Past, present and future fluid challenges - Gudrun field

European Well Performance Forum (EWPF) 2025

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Outline

- Introduction to Gudrun field
- Completion fluids
  - Past experiences
  - Present challenges
  - Future & way forward

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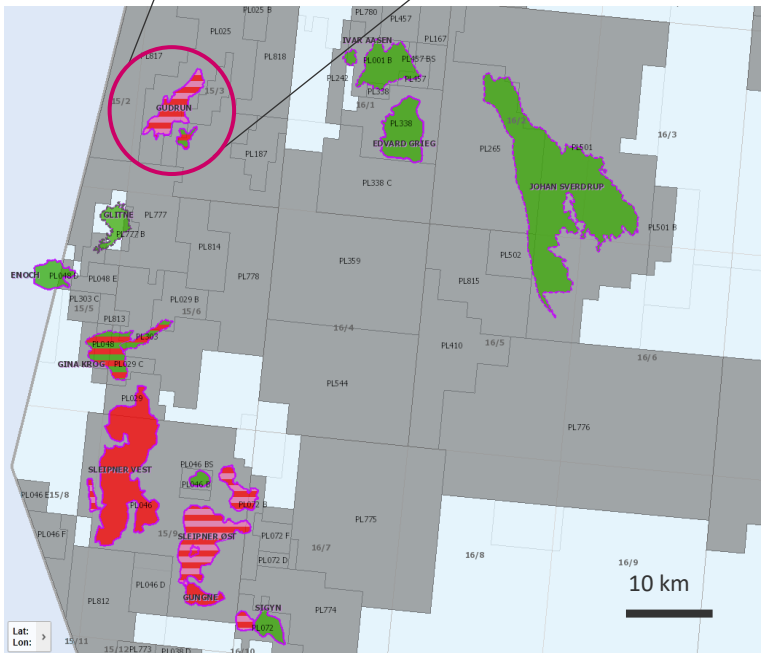
Introduction to Gudrun field

Gudrun field (NCS)

- Discovered in 1975
- Production start-up 7th April 2014
- HPHT-field (780-815 bar, 137-157°C)
- Intricated geology – Tectonically influenced turbidite deposition
- Phase 1: 7 production wells (oil and gas-condensate)
  - Natural pressure drive
- Phase 2: 4 new producers + 1 recompletion + 2 water inj + 2 water prod
  - Water injection in Draupne 3 formation

Reservoir	Fluid	Permeability [mD]	NTG	GOR [Sm3/Sm3]
Draupne Fm 3	Oil	0.1 – 1000	0.40	368
Draupne Fm 1	Gas condensate	2 – 850	0.80	662
Hugin Fm	Gas condensate	0.05 - 33	0.45	6200



From www.npd.no

Gudrun reservoirs and wells

Draupne 3

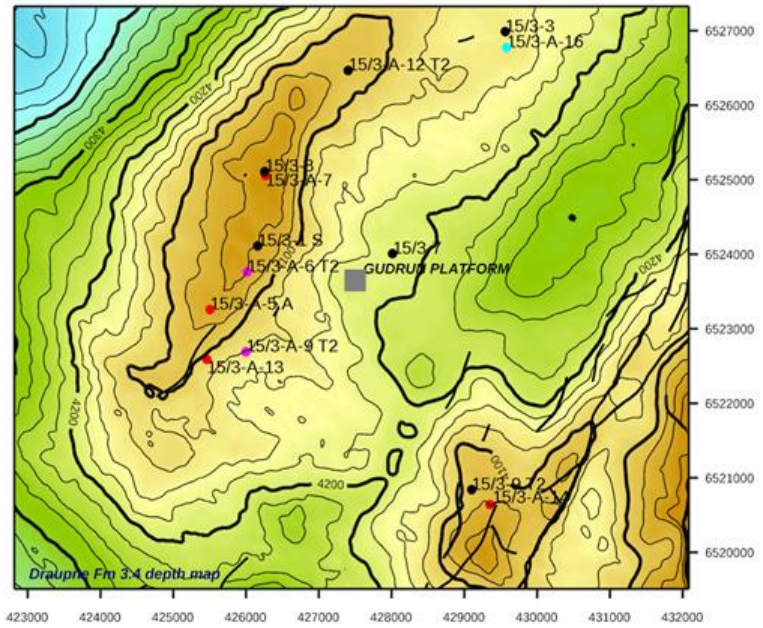
- Main reservoir in Gudrun
- Heterogeneous reservoir, mixed sand-shale, N/G ~ 30%
- Gudrun Main Field: Draupne Fm 3 (oil) – 6 near vertical wells
- Gudrun East: Draupne Fm 3 (oil) – 2 near vertical wells
- GOR = 360 Sm3/Sm3
- Dedicated wells are near vertical open hole wells with stand-alone sand screens

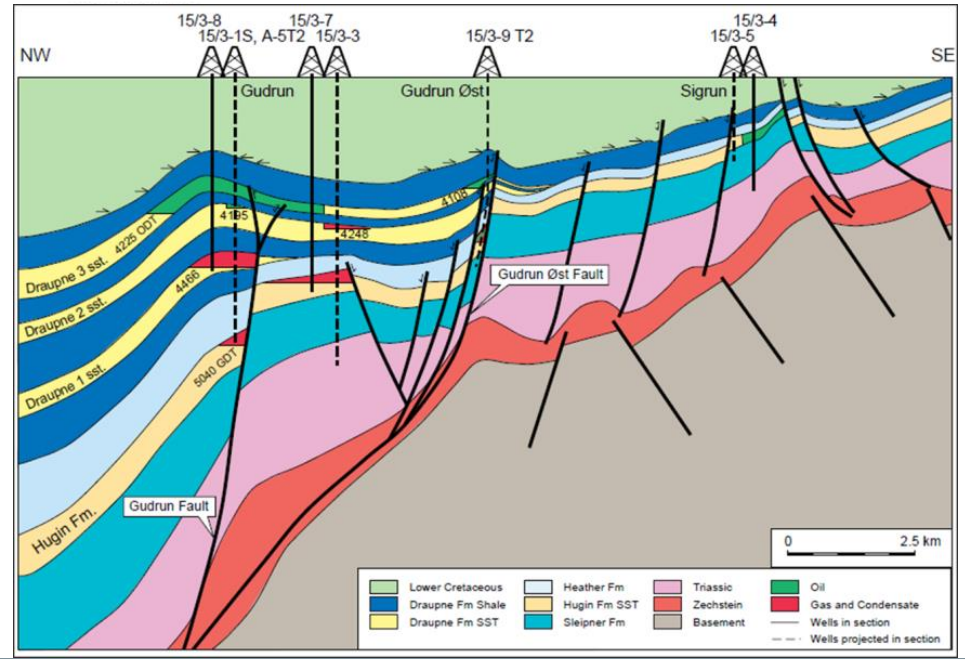
Draupne 1&2

- Sandrich, N/G ~ 75%
- Draupne Fm 1: 2 wells (1 deviated + 1 horizontal)
- Draupne Fm 2: 1 well (horizontal)
- GOR = 630 Sm3/Sm3
- Horizontal/Deviated wells with cased and perforated liner

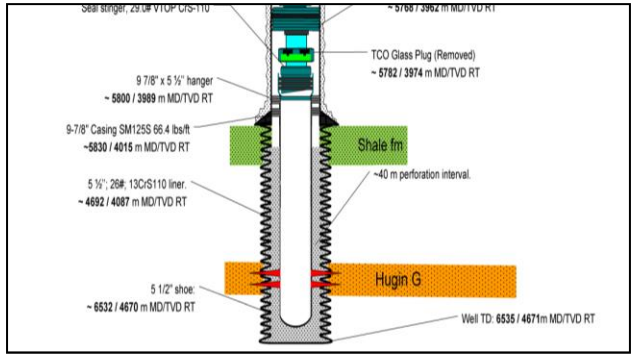
Hugin

- 1 vertical gas producer
- GOR = 6200 Sm3/Sm3
- Near vertical well with cased and perforated liner

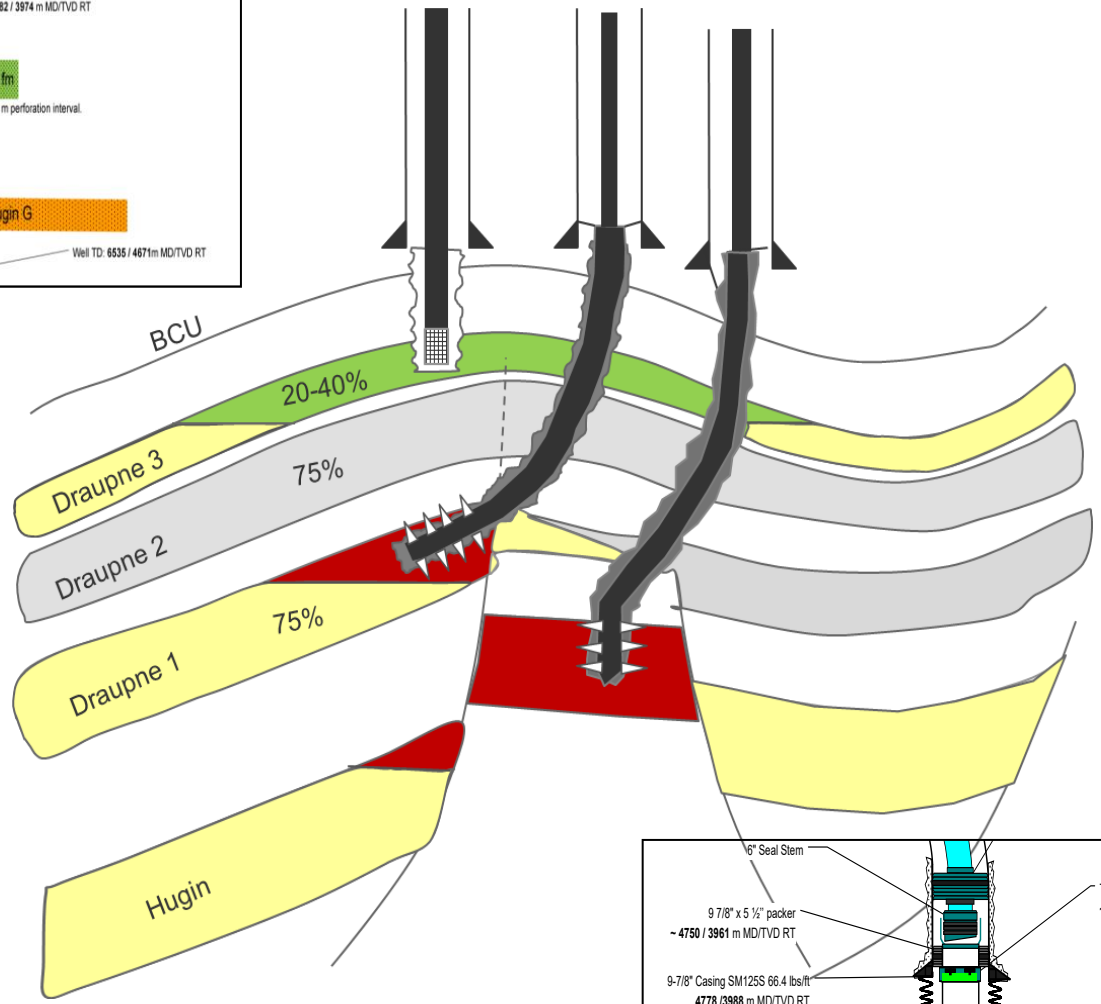


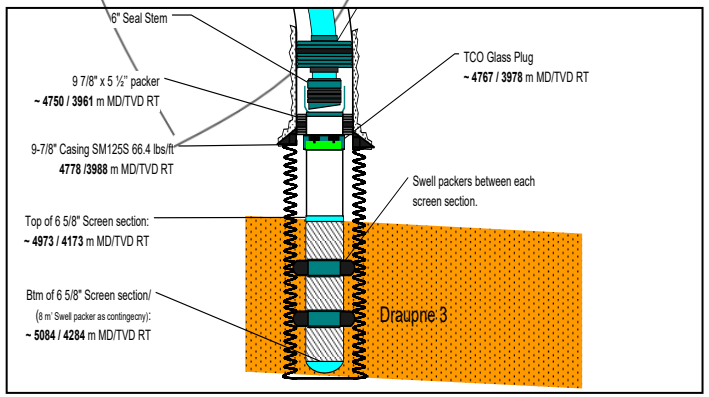


Well design



- Draupne 3
  - Stand alone screens (open hole)
  - Near vertical reservoir sections
- Draupne 1&2
  - Cased&Perforated liner
  - >67° reservoir sections (67° and 89°)
- Hugin
  - Cased&Perforated liner
  - Vertical reservoir section





Past experiences

Completion fluids in Phase1 and Phase 2 drilling campaigns

Development of BaraECD as a drilling and completion fluid for:
Phase 1 (2014-2016)
Phase 2 (2019-2020)

SPE paper 189531

Challenge

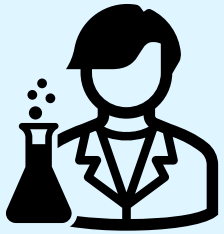
- The main fluids challenge in Gudrun (HPHT field) was the identification of an appropriate high density completion fluid for the planned SAS completion
- Use of OBM as completion fluid was deemed as not optimal. High solids content might plug screens and ports. LSOBM preferred
- LSOBM was not heavy enough to be used in Gudrun and K/Cs formate, had its own cost-related disadvantages despite some successful applications

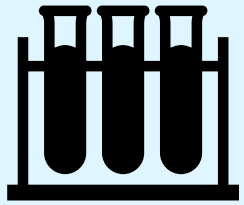
Solution

- Qualify a "new type" of clay-free OBM (BaraECD) weighted with small particle size (micronized) barite to be used as a drilling and completion fluid for SAS wells

Note: Initially drilled with XP07 fluid system, then OB Warp form MI was used pending the qualification of BaraEDC

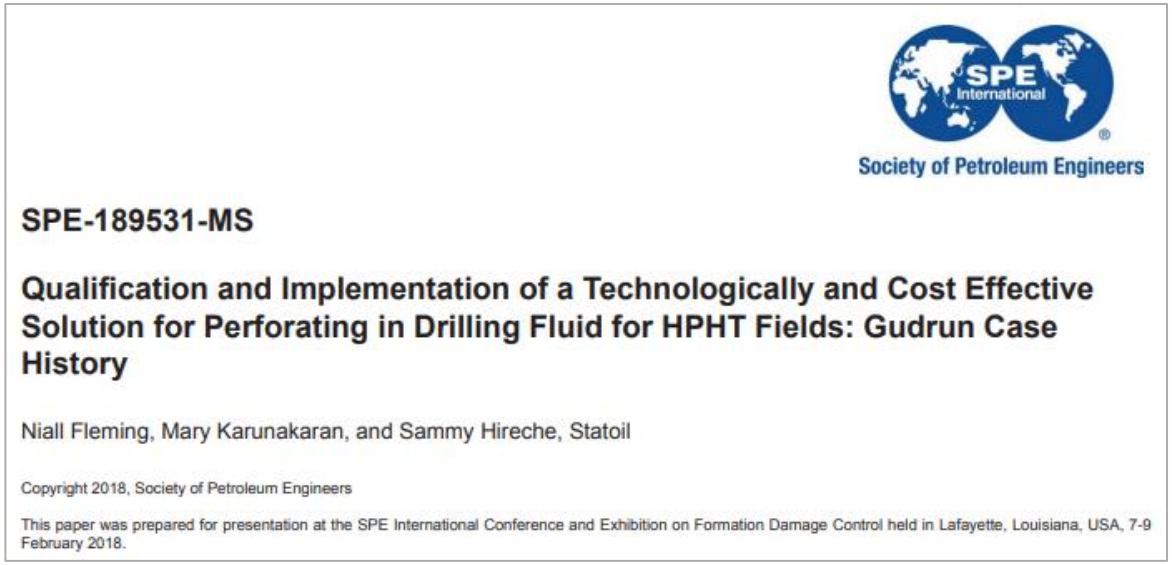
BaraECD lab testing





- Screen fluid testing for **1,95sg** fluid, for **6 weeks** static time and **135 °C**
- Test initially conducted for standard **250 µm screen aperture.** However, results showed higher potential for screen plugging
- Larger screen aperture size testing was undertaken showing acceptable results for **610 µm screen.** This screen size was confirmed acceptable from rock mechanics perspective
- Lab mix BaraECD gives **low dPmax at** production start production, however, some **residual mud mass** (soft) on the wall was observed
- This mud mass could not be displaced during flow, meaning that mud mass was left behind the screen
- **Partial plugging** of the screens could not be ruled out

BaraECD experience in Gudrun (Phase 1 and 2)



Society of Petroleum Engineers

SPE-189531-MS

Qualification and Implementation of a Technologically and Cost Effective Solution for Perforating in Drilling Fluid for HPHT Fields: Gudrun Case History

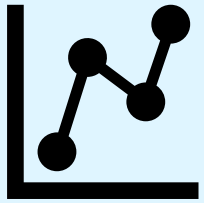
Niall Fleming, Mary Karunakaran, and Sammy Hireche, Statoil

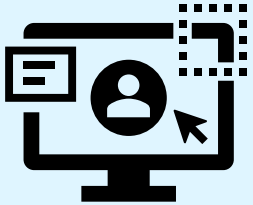
This paper was prepared for presentation at the SPE International Conference and Exhibition on Formation Damage Control held in Lafayette, Louisiana, USA, 7-9 February 2018.

- *"This new fluid (BaraECD) underwent a rigorous formation-damage-testing program and combined with an assessment of its use as a screen-running fluid, showed promising results"*
- *Well-test data taken as soon as possible after the startup of the four SAS wells using the OBM* ***indicated that the wells had no skin, and they did have an initial productivity index (PI) close to that estimated***

Overall, BaraECD proved to be a **low-damaging and cost-effective solution for Gudrun wells** for both those equipped with Stand Alone Screens and Cased and Perforated liner

Well production experiences Phase 1 & 2





PI → Initial PI within uncertainty span

- Early production experience shows no signs of screen plugging, however, all wells in Gudrun have exhibited continuous decline in productivity with time.
- At least one well from each phase suspected of screen erosion

Skins → Minimal skin initially for most SAS wells

- In general, PTA analysis at early production stage (start-up) showed close to zero skin with some development overtime

Clean-up → All well have been cleaned-up to high production rates and for long enough time

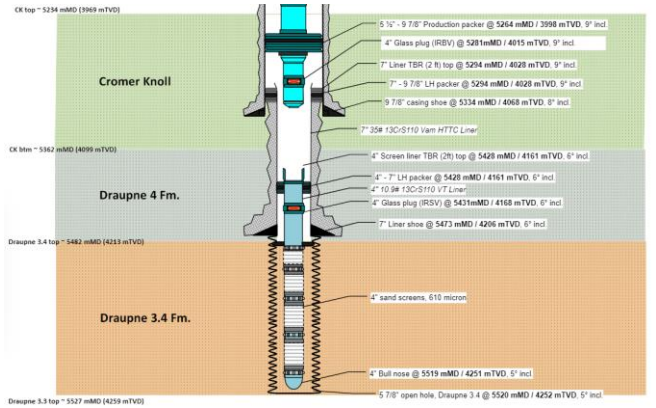
- Well interventions reaching the reservoir sections revealed no sings of significant remanent completion fluid inside the completion, even for long horizontal (>1 Km) reservoir section

Present challenges

Screen failure observed leading to uncontrolled sand production

Present challenges

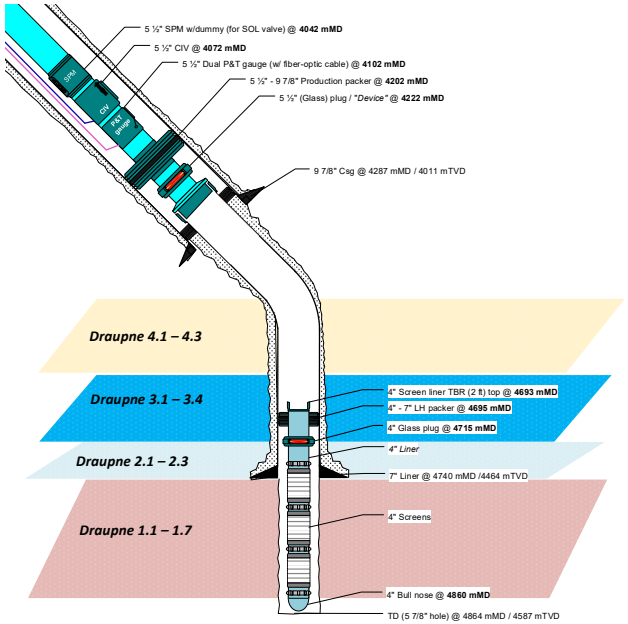
What is different now? What has changed?
Why do we need to discuss about the use of BaraECD as completion fluid in Gudrun?



1. **Need for slim-hole for the reservoir section in Phase 3**:

   Phase 1&2 -> 6-5/8" screens (8-1/2" hole) vs **Phase 3 -> 4" screens** (5-7/8" hole)

   - 6-5/8" screens → less chance to experience severe issues in case of high velocities
   - 4" screens → significantly reduces the margins to stay below 1 m/s in case of plugging and are more prone to be plugged due to reduction in the effective area of flow



2. **Sand production observations**:
   - 1 well (Phase 1) exhibiting sand production (water breakthrough) since 2023
   - 1 well(Phase 2) showing significant sand production since 2023 (1 year after start-up)
   - Rock Mechanics revised screen aperture recommendation: 250µm for future wells

3. **On the other hand, lower reservoir pressure means lower completion fluid weight**
   - **>1,95 sg** (Initial ResPress) **vs** **~1,6 sg** (Expected ResPress)

NETool simulations comparison: Screen Base Pipe OD - Slot aperture

Sensitivities were run for different screen base pipe OD and wire-wrap slot aperture with the following results:

Screen Base Pipe OD - Slot aperture	No plugging	Partial plugging	Severe plugging
4in – 400µm	All cases <1 m/s Max vel 0,88	Only one case < 1 m/s Max vel 1,48 m/s	All cases > 1 m/s Max vel 2,73 m/s
4in – 610µm	All cases <1 m/s Max vel 0,56 m/s	All cases <1 m/s Max vel 0,96 m/s	Only one case < 1 m/s Max vel 1,75 m/s
4-1/2in – 610µm	All cases <1 m/s Max vel 0,31 m/s	All cases <1 m/s Max vel 0,61 m/s	One case >1 m/s Max vel 1,18 m/s

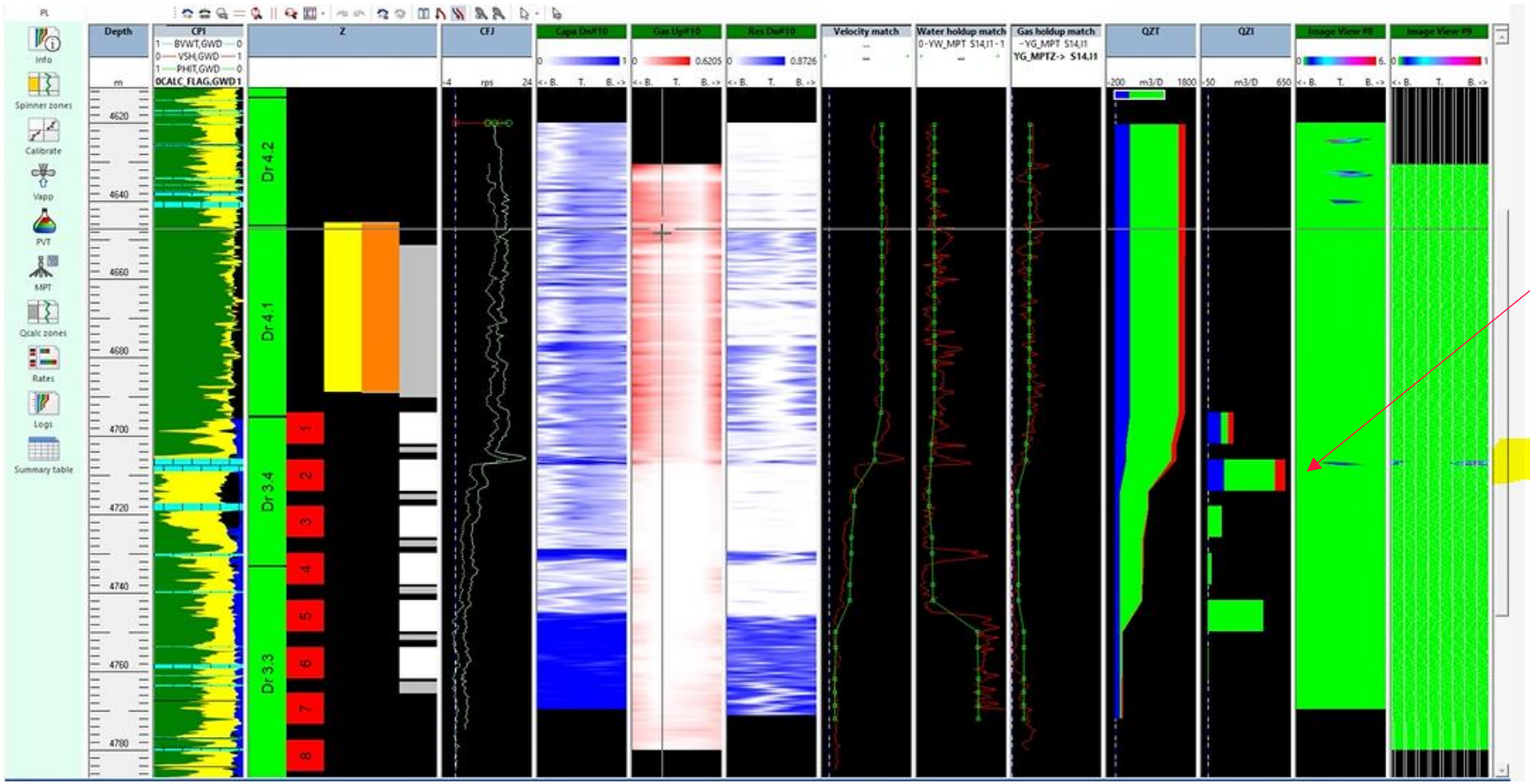
OK velocities
Marginally acceptable velocities
Unacceptable high velocities

-Larger screen base pipe OD/Slot aperture translates into lower velocities.

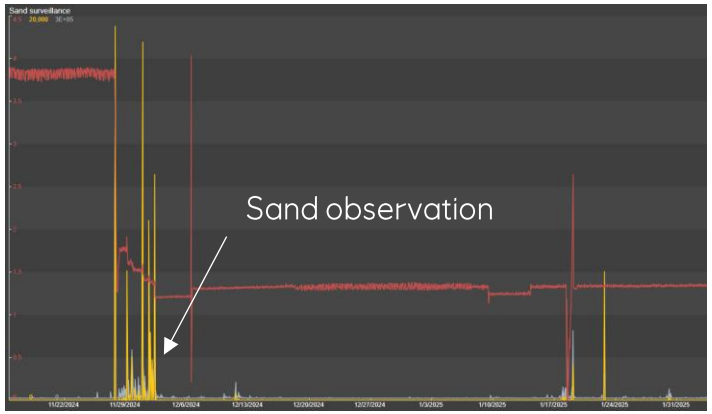
-This provides larger tolerance for eventual plugging while ensuring velocities < 1 m/s

Well#1 - PLT with FAST (Flow Array Sensing Tool) Feb 2025

- Major sand observation late Nov 2024
- Gas production picked over 1 MSm3 gas at periods, meaning high velocities
- Well choked back since and optimized through ASR



Possible interpretation is annular flow behind the screen and entry from the top part of the screen (Hotspot)

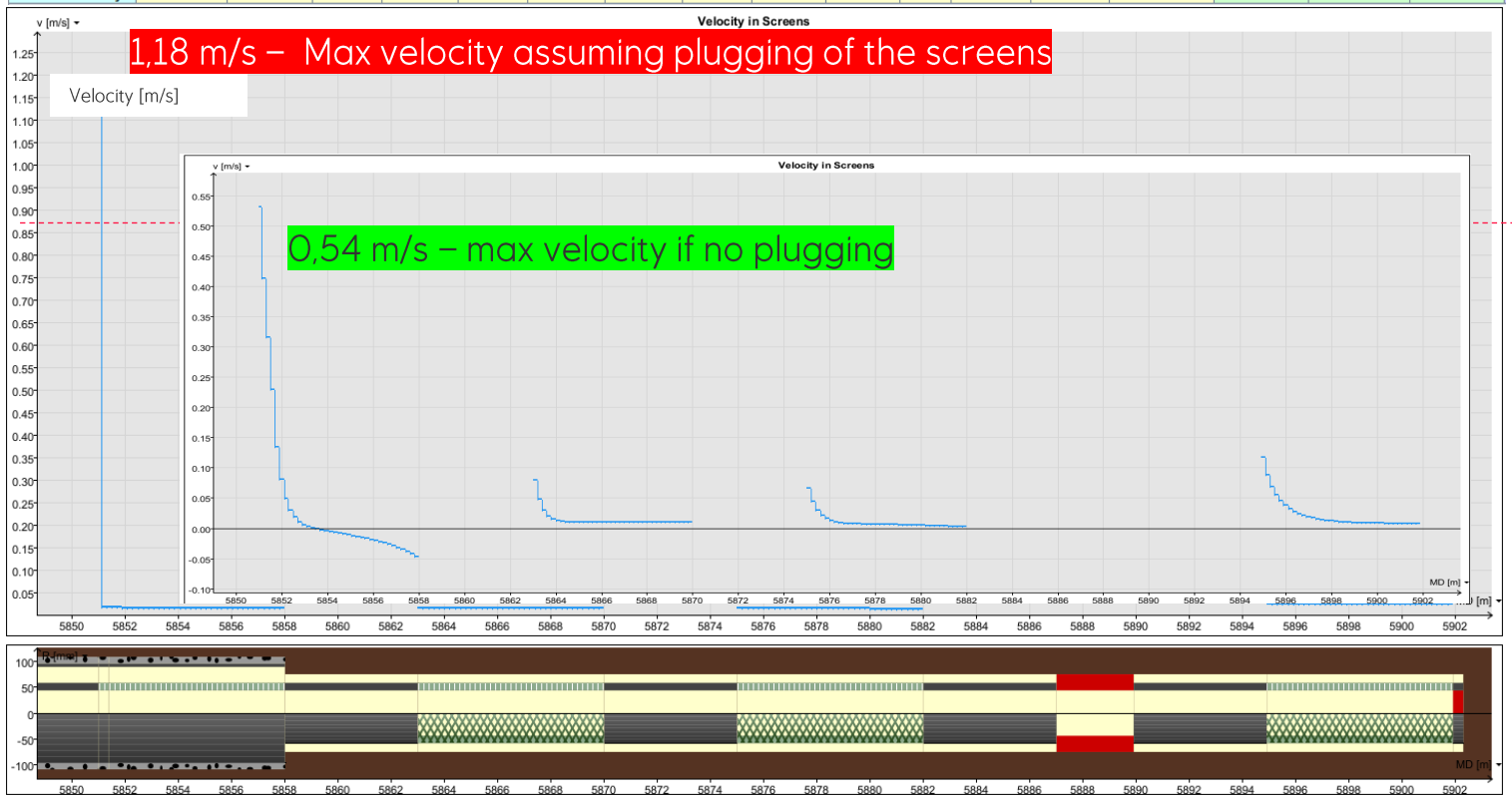


Well#2 - Sand production and clogging

- At least 40% well rate reduction in one well (phase 2) due to sand production

- Completed with 4" (610 µm) screens
- Assuming no plugging the, the max expected velocity through the screens is 0,54 m/s
- In case of screens plugging, simulations also shows that Max Velocity through the is expected to be **> 1 m/s**

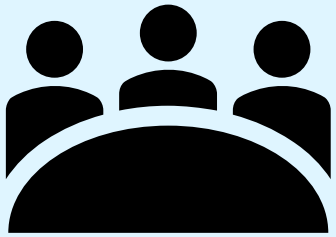
Run	Tubing Head Pressure	Bottomhole Pressure	Oil rate	Gas rate	Water rate	Oil mass rate	Gas mass rate	Liquid rate	Gas-oil ratio	Oil-gas ratio	Water cut	Water-gas ratio	Liquid-gas ratio	Downhole rate at tubing head	BH PI Oil	BH PI Gas	BH PI Water
	[Bar]	[Bar]	[Sm³/day]	[kSm³/day]	[Sm³/day]	[t/day]	[t/day]	[Sm³/day]	[Sm³/Sm³]	[Sm³/Sm³]	[%]	[Sm³/Sm³]	[Sm³/Sm³]	[Rm³/day]	[Sm³/day/Bar]	[kSm³/day/Bar]	[Sm³/day/Bar]
Time = 531.0 days	208.823	208.888	1174.0	146.75	0.0	1033.12	118.868	1174.0	125.0	0.008	0.0	0.0	0.008	1680.83	24.7759	3.09699	0.0



Future & way forward

Continue with BaraECD or move to Low Solid completion fluid

Cross-disciplinary fluids/formation damage Competence Group in Equinor



- The team assessed the current/future Gudrun situation: Need for slimer boreholes (smaller Screens OD), potential for high velocities (increased risk for erosion), likely SAS failure in two wells and depleted reservoirs

- Two alternatives proposed for further evaluation in the upcoming drilling campaign:

    1. Continue using BaraECD 3.3 as screen running fluid
    2. Displace BaraECD 3.3 with a low solids screen running fluid
        - OBCF
        - WBCF

- Recommended mapping the cost/risk of the two options for the running screen fluid for future Draupne wells in Gudrun considering field experiences with 2 wells with sand production

Comparison BaraECD 3.3 vs Low solid completion fluid (summarized)

	BaraECD 3.3	Low Solid completion fluid
Cost	No changes to current plan	Potential higher cost due to use of Cs formate (internal phase) to weight up to 1,56 SG
Low solid content	Screen fluid as particle content is high ~ 750 kg/m^3	Designed for 40 kg/m^3
Reservoir pressure regime (Exp 348 bar)	Suitable when Res Press is high – not the case for Draupne 3 anymore	OBCF suitable up to 1,64 SG. Planned 1,56 SF for Draupne 3
Risk for screens hotspotting/erosion	High risk of screen plugging → erosion and sand production	Low risk for screen plugging and therefore low erosion risk
Sand management	Increase risk for sand management challenges at top side	Low risk for sand production linked to low probability for screen erosion/failure
Velocity through screens	High risk of high velocities during the well lifetime causing erosion and sand production2)	Low risk for high velocities based on NETooL simulations
Weight material sag	Barite settling and compaction increases with static time	Low risk. Low solids system and no HGS

Main take-aways

Continuous evaluation of the completion fluid strategy is crucial to adapt to changes in completion designs, reservoir conditions, and production challenges

It is crucial to prioritize the use of a "Screen Running Fluid" (SRF) with low particulate concentration (around 40 kg/m³) to prevent screen blockage and to reduce the risk for screen erosion

The implementation of a low solid SRF is now the preferred approach for upcoming Gudrun wells equipped with SAS, aiming for reducing the risk of plugging the screens (erosion) and to ensure contributions from the entire reservoir interval

Lab testing for low solid fluid compatibility test has been initiated for two different alternatives

-Low Solid OBCF

-Low Solid WBCF

Acknowledgments

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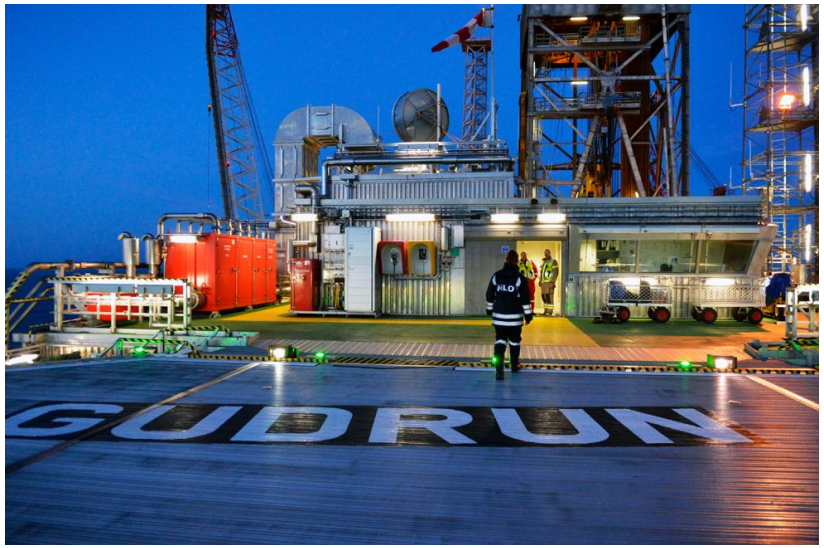

Thanks for your attention!

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