This experimental study investigates the oil recovery mechanisms and feasibility of CO₂ injection for harvesting the energy stored in tight shale-oil reservoirs.

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ABSTRACT
Harvesting the energy stored in tight shale-oil formations, does neither have to involve hydraulic fracturing, nor horizontal drilling of wells. By utilizing the differential pressure driven oil displacement from continuous injection of supercritical CO₂ in shale-oil reservoir cores, all experimental tests presented here yielded recoveries in the range of 19.8% of OOIP to 55.0% of OOIP. A total of 22 miscible CO₂-injection tests were performed in a high-temperature, high-pressure experimental setup to systematically evaluate the effect of system length, permeability and the ability to develop miscibility on the recovery of oil. In addition, the fluid flow capacity for the cores was estimated by calculating effective end-point permeabilities, yielding values between 59 nD - 2.68 μD. Rock structure characterization based on data obtained by CT scanning proved to be a feasible method for determining production capacity of tight shale formations. The low fluid flow capacity in combination with miscible displacement suggested diffusion to be a key recovery mechanism. In addition, associated CO₂ storage in nano- and micropores incentivizes this production method both from an environmental- and economic perspective.

Materials and Methods
Oil recovery tests were conducted by liquid and supercritical CO₂-injection and permeability was used as a fluid flow capacity measure based on the boundary conditions and parameters obtained from the experiments.

The rock structures for each sample were obtained with a medical X-ray computed tomography (CT) scanner located at Haukeland University Hospital (HUH), CT uses an X-ray source and a series of detectors to scan and image a sample. The detectors measure the X-ray signal attenuation through the sample and by rotating the cores; high resolution 2D-slices were obtained. A high CT value relates closely to high rock density (high degree of attenuation) and by using imaging software, visual interpretation of the results could yield desirable qualitative information about porosity, permeability, laminations, and flow barriers. CT scanning in combination with image analysis can be used to quantitatively determine rock properties and fluid flow (Withjack, 1988), creating a fundament for numerical simulations. By stacking images on top of each other a 3D visualization of the sample is obtainable without destroying/altering the sample (Ketcham and Carlson, 2001).

Results
Rock Structure Using Computed Tomography (CT)
Image montages from CT scans of the three 1.5” cores are shown in Figure 2 and Figure 3. The images are chosen to best represent the cores as a whole, by selecting 6 out of 40-60 images. A normalized position is added to each slide (0 is the inlet; 1 is the outlet). Each of the slides is 0.6 mm thick and there are distinct differences in the typology of the cores, likely to affect the fluid transport and hence could be important when analyzing dynamic production data.

The plot of average CT values of the length fraction as a function of normalized length for the 1” cores is given in Figure 4.

Fluid Flow Capacity
Determining the fluid flow capacity in unconventional tight shale-oil cores was an important part of the experimental investigation. It is described in terms of end-point effective permeability during continuous supercritical CO₂-injection and the results are summarized in Figure 5.

Oil Recovery
A total of 13 CO₂-injection tests were performed on crude oil re-saturated shale-oil reservoir cores. 8 performed on 1.5” cores and 5 performed on 1” cores. All experiments were performed at 60 °C, inlet pressure of 220-223 bar, outer pressure of 149-152 bar and overburden pressure of 310-313 bar. The average oil recovery factor yielded 34.9% of OOIP (±5.4% of OOIP). The oil recovery vs. PV CO₂ graphed for 7 1.5” cores are given in Figure 6.

Conclusions
• The experimental results demonstrate that CO₂-injection may be used for oil recovery in tight shale-oil reservoir cores.
• Average recovery factors during supercritical CO₂-injection in crude oil saturated cores varied between 19.8-55.0% of OOIP (± 4.1% of OOIP) for 13 CO₂-injection tests.
• Initial analysis indicates correlation between average CT values and final recovery factor for tight shale samples.

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REFERENCES

Fig. 1 - Schematic illustration of the experimental setup used for CO₂ injection in tight shale-oil reservoir cores. Autoroute valves (two- and three-way) are numbered and represented in light blue. Green lines represent digital information from pressure transducers, pumps and web camera. These units are connected to a computer and their respective data processing software for analysis. Thick purple lines represent fluid flow path, where flow direction is indicated by arrows. Black lines represent remaining tubing. The heating cabinet is indicated by the thick red rectangle. The pressure P₁, P₂, and P₃ measure the inlet, outlet and back-pressure, respectively.

Fig. 2 - Selected images of shale core 12L. Above each image in a number fraction relating the slice to its dimensionless position from the end. Regions of higher density structure (bright grey) were observed with varying degree of continuity along the length of the core. Laminations are not observed.

Fig. 3 - Selected images of shale core 5CS. Above each image in a number fraction relating the slice to its dimensionless position from the end. Regions of higher density structure (bright grey) were observed with varying degree of continuity along the length of the core. Laminations are not observed.