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ESTIMATION OF REMAINING OIL RESERVES ON 2700 FT SAND (PYAWBWE FORMATION) CD FAULT BLOCK, MANN OIL FIELD

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Abstract

Reserves estimation is heavily affected by technical uncertainty. The underground oil reserves estimation methods can be grouped in three groups. There are Analogy Method, Volumetric Method and Performance Method. Performance Method includes Material Balance Method, Decline Curve Analysis and Reservoir Simulation. In early stages of development, reserves estimates are restricted to the Analogy and Volumetric calculation. As production and pressure from a field become available, Decline Curves Analysis and Material Balance calculation, become predominant methods of calculating reserves. These methods greatly reduce the uncertainty in reserve estimates; however, during early depletion, caution should be exercised in using them. Decline Curves relationships are empirical, and rely on uniform, lengthy production periods. It is more suited to oil wells, which are usually produced against fixed bottom-hole pressure. Analysis on these methods, however provide quality assurance, for estimating hydrocarbon reserves. Different estimation methods may yield significantly different results, and reconciliation of the differences may be difficult. If there are wide differences, application of two or more methods may reveal the need for future investigation. Comparison of the reserves estimates with actual results on a post mortem basis will provide valuable learning point. The comparison must include quantitative assessment of basis and accuracy of estimate.

Keyword: reserves, material balance, decline curve, volumetric and simulation

Introduction

The Mann anticline is located in the Minbu District, Magway Region, between latitude 18° 10′ to 18° 18′ and longitudes 94° 45′ to 95° 0′, covering about 10 square miles (6400 arces). The Mon Chaung is the northern boundary and the Sabwet Chaung is the southern boundary. The area north of latitude 18° 14′ is a flat plain with average elevation of 140 ft above sea level covered by alluvium. The area between latitudes 18° 14′ and 18° 10′ is a fairly rugged terrain with average elevation of 250 ft covered by Miocene to Oligocene rocks.

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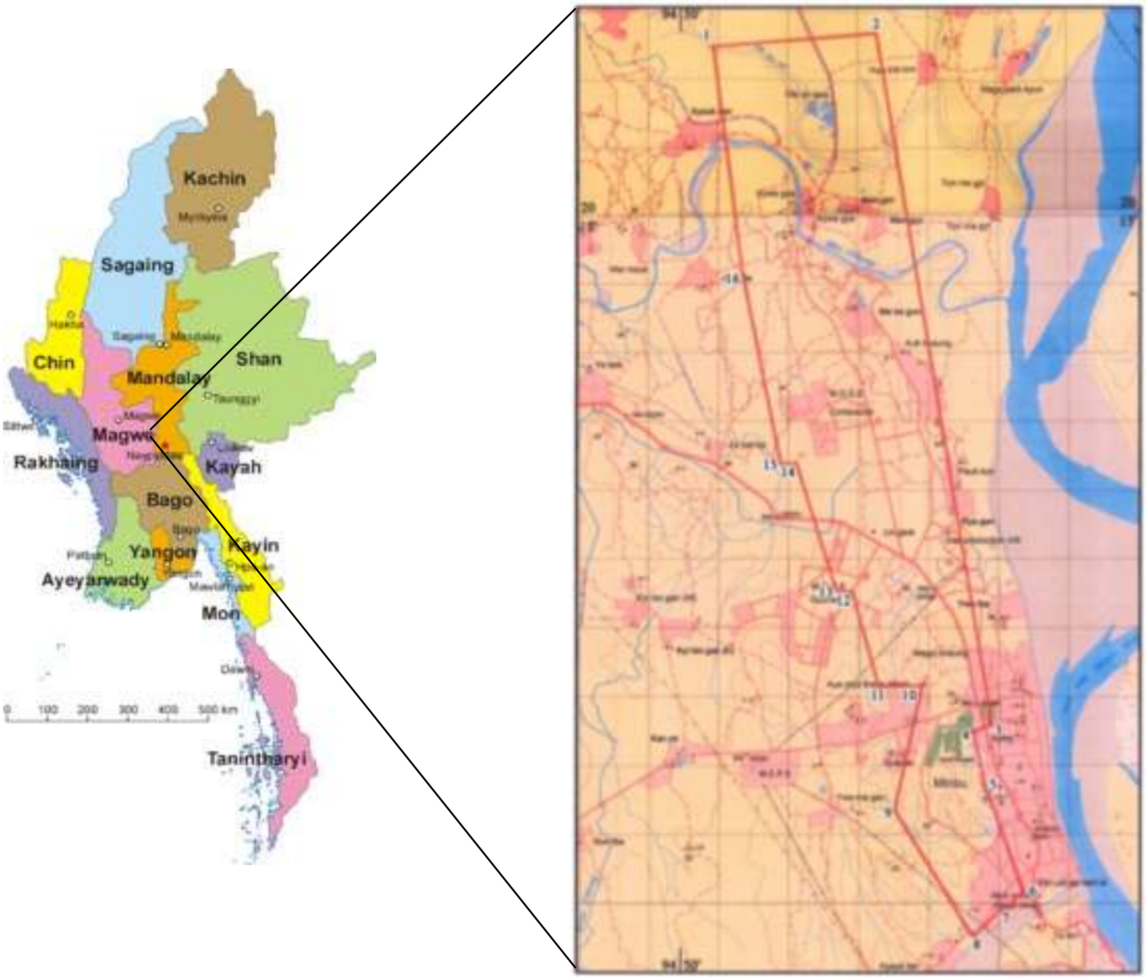


Figure (1) Location map of the study area

Geology of Mann Oil field

The Mann anticline occupies northern crestal area and northern plunging area of the Minbu anticline. The Minbu anticline is an asymmetrical, elongated anticline continuing from the Tagaing-Chaungtha structural trend through Peppi, Palanyon, and Htaukshabin to Minbu with the NNW-SSE trend. The Minbu-Taggaing- Chaungtha anticlinal structure trend is the first line of structure reference to the Salin Syncline developed on the east flank of Salin Basin shown in figure. The Sabwet Chaung fault located at the latitude 18° 10′ divided Minbu anticline into two anticlines namely Mann anticline and Htaukshabin anticline.

Mann anticline is a broad-crested, asymmetric, cross and crest ally faulted anticline bound to the east by the west hading thrust. The dips are as high as 70° on the west flank and rarely exceed 30° on the east flank. The nose of the anticline and most of the crestal area have dips in the range 10° -15°.Geological map of the Mann anticline is shown in figure.

The Minbu Structure is thrusted in the east flank hading toward west, there are both longitudinal and cross fault. It is rise from the Salin syncline around Latitude 20° 21' N and terminates in the Peppi area, a distance of 30 miles. The northern plunging end of this structure (where Mann oil field is situated), which is to aboard, gentle and stable anticline, under cover of the alluvial and Irrawaddies was discovered by gravity and seismic surveys. To the south a number of structural highs are present along the trend on which 6 small oil fields; Shwelinban, Taukshabin, Palanyon, Yethaya, and Peppi are siturated. A west ward hading thrust is present along the eastern flank of the structure to the south of Sabwet Chaung. To the south, the Minbu structure is in continuation with the Tagaing-Chaungtha structural trend. Minbu structure consist of four oil and gas fields Peppi, Htaukshabin, Tabin and Mann. Mann is latest one of the largest oil field discovered by MOGE in 1970.

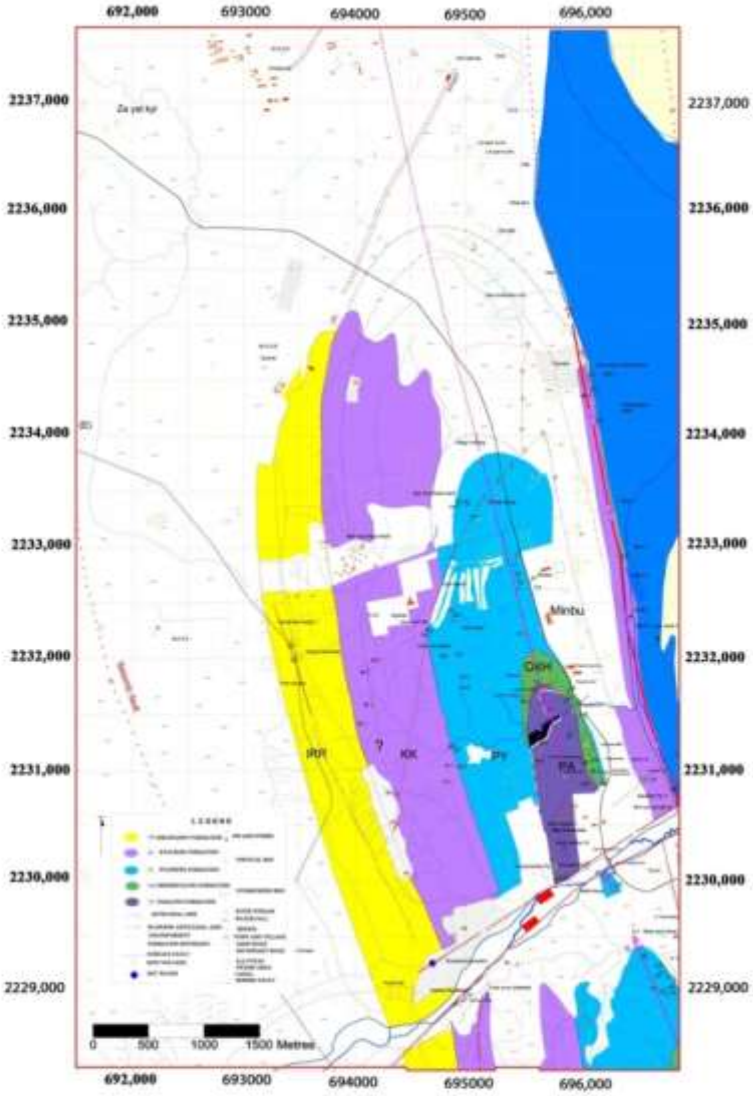


Figure (2): Geological map of Mann anticline (source: MPRL E&P,2009)

Well log correlation to Pyawbwe Formation

The Pyawbwe Formation of Early Miocene age has been described as open marine / deeper shelf deposits (Stuart et al., 1992). They also state that the non-marine to paralic environments grade southwards through delta front and prodelta environments. Mann Field is located in a mid-outer neritic environment according to Stuart et al. (1992). Within the sequences, Stuart et al. (1992) describes the occurrence of a basal Sequence Boundary, a Transgressive System Tract and a Highstand System Tract.

The Pyawbwe Formation is characterized by a series of prograding and aggrading log characteristics. The progrades are subtle, and it is often not possible to recognize a general increase or decrease in prograde thickness and sand content. This is especially true for the lower portion of the formation. A significant break in lithological characterisation occurs at the top 3200’sand. Generally, the sequence below the 3200’sand is less mud prone and consists of a series of sands and shales, according to the serrated log pattern. The succession on top of the 3200’sand shows a higher mudstone content. The top 3200’sand is a very significant marker horizon and characterises a break in sedimentation character (also observed in core). It is believed to form a major break in sedimentation in the entire area and is definitively a sequence boundary and showing a change in depositional setting in the delta environment.

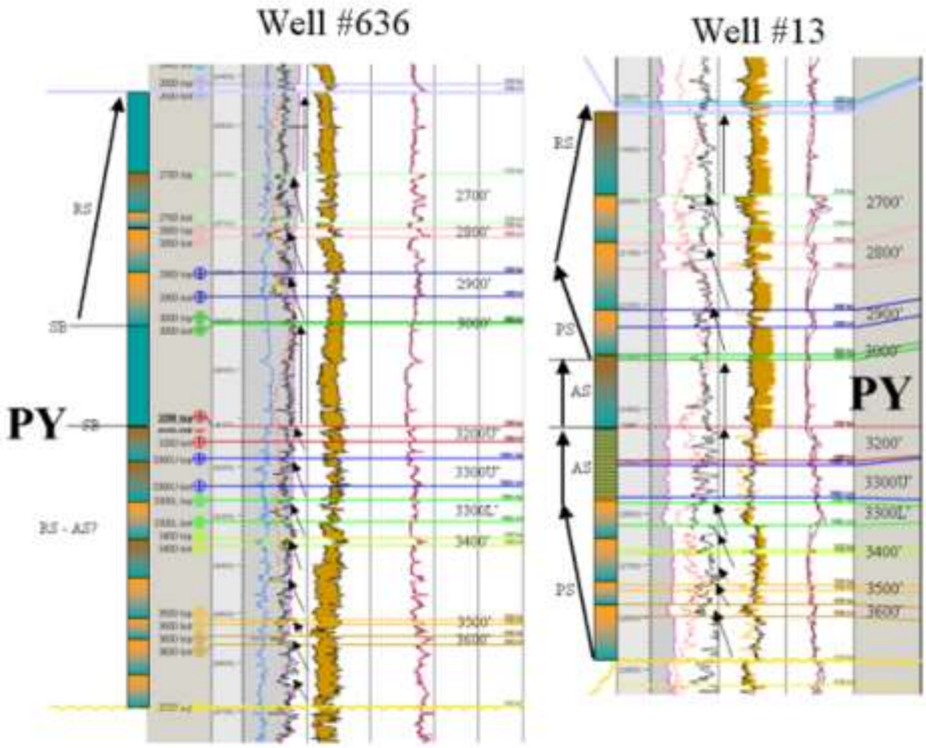


Figure (3): Wells M-636 and M-13, sequences in Pyawbwe Formation. (SB = Sequence boundary, PS = Progradational seq., AS = Aggradational seq., RS = Retrogradational seq.)(source: MRRL.E&P,2009)

The base of Pyawbwe is characterized by a regional unconformity. From core, the location of this regional unconformity is located at the base of the 3600ft sand. The base 3600ft sand is a generally sharp-based event in log expressions. Individual sand units show a typically serrated log pattern, indicative for mudstone intercalations in the sand bodies. This is also defined by core descriptions. Individual, well-to-well correlations of sand bodies with a similar log character are hard to make. This would indicate a high degree in mudstone intercalations and reservoir heterogeneities on a local scale.

The overall deepening of the depositional environment up to the 3200ft sand, interpreted in core, is not directly expressed by the sequence visible in logs in this lower Pyawbwe Formation. However, the core interpretations agreed with the general observation on the deepest deposits, the thick sequences of prodelta mudstones overlying the 3200ft sand, with its deepest deposits to occur between the 2900ft and the 2800ft sand. This brake represents a change from a more sandstone and shale dominated lower Pyawbwe sequence into a series of thicker prodelta mudstones and lower to upper delta front sands in the upper Pyawbwe sequence on basis of log characteristics. In literature, there is not referred to any break in the Pyawbwe Formation, and has as such not been identified. If this is a local Mann Field feature is not known. Wells located towards the northern part of the Mann Field show less well developed sand units, according to log expressions, and sequences are increasingly mud rich.

Analytical Methods

Primary reservoir performance of oil and gas reservoirs is dictated by natural viscous, gravity and capillary forces. It is characterized by variations in reservoir pressure, production rates, gas oil and water oil ratios, aquifer water influx and gas cap expansion. Factor influencing the reservoir performance are geological characteristics, rock and fluid properties, fluid flow mechanisms, and production facilities. The quality of reservoir management is also very important because the same reservoir exploited by different engineering and operating personnel with different method used in reserves estimation.

Procedure

General

To better understand reserves estimation, a few important terms require definition. Original oil in place (OOIP) and original gas in place (OGIP) refer to the total volume of hydrocarbon stored in a reservoir prior to production. Reserves or recoverable reserves are the volume of hydrocarbons that can be profitably extracted from a reservoir using existing technology. Resources are reserves plus all other hydrocarbons that may eventually become producible; this includes known oil and gas deposits present that cannot be technologically or economically recovered (OOIP and OGIP) as well as other undiscovered potential reserves.

The process of estimating oil and gas reserves for a producing field continues throughout the life of the field. There is always uncertainty in making such estimates. The level of uncertainty is affected by the following factors:

1. Reservoir type,
2. Source of reservoir energy,
3. Quantity and quality of the geological, engineering, and geophysical data,
4. Assumptions adopted when making the estimate,
5. Available technology, and
6. Experience and knowledge of the evaluator.

Estimating hydrocarbon reserves is a complex process that involves integrating geological and engineering data. Depending on the amount and quality of data available, one or more of the following methods may be used to estimate reserves: 1. Analogy, 2. Volumetric, 3. Material balance calculations 4. Reservoir simulation 5. Decline analysis

Volumetric Estimation of Remaining Original Oil In Place Reserves

In the present study, the remaining original oil in place reserves of three oil pools such as 2400ft sand CD fault block, 2700 ft sand CD fault block and 3700 ft sand BC fault block by volumetric method..

The steps of the volumetric estimation used in the present are:

1. Measure the depth of the top of the oil reservoirs (below sea level) in the drilled wells by well to well correlation

2. Measure the subsurface position (distance and direction from surface position) of the individual oil reservoir by well deviation plot.
3. Draw the equal depth contour map of the top of the individual oil reservoir.
4. Draw the equal depth contour map of the each fault identified in the wells by well to well correlation
5. Superimpose fault contour map and depth contour map of the oil reservoir and generate stratum contour map on top of individual reservoir.
6. Draw the bubble map based on the cumulative production of the reservoir in each well.
7. Draw the original oil-water margin and original gas- oil margin based on the initial production of wells.
8. Draw the current oil- water margin and gas-oil margin based on the current production data of the well.
9. Calculate true vertical gross thickness of the reservoir from the thickness measured from the deep resistivity log motifs of the wells located in the oil zone.

TVT=(MLT)(cos Ø1-Øa)(cos Øa)

Where; TVT = true vertical thickness

MLT = MT=measured log thickness

Ø = apparent bed dip along directional well depth

Ø1= Angle of well Drilled up dip

MC=VE= true stratigraphic thickness

VT= true vertical thickness

Measure thickness of the shale and hard ban by using spontaneous potential (SP), gamma ray (GR) and deep resistivity log motifs. Then calculate net reservoir thickness by deducting the thickness of shale and hard band from the true vertical gross thickness.

10. Draw the net reservoir isopach map and transfer current oil-water margin and gas-water margin on the isopach map.
11. Calculate Sw value of the individual reservoir in the wells located within oil zone. Then draw iso-saturation map (Isosat) of the reservoir. Then transfer the oil-water margin and gas-oil margin on the isosat maps.
12. Calculate porosity value of the individual reservoir in the wells located within oil zone. Then generate iso-porosity (Isopor) map of the reservoir.
13. Generate 200m x 200m grid map and transfer on the isopach, isosat and isopor maps.
14. Calculate the area of the grid, respective average thickness, average Sw and average porosity.
15. Calculate oil formation volume factor of the individual reservoir based on the current reservoir pressure.
16. Calculate the original oil in place for each grid by using the formula OOIP= [7758x grid area (acre) X average thickness within the grid (in feet) x average porosity within the grid (fraction) x average Sw within the grid (fraction)]/ oil formation volume factor (Bo)

The OOIP results of the reservoirs within the remaining oil zones are described in table (5).

Calculation of net pay thickness

The net pay thickness of the individual sand is calculated as follows;

Net pay thickness = True stratigraphic thickness (TST) – Shale and hard band thickness (SHT)

True stratigraphic thickness of the sand is calculated by

BED DIP = DEGREES (ATAN (CI/HCS)

TST = MLT*(COS (RADIANS (WELL DEV - BED DIP)))

Where; CI = contour interval

HCS= horizontal contour spacing

TST = true stratigraphic thickness

MLT= measured log thickness

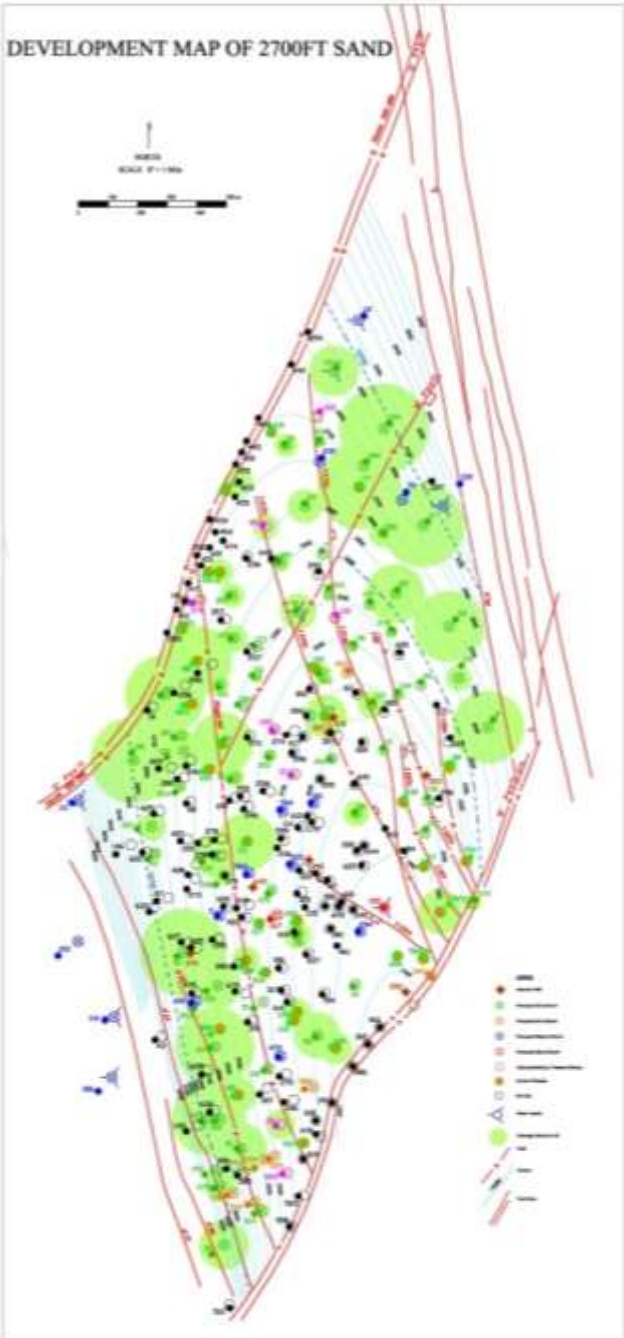


Figure (4) Strantum contour map on top of 2700 ft sand CD fault block, Mann oil field (Source: MPRL.E&P,2009)

Table (1) Net pay thickness of 2700 ft sand remaining oil area CD fault block

Well No	Top	Base	Gross Thickness (ft)	HCS (ft)	CI(ft)	Bed Dip angle	Well Deviation angle	TST (ft)	SHT (ft)	Sub-X	Sub-Y	NPT (ft)
80	2342.6	2409.1	67	121	100	39	2.1	53	12	694710.9	2237108.6	41
241	2458.9	2524.3	65	121	100	39	3.3	53	22	694768.6	2236788.1	31
13	1990	2051.1	61	151	100	34	3.5	53	12	694625.3	2236771.1	41
215	2068.3	2118	50	151	100	34	3.4	50	17	694628.5	2236884	33
196	2153.9	2200	46	151	100	34	3	40	12	694637.7	2236993.7	28
296	2194.7	2244	49	151	100	34	3	42	16	694674.6	2236989.1	26
139	2291.9	2330	38	151	100	34	4.3	33	10	694539.1	2237350.1	23
86	2460	2513	53	213	100	25	2.8	49	10	694615.5	2237384.3	39
620	2425.1	2480	55	243	100	22	1.5	51	20	694542.3	2237487.9	31
578	2451	2510	59	243	100	22	0	55	18	694516.4	2237565.1	37
137	2497	2545	48	272	100	20	1.9	46	18	694441.3	2237656.7	28
221	2481.7	2525	43	607	100	9	4.9	43	20	694304.4	2237691.6	23
38	2357	2401	44	453	100	12	3.7	43	20	694383.4	2237516	23
117	2234	2280	46	377	100	15	1.5	45	18	694448.9	2237319.3	27
185	2222.7	2270	47	377	100	15	2.5	46	21	694490.9	2237292.9	25
41	2134.2	2180	46	728	100	8	2.4	46	22	694490.5	2237164.6	24
196	2153.9	2200	46	728	100	8	3	46	12	694637.7	2236993.7	34
215	2068.3	2115	47	728	100	8	3.4	47	24	694628.5	2236884	23
94	1977.8	2000	22	607	100	9	2.5	22	3	694552.6	2236817.2	19
545	2166.7	2226	59	151	100	34	7	53	30	694680.8	2236617.2	23
19	2801.5	2852	51	545	100	10	1.4	50	18	694159.5	2238195.8	32
519	2838.2	2878	40	545	100	10	1.4	39	19	694274.3	2238208.9	20
632	2791.1	2845.9	55	545	100	10	0	54	31	694273.8	2238140.4	23
77	2818	2865	47	182	100	29	3.3	42	12	694407.4	2238053.8	30
184	2897	2942	45	213	100	25	4.1	42	9	694423	2238126.3	33
7	2572	2615	43	607	100	9	2.3	43	11	694283.6	2237827.3	32
293	2525	2565	40	607	100	9	1.5	40	12	694268.8	2237759.5	28
90	2469.3	2515	46	607	100	9	1.6	45	12	694201.2	2237632.7	33
154	2577.7	2618	40	394	100	14	2	39	9	694141.5	2237799.1	30
99	2666.1	2700	34	456	100	12	1.8	33	4	694091.1	2237920.4	29
443	7358	7418	60	545	100	10	0	59	30	693955.5	2238040.8	29
236	2653	2682	29	394	100	14	2.6	28	3	694035.6	2236642.2	25
2	2709.1	2760	51	331	100	17	2.4	49	7	693936.2	2237766.3	42
303	2650.4	2696	46	364	100	15	2	44	12	693977.7	2237687.5	32
357	2644.5	2690	46	364	100	15	2.3	44	17	693955.2	2237606.7	27
127	2590.8	2635	44	364	100	15	1.5	43	12	693983.1	2237542.1	31
173	2531	2575	44	364	100	15	1.9	43	11	694064.1	2237515.6	32
23	2471.5	2514	43	394	100	14	3	42	9	694060.4	2237413.3	33
103	2553.6	2597	43	269	100	20	4.5	42	6	693935.2	2237386.4	36
262	2490.9	2535	44	394	100	14	5	44	9	694018.3	2237313	35
89	2526.1	2571	45	269	100	20	2	43	2	693943.4	2237186.7	41
220	2550	2600	50	180	100	29	4.9	46	10	693899.8	2237100	36
298	2751.3	2800	49	304	100	18	7	48	10	693817.9	2237384.1	38
356	2679	2723	44	304	100	18	3	42	13	693910.5	2237455.7	29
98	2699.1	2745	46	304	100	18	2	44	6	693858.6	2237465.7	38
276	2768.2	2803	35	331	100	17	4	34	3	693869.4	2237674.1	31
278	2477.6	2516	38	304	100	18	4	37	5	693943.5	2236864.6	32
158	2456.8	2495	38	180	100	29	3.1	34	15	693949.2	2236743.1	19
5	2455	2500	45	180	100	29	2.8	40	8	693933.6	2236604.8	32

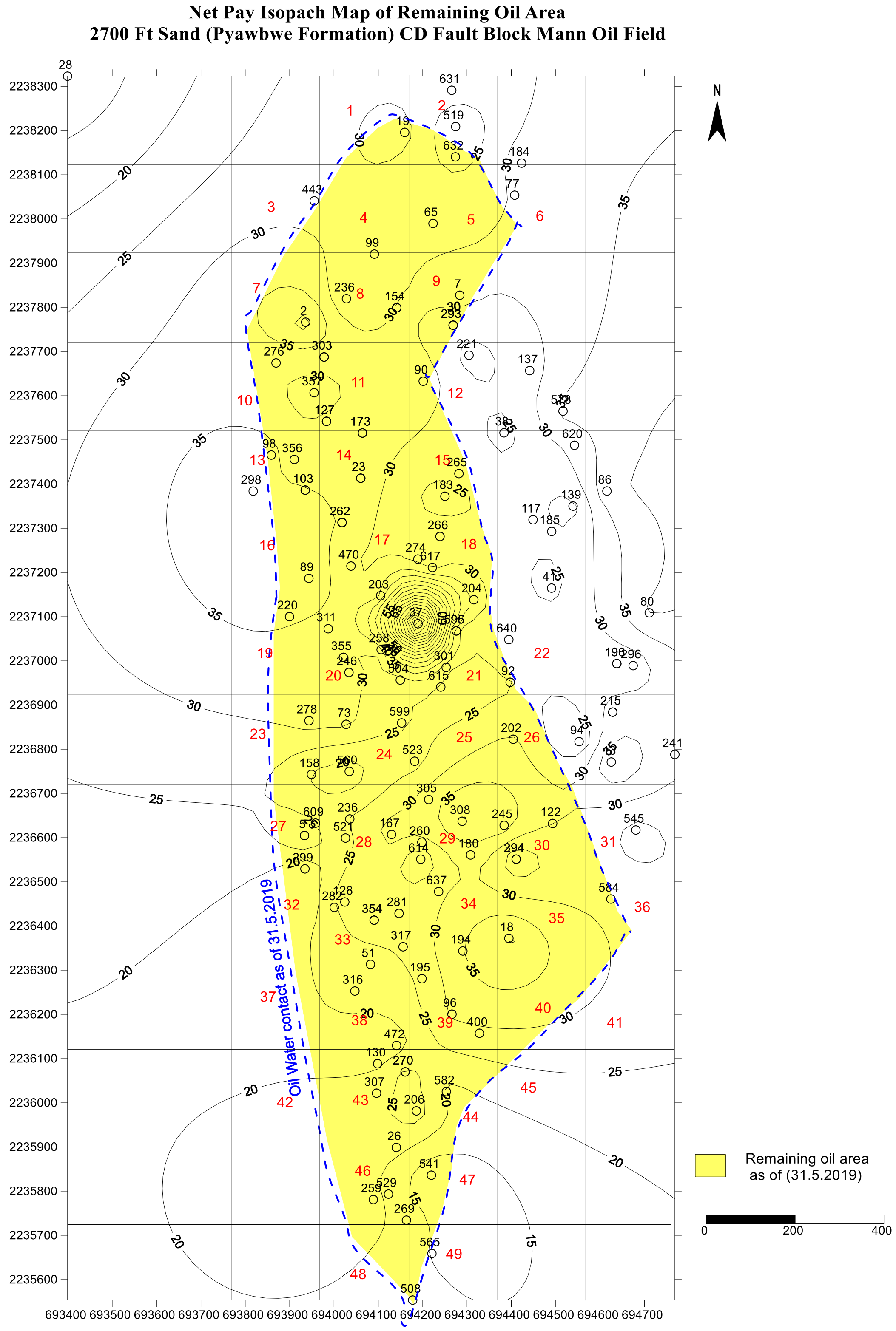


Figure (5) Net pay isopach map of remaining oil area 2700ft sand CD fault block

Calculation of Sw

Table (2) Calculation of Rw at reservoir depth from Rw catalog

RW CATALOGUE MANN OIL FIELD								
SR NO	**WELL NO**	**F/B**	**RW(OHM)**	**@DEG**	**SALINITY(PPMCL)**	**SAMPLE DEPTH**	**SAND(FT)**	**FORMATION**
1	25	BC/CD	1.05	@86	1600	2750-2770	2200	KYAUKKOK
2	100	BC/CD	1.14	@86	1200	3015-3160	23/2400	KYAUKKOK
3	170A	BC	2	@86	1900	2765-2810	2200	KYAUKKOK
4	170B	BC	1.13	@86	400	2890-2940	2300	KYAUKKOK
5	181	BC	0.92	@86	1150	2680-3020	22/23/24/2500	KYAUKKOK
6	187	BC	1.34	@82	1000	2875-3025	24/2500	KYAUKKOK
7	229	BC	1.69	@82	500	2940-3055	2400	KYAUKKOK
8	234	BC	1.69	@86	850	3065-3085	2300	KYAUKKOK
9	15	BC	0.59	@83	4900	4810-4825	3600	PYAWBWE
10	71	DS	0.74	@86	4000	1485-1510	2800	PYAWBWE
11	106	CD	1.64	@86	550	2932-2965	2700	PYAWBWE
12	123	CD	0.93	@82	2750	3090-3125	2700	PYAWBWE
13	149	AB	0.59	@83	5000	5225-5250	3600	PYAWBWE
14	193	CD	0.85	@80	3450	2992-3780	27/3200	PYAWBWE
15	197	CD	0.65	@82	4500	2815-3378	27/3200	PYAWBWE
16	240	CD	0.45	@82	7500	3160-3340	32/3300	PYAWBWE
17	32	CD	0.57	@94	4850	4965-4995	3800	OKHMINTAUNG
18	97	CD	0.52	@80	5850	4045-4080	3700	OKHMINTAUNG
19	150	CD	0.47	@84	7000	3530-3720	37/3800	OKHMINTAUNG
20	172	BC	0.49	@82	6350	4735-4810	3700	OKHMINTAUNG
21	193	CD	0.66	@82	4400	4735-4850	3800	OKHMINTAUNG
22	56	AB	0.56	@94	5050	5920-6315	44/45/4700	PADAUNG
23	61	DS	0.58	@86	5250	3167-3416	L41/43/4500	PADAUNG
24	173	CD	0.38	@80	8200	4120-4230	44/4500	PADAUNG
25	175	BC	0.51	@80	5400	5615-5685	U/L4100	PADAUNG
26	265	CD	0.42	@84	6950	3625-3640	U4100	PADAUNG
27	274	CD	0.43	@80	8750	3957-3967	4500	PADAUNG

Rw Catalogue of Mann oil field provides results at surface temperature and this value must be transformed to a different value based on the formation temperature.

STEP 1: Calculate formation temperature:

1. GRAD = (BHT – SUFT) / BHTDEP

2: FT = SUFT + GRAD * DEPTH

STEP 2: Calculate water resistivity at formation temperature:

3: RW@FT = RW@TRW * (TRW + KT1) / (FT + KT1)

Where: KT1 = 6.8 for English units

KT1 = 21.5 for Metric units

If water salinity is reported instead of resistivity, as may happen in reporting direct from the well site, convert salinity to resistivity with:

4: RW@FT = (400000 / FT1 / WS) ^ 0.88

Note: FT1 is in Fahrenheit

In some cases, salinity is reported in parts per million Chloride instead of the more usual parts per million salt (NaCl). In this situation convert Chloride to NaCl equivalent with:

5: WS = Ccl * 1.645

To convert a downhole RW to a surface temperature, reverse the terms in equation 3:

6: RW@SUFT = RW@FT * (FT + KT1) / (SUFT + KT1)

Where: KT1 = 6.8 for English units

KT1 = 21.5 for Metric units

Sometimes, it is nice to know what the resistivity log would read in a water zone (R0). For quick look work, use the following:

7: R0 = RW@FT ‘ (PHIe ^ 2) For example,

If RW@FT = 0.10 and PHIe = 0.20, then R0 = 0.10 / (0.20^2) = 2.5 ohm-m.

Calculation of Rw from spontaneous potential (SP)

If a good SP log is available, it may be used to calculate RW@FT, as shown below.

STEP 1: Calculate constants

1: GRAD1 = (BHT – SUFT) / BHTDEP

2: FT1 = SUFT + GRAD1 * DEPTH

3: KSP = 60 + 0.122 * FT1 , NOTE: FT1 is in Fahrenheit

STEP 2: Calculate resistivity values

4: RSP = 10 ^ (– SSP / KSP) 5: IF RMF@FT > 0.1

6: THEN RMFE = 0.85 * RMF@FT 7: IF RMF@FT <= 0.1

8: THEN RMFE = (1.46 * RMF@FT – 5) / (337 * RMF@FT + 77)

9: RWE = RMFE / RSP 10: IF RWE > 0.12

11: THEN RW@FT = – (0.58 - 10 ^ (0.69 * RWE – 0.24))

12: IF RWE <= 0.1213: THEN RW@FT = (77 * RWE + 5) / (146 – 337 * RWE)

Note: SP method is not applicable in low porosity (less than 5%) or where shale content is high (greater than 20%) and not work well in a hydrocarbon bearing zone.

Table (3) Well by well calculation of Rw for 2700Ft Sand in the oil remaining area CD fault block

Well No	Surf. Temp. (°F)	BHT (°F)	BHT Measured depth (ft)	Reservoir Depth (ft)	RMF @ surf.Temp. (°F)	SP mv	Fm Temp (°F)	RSP	RwCatlog (Ohm-m)	RwCatlog (TRW) (ohm-m)	RW @ FT Catalog (ohm-m)	RMFE Ohm-m	RMF@FT Ohm-m	RWE Ohm-m)	RW @ FT SP Ohm-m	KT1	KSP
5	74	122	2013	2465	0.84	5	132.8	1.16	1.64	86	1.09	0.41	0.49	0.36	0.43	6.8	76.2
19	91	131	4569	2800	0.52	10	115.5	1.36	1.64	86	1.24	0.35	0.42	0.26	0.29	6.8	74.09
26	78	130	4218	2185	0.67	5	104.9	1.17	1.64	86	1.36	0.43	0.51	0.37	0.45	6.8	72.8
41	86	124	3500	2135	0.79	10	109.2	1.37	1.64	86	1.31	0.54	0.63	0.39	0.49	6.8	73.32
51	99	126	4000	2265	0.52	8	114.3	1.28	1.64	86	1.26	0.39	0.45	0.3	0.35	6.8	73.94
65	85	117	3350	2660	0.48	9	110.4	1.33	1.64	86	1.3	0.32	0.38	0.24	0.26	6.8	73.47
90	76	100	3400	2471	0.62	5	93.4	1.17	1.64	86	1.52	0.44	0.51	0.37	0.46	6.8	71.4
130	72	120	3500	2260	0.36	3	103	1.1	1.64	86	1.39	0.22	0.26	0.2	0.21	6.8	72.57
158	71	124	3450	2456	1.85	15	108.7	1.6	1.64	86	1.32	1.06	1.25	0.66	1.06	6.8	73.27
173	98	132	4266	2530	0.74	8	118.2	1.28	1.64	86	1.22	0.53	0.62	0.41	0.53	6.8	74.42
184	80	118	3600	2897	0.3	8	110.6	1.28	1.64	86	1.3	0.19	0.22	0.15	0.15	6.8	73.49
185	73	116	2950	2223	0.69	8	105.4	1.29	1.64	86	1.36	0.42	0.49	0.32	0.38	6.8	72.86
194	76	124	2570	2012	0.6	1	113.6	1.03	1.64	86	1.26	0.35	0.41	0.34	0.41	6.8	73.86
202	100	122	2612	2010	1.39	18	116.9	1.75	1.64	86	1.23	1.02	1.2	0.58	0.87	6.8	74.27
206	96	123	2348	2114	1.5	20	120.3	1.85	1.64	86	1.2	1.03	1.21	0.56	0.81	6.8	74.68
215	80	128	2550	2068	0.56	9	118.9	1.32	1.64	86	1.21	0.33	0.39	0.25	0.27	6.8	74.51
236	90	130	3612	2653	0.35	5	119.4	1.17	1.64	86	1.21	0.23	0.27	0.2	0.21	6.8	74.56
246	78	121	3136	2381	1.11	6	110.6	1.21	1.64	86	1.3	0.68	0.8	0.56	0.83	6.8	73.5
262	87	130	4223	2490	0.43	7	112.4	1.24	1.64	86	1.28	0.29	0.34	0.23	0.25	6.8	73.71
276	75	136	4594	2770	0.9	5	111.8	1.17	1.64	86	1.28	0.53	0.62	0.45	0.6	6.8	73.64
278	66	126	4142	2478	0.64	2	101.9	1.07	1.64	86	1.4	0.36	0.43	0.34	0.41	6.8	72.43
294	92	110	2857	1951	0.83	2	104.3	1.07	1.64	86	1.37	0.63	0.74	0.59	0.89	6.8	72.72
296	88	122	3613	2195	0.98	5	108.7	1.17	1.64	86	1.32	0.68	0.8	0.58	0.88	6.8	73.26
298	78	132	4572	2750	0.56	5	110.5	1.17	1.64	86	1.3	0.34	0.4	0.29	0.34	6.8	73.48
303	95	126	3901	2650	0.48	5	116.1	1.17	1.64	86	1.24	0.34	0.4	0.29	0.33	6.8	74.16

Determination of Sw

Water saturation values of the 2400 ft sand CD fault block, 2700 ft sand CD fault block and 3700 ft sand BC fault block are calculated well by well in remaining oil area using the Archie's and Hingle methods.

Archie's method

Sw = SQRT (Ro/Rt) Where; SQRT = square root,

Ro = resistivity of 100% water zone-ohm-m, Rt = resistivity of uninvited zone ohm-m

Hingle method

1: Sw = (F*RW@FT/RES)^(1/N) 2: F = A/(PHIe^M)

Where; A= tortuosity exponent (fractional), F = formation factor (fractional)

M = cementation exponent (fractional), N = saturation exponent (fractional)

PHIe = effective porosity (fractional), RESD = deep resistivity (ohm-m)

RW@FT = water resistivity (ohm-m), Sw = water saturation (fractional)

Calculation of porosity

Since there is a limited porosity and core analysis data, the porosity value in each well within the current remaining oil zone is calculated by the formula below using deep resistivity value.

PHIrt = (A / ((RESD / RW@FT) * (SW ^ N))) ^ (1 / M)

Where:

A = tortuosity exponent M = cementation exponent

N = saturation exponent, PHIrt = porosity from deep resistivity (fractional)

RESD = deep resistivity log reading (ohm-m), RW@FT = fm. water resistivity (ohm-m)

SW = water saturation in un-invaded zone (fractional)

Comment

No shale corrections are applied, so use caution. This method is not usually used in hydrocarbon zones and is an absolute last resort. The result is often used in a porosity playback log (with SW = 1.00) to look for possible hydrocarbon zones by observing the separation between PHIrt and the other porosity logs. Shale corrected methods may be created from the various shale corrected saturation equations.

Recommended Parameters

Normal values for A, M, N and SW: for water zones SW = 1.00

for sandstone A = 0.62 M = 2.15 N = 2.00 and for carbonates A = 1.00 M = 2.00 N = 2.00

for hydrocarbon zone with (high porosity SW = 0.20,medium =0.04 and low= 0.60)

Table (4) Calculation of Sw and porosity for 2700ft sand in remaining oil area CD fault block

Well No	Fault Block	Sand (FT)	A tortuosity exponent	M Cementation Exponent	N Saturation Exponent	RESD (Deep resistivity (Ohn-m)	Ro (Ohn-m)	RW@FT Catalog (Ohn-m)	RW@FT SP Ohn-m	SW (Archie's) uninvated zone (fractional)	PHIrt Catalog Fraction	PHI SP fraction	PHI Deep fraction	Avg. PHI (friction)	F	Sw (HINGLE) (friction)
19	CD	2700	0.62	2.15	2	15	5	1.24	0.29	0.58	0.54	0.43	0.43	0.47	3.17	0.51
26	CD	2700	0.62	2.15	2	30	7	1.36	0.45	0.48	0.57	0.51	0.43	0.5	2.72	0.35
41	CD	2700	0.62	2.15	2	18	7	1.31	0.49	0.62	0.5	0.42	0.38	0.43	3.76	0.52
51	CD	2700	0.62	2.15	2	20	7	1.26	0.35	0.59	0.51	0.41	0.39	0.44	3.67	0.48
65	CD	2700	0.62	2.15	2	13	7	1.3	0.26	0.73	0.45	0.3	0.35	0.37	5.37	0.73
90	CD	2700	0.62	2.15	2	11	6	1.52	0.46	0.74	0.48	0.36	0.39	0.41	4.22	0.76
130	CD	2700	0.62	2.15	2	23	5	1.39	0.21	0.47	0.6	0.5	0.47	0.52	2.49	0.39
158	CD	2700	0.62	2.15	2	23	5	1.32	1.06	0.47	0.6	0.59	0.46	0.55	2.24	0.36
173	CD	2700	0.62	2.15	2	13	5	1.22	0.53	0.62	0.52	0.45	0.41	0.46	3.25	0.55
184	CD	2700	0.62	2.15	2	23	6	1.3	0.15	0.51	0.56	0.43	0.43	0.48	3.05	0.41
185	CD	2700	0.62	2.15	2	15	4	1.36	0.38	0.52	0.59	0.51	0.48	0.53	2.46	0.47
194	CD	2700	0.62	2.15	2	25	5	1.26	0.41	0.45	0.61	0.55	0.47	0.54	2.34	0.34
202	CD	2700	0.62	2.15	2	17	6	1.23	0.87	0.59	0.52	0.49	0.4	0.47	3.13	0.48
206	CD	2700	0.62	2.15	2	25	6	1.2	0.81	0.49	0.57	0.55	0.43	0.52	2.58	0.35
215	CD	2700	0.62	2.15	2	20	4	1.21	0.27	0.45	0.62	0.54	0.48	0.55	2.28	0.37
236	CD	2700	0.62	2.15	2	10	5	1.21	0.21	0.71	0.49	0.33	0.39	0.4	4.41	0.73
246	CD	2700	0.62	2.15	2	18	5	1.3	0.83	0.53	0.57	0.54	0.45	0.52	2.55	0.43
262	CD	2700	0.62	2.15	2	12	5	1.28	0.25	0.65	0.52	0.38	0.41	0.44	3.69	0.63
276	CD	2700	0.62	2.15	2	12	4	1.28	0.6	0.58	0.57	0.5	0.46	0.51	2.65	0.53
278	CD	2700	0.62	2.15	2	23	4	1.4	0.41	0.42	0.64	0.58	0.51	0.57	2.04	0.35
294	CD	2700	0.62	2.15	2	13	5	1.37	0.89	0.62	0.54	0.5	0.43	0.49	2.93	0.56
296	CD	2700	0.62	2.15	2	15	4	1.32	0.88	0.52	0.59	0.56	0.48	0.54	2.3	0.45
298	CD	2700	0.62	2.15	2	10	4	1.3	0.34	0.63	0.55	0.43	0.45	0.47	3.1	0.63
303	CD	2700	0.62	2.15	2	13	4	1.24	0.33	0.55	0.57	0.47	0.46	0.5	2.74	0.51

PVT Analysis Result

The PVT analysis of the 2400ft sand CD fault block, 3200 ft sand CD fault block and 3700 ft sand BC fault block are mentioned in table. The oil formation volume factor of 2700 ft sand was not available in the present study and used the value of 3200 ft sand.

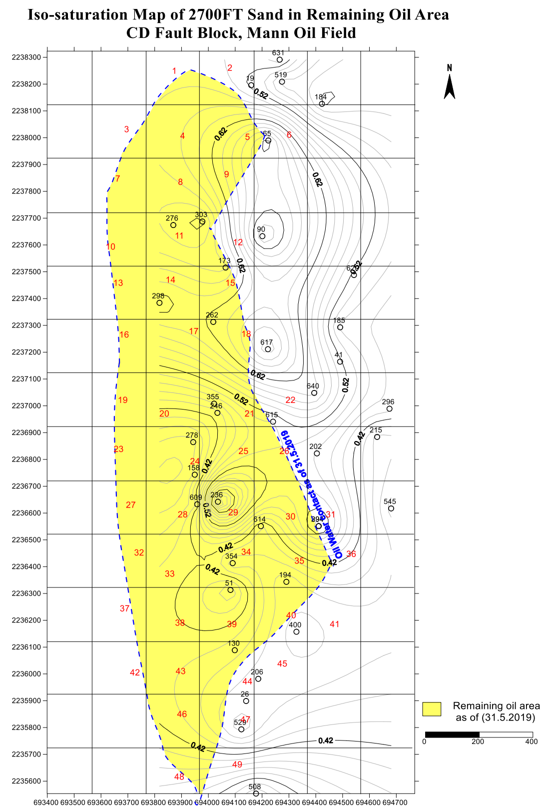


Figure (6) Iso-Saturation map of 2700ft sand CD fault block

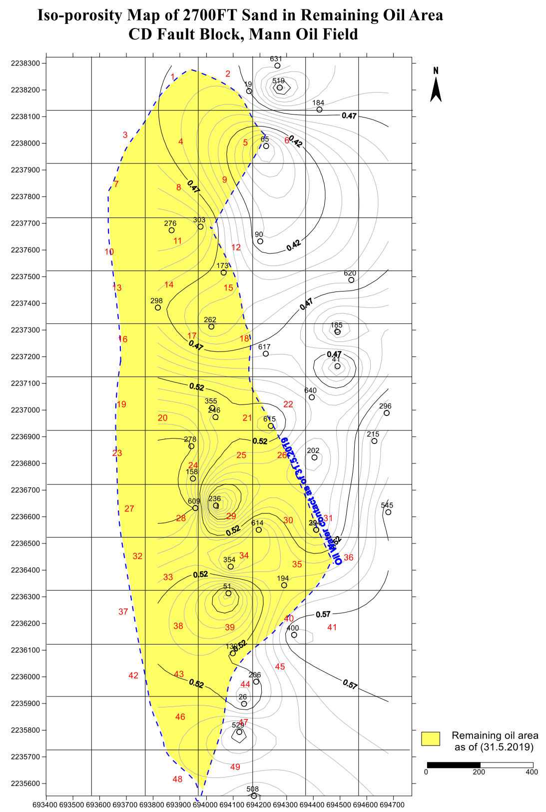


Figure (7) Iso-porosity map of 2700ft sand CD fault block

Table (5) 2700FT SAND CD FAULT BLOCK

Grid No	Area (m^2)	Area (acre)	Avg. Net Sand Thickness (ft)	Average Porosity	Average water saturation fraction)	Boi (rbbl/stb)	IOIP (stb)
1	17311.01	4.3	30	0.465	0.56	1.122	181547
2	17293.19	4.3	25	0.455	0.56	1.122	147883
3	8152	2	30	0.48	0.68	1.122	64182
4	40000	9.9	30	0.465	0.66	1.122	324154
5	40000	9.9	27.5	0.42	0.6	1.122	315748
6	3614.86	0.9	35	0.41	0.67	1.122	29248
7	25705.84	6.4	30	0.5	0.58	1.122	276701
8	40000	9.9	30	0.48	0.58	1.122	413343
9	27255.9	6.7	30	0.45	0.62	1.122	238900
10	26266.52	6.5	35	0.5	0.57	1.122	337713
11	40000	9.9	32.5	0.46	0.58	1.122	429130
12	16309.4	4	30	0.48	0.62	1.122	152483
13	21841.97	5.4	35	0.49	0.59	1.122	262409
14	40000	9.9	32.5	0.47	0.59	1.122	428020
15	30782.59	7.6	27.5	0.46	0.57	1.122	286090
16	18920.7	4.7	35	0.475	0.56	1.122	236478
17	40000	9.9	32.5	0.485	0.57	1.122	463225
18	38279.3	9.5	35	0.465	0.56	1.122	468356
19	21589.08	5.3	35	0.55	0.47	1.122	376339
20	40000	9.9	30	0.55	0.46	1.122	608943

Grid No	Area (m^2)	Area (acre)	Avg. Net Sand Thickness (ft)	Average Porosity	Average water saturation fraction)	Boi (rbbl/stb)	IOIP (stb)
21	40000	9.9	35	0.52	0.51	1.122	609489
22	6627.1	1.6	25	0.51	0.52	1.122	69297
23	21700.62	5.4	27.5	0.57	0.36	1.122	371962
24	40000	9.9	25	0.57	0.36	1.122	623295
25	40000	9.9	25	0.52	0.44	1.122	497542
26	27100.87	6.7	30	0.51	0.49	1.122	361313
27	19778.61	4.9	25	0.57	0.36	1.122	308198
28	40000	9.9	25	0.56	0.44	1.122	535815
29	40000	9.9	32.5	0.48	0.52	1.122	511758
30	40000	9.9	32.5	0.52	0.47	1.122	612155
31	4321.09	1.1	30	0.49	0.52	1.122	52094
32	14540.8	3.6	20	0.54	0.4	1.122	160991
33	40000	9.9	25	0.53	0.42	1.122	525222
34	40000	9.9	30	0.53	0.42	1.122	630266
35	40000	9.9	32.5	0.51	0.42	1.122	657023
36	14074.54	3.5	30	0.53	0.42	1.122	221768
37	8220.81	2	20	0.52	0.42	1.122	84726
38	40000	9.9	22.5	0.51	0.42	1.122	454862
39	40000	9.9	30	0.49	0.42	1.122	582699
40	25490.87	6.3	32.5	0.54	0.38	1.122	473906
43	40000	9.9	22.5	0.52	0.4	1.122	479773
44	28388.18	7	22.5	0.52	0.39	1.122	346172
46	30361.11	7.5	20	0.53	0.41	1.122	324425
47	17644.68	4.4	15	0.54	0.37	1.122	153843
48	8523.01	2.1	17.5	0.54	0.38	1.122	85321
49	6106.66	1.5	17.5	0.54	0.38	1.122	61132
							15835938

Determination of the Driving Mechanism of Mann Field Oil Reservoirs

The natural energy which is responsible for moving the reservoir fluids (oil, gas and water) from the reservoir to the wellbore come from are; liberation and expansion of solution gas, influx of aquifer water, contraction of reservoir rock skeleton, expansion of original reservoir fluids(free gas, interstitial water, oil etc.), gravitational forces. In order to properly understand the nature of a reservoir and to make predictions about its performance, it is necessary to evaluate how those mechanisms control fluids behavior. Seven types of driving mechanism that provide natural energy sources for hydrocarbons recovery.

In order to properly understand the nature of a reservoir and to make predictions about its production performance, it is necessary to evaluate how those mechanisms control fluids behavior and movement.

Table (6) Estimation of recoverable reserves based on driving mechanism

Pool	Driving Mechanism	Recovery Factor	OOIP (mmstb)	Recoverable Reserves (mmstb)
2400 "B" CD	Solution gas	0.18	2.899621	0.5219318
2400 "C" CD	Solution gas	0.18	1.260102	0.2268183
2700 CD	Gas cap + solution gas	0.30	15.835938	4.750781
3700 BC	Gas Cap + Water	0.35	7.951607	2.783063
Total			**27947268**	**8.282594**

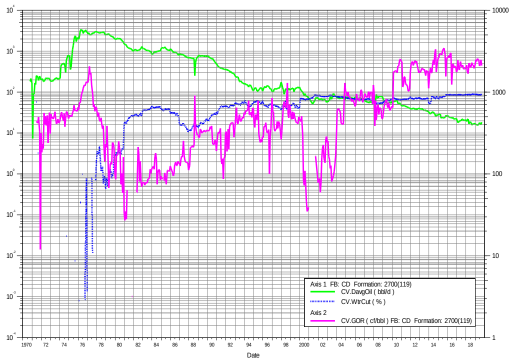


Figure (8) 2700 FT Sand CD Fault Block (Water Drive)

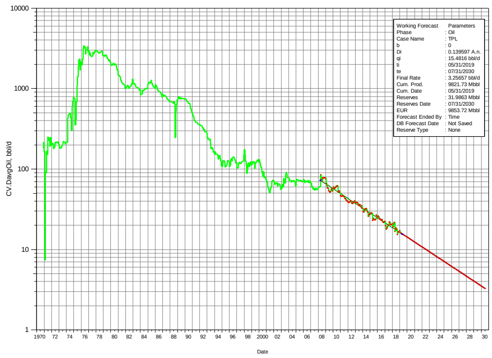
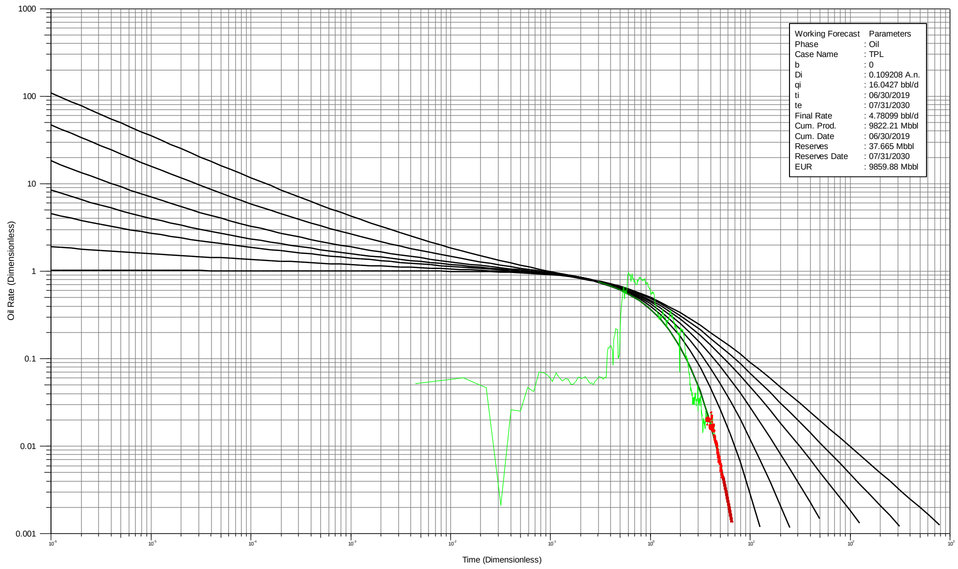


Figure (9) 2700 FT Sand CD Fault Block showing recoverable reserves by decline curve analysis (DCA)

Fetkovich Log-Log Type-Curves

Conventional decline-curve analysis should be used only when mechanical conditions and reservoir drainage remain constant and the well is producing at capacity. An advanced approach for decline-curve analysis, which is applicable for changes in pressure or drainage, has been presented by Fetkovich. This technique, which is similar to the approach used in pressure testing, involves log-log plots of q/qi (or qDd) versus at (or tDd) for different values of n. As shown in this figure, a log-log plot of the dimensionless rate and dimensionless time can identify transient data and/or depletion data, the Arps' equations only be applied to rate-time data that indicate depletion. Use of transient data in the Arps' equations will result in incorrect forecasts that are overly optimistic. Fetkovich focused on the early period of production i.e. transient flow and came up with set of type curves that could be combined with Arps empirical decline curve equation. Combining the Fetkovich transient type curves with Arps decline curves and blending them where the two sets of curves meet, result in Fetkovich Decline Type Curve. Fetkovich noted that sometimes the value of b as determined using Arps decline curves was greater than

1(expected to be between 0 and 1). He explained that this could happen if the data being analyzed was still in transient condition and has not reached boundary dominated flow. Accordingly, the Fetkovich type curves are made up of two regions which have been blended to be continuous and thereby encompass the whole production life from early time (transient flow) to late time (boundary dominated flow). The right hand side of Fetkovich type curves is identical to Arps type curve as shown below: The left hand side of Fetkovich type curves are derived from the analytical solution to the flow of a well in the center of a finite circular reservoir producing at a constant wellbore flowing pressure. Fetkovich was able to demonstrate that for all sizes of reservoirs, when transient flow ended, the boundary dominated flow could be represented by an exponential decline.



Figure(10) Type curve analysis of 2700 FT Sand CD Fault Block. (Fetkovich Method) using OFM 2014.

The field data are plotted on tracing paper that has the same log-log scale as the full-size type-curves. The log-log plot of flow rate and time can be in terms of barrels/day versus days, barrels/month versus months, or barrels/year versus years, depending on the time interval being studied. Using the best fit on the appropriate type-curve, a match point can be used to obtain qi and ai for the actual data. The appropriate equation can then be used to analyze the rate, time, and cumulative production behavior.

The decline rate and Ultimate Recovery of the individual pool are calculated by Oil Filed Manager (OFM) software version 2014.

Table (7) Reserves calculation of 2400 CD, 2700 CD and 3700 BC Fault block by Fetkovich Method

Sr. no.	Pool Name	b	Di	Production as of (31/7/2030)		Cumulative Oil Production)	Remaining Oil Reserves
				Rate Bbl/day	EUR Mbbl		
1	2400 CD	0.2939	0.0508	22.607	5769.93	5650.54	119.387
2	2700 CD	0	0.1092	16.043	9859.88	9822.21	37.665
3	3700 BC	0.2411	0.08494	19.572	8713.06	8590.04	123.023

Conclusion

The main objective of the present study is to evaluate the remaining oil potential of the developed oil reservoirs and potential of undeveloped reservoirs. Due to the limited PVT data, fluid properties measurement data, reservoir pressure measurement data and core analysis data, the remaining oil potential of the developed oil reservoirs are not calculated by material balance and reservoir simulation software. Two techniques; volumetric and production curve analysis could be done in the present study. The developed reservoirs in the field are in mature stage and most of them are nearly depleted. Therefore, Original Oil In Place (OOIP) of the four major oil pools which are still producing in considerable amount are estimated by volumetric method in the study.

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