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Use of hot supercritical CO_2 produced from a geothermal reservoir to generate electric power in a gas turbine power generation system

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ABSTRACT

CO_2 capture and sequestration in deep saline aquifers is widely considered to be a leading option for controlling greenhouse gas emissions. One such possibility involves injection of supercritical carbon dioxide into a high-permeability geothermal reservoir. In addition to the benefit of sequestering the CO_2 in the reservoir, the CO_2 can be used to mine geothermal heat for utilization above ground. This paper describes one of the options for generating power from hot supercritical CO_2 obtained from CO_2 production wells connected to a geothermal reservoir, where the original source of the CO_2 is CO_2 captured from fossil-fired power plants or industrial processes. The cost of power generated using CO_2 produced from a geothermal reservoir with a gas turbine generation system is compared to the cost of generating power from a conventional geothermal steam power plant.

1. Introduction

Carbon capture and sequestration is widely recognized as one of the more promising methods for preventing CO_2 formed in fossil-fired power plants or industrial processes from being released into the atmosphere. Fig. 1 shows a fossil-fired power plant with a post combustion carbon capture system, with the captured CO_2 compressed to supercritical pressures and then injected into a porous geologic reservoir for long term storage. Over the last few decades, numerous investigators have been developing a variation of the CCS approach shown in Fig. 1, in which compressed CO_2 from a carbon capture process is injected into a hot geothermal reservoir. The heated high pressure CO_2 flows through production well(s) to the surface of the earth. It then flows into a CO_2-water separator and from there into a power generation system and it is then reinjected into the reservoir for ultimate sequestration (Fig. 2). These investigations have resulted in publications describing studies of the fluid flow and heat transfer processes in injection and production wells and through the porous material in the reservoir [1–9], papers describing the importance of CO_2 thermosiphons which occur due to injection of cold supercritical CO_2 into geothermal reservoirs and production of hot pressurized CO_2 from the reservoirs to the earth's surface [10–13], and papers dealing with the use of either Organic Rankine Cycle power systems or power systems which rely on expansion of hot pressurized CO_2 through turbines to generate electric power from the hot produced CO_2 [14–16].

Also pertinent are publications dealing with production of water from geologic reservoirs to control reservoir pressure during CO_2 injection, to recover water from the reservoir for subsequent use in water scarce areas, and/or to control the CO_2 production process [17–20].

The present paper describes analyses which link the pressure and flow rate of the CO_2 injected into a geologic reservoir, the arrangement of the injection and production wells, and the pressure, temperature and flow rate of the produced CO_2 to the power generated from Direct Turbine Expansion Power Generation Systems. In addition, results from thermoeconomic analyses are presented to compare the cost of power generated from CO_2-based geothermal power systems to the cost of power generated by a steam cycle geothermal power plant.

2. Reservoir and well modeling of CO_2 flow rate, temperature and pressure

The inputs needed for the type of power plant performance and cost analyses described in this paper include information on the temperature, pressure and flow rate of the hot CO_2 at the production well head and pressure and temperature at the injection well head. Simulations, using an analytic expression for the Darcy Law for CO_2 pressure drop in the reservoir in combination with the T2Well/ECO2N code [21], were performed for a system of five wells arranged as shown in Fig. 3. It was assumed that the top and bottom of the reservoir were 2000 m and 2500 m below the surface of the earth, the horizontal distance between

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Nomenclature

Roman symbols

R	Radial distance from injection well to production well [m]
T	Temperature [°C]
P	Pressure [MPa]
h	Specific enthalpy [kJ/kg]
s	Specific entropy [kJ/kg K]
m	Mass flow rate [kg/s]
W_{net}	Plant net power output [MW_e]
Q_{in}	Heat from geothermal reservoir [MW_{th}]
m_{VG}	Van Genuchten parameter

Subscripts

inj	Injection well
prod	Production well

Greek letters

η_{th}	Thermal efficiency [%]

Acronyms

O&M	Operation and maintenance
COE	Cost of electricity
LCOE	Levelized cost of electricity
HP	High pressure
LP	Low pressure

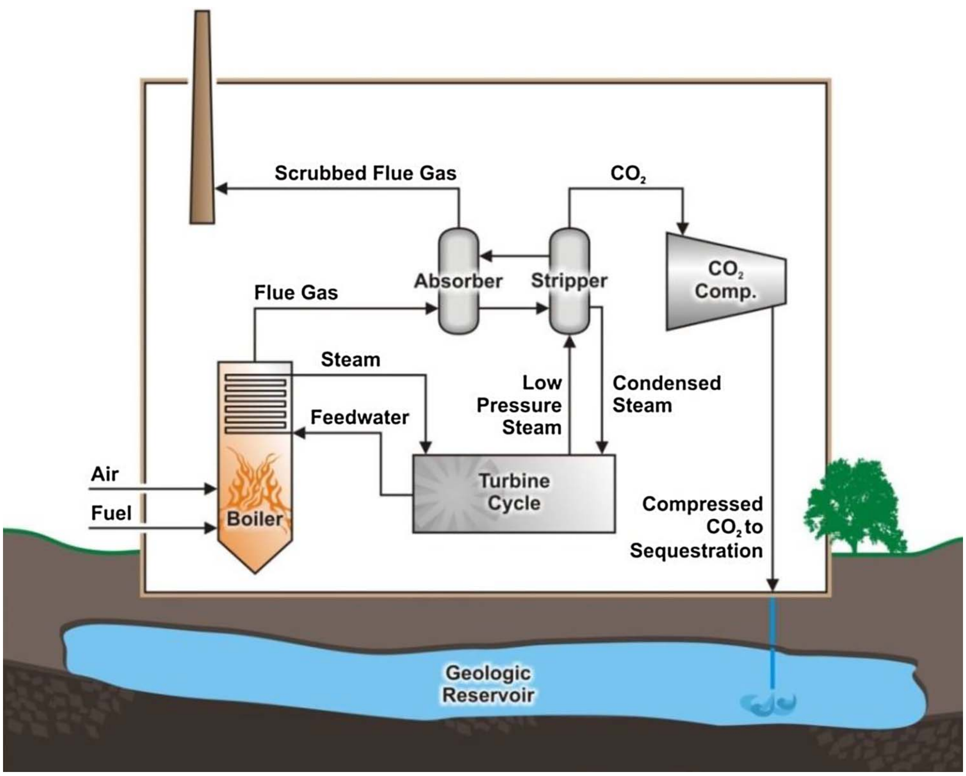

Fig. 1. Steam Power Plant with Post-Combustion CO_2 Capture and Sequestration in Geologic Reservoir.

the injection well and each of the four production wells was 425 m, the bottom of the injection well was at the bottom of the reservoir (see Fig. 3) and the radial velocity of the injected CO_2 flowing from the injection well was uniform from the top of the reservoir to the bottom. It was also assumed the reservoir has a single porosity with a value of 0.1 and a permeability of 30 mD and the specific heat and thermal conductivity of the cap rock equals are 920 J/(kg K) and 2.51 W/(m K) (see Table 1). The temperature of the injected CO_2 was assumed to be 30 °C, the initial temperature in the reservoir was 225 °C, the reservoir was initially filled with water, and the pressure at the top of the reservoir at the location of the injection well at the beginning of the injection process was 8.77 MPa.

The phase velocities in the wellbore were calculated using the Drift-Flux-Model (DMF) and obtained by salving the momentum equation for the DFM [22]:

$$\frac{\partial}{\partial t}(\rho_m u_m) + \frac{1}{A}\frac{\partial}{\partial z}[A(\rho_m u_m^2 + \gamma)] = -\frac{\partial P}{\partial z} - \frac{\Gamma f \rho_m |u_m| u_m}{2A} - \rho_m g \cos\theta$$

where$\gamma = (S_G/1 - S_G)((\rho_G \rho_L \rho_m)/\rho^{*2}_m)[(C_0 - 1)u_m + u_d]^2$ is caused by slip between the two phases. The terms ρ_m, u_m, $\rho^*_m$and u_d are the mixture velocity, the profile-adjusted average density of the mixture and the drift velocity, respectively.

It was assumed the injection flow rate was 120 kg/s, with the four production wells each receiving equal flow rates of CO_2. In addition, all five wells had 0.32 m wellbore diameters.

In the flow model used here, the injected CO_2 flows radially outward from the injection well, with part of it being captured by the four production wells (Fig. 4). The remainder bypasses the production wells and forms a plume of CO_2 in the region beyond the production wells where it is ultimately permanently sequestered.

This is illustrated by the results in Figs. 5–8 for an injection flow rate of 120 kg/s. Fig. 5 shows the flow rates of CO_2 and water at one of the