Production of energy from saline aquifers: A method to offset the energy cost of carbon capture and storage

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Abstract

Technologies considered for separating CO₂ from flue gas and injecting it into saline aquifers are energy intensive, costly, and technically challenging. Production of dissolved natural gas and geothermal energy by extraction of aquifer brine has shown the potential of offsetting the cost of CO₂ capture and storage along with other technical and environmental advantages. Preliminary investigations demonstrate that the amount of produced energy by extracted methane exceeds the energy required for pressurization of CO₂ and extracted brine to be injected into the same aquifer. In case of brine temperatures of higher than 150 °C, geothermal energy from the produced hot brine can be used in amine scrubbing process to capture CO₂ from flue gas. The amount of thermal energy from hot brine exceeds the amount of energy required for amine scrubbing. In case of lower temperatures, it is suggested that the produced geothermal energy can be converted to power required for pressurization in a membrane separation process. It is estimated that the total power produced from methane and geothermal energy exceeds the power required for capture and pressurization.

Keywords: CO₂ capture and storage; dissolved methane; geothermal energy; geopressured-geothermal aquifers; membrane; amine scrubbing

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1 Introduction

The current approach to carbon capture and sequestration (CCS) in deep saline aquifers is not economically attractive without large subsidies or a very high price on carbon (Rochelle, 2009). Moreover, the standard approach to geologic carbon storage (GCS) of simply injecting supercritical CO₂ into deep brine-filled geological structures rises technical and environmental difficulties when scaled up to the rates needed for mitigating anthropogenic emissions. The main technical difficulties are pressure buildup (Zhou, 2008; Oruganti, 2009; Birkholzer, 2009), brine displacement (Nicot et al., 2009), and risk of buoyant escape of CO₂ (Pruess, 2004). Production of brine from the storage formations addresses many of the GCS difficulties (Burton et al., 2009; Hosseini and Nicot, 2012). In this study, it is examined that how brine production reduces the economic challenges facing CCS.

The key to understanding the benefit of brine extraction for the economy of CCS is to recognize the inherent value in the energy content of brine in many parts of the world. Dissolved methane in brine is one of the sources of energy of many aquifers. For example, geopressured-geothermal aquifers lie along much of the Gulf Coast of the United States at depths exceeding 3,000 meter. The brine in these formations is saturated with methane, with concentrations on the order of 5 to

1 10 cubic meter per cubic meter of brine (Griggs, 2005). Because of the sheer volume of brine,
 2 the total amount of methane held in this form is prodigious, estimated to be between 85 and
 3 1,300 trillion cubic meter (Taggart, 2010). For the same reason, the capacity of these
 4 geopressured-geothermal aquifers for storage of CO₂ is remarkable. Figure 1 shows the average
 5 bottomhole pressure and temperature versus depth for several wells in Lavaca County, Texas. It
 6 is observed that the pressure and temperature grows abnormally below the depth of 3,000 meter.
 7

8
 9 Figure 1: Average pressure and temperature gradients based on bottomhole pressure and temperature of 57
 10 wells in Texas (Lavaca County).
 11

12 Hydrostatically pressured aquifers may also contain dissolved methane as source of energy.
 13 Every aquifer in the neighborhood of source rock with open faults contains CH₄, CO₂, N₂, etc.
 14 Figure 2 illustrates the solubility of methane in brine for wide ranges of pressures and
 15 temperatures. It is shown that the solubility of methane in hydrostatically pressured cases is
 16 comparable to the geopressured cases. The observations from the ongoing CO₂ storage project in
 17 Cranfield (Hosseini et al., 2013) shows that the brine of the water leg of the reservoir is saturated
 18 with methane. This is an example of methane saturated brine in hydrostatically pressured
 19 aquifers in the United States. Also, production of methane from deep saline aquifers has been
 20 undertaken in Russia (Littke et al., 1999) and Japan (Manrique, 2000). Hosseini et al. (2012)
 21 investigated the effect of dissolved methane on CO₂ storage capacity and injectivity.
 22

Figure 2: Methane solubility in brine at 55,000 ppm. Geopressured-geothermal conditions and hydrostatically-pressured conditions are distinguished by rectangular boxes.

The geothermal energy content of the hot brine is also significant. For example, the temperature of U.S. Gulf Coast aquifers is about 150 °C at depths where the geopressured condition begins (Knapp et al., 1977). Also, the reported temperature of Cranfield is about 125 °C. Hence, the geothermal potential of some of hydrostatically-pressured aquifers might be remarkable. The extractable geothermal energy from each cubic meter of the produced brine is of the same order of magnitude as the energy from the produced methane.

On the other hand, the majority of energy required for the CCS process is consumed by the CO₂ capture from flue gas. Two methods for capturing CO₂ from flue gas are chemical absorption and separation by membranes. Amine scrubbing has been developed as an absorption method for CO₂ capture from coal-fired power plants. Figure 3 illustrates the simple schematic of this process. This method is capable of removing about 90% of the CO₂ from flue gas (Plaza et al., 2010). It is estimated that amine scrubbing takes about 20% of the output of the power plant in the form of diverted low pressure steam from turbines. In this process, amine solution absorbs CO₂ in the absorber column. This CO₂ is released after the temperature of the solution is increased in the stripper column. The diverted steam provides the heat for stripper. Thermal degradation of amine determines the maximum temperature of the column. This temperature is 120 °C for monoethanolamine (Van Wagener et al., 2011) and 155 °C for piperazine (Van Wagener et al., 2013).

Figure 3: CO₂ capture by amine stripping process.

The driving force for membrane process is pressure difference between the feed and the permeate sides (Bounaceur et al., 2006). Membrane process operates by passing the gas mixture over a CO₂-selective membrane. The pressure on either side of the membrane is different. This pressure difference can be achieved by compressing the flue gas or by using vacuum pumps on the permeate side or a combination of both (Favre, 2007). The main advantage of membranes is their lower energy requirement for operation compared to other CO₂ capture methods (Ho et al., 2008). The flue gas containing CO₂ is fed along one side of the porous membrane. CO₂ diffuses through the pores of the membrane and is captured in the permeate side. Figure 4 illustrates the simple schematic of this process using blower and vacuum pump instead of compressor. Merkel et al. (2010) suggests a counter-flow module using vacuum pump to achieve higher enrichment and consume less energy.

Figure 4: CO₂ capture by membrane process.

The potential for offsetting the cost of CO₂ capture and storage by producing large quantities of valuable methane and geothermal energy is clearly significant. The magnitude of this cost offset has been evaluated for two injection strategies: dissolving the CO₂ into extracted brine and then re-injecting the brine, and injecting supercritical CO₂ (Ganjdanesh et al. 2014). Figure 5 illustrates the simple schematic of injection of dissolved CO₂. Geothermal energy and dissolved methane are extracted from produced high pressure hot brine. Then captured CO₂ and low

temperature brine are pressurized and co-injected into the same aquifer, while in the case of injecting supercritical CO₂, only captured CO₂ is injected into the same aquifer and the extracted brine should be disposed elsewhere. Numerical simulations indicate that injecting dissolved CO₂ yields higher cost offset per metric ton of stored CO₂ compared to the offset obtained when supercritical CO₂ is injected. Injecting dissolved CO₂ conveys other significant advantages such as (1) the produced brine is injected into the same aquifer rather than requiring disposal elsewhere; (2) the stored CO₂ has negligible tendency to escape from the aquifer; (3) a higher fraction of the energy in the aquifer is recovered because single-phase flow has much larger sweep efficiency (4) the process is less sensitive to aquifer heterogeneities and other uncertain geological characteristics and (5) lower surface pressure is needed to inject CO₂ dissolved in brine due to the gravity head of brine in the wellbore.

Another challenge of injecting supercritical CO₂ is drying around the wellbore of the injector. Monitoring of the CO₂ storage project in Ketzin pilot site (Baumann et al., 2014) shows that the injected supercritical CO₂ vaporizes the irreducible water around the injector which leads to salt precipitation and decline in permeability and porosity. Bacci et al. (2013) and Roels et al. (2014) performed experimental and numerical studies on drying effects of CO₂ to quantify the salt precipitation and permeability reduction. Another advantage of injecting CO₂-saturated brine is that the risk of drying and salt precipitation would be eliminated.

Figure 5: Schematic of injection of CO₂-saturated brine and energy extraction from aquifers.

1 The level of cost offset of CCS technology by producing energy from target aquifers depends on
2 how the produced energy is used. For example, the efficiency of converting geothermal energy to
3 electricity is on the order of 10 percent. Developing other applications of geothermal energy
4 might be more beneficial than converting it to electricity. The temperature of the produced brine
5 from geopressured-geothermal aquifers is higher than the temperature of amine stripper column.
6 Ganjdanesh et al. (2013) proposed that the produced geothermal energy from geopressured-
7 geothermal aquifers could be used to regenerate the solvent for CO₂ capture by amine scrubbing.
8 The calculations for the strategy of injecting dissolved CO₂ show that the amount of extracted
9 thermal energy from geopressured-geothermal aquifers exceeds the amount of heat required for
10 capturing CO₂. This means that steam would not have to be withdrawn from an existing power
11 plant cycle.

12
13 The produced methane can be used for pressurization. In the process of injecting dissolved CO₂,
14 compressors and pumps should run to pressurize the CO₂ and brine to be transported and achieve
15 the required wellhead pressure. The produced methane can be used in a gas cycle or a combined
16 gas cycle power plant to generate additional electricity. This additional electricity is used to
17 compensate the power used for pressurization. Also, this methane can be directly used in engines
18 to run the coupled compressors and pumps. The preliminary estimations indicate that the
19 produced methane provides more energy than that required for pressurization.

20
21 In the regions where the temperature gradient is normal, the temperature of the produced brine
22 may not be high enough for using in the chemical absorption processes. Separation mechanisms
23 driven by pressure difference might be the alternatives for chemical absorption processes since
24 the produced methane can be burned for running the compressors and pumps. Membrane process
25 seems to be the leading technology candidate. Vast amount of studies have been performed to
26 develop innovative membrane process designs. These studies have been mainly focused on
27 improving the membrane CO₂/N₂ selectivity and permeance of CO₂. They also attempt to
28 perform the separation in single stage or multi stage operations to achieve more than 95% CO₂ in
29 permeate stream. In all the cases, the target of removing more than 90% of CO₂ is achieved. But
30 the energy and capital cost are very high. The preliminary estimations show that the produced
31 power by extracted methane and geothermal energy exceeds the power needed for membranes,
32 compressors, and pumps.

33
34 Recently, several studies have been performed to integrate the CO₂ storage and energy
35 production from geothermal aquifers. The Delft Geothermal Program (DAP) (Wolf et al., 2008;
36 Salimi and Wolf, 2012) is an ongoing project to capture the CO₂ and co-inject it with the cooled-
37 down water of the geothermal system.

38
39 One of the problems with temperature and pressure drop in the aquifer and heat exchanger is
40 scaling. Bacci et al. (2011) performed experimental and numerical studies to investigate the

precipitation mechanism caused by temperature and pressure change. A decline in injectivity as a result of precipitation in the formation and clogging of the wellbore and surface facilities are considered as key technical and economic issues. Several water treatment techniques and inhibitors have been developed to help control the chemical balance and prevent scale precipitation (Crabtree et al., 1999). Also, co-injection of CO₂ increases the acidity of the injected brine. Using inhibitors is a solution to control the corrosion in the injectors.

Neither storage of greenhouse gases in saline aquifers nor production of methane and/or geothermal energy from these aquifers are profitable. However, designing a closed looped system by combining methods of capture, storage and production may pay off the whole process at least from the energy point of view (Bryant, 2013). This assessment suggests that further investigation of the process of coupling of CO₂ geological storage with methane and geothermal energy production from geopressured-geothermal aquifers is warranted. Also, co-optimization of CO₂ capture and storage processes seems to be justified.

2 Phase behavior of mixtures of CO₂, CH₄ and brine

Modeling the phase behavior of the mixture of gas components and brine is the primary step in modeling the CO₂ storage and production of energy from aquifers. Solubility of methane in brine determines the amount of methane reserves as dissolved gas. Aquifer brine around hydrocarbon reservoirs contain dissolved methane. In many cases, brine is saturated with methane. While, in some cases, some initial trapped gas saturation exists. Solubility of heavier hydrocarbons diminishes quickly after methane. Therefore, their presence is rarely considered in the calculations. Also, the solubility of CO₂ governs the solubility trapping mechanism. High concentrations of N₂ and other impurities such as H₂S and NO_x in the injected gas deteriorate the solubility of CO₂ in brine.

Solubility of gas components in brine depends on the temperature, pressure and salinity of the brine. Duan and Sun (2003) and Duan and Mao (2006) present thermodynamic models for solubility of CO₂ and CH₄ in aqueous NaCl solutions for wide ranges of temperatures, pressures and salinities. Comparison of predicted solubility from these models and experimental data shows high accuracy of these models. In this study, predicted solubility from these models has been used for phase behavior modeling. Figure 6 compares the solubility of CO₂ and CH₄ in brine versus pressure for a specific temperature and salinity. It is observed that the solubility of CO₂ is about an order of magnitude higher than the solubility of CH₄. For example, at 690 bar, this ratio is about six which means that each mole of CH₄ can be substituted by six moles of CO₂ in the dissolved form.

Figure 6: Solubility of CO₂ and CH₄ in brine at 150 °C and 55,000 ppm.

3 Storage Strategies in geopressured-geothermal aquifers

In this section, the aquifer model that was used for numerical simulation of geopressured-geothermal aquifers is described. The results of numerical simulations are presented. Finally, an energy analysis for a 500 MW power plant is performed based on the results from simulations.

3.1 Simulation model

At the beginning of 1970's, Department of Energy commenced to explore the unconventional hydrocarbon resources. DOE funded several studies related to the development of the geopressured-geothermal reservoirs as prospective sources of both heat and natural gas. Several "wells of opportunity" were tested to assess the amount and quality of the natural gas associated with the geopressured-geothermal waters (Swanson et al., 1986). Production of the Pleasant Bayou No. 2 well located in Brazoria County, Texas is an example of a detailed investigation of geopressured-geothermal energy (Riney, 1991). The goal of the project was to provide the information necessary to assess the production characteristics of geopressured-geothermal reservoirs and their economic potential. The other example of the well tests in this study was Gladys McCall No. 1 which is located in Cameron Parish, Louisiana (Riney, 1988). The model in this study was built based on the data from DOE studies.

A compositional numerical reservoir simulator was used to model the fluid and geological complexities of the process. The Peng-Robinson equation-of-state (PREOS) was used to model the fluid containing carbon dioxide, methane and brine. The PREOS parameters were tuned to fit the model with experimental data under aquifer conditions.

A numerical simulation model of the aquifer was developed. Properties such as pressure, temperature, salinity, dimensions, depth, porosity and permeability were chosen from typical

conditions of geopressured-geothermal aquifers of the U.S. Gulf Coast. Relative permeability curves and capillary pressure were built using Corey model. A modified Land's equation was used to model the hysteresis including gas trapping during imbibition.

Horizontal wells both produce at higher rates and yield higher energy recovery. Also, they are less sensitive to heterogeneity (Ganjdanesh, 2014). Therefore, parallel horizontal well patterns were chosen for injector and producer. Figure 7 illustrates the schematic of aquifer and well placement. A unit cell with an injector and a producer was used for reservoir simulation. The wells were placed at the edges of the unit cell. The injection and production rates are half of the values for full wells in a repeated well pattern. Well types and locations affect the time of CO₂ breakthrough and the fraction of the initial methane and brine in place that can be recovered before CO₂ breakthrough. If CO₂-saturated brine is injected low in the aquifer to displace the CH₄-saturated brine upward, the displacement is gravity stable. Thus, the sweep efficiency will be high and the breakthrough late.

Figure 7: Schematic of a simulation unit cell with horizontal injector and producer. The symmetry of the parallel well pattern allows modeling a half of the pattern.

Table 1 summarizes the specifications of the unit cell. The in-place brine was initially saturated with methane that corresponds to 0.57% CH₄ and 99.43% brine based on mole fraction. Constant wellhead pressure was used to simplify the calculation of energy required for compression. The producer and injector flow rates depend on the surface pressure, the pressure change in the wellbore and pressure drop in the aquifer. There is a strong coupling between the aquifer, the wellbore and the surface facility. CMG's compositional simulator GEM (2011) takes into account the hydrostatic pressure over the length of the well, pressure drop due to friction and pressure drop due to kinetic energy.

Table 1: Properties of geopressured-geothermal aquifer at 4,500 meter.

Length and width, m	1600
Thickness, m	90
Number of gridblocks	80×80×30
Gridblock size, m	20×20×3
Depth at top of the formation, m	4,500
Temperature, °C	150
Initial pressure, bar	760
Salinity, ppm	55,000
Porosity	0.2
Horizontal permeability, md	100
Vertical permeability, md	10
Initial CH ₄ in place, million m ³	351.3
Initial brine in place, million m ³	45.95
Solution gas-brine-ratio, m ³ /m ³	7.65
Wellhead pressure of injector, bar	310
Wellhead pressure of producer, bar	20.7

3.2 Simulation results

The model aquifer is homogeneous and highly idealized since the purpose of this study was to explore the concept of methane and geothermal energy production by CO₂ injection. The aquifer brine was saturated with methane at the initial pressure of the reservoir of 760 bar. The process of injecting CO₂-saturated brine was simulated. The mole fraction of CO₂ in the injected brine was 0.025, which is equivalent to the brine saturated with CO₂ at the initial aquifer pressure of 760 bar. About 2.05 million metric tons of CO₂ was injected in 5810 days (16 years) at a constant wellhead pressure of 310 bar. About, 234 million m³ of methane and 35 million m³ of brine were produced at a constant wellhead pressure of 20.7 bar. The amount of energy from produced methane is about 9.0E+15 Joule which is calculated from the heat of combustion of methane. Also, the amount of produced geothermal energy is about the same as energy from methane. The geothermal energy is extracted by decreasing the brine temperature from 150 to 95 °C. The results are summarized in Table 2.

Table 2: Injection and production summary for a unit cell (geopressured-geothermal).

Injection and production periods, day (year)	5810 (16)
Cumulative injected CO ₂ , million ton	2.05
Cumulative injected brine, million m ³	32.9
Cumulative produced CH ₄ , million m ³	234.2
Cumulative produced brine, million m ³	35.2
Recovery of original CH ₄ -in-place, %	66.5
Recovery of original brine-in-place, %	76.5
Produced CH ₄ energy, Joule	8.98E+15
Produced thermal energy, Joule	8.18E+15

1
2 The injection and production periods were chosen based on the breakthrough time of CO₂. It
3 means that CO₂ was observed at the production stream after 16 years. After CO₂ breakthrough,
4 producers can be converted into injectors and additional CO₂ can be injected into the aquifer
5 since the facilities would be in place. Also, the propagation speed of thermal front was much
6 slower than the CO₂ front. Thus, the temperature of the produced brine at CO₂ breakthrough time
7 was still close to 150 °C.
8

9 It is assumed that the mixture of CO₂ and produced brine is injected into the same aquifer. The
10 solubility of CO₂ in brine at 95 °C and 760 bar is 2.5 mole percent. Therefore, the amount of
11 required brine to store one metric ton of CO₂ is 16.6 ton, which is equivalent to 15.9 m³. By
12 dropping the temperature of one cubic meter of hot brine from 150 °C to 95 °C, about 37 million
13 Joule of energy can be extracted. Also, by dropping the pressure of brine to 3 bar, 6.66 m³ of
14 methane can be extracted. A comprehensive design is required to calculate the amount of
15 pressure drop in the heat exchangers and separators. Also, the temperature and pressure drop in
16 surface facilities cause the problem of scale deposition which requires using prevention and
17 remediation techniques.
18

19 During the production period, the average pressure of the aquifer decreases gradually from 760
20 bar to about 585 bar. A fraction of dissolved methane is released from brine forming a very small
21 saturation of free gas. Thus, this small saturation of gas remains immobile. Maintaining the
22 aquifer pressure above the bubble point pressure demands much higher wellhead pressure,
23 causing much higher energy and capital cost. Therefore, operation under lower pressures seems
24 justified. The pressure and temperature drop in the aquifer decrease the fracture initiation
25 pressure of the formation (Wu and Bryant, 2014). Though the formation pore pressure is
26 decreased during the operation, a careful study is required to estimate the formation breakdown
27 pressure after including the thermos-elastic and poro-elastic effects.
28

29 **3.3 Analysis of energy balance for a 500 MW power plant**

30 The process of CO₂ capture and storage for a 500 MW power plant coupled with production of
31 energy from geopressured-geothermal aquifers was illustrated in Figure 5. The energy balance
32 for CCS combined with energy production from the aquifer is presented in the following section.
33 The energy required for the operation of each part of the process is analyzed separately. Also, the
34 produced energy from methane and hot brine is estimated.
35

36 Table 3 summarizes the injection and production rates scaled up for emission rate from a 500
37 MW power plant. The average CO₂ emission rate from a 500 MW power plant is estimated to be
38 10,000 metric ton per day. The capture process and pressurization are the major energy
39 consumers. The pressurization process includes the compression of CO₂ and pumping the brine
40 to the wellhead pressure of injectors. About 10,000 metric ton of CO₂ and 160,000 m³ of brine
41 should be pressurized from atmospheric pressure to 310 bar.

Table 3: Injection and production summary for a 500 MW power plant (geopressured-geothermal).

CO ₂ injection rate, Metric ton per day	10,000
Brine injection rate, m ³ /day	160,000
Brine production rate, m ³ /day	170,000
Methane production rate, m ³ /day	1,138,000
Total number of injectors and producers	28

The methods of energy estimation for pressurization are described in Tables 4 and 5. The power required for compressors and pumps are summarized in Table 6. In these illustrative calculations, the efficiency of compressors and pumps are assumed to be 80%. The estimated power for compressors and pumps are 43 MW and 73 MW, respectively. The majority of energy for capture process by amine scrubbing is taken in the form of heat by stripper. The heat load for a 500 MW power plant is about 400 MW. In the conceptual designs, this heat is provided by diverting a fraction of low pressure steam from turbines. The equivalent work of this amount of heat is about 100 MW which will be deducted from the output of the power plant.

Table 4: CO₂ compression properties and relationships.

Property	Relationship or Value
Energy per unit mass of stored CO ₂	$W_{CO_2} = \frac{SnRT_1}{(n-1)M_{CO_2}} \left(\left(\frac{p_x}{p_1} \right)^{\frac{n-1}{n}} - 1 \right)$
Intermediate pressure	$p_x = p_1 \left(\frac{p_{mixing}}{p_1} \right)^{\frac{1}{S}}$
Polytropic coefficient	$n = \frac{ky_p}{1 + ky_p - k}$
Compressor polytropic efficiency	$y_p = 80\%$
Number of Stages	$S = 10$
Ratio of Specific Heats	$k = 1.3$
Inlet temperature	$T_1 = 40^\circ C$
Inlet pressure	$p_1 = 1.0bar$
Gas constant	$R = 8.314 \frac{Joule}{mole.^{\circ}K}$

Table 5: Brine compression properties and relationships.

Property	Relationship or Value
Energy per unit mass of injected brine	$W_{brine} = \frac{p_{mixing} - p_1}{\rho_{brine} y_{pump}}$
Mass of required brine to store unit mass of CO ₂	$m_{brine} = m_{CO_2} \frac{(1 - x_{CO_2}) M_{brine}}{x_{CO_2} M_{CO_2}}$
Mole fraction of CO ₂ in CO ₂ -saturated brine	$x_{CO_2} = 0.025$
Pump efficiency	$y_{pump} = 80\%$

Table 6: Power consumption by compressors and pumps (geopressured-geothermal).

CO ₂ compression, MW	43
Brine pumping, MW	73

Table 7 summarizes the gross energy and power produced from extracted methane and hot brine. The gross rate of produced energy based on heat of combustion of methane is about 505 MW. The rate of recoverable work from this amount of energy depends on the efficiency of the cycle which is used for power generation. Overall, this efficiency varies between 30 to 60%. In this work, it is assumed that about 235 MW of power can be generated from extracted methane that exceeds the amount of power required for pressurization.

Table 7: Gross and net power from methane and hot brine (geopressured-geothermal).

	Gross Power	Efficiency	Equivalent Power
Energy from CH ₄ , MW	505	0.47	235
Energy from Brine, MW	459	0.12	55

Furthermore, the gross rate of extracted heat from extracted hot brine is about 459 MW. The efficiency of geothermal power plants is on the order of 10 percent. In this work, it is supposed that 55 MW of electricity can be produced. However, the superior application of this heat is the direct use in amine scrubbing since the amount of produced heat exceeds the heat load of the stripper and the temperature of the produced brine is sufficient for solvent regeneration.

About 14 injectors and 14 producers are needed to maintain the required injection and production rates for a 500 MW power plant. Thus, the footprint of the project would be 28 unit cells which is equivalent to 71.7 km². It should be mentioned that the geothermal energy cannot be transported for long distances. Thus, the capture facility should be close to the storage site. This condition results in limitations on the offshore operations.

4 Storage Strategies in hydrostatically-pressured aquifers

In this section, the aquifer model used for numerical simulation of hydrostatically-pressured aquifers is described. The results of numerical simulations are presented. Finally, an energy analysis for a 500 MW power plant is performed based on the results from simulations.

4.1 Simulation model

Energy resources of hydrostatically-pressured aquifers have been assessed and documented much less than geopressured-geothermal aquifers. But, it is expected that huge reserves of energy may exist at shallower depths with normal pressure and temperature gradients.

The aquifer model for simulation of hydrostatically-pressured aquifers has the same dimensions and petrophysical properties of the ones used for simulation of geopressured-geothermal aquifers. Also, the well types and placements are the same. However, this aquifer is located at depth of 3,000 meter which is above the geopressured-geothermal zone. The initial pressure and temperature of the aquifer are 325 bar and 125 °C corresponding normal pressure and temperature gradients. Thus, the gas content of the brine is about $3.85 \text{ m}^3/\text{m}^3$ which is about the half the value in a geopressured-geothermal aquifer located at 4,500 meter. Table 8 shows the properties of the aquifer used in this study. The remaining properties are similar to those at Table 1. The initial composition of the in situ fluid is 0.29 mole percent methane and 99.71 mole percent brine.

Table 8: Properties of hydrostatically-pressured aquifer at 3,000 meter.

Depth at top of the formation, m	3,000
Temperature, °C	125
Initial pressure, bar	325
Initial CH ₄ in place, million m ³	174.9
Initial brine in place, million m ³	45.3
Solution gas-brine-ratio, m ³ /m ³	3.85
Wellhead pressure of injector, bar	172
Wellhead pressure of producer, bar	20.7

4.2 Simulation results

The process of injecting a mixture of CO₂ and brine was simulated. The injection stream consists of 2.5 mole percent gas and 97.5 mole percent brine. This composition is close to the CO₂ saturated brine at reservoir condition. About 2.0 million metric tons of CO₂ was injected in 6916 days (19 years) at a constant wellhead pressure of 172 bar. About 127 million m³ of methane and 33 million m³ of brine were produced at a constant wellhead pressure of 20.7 bar. The amount of energy from produced methane is about $4.86\text{E}+15$ Joule which is calculated from the heat of combustion of methane. Also, the amount of produced geothermal energy is about $7.44\text{E}+15$ Joule. The geothermal energy is extracted by decreasing the brine temperature from 125 to 70

°C. The injection and production periods were chosen based on the breakthrough time of CO₂. The results are summarized in Table 9.

Table 9: Injection and production summary for a unit cell (hydrostatically-pressured).

Injection and production periods, Day (Year)	6916 (19)
Cumulative injected CO ₂ , million ton	2.0
Cumulative injected brine, million m ³	32.0
Cumulative produced CH ₄ , million m ³	126.9
Cumulative produced brine, million m ³	33.2
Recovery of original CH ₄ -in-place, %	73.3
Recovery of original brine-in-place, %	73.3
Produced CH ₄ energy, Joule	4.86E+15
Produced thermal energy, Joule	7.44E+15

By dropping the pressure of brine to 3 bar, 3.85 m³/m³ of methane can be extracted. During the production period, the aquifer pressure remains above the initial bubble point pressure of 325 bar. Thus, the methane content of the produced fluid is very close to the methane content of the aquifer brine. Another advantage of maintaining the aquifer pressure above the bubble point pressure is very high recovery of methane and brine. Single phase flow through the aquifer results in almost ideal displacement efficiency. Also, injected brine has lower temperature than the in-situ brine. Therefore, injected brine is more viscous and denser than the in situ brine resulting in very high sweep efficiency.

4.3 Analysis of energy balance for a 500 MW power plant

The strategy of injection and production from hydrostatically-pressured aquifers is the same as the one for geopressed aquifers. The results of simulations are scaled up for a 500 MW power plant. The rate of emission from a 500 MW power plant is 10,000 metric tons per day. Thus, about 160,000 m³ of brine per day should be injected along with CO₂. The production rate of brine is about the same 160,000 m³ per day. Also, 635,000 m³ of methane is produced along with brine. About 17 injectors and 17 producers are needed to maintain the calculated injection and production rates. Table 10 summarizes the injection and production rates for a 500 MW power plant.

Table 10: Injection and production summary for a 500 MW power plant (hydrostatically-pressured).

CO ₂ injection rate, Metric ton per day	10,000
Brine injection rate, m ³ /day	160,000
Brine production rate, m ³ /day	166,600
Methane production rate, m ³ /day	635,000
Total number of injectors and producers	34

Table 11 shows the power needed for pressurization. The power for compressing CO₂ to 172 bar is about 38 MW. The power for pumping brine is about 39 MW. Table 12 summarizes the energy rate and net power from extracted methane and hot brine. The energy rate from produced methane calculated from heat of combustion is about 281 MW. Assuming an efficiency of 47 percent, about 132 MW of net power is generated. The heat rate from extracted brine is about 448 MW. Assuming an efficiency of 10%, the generated power from hot brine is about 45 MW.

Table 11: Power consumption by compressors and pumps (hydrostatically-pressured).

CO ₂ compression, MW	38
Brine pumping, MW	39

Table 12: Gross and net power from methane and hot brine (hydrostatically-pressured).

	Gross Power	Efficiency	Equivalent Power
Energy from CH ₄ , MW	281	0.47	132
Energy from Brine, MW	448	0.10	45

The temperature of produced brine might not be sufficient for solvent regeneration. But, a significant amount of power can be generated from produced methane and hot brine. This power can be used to generate the pressure difference across the sides of membranes. In the membrane configuration proposed by Merkel (2010), about 16 percent of the output of power plant is consumed to enrich the CO₂ purity to more than 95 percent. Therefore, about 80 MW of power is required for the multi-stage membrane separation. Overall, the total consumed power for capture and pressurization is about 157 MW; while the total produced power is about 177 MW.

5 Comparison of approaches

In this section, results of four different approaches of coupled capture, storage, and production are compared. These approaches consist of capture by amine scrubbing or membrane separation and storage and production from geopressured or hydrostatically-pressured aquifers. Table 13 shows the energy consumption and production and the net power for all of the approaches.

Table 13: Energy analysis for four approaches.

Aquifer condition	Geopressured-geothermal		Hydrostatically-pressured	
	Amine	Membrane	Amine	Membrane
Capture method				
CO ₂ compression, MW	-42	-42	-38	-38
Brine pumping, MW	-73	-73	-39	-39
Capture, MW	-100*	-80	-100	-80
CH ₄ power, MW	+235	+235	+132	+132
Geothermal power, MW	+100*	+55	+45	+45
Net power, MW	+120	+95	0	+20
Energy per ton of stored CO ₂ , kWh	+288	+228	0	+48

* Equivalent works of the consumed heat for capture and the produced geothermal energy.

Overall, comparison of four approaches is summarized as follows:

- The temperature and energy from the brine produced from geopressured-geothermal aquifers is sufficient for the amine scrubbing of CO₂.
- Amine scrubbing seems to be the superior capture method for storage in geopressured-geothermal aquifers.
- Membrane separation shows better energy balance for storage in hydrostatically-pressured aquifers.
- Energy balance of approaches consist of production from geopressured aquifers are much more promising than the hydrostatically-pressured aquifers.
- Capital cost of surface facilities is much higher for geopressured aquifers since pressure and temperature of the fluids are higher.
- The cost of the wells is higher for geopressured-geothermal aquifers since depth, pressure, and temperature are higher.
- Hydrostatically-pressured aquifers are much more widespread, but their methane content is less well established.
- Site specific studies and detailed economics will be needed to determine the best strategy.

6 Summary and conclusions

Geologic storage of carbon dioxide in deep saline aquifers was introduced as the primary option for storage of significant amounts of CO₂ emitted from coal-fired power plants. Several studies have focused on overcoming the technical and economic challenges inhibiting this technology from becoming widespread. Extraction of brine from storage formations brings the prospects of mitigation of some of the challenges. From the economic point of view, the produced brine may convey amounts of energy comparable to the amounts required for CO₂ capture and storage processes. The success of offsetting the energy cost of capture and storage depends on the applications of the produced energy.

Geopressured-geothermal aquifers contain vast amount of dissolved methane and geothermal energy. A rough estimation indicates that the amount of produced energy exceeds the energy needed for capture and storage. It is proposed that the geothermal energy can be used in the capture process by amine scrubbing and the produced methane can be used for pressurization of CO₂ and brine up to the wellhead pressure. In this strategy, CO₂ remains dissolved in brine. Thus, pressure buildup and CO₂ leakage will be mitigated. Also, brine is disposed into the same aquifer.

In shallower depths, where temperature of brine is not high enough to be used for chemical absorption, pressure driven separation processes can be used. The produced methane is used in compressors or vacuum pumps to generate the pressure difference for membrane process.

Review of energy analysis of four possible approaches of combined capture, storage, and production indicates that

- The energy revenue from all approaches offset all the energy cost of CO₂ capture and storage.
- The net energy gain from geopressured-geothermal aquifers is higher than from hydrostatically-pressured aquifers. The net energy gain is about 288 kWh per ton of stored CO₂ for capture by amine scrubbing and about 228 kWh by membrane separation.
- Production from hydrostatically pressured aquifers leads to about zero energy gain for capture by amine scrubbing and about 48 kWh per ton of stored CO₂ by membrane separation.
- Storage and production from geopressured-geothermal aquifers shows much better energy balance while the operating and capital cost of the process is higher for these aquifers.
- Extraction of brine from aquifers mitigates the concerns of pressure buildup, CO₂ leakage, and brine displacement. This also lowers the monitoring cost.

The coupling of CCS with energy production from geopressured-geothermal aquifers is a new and promising idea. There is a significant potential for offsetting the energy cost of CCS by producing large quantities of methane and geothermal energy. Determining the actual economics will of course require closer examination of CO₂ capture methods, well costs, surface facilities, the price of the produced gas, whether the geothermal energy can be used for process heat, incentives for CO₂ storage, etc. However, preliminary calculations indicate that the revenue from the energy in hot brine saturated with methane can offset much of the energy costs of CCS or even pay for it under favorable conditions such as exist along the U.S. Gulf Coast.

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