FEASIBILITY STUDIES AND RESULTS
PETERHEAD AND QUEST CCS PROJECTS
DAS VSP/MICROSEISMIC AND TRACERS

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OVERVIEW

- **Distributed Acoustic Sensing (DAS)**
  - Introduction – the technology
  - Motivation – why use fiber optic technologies?
  - Challenges – what are the current challenges?
  - Shell CCS projects – Overview of in-well acoustic monitoring

- **DAS Feasibility Studies, Field Trials, First Results**
  - Quest CCS Project: DAS Vertical Seismic Profiling (VSP) field trial results and first time-lapse results after injection start-up
  - Peterhead CCS Project: DAS VSP and DAS microseismic feasibility studies

- **Tracer Feasibility Study**
  - Peterhead CCS Project: Summary of insights for offshore CO₂ tracers
1.0

IN WELL ACOUSTIC MONITORING FOR CO$_2$ STORAGE OPERATIONS

INTRODUCTION TO DISTRIBUTED ACOUSTIC SENSING

OVERVIEW APPLICATION FOR SHELL CCS PROJECTS

Dean, The Quest CCS Team, The Peterhead CCS Team
Distributed Acoustic Sensing (DAS) converts a fiber optic cable into an array of sensors

- **System**: DAS system uses a fiber optic cable for distributed strain sensing and an optoelectronic device (interrogator box) for recording

- **Fiber Optic Sensing**: Rayleigh scatter based distributed optic sensing is very sensitive to both strain and temperature variations

- **Full Well Coverage**: Continuous acoustic measurements – a single optical fiber can replace 100/1000s of traditional geophones

- **Applications**:
  - **Time-lapse Vertical Seismic Profiling (VSP)**, refraction monitoring, fracture monitoring with active source
  - **Microseismic** hydraulic fracture monitoring, production induced or natural seismicity
DAS – MOTIVATION & CHALLENGES

Why use fiber optic technologies for containment monitoring?

1. **Non-intrusive**: Can be deployed in wells (on or inside tubing) that are not accessible to geophones
2. **Continuous**: Does not require well intervention, i.e. continuous recording is possible
3. **Low-cost**: Permanent and on demand monitoring
4. **Efficient**: Synergy with other in-well fiber optic technologies – a single line can be used for many applications (acoustic, temperature, chemical)
5. **Full vertical coverage**: Fast acquisition, full well coverage

**Challenges for acoustic applications**

1. **Noise**: Higher noise floor than geophones
2. **Directional and wavelength sensitivity**: Amplitudes decay with incident angles faster than in geophones and depend strongly on incident wavelength
Monitoring Objectives

Below the salt:
- Detect migration of CO$_2$ or brine along an injector, via matrix pathways, along fault pathways
- Detect induced fractures opening

Above the salt:
- Detect CO$_2$ or brine entering the upper formations or groundwater

Storage Site (deep saline aquifer):
- Detect migration of CO$_2$
- Detect migration of pressure
MONITORING OBJECTIVES

Storage Complex:
- Detect migration of \( \text{CO}_2 \) along an injector, via matrix pathways, along fault pathways
- Migration of \( \text{CO}_2 \) into overlying secondary storage

Storage Site (depleted Goldeneye gas reservoir):
- Detect migration of \( \text{CO}_2 \) within the Captain Sandstone – will be very challenging as acoustic impedance change is expected to be small (\( \text{CO}_2 \) gas replacing \( \text{CH}_4 \) gas)

Multi-well DAS VSP

Modelled source array utilizing shots from planned 3D surface seismic acquisition
2.0

DAS VSP  FIELD TRIAL RESULTS FOR QUEST CCS

COMPARISON BETWEEN
CONVENTIONAL GEOPHONES
AND DAS

FIRST TIMELAPSE RESULTS AFTER
INJECTION START UP

The Quest CCS Team
**Quest field trial:** Comparison between conventional Walk-Away Vertical Seismic Profiling (VSP) with geophones and DAS VSP shows that similar results can be generated. DAS has slightly lower frequency content. Walk-Away lines tie.

- **Identical Processing**
- First Break picking
- Noise filtering
- Amplitude balancing
- Phase deconvolution
- Whitening
- Migration

126 channels; first @180m, Δz=15m

177 channels; first @170m, Δz=10m
Time-lapse application is possible: Good repeatability (NRMS =0.15) in target area

\[
NRMS = \frac{2 \times \text{RMS}_{\text{monitor}} - \text{RMS}_{\text{base}}}{\text{RMS}_{\text{monitor}} + \text{RMS}_{\text{base}}}
\]
VSP BASELINE PROCESSING

VSP vs 3D seismic for 2015 baseline survey

Processing workflow for baseline and monitor include:

- Data QC
- Wave field Separation
- Noise attenuation
- Deconvolution
- Reverse Time Migration (RTM) using smooth sonic velocities.
- Post stack noise attenuation
DAS VSP DATA: SAMPLE SHOTS

2015 Baseline – Raw

2015 Baseline – Basic Processing

2016 Monitor – Raw

2016 Monitor – Basic Processing
3.0

**DAS VSP FEASIBILITY STUDY FOR THE FORMER PETERHEAD CCS PROJECT**

**MODELLING BUSINESS CASE**

Grandi
The goal of the study was to answer the following question:

1. What is the size of the image area for a multi-well DAS VSP?
2. Are there clear benefits in recording at all wells?
3. What is the achievable horizontal resolution?
4. Can the Goldeneye well geometry mitigate DAS directionality limitations?
5. What are the minimum requirements for the source coverage?
**Modelling Approach:**

- **Ray Tracing:** Kinematic ray tracing was performed using a simplified velocity model from Pre-stack Depth Migration.

- **Geometry:** P-wave rays are shot from determined source positions at the surface, transmitted and received at wells with DAS channels acting as receiver arrays (with receiver spacing ~10m).

- **Diagnostics:** Derive incidence angles and travel times, fold, azimuth and offset distribution, image area, horizontal and vertical resolution.

Ray tracing with simplified 3D PreSDM velocities.

Shot arrays input used for modelling (black = 12km$^2$) and larger area (green = 35km$^2$), both 50m x 50m.

Interpolated positions of DAS channels along well paths.
Challenge: Assuming standard fiber optic cables (straight fiber) and considering the higher noise floor of interrogator units, the useable angle range of DAS is smaller than that of a 1C geophone

- Waves arriving perpendicularly to the cable will not be sensed (no differential displacement of fibers)
- The angular dependence of DAS is stronger than that of a geophone: \(\cos^2 \theta \) vs. \(\cos \theta\)
- The incident wavelength must be larger than the section over which strain is measured

Modelling Results: Sufficient rays arrive at required angles for containment monitoring along injectors

- Top of storage site: 82% of rays arrive at angles below 45°
- Top of secondary storage: 21% of rays arrive at angles below 45°. This effect can be mitigated by adding more shot points to compensate for exclusion zone around platform
Modelling Results:

- **Resolution**: horizontal = 10m – 60m, vertical = 10m-16m
- **Image area top primary storage**: high fold image area of ~2Km² around the wells
- **Image area top secondary storage**: ~0.5Km² around the wells (fold ~50)
- **Offset and Azimuth Distribution**: Reflect well geometry with offset ranges from 0 – 3600m

**Effective fold map at the top of the storage site.**

\[ \text{Effective fold} = \text{fold} \times \cos^2\theta \]

**Effective fold map at the top of the secondary storage site (near top of storage complex).**
DAS VSP FEASIBILITY STUDY FOR GOLDENEYE – SUMMARY

- **DAS VSP IS FEASIBLE:** The multi-well geometry at Goldeneye can compensate for the broadside limitation of DAS

- **SOURCE:** Modelled source area was 12km$^2$ which can be done in a 1 day operation (Source spacing = 50mx50m, ~5000 shots). Possible to increase image area with additional shots

- **IMAGING:** Possible high fold image area of ~2km$^2$ around the platform at the level of the storage site and ~0.5km$^2$ at the level of the secondary storage (near top of storage complex)

- **CONTAINMENT MONITORING:** A multi-well DAS VSP is likely to identify CO$_2$ migrating vertically near injectors or along abandoned wells. Horizontal resolution is ~10m – 60m and vertical is ~10m-16m

- **CONFORMANCE MONITORING:** Time-lapse saturation changes within the depleted gas reservoir are expected to be small, pressure changes may generate a signal. DAS VSP provides a lower cost conformance monitoring alternative to costly surface seismic

- **PLATFORM UNDERSHOOT:** DAS VSP is a viable alternative to an expensive platform undershoot

- **CHALLENGES:** The imaging area is limited and dependent on well geometry. Future generation of interrogators need to deliver a lower noise floor in order to improve SNR
**DAS VSP Feasibility Study for Goldeneye – Costs**

- **Option 1**
  - 1 streamer baseline survey (storage complex) with OBN undershoot. Excluding pre-hand over survey
  - 2 repeat OBN surveys (storage site)
  - 1 baseline + 2 monitors: ~26 million USD
  
  *Note that costs are indicative only.*

- **Option 2**
  - 1 streamer baseline survey (storage complex). Excluding pre-handover survey
  - Multi-well 4D VSP and micro-seismic monitoring near platform
  - 1 baseline (streamer and DAS) + 4 monitors (DAS): ~11.5 million USD
  - Excluding streamer baseline: ~5.0 million USD
4.0
DAS MICROSEISMIC FEASIBILITY STUDY FOR THE PETERHEAD CCS PROJECT

MODELLING

Grandi, Oates
Opportunities:
- Low-cost, synergy with other applications (DAS VSP, DTS)
- Multi-well geometry including vertical and deviated wells. Long aperture, smaller location error than geophones
- Monitor any induced activity confined to an area of few kilometers around the platform

Challenges:
- Amplitude dependence with incidence angle and wavelength (limited angular sensitivity). Ongoing development
- Need to develop: robust localization algorithms, triggering system, and real time diagnostics
- Noise related from injection, high instrument noise floor. Ongoing development
Modelling Approach:

- Estimate relative detectability and expected location error assuming worst case noise scenario (noise floor of DAS is 10s of dB higher than for geophones).
- Using internal earthquake detectability modelling tool:
  - Straight ray tracing between a set of modelled source locations and given receivers using a constant velocity medium
  - Error ellipsoid surfaces are obtained by minimizing travel times residuals between true hypocenter location and nearby locations

Results: Map view of minimum detectable moment magnitudes:

- Modelled hypocentres at Z=2500m; detectability comparison between geophones and DAS
Results: Estimated location errors

- Histograms of half length location errors for events at z=2500 m
- The DAS long aperture and the multi-well geometry (with deviated wells) create the potential to locate events with less than 15 m error.
- Errors are similar in all directions (x, y, z)
Results: Map view of estimated z location errors
DAS MICROSEISMIC FEASIBILITY STUDY – SUMMARY

- **DAS MICROSEISMIC IS RECOMMENDED AS R&D ACTIVITY:** DAS micro-seismic is not fully developed, but synergy with DAS VSP should be leveraged.

- **LIMITED APERTURE:** Multi-well geometry is favorable to offset aperture limitation.

- **LOCATION ERROR:** Potentially less than 15m error.

- **DETECTION RANGE:** At reservoir level events may not be detected below -0.9 moment magnitude. Detection is proven in settings where events are sufficiently close to the DAS cable.

- **LIMITATIONS:** Micro-seismicity, natural or induced by extensive reservoir processes have not been detected by current DAS systems.

- **LOCATION PROCESSING:** Some location processing has been developed but still experimental – need data and field trials!

- **NOISE:** Broadside sensitive cables and lower instrument noise are required. New generation of interrogators are expected to have much lower noise floor.

- **DECISION LOGIC:** Need to develop site-specific workflows to transform detected/located micro-seismic data to information for decision making.
5.0

**TRACER** FEASIBILITY STUDY FOR THE PETERHEAD CCS PROJECT

**KEY INSIGHTS**

Peters, Kampman, SGSI
TRACER FEASIBILITY STUDY FOR GOLDENEYE – SUMMARY

■ TRACER RECOMMENDATION: Identify all natural tracers in injected CO$_2$ (noble gases and $\delta^{13}$C) and inject artificial Xe isotope tracer ($^{129}$Xe/$^{134}$Xe or $^{129}$Xe/$^{136}$Xe)

■ ARTIFICIAL TRACER: Xe isotope is preferred to uniquely identify injected CO$_2$ (see next slide). Feasible as background of Xe is lower in subsea gases

■ BASELINE: A composition baseline of subsea gases, bottom waters, reservoir formation gas and source (flue) gas is required as a minimum

■ BASELINE +: Ideally a baseline survey would include gas/liquid from formations overlying the reservoir

■ ARTIFICIAL TRACER CONCENTRATION: The target injected Xe tracer concentration is $1 \times 10^{-9}$ to $1 \times 10^{-10}$ cc Xe/cc CO$_2$

■ ARTIFICIAL TRACER COST: A $5 \times 10^{-10}$ cc/cc $^{129}$Xe/$^{136}$Xe spike would require 250L/annum tracer volume and cost $100k\ USD$. Analytical costs for 12 samples per annum would cost $25k\ USD$
FEASIBILITY STUDY FOR GOLDENEYE – ARTIFICIAL TRACERS

**Pro**

**XE ISOTOPES:**
- Inert
- Little loss to rock
- No loss on CO\textsubscript{2} phase change
- Measurable, unique identifier

**PFCs:**
- Cheap
- Low analytical cost
- CO\textsubscript{2} affinity, unique

**Con**

**XE ISOTOPES:**
- High analytical cost
- Very specific analytical equipment needed

**PFCs:**
- Major loss during CO\textsubscript{2} phase change
- Loss during contact with light HCs
- Adsorption on clays/dry surfaces