DIAMETER OPTIMIZATION IN MULTIPHASE PIPELINE NETWORK

Ristiyan Ragil Putradianto¹, Silvyah Dewi Rahmawati²
¹Universitas Pembangunan Nasional “Veteran” Yogyakarta
²Institut Teknologi Bandung
Email of Corresponding Author: ristiyan@upnyk.ac.id

ABSTRACT
Optimization is a continuous work in oil and gas operation in every section by maximizing the profit and minimizing cost. One of the sections that can be optimized is production system, starting from the wellbore to separator through pipeline network. Simulation are made and conducted from reservoir to separator to see the pressure distribution along the pipeline with various diameter. The result will be subject to be optimized by putting pipeline cost into account. The simulation result shows that at some point, increasing in diameter has a good effect to the revenue thanks to the increasing production rate, but it also shows that the increasing diameter in all section is not always the best scenario due to high cost. Benefit-to-cost ratio is chosen to be the economical parameter to find the best diameter configuration.

Kata kunci: optimization; pressure; diameter

INTRODUCTION
Optimizing production is a necessity in the oil and gas industry by maximizing revenue and minimizing costs. Optimization can be done in various sections such as reservoirs, tubing, or pipelines.

For the reservoir, there are many ways to maintain production in a manner that can prevent problems such as fingering, sand problems, or even water coning. One of the methods is by controlling the wellhead pressure (Pwh) which consequently affects the flow from the reservoir to the wellbore. However, the reservoir has its own production window based on Inflow Performance Relationship (IPR), so that it becomes the upper limit of the rate of oil that can be produced.

For the tubing section, optimization is far more complicated than the reservoir section, because the tubing size was designed from the beginning of the drilling. Then it cannot be changed easily to another size. A Tubing Performance Relationship (TPR) is needed so that the pressure drop throughout the system can be calculated. The IPR and TPR then be combined to obtain fluid rate data.

From the surface facilities section, it can be done by designing the pipe configuration correctly, including the arrangement of junctions and nodes, pipe diameters, and separator pressure.

Therefore, the optimization cannot be done separately without seeing the whole sections since they are interacting and affecting one another.

Since last decades, integrated optimization has been studied by many researchers. Bhaskaran (1978) made an optimization method of pipeline diameter and configuration using Dynamic Programming formulation and Linear Programming Calculation, but the model is for dry gas only. Jansen and Curry (2004) included economic parameter for optimization, along with other consideration such as fluid flow correlation and nodal system analysis.

Serbini et al (2009) introduced integrated subsurface-to-surface-to-economic modelling technology that combines reservoirs, wells, surface infrastructure, and process facilities as well as the asset's operating parameters, financial metrics, and economic conditions into a single production management environment.

Rahmawati (2012) proposed integrated optimization from downstream to upstream, including reservoir, well, pipeline, and surface process, and economic calculation. Integrated
simulation system can be readily developed using available commercial software technology.

Abidin et al (2014) concluded that optimization software in both sides of surface and subsurface must be integrated to achieve system stability.

Sarra et al (2015) used genetic algorithms to identify the best field configuration and handling operational variables simultaneously in order to reach the global optimum limited by the system constraints. The integrated optimization is defined by combining subsurface models with surface production and process models in a single management tool.

From the previous works above, it can be concluded that integrating the whole system is a must for running the simulation for optimization. But the object for optimization is a must for running optimization software in both sides of surface technology.

Many properties of the fluid are approached using correlation. The first property to be calculated is gas compressibility factor (z). Sutton’s correlations for pseudo-critical properties of gas are defined as:

\[
P_{pc} = 756.8 - 131\gamma_g - 3.6\gamma_g^2\]
\[
T_{pc} = 169.2 + 349.5\gamma_g - 74\gamma_g^2
\]

If there are impurities within the gas, the pseudo-critical properties need to be corrected as follows:

\[
\epsilon = 120(A^{0.9} - A^{1.6}) + 15(B^{0.5} - B^{4})
\]

where

\[A = \text{mole fraction of both CO}_2 \text{ and H}_2\text{S}\]
\[B = \text{mole fraction of N}_2\]

\[
P'_{pc} = P_{pc} T'_{pc}
\]

\[
T'_{pc} = T_{pc} - \epsilon
\]

Pseudo-reduced properties are calculated as:

\[
T_{pr} = \frac{T}{T_{pc}}
\]
\[
P_{pr} = \frac{P}{P_{pc}}
\]

where \(P\) and \(T\) is the average pressure and temperature of the gas across the system. The gas compressibility factor then can be written as follows:

\[
z = 1 + A_{11} \rho_{pr} + A_{22} \rho_{pr}^2 - A_{33} \rho_{pr}^3 + 0.6134 (1 + 0.721 \rho_{pr}^2) \left(\frac{P_{pr}}{T_{pr}}\right) \exp(-0.721 \rho_{pr}^2)
\]

where

\[
A_{11} = 0.3265 - \left(\frac{1.07}{T_{pr}}\right) - \left(\frac{0.539}{T_{pr}^2}\right) + \left(\frac{0.01569}{T_{pr}^3}\right) - \left(\frac{0.05165}{T_{pr}^4}\right)
\]
\[
A_{22} = 0.5475 - \left(\frac{0.736}{T_{pr}}\right) + \left(\frac{0.1844}{T_{pr}^2}\right)
\]
\[
A_{33} = 0.1056 - \left(\frac{0.736}{T_{pr}}\right) + \left(\frac{0.1844}{T_{pr}^2}\right)
\]
\[
\rho_{pr} = 0.27 \left(\frac{P_{pr}}{T_{pr}}\right)
\]

After knowing the \(z\) factor, the density of gas \(\rho_g\) can be calculated using the equations below:

\[
M_a = 29\gamma_g
\]
\[
\rho_g = \frac{PM_a}{10.732zT}
\]
Viscosity of gas ($\mu_g$) then can also be calculated using Standing correlation, considering the effect of non-hydrocarbon molecules on viscosity at atmospheric pressure.

$$\mu_{g \, uncorrected} + (\Delta \mu)_{H_2S} + (\Delta \mu)_{N_2} + (\Delta \mu)_{CO_2}$$

where

$$\mu_{g \, uncorrected} = \left[1.79(10^{-6}) - 2.062(10^{-6})y_g\right](T - 460) + 8.188(10^{-6}) - 6.15(10^{-9})log y_g$$

$$\Delta \mu_{H_2S} = y_{H_2S}[8.48(10^{-9})log y_g + 9.59(10^{-9})]$$

$$\Delta \mu_{N_2} = y_{N_2}[9.08(10^{-9})log y_g + 6.24(10^{-9})]$$

$$\Delta \mu_{CO_2} = y_{CO_2}[8.49(10^{-9})log y_g + 3.73(10^{-9})]$$

To determine the viscosity of gas at any pressure other than atmospheric pressure, it must be corrected as follows:

$$\mu_g = \mu_{g \, uncorrected} \frac{exp(C_{11})}{T_{pr}}$$

where

$$C_{11} = B_{11} + B_{22}T_{pr} + B_{33}T_{pr}^2 + B_{44}T_{pr}^3$$

$$B_{11} = -2.4621182 + 2.970547P_{pr}$$

$$-2.86264x10^{-1}P_{pr} + 8.054205x10^{-3}P_{pr}$$

$$B_{22} = 2.80860949 - 3.49803305P_{pr}$$

$$+3.60373020x10^{-1}P_{pr} - 1.0443x10^{-2}P_{pr}$$

$$B_{33} = -7.933856x10^{-1} + 1.396433P_{pr}$$

$$-1.491449x10^{-1}P_{pr} + 4.41015x10^{-3}P_{pr}$$

$$B_{44} = 8.39387x10^{-2} - 1.86409x10^{-3}P_{pr}$$

$$+2.03368x10^{-2}P_{pr} - 6.09579x10^{-4}P_{pr}$$

The next step is determining the density of oil ($\rho_o$) which is conversion from known oil specific gravity from the data, using the following relationship.

$$\rho_o = Y_o\rho_w$$

where $Y_o$ and $\rho_w$ is oil specific gravity and water density, respectively.

Viscosity of oil ($\mu_o$) is calculated using Glaso’s correlation as follows,

$$\mu_o = [3.141(10^{10})(T - 460)^{3.444}[log(API)]^a$$

$$a = 10.313[log(T - 460)] - 36.447$$

$$API = \left(\frac{141.5}{Y_o}\right) - 131.5$$

Density of Water ($\rho_w$) is calculated using the following formula:

$$\rho_w = 62.368 + 0.438603S + 1.60074(10^{-3})S^2$$

where

$$S = \text{salinity in weight percent solids}$$

Viscosity of Water ($\mu_w$) is obtained from the following calculation:

$$\mu_{w \, uncorrected} = A(T - 460)^B$$

where

$$A = a_0 + a_1S + a_2S^2 + a_3S^3$$

$$a_0 = 109.574A_1 = -8.4056$$

$$A_2 = 0.313314A_3 = 8.72213(10^{-3})$$

$$B = B_0 + B_1S + B_2S^2 + B_3S^3$$

$$B_0 = -1.12166B_1 = 2.63951(10^{-2})$$

$$B_2 = -6.79461(10^{-3})B_3 = -5.47119(10^{-5})$$

Then, viscosity of water in a certain value of pressure can be obtained from the following relationship

$$\mu_w = \mu_{w \, uncorrected}[0.9994 + 4.0295(10^{-5})P + 3.1062(10^{-9})P^2]$$

After density and viscosity of condensate and water are obtained, next step is to combine them into liquid property ($\rho_l$ and $\mu_l$) using the following equations

$$\rho_l = (1 - WC)\rho_o + (WC)\rho_w$$

$$\mu_l = (1 - WC)\mu_o + (WC)\mu_w$$

**Nodal System Analysis**

Production rate is a direct function of reservoir performance, which is known as Inflow Performance Relationship (IPR). It is a relationship between production rate and wellbore pressure as expressed in a curve, which $x$-axis for fluid production rate ($Q$), and $y$-axis for wellbore pressure ($P_{wf}$). According to Darcy’s law, the higher the higher pressure drawdown, that can be achieved by lowering the $P_{wf}$.

To obtain actual rate that occurs in certain condition, the inflow performance curve must be combined in the same space with outflow performance curve in the section next to reservoir, which is Tubing Performance Relationship (TPR). Same as IPR, it shows the fluid rate ($Q$) versus wellbore pressure ($P_{wf}$). The difference is that in TPR, the rate will be proportional to...
wellbore pressure. The interception of the two curves is the actual rate and wellbore pressure that occurs in that condition.

![Figure 2. IPR and TPR](image)

The nodal point is not always in the \( P_{wf} \), since there are more than one point of measurement along the system between the reservoir to separator. The well head can also be the nodal point, that is used in this study.

When the well head is the nodal point, the curve will have well head pressure (Pwh) in y-axis, and the inflow performance relationship (IPR) will be the flow from reservoir to well head. This requires integration of IPR and TPR to be one single curve as inflow, and flowline performance relationship (FPR) as the outflow.

By simulating for various fluid rates, the pressure for each well head is obtained and the curves can be formed. The values can be calculated using the interpolation method without having to create a graph and combine the curves manually.

**Interpolation Method**

Interpolation is needed in this simulation to obtain the value of rate and pressure generated by intersection between inflow and outflow curve.

It is executed by linear interpolation of two adjacent data, but one of the data will be iterated many times to make the range as short as possible so that the error will also be smaller and the result can be accurate. The method is known as False Position Method.

Interpolation lines are drawn linearly through the most recent points that bracket the root. In this picture, point 1 remains in constant position for any steps. Because the goal is finding \( f(x) = 0 \), the interpolation line are intersected with x-axis, and hence resulting in \( x \), as the first point to iterate.

The next step is find the \( f(x_0) \), and make it as the new boundary point of the bracket, in this picture, from point 2 to point 3. Draw the interpolation line from the new boundary point, and intersect it with x-axis, resulting in \( x_1 \). Do the same step until \[ |x_n - x_{n-1}| \] satisfy the minimum error desired.

For the case of the study, the difference is that the root is not x-axis but the intersection of two curves. The iteration schematic can be seen below:

![Figure 4. Interpolation and Iteration Process](image)
data that is ready to be interpolated and intersected linearly.

At the first intersection, a single value of rate \( Q' \) is generated, but there is a gap between interpolated pressure \( P^* \) and actual pressure generated from correlation in both curve, \( P'_{in} \) and \( P'_{out} \) because interpolated pressure is just a linear approximation, not actual.

The next step is calculating the new pressure from inflow and outflow using \( Q' \), and making it as new boundary of interpolation. After that, a new rate \( Q'' \) is obtained. Using the newest rate, calculate the pressure from both inflow and outflow curve as a new boundary.

The same procedure is done until there is no significant gap between approximated pressure and actual pressure, and it will finally lead to single value of pressure for both inflow and outflow, that will be the end of iteration.

**Network Model**

Consider a simple network with one main pipeline and two branches connected through a junction as illustrated below:

![Figure 5. Network Model](image)

The continuity equations for the junction is simply expressed as:

\[
\sum_{j=1}^{n_j} (\rho v A_p)_{ij} = 0; \ i = 1, \ldots, n
\]

In a simple expression, the total mass out at the trunk pipe is the sum of fluid mass in at the branch pipe. But since the density of fluid (\( \rho \)) is relatively constant across the segment, it can be expressed as the sum of the rate, \( Q \), then the equation becomes:

\[
\sum_{j=1}^{n_i} q_{ij} = 0; \ i = 1, \ldots, n
\]

In the presence of the mass flow rate coming from an external source (supply) and leaving from the system (demand), the continuity equations can be written as:

\[
\sum_{j=1}^{N_i} Q_{ij} = D_i - S_i; \ i = 1, \ldots, N
\]

where

- \( i = i \)-th node within the network
- \( j = j \)-th segment connected to node \( i \)
- \( N_i = \) number of segments connected to node \( i \)
- \( N = \) total number of nodes within the network
- \( D_i = \) demand or flow leaving the system from the \( i \)-th node
- \( S_i = \) supply or flow coming into the system through node \( i \)

**Economic Parameter**

Last, the optimization cannot be apart from economic considerations, which in general are comparison between costs and revenues from oil production. One of the parameters that can be used for economic consideration is the Benefit to Cost Ratio (BCR) which is defined by the ratio between revenue and costs.

The BCR is calculated at the time of installation for one day oil production. It is the total revenue divided by the cost of pipeline installed. The revenue comes from oil production in one day using current oil price in dollars. The definition can be formulated as:

\[
BCR = \frac{QP}{C}
\]

where

- \( Q = \) oil production for one day, STB
- \( P = \) oil price, US$/STB
- \( C = \) total cost of pipe, US$

The best scenario is chosen among several proposed scenarios based on the highest BCR using Generalized Reduced Gradient (GRG) for nonlinear optimization that has been introduced by Lasdon, Fox, and Ratner (1973).

The nonlinear program to be solved is assumed to have the form:

\[
\text{minimize } f(x)
\]

subject to \( g_i(x) = 0, \ i = 1, \ldots, m \)

and \( l_i \leq x \leq u_i, \ i = 1, \ldots, n \)
The fundamental idea of GRG is to use the equalities to express \( m \) of the variables, called basic variables, in terms of the remaining \( n-m \) nonbasic variables. This is also the way the Simplex Method of linear programming operates.

**RESULT AND DISCUSSION**

**Pipeline Data**

The case of this study is a branch of Field X pipeline network in East Kalimantan that has been producing for many years. Some of the data could not be obtained, such as the IPR and the well depth, therefore the remaining data used is hypothetical.

| Table 1. Fluid Data |
|---------------------|
| Parameter           | Value | Unit  |
| Pipe roughness, \( r \) | 0.001 | Ft    |
| Temperature, \( T \)   | 590   | Rankine |
| GOR                  | 5000  | SCF/STB |
| Water Cut            | 0.25  | Fraction |
| SG gas               | 0.7   | Sp gr   |
| SG oil               | 0.816 | Sp gr   |
| SG water             | 1.06  | Sp gr   |
| Mol fraction of \( N_2 \) | 0 | Mole % |
| Mol fraction of \( CO_2 \) | 0 | Mole % |
| Mol fraction of \( H_2 S \) | 0 | Mole % |
| Total dissolved solid, TDS | 0 |         |
| Salinity, \( S \)    | 0     |         |

The pipeline network consists of 32 wells with 6 junctions and one sink point, which is the separator or gathering station. The illustration of the network can be seen below:

![Field X Pipeline Network](image)

Figure 6. Field X Pipeline Network

The pipe data for the network above can be seen below:

| Table 2. Pipeline Data |
|------------------------|
| Segment | D | L (ft) | Seg | D | L (ft) |
| 1-13     | 6 | 56.0    | 14-22 | 6 | 55.0    |
| 2-13     | 6 | 82.0    | 15-22 | 6 | 55.0    |
| 3-13     | 6 | 82.0    | 16-22 | 6 | 110.0   |
| 4-13     | 6 | 109.0   | 17-22 | 6 | 140.0   |
| 5-13     | 6 | 109.0   | 18-22 | 6 | 165.0   |
| 6-13     | 6 | 137.0   | 19-22 | 6 | 191.0   |
| 7-13     | 6 | 197.0   | 20-22 | 6 | 191.0   |
| 8-13     | 6 | 197.0   | 21-22 | 6 | 218.0   |
| 9-13     | 6 | 221.0   | 22-22 | 6 | 145.0   |
| 10-13    | 6 | 221.0   | 23-31 | 6 | 45.0    |
| 11-13    | 6 | 250.0   | 24-31 | 6 | 70.6    |
| 12-13    | 6 | 250.0   | 25-31 | 6 | 70.6    |
| 13-13    | 6 | 250.0   | 26-31 | 6 | 995.0   |
| 13-36    | 6 | 73.0    | 27-31 | 6 | 123.9   |
| 33-36    | 6 | 97.4    | 28-31 | 6 | 150.5   |
| 34-36    | 6 | 125.0   | 29-31 | 6 | 205.1   |
| 35-36    | 6 | 148.0   | 30-31 | 6 | 205.4   |
| 13-38    | 8 | 98.42   | 31-37 | 8 | 22696   |
| 22-38    | 8 | 6640    | 36-37 | 8 | 1017    |
| 37-38    | 8 | 15111   | 38-39 | 8 | 328     |

The diameter data above is the initial data before it will be optimized. All pipe segments have one value of pipe roughness (\( \epsilon \))
= 0.001 inch, which is taken from common commercial steel pipe.

It must be emphasized that the network is still considered simple due to some conditions and assumptions: no fittings, no mechanical work, and no looping structure in the network.

**IPR and Tubing Data**

The IPR data comes from the well testing as follows:

| Name  | Well | ID     | Depth (ft) | Well | ID     | Depth (ft) |
|-------|------|--------|------------|------|--------|------------|
| Well #1 | 1.995 | 9791   | 1.995      | Well #17 | 1.995 | 9814       |
| Well #2 | 1.995 | 8885   | 1.995      | Well #18 | 1.995 | 9930       |
| Well #3 | 1.995 | 9547   | 1.995      | Well #19 | 1.995 | 8727       |
| Well #4 | 1.995 | 8811   | 1.995      | Well #20 | 1.995 | 9799       |
| Well #5 | 1.995 | 9632   | 1.995      | Well #21 | 1.995 | 9224       |
| Well #6 | 1.995 | 8653   | 1.995      | Well #22 | 1.995 | 9530       |
| Well #7 | 1.995 | 8975   | 1.995      | Well #23 | 1.995 | 8854       |
| Well #8 | 1.995 | 9867   | 1.995      | Well #24 | 1.995 | 9566       |
| Well #9 | 1.995 | 9136   | 1.995      | Well #25 | 1.995 | 9286       |
| Well #10 | 1.995 | 9477   | 1.995      | Well #26 | 1.995 | 9289       |
| Well #11 | 1.995 | 9840   | 1.995      | Well #27 | 1.995 | 9464       |
| Well #12 | 1.995 | 8987   | 1.995      | Well #28 | 1.995 | 9091       |
| Well #13 | 1.995 | 8964   | 1.995      | Well #29 | 1.995 | 9598       |
| Well #14 | 1.995 | 8665   | 1.995      | Well #30 | 1.995 | 9153       |

Using Vogel’s correlation, the maximum rate can be determined as follows:

\[
Q_{\text{max}} = Q_0 \left[ 1 - 0.2 \left( \frac{P_{\text{wf}}}{P_r} \right) - 0.8 \left( \frac{P_{\text{wf}}}{P_r} \right)^2 \right]
\]

Therefore, the maximum rate for this reservoir is 1000 STB/d, and it applies to the whole reservoir, and consequently all wells. Meanwhile, the tubing data for each well can be seen below:

| Name  | ID     | Depth (ft) | Name  | ID     | Depth (ft) |
|-------|--------|------------|-------|--------|------------|
| Well #15 | 1.995 | 8696       | Well #31 | 1.995 | 8673       |
| Well #16 | 1.995 | 9005       | Well #32 | 1.995 | 9876       |

The well cannot produce oil at its maximum rate, so it must be in a range called production corridor.

From the well test data above, it can be inferred that the rate is between 200 STB/d to 400 STB/d. Since this reservoir has maximum rate = 1000 STB/d, then the production corridor is by 20% to 40% from maximum rate.

Recall Vogel’s correlation:

\[
P_{\text{wf}} = 0.125P_r \left[ 0.81 - 0.8 \left( \frac{Q}{Q_{\text{max}}} \right)^{0.5} \right]
\]

where \(P_r\) is average reservoir pressure.

The equation then put on the interpolation of inflow and outflow curve.

The inflow is combination of Vogel’s IPR above and TPR using the correlations for vertical pipe such as Hagedorn Brown, Beggs and Brill, and other established correlation for multiphase fluid flow in pipe. Whether the outflow is the FPR using the same fluid flow in pipe correlation mentioned before.

The result of interpolation is the fluid rate (Q) and wellhead pressure (Pwh), that can be seen below for each well:

| Segment | D (feet) | L (feet) | Q (STB/d) | Pwh (psi) |
|---------|----------|----------|-----------|-----------|
| 1-13    | 6        | 56.0     | 335.19    | 218.75    |
| 2-13    | 6        | 82.0     | 383.68    | 218.76    |
| 3-13    | 6        | 82.0     | 348.65    | 218.76    |
| 4-13    | 6        | 109.0    | 387.47    | 218.77    |
| 5-13    | 6        | 109.0    | 343.99    | 218.77    |
| 6-13    | 6        | 137.0    | 395.54    | 218.78    |
| 7-13    | 6        | 197.0    | 379.01    | 218.79    |
| 8-13    | 6        | 197.0    | 330.90    | 218.78    |
| 9-13    | 6        | 221.0    | 370.60    | 218.80    |
| 10-13   | 6        | 221.0    | 352.43    | 218.79    |
| 11-13   | 6        | 250.0    | 332.41    | 218.79    |
| 12-13   | 6        | 250.0    | 378.37    | 218.81    |
| 14-22   | 6        | 55.0     | 367.02    | 239.71    |
| 15-22   | 6        | 55.0     | 382.82    | 239.71    |
The object to be optimized in this study is the diameter of pipeline. Changing in diameters will affect the fluid velocity, which is the greatest factor of pressure loss in pipe. Pressure drop is not a consideration when the length of pipe is short, since the difference is very small. Therefore, the sensitivity analysis will only be done in the main line that has significant length.

Here is the cost data for Electric-Weld type of pipe, Schedule-40 taken from Columbia Pipe and Supply, Co. price list as updated and distributed by February 2017:

| Nominal ID (in) | Price (US$/ft) |
|----------------|----------------|
| 4              | 22.6           |
| 5              | 30.61          |
| 6              | 39.74          |
| 8              | 58.45          |
| 10             | 86.52          |
| 12             | 105.93         |

The pipeline price can be formulated by taking regression of the table, as can be seen below:

\[
C = \sum_{j=1}^{6} (10.673D_j - 22.74)
\]

where
\[
C = \text{total cost of pipe, US$}
\]
\[
j = \text{pipe segment number}
\]
\[
D = \text{oil price, US$/STB}
\]

As explained before, the pipe segments that will be optimized will only the main pipeline after the branch line from well head, as can be seen below (the colored one):
Figure 7. Pipe Segment to be Optimized

The segments data can be seen in this table:

| j     | Segment | Initial Diameter (in) | Length (ft) |
|-------|---------|-----------------------|-------------|
| 1     | 31-37   | 8                     | 22696       |
| 2     | 36-37   | 8                     | 1017.06     |
| 3     | 13-38   | 8                     | 98.42       |
| 4     | 22-38   | 8                     | 6640.42     |
| 5     | 37-38   | 8                     | 15111.55    |
| 6     | 38-39   | 8                     | 328         |

As for revenue, the oil price is taken at $50/bbl. The revenue function can be formulated as:

\[ R = PQ \]

where

\( R \) = total revenue in one day production, US$
\( P \) = oil price, US$/bbl
\( Q \) = oil production in one day, bbls

The objective function for the optimization can be written as:

\[ \text{Maximize } BCR = \frac{PQ}{\sum_{i=1}^{6}(10.673D_i - 22.74)} \]

Whether the constraints of the optimization are:

\[ 6 \leq D_{31-37} \leq 12, \quad 6 \leq D_{36-37} \leq 12, \]
\[ 6 \leq D_{13-38} \leq 12, \]
\[ 6 \leq D_{22-38} \leq 12, \quad 6 \leq D_{37-38} \leq 12, \]
\[ 6 \leq D_{28-39} \leq 12, \]
\[ 0 \leq P_{wf} \leq 1320, \quad 0 \leq Q \leq 1000, \]
\[ P_{separator} = 200 \]

The method used for this analysis is Generalized Reduced Gradient for nonlinear optimization. The result for diameter selection can be seen below:

| Segment | Diameter (in) | Length (ft) |
|---------|---------------|-------------|
| 31-37   | 6.00          | 22696       |
| 36-37   | 6.89          | 1017.06     |
| 13-38   | 7.00          | 98.42       |
| 22-38   | 6.46          | 6640.42     |
| 37-38   | 7.53          | 15111.55    |
| 38-39   | 7.46          | 328         |

With the current result, the highest benefit-to-cost ratio (BCR) calculated in this optimization is 0.37.

The configuration above shows that the optimum diameter is not always the maximum, because at certain point, the increasing cost of pipe is above the increasing of revenue as manifested in oil production rate.

CONCLUSIONS

From this study, it can be concluded that:

1. Combination of nodal system analysis and mathematical method of interpolation can be applied to obtain fluid rate from IPR and TPR.
2. Integrated simulation of the whole production system from the reservoir to separator is a mandatory to be done to get accurate result of optimization.
3. Pipeline has its optimum diameter configuration, and it is not always the maximum diameter due to economical limit.
4. The optimum design for the network is concluded by the maximum benefit to cost ratio (BCR) obtained from the optimization using GRG Nonlinear Method, which is 0.37, with diameter distribution vary from 6 inches to 7.53 inches.

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