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NOMENCLATURE

A	gaseous species that is being absorbed into the liquid B in equation (2.34)
$[A]$	local concentration of A at any point in the liquid phase, $kmol.m^{-3}$
$[A^*]$	concentration of dissolved gas A at gas-liquid interface, in equilibrium with gas at interface, $kmol.m^{-3}$
$[A_0]$	concentration of A in bulk of liquid, $kmol.m^{-3}$
a	gas-liquid interfacial area per unit volume of liquid, m^{-1}
AMP	2-amino-2-methyl-1-propanol
B	base in reaction (2.2); or dissolved reactive species present in the liquid phase (equation (2.34))
$[B]$	local concentration of B at any point in the liquid phase, $kmol.m^{-3}$
$[B_0]$	concentration of species B in bulk of the liquid, $kmol.m^{-3}$
D	diffusivity, $m^2.s^{-1}$
D_A	diffusivity of dissolved gas A in the liquid phase, $m^2.s^{-1}$
D_B	diffusivity of reactant B, $m^2.s^{-1}$
D_{CO_2}	diffusivity of dissolved CO_2 in the liquid phase, $m^2.s^{-1}$
D_{N_2O}	diffusivity of dissolved N_2O in the liquid phase, $m^2.s^{-1}$
D_i	diffusivity of species i in the liquid phase, $m^2.s^{-1}$
$D_{CO_2-water}$	diffusivity of CO_2 in water, $m^2.s^{-1}$
$D_{CO_2-amine}$	diffusivity of CO_2 in amine solution, $m^2.s^{-1}$
$D_{N_2O-amine}$	diffusivity of N_2O in amine solution, $m^2.s^{-1}$
$D_{N_2O-water}$	diffusivity of N_2O in water, $m^2.s^{-1}$
d_c	diameter of the wetted wall contactor, m
DEA	diethanolamine
DIPA	di-2-propanolamine
E	enhancement factor defined by equation (2.36), dimensionless
E_{CO_2}	enhancement factor for absorption of CO_2, dimensionless
E_∞	enhancement factor for an infinitely fast reaction regime defined by equations (2.41) and (2.42)
f	vapour pressure of liquid, kPa
g	gravitational acceleration, $m.s^{-2}$
H	Henry's constant, $kPa.m^3.kmol^{-1}$
H_i	Henry's constant of species i, $kPa.m^3.kmol^{-1}$
H_{CO_2}	Henry's constant for CO_2, $kPa.m^3.kmol^{-1}$

H_{N_2O}	Henry's constant for N_2O, $kPa.m^3.kmol^{-1}$
$H_{CO_2-water}$	Henry's constant of CO_2 in water, $kPa.m^3.kmol^{-1}$
$H_{CO_2-amine}$	Henry's constant of CO_2 in amine solution $kPa.m^3.kmol^{-1}$
$H_{N_2O-amine}$	Henry's constant of N_2O in amine solution, $kPa.m^3.kmol^{-1}$
$H_{N_2O-water}$	Henry's constant of N_2O in water, $kPa.m^3.kmol^{-1}$
h	absorption length, m
Ha	Hatta number defined by equation (2.38)
K_i	equilibrium constant of reaction i
k_i	rate coefficient of reaction i
k_{-i}	reverse rate coefficient of reaction i
k_{ij}	forward rate coefficient for reaction j, equations (4.10) – (4.12) and equations (5.1) –(5.6)
k_1	pseudo-first-order rate constant for reaction between A and B, s^{-1}
k_2	second order rate constant for reaction between A and B, $m^3.kmol^{-1}.s^{-1}$
k_b	rate coefficient for reaction (2.2)
k_g	gas phase mass transfer coefficient, $kmol.m^{-2}\,s^{-1}\,kPa^{-1}$
k_L	liquid phase mass transfer coefficient, $m.s^{-1}$
$k_L{}^{/}$	liquid phase mass transfer coefficient in presence of chemical reaction, $m.s^{-1}$
k_{mn}	rate constant for reaction, m^{th} order in A and n^{th} order in B, $(m^3/kmol)^{m+n-1}\,s^{-1}$
l	fractional liquid volume holdup of B phase, dimensionless
MEA	monoethanolamine
MDEA	N-methyldiethanolamine
m	order of reaction with respect to species A
n	order of reaction with respect to species B
N_{Re}	liquid film Reynolds number
P	total pressure, kPa
p_A	partial pressure of species A, kPa
p_{CO_2}	partial pressure of CO_2, kPa
PZ	piperazine
$PZCOO^-$	piperazine monocarbamate
$PZ(COO^-)_2$	piperazine dicarbamate
Q	quantity of gas absorbed by unit area in time of contact θ, $kmol.m^{-2}$
q	total rate of absorption, $kmol.s^{-1}$
R_A	specific rate of absorption of species A, $kmol.m^{-2}.s^{-1}$
R_{CO_2}	specific rate of absorption of CO_2, $kmol.m^{-2}.s^{-1}$

r_{CO_2}	rate of reaction defined by equation (2.4)
S_1, S_2	coefficients in equation (3.13)
s	fractional rate of surface-renewal, s^{-1}
T	temperature, K
t	time, of the order of contact, s
TEA	Triethanolamine
u	velocity of the liquid element at any depth from surface, $m.s^{-1}$
u_s	velocity at surface, $m.s^{-1}$
u_i^0	concentration of species i in the liquid phase, $kmol.m^{-3}$
u_i^*	initial liquid bulk concentration of species i, $kmol.m^{-3}$
u	interfacial concentration of CO_2 in the liquid, $kmol.m^{-3}$
V_G	volumetric gas flow rate, $m^3.s^{-1}$
V_L	volumetric liquid flow rate, $m^3.s^{-1}$
υ_L	volume of clear liquid, m^3
w	film thickness, m
w_{PZ}	mass fraction of PZ in solution
W_{MDEA}	mass fraction of MDEA in solution
W_{AMP}	mass fraction of AMP in solution
x	independent spatial variable, m
x_i	mole fraction of species i in equation (4.5)
α	parameter defined by equations (3.19) and (3.25)
α_1	initial CO_2 loading of the solution in equation (4.18), kmol CO_2/kmol total amine
δ	thickness of diffusion film, m
ϕ_L	fractional liquid volume holdup of B-phase, dimensionless
η	viscosity of the mixture in equation (3.14), mPa.s
λ	reaction plane location measured from the interface, m
μ	viscosity of liquid, $kg.m^{-1}.s^{-1}$ or mPa.s
θ	contact time, s
ρ	density of the liquid, $kg.m^{-3}$
ν	stoichiometric coefficient in equation (2.34)

Chapter 1

INTRODUCTION TO GAS TREATING

1.1   INTRODUCTION

The removal of acid gas impurities such as carbon dioxide (CO_2), hydrogen sulfide (H_2S), and carbonyl sulfide (COS) from industrial gases is an essential step in processing sour natural gas, refinery off-gases, and synthesis gas for ammonia production. The removal of acid gases from gas streams, commonly referred to as acid gas treating and also as gas sweetening, is a technology that has been in use for several years in natural gas processing units, refineries, petrochemicals, and fertilizer industries. In 1930 Bottoms (Bottoms, 1930) presented a process to remove CO_2 using alkanolamines.

CO_2 and H_2S concentrations in the sour natural gas streams may vary widely, from several parts per million to 50% by volume of the gas streams. These impurities when present in the gas streams may lead to very serious problems in pipeline transportation and downstream processing of the gas. CO_2 present in natural gas will reduce the heating value of the gas and may cause corrosion in pipelines and equipment in presence of moisture. Moreover, energy is wasted in compressing this extra volume for pipeline transportation of natural gas. The CO_2 specification in the treated natural gas may be about < 1% by volume for pipeline gas, but for natural gas liquefaction plants CO_2 in the treated natural gas must be below 100 ppm to avoid freezing in the cryogenic equipment. The CO_2 specification is < 10 ppm by volume for treated syngas for ammonia manufacture to protect ammonia synthesis catalyst (Astarita *et al.*, 1983). Bio-generated methane from the decomposition of organic material often contains large amounts of CO_2, which must be removed in order to improve its heating value (Ashare, 1981; Zimmerman *et al.*, 1985). The cleanup target for H_2S is particularly stringent, e.g., 4 ppm by volume for pipeline gas, 0.1 ppm for ammonia synthesis and in petrochemical plants (Astarita *et al.*, 1983). In refinery operations, H_2S must be