Techno-economic analysis of a CCUS-EGR project in an offshore gas reservoir in China

Introduction

CCUS-enhanced gas recovery (CCUS-EGR) enables simultaneous CO_2 sequestration and improved gas recovery, partially offsetting storage costs and enhancing project economics. Previous studies indicate that CO_2 injection can increase gas recovery by approximately 10% (Jikich et al., 2003), with each ton of injected CO_2 displacing 0.03-0.05 tons of methane (Van der Meer et al., 2006). While most global CCUS projects focus on geological storage and enhanced oil recovery (EOR), CCUS-EGR remains at the mechanistic research and pilot-testing stage (Zhang et al., 2023).

Representative field applications include the K12-B gas field (Netherlands), the CLEAN project in the Altmark gas field (Germany), the Long Coulee Glauconite F Pool (Canada), and the Otway project (Australia) (Wang et al., 2023). The K12-B project injected over 100,000 tons of a 95% CO_2 mixture between 2003 and 2017, verifying technical feasibility and economic potential (Van der Meer et al., 2006; Vandeweijer et al., 2021). The CLEAN project confirmed the safety and injectivity of up to 100,000 tons of CO_2 through laboratory and field studies (Ganzer et al., 2014; Kühn et al., 2012). In Canada, an early CO_2 breakthrough highlighted the influence of injection pressure and fluid-density differences (Pooladi et al., 2008; Cao et al., 2022). The Otway project demonstrated secure storage through tracer-monitored injection of 6,544 tons of CO_2-rich gas (Underschultz et al., 2011; Jenkins et al., 2012; Boreham et al., 2011).

Previous studies have analyzed various factors affecting CO_2 breakthrough but lacked technical and economic evaluations for full-field CO_2 injection development. Most research focused on early-stage EGR projects, with limited studies on full-cycle economics. The Yinggehai Basin, located in the South China Sea, is a sedimentary basin rich in hydrocarbon resources (Liu, 2022). The basin also contains deep saline aquifers, which offer significant potential for CO_2 storage (Aminu et al., 2017). Meanwhile, the Yinggehai Basin contains many sandstone gas reservoirs with high CO_2 content, with local concentrations reaching up to 74.15% (Jiang et al., 2022). These gas reservoirs can serve as a potential CO_2 source for CCUS-EGR projects. The produced high-CO_2 methane can be separated and reinjected into other low-CO_2 gas reservoirs to enhance recovery. Compared to direct air capture (Kuramochi et al., 2012) or purchasing external CO_2, this approach significantly reduces capture and transportation costs, improving economic viability. Therefore, developing CCUS-EGR projects in the Yinggehai Basin offers distinct resource advantages.

Method and/or Theory

The studied sandstone reservoir has a burial depth of 1200–1500 m, an initial pressure of 14 MPa (currently ~5 MPa), an average porosity of 21%, a permeability of 24 mD, and geological reserves of approximately 5 bcm. Significant edge and bottom water invasion occurred after prolonged depletion. The region containing the gas reservoir was extracted from the geological model of the D gas field (as shown in Fig. 2), and other areas in the model were rendered inactive. The study area is irregular, with approximate dimensions of 10000 m × 6000 m × 220 m in different directions. The grid step size is 200 m in the I and J directions, and the K direction is divided into approximately 60 layers with a certain number of barriers and interbeds. The model's study area consists of about 54000 grids. The main components of the fluid are CH4, CO_2, N_2, $C_{2\text{-}4}$, $C_{5\text{-}6}$, and C_{7+}, with the composition and related parameters shown in Table 1. The component simulation was conducted using the Peng-Robinson equation. History matching was performed for Well 1 (Fig.2), Well 2, and Well 3 to ensure the accuracy of the model. Well 4 is a newly drilled gas production well located in the upper section of the reservoir, so no matching was performed.

Based on the history-matched reservoir model, this study conducted compositional numerical simulations to analyze the technical and economic performance of key development strategies for CCUS-EGR in the Yinggehai Basin. The strategies were further optimized to balance methane production and economic returns, which provides a basis and guidance for development planning and economic evaluation of this and other similar CCUS-EGR projects.

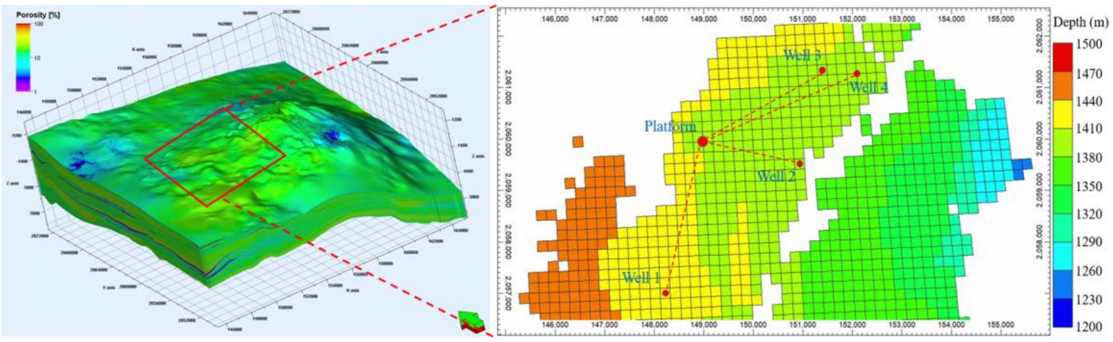

Figure 1 *Geological model of the gas field and 2D map of the main production layers in the study area*

Table 1 *Mole fraction and thermodynamic parameters of the in-situ fluid*

Composition	CH_4	CO_2	N_2	C_{2-4}	C_{5-6}	C_{7+}
Mole fraction, mol%	76.55	0.22	21.75	1.36	0.06	0.06
Molecular weight	16.04	44.01	28.01	36.27	72.15	158.00
P_c, atm	45.40	72.80	33.50	45.41	33.37	21.62
T_c, K	190.60	304.20	126.20	334.93	463.45	670.75
Acentric factor	0.008	0.225	0.040	0.120	0.235	0.463
V_c, 1/mol	0.099	0.094	0.090	0.171	0.305	0.629

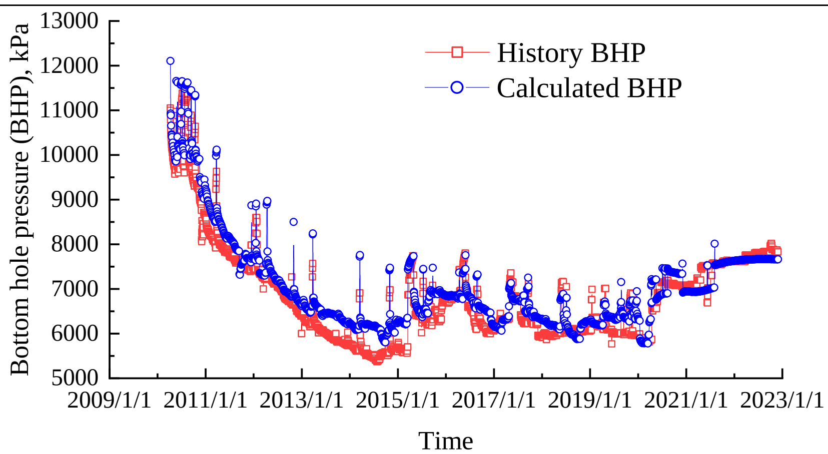

Figure 2 *History matching results of Well 1, while Well 2 and Well 3 were also history matched, but results were not displayed due to the length limit of the extended abstract.*

Economic analysis of similar projects typically focuses on Net Present Value (NPV), where an NPV > 0 indicates profitability. In CCUS-EGR projects, expenditures primarily consist of capital expenditures and operating expenses. Capital Expenditure includes costs for surface CO_2 purification equipment, CO_2 compression equipment, CO_2 pipeline construction, and drilling new injection or production wells (where required). Operating expenses cover purchasing CO_2 (where needed), purifying CO_2, transporting CO_2, compressing and injecting CO_2, and various costs related to fluid production. Revenue mainly comes from natural gas sales and trading in CO2 emission credits in China's carbon emissions trading market. Thus, in this analysis, NPV is primarily composed of natural gas sales revenue, CO_2 storage revenue, and operating expenses. The NPV calculation is provided in Equation (1), with each component calculated in Equations (2) through (10). Although the CO_2 purchase cost is mentioned in Equation (4), due to the high CO_2 content in certain production blocks of this gas field, which can be used as a CO_2 source for CCUS, the actual CO_2 purchase cost is set to 0 in the calculations. This portion of the price will be allocated to CO_2 purification expenses.

$$NPV = \sum_{n=1}^{N} \frac{\left[(Gas_{rev\,n} \times (1-T_r) + Carbon_{rev\,n}) \times (1-T_v) - Cost_n\right] \times (1-T_i)}{(1+r)^n} \tag{1}$$

$$Gas_{rev\,n} = \left[Q_{g(n)} - Q_{g(n\text{-}1)}\right] \times Price_M \tag{2}$$

$$Carbon_{rev\,n} = \left(\left[Q_{ci(n)} - Q_{ci(n\text{-}1)}\right] - \left[Q_{cp(n)} - Q_{cp(n\text{-}1)}\right]\right) \times Storage_{rev} \tag{3}$$

$$Cost_n = Gas_{pur\,n} + Gas_{cap\,n} + Gas_{tran\,n} + Gas_{inj\,n} + Liquid_{lift\,n} + W_{man\,n} \tag{4}$$

$$Gas_{pur\,n} = \left(\left[Q_{ci(n)} - Q_{ci(n-1)}\right] - \left[Q_{cp(n)} - Q_{cp(n-1)}\right]\right) \times Price_C \tag{5}$$

$$Gas_{cap\,n} = \left(\left[Q_{ci(n)} - Q_{ci(n-1)}\right] - \left[Q_{cp(n)} - Q_{cp(n-1)}\right]\right) \times Capture_{cost} \tag{6}$$

$$Gas_{tran\,n} = \left(\left[Q_{ci(n)} - Q_{ci(n-1)}\right] - \left[Q_{cp(n)} - Q_{cp(n-1)}\right]\right) \times Distance \times Transportation_{cost} \tag{7}$$

$$Gas_{inj\,n} = \left(\left[Q_{ci(n)} - Q_{ci(n-1)}\right] - \left[Q_{cp(n)} - Q_{cp(n-1)}\right]\right) \times Cost_{inj} \tag{8}$$

$$Liquid_{lift\,n} = \left(\left[Q_{ci(n)} - Q_{ci(n-1)}\right] - \left[Q_{cp(n)} - Q_{cp(n-1)}\right]\right) \times Lift_{cost} \tag{9}$$

$$W_{man\,n} = \left[Q_{wp(n)} - Q_{wp(n-1)}\right] \times W_{cost} \tag{10}$$

Results and Discussions

A three-stage hybrid injection strategy was designed: (1) high-purity CO_2 (95%) injection for pressure restoration; (2) medium-purity CO_2 (70%) injection after breakthrough; and (3) final depletion. Four scenarios were constructed to evaluate injection – production ratios and operating conditions. Over a 20-year period, CCUS-EGR increases the recovery factor by 17.8%, representing an 11.2% improvement over continued depletion. Hybrid injection enhances methane production while maintaining favorable CO_2 retention, whereas continuous high-purity injection leads to significant CO_2 recycling without proportional gains in permanent storage.

Economic evaluation was conducted using discounted cash flow analysis (discount rate = 10%). Revenues include methane sales and CO_2 storage credits, while costs are dominated by capture, purification, transportation, and injection. CO_2 capture accounts for 70 – 85% of total expenditure and is the primary economic constraint. Under current China carbon prices, methane revenue dominates NPV; under the U.S. 45Q tax credit ($60/ton), sequestration revenue becomes comparable to gas sales, shifting the optimal injection–production ratio. Reducing capture cost markedly improves economic feasibility. Technical comparisons show clear trade-offs among scenarios. Depletion-only development yields the lowest cost but also the lowest methane production and the highest water production, with long-term risks of water locking. Continuous high-purity CO_2 injection achieves the largest injection volume but incurs substantially higher costs without improving retention efficiency. The hybrid high-rate scenario maximizes methane production, representing the upper recovery bound. The lower production-rate hybrid scenario achieves the highest CO_2 retention fraction, as a reduced injection – production ratio allows more CO_2 to remain stored underground. Excessive reduction of production rate, however, diminishes methane revenue.

Overall, the injection strategy primarily controls methane recovery, while the injection–production ratio governs CO_2 retention. Economic performance is therefore determined by balancing methane sales against capture cost and carbon pricing incentives.

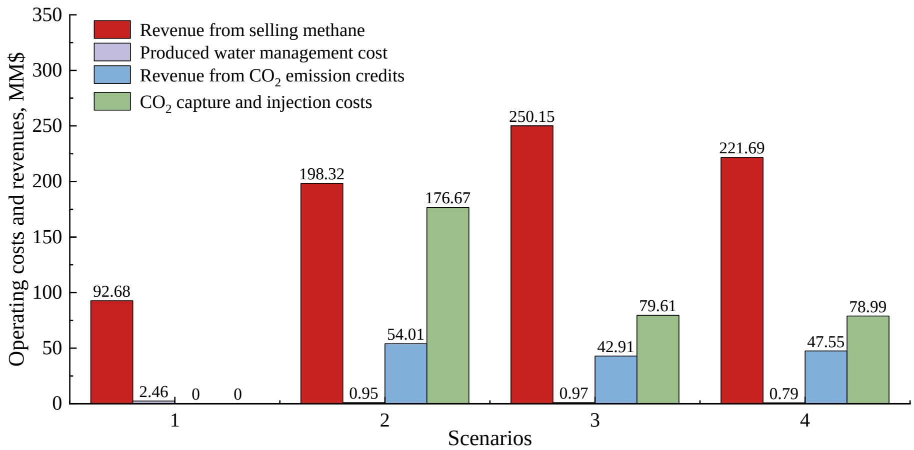

***Figure 3** Comparison of operating costs and revenues across scenarios: depletion, continuous high-purity CO_2 injection, and two optimized variable-composition injection strategies.*

Conclusions

We conducted a compositional simulation study and economic analysis on CCUS-EGR in a water-drive gas reservoir in the South China Sea. And the following conclusions can be drawn:

1) After 20 years of CO_2 injection, the total recovery factor of this reservoir increases by 17.8%, which is 11.2% higher than that of continued depletion development.

2) Compared to continuous injection of high-purity (95%) CO_2, a hybrid development strategy that injects high-purity CO_2 initially, switches to medium-purity (70%) CO_2 after a significant breakthrough, and finally transitions to depletion development yields better results.

3) When the carbon credit trading price is greater than $60/ton, an injection-production ratio of approximately 1.67 can achieve higher NPV and more significant CO_2 sequestration.

4) Although CCUS-EGR offers greater CO_2 storage potential than CCUS-EOR, its profitability is highly sensitive to CO_2 capture costs and carbon pricing incentives.

5) Compared to relatively stable methane prices, increasing carbon credit trading prices and reducing CO_2 capture and purification costs are key to improving the NPV of EGR projects.

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