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Fiber-Optic Sensing for Field Development
Asset Integrity & Optimization Workshop

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From Blind Injection to Informed Decisions: The Value of DTS in Gas Injection Wells

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Introduction

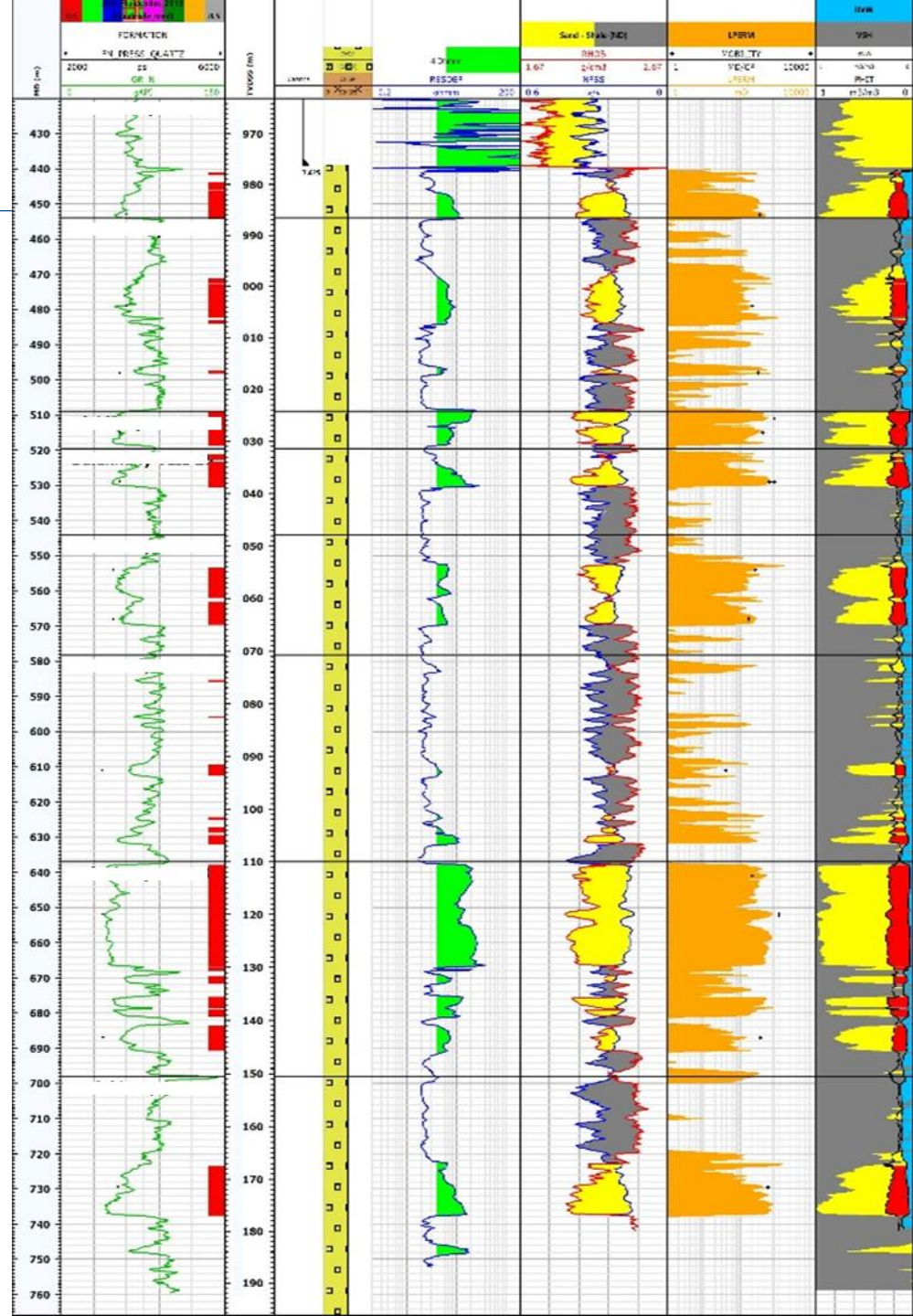
- Well A: Gas injection well delivered without DTS. The first surveillance log was acquired more than one year after injection start, revealing that injection was not occurring into the main reservoir sands. Extensive surveillance was required to investigate the injectivity deferral.

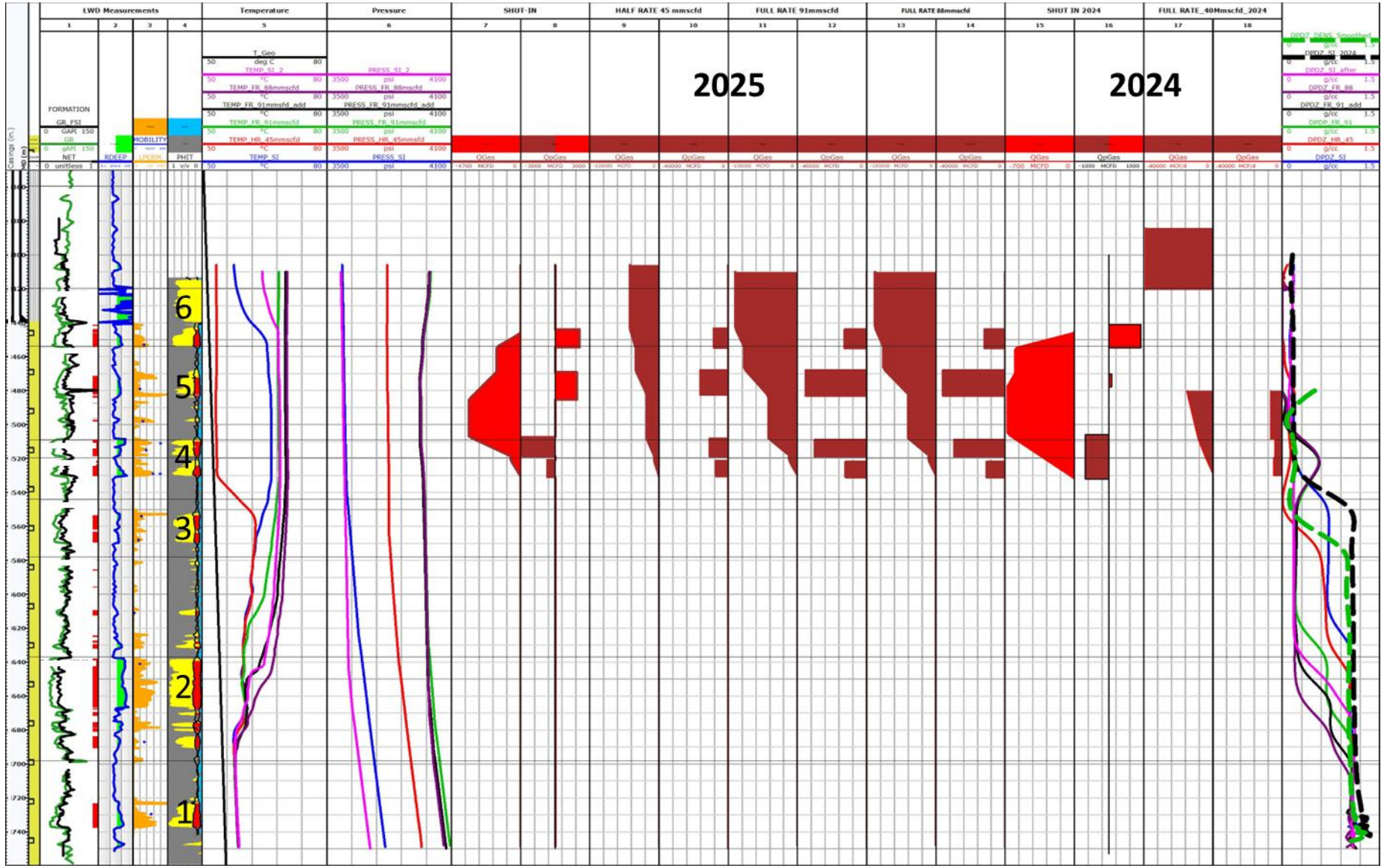
- Well B: Gas injection well delivered with DTS fiber installed. DTS was used to confirm clean-up during flowback and to monitor the injection profile. Injection rate was almost doubled following DTS-driven, real-time insights.

- Well C: A critical gas injection well where DTS was not installed due to a sidetrack during drilling. As DTS was unavailable, flowback had to be performed from the rig, resulting in an additional five days of rig time.

Case #1: Gas injection well with no surveillance and DFO

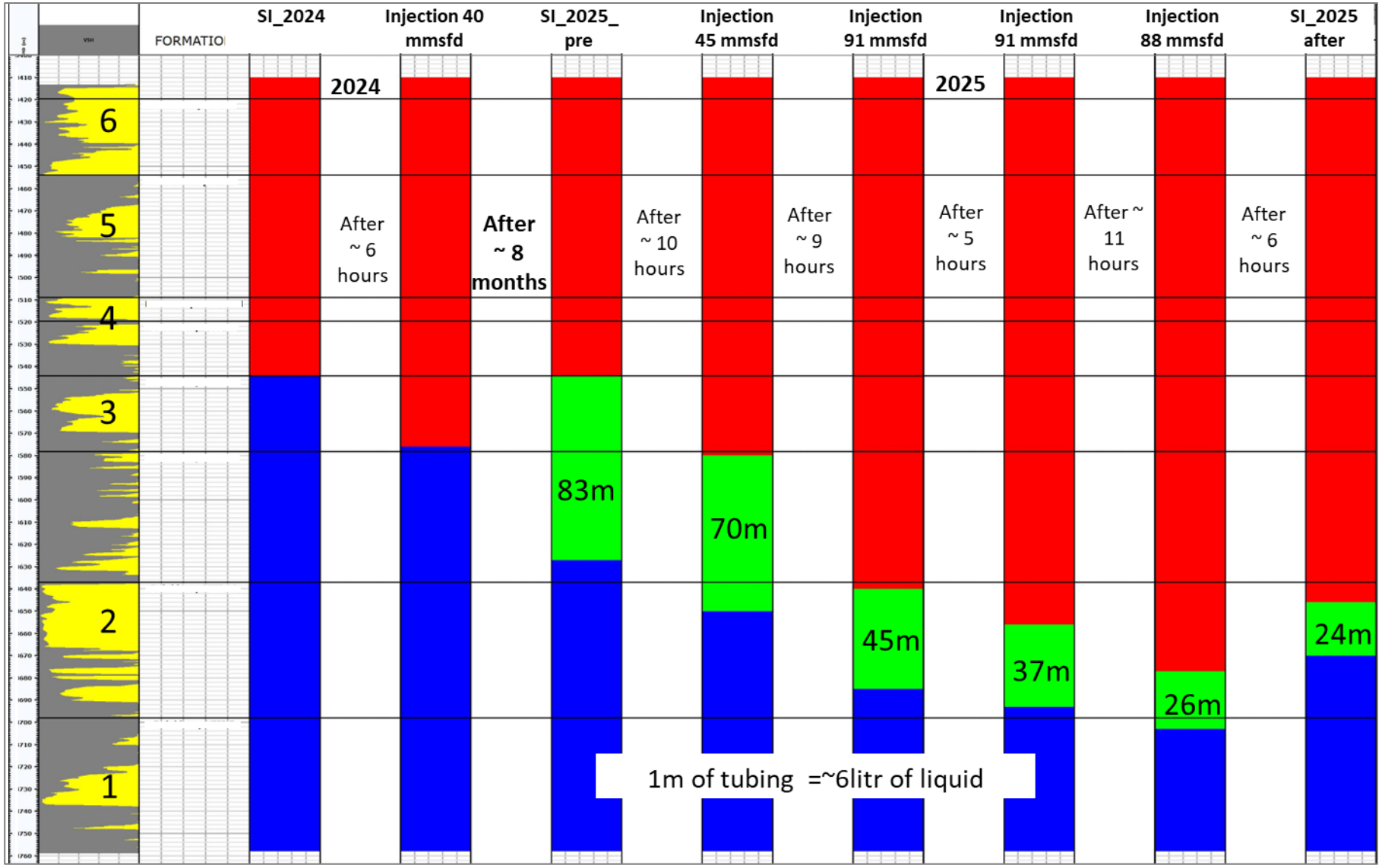
- The well was put on injection Jul 2023 and achieved 45 Mmscfd injection rate against prediction of 105 Mmscfd
- An investigation was initiated to understand the causes of under-injection and to apply learnings to future gas injectors.
- Poor clean-up of all sands revealed as main root cause of well under-injection
- Additionally, there was a sanding event during flowback, which was additional reason for suspended flowback
- As part of the investigation, surveillance was performed in Sep-2024.
- The scope included IPROF and GPE to understand the gas injection profile and evaluate GP quality.





Surveillance Analysis

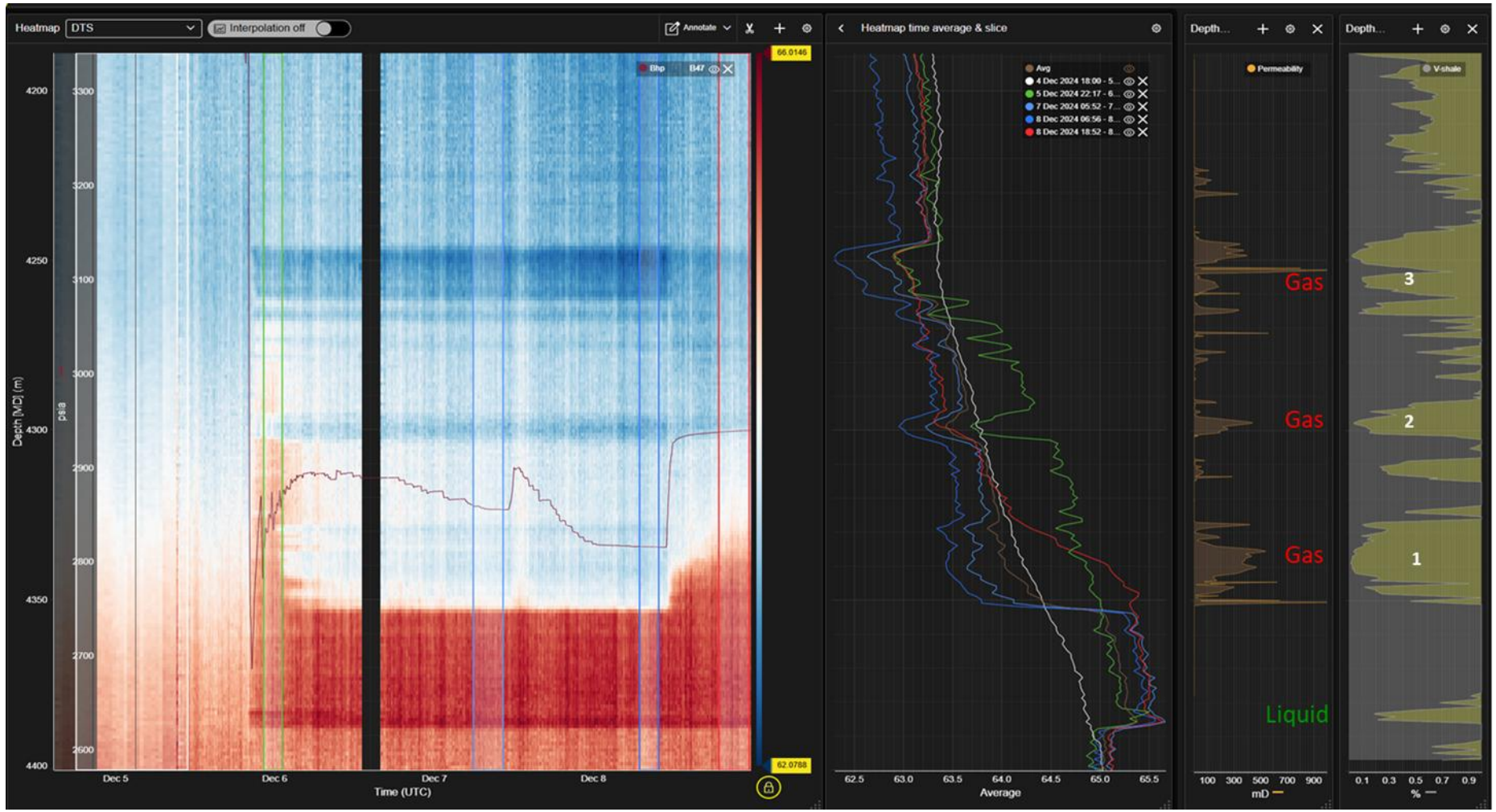
- Chemical shut-off used to block off top high-pressure sands (5, 6) and create favorable conditions to apply drawdown on bottom sands of interest to flowback liquid
- No difference in cross-flow and injection profile between 2024 and 2025 surveillances;
- All injected gas goes into the top sands – already pressurized
- The gas–liquid interface deepens progressively with continued injection.
- The temperature log does not indicate any dynamic flow behavior at the well bottom.



Fluid Level Change during ILT

- Fluid column moves down as the injection continues;
- Oil column height decreases from pass to pass, meaning oil & water are getting injected into the formations.
- Injection appears to be minimal, resembling slow seepage into the formations rather than effective injection
- No liquid or gas movement was identified on the spinners across sands #2 and #1.
- Ultimately after few well-work jobs it has been decided to sidetrack this well and recomplete.

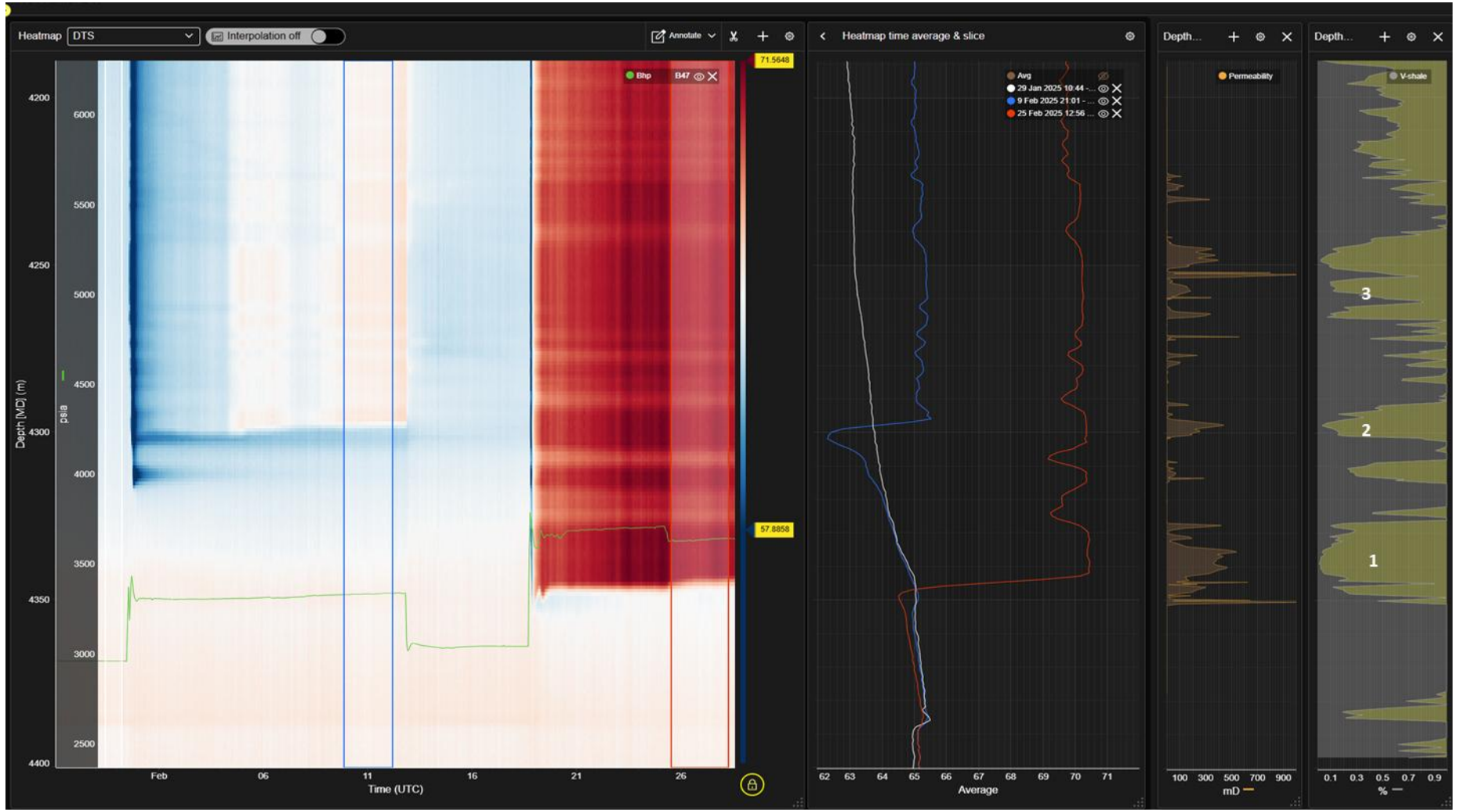
Case #2: Gas injection well with DFO (flowback)



Flowback Summary

- Well #2 is OHGP gas injection well with DFO pumped prior flowback & first injection.
- DTS confirms clean-up across all sands.
- DTS indicates liquid contribution primarily from the bottom-most sand, this aligns with surface test separator reported 800-1000 bbl of oil production during flowback and fluid flag
- DTS shows crossflow from bottom most sand into sand #1.
- Flowback completed and monitored on DTS, eliminating the need for additional surveillance runs or extended flowback duration.

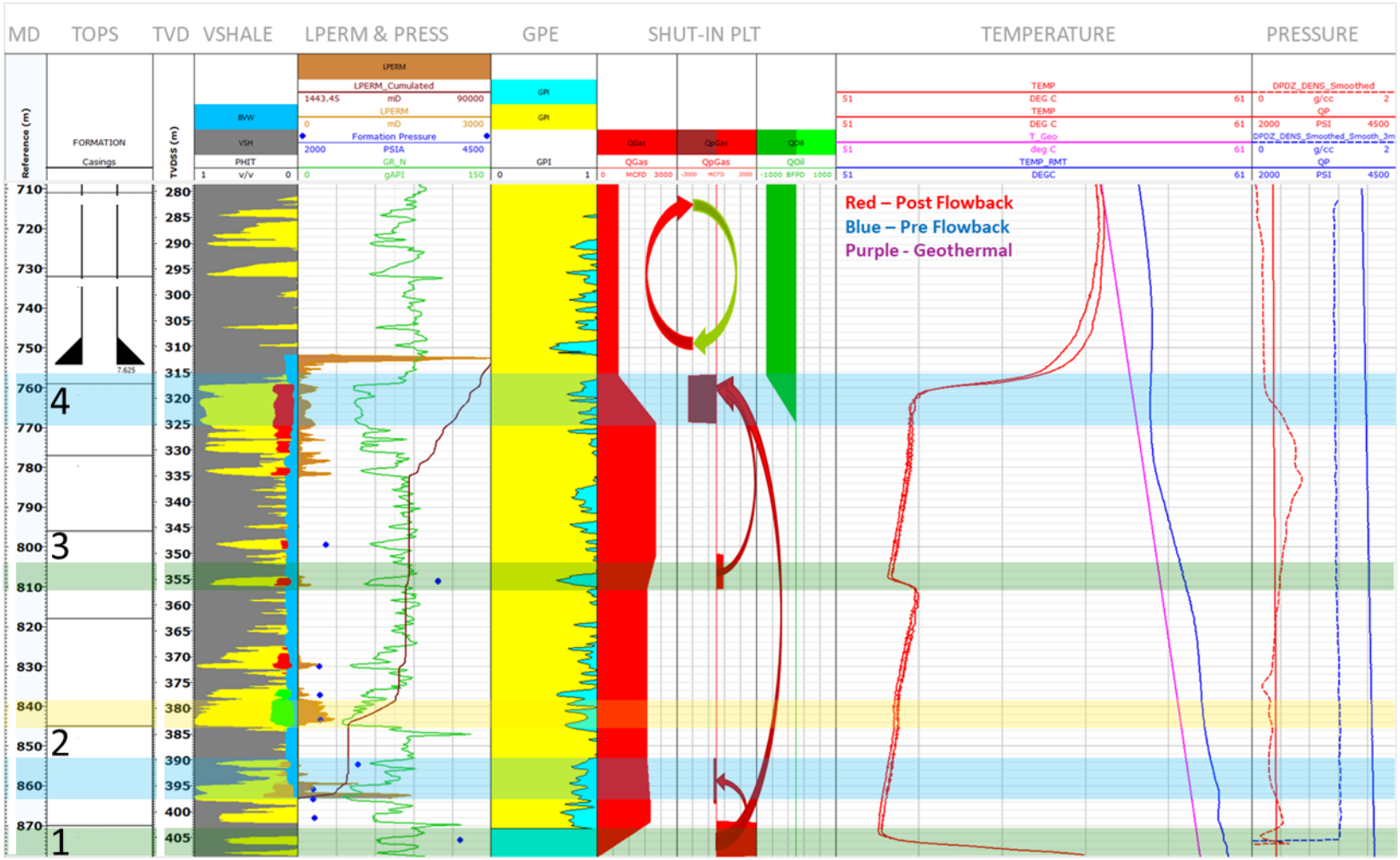
Case #2: Gas injection well with DFO (injection)



Injection Summary

- Initially planned 40 mmscfd injection rate achieved. This is the maximum injection rate planned as per SOR.
- DTS suggests injection goes only into Sand 3 and Sand 2.
- With the injection rate increased to 90 mmscfd, injection was confirmed across all three completed sands.
- With 90 mmscfd – injection goes into all 3 completed sands.
- The injection rate was optimized based on DTS readings, confirming that all targeted sand layers are effectively receiving injection.

Case #3: Gas injection well without DTS but with extended surveillance



Flowback Interpretation

- The objective of flowback is to produce completion fluid back to surface and put each sand on production. Post flowback PLT will be used to confirm clean-up and flowback from each sand unit.
- Temperature and spinner passes acquired ~9 hours post well shut-in after 3.5 days of flowback.
- There is crossflow in the well at shut-in condition into Sand #2 and Sand#4. This confirms Sands #6 and #2 accept injection.
- Gas production signature confidently seen on temperature across Sand #1 and Sand #3, these are high pressure sands (green highlight).
- Temperature signature suggests liquid production from bottom of Sand 3 during flowback, and this observation agrees well with fluids interpretation.
- ~5 days were required to complete Clean-up & ILT.

Conclusions

- Effective clean-up and flowback from each sand is critical before placing a well into gas injection mode.
- Distributed Temperature Sensing (DTS) enables real-time monitoring of flowback, significantly reducing flowback duration and operational uncertainty.
- DTS can be used to assess injection performance without need of ILT or other surveillance
- DTS provides continuous, qualitative assessment of the injection profile without the need for well shut-in or conventional ILT acquisition.
- Installing Distributed Fiber-Optic (DFO) sensing in gas injection wells delivers comprehensive surveillance capability, improves injectivity performance, and reduces rig time, intervention costs, and operational risk.

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Thank You

We Welcome Your Questions!

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