A Python-based Evaluation of Kazakhstan's Fields for Carbon Capture, Utilization, and Storage Projects

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Received: 14 November 2024 | Revised: 16 December 2024 | Accepted: 21 December 2024

 DOI: https://doi.org/10.48084/etasr.9613

ABSTRACT

The purpose of this study is to evaluate the feasibility of different oil fields in Kazakhstan for Carbon Capture, Utilization, and Storage (CCUS) projects using advanced algorithms in Python. Using automated methods, the approach greatly simplifies and accelerates the selection process, allowing efficient analysis of

large data sets. Taking into account key geological and operational parameters, with particular emphasis on the importance of the Dykstra-Parsons coefficient, the study presents a comprehensive ranking system for evaluating reservoir suitability. This coefficient is critical to accurately assess the fluid displacement efficiency, which significantly influences the selection of candidates for Enhanced Oil Recovery (EOR). The results show that the inclusion of the Dykstra-Parsons coefficient improves the accuracy of field evaluation by accounting for key reservoir heterogeneity factors along with conventional properties. The comparative analysis shows that this approach provides more reliable field selection compared to the existing methods that do not consider this parameter, thereby improving the efficiency of CO_2 storage projects.

Keywords-CO_2; CCS; EOR; storage; Dykstra-Parsons coefficient; injection

I. INTRODUCTION

Carbon Capture, Utilization, and Storage CCUS technology, which aims to capture, utilize and store carbon dioxide (CO_2), uses different types of geological formations to reduce CO_2 emissions into the atmosphere, such as salt domes, which are ideal for creating airtight storage conditions due to their impermeability. Depleted oil and gas fields can also serve to inject and store CO_2, helping to further increase the production of residual hydrocarbons through a process of enhanced oil recovery. Deepwater aquifers are another option for long-term CO_2 storage, especially if they contain salt water and are located at significant depths. Unexploited coal seams can be used not only to store CO_2 but also to release methane, which can then be used as an energy source. Finally, basalt formations are volcanic rocks that can react with CO_2 and mineralize it, converting it into stable minerals such as calcium carbonate, providing additional security and stability to the storage process. These deposits are selected based on their geological properties, including permeability, porosity, and structural integrity, to ensure effective and safe management of CO_2 [1]. Using a depleted oil or gas reservoir for CO_2 storage has several interesting advantages among which the relatively large pressure range available for injection, allowing the storage of significant gas quantities for a low compression power, without altering the caprock integrity. Research on CO_2 storage in depleted oil and gas reservoirs emphasizes its advantages such as strong storage capacity and sealing performance, along with the use of the existing infrastructure. Notable contributions in this area include [2], which reviews developments in CO_2 storage.

CO_2 storage efficiency, first defined in 2007 within broad assessments of capacity in North America and Europe, measures the volume of CO_2 injected against the pore volume within an aquifer. The efficiency is influenced by various factors: (1) Aquifer characteristics, such as pressure, temperature, salinity, CO_2/brine displacement, rock type, porosity, permeability, uniformity and directional qualities, area size, depth, and limits; (2) qualities of the sealing aquitards, particularly their permeability and threshold capillary pressure; (3) operational factors of CO_2 storage, including injection rates, duration, number and layout of wells, spacing, and management strategies for injection and water handling; (4) regulatory frameworks, like maximum permitted injection pressure, and volume definition for CO_2 storage in a project, which takes into account the scope of assessment, time frame considered, and designated aquifer area. Efficiency values calculated thus far vary widely due to these variables, ranging broadly from less than 1% to over 10%. No universally applicable value exists due to the wide range of factors. Storage efficiency is dependent on both space and time, with initial constraints by pressure followed by spatial limitations, emphasizing the importance of defining the specific aquifer area and time period for any efficiency assessment [3].

Although CCUS technology holds significant promise for meeting the objectives of the Paris Agreement, the existing number of projects in this area is small. The progress in developing the CO_2 storage sector does not match the strategic goals of the International Energy Agency's Sustainable Development Scenario, which calls for the formation of a new worldwide industry dedicated to CO_2 transportation and storage. While risks are inherent in any technological process, the primary benefit of CCUS technologies is their ability to reduce the greenhouse effect on the environment and facilitate a smoother energy transition. CCUS enables the decarbonization of industries without altering their core processes. Its key environmental advantage lies in the capacity to lower CO_2 emissions in the atmosphere, even as fossil fuels continue to meet global energy demands. This potential, however, is contingent upon the amount of CO_2 captured and any potential leaks during transportation and long-term storage.

The potential benefits must also be weighed against the environmental risks associated with CCUS, compared to the risks if CCUS is not implemented. This paper describes the possible types of storage of CO_2 with indication of advantages of storing gas as well as the potential risks occurring within the CO_2 injection and during the storage itself. The CO_2 can be stored within depleted oil and gas fields and saline aquifers, and also, on the basis of the factors given in the article, the potential of burial of CO_2 on the territory of the Republic of Kazakhstan.

Authors in [4] studied the relationship between reservoir fluid properties and natural gas behavior in the Kurdistan Region. The study developed 38 empirical models linking dissolved and separated gas content with reservoir parameters (depth, pressure, temperature) based on PVT data and linear regression. The concentration of extracted methane reaches 79.7% and dissolved methane up to 12.4%. The released gas decreases with depth, pressure and temperature, which is attributed to the increase in adsorption and decrease in free gas volume. Dissolved gas, on the other hand, increases, which is attributed to an increase in solubility with increasing temperature and pressure. The used linear regression models have high correlation coefficients ($R^2 > 0.9$ for most parameters). From the perspective of reservoir geometry and pore space, deep learning-based technologies were applied in [5]. With an error of less than 10%, the researchers successfully identified key transport mechanisms such as pore-filling and phase equilibrium, while the proposed productivity indices enable the evaluation of drainage and reservoir performance. Deep learning-based techniques were also applied in terms of reservoir geometry and pore space. With an error of less than 10%, the authors were able to identify key transport mechanisms such as pore filling and phase equilibrium, and the proposed productivity indices allow for the evaluation of drainage and productivity.

This study develops and applies automated methods to optimize the process of selecting suitable reservoirs for the introduction of CCUS technology in the Republic of Kazakhstan. The peculiarity of the approach lies in its ability to significantly simplify and speed up the analysis, providing simultaneous processing of large volumes of data thanks to innovative algorithms created in the Python programming language.

II. LITERATURE REVIEW

A. CO_2 Storage

Utilizing exhausted oil or gas fields for CO_2 storage offers notable benefits, including a wide pressure range for injection that enables storing substantial amounts of gas with minimal compression energy, whereas maintaining the integrity of the overlying rock layer. A significant body of research has focused on reducing CO_2 emissions through its capture and subsequent injection into depleted oil reservoirs to enhance oil recovery [6-8]. The practice of CO_2 sequestration in these depleted oil fields is highly advantageous, providing economic benefits that surpass those of other available geological storage methods. CO_2 storage in depleted oil and gas reservoirs has advantages such as strong storage capacity and sealing performance, while using the existing infrastructure. Notable contributions in this area include studies which review developments in CO_2 storage and focusing on gas source attribution techniques for assessing leakage at storage sites. Besides, the availability of reservoir dynamical and geological characterization and existing production/injection wells contributes to the optimization of the project, both technically and economically [2, 8, 9]. In particular the following advantages have been noted:

- Since a depleted oil reservoir already contains hydrocarbons, it cannot be considered a water reservoir, so there is no risk of groundwater contamination.
- Such fields are usually well characterized in terms of both basic reservoir properties (rock type, porosity, permeability) and geology (cap integrity, faults, strike).
- Some production wells can be converted to gas injection at low cost.

The possibility of burying CO_2 in saline aquifers has also been investigated. Storage in oil and gas reservoirs has many similarities to storage in saline aquifers (since the rock types are similar) and brine is present in both cases [8]. On the other hand, oil and gas reservoirs can be potentially considered for Enhanced Oil Recovery (EOR), which makes them economically more favorable than saline aquifers.

Their preliminary characterization during oil and gas field operations can lead to cost savings. In addition, utilizing existing infrastructure in depleted fields, as well as enhanced hydrocarbon production through CO_2 injection (so-called CO_2-EOR), can provide additional financial benefits and improve project economics.

B. Leakage Risk

To contribute to climate mitigation, CO_2 must be safely trapped underground for long periods of time. Ideally, geologic repositories would consist of porous rock overlain by non-porous rock, ensuring that the CO_2 remains trapped. Over time, most of the CO_2 is expected to dissolve into the reservoir water, becoming denser and settling to the bottom. Eventually, the CO_2 will turn into solid minerals through natural processes. Deep saline aquifers, which are typically deeper than 800 m, are well suited for long-term carbon storage. Similarly, depleted oil and gas fields can also serve as reliable storage sites. These reservoirs have already demonstrated their ability to hold liquids for millions of years.

Leakage risks are also assessed using numerical modeling techniques. In [11], an investigation of potential leakage from a geologically stored CO_2 reservoir was conducted using a hypothetical fault scenario to represent an extreme leakage case. The size and characteristics of the fault were extrapolated from studies of faults and fractures in Tertiary formations in Japan. The theoretical fault was modeled to be 1 km long and 5 m wide, with permeability ranging from 100 to 1000 mDa. The TOUGH2 simulator, supplemented by the ECO2M module, was used to reproduce subsurface three-phase CO_2 conditions. The simulation results showed that the CO_2 leakage rate peaked at about 5 years after injection, after which a gradual decline began. The results concluded that the CO_2 injection scenario has a significant effect on the leakage rate. The final estimates of cumulative CO_2 loss and peak annual leakage rate were approximately 1% and 0.3% of the total CO_2 injected per year, respectively. Authors in [12] evaluated CO_2 leakage in the Yort-e-Shah aquifer. It was shown that leakage can significantly reduce the pressure in the central part of the reservoir, especially when leakage accumulates in the middle of the aquifer. In numerical simulations, the optimum injection pressure was found to be 15.5 MPa, providing a sufficient factor of safety against leakage. However, the heterogeneity of the aquifer properties at different depths creates additional risks, which emphasizes the importance of careful study of the geomechanical characteristics of the cover for reliable CO_2 storage and leakage prevention in similar geological structures [12].

C. Joule-Thomson Cooling Effect

The Joule-Thomson (JT) cooling effect is localized cooling when CO_2, injected in its liquid or supercritical state, vaporizes and expands within the well tubing or near-wellbore region of the reservoir. This phenomenon can result in dry ice or hydrate formation, potentially reducing CO_2 injectivity and causing flow assurance problems, such as erosion and cavitation in the flowlines due to abrupt increases in flow velocity. The main concern for the JT effect is the high velocity flow across control valves, for which the flow can be choked- usually resulting in temperature drop. The JT effect may challenge material selection in order to be resistant for low temperatures. The operability of the system may also be affected by phase change due to the JT effect and risk of water drop out in humid CO_2 streams. In CCUS applications, in addition to choked flow scenarios and impact of JT effect on systems operability, the JT cooling effect may happen during the injection of pressurized CO_2 into the depleted oil and gas reservoirs in which the initial pressure is low [13]. The large pressure gradient could lead to adiabatic expansion of CO_2 stream and a significant drop in temperature near the injection well. The main concern, then, is freezing the native brine in pores and hydrate formation within the presence of CO_2 and other impurities. These could lead to a blockage of the pores and severely impact the formation permeability and injectivity of CO_2 [14].

The transition of CO_2 from a dense state (liquid or supercritical) to the gas state is associated with a sharp drop in density, affecting wellhead pressure control and pressure response at the well bottomhole. The JT effect, therefore, poses several operational hazards, including the risk of well integrity issues due to the formation of hydrates or dry ice which can impair CO_2 injectivity. Authors in [16] performed compositional modeling using two different approaches, coupled and uncoupled. In the latter, the simulation did not take into account the internal processes of the reservoir, which gave unrealistic results, whereas using a coupled model that takes into account geomechanical parameters gave realistic simulation results. Based on these results, the following potential solution is proposed. CO_2 in liquid state is a hazard during operation, and heating it at the well-head, would allow CO_2 to be injected in a supercritical state. In addition, based on averaged data on injection pressure and heating temperature, it was estimated that it would take about 60-70 kWh per metric ton to convert CO_2 to the supercritical state at pressures between 600 and 1,000 PSIA [16].

D. Effect of Imputiries

Unfortunately, CO_2 sources are often not highly concentrated. CO_2 is most often derived from the exhaust gases of thermal power plants, which include nitrogen and other gases in addition to CO_2. Treating these gases significantly increases operating costs. In addition, to reduce the cost of CO_2 treatment and procurement, oil and gas fields often apply water cycling and use the recovered gas, usually methane, without additional treatment. The presence of impurities in CO_2-enriched streams can have a marked effect on their thermophysical characteristics, which in turn causes changes in pressure and temperature. These changes may require revision of pipeline design characteristics such as diameter, wall thickness, and thermal insulation characteristics. In addition, the spacing of additional compression stations may need to be adjusted. These factors increase capital and operating costs for transportation systems.

A study by the Global CCS Institute, published on July 1, 2011 [17], reviewed existing information and published studies on the potential impact of the cleanliness of the CO_2 waste stream on repository design and associated costs. The focus was on deep-sea saline reservoirs due to their large theoretical capacity and significant potential for complex geologic reactions. The study considered the potential effects of impurities on storage capacity behavior and calculations, effects on geochemical reactions, effects on reservoir injectivity and permeability, and the potential for corrosion of well components. Authors in [18] investigated the physicochemical effects of typical impurities on CO_2 storage using both experimental approaches and theoretical modeling. They showed that non-condensable impurities such as N_2, O_2, and Ar produced during the combustion of oxygen fuel lead to a decrease in CO_2 density, a decrease in storage capacity, and an increase in buoyancy in saline aquifers. In contrast, the inclusion of condensable SO_2 impurity resulted in higher densities than pure CO_2, increasing storage capacity. The authors also examined how these impurities affect the phase behavior of CO_2, which is very important for CO_2 transport, as well as rock chemistry, and proposed an equation to predict the effect of rock chemistry on rock porosity.

A group of researchers from universities in Iran, Russia and China have investigated the effect of chemical additives on the phase properties and viscosity of water-in-oil emulsions used in EOR techniques [19]. Emulsions were prepared for the experiments using different salts (NaCl, $MgCl_2$, $CaCl_2$, $CaCl_2$, Na_2SO_4) at concentrations up to 50,000 ppm, silica nanoparticles (0.1-0.5%) and Span 80 surfactant (up to 200 ppm). The stability of the emulsions was determined using the bottle test method for 30 days and viscosity was measured with a rheometer. The best stability and viscosity results were achieved with a water cut of 50%, $MgCl_2$ concentration of 10,000 ppm, addition of 0.1% silica nanoparticles and 200 ppm surfactant. It was found that the synergistic use of nanoparticles and surfactant created a mechanical barrier and reduced droplet size, which prevented coalescence and increased the viscosity of the emulsion. Among the salts, $MgCl_2$ showed the greatest effectiveness in reducing surface tension and increasing stability.

E. Dykstra-Parsons Coefficient

The Dykstra-Parsons coefficient plays a key role in selecting a reservoir for CO_2 disposal because it describes the heterogeneity of the reservoir and the degree of variation in its permeability. This coefficient is calculated based on the permeability distribution in the reservoir and helps assess how evenly distributed the fluid flow through the rock is.

In CO_2 burial, uniformity of distribution and migration of injected gas is critical to prevent CO_2 accumulation in particular zones. Gas accumulation can lead to high pressures and increased risk of leaks. Inhomogeneous formations with high Dykstra-Parsons ratios contribute to uneven distribution of CO_2, causing it to accumulate in areas of low permeability. This reduces disposal efficiency and increases the risk of gas leaks. The use of the Dykstra-Parson coefficient in modeling CO_2 burial processes in geologic formations with heterogeneity has shown significant benefits. For example, studies have shown that high formation heterogeneity (high Dykstra-Parsons coefficient) promotes more efficient CO_2 capture, including structural and residual burial because heterogeneity creates different pathways and barriers for CO_2 movement, which increases the volume of gas retained and reduces the risk of leakage [20]. Accounting for this factor allows for more accurate modeling and optimization of injection processes, which improves CO_2 burial performance compared to models that do not account for this heterogeneity. This is particularly important for long-term storage of CO_2 and minimization of environmental risks.

F. CO_2 Storage Potential in Kazakhstan

Kazakhstan ranks as the ninth largest country in the world by area and holds the 12^{th} largest position globally for its verified oil and gas reserves, according to the US Energy Information Administration (EIA) [18]. This abundance of fossil fuels in Kazakhstan serves as a key indicator of the nation's significant potential for CO_2 storage, which led to the start of the "KazCCUS" research initiative. The geological formations most suitable for CO_2 storage include oil and gas reservoirs, saline aquifers, and coal seams that cannot be mined, which are typically found in sedimentary basins [19, 22].

The geological structure of Kazakhstan is characterized by great diversity. The western part of the country includes the ancient continent of Eastern Europe, the Turan Platform, which is covered by Mesozoic sediments, and several small continental formations attached during the disappearance of the ancient Paleo-Asian seas. The Turanian Platform is divided into parts by the Paleozoic folded regions of the Urals and Karatau-Talas-Fergana. The eastern part of Kazakhstan is mainly formed by the Kazakh continental block, which consists of a mosaic of Precambrian continental fragments [23, 25].

A review of the geological literature on Kazakhstan, encompassing early Soviet geologist studies, contemporary research, and local geological databases, indicates that most of the geological data necessary for evaluating the potential for CO_2 storage are found within basins containing hydrocarbons. For economic reasons, including existing infrastructure and the potential for EOR (CO_2-EOR), the implementation of CCUS in Kazakhstan's petroleum basins is deemed more feasible and realistic. For example, researchers from Kazakhstan considered 6 sedimentary basins to evaluate the potential for CO_2 burial [6, 24]. The evaluation was based on 15 criteria. The six selected sedimentary basins in Kazakhstan were evaluated using criteria such as tectonic setting, depth, faulting intensity, presence of salts, size, aquifers, hydrocarbon potential, geothermal regime, presence of coal, industry maturity, onshore/offshore location, climate, accessibility, infrastructure and CO_2 sources. Various geologic information such as stratigraphy, reservoir-swell pairs, tectonic stability, and others were obtained from the publicly available literature. Geothermal data (pressure and temperature) and injectivity data (permeability and porosity) used to verify the quality of reservoir-seal pairs and lithologic facies were checked against the Kazakhstan Oil and Gas Field Database, prepared by the Information and Analytical Center of Geology and Mineral Resources of Kazakhstan. Based on the evaluation of the above factors, a ranking of sedimentary basins suitable or poorly suitable for CO_2 sequestration was made.

G. CO_2 as an Enhanced Oil and Gas Recovery Method

CO_2, in addition to being sequestered in depleted field strata, is known as an excellent reagent for enhancing oil and gas recovery. Injecting CO_2 can help sustain reservoir pressure and boost methane extraction, assuming proper management of both injection and production processes. This process, known as Enhanced Gas Recovery (EGR), mirrors secondary recovery techniques. Integrating EGR with Carbon Capture and Storage (CCS) could be crucial for making projects feasible and profitable. Leveraging existing infrastructure, such as wells, pipelines, and platforms, can lower the investment costs for CO_2 sequestration and minimize the environmental impact.

The use of CO_2 as an EOR technique has been studied by many authors. Authors in [26] analyzed CO_2-EOR's sustainability, using pilot examples to evaluate the sequestration efficiency and sustainability of CO_2 storage through EOR. They concluded that with current technology, CCS processes are not sustainable without significant enhancements in CO_2 separation efficiency or reduction in capture-related emissions, underlining the need for technological advances for effective CO_2 reduction. Authors in [27] explored the impact of CO_2 with impurities on EOR and associated storage performance, using laboratory experiments and reservoir simulation to assess oil recovery and CO_2 storage efficiency under varying conditions. The study underscored the feasibility of using impure CO_2 for effective EOR and cost-effective carbon management strategies in the context of the compatibility of CCS technologies and EOR evaluated CO_2-EOR's sustainability from an exergetic perspective, using pilot examples. They concluded that the current CCS technology in EOR projects is not sustainable, as it consumes more energy than it produces. The study suggested that for CCS to be efficient, the exergetic cost of CO_2 separation must be reduced, and the capture process should not lead to additional car-bon emissions [15]. Utilizing a depleted reservoir minimizes geological uncertainties since the reservoir's volumes are established, detailed production data are accessible, and the integrity of the reservoir's closure is confirmed. The flooding effect of CO_2 can also be beneficial in maintaining subterranean pressure and mobilizing residual gas saturation. Additionally, natural gas extraction can see an improvement by distributing operational expenses and integrity costs, thereby extending the economic viability of gas production and maximizing the field's economic yield.

III. MATERIALS AND METHODS

For our experiment we selected 16 fields characterized by various geological properties and degrees of development. Fields located in different regions were taken into account, allowing a wide range of conditions and reservoir types to be covered.

Critical analysis of literature and reference books on oil and gas fields in Kazakhstan was conducted to create a database and analyze potential fields. The field evaluation was implemented in Python using the libraries Pandas (processing and analysis of structured data, obtaining results in the form of tables), Openpyxl (reading and writing data in Microsoft Excel formats) to simplify work with data, as well as the built-in module Tabulate to display data in the form of tables. In addition, Dykstra-Parsons parameter is included in the criteria for selecting potential deposits for CO_2 disposal. Its calculation was also performed at the software level with determination of the type of data distribution for the permeability range of a particular deposit.

We selected 16 fields that differ in geological properties and degree of development. For the source of geologic data, the reference book on oil and gas fields of Kazakhstan was chosen [28]. Among the selected fields there are both large fields with large oil reserves and small fields that have already been partially or fully depleted. Among them, there are fields with different degrees of water and gas saturation, which also affects their potential CO_2 storage capacity (Table I presents selected Kazakhstani fields data on CO_2 storage capacity). We consider fields located in different regions, which allows us to cover a wide range of conditions and reservoir types. The field data included parameters such as initial oil in formation (*OOIP*), reservoir volume factor (B_f), recovery factor (R_f) and depletion rate (Depletion). The collected dataset was processed using Pandas for structured analysis.

TABLE I. INITIAL DATA OF CANDIDATE FIELDS [28]

No	Field	R_f	*OOIP* (MMt)	B_f	Depletion (%)
1	Karsak	0.272763029	20.34	1.2	67.687837
2	Kosshagyl	0.293672581	29.87	1.4	36.4740235
3	Pribrezhnoe	0.288461538	14.56	1.1	86.96484393
4	Tazhigali	0.27370479	10.23	1.3	47.88379311
5	Tengiz	0.303766707	987.6	1.5	74.39386411
6	Martyshy	0.289687138	25.89	1.25	47.72749183
7	Zaburunye	0.304012971	49.34	1.35	72.15673524
8	Komsomolskoye	0.264550265	5.67	1.2	44.03882885
9	Kumkol	0.299401198	60.12	1.3	59.36116349
10	Kemerkol	0.295857988	40.56	1.2	73.38176079
11	South Koshkar	0.293460034	35.78	1.4	53.75736368
12	Sagyz	0.298474464	45.23	1.3	84.57550373
13	Makat	0.295222759	55.89	1.25	38.19687461
14	Dossor	0.2985499	70.34	1.15	88.86341302
15	Baklaniy	0.301659125	79.56	1.35	48.60113792
16	Eskene	0.292169848	25.67	1.2	72.40187561

The oil fields were evaluated using a Python-based algorithm that takes into account geological and dynamic reservoir parameters. The method involves calculation of the effective CO_2 storage capacity (M_{CO2e}), normalization of key parameters, and ranking of fields according to their suitability for CCUS. M_{CO2e} is calculated by:

$$M_{CO2e} = C_e \cdot P_{CO2r} \cdot \left(R_f \cdot \frac{OOIP}{B_f}\right) \tag{1}$$

The Dykstra-Parson coefficient (*DP*) was calculated based on a range of permeability values for the fields. The formula for calculating the *DP* is based on the assessment of rock heterogeneity and uniformity of permeability distribution in the reservoir:

$$DP = \frac{K_{84.1} - K_{50}}{K_{50}} \tag{2}$$

To ensure comparability, all parameters were normalized:

$$\text{Normalized value } (N_a) = \frac{\text{Value}}{\text{Max value}} \tag{3}$$

The final ranking was based on the overall suitability score, calculated as the average of normalized parameters:

$$\text{Overall rating} = \frac{N_{depletion} + N_{DP} + N_{M_{CO2e}}}{3} \tag{4}$$

IV. RESULTS

Tables II and III show the results of our algorithm with and without the consideration of the DP, respectively. The Tengiz field is highly ranked (Table I) due to its high permeability, significant initial oil saturation and low *DP*. This indicates efficient CO_2 displacement of oil, creating more space for CO_2 storage. Excluding this factor, Tengiz still retains a high ranking due to its physical characteristics, but its position may change slightly as dynamic characteristics are not taken into account.

TABLE II. FIELD SELECTION RESULTS WITH DP

No	Field	*DP*	Overall rating	Rank
1	Tengiz	0.21682	0.851524	Excellent
2	Sagiz	0.282725	0.528345	Excellent
3	Kemerkol	0.198701	0.522704	Excellent
4	Karsak	0.165929	0.515248	Excellent
5	Zaburunie	0.236734	0.501896	Good
6	South Koshkar	0.147898	0.47112	Good
7	Kumkol	0.262581	0.442975	Good
8	Eskene	0.43177	0.417504	Good
9	Komsomolskoye	0.216767	0.404357	Fair
10	Martyshi	0.267194	0.396459	Fair
11	Baklaniy	0.404041	0.342033	Fair
12	Dossor	0.764045	0.335993	Fair
13	Pribrezhnoe	0.767233	0.326262	Poor
14	Makat	0.375223	0.314457	Poor
15	Kosshagyl	0.369041	0.310091	Poor
16	Tazhigali	0.615553	0.245543	Poor

TABLE III. FIELD SELECTION RESULTS WITHOUT CONSIDERING DP

No	Field	Overall rating	Rank
1	Tengiz	0.918585	Excellent
2	Dossor	0.501911	Excellent
3	Pribrezhnoye	0.489393	Excellent
4	Sagiz	0.476767	Excellent
5	Kemerkol	0.413548	Good
6	Eskene	0.407637	Good
7	Zaburunye	0.407122	Good
8	Karsak	0.381006	Good
9	Kumkol	0.335585	Fair
10	South Koshkar	0.303064	Fair
11	Baklaniy	0.27636	Fair
12	Tazhigali	0.269465	Fair
13	Martyshi	0.268817	Poor
14	Komsomolskoye	0.247801	Poor
15	Makat	0.216216	Poor
16	Kosshagyl	0.205638	Poor

On the other hand, the Komsomolskoye field ranks in the middle taking into account the *DP* because of its moderate permeability and displacement efficiency. Without this parameter, its ranking declines because important displacement characteristics are not taken into account, making it less attractive to CCUS. The Makat field, has a low rating due to its high permeability and high *DP*, indicating low displacement efficiency. However, as can be seen in Table II, without taking this coefficient into account, its ranking position improves because the evaluation will be based only on physical characteristics such as initial oil saturation and permeability, without taking into account the low displacement efficiency.

V. CONCLUSION

The inclusion of the Dykstra-Parsons coefficient in the evaluation of oil fields for CCUS projects in Kazakhstan has a significant impact on the ranking and overall evaluation of these fields. This coefficient, which reflects reservoir heterogeneity and fluid displacement efficiency, is critical in determining the suitability of an area for CO_2 storage. Deposits with high permeability, significant initial oil saturation and low Dykstra-Parsons ratios, such as Tengiz, are very suitable for CCUS. Conversely, fields such as Makat, with high permeability but low fluid displacement efficiency, are less suitable unless additional measures are taken to improve their performance.

The proposed automated approach, based on Python and libraries such as Pandas and Openpyxl, enables efficient processing and analysis of large data sets. This ensures that all relevant parameters are taken into account, greatly simplifying and speeding up the evaluation process, and provides a robust and scalable solution. However, the effectiveness of the methodology depends on the availability and accuracy of the input data, which remains a limitation due to possible data scarcity and data quality issues.

In conclusion, incorporating the Dykstra-Parson coefficient into the evaluation process improves the accuracy and reliability of CCUS project suitability assessments. By accounting for reservoir heterogeneity and optimizing site selection, this approach facilitates efficient and cost-effective implementation of CO_2 storage solutions, contributing to global efforts to reduce greenhouse gas emissions and combat climate change.

ACKNOWLEDGMENT

The research was funded by the Committee of Science of the Ministry of Science and Higher Education of the Republic of Kazakhstan (Grant No. BR21882241).

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