RESERVOIR ENGINEERING FOR GEOLOGISTS
Part 8b – Monte Carlo Simulation/Risk Assessment

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In the introductory article (part 8a), recoverable gas from Geologist A's development prospect was estimated to be between 285 and 1,219 10^6m^3 of gas.

	P90 10^6m^3	P50 10^6m^3	P10 10^6m^3
Gas-in-Place	380	808	1624
Recoverable Gas	285	607	1219

What is this gas worth? The first factor to consider is the time value of production. The following chart presents the present day value of $100 of future year's production at a 12% discount rate.

Year 1	$88.00	Year 8	$35.96	Year 15	$14.70
Year 2	$77.44	Year 9	$31.65	Year 16	$12.93
Year 3	$68.15	Year 10	$27.85	Year 17	$11.38
Year 4	$59.97	Year 11	$24.51	Year 18	$10.02
Year 5	$52.77	Year 12	$21.57	Year 19	$ 8.81
Year 6	$46.44	Year 13	$18.98	Year 20	$ 7.76
Year 7	$40.87	Year 14	$16.70		

While $100 received today is worth $100, next year's production is only worth 88% of today's value. In year five it is only worth 52.77%; in year ten, 27.85% and in year 20, 7.76%. Clearly, we would like to produce the gas as quickly as possible to maximize its value but there is a limit. Each incremental increase in production rate requires more wells and larger, more costly facilities so that eventually the incremental value of further acceleration cannot offset the increased capital requirement.

What should we assume for a depletion rate? In Fekete's experience, a seven-year rate-of-take provides a starting point for a production profile with good economic value. Note that the calculation provides an estimate of the annual produced volume during the initial one-to-three years of production. Since well productivity declines over time, it will take between 10 and 15 years to produce the prospect to depletion but about half the gas will be recovered during the initial five years.

Dividing Geologist A's recoverable gas range by seven yields an initial annual production volume of between 41 and 176 $10^6m^3/yr$ (Figure 1). A daily production rate of between 118 and 502 $10^3m^3/day$ (also Figure 1) was obtained by dividing the annual volume range by 350 producing days per year.

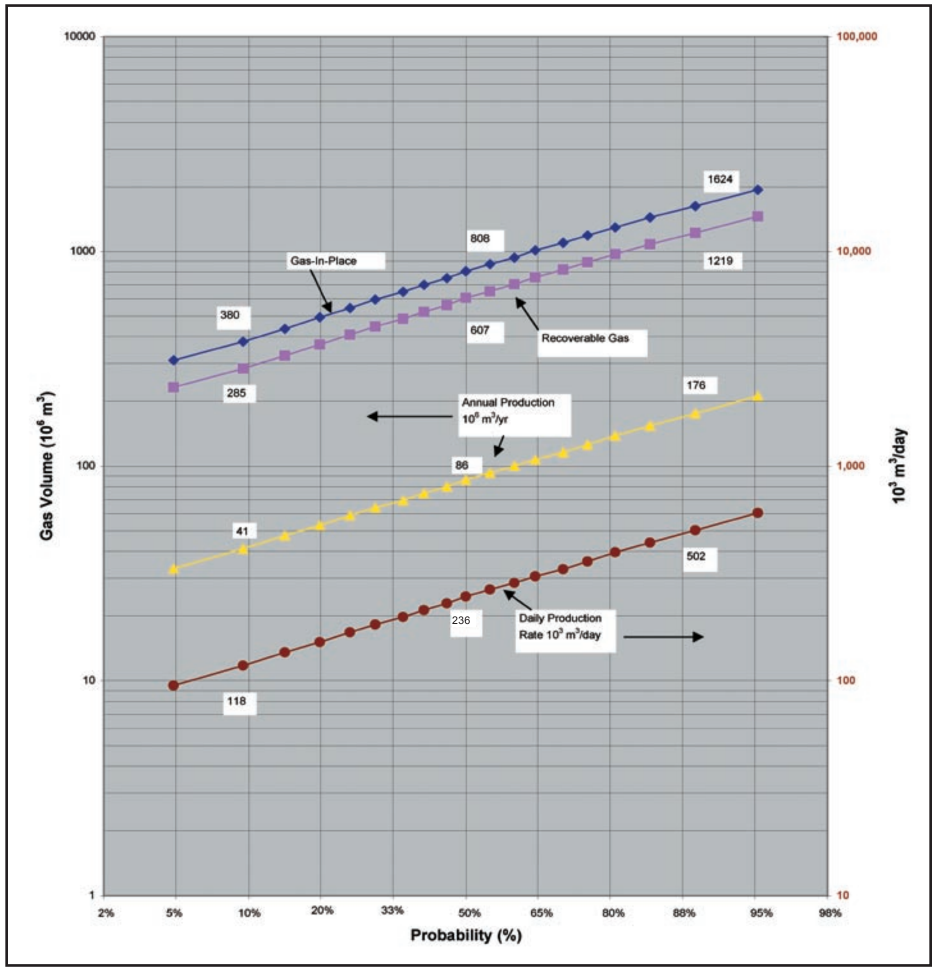

Figure 1. Probability Chart, Gas Development Prospect.

With an estimated daily rate and knowledge of the gas composition, the type and size of the central facilities can be determined. Since the gas contains mostly methane and ethane with no H_2S and a low concentration of other non-hydrocarbon gases, only dehydration and compression will be required to treat the raw gas to sales gas specifications. If the design capacity of the facilities is set at 236 $10^3m^3/day$ of raw gas, a plant with a (typical) 2:1 turndown ratio will be able to operate down to about 118 $10^3m^3/day$.

By inspection of Figure 1, 118 $10^3m^3/day$ corresponds to the 10th percentile of the daily production rate curve and 236 $10^3m^3/day$ is about the 47th percentile. The plant is the correct size for the lower 37% of the range and thus capital and operating costs for the central facilities can be estimated. If development drilling ultimately proves that larger facilities are required, increased gas revenues will more than offset the incremental cost of larger facilities.

Geologist A's prospect also requires a 70 km sales gas pipeline to connect to the nearest sales point. The central facility design rate can similarly be used to estimate the size and associated capital and operating costs of the sales gas pipeline. Accounting for processing shrinkage and fuel gas consumption, the 236 $10^3m^3/day$ raw gas production rate equates to 217 $10^3m^3/day$ of sales gas.

The next issue is the number of wells

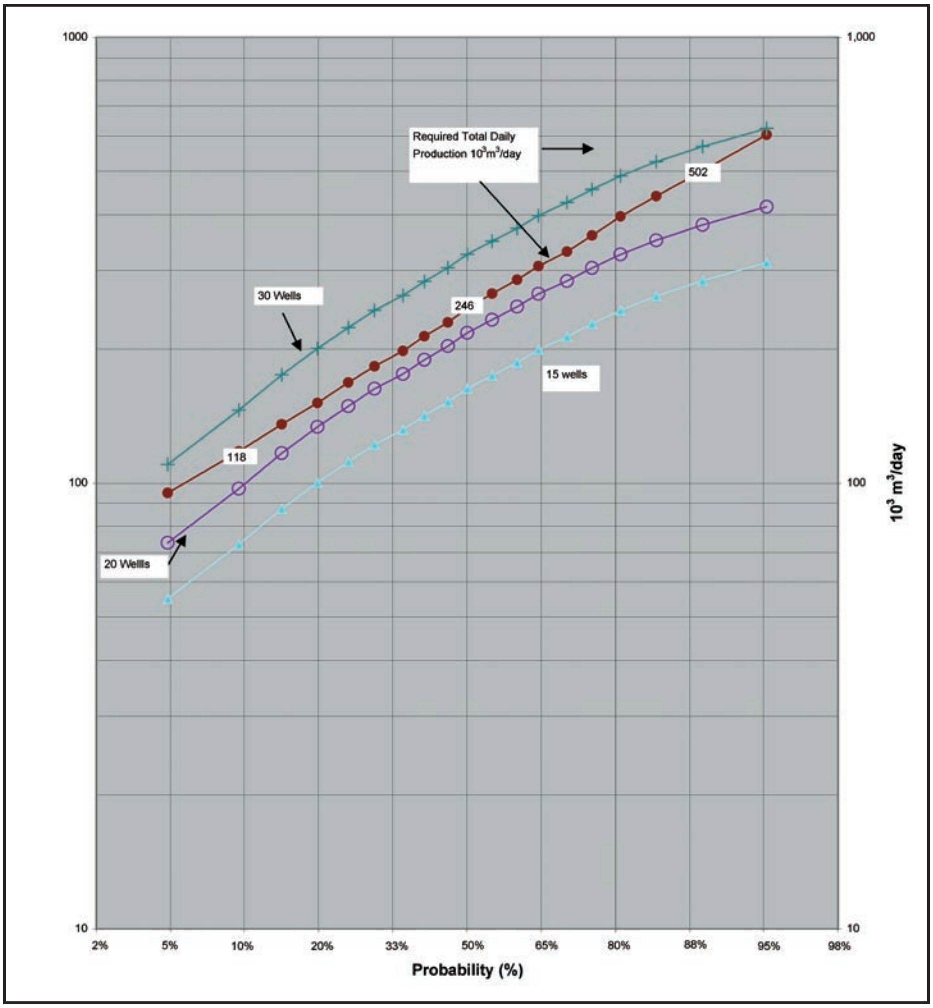

Figure 2. Probability Chart, Gas Development Prospect Number of Wells Required.

required to produce at the desired rate. From the available test information, a well's 1st year average production rate, based on the year's production volume, could range from 3 to 21 10^3m^3/day but most likely will be about 8.5 10^3m^3/day. Multiplying the range for an individual well by the number of wells yields deliverability curves for the selected numbers of wells. From inspection of Figure 2, about 22 wells will most likely be required to provide the required deliverability for the prospect but as few as 15 or as many as 30 wells may be needed.

Knowing the number of wells, a scoping level layout of the well locations and the production gathering system can be undertaken. The scoping plan addresses issues such as the timing and sequencing of well drilling, drilling and completion design, surface access, the required wellsite facilities, and wellsite layouts. The level of effort expended is just sufficient to develop three-point estimates for the capital and operating costs of system components.

Contractual terms are obtained from the licence/lease agreement while a price forecast(s) for the production period may be obtained from a variety of sources. At this point, estimate ranges have been developed for all the inputs necessary to evaluate the economics of the prospect. The general calculation sequence is:

- Calculate the net cash flow for each year's production, NCF=(Sales Volume*Sales Price) - Royalties - Operating Costs - Taxes - Capital
- Discount each year's net cash flow to its present day value
- Sum each year's discounted value to arrive at the prospect net present value NPV = Σ{Yearly NCF*Yearly Discount Factor} (See table 1.)

The calculations are amenable to spreadsheet analysis (Table 1) and Monte Carlo simulation. Since no two prospects are exactly alike, the calculations and their presentation can and should be modified to fit the details of each particular situation.

Although the final goal of Monte Carlo is to generate the expected NPV range for Geologist A's prospect, Fekete has found it useful to calculate some intermediate values as follows:

- Calculate the cash flow for each year's production before capital investment, CF=(Sales Volume*Sales Price) - Royalties - Operating Costs - Taxes
- Discount each year's cash flow to its present day value (PV)
- Sum each year's discounted value to arrive at the prospect present day value $PV_{CF} = \Sigma${Yearly CF*Yearly Discount Factor}
- Categorize each year's capital investment and discount it to its present day value
  $PV_{capital}$ = Sales line*DF + Plant*DF + Gathering System*DF + Dev. Wells*DF
  $PV_{capital} = \Sigma\{PV_{sales\ lines} + PV_{plant} + PV_{gathering\ system} + PV_{dev.\ wells}\}$
- Calculate the net present value $NPV = PV_{CF} - PV_{capital}$

The mathematical manipulation generates the same NPV range for a prospect. But additionally, the present day value of a unit of production can be estimated by dividing the prospect's present day value before capital (highlighted in blue) by the projected total gas sales volume (in pink).

In Fekete's experience, the uncertainty

(Continued on page 18...)

Year	Annual Sales Volume 10^3m3	Sales Price $/$10^3$m3	Less Royalty $	Less Total Opex $	Less Taxes $	Cash Flow Before Capital $	PV Before Investment @12% $	Capital Invested $	PV of Capital @12% $	Annual Net Cash Flow $	Net Present Value @12% $
1											
2											
3											
4											
5											
TOTAL											

*Table 1. Example input spreadsheet, in any given year: Net Present Value@12% = Annual Net Cash Flow*12% discount factor; Net Present Value @ 12% = PV before investment @ 12% - PV of capital investment.*

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range on the present day value of a unit of production is relatively small compared to the uncertainty range of the input parameters. The reason is because increased sales revenue, due to higher production volumes and/or gas prices tends to be offset by increased royalties, operating costs, and taxes. Conversely, lower revenue scenarios have reduced royalties, operating costs, and taxes.

At the time that Geologist A's prospect was evaluated, its unit of production PV was estimated to be between \$35.50 and \$71 per $10^3 m^3$ (\$1 to \$2/Mcf). Using Monte Carlo simulation to multiply the unit PV by the recoverable gas estimate yields the present day value of the prospect before capital investment. As shown in Figure 3, there is an 80% probability (P10 to P90 values) that Geologist A's prospect has a present day value before capital of between \$12 and \$66 Million.

While the PV before investment range looks promising, it must be compared with the required capital investment to know if the prospect has economic potential. The present value capital costs for the prospect were estimated for each category as follows:

Capital Cost Estimates
All values in Millions of Dollars

Item	Low	Medium	High
Sales pipeline	9	13	16
Plant	4	4.8	5.9
Gathering System	2.4	3.2	3.9
Well Cost \$MM/well	0.25	0.3	0.4
Wellsite costs \$MM/well	0.1	0.15	0.2
Drilling Success Rate	70%	80%	85%
Dry Hole Cost \$MM/hole	0.15	0.2	0.3

Monte Carlo simulation can be used to successively add the cost range for each category and estimate the total capital cost range for the project. Cost estimates for well costs and wellsite facilities that were provided on a per well basis were added together and then multiplied by the distribution for the expected number of development wells to determine the total cost range for the development well category.

The development well category should also include the cost of the dry holes that will be encountered. The number of dry holes can be estimated by dividing the number of wells required by the drilling success rate to yield the total number of drilling attempts that must be undertaken. Multiplying by the chance of a dry hole (between 15 and 30%) yields the number of dry holes that are likely to be encountered. Multiplying by the cost per dry hole yields an estimated range of values for total dry hole cost. The updated capital cost table follows:

Capital Cost Estimates
All values in Millions of Dollars

Item	Low	Medium	High
Sales pipeline	9	13	16
Plant	4	4.8	5.9
Gathering System	2.4	3.2	3.9
Wells & Wellsites Cost	6.8	10.4	14.8
Dry Hole Costs	0.7	1.3	2.3

As can be observed, the sales pipeline and the wells are the two largest capital cost categories. Monte Carlo simulation is once more used to add the separate cost distributions and estimate the range of total costs for the project. In Fekete's experience it is useful to track the effect of each successive cost category on the total cost profile as follows:

Cumulative Costs
All values in Millions of Dollars

Item	Total Project Costs		
	P10	P50	P90
Sales pipeline	10.0	12.8	15.4
Sales P/L + Plant	14.8	17.7	20.4
Sales P/L + Plant + Gathering System	18.0	20.9	23.6
Sales P/L + Plant + Gathering System + Wells + Dry Hole costs	28.3	32.7	37.3

From Figure 4 (pg 19), the P10 (blue line) and P90 (upper red line) values of the capital cost range intersect the PV before capital investment curve at about the 43rd and 63rd percentiles. Thus the prospect has between a 37 and 57% chance of achieving a positive NPV. The graph also illustrates that even at the upper end of the reserve range we cannot do any better than double the value of the capital invested and that the sales pipeline and well costs have the greatest impact on financial performance.

Should a prospect with these financial characteristics be developed? One company may choose to develop the prospect because this is the best investment opportunity available at the time. Another may determine that its time has not yet come and choose to wait until the price of gas rises sufficiently and/or other developments in the area reduce the distance and cost of the sales pipeline. Either way, a consistent Monte

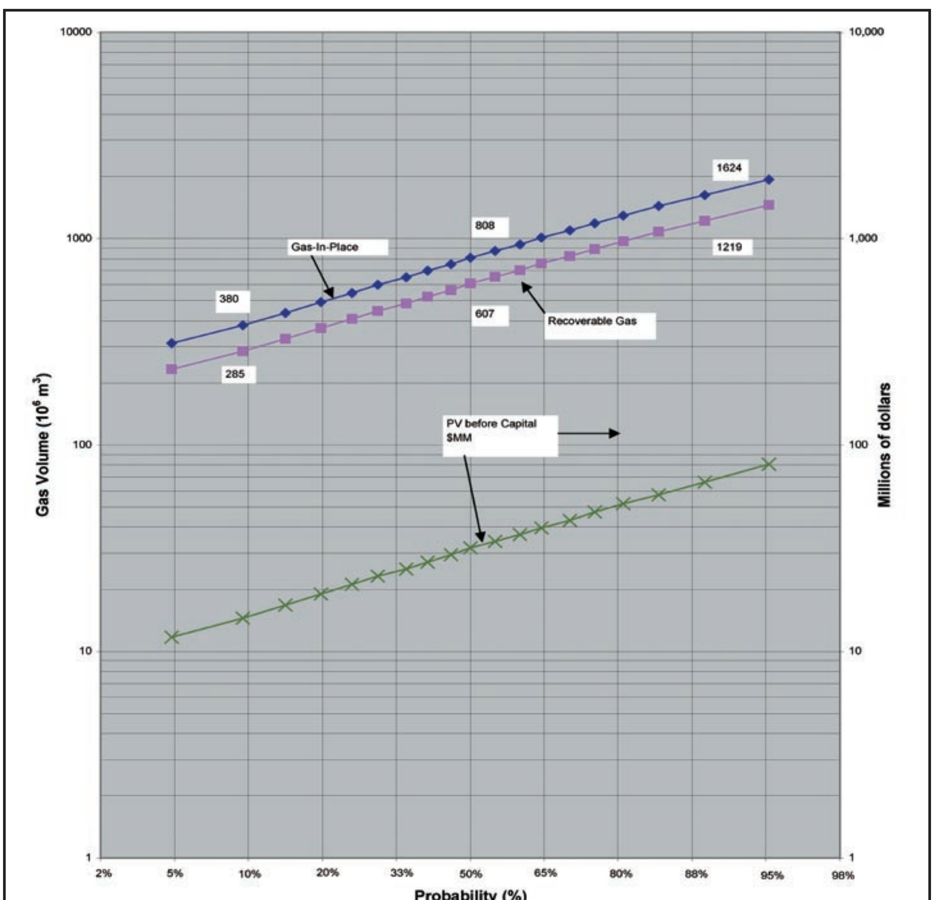

Figure 3. Probability Chart, Gas Development Prospect Present Value (PV).

Carlo evaluation methodology helps management make informed decisions.

Can Monte Carlo simulation also evaluate Geologist B's exploration prospect? We'll show you how in the next issue of the Reservoir.

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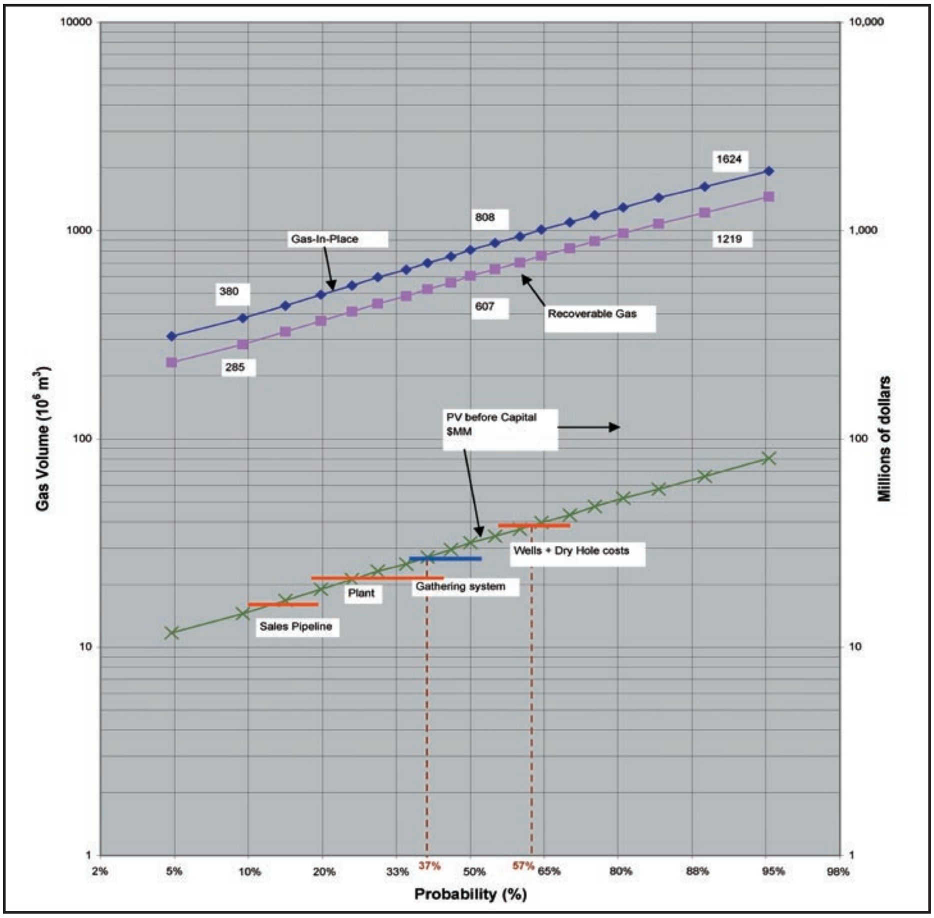

Figure 4. Probability Chart, Gas Development Prospect PV vs. Capital.