SỰ CÔ LẬP ĐỊA CHẤT KHÍ CO_2 VÀ VAI TRÒ CỦA NGÀNH CÔNG NGHIỆP DẦU KHÍ TRONG VIỆC GIẢM KHÍ THẢI GÂY HIỆU ỨNG NHÀ KÍNH

CO_2 GEOLOGICAL SEQUESTRATION AND PETROLEUM INDUSTRY'S ROLES IN REDUCING GREENHOUSE GAS EMISSIONS

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TÓM TẮT

Sự cô lập địa chất khí CO2 là một công nghệ làm giảm lượng lớn khí thải gây hiệu ứng nhà kính, chủ yếu là CO_2 thải ra từ các khu vực công nghiệp như các nhà máy chiết xuất dầu hoặc các nhà máy nhiệt điện sử dụng nhiên liệu hóa thạch. Công nghệ này bao gồm việc tách khí CO2 ra khỏi các khí khác, khử nước rồi nén và dẫn nó đến trạm bơm ép. Tại đây khí CO2 có thể được nén lại nếu cần, sau đó được bơm xuống dưới lòng đất vào các vỉa địa chất và được giám sát về chuyển động và ứng xử của nó sau khi bị giữ lại dưới đất. Ngành công nghiệp dầu khí là một trong những nguồn thải khí gây hiệu ứng nhà kính. Tuy nhiên ngành này cũng có kinh nghiệm lâu năm về công nghệ cô lập địa chất khí CO2, ở đó chất khí này được dùng cho việc thu hồi tăng cường dầu. Công nghệ này không chỉ giúp cho ngành dầu khí giảm nguồn gây ô nhiễm của bản thân nó mà còn mang lại cơ hội kinh doanh trong việc cung cấp công nghệ này cho những ngành công nghiệp khác.

ABSTRACT

Geological sequestration is a potential technology to reduce large amount of greenhouse gas emissions which are essentially carbon dioxide (CO_2) released from stationary industrial sources such as petroleum extractive plants or fossil fired power plants. Sequestering CO_2 involves separating CO_2 from other gases, dehydrating and compressing CO_2, transporting it via pipeline to injection site, re-compressing if applicable, injecting it into geological reservoirs and monitoring its movement and behaviour after sequestration. The petroleum industry is one of the sources of industrial greenhouse gas emissions. It, however, also has long time experience on this technology where CO_2 is used for enhancing oil recovery. CO_2 geological sequestration potentially not only helps the petroleum industry to reduce its own source of greenhouse gas emissions but also bring in the business opportunity in providing the technology and infrastructure to other major stationary source of greenhouse gas emissions.

1. Introduction

Carbon dioxide (CO_2) emission is one of the environmental challenges for the petroleum industry. Gas flaring in oil production and CO_2 venting from natural gas extractive process could release significant amount of CO_2 into the atmosphere. Under the Kyoto protocol [1], industrialized countries target to reduce their collective emissions of greenhouse gases including CO_2, CH_4, N_2O, HFCs, PFCs and SF_6) at least 5% below the 1990 level by the period of 2008-2012. Among the sources of greenhouse gas emissions, stationary sources including fossil-fired power stations, petroleum developments, steel and non-ferrous metal plants are significant contributors of the CO_2 emissions. This paper will focus on CO_2

geological sequestration from a natural gas development. CO_2 geological sequestration is the process that (i) captures CO_2 from stationary emission sources and (ii) stores it safely in geological reservoirs over thousands of years to reduce the net emissions of CO_2 into the atmosphere.

2. TECHNOLOGIES FOR CO_2 GEOLOGICAL SEQUESTRATION

2.1. Capturing CO_2

CO_2 capture involves (i) the separation of CO_2 from the hydrocarbon gases and (ii) the dehydration and initial compression of CO_2 so that CO_2 is suitable for transport via pipeline. Chemical absorption is the most widely used technology in existing plants to separate CO_2 from natural gas stream. Cryogenic, physical adsorption and membrane technologies are also being used, tested or developed. Generally, separating CO_2 from hydrocarbon gases is part of the gas processing because CO_2 content must be lowered to about 2% by volume before the gases could be sold. Therefore, the additional cost of capturing CO_2 from hydrocarbon gases is essentially involves the cost of dehydration and initial compression of CO_2.

2.1.1 Dehydrating CO_2

Dehydration has the dual purpose of preventing both corrosion and formation of hydrates. CO_2 hydrates can form in the presence of free water at pipeline operating pressure and at temperatures up to about 11^{o}C. These solids can create operating problems such as plugging equipment and flow lines and fouling heat exchangers. CO_2 and free water also forms carbonic acid that corrodes the carbon steel equipment. The maximum water content in CO_2 must be less than the saturation water content at operating temperature and pressure to avoid corrosion.

Water could be removed between each compression stages through condensation. At around 5.5 MPa (800 psi), the water solubility in CO_2 is at a minimum. Further water vapour removal is achieved by contact with a cool lean triethylene glycol (TEG) solution in an absorber.

2.1.2 Compressing CO_2

Compressing CO_2 itself requires energy and this might be supplied from a energy source that is also emitting CO_2 such as a coal-fired power plant. The CO_2 generated from this energy requirement must be taken into account and be deducted from the amount of CO_2 disposed. In considering how much CO_2 would be produced to generate the energy for compressing CO_2, a study by Ennis-King and Paterson [2] shows the isothermal work requirement to compress the CO_2 at 35 ^{o}C from an initial pressure of 0.101 MPa (14.7 psi). (**Figure 1**).

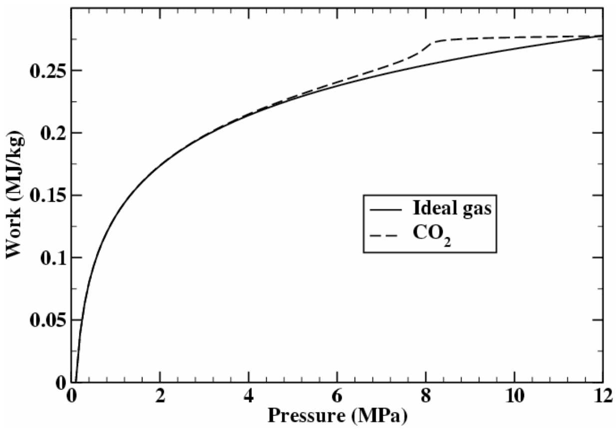

Figure 1 Isothermal work to compress CO_2 at 35^{o}C

For example, compressing 1 kg of CO_2 from 0.101 MPa (14.7 psi) to 12 MPa (1,740 psi) requires 0.275 MJ. Assuming that the energy is supplied from a coal-fired power plant that emits 0.8 kg CO_2/kWh (2.2x10-7 kg/J), the CO_2 generated would be about 6.05% of the CO_2 being compressed. This number is lower if the energy comes from power plants that emit less CO_2 - such as a natural gas-fired type.

2.2 Storing CO_2

CO_2 geological storage involves (i) transporting the CO_2 by pipeline to injection site, (ii) re-compressing to maintain CO_2 pressure in the pipeline or to achieve injection pressure if applicable, (iii) injecting it by injection wells and (iv) monitoring the movement of CO_2 in the reservoir during and after sequestration.

2.2.1 Transporting CO_2

The CO_2 is typically kept at a pressure higher than its critical pressure during transporting through pipeline. The critical pressure for CO_2 is 7.4 MPa (1,070 psi) and the CO_2 pipeline is usually operated at pressure between 8 and 17 MPa (1,200 and 2,500 psi). At pressures above the critical pressure, CO_2 exists as a dense single phase over a wide range of temperatures. Operating the system with CO_2 in this state avoids problems associated with two-phase flow in the pipeline and injection wells. Two-phase flow induces pressure surges and is more expensive to operation because of the need for larger pipelines or the construction and operation of additional compression stations.

The pipeline diameter is determined by several factors including intake pressure at the input to the pipeline, required pressure at the output end of the pipeline, maximum and minimum operating pressures, ground elevation, ambient temperature, pipeline length, CO_2 flow rate and the number of boosting compressor stations installed along the pipeline route. **Table 1** below shows how pipeline diameters typically vary depending on the flow rate.

Table 1: Operating pipeline capacities for CO_2 [3]

Flow range		Diameter
8-10 m^3/s	(23-31 MMcfd)	168 mm (6 in)
16-21 m^3/s	(48-64 MMcfd)	219 mm (8 in)
28-38 m^3/s	(84-115 MMcfd)	273 mm (10 in)
43-55 m^3/s	(130-168 MMcfd)	324 mm (12 in)
56-77 m^3/s	(170-235 MMcfd)	356 mm (14 in)
75-108 m^3/s	(230-330 MMcfd)	406 mm (16 in)
131-180 m^3/s	(400-550 MMcfd)	507 mm (20 in)

2.2.2 Injecting CO_2

We inject CO_2 into geological reservoirs using injection wells. Well locations would be selected as part of the optimisation of the complete CO_2 storage system. The latter will reflect the nature of the reservoir and the volume of CO_2 to be stored. To prevent any CO_2 from leaking from reservoir, the casing cement must be high quality where the casing passes through the cap rock. The perforated completion or bottom part of the well could be made of stainless steel (or carbon steel with a plastic coating) to prevent corrosion [4]. Old wells could also be converted into CO_2 injection wells if it is cheaper than drilling new wells.

2.2.3 Reservoirs

There are several options for CO_2 geological sequestration.

First, CO_2 can be used in enhanced oil recovery (EOR). For many years, the oil industry has injected CO_2 into oil reservoirs to increase oil production. CO_2-EOR accounts for 0.3% of world oil production [5]. Therefore, utilising CO_2 for EOR not only reduces greenhouse emissions but also confers commercial benefits.

Second, we can also use CO_2 to enhance coalbed methane recovery (ECBMR) or store it in deep unmineable coal seams. Coals store CO_2 by adsorption and desorb the methane as free gas for recovery (in the case of ECBMR). Coal can adsorb roughly twice as much CO_2 by volume as methane [6]. However, the low permeability of coalbeds means that they generally have low CO_2 injectivity. Therefore, they generally require large number of injection wells.

Third, CO_2 can be stored in depleted oil and gas reservoirs. Existing wells, flowlines, pipelines and other facilities could be re-used. If a reservoir has aquifer support, the reservoir pressure is low shortly after the reservoir is depleted, but might increase significantly in the medium term. Therefore, to take advantage of low injection pressure, we would need to consider injecting CO_2 as soon as the reservoir is depleted of hydrocarbons.

Fourth, we can store CO_2 in deep unusable saline aquifers. Such aquifers exist in many part of the world and therefore, there is high potential to find suitable aquifers with large capacity. Current research on CO_2 geological sequestration worldwide tends to focus on aquifers as promising large storage capacity sinks. Bradshaw et al [7] quoted that the worldwide geological storage capacity is estimated to be at the order of 100's to 1,0000's Giga tonnes of CO_2.

The density of CO_2 varies with temperature and pressure. Therefore, density is a function of reservoir depth. Assuming a hydrostatic pressure gradient of 10 MPa/km, a geothermal gradient of 30°C/km and a mean surface temperature of 15°C, the CO_2 density increases sharply at depth between 500 and 1,000 m. At greater than 1,000 m depth, it becomes roughly constant in the range 600 and 700 kg/m^3 (**Figure 2**). Therefore, there would be no obvious benefit in term of increasing CO_2 density by injecting at deeper than 1,000 m.

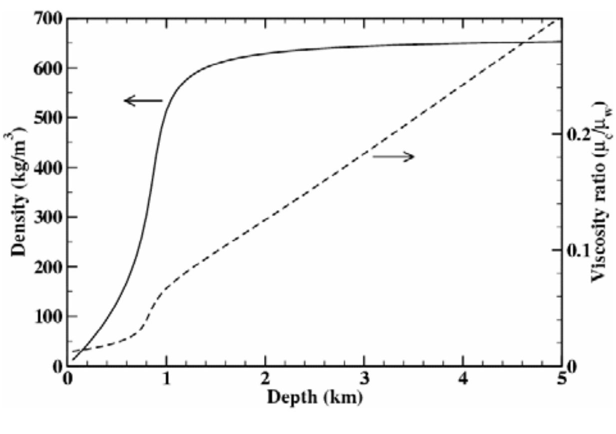

Figure 2 CO_2 density and viscosity at subsurface conditions [8]

The density of CO_2 at reservoir conditions could be significantly less than the density of formation water. Due to this density difference, the injected CO_2 is lighter and tends to migrate upwards and form a bubble beneath the reservoir sealing formation. Reservoir simulations of injection into horizontal aquifers show a very slow rate of CO_2 migration. The simulations suggest that it could be several thousand years before the CO_2 reaches a maximum lateral radius of a few kilometres from the injection wells.

2.2.4 Monitoring CO_2 sequestration

Monitoring CO_2 in the reservoir during and after sequestration is necessary to ensure and demonstrate the movement of CO_2 and that the CO_2 is retained in the formation. Two methods for monitoring the subsurface movement of CO_2 are reservoir simulation, and geophysical surveys. Reservoir simulations provide guidance on how CO_2 is distributed in the reservoir during and after sequestration. Geophysical measurements including seismic provide regional, cross-well or single well mapping of CO_2. The effectiveness of these geophysics measurements depends on several factors including the contrast between physical properties of CO_2 and formation fluids, the lithology and structure of the reservoir, formation fluid pressures and pressure variations, well spacing and the injection pattern [9].

3. ECONOMICS OF CO_2 SEQUESTRATION

CO_2 separation from natural gas is part of the base project (natural gas processing) because its concentration in the gas must be reduced to a certain level (e.g. 2% by volume) before the gas is sold regardless of sequestering or not sequestering CO_2. Therefore, the costs of CO_2 geological sequestration in this case essentially include costs of compression, transport and/or recompression, injection and monitoring. These processes require additional investment which increases the costs of producing natural gas. A generic economic model was built to estimating the costs quoted below.

My study with real data from over 50 CO_2 source and aquifers in Australia shows that sequestration cost per tonne of CO_2 sequestered can vary from below US$5/tonne (US$260/MMcf of CO_2) to over US$20/tonne (US$1,050/MMcf of CO_2). The cost highly depends on throughput volume (the higher the volume, the lower the unit cost), distance from source to sink and whether it is an offshore or onshore injection site. **Figure 3** below indicates how this cost could vary with flow rate, distance and sink location. The study assumes a 25 year project life.

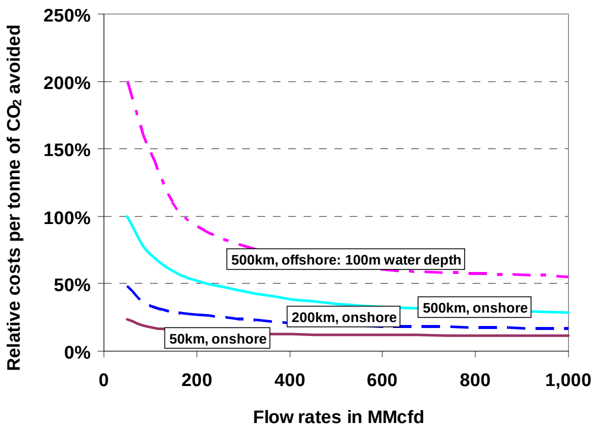

Figure 3: Indicative sequestration unit costs against flow rates and distances.

These analyses indicate that the sequestration costs per tonne of CO_2 largely depend on the CO_2 flow rate (higher flow rate gives lower unit costs), distance from source to sink (shorter distance gives lower unit costs) and reservoir injectivity (higher injectivity gives lower unit costs). The costs per tonne of CO_2 could be translated into the incremental costs per thousand cubic feet (Mcf) of gas produced if we know the CO_2 volume fraction in raw natural gas. As a rough estimate, sequestering the CO_2 from a 25% CO_2 by volume raw natural gas field would increase the costs of natural gas production by US¢9/Mcf to US¢35/Mcf of processed natural gas. Again, this incremental cost excludes the separation cost which is considered to be part of the gas processing.

4. CONCLUSIONS

Geological sequestration is a potential mean to reduce large amount of CO_2 that otherwise be released into the atmosphere from petroleum developments as well as other stationary sources including fossil-fired power plants. The petroleum industry has transported and injected CO_2 into oil reservoirs to increase oil productions for decades. Technical and economic expertise from these projects together with current researches provides the necessary foundations for future sequestration projects.

Technical steps for CO_2 geological sequestration from natural gas developments include separation, dehydration, compression, transport and/or re-compression, injection and monitoring. Reservoir and geology studies are important, especially to optimize the sequestration process and to predict the movement of the injected CO_2 in short and long term. Monitoring the injected CO_2 after sequestration is to ensure that CO_2 is retained in the reservoirs.

Economic studies of CO_2 sequestration for a natural gas development are to find out how much additional investment is needed or ultimately to find out the incremental costs of producing natural gas. The costs of sequestration could vary from below US$5 to over US$20 per tonne of CO_2, which largely depends on the amount of CO_2, distance and reservoir properties. Economic results are in favour of large CO_2 flow rate, short distance and high injectivity reservoirs.

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