CHARACTERIZATION OF OIL AND GAS RESERVOIR HETEROGENEITY

Cooperative Agreement DE-FG07-90ID12839

DOE/ID/12839--9

DE93 003304

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Reporting Period: July 1, 1992 - September 30, 1992

RECEIVED 0371
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OBJECTIVE

The ultimate objective of this cooperative research project is to characterize Alaskan petroleum reservoirs in terms of their reserves, physical and chemical properties, geologic configuration in relation to lithofacies and structure, and development potential.

The project has two tasks: Task 1 is a geological description of the reservoirs including petrophysical properties, i.e., porosity, permeability, permeability variation, formation depth, temperature, and net pay, facies changes and reservoir structures as drawn from cores, well logs, and other geological data. Task 2 is reservoir fluid characterization—determination of physical properties of reservoir fluids including density, viscosity, phase distributions and composition as well as petrogenesis—source rock identification; and the study of asphaltene precipitation for Alaskan crude oils.

SUMMARY OF TECHNICAL PROGRESS

WELL LOG ANALYSIS OF KUPARUK FIELD, NORTH SLOPE, ALASKA

During the last quarter, preliminary analysis of approximately 50 Kuparuk Field wells was undertaken at PDL. Figure 1 shows locations of wells which have been analyzed or are currently being analyzed. The analysis is focusing on the Lower Cretaceous Kuparuk River Upper and Lower Sands, which are the main producing Kuparuk intervals (Figure 2). Calculation of porosity, water saturation, gross and net pay, and shale volume at each well has been completed and results are being stored for future mapping and reservoir description. Tables 1 and 2 list petrophysical values computed to date in Kuparuk Field wells. The analysis was initiated in the southern portion of the field and is currently being carried north.

Plots of the Kuparuk Upper and Lower Sands similar to those in Figures 3 and 4 have been generated as a means of determining field-wide patterns in log character (and corresponding rock character). Figures 5 and 6, depicting results of petrophysical analysis of the Upper and Lower Sands, indicate the presence of hydrocarbons. Cross sections like those in Figures 7 and 8 are also being generated in the effort to better delineate areal continuity of the producing sands and to isolate faults and structural trends.

Literature discussing Kuparuk River Field indicates the structure and stratigraphy of the sands to be complex, as indicated in Figure 9. Extensive faulting as shown in Figure 10 has played an important role in development of hydrocarbon migration patterns. An example of stratigraphic complexity within the Lower Sand interval is

exhibited where progressively younger "A" sands pinchout southward across the field (Figure 11).

As input of well log data into the Kuparuk Field database continues during the next quarter, analysis of the Upper and Lower Sand intervals will be intensified in order to isolate and identify individual sand members within each interval. Placement of faults and identification of structural elements will be incorporated in the reservoir description. Stratigraphy of the various sands will be analyzed, with efforts being concentrated on the interrelationship of faulting and sand thickening, thinning, and pinchouts. Log character will be evaluated to determine environments of deposition and reservoir sand quality. In addition, contour maps and three-dimensional plots will be generated as part of the reservoir description.

REFERENCE

Masterson, W.D., and C.E. Paris: *"Depositional History and Reservoir Description of the Kuparuk River Formation, North Slope, Alaska,"* Alaskan North Slope Geology, Vol. 1, edited by Irv Tailbur and Paul Weirner, published by the Pacific Section, Society of Economic Paleontologists and Mineralogists, Bakersfield, CA, and the Alaskan Geology Society, Anchorage, AK (1987).

LEGEND

	SANDSTONE		SILTSTONE		SIDERITE CEMENT
	MUDSTONE		GLAUCONITE		INTERBEDDED SANDSTONE, SILTSTONE, AND MUDSTONE

Figure 2. Stratigraphy of Kuparuk Formation
Showing Upper and Lower Sand Members (Masterson and Paris).

Table 1. Upper Sand Petrophysical Values at Kuparuk Field

UPPER SAND	GROSS THICKNESS (ft)	NET PAY (ft)	ϕ (%)	Sw (%)	VOLUME OF SHALE (%)
1A-11	40	15	25	35	
1A-14	120	(16)	(25)	(34)	
1B7	43	1	19	78	
1C2	122	117	22	34	15
1C5	157	137	26	35	18
1D2	80	17	25	54	
1D4	122	109	34	18	58
1D6	48	15	17	2?	26
1G7	51	41	19	53	20
1G13	94	47	16	28	
1H3	(108)	(19)	(23)	(42)	
1H6	38	0	27	90	
1H7	42	9	26	85	
1H13	118	22	20	32	
1L8	51	38	23	35	
1Q11	65	41	18	30	
1Q15	58	44	13	70	23
1Y16	43	35	17	46	
2A5	36	36	21	27	11
2B3	133	57	17	54	26
2D11	26	6	15	53	56
2D12	20	15	16	42	14
2E11	27	26	18	65	18
2F1	120	120	29	25	3
2F2	12	12	17	42	27
2F15	119	60	23	24	9

UPPER SAND	GROSS THICKNESS (ft)	NET PAY (ft)	ϕ (%)	Sw (%)	VOLUME OF SHALE (%)
2G6	120	2	13	35	28
2h13	154	115	19	39	20
2h15	120	4	12	44	27
2u1	74	62	14	33	4
2u6	45	37	16	40	1
2u16	67	63	23	15	14
2v14	51	49	18	23	4
2w2	58	49	17	29	11
2w7	60	59	21	20	12
2z7	51	47	19	40	17
2x2	129	108	21	41	19
2z15	87	71	26	15	19
3a9	90	79	18	42	17
3b5	40	8	14	44	37
3b14	150	150	21	41	11
3n12	64	15	15	39	32
3n13	35	29	15	54	19

Table 2. Lower Sand Petrophysical Values at Kuparuk Field

LOWER SAND	GROSS THICKNESS (ft)	NET PAY (ft)	ϕ (%)	S_w (%)	VOLUME OF SHALE (%)
1A-11	46	22	28	31	
1A-14	92	(16)	(17)	36	
1B7	47	4	29	38	
1C2	16	12	25	46	10
1C5	107	77	25	49	49
1D2	42	0	21	77	
1D4	33	33	34	18	58
1D6	33				
1G7					
1G13	118	22	20	33	
1H3	(105)	(21)	(22)	(50)	
1H6	119	0	23	93	
1H7	50	25	28	35	
1H13	118	22	20	32	
1L8	94	1	25	66	
1Q11	(120)	(37)	(22)	(26)	
1Q15	90	80	21	32	18
1Y16					
2A5	121	721	19	35	17
2B3	(45)	(30)	(20)	(43)	(15)
2D11	50	50	17	45	23
2D12	83	83	22	32	12
2E11	103	103	22	54	22
2F1					
2F2	120	120	20	32	26
2F15	14	1	20	39	11

LOWER SAND	GROSS THICKNESS (ft)	NET PAY (ft)	ϕ (%)	Sw (%)	VOLUME OF SHALE (%)
2G6	127	115	15	10	22
2h13	104	100	20	37	21
2h15	127	115	15	10	22
2u1	121	110	17	38	38
2u6	124	123	21	49	15
2u16	39	39	20	22	17
2v14	134	133	20	39	16
2w2	113	102	18	32	19
2w7	115	91	17	32	26
2z7	62	40	18	20	12
2x2	92	92	20	23	8
2z15	119	37	19	29	29
3a9	109	108	22	32	14
3b5	96	82	22	38	11
3b14	137	75	25	46	6
3n12	120	120	17	39	31
3n13	109	109	19	29	30

Figure 3. Upper and Lower Sands in Well 2w2.

Figure 4. Upper and Lower Sands in Well 1Q-15.

Figure 5. Analysis Plot of Well 2w2.

Figure 6. Analysis Plot of Well 1Q-15.

Figure 7. Cross Section Showing Northerly Dip Across Kuparuk Field.

Figure 8. Westerly Component of Dip and Inter-Sand Thinning Across Kuparuk Field.

Figure 9. Structural Cross Section Across Kuparuk Field (Masterson and Paris).

Figure 10. Faulting Within Kuparuk Field (Masterson and Paris).

Figure 11. Stratigraphic Cross Section Across Kuparuk Field (Masterson and Paris).

RESERVOIR HETEROGENEITY CLASSIFICATION SYSTEM

FOR TORIS AND TORIS DATA BASE

The work performed during this quarter as part of the Reservoir Heterogeneity Classification System for TORIS and TORIS data base included the compilation of production and injection data from the Alaskan oil fields and the compilation of geological and reservoir data. Following an extensive literature review, these data were collected, completed and plotted. Data not available in the literature have been requested from the field operators. Figures 12-15 display the monthly production and injection data for the Ivishak and Kekiktuk formations of Endicott oil field. Tables 3 and 4 include the reservoir heterogeneity and TORIS data base data for the Kekiktuk formation of Endicott oil field.

The collection of data for TORIS data base for all the Alaskan oil fields continues during the next quarter and will be included in the final report.

RESERVOIR FLUID CHARACTERIZATION

Under the reservoir fluid characterization task, work on two subtasks, namely: 1) modeling of asphaltene equilibria and prediction of asphaltene precipitation from Alaskan crude oils under influence of a miscible solvent; and 2) study of effect of asphaltene deposition on rock-fluid properties has been completed. Preliminary results on these tasks were provided in the last Technical Progress Report and all the final results will be provided in the Final Technical Report.

Figure 12.

Figure 13.

Figure 14.

Figure 15.

Reservoir Heterogeneity Classification System for TORIS

1. Reservoir Identification

Reservoir Play: _____

Reservoir Name: EndicottGeologic Province: Arctic Coastal PlainDate: 7/10/92Field Name: EndicottGeologic Age: MississippianPrepared By: UAF/PDLState: AKFormation: KekiktukVersion: 1

2. Depositional System

☒ 1 ☐ 2 ☐ 3

Degree of Confidence in Selection (1=Highest, 3= Lowest)

Carbonate Reservoirs

- ☐ Lacustrine
- ☐ Peritidal
- ___ Supratidal
- ___ Intertidal
- ___ Subtidal
- ☐ Shallow Shelf
- ___ Open Shelf
- ___ Restricted Shelf
- ☐ Shelf Margin
- ___ Rimmed Shelf
- ___ Ramp
- ☐ Reefs
- ___ Pinnacle Reefs
- ___ Bioherms
- ___ Atolls
- ☐ Slope/Basin
- ___ Debris Fans
- ___ Turbidite Fans
- ___ Mounds
- ☐ Basin
- ___ Drowned Shelf
- ___ Deep Basin

Clastic Reservoirs

- ☐ Eolian
- ___ Ergs
- ___ Coastal Dunes
- ☐ Lacustrine
- ___ Basin Margin
- ___ Basin Center
- ☒ Fluvial
- ___ Braided Streams
- ___ Meandering Streams
- ☐ Alluvial Fan
- ___ Humid (Stream-Dominated)
- ___ Arid/Semi-Arid
- ___ Fan Deltas
- ☐ Delta
- ___ Wave-Dominated
- ___ Fluvial-Dominated
- ___ Tide-Dominated
- ☐ Strandplain
- ___ Barrier Cores
- ___ Barrier Shorelines
- ___ Back Barriers
- ___ Tidal Channels
- ___ Washover Fan/Tidal Deltas
- ☐ Shelf (Accretionary Processes)
- ___ Sand Waves
- ___ Sand Ridges/Bars
- ☐ Slope/Basin
- ___ Turbidite Fans
- ___ Debris Fans
- ☐ Basin
- ___ Pelagic

3. Diagenetic Overprint

☒ 1 ☐ 2 ☐ 3

Degree of Confidence in Selection (1=Highest, 3= Lowest)

Carbonate Reservoirs

- ☐ Compaction/Cementation
- ☐ Grain Enhancement
- ☐ Dolomitization
- ☐ Dolomitization (Evaporites)
- ☐ Massive Dissolution
- ☐ Silicification

Clastic Reservoirs

- ☐ Compaction/Cementation
- ☒ Intergranular Dissolution
- ☐ Authigenic Clay
- ☐ Chertification

4. Structural Compartmentalization

☒ 1 ☐ 2 ☐ 3

Degree of Confidence in Selection (1=Highest, 3= Lowest)

- ☐ Natural Fracture Permeability
- ☐ Unstructured
- ☐ Faulted
- ___ Normal Fault
- ___ Reverse Fault
- ___ Strike-Slip Fault
- ☒ Fault/Fold
- ___ Normal Fault
- ___ Reverse Fault
- ___ Strike-Slip Fault
- ☐ Folded

5. Reservoir Heterogeneity Ternary Diagram

Predominant Element of
Reservoir Heterogeneity:
(Check Only One)

- Depositional System _____
- Diagenetic Overprint _____
- Structural Compartmentalization X

6. Trap Type

☐

Stratigraphic

☐

Structural

☒

Combination

7. Optional Comments (References, Details on Above Selections, Etc.)

"Reservoir Description on the Endicott Field, North Slope, Alaska."Keith Woldneck and others.

Table 4.

TORIS DATA BASE
FIELD: ENDICOTT (KEKIKTUK)

Record 1:

Field Code	N/A
STATE Postal Code	AK
Lithology Code (-1, 0 = Unknown; 1 = SS, 2 = LS; 3 = Dolo.)	1
Geologic Age Code AAPG	330
Field Name	Endicott
Reservoir Name	Endicott
Reference Number	N/A
Load Number	N/A
Formation Name	Kekiktuk

Record 2:

(1) Field Acres (Acres)	8700
(2) Proven Acres (Acres)	8700
(3) Well Spacing (Acres)	160
(4) Total Wells (Number)	80
(5) Net Pay (Feet)	56
(6) Gross Pay (Feet)	240 TVT
(7) Porosity (%)	22.0
(8) Initial Oil Saturation (%)	80-94%
(9) Current Oil Saturation (%)	N/A
(10) Initial Water Saturation (%)	20-6%
(11) Current Water Saturation (%)	N/A
(12) Initial Gas Saturation (%)	N/A
(13) Current Gas Saturation (%)	N/A
(14) Initial Oil FVF (Res bbl/STB)	1.35
(15) Current Oil FVF (Res bbl/STB)	1.36
(16) True Vertical Depth (Feet)----Mid-Perforation	10000.0
(17) Formation Temperature (°F)	218.0

Record 3:

(18) Current Formation Pressure (PSI)	N/A
(19) Permeability (md)	847
(20) Geologic Age (AAPG)	330
(21) API Gravity (°API)	23
(22) Oil Viscosity (CP) :e Reservoir condition	1
(23) Formation Salinity (ppm TDS)	28000
(24) OOIP (BBL)	1.170×10^9
(25) Primary Recovery Factor (Fraction of OOIP)	10%
(26) Cumulative Oil Production (BBL)	11.82×10^7

Table 4. (Continued)

(27)	Year For Cumulative Oil Production; EX/1986	1990
(28)	Technical Availability Date (Year); Ex/1990	N/A
(29)	Primary Recovery (BBL/AC.FT.)	100
(30)	Primary Recovery (BBL)	115.5 x 10 ⁶
(31)	Year For Primary Recovery	1982
(32)	Current Producing GOR (SCF/BBL)	1220.0
(33)	Initial Producing GOR (SCF/BBL)	763.0

Record 4:

(34)	Reservoir Acreage (Acres)	8700
(35)	Initial Formation Pressure (PSI)	4890 psi @ 10,000 TVDSS
(36)	Reservoir Dip (DEG)	5.5
(37)	Production Wells (Number)	61
(38)	Injection Wells (Number)	18
(39)	Swept Zone Oil Saturation (%) (Residual to Water)	N/A
(40)	Injection Water Salinity (ppm TDS)	N/A
(41)	Clay Content (%)	Trace - 5%
(42)	Dykstra-Parsons Coefficient	N/A
(43)	Current Injection Rate (B/D/WELL)	10,000
(44)	Fractured-Fault (Y,N) (N = 0, Y = 1)	1
(45)	Shale Break or Laminations (Y,N) (N = 0, Y = 1)	1
(46)	Major Gas Cap (Y,N) (N = 0, Y = 1)	1
(47)	Field Multiplier (Number)	N/A
(48)	RRC District	N/A
(49)	Production Rate (MBBL/D); For the Year shown in element 28	100.0
(50)	Recovery Efficiency-Waterflood (Factor)	67%
(51)	Ultimate Recovery Factor (Fraction of OOIP) (Primary Plus Secondary)	45%

Record 5:

(52)	Geologic Play Code (Table II)	-1
(53)	Depositional System Code (Table III)	130
(54)	Depositional System Degree of Confidence (1 = Highest, 2 = Moderate, 3 = Lowest)	1
(55)	Diagenetic Overprint Code (Table IV)	7
(56)	Diagenetic Overprint Degree of Confidence (1 = Highest, 2 = Moderate, 3 = Lowest)	1
(57)	Structural Compartmentalization (Table V)	41
(58)	Structural Compartmentalization Degree of Confidence (1 = Highest, 2 = Moderate, 3 = Lowest)	1
(59)	Predominant Element of Reservoir Heterogeneity (1 = Depositional System, 2 = Diagenetic Overprint, 3 = Structural Compartmentalization)	3
(60)	Trap Type (1 = Stratigraphic, 2 = Structural, 3 = Combination)	3
(61)	Geologic Province (Table VI)	058

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