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New correlations for predicting two-phase electrical submersible pump performance under downhole conditions using field data

Thuy Chu[1] · Tan C. Nguyen[1] · Jihoon Wang[2] · Duc Vuong[3]

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Abstract
Electrical Submersible Pump (ESP) is one of the major Artificial Lift methods that is reliable and effective for pumping high volume of fluids from wellbores. However, ESP is not recommended for applications with high gas liquid ratio. The presence of free gas inside the pump causes pump performance degradation which may lead to problems or even failure during operations. Thus, it is important to investigate effect of free gas on ESP performance under downhole conditions. At present, existing models or correlations are based on/verified with experimental data. This study is one of the first attempts to develop correlations for predicting two-phase gas–liquid pump performance under downhole conditions by using field data and laboratory data. Field data from three oil producing wells provided by Strata Production Company and Perdure Petroleum LLC. as well as experimental data obtained from experimental facility at Production and Drilling Research Project—New Mexico Tech were used in this study. Actual two-phase pump differential pressure per stage is obtained from experiments or estimated from field data and was normalized using pump performance curve. The values are compared to pump performance curve to study the relationships between pump performance and free gas percentage at pump intake. Correlations to predict ESP performance in two-phase flow under downhole and experimental conditions was derived from the results using regression technique. The correlation developed from field data presented in this study can be used to predict two-phase ESP performance under downhole conditions and under high gas fraction. The results from the experimental data confirm the reliability of the developed correlation using field data to predict two-phase ESP performance under downhole conditions. The developed correlation using the laboratory data predicts quite well the two-phase pump performance at the gas fraction of less than 15% while it is no longer reliable when free gas fraction is more than 15%. The findings from this study will help operating companies as well as ESP manufacturers to operate ESPs within the recommended range under downhole conditions. However, it is recommended to use the proposed correlation on reservoirs with conditions similar to those of the three presented wells.

Keywords Electrical Submersible Pump · Pump performance · Free gas · Correlation

Abbreviations

Variables

n	Pump speed (RPM)
P	Pressure (P)
r	Radius (L)
SG	Specific gravity
TVD	True vertical depth (L

✉ Thuy Chu
thuy.chu@student.nmt.edu

[1] New Mexico Tech, Socorro, USA

[2] Hanyang University, Seoul, South Korea

[3] Deepcast Company, Houston, USA

Subscript

cal	Calculated
dis	Discharge
elev	Elevation
fric	Friction
g	Gas
int	Intake
mea	Measured
o	Oil
sp	Single-phase
stage	Per pump stage
ti	Inner tubing
tp	Two-phase

Greek letter

Δ	Differential

Introduction and literature review

Electric submersible pump (ESP) is a multistage centrifugal pump. An ESP system consists of surface equipment (transformer, switchboard, junction box and wellhead) and subsurface equipment (electric motor, protector, pump and cable) as shown in Fig. 1. A single stage consists of a rotating impeller inside a stationary diffuser via a shaft connected with a subsurface electric motor. The operating motor generates heat due to its inefficiency. Produced formation fluid will then carry this heat up to the surface and cool the motor. If motor temperature exceeds the recommended operating temperature, the life time of the system is reduced and eventually fail. According to Nguyen (2020), motor overheating is one of the leading causes of ESP failure.

In multiphase flow, the presence of gas inside ESP negatively impacts the pump performance. A significant volumes of free gas leads to a change in fluid mixture properties (density, viscosity, specific heat and thermal conductivity) causing changes in pump pressure and heat absorption ability of production fluid. In wells with high Gas Oil Ratio (GOR), gas separator is usually installed in order to vent free gas up the annulus. In spite of that, there can still be an amount of free gas entering ESP negatively affects pump performance when efficiency of gas separator is not high enough.

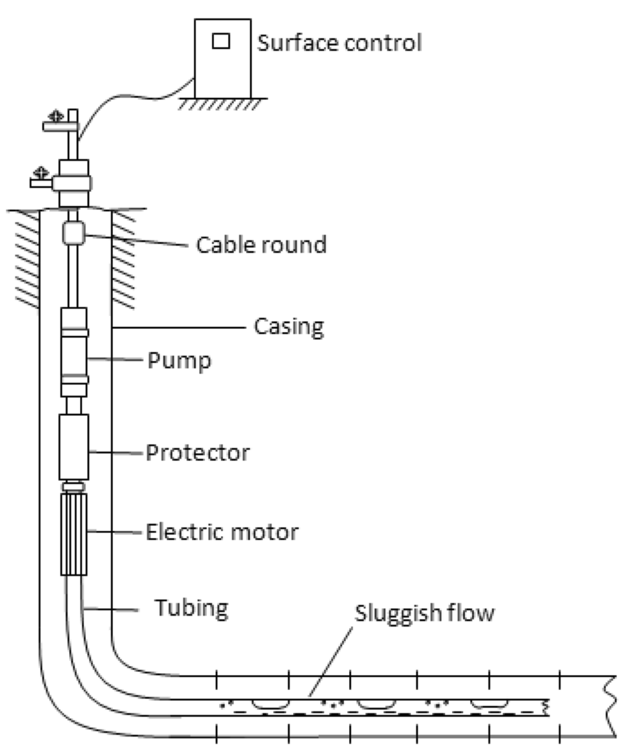


Fig. 1 Schematic of an ESP system

When high amount of free gas enters an ESP, gas velocity increases while liquid phase inside the pump is slow down causing a sudden decrease in pump pressure. This problem is called surging. When surging occurs, fluid flow fluctuates and pump may vibrate considerably resulting in shorter pump life or even failures. In case pump cavities are filled by free gas entirely, pump only provides minimal amount of energy to production fluid and subsequently there is no production at the surface. This problem is called gas-locked.

There have been many experimental studies as well as modeling attempts to understand and simulate ESP performance in two-phase flow. Even though many correlations and models were developed, most of them have been only partially validated. Table one shows a summary of experimental study of ESP under two phase conditions at the Tulsa University Artificial Lift Project. This summary was conducted by Zhu and Zhang (2017). All of these works were conducted under low pressure conditions to study the effects of gas on the ESP's performance.

Murakami and Minemura (1974) reported that pump head decrease as the amount of air increases while head of each impeller remains pretty constant. Lea and Bearden (1982) conducted experiments using diesel and CO_2 to observe performance of radial and mixed flow type pumps. Their results were later adopted by Turpin et al. (1986) to develop empirical correlations. After that, many experimental studies on the subject were conducted.

Pessoa (2001) observed and evaluated pump performance using water–air across each stage on the basis of average pump efficiency and average brake horse power consumption. His results shown that performance of the first few pump stages severely degrades due to effect of gas and may have negative pump pressure. Banjar et al. (2013) conducted a test using pump DN-1750 to investigate effects of both viscosity and gas on ESP performance and concluded that viscosity has an important impact on surging initiation.

The simplest approach to present two-phase flow is to treat it as a homogeneous mixture. Homogeneous models assume that both liquid and gas phases behave as a homogeneous mixture, their velocities are identical and equal to the homogeneous velocity. Hence, this approach usually over estimate pump performance due to assumptions, especially when surging occurs.

Many approaches were made as well. Sachdeva et al. (1991) developed a dynamic model that accounts for pump geometry, fluid properties, intake pressure and void fraction. However, the simulation could not predict events of surging. Zhu et al. (2018) proposed a mechanistic model to determine ESP performance in single-phase and two-phase flow. The model was based on the Euler equation for centrifugal pump. Their results matched well with experimental data yet further improvements on closure relationships were needed. Estevam et al. (2005) introduced a mechanistic model that focused on the two-phase flow model which was based relationship in order to correlate experimental data. In this work, flow regimes as well as surging region inside a pump could be determined.

Turpin et al. (1986) proposed a correlation for I-42B and K-70 pumps using experimental results from Lea and Bearden (1982).

$$H = H_{sp} \exp\left[-\frac{Q_g}{Q_l}\left(\frac{346430}{(C_1 P_{in})^2}\frac{Q_g}{Q_l} - \frac{3410}{C_1 P_{in}}\right)\right] \tag{1}$$

where H_{sp} and H are pump head in single-phase and two-phase flow in ft respectively, Q_l and Q_g are liquid and gas rates in B/D respectively, P_s is pump intake pressure in psi, $C_1 = 0.145$ is a unit conversion constant.

Sachdeva et al. (1992) developed a correlation that used different constant for different pumps using data from Lea and Bearden (1982). For I-42B pump, $K = 1.154562$, $E1 = 0.943308$, $E2 = -1.175596$, $E3 = -1.300093$. For K-70 pump, $K = 0.0936583$, $E1 = 0.622180$, $E2 = -1.350338$, $E3 = -0.317039$.

$$\Delta P = K P_{in}^{E1} \alpha_{in}^{E2} (0.02917 Q_L)^{E3} \tag{2}$$

where ΔP is pump pressure per stage in two-phase flow in psi, α_{in} is pump stack inlet void fraction, Q_L is liquid flow rate in B/D.

Duran and Prado (2004) proposed a model applicable for head degradations in bubbly and elongated bubble flow regimes (Eqs. (3) and (4)).

$$\Delta P = (1-\alpha)\rho_l H \frac{Q_l}{1-\alpha} + \alpha \rho_g H \frac{Q_g}{\alpha} \tag{3}$$

$$\Delta P = -0.47075 - 0.2163 \ln\left(\frac{Q_g(1-\alpha)}{Q_{max}}\right) \tag{4}$$

There are other correlations yet the use of empirical correlations is very limited in general because they were developed using experimental data from specific setup and testing condition. This study is one of the first attempts to develop correlations for predicting two-phase gas–liquid pump performance under downhole conditions by using field data and laboratory data. Future work will attempt to derive analytical solution for the model similar to how Nguyen et al. (2021) approached the progressive cavity pump.

Methodology

ESP performance in two-phase flow was investigated using field data from three producing oil well by Strata Production Company and Perdure Petroleum LLC. Available data are well completion, fluid properties, production rate, ESPs in use and their operating parameters in real-time. From the available data, actual pump differential pressure per stage in gassy flow under downhole conditions is estimated. The estimated values are compared to pump performance curve in order to investigate relationships between pump performance and free gas percentage at pump intake. A correlation to predict ESP performance in two-phase flow under downhole conditions was derived from the results.

Experimental tests were conducted using the ESP Testing Facility at the Production and Drilling Research Project—New Mexico Tech as shown in Fig. 2 to study the impact of gas on a 20-stage ESP. Water and air were used as testing fluids. This ESP testing facility allows us to simulate tests under different pump speeds, water air ratio, pump intake and discharge pressures, etc. The computer data acquisition system allows us to record pump performance under single-phase and two-phase flow conditions.

Water from a liquid tank goes into pipes connecting to the pump intake. The amount of water is measured using liquid flow meter. Gas is injected into the pipeline before reaching the pump intake. The amount of gas injected is controlled using valves and is measured using gas flow meter. The water and injected gas go through the pump and to a gas/liquid separator where liquid and gas phases are separated to ensure only water goes back to the liquid tank. There are sensors measuring pressure at the pump intake and outtake. In this study, the amount of gas and pump speed are controlled to observe the pump performance in two-phase flow.

During a test, liquid and gas flow rates, pump intake and discharge pressures, gas pressure and temperature were monitored constantly to study pump performance under gassy flow conditions. At first, pump performance in single-phase was experimented in order to obtain pump performance curves at different pump speed. Then, at a specified point on pump performance curve, the amount of gas injected into the flow was adjusted to get pump performance at different free gas percentage. The performances in two-phase and single-phase were compared to investigate relationships between pump performance and free gas percentage at pump intake. A correlation to estimate ESP performance in two-phase flow under laboratory conditions was developed from the experimental data Table 1.

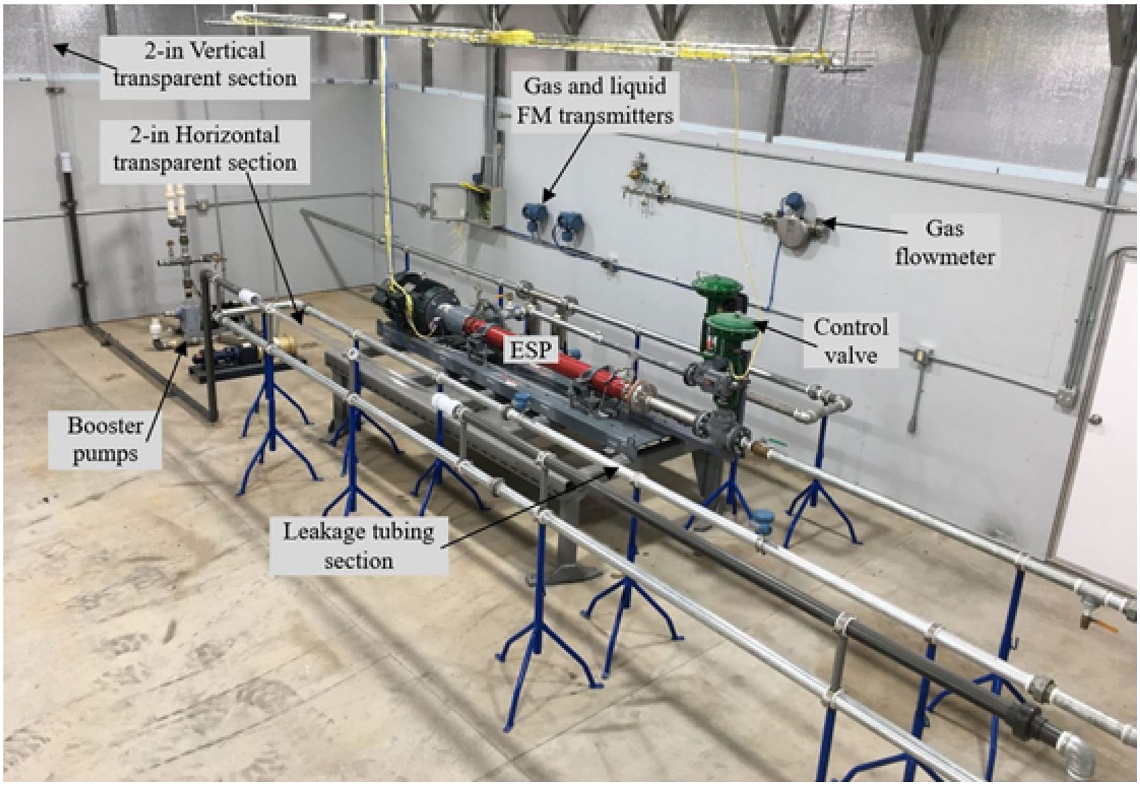


Fig. 2 ESP testing facility at Production and Drilling Research Project—New Mexico Tech

Table 1 Experimental study of ESP performance in gassy flow at Tulsa University Artificial Lift Projects (Zhu and Zhang, 2017)

Authors	Study	Pump	Fluid
Cirilo (1998)	Compare two-phase flow performance of three different ESPs	GN4000 GN7000	Air/water
Romero (1999)	ESP gas–liquid performance with an advanced gas handler installed upstream	GN4000	Air/water
Pessoa (2001)	Measure stage-by-stage pump pressure increment of a multistage ESP	GC6100	Air/water
Beltur (2003)	Investigate pressure surging in ESP and affecting factors	GC6100	Air/water
Duran (2003)	Correlate experimental data of ESP two-phase performance	GC6100	Air/water
Zapata (2003)	Investigate pump rotational speed effect on ESP two-phase performance	GC6100	Air/water
Barrios (2007)	Visualize the internal flow of a 2nd stage ESP under gas/liquid flow conditions	GC6100	Air/water
Gamboa (2007)	Visualize ESP two-phase flow pattern using a similar pump prototype as Barrios	GC6100	Air/water
Trevisan (2009)	Visualize ESP internal flow under air/viscous liquid flow	GC6100	Air/oil visualization
Banjar (2013)	Investigate ESP performance with air/oil flow	DN1750	Air/oil
Salehi (2012)	Investigate ESP gas/liquid performance with various flow conditions	TE2700	Air/water
Croce (2014)	Investigate ESP performance with water/oil emulsion flow	DN1750	Oil/water emulsion
Zhu (2017)	Investigate ESP gas/liquid flow performance with/without surfactant injections	TE2700	Air/water surfactant

Table 2 Wells from which field data were obtained

Well	Location
Sandy federal 001	Eddy, New Mexico
Roadrunner federal 002H	Eddy, New Mexico
Farnsworth unit 1314	Ochiltree, Texas

Results and discussion

To study how the gas–liquid two-phase flow in an ESP affects the pump performance, field data from three producing oil well were used. The wells are listed in Table 2. Available data are well completion, fluid properties,

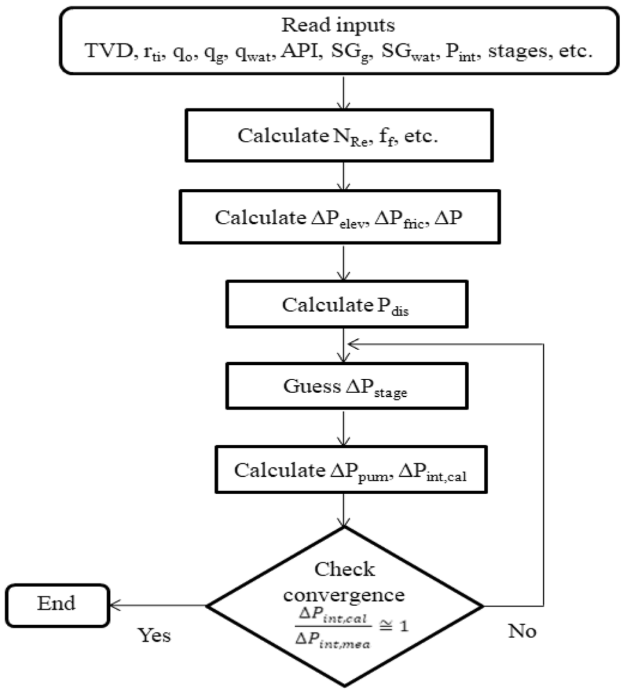


Fig. 3 Procedure to determine actual pump pressure per stage

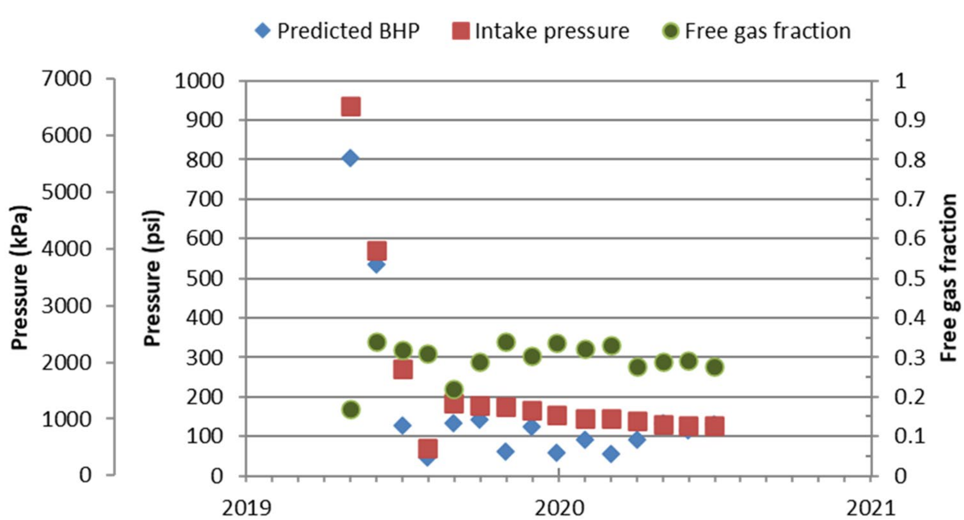
production rate, ESPs in use and their operating parameters in real-time.

Because actual pump differential pressure per stage under downhole conditions is unknown, a software application developed by the Permian Basin Software Company of New Mexico, was used to predict the actual pump performance. Figure 3 shows the solution procedure of the program. The inputs are well geometry, fluid properties, actual pump intake pressure and number of pump stage. Froude number and input liquid content is calculated to determine flow type. After that, liquid hold-up, correction factor, Reynolds number and friction factor are calculated to determine flow patterns and pressure drops inside the tubing due to elevation and friction. From wellhead pressures, pump discharges are estimated. Next, a guessed pump differential pressure per stage (ΔP_{stage}) is input, pump pressure (ΔP_{pump}) and pump intake pressure are calculated. Details of the calculations and equations are presented in the Appendix A. The calculated pump intake pressure is compared to the measured pump intake pressure to check for the convergence of the iteration. Pump intake pressure can be assumed to be approximately equal to measured bottomhole pressure as the pump setting depth is close to the bottomhole. Note that the downhole separator efficiency is assumed to be 75% and used in all of the calculations. The purpose of this step is to approximate actual pump differential pressure per stage from production data to later compare to that in catalog in order to observe pump performance degradation due to the presence of gas.

The predicted bottomhole pressure, actual pump intake pressure and actual free gas fraction with respect to time of wells Sandy, Roadrunner, and Farnsworth Unit 1314 are plotted and shown in Figs. 4, 5, and 6, respectively. The comparisons show that the predicted bottomhole pressures (BHPs) match quite well the measured pump intake pressures with a maximum discrepancy of 10%.

The approximated pump pressure per stage and the pump pressure per stage from the catalog along with free gas fraction of the wells Sandy, Roadrunner, and Farnsworth Unit 1314, respectively, are plotted and presented in Figs. 7, 8, and 9. The purpose of these comparison is to investigate the effects of free gas fraction on the pump performance under downhole conditions. Well Sandy and Farnsworth Unit 1314 only have one ESP installed while there are two different ESPs installed in series in well Roadrunner. Because pump catalog pressure per stage of the two pumps in well Roadrunner are very similar, approximated pump pressure per stage for both pumps are assumed to be identical as shown

Fig. 4 Predicted BHP and measured pump intake pressure of well Sandy



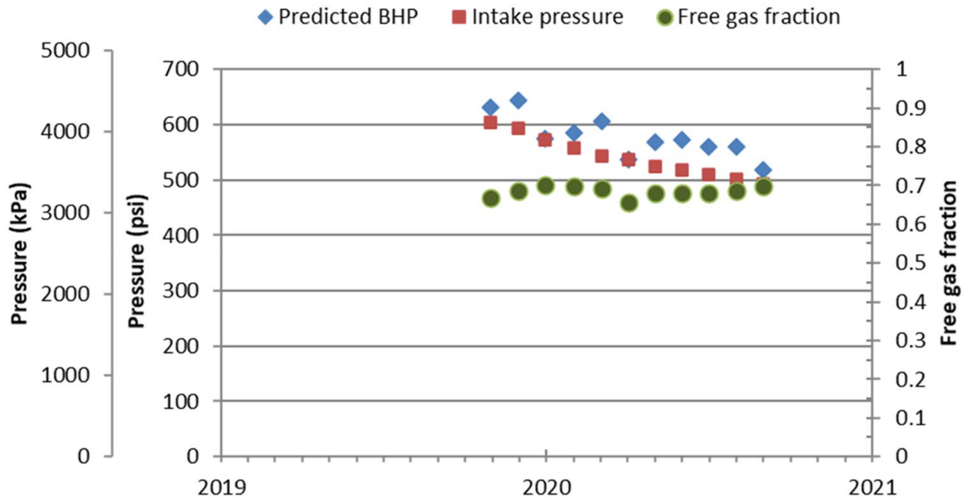


Fig. 5 Predicted BHP and measured pump intake pressure of well Roadrunner

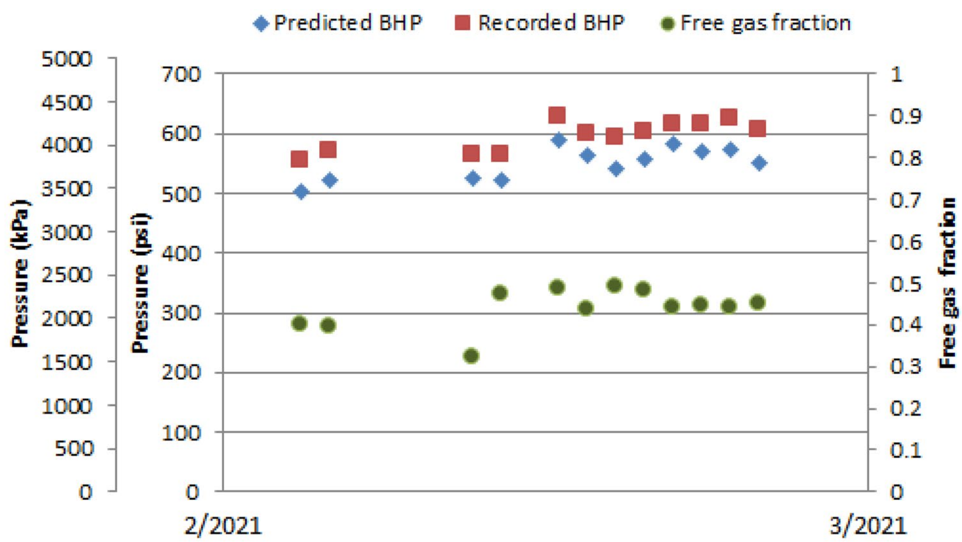


Fig. 6 Predicted BHP and measured pump intake pressure of well Farnsworth Unit 1314

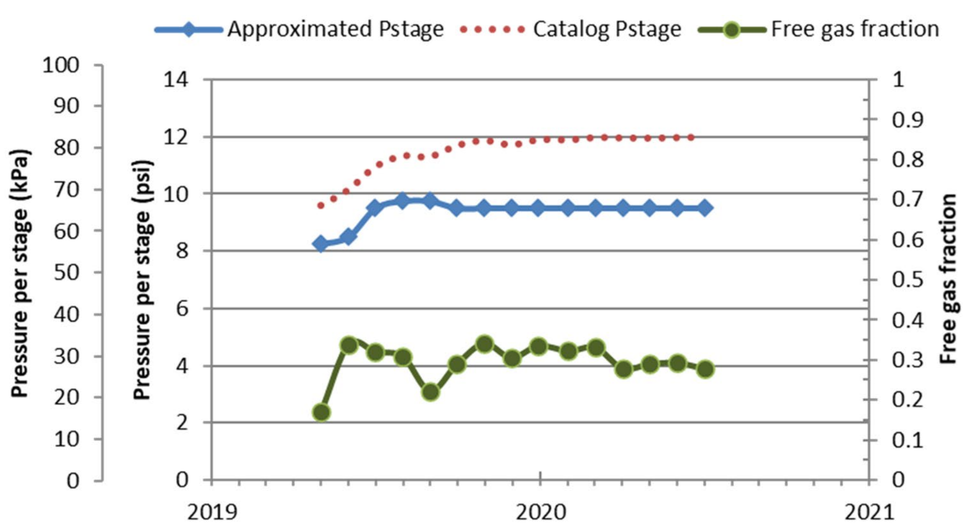


Fig. 7 Approximated and catalog pump pressure per stage (well Sandy)

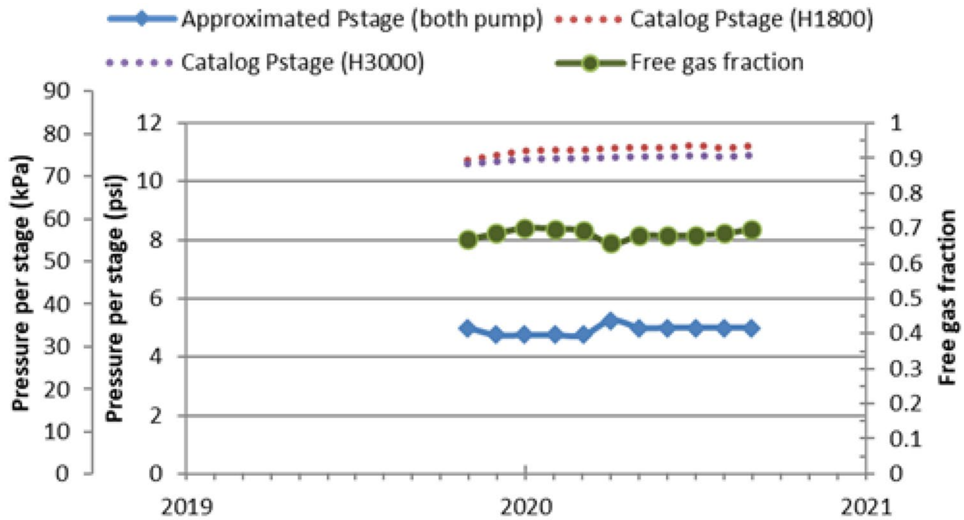


Fig. 8 Approximated and catalog pump pressure per stage (well Roadrunner)

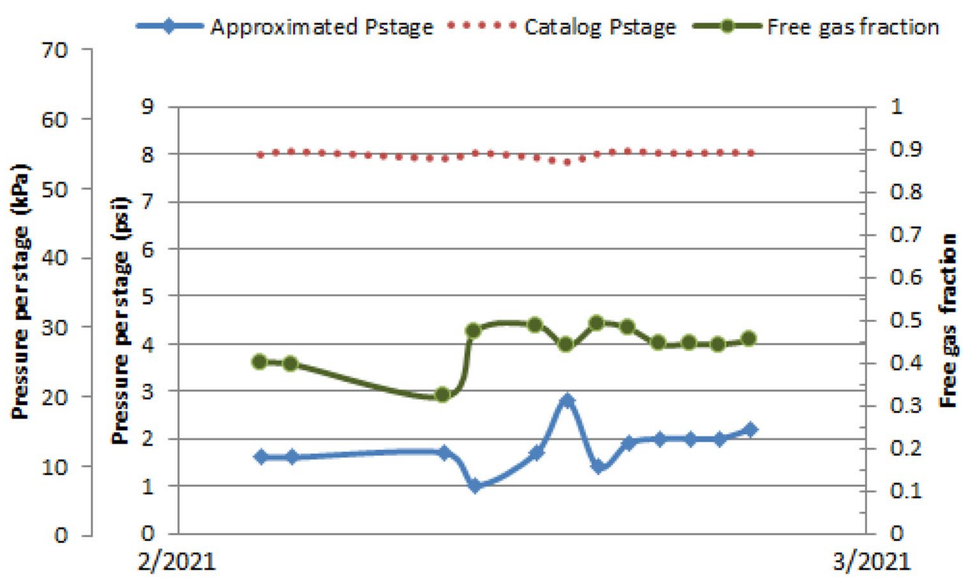


Fig. 9 Approximated and catalog pump pressure per stage (well Farnsworth Unit)

in Fig. 8. Note that variations in pump catalog pressure per stage are due to variations in flow rates, not because of changes in free gas fraction.

The results obviously show that free gas inside the pumps greatly impact the pump performance. The difference between approximated pump pressure per stage and pump catalog pressure per stage are small when free gas fraction is low and the gaps are larger when free gas fraction is higher, which means that pump performance degrades as free gas fraction increases. Data trends in three wells show similar behaviours. For the well Sandy, when the free gas is about 30%, the pump degradation is about 16% compared to the pump catalog pressure. For the well Roadrunner, the pump degradation is about 55% when the free gas is about 65%. For the Farnsworth Unit 1314, the pump degradation is about 50% when the free gas is about 45%.

The free gas fraction and the ratio between two-phase pressure per stage and pump catalog pressure per stage obtained from field data are plotted and shown in Fig. 10. Using the curve fitting regression technique, a correlation shown in Eq. (5) between the pump pressure per stage ratio and free gas fraction is achieved with the coefficient R-squared value of 0.933. Equation (5) is used to predict pump performance in two-phase flow from free gas fraction.

$$\frac{Pstage_{tp}}{Pstage_{sp,catalog}} = -1.5727 \times \text{free gas fraction} + 0.9717 \quad (5)$$

To confirm the analysis of the field data, controlled experiments were conducted using the ESP Testing Facility at New Mexico Tech. During the experiments, pump

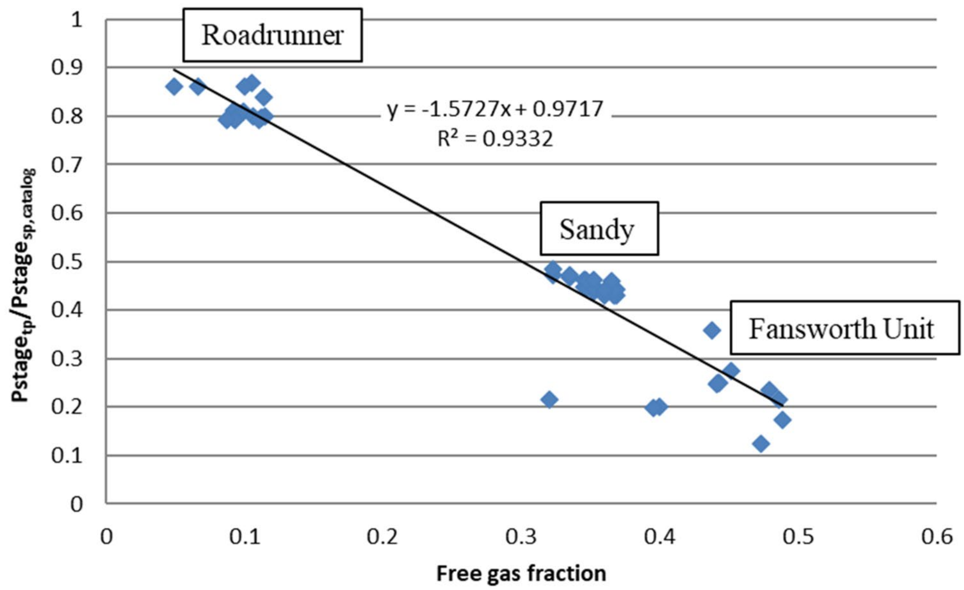


Fig. 10 Two-phase and catalog pump pressure per stage versus free gas fraction

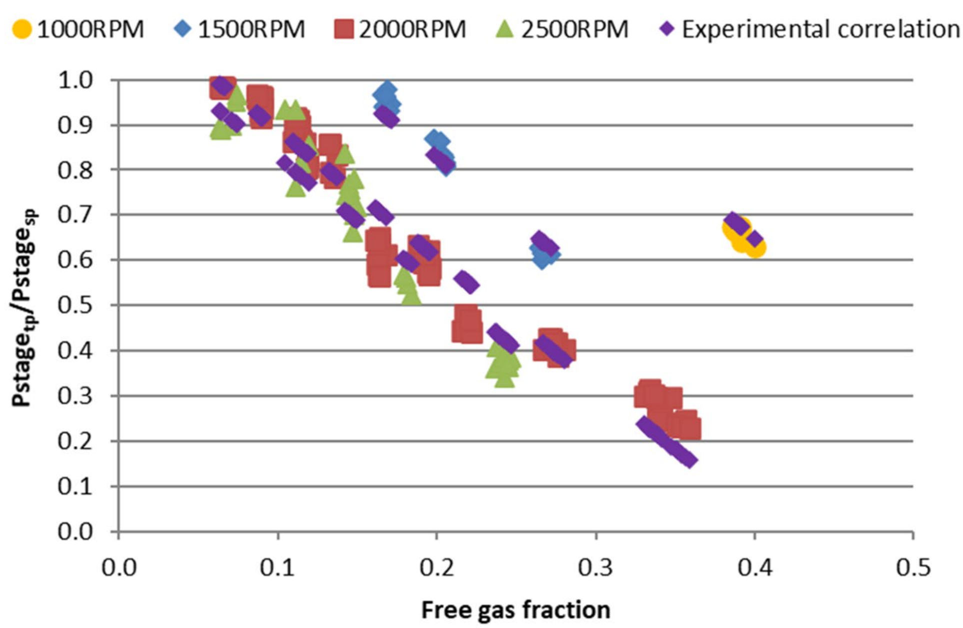


Fig. 11 Two-phase and catalog pump pressure per stage ratio versus free gas fraction (Experimental data)

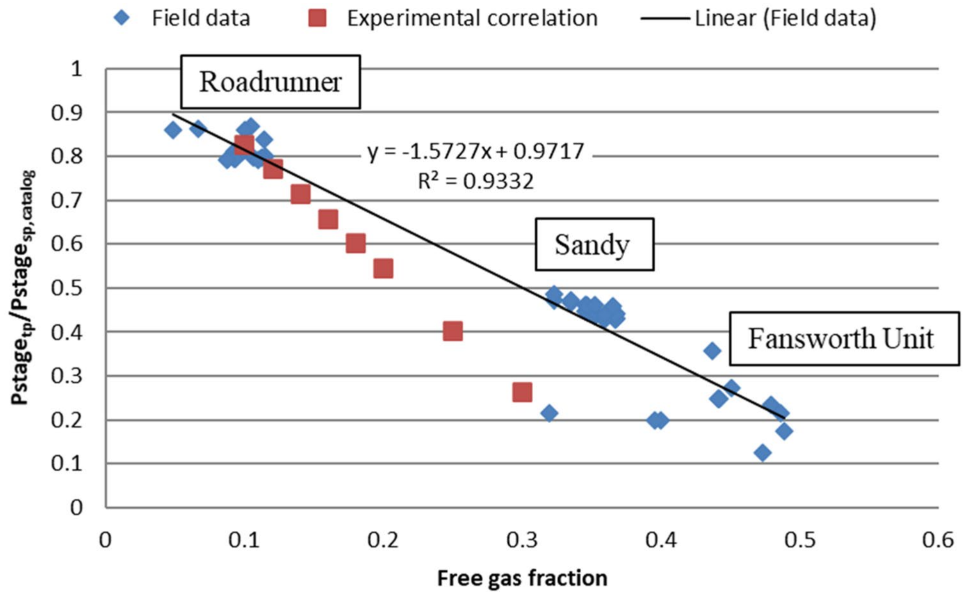
speed was varied from 1000 to 2500 RPM (from 17 to 43 Hz) and free gas fraction was changed from 8 to 42%. The two-phase pump pressure per stage was then normalized using the single-phase pump pressure per stage. The ratio between two-phase and single-phase pump pressure per stage versus free gas fraction at different pump speed is shown in Fig. 11. It is clear that pump performance in two-phase flow is lower than that in single-phase flow. The difference in pump performance at the same free gas fraction is getting less as pump speed increases and eventually, pump performance at 2000 and 2500 RPM are very similar.

From the experimental data, a correlation is obtained in which the pump pressure per stage ratio is a function of free gas fraction and pump speed as shown in Eq. (6). As can be seen in Fig. 11, calculated values using Eq. (6) match well with experimental data.

$$\frac{Pstage_{tp}}{Pstage_{sp}} = -2.83 \times \text{free gas fraction} - 0.0016 \times n + 3.2623 \times n^2 + 3.0417 \tag{6}$$

The developed correlations using field data from wells Sandy, Roadrunner, and Farnsworth Unit 1314, Eq. (5), and

Fig. 12 Two-phase and catalog pump pressure per stage versus free gas fraction



using experimental data, Eq. (6), are plotted and presented in Fig. 12. As the free gas is less than 15%, the prediction using field data and experimental data agrees at a high level. The percentage difference between these two correlations is less than 10%. However, at free gas fraction is higher than 15%, the prediction difference between these two correlations is considerable. At the free gas of 30%, the difference is about 50%. This high discrepancy at high free gas fraction can be explained by the fact that pump differential pressure and pump intake pressure under laboratory conditions are very low compare to that in the field. Hence, ESPs in the field can handle two-phase flow better because the higher the pressure, the easier for gas to dissolve into liquid phase. The results once again confirm the reliability of the developed correlation, Eq. (5), using field data to predict two-phase ESP performance under downhole conditions. However, because the three presented wells have similar conditions, it is recommended to use the correlation on reservoirs with similar conditions.

Concluding remarks

The presence of gas inside ESP negatively impacts the pump performance. This study proposes a simple correlation from field data to predict ESP performance under two-phase flow and downhole conditions. Field data from three oil producing wells provided by Strata Production Company and Perdure Petroleum LLC. as well as experimental data obtained from experimental facility at Production and Drilling Research Project—New Mexico Tech were used in this study.

Equation (5) can be used to predict ESP performance under two-phase gas–liquid and downhole conditions. The correlation obtained using the laboratory data, Eq. (6), predicts quite well the two-phase pump performance at the gas fraction less than 15%. If gas fraction is more than 15%, the correlation developed using experimental data is no longer reliable. Therefore, the authors recommend Eq. (5) should be used to predict two-phase ESP performance under downhole conditions and under high gas fraction. However, it is recommended to use the correlation on reservoirs with conditions similar to those of the three presented wells. The correlation can be improved with more field data and more physics constraints considered.

Appendix A

1. Determining pump discharge pressure

A flow pattern map is determined using Froude number (Fr) of the mixture and input liquid content (C_L)

$$Fr = \frac{u^2}{gD} \tag{A.1}$$

$$C_L = \frac{q_L}{\left(q_L + q_g\right)} \tag{A.2}$$

The transition lines for the correlations are defined as:

$$L_1 = 316C_L^{0.302} \tag{A.3}$$

$$L_2 = 0.0009252C_L^{-2.4684} \tag{A.4}$$

$$L_3 = 0.1C_L^{-1.4516} \tag{A.5}$$

$$L_4 = 0.5C_L^{-6.738} \tag{A.6}$$

The flow is segregated flow if:

$C_L < 0.01$ *and* $Fr < L_1$ *or* $C_L \geq 0.01$ *and* $Fr < L_2$

The flow is intermittent flow if:

$0.01 \leq C_L < 0.4$ *and* $L_3 < Fr \leq L_1$ *or* $C_L \geq 0.4$ *and* $L_3 < Fr \leq L_4$

The flow is distributed flow if:

$C_L < 0.4$ *and* $Fr \geq L_4$ *or* $C_L \geq 0.4$ *and* $Fr < L_4$

The flow is transition flow if:
$L_2 < Fr \leq L_3$

Liquid holdup for horizontal flow $E_L(0)$ is calculated. This value must be greater than C_L, if it is smaller than C_L, $E_L(0)$ is assigned a value of C_L.

$$E_L(0) = \frac{aC_L^b}{Fr^c} \tag{A.7}$$

where

- Segregated: $a=0.98$, $b=0.4846$, $c=0.0868$
- Intermittent: $a=0.845$, $b=0.5351$, $c=0.0173$
- Distributed: $a=1.065$, $b=0.5824$, $c=0.0609$

Liquid velocity number NLV is calculated as:

$$N_{\mathrm{LV}} = 1.938u\left(\frac{\rho}{g\sigma}\right)^{1/4} \tag{A.8}$$

Correction factor β is calculated as:

$$\beta = \left(1 - C_L\right)\ln\left(dC_L^e N_{\mathrm{LV}}^f Fr^g\right) \tag{A.9}$$

For uphill:

- Segregated: $d=0.011$, $e=-3.768$, f$=3.539$, $g=-1.614$
- Intermittent: $d=2.96$, $e=0.305$, f$=-0.4476$, $g=0.0978$
- Distributed: $d=0.011$, $e=-3.768$, f$=3.539$, $g=-1.614$

For downhill: $d=4.7$, $e=-0.3692$, $f=0.1244$, $g=-0.5056$.

Actual liquid volume fraction $E_L(\theta)$ is determined to calculate mixture density:

$$E_L(\theta) = B(\theta) \times E_L(0) \tag{A.10}$$

$$\rho = \rho_l E_L(\theta) + \rho_g\left(1 - E_L(\theta)\right) \tag{A.11}$$

where $B(\theta) = 1 + \beta\left(\sin(1.8\theta) - {}^1/_3 \sin^3(1.8\theta)\right)$, θ is the angle of inclination of pipe with horizontal.

For transition flow,

$$E_L(\theta)_{\mathrm{transition}} = AE_L(\theta)_{\mathrm{segregated}} + BE_L(\theta)_{\mathrm{intermittent}} \tag{A.12}$$

where $A = \frac{L_3 - Fr}{L_3 - L_2}$ and $B = 1 - A$

Pressure change due to hydrostatic head of vertical component of the pipe is determined as:

$$\frac{dP}{dZ}_{\mathrm{elevation}} = \frac{\rho g \sin(\theta)}{144 g_c} \tag{A.13}$$

No slip Reynold's number is calculated using no slip mixture density and viscosity:

$$N_{\mathrm{Re}} = \frac{\rho_{\mathrm{NS}} u_{\mathrm{NS}} D}{\mu_{\mathrm{NS}}} \tag{A.14}$$

Under turbulent flow, Fanning friction factor is determined using Colebrook—White equation (Colebrook and White 1937):

$$\frac{1}{\sqrt{f_{\mathrm{NS}}}} = -2\log_{10}\left(\frac{{}^{\varepsilon}/_{D}}{3.7} + \frac{2.51}{N_{\mathrm{Re}}\sqrt{f_{\mathrm{NS}}}}\right) \tag{A.15}$$

where ε and D are absolute pipe roughness and pipe inside diameter in ft respectively.

Ratio of friction factor is defined as:

$$\frac{f_{\mathrm{TP}}}{f_{\mathrm{NS}}} = e^S \tag{A.16}$$

If $1 < y < 1.2$, where $y = \frac{C_L}{E_L(\theta)^2}$, then:

$$S = \ln(2.2y - 1.2) \tag{A.17}$$

Otherwise:

$$S = \frac{\ln(y)}{-0.0523 + 3.182\ln(y) - 0.8725\ln(y)^2 + 0.01853\ln(y)^4} \tag{A.18}$$

Pressure loss due to friction is calculated as:

$$\frac{dP}{dZ}_{\mathrm{friction}} = \frac{2f_{\mathrm{TP}}u^2\rho}{144 g_c D} \tag{A.19}$$

Factor E_K is given as:

$$E_K = \frac{\rho u u_{\mathrm{sg}}}{g_c P_{\mathrm{gas}}} \tag{A.20}$$

where u_{sg} is no slip gas velocity in ft/s.

Total pressure gradient is determined as:

$$\frac{dP}{dZ} = \frac{\frac{dP}{dZ}_{\text{friction}} + \frac{dP}{dZ}_{\text{elevation}}}{1 - E_K} \tag{A.21}$$

Pump discharge pressure is calculated as:

$$P_{\text{dis}} = P_{\text{wh}} + \frac{dP}{dZ}Z \tag{A.22}$$

2. Determining pump intake pressure

At first, an assumed pump pressure per stage is used to calculate pump pressure and pump intake pressure:

$$\Delta P_{\text{pum}} = \Delta P_{\text{stage}} \times \text{Number of stages} \tag{A.23}$$

$$P_{\text{int,cal}} = P_{\text{dis}} - P_{\text{pump}} \tag{A.24}$$

If the calculated pump intake pressure is not converged with the measured pump intake pressure, a new value of pump pressure per stage is used until reaching convergence.

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