On the use of supercritical carbon dioxide to exploit the geothermal potential of deep natural gas reservoirs for power generation

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ABSTRACT

Deep natural gas reservoirs, with high temperatures, can have significant geothermal potential, so that geothermal energy (in addition to natural gas) may also be produced from these resources. This study investigates the feasibility of exploiting both the natural gas and the geothermal energy contained in the reservoir, while using mainly supercritical CO_2 ($scCO_2$) as the heat energy extraction fluid. Particularly pronounced synergy effects may be achievable if CO_2 is used for CO_2-based enhanced gas recovery (EGR) and CO_2-based geothermal energy production (CO_2-Plume Geothermal, CPG). For example, the produced geothermal energy could be used to power some of the operational facilities of the gas field.

We present a general implementation process of the combined system that integrates the reservoir processes with the wellbore and surface power-generation systems. The components of the produced fluid, mostly methane (CH_4) and CO_2, are separated at the surface. In this way, power can be generated from the CO_2 via a direct CO_2-turbine expansion system and from the heat extracted from the CH_4 via a Rankine cycle. This optimises the electric power output of the combined system. When methane is depleted in the reservoir and only CO_2 is produced, power is generated only with the direct CO_2-turbine expansion system.

Using a reference numerical model (set up in TOUGH2), which depicts a 100 m thick natural gas reservoir at a depth of 3 km, and selecting a production well inner diameter of 0.14 m, a combined CO_2 EGR-CPG system is modelled to estimate the geothermal power generation, for two example cases of: a) relatively low and b) high CO_2 circulation rates. We consider three operational stages. The first stage involves only natural gas production, while the two other stages (EGR and CPG) are associated with simultaneous $scCO_2$ injection and production. The results show good heat-mining performance for all three stages, with the CPG stage having the highest power output. Additionally, CO_2 sequestration is achieved during EGR and CPG stages. Hence, the combination of CO_2-based EGR and CPG in deep natural gas reservoirs can significantly increase the gas field's overall power-generation efficiency, which may have a noticeable effect on investment and operation costs.

1. INTRODUCTION

Geothermal energy is regarded as a promising renewable and clean energy source if it is more extensively developed and efficiently exploited (Rybach 2003; Lund and Boyd 2015). It has also been proposed that $scCO_2$, due to its high expansivity and low kinematic viscosity, can be utilised as a particularly effective working fluid for heat recovery from sedimentary basin reservoirs, referred to as CO_2-Plume Geothermal (CPG) systems. The concept of CPG systems, as proposed by Randolph and Saar (2011), involves the injection of CO_2 into deep, naturally porous and permeable geologic (sedimentary) formations for geothermal exploitation and geological storage. A portion of the heated CO_2 is produced at the surface, providing energy for electricity production or direct heat utilisation. The sedimentary reservoirs can be deep saline aquifers, geopressured reservoirs or oil and gas reservoirs.

Hot natural gas reservoirs contain both natural gas resources and, potentially, considerable geothermal energy. In general, these hot natural gas reservoirs are deeply buried, associated with a depth of more than 3000 m, and are characterised by high reservoir temperatures and pressures (Pathak 2004; Burke 2009; Zhang et al. 2017). There is potential for utilising supercritical CO_2 ($scCO_2$) as a working fluid for the dual purpose of enhancing natural gas recovery (CO_2-EGR) and geothermal energy exploitation, employing CPG from the deep (hot) natural gas reservoir. We refer to this combined approach as CO_2 EGR-CPG. In combining these two systems, there are clear synergy effects that increase the overall system's efficiency. They include:

- ⇒ increasing the gas field's total amount of producible energy (natural gas and geothermal energy);
- ⇒ sharing of some existing infrastructure (surface facilities, wells etc.) and multidisciplinary datasets (on reservoir parameters), thereby reducing investment costs significantly;
- ⇒ providing energy (electricity, heat) to, and compensating for the cost of, both CCS and gas-field operations;
- ⇒ extending the useful life of the gas field, hence postponing the expensive clean-up and abandonment stages of the field;
- ⇒ CO_2 storage is a favourable by-product of the combined system.

In this paper, we investigate the potential, in terms of energy co-production and associated power generation, of combining these two systems in deep, porous and naturally permeable natural gas reservoirs. We have also presented a general implementation process that may optimise power generation for the combined system. We use some basic information of some deep natural gas reservoirs worldwide to set up a typical natural gas reservoir model. Using this model, a reservoir simulation study is carried out, employing TOUGH2 (Pruess et al. 1999; Yamamoto 2008), to evaluate the natural gas recovery and geothermal-mining performance of the system. A coupled reservoir, wellbore and surface power-plant model is also presented to accurately determine the potential of geothermal energy exploitation (and power generation) of a deep (and hot) natural gas reservoir. We evaluate two cases of relatively low and high CO_2-circulation mass flowrate and analyse the results of the co-produced energy.

2. THE PROPOSED IMPLEMENTATION PROCESS FOR POWER GENERATION FOR THE COMBINED SYSTEM

Figure 1 shows the general concept of the combined CO_2 EGR-CPG system (Ezekiel et al. 2019).

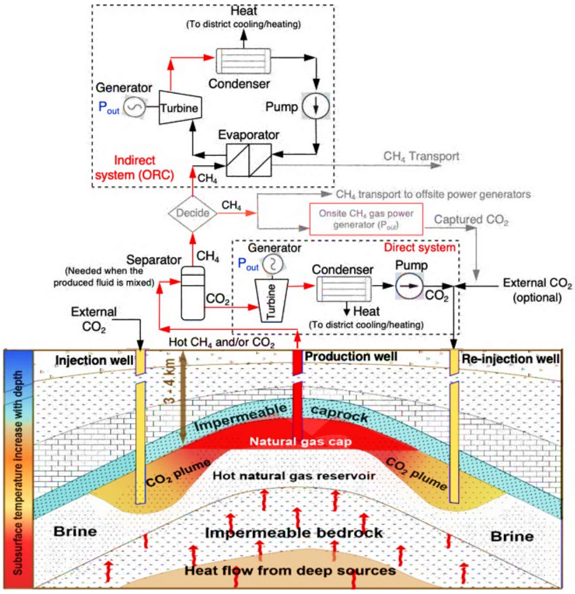

Figure 1: Schematic of the combined CO_2 EGR-CPG system for the generation of electricity.

Initially, natural gas is conventionally produced until the gas pressure declines (especially in compartmentalised reservoirs) or the natural gas is depleted (usually for non-compartmentalised reservoirs). We refer to this stage as the conventional natural gas recovery (CNGR) stage. Thereafter, supercritical CO_2 is injected into the deep natural gas reservoir, commencing the enhanced gas recovery (EGR) stage. In the reservoir, the CO_2 temperature increases as the CO_2 moves from the injection well to the production well, where the hot CO_2 is produced to the land surface. At the land surface, the produced mixed gas (CH_4 and CO_2) is separated from any potentially co-produced liquid (not shown in Figure 1) and the CO_2 is separated from the mixed CH_4-CO_2 gas. We stop this separation when the CO_2 mass fraction in the produced gas phase is between 90 and 96%, marking the onset of the CPG stage. The produced and separated hot CO_2 is sent directly to a CO_2 gas turbine (direct system) and expanded to generate electricity (Figure 1). The cooled (but still warm) CO_2 recovered at the outlet of the turbine is cooled and condensed to the liquid phase by a cooler-condenser. This reduces or (typically) eliminates the need for pumping the CO_2 back from the geothermal cycle back into the reservoir (Adams et al. 2014). Furthermore, the waste heat at the condenser may be recovered and used for heating purposes. Electric power may also be generated from the heat extracted from the produced methane (during the CNGR stage), and the separated methane (EGR stage), via a Rankine cycle (indirect system, see Figure 1).

3. NUMERICAL MODELLING AND SIMULATION

3.1 Reservoir Model Description

Using some of the reservoir properties of the examples of hot natural gas fields in the world, we set up a model of a natural gas reservoir with an anticlinal structure. The size of the full model is 4.5 x 3.0 x 0.1 km, with the natural gas reservoir having a thickness of 100 m. Figure 2 shows that the full model (left) has 4 injection (blue) and 4 production (red) wells, where the injection wells are located 550 m from the dome centre, and the production wells are 100 m from each other. This well arrangement has been chosen to reduce the modelling domain to one-quarter of the full model, due to symmetry. The initial distribution of gas saturation is shown in the one-quarter model.

We use the TOUGH2-EOS7C module (Oldenburg et al. 2004) for simulating gas and water flow, and heat transport, in the natural gas reservoir. The rock and fluid properties, as well as the initial conditions, are summarised in Table 1.

Table 1: Parameters for the reservoir model

Reservoir type	Non-compartmentalised; anticlinal structure (open sides)
Reservoir size (m)	4500 x 3000 x 100
Porosity	0.20
Horizontal permeability (m^2)	10^{-13}
Depth (m)	3000
Initial fluid pressure (MPa)	Hydrostatic (30 MPa at the reservoir base)
Reservoir temperature (ºC)	150
Initial natural gas composition	99% methane (CH_4) and 1% CO_2
Initial methane gas saturation	see Fig. 2 (right)
Residual liquid saturation	0.25
Well diameter (m)	0.14
Vertical boundary conditions	No fluid flow and no heat flow
Lateral boundary condition	Dirichlet boundary condition

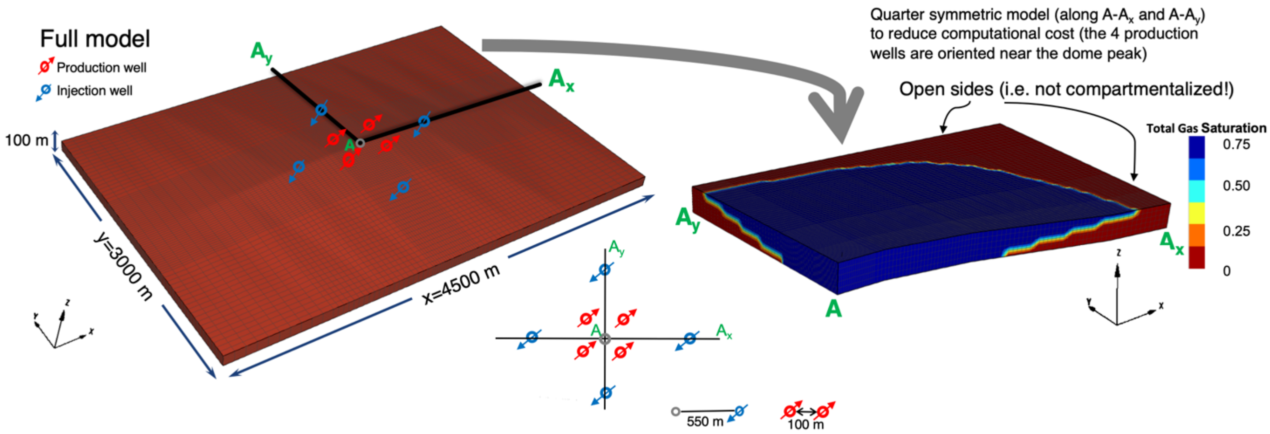

Figure 2: The full model (left) and the symmetric quarter model showing the initial gas saturation distribution (right).

Table 2: Simulation time, injection and production rates of the three operational stages of the combined system.

Stage	Conventional natural gas recovery (CNGR)	EGR		CPG
Duration (years)	26	1	1	Case 1: 42
				Case 2: 32
Production rate (kg/s/well)	2.5	6	Case 1: 9	Case 1: 9
			Case 2: 27.5	Case 2: 27.5
CO_2 injection rate (kg/s/well)	-	18	Case 1: 9	Case 1: 9
			Case 2: 27.5	Case 2: 27.5

3.2 Numerical simulations

The aim of the numerical simulations is to assess the potential for geothermal energy production and power generation of the proposed system from a technical point of view. We consider three operational stages, namely a conventional natural gas recovery (CNGR) stage, an EGR stage, and a CPG stage. We evaluate two cases of varying mass flowrates at the start of CO_2 circulation (equal injection and production rates). The duration of each stage and its corresponding production and injection rates (for the two cases considered in this study) are presented in Table 2. For the CNGR stage, natural gas is produced initially until depletion (when the water saturation, around the production well, starts increasing). Heat is extracted from the produced natural gas via the indirect system. After the CNGR stage, CO_2 is injected to enhance the natural gas recovery (EGR stage) and extract geothermal energy from the produced fluids, and establish a CO_2 reservoir (CPG stage) for geothermal energy production using CO_2 as the working fluid. For the CO_2 injection (EGR and CPG) stages, four vertical injection wells are used (Figure 2). Only two of the injection wells can be seen in the quarter-symmetric model. In the first year of the EGR stage, the CO_2 injection rate is set to be much larger than the fluid (mostly gas) production rate (here a ratio of 3:1) to ensure that formation water is not drawn into the production well (up-coning). The production and injection rates change (after a year of EGR), and become equal when the gas connection between the injection and production well has been established. The CPG period lasts for a period of 42 years for Case 1 (lower flowrate – 9 kg/s/well) and 32 years for Case 2 (high flowrate – 27.5 kg/s/well). The disparity in the duration for both cases is caused by thermal breakthrough occurring in Case 2 faster than in Case 1. Hence, Case 1 is set to run for a longer time.

3.3 Coupled (transient) reservoir simulation-wellbore heat transfer model

The transient wellbore heat transfer model is coupled with the reservoir simulation results to obtain the final wellhead temperature and wellhead pressure of the produced fluid with time. A coupled reservoir-wellbore model is important in this study, so as to determine the influence of the mixed-fluid proportions and the different fluid components on the final temperature and pressure of the produced fluid at the production wellhead (Ramey 1962, Atrens et al. 2009; Randolph et al. 2012; Zhang et al. 2011). These parameters are important input values for the power calculations. The wellbore model parameters are presented in Table 3. The results are presented in Figs. 3 and 4 for the wellhead temperature and wellhead pressure, respectively. The blue lines show the reservoir simulation results, while the red line shows the calculated wellhead temperature and pressure results.

Table 3: Parameters for coupled reservoir-wellbore heat transfer and power-plant model (Adams et al. 2015)

Wellbore parameter	Values
Well length (m)	3000
Geothermal gradient (ºC/km)	45
Ambient mean annual temperature (ºC)	15
Mean formation thermal conductivity (W/m ºC)	2.1
Mean formation density (kg/m³)	2650
Mean formation specific heat capacity (J/kg ºC)	1000
Power system	Direct CO_2 system – supplemental pumping Indirect system – 1,1,1,3,3-Pentafluoropropane (R245fa)
Direct turbine isentropic efficiency, η_{ie}	0.78
ORC turbine efficiency	0.8
Pump efficiency	0.9
Condensing or cooling tower approach temperature (ºC)	7

For Fig. 3, we consider the change in temperature, as the fluid is produced, due to pressure loss and wellbore heat loss as the fluid rises through a wellbore of 14 cm diameter. During the CNGR stage, we observe that the wellhead temperature of the produced fluid shows a large drop in temperature of ~39°C, which is caused by small well diameter used and the low production rates used during the CNGR stage. At the start of the first year of EGR, when the production flowrate is increased from 2.5 to 6 kg/s/well, heat loss in the production wellbore to the surrounding rock is reduced, so that the production wellhead temperature increases from 110°C to 125°C. Thereafter, as the produced gas composition changes from mostly methane to mostly CO_2, the produced gas temperature decreases.

The two flowrate cases considered in this study start after the first year of EGR and continue to the end of the CPG stage. The results for the two cases will be discussed together, and they are also presented in the same plot (see Figs. 3 and 4). For Case 1, following the bottom-hole temperature curve (blue curve), between Years 30 and 50, the wellhead produced CO_2 temperature is fairly constant at around 90ºC and after Year 50, a thermal breakthrough occurs, decreasing wellhead produced CO_2 temperature. For Case 2, between Years 29 and 36, the wellhead produced CO_2 temperature is fairly constant at around 85ºC and after Year 36, thermal breakthrough occurs. Here we can see that, for the lower flowrate, it will take a longer time for thermal breakthrough to occur.

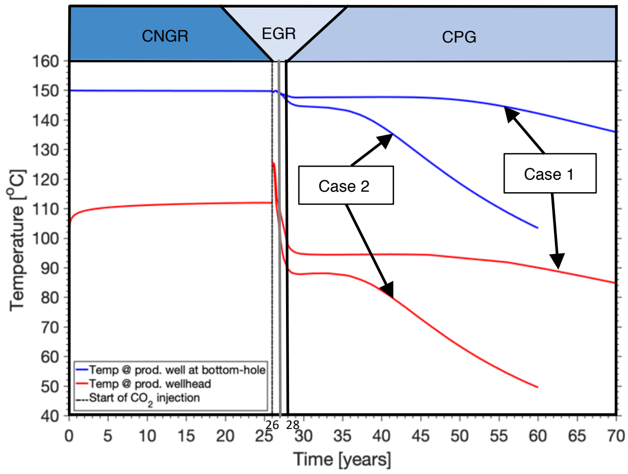

Figure 3: Temperature time series in the reservoir and at the production wellhead for the two cases considered.

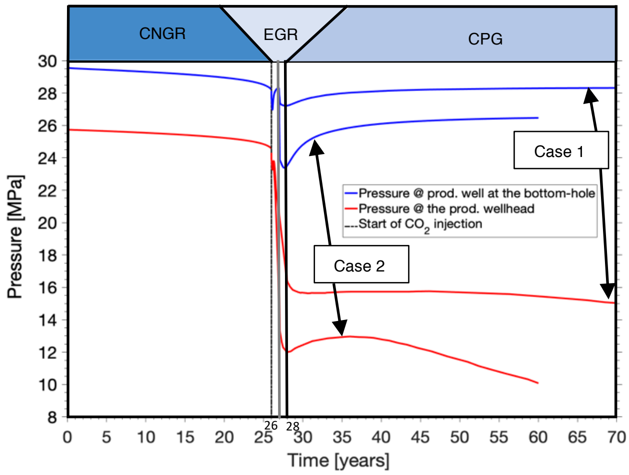

Figure 4: Pressure time series in the reservoir and at the production wellhead for the two cases considered.

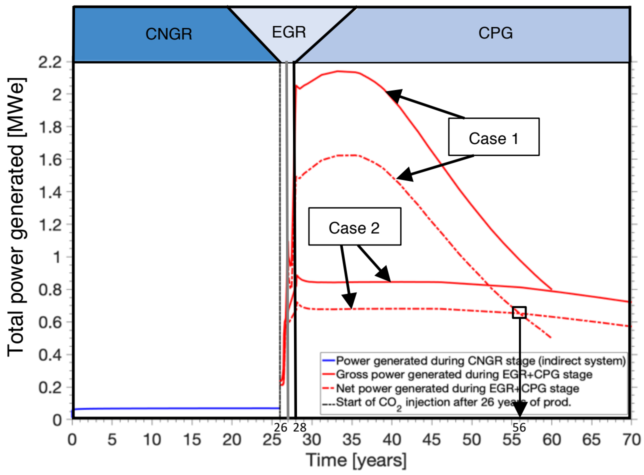

Figure 5: Time series of total geothermal electricity generated from all 4 production wells for the two cases considered.

Table 4: Simulation results for energy produced and CO_2 stored for the two cases considered.

Stages	Simulation calculations	Results	
Methane production stage (26 years)	Natural gas recovery factor, %	82.53	
	Ave. heat energy extractable from the produced methane for 26 years, MW_{th}	1.737 (0.396 $TW_{th}h$)	
	Ave. power generated from the heat extracted from the produced methane for 26 years, MW_e	0.077 (17.54 GW_eh)	
CO_2 injection starts		**Case 1**	**Case 2**
CO_2-EGR stage (2 years)	Additional natural gas recovery factor, %	2.13	2.67
	Total net power generated from the produced fluid (separated at the surface) for 2 years, MW_e	0.244 (4.275 GW_eh over 2 years)	0.708 (8.637 GW_eh over 2 years)
CPG stage	Ave. net power generated, from the produced CO_2, in a direct system, MW_e	0.656 (0.422 TW_eh over 42 years)	1.187 (0.333 TW_eh over 32 years)
SUMMARY			
Net power generated	Total (weighted) average net power generated from the: indirect system (28 years), MW_e and direct system (34 years), MW_e	0.098 (24.04 GW_eh) 0.638 (0.246 TW_eh)	0.090 (22.13 GW_eh) 1.143 (0.341 TW_eh)
CO_2 stored	Total amount of CO_2 stored, MMtonnes	7.75	14.24
Others	CO_2-charging time to reach 90, 99% XCO_2, years	2,12	1.374, 10

Fig. 4 shows the reservoir fluid pressure at the bottom-hole (blue colour) and the corresponding production wellhead pressure (red colour). As shown in Fig. 4, during the CNGR stage (Years 0 to 26), the production wellhead pressure is about 4 MPa lower than the reservoir production pressure. During EGR and CPG stages, for both cases considered, the production wellhead pressure increases as the reservoir production pressure is increasing, but gradually declines due to decreased reservoir production temperatures (Fig. 4) increasing CO_2 density and due to thermal breakthrough.

4. ENERGY CO-PRODUCTION AND CO_2 STORAGE ANALYSES

The wellhead information (temperature, pressure) obtained from the coupled wellbore heat transfer analysis, and the information about production rate and CO_2 mass fraction in the produced fluid, are applied to calculate the power generated, using the two power systems at the different stages. The CNGR stage requires only the indirect system, the EGR stage requires both power systems, and the CPG stage requires only the direct system for power generation. The extractable heat energy and power generated for the different stages are calculated and discussed below. Fig. 5 shows the results of the calculated power generated over the simulation time for the two cases considered in this study (at the different operational stages). Table 4 shows the summarized energy analysis results for the different stages and for the two cases considered in this study. The results comprise: the amount of natural gas that can be recovered before and during CO_2 injection (i.e. during the CNGR and EGR stages), the quality and time to establish a CO_2 plume in the natural gas reservoir; how much heat and power can be produced; and the amount of CO_2 that can be stored.

The power generated (via an indirect system) from the heat extracted from the produced methane, during the CNGR stage, is about 0.077 MW_e. This is quite low and is caused by the low production rate and small well diameter associated with this stage. Higher production rates would result in more power during the CNGR stage. Table 4 shows that more power is generated during Case 2 (1.187 MW_e net average power) than during Case 1 (0.656 MW_e net average power). However, because of an early thermal breakthrough during Case 2, the power declines faster (after a peak of 1.624 MW_e between the 29th – 36th year). At 56 years (28 years after the EGR stage), the net power generated during Case 2 becomes equal to the net power generated during Case 1 (Fig. 5). During the CPG stage, further calculations show that passing the produced CO_2 directly to the CO_2-turbine expansion system, instead of extracting heat from the produced CO_2 and using the indirect system (ORC), results in 3.5 and 4 times more power for Case 1 and for Case 2, respectively. In terms of economics, Case 2 favors higher investment returns than Case 1, due to Case 2 exhibiting more power output in less time (thus reducing the operation and maintenance costs).

The total amount of CO_2 stored in the reservoir during Case 2 is two times greater than that of Case 1 (Table 4). Additional external CO_2 could be stored in the reservoir if required.

5. CONCLUSIONS

1. Considering the synergy effects associated with combining EGR and CPG systems, and using the proposed implementation strategy of separating the produced fluids at the land surface and passing the separated CO_2 in a directly through a CO_2 turbine expansion system, makes the proposed concept of energy co-production from a deep natural gas reservoir using CO_2 as a working fluid more attractive.

2. Our wellbore heat transfer model shows that during fluid rise in the production well, the temperature and pressure decrease with increasing CO_2 mass fraction in the produced fluids.

3. Our simulations indicate that the average geothermal net electricity generated in our particular model, which includes the 4 injection and 4 production wells, is on average: 0.077 MW_e (ORC-based) over the 26 years of the CNGR stage and 0.656 MW_e over 42 years (Case 1) and 1.187 MW_e over the 32 years (Case 2) of the CPG Stage, for the relatively low and high flowrate cases considered, respectively. Running the CPG stage with higher flowrate and using the direct CO_2 turbomachinery results in higher power output rates within a shorter timeframe and thus reduces investment costs. Our example represents just one well cluster (with 4 injection and 4 production wells) out of potentially many well configurations in a natural gas field. We thus expect more net power generated, where likely much larger development strategies (number of wells, well placement, production rates) are employed.

4. All the external CO_2 used during the EGR stage is permanently stored in the reservoir. More external CO_2 could likely be stored both during the CPG and during a post-CPG stage, depending on reservoir storage capacity.

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