

Non-resin based Chemical Sand Consolidation: A First UK Application of a Proven Technology

Authors –

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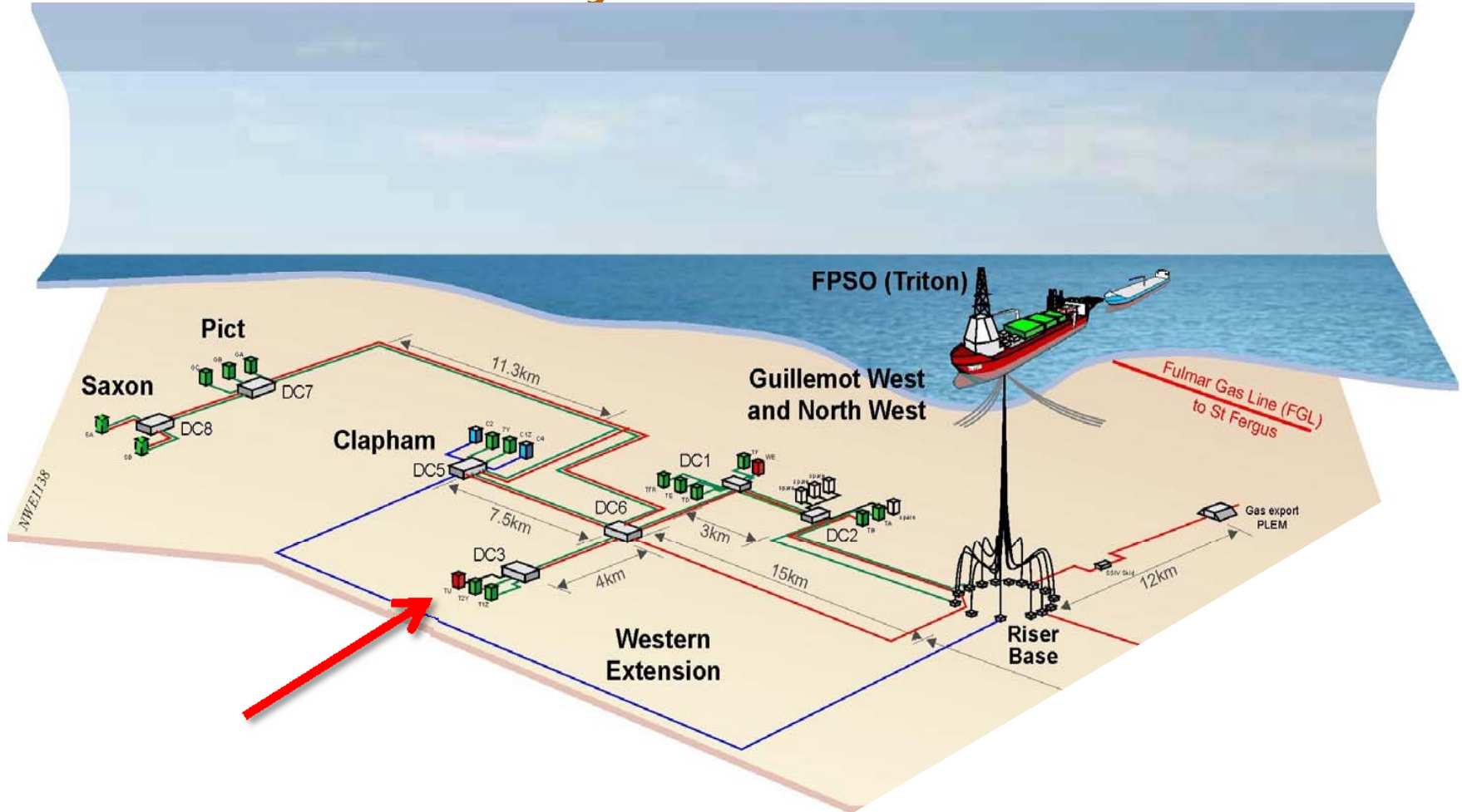
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Contents

- Introduction to the field and the problem well
- Introduction to the technology solution
- Well considerations
- Treatment Application
- Treatment Outcomes
- Conclusions

Triton Field Layout – Petro-Canada Assets



Guillemot West TU Well – Overview

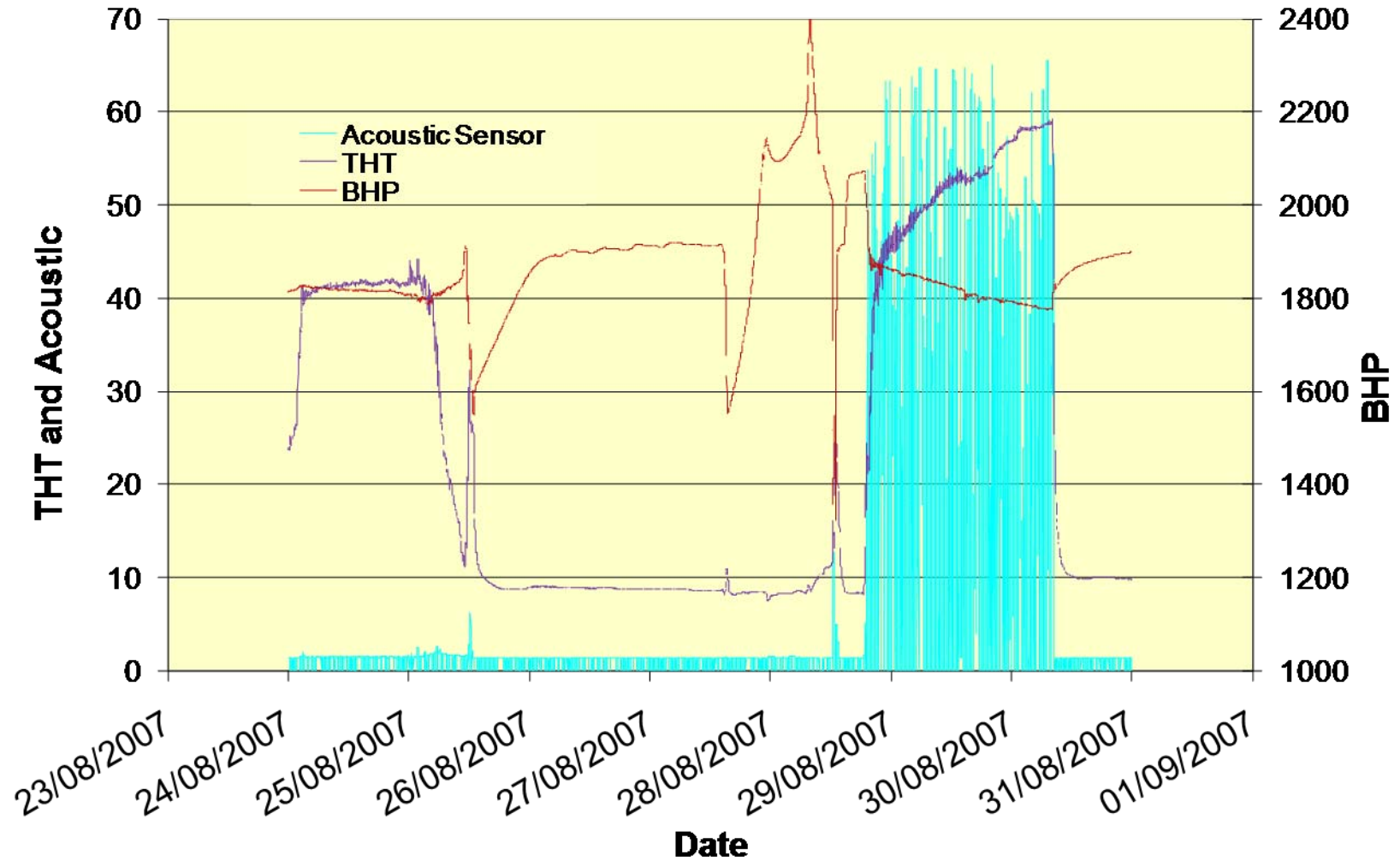
- Guillemot West & Guillemot North West fields operated by Petro-Canada UK with 90% equity, ExxonMobil 10% equity
- Part of the Triton field complex block (21/25, North Sea, 190 Km east of Aberdeen)
- Well completed 2007 with Expandable Sand Screens
(No installation issues recorded)
- 100m Horizontal completion
- 100% oil, no water.
- Maximum flowrate of approx 5000 bopd.
- GOR approx 1500 scf/stb, increasing with test duration
- Minimum FBHP 1840 psia

TU Well – Production History 2007

- 15th July - Well opened
- 15th July - Acoustic Sensor (d/s Production tree) shows large increase in noise
- 16th July - Sand confirmed topside, well cut back until sensor noise on par with others.
- 18th July - Choke increased, noise detected, cut back to stable 'sand free flow'
- 25th August – Well stopped flowing naturally
- 25th-28th August – Several gas lift restarts, but sand production confirmed.
- 30th August – Well shut in due to excessive sand production.

Cause - Screen Failure? Location unknown

TU Well – Critical Sand Production



Weak Reservoir Material



TU Well – Remedial Options

- Abandon well
 - Only 6 weeks of production, so negative cost variance
 - Significant reserves still in place
- Re-complete/Sidetrack
 - Expensive option. Query over whether further outlay will be recouped
 - May not resolve problem as root cause hard to confirm/not known
- Look at alternative remedial treatments
 - Champion Technologies SECURE SC2020
 - A technology with a proven and growing track record

SC2020: Introduction to the Technology

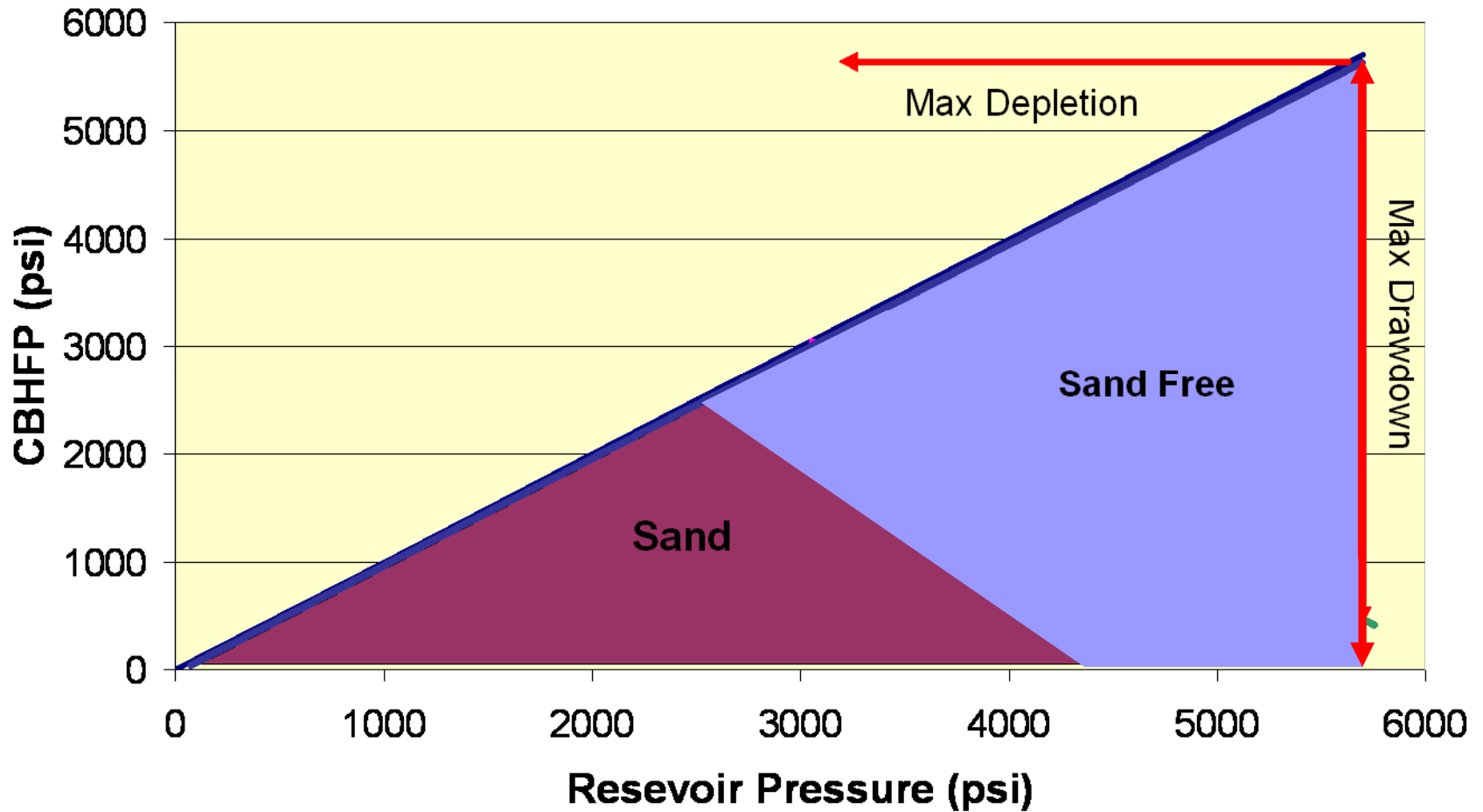
- Champion chemical sand consolidation technology - SECURE SC2020
- Key features:
 - Targets moderate increase in sand strength with minimum loss in permeability
 - Deployed using simple process from dilute solution in diesel
 - Short shut-in period
 - Controlled returned to production
 - Environmentally acceptable
 - Designed to allow increased production from wells on MSFR*

* Maximum sand free rate

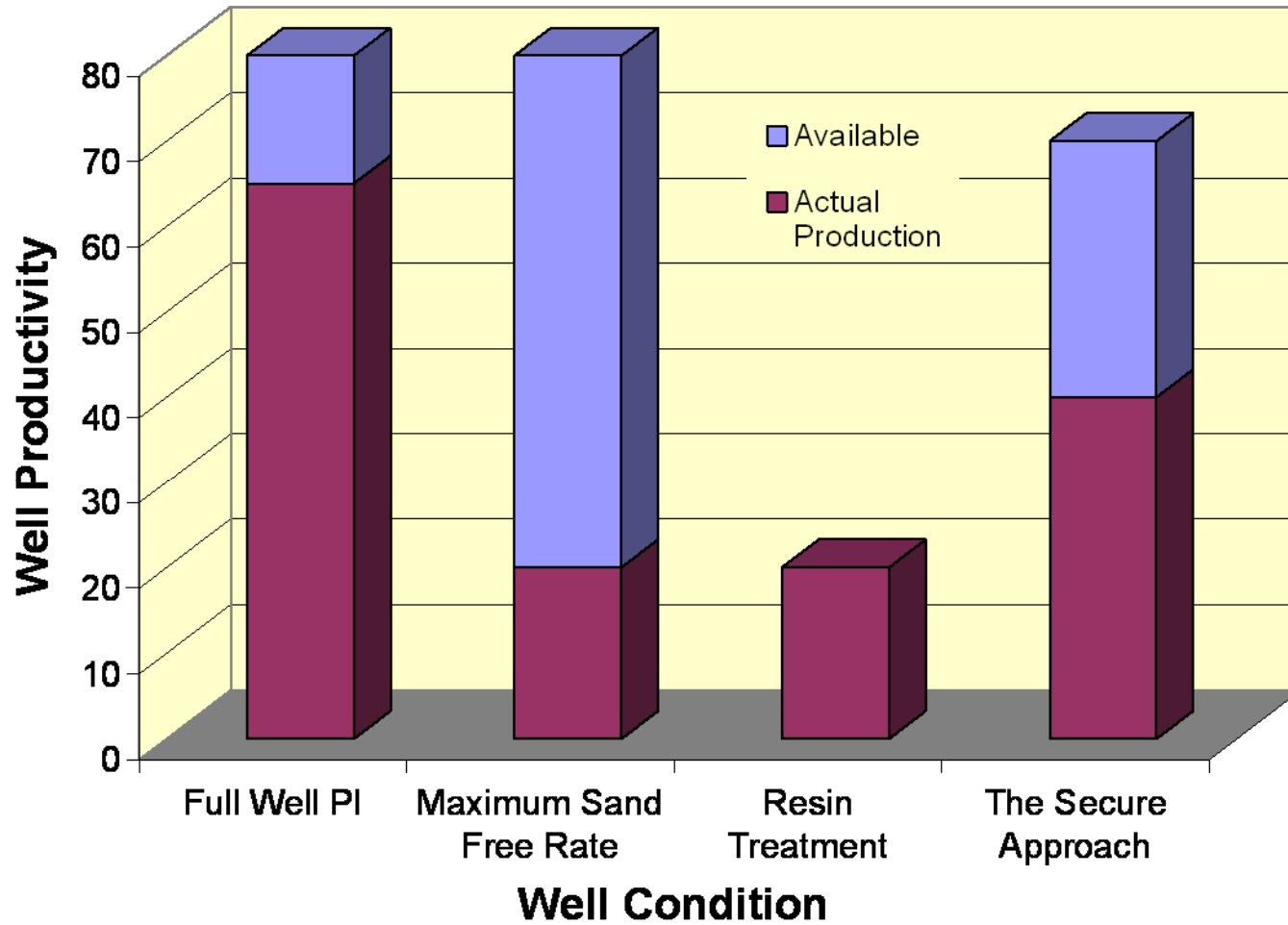


Increasing Reservoir Strength

The SECURE approach



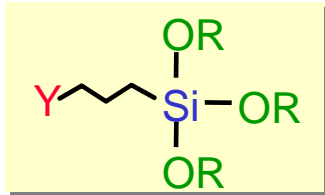
Restoring Well Production



Introduction to the Technology

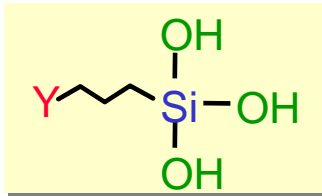
- Oil soluble organo-silane, supplied as concentrate in protective atmosphere
- Dissolved in diesel prior to application, typical concentration 4 – 7% v/v
- Molecule contains hydrolysable leaving groups
- On contact with in-situ reservoir water:
 - Hydrolysis changes functional groups from silane to silanol
 - Changes chemistry from oil soluble to water soluble
 - Drives partition to water phase
 - Yields molecule with active silanol sites
- Silanol groups form strong attachment to sand grains via primary chemical bonds
- Further reactions lead to formation of flexible visco-elastic network within water phase
- Reaction driven by hydrolysis and increase in temperature

Overview of Product Chemistry



Silane

Soluble in oil

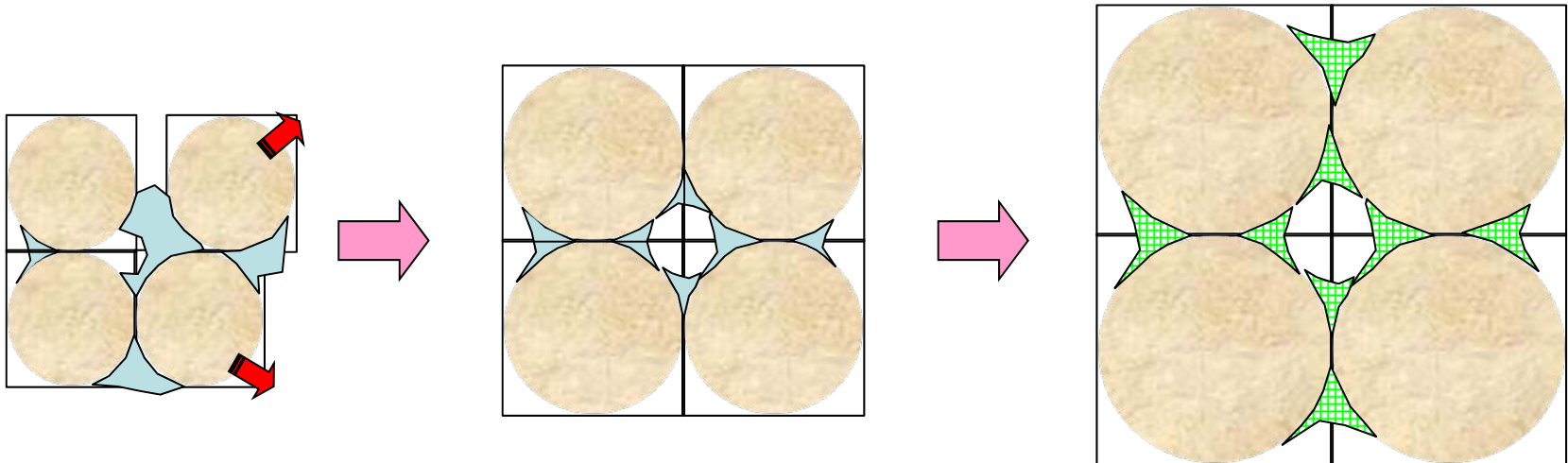


Silanol

Soluble in water

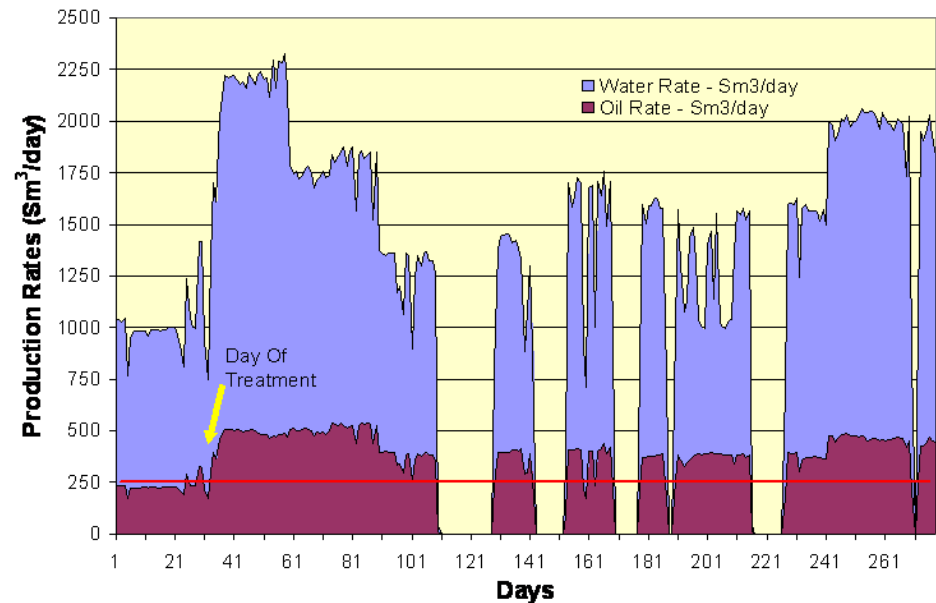
Application Strategy

- Diesel spearhead to reduce to Swi
 - Injection of Main Pill and placement
 - Shut-in
 - Controlled return to production



Supporting Evidence

- 12 Treatments in 5 Norwegian fields
- 6th & 7th Fields – at planning stage
- Other qualification work results
- 3 SPE papers on Field Treatment outcomes
- Good Case Histories



Treatment Challenges

- A first treatment outside of Statoil/Norway
- No core material available for qualification test work
 - Analogue field results were taken into consideration
- A failed ESS completion had not been treated in previous treatments
 - Temperature limitations with respect to screen cooling
- The system was static
 - What impact of sand in completion etc.?
- A 100m interval much longer than previous successful and durable treatments
- The well had been producing dry oil
 - Previously treated wells had 20-80% water cut
 - A test to the 'placement' theory with respect to Swi

Treatment – Assumptions and Notes

- The aim is to treat by radial dispersion into reservoir
 - Typical treatment depth 0.75m – 1.25m (depending on completion)
 - Target depth has significant influence on the volumes required
- Deployment concentrations are typically 4%-7% (based on treatments run to date)
 - Petro-Canada opted to go with low-mid range concentration
- Job cost to be evaluated against potential revenue gains.
 - Looking to re-coup all treatment costs in a few weeks.

Further Treatment Considerations

- Test for Asphaltene impact
 - Risk evaluated as very minor/acceptable
- Test for Material compatibility
 - Main Seal material in completion (HNBR) was unaffected by active chemical.
- Water content in Marine Gas Oil and DSV tanks
 - Evaluated as <100ppm typical. Offshore check to be made.
- Test for Longer shut-in period, to meet wider operational needs
 - Previous shut-ins <24hrs.
 - 70 hrs tested with no negative impact
- Contingency plans for interruptions to operation
 - Detailed plans for all stages of pumping operations

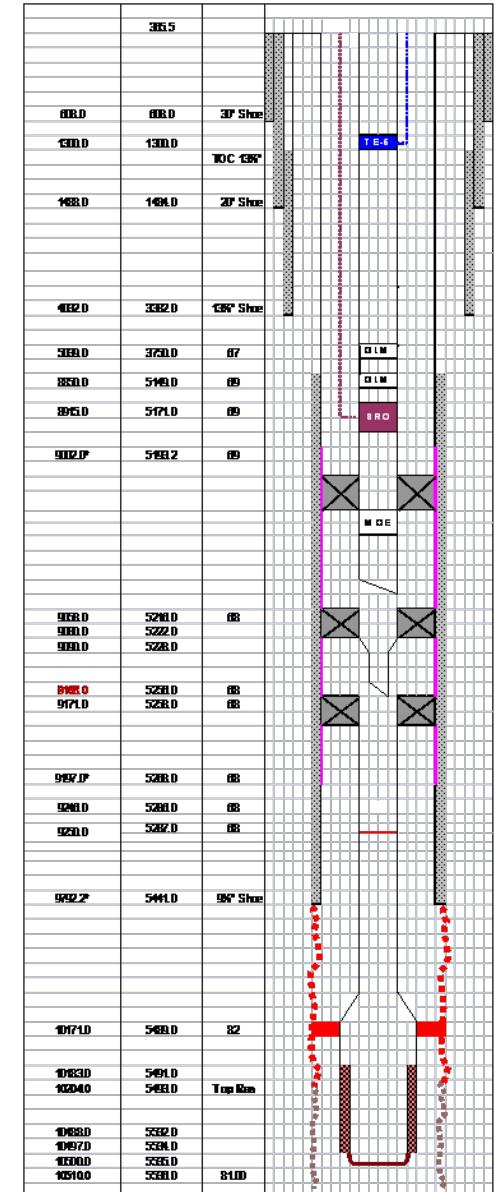
Treatment Design Data

- Tubing Volume – ~ 250bbl (40m³)
- Production Interval – 339ft (104m)
- Reservoir Porosity – 0.12 - 0.35
- Casing Outer Radius – 8 inches
- Perforations – None.

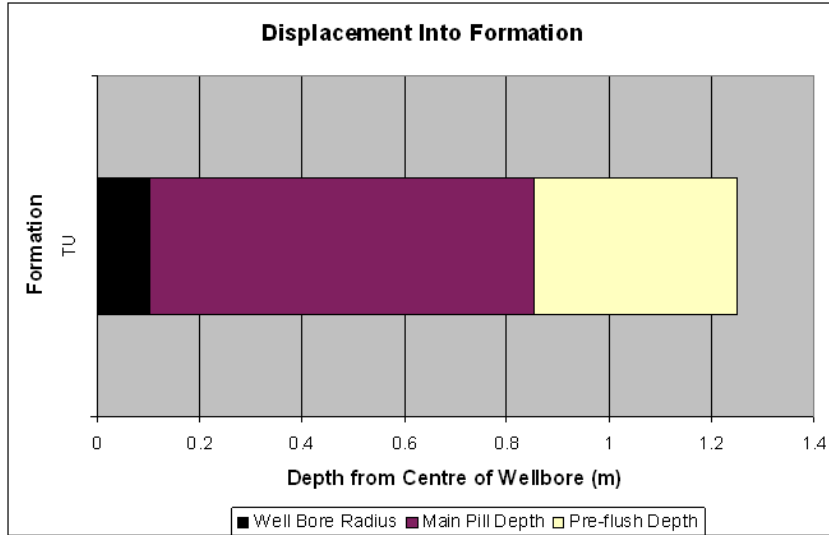
Zones within TU Well

Interval no.	Interval Length Meters	Interval Length (Feet)	Por [%]	Permeability [mD] Petro Canada Est.	Sw*
1	6	20	30	180-300	0.2
2	24.5	80	20	4-20	0.2
3	15.4	50	12	0.2-3	0.2
4	46	150	35	1000	0.2

*Estimated water saturation after diesel preflush.

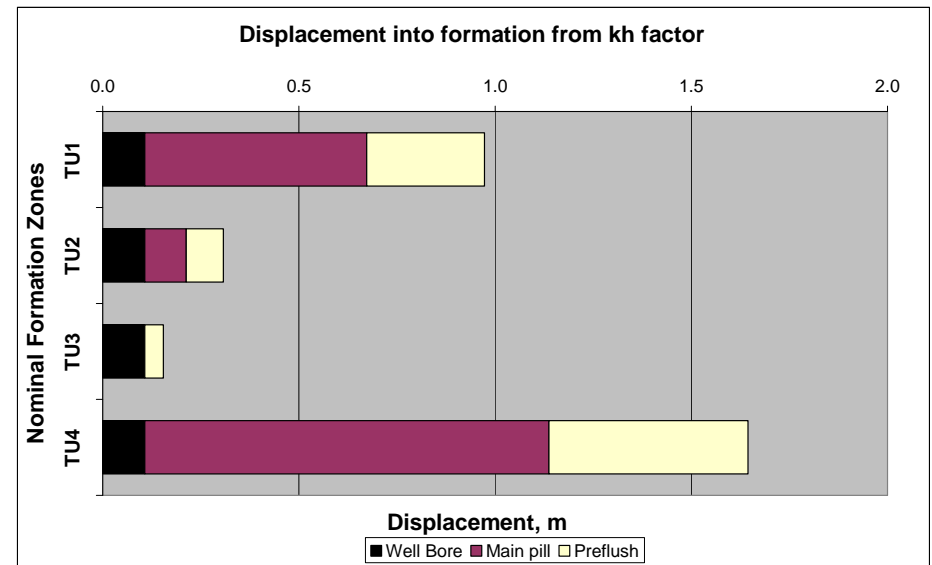


Placement Assumptions



- Uniform Radial Distribution
- Target depth of 0.75m
- Diesel pre-flush depth sensible

- Model zones with permeability
- Less uniform placement
- Does not account for Horizontal orientation
- Pump rate will have affect



Evaluation Criteria

Sequential series of treatment targets:

1. Successful deployment of treatment
 - Record of work / sample analysis (retains and flow-back) / process behaviour
2. Return of well to initial production target
 - Ideally agreed before deployment / controlled start up strategy
3. Confirmation of sand free rate
 - Monitoring method available
4. Short term persistence
 - Behaviour over first days / weeks
5. Increase in maximum sand free rate?
6. Long term persistence
 - Behaviour over following months, noting well history

Offshore Plan

- Operation included as part of a wider DSV field programme
- Choke change out first
 - In case of erosion from previous sand production
 - Opportunity to improve trim for better flow control
- Pumping operation
 - Treatment design
 - Preflush - 378bbl (60m³) diesel
 - Main pill – 350bbl (55m³) 5% SC2020 in diesel. To be mixed on the fly
 - Placement volume - 250bbl (40m³) diesel
 - Pump at the maximum rate the ESS temperature limitation would allow.
(Main pill at 3.5bbl/min, reduced for placement vol. due to cooling in well)
- Longer shut in period than typical

Well Start Up Procedures

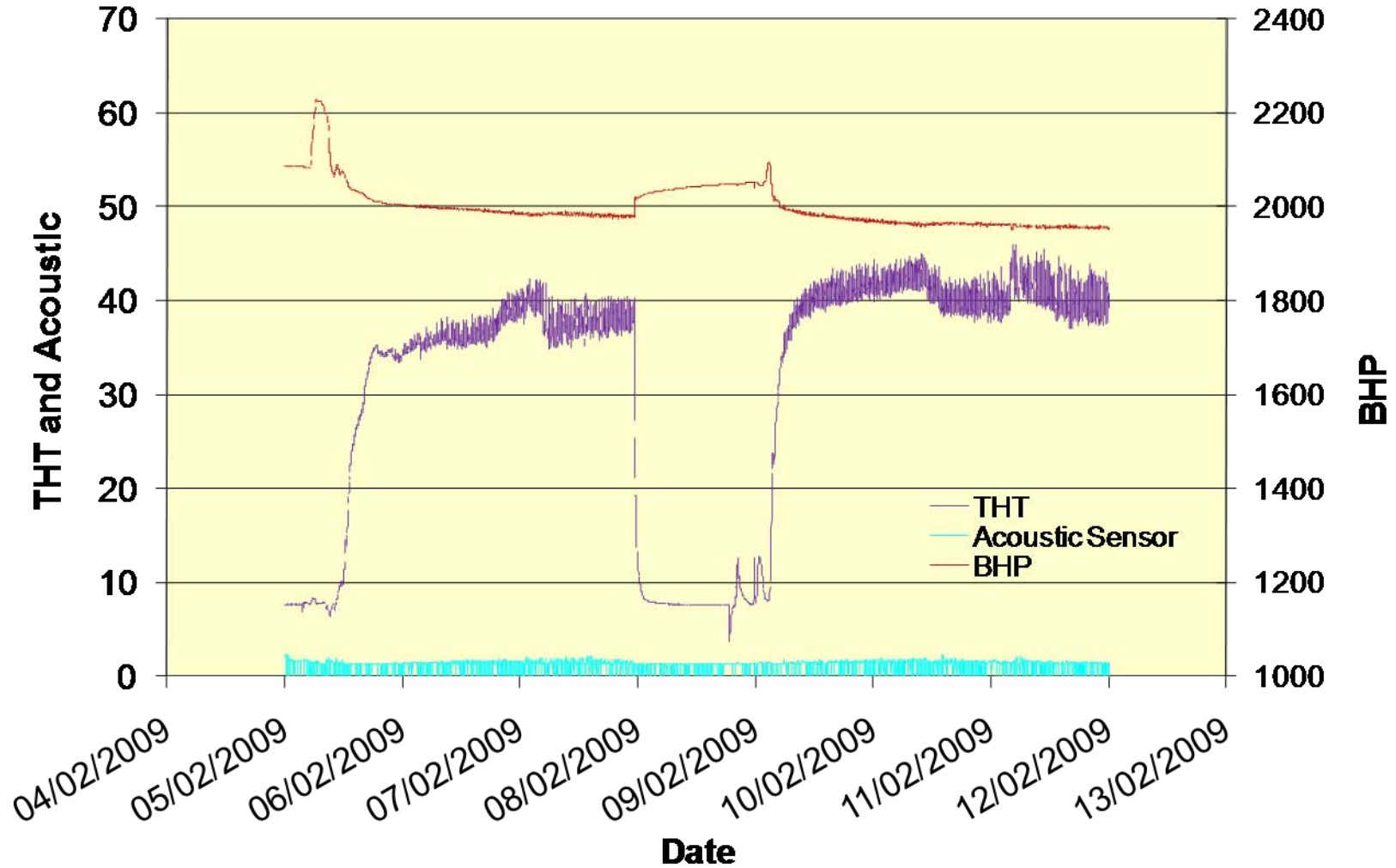
- Current 'best practice' for wells liable to produce sand suggests gradual re-start

- Agreed procedure:

Choke Size	Duration	Total Time
0 – 10%	1% every 20mins	200 mins
10 – 16%	1% every 20 mins	120 mins

- Monitor BHP and do not allow to fall below target value
- When the well starts flowing, allow period of stable flow
- Monitor and proceed as advised by Production Engineer

TU Well – Critical Sand Production



Evaluation Criteria

1. Successful deployment of treatment
 - Target met – no significant issues
2. Return of well to initial production target
 - Target met – straight forward start-up
3. Confirmation of sand free rate
 - Target met – acoustic monitoring
4. Short term persistence
 - Target met – operation recouped treatment costs within few weeks
5. Increase in maximum sand free rate
 - Operator decided not to challenge current rate
6. Long term persistence
 - Target met – well has remained in operation since treatment

Technical & Economic Benefits

- Increased production and revenue from TU Well
 - 12 Months Production at 2000 BOPD
 - Petro-Canada decided not to push for increasing the rate to test technology
- Fuller evaluation of well location with respect reserves
 - Drilling operation able to be removed from 2009 work Plan
- Treatment has lasted despite increasing water cut in well
 - Often a trigger for further sand production
- Petro-Canada consider treatment to have given a huge boost to 2009 revenue and costs.
 - The technology delivered the solution as proposed.
 - The eventual outcomes have greatly exceeded expectations

Conclusions

- A 'lost' well was brought back to production by SECURE SC2020 technology
- Petro-Canada gained significant financial benefit
- A first UK treatment

- The scope of applicability of the technology was significantly widened
 - ESS completions
 - Dry Oil well treatments
 - Longer intervals

- The value of the SECURE SC2020 technology was proven again.

Conclusions

Thank You

Thanks to Alasdair Pirie (Petro-Canada) – for well data and information.