energies

MDPI

Editorial

Editor's Choice: Advances in Carbon Capture Subsurface Storage and Utilization

Pål Østebø Andersen

Department of Energy Resources, University of Stavanger, 4021 Stavanger, Norway; pal.andersen@uis.no

This "Editor's Choice" article summarizes nine recent articles in *Energies* focusing on carbon capture, subsurface storage, and utilization. This technology is considered to be vital for limiting the carbon concentration in the atmosphere, thus mitigating climate change, while meeting the energy demands of society. The topics of this Editorial include: evaluation of potential underground storage sites [1]; using CO_2 as cushion fluid in subsurface gas storage [2]; economic hydrogen production from coal gasification with carbon storage [3]; life cycle analysis of CO_2-enhanced oil recovery [4]; improved carbon storage as hydrate [5]; history matching and optimizing CO_2 water-alternating-gas (WAG) [6]; enhancing CO_2-based foams with polymer [7]; evaluation of cap rock integrity [8]; and economical assessment of carbon capture and injection technologies [9]. What follows is a brief summary of each selected paper (in alphabetical order):

Arvanitis et al. [1] evaluated potential subsurface locations in Greece for the storage and production of thermal energy and hydrogen and CO_2 storage. They applied petrological and geochemical data, field observations and literature data, and storage calculations accounting for the physicochemical properties of target reservoirs. Aquifers were found to be better options for thermal energy than abandoned mines. Suggestions were made for three aquifers to cover regional heating energy consumption. Gas fields, aquifers, and evaporites were considered the most relevant underground natural gas storage options in Greece, where the gas fields Prinos and South Kavala displayed the highest storage capacity. Gas storage in these fields were evaluated to cover the regional household electricity needs. Hydrogen storage options were proposed in evaporite caverns near on-shore wind farms where hydrogen could be produced. One third of the hydrogen was considered to be working gas, while the rest was cushion gas. It was found that hydrogen could cover electricity needs of almost 7000 households. Basalts, sandstones, and evaporites in Greece were evaluated for CO_2 storage. One suggestion (of a few) was to store CO_2 from nearby power plants in the Pentalofos and Tsotyli formations, trapping carbon geologically and by mineralization.

Cao et al. [2] presented numerical simulations of underground gas storage where the Korean Donghae-depleted gas reservoir was repressurized with CO_2 as cushion gas and CH_4 as working gas (for storage and production). They simulated a quarter of a five-spot pattern. The initial CO_2 was injected in one well, while CH_4 was injected in another (at a higher level) until the reservoir was repressurized. Cyclic injection (of CH_4) and production (of CH_4-CO_2 mixture) from the latter well was then considered, each cycle lasting a year, for 15 years. Although CO_2 had a considerable higher density and viscosity than CH_4 at reservoir conditions, the gases were gradually mixed with time. Notably, an injection of mobile CH_4 caused CH_4 to mix with CO_2 at the far end of the system. A higher initial amount of CO_2 naturally led to higher concentration of CO_2 in the produced fluid. They also showed that mixing occurred more easily and that higher concentration peaks of produced CO_2 would occur at a higher reservoir permeability. They noted that the presence of initial residual water would lead to a more rapid pressure buildup (due to the low compressibility) and mixing. Limits on produced CO_2 concentrations were used to suggest initial amounts of CO_2 used as the cushion gas.

check for updates

Citation: Andersen, P.Ø. Editor's Choice: Advances in Carbon Capture Subsurface Storage and Utilization. *Energies* **2023**, *16*, 2082. https://doi.org/10.3390/en16052082

Received: 21 October 2022
Revised: 28 January 2023
Accepted: 9 February 2023
Published: 21 February 2023

Copyright: © 2023 by the author. Licensee MDPI, Basel, Switzerland. This article is an open access article distributed under the terms and conditions of the Creative Commons Attribution (CC BY) license (https://creativecommons.org/licenses/by/4.0/).

Kaplan and Kopacz [3] aimed to determine economic conditions in Poland for commercial coal gasification with carbon capture and storage (CCS) for hydrogen production. They point out that globally, most hydrogen comes from fossil fuels where 20–25% is from coal-to-hydrogen facilities. Electrolysis of water produces environmentally friendly hydrogen, but this makes up only 2% of the production. The shell reactor process was considered for gasification and applied to either coal or lignite with or without CCS. This process converts coal or lignite into separate components, including hydrogen and CO_2 streams and gas burnt to generate steam-driving turbines for the generation of electricity. Their economic assessment considered the revenues related to the sale of hydrogen, capital expenditures (infrastructure and construction), and operating costs (feedstock of coal, material consumption, electricity, taxes, and administration). For the cases considered (coal/lignite, with/without CCS), the process was found to be economically inefficient (negative net present value (NPV) and lower rate of revenue than the discount rate) under the base assumptions, indicating prices or circumstances would need to change. From a sensitivity analysis, a higher price of H_2 (at least by 20%) was found to be the most critical for profit for all considered options, followed by a reduction in the discount rate.

Morgan et al. [4] conducted a life cycle analysis (LCA) of the CO_2-enhanced oil recovery (EOR) operations at the Farnsworth Unit (US). The field was waterflooded in the early 1960s and the CO_2 injection started in 2010. The injected CO_2 was from anthropogenic sources (nearby ethanol or fertilizer plants) or the reinjection of produced CO_2. The injection was performed as water-alternating-gas. First, LCA was performed considering the historical CO_2-EOR operation from 2010 to 2020. Flaring and venting was the prime source of emission (60%), while CO_2 compression and injection was the second (based on electricity usage). Artificial lift, construction, land usage, and brine injection/disposal were the remaining key sources. Negative net emissions were calculated. A sensitivity analysis showed that net emissions would increase by adding gas separation, as the alternatives were more energy demanding than contributing for the studied case. Next, a compositional reservoir simulator was used to history match the first 55 years of primary and secondary recovery, and the next 10 years of tertiary recovery, and were used to forecast the operation 18 years into the future. They found that reducing fugitive emissions and limiting venting and flaring to compressor maintenance downtimes would increase the net storage of CO_2 to 86% of the purchased volumes.

Pandey et al. [5] presented an experimental investigation of a CO_2-rich gas injection for CO_2 storage in porous media. At conditions with a low temperature and high pressure, CO_2 can form solid gas hydrates by an interaction with water or pre-existing methane hydrates. They saturated various unconsolidated porous media (of specified grain sizes) with an initial water saturation of 35% and investigated how different chemicals added to the water affected the CO_2 hydrate formation when CO_2-rich gas (the other component was N_2) was injected. The benefit of diluting the gas with N_2 was a slower hydrate growth (allowing greater injectivity and sweep, and thus storage capacity) as well as less corrosive transport. A downside is that hydrate forms at a higher pressure in such gas mixtures and a higher injection pressure may be needed. Hydrate promoters address this issue and can also improve the gas uptake and CO_2 fraction of captured gas. An environmentally friendly option (amino acids) was proposed and compared to an existing alternative (SDS). Both promoters improved the gas uptake and CO_2 fraction compared to using distilled water. A high induction time (time to form hydrate) was observed in the presence of amino acids, allowing for a good injectivity and sweep. The gas uptake was higher in coarse sand.

Sun et al. [6] performed history matching and optimization of miscible CO_2 WAG in the Farnsworth Unit (US). They made use of machine learning approaches such as response surfaces, support vector machines, and neural networks as alternative proxy models for an efficient reservoir simulation. The geological model contained several hydraulic flow units with separate porosity–permeability relations and saturation functions. The model grid had to be coarsened considering the long production history. Some proxies were designed to predict field production responses with a variation in the reservoir hydrody-

namical properties, thus acting efficiently for history matching. A total of 100 simulations were run with variation in 62 uncertain parameters. A multi objective function based on matching the historical injected and produced fluid volumes was used for training. The uncertain parameters were then tuned to optimize the fit to historical observations. Other proxies were designed to predict future cumulative oil production, CO_2 stored, and project economics with variation in the WAG operational parameters. A multi objective function based on the oil produced, CO_2 stored, and NPV was optimized, resulting in the optimal WAG scheme. Considering the Pareto front solutions, a higher oil recovery was obtained at the expense of CO_2 stored and NPV, while NPV increased with the amount of CO_2 stored.

Telmadarreie and Trivedi [7] conducted an experimental study where CO_2 and surfactant-based foam, with or without polymer enhancement (PEF), was investigated during the flow, displacement of heavy oil, and in fractured or unfractured porous media. Silica sand packs and sandstone and carbonate core samples were tested. In static foam tests, adding polymer caused the foamability to reduce, but the stability to increase, regardless of the presence of oil. The pressure drop during the flooding of unconsolidated sand was higher with PEF compared to CO_2 foam, and was more significant when displacing oil. The oil recovery was boosted after waterflood by both foam alternatives, but more by PEF. PEF resulted in a close to piston-like displacement. In the intact core samples, PEF foam propagated better than the regular foam and the gas phase was produced predominantly as bubbles and free gas, respectively. A higher oil recovery was observed with PEF and foam after waterflooding, which was also observed in fractured samples, as fluid, then it better displaced the matrix oil, with PEF again performing better. It seemed that the liquid solution, rather than foam, invaded the matrix in fractured systems. More CO_2 was stored with PEF than with regular foam, but in the fractured systems, the amount of CO_2 stored was not significant.

Trujillo et al. [8] presented a multi-scale characterization of cap rock integrity for CO_2 storage in the Farnsworth Unit based on multiple analysis techniques and sources of data. They mention the important features necessary for storage, including a (very) low permeability cap rock with a high displacement pressure to CO_2, that the cap rock overlays the reservoir continuously to trap the fluids, that fractures are not opened or activated, and that the wellbore surroundings are well sealed. They classified the overlaying Morrow shale and Thirteen Finger limestone formations into nine facies to characterize the caprock heterogeneity. The thickness was evaluated areally to 240 ft in the East to 120 ft in the West. Permeabilities in the microDarcy range corresponded with the high capillary pressure entry pressure obtained from mercury injection experiments. Four types of fractures were identified from long core sections where the drilling induced was the most common. The directions of potential slipping fractures upon pore pressurization could be indicated. Geomechanical tests showed that fractures started in the reservoir would not propagate into the cap rock. The isotope analyses of dissolved noble gases in the reservoir and cap rock indicated distinct compositions and, hence, that the cap rock prevented communication between the reservoir and surroundings. Overall, the study indicated a strong sealing capacity for CO_2 storage.

Zhang et al. [9] presented a screening model for a economic and technical evaluation of the options for carbon capture and reinjection process (CCRP), applied to the Xinjiang oilfield. Due to gas breakthrough, reinjection is vital for both an effective CO_2 storage and oil production. They modeled the CCRP with one module separating the well stream into produced water, oil, and gas; a carbon capture module where the gas was split into CO_2-rich and CO_2-lean streams; and an injection module where the CO_2-rich stream was reinjected. The carbon capture and reinjection modules were the main focus. Five carbon capture technologies were considered: chemical absorption, pressure swing adsorption, low temperature fractionation, membrane separation, and direct reinjection mixed with purchased CO_2. For CO_2 in gas or supercritical form, compressors were assumed for reinjection, while for liquid CO_2, pumps were considered. The cost, energy consumption, injected purity of CO_2, and the capture efficiency were considered. For the studied case,

the lowest unit cost and energy consumption were found using direct reinjection mixed with purchased CO_2, while pressure swing adsorption was the second-best alternative.

Acknowledgments: The author acknowledges the Research Council of Norway and the industry partners of NCS2030–RCN project number 331644—for their support.

Conflicts of Interest: The author declares no conflict of interest.

References

1. Arvanitis, A.; Koutsovitis, P.; Koukouzas, N.; Tyrologou, P.; Karapanos, D.; Karkalis, C.; Pomonis, P. Potential Sites for Underground Energy and CO_2 Storage in Greece: A Geological and Petrological Approach. *Energies* **2020**, *13*, 2707. [CrossRef]
2. Cao, C.; Liao, J.; Hou, Z.; Xu, H.; Mehmood, F.; Wu, X. Utilization of CO_2 as Cushion Gas for Depleted Gas Reservoir Transformed Gas Storage Reservoir. *Energies* **2020**, *13*, 576. [CrossRef]
3. Kaplan, R.; Kopacz, M. Economic Conditions for Developing Hydrogen Production Based on Coal Gasification with Carbon Capture and Storage in Poland. *Energies* **2020**, *13*, 5074. [CrossRef]
4. Morgan, A.; Grigg, R.; Ampomah, W. A Gate-to-Gate Life Cycle Assessment for the CO_2-EOR Operations at Farnsworth Unit (FWU). *Energies* **2021**, *14*, 2499. [CrossRef]
5. Pandey, J.S.; Daas, Y.J.; Karcz, A.P.; von Solms, N. Enhanced Hydrate-Based Geological CO_2 Capture and Sequestration as a Mitigation Strategy to Address Climate Change. *Energies* **2020**, *13*, 5661. [CrossRef]
6. Sun, Q.; Ampomah, W.; You, J.; Cather, M.; Balch, R. Practical CO_2—WAG Field Operational Designs Using Hybrid Numerical-Machine-Learning Approaches. *Energies* **2021**, *14*, 1055. [CrossRef]
7. Telmadarreie, A.; Trivedi, J.J. CO_2 Foam and CO_2 Polymer Enhanced Foam for Heavy Oil Recovery and CO_2 Storage. *Energies* **2020**, *13*, 5735. [CrossRef]
8. Trujillo, N.; Rose-Coss, D.; Heath, J.E.; Dewers, T.A.; Ampomah, W.; Mozley, P.S.; Cather, M. Multiscale Assessment of Caprock Integrity for Geologic Carbon Storage in the Pennsylvanian Farnsworth Unit, Texas, USA. *Energies* **2021**, *14*, 5824. [CrossRef]
9. Zhang, L.; Geng, S.; Yang, L.; Hao, Y.; Yang, H.; Dong, Z.; Shi, X. Technical and Economic Evaluation of CO_2 Capture and Reinjection Process in the CO_2 EOR and Storage Project of Xinjiang Oilfield. *Energies* **2021**, *14*, 5076. [CrossRef]

Disclaimer/Publisher's Note: The statements, opinions and data contained in all publications are solely those of the individual author(s) and contributor(s) and not of MDPI and/or the editor(s). MDPI and/or the editor(s) disclaim responsibility for any injury to people or property resulting from any ideas, methods, instructions or products referred to in the content.