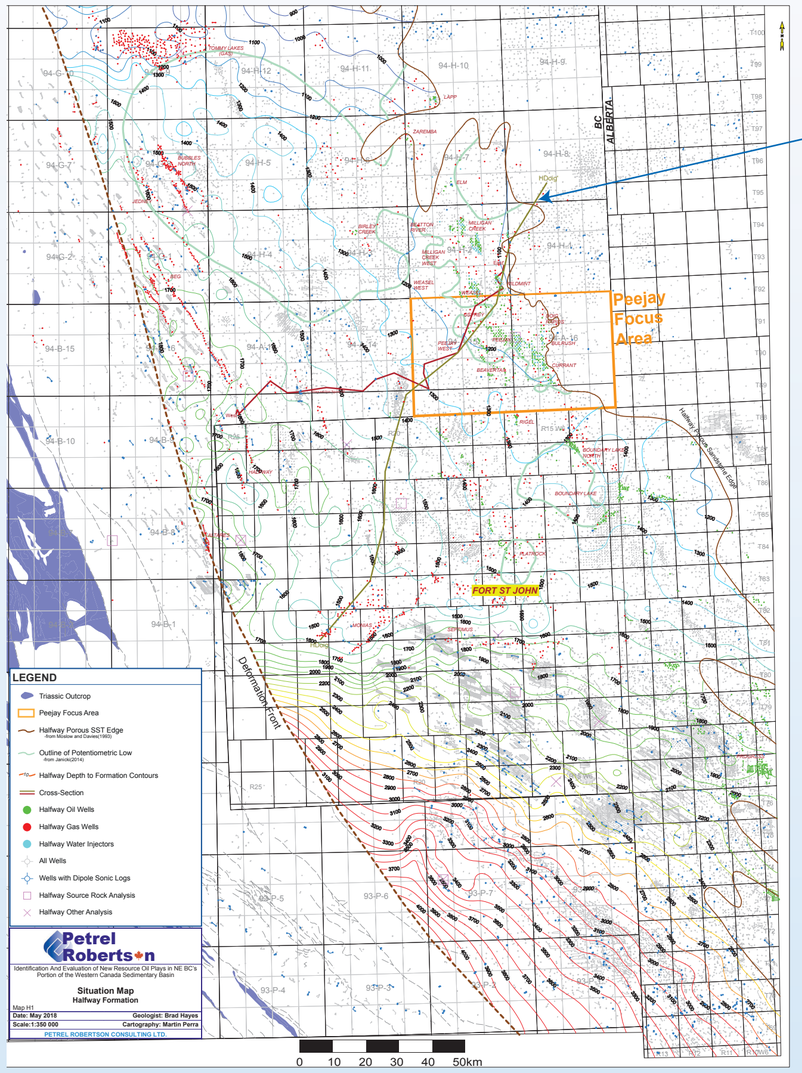
Carlos Salas, Geoscience BC, salas@geosciencebc.com

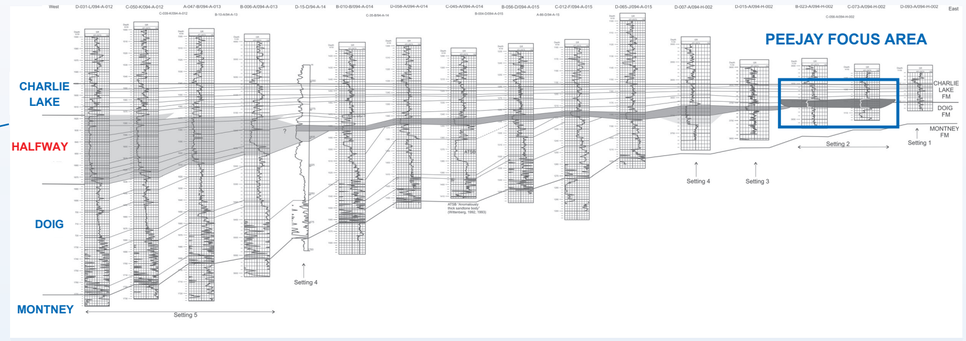
Raphael Wust, AGAT Laboratories, wust@agatlabs.com

Howard Anderson, howard.anderson@outlook.com

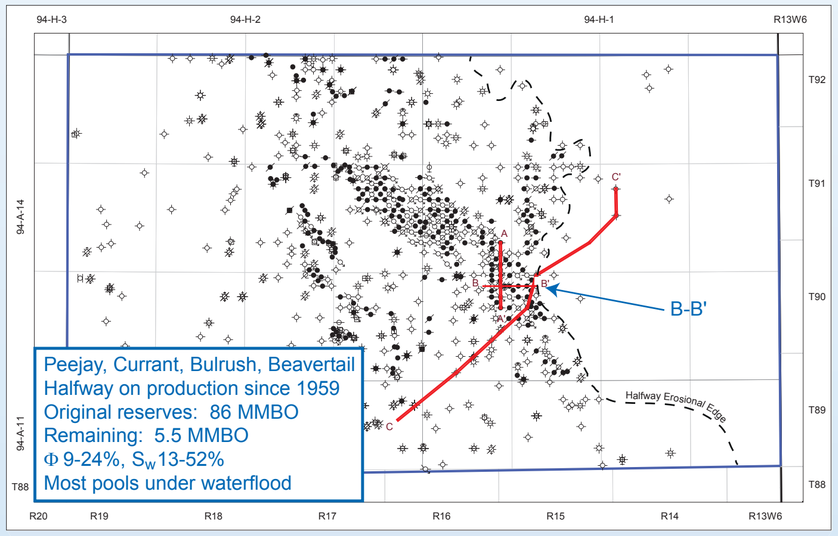
Geoscience BC is an independent, non-profit organization that generates earth science in collaboration with First Nations, local communities, governments, academia and the resource sector. Our independent earth science enables informed resource management decisions and attracts investment and jobs. Geoscience BC gratefully acknowledges the financial support of the Province of British Columbia.

HALFWAY FORMATION PEEJAY FOCUS AREA CASE STUDY





Regional SW-E Halfway section HD-HD'
Note Eastward-thinning shallow marine package, exhibiting complex internal stratigraphic architecture, and lying on Doig Formation.

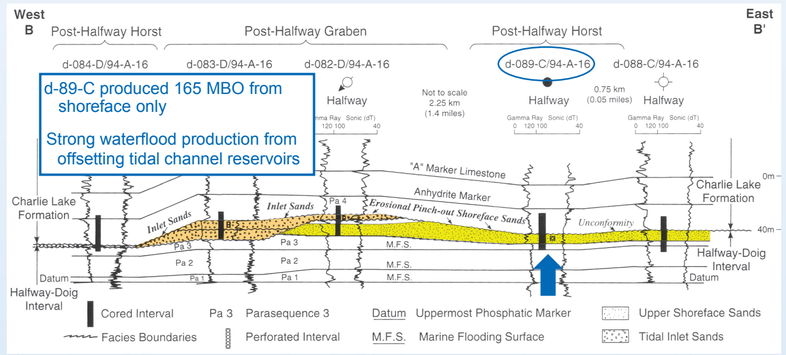


Peejay focus area

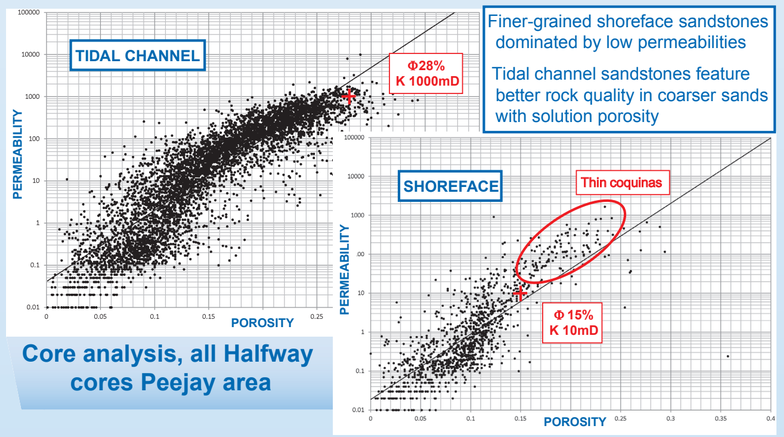
In the broad fairway of Halfway oil production trending across NEBC, high-quality tidal channel and upper shoreface reservoirs have been developed in many pools strongly compartmentalized by structural and stratigraphic elements. Most Halfway exploration and development was undertaken in the 1980's and earlier, and oil pools are developed almost exclusively with conventional vertical wells.

Flanking tidal channel reservoirs, Halfway regional shoreface reservoirs exhibit consistent reservoir quality, are regionally charged with oil, and are capable of oil production from vertical wells in isolated cases. Detailed reservoir and production analysis in the Peejay area demonstrates that there may be abundant opportunity to develop lower-quality Halfway "halo" shoreface reservoirs in areas undrained or ineffectively drained by existing vertical producers.

Halfway "halo" oil prospectivity should be assessed offsetting conventional production along the oil fairway, where abundant historical data are available. Shoreface reservoir thickness, quality, and in-place oil resources should be characterized in detail, and detailed structural mapping should be undertaken to identify reservoir compartments. Horizontal wells may not only enable economic development of marginal-quality sandstones, but may tap into isolated small tidal channels or better-quality coquinoid sandstone developments in the shoreface.



Stratigraphic cross-section B-B', demonstrating stratigraphic separation of tidal channel reservoirs and shoreface sandstone section at d-89-C/94-A-16 *(Caplan and Moslow 1997)*



Core analysis, all Halfway cores Peejay area

Production Analysis
Peejay Focus Area

In order to assess "halo" oil potential in the Halfway, we examined production from tidal channel (high-quality) and regional shoreface (generally low-quality) sandstone reservoirs in the Peejay area, relying on reservoir analysis by Caplan and Moslow (1997, 1999). In addition to Peejay, the focus study area also includes Halfway pools at Beavertail, Currant, Bulrush, Doig Rapids and Osprey.

Key parameters for the Peejay area Halfway include:

- Original oil in place: 244 MMBO
- Initial reserves: 86 MMBO
- Production to date: 80.5 MMBO
- Porosity: 9-24% (average 17%)
- Water saturation: 13-52% (average 29%)
- Oil density: 810-846 (average 823) kg/m³ (light oil)

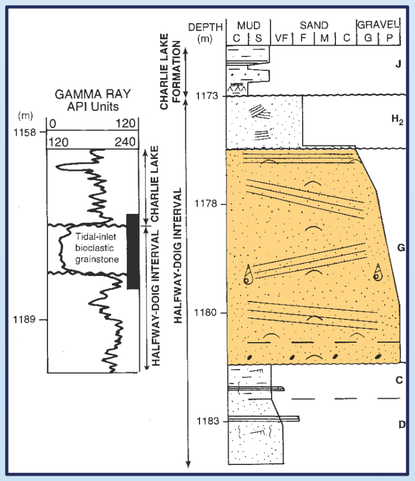
Examining test and production data, we discovered (not surprisingly) that almost all evaluations and completions were conducted on the tidal channel reservoirs, which are readily distinguished from tighter shoreface sandstones on density and sonic logs. Shoreface sandstones were tested in a number of wells, but we found only nine wells where they were DST'd alone, and five where they were completed alone – either separately from tidal channel facies in the same well, or in wells where there are no tidal channel facies. Most test results showed the shoreface to be tight by conventional standards, but oil has been produced from all five Halfway shoreface completions.

At well d-89-C/94-A-16, a Halfway shoreface section was cored, and showed permeabilities of 4mD or less throughout. An eight-foot section was acidized and frac'd, and 164,730 barrels oil produced at rates up to 100 BOPD between 1966 and 1987. A reservoir pressure of 1312 psia was taken shortly after production commenced; a measurement in 1986 showed a decline to 435 psia.

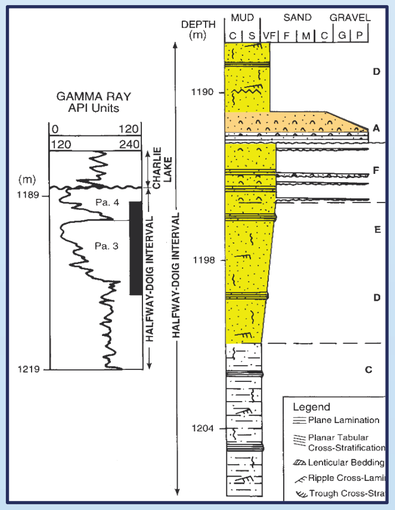
Surveying seven offsetting Halfway wells (five producers and two water injectors, all completed in tidal channel facies), we saw fairly consistent pressure behaviour and good waterflood responses, with reservoir pressures mostly within a fairly narrow band of 1100-1400 psia. The five producers show limited gas/oil ratio increases and water breakthrough with increasing water/oil ratios.

Production behaviour at d-89-C demonstrates that it is in a separate reservoir compartment; besides the declining reservoir pressures, we see little water production and generally smoothly-declining oil production rates. Compartmentalization results from stratigraphic separation of the shoreface reservoir at d-89-C from tidal channel reservoirs producing in the offsetting wells.

Effective horizontal drilling and multi-frac completion of low-permeability shoreface sandstone "halo" facies could substantially improve oil recovery from the Halfway Fm at Peejay.

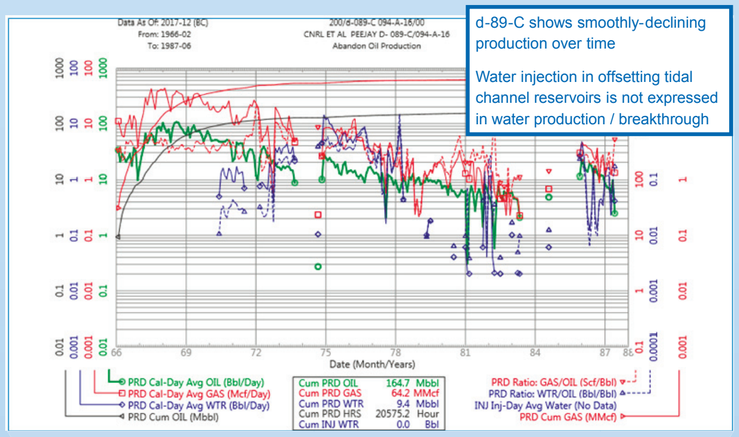


TIDAL CHANNEL FACIES
d-99-C / 94A-16

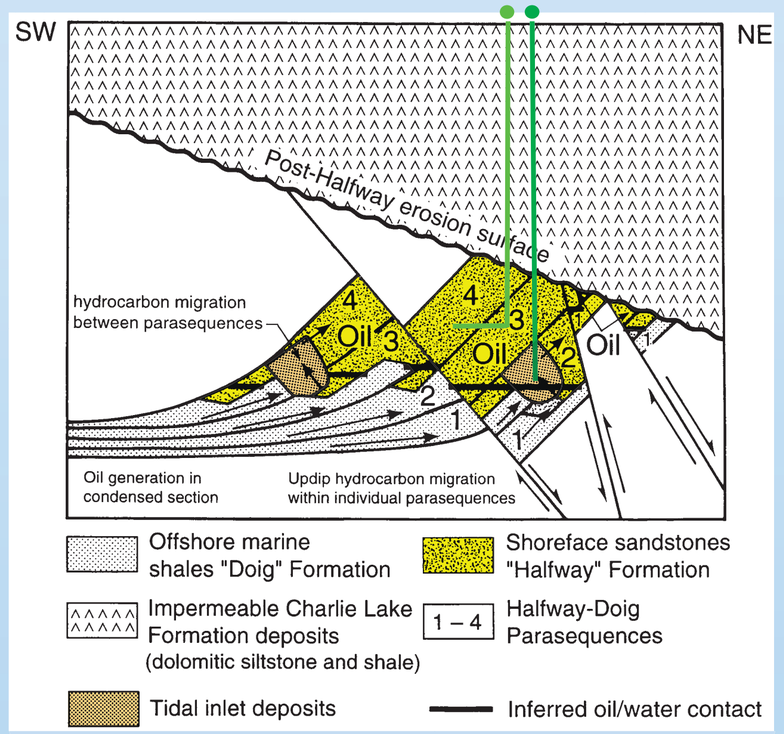


SHOREFACE FACIES
d-27-C / 94A-16

Typical Halfway tidal channel and shoreface facies in core
(Caplan and Moslow, 1997)



Production plot, well d-89-C/94-A-16



Schematic horizontal wellbore accessing 'halo' oil in Halfway shoreface sandstones offsetting primary tidal channel reservoirs. *(Caplan and Moslow 1997)*