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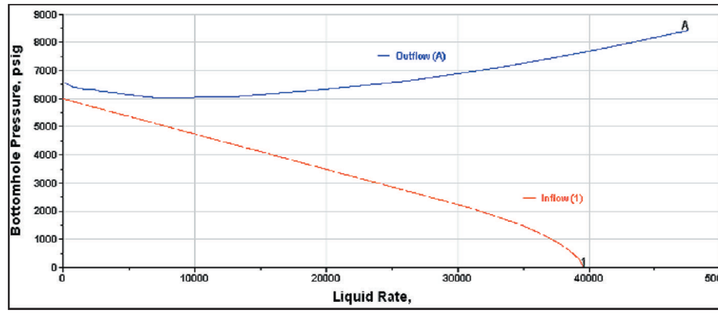
Figure 2: Well system deliverability – Inflow (red) does not intersect outflow (blue) at any flow rate.



Designing and evaluating artificial lift systems – a combined approach

Proper utilization of engineering tools in the analysis of subsea production systems will help operators to identify the best artificial lift technique and maximize production from the system. IHS's **Mofazzal Bhuiyan** explains.

A model is developed to determine the subsea production system's deliverability under various artificial lift scenarios utilizing several engineering tools. This model illustrates the advantages of using proper engineering tools to identify the best combination of the lift methods. A procedure has been developed to check if the wells have the potential to produce under natural flow; use of gaslift or electrical submersible pump (ESP) alone is a good choice or even if subsea boosting can help to maximize production.

Combinations of different lift methods are specifically studied here. Indicating that a combination of ESP and subsea boosting (SSB) permits 17% to 62% production rate increase compared to different artificial lift techniques. For example, this combination would yield 62% increase in production compared to GasLift (GL) use alone and only 17% increase compared to GL and SSB together. *Figure 1* shows the schematic diagram of this production system. The color change in this diagram indicates pressure distribution at various sections of the flow lines ranging from 598 psig to 185psig. Red color indicates the highest pressure and blue being the lowest.

For simplicity, identical well profiles are kept for the four wells used in this study that are tied to a subsea manifold. A long subsea tieback of 36,960ft (7 miles) is connected to the platform through a 6600ft riser. Each well has a kick-off point at 5000ft of MD from which they have approximately 35° deviation to reach the perforation depth of 13,800ft. Reservoir productivity index is considered as 8STB/D/psi and the pressure is 5985psig with formation GOR of 400SCF/STB. As a first step of the analysis, single well system (Nodal) analysis is conducted to find the potential of the natural flow. Then, gaslift analysis is done for the same well to find the optimum gas injection rate at a valve measured depth of 10,800ft. Considering a desired liquid rate of 16,000b/d, an ESP design calculation is also carried out to get the most suitable electrical submersible pump at 13,300ft MD for each well. Finally, to quantify the relative benefits from the various artificial lift techniques, an integrated network model is developed to simulate various cases. Step by step procedure is described in rest of the study.

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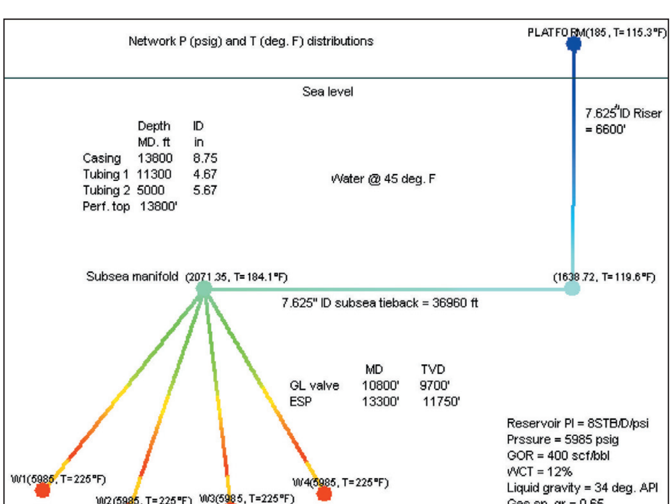

Figure 1: Schematic diagram of the subsea production systems with required data.

System analysis on a single well

Well system analysis is often conducted in a steady state producing system to optimize production. In this case, to investigate the potential of natural flow, a model is developed using the industry leading system analysis program Perform. This model consists of wellbore, subsea tieback and riser system starting from the top of perforation and going up to the platform. The Chokshi *et al* (1996) mechanistic and Beggs, Brill flow correlations are selected to calculate the two phase pressure drop for vertical and horizontal flow respectively for the entire study (except for the riser). The Orkiszewski vertical flow correlation is used for the riser pressure loss calculation. Since the riser is submersed into deep water, temperature profile generation is crucial to account for the heat transfer between riser and the sea current. The Alves *et al* unified heat transfer model is selected to do this considering 10ft of air gap with 15ft/sec of air velocity and 2ft/sec of sea current velocity.

Figure 2 shows the inflow and outflow plots with bottomhole as the solution point (or node) for this system. This plot indicates that it is not possible to make this well flow under natural conditions since inflow and outflow do not intersect.

Gaslift analysis

To evaluate alternatives to natural flow, gaslift analysis is performed for this single well to find the optimum gas injection rate and corresponding production. The deepest possible valve depth is selected with the use of high pressure valves rated for operating pressures of 5000psig. This valve permits injection depth of 10,800ft (9700ft TVD) to analyze gaslift performance. *Figure 3* shows gaslift performance plot with oil and total liquid productions for different gas injection rates. *Figure 4* represents the incremental increase in total liquid production due to increase in gas injection rates. It is found from these two figures that an injection

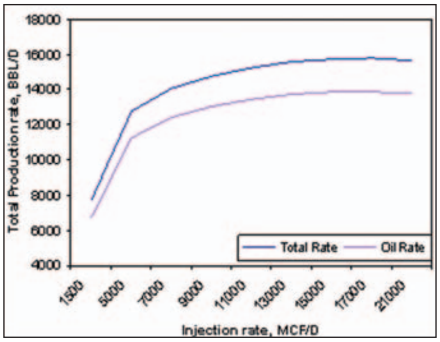

Figure 3. Gaslift performance plots.

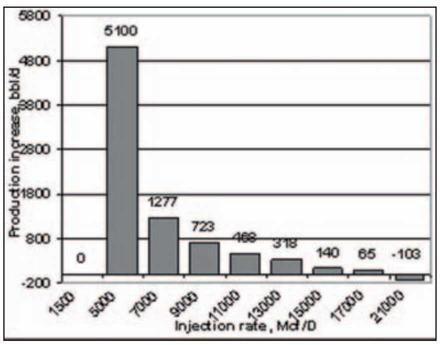

Figure 4. Incremental total production rate increase for various gas injection rates.

rate of 9mmscf/d is capable of lifting about 14,800b/d of total liquids from the single well, if used alone.

ESP design and analysis

Another alternative to natural flow would be the use of electrical submersible pumps to lift the liquid. A pump design model is developed using the industry's only vendor neutral ESP design program SubPump. This tool allows comparison and analysis of different pumps side by side from the major vendors around the world in terms of rate, efficiency, required horse power, etc. This capability gives greater flexibility to select the best pump suitable for individual operator's requirement. For this study, performances of four major manufacturers' 675 series pumps are analyzed with 42 stages for each pump. This stage numbers are within the manufacturers' recommended allowable limit for the chosen pumps. *Table 1* shows the operation and performance results for each pump and *Figure 5* shows the pump sensitivity plots for the selected pumps.

Network model

Finally, to compare the relative benefits of each artificial lift technique, a model is developed using appropriate network simulation tool PipeSoft-2. This tool has the capability of comparing up to 15 different cases including but not limited to the change of fluid properties, water cut, flow line variables, gas injection rates, pump horse power and efficiency, well and reservoir properties, etc. The six cases investigated are:

- ESP only
- Subsea boosting (SSB)
- Gaslift only
- ESP with SSB
- Gaslift with SSB
- Gaslift with ESP

Wellbore pressure profile analysis obtained from this tool, indicates that each electrical submersible pump is capable of generating 1180psig of pressure differential between the pump intake and discharge. This value is considered as the subsea boosting requirement for case number two, four and five. Comparisons of total system deliverability for various methods are shown in *Figure 6*. The Newton-Raphson pressure imbalance method (PBAL) is used to solve the network model. The total liquid production ranges from 35,000b/d to 51,000b/d, depending on the type of artificial lift method selected. For the first case (also known as base case), all four wells are equipped with Model 'A' pumps by importing the head curve developed earlier to represent the pumps. This system can produce at a rate of about 35,100b/d.

In the second case, subsea boosting (SSB) potential has been analyzed. A constant pressure differential of 1180 psig is considered between pump's inlet and discharge. This booster is placed just after the subsea manifold. A special device known as P vs Q is used to reflect this pressure differential for any flow rate ranging from 5000b/d to 10,0000b/d. This device allows users to enter pressure and temperature differential values for each flow rate, eliminating the complexity of subsea boosting modeling. Use of only SSB alone is able to support a liquid production rate of about 37,600b/d.

Total gas injection rate of 36mmscf/d for four wells results in a liquid production rate of about 31,600b/d. But a combination of ESP and SSB will achieve a rate close to 51,000b/d which is 46% higher than ESP use alone and 36% higher than SSB alone. Combining gaslift (GL) and SSB would yield a total production of about 43,500b/d, which is 16% higher than SSB alone and 38% higher than gaslift use alone. Another familiar practice of arranging ESP and gaslift together would produce at a rate of 41,400b/d which is 18% higher than ESP use alone and 31% higher than gaslift use alone.

Among all the combinations, ESP+SSB will be able to produce at a maximum rate which is 17% higher than GL+SSB and 23% higher than GL+ESP. However, it is important to note that unstable two-phase

Pump model	Model A	Model B	Model C	Model D
Frequency (Hz)	60	60	60	60
Total stages	42	42	42	42
Free gas by volume into pump (%)	0	0	0	0
Operating speed (rpm)	3504	3453	3455	3495
Operating current (Amps)	96	99	105	137
Operating voltage (Volts)	2616	2116	2200	1966
Adjusted for motor slip	Yes	Yes	Yes	Yes
Pump efficiency (%)	76	67	68	71
Motor efficiency (%)	88	86	85	87
Surface final liquid rate (O+W) (b/d)	17,813	18,070	17,698	18,044
Total dynamic head (TDH) (ft)	2470	1877	1954	2337
Pump intake pressure (psig)	3071	3727	3773	3592
Pump operating power (hp)	411	356	357	423
Fluid level [MD] (ft)	3089	2736	2581	3157

Table 1: Operation and performance comparison of electrical submersible pumps.
Note: Head – capacity curve is generated for the model 'A' pump to use in this study. (The data for the curve is exported in such a way that it can be imported later in the network simulation model to represent the pump).

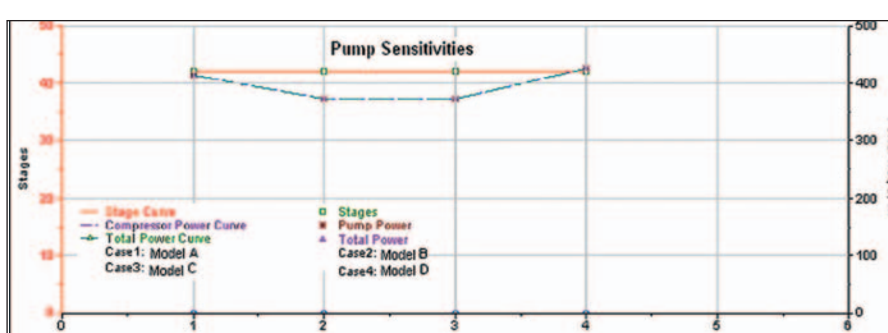

Figure 5: Pump sensitivity plots for the selected pump models.

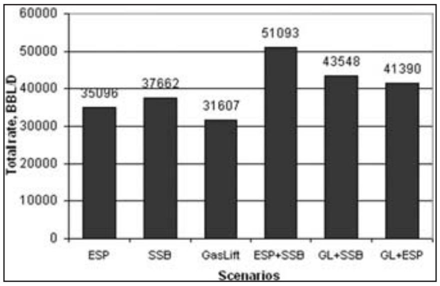

Figure 6: Comparisons of different artificial lift cases with total system deliverability.

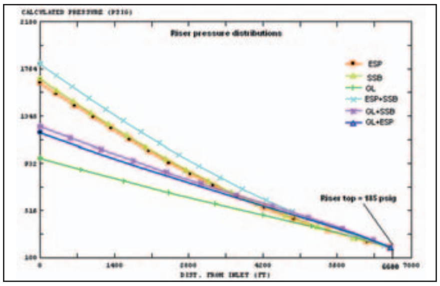

Figure 7: Riser pressure profile from the seabed up to the platform for all six cases.

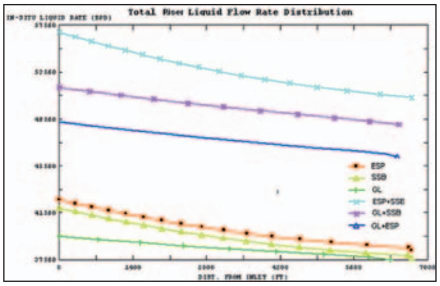

Figure 8: Riser total in-situ liquid rates for all six cases.

flow pattern of severe slugging is often found in offshore flow line/riser systems, more apparent with gaslift. Slug prediction model (developed by Pots *et al*) indicates severe slugging could occur for the gaslift cases. If necessary, slug volume and size can be predicted also. The final pressure profile for the riser system is shown in *Figure 7* with all six cases together and total in situ liquid rates for the same are shown in *Figure 8*.

Checking temperature profile, liquid and gas velocity distribution, flow regime change, single and two phase density and viscosity distributions for each link, etc. can reveal important information regarding the fluid flow. These types of analysis are available in Pipesoft-2 for each link. It should be noted that selecting the best technique will not only depend on the system deliverability but also other factors, such as gas availability for injection, economic analysis, technical feasibility, etc.

Summary

This systematic approach to network simulation will allow users to quantify and uncover the relative benefits of different artificial lift techniques.

Use of appropriate engineering tools will also ensure greater accuracy of the results from the overall analysis. The procedure followed in the study can be summarized as:

- single well Nodal (system) analysis;
- single well gaslift analysis;
- analysis and comparison of several electrical submersible pump models; and
- evaluate the potential of subsea boosting with the combination of other artificial lift methods.

Combined use of available tools will improve the best in class decision making process that leads to greater benefit for the company. **OE**

About the author

Mofazzal Bhuiyan has been a senior petroleum engineer in the energy division of IHS in Dallas, Texas since 2004 and is responsible for engineering support of Nodal analysis, ESP design, steady state network simulation and material balance appplications.