Impurity types, concentration influence hydraulic design

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CO_2 PIPELINES—Conclusion

Real CO_2 streams—those from CO_2-capture plants likely to contain impurities as opposed to pure CO_2 streams—will likely contain at least 95 mole % CO_2 but will also contain impurities generated in the individual power plant and carbon capture-related facilities.

The first part of this article (OGJ, Apr. 12, 2010, pp. 39) described in detail methods for determining steady-state pressure and temperature profiles of such CO_2 streams. The conclusion, presented here, addresses the expected influence of impurities present in real CO_2 streams on the hydraulic pipeline layout and presents an overview diagram enabling a first estimation of the most economic pipeline diameter, depending on intended CO_2 throughput rates.

Background

Type and concentration of the impurity components contained in the CO_2 stream will influence the hydraulic design of a pipeline system transporting real CO_2 streams, which depend on a series of considerations like:

- Power plant fuel type and carbon-capture technology.
- Health-related safety considerations referring to the maximum allowable concentration of toxic CO_2 stream components (e.g., H_2S, SO_2) in hypothetical leak situations.
- Pipeline material-related aspects to limit corrosion (e.g., limitation of H_2O concentration) or other pipe-material related adverse effects like hydrogen embrittlement of the pipeline steel, hydrogen-induced cracking, or sulfide stress cracking (which can be mitigated by appropriate pipe material selection).
- Storage requirements (e.g., concentration limitation of oxygen and noncondensable components).
- Limitation of the amount of economically usable additional components transported (e.g., thermal usage of hydrogen or methane).
- Limitation of the amount of additional components in order to minimize friction pressure losses or losses of pipeline transportation capacity.
- Limitation of the concentration of additional components in order to minimize the amount of energy required in the pipeline system's compression and transportation stations.

Impurity sources

The process or power plant application for combustion of the primary fossil fuels—coal, oil, gas, biomass, or a mixture of these—determines the CO_2 capture techniques, which for power plant applications are characterized commonly as precombustion, postcombustion, or oxy-fuel processes (Table 1).

The processes mentioned may generate components appearing at different combinations and concentrations in the CO_2 streams captured, H_2S and SO_2 resulting from the fuel's sulfur content. Table 2 gives an overview on the concentrations of the impurities expected in dried CO_2 streams.[1]

While the stream compositions giv-

CO_2 CAPTURE PROCESSES FOR POWER GENERATION

Table 1

Process	Description
Postcombustion	Separated from power plant flue gases by amine or other process.
Precombustion	Integrated gasification combined cycle generation of synthesis gas, gas shift reaction to H_2 + CO_2, separation of CO_2 and H_2, combustion of H_2 in power plant.
Oxy-fuel systems	Combustion of fuel with almost pure oxygen, recycle flue gas consisting mainly of CO_2.

EXPECTED IMPURITY CONCENTRATION IN DRIED CO_2 STREAMS

Table 2

	Coal-fired plants			Gas-fired plants		
Component	Postcombustion	Precombustion	Oxy-fuel	Postcombustion	Precombustion	Oxy-fuel
	vol %					
SO_2	<0.01	0	0.5	<0.01	0	<0.01
NO	<0.01	0	0.01	<0.01	0	<0.01
H_2S	0	0.01-0.6	0	0	<0.01	0
H_2	0	0.8-2.0	0	0	1.0	0
CO	0	0.03-0.4	0	0	0.04	0
CH_4	0	0.01	0	0	2.0	0
N_2/Ar/O_2	0.01	0.03-0.6	3.7	0.01	1.3	4.1
Total	**0.01**	**2.1-2.7**	**4.2**	**0.01**	**4.4**	**4.1**

en in Table 2 reflect the aspects of the capture processes, Table 3 shows the DYNAMIS specification[2] taking safety and toxicity limits into account.

The DYNAMIS report[2] also states, however, that this recommendation covers a capture process applied to coproduction of electricity and hydrogen and, further, care must be used in applying this quality recommendation to other types of capture processes.

CO_2 STREAM SPECIFICATIONS, DYNAMIS

Table 3

Component	Aquifer	Enhanced oil recovery	Remark, limitation[1]
H_2O	500 ppm		Technical aspects[2]
H_2S	200 ppm		Health, safety considerations
CO	2,000 ppm		
O_2	<4 vol %	100-1,000 ppm	Technical aspects[3]
CH_4	<4 vol %	<2 vol %	Reference to ENCAP project
N_2	<4 vol %, all noncondensable gases		
Ar			
H_2			Reduction recommended[4]
SO_x	100 ppm		Health, safety considerations
NO_x	100 ppm		
CO_2	>95.5%		Balanced with other components

[1]Abridged remarks from DYNAMIS report. [2]Expected in the future to range near 250 ppm. [3]Range of EOR due to lack of practical experiments on O_2 effects underground. [4]Due to energy content.

Impurity influence

Estimating the influence of impurities on the pressure and temperature profiles of a CO_2 pipeline system and on the power demand of the initial compression stations and potentially installed intermediate transportation station(s) requires estimating the influence of impurities on vapor pressure-critical pressure, density, viscosity, specific heat capacity, Joule-Thomson coefficient, and isentropic p-T-relationship.

IMPURITY INFLUENCES AT 100 BAR, VARIABLE TEMPERATURE

Table 4

	Unit	CO_2, 100%	CO_2 + 2% CH_4	CO_2 + 2% H_2	CO_2 + 2% N_2	CO_2 + 2% Ar	CO_2 + 2% SO_2	CO_2 + 2% H_2S	CO_2 + 2% O_2
Relative density deviation compared with 100% CO_2									
10° C.	%	0.0	−2.6	−5.0	−2.6	−1.6	1.6	−0.3	−2.3
20° C.	%	0.0	−4.1	−6.2	−4.2	−2.7	2.0	−0.5	−3.1
30° C.	%	0.0	−6.1	−8.8	−6.6	−4.1	2.8	0.0	−5.2
Relative dynamic viscosity deviation compared with 100% CO_2									
10° C.	%	0.0	−6.0	−10.4	−6.8	−5.5	—	0.5	−6.0
20° C.	%	0.0	−6.0	−11.8	−7.6	−5.4	—	0.5	−6.3
30° C.	%	0.0	−7.7	−14.0	−10.7	−7.7	—	0.0	−8.6
CO_2 absolute vapor pressure, deviation compared with 100% CO_2									
10° C.	bar	45.0	5.3	17.6	9.8	8.3	−1.3	−0.4	10.8
20° C.	bar	57.3	5.1	13.7	8.9	7.9	−1.7	−0.3	11.6
30° C.	bar	72.1	6.8	8.5	6.3*	4.3	−2.7	−0.4	6.7

*Extrapolated value.

The published data on the influence of impurities on CO_2 stream properties, the applicability of existing equations of state, and the applicable mixing rules and parameters data are, however, limited.[3,4]

The Polytec report provides example estimates for pressure and temperature-dependent density, dynamic viscosity, and vapor pressure values.[3] The REFPROP program from National Institute of Standards and Technology obtained the data used by the report, referring to the statement by NIST that the program uses the most accurate equations of state currently available. The report[3] comprises a compilation of available measurement data on pressure vs. temperature and vapor-liquid equilibrium data of mixtures of CO_2 with other components.

SENSITIVITY CALCULATIONS VARYING INDIVIDUAL PROPERTIES ±10%

Table 5

	Calculated pressure, temperature at pipeline end			
	Absolute values		Differences	
Property variation	Pressure, bar	Temperature, °C.	Pressure, bar	Temperature, °C.
Base case	91.41	27.09	—	—
Density				
0.9	85.56	26.62	−5.85	−0.47
1.1	95.82	27.40	4.41	0.31
Kinematic viscosity				
0.9	91.51	27.10	0.10	0.01
1.1	91.31	27.08	−0.10	−0.01
Specific heat capcity				
0.9	91.74	26.44	0.33	−0.65
1.1	91.13	27.66	−0.28	0.57
Joule-Thompson coefficient				
0.9	91.14	27.63	−0.27	0.54
1.1	91.66	26.59	0.25	−0.50
Isentropic dp/dt coefficient				
0.9	91.34	27.20	−0.07	0.11
1.1	91.48	26.98	0.07	−0.11

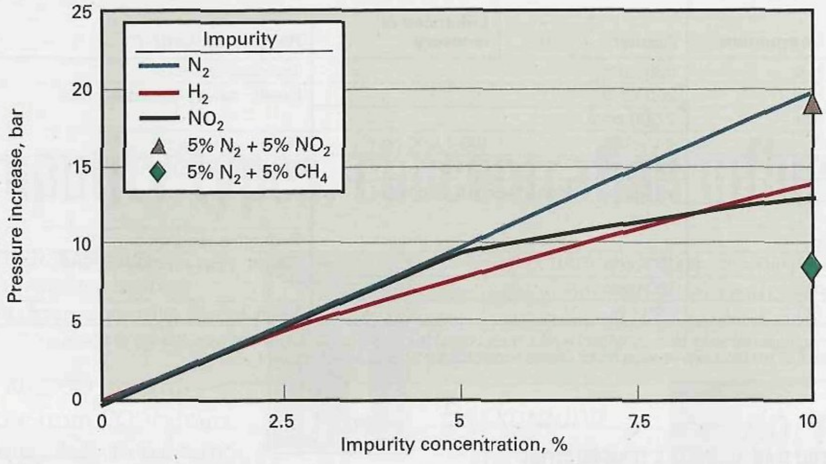
Table 4 presents the influence of impurities on density, viscosity, and vapor pressure of CO_2 streams at 100 bar with different temperatures, using an impurity concentration of 2%. These data were extracted graphically from the report's diagrams and are for illustration purpose only.

SO_2 is the only component increasing stream density compared to pure CO_2, the estimated density for this mixture is very uncertain since no mixture parameters were available. H_2S has a minimal impact on the fluid density while H_2 has a large impact.

Impurities typically will reduce dynamic viscosity (Table 4).

CO_2 STREAM CRITICAL PRESSURE INCREASE, BY IMPURITY

Fig. 1



Impurities affect vapor pressure with the exception of H_2S and SO_2 (Table 4). The values for CO_2-SO_2 mixture are very uncertain, since mixing parameters were estimated and not based on actual measurement data. The presence of impurities also implies the presence of a two-phase region.[3]

Table 4 shows, for example, for a temperature of 30° C. (near CO_2's critical temperature ~31° C.) the vapor pressure of a CO_2 mixture with 2% H_2 is about 8.5 bar higher than that of pure CO_2.

Literature addresses the influence of impurities on critical pressure.[4] Fig. 1 presents the relationships and shows variations of critical pressure of CO_2 streams with different impurities.

Fig. 1 shows the increase of the critical pressure due to impurities is expected to remain moderate (<10 bar) if type and concentration of impurities remain in the ranges estimated in Table 2.

Fluid properties

Estimating the influence of impurities on the results of steady-state pressure and temperature profile calculations assumed modifications of relevant fluid properties of ±10%. Table 5 shows the results of related calculations performed for the hypothetical CO_2 transportation system.

Table 5 shows variations of the CO_2 stream density due to impurities as representing a dominant factor in determining pressure losses along a pipeline system. Accurate determination of the CO_2 stream density regarding the presence of impurities therefore represents the major hurdle for reliable prediction of hydraulic pressure and temperature profiles along a new pipeline system for captured CO_2.

The development of a new CO_2 pipeline system requires estimation of the types and concentration ranges of impurity components of the CO_2 stream. Tables 1 and 2 estimates for this purpose depend on the technologies applied for power generation and carbon capture.

Table 4 and Fig. 1 can estimate the critical pressure of the transported CO_2 stream, defining the minimum operating pressure by considering the sufficient safety distance to the critical pressure.

Table 4 allows estimation of appropriate correction factors for density and viscosity of the CO_2 stream and after selection of an appropriate pipeline diameter, first hydraulic pressure and temperature profiles can be determined applying equations for consecutive pipeline sections from the pipeline system inlet to the system outlet presented in Part 1 of this article.

This procedure provides a straightforward methodology to develop basic hydraulic pipeline profiles for new CO_2 transportation systems, respecting also the influence of impurities on the calculated pressure and temperature profiles.

Economic aspects

After defining minimum operating pressure to avoid two-phase flow, minimizing specific CO_2 transportation costs, including initial investment cost and energy cost to compensate the friction losses, can estimate the optimum pipeline diameter.

Assuming a constant annual CO_2 throughput over the life of the project, the specific CO_2 transportation cost C_{sp} can be estimated with initial investment cost C_{inv}, the annuity factor a, the annual energy cost C_{en}, and the annual mass m_{yr} transported (Equation 1).

Annuity factor a is calculated as a function of interest rate i and number of operating years n (Equation 2).

Initial investment cost C_{inv} depends on parameters in-

EQUATIONS

$$C_{sp} = \frac{C_{inv} \cdot a + C_{en}}{m_{yr}} \quad (1)$$

$$a = \frac{i \cdot (1+i)^n}{(1+i)^n - 1} \quad (2)$$

MAIN INPUT DATA FOR RAW PIPELINE SYSTEM OPTIMIZATION

Table 6

Specific pipeline transportation cost	Unit	Value
Basic process data:		
Density, average	kg/cu m	770
Kinematic viscosity, average	cst, sq mm/sec	0.08
Pump motor efficiency	%	75
Annual operating time	hr	8,322
Specific cost:		
Specific pipeline system cost	€/(in.*m)	39.0
Specific energy cost	€/Mw hr	90.0
Financial data:		
Time period considered	years	20
Interest rate	%/year	10

cluding pipe OD, design pressure, pipe WT, steel and coating delivery cost, and pipelaying cost. Estimates for a new CO_2 pipeline system in the 16-32 in. OD range with a design pressure of about 150 bar using typical western European costs of about €39/(inch*m) yield a price for a 24-in. OD pipeline of roughly 39*24 €/m = €936/linear pipeline m.

Annual energy costs C_{en} are based on a determination of diameter-dependent friction losses of the specific energy costs to operate the injection-transport stations and the annual operation time of the system.

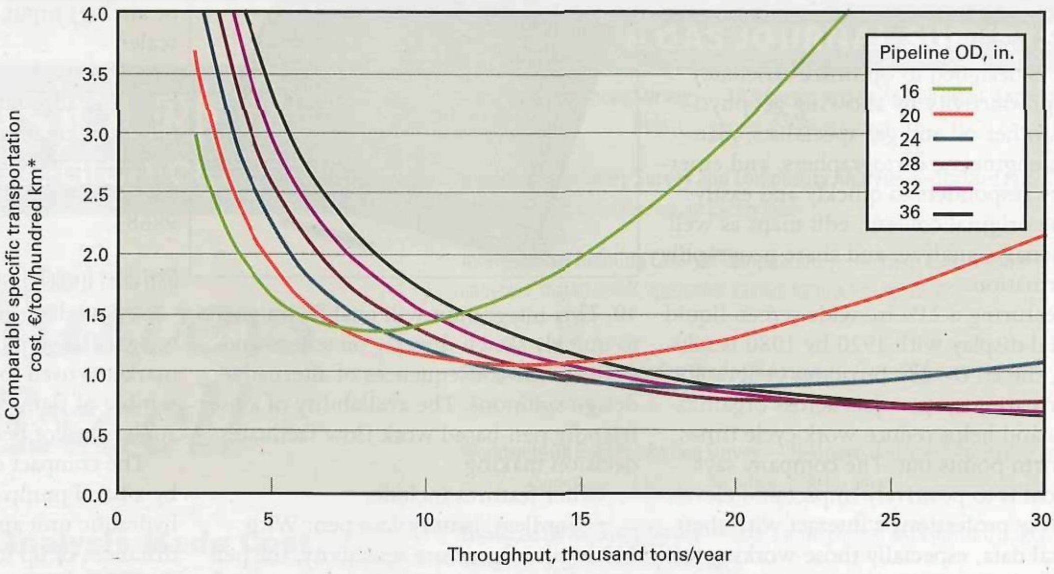
Table 6 shows the main input data used for economic calculations, assuming the CO_2 stream is transported in dense phase at a density of 770 kg/cu m.

Fig. 2 shows the results of raw pipeline system optimization. For transportation of 10 million tons/year CO_2, a 20-in. OD pipeline system would represent the optimum techno-economic solution. The calculated specific transportation cost equals about €1.2/ton at 100 km transportation distance. A 24-in. OD pipeline system could, however, be even more suitable if a future CO_2 throughput expansion were intended (e.g., to 15 million tons/year).

The specific transportation cost shown in Fig. 2, however, reflects only the friction-loss related cost along the pipeline route. The specific cost to compress the CO_2 from the capture pressure level to the dense phase has to be added separately to the specific transportation cost.

DIAMETER OPTIMIZATION

Fig. 2



*Initial compression in head station to 80 bar excluded. Inclusion adds about €9/ton energy cost, €2/ton annuity cost.

The specific shaft rated power demand for CO_2 compression assuming equal stage pressure ratios as well as isentropic and mechanical efficiencies of 0.80 and 0.90, respectively, is about 366 kJ/kg (1 bar/30° C. to 80 bar) and 21 kJ/kg (80 bar/40° C. to 130 bar). Estimates for the shaft rated power demand to compress 1,200 ton/hr CO_2 from 1 bar to 130 bar in the initial station measured about 122 + 7 = 129 Mw. Friction pressure losses inside the compressor station are not addressed.

Assumed specific shaft-rated energy cost of €90/Mw-hr yields a resulting specific compression energy cost of about €9.1/ton CO_2 (1-80 bar) and €0.53/ton CO_2 (80-130 bar). Specific annuity cost of the injection compression station is about €2/ton CO_2.

The intermediate transport station's shaft-rated power demand to increase pressure to 128 bar from 88 bar is about 2.4 Mw, about 1.9% of the compression power demand of the initial station.

The curves shown in Fig. 2 provide only a rough indication of optimum diameter for a given annual CO_2 throughput. Determining the optimum solution in each individual case requires more detailed calculations. ✦

References

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3. Polytec Report No. POL-O-2007-138-A, "State-of-the-Art Overview of CO_2 Pipeline Transport with relevance to Offshore Pipelines," Jan. 8, 2008.
4. Seevam, P.N., Race, J.M., and Downie, M.J., "Carbon dioxide pipelines for sequestration in the UK: an engineering gap analysis," Journal of Pipeline Engineering, Vol. 6, No. 3, pp. 140-141, September 2007.