Surface Mixing as Method for Minimizing Leakage Risk in CO_2 Sequestration

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GEOLOGICAL CO2 STORAGE

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TEXAS

ABSTRACT

The economic feasibilities and stakeholder acceptance of geologic CO2 sequestration must account for the risk of leakage from the target formation. The standard approach to geologic sequestration assumes that CO2 will be injected as a bulk phase. In this approach, the primary driver for leakage is the buoyancy of CO2 under typical deep conditions (depths > 800 m). An alternative approach is to dissolve the CO2 into brine at the surface, then inject the saturated brine into deep subsurface formations. The CO2-laden brine is slightly denser than brine containing no CO2, so ensuring the complete dissolution of all CO2 into brine at the surface prior to injection will eliminate the risk of buoyancy-driven leakage.

We estimate that the power consumption for injecting CO2 saturated brine is comparable to that for injecting bulk phase CO2 (see Fig. 13). Injecting saturated brine requires greater initial capital investment than required for injecting bulk CO2 (see Fig. 14) and a large volume of available brine (Fig. 1).

INTRODUCTION

A typical case of interest is the CO2 emission from a 1000MW coal-fired power plant which amounts to 8Mt CO2/year (Benson, 2006) with realistic capture of 90% of the CO2 (Fisher, Beitler, Rueter, Searcy, Rochelle, & Jassim, 2005). The mass, mole, and volumetric flow rates of the captured stream are shown in Table 1.

Table 1—Carbon dioxide disposal rates for 1000MW coal-fired power plant are shown after 90% capture.

Captured Yearly Mass Flow Rate	7,200,000	tonne/year
Captured Daily Mole Rate	988,000	lbmol/day
Captured Volumetric Flow Rate	344.9	mmscf/day
Captured Daily Mass Flow Rate	19,700	tonne/day

METHOD

Solubility Model: We modeled the solubility of CO2 in brine with the Duan equation of state fitted by Hangx (2005). The solubility is pressure, temperature, and salinity (sodium chloride, NaCl) dependant. We fixed the temperature at 68°F, but we varied the pressure and salinity to observe the solubility dependence. With the solubility expressed as mole fraction and the rate of CO2 from the power plant (shown in Table 1), we determine volumetric flow rate of brine (see Figure 1).

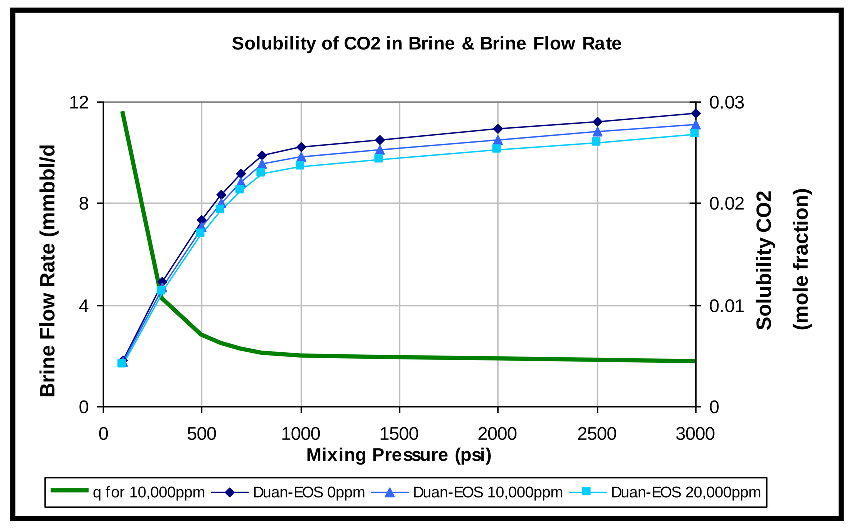

Figure 1—The solubility of CO2 in brine (blue lines) at 68°F is shown for pressure of 100psia to 3000psia and salinities of 0ppm, 10,000ppm, and 20,000ppm (NaCl) using the Duan EOS (Hangx, 2005). The brine flow rate for 10,000ppm (green line) varies from 2 to 12mmbbl/d depending on pressure. The important point to note is that the higher the pressure the higher the solubility.

Reservoir and Wellbore Model: The pressure in the wellbore can be related to the reservoir property *kh* (permeability height product) by use of the steady-state reservoir performance equation (Eq. 1) given by Economides (1993). The *kh* for the reservoir varies from 2.5×10^4 to 2.5×10^5. After modeling the reservoir, we developed a simple wellbore model that can be applied to either strategy based on the mechanical energy balance to include the contribution of gravity and friction to the pressure profile along the length of the well (Eq. 2). We use the wellbore model to determine the pressure at the wellhead (Fig 4, 5, and 6). The wells are expected to handle 35,000bbl/d of saturated brine or 125mmscf/d of CO2.

$$\Delta p=\frac{141.2qB\mu}{kh}\ln\frac{r_e}{r_w} \qquad \text{(Eq. 1)}$$

$$P_{n+1}=P_n+\rho g\Delta L+\frac{2\rho f_f u^2\Delta L}{D} \qquad \text{(Eq. 2)}$$

Power Consumption Model: We modeled compression processes to determine the power required for each injection strategy (see Fig. 7-9). The schematic for the compression of CO2 process is shown in Fig. 9, and the schematic for the compression of brine is shown in Fig. 7. Equations and parameters from, Fisher *et. al.*, (2005), Cengel & Boles (1989), and Boyce (2005).

Capital Cost Model: For the saturated brine injection strategy, we expect our capital costs to include the following: compressor purchase and setup, construction of injection wells, and a pressure vessel in which CO2 dissolution occurs prior to injection. The compressor pricing was based upon Fisher *et. al.*, (2005) where compressor costs amounted to approximately $500,000 per MW of power consumed. Injection wells were priced at $200,000 each, and the mixing tank at $.80/lb manufactured. A residence time of one minute was assumed to be sufficient.

Similarly, the CO2 bulk phase injection strategy will require compressors and injection wells. The prices for these are the same as in the previous strategy.

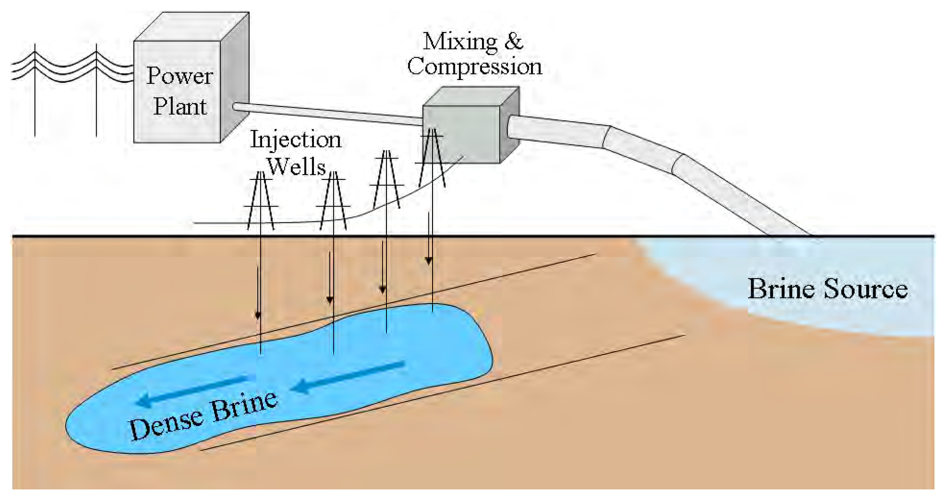

Figure 2—We define the saturated brine injection strategy as mixing compressed CO2 and compressed brine until the CO2 dissolves. The saturated brine is then injected into the reservoir. Once in the reservoir, the CO2-laden brine will migrate down. This method requires a large volume of water and more injection wells than injecting bulk phase CO2.

RESULTS and DISCUSSION

We compare CO2 saturated brine injection strategy (Fig. 2) and CO2 bulk phase injection strategy (Fig. 3) by measures of power consumed (Fig. 7-9) and capital costs (Fig. 10-12). The direct comparison can only be made from injection into same aquifer by means of the the reservoir and wellbore model (Fig. 4-6). The information in Figure 5 can be combined with Figure 8 and 11 to produce Figure 13 and 14. Figures 13 compares the power consumption of the two strategies, and Figure 14 compares the capital costs.

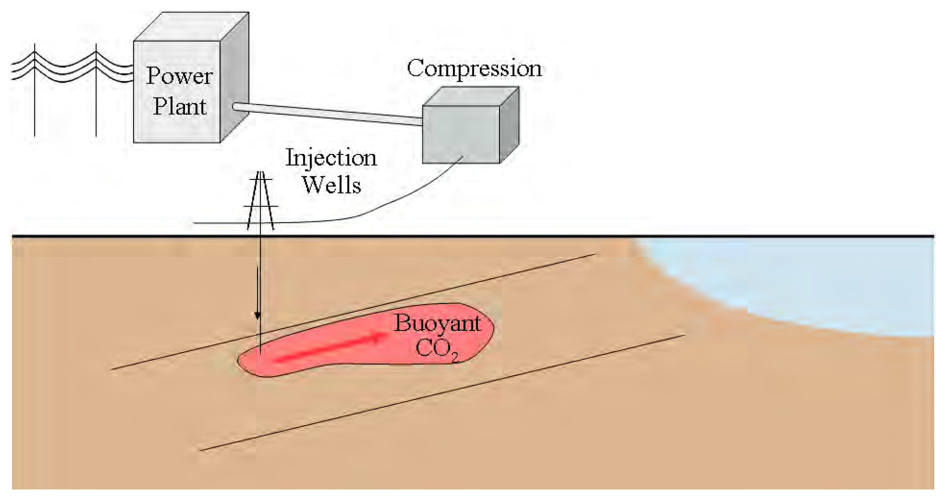

Figure 3— We define the CO2 bulk phase injection strategy as compressing and injecting the CO2 stream. The CO2 is compressed to a relatively high pressure for injection into the reservoir. Once in the reservoir, the CO2 will migrate up and has the potential to leak.

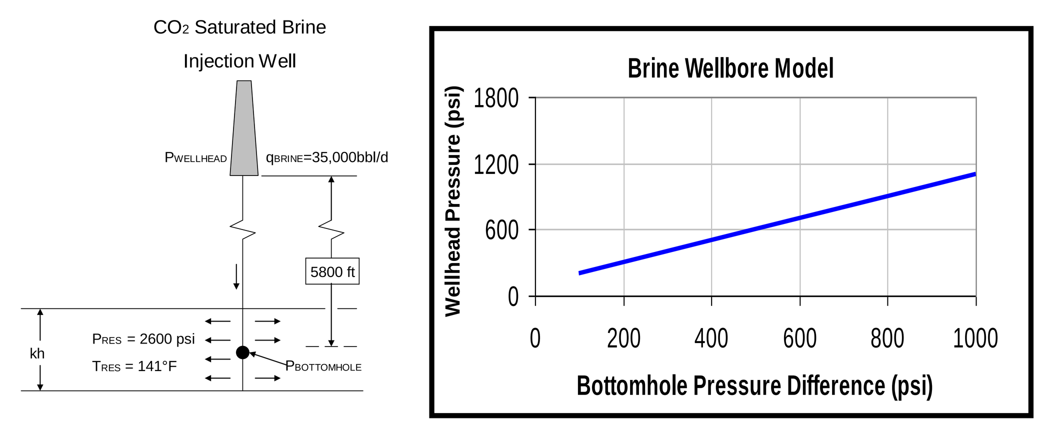

Figure 4—Because the brine is relatively dense, the wellhead pressure required for injection is low. By using the wellbore model, Eq. 2, we can compute the wellhead pressure for a 35,000bbl/d injection well as a function of bottomhole pressure difference. The bottomhole pressure difference is the bottomhole pressure minus the reservoir pressure.

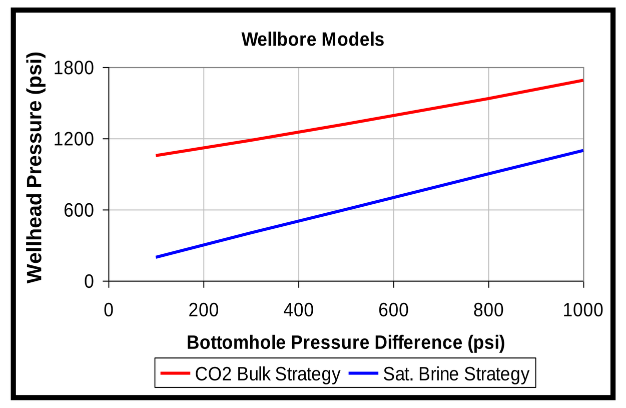

Figure 5—Using the wellbore model, the wellhead pressure required to inject into common reservoir is significantly higher for the CO2 bulk phase injection strategy than the saturated brine strategy.

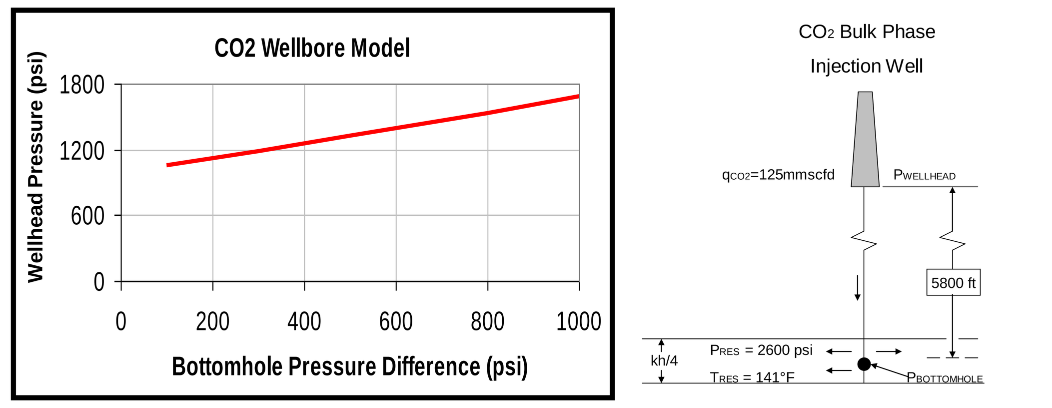

Figure 6—Because the CO2 is less dense than brine, the wellhead pressure required for injection is higher than for the brine injection strategy. By using the wellbore model, we can compute the wellhead pressure for an 125mmscf/d injection well as a function of bottom hole pressure difference. Recall the bottomhole pressure difference is the bottomhole pressure and the reservoir pressure.

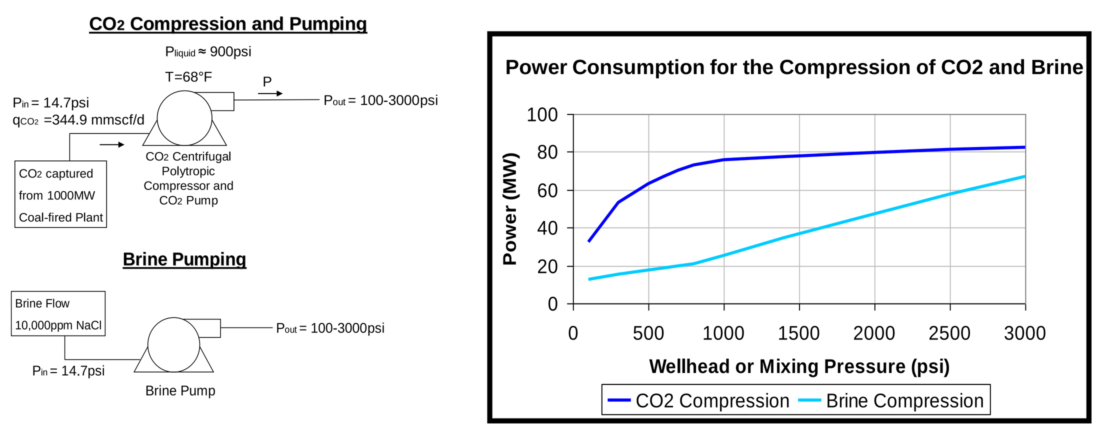

Figure 7—For the brine strategy, both brine and CO2 require compression between 200-1100 psi (Fig. 4). The compression of CO2 in the gas phase (dark blue) is modeled as multi-stage polytropic gas compression and the liquid phase as incompressible pumping. The CO2 compression curve is consistent with other sources (Fisher *et. al.*, 2005; Ennis-King *et. al.*, 2002). The pumping of brine (light blue) is modeled.

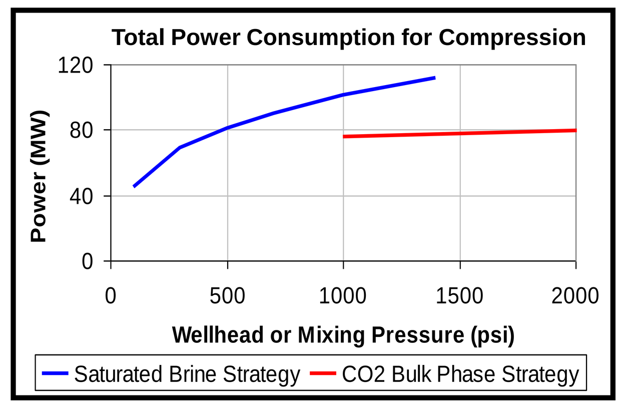

Figure 8—The CO2 bulk phase strategy power requirement (red) is ~80MW. The power consumption for the brine strategy (blue) is the addition of the curves from Fig. 7 and varies from 50MW to 110MW. The curves are truncated to the ranges of wellhead pressures from Fig. 5.

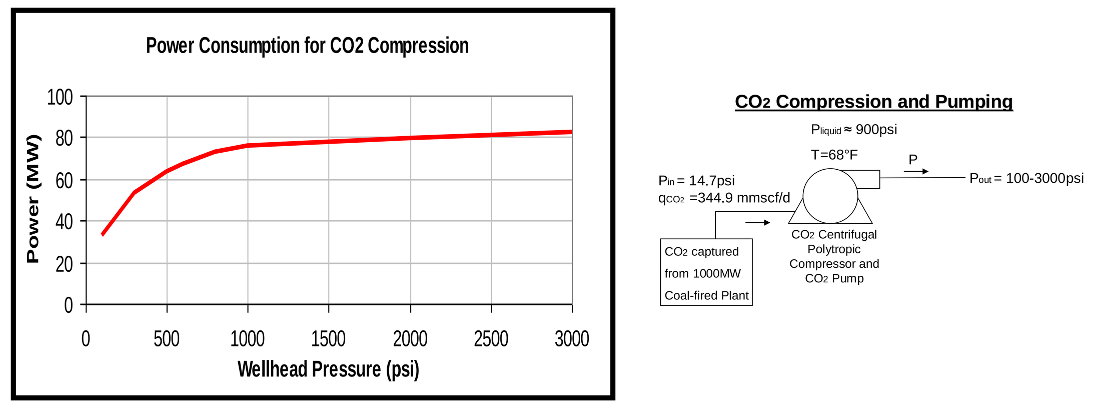

Figure 9—The compression of CO2 in the gas phase is modeled as multi-stage polytropic gas compression and the liquid phase as incompressible pumping. This compression curve is consistent with other sources (Fisher *et. al.*, 2005; Ennis-King *et. al.*, 2002). For this strategy, CO2 will not enter the reservoir 5800 ft down unless the wellhead pressure is between 1000-1700 psi (Fig. 6).

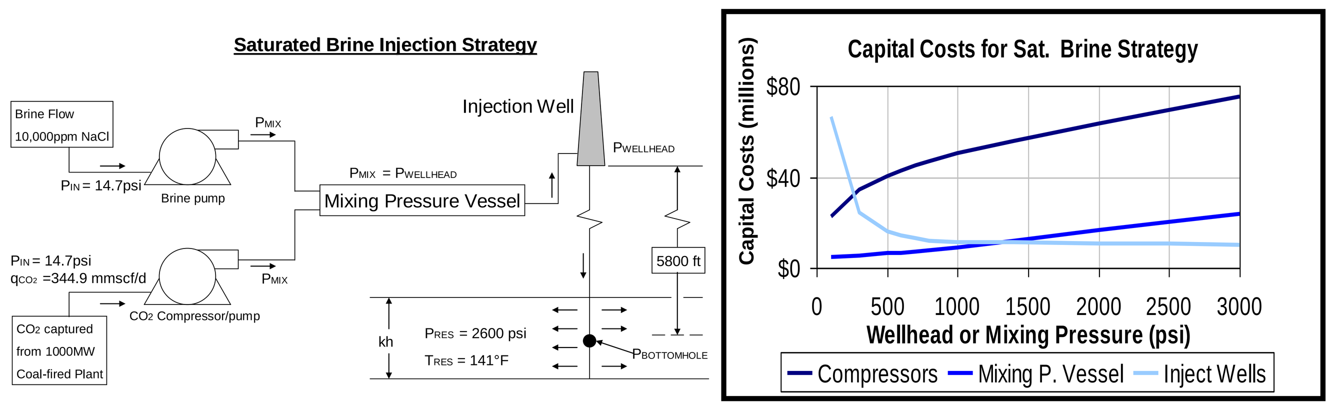

Figure 10—We estimate the capital costs of three necessary components for the saturated brine injection strategy: compressors, injection wells, and the mixing pressure vessel. The compressor curves (darkest blue) follow the power curve from Fig. 8. The mixing pressure vessel curve (blue) is a function of pressure, flow rate, and residence time (assumed to be one minute) for the CO2 to dissolve. The injection well curve (light blue) follows the solubility curve (Fig. 1).

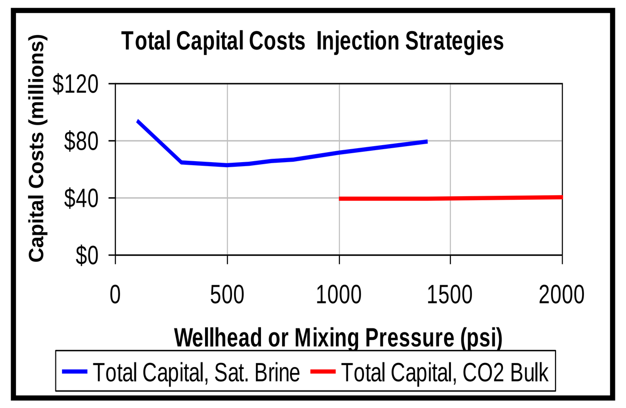

Figure 11—The capital costs for the saturated brine strategy (blue) and CO2 bulk phase strategy (red) are the sum of their representative curves (see Fig. 10 and 12) for the ranges of wellhead pressures (Fig. 4). The CO2 curve generally follows the power consumption curve, but the brine curve is dominated by the cost of injection wells below 300 psi and by the cost of compressors after 800 psi.

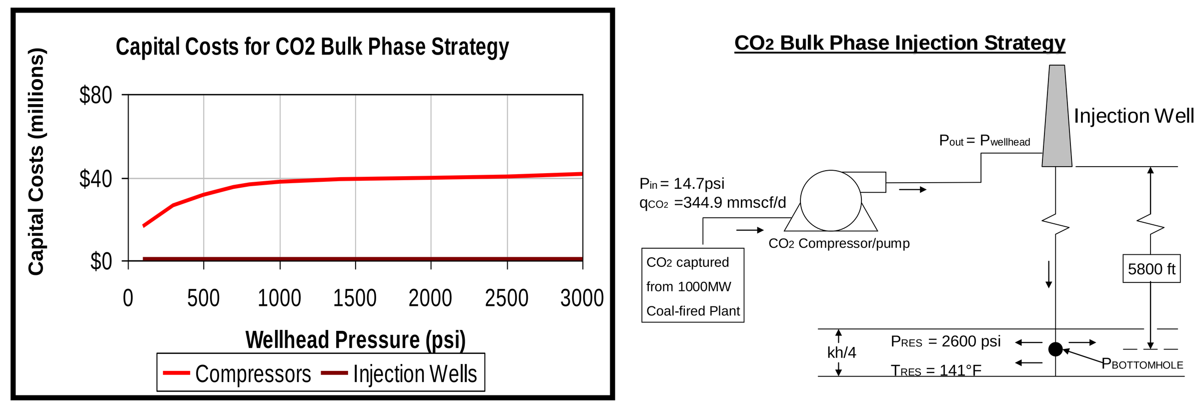

Figure 12—We estimate the capital costs of two necessary components for the CO2 bulk phase injection strategy: compressors and injection wells. The compressor curves (red) follow the power curve from Fig. 9. Only three injection wells (brown curve) will be required for any pressures.

CONCLUSIONS

- The **operating and capital costs** for the saturated brine injection strategy proposed here are **comparable** with bulk phase CO2 injection.
  - The operating costs (related directly to power consumption) will be competitive (Fig. 13) between the two strategies—assuming the source brine is cheap and low salinity.
  - The capital costs for injecting saturated brine will exceed those for injecting bulk phase CO2 by ~$20 million, a 4% increment on a $500 million project and 6% of the annual operating budget of the capture process.
- Most importantly, **risk of migration** to the surface has been **minimized**, hence, monitoring of the subsurface CO2 will not be necessary.

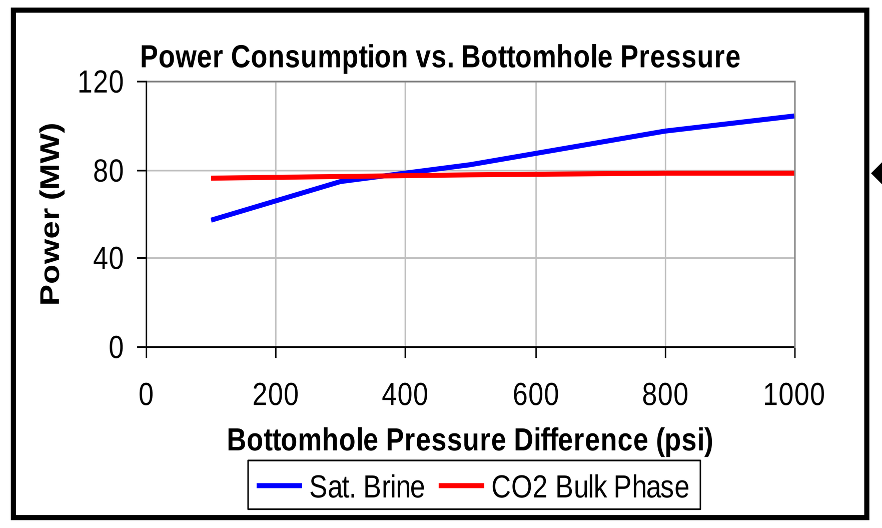

Figure 13—Combining the information from Fig. 5 and 8, the brine strategy consumes less power for bottomhole pressures differences less than about 400 psi with the assumption that the brine is free and accessible. We show that the power consumption for brine injection (blue) increases as the bottomhole pressure difference increases. The CO2 power consumption (red) changes very little with respect to the bottomhole pressure difference.

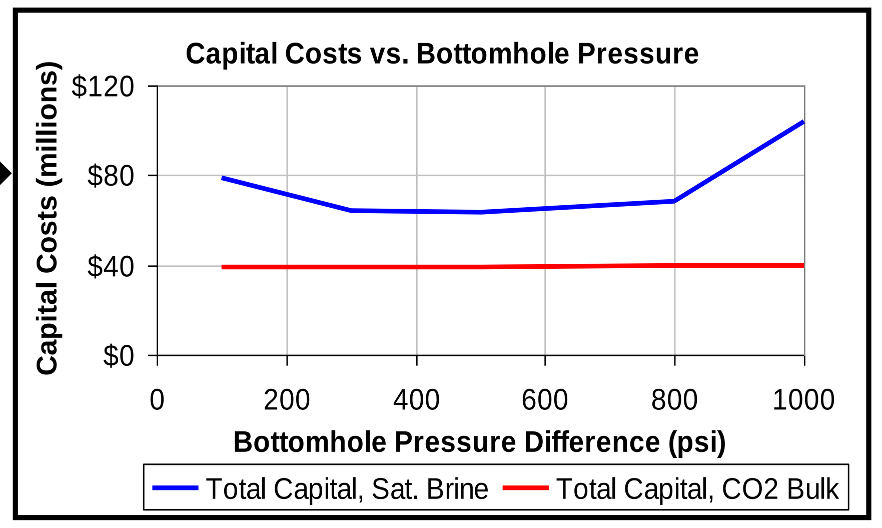

Figure 14—Combining the information from Figure 5 and 11, we estimate that the total capital costs for the saturated brine injection strategy (blue) is $20 to $60 million more than for the CO2 bulk phase injection strategy (red) into the same reservoir. Compared with the $500 million needed for capture and the $700 million annual operating budget, the relatively small additional capital provides a no risk alternative.

FUTURE WORK

- Are there reservoirs available with storage capacity for the injected brine?
- Are there fluids sources (brine or seawater) available in sufficient quantity?
- With such a large injection volume, what will become of the displaced fluid?
- If the brine must be lifted from the same reservoir, what are the added operational costs and capital costs?

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