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An Approach to Estimation of Gas Reserve of Narshingdi Gas Field in Bangladesh with Dynamic Reservoir Simulation

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Abstract:

Increasing demand of fuel globally formulates gas as one of the most valuable natural resources. There is lot of uncertainties in estimating hydrocarbon volume correctly from exploration to development stage of a gas field. The accuracy and reliability of data (reservoir geological model, fluid and rock properties) make the implement very hard-hitting. So estimating and updating the gas reserve has become vital issue, as it helps the planners for drawing mid-term and long-term development plan from field development level to national level. This paper presents the study of reserve estimation of a Narshingdi Gas Field in Bangladesh. In this paper, a dynamic reservoir simulation model has been used to perform a history match "pressure and production" using commercial simulator for reserve estimation. The result of this study is expected to provide Gas Initially in Place (GIIP) and recoverable gas volume. Simultaneously three forecast scenarios have also been investigated. There is no strong aquifer pressure support in the producing gas zone, so gas production continues from the reservoir due to pressure depletion.

Key words: *Gas Reserve Estimation, History Match, Forecasting.*

1. Introduction

Narshingdi gas field is located in northeastern part of Bangladesh in the western edge of the eastern fold belt in the northern portion of Block 9.[1] The Narshingdi Field is an anticline with a simple four-way dip closure at the northern end of the Bakhrabad-Meghna-Narshingdi structure trend and it lies on the southern fringes of the Surma Basin which is located at the western margin of the North-South trending Chittagong-Tripura folded belt. Narshingdi structure was identified by Pakistan Shell Oil Company (PSOC).[1] Two commercial accumulations of gas sands named as lower gas sand (LGS) and upper gas sand (UGS) have been discovered in two different depositional environments. Production is continuing only from lower gas sand through two wells named NAR-1 and NAR-2 from 25th July 1996 and 18th February 2007 respectively. Table 1 and table 2 shown below gives the information about the wells and the reservoir respectively .[1, 3, 4]

Table-01: Well Summary

Parameters	Lower Gas Sand (LGS)	
Well Name	NAR-1	NAR-2
Well type	Vertical	Vertical
Well depth (m)	3450	3285
Initial production rate (MMscfd)	25	17
Cum Prod. Up to Dec 2013(BCF)	114.25	35.9655
Initial Pressure (psia)	4228	3233
Initial Temperature (^oF)	205	163
Tubing size (inch)	3.5	4.5
Shut in well head pressure (psia)	3480	2857
Tubing head pressure in Dec. 2013(psia)	1443	1330

Table 02: Reservoir Parameters

Parameters	Values
Rock compressibility ($psia^{-1}$)	$3x10^{-6}$ at 3804 psia
specific gravity	0.6
condensate-gas-ratio (CGR)	2.24 bbl/MMscf
water gas ration (WGR)	1 bbl/MMscf
Minimum water saturation	0.35

The static geological grid model (used in this study) has a dimension of 101×149×29 representing four sand layers of the field. It has been discretized into 328 x 328 ft grid blocks. For simulating of gas water system the model grid layering was designed with average thickness of 10 ft. The total number of active grid blocks of 66,966. Other properties of the grid model are shown in table 2.[6]

Table-03: Properties of static geological grid model:

Sand layer	Porosity (%)	Permeability (mD)	Thickness (m)	status
UGS	0.15-0.22	77	9.5	Not Producing
MGS-1	-	-		Inactive
MGS-2	-	-		Inactive
LGS	0.07-0.22	1-100	14	Producing

The fluid from the lower gas sand of the Narshingdi Gas Field is non-retrograde at reservoir condition and can be defined as lean gas. The fluid contains over 97% methane and ethane. The gas properties were analyzed at the reservoir temperature of 205.8 ^oF and pressure range of 15 – 5000 psia.

Brooks-Corey's equations for two-phase flow have been used to generate relative permeability curves. The assumption 'fluid flow is neither segregated nor evenly distributed' gives Corey exponents of 4 for water and 2 for gas. Minimum water saturation is selected as the endpoint[2].

To calculate well head pressure for history match and production forecast, vertical lift performance (VFP) curves have been generated by using commercial software for two wells NAR-1 and NAR-2. For pressure traverse calculation, Beggs and Brill flow correlations has been chosen because it performs well in gas and gas condensate well[2]. The minimum gas flow rate for continuous removal of liquid is approximately 4MMscfd and 5MMscfd for NAR-1 and NAR-2 respectively.

2. History Matches

In this section the simulation model has been applied to match production and pressure data obtained from history by manipulating permeability, porosity, fluid contact to confirm the initial reservoir conditions.

2.1 Average Reservoir Pressure Match:

For reservoir pressure match, the recorded shut in well head pressure was converted into shut in bottomhole pressure using the average temperature and Z factor method[2]. After that an effort was taken to match with the simulated reservoir pressure and obtained a good match that is shown in Figure 1.

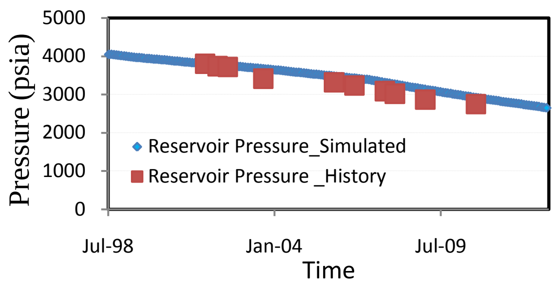

Figure 1: Average reservoir pressure match

2.2 Tubing Head Pressure (THP) Match:

In addition to, another attempt was taken to match THP for two wells (NAR-1 and NAR-2). Here both wells are controlled on the gas rate and the all historical tubing head pressure data have been introduced to the simulated tubing head pressure data. Though there is a slight difference between the simulated THP and historical THP in case of NAR-1 (Figure 2) and NAR-2 (figure 3), but the overall match is satisfactory. In case NAR-1, there are some peak points in tubing head pressure.It may be for keeping the well shut down for development purpose and thereby pressure went up.

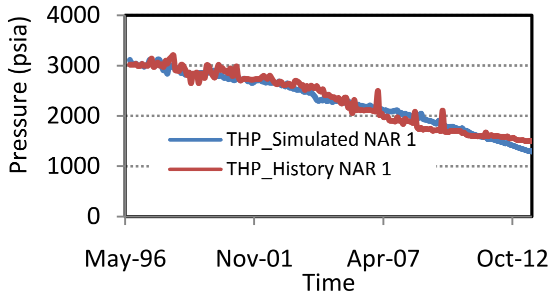

Figure 2: Tubing Head Pressure Match for well NAR-1

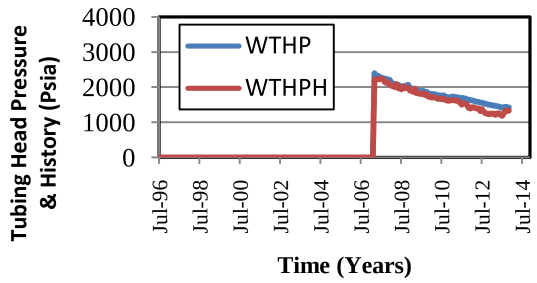

Figure 3: Tubing Head Pressure Match for well NAR-2

After obtaining a good pressure match with recorded reservoir SIWHP and individual well's THP , it can be said that pressure history match validates the reservoir grid model satisfactorily.

2.3 Simulation Result:

The simulated result is shown in figure 4. GIIP for upper gas sand and lower gas sand are 83.53 Bcf and 302.72 Bcf respectively. So the field total GIIP is 386.24 Bcf.

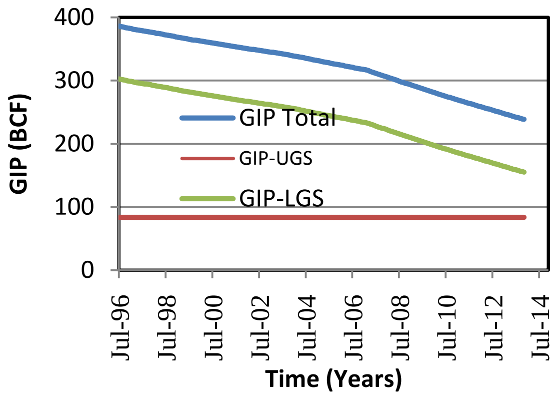

Figure 4: GIP vs Time plot

From figure 4, up to December 2013, 149 BCF gas from lower gas sand has been produced. GIIP of upper gas sand remained unchanged since this sand zone has not been under production.

3. Performance Projections

Between two gas sands (upper and lower gas sands), only the lower gas sand has been developed. Two cases are considered to forecast the future performance of the LGS. The cases are-

3.1 Forecast case 1: Present condition that involves predicting future production with the existing wells until the economic rates of the wells are reached.

3.2 Forecast case 2:

Impact of additional well which is defined by drilling of a new vertical well to the lower gas sand to produce at a rate of 10 MMscfd from the January 2015 along with other two existing wells (NAR-1 and NAR-2) producing at a rate of 18 and 15 MMscfd accordingly.

3.3 Forecast Case 3: Effect of using compressor

This forecast case has been divided into two sub groups. In both two groups abandonment wellhead pressure is reduced from 1000 psia to 500 psia to show the effect of compressor on ultimate recovery.

Case 3a: Present condition

Case 3b: With one additional well

The economic limit: Constraint for the three wells is

NAR-1: 4 MMscfd,

NAR-2: 5 MMscfd,

NAR-3: 4 MMscfd

The abandonment tubing head pressure limit is 1000 psia.

4. Result

All the forecast cases are set up to run till December 2030 with the current well production capacity and continued till the economic limit is reached.

4.1 Forecast case-01: Present Condition

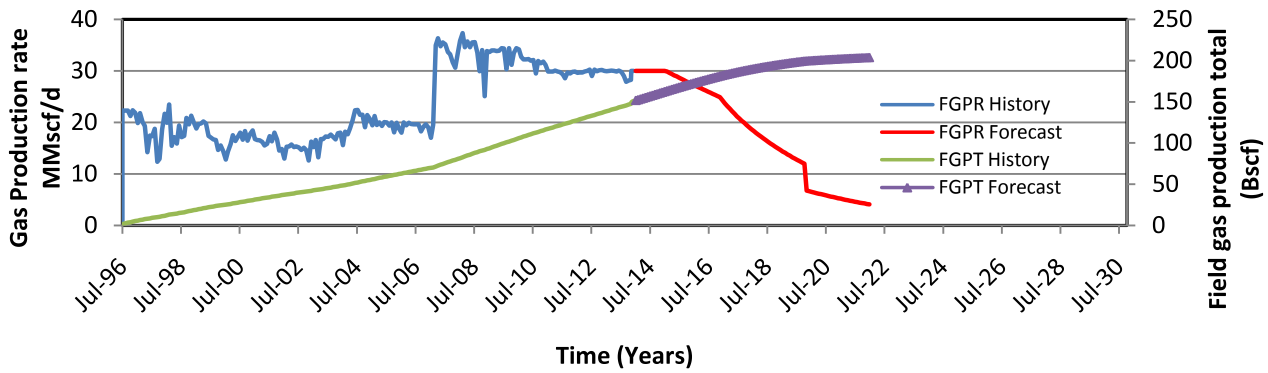

Figure 5: Forecasting of existing condition for THP 1000 psi.

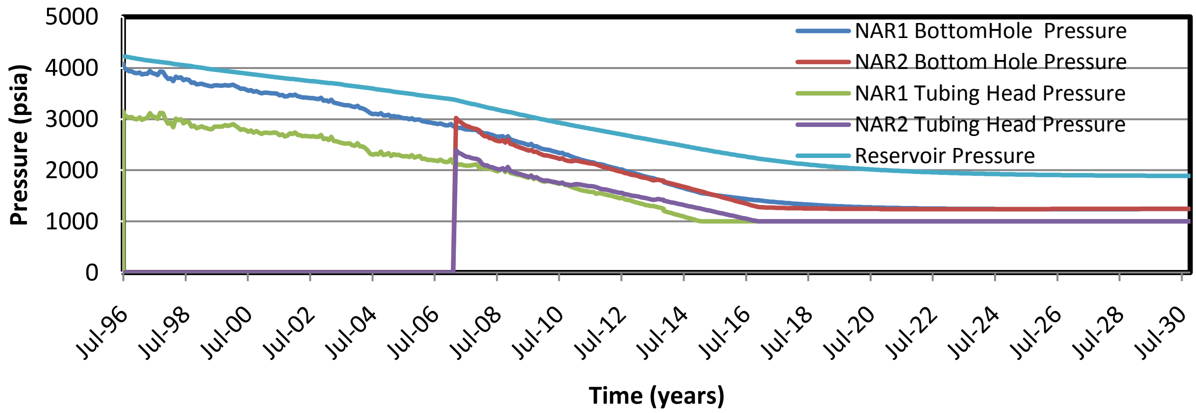

Figure 6: Pressure profile for existing condition.

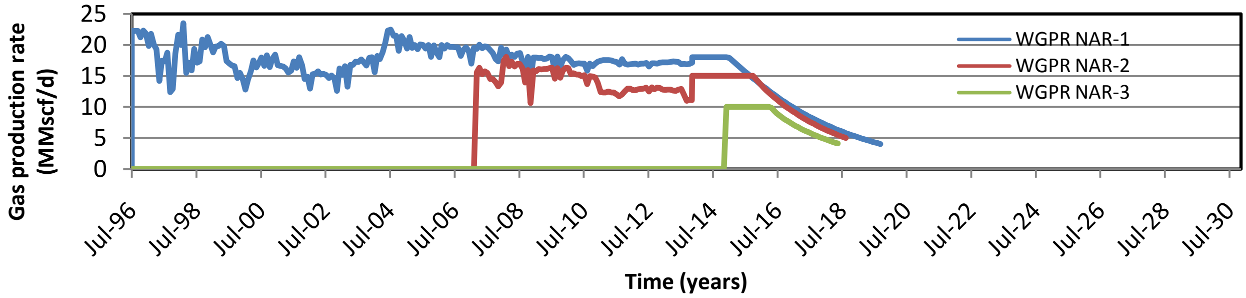

Figure 7: Impact of additional vertical well on well gas production rate

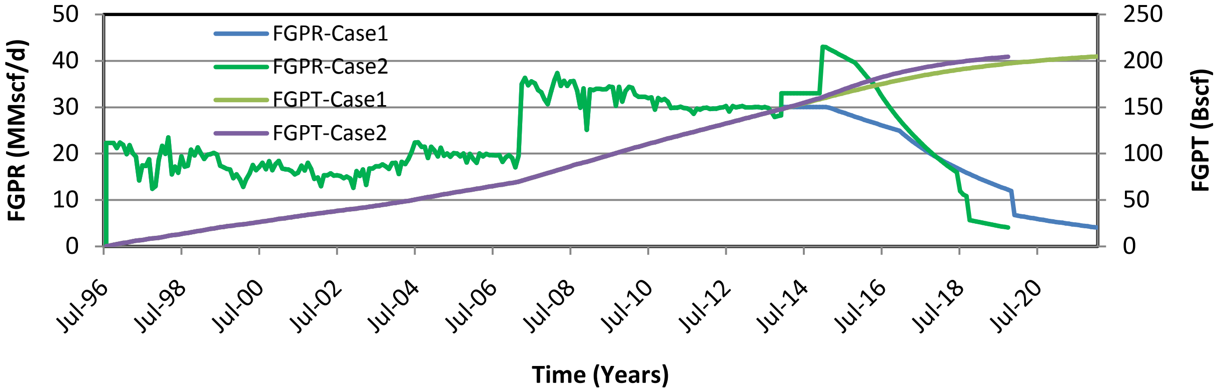

Figure 8: Forecasting of gas production when a vertical well is added.

From figure 5 it can be shown that production will be continued till January 2022 as the limiting constraints have been met. At that time field gas production total will be 204.022 Bcf.

The pressure profile plot shown in figure 6 shows that NAR-1 will produce up to January 2022 while due to low bottom hole flowing pressure, NAR-2 will be ceased in October 2019.

In 2010 shut in bottom hole pressure is 2753psia. So, as the reservoir pressure is declining, so new well NAR-3 will have low pressure support. The additional vertical well will have some initial improvement on total field production rate but would not last for longer time. From figure 7, when NAR-3 goes under production, plateau rate continued from January 2015 to July 2016 and then falls. NAR-3 will decline and meet the limiting condition before NAR-1 and NAR-2.

The Figure 8 shows that there is no significant change in field production total if one additional vertical well is added to LGS. From January 2015 to December 2017, the production will be faster but after that it will go down rapidly indicating very shorter plateau time than the existing condition.

Table 4: Lower Gas Sand Forecast Simulation Results THP 100psia.

Forecast cases	GIIP (BCF)	FGPT (BCF)	RF (%)	Field life (years)
Case-1	302.72	204.02	67.40	26 (1996-2022)
Case-2	302.72	203.98	67.38	23 (1996-2019)

Table 4 describes the comparison of the results for case 1 and case 2. The present situation gives recovery factor of 67.40% and the total production time will be 26 years, but adding one vertical well gives recovery factor and field life less than the current scenario.

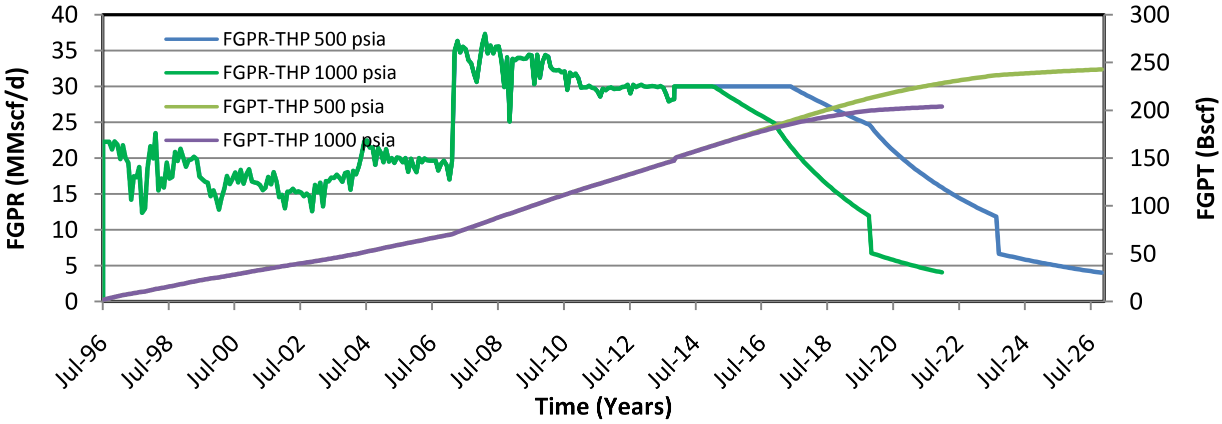

Figure 9: Impact of adding compressor on FGPR and FGPT for THP 1000 psia and 500 psia

Figure 9 shows that by installing compressors, total production will be 242.595 Bcf. Again in current situation, after 2015, the plateau will be diminished due to low bottomhole pressure, but adding compressor causes the increased production time for each of the wells and makes a little increase in field life from 26 years to 30 years and hence shifts the recovery factor significantly from 67.40% to 80.14%.

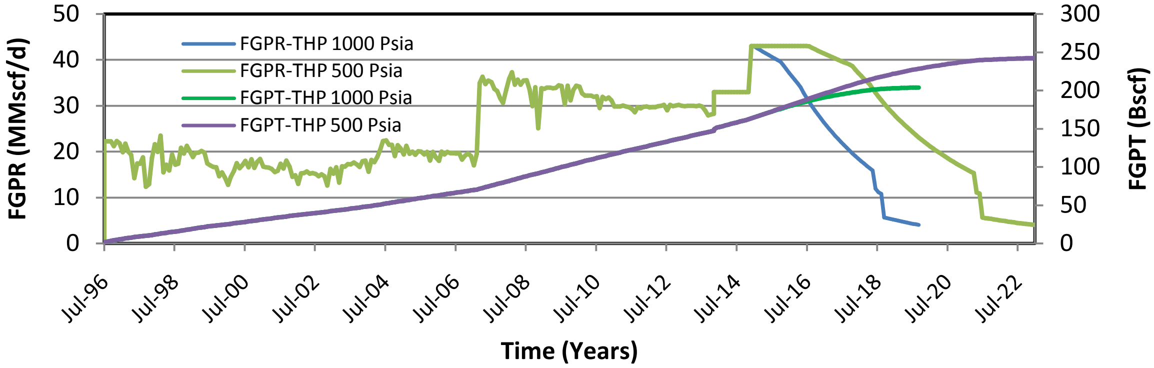

Figure 10: Impact of adding compressor on FGPR and FGPT for THP 1000 psia and 500 psia

Figure 10 shows the recovery factor of 80.09% which is same as seen in the forecast case 3a shown in figure 9 and to attain the desired recovery, field life would be 27 years. Table 5 gives the summarized results of forecast case 3a and 3b.

Table 5: Lower Gas Sand Forecast case 3 Simulation Results at THP=500 psia

Forecast cases	GIIP (BCF)	FGPT (BCF)	RF (%)	Field life(Years)
Case 3a	302.72	242.60	80.14	30 (1996-2026)
Case 3b	302.72	242.46	80.09	27 (1996-2023)

5. Conclusions

According to simulation model the GIIP is about 386.24 Bcf, where upper and lower gas sand contains 83.53 Bcf and 302.72 Bcf respectively. This study shows that for existing condition, the use of compressor will increase the ultimate recovery from 67.40% to almost 80%. Extra 4 years will be needed to achieve the recovery. In that case economic analysis about the installation of the compressor is required. Drilling one more vertical well in the lower gas sand will not be beneficial as it gives almost the same recovery of 67.38% as doing nothing case, though the recoverable reserve of 204 Bcf could be attained earlier than 'Current Situation'. All the analysis done in this article does not include economic analysis. So, for field development, economic analysis for each of the forecast case is urgent. By doing this the optimum condition could be determined.

6. References

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7. Nomenclature

FGPT : Field Gas Production Total
FGPR : Field Gas Production Rate
GIIP : Initially In Place
GIP : Gas In Place
GPR : Gas Production Rate
GPRH : Gas Production Rate History
MMscfd : Millions of Standard Cubic Feet per Day
FPR : Average Reservoir Pressure
THP : Tubing Head Pressure
THPH : Tubing Pressure History
WGPR : Well Gas Production Rate
WGPRH : Well Gas Production Rate History
WGR : Water-Gas-Ratio
SIWHP : Shut In Well Head Pressure
VFP : Vertical Flow Performance
MGS : Middle Gas Sand
RF : Recovery Factor
Bcf : Billion CUBIC feet