PRJ, Vol. 2 (January 1990); P. 17–24, 7 FIGS, 3 TABLES.

SIMPLE MODEL TO PREDICT THE DELIVERABILITY OF VOLUMETRIC GAS RESERVOIRS

M.A Benrewin*

نموذج رياضي بسيط لحساب توقعات الإنتاج من المكامن الغازية الحجمية

المبروك أحمد بن روين

تم تطوير نموذج رياضي بسيط يمكن إستخدامه في حساب توقعات الإنتاج من المكامن الغازية الحجمية تحت ظروف مختلفة للإنتاج. كما تم أيضاً إختبار هذا النموذج الرياضي على مكمن غازي ، وكانت النتائج إيجابية ومعقولة وفي مستوى ما هو متعارف عليه في صناعة الغاز. وبالإمكان إستخدام هذه الطريقة الرياضية في الدراسات المبدئية لتطوير حقول الغاز على أن يؤخذ في الإعتبار بعض القيود المفروضة عند إستخدام النموذج.

ABSTRACT

There are many ways to predict the deliverability of gas reservoirs ranging from a simple material balance equation to very complicated gas models.

A simple mathematical model was developed in this study which can be used to predict the deliverability of volumetric gas reservoirs under different production scenarios. The model was tested with real data and proved to be reasonable for initiating any development plan for volumetric gas reservoirs. Some limiting assumptions were imposed on the model and must be considered when using it.

INTRODUCTION

Predicting deliverability from a gas reservoir is an essential element in deciding whether or not it can be developed economically. An optimum development plan depends on the specific characteristics of the reservoir and the market conditions.

If a gas reservoir is to be produced against a constant back pressure of a pipeline, it is important to know if contract rates can be met, and for what time period. When contract rates are predicted to be in deficit, remedial alternatives must be investigated to sustain the required rate.

There are many ways to predict the deliverability of gas reservoirs ranging from a simple material balance equation to very complicated compositional model. In this paper a mathematical model was developed to predict the deliverability of a volumetric gas reservoir, for different producing scenarios, to meet and maintain desired contract demand rates.

MODEL FORMULATION

Consider the situation when a pipeline company prepares a contract for purchase of gas from a gas reservoir. The contract may include a variable demand rate schedule and may also require that the gas be delivered at a specific delivery pressure.

If that gas reservoir is to be produced against a constant back pressure of a pipeline, the production performance will consist of an initial period of a constant rate followed by a decline. To control the decline and maintain the deliverability, it will be necessary to:

1. reduce the delivery pressure,
2. reduce the tubing head pressure and install gas compressor, or
3. drill more wells.

The reservoir development problem becomes one of providing sufficient well deliverability capacity to meet the target rates. Then, facilities need to be constructed to transport gas from the well head to the pipeline, at the specified delivery pressure. The production must pass through separators, dehydrators, meter runs and flow lines to the pipeline. Some pressure drop is associated with each of these equipment parts.

*Petroleum Engineering Department, Al-Raya Al-Khadra University Tripoli, Libya, (G.S.P.L.A.J.)

There should be a relationship between the delivery conditions (rates and delivery pressure) and the ability of the reservoir to meet those conditions. The relation can be formulated by integrating the reservoir, wellbore and flow facilities by specifying the delivery conditions (rates and delivery pressures) at the pipeline; pressure losses in the surface facilities and wellbore can be calculated to provide the correct pressure drop between the reservoir and the wellbore. From this pressure drop the deliverability of the wells and the reservoir can be determined.

This study was concerned with the development of volumetric gas reservoir near a large pipeline. Some assumptions are to be considered to simplify the formulation of the model.

1. A volumetric dry gas reservoir under natural depletion, no water influx, and no water or hydrocarbon liquid production. There is no need for gas separators, dehydrators.
2. All producing wells are a short distance from the transmission line so the pressure drop in the gathering line is negligible.
3. The largest pressure drop was assumed to occur between the gathering stations and the farthest well. Accordingly, any well can be assumed to behave as the farthest well.

Fig. 1 shows a schematic drawing of the proposed network to be modelled. The surface facilities in the field consist of a transmission line between the well and the delivery point at the pipeline.

By specifying the delivery pressure and the daily required rate, the well head pressure can be computed by calculating the pressure drop along the transmission line using Weymouth's equation for horizontal flowlines [1]:

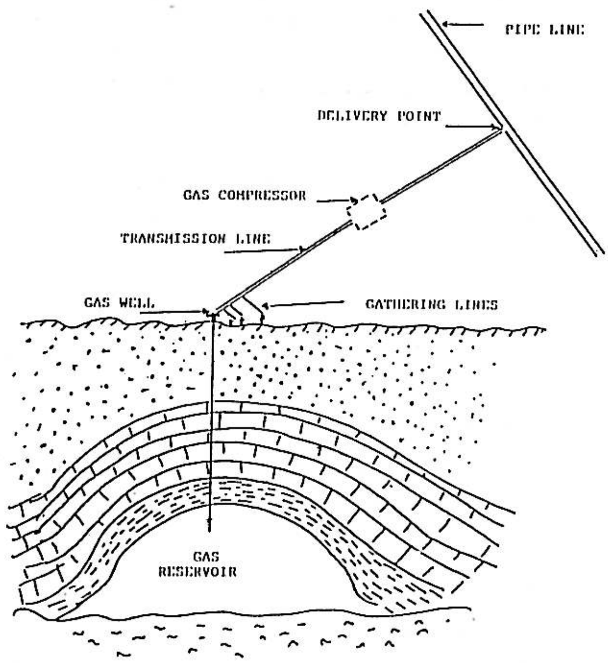

FIG. 1. Model Layout.

$$Q = 5615.5\frac{T_{sc}}{P_{sc}}\left(\frac{(P_{in}^2 - P_{out}^2)\cdot d^5}{\gamma_g \cdot T \cdot L \cdot f \cdot Z}\right)^{0.5} \tag{1}$$

The same equation can be used in a situation where a gas compressor is installed on the transmission line. The output pressure of the compressor can be calculated by computing the pressure drop between the delivery point and the gas compressor station. The brake horse-power of the compressor can be calculated by assuming different suction pressures and using the following equation:

$$-W = \frac{K}{K-1}\cdot T \cdot C\left(\left(\frac{P_{out}}{P_{in}}\right)^{Z\left(\frac{K-1}{K}\right)} - 1\right)\cdot E \tag{2}$$

Where E is the efficiency of the compression.

Also, the well head pressure can be calculated by computing the pressure drop between the suction pressure of the gas compressor and the well head.

The well head pressure influences the bottom hole flowing pressure of a well. Low well head pressure increases the rate of flow due to the low back pressure on the reservoir. The bottom hole flowing pressure can be computed using the Cullender and Smith equation [2]:

$$\frac{\gamma_g \cdot L}{53.34} = \int_{P_{tf}}^{P_{wf}} I \cdot dP \tag{3}$$

$$I = \frac{X}{(x^2 + 666.6 \cdot f \cdot Q^2/d^5)} \tag{4}$$

$$X = \frac{P}{T \cdot Z} \tag{5}$$

The Cullender and Smith equation can be evaluated numerically in a two-step calculation. Simpson's rule may be used to perform the integration:

$$\frac{\gamma_g \cdot L}{53.34} = \frac{2}{3}(ITf + 4IMf + IWf)(P_{wf} - P_{tf}) \tag{6}$$

The back pressure behaviour of a gas well is usually related to the daily rate of delivery of the gas and the pressure drop within the reservoir. Rawlins and Schelhardt [3] presented an empirical equation which relates the flow rate and the pressure difference between the bottom hole pressure and the reservoir pressure as follows:

$$Q = c(P_{ws}^2 - P_{wf}^2)^n \tag{7}$$

The factors "c" and "n" are considered to be constant throughout the life of the well. By knowing the average values of c, n, from testing number of wells, and bottom hole flowing pressure, the static reservoir pressure can be calculated.

For natural gas reservoirs, under volumetric control the cumulative gas produced at any reservoir pressure is the difference between the volumetric estimates of gas-in-place at the initial and subsequent pressure conditions. This relation is known as the Material Balance equation, which can be expressed as:

$$G_P = c \cdot GI\left(\frac{P_i}{Z_i} - \frac{P}{Z}\right) \tag{8}$$

Accordingly, knowing the initial gas in place (GI) and the subsequent reservoir condition, the cumulative gas production can be determined.

Also, the production time can be easily calculated as a result of dividing GP by total daily contract rate.

Calculation Procedures and Model Description

Based on the above discussion, the calculation procedures can be summarized as follows:

1. Knowing the delivery conditions (contract rate and delivery pressure), the pressure drop along the transmission line and the well head flowing pressure can be computed using Weymouth equation.
2. Knowing the well head flowing pressure, the bottom hole flowing pressure can be computed using Cullender and Smith method.
3. The calculated bottom hole flowing pressure is then used with the back pressure equation to calculate the static reservoir pressure.
4. Knowing the initial reservoir pressure and the current static reservoir pressure the deliverability of the reservoir can be computed from the material balance equation.

The above procedures require trial and error calculations which are best carried out on a computer.

A computer program was developed to carry out the calculations.

It is composed of a main program and nine subroutines. The subroutines are listed below, along with their main functions.

GASMODE:	Carries all the calculations for the model.
GASPRO:	Calculates the gas properties such as gravity, molecular weight, etc.
ZSTAR:	Calculates the gas compressibility factor [4].
VISC:	Calculates gas viscosity.
FRICT:	Calculates friction factor.
FBHP:	Calculates bottom hole flowing pressure using Cullender and Smith equation.
PREDR:	Calculates pressure drop along any horizontal flow line using Weymouth's equation.
GPP.	Calculates gas production and static reservoir pressure using the back pressure and material balance equation.
COMPHP:	Calculates the brake horsepower for the gas compressors.

MODEL STUDIES

The developed computer model was used to predict the performance of the carbon gas field [5]. The data used to run the model are listed in Table 1 and 2. The following four production scenarios were studied:

1. Base Case: Natural depletion until the contract rate can no longer be met.

Table 1. Carbon reservoir – Well effluent

Well: CWNG **Carbon** 10–19–29–22
Date of Sampling: January 26, 1968
Date of Report: January 29, 1968

Component	*Well Effluent*	
O_2	0.003	All measurements at 14.65 psia and 60°F
H_2	1.912	
CO_2	0.219	Pressure of the sample: 1002 psig
C_1	85.518	
C_2	6.462	Temperature o the sample: 68°F
C_3	3.311	
iC_4	0.797	
nC_4	0.451	
iC_5	0.302	
nC_5	0.225	Properties of C_7^+
C_6	0.685	Density = 0.7471 gms/cc
C_7^+	0.115	API Gravity = 57.9
	100.000	Molecular Weight = 119.0

2. Scheme I: Same as the base case except the delivery pressure was continually reduced to maintain the contract rate, after the point in the base case where deliverability declined.
3. Scheme II: Same as the base except the compressor was installed to maintain the rate.
4. Scheme III: Same as the base case except infill drilling was initiated to maintain the rate.

Table 2. Carbon reservoir – Average reservoir properties

Initial Reservoir Pressure, psia	1462
Reservoir Temperature, °F	115
Porosity, percent	19.4
Permeability, millidarcies	196.3
Water Saturation, percent	29.5
Bulk Volume, acre-feet	325,873
Initial Gas-In-Place, billion scf	219.7
Reserves per Acre-Foot, million scf/acre-ft.	674.2
Average Absolute Open Flow, million scf/d	26.03
Average Exponent, "n"	0.887
Average Performance Coefficient, "C"	256.81

The above schemes were studied under different flow rates ranging from 20.3 to 29.3 MMSCFD. Some of the results obtained by the model are shown in Table 3 and Figs. 2, 3 and 4. Base Case-natural depletion against a delivery pressure of 950 psia until the demand rate of 29.3 MMSCFD could no longer be met, recovered 58 billion SCF of gas in 5.4 years. This is 26 percent of the initial gas in place.

Scheme I: Implementing a strategy of lowering the delivery pressure to maintain the demand rate after 5.4 years, recovered an incremental 37 percent of the initial gas in place, for a total recovery of 63% at a delivery pressure of 250 psia.

Scheme II: Utilizing gas compression to maintain the demand rate after 5.4 years, recovered an incremental 43 percent of the initial gas in place, for a total recovery of 69 percent at a suction pressure of 100 psia.

Scheme III: Adapting a strategy of infill drilling after 5.4 years, had minimal incremental recovery about 1% and was not considered a feasible development alternative.

The model can also be used to study the effect of tubing size on the gas recovery as shown in Figs. 5, 6, 7. The results show that using large tubing size yields more recovery due to low pressure losses in this tubing.

The results obtained by the model for the carbon gas field were consistent with the common figures for the kind of gas reservoir.

As a general result, the model can be used to predict the deliverability of any volumetric gas reservoir under different production scenarios. The assumptions which imposed on the model should be considered.

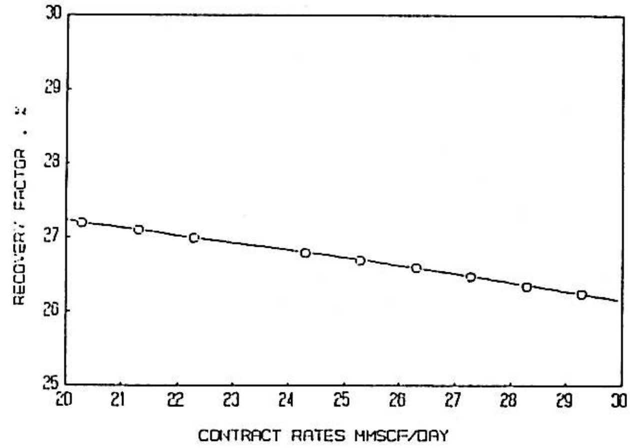

FIG. 2. Recovery factor Vs rates-Base case.

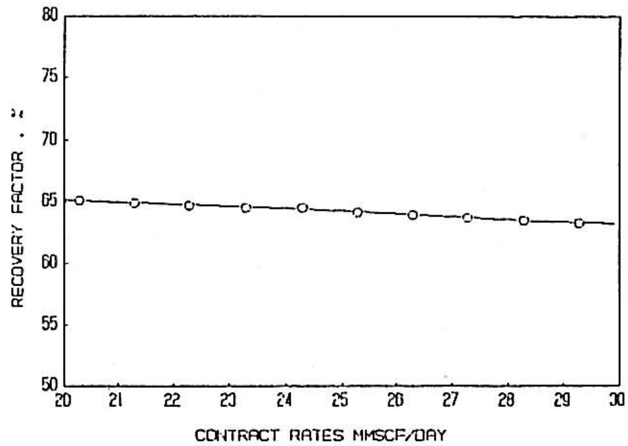

FIG. 3. Recovery factor Vs rates-Scheme I.

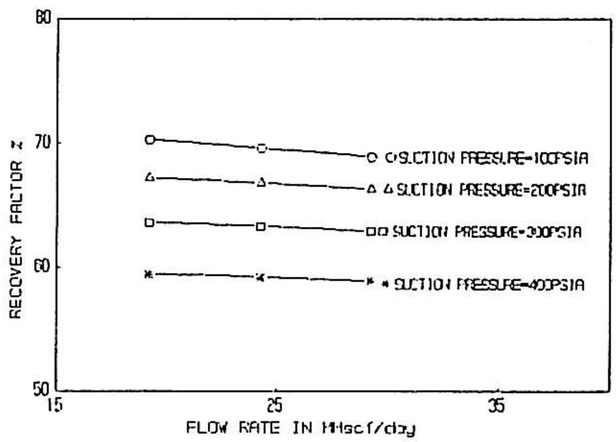

FIG. 4. Recovery factor Vs rates-Scheme II.

Table 3. Sample of model results

BASE CASE: CONTRACT RATE=.29300E+02

DELT. TIME YEARS	CUM. TIME YEARS	FLOW RATE SCF/DAY	DELT. GAS. PR SCF	CUM. GAS. PR SCF	REC. FACTOR FRACTION	RES. PRESS PSIA	DELIV. PRESS PSIA
0.53924E+01	0.53924E+01	0.29300E+02	0.57669E+11	0.57669E+11	0.26243E+00	0.11551E+04	0.95000E+03

SCHEME I=CONTRACT RATE=0.29300E+02

DELT. TIME	CUM. TIME	FLOW RATE	DELT. GAS. PR	CUM. GAS.PR	REC. FACTOR	RES. PRESS	DELIV. PRESS
0.70341E+00	0.609300E+01	0.29300E+02	0.75226E+10	0.65191E+11	0.29666E+00	0.11092E+04	0.90000E+03
0.68484E+00	0.67806E+01	0.29300E+02	0.73241E+10	0.72515E+11	0.32999E+00	0.10641E+04	0.85000E+03
0.66509E+00	0.74457E+01	0.29300E+02	0.71127E+10	0.79628E+11	0.36235E+00	0.10198E+04	0.80000E+03
0.64404E+00	0.80897E+01	0.29300E+02	0.68877E+10	0.86516E+11	0.39370E+00	0.97660E+03	0.75000E+03
0.52146E+00	0.87112E+01	0.29300E+02	0.66461E+10	0.93162E+11	0.42394E+00	0.93443E+03	0.70000E+03
0.39697E+00	0.93082E+01	0.29300E+02	0.63843E+10	0.99546E+11	0.45299E+00	0.89348E+03	0.65000E+03
0.37178E+00	0.98799E+01	0.29300E+02	0.61148E+10	0.10566E+12	0.48082E+00	0.85387E+03	0.60000E+03
0.34455E+00	0.10424E+02	0.29300E+02	0.58237E+10	0.11148E+12	0.50732E+00	0.81577E+03	0.55000E+03
0.51558E+00	0.10940E+02	0.29300E+02	0.55138E+10	0.11700E+12	0.53241E+00	0.77932E+03	0.50000E+03
0.48447E+00	0.11425E+02	0.29300E+02	0.51812E+10	0.12218E+12	0.55599E+00	0.74475E+03	0.45000E+03
0.45188E+00	0.11876E+02	0.29300E+02	0.48327E+10	0.12701E+12	0.57798E+00	0.71219E+03	0.40000E+03
0.41728E+00	0.12294E+02	0.29300E+02	0.44626E+10	0.13147E+12	0.59829E+00	0.68187E+03	0.35000E+03
0.38099E+00	0.12675E+02	0.29300E+02	0.40745E+10	0.13555E+12	0.61683E+00	0.65394E+03	0.30000E+03
0.34214E+00	0.13017E+02	0.29300E+02	0.36590E+10	0.13921E+12	0.63348E+00	0.62868E+03	0.25000E+03
0.29955E+00	0.13316E+02	0.29300E+02	0.32036E+10	0.14241E+12	0.64806E+00	0.60641E+03	0.20000E+03
0.25186E+00	0.13568E+02	0.29300E+02	0.26935E+10	0.14511E+12	0.66031E+00	0.58757E+03	0.15000E+03
0.19526E+00	0.13764E+02	0.29300E+02	0.20882E+10	0.14719E+12	0.66982E+00	0.57289E+03	0.10000E+03

Table 3 (*cont*)

SCHEME II: INSTALL GAS COMPRESSOR

DELT. TIME YEARS	CUM. TIME YEARS	FLOW RATE SCF/DAY	DELT. GAS. PR SCF	CUM. GAS. PR SCF	REC. FACTOR FRACTION	RES. PRESS PSIA	DELIV. PRESS PSIA
0.87794E+01	0.14172E+02	0.29300E+02	0.93891E+11	0.15156E+12	0.68969E+00	0.54200E+03	0.95000E+03

SUCTION PRESSURE=100.0 DISCHARGE PRESSURE=959.847 BRAKE HORSE POWER=2652.76831 CONTRACT RATE=29300E+02

DELT. TIME YEARS	CUM. TIME YEARS	FLOW RATE SCF/DAY	DELT. GAS. PR SCF	CUM. GAS. PR SCF	REC. FACTOR FRACTION	RES. PRESS PSIA	DELIV. PRESS PSIA
0.82442E+01	0.13637E+02	0.29300E+02	0.88167E+11	0.14584E+12	0.66364E+00	0.58244E+03	0.95000E+03

SUCTION PRESSURE=200.0 DISCHARGE PRESSURE=959.847 BRAKE HORSE POWER=2007.79883 CONTRACT RATE=29300E+02

DELT. TIME YEARS	CUM. TIME YEARS	FLOW RATE SCF/DAY	DELT. GAS. PR SCF	CUM. GAS. PR SCF	REC. FACTOR FRACTION	RES. PRESS PSIA	DELIV. PRESS PSIA
0.75478E+01	0.12940E+02	0.29300E+02	0.80719E+11	0.13839E+12	0.62975E+00	0.63436E+03	0.95000E+03

SUCTION PRESSURE=300.0 DISCHARGE PRESSURE=959.847 BRAKE HORSE POWER=1411.89893 CONTRACT RATE=29300E+02

DELT. TIME YEARS	CUM. TIME YEARS	FLOW RATE SCF/DAY	DELT. GAS. PR SCF	CUM. GAS. PR SCF	REC. FACTOR FRACTION	RES. PRESS PSIA	DELIV. PRESS PSIA
0.67158+01	0.12108E+02	0.29300E+02	0.71823E+11	0.12949E+12	0.58926E+00	0.69538E+03	0.95000E+03

SUCTION PRESSURE=400.0 DISCHARGE PRESSURE=959.847 BRAKE HORSE POWER=981.69214 CONTRACT RATE=29300E+02

SCHEME III INFILL DRILLING: NO OF WELLS=25.00

DELT. TIME YEARS	CUM. TIME YEARS	FLOW RATE SCF/DAY	DELT. GAS. PR SCF	CUM. GAS. PR SCF	REC. FACTOR FRACTION	RES. PRESS PSIA	DELIV. PRESS PSIA
0.37031E-01	0.55710E+01	0.29300E+02	0.39603E+09	0.59580E+11	0.27112E+00	0.11434E+04	0.95000E+03

INFILL DRILLING: NO OF WELLS=30.00

DELT. TIME YEARS	CUM. TIME YEARS	FLOW RATE SCF/DAY	DELT. GAS. PR SCF	CUM. GAS. PR SCF	REC. FACTOR FRACTION	RES. PRESS PSIA	DELIV. PRESS PSIA
0.26207E-01	0.55972E+01	0.29300E+02	0.28027E+09	0.59860E+11	0.27240E+00	0.11417E+04	0.95000E+03

INFILL DRILLING: NO OF WELLS=35.00

DELT. TIME YEARS	CUM. TIME YEARS	FLOW RATE SCF/DAY	DELT. GAS. PR SCF	CUM. GAS. PR SCF	REC. FACTOR FRACTION	RES. PRESS PSIA	DELIV. PRESS PSIA
0.19914E-01	0.56172E+01	0.29300E+02	0.21297E+09	0.60073E+11	0.27337E+00	0.11404E+04	0.95000E+03

INFILL DRILLING: NO OF WELLS=40.00

DELT. TIME YEARS	CUM. TIME YEARS	FLOW RATE SCF/DAY	DELT. GAS. PR SCF	CUM. GAS. PR SCF	REC. FACTOR FRACTION	RES. PRESS PSIA	DELIV. PRESS PSIA
0.15924E-01	0.56331E+01	0.29300E+02	0.17029E+09	0.60243E+11	0.27414E+00	0.11394E+04	0.95000E+03

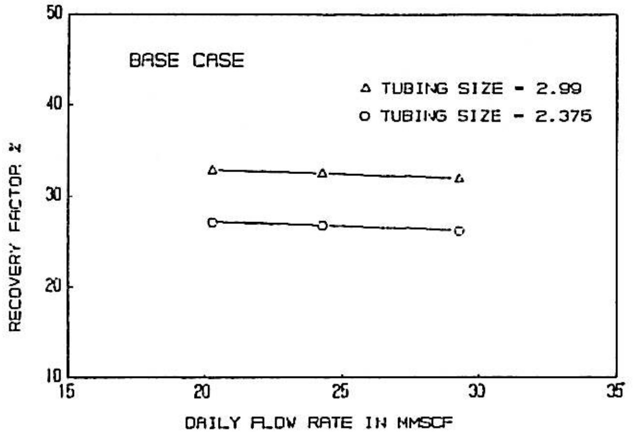

FIG. 5. Effect of tubing size on gas recovery-Base case.

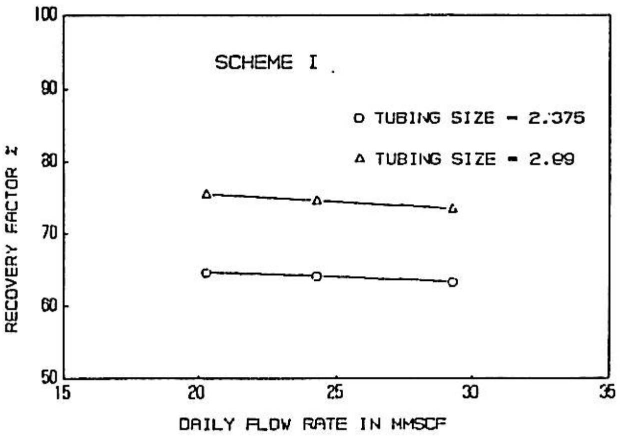

FIG. 6. Effect of tubing size on gas recovery-Scheme I.

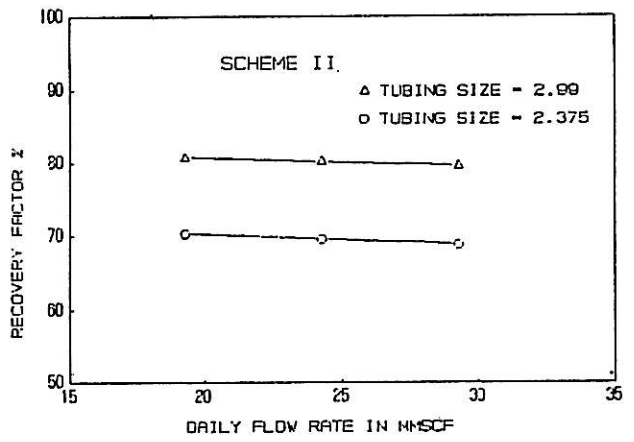

FIG. 7. Effect of tubing size on gas recovery-Scheme II.

CONCLUSIONS AND RECOMMENDATIONS

Based on the work carried out in this study, the following conclusions were made.

1. A simple mathematical model has been developed which predicts the deliverability of any volumetric gas reservoir.
2. The model can be used to predict the deliverability of volumetric gas reservoirs under different production scenarios.
3. The model results are very reasonable to be used for initiating development plans.
4. The assumptions imposed on the model should be considered when using the model.
5. The model can be used to investigate many variables such as flow rates, tubing sizes, pipe line sizes, etc.
6. This model can serve as an important planning tool for proper development and management of a volumetric gas reservoir.

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NOMENCLATURE

Q	Flow rate or production rate (MMSCF/d)
Z	Gas compressibility factor
d	diameter (inch)
L	length (miles)
f	friction factor
K	specific heat capacity ratio
T	Temperature (°F)
E	Efficiency of the compression
G_p	Gas produced (BSCF)
$-W$	Theoretical Horse power per MMSCF
γ_g	Gas gravity
P	Pressure (psia)
P_{sc}	Pressure standard condition (psia)
P_{ws}	Pressure, reservoir at static condition (psia)
P_{wf}	Pressure, bottom hole flowing (psia)
P_{tf}	Pressure, Tubing flowing (psia)
P_i	Initial Pressure (psia)
P_{in}	Inlet Pressure (psia)
P_{out}	Outlet Pressure (psia)

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