PetroChina Canada

2025 Performance Presentation

MacKay River Commercial Project

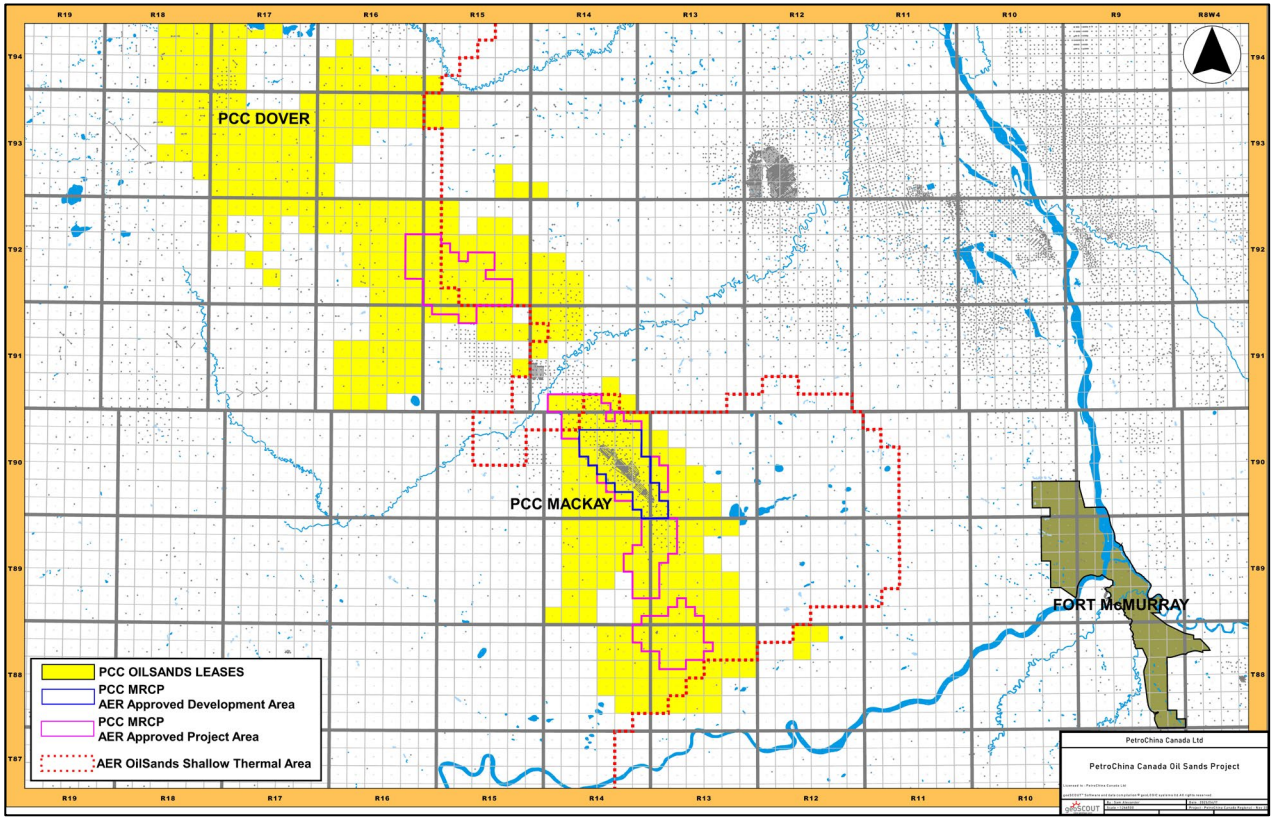
AER Scheme Approval No. 11715

January to December 2025

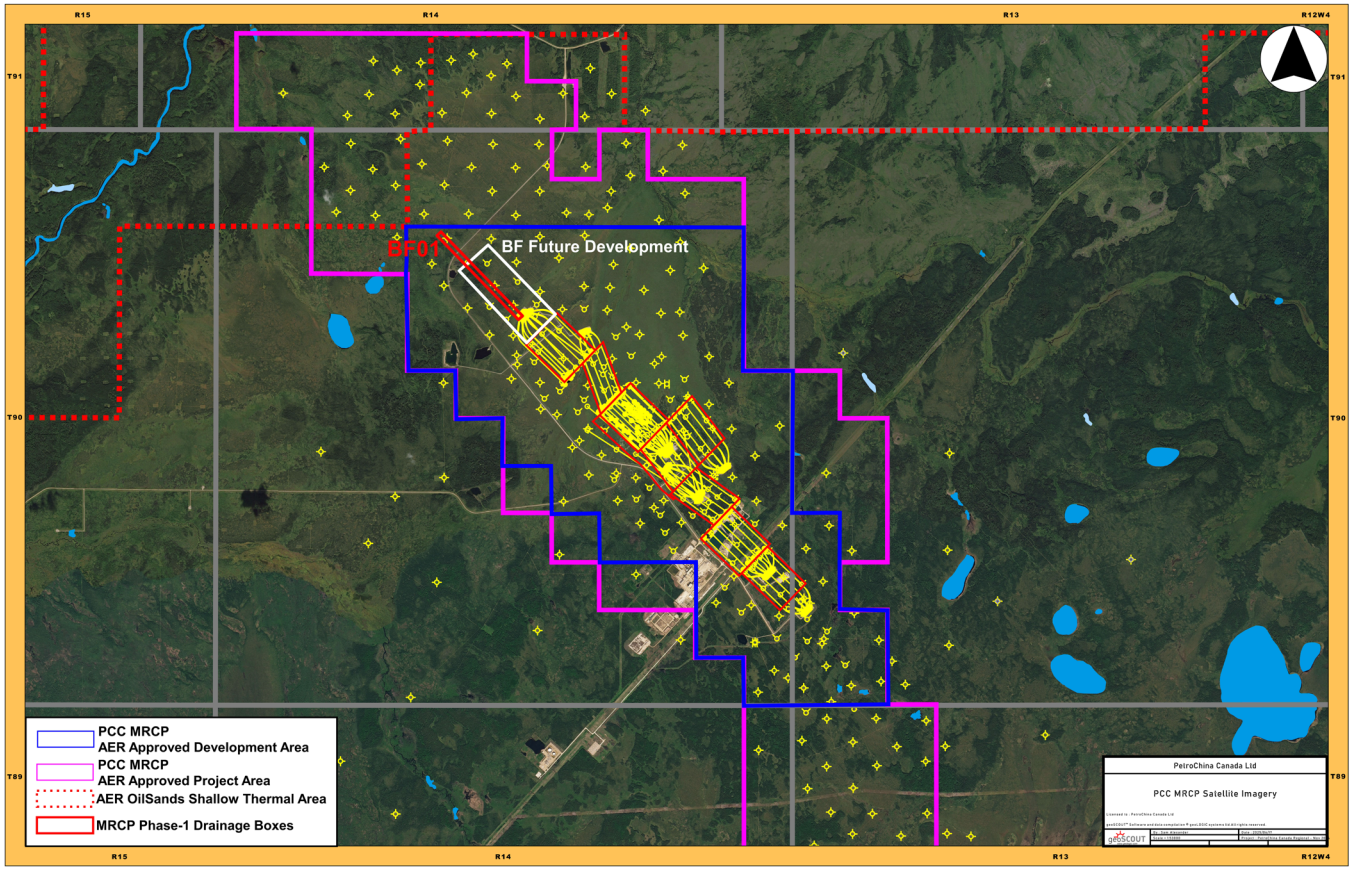
4.1 Introduction

Project Background

- PetroChina Canada (PCC) owns and operates the MacKay River Commercial Project (MRCP).
- The MRCP is a bitumen recovery project located within the Regional Municipality of Wood Buffalo in northeast Alberta; approximately 30 km northwest of Fort McMurray.
- The MRCP utilizes steam-assisted gravity drainage (SAGD) technology.
- The MRCP is planned for phased development to maximum capacity of 150,000 barrels per day (bpd) of bitumen.



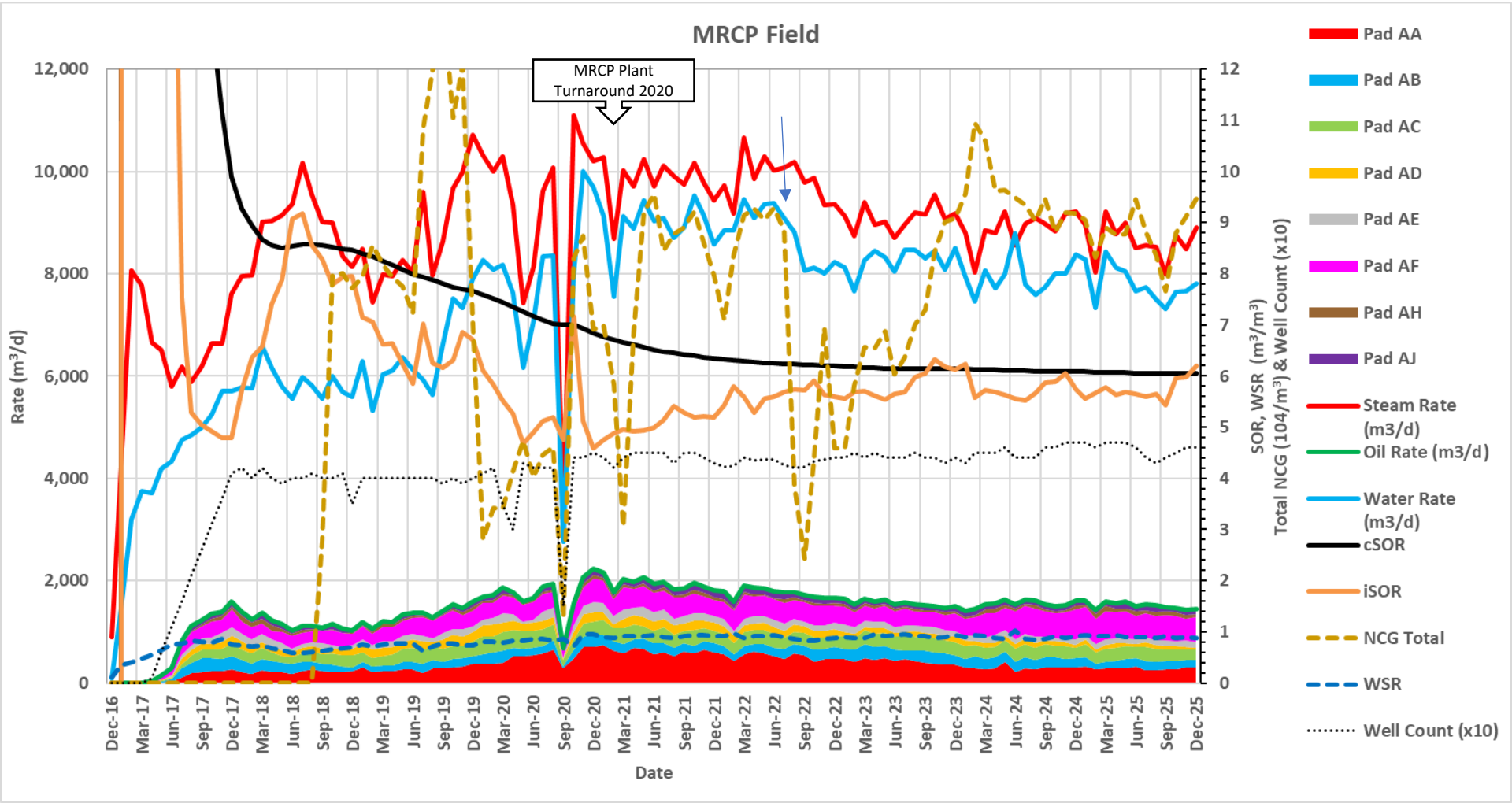
MRCP Phase 1 Overview



- Phase 1 has a bitumen capacity of 35,000 bpd.
- The Phase 1 development area (DA) includes:
  - 8 SAGD surface well pads and associated subsurface drainage patterns.
  - 42 initial SAGD Horizontal well pairs.
  - 4 Horizontal infill well pairs (PAD AA).
  - 2 horizontal infill well pair (Pad AF).
  - The Central Processing Facility (CPF).
  - Water source wells and associated pipelines.
  - Observation wells.
  - Borrow areas.
  - Access roads.
  - Camps.

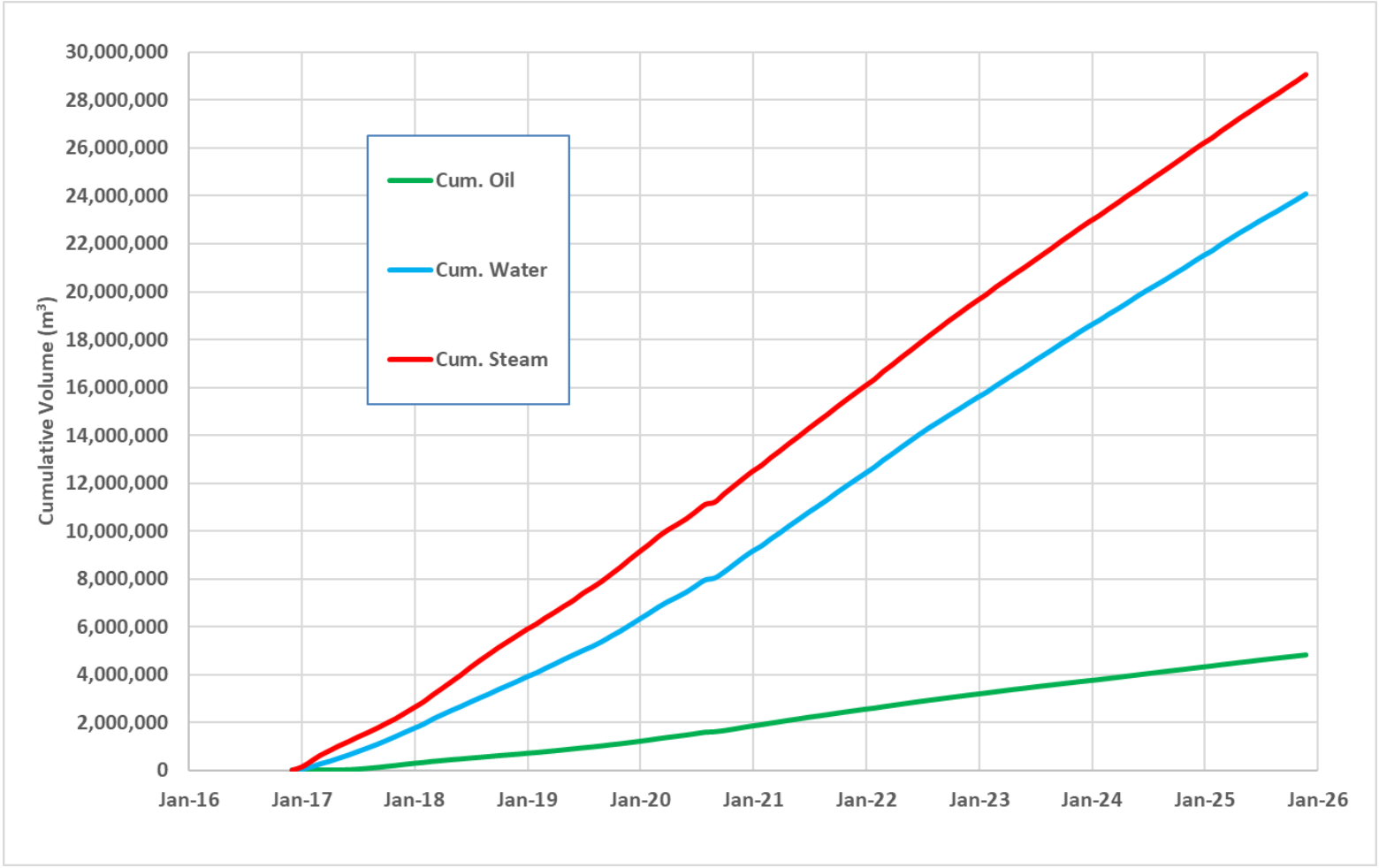
4.2 SUBSURFACE

MRCP – Field Performance



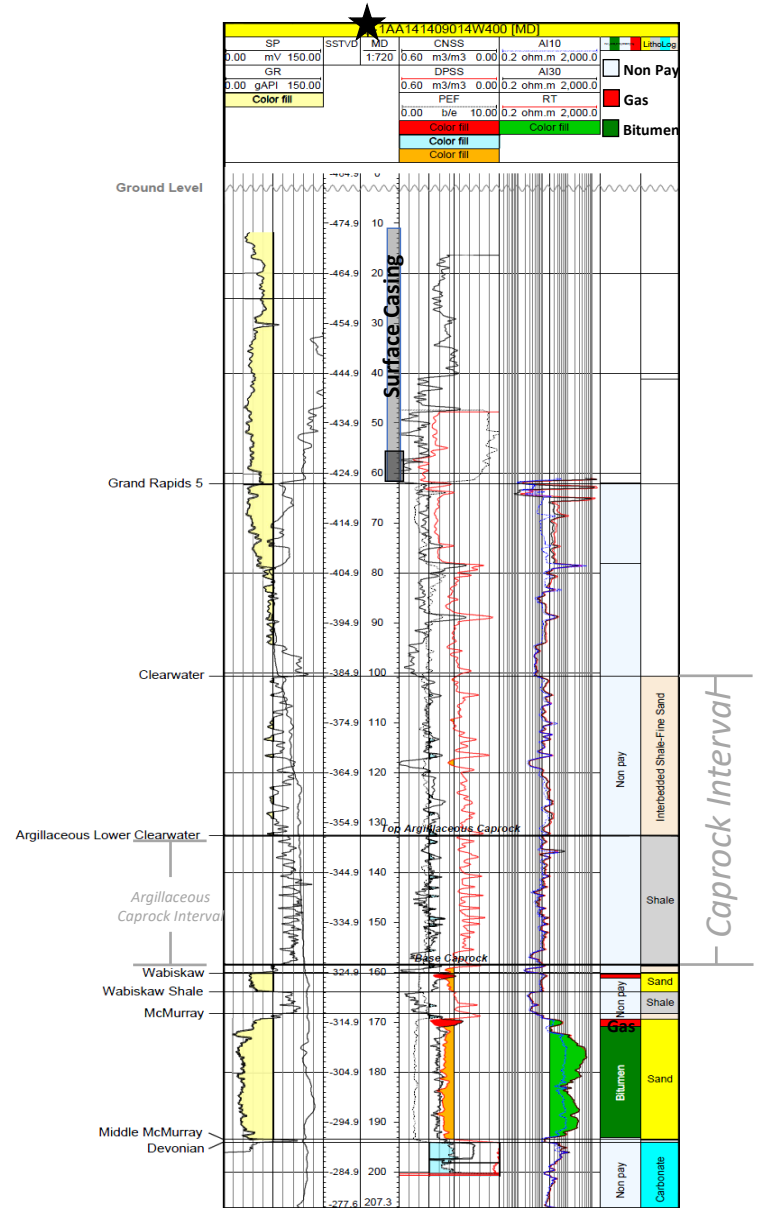
- MRCP maintained steady production throughout 2025. The average bitumen production was approximately 1,510 m^3/d (9,498 bpd). The instantaneous Steam-to-Oil Ratio (iSOR) was stable and averaged approximately 5.73 throughout the year.
- PCC is continuing with field operation optimizations.
- Non-Condensable Gas (NCG) co-injection continued at selected well pairs in 2025.

MRCP – Cumulative Fluid Volumes



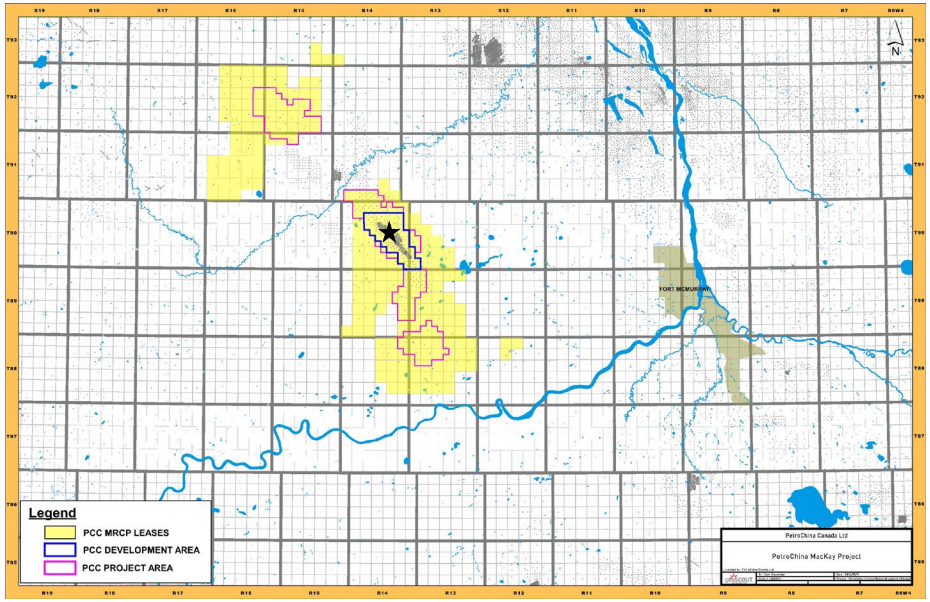
- Production performance was impacted by the presence of top gas/top lean zones, areas of thicker lower transition zones, and the presence of geological baffles (i.e., zones of higher mud bed frequency) affecting steam chamber growth.
  - Steam chamber interactions with top gas and losses to the lower transition zone in certain areas have resulted in higher water retention by the reservoir.
  - Mitigations implemented includes gas cap pressurization (e.g., NCG injection and co-injection) and balancing operating pressures with multiple thief zones. These strategies have helped to reduce water retention and steam losses.

MacKay River Stratigraphy

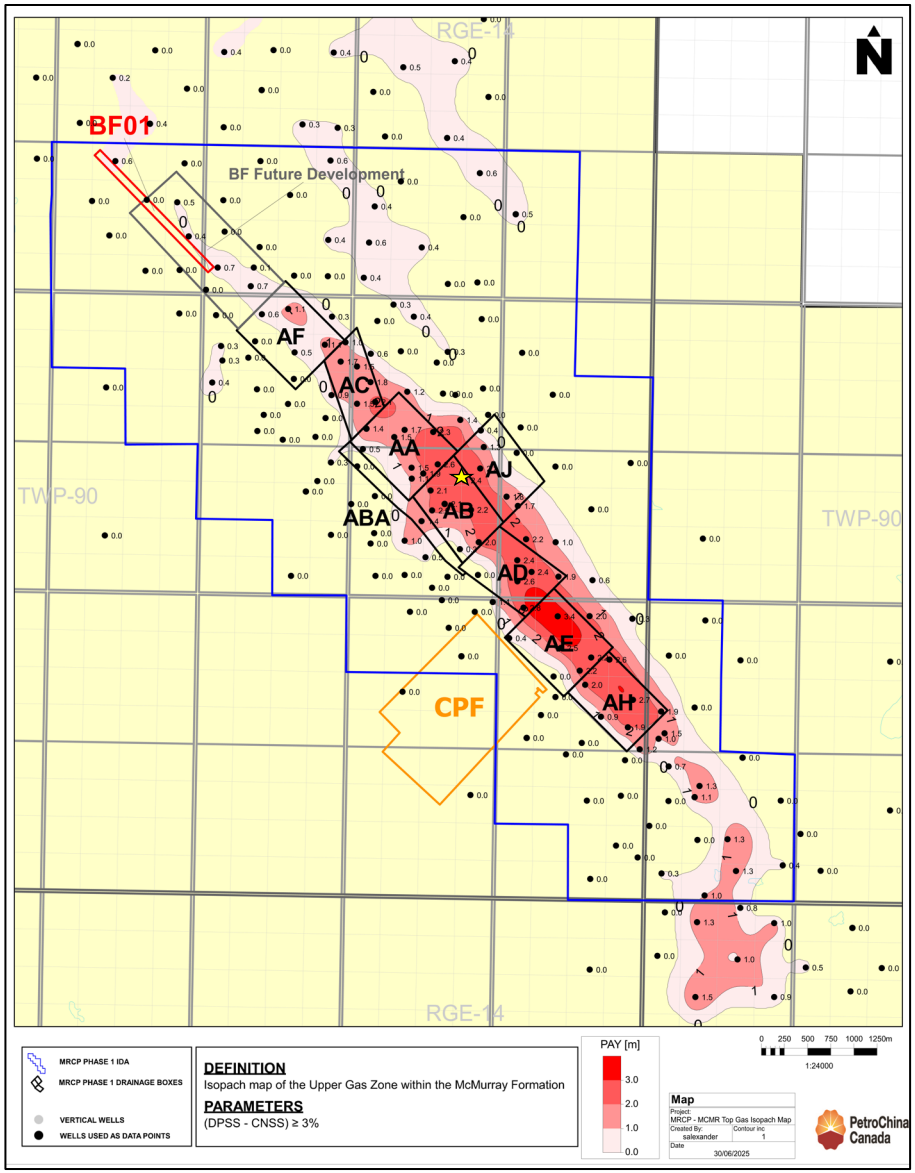


Within the Development Area (DA):

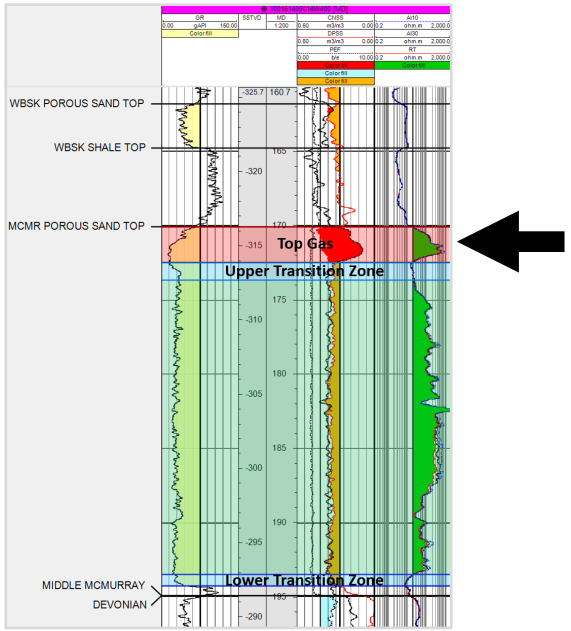
- The McMurray Formation directly overlies the Sub-cretaceous Unconformity.
- Wabiskaw Member shale and sand followed Upper McMurray Formation Deposits.
- Clearwater Formation deposits overlie the Wabiskaw Member.
- Grand Rapids Formation overlies Clearwater Formation shale and heterolithics.
- Quaternary deposits ultimately overlies the Grand Rapids deposits.



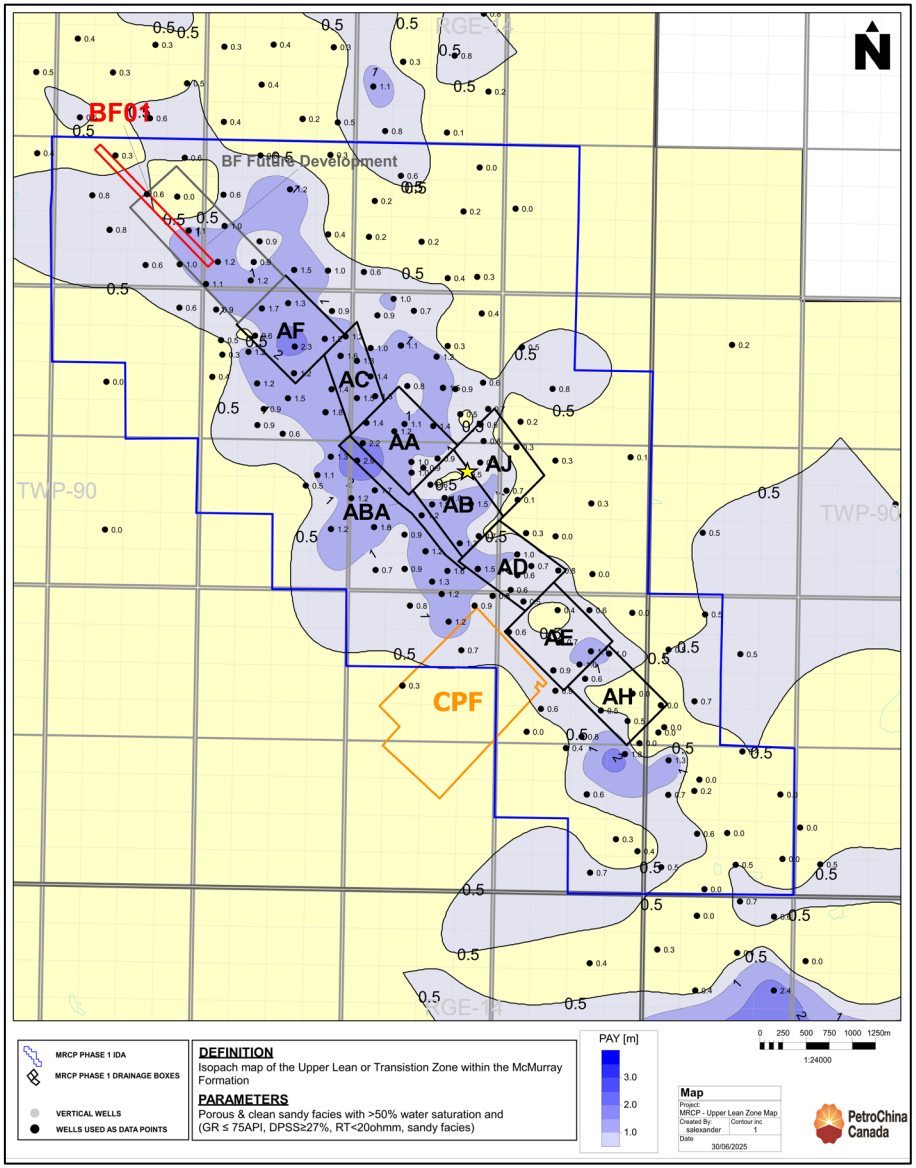
MCMR Top Gas Isopach Map



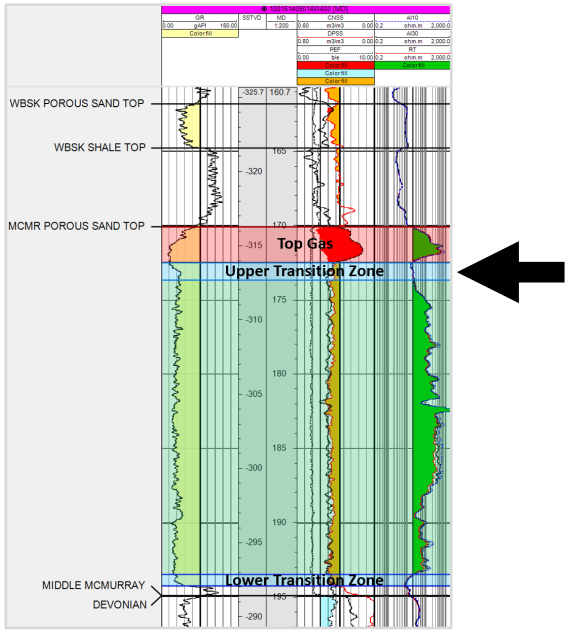
- Top gas zone present in the upper McMurray Formation over the DA.
- Ranges in thickness from approximately 0 to 3 m.



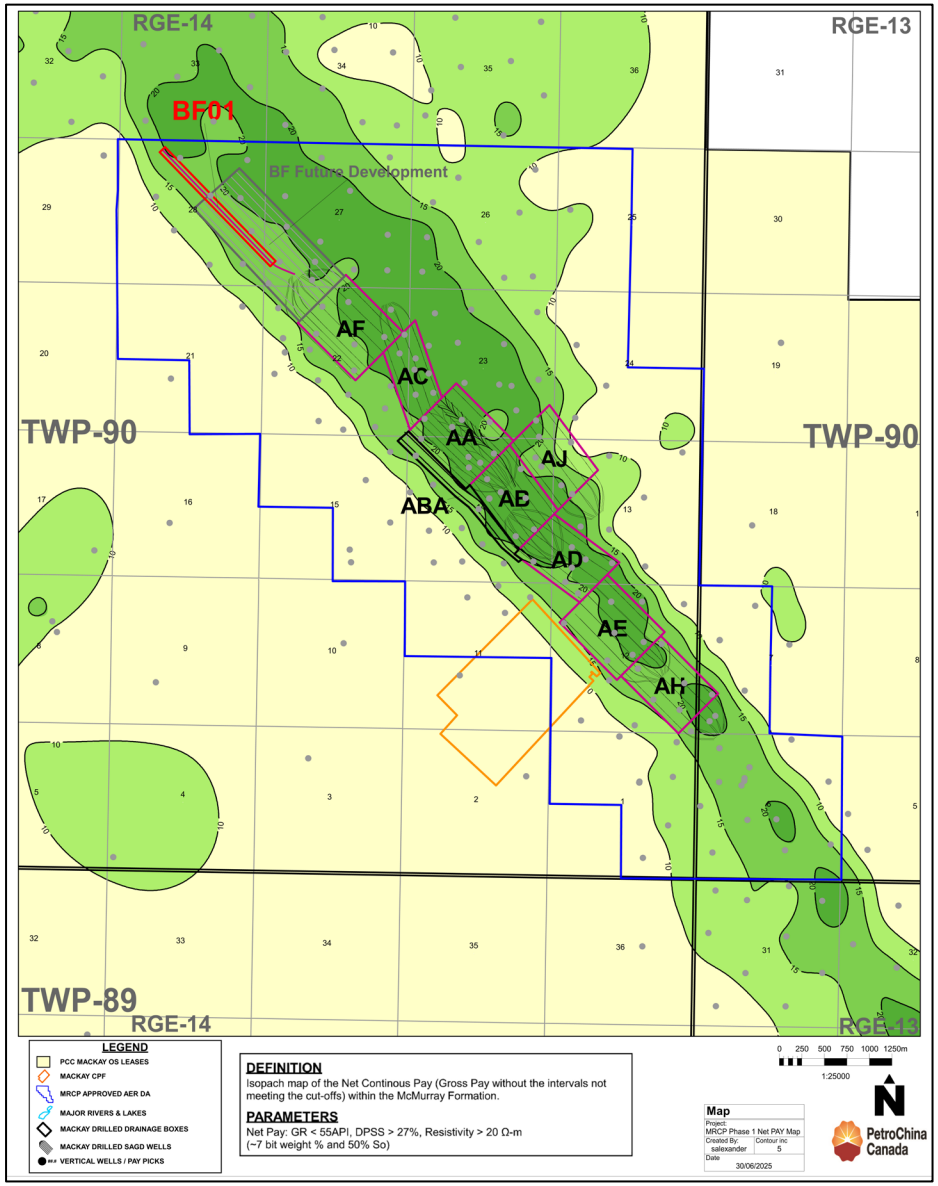
Upper Transition Zone Map



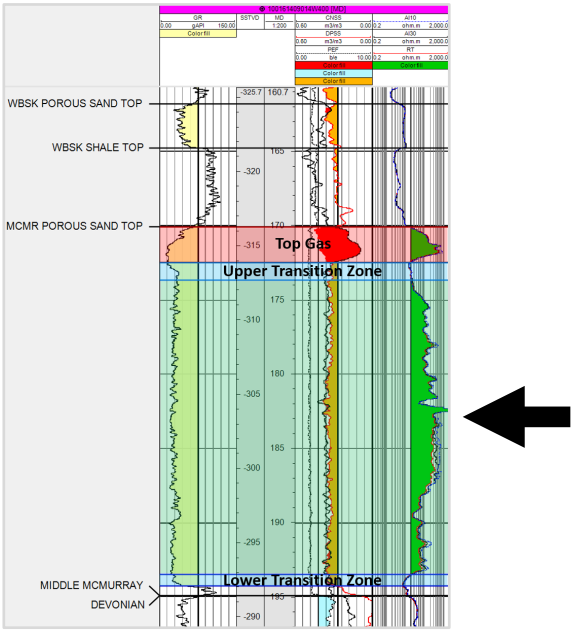
- Criteria:
  - Porous and clean sandy facies with greater than 50% water saturation (GR ≤ 75API, DPSS≥27%, RT<20ohmm, sandy facies).
  - In communication with the pay zone.
- Characteristics:
  - < 1.5m over most of the Phase 1 drainage boxes.
  - Limited Lateral Extent.



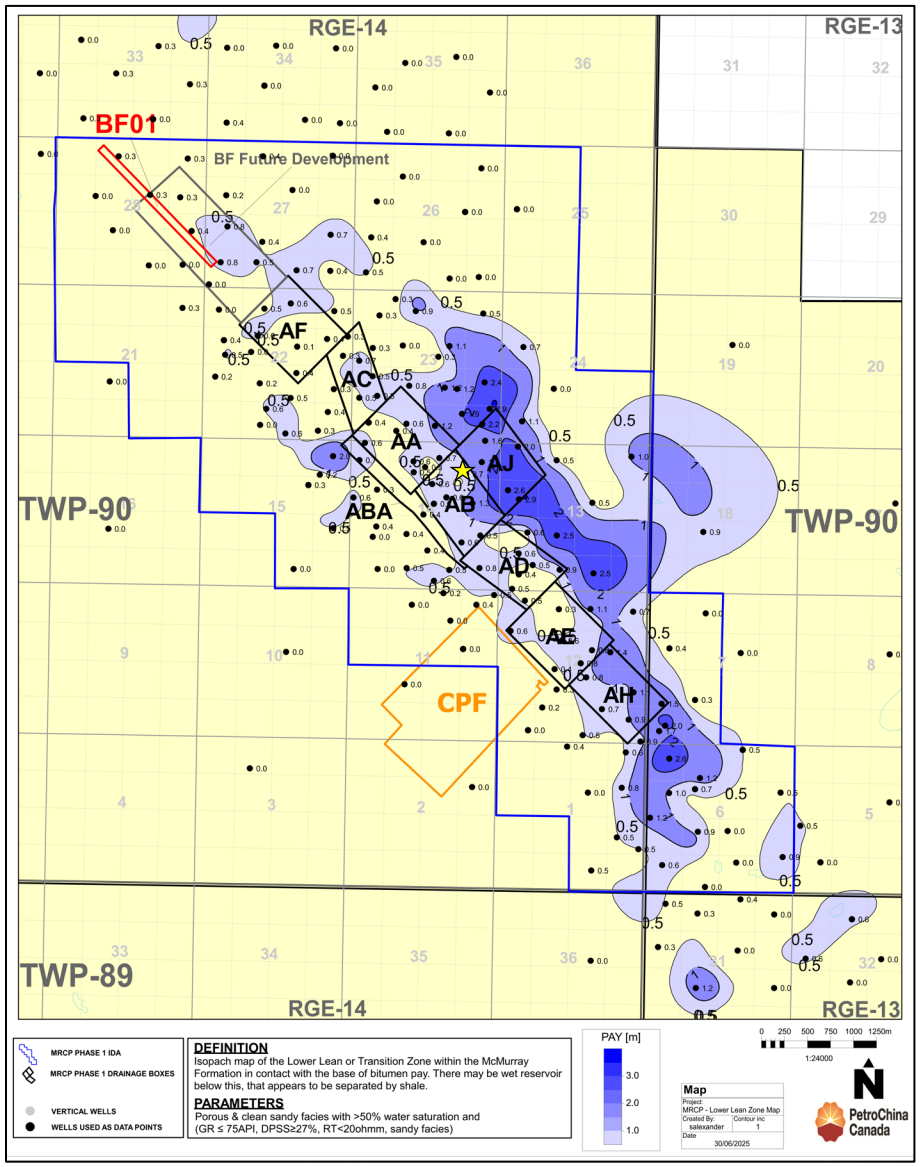
Bitumen Net Pay Map – Development Area



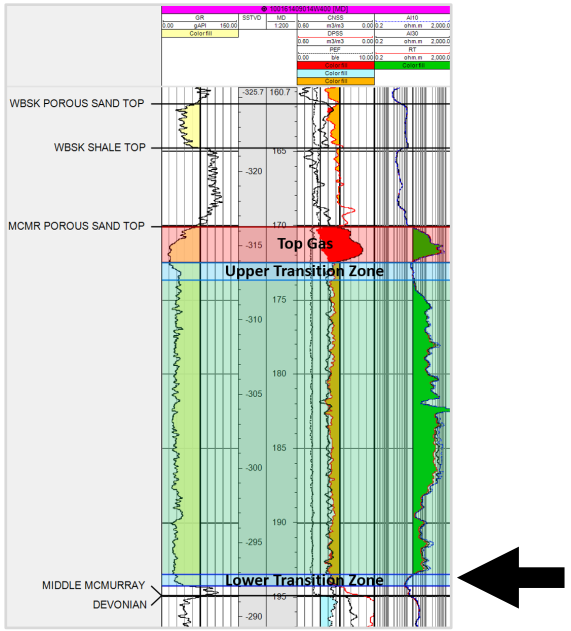
- Net pay cut-off at ≥10m.
- Thickness ranges from 10 to 25m in the DA.
- Upper McMurray Formation reservoir shows strong NW to SE trend.
- The central processing facility located Southwest of development area.
- Majority of 8 drainage boxes are >15m bitumen pay.



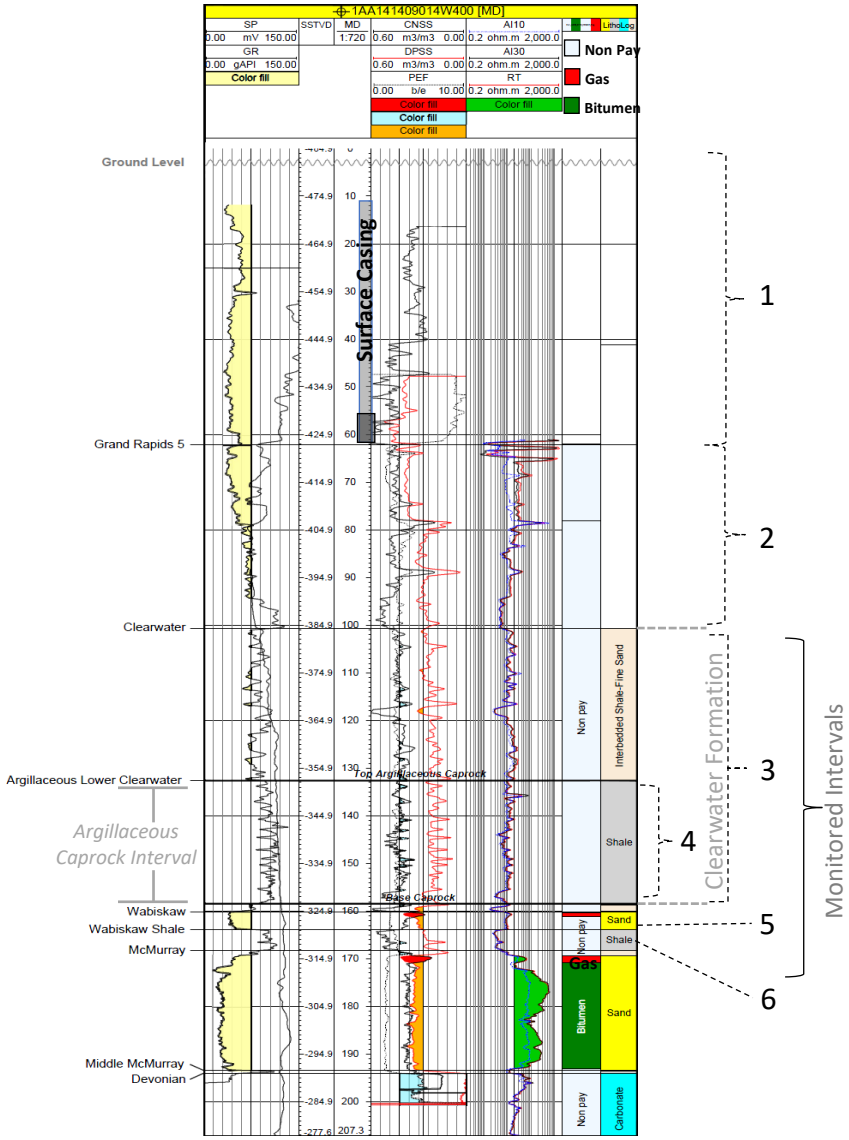
Lower Transition Zone Map



- Criteria:
  - Porous and clean sandy facies with >50% water saturation (GR ≤ 75API, DPSS≥27%, RT<20ohmm, sandy facies).
  - In communication with the pay zone.
- Characteristics:
  - <1.0m over most of the Phase 1 drainage boxes.
  - Limited Lateral Extent.



Caprock Monitoring: Overburden & Cap Rock Intervals

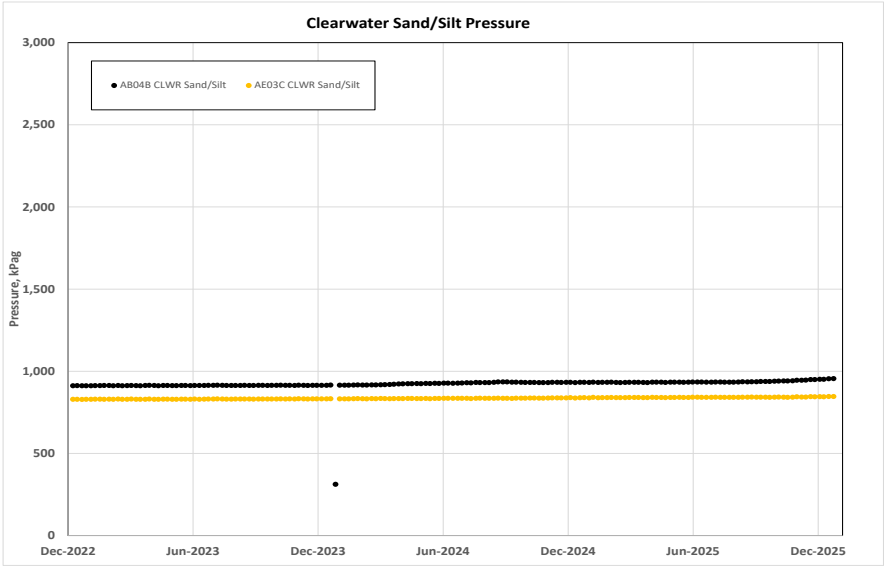


Overburden intervals:

1. Quaternary Sediments: surface to the Grand Rapids.
2. Grand Rapids, overlies Clearwater Formation.
3. Clearwater Formation, which is the gross caprock.
4. Argillaceous interval of Clearwater Formation is the primary caprock for present across the MRCP DA, it is a thick (greater than 21 m), and laterally continuous, consistent, clay-rich caprock, and is free of influence of any vertical pore pressure transmission pathways.
    - Some instrumentation is set outside the casing of observation wells to monitor the sandier Clearwater Formation intervals above the Argillageous caprock.
5. Wabiskaw Formation sand is the first known horizontal pathway on top of the reservoir. It is the main target for reservoir containment assurance and/or caprock integrity monitoring, as it acts as an early warning for pressure build-up.
6. Wabiskaw Formation shale lies above the McMurray Formation reservoir and is the lower-most interval included within the overburden monitoring strategy.
7. No geomechanical anomalies identified in the overburden

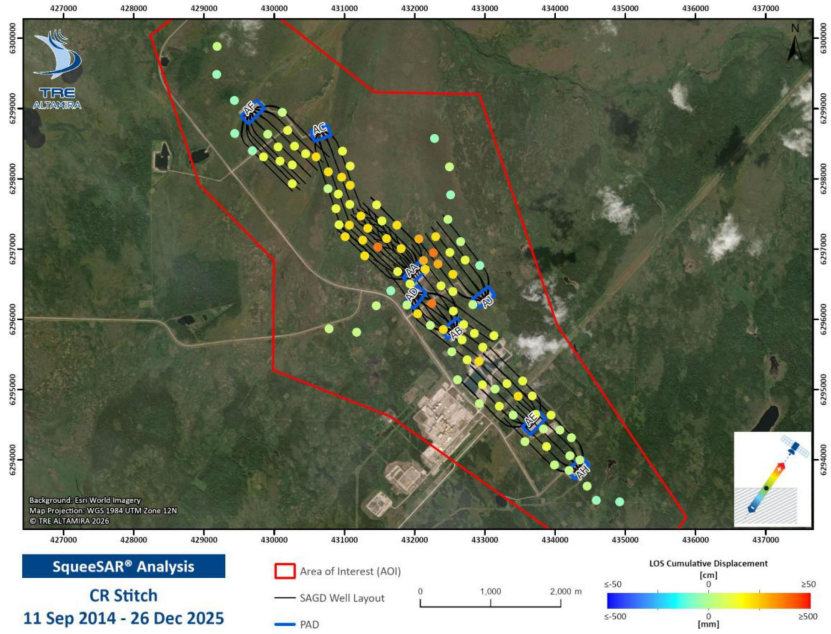
Caprock & Surface: Clearwater and Heave Monitoring

- Overburden surveillance above MRCP caprock (Clearwater Argillageous)
  - Clearwater sand/silt is above the MRCP caprock.
  - Pressure range in 2025: 847 to 956 kPag (initial range: 829 to 907 kPag), Remains at virgin conditions, as expected.
  - **Temperature: range 4 to 5 ℃ (initial range: 4 to 5 ℃).**
  - Pressure and temperature expected to remain steady as this interval is immediately above the caprock.

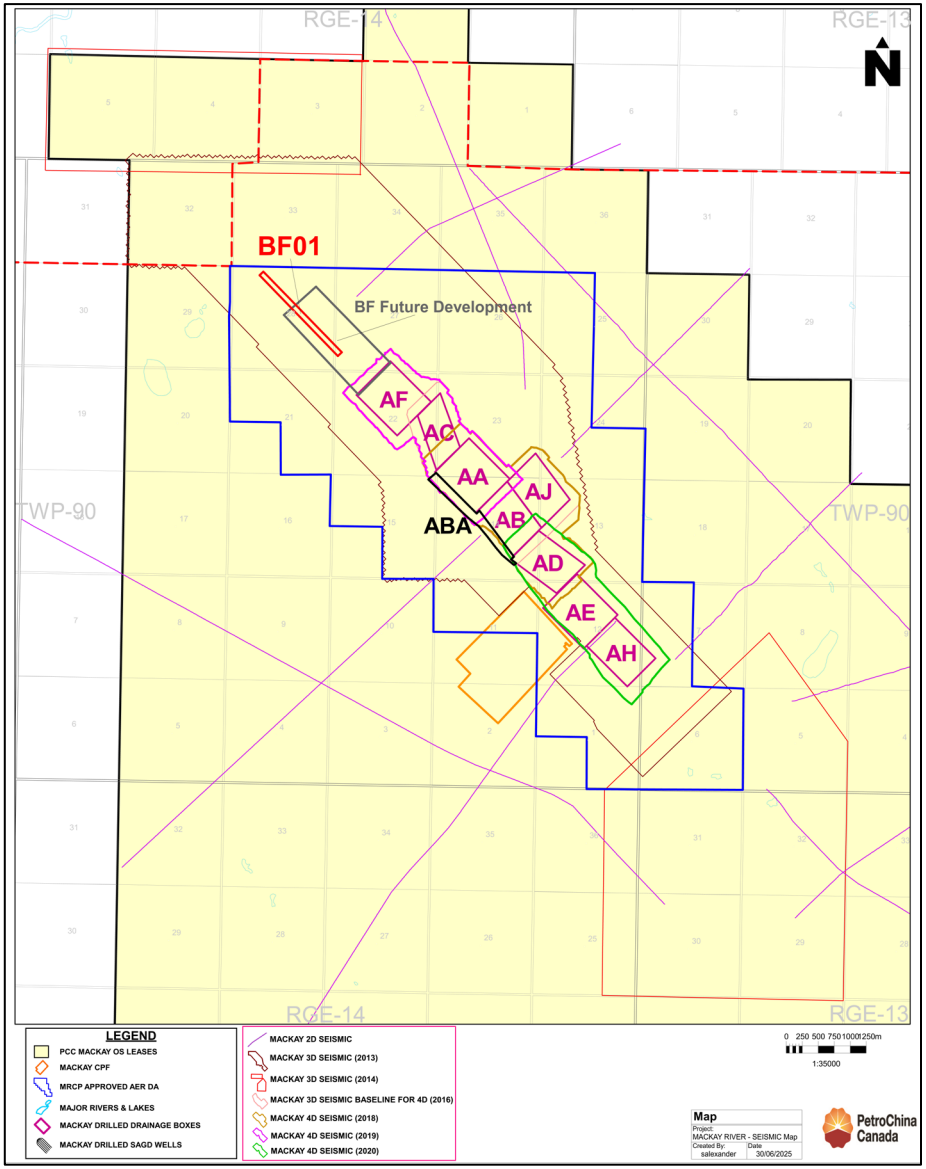


- Surface Displacement Monitoring
  - PCC implemented ground displacement monitoring using 104 corner reflectors (CR) over MRCP using Synthetic-aperture Radar Interferometry (InSAR) technology.
  - Cumulative heave up to 45.9 cm has been recorded in MRCP pads (MAX at pad AJ).
  - PCC also monitors natural reflectors (NR) displacement for snow-free periods of each year. Heave was the dominant ground displacement effect registered in 2025 with NR. However, NR data can't be used to record trends.
  - Estimated cumulative displacement per pad, Sep 2014 to Dec 2025 is shown in the adjacent table.
  - The displacement measured at each CR for the period Jan to Dec 2025 is shown on the adjacent map.

Pad	Cumulative Heave 2014-2025	
	Ave Heave (cm)	Max Heave (cm)
AA	24.8	44.5
AB	23.8	43
AC	15.7	26
AD	16.3	22.7
AE	14.6	27.2
AF	17	23.7
AH	9.3	16
AJ	20.4	45.9



MRCP Seismic



Coverage Across MRCP includes (approximate):

- 96 km of 2D.
- 58.4 km^2 of 3D.
- 3.9 km^2 of 3D baseline for 4D.
- 3.5 km^2 of 4D in 2018 – Interpreted.
- 3.0 km^2 of 4D in 2019 – Interpreted.
- 2.9 km^2 of 4D in 2020 – Interpreted.

3D acquired in MRCP to help:

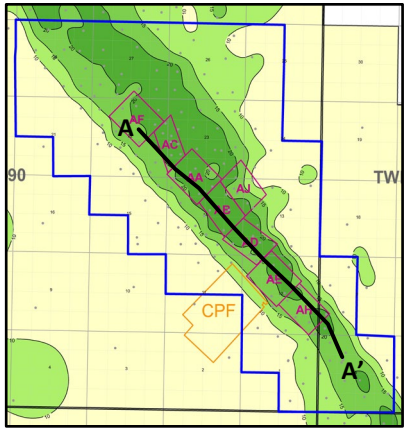
- Assess Caprock.
- Plan/drill horizontal well trajectories.
- Assess McMurray reservoir.

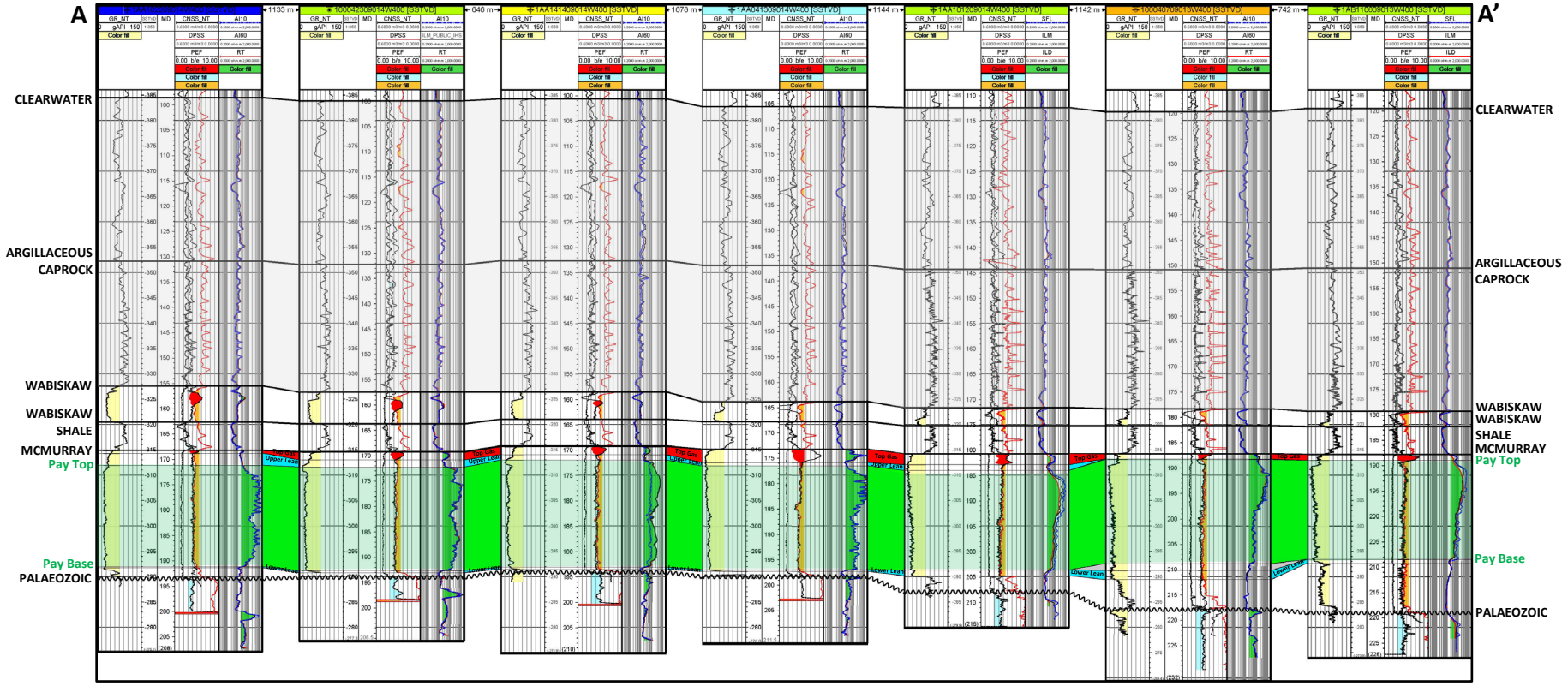
4D seismic surveys acquired at MRCP in 2018, 2019, and 2020

- Used to monitor steam chamber growth.
- 2018: Pads AA, AB, AJ, AD.
- 2019: Pads AF, AC, AA.
- 2020: Pads AD, AE, AH.

Structural Cross-Section across MRCP

- Good reservoir quality with continuity across the DA.
- Minor structural variation at base of pay.
- Thick and laterally continuous caprock with consistent lithology.





Geologic and Reservoir Properties – OBIP For Operating Areas

Drainage Box	# Well Pairs	Drainage Box Area	Average	Average	Average	Average	Average Bitumen Pay Thickness	Drainage Box OBIP (10^6 bbl)	Estimated RF	Estimated Drainage Box RBIP
		(m^2)	S_o	Φ	K_h	K_v	(m)		(%)*	(10^6 bbl)*
			(frac)	(frac)	(D)	(D)				
AA	10	698,200	0.83	0.34	2.7	1.1	21.3	26.4	54	14.3
AB	5	562,600	0.8	0.34	2.7	1.1	22.6	21.8	57	12.4
AC	4	418,700	0.85	0.34	2.6	1	21.9	16.7	63	10.5
AD	5	560,100	0.77	0.33	2.6	1	20.8	18.6	54	10.1
AE	6	674,700	0.76	0.33	2.2	0.9	20.8	22.1	53	11.7
AF	8	763,200	0.82	0.34	2.6	1	22	29.5	62	18.3
AH	5	594,300	0.77	0.34	2.6	1	20.4	20	48	9.6
AJ	5	562,300	0.75	0.34	2.5	0.9	20.5	18.5	57	10.5
Total	***48***	***4,834,100***	***0.79***	***0.34***	***2.6***	***1***	***21.3***	***173.6***	***56***	***97.4***

- **OBIP** = Original Bitumen In-Place and measured in $10^6 m^3$ units and converted to 10^6 barrels using conversion factor of 6.2898.
- **NRV** = Net Rock Volume in $10^6 m^3$ derived from deterministic mapping of SAGDable net pay, or from geomodel calculations.
- **SO** = Average bitumen saturation from the SAGD exploitable reservoir interval generated from 1-SWT (in fractions).
- **PORT** = Average porosity from the SAGD exploitable reservoir interval generated from PORT (in fractions).
- **RBIP** = Recoverable Bitumen in Place.

$$OBIP = (NRV \times PORT \times SO)$$

Geologic and Reservoir Properties – OBIP

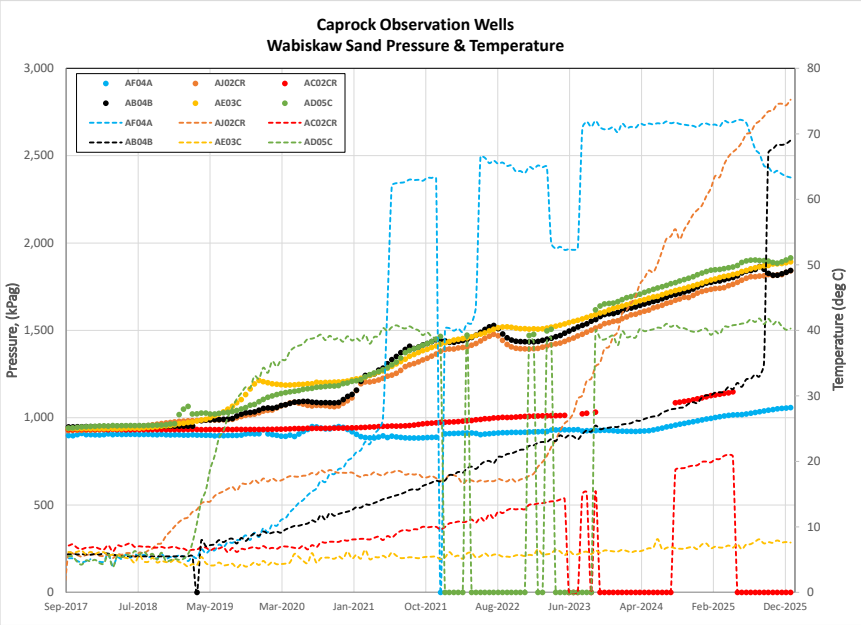
Parameters	Development Area	Project Area
Top of Reservoir Depth (mTVD)	176	175
Top of Reservoir Depth (TVD masl)	315	311
Base of Reservoir Depth (mTVD)	197	193
Base of Reservoir Depth (TVD masl)	294	293
Net Pay Thickness (m)	21.3	12.8
Porosity (frac)	0.34	0.33
Bitumen Saturation (frac)	0.79	0.75
OBIP (10^6 bbl)	173.6	2,890.8
OBIP (10^6 m^3)	27.6	459.6
Initial Pressure (kPaa)	220 (top) to 400 (bottom)	220 (top) to 400 (bottom)*
Original Reservoir Temperature (°C)	6	6*

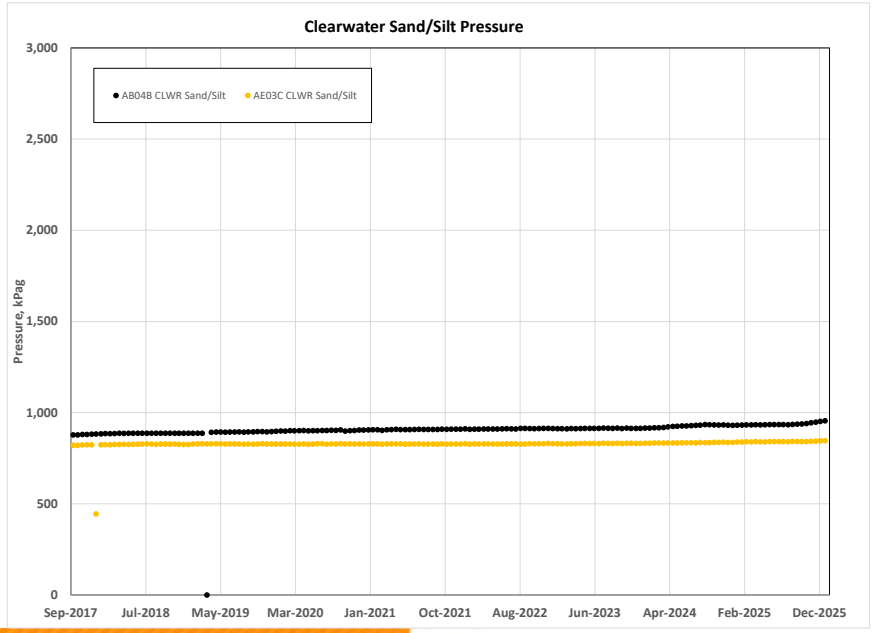
***** *Extrapolated from operating area.*

Caprock Monitoring: P & T Wabiskaw and Clearwater Sands

Overburden surveillance below and above MRCP caprock (Clearwater Argillageous)

- **Wabiskaw Sand: first line of defense (above reservoir, below caprock):**
  - Pressure ranges from 988 to 1,834 kPag (initial range: 918 to 1,508 kPag); Averages 1,411 kPag.
  - Temperature ranges from 8 to 75 ℃ (initial range: 6 to 43 ℃); Averages 51 ℃.
  - All pressure and temperature trends were considered normal in 2025 and attributed to thermal operations in the McMurray reservoir.
- **Clearwater sand/silt is above of MRCP caprock**
  - Pressure ranges from 847 to 956 kPag (initial range: 829 to 907 kPag) – <u>remains at pre-development conditions as expected.</u>
  - Temperature ranges from 4 to 5 ℃, (initial range: 4 to 5 ℃).
  - Pressure and temperature are expected to remain steady as this interval is immediately above the caprock.





MRCP – Performance Indicators by Pad

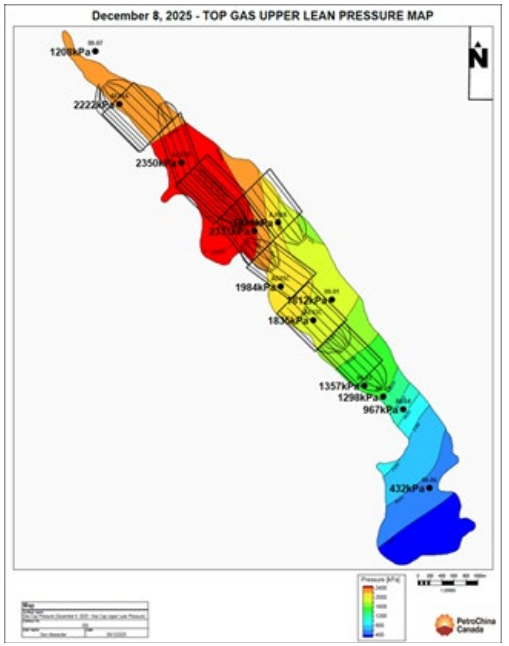
Pad	OBIP (m^3)	Cum. Oil to Dec 31, 2025 (m^3)	Recovery to Dec 31, 2025 (%)	CSOR by Dec 31, 2025	ISOR by Dec 31, 2025	Ultimate Recovery (%)
AA	4,197,138	1,182,309	28%	5.2	6.0	54%
AB	3,465,819	565,904	16%	6.5	8.1	57%
AC	2,655,008	748,249	28%	4.1	5.0	63%
AD	2,957,075	381,360	13%	8.2	19.5	54%
AE	3,513,514	369,151	11%	9.2	9.8	53%
AF	4,688,859	1,112,887	24%	4.4	3.8	62%
AH	3,179,650	155,353	5%	13.4	6.9	48%
AJ	2,941,176	292,865	10%	9.5	8.5	57%
Total	27,058,824	4,808,077	18%	6.0	6.2	56%

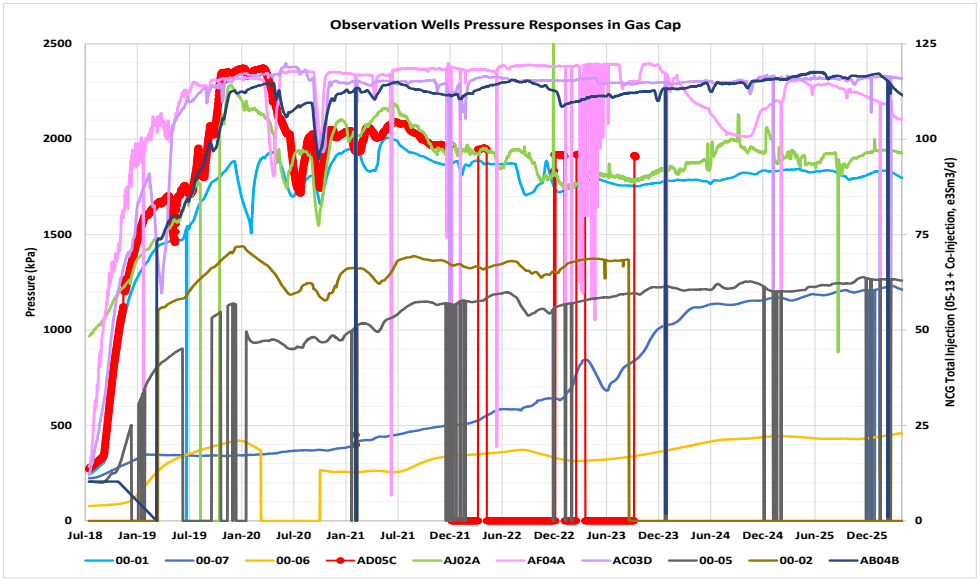
- The higher SORs experienced at Pads AD, AE, AH, and AJ are primarily due to gas cap contact and/or slightly larger lower transition zone leak off.

- Mitigations:
  - Operating pressure was balanced with the thief zones pressure, accordingly.
  - Gas cap pressurization with natural gas started in September 2018. More detail is provided on Slide 21.
  - Gas co-injection started in well pairs of pads AH, AE, AD in January 2019. More detail is provided on Slide 22.

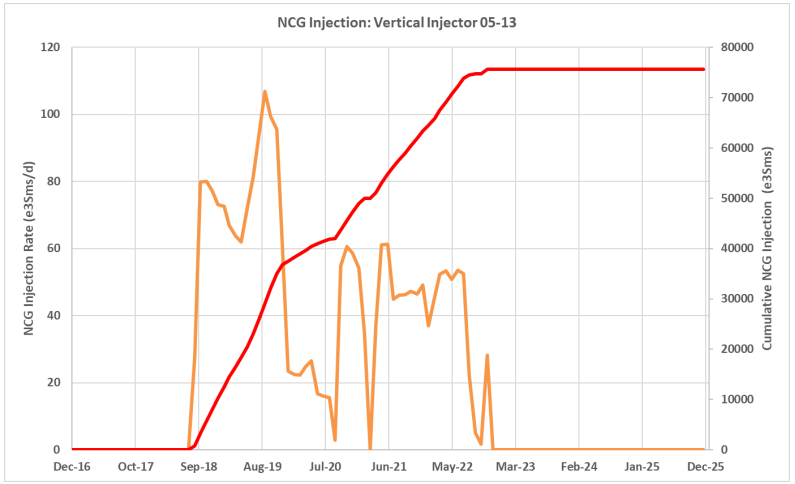
Gas Cap Pressurization: NCG Injection

- The purpose of gas cap pressurization at MRCP is to increase the pressure in the gas cap to operate at a more favorable pressure balance between steam chambers and top thief zones to minimize steam losses.
  - Initial gas cap pressure of 200 kPag, presented a challenge to SAGD operation pressure balance.
  - These has been evidence of steam chamber communication to the gas cap since early 2018.
  - The pressurization process started in September 2018. Natural gas was injected in the vertical well 103/05-13-090-14W4-00. Injection reached a maximum of 106,000 Sm^3/d (max approved by AER is 120,000 Sm^3/d per injector) by Q3 2019.
  - Injection suspended from December 2019 to October 2020. PCC reactivated NCG injection to continue support field pressure ramp-up. Intermittent injection from 2021 to mid-2022.
  - Injection was suspended in August 2022, mechanical issues were identified and the well remained shut in for the rest of 2022, except for a 2-week test period in November 2022. The well was deemed irreparable, and abandonment was conducted in Q1 2023.
  - Final cumulative NCG injection since August 2022 (05-13 abandonment) was approximately 75,600 e^3Sm^3
  - The gas cap pressurization process has helped reduced SOR and maintain stable operation and production of wells affected by gas cap contact.



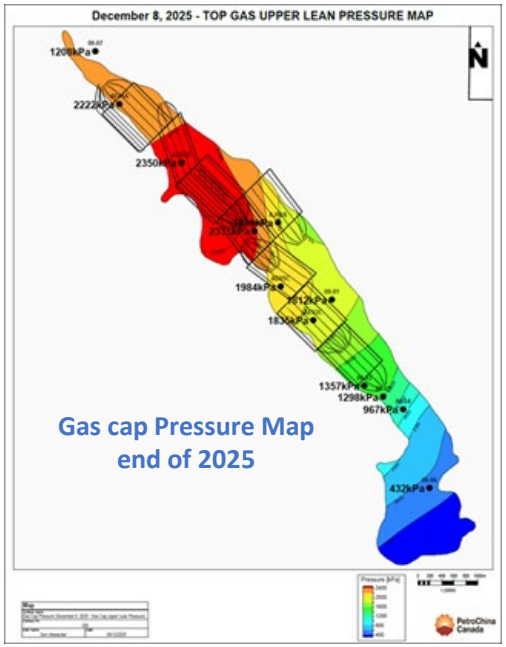


NCG Injection: Vertical Injector Well

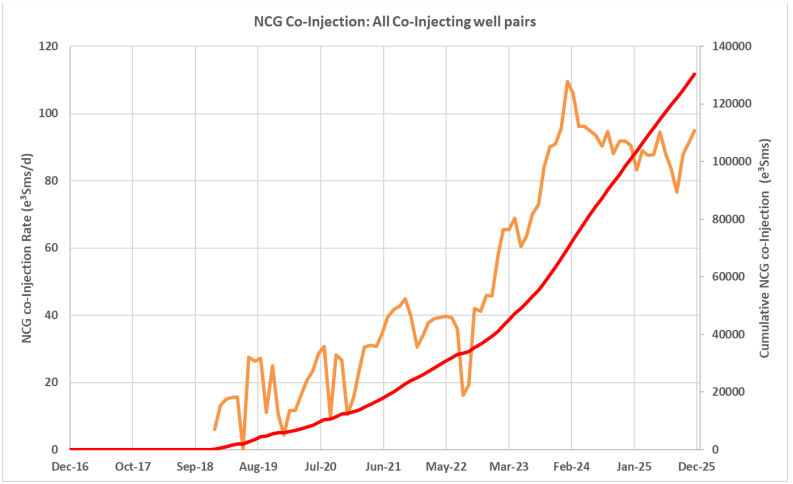


Gas Cap Pressurization: NCG Co-Injection

- NCG co-injection supports the gas cap pressurization at MRCP
  - Gas co-injection was implemented in January 2019 for additional support to gas cap pressurization in areas distanced from vertical injector 05-13.
  - Typical co-injection rates range from 1,920 to 4,800 Sm^3/d per well (Max approved by AER is 5,000 Sm^3/d per well). Cumulative NCG co-injection was approximately 130,423 e^3Sm^3 (as per chart below, right), by December 2025.
  - Typical mole fractions (concentration) range between 0.5 and 2.0%.
  - NCG co-injection parameters are evaluated weekly: Co-Injection rates (within the permitted range) are adjusted as per each well pair response. Wells could be on and off co-injection depending on SOR and Total Fluid to Steam Ratio evaluation.
  - PCC has expanded the NCG co-injection network up to 30 well pairs by December 2025:
    - AA01, AA02, AA03, AA04, AA05, AA06
    - AB01, AB02, AB03, AB04, AB05
    - AJ01, AJ02, AJ04
    - AD01, AD02, AD03, AD04, AD05
    - AE01, AE02, AE03, AE04, AE05, AE06
    - AF03, AF04, AF05, AF06
    - AH01, AH02, AH03, AH04, AH05
  - Additional wells could be added to the co-injection group if the need is identified.
  - NCG co-injection helps provide extra buoyancy to the steam chambers and support growth through tortuous and heterogeneous reservoir paths. At current SAGD stage, NCG co-injection also provides pressure support and partial replacement of steam.
  - Pressure monitoring of the gas cap indicates that co-injected NCG reaches the top of the reservoir, effectively providing pressure support, preventing excessive steam losses and supporting effective SAGD operation.
  - The total produced gas corresponded to 14% of the co-injected volumes in 2025.
  - No wellbore integrity issues have been identified.



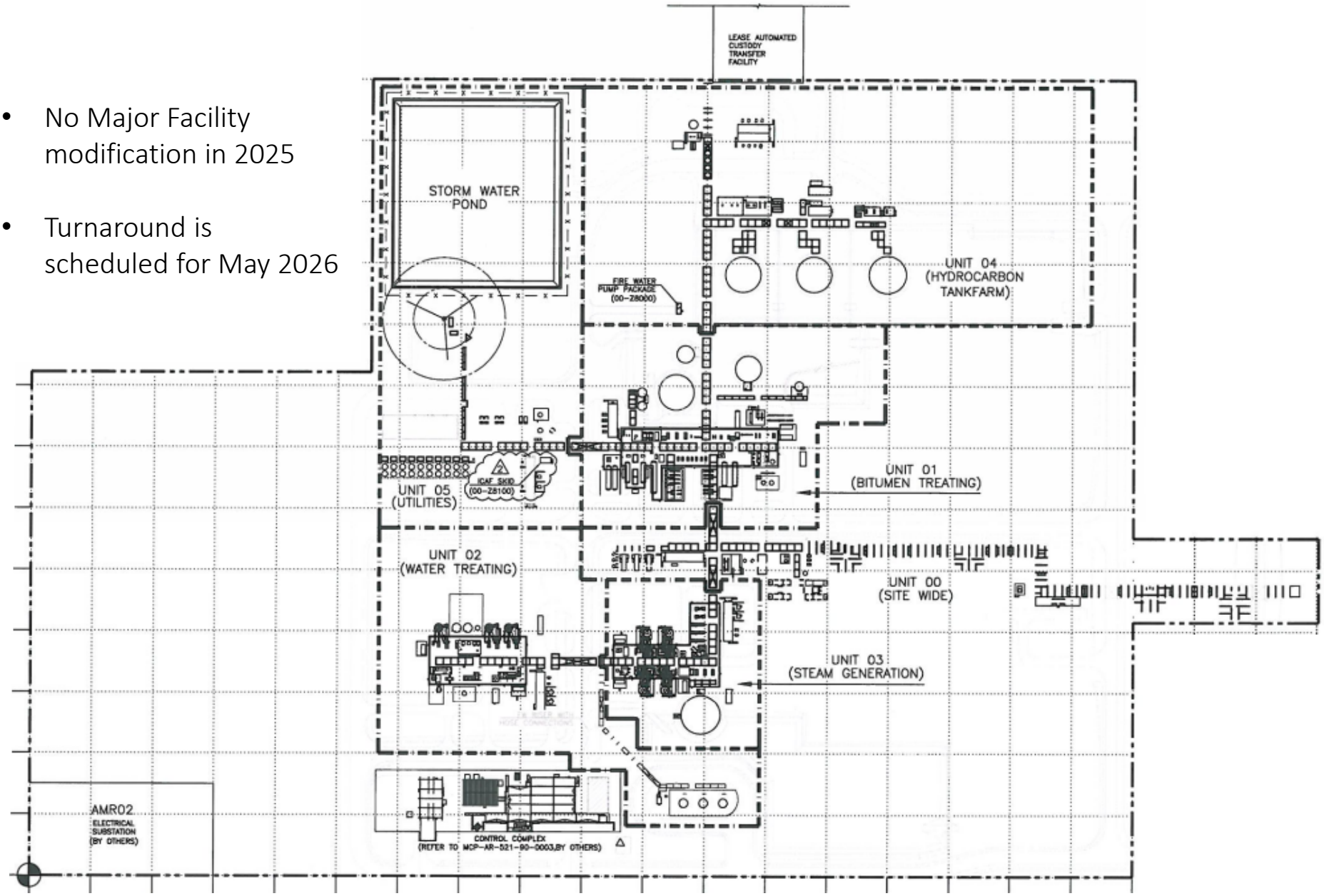
NCG co-Injection: Several Well Pairs



4.3 SURFACE

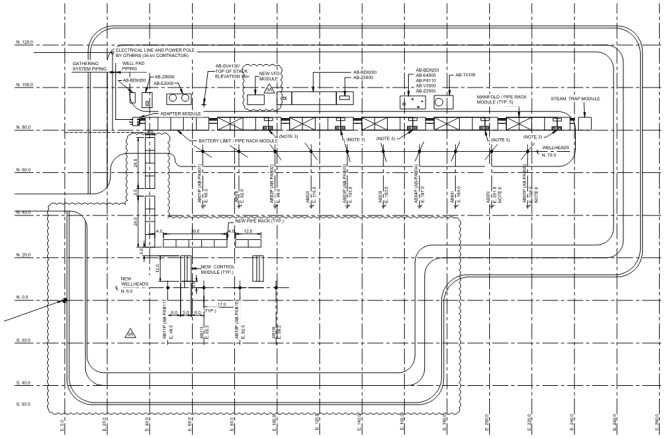
Central Plant Facility Development Plot Plan

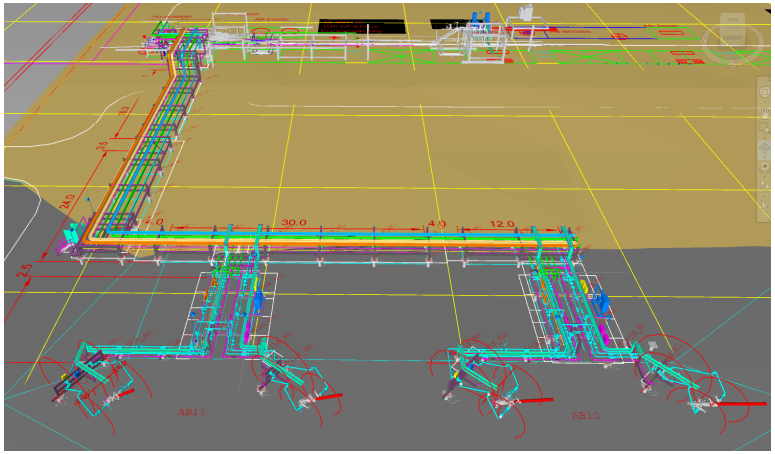
- No Major Facility modification in 2025
- Turnaround is scheduled for May 2026

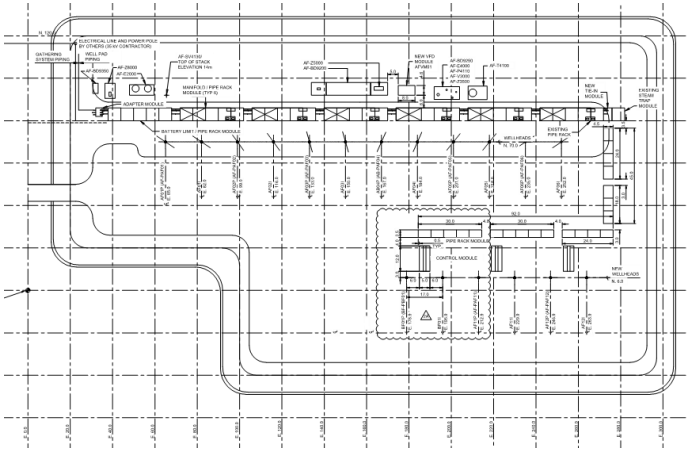


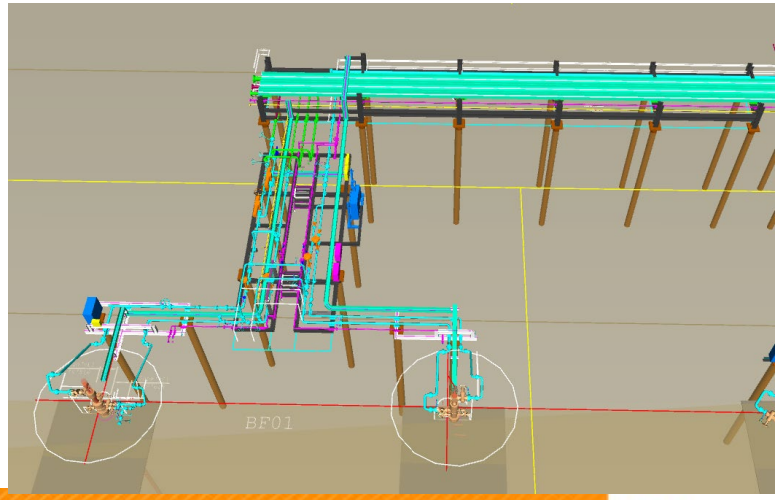
Field Facility Development

- No field expansion work took place in 2025. Design work has begun on surface facilities for new wells to be developed in 2026:
  - Two new long length well pairs on Well Pad AB.
  - One new vertical spud, long lateral length well pair on Well Pad AF.

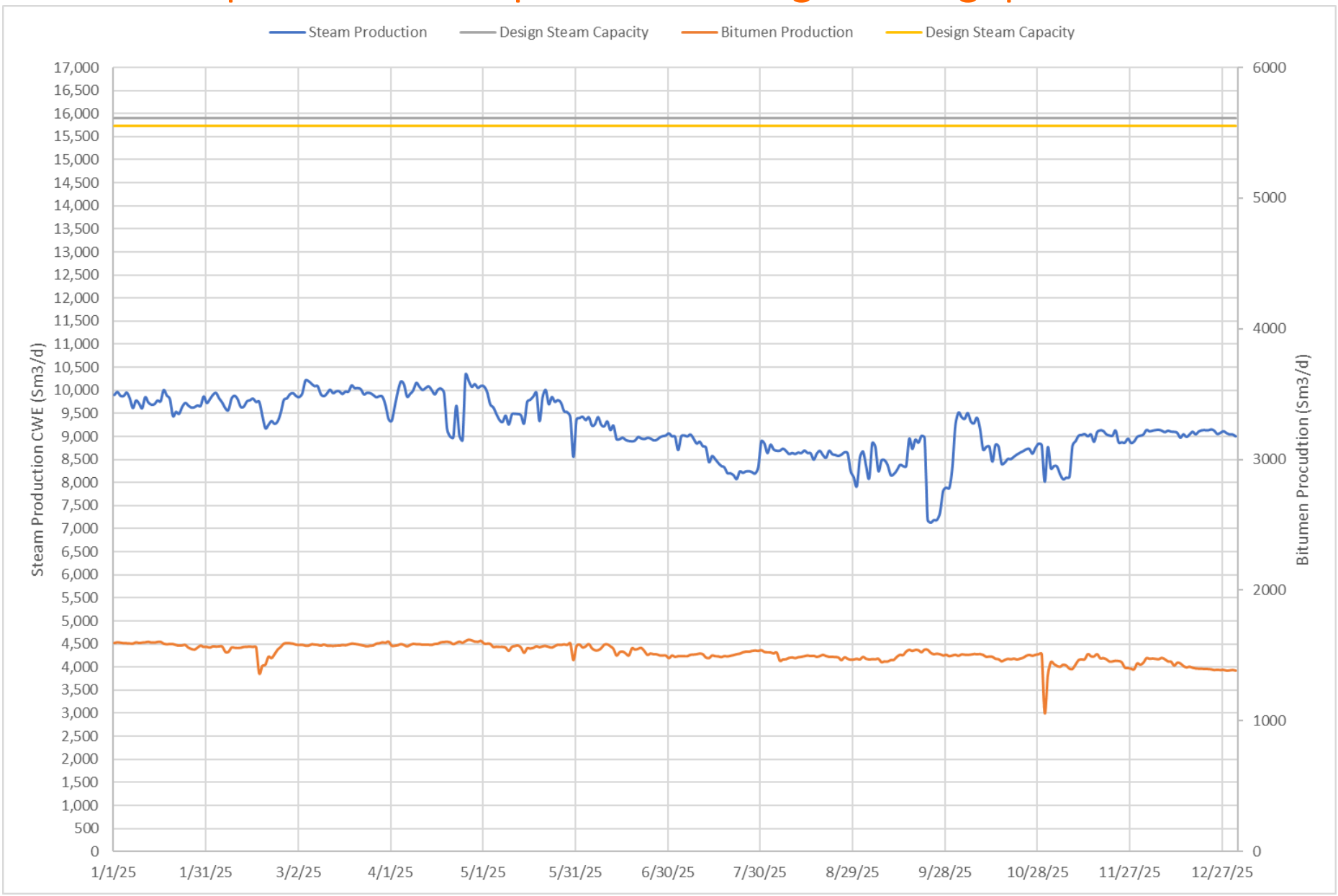








Operational Comparison to Design Throughputs



4.4 Historical and Upcoming Activity

AER Request: Information on Any OVG Exceedances at the Facility

- The MRCP facility has not exceeded the 15 e3m3 OVG limit outlined within Directive 060. PCC completed a review of historical vent reports to confirm. The following two events were further investigated.

  - July 2020, a vent volume of 33 e^3m^3 was reported to Petrinex. This event has been checked against our flare & vent log, and the AER notification (ID 30690533). The event was a flaring event that was incorrectly entered to Petrinex as vent.

  - March 2021, flare and vent log with corresponding AER notification (ID 31169283) shows a vent volume of 39 e^3m^3. Knowing the flow rate (61 Sm^3/hr), and the duration of the event (~65 hours), the actual volume was 3.9 e^3m^3. The flare & vent log and AER notification incorrectly included an extra 0.

2025 Historical/Upcoming Activity and Regulatory Changes

- Summary of suspension and abandonment activity:
  - The AJ05 Injection and Production wells suspended in 2024, were subject to monitoring required under *Directive 013: Suspension Requirements for Wells*, in 2025.

- There were no phase expansions, change in injection strategy, or infrastructure changes throughout 2025 that materially affected scheme performance or energy material balances

Amendments to Scheme Approval No. 11715

Amendment No.	Application No.	Description	Approval Date
11715X	1958223	Approval to develop the BF01 Drainage Area with one vertical spud, long lateral length well pair	18-Sep-2025

Key Learnings To-Date

- Continuing to maintain production through optimization efforts and mitigating the effects of:
  - Top gas and thicker lower transition zones
  - Operational pressure strategies tied to “thief” zones
  - Effects of baffles and barriers
  - Fines migration
- Electrical Submersible Pump (ESP) conversions continue to meet run-life expectations and are in-line with industry averages.
- The use of fiber optic temperature coils has proven to be a valuable tool to diagnose downhole issues and survey the conformance along the horizontal section.
- Implementation of Control Flow Devices (ICD)has proven a valuable contribution to well management and optimization. Continuous lessons learned from these implementations are valuable for current and future well developments.

2025 Compliance Summary

Event Description and AER Reference Number (if applicable)	Event Details	Event Reason (if applicable)	Plan to Resolution
445334	PCC identified that some water diverted under TDL No. 00508492 in Late July and August 2025 were used outside of the authorized area of use for that TDL.	PCC held two adjacent TDLs (MRCP dust control; MWR road maintenance); water withdrawn under one TDL was used in the other area.	PCC is planning to revise the TDL with a single Areas of use for both the MRCP and MWR to prevent a similar occurrence
446733	PCC failed a Cylinder Gas Audit (CGA) on October 15 at MRCP. This resulted in a drop below the 90% availability of our CEMS units as the data was considered out of control back to the previous successfully completed performance test. This is in contravention of the CEMS code, Section 6.1.	When the initial CGA failed, the technician completing the work assumed there was a component on the CEMS unit that required replacement. Communication within PCC was delayed and the Analyzer Maintenance Error Correction Procedure wasn't consulted. A repeat CGA was scheduled a week after the failed CGA.	Train technicians on CEMS Quality Assurance Program; update CGA procedure to clarify steps after a failure and reference the Analyzer Maintenance Error Correction Procedure. The CGA procedure will be enhanced to clearly explain steps to follow in the event of a failure.
447241	PCC conducted a Cylinder Gas Audit (CGA) on February 22, 2024, which failed. A successful CGA was completed the following day, on February 23, 2024. The failed CGA invalidated the CEMS data back to the previous successful performance test, which was a RATA, completed in November 2023. The data invalidation results in CEMS availability being less than 90% from November 2023 to February 2024.	PCC determined that the failed CGA was a result of operator error, and not a CEMS equipment issue. A successful CGA was completed the following day. There were no corrective maintenance or calibration activities completed on the equipment between the failed and successful CGAs.	
318	PCC identified that approximately 66 m3 of topsoil and 11m3 of subsoil salvaged from Well Pad AB expansion (MSL 112211) were transported to nearby Borrow Pit 34 for stockpiling in late December 2025. This is a non-compliance with conditions of 1136 and 1139 of MSL 112211 that require salvaged soils to be stored on the same lease.	Factors leading to this incident included: • Conducting soil salvage operations under heavy snow and deep cold (approximately -28°C) • Having to salvage more soils than originally planned due to ditch grading, and • Lack of engagement with soil salvage experts.	• Plan for soil salvage and stockpiling activities to avoid heavy snow and deep cold, as much as practicable. • Plan for contingency stockpiling locations should additional salvage be required. • Reinforce the importance of field staff engaging with technical experts when situations such as this arise in the field.

Future Initiatives

Producer sidetracks and new wells:

- Continue to propose/execute producer sidetracks for cases requiring complicated workovers, and/or production liner remediation
- New well programs:
  - Gradually complete infill drilling on pads: AF, AC, AA, AB
  - PCC Plan 2026: New long wells AB10 and AB11 (length of up to 1,700m); and additional well to the north of Well Pad AF
  - Development extends from current drainage boxes:
    - Use existing footprint and pad facilities wherever possible.

Potential Amendment Applications:

- Application for additional infill wells and producer sidetracks.

Delineation and Seismic:

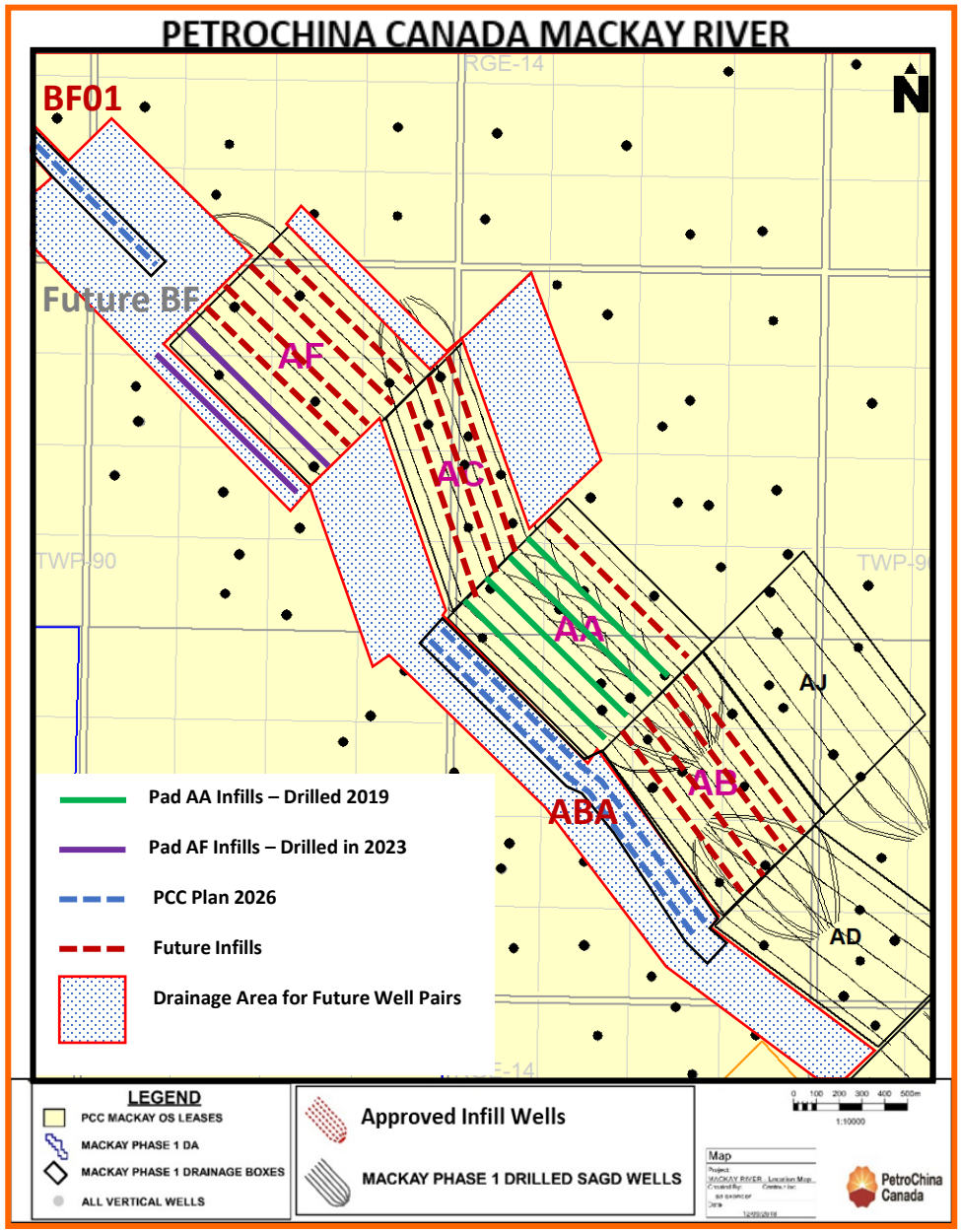
- No new delineation wells are planned.
  - Sufficient delineation in near term (approximately 5 years).
- No immediate plans for 4D seismic acquisition at MRCP.

Continue to Evaluate New Technologies:

- Improve Energy Efficiency.
- Improve Reservoir Recovery.

Central Processing Facility Major Maintenance:

- Plant turnaround planned for Q2 2026.



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