Appendix H   Scaling-rules from the oil industry

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1   Scaling-rule after Leverett /LEV 41/

A fundamental scaling-rule was derived by Leverett /LEV 41/. Theoretical considerations for a medium consisting of sphere-like particles were confirmed by experiments with water and air in six different unconsolidated sands. The hydraulic conductivity of the samples varied between 0.7 and 17.2 Darcy[1] and the porosity between 39 % and 49 %. The measurements were performed under saturating as well as de-saturating conditions.

All capillary-pressure-saturation relations (CPS) could be more or less well aligned after multiplying the capillary pressure by the factor

$$\frac{1}{\sigma}\sqrt{\frac{k}{\Phi}} \qquad\qquad\qquad (\,3.1\,)$$

> σ - surface tension at the phase interface [N/m]
> k - permeability [m²]
> Φ - porosity [-]

and thus making the product dimensionless[2]. Leverett concluded that a unique, characteristic, and dimensionless function exists that represents a variety of different sands. This function was later called "J-function":

$$J(S_w)=\frac{p_c}{\sigma}\sqrt{\frac{k}{\Phi}} \qquad\qquad\qquad (\,3.2\,)$$

> $J(S_w)$ - characteristic and dimensionless function (J-function) [-]
> S_w - saturation oft he wetting phase [-]
> p_c - capillary pressure [Pa]

For a specific J-function it must be known which two fluids are present in the pore space in order to quantify the surface tension σ. Additionally, as many data defining the relation between saturation, capillary pressure, permeability and porosity as possible are required. From these data an approach for the saturation-dependent J-function can be formulated that inserted into (3.2) results in a scaling-rule for a specific material. An

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[1] 1 Darcy $\,\widehat{=}\,$ 0,987 10^{-12} m²

[2] The analysis showed also clearly a hysteresis between saturation and de-saturation.

approach that is easy to fit to the data has been found in form of a power law /HAR 01/ (q.v. /IBR 92/):

$$J(S_w) = a\frac{1}{S_w^b}$$ (3.3)

a, b - constants [-]

Later, also the contact angle θ between the interface and the solid phase was introduced in (3.2) to incorporate the influence of the surface structure of the solid phase on the wetting behaviour /ROS 49/:

$$J(S_w) = \frac{p_c}{\sigma \cos \theta}\sqrt{\frac{k}{\Phi}}$$ (3.4)

θ - contact angle between the interface and the solid phase [-]

Including surface tension and contact angle allows to use other fluids in the laboratory for the measurement of the capillary pressure than those that are present in the field. By changing the fluids involved the measurements can be accelerated or the accuracy can be increased. While the surface tension can be measured rather easily in the laboratory the value might be a bit different in the field /HAR 81/. An even higher uncertainty is related to the contact angle. Typical data for conversion of the capillary pressure for different combinations of fluids are compiled in Tab. 3.1.

Tab. 3.1 Surface tension and contact angle for interfaces between brine, mercury, and gas; from /COR 82/ (cited in /HAR 01/)

wetting phase	non-wetting phase	measured in	contact angle θ [°]	surface tension σ [mN/m]
brine	oil	laboratory	30	30
brine	oil	reservoir	30	48
brine	gas	laboratory	0	72
brine	gas	reservoir	0	50
gas	mercury	laboratory	140	480

The applicability of the J-function meaning scaling a known CPS-relation from one rock type to another type of rock is theoretically restricted to rocks with comparable pore space geometry /HAR 01/. Initially, this had not been considered but with increasing examples of applications it was found that the prognosis of capillary forces became much better if a J-function was established for each rock type of a formation /BRO 51/. It was nevertheless common practice for quite some time still to work with just one J-function for a whole reservoir /CUD 93/. Further experience brought to light that this approach works satisfyingly only within a permeability range of two to three orders of magnitude /HAR 01/.

2   Scaling-rule after Thomeer /THO 60/

Another general scaling-rule for the CPS was suggested by Thomeer /THO 60/. It is an empirical approach based on tests involving mercury porosimetry on rock samples that are unfortunately not described in detail.[3] Thomeer states that a plot of the capillary pressure over mercury saturation in a double-logarithmic scale shows a hyperbolic curve. Note that mercury is the non-wetting phase in a mercury-air system. The resulting approach reads:

$$\left(\log p_c - \log p_e\right) \cdot \left(\log S_{nw} - \log\left(1 - S_{wr}\right)\right) = -G \tag{3.1}$$

p_e -   entry pressure [Pa]

G -   geometry factor[4] [-]

S_{nw} -   saturation of the non-wetting phase [-]

S_{wr} -   residual saturation of the wetting phase [-]

With the help of the relations

$$S_{nweff} = \frac{S_{nw}}{1 - S_{wr}} \quad \text{and} \quad S_{nweff} = 1 - S_{weff} \tag{3.2}$$

S_{nweff} -   effective saturation of the non-wetting phase [-]

S_{weff} -   effective saturation of the wetting phase [-]

equation (3.5) can be transformed into

$$p_c = p_e \cdot 10^{\frac{G}{\log\left(1 - S_{weff}\right)}} \tag{3.3}$$

under the condition

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[3] The terminology used in this literature source differs strongly from the terminology of the two-phase flow community working in classic soils. This was a problem encountered often in the literature. Such expressions were therefore translated here into a uniform terminology.

[4] What Thomeer calls "geometry factor" is just a parameter of the hyperbola that is described by his approach. It is not to be confused with the geometry factor commonly used in the groundwater community.

$$S_{wr} \leq S_w \leq 1 \qquad\qquad\qquad\qquad (3.4)$$

According to /THO 60/ the main scaling factors are the entry pressure and the residual saturation of the mercury i.e. the non-wetting phase. The influence of the pore space geometry is taken into account by the geometry factor. This approach is not so much a direct scaling-rule but rather an operative basis for producing a CPS-relations with only few data available. Thomeer admits, though, that there may be significant deviations especially in the steep part of the curve.

Also reported in /THO 60/ is a relation between the gas permeability and the geometry factor. This relation is not quantified but only substantiated by some plots of the permeability over saturation. However, these plots indicate a permeability range of the examined rock samples between 0.001 and 2 Darcy.

3 Scaling-rule after Heseldin /HES 74/

In /HES 74/ another empirical method is introduced which allows to set up a scaling-rule from a larger amount of data consisting of porosity or permeability as well as the related saturation and capillary pressure. It is assumed that measurements are always performed for specific capillary pressures. The whole procedure is described as follows:

– All available data for a certain capillary pressure are plotted as the porosity[5] over the saturation of the non-wetting phase $\overline{S}_{nw}$. Here, the saturation $\overline{S}_{nw}$ related to the pore volume but to the bulk volume.

$$\overline{S}_{nw} = \frac{V_{nw}}{V_b} \qquad (3.1)$$

$\overline{S}_{nw}$ - saturation of the non-wetting phase related to the bulk volume [-]
V_{nw} - volume of the non-wetting phase [m³]
V_b - bulk volume [m³]

with

$$\overline{S}_{nw} = \Phi\, S_{nw} \qquad (3.2)$$

S_{nw} - saturation of the non-wetting phase related to the pore volume [-]
Φ - porosity [-]

This method reduces the scatter of the data and thus helps identifying trends. The saturation of the non-wetting phase is consciously chosen because the resulting best-fit curve is a less curved which is advantageously according to /HES 74/. In the end a relation of the form $\Phi\left(\overline{S}_{nw},\, p_c = const.\right)$ is considered.
– Based on the data plot a best-fit curve for the porosity is determined. In /HES 74/ a hyperbolic approach is preferred

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[5] Theoretically also the permeability could be used instead of the porosity. For practical reasons porosity is preferable, though, because it is determined with much less effort by "core logging" than the permeability.

$$(\overline{\Phi} - A)^2 = \overline{S}_{nw}^2 + B^2 \qquad\qquad (3.3)$$

$\overline{\Phi}$ -   porosity [%]

A, B -   parameters of the best-fit curves for the porosity [-]

but in principle other types of curves would be feasible also.

– This process is then repeated for other capillary pressures.

– Then the parameters A and B for the best-fit curves are plotted over the capillary pressure allowing to formulate a relation between A and B, respectively, and the capillary pressure. Now the parameters $A(p_c)$ and $B(p_c)$ of the chosen ansatz function for the porosity are quantified and result in a continuous multidimensional formulation for the porosity $\Phi\left(\overline{S}_{nw}, p_c\right)$.

– In the last step an inverse function $p_c\left(\overline{S}_{nw}, \Phi\right)$ containing the porosity as a parameter has to be determined.

This process is illustrated in /HES 74/ by an example for an unspecified boring campaign. The determined data cover a porosity range of 2 % up to 24 % and a range of the capillary pressure between 50 psia and 1000 psia. The resulting parameters A and B are plotted in this example in a half-logarithmic scale over the capillary pressure allowing to draw straight lines as best fit curves for the parameters A and B:

$$\begin{aligned} A &= a + b \log p_c \\ B &= c + d \log p_c \end{aligned} \qquad\qquad (3.4)$$

a, b, c, d -   parameters of the best-fit curves for the parameters A and B [-]

p_c -   capillary pressure [psia[6]]

The resulting parameters a to d are quantified as $a = 4.02214, b = -0.989722,$ $c = 10.85097, d = -3.01721$ but relate to measurements with mercury and air. Conversion into a fluid system of brine and air can be done with the help of Tab. 3.1:

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[6] 1 psia = 6895 Pa

$$p_{c\,H_2O-Gas} = p_{c\,Hg-Gas} \frac{\sigma_{H_2O-Gas} \cos\theta_{H_2O-Gas}}{\sigma_{Hg-Gas} \cos\theta_{Hg-Gas}}$$

(3.5)

index $H_2O - Gas$ - water/brine-air system

index $Hg - Gas$ - mercury-air system

According to this conversion the capillary pressure between brine and air is lower than between mercury and air by a factor of 0.196 or 0.136, repectively, depending on whether laboratory or field based data is used. In the example from /HES 74/ the resulting scaling-rule reads

$$p_c = 10^{\left\{ \frac{1}{2f} \left(-g + \sqrt{g^2 - 4fh} \right) \right\}}$$

(3.6)

f, g, h - auxiliary functions [-]; (q.v. (3.15))

with

$$\begin{aligned}
f &= b^2 - d^2 \\
g &= 2\left(-ab + cd + b\overline{\Phi} \right) \\
h &= a^2 - c^2 - 2a\overline{\Phi} + \overline{\Phi}^2 - \left(1 - S_w \right)^2
\end{aligned}$$

(3.7)

S_w - saturation of the wetting phase related to the pore volume [-]

and in SI units

$$p_c = 6895 \cdot 10^{\left\{ \frac{1}{2f} \left(-g + \sqrt{g^2 - 4fh} \right) \right\}}$$

(3.8)

The scaling-rule of /HES 74/ is an exclusive function of the porosity. However, it works apparently only for materials for which a certain amount of data has already been collected.

4   Scaling-rule after Swanson /SWA 81/

Bases for the scaling-rule after Swanson /SWA 81/ are empirical observations on Sandstone and carbonate rock. It appeared that the ratio of the saturation of the non-wetting phase to the capillary pressure is linear proportional to the permeability of brine if plotted in a double-logarithmic scale:

$$k = a \left(\frac{\Phi S_{nw}}{p_c} \right)^b$$

(3.1)

k -   brine permeability [Darcy]

Φ -   porosity

S_{nw} -   saturation of the non-wetting phase [%]

p_c -   capillary pressure [psia]

a, b -   parameters[7]

The investigation covers a permeability range between 0.001 and 10 Darcy and capillary pressures up to approx. 600 psia. For sandstone and the fluids mercury and air the parameters a and b are quantified as $a = 431$ and $b = 2.109$. For carbonate rock they amount to $a = 290$ and $b = 1.901$. If unable to differentiate between these two rock types the use of $a = 355$ und $b = 2.005$ is suggested.

A scaling-rule can easily derived by rearranging (3.17):

$$p_c = \left(\frac{a}{k} \right)^{\frac{1}{b}} \Phi \, S_{nw}$$

(3.2)

The exponent $1/b$ for the regression for both rock types corresponds nicely to the square root in the scaling-rule after /LEV 41/. However, the dependency on the porosity is linear according to /SWA 81/ while the capillary pressure is proportional to the square root in /LEV 41/.

Transformed into SI units scaling-rule (3.18) reads

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[7] The dimension of the parameters cannot be given because equation (3.17) is dimensionally incorrect.

$$p_c = 6895 \left(\frac{0,987 \cdot 10^{-12}\, a}{k} \right)^{\frac{1}{b}} \Phi\, S_{nw} \qquad\qquad (\,3.3\,)$$

5   Scaling-rule after Johnson /JOH 87/

Also the scaling-rule after Johnson /JOH 87/ is not derived by theoretical means but is based on empirical observations on reservoir rocks in the North Sea. Here, a linear relation between porosity and permeability in double-logarithmic scale was found:

$$\log S_w = a \log k + b \qquad (3.1)$$

S_w - saturation of the wetting phase [%]

k - permeability [mD]

a, b - constants [-]

The observed straight lines appeared also to be shifted parallel for different capillary pressures. Based on the mean slope $\overline{a}$ of these lines (3.20) can be written as

$$\log S_w = \overline{a} \log k + \overline{b} \qquad (3.2)$$

$\overline{a}, \overline{b}$ - Konstanten for the line with a mean slope [-]; $\overline{a} = -0.223$

The remaining summand $\overline{b}$ depends on the capillary pressure also linearly in a double logarithmic scale.

$$\log \overline{b} = \log c + d \cdot \log p_c \qquad (3.3)$$

p_c - capillary pressure [psi]

c, d - constants [-]; $c = 2.301, d = -0.047$

Combining (3.21) and (3.22) results eventually in

$$\log S_w = \overline{a} \log k + c(p_c)^d \qquad (3.4)$$

or

$$p_c = \left[\frac{1}{c} \log\left(\frac{S_w}{k^{\overline{a}}} \right) \right]^{\frac{1}{d}} \qquad (3.5)$$

Scaling-rule (3.24) depends beside on the saturation only on the permeability but not on porosity. Johnson concedes that while the method has been applied quite effectively to the formations in the North Sea it might not be universally applicable. The samples

investigated had permeabilities between 1 mD and 10 D, porosities between 15 % and 29 % and a capillary pressure between 1 psi und 180 psi[8] related to a brine-air fluid-system.

Related to a mercury-air fluid-system the scaling-rule reads in SI units

$$p_c = 6895 \left[\frac{1}{c} \log \left(S_w \left\{ \frac{k}{0{,}987 \cdot 10^{-15}} \right\}^{-\overline{a}} \right) \right]^{\frac{1}{d}} \tag{3.6}$$

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[8] 1 psi $\stackrel{\wedge}{=}$ 6895 Pa

6   Scaling-rule after Prickett and Bremer /PRI 89/

The scaling-rule after Prickett and Bremer /PRI 89/ is based on bore cores of rocks from a large oil reservoir in Saudi Arabia as well as the J-function (3.2) after /LEV 41/. Data for 11 different rocks – limestones and dolomites – were evaluated according to the following approach

$$S_w = \frac{a + S_{wr}(J-b)^c}{a + (J-b)^c}$$ (3.1)

S_w -   saturation of the wetting phase [-]
S_{wr} -   residual saturation of the wetting phase [-]
J -   J-function [-]
a, b, c -   parameters [-]; (q.v. Tab. 3.2)

and the parameters a to c as well as the residual saturation of the wetting phase S_{wr} determined. Inserting (3.4) into (3.26) yields the scaling-rule

$$p_c = \left[\left(a\frac{1-S_w}{S_w - S_{wr}} \right)^{\frac{1}{c}} + b \right] \frac{\sigma \cos\theta}{0,217} \sqrt{\frac{\Phi}{k}}$$ (3.2)

p_c -   capillary pressure [psi]
σ -   surface tension [dyn/cm][9]
θ -   contact angle [-]
Φ -   porosity [-]
k -   permeability [mD]

The measured data and thus the determined parameters are based on a water-oil fluid-system. The capillary pressure for the phases brine and air can be calculated analogously to (3.13):

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[9] 1 dyn/cm = 10^{-3} N/m

$$p_{c\,H_2O-gas} = p_{c\,H_2O-oil} \frac{\sigma_{H_2O-gas} \cos\theta_{H_2O-gas}}{\sigma_{H_2O-oil} \cos\theta_{H_2O-oil}}$$

(3.3)

index $H_2O - gas$ - water/brine-air fluid-system

index $H_2O - oil$ - water-oil fluid-system

The capillary pressure at the brine-air interface is therefor higher than at the brine-oil interface by a factor of 1.73 or 1.92, respectively, depending on whether laboratory or field based data is used from Tab. 3.1.

To come up with a scaling-rule a porosity-permeability (PP) relation was derived based on 17 samples:

$$\ln k = A + B\Phi + C\Phi^2$$

(3.4)

A, B, C - constants [-]; (q.v. Tab. 3.2)

Tab. 3.1   Measured data to derive the parameters in (3.27) und (3.29);
from /PRI 89/

COEFFICIENTS USED TO CALCULATE S_{wi} FROM J_{sw} [1]

J-Function	a	b	c	S_{wi}
Zone-A - Limestone	0.49437	0.06	0.76249	0.00
Zone-B - Limestone				
k greater than 100 md	0.52760	0.06	0.81906	0.06
k less than 100 md	0.10744	0.06	1.68320	0.06
Zone-C - Limestone				
k greater than 10 md	0.43198	0.06	0.78955	0.06
k less than 10 md	0.23478	0.06	1.06193	0.035
Zone-D - Limestone				
k greater than 1 md	0.47899	0.06	0.49035	0.06
k less than 1 md	0.36449	0.06	0.72292	0.00
Zone-E - Limestone	0.53767	0.06	0.48656	0.06
Zone-A - Dolomite	0.05414	0.05	0.49209	0.00
Zone-B+C - Dolomite	0.17386	0.05	0.40551	0.00
Zone-D+E - Dolomite	0.24931	0.05	0.34594	0.00

[1]

$$S_{wi} = \frac{a + S_{iw}\,(J_{sw} - b)^C}{a + (J_{sw} - b)^C}$$

COEFFICIENTS FOR Ø-k TRANSFORMS [1]

LIMESTONES

LAYERS	A	B	C	max Ø	max k (md)
1,5,6	-3.106	35.04	- 55.41	0.316	272
2,7	-2.275	26.62	- 37.30	0.357	297
3	-1.937	20.78	- 20.85	0.350	603
4	-3.672	34.78	- 41.73	0.304	1117
8,10	-2.912	26.00	- 28.01	0.397	998
9,11	-2.672	26.04	- 31.52	0.394	495
12,14,16	-4.648	60.08	-127.80	0.235	258
13,15,17	-4.577	60.53	-141.69	0.214	77

DOLOMITES

LAYERS	A	B	C	max Ø	max k (md)
1,2	-4.299	57.80	-145.06	0.199	29
5,6	-4.327	67.33	-143.37	0.235	3785
3,4,7-15	-4.309	67.93	-143.06	0.222	609

1
    log k = A + BØ + CØ[2] ; Ø in fraction,
                              k in md

    if Ø greater than or equal max Ø , use max k

It was stressed here that the PP-relation should also be valid for a low porositiy and a low permeability (k < 1 mD). An upper limit for the permeability was determined as follows:

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$$k_{max} = f\left(\Phi_{max}\right) \quad \text{und} \quad k = k_{max} \quad f\ddot{u}r \quad \Phi > \Phi_{max}$$

(3.5)

Maximum permeability was found to lie between 29 and 3785 mD and maximum porosity between 19.9 to 39.4 %. The determined maximum values for porosity and permeability were found to be only weakly correlated, though.

Formulated for SI units the scaling-rule (3.27) and the PP-relation (3.29) are written as

$$p_c = 6895\left[\left(a\frac{1-S_w}{S_w - S_{wr}}\right)^{\frac{1}{c}} + b\right]\frac{\sigma}{10^{-3}}\cos\theta\sqrt{\frac{\Phi\, 0.987 \cdot 10^{-15}}{k}}$$

(3.6)

and

$$\ln k = A + B\Phi + C\Phi^2 + \ln 0{,}987\, 10^{-15}$$

7　　　Scaling-rule after Ibrahim et al. /IBR 92/

A scaling-rule for a water-air fluid-system in low permeable sands is set up by Ibrahim et al. /IBR 92/ based on Leverett's J-function and an extensive set of data[10] starting with the approach

$$p_c = \frac{a}{S_w^b}$$

(3.1)

p_c　-　capillary pressure [dyn/cm]

S_w　-　saturatin of the wetting phase [%]

a,b　-　parameters [dyn/cm], [-]

Evaluation the same data according to the J-function (3.4) leads to

$$J = \frac{\alpha}{S_w^\beta}$$

(3.2)

α, β　-　parameters [-], [-]; $\alpha = 0.039, \beta = 2.308$

Combining (3.4) and (3.33) results in the scaling-rule

$$p_c = \frac{\alpha}{S_w^\beta} \sigma \cos\theta \sqrt{\frac{\Phi}{k}}$$

(3.3)

σ　-　surface tension [dyn/cm]; $\sigma = 74$ dyn/cm

θ　-　contact angle between wetting and solid phase [°][11]

Comparing (3.32) and (3.34) reveals that parameter a in (3.32) includes physical constants σ and θ, ansatz constant α and the square root for the scaling transformation. Identity of b und β is called an approximation in /IBR 92/. The bandwidth of the parameters for the examples cited there are compiled in Tab. 3.3.

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[10] The treatment in /IBR 92/ is remarkable in that not only the related RPS-relations for the wetting and the non-wetting phase are derived but this is also done separately for saturating and desaturating conditions. Additionally, a rule of thumb for estimating the residual saturation of the non-wetting phase can be found.

[11] The contact angle θ is given in /IBR 89/ with a value of 90°. From this would follow $\cos\theta = 0$, though. Probably the value $\theta = 0°$ is rather meant which is indirectly confirmed in /CUD 93/.

Tab. 3.1   Bandwidth of parameters for the examples presented in /IBR 92/

quantity	dimension	value$_{min}$	value$_{max}$
a	-	5	22
k	mD	0,05	0,3
Φ	%	7,9	12,5

Modifying the CPS relation (3.34) for usage of parameters in SI-units leads to

$$p_c = 0{,}2166 \frac{\alpha}{S_w^{\beta}} \sigma \cos \theta \sqrt{\frac{\Phi}{k}} \qquad (\,3.4\,)$$

8 Scaling-rule after Cuddy et al. /CUD 93/

A scaling-rule that is equivalent to (3.34) is also derived by /CUD 93/[12]. Typical input data for this approach referring to formations in the southern North Sea and a water-gas system are $\alpha = 0,06, \beta = 2,31, \sigma = 74 dyn/cm$ and $\theta = 0°$. According to /HAR 01/ the relation was applied using porosities in the range of 5 % – 20 % and permeabilities in the range of 0.1 mD – 10 mD.

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[12] Noteworthy is here a rule of thumb for the PP-relation for rock formations in the southern North Sea.

9   Scaling-rule after Skelt and Harrison /SKE 95/

Skelt and Harrison state that many site-specific approaches for the saturation-height relation have been established based on bore core or log data. Exemplarily they cite a list of 5 strongly differing approaches from /CUD 93/ and criticize that the referring parameters have no physical meaning. As an alternative they suggest the following relation

$$p_c = -\frac{b}{\left[-\ln\left(\frac{1-S_w}{a}\right)\right]^{\frac{1}{c}}} - d$$

(3.1)

p_c - capillary pressure [psi]

S_w - saturation of the wetting phase [-]

a - horizontal shift of the CPS-curve [-]

b - linear factor for a vertical scaling [psi]

c - non-linear factor for a vertical scaling [13] [-]

d - vertical shift of the CPS-curve [psi]

According to /SKE 95/ the parameter a in the CPS-relation (3.36) can also be written as

$$a = 1 - S_{wr}$$

(3.2)

S_{wr} - residual saturation of the wetting phase [-]

The argument of the logarithm thus corresponds to the effective saturation

$$S_{nw\,eff} = \frac{1-S_w}{1-S_{wr}}$$

(3.3)

$S_{nw\,eff}$ - effective saturation of the non-wetting phase [-]

Parameter d can be interpreted as a gas entry pressure p_e:

$$p_e = p_c(S_w = 1)$$

(3.4)

p_e - gas entry pressure [psi]

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[13] /HAR 01/ comment that the parameter c is usually close to 1.

The CPS-relation (3.36) can therefore also be written as

$$p_c = -\frac{b}{\left[-\ln\left(S_{nw\,eff}\right)\right]^{\frac{1}{c}}} - p_e$$

(3.5)

Exemplarily a parameter fit is presented by /SKE 95/ for each of two not specified sites in the North Sea. The resulting parameters are compiled in Tab. 3.4. Apparently, this CPS-relation has also been successfully used in South America and in Asia /HAR 01/.

Tab. 3.1   Two examples for the parameters for the CPS-relation after /SKE 95/

	b	c	p_e	S_{wr}
example 1	2,35	0.792	0	0,209
example 2	24,60	0,900	0	0,070

The CPS-relation after /SKE 95/ is not really a scaling-rule because neither permeability nor porosity appear in formulation (3.40). A certain scaling would be possible only indirectly via the gas entry pressure p_e if a relation between p_e and the porosity or the permeability were known.

No difference is made in /SKE 95/ between oil and gas as the non-wetting phase. Instead both fluids are denoted as "hydrocarbons". The surface tension of 10 – 20 dyn/cm, however, stated to be a typical value under in-situ conditions indicates a water-oil system according to Tab. 3.1. This would have to be corrected for a brine-gas system by a factor 1.73 or 1.92, respectively.

Modifying the CPS relation (3.40) for usage of parameters in SI-units leads to

$$p_c = -\frac{6895\,b}{\left[-\ln\left(S_{nw\,eff}\right)\right]^{\frac{1}{c}}} - p_e$$

(3.6)

10 Scaling-rule after Ding et al. /DIN 03/

In /DIN 03/ it is suggested to combine the J-function (3.3) with the approach

$$J(S_w) = a\, e^{b\, S_w} \qquad\qquad (3.1)$$

S_w - saturation of the wetting phase [-]

a, b - parameters [-]

This approach is claimed to be better fitting especially for hydraulically tighter gas reservoirs. From this consideration results the scaling-rule

$$p_c = a\ e^{b\, S_\cdot}\, \sigma \cos\theta \sqrt{\dfrac{\Phi}{k}} \qquad\qquad (3.2)$$

Actual values for the parameters are not given in /DIN 03/. A comparison of approach (3.42) with (3.3) or (3.33), respectively, indicates that b in (3.42) is negativ. The parameters from /IBR 92/ are used for concrete applications.

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