Enhanced Oil Recovery
North Sea Case Studies

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‘North Sea’ is a catch-all label covering North Sea, West of Shetland and Norwegian Sea

EOR projects reviewed were either on UK Continental Shelf, UKCS, or on Norwegian Continental Shelf, NCS

Both producing regions are considered mature, but also have areas in which significant new developments are occurring:

► for UKCS - West of Shetland
► for NCS - Norwegian Sea

UKCS oilfields are predominantly sandstones

NCS fields are mostly sandstones but a significant chalk play exists
Orientation

- Water depth ca. 100-400m, deepens as move North
- Initial large fields developed with fixed platforms
- FPSO more common in deeper and less sheltered water
North Sea - Potted History

➢ **Geological ages** of developed oil reservoirs, in declining order of historic recovery, were
  - For UKCS: Jurassic, Tertiary, Cretaceous
  - For NCS, Jurassic, Cretaceous (chalk) and Tertiary

➢ **Waterflooding** has featured in the majority of oil field developments

➢ Initial, large field developments typically preceded gas evacuation

➢ **Gas injection** (GI) adopted as
  - Large volumes of gas
  - structural relief
  - rock quality
  - a need to replace reservoir voidage (production)

➢ Oilfields that used GI include **Brent, Beryl, Fulmar** (all UKCS) and **Ekofisk, Statfjord, Gullfaks, Oseberg, Snorre** (all NCS)
North Sea - Gas Market Effect

➢ Since early 1990’s GI has not featured in initial field developments in UKCS
  ▶ UK switched to natural gas for power generation and domestic consumption and associated gas was increasingly diverted there
  ▶ UK is gas deficient and imports over 50% of its requirements

➢ NCS saw more gradual build-out of pipeline and market
  ▶ Norway internal markets are small and dispersed, fully supplied by hydroelectric

➢ For NCS, GI continues to feature in some new field developments dependent on gas export options, area gas sales agreements etc.
  ▶ Potential for CO₂ as part of Carbon Capture and Storage (CCS)
North Sea - Recovery Factor Snapshot

➢ Both UKCS and NCS oilfields have enjoyed very high recovery factors

➢ High cost environment with limited, high-cost wells meant focus on:
  ► Reservoir characterisation (3D seismic then 4D, geological modelling)
  ► Reservoir management strategies (solution gas drive not used)
  ► Well construction (extended reach drilling, smart wells, flow assurance)

➢ Favourable geology, light oil translated into good waterflood recovery and, where used, from gas flood

➢ Estimated ultimate recovery for UKCS and NCS oilfields 46%
UKCS and NCS EOR

North Sea EOR Projects, Total 27

North Sea EOR by Country

- HCGI
- WAG
- MEOR
- Polymer
- LWSF

- Norway
- UK
- Denmark
Water Alternating Gas (WAG) is a hybrid scheme that combines water and gas flooding

Features

- A compartment/ fault-block is injected with water for a set volume typically then the injector is switched to gas injection for a set volume
- Sequence performed multiple times to maximise incremental oil
- Limits gas cost burden but changeover adds operational complexity
- Preceded by core floods to establish incremental recovery target and detailed reservoir modelling to scale up lab results (or field pilots)

Applied successfully in several North Sea fields - cycles ca. 6-12 months

Currently by

- BP - Magnus (UKCS) and Ula (NCS)
- Statoil - Gullfaks, OsebergE, Snorre, Veslefrikk; W’shall - Brage
Magnus Field Production Plot

- Built on learning from Miller, Ula, S.Brae
- Imports associated gas from West of Shetland
- Increased contribution from WAG as more fault blocks added
- Long payback often a feature of EOR
Ula Field Production Plot

- Built on Miller, S.Brae, onshore experience
- Imports associated gas from nearby fields
- Increased contribution as WAG widened
Recovery by water flooding impacted by viscosity difference with oil

- For typical light N.Sea oil, >30°API, 1-10cP contrast not significant
- Where oil heavier and more viscous, making injection water (<1cP) more viscous introducing polymers may improve recovery vs seawater

UKCS pilot scheme by **Chevron in Captain** (ca.100cP oil), NCS pilot by **Statoil in Heidrun**, long running Total project in Dalia, offshore Angola:

- Identifying best polymer, temperature and salinity constraints
- Logistics and supply chain getting chemical to offshore wellsites
- Onsite QC ensuring intended quality is injected in reservoir
Results encouraged incorporation of facilities for polymer flooding in asset development planning

- **Captain** late life development planning
- Redevelopment planning for BP’s **Schiehallion field**, West of Shetland
- Final FID pending for both

EOR favours companies with

- ‘long time perspective’ as offshore EOR project risk mitigation reflected in v.long time frames
- R&D resources
- ability to move opportunities out of the laboratory and into field
- access to cheaper, proving grounds
- Collaborative approaches to shared risk mitigation e.g. for polymer BP+Statoil partners in Dalia
Emerging EOR Methods

- Emerging EOR methods
  - Microbial EOR (MEOR)
  - Low Salinity Water Flooding, LSWF

- Both reduce residual oil saturation in rock
  - In MEOR bacteria is introduced and nourished in reservoir to effect a reduction in surface tension and reduce oil trapping in pores
  - Science behind low salinity effect is still under debate

- ‘Cheap’ proving grounds have been important
  - Statoil - ongoing MEOR trial in Norne, NCS, but have collaborated on N.American field trials with Glori Energy (early Gullfaks pilot too)
  - BP – at forefront of evaluation of Low Salinity WF, have progressed the technique through a succession of field trials initially onshore Alaska

- LSWF/ LoSal® has been adopted by BP for field-wide deployment in the next development phase of Clair, West of Shetland (under construction)
## Challenges:
- Remoteness, weather, sea-state
- Space and weight limitations
- Expensive wells, wide well spacing
- Reservoir understanding
- Seawater main resource
- Flow assurance
- Mature field: old wells, commingled
- Pilot testing
- Access to experienced specialists

## Resourcing:
- Integrated team incl.wells, facilities from outset for early ID of issues
- Location/ nature of unswept oil coupled with geology
- Supplementary core analysis to confirm EOR opportunity
- Additional PVT analysis
- Flow assurance provision
- Monitoring and surveillance plan
- People: continuity, long term
Offshore EOR Incremental Recovery

- Reporting sporadic, estimates not always consistent/comparable
  - N.Sea regional average RF 46% but range is wide ca.20%-70%
  - Similarly incremental RF from EOR has range ca.2%-15%

- Localised EOR dilutes incremental field recovery e.g. if EOR adds 10% RF from a 200MMstb fault block of a 1000MMstb field, field RF +2%

- Field specifics incl. development history impact EOR increment also size of field, nature of reservoir (sandstone/carbonate), temperature

- EOR understanding, practises steadily evolving – collaboration and information dissemination/sharing important

- UKCS review identifies GI probably as WAG (possibly incl.CO₂), polymer EOR and LSWF as most applicable
Questions?

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