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SENSITITIVITY ANALYSIS FOR DEVELOPMENT OF GULF OF ALASKA

Ee-Tong Pak
Hongneung Machine Industry Co., Ltd.

ABSTRACT

It was attempted to analyze the sensitivity of the oil prospect place named MARIA which placed inside Gulf of Alaska. For the analysis, P6031090, ECOANA(computer) which installed in the head office, Shell Oil Co. was used and the data needed for computer programming were 1) Unit of Production data 2) Production Schedule 3) Total Gross Yearly Expenses and 4) Total Gross Capital and so on. The important data among the computer output were 1) PVPAT (Present Value After Tax): $ 1,167,077,500 2) Payout After Tax: 3.14 Yeaes (256,284,810 BBL Production) 3) Earning Power : 42% (After Tax) 4) PVPAT/BBL : $ 1.22 5) Capital/BBL : $ 2.00.

On the other hand, the effect acted upon PVPAT with varying the Platform cost, Facility cost, Pipeline cost and Well cost was observed in comparion with the basic for range from 50% to 200%. Resultantly, the order was 1) Well cost 2) Facility cost 3) Platform cost 4) Pipeline cost from 50% to 100% (basic cost) but it was 1) Pipeline cost 2) Facility cost 3) Well cost 4) Platform cost for range form 100% to 200%.

This project was completed by the contract with Shell Oil Co., and the geological data needed for this analysis were given by the head office and the development project started from Jan. 1976.

INTRODUCTION

This report presents the results of study on sensitivity analysis for development of MARIA, Gulf of Alaska. In the analysis, the Exploration and Production Economic Analysis Program, P6031090, ECOANA[1] was available in the UNIVAC 1110 EXEC 10 Program Library at the Technical Computing Division of the Shell Information Center. All calculation were preparations for input data on ECOANA sensitivity analysis.

Serval significant output data such as PVPAT,[2] Payout after tax, Earning power, PVPAT/BBL, and Capital/BBL were obtained after the computer running. Finally, the sensitivity analysis was completed by comparative graphical presentation of PVPAT variation on same percent according to change of input data on computer.

BASIC CRITERIA

A. Prospect (MARIA)

All geological data were given by Exploration Department, Shell Oil Company. Emphasizing that Exploration Department gave map for field of prospect, recovery and net pay zone were taken for Lower Cook-Inlet assuming production capability similar to Middle Ground Shoale, Gulf of Alaska. Total area of the field was 34,000ac., and 150′ pay and 200B/ac. ft were available for recover. Recoverable Reservers were expected to 1,018,005,510 BBL. Table 1 presents several available data in this study, which were given by the previously mentioned Exploration Department, Head Office.

Table 1.

	Success Worse Minimum	Most level	Reasonable best
Prospect	6	10	30
Development depth	3,000	8,000	15,000
Tracts/Trip	2	4—5	10
Trip area(a)	5,000	15,000	35'000
Porosity(%)	10	18	28
Permeability(MD)	2	100	500
Pay(ft)	100	150	800
Gravity	28	32	40—45
Recovery B/ac ft	150	200	300—700
Water depth	100	480	650—1,200

B. Basic data

Both beginning time of project and or present value calculation were dated January, 1976. 0.11% of fraction was given for both overhead fraction application to development capital and to operating cost by Head office. Zero was assumed for depletion allowance calculation. And Shell gross production schedule was output, listing and retaining all oil, gas, condensate, and plant product schedules. Unit value were per barrel of oil plus condensate. Working interest was coded as 1.00 and 0.1667 for royalty interest.

PRODUCTION DATA AND EXPENSES

A. Unit of production data:

By long term forecast from Head office, 10.67 \$/B was adapted for unit values of oil, and 0.300\$/MCF for unit values of gas at 1981 respectively. And 4% of escalation factor was taken for increase rate each year.

B. Production schedule

Following production schedules(refer table 2) were estabilished from Decline Curve[3]:

Table 3 shows the additional production schedule.

Table 2.

1981: Beginning time of Production
1983: 202,500B/D(Peak)
1984: 71,540,000B/Y(Peak)
2015: 10,500B/D(1500 B/D×7 platforms)
2015: 3,832,500B/Y

Table 3.

Production interval	Initial Production rate	Decline Factor	Gas poduction (GOR)of/BBL
8 years	73,912,500	0.025830	500
8 years	60,225,000	0.153867	500
16 years 4 mo.	17,739,000	0.094051	500

C. Total Gross Yearly Expenses

All data amounts coded for the computer input sheets in this study were direct operating costs in dollars, and all yearly expenses were obtained by calculation based on "Cook Inlet" which was also initiated from Middle Ground Shoale exprience. All operation costs were obtained by multiplied 1.5 to operation costs of "Cook Inlet" because of adverse working conditions and 5% escalation factor each year was adapted because of annual escalation tendency.

Items included in direct operect operation cost were as follow:

1. Fluid lifiting costing cost: 3.8¢/BBL
2. Water flood cost: 6.2¢/BBL
3. Gas handling cost: 6.2¢/BBL
4. Oil handling cost: 1.4¢/BBL
5. Reconditioning cost: 7.5¢/BBL
6. Field operation cost: 28¢/BBL

but since actual production life was 32 years, total gross expenses was \$501,792,970(1981—2013)

TOTAL GROSS CAPITAL

A. Platform cost[4] (Platform itself):

B. Platform Procuction facility cost (not

Table 4. Platform Costs

Platform #	W.D. (ft)	Total ($)	Tangible ($)	Intangible ($)
1	540	105,532,532	31,659,760	73,872,772
2	570	109,753,833	32,926,150	76,827,683
3	660	147,745,501	44,323,650	103,421,851
4	750	168,852,051	50,655,615	118,196,436
5	810	183,923,055	55,176,917	128,746,139
6	840	196,990,631	50,097,189	137,893,441
7	930	236,392,871	70,917,861	163,475,010
TOTAL($)		1,149,190,473	344,757,142	804,433,331

Escalation: 5% increase for 7 years

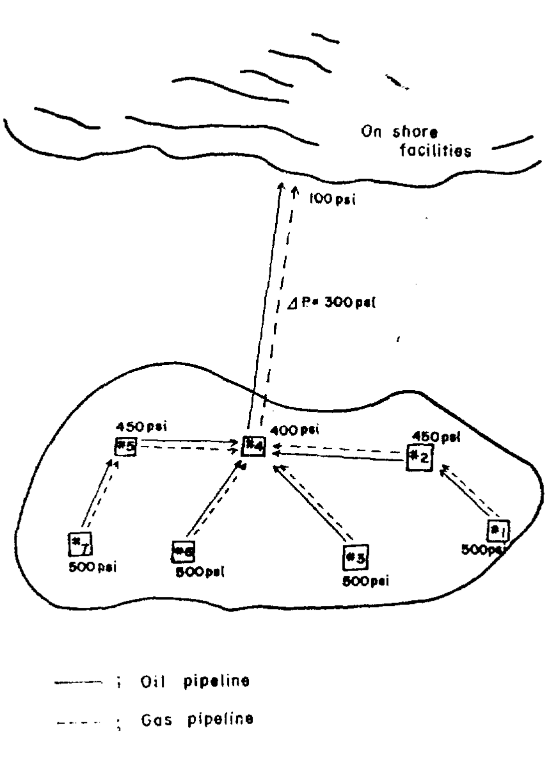

Fig. 1. Schematic Dingram for Pipeline Arrangement

included compressors, tangible cost: 80% of total cost): refer table 6

C. Pressure maintenance facility cost: Table 6

D. Onshore Production handling cost: Table 6

E. Pipeline cost: Table 6

Assuming 50°F for temperature of crude oil, kinematic viscosity: $1.4\times10^{-4}ft^2/sec=13$ centistake Refering fig. 1, pressure drop: $\Delta P=300$ psi (Platform #4 to onshore) and $\Delta P=50$ psi (each platform to platform #4).

For crude oil flow rate, Q, by Engineering Data Book[5]

Platform #4 to shore: 20″ pipe 64,000ft
Platform #1 to #2: 10″ pipe 11,500ft
Platform #3 to #4: 10″ pipe 14,700ft
Platform #6 to #4: 10″ pipe 14,400ft
Platform #7 to #5: 10″ pipe 14,400ft
Platform #2 to #4: 14″ pipe 14,400ft
Platform #5 to #4: 14″ pipe 14,200ft

Total:

10″ SCH 40 5,500ft: 104.2 in-mile
14″ SCH 30 28,600ft: 75.88 in-mile
20″ SCH 20 64,000ft: 242.42 in-mile

Pipeline cost[6]:

to shore 32″
Lengths 105 miles
Cost $165 MM

From above,

32 in × 105 miles = 3,360 in-miles
$165MM ÷ 3,360 = 49,107 $/in-miles
(Say $50,000/in-miles)

Assuming 5% increase escalation for 7 years and same condition for gas pipe so total cost were gained by oil pipe cost doubled.

Tangible Cost are 1/3 of total(Table 6).

F. Compressor Cost:

Suction pressure(assumed): 50 psia. Discharge pressure: 500psia. Compression Ration$=\frac{500}{50}=10$ Using 2 stages; each stages compression ratio:

$\sqrt{10}=3.1623$

Theoretical HP: 60HP/MMcf / Day,[5] and Assuming overall efficiency : 85%

$\frac{60HP}{0.85}=70,588$ HP

for 2 stages

$70,588HP \times 2=141,176HP$

Maximum Gas Producation : 98MMcf/Day (1984)

141,176 HP/MMcf/Day × 98 MMcf/Day=13, 835.25HP Cost :

Assuming $600 per HP and still 5% increase escalation for 7 years, Tangible Cost : 80% of total (Refer to Table 6)

G. Well Cost : (7)

Straight hole cost for 10,000 feet: $1,011,000

Straight hole cost for 5,000 feet : $776,000

By Interpolation

8,000 feet (for this study), for straight hole drilling : $917,000

Assuming cost per day drilling : $20,000. Escalation rate is 5% year.

1/3 of Wells in 7th year

1/3 of Wells in 8th year

1/3 of Wells in 9th year

Tangible Cost : 10% of total

Refer to Table 5 and 6

Table 5. Well Costs

Devistion Angle (Degree)	Drilling	Additional Days Test	Casting	Comple-tion	Total (Days)	Cost Added	No. of Wells	Total ($)
0					1			917,000
15	1.3	0	0	0	1.3	26,000	1	7,544,000
26	1.25	1,167	0.1	0.1	1.62	32,400	12	11,392,802
37	5.1	0.5	0.25	0.3	6.15	123,000	16	16,640,000
47	7.5	1.0	0.5	0.7	9.7	194,000	21	23,331,000

TOTAL/Platform(Present value) 59,824,800 (Say $60,000,000)

For 7 platforms $59,824,800×7=$418,773,600

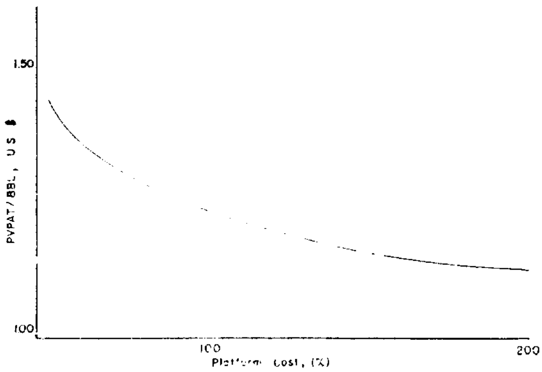

Fig. 2. Prospect Profitability
vs
Platform Cost
(Costs are Given as a Persentage of Base Cost Assumptions)

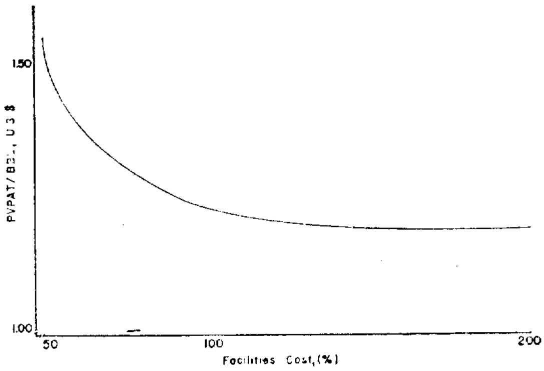

Fig. 3. Prospect Profitability
vs
Facilities Cost
(Costs are Given as a Persentage of Base Cost Assumptions)

Table 6. Escalated Cost

	Total ($)		Tangible ($)	
	Total	Average/Platform	Total	Average/Platform
Platform Cost	1,149,190,473	164,170,068	344,757,142	49,251,020
Prod Fac.	40,899,025	5,842,718	32,719,220	4,674,174
Press. Maint. Facility	21,810,056	3,115,722	17,448,045	2,492,578
Onshore Handling	16,603,785		13,283,028	
Pipeline Cost	58,388,798		19,462,932	
Comp. Cost	11,680,550		9,344,440	
Well Cost	619,210,382	88,458,626	117,649,973	16,807,139
Total	1,917,783,069		554,664,780	

	Intangible ($)		Per Weel		
	Total	Average/Platform	Total	Tangible	Intangible
Platform Cost	804,433,331	114,919,047			
Prod Fac.	8,179,805	1,168,544			
Press. Maint. Facility	4,362,011	623,144			
Onshore Handling	3,320,757				
Pipeline Cost	38,925,866				
Comp. Cost	2,336,110				
Well Cost	501,560,409	71,651,487	1,525,149	289,778	1,235,371
Total	1,303,118,289				

SEVERAL SIGNIFICANT OUTPUT DATA OBTAINED BY COMPUTER (FOR 100% OF COST)

A. PVAPT: $1,167,077,500-with 9% of discount rate

B. Payout after tax: 3.14years-with production of 156,284,810 bbl

C. Earning power: 42% after tax

D. PVPAT/BBL= $1.22

E. Capital/BBL = $2.00. Refer computer output for other data.

SENSITIVITY ANALYSIS

Change of input data on computer:

A. 50% of Platform Cost. 200% of Platform Cost.

B. 50% of Facilities Cost. 200% of Facilities Cost.

C. 50% sof Pipeline Cost. 200% of Pipeline Cost.

D. 50% of Well Cost. 200% of Well Cost.

Table 7: Variation of computer output data according to variations of each capital.

Figure 2, 3, 4 and 5: Graphical presentation of PVPAT variation with variation of platform, facilities, pipeline and well cost respectively.

Figure 6: Comparative graphical presentation of PVPAT variation on the same % of cost.

CONCLUSION AND DISCUSSION

On Figure 6.

Sequences of decreasing tendency on PVPAT with same increase on % of cost:

Table 7. Significant Output Data from Computer

Cost	% of Cost	PVPAT($)(discount rate : 9%)	Payout (At)Rear	Earning Power(At)(%)	PVPAT/BBL($)	Capital/BBL($)
	50	1,374,191,700	1.89	80.31	1.43	1.40
Platform	100	1,167,077,500	3.14	42.00	1.22	2.00
	200	896,367,420	3.67	27.87	1.10	3.45
	50	1,482,318,200	1.40	161.13	1.55	1.87
Facilities	100	1,167,077,500	3.14	42.00	1.22	2.00
	200	1,131,997,700	3.31	38.58	1.18	2.09
	50	1,206,400,600	3.09	43.43	1.26	1.97
Pipeline	100	1,167,077,500	3.15	42.00	1.22	2.00
	200	1,145,973,000	3.24	40.18	1.19	2.06
Well	50	1,508,223,100	1.28	176.76	1.57	1.68
	100	1,167,077,500	3.14	42.00	1.22	2,00

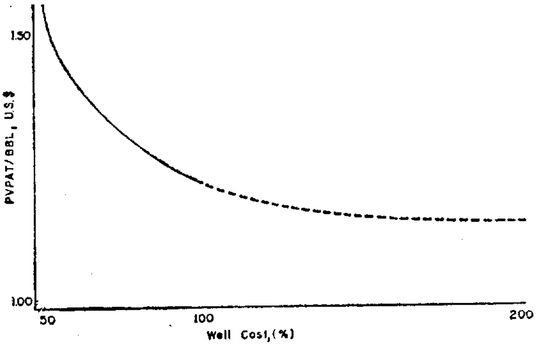

Fig. 4 Prospect Profitablity
vs
Pipeline Cost
(Costs are Given as a Persentage of Base Cost Assumptions)

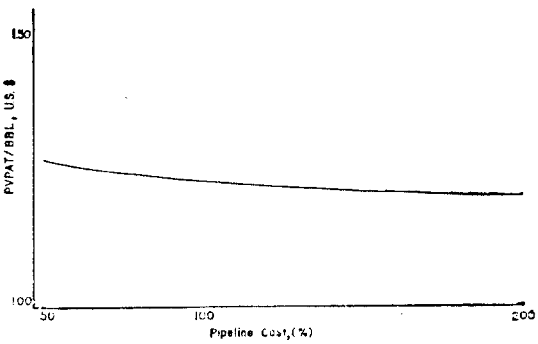

Fig. 5 Prospect Profitability
vs
Well Cos
(Costs are Given as a Persentage of Base Cost Assumptions)

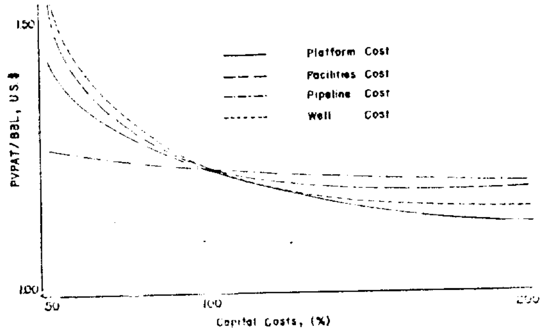

Fig. 6 Comparison of Pvpat
vs
Capital Cost
(Costs are Given as a Persentage of Base Cost Assumptions)

A. from 50% to 100%
the most sharp tendency of decrease…………
…well cost
2nd most sharp tendency of decrease…………
…facilities cost
3rd most sharp tendency of decrease…………
…platform cost
4th most sharp tendency of decrease…………
…pipeline cost

B. from 100% to 200%
the most sharp tendency of decrease…………
…platform cost
2nd most sharp tendency of decrease…………

…well cost

3rd most sharp tendency of decrease…………

…facilities cost

4th mostsharp tendency of decrease…………

…pipeline cost

Generally, on region under 100%…………sharp variation on PVPAT except pipeline cost

Pipeline cost…………vary very slowly

It was impossible to get reasonable data for PVPAT variation to well cost variation by computer. In order to get the PVPAT variation, *tendency of continuous curve on region under* 100% of well cost was extended to region of 200% of well cost. Slope and curvature of the *continuous curve on region over the* 150% *to* the 200% coincided with those which were obtained by computer.

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