

Forecasts for Canada oil and gas production

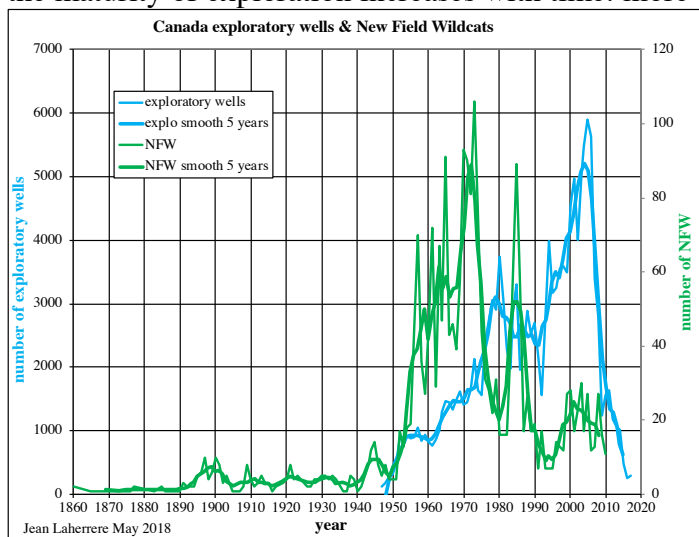
To follow my last paper “Forecasts for US oil and gas production”

<https://aspofrance.files.wordpress.com/2018/03/lahall19march.pdf>, this forecast for Canadian oil and gas production is based on better data, because, in the US, oil and gas belong to the land owner, when in Canada they belong (with a few exceptions) to the government. In Texas, under the clause of confidentiality, oil producers can wait two years before reporting the right production data; USDOE/EIA reports monthly recent estimates of the US production and not measures. In Canada production data is reported by the provinces agencies (BCOGC for BC, AER for Alta and gov.sk.ca for Sask.) and by the national agency NEB.

The main assumption for forecasting future production is to estimate “ultimate” using the HL (Hubbert Linearization) of past production and to plot a symmetrical decline of the last cycle (it is worth to notice the symmetry of the past cycles of most graphs of this paper).

Many consider only one cycle with one peak, but the reality shows several cycles for many reasons. Life is a succession of ups and downs, of births and deaths.

In Canada, the number of exploratory wells displays several cycles, the number of New Field Wildcat (green) has a peak in 1973 when the number of exploratory wells a peak in 2005, but every time sharp increase, sharp decrease. A smoothing on 5 years does not change much. But the maturity of exploration increases with time: more exploratory wells, but less new fields.

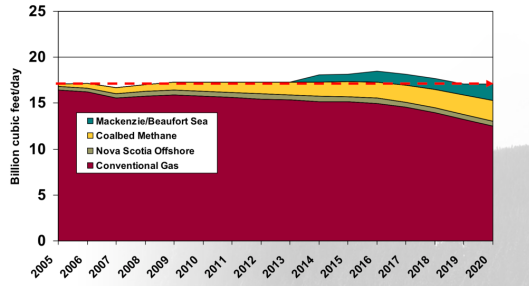


-Natural gas

There is no consensus on the definition of unconventional and there is confusion between tight gas and shale gas, because both use the same technology = horizontal drilling and hydraulic fracturing (fracking). The main difference is that the shale gas is adsorbed in organic matter, when the tight gas is in pore space

	Shale gas	Tight gas
Grain-size	Mostly mud	Substantially silt or fine sand
Porosity	up to 6%	up to 8%
TOC	up to 10%	up to 7%
Permeability	up to 0.001 mD	up to 1 mD
Source	Mostly self-sourced	Mostly extra-formation
Trap	None	Facies and hydrodynamic
Gas	Substantially adsorbed	Almost all in pore space
Silica	Biogenic, crypto-crystalline	Detrital quartz
Brittleness	From silica	From carbonate cement

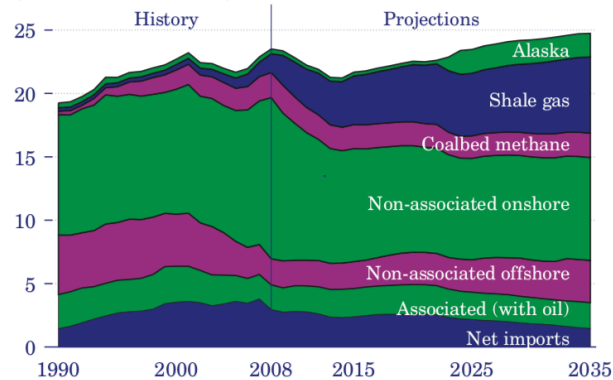
CAPP 2007 forecasts no unconventional gas outside CBM, tight gas is considered as conventional (in 2010 EIA reported tight gas as conventional in contrary with previous and later reports where tight gas is unconventional as shale gas and coalbed methane)



EIA/AEO in AEO2010 considers tight gas as conventional, but in AEO2011 tight gas is unconventional, as CBM and shale gas; but EIA has also completely changed the global volume (in 2000 23 Tcf for AEO 2010 when 19 Tcf for AEO 2011) showing the lack of reliability of the past data! For the last few years the quality of EIA national and international data has greatly deteriorated.

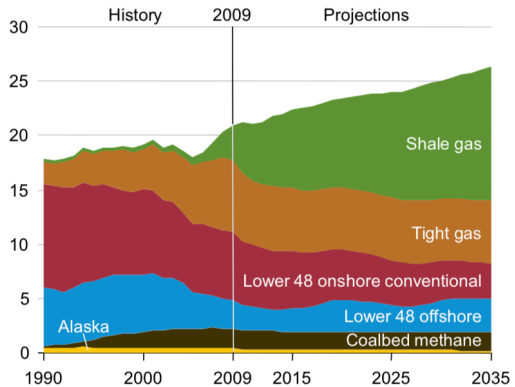
AEO2010 no tight gas

Figure 3. U.S. natural gas supply, 1990-2035 (trillion cubic feet)



AEO2011 tight gas

Figure 2. U.S. natural gas production, 1990-2035 (trillion cubic feet per year)

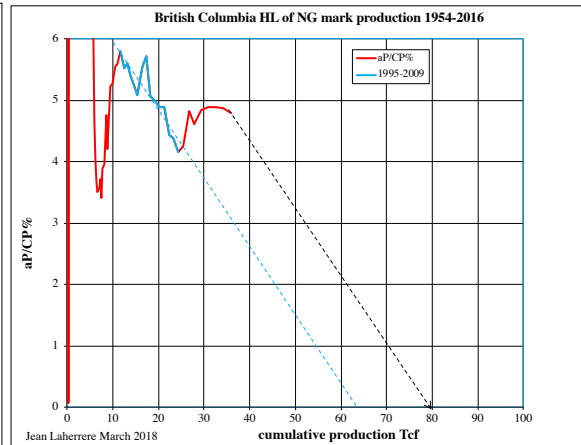
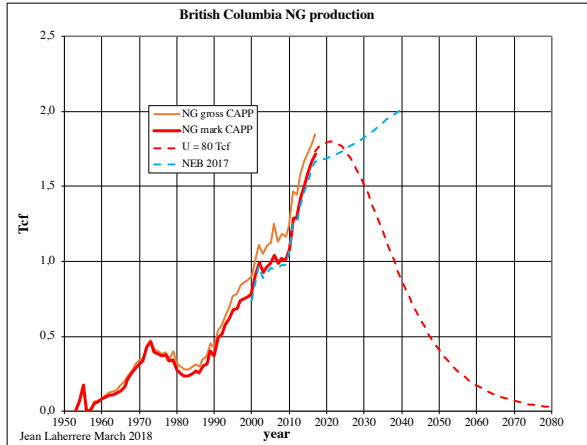


It is not surprising to find below a certain confusion between tight gas, shale gas and conventional gas. There is the same confusion between reserves and resources.

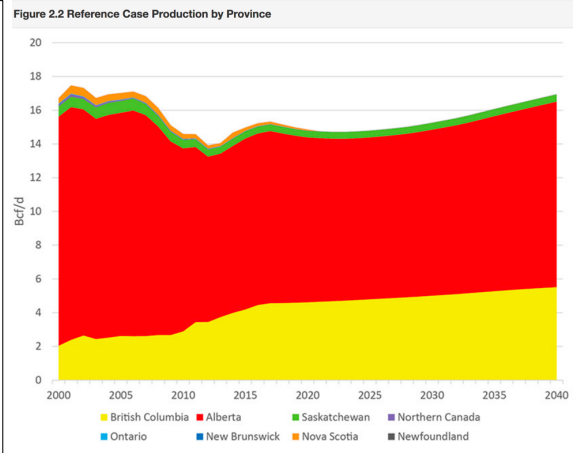
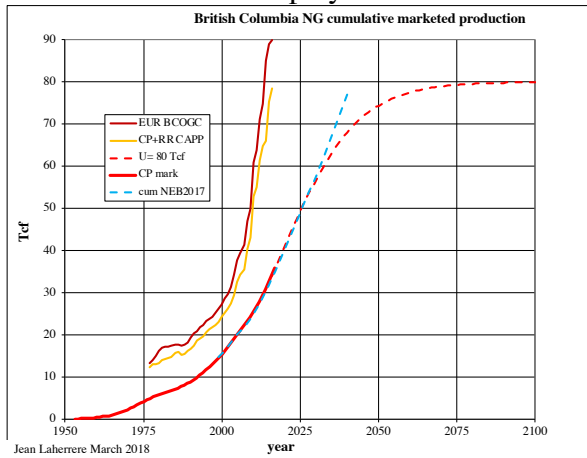
-British Columbia = BC

The BC annual NG production is rising since 1985 and likely will peak around 2020, assuming an ultimate of 80 Tcf.

The HL of past production 1995-2009 is about 62 Tcf, and from 2016, assuming a parallel trend towards 80 Tcf, when BCOGC reports an ultimate of 90 Tcf and CAPP 78 Tcf for cumulative production plus remaining reserves.



NEB2017 forecast displays a continuous rise up to 2040, contrary to my forecast in decline!



-Montney play

BCOGC 2016 “British Columbia’s Oil and Gas Reserves and Production Report” notices that in the Montney basin the resource estimate is 1965 Tcf (queer accuracy with 4 significant digits! what is the uncertainty of such estimate? Several hundred Tcf at least!), when the initial reserves (it is useless to add recoverable because reserves are what will be recovered) are 35.4 Tcf, **less than two per cent (1.8%) recovery factor**. Most of estimates use much larger recovery rate. The recovery rate for Liard Basin is 0.01%!

Reserves: What we can get.
Resources: What is there.

Resources
What is there:
• Potentially recoverable
• Undiscovered accumulations
• Unknown certainty

Reserves
What we can get:
• Known accumulations
• Recoverable
• Established technology
• Economic

The resource volume provides an understanding of the size of these accumulations and potential for further development. An often used graphic when comparing resources and reserves is the iceberg image to the right. It shows the vast quantity of hydrocarbons available (resources) versus the known established reserves.

A comparison between the resource estimate and remaining reserves (Table 1) illustrates the large differences in gas volumes between the two categories. For example, in the Montney basin the resource estimate (P50) is 1,965 Tcf; however, currently recoverable initial raw gas reserves of 35.4 Tcf is less than two per cent.

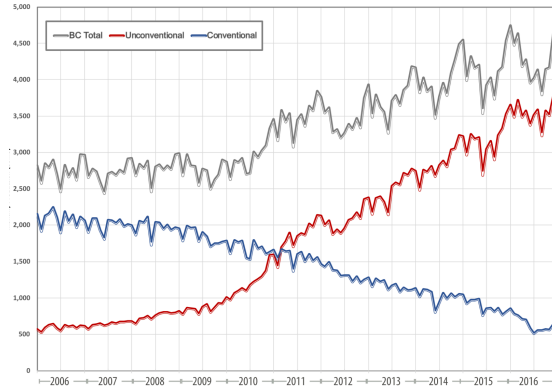
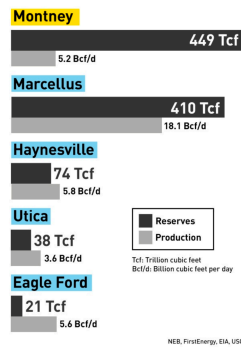
Table 1: Unconventional Gas Resource, Reserves and Cumulative Production

Basin/Play	Resource		Reserve			% Reserve per Resource
	Basin Total GIP Resource (Tcf)	Ultimate Potential (Marketable, Tcf)	Initial Raw Gas Reserves (Raw, Tcf)	Remaining Reserves (Raw, Tcf)	Cumulative Production (Raw, Tcf) ^a	
Montney ¹	1,965	271	35.40	29.84	5.61	1.80%
Liard Basin ²	848	167	0.10	0.07	0.04	0.01%
Horn River Basin ³	448	78	11.72	10.72	1.00	2.62%
Cordova ⁴	67	9	0.11	0.06	0.05	0.16%
Deep Basin (Cadomin, Nikanassin) ⁵	9	7	1.04	0.41	0.64	11.67%
Total	3,337	532	48.37	41.10	7.33	1.45%

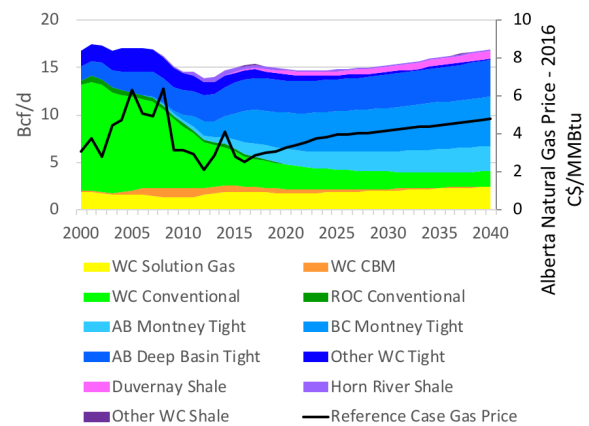
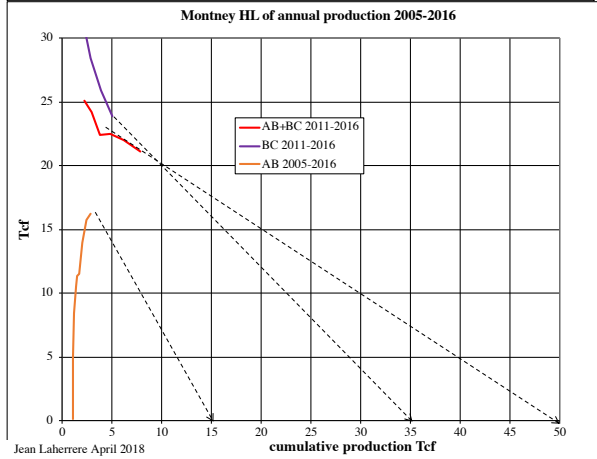
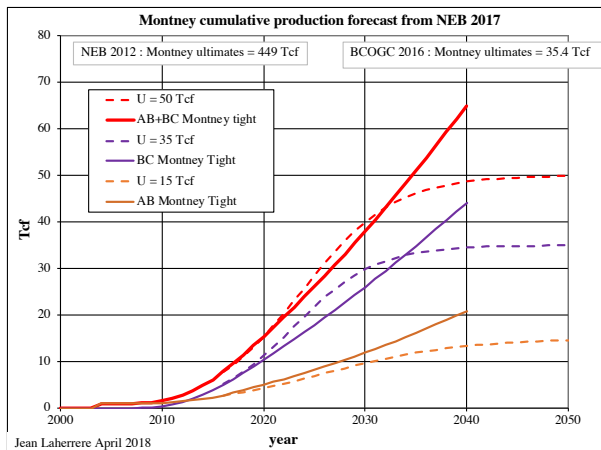
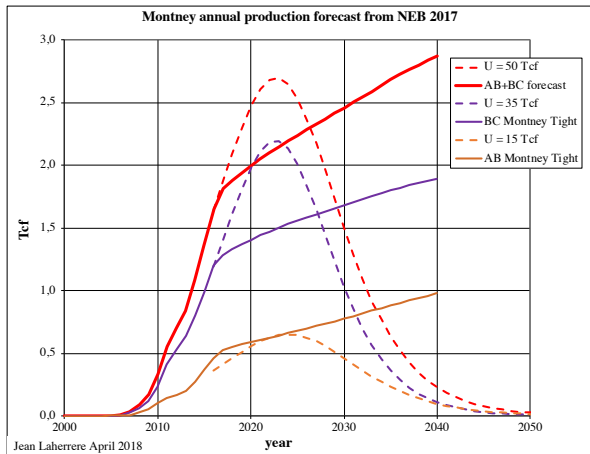
It is amazing to find that NEB reports Montney reserves 13 times higher than BCOGC, which is involved in the production!

NEB has estimated the Montney reserves at 449 Tcf compared with 410 Tcf for Marcellus. But they confuse resources (in the ground) and reserves (what will be recovered)!

Compared to 4 large shale natural gas plays in the U.S



NEB 2017 Montney production forecast displays a constant rise from 2017 to 2040, assuming an ultimate of 449 Tcf (178 Tcf for Alberta and 271 Tcf for BC): for me it is unlikely, more likely 50 Tcf (35 Tcf for BC and 15 Tcf for Alberta)! Montney production will peak around 2022.



Montney reservoir is Triassic, but was reported in 2008 as Paleozoic

Moslow & Zaitlin AAPG 2008

http://ags.aer.ca/document/OFR/OFR_2012_06.pdf

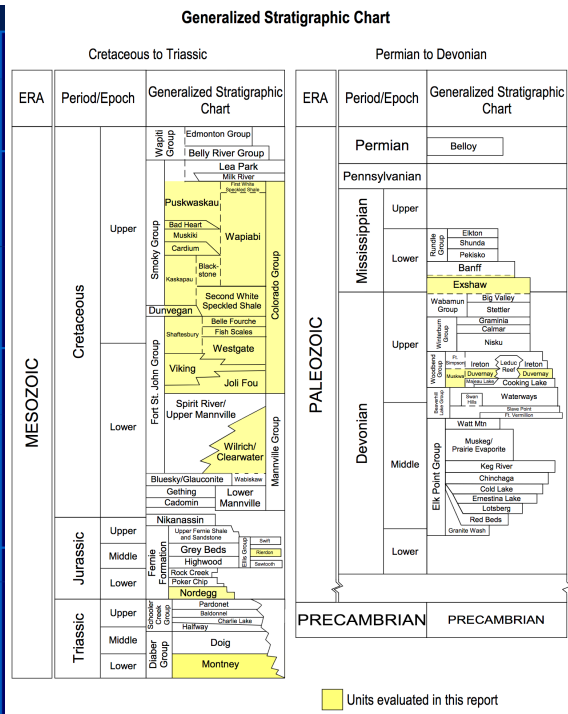
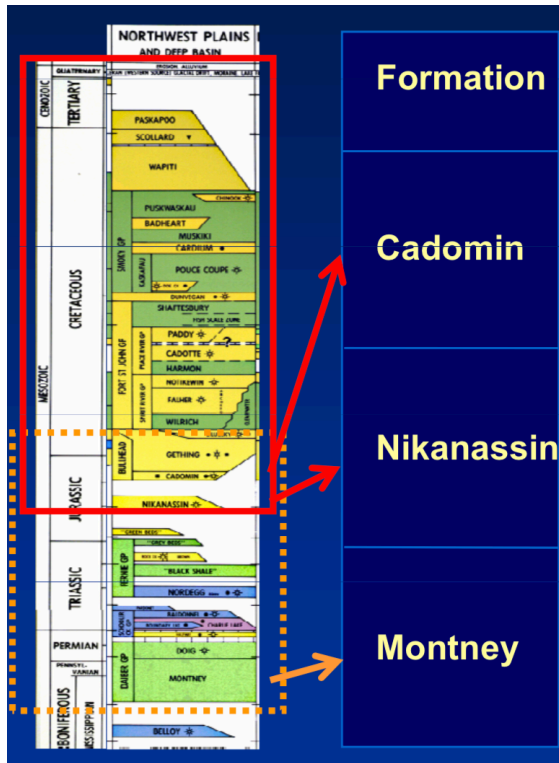


Figure 1.5.1. Generalized stratigraphic chart for Alberta highlighted with units evaluated in this report. Cambrian and Ordovician units are omitted.

The Montney play belongs to the Deep Basin, which was initiated by John Masters (Canadian Hunter Exploration) in 1976 with the discovery of Elmworth gas field in tight reservoirs (already drilled with gas shows but considered as uneconomical) downdip of porous aquifer reservoirs (hydrodynamic trapping). It was quite a revolution to find gas downdip from water, in poor reservoirs already drilled by many wells!

He wrote in AAPG 1979 “Deep Basin Gas Trap, Western Canada” with the following graphs:

154

John A. Masters

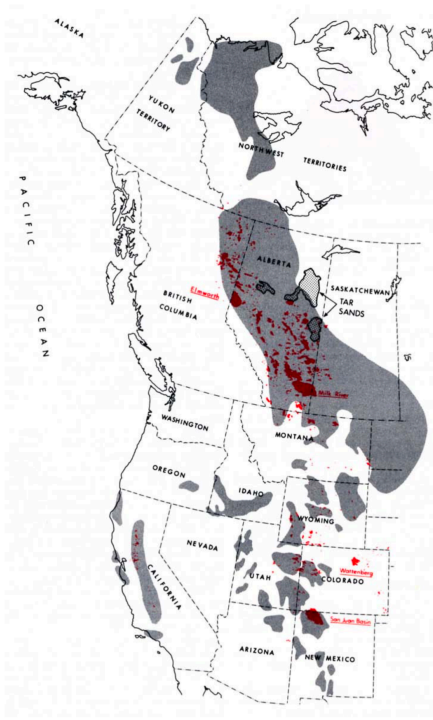


FIG. 2.—Western North America sedimentary basins, gas fields, and tar sand deposits.

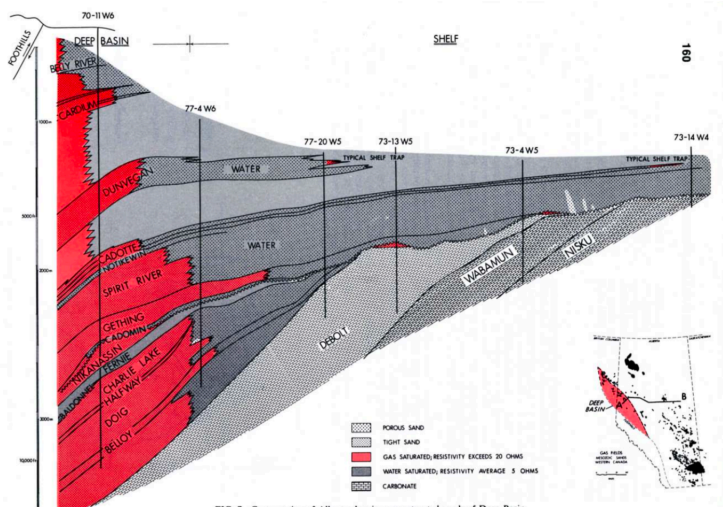


FIG. 7.—Cross section of Alberta showing gas-saturated sands of Deep Basin.

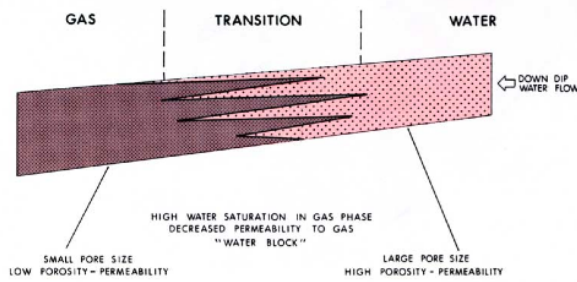


FIG. 13—Physical forces holding gas in place are not fully understood. Downdip water flow, or “water block,” or both appear to be involved.

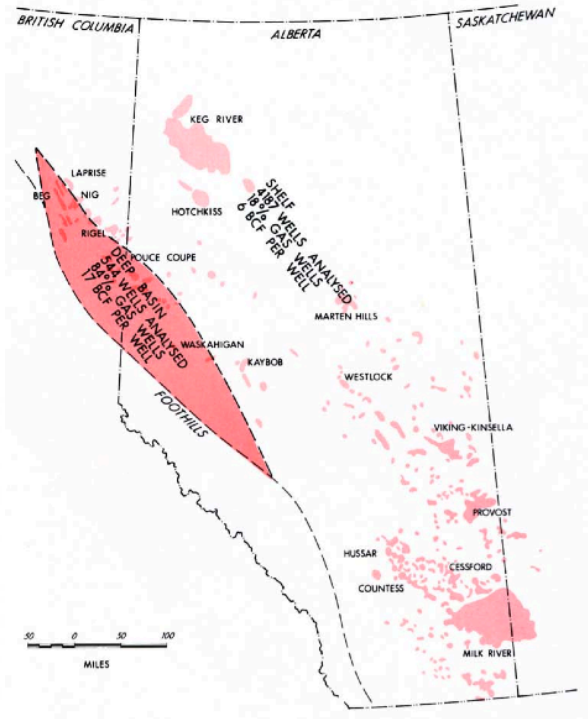


FIG. 20—Statistical data from regional Bcf per section map.

Masters wrote a book in 1980 “The Hunters” stating that the potential recoverable resources of the Deep basin are 440 Tcf (page 77). The Britannica Riva site gives 560 Tcf for Elmworth. In OGJ 15 Nov.1993 Elmworth is stated as Canada’s largest gas field. But in 2008 Elmworth ultimate is estimated around 5 Tcf: one hundred time less than Masters’ estimate. The hype was overestimated!

At end 2012, the Ultimate for WCSB Western Canadian Sedimentary Basin was estimated at 821 Tcf (already 189 Tcf produced) with Montney ultimate = 449 Tcf (178 Tcf Alta and 271 Tcf in BC)

https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/natural-gas-oil/petroleum-geoscience/oil-gas-reports/og_report_2013-1_montney_assessment.pdf

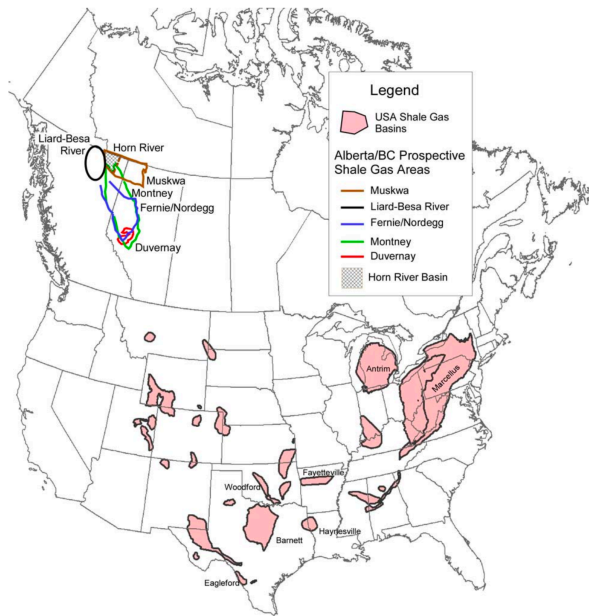
Table 4. Ultimate potential for marketable natural gas in the WCSB

Estimate of Ultimate Potential for Marketable Natural Gas in the WCSB – Year End 2012								
Area		Billion Cubic Metres			Trillion Cubic Feet			
		Ultimate Potential	Cumulative Production	Remaining	Ultimate Potential	Cumulative Production	Remaining	
Alberta	Conventional	6,276	4,425	6,994	222	156	247	
	Unconventional							
	CBM	101			4			
	Montney	5,042			178			
	Unconventional Total	5,143			182			
	Total	11,419			403			
British Columbia	Conventional	1,462	695	10,642	52	25	376	
	Unconventional							
	Horn River Basin	2,198			78			
	Montney	7,677			271			
	Unconventional Total	9,875			349			
	Total	11,337			400			
Saskatchewan	Conventional	297	211	86	10	7	3	
Southern Territories	Conventional	196	20	176	7	1	6	
WCSB Total		23,249	5,351	17,898	821	189	632	

- Notes for Table 4:
- Determined from previously published assessments by the National Energy Board and/or provincial agencies; coalbed methane (CBM) ultimate potential based on initial reserves in the AER ST-98 Report (available at: www.aer.ca).
 - Cumulative production current to year-end 2012.
 - Additional gas potential can be found in other regions of Canada. Please see Tables 2.6A and 2.6B of Saskatchewan’s Ultimate Potential for Conventional Natural Gas, available at: www.neb-one.gc.ca
 - Values may contain rounding errors when added.

Montney is tight gas but is also reported as shale play by some. Montney extends into Alberta.

AER (Alberta Energy Regulator) 2011 displays shale gas plays in North America
<http://www.aer.ca/documents/reports/r2011-A.pdf>

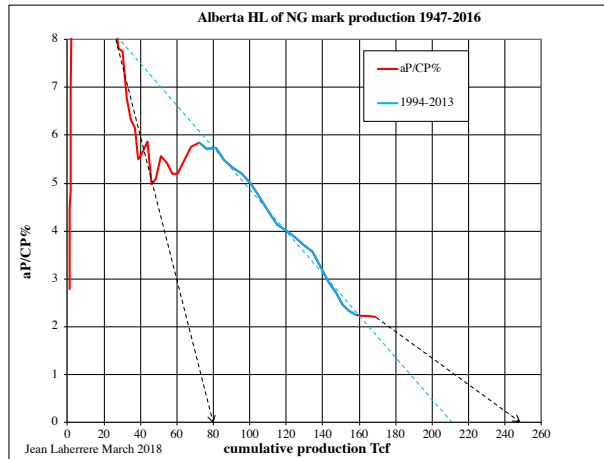
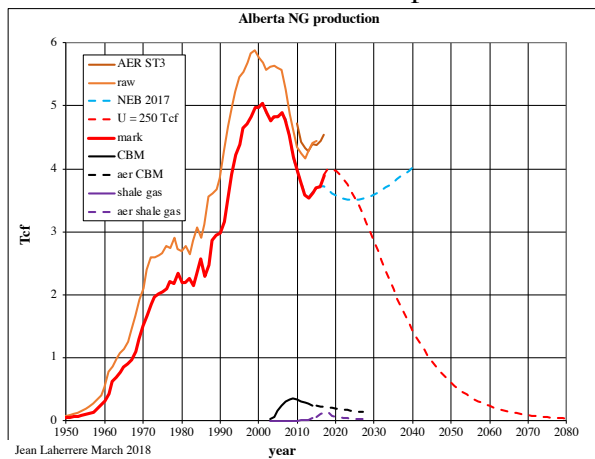


North American Shale Gas Plays

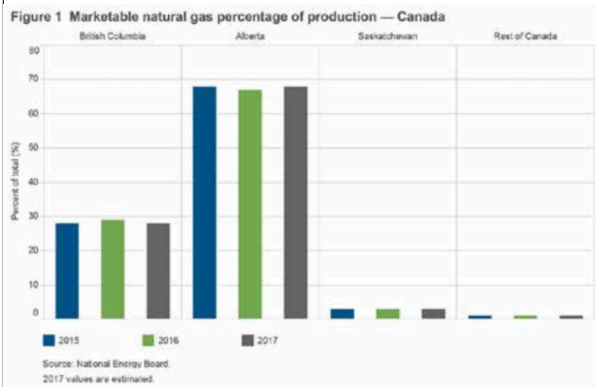
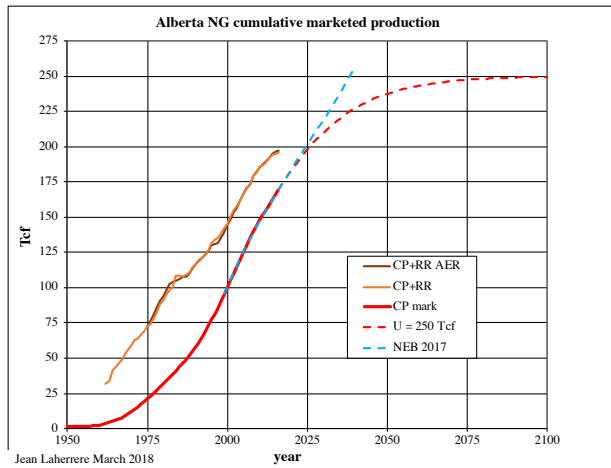
It appears that many prefer ambiguity, leaving room for optimistic messages and making more difficult to compare present data and past forecasts.

-Alberta = Alta = AB

Alberta NG production has peaked in 2000: its ultimate from HL for 1994-2013 was 210 Tcf, now estimated at 250 Tcf, meaning that the last rise 2013-2016 will end soon. NEB2017 forecast is for a new peak after 2040



CBM production peaked in 2009 at 0,35 Tcf and shale gas production is only 0,04 Tcf (3 M.m3/d) in 2014 in ST98-2015

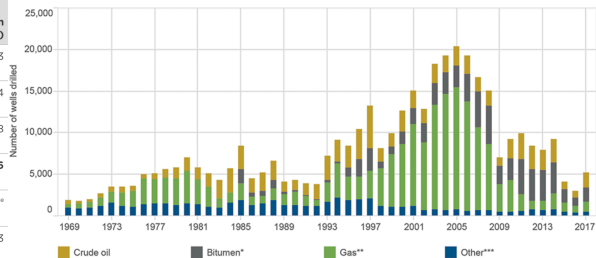


AER (Alberta Energy Regulator), operating 167 000 oil & gas wells, reports NG initial reserves of 201.4 Tcf (again what accuracy not justified by a measure of uncertainty)
 ST98: 2018 Alberta's energy reserves & supply/demand outlook

Table 1 Resources, reserves, and production summary, 2017

	Crude bitumen		Crude oil		Natural gas*		Raw coal	
	(million m ³)	(billion barrels)	(million m ³)	(billion barrels)	(billion m ³)	(trillion cubic feet)	(billion tonnes)	(billion tons)
Initial in-place resources	293 125	1 845	13 171	82.9	9 888	351	93.7	103.3
Initial established reserves ^b	28 092	177	3 047	19.2	5 675	201.4	34.8	38.4
Cumulative production	2 112	13.3	2 804	17.6	4 989	177	1.7	1.8
Remaining established reserves	25 980	164	242.3	1.6	686^c	24.4^c	33.1	36.6
Annual production	160.8	1.012	25.3	0.159	110.1 ^d	3.9 ^d	0.024 ^e	0.028 ^e
Ultimate potential (recoverable)	50 000	315	3 130	19.7	6 276 ^f	223 ^f	620	683

Figure 12 Historical drilling activity in Alberta



Ultimate excluding unconventional = 223 Tcf (6276 G.m3)
 Large gas drilling: 1999-2008; but in 2017 one fourth of 2005

ST98-2015 ultimate 6276 G.m3 (at 39.2 MJ/m3) or 6584 G.m3 (at 37.4 MJ/m3)

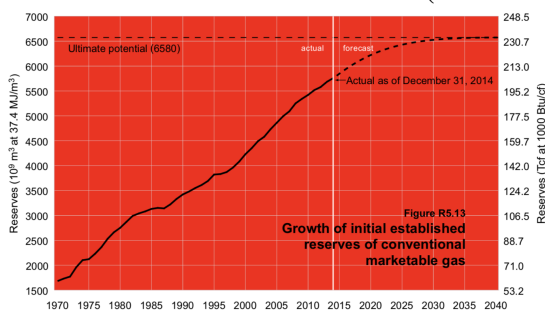


Table R5.9 Remaining ultimate potential of marketable conventional gas, 2014 (10⁹ m³)

	Gross heating value	
	As is (39.2 MJ/m ³)	At 37.4 MJ/m ³
Ultimate potential	6 276	6 584
Minus initial established reserves	-5 487	-5 756
Yet-to-be-established reserves	789	828
Initial established reserves	5 487	5 756
Minus cumulative production	-4 622	-4 848
Remaining established reserves	865	908
Yet-to-be-established reserves	789	828
Plus remaining established reserves	+865	+908
Remaining ultimate potential	1 654	1 736

AER in its annual report 2016-2017 revealed Duvernay Formation (Devonian = source rock of the Leduc reefs) resources between 353 and 540 Tcf, but later reported only 2P reserves of 1.2 Tcf at end 2016

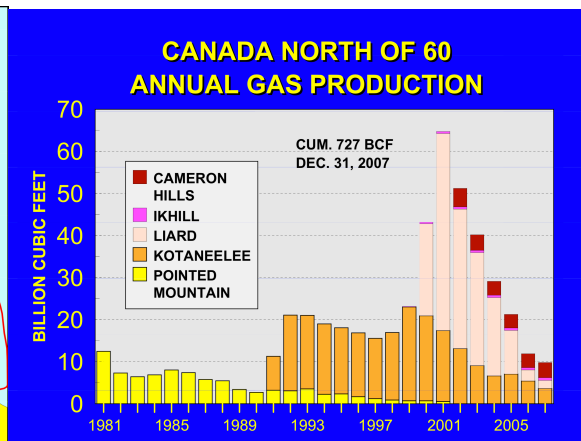
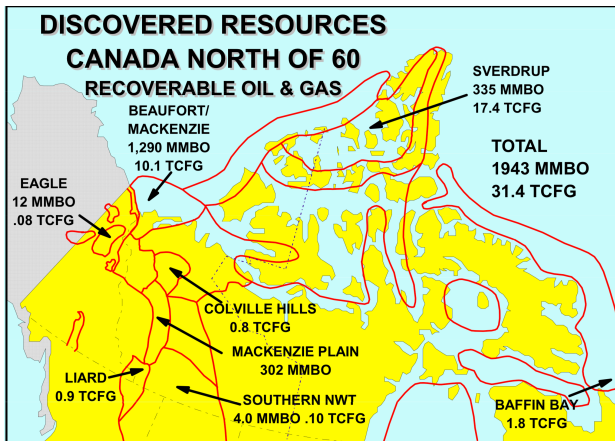
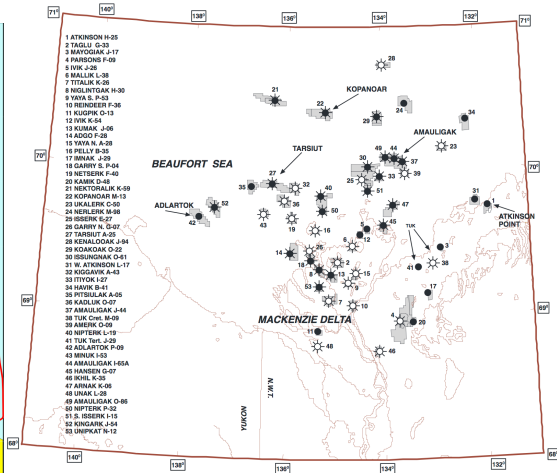
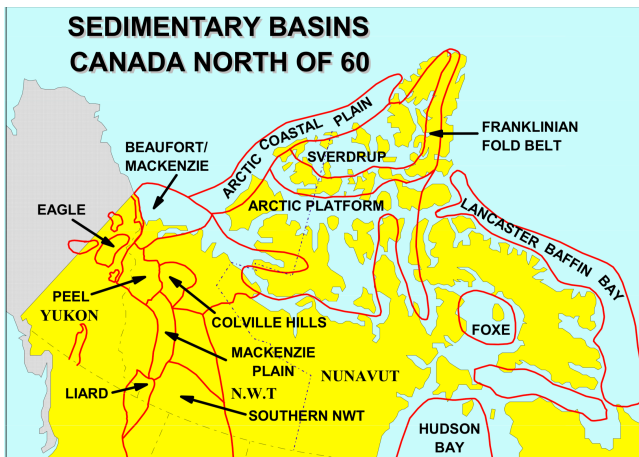
-Northern Territories & Arctic islands

This huge area covers many sedimentary basins and many Petroleum Systems. Many discoveries have been made in the last century, but no development because gas pipeline too expensive.

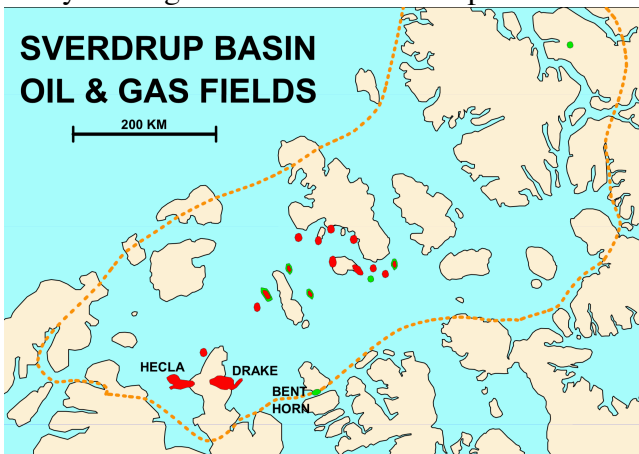
Drummond 2005

NEB 1998

Beaufort Sea - Mackenzie Delta Significant Discoveries

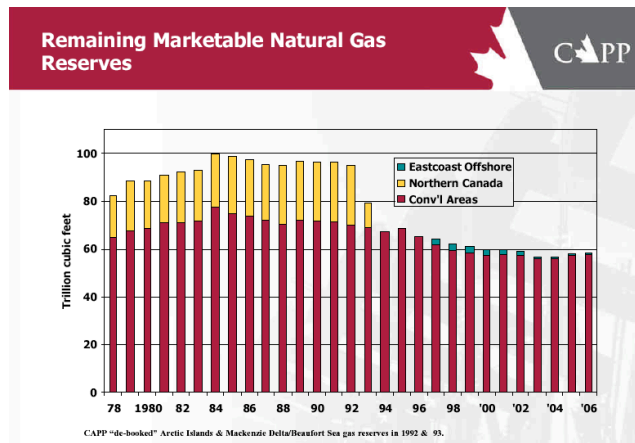


North of 60° 1.9 Gb and 31 Tcf have been discovered
 Many small gasfields in the Sverdrup basin discovered before 1980

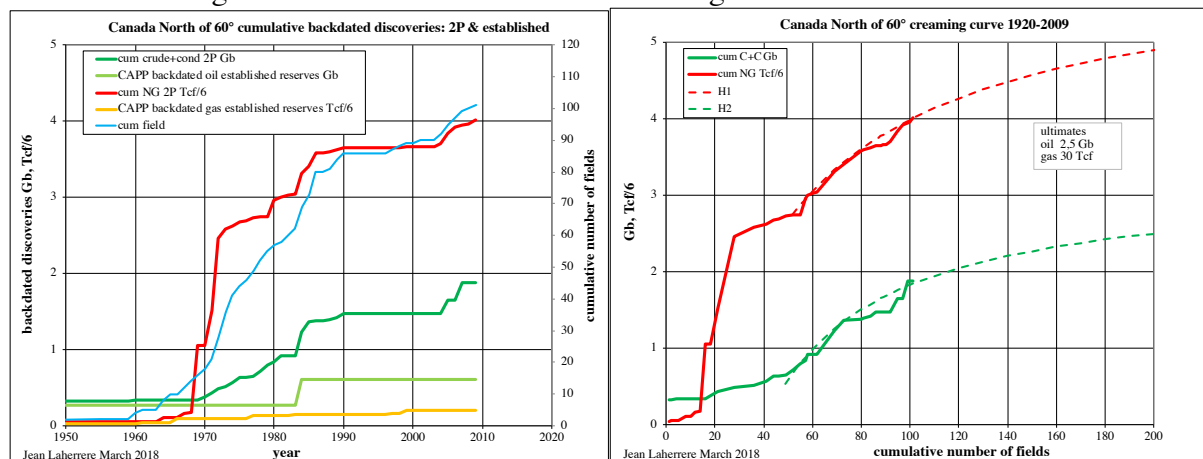


CANADA NORTH OF 60 RECOVERABLE OIL & GAS		
	DISCOVERED OIL (MMB)	DISCOVERED GAS (BCF)
LIARD PLATEAU	0	895
GREAT SLAVE PLAIN	4	102
MACKENZIE PLAIN	302	156
COLVILLE HILLS	0	837
EAGLE PLAINS	12	84
MACKENZIE DELTA	173	5,183
BEAUFORT SEA	1,117	4,953
SVERDRUP BASIN	335	17,383
BAFFIN BAY	0	1,809
TOTAL	1,943	31,402

CAPP reported about 20 Tcf of reserves in the Northern Canada from 1978 to 1994, nothing after. The hope of a development has disappeared!
 NEB2014 reports 6.2 Tcf in Beaufort and 2.6 Tcf in the Arctic Islands



The cumulative 2P backdated discoveries (1920-2009) are at end 2009 for 101 fields 1,9 Gb and 24 Tcf (4 Gboe) and the “ultimate” is 2.5 Gb for oil and 30 Tcf for gas. CAPP reported at end 2009 the cumulative initial established backdated reserves are only 0.6 Gb and 1.2 Tcf, which is 4 times less for oil and 25 times less for gas. It is difficult to explain such discrepancy. 2P reserves are geological when CAPP established reserves look economical. For some unknown reasons CAPP stopped in 2010 to report backdated reserves per year of discovery. Their 2010 Handbook data for Canada North of 60° disagree with IHS data and their “unbooking” in 1994 of about 20 Tcf of remaining reserves in Northern Canada



The gas pipelines needed to produce these discoveries are not economical for the moment and it is not sure that they will be in the future, as the discoveries are small and dispersed.

But methane was found also as hydrate in the permafrost of conventional gas field as Mallik onshore Mackenzie delta in 1973

-Methane hydrate in the permafrost

I have published several papers on hydrate (oceanic and permafrost)

I chaired the 2002 World Petroleum Congress (Rio of Janeiro) panel on hydrates (RFP9 "Economic Use of Hydrates: Dream or Reality?").

-Laherrere J.H. 2008 “Hydrates updated” The Oil Drum 17 April

<http://europe.theoil Drum.com/node/3819>

-Laherrère J.H. 2002 "Hydrates: some questions from an independent O&G explorer"

Introduction as chairman of RFP 9 "Economic use of hydrates: dream or reality?" WPC Rio, Sept 5 <http://www.oilcrisis.com/laherrere/hydratesRio/>

- Laherrère J.H. 2000 "The uncertainties of oceanic hydrates" Tomorrow's Oil Dec. p11-16
- Laherrère J.H. 2000 "Oceanic hydrates: more questions than answers" Energy Exploration & Exploitation, Special issue on hydrates Nov-Dec vol 18 n°4 p349-383
<http://dieoff.com/page225.htm>
- Laherrère J.H. 1999 " Gas Hydrates" "Uncertain resource size enigma" & "The SOFAR channel: what and why" Offshore Magazine Part 1 August, p140-141,160-162, "Data shows oceanic methane hydrate resource over-estimated" Part 2 September p156-158,
<http://dieoff.com/page192.htm>
- Laherrère J.H. 1999 « Oceanic Hydrates: an Elusive Resource » Part 1: "Gas Hydrate, Uncertain resource size enigma" Offshore, August 1999, p140-141,160-162, Part 2: "Data shows oceanic methane hydrate resource over-estimated" Offshore, September 1999, p156-158 <http://www.hubbertpeak.com/laherrere/hydrates/>

Osadetz et al 2005 estimated the hydrate resource in the Mackenzie delta from 2 to 87 T.m³ (70 to 3000 Tcf) of raw natural gas in place. But, it is far from resources in the ground and reserves which will be produced in the future (the world largest gold (or uranium) mine is in ocean, but no one bothers to look at extracting it).

Methane hydrate in permafrost was found first in Russia in 1964 with Messoyakha field, reported producing hydrate from 1970 to 1978 (but Ginsburg disputed in 1993 this claim of hydrate production; methanol was used not to produce hydrate, but to prevent the formation of hydrate = the main nuisance in tubing and gas pipeline), but also in Canada with Mallik in 1973 (Bily 1974).

Canada has been involved with research to develop extraction techniques from hydrates since 1998, when the Mallik Methane Hydrate Site was set up in the Mackenzie River delta, 130 km north of Inuvik in the Northwest Territories.

Test to produce methane by heating was carried on in 2002, with a very small production. In 2007 & 2008 using pressure reduction Canadian and Japanese researchers (eager to produce oceanic hydrate in their country in Nankai sea) extracted 120 000 m³ of methane over the course of five days. It is less than the production of one CBM well, and completely uneconomical in such location.

CERI May2012 quotes a study by IIASA estimating hydrate in place at 7031 Tcf for the US and at 2228 Tcf for Canada

In 2013 Canada drops out of race to tap methane hydrates: why to bother developing unconventional gas in Arctic when more than 20 Tcf of undeveloped conventional gas is stranded since more than 40 years (same in the US with the 26 Tcf of stranded Prudhoe Bay gas)

-shale gas

It is indicated above that methane is adsorbed with shale gas trapped in a shale and in the pore space with tight gas in a tight sediment.

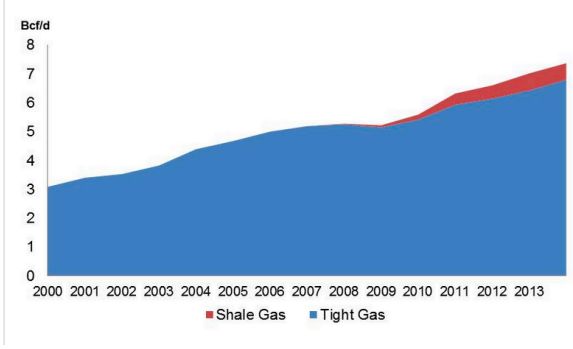
The 2013 EIA/ARI report on world shale plays estimating 573 Tcf of technically recoverable shale gas in Canada (665 Tcf in the US) is today proven unrealistic with the poor results in several countries in particular Poland.

NEB in several reports confuses shale gas and tight gas.

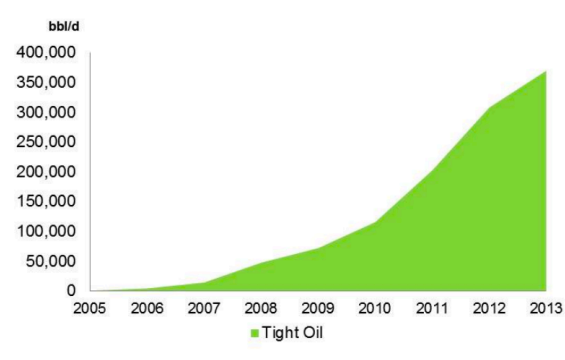
It is difficult to obtain detailed data on shale gas: NRCAN reports a small amount of shale production compared to tight gas (starting much sooner than tight oil)

<http://www.nrcan.gc.ca/energy/sources/shale-tight-resources/17677>

Canadian Shale and Tight Gas Production

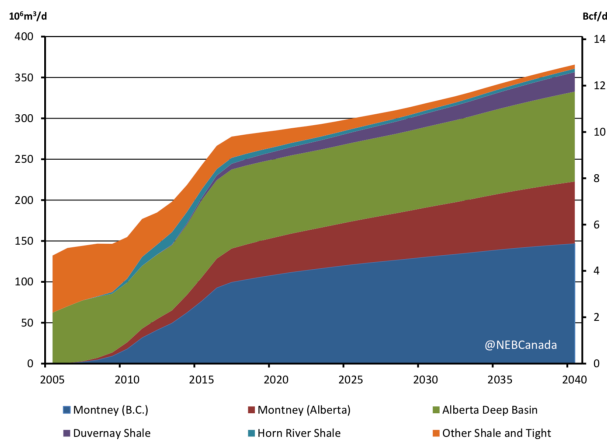


Canadian Tight Oil Production



NEB 2017 gathers tight gas and shale gas without specifying the difference, in disagreement with NRCAN

FIGURE 3.14
Tight and Shale Natural Gas Production by Play, Reference Case



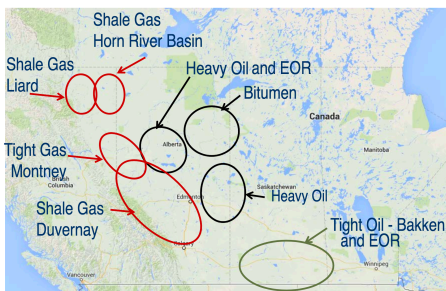
Schlumberger reports tight gas for Montney and shale gas for Duvernay.

<https://ptrc.ca/+pub/document/tightOil2015/4.%20Unconventional%20Oil%20and%20Gas%20-%20Rob%20Mitchell.pdf>

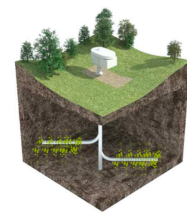
Unconventional Oil and Gas in Canada

Tight & Shale Oil/Gas

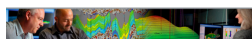
- Heavy oil
- Bitumen
- Tight/Shale gas
- Tight/Shale oil
- “EOR”



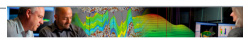
- Low porosity (3-6%)
- Low permeability (under 0.01mD)
- Gas is easier than oil to flow
- Production mechanism:
 - Hydraulic fracturing
 - Horizontal, multi-well pads



Challenges: Heterogeneities. Costs. Understanding of how the fractures go for field development.



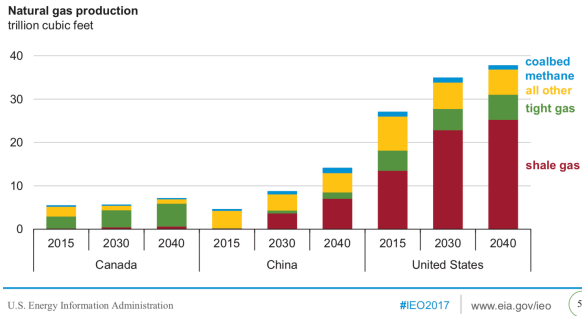
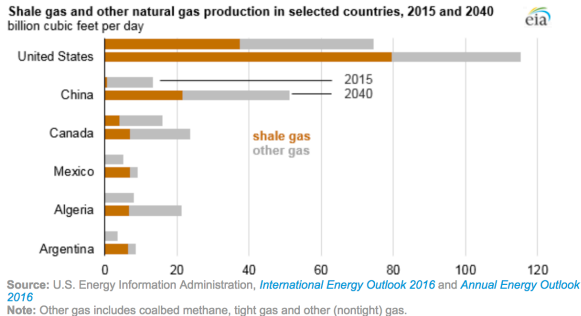
PetroTechnical Services
Global Expertise



PetroTechnical Services
Global Expertise



EIA/IEO 2016: Canada has been producing shale gas since 2008, reaching 4.1 Gcf/d in 2015. Shale gas production in Canada is projected to continue increasing and to account for almost 30% of Canada's total natural gas production by 2040 (8 Tcf). Shale gas is assumed to be different from tight gas included in other gas.

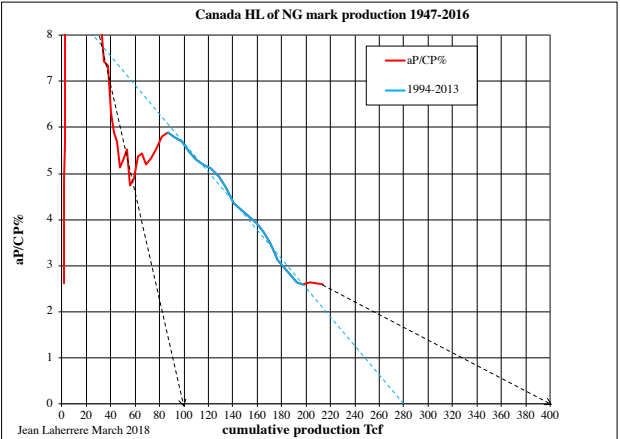
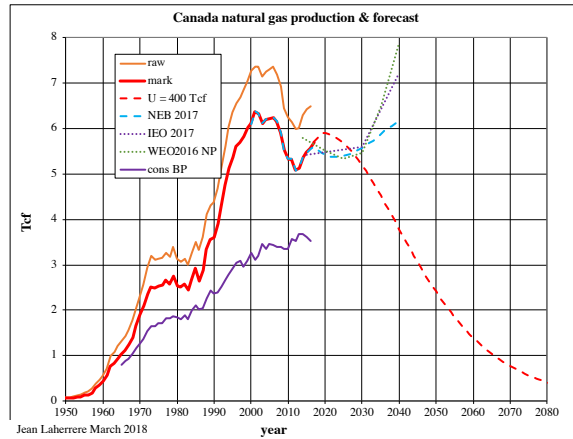


But IEO2017 shale gas production percentage in 2040 is less 5% compared to 30% in IEO2016. In IEO2014 it is said that in 2010, almost 40 percent of Canada's natural gas production came from tight reservoirs: EIA confuses shale gas and tight gas!

-All Canada NG

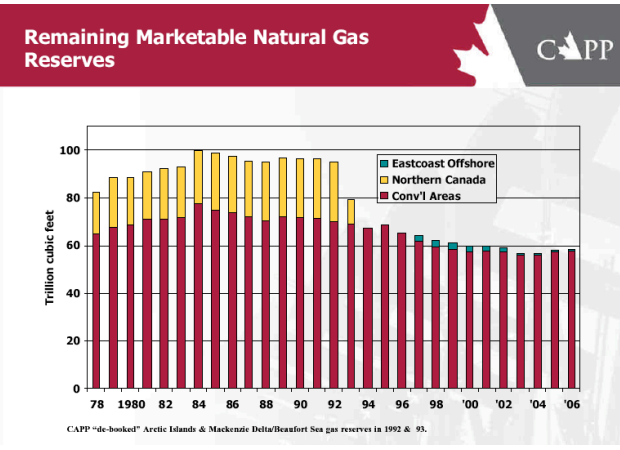
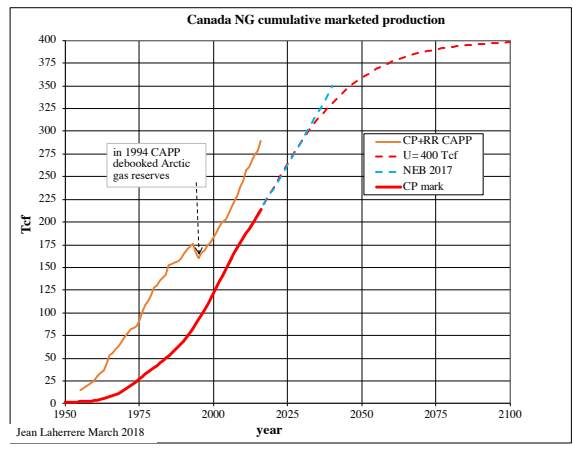
CAPP reports raw and marketed production, NG production can be wet or dry (after extraction of NGPL).

HL of past marketed NG production tends towards 280 Tcf for the period 1994-2013 but rises again after 2013: my guess is 400 Tcf, which is rather high compared with 300 Tcf for cumulative production plus remaining reserves (but excluding Arctic discoveries since 1994). Despite this high ultimate gives a peak around 2020 when NEB 2017 reports a rise from 2022 to 2040. EIA/IEO2017 is more optimistic than NEB for 2040, but less than IEA/WEO2016.

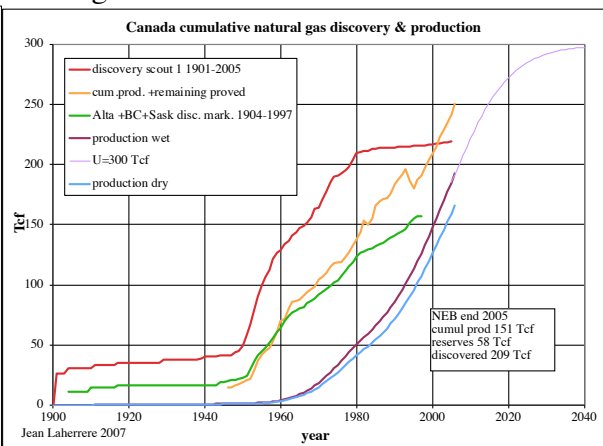
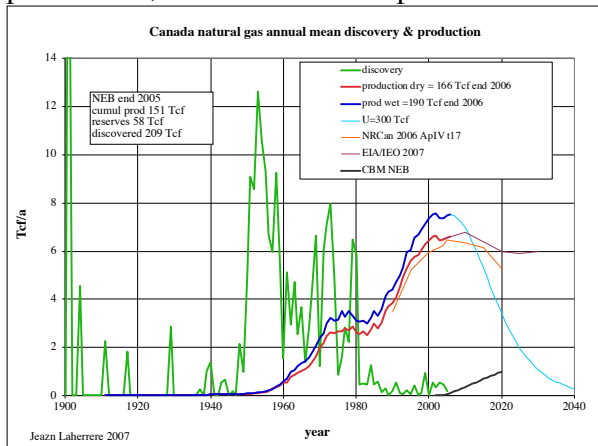


For 2040 my forecast is 4 Tcf, which is 3 Tcf less than EIA and 4 Tcf less than IEA.

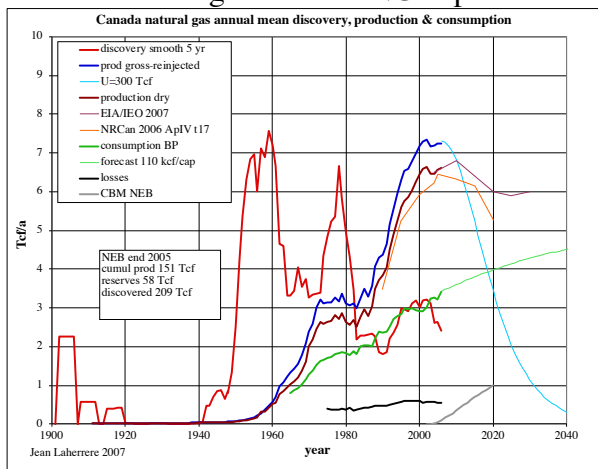
Canada NG consumption increases since 1973 and extrapolated will cross my forecast before 2040!



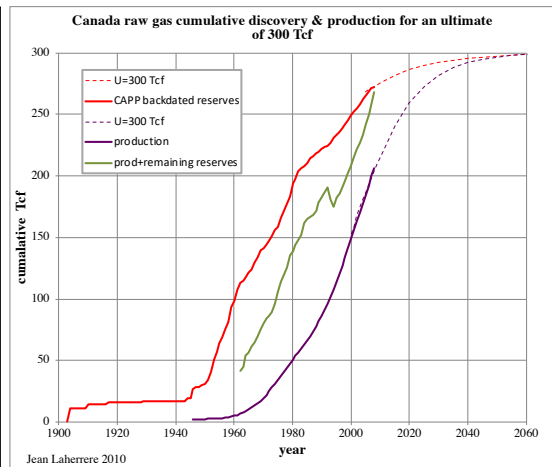
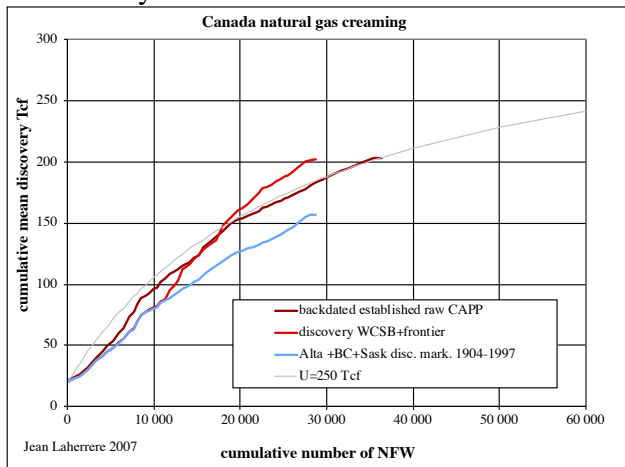
In 2007 my forecast was for an “ultimate” of 300 Tcf giving a decline after 2007: I was too pessimistic, based on the extrapolation of the creaming curve from!



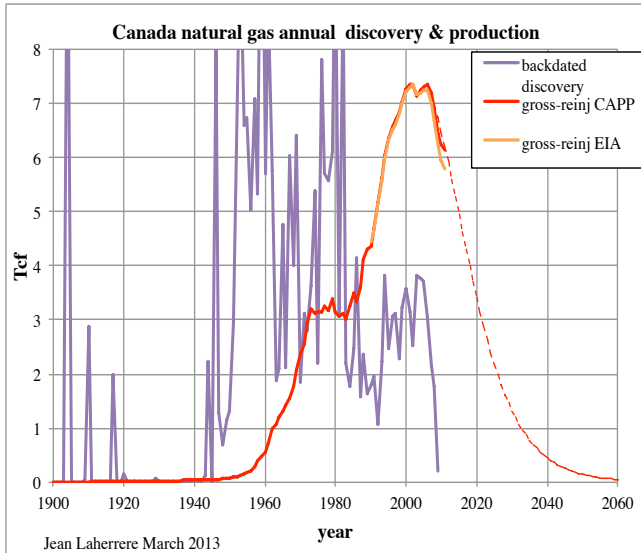
I was forecasting the end of NG export in 2020 with consumption catching production



In 2010 my forecast has the same “ultimate” of 300 Tcf

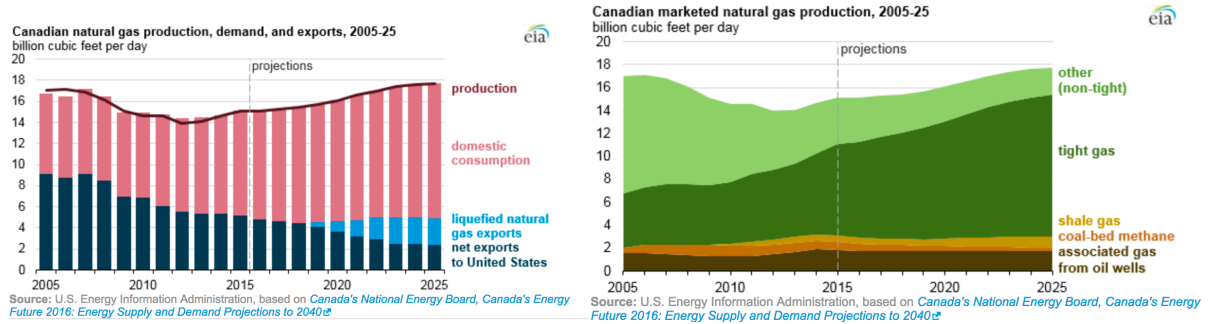


In 2013 my forecast missed the tight gas new cycle starting in 2012



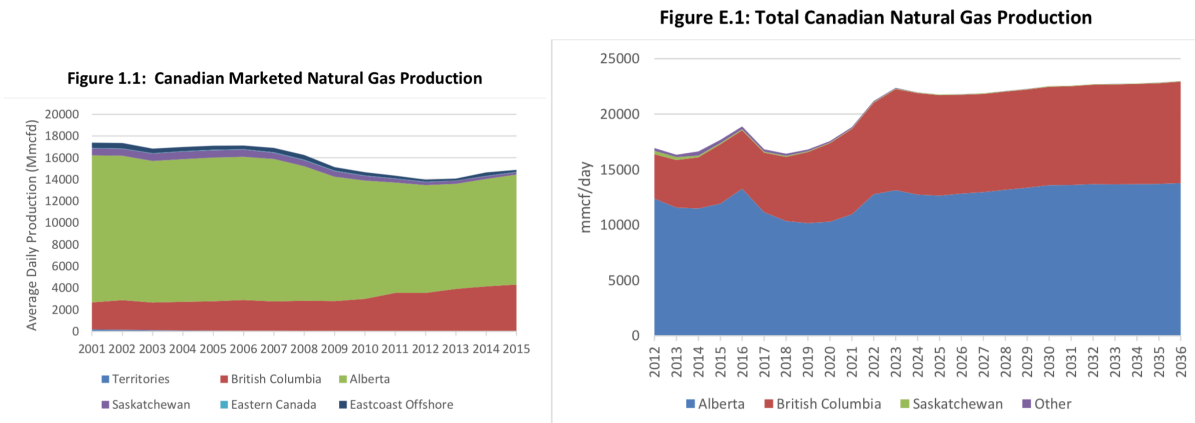
EIA 2016 forecast <https://www.eia.gov/todayinenergy/detail.php?id=25972>

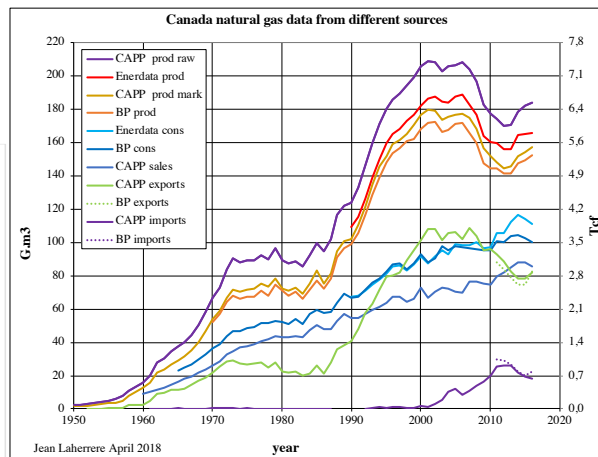
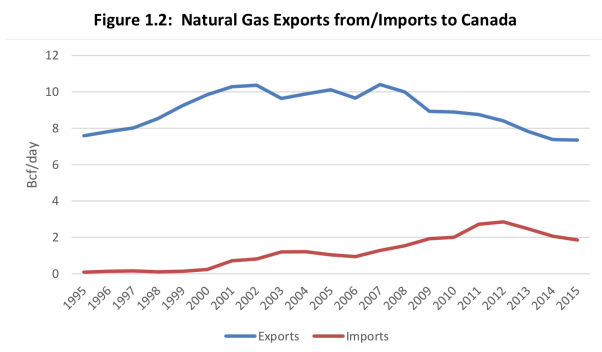
EIA forecasts (following NEB) NG production in 2025 at <18 Gcf/d (6.5 Tcf) against 5.8 Tcf for my forecast. Shale gas production is small in 2025 where the majority (70%) is tight gas. Montney production is forecasted to rise from 3 Gcf/d in 2014 at 9.6 Gcf/d in 2040



CERI Canadian Energy Research Institute Study N°159 Sept 2016 Outlook 2016-2036

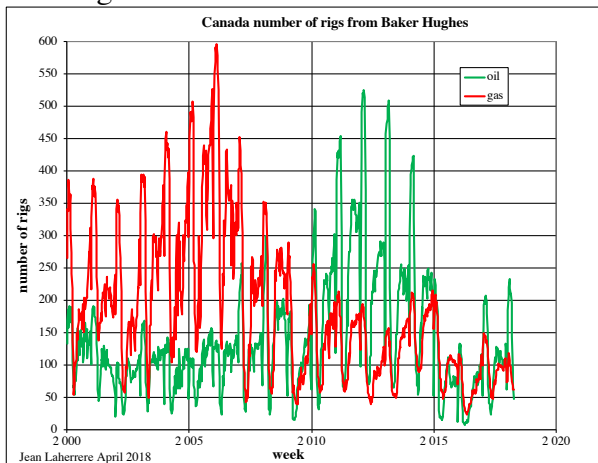
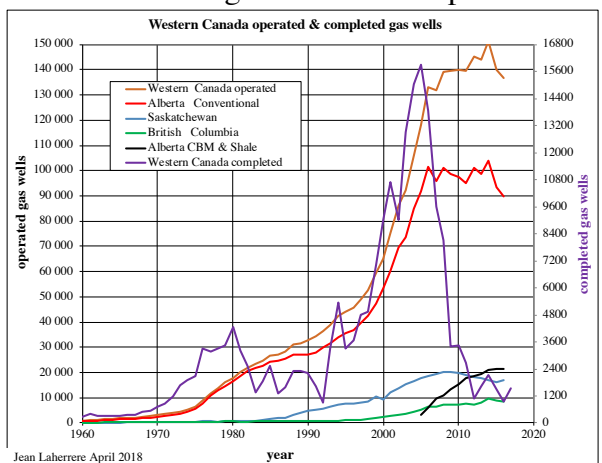
CERI forecasts on Fig E.1 constant NG production from 2026 to 2036, but there is a slight discrepancy for 2012 to 2015 with Fig1.1



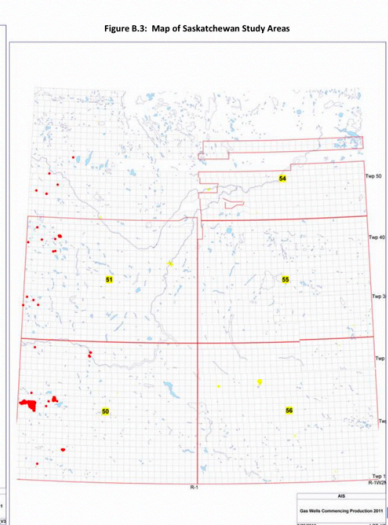
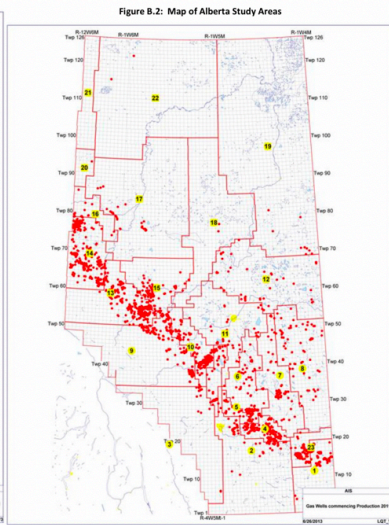
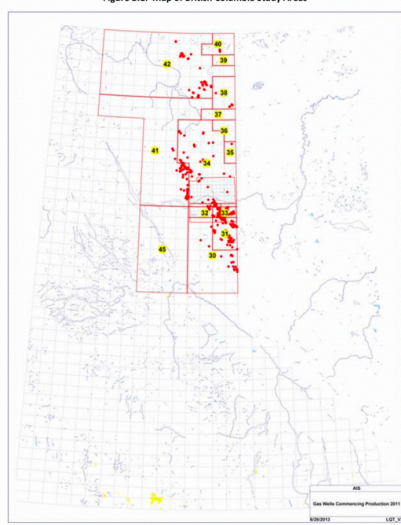


The number of operated gas wells peaked in 2014 over 150 000 with Alberta conventional over 100 000 (plus 20 000 CBM and shale wells). Saskatchewan gas wells peaked in 2010, BC peaked in 2014. For Western Canada the peak of completed gas wells was in 2005 with 15 931 gas wells down to 1 542 in 2017

The number of rigs in Canada has peaked in 2006 for gas and in 2012 for oil.

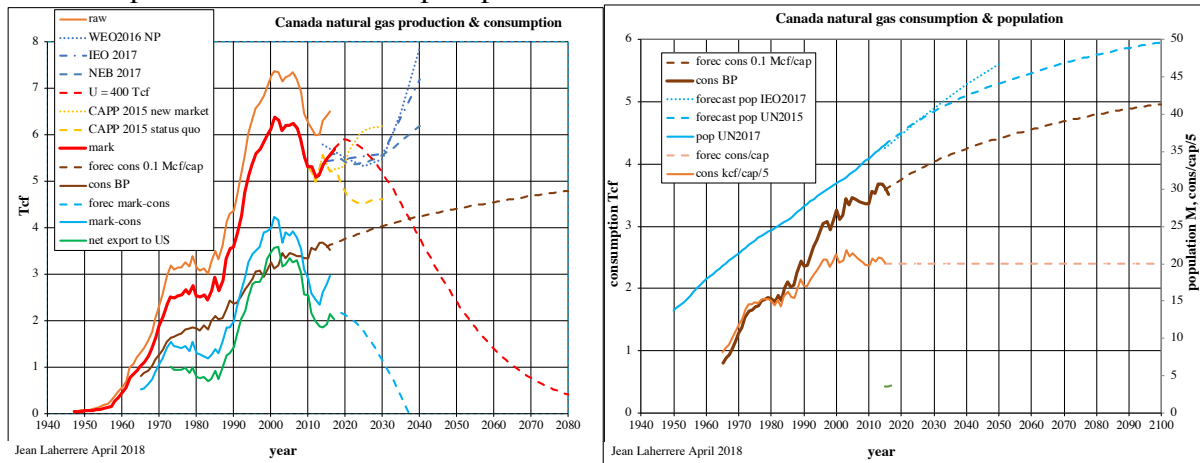


The map of gas wells on BC, AB and SK commencing production in 2011 shows that most of the present activity is in Alberta



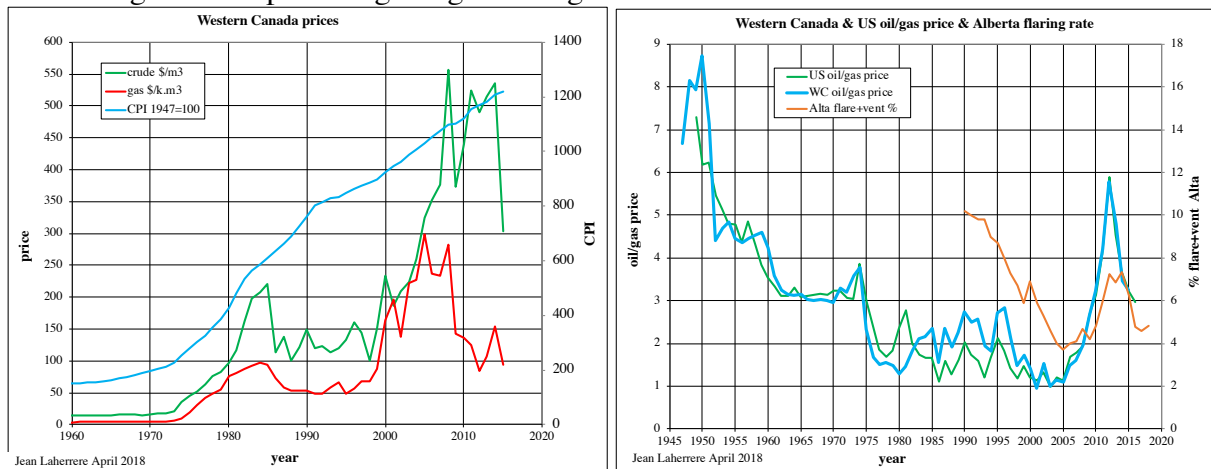
-Canada NG production, consumption and export

Canada NG marketed production peaked in 2001 at 6.4 Tcf, went to a low of 5.1 Tcf in 2012 and up to 5.7 Tcf in 2017: it is likely to peak in 2019 at 5.9 Tcf(for an ultimate of 400 Tcf), going down to 3.8 Tcf in 2040 against a forecast of 7.2 Tcf for EIA/IEO 2017. Canada NG consumption forecast will cut production forecast before 2040, leaving no room for net export after 2040. Net export peaked in 2002 with 2.2 Tcf.



-Western Canada oil and gas prices

Crude oil price (\$/m3) and NG price (\$/k.m3) in Western Canada vary much more than the Consumer Price Index. The ratio oil price/gas price was high (>8) in 1950 and declined towards 1 at the beginning of the 2000s and peaked in 2012 at 5.8 and down to 3.3 in 2015, correlating with the percentage of gas flaring in Alberta.

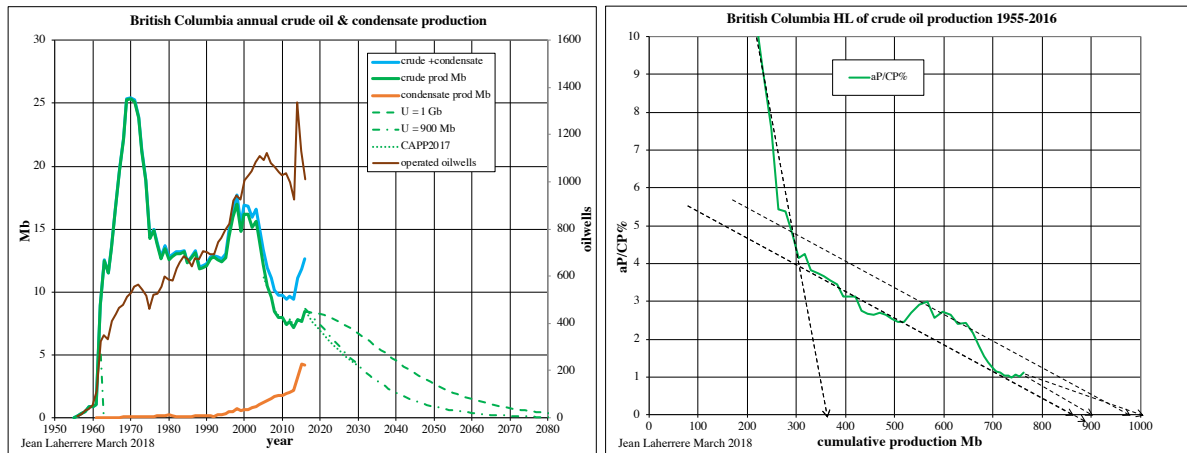


From 1975 to 2008 Canada ratio oil price/gas price was between 1 and 3, since 2009 it is over 3, and EIA forecast that it will increase in the US up to 2040!

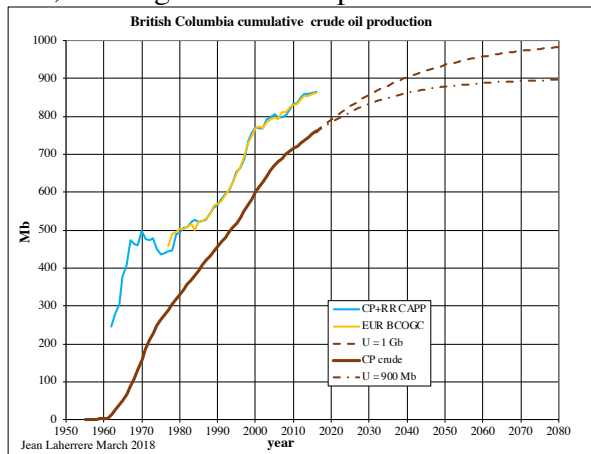
-Oil production

-British Columbia

BC crude oil production peaked in 1970 (25 Mb/a), also in 1998 (17 Mb/a) and likely in 2018 (8 Mb/a), but condensate production started to be significant only from 1990



BC crude oil ultimate is estimated at 1 Gb from the extrapolation of the HL (higher than the cumulative production + remaining reserves = 0.85 Gb at end 2016), leading to a slow decline, contrary to the sharp slopes of previous increases and decreases. But this 1 Gb estimate looks too optimistic compared with CAPP 2017 forecast, it should be lower as 900 Mb, which gives a future production similar with CAPP 2017.



CERI 2016 forecasts new oilwell constant from 2016 to 2036 at a very low rate (3) compared to the new gas wells (around 500)?

Figure 2.6: British Columbia New Oil Well Forecast

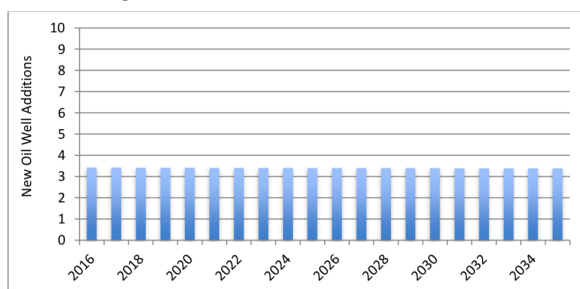
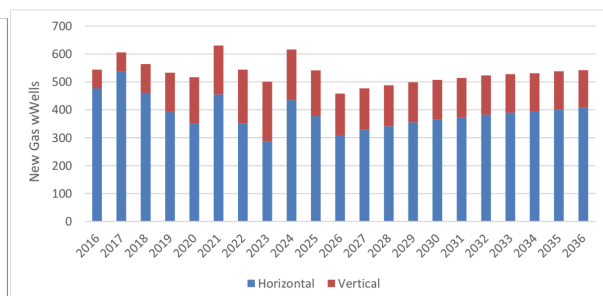


Figure 2.24: British Columbia New Gas Well Forecast



It is unlikely to see constant oil production with constant drilling rate of 3 oilwell per year? CERI crude oil production is forecasted to be 5 000 b/d in 2036 = 1.8 Mb
 The only explanation is the addition of C5/condensate in the crude oil production coming from the numerous gas wells. CERI graph BC crude oil production forecast is misleading, because most of the production is from C5/condensate.

Figure 2.9: British Columbia Crude Oil Production Forecast

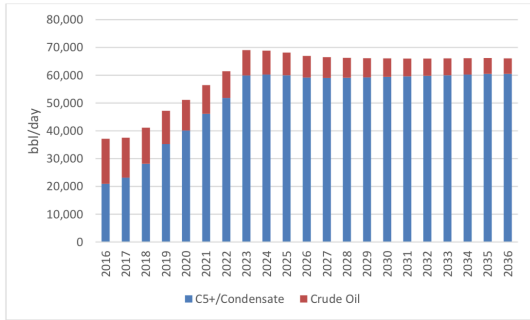
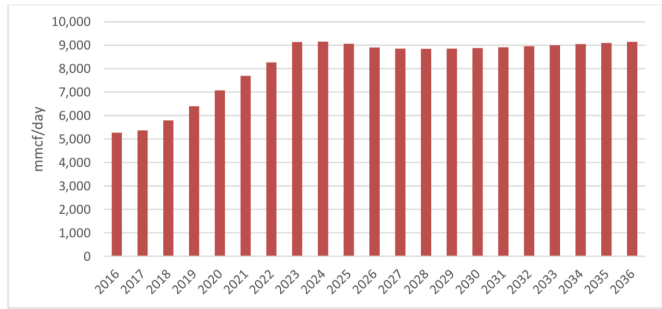


Figure 2.27: British Columbia Field Gate Natural Gas Production Forecast

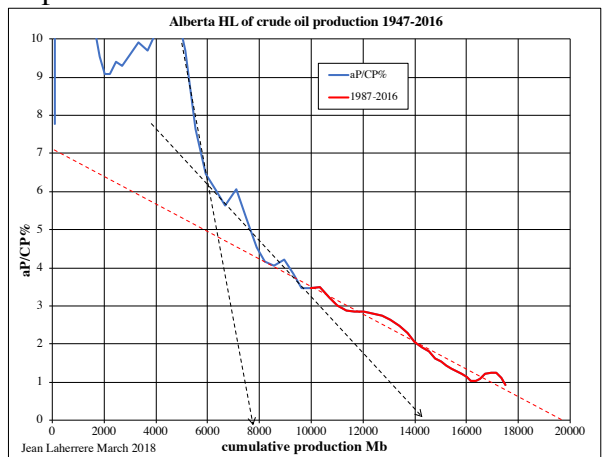
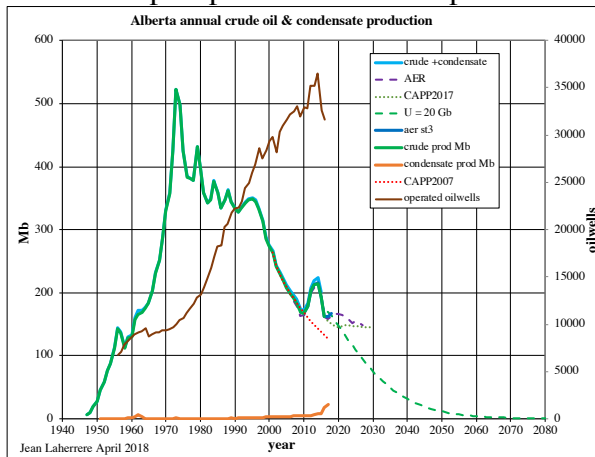


Most of the problem with crude oil production data in the world is the lack of precise definition and the aggregation with NGL = natural gas liquids. It explains a 2 Mb/d discrepancy between EIA and IEA oil supply (IEA has a bad definition for condensate being either crude oil or NGL, depending the sale contract).

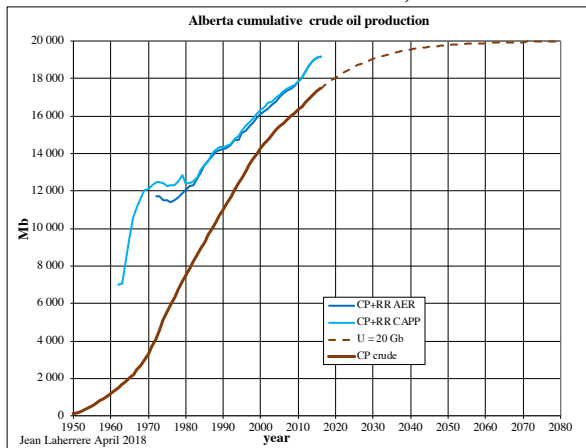
-Alberta

Alberta crude oil production decline for the period 1995-2010 is stopped by a new cycle of tight oil peaking in 2014 and condensate from the tight gas is adding a small amount. The number of operated oil wells has peaked in 2014.

The HL of past production is extrapolated for the period 1987-2016 towards 20 Gb.



The cumulative crude oil production plus remaining reserves at end 2016 is 19 Gb and AER ST98 2017 ultimate is 19.7 Gb, close to the ultimate of 20 Gb

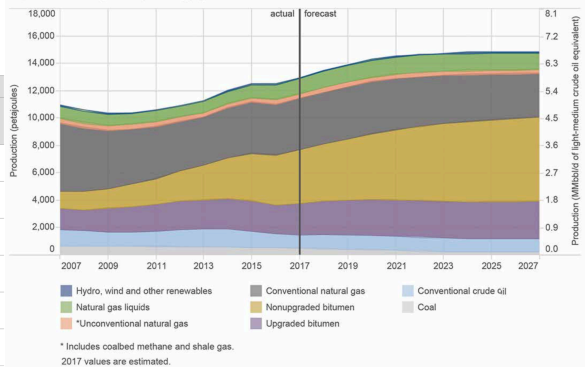


AER ST98 displays the total primary energy of Alberta where in 2027 is oilsands, then conventional gas, NGL, conventional crude, renewable being negligible.

Table 1 Resources, reserves, and production summary, 2017

	Crude bitumen		Crude oil		Natural gas ^a		Raw coal	
	(million m ³)	(billion barrels)	(million m ³)	(billion barrels)	(billion m ³)	(trillion cubic feet)	(billion tonnes)	(billion tons)
Initial in-place resources	293 125	1 845	13 171	82.9	9 888	351	93.7	103.3
Initial established reserves ^b	28 092	177	3 047	19.2	5 675	201.4	34.8	38.4
Cumulative production	2 112	13.3	2 804	17.6	4 989	177	1.7	1.8
Remaining established reserves	25 980	164	242.3	1.6	686^c	24.4^c	33.1	36.6
Annual production	160.8	1.012	25.3	0.159	110.1 ^d	3.9 ^d	0.024 ^d	0.028 ^d
Ultimate potential (recoverable)	50 000	315	3 130	19.7	6 276 ^e	223 ^e	620	683

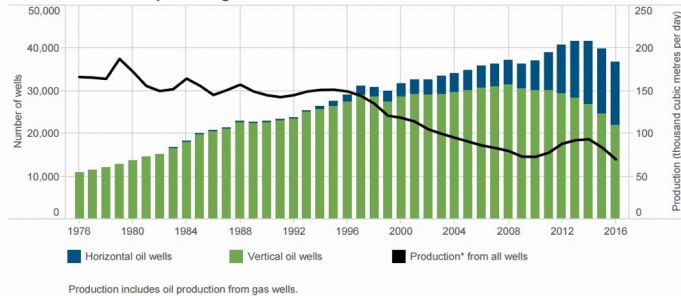
Figure 6 Total primary energy production in Alberta



AER reports an ultimate potential (recoverable) of 315 Gb for oilsands (bitumen) and 19.7 Gb for crude oil.

The number of horizontal wells in conventional crude production in 2016 is still minor.

Figure S4.12 Alberta conventional crude oil average daily production from all wells and number of crude oil producing wells



CERI 2016 forecast

CERI forecasts Alberta oil wells to be mainly horizontal (in contradiction for 2016 with AER: difference of display: AER graph for producing wells and CERI graph for new wells) and the oil price will increase to almost 120 \$/b in 2036. The crude production (in red) will decrease to 0.4 Mb/d in 2025 and rise slowly again to 0.46 in 2036. Pentanes plus condensate will stay around 0.2 Mb/d

Figure 2.1: Alberta New Oil Well Forecast

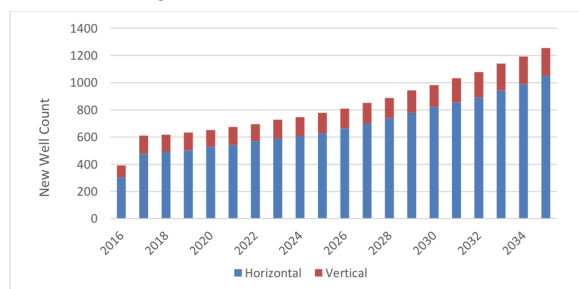


Figure 2.2: WTI Crude Oil Price Forecast

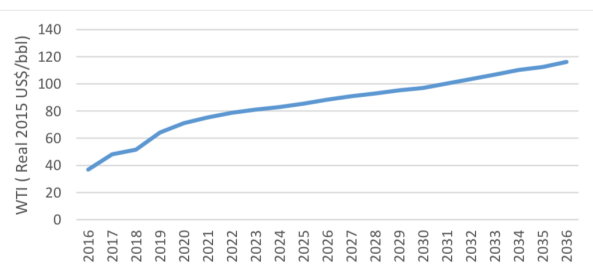
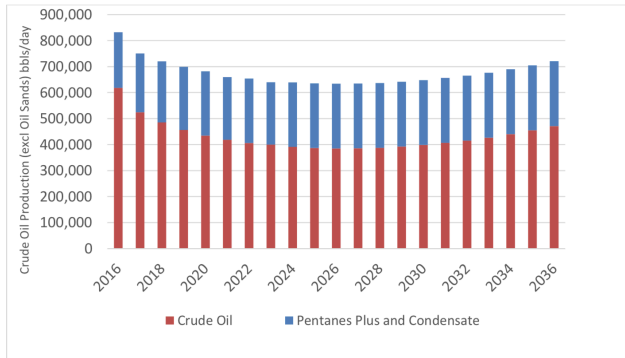
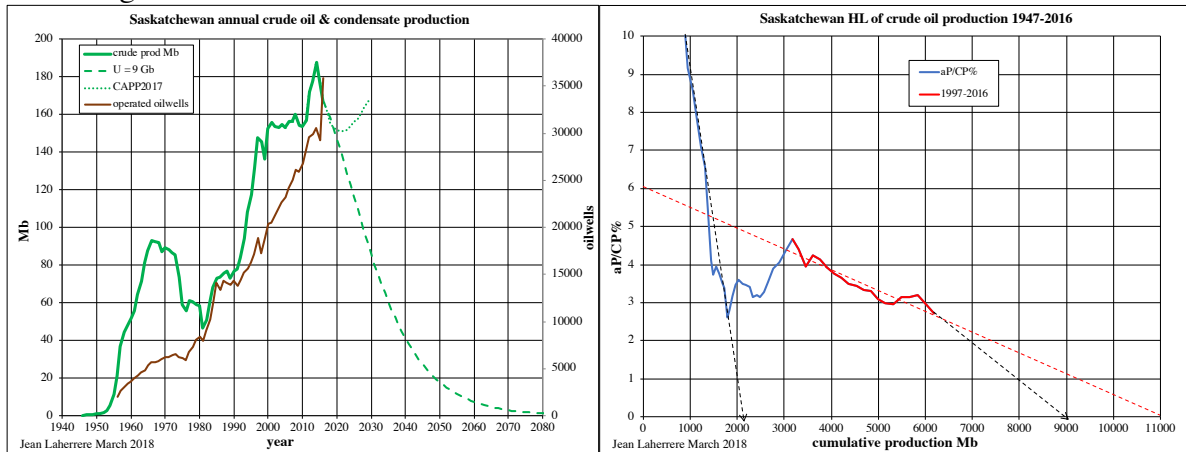


Figure 2.5: Alberta Crude Oil Production Forecast

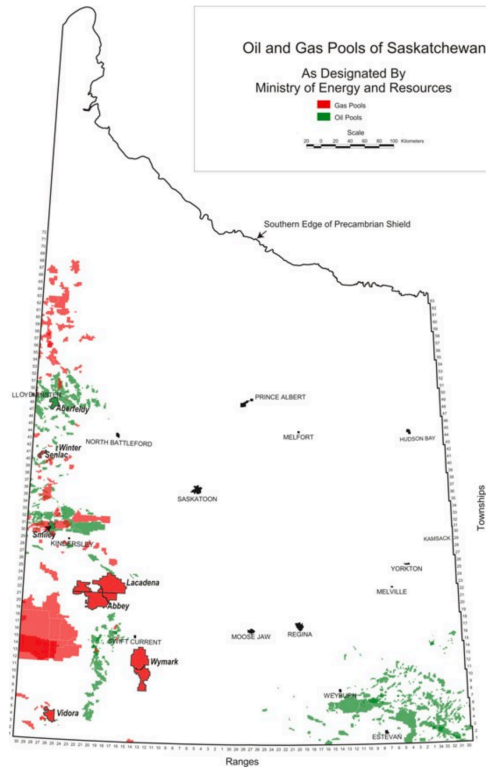
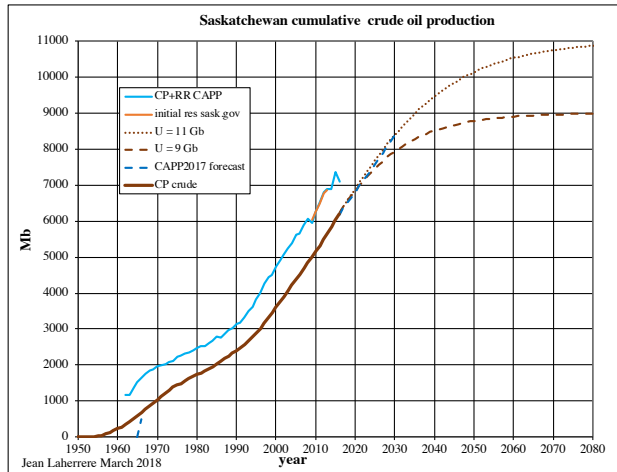


-Saskatchewan

Saskatchewan crude oil production has peaked in 1967 and again in 2014. HL can be extrapolated towards 11 Gb or 9 Gb, which gives a better symmetrical decline. CAPP forecasts after 2020 an increase of the crude oil production, in contradiction with its remaining reserves.



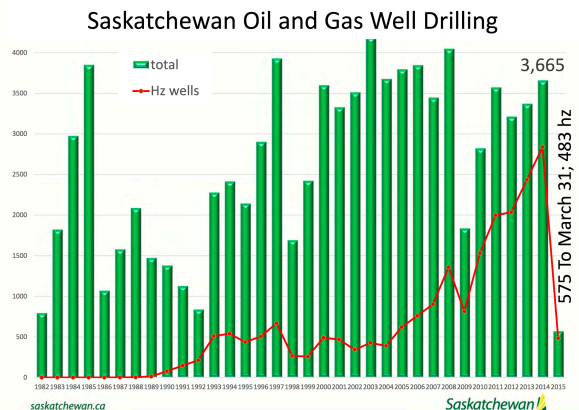
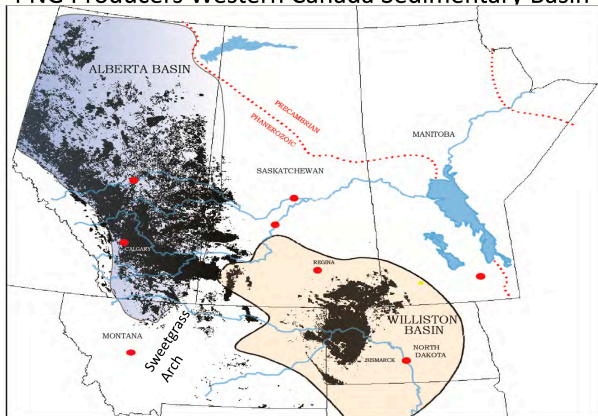
The cumulative production plus remaining reserves is about 7 Gb in 2016

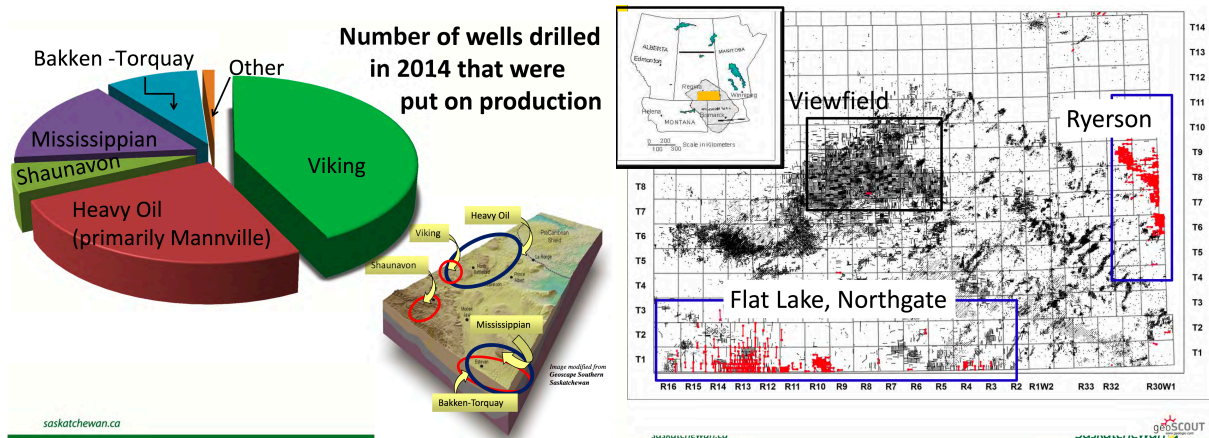


If the Bakken (including the Three Forks) production is well reported in the US, in particular in North Dakota, its extension in the south east of Saskatchewan is not reported separately, considered as conventional.

<http://wbpc.ca/pub/documents/archived-talks/2015/Presentations/Yurkowski%20-%20Petroleum%20Geology%20of%20Sask.pdf>

Saskatchewan drilling was erratic from 1982 to 2015, but it is concentrated in few areas PNG Producers Western Canada Sedimentary Basin

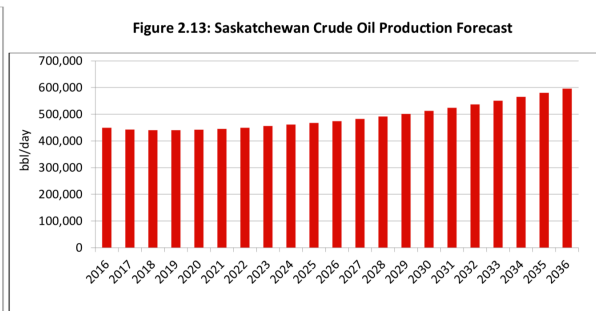
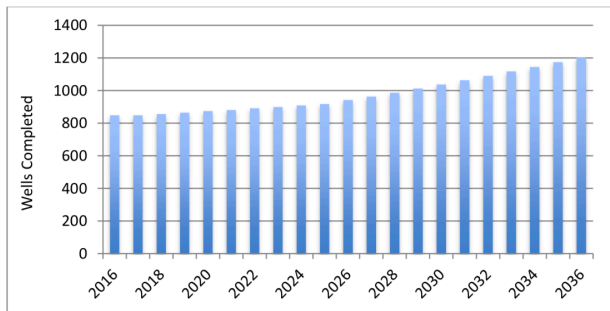




There is in 2015 little room left to drill on Bakken on Viewfield (the source rock is in North Dakota)! The so called “continuous type accumulation” is concentrated in limited “sweet spots“.

CERI 2016 forecasts an increase in the number of oil wells and in crude oil production up to 2036 (like CAPP): they did not bother to check if there are enough locations to drill

Figure 2.10: Saskatchewan New Oil Well Forecast

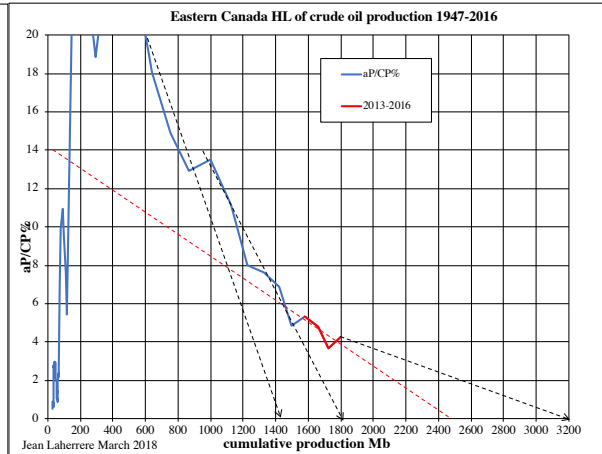
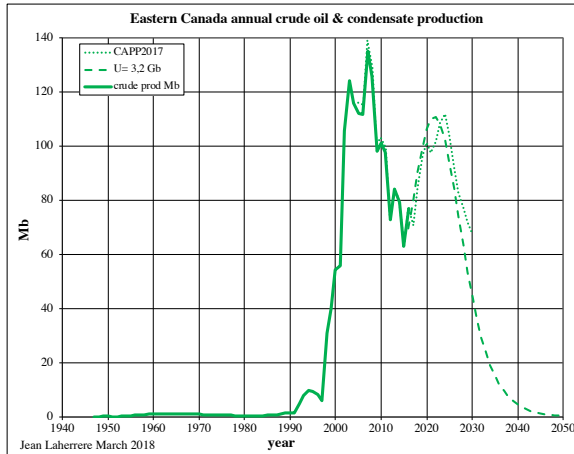


In 2017 flare and vent represents 32% of NG production: NG is too cheap to build pipeline!

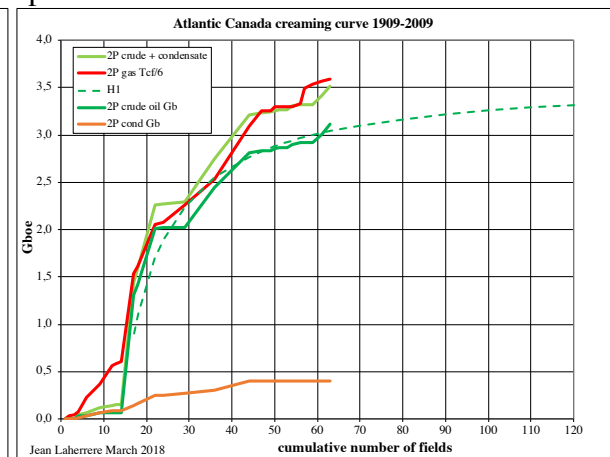
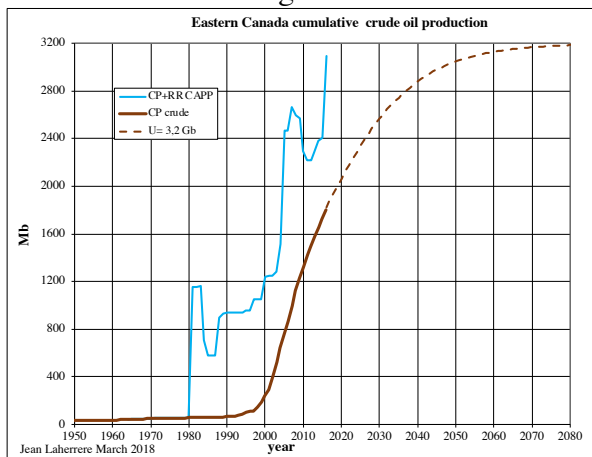
-Eastern Canada:

Ontario and New Brunswick have already produced 31 Mb before 1947, but in 2016 their cumulative production of 93 Mb represents only 5% of the Eastern Canada production, which increased sharply with East coast offshore production starting in 1992. Eastern Canada crude oil production peaked in 2008 with over 130 Mb and, after a symmetrical decline, its production will peak again with the recent development of Hebron-Ben Nevis (discovered in 1981 with 566 Mb) starting production in Nov 2017.

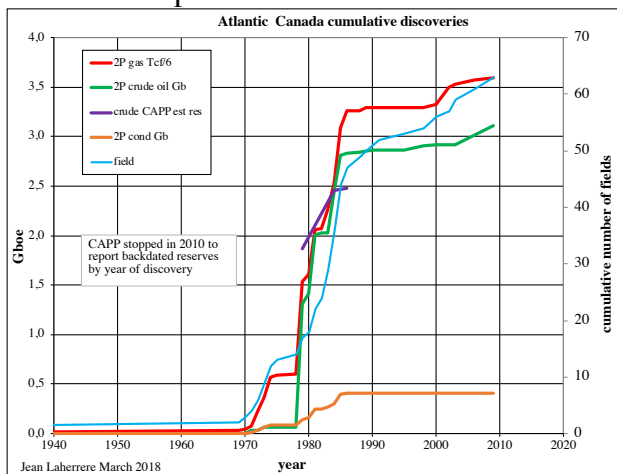
The HL of past production is extrapolated towards an ultimate of 3.2 Gb, in agreement with a cumulative production plus remaining reserves at 3.1 Gb. With an ultimate of 3.2 Gb, the crude oil + condensate production will peak in 2023, in agreement with the forecast of CAPP 2017



The Atlantic creaming curve 1909-2009 is extrapolated towards an ultimate of 3.3 Gb.



CAPP stopped in 2010 to report backdated reserves by year of discovery, the cumulative discoveries up to 2009 shows that the bulk of discoveries occurred from 1979 to 1985.



CERI 2016 forecasts a peak of offshore Newfoundland production in 2020, and for Newfoundland and Labrador in 2024

Newfoundland & Labrador

Figure 2.18: Offshore Newfoundland Crude Oil Production Forecast

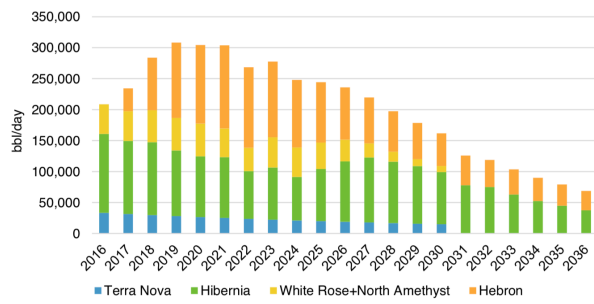


FIGURE 2.2 NEWFOUNDLAND AND LABRADOR PRODUCTION

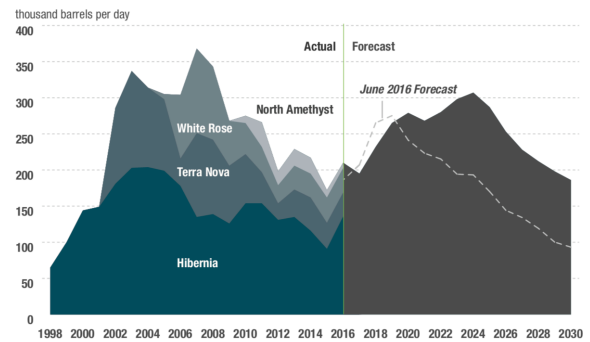


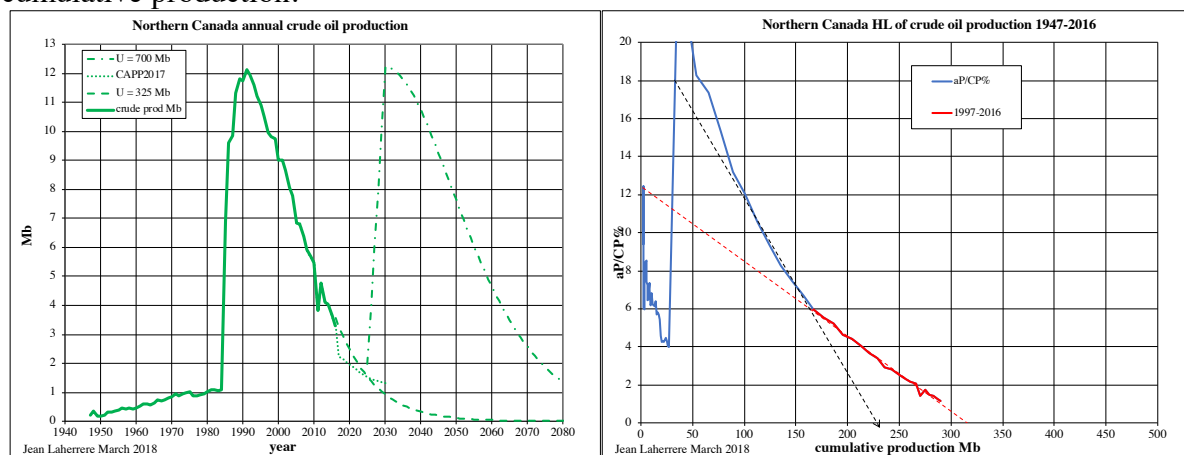
TABLE 2.2 ATLANTIC CANADA PROJECTS AND RECENT DISCOVERIES

Producing Field	Year Discovered	First Oil	Cumulative Production to December 31, 2016 (million barrels)	Estimated Recoverable Reserves (million barrels)
Hibernia	1979	Nov 1997	1,002 (61% of reserves)	1,644
Hibernia South Extension				
Terra Nova	1984	Jan 2002	391 (77% of reserves)	506
White Rose	1984	Nov 2005	269 (56% of reserves)	479
North Amethyst		May 2010		
South White Rose Extension		Mid 2015		
North Amethyst Hibernia		Sep 2015		
West White Rose		2022		
Hebron	1980	Late 2017	n/a	707
Recent Discoveries	Year Discovered	First Oil		Estimated Recoverable Reserves (million barrels)
Mizzen	2009	no estimate		102 (heavy oil)
Harpoon	Jun 2013	no estimate		Under evaluation
Bay du Nord	Aug 2013	2020+		300 to 600 (light oil)

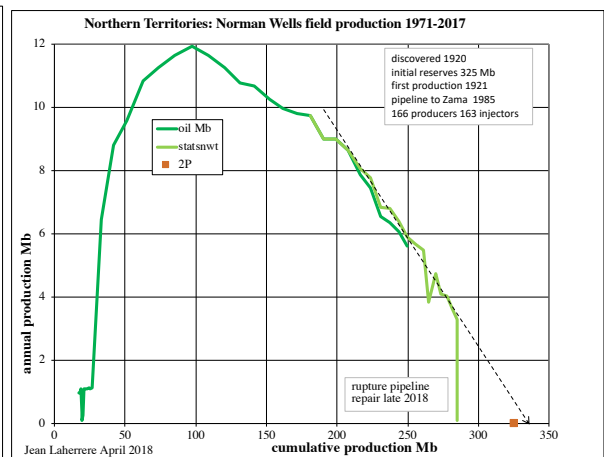
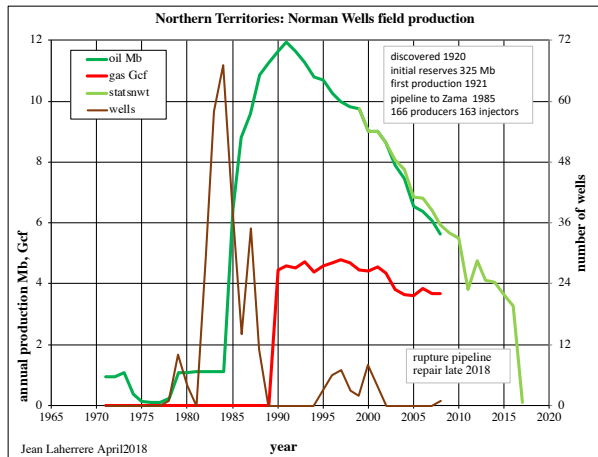
Source: Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB)

- Northern Canada, North of 60°, Arctic Islands

Northern Canada crude oil production has peaked in 1991, after a sharp increase and since has a decline less drastic than the increase; it is due mainly to the production of Norman Wells field, produced by one company Imperial (Exxon). Norman Wells was discovered in 1920, produced locally but fully developed in 1985 when connected by a pipeline to Zama field. The 2P reserves were estimated at 325 Mb, confirmed by the decline of annual versus cumulative production.

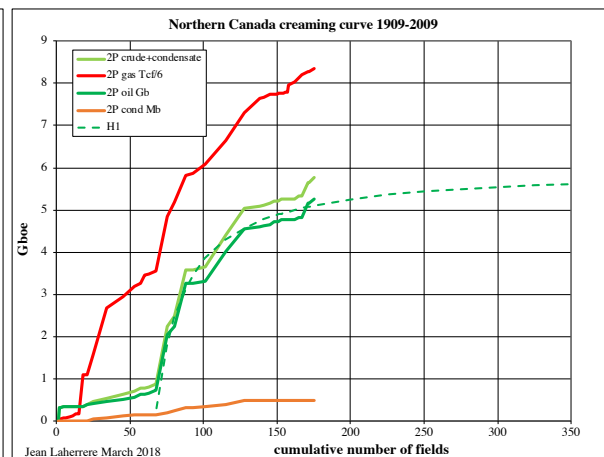
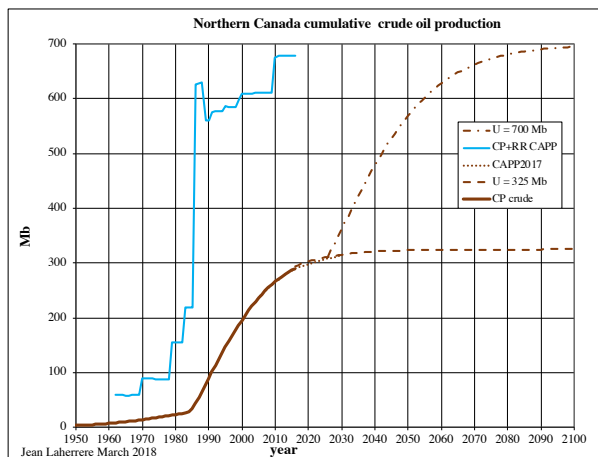


But Norman Wells production was stopped in 2017 because the shutdown of the pipeline due to the rupture by the Mackenzie River, forecasted to resume in late 2018: 40 Mb seem be yet to produce.



The HL of past N Canada production trends towards 325 Mb, equal to Norman Wells 2P, but ignoring the undeveloped discoveries in the Arctic in particular the Mackenzie delta, because the 2P ultimate from the creaming curve is over 5 Gb and the CAPP2017 cumulative production plus remaining reserves = 0.7 Gb.

The 325 Mb ultimate is modelled assuming no more development (in line with CAPP 2017 forecast up to 2030), but also a 700 Mb ultimate (on line with CAPP reserves is displayed, assuming a pipeline towards the Arctic, despite that 0.7 Gb is well below the >5 Gb discoveries in the Mackenzie delta and the Arctic islands.



The bulk of Arctic discoveries were between 1968 and 1984. I participated in the exploration of the Arctic (I recommended a bid on Prudhoe before the drilling, not accepted) and the Labrador (where we did several discoveries: first Bjarni 1973) being in Calgary VP Explo pf Total Eastcan from end 1966 to end 1971.

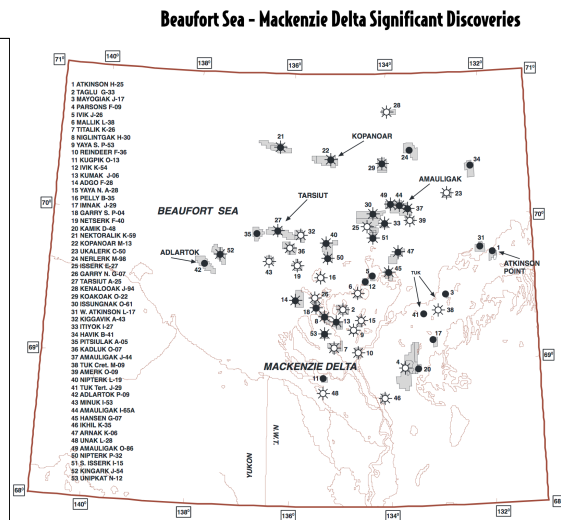
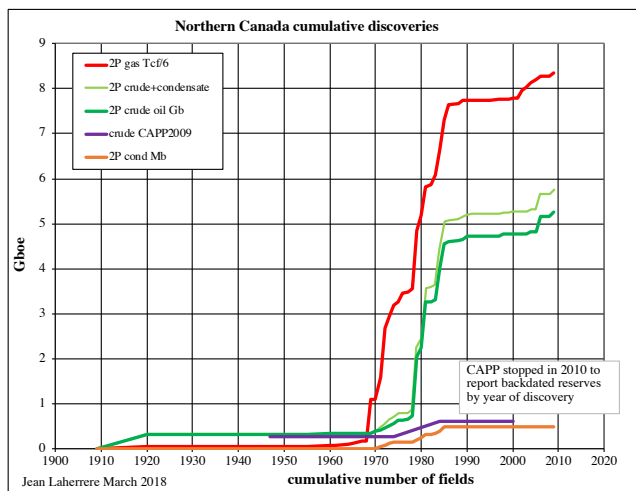
In exploring all Canada but also Michigan (finding oil in reefs) from Calgary, I am proud of, after participating in a large seismic refraction survey of the offshore of the Hudson Bay (820 000 km²) with Aquitaine, to have refused to participate in the drilling of the first well Walrus A-71 in 1969, aiming to find a tiny Paleozoic reef in such remote location: it was dry, followed by some more dry wells. Success can be negative recommendation!

My first contact with Canada was in 1959 when I supervised a reflection-refraction seismic survey to confirm in depth a surface anticline in the Northern Territories (no line bulldozing, using dog teams) with French Petroleum Company Canada for few months, being still with CPFA after the discoveries of Hassi Messaoud (found with refraction surveys) and Hassi R'Mel in the Sahara.

In 1990 being on the board of Ranchmen's (subsidiary of Total) and going from time to time to Calgary I recommended Total management to take a farm out from Gulf on Surmont (with 800 Mb of reserves) where 50% could be obtained by financing (10 M\$) a pilot plant of SAGD (steam assisted gravity drainage) paid half by the government: the real cost was then 5 M\$ to acquire undeveloped 400 Mb = about one cent per barrel. But the deal was rejected by Total management (Tchuruk) because too long term and low oil price. The deal was still available ten years later (Gulf replaced by ConocoPhillips) and Total took 50 % of Surmont, because, at that time, peak oil was considered coming in the 2010s. Surmont started production in 2007.

The discoveries in Northern Canada are more than 100

NEB 1998



NEB estimates vary with time

NEB 1998	oil M.m3	NG G.m3	cond M.m3
Mackenzie	34,5	139,7	10,7
Beaufort	121,9	115,0	0,7
Total	161,4	254,7	11,4
NEB2014 mark			
Beaufort	106,1	178	0,2

Canada tight oil

NEB <https://www.neb-one.gc.ca/nrg/sttstc/crdlndprlmpdct/rprt/tgthtdvlpmntwscb2011/tgthtdvlpmntwscb2011-eng.pdf> Dec 2011 displays many plays forecasts: "Tight Oil Developments in the Western Canada Sedimentary Basin" many tight oil plays few shale oil play = Duvernay
Tight oil map
Horizontal drilling 2005-2011

Map of the WCSB and location of tight oil land activity and drilling

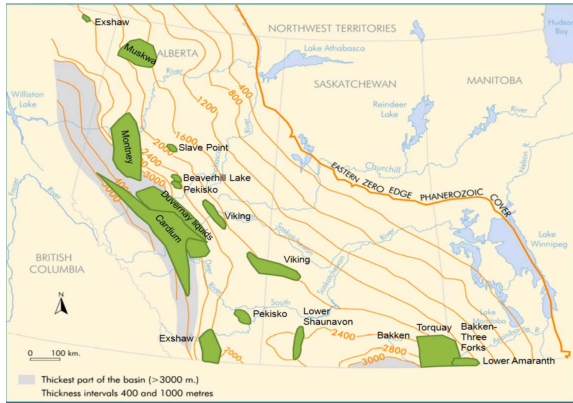
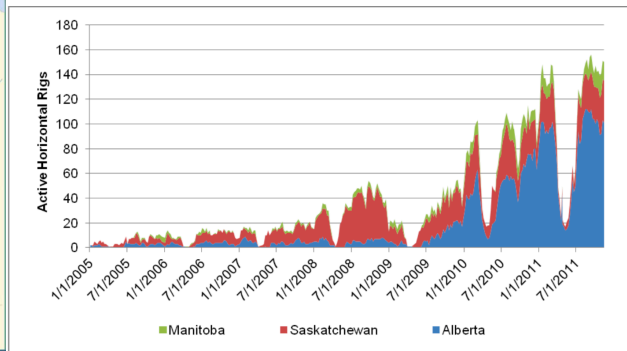
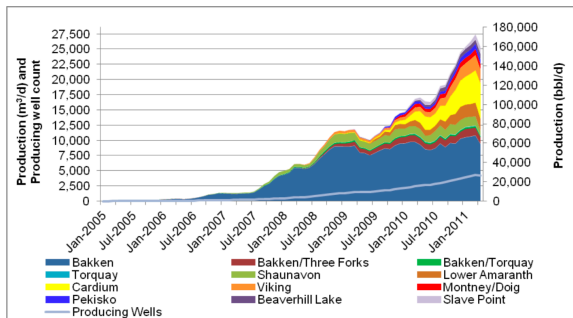


Figure 4
Rig Activity in WCSB tight oil plays



Tight oil production 2005-2011

Figure 5
Canadian tight oil production by play



Tight oil reserves

Summary of Tight Oil Formations in Western Canada

Formation	Bakken/ Exshaw	Cardium	Viking	Lower Shaanavon	Montney/ Doig	Duvernay/ Muskwa	Beaverhill Lake	Lower Amaranth
Type	Tight	Tight	Tight	Tight	Tight	Shale	Tight	Tight
Province	MB/SK/ AB/BC	AB	AB/SK	SK	AB	AB	AB	MB
Related Conventional Production?	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes
Typical depths – m	900-2500	1200- 2300	600-900	1300-1600	800-2200	2000+	2000-2900	800-1000
Reported Reserves – million m³ (million bbl)	36 (225)	21 (130)	9 (58)	15 (93)	-	-	-	-
Typical initial production rates per well – m³/d (bbl/d)	20-40 (120- 250)	25-80 (150- 500)	15-30 (100- 200)	15-40 (100-250)	30-95 (200- 600)	unknown	50-320 (250- 2000)	15-30 (100-200)

Western Canada – Tight Oil Activity

Figure A.4. Tight Oil Licences – Horizontal Only

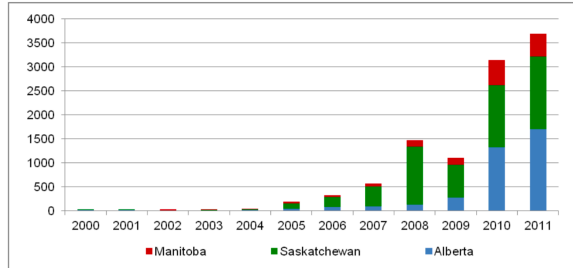


Figure A.6. Canadian Tight Oil Production by Province

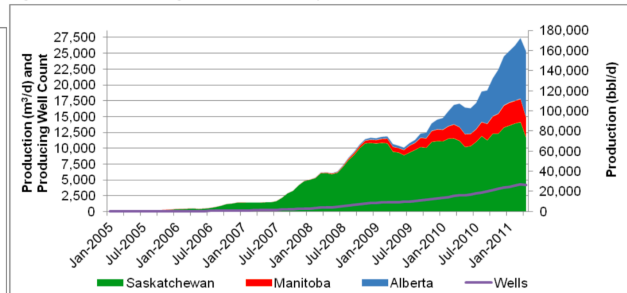


Figure A.8. Bakken, Torquay, and Three Forks Horizontal Oil Well Licences by Province

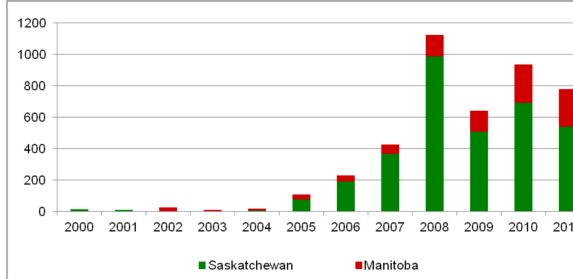


Figure A.10. Bakken, Three Forks, and Torquay Oil Drilling Activity

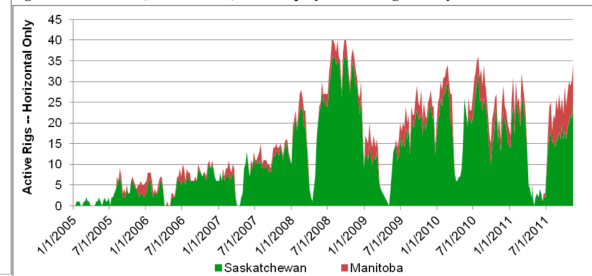


Figure A.11. Bakken, Three Forks, and Torquay Tight Oil Production by Play

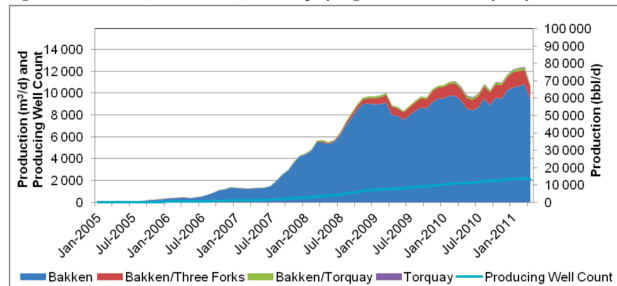


Figure A.12. Bakken, Three Forks, and Torquay Tight Oil Production by Province

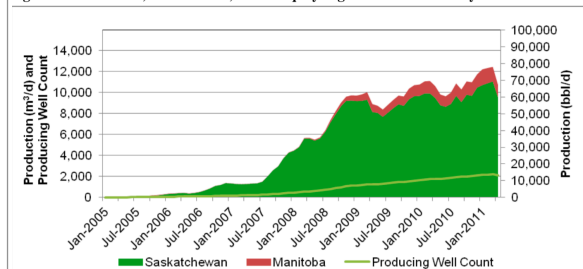


Figure A.15. Cardium Tight Oil Production

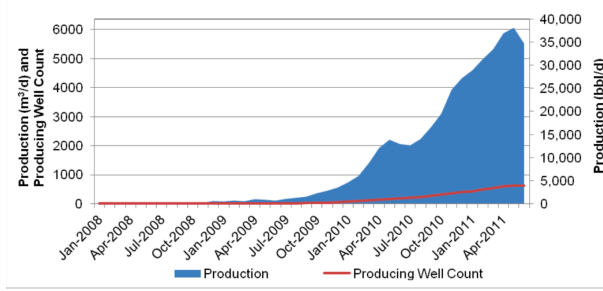


Figure A.18. Viking Tight Oil Production

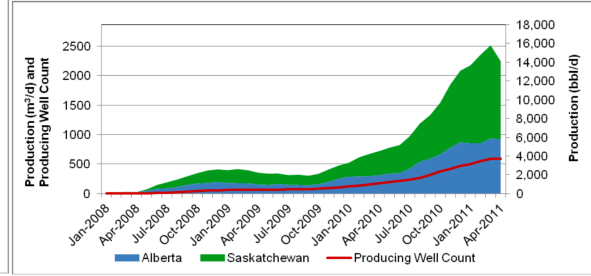


Figure A.26. Montney/Doig Oil Drilling Activity

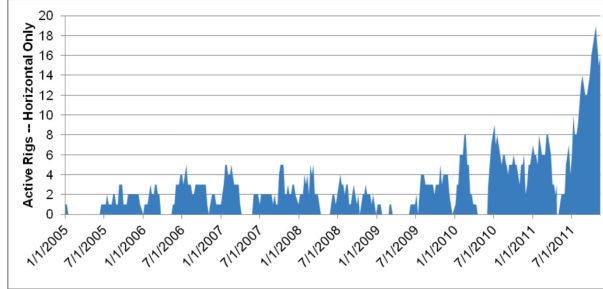


Figure A.27. Montney/Doig Tight Oil Production

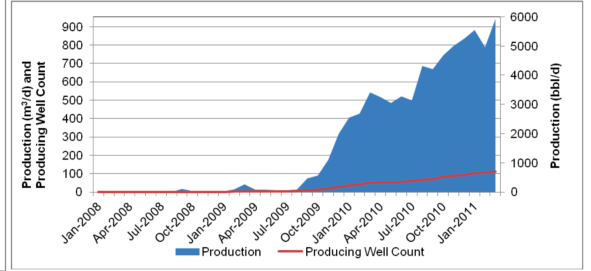


Figure A.29. Beaverhill Lake and Slave Point Oil Drilling Activity

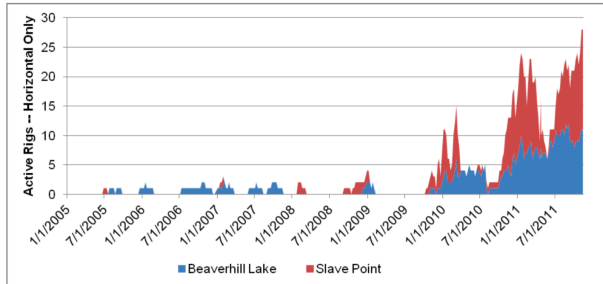
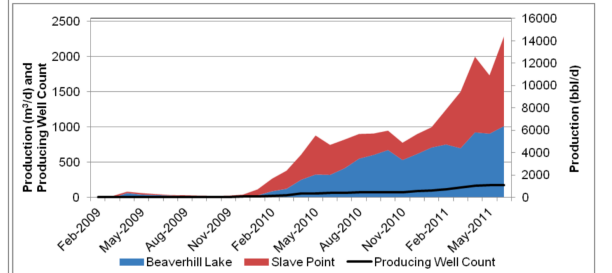
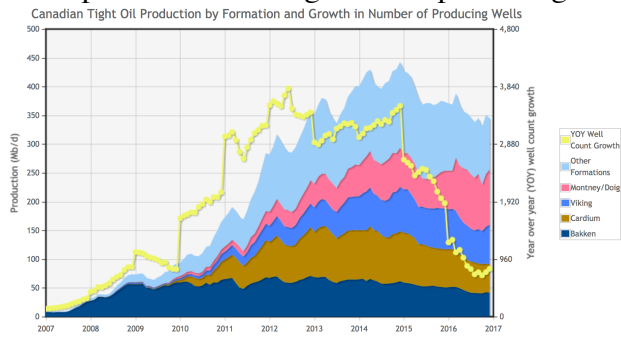


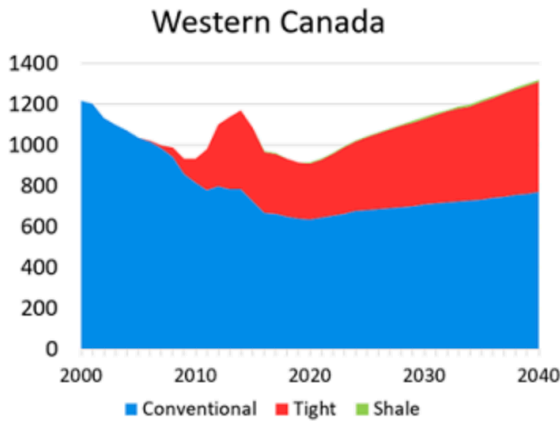
Figure A.30. Beaverhill Lake and Slave Point Tight Oil Production



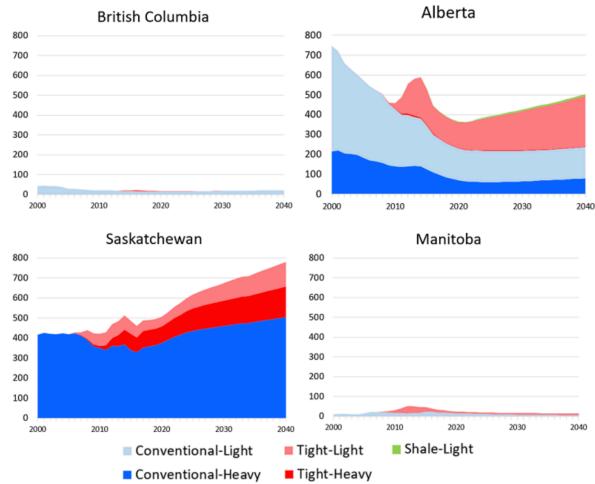
NEB June 2017 reports tight oil production by play for 2007 to 2016 with a peak in 2014 with a sharp decrease in the growth of producing wells



NEB “Canada’s energy future 2017”, supplement published in 2018, reports tight oil production from 2004 to 2040, with a new cycle starting in 2020 with a new peak after 2040

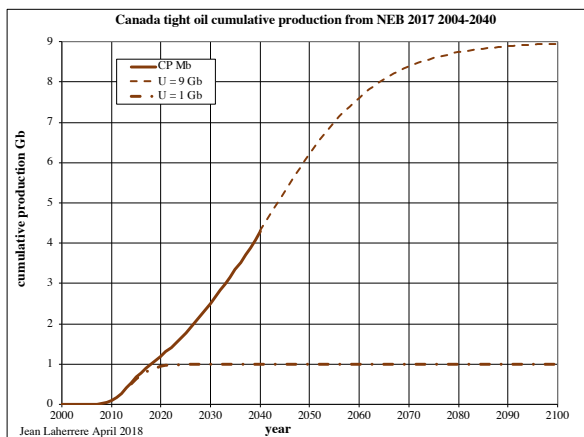
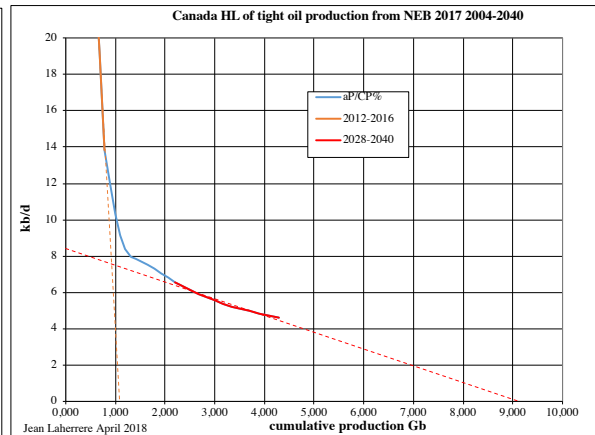
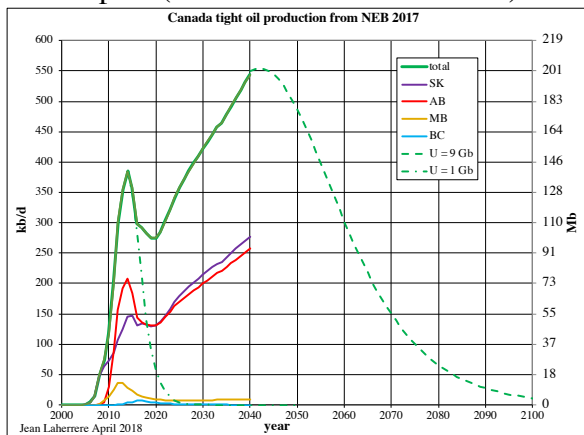


Oil Production by Province, Class, and Type (Mb/d)



The two main province producers are Alberta and Saskatchewan forecasted to produce about 250 000 b/d in 2040.

The HL of tight oil production is extrapolated towards 1 Gb for the period 2004-2016 and for 9 Gb for the period. But NEB does not report tight oil reserves, in contrary to other type of oil. It is likely that an ultimate of 1 Gb is too low with only one cycle peaking in 2014 and of 9 Gb too high with a second cycle peaking after 2040 with 550 000 b/d. If a second cycle occurs, it will be due to high price and the assumption that there is enough room to drill in the sweet spots (as it is with EIA in the US)



OPEC World oil outlook 2017 forecasts a tight oil production with a peak in 2030 at 520 kb/d and 480 kb/d in 2040, different from NEB.

Saskatchewan reports Bakken reserves for oil and NG, as in place

Table 1. Ultimate potential for Bakken unconventional oil in Saskatchewan

Oil – million m ³ (million barrels)	In-Place			Marketable		
	Low	Expected	High	Low	Expected	High
	8,420 (52,984)	11,279 (70,970)	14,627 (92,033)	132 (835)	223 (1,401)	345 (2,173)

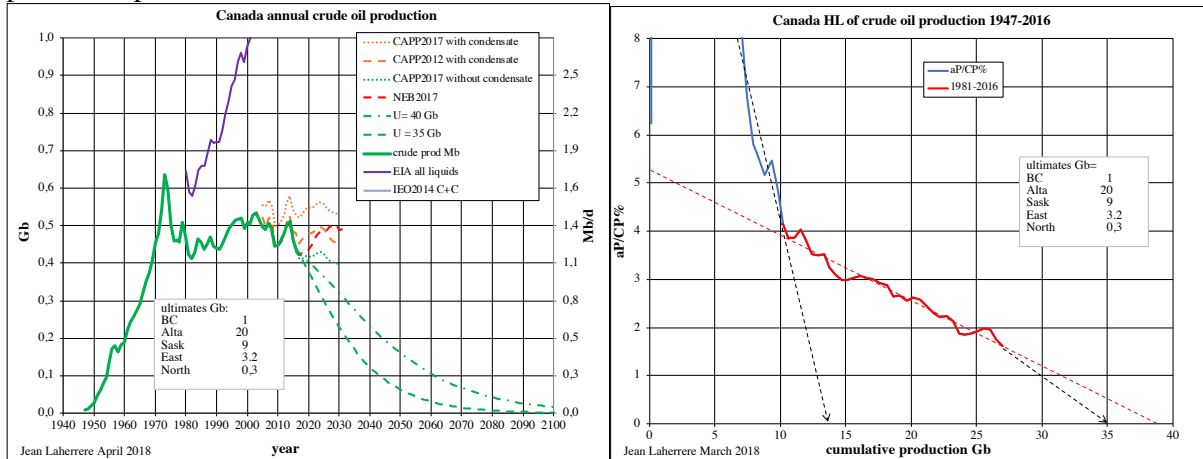
Table 3. Ultimate potential for Bakken unconventional natural gas in Saskatchewan

Natural Gas – billion m ³ (trillion cubic feet)	In-Place			Marketable		
	Low	Expected	High	Low	Expected	High
	2,281 (81)	3,041 (107)	3,944 (139)	48 (1.69)	82 (2.89)	128 (4.52)

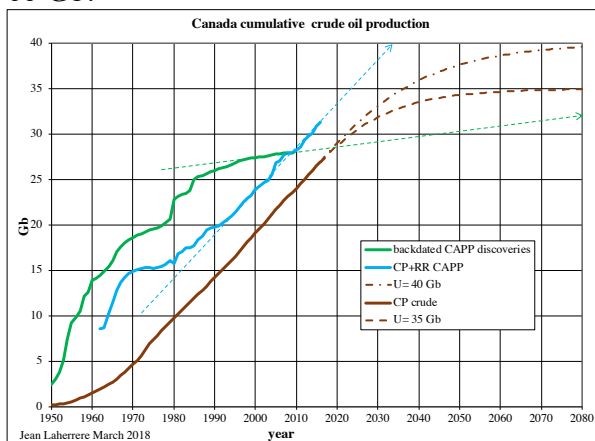
The Bakken recovery factor is only 2% for oil and 2.7% for gas: IP 71 Gb reserves 1,4 Gb and IP 107 Tcf reserves 2,9 Tcf. It is similar with what BCOGC reports for the Montney gas recovery with 1.8% (page 3)

-Canada crude oil

Canada crude oil production has peaked in 1973 and was plateauing from 1975 to 2013 around 1.4 Mb/d, the present decline will continue if the ultimate is around 35 Gb (Alberta 20, Saskatchewan 9, Eastern 3, BC 1), the decline will be symmetrical to the increase 1947-1973. But the undeveloped discoveries and yet to find can increase the ultimate to 40 Gb. The cumulative production plus remaining reserves at end 2016 is 31 Gb. The HL of past crude oil production trends towards 40 Gb. But an ultimate of 40 Gb will still decline but with a lower slope. CAPP2017 forecast, as NEB 2017 is keeping the crude oil production on a bumpy plateau. I prefer the 35 Gb estimate!



The cumulative crude oil production plus the CAPP remaining established reserves is compared to the CAPP 2009 handbook Table 2.21 initial established reserves by year of discovery, which aggregated gives the backdated oil discoveries (green curve). The linear extrapolation of the backdated reserves (2000-2009) trends towards 32 Gb when the linear extrapolation of the current discoveries (blue curve) trends for the period 1990-2007 towards 60 Gb.

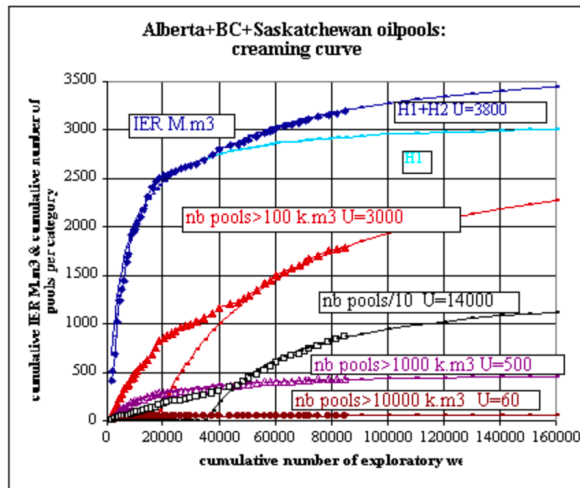
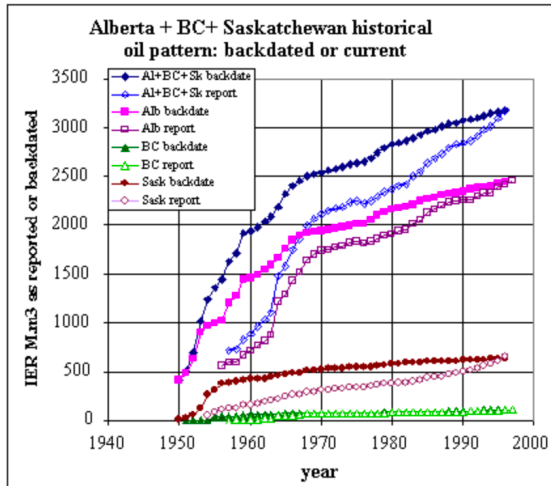


The discrepancy is so devastating that CAPP stopped in 2010 to update backdated reserves (leading to more pessimistic forecasts) and in 2017 to report them..

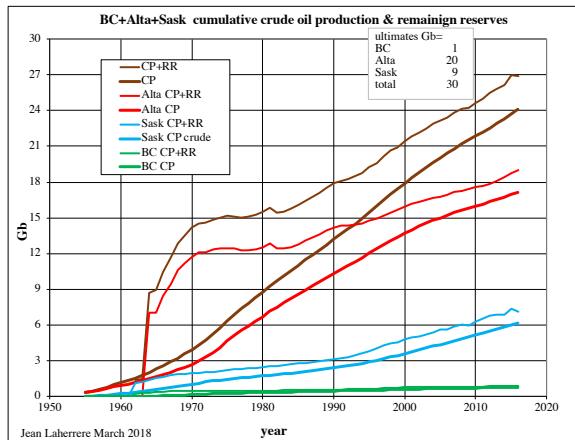
-My past forecasts

In 1999, crude oil ultimate for Alberta, Saskatchewan & BC was estimated, using creaming curve from oil pools up to 2006, to be 3500 G.m³ or 22 Gb against 30 Gb now:

Presentation in Calgary in 1999 Laherrère J.H. "Assessing the oil and gas future production and the end of cheap oil ?" CSEG Calgary April 6 <http://dieoff.com/page179.htm>



But in 1999 the cumulative production + remaining reserves for these three provinces was less than 20 Gb.



In 2011 I estimated Canada crude oil ultimate at 30 Gb from creaming curve and at 38 Gb from HL, against today between 35 and 40 Gb,

The difference between extrapolation from backdated discoveries (30 Gb) and current discoveries (45 Gb) is huge and in 2010 CAPP dropped reporting backdated reserves.

-Laherrère J.H. 2011 «Backdating is the key » ASPO 9 Brussels 27 April

http://www.aspo9.be/assets/ASPO9_Wed_27_April_Laherrere.pdf

http://aspofrance.viabloga.com/files/JL_ASPO2011.pdf

Figure 3: Canada remaining crude oil current & backdated established oil reserves, with proven remaining reserves from OGJ/EIA, BP & WO.

Figure 4: Canada crude oil creaming curve from CAPP 2009 handbook

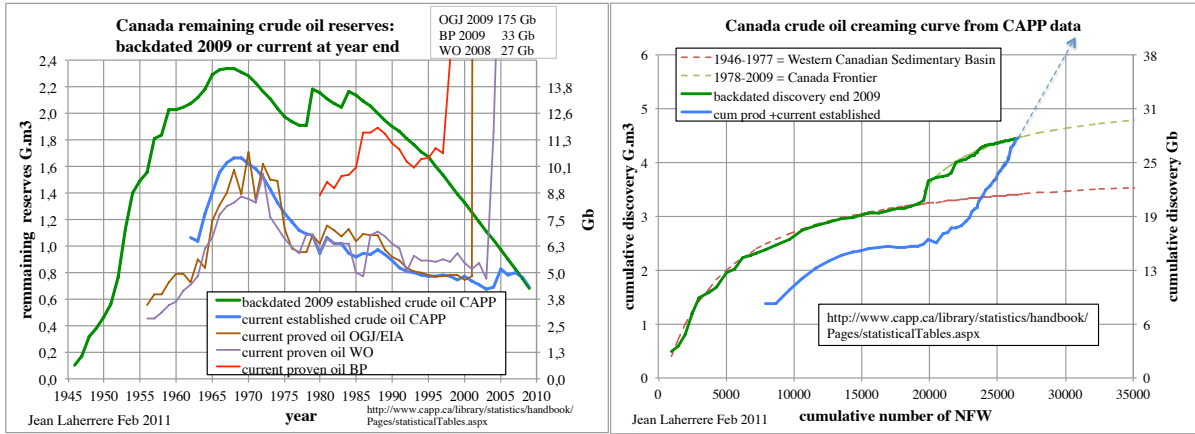
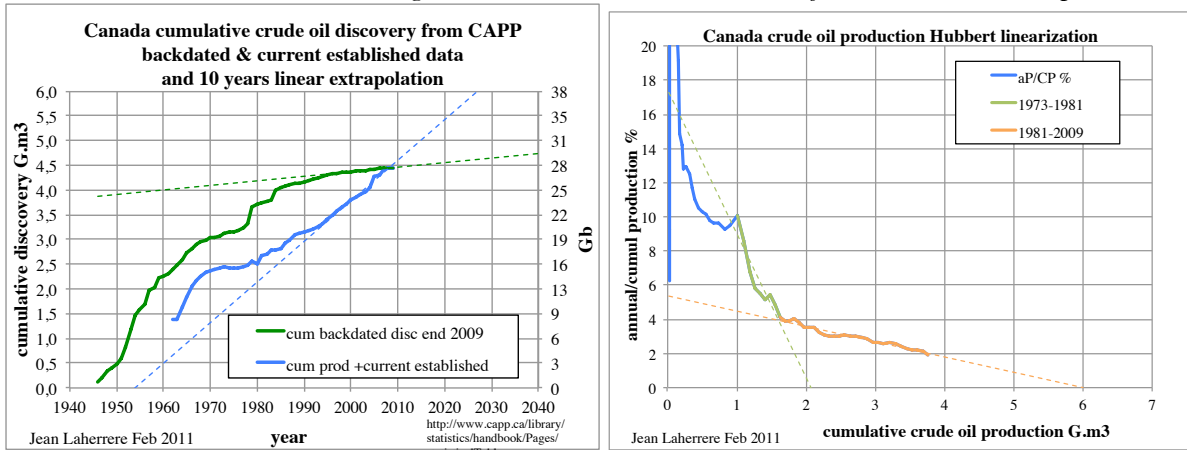


Figure 5: Canada cumulative crude oil discovery from CAPP backdated & current established data with 10 yr extrapolation

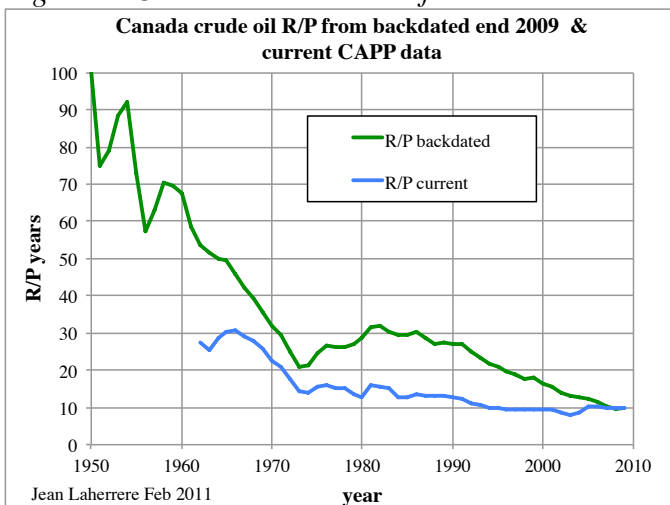
Figure 6: Hubbert linearization of Canada crude oil production



The Hubbert linearization of crude oil production is far to show a simple linear decline and trends towards about 6 G.m³ (38 Gb).

Another poor indicator, which is the R/P, shows that R/P will stay around 10 years despite it is from backdated or current data. US R/P from current reserves has stayed around 10 years since 1020 and it will stay at 10 years until the last barrel.

Figure 7: Canada crude oil R/P from backdated and current CAPP reserves



R/P is an useless indicator.

-other forecasts

-CERI Canadian Energy Research Institute Sept 2016 Study N°159
Canadian Crude Oil and Natural Gas Production and Supply Costs Outlook (2016–2036) Laura Johnson, Paul Kralovic, Andrei Romaniuk ISBN 1-927037-43
 The conventional crude oil production is plateauing from 2001 to 2036

Figure 1.3: Canadian Conventional Crude Oil Production (Light, C5+/Condensate, Heavy)

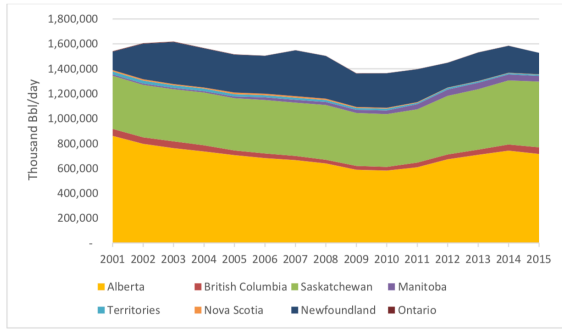
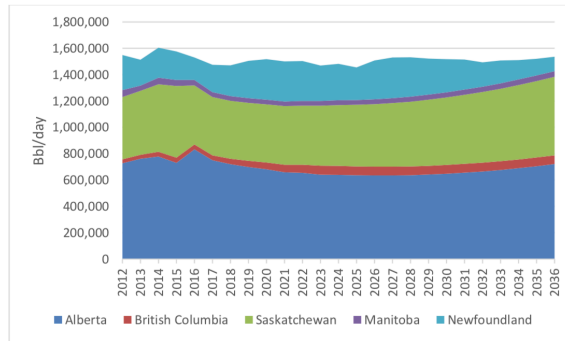
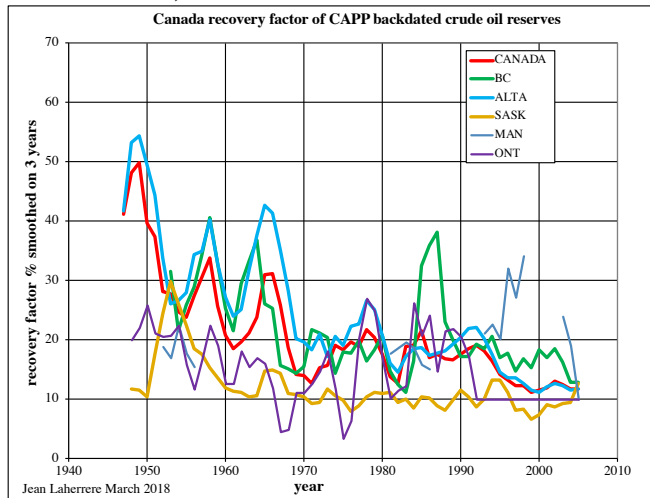


Figure E.2: Total Canadian Conventional Crude Oil Production



-Canada crude oil recovery factor

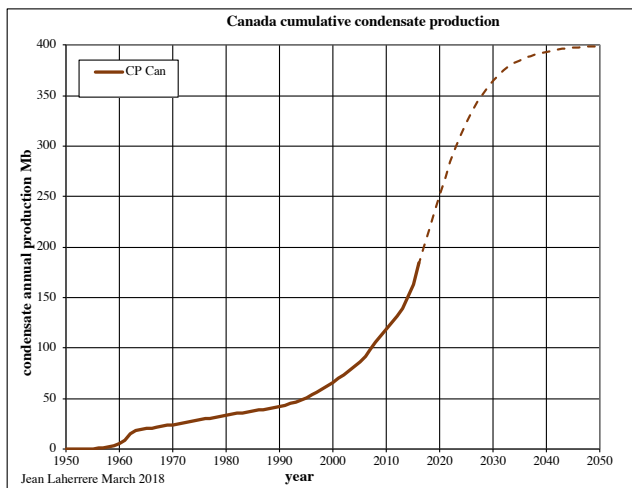
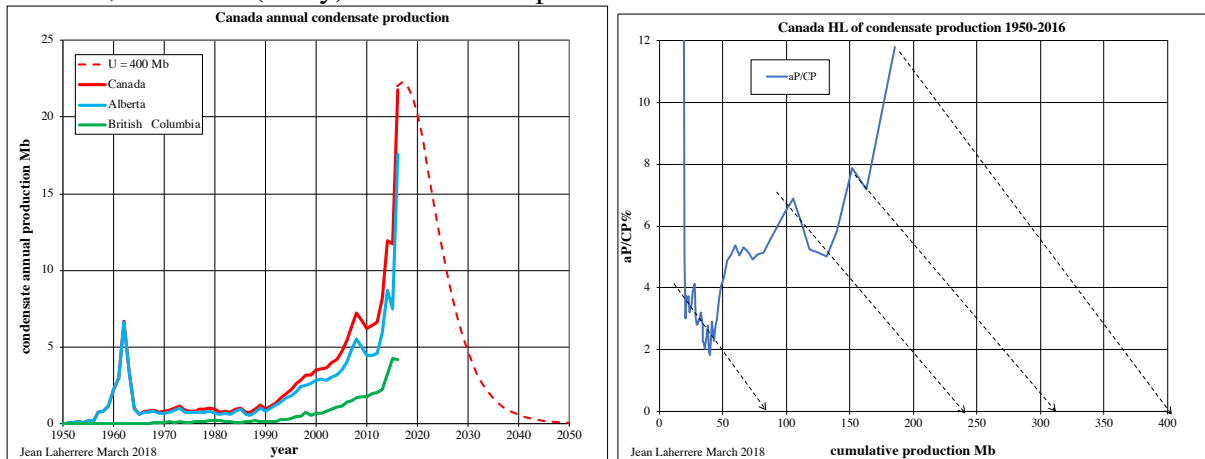
As CAPP was reporting in place and backdated crude oil reserves it is possible to plot the recovery factor evolution with time until 2006 for each province of the WCSB (Western Canadian Sedimentary Basin). It is obvious that the oil recovery factor has decreased since the first discovery of reefs in Alberta: the first reef cycle was Leduc in 1948 after about 100 dry holes, then 1958 with Swan Hills and 1965 with Rainbow. Canada recovery oil factor was 50% in 1948, but around 10% in 2006



-Canada condensate

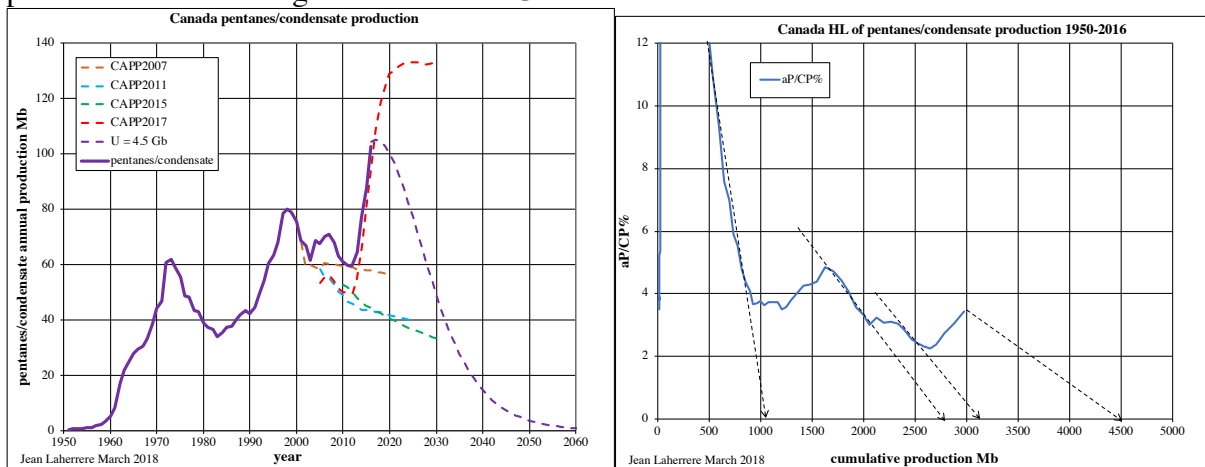
Condensate production is badly reported in the world, as it is by IEA, which following Norway, reports condensate either as crude oil if sold with it, or as NGL if sold with them. There is a discrepancy of 2 Mb/d for world NGL between IEA and EIA. CAPP handbook 2018 reports production table 3.1= crude oil, 3.2 synthetic, 3.3 condensate, 3.4 pentanes plus, 3.5 propane, 3.6 butanes, 3.7 liquid hydrocarbon. But CAPP does not report condensate reserves, but pentanes plus reserves. CAPP reports NGL reserves (2.10 including incomplete production), but not NGL production in the production section 3. It looks as if different experts take care of reserves and production and do not communicate.

Canada condensate production has peaked in 1961 and will peak soon for an “ultimate” of 400 Mb, estimated (badly) from the extrapolation of HL

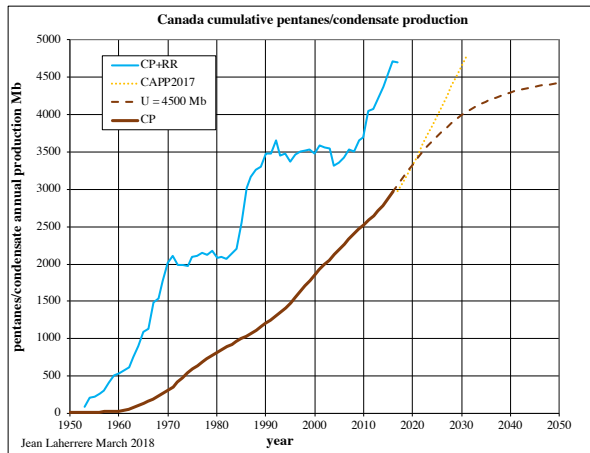


-Canada pentanes/condensate

Canada pentanes plus has peaked in 1974, 1999 and will peak soon for an “ultimate” of 4.5 Gb, estimated with the HL (symmetrical of last increase), not far from CAPP cumulative production + remaining reserves of 4.7 Gb

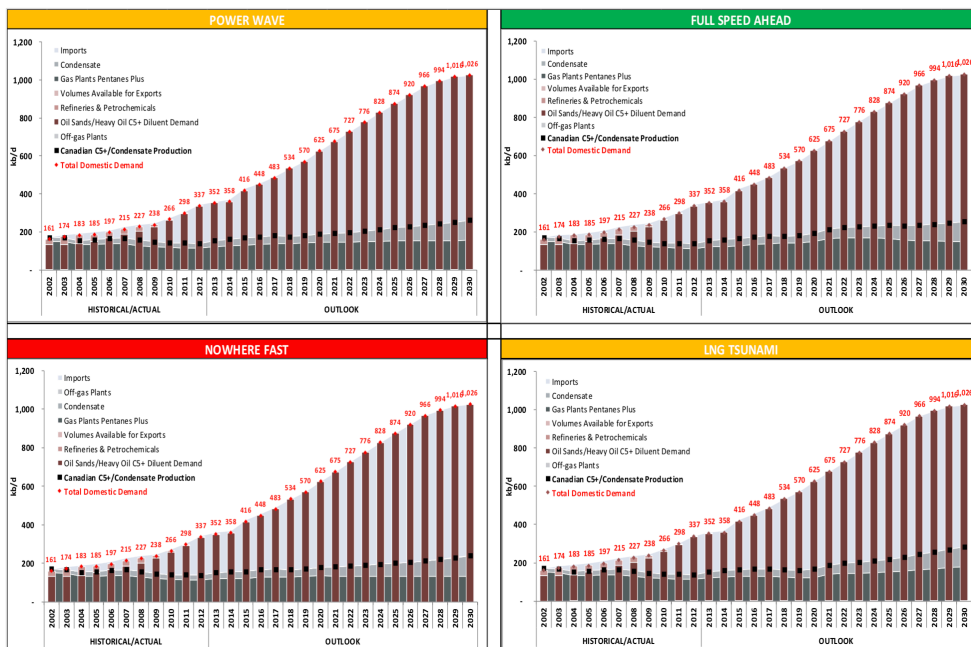


My forecast for 2030 is 50 Mb against 132 for CAPP2017



<https://www.ceri.ca/assets/files/CERI%20Study%20139%20Part%20V.pdf>
 CERI 2014 Natural Gas Liquids (NGLs) in North America: An Update part V outlook was too low for 2016 being < 2002

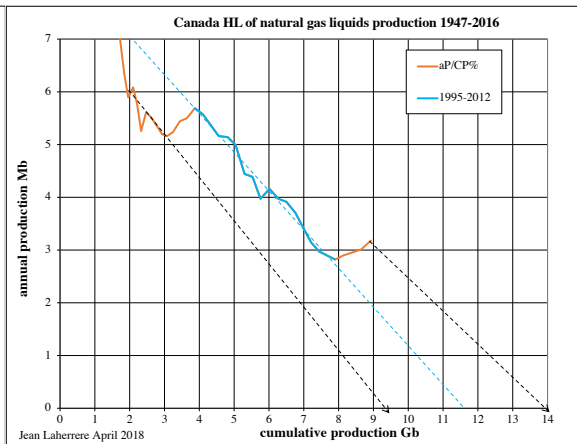
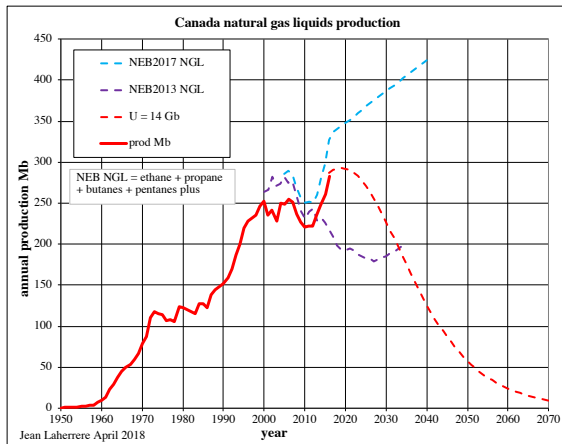
Figure A.14: Pentanes Plus/Condensate Supply and Demand in Canada (kb/d) by Scenario, 2002-2030



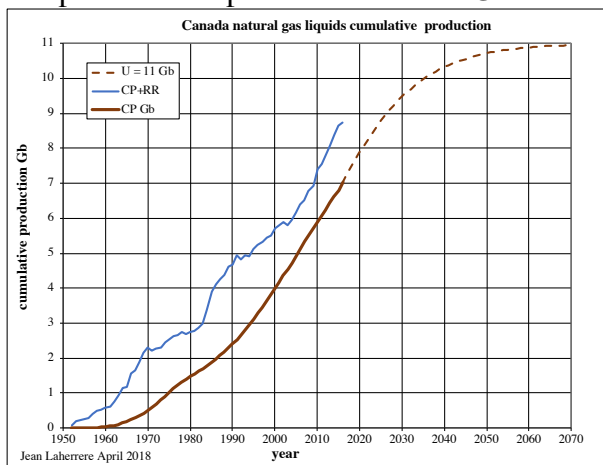
-Canada natural gas liquids = NGL

NGL are ethane+ propane + butanes + pentanes plus (including condensate)

CAPP reports NGL reserves (with production up to 2009, but erratic values needing smoothing), and NGL production in CAPP section 3.7. Statcan reports NGL production (its 4 components) since 1995 to 2016



HL of past production on the period 1995-2012 trends towards an ultimate of 11.5 Gb, but the last point is extrapolated towards 14 GB

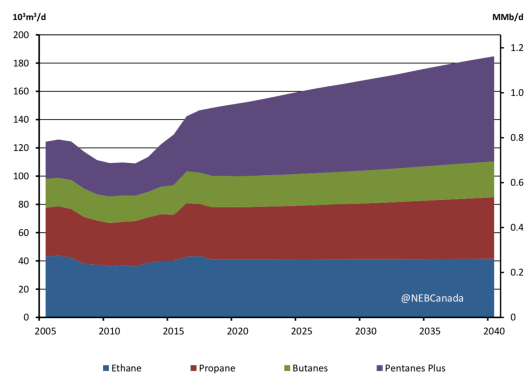
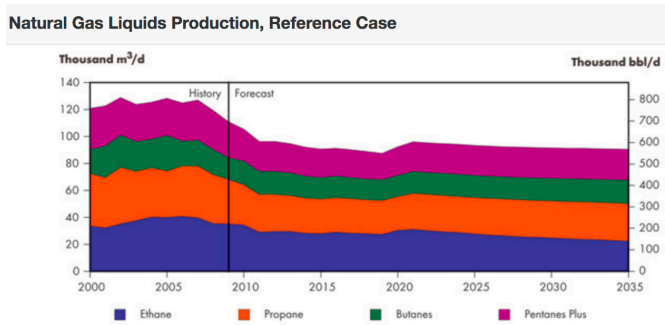


NGL production peaked in 1974, 2007 and likely 2019 from the forecast for an ultimate of 14 Gb. But NEB 2017 forecast does not see any new peak before 2040.

NEB 2010 forecast was 0.58 Mb/d 2035

NEB 2017 forecast was 1.1 Mb/d 2035

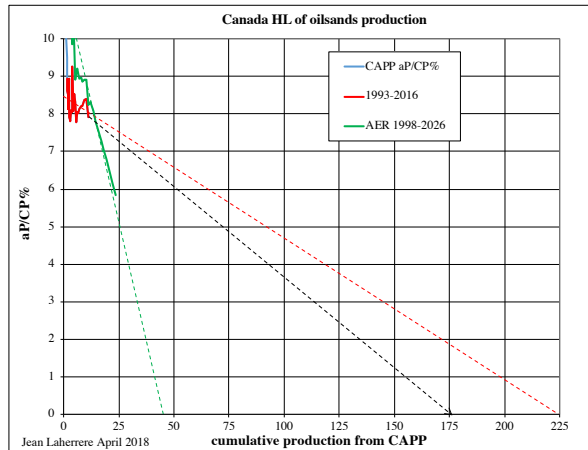
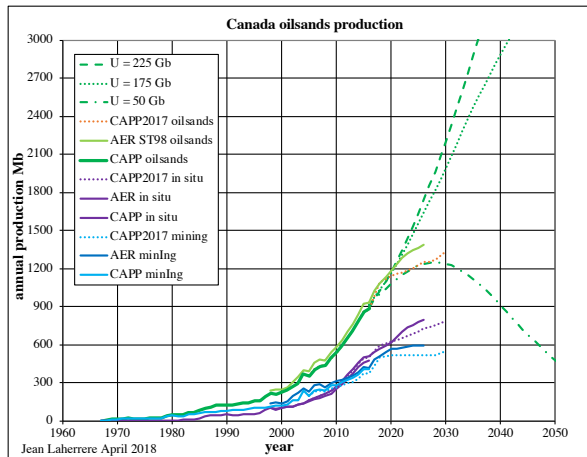
FIGURE 3.15 Natural Gas Liquids Production, Reference Case



-Canada oilsands

Canada Athabasca oilsands (known since the XVIII century) produce extra-heavy oil, as Orinoco fields (discovered between 1936 and 1939): both oil are similar, same gravity, same source rock, but different temperature of the reservoir (5°C for Athabasca and 55°C for Orinoco) giving completely different viscosity: Orinoco can flow, Athabasca cannot flow (bitumen = viscosity > 10 000 centipoise) and need to be heated (steam) or mined to be produced.

CAPP reports production for in situ (steam) and for mining (lower since 2011°)

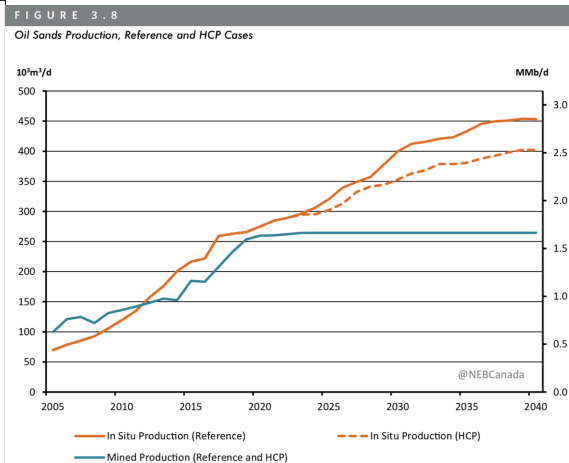
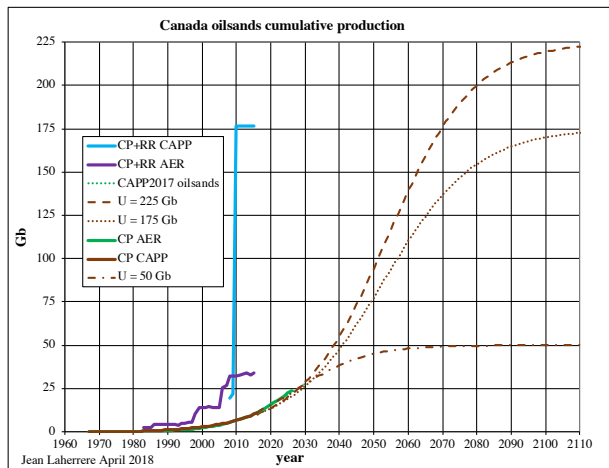


The HL of past production is too short to be reliably extrapolated: CAPP 1993-2016 trends towards 225 Gb, AER 1998-2026 trends towards 50 Gb. CAPP cumulative production plus remaining reserves at end 2016 are about 175 Gb: there is a large discrepancy with a range from 50 to 225 Gb. For more than 10 years, my ultimate for Athabasca extra-heavy is 250 Gb (as for Orinoco).

The problem is not the limits of the resources but the above ground constraints: pipeline and CO2 emissions. Canada's Trans Mountains pipeline expansion project (interest started in 1947 with Leduc discovery and first pipeline built in 1953) is presently delayed due to political infighting. Oilsands future production needs a bigger pipeline (3 times) to the Pacific coast for export (WCS is sold 10-30 \$/b cheaper than WTI). The builder Kinder Morgan menaces to cancel the project if nothing is done before end May 2018.

The future production for these 3 "ultimates" shows that 50 Gb is in line with CAPP 2017 forecast, but not with AER forecast (queer as 50 Gb is from AER forecast)

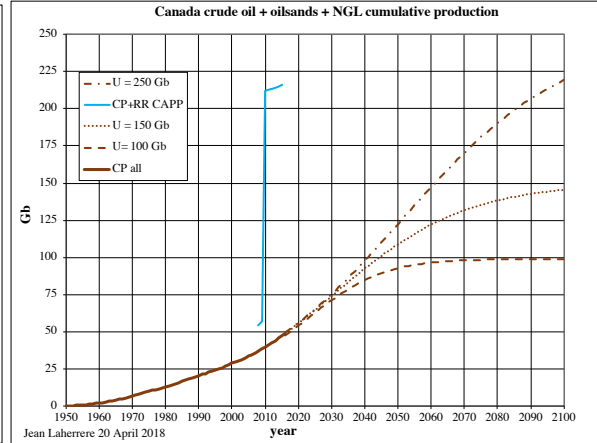
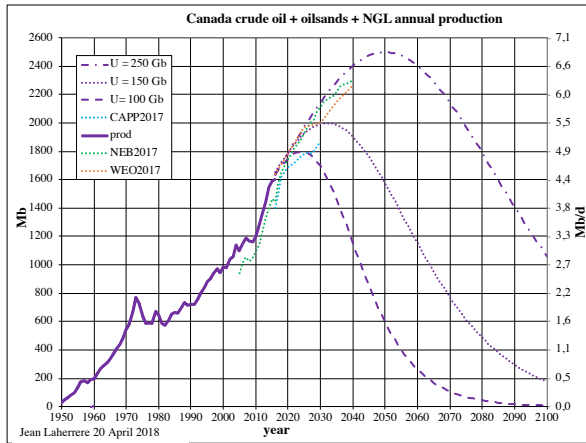
NEB 2017



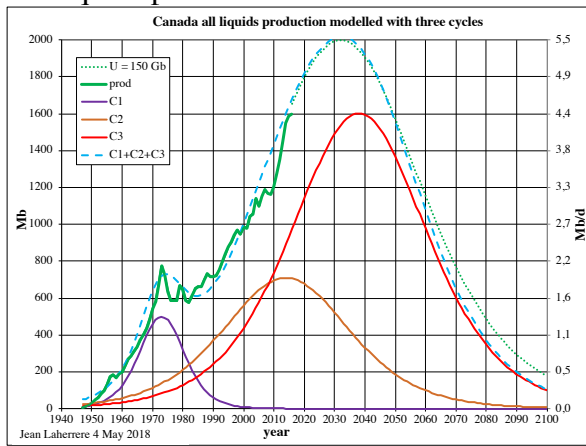
-Canada crude oil and oilsands and NGL

The addition of the previous estimates for ultimate of crude (35 or 40 Gb) and of oilsands (50 or 175 or 225 Gb) and of NGL (14 Gb) is simplified with three estimates for crude + oilsands of 100, 150 and 250 G.

Canada all liquids production for an ultimate of 150 Gb is the aggregation of three main cycles with peaks in 1973, 2016 and 2040.



All liquids production can be modelled with three cycles of increasing peaks and widths



The choice between these three ultimates from 100 to 250 Gb is not easy, because the real ultimate is not due to the ground but above ground, mainly political (authorization to build gas pipeline, with the present fight between BC and Alberta provinces).

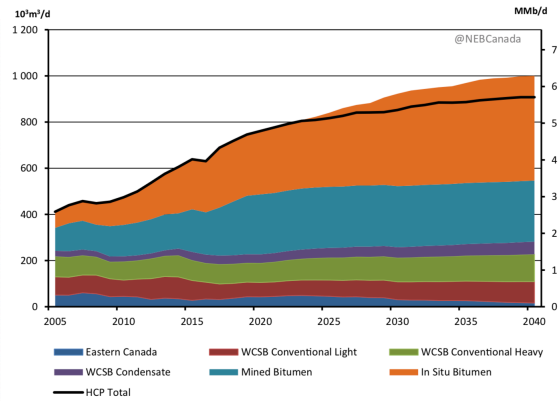
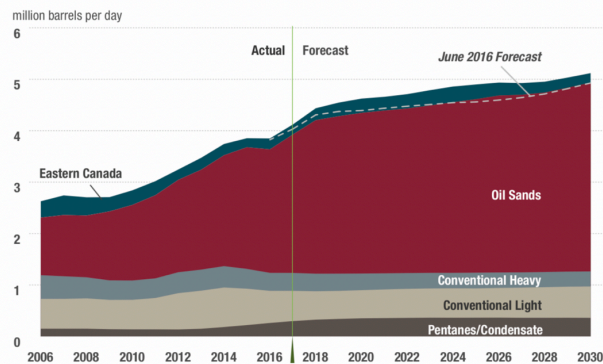
CAPP 2017 forecast is close to U= 150 Gb when NEB and IEA are close to U = 250 Gb

CAPP 2017

NEB 2017 HCP = higher carbon price

FIGURE 3.7 Total Canadian Crude Oil and Equivalent Production, Reference and HCP Cases

FIGURE 2.1 CANADIAN OIL SANDS & CONVENTIONAL PRODUCTION



For Canada oil production in 2030, CAPP 2017 forecasts 5 Mb/d, when NEB 2017 forecasts 5.9 Mb/d, 18% higher;

-Conclusions

Canada future oil production depends mainly upon oilsands and their above ground constraints with a huge range of oil ultimate reserves (from 100 to 250 Gb) , but it is likely that, in the long term, the huge resources of extra-heavy oil (oilsands) will overcome most of the above ground constraints when most of the conventional and unconventional oil will be depleted, because oil is so convenient and many forget that electric cars need permanent electric sources.

In contrary, Canada future natural gas production will peak soon and decline without any new cycle. NEB and EIA optimistic forecasts of an increase from 2030 to 2040 look unlikely. There is confusion between tight gas and shale gas. There is a large range of uncertainty in Canada unconventional gas reserves.

But Canada oil and gas production & consumption is so much connected with US oil and gas production & consumption, that my next paper will be North America oil and gas production, consumption and export.

NB Sorry for my broken English, but I care more on graphs than on text.

“A graph is worth a thousand words” or as said Napoleon: "A good sketch is better than a long speech"