International Journal of Greenhouse Gas Control 44 (2016) 238–248

Contents lists available at ScienceDirect

International Journal of Greenhouse Gas Control

journal homepage: www.elsevier.com/locate/ijggc

Reducing operational costs of CO_2 sequestration through geothermal energy integration

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ARTICLE INFO

Article history:
Received 16 June 2015
Received in revised form 1 November 2015
Accepted 10 November 2015
Available online 9 December 2015

Keywords:
Australia
Carbon storage
CCS flagship
Geothermal direct use
Energy integration
Electricity
Pressure management

ABSTRACT

Commercial scale Geological Carbon Storage (GCS) projects have high capital costs and energy penalties that could be partially offset by including the production of geothermal energy. An important requirement is to match the geothermal resources available at GCS sites with local market opportunities. This paper examines the key parameters that determine viable economics for various hybrid GCS-Geothermal energy applications with a focus on Australian GCS flagship sites as case study examples linked with the initial observations from a pilot trial at the SECARB Cranfield CO_2 demonstration project in Cranfield, Mississippi, USA. At first approximation, offshore GCS-Geothermal coupling seems unlikely due to well costs and the additional engineering requirements. The Perth Basin provides the best opportunity for GCS-Geothermal direct use for desalination. Whilst none of the case study examples would be ideally suited for GCS-Geothermal, insights gained are used to speculate on what conditions would be required for an economically viable opportunity. A strong enabling economic driver is when a GCS project already includes pressure relief water production as part of its base case.

1. Introduction

Geological Carbon Storage (GCS) has been identified as one of the important elements of greenhouse gas reduction strategies. Many of the technical aspects of carbon storage are well understood and for decades the oil and gas industry has injected into oil reservoirs as a method of enhancing recovery (Grigg, 2005). Large operations of this kind such as Weyburn (Whittaker et al., 2004), Cranfield (Meckel and Hovorka, 2009), and Rangely (Klusman, 2003) in the United States and Canada are monitored for reservoir and seal performance and storage conformance as case studies. While these commercial projects are useful case studies for understanding carbon storage processes in the subsurface, their primary business drivers are related to enhanced oil recovery, not carbon storage. In 1996, the world's first large-scale purely storage project was initiated by Statoil and its partners at the Sleipner Gas Field in the North Sea to remove CO_2 as part of its natural gas production operation. However by almost any measure, the subsequent uptake of commercial-scale carbon storage has underwhelmed predictions mainly due to the lack of a business case. Most new storage projects have remained at the research and pilot scale, for example, Otway (Jenkins et al., 2011).

In Australia, various studies (Grant et al., 2013; Cook, 2012; Neal et al., 2009; Department of Resources, Energy and Tourism, 2009; Gorgon Project in Western Australia) have suggested that the CO_2 storage cost is in the range of AUD\$4–\$36 per tonne avoided (saline aquifer storage) and AUD\$2–\$11 per tonne per 100 km distance for transport with monitoring costs being negligible (IPCC, 2005). The large range appropriately reflects the wide range of geological and geographical conditions for possible CO_2 injection projects. This can also be expected to be the case for storage costs across the world. All costs in this paper are converted to Australian Dollars in 2013 (base year). The current cost is likely to be slightly lower compared to the literature data due to mainly the low oil price which drives the rig availability high and cost low, and also the technology development and growing knowledge of the subsurface in recent years. Even excluding capture cost, which in the case of the Oil and Gas (O&G) industry might be argued to already be a part of the core business,

Abbreviations: AEMO, Australian Energy Market Operator; EGS, Enhanced Geothermal System; GCS, Geological Carbon Storage; HSA, Hot Sedimentary Aquifer; IMO, Independent Market Operator; LCA, life cycle analysis; O&G, Oil and Gas; O&M costs, Operating and Maintenance costs; ORC, Organic Rankine Cycle; RRP, Regional Reference Price.

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http://dx.doi.org/10.1016/j.ijggc.2015.11.012
1750-5836/

Table 1
High level comparison of power generation and direct use geothermal applications.

	Power generation	Direct use applications
Efficiency	Low efficiency	High efficiency
Usage	Wide usage (electricity)	Specific use
Transport	Can be transported	Need to be used locally
Flexibility on resources	Depend on the surface facility and its requirements on working temperature and flow rate fluctuations and evolution over the project lifetime	
Flexibility on demand	Depend on the energy demand	
Energy supplied	kWe	MW_{th}
Minimum temperature (°C)	98	30

there is no current or historical price signal that would make carbon storage generally economically viable in almost any jurisdiction. In this paper, we examine if there is a realistic opportunity to improve the carbon storage business case by integrating a component of geothermal energy generation. We use Australia's planned carbon storage projects as a case study context.

2. Integrating Geothermal and Carbon Storage

While there are many different possible sources of geothermal energy (volcanic systems, Enhanced Geothermal Systems (EGS) or Hot Sedimentary Aquifers (HSA)), since most commercial scale carbon storage projects target sedimentary rocks at depths greater than 800 m, we restrict ourselves to HSA type of geothermal resource applications. Since carbon storage requires suitable injectivity, capacity and containment as a prerequisite (IPCC, 2005), there should generally be a good match of desirable rock properties for HSA. Fig. 1 shows the location of Australia's planned carbon storage projects on the backdrop of the estimated temperature at 5 km depth. This gives a first order indication of potential geothermal resources near planed carbon storage sites.

Geothermal energy is commonly harvested in two ways: electricity generation and direct utilisation. Conventional geothermal electric power production normally requires fluid temperatures around 98 °C or higher as low-temperature geothermal tends to be very inefficient with a strong dependence on heat rejection temperature, although selected examples were proved successful for as low as 74 °C in Alaska depending on other site characteristics and business drivers. Direct utilisation in comparison, is possible from anything above seasonal surface temperature. A comparison between power generation and direct-use geothermal options and the minimum production temperature requirements for various applications are presented in Table 1 and Fig. 2, respectively. The sustainability of geothermal production over time in sedimentary basins is critically dependent of pressure support. Therefore, power and direct-use geothermal plants do not differ significantly, the working fluid is extracted from the reservoir to the surface, circulates within a heat exchanger and is then re-injected. The thermal energy is transferred from the reservoir working fluid to a secondary fluid. This secondary fluid is then used in a closed cycle (Fig. 3a). In the case of geothermal coupled with GCS, the GCS can provide the pressure support and reinjection may not be required.

2.1. Direct use

Direct use of geothermal energy can utilise a range of temperatures (depending on the application). Applications include district heating, bathing, agricultural drying, greenhouse heating (Lund et al., 1998, 2011) and others (Fig. 2). With 93.2% of the worldwide installed capacity specialised on residential applications (heat pumps, space heating, bathing and swimming; Lund et al., 2011) and most industrial uses of direct heat remain niche applications, which are also developed on a very site specific basis.

Italimpianti (2013) pointed out that low-enthalpy geothermal (below 150 °C) is ideal for thermal desalination. Due to the nature of the process and the temperature available in the low-enthalpy geothermal energy, it is most cost effective to provide direct geothermal heat to a Multi-Effect Distillation (MED) plant (European Geothermal Energy Council).

Geothermal energy could be used to assist in coal drying, especially brown coal where the water content is high (50–60% in Victoria, Australia). Exergen's Continuous Hydrothermal Dewatering (CHTD) process of brown coal reduces the moisture content in brown coal from 60–70% to 20–25% but operates at high temperature 300 °C and 100 bar (1450 psi) (Exergen, 2014). A pre-drying stage might be considered using CO_2 or water at temperatures as low as 98 °C (direct or indirect heat exchange) which could help reduce coal drying costs.

Some direct-use applications have a narrow working temperature window whereas others are widespread (Dickson and Fanelli, 2003). Therefore the sophistication employed in the temperature analysis and thermal characterisation of the geothermal reservoir must match the flexibility/complexity of the temperature requirements of the envisaged direct use application(s). The key in direct use applications is that the required use must be located near the source of the geothermal energy. Site specific evaluation is a requirement to identify direct use opportunities.

2.2. Power generation

The binary cycle technology with Organic Rankine Cycle (ORC) and Kalina cycle appears to be the most efficient in comparison to dry steam, single and double flash steam plants for power generation (Zarrouk and Moon, 2014). They represent a convenient solution for resources with temperature lower than 150 °C. Binary power plants are generally preferred because of the fluid separation and the benefit of almost total re-injection (Di Pippo, 2008). They can also be modified to suit the specific working fluid and reservoir conditions (pressure, temperature, chemical composition and flow rate).

Electricity generation using low-temperature heat sources is generally characterised by relatively low conversion efficiencies (less than 10%). A current limitation of the power plants exists on the lower input temperature which is recorded at 86 °C in Australia (influenced by the high mean annual surface temperatures compared to colder climates). These working examples provide a context for the power that could be generated if, for example, hot formation water were being produced to surface as part of a carbon storage pressure management scheme.

Two geothermal power plants have been developed in sedimentary basins in Australia. The first one at Mulka (South Australia), started in 1986 utilising 86 °C water to produce 20 kWe (Popovsky, 2013). The second power plant in Birdsville (Queensland) benefits from 98 °C water to produce 150 kWe.

While power generation enables wider end use of the energy and transportation options, direct use geothermal applications provide better energy transfer efficiencies. Power generation efficiency of transferring heat energy into electricity from low temperature reservoirs is about 8–20% (Zarrouk and Moon, 2014) while direct use energy efficiency can reach a coefficient of performance (ratio of electricity required to recover the heat to the net heat recovered) of as high as 39% (Pujol et al., 2015). Power generation is more suited to base-load grid-connected power supply while direct