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Managing potential interactions of subsurface resources

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Abstract

Subsurface resources include oil, gas, coal, groundwater, saline aquifer minerals, and heat (for geothermal use). Pore space itself should also be considered as a resource as it can be used for injection of waste fluids, produced water, storage of natural gas, compressed air, and supercritical CO_2. Use of subsurface resources can overlap in space, and pressure changes at one site can remotely influence resource use at other sites. Resource use can also vary in time, such as the use of depleted oil or gas fields for natural gas or CO_2 storage. Before allocation of a subsurface resource it is therefore useful to understand the potentially wide range of resources available in an area, how they might be developed successively, and how they could affect each other if used concurrently. While these issues are primarily geological, they have critical significance for legal, environmental and economic considerations.

Introduction

There are many types of subsurface resources, which occur over a range of depths (Fig. 1)[1]. Many of them exist in pore spaces of rocks, such as sandstones, and in natural fractures of rocks. Subsurface pore space is a valuable commodity, fixed geographically but potentially subject to multiple uses over time. It can house resources worth many billions of dollars, and be of vital strategic value to companies and nations. The strategic importance of pore space can vary with time, as witnessed in the growth of unconventional oil/gas extraction in response to price rises, or of increased interest in geothermal resources and requirement for CO_2 storage space to mitigate climate change. It is therefore useful to consider pore space as a strategic asset that is likely to have potential future uses and where direct and indirect interactions need to be assessed and prioritised[1, 2, 3, 4, 5] (Figure 2).

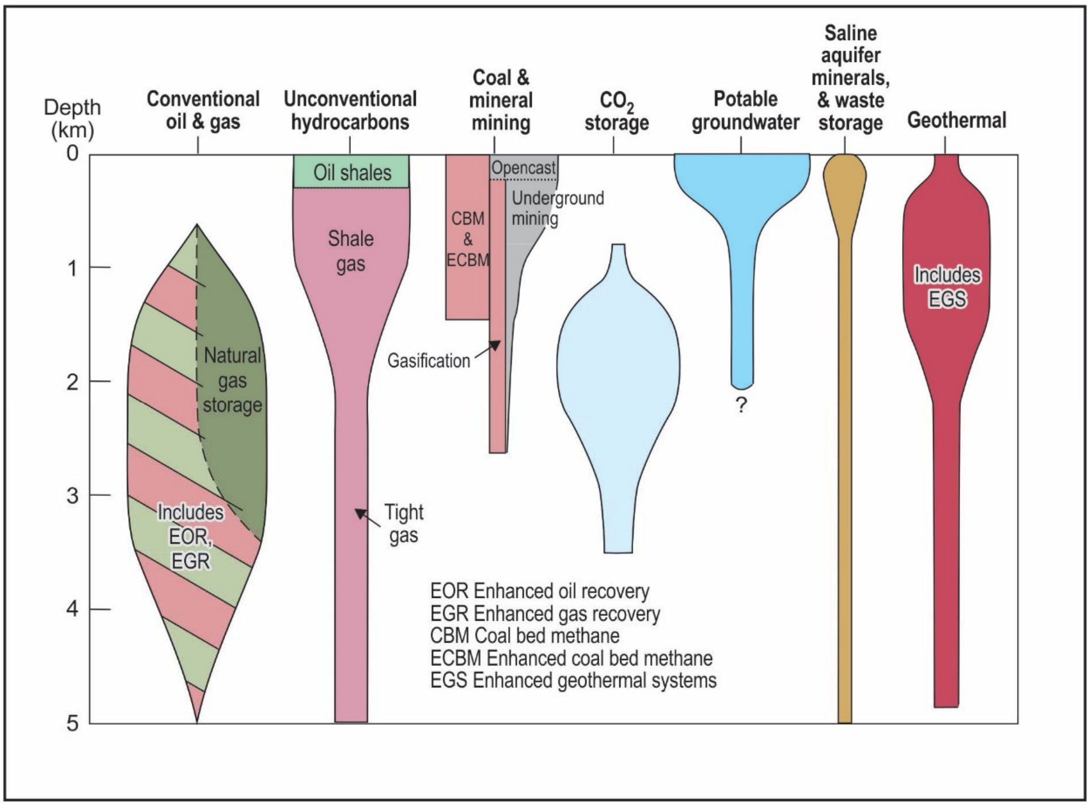

Figure 1. Typical depth ranges for the use of subsurface resources, with widths of polygons reflecting intensity of use. Modified after [1, 3].

Figure 2. Known and likely concurrent and sequential uses of subsurface resources. See also Figure 1.

	Oil & gas	EOR/EGR	Natural gas/air storage	Shale gas	Deep tight gas	CBM & ECBM	Coal gasification	Deep coal mining	CO_2 storage	Potable groundwater	Saline aquifer minerals	Waste storage	Hot geothermal
Oil & gas		C	S	C	C	D	D		S	D	C	S	C
EOR/EGR			S	C	C	C			C	D	C	S	
Natural gas/air storage				S	I	S	S	S	S	D	S	S	
Shale gas					D	C		S	D			S	
Deep tight gas							D		I	D		S	
CBM & ECBM							C	S	D			S	
Coal gasification								S	S			S	
Deep coal mining									S			S	
CO_2 storage										D	D	D	C
Potable groundwater													
Saline aquifer minerals												S	C
Waste storage													
Hot geothermal													

	No potential	D	Mainly at different depths
	Generally low potential; unlikely	I	Injectivity issues
	Needs more assessment	S	Sequential use potential; prioritise
	Likely to be in competition	C	Potential for concurrent use
	Likely to be compatable		

Types of physical interactions

Direct contact

CO_2 can be injected directly into a reservoir in order to improve the recovery of other resources, such as in enhanced oil or gas recovery (EOR, EGR; e.g.,[6]), and the use of CO_2 as a heat transfer medium has also been proposed for use in geothermal fields[7,8,9]. Direct contact between CO_2 or other injected fluids can affect the composition and physical properties of both reservoir rocks and formation fluids (see Effects of prior use, below).

Pressure fronts

When a fluid is injected underground, it creates a pressure front that can extend many kilometres beyond the site of injection[10,11,12]. Pressure fronts are transmitted via formation fluids and their direction, speed of transmission and magnitude depends on the injection rate, the permeability of the rocks and whether fluids are in communication, either laterally or vertically. These factors might not easily be predicted, particularly if the reservoir has high-permeability channels, intraformational seals or baffles, or if there are sealing or leaking faults nearby. Nevertheless, on a local scale, an increase in pressure could assist with extraction of resource fluids such as oil or gas[13], particularly where water drive is weak or, in the case of CO_2 injection, where eventual flushing by direct contact of CO_2 through EOR is planned.

Effects of prior use

Physical effects

Extraction of resources such as oil or gas results in a reduction of pressure within the reservoir rocks, which, in turn, can lead to an influx of local formation waters and a relaxation of stress in both reservoir and seal rocks. The opposite occurs when fluids are injected. During fluid injection into a depleted reservoir, it may be possible to re-pressure the reservoir to its original conditions, or beyond. However, it is generally regarded as safer to limit re-pressuring to significantly less than original conditions, to reduce the likelihood of seal rupture due to imperfect elasticity in the seal rocks[10,11,13,14]. It is therefore useful to measure the original reservoir pressure, prior to injection, and to understand the reservoir response to any previous attempts to use pressure to enhance production (e.g., by water or gas injection). This history-matching, where models that assess planned use can be checked against past performance, is an essential part of the wide range of studies to evaluate specific sites[15].

Operations that fracture the reservoir, and therefore potentially the seal (e.g., hydraulic fracturing operations), will affect later use of the reservoir. Fracturing potentially increases injection rates, and may affect the migration directions of injected fluids, and decrease confidence in seal integrity. In other cases, prior use might be beneficial for future uses, for example, capitalizing on enlarged storage capacity arising from coal gasification or deep mining to store produced CO_2[16, 17].

Extraction or injection operations are also likely to change the chemistry of the fluids in the reservoir, leading to dissolution or growth of minerals that could (respectively) enhance or hinder reservoir performance[13,18]. For example, injection of substances that increase acidity when in solution, such as CO_2, H_2S, and sulphur and nitrogen oxides, can increase oil or gas extraction rates by dissolving minerals such as calcite, feldspar and chlorite[19,20,21]. However, reactions may also cause new minerals to grow,

and these new minerals might restrict later injection rates. If their rates of formation are low during the injection period, and CO_2 or waste storage is the last use planned for the reservoir, mineral formation that locks in the injected material might be a desirable component of permanent mineral storage[22].
Historic infrastructure must be assessed for leakage potential, particularly if corrosive fluids such as water with dissolved CO_2 or H_2S are likely to contact cements, seals or pipework[13,23,24]. Leakage could be to the surface or to other levels in the subsurface.

Effects on fluids
Natural formation waters in a reservoir comprise “fossil water” held at the time of deposition that is modified by later, migrated fluids or by natural mineral changes in the rock (diagenesis). Formation water is co-produced when oil or gas is extracted and this “produced water” is usually disposed of, commonly by re-injection at shallower levels. If the shallower levels are then targeted for CO_2 or natural gas injection, the formation fluids might differ from those expected. Clearly, injection of any waste fluids, including CO_2, will alter the composition of formation fluids and their physical properties such as temperature (e.g., cooling), density and miscibility, and will potentially affect re-use of a reservoir, or affect nearby reservoirs if leakage occurs[25]. Beneficial interaction of fluids through miscibility is a key determinant of the viability of enhanced recovery using CO_2, for example, but would affect reservoir conditions for any later use. We are not aware of any re-use of a CO_2 storage reservoir for other purposes (e.g., natural gas or compressed air storage), yet such use may be viable after injection pressures have dissipated.

Avoidance of interactions
In some cases interactions of resource use might be undesirable. Examples would be the storage of CO_2 in reservoirs containing coal suitable for gasification, or in reservoirs containing deep, fresh or low-salinity formation water, or highly saline formation water containing usable elements. In the case of CO_2 injection, predicting and verifying plume migration are critical aspects of the evaluation and monitoring of a storage site. Unexpected movement of CO_2 could affect other subsurface resources (e.g., by mixing with hydrocarbons or potable groundwater), or may trigger seismicity (if it were to reach stressed fault planes[26,27,28,29,30]), or lead to surface leakage with flow-on effects such as loss of carbon credits. Containment by effective seal rocks is clearly paramount, such that a plume cannot migrate laterally around the edge of a seal unit, or pass vertically up through the seal under buoyancy pressure. While leakage through seal permeability (fluid flow) and seal integrity (fracturing) can be assessed empirically, and leakage via unsound infrastructure can be mitigated with some certainty, leakage up fault zones is more difficult to assess, mainly because of their heterogeneity[31,32].

The magnitude and extent of a pressure front depends on the rate of injection versus the effective permeability of the reservoir, and how readily the pressure can be transmitted. Pressure relief wells[33] that withdraw formation water create a zone of reduced pressure that can allow more rapid injection nearby, guide the direction of movement of the injected material, or potentially eliminate a pressure front entirely. Relief wells (vertical and horizontal) are a key mitigation method in risking and contingency planning for large-scale injection operations. Disposal of produced formation waters from pressure-reduction wells might be through injection into nearby geological units, provided these operations do not create undesired pressure

fronts in themselves. Nine pressure-reducing wells are planned for the Gorgon project[34,35]; these will allow higher rates of injection into the CO_2 storage reservoir, with injection of produced waters into shallower reservoirs, and with no adverse pressure effects on the storage reservoir (or on other subsurface resources).
Indirect interactions via pressure fronts are most likely during and immediately following injection of CO_2 as pressure will decrease after injection ceases, as the CO_2 plume disperses and dissolves in formation waters. Pressure reduction via dissolution does not apply to waste water disposal or natural gas storage.

Legal aspects

Several different legal problems need to be addressed in order to provide good management of subsurface resources. A basic initial question is property ownership. At least in the common-law jurisdictions of the world, the owner of the land has property rights that extend downwards indefinitely[36]. Where mineral rights are severed, such as being held in state ownership, mineral extraction cannot be attacked as an act of trespass or nuisance. However, an innovative use of subsurface resources such as CO_2 storage may require its own authorization.

Typically, mineral extraction is carried out under mining or petroleum laws that regulate the activity carefully but such laws rarely give a company rights to use the subsurface for any purpose other than mineral exploration and production. For that reason, CCS and similar activities need specific legislation. Good legislation has been recognized as essential to establishing a sound commercial framework for CCS[37,38,39], and a number of jurisdictions have enacted CCS-specific laws. Legislation is likely to be similarly necessary for other innovative uses of the subsurface.

Valuable opportunities may exist to move from one use of pore space to another, for example from enhanced oil recovery (EOR) to CCS. Such transitions and multiple-benefit projects, involving the interaction of different subsurface activities, will usually involve the interaction of different laws and regulations, and often involve the agendas of different agencies and bureaucracies. Coordination is essential, but in most jurisdictions around the world the legal basis for coordination for interactions such as EOR-CCS is little advanced[39page150]. Law and regulations to facilitate such coordination and to manage the interactions is important for the business environment. There have been some cases where extended controversy about subsurface interactions have delayed development, such as coal seam gas in Queensland[40] and 'gas over oil sands' in Alberta[41]. It is also important to ensure that petroleum and like operations are decommissioned in a manner that facilitates future subsurface resource use, for example, how boreholes are plugged and abandoned. There is also a need for rules to preserve subsurface data such as reservoir models that permit-holder companies have usually developed. Regulations (or lack of them) may well influence the order in which pore space is used, or whether it is available at all, taking into consideration consequent environmental and economic impacts.

Mitigation tools

Preparation for the mitigation of adverse effects of subsurface interactions can be viewed as a two-stage process where 1) geologically-governed, physical interactions are predicted, and 2) the significance and impacts of likely interactions are assessed and resolved through legal, economic and cultural responses. For 1) the tool is primarily dynamic modelling at relevant scales, preferably basin-wide assessment followed by focus on specific sites and their associated "fringes" of potential interaction, and these tools are well-established[2,3,4,5], though not commonly implemented at a basin-wide scale. Preparation for mitigation at specific sites, as part of contingency planning, can include cessation or reduction in activities (perhaps balanced by the use of back-up alternative sites), and the use of injection or extraction wells to alter subsurface pressure fronts[32]. Further research on practical and cost-effective monitoring techniques for detecting interactions would help reduce company and environmental risk, and potentially streamline regulatory approvals, in particular defining what detectable degree of interaction or leakage should trigger a remedial response, which could be costly[42]. For 2) mitigation is less clear, and will depend on the region's regulations (regulatory/legal tools and their application in early planning stages), resource needs and opportunities (e.g., political priorities), and societal knowledge and perceptions. Impartial education, to ensure informed opinion, combined with ongoing engagement are crucial to societal acceptance[43].

Conclusions

Resource interactions can be beneficial or detrimental for future usage. Planning is essential to ensure effectual use of pore space as a resource for both extractive and storage industries. This will reduce the risk of resource damage or sterilization and litigation between industry operators, and create more transparency and certainty for the roles of regulators and for the public. Such planning should ideally be done at a basin-wide scale before resource development occurs, and be reviewed periodically as knowledge of a region improves, particularly in regard to specific, depleting fields, where pore space parameters and reservoir geology in general are best understood. Regulatory frameworks are important for enabling subsurface resource use and addressing potential interactions.

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