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Coalbed Methane Recovery by Injection of Hot Carbon Dioxide

Hon Chung Lau, National University of Singapore, Chaobin Zhao, University of Calgary, Samuel W. Lau, University of Houston

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Abstract

A new method of coalbed methane (CBM) recovery is proposed wherein hot carbon dioxide at or near supercritical condition is injected into a CBM reservoir to take advantage of enhanced desorption of methane at elevated temperatures and the preferential adsorption of CO_2 on coal surfaces compared to methane. The feasibility of this concept was studied by reservoir simulations using one quarter of an inverted five spot pattern using CO_2 and CH_4 adsorption isotherms published in the literature. The study compared CBM recovery by pressure depletion, CO_2 injection and injection of CO_2 that is 10°C hotter than the reservoir temperature. Results show that hot CO_2 injection can significantly increase the production rate and recovery factor over and above that achievable by reservoir heating or CO_2 injection alone. This new method holds promise for enhanced CBM recovery and also CO_2 sequestration, especially for high-rank coals where swelling of coal by CO_2 injection is minimized. Preliminary considerations suggest that this method can be economic over a range of CO_2 and natural gas price if the CO_2 comes from natural sources and the CBM field is located near an existing CO_2 pipeline. Alternatively, if the source of CO_2 is industrial, this method can be profitable if the cost of CO_2 capture is offset by the trading price of CO_2 and if the CBM project is located near the CO_2 source.

Introduction

Coalbed methane, also known as coal seam gas, is a significant source of natural gas worldwide, with sizable reserves in the United States, Australia, Russia, Canada and China. In 2015, CBM production in the US was 1.27 Tcf (35.97 Bcm), accounting for 3.9% of all US natural gas production (EIA, 2017). Commercial production of CBM occurs in ten US basins with major production coming from the San Juan, Black Warrior and the Central Appalachian. In 2015, CBM production in Australia was 270 Bcf (7.65 Bcm) accounting for 18% of Australia's total natural gas production (Australian Government, 2016).

CBM Recovery Mechanisms

There are several known methods for CBM recovery. They are summarized below.

Depletion Drive. Unlike conventional natural gas deposits where natural gas resides within the pore space of a reservoir, the methane gas in a CBM reservoir is not stored as free gas but rather as sorbed gas on the surface of coal. Figure 1 is a methane sorption isotherm of Pittsburgh coal in the North Appalachian Basin (Rogers *et al*., 2007). At a reservoir pressure of 800 psi, and temperature of 30°C, the coal is undersaturated with respect to methane. A drop of reservoir pressure to 200 psi will result in desorption of methane from the coal surface, giving a recovery factor of about 27%. This method of CBM recovery is called pressure depletion and is the predominant method used for CBM recovery.

Hitherto, most commonly used CBM production method is pressure depletion wherein a large amount of formation water is produced to lower the reservoir pressure to allow methane desorption from the coal surface. Recovery factor is estimated to be between 20-60% of original gas-in-place, depending on coal permeability, gas saturation, well spacing and other reservoir properties and operational practices.

Enhanced CBM Recovery by CO_2 Injection (CO_2-ECBM). This method utilizes the concept of displacement desorption due to the fact that CO_2 has a higher affinity than methane for adsorption on coal surfaces (Stevens *et al.,* 1998). In this process, injected CO_2 is preferentially adsorbed at the expense of methane. The displaced methane diffuses into the cleat system and is produced as free gas. Laboratory studies have shown that one to several volumes of injected CO_2 are required per volume of incremental produced methane, depending on the coal rank. In general, for high rank coals, the CO_2/CH_4 replacement ratio approaches one (Gonzales *et al.,* 2008). However, CO_2-ECBM suffers from coal swelling and permeability reduction that occur when CO_2 displaces methane in low to medium rank coal (Anggara *et al.,* 2013; Gonzales *et al.,* 2008; Mazumder and Wolf, 2008) This phenomenon, however, is less pronounced in high rank coals, where perhaps the largest potential of CO_2-ECBM resides (Gonzales *et al.,* 2008). The effect of CO_2 adsorption on coal swelling has been a subject of considerable experimental and numerical research (Law, *et al.,* 2002; van Hemert *et al.,* 2007; Chen *et al.,* 2009).

In the US, there have been several CO_2-ECBM pilot projects with various degree of success (Gonzales *et al*., 2008). This method has also been piloted in China, Canada, Japan and Poland (Pagnier *et al.,* 2005).

Enhanced CBM Recovery by Nitrogen Injection (N_2-ECBM). This method utilizes the concept of inert gas stripping. Due to its low sorption characteristics, nitrogen acts more like an inert gas in the presence of coal. Nitrogen injected into a CBM reservoir reduces the methane concentration in the gas phase while maintaining the total system pressure. Consequently, the partial pressure of methane is reduced. This allows methane to desorb from the coal surface and diffuse to the cleat network. Simulation and pilot results suggest that N_2-ECBM is capable of recovering significant amount of gas-in-place (Puri and Yee, 1990). Where there is no significant CO_2 source, N_2-ECBM may be an alternative.

Enhanced CBM Recovery by Underground Coal Gasification. This method utilizes the concept of thermal desorption. Thermal desorption uses heating to increase the temperature of the coal so as to reduce its adsorption capacity. Thermal treatment can therefore increase gas desorption and diffusion in coal seam gas reservoirs resulting in higher ultimate recovery, lower water production and higher wellhead pressure. The use of underground coal gasification as a thermal recovery process for a CBM

reservoir has been proposed (Salmachi *et al*., 2011) but not been applied in the field.

Enhanced CBM Recovery by Hot CO_2 Injection

Our proposal is to combine CO_2 exchange with thermal desorption of CBM by injecting hot CO_2 at or near supercritical conditions into a CBM reservoir. This method encompasses the benefits of CO_2-ECBM and thermal recovery. It has the following advantages.

Firstly, sorption of gas on coal is governed by the Langmuir isotherm. At high temperatures, the ability of coal to adsorb gas is significantly reduced. Consequently, heating up coal by injecting hot CO_2 can significantly enhance desorption of methane from coal surfaces.

Secondly, for an undersaturated coal, an increase in temperature increases the critical desorption pressure at which methane desorption initiates. Consequently, methane production can start at a higher reservoir pressure and less dewatering is required. Furthermore, the total gas recovery for a fixed initial and abandonment pressure increases at higher temperatures as shown in Fig. 1.

Thirdly, transport of methane from the pores to the cleats in the coal is controlled by diffusion. A higher temperature increases the diffusion coefficient and therefore the rate of methane diffusion into the cleats.

Fourthly, isotherms measured in the laboratory have shown that coal can adsorb up to three times as much CO_2 by volume than methane, depending on coal rank. Since CO_2 preferentially adsorbs on the coal surface, it displaces methane from the coal surface.

Fifthly, hot CO_2 can strip water from cleat network, which enhances CO_2-methane mass transfer.

Sixthly, this method has the added advantage of sequestering large quantities of CO_2 in CBM reservoirs which is beneficial for mitigating greenhouse effects of CO_2 emission to the atmosphere.

In summary, the heat supplied by the hot CO_2 enhances desorption of methane from the coal surfaces and speeds up its diffusion into the cleats. It also allows desorption to occur at a higher reservoir pressure and therefore reduces the need for dewatering. In addition, CO_2 enhances desorption of methane gas from the coal surfaces by nature of its higher affinity on coal.

However, the injection pressure of CO_2 should not be too high to fracture the overburden. This process works best in a high rank coal which is usually not susceptible to coal swelling and permeability reduction due to injection of CO_2 (Anggara *et al.,* 2013).

Reservoir Simulation

Approach. A dual-porosity compositional reservoir model for a typical high rank CBM reservoir was constructed in a commercial reservoir simulator that included one injection well and one producer well arranged in an one quarter of an inverted five-spot pattern (Fig. 3). This model employed temperature-dependent Langmuir isotherms for methane and CO_2. The simulations compared gas rate, cumulative gas production and gas recovery factor between simple pressure depletion versus CO_2 injection at reservoir temperature and at 10^oC higher than reservoir temperature.

Assumption. Current commercial reservoir simulators are inadequate to fully simulate the non-

isothermal process of hot CO_2 injection into CBM which involves the heat exchange between injected CO_2 with the reservoir fluid and rock and the temperature dependence of CO_2 and methane adsorption. Consequently the following assumptions were made in our simulations.

1. The methane and CO_2 adsorption isotherms on coal at 45°C published in the literature (Zhang *et al.,* 2011; Law *et al.,* 2002) are used (Fig. 2).
2. At elevated reservoir temperatures, adsorption capability of CO_2 and methane should be reduced, the amount of this reduction with temperature is assumed to form different cases.
3. When the temperature of injected CO_2 is different from the reservoir temperature, there is heat exchange between injected CO_2 and the reservoir. This process depends on the temperature difference between injected CO_2 and the reservoir, CO_2 injection rate and volume, and the thermal conductivity of the reservoir fluid and rock. This means that the reservoir temperature during hot CO_2 fluid injection is location specific. Therefore, the desorption parameters of CO_2 and methane are also location specific. To simplify the problem, it is assumed that the temperature throughout the whole reservoir is instantly increased to the injected CO_2 temperature. This will cause a higher gas production rate, but should not affect the ultimate recovery.
4. There is no coal swelling due to CO_2 injection.

Model Description. A quarter of inverted five-spot model was built for our study (Fig. 3). The dimension of the model was 11x11x2 and grid size in x and y directions was about 25 m x 25 m. Reservoir depth is 750 m. Initial reservoir pressure and temperature are 7.65 MPa and 45°C, respectively, which is inside the supercritical region of the CO_2 phase diagram (Fig 4). Coal density is 1,434 kg/m^3. At 45°C, dry, ash-free Langmuir pressures for methane and CO_2 are 4.6885 MPa and 1.903 MPa, respectively, and Langmuir volumes for methane and CO_2 are 0.0118 m^3/kg and 0.024 m^3/kg, respectively (Zhang *et al.,* 2011). The isotherms are given in Fig. 2. Initial gas content is 6.0 m^3/t and gas is 19.1% undersaturated with respect to the isotherm. Porosity is 0.5% and permeability is 2 md. The PVT properties of methane and CO_2 under various temperatures and pressures are calculated using the Peng-Robinson Equation of State. Gas and water relative permeability curves are shown in Fig. 5. The model takes into account the competitive adsorption of CO_2 in the presence of CH_4 by using the partial pressures of the two gases. The cleat is 100% water saturated initially.

Operational constraints. The operational constraints for injection and production wells are as following:

- CO_2 injection rate (1/4 well) = 1,000 m^3/d
- Maximum injection well bottom hole pressure = 10 MPa
- Maximum gas production rate (1/4 well) = 1,000 m^3/d
- Minimum production well bottomhole pressure = 0.275 MPa

Case Design. To compare CBM recovery by hot CO_2 injection to that by pressure depletion, the following cases were designed (Table 1 and Figs. 6-7).

- Case 1: Depletion drive at reservoir temperature of 45°C
- Case 2: CO_2 injection at 45°C

- Case 3: CO_2 injection at 55°C assuming reservoir temperature equilibrated to 55°C instantly. Langmuir volumes for CO_2 and methane are reduced by 10% and 20%, respectively. Langmuir pressure for CO_2 is increased by 10% and unchanged for methane.
- Case 4: Same as Case 3 except it is assumed that Langmuir pressure for CO_2 remains the same as that at 45°C.
- Case 5: Same as Case 4 except it is assumed that Langmuir volumes for CO_2 and methane are reduced by 20% and 10%, respectively, from their values at 45°C.
- Case 6: Depletion development at 55°C. Langmuir volume of methane is unchanged from that at 45°C. Langmuir pressure of methane is reduced by 20% from that at 45°C.
- Case 7: Depletion drive at 55°C. Langmuir volume of methane is unchanged from that at 45°C. Langmuir pressure of methane is reduced by 10% from that at 45°C.

Case 1 is the base case for depletion drive at 45°C. Cases 6 and 7 are the depletion drives at 55°C with different impact of temperature on the Langmuir isotherm. Cases 2 represents the case of CO_2 injection without raising reservoir temperature. Cases 3 through 5 are cases of hot CO_2 injection at 55°C assuming different impact of temperature on the Langmuir isotherms. We believe the aforementioned assumptions on the impact of temperature on the Langmuir volume and pressure are reasonable and generally agrees with experimental data published by Zhang *et al*. (2011).

Simulation Results

Simulations results are given in Table 1 and can be summarized below where recovery factor (RF) refers to that at 20 years.

1. Depletion drive at 45°C gives a gas RF of about 44% (Case 1).
2. CO_2 injection at 45°C increases the gas RF to 73% (Case 2), a roughly 60% increase.
3. Heating up the reservoir by 10°C increases the gas RF to 50-58% (Cases 6 and 7), a 15-32% increase.
4. However, injection of CO_2 at 55°C increases the gas RF to 83% (Cases 3, 4 and 5), a 90% increase.

The gas rate and cumulative gas rate from our simulations are given in Figs. 8 and 9, respectively. It can be seen from these figures that heating up the reservoir by 10°C has a primary impact on production acceleration and a secondary impact on ultimate recovery, although both impacts are significant. This is demonstrated by a higher production peak that occurs sooner for Case 6 compared to Case 1 (Fig. 8). Note that at later times, the production rate for Cases 1 and 6 are the same.

However, CO_2 injection has a primary impact on ultimate recovery and a secondary impact on production acceleration. This is demonstrated in Fig. 9 showing that for the first few years, gas cumulative gas production is roughly the same for Cases 1 and 2, but at later times, Case 2 has a much higher cumulative gas production than Case 1.

Consequently, hot CO_2 injection has the dual benefits of both accelerating production and increasing ultimate recovery. The effects of heating the reservoir and injecting CO_2 are roughly additive. Heating increases ultimate recovery by approximately 30% whereas CO_2 injection by approximately 60%. Hot CO_2 injection increases ultimate recovery by approximately 90%.

Model Limitations. There are, however, limitations to our simulations. Firstly, our simulations are

isothermal where we assumed the reservoir to heat up to the injected CO_2 temperature instantaneously. This will lead to a faster gas production rate, but should not affect the ultimate recovery. Secondly, CO_2 injection is not optimized but assumed to be at a constant rate. In field applications, both CO_2 injection rate and duration of injection should be optimized using adsorption isotherms measured from the coal samples. Then economics can be run to determine which combinations will give the best NPV and ultimate recovery. Thirdly, we have only investigated increasing the reservoir temperature by 10^oC by injecting hot CO_2. In field applications, the CO_2 injection temperature should also be optimized by running non-isothermal simulations to take into account the time it takes to heat up the reservoir, based on thermal properties of the coal. Fourthly, the isotherms used in our simulations are taken from the literature. We make reasonable assumptions on the impact of temperature increase on the isotherms. For field applications, experimental measured isotherms from the target coal seams should be used in simulations. Fifthly, the assumption that CO_2 has no impact on coal swelling needs to be verified with coal samples from the field. These limitations notwithstanding, our simulation study demonstrated the potential of hot CO_2 injection as a CBM recovery mechanism.

Conceptual Design

The following is a conceptual design of the proposed method.

1. Carbon dioxide from either a natural or industrial source is captured, filtered and transported by pipeline to a CBM field under supercritical conditions.
2. The CO_2 is heated to a temperature that is 10^oC or higher than the reservoir temperature by heat exchangers using produced natural gas from the field.
3. Hot CO_2, at or near supercritical condition, is injected into a CBM formation through an injection well. Natural gas and water is produced from producers with injectors and producers arranged in a usual well pattern such as inverted five-spot or inverted nine-spot.
4. An alternative design is to inject hot CO_2 into a CBM well. The well is shut in for a soaking period after which it is opened for production. The process can be repeated. The injection, soaking and production times can be optimized by reservoir simulations.

CO_2 Sources and CBM fields in US

The source of CO_2 is a major consideration in the proposed process. The CO_2 source can be either natural or industrial. Figure 10 shows the natural and industrial CO_2 sources, existing CO_2 pipelines and CBM fields in the US. Natural sources of CO_2 exist in Mississippi (Jackson Dome), New Mexico (Bravo Dome) and Colorado (Sheep Mountain and McElmo Dome). Industrial CO_2 sources exist in Texas, Kansas, Oklahoma, Wyoming, North Dakota and Michigan. Extensive CO_2 pipeline exists in the Gulf coast, Texas, New Mexico, Colorado, and Wyoming. In the US, CBM fields are located in New Mexico (San Juan Basin), Colorado (Piceance Basin), Wyoming (Powder River Basin), Kansas (Arkoma Basin), Oklahoma (Cherokee Platform), Alabama (Black Warrior Basin), Virginia (Central Appalachian Basin) and Pennsylvania (Northern Appalachian Basin). Many of these are located close to existing CO_2 pipelines making them especially attractive for enhanced CBM recovery by hot CO_2 injection. Outside of the US, CO_2 pipeline infrastructure exists in UK and Canada, but not elsewhere (IEA, 2013).

The Economic Case

Where a CBM reservoir is located near an existing CO_2 pipeline and the CO_2 source is natural, e.g. in Texas or Wyoming, the cost of CO_2 can be around \$0.50-1.0/Mcf. In existing pipelines, CO_2 is usually transported in dense liquid phase near supercritical conditions (31°C, 74 bar). Therefore the line pressure of CO_2 is usually high enough for CO_2 injection into the CBM without the need for compression. The other cost is the heating up of CO_2. Since produced methane can be used as fuel to heat up the CO_2, the heating cost can be assumed to be a fraction of the produced methane. In this case, an economic case can be constructed for various price of natural gas using the results of reservoir simulations. Since our simulations were not optimized for CO_2 injection, no detailed economic case is given here. However, assuming that no additional well and facility cost is incurred and heating of CO_2 consumes up to 20% of produced natural gas, our rough estimate suggests that hot CO_2 injection can be economic under a low CO_2 price (\$0.5/Mscf) and a low natural gas price (~ \$3.0/Mscf) scenario or a high CO_2 price (\$1.0/Mscf) and moderate to high natural gas price scenario (> \$4.0/Mscf).

When CO_2 has be to captured from industrial sources such as flue gas from power generation plants, then its capturing cost can fall within the range of \$0.8-1.0/Mscf (Iwasaki *et al*., 2004). Furthermore, when the distance between the power plant and the CBM reservoir is 100 km or less, the cost of pipelines used to transport CO_2 is relatively small. The same is true if the power plant is located near an existing CO_2 pipeline. In this case, it is conceivable that an enhanced CBM project by hot CO_2 injection can also be economical under a moderate to high natural gas price scenario (>\$4.0/Mscf).

If, on the other hand, a trading price of CO_2 emission is applicable, the economic case can be considerably improved. For CO_2, \$1.0/Mscf is equivalent to \$19/ton. Therefore, when the trading price of CO_2 emission exceeds \$20/ton, the cost of CO_2 capture from flue gas can be completely offset by that price, and an enhanced CBM recovery project by hot CO_2 injection can result in a large profit. Current estimate is that the price of CO_2 will be close to \$20/ton in year 2020 (Luckow *et. al*., 2015).

The economic case will be worsened if the source of industrial CO_2 is located far from CBM fields or existing CO_2 pipelines. In this case, the cost of constructing a long CO_2 pipeline needs to be included.

Future Research

Coal swelling experiments using field samples in the presence of CO_2 should be used to screen potential candidate CBM reservoirs for hot CO_2 injection. Only those samples that do not show significant swelling should be considered as candidates. Next, the adsorption isotherms of both methane and CO_2 in candidate CBM reservoirs should be measured using coal samples from target coal seams over a range of temperature at and above reservoir temperature. The thermal conductivities of coal should also be measured. The experimental results can then be input into a reservoir simulator to investigate the potential of CBM recovery by hot CO_2 injection. To fully simulate the process, a non-isothermal CBM reservoir simulator will be needed.

Conclusions

The following conclusions can be made from the present study.

1. A new method of CBM recovery by injection of hot CO_2 is proposed. This method takes advantage of the competitive adsorption of CO_2 over methane on coal surfaces and enhanced desorption of methane at elevated temperatures. In addition, it holds promise to sequester large

amount of industrial CO_2 in a CBM reservoir to mitigate the adverse effect of CO_2 on the environment.

2. Simulation studies using a quarter of an inverted five spot pattern were conducted to determine the effectiveness of this process by using literature derived adsorption isotherms for CO_2 and CH_4 and by making various assumptions on the effect of temperature on these isotherms.
3. Simulation results show that heating has a primary impact on gas production acceleration and a secondary impact on ultimate recovery, whereas the opposite is true for CO_2 injection. The combined result is that hot CO_2 injection can lead to significant production acceleration and increase in ultimate recovery.
4. A hot CO_2 injection project can be economically attractive if CO_2 comes from a natural source and the CBM field is located near an existing CO_2 pipeline, or where the source of CO_2 is industrial and the trading price for CO_2 emission offsets the cost of CO_2 capture and transportation.

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Table 1 – Simulation results

Case	1	2	3	4	5	6	7
Recovery mechanism	Depletion drive at 45°C	CO_2 injection at 45°C	CO_2 injection at 55°C	CO_2 injection at 55°C	CO_2 injection at 55°C	Depletion drive at 55°C	Depletion drive at 55°C
Initial reservoir temperature, °C	45	45	45	45	45	55	55
Initial reservoir pressure, MPa	7.64	7.64	7.64	7.64	7.64	7.64	7.64
Injected CO_2 temperature, °C	NA	45	55	55	55	NA	NA
CO_2 Langmuir Pressure, MPa	NA	1.903	2.100	1.903	1.903	NA	NA
CO_2 Langmuir Volume, m^3/t	NA	24.0	21.6	21.6	19.2	NA	NA
CH_4 Langmuir Pressure, MPa	4.689	4.689	4.689	4.689	4.689	4.689	4.689
CH_4 Langmuir Volume, m^3/t	11.8	11.8	9.44	9.44	10.62	9.44	10.62
Cummulative gas production, MMscf	2.11	3.50	4.03	3.97	4.01	2.79	2.42
Gas recovery factor, %	43.8	72.6	83.5	82.4	83.2	57.9	50.2

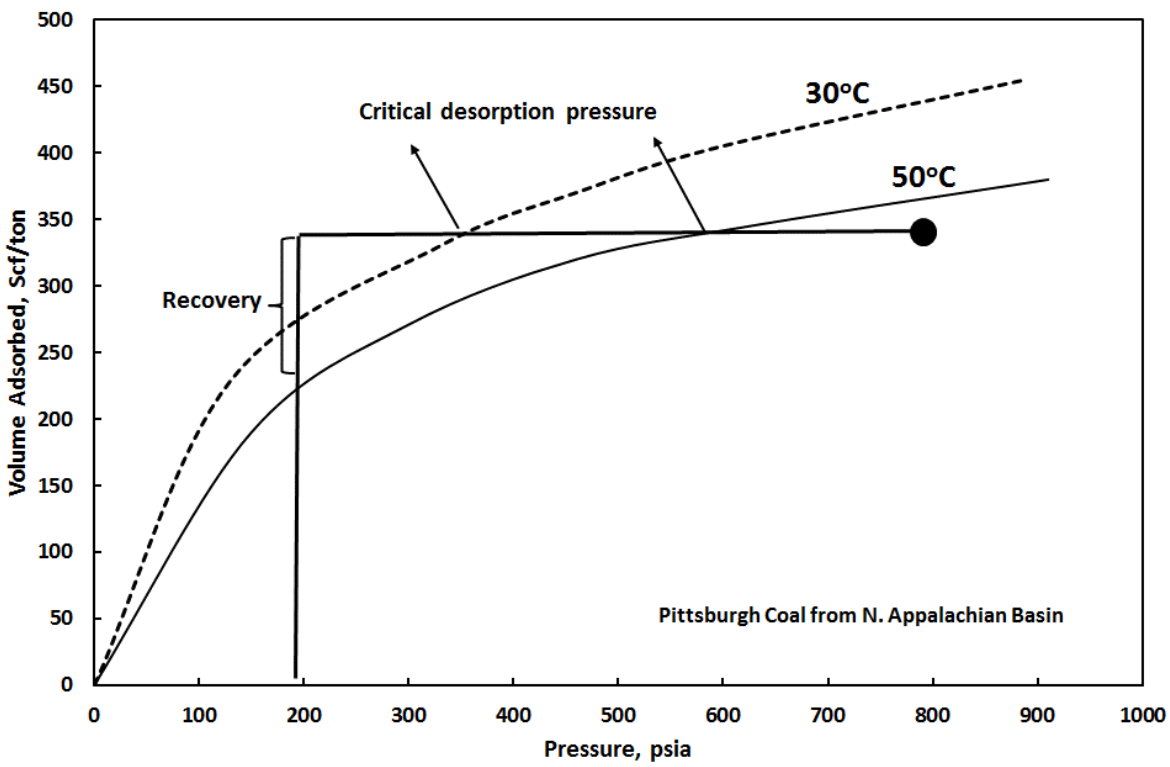

Figure 1 – Effect of temperature on methane sorption isotherms (data from Rogers *et al.* 2007)

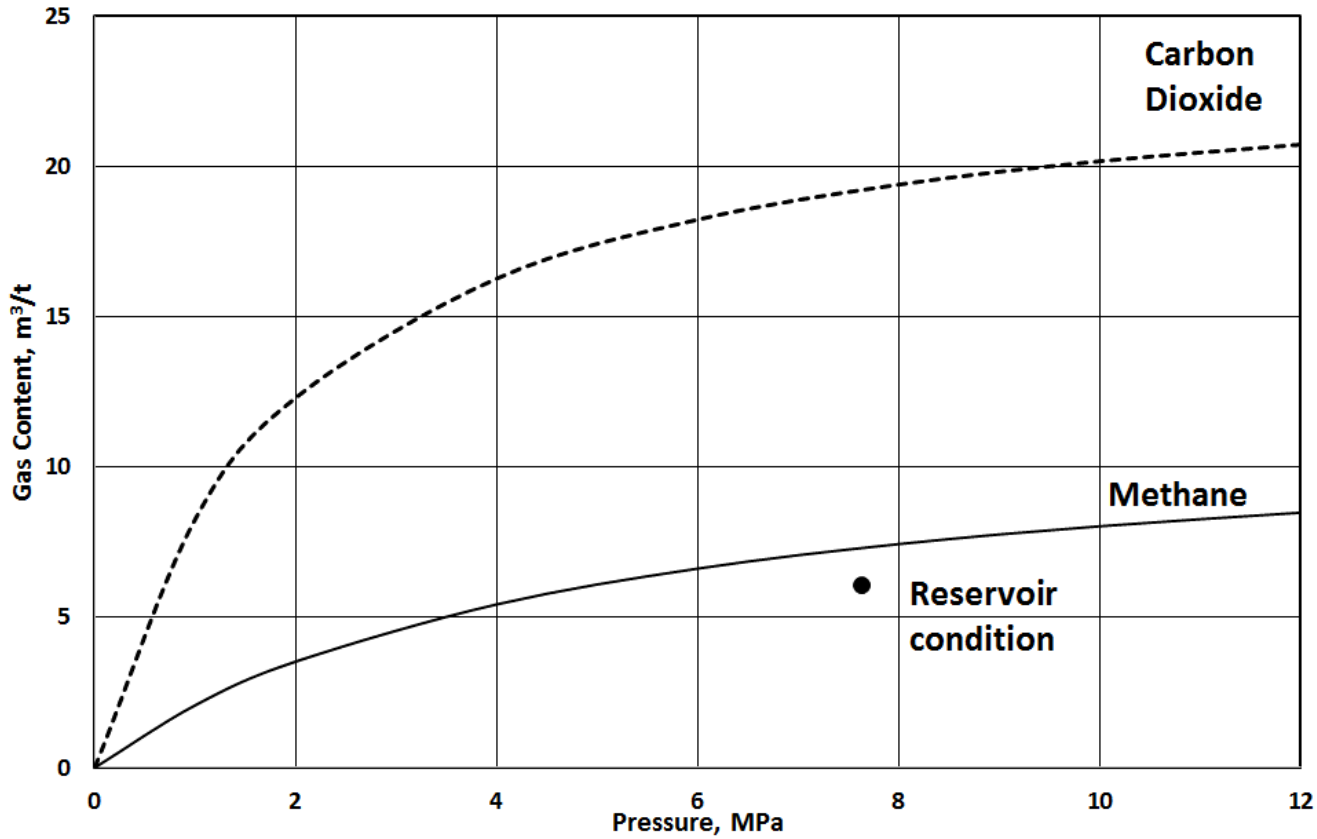

Figure 2 – Langmuir isotherm for methane and carbon dioxide at 45°C and initial reservoir condition

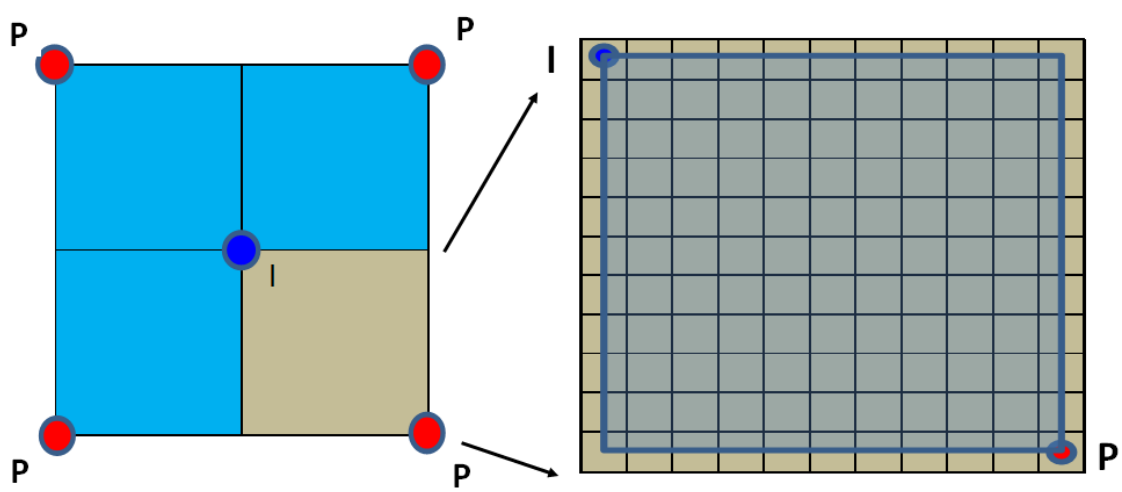

Figure 3 – Schematic of an inverted five spot well pattern

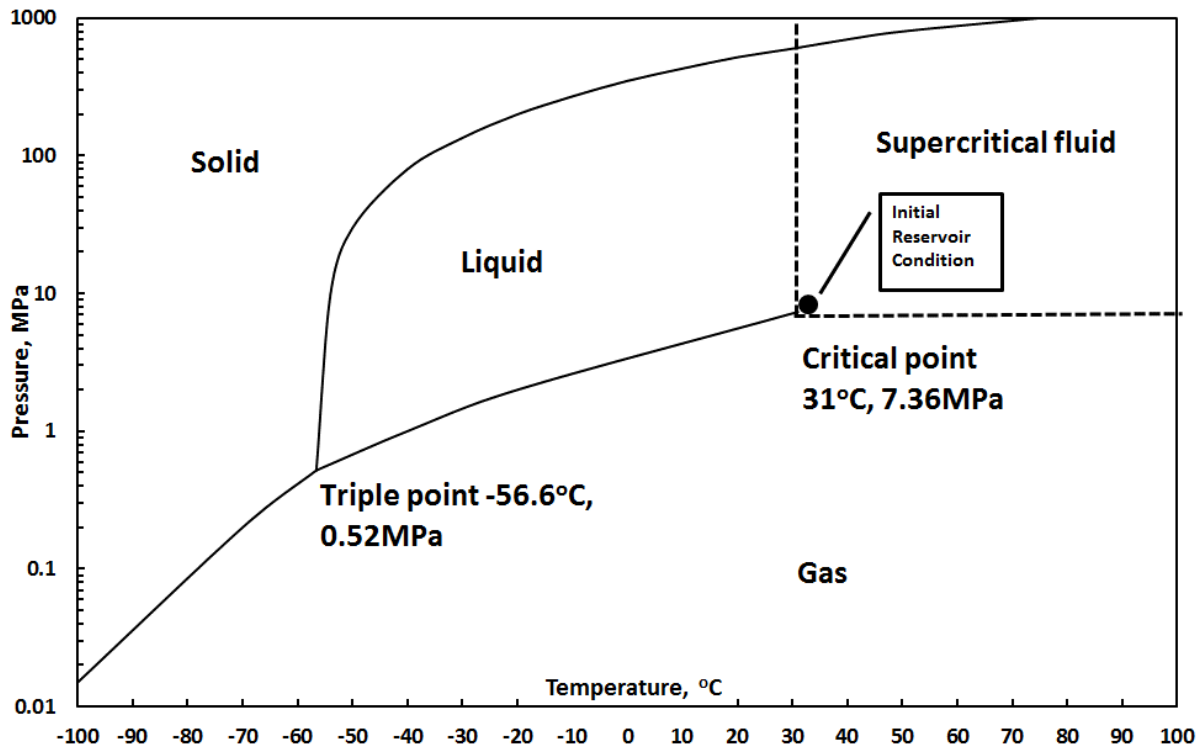

Figure 4 – CO_2 phase diagram and initial reservoir condition

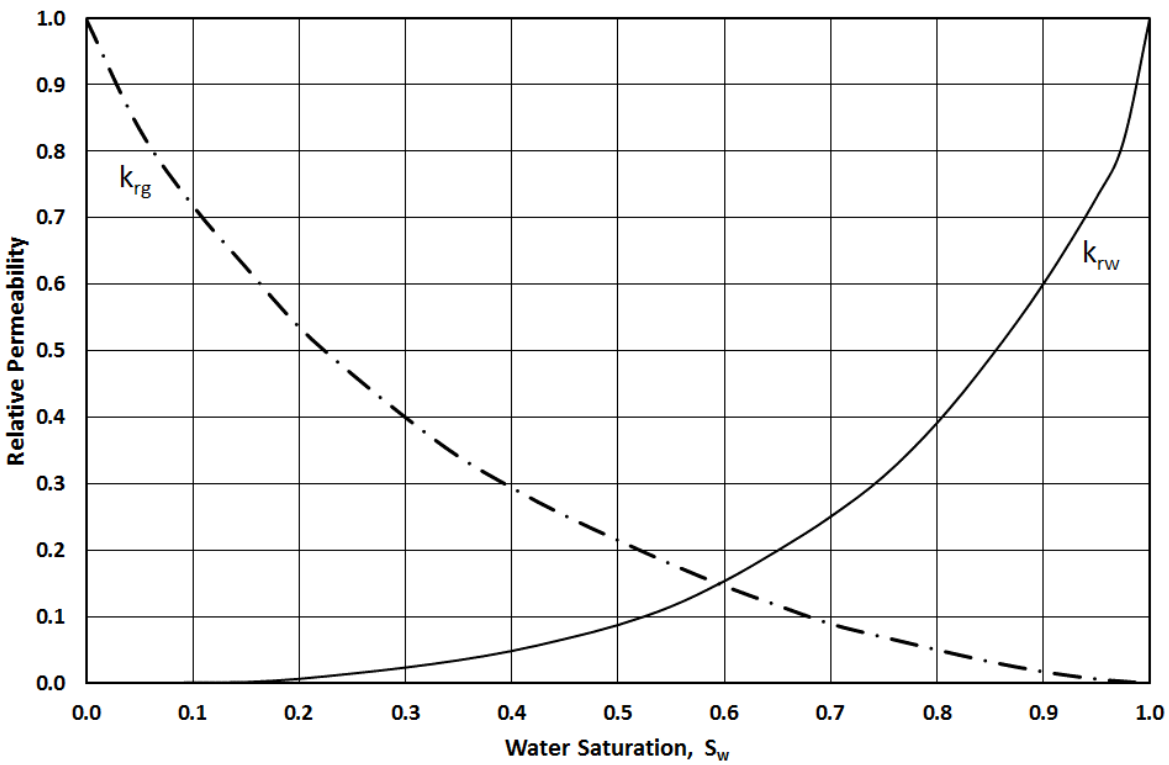

Figure 5 – Relative permeability curves

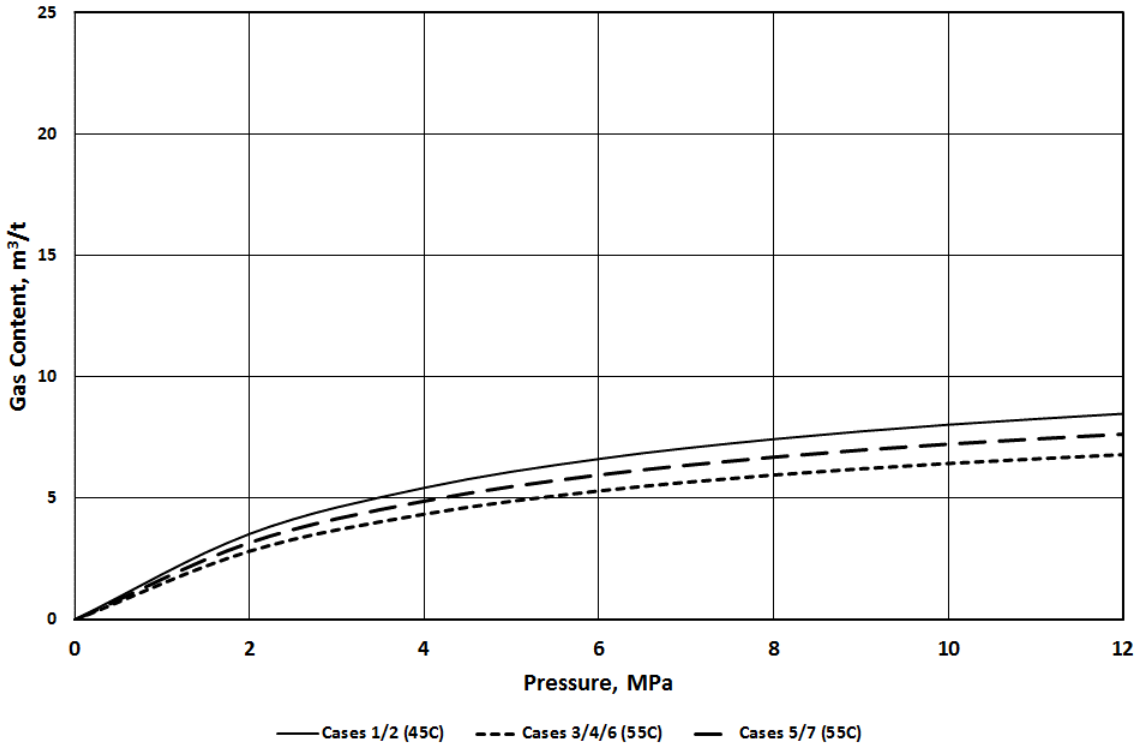

Figure 6 – CH_4 Langmuir isotherms for different simulation cases

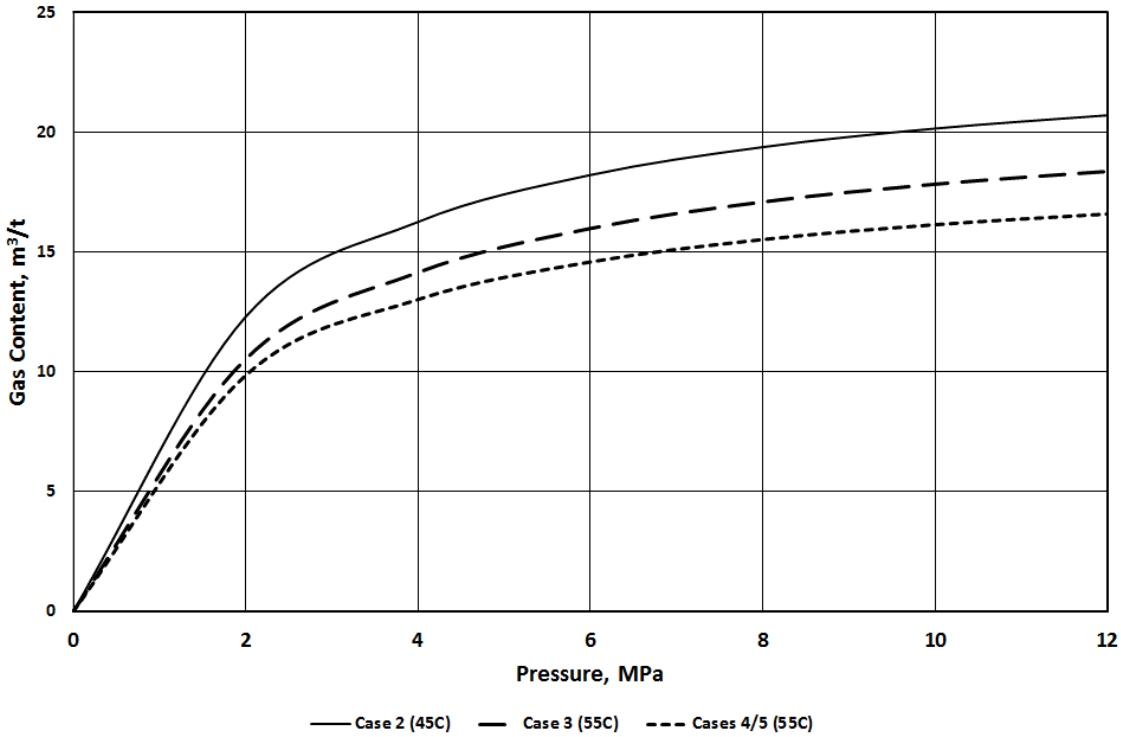

Figure 7 – CO_2 Langmuir isotherms for different simulation cases

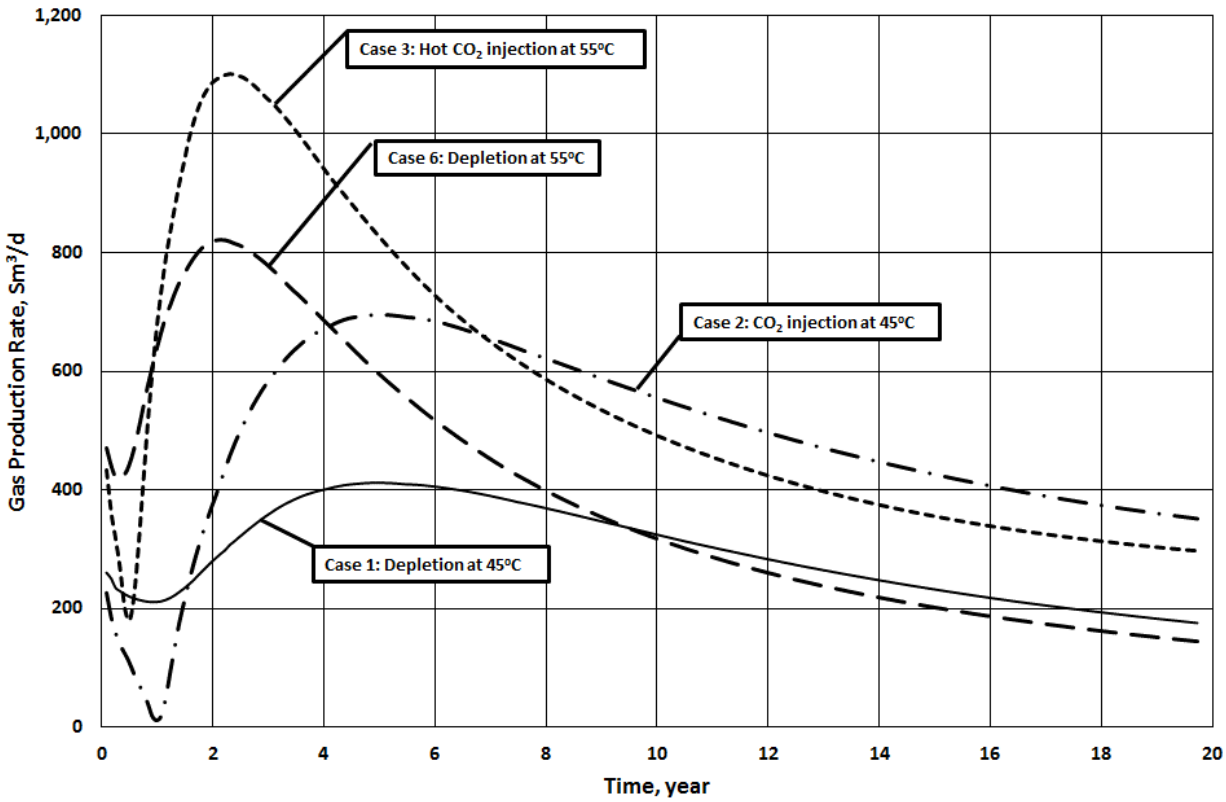

Figure 8 – Gas production rate from simulations

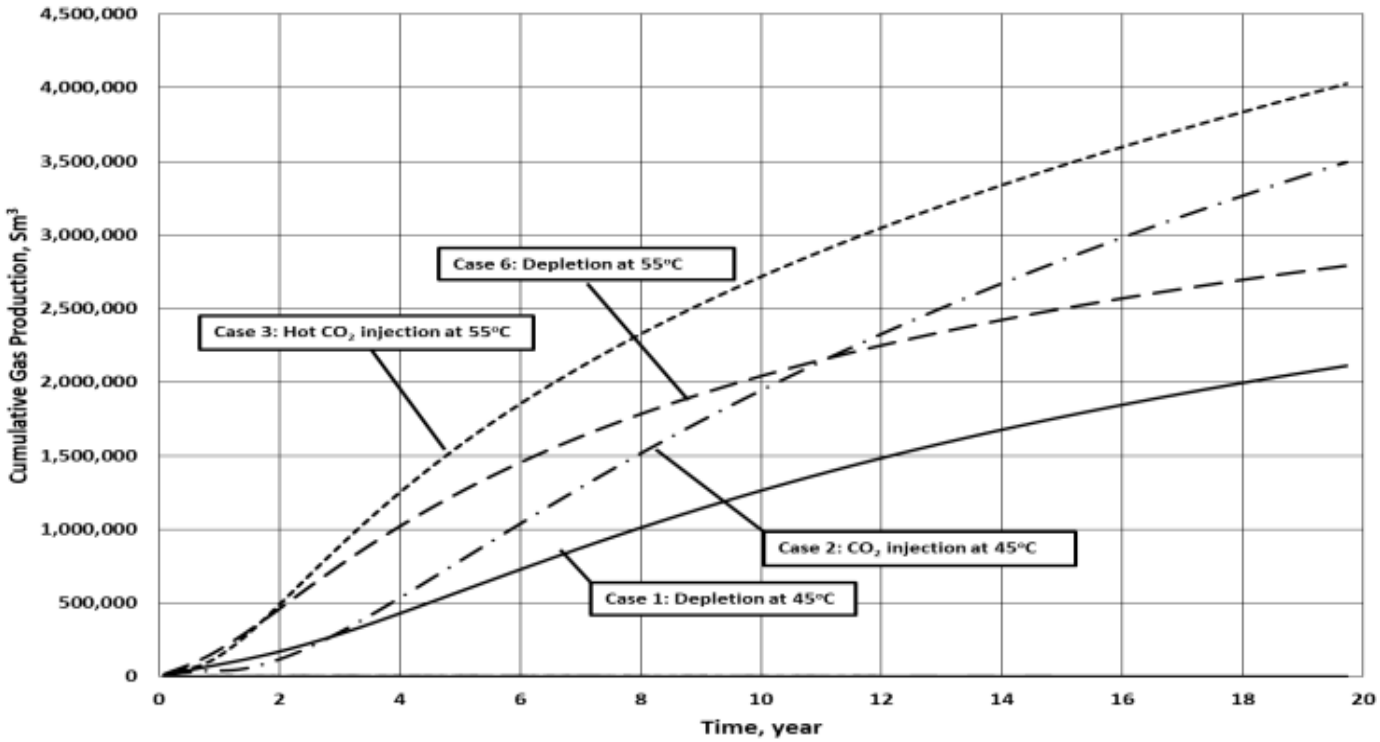

Figure 9 – Cumulative gas production from simulations

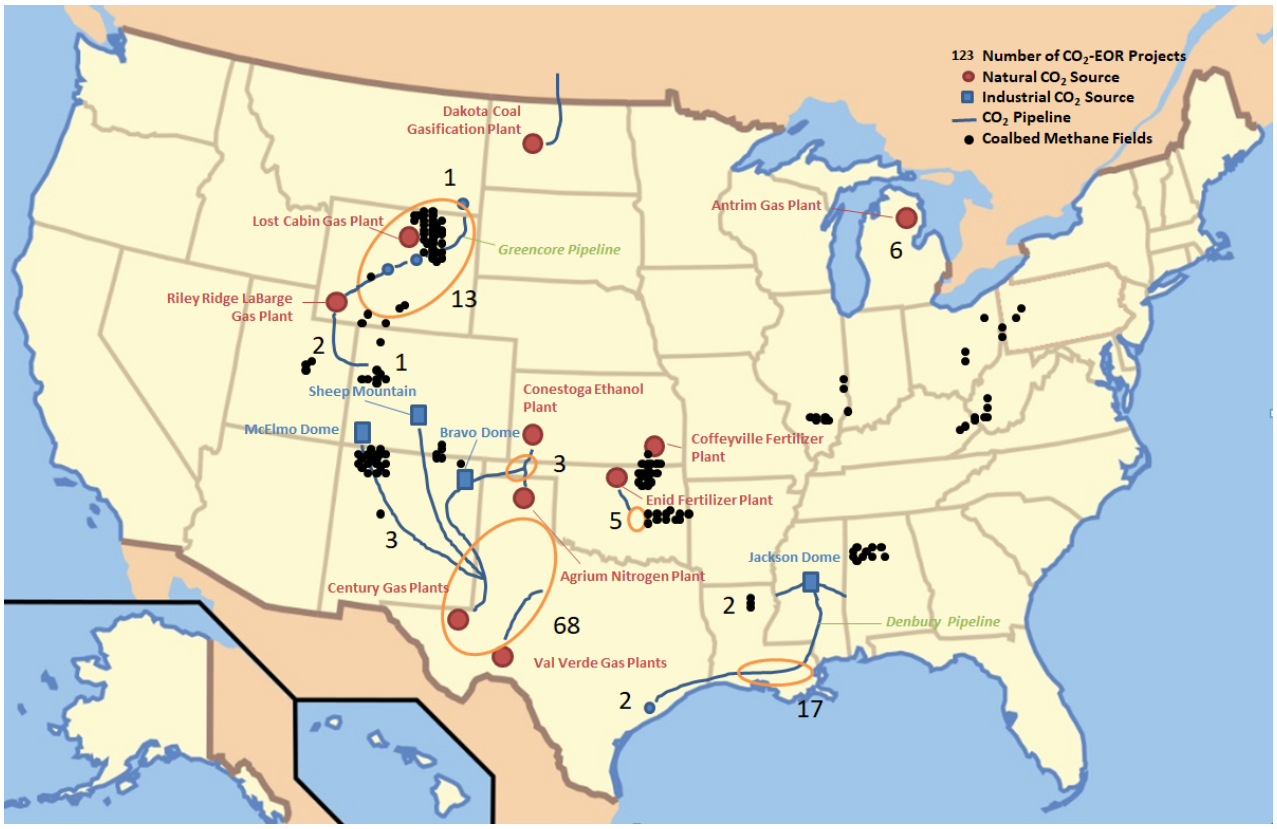

Figure 10 – Location of CBM fields, CO_2 sources and CO_2 pipelines in the US