British Columbia's 2024 Oil and Gas Reserves and Production Report

October 2025

BCER

Vision, Mission and Values

Vision

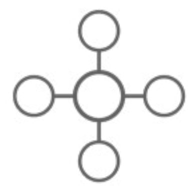
A resilient energy future where B.C.'s energy resource activities are safe, environmentally leading and socially responsible.

Mission

We regulate the life cycle of energy resource activities in B.C., from site planning to restoration, ensuring activities are undertaken in a manner that:

Protects public safety and the environment

Supports reconciliation with Indigenous peoples and the transition to low-carbon energy



Conserves energy resources

Fosters a sound economy and social well-being

Values

Respect is our commitment to listen, accept and value diverse perspectives.

Integrity is our commitment to the principles of fairness, trust and accountability.

Transparency is our commitment to be open and provide clear information on decisions, operations and actions.

Innovation is our commitment to learn, adapt, act and grow.

Responsiveness is our commitment to listening and timely and meaningful action.

BC Energy Regulator Office Locations Throughout B.C.

With over 25 years' dedicated service, we're committed to ensuring safe and responsible energy resource management for British Columbia.

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About This Report

This annual report summarizes provincial oil and gas production and remaining recoverable reserves in British Columbia, providing assurance of supply for the development of policy, regulation and industry investment. The report also qualifies the growth and future potential of unconventional resources as a long-term source of natural gas for the province.

Estimates of British Columbia's natural gas, oil, condensate and associated by-product reserves are presented in this report as of Dec. 31, 2024. The estimates have been prepared by the British Columbia Energy Regulator (BCER) using the principles of accepted engineering methods (including the Canadian Oil and Gas Evaluation Handbook (COGEH)), the Society of Petroleum Evaluation Engineers (SPEE) Monograph 3: Guidelines for the Practical Evaluation of Undeveloped Reserves in Resource Plays, and SPEE Monograph 4: Estimating Ultimate Recovery of Developed Wells in Low-Permeability Reservoirs. This report is not subject to the audit requirements of publicly traded companies and is not intended for the evaluation of individual companies.

The reserve numbers represent proved plus probable (2P) recoverable reserves using current technology. The proved reserves reflect a "reasonable certainty" to be commercially recoverable. Probable reserves are less likely to be recovered than proved reserves and are interpreted from geological data or engineering analyses.

Reserves Data Downloads

Detailed gas, oil, and by-product reserves data can be downloaded in CSV format on the BCER website under Data & Reports, Reservoir Management, Reserves.

The reserves presented in this report are estimates. Economic production limits are assumed and applied uniformly across wells or at the pool level, without analysis of location specific factors or operator financials. While Montney Basin reserves are typically estimated using individual well declines, reserves in other areas are often based on pool-wide declines or volumetric analysis when production data is limited. Montney wells are individually declined each year and their production profile is generally harmonic or super-harmonic for the first several production years and transitions to exponential later in life. A terminal rate of 2.8 e^3m^3/d or 100 Mcf/d is used for Montney wells (whereas 0.56 e^3m^3/d or 20 Mcf/d are used for most other wells). For oil wells, 0.5 m^3/d is used as a terminal rate. Please see disclaimer in the Professional Authentication section of this report on page 81.

Difference Between Resources and Reserves

Resources

Resources are the total quantity of oil and natural gas estimated to be contained in subsurface accumulations. The term resource is applied to a geologic formation in a large geographic region or a specific geologic basin. Resource estimates include proven reserves, produced quantities and unproven resources which may not be recoverable with current technology and economics.

The BCER cautions those using resources (prospective or contingent) as an indicator of future production.

The terms "resources" and "reserves" are not interchangeable.

This section highlights the significant differences in the criteria associated with their classification.

Reserves

Reserves are quantities of oil and natural gas commercially recoverable with development projects from a given date under defined conditions. To be classified as reserves, the oil or gas must meet these criteria:

- Penetrated by a wellbore.
- Confirmation the well will produce (either a production test or on production).
- Meets regulatory requirements (production or development not prohibited by government policy or legislation).
- Marketable to sell (viable transportation to sales point available either through pipelines, rail or trucking).
- Developed within a reasonable time frame (up to five years for probable reserves).
- Economic to recover, considering development costs, sales price, royalties, etc.

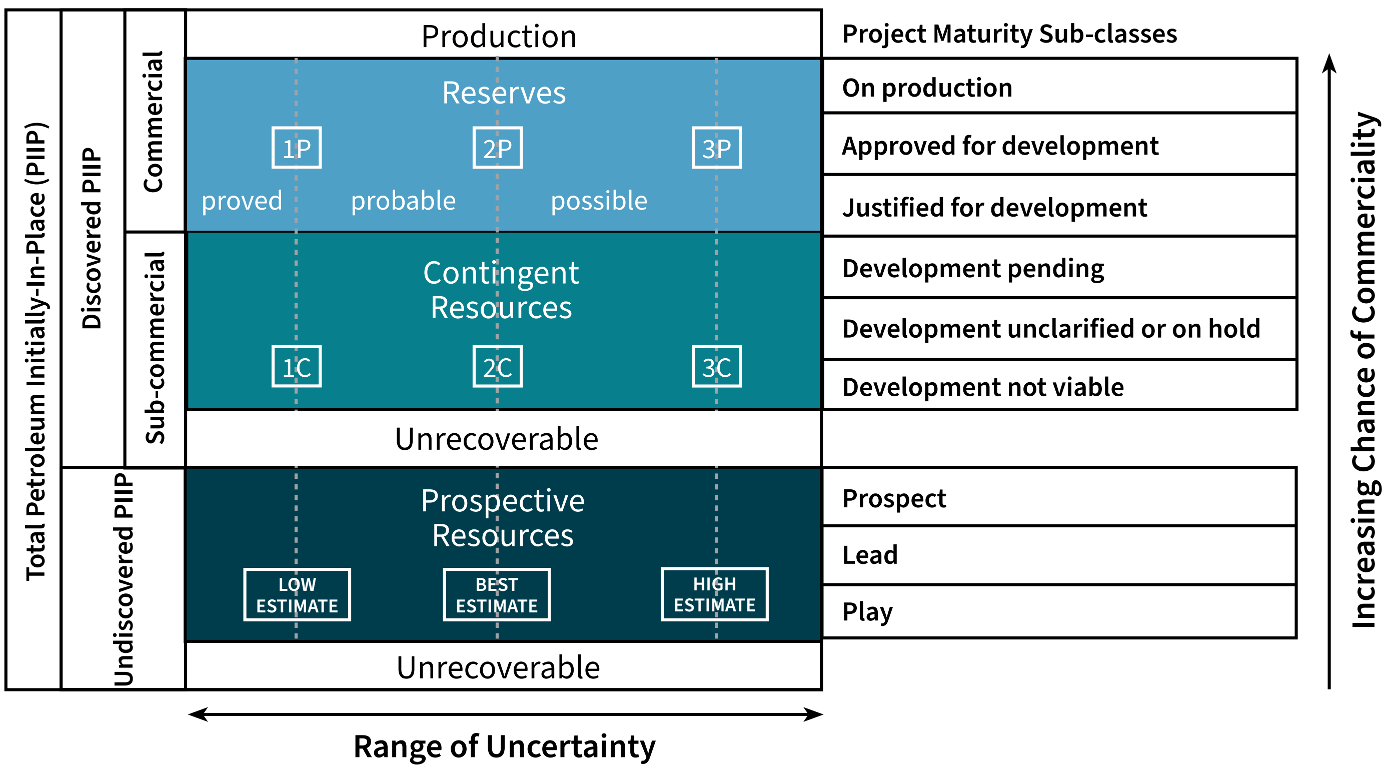
The Petroleum Resources Classification Framework published by the Society of Petroleum Engineers (Figure 1) provides a detailed analysis of the differences between resources and reserves.

The resources classification system is based on project maturity. This classification system uses an increasing chance of commerciality to categorize the petroleum initially-in-place (PIIP) as prospective resources (undiscovered resources), contingent resources (discovered but sub-commercial) or as reserves (commercial).

Along the horizontal axis, prospective resources are subdivided into three uncertainty categories providing a low estimate, best estimate or high estimate. Contingent resources are subdivided into 1C, 2C and 3C estimates of recovery with 3C having the highest number of resources. Reserves have a comparable system to that of contingent resources with 1P, 2P and 3P to represent proved, probable and possible reserves.

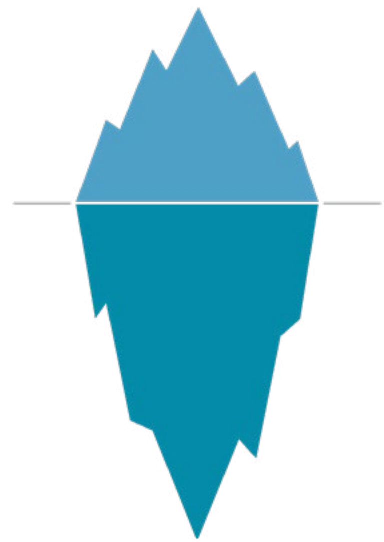
Figure 1: Resources Classification Framework and Sub-classes Based on Project Maturity

Sourced from: Petroleum Resources Management System (no scale inferred).



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 55,610 e^9m^3 (1,965 Tcf); however, currently recoverable initial raw gas reserves of 3,313.51 e^9m^3 (117.09 Tcf) are approximately six per cent of the resource estimate. This reserves percentage is expected to increase with continued development of the play.



Reserves

What we can get:

- Known accumulations
- Recoverable
- Established technology
- Economic

Resources

What is there:

- Potentially recoverable
- Undiscovered accumulations
- Unknown certainty

Table 1: Unconventional Gas Resource, Reserves and Cumulative Production

	RESOURCE				2024 RESERVES						
Basin/Play	Basin Total GIP Resource		Ultimate Resource Marketable		Initial Raw Gas Reserves		Remaining Reserves (Raw)		Cumulative Production (Raw)[6]		% Reserve per Resource
Unit	E^9M^3	Tcf	E^9M^3	Tcf	E^9M^3	Tcf	E^9M^3	Tcf	E^9M^3	Tcf	
Montney [1]	55,610	1,965	7,669	271	3,313.51	117.09	2,704.87	95.58	608.64	21.51	5.96%
Liard Basin[2]	23,998	848	4,726	167	2.13	0.08	0.00	0.00	2.13	0.07	0.01%
Horn River Basin[3]	12,678	448	2,207	78	39.54	1.40	0.00	0.00	39.54	1.40	0.31%
Cordova[4]	1,902	67	249	9	3.06	0.11	0.84	0.03	2.22	0.08	0.16%
Deep Basin Cadomin, Nikanassin[5]	255	9	207	7	27.86	0.98	5.76	0.20	22.10	0.78	10.94%
Total	**94,443**	**3,337**	**15,058**	**532**	**3,386.10**	**119.66**	**2,711.47**	**95.81**	**674.63**	**23.84**	3.59%

[1] NEB/OGC/AER/MNGD Energy Briefing Note - The Ultimate Potential for Unconventional Petroleum from the Montney Formation of BC and Alberta (Nov. 2013)

[2] NEB/OGC/ NWT/Yukon Energy Briefing Note – The Unconventional Gas Resources of Mississippian-Devonian Shales in the Liard Basin

[3] NEB/MEM Oil and Gas Reports 2011-1, Ultimate Potential for Unconventional Natural Gas in Northeastern BC's Horn River Basin (May 2011)

[4] MNGD/OGC Cordova Embayment Resource Assessment (June 2015)

[5] MEMPR/NEB Report 2006-A, NEBC's Ultimate Potential for Conventional Natural Gas

[6] Cumulative production to Dec. 31, 2024

Executive Summary

In 2024, there were 10,433 producing wells — 9,628 gas wells and 805 oil wells. The remaining 431 active wells consist of observation (75), water source (12), water injection (242), gas injection (14), deep disposal (79), and storage (9).

In 2024, a total of 895 new well applications were approved, and 621 wells were drilled—all within the Montney Basin, which continues to be the primary focus of development activity, as shown in Figure 2. This represents a 19 per cent increase compared to the 524 wells drilled in 2023.

As shown in Table 2, all hydrocarbon reserves saw growth in 2024. Gas reserves increased by 8.4 per cent, while hydrocarbon liquids saw a remarkable rise. Province-wide oil reserves grew 21.4 per cent, driven largely by further development of the Heritage oil areas, where production more than doubled mid-year. LPG and pentanes+ reserves increased 16.3 and 23.3 per cent, respectively, reflecting both higher gas production and strong liquids yields. These gains were almost entirely driven by focused development in liquids-rich areas and layers of the Montney formation.

The Fort Nelson Gas Plant was suspended in June 2024 following a widespread upstream shut-in and resulting insufficient gas supply. With no firm producer commitments or plans to restart, the plant and regional production remain offline. Consequently, there is currently no viable market or infrastructure for these gas resources. Reserves in the Horn River and Liard Basins have therefore been reclassified as contingent resource, pending restoration of infrastructure, market access, and reasonable certainty of production resumption.

	2024		2023		Percent Change
Gas (raw)	2,817.3 $10^9 m^3$	99.6 Tcf	2,598.9 $10^9 m^3$	91.8 Tcf	8.40%
Oil	14.4 $10^6 m^3$	90.6 MMSTB	11.9 $10^6 m^3$	74.7 MMSTB	21.44%
Pentanes+	179.6 $10^6 m^3$	1,130.7 MMSTB	145.6 $10^6 m^3$	916.1 MMSTB	23.31%
LPG	211.1 $10^6 m^3$	1,329.8 MMSTB	181.5 $10^6 m^3$	1,143.5 MMSTB	16.30%
Sulphur	5.4 10^6 tonnes	5.3 MMLT	5.4 10^6 tonnes	5.3 MMLT	-0.71%

Table 2: B.C. Remaining Reserves as of Dec. 31, 2024

Best practices for hydraulic fracturing continue to evolve, and demand remains high for deep disposal to support the geological storage of flowback water. Sections on hydraulic fracturing, deep disposal, deep saline water sourcing, and drilling activity and decommissioning, can be found at the end of this report.

B.C. Production Dashboard

In July 2024, the BCER launched the B.C. Production Dashboard, featuring several figures and tables such as those found in this report, along with additional data. The interactive report is updated monthly with the latest information.

Access the dashboard and related documentation through the [Data Centre] on our website.

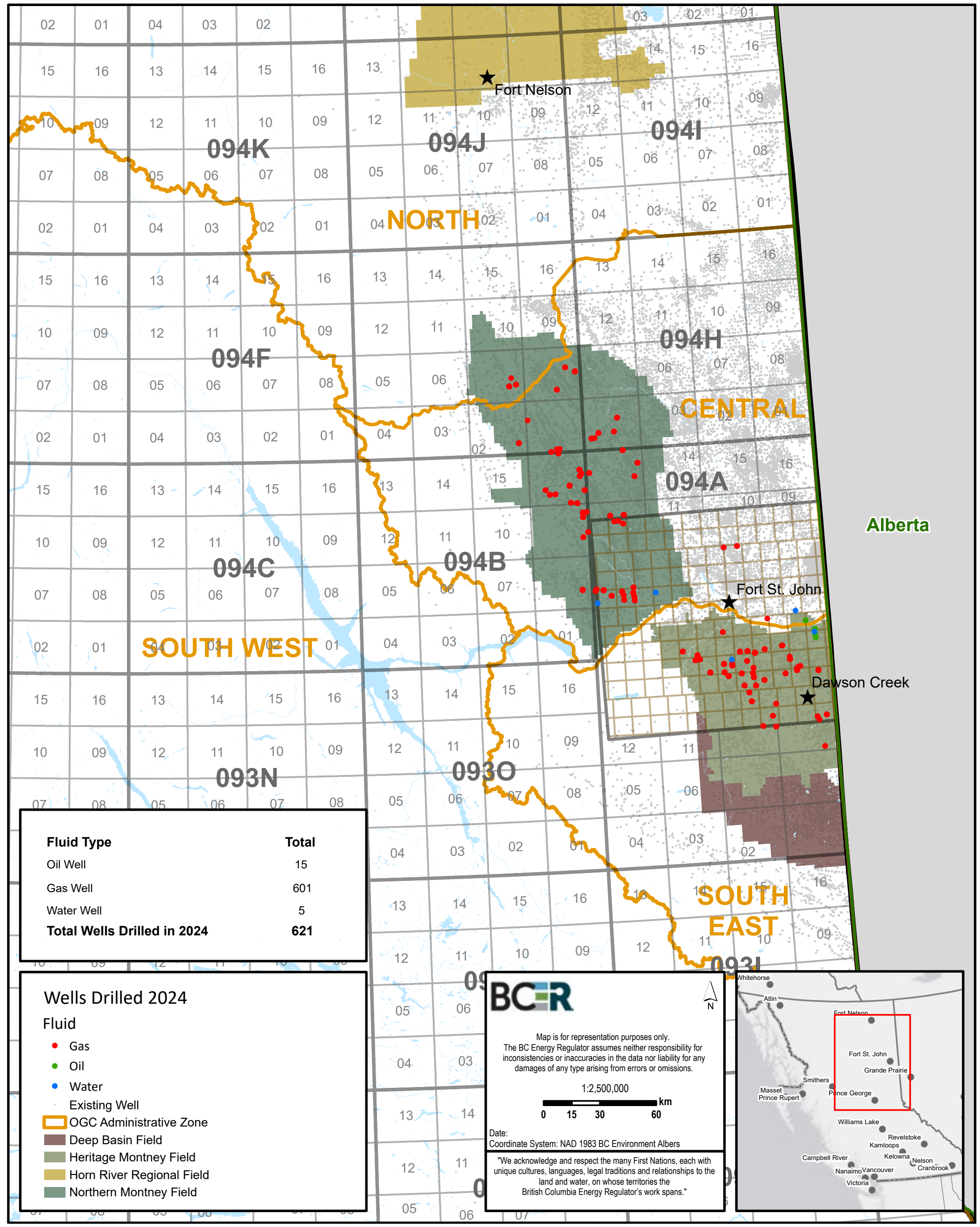


Figure 2: 2024 Wells Drilled by Fluid Type

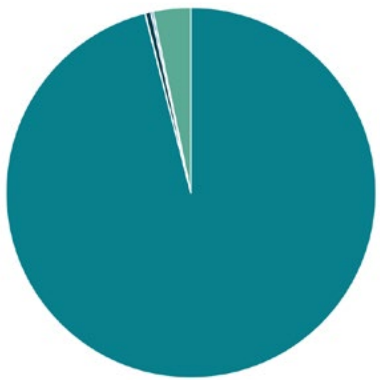
Discussion: Gas Reserves and Production

As of December 2024, unconventional gas zones accounted for 96.7 per cent of all remaining gas reserves and 94.7 per cent of annual gas production in the province.

As of Dec. 31, 2024, B.C.'s remaining raw gas reserves were 2,817.3 e^9m^3, an 8.4 per cent increase from the 2023 remaining reserves.

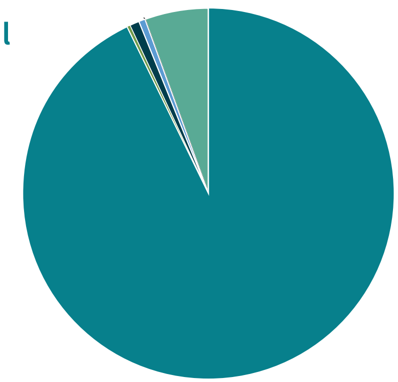
Figure 3 illustrates the distribution of remaining conventional and unconventional gas reserves, with 96.0 per cent of the remaining recoverable reserves held in the Montney Basin. Figures 4 and 5, which show gas production split by source, reflect a similar distribution pattern. The majority of production in B.C. originates from the Montney. The provincial annual average gas production rate increased by 5.7 per cent from 2023 to 2024, from an average of 204.5 e^6m^3/d to 216.1 e^6m^3/d.

Figure 3: 2024 Remaining Gas Reserves



Montney	96.0%	2,704.9 e^9m^3	(95,522 Bcf)
Conventional	3.3%	93.0 e^9m^3	(3,283 Bcf)
Jean Marie	0.5%	13.5 e^9m^3	(475 Bcf)
Deep Basin Cadomin, Nikanassin	0.2%	5.8 e^9m^3	(203 Bcf)
Cordova	0.03%	0.8 e^9m^3	(30 Bcf)
Horn River + Liard	0.0%	0.0 e^9m^3	(0 Bcf)

Figure 4: 2024 Annual Raw Gas Production by Source



Montney	92.97%	73,520 e^6m^3	(2,609.5 Bcf)
Conventional	5.3%	4,165 e^6m^3	(147.9 Bcf)
Jean Marie	0.91%	723 e^6m^3	(25.7 Bcf)
Deep Basin Cadomin, Nikanassin	0.49%	391 e^6m^3	(13.8 Bcf)
Horn River	0.35%	280 e^6m^3	(9.9 Bcf)
Cordova	0.04%	32 e^6m^3	(1.1 Bcf)
Liard	0.0%	0 e^6m^3	(0.0 Bcf)

B.C. Gas Production by Source

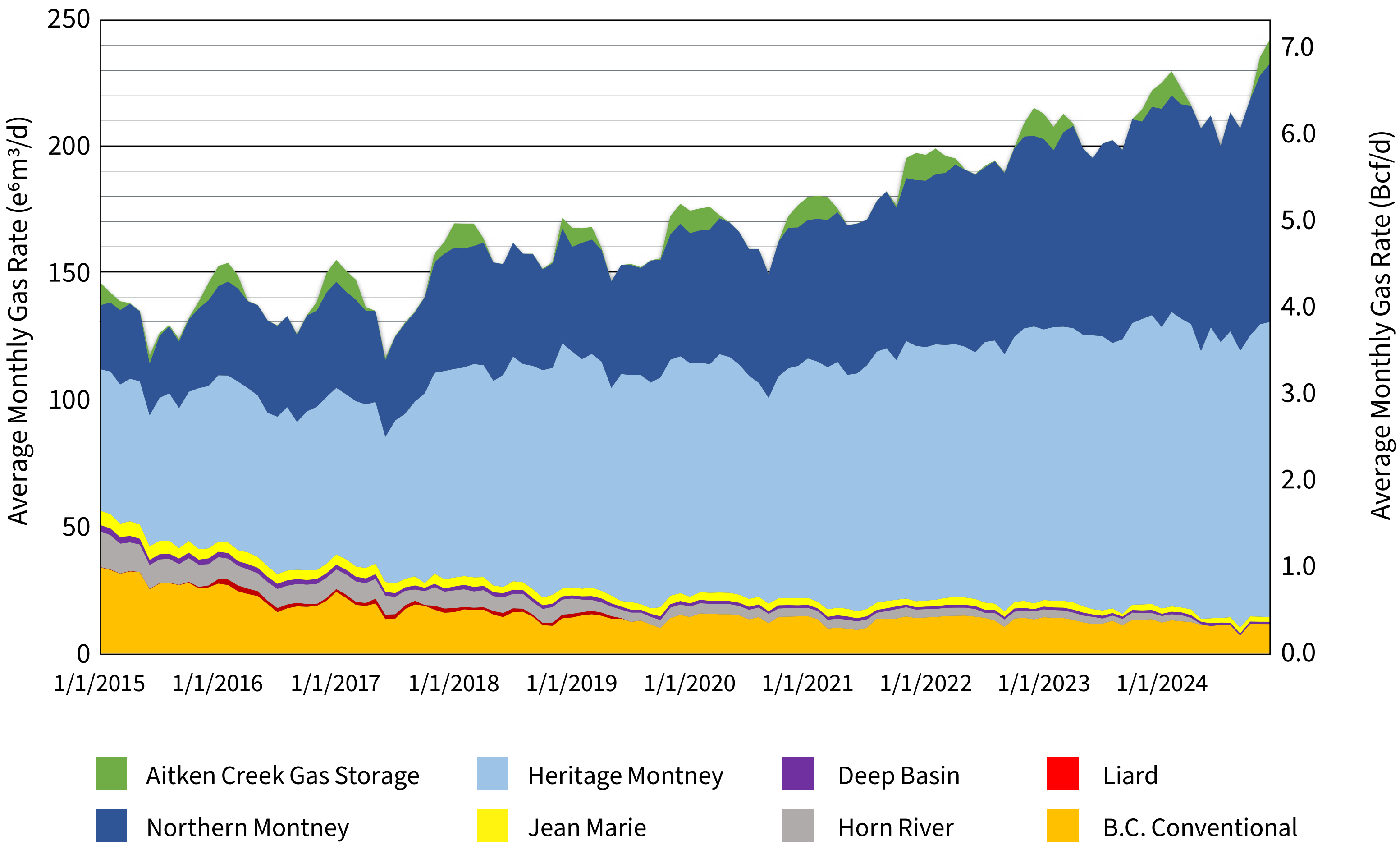


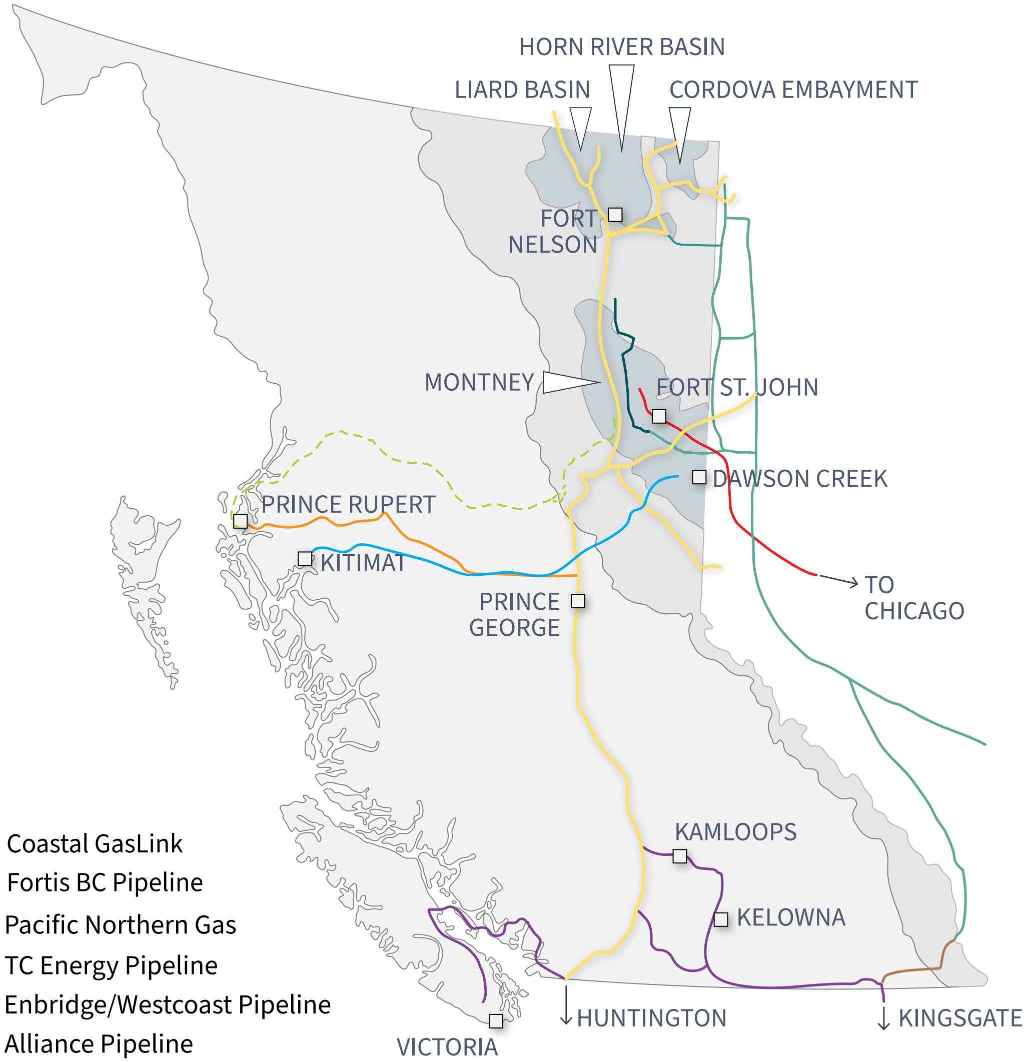
Figure 5: Raw Gas Production by Source 2015 - 2024

In the last five years, gas production in B.C. has increased 37 per cent, resulting in increased loads within existing pipeline delivery points for the Montney. Gas within these regions is transported by pipelines to Station 2 (shipped on Enbridge/ Westcoast Pipeline, formerly Spectra), AECO (shipped on TC Energy Pipeline) and Chicago (shipped on Alliance Pipeline). See Figure 6.

The TC Energy North Montney Mainline (NMML), connecting from the Buckinghorse River area to the Dawson Creek area, came into service in 2020, providing a significant increase in capacity. The Coastal GasLink natural gas pipeline (CGL), connecting northeast B.C. to LNG Canada, was completed in October of 2023, however commercial operation did not begin until mid-2025. Additionally, construction of the 900-kilometre Prince Rupert Gas Transmission (PRGT) pipeline began in August 2024. The pipeline will transport natural gas from near Chetwynd to Pearse Island to supply the proposed Ksi Lisims LNG terminal, further expanding northeast B.C.'s natural gas export capacity.

Figure 7 represents the BCER's raw gas reserves bookings from 2004 to 2024, highlighting unconventional Montney and Horn River reserves versus all other reserves grouped together.

Remaining reserves were consistent for a decade prior to 2003, then increased due to a number of factors, including Deep Basin development followed by horizontal unconventional development.



- Coastal GasLink
- Fortis BC Pipeline
- Pacific Northern Gas
- TC Energy Pipeline
- Enbridge/Westcoast Pipeline
- Alliance Pipeline
- Nova Pipeline
- TC Energy North Montney Mainline
- Proposed Prince Rupert Gas Transmission route

Figure 6: British Columbia's Gas Pipeline Systems

This map is intended to serve as a graphic representation only and may be subject to change. Explore the BCER Open Data Portal to view major projects and pipeline datasets.

Between 2003 and 2006, activity reached record levels (1,300 gas wells drilled in 2006), with predominant targets being shallow Cretaceous (Notikewin, Bluesky and Gething) and Triassic (Baldonnel and Halfway), in the Deep Basin (the Cadomin and Nikanassin) and the Jean Marie in the northeast.

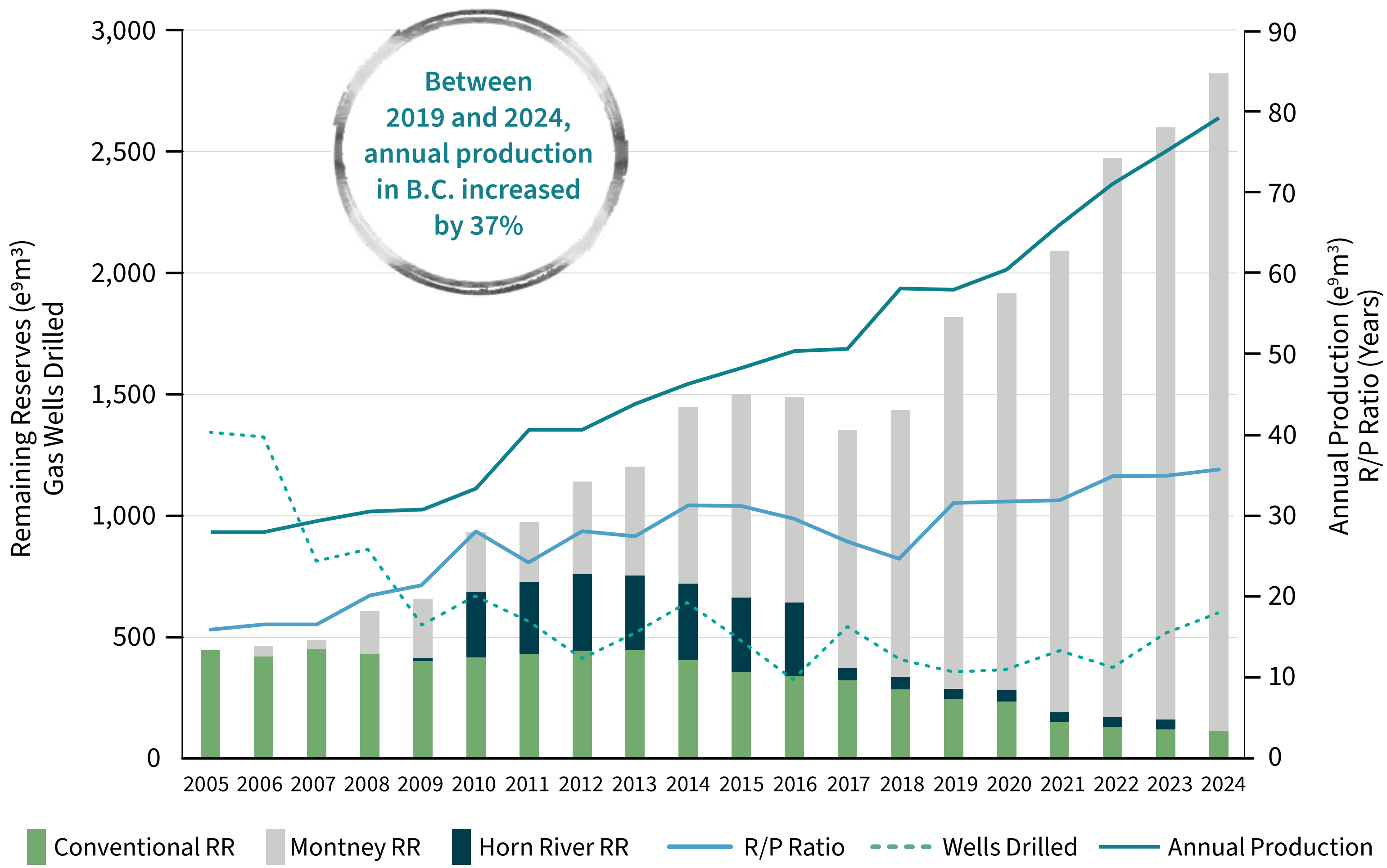


Figure 7: Historical Development in B.C. 2005 - 2024

In 2005, the onset of Montney horizontal drilling with hydraulic stimulation created a significant new supply of gas. This was followed by Liard Basin development in 2008 and Horn River development in 2010. Liard production ceased in 2019 while production from the Horn River Basin was suspended in mid-2024. In both cases, gas volumes are effectively stranded due to the ongoing suspension of the Fort Nelson Gas Plant. As a result, reserves in these basins have been reclassified as contingent resources, pending restoration of infrastructure, market access, and reasonable certainty of production resumption.

The province's monthly raw and marketable gas volumes for 2024 can be seen in Figure 8. Average annual raw gas production in 2024 was 216.1 e^6m^3 per day (7.63 Bcf/d).

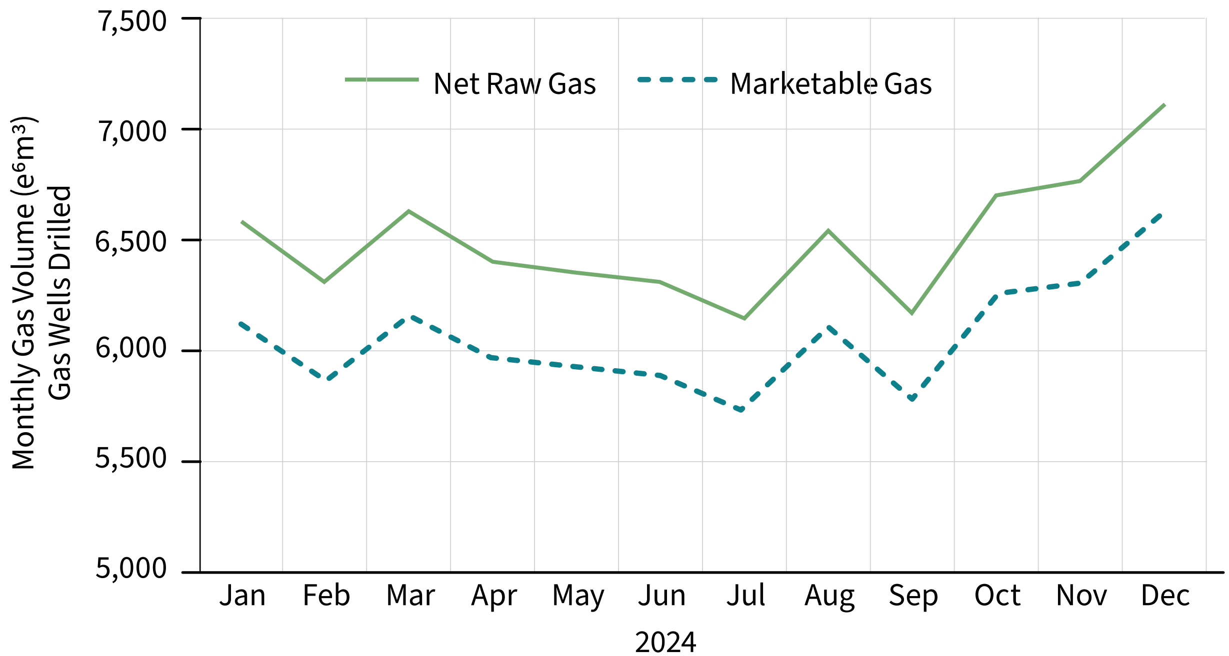


Figure 8: 2024 Raw Gas and Marketable Gas

Figures 9 and 10 show gas production by well initial production (IP) year, excluding Aitken Creek gas storage. These figures demonstrate a large portion of production at any given time comes from newly on-production wells, and if the addition of wells were to stop, there would be a sharp decline in gas production. This is due to the steep decline in the production profile of unconventional gas wells (see figure 20 on page 28).

Figure 10: 2024 Gas Production by Well IP Date

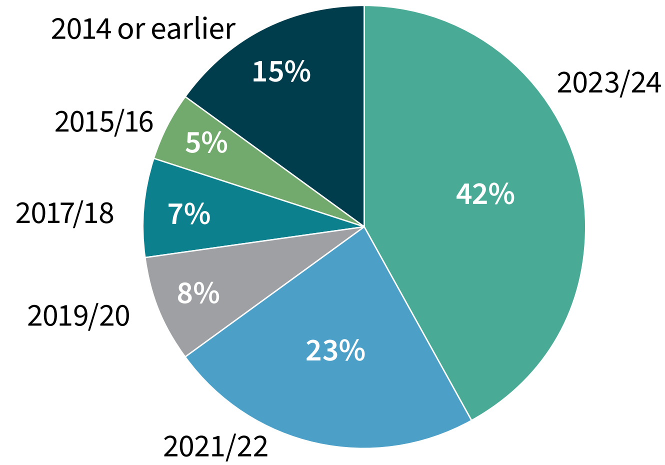
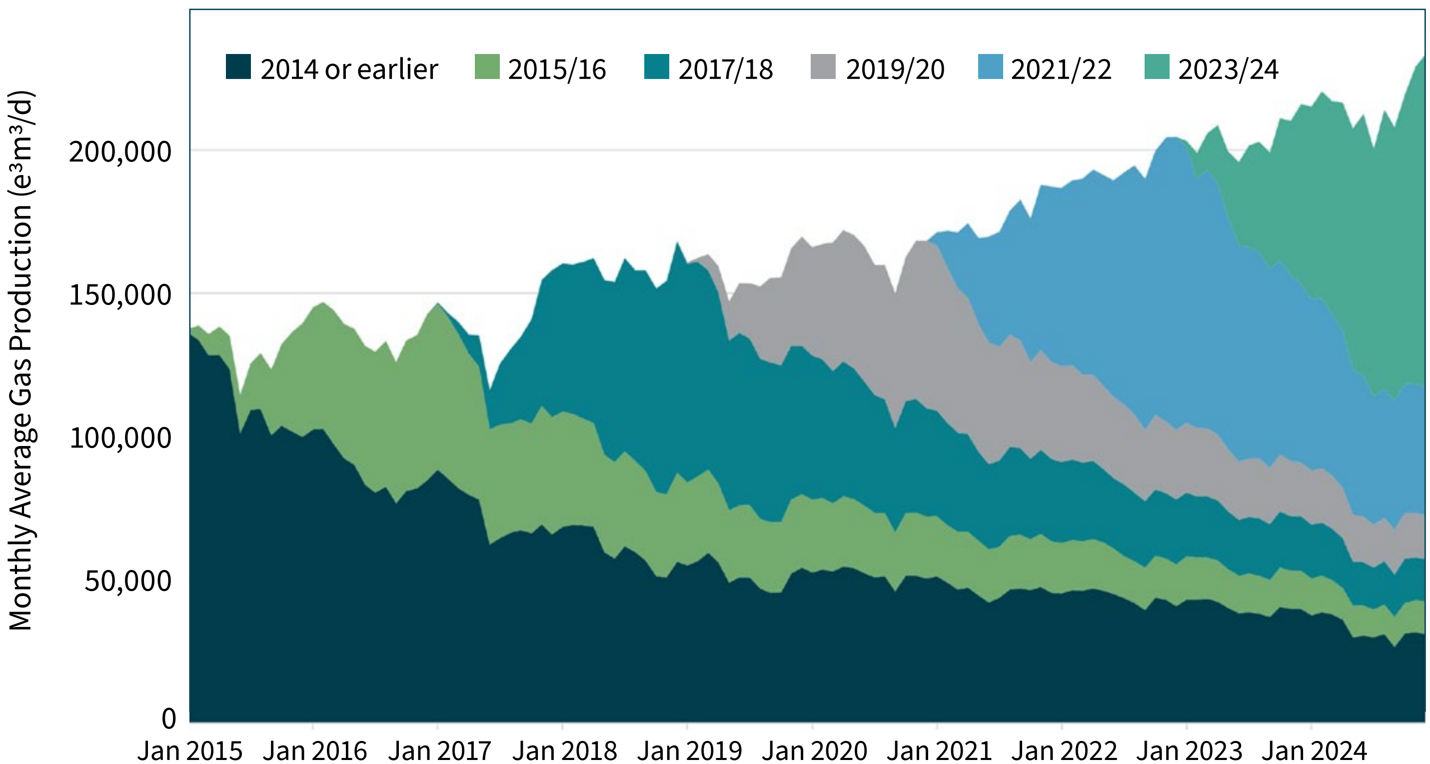


Figure 9: Gas Production by Well IP Date 2015 - 2024



Montney Unconventional Gas Play

The Montney contains 96 per cent (95.5 Tcf) of B.C.'s remaining raw gas reserves and contributed 93 per cent (7.09 Bcf/d; annual average rate) of the province's 2024 production.

Significant development of the Montney began in 2005 and has since become the largest contributor to natural gas production volumes in the province. Since 2019, drilling has focused on the liquid rich gas portions of the play trend. As a result, production of liquefied petroleum gas (LPG), pentanes+ and condensate increased significantly. The increase in pentanes+ and condensate is also a reflection of a 2019 change in BCER policy regarding how the primary product of a Montney well is assigned, with few new wells with high liquid hydrocarbon content qualifying as oil wells. Of the 10,433 producing wells in the province in 2024, 6,151 wells were producing from the Montney formation.

Figure 11 displays the identified dry gas, rich gas and oil trends within the greater Montney play trend.

A prolific, high-quality condensate window exists in the eastern part of the trend. Drilling activity remains focused along the eastern margin of this super-condensate-rich zone, which extends significantly northeast.

The 2024 average daily gas production rate was 88.5 e^{6}m^3/d (3.12 Bcf/d) in the Northern Montney field and 112.4 e^{6}m^3/d (3.97 Bcf/d) in the Heritage field.

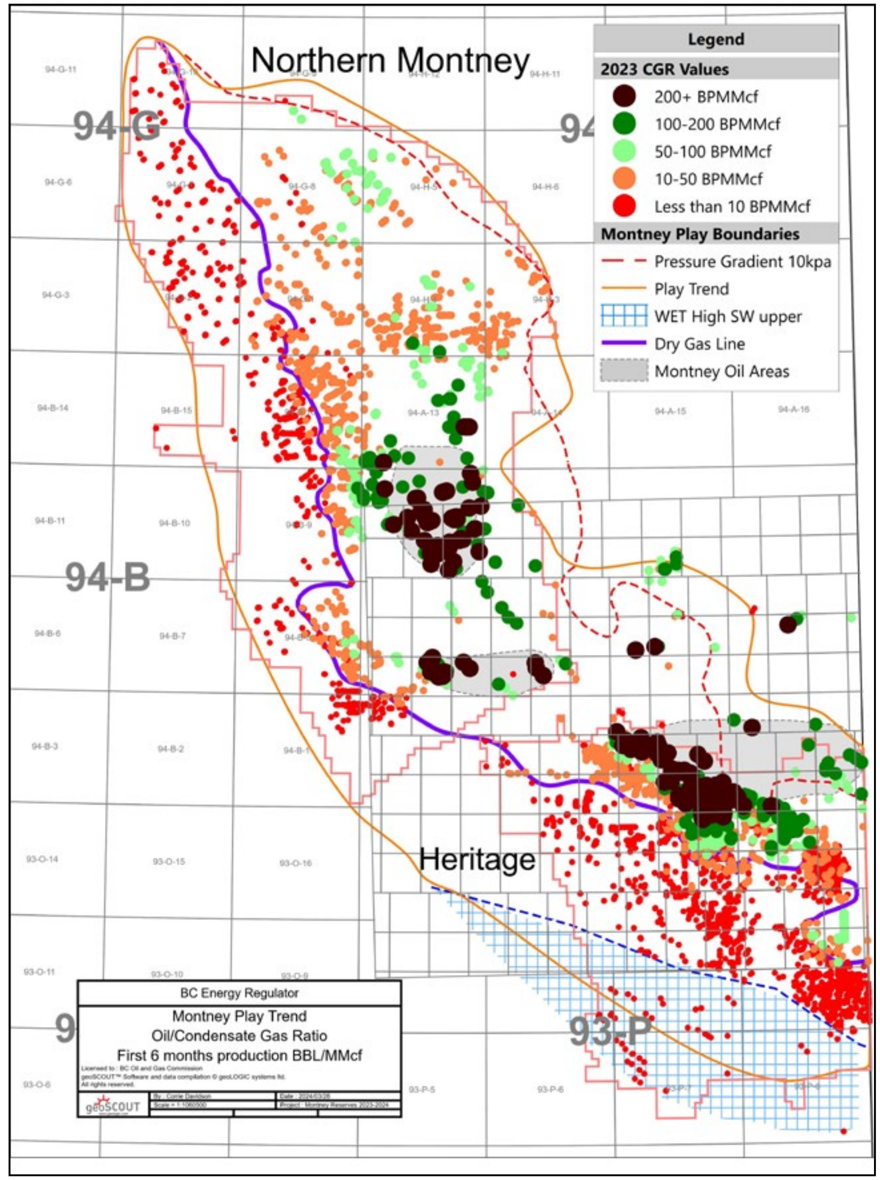


Figure 11: Montney Dry/Wet/Oil Distribution

As of Dec. 31, 2024 the remaining gas reserves for the Montney formation was 2,704.9 e^9m^3 (95.5 Tcf) (raw). The initial reserves of 3,313.5 e^9m^3 represents nearly a six per cent recovery of the estimated total basin gas-in-place of the Montney resource.

Both reserves and recovery factor will increase with additional drilling and production. A detailed record of remaining reserve estimates for each Montney pool/sub-zone can be found in Table 3 below.

Field/Pool	Sub-areas/Layers	Horizontal Well EUR(Bcf) Per Well				Initial Reserves (Raw) Bcf	Remaining Reserves (Raw) Bcf	Exisiting HZ Wells	PUDs*	Development Phase
		Pmean	P90	P50	P10					
Heritage - Montney A	Dry Upper	8.02	2.39	6.76	15.86	36,964.4		1,415	3,192	Statistical
	Dry Middle/Lower	8.05	2.53	6.55	16.74	12,466.7		700	848	Statistical
	Liquid Upper	4.12	1.08	3.36	8.00	9,957.5		1,012	1,403	Statistical
	Liquid Middle/Lower	3.04	1.22	2.47	5.24	4,882.8		320	1,280	Intermediate
	Area Average/Total	**5.81**	**1.81**	**4.79**	**11.46**	**64,271.3**	**50,756**	**3,447**	**6,723**	
Northern Montney - Montney A	NW - Upper	5.88	1.49	5.58	11.48	7,689.0		263	1,052	Intermediate
	NW - Middle/Lower	4.16	1.01	3.42	8.46	5,444.6		262	1,048	Intermediate
	SW - Upper	5.58	1.30	4.90	10.95	8,154.8		295	1,180	Intermediate
	SW - Middle/Lower	5.28	1.32	4.61	10.89	4,684.5		178	712	Intermediate
	NE - Upper	6.27	1.54	6.00	11.41	11,312.7		731	1,080	Statistical
	NE - Middle/Lower	4.20	1.14	3.70	8.01	7,308.1		622	1,114	Statistical
	SE - Upper	3.62	0.76	2.75	7.67	3,617.2		250	750	Early
	SE - Middle/Lower	3.09	0.82	2.30	6.24	3,969.0		257	1,028	Intermediate
	Area Average/Total	**4.76**	**1.17**	**4.16**	**9.39**	**52,179.9**	**44,557**	**2,858**	**7,964**	

Table 3: Montney Reserves Details by Subgroup, as of Dec. 31, 2024

The initial reserves and remaining reserves in Table 3 do not include solution gas reserves nor reserves for vertical wells. Due to limited well count, the upper-middle and the lower-middle were combined with the lower Montney wells. For maps with outlined areas see Appendix B.

The Montney trend is divided into two regional fields by the west-to-east flowing Peace River: the Heritage field to the south and the Northern Montney field to the north. While there is some Montney production outside these regional fields—from legacy vertical wells and limited new horizontal wells—this production accounts for only about 0.5 per cent of total Montney gas. In this report, "Montney" refers exclusively to the two regional fields unless otherwise specified.

As seen in Table 4, horizontal Montney gas wells make up the vast majority of Montney gas reserves and well count compared to vertical Montney gas wells and solution gas from Montney oil wells.

Figure 12 compares the number of new Montney wells put on production each year to the total number of producing Montney wells in each year from 2005 to 2024. The number of producing wells has increased steadily, rising from 105 in 2005 to 6,151 in 2024. Annual additions of new production wells initially peaked in 2014, followed by several years of lower or comparable activity. In 2024, however, a new peak was reached, with 573 new wells brought online surpassing the previous record. Importantly, even in years with fewer new wells, total Montney gas production continued to grow, reflecting improvements in per-well productivity driven by advancements in horizontal drilling and completion technologies.

Field/Pool		Initial Reserves (Raw) Bcf	Remaining Reserves (Raw) Bcf	Exisiting Wells	PUDs
Heritage - Montney A	Horizontal wells	64,271.3	50,756.2	3,447	6,723
	Vertical wells	180.6	12.7	223	0
	Solution gas	419.0	192.5	176	352
	Heritage total	**64,870.9**	**50,961.4**	**3,846.0**	**7,075.0**
Northern Montney - Montney A	Horizontal wells	52,179.9	44,557.1	2,858	7,964
	Vertical wells	24.8	3.4	39	0
	Solution gas	3.1	0.1	7	14
	Northern Montney Total	**52,207.8**	**44,560.6**	**2,904.0**	**7,978.0**
Total Montney Play		**117,078.7**	**95,522.0**	**6,750.0**	**15,053.0**

Table 4: Montney Gas Reserves and Well Count by Horizontal, Vertical and Solution Gas

The line "Ceased Production" in Figure 12 is a cumulative count of wells which had produced for six months or more but have since ceased production for more than two years and may be presumed to have reached the end of economic life in their present state. The reasons for suspension vary, from poor initial completion, to reservoir damage from subsequent frac "hits" from offsetting wells. The majority of Montney wells have an anticipated economic life of decades, however, this example illustrates not all are successful. Approximately one-third of these suspended Montney wells are vertical wells, while the rest are horizontal. The average cumulative production of these "ceased production" wells is 31 e^6m^3 (1.1 Bcf) in the Heritage and 22 e^6m^3 (0.8 Bcf) in the Northern Montney, averaging 28 e^6m^3 (1.0 Bcf) overall.

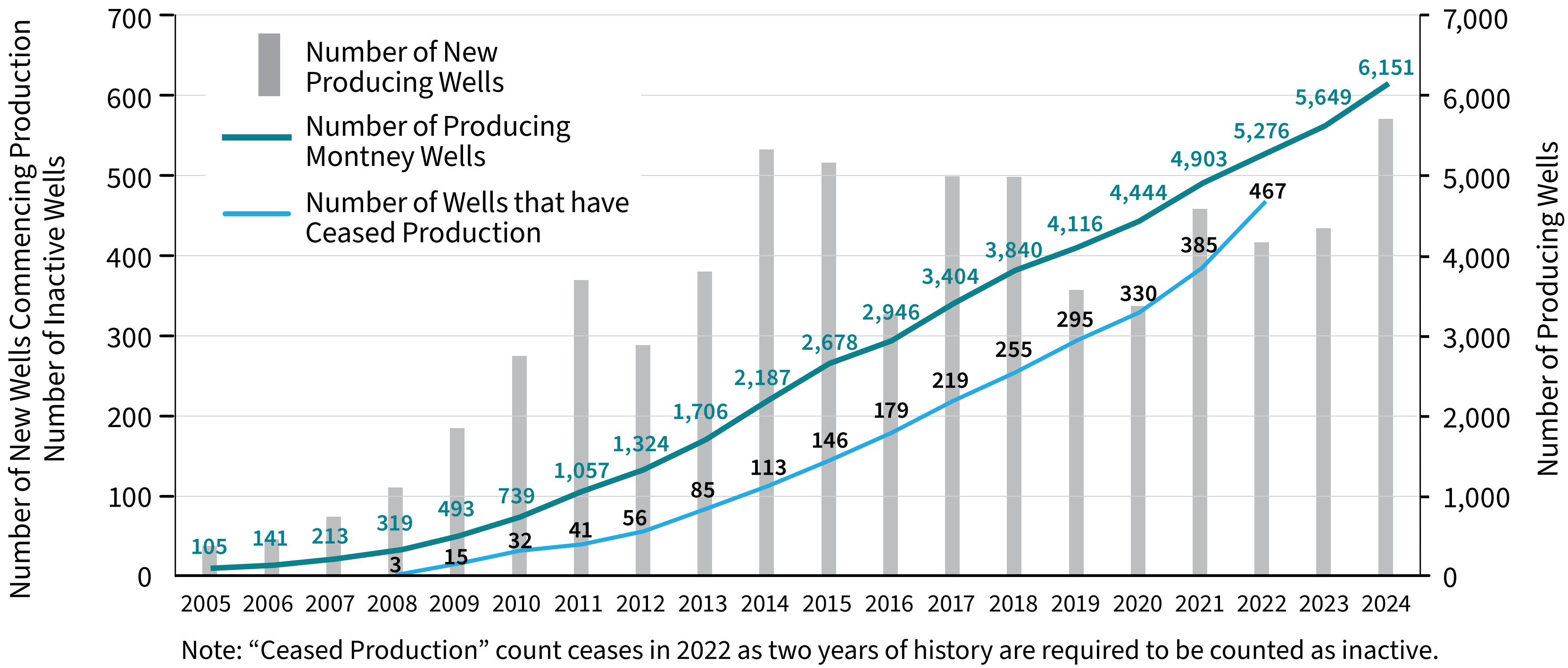


Figure 12: Number of New Wells, Wells that Ceased Production, and Producing Wells in Montney Play 2005 - 2024

A general upward trend in average new well Estimated Ultimate Recovery (EUR) over the course of play development is shown in Figure 13. Heritage area wells have consistently had higher gas EURs than wells in the Northern Montney with the exception of those put on production in years 2018 to 2020.

Annual variations over the period are due to several factors including shifting operator focus across Montney sub-zones, changes in well spacing and lateral length, and differences in well completion designs and hydraulic fracture stimulation methods—each aiming to optimize reserves recovery, economic return and liquids yield.

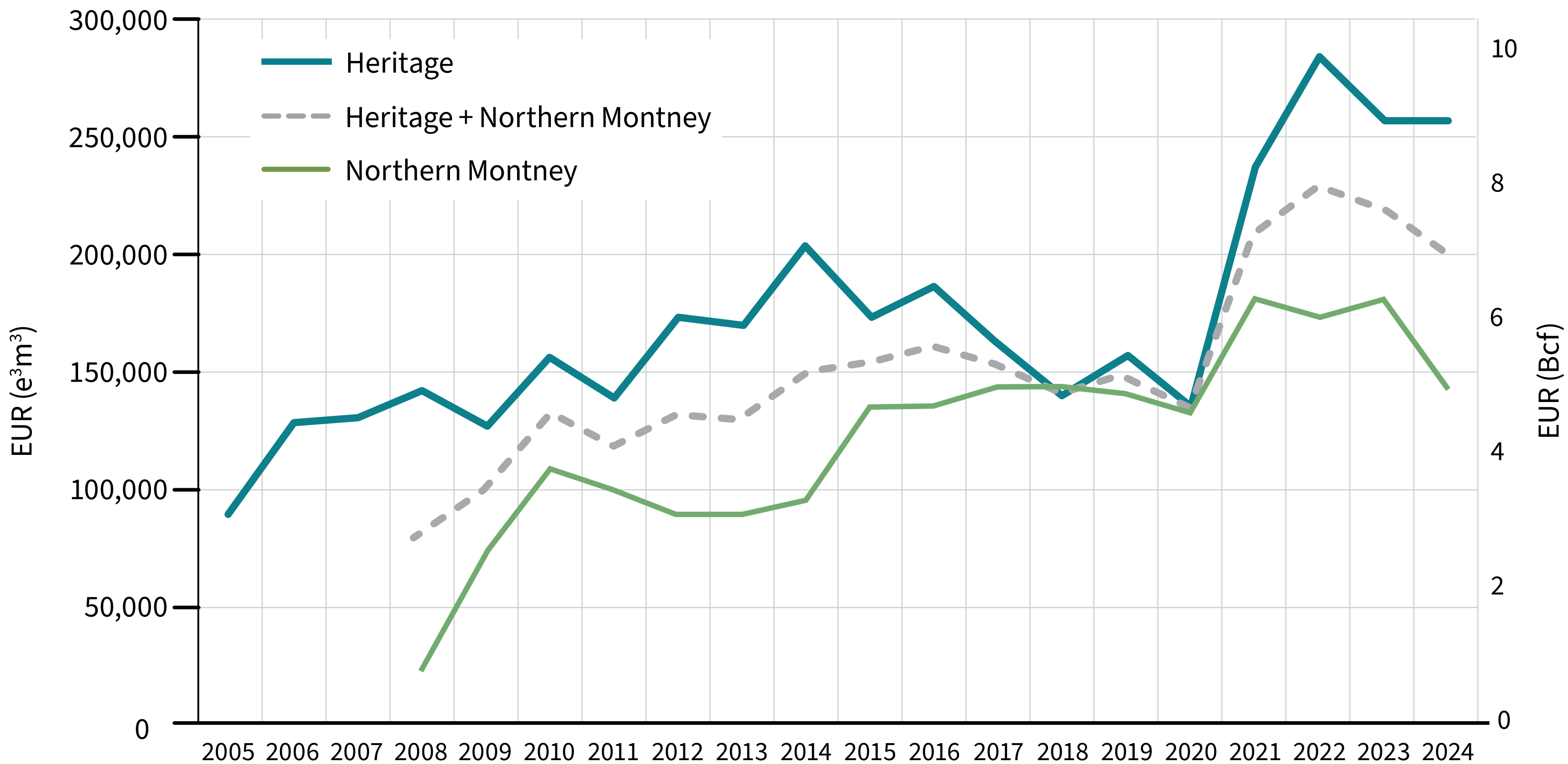


Figure 13: Well EUR Average by IP Year - Heritage and Northern Montney

As shown in Figure 14 and 15, the Montney's various sub-areas and zones differ in their gas EUR volumes.

The Heritage field has been divided into four subgroups based on liquid content and targeted Montney layer, with P50 EURs ranging from 2.5 to 6.8 Bcf per well.

The Northern Montney has been divided into eight subgroups, by geographic area and targeted Montney layer, with P50 EURs ranging from 2.3 to 6.0 Bcf per well.

These variations reflect differences in formation characteristics, completion methods and stage of development. For maps of sub-area locations, see Appendix B.

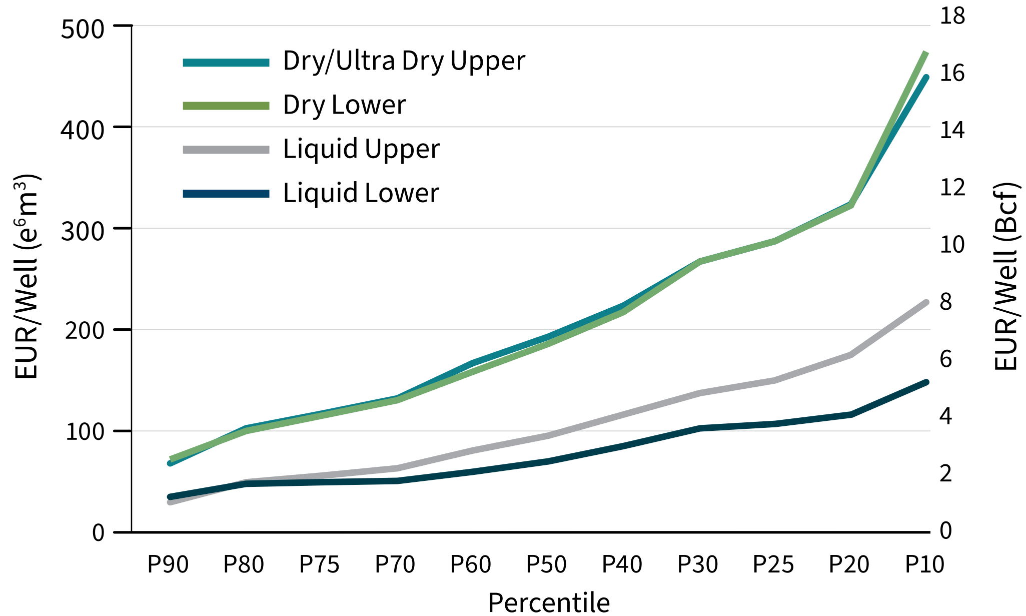


Figure 14: Heritage Montney EUR Distribution by Sub-areas/Zones

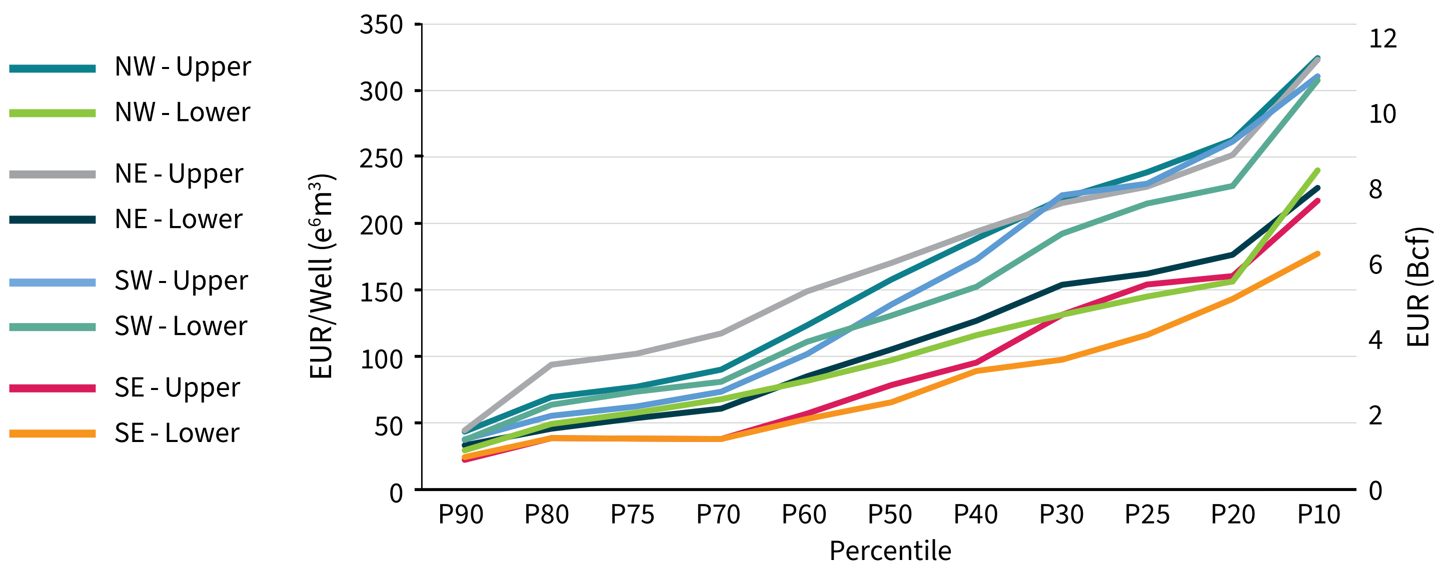


Figure 15: Northern Montney EUR Distribution by Sub-areas/Zones

As seen in Figure 16, most of the top gas producers operate in only one Montney regional field, with the exception of Tourmaline, CNRL, and ARC, which produce from both the Northern Montney and Heritage fields. Operators tend to focus on specific areas to optimize operating, infrastructure and facility costs. A limited number of wells are drilled outside these focus areas for reserves delineation or to meet land continuation obligations.

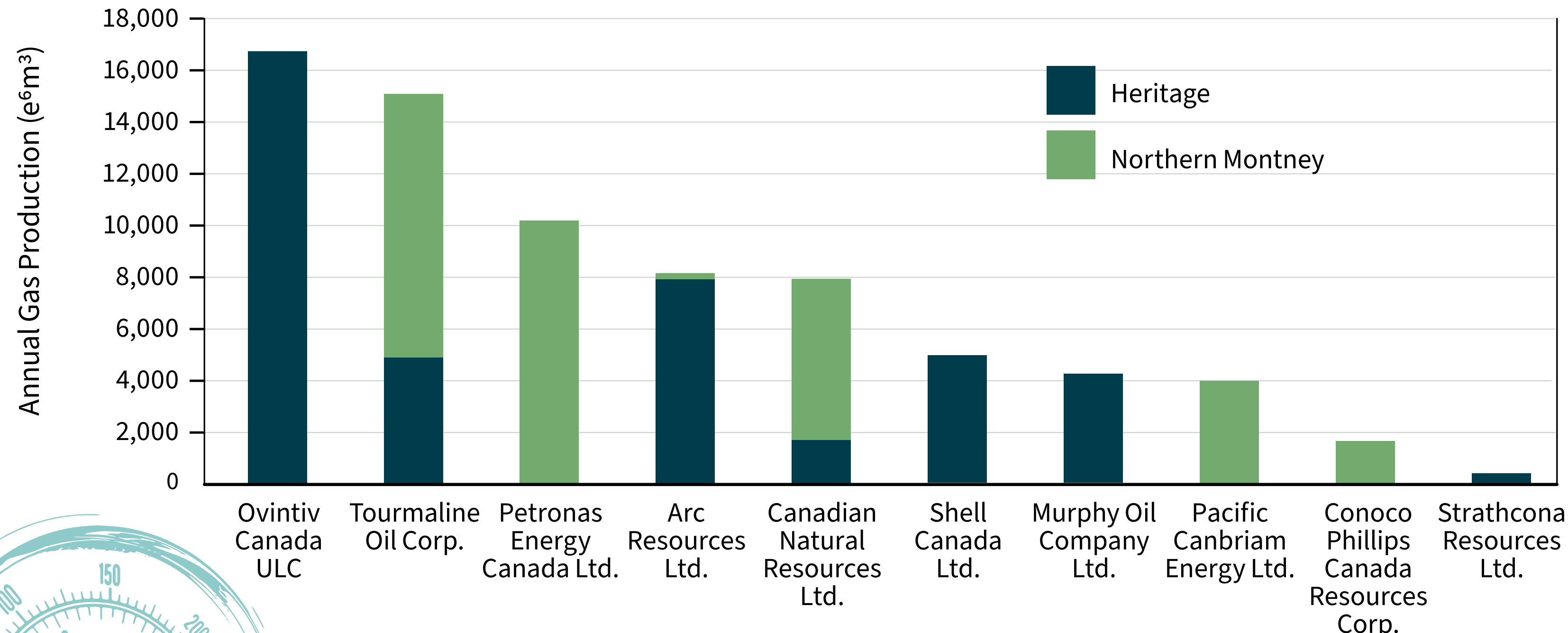


Figure 16: Top 10 Gas Producers in Montney Play 2024

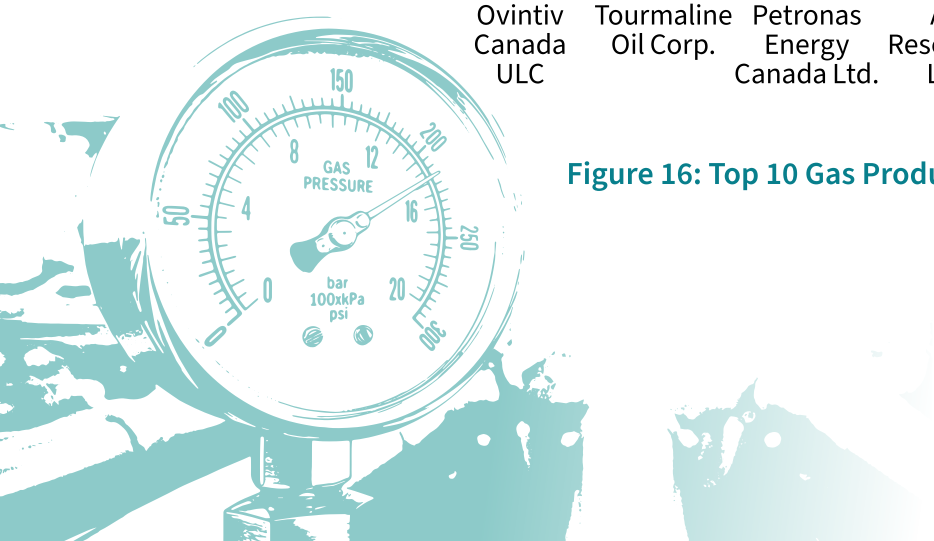


Figure 17 shows the top condensate/pentanes+ producers, which differ slightly from the top gas producers.

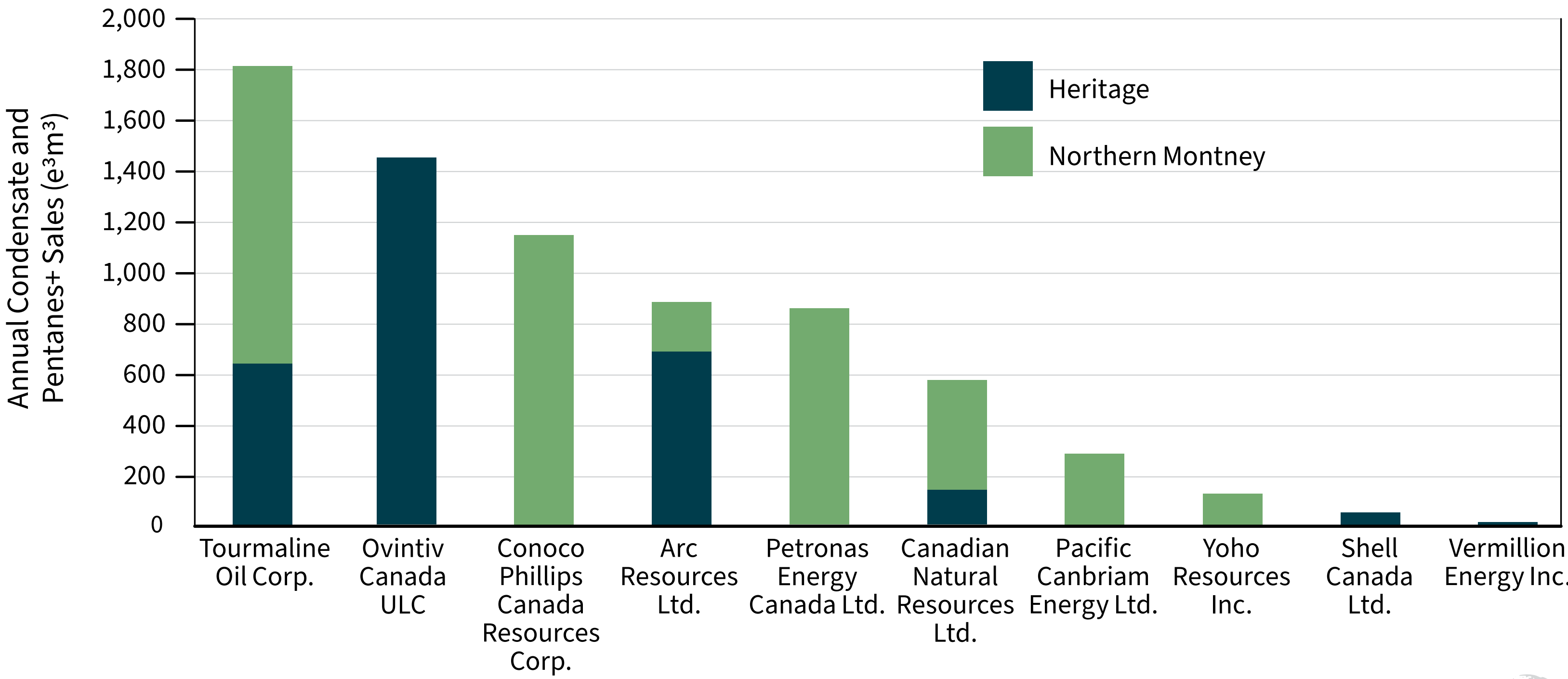


Figure 17: Top 10 Condensate and Pentanes+ Producers in Montney Play 2024

Other Unconventional Gas Plays: Horn River Basin, Cordova Basin and Liard Basin

British Columbia has seen significant activity in the exploration and development of unconventional natural gas resources, beginning in the mid 1990's with horizontal drilling in the Devonian carbonates of the Jean Marie. Starting in 2006, unconventional tight gas resource development shifted to shale gas in the Devonian Muskwa, Otter Park and Evie shales in the Horn River Basin and the Triassic aged siltstones of the Montney formation. Later, drilling and production in the Liard Basin resulted in the delineation of a new play.

Resource and reserve data for each gas play is contained in Table 1 on page 8 of this report.

British Columbia's Oil and Gas Resource Basins

Horn River Basin

The Horn River Basin began producing in 2006 and experienced rapid growth between 2008 and 2012, reaching a peak production rate of 16,515 e^3m^3/d (0.58 Bcf/d) in November 2013, and contributing a maximum of 13.8 per cent of the province's total raw gas production in May 2013.

Beginning in late 2014, the basin entered a steep production decline. While the wells boast fairly impressive gas rates, the relatively remote location, high CO_2 content (and thus high processing costs) and lack of hydrocarbon liquids make the basin economically challenging with sustained low natural gas prices. The last month with substantial output was April 2024, when 95 wells produced a combined 1,686 e^3m^3/d (59 MMcf/d). By July 2024, only one well remained active, and no production was reported after September 2024.

In June 2024, the Fort Nelson Gas Plant was suspended due to lack of available supply following widespread upstream shut-ins, including the Horn River. With no firm commitments from producers or plans to restart operations, both the plant and regional production remain offline. The regional pipeline that once exported Horn River gas now operates in reverse, supplying gas north to Fort Nelson, further underscoring the absence of local marketable production. As a result, there is currently no viable market or infrastructure for gas from the Horn River or Liard Basins. Accordingly, reserves in both areas have been reclassified as contingent resources, pending the restoration of infrastructure, market access and reasonable certainty of production resumption.

Cordova Basin

Development activity in the Cordova Basin ceased in February 2014 when the last new well was drilled. During the calendar year of 2024, there were 14 wells producing from the Cordova Basin shale play, with a total production rate of 87.6 e^3m^3/d (3.1 MMcf/d). However, following March of 2024, most production has been shut-in with only two wells on production.

Further background information on the Horn River and Cordova fields is available in the 2014 Hydrocarbon and By-Products Reserves Report.

Liard Basin

Exploration in the Liard Basin started in 2008. Production has totalled 2,134.5 e^6m^3 (0.07 Tcf) from seven wells (two vertical and five horizontal wells).

The Exshaw-Patry shales within the B.C. portion of the Liard Basin, while depositionally similar, are significantly deeper than the productive shales of the adjacent Horn River Basin. Despite very high individual well production rates, economics were severely hampered by the remote location and deep drilling depth.

By June 2019, all wells in the Liard Basin had been shut-in, resulting in an estimated recovery factor of approximately 7.3 per cent from the developed locations, with total cumulative production representing only 0.01 per cent of the basin’s estimated resource in place. Due to the many years of inactivity and the suspension of the Fort Nelson gas plant essentially stranding the gas, any remaining reserves have been reclassified to contingent resources, pending restoration of infrastructure, market access, and reasonable certainty of production resumption. Additional information on this play is available in previous BCER [Oil and Gas Reserves Production reports](https://www.bc-er.ca).

Historical gas production and well count of these three basins can be seen in figure 18.

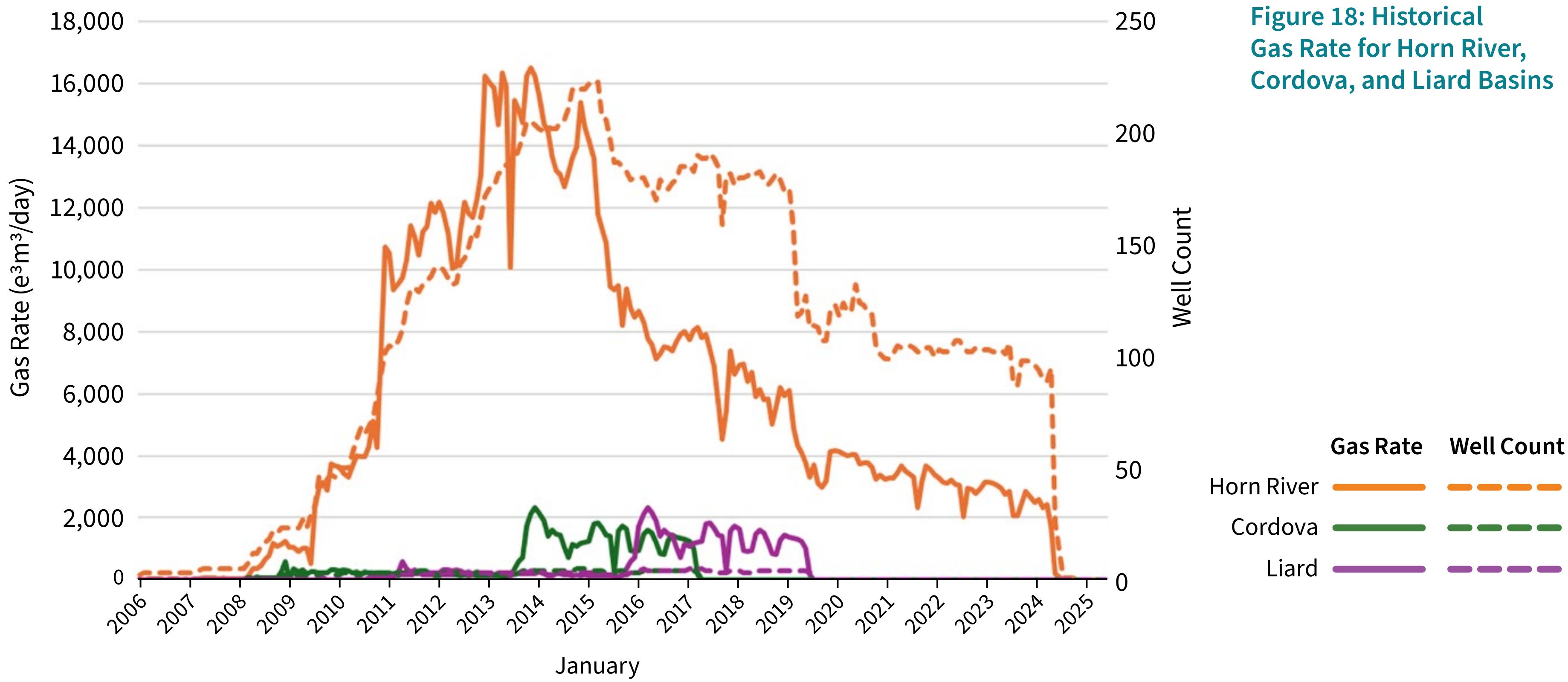


Figure 18: Historical Gas Rate for Horn River, Cordova, and Liard Basins

Comparison of Unconventional Basins

Figure 19 shows the initial reservoir pressure versus temperature plot for the Montney, Horn River, Cordova and Liard areas. The temperatures of these fields fall within expected ranges for depth except for Liard, which is significantly higher than the Horn River, Cordova or Montney fields. The wide range in values reflects the large geographic area and depths of deposits. The over-pressured areas of these formations have been the focus of development, due to gas charging and their favourable response to hydraulic fracture stimulation.

Figure 20 illustrates “type wells” for the Montney, Horn River, Liard and Cordova fields. The most prolific wells are in the Liard Basin where operators have stated “exceptional results from two proof-of-concept horizontal wells” and “world-class deliverability of the basin”, however further development has ceased because of significant capital and operating expenses due to the depth and remote location.

Figure 19: Pressure vs. Temperature Plot

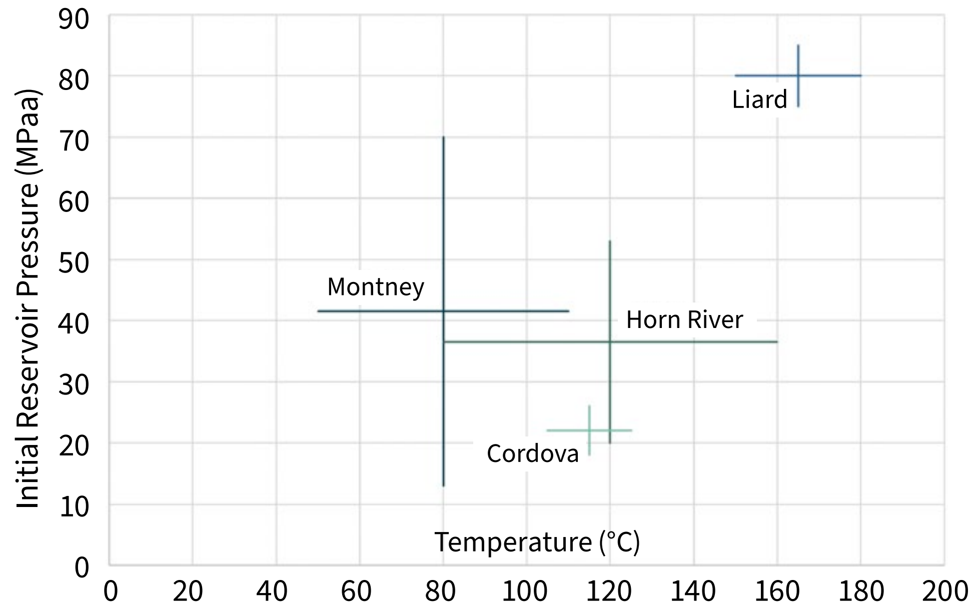
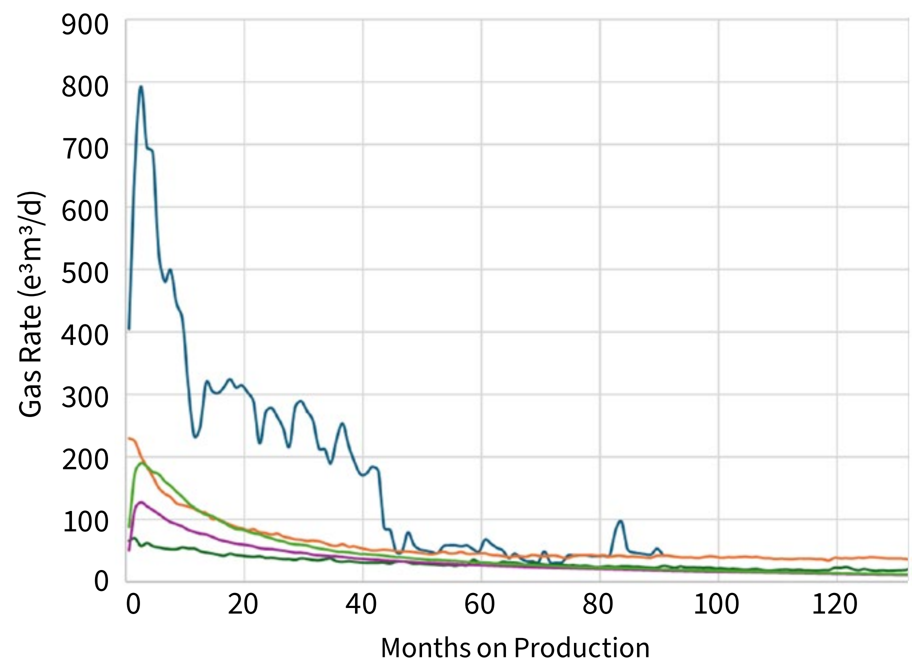


Figure 20: Comparison of Montney, Horn River, Liard and Cordova Production Typewells



Discussion: Oil Reserves

Annual oil production increased 19.0 per cent from 1.47 to 1.74 10^3m^3/d (10.9 Mbbl/d) in 2024.

As shown in Figure 21, oil production in the province has generally declined since 2016, primarily due to a lack of new oil discoveries and a 2019 policy change that reclassified certain Montney hydrocarbon liquids from oil to condensate. However, 2024 marked a notable reversal of this trend, with oil production increasing by 19 per cent compared to 2023. This increase is largely attributed to the reactivation of the Hay River field, which had been partially shut-in during 2023 due to wildfires, as well as the addition of new Montney oil wells in the Heritage field.

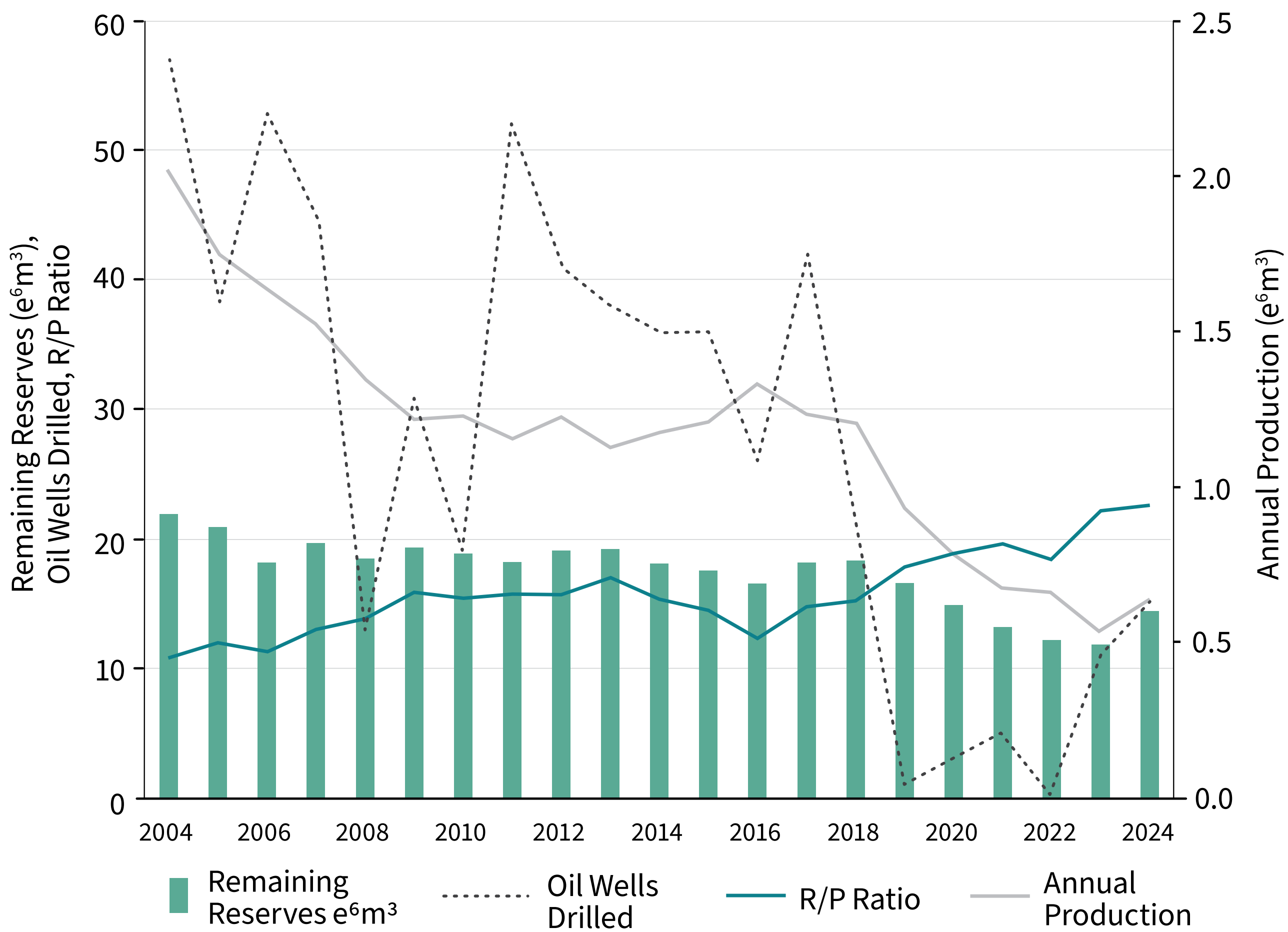


Figure 21: Historical Oil Development 2004 to 2024

The Heritage field, in particular, saw a substantial increase in oil output, with its production rate more than doubling mid-year. This surge led to a 30 per cent increase in annual production from the field compared to 2023. In total, 21 new oil wells were brought on production in 2024, all of which were Montney wells located within the Heritage regional field. This number exceeds the total number of new oil wells added in the previous four years combined, as illustrated in Figure 23.

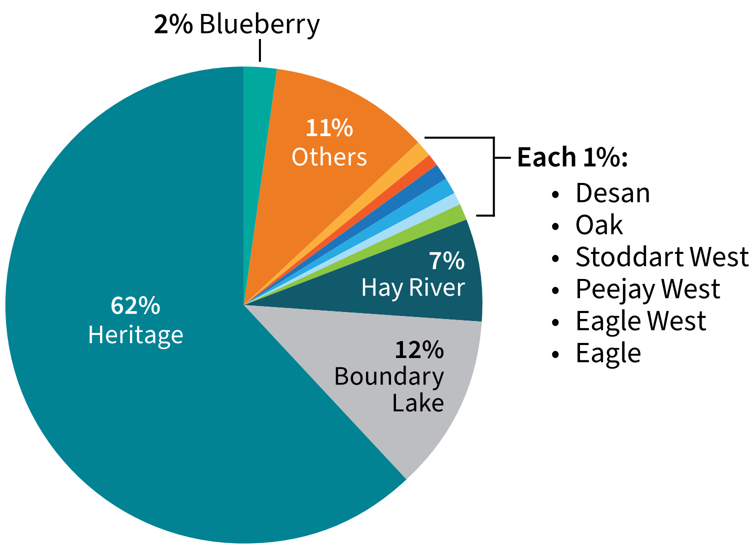


Figure 22: Remaining Oil Reserves by Field

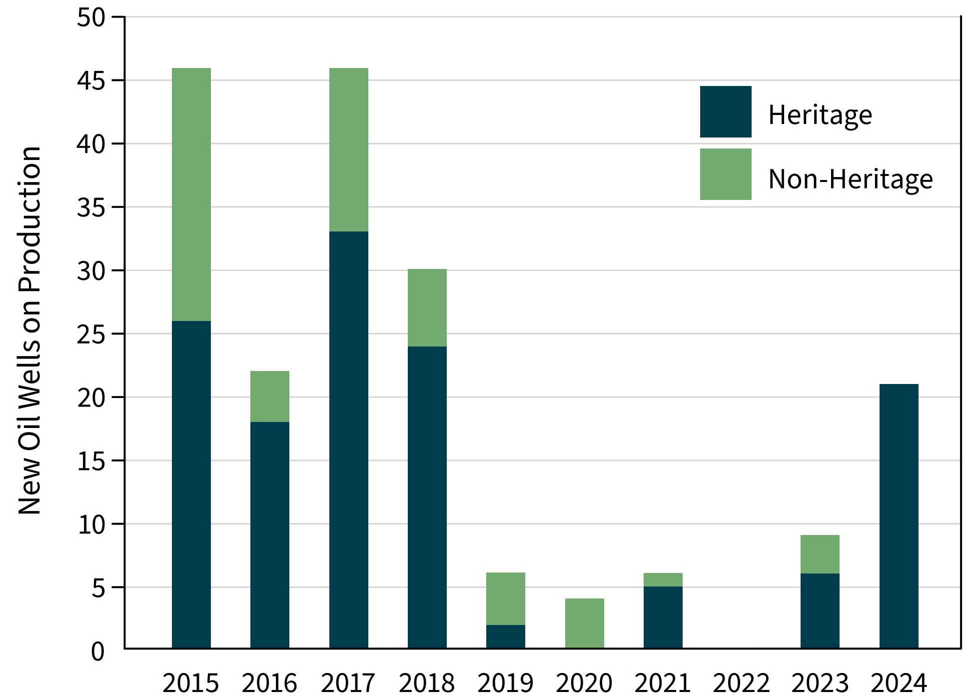


Figure 23: New Oil Wells on Production by Calendar Year

As a result of this sharp rise in production and new well activity, remaining oil reserves increased by 21.4 per cent from 2023 to 2024, reaching 14.4 $10^6 m^3$ (90.6 MMbbl), a majority of which is in the Heritage, as shown in Figure 22.

Some Montney oil development has occurred outside the regional Heritage and Northern Montney fields. In 2024, five minor fields reported Montney production. Three fields (Dahl, Gutah, and Boundary Lake) produced from legacy vertical wells, while Oak and Two Rivers are under active development with horizontal wells. These fields are tallied in the "conventional" category in earlier sections of this report. Together, they accounted for 0.5 per cent of gas production and 6.9 per cent of oil production from the B.C. Montney in 2024, with Oak contributing most of the gas and Two Rivers the majority of the oil.

Optimization of waterflood projects with injection locations, which support the large majority of conventional pool oil production, is also still taking place. The estimated recovery factors for waterflood projects ranges from 4.5 per cent in tight rock to 65 per cent in pools with exceptional reservoir quality, with an average of approximately 35.7 per cent, showing good production management of conventional oil pools in the province.

The 2024 oil reserves-to-production (R/P) ratio is 22.6 years. This compares to a previous peak of 17.1 years in 2013, followed by a decline to a low of 12.4 years in 2016. Since then, the R/P ratio has trended upward, reaching recent highs of 22.1 years in 2023 and 22.6 years in 2024. This trend reflects two key dynamics: in mature fields, production has declined more rapidly than reserves, while in developing areas such as the Montney, reserves have been growing faster than production.

There is 21.1 per cent of the remaining oil reserves in B.C. located in pools with secondary recovery pressure maintenance waterflood projects. These oil pools are listed in Table A-4: Oil Pools Under Waterflood, on page 70. Gas injection recovery schemes account for 0.6 per cent of remaining oil reserves, occurring in six oil pools. See Table A-5: Oil Pools Under Gas Injection, on page 71.

As shown in Figure 24, the vast majority of fluids injected into waterflood pools consist of produced water, which is typically recycled from the same pool. In 2024, only 2.5 per cent of injected water was freshwater. This is slightly lower than the typical range of three to four per cent observed in previous years. An exception occurred in 2023, when wildfires led to the shut-in of the Hay River pool—which uses produced water—causing the proportion of freshwater injection to increase (though total amount of fresh water injected remained low). For further information on regulation of water use in B.C.'s energy resource sector, please see the BCER's Water Management page.

Montney A Oil

Conventional oil production has continued to decline since 2006; however, growth from the unconventional Montney became significant starting in late 2013, as shown in Figure 25 and 26. The regional Triassic Montney in northeast B.C. generally consists of dry gas in the west, transitioning to oil in the east. Significant oil reserves are present in the Tower Lake and Mica areas of the Montney play trend, both within the Heritage regional field. In 2019, the BCER revised its policy for determining the primary product of Montney wells. Since then, most new wells have been classified as gas wells, even when producing substantial volumes of hydrocarbon liquids. Montney oil production peaked at 1,879 m^3/d (11,817 bbl/d) in August 2018, followed by a sharp decline through mid-2019. The decline then stabilized over the following years.

In contrast to this trend, 2024 saw a significant increase. The Heritage 'A' pool more than doubled production in August, rising from around 300 m^3/d (1,900 bbl/d) to approximately 700 m^3/d (4,400 bbl/d), as shown in Figure 25. This increase was largely driven by new oil wells brought on production in the Tower and Mica areas, primarily operated by Vermilion, with some development by Tourmaline.

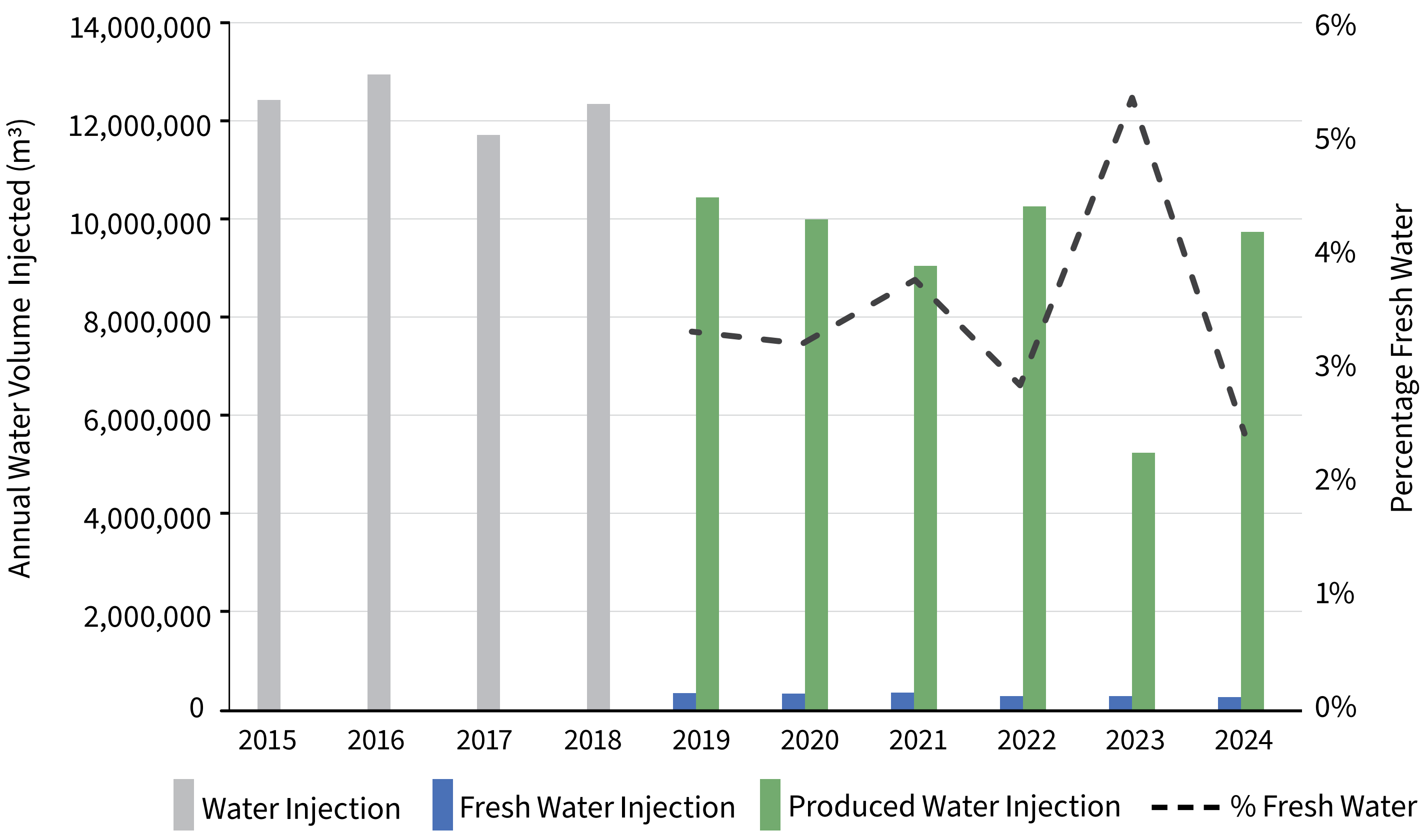


Figure 24: Annual Fresh and Produced Water Injected in Waterfloods

Figure 25:
B.C. Oil Production 2014 to 2024

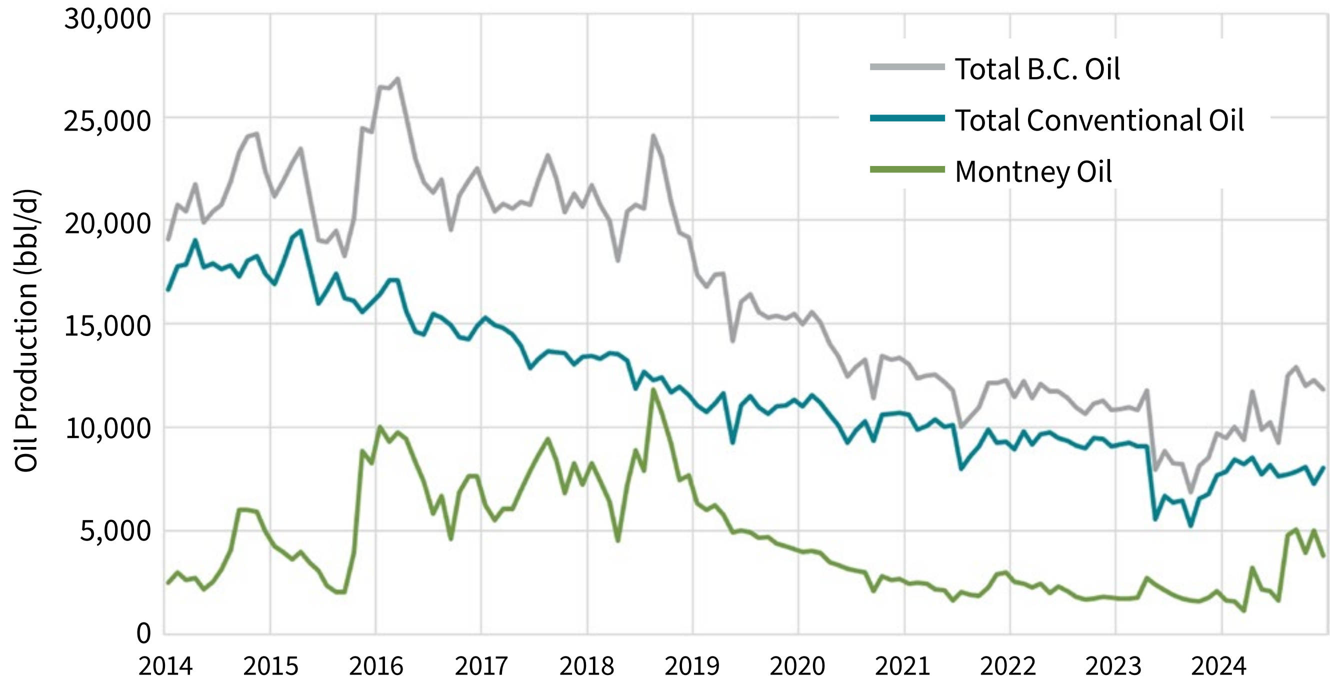
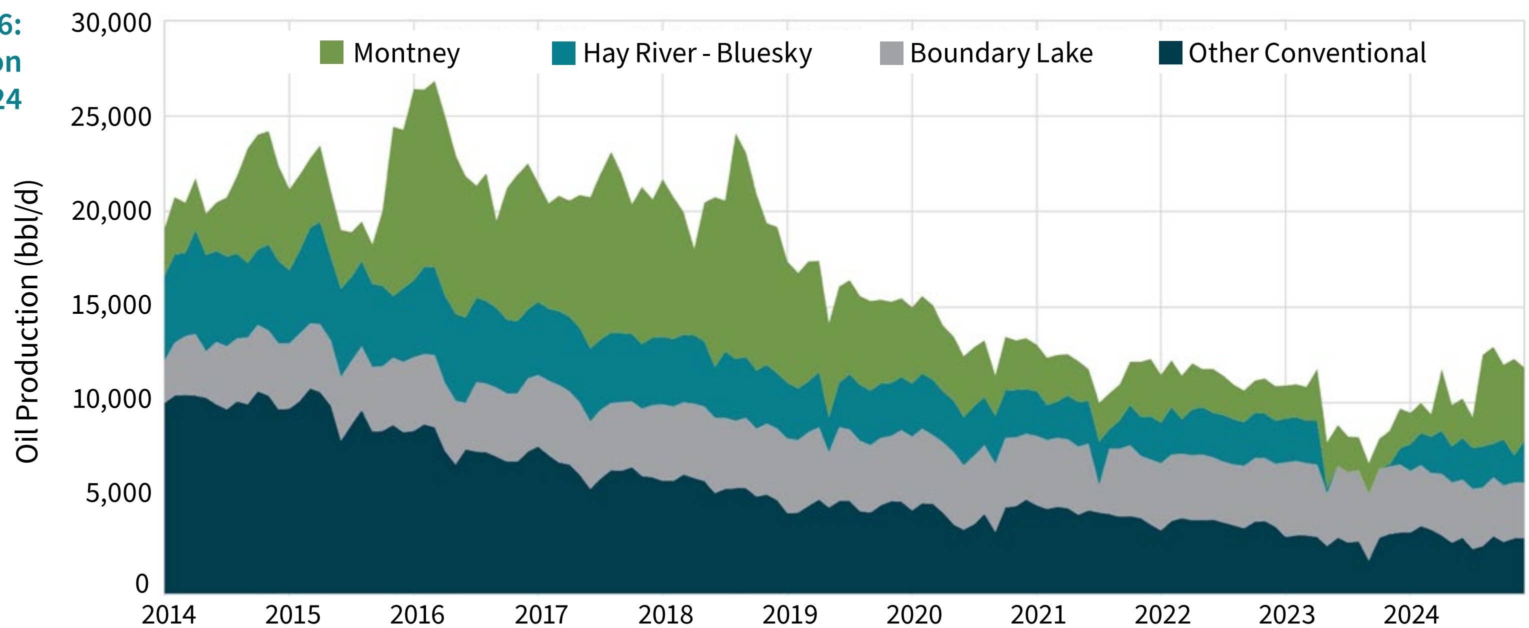


Figure 26:
B.C. Oil Production Sources 2014 to 2024



Discussion: Condensate, Pentanes+ and Liquefied Petroleum Gas (LPG)

Production of condensate/pentanes+ and LPG increased in 2024.

Both condensate/pentanes+ and LPG production have shown a general upward trend over the past decade. However, between 2019 and 2023, production levels were relatively flat, with liquid yields stalling or even declining in some years. In 2024, all categories of liquid by-product production increased significantly compared to 2023. Annual natural gas liquids and oil production from 2014 to 2024 is shown in Figure 27.

Historically, annual ethane sales had remained relatively stable at approximately 950 e^3m^3 from 2012 until 2019, after which they began to decline significantly. Sales reached a record low of just 160.6 e^3m^3 in 2023, followed by a modest rebound to 186.9 e^3m^3 in 2024. This sustained decline suggests more ethane is remaining in plant outlet gas streams, either to be extracted in other jurisdictions closer to end markets or to continue through to the burner tip as part of the sales gas.

Butane and propane sales have shown a general upward trend since 2008. In 2024, propane sales increased by 12.8 per cent compared to 2023, while butane sales rose by 17.2 per cent. These increases can be attributed not only to higher overall gas production and greater liquid yields per unit of gas, but also to the added capability of some operators to extract propane and butane within the province for export.

In 2024, condensate/pentanes+ production saw a significant increase of 23.1 per cent, reaching 7,414.0 e^3m^3. LPG production also rose by 14.8 per cent to 5,761.6 e^3m^3 compared to 2023 (Figure 27).

The overall increase in hydrocarbon liquids production is due to both an increase in gas production and higher liquid yields, which both saw a notable jump in 2024. The rise in gas production is largely due to a greater number of wells brought on production, as well as longer horizontal well lengths. The increase in liquids production can be attributed to several factors, including targeted development of liquids-rich areas and benches of the Montney formation, and potentially improved recovery techniques, such as fracture designs tailored to liquids-rich sections of the Montney. However, it should be noted the sharp increase observed in 2018 and 2019 was largely the result of a policy change in how the primary product of Montney wells is determined. Hydrocarbon liquids that may previously have been classified as oil are now reported as condensate volumes.

Driven by the increase in gas reserves and a substantial rise in annual liquids yield, remaining reserves of both pentanes+ and LPGs increased significantly in 2024. This is based on the BCER's assumption the most recent annual liquids yield remains constant going forward. Remaining pentanes+ reserves reached 179.6 e^6m^3

in 2024, representing a 23.3 per cent increase from the previous year. LPG remaining reserves rose by 16.3 per cent to 211.1 e^6m^3. Due to limitations in the BCER's Reserves Management Information System, only pentanes+ reserves are currently calculated, with wellhead condensate excluded from reserves estimates. An upgrade to address this limitation is planned for the coming years.

The Montney formation continues to be the dominant driver of hydrocarbon liquids production in the province, accounting for 97.4 per cent of total liquids produced in 2024 (by volume). In 2024, condensate/pentanes+ production in the Heritage region increased by 10.4 per cent compared to 2023, while the Northern Montney region saw a larger increase of 34.8 per cent (Figure 29).

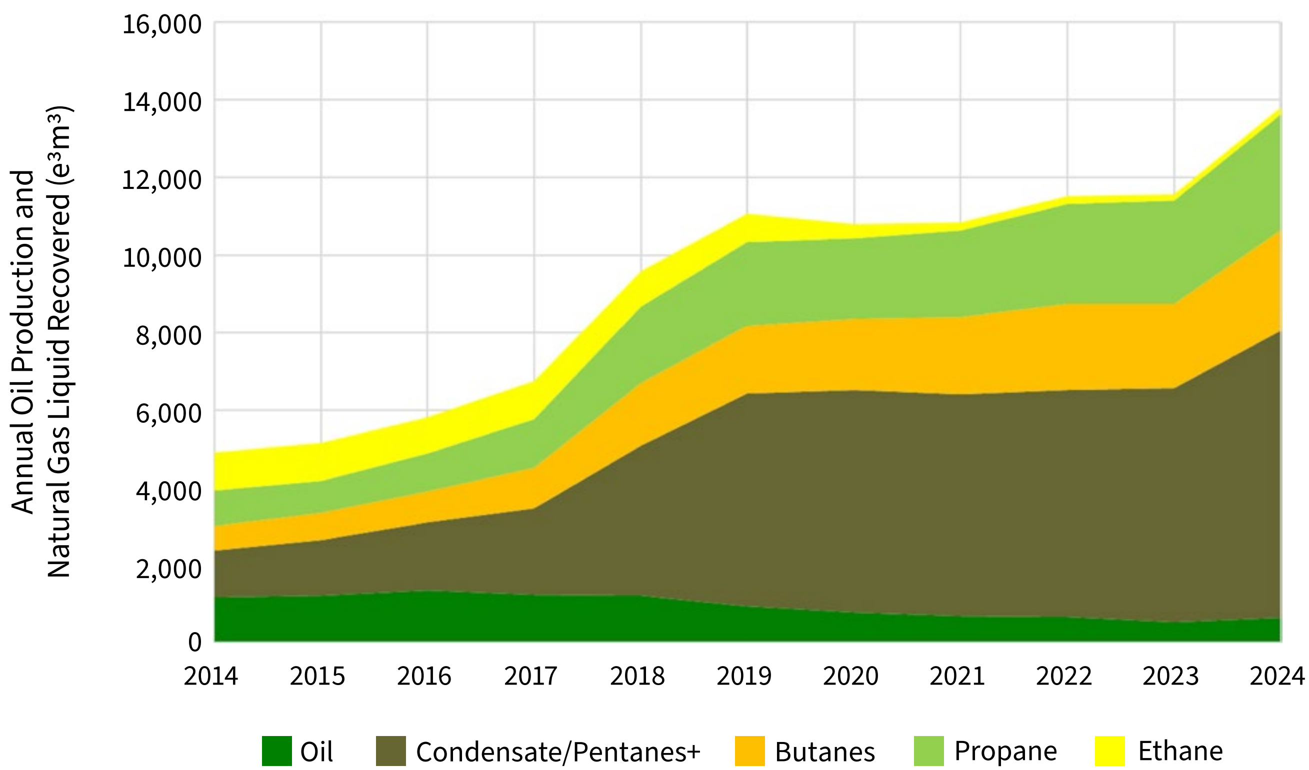


Figure 27: Annual Oil, Condensate and LPG Production 2014 to 2024

As shown in Figure 30, both regions experienced an increase in condensate-gas ratio (CGR). The Northern Montney recorded a significant rise of 16.3 per cent, reaching an all-time high of 0.13 m^3/e^3m^3. The Heritage region saw a more modest increase of 6.6 per cent, and CGR levels remain below the regional field's 2019 peak. The BCER also identifies an oil leg and several "oily" areas of the Montney, as illustrated earlier in Figure 11 on page 17.

The large increase in condensate/pentanes+ production in 2024 was primarily driven by expanded development and higher output from liquids-rich areas. Notably, the Inga field within the Northern Montney regional field accounted for nearly one-fifth of the total year-over-year increase. Other major contributing fields included the Altares, Town, Inga North, and Blueberry fields in the Northern Montney, as well as the Tower Lake area within the Heritage regional field. Each of these fields increased condensate production by at least 100,000 m^3 compared to 2023.

Figure 28 shows the annual reported volumes of two hydrocarbon liquid types: condensate, obtained at the wellhead of gas wells, and pentanes+, which are pentanes and heavier hydrocarbons recovered during gas plant processing. These two liquid streams have nearly identical properties and are typically grouped together in reporting and analysis. As illustrated in the chart, approximately two-thirds of the total volume is pentanes+, with the remaining one-third being wellhead condensate.

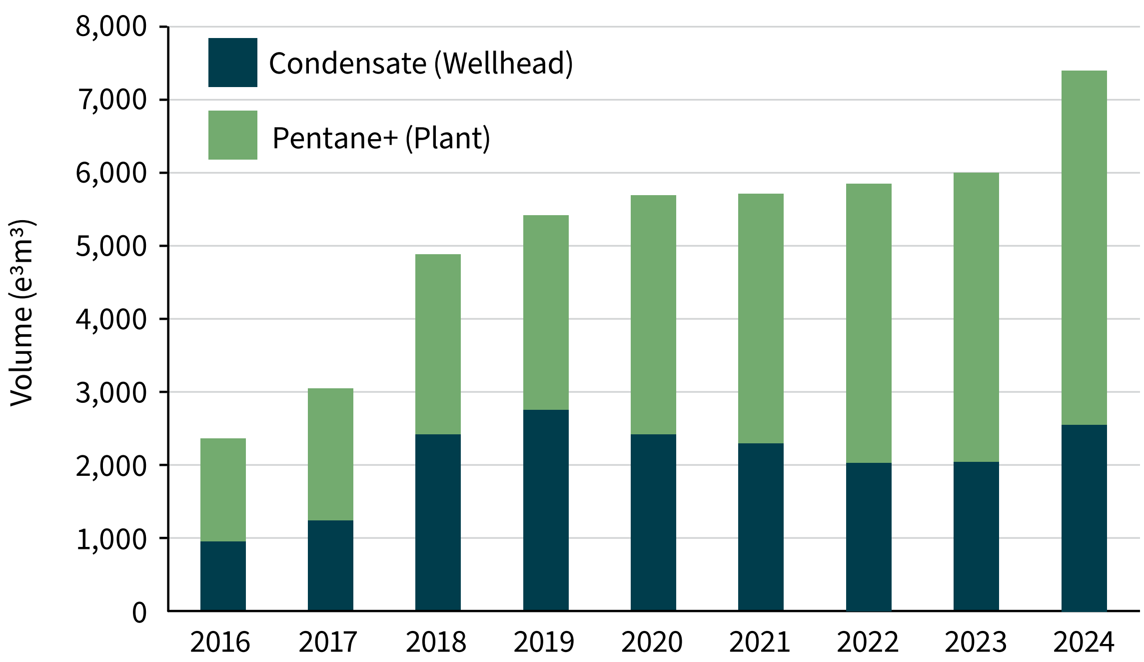
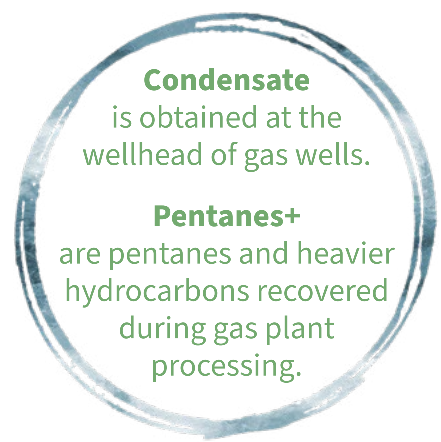
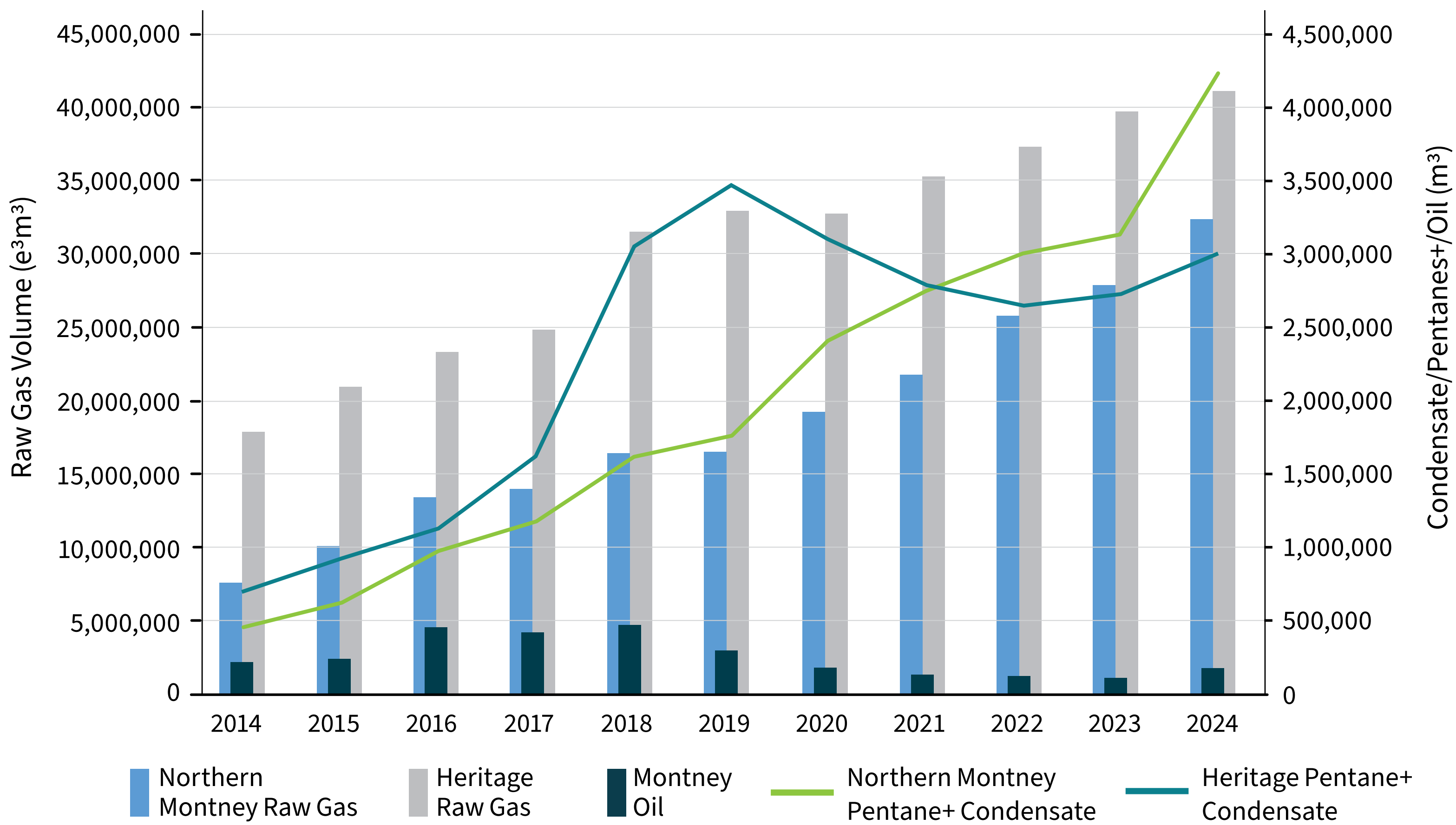


Figure 28: Annual Wellhead Condensate and Plant Pentanes+ Volumes



While Tourmaline and Ovintiv, the province's two largest condensate producers, recorded only modest increases of four and six per cent respectively, the majority of growth came from ConocoPhillips, ARC Resources, and Petronas, which posted year-over-year increases of 79, 46, and 47 per cent, respectively. It's worth noting Tourmaline did see a substantial increase in total condensate production; however, this was primarily due to its acquisition of Crew Energy. The four per cent figure reflects the change between combined Tourmaline and Crew production in 2023 versus 2024.

Figure 29: Annual Montney Oil, Raw Gas and Condensate/Pentanes+ Production 2014 to 2024



A significant portion of LPG volume is captured as increased heating value in marketable gas, with the liquids recovered at the pipeline delivery point. To improve resilience to changing market conditions, operators have invested in upgrading existing infrastructure and constructing additional deep-cut processing facilities to extract more NGL volumes. However, plant-level liquid recovery can fluctuate month to month, influenced by product pricing and available take-away capacity.

Western Canadian condensate prices are expected to continue tracking the WTI benchmark for the foreseeable future. A significant portion of condensate demand comes from its use as a diluent for Alberta heavy oil and bitumen, allowing it to be transported by pipeline. This demand has increased due to rising oil production, the completion of the Enbridge Line 3 expansion in late 2021, and the startup of the expanded Trans Mountain pipeline in mid 2024. Condensate and pentanes+ production from the Montney, in both B.C. and Alberta, is estimated to account for approximately 70 per cent of total diluent supply in the Western Canadian Sedimentary Basin.

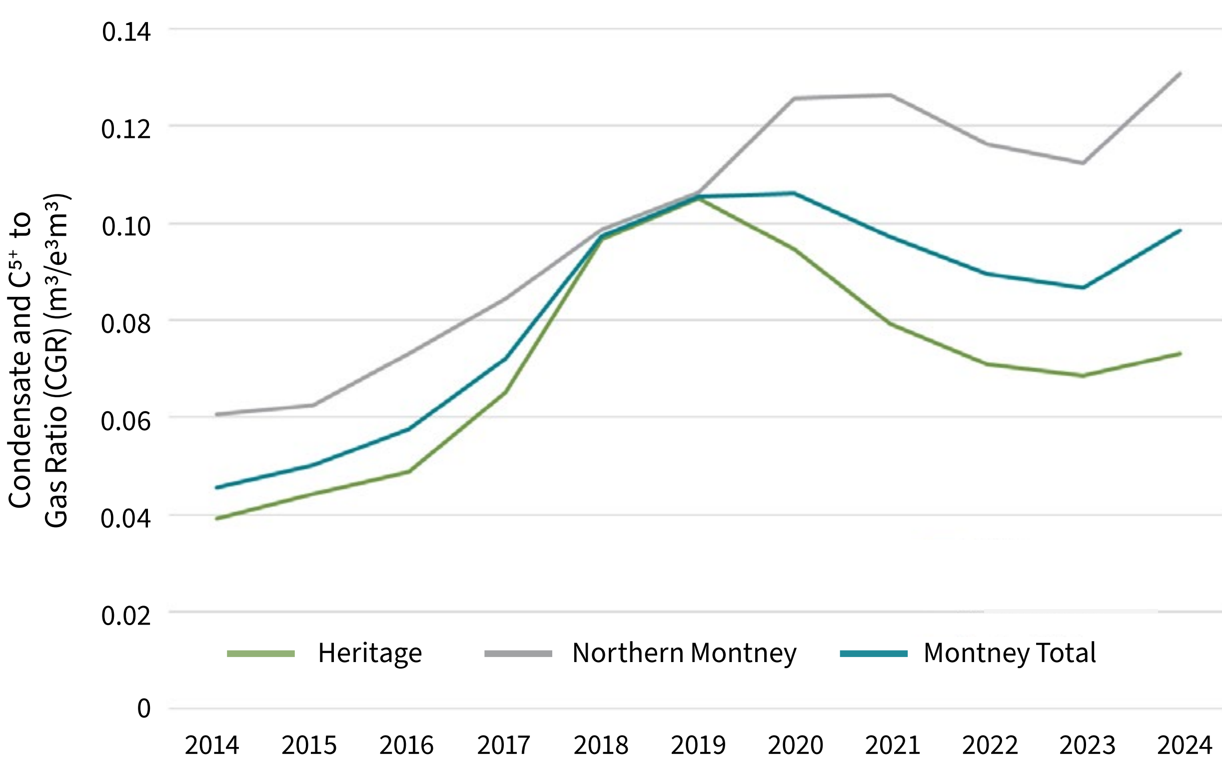
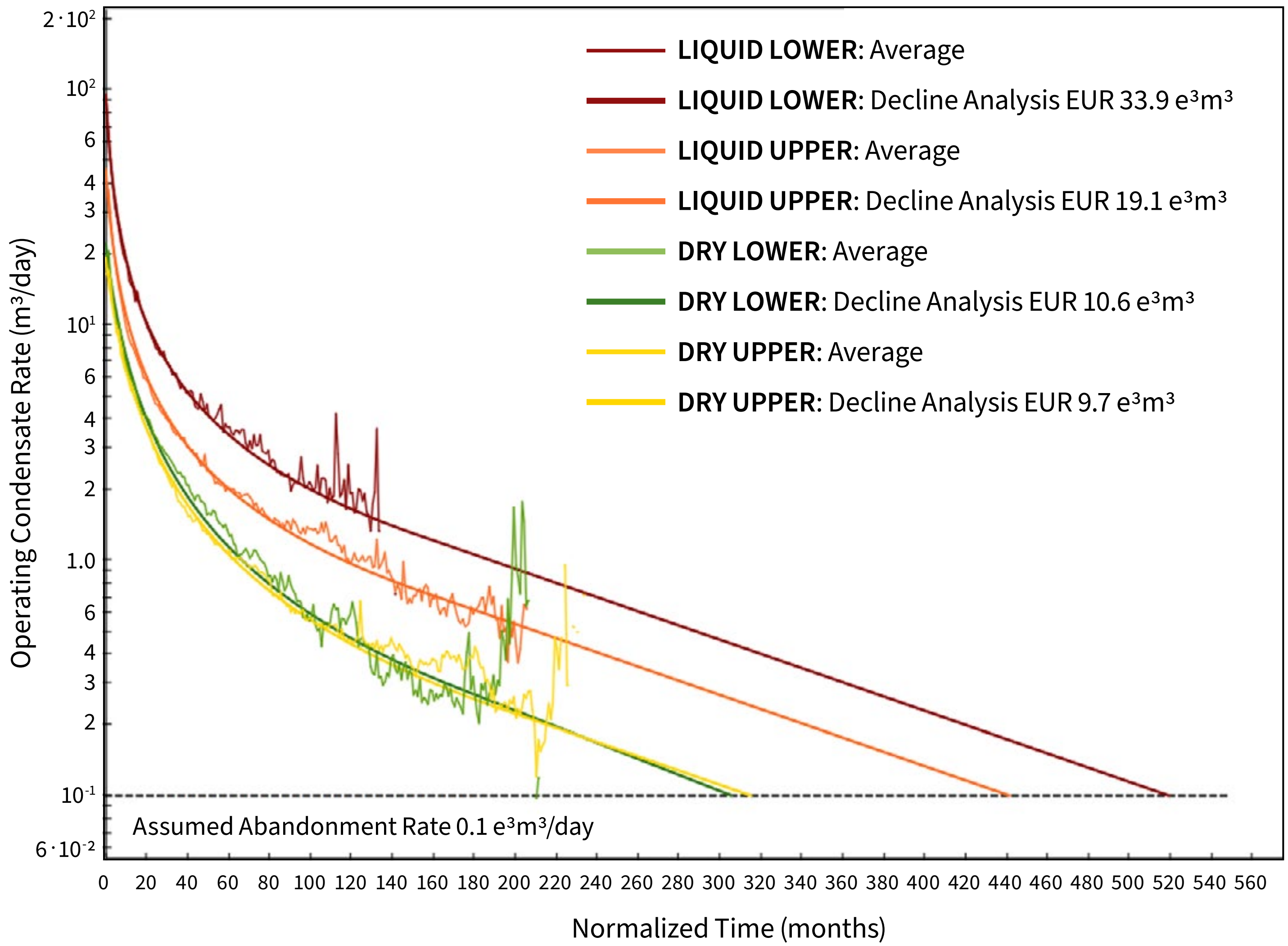


Figure 30: Condensate and Pentanes+ to Raw Gas Ratio 2014 to 2024

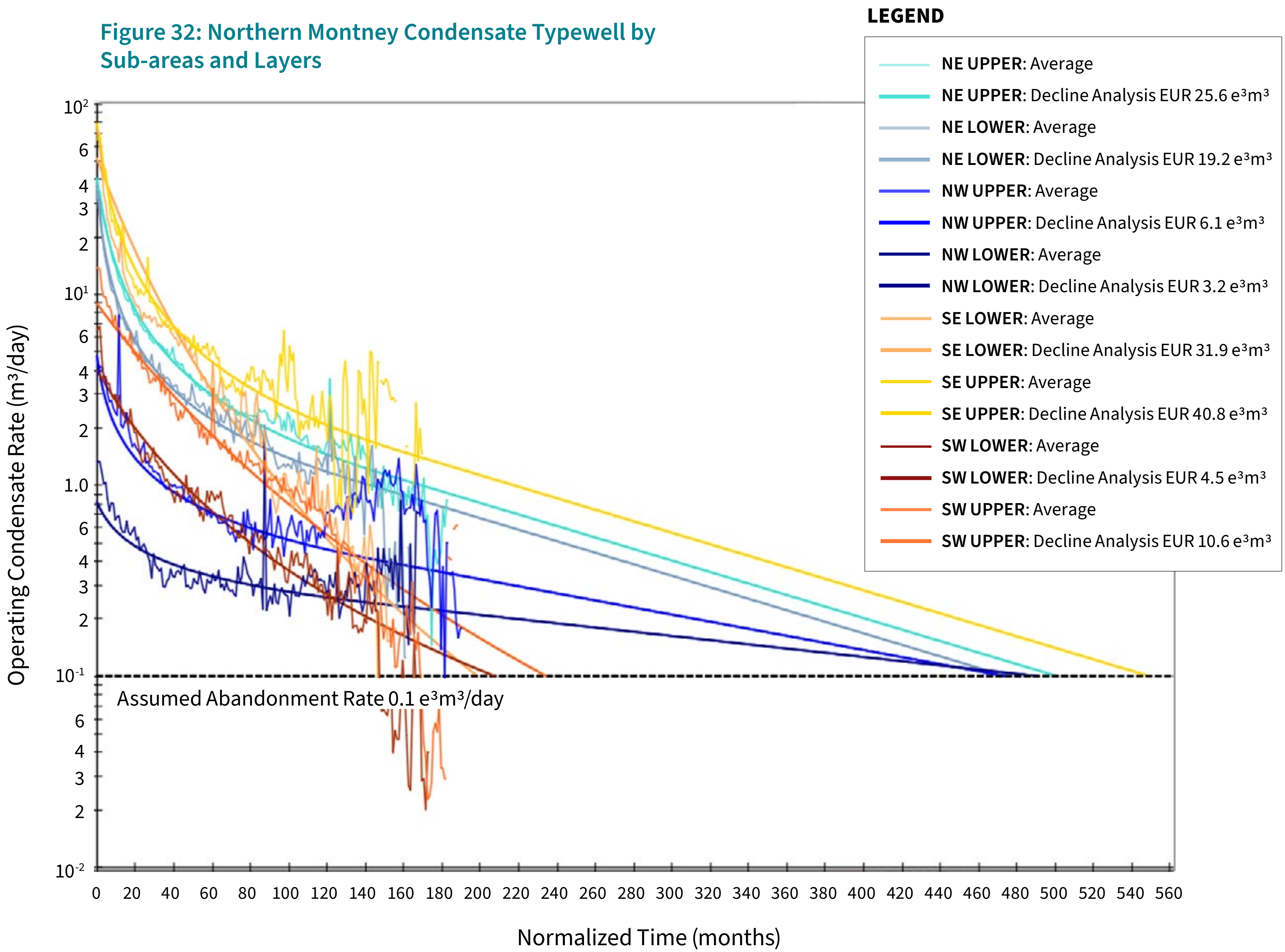
Significant capital investment in gas processing, pipelines, and export facilities for gas and associated liquids has continued in recent years. Pembina's LPG export terminal on Watson Island near Prince Rupert began operations in April 2021, with a design capacity of 25,000 barrels per day and an expected throughput of 20,000 barrels per day. Pembina also operates a northeast B.C. pipeline that transports liquids from the Montney to Edmonton, Alberta. This expansion, which has been in service since October 2017, has a capacity of 75,000 barrels per day. In addition, propane and butane arriving by rail at the AltaGas Ridley Island Propane Export Terminal (RIPET), also near Prince Rupert, are exported as LPG. RIPET has a capacity of 77,500 barrels per day.

Figure 31: Heritage Montney Condensate Typewell by Sub-areas and Layers



Figures 31 and 32 show the condensate type curves for each sub-area and layer for the Heritage and Northern Montney areas. At the current level of development (not including PUDs), the estimated condensate average EUR using the type wells in Figure 31 and 32 is 9.7 to 10.6 e³m³ (61.0 to 66.7 Mbbl) per well in dry and ultra dry areas and 19.1 to 33.9 e³m³ (120.1 to 213.2 Mbbl) per well in liquid rich areas of Heritage Montney. For the Northern Montney, from the east liquid rich area to the west dry area, the average EUR ranges from 3.2 to 40.8 e³m³ (20.1 to 256.6 Mbbl) per well.

Figure 32: Northern Montney Condensate Typewell by Sub-areas and Layers



Discussion: Sulphur

Sulphur sales and reserves decreased in 2024.

As of Dec. 31, 2024, recoverable sulphur remaining reserves was 5.4 e^6 tonnes (5.3 MMLT). Sulphur reserves decreased by 0.7 per cent in 2024. Figure 33 shows the breakdown of remaining sulphur reserves in the major sour fields as of Dec. 31, 2024.

As shown in Figure 34, sulphur sales have declined significantly from their 2014–2015 levels of over 600,000 tonnes, dropping to well below 400,000 tonnes during the 2016–2019 and 2021 periods. Annual sales in 2020, and from 2022 onward, have remained relatively stable at approximately 400,000 tonnes. In 2024, sulphur sales declined slightly to 389,598 tonnes. Areas with high acid gas content tend to become uneconomic at lower commodity prices and are often among the first to be shut-in.

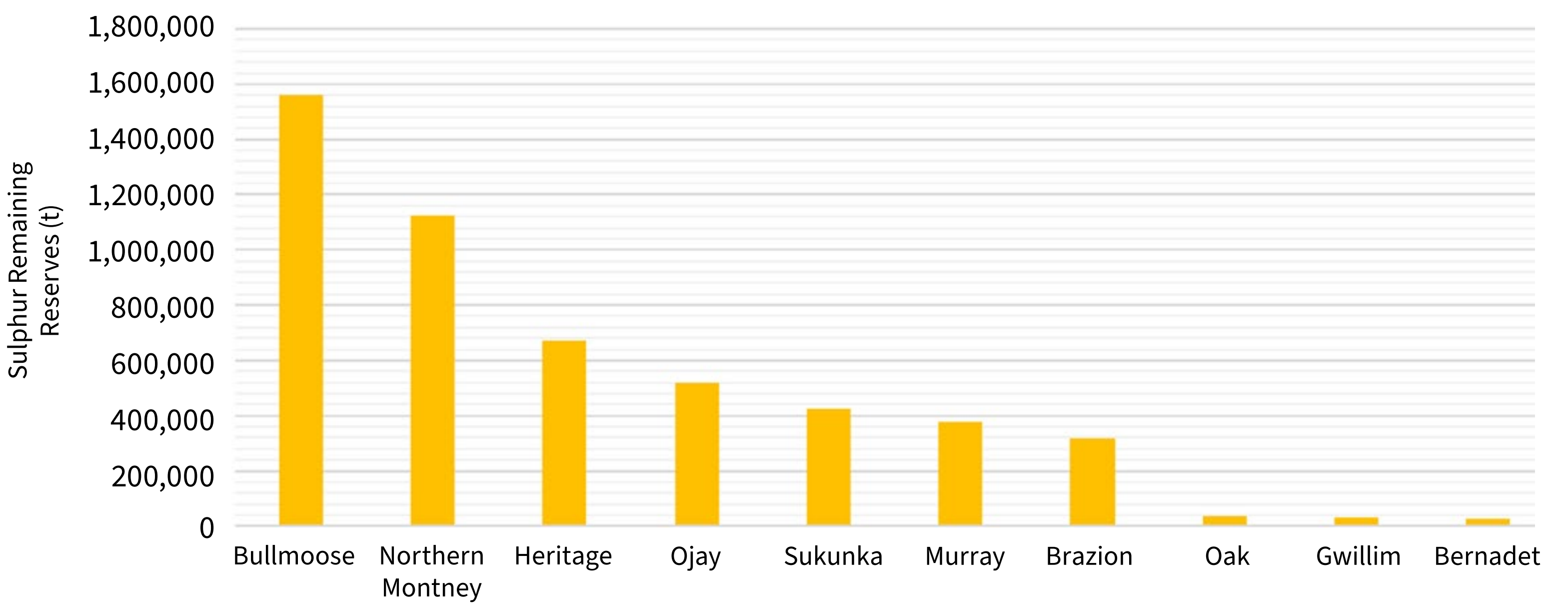


Figure 33: 2024 Major Sour Field by Remaining Sulphur

Most of the natural gas recovered from the unconventional Montney play Trend in B.C. has little to no H_2S content. However, even with minimal H_2S content, the immense volumes of natural gas recovered from the Montney play result in an appreciable amount of sulphur. Sulphur production occurs at the McMahon gas plant in Taylor, B.C.

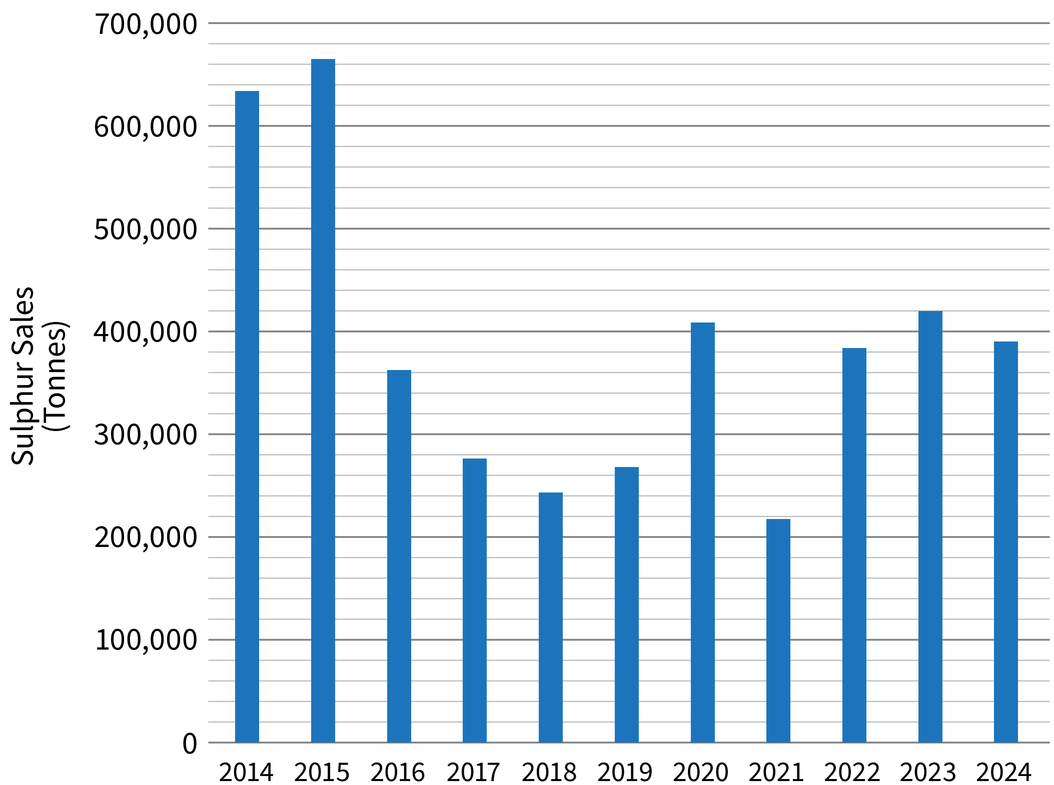
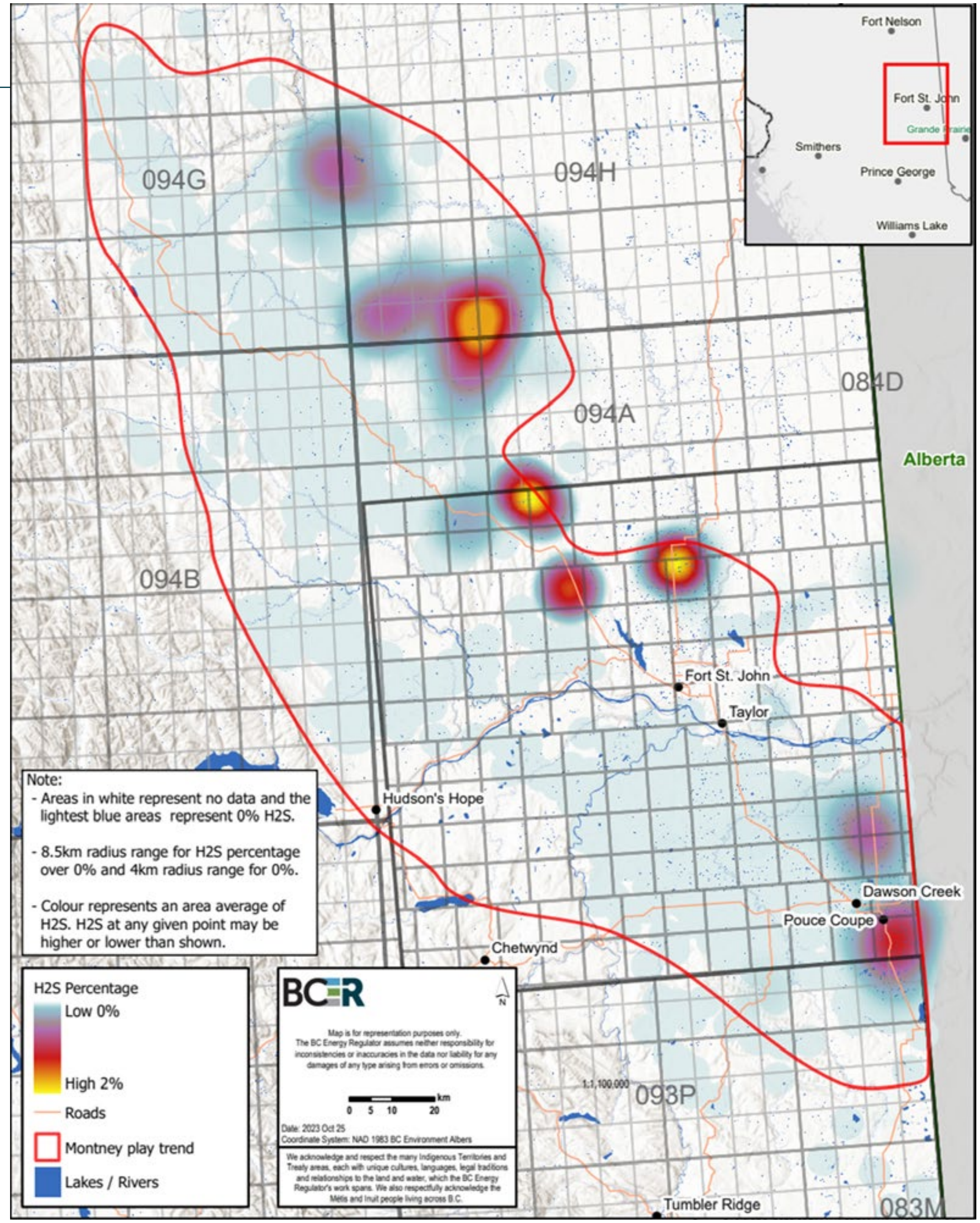


Figure 34: 2014 to 2024 Annual Sulphur Sales

Figure 35:
Heat Map of H_2S
in the Montney Basin



Additionally, there are some specific areas where the percentage of H_2S can be significant in Montney gas (Figure 35). In the Doe-Dawson area of the regional Heritage Field, average H_2S concentrations are 0.1 per cent, with some levels recorded above 0.5 per cent. In the Northern Montney Field, the Birch-Nig-Umbach area has a more significant H_2S presence, as concentration levels average over one per cent, with some recorded values as high as 2.2 per cent.

The most active areas in the Montney contain little to no H_2S and are expected to have a minimal effect on future sulphur reserves. The trend in Montney gas plants is to use dedicated H_2S (acid gas) disposal wells, where the sulphur is sequestered for deep storage rather than sold.

Discussion: Deep Disposal

Disposal wells inject waste fluid by-products of oil and gas production into deep subsurface geological formations for long-term storage.

Disposal fluids fall into three categories: produced water (including flowback water from hydraulic fracturing), non-hazardous waste (NHW) and acid gas (CO_2 and H_2S). Formations used for disposal and storage are either wet non-hydrocarbon bearing or depleted oil or gas pools. Disposal availability is key to economic production and reserves.

Produced Water Disposal

The most common type of disposal fluid is produced water. Production of oil and gas brings saline formation water to the surface, trapped in the same formation. By regulation, this associated produced water must be disposed back into the subsurface. For oil waterflood projects, the produced water is re-injected back into the producing pool. Nearly all new production wells target unconventional resources, with an initial multi-stage hydraulic fracture stimulation creating a significant amount of highly saline stimulation flowback fluid. A large portion of this fluid is reused for subsequent hydraulic fracturing; however, the remainder is injected into produced water disposal wells. As a result, produced water disposal activity is now highly correlated with new well stimulations.

Oilfield NHW, which includes fluids such as landfill leachate water, spent acid, and tank wash, makes up a small portion of total disposal. Wells approved for NHW disposal usually also dispose of produced water as the majority of the fluid, and the combined monthly volume is reported as a single value.

Figure 36 shows the monthly active water disposal well count and volume from 2010 to 2024. Total water disposal volume has mostly remained in the range of 400 ± 100 e^3m^3/month over this 15-year period, as disposal of fracture flowback water has been replacing conventional formation produced water. The large spike in water disposal occurring in 2011 is attributed largely to increased development (and thus increased wastewater from hydraulic fracturing) in the Horn River Basin. Development of this area ceased in 2015.

The recent increase in water disposal starting in 2018 is due to increased development of the Montney. However, disposal volumes have been declining since, likely due to increased recycling of hydraulic fracture flowback fluid for further fracturing operations (see hydraulic fracturing section for a discussion of recycling). Development activity not only affects disposal volume but also the location of the active disposal wells. Currently, there is a significant demand for disposal capacity in the Montney fairway, while disposal wells in other areas with no current development have largely reduced or ceased operations, despite having significant remaining disposal ability in some cases. A map of disposal well locations and information is available in the Subsurface Disposal section of our website here.

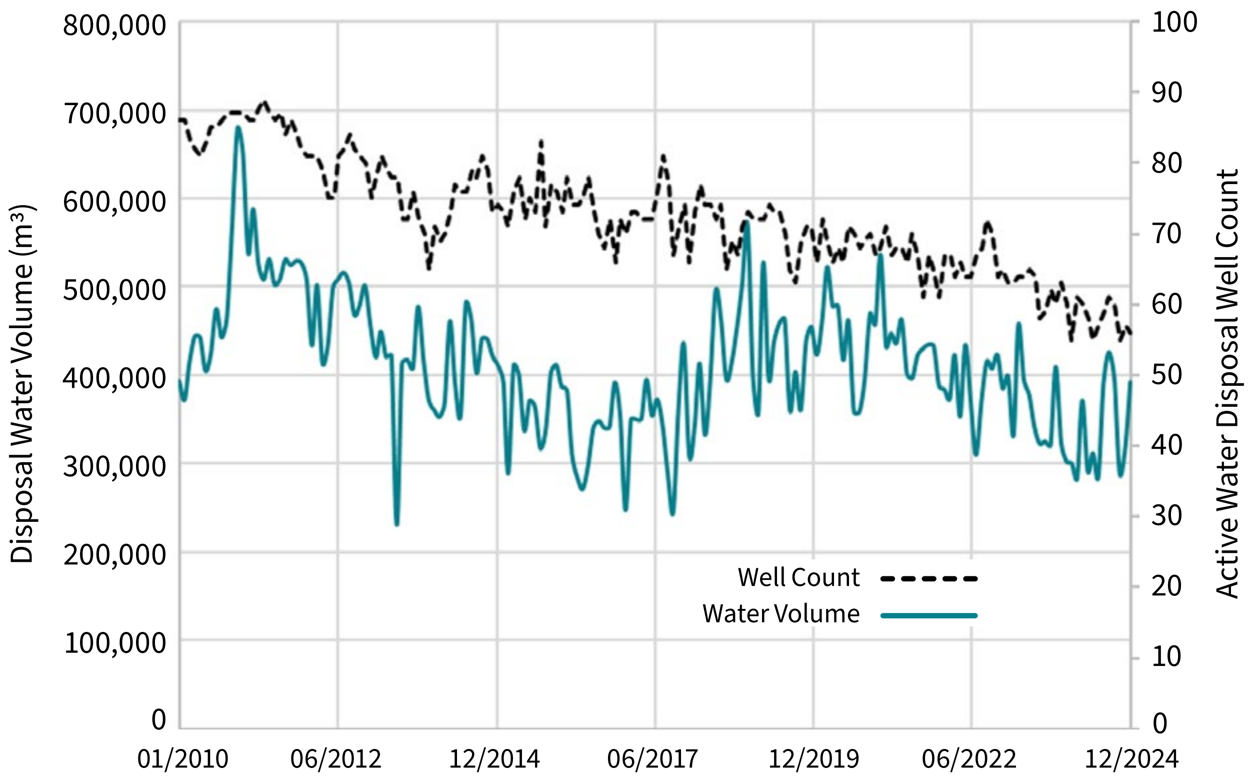


Figure 36: Monthly Water Disposal Well Count and Volume 2010 to 2024

Acid Gas Disposal

CO_2 and H_2S that constitute acid gas are the by-products from upgrading 'sour' raw natural gas. The process for removal of H_2S in raw natural gas also captures CO_2. Acid gas disposal is a lower-pollution alternative to flaring and the atmospheric release of SO_2 and CO_2. Figure 37 shows annual estimates for CO_2 production in raw gas for the province over the past decade. Both total CO_2 volume and CO_2 as a percentage of total raw gas steeply decline from 2015 to 2019, whereafter they have been relatively constant.

This decrease is largely driven by decreased production from the Horn River and lower estimated CO_2 composition from the Heritage Montney. Note CO_2 composition is estimated from pool-wide sample gas analyses and is not based on true measured volumes.

Figure 38 shows the active monthly acid gas disposal well count and CO_2 and H_2S volumes from 2009 to 2024. Total acid gas disposal volume averaged around 25-40 e^6m^3/month from 2009 to 2012, before decreasing to the current approximate value of 5 e^6m^3/month. The large drop was a result of the cessation of disposal operations of three acid gas disposal wells in the Foothills sour gas fields: Sukunka, Burnt River and Brazion fields. The current trend in acid gas disposal is the installation of smaller rate acid gas disposal wells for plants processing Montney gas, which varies from sweet to around 1.5 per cent H_2S content.

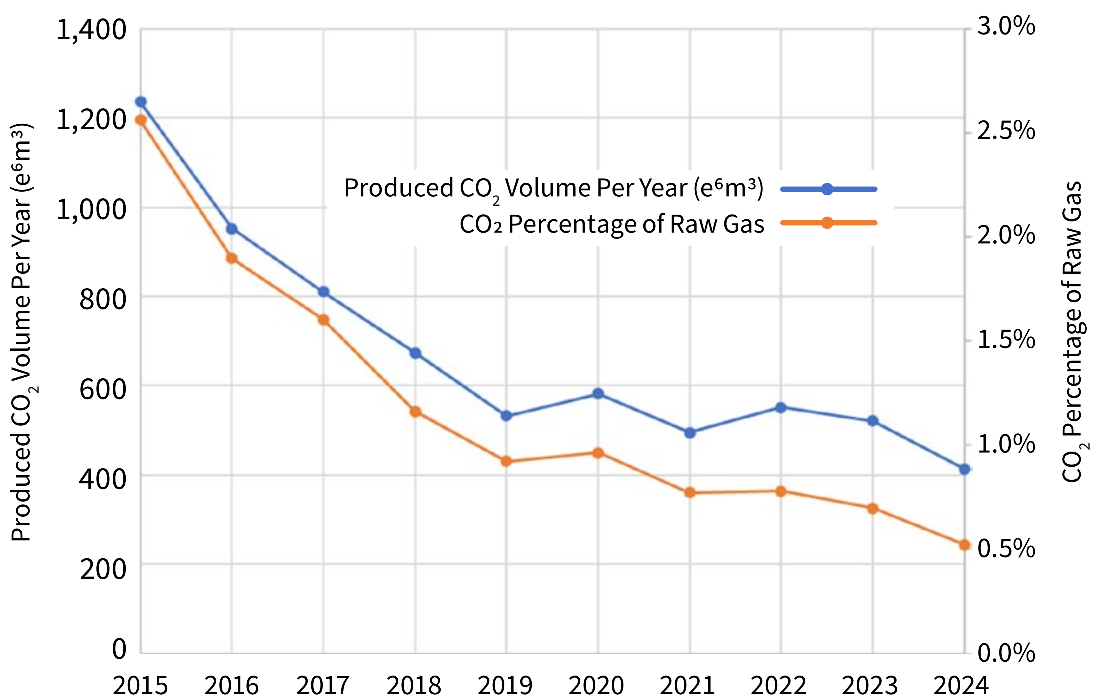


Figure 37: $C0_2$ Production from Raw Gas 2015 - 2024

When H_2S is removed and transformed to solid elemental sulfur, the CO_2 component of the natural gas is generally vented to the atmosphere. When H_2S is instead captured for injection into acid gas disposal wells, most of the CO_2 is captured as well, leading to lower CO_2 emissions. It should be noted an estimated total of 2.803 megatonnes of CO_2 have been sequestered as of December 2024, since acid gas disposal began in 1996.

Additionally, during this time period, acid gas disposal has diverted the atmospheric release of 8.955 megatonnes of SO_2, if the H_2S had instead been flared.

Annual tonnage of CO_2 and H_2S stored in acid gas disposal wells can be seen in Figure 39.

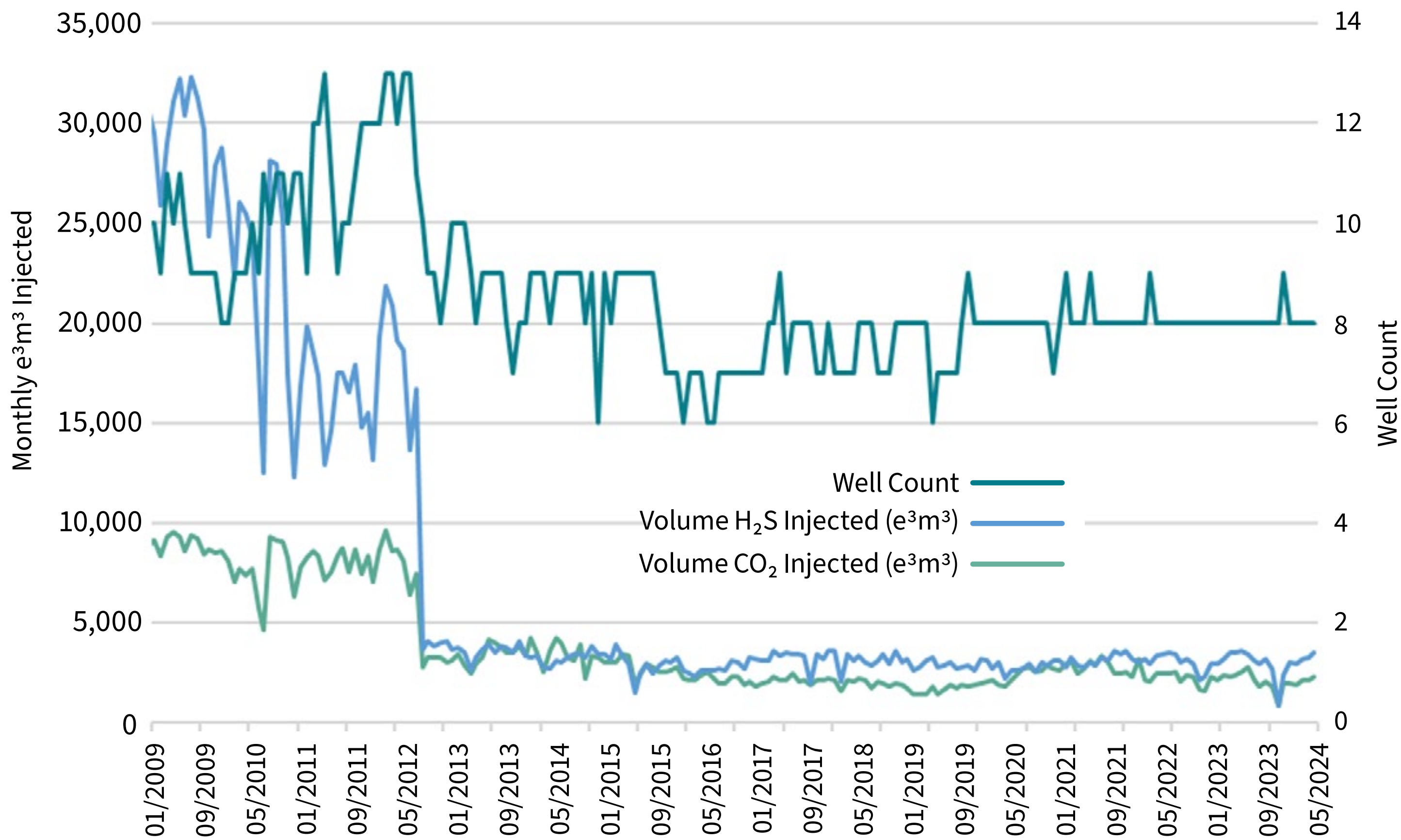


Figure 38: Monthly Acid Gas Disposal Well Count and Volume 2009 - 2024

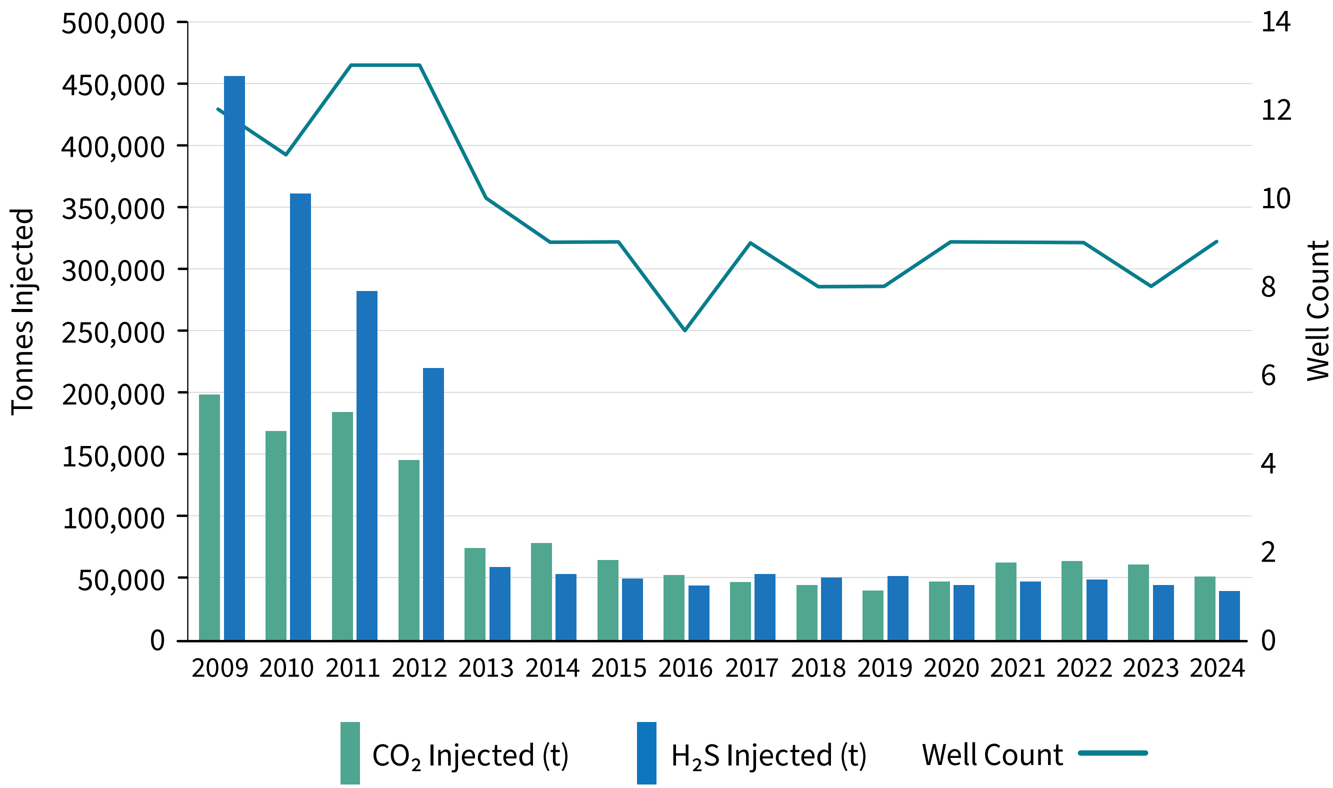


Figure 39: Annual Acid Gas Disposal Well Count and Tonnage 2009 - 2024

Disposal Summary

In summary, 2024 disposal represented a continuation of existing trends for both water and acid gas disposal. Total water disposal for 2024 averaged 339 e^3m^3/month (2,134 Mbbl/month) which was within the recent historical range, though it appears to be on a decreasing trend, with an 11 per cent decrease in 2022, a seven per cent decrease in 2023, and a five per cent decrease in 2024. This may be due to increased use of recycled frac flowback fluid, which the BCER started tracking in mid 2024 (further details can be seen in the Discussion: Hydraulic Fracturing Activity and Trends section of this report on page 52).

In recent years, the location of new disposal demand has been in the Montney fairway, and all three disposal wells approved in 2024 are located in that fairway. All of the operating acid gas disposal wells are located in the Montney fairway. Additional information regarding disposal wells can be found on the BCER's website. Chapter 3 of the Water Service Wells Summary Information Document and Acid Gas Disposal Wells Summary Document provide comprehensive guides on the regulation of disposal wells in B.C. Individual disposal well approvals (and other reservoir engineering project approvals) can be found on the BCER's website under Reservoir Management, here.

Disposal data for each well, monthly volume and injection pressure, can be downloaded in .csv or .txt format from the BCER's Data Centre (Drilling Data for All Wells in B.C. zip, water_gas_disposal file). Additionally, the BCER's Disposal Dashboard provides a concise view of the performance of each well, province-wide disposal well statistics, as well as the projected remaining disposal capacity.

The BCER regulates disposal wells with conditions for operating, monitoring, measurement, testing and reporting. The requirement for annual disposal reservoir pressure testing, together with volume reporting, allows the calculation and management of remaining disposal capacity "reserves" for existing wells.

Discussion: Deep Saline Water Sourcing

Deep saline water source wells extract "deep groundwater", as defined in the Water Sustainability Regulation, and operate primarily to supply hydraulic fracture stimulation fluid as an alternative to the use of surface water.

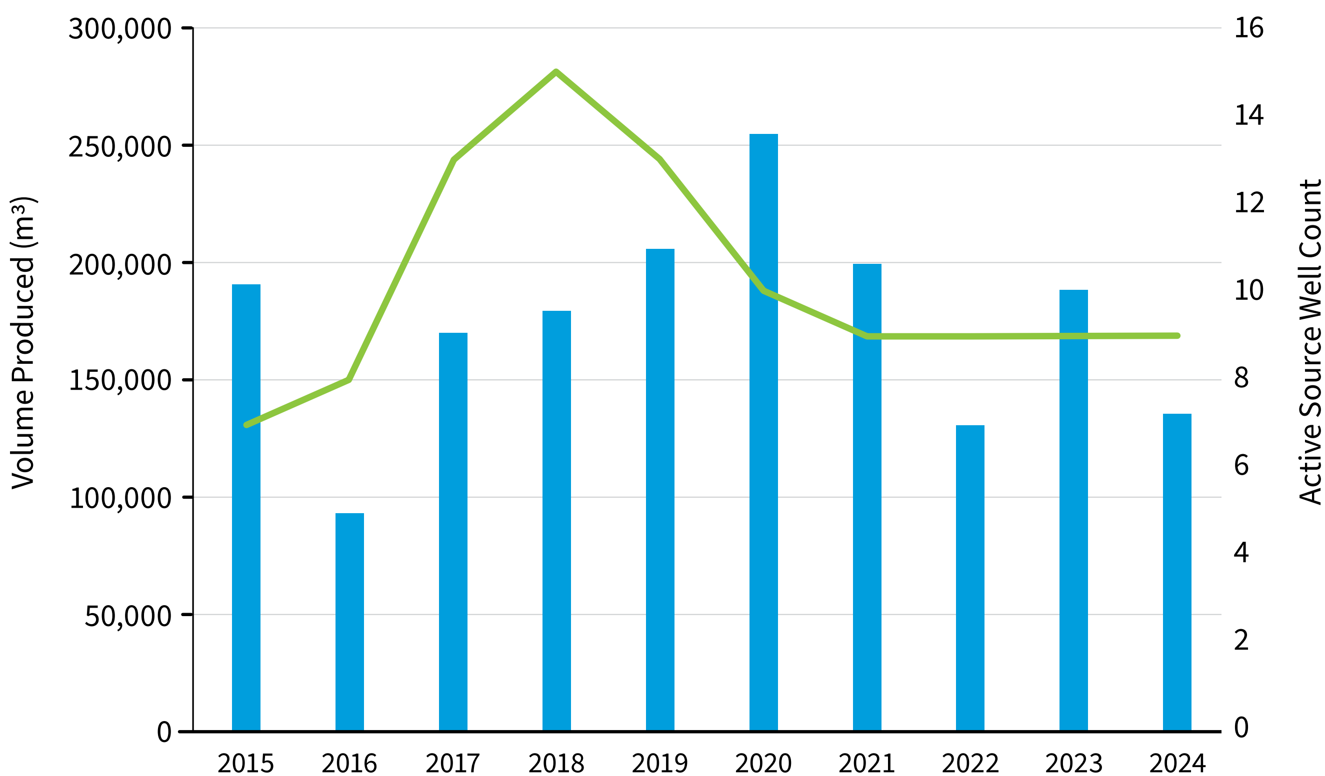


Figure 40: Annual Deep Saline Water Data 2015 - 2024

Deep saline water source wells extract "deep groundwater" and operate primarily to supply hydraulic fracture stimulation fluid as an alternative to the use of surface water.

Deep water source wells producing salt water are excluded from the requirements of the Water Sustainability Act for a water production licence; however, these wells are subject to normal BCER regulation for well life cycle permitting and monthly volumetric reporting. In some cases, deep water source reservoirs contain small amounts of natural gas in solution at reservoir conditions, which is separated at surface upon production, and for royalty purposes, the wells are designated as gas wells. These wells remain categorized internally as "Source" wells, based on the permit intent.

Figure 40 illustrates the trend in deep saline water source well activity. Some source wells withdraw from the same reservoir utilized for active disposal, with the deep subsurface acting as effective storage. The BCER does not maintain an inventory for deep saline water reservoir 'reserves'. However, understanding the location and potential reservoir size is informed in part by the extensive data obtained from disposal wells.

Discussion: Hydraulic Fracturing Activity and Trends

Horizontal drilling combined with hydraulic fracture stimulation (fracking) has been instrumental in unlocking the province's vast unconventional resources, driving both reserves and production growth.

Over 99 per cent of wells drilled in 2024 targeted the Montney formation, where hydraulic fracturing is essential to achieve economic production rates. A detailed overview of the hydraulic fracturing process is available in the Regulator's [Hydraulic Fracturing Factsheet].

Hydraulic fracturing has been used in the province since the 1950s, initially applied to vertical wells with comparatively small stimulation volumes. Beginning around 2004, the combination of hydraulic fracturing with horizontal drilling enabled stimulation of much larger areas within deep target formations, mirroring successful developments in other North American plays. Early Montney horizontal drilling and fracturing activity started in the Heritage field south of Dawson Creek, followed by expansions into the Horn River and Liard deep shale plays. As noted elsewhere in this report, hydraulic fracturing activity has now ceased in the Liard and Horn River areas.

The BCER maintains records of all well completions and hydraulic fracture operations in the province. Data collection in electronic format began in 2014, providing more detailed information in a consistent format for comparison analysis.

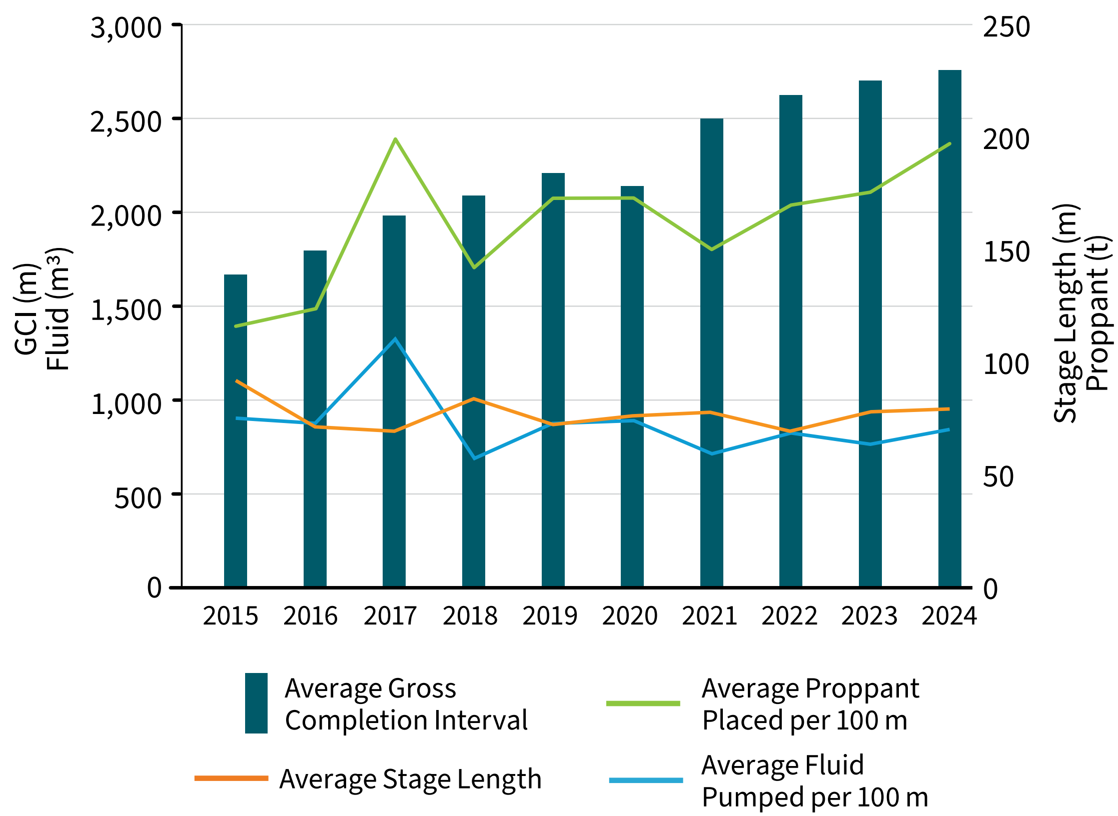


Figure 41: Annual Fracture Data 2015 - 2024

The Montney formation covers a vast area, as shown in the Oil and Gas Resource Basins map on page 25. Throughout the fairway, reservoir quality varies significantly, with factors such as hydrocarbon content, reservoir pore pressure, rock stress and potential for induced seismicity being a few of the variables which influence fracture stimulation design. Wells from a common pad are completed in different Montney layer sub-units, each with these variations.

The following graphs include data for Montney wells representing averaging of values and trends, unless specified as data for specific sub-layer or region.

Figure 41 illustrates horizontal well lengths (gross completion intervals, or GCI). Average GCI has increased steadily since 2015, with a significant jump of several hundred metres in 2021, followed by continued moderate year-over-year increases. Proppant volumes per 100 metres have generally trended upward, with a modest increase observed in 2024. However, the 2024 average remains below the peak value recorded in 2017. Water injection volumes and stage length have been fairly consistent, showing a slight decline over several years. Additional information on water sourcing and use is available in BCER Water Management Summaries.

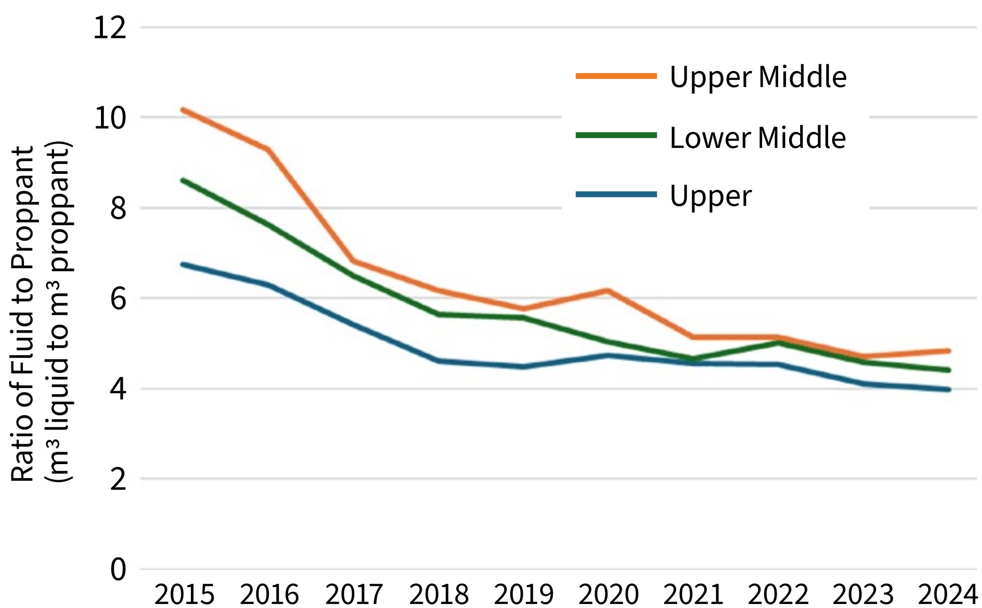


Figure 42: Annual Pumped Fluid to Proppant Ratio 2015 - 2024

Figure 42 presents the ratio of pumped fluid to proppant by Montney stratigraphic layer. All three trends show a decline over time, indicating less fluid is being used per unit of proppant. This suggests the injected slurry is becoming denser, potentially reflecting changes in stimulation design or operational efficiency.

Variations in water use and well length often reflect differences in operator practices and indicate ongoing optimization efforts. These parameters also vary depending on whether the target is liquid-rich or dry natural gas. Liquid-rich zones typically require maximum fracture surface area to optimize production. Fractures in dry gas zones are designed to maximize fracture extent, while recovery of wet gas relies on creation of fracture surface area. The distance between horizontal wells is balanced with the ability to effectively open or stimulate the rock between wells while limiting "frac hit" contacts.

Figure 43 shows the average lengths of horizontal GCIs for the two primary fracture methods: open hole (OHB) and cemented (either plug-and-perf or sliding sleeve). The data indicate a shift in completion strategy beginning in 2017, when cemented completions began to outpace open hole completions. Since 2021, the proportion of open hole completions has declined steadily, accounting for only 13 per cent of completions in 2024. Over the same period, average GCIs have increased consistently, reflecting an ongoing trend toward maximizing reservoir contact while minimizing surface disturbance.

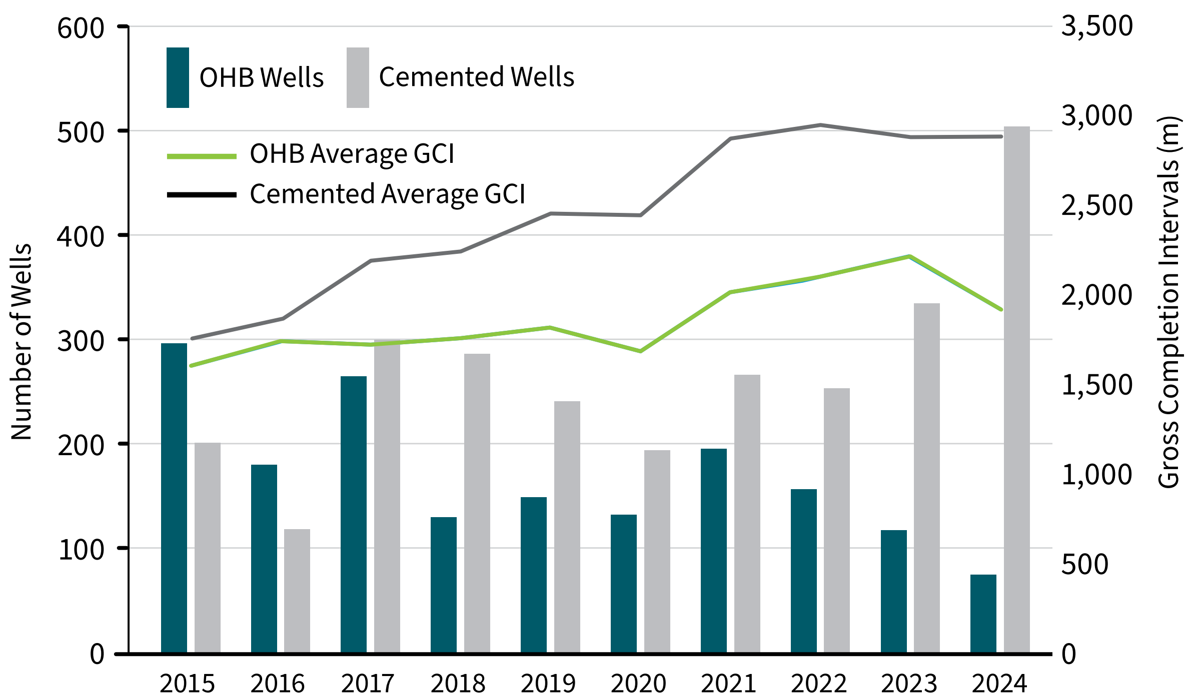
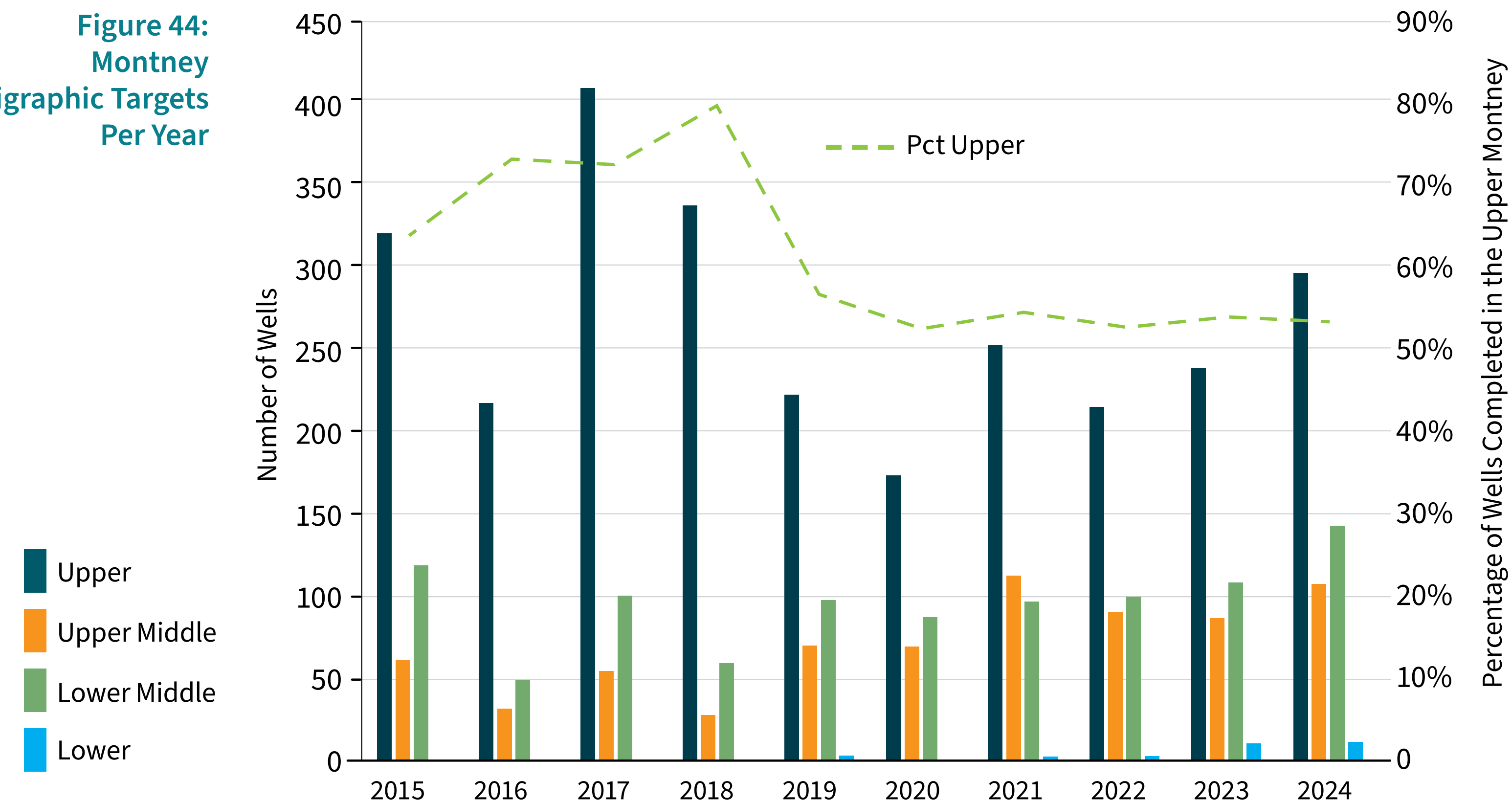


Figure 43: Well Completion Types

It is notable cemented completions have consistently achieved longer gross completion intervals (GCI) compared to open hole wells. In 2024, cemented wells averaged approximately 2,900 metres and open hole wells averaged around 1,950 metres. Open hole completions rely on sleeves that open using sequential ball sizes, which imposes a limit on the maximum well length that can be completed using this method. Other factors that may contribute to this disparity, include resource recovery optimization, and land or lease constraints.

Figure 44 illustrates the distribution of Montney layer targets by year. The Upper Montney has consistently been the most frequently targeted interval, followed by the Lower Middle, Upper Middle, and Lower Montney. Since 2019, the Upper Montney has accounted for just over 50 per cent of completions annually. Notably, Lower Montney activity has increased in recent years, rising from zero to four wells per year prior to 2023 to 11 completions in 2023 and 12 in 2024—though this still represents only a small share of total completions (~2 per cent). As discussed earlier, different Montney intervals produce a range of hydrocarbon products, from dry gas to light oil. Operators select targets based on market pricing and transportation capacity for each product type.

Figure 44: Montney Stratigraphic Targets Per Year



In some other jurisdictions, the practice of "re-fracking" wells has been common. Generally, this is done to wells previously hydraulically fractured using outdated techniques. Significant production increases can be yielded by hydraulically fracturing the same interval with modern methods. However, this has not been observed in the Montney. Of the over 7,000 Montney completions performed in B.C., there have been less than a dozen Montney re-fracs.

Beginning in August 2024, the BCER required the reporting of saline (recycled) and non-saline (fresh) water volumes used in hydraulic fracturing operations. Data collected from August to December 2024 indicates approximately 68 per cent of the total fluid volume used was saline, with the remainder being non-saline, as shown in Figure 45.

Figure 46 illustrates the number of wells that used entirely saline water, entirely non-saline water, or a blend of the two for hydraulic fracturing. Overall, the data suggests recycling of hydraulic fracture flowback fluid is a very common practice. The BCER will continue to monitor and report on these trends going forward.

Figure 45: Montney Fluid Volume Pumped, Saline vs. Non-Saline (Aug-Dec 2024)

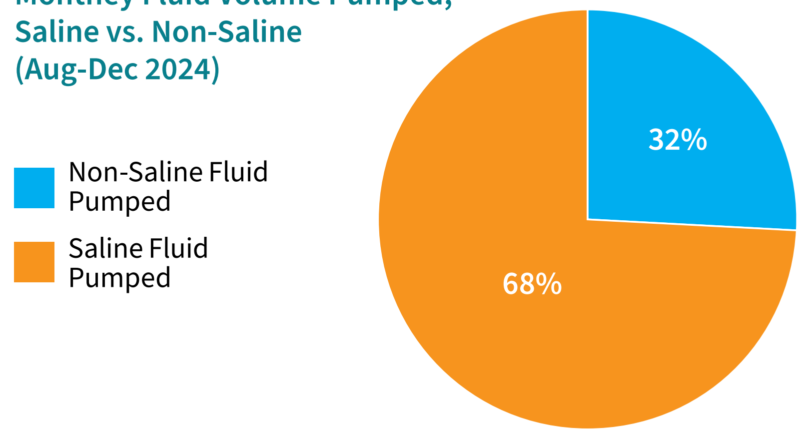
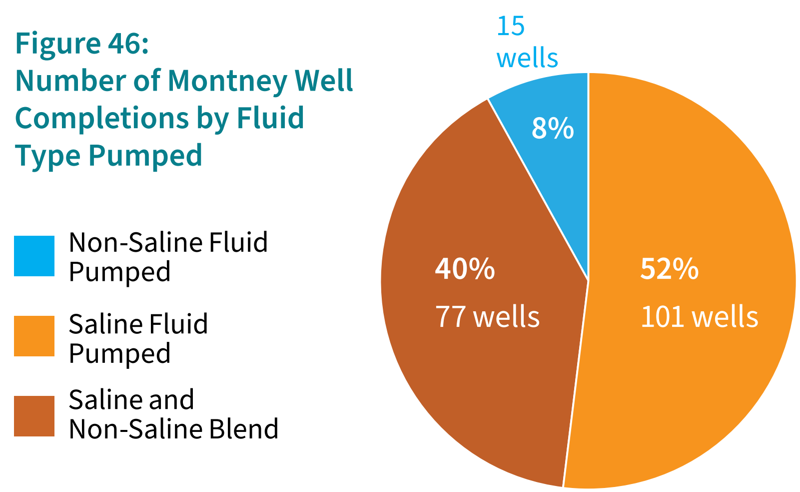


Figure 46: Number of Montney Well Completions by Fluid Type Pumped



The BCER also collects data on fracture perforation clustering—that is, the number and characteristics of perforation intervals within each frac stage. As shown in Figure 47, the number of clusters per stage increased sharply from approximately three to six between 2016 and 2018. Since then, the rate of increase has been more gradual, with current practices averaging around seven clusters per stage.

Figure 48 shows the average perforation cluster length by year and Montney bench. Between 2015 and 2018, there was a sharp decrease in average length—from approximately 0.8 metres to 0.4 metres. Since then, lengths have largely stabilized, with some indication of a slight upward trend.

Figure 49 shows the ratio of total perforated length (i.e., the combined length of all clusters) to GCI. This metric has been on a steady upward trend, indicating a greater portion of the wellbore is being perforated in newer vintage wells.

In summary, perforation design has evolved toward shorter but more numerous clusters within similar stage lengths, resulting in an increasing proportion of each stage being perforated. As illustrated in the

Figure 47: Average Number of Clusters per Stage by Year and Montney Bench

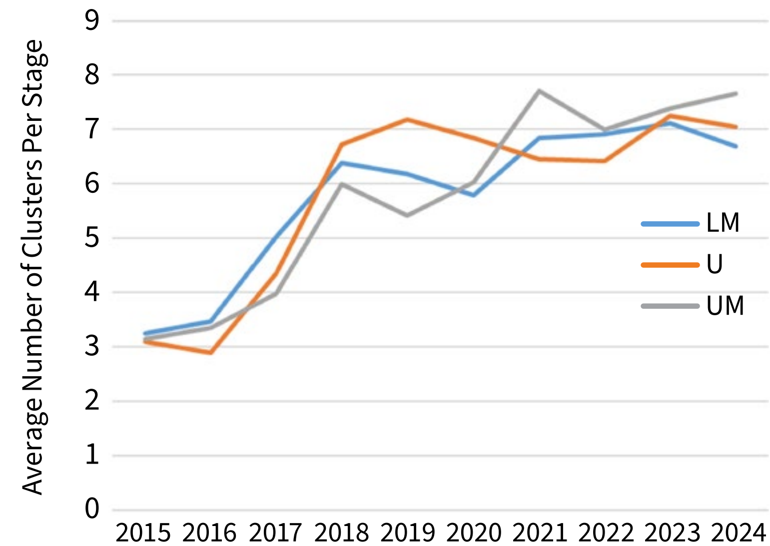
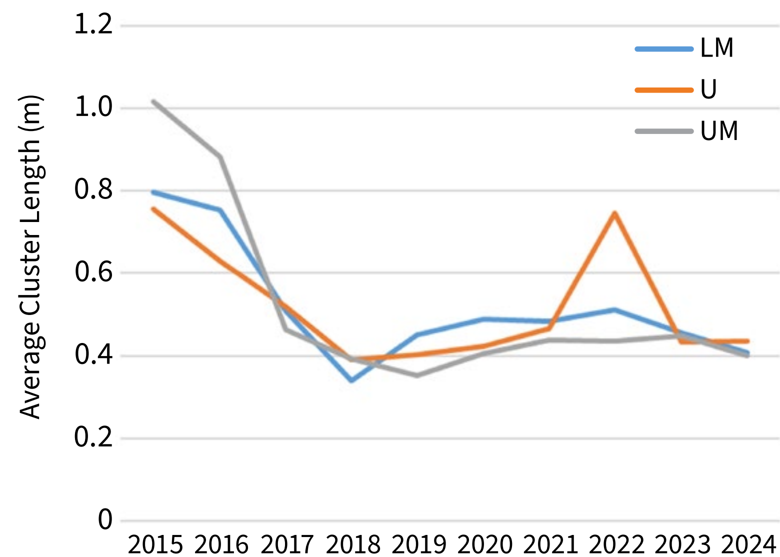


Figure 48: Average Cluster Length by Year and Montney Bench



preceding figures, there appears to be minimal variation in clustering practices across the different Montney benches.

Fracture intensity per cluster—measured as fluid or proppant volume per cluster—follows a similar trend, with a sharp decline from 2015 to 2018, followed by a period of relative stabilization, as shown in Figure 50. While bench-level detail is omitted from this figure for simplicity, minimal variation in fracture intensity per cluster is observed across the different Montney benches.

The source for graphs in this section is available in the BCER's [Data Centre](#) (Hydraulic Fracture Summary Data). Additionally, information regarding frac fluids can be found in the BCER's [FracFocus Data](#) report.

Information on how hydraulic fracturing is regulated can be found on the BCER's [Hydraulic Fracturing webpage](#).

Figure 49: Ratio of Total Perforated Length to GCI by Year and Montney Bench

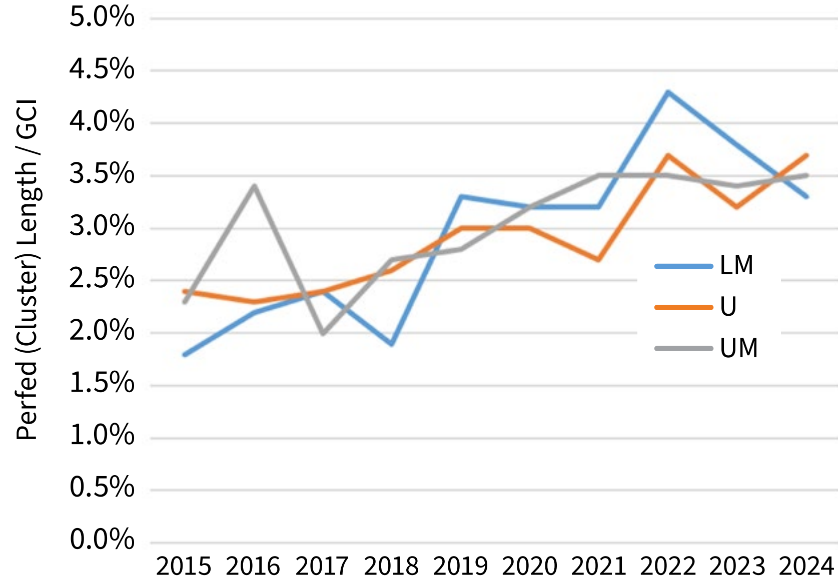
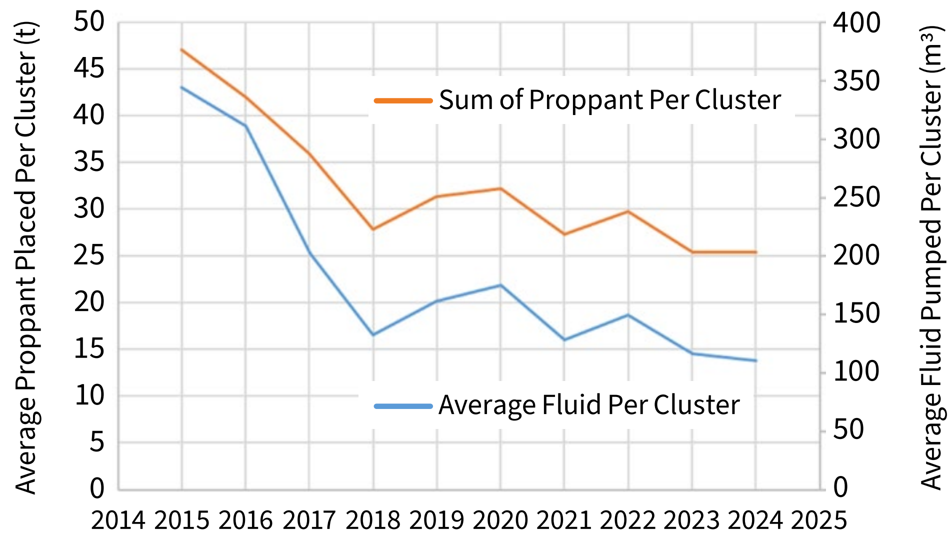


Figure 50: Average Proppant and Fluid Placed (Intensity) per Cluster



Discussion: Drilling

In 2020, for the first time in the province's history, more wells were decommissioned than drilled, a trend that continued through 2023, but did not occur in 2024.

Figure 51 shows the number of wells drilled by well classification. The number of non-development wells drilled per year has been steadily decreasing, with only one or two wells drilled per year from 2019 to 2024. Few exploratory or special data wells are needed, as operators target the Montney near existing wells.

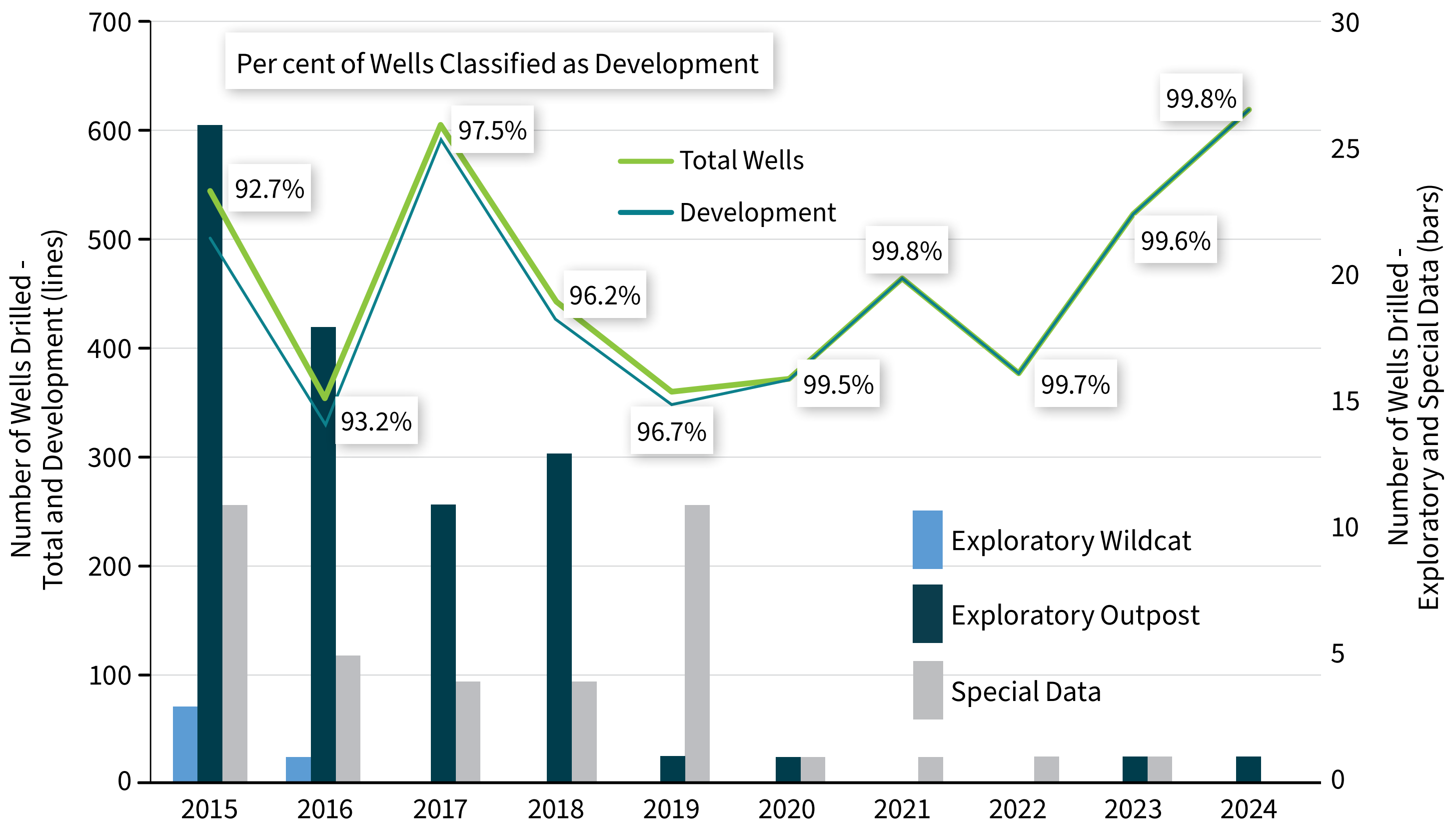


Figure 51: Number of Wells Drilled by Classification Per Year

Figure 52 shows the number of wells drilled and decommissioned by year. In 2020, for the first time in the province's history, more wells were decommissioned than drilled, a trend that continued through 2023, but did not occur in 2024. Note that due to a delay in processing decommissioning reports, the number of decommissioned wells in recent years may be amended upwards as reports are entered into the database. The BCER is improving systems to address this increase in data. The large increase in the number of wells decommissioned in recent years is mostly due to the introduction of the Dormancy and Shutdown Regulation, which requires operators to decommission inactive wells and restore inactive sites within a strict timeline.

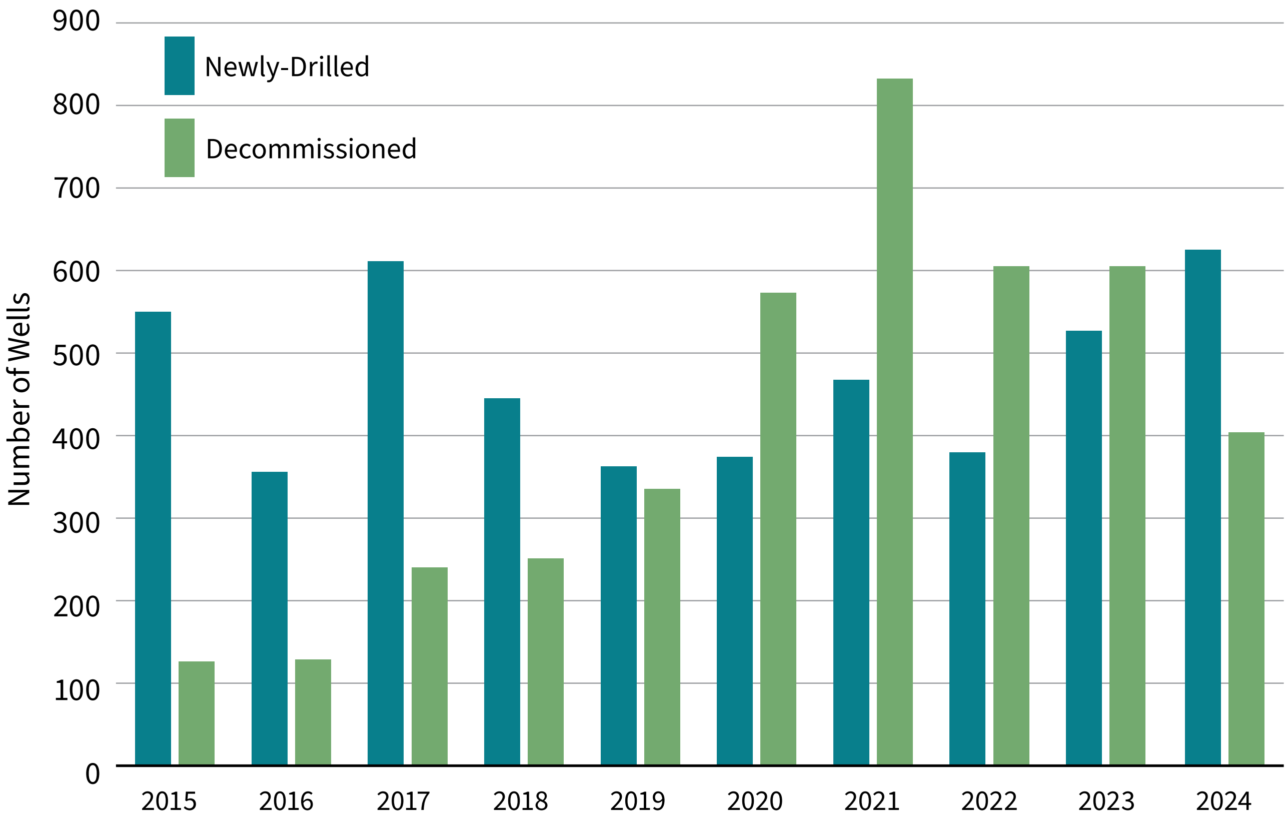


Figure 52: Number of Wells Drilled and Decomissioned by Year

Definitions

SI UNITS

British Columbia's reserves of oil, natural gas, hydrocarbon liquids (HCL) and sulphur are presented in the International System of Units (SI). Both SI units and the Imperial Equivalents are used throughout this report. Conversion factors used in calculating the Imperial equivalents are listed:

1 cubic metre of gas (101.325 kilopascals and 15° Celcius)	=	**35.493 73 cubic feet of gas** (14.65 psia and 60° Fahrenheit)
1 cubic metre of ethane (equilibrium presssure and 15° Celcius)	=	**6.330 0 Canadian barrels of ethane** (equilibrium pressure and 60° Fahrenheit)
1 cubic metre of propane (equilibrium pressure and 15° Celcius)	=	**6.300 0 Canadian barrels of propane** (equilibrium pressure and 60° Fahrenheit)
1 cubic metre of butanes (equilibrium pressure and 15° Celcius)	=	**6.296 8 Canadian barrels of butanes** (equilibrium pressure and 60° Fahrenheit)
1 cubic metre of oil or pentanes+ (equilibrium pressure and 15° Celcius)	=	**6.292 9 Canadian barrels of oil or pentanes+** (equilibrium pressure and 60° Fahrenheit)
1 cubic metre of water (equilibrium pressure and 15° Celcius)	=	**6.290 1 Canadian barrels of water** (equilibrium pressure and 60° Fahrenheit)
1 tonne	=	**0.984 206 4 (U.K.) long tons** (2,240 pounds)
1 tonne	=	**1.102 311 short tons** (2,000 pounds)
1 kilojoule	=	**0.948 213 3 British thermal units** (Btu as defined in the Electricity and Gas Inspection Regulations [60° - 61° Fahrenheit])

Aggregated P90
The 90 per cent probability of a distribution that forms as a result of an aggregation of outcomes.

Area
The area used to determine the adjusted bulk rock volume of the oil, or gas-bearing reservoir, usually the area of the zero isopach or the assigned area of a pool or deposit.

Butane
(C_4H_{10}) An organic compound found in natural gas. Reported volumes may contain some propane or pentanes+.

COGEH
Canadian Oil and Gas Evaluations Handbook (Volume 1, 2 and 3). First published in 2002 by the Calgary Chapter of the Society of Petroleum Evaluation Engineers to act as a standard for the evaluation of oil and gas properties.

Compressibility Factor
A correction factor for non-ideal gas determined for gas from a pool at its initial reservoir pressure and temperature and, where necessary, including factors to correct for acid gases.

Condensate
A mixture mainly of pentanes and heavier hydrocarbons (C_5^+) that may be contaminated with sulphur compounds recovered at a well or facility from an underground reservoir and may be gaseous in its virgin reservoir state but is liquid at the conditions under which its volume is measured.

Density
The mass or amount of matter per unit volume.

Density, Relative (Raw Gas)
The density, relative to air, of raw gas upon discovery, determined by an analysis of a gas sample representative of a pool under atmospheric conditions.

Discovery Year
The year in which the well that discovered the oil or gas pool finished drilling.

Estimated Ultimate Recovery (EUR)
Total volume of oil or gas recoverable under current technology and present and anticipated economic conditions, specifically proven by drilling, testing, or production; plus contiguous undeveloped reserves interpreted from geological, geophysical, and/or analogous production, with reasonable certainty to exist. Also referred to as Initial Reserves in the detailed reserves tables listed in Appendix A.

Ethane
(C_2H_6) An organic compound in natural gas that belongs in the Liquefied Petroleum Gas (LPG) category. Reported volumes may contain some methane or propane.

Formation Volume Factor
The volume occupied by one cubic metre of oil and dissolved gas at reservoir pressure and temperature, divided by the volume occupied by the oil measured at standard conditions.

Gas (Non-associated)
Gas not in communication in a reservoir with an accumulation of liquid hydrocarbons at initial reservoir conditions.

Gas Cap (Associated)
Gas in a free state in communication in a reservoir with crude oil, under initial reservoir conditions.

Gas (Solution)
Gas dissolved in oil under reservoir conditions and evolves as a result of pressure and temperature changes.

Gas (Raw)
A mixture containing methane, other paraffinic hydrocarbons, nitrogen, carbon dioxide, hydrogen sulphide, helium, and minor impurities, or some of them, which is recovered or is recoverable at a well from an underground reservoir and which is gaseous at the conditions under which its volume is measured or estimated.

Gas (Marketable)
A mixture mainly of methane originating from raw gas, if necessary, through the processing of the raw gas for the removal or partial removal of some constituents, and which meets specifications for use as a domestic, commercial, or industrial fuel or as an industrial raw material.

Gas-Oil Ratio (Initial Solution)
The volume of gas (in thousand cubic metres, measured under standard conditions) contained in one stock-tank cubic metre of oil under initial reservoir conditions.

Gross Heating Value (of dry gas)
The heat liberated by burning moisture-free gas at standard conditions and condensing the water vapour to a liquid state.

Initial Reserves
Established reserves prior to the deduction of any production. Also referred to as Estimated Ultimate Recovery (EUR).

Liquefied Petroleum Gas (LPG)
LPG consists primarily of propane and butane with minor components ranging from ethane to normal hexane. It is produced either as a by-product of natural gas processing or during refining and processing operations. For the purposes of this report, reported LPG include all ethane, propane and butane.

Maturity of Resource Play Development is divided into four phases:

- **Early phase**: exploration phase with minimal well density. Statistical evaluation unreliable due to less than minimum well count.
- **Intermediate phase**: exploration drilling/ delineation drilling is less than 50 per cent of total well count. Statistical analysis difficult.
- **Statistical phase**: development phase is reached, some uncertainty remains regarding choice of completion techniques. Statistical analysis of the interior proved area possible.
- **Mature phase**: delineation complete, well defined well density. Possible production interference seen. Well count sufficient for statistical analysis.

Mean Formation Depth
The approximate average depth below kelly bushing of the mid-point of an oil or gas productive zone for the wells in a pool.

Methane
In addition to its normal scientific meaning, a mixture mainly of methane which ordinarily may contain some ethane, nitrogen, helium or carbon dioxide.

Natural Gas Liquids (NGL)
Components of natural gas in a liquid state at surface and include propane, butane, pentane and heavier hydrocarbons.

Oil
A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds, recovered or is recoverable at a well from an underground reservoir, and is liquid at the conditions under which its volume is measured or estimated, and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas or condensate.

Original Gas and Original Oil in Place (OOIP)
The volume of oil, or raw natural gas estimated to exist originally in naturally occurring accumulations, prior to production.

Pay Thickness (Average)
The bulk rock volume of a reservoir of oil or gas, divided by its area.

Pentanes+

A mixture mainly of pentanes and heavier hydrocarbons, (which may contain some butane), obtained from the processing of raw gas, condensate, or oil.

Pool

A natural underground reservoir containing or appearing to contain an accumulation of liquid hydrocarbons or gas or both separated or appearing to be separated from any other such accumulation.

Porosity

The effective pore space of the rock volume determined from core analysis and well log data, measured as a fraction of rock volume.

Pressure (Initial)

The reservoir pressure at the reference elevation of a pool upon discovery.

Probabilistic Aggregation

The adding of individual well outcomes to create an overall expected reserve outcome.

Project/Units

A scheme by which a pool or part of a pool is produced by a method approved by the BCER.

Propane

(C_3H_8) An organic compound found in natural gas. Reported volumes may contain some ethane or butane.

Proved Plus Probable Reserves

Estimates of hydrocarbon quantities to be recovered. There is at least a 50 per cent probability the actual quantities recovered will equal or exceed the estimated proved plus probable reserves.

PUD (Proved Undeveloped)

Proved undeveloped reserves assigned to undrilled well locations interpreted from geological, geophysical, and/or analogous production, with reasonable certainty to exist.

P10

There is a 10 per cent probability (P10) the quantities actually recovered will equal or exceed this value.

P50

There is a 50 per cent probability (P50) the quantities actually recovered will equal or exceed this value.

P90

There is a 90 per cent probability (P90) the quantities actually recovered will equal or exceed this value.

Pmean

The expected average value or risk-weighted average of all possible outcomes.

Recovery

Recovery of oil, gas or natural gas liquids by natural depletion processes or by the implementation of an artificially improved depletion process over a part or the whole of a pool, measured as a volume or a fraction of the in-place hydrocarbons so recovered.

Remaining Reserves

Initial Reserves (IR) less cumulative production.

Reserves

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable.

Reserves are further classified according to the level of certainty associated with the estimates and may be sub-classified based on development and production status (from COGEH).

Resource

Resources are those quantities of hydrocarbons estimated to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development (adapted from COGEH).

Saturation (Water)

The fraction of pore space in the reservoir rock occupied by water upon discovery.

SPEE Monograph 3

Society of Petroleum Evaluation Engineers -- Guidelines for the Practical Evaluation of Undeveloped Reserves in Resource Plays.

SPEE Monograph 4

Society of Petroleum Evaluation Engineers -- Guidelines for the Practical Evaluation of Undeveloped Reserves in Resource Plays. Estimating Ultimate Recovery of Developed Wells in Low-Permeability Reservoirs. Provides an understanding of current available methods to analyze well performance of these now developed unconventional plays and to estimate the associated recoverable volumes.

Surface Loss

A summation of the fractions of recoverable gas removed as acid gas and liquid hydrocarbons, used as lease or plant fuel, or flared.

Temperature

The initial reservoir temperature upon discovery at the reference elevation of a pool.

Ultimate Potential

Defined in the NEB/MEM Oil and Gas Reports 2011-1, Ultimate Potential for Unconventional Natural Gas in Northeastern BC's Horn River Basin (May 2011): A term used to refer to an estimate of the marketable resources that will be developed in an area by the time exploratory and development activity has ceased, having regard for the geological prospects of an area, known technology and economics. It includes cumulative production, remaining reserves and future additions to reserves through extension and revision to existing pools and the discovery of new pools. For most of this report it is used as a short form of "ultimate potential of natural gas."

Unconnected Reserves

Gas reserves which have not been tied in to gathering facilities and therefore do not contribute to the provincial supply without further investment.

Unconventional Gas

Natural gas and associated hydrocarbon liquids from a geologic formation not previously capable of economic production rates, but with horizontal drilling and hydraulic fracture stimulation technology is now a development objective.

Zone

Any stratum or any sequence of strata designated by the BCER as a zone.

APPENDIX A

Table A-1: Established Hydrocarbon Reserves (SI Units) by Dec. 31, 2024

	Oil ($10^3 m^3$)	Raw Gas ($10^6 m^3$)
Initial Reserves, Current Estimate	141,559	4,396,252
Discovery 2024	0	0
Revisions 2024	3,218	297,401
Production 2024	637	79,083
Cumulative Production Dec. 31, 2024	127,152	1,578,919
Remaining Reserves Estimate Dec. 31, 2024	14,407	2,817,333

Table A-2: Historical Record of Raw Gas Reserves

Year	Estimated Ultimate Recovery 10^6 m^3	Yearly Discovery 10^6 m^3	Yearly Revisions 10^6 m^3	Yearly Other 10^6 m^3	Annual Production 10^6 m^3	Cumulative Production at Year-end 10^6 m^3	Remaining Reserves at Year-end 10^6 m^3
1977	376,960	18,119	-14,107		11,039	143,958	233,002
1978	399,535	21,190	1,386		9,943	153,900	245,635
1979	424,805	26,142	-872		11,394	165,294	259,511
1980	462,596	28,909	8,882		8,968	174,262	288,334
1981	478,689	13,842	2,251		8,293	182,555	296,134
1982	488,316	7,765	1,862		7,995	190,550	297,766
1983	490,733	2,550	-133		7,845	198,395	292,338
1984	496,703	1,798	4,172		8,264	206,659	290,044
1985	505,233	2,707	5,823		8,799	215,458	289,775
1986	501,468	4,822	-8463		8,506	223,964	277,628
1987	497,466	1,986	-5940		9,810	233,794	263,777
1988	500,738	6,083	-1661		10,275	244,249	256,483
1989	513,662	12,193	-2		13,276	257,862	255,782
1990	547,058	27,683	5,888		13,226	271,344	275,685
1991	574,575	24,708	3,812		15,162	285,965	288,582
1992	591,356	6,377	10,404		16,510	302,916	288,408
1993	617,379	22,901	3,122		18,202	321,090	296,246
1994	635,774	22,004	-3301		19,069	339,861	295,885
1995	657,931	21,065	1,051		21,157	361,106	296,825
1996	677,769	16,083	3,852		21,435	382,332	295,437
1997	688,202	12,835	-2394		22,811	405,157	283,045
1998	712,677	9,957	14,502		23,375	428,822	283,855
1999	743,816	13,279	17,824		23,566	453,000	290,816
2000	772,221	13,832	14,571		23,894	477,381	294,800
2001	811,146	7,199	31,690		26,463	504,620	306,526
2002	843,612	19,004	13,462		28,348	533,548	310,064
2003	889,488	19,317	26,282		26,639	562,560	326,928
2004	973,771	6,412	65,149	12,897	26,430	584,033	389,738
2005	1,065,288	8,974	63,268	19,104	27,854	620,696	444,592
2006	1,114,562	15,356	33,912		28,056	652,137	462,425
2007	1,172,136	21,468	36,109		29,362	689,209	482,927
2008	1,328,729	6,559	150,167		30,346	722,769	605,280
2009	1,415,172	30,331	56,133		30,846	757,291	657,881
2010	1,724,769	275,942	33,691		33,202	792,798	931,971
2011	1,809,591	7,909	76,934		40,519	834,715	974,876
2012	2,014,054	1,646	202,809		40,482	875,580	1,138,474
2013	2,116,236	428	101,754		43,722	919,007	1,197,229
2014	2,408,673	0	292,437		46,222	964,803	1,443,870
2015	2,517,904	0	10,231		48,106	1,013,247	1,504,657
2016	2,547,406	0	29,502		50,131	1,062,296	1,485,110
2017	2,467,579	0	-79,827		50,511	1,112,807	1,354,772
2018	2,605,099	0	137,520		57,881	1,171,010	1,434,089
2019	3,048,050	0	442,951		57,683	1,229,301	1,818,749
2020	3,202,111	0	154,061		60,282	1,289,624	1,912,487
2021	3,447,399	0	245,363		64,227	1,354,622	2,092,853
2022	3,900,387	0	452,988		70,802	1,425,323	2,475,065
2023	4,098,851	0	198,464		74,649	1,499,944	2,598,907
2024	4,396,252	0	297,401		79,083	1,578,919	2,817,333

These values are taken from previously published ministry reserve estimates. This compilation is provided for historical value and to aid in statistical analysis only. Values shown for any given year may not balance due to changes in production and estimates over time.

Table A-3: Historical Record of Oil Reserves

Year	Estimated Ultimate Recovery $10^3\ m^3$	Yearly Discovery $10^3\ m^3$	Yearly Revisions $10^3\ m^3$	Yearly Other $10^3\ m^3$	Annual Production $10^3\ m^3$	Cumulative Production at Year-end $10^3\ m^3$	Remaining Reserves at Year-end $10^3\ m^3$
1977	72,841	4,159	-84		2,201	46,318	26,523
1978	77,826	2,650	2,376		2,004	48,280	29,546
1979	78,882	427	629		2,140	50,397	28,485
1980	80,043	234	927		2,002	52,399	27,644
1981	79,968	143	-218		2,060	54,459	25,509
1982	80,760	126	666		2,095	56,554	24,206
1983	82,149	661	727		2,079	58,634	23,515
1984	79,551	781	-3,378		2,113	60,747	18,805
1985	82,887	1,767	1,569		1,944	62,691	20,196
1986	83,501	456	144		2,010	64,701	18,786
1987	84,201	631	68		2,084	66,793	17,361
1988	85,839	1,238	-50		1,937	68,759	16,623
1989	89,899	2,306	2,402		1,978	70,737	19,129
1990	90,650	569	181		1,954	72,714	17,823
1991	91,606	233	630		1,974	74,689	16,911
1992	94,030	823	1,596		2,017	76,750	17,273
1993	96,663	803	1,830		1,976	78,726	17,925
1994	99,619	1,477	1,482		1,929	80,664	18,956
1995	102,823	2,887	290		1,997	82,658	20,167
1996	106,009	1,306	1,878		2,205	84,856	21,153
1997	110,765	3,199	1,561		2,525	87,401	23,364
1998	116,294	815	4,717		2,670	90,105	26,189
1999	118,840	345	2,201		2,338	92,453	26,388
2000	122,363	504	3,018		2,568	95,031	27,357
2001	123,048	106	582		2,569	97,591	25,478
2002	122,245	427	-1,233		2,426	99,977	22,313
2003	124,660	424	1,990		2,203	102,234	22,426
2004	125,953	154	947	188	2,015	104,104	21,873
2005	126,941	247	636	110	1,750	106,086	20,857
2006	125,845	222	-1,322		1,631	107,603	18,244
2007	128,971	266	2,859		1,520	109,283	19,692
2008	129,117	162	25		1,341	110,632	18,485
2009	131,172	289	1,766		1,282	111,924	19,252
2010	131,840	643	28		1,270	113,197	18,653
2011	132,414	99	475		1,154	114,253	18,161
2012	134,600	537	1,614		1,222	115,492	19,108
2013	135,883	0	1,278		1,129	116,633	19,250
2014	135,657	0	-226		1,177	117,598	18,059
2015	136,691	0	1,034		1,210	119,138	17,553
2016	136,956	0	256		1,331	120,473	16,483
2017	139,952	0	2,996		1,233	121,752	18,200
2018	141,317	0	1,365		1,196	122,968	18,349
2019	140,582	0	-735		935	123,937	16,645
2020	139,666	31	-947		790	124,728	14,938
2021	138,660	0	-1,006		676	125,403	13,257
2022	138,142	0	-518		662	125,975	12,167
2023	138,341	0	199		508	126,483	11,857
2024	141,559	0	3218		637	127,152	14,407

These values are taken from previously published ministry reserve estimates. This compilation is provided for historical value and to aid in statistical analysis only. Values shown for any given year may not balance due to changes in production and estimates over time.

Table A-4: Oil Pools Under Waterflood

Field	Pool	Pool Sequence	Project Code	OOIP 10^3 m^3	RF %	EUR 10^3 m^3	Cum Oil 10^3 m^3	RR 10^3 m^3
BEATTON RIVER	HALFWAY	A	02	3,430.1	47.1%	1,616.2	1,616.2	0.0
BEATTON RIVER	HALFWAY	G	05	1,438.4	29.6%	425.8	425.8	0.0
BEATTON RIVER WEST	BLUESKY	A	02	2,956.3	37.2%	1,098.3	1,098.3	0.0
BEAVERTAIL	HALFWAY	B	06	499.0	18.0%	89.8	87.7	2.1
BEAVERTAIL	HALFWAY	H	05	874.1	20.0%	174.8	173.4	1.4
BIRCH	BALDONNEL	C	03	2,200.4	49.0%	1,078.2	995.9	82.3
BLUEBERRY	DEBOLT	E	03	1,211.5	30.0%	363.4	354.2	9.2
BOUNDARY LAKE	BOUNDARY LAKE	A	02	43,666.1	48.0%	20,959.7	20,403.6	556.1
BOUNDARY LAKE	BOUNDARY LAKE	A	03	30,218.0	44.0%	13,295.9	13,061.6	234.4
BOUNDARY LAKE	BOUNDARY LAKE	A	04	5,769.2	60.0%	3,461.5	3,249.7	211.8
BOUNDARY LAKE	BOUNDARY LAKE	A	05	1,587.4	65.0%	1,031.8	1,004.4	27.4
BOUNDARY LAKE	HALFWAY	M	03	2,415.7	20.0%	483.1	271.8	211.3
BOUNDARY LAKE NORTH	HALFWAY	D	03	588.3	20.0%	117.7	112.8	4.9
BOUNDARY LAKE NORTH	HALFWAY	I	04	1,085.8	40.0%	434.3	407.1	27.2
BUBBLES NORTH	COPLIN	A	02	143.8	29.0%	41.7	41.7	0.0
BUICK CREEK	LOWER HALFWAY	C	19	2,761.8	24.2%	667.3	667.3	0.0
BULRUSH	HALFWAY	C	02	96.4	4.3%	4.2	4.2	0.0
CRUSH	HALFWAY	A	02	1,449.4	34.7%	503.2	503.2	0.0
CRUSH	HALFWAY	B	02	148.6	33.6%	49.9	49.9	0.0
CURRANT	HALFWAY	A	02	792.7	52.9%	419.0	419.0	0.0
CURRANT	HALFWAY	D	02	121.8	6.6%	8.0	8.0	0.0
DESAN	PEKISKO		03	5,388.1	20.0%	1,077.6	1,001.4	76.3
EAGLE	BELLOY-KISKATINAW		02	6,928.9	40.0%	2,771.5	2,627.0	144.6
EAGLE WEST	BELLOY	A	03	20,337.5	31.0%	6,304.6	6,280.5	24.1
ELM	GETHING	B	04	1,772.6	7.3%	129.4	129.2	0.2
HALFWAY	DEBOLT	A	03	949.9	10.0%	94.7	94.7	0.0
HAY RIVER	BLUESKY	A	05	36,992.5	20.0%	7,398.5	6,367.3	1,031.2
INGA	INGA	A	04	8,355.6	39.9%	3,331.4	3,331.4	0.0
INGA	INGA	A	06	7,521.3	31.1%	2,335.4	2,335.0	0.3
INGA	INGA	A	07	1,400.6	44.8%	627.5	627.5	0.0
INGA	INGA	A	08	1,716.5	32.5%	557.7	557.7	0.0
LAPP	HALFWAY	C	02	1,036.8	43.6%	451.7	451.7	0.0
LAPP	HALFWAY	D	02	395.3	42.0%	165.8	165.8	0.0
MICA	MICA	A	04	1,128.7	40.0%	451.5	381.7	69.8
MICA	DOIG	B	04	509.7	35.0%	178.4	143.2	35.2
MILLIGAN CREEK	HALFWAY	A	02	12,120.0	52.6%	6,376.3	6,376.3	0.0
MILLIGAN CREEK	HALFWAY	A	03	2,159.6	49.0%	1,058.2	1,034.5	23.7
MUSKRAT	BOUNDARY LAKE	A	03	1,142.8	40.0%	457.1	407.3	49.8
MUSKRAT	LOWER HALFWAY	A	03	464.4	23.0%	107.0	107.0	0.0
OAK	CECIL	B	02	424.3	23.5%	99.8	99.8	0.0
OAK	CECIL	C	03	907.7	55.0%	499.3	454.8	44.5
OAK	CECIL	E	03	1,264.4	47.7%	603.4	603.4	0.0
OAK	CECIL	I	03	616.1	39.0%	240.3	237.5	2.8
OWL	CECIL	A	03	717.0	44.7%	320.3	320.3	0.0
PEEJAY	HALFWAY		02	5,802.7	38.4%	2,227.1	2,227.1	0.0
PEEJAY	HALFWAY		03	8,937.6	43.5%	3,887.9	3,839.8	48.0
PEEJAY	HALFWAY		04	10,137.3	44.3%	4,490.8	4,477.7	13.1
PEEJAY WEST	HALFWAY	A	03	1,904.0	23.0%	437.9	431.4	6.5
PEEJAY WEST	HALFWAY	C	02	510.9	34.2%	174.6	174.6	0.0
RED CREEK	DOIG	C	03	609.3	30.0%	182.8	153.7	29.1
RIGEL	DUNLEVY	A	02	195.5	9.7%	19.0	19.0	0.0
RIGEL	CECIL	B	02	1,502.8	39.7%	596.8	596.8	0.0
RIGEL	CECIL	G	02	952.8	44.0%	419.0	419.0	0.0
RIGEL	CECIL	H	03	1,821.0	48.8%	888.8	888.8	0.0
RIGEL	CECIL	I	02	1,961.9	39.6%	776.9	776.9	0.0
RIGEL	HALFWAY	C	02	738.7	26.6%	196.6	196.6	0.0
RIGEL	HALFWAY	C	03	752.3	38.8%	292.0	292.0	0.0
RIGEL	HALFWAY	Z	02	104.3	6.6%	6.9	6.9	0.0
SQUIRREL	NORTH PINE	C	03	1,376.7	29.7%	408.9	408.9	0.0
STODDART	NORTH PINE	G	04	214.0	35.3%	75.4	75.4	0.0
STODDART WEST	BEAR FLAT	D	03	451.9	34.5%	156.0	156.0	0.0
STODDART WEST	BELLOY	C	05	5,784.4	25.0%	1,446.1	1,402.8	43.3
SUNSET PRAIRIE	CECIL	A	02	882.3	37.3%	328.9	328.9	0.0
SUNSET PRAIRIE	CECIL	C	02	420.2	28.6%	120.2	120.2	0.0
SUNSET PRAIRIE	CECIL	D	02	379.3	1.4%	5.2	5.2	0.0
TWO RIVERS	SIPHON	A	03	1,475.6	19.0%	280.4	263.3	17.1
WEASEL	HALFWAY		02	3,719.9	64.1%	2,383.3	2,383.3	0.0
WEASEL	HALFWAY		03	1,729.5	58.2%	1,005.7	1,005.7	0.0
WILDMINT	HALFWAY	A	02	2,867.9	53.8%	1,542.3	1,542.3	0.0
WOODRUSH	HALFWAY	E	02	880.6	16.0%	140.9	127.3	13.6
Total				273,817.9		104,451.5	101,410.3	3,041.2
% of Total British Columbia Oil Reserves						73.8%	79.8%	21.1%

Table A-5: Oil Pools Under Gas Injection

Field	Pool	Pool Sequence	Project Code	OOIP (10^3m^3)	RF %	EUR (10^3m^3)	Cum. Prod. (10^3m^3)	RR (10^3m^3)
BRASSEY	ARTEX	A	02	94.5	14.6%	13.8	13.8	0.0
BRASSEY	ARTEX	G	02	353.4	42.3%	149.3	149.3	0.0
BULRUSH	HALFWAY	A	02	935.5	40.0%	374.2	340.2	34.0
CECIL LAKE	CECIL	D	03	1,091.3	40.0%	436.5	380.7	55.8
RIGEL	HALFWAY	H	03	702.8	12.9%	90.7	90.7	0.0
STODDART WEST	BELLOY	C	03	1,525.5	25.3%	385.9	385.1	0.9
TOTAL				4,702.9		1,450.5	1,359.8	90.6
% OF TOTAL BRITISH COLUMBIA RESERVES						1.0%	1.1%	0.6%

APPENDIX B

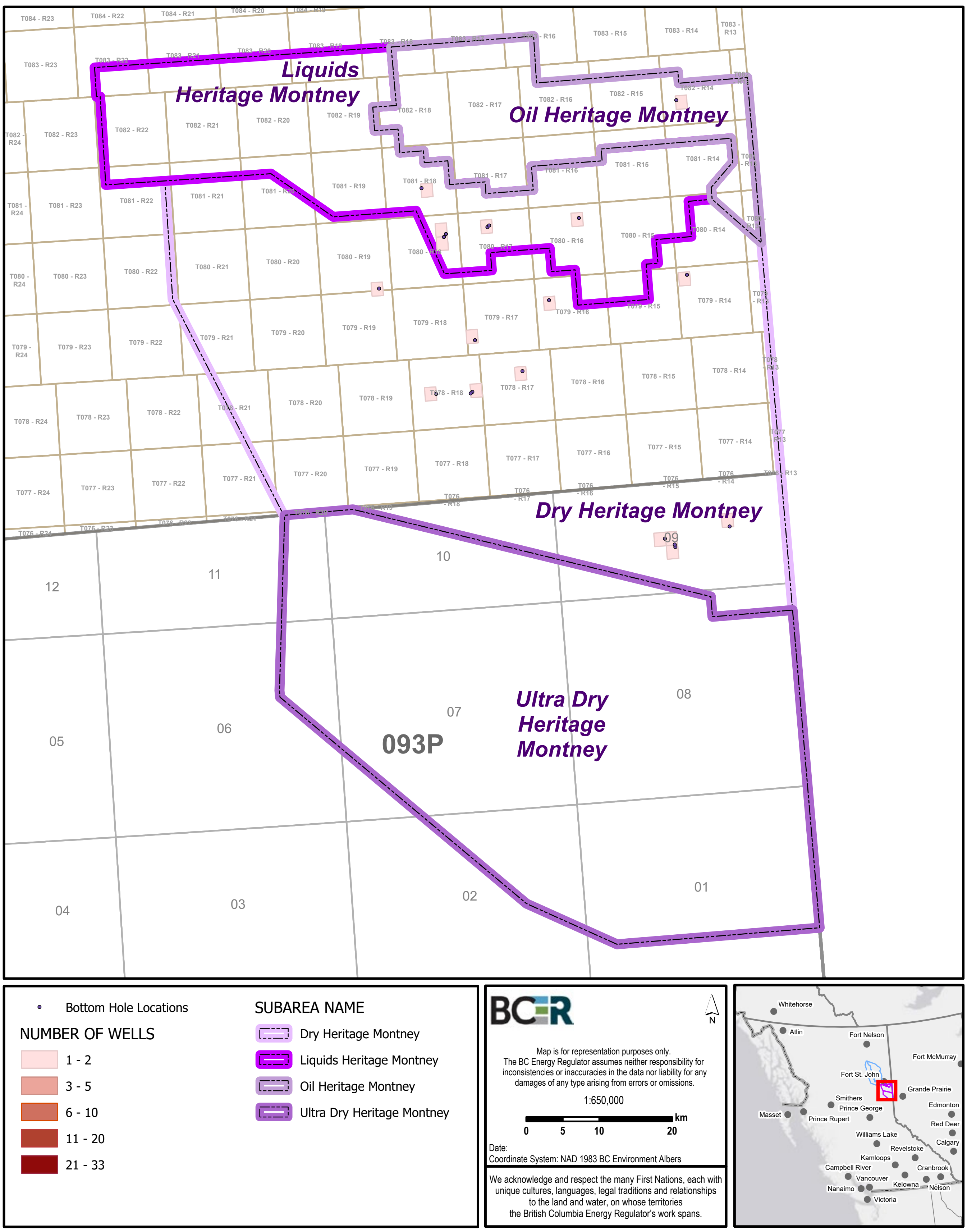
Well density is an indicator of the current phase of Montney development and the number of wells per gas spacing unit is used to determine the number of PUD locations for the estimation of recoverable reserves. For regulatory purposes, the BCER has split the Montney Regional field into the Heritage Montney A and Northern Montney A pools.

The following well density maps are for the three Montney areas. As illustrated, the variable density and coverage of wells in the areas reflects the current ability to establish proven reserves.

Note the majority of the wells in the Doig Phosphate pool have been merged into the Montney A pool resulting in changes to Montney A well density.

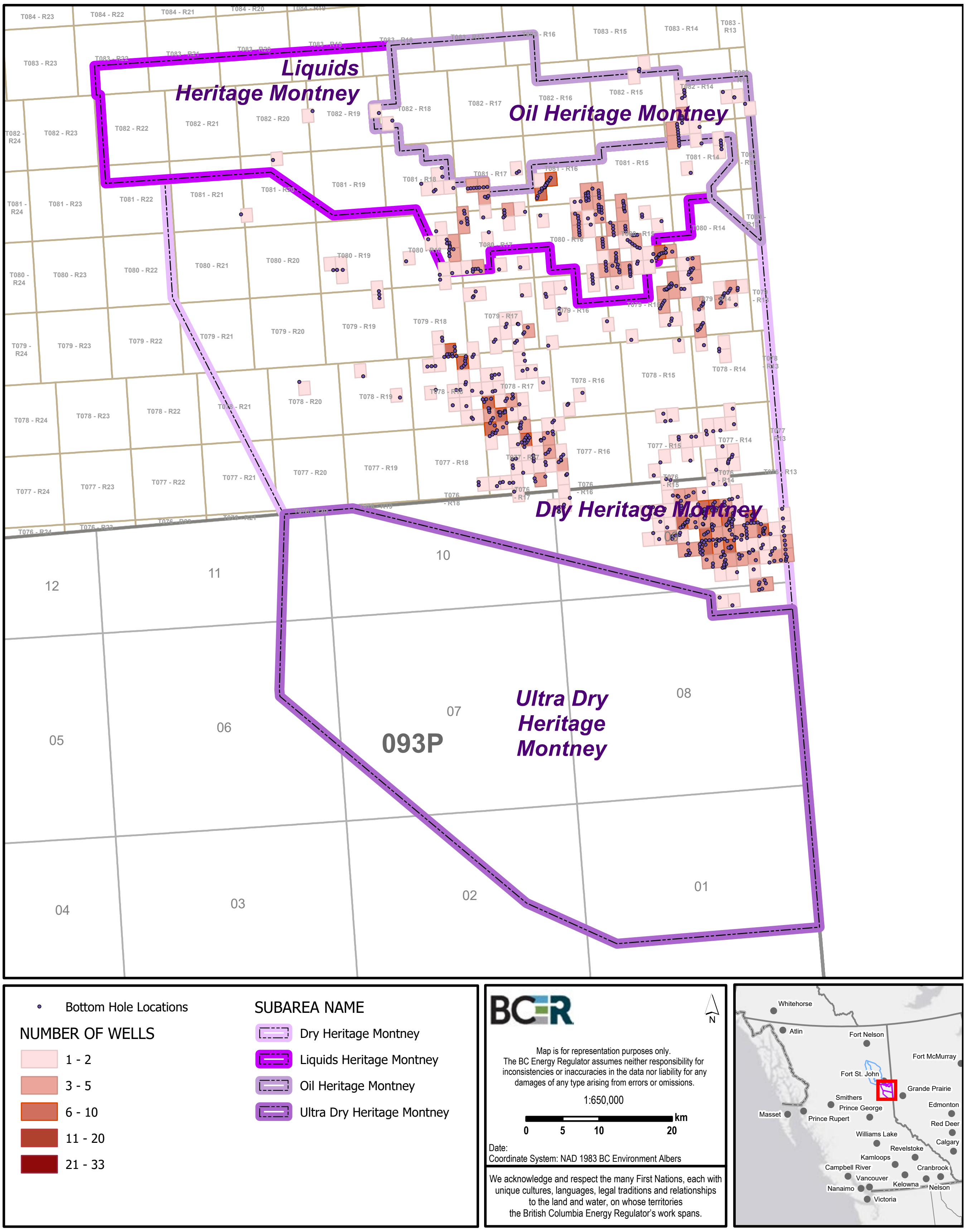
Map B-1: Heritage Montney - Montney "A" Well Density Maps

Lower Montney



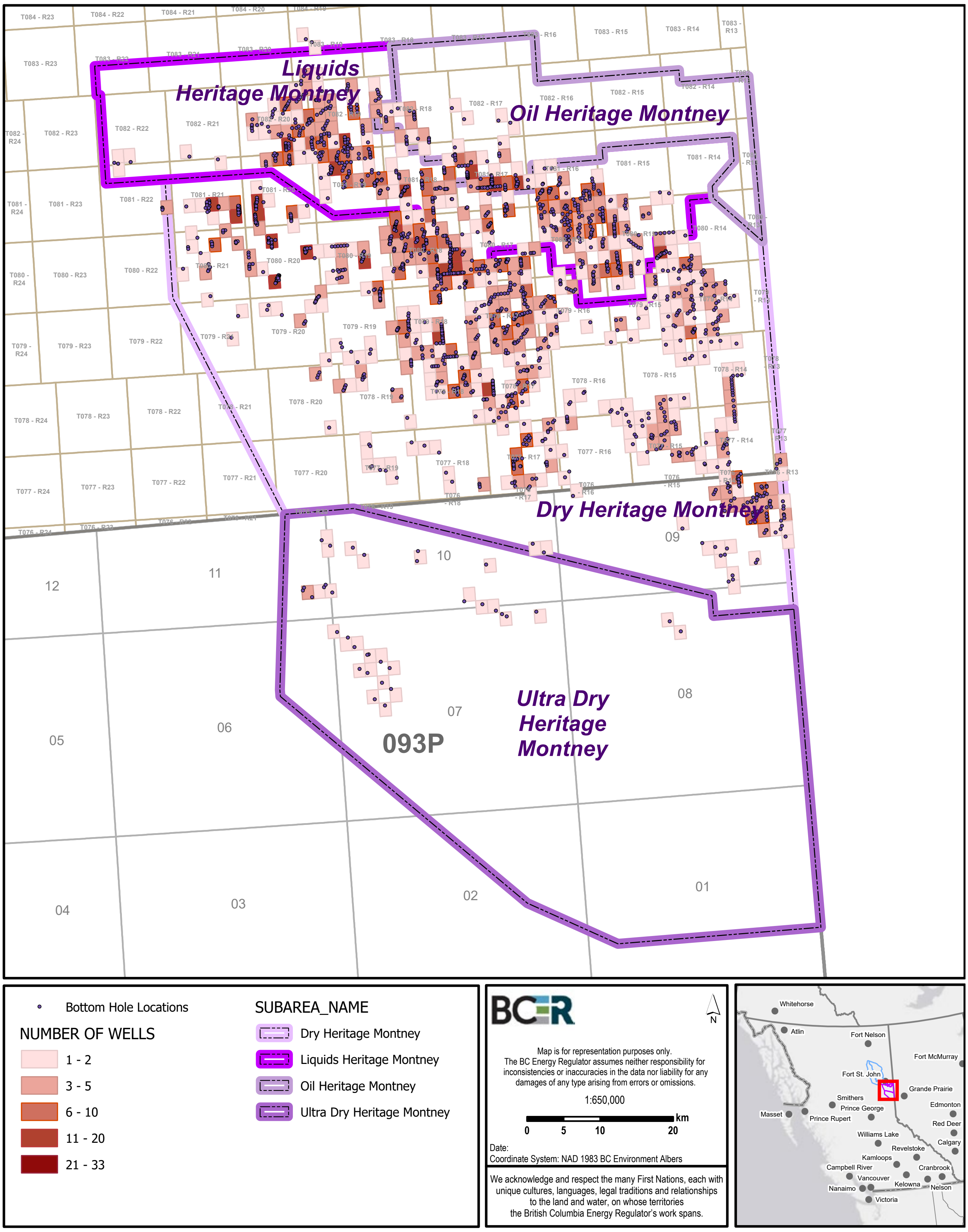
Map B-1: Heritage Montney - Montney "A" Well Density Maps

Lower Middle Montney



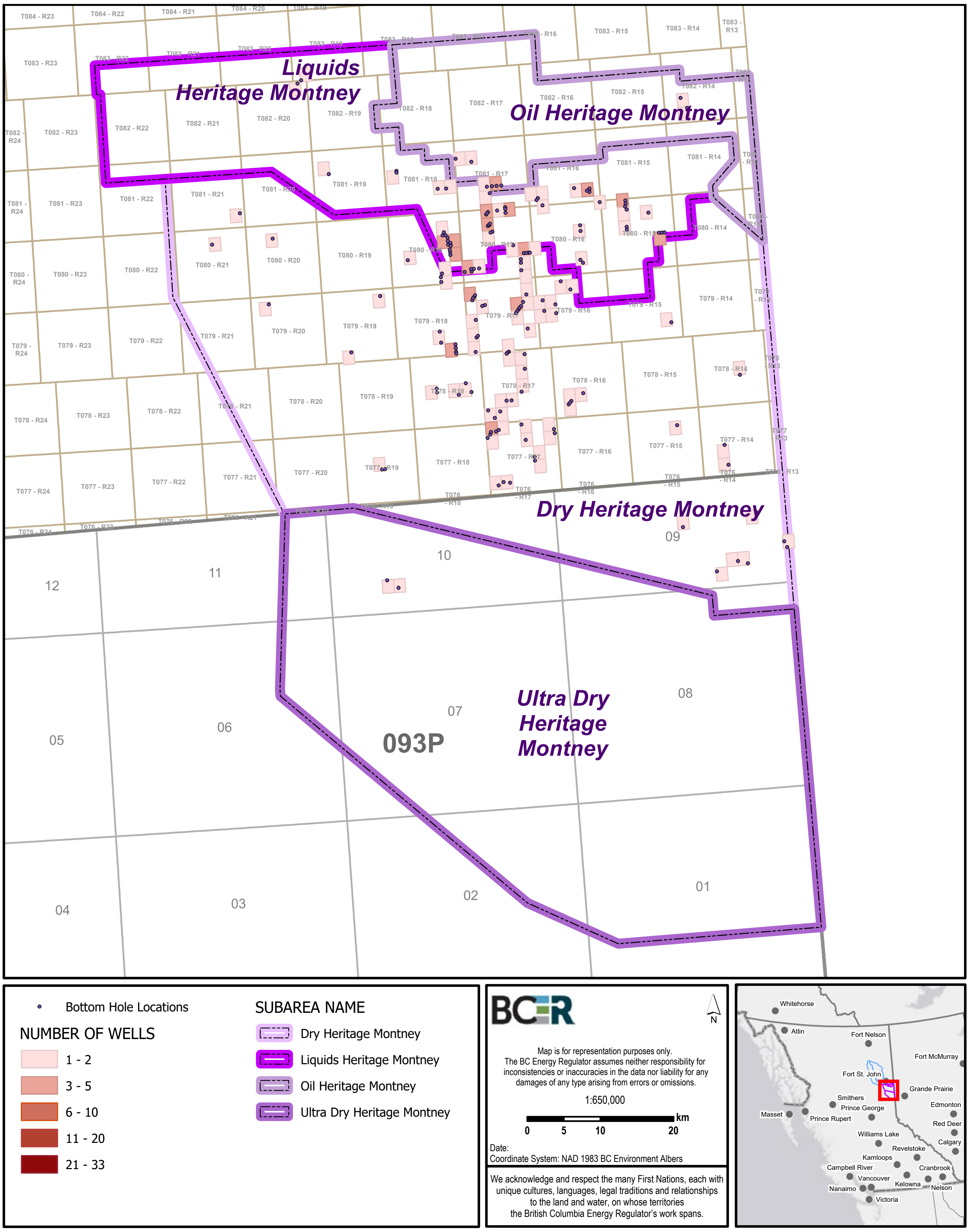
Map B-1: Heritage Montney - Montney "A" Well Density Maps

Upper Montney



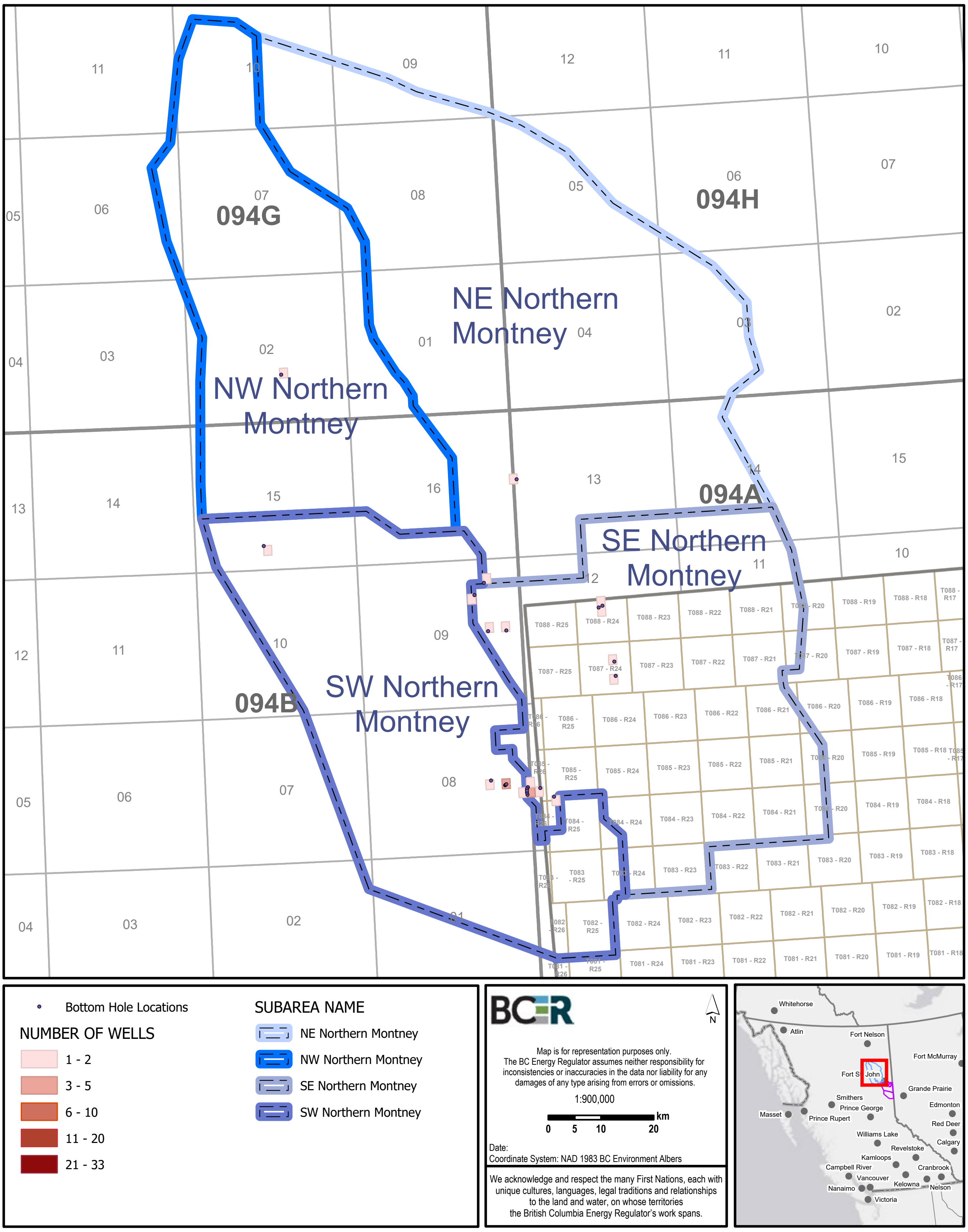
Map B-1: Heritage Montney - Montney "A" Well Density Maps

Upper Middle Montney



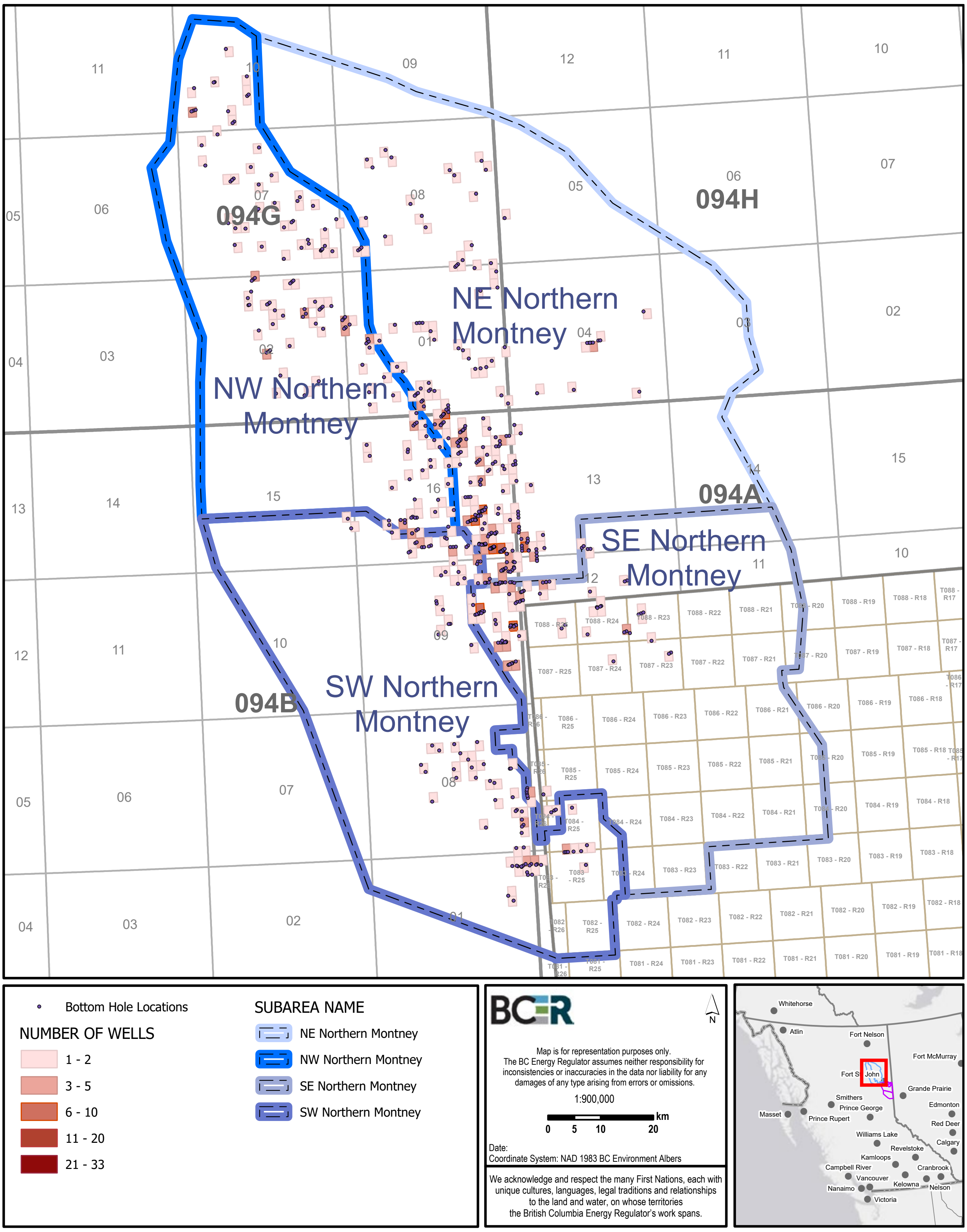
Map B-2: Northen Montney - Montney "A" Well Density Maps

Lower Montney



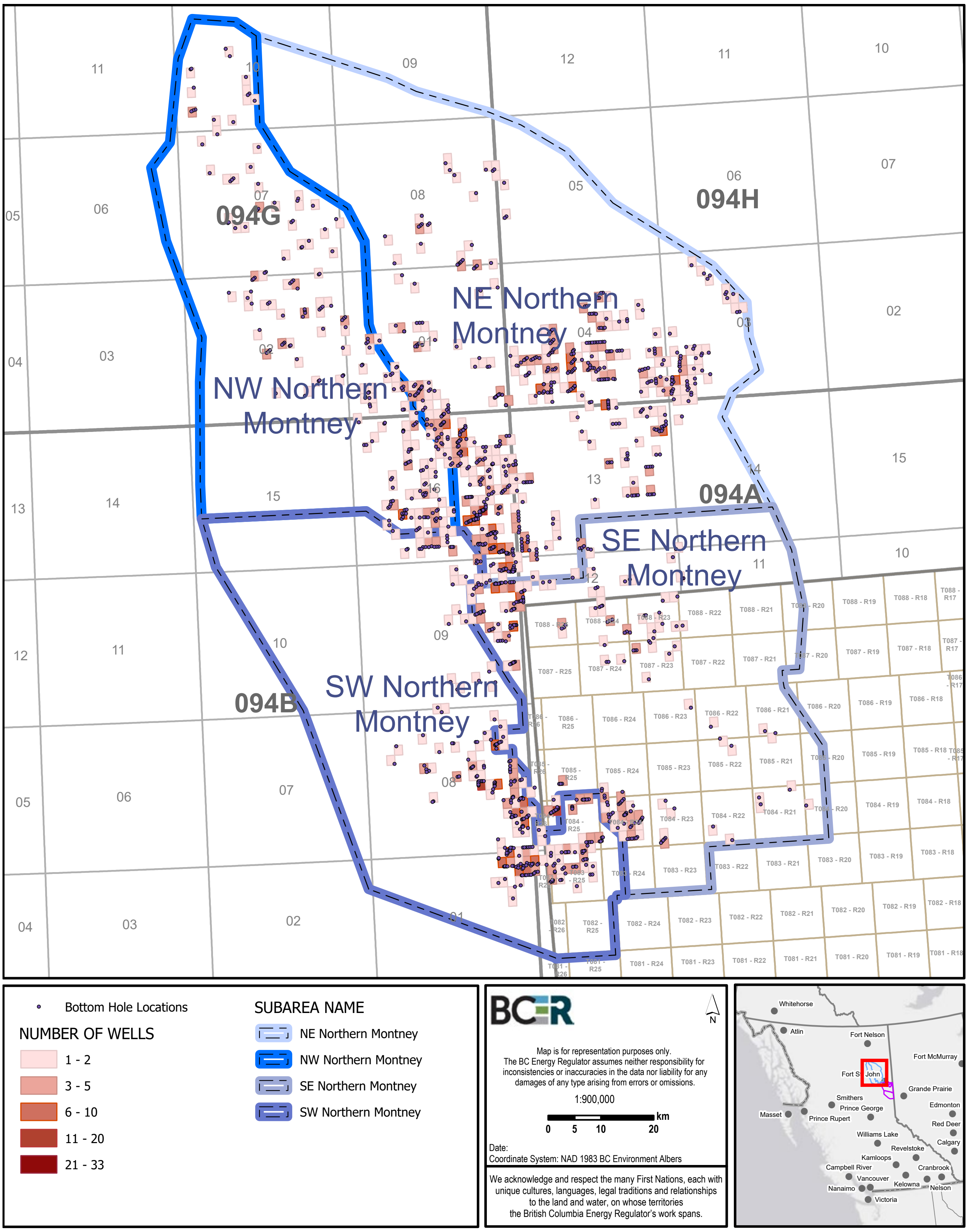
Map B-2: Northen Montney - Montney "A" Well Density Maps

Lower Middle Montney



Map B-2: Northen Montney - Montney "A" Well Density Maps

Upper Montney



Upper Middle Montney

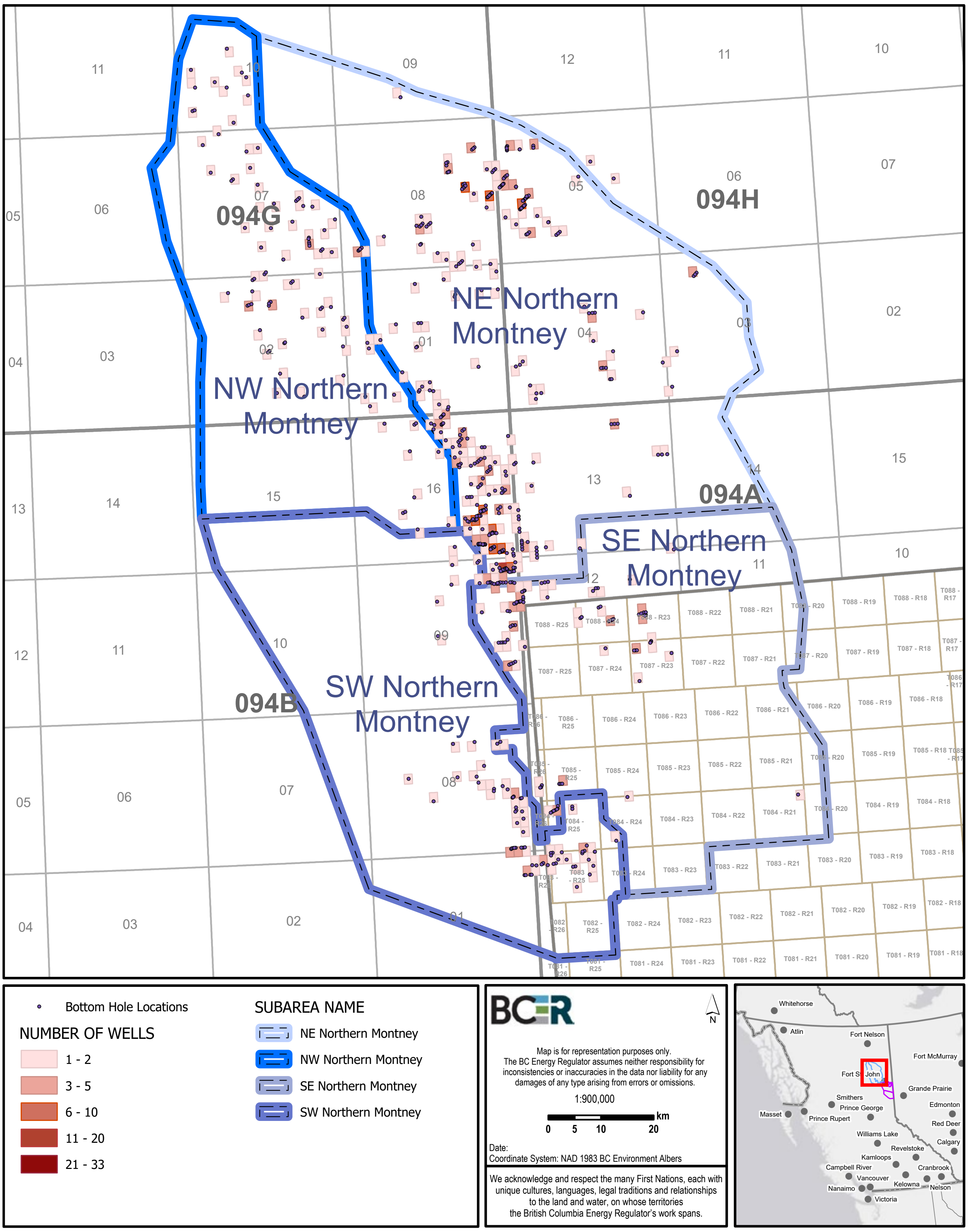


Figure B-1: Heritage Montney HZ Gas Wells EUR Distribution

RiskPearson6 (1.8005,17.563,1664901)

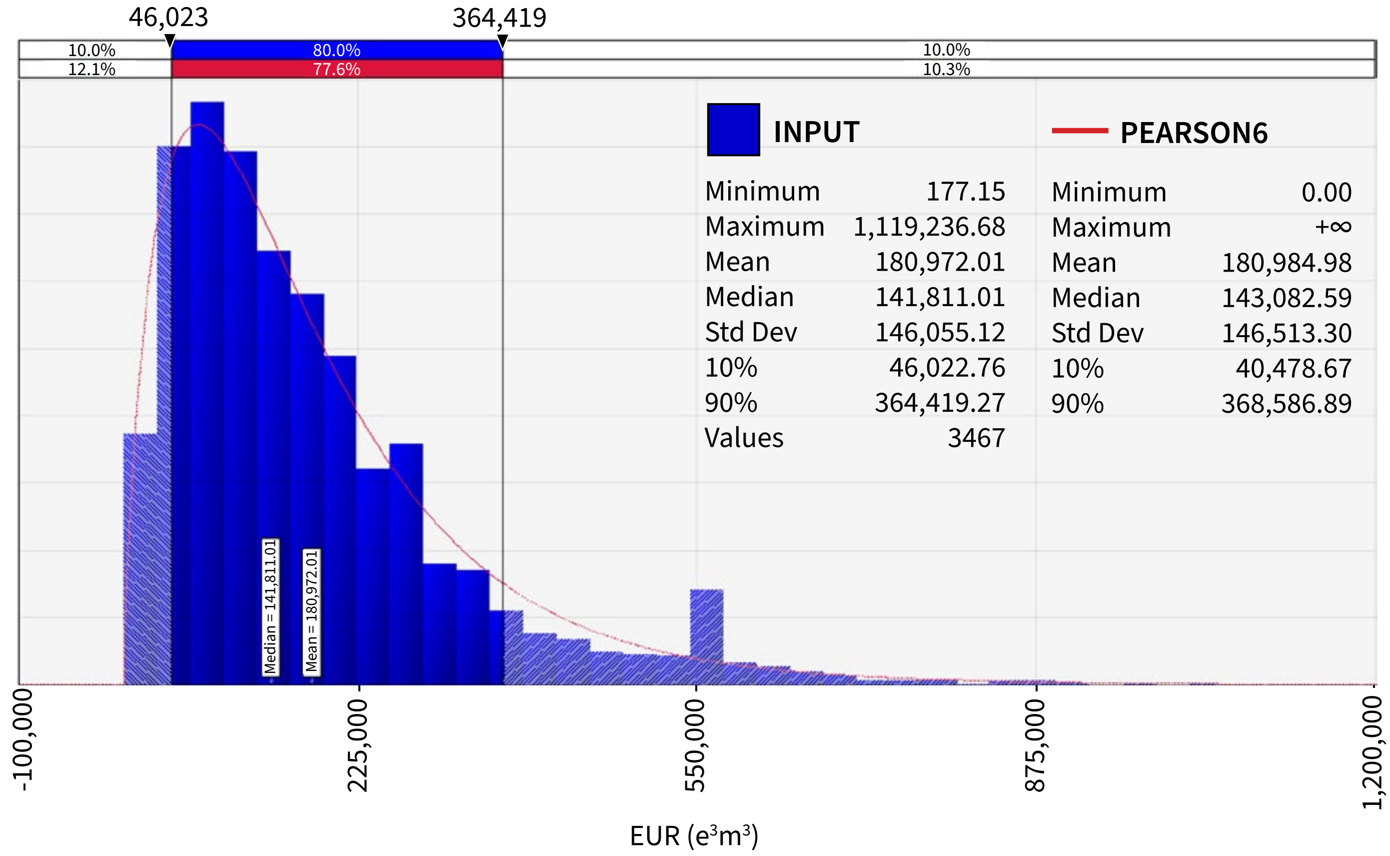
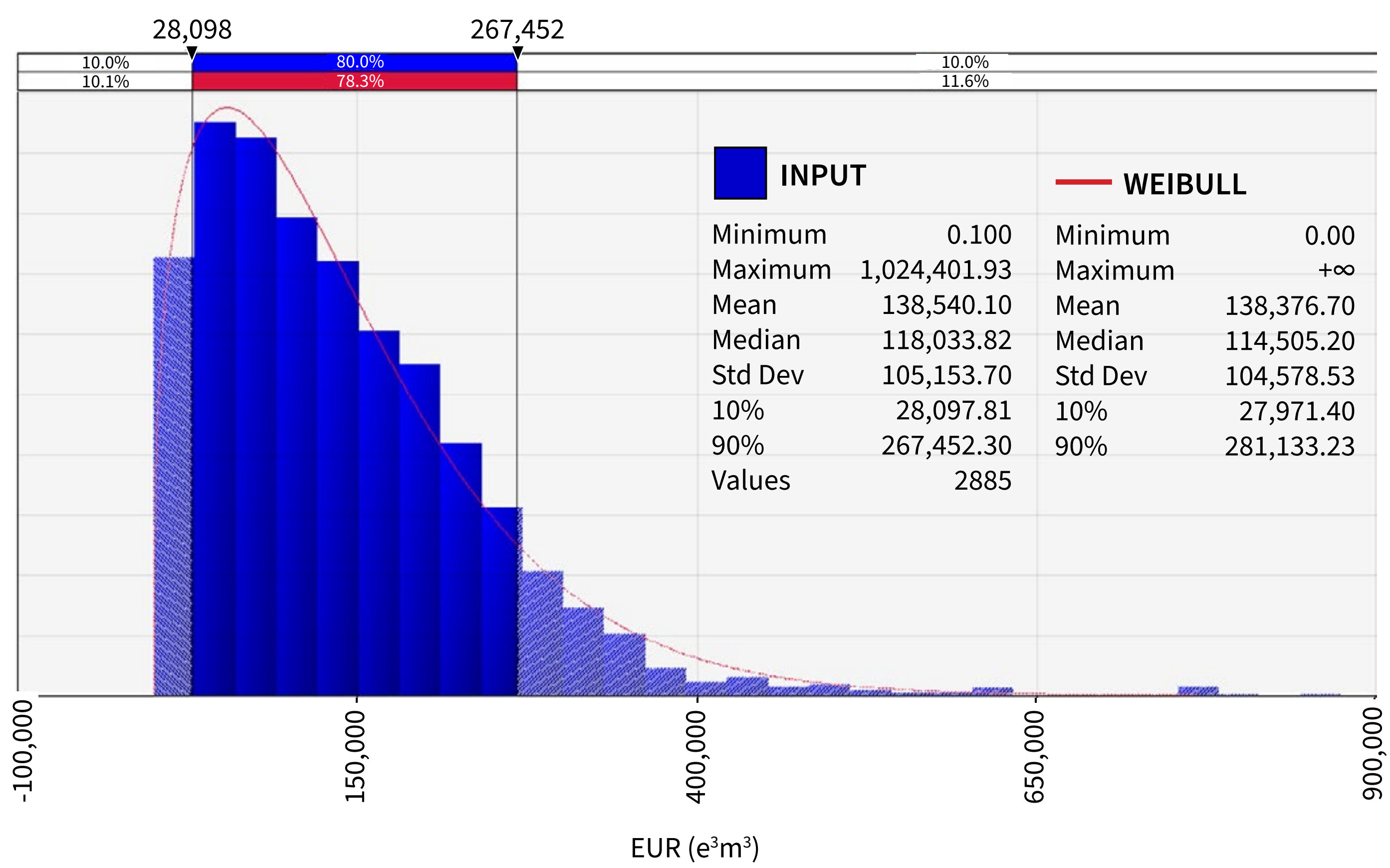


Figure B-2: Northern Montney HZ Gas Wells EUR Distribution

RiskWeibull (1.3366,150631)



Professional Authentication

Authenticating Engineer	Responsible Registrant
 Logan gray September 25, 2025	PERMIT NUMBER: 1000398 BC ENERGY REGULATOR ______________________ Date: 2025-09-25
Company: BC Energy Regulator	Company: BC Energy Regulator
Title: Reservoir Engineer	Title: Vice President, Well and Energy Resource Stewardship
Name: Logan Gray, P. Eng.	Name: Richard Slocomb, M.A.Sc., P. Eng.

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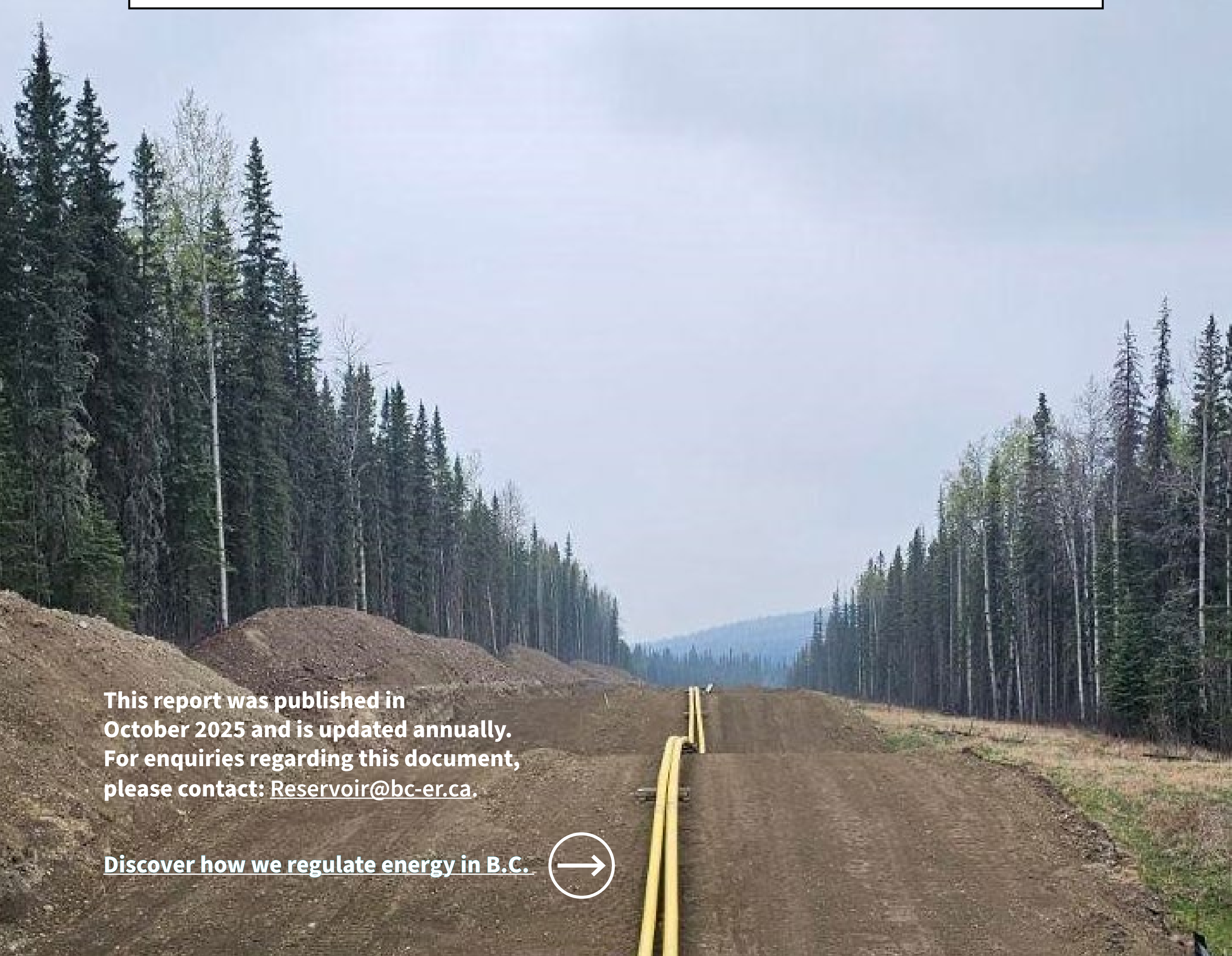

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