Makara Journal of Technology

Volume 17 | Issue 2 Article 9

8-2-2013

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Recommended Citation

Soemardan, Suprapto; Purwanto, Widodo Wahyu; and Arsegianto, Arsegianto (2013) "Production Optimization for Plan of Gas Field Development Using Marginal Cost Analysis," *Makara Journal of Technology*: Vol. 17: Iss. 2, Article 9.
DOI: 10.7454/mst.v17i2.1953
Available at: https://scholarhub.ui.ac.id/mjt/vol17/iss2/9

Makara Seri Teknologi, 2013, 17(2): 94-102
DOI: 10.7454/mst.v17i2.1953

Production Optimization for Plan of Gas Field Development Using Marginal Cost Analysis

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Abstract

Gas production rate is one of the most important variables affecting the feasibility plan of gas field development. It take into account reservoir characteristics, gas reserves, number of wells, production facilities, government take and market conditions. In this research, a mathematical model of gas production optimization has been developed using marginal cost analysis in determining the optimum gas production rate for economic profit, by employing the case study of Matindok Field. The results show that the optimum gas production rate is mainly affected by gas price duration and time of gas delivery. When the price of gas increases, the optimum gas production rate will increase, and then it will become closer to the maximum production rate of the reservoir. Increasing the duration time of gas delivery will reduce the optimum gas production rate and increase maximum profit non-linearly.

Abstrak

Optimisasi Produksi untuk Perencanaan Pengembangan Lapangan Gas dengan Analisis Biaya Marginal. Laju produksi merupakan salah satu variabel penting yang mempengaruhi kelayakan perencanaan pengembangan lapangan gas berdasarkan atas karakteristik reservoir, jumlah sumur, fasilitas produksi, kondisi pasar dan memenuhi porsi penerimaan pemerintah. Dalam penelitian ini suatu model matematika optimisasi produksi gas dikembangkan untuk menentukan laju produksi gas optimum berdasarkan pendekatan analisis biaya marginal yang mengacu pada keuntungan ekonomi, khususnya untuk kasus kajian di lapangan gas Matindok.. Hasil penelitian memperlihatkan bahwa laju produksi gas optimum sangat tergantung harga gas dan durasi lamanya pengiriman gas. Ketika harga gas naik, laju produksi gas optimum akan naik dan mendekati laju produksi maksimum reservoir. Peningkatan durasi pengiriman gas akan menurunkan laju produksi gas optimum dan meningkatkan keuntungan maksimumnya secara non-linear.

Keywords: marginal cost, natural gas fields, production optimization

1. Introduction

Accurate planning of gas field development is not only dependent on the characteristics of the reservoir, but also on proper emphasis of cost allocation for each work activities of gas production capacity [1-2].

Several studies have been conducted to optimize the gas business through a variety of methods. These include surveys of the literature dealing with the optimization of petroleum and natural gas production; drilling, reservoir simulation, production planning and operations, enhanced recovery processes [3]; the daily production rates for an offshore oilfield to achieve a production target [4]; and a network model of production allocation incorporated in an infrastructure model of pressure-flow rates for wells, pipelines and facilities [5]. An optimization model of hybrid economic and production systems of gas wells was presented by Chermak *et al.* [6]. Another model, known as "forecasting production in the medium and long-term," is the model of allocation of production which was developed by Shell [7]. Zhao *et al.* [8] presented an optimization model of oil production rate by marginal cost analysis with contract effects for international oil development projects. The effects of geology, technology, and oil contracts of the host country on oil production rates are described in their study. The result indicates that the optimal production rate is greatly influenced by the contract terms, and at the optimal rate the production is in a plateau phase. Abdel Sabour [9] showed that marginal cost analysis can be used to create a model to estimate the optimum mine size. The model was developed on the basis of marginal analysis, assuming that the optimum level of production is a condition in which the present value of the marginal cost is equal to the present value of marginal revenue.

The aim of this paper is to develop a model of gas production optimization to solve the optimum gas production rate using marginal cost analysis.

Marginal Cost Model: Cost curves. Fig. 1 shows the total cost curve versus gas production rate of the developed gas field. In the early stage of field development, some expenses have been paid, while the exploration stage for discovery of the gas reserve is considered as a fixed cost. Primary production will entail costs to set up the production facility. This stage is called the *high cost for low production zone.*

The fully developed stage of high daily production, which is approaching the reservoir's maximum capacity, will impose a substantial cost for numerous production wells, environmental handling, treatment of CO_2 and H_2S, and the possible addition of compressed gas in the *declining reservoir pressure* phase. This stage is called the *high cost for high production zone*. Between the intervals of the *high cost for low production zone* and the *high cost for high production zone*, there is the effective stage where the additional cost of adding gas production will be lower than the previous stages. The zone between the two stages is called the *cost effective zone*.

Total Cost (*TC*) is generated by the sum of Fixed Cost (*FC*) and Variable Cost (*VC*) [10]. Fixed costs are the costs of identifying gas reserves through seismic and exploration activity, whereas variable costs are the costs of field development and operations/maintenance.

$$TC = FC + VC \tag{1}$$

Total cost for each production unit (TC/Qg_{cum}) will be very high at the low production zone and will decrease in the effective production zone; however it will rise again at the high production zone. Average cost (*AC*) is the cost for each production unit of gas, while marginal cost (*MC*) refers to the total additional cost as a result of the increase in one unit of gas produced [11-12].

$$AC = \frac{TC}{Qg_{cum}} \tag{2}$$

$$MC = \frac{dTC}{dQg} \tag{3}$$

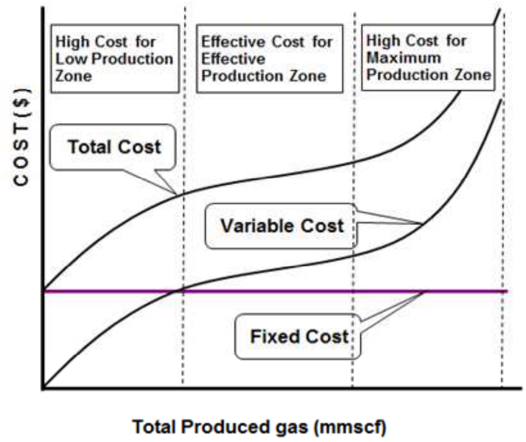

Fig. 1. The Fixed Cost, Variable Cost and Total Cost Versus Gas Production Rate

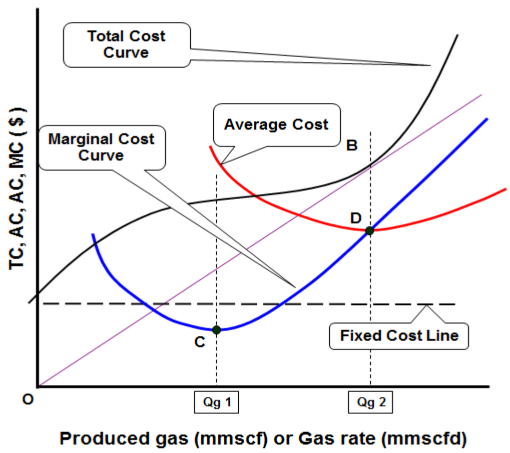

Fig. 2. Curves of Total Cost, Marginal Cost and Average Cost

Each curve of total cost (*TC*), average cost (*AC*), and marginal cost (*MC*) are illustrated in Fig. 2. Value and curve shape of *TC* is very dependent on gas rate and time of delivery; therefore, *AC* and *MC* also depend on *Qg* and *TP*. *TC* is non-linear to Qg_{cum}, and *AC* and *MC* are non-linear to *Qg* or Qg_{cum}. In particular, the *MC* curve will cross the *AC* curve at the minimum point of *AC* in the D point. The D point will give the Qg_2 as the recommended minimum gas rate ($Qg_{min\text{-}rec}$) which is based on the reservoir capacity and costs incurred. At the point of D, there shall be applied $dAC/dQg = 0$.

Total and marginal revenue. Total revenue is revenue earned from all products (gas and condensate) in monetary units. It is written as:

$$TR = (GP \times Qg_{cum}) + (CP \times Qc_{cum}) \tag{4}$$

Where: *TR* is total revenue in US dollars. *GP* and *CP* are the price of gas ($/mscf or $/mmbtu) and condensate price ($/bbl) respectively, while Qg_{cum} and Qc_{cum} are

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DOI: 10.7454/mst.v17i2.1953

total cumulative gas production (mscf) and cumulative condensate production (bbl).

Condensate production rate (Qc) in Eq. (4) is predicted using condensate/gas ratio (CGR) multiplied by gas production rate (Qg), and is written:

$$Qc = Qg \times CGR \tag{5}$$

Where: Qc in bbl/d and the CGR in bbl/mmscf depend on reservoir type. For dry-gas and wet-gas reservoirs, condensate rate is generally linear to gas deliverability, with CGR considered constant during gas production [13-15]. For the gas-condensate reservoir type, condensate rate can be predicted by Boogar's equation [16], where CGR will remain constant at pressure above the dew point. When pressure drops below the dew point, the CGR will decline depending on the reservoir pressure.

Marginal Revenue (MR) is the result of differentiating incremental total revenue to additional gas production rate as given in the equation:

$$MR = \frac{dTR}{dQg} \tag{6}$$

Gas price and condensate price. Gas price should preferably be set higher than the minimum gas price (GP_{min}). The GP_{min} is most likely acceptable to all stakeholders, both government and the oil and gas producer. GP_{min} is calculated from production cost (PC), risk factor during exploration (ER), the return on costs (ROC), and what the government takes (GT), so that the GP_{min} can be written as follows:

$$GP_{\min} = PC + ROC + ER + GT \tag{7}$$

Where GP_{min}, PC, ROC, ER and GT are in \$/mscf or \$/mmbtu. The ROC is determined from $\%ROC \times PC$ and the ER is calculated from $\%ER \times PC$. The $\%ROC$ and $\%ER$ is determined by the operator on its investment policy. GT is estimated from ($\%BN$ / $\%BO$) $\times$ ROC, where $\%BN$ is the portion the government takes and %BO is the operator's portion. The government's portion is based on the oil and gas mining contract subject to the Law of Oil and Gas.

Gas price may be formulated as follows:

$$GP \geq PC \times \left[1 + \%ROC + \%ER + \frac{\%BN}{\%BO} \times \%ROC \right] \tag{8}$$

PC is calculated by Eq. (9) as follows:

$$PC = \frac{TC}{(Qg_{cum})} \tag{9}$$

Boucher [17] emphasizes that the gas price needs to be carefully considered by the prospective users of gas in terms of willingness to pay to generate the best price, and considering the long-term economics.

Optimum production rate. Optimum gas production rate (Qg_{opt}) is defined as gas production rate which results in maximum profit (π) for the operator as investor without reducing the government's portion. Profit for the operating party means that total cost is deducted from total revenue and multiplied by the operator's portion (%BO):

$$\pi = \%BO \times (TR - TC) \tag{10}$$

Where: $\%BO + \%BN = 1$.

Furthermore, Eq. (10) is differentiated to incremental gas rate; then, considering Eqs. (3) and (6), then:

$$\frac{d\pi}{dQg} = \%BO \times (MR - MC) \tag{11}$$

Mathematically, maximum profit (π_{max}) will occur at the gas rate point where the increasing gas rate has no more influence on profit, either positive or negative. In other words, optimum gas production rate (Qg_{opt}) will occur when $d\pi / dQg = 0$**,** or $MR = MC$, which will also generate maximum profit. The maximum profit is a function of TR which contains the gas price; thus, the value of π_{max} will highly depend on gas and condensate prices.

2. Methods

This study uses the case of development planning of Matindok Field in Central Sulawesi, which is one of the suppliers to LNG plants [18]. Fig. 3 is a schematic diagram for solving the optimization of gas production planning by the following steps:

Data acquisition and processing. There are three kinds of data that are input in the data acquisition and analysis process. Technical data consist of geology-reservoir data which result from Geology-Geophysics-Reservoir (GGR) analysis and simulation. Other technical data include production facility data required by the production system [13-15]. Several engineering data in Matindok Field are summarized in Table 1 [18].

Financial data consist of fixed expenses such as exploration expenses, including predevelopment expenses in the past. Future costs are dependent on the scheduled plan for well development and production facilities which are aligned to required gas rate, duration time of gas delivery, and pressure system. Fixed expenses consist of exploration activities which include costs of preparation, sub-surface engineering studies, seismic acquisition and interpretation, and realization of exploration drilling and pre-development. Table 2 shows that exploration cost was \$5.5 million US, while well development is expected to cost US\$51.4 million [18].

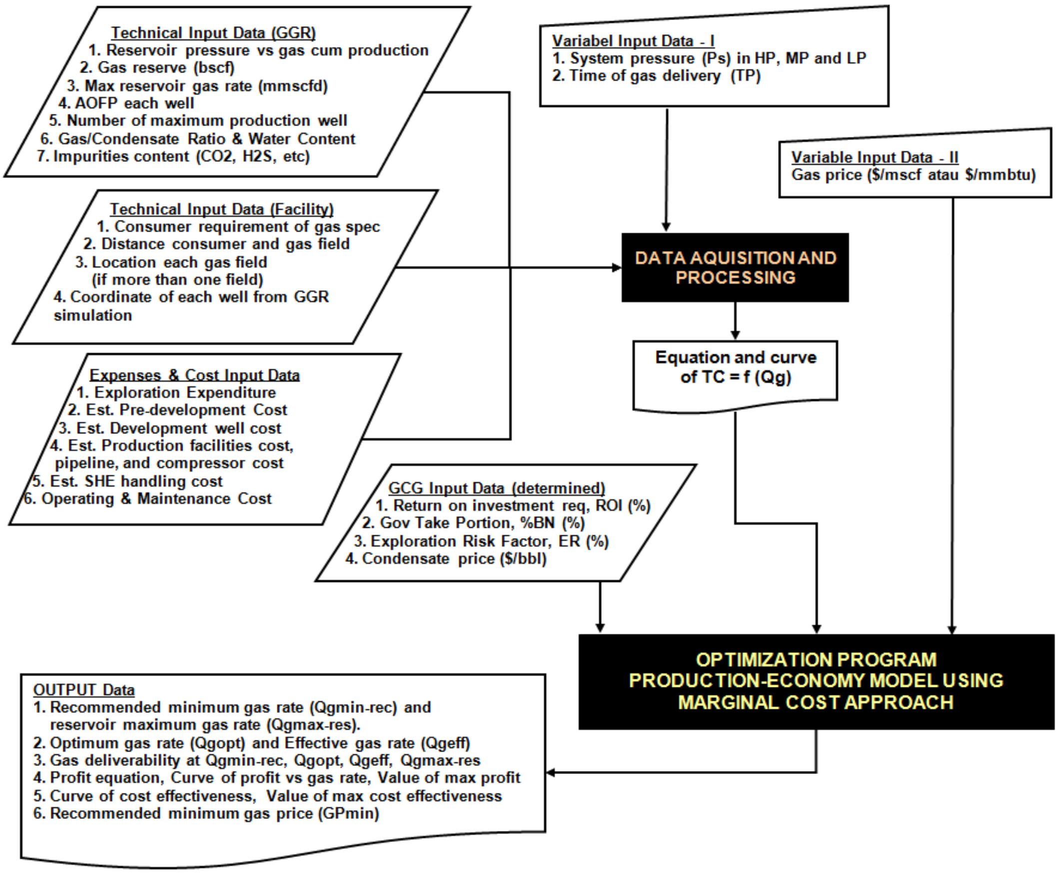

Fig. 3. Schematic Diagram of Gas Field Development Using Marginal Cost Approach

Table 1. Summary of Engineering Data in Matindok Field

Description	Code, Formula	Value	Unit
Gas Reserve (90%P_1+50%P_2)	Calculated	236.44	bscf
Maximum Gas Deliverability	Calculated	196.25	bscf
Bottom Hole Pressure	well test	2,725	psi
Estimated Well Max Capacity	well test	35.74	mmscfd
Reservoir Expansion Factor (Bg)	test lab	0.0082738	cuft/scf
CO_2 Content	test lab	5	Mol%
H_2S Content	test lab	4,000	ppm
Gas-condensate ratio	well test	71,400 (wet gas)	Scf/bbl
Water Content	from the DST	See curve	bbl/mmscf
	High	X $\geq$ 800	psi
Pressure System	Medium	400<X<800	psi
	Low	400	psi
Well production capacity	20% of AOFP	Max 10	mmscfd/well

Note: AOFP = Absolute Open Flow Potential, DST = Drill Stem Test

Variable costs consist of well development, production facilities, pipeline, land acquisition and preparation, utilities, and allocated cost for plant abandonment. All are determined according to the amount of gas produced based on reservoir capacity. Production facility costs are mainly flow line and pipeline, Acid Gas Removal Unit and Sulfur Recovery Unit (AGRU/SRU), water treatment unit, booster compressor, and CO_2 injection compressor. Based on the experiences in upstream activity planning, the current cost for an onshore

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development well is around \$5,600 per meter of depth [18]. The operating costs consist of direct operating for gas and condensate production, handling for produced water, CO_2 compression to reservoir, H_2S handling, AGRU-SRU operation, and insurance of assets. Direct operating costs also cover all costs for production and processing, pipeline, utilities, operation and maintenance for all equipment, and booster compressor.

From the acquisition and processing steps, an equation and curve of *TC* and gas deliverability patterns will result in maximum reservoir gas rate. The equation and curve of *TC* will be the main object that will be solved.

Gas deliverability estimation. A gas deliverability scenario is based on pressure system and duration time desired by agreement between the gas producer and consumer. Reservoir pressure and pressure drop for each gas flow rate is set for each gas reservoir. Reservoir engineering knowledge [16-17] has correlated between Bottom Hole Flowing Pressure (*BHFP*) and cumulative gas production (Qg_{cum}) by:

$$BHFP / Z = -m(Qg_{cum}) + (BHFP)_i \quad (12)$$

After correlation among reservoir pressure, Qg_{cum}, remaining gas reserve at every flow rate (Qg), and the number of production wells which can be drilled, it is then necessary to install the production facilities, including booster compressor and pipeline. Qg_{cum} is calculated from gas deliverability during production year based on the reservoir characteristics using petroleum engineering practice [14] and Boogar's approach [16]. When reservoir pressure has dropped below the pressure system setting, the gas compressor should then be installed to increase outlet pressure up to the pressure setting. The remaining gas reserve is calculated by deducting the initial reserve from Qg_{cum} at the pressure condition of the reservoir.

Table 2. Realization Exploration Costs and Estimated Development Well for Matindok Field

Well	Depth (m)	Cost (million \$)	Remarks
Existing wells		5.5	Exploration well
MTD-2	2,200	12.5	Delineation vertical well
MTD-3	2,347	13.4	New directional well
MTD-4	2,235	12.7	New vertical well
MTD-5	2,235	12.7	New directional well

Table 3. *Qg* and *TC* Data Summary in Matindok Field for 15 Years

Qg mmscfd	Qg_{cum} mmscf	Qc Bcpd	Prod. Well	Booster Compressor	CO_2 injection Compressor	Total Cost (million \$)
0.00	0	0	0	Not required	Not required	10.54
4.73	23,414	70	2	Not required	Not required	141.16
6.15	30,438	91	2	Not required	Not required	146.35
7.57	37,462	112	2	Not required	Not required	151.55
9.46	46,827	140	2	Not required	Not required	158.47
11.35	56,192	168	2	Not required	Not required	193.09
13.24	65,558	196	2	Not required	Not required	208.80
15.14	74,923	224	3	Not required	Not required	230.66
16.08	79,606	238	3	Not required	Not required	234.83
17.88	88,503	265	3	Not required	Not required	258.41
18.92	93,447	280	3	Required	Not required	271.03
19.87	97,635	294	3	Required	Not required	303.21
20.81	10,588	308	4	Required	Not required	329.03
22.70	108,953	336	4	Required	Not required	360.06
24.43	115,209	362	4	Required	Not required	386.83
26.02	119,048	385	4	Required	Not required	406.47
27.43	125,342	406	4	Required	Not required	414.94
28.43	128,545	421	4	Required	Not required	456.14
29.33	131,391	434	4	Required	Not required	467.28
30.57	135,248	452	4	Required	Not required	474.42

Correlation of gas production and total cost. Based on estimated gas production rate and total cost at time of gas delivery, the correlation of the polynomial equation is adopted by using MATLAB within an accuracy of R^2. The polynomial equation is a third-order equation. Based on the equation of total cost and cumulative gas production rate, marginal cost (*MC*), average cost (*AC*), and minimum gas price (GP_{min}) should have a polynomial equation using Eqs. (2), (3), and (7).

Production rate optimization. The optimum production rate is obtained by maximizing the objective function of profit (π) as explained in the previous section. Gas price (*GP*) and duration time of gas delivery (*TP*) are put in exogenous variables. There are also *GCG* input data as constant variables, such as government take portion (*%BN*) as stipulated in the contract, return on cost (*ROC*), and exploration risk factor (*%ER*) determined by operator requirement.

The equation of *TR* as a function of *Qg* can be generated by a computer program using a one-dimensional, non-linear model. After that, the value of π can be estimated for each *Qg* by using Eq. (10). The recommended minimum gas rate ($Qg_{min\text{-}rec}$), the effective production rate (Qg_{eff}), the optimum gas production rate (Qg_{opt}) and the maximum profit (π_{max}) can be estimated from the equation of π. Maximum and minimum gas production rates of the reservoir and a combination of contract terms will be constraints in this research.

3. Results and Discussion

Cost curve. For a duration of 15 years, the estimated *Qg* and *TC* is made in 20 data points about the total of capital and operating costs for each gas rate as shown in Table 3. The equation of total cost as a function of cumulative gas production rate is represented in Fig. 4.

$$TC = 3.11\text{E-}7(Qg_{cum})^3 - 0.056(Qg_{cum})^2 + 5{,}449(Qg_{cum}) + 10.54\text{E}6 \quad (13)$$

To simplify, the correlation between gas rate and cumulative produced gas can be shown in Fig. 5 and its correlation can be written as:

$$Qg_{cum} = -1.76Qg^3 + 44.02Qg^2 + 4{,}702\ Qg + 85.29 \quad (14)$$

Average and marginal cost. The average cost (*AC*) and marginal cost (*MC*) according to Eqs. (2) and (3) can be determined from the equation of total cost in Eq. (13). The equations of *AC* and *MC* are as follows:

$$AC = 3.11\text{E-}7(Qg_{cum})^2 - 0.056(Qg_{cum}) + 5{,}449 + 05\text{E}7(Qg_{cum})^{-1} \quad (15)$$

$$MC = 9.34\text{E-}7(Qg_{cum})^2 - 0.112(Qg_{cum}) + 5{,}449 \quad (16)$$

MC and *AC* curves in function *Qg* are obtained from Eqs. (14), (15), and (16) as shown in Fig. 6. From the *AC* curve, we get point AC_{min} at about $3.05/mscf at

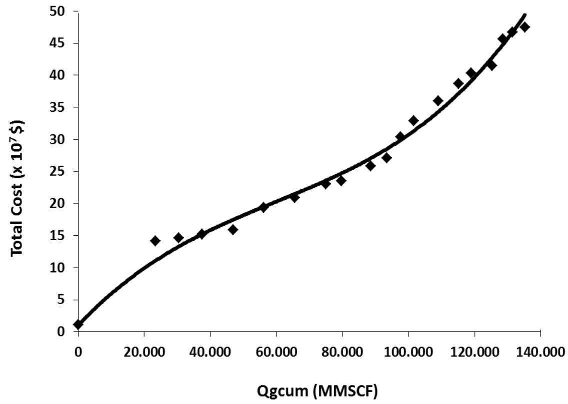

Fig. 4. *TC* vs. Qg_{cum} Curve in Matindok Field with *TP* = 15 Years

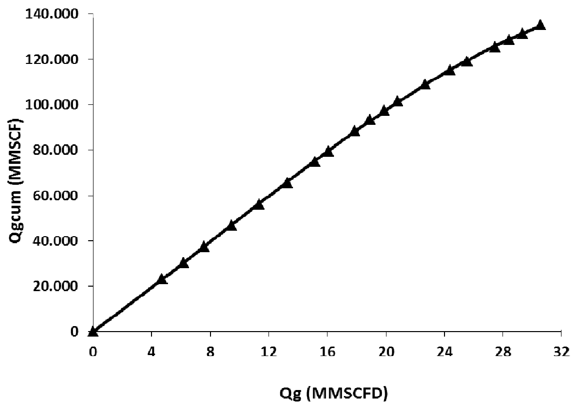

Fig.5. Qg_{cum} vs. *Qg* curve with *TP* = 15 years

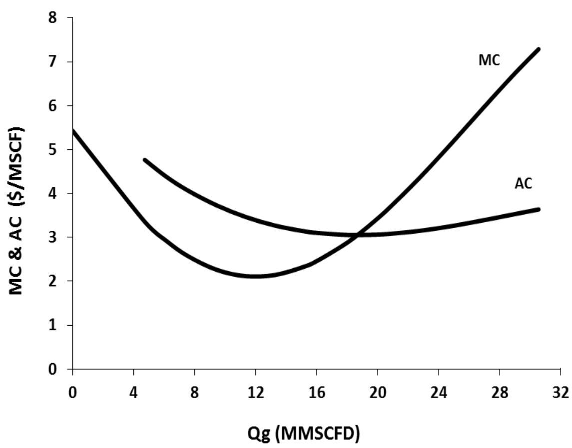

Fig. 6. *MC* and *AC* vs. *Qg* in Matindok Field with *TP* = 15 Years

AC = *MC*, and minimum gas production rate ($Qg_{min\text{-}rec}$) is 18.64 mmscfd. For another time of delivery (*TP*), more or less than 15 years, another recommended minimum gas production rate ($Qg_{min\text{-}rec}$) will be identified as different from previously.

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Gas price and total revenue. Given that Production Sharing Contractor (*PSC*) policy for the *ROC* is 16%, *ER* is 10%, *GT* is 67.5%, then the GP_{min} at Matindok Field for various durations of gas delivery can be simulated using equations (7) and (8). Fig. 7 shows minimum gas price (GP_{min}) at each *Qg* for Matindok Field with *TP* = 15 years compared to average cost (AC). The GP_{min} of around \$5.49/mscf occurs when recommended gas rate ($Qg_{min\text{-}rec}$) = 18.67 mmscfd. At another gas production rate, the gas price will be higher than \$5.49/mscf.

By putting in values of gas price (*GP*), condensate price (*CP*), cumulative gas (Qg_{cum}) and cumulative condensate (Qc_{cum}), total revenue will be identified from Eq. (4). Fig. 8 shows *TR* curve versus *Qg* and then the equation of TR can be obtained:

$$TR = -10{,}798Qg^3 + 26{,}6136\ Qg^2 + 3E{+}07Qg \qquad (23)$$

Optimum gas production. Based on *TC* and *TR*, profit (π) can be determined by Eq. (10). For *GP* = \$5/mscf, *CP* = \$80/bbl, *TP* = 15 years and the government's take portion (*%BN*) is 67.5%, the profit curve will be as shown in Fig. 9. The profit will increase if gas production

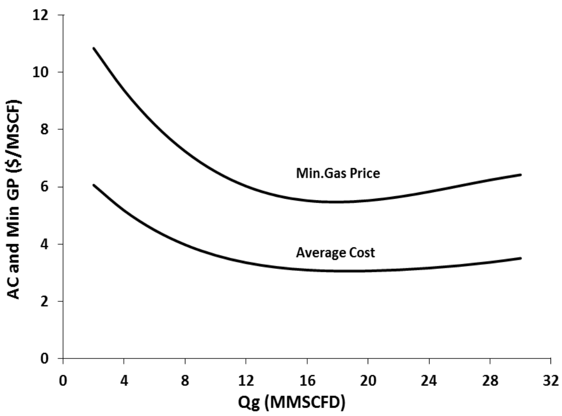

Fig. 7. Average Cost and Minimum Gas Price vs. *Qg* Plateau at Ps = 800psi, *GP* = \$5/mscf, *CP* = \$80/bbl, *TP* = 15 Years

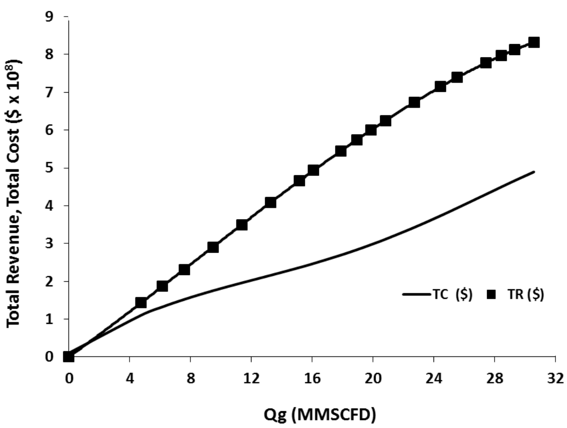

Fig. 8. *TC*, T*R* and π vs. *Qg* in Matindok Field at *GP* = \$5/mscf, *CP* = \$80/bbl, *TP* = 15 Years

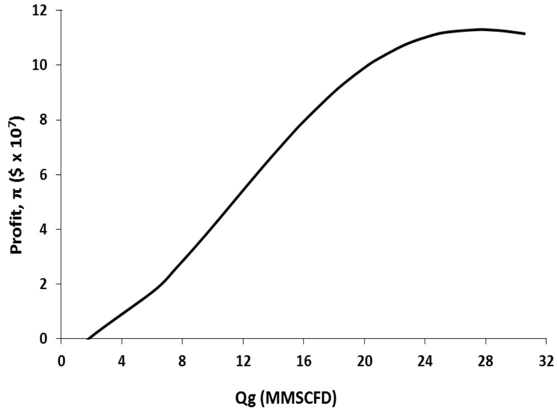

Fig. 9. Profit vs. Qg in Matindok Field at *GP* = \$5/mscf, *CP* = \$80/bbl and *TP* = 15 Years

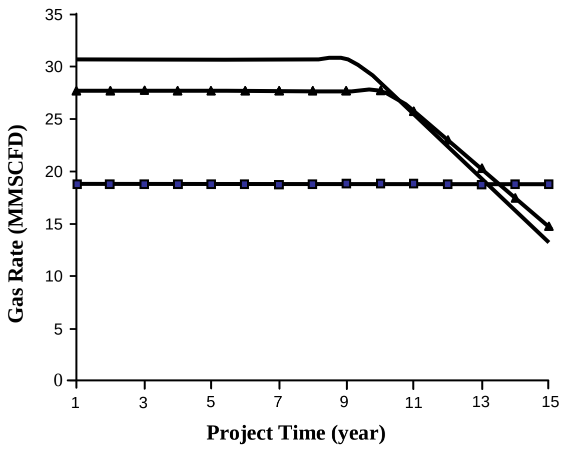

Fig. 10. Gas Deliverability in Matindok Field at *GP* = \$5/mscf, *CP* = \$80/bbl, *TP* = 15 Years. Qgmax-res (▬), Qgopt (▲), and Qgmin-rec (■)

rate increases. However, it can be seen that the profit will reach a maximum value at a certain gas production rate. The maximum profit (π_{max}) is about \$114.9 million and the prediction of optimum gas production rate (Qg_{opt}) will be at 27.63 mmscfd.

Fig. 10 shows how the position of optimum gas rate (Qg_{opt}) compares to another gas rate position such as minimum gas rate ($Qg_{min\text{-}rec}$), and maximum reservoir gas rate ($Qg_{max\text{-}res}$).

Factors influencing optimum production rate. If the gas price increases from \$4 to \$8/mscf and condensate price is kept at \$80/bbl, the values of Qg_{opt} and π_{max} are shown in Table 4. The gas can generate a maximum profit that becomes higher and higher at the high value of *GP*.

Profit is highly dependent on the prices of gas and condensate. For example, if *GP* is raised to \$5.5/mscf then π will increase to \$135.9 million and optimum flow rate will be at 28.84 mmscfd. Increasing gas prices will generate an optimum production rate (Qg_{opt}) closer to the maximum production rate of the reservoir ($Qg_{max-res}$). The table also presents that a gas price around \$6/mscf will generate Qg_{opt} equal to $Qg_{max-res}$, 30.57 mmscfd, with π_{max} around \$155.2 million. In contrast, a GP = \$5/mscf will generate $Qg_{opt} < Qg_{max-res}$. This condition can be explained by observing that the gas price of \$6/mscf has exceeded the previously-calculated minimum gas price of \$5.49/mscf. Therefore, $Qg_{opt} = Qg_{max-res}$ and total cost will stabilize at the same value when the gas price is higher than the minimum.

Duration time of gas delivery affects the optimum production rate as shown in Table 5. By increasing the duration of gas delivery, the optimum gas rate will be decreased non-linearly, while the maximum profit will rise sharply at TP less than 20 years. The values then tend toward constant at TP greater than 20 years, as shown in Fig. 11.

Table 4. Impact of Gas Price (GP) on Optimum Gas Production Rate at CP = \$80/bbl, TP = 15 Years

GP \$/mscf	Qg_{opt} mmscfd	Qg_{max} mmscfd	π@ Qg_{opt} (MM\$)	π@Qg_{max} (MM\$)
4	25.09	30.56	73.65	67.25
5	27.63	30.56	113.16	111.26
6	30.57	30.56	155.25	155.25
7	30.57	30.56	199.23	199.23
8	30.57	30.56	243.20	243.20

Table 5. Impact of *TP* on Optimum Production Rate with *GP* @ \$5/mscf and *CP* @ \$80/bbl

TP (years)	Qg_{opt} mmscfd	π @Qg_{opt} (MM\$)
10	35.60	97.25
15	27.63	113.16
20	22.04	120.58
25	18.31	123.17

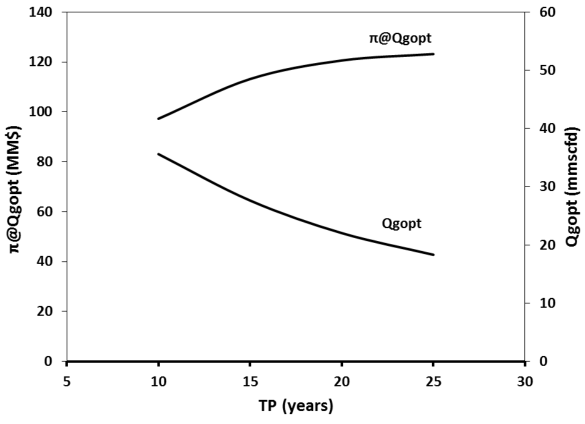

Fig. 11. Effect of Time of Gas Delivery on Optimum Gas Rate and Maximum Profit in Matindok Field

4. Conclusions

In this paper, we estimated the empirical cost function based on technical and economic data of gas field development. The optimization based on marginal cost was done to find the optimum gas production rate for given constraints and exogenous variables.

The optimization results revealed that the optimum production rate was greatly influenced by the gas price and duration time of gas delivery. It was found that as the gas price increased by \$1/mmscf, gas production rate increased by 10% and then tended closer to the maximum production rate of the reservoir. At the range of reservoir ability, increasing duration time of gas delivery will reduce the optimum gas production rate and increase maximum profit non-linearly.

The analysis of the relationship between exogenous variables and optimum production rate is helpful for companies in negotiating gas prices in contracts. It provides vital information for companies developing a gas field strategy.

Acknowledgments

The author (Soemardan) wishes to express many thanks to the *Matindok Gas Development Project* of PERTAMINA EP during his (Soemardan) position as Field Development Manager from 2003-2008, Prof. Widjajono Partowidagdo (Petroleum Department ITB) for his support and guidance during this research, and Mr. Abdullah (Mathematics Department ITB) for his assistance in computer programming.

List of Notations

AC	Average cost
AC_{min}	Minimum average cost
$AOFP$	Actual open flow potential
$BHFP$	Bottom hole flowing pressure
$\%BO$	Operator take portion
$\%BN$	Government take portion
CP	Condensate price
CGR	Condensate/gas ratio
ER	Exploration risk
$\%ER$	Percentage of exploration risk
FC	Fixed cost
GP	Gas price
GP_{min}	Minimum gas price
GT	Government takes
GCR	Gas/condensate ratio
GGR	Geology-Geophysics-Reservoir
$G\&G$	Geology and Geophysics
MC	Marginal cost
MR	Marginal revenue
PC	Production cost
PSC	Production Sharing Contractor

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DOI: 10.7454/mst.v17i2.1953

P_oBS	Output pressure after Block Station
Qg	Gas production rate
Qg_{opt}	Optimum gas production rate
$Qg_{min\text{-}rec}$	Recommended minimum gas rate
$Qg_{max\text{-}res}$	Maximum gas production rate of reservoir
Qg_{cum}	Cumulative gas production rate
Qc	Condensate production rate
ROC	Return on Cost
$\%ROC$	Percentage of return on cost
TC	Total cost
TP	Duration time of gas production or delivery
TR	Total revenue
VC	Variable cost
Z	Compressibility factor
π	Profit
π_{max}	Maximum profit
$\pi@Qg_{min}$	Profit at minimum gas production rate
$\pi@Qg_{max\text{-}res}$	Profit at maximum reservoir gas production rate
$\pi@Qg_{opt}$	Profit maximum at optimum gas production rate
$\pi@Qg_{eff}$	Profit at effective gas production rate

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