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A Practical Approach and Workflow to Assess the Storage Capacity of CCS Projects at Early Stage

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ABSTRACT

Preliminary CO_2 storage capacity estimation is important when screening Carbon Capture and Storage (CCS) subsurface candidates, prior to selecting those for detailed modelling. This paper will describe a refined analytical approach which enables an initial estimation of CO_2 storage capacity and the required number of wells and provides a high-level scoping subsurface design for CCS in depleted gas reservoirs.

Various analytical principles and other controlling parameters have been used to develop an improved estimation of CO_2 storage capacity in a depleted gas reservoir. The material balance approach suggested in this paper has been elaborated and the workflow defined. Dynamic modelling has refined and extended the calculations to account for the mixing of CO_2 and remaining hydrocarbon gas. The results have been integrated with those of CO_2 injection well modelling and geomechanics to develop guidelines and a workflow for early-stage CCS project design and assessment.

A refined calculation validated using dynamic modelling has increased rigour in the initial estimation of CO_2 storage capacity in depleted gas reservoirs. The results and knowledge gained from the detailed geological and geomechanics understanding, dynamic modelling and well flow modelling studies have been combined to create a workflow for the initial, scoping design of a CO_2 sequestration project in a depleted gas reservoir or saline aquifer.

The outcome provides a workflow for rapidly estimating CO_2 storage capacity and well numbers for a CO_2 sequestration project. The results can be used for relative cost-benefit analysis prior to more detailed economic studies.

The paper develops the understanding of analytical principles affecting CO_2 storage capacity in depleted gas reservoirs. It provides a practical and useful workflow to generate the initial scoping design of a CCS subsurface project for a range of depleted gas reservoirs.

EXTENDED ABSTRACT

The carbon capture and storage (CCS) industry is growing and there is increasing demand for available CO_2 storage resources. Several storage targets have been identified to inject and store CO_2, most notably the oil and gas reservoirs, saline formations and un-minable coal seams. Within these storage targets, a variety of trapping mechanisms are also considered, e.g., structural, solubility, residual, and mineralisation. Each of these trapping mechanisms varies in its performance and relevance over different timescales. For example, the structural trapping of CO_2 beneath a low-permeability cap rock is the most notable in the short term.

Typically, the material balance approach forms a type of analytical procedure to estimate CO_2 quantities. It includes the analysis of pressure and production data as CO_2 is injected into a storage resource. In situations where the injection is in a homogeneous formation in a closed system e.g., a gas reservoir bounded by impermeable boundaries and in which sufficient high-quality production data are available, estimation on the basis of material balance may deliver very reliable estimates of ultimate storage at virgin reservoir pressure. In complex formations where there is water ingress, compartmentalization, heterogeneous layers, etc., computer-aided modelling can be considered a more sophisticated form of material balance analysis [1]. It is worth noting that a large amount of data is required for numerical simulation, such as rock properties, formation geometry, relative permeability functions, fluid properties, fault network, etc., to reliably predict storage.

Methodology

Analytically, a first-pass estimation of potential CO_2 storage capacity in a depleted gas reservoir can be made by assuming:

1) The injected CO_2 will fill the space created by the produced natural gas.
2) The reservoir pressure can be safely restored to its initial value.
3) There has been no water or gas influx or other subsurface mechanisms during the depletion period to reduce the storage capacity.

The assumption that the pressure can be restored to its initial value is based on the reservoir seal integrity having been unaffected during the gas depletion and subsequent CO_2 injection repressuring phases.

A first pass estimate of CO_2 storage capacity in a depleted gas reservoir can be calculated using Equation 1 [2].

$$M_{CO_2} = GIIP \times \rho_{CO_2} \times R_f \times (1 - F_{inj}) \times B_{gi} \times CF \quad \text{---------- Equation 1}$$

where;

M_{CO_2} = CO_2 storage capacity (Mt)
$GIIP$ = Volume of gas initially in-place, expressed in surface units (sm^3)
ρ_{CO_2} = CO_2 density at initial reservoir condition (kg/m^3)
R_f = Gas recovery factor (fraction)

F_{inj} = Fraction of gas injected into reservoir during depletion phase (could also represent aquifer ingress and/or water injected)

B_{gi} = Initial gas formation volume factor (volume that a unit volume of gas at standard, surface conditions would occupy at reservoir conditions) (rm^3/sm^3)

CF = Conversion factor to convert from kg to Mt (CF = $1x10^{-9}$ Mt/kg)

Bgi can be calculated using Equation 2 with fluid modelling software to calculate natural gas and CO_2 fluid properties.

$$B_g = \frac{Gas\ vol_{res}}{Gas\ vol_{surf}} = \frac{Z_{res} \times T_{res}}{p_{res}} \times \frac{p_{surf}}{Z_{surf} \times T_{surf}} = 0.001953 \frac{Z_{res} \times T_{res}}{p_{res}} \quad \text{---------- Equation 2}$$

where;

Z_{surf} = Gas compressibility factor at standard, surface conditions

T_{surf} = Temperature at standard, surface conditions (°R)

p_{surf} = Pressure at standard, surface conditions (bara)

Z_{res} = Gas compressibility factor at reservoir conditions

T_{res} = Temperature at reservoir conditions (°R)

p_{res} = Pressure at reservoir conditions (bara)

The term F_{inj} in Equation 1 was set to be zero in this case since it has been assumed that no gas or water injection and no water encroachment had taken place during the gas depletion period. In the case of complex material balance where gas or water injection has taken place during depletion, geological evaluation and dynamic modelling studies would be required to evaluate the effects of aquifer ingress and/or water/gas injection.

Case study

In this case study, the cumulative gas volume produced from the field was 2,285 Msm^3, which represented the terms "GIIP $\times$ R_f" in Equation 1. Other inputs to Equation 1 are shown in Table 1. It was assumed that repressuring of the depleted reservoir with CO_2 injection was limited to it reaching the initial virgin reservoir pressure of 124 bara. Using Equation 1, the calculated CO_2 storage volume in this particular depleted gas field is 9.8 Mt.

Table 1: CO_2 Storage Capacity – input data

CO_2 Storage Capacity –Depleted Gas Reservoir	
Material Balance Inputs	
Cumulative gas production (million sm^3)	2,285
Initial reservoir pressure (bara)	124
Current reservoir pressure (bara)	24.5
Reservoir temperature (°C)	57
Surface temperature (°C)	15
Density of 100% CO_2 at initial conditions (kg/m^3)	526
B_{gi}(rm^3/sm^3)	0.0081
Potential CO_2 Storage Capacity (Mt)	**9.8**

Material Balance Approach

The new approach suggested in this paper is to use the traditional material balance method used in the oil and gas industry, where the effect of instantaneous mixing of the remaining gas in place and the injected CO_2 can be considered. Note that this effect has not been considered in equation 1.

It's worth mentioning that in this process of material balance calculation, a zero-dimensional tank with instantaneous fluid mixing and isothermal conditions has been considered. Figure 1 shows a schematic of the material balance workflow.

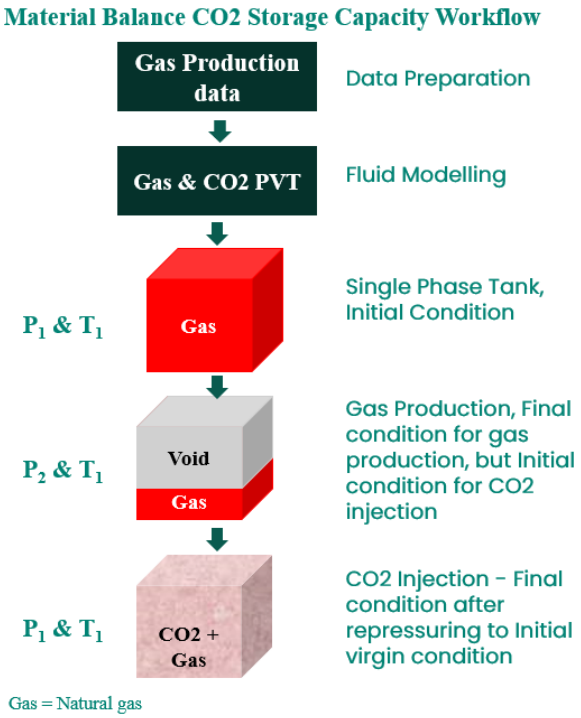

Figure 1: Schematic of material balance workflow

Storage estimation using material balance

Based on the described material balance workflow and the input data in this case study, the final CO_2 injection volume at the point where the tank re-pressurises to the virgin reservoir pressure of 124 bara was 3,800 Msm^3, as shown in Figure 2. This volume of CO_2 equates to a mass of 7.1 Mt at the final pressure and temperature of 124 bara and 57 ºC, respectively.

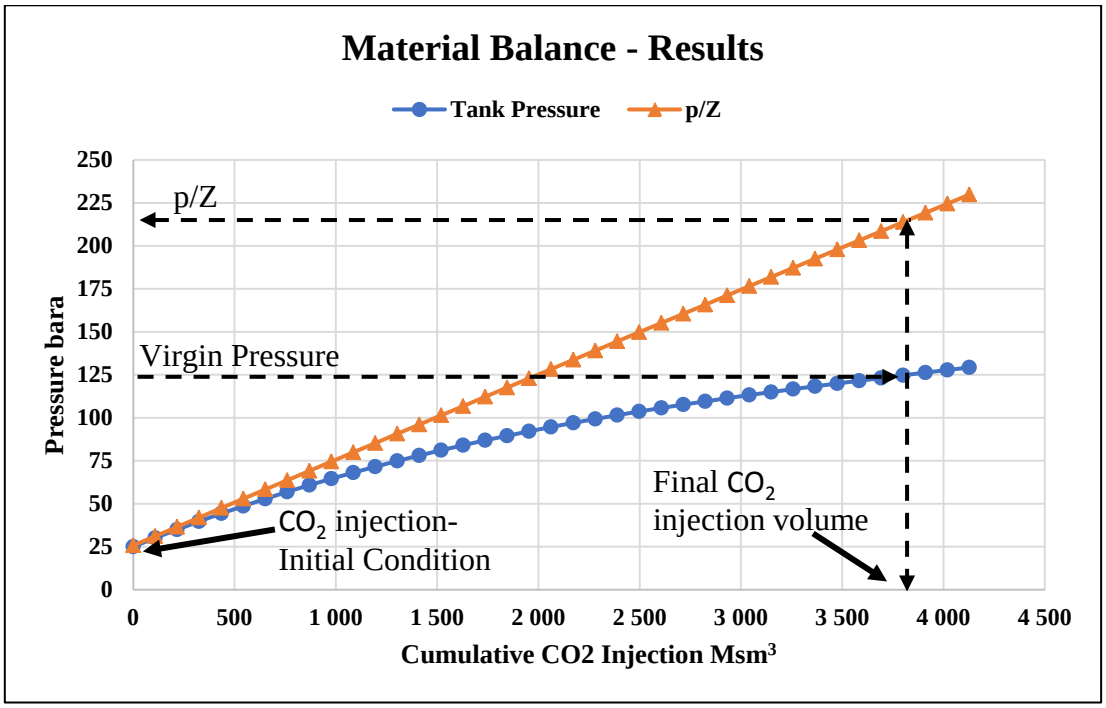

Figure 2: Material balance results

Well performance modelling

After calculating the volume of CO_2 using the material balance approach, well performance modelling can be conducted to define the maximum injection capacity per well and define the total number of wells that could be required to achieve the injection plan accordingly. This can feed into the feasibility study and the economic analysis at early stage.

Injecting into a depleted gas reservoir may cause an operational problem at early stage until reservoir pressure builds up and also problems in well performance modelling due to the transient behaviour inside the tubing. Figure 3 shows an example of nodal analysis issue during CO_2 injection into highly depleted gas reservoirs where slight changes in WHIP can cause significant changes in injection rate due to the sudden phase changes from gas to liquid inside tubing.

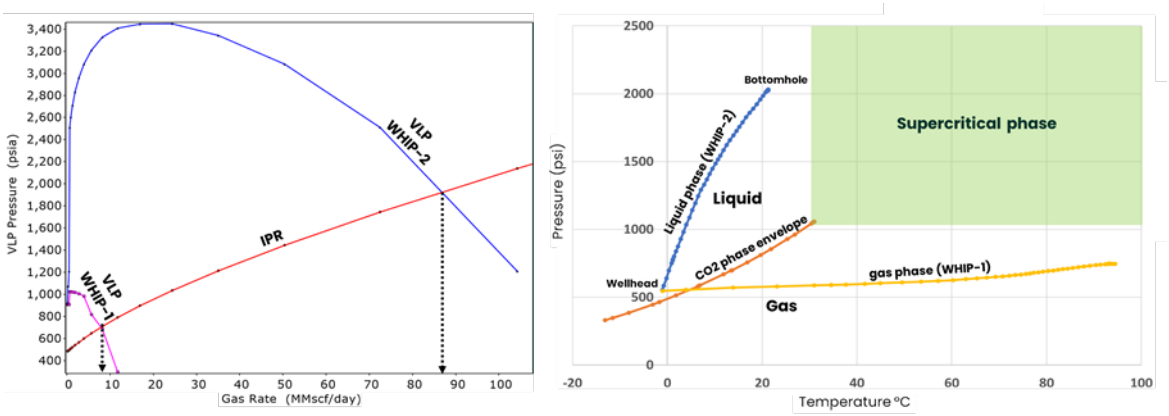

Figure 3: Example of nodal analysis issue during CO_2 injection

The difference between WHIP-1 and WHIP-2 is typically 5 – 10 psi only, and this difference can cause an increase of around 2000 psi in bottomhole injection pressure. This is due to CO_2 phase change from gas phase (WHIP-1 case) to liquid phase (WHIP-2 case) and a significant increase in density, hydrostatic head, bottomhole pressure and injection rate accordingly. In fact, the two-phase transition period between those two conditions couldn't be captured by traditional nodal analysis tools and more sophisticated transient analysis would be required to capture the multiphase flow behaviour of CO_2 including changes in pressure, temperature and CO_2 phase. However, it is believed that practically the well can produce during this transient condition (in between WHIP-1 and WHIP-2) but under unstable flow condition.

The reason of this unstable flow condition within this transient region is the fact that the delivery rate of CO_2 is limited to a value in between those two wellhead pressures (in this example). Once this rate is reached, a reduction in wellhead injection pressure will occur and phase will be changed from two phase (liquid and gas) to gas phase, then pressure will build up again and phase will be changed again to two phase condition inside tubing, creating a cycle of instability.

It is always recommended to avoid such unstable operating condition during CO_2 injection into depleted gas reservoirs which may negatively impact completion, reservoir, and cap rock integrity. Potential solutions to maintain stable operating condition includes heating CO_2 at surface during early stage until reservoir pressure builds up in order to keep CO_2 in liquid or supercritical phase or to use smaller tubing size or bottomhole choke.

Hoteit et al. [3] described a solution to mitigate the modelling issue of this transient region (pressure gap) by coupling wellbore and reservoir models using a compositional reservoir simulator where the transient behaviour of CO_2 inside tubing can be captured.

Conclusion

A case study has been presented to calculate CO_2 storage capacity in a depleted gas reservoir using material balance method. This method considers the effect of instantaneous mixing of the remaining gas in the reservoir and the injected CO_2, and hence the mixture compressibility is the key parameter to determine the volume of CO_2 that could be stored in depleted reservoirs. The results showed that the estimated volume is less than the other method by approximately 30% due to the mixture compressibility effect. This method can provide a realistic early estimation of CO_2 storage capacity which can impact the development plan and economic analysis.

Operational and wellbore modelling concerns during injecting CO_2 into depleted gas reservoirs have been presented where cycles of instability due to CO_2 phase changes inside tubing at early stage is expected until reservoir pressure builds up and establishes a stable flow condition. Potential solutions to mitigate such problem has been presented.

References

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