REPORT
ON
MASTER PLAN STUDY
FOR
THE DEVELOPMENT OF PETROLEUM AND NATURAL GAS RESOURCES
IN
MALAYSIA

- VOLUME III -

(SABAH)

JANUARY 1978

JAPAN INTERNATIONAL COOPERATION AGENCY

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PART A EVALUATION OF OIL AND GAS FIELD AND PERFORMANCE PREDICTION

1. GENERAL

There are two oil producing fields in this area. One is Samarang field and the other is Tembungo field. Their production rates during the month of June 1976 are 28 and 4.3 MSTB/D, respectively.

Samarang field was estimated to have highest production capacity in this area, while the future performance of Tembungo field was estimated to be not prospective.

There are two fields for development in this area, one is Erb South and the other is South Furious fields. The former has small original oil in place, while the latter has oil displacement problem with all its comparatively big original oil in place, as the field is devided into numerous blocks and the recovery was estimated to be very poor.

There are other three fields which have some potential of oil production. The fields need more exploratory works for defining the reservoir.

The original hydrocarbon in place of Sabah area was shown on Tables A-1 - 3.

2. GEOLOGY OF THE BASIN

On the west coast area of Sabah, rocks of Paleocene to Miocene age are exposed but most of them are considered as indurated geosynclinal deposits. However, it is thought that in the western offshore there is a continuation of the Miocene - Pliocene sedimentary basin of Sarawak, which has hydrocarbon occurrences in the clastic sediments. Well data indicate that in the Sabah area unconformities are found in Upper Miocene sections in several fields, but regional stratigraphy seems to have not yet been completely established for the area. It remains also a problem to be solved whether the sedimentary cycles in Sarawak based on the palynologic data is applicable in the Sabah area.

Sedimentary sequences of the Sabah fields consist of sandstones and argillaceous rocks, the latter of which in some horizons indicate better development than in the Sarawak area. Reservoir rocks are fine-grained sandstones in general, for which the lithological correlation is difficult in some of the fields. The fields vary both in sedimentary environments and in structural types. Although hydrocarbons occur generally in anticlinal and/or faulted structure, unconformity trapping is also observed.

3. EXISTING PRODUCING FIELDS

3.1 Samarang Field

3.1.1 Field Status

The Samarang field is located 50 km north of Sabah shore and is the biggest field in Sabah area. Production started June 1975 and cumulative oil production during the history stage is 8.28 MMSTB, which is equivalent to 2.53 per cents of original oil in place.

Oil zone consists of sand layers developed in the depth interval of 4300 ft to 7400 ft s.s. The reservoir was interpreted to be of a combination drive of gas cap expansion and the aquifer water.

The field was estimated to have good reservoir performance and further development together with strict production control will be required.

3.1.2 Geology

(1) Reservoir Beds

In the Samarang field hydrocarbons are accumulated in clastic sediments which are probably equivalent to sedimentary cycles VI and V of the Sarawak area. Hydrocarbon bearing zones are concentrated in a relatively small number of horizons where reservoir beds are sandstones of generally good continuity.

Main reservoirs are zones a_2, b, and c_1 - c_5 of which correlation is shown in Table 1-2-1. Zone a_1 is a total 200 ft thick sandstone frequently intercalated with shale less than 15 ft thick, zone a_2 is a total 250 ft thick sandstone intercalated with about 10 shale beds less than 15 ft thick, and zone b is also intercalated with many shale beds less than 20 ft thick for a 270 ft interval. However, it is considered that fluid contact levels are single in zones a_1, a_2, and b, respectively, in spite of their shale intercalations. Each sandstone of zones c_1 to c_5 is interbedded with 40 to 70 ft thick shale beds and has separate independent OWC within it.

(2) Geologic Structure and Hydrocarbon Trapping

Structural contour maps of zones a_2, b, and c_1 are shown in Figs. 1-2-1 - 3, and a structural cross-section in Fig. 1-2-4. The Samarang structure is a NNE-SSW trending anticlinal high, but its east-southeast side is thrown down by a step-like occurrence of normal faults. The faults have strikes subparallel to the anticlinal elongation and dip 45 to 60 degrees toward ESE. To the east-southeast they reach shallower horizons, and have greater throws attaining 530 ft for the easternmost mapped one.

Seismic record sections suggest that the structure proved by well drilling is a western portion of a larger-scale structure. This "large" structure is thought to be a result of uplift caused by an unknown tectonic movement, possibly by igneous intrusion, and is accompanied by consequent normal faulting produced in the field of horizontal tension. It can be said there still remains the possibility of hydrocarbon trapping in an area east or south of the Samarang field by the combination of upwarping and faulting.

3.1.3 Reservoir Analysis

The field is divided into four zones, that are zones a, b, c and d. In the actual performance calculation, the analyses were made for zones a, b and c+d. Individual reservoir parameters used in the estimation are illustrated on Figs. 1-3-5 - 16. Performance estimation based on the history match calculation is shown on Figs. 1-3-2 - 4 and Tables 1-3-2 - 4 for zone by zone. Field total performance is shown on Fig. 1-3-1 and Table 1-3-1.

(a) Samarang A Zone

Oil zone consists of sand layers developed from the depth of 4300 to 4600 ft s.s. The oil displacement mechanism was interpreted to be combination drive of small gas cap and aquifer water.

Production started June 1975. Cumulative oil production during the history stage is 8.28 MMSTB. Water production started April 1976 and water oil ratio is 0.0048 as of June 1976. Heavy oil with API gravity of 26° to 27° is produced from this zone and gas cap is interpreted to be comparatively small.

Oil properties were determined from reservoir fluid study at SM-Well No.1 A Zone. Gas properties were determined by gas analysis at SM-Well No.1 A Zone. Oil properties and gas properties are shown on Fig. 1-3-11 and Fig. 1-3-14, respectively.

Relative permeability relation was obtained by revising general trend of representative sample through the history match calculation. Relative permeability relation is shown on Fig. 1-3-5 and Fig. 1-3-8.

Initial reservoir pressure is decided to be 1990 psig at datum level of 4450 ft s.s. determined by FIT and BHP survey. Five wells were producing during the history stage and for future performance calculation, 9 expected producers were used. Reservoir performance is shown on Fig. 1-3-2 and tabulated on Table 1-3-2.

(b) Samarang B Zone

Oil zone is composed of sand layers developed from the depth of 5200 ft to 5400 ft s.s. This zone was interpreted to be combination drive of small gas cap and aquifer water. Production started August 1975 and cumulative oil production reached to 0.571 MMSTB, which was 0.79 per cent of original oil in place.

API gravity of produced oil is 37° - 38° and oil properties were estimated from reservoir fluid study of SM-Well No.1 B Zone. Gas properties were calculated by gas analysis at SM-Well No.3 B Zone. Oil properties and gas properties are shown on Fig. 1-3-12 and Fig. 1-3-15, respectively.

Relative permeability relation was obtained by revising the general trend of representative sample by history match calculation. Relative permeability relation is shown on Fig. 1-3-6 and Fig. 1-3-9.

Initial reservoir pressure was decided to be 2344 psig at datum level of 5350 ft s.s. from the results of FIT and BHP survey. There were 3 producers in this zone as of June 1976, and in the future performance calculation, 7 expected producers were added to 3 existing producers. Reservoir performance is shown on Fig. 1-3-3 and tabulated on Table 1-3-3.

(c) Samarang C Zone

Oil zone consists of sand layers developed from the depth of 6000 ft to 6600 ft s.s. and from 7200 ft to 7400 ft s.s. The reservoir was interpreted to be combination drive of gas cap and aquifer water. Production started June 1975. Cumulative oil production during history was 6.832 MMSTB, which was 5.85 per cent of original oil in place. API gravity is almost same as Samarang B Zone. Oil properties were determined from reservoir fluid study of SM-Well No.1 C Zone. Gas properties were calculated by gas analysis at SM-Well No.1 C Zone. Oil and gas properties are shown on Fig. 1-3-13 and Fig. 1-3-16, respectively.

Relative permeability was estimated by the same ways as Samarang A and B Zone. The relative permeability is shown on Fig. 1-3-7 and Fig. 1-3-10.

Initial reservoir pressure was determined to be 2834 psig at datum level of 6450 ft s.s. from the results of FIT and BHP survey. There were 21 producers in this zone, and no producer was added in the performance calculation. Reservoir performance is shown on Fig. 1-3-4 and tabulated on Table 1-3-4.

(d) Additional Wells Case

The performance projections described in (a) to (c) were conducted on the basis of existing and scheduled wells.

More additional wells case was studied from the view point of enhancing production rate and obtaining reservoir information required for establishing the secondary recovery device.

Additionally required wells in this case are as follows.

A Zone	SM-A 1, 2, 3
B Zone	SM-A 1, 2, 4, 5, 6, 8, 9, 11
C Zone	SM-A 6, 7, 8, 10

The proposed locations for the additional wells are shown on Fig. 1-3-20. The reservoir performance prediction was made by using the 11 additional wells and starting the production from July, 1976.

The anticipated reservoir performance is shown on Fig. 1-3-1 and Table 1-3-5.

(e) The Concept of Maximum Allowable Production Rate

Under the current PS Agreement, it is difficult to define the most efficient production rate for PETRONAS. Therefore, discussion is made here from the purely technical point of view.

The locations of the additional wells were determined for the purpose of increasing areal sweep efficiency, while the primary recovery increased slightly from 26.4% of existing condition to 27.8%. Increased rate of production will shorten the economic life of the field.

The production rate estimated from the additional wells case can be defined as the maximum allowable production rate not only from the technical point of view but from the field operational reason, which can be explained hereunder.

In the additional wells case, several wells are estimated to be shut-in in 1983 due to increased producing gas oil ratio, and the pressure maintenance should be initiated before that time.

It is difficult to decide based on the current reservoir information whether water or gas injection is preferable for the pressure maintenance.

Reservoir performance information for 2 more years are required. During this 2 years reservoir pressure and producing gas oil ratio should be observed.

Three years will be additionally required for engineering, construction and installation of the facilities.

The most important factor in this type of field is the control of producing gas oil ratio. The allowable gas oil ratio is described as a function of cumulative oil production in the following figures for individual zones.

Samarang A Zone	Fig. 1-3-17
B Zone	Fig. 1-3-18
C Zone	Fig. 1-3-19

3.2 Tembungo Field

3.2.1 Field Status

The Tembungo field is located approximately 70 km west of Sabah coast. Oil reservoir is composed of sand layers developed in the depth of 4500 feet to 7500 feet s.s.

Thirteen wells including sidetrack wells have been drilled, but only 4 wells have been completed as oil producers.

Production started October 1974 and average daily production rate during the month of June 1976 was 4.3 MSTB/D and cumulative production as of June 1976 amounts to 2.3 MMSTB.

3.2.2 Geology

(1) Reservoir Beds

The Tembungo field produces oil from sandstones of Miocene age. Sedimentary sections penetrated by wells consist of marine deposits, mainly sandstones and mudstones of Late Miocene to Pleistocene time but a limestone deposit ranging from 100 to 500 ft in thickness is known in the Pliocene sequence. Thick upper Miocene shale beds attaining 1700 ft thick overlie a sandstone-shale alternation 500 to 800 ft thick, Tembungo Sandstone, which is oil and gas bearing.

Reservoirs are sandstones 20 to 50 ft thick of generally poor continuity and were named as zone a through zone d (Table 2-2-1). Among them zones c and d are of well developed sandstones which are found typically in well Nos. 5, A-4 and A-7, zone c_1 being about 100 ft thick and zone d 100 to 150 ft thick.

(2) Geologic Structure

The Tembungo structure is an ENE-WSW trending anticline which is strongly faulted into many blocks with a normal fault system approximately perpendicular to the direction of anticlinal axis. Figs. 2-2-1, 2 give structural depth maps of zones b_1 and c_1, and Fig. 2-2-3 gives a cross-section of the reservoir horizons.

Since thick shale beds rest on the reservoir sequence, it is not easy to determine the location of the fault occurrence by using only well data. However, seismic record sections were also not convincing of the fault locations, for example, even that of the fault that is proved by well correlation to locate in well No. A-3 at a depth of 4130 ft with a west-side throw of about 550 ft. It is considered that other faults are in general with similar throws and with the west side down.

The fault-confined blocks are named as I through VII in consideration of some continuity of reservoir fluids and the estimation of hydrocarbons-in-place was carried out for each block (Table 1-1-1).

[Seismic Interpretation]

A horizon between zones b_1 and b_2 was interpreted. Quality of reflections from the interpreted horizon is fair to very poor. Faults are not clear at deep level due to poor data quality. Accordingly, correlation of reflections across faults was difficult. The identification of reflection with geological horizon was based on the well data in each fault block where well shooting data of Tembungo Nos. 1, 4 and 5 were available. Interpretation result and representative seismic section are shown in Fig. 2-1-1 and Fig. 2-1-2.

3.2.3 Reservoir Analysis

The field is divided into several blocks by many faults and producing horizons are classified into 4 zones, which are zone a, b, c and d. The main producing zones are b and c.

Productive zones in the individual blocks were evaluated by the following models.

Model	Well No.	Zone	Block No.
1	A-1	b_2	IV
2	A-7	c_1	IV
3	A-4	b_2	V
4	A-2A	b_1 and b_2	VI

Proved and probable oil in place for the field calculated by volumetric method are 34.3 and 30.5 MMRB, respectively.

Estimated field total performance excluding Model 4 is shown on Fig. 2-3-1 and Table 2-3-1. The anticipated field performance by Model 4 was estimated to be highly pessimistic and was discarded.

(a) Model 1

Analysis for Block IV b_2

This Block IV b_2 is located in the central area of the field. Well A-1 and Well A-7 were drilled in this area and oil water contact was confirmed at the depth of 5505 feet s.s. at Well A-7.

Well A-1 was completed as a producing well and production started October 1974 with initial oil production rate of 1367 STB/D and API gravity of 37.5°. Cumulative production amounts to 1.108 MMSTB, which is equivalent to 35% of proved reserves. In this block, there exist 18.28 MMRCF of probable hydrocarbon volumes for which definition of oil or gas can not be made at current stage.

The result of performance prediction by block model is shown on Fig. 2-3-2 and Table 2-3-2, and reservoir parameters used in the calculation are on Figs. 2-3-7, 12, 17, 24.

Production behavior of this block will be quite favorable if the restricted gas and water production is to be made.

(b) Model 2

Analysis for Block IV c_1

The analysis was made for the lower zone of the same block as in Model 1. Well A-1 and A-7 were drilled into this block and Well A-7 only was completed as a producer.

No free gas zone was detected and oil water contact was confirmed at the depth of 6640 feet s.s. by Well A-7.

Initial production rate in May 1975 was 2500 STB/D but declined to 600 STB/D in June 1976 and cumulative production by this stage is 0.26 MMSTB.

Reservoir performance calculation was made by the use of reservoir parameter shown on Figs. 2-3-8, 13, 18, 25, and computed result is shown on Fig. 2-3-3 and Table 2-3-3.

In the calculation, increase of water oil ratio was predicted. This is due to encroachment of water detected at Well A-7.

It can be thought of that the area of Well A-1 and southern part of the block may possibly be developed in future.

(c) Model 3

Analysis for Block V b_2

In this Block V, two wells, Well A-4 and Tembungo 5 are located side by side with the distance of approximately 100 m, while remarkable geological changes were observed. No oil water contact was detected in this block. Original oil and hydrocarbon in place were estimated to be 2.584 MMSTB and 0.601 MMRCF, respectively.

Well A-4 was completed as a producer and production started March 1975. Production rate as of June 1976 was 2200 STB with no remarkable production decline. Observed pressure drop was very small.

Reservoir performance calculation was made on the basis of oil in place data as estimated by the decline curve method by the block model, and predicted performance is shown on Fig. 2-3-4 and

Table 2-3-4. Reservoir parameters used in the calculation are shown on Figs. 2-3-9, 14, 19, 26.

(d) Model 4

Block VI $b_1 + b_2$ Analysis

Well A-2A, which is second side track of Well A-2, was completed in zone $b_1 + b_2$. The zone is oil bearing with oil water contact at 7986 s.s. depth, while at the location of Well A-2 (S.T), which is a first side track, the zone is completely gas.

Production started November 1974 with initial rate of 2000 STB but remarkable pressure and production decline were observed, and the well has been kept shut-in since March 1975.

Judging from the facts, the well is located in the highly limited area.

In the model calculation, the trial was made to produce from the well, however, no prospective result was obtained as shown on Fig. 2-3-5 and Table 2-3-5, and reservoir parameter used in the calculation are illustrated on Figs. 2-3-10, 15, 20, 27.

(e) Additional Wells Case

It was quite difficult to define individual reservoirs accurately only by existing well information due to several faults.

Presented here is a sample performance calculation based on the total undeveloped proved and probable reserves for the purpose of obtaining gross estimates of possible case.

Additional wells required for the development of the undeveloped portion of the field are as follows.

Well TM	AD-1	for Block	I	zone	c_1
	AD-2	"	I	"	d
	AD-3	"	V	"	$a + b_1$
	AD-4	"	VII	"	c_1

The locations for those wells are illustrated on Fig. 2-3-38.

Reservoir fluid properties and relative permeability data are summarized on Figs. 2-3-21 - 23, Figs. 2-3-28 - 30 and Figs. 2-3-11,16, respectively.

Estimated reservoir performance is shown on Fig. 2-3-6 and Tables 2-3-7 - 10.

The hydrocarbon in place used in this performance calculation is as follows.

				Original Oil in Place (MMSTB)	Free Gas (MMMSCF)
Block	I	Zone	c_1	2.235	5.600
"	I	"	d	2.136	-
"	V	"	$a+b_1$	5.653	-
"	VII	"	c_1	7.448	10.881
Total				17.472	16.481

(f) Maximum Recommendable Production Rate

The most important factor to attain maximum recovery is the control of producing gas oil ratio. The value changes with the progress of the depletion stage.

The most recommendable producing gas oil ratio was described for the individual zones as a function of cumulative oil production, and summarized on the following figures.

Block	IV	Zone	b_2	Well A-1	Fig. 2-3-31
	IV		c_1	A-7	Fig. 2-3-32
	V		b_2	A-4	Fig. 2-3-33
Block	I	Zone	c_1		Fig. 2-3-34
	I		d		Fig. 2-3-35
	V		$a+b_1$		Fig. 2-3-36
	VII		c_1		Fig. 2-3-37

Production rate described on the performance curve is the most recommendable production rate, as one well represents one block.

4. FIELDS FOR DEVELOPMENT

4.1 Erb West Field

4.1.1 Geology

(1) Stratigraphy and Reservoir Beds

The Erb W. field has been drilled by four wells, of which geological data show that sedimentary sections consist of Late Miocene and Pliocene clastics. The lowest part of the Pliocene strata is argillaceous beds of approximately 2000 ft and below this there are gas bearing alternations of sandstone and shale of 2000 ft for which sandstones of gas bearing zones a_1 to a_7 and oil bearing zone b were defined. The reservoir sandstones are in general 30 to 60 ft thick and have good lateral continuity.

Further below, there is a shale section of a thickness of about 1000 ft as a cap rock of other gas and oil bearing sandstones. These are zones c_1 and c_2, the latter being a main oil reservoir of this field and being composed of a total 400 ft thick packet of shale and sandstones ranging from a few to 20 ft in each thickness.

(2) Geologic Structure

Structural maps of zones a_2 and c_1 are shown in Figs. 3-2-1, 2 and a cross-section in Fig. 3-2-3.

The Erb W. structure is an east-west elongate anticlinal high with extensive fault development. The faults formed mostly in horizons shallower than zone c_1, but major ones penetrated into the deeper horizons.

GWC levels in zones a_1 - a_7 are considered different across the faults, then hydrocarbons-in-place were calculated to each of the fault blocks that were penetrated by the wells, whereas GOC and OWC in zone c_2 are thought probably constant across the faults.

[Seismic Interpretation]

Target horizons of seismic interpretation were the tops of zones a_2 and c_1. Quality of reflections arising from the top of zone a_2 is fair to good in the marginal area of the structure, but poor in the crestal part and in the surroundings of faults. Reflections from the top of zone c_1 have generally poorer quality than above ones. Correlation of reflections across the faults is difficult. Well shooting data were not available at all in this field. Accordingly, a time-depth curve was constructed from the sonic log of Erb West No.2. Interpretation result and representative seismic section are shown in Fig. 3-1-1, Fig. 3-1-2 and Fig. 3-1-3.

4.1.2 Reservoir Analysis

The structure is divided into several blocks by many faults. Hydrocarbon accumulation was confirmed mainly in zone c developed from 6000 feet to 7000 feet s.s. depth. In the shallower zone, small amounts of oil and gas can be detected in the crestal small block.

Zone c_2 is the main productive zone with gas cap and aquifer. According to the qualitative log interpretation, the oil zone is interpreted to be the alternation of thin sands and shales and seems to be not so much prospective. According to the production test results of Well No.3, however, daily rate of 1770 STB/D with productivity of 118 B/D/psi is reported.

Four wells were drilled in the independent blocks and the northern block where there exists Well No.3 is the most prospective.

The reservoir was interpreted to be the combination drive of gas cap expansion and aquifer water with API gravity of 30°.

Performance prediction was made by setting gas oil contact at 6705 feet s.s. and oil water contact at 6705 feet s.s. depth.

Computed results are shown on Fig. 3-3-1 and Table 3-3-2, and reservoir parameters are tabulated on Table 3-3-1.

In general, oil reservoirs in Sabah area are composed of many sands layers, while in this field, the reservoir is composed of a single oil zone. The reservoir extent is comparatively small with all its high productivity at the location of Well No.3.

In the actual field development, reservoir evaluation should primarily be made for the northern block. Information is also necessary for the western side of block where no well has been drilled so far.

The coordinates of the well locations required for the further exploration and appraisal purposes are as follows.

Well No.5	E2165000	N230600
6	E2162000	N230200
7	E2174000	N229950

Currently estimated maximum production rate is 20 MSTB.

4.2 South Furious Field

4.2.1 Geology

(1) Stratigraphy

Well data of S. Furious wells indicate sedimentary sections of Middle Miocene to Pliocene time. Upper Miocene sediments are eroded out for the most part owing to tectonic movements which took place toward the end of Miocene age and they are overlain by marine argillaceous rocks which are thicker westward. Hydrocarbons are accumulated in the Middle Miocene sequence of sand-shale alternations unconformably rested upon by the shale section.

The hydrocarbon bearing sequence attains 5000 ft in a total thickness and consists of alternating sandstone and shale beds generally a few to several tens feet thick, making correlation extremely difficult. It has been interpreted that sedimentary environments of such sediments deficient in distinctive features are of non-deltaic upper or lower coastal plain. Moreover, data of well core, dipmeter results, and seismic record sections indicate that there were very intensive tectonic disturbances in the section.

It must be mentioned, therefore, that the correlation shown in Table 4-2-1 is probably far from final and conclusive one over some or the whole sections.

(2) Geologic Structure

As Fig. 4-2-1 gives a seismically interpreted structural map for zone c, the S. Furious structure is an east-west anticline intersected by many faults. The faults occur so frequently that it is likely that one well is crossed by several or ten major fault planes. The size of the hydrocarbon distribution area is estimated about 6 km from east to west and 2 km from north to south. Among 7 wells drilled roughly in an east-west line on this field, well Nos.1 and 7 are beneath the western flank and 5 wells of Nos.2 through 6 are located on the structure proper. The structure has two culminations penetrated by a group of well Nos.2, 3 and 4 and by a group of well Nos.5 and 6.

In the case of well No.2 which is located at a crestal part, it is known from well logs that there is a formation interval as long as 3400 ft which indicates the existence of oil and gas but not that of water. Since it is very difficult to know exact fluid contact levels in detail on a great number of gas and oil zones for the above-mentioned reasons, calculation of hydrocarbons-in-place was done for the areas included in circles with a radius of a quarter mile.

It is desired to perform an intensive geologic study including seismic interpretation and stratigraphic analysis.

[Seismic Interpretation]

An interpreted horizon was the top of zone c. Quality of reflections is very poor all over the structure. It was difficult to point out the locations of the faults in the seismic sections and to correlate reflections across the faults. Therefore, reflections in each fault block where no well has been drilled were selected assuming that the throw of fault is not big. Accordingly, reliability of the interpretation result is low. Well shooting data of South Furious Nos.4, 5 and 6 wells were available for time-depth conversion. Interpretation result and representative seismic section are shown in Fig. 4-1-1 and Fig. 4-1-2.

4.2.2 Reservoir Analysis

Among the 7 wells drilled in this area, 5 wells from Well Nos.2 to 6 were drilled into the objective reservoir. As illustrated in the structure map, the field is divided into so many blocks by numerous faults.

Production tests have been conducted for 4 wells from Well Nos.2 to 5. The production rates are comparatively high but productivity indexes are less than 2 STB/D/psi and drainage radius for individual wells are less than 1000 feet.

Among the sand layers developed from 1100 feet to 7800 feet s.s. depth, main productive zones develop from 2000 feet to 5000 feet s.s. depth. The reservoir is composed of 10 to several ten feet sand layers with average API gravity of 32°. Although the net oil columns range from 200 to 600 feet in thickness, the production is made from completely closed system, with no remarkable gas cap to be found.

Performance calculation was made including the possible hydrocarbon in place, the area of which corresponds to the area enveloping the proved and probable area. Computed results are shown on Fig. 4-3-1 and Table 4-3-2 and reservoir parameters are tabulated on Table 4-3-1. Maximum production rate was estimated to be 16 MSTB.

According to the preliminary analysis, highly limited area can only be confirmed, as the field is divided into many blocks by numerous faults. The estimated original in place calculated here is apt to be underestimated.

By the application of commingled production system and drilling one well in one block, recovery may possibly be increased a little.

The quality of seismic section is poor and existing numbers of wells are not sufficient to make fault analysis.

The most important factor to attain maximum recovery is the control of producing gas oil ratio. The value changes with the progress of the depletion stage.

The most recommendable producing gas oil ratio was described for the individual zones as a function of cumulative oil production and summarized on Fig. 4-3-2.

5. POTENTIAL FIELDS

5.1 West Emerald Field

5.1.1 Geology

Well data of two W. Emerald wells indicate that there are sediments more than 6000 ft thick of late Miocene time, which are divided into the upper unit consisting of about 1000 ft thick argillaceous rocks, the middle unit of 3000 ft thick alternations of sandstone and shale, and the lower unit of 2000 ft thick shale.

Fig. 5-2-1 shows a structural map of the field by a seismic interpretation. The structure is an uplift like dome cut by several systems of faults. As the faults develop in intervals of 500 m or less, well correlation demonstrates that the middle unit of well No.1 is missing approximately 1000 ft by normal faulting compared with that of well No.2.

[Seismic Interpretation]

A target horizon of the seismic interpretation was the top of zone a. The seismic sections used were the latest ones shot in 1974. However, quality of reflections is very poor throughout the structure. This structure is cut by numerous faults, but the locations of them are not clear in the seismic sections. Besides, correlation of reflections across faults is quite bad. The relation of reflection time versus depth was based on well velocity survey data of West Emerald No.2. Interpretation result and representative seismic section are shown in Fig. 5-1-1 and Fig. 5-1-2.

5.1.2 Reservoir Analysis

Two wells have been drilled in this field where the area is divided into several blocks. In the Well No.2 drilled in the crestal area, the oil was confirmed in the shallow zone (zone a) whose gas oil and oil water contacts can be detected in the same well and its proved and probable oil in place is very small as listed on Table 1-1-3.

Information on the western side of the fault crossing the central area from north to south is not available. More exploratory wells are required in the western area to define the reservoir, however, the field is not prospective.

5.2 St. Joseph Field

5.2.1 Geology

Well data of St. Joseph well No.1 indicate that there are thick sediments of Middle Miocene age, attaining 7000 feet in a total thickness. The sedimentary column is divided into the upper unit (250 - 1670 ft) consisting of shale, the middle unit (1670 - 5740 ft) consisting of alternations of sandstone and shale, and the lower unit (down to 6800 ft) consisting of shale. The upper third of the middle unit is predominant in shaly rocks and is oil and gas bearing. Reservoir rocks are shaly sandstones 20 to 70 ft thick. Structural mapping was impossible owing to the only one well and too poor quality in the seismic sections to interpret.

The seismic interpretation for the field was not carried out because no reflection could not be recognized virtually. A representative seismic section is shown in Fig. 6-1-1.

5.2.2 Reservoir Analysis

Only one well was drilled in this area and the reservoir is composed of 6 sand layers developed in the interval from 1672 feet to 2565 feet s.s. depth and the total oil column exceeds more than 150 feet.

No information is available as to reservoir extent, location of the fault and the anticipated type of reservoir due to very poor seismic record quality.

Production test results conducted in the interval from 2397 feet to 2412 feet BDF is prospective.

Recommended is to conduct additional seismic survey.

5.3 Erb South Field

5.3.1 Geology

The Erb S. field is located about 12 km southeast of the Erb W. field. Well data of well No.1 indicate that Middle Miocene rocks are overlain with unconformity by a unit of sand-shale alternations probably of Pliocene age. The lowest 190 ft interval of sandstones of the alternations are oil bearing.

The Erb S. structure, shown in Fig. 7-2-1 for the oil bearing horizon, is a NNE-SSW trending anticline with a crestal part drilled by well No.1 in the southern area. A few faults are found to run in the N-S direction through the center of the structure. Seismic record sections suggest that the location of the well is the highest point of the Middle Miocene basement and the Pliocene and/or Upper Miocene strata seem to abut on the basement high. It is desirable, therefore, to drill further exploratory wells on the north-west flank, taking into consideration the fact that OWC has not been caught in well No.1.

[Seismic Interpretation]

A target horizon of the seismic interpretation was near the top of zone a. Data quality is usually fair except in the crestal part of the structure and in surroundings of faults. Well shooting data of Erb South No.1 was available. Interpretation result and representative seismic section are shown in Fig. 7-1-1 and Fig. 7-1-2.

5.3.2 Reservoir Analysis

Good oil sands with more than 90 feet oil column are detected at the location of Well No.1 whose location is near the crestal area of the south western block.

Fluid sample obtained has the API gravity of 20°.

No oil water contact is detected and more exploratory works are required.

No information on the north east block is obtained. The field needs more exploratory works. Recommendable well locations for defining the reservoir are as follows.

Well No.2	E219400	N227420
Well No.3	E219860	N228450

6. CONCLUSION AND RECOMMENDATIONS

1. Samarang field is a main producing field in Sabah area. The reservoir energy was interpreted to be combination of aquifer water, solution gas and gas cap expansion.

High production rate was reported so far, however, production control especially strict gas oil ratio control, is required for efficient utilization of the reservoir energy.

Optimum producing gas oil ratio is illustrated as a function of cumulative produced oil for your reference. The relation should, of course, be revised year by year by reviewing actual field performance.

Reservoir performance was made for additional wells case, where rapid production decline was anticlipated. The reservoir has only short production history. Survey of well behavior at the crest and down flank of the structure is required to confirm what is the dominant reservoir energy.

Only a few special core analysis data are available, which seems to be not so much favorable to gas injection. However, more data are required to conclude the most suitable secondary recovery method.

2. Exhaustive efforts to produce oil from Tembungo field seem to be meaningless, because of small amount of recoverable oil and poor oil displacement energy. Prediction was also made for additional few wells case.

3. Minimum three wells are required for the reservoir evaluation of Erb-West field.

4. In South-Furious field, the productive area is divided into numerous block by many faults. Drainage radius for individual wells was interpreted to be extremely limited and strong water drive for the individual blocks can never be anticipated.

Detailed production test is recommended at the time of well completion and the most optimum production rate should be determined. The main reservoir energy was interpreted to be solution gas with little effect of gas cap expansion.

5. Reservoir characteristics are estimated to be comparatively good for St-Joseph field, however, the seismic interpretation was not carred out because of very poor seismic record quality. Additional seismic survey is recommended.

Followings are recommended in the actual field operation.

(1) Special core analysis data should be collected for the main productive zones of individual fields.

The data will be helpful in establishing the most effective secondary recovery method, to say nothing of performance analysis.

(2) Special fluid analysis should be made for the samples collected through the actually applied well completion system.

The data will be helpful in establishing the most optimum operating conditions (separator pressure and temperature) and resultantly increase recoverable oil.

Analysis for the separator liquid together with liberated gas is indispendable for the estimation of fluid characteristics under any operating conditions by phase equilibrium calculation.

(3) Detailed production test is required at the time of well completion.

Minimum three sizes of choke are recommended to be used for the test, and draw-down, productivity and producing gas oil ratio data should be obtained.

The data will be helpful in deciding the most optimum production rate.

(4) Control of producing gas oil ratio is required for the producing field.

In order to preserve the reservoir energy, it is recommended to make production control to restrict producing gas oil ratio for the fields whose main displacement energy is the gas cap expansion and solution gas. The maximum allowable producing gas oil ratio is not constant, depending on the progress of reservoir depletion stage.

For individual producing fields, recommendable producing gas oil ratio is described as a function of cumulative oil production.

(5) Countermeasures for High Producing Gas Oil Ratio

The cause of high producing gas oil ratio should be detected by the use of Combination Production Log survey, if necessary.

Control of producing gas oil ratio should be made not only by the use of reduced choke at well head but also by the shut-off of high gas saturation zone through the work over or by closing the sliding side door.

(6) Commingled Production System and Well Test

The commingled production system by the use of the sliding side door is efficient ways in completing highly stratified reservoirs, but production profile information by the periodical production test and profile survey is indispendable for the proper field operation.

PART B SURFACE FACILITIES

1. SURFACE FACILITIES

1.1 Present Status of the Existing Production Facilities

1.1.1 Labuan Stream

Samarang field is located 32 miles northwest off Labuan Island and operated by Sabah Shell Petroleum Company (SSPC). Onshore crude terminal is situated on the west side of the island.

Fig. 8-4-1 shows the general facility layout of Labuan Stream. Production from each well is gathered into two Production Platforms (SMP-A and SMP-B) and gas is separated from oil by the separators there. A part of gas is utilized as power gas, instrument gas, lift gas, etc. The exhaust and remainder flow to a Vent Structure through three 10" x 1,000' - 2,000' submarine vent lines and are vented to the air.

The production (crude and water) treated at SMP-A and SMP-B are once transferred to Riser Platform (SMR-A) by 8" submarine pipelines respectively. Then, after mixed it flows to Labuan Terminal through an 18" pipeline.

At Labuan Terminal, the incoming crude is dehydrated and stored in storage tanks and then the crude is loaded into a visiting tanker at SBM to which a 48" sea loading line is installed from the terminal.

In this field total oil plus formation water of 70,000 BPD was produced at the time of site survey.

(1) Offshore Production Facilities

1) Drilling Platforms

The following drilling platforms or jackets are installed in Samarang field.

SMDP-A:	8-leg/21 Well Self-contained Drilling Platform	
SMDP-B:	8-leg/28 Well Tender Assisted	ditto
SMJT-C:	4-leg/6 Well Cluster	ditto
SMJT-D:	4-leg/6 Well Cluster	ditto
SM-4 :	Single Leg/Single Isolated Well Structure	

Although drilling at SM-4 and SMDP-A had already been completed, it was under way or provision at SMDP-B, SMJT-C and SMJT-D as of December, 1976.

A Drilling Platform is installed apart from a Production Platform due to safety reason and is connected to it by a bridge. At SMDP-A there were 19 producing wells and among them there was one fluid lifting well.

2) Production Platforms

A standard modular design of Production Platform is adopted in Samarang field. Two 4-leg Production Platforms had been already installed in this field at the time of site survey.

One Production Platform named SMP-A accommodates two banks of separators and five crude transfer pumps, and treats the production of approximately 65,000 BPD. The other named SMP-B accommodates one bank of separators and two crude transfer pumps and is connected by two submarine pipelines with SMP-A. SMP-B treats the production from seven high pressure wells sent from SMP-A by the pipelines.

There are several separators including a Test Separator and the operating pressures of SMP-A separators at the time of site survey were as follows:

HHP Separator	:	1,000 psig
HP Separator	:	250 psig
LP Separator	:	60 psig
Surge Vessel	:	5 psig

As for a Test Separator, wells are normally put on test for four hours and provided well test programmer was not in use. Wells were put on test manually.

A. O. Smith PD flow meter is used to measure liquid (oil and water) production rate.

Total production rate of each platform cannot be measured, although measuring of gas flow rate at necessary points is made by orifice flow recorders.

The drains at each Production Platform are collected into a caisson type oil-water separator partly submerged in the sea and treated by it.

Major equipment with simple specifications of two Production Platforms are listed in Tables 8-4-1 and 8-4-2 and the typical mechanical flow diagram is shown in Fig. 30-4-1.

3) Submarine Pipelines

Submarine pipelines except a loading line consist of the following:

a. Oil Lines

(i) to transfer well fluids from the Single Isolated Well Structure (SM-4) to the Production Platform (SMP-A)

(ii) to transfer well fluids from SMDP-A to SMP-B

(iii) to transfer gas-separated oil with formation water from SMP-A and SMP-B respectively to the Riser Platform (SMR-A)

(iv) to transfer the above-mentioned combined oil from SMR-A to Labuan Terminal

b. Gas Lines

(i) to transfer separated gas at a Production Platform to a Vent Structure

(ii) to transfer gas lift gas to satellite platform wells

Summary of the above-mentioned pipelines is shown in Table 28-4-2 and the general layout of the pipelines is shown in Fig. 8-4-2.

(2) Labuan Terminal

1) Terminal Facilities

The terminal is located at the west side of Labuan Island. Onshore crude terminal facilities mainly consist of crude receiving facilities for offshore Samarang field, dehydration and storage tank yard, crude loading facilities and utility facilities as shown on Fig. 8-4-3. Incoming crude flows into three storage tanks, each of which is 439,000 barrels floating roof tank. After settled for 36 - 48 hours to separate formation water sent from offshore together with the crude, the crude is transferred to SBM terminal for shipment by crude oil loading pumps. This scheme can be seen on Fig. 8-4-4.

Water content in incoming crude was 2.7% at the time of site survey in December, 1976. As shown on Fig. 8-4-5 the water from the tanks and oily sewer in the terminal are treated by CPI (Corrugated Plate Intercepter) and then holding basin to separate remained oil and water. The lean water is finally disposed to the sea.

The official measurement of produced and export crude quantity is made by mannual dipping at storage tanks. BS & W in export crude is about 0.05%.

Fire water tank with a capacity of 35,000 barrels and two fire fighting pumps including one spare, sea water supply facility, utility facilities such as electrical power generators, air compressors, distillation unit, etc. and buildings such as office, power plant, pump house, fire station and gate house are provided in Labuan Terminal. Simple flow diagram for these utilities are shown on Figs. 8-4-6 and 8-4-7. Major equipment list with simple specifications is attached as Table 8-4-3.

2) Loading Facilities

The SBM with the mooring capacity for maximum tanker size of 310,000 DWT is located approximately 15,000' west of Labuan Island and connected with the shore terminal by one 48" submarine loading line.

The total number of loaded tankers at the end of December, 1976 had been 50 since September, 1975. Maximum volume of loaded crude to one tanker was 645,000 barrels.

Three diesel engine driven loading pumps with maximum capacity of 54,000 BPH (7,200 tons/hour) in total are installed. The allowable space for another future addition is provided. The crude loading facilities such as pumps, loading line and SBM are designed for an ultimate maximum loading rate of 72,000 BPH (9,600 tons/hour) in future.

1.1.2 Tembungo Stream

Tembungo field is located about 47 miles northwest offshore Sabah and Exxon Production Malaysia, Inc. is now developing the field. Up to this time, one 8-leg self-contained platform was installed to accommodate all facility and personnel necessary for drilling and production operation. And for offshore crude loading, one single anchor leg mooring system (SALM) was also installed at a distance of 7,000' from the platform. A submarine pipeline, 10" in diameter, is connecting the platform with the SALM. All of the produced crude is treated on and loaded from the offshore facilities and no onshore field facilities or terminal exist except support facilities. Tembungo field is characterized by this field development scheme.

Daily average gross liquid production in May, 1976 is reported to be 5,294 barrels against the design capacity of the existing facility of 20,000 barrels.

(1) Offshore Production Platform

The outline of the platform named Tembungo "A" is shown in Table 28-4-1. Major equipment arrangement of Tembungo "A" is shown on Fig. 8-4-8.

The jacket is conventional template type fabricated by Brown & Root and installed by McDermott. Deck part consists of two decks, that is, the upper one for drilling and the lower one for production. Besides the crude oil handling facilities, the platform has living quarters which can accommodate maximum 72 persons and are equipped with a weather station, gas detection panel, fire alarm panel, etc. A heliport is on the living quarters. Wellhead area is provided with eighteen slots.

(2) Crude Oil Production Facilities

Mechanical flow diagram on crude oil production and processing is shown on Fig. 8-4-9.

Six wells had been drilled from this platform and three of them were producing as of January 1977. No artificial lift such as pumping and gas lift is employed. Four well headers are provided and two of them which are test header and B train header are now in use. Remaining two which are weak well header and another train header are furnished for future expansion of the facility.

Oil and gas produced are first separated in Production Separator at the operating pressure and temperature of 150 psig and 135°F respectively. Free water accumulated in the separator is dumped manually. The second stage separation is carried out in the vessel named Free Water Knockout and Surge at the operating pressure and temperature of 5 psig and 120°F. This vessel is three-phase type separator and free water is automatically drained off. Crude oil is then transferred through 10" submarine pipeline to the SALM by two S.P.M. Oil Pumps. Separated gas from Production Separator and Free Water Knockout and Surge are treated in H.P. Flare Scrubber and L.P. Flare Scrubber respectively and then flared at the flare stack extended from the platform. Liquid accumulated in those scrubbers is transferred to Free Water Knockout and Surge by H.P. and L.P. Flare Transfer Pumps.

Drain waters such as open drain from deck and pressure drain from various vessels are gathered into individual headers and flow into submerged caisson separator. Recovered oil is returned back into the inlet line of Free Water Knockout and Surge by Caisson Oil Pump.

Each well is put on test once a week with Test Separator. Gas and liquid separated are measured with orifice type and turbine type flow meters respectively. Because the production separator is for liquid and gas two-phase separation, individual flow rate of oil and water cannot be measured. Instead, at Free Water Knockout and Surge vessel each of three phases can be measured.

For the measurement of total produced oil two positive displacement type flow meters, manufactured by A. O. Smith Company are installed in parallel at downstream of S.P.M. Oil Pumps. These meters are each nominally rated at 1,425 barrels per hour. Another flow meter shown in the mechanical flow sheet supplied on and seemed to be used for calibration purpose is not installed. The figures read from these meters are used only for technical purpose and not used for sales purpose. Measuring of sales figures is carried out at a moored tanker by manual gauging. Measuring is officially made at the end of each month and at the completion of crude loading to the tanker.

On control of facilities, concept of remote control is not adopted and only alarm signals are indicated on the panel.

Major equipment list with simple specifications is attached as Table 8-4-4.

(3) Storage and Loading Facilities

There is no storage tanker now in use, though the system is designed so that a storage tanker is moored to the SALM and that ocean tankers come alongside the storage tanker to receive crude oil stored in it. Therefore crude oil produced is loaded directly from the SALM to the ocean tanker which is moored until fully loaded. The SALM can moor up to 94,000 DWT tanker.

1.2 Review on the Capacity of the Existing Production Facilities

Review was performed to evaluate the capacity of the existing production facilities and to proceed to the subsequent assessment of the capacity compared with the predicted production performance. The major facilities and items for reviewing are as follows and these are considered to dominate the capacity of total facilities. For the execution of the study several assumptions have been made in accordance with the availability of the data.

Facility Items for Review

1) Offshore Production Facilities
   - Oil and gas separator
   - Gas venting line
   - Oil gathering line
   - Oil transmission line

2) Onshore Production Facilities
   - Storage tank
   - Loading system

Study Items

1) Separator

- Liquid capacity or retention time for proper oil-gas separation and for absorbing possible surge
- Gas capacity to handle separated gas

2) Vent or Flare Line

- Gas capacity to handle separated gas

3) Oil Gathering and Transmission Line

- Pressure balance for present oil production rate and for maximum oil handling capacity of production platforms

4) Storage Tank

- Storage capacity to meet maximum visiting tanker and enough allowance for daily production

5) Loading System

- Pressure loss and flow speed in loading line

1.2.1 Labuan Stream

(1) Offshore Production Facilities

1) Separator

<u>Calculation Bases</u>

Flow Rate 30,000 BPD

	H.P. Separator	L.P. Separator	Surge Vessel
Operating Pressure	250 PSIG	50 PSIG	10 PSIG
Operating Temperature	123°F	113°F	110°F
Separator Dimension	72"I.D.x20'	72"I.D.x20'	126"I.D.x32'

Specific Gravity (Assumed)

Gas	0.671	0.764	1.077
Oil	0.830	0.830	0.830
Gas Velocity Factor	0.40	0.40	0.40

<u>Calculated Resutls</u>

	Retention Time	Gas Capacity
H.P. Separator	2.7 minutes	61.5 MMSCFD
L.P. Separator	2.7 minutes	28.9 MMSCFD
Surge Vessel	13.6 minutes	46.4 MMSCFD

2) Vent Line

Calculation Bases

Same as those for separator calculation.

Calculated Results

	Size and Length	Maximum Gas Flow Rate
High Pressure Vent Line	10" x 2,000'	167 MMSCFD
Low Pressure Vent Line	10" x 2,000'	36 MMSCFD
Low Pressure Vent Line	10" x 2,000'	11 MMSCFD

3) Oil Gathering and Transmission Line

Fig. 8-4-10 and Fig. 8-4-11 show pressure balance of gathering and transmission lines under present production rate and design maximum liquid handling capacity of Production Platforms.

(2) Onshore Facilities

1) Storage Tank

There are three floating roof storage tanks having nominal capacity of 439,000 barrels for each and one tank is being used for receiving and settling transported gross production (oil plus formation water) from offshore platforms.

The following is analysis on storage tank capacity made by the operating company:

Gross Tankage	1,317,000 BBLS
Unpumpable	(-) 156,000
Pumpable	1,161,000
Receiving, Settling & Drainage	(-) 387,000
Net Storage Capacity	774,000

Analyzed net storage capacity which is 774,000 barrels is about equivalent to the cargo volume of 100,000 DWT tanker or is also approximately equal to 10-day production for present production rate in the Labuan Stream.

2) Loading System

<u>Calculation Bases</u>

Installed Line Size	48" O.D.
Assumed Wall Thickness	0.500"
Installed Length	15,000'
Loading Rate	
Case 1	30,200 BPH
(equivalent to tanker size of 100,000 DWT)	
Case 2	45,300 BPH
(equivalent to tanker size of 150,000 DWT)	
Case 3	60,400 BPH
(equivalent to tanker size of 200,000 DWT)	
Case 4	90,600 BPH
(equivalent to tanker size of 300,000 DWT)	

Note: The above loading rates are to complete loading within 24 hrs. in each case.

Calculated Results

	Pressure Loss (PSI)	Velocity (feet/sec.)
Case 1	22.0	10.8
Case 2	24.5	11.3
Case 3	41.1	15.0
Case 4	86.3	22.5

Head of the existing loading pumps is sufficient for each loading rate, but only Case 1 and Case 2 are possible in loading rate by the existing pumps. The capacity of each of the three pumps is 18,000 BPH at 275' head. Actually Case 3 and Case 4 are not realistic from the viewpoint of storage capacity, although the mooring capacity of the existing SBM is reported to be sufficient for 310,000 DWT.

(3) Conclusion

- Specified design capacity of the existing vent lines and separation system with two banks of separators is reasonable and sufficient. The design capacity is 60,000 BPD gross liquid production and 180 MMSCFD separated gas.

- Gathering and transmission lines will cover maximum oil handling capacity of the existing Production Platforms in hydraulic design aspects including oil transfer pumps which have a design capacity of 13,000 BPD/unit.

- Storage tank capacity is considered reasonable unless the present production rate increases or full cargo for 200,000 DWT tanker or larger is expected.

- Loading system has enough capacity for the present production rate. Even if production increases, this system could meet the requirements by loading pump addition.

1.2.2 Tembungo Stream

Original design capacity of Tembungo "A" is 20,000 BPD. The review was performed based on this production rate.

(1) Separator

Calculation Bases

	H.P. Separator	L.P. Separator
Flow Rate	20,000 BPD	
Operating Pressure	150 PSIG	5 PSIG
Operating Temperature	135°F	120°F
Separator Dimension	72"I.D.x20'	144"I.D.x30'
Specific Gravity (Assumed)		
Gas	0.671	1.077
Oil	0.838	0.838
Gas Velocity Factor	0.40	0.40

Calculated Results

	Retention Time	Gas Capacity
H.P. Separator	4.0 minutes	49.0 MMSCFD
L.P. Separator	17.1 minutes	53.9 MMSCFD

(2) Flare Line

Calculation Bases

Same as those for separator calculation.

Calculated Results

	Size and Length	Maximum Gas Flow Rate
High Pressure Flare Line	12" x 240'	113 MMSCFD
Low Pressure Flare Line	10" x 240'	15 MMSCFD

(3) Loading System

Calculation Bases

Installed Line Size	10" O.D.
Assumed Wall Thickness	0.500"
Installed Length	7,000'
Transfer Capacity	
Case 1	4,983 BPD
(equivalent to present production rate)	
Case 2	20,000 BPD
(equivalent to capacity of the present production facility)	
Case 3	30,000 BPD
(equivalent to future maximum capacity of production facility)	

Calculated Results

	Pressure Loss (PSI)	Velocity (feet/sec.)
Case 1	1.0	0.8
Case 2	11.3	3.0
Case 3	23.5	4.4

Note: Two (2) transfer pumps are installed on the platform and the capacity is 600 GPM (20,600 BPD) at 60 psi pressure difference for each unit.

(4) Conclusion

- Specified design capacity for the existing separation system as well as flare line is reasonable and sufficient under condition of 20,000 BPD gross oil production at 800 ft^3/bbl of GOR.

- Transfer line from the platform to SPM and the transfer pumps have enough capacity for the present and future maximum design capacities.

1.3 Assessment of the Facilities Capacity for the Predicted Production Scheme

The assessment of the facilities capacity was executed from a viewpoint of handling capacity of major production facilities by comparing the predicted maximum production rate with the facilities capacity on which the evaluation was made in the previous section. Therefore the study does not cover the capability of the facilities to adopt unforeseen additional facilities or modifications which have no relation with the predicted production performance of each field.

The additional well development case is discribed later for reference.

The maximum production rate of gross liquid and gas for each field and its occurrence year after 1976 are shown below based on the reservoir study in previous sections.

<u>Predicted Maximum Production Rate after 1976</u>

Oil Field	Gross Liquid (year) BPD	Oil BPD	Water BPD	Gas (year) MMSCFD
Samarang	38,530 (1977)	38,230	300	56.6 (1979)
Tembungo	4,060 (1977)	3,470	590	4.8 (1977)

As shown in the above table, predicted maximum gross liquid production rates will not exceed the production rates in 1976. When new fields such as

Erb West and South Furious would be joined in future, the total handling rate would not increase due to the decline of the existing fields before the start-up of the new fields.

1.3.1 Labuan Stream

(1) Offshore Production Platform

Table 28-4-3 shows the comparison of the present production rates versus the evaluated capacity of Production Platforms for each field. While, the comparisons of the predicted maximum production rates after 1976 versus the evaluated capacity of them for each field are shown on Table 28-4-4 for gross liquid and on Table 28-4-5 for gas.

Two Samarang Production Platforms (SMP-A & B) have the total oil handling capacity of 90,000 BPD, while the present gross liquid production rate is 39,741 BPD. The production was increased to about 70,000 BPD in December, 1976, but no higher is expected in future by the reservoir study. Therefore the platforms have enough liquid handling capacity throughout the field life as well as the capacity for gas.

(2) Offshore Gathering and Transmission Pipelines

Fig. 8-4-12 shows the pressure balance for the present and predicted maximum gross liquid production rate. As can be seen from the above figure, the existing gathering and transmission network will have enough capacity to handle the predicted maximum production rate after 1976. On the other hand, high pressure gas is required for the transmission pumps as required for the Lutong Stream. According to the predicted gas production rate for the Samarang field, the enough required gas will be available.

(3) Storage Facilities

As evaluated in the previous section concerning review on the storage capacity, the Labuan Terminal has enough storage volume for the present production level. Therefore it will not have a problem on this matter in future, as the predicted production rate will not surpass the present production level.

(4) Loading Facilities

At present, the loading facility has the confirmed capacity of 54,000 BPH (7,200 tons/hour) and the mooring capacity of 310,000 DWT. The crude loading facilities such as pumps, loading line and SBM are designed for an ultimate maximum loading rate of 72,000 BPH

(9,600 tons/hour).

For the production rate of 70,000 BPD at the time of site survey, tanker arrival frequency was one tanker a week. This frequency is not tight. Therefore, the existing loading facilities will cover the future oil loading operation for predicted maximum production rate without any expansion or modification.

1.3.2 Tembungo Stream

(1) Offshore Production Platform

Table 28-4-3 shows the comparison of the present production rates versus the evaluated capacity of Production Platforms for each field. While, the comparisons of the predicted maximum production rates after 1976 versus the evaluated capacity of them for each field are shown on Table 28-4-4 for gross liquid and on Table 28-4-5 for gas.

The Tembungo "A" has the liquid handling capacity of 20,000 BPD, whereas the present gross liquid production rate is 5,294 BPD and the rate will not increase over the value after 1976. Therefore the platform has enough liquid handling capacity throughout the field life as well as the capacity for gas.

(2) Offshore Gathering and Transmission Pipelines

At Tembungo oil field the only offshore pipeline is a transfer line to SPM and so assessment is carried out in the following item of Storage and Loading Facilities.

(3) Storage Facilities

The offshore storage and loading concept is applied to this stream but no fixed storage tanker is used at present. Oil production is directly sent to and stored in an export tanker moored at SPM. So far as this concept is adopted, storage capacity will be varied by the moored tanker size. In any case, the maximum oil production rate predicted as 3,470 BPD will cause no problem on required storage capacity, if a tanker is continuously available to be moored and loaded at SPM.

(4) Loading Facilities

The confirmed design capacity rate for oil loading is 20,000 BPD, whereas predicted maximum oil production rate is 3,470 BPD. It is obvious, from the comparison of the above rates, that the existing loading facilities will have no problem in future. However, the production system is operated on the tight line principle that there is no storage allowance except the buffer volume in the surge drum (238 barrels). Therefore, the continuous loading to a tanker connected with the SPM buoy is the only way to continue the daily production.

1.3.3 Conclusion

In accordance with the assessment of key components of the producing, storage and loading facilities for each field, the existing field facilities will basically cover the predicted future oil production, as well as associated gas and formation water, for all fields without any bottleneck. This conclusion, of course, results from the decline of oil production from the existing fields except gas and water and the time lag due to the necessity of lead time even if new field(s) will be tied in.

In case of the adoption of gas lift, possible artificial lifting method, gas source will be available from high pressure gas reservoirs or high GOR wells and the addition of a high pressure separator and simple modification of the existing facilities are only the work required for it.

1.3.4 Additional Well Development Case

Additional wells will be drilled and their productions are assumed to be started in 1976, the total predicted maximum gross liquid and gas production rate for each field and it's occurence year after 1976 are as follows.

Predicted Maximum Production Rate after 1976

Oil Field	Gross Liquid (year) BPD	Oil BPD	Water BPD	Gas (year) MMSCFD
Samarang	49,150 (1977)	48,650	500	73.1 (1978)
Tembungo	9,770 (1977)	8,460	1,310	15.7 (1978)

Production Facilities to be required in additional well case are as follows;

(1) Offshore Drilling and Production Platform

a. Samarang Field

Eleven (11) additional wells will be drilled in this field. Among these, six (6) are near and other five (5) are far from existing SMDP-B. And in this field SMDP-B is a only platform to be ever used for drilling. Therefore, a new drilling platform (8P/10W) will be required. As for production platform, existing SMP-A and SMP-B have enough handling capacity throughout the field life compared with the predicted maximum gross liquid, 49,150 BPD (1977).

b. Tembungo Field

Four (4) additional wells will be drilled in this field. All of these can be drilled from existing Tembungo 'A' (8P/18W) Platform. And also new production platform will not be need because of small quality of additional liquid as shown on previous table.

(2) Offshore Gathering and Transmission Pipelines

a. Samarang Field

The 10" x 4,700 ft submarine gathering pipeline will be installed between SMP-A and new drilling platform. There is no need of the new transmission line from the viewpoint of the pressure balance as shown on Fig. 8-4-12.

b. Tembungo Field

As previously described, the only offshore pipeline is a transfer line to SPM at Tembungo Field. And if the value of predicted maximum oil production rate 8,460 BPD is substituted for 3,470 BPD, there will be no problem about storage and loading facilities.

1.4 Assessment on Present Production Practices

In this section assessment and recommendation are made on the topics related to present production practices which have been noticed during the course of the study on the review and assessment of the existing oil production facilities including site survey.

1.4.1 Labuan Stream

(1) Associated Gas Utilization

As shown in Table 28-4-6, total separated gas at offshore platforms in Samarang field was about 40 MMSCFD. The utilization status of this associated gas was as follows:

	MMSCFD	%
Pump Driving	10.2	24.8
Venting	30.9	75.2
Total	41.1	100.0

Separated gas is not actually utilized except expansion energy used for transfer pumps. As for the utilization of this associated gas it is pessimistic because the gas production decreases rapidly after 1979 and utilization will not be started before this considering the lead time for construction work, even if any demand is expected.

(2) Metering System

1) Offshore Platforms

There are no metering facilities of liquid at offshore Production Platforms.

Many informations should be checked such as fluctuation of flow and pressure and space limitation to select optimum metering system to be applied on the platform because conventional method may not be applied due to the existing pumps of reciprocating type. But the existing system will be enough for the purpose of measurement of produced crude.

2) Labuan Terminal

Measurement of produced oil to be transmitted from offshore and exported crude is carried out by hand dipping at storage tank, and official measurement of exported oil is also being made by hand dipping at storage tanks. This is not a conventional method at modern facilities but a conservative method which is adopted in fields in Saudi Arabia, etc.
But the existing system will be enough for the purpose of measurement of loaded crude.

(3) Waste Water Treatment System

Produced formation water, which is major waste water source on all offshore platforms, is transported with oil to Labuan Terminal by submarine pipelines and combined oil and water is dehydrated by being settled in storage tanks for 24 hours. As a modern and effective waste water treatment system is employed at the terminal, there is little possibility of sea pollution under suitable operation of this system.

(4) Crude Oil Dehydration System

Formation water produced with crude is separated at a conventional storage tank in Labuan Terminal. At present this method is applicable because of small amount of associated water and enough storage tank capacity, although care must be taken against the corrosion on the tank bottom and lower part of the tank shell.

(5) Control and Monitoring System

In offshore operations for Labuan Stream, no monitoring system at the onshore terminal is applied on. It will be worthy to take into consideration the adoption of telemetering system to monitor the operating conditions of offshore facilities to add more safety. This is because nobody can watch offshore facilities at night without the installation of an accommodation platform in addition and it takes time to find out any accident and to reach the location. Efficiency and safety of oil production operation will be improved by the adoption of the system by which working conditions can be monitored at an on-shore control room. At least the following status had better be monitored with alarm function.

a. Emergency shut-down valve closed
b. Low pressure of each seaparator
c. High pressure of each separator
d. High level of each separator
e. Fire
f. Transmission pump stopped

1.4.2 Tembungo Stream

(1) Associated Gas Utilization

As of May, 1976, 3.7 MMSCFD separated gas at the Tembungo platform was all flared and not utilized. The flaring of the separated gas is reasonable here, because the location of the platform is remote and utilization is not expected for this small quantity of gas with rather short life.

(2) Metering System

Measuring points and objective fluids on the Tembungo platform are as follows:

Measuring Point	Fluid	Kind of Meter
Gas outlet of production separator	Separated gas	Orifice
Liquid outlet of test separator	Separated oil and formation water	Turbine meter
Gas outlet of test separator	Separated gas	Orifice
Formation water outlet of free water knockout and surge vessel	Formation water	Turbine meter
Gas outlet of free water knockout and surge vessel	Separated gas	Orifice
Outlet of S.P.M. oil pump	Oil	P.D. meter

Present measuring method applied on determination of sales quantity is manual gauging in a moored tanker tank and measuring is officially made at the end of each month and at the completion of crude loading to the tanker. Such a measuring method is not conventional as official one by following reasons.

The present method of measuring loaded crude volume at a moored tanker will possibly cause an inaccurate figure unless the sea is very calm and the tanker is always kept flat. The above conditions are seemed to be rather difficult to expect in the open sea area like here.

There is the possibility that the error on sales figure would be caused by the swelling of cargo tanks in the tanker in proportion as quantity of loaded crude increases. This field, however, is in special circumstances to be applied on offshore loading concept due to low oil production rate. It is usual manner that a P.D. meter or other suitable meter is employed on a platform to measure sales volume, even if a storage tanker method is adopted.

It is recommended to use an appropriate flow meter, of which the specification has to meet the present production conditions, along with utilization of a meter prover or alternatively utilization of a standard flow meter which will be calibrated at a manufacturer's factory at some time intervals such as once a year or two.

(3) Waste Water Treatment System

Formation water is treated in a submerged caisson waste water separator and disposed to the sea. The submerged caisson waste water separator is suitable for disposal of relatively small volume of water less than 60 GPM (2057 BPD) at offshore platforms as it does not arise a space problem.

Although waste water treating capacity depends on waste water temperature, the existing caisson can handle approximately 1,000 BPD. This capacity is large enough to treat the predicted maximum water production.

(4) Crude Oil Dehydration System

Formation water produced with crude is separated at a separator and a free water knockout vessel. At present there seems to be no problem on this system, as both water cut and total water production are small.

(5) Control and Monitoring System

Local control system of conventional type is fundamentally adopted for the Tembungo platform. Only alarm signals are indicated on the central panel. For the production system of this grade, present control system will be sufficient.

2. PROPOSED FACILITIES

2.1 General Design Bases

All data and informations collected mainly in data collection and site survey phases have been reviewed, and accurate and realistic data required for conceptual design have been selected out of those data and informations.

However some of collected data and informations are imperfect or not clarified to adopt as design data. So some of design bases are assumed so as to be realistic and reasonable taking into consideration the purpose of this study.

Only common design bases to all fields have been described in this section and specified design bases for each field are mentioned in the subsequent sections.

2.1.1 Basic Design Data from Collected Data

(1) Fields Location

As shown in Fig. 30-9-1.

(2) Meteorological and Oceanographical Data

<u>Atmospheric Temperature</u>

Max.	110°F
Min.	65°F

Sea Water Temperature at Sea Bottom

Min.	60°F

Relative Humidity

Max.	90%

(3) Hydrographic and Topographic Data

Sea Water Depth

Sea water depths for offshore structures in new fields are maximum water depths obtained from drilling reports in each field. Design water depth for each field is summarized below.

Field	Sea Water Depth (feet)
Erb West	252
South Furious	188

(4) Soil Data at Sea Bed

The soil character under offshore structures is taken into consideration in the conceptual design in accordance with the soil data received from Petronas. For the offshore structures, typical soil data considered to be average are tentatively used.

2.1.2 Assumed Design Conditions

(1) Development Well

Development wells are assumed to be drilled by the following two types of rig.

- Rig on self-contained platform
- Rig on tender assisted platform

2.1.3 Determination of Facilities Capacity

(1) Onshore Storage Tank

Storage tank capacity is assumed in accordance with the following formula.

Total Gross Capacity

= { Design Production Capacity (BPD) x 6 days

+ Full Cargo of 100,000 DWT Tanker (724,500 barrels)}

÷ Pumpable Factor (0.9)

As for the required number of tanks, minimum three tanks are required for the purpose of receiving, settling and loading.

(2) Offshore Storage Barge

An oil storage barge which is to be newly built is adopted as an offshore storage facility and its capacity is assumed in accordance with the following formula.

Storage Capacity
= Design Production Capacity (BPD) x 6 days
+ Full Cargo of 100,000 DWT Tanker (724,500 barrels)

(3) Loading Pump

Loading pumps and a loading line are sized to complete the full cargo loading to a visiting tanker of 100,000 DWT (724,500 barrels) within 24 hours.

(4) Loading Line

Flowing velocity of crude oil in pipeline is limited to within 10 ft/sec to prevent static electricity generation and maximum internal pressure in hose line is limited within allowable pressure of 150 psig.

(5) Mooring Facilities

An SBM system which is popular all over the world at present is adopted in Malaysia. But in deep sea water (over approximately 200') a SALM system is adopted. In case of offshore storage and loading, two SBMs (or SALMs) are to be installed, one for an oil storage barge and the other for a visiting tanker. The system to moor a visiting tanker alongside the oil storage barge was not adopted at this time for safety reason.

2.2 Conceptual Design

2.2.1 Erb West and South Furious Oil Fields

(1) Design Bases

Field facilities have been designed in accordance with the following bases.

1) Production Rate and Number of Wells

Field	Production Rate (BPD)	No. of Wells
Erb West	20,000	10
South Furious	16,000	10

2) Fluid Property

Field	API Gravity	Viscosity (60°F) cp	Max. GOR (SCF/STB)
Erb West	30	19	22,000
South Furious	32	14	5,000

(2) Conceptual Design

Location of Erb West and South Furious oil field is shown in Fig. 30-9-1. Based upon the design bases described above, conceptual design and subsequent cost estimates for several development cases including off-shore storage and loading case have been performed.

As the result of screening several development cases from geographical, economic and operational points of view, the following three cases have been selected as realistic and reasonable ones to be more precisely compared.

1) Case Setting

a. Case I - Erb West and South Furious, Labuan Terminal Case

This is a combined development case of Erb West and South Furious fields. All produced crude will be transported to the existing Labuan Terminal and will be stored and loaded by use of the existing facilities in Labuan Island. The facilities arrangement is shown in Fig. 9-5-1 and block flow diagram is shown in Fig. 9-5-2.

b. Case IIA - Erb West, Labuan Terminal Case

This is a case for the development of only Erb West field. Similar to Case I, produced crude will be transported to the existing Labuan Terminal. The facilities arrangement is shown in Fig. 9-5-3 and block flow diagram is shown in Fig. 9-5-4.

c. Case IIB - Erb West, Mangalum Terminal Case

This is a case for the development of only Erb West field and similar to Case IIA. Produced crude will be transported to a new onshore oil terminal, which will be located on the nearest island named Mangalum Island, from Erb West field. The facilities arrangement is shown in Fig. 9-5-5 and block flow diagram is shown in Fig. 9-5-6.

2) Facilities Description

For the above-mentioned three cases, capital investment costs and operating costs have been estimated and then economic analysis has been performed as described in Part C. As the result of the economic analysis, Case IIA is the most profitable case among the above three cases. So field facilities are described below for this case. Whereas, field facilities for Case I, which is the better case in the combined development cases, are described below for reference to cover the facilities for both fields.

a. Case I - Erb West and South Furious,
Labuan Terminal Case

Crude oil production system for these two fields consists of the following facilities:

Erb West Field

2 ...	6-leg Well and Production Platform	EWWP-A & B
1 ...	4-leg Accommodation Platform	EWA-A
2 ...	3-leg Flare Jacket	EWV-A & B

Submarine Pipelines

South Furious Field

2 ...	6-leg Well and Production Platform	SFWP-A & B
2 ...	3-leg Flare Jacket	SFV-A & B

Submarine Pipelines

Facilities arrangement is shown in Fig. 9-5-1. Major equipment to be installed are tabulated with simple specification in Table 9-5-1.

(i) Erb West Field

(a) 6-leg Well and Production Platform

Two 6-leg Well and Production Platforms (EWWP-A & B) will be installed in Erb West (approx. 252 water depth). Maximum 6 wells can be drilled from this platform by a tender assisted drilling rig. Typical plan and elevation is shown in Fig. 30-5-16. Major process equipment are provided on this platform to treat well fluid up to 10,000 BPD. Produced crude from EWWP-B will be transported to EWWP-A through 6" submarine Gathering Line. And produced crude oil from

South Furious Field will be transferred to EWWP-A, combined with that from Erb West, and sent through 12" submarine Transmission Line to the existing Labuan Terminal. Typical mechanical and utility flow diagrams are shown in Figs. 30-5-2 and 30-5-10.

(b) 3-leg Flare Jacket

A 3-leg Flare Jacket will be installed 2,000' apart from each Well and Production Platform and connected with the Well and Production Platform by two 8" submarine Flare Lines which are for HP gas and LP gas respectively. Separated gas at three-stage separators on Well and Production Platform is flared at the top of a Flare Jacket for safe disposal of waste gas.

(c) Accommodation Platform

One 4-leg Accommodation Platform (EWA-A) will be installed at approximately 252' water depth adjacent to Well and Production Platform (EWWP-A) in Erb West field for offshore operating personnel and connected with EWWP-A by a bridge. A heliport is provided on this platform for the transportation between offshore and onshore oil terminal at Labuan Island. Typical plan and elevation is shown in Fig. 30-5-31.

(ii) South Furious Field

(a) 6-leg Well and Production Platform

Two 6-leg Well and Production Platforms (SFWP-A & B) will be installed in Erb West (approx. 188 water depth). These platforms are similar to Erb West 6-leg Well and Production Platform. Produced crude oil from SFWP-B will be transferred to SFWP-A through 6" submarine Gathering Line and sent through 10" submarine Gathering Line to Well and Production Platform (EWWP-A) in Erb West after mixing.

(b) 3-leg Flare Jacket

A 3-leg Flare Jacket is almost the same as that of Erb West.

(iii) Labuan Terminal

Labuan Terminal is the existing oil terminal at Labuan Island to receive crude oil from Samarang field. Judging from future production performance of Samarang field, the existing Labuan Terminal can afford to receive crude oil from Erb West and South Furious without any expansion. Incoming crude oil from the both fields will be settled and stored in the existing storage tanks and loaded to a visiting tanker by the existing loading system. Major facilities installed at the existing Labuan Terminal are shown in Fig. 8-4-3.

b. Case IIA - Erb West, Labuan Terminal Case

Facilities arrangement and production system for this case are similar to those for Case I, although crude is produced from only Erb West field. The production system will consist of the following:

2 ...	6-leg Well and Production Platform	EWWP-A & B
1 ...	4-leg Accommodation Platform	EWA-A
2 ...	3-leg Flare Jacket	EWV-A & B

Submarine Pipelines

Facilities arrangement is shown in Fig. 9-5-3. Major equipment to be installed are tabulated with simple specification in Table 9-5-1. The size of a Transmission Line is 10" in this case instead of 12".

3. CONCLUSIONS AND RECOMMENDATIONS

3.1 Existing Facilities

(1) Present Status of the Existing Production Facilities

At present two offshore fields are producing oil in Sabah Area. Data collection and site survey were executed to investigate the present status of these existing production facilities at September, 1976 and January, 1977 respectively. Operating Company names, field names and oil production rates as of May, 1976 are shown below for each field.

Field	Oil Production Rate (BPD)	Major Facilities
Samarang (Sabah Shell Petroleum Co.)	39,055	Drilling Platforms Production Platforms Labuan Terminal Single Buoy Mooring System Submarine Pipelines
Tembungo (Exxon Producton Malaysia, Inc.)	4,983	Drilling and Production Platform Single Anchor Leg Mooring System Submarine Pipelines

(2) Review on the Capacity of the Existing Production Facilities

Review and evaluation on the capacity of the existing production facilities have been carried out for the above-mentioned fields. These results are to be used for the assessment of the ability of those facilities to meet the predicted production performance of the relevant fields. The major objective facilities for reviewing are as follows and these are basic items to evaluate the capacity of whole production facilities.

Oil and Gas Separator
Vent or Flare Line
Oil and Gas Gathering Pipeline
Storage Tank
Loading System

As a result of review, it was confirmed that the processing facilities have sufficient capacity to handle the initial design rate. As for storage tank and loading system, except the case for Tembungo oil field where there are no storage facilities for its own, storage capacity of Lauban Terminal is appropriate for the level of present production rate.

The handling capacity of the offshore production facilities is shown below.

Field	Capacity of Offshore Production Facilities (BPD)
Samarang	90,000
Tembungo	20,000

(3) Assessment of the Facilities Capacity for the Predicted Production Scheme

Based upon the review described above, assessment of capacity of the existing production facilities was performed based on the predicted maximum production rate of well fluids for each field except additional well development case.

As a result of the study, it has been confirmed that any bottlenecks on the capacity of the production facilities will not basically occur even if the changes of production rate of associated gas and formation water are considered, because the oil production rates from each field will decline gradually and predicted maximum production rate of oil plus formation water will not exceed the present production rate as shown below.

	Production Rate as of May, 1976 (BPD)			Predicted Max. Prod. Rate after 1976 (BPD)		
Field	Crude Oil + Formation Water	Crude Oil	Formation Water	Crude Oil + Formation Water (Year)	Crude Oil	Formation Water
Samarang	39,741	39,055	686	38,530('77)	38,230	300
Tembungo	5,294	4,983	311	4,060('77)	3,470	590

Note: The oil production facilities of Fairley Baram are mostly located in Brunei area and the site survey was not performed.

(4) Assessment on Present Production Practices

Related to the evaluation study on the existing oil production facilities including site survey, the study on the following items was performed, although these items have no direct relation to the handling capacity of the production facilities.

- Associated Gas Utilization
- Metering System
- Waste Water Treatment System
- Crude Oil Dehydration System
- Control and Monitoring System

And the item shown below about existing facilities is recommended to be improved.

1) Control and Monitoring System

In offshore operations for Labuan Stream, no monitoring system at the onshore terminal is applied on. It will be worthy to take into consideration the adoption of telemetering system to monitor the operating conditions of offshore facilities to add more safety. This is because nobody can watch offshore facilities at night without the installation of an accommodation platform in addition and it takes time to find out any accident and to reach the location. Efficiency and safety of oil production operation will be improved by the adoption of the system by which working conditions can be monitored at an onshore control room.

3.2 Proposed Facilities

Several alternative cases for the development of the following oil fields in Sabah area have been established including the cases for single field development and for the combined development of two fields. Conceptual design for the alternative cases has been carried out in accordance with the production performance predicted in Part A. As a result of the conceptual design, flow diagrams, facilities layouts and so on have been prepared.

- Erb West and South Furious fields (crude oil)

(1) Field Development Scheme

1) Erb West Field (crude oil)

The combined development scheme of Erb West and South Furious was included in the established alternative schemes. However, the scheme for Erb West single field development with the connection to the existing Labuan Terminal has been selected from the economic viewpoint. Even this scheme has the economic problem mainly due to short production life against the required investment cost.
The maximum production rate is predicted as 20,000 BPD.

The facilities mainly consist of well and production platforms, accommodation platform and submarine pipelines.

PART C COST ESTIMATE AND ECONOMIC ANALYSIS

1. COST ESTIMATE

1.1 General Cost Estimate Bases

1.1.1 Basic Cost Data

Cost data on materials and services, which are required for the estimate of cost for drilling, facilities construction and operation and maintenance, have been collected and tabulated as the values as of middle of 1976.

The following basic cost data tables and figures have been prepared;

- Basic cost data for wells and facilities cost -

Development wells .... Fig. 31-6-1
Offshore structures .... Table 29-6-1 to 29-6-10
Submarine pipelines .... Table 29-6-11, 29-6-12
Oil production equipment .... Table 29-6-14
Other production equipment .. Table 29-6-15
Offshore storage barge ...... Table 29-6-16
Onshore support facilities .. Table 29-6-17

- Basic cost data for operating cost -

Operating personnel .... Table 29-6-18
Chemicals .... Table 29-6-19
Service contractors .... Table 29-6-20

Computation for cost estimation has been performed in the currency of U.S. dollars, and then the results are converted into Malaysian dollars (M$) with the shown exchange rate.

U.S.$1 = M$2.54

1.1.2 Estimate of Other Cost Items

The following items of capital investment cost and operating cost have been computed in accordance with the following formulas using some of the above-mentioned basic cost data:

<u>Capital Investment Cost</u>

Engineering Fee (C_1)	:	10% of ($C_2 + C_3$)
Pre-start-up Expenses	:	1% of ($C_1 + C_2 + C_3$)
Contingency	:	10% of ($C_1 + C_2 + C_3$)

<u>Annual Operating Cost</u>

Operation Management (C_4)	:	10% of C_5
Repair and Maintenance		
Pipelines	:	0.1% of C_6
Others	:	2% of ($C_7 + C_8$) (in case of onshore storage)
		3% of ($C_7 + C_8$) (in case of offshore storage)
Operating Supplies	:	0.3% of ($C_6 + C_7 + C_8$)
Indirect Personnel	:	50% of ($C_4 + C_5$)

Insurance

Pipelines	:	0.5% of C_6
Others	:	1.5% of $(C_7 + C_8)$

where,

C_1: Engineering Fee

C_2: Development Well Cost from Basic Cost Data

C_3: Facilities Cost from Basic Cost Data

C_4: Operation Management Cost

C_5: Operation Personnel Cost from Basic Cost Data

C_6: Pipeline Cost including Miscellaneous Cost

C_7: Development Well Cost including Miscellaneous Cost

C_8: Facilities Cost except Pipeline Cost including Miscellaneous Cost.

Note: Miscellaneous costs include engineering, pre-start-up expenses and contingency.

1.1.3 Estimate of Past Investment

Only exploration wells cost has been counted in capital investment and other past investment is not included in this study.

1.1.4 Estimate of Annual Operating Cost

Annual operating costs for each field have been counted only for its oil or gas production life span when two or more fields are produced in the combined production system.

1.2 Cost Estimate

1.2.1 Erb West and South Furious Oil Fields

(1) Bases of Cost Estimate

Capital investment cost and operating cost for Erb West and South Furious fields have been estimated based upon the basic data and methods of cost estimation which are discribed in 1.1, taking into consideration the following:

- It is assumed that all existing facilities at Labuan Terminal will be utilized for not only Samarang field but also Erb West and/or South Furious fields in common.
- Operating organization for all existing facilities at Labuan Terminal as well as offshore facilities for the objective fields is tentatively assumed as shown in Fig. 31-6-2. Based upon the above tentative operating organization, operating personnel costs have been estimated.
- It is difficult to estimate and allocate the operating costs related to the existing facilities which will be commonly used for Samarang field and new fields. Therefore at this time the allocation is simply made based on the ratio of initial

production rate of new fields to that of Samarang field in the same year. Existing Labuan Terminal costs as the base of the above calculation are assumed as US$20,000,000 at the value in 1976. The costs allocated in this manner are repairs and maintenance cost, operating supplies and insurance.

(2) Capital Cost Estimate

Capital investment costs for the development of Erb West and South Furious oil fields are summarized in Table 9-6-1. Total amount becomes the following;

Case I	M$406,314,000
Case IIA	M$261,872,000
Case IIB	M$272,234,000

(3) Annual Operating Cost Estimate

Annual operating costs for the production facilities in Erb West and South Furious oil fields are summarized in Tables 9-6-2, 9-6-3 and 9-6-4.

(4) Project and Investment Schedules

The project schedule for Case IIA on the development of Erb West and South Furious oil fields has been made as shown in Fig. 9-6-1, based upon the following conditions for availability of construction equipment.

Tender Assisted Drilling Rig 1

Derrick Barge (500 ton) 1

Lay Barge (up to 12" ϕ) 1

Subsequently based upon the above project schedule, the investment schedule has been prepared as shown in Table 9-6-6. For reference, the investment schedules for other cases are shown in Table 9-6-5 and Table 9-6-7.

2. ECONOMIC ANALYSIS

2.1 General Economic Analysis Bases

2.1.1 Oil

(1) Method of Economic Analysis

Necessary items and formulas for the calculation of profitability of both Petronas and Operating Company in accordance with PS Agreements are shown in Appendix II.

(2) Profitability Yardsticks

The following profitability yardsticks are used for profitability analysis and for comparison of alternative schemes which are settled at conceptual design phase;

- Cumulative Net Cash Flow
- DCF ROR
- Cumulative Present Worth
- Payout Time

(3) Production Schedule

Annual oil production is obtained from calendar days (365) multiplied by daily oil production which has been estimated in Part A. Table 30-6-1 shows annual oil production for each field. Starting time of production is to be at the completion of all of the drilling and installation of facilities.

(4) Oil Sales Price

The method to establish oil sales price has been presented from downstream team as follows;

1) As for the oil, of which the actual price at the middle of 1976 is known, the following actual prices are to be adopted.

Labuan Crude	M$31.88 (US$12.55)/BBL
Miri Crude	M$32.00 (US$12.60)/BBL

2) As for the oil, of which the actual price at that time does not exist or can not be obtained, the price is to be established by making adjustment for API premium based on the price of the above-mentioned crudes or actual price of other oils.

The method to adjust oil price for API premium of each oil is to be made as follows;

a. As for the oil exceeding API 40.3°, M¢7.62 (US¢3)/°API is to be added to the standard price, M$32.00 (US$12.60)/BBL.

b. As for the oil under API 36.4°, M¢7.62 (US¢3)/°API is to be reduced from the standard price M$31.88 (US$12.55)/BBL.

c. As for the oil between API 36.4° and 40.3°, price is to be established in proportion calculation based on the above standard price.

And as for the oil produced from several combined fields, establishment of sales price is to be made by calculating the weighted average of oil production per year from each field. The prices established by this method are shown in Table 30-6-1, with oil production per year from each field.

(5) Investment Schedule

Capital investment schedules based on alternative schemes are shown in Table 31-6-1.

(6) Annual Operating Costs

Annual operating costs based on alternative schemes are shown in Table 31-6-2.

(7) Common Input Data

Common input data for economic analysis to all cases of alternative schemes are as follows;

• Royalty Rate		10%
• Maximum Cost Recovery Ratio - Oil		20%
(Gas		25%)
• Profit Oil Share	Petronas	70%
	Operating Company	30%
• Rate of Payment for Research Fund		0.5%
• Initial Basic Price (at 1976 Base)		M$32.31 (US$12.72)/BBL
• Rate of Increase for Basic Price		5%/year
• Rate of Payment for Profit Oil above Basic Price		70%
• Production Bonus above 50,000 BPD		M$5,000,000
• Discovery Bonus*		M$2,500,000
• Income Tax Rate		45%
• Discount Rate		5%, 10%, 15%

Note: * It is assumed that the value of M$2,500,000 as discovery bonus is applied to even combined production fields case.

2.2 Profitability Analysis on Oil

The production rate and the production life of each field have important effect upon its profitability. As the result of analysis, it can be said that more advantageous case by comparison of investment cost based on the same production rate is not always advantageous for Operating Company in view of profitability when operating costs are not the same. In the various cases selected in the conceptual design phase, included are the cases for developing fields as a group by combining them or for developing them individually and also the alternative cases for developing the same field or the same group of fields by onshore storage and loading. In this part C.2.2, a comparative study on the results of profitability analysis of each case and selection of a more profitable case in view of profitability are made for the above alternatives taking into consideration technical viewpoints. Detailed explanation of the facilities is made for the case(s) selected considering these results in Part B.2. And as for the selection standard of the alternative cases in the conceptual design, we adopted the value of DCF ROR of the year when that of the Operating Company is the largest, because the case of the largest oil production is most profitable for Petronas at all times, which cannot be the selection standard.

In this area the following three cases for Erb West and South Furious oil fields have been selected as alternative schemes, and the profitability analysis for each case has been carried out.

2.2.1 Erb West and South Furious Oil Fields

Case I : Erb West and South Furious, Labuan Terminal Case

Case IIA: Erb West, Labuan Terminal Case

Case IIB: Erb West, Mangalum Terminal Case

Each of the profitability yardsticks obtained for each case is shown in Table 31-6-6. Cash Flow Tables for Petronas and Operating Company are shown in Tables 9-6-8, 9 and 10. Profitability of Operating Company in each case selected as alternative is extremely bad. Descriptions for each case are as follows;

Case I: South Furious field is located far way from Labuan Island. Therefore, capital investment cost becomes high. Oil production rate is lower and production life is shorter in this field compared with Erb West Field. In this case Operating Company will not be able to recover the investment cost even at the time of project end and the cash flow conditions for Operating Company are very bad.

Case IIA: Erb West field is also located far away from Labuan Island. However, as produced oil can be transported to the existing Labuan Terminal by laying a submarine pipeline, capital investment cost of onshore oil terminal is not necessary as in Case I. The profit will become a peak in the eighth year after the project start (in the fifth year after the production start) as shown in Cash Flow Table for Operating Company. Maximum DCF ROR in this year is 1.31%.

Case IIB: Mangalum Island is located near Erb West field. However, as a new onshore oil terminal must be installed, capital investment cost is high. The profit will become a peak in the eighth year after the project start (in the fifth year after the production start) as shown in Cash Flow Table for Operating Company. Maximum DCF ROR is 0.23% in this year.

Common to above three cases, profitability of Operating Company is extremely bad. However, Case IIA will be more profitable than other cases from a viewpoint of comparison.

2.3 Sensitivity Analysis

The sensitivity analysis has been carried out on the profitability yardstick for the optimum case of the production schemes as described in Part B.2 and the sensitivity curve is shown in Fig. 31-6-7. The result of sensitivity analysis is as follows;

2.3.1 Erb West and South Furious Oil Fields (Case IIA)

Sales Price Change	0%	10%	20%
DCF ROR (%)	1.31	4.38	7.22

Investment Change	-20%	-10%	0%
DCF ROR (%)	7.24	4.06	1.31

For this case, sensitivity analysis for the value of factors to increase profits has been carried out due to unfavorable profitability analysis results obtained in the previous section.

3. CONCLUSIONS AND RECOMMENDATIONS

3.1 Cost Estimate

Capital investment and annual operating cost have been estimated for each of the alternative cases for which the conceptual design of production facilities of the oil fields has been performed. As a result, capital investment schedules have been prepared to be used as basic data for subsequent economic analysis.

The capital investment cost estimate has been performed for the drilling of production wells, offshore platforms, submarine pipelines, oil and gas processing equipment, onshore storage and loading facilities, support facilities, etc. The operating cost has been estimated for operating personnel, chemicals, service contractors, repair and maintenance, insurance and so on required for the field operation of the above-mentioned facilities.

Estimated capital investment cost in each case is summarized and shown below with design capacity of the production faiclities.

Erb West and South Furious group (crude oil)

Case I	36,000 BPD	M$ 406,314,000
Case IIA	20,000 BPD	M$ 261,872,000
Case IIB	20,000 BPD	M$ 272,234,000

3.2 Economic Analysis

The economic analysis has been performed regarding various production schemes for oil fields selected in the conceptual design phase. Regarding oil, the profitability of each production scheme is analyzed based on Production Sharing Agreements in Malaysia from the standpoint of Petronas and Operating Company respectively. Sales price of crude was given by the down-stream team of the Master Plan study.

Consequently, the following has been selected as more profitable case:

Erb West single field development case with the use of the existing Labuan Terminal. This case, however, has the problem on profitability.

The summary of the results is shown below. For the cases of crude oil the indicated figures belong to the year when the profitability indexes become maximum.

- Crude Oil -

	Petronas		Operating Company	
Name of Field	Cumulative Net Cash Flow (M$ 1,000)	DCF ROR (%)	Cumulative Net Cash Flow (M$ 1,000)	Payout Time (Year)
Erb West	297,213	1.31	13,964	7.7

TABLE

TABLE

TABLE LIST VOL. III SABAH AREA

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Vol. III Table A-1

ORIGINAL HYDROCARBONS IN PLACE - PRODUCING FIELDS OF SABAH

FIELD NAME	BLOCK & ZONE	O.O.I.P. (MMSTB)	O.G.I.P. (MMMSCF)	PRODUCED RESVS. OIL (MMSTB)	PRODUCED RESVS. GAS (MMMSCF)	RECOVERABLE RESVS. OIL (MMSTB)	RECOVERABLE RESVS. GAS (MMMSCF)
SAMARANG	A Zone	137.84	44.04	0.873	0.329	28.319	29.695
	B Zone	72.14	54.61	0.571	0.338	20.131	39.557
	C Zone	116.72	220.47	6.832	8.834	42.485	129.070
	TOTAL	326.70	319.12	8.276	9.051	90.935	198.322
	PROVED RESVS.	326.70	319.12				
TEMBUNGO	MODEL-1	4.63	3.24	1.108	0.499	2.056	1.572
	MODEL-2	3.41	3.19	0.260	0.201	0.865	1.928
	MODEL-3	8.84	4.86	0.883	0.633	2.561	3.004
	MODEL-4	2.36	3.37	0.070	0.229	0.070	0.229
	ADD. WELL	17.47	16.48	0.0	0.0	5.605	14.826
	UNDEVLP. RESVS.	10.20	31.26	0.0	0.0	0.0	0.0
	TOTAL	46.97	62.40	2.321	1.562	11.157	21.559
	PROVED	24.86	49.35				
	PROBABLE RESVS.	22.11	13.05				
GRAND TOTAL	TOTAL	373.67	381.52	10.597	10.613	102.092	219.881
	PROVED RESVS.	351.56	368.47				
	PROBABLE RESVS.	22.11	13.05				

Vol. III Table A-2

ORIGINAL HYDROCARBONS IN PLACE - DEVELOPMENT FIELDS OF SABAH

FIELD NAME	BLOCK & ZONE	O.O.I.P. (MMSTB)	O.C.G.I.P. (MMMSCF)	O.S.G.I.P. (MMMSCF)	O.H.I.P. (MMCF)	RECOVERABLE RESVS. OIL (MMSTB)	RECOVERABLE RESVS. GAS (MMMSCF)
ERB WEST	a1	0.0	8.39	0.0	6.0		
	a2	0.0	0.0	0.0	6.0		
	a3	0.0	0.0	0.0	2.0		
	a4	0.0	0.0	0.0	2.0		
	a5	0.0	0.22	0.0	0.2		
	a6		0.36	0.0	0.0		
	a7		0.0	0.0	0.5		
	b	9.11	8.76	5.41	0.0		
	c1	0.0	0.0	0.0	285.0		
	c2	169.90	506.70	84.95	0.0		
	TOTAL	179.02	524.44	90.36	301.7	25.122	475.374
	PROVED RESVS.	19.85	291.23				
	PROBABLE RESVS.	159.17	251.21	90.36			
	POSSIBLE RESVS.						
SOUTH FURIOUS	a	4.95	10.88	0.67	0.0		
	b1	7.82	10.98	1.44	0.0		
	b2	15.98	0.42	2.94	0.0		
	c	33.08	10.97	8.50	0.0		
	d	31.84	27.72	10.35	0.0		
	e	6.95	32.48	2.41	0.0		
	f	20.23	13.24	8.13	0.0		
	g	1.69	1.38	0.74	0.0		
	h	0.0	6.72	0.0			
	TOTAL	122.53	114.79	35.18	0.0	22.957	82.389
	PROVED RESVS	122.53	114.79	35.18			
	PROBABLE RESVS.						
	POSSIBLE RESVS.						

Vol. III Table A-3

ORIGINAL HYDROCARBONS IN PLACE - POTENTIAL FIELDS OF SABAH

FIELD NAME	BLOCK & ZONE	O.O.I.P. (MMSTB)	O.C.G.I.P. (MMMSCF)	O.S.G.I.P. (MMMSCF)	O.H.I.P. (MMCF)	RECOVERABLE RESVS. OIL (MMSTB)	RECOVERABLE RESVS. GAS (MMMSCF)
WEST EMERALD	a	14.86	0.94	0.97	0.0		
	b	0.19	0.22	0.04	0.0		
	TOTAL	15.04	1.16	1.01	0.0		
	PROVED RESVS.	7.59	1.16	0.46			
	PROBABLE RESVS.	7.45		0.55			
	POSSIBLE RESVS.						
SAINT JOSEPH	a1	0.0	0.0	0.0	1.94		
	a2	0.0	0.0	0.0	8.09		
	b1	8.04	0.0	1.29	0.88		
	b2 b2	0.0	0.0	0.0	10.96		
	b3	0.0	0.44	0.0	0.0		
	b4	0.81	0.25	0.13	1.18		
	TOTAL	8.85	0.69	1.42	23.05		
	PROVED RESVS.	8.85	0.69	1.42			
	PROBABLE RESVS.						
	POSSIBLE RESVS.						
ERB SOUTH	a	1.97	0.0	0.29	0.0		
	TOTAL	1.97	0.0	0.29	0.0		
	PROBED RESVS.	1.97		0.29			
	PROBABLE RESVS.						
	POSSIBLE RESVS.						

Table 1-2-1 CORRELATION TABLE
Vol. III SAMARANG FIELD

Well No.	1		2		3		4		5		6	
D.F.E.	111		72		72		70		85		85	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top V?	6325	6214										
Top a_1	3795	3684	3847	3775	3962	3890	3696	3528	3571	3485	3718	3445
a_2	4608	4497	-	-	4661	4589	4683	4503	4464	4379	5047	4392
Top b	5361	5250	5479	5407	5379	5307	5573	5392	5417	5332	6197	5231
Top c_1	6161	6050	6304	6232	6183	6111	6505	6322	6185	6100	7420	6175
c_2	6253	6142	6410	6338	6263	6191	6603	6420	6263	6178	7558	6279
c_3	6324	6213	6498	6426	6334	6262	6692	6509	6343	6258	7680	6370
c_4	6410	6299	6600	6528	6424	6352	6786	6603	6436	6351	7809	6466
c_5	6498	6387	6709	6637	6483	6411	6901	7808	6533	6448	7957	6576
Top d	7292	7181	7668	7596	7299	7227	7859	7675	7400	7315	-	-
T.D.	10440	10329	8500	8428	8077	8005	8150	7966	9000	8915	8196	6750

Table 1-2-1 (Continued) CORRELATION TABLE
Vol. III SAMARANG FIELD

Well No.	7		8 (SDTR)		8 (original)		9		10		11	
D.F.E.	85		85		85		85		85		85	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top V?												
Top a_1	3758	3530	3955	3675	3955	3675	3786	3546	3877	3528	3814	3553
a_2	4738	4414	4737	4403	4745	4403	4785	4436	4963	4423	4938	4465
Top b	5697	5299	5773	5385	5901	5364	5719	5274	6011	5229	6052	5347
Top c_1	6659	6186	6570	6138	7150	6278	6646	6110	7090	6043	7071	6200
c_2	6770	6288	6676	6238	7297	6387	6751	6205	7203	6135	7188	6299
c_3	6860	6371	6758	6316	7390	6456	6838	6283	7294	6209	7283	6380
c_4	6958	6461	6856	6410	7523	6558	6931	6367	7404	6297	7383	6465
c_5	7063	6557	6954	6503	7627	6636	7028	6454	7510	6382	7493	6558
Top d	-	-	-	-	-	-	7913	7261	8555	7153	-	-
T.D.	7110	6601	7363	6891	7930	6862	8181	7508	9028	7483	7600	6647

Table 1-2-1 (Continued)
Vol. III

CORRELATION TABL
SAMARANG FIELD

Well No.	12		13		14		15		16		17	
D.F.E.	85		85		85		85		85		85	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top V?												
Top a_1	4016	3498	3967	3458	4014	3587	3966	3577	3662	3436	4114	3579
a_2	5031	4361	5124	4339	4917	4454	4910	4396	4677	4351	5088	4389
Top b	-	-	-	-	5743	5276	5883	5258	5716	5311	6105	5256
Top c_1			7547	6169	-	-	6924	6197	6588	6116	-	-
c_2			7683	6276			7039	6303	6699	6219		
c_3			7801	6369			7132	6388	6789	6303		
c_4			7933	6473			7242	6490	6890	6397		
c_5			8076	6586			7359	6598	7002	6502		
Top d			-	-			-	-	-	-		
T.D.	5407	4687	8300	6763	6057	5590	7537	6762	7218	6705	6265	5953

Table 1-2-1 (Continued) Vol. III

CORRELATION TABLE
SAMARANG FIELD

Well No.	18		19		20		21		22		23	
D.F.E.	85		77		85		77		85		77	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top V?												
Top a_1	3728	3514	3546	3469	3812	3652	3859	3342	3645	3512	3838	3390
a_2	4679	4397	4391	4297	4552	4391	5106	4391	4617	4452	4953	4433
Top b	5642	5318	5373	5234	5438	5277	6074	5306	5454	5254	5761	5237
Top c_1	6402	6046	6402	6226	-	-	7082	6310	6372	6144	-	-
c_2	6505	6145	6513	6333			7188	6416	6475	6245		
c_3	6586	6222	6612	6430			7287	6515	6558	6327		
c_4	6682	6314	6727	6541			7400	6628	6647	6414		
c_5	6779	6407	6853	6663			7519	6747	6746	6513		
Top d	-	-	-	-			-	-	-	-		
T.D.	6974	6594	7090	6891	5785	5624	7751	6979	6900	6663	6060	5536

Table 1-2-1 (Continued) CORRELATION TABLE
Vol. III SAMARANG FIELD

Well No.	24		25		26		27		28		29	
D.F.E.	77		77		77		85 (log)		85		85	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top V?												
Top a_1 a_2	3721 4841	3346 4347	3705 4621	3480 4339	3956 5004	3358 4307	3701 4645	3529 4407	4151 5371	3549 4483	3573 4510	3488 4402
Top b	5806	5292	5535	5211	-	-	-	-	6373	5278	5405	5250
Top c_1 c_2 c_3 c_4 c_5	-	-	-	-					-	-	-	-
Top d												
T.D.	6200	5685	5935	5585	5400	4696	4996	4748	6760	5589	5675	5512

Vol. III Table 1-3-1

PREDICTED PERFORMANCE OF SAMARANG FIELD

PRODUCTION START : Jun.1975
PRODUCTION END : Mar.1995

TIME (YEAR)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Dec.1975	0.68	12.16	12.83	1055	0.004	2.218	2.341	0.009
1976	4.88	37.57	38.93	1034	0.0069	15.934	16.55	0.104
1977	9.15	38.23	47.66	1247	0.0078	29.889	33.95	0.213
1978	12.67	31.56	50.11	1588	0.0117	41.409	52.24	0.348
1979	15.76	28.41	56.60	1992	0.0177	51.473	72.9	0.532
1980	18.31	23.02	52.69	2289	0.0214	59.833	92.13	0.712
1981	20.21	16.87	40.51	2401	0.0213	66.036	106.91	0.843
1982	21.63	12.64	32.32	2557	0.0191	70.651	118.71	0.931
1983	22.77	10.2	28.11	2755	0.0201	74.374	128.97	1.006
1984	23.72	8.57	25.01	2917	0.0214	77.501	138.1	1.073
1985	24.24	4.65	18.57	3994	0.0572	79.201	144.88	1.17
1986	24.68	3.88	16.23	4183	0.0805	80.618	150.8	1.284
1987	24.94	2.4	11.81	4921	0.0023	81.494	155.11	1.286
1988	25.19	2.23	11.29	5063	0.0025	82.309	159.23	1.288
1989	25.43	2.08	10.61	5101	0.0026	83.069	163.11	1.29
1990	25.65	1.94	10.22	5268	0.0014	83.806	166.84	1.291

Vol. III Table 1-3-1 (Continued)

PREDICTED PERFORMANCE OF SAMARANG FIELD

PRODUCTION START : Jun.1975
PRODUCTION END : Mar.1995

TIME (YEAR)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	GAS (MMMSCF)	WATER (MMSTB)
1991	25.84	1.79	9.49	5302	0.0031	84.43	170.3	1.293
1992	26.13	1.67	8.96	6365	0.0016	85.38	173.57	1.296
1993	26.21	1.58	8.67	5487	0.0035	85.613	176.73	1.296
1994	26.37	1.50	8.24	5493	0.0018	86.16	179.74	1.297
Mar.1995	26.41	1.45	8.21	5662	0.0027	86.293	180.49	1.297

Vol. III Table 1-3-2

PREDICTED PERFORMANCE OF A ZONE,

SAMARANG FIELD

PRODUCTION START : Jun. 1975
PRODUCTION END : Dec. 1984

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION		
							OIL (MMSTB)	GAS (MMMSCF)	WATER (MMSTB)
Jun.1976	1939	0.63	5.38	1.43	285	0.02	0.873	0.249	0.021
Dec.1976	1824	2.15	11.47	3.27	285	0.02	2.966	0.845	0.069
1977	1698	5.19	11.47	3.35	292	0.01	7.151	2.066	0.122
1978	1542	8.22	11.47	7.04	614	0.02	11.337	4.635	0.187
1979	1285	11.26	11.47	17.00	1482	0.03	15.522	10.284	0.295
1980	1015	14.25	11.30	15.75	1394	0.03	19.646	16.588	0.408
1981	809	16.62	8.96	13.80	1540	0.03	22.916	21.623	0.494
1982	684	18.35	6.53	9.81	1503	0.02	25.299	25.205	0.546
1983	586	19.61	4.73	7.04	1488	0.02	27.027	27.774	0.587
1984	507	20.54	3.54	5.26	1485	0.03	28.318	29.693	0.62

Vol. III Table 1-3-3

PREDICTED PERFORMANCE OF B ZONE,

SAMARANG FIELD

PRODUCTION START : Aug. 1975
PRODUCTION END : Sep. 1986

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Jun.1976	2324	0.79	2.20	1.37	623	0.01	0.571	0.357	0.005
Dec.1976	2247	2.71	7.59	4.96	653	0.01	1.957	1.262	0.024
1977	2074	6.55	7.59	6.88	907	0.02	4.728	3.774	0.074
1978	1855	10.40	7.59	10.74	1415	0.02	7.500	7.693	0.138
1979	1604	14.21	7.54	13.86	1839	0.03	10.251	12.753	0.210
1980	1386	17.10	5.72	13.04	2279	0.03	12.338	17.512	0.273
1981	1237	18.92	3.59	9.52	2651	0.03	13.649	20.986	0.316
1982	1121	20.18	2.48	7.18	2895	0.04	14.556	23.607	0.349
1983	1028	21.28	2.18	6.45	2960	0.04	15.350	25.962	0.380
1984	942	22.29	2.00	5.88	2938	0.04	16.081	28.107	0.412
1985	861	23.23	1.86	5.37	2887	0.14	16.760	30.067	0.507
Sep.1986	805	23.89	1.73	4.94	2857	0.24	17.233	31.420	0.619

Vol. III Table 1-3-4

PREDICTED PERFORMANCE C ZONE,

SAMARANG FIELD

PRODUCTION START : Jun. 1975
PRODUCTION END : Mar. 1995

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	GAS (MMMSCF)	WATER (MMSTB)
Jun.1976	2589	5.85	24.18	36.36	1303	0.0	6.832	8.503	0.008
Dec.1976	2507	9.43	22.90	32.57	1422	0.0	11.011	14.447	0.011
1977	2327	15.43	19.18	37.44	1952	0.0	18.010	28.111	0.017
1978	2179	19.34	12.50	32.34	2587	0.0	22.572	39.915	0.023
1979	2055	22.02	8.57	27.26	3181	0.0	25.700	49.866	0.027
1980	1956	23.90	6.01	21.89	3642	0.0	27.894	57.855	0.031
1981	1880	25.25	4.32	17.11	3961	0.0	29.471	64.100	0.033
1982	1809	26.38	3.63	15.33	4224	0.0	30.796	69.696	0.036
1983	1738	27.41	3.29	14.62	4445	0.0	31.997	75.034	0.039
1984	1674	28.36	3.03	13.88	4580	0.0	33.102	80.099	0.041
1985	1619	29.23	2.80	13.20	4713	0.0	34.123	84.916	0.043
1986	1564	30.04	2.59	12.53	4837	0.0	35.067	89.489	0.045
1987	1510	30.79	2.40	11.81	4920	0.0	35.943	93.799	0.047
1988	1456	31.49	2.23	11.29	5064	0.0	36.757	97.921	0.049
1989	1404	32.14	2.08	10.61	5100	0.0	37.518	101.793	0.051
1990	1361	32.75	1.94	10.22	5266	0.0	38.225	105.522	0.052
1991	1321	33.31	1.79	9.49	5302	0.0	38.879	108.986	0.054
1992	1281	33.83	1.67	8.96	5368	0.0	39.487	112.258	0.055
1993	1240	34.32	1.58	8.66	5483	0.0	40.062	115.420	0.057
1994	1201	34.79	1.50	8.24	5492	0.0	40.609	118.427	0.058
Mar.1995	1191	34.91	1.46	8.21	5622	0.0	40.742	119.176	0.058

Vol. III TABLE 1-3-5

PREDICTED PERFORMANCE OF SAMARANG FIELD

- ADDITIONAL WELL CASE -

PRODUCTION START : Jun.1975

PRODUCTION END : Mar.1995

TIME	RECOVERY	OIL PROD. RATE	GAS PROD. RATE	G.O.R.	W.O.R.	CUMULATIVE PRODUCTION		
						OIL	GAS	WATER
(YEAR)	(%)	(MSTB/D)	(MMSCF/D)	(SCF/STB)	(STB/STB)	(MMSTB)	(MMMSCF)	(MMSTB)
Dec.1975	0.68	12.16	12.83	1055	0.004	2.218	2.341	0.009
1976	5.59	44.03	45.10	1024	0.008	18.287	18.802	0.129
1977	11.03	48.65	65.92	1355	0.010	36.043	42.863	0.310
1978	15.34	38.53	73.04	1916	0.016	50.108	69.814	0.540
1979	18.45	27.88	64.87	2327	0.021	60.284	93.493	0.753
1980	20.78	20.82	50.73	2436	0.022	67.885	112.010	0.923
1981	22.51	15.45	39.66	2567	0.042	73.524	126.486	1.158
1982	23.85	12.00	33.17	2765	0.089	77.904	138.595	1.546
1983	24.73	7.10	25.96	3287	0.122	80.787	148.070	1.899
1984	25.31	5.19	20.78	4007	0.163	82.680	155.657	2.209
1985	25.78	4.25	18.10	4255	0.143	84.232	162.262	2.431
1986	26.08	2.68	13.47	5035	0.002	85.209	167.180	2.434
1987	26.36	2.46	12.59	5112	0.002	86.108	171.775	2.436
1988	26.61	2.26	11.94	5294	0.002	86.931	176.132	2.438
1989	26.84	2.06	10.90	5497	0.002	87.682	180.112	2.439
1990	27.05	1.91	10.49	5497	0.003	88.379	183.940	2.441

Vol. III TABLE 1-3-5 (CONTINUED)

PREDICTED PERFORMANCE OF SAMARANG FIELD

- ADDITIONAL WELL CASE -

TIME (YEAR)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
1991	27.25	1.80	9.88	5297	0.003	89.034	187.545	2.443
1992	27.44	1.70	9.61	5644	0.003	89.654	191.051	2.445
1993	27.62	1.61	9.11	5677	0.003	90.239	193.378	2.446
1994	27.79	1.53	8.68	5673	0.002	90.798	197.547	2.448
1995	27.83	1.50	8.49	6672	0.002	90.935	198.322	2.448

Table 2-2-1 CORRELATION TABLE
Vol. III TEMBUNGO FIELD

Well No.	1		2		3		4		5		A-1	
D.F.E.	31		31		31		31		31		94	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top Cycle VII?	2022	1991	2712	2681	3225	3194	2864	2833	1705	1674	2117	2019
Cycle VI?	4066	4035	5038	5077	4311	4280	5890	5859	3974	3943	3828	3725
Top a	5766	5735							5354	5323		
Top b_1	5915	5884			6310	6279	7614	7583	5626	5595	5612	5326
b_2	6055	6024			6411	6380	7679	7648	5666	5635	5689	5389
Top c_1	9096	6065	6730	6699	6510	6479	7803	7772	5771	5740	5801	5492
c_2	6216	6185	6922	6891	6639	6608	7880	7849	5880	5849	5948	5625
Top d	6294	6263	7033	7002			8013	7982	6057	6026	6046	5713
T.D.	7458	7427	7670	7639	7508	7277	8784	8753	6615	6584	6518	6134

Table 2-2-1 (Continued)
Vol. III

CORRELATION TABLE
TEMBUNGO FIELD

Well No.	A-2A		A-2		A-3		A-4		A-5		A-7	
D.F.E.	94		94		94		94		94		94	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top Cycle VII?	2210	1996	2210	1996	2043	1902	2122	2022	2246	2067	2084	1918
Cycle VI?	5293	3787	5172	3767	6761	4839	3686	3467	5973	4167	4026	3460
Top a					-	-	5638	5214	8684	5664	6144	5150
Top b_1	7858	5223	7290	4904			5913	5454	9053	5888	6405	5372
b_2			5470	4998			6020	5521	9172	5962	6476	5434
Top c_1			7700	5113			6150	5662	9308	6045	6612	5551
c_2			8017	5287			6275	5768			6802	5717
Top d			8143	5358			6424	5896			6870	5776
T.D.	8219	5421	9482	6083	9523	6523	6600	6047	9733	6290	7131	6002

Vol. III Table 2-3-1

PREDICTED PERFORMANCE OF TEMBUNGO FIELD

PRODUCTION START : Oct. 1974
PRODUCTION END : Sep. 1982

TIME (YEAR)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Dec.1974	1.14	2.4	1.31	558	0.0	0.219	0.12	0.0
1975	8.12	3.68	2.41	655	0.03	1.561	0.999	0.038
1976	16.27	4.30	3.90	907	0.06	3.129	2.424	0.131
1977	22.50	3.47	4.76	1372	0.17	4.397	4.163	0.347
1978	27.03	2.39	3.65	1527	0.27	5.199	5.497	0.579
1979	28.06	0.54	1.23	2278	0.52	5.397	5.945	0.682
1980	28.42	0.19	0.79	4158	1.07	5.465	6.232	0.756
1981	28.70	0.15	0.80	5333	1.13	5.519	6.525	0.818
Sep.1982	28.86	0.07	0.43	6143	1.73	5.551	6.733	0.877

Vol. III Table 2-3-2

PREDICTED PERFORMANCE OF MODEL-1,

TEMBUNGO FIELD

PRODUCTION START : Oct. 1974
PRODUCTION END : Jun. 1978

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Jun.1976	1774	23.92	1.68	0.75	463	0.01	1.108	0.490	0.006
Dec.1976	1586	30.54	1.68	0.95	565	0.02	1.414	0.663	0.011
1977	1190	40.88	1.31	1.67	1275	0.04	1.893	1.273	0.030
Jun.1978	1018	44.40	0.89	1.64	1843	0.06	2.056	1.572	0.039

Vol. III Table 2-3-3

PREDICTED PERFORMANCE OF MODEL 2,

TEMBUNGO FIELD

PRODUCTION START : May 1975
PRODUCTION END : Sep.1982

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Jun.1976	2136	7.62	0.61	0.63	1085	0.19	0.26	0.210	0.053
Dec.1976	1987	10.48	0.53	0.66	1241	0.31	0.357	0.330	0.083
1977	1742	14.97	0.42	0.72	1722	0.42	0.510	0.594	0.147
1978	1504	18.33	0.32	0.74	2312	0.65	0.625	0.864	0.223
1979	1334	20.86	0.24	0.76	3151	0.67	0.711	1.14	0.282
1980	1125	22.86	0.19	0.79	4138	1.07	0.779	1.427	0.356
1981	972	24.44	0.15	0.80	5352	1.13	0.833	1.72	0.418
Sep.1982	842	25.39	0.12	0.76	6332	1.80	0.865	1.928	0.477

Vol. III Table 2-3-4

PREDICTED PERFORMANCE OF MODEL-3,

TEMBUNGO FIELD

PRODUCTION START : Mar. 1975
PRODUCTION END : Mar. 1979

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION		
							OIL (MMSTB)	GAS (MMMSCF)	WATER (MMSTB)
Jun.1976	2147	10.00	2.34	2.49	1064	0.0	0.883	0.775	0.0
Dec.1976	1847	14.59	2.22	2.34	1054	0.08	1.289	1.202	0.034
1977	1330	21.78	1.74	2.37	1362	0.22	1.924	2.067	0.167
1978	910	27.72	1.44	2.10	1458	0.28	2.449	2.832	0.313
Mar.1979	805	28.99	1.23	1.88	1528	0.40	2.561	3.004	0.358

Vol. III Table 2-3-5

PREDICTED PERFORMANCE OF MODEL-4,

TEMBUNGO FIELD

PRODUCTION START : Nov. 1974
PRODUCTION END : Mar. 1975

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Mar.1975	2142	3.00	0.22	1.24	5227	0.34	0.069	0.229	0.003
1	1591	6.31	0.22	1.82	8269	1.30	0.149	0.893	0.107
1.5	1093	8.05	0.22	4.43	20125	2.81	0.190	1.701	0.220

Vol. III TABLE 2-3-6

PREDICTED PERFORMANCE OF TEMBUNGO FIELD

- ADDITIONAL WELL CASE - TOTAL

TIME (YEAR)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
1.0	15.75	7.54	6.53	866	0.086	2.751	2.383	0.236
2.0	26.18	4.99	10.87	2177	0.143	4.575	6.350	0.497
3.0	29.52	1.60	10.47	6536	0.247	5.159	10.172	0.644
4.0	31.06	0.73	6.53	8940	0.369	5.427	12.554	0.740
5.0	32.08	0.49	6.23	12714	0.635	5.605	14.826	0.853

Vol. III TABLE 2-3-7

PREDICTED PERFORMANCE OF TEMBUNGO FIELD

- ADDITIONAL WELL CASE - WELL TM AD-1

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
1.00	2957	16.33	1.00	1.07	1071	0.044	0.365	0.391	0.016
2.00	2176	31.01	0.90	3.71	4119	0.110	0.693	1.744	0.052
2.75	1465	36.29	0.43	5.91	13737	0.425	0.811	3.361	0.102

Vol. III TABLE 2-3-8

PREDICTED PERFORMANCE OF TEMBUNGO FIELD

- ADDITIONAL WELL CASE - WELL TM AD-2

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MMSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
1.00	1844	15.47	0.90	0.92	1017	0.192	0.330	0.334	0.063
2.00	1024	24.42	0.53	0.96	1804	0.352	0.522	0.683	0.131
2.25	893	26.02	0.37	0.82	2221	0.444	0.556	0.758	0.146

Vol. III TABLE 2-3-9

PREDICTED PERFORMANCE OF TEMBUNGO FIELD

- ADDITIONAL WELL CASE WELL TM AD-3

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
1.0	1409	17.26	2.67	1.94	727	0.11	0.975	0.707	0.112
2.0	868	27.26	1.55	1.83	1179	0.16	1.541	1.374	0.205

Vol. III TABLE 2-3-10

PREDICTED PERFORMANCE OF TEMBUNGO FIELD

- ADDITIONAL WELL CASE - WELL TM AD-4

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
1.00	2415	14.52	2.96	2.61	880	0.042	1.081	0.951	0.045
2.00	2018	24.42	2.02	4.38	2166	0.085	1.819	2.548	0.108
3.00	1613	30.22	1.18	5.84	4945	0.186	2.251	4.678	0.188
4.00	1208	33.82	0.73	6.53	8940	0.368	2.519	7.060	0.286
5.00	837	36.21	0.49	6.23	12709	0.637	2.697	9.333	0.400

Table 3-2-1 CORRELATION TABLE
Vol. III ERB WEST FIELD

Well No.	1		2		3		4	
D.F.E.	112		112		111		112	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top Upper V	3795	3683	3493	3381	3308	3197	3853	3736
Top a_1	3795	3683	3493	3381	3308	3197	3853	3736
a_2	3942	3830	3846	3734	3648	3537	4253	4119
a_3	4091	3979	3991	3879	3782	3670	4414	4272
a_4	4298	4186	4192	4080	3960	3849	4644	4492
a_5	4459	4347	4335	4223	4132	4021	4817	4657
a_6	4664	4552	4547	4435	4371	4260	5041	4871
a_7	5005	4893	4882	4770	4615	4504	5336	5152
Top b	5192	5080	-	-	4901	4790	5650	5452
Top c_1	6462	6350	6285	6173	6601	6490	7099	6827
c_2	6550	6438	6385	6273	6755	6644	7162	6886
Top d	7772	7660						
T.D.	8015	7903	8775	8663	8531	8420	7878	7557

RESERVOIR DATA

FIELD NAME; ERB WEST RESERVOIR NAME;

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.048	0.	1.191258	1.3900	0.01209
200.	1.050	33.	0.080132	1.2900	0.01230
400.	1.060	65.	0.040746	1.2100	0.01252
600.	1.069	98.	0.026989	1.1400	0.01274
1000.	1.088	163.	0.015826	1.0300	0.01350
1400.	1.107	228.	0.011007	0.9400	0.01436
2000.	1.135	326.	0.007538	0.8400	0.01597
3070.	1.186	500.	0.004939	0.7250	0.01909
3100.	1.186	500.	0.004897	0.7251	0.01919

SL	KG/KO	KRO
0.65	70.0000	0.0668
0.70	26.5000	0.1146
0.75	10.0000	0.1828
0.80	3.0000	0.2761
0.85	1.2000	0.3992
0.90	4.0000	0.5573
0.95	0.1300	0.7557
1.00	0.0200	1.0000

BUBLE POINT PRESSURE (PSIG)	= 3070.0000
INITIAL RESERVOIR PRESSURE (PSIG)	= 3101.0000
EFFECTIVE COMPRESSIBILITY	= 0.0000142
WATER FORMATION VOLUME FACTOR	= 1.0250
IREDUCIBLE WATER SATURATION	= 0.2900
FINAL PRESSURE (PSIG)	= 500.0000
ORIGINAL OIL IN PLACE (MMSTB)	= 169.5115
OIL PRODUCTION RATE (MSTB/D)	= 2.0000
FRACTION OF RESERVOIR GAS AND OIL VOL.	= 2.1984

Vol. III Table 3-3-1

RESERVOIR PARAMETERS

FIELD NAME; ERB WEST RESERVOIR NAME;

NATURAL DEPLETION CASE

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	PRODUCTION RATE OIL (MSTB/D)	PRODUCTION RATE GAS (MMSCF/D)	GAS OIL RATIO (SCF/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	WATER ENCROACH. (MMBBL)
0.50	3066.	2.15	20.00	11.49	611.	3.650	2.098	0.05
1.00	3014.	4.31	20.00	31.97	2244.	7.301	7.932	0.55
1.50	2942.	6.46	20.00	54.57	3587.	10.951	17.892	1.74
2.00	2827.	8.61	20.00	93.15	5958.	14.602	34.895	2.64
2.50	2619.	10.77	20.00	189.93	10935.	18.252	69.561	3.52
3.00	1781.	12.92	20.00	885.56	48602.	21.902	231.192	4.36
3.50	545.	14.82	17.64	1337.83	750144.	25.122	475.374	4.97

Vol. III Table 3-3-2

PREDICTED PERFORMANCE

Table 4-2-1 CORRELATION TABLE
Vol. III SOUTH FURIOUS FIELD

Well No.	1		2		3		4		5		6	
D.F.E.	111		70		75		41		41		41	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top Upper V Lower V	2540? 6635	2429 6524	1680 2826?	1610 2756?	1580 2722?	1505 2647?	1822 3124?	1781 3083?	1170 2206?	1129 2165?	1140 2630?	1099 2589?
Top a			1680	1610	1580	1505	1822	1781	1170	1129	1140	1099
Top b_1 b_2			2065	1995	2120	2045	2590	2549	1258 1870	1217 1829	1534 2290	1493 2249
Top c			2826	2756	2722	2647	3124	3083	2206	2165	2630	2589
Top d			3261	3191	3225	3150	3504	3463	2681	2640	3068	3027
Top e			3707	3637	3837	3762	4014	3973	3153	3112	3497	3456
Top f			4259	4189	4640	4565	4539	4498	3886	3845	4216	4175
Top g			5110	5040	5696	5621	5297	5256	4710	4669	4987	4946
Top h			5872	5802	6456	6381	6044	6003	5620	5579	5990	5949
T.D.	9000	8889	6847	6777	7880	7805	6800	6759	9010	8969	6503	6462

Table 4-2-1 (Continued) CORRELATION TABLE
Vol. III SOUTH FURIOUS FIELD

Well No.	7	
D.F.E.	41	
Cycle/Zone	Log	Subsea
Top Upper V Lower V	2138 4757?	2097 4716?
Top a	2138	2097
Top b_1 b_2	4213	4172
Top c	4757	4716
Top d	5275	5234
Top e	6306	6265
Top f	6709	6668
Top g	7681	7640
Top h	8290	8249
T.D.	9100	9059

RESERVOIR DATA

FIELD NAME; SOUTH FURIOUS RESERVOIR NAME;

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.048	0.	1.185485	1.6600	0.01202
200.	1.066	35.	0.079568	1.5150	0.01225
400.	1.079	70.	0.040367	1.4100	0.01247
600.	1.088	105.	0.026674	1.3200	0.01270
1000.	1.107	175.	0.015556	1.1840	0.01352
1400.	1.124	240.	0.010780	1.0700	0.01445
2000.	1.149	350.	0.007343	0.9200	0.01609
2101.	1.147	350.	0.006971	0.9210	0.01639

SL	KG/KO	KRO
0.65	70.0000	0.0983
0.70	26.5000	0.1561
0.75	6.0000	0.2330
0.80	2.5000	0.3318
0.85	0.9500	0.4552
0.90	0.1380	0.6058
0.95	0.1300	0.7865
1.00	0.0440	1.0000

BUBLE POINT PRESSURE (PSIG)	= 2000.0000
INITIAL RESERVOIR PRESSURE (PSIG)	= 2101.0000
EFFECTIVE COMPRESSIBILITY	= 0.0000167
WATER FORMATION VOLUME FACTOR	= 1.0250
IREDUCIBLE WATER SATURATION	= 0.3500
FINAL PRESSURE (PSIG)	= 500.0000
ORIGINAL OIL IN PLACE (MMSTB)	= 340.0649
OIL PRODUCTION RATE (MSTB/D)	= 4.0000
FRACTION OF RESERVOIR GAS AND OIL VOL.	= 0.0000

Vol. III Table 4-3-1

RESERVOIR PARAMETERS

FIELD NAME: SOUTH FURIOUS   RESERVOIR NAME;

NATURAL DEPLETION CASE

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	PRODUCTION RATE OIL (MSTB/D)	PRODUCTION RATE GAS (MMSCF/D)	GAS OIL RATIO (SCF/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	WATER ENCROACH. (MMBBL)
0.25	1935.	0.54	20.00	32.24	2724.	1.825	2.942	0.0
0.50	1821.	1.07	20.00	57.05	2988.	3.650	8.148	0.0
0.75	1703.	1.61	20.00	62.55	3274.	5.476	13.857	0.0
1.00	1580.	2.15	20.00	68.48	3579.	7.301	20.106	0.0
1.25	1455.	2.68	19.74	73.64	3886.	9.102	26.826	0.0
1.50	1323.	3.18	18.92	76.32	4184.	10.829	33.791	0.0
1.75	1190.	3.66	17.82	76.85	4436.	12.455	40.804	0.0
2.00	1063.	4.11	16.80	76.22	4635.	13.988	47.760	0.0
2.25	947.	4.54	15.90	73.97	4563.	15.439	54.511	0.0
2.50	848.	4.95	15.12	66.57	4244.	16.818	60.586	0.0
2.75	762.	5.33	14.46	59.15	3943.	18.138	65.984	0.0
3.00	687.	5.71	13.90	52.86	3658.	19.406	70.808	0.0
3.25	621.	6.07	13.41	47.07	3373.	20.629	75.103	0.0
3.50	563.	6.41	12.96	42.06	3121.	21.812	78.942	0.0
3.75	511.	6.75	12.54	37.77	2893.	22.957	82.389	0.0

Vol. III   Table 4-3-2
PREDICTED PERFORMANCE

Table 5-2-1 CORRELATION TABLE
Vol. III WEST EMERALD FIELD

Well No.	1		2	
D.F.E.	72		80	
Cycle/Zone	Log	Subsea	Log	Subsea
Top V				
Top a	1250	1178	1120	1040
Top b			4710	4630
T.D.	6523	6451	5400	5320

Table 6-2-1 CORRELATION TABLE
Vol. III ST. JOSEPH FIELD

Well No.	1	
D.F.E.	71	
Cycle/Zone	Log	Subsea
Top Middle V	809	738
Lower V	2321	2250
IV	5546	5475
Top a_1	1741	1670
a_2	1890	1819
Top b_1	2198	2127
b_2	2321	2250
b_3	2396	2325
b_4	2610	2539
T.D.	6928	6857
unconf.	5808	

Table 7-2-1 CORRELATION TABLE
Vol. III ERB SOUTH FIELD

Well No.	1	
D.F.E.	71	
Cycle/Zone	Log	Subsea
Top VI Middle V	2964	2893
Top a	2778	2707
T.D.	4726	4655
unconf.	2965	

Table 8-4-1 (Vol. III) **MAJOR EQUIPMENT SPECIFICATIONS OF PRODUCTION STATION SMP-A**

SEPARATOR

Name & Tag No.	No.	Type	Size	Design Capacity BPD	Pressure Design/ Operation PSIG
HP Separator V-100 & 101	2	Hori.	72"øx20'	30,000	385/250
LP Separator V-200 & 201	2	ditto	72"øx20'	30,000	125/50
Surge Vessel V-300 & 301	2	ditto	126"øx32'	30,000	85/10
Test Separator V-400	1	ditto	60"øx15'		385
Gas Lift Separator V-500	1	ditto	42"øx15'		1,440/950

PUMP

Name & Tag No.	No.	Capacity BPD	Type	Header Suction/ Discharge
Crude Oil Transfer Pump P-801 - 805	5	13,000	Recipro. Gas Expansion Driven	20" 150# ANSI/ 8" 600# ANSI

ELECTRICAL GENERATOR

No.	Type	Voltage volts	Phase	Frequency Hz	Capacity Kw	Speed RPM	Service
1	Gas Expansion Turbine-driven	415	3	50	20	1,500	Lighting, Instr., etc.

Table 8-4-2 (Vol. III) MAJOR EQUIPMENT SPECIFICATIONS OF PRODUCTION STATION SMP-B

SEPARATOR

Name & Tag No.	No.	Type	Size	Design Capacity BPD	Pressure Design/ Operation PSIG
HP Separator V-100	1	Hori.	72"øx20'	30,000	385/250
LP Separator V-200	1	ditto	72"øx20'	30,000	125/50
Surge Vessel V-300	1	ditto	126"øx32'	30,000	85/10
Test Separator V-400	1	N/A	N/A		385

PUMP

Name & Tag No.	No.	Capacity BPD	Type	Header Suction/ Discharge
Crude Oil Transfer Pump P-801 - 802	2	13,000	Recipro. Gas Expansion Driven	20" 150# ANSI/ 8" 600# ANSI

ELECTRICAL GENERATOR

No.	Type	Voltage volts	Phase	Frequency Hz	Capacity Kw	Speed RPM	Service
1	Gas Expansion Turbine-driven	415	3	50	20	1,500	Lighting, Instr., etc.

Table 8-4-3 (Vol. III) MAJOR EQUIPMENT SPECIFICATIONS OF LABUAN TERMINAL

STORAGE TANK

Name & Tag No.	No.	Nominal Capacity BBLS	Size	Type
Crude Oil Storage Tank T-1 - T-3	3	439,000	214'øx72'	Floating Roof

CRUDE OIL LOADING PUMP SYSTEM

Name & Tag No.	No.	Capacity BPH x Head	Type
Crude Oil Loading Pump P-21 - P-23	3	18,000 x 275'	Centrifugal, Diesel Engine Driven

SINGLE BUOY MOORING

Name & Tag No.	No.	Water Depth	Tanker Mooring Capacity, DWT
SBM	1	95'	310,000

SURFACE/FORMATION WATER DRAINAGE SYSTEM

Name & Tag No.	No.	Type
CPI	1	Corrugated Plate Interceptor
Holding Basin	1	Gravity Separation

Table 8-4-3 (Vol. III) **MAJOR EQUIPMENT SPECIFICATIONS OF LABUAN TERMINAL (Cont'd)**

FIRE FIGHTING SYSTEM

Name & Tag No.	No.	Capacity	Type
Firewater Tank T-61	1	35,000 BBLS	Open Top
Fire Fighting Pump P-61 - P-62	2	7,200GPM x 430'	Centrifugal, Diesel Engine Driven

POWER PLANT

Name & Tag No.	No.	Capacity HP	Type
Generator	3	325	Diesel Engine Driven

SEA WATER DISTILLATION UNIT

Name & Tag No.	No.	Output	Type
Aqua-Chem Unit	1 Unit	167 UKGPH	Aqua-Chem/ Type S200 Spec. E

UTILITIES TANK

Name & Tag No.	No.	Capacity	Type
Diesel Fuel Tank T-51 - T-52	2	300 BBLS	Cone Roof
Potable Water Tank V-73	1	6,000 UKGAL.	

Table 8-4-4 (Vol. III) **MAJOR EQUIPMENT SPECIFICATIONS OF TEMBUNGO "A"**

SEPARATOR

Name & Tag No.	No.	Type	Size	Design Capacity BPD/MMSCFD	Pressure Design/ Operating PSIG
Test Separator V-190	1	Hori.	48"øx15'	6,000/	710/ 100-600
Prod. Separator V-200	1	Hori.	72"øx20'	20,000/	710/ 100-600
FWKO & Surge V-250	1	Hori.	144"øx30'	30,000/	50/ ATM.
LP Flare Scrubber V-400	1	Hori.	48"øx10'	20/0.5	50/ ATM.
HP Flare Scrubber V-410	1	Hori.	72"øx15'	20,000/ 15.5	50/ ATM.
Caisson Separator V-535	1	Vert.	30"øx172'		

PUMP

Name & Tag No.	No.	Type	Capacity GPM	Head PSI	Motor Power HP
SPM Oil Pump P-290 & 300	2	Centri. Motor-driven	600	60	40
LP Flare Transfer Pump P-405	1	ditto	80	15	3
HP Flare Transfer Pump P-415	1	ditto	80	15	3
Caisson Oil Pump P-535	1	ditto	40	45	

ELECTRICAL GENERATOR

No.	Type	Capacity	Service
1	Diesel Engine driven	400 kw	Motor Drivers, Lighting, Instrumentation, etc.

Table 9-5-1 (Vol. III)

MAJOR EQUIPMENT LIST

FOR ERB WEST AND SOUTH FURIOUS OIL FIELDS-CASE I

ITEM NO. & NAME	LOCATION	QUANTITY	DESCRIPTION
V - 1 1ST STAGE PRODUCTION SEPARATOR	SFWP-A SFWP-B EWWP-A EWWP-B	1 1 1 1	SIZE: 4'-6" I.D. x 13'-6" S-S DESIGN PRESS.: 300 PSIG @ 150°F TYPE: HORIZONTAL
V - 2 2ND STAGE PRODUCTION SEPARATOR	SFWP-A SFWP-B EWWP-A EWWP-B	1 1 1 1	SIZE: 4'-6" I.D. x 13'-6" S-S DESIGN PRESS.: 100 PSIG @ 150°F TYPE: HORIZONTAL
V - 3 3RD STAGE PRODUCTION SEPARATOR	SFWP-A SFWP-B EWWP-A EWWP-B	1 1 1 1	SIZE: 11'-0" I.D. x 22'0" S-S DESIGN PRESS.: 50 PSIG @ 150°F TYPE: HORIZONTAL
V - 4 TEST SEPARATOR	SFWP-A SFWP-B EWWP-A EWWP-B	1 1 1 1	SIZE: 3'-6" I.D. x 10'-0" S-S DESIGN PRESS.: 300 PSIG @ 150°F TYPE: HORIZONTAL
C - 151 INSTRUMENT AIR COMPRESSOR	SFWP-A SFWP-B EWWP-A EWWP-B	2 2 2 2	CAPACITY: 35 SCFM
P - 2 CRUDE TRANSFER PUMP	SFWP-A SFWP-B	2 2	CAPACITY: 240 GPM TYPE: HORIZONTAL
	EWWP-A EWWP-B	2 2	CAPACITY: 300 GPM TYPE: HORIZONTAL
P - 152 FIRE WATER PUMP	SFWP-A SFWP-B EWWP-A EWWP-B	1 1 1 1	CAPACITY: 1,500 GPM TYPE: VERTICAL
TK - 1 DEEMULSIFIER TANK	SFWP-A SFWP-B EWWP-A EWWP-B	1 1 1 1	SIZE: 6'-0" I.D. x 15'-6" H
TK - 2 DEFOAMANT TANK	SFWP-A SFWP-B EWWP-A EWWP-B	1 1 1 1	SIZE: 6'-0" I.D. x 15'-6" H
TK - 152 DIESEL STORAGE TANK	SFWP-A SFWP-B EWWP-A EWWP-B	1 1 1 1	CAPACITY: 500 BBL SIZE: 15'-6" I.D. x 16'-0" H
M - 1 INLET MANIFOLD	SFWP-A SFWP-B EWWP-A EWWP-B	1 1 1 1	HIGH PRESSURE HEADER LOW PRESSURE HEADER TEST HEADER
G - 151 DIESEL DRIVEN GENERATOR	SFWP-A SFWP-B EWWP-A EWWP-B	2 2 2 2	CAPACITY: 300 KVA
FM - 1 FLOW METER	SFWP-A SFWP-B	1 1	DESIGN RATE: 280 GPM (MAX.)
	EWWP-A EWWP-B	1 1	DESIGN RATE: 350 GPM (MAX.)

Table 9-6-1 (Vol. III) **CAPITAL INVESTMENT COST ESTIMATION**

ERB WEST AND SOUTH FURIOUS OIL FIELDS

(M$ 1,000)

		CASE I	CASE II A	CASE II B
1.	Exploration & Appraisal Wells	63,259	63,259	63,259
2.	Engineering	28,096	16,266	17,115
3.	Development Wells	99,060	57,150	57,150
4.	Facilities			
	a. Offshore Platforms	82,515	50,071	39,733
	b. Offshore Production Equipment	21,864	13,355	7,633
	c. Submarine Pipelines	77,523	42,088	11,054
	d. Offshore Storage & Loading Facilities .	-	-	-
	e. Onshore Terminal & Loading Facilities .	-	-	35,802
	f. Support Facilities	-	-	19,779
	Sub Total	181,902	105,514	114,001
5.	Pre-start up Expense	3,091	1,788	1,883
6.	Contingencies	30,906	17,895	18,826
	TOTAL	406,314	261,872	272,234

ANNUAL OPERATION COST ESTIMATION

Table 9-6-2 (Vol.III) (M$ 1,000)

ERB WEST AND SOUTH FURIOUS OIL FIELDS CASE I

	1	2	3	4	5	6	7	8	9
1. Direct Cost									
a. Operating Personnel					1,801	1,801	1,801	1,801	1,801
b. Operating Management					180	180	180	180	180
c. Repair & Maintenance					5,992	5,992	3,091	3,091	3,091
d. Operating Supplies					1,135	1,135	602	602	602
e. Chemical					1,494	1,494	843	843	650
f. Service Contract					2,972	2,972	2,972	2,972	2,972
Sub Total					13,574	13,574	9,489	9,489	9,296
2. Indirect Cost									
a. Indirect Personnel					991	991	991	991	991
b. Insurance					4,486	4,486	2,525	2,525	2,525
Sub Total					5,477	5,477	3,516	3,516	3,516
TOTAL					19,051	19,051	13,005	13,005	12,812

ANNUAL OPERATION COST ESTIMATION

Table 9-6-3 (Vol.III) (M$ 1,000)

ERB WEST AND SOUTH FURIOUS OIL FIELDS CASE IIA

	1	2	3	4	5	6	7	8
1. Direct Cost								
a. Operating Personnel				1,801	1,801	1,801	1,801	1,801
b. Operating Management				180	180	180	180	180
c. Repair & Maintenance				3,739	3,739	3,739	3,739	3,739
d. Operating Supplies				691	691	691	691	691
e. Chemical				843	843	843	843	650
f. Service Contract				2,083	2,083	2,083	2,083	2,083
Sub Total				9,337	9,337	9,337	9,337	9,144
2. Indirect Cost								
a. Indirect Personnel				991	991	991	991	991
b. Insurance				3,000	3,000	3,000	3,000	3,000
Sub Total				3,991	3,991	3,991	3,991	3,991
TOTAL				13,328	13,328	13,328	13,328	13,135

ANNUAL OPERATION COST ESTIMATION

Table 9-6-4 (Vol.III)

ERB WEST AND SOUTH FURIOUS OIL FIELDS CASE IIB

(M$ 1,000)

	1	2	3	4	5	6	7	8
1. Direct Cost								
a. Operating Personnel				1,801	1,801	1,801	1,801	1,801
b. Operating Management				180	180	180	180	180
c. Repair & Maintenance				3,990	3,990	3,990	3,990	3,990
d. Operating Supplies				622	622	622	622	622
e. Chemical				843	843	843	843	650
f. Service Contract				2,083	2,083	2,083	2,083	2,083
Sub Total				9,519	9,519	9,519	9,519	9,326
2. Indirect Cost								
a. Indirect Personnel				991	991	991	991	991
b. Insurance				3,028	3,028	3,028	3,028	3,028
Sub Total				4,019	4,019	4,019	4,019	4,019
TOTAL				13,538	13,538	13,538	13,538	13,345

Table 9-6-5 (Vol. III) INVESTMENT SCHEDULE

ERB WEST AND SOUTH FURIOUS OIL FIELDS CASE I

(M$ 1,000)

Item \ Year	1ST	2ND	3RD	4TH
1. Exploration & Appraisal Wells	63,259	-	-	-
2. Engineering	28,096	-	-	-
3. Development Wells	-	10,716	42,863	45,481
4. Offshore Platforms	1,481	31,255	40,960	8,819
5. Offshore Production Equipment	780	13,538	5,974	1,572
6. Submarine Pipelines	-	-	43,261	34,262
7. Offshore Storage & Loading Facilities	-	-	-	-
8. Onshore Terminal & Loading Facilities	-	-	-	-
9. Support Facilities	-	-	-	-
10. Pre-start up Expense	304	555	1,331	901
11. Contingencies	3,036	5,551	13,306	9,013
Total	96,956	61,615	147,695	100,048

Table 9-6-6 (Vol. III) INVESTMENT SCHEDULE

ERB WEST AND SOUTH FURIOUS OIL FIELDS CASE II A (M$ 1,000)

Item \ Year	1ST	2ND	3RD	
1. Exploration & Appraisal Wells	63,259	-	-	
2. Engineering	16,266	-	-	
3. Development Wells	-	28,575	28,575	
4. Offshore Platforms	15,019	32,888	2,164	
5. Offshore Production Equipment	4,237	8,194	924	
6. Submarine Pipelines	-	-	42,088	
7. Offshore Storage & Loading Facilities	-	-	-	
8. Onshore Terminal & Loading Facilities	-	-	-	
9. Support Facilities	-	-	-	
10. Pre-start up Expense	355	696	737	
11. Contingencies	3,553	6,967	7,375	
Total	102,689	77,320	81,863	

Table 9-6-7 (Vol. III) **INVESTMENT SCHEDULE**

(M$ 1,000)

ERB WEST AND SOUTH FURIOUS OIL FIELDS CASE II B

Item \ Year	1ST	2ND	3RD	
1. Exploration & Appraisal Wells	63,259	-	-	
2. Engineering	17,115	-	-	
3. Development Wells	-	28,575	28,575	
4. Offshore Platforms	10,884	26,685	2,164	
5. Offshore Production Equipment	2,205	5,146	282	
6. Submarine Pipelines	-	-	11,054	
7. Offshore Storage & Loading Facilities	-	-	-	
8. Onshore Terminal & Loading Facilities	3,975	18,563	13,264	
9. Support Facilities	6,594	13,185	-	
10. Pre-start up Expense	408	922	553	
11. Contingencies	4,077	9,215	5,534	
Total	108,517	102,291	61,426	

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* E C O N O M I C A N A L Y S I S F O R M A L A Y S I A P R O J E C T *

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TABLE 9-6-8 CASH FLOW TABLE FOR OIL ERB WEST AND SOUTH FURIOUS OIL FIELDS

VOL.III CASE I : ERB WEST & SOUTH FURIOUS, LABUAN TERMINAL CASE

* P R E M I S E S *

PRODUCTION LIFE	: 5 YEARS
PRE-STARTUP PERIOD	: 4 YEARS
EQUITY RATIO OF OIL COMPANY	: 100.00 %
INTEREST RATE	: 8.00 %

* B A S I C T E R M S O F P/S A G R E E M E N T S *

ROYALTY RATE	: 10.00 %
MAXIMUM COST RECOVERY RATIO	: 20.00 %
PROFIT OIL SHARE	
PETRONAS	: 70.00 %
OPERATING COMPANY	: 30.00 %
RATE OF PAYMENT FOR RESEARCH FUND	: 0.50 %
INITIAL BASIC PRICE (AT 1976 BASE)	: M$ 32.31 /BBL
RATE OF INCREASE FOR BASIC PRICE	: 5.00 %
RATE OF PAYMENT FOR PROFIT OIL ABOVE BASIC PRICE	: 70.00 %
PRODUCTION BONUS ABOVE 50000BBL/DAY	: M$ 5000000.
DISCOVERY BONUS	: M$ 2500000.
INCOME TAX RATE	: 45.00 %

* INPUT DATA BY YEAR *

TERM	1	2	3	4	5	6	7	8	9	9YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	96956.	61615.	147695.	100048.	0.	0.	0.	0.	0.	406314.
OIL PRODUCTION (M BBL/YEAR)	0.	0.	0.	0.	12932.	12063.	7300.	7300.	5625.	45220.
SALES PRICE OF OIL (M$/BBL)	0.0	0.0	0.0	0.0	31.45	31.45	31.39	31.39	31.39	
BASIC PRICE OF OIL (M$/BBL)	35.62	37.40	39.27	41.24	43.30	45.46	47.74	50.12	52.63	

TABLE 9-6-8 CASH FLOW TABLE FOR OIL ERB WEST AND SOUTH FURIOUS OIL FIELDS

VOL.III CASE I : ERB WEST & SOUTH FURIOUS, LABUAN TERMINAL CASE

** CASH FLOW TABLE FOR PETRONAS **
(X M$ 1000)

(CONT'D)
PAGE 2

TERM	1	2	3	4	5	6	7	8	9	9YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	0.	0.	0.	0.	199289.	185897.	112282.	112282.	86519.	696268.
2 REVENUE FROM OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 BONUS FROM OIL COMPANY	0.	0.	0.	0.	2500.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	0.	2500.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 RESEARCH FUND FROM OIL CO.	0.	0.	0.	0.	834.	778.	470.	470.	362.	2913.
5 TOTAL CASH INFLOW	0.	0.	0.	0.	202622.	186674.	112752.	112752.	86881.	701681.
6 INCOME TAX	0.	0.	0.	0.	91180.	84003.	50738.	50738.	39096.	315756.
7 NET CASH FLOW	0.	0.	0.	0.	111442.	102671.	62013.	62013.	47784.	
8 CUMULATIVE NET CASH FLOW	0.	0.	0.	0.	111442.	214113.	276127.	338140.	385924.	

TABLE 9-6-8 CASH FLOW TABLE FOR OIL ERB WEST AND SOUTH FURIOUS OIL FIELDS

VOL.III CASE I : ERB WEST & SOUTH FURIOUS, LABUAN TERMINAL CASE

* * PRESENT WORTH OF NET CASH FLOW FOR PETRONAS * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9
PRESENT WORTH									
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66
PRESENT WORTH	0.	0.	0.	0.	89475.	78507.	45160.	43010.	31563.
CUMULATIVE PRESENT WORTH	0.	0.	0.	0.	89475.	167981.	213142.	256152.	287715.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44
PRESENT WORTH	0.	0.	0.	0.	72574.	60784.	33376.	30342.	21254.
CUMULATIVE PRESENT WORTH	0.	0.	0.	0.	72574.	133358.	166734.	197076.	218331.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30
PRESENT WORTH	0.	0.	0.	0.	59417.	47600.	25001.	21740.	14566.
CUMULATIVE PRESENT WORTH	0.	0.	0.	0.	59417.	107017.	132018.	153758.	168324.

TABLE 9-6-8 CASH FLOW TABLE FOR OIL ERB WEST AND SOUTH FURIOUS OIL FIELDS
VOL.III CASE I : ERB WEST & SOUTH FURIOUS, LABUAN TERMINAL CASE

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9	9YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	0.	0.	0.	0.	85409.	79670.	48121.	48121.	37079.	298400.
2 SALES REVENUE FROM COST OIL	0.	0.	0.	0.	81342.	75876.	45829.	45829.	35314.	284191.
3 SALES REVENUE FROM ROYALTY OIL	0.	0.	0.	0.	40671.	37938.	22915.	22915.	17657.	142095.
4 TOTAL CASH INFLOW	0.	0.	0.	0.	207423.	193484.	116865.	116865.	90050.	724687.
5 ROYALTY	0.	0.	0.	0.	40671.	37938.	22915.	22915.	17657.	142095.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 BONUS	0.	0.	0.	0.	2500.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	0.	2500.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
8 RESEARCH FUND TO PETRONAS	0.	0.	0.	0.	834.	778.	470.	470.	362.	2913.
OPERATING EXPENSES	0.	0.	0.	0.	81342.	75876.	45829.	45829.	35314.	284191.
(M$/BBL)	0.0	0.0	0.0	0.0	6.29	6.29	6.28	6.28	6.28	6.28
9 OPERATING COST	0.	0.	0.	0.	19051.	19051.	13005.	13005.	12812.	76924.
CAPITAL COST RECOVERY	0.	0.	0.	0.	62291.	56825.	32824.	32824.	22502.	207267.
INCOME BEFORE TAX	0.	0.	0.	0.	82076.	78892.	47651.	47651.	36717.	292987.
10 INCOME TAX	0.	0.	0.	0.	36934.	35502.	21443.	21443.	16523.	131844.
11 CAPITAL INVESTMENT	96956.	61615.	147695.	100048.	0.	0.	0.	0.	0.	406314.
12 TOTAL CASH OUTFLOW	96956.	61615.	147695.	100048.	99990.	93268.	57832.	57832.	47354.	762591.
13 NET CASH FLOW	-96956.	-61615.	-147695.	-100048.	107433.	100216.	59033.	59033.	42696.	
14 CUMULATIVE NET CASH FLOW	-96956.	-158571.	-306266.	-406314.	-298881.	-198665.	-139633.	-80600.	-37904.	
15 DCF ROR OF NET CASH FLOW (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
16 CORPORATE CAPITAL	96956.	61615.	147695.	100048.	0.	0.	0.	0.	0.	406314.
17 INTEREST	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
20 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	0.	

21 PAYOUT TIME 0.0 YEARS

TABLE 9-6-8 CASH FLOW TABLE FOR OIL ERB WEST AND SOUTH FURIOUS OIL FIELDS

VOL.III CASE I : ERB WEST & SOUTH FURIOUS, LABUAN TERMINAL CASE

* * PRESENT WORTH OF NET CASH FLOW FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9
PRESENT WORTH									
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66
PRESENT WORTH	-94619.	-57267.	-130735.	-84343.	86255.	76630.	42990.	40942.	28202.
CUMULATIVE PRESENT WORTH	-94619.	-151886.	-282622.	-366964.	-280709.	-204079.	-161089.	-120147.	-91945.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44
PRESENT WORTH	-92444.	-53407.	-116382.	-71670.	69963.	59331.	31772.	28883.	18991.
CUMULATIVE PRESENT WORTH	-92444.	-145851.	-262232.	-333902.	-263939.	-204608.	-172836.	-143953.	-124962.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30
PRESENT WORTH	-90412.	-49962.	-104141.	-61343.	57279.	46462.	23799.	20695.	13015.
CUMULATIVE PRESENT WORTH	-90412.	-140374.	-244515.	-305858.	-248579.	-202117.	-178318.	-157623.	-144607.

*** E C O N O M I C   A N A L Y S I S   F O R   M A L A Y S I A   P R O J E C T ***

TABLE 9-6-9 CASH FLOW TABLE FOR OIL ERB WEST AND SOUTH FURIOUS OIL FIELDS

VOL.III CASE II A : ERB WEST, LABUAN TERMINAL CASE

* P R E M I S E S *

PRODUCTION LIFE	: 5 YEARS
PRE-STARTUP PERIOD	: 3 YEARS
EQUITY RATIO OF OIL COMPANY	: 100.00 %
INTEREST RATE	: 8.00 %

* B A S I C   T E R M S   O F   P/S   A G R E E M E N T S *

ROYALTY RATE	: 10.00 %
MAXIMUM COST RECOVERY RATIO	: 20.00 %
PROFIT OIL SHARE	
PETRONAS	: 70.00 %
OPERATING COMPANY	: 30.00 %
RATE OF PAYMENT FOR RESEARCH FUND	: 0.50 %
INITIAL BASIC PRICE (AT 1976 BASE)	: M$ 32.31 /BBL
RATE OF INCREASE FOR BASIC PRICE	: 5.00 %
RATE OF PAYMENT FOR PROFIT OIL ABOVE BASIC PRICE	: 70.00 %
PRODUCTION BONUS ABOVE 50000BBL/DAY	: M$ 5000000.
DISCOVERY BONUS	: M$ 2500000.
INCOME TAX RATE	: 45.00 %

* INPUT DATA BY YEAR *

TERM	1	2	3	4	5	6	7	8	8YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	102689.	77320.	81863.	0.	0.	0.	0.	0.	261872.
OIL PRODUCTION (M BBL/YEAR)	0.	0.	0.	7300.	7300.	7300.	7300.	5625.	34825.
SALES PRICE OF OIL (M$/BBL)	0.0	0.0	0.0	31.39	31.39	31.39	31.39	31.39	
BASIC PRICE OF OIL (M$/BBL)	35.62	37.40	39.27	41.24	43.30	45.46	47.74	50.12	

TABLE 9-6-9 CASH FLOW TABLE FOR OIL ERB WEST AND SOUTH FURIOUS OIL FIELDS

VOL.III CASE II A : ERB WEST, LABUAN TERMINAL CASE

(CONT'D)
PAGE 2

* * CASH FLOW TABLE FOR PETRONAS * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	8YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	0.	0.	0.	112282.	112282.	112282.	112282.	86519.	535647.
2 REVENUE FROM OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 BONUS FROM OIL COMPANY	0.	0.	0.	2500.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 RESEARCH FUND FROM OIL CO.	0.	0.	0.	470.	470.	470.	470.	362.	2241.
5 TOTAL CASH INFLOW	0.	0.	0.	115252.	112752.	112752.	112752.	86881.	540388.
6 INCOME TAX	0.	0.	0.	51863.	50738.	50738.	50738.	39096.	243174.
7 NET CASH FLOW	0.	0.	0.	63388.	62013.	62013.	62013.	47784.	
8 CUMULATIVE NET CASH FLOW	0.	0.	0.	63388.	125402.	187415.	249429.	297213.	

TABLE 9-6-9 CASH FLOW TABLE FOR OIL ERB WEST AND SOUTH FURIOUS OIL FIELDS

VOL.III CASE II A : ERB WEST, LABUAN TERMINAL CASE

* * PRESENT WORTH OF NET CASH FLOW FOR PETRONAS * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8
PRESENT WORTH								
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69
PRESENT WORTH	0.	0.	0.	53438.	49789.	47418.	45160.	33141.
CUMULATIVE PRESENT WORTH	0.	0.	0.	53438.	103227.	150645.	195806.	228947.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49
PRESENT WORTH	0.	0.	0.	45408.	40385.	36714.	33376.	23380.
CUMULATIVE PRESENT WORTH	0.	0.	0.	45408.	85793.	122507.	155883.	179263.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35
PRESENT WORTH	0.	0.	0.	38866.	33063.	28751.	25001.	16751.
CUMULATIVE PRESENT WORTH	0.	0.	0.	38866.	71929.	100680.	125680.	142432.

TABLE 9-6-9 CASH FLOW TABLE FOR OIL ERB WEST AND SOUTH FURIOUS OIL FIELDS
VOL.III CASE II A : ERB WEST, LABUAN TERMINAL CASE

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

(CONT'D)
PAGE 4

TERM	1	2	3	4	5	6	7	8	8YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	0.	0.	0.	48121.	48121.	48121.	48121.	37079.	229563.
2 SALES REVENUE FROM COST OIL	0.	0.	0.	45829.	45829.	45829.	45829.	35314.	218631.
3 SALES REVENUE FROM ROYALTY OIL	0.	0.	0.	22915.	22915.	22915.	22915.	17657.	109316.
4 TOTAL CASH INFLOW	0.	0.	0.	116865.	116865.	116865.	116865.	90050.	557510.
5 ROYALTY	0.	0.	0.	22915.	22915.	22915.	22915.	17657.	109316.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.
8 RESEARCH FUND TO PETRONAS	0.	0.	0.	470.	470.	470.	470.	362.	2241.
OPERATING EXPENSES	0.	0.	0.	45829.	45829.	45829.	45829.	35314.	218631.
(M$/BBL)	0.0	0.0	0.0	6.28	6.28	6.28	6.28	6.28	6.28
9 OPERATING COST	0.	0.	0.	13328.	13328.	13328.	13328.	13135.	66447.
CAPITAL COST RECOVERY	0.	0.	0.	32501.	32501.	32501.	32501.	22179.	152184.
INCOME BEFORE TAX	0.	0.	0.	45151.	47651.	47651.	47651.	36717.	224822.
10 INCOME TAX	0.	0.	0.	20318.	21443.	21443.	21443.	16523.	101170.
11 CAPITAL INVESTMENT	102689.	77320.	81863.	0.	0.	0.	0.	0.	261872.
12 TOTAL CASH OUTFLOW	102689.	77320.	81863.	59530.	58155.	58155.	58155.	47677.	543545.
13 NET CASH FLOW	-102689.	-77320.	-81863.	57335.	58710.	58710.	58710.	42373.	
14 CUMULATIVE NET CASH FLOW	-102689.	-180009.	-261872.	-204538.	-145828.	-87119.	-28409.	13964.	
15 DCF ROR OF NET CASH FLOW (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.31	
16 CORPORATE CAPITAL	102689.	77320.	81863.	0.	0.	0.	0.	0.	261872.
17 INTEREST	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	0.	0.
19 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.
20 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	

21 PAYOUT TIME 7.7 YEARS

TABLE 9-6-9 CASH FLOW TABLE FOR OIL ERB WEST AND SOUTH FURIOUS OIL FIELDS

VOL.III CASE II A : ERB WEST, LABUAN TERMINAL CASE

** PRESENT WORTH OF NET CASH FLOW FOR OPERATING COMPANY **
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8
PRESENT WORTH								
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69
PRESENT WORTH	-100214.	-71863.	-72463.	48334.	47137.	44892.	42754.	29388.
CUMULATIVE PRESENT WORTH	-100214.	-172078.	-244540.	-196206.	-149070.	-104178.	-61423.	-32035.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49
PRESENT WORTH	-97910.	-67020.	-64507.	41072.	38233.	34758.	31598.	20732.
CUMULATIVE PRESENT WORTH	-97910.	-164930.	-229437.	-188365.	-150132.	-115374.	-83776.	-63044.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35
PRESENT WORTH	-95758.	-62697.	-57722.	35154.	31302.	27219.	23669.	14855.
CUMULATIVE PRESENT WORTH	-95758.	-158455.	-216177.	-181023.	-149721.	-122502.	-98834.	-83979.

*** E C O N O M I C   A N A L Y S I S   F O R   M A L A Y S I A   P R O J E C T ***

TABLE 9-6-10 CASH FLOW TABLE FOR OIL ERB WEST AND SOUTH FURIOUS OIL FIELDS

VOL.III CASE II B : ERB WEST, MANGALUM TERMINAL CASE

* P R E M I S E S *

PRODUCTION LIFE	: 5 YEARS
PRE-STARTUP PERIOD	: 3 YEARS
EQUITY RATIO OF OIL COMPANY	: 100.00 %
INTEREST RATE	: 8.00 %

* B A S I C   T E R M S   O F   P/S   A G R E E M E N T S *

ROYALTY RATE	: 10.00 %
MAXIMUM COST RECOVERY RATIO	: 20.00 %
PROFIT OIL SHARE	
PETRONAS	: 70.00 %
OPERATING COMPANY	: 30.00 %
RATE OF PAYMENT FOR RESEARCH FUND	: 0.50 %
INITIAL BASIC PRICE (AT 1976 BASE)	: M$ 32.31 /BBL
RATE OF INCREASE FOR BASIC PRICE	: 5.00 %
RATE OF PAYMENT FOR PROFIT OIL ABOVE BASIC PRICE	: 70.00 %
PRODUCTION BONUS ABOVE 50000BBL/DAY	: M$ 5000000.
DISCOVERY BONUS	: M$ 2500000.
INCOME TAX RATE	: 45.00 %

* INPUT DATA BY YEAR *

TERM	1	2	3	4	5	6	7	8	8YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	108517.	102291.	61426.	0.	0.	0.	0.	0.	272234.
OIL PRODUCTION (M BBL/YEAR)	0.	0.	0.	7300.	7300.	7300.	7300.	5625.	34825.
SALES PRICE OF OIL (M$/BBL)	0.0	0.0	0.0	31.39	31.39	31.39	31.39	31.39	
BASIC PRICE OF OIL (M$/BBL)	35.62	37.40	39.27	41.24	43.30	45.46	47.74	50.12	

TABLE 9-6-10 CASH FLOW TABLE FOR OIL ERB WEST AND SOUTH FURIOUS OIL FIELDS

VOL.III CASE II B : ERB WEST, MANGALUM TERMINAL CASE

(CONT'D)
PAGE 2

* * CASH FLOW TABLE FOR PETRONAS * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	8YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	0.	0.	0.	112282.	112282.	112282.	112282.	86519.	535647.
2 REVENUE FROM OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 BONUS FROM OIL COMPANY	0.	0.	0.	2500.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 RESEARCH FUND FROM OIL CO.	0.	0.	0.	470.	470.	470.	470.	362.	2241.
5 TOTAL CASH INFLOW	0.	0.	0.	115252.	112752.	112752.	112752.	86881.	540388.
6 INCOME TAX	0.	0.	0.	51863.	50738.	50738.	50738.	39096.	243174.
7 NET CASH FLOW	0.	0.	0.	63388.	62013.	62013.	62013.	47784.	
8 CUMULATIVE NET CASH FLOW	0.	0.	0.	63388.	125402.	187415.	249429.	297213.	

TABLE 9-6-10 CASH FLOW TABLE FOR OIL ERB WEST AND SOUTH FURIOUS OIL FIELDS

VOL.III CASE II B : ERB WEST, MANGALUM TERMINAL CASE

* * PRESENT WORTH OF NET CASH FLOW FOR PETRONAS * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8
PRESENT WORTH								
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69
PRESENT WORTH	0.	0.	0.	53438.	49789.	47418.	45160.	33141.
CUMULATIVE PRESENT WORTH	0.	0.	0.	53438.	103227.	150645.	195806.	228947.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49
PRESENT WORTH	0.	0.	0.	45408.	40385.	36714.	33376.	23380.
CUMULATIVE PRESENT WORTH	0.	0.	0.	45408.	85793.	122507.	155883.	179263.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35
PRESENT WORTH	0.	0.	0.	38866.	33063.	28751.	25001.	16751.
CUMULATIVE PRESENT WORTH	0.	0.	0.	38866.	71929.	100680.	125680.	142432.

TABLE 9-6-10 CASH FLOW TABLE FOR OIL ERB WEST AND SOUTH FURIOUS OIL FIELDS
VOL.III CASE II B : ERB WEST, MANGALUM TERMINAL CASE

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

(CONT'D)
PAGE 4

TERM	1	2	3	4	5	6	7	8	BYR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	0.	0.	0.	48121.	48121.	48121.	48121.	37079.	229563.
2 SALES REVENUE FROM COST OIL	0.	0.	0.	45829.	45829.	45829.	45829.	35314.	218631.
3 SALES REVENUE FROM ROYALTY OIL	0.	0.	0.	22915.	22915.	22915.	22915.	17657.	109316.
4 TOTAL CASH INFLOW	0.	0.	0.	116865.	116865.	116865.	116865.	90050.	557510.
5 ROYALTY	0.	0.	0.	22915.	22915.	22915.	22915.	17657.	109316.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.
8 RESEARCH FUND TO PETRONAS	0.	0.	0.	470.	470.	470.	470.	362.	2241.
OPERATING EXPENSES	0.	0.	0.	45829.	45829.	45829.	45829.	35314.	218631.
(M$/BBL)	0.0	0.0	0.0	6.28	6.28	6.28	6.28	6.28	6.28
9 OPERATING COST	0.	0.	0.	13538.	13538.	13538.	13538.	13345.	67497.
CAPITAL COST RECOVERY	0.	0.	0.	32291.	32291.	32291.	32291.	21969.	151134.
INCOME BEFORE TAX	0.	0.	0.	45151.	47651.	47651.	47651.	36717.	224822.
10 INCOME TAX	0.	0.	0.	20318.	21443.	21443.	21443.	16523.	101170.
11 CAPITAL INVESTMENT	108517.	102291.	61426.	0.	0.	0.	0.	0.	272234.
12 TOTAL CASH OUTFLOW	108517.	102291.	61426.	59740.	58365.	58365.	58365.	47887.	554957.
13 NET CASH FLOW	-108517.	-102291.	-61426.	57125.	58500.	58500.	58500.	42163.	
14 CUMULATIVE NET CASH FLOW	-108517.	-210808.	-272234.	-215110.	-156610.	-98111.	-39611.	2552.	
15 DCF ROR OF NET CASH FLOW (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.23	
16 CORPORATE CAPITAL	108517.	102291.	61426.	0.	0.	0.	0.	0.	272234.
17 INTEREST	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	0.	0.
19 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.
20 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	

21 PAYOUT TIME 7.9 YEARS

TABLE 9-6-10 CASH FLOW TABLE FOR OIL ERB WEST AND SOUTH FURIOUS OIL FIELDS

VOL.III CASE II B : ERB WEST, MANGALUM TERMINAL CASE

* * PRESENT WORTH OF NET CASH FLOW FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8
PRESENT WORTH								
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69
PRESENT WORTH	-105902.	-95072.	-54373.	48157.	46968.	44731.	42601.	29243.
CUMULATIVE PRESENT WORTH	-105902.	-200974.	-255347.	-207189.	-160221.	-115490.	-72889.	-43646.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49
PRESENT WORTH	-103467.	-88664.	-48403.	40921.	38097.	34633.	31485.	20630.
CUMULATIVE PRESENT WORTH	-103467.	-192131.	-240534.	-199613.	-161516.	-126883.	-95398.	-74768.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35
PRESENT WORTH	-101193.	-82945.	-43312.	35025.	31190.	27122.	23584.	14781.
CUMULATIVE PRESENT WORTH	-101193.	-184138.	-227450.	-192424.	-161235.	-134113.	-110529.	-95748.

Table 28-4-1 SUMMARY OF OFFSHORE STRUCTURES
(Vol. III)

FIELD/ FACILITY NAME	W.D. FT MSL	PLATFORM TYPE	PLATFORM OVERALL DIMENSION	FACILITY LOCATION				DATE INSTALLED
				BORNEO GRID		GEOGRAPHICAL		
				NORTH	EAST	LAT.-N	LONG.-E	
TEMBUNGO		47 Miles NNW off K. Kinabalu						
A	277	8P/18W Self-Cont. Drill & Prod. P/F	90'-0" x 185'-0"			6° 37' 8.848"	115° 47' 12.889"	
SALM	292	Single Anchor Leg Mooring System						
SAMARANG	35	32 Miles off Labuan		2,040,000 FT	1,894,000 FT	5 37 7	114 53 10	
SMDP-A	35	8P/21W Self-Cont. Drill. P/F	45'-0" x 18'-10-1/2"	2,040,200	1,894,040	5 37 9	114 53 10	Mar. '75
SMDP-B	160	8P/28W Tender-Ass. Drill. P/F		2,046,250	1,897,300			
SMJT-C	32	4P/6W Cluster Drill. P/F	30'-0" x 30'-0"					
SMJT-D	32	4P/6W Cluster Drill. P/F	30'-0" x 30'-0"					
SM-4	35	1P/1W WHPJ				5 36 39.27	114 52 33.02	Mar. '75
SMP-A	35	4P Prod. P/F	50'-0" x 62'-0"					Feb. '75
SMP-B	160	4P Prod. P/F	50'-0" x 62'-0"	2,046,432	1,897,405			
SMV-A	35	3P Vent Structure						Mar. '75
SMV-B	156	3P Vent Structure						
SMR-A	35	4P Riser P/F	35'-0" x 35'-0"	2,039,330	1,900,000			Jan. '75

Table 28-4-1 **SUMMARY OF OFFSHORE STRUCTURES** (Cont'd)
(Vol. III)

FIELD/ FACILITY NAME	W.D. FT MSL	PLATFORM TYPE	PLATFORM OVERALL DIMENSION	FACILITY LOCATION				DATE INSTALLED
				BORNEO GRID		GEOGRAPHICAL		
				NORTH	EAST	LAT.-N	LONG.-E	
LABUAN TERMINAL				1,909,667 FT	1,992,808 FT			
SBM	95	Single Buoy Mooring System		1,909,667	1,992,808			
LUTONG TERMINAL								
WL-M.P.	50	4P Manifold P/F				40° 29' 33"	113° 56' 37"	Mid. '66
SBM-1		Single Buoy Mooring System						
SBM-2		ditto						
SBM-4		ditto						

Table 28-4-2 **SUMMARY OF SUBMARINE PIPELINES**
(Vol. III)

ORIGIN	TERMINAL	DIAMETER (IN.)	LENGTH (FT.)	SERVICE	NOS.	REMARKS
TEMBUNGO FIELD						
TEMBUNGO "A"	SALM	10	7,000	CRUDE	1	
SAMARANG FIELD						
SMDP-A	SMP-B	6	7,000	WELL FLUID	2	VIA SMP-A
SM-4	SMP-A	6	5,200	WELL FLUID	1	
SMJT-C	SMP-A	6	5,460	WELL FLUID	3	
SMJT-D	SMJT-C	6		WELL FLUID	4	
SMP-B	SMR-A	8	15,300	CRUDE	1	
SMP-A	SMR-A	8	10,300	CRUDE	1	
SMR-A	LABUAN T.	18	156,412	CRUDE	1	
SMP-A	SMJT-C	10	5,460	GAS LIFT	1	
SMJT-C	SM-4	3	2,150	GAS LIFT	1	
SMP-B	SMV-B	10	2,000	VENT	3	
SMP-A	SMV-A	10	1,000	VENT	3	

Table 28-4-2 (Vol. III) SUMMARY OF SUBMARINE PIPELINES (Cont'd)

ORIGIN	TERMINAL	DIAMETER (IN.)	LENGTH (FT.)	SERVICE	NOS.	REMARKS
TUKAU FIELD						
TK-3	TKP-A	6	4,910	WELL FLUID	1	
TKP-B	TKP-A	10	3,000	CRUDE	1	
TKP-A	WLDP-C	10	67,970	CRUDE	1	
TKP-B	TKV-B	10	2,000	VENT	3	
TKP-A	TKV-A	10	2,000	VENT	3	
TKP-A	TKDP-B	6	3,000	GAS LIFT	1	
LABUAN TERMINAL						
LABUAN T.	SBM	48	15,000	CRUDE	1	
LUTONG TERMINAL						
LUTONG T.	SBM NO. 1	12	20,454		1	1B
LUTONG T.	SBM NO. 1	12	20,700		1	1C
LUTONG T.	M.P.	6	26,550	GAS OIL	1	1A
LUTONG T.	M.P.	12	19,212		1	2B
LUTONG T.	M.P.	12	19,630		1	2C

Table 28-4-3
(Vol. III)

COMPARISON OF PRESENT PRODUCTION RATE VS. PLATFORM CAPABILITY

OIL FIELD	PRODUCTION PLATFORM	PRESENT PRODUCTION RATE @ MAY, 1976 GROSS LIQUID (BPD)	NET OIL (BPD)	GAS (MMSCFD)	WATER (BPD)	PRODUCTION PLATFORM CAPABILITY NO. OF SEPARATION BANKS	GROSS LIQUID THROUGHPUT (BPD)	GAS (MMSCFD)	EFFICIENCY* (%)
TEMBUNGO	A	5,294	4,983	3.7	311	1	20,000	16	26.5
BARONIA	BNP-A	51,977	49,162	106.1	2,815	2	60,000	180	86.6
WEST LUTONG	WLP-A	23,191	10,033	24.6	13,158	1	30,000	90	77.3
	WLP-C	9,939	4,300	10.6	5,639	1	30,000	90	33.1
		33,130	14,333	35.2	18,797	2	60,000	180	55.2
BARAM	BAP-A	33,503	21,478	82.2	12,025	2	60,000	180	55.8
	BAP-B	14,358	9,205	35.2	5,153	1	30,000	90	47.9
		47,861	30,683	117.4	17,178	3	90,000	270	53.2
BAKAU	BKP-A	5,316	5,203	10.5	113	1	30,000	90	17.7
TUKAU	TKP-A	6,706	6,516	8.8	190	1	30,000	90	22.4
	TKP-B	6,705	6,515	8.8	190	1	30,000	90	22.4
		13,411	13,031	17.6	380	2	60,000	180	22.4
SAMARANG	SMP-A	65,000**				2	60,000	180	108.3
	SMP-B	5,000**				1	30,000	90	16.7
		70,000**				3	90,000	270	77.8

NOTE: * EFFICIENCY = GROSS LIQUID/GROSS LIQUID THROUGHPUT

** ROUNDED FIGURE IN DECEMBER, 1976

Table 28-4-4 (Vol. III) COMPARISON OF MAXIMUM PREDICTED PRODUCTION RATE VS. PLATFORM CAPABILITY, GROSS LIQUID BASE

OIL FIELD	PRODUCTION PLATFORM	PREDICTED PRODUCTION RATE BASED ON MAX. GROSS LIQUID RATE: GROSS LIQUID (BPD)	NET OIL (BPD)	GAS (MMSCFD)	WATER (BPD)	PRODUCTION PLATFORM CAPABILITY: NO. OF SEPARATION BANKS	GROSS LIQUID THROUGHPUT (BPD)	GAS (MMSCFD)	EFFICIENCY* (%)
TEMBUNGO	A	4,060 [9,770]	3,470 [8,460]	4.8 [15.7]	590 [1,310]	1	20,000	16	20.3 [48.9]
BARONIA	BNP-A	55,150 [86,980]	48,680 [74,130]	133.5 [220.4]	6,470 [12,850]	2	60,000	180	91.9 [145.0]
WEST LUTONG	WLP-A					1	30,000	90	
	WLP-C					1	30,000	90	
		30,230 [33,010]	14,500 [15,570]	57.0 [62.5]	15,730 [17,440]	2	60,000	180	50.4 [55.0]
BARAM	BAP-A					2	60,000	180	
	BAP-B					1	30,000	90	
		40,670	25,440	137.8	15,230	3	90,000	270	45.2
BAKAU	BKP-A	2,830	2,530	4.7	300	1	30,000	90	9.4
TUKAU	TKP-A					1	30,000	90	
	TKP-B					1	30,000	90	
		12,930 [18,680]	12,380 [18,080]	30.1 [36.7]	550 [600]	2	60,000	180	21.6 [31.2]
SAMARANG	SMP-A					2	60,000	180	
	SMP-B					1	30,000	90	
		38,530 [49,150]	38,230 [48,650]	47.7 [66.0]	300 [500]	3	90,000	270	42.8 [54.6]

NOTE * EFFICIENCY = GROSS LIQUID/GROSS LIQUID THROUGHPUT

[ ] = ADDITIONAL WELL DEVELOPMENT CASE

Table 28-4-5
(Vol. III)

COMPARISON OF MAXIMUM PREDICTED PRODUCTION RATE VS. PLATFORM CAPABILITY, GAS BASE

OIL FIELD	PRODUCTION PLATFORM	PREDICTED PRODUCTUIN RATE BASED ON MAX. GAS RATE: GROSS LIQUID (BPD)	NET OIL (BPD)	GAS (MMSCFD)	WATER (BPD)	PRODUCTION PLATFORM CAPABILITY: NO. OF SEPARATION BANKS	GROSS LIQUID THROUGHPUT (BPD)	GAS (MMSCFD)	EFFICIENCY* (%)
TEMBUNGO	A	4,060 [9,770]	3,470 [8,460]	4.8 [15.7]	590 [1,310]	1	20,000	16	20.3 [48.9]
BARONIA	BNP-A	31,540 [49,190]	25,790 [41,320]	164.6 [250.3]	5,750 [7,870]	2	60,000	180	52.6 [82.0]
WEST LUTONG	WLP-A					1	30,000	90	
	WLP-C					1	30,000	90	
		29,200 [33,960]	15,200 [17,090]	58.3 [67.4]	14,000 [16,870]	2	60,000	180	48.7 [56.6]
BARAM	BAP-A					2	60,000	180	
	BAP-B					1	30,000	90	
		40,670	25,440	137.8	15,230	3	90,000	270	45.2
BAKAU	BKP-A	2,830	2,530	4.7	300	1	30,000	90	9.4
TUKAU	TKP-A					1	30,000	90	
	TKP-B					1	30,000	90	
		11,290 [16,560]	10,860 [16,080]	34.5 [40.8]	430 [480]	2	60,000	180	18.8 [27.6]
SAMARANG	SMP-A					2	60,000	180	
	SMP-B					1	30,000	90	
		28,910 [39,160]	28,410 [38,530]	56.6 [73.1]	500 [630]	3	90,000	270	32.1 [43.5]

NOTE: *EFFICIENCY = GROSS LIQUID/GROSS LIQUID THROUGHPUT
[ ] = ADDITIONAL WELL DEVELOPMENT CASE

Table 28-4-6 SUMMARY OF GAS UTILIZATION (UNIT: MMSCFD)
(Vol. III)

LUTONG STREAM	PUMP DRIVE GAS	GAS TO SHORE	VENT GAS	TOTAL
BARONIA	23.3		82.8	106.1
WEST LUTONG	7.3	11.2	16.7	35.2
BARAM	11.4		106.0	117.4
BAKAU	1.8		8.7	10.5
TUKAU	3.0		14.6	17.6
TOTAL	46.8	11.2	228.8	286.8
LABUAN STREAM				
SAMARANG	10.2		30.9	41.1

* Figures are as of May, 1976

Table 29-6-1 (Vol. III) **4-LEG OFFSHORE PLATFORM COST**

UNIT: US$

Field Name	Water Depth	Total Cost	Breakdown: Material Cost (Weight: ton)	Fabrication Cost	Installation Cost
Sarawak Area					
Central Luconia					
E-8	207'	3,618,000	682,000 (852)	546,000	2,390,000
E-11	230'	3,805,000	772,000 (965)	618,000	2,415,000
F-6	285'	4,289,000	962,000 (1,202)	790,000	2,537,000
F-13	250'	4,054,000	864,000 (1,080)	691,000	2,499,000
F-14	347'	4,899,000	1,272,000 (1,590)	1,018,000	2,609,000
F-23	280'	4,239,000	958,000 (1,197)	760,000	2,521,000
Temana	99'	3,261,000	426,000 (532)	341,000	2,494,000
E-6	239'	3,910,000	819,000 (1,023)	655,000	2,436,000
Betty	247'	3,998,000	853,000 (1,066)	683,000	2,462,000
Bokor	228'	3,788,000	765,000 (956)	612,000	2,411,000
Baronia	254'	4,086,000	880,000 (1,100)	705,000	2,501,000
B-12	298'	4,425,000	1,025,000 (1,281)	830,000	2,570,000
Sabah Area					
South Furious	188'	3,481,000	610,000 (762)	485,000	2,386,000
Erb West	252'	4,070,000	872,000 (1,090)	698,000	2,500,000
Peninsular Area					
Bekok	234'	3,849,000	793,000 (991)	634,000	2,422,000
Pulai	245'	3,981,000	844,000 (1,055)	675,000	2,462,000
Seligi	248'	4,003,000	856,000 (1,070)	685,000	2,462,000
Tapis	225'	3,767,000	754,000 (942)	604,000	2,409,000
Jerneh	205'	3,590,000	668,000 (835)	534,000	2,388,000

Table 29-6-2 (Vol. III) **6-LEG OFFSHORE PLATFORM COST**

UNIT: US$

Field Name	Water Depth	Total Cost	Breakdown		
			Material Cost (Weight: ton)	Fabrication Cost	Installation Cost
Sarawak Area					
Central Luconia					
E-8	207'	5,011,000	1,339,000 (1,673)	1,071,000	2,601,000
E-11	230'	5,347,000	1,504,000 (1,880)	1,203,000	2,640,000
F-6	285'	6,063,000	1,820,000 (2,275)	1,452,000	2,791,000
F-13	250'	5,781,000	1,680,000 (2,100)	1,344,000	2,757,000
F-14	347'	7,204,000	2,400,000 (3,000)	1,920,000	2,884,000
F-23	280'	5,915,000	1,736,000 (2,170)	1,397,000	2,782,000
Temana	99'	3,955,000	744,000 (930)	593,000	2,618,000
E-6	239'	5,451,000	1,551,000 (1,938)	1,241,000	2,659,000
Betty	247'	5,655,000	1,649,000 (2,061)	1,319,000	2,687,000
Bokor	228'	5,329,000	1,495,000 (1,868)	1,197,000	2,637,000
B-12	298'	6,631,000	2,103,000 (2,628)	1,702,000	2,826,000
Sabah Area					
South Furious	188'	4,827,000	1,241,000 (1,551)	997,000	2,589,000
Erb West	252'	5,831,000	1,706,000 (2,132)	1,364,000	2,761,000
Peninsular Area					
Bekok	234'	5,396,000	1,525,000 (1,906)	1,220,000	2,651,000
Pulai	245'	5,595,000	1,618,000 (2,022)	1,295,000	2,682,000
Seligi	248'	5,669,000	1,655,000 (2,068)	1,324,000	2,690,000
Tapis	225'	5,260,000	1,466,000 (1,832)	1,173,000	2,621,000
Jerneh	205'	4,980,000	1,322,000 (1,652)	1,058,000	2,600,000

Table 29-6-3 (Vol. III) **8-LEG OFFSHORE PLATFORM COST**

UNIT: US$

Field Name	Water Depth	Total Cost	Breakdown		
			Material Cost (Weight: ton)	Fabrication Cost	Installation Cost
Sarawak Area					
Central Luconia					
E-8	207'	7,459,000	2,518,000 (3,147)	2,015,000	2,926,000
E-11	230'	8,180,000	2,864,000 (3,580)	2,291,000	3,025,000
F-6	285'	9,805,000	3,683,000 (4,603)	2,947,000	3,175,000
F-13	250'	8,688,000	3,120,000 (3,900)	2,496,000	3,072,000
F-14	347'	12,251,000	4,960,000 (6,200)	3,968,000	3,323,000
F-23	280'	9,596,000	3,574,000 (4,467)	2,857,000	3,165,000
Temana	99'	5,568,000	1,447,000 (1,808)	1,158,000	2,963,000
E-6	239'	8,419,000	2,990,000 (3,737)	2,392,000	3,037,000
Betty	247'	8,613,000	3,086,000 (3,857)	2,468,000	3,059,000
Bokor	228'	8,125,000	2,837,000 (3,546)	2,269,000	3,019,000
B-12	298'	10,139,000	3,839,000 (4,798)	3,085,000	3,215,000
Sabah Area					
South Furious	188'	7,012,000	2,280,000 (2,850)	1,824,000	2,908,000
Erb West	252'	8,740,000	3,149,000 (3,936)	2,519,000	3,072,000
Peninsular Area					
Bekok	234'	8,283,000	2,920,000 (3,650)	2,336,000	3,027,000
Pulai	245'	8,563,000	3,062,000 (3,827)	2,450,000	3,051,000
Seligi	248'	8,644,000	3,097,000 (3,871)	2,477,000	3,070,000
Tapis	225'	8,032,000	2,796,000 (3,495)	2,237,000	2,999,000
Jerneh	205'	7,413,000	2,496,000 (3,120)	1,997,000	2,920,000

Table 29-6-4 (Vol. III) **3-LEG VENT AND FLARE JACKET COST**

UNIT: US $

Water Depth	Total Cost	Breakdown		
		Material Cost (Weight: ton)	Fabrication Cost	Installation Cost
20'	343,000	100,000 (125)	80,000	163,000
40'	395,000	120,000 (150)	96,000	179,000
60'	447,000	140,000 (175)	112,000	195,000
100'	595,000	204,000 (255)	163,000	228,000
160'	660,000	240,000 (300)	192,000	228,000
180'	696,000	260,000 (325)	208,000	228,000
200'	764,000	280,000 (350)	224,000	260,000
220'	800,000	300,000 (375)	240,000	260,000
240'	869,000	320,000 (400)	256,000	293,000
260'	905,000	340,000 (425)	272,000	293,000
280'	973,000	360,000 (450)	288,000	325,000

Table 29-6-5 (Vol. III) COST OF 3 CONDUCTORS

UNIT: US$

Field Name	Water Depth	Total Cost	Breakdown		
			Material Cost (Weight: ton)	Fabrication Cost	Installation Cost
Sarawak Area					
Central Luconia					
E-8	207'	571,000	128,000 (160)	38,000	405,000
E-11	230'	581,000	135,000 (168)	41,000	405,000
F-6	285'	609,000	152,000 (190)	46,000	411,000
F-13	250'	587,000	140,000 (175)	42,000	405,000
F-14	347'	627,000	166,000 (207)	50,000	411,000
F-23	280'	606,000	150,000 (187)	45,000	411,000
Temana	99'	411,000	92,000 (115)	28,000	291,000
E-6	239'	584,000	138,000 (172)	41,000	405,000
Betty	247'	587,000	140,000 (175)	42,000	405,000
Bokor	228'	580,000	135,000 (168)	40,000	405,000
B-12	298'	614,000	156,000 (195)	47,000	411,000
Sabah Area					
South Furious	188'	546,000	150,000 (187)	36,000	360,000
Erb West	252'	588,000	141,000 (176)	42,000	405,000
Peninsular Area					
Bekok	234'	582,000	136,000 (170)	41,000	405,000
Pulai	245'	587,000	140,000 (175)	42,000	405,000
Seligi	248'	587,000	140,000 (175)	42,000	405,000
Tapis	225'	579,000	134,000 (167)	40,000	405,000
Jerneh	205'	569,000	126,000 (157)	38,000	405,000

Table 29-6-6
(Vol. III)

COST OF 4 CONDUCTORS

UNIT: US$

Field Name	Water Depth	Total Cost	Breakdown		
			Material Cost (Weight: ton)	Fabrication Cost	Installation Cost
Sarawak Area					
Central Luconia					
E-8	207'	778,000	171,000 (213)	51,000	556,000
E-11	230'	791,000	181,000 (226)	54,000	556,000
F-6	285'	841,000	204,000 (255)	61,000	576,000
F-13	250'	802,000	189,000 (236)	57,000	556,000
F-14	347'	868,000	225,000 (281)	67,000	576,000
F-23	280'	839,000	202,000 (252)	61,000	576,000
Temana	99'	534,000	122,000 (152)	36,000	376,000
E-6	239'	795,000	184,000 (230)	55,000	556,000
Betty	247'	800,000	188,000 (235)	56,000	556,000
Bokor	228'	790,000	180,000 (225)	54,000	556,000
B-12	298'	846,000	208,000 (260)	62,000	576,000
Sabah Area					
South Furious	188'	658,000	162,000 (202)	48,000	448,000
Erb West	252'	803,000	190,000 (237)	57,000	556,000
Peninsular Area					
Bekok	234'	793,000	182,000 (227)	55,000	556,000
Pulai	245'	800,000	188,000 (235)	56,000	556,000
Seligi	248'	802,000	189,000 (236)	57,000	556,000
Tapis	225'	789,000	179,000 (223)	54,000	556,000
Jerneh	205'	777,000	170,000 (212)	51,000	556,000

Table 29-6-7 (Vol. III) COST OF 6 CONDUCTORS

UNIT: US$

Field Name	Water Depth	Total Cost	Breakdown: Material Cost (Weight: ton)	Breakdown: Fabrication Cost	Breakdown: Installation Cost
Sarawak Area					
Central Luconia					
E-8	207'	1,269,000	256,000 (320)	77,000	936,000
E-11	230'	1,286,000	269,000 (336)	81,000	936,000
F-6	285'	1,378,000	312,000 (390)	94,000	972,000
F-13	250'	1,308,000	286,000 (357)	86,000	936,000
F-14	347'	1,422,000	346,000 (432)	104,000	972,000
F-23	280'	1,367,000	304,000 (380)	91,000	972,000
Temana	99'	919,000	182,000 (227)	55,000	682,000
E-6	239'	1,300,000	280,000 (350)	84,000	936,000
Betty	247'	1,306,000	285,000 (356)	85,000	936,000
Bokor	228'	1,284,000	268,000 (335)	80,000	936,000
B-12	298'	1,386,000	318,000 (397)	96,000	972,000
Sabah Area					
South Furious	188'	1,087,000	242,000 (302)	73,000	772,000
Erb West	252'	1,309,000	287,000 (358)	86,000	936,000
Peninsular Area					
Bekok	234'	1,290,000	272,000 (340)	82,000	936,000
Pulai	245'	1,302,000	282,000 (352)	84,000	936,000
Seligi	248'	1,306,000	285,000 (356)	85,000	936,000
Tapis	225'	1,284,000	268,000 (335)	80,000	936,000
Jerneh	205'	1,266,000	254,000 (317)	76,000	936,000

Table 29-6-8 (Vol. III)

COST OF 8 CONDUCTORS

UNIT: US$

Field Name	Water Depth	Total Cost	Breakdown		
			Material Cost (Weight: ton)	Fabrication Cost	Installation Cost
Sarawak Area					
Central Luconia					
E-8	207'	1,903,000	384,000 (480)	115,000	1,404,000
E-11	230'	1,934,000	408,000 (510)	122,000	1,404,000
F-6	285'	2,061,000	464,000 (580)	139,000	1,458,000
F-13	250'	1,955,000	424,000 (530)	127,000	1,404,000
F-14	347'	2,130,000	517,000 (646)	155,000	1,458,000
F-23	280'	2,051,000	456,000 (570)	137,000	1,458,000
Temana	99'	1,234,000	275,000 (343)	77,000	882,000
E-6	239'	1,945,000	416,000 (520)	125,000	1,404,000
Betty	247'	1,952,000	422,000 (527)	126,000	1,404,000
Bokor	228'	1,934,000	408,000 (510)	122,000	1,404,000
B-12	298'	2,080,000	478,000 (597)	144,000	1,458,000
Sabah Area					
South Furious	188'	1,643,000	364,000 (455)	109,000	1,170,000
Erb West	252'	1,958,000	426,000 (532)	128,000	1,404,000
Peninsular Area					
Bekok	234'	1,942,000	414,000 (517)	124,000	1,404,000
Pulai	245'	1,950,000	420,000 (525)	126,000	1,404,000
Seligi	248'	1,953,000	422,000 (527)	127,000	1,404,000
Tapis	225'	1,926,000	402,000 (502)	120,000	1,404,000
Jerneh	205'	1,901,000	382,000 (477)	115,000	1,404,000

Table 29-6-9 (Vol. III)

COST OF 12 CONDUCTORS

UNIT: US$

Field Name	Water Depth	Total Cost	Breakdown: Material Cost (Weight: ton)	Fabrication Cost	Installation Cost
Sarawak Area					
Central Luconia					
E-8	207'	2,442,000	512,000 (640)	154,000	1,776,000
E-11	230'	2,478,000	540,000 (675)	162,000	1,776,000
F-6	285'	2,649,000	616,000 (770)	185,000	1,848,000
F-13	250'	2,514,000	568,000 (710)	170,000	1,776,000
F-14	347'	2,737,000	684,000 (855)	205,000	1,848,000
F-23	280'	2,638,000	608,000 (760)	182,000	1,848,000
Temana	99'	1,748,000	366,000 (457)	110,000	1,272,000
E-6	239'	2,494,000	552,000 (690)	166,000	1,776,000
Betty	247'	2,512,000	566,000 (707)	170,000	1,776,000
Bokor	228'	2,473,000	536,000 (670)	161,000	1,776,000
B-12	298'	2,678,000	638,000 (797)	192,000	1,848,000
Sabah Area					
South Furious	188'	1,978,000	488,000 (610)	146,000	1,344,000
Erb West	252'	2,517,000	570,000 (712)	171,000	1,776,000
Peninsular Area					
Bekok	234'	2,483,000	544,000 (680)	163,000	1,776,000
Pulai	245'	2,504,000	560,000 (700)	168,000	1,776,000
Seligi	248'	2,512,000	566,000 (707)	170,000	1,776,000
Tapis	225'	2,468,000	532,000 (665)	160,000	1,776,000
Jerneh	205'	2,439,000	510,000 (637)	153,000	1,776,000

Table 29-6-10 (Vol. III)

COST OF 18 CONDUCTORS

UNIT: US$

Field Name	Water Depth	Total Cost	Breakdown		
			Material Cost (Weight: ton)	Fabrication Cost	Installation Cost
Sarawak Area					
Central Luconia					
E-8	207'	3,600,000	762,000 (952)	228,000	2,610,000
E-11	230'	3,681,000	824,000 (1,030)	247,000	2,610,000
F-6	285'	3,914,000	920,000 (1,150)	276,000	2,718,000
F-13	250'	3,733,000	864,000 (1,080)	259,000	2,610,000
F-14	347'	4,018,000	1,000,000 (1,250)	300,000	2,718,000
F-23	280'	3,893,000	904,000 (1,130)	271,000	2,718,000
Temana	99'	2,615,000	544,000 (680)	163,000	1,908,000
E-6	239'	3,702,000	840,000 (1,050)	252,000	2,610,000
Betty	247'	3,723,000	856,000 (1,070)	257,000	2,610,000
Bokor	228'	3,671,000	816,000 (1,020)	245,000	2,610,000
B-12	298'	3,945,000	944,000 (1,180)	283,000	2,718,000
Sabah Area					
South Furious	188'	2,962,000	728,000 (910)	218,000	2,016,000
Erb West	252'	3,738,000	868,000 (1,085)	260,000	2,610,000
Peninsular Area					
Bekok	234'	3,692,000	832,000 (1,040)	250,000	2,610,000
Pulai	245'	3,702,000	840,000 (1,050)	252,000	2,610,000
Seligi	248'	3,723,000	856,000 (1,070)	257,000	2,610,000
Tapis	225'	3,650,000	800,000 (1,000)	240,000	2,610,000
Jerneh	205'	3,598,000	760,000 (950)	228,000	2,610,000

Table 29-6-11 (Vol. III)

UNIT COST OF SUBMARINE PIPELINE (PER 1,000 FEET)

UNIT: US $

Size	Total	Breakdown		
		Materials	Corrosion & Weight Coating*	Installation
6"	31,000	7,000	2,000	22,000
8"	33,000	8,000	3,000	22,000
10"	36,000	11,000	3,000	22,000
12"	39,000	13,000	4,000	22,000
14"	46,000	14,000	4,000	28,000
16"	50,000	17,000	5,000	28,000
18"	53,000	20,000	5,000	28,000
20"	61,000	20,000	6,000	35,000
24"	68,000	25,000	8,000	35,000
28"	76,000	31,000	10,000	35,000
30"	94,000	34,000	13,000	47,000
32"	99,000	37,000	15,000	47,000
36"	106,000	41,000	18,000	47,000
42"	172,000	48,000	29,000	95,000
48"	204,000	69,000	40,000	95,000

* Pipelines of size from 6" to 10" exclude weight coating cost.

Table 29-6-12
(Vol. III)

UNIT COST OF RISER PIPE (PER ONE RISER)

UNIT: US $

Size	Total	Breakdown		
		Materials	Prefabrication	Riser Installation & Tie-in
6"	190,000	7,000	2,000	181,000
8"	194,000	11,000	2,000	181,000
10"	198,000	15,000	2,000	181,000
12"	203,000	20,000	2,000	181,000
14"	299,000	24,000	3,000	272,000
16"	303,000	28,000	3,000	272,000
18"	308,000	33,000	3,000	272,000
20"	404,000	38,000	4,000	362,000
24"	409,000	43,000	4,000	362,000
28"	414,000	48,000	4,000	362,000
30"	508,000	50,000	5,000	453,000
32"	513,000	55,000	5,000	453,000
36"	518,000	60,000	5,000	453,000
42"	614,000	65,000	6,000	543,000
48"	619,000	70,000	6,000	543,000

Table 29-6-14 (Vol. III)

OIL PRODUCTION EQUIPMENT COST

UNIT : US$

CASE 10,000BPD

	Material Cost	Installation Cost	Total Cost
Process Equipment (including Piping)	593,000	322,000	915,000
Electrical Equipment	320,000	80,000	400,000
Instrument Equipment	105,000	27,000	132,000
Total Cost	1,018,000	429,000	1,447,000

CASE 20,000 BPD

	Material Cost	Installation Cost	Total Cost
Process Equipment (including Piping)	664,000	340,000	1,004,000
Electrical Equipment	336,000	84,000	420,000
Instrument Equipment	113,000	29,000	142,000
Total Cost	1,113,000	453,000	1,566,000

CASE 30,000BPD

	Material Cost	Installation Cost	Total Cost
Process Equipment (including Piping)	795,000	400,000	1,195,000
Electrical Equipment	368,000	93,000	461,000
Instrument Equipment	128,00	32,000	160,000
Total Cost	1,291,000	525,000	1,816,000

Table 29-6-15
(Vol. III)

UNIT COST OF
OTHER PRODUCTION EQUIPMENT

UNIT : US$

1.	ONSHORE TANKAGE	5 / BBL
2.	PUMP WITH ELEC. MOTER & ACCESSORIES	650 / HP
3.	GAS COMPRESSOR WITH GAS TURBINE	600 / HP

Table 29-6-16
(Vol. III)

NEWLY BUILT

STORAGE BARGE COST

UNIT : US$

STORAGE CAPACITY	STORAGE BARGE COST
940,000 BBLS	19,000,000
1,100,000 BBLS	23,000,000
1,200,000 BBLS	25,000,000
1,270,000 BBLS	27,000,000
1,400,000 BBLS	32,000,000

Table 29-6-17
(Vol. III)

ONSHORE SUPPORT FACILITIES COST

(IN CASE OF 30,000BPD)

UNIT : US$

	OFFSHORE STORAGE CASE	ONSHORE STORAGE CASE
SITE PREPARATION	50,000	173,000
BUILDING	1,960,000	2,000,000
JETTY	2,000,000	2,000,000
OTHERS	1,203,000	1,252,000
AUXILIARY FACILITIES FOR TANKAGE	—	2,360,000
TOTAL	5,213,000	7,785,000

* Cost for the other capacity case is estimated based on above shown table considering scale factor.

Table 29-6-18
(Vol. III)

OPERATING PERSONNEL COST

US$/Person/Year

1.	Manager	72,000
2.	Superintendent	44,000
3.	Supervisor	28,800
4.	Engineer	19,200
5.	Geologist	19,200
6.	Clerk	4,800
7.	Officer	4,800
8.	Mechanician	1,800
9.	Electrician	1,800
10.	Instrument	1,800
11.	Foreman	1,800
12.	Field Operator	1,500
13.	Store Keeper	960
14.	Laborer	1,200

Table 29-6-19
(Vol. III)

UNIT COST

OF

VARIOUS CHEMICALS

UNIT : US$

1.	Tri-Ethylene-Glycol	3.30/ gal.
2.	Corrosion Inhibitor for Gas	20.0/ gal.
3.	Deemulsifier	0.74/lb
4.	Defoamant	o.73/lb

Table 29-6-20
(Vol. III)

UNIT COST
OF
SERVICE CONTRACTORS

UNIT: US$

1.	One Work Boat	30,000 per year
2.	One Crew Boat	10,000 per year
3.	One Tug Boat Fleet*	18,000 for each berthing and unberthing operation
4.	One Helicopter	150,000 per year assuming one flight a day
5.	Catering Service Personnel	
	a. Cook	8,760 per year
	b. Waiter	6,570 per year
	c. Room Boy	4,380 per year

* Consisting of one tug boat, one hose handling boat and one mooring line handling boat.

Table 30-6-1 (Vol. III) ANNUAL OIL PRODUTION AND FOB PRICE PER BARREL

Sabah Area

FIELD / CASE / YEAR	South Furious & Erb West Fields					
	CASE I (South Furious & Erb West Fields)			CASE IIA, IIB (Erb West Field)		
	Annual Production (M BBLS)	F.O.B. Price (M$)	F.O.B. Price (US$)	Annual Production (M BBLS)	F.O.B. Price (M$)	F.O.B. Price (US$)
1						
2						
3						
4				7,300	31.39	12.36
5	12,932	31.45	12.38	7,300	31.39	12.36
6	12,063	31.45	12.38	7,300	31.39	12.36
7	7,300	31.39	12.36	7,300	31.39	12.36
8	7,300	31.39	12.36	5,625	31.39	12.36
9	5,625	31.39	12.36			

Note: Crude price is as of middle of 1976

Table 31-6-1 (Vol. III) INVESTMENT SCHEDULE FOR OIL

UNIT: M$1,000

AREA	SARAWAK AREA					SABAH AREA			PENINSULAR AREA					
FIELD	West Temana & E-6 Fields			Betty & Bokor Fields		South Furious & Erb West Fields			Bekok, Pulai & Seligi Fields				Tapis Field	
YEAR	CASE I	CASE IIA	CASE IIB	CASE I	CASE II	CASE I	CASE IIA	CASE IIB	CASE IA	CASE IB	CASE II	CASE III	CASE IA	CASE IB
1	102,168	48,153	51,365	54,093	30,537	96,956	102,689	108,517	201,002	240,976	179,848	150,020	72,691	80,694
2	178,787	172,085	115,072	67,270	33,133	61,615	77,320	102,291	275,415	305,619	262,407	205,658	148,355	197,443
3	135,628	65,128	132,697	110,837	58,496	147,695	81,863	61,426	259,019	241,490	193,549	153,643	186,690	175,568
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Table 31-6-2
(Vol. III)

ANNUAL OPERATING COST FOR OIL

UNIT: M$1,000

AREA / FIELD / YEAR	SARAWAK AREA					SABAH AREA			PENINSULAR AREA					
	West Temana & E-6 Fields			Betty & Bokor Fields		South Furious & Erb West Fields			Bekok, Pulai & Seligi Fields				Tapis Field	
	CASE I	CASE IIA	CASE IIB	CASE I	CASE II	CASE I	CASE IIA	CASE IIB	CASE IA	CASE IB	CASE II	CASE III	CASE IA	CASE IB
1														
2														
3														
4	22,155	21,525	15,256	11,297	7,119		13,328	13,538	44,319	36,097	38,158	31,560	27,486	22,276
5	20,409	21,525	15,256	11,246	7,076	19,051	13,328	13,538	44,241	36,019	38,120	31,523	27,318	22,108
6	18,658	21,525	15,256	9,380	7,031	19,051	13,328	13,538	43,885	35,663	37,904	31,286	27,095	21,885
7	18,658	21,525	15,256	7,081	6,886	13,005	13,328	13,538	43,000	34,778	37,166	30,487	26,655	21,445
8	18,547	21,414	15,145	6,961	6,766	13,005	13,135	13,345	40,430	32,208	31,277	29,184	26,305	21,095
9	18,303	21,170	14,901	5,027	4,882	12,812			39,165	30,943	30,347	28,286	25,654	20,444
10	18,051	20,918	14,649						30,408	23,799	29,688	27,636		
11	17,828	20,695	14,426						29,897	23,288	29,182	27,151		
12	17,729	20,596	14,327						28,917	22,308	28,203	22,917		
13	17,670	20,537	14,268						24,861	18,662	24,066	22,221		
14	17,625	20,492	14,223						24,617	18,418	23,822	21,987		
15	17,592	20,459	14,190						24,399	18,200	23,626	21,780		
16	17,561	20,428	14,159						24,241	18,042	23,456	21,603		
17	17,541	20,408	14,139						24,119	17,920	23,324	21,512		
18	8,768	10,202	8,216						24,000	17,801	23,211	21,396		
19									23,913	17,714	23,108	21,316		
20									23,824	17,625	23,018	21,227		
21									23,738	17,539	22,963	21,148		
22									23,694	17,495	22,899	21,108		
23									23,372	17,173	22,582	20,796		

Table 31-6-6 (Vol. III)

PROFITABILITY YARDSTICKS OF OIL

AT THE YEAR OF MAX. R.O.R. FOR OPERATING COMPANY

UNIT : M$1,000

AREA	FIELD	CASE	PETRONAS Cumulative Net Cash Flow	PETRONAS Cumulative Present Worth at Discount Rate 10%	OPERATING COMPANY Maximum ROR Year (*)	OPERATING COMPANY Maximum ROR ROR (%)	OPERATING COMPANY Maximum Cumulative Net Cash Flow	OPERATING COMPANY Maximum Cumulative Present Worth at Discount Rate 10%	OPERATING COMPANY Payout Time (year)
Sarawak Area	West Temana & E-6 Fields	CASE I	688,786	369,459	14	7.88	174,935	-29,685	7.5
		CASE IIA	653,618	352,124	13	15.48	259,503	57,673	6.3
		CASE IIB	697,320	363,228	16	16.75	282,672	70,265	6.2
	Betty & Bokor Fields	CASE I	223,742	140,256	8	-	-21,229	-64,611	-
		CASE II	188,132	116,397	8	12.62	58,526	8,266	5.7
Sabah Area	Erb West & South Furious Fields	CASE I	385,924	218,331	9	-	-37,904	-124,962	-
		CASE IIA	297,213	179,263	8	1.31	13,964	-63,044	7.7
		CASE IIB	297,213	179,263	8	0.23	2,552	-74,768	7.9
Peninsular Area	Bekok, Pulai & Seligi Fields	CASE IA	1,770,974	1,015,256	14	21.04	727,775	252,866	5.1
		CASE IB	1,826,413	1,028,039	17	19.42	748,844	239,115	5.2
		CASE II	1,529,282	858,248	15	19.78	622,606	202,485	5.2
		CASE III	1,337,232	738,332	15	20.77	547,063	184,618	5.2
	Tapis Field	CASE IA	702,728	428,202	9	15.05	239,153	53,873	5.6
		CASE IB	702,728	428,202	9	12.51	224,444	30,337	5.8

Note: (*) - In the case that cumulative net cash flow is not positive, the year shown above is a peak year of cumulative net cash.

FIGURE

FIGURE

FIGURE LIST VOL. III SABAH AREA

Vol. III

TITLE

Vol. III

TITLE

Vol. III

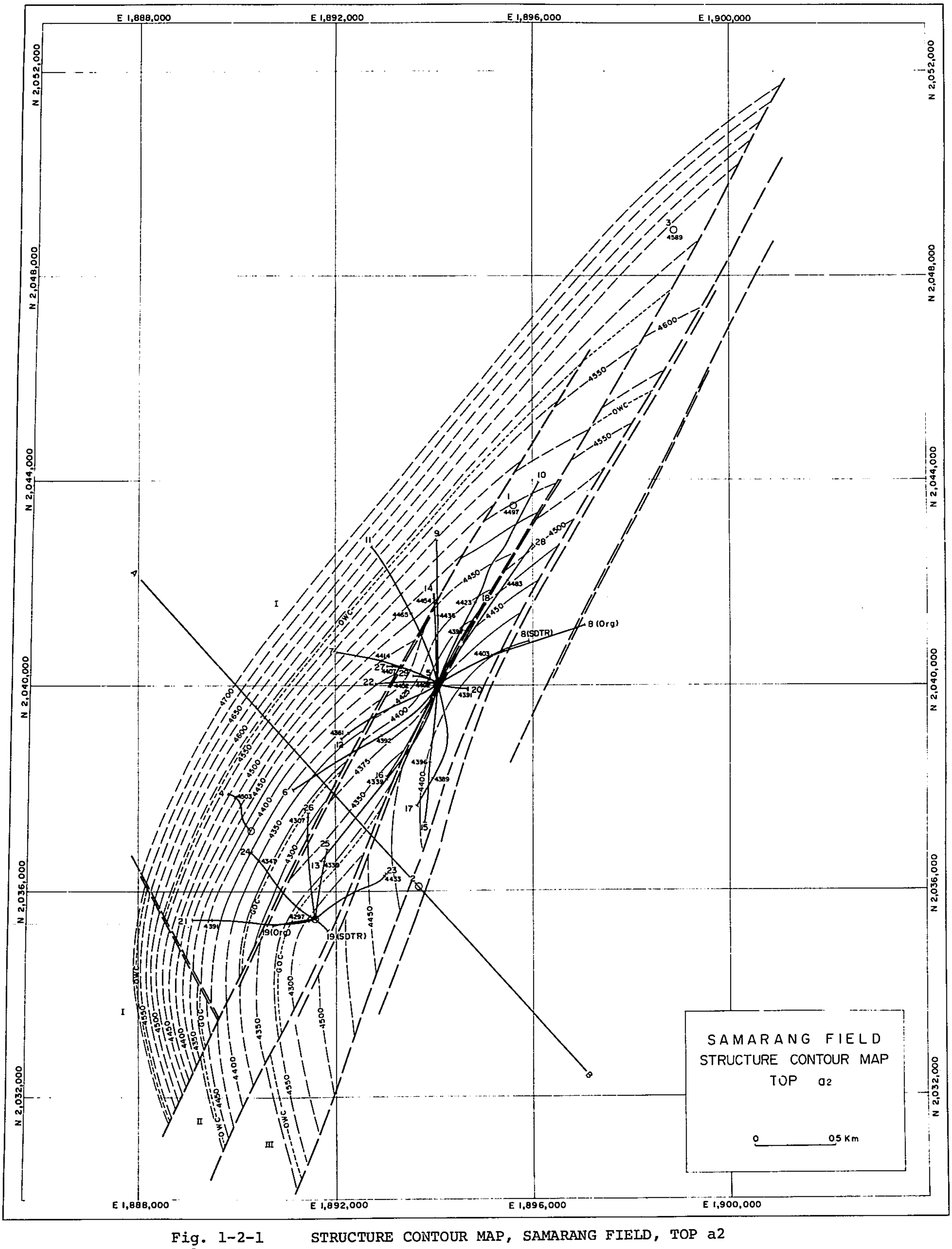


Fig. 1-2-1 STRUCTURE CONTOUR MAP, SAMARANG FIELD, TOP a2
Vol. III

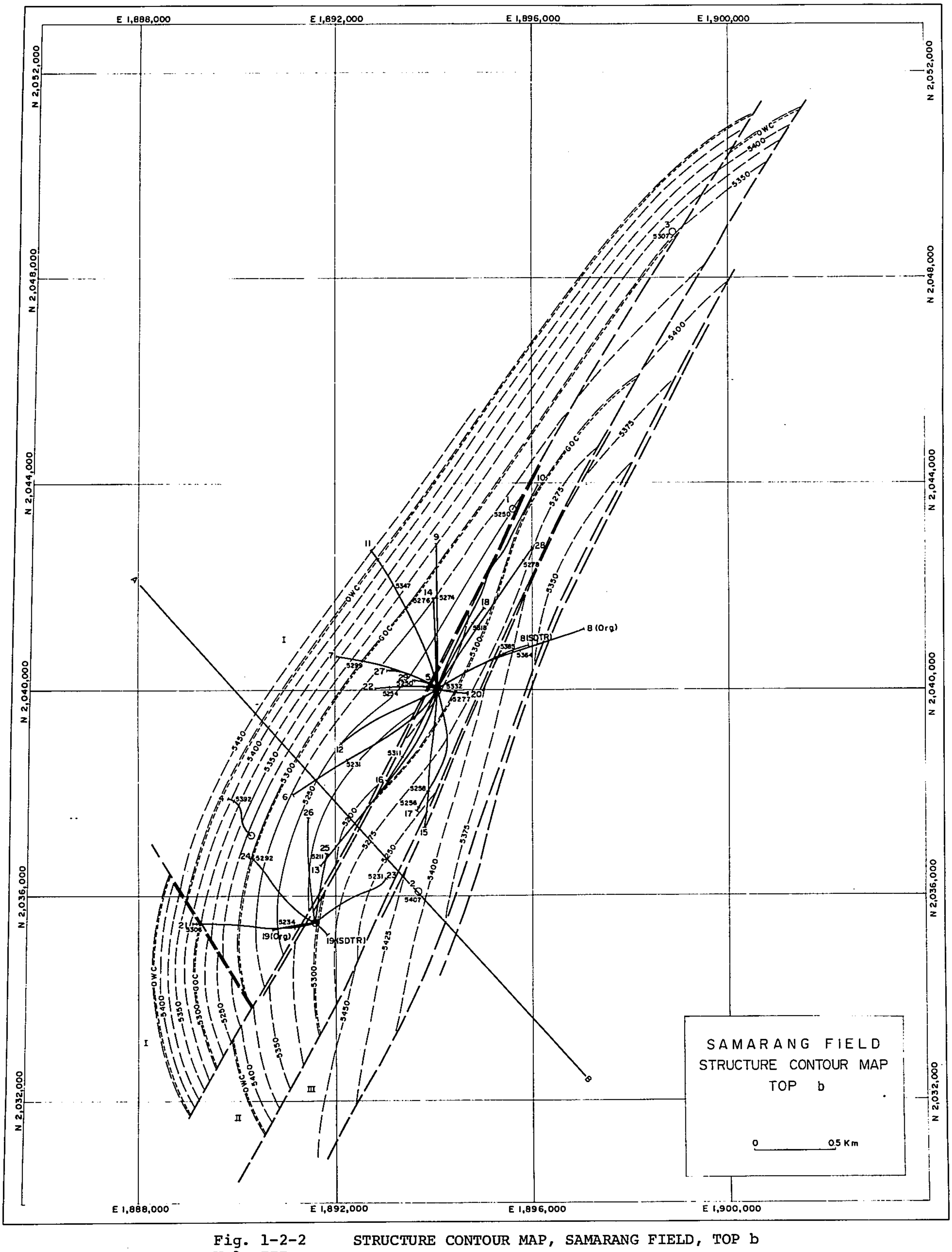


Fig. 1-2-2 STRUCTURE CONTOUR MAP, SAMARANG FIELD, TOP b
Vol. III

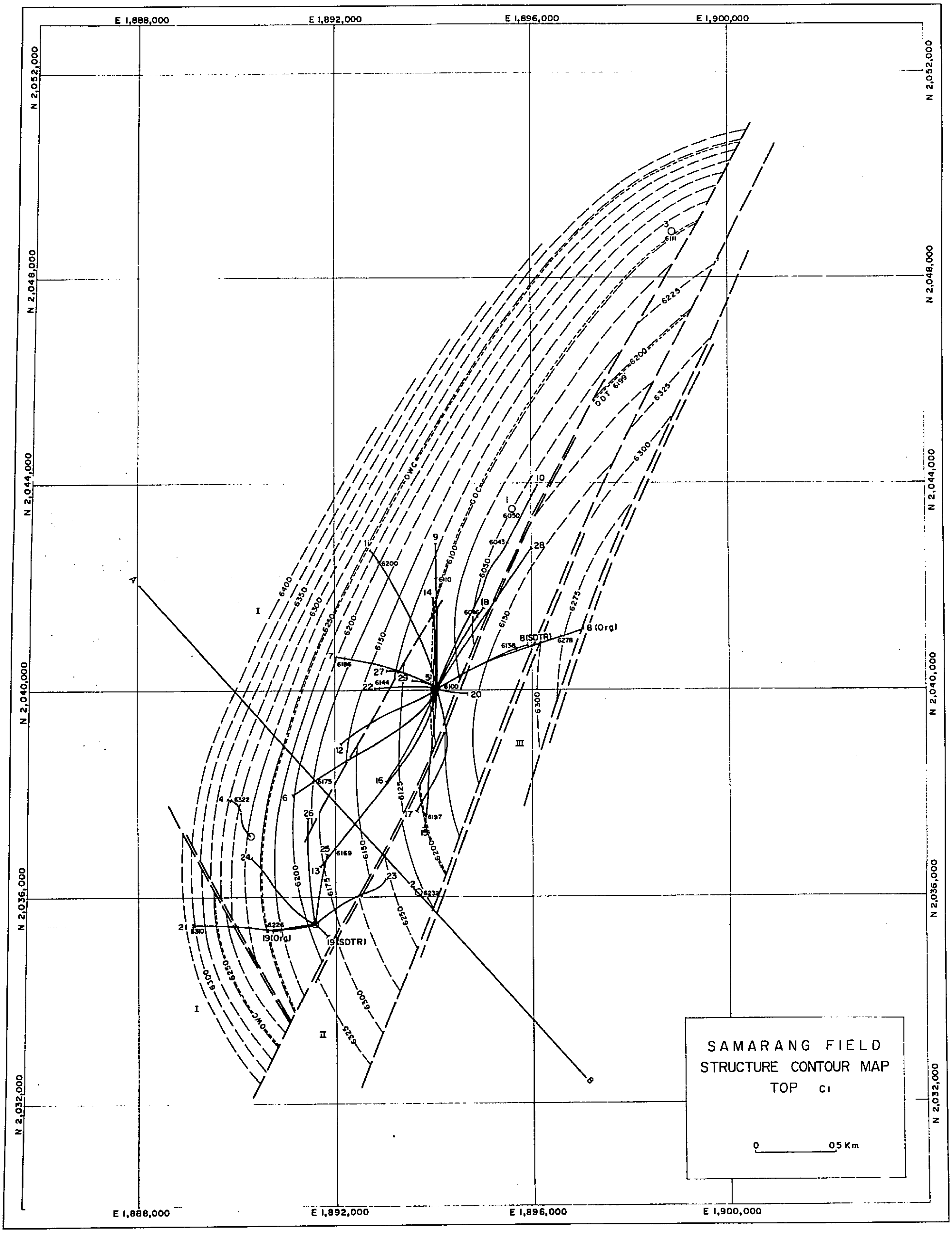


Fig. 1-2-3 STRUCTURE CONTOUR MAP, SAMARANG FIELD, TOP c1
Vol. III

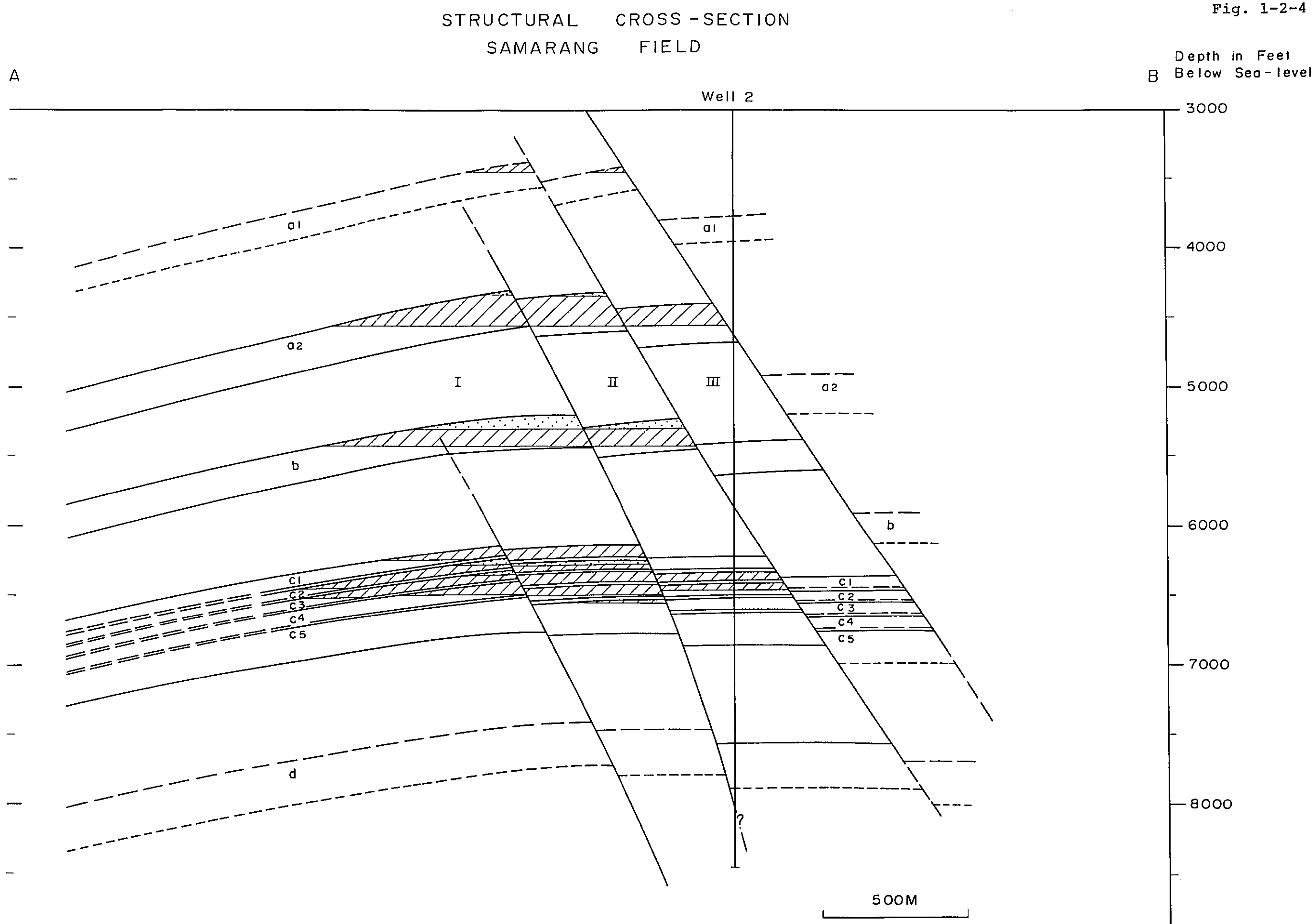


Fig. 1-2-4 STRUCTURAL CROSS-SECTION, SAMARANG FIELD
Vol. III

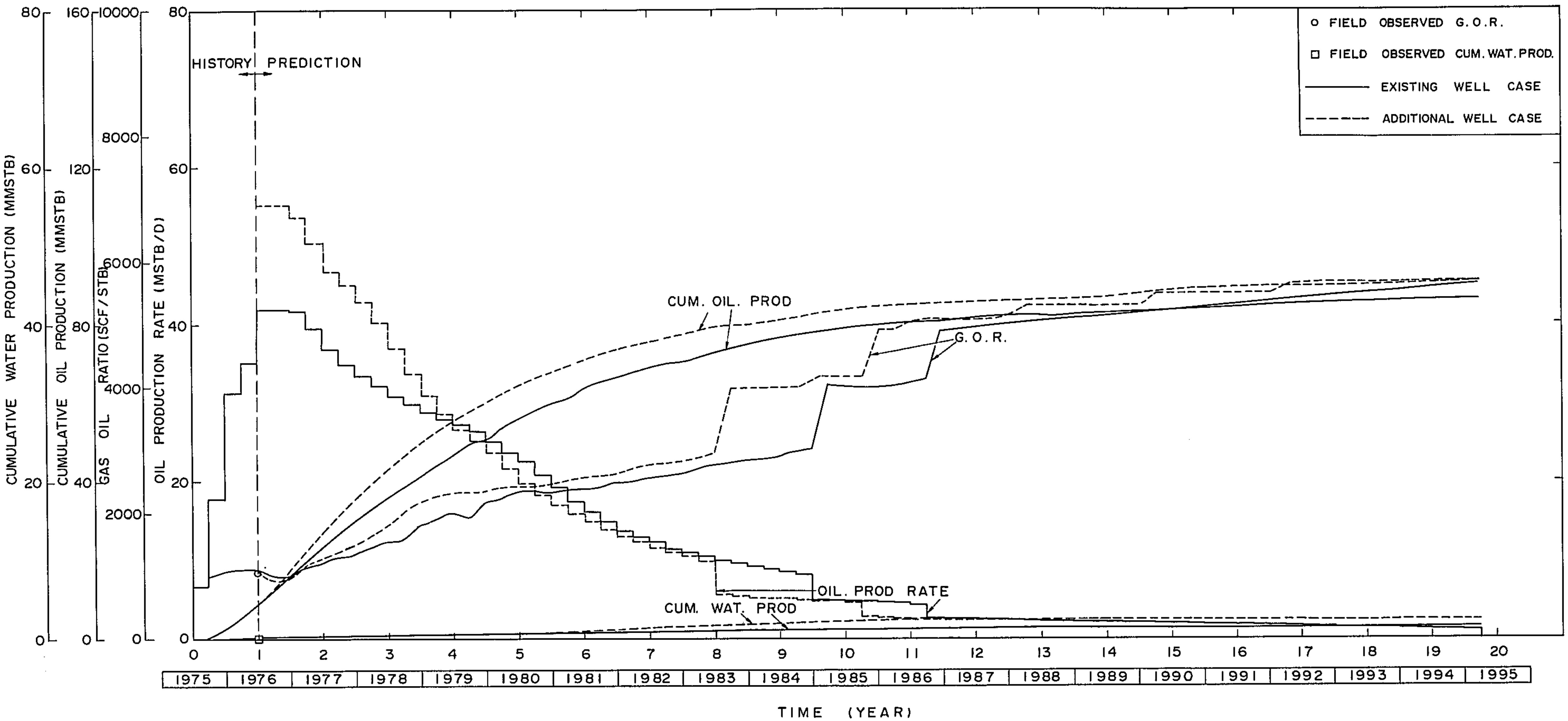


Fig. 1-3-1 PREDICTED PERFORMANCE OF SAMARANG FIELD
Vol. III

Fig. 1-3-2

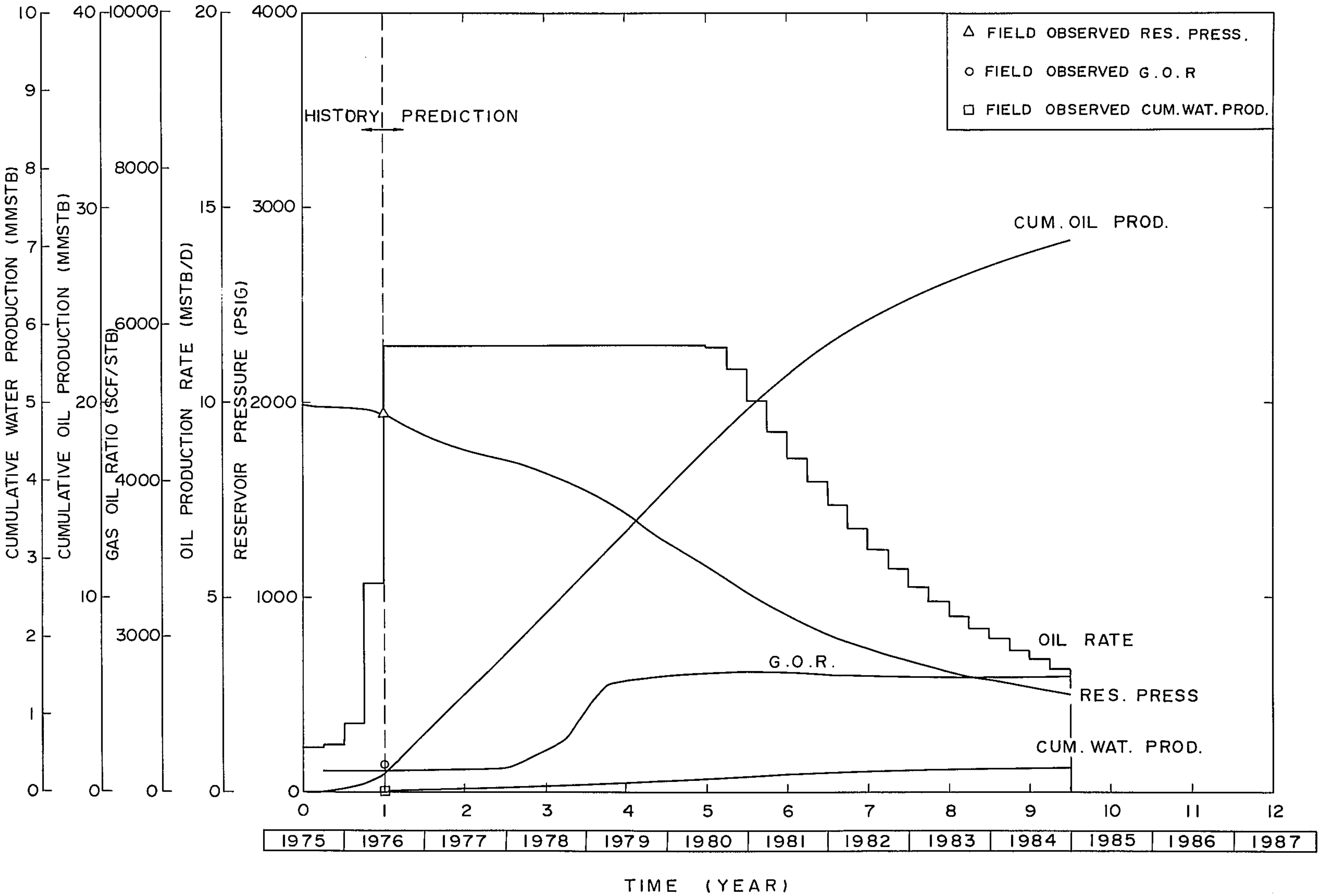


Fig. 1-3-2 PREDICTED PERFORMANCE OF A ZONE, SAMARANG FIELD
Vol. III

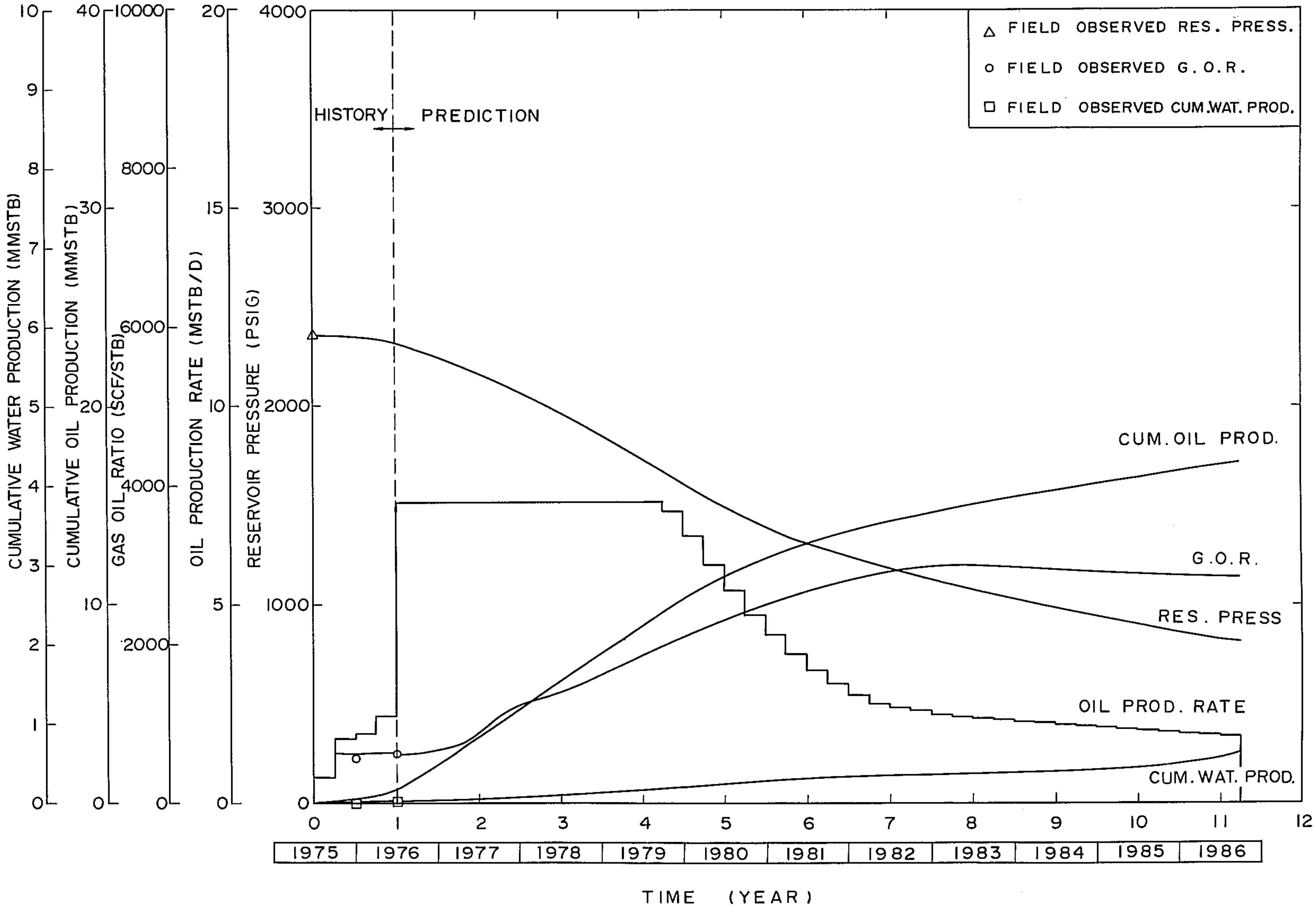


Fig. 1-3-3 PREDICTED PERFORMANCE OF B ZONE, SAMARANG FIELD
Vol. III

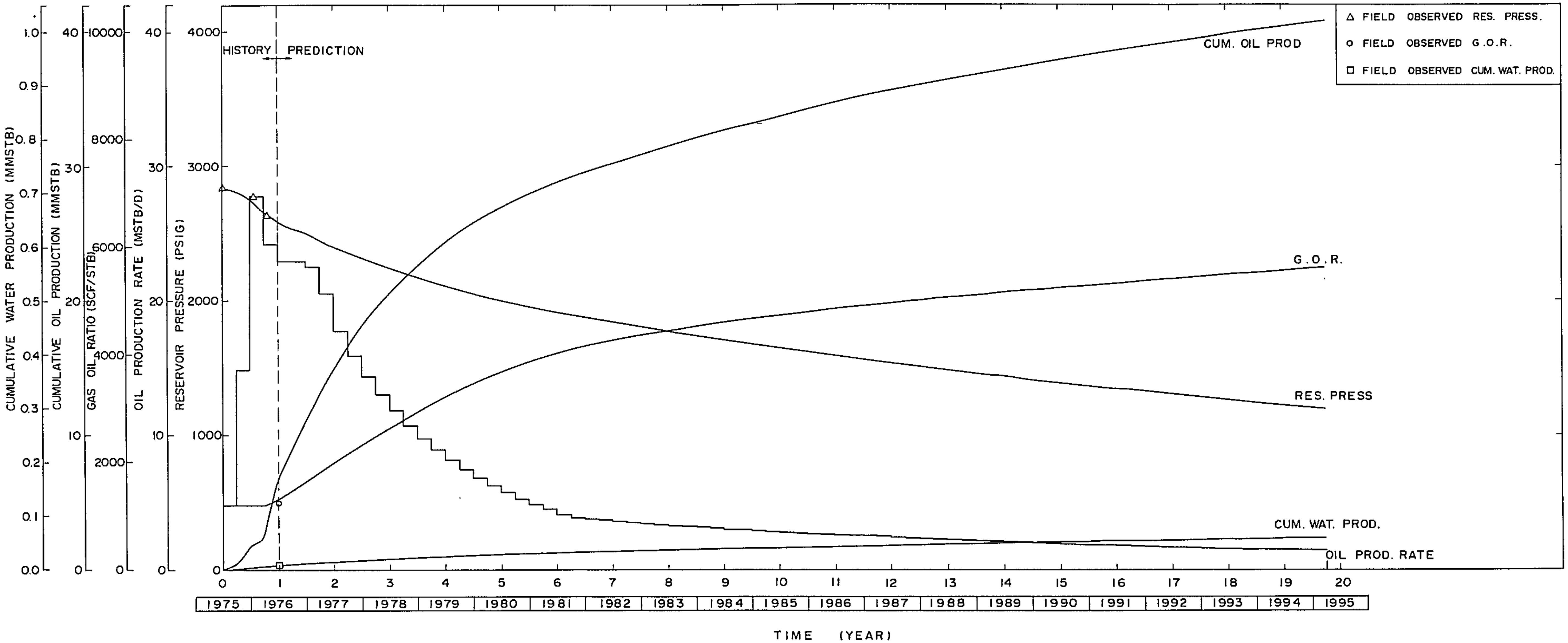


Fig. 1-3-4 PREDICTED PERFORMANCE OF C ZONE, SAMARANG FIELD
Vol. III

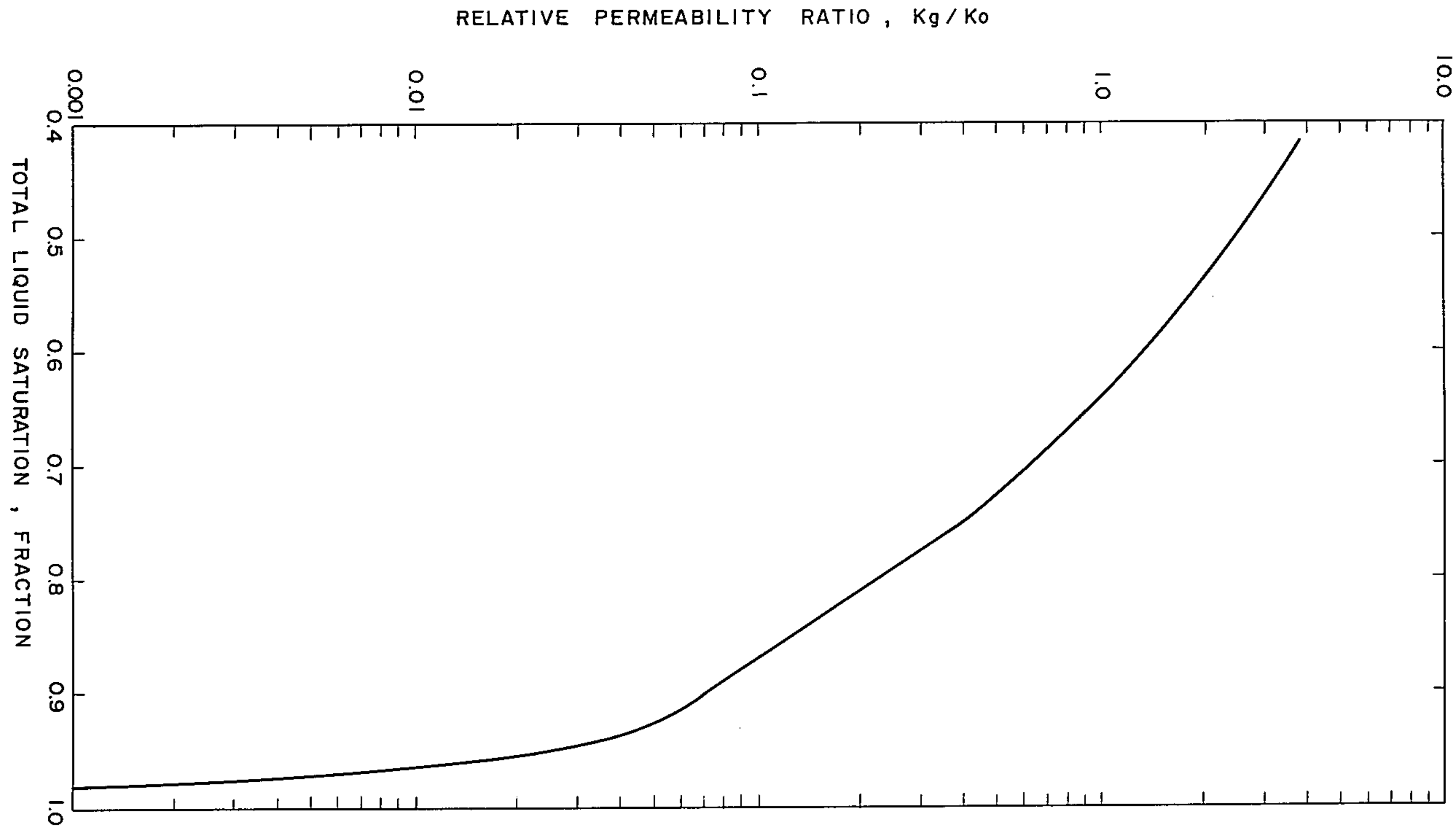


Fig. 1-3-5 GAS-OIL RELATIVE PERMEABILITY RATIO OF A ZONE, SAMARANG FIELD
Vol. III

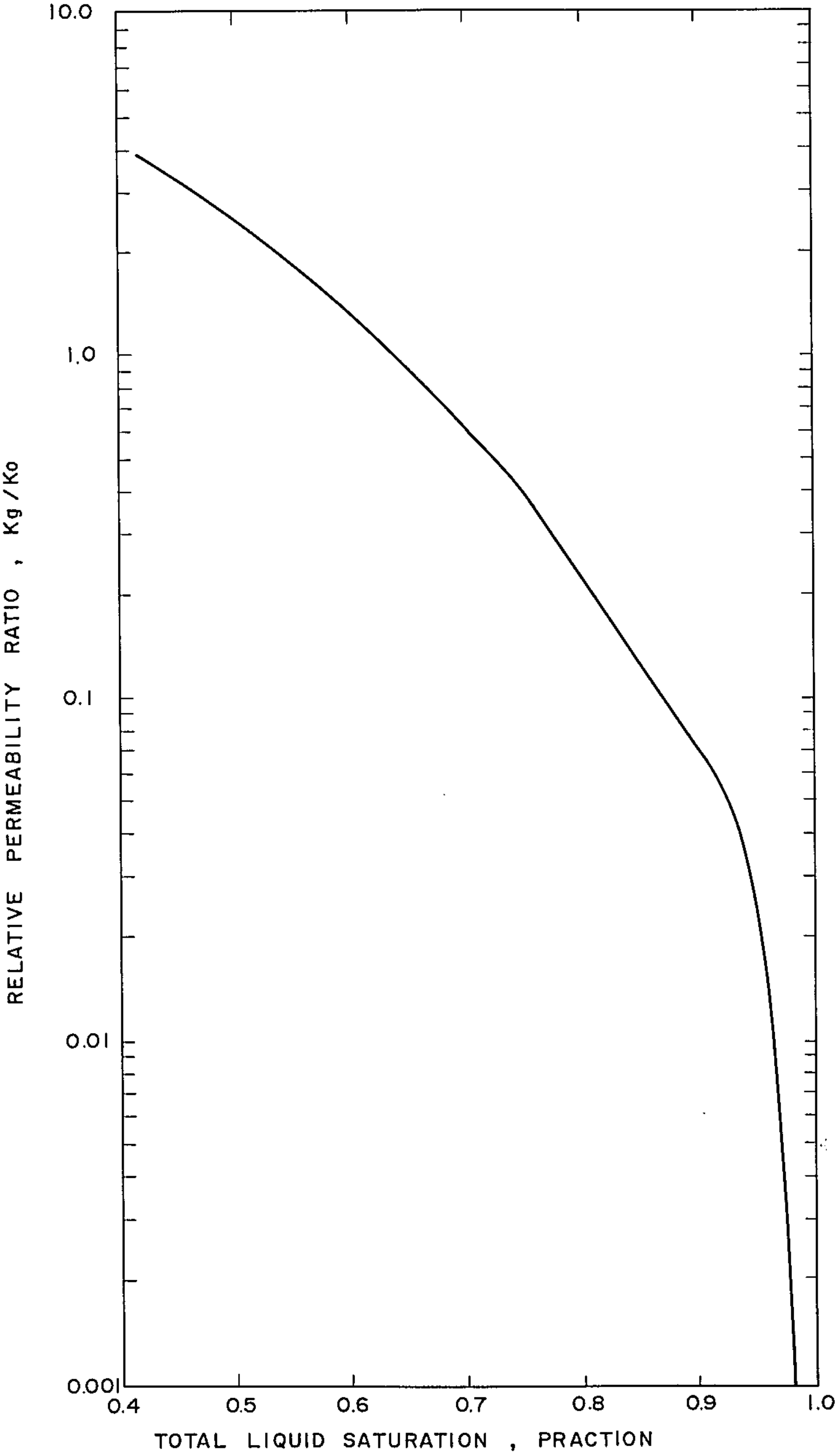


Fig. 1-3-6 GAS-OIL RELATIVE PERMEABILITY RATIO OF B ZONE, SAMARANG FIELD
Vol. III

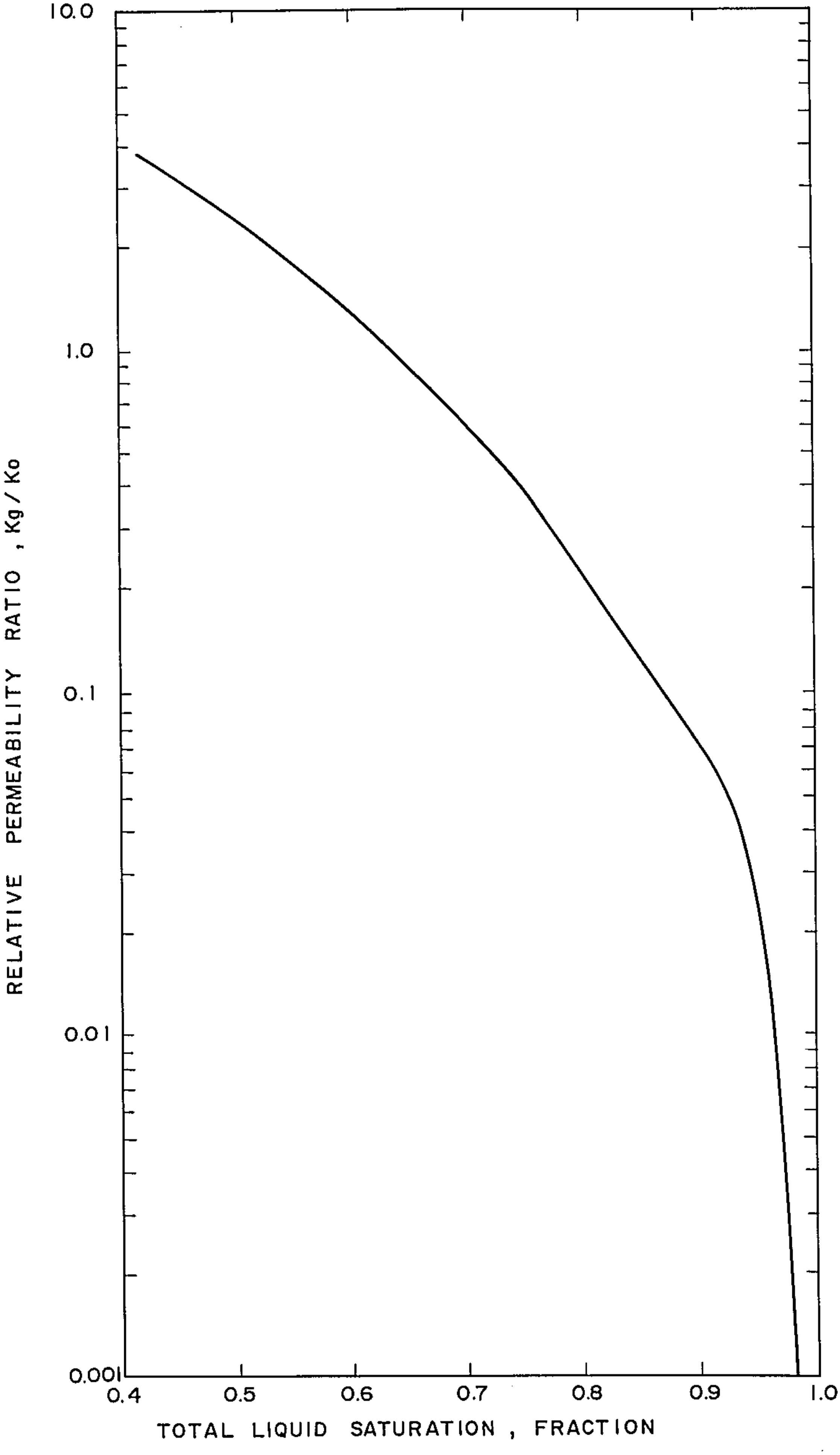


Fig. 1-3-7 GAS-OIL RELATIVE PERMEABILITY RATIO OF C ZONE, SAMARANG FIELD
Vol. III

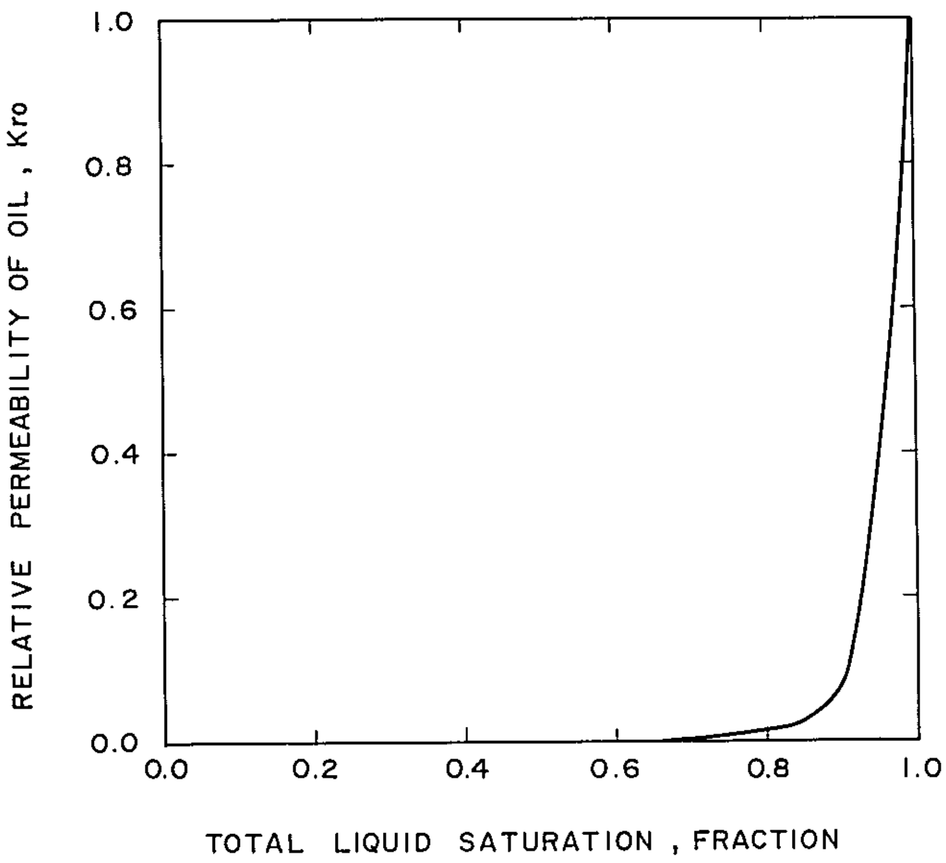


Fig. 1-3-8 Vol. III OIL RELATIVE PERMEABILITY CURVE OF A ZONE, SAMARANG FIELD

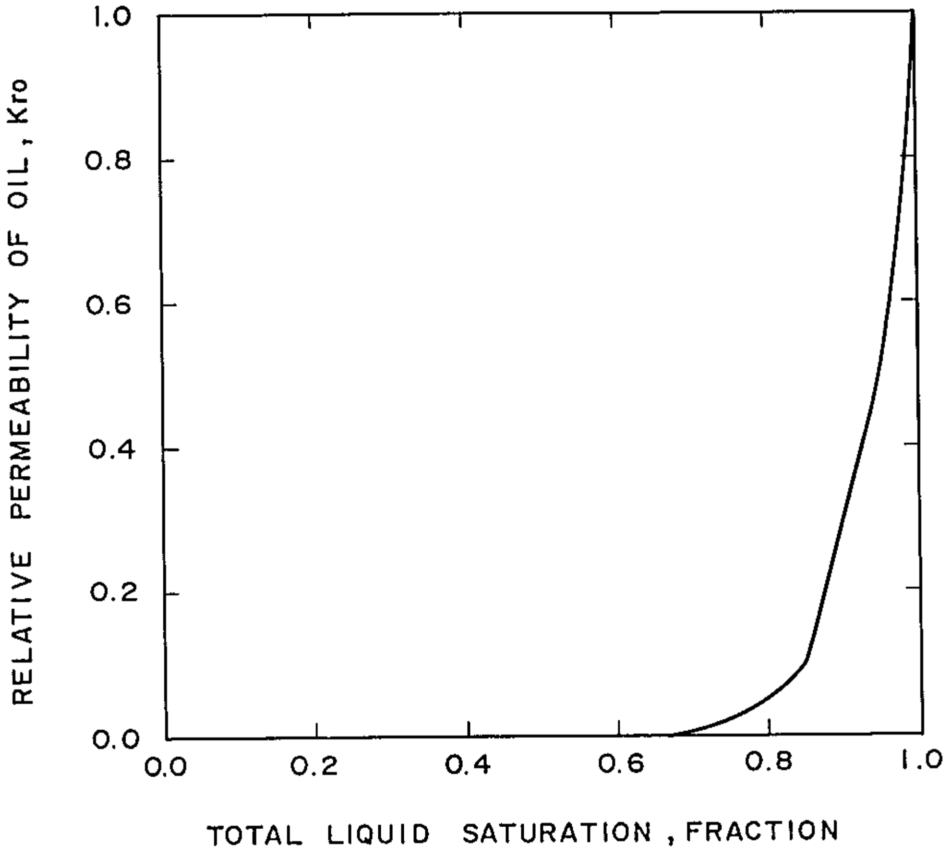


Fig. 1-3-9 Vol. III OIL RELATIVE PERMEABILITY CURVE OF B ZONE, SAMARANG FIELD

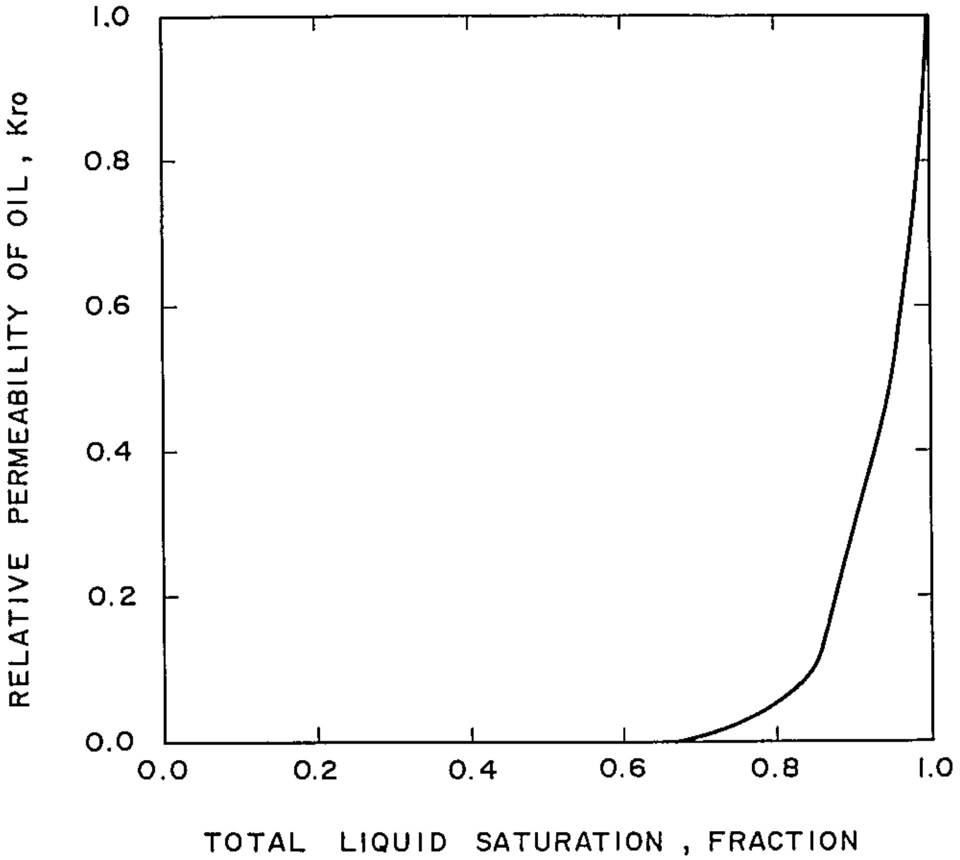


Fig. 1-3-10 OIL RELATIVE PERMEABILITY OF C ZONE, SAMARANG FIELD
Vol. III

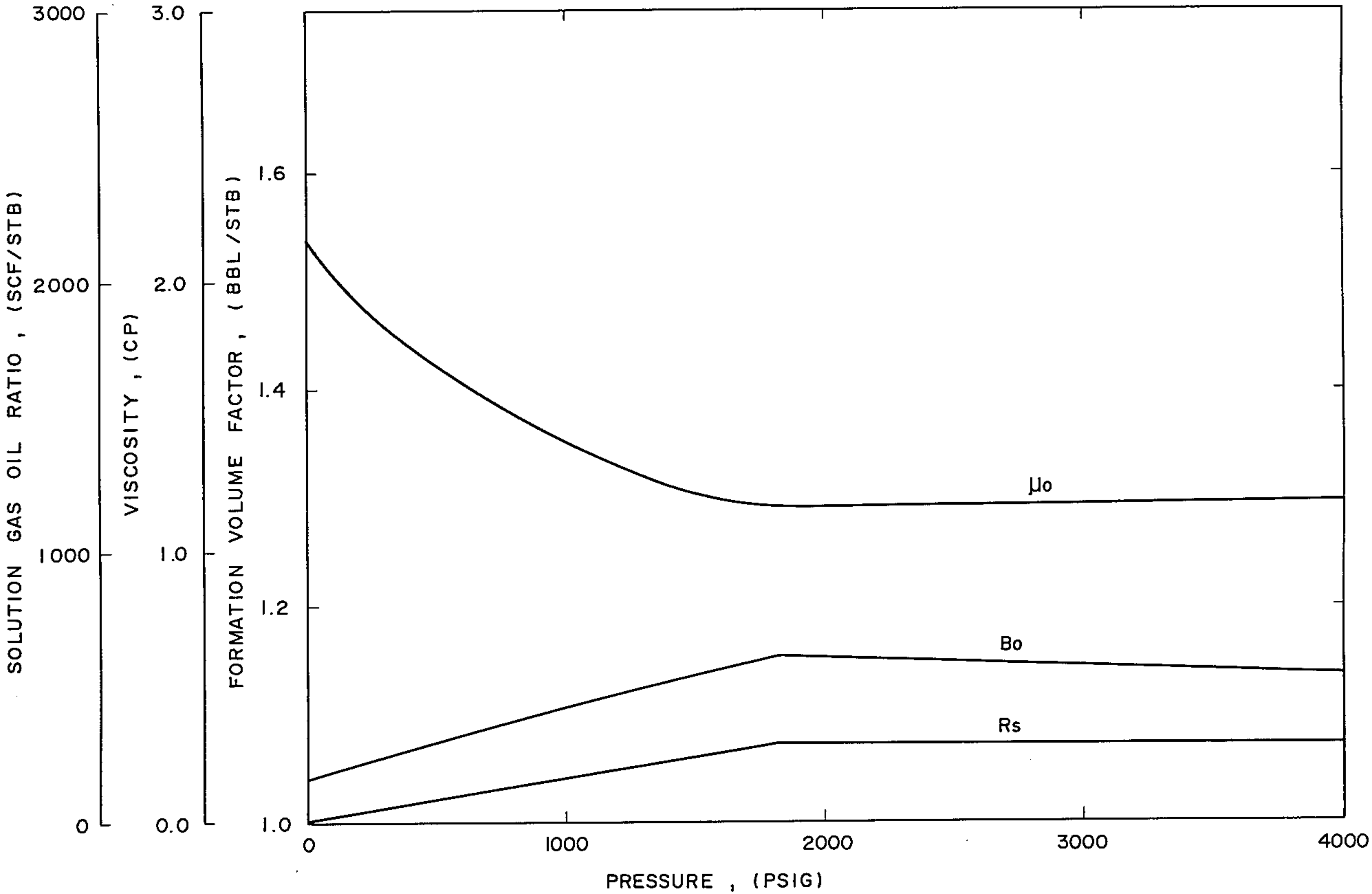


Fig. 1-3-11 OIL PROPERTIES OF A ZONE, SAMARANG FIELD
Vol. III

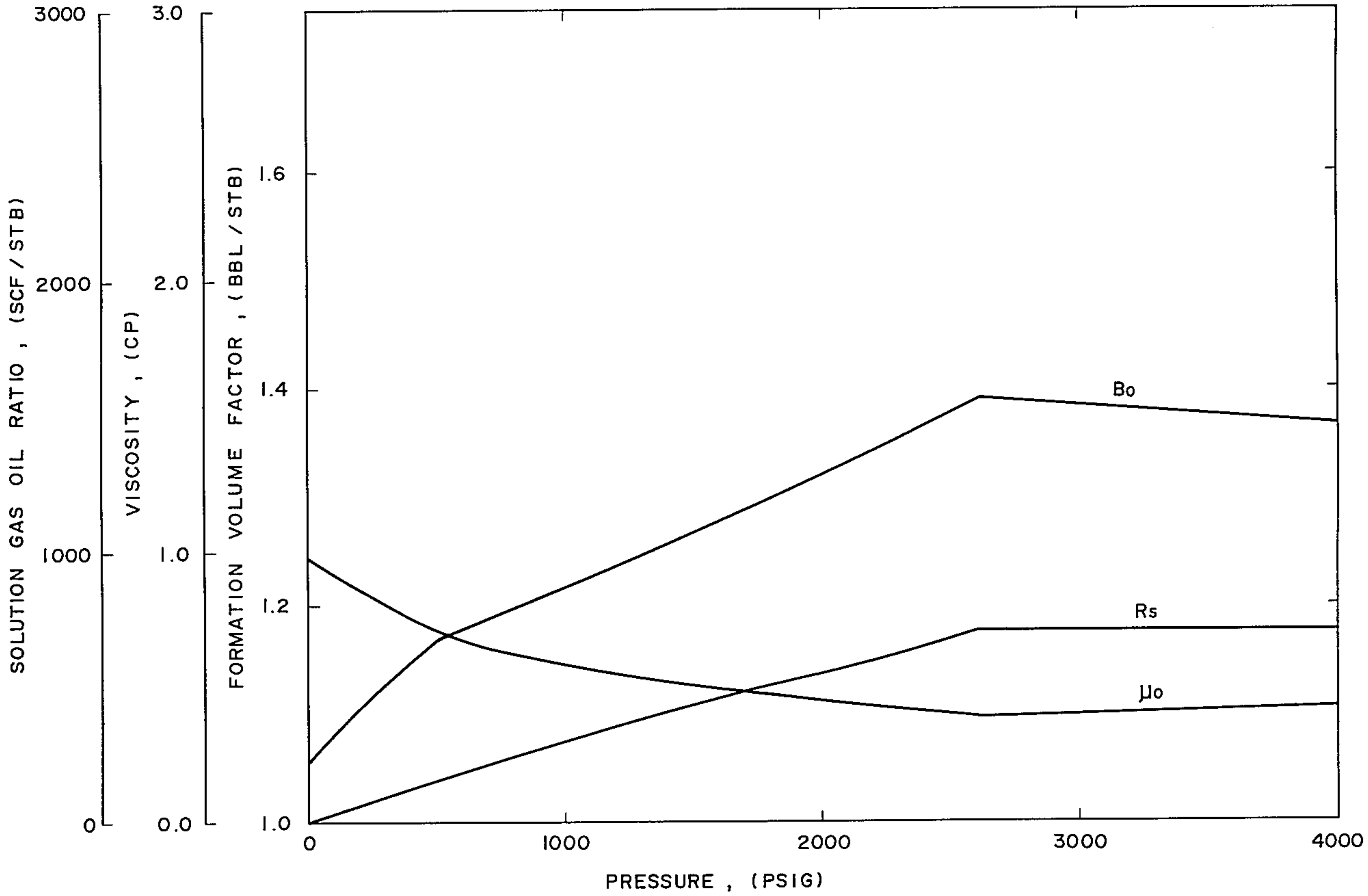


Fig. 1-3-12 OIL PROPERTIES OF B ZONE, SAMARANG FIELD
Vol. III

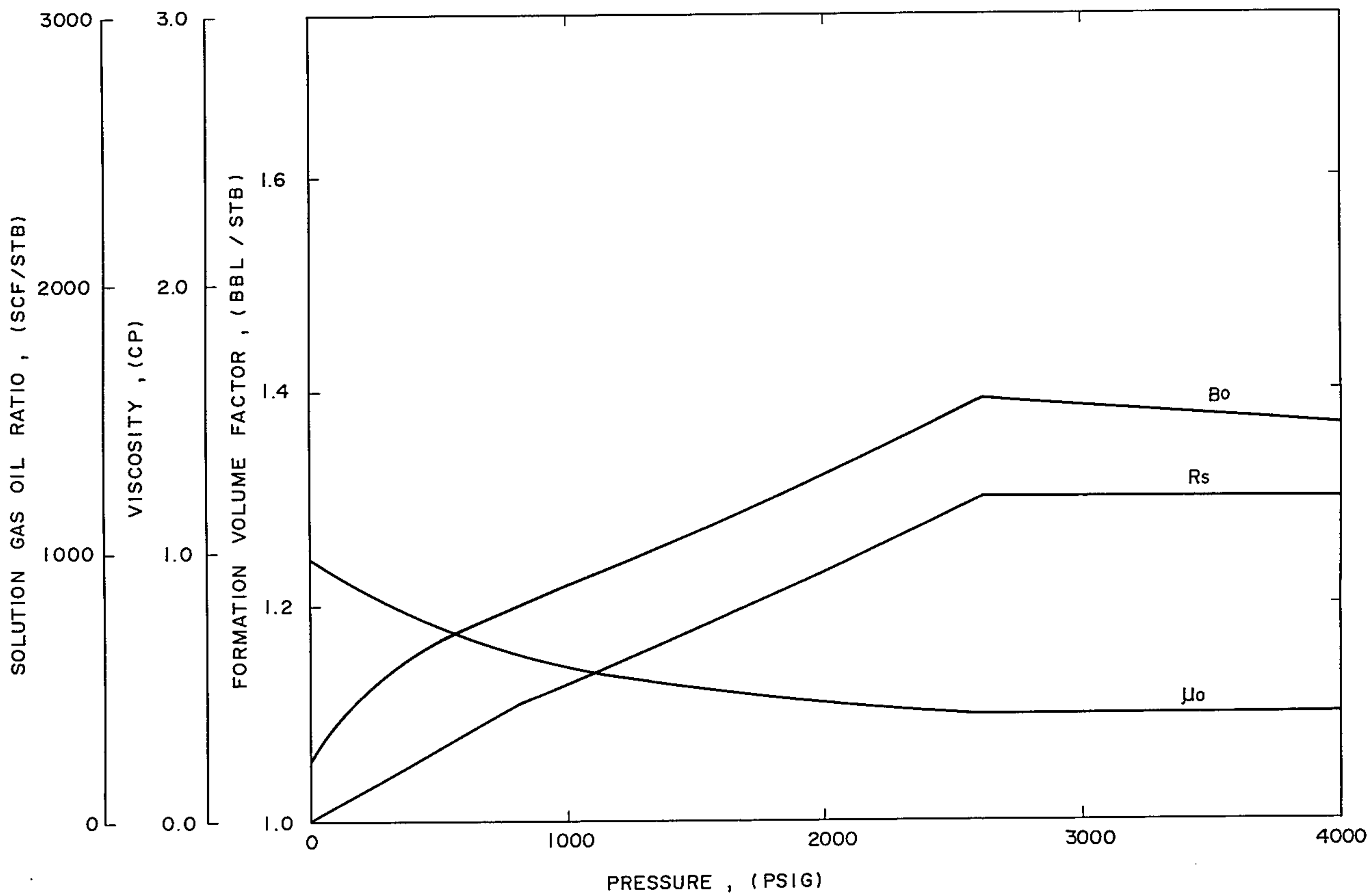


Fig. 1-3-13 OIL PROPERTIES OF C ZONE, SAMARANG FIELD
Vol. III

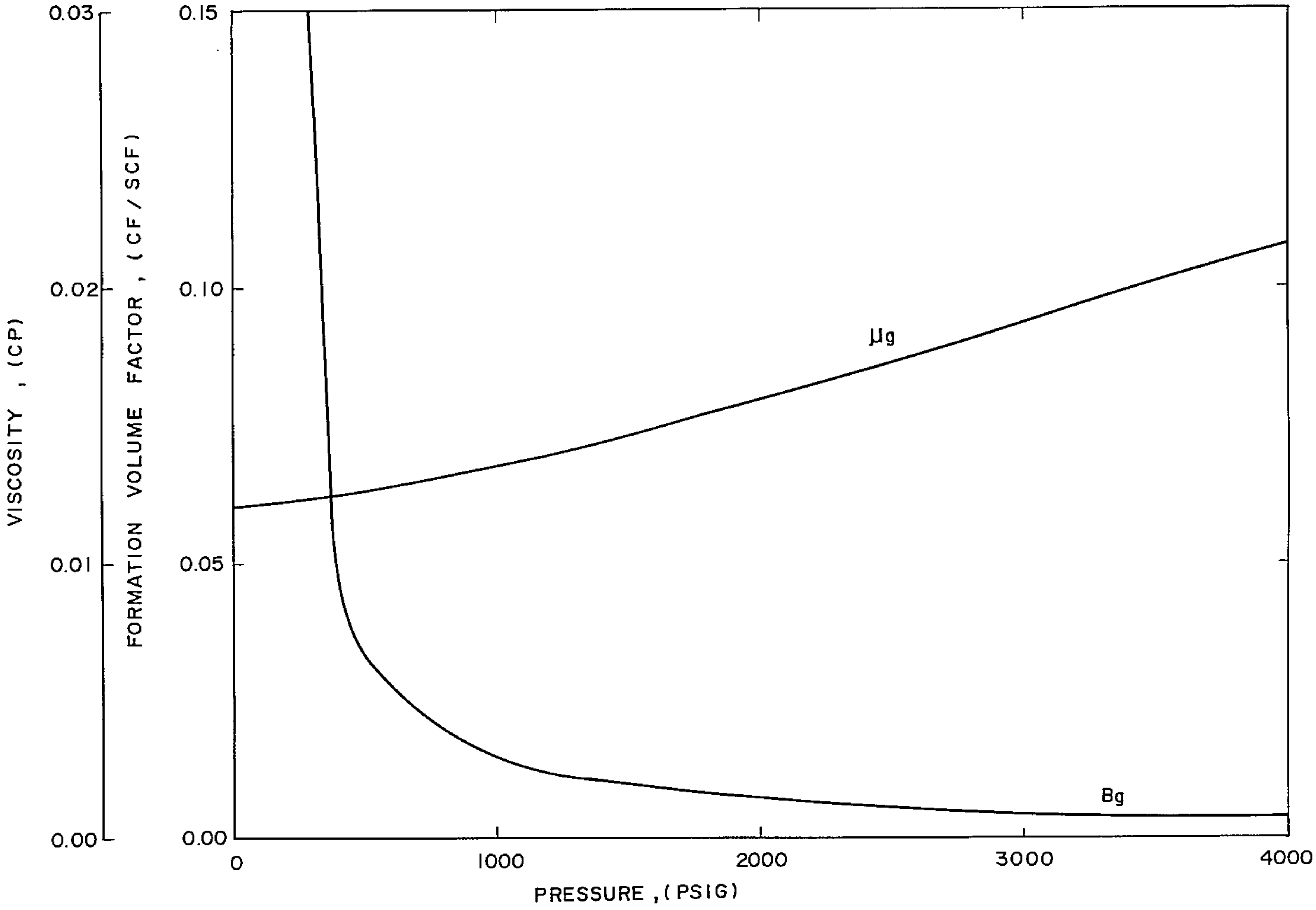


Fig. 1-3-14 GAS PROPERTIES OF A ZONE, SAMARANG FIELD
Vol. III

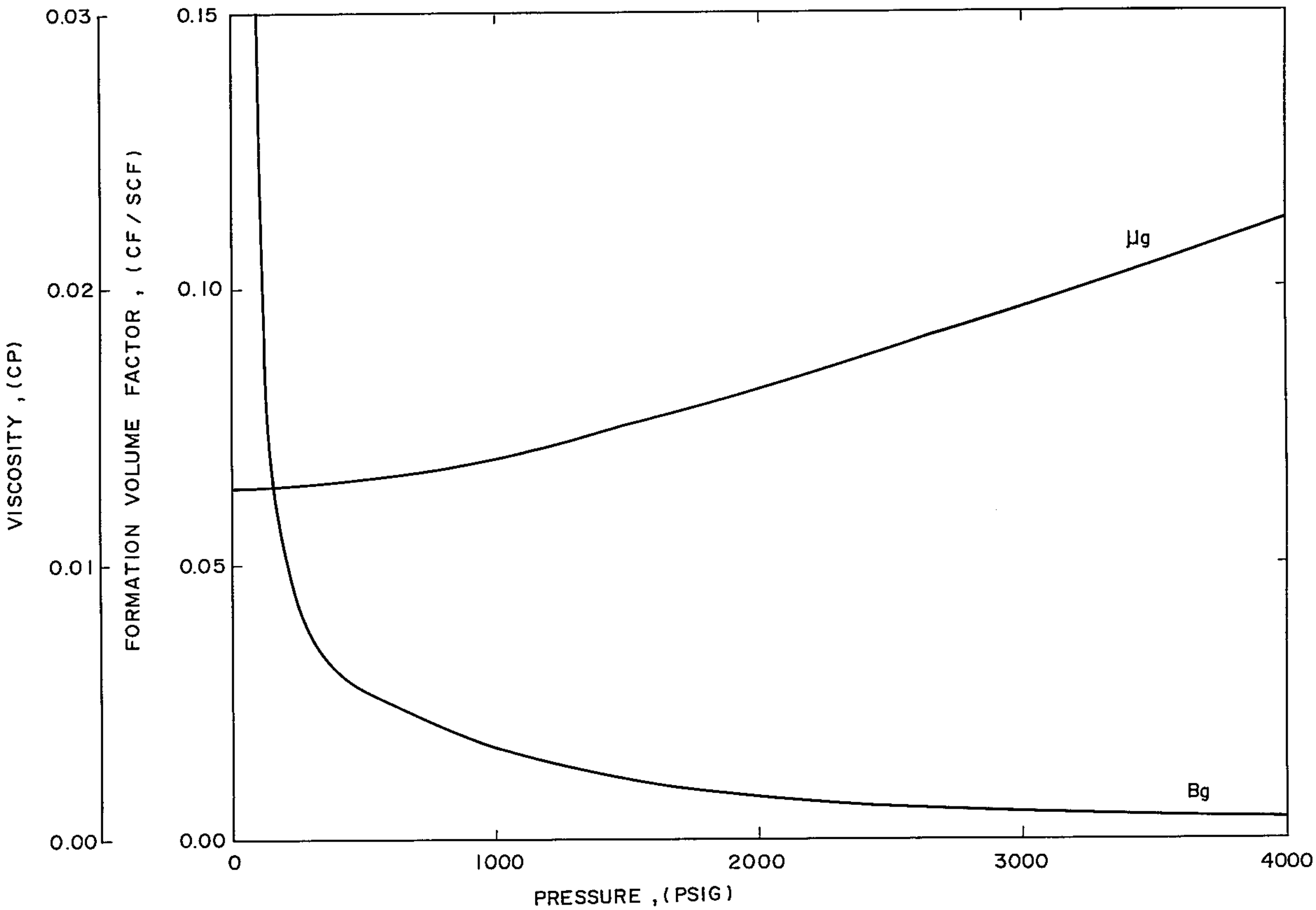


Fig. 1-3-15 GAS PROPERTIES OF B ZONE, SAMARANG FIELD
Vol. III

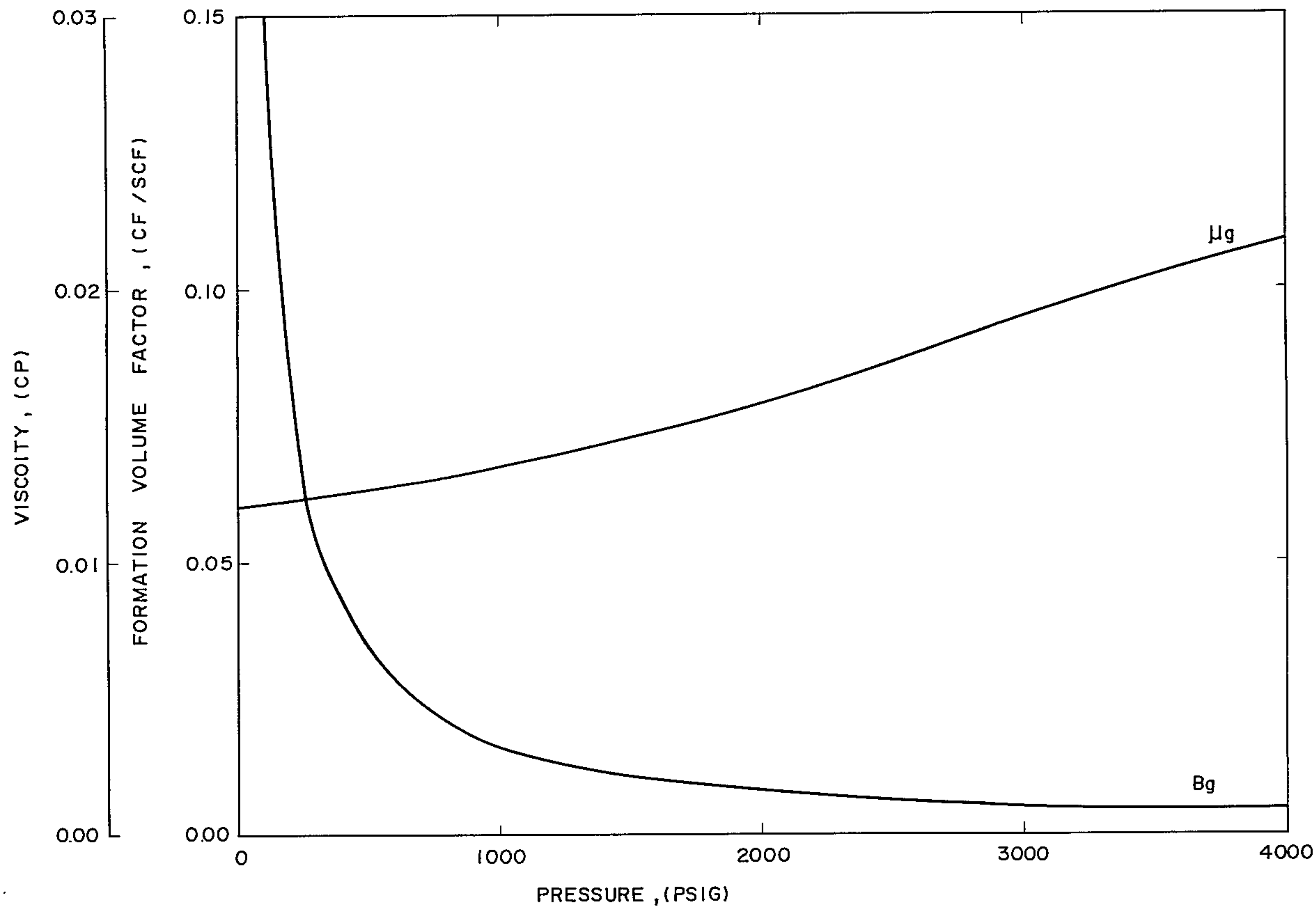


Fig. 1-3-16 GAS PROPERTIES OF C ZONE, SAMARANG FIELD
Vol. III

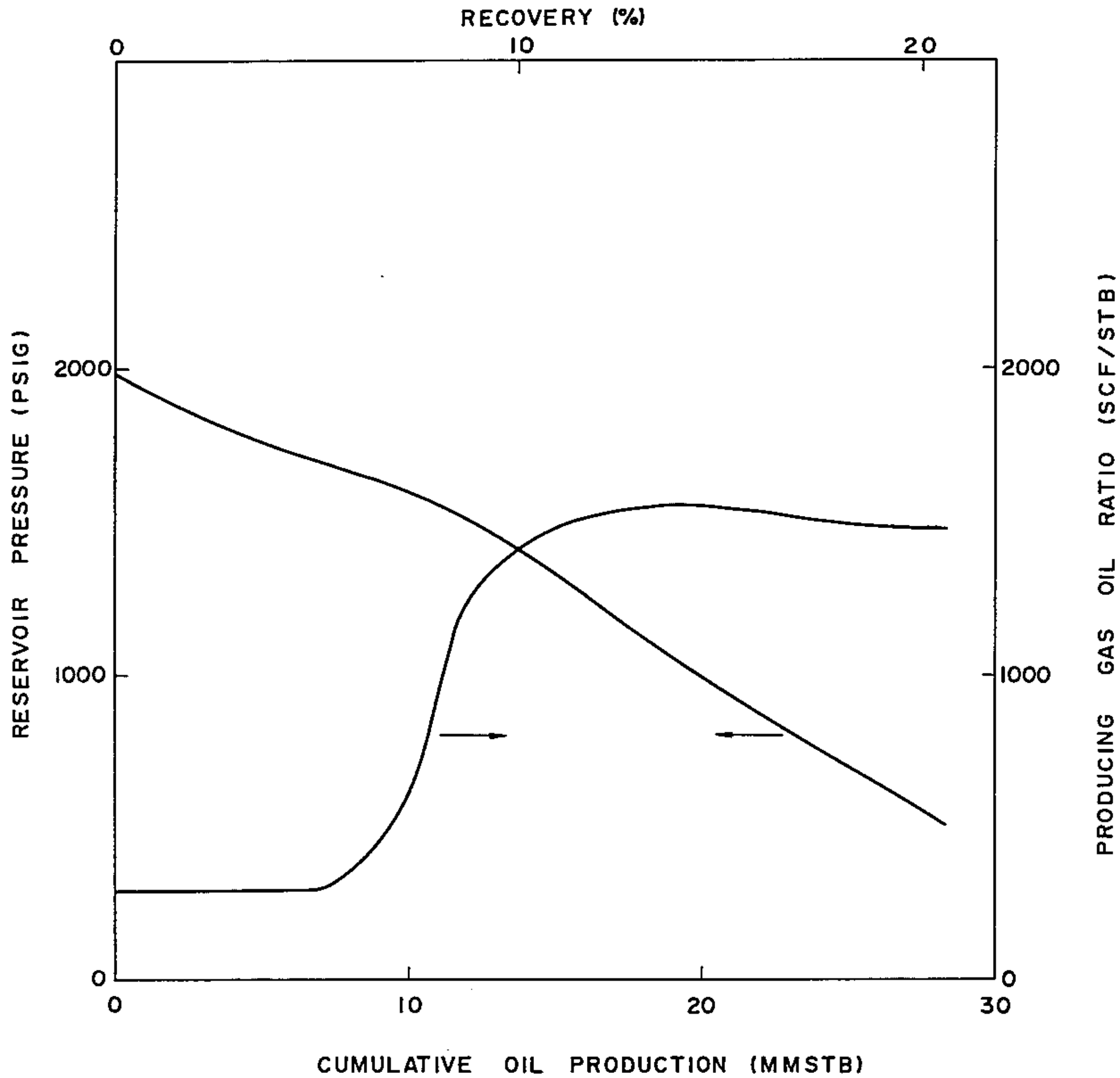


Fig. 1-3-17 Vol. III — CUMULATIVE OIL PRODUCTION VS. RESERVOIR PRESSURE AND PRODUCING GAS OIL RATIO OF A ZONE, SAMARANG FIELD

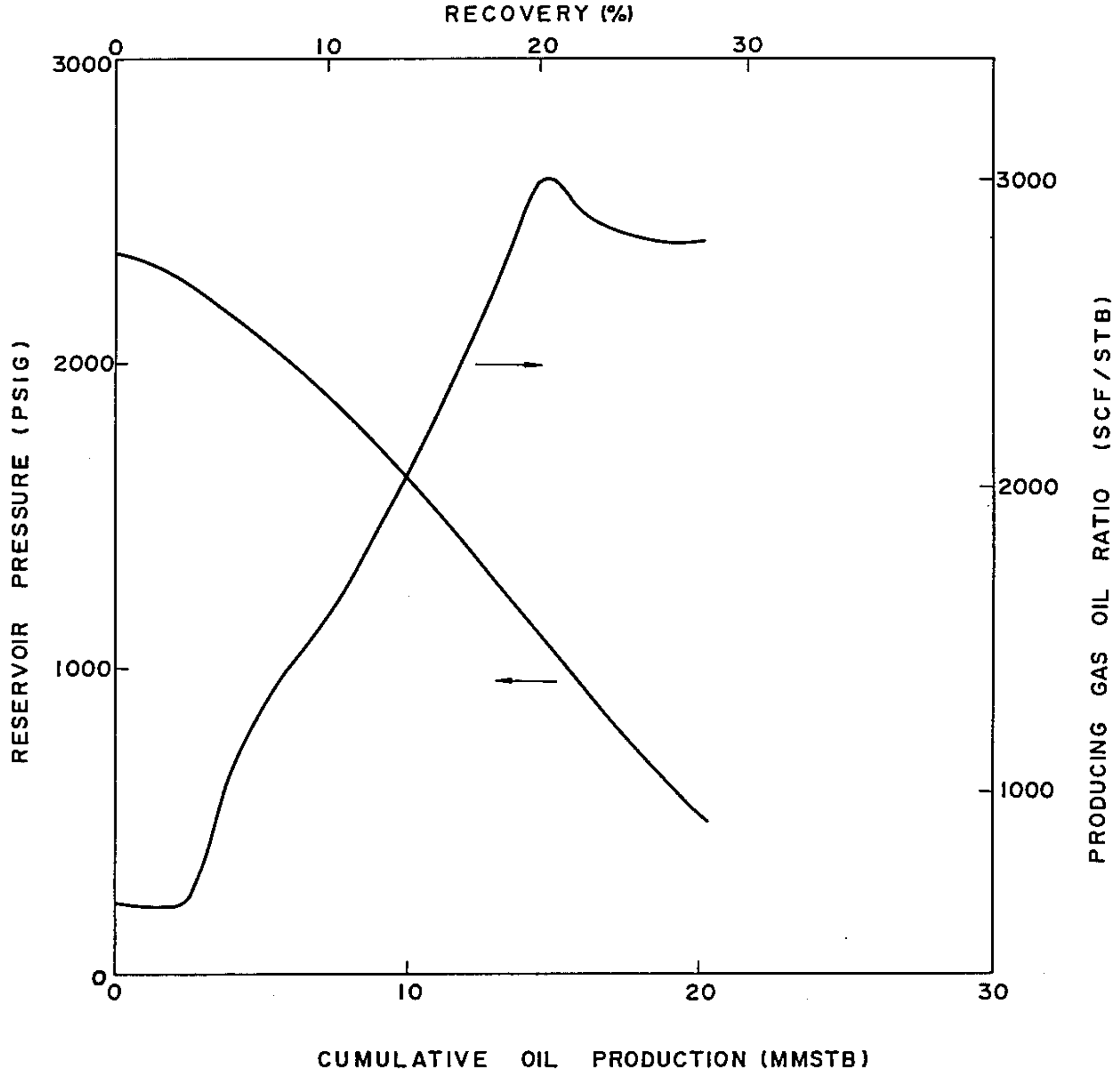


Fig. 1-3-18 Vol. III CUMULATIVE OIL PRODUCTION VS. RESERVOIR PRESSURE AND PRODUCING GAS OIL RATIO OF B ZONE, SAMARANG FIELD

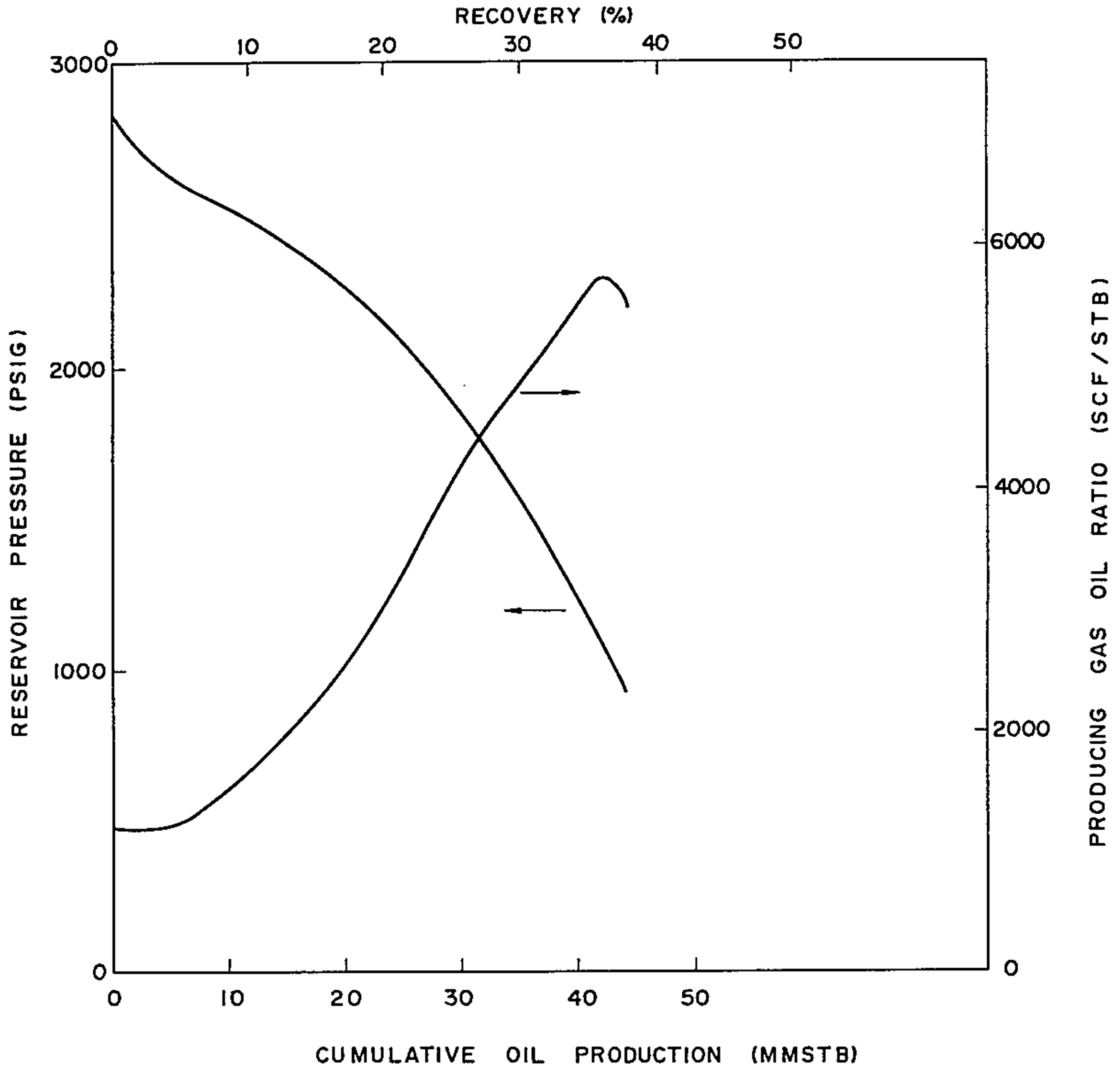


Fig. 1-3-19 CUMULATIVE OIL PRODUCTION VS. RESERVOIR PRESSURE AND PRODUCING GAS OIL RATIO OF C ZONE, SAMARANG FIELD

Vol. III

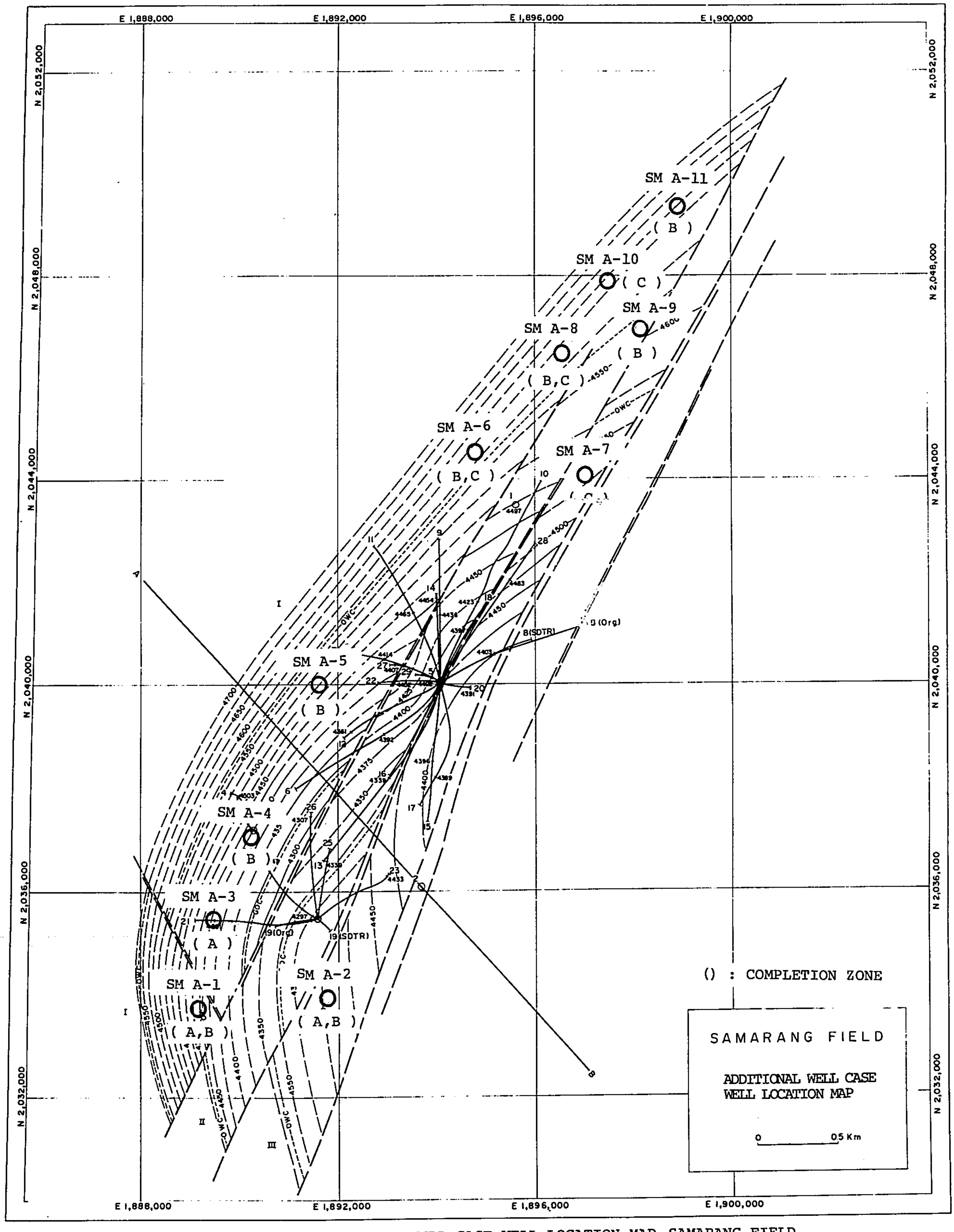


Fig. 1-3-20 ADDITIONAL WELL CASE-WELL LOCATION MAP ,SAMARANG FIELD
Vol. III

Fig. 2-1-1

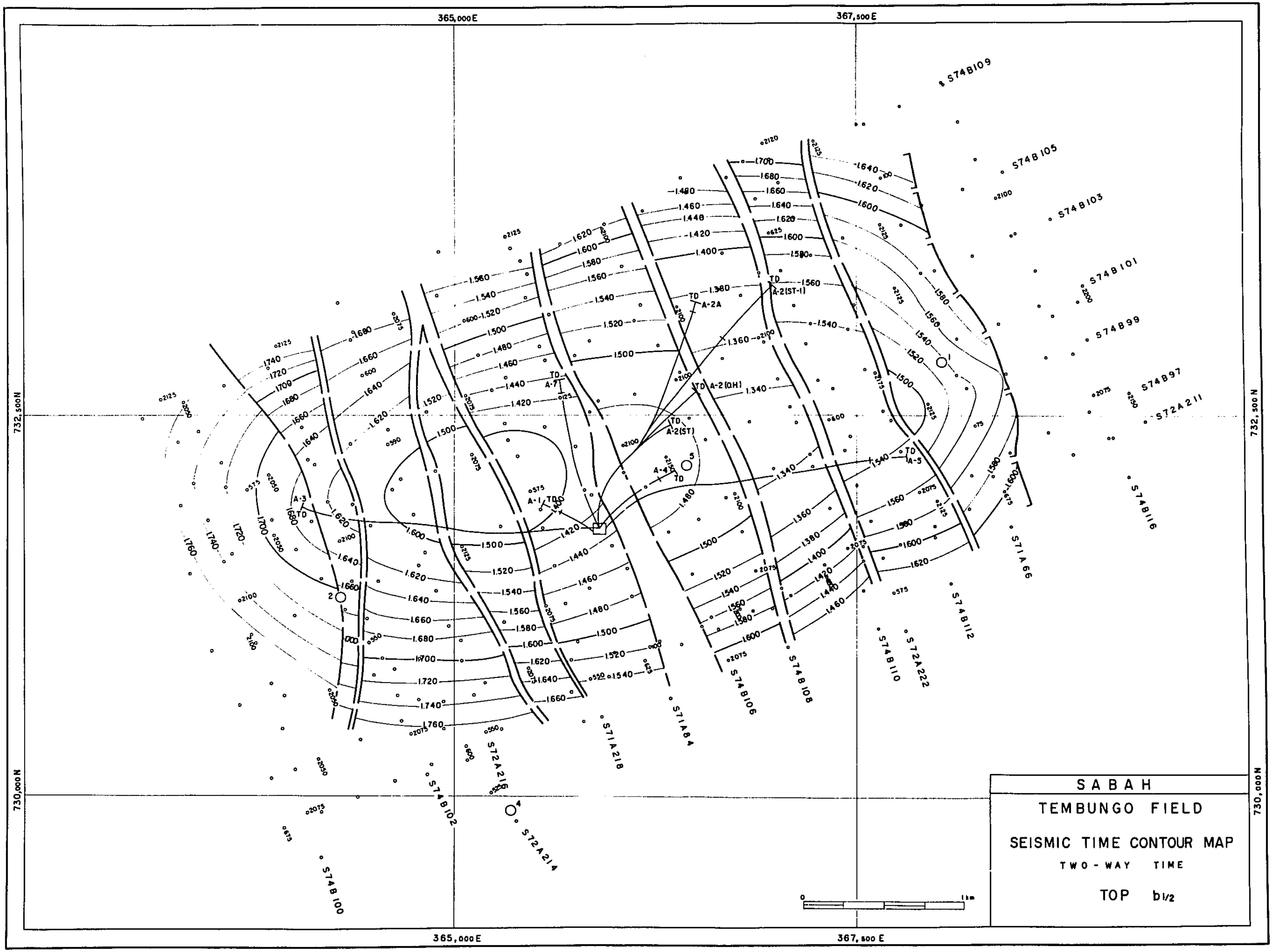


Fig. 2-1-1 TIME CONTOUR MAP, TEMBUNGO FIELD, TOP b 1/2
Vol. III

Fig. 2-1-2

Fig. 2-1-2 SEISMIC SECTION, TEMBUNGO FIELD, Line S74B101
Vol. III

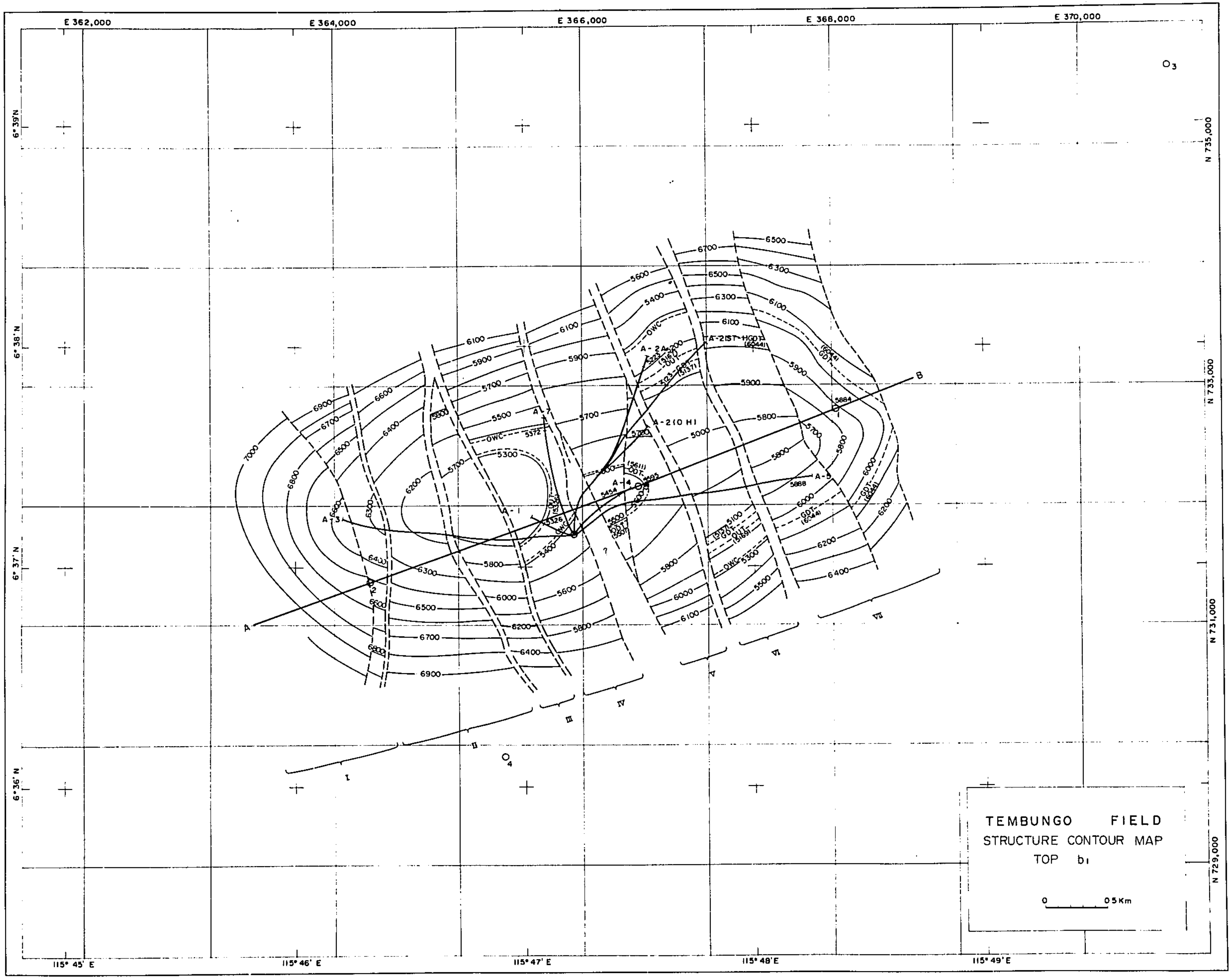


Fig. 2-2-1 STRUCTURE CONTOUR MAP, TEMBUNGO FIELD, TOP b1
Vol. III

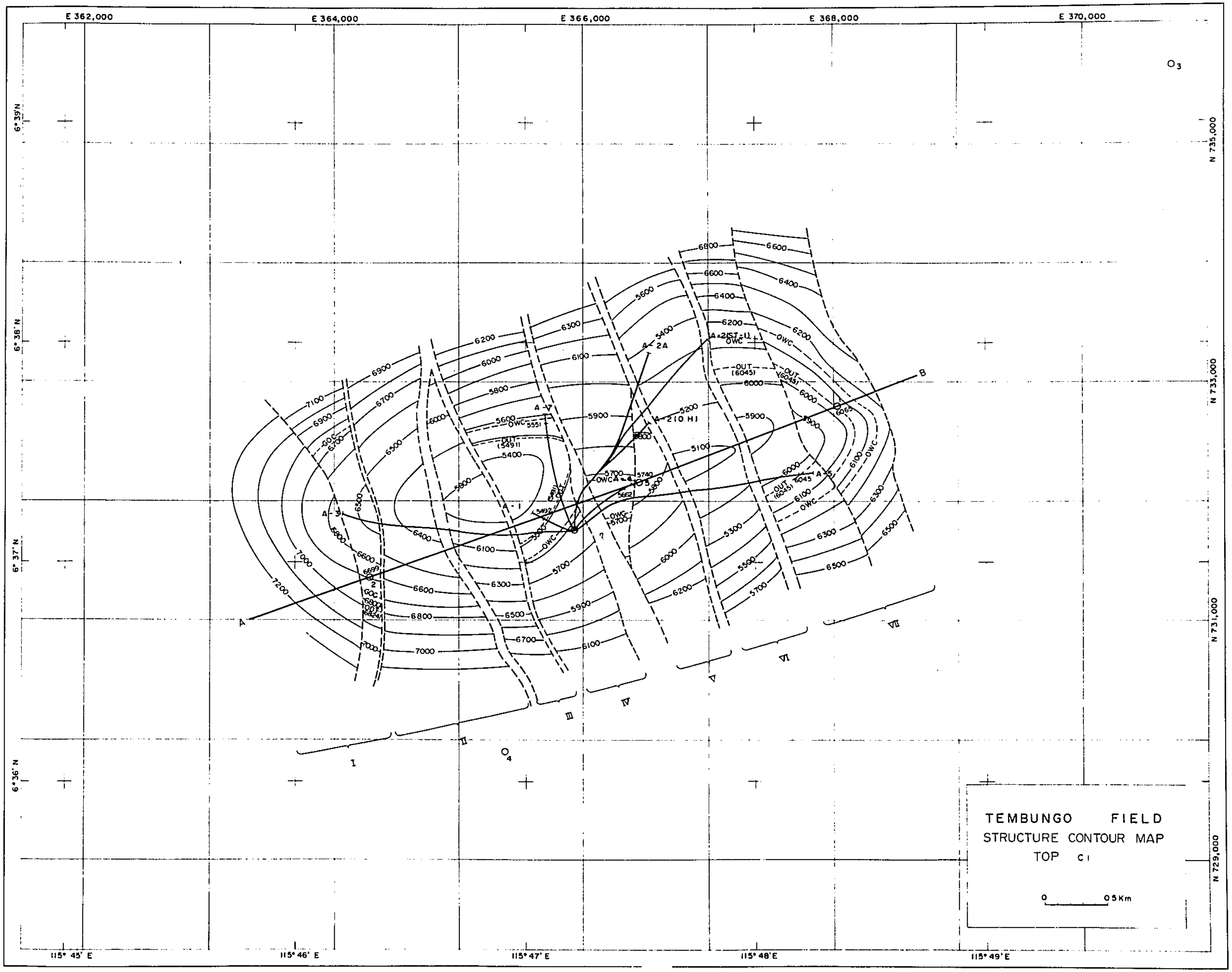


Fig. 2-2-2 STRUCTURE CONTOUR MAP, TEMBUNGO FIELD, TOP c1
Vol. III

STRUCTURAL CROSS-SECTION
TEMBUNGO FIELD

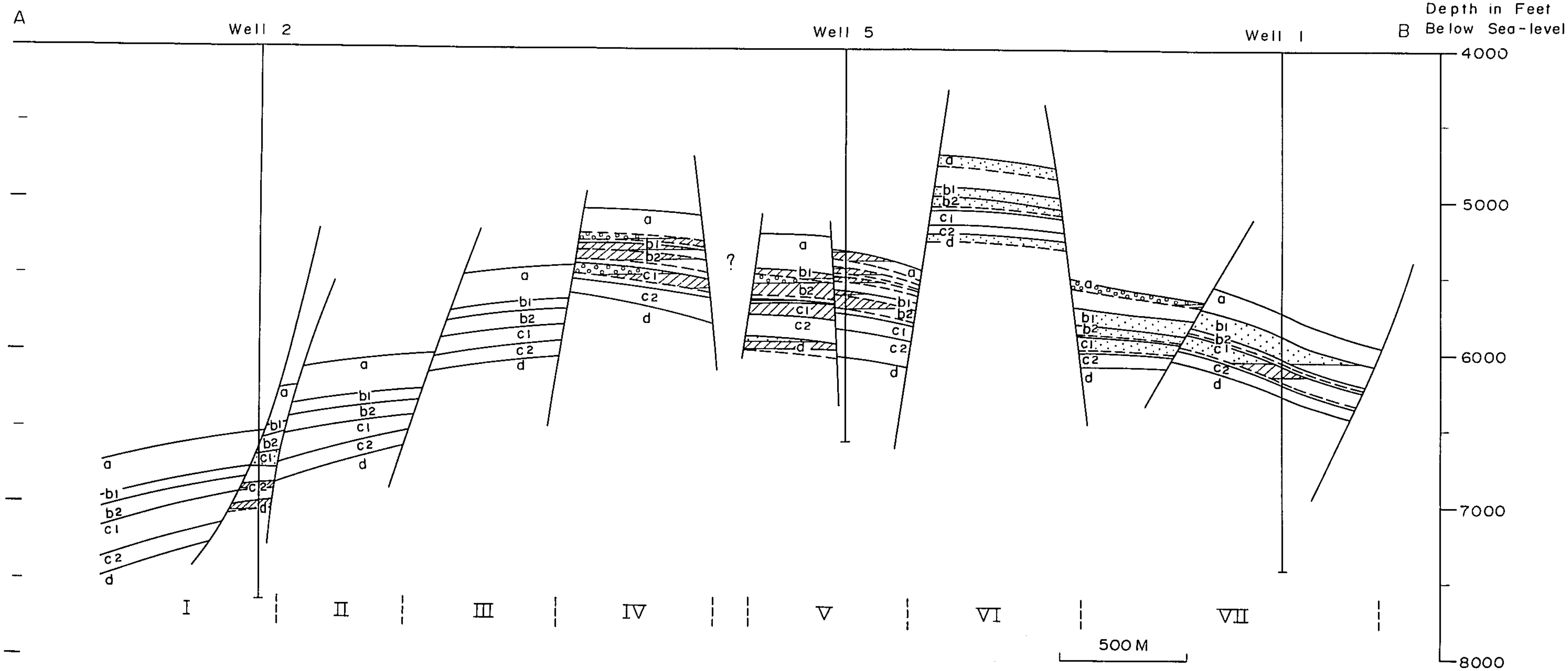


Fig. 2-2-3 STRUCTURAL CROSS-SECTION, TEMBUNGO FIELD
Vol. III

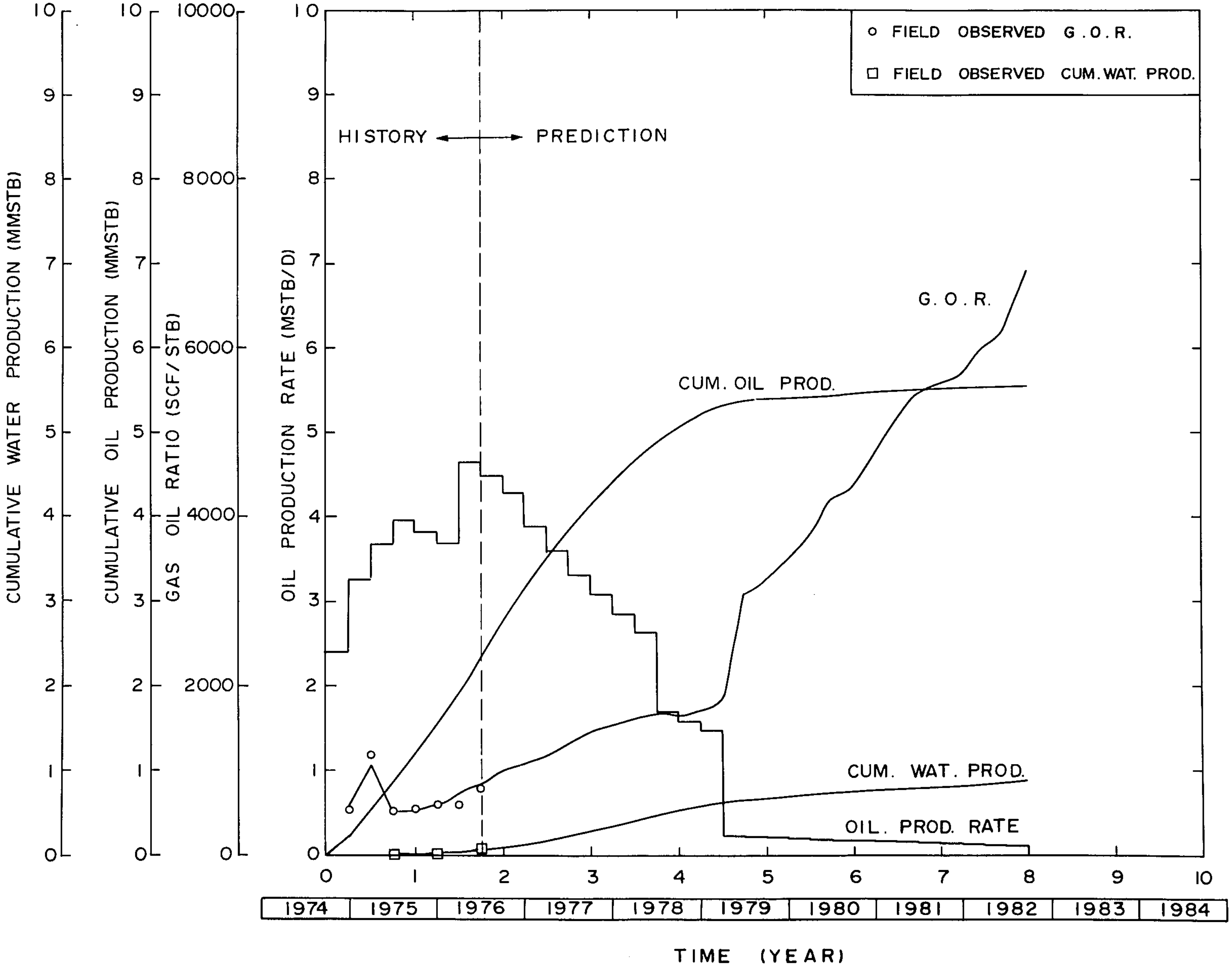


Fig. 2-3-1 Vol. III **PREDICTED PERFORMANCE OF TEMBUNGO FIELD**

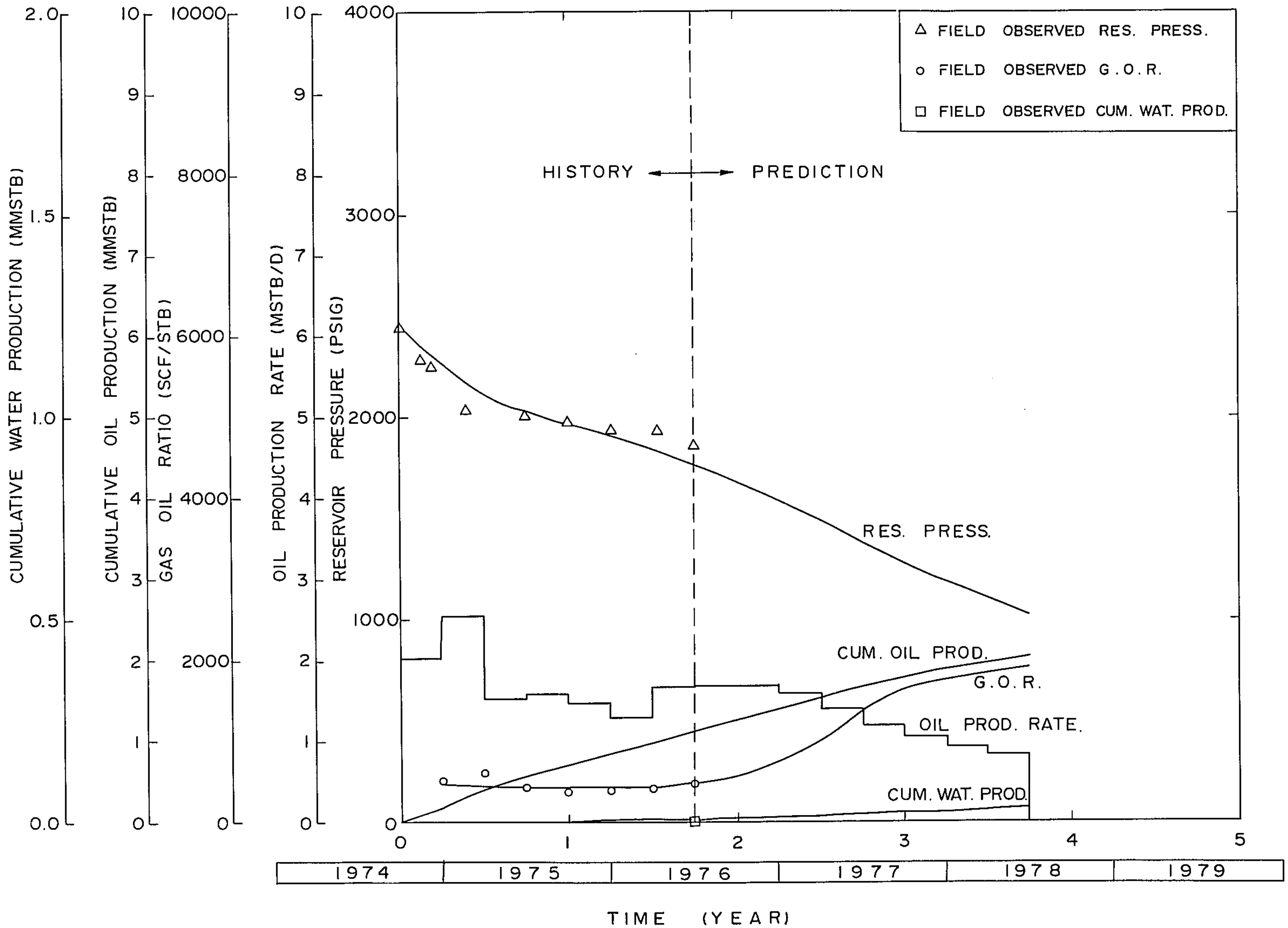


Fig. 2-3-2 PREDICTED PERFORMANCE OF MODEL-1, TEMBUNGO FIELD
Vol. III

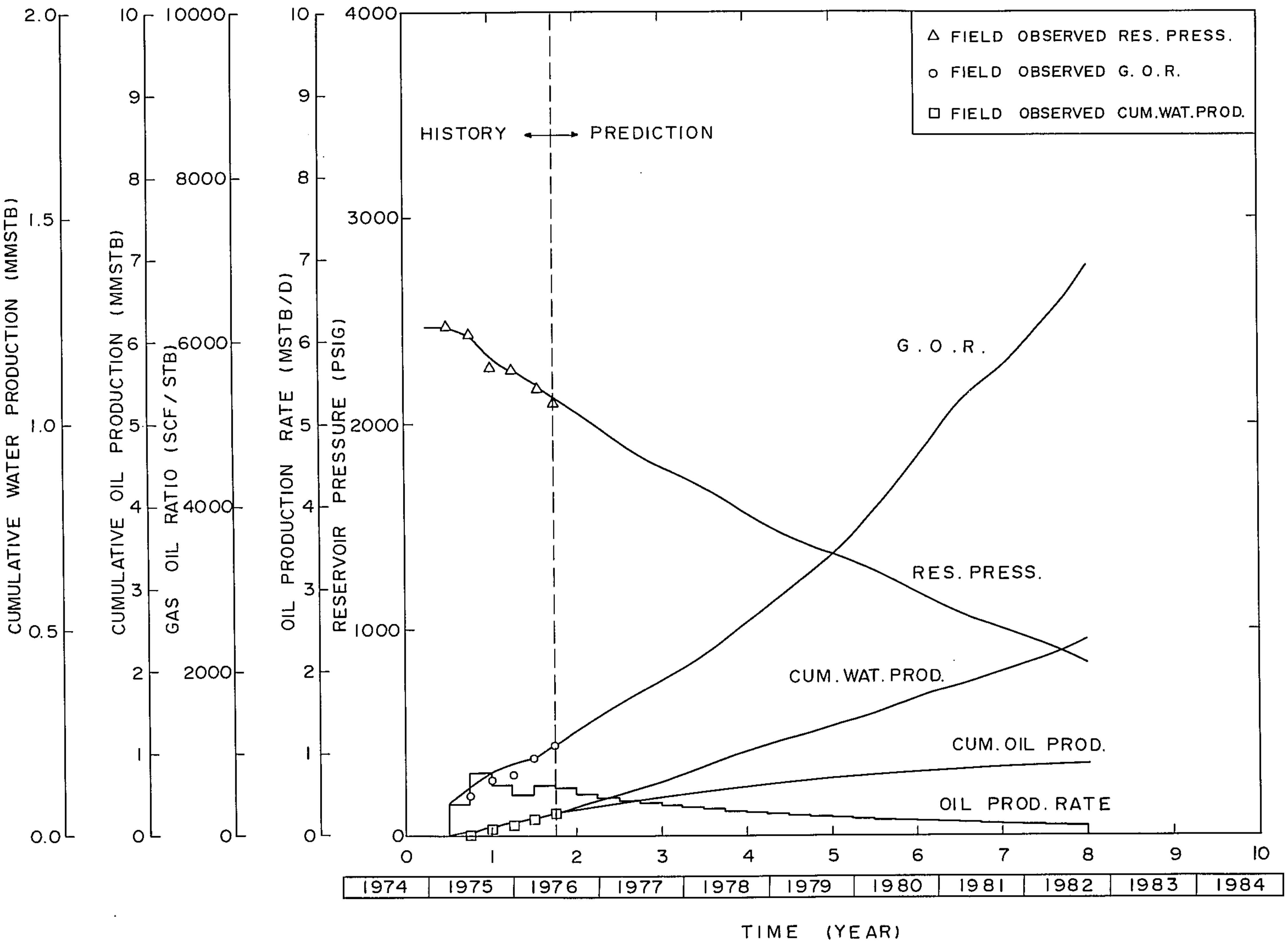


Fig. 2-3-3 PREDICTED PERFORMANCE OF MODEL 2, TEMBUNGO FIELD
Vol. III

Fig. 2-3-4

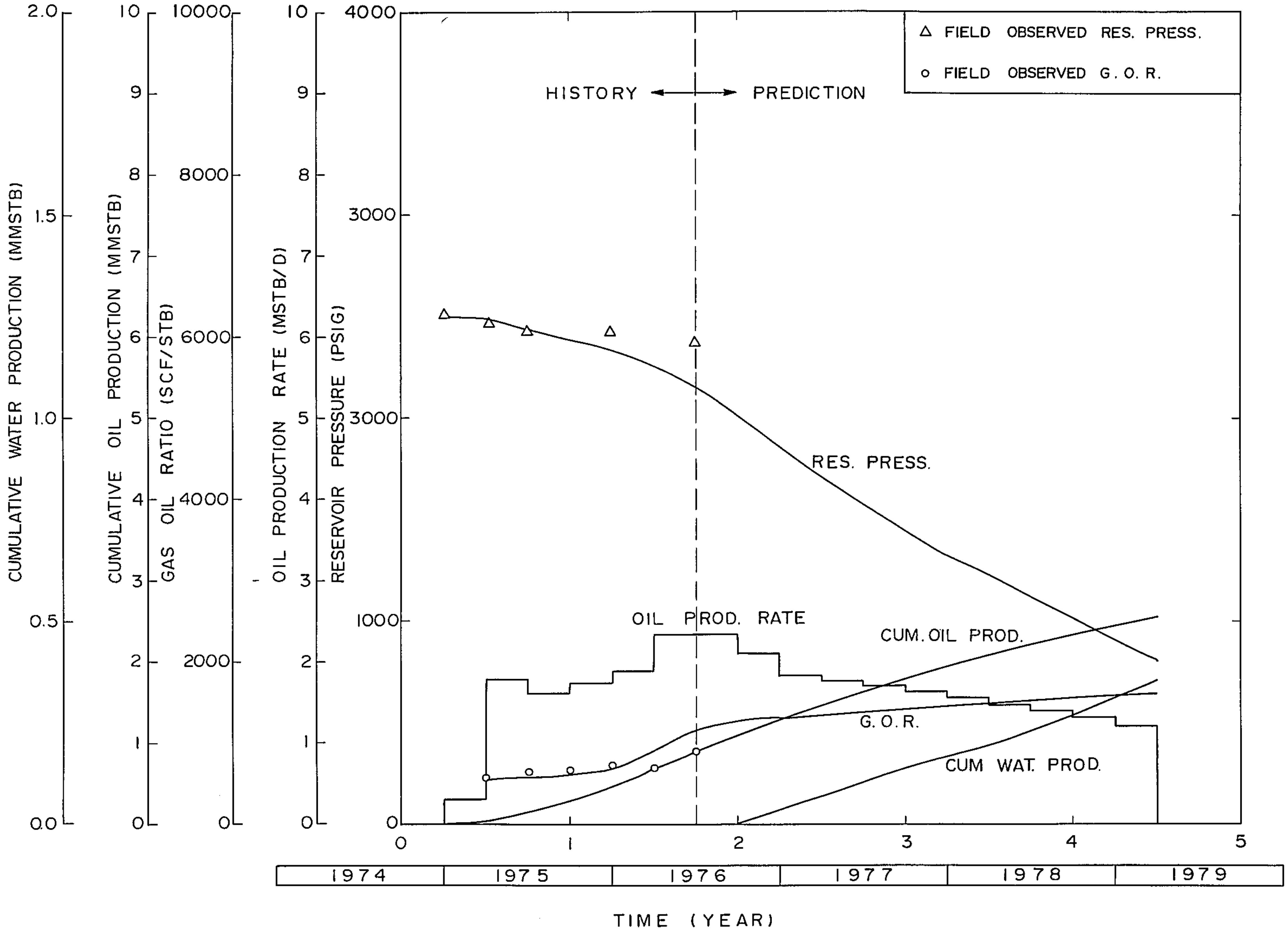


Fig. 2-3-4 PREDICTED PERFORMANCE OF MODEL 3, TEMBUNGO FIELD
Vol. III

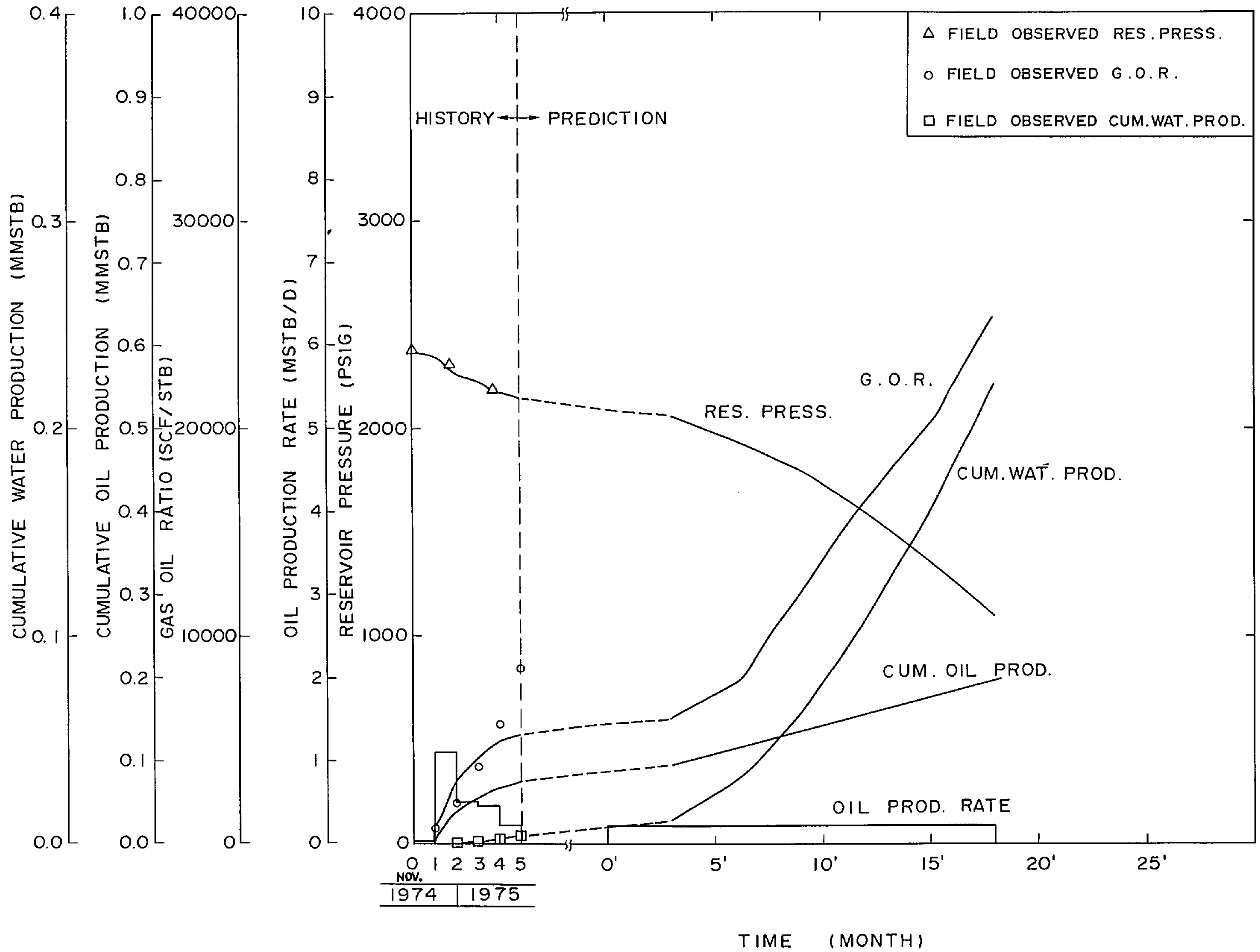


Fig. 2-3-5 PREDICTED PERFORMANCE OF MODEL 4, TEMBUNGO FIELD
Vol. III

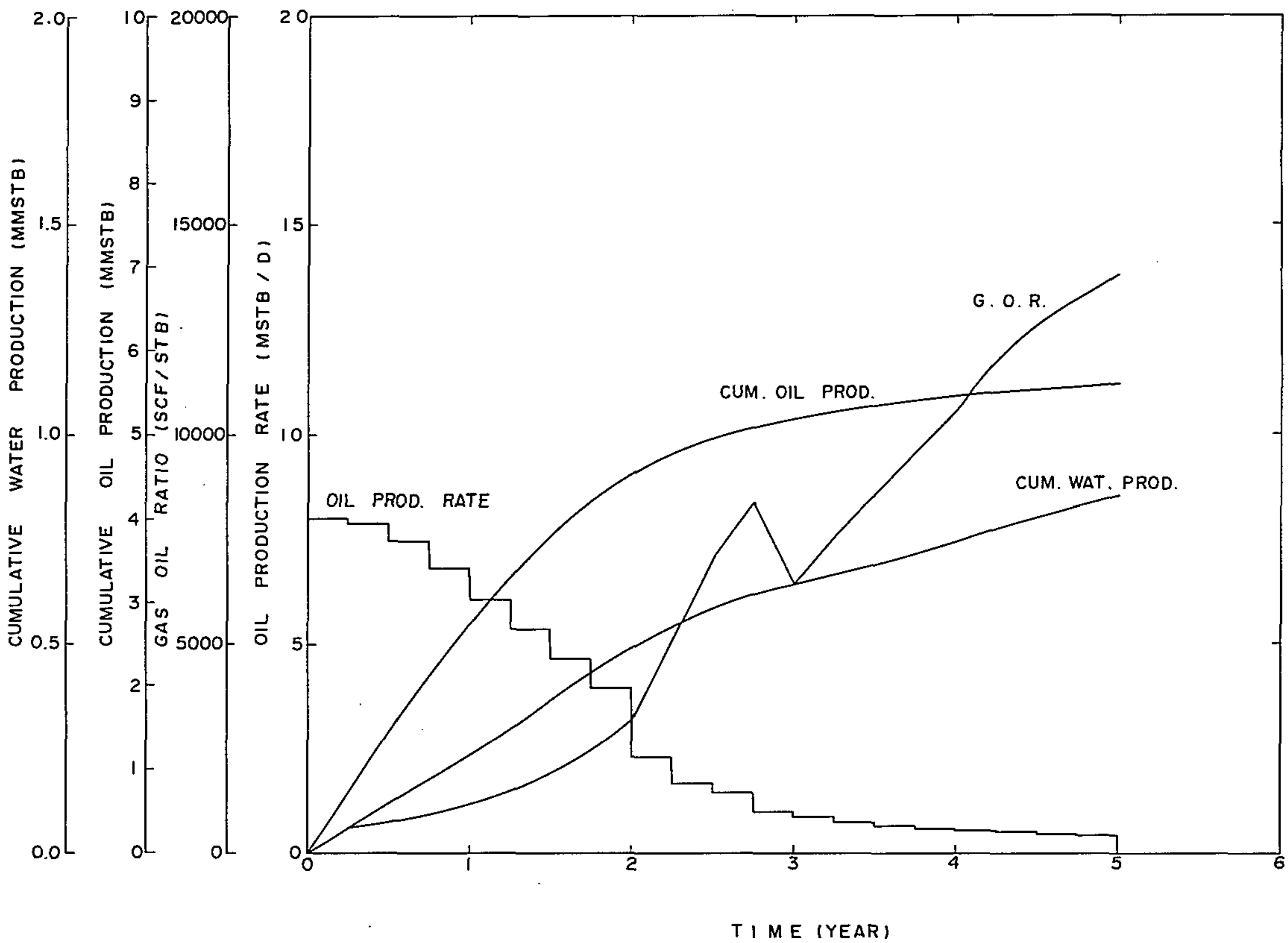


Fig. 2-3-6 PREDICTED PERFORMANCE OF ADDITIONAL WELL CASE, TEMBUNGO FIELD

Vol. III

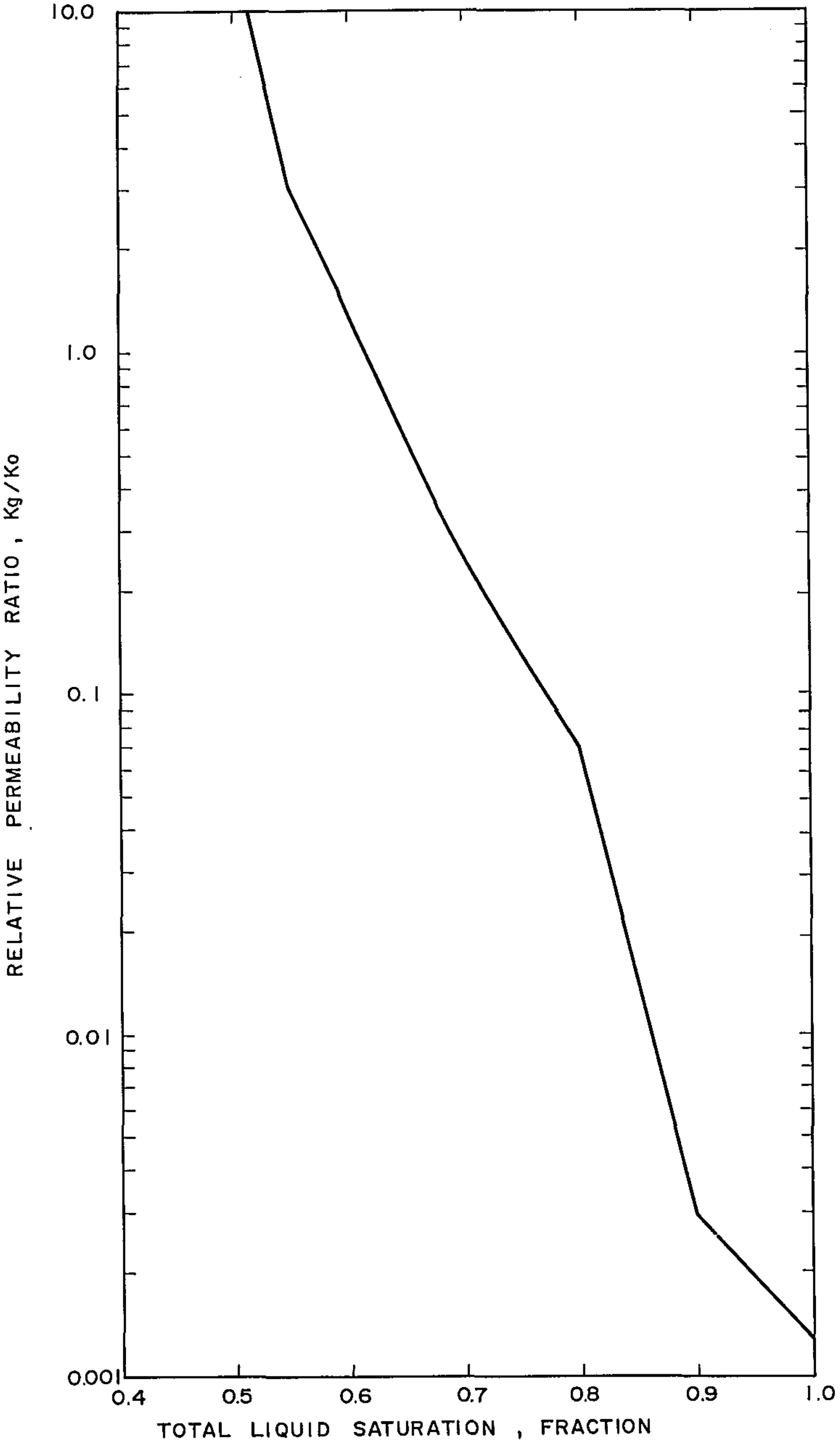


Fig. 2-3-7 GAS-OIL RELATIVE PERMEABILITY RATIO OF MODEL 1, TEMBUNGO FIELD
Vol. III

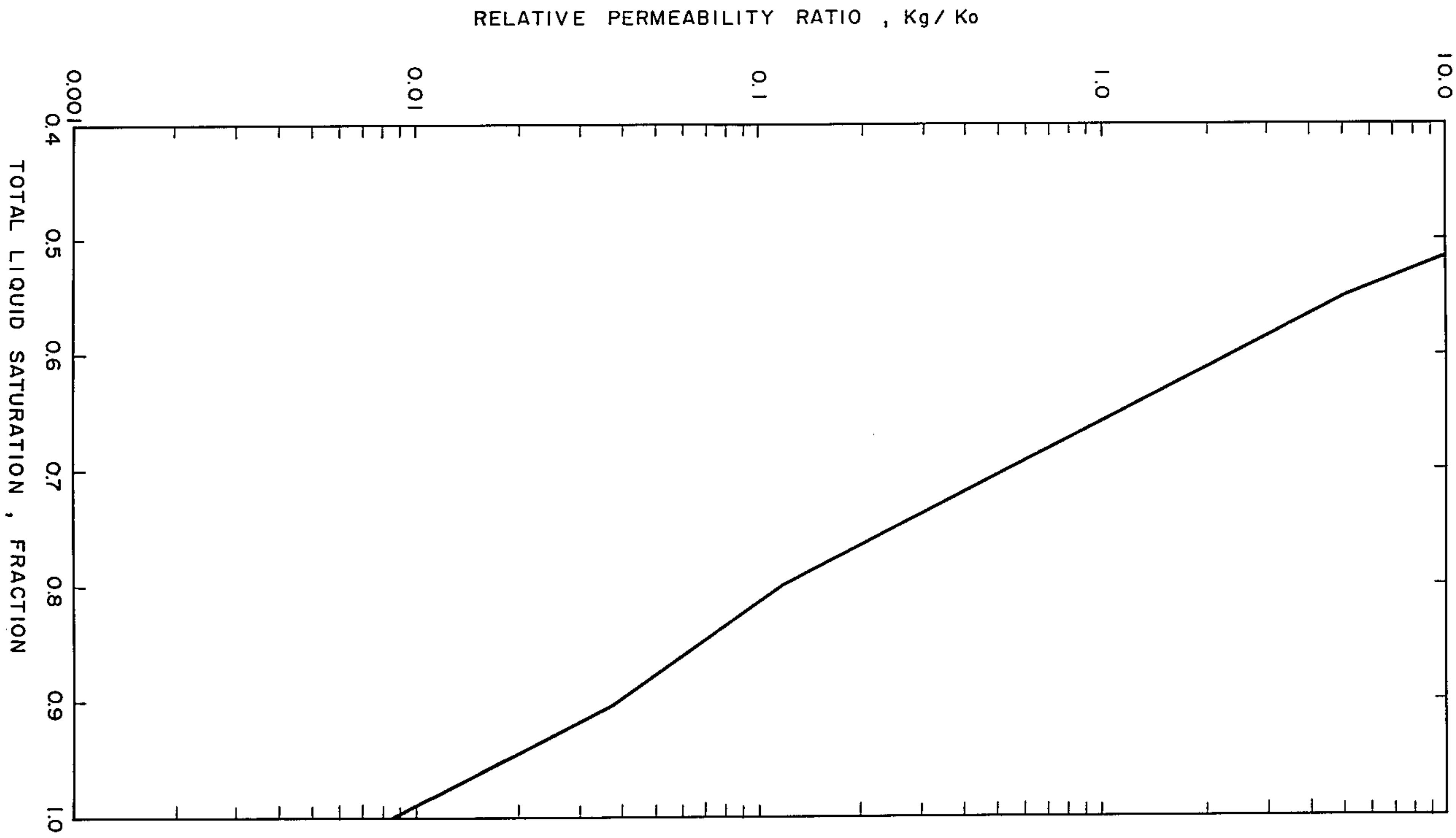


Fig. 2-3-8 GAS-OIL RELATIVE PERMEABILITY RATIO OF MODEL 2, TEMBUNGO FIELD
Vol. III

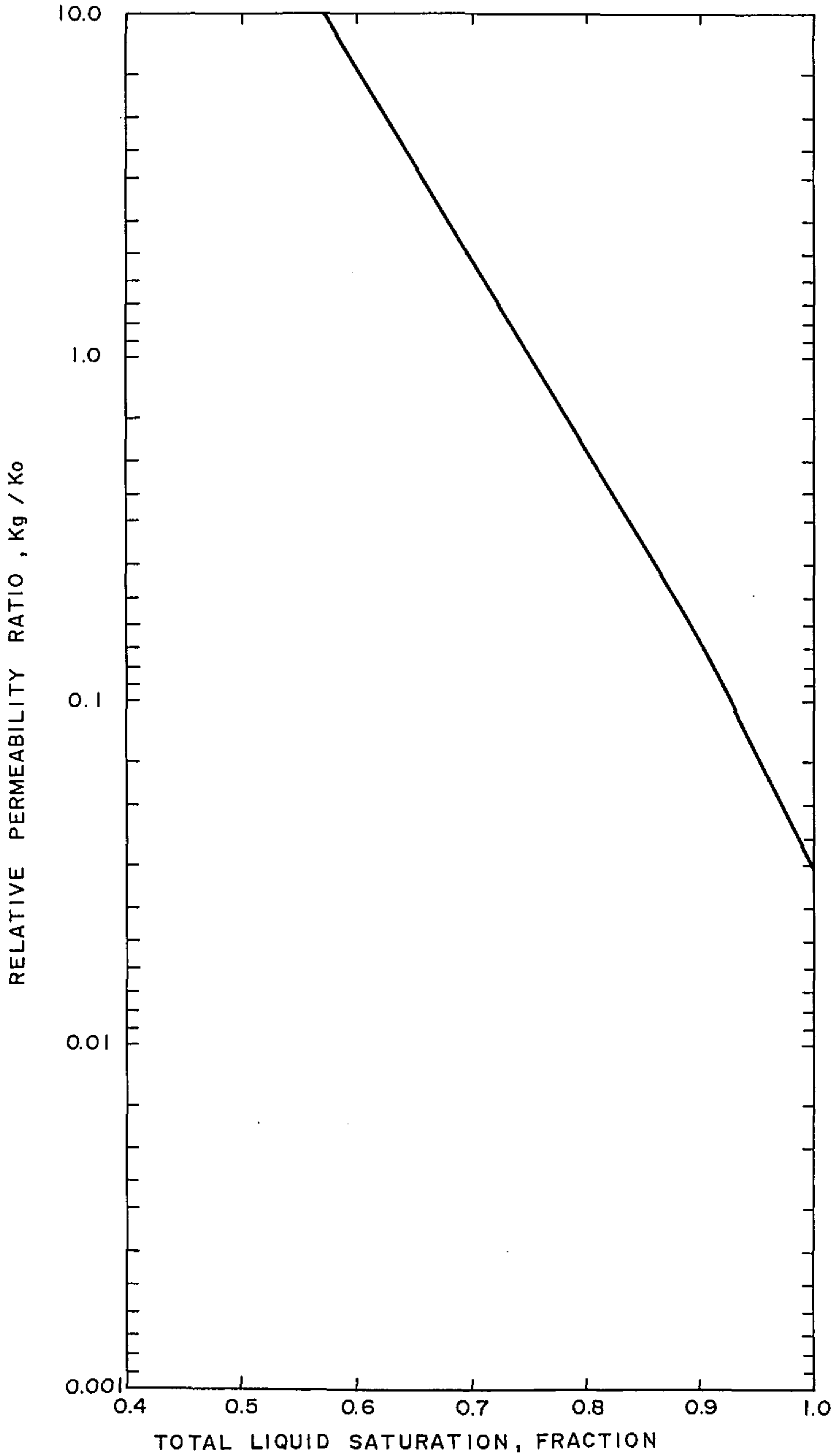


Fig. 2-3-9 GAS-OIL RELATIVE PERMEABILITY RATIO OF MODEL 3, TEMBUNGO FIELD
Vol. III

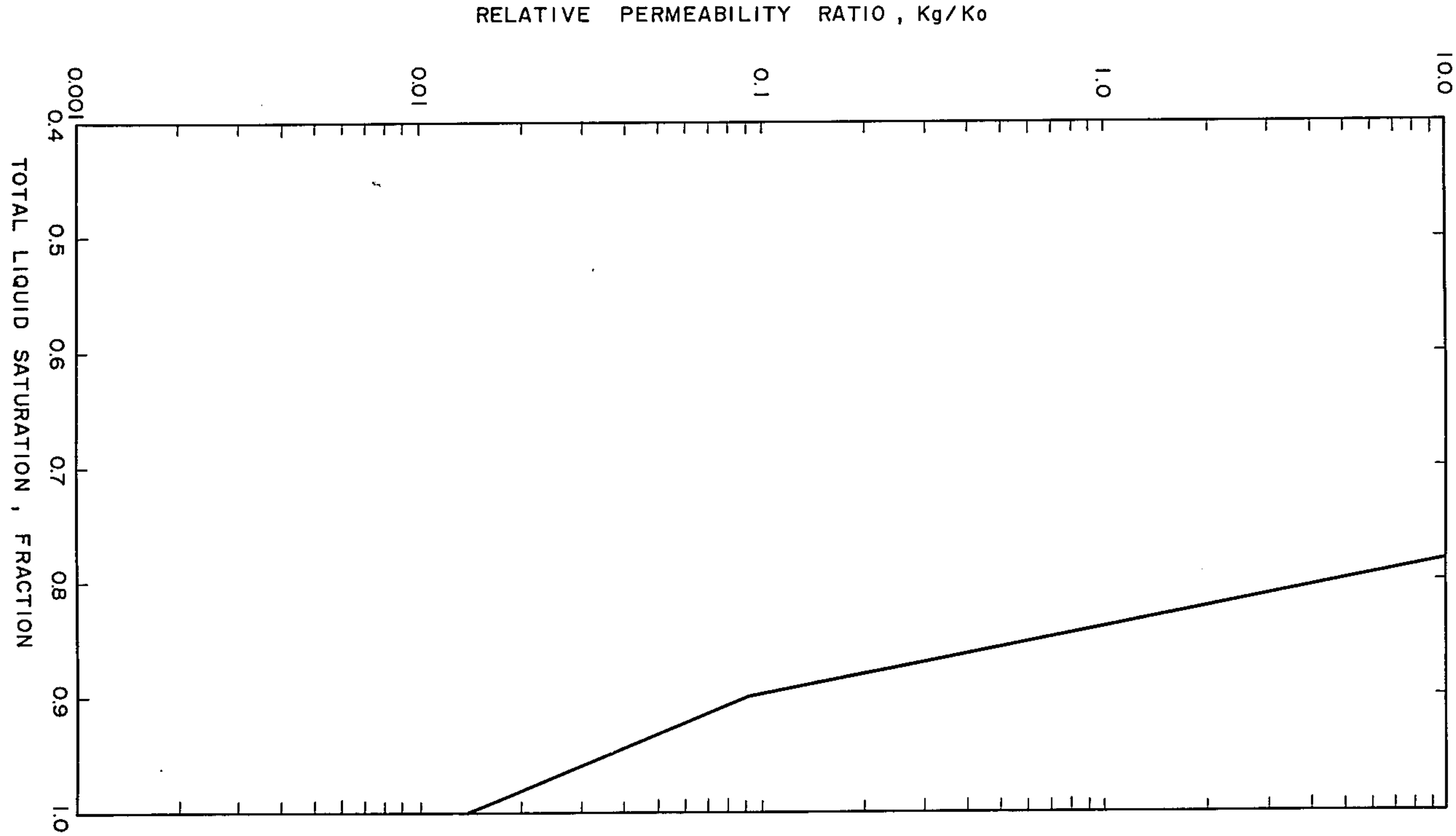


Fig. 2-3-10 GAS-OIL RELATIVE PERMEABILITY RATIO OF MODEL 4, TEMBUNGO FIELD
Vol. III

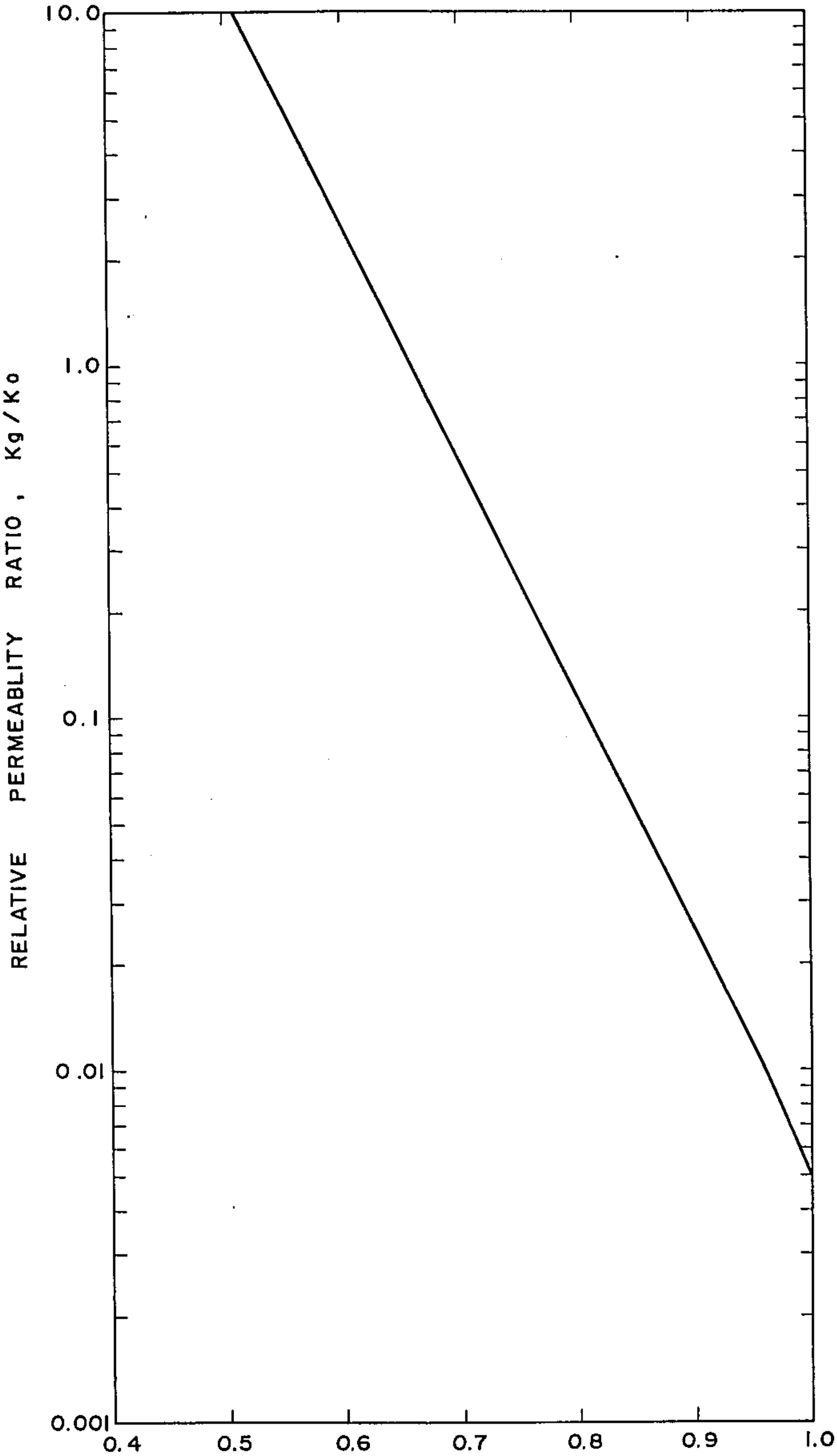


Fig. 2-3-11 Vol. III GAS-OIL RELATIVE PERMEABILITY RATIO - ADDITIONAL WELL CASE, TEMBUNGO FIELD

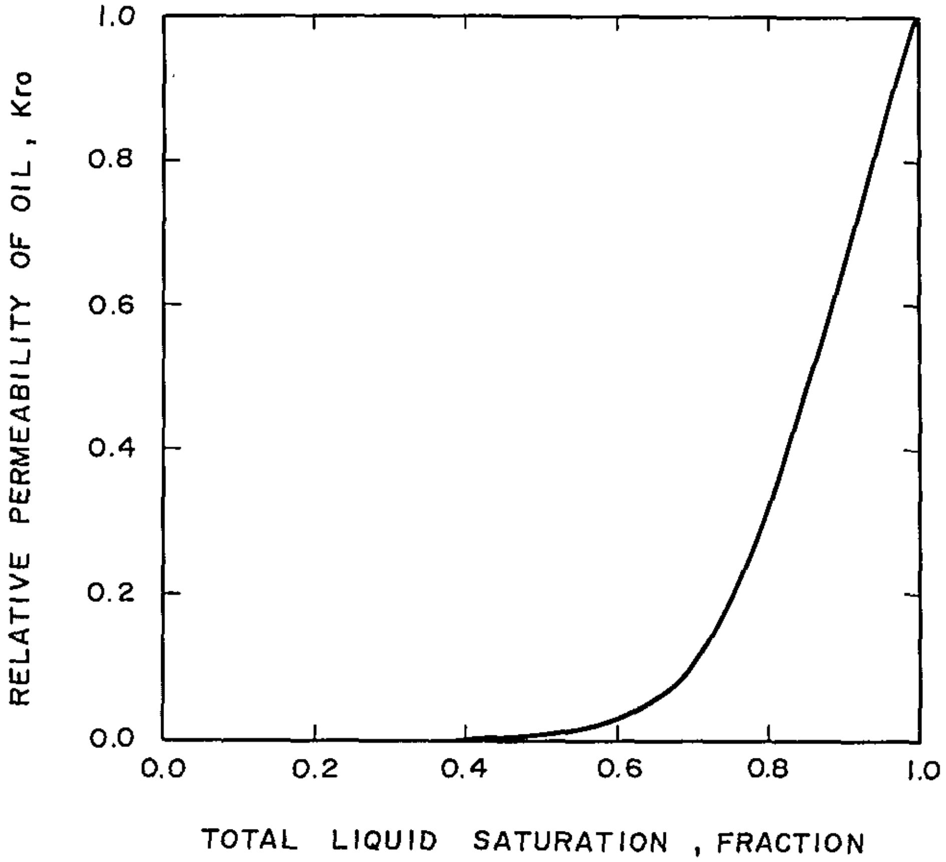


Fig. 2-3-12 OIL RELATIVE PERMEABILITY CURVE OF
Vol. III MODEL 1, TEMBUNGO FIELD

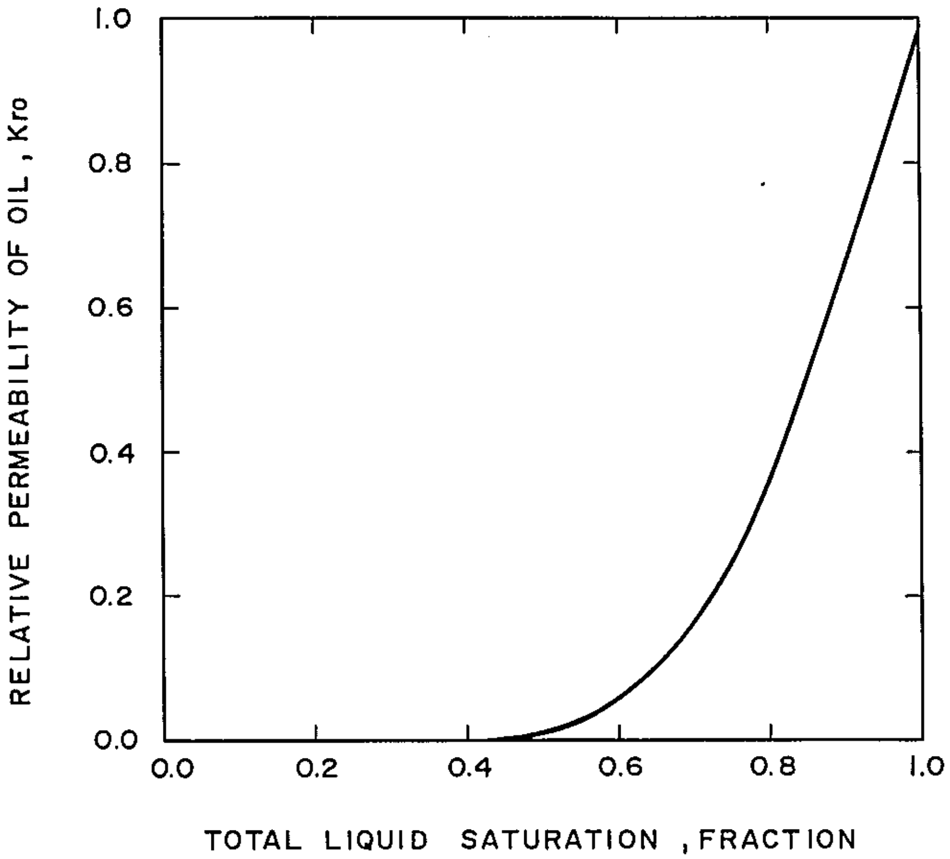


Fig. 2-3-13 OIL RELATIVE PERMEABILITY CURVE OF
Vol. III MODEL 2, TEMBUNGO FIELD

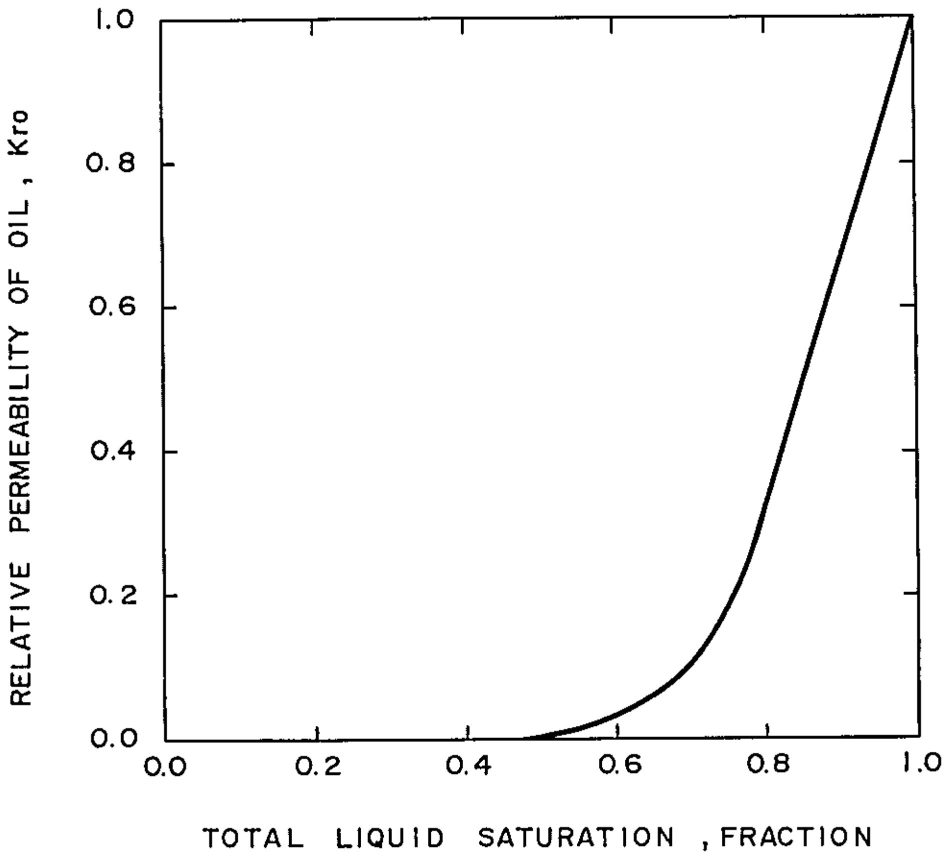


Fig. 2-3-14 OIL RELATIVE PERMEABLITY CURVE OF
Vol. III MODEL 3, TEMBUNGO FIELD

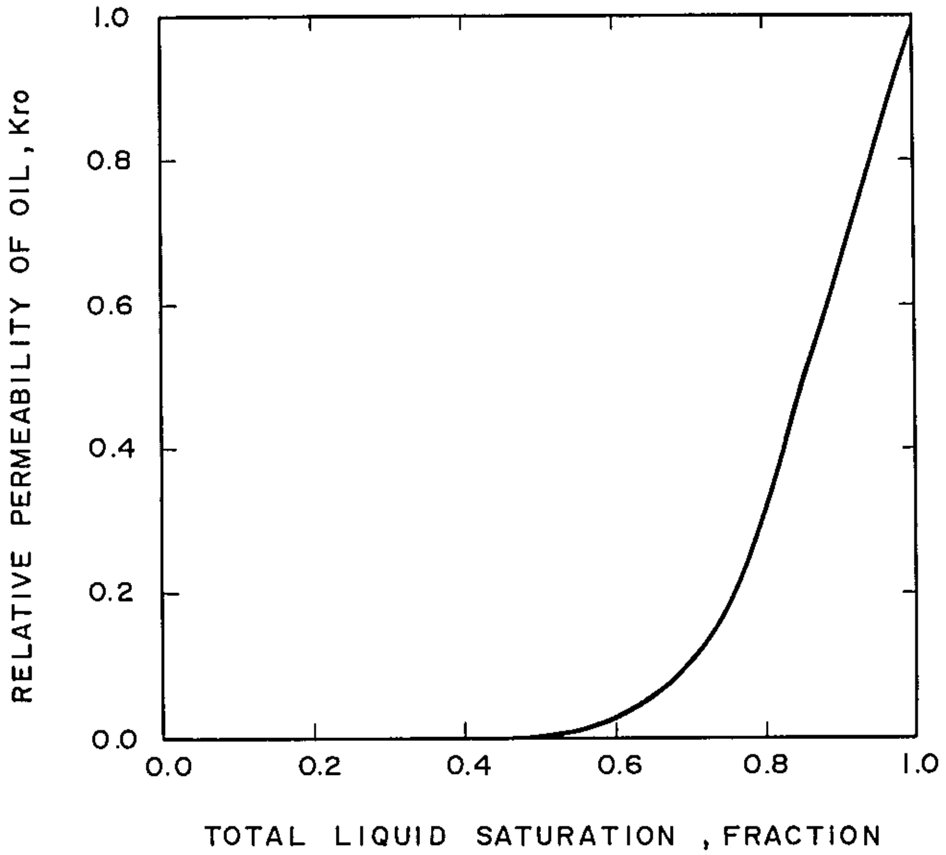


Fig. 2-3-15 OIL RELATIVE PERMEABILITY CURVE OF
Vol. III MODEL 4, TEMBUNGO FIELD

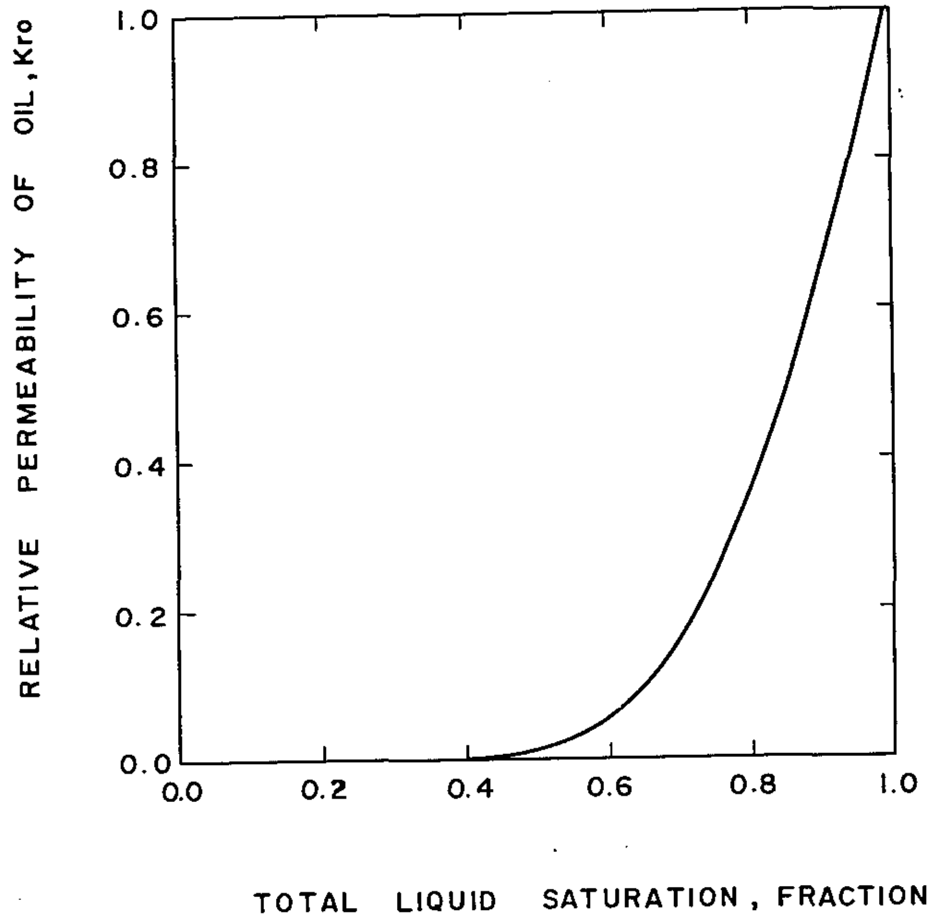


Fig. 2-3-16 Vol. III — OIL RELATIVE PERMEABILITY CURVE - ADDITIONAL WELL CASE, TEMBUNGO FIELD

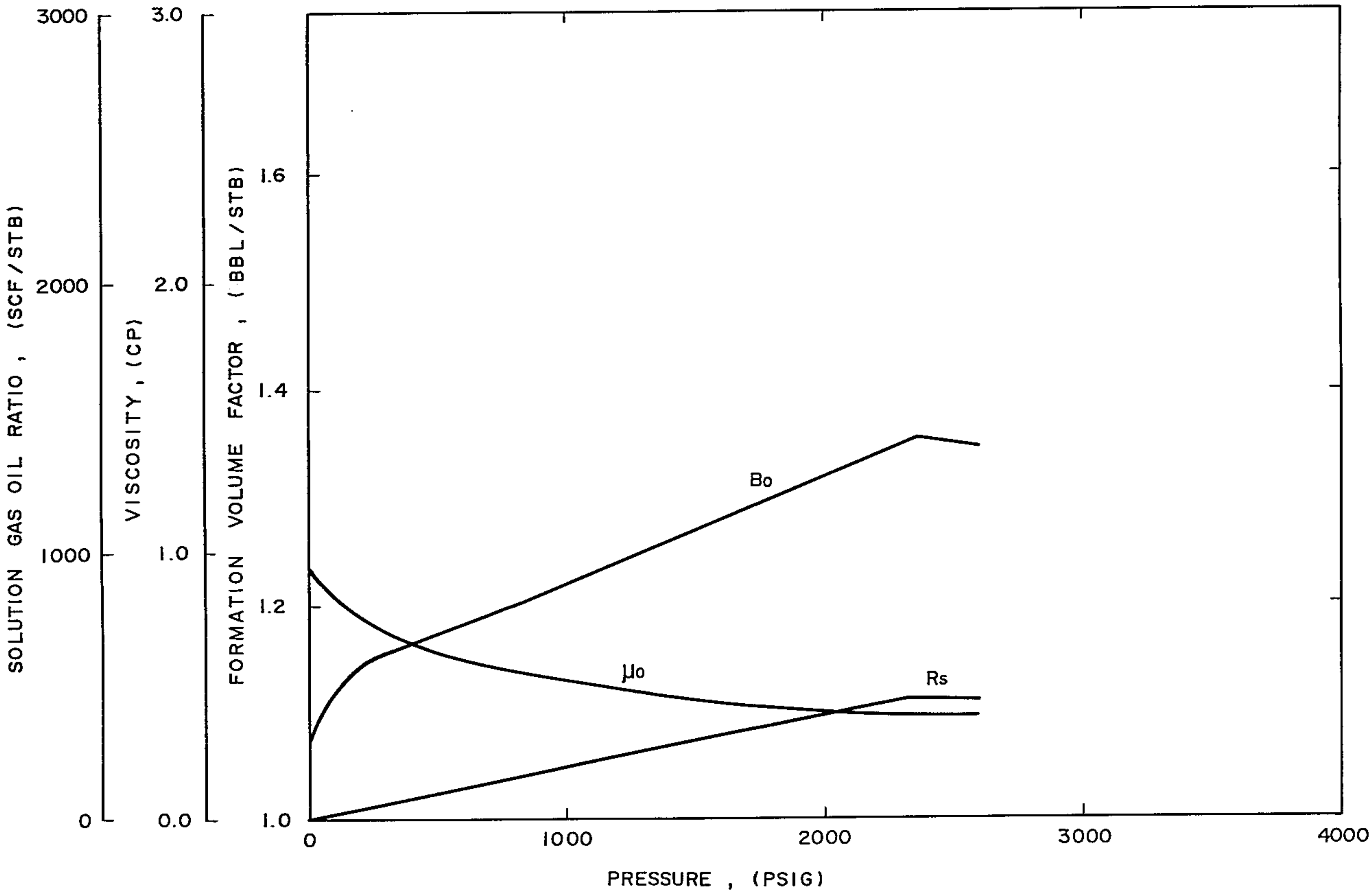


Fig. 2-3-17 OIL PROPERTIES OF MODEL 1, TEMBUNGO FIELD
Vol. III

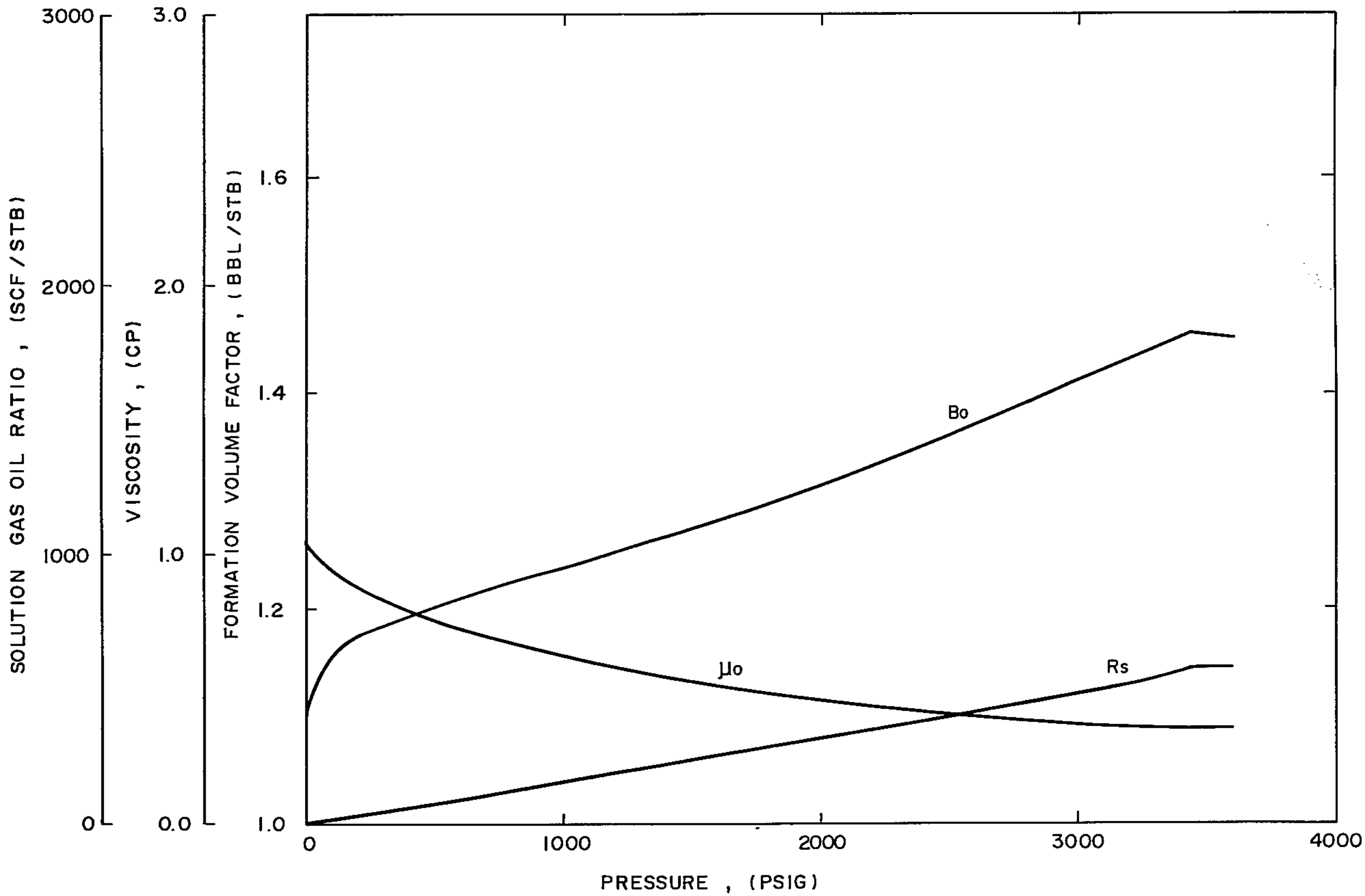


Fig. 2-3-18 Vol. III OIL PROPERTIES OF MODEL 2, TEMBUNGO FIELD

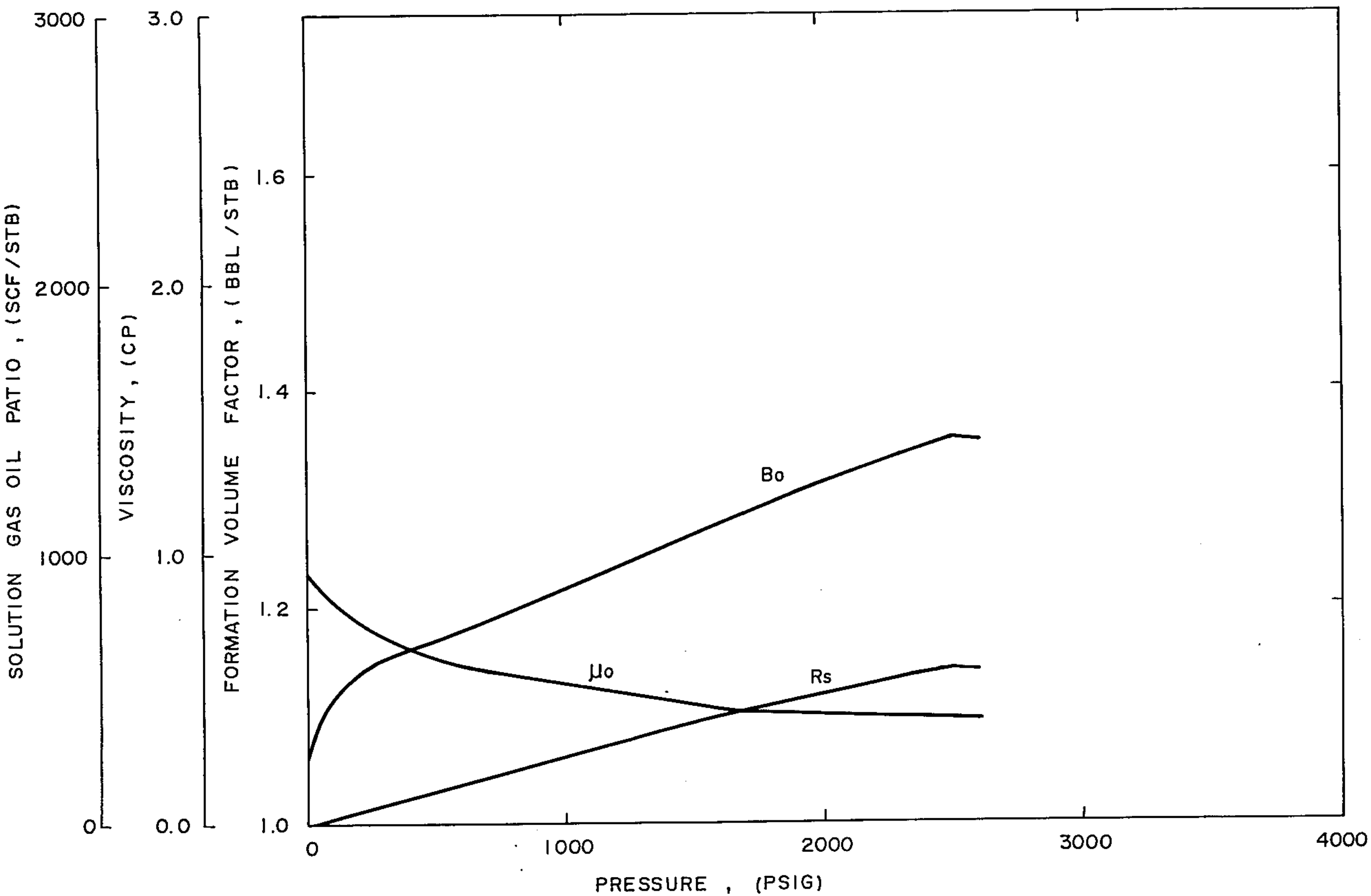


Fig. 2-3-19 OIL PROPERTIES OF MODEL 3, TEMBUNGO FIELD
Vol. III

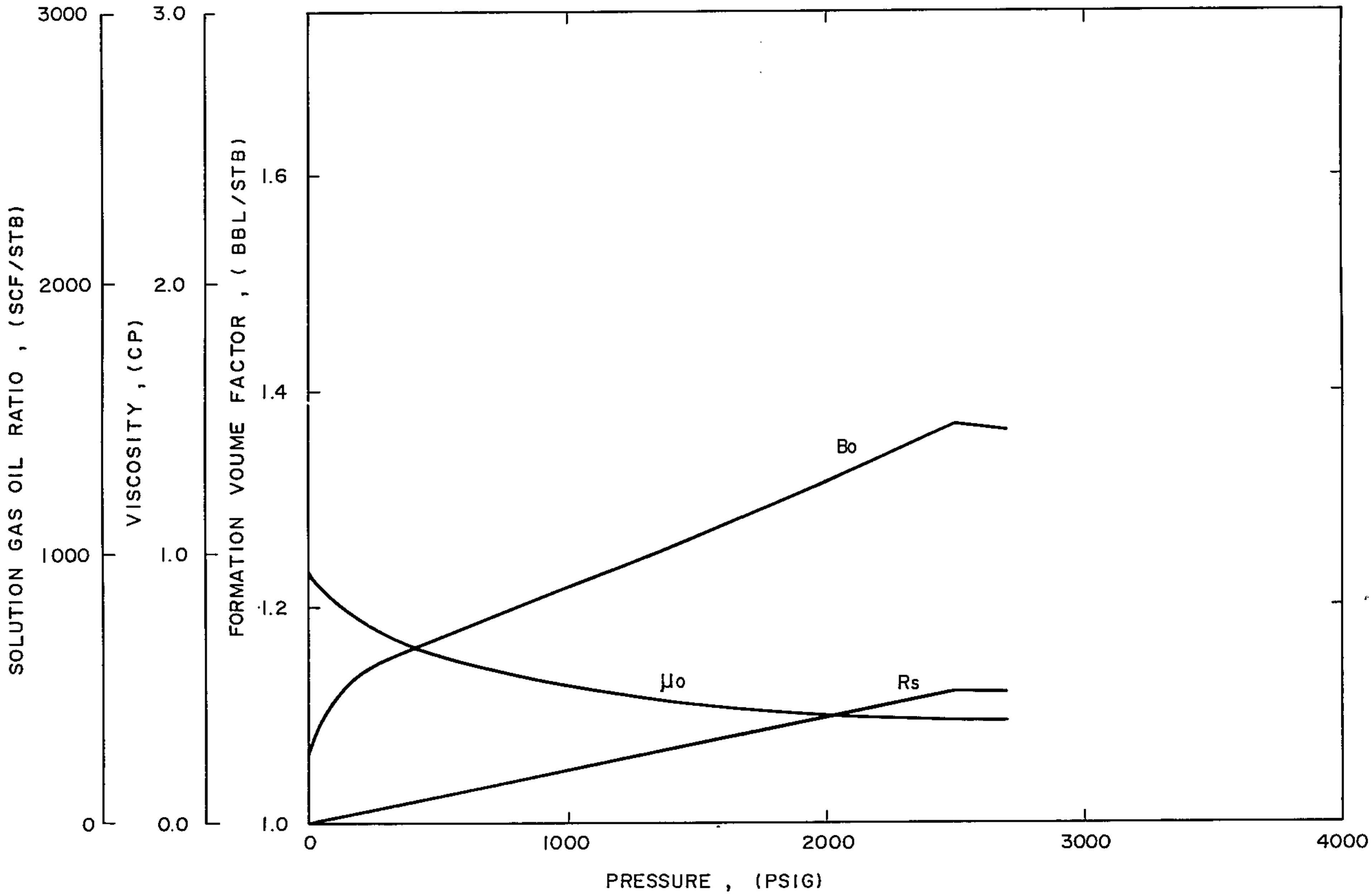


Fig. 2-3-20 OIL PROPERTIES OF MODEL 4, TEMBUNGO FIELD
Vol. III

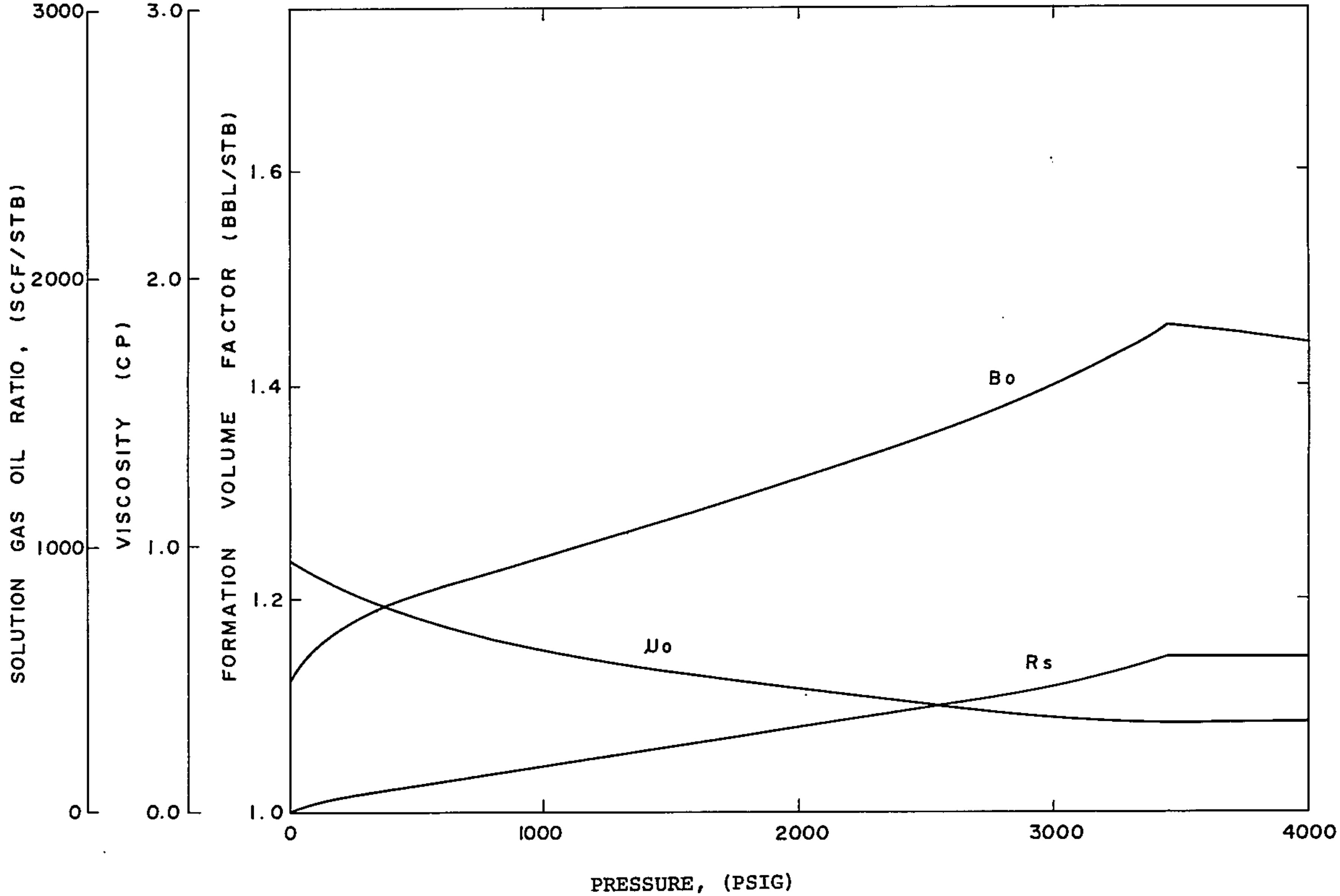


Fig. 2-3-21 OIL PROPERTIES OF WELL TM AD-1 AND AD-4, TEMBUNGO FIELD
Vol. III

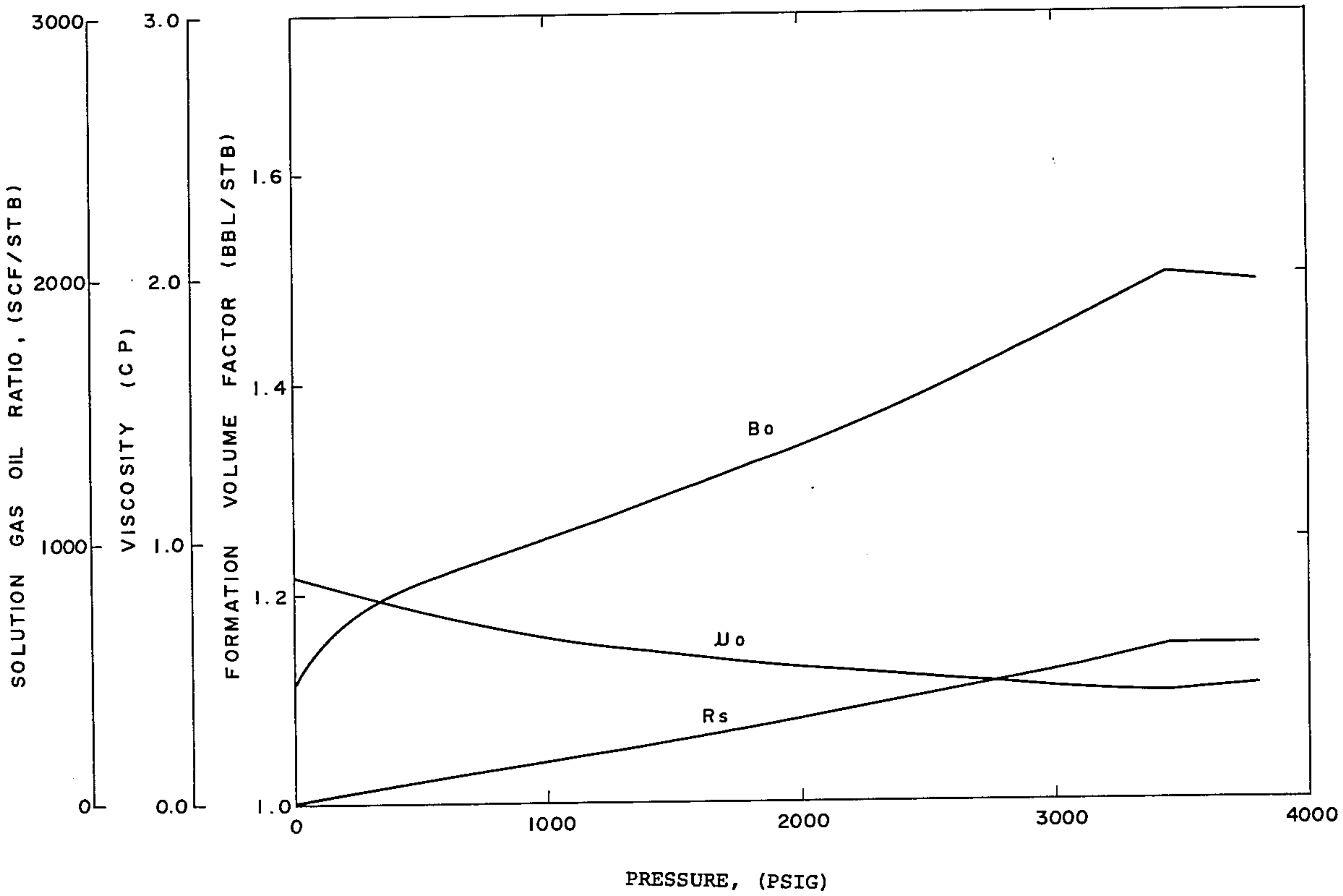


Fig. 2-3-22 OIL PROPERTIES OF WELL TM AD-2, TEMBUNGO FIELD
Vol. III

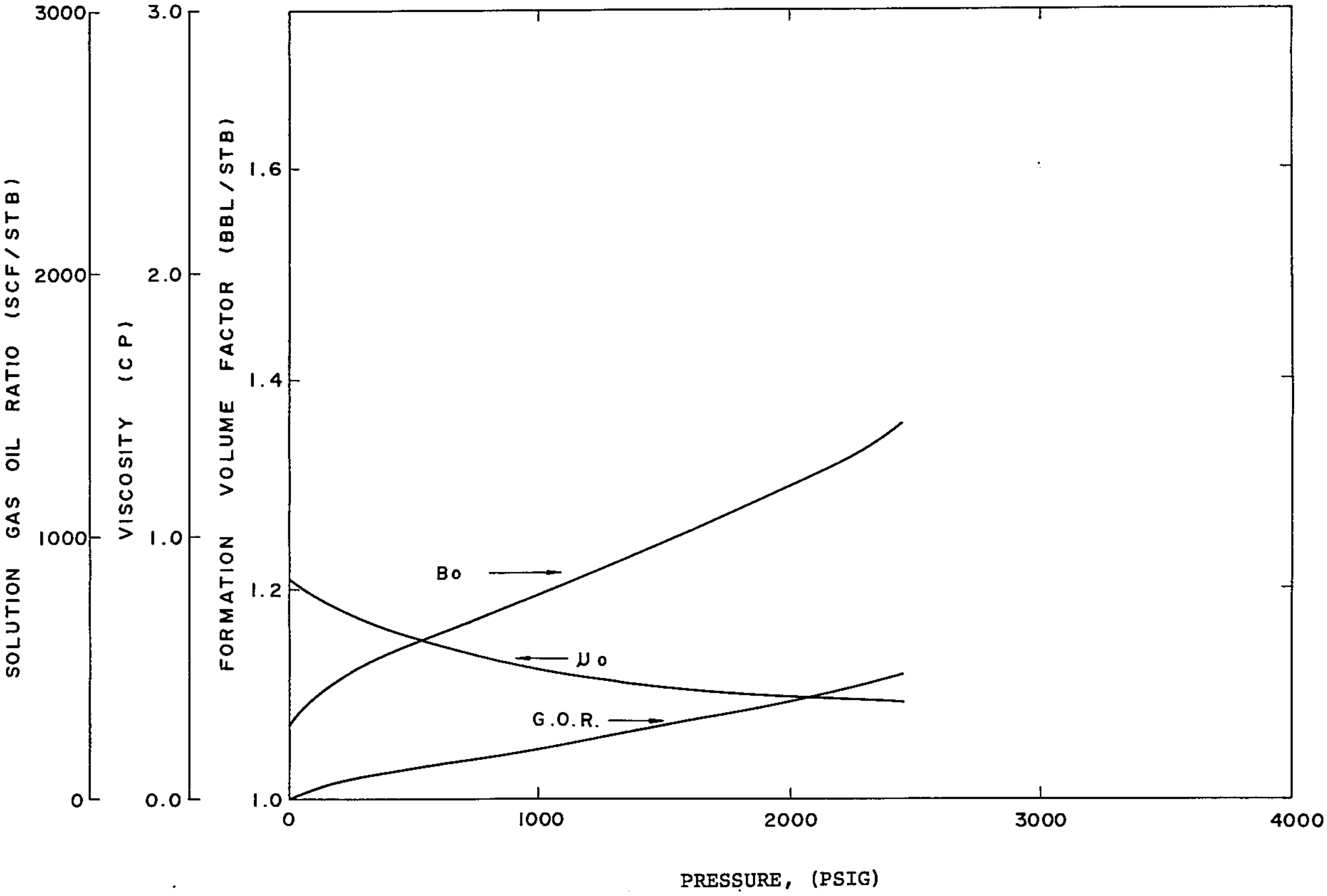


Fig. 2-3-23 OIL PROPERTIES OF WELL TM AD-3, TEMBUNGO FIELD
Vol. III

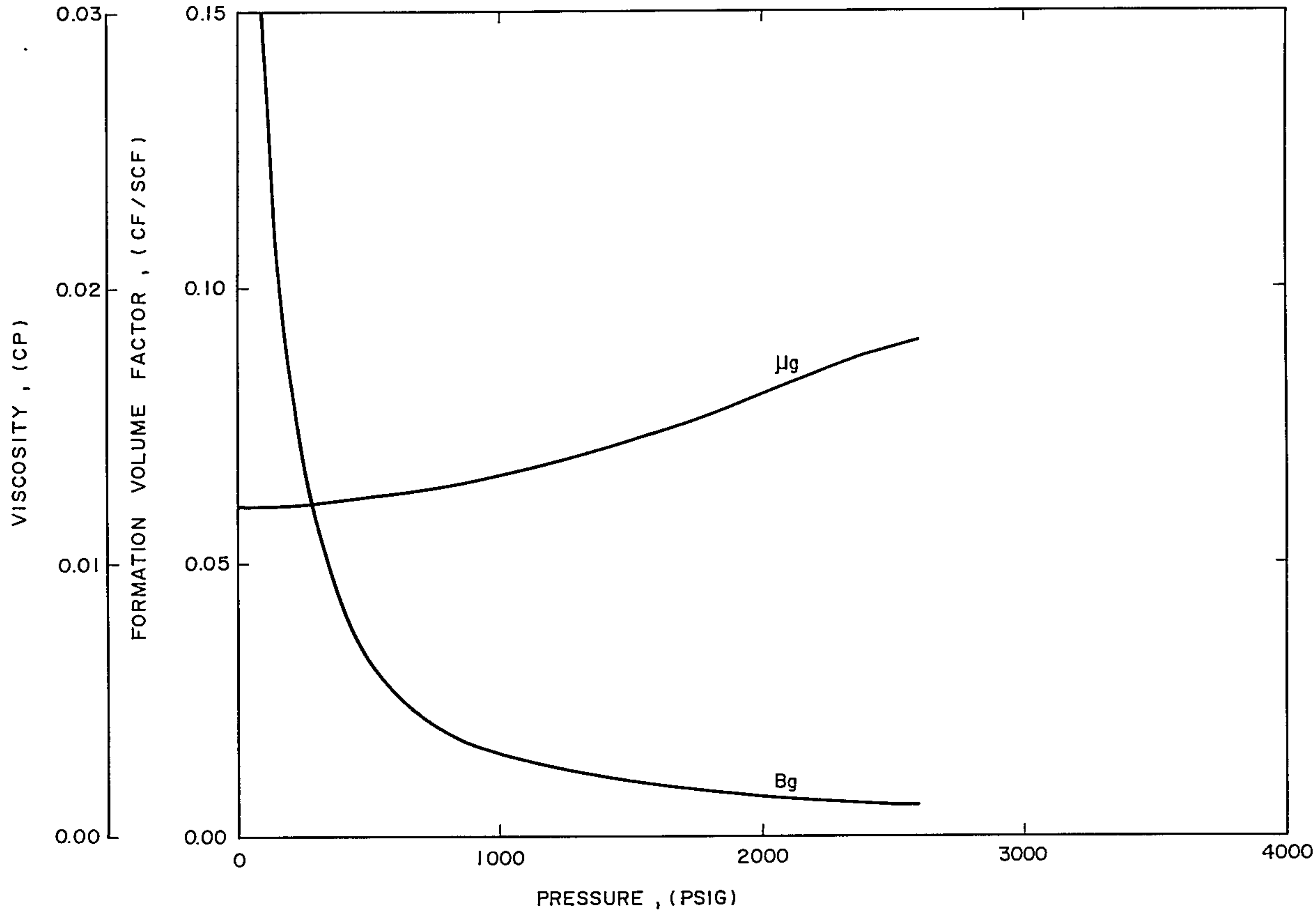


Fig. 2-3-24 GAS PROPERTIES OF MODEL 1, TEMBUNGO FIELD
Vol. III

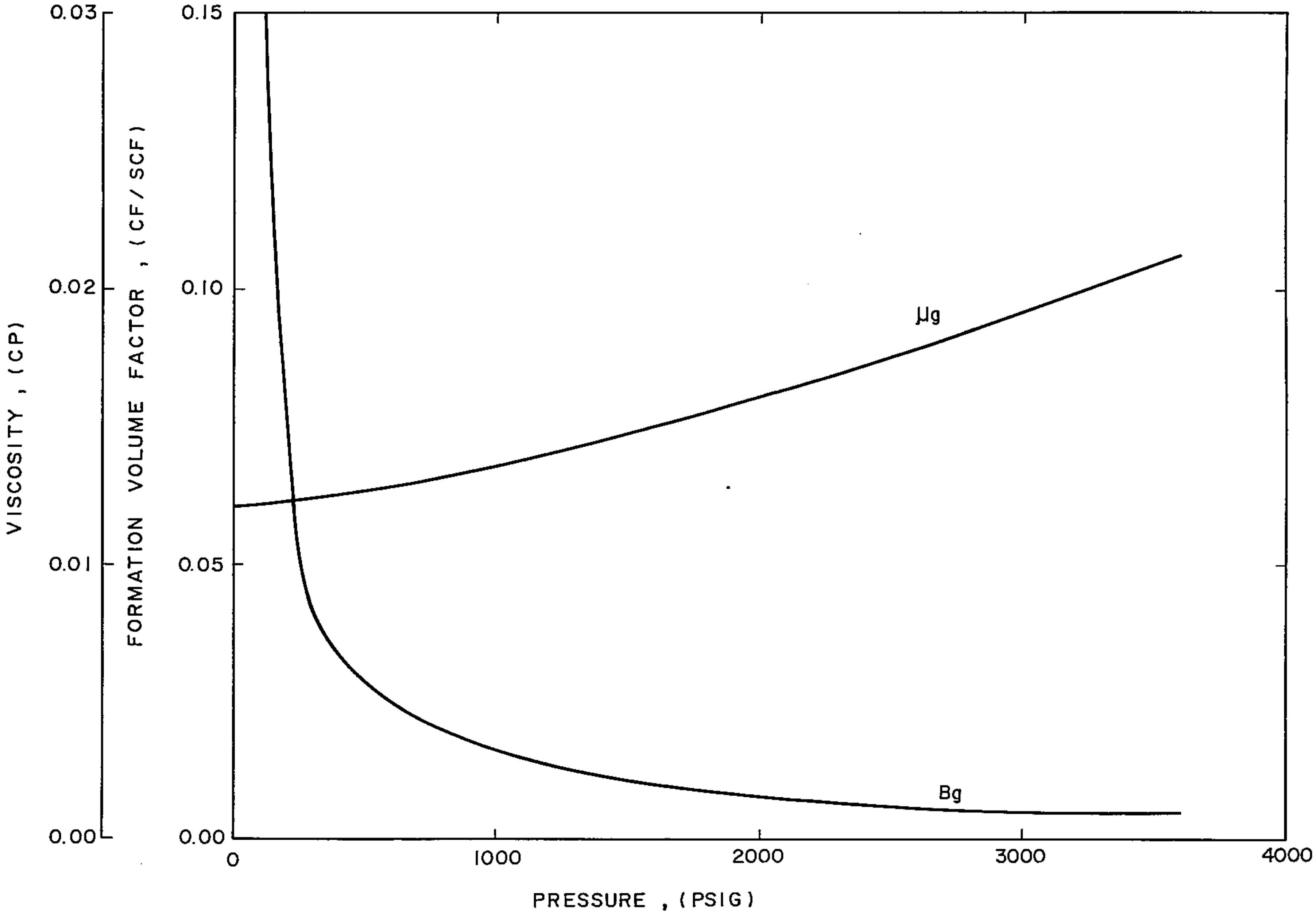


Fig. 2-3-25 GAS PROPERTIES OF MODEL 2, TEMBUNGO FIELD
Vol. III

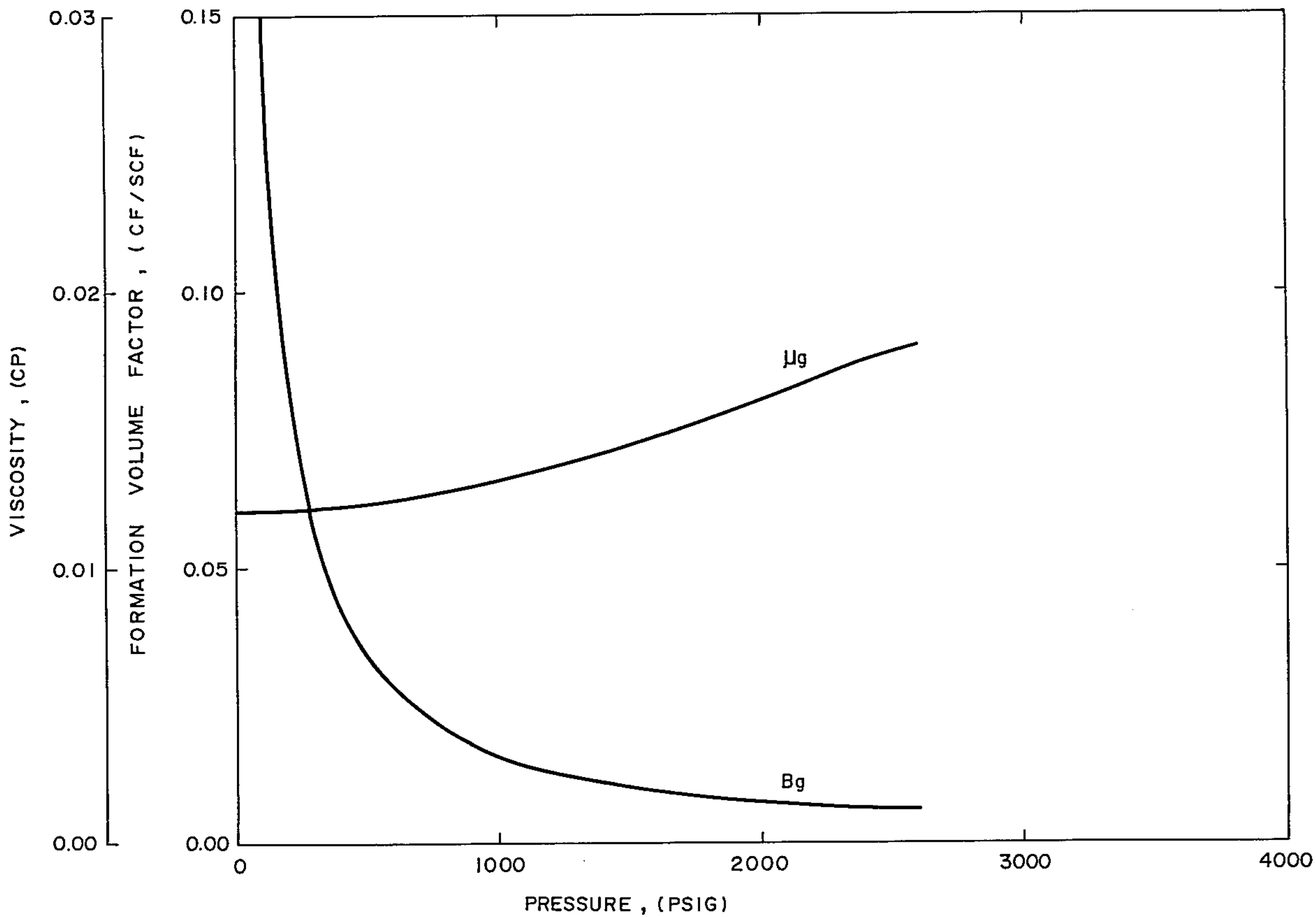


Fig. 2-3-26 GAS PROPERTIES OF MODEL 3, TEMBUNGO FIELD
Vol. III

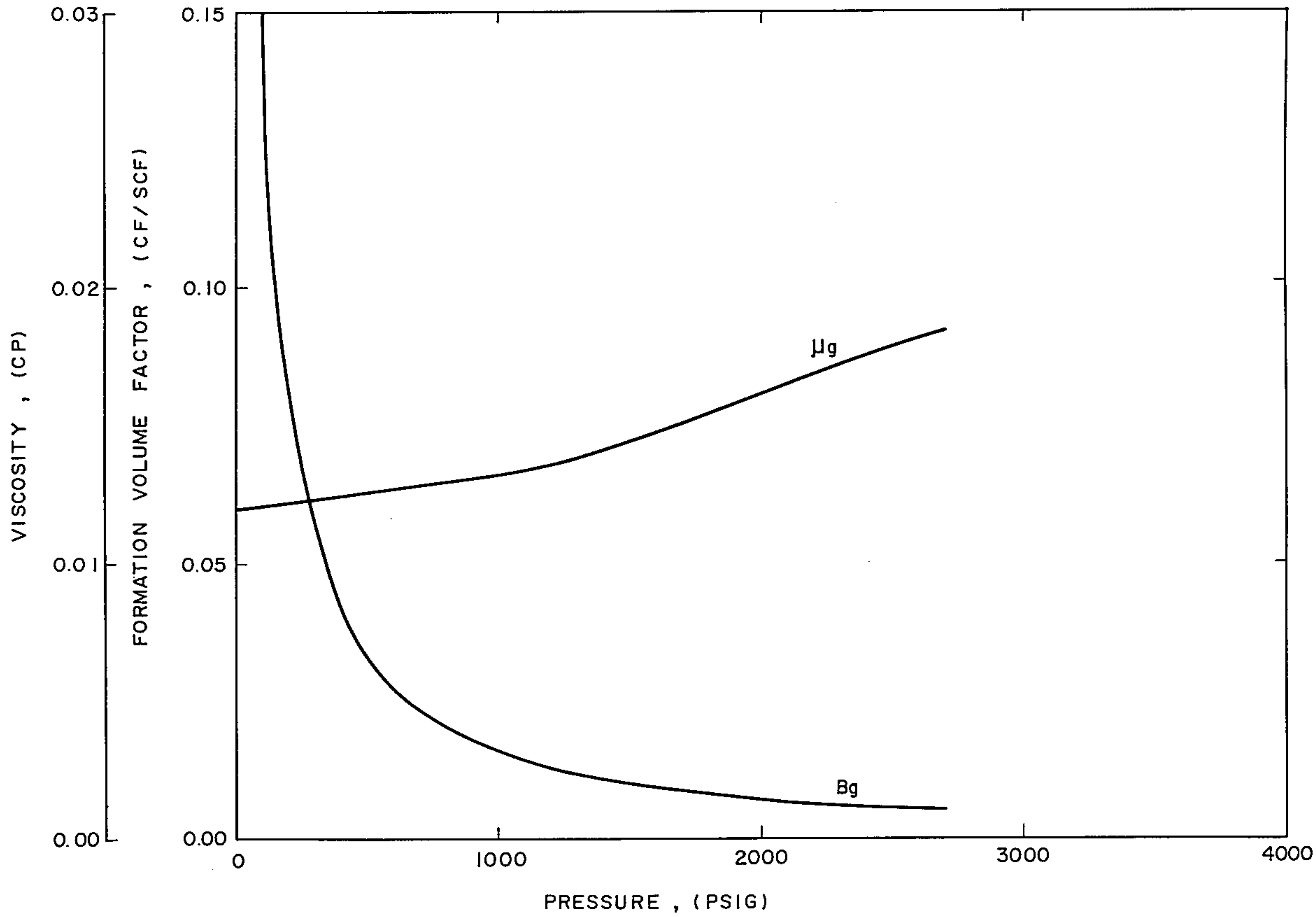


Fig. 2-3-27 GAS PROPERTIES OF MODEL 4, TEMBUNGO FIELD
Vol. III

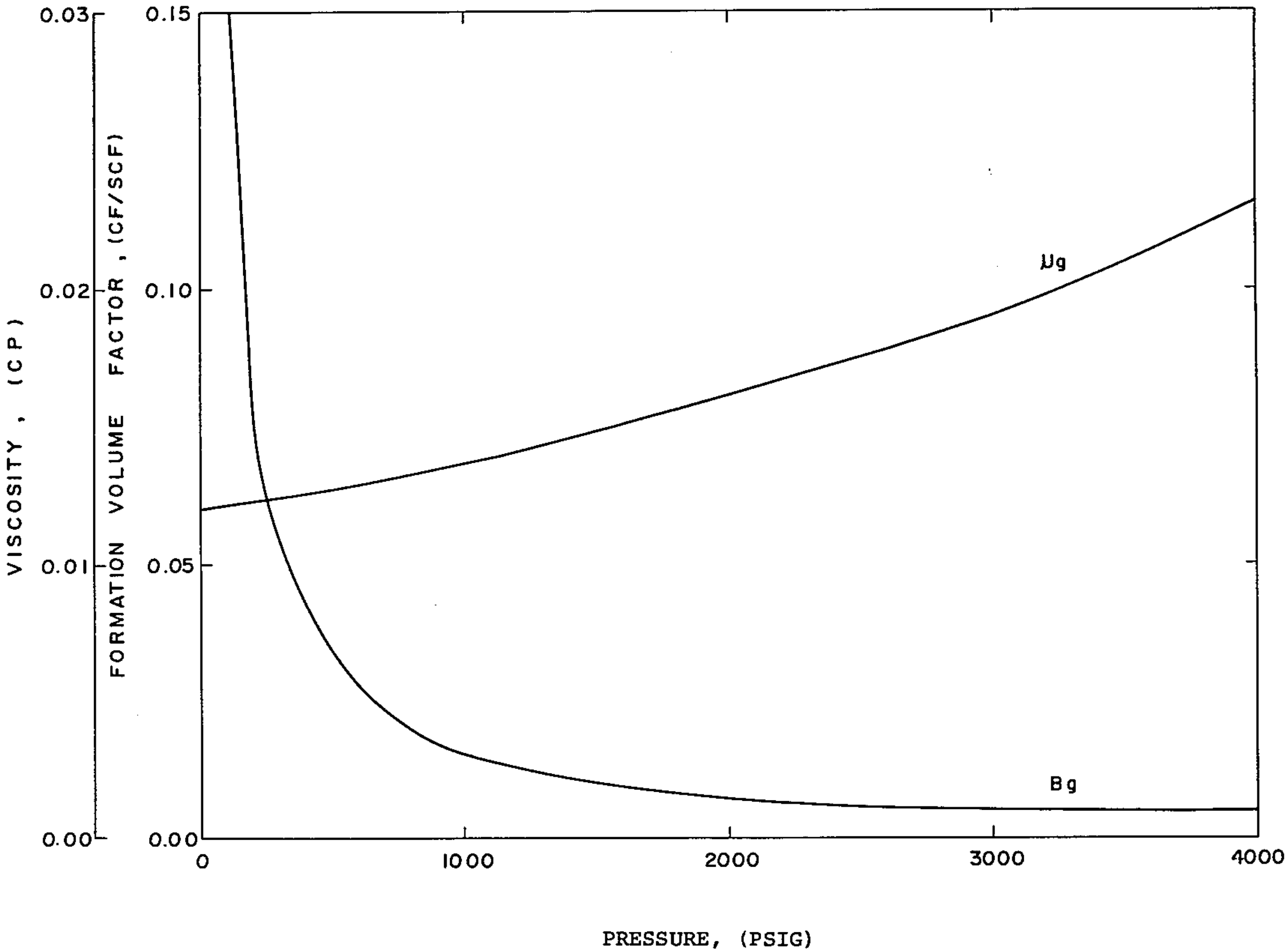


Fig. 2-3-28 GAS PROPERTIES OF WELL TM AM-1 AND AD-4, TEMBUNGO FIELD
Vol. III

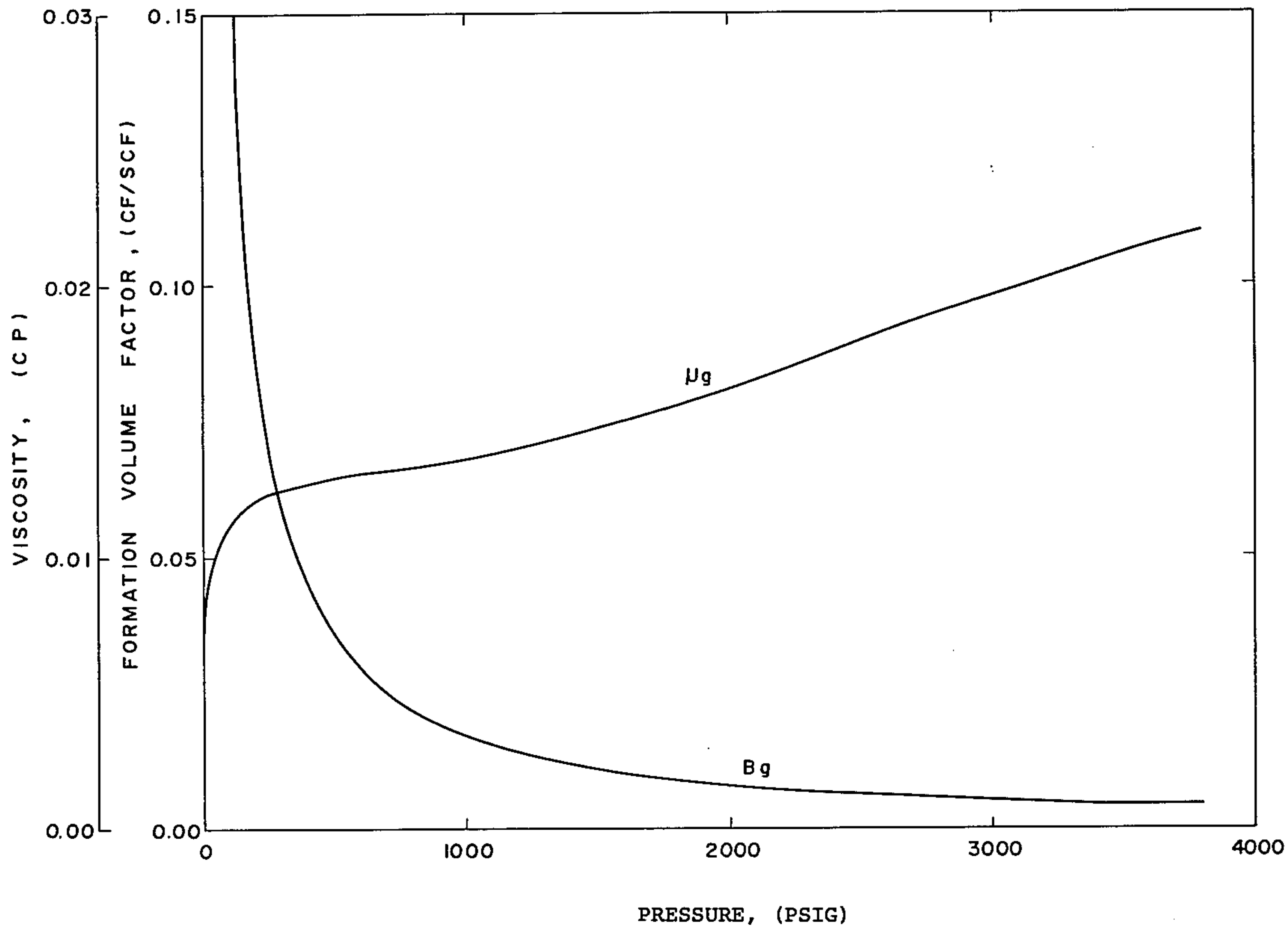


Fig. 2-3-29 GAS PROPERTIES OF WELL TM AD-2, TEMBUNGO FIELD
Vol. III

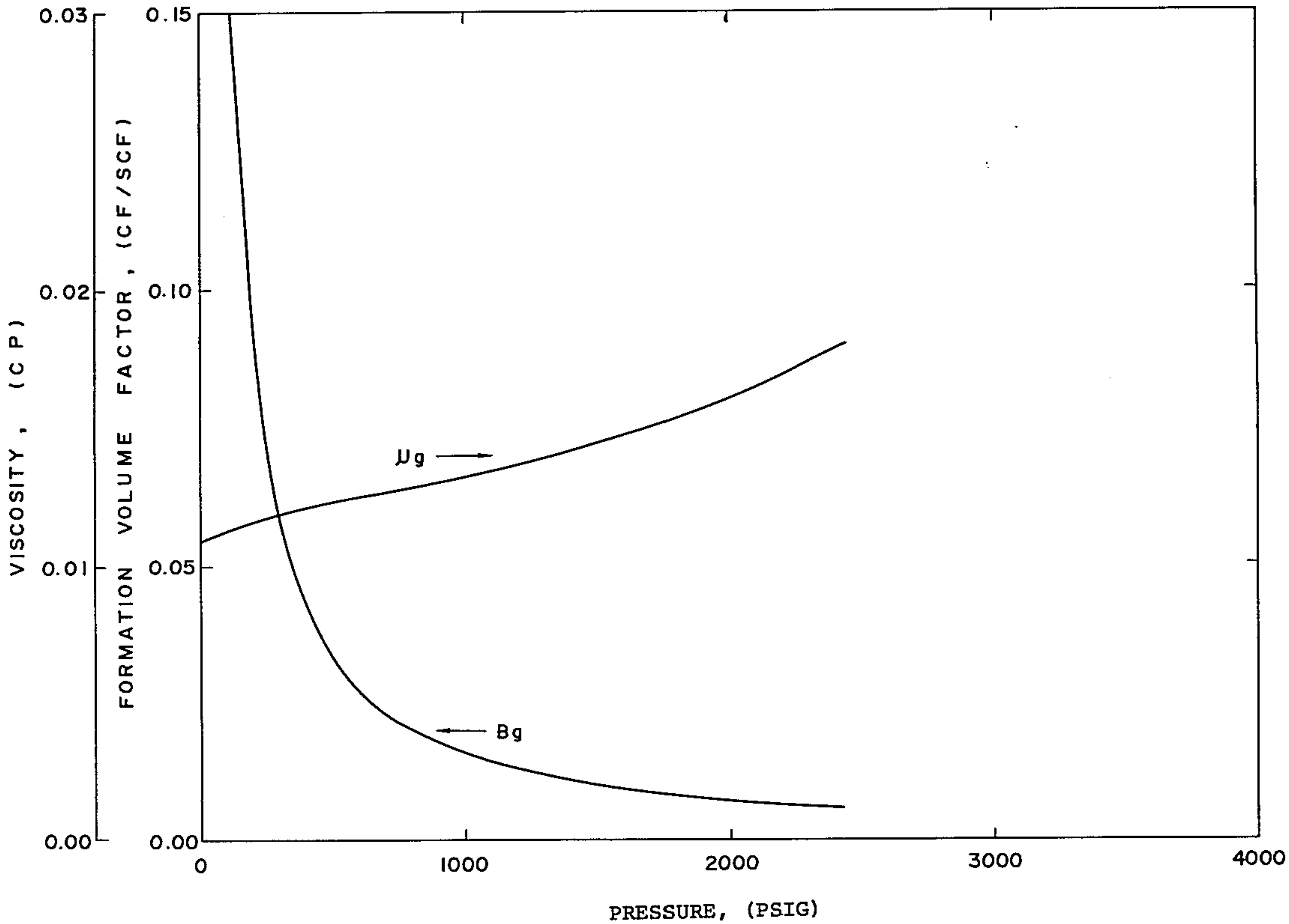


Fig. 2-3-30 GAS PROPERTIES OF WELL TM AD-3, TEMBUNGO FIELD
Vol. III

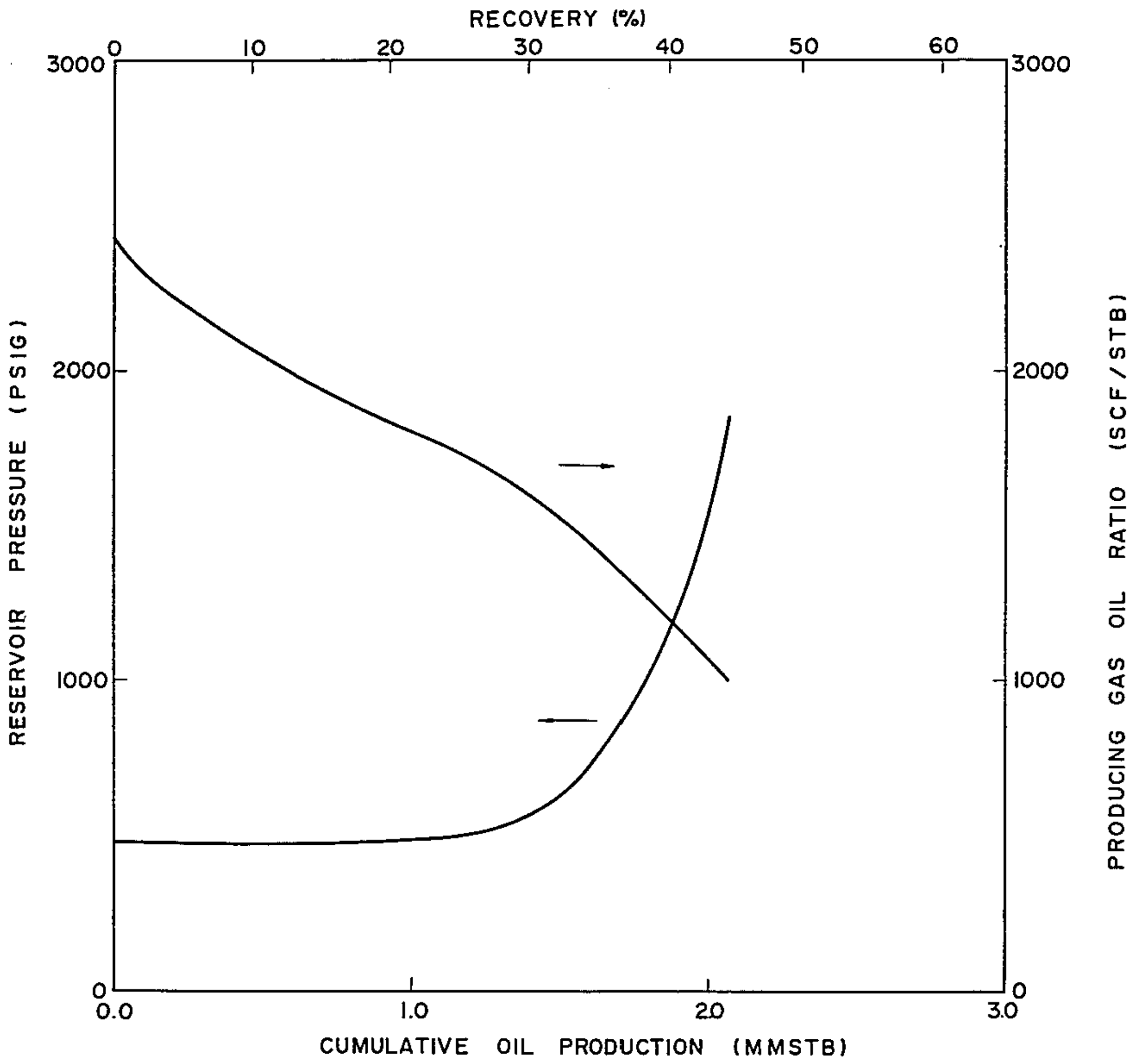


Fig. 2-3-31 CUMULATIVE OIL PRODUCTION VS. RESERVOIR PRESSURE AND PRODUCING GAS OIL RATIO OF MODEL-1, TEMBUNGO FIELD
Vol. III

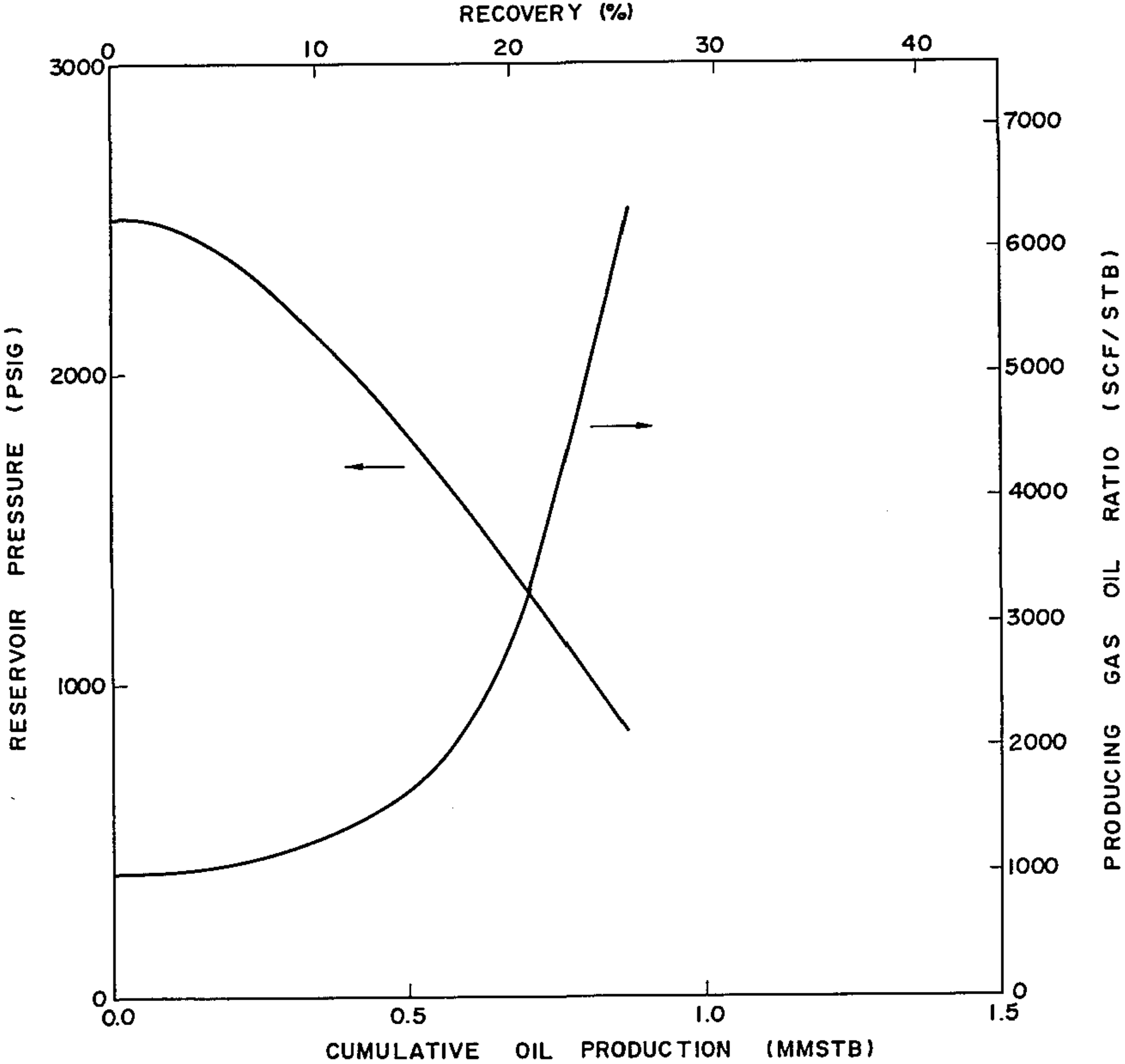


Fig. 2-3-32 CUMULATIVE OIL PRODUCTION VS. RESERVOIR PRESSURE AND PRODUCING GAS OIL RATIO OF MODEL-2, TEMBUNGO FIELD
Vol. III

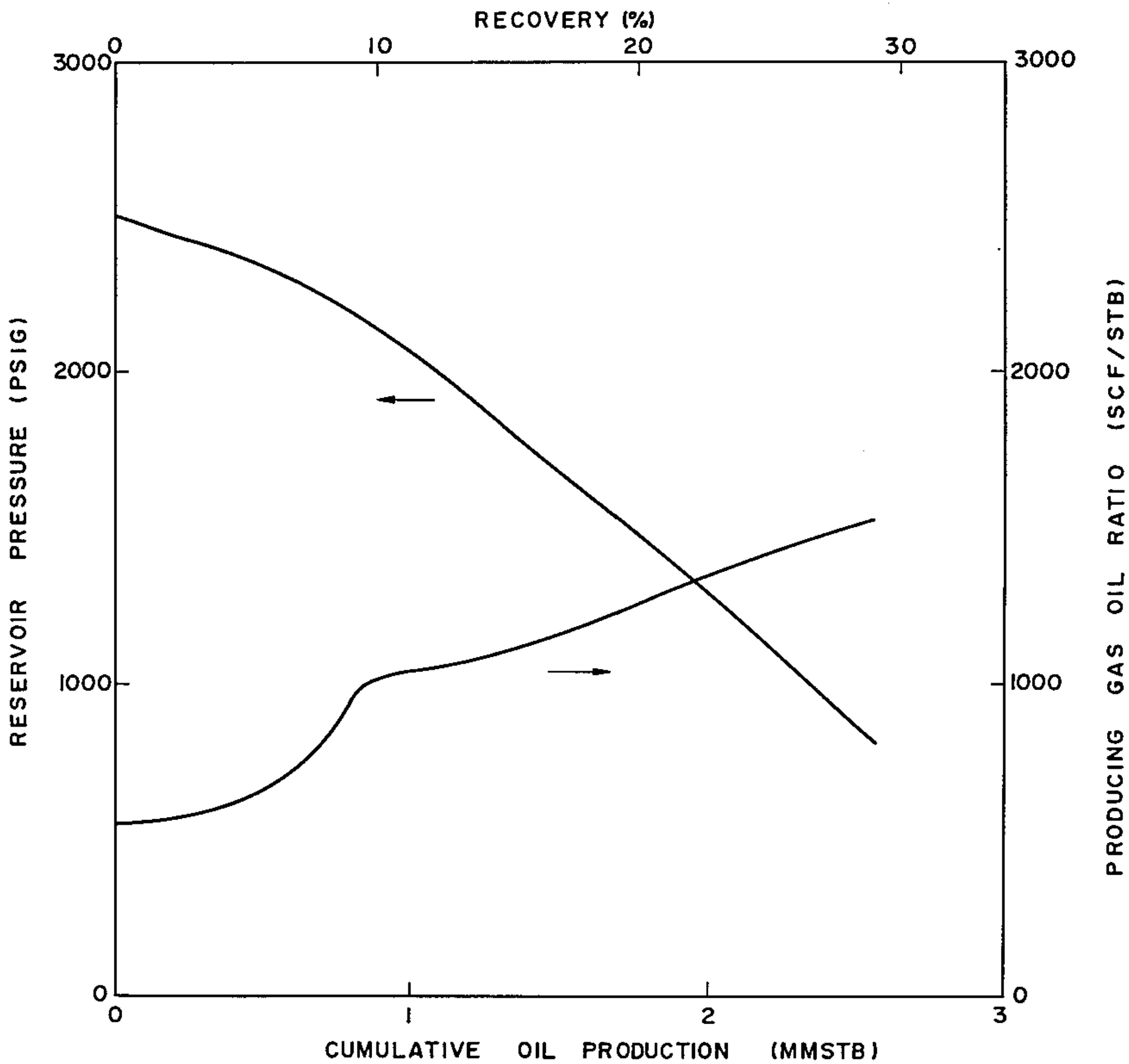


Fig. 2-3-33 Vol. III CUMULATIVE OIL PRODUCTION VS. RESERVOIR PRESSURE AND PRODUCING GAS OIL RATIO OF MODEL-3, TEMBUNGO FIELD

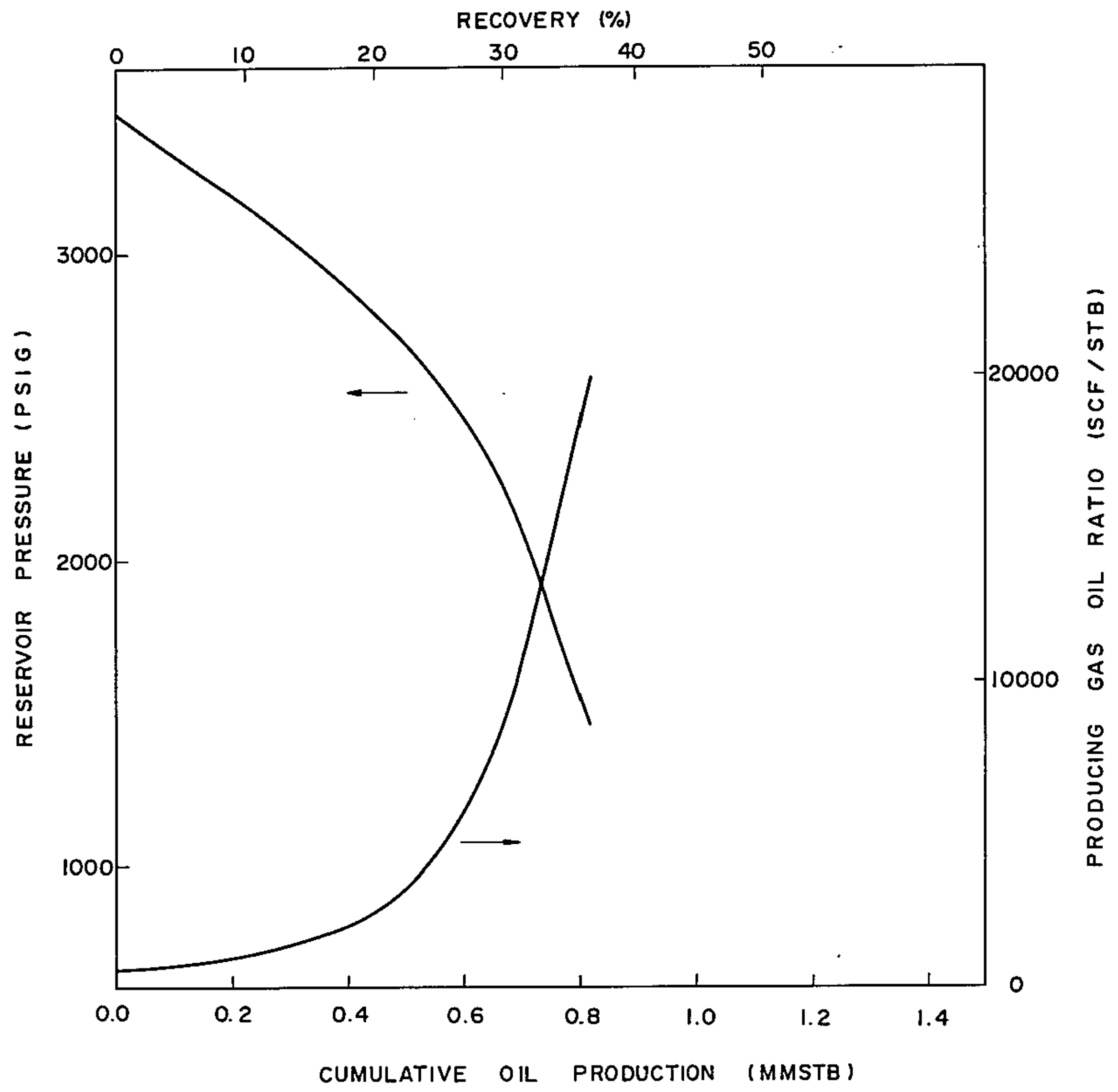


Fig. 2-3-34 Vol. III CUMULATIVE OIL PRODUCTION VS. RESERVOIR PRESSURE AND PRODUCING GAS OIL RATIO OF WELL TM AD-1, TEMBUNGO FIELD

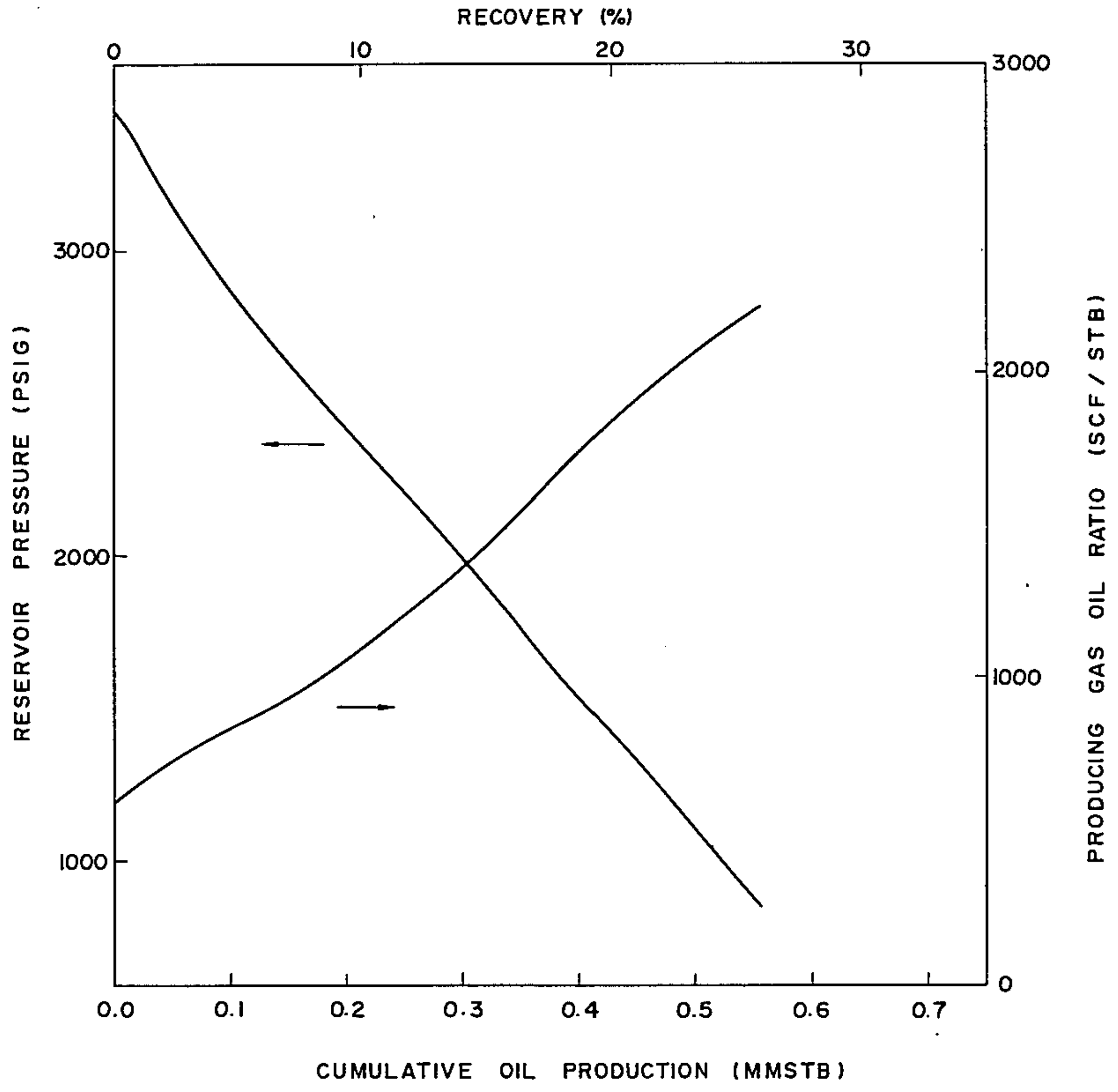


Fig. 2-3-35 Vol. III CUMULATIVE OIL PRODUCTION VS. RESERVOIR PRESSURE AND PRODUCING GAS OIL RATIO OF WELL TM AD-2, TEMBUNGO FIELD

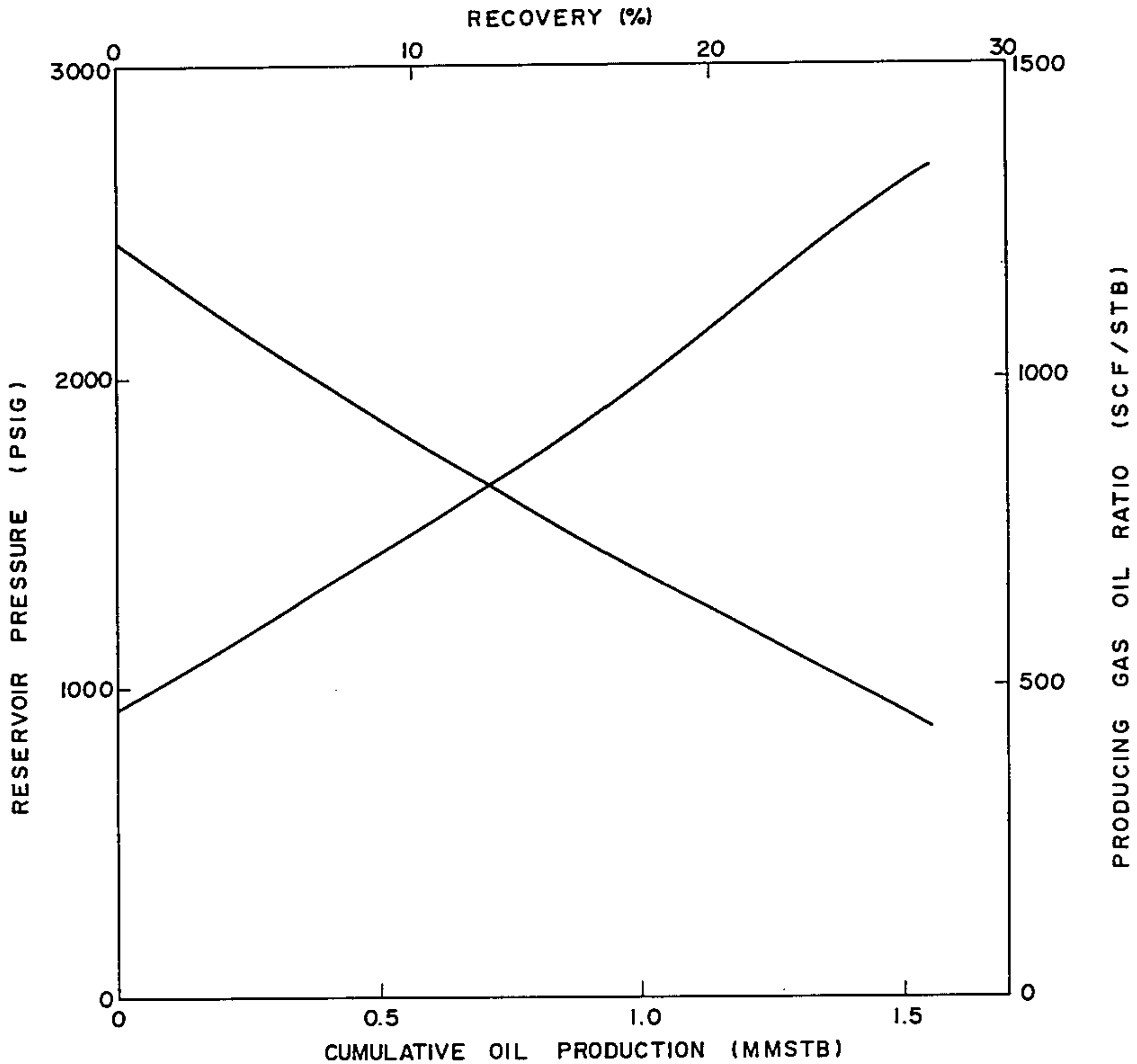


Fig. 2-3-36 CUMULATIVE OIL PRODUCTION VS. RESERVOIR PRESSURE AND PRODUCING GAS OIL RATIO OF WELL TM AD-3, TEMBUNGO FIELD

Vol. III

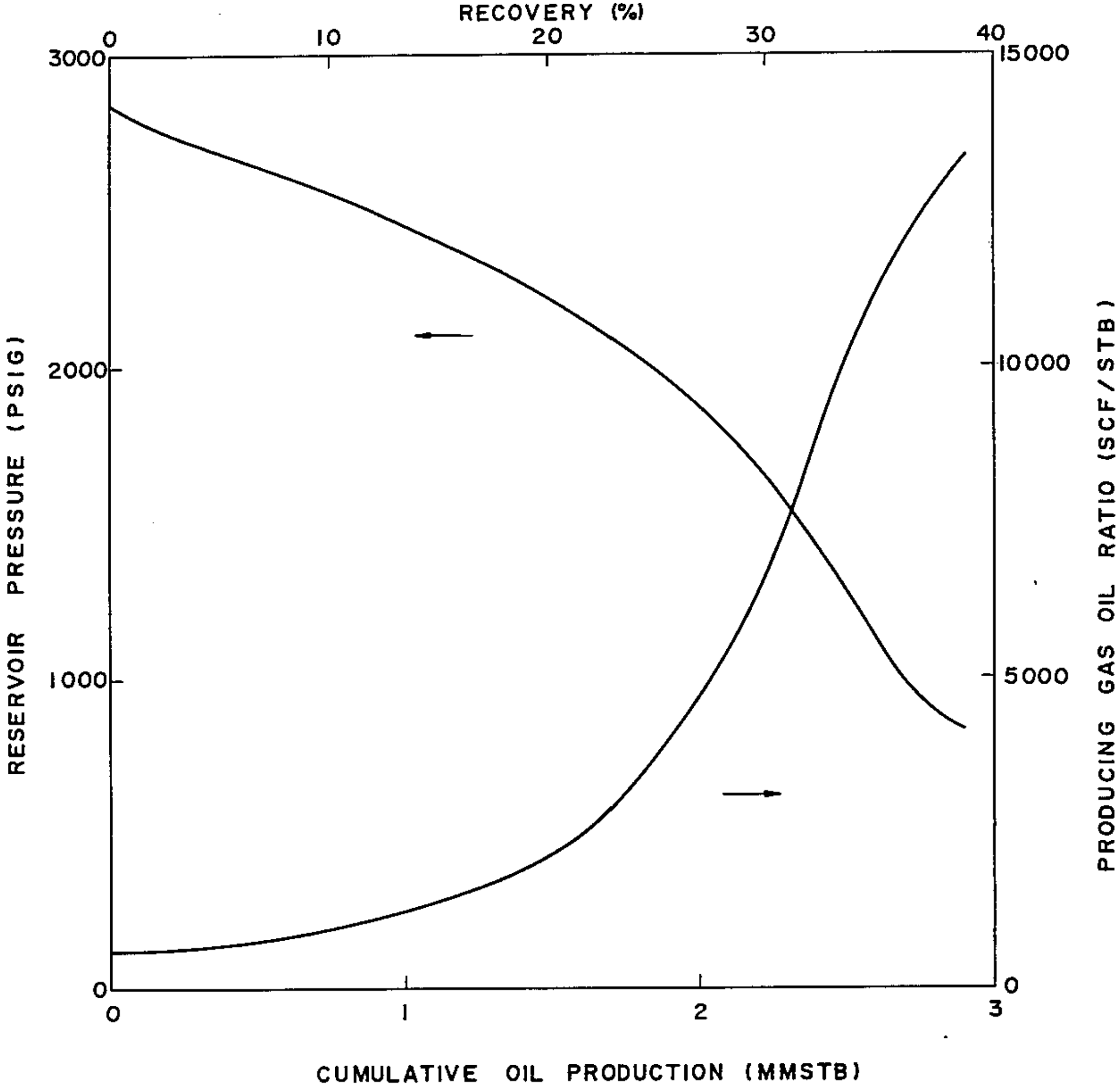


Fig. 2-3-37 Vol. III CUMULATIVE OIL PRODUCTION VS. RESERVOIR PRESSURE AND PRODUCING GAS OIL RATIO OF WELL TM AD-4, TEMBUNGO FIELD

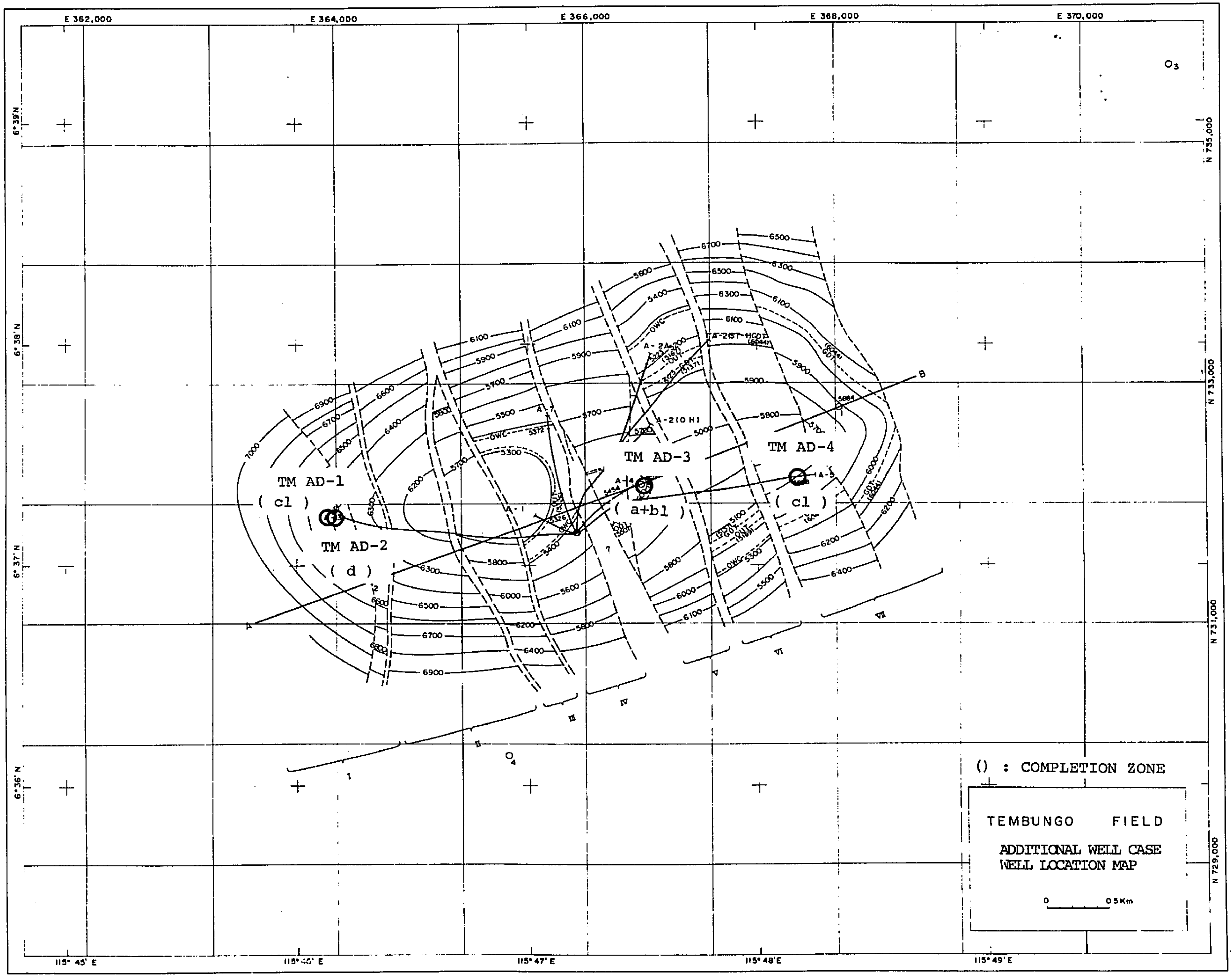


Fig. 2-3-38 ADDITIONAL WELL CASE-WELL LOCATION MAP ,TEMBUNGO FIELD
Vol. III

Fig. 3-1-1

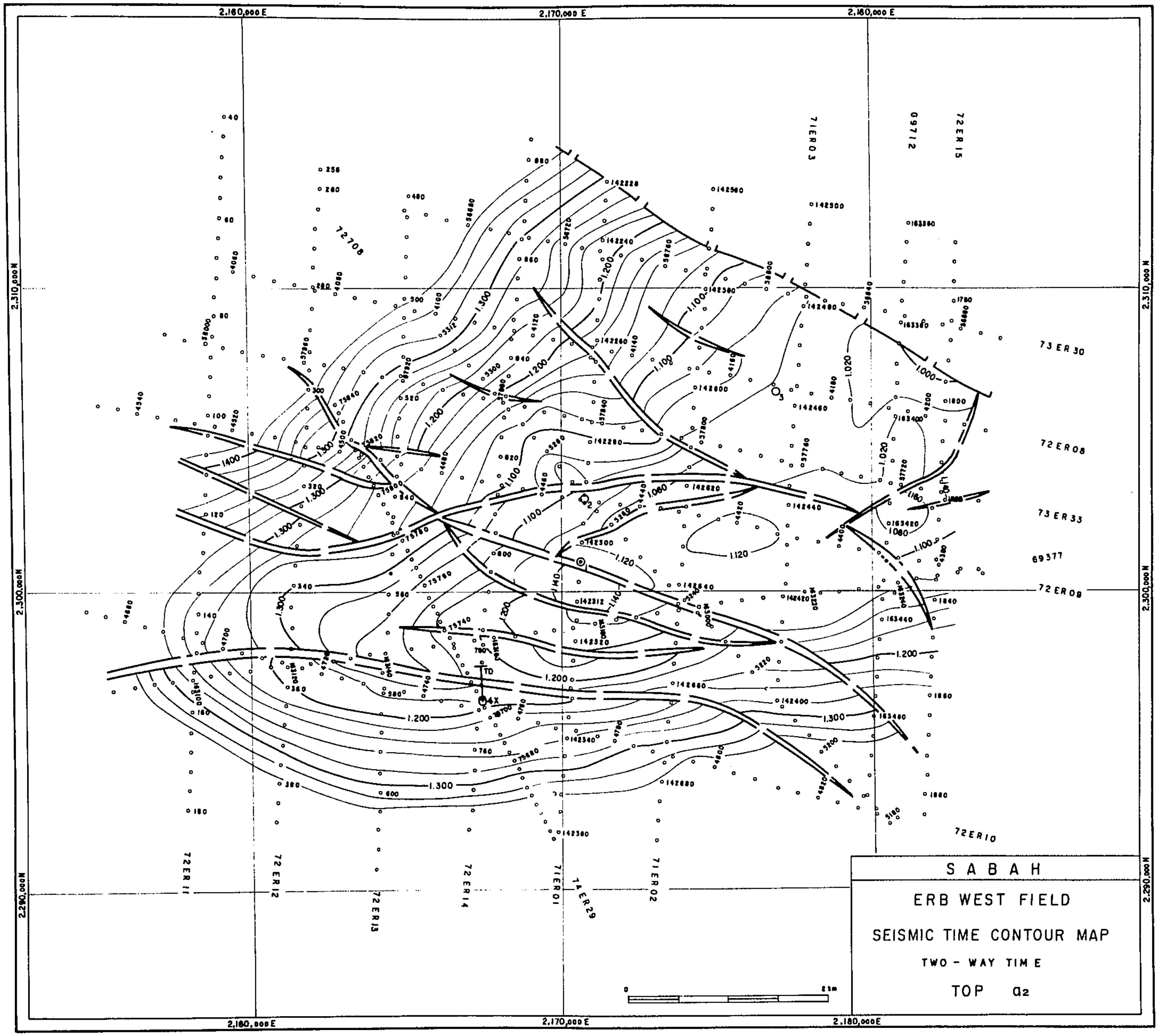


Fig. 3-1-1 TIME CONTOUT MAP, ERB WEST FIELD, TOP a2
Vol. III

Fig.

3-1-2

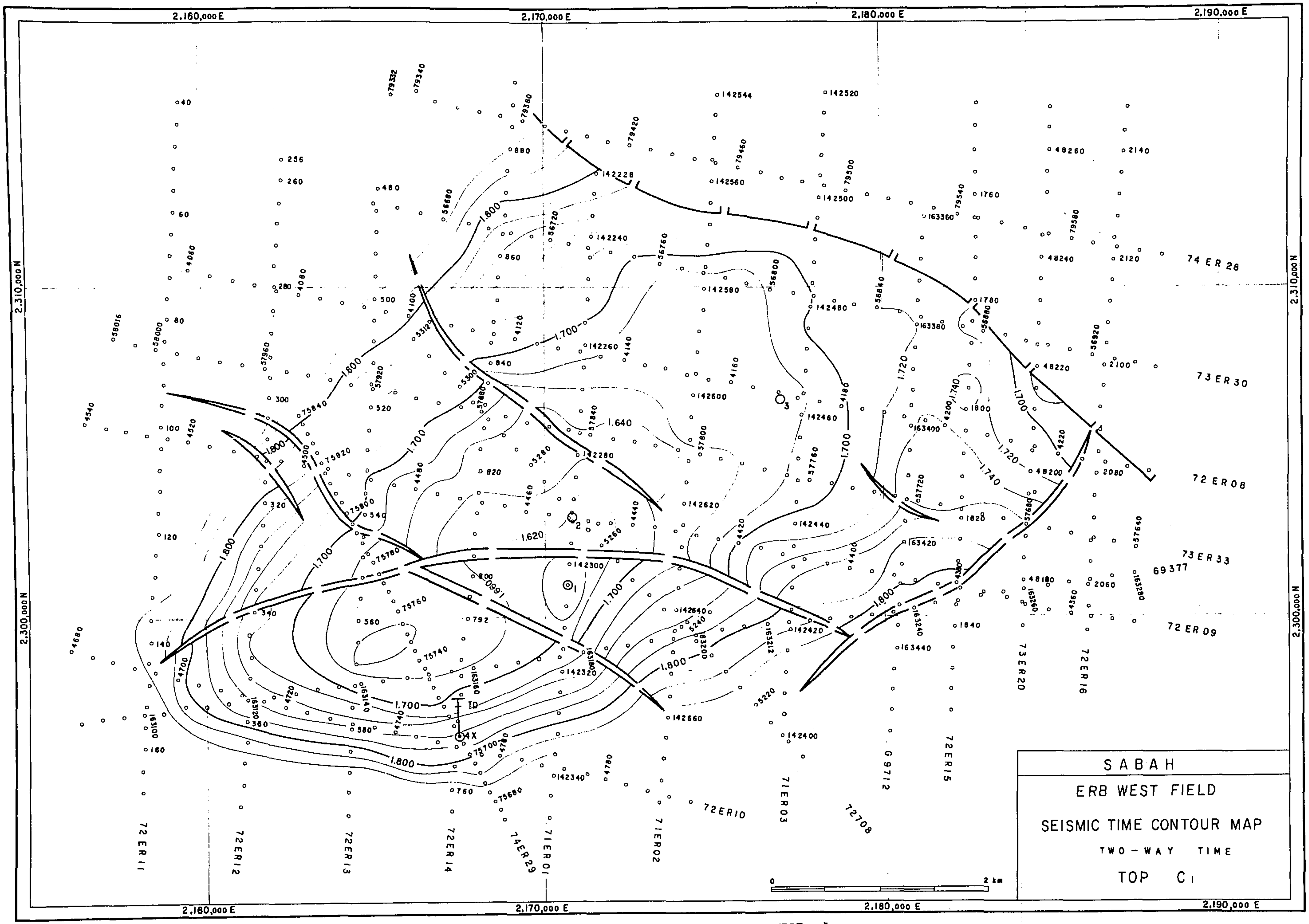


Fig. 3-1-2 TIME CONTOUR MAP, ERB WEST FIELD, TOP c1
Vol. III

Fig. 3-1-3

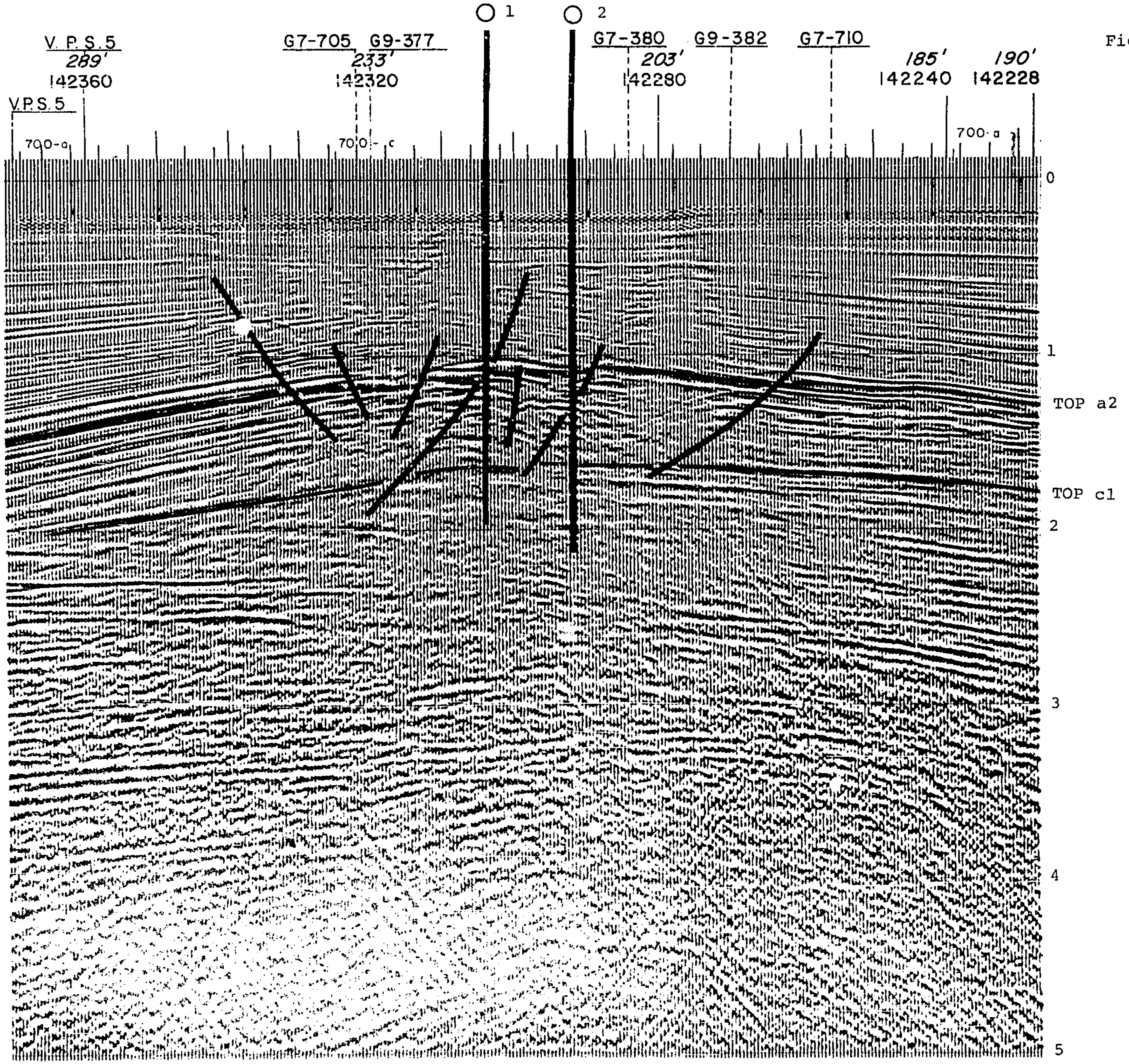


Fig. 3-1-3 SEISMIC SECTION, ERB WEST FIELD, Line 71-ERB-01
Vol. III

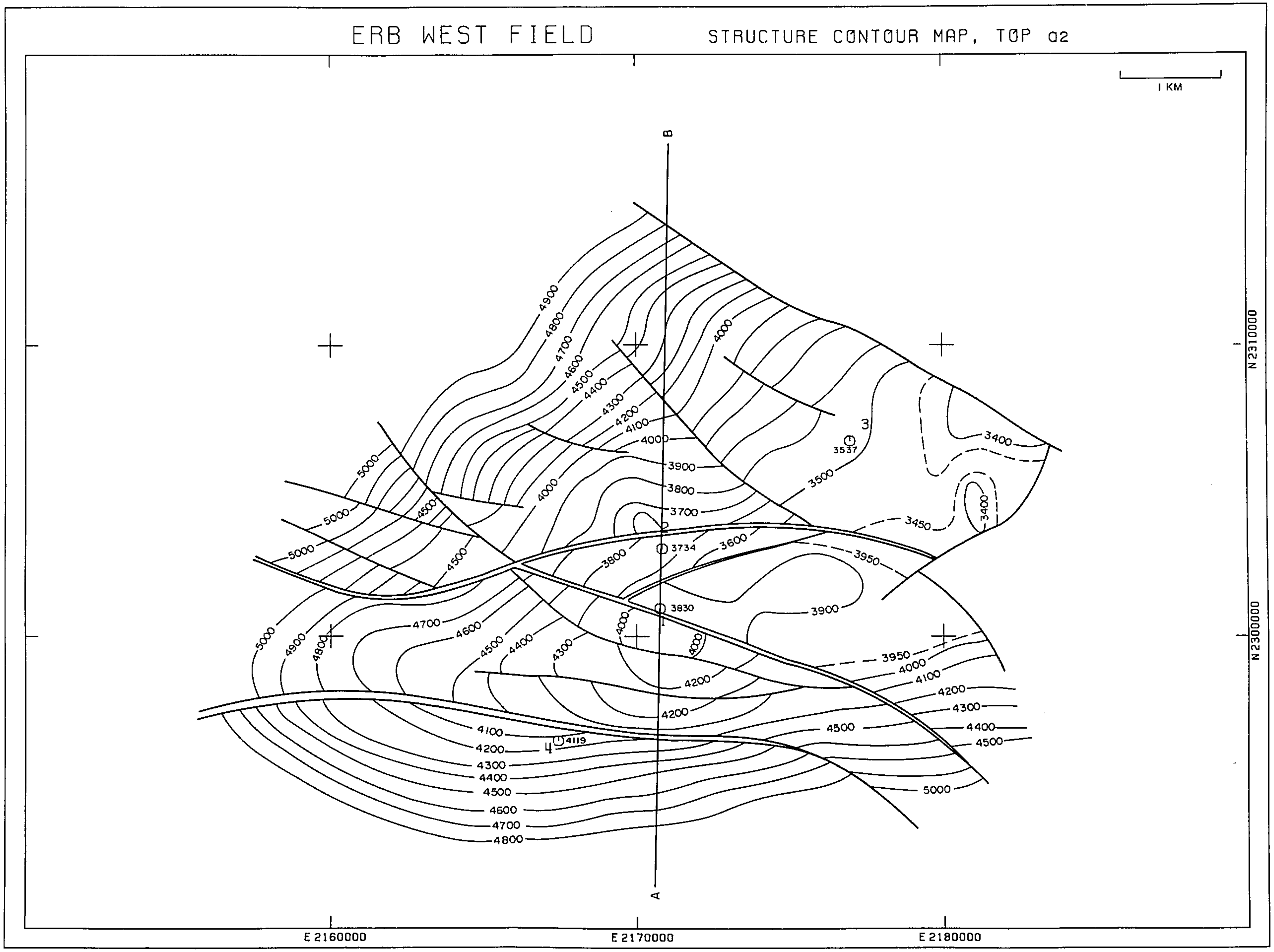


Fig. 3-2-1 STRUCTURE CONTOUR MAP, ERB WEST FIELD, TOP a2
Vol. III

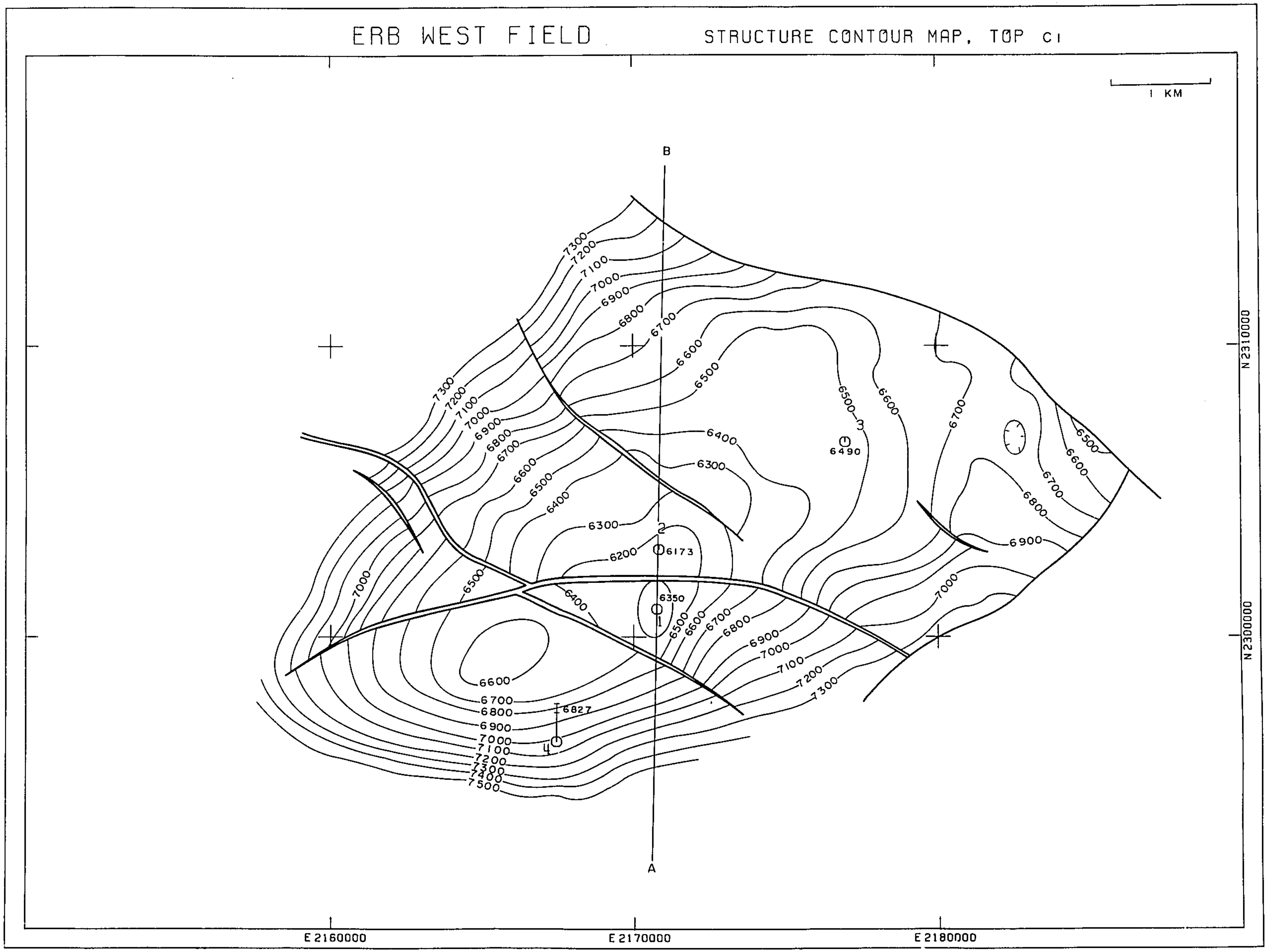


Fig. 3-2-2 STRUCTURE CONTOUR MAP, ERB WEST FIELD, TOP c1
Vol. III

ERB WEST FIELD

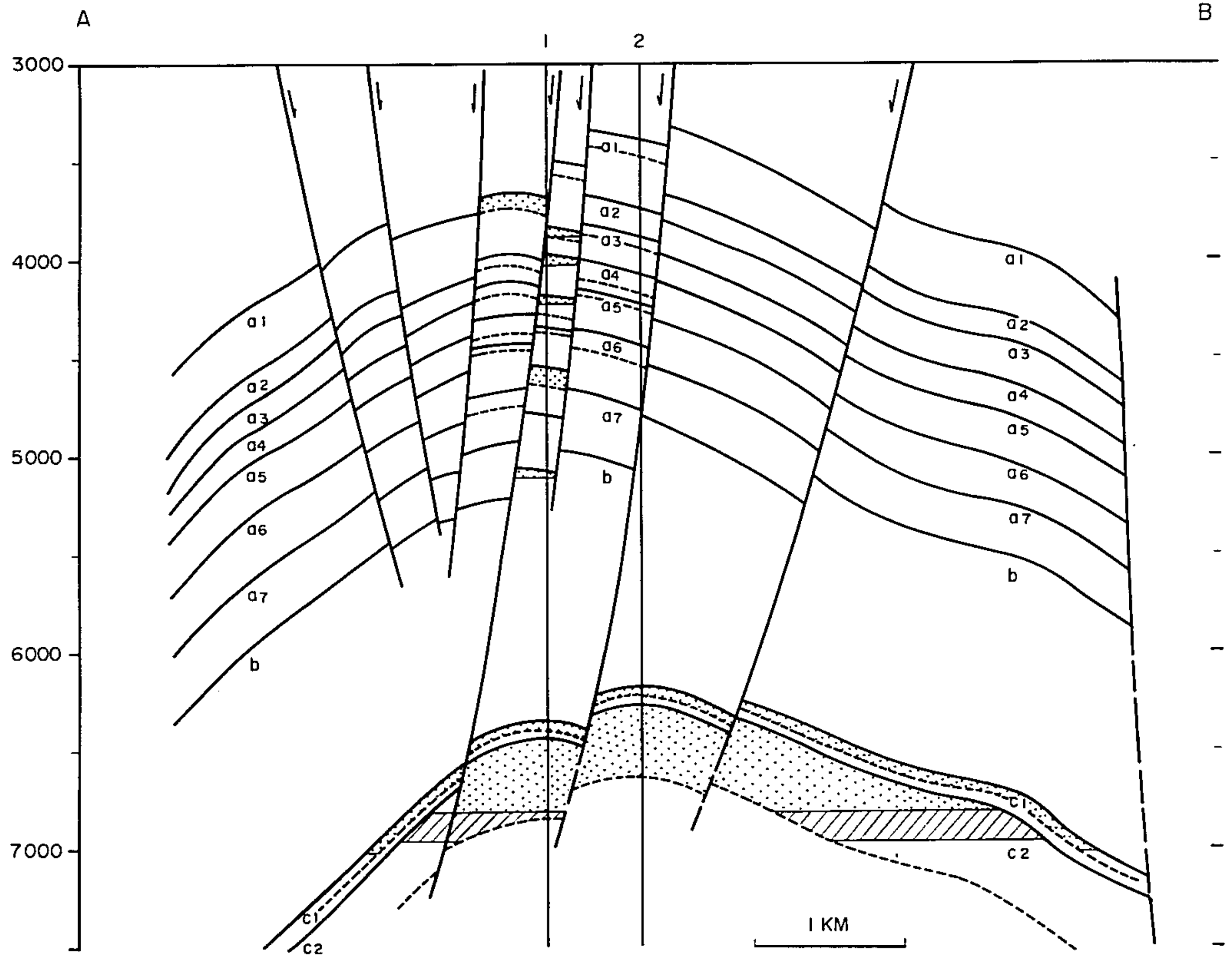


Fig. 3-2-3 STRUCTURAL CROSS-SECTION, ERB WEST FIELD
Vol. III

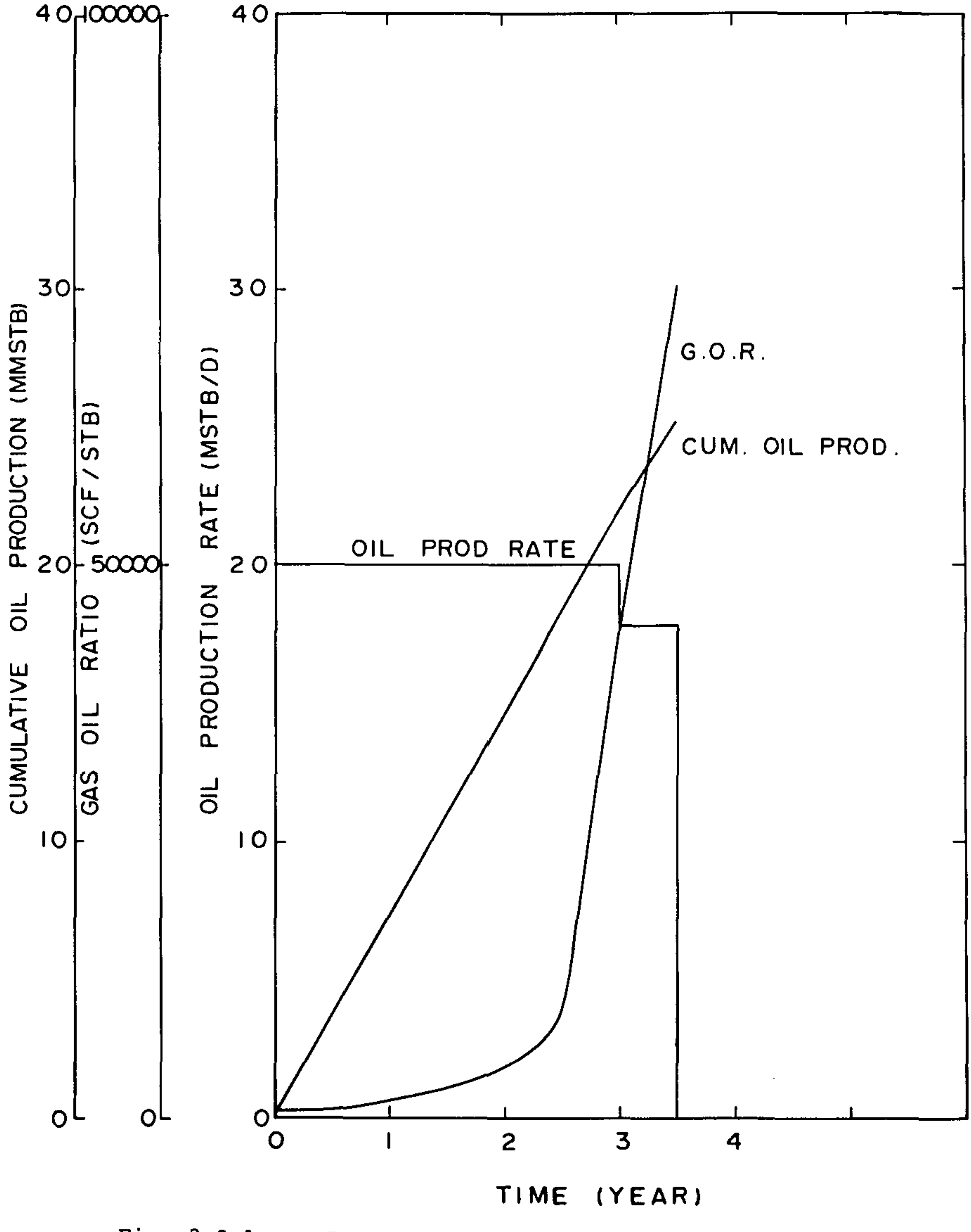


Fig. 3-3-1 PREDICTED PERFORMANCE OF ERB WEST FIELD
Vol. III

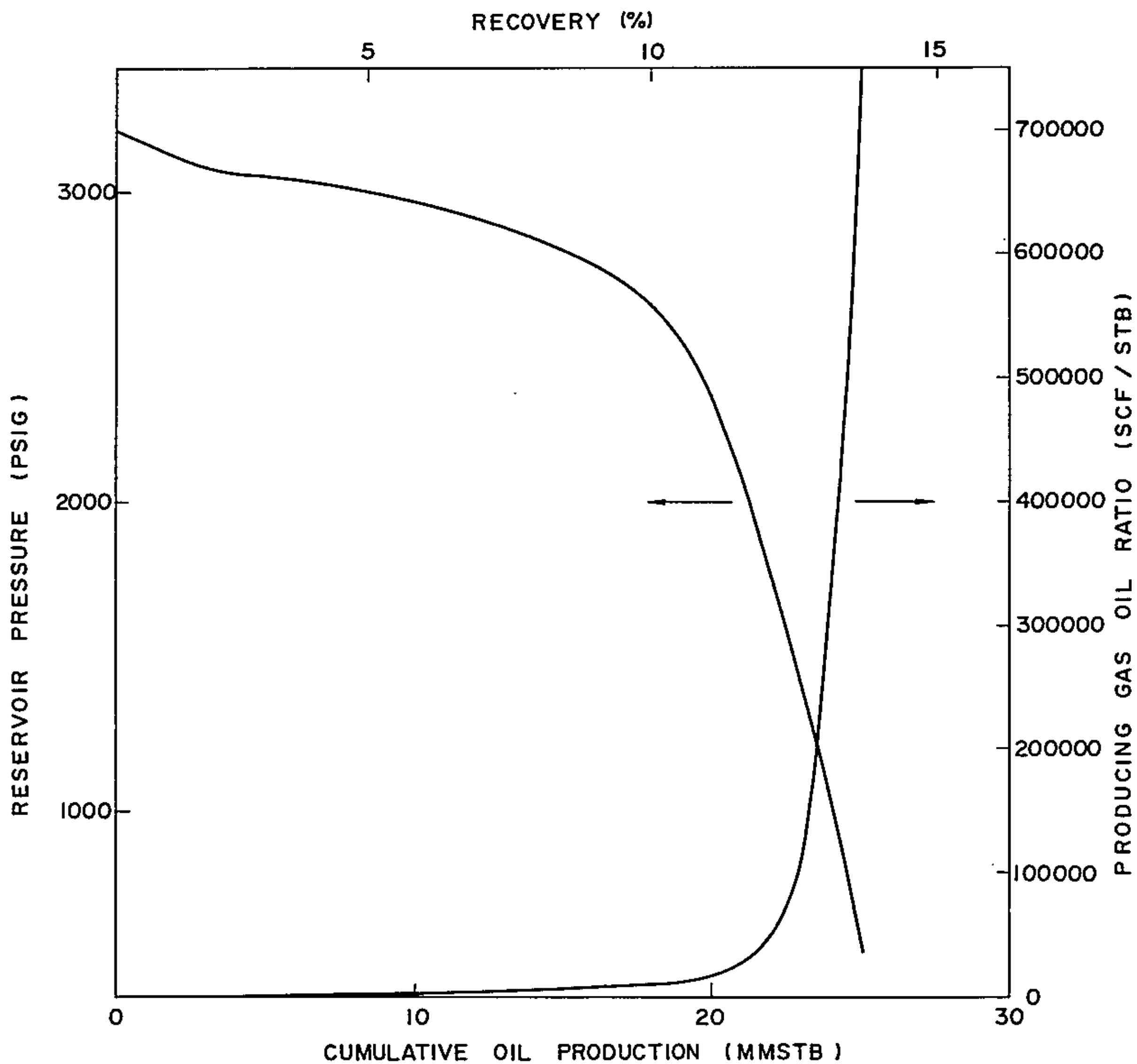


Fig. 3-3-2 CUMULATIVE OIL PRODUCTION VS. RESERVOIR PRESSURE AND PRODUCING GAS OIL RATIO OF ERB WEST FIELD
Vol. III

Fig. 4-1-1

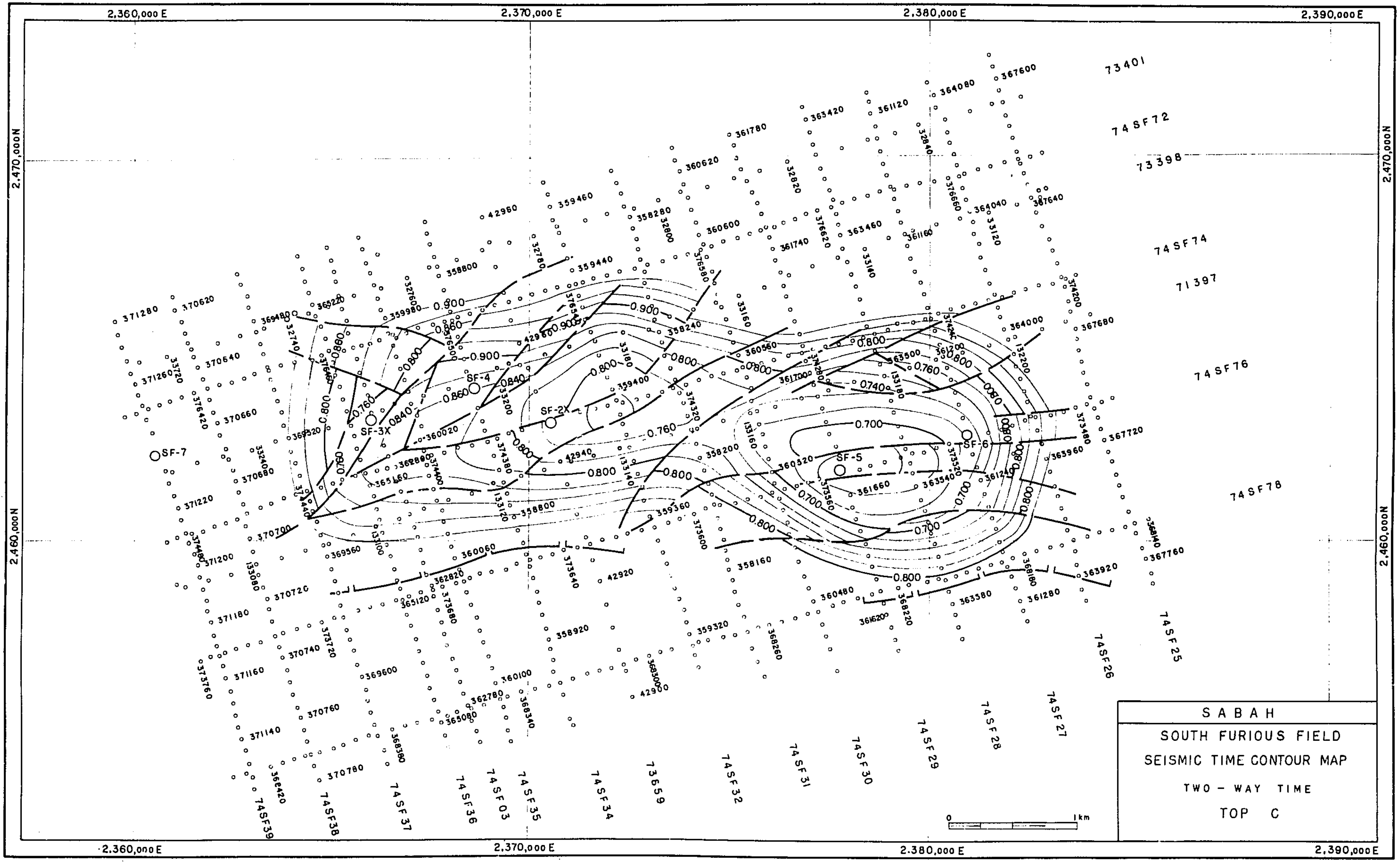


Fig. 4-1-1 TIME CONTOUR MAP, SOUTH FURIOUS FIELD, TOP c
Vol. III

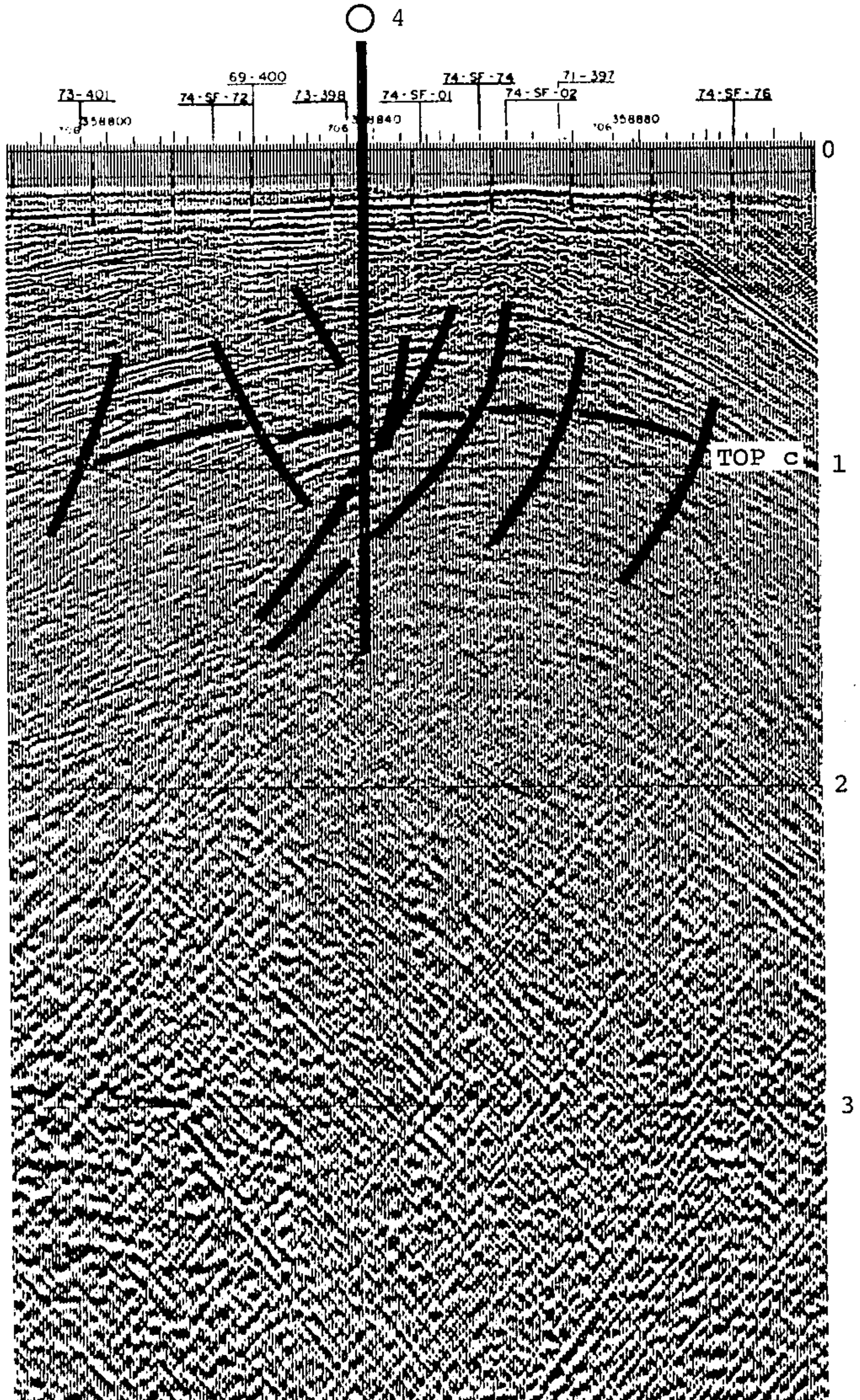


Fig. 4-1-2 SEISMIC SECTION, SOUTH FURIOUS FIELD, Line 74-SF-34
Vol. III

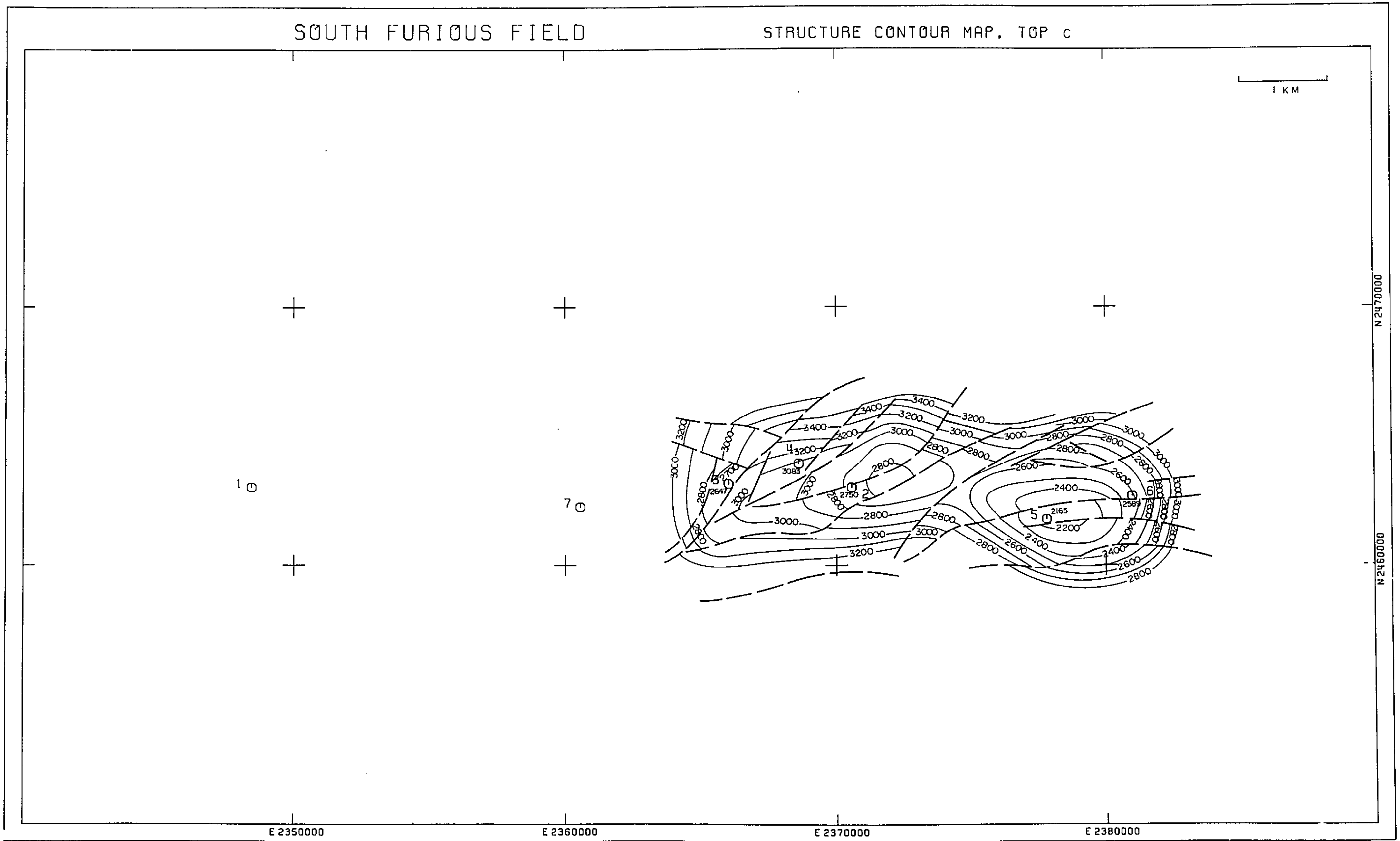


Fig. 4-2-1 STRUCTURE CONTOUR MAP, SOUTH FURIOUS FIELD, TOP c
Vol. III

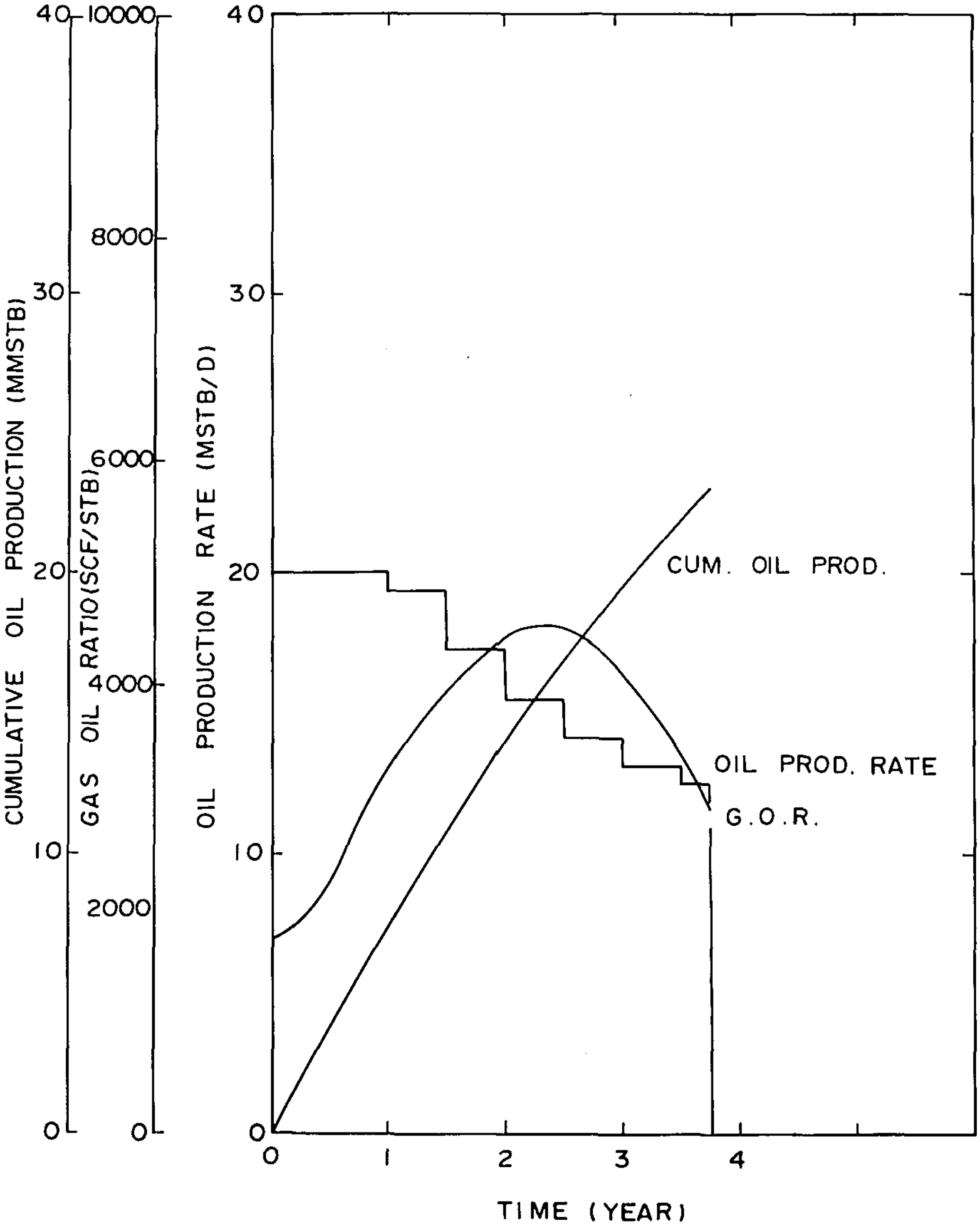


Fig. 4-3-1 PREDICTED PERFORMANCE OF SOUTH FURIOUS FIELD
Vol. III

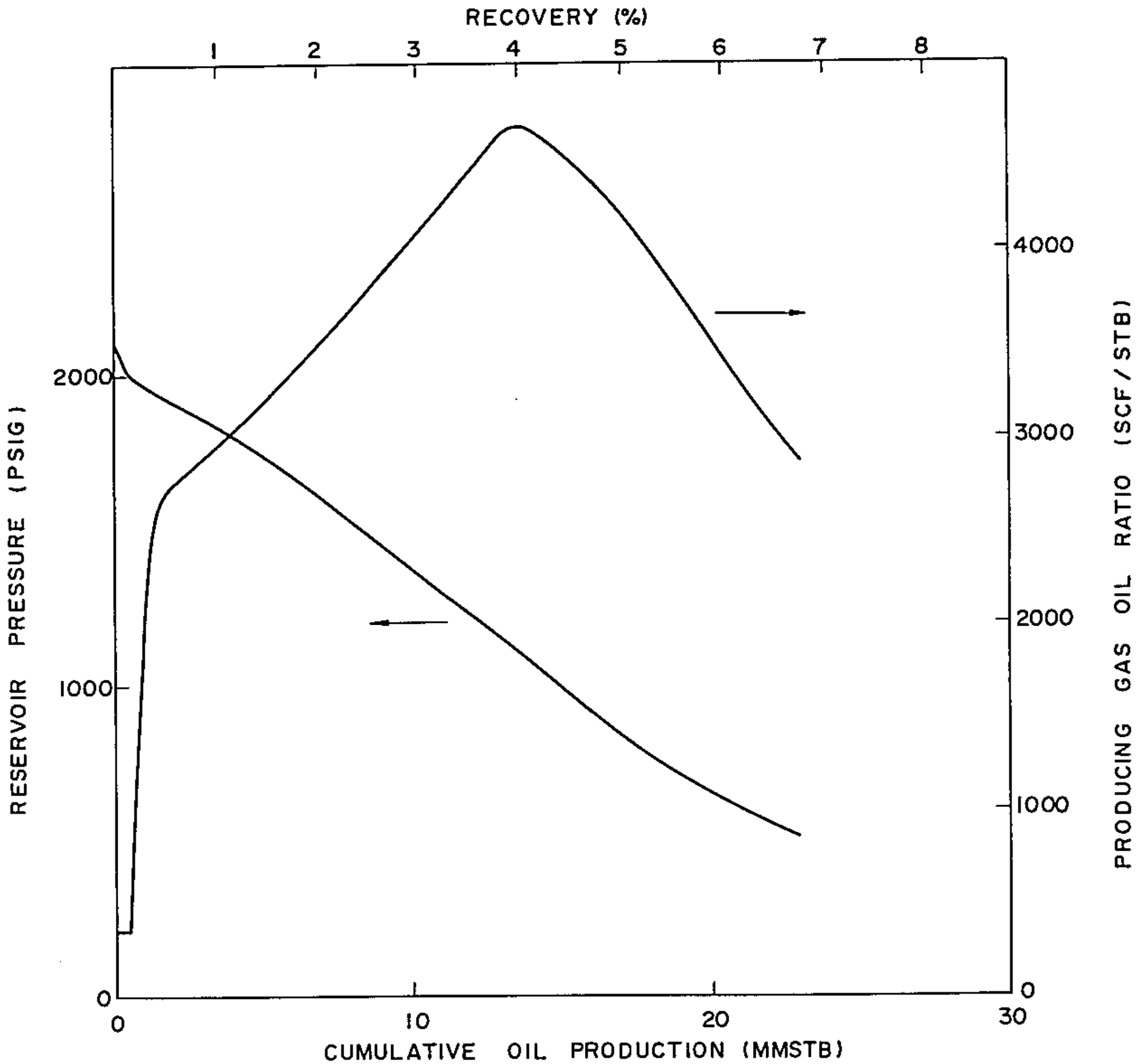


Fig. 4-3-2 CUMULATIVE OIL PRODUCTION VS. RESERVOIR PRESSURE AND PRODUCING GAS OIL RATIO OF SOUTH RURIOUS FIELD
Vol. III

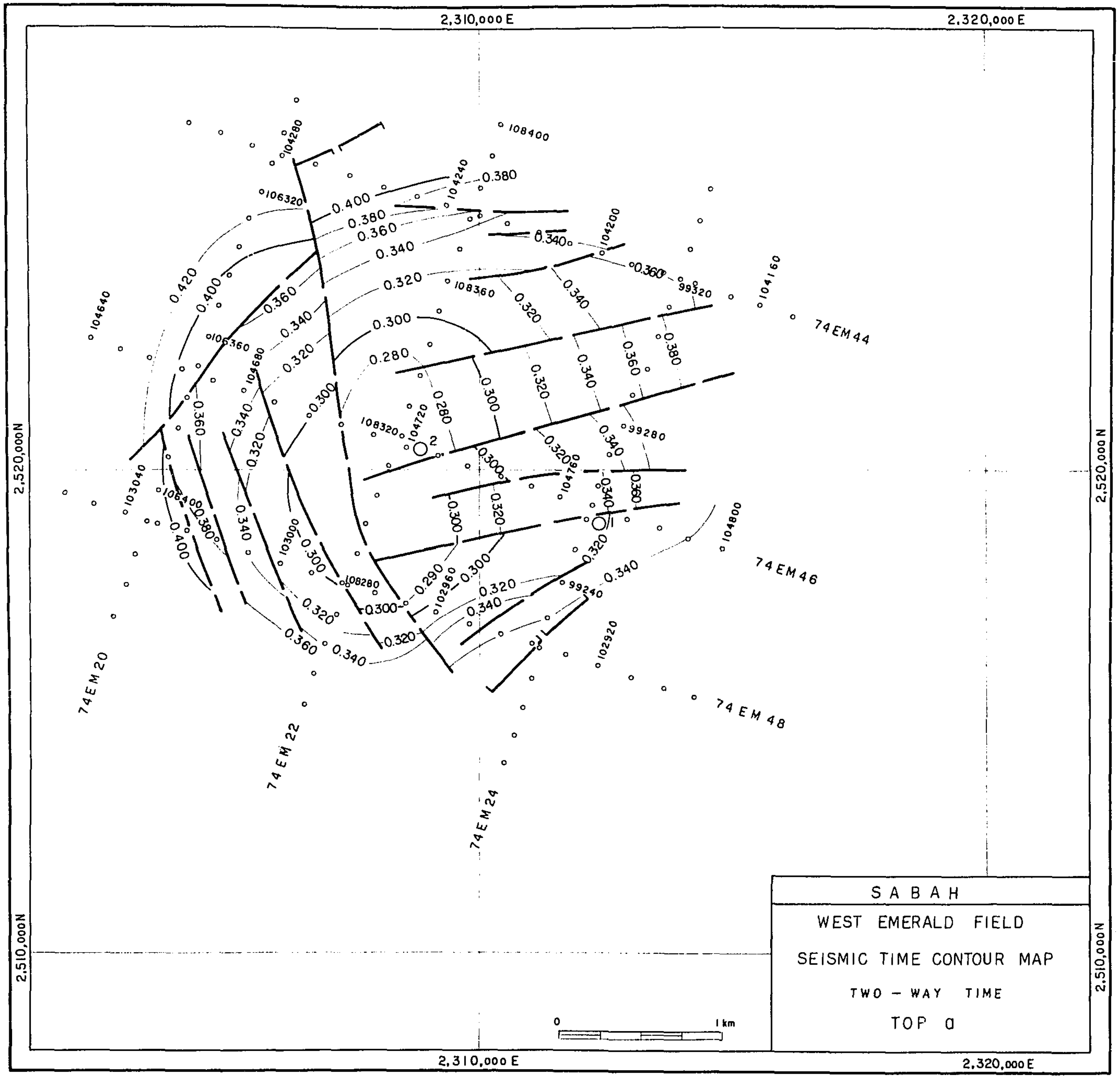


Fig. 5-1-1 TIME CONTOUR MAP, WEST EMERALD FIELD, TOP a
Vol. III

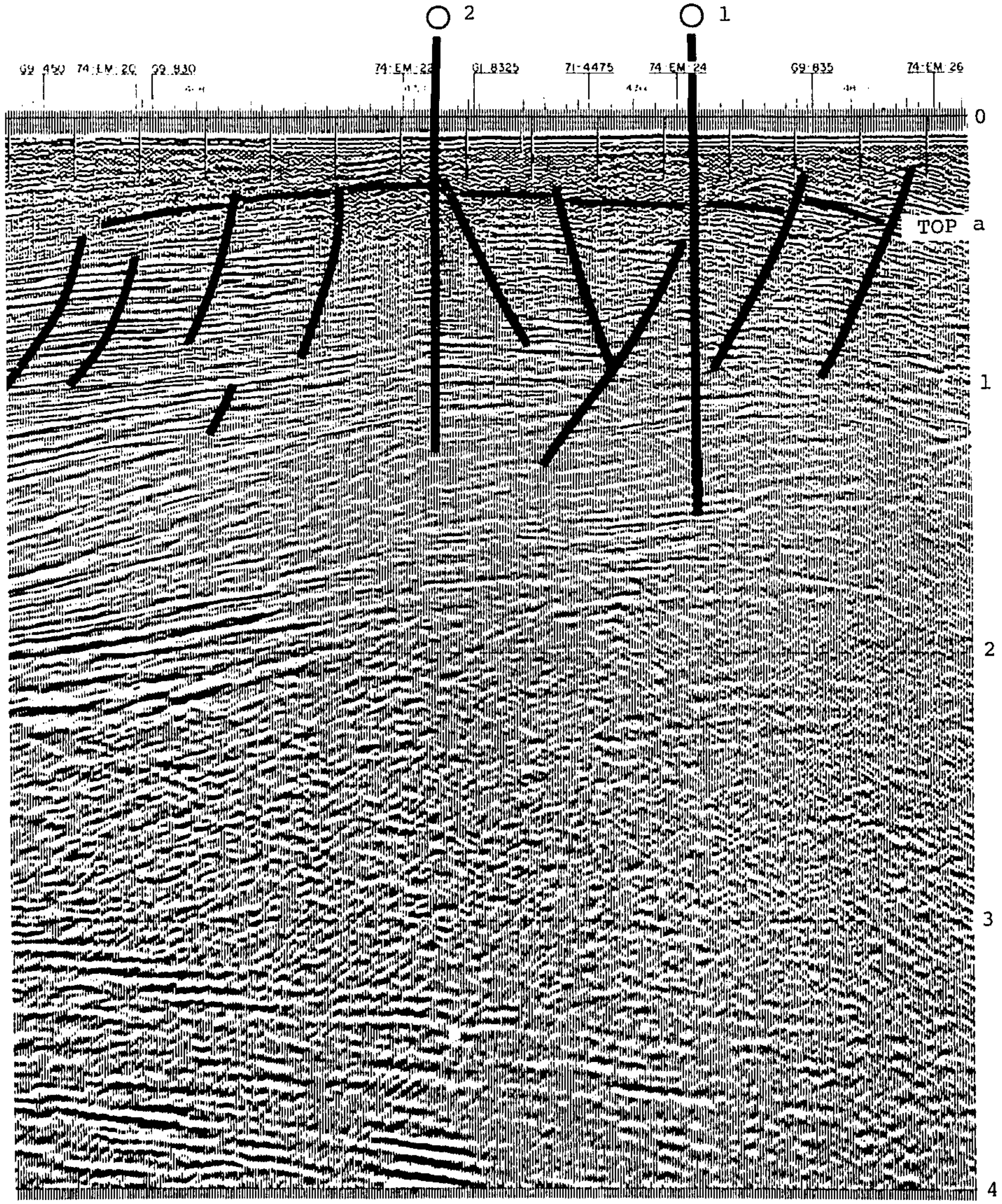


Fig. 5-1-2 SEISMIC SECTION, WEST EMERALD FIELD, Line 74-EM-46
Vol. III

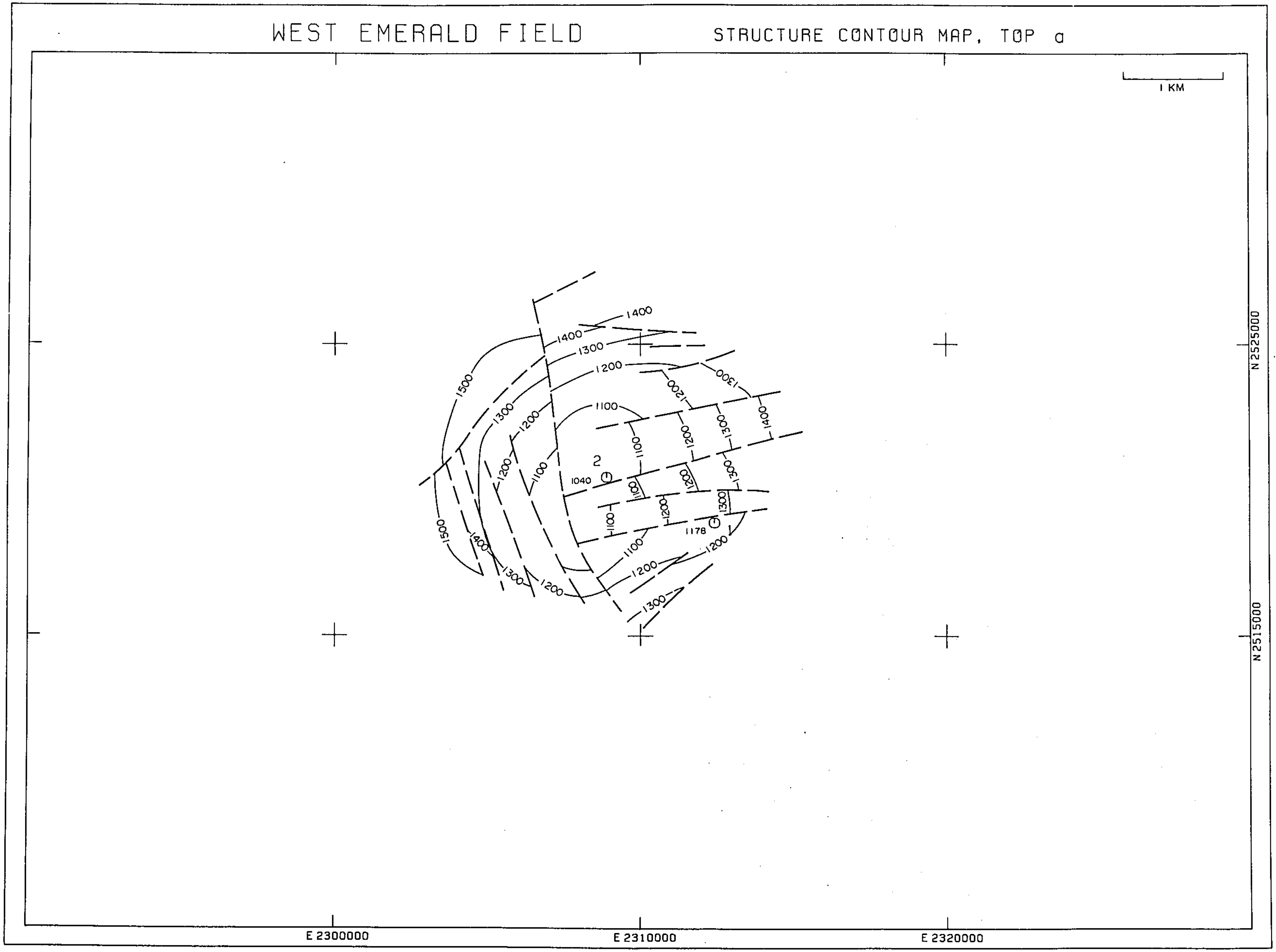


Fig. 5-2-1 STRUCTURE CONTOUR MAP, WEST EMERALD FIELD, TOP a
Vol. III

Fig. 6-1-1

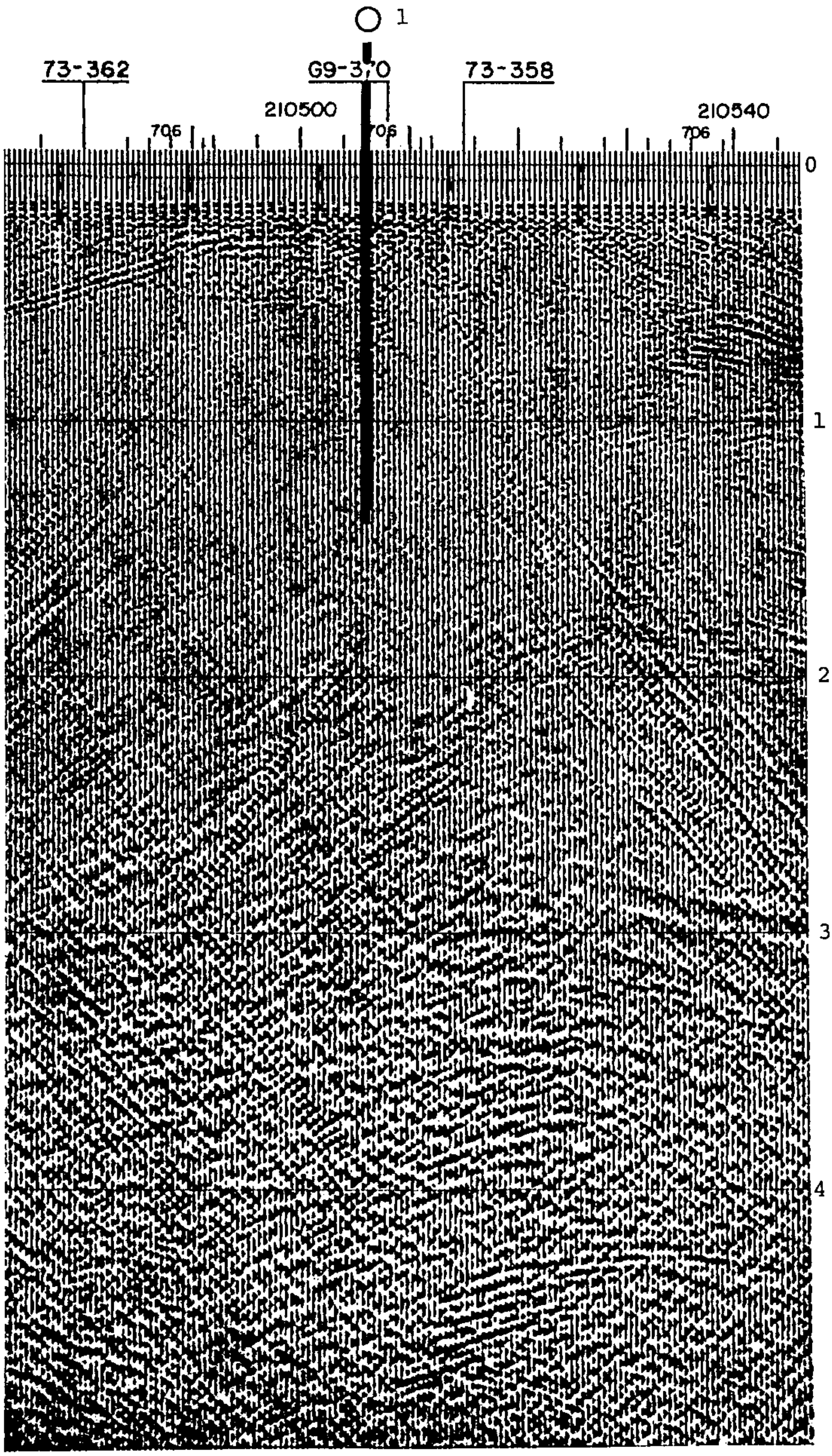


Fig. 6-1-1 SEISMIC SECTION, St. JOSEPH FIELD, Line 73-839
Vol. III

Fig.

7-1-1

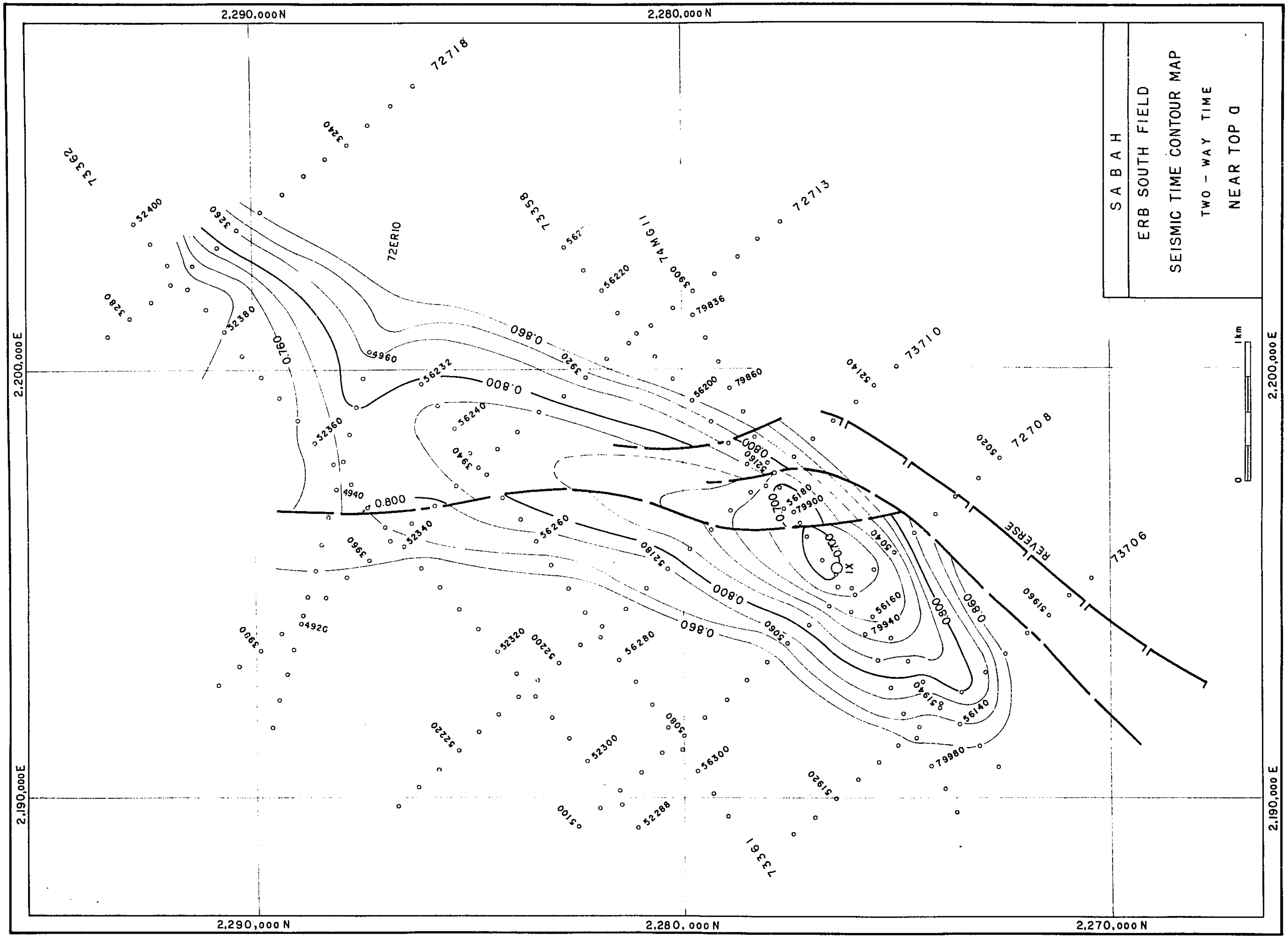


Fig. 7-1-1 TIME CONTOUR MAP, ERB SOUTH FIELD, NEAR TOP a
Vol. III

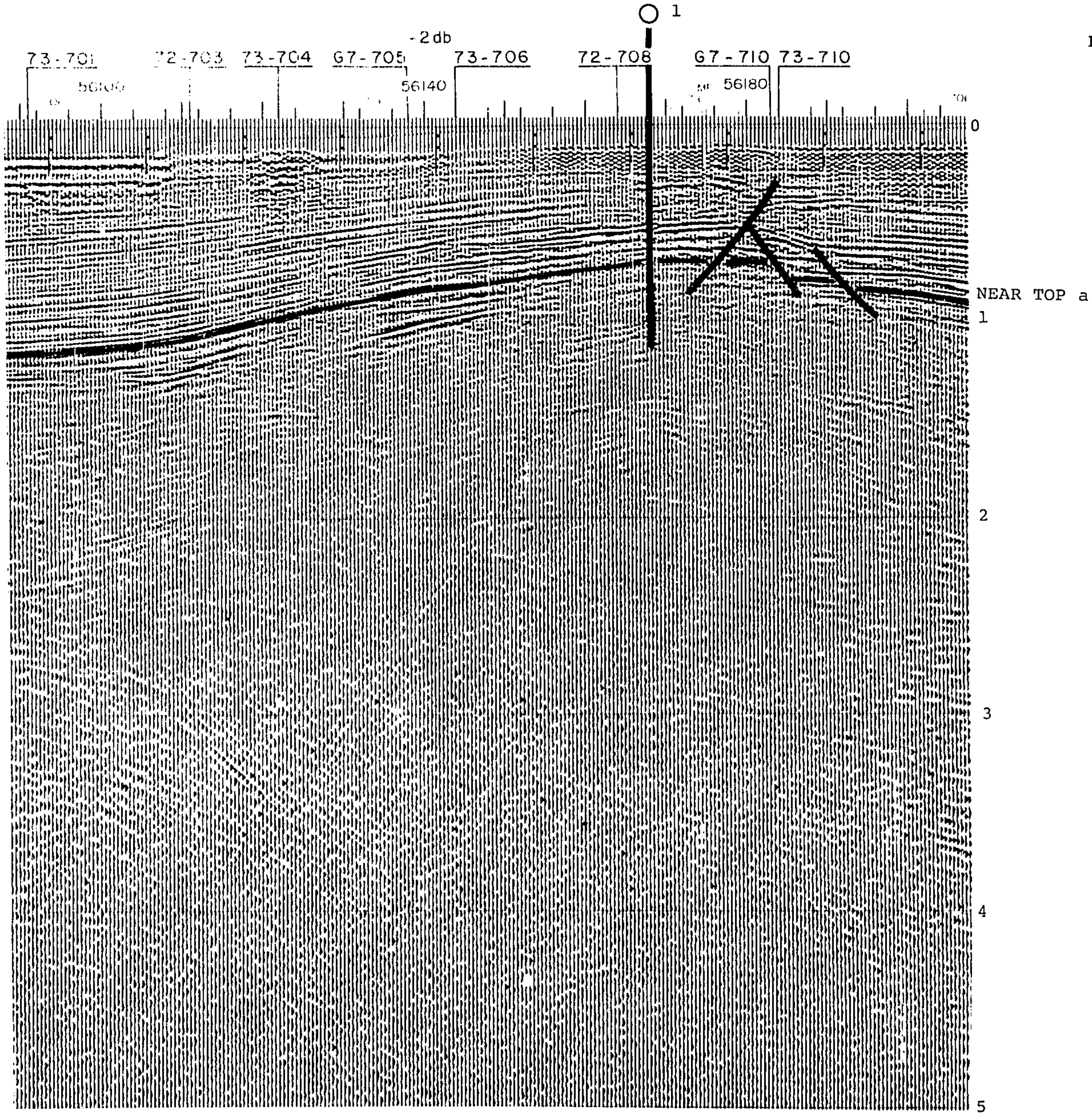


Fig. 7-1-2 SEISMIC SECTION, ERB SOUTH FIELD, Line 73-358
Vol. III

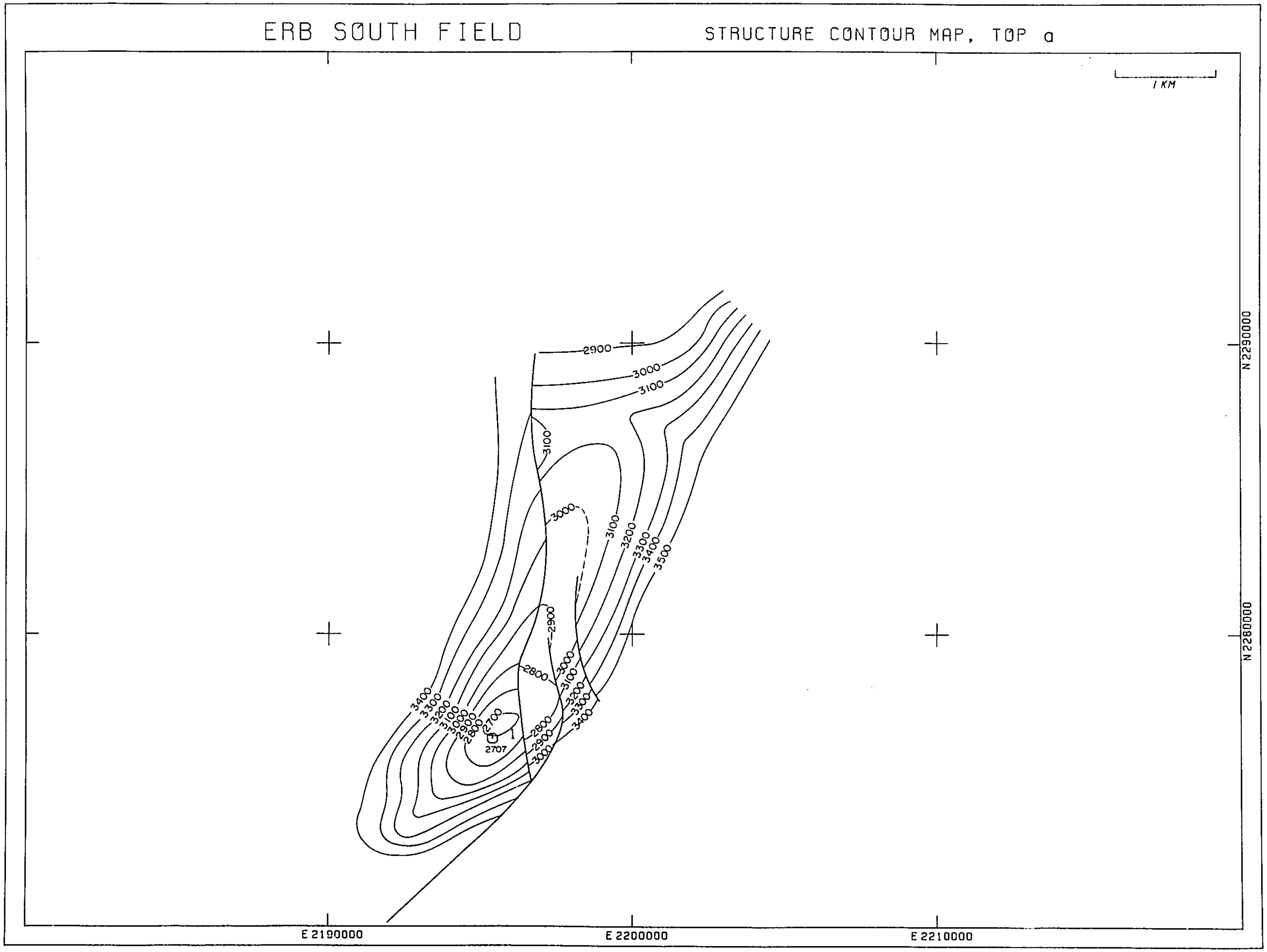
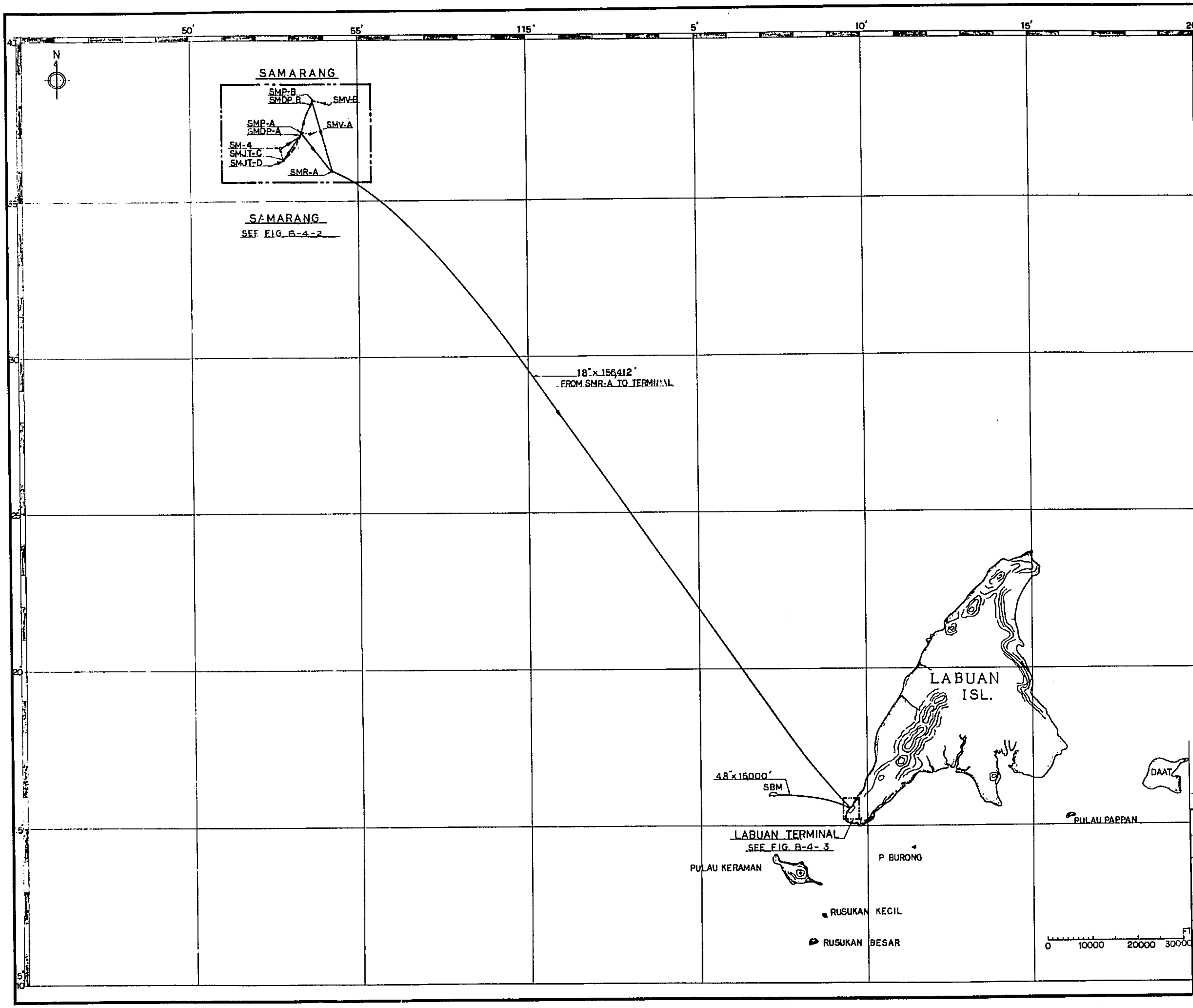


Fig. 7-2-1 STRUCTURE CONTOUR MAP, ERB SOUTH FIELD, TOP a
Vol. III



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FOR PETRONAS
PETROLIAM NASIONAL BERHAD

TITLE FIG. 8-4-1 (Vol. III)
LABUAN STREAM GENERAL FACILITY LAYOUT

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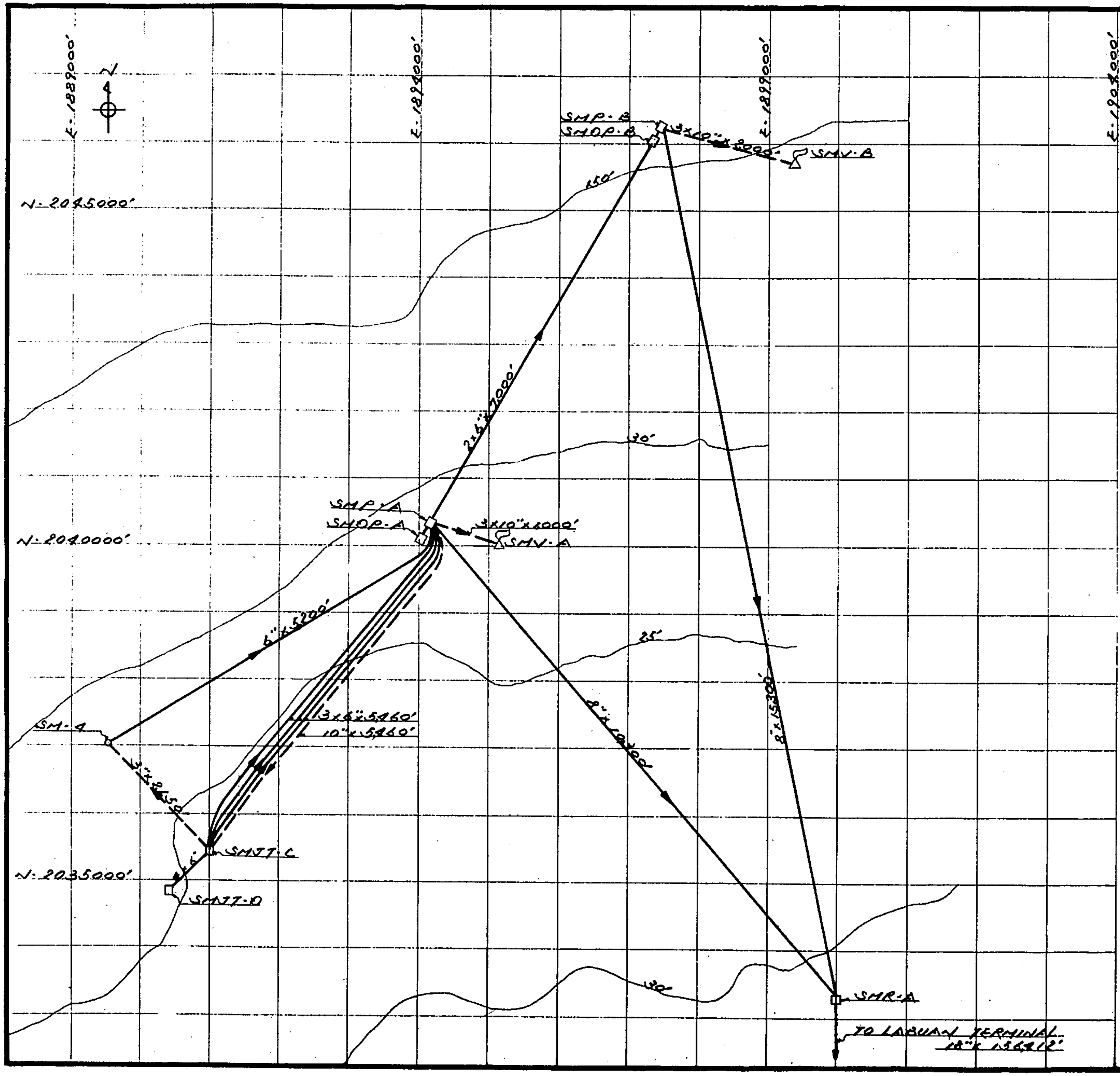

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FIG. 8-4-2 (Vol. III)
SAMARANG FIELD FACILITY LAYOUT

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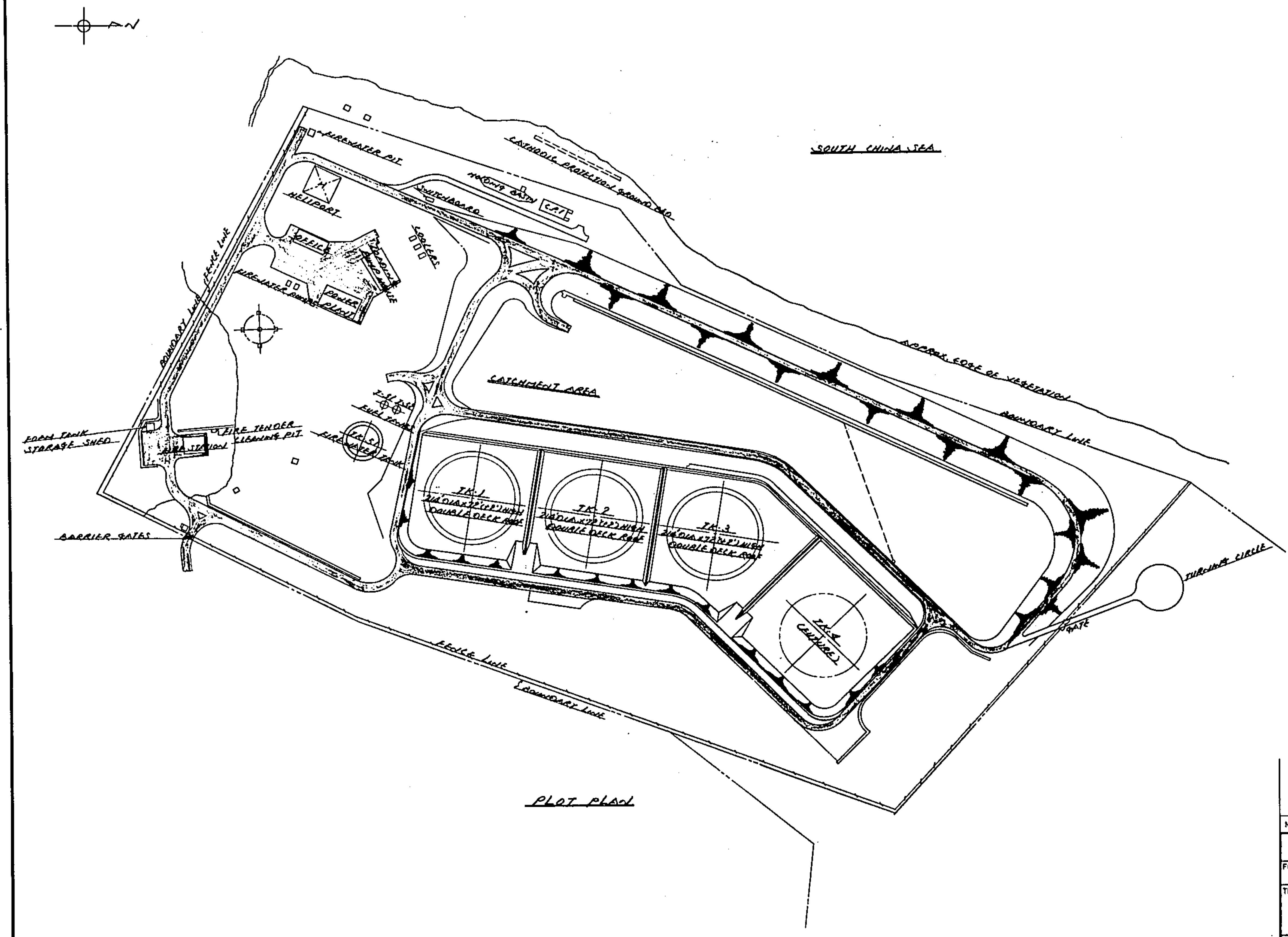

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FIG. 8-4-3 (Vol. III)
LABUAN TERMINAL FACILITY LAYOUT

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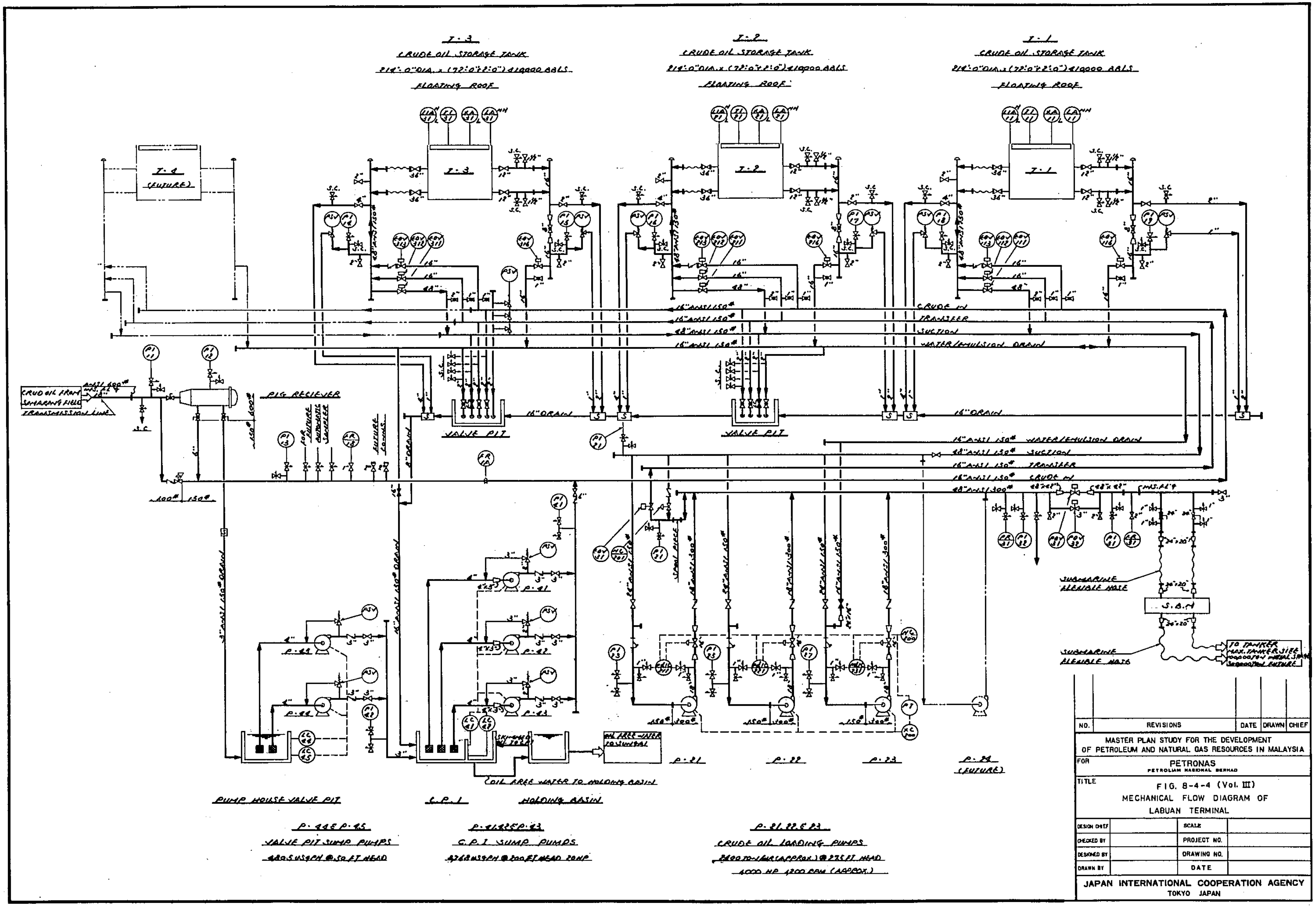

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TITLE FIG. 8-4-4 (Vol. III)
MECHANICAL FLOW DIAGRAM OF LABUAN TERMINAL

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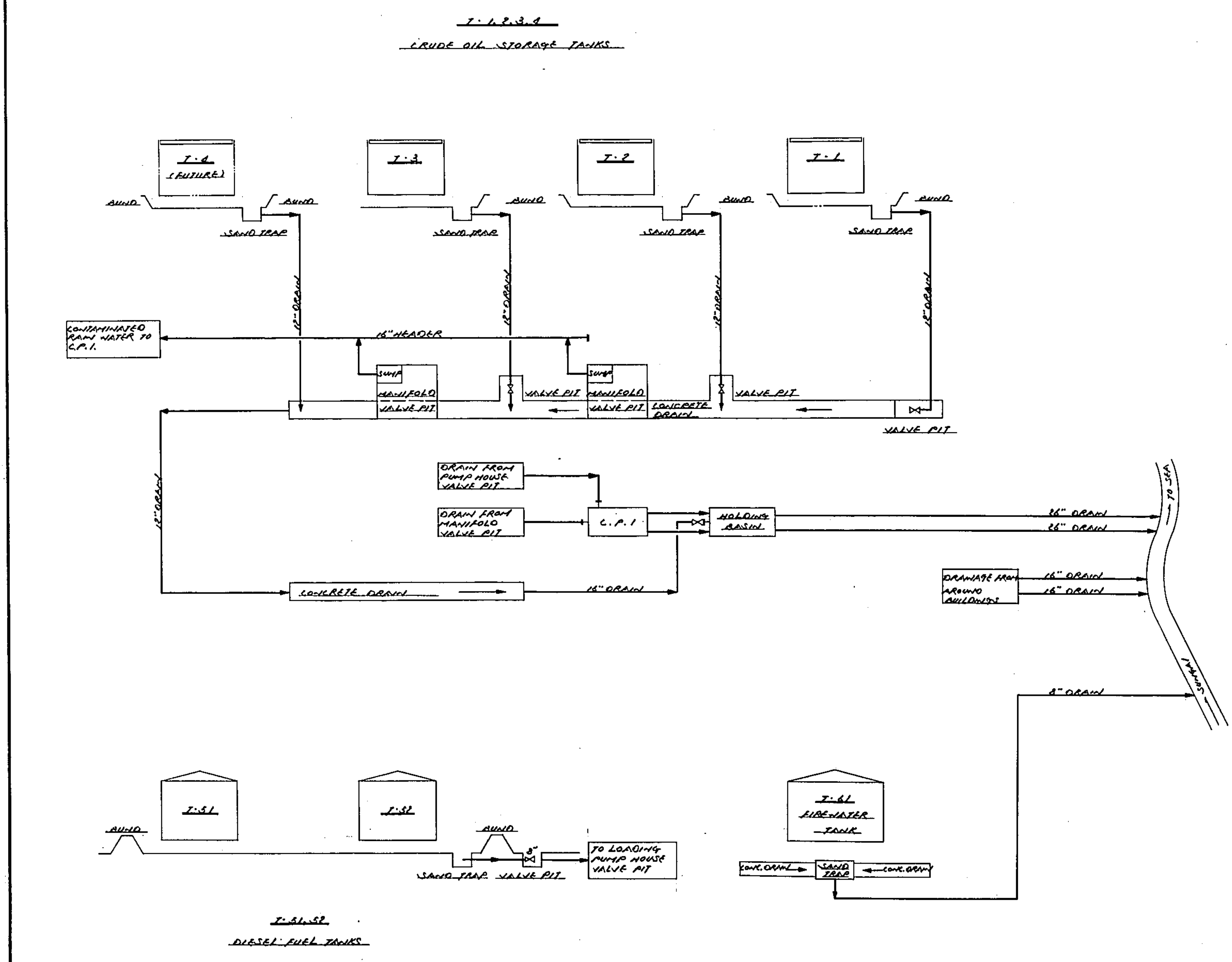

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TITLE FIG. 8-4-5 (Vol. III)
UTILITY FLOW DIAGRAM OF LABUAN TERMINAL NO.3

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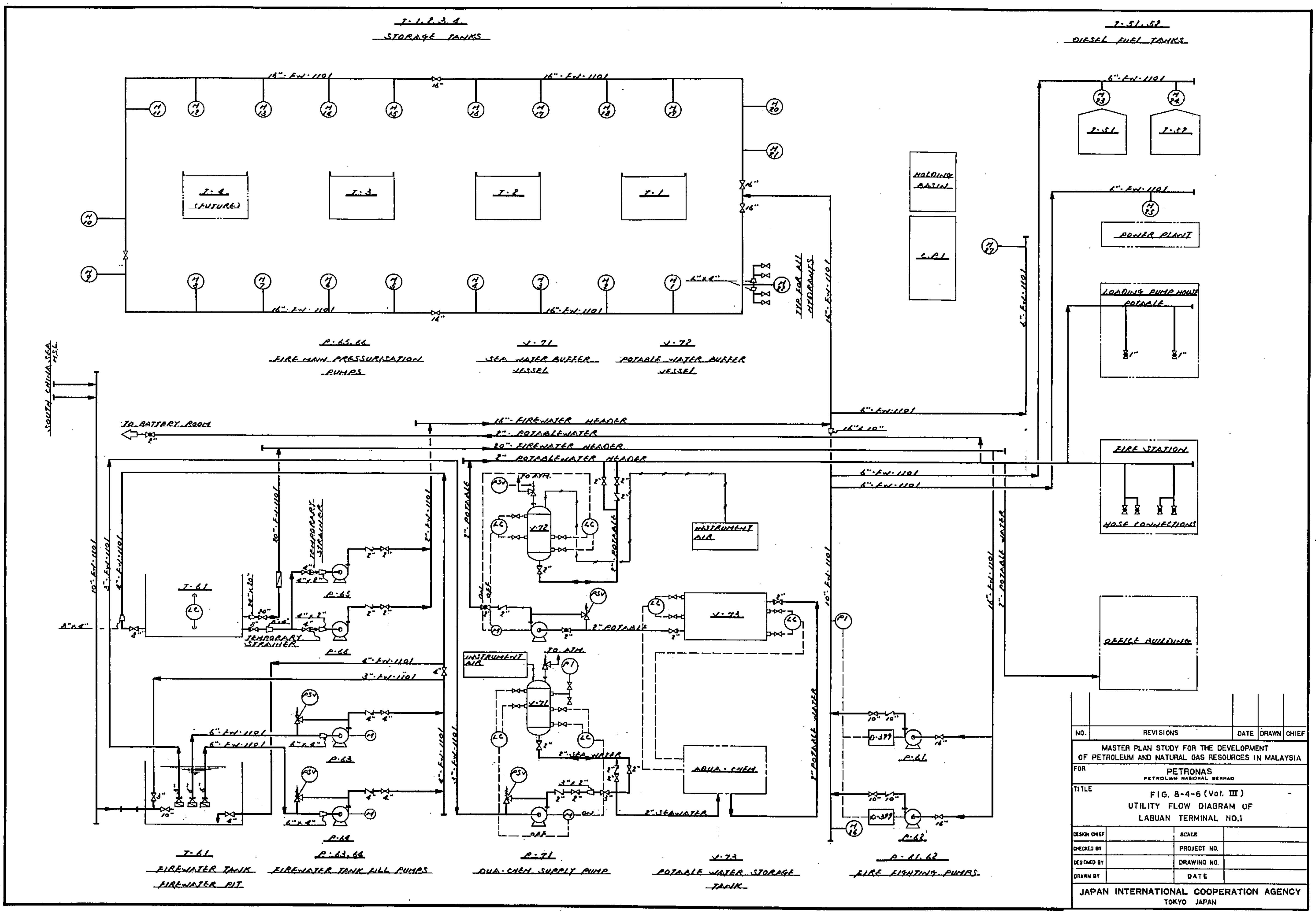

T-1,2,3,4
STORAGE TANKS
T-51,52
DIESEL FUEL TANKS
16"-FW-1101
6"-FW-1101
T-4 (FUTURE)
T-3
T-2
T-1
T-51
T-52
HOLDING BASIN
C.P.I
POWER PLANT
LOADING PUMP HOUSE
POTABLE
TYP FOR ALL HYDRANTS
P-65,66
FIRE MAIN PRESSURISATION PUMPS
V-71
SEA WATER BUFFER VESSEL
V-72
POTABLE WATER BUFFER VESSEL
SOUTH CHINA SEA
TO BATTERY ROOM
16"-FIREWATER HEADER
2"-POTABLEWATER
20"-FIREWATER HEADER
2"-POTABLEWATER HEADER
FIRE STATION
HOSE CONNECTIONS
INSTRUMENT AIR
TEMPORARY STRAINER
TO ATM.
2" POTABLE
OFFICE BUILDING
2"-SEA WATER
2"-SEAWATER
AQUA-CHEM
T-61
FIREWATER TANK
FIREWATER PIT
P-63,64
FIREWATER TANK FILL PUMPS
P-71
AQUA-CHEM SUPPLY PUMP
V-73
POTABLE WATER STORAGE TANK
P-61,62
FIRE FIGHTING PUMPS
NO.
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TITLE
FIG. 8-4-6 (Vol. III)
UTILITY FLOW DIAGRAM OF LABUAN TERMINAL NO.1
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PROJECT NO.
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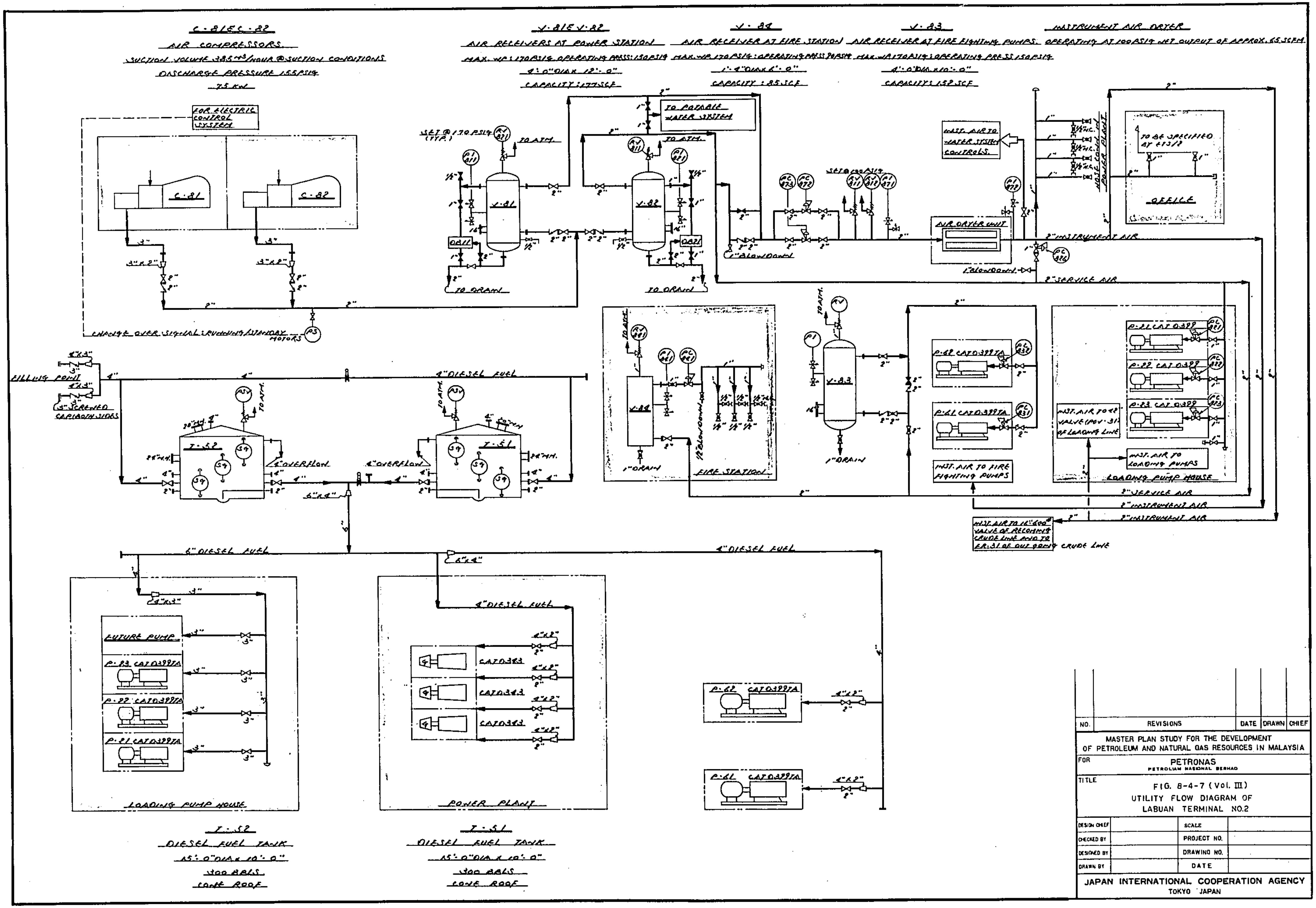

NO.	REVISIONS	DATE	DRAWN	CHIEF

MASTER PLAN STUDY FOR THE DEVELOPMENT OF PETROLEUM AND NATURAL GAS RESOURCES IN MALAYSIA

FOR: PETRONAS
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TITLE: FIG. 8-4-7 (Vol. III)
UTILITY FLOW DIAGRAM OF LABUAN TERMINAL NO.2

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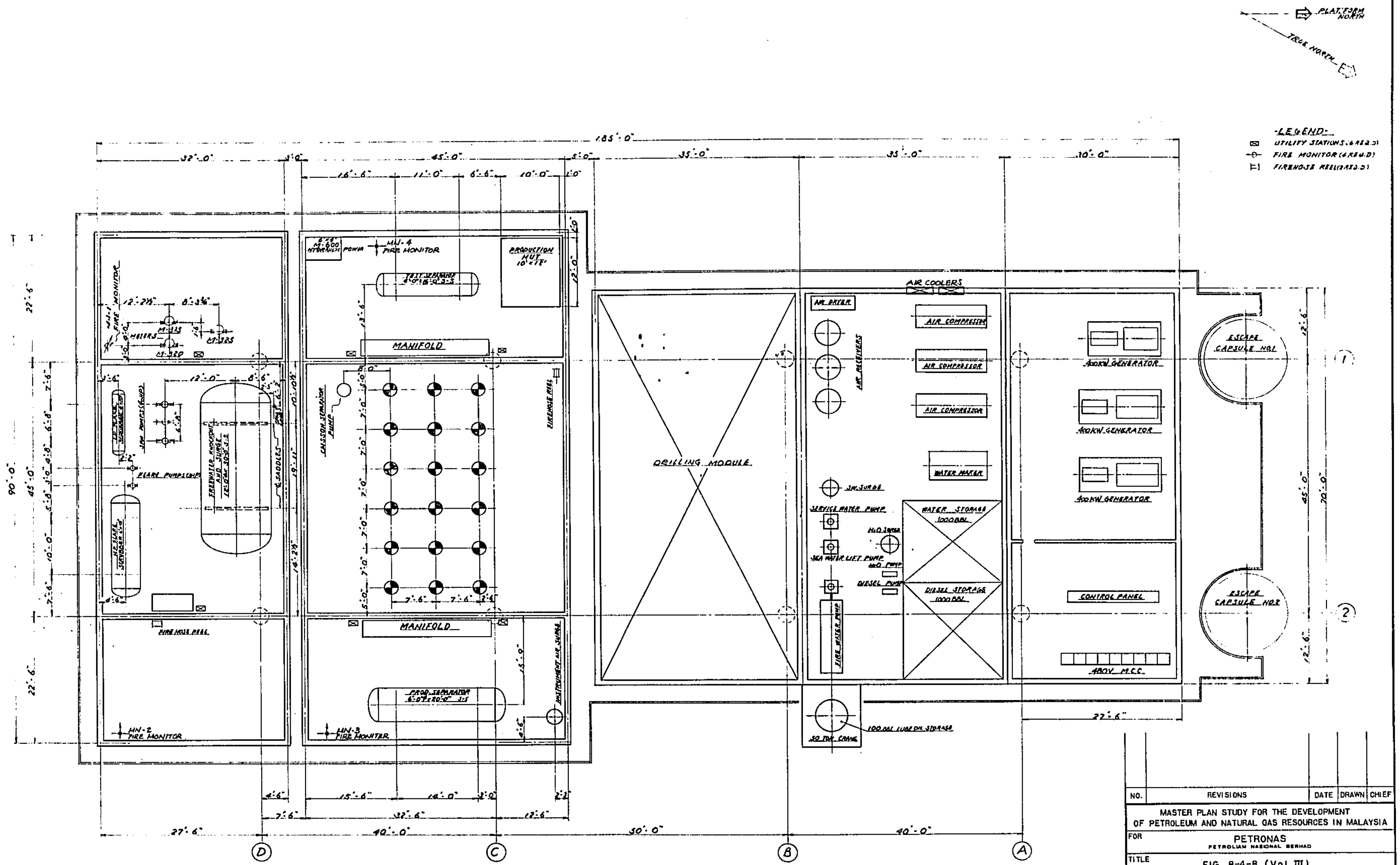

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MASTER PLAN STUDY FOR THE DEVELOPMENT OF PETROLEUM AND NATURAL GAS RESOURCES IN MALAYSIA

FOR PETRONAS
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TITLE FIG. 8-4-8 (Vol. III)
MAJOR EQUIPMENT ARRANGEMENT OF TEMBUNGO PLATFORM "A"

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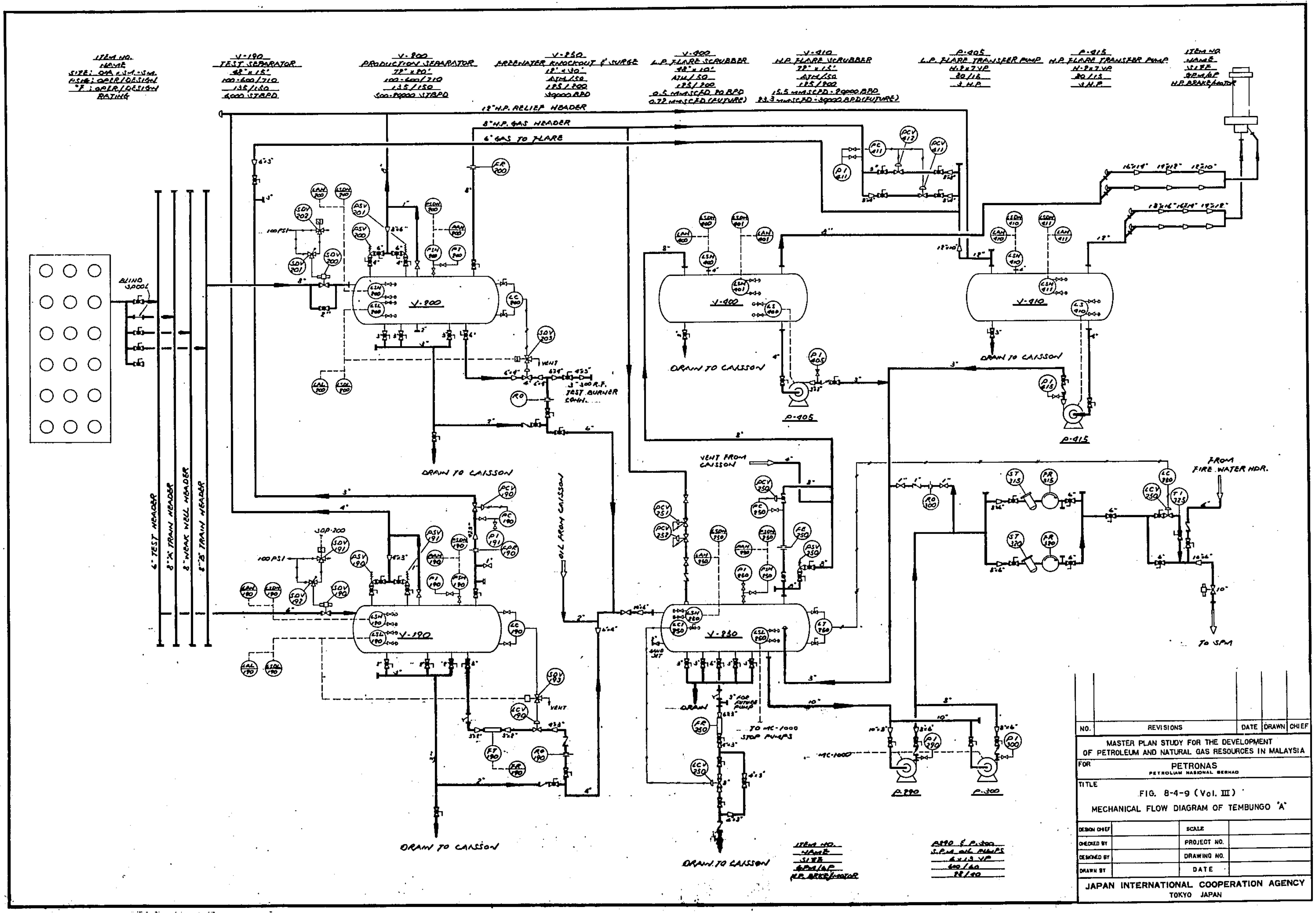

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FIG. 8-4-9 (Vol. III)

MECHANICAL FLOW DIAGRAM OF TEMBUNGO "A"

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Fig. 8-4-10 (Vol. III)

LABUAN STREAM PRESSURE BALANCE

AT PRESENT PRODUCTION RATE

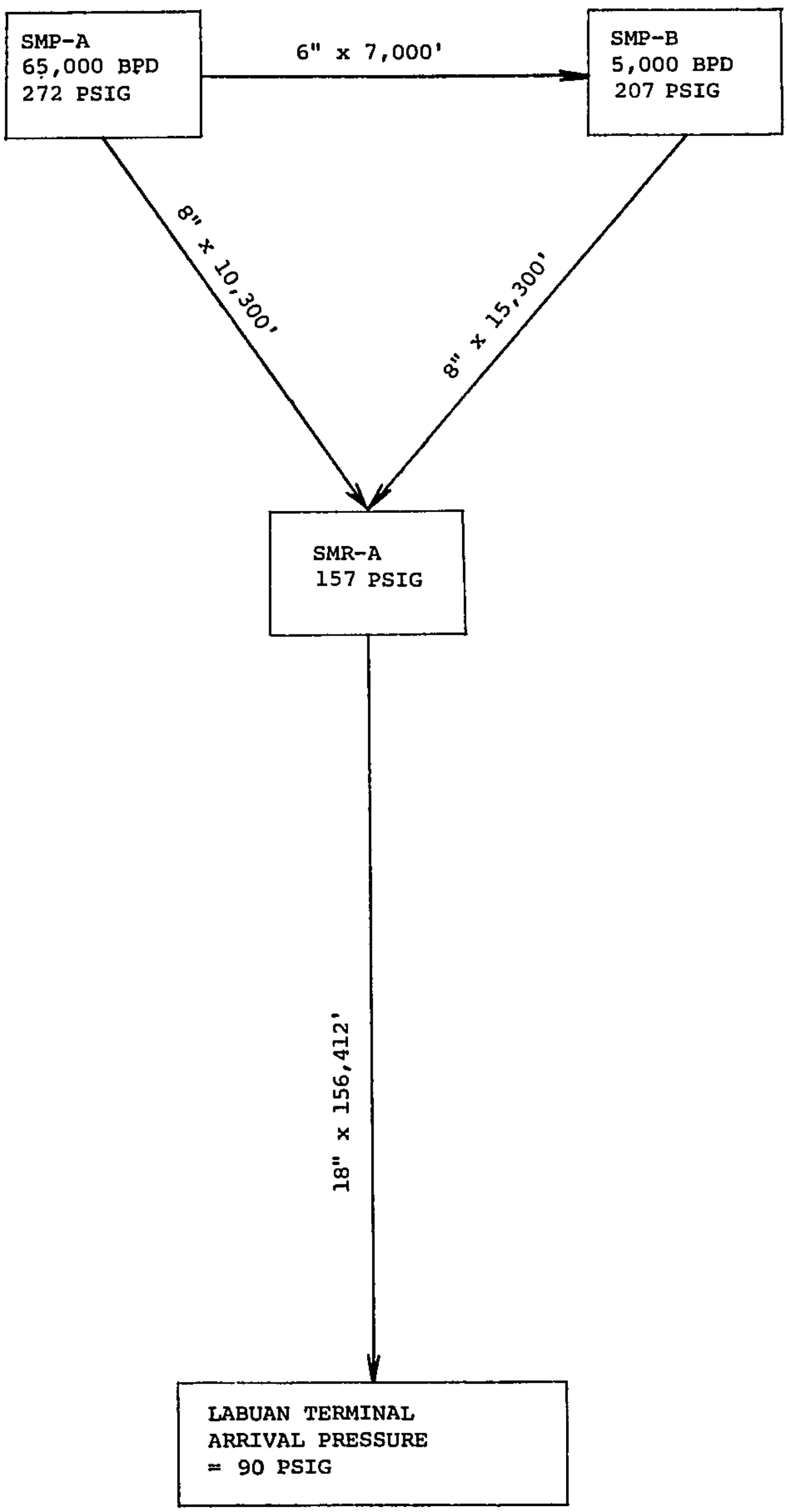


Fig. 8-4-11 LABUAN STREAM PRESSURE BALANCE
(Vol. III)
AT MAXIMUM HANDLING CAPACITY OF PRODUCTION PLATFORMS

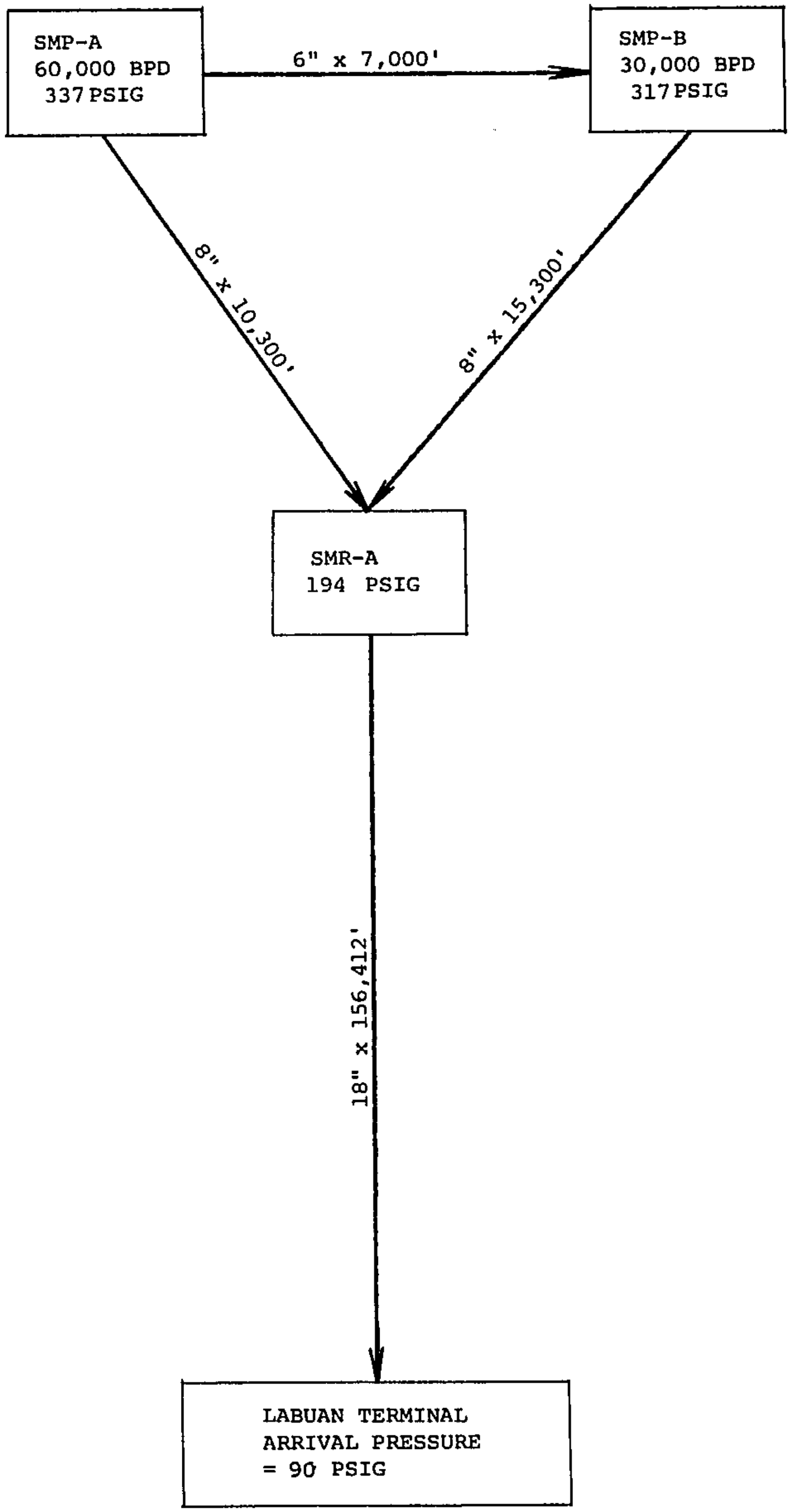
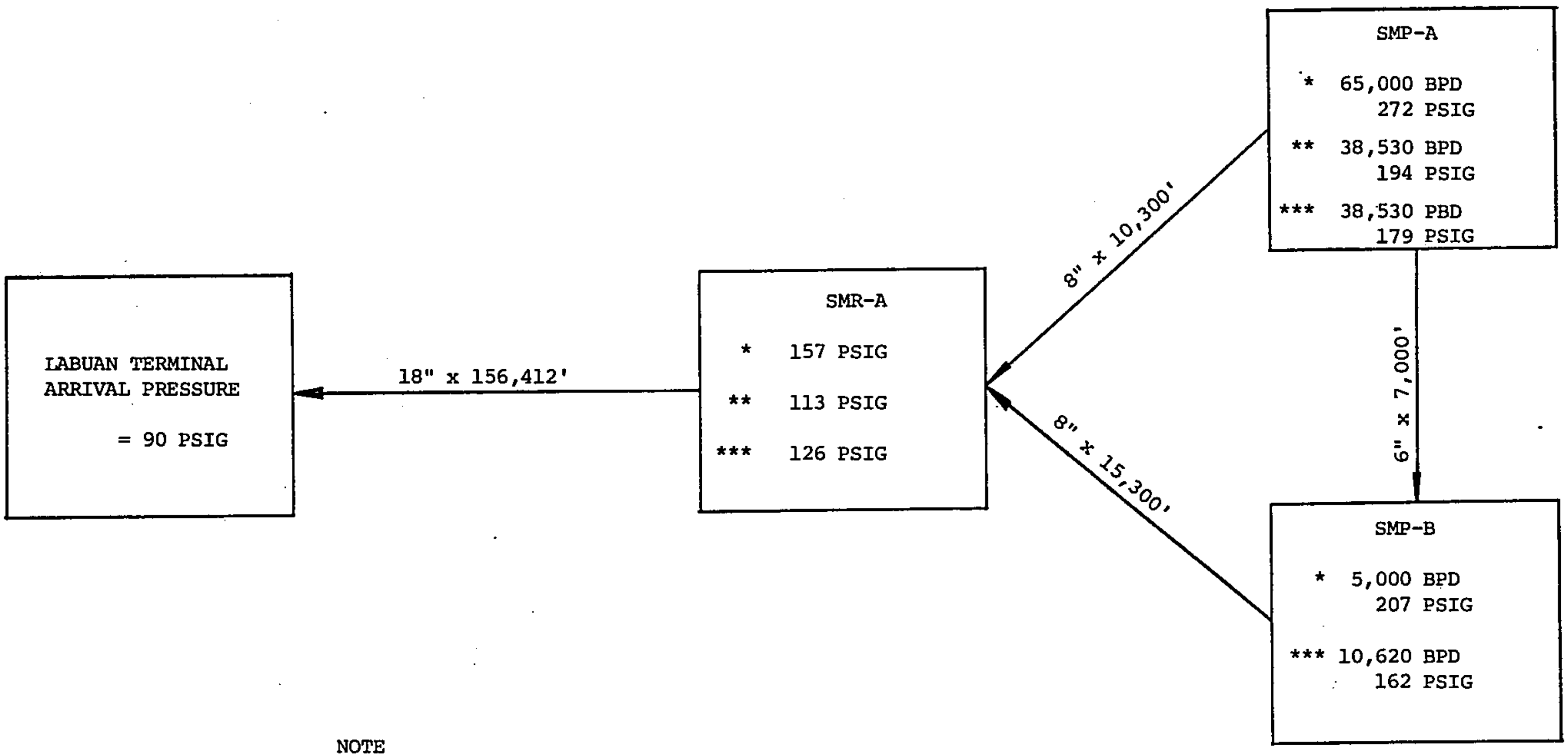


Fig. 8-4-12 PRESSURE BALANCE FOR PRESENT AND MAXIMUM
(Vol. III) PREDICTED PRODUCTION RATE IN LABUAN STREAM



NOTE

* VALUE AT PRESENT PRODUCTION RATE
** VALUE AT PREDICTED PRODUCTION RATE
*** VALUE AT PREDICTED PRODUCTION RATE OF ADDITIONAL WELL CASE

FIG. 9-5-1 (VOL. III)

FACILITIES ARRANGEMENT

FOR ERB WEST AND SOUTH FURIOUS OIL FIELDS - CASE I

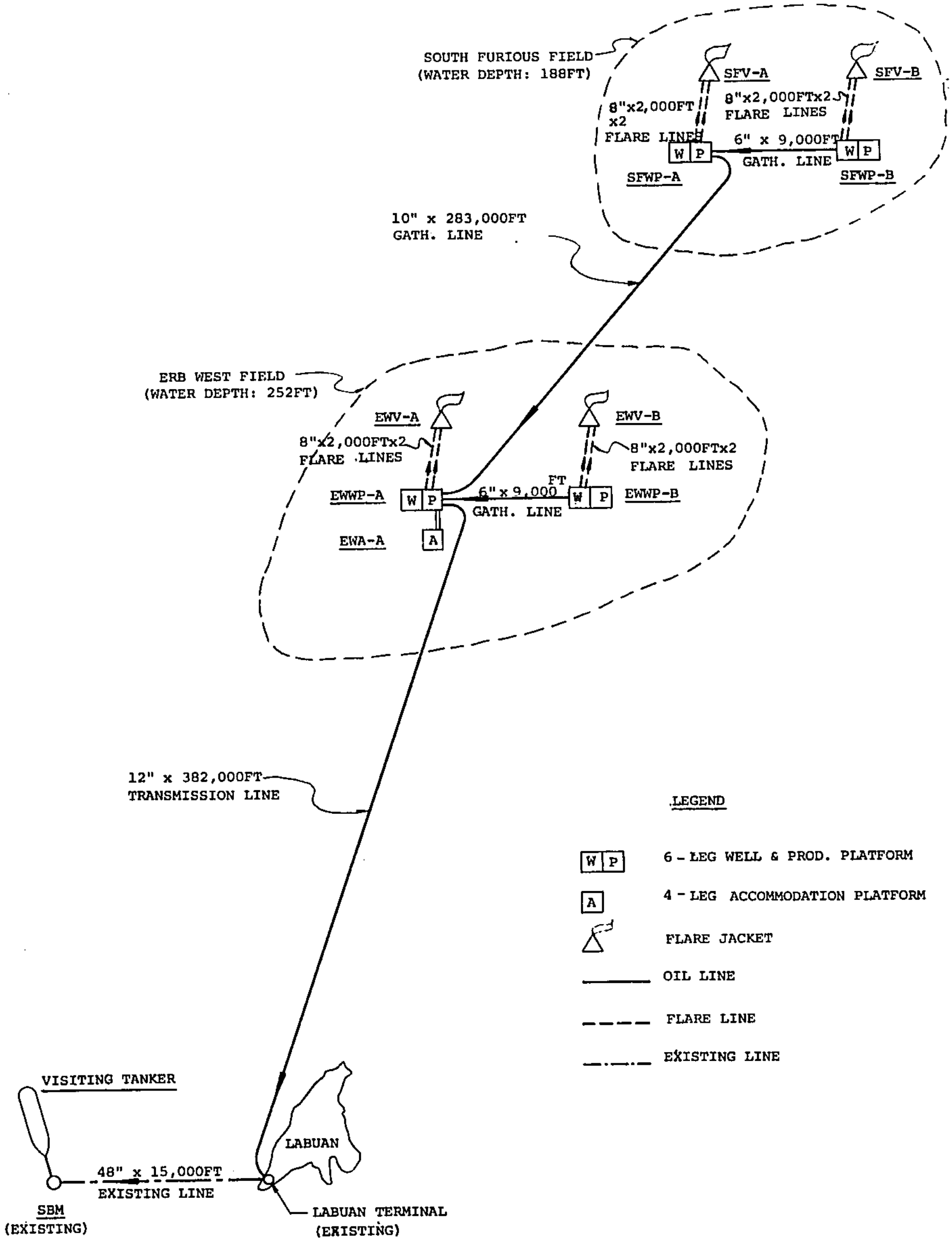


FIG. 9-5-2 (VOL. III)

BLOCK FLOW DIAGRAM

FOR ERB WEST AND SOUTH FURIOUS OIL FIELDS - CASE I

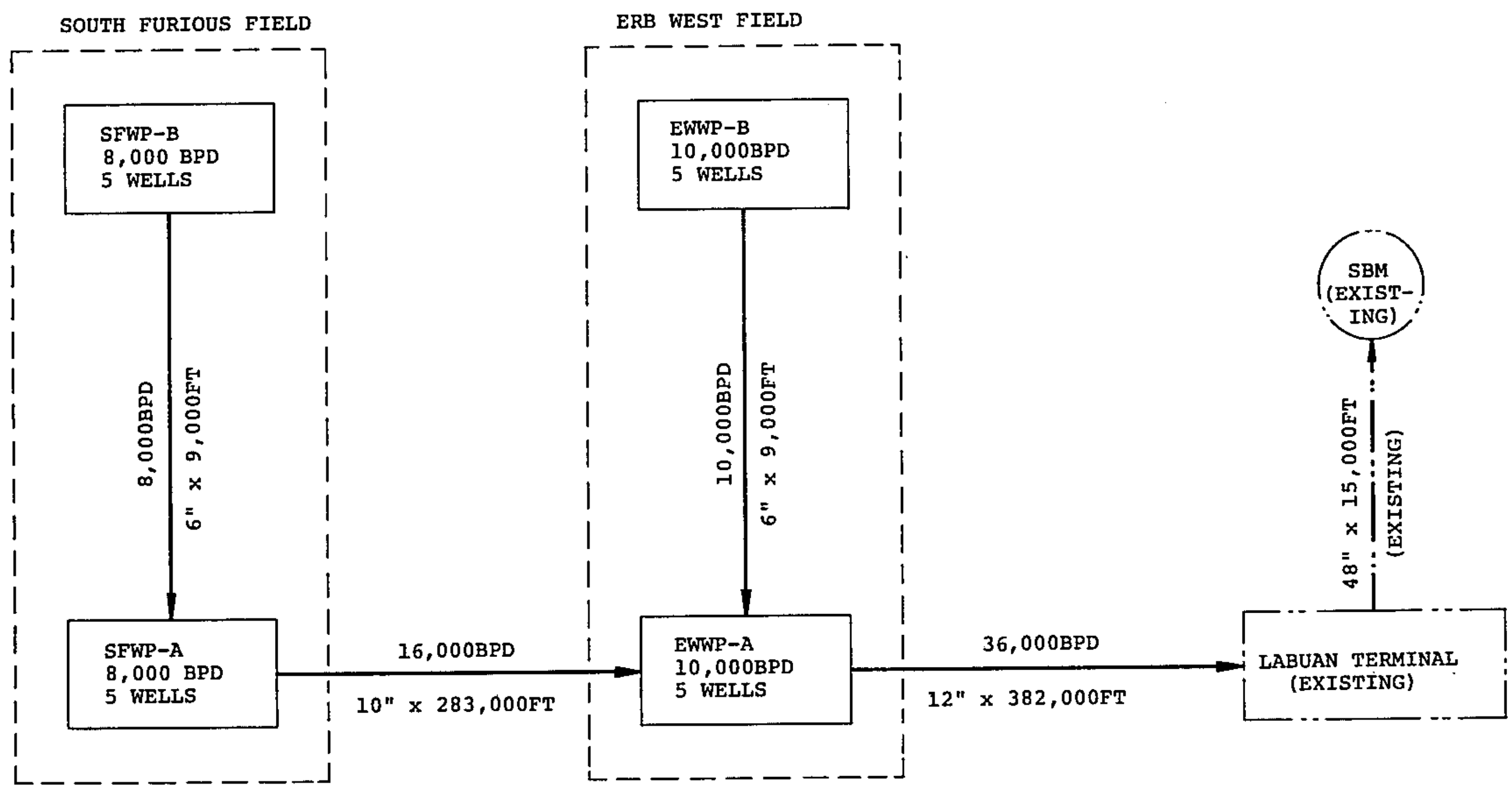


FIG. 9-5-3 (VOL. III)

FACILITIES ARRANGEMENT

FOR ERB WEST AND SOUTH FURIOUS OIL FIELDS-CASE II A

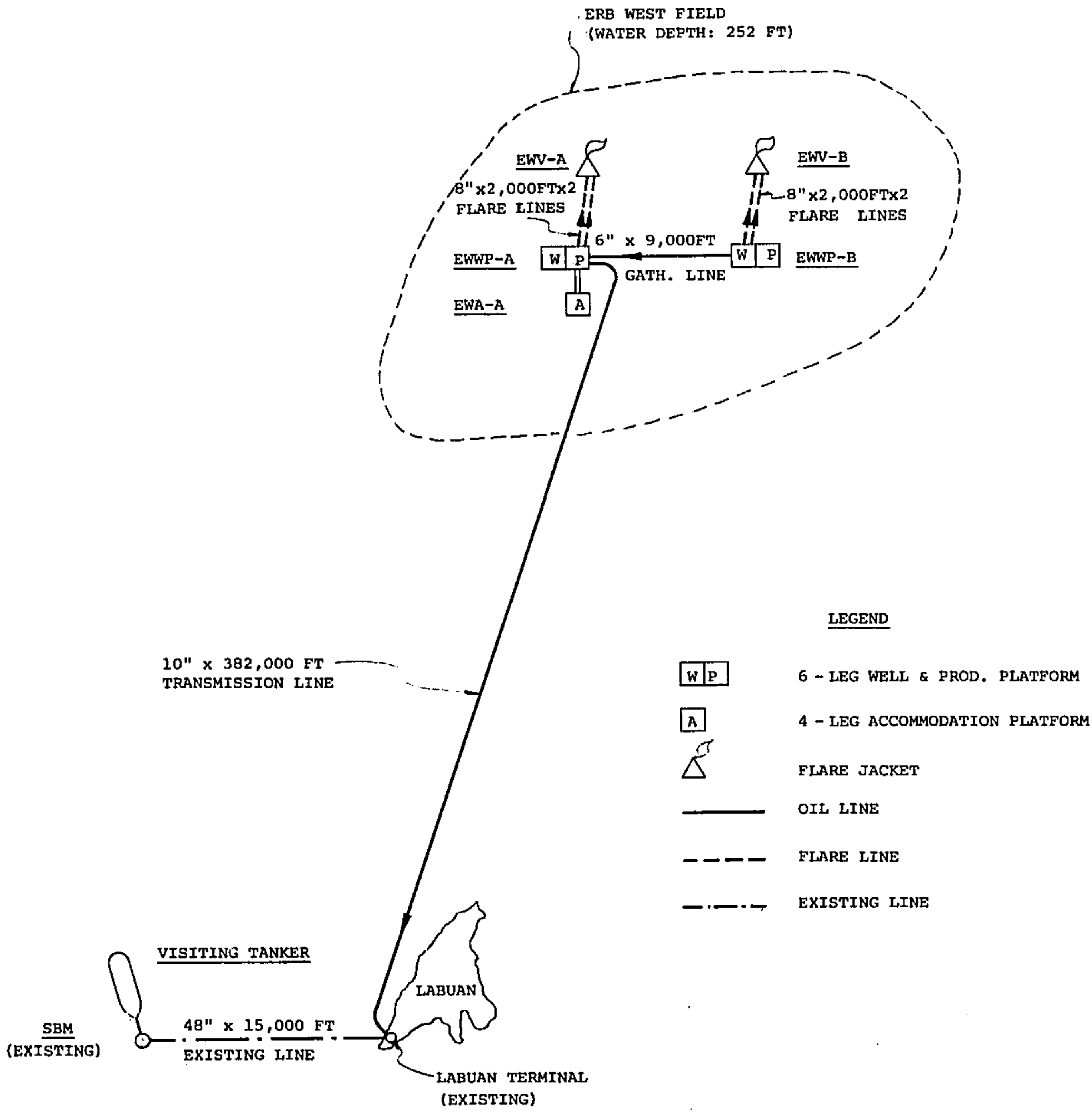


FIG. 9-5-4 (Vol. III)

BLOCK FLOW DIAGRAM

FOR ERB WEST AND SOUTH FURIOUS OIL FIELDS - CASE II A

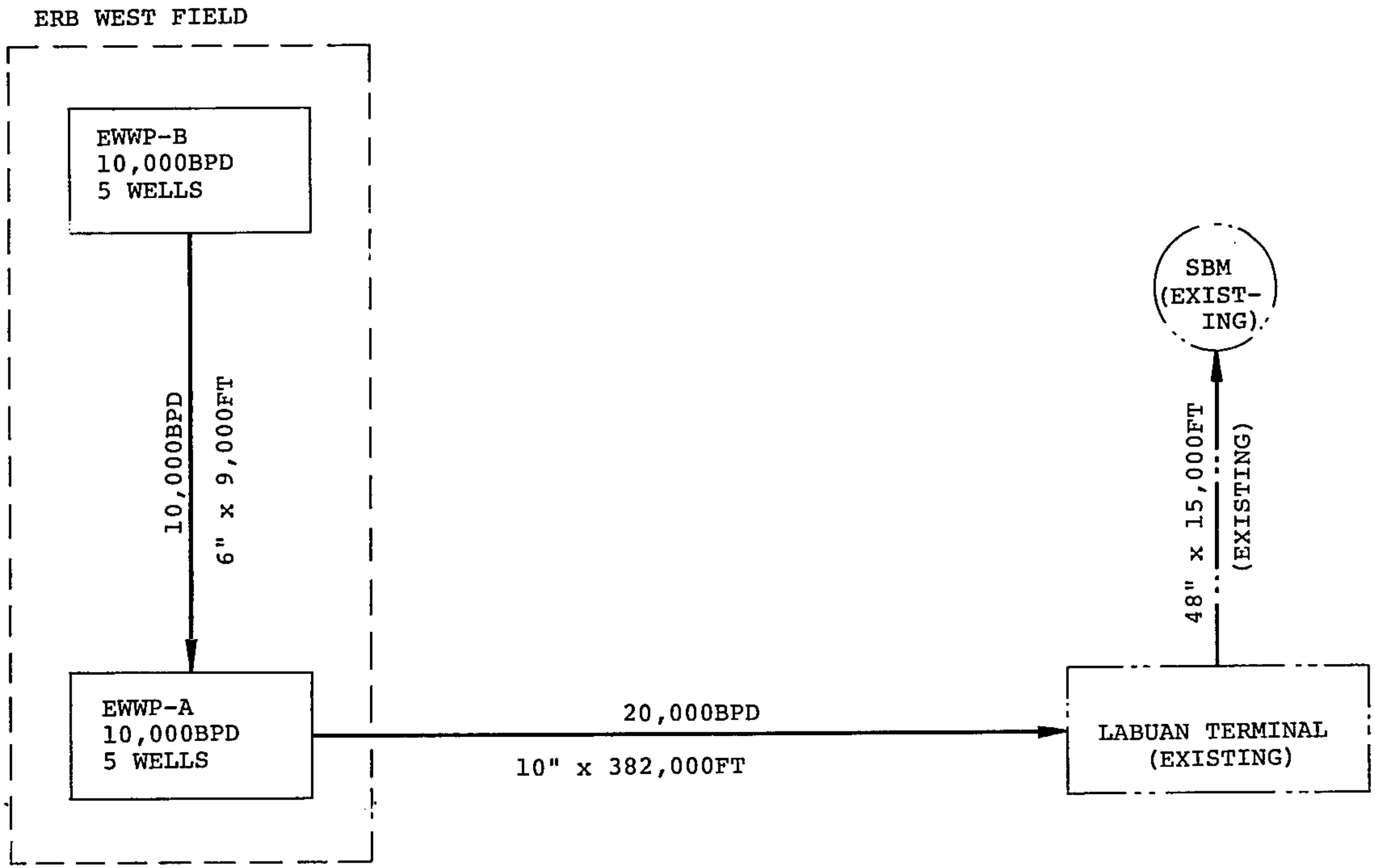
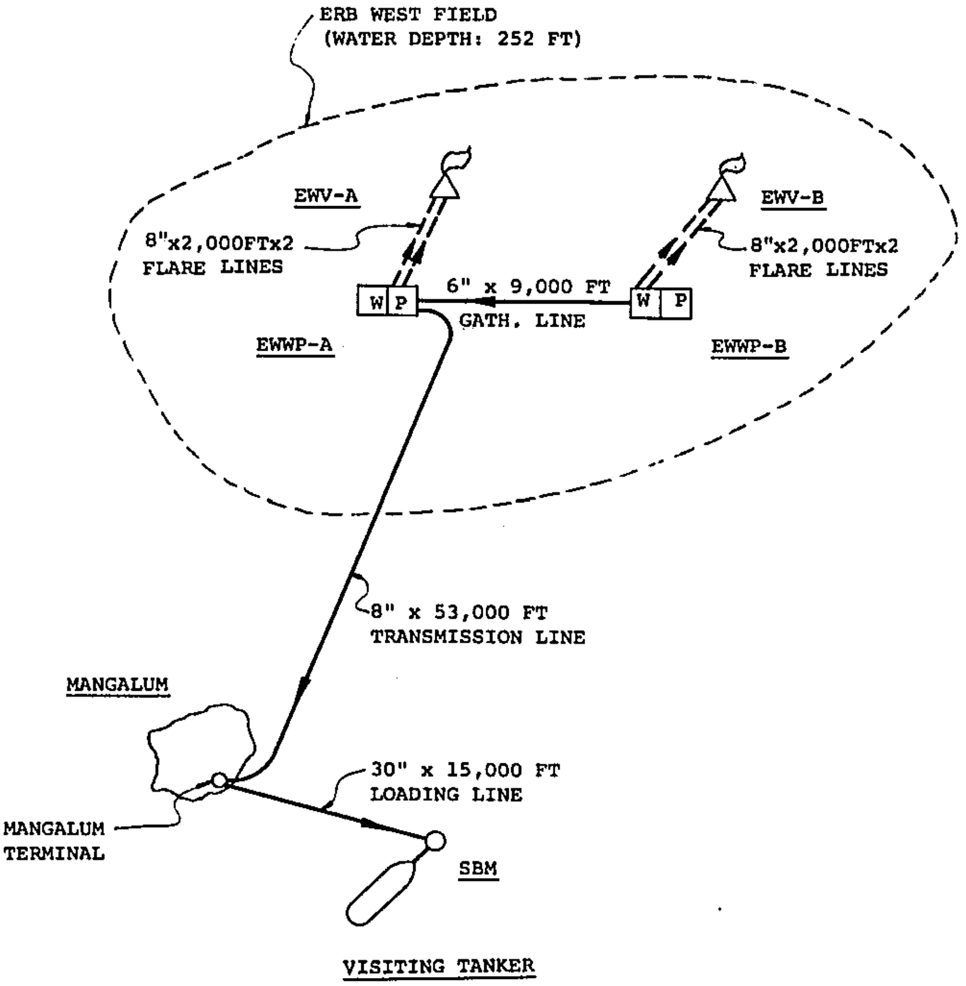


FIG. 9-5-5 (Vol. III)
FACILITIES ARRANGEMENT
FOR ERB WEST AND SOUTH FURIOUS OIL FIELDS - CASE II B



LEGEND

W P — 6 - LEG WELL & PROD. PLATFORM

FLARE JACKET

OIL LINE

FLARE LINE

FIG. 9-5-6 (VOL. III)

BLOCK FLOW DIAGRAM

FOR ERB WEST AND SOUTH FURIOUS OIL FIELDS-CASE II B

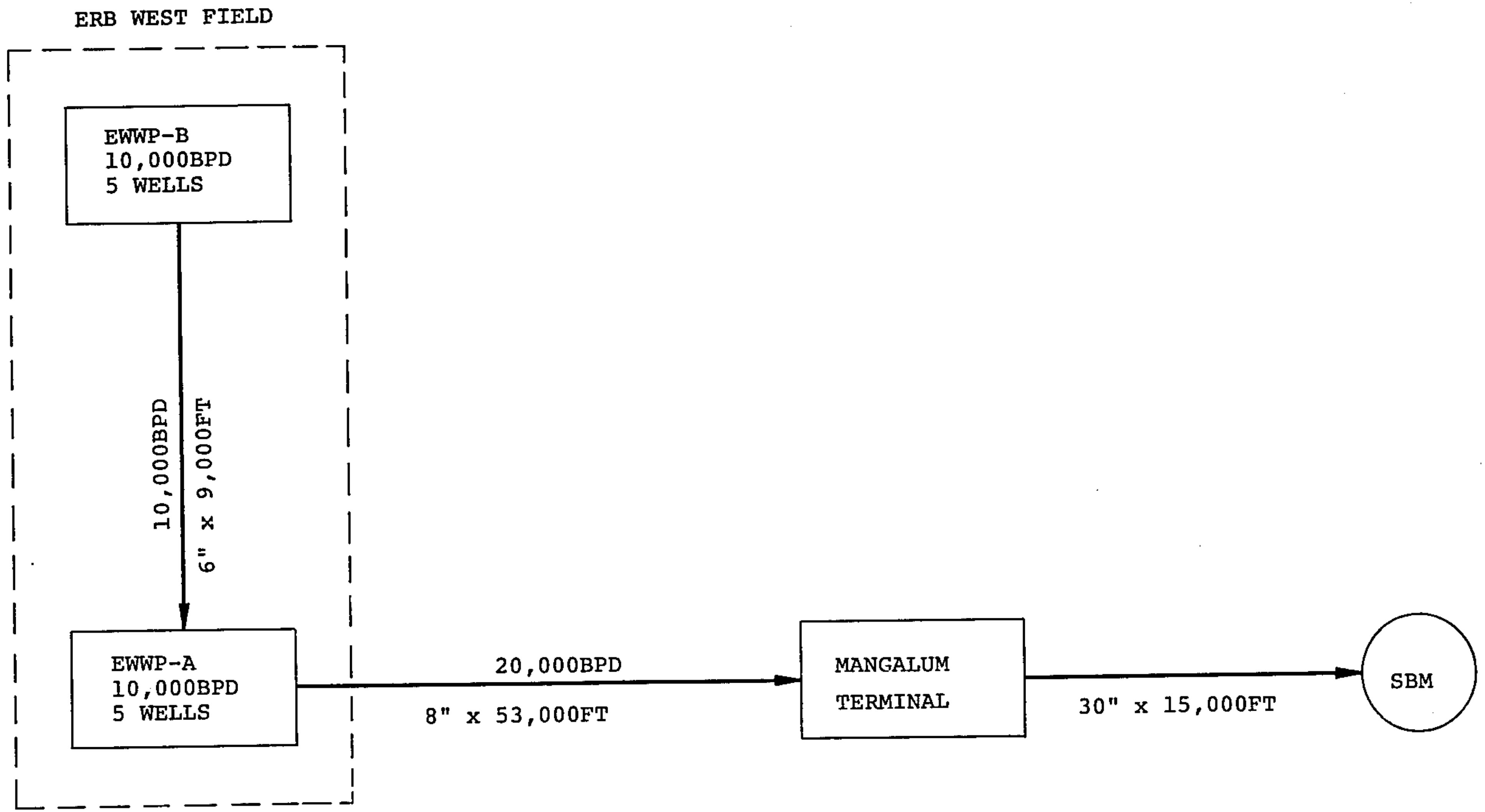
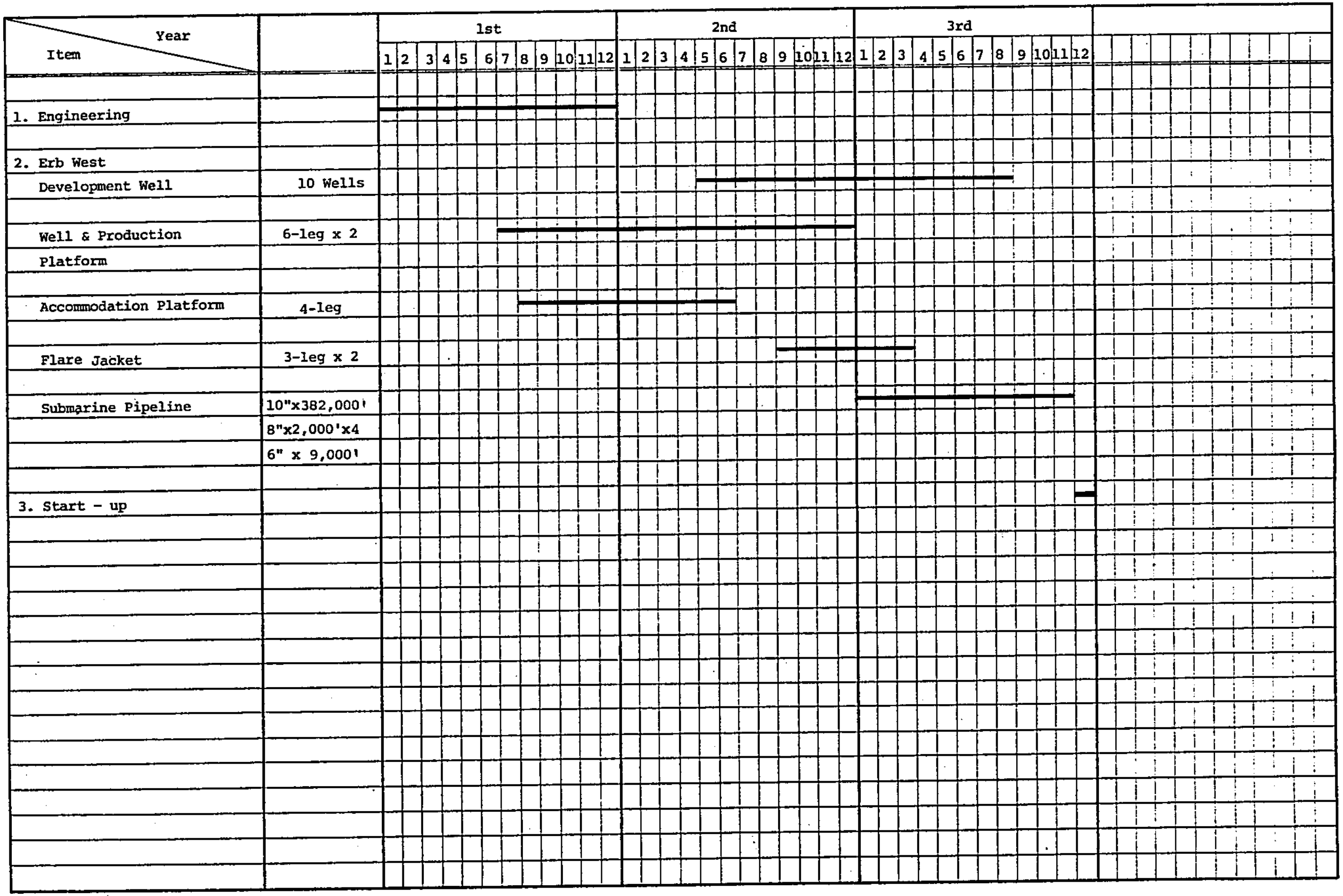
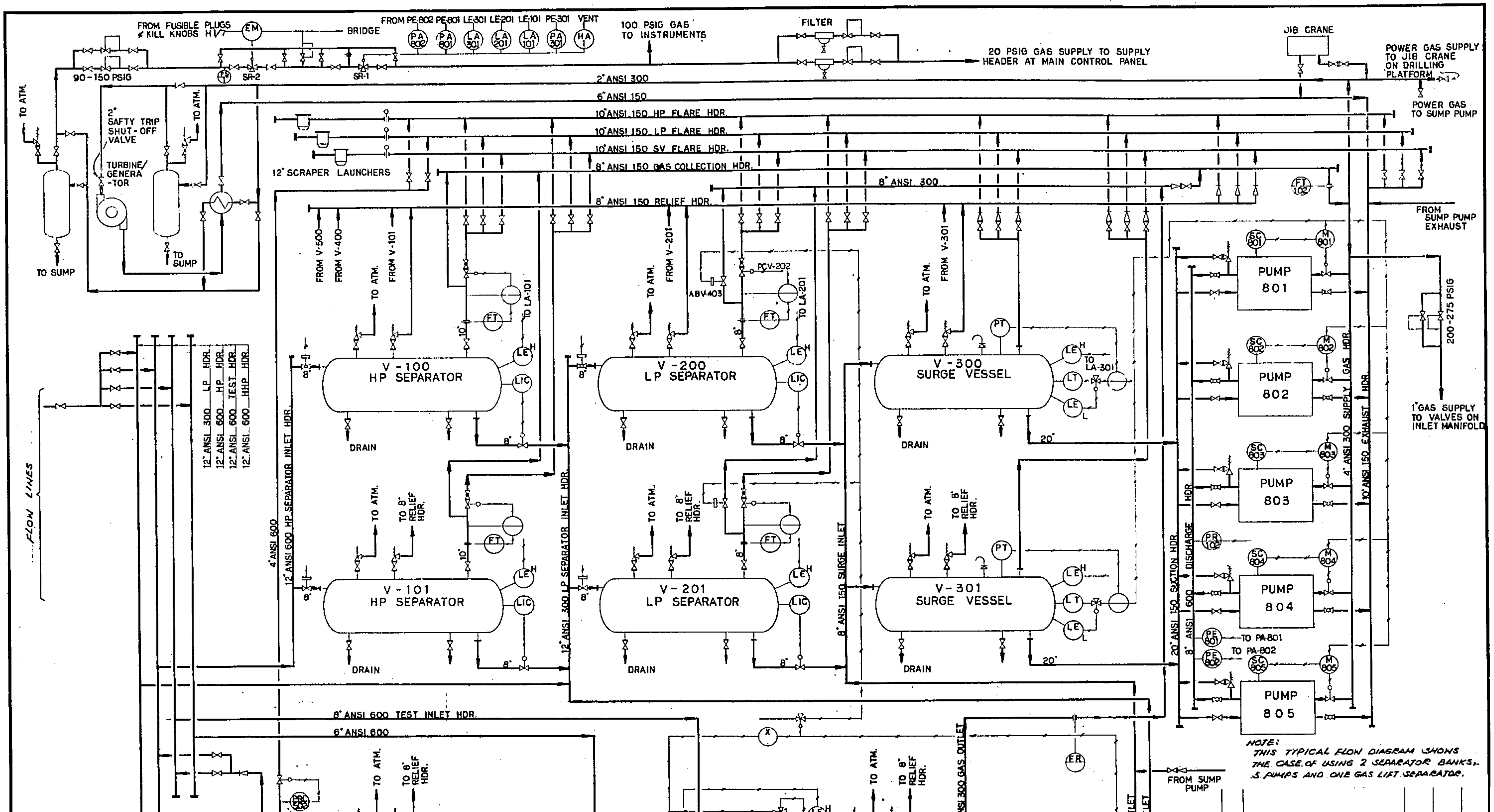


Fig. 9-6-1 (Vol. III)

PROJECT SCHEDULE

ERB WEST AND SOUTH FURIOUS OIL FIELDS CASE II A





NOTE: THIS TYPICAL FLOW DIAGRAM SHOWS THE CASE OF USING 2 SEPARATOR BANKS, 5 PUMPS AND ONE GAS LIFT SEPARATOR.

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TITLE FIG. 30-4-1 (Vol. III)
TYPICAL MECHANICAL FLOW DIAGRAM OF STANDARD PRODUCTION PLATFORM

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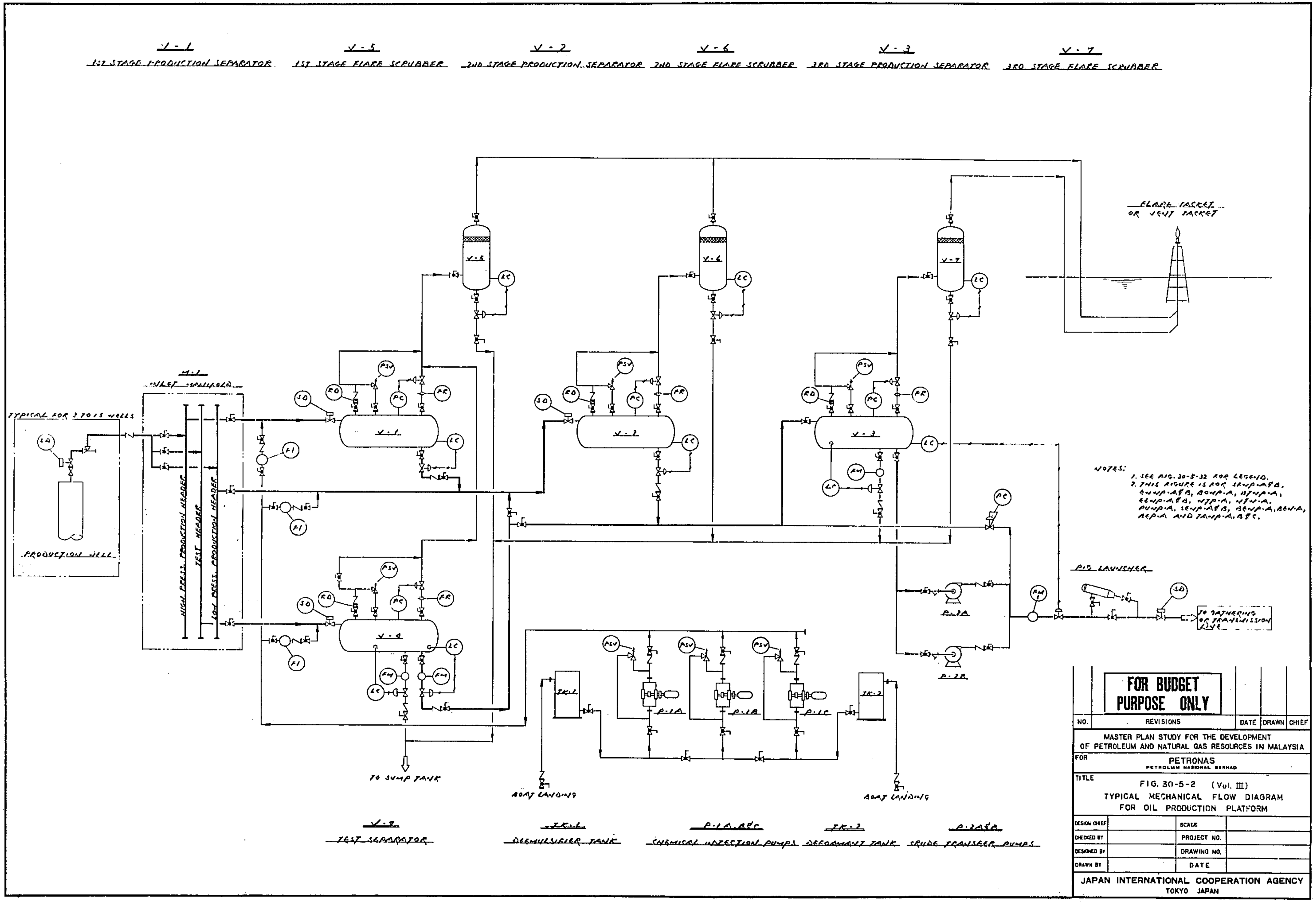

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TITLE
FIG. 30-5-2 (Vol. III)
TYPICAL MECHANICAL FLOW DIAGRAM FOR OIL PRODUCTION PLATFORM

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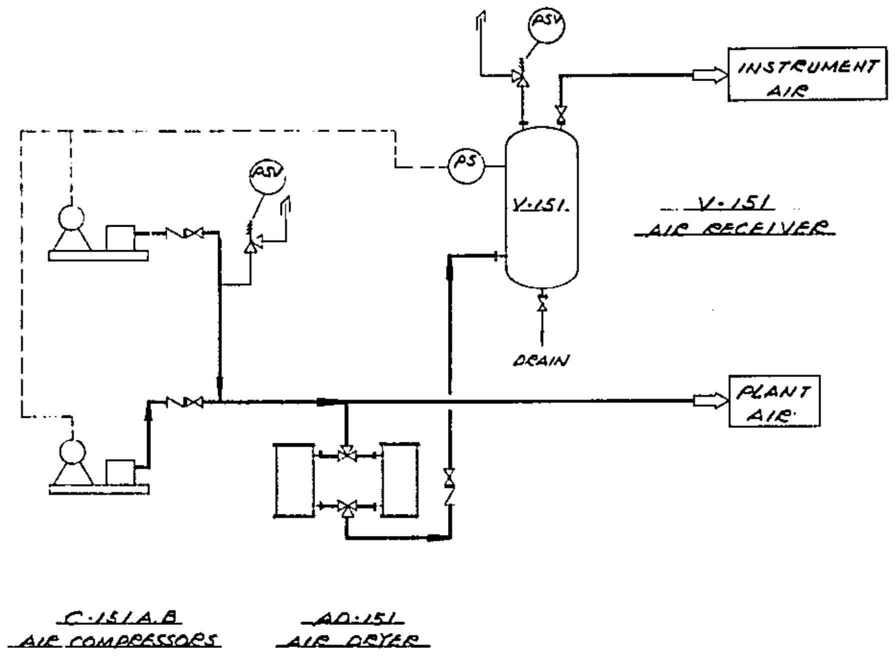
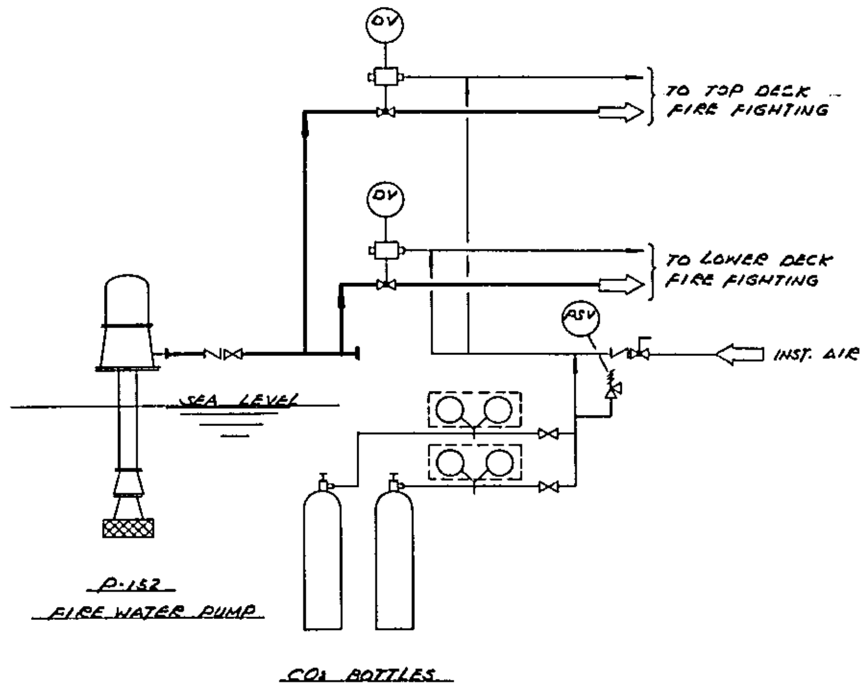
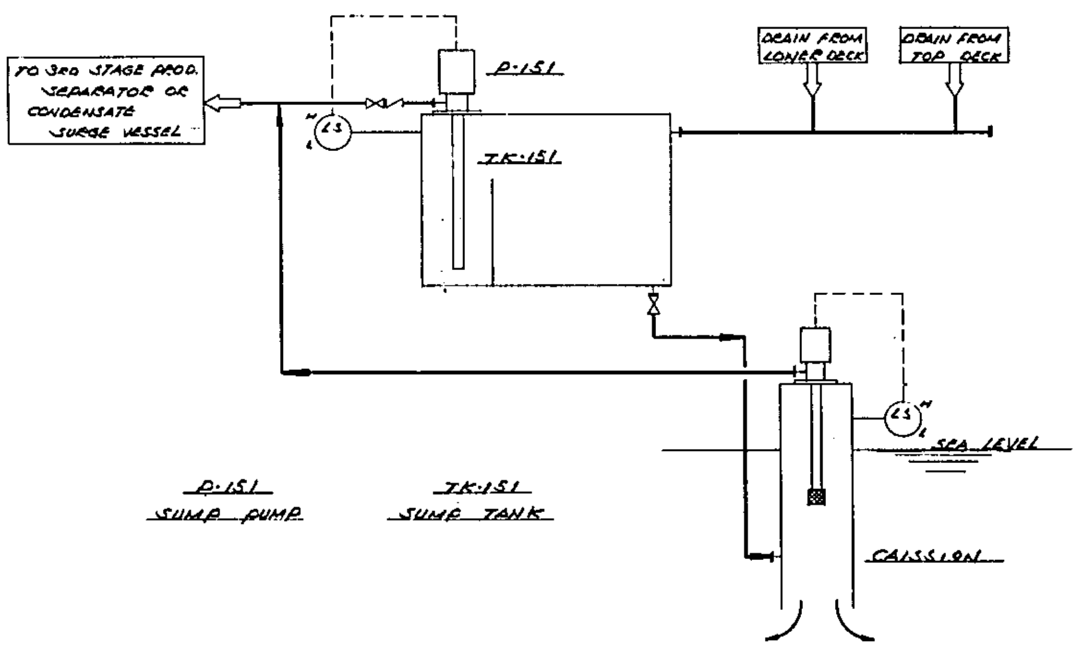
INSTRUMENT AIR SYSTEM



FIRE FIGHTING SYSTEM



DRAIN SYSTEM



NOTES:

1. SEE FIG. 30-5-32 FOR LEGEND.
2. THIS FIGURE IS FOR SENP-A&B, ENWP-A&B, BONP-A, ATNP-A, EBNP-A&B, NTP-A, PUNP-A, SENP-A&B, BENP-A, BEP-A, TANP-A,B&C, F13NP-A, F18NP-A, F23P-A, FENP-A&B, E8NP-A, E11NP-A, A12NP-A, PUPC-A, AND BEPC-A.

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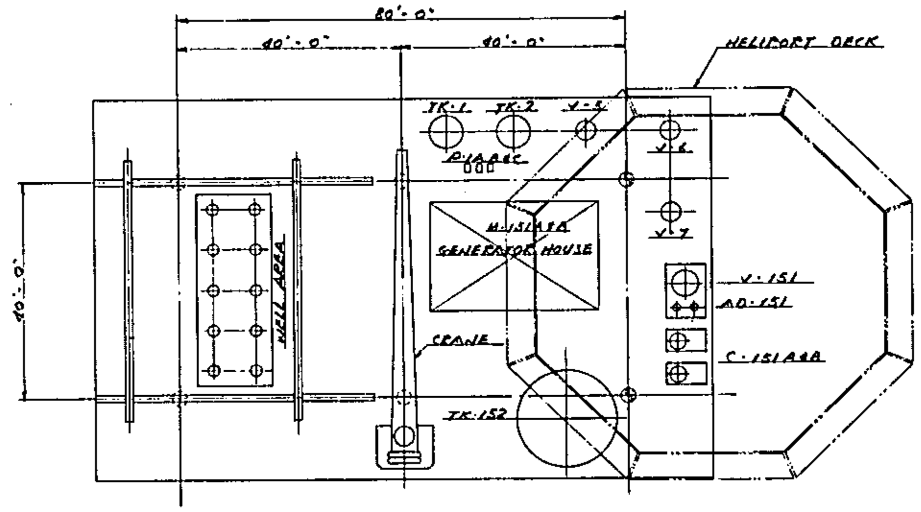
MASTER PLAN STUDY FOR THE DEVELOPMENT OF PETROLEUM AND NATURAL GAS RESOURCES IN MALAYSIA

FOR: PETRONAS
PETROLIAM NASIONAL BERHAD

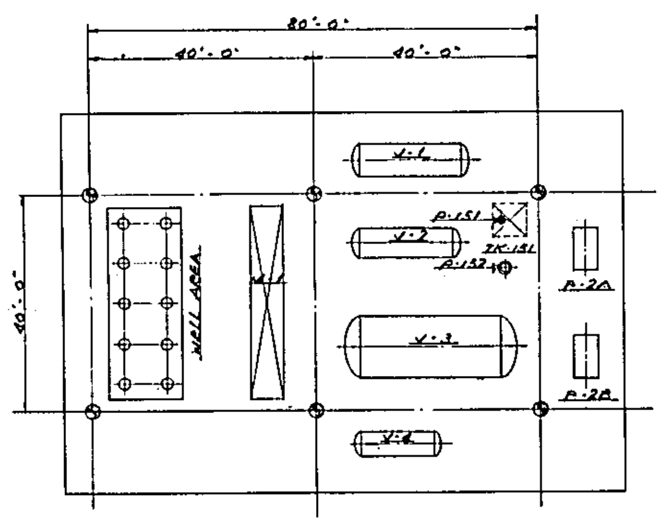
TITLE: FIG. 30-5-10 (Vol. III)
TYPICAL UTILITY FLOW DIAGRAM
FOR OIL & GAS PRODUCTION PLATFORM

DESIGN CHIEF		SCALE	
CHECKED BY		PROJECT NO.	
DESIGNED BY		DRAWING NO.	
DRAWN BY		DATE	

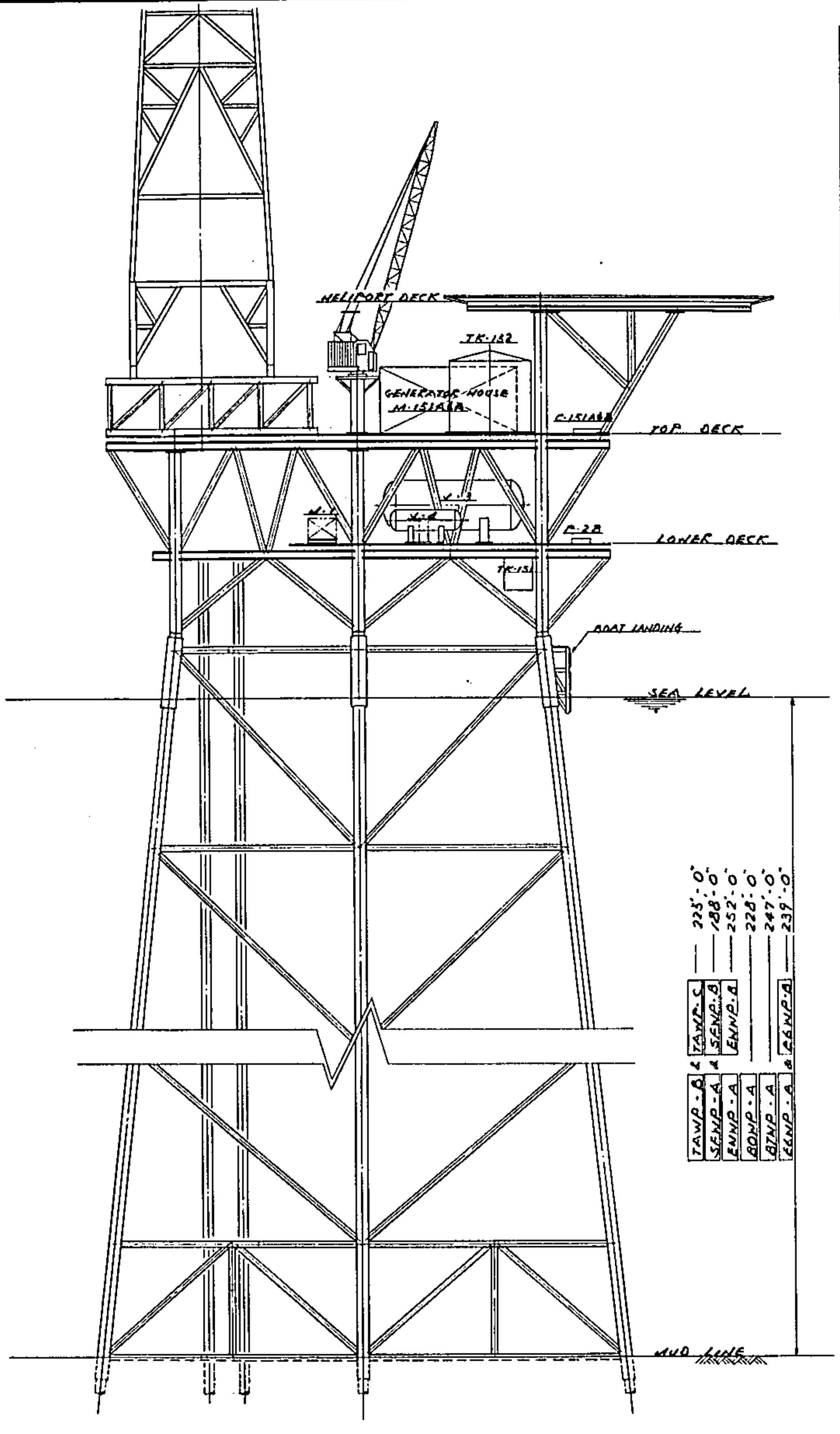
JAPAN INTERNATIONAL COOPERATION AGENCY
TOKYO JAPAN



TOP DECK PLAN



LOWER DECK PLAN



ELEVATION

EQUIPMENT LIST	
ITEM NO.	DESCRIPTION
	VESSEL
V - 1	1ST STAGE PRODUCTION SEPARATOR
V - 2	2ND STAGE PRODUCTION SEPARATOR
V - 3	3RD STAGE PRODUCTION SEPARATOR
V - 4	TEST SEPARATOR
V - 5	1ST STAGE FLARE SCRUBBER
V - 6	2ND STAGE FLARE SCRUBBER
V - 7	3RD STAGE FLARE SCRUBBER
V - 151	INSTRUMENT AIR RECEIVER
	MACHINERY
C - 151A&B	INSTRUMENT AIR COMPRESSORS
AD - 151	INSTRUMENT AIR DRYER
	PUMP
P - 1A,B&C	CHEMICAL INJECTION PUMPS
P - 2A&B	CRUDE TRANSFER PUMPS
P - 151	SUMP PUMP
P - 152	FIRE WATER PUMP
	TANK
TK - 1	DEEMULSIFIER TANK
TK - 2	DEFOAMANT TANK
TK - 151	SUMP TANK
TK - 152	DIESEL STORAGE TANK
	MISCELLANEOUS
M - 1	INLET MANIFOLD
M - 151A&B	DIESEL DRIVEN GENERATORS

FOR BUDGET PURPOSE ONLY

NOTE:
THIS FIGURE IS FOR SFWP-A&B, EWWP-A&B, BONP-A, BTNP-A, E6WP-A&B, AND TAWP-B&C.

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MASTER PLAN STUDY FOR THE DEVELOPMENT OF PETROLEUM AND NATURAL GAS RESOURCES IN MALAYSIA

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PETROLIAM NASIONAL BERHAD

TITLE FIG 30-5-16 (Vol. III)
TYPICAL PLAN AND ELEVATION FOR 6-LEG WELL & OIL PRODUCTION PLATFORM

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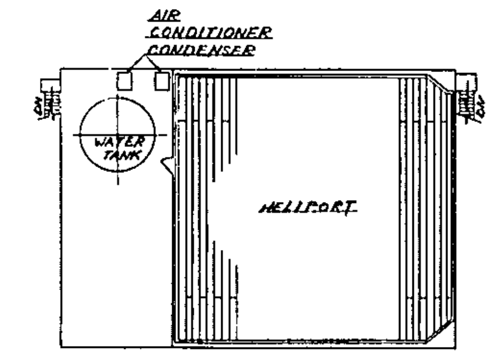
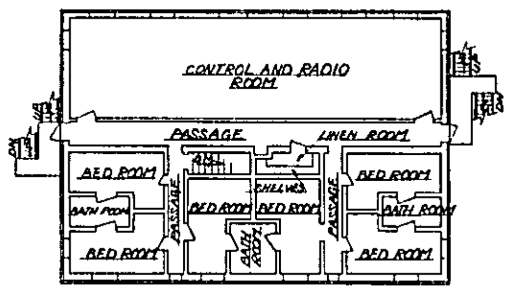
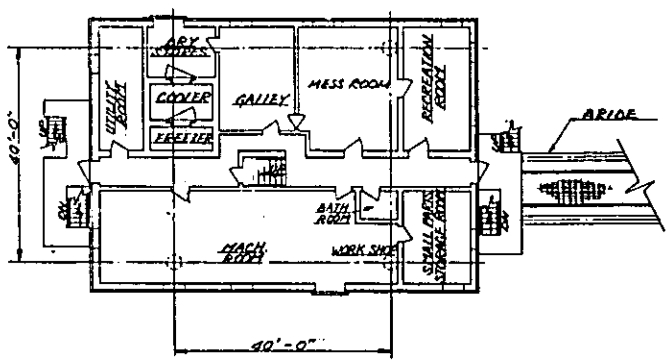


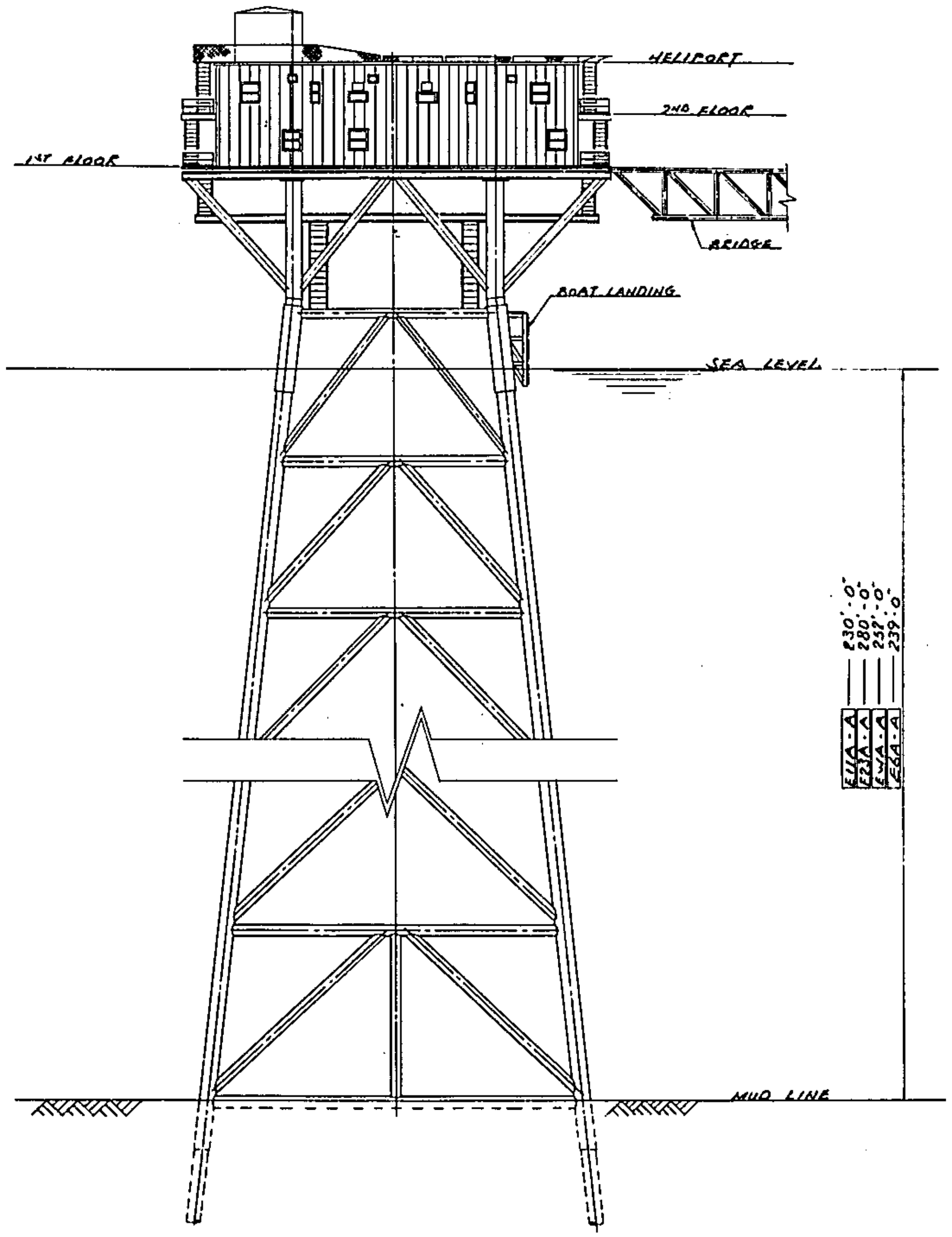
HELIPORT DECK PLAN



2ND FLOOR PLAN



1ST FLOOR PLAN



ELEVATION

NOTE:
THIS FIGURE IS FOR F23A-A, E11A-A, E4A-A AND E6A-A.

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MASTER PLAN STUDY FOR THE DEVELOPMENT OF PETROLEUM AND NATURAL GAS RESOURCES IN MALAYSIA

FOR PETRONAS
PETROLIAM NASIONAL BERHAD

TITLE
FIG. 30-5-31 (Vol. III)
TYPICAL PLAN AND ELEVATION FOR 4-LEG ACCOMMODATION PLATFORM

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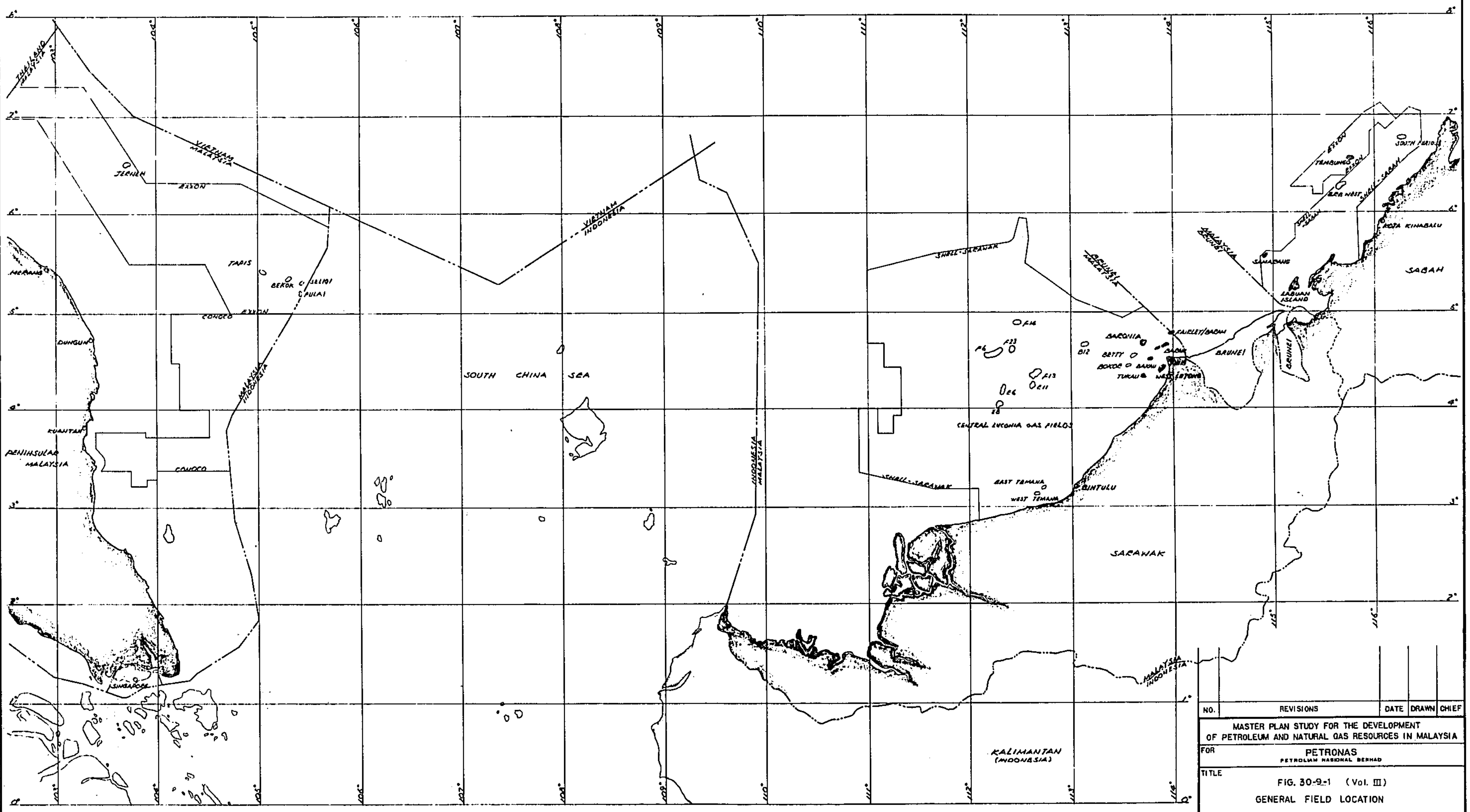
Fig. 30-5-32 (Vol. III)

LEGEND FOR FLOW DIAGRAMS

PIC	PRESSURE INDICATING CONTROLLER
PC	PRESSURE CONTROLLER
PS	PRESSURE SWITCH
FRC	FLOW RECORDING CONTROLLER
FM	FLOW METER
FR	FLOW RECORDER
FI	FLOW INDICATOR
LC	LEVEL CONTROLLER
LS	LEVEL SWITCH
PSV	PRESSURE SAFETY VALVE
RD	RUPTURE DISC
DV	DELUGE VALVE
SD	SHUTDOWN VALVE
XV	MISCELLANEOUS VALVE

NOTE: PI (PRESSURE INDICATOR) AND TI (TEMPERATURE INDICATOR) ARE NOT SHOWN ON THE FLOW DIAGRAMS FOR SIMPLIFICATION.



EXISTING FIELD
DEVELOPMENT FIELD

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FOR PETRONAS
PETROLIUM NASIONAL BERHAD

TITLE FIG. 30-9-1 (Vol. III)
GENERAL FIELD LOCATION

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Fig. 31-6-1 (Vol. III) DRILLING & COMPLETION COST OF DEVELOPMENT WELL

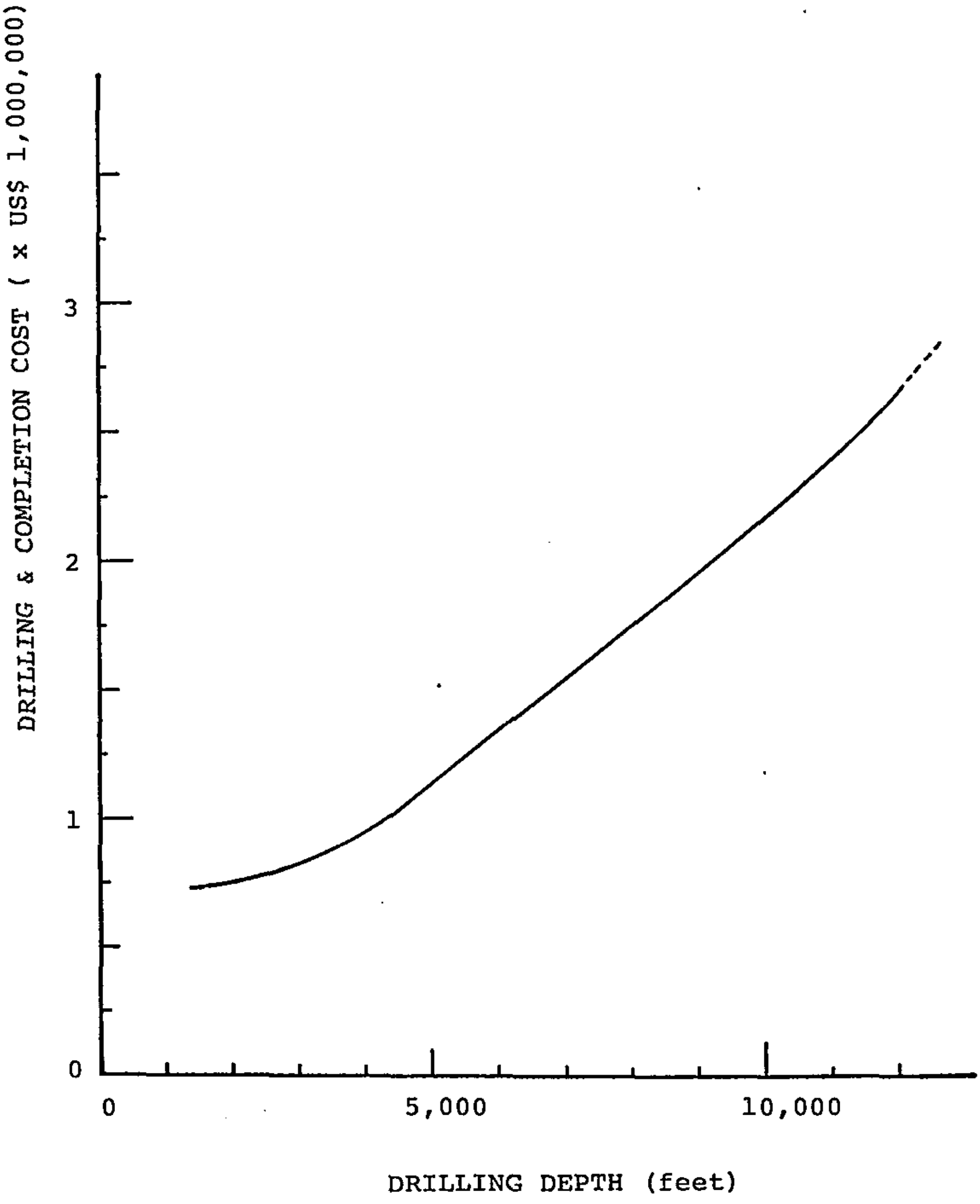


Fig. 31-6-2 (Vol. III) <u>TENTATIVE ORGANIZATION FOR FIELD OPERATION</u>

(80 Persons Case)

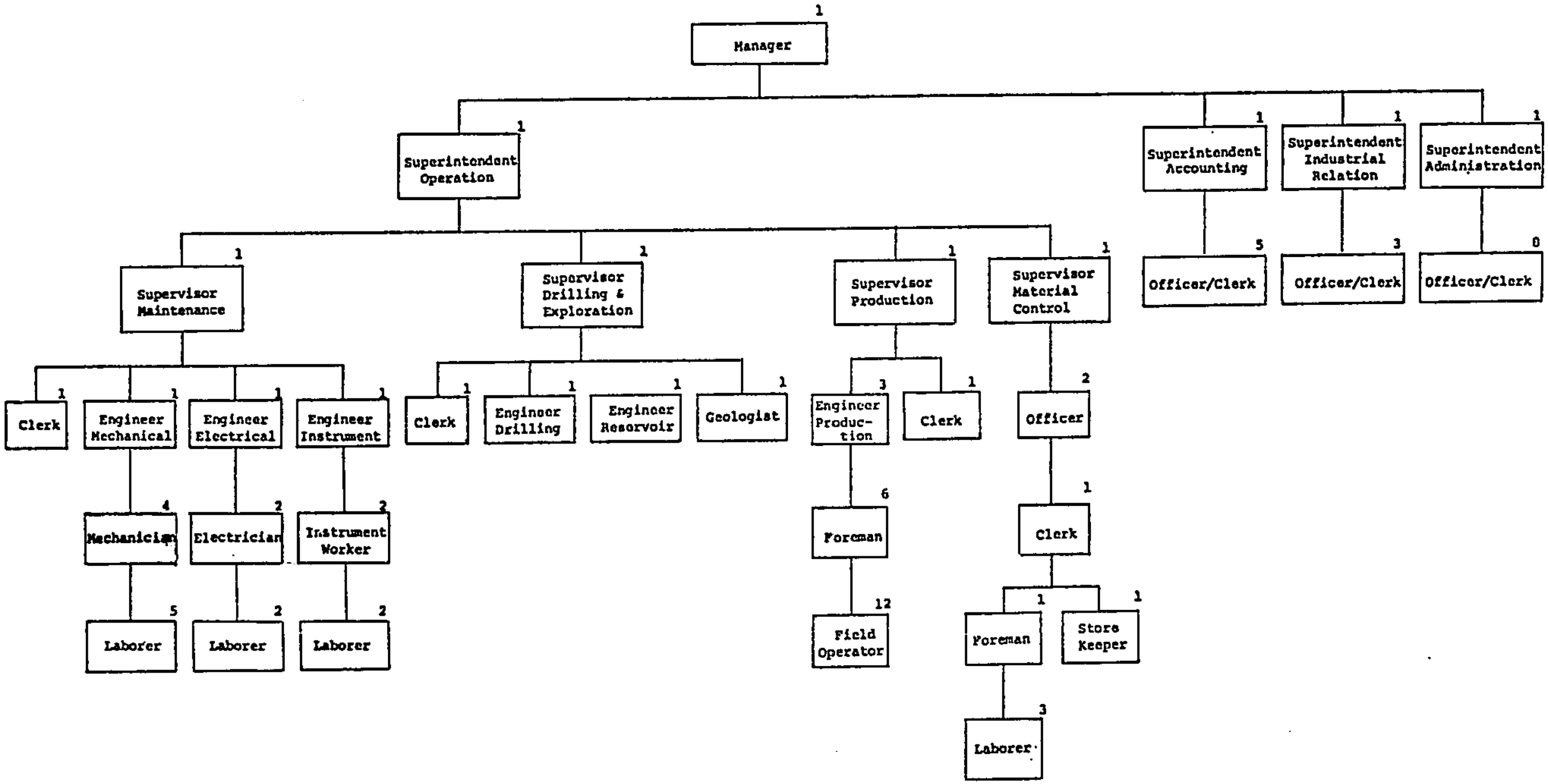


Fig. 31-6-3 (Vol. III) TENTATIVE ORGANIZATION FOR FIELD OPERATION

(128 Persons Case)

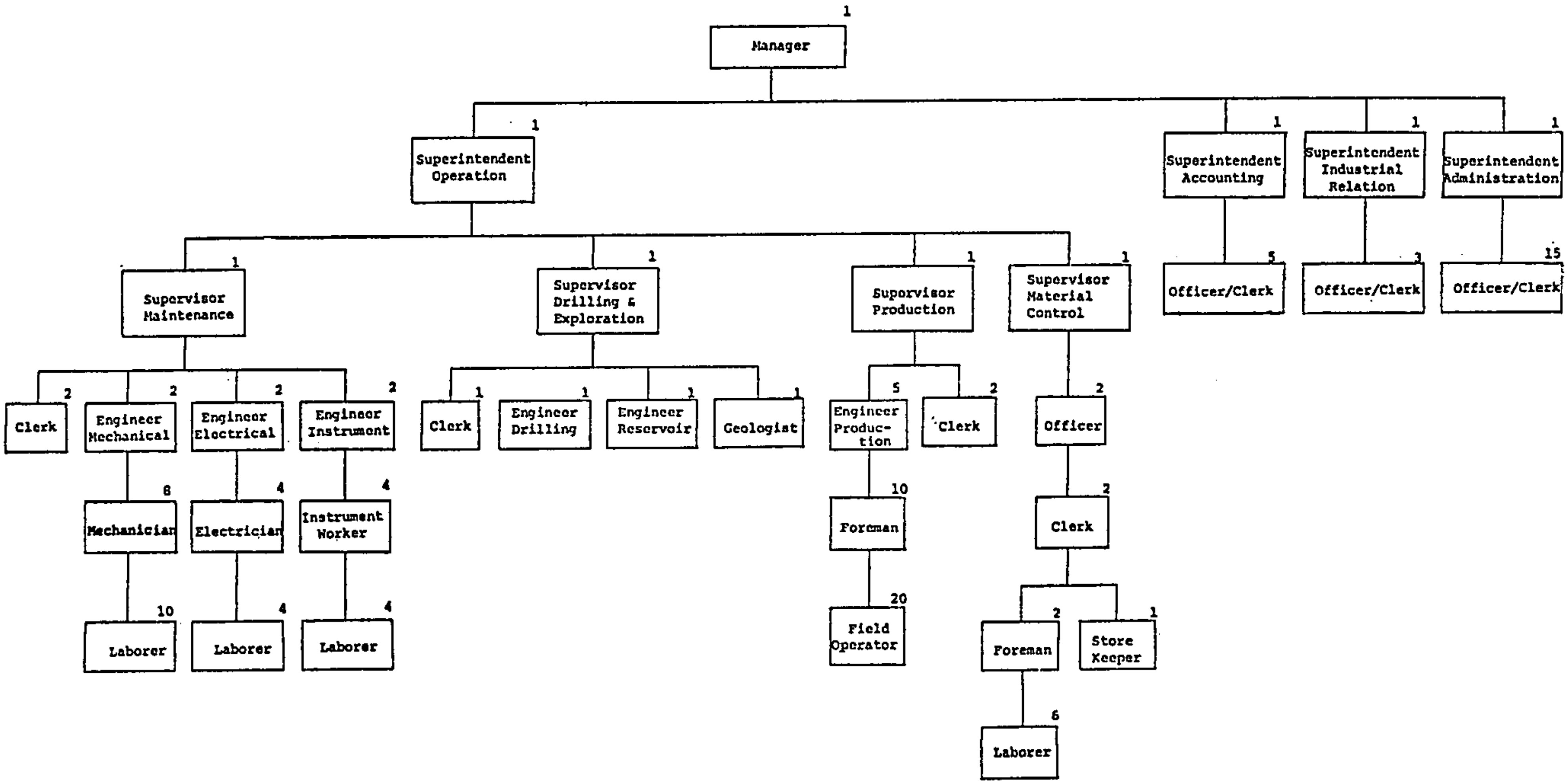


Fig. 31-6-4 (Vol. III)

TENTATIVE ORGANIZATION FOR FIELD OPERATION

(135 Persons Case)

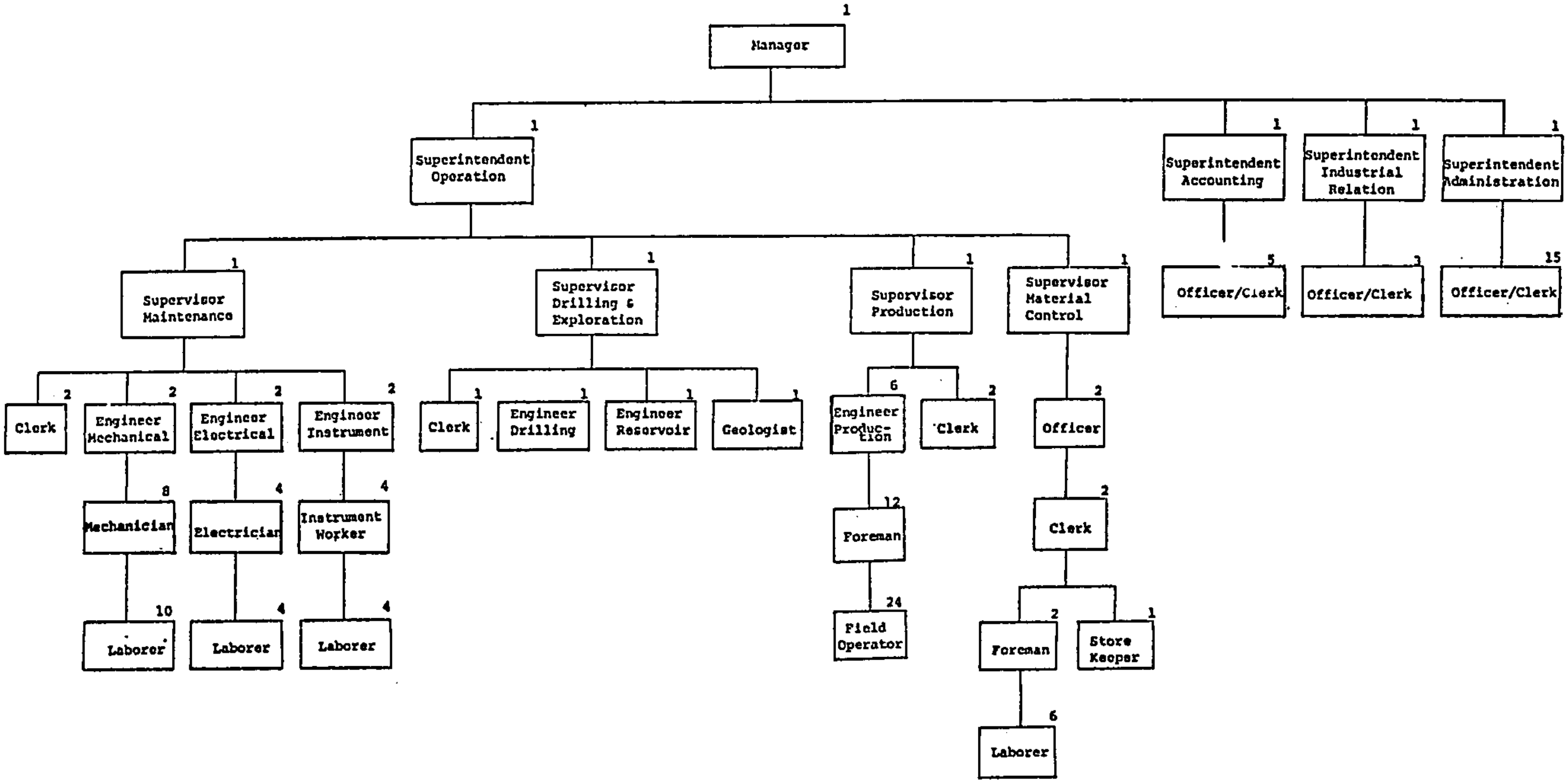


Fig. 31-6-5 (Vol. III) TENTATIVE ORGANIZATION FOR FIELD OPERATION

(146 Persons Case)

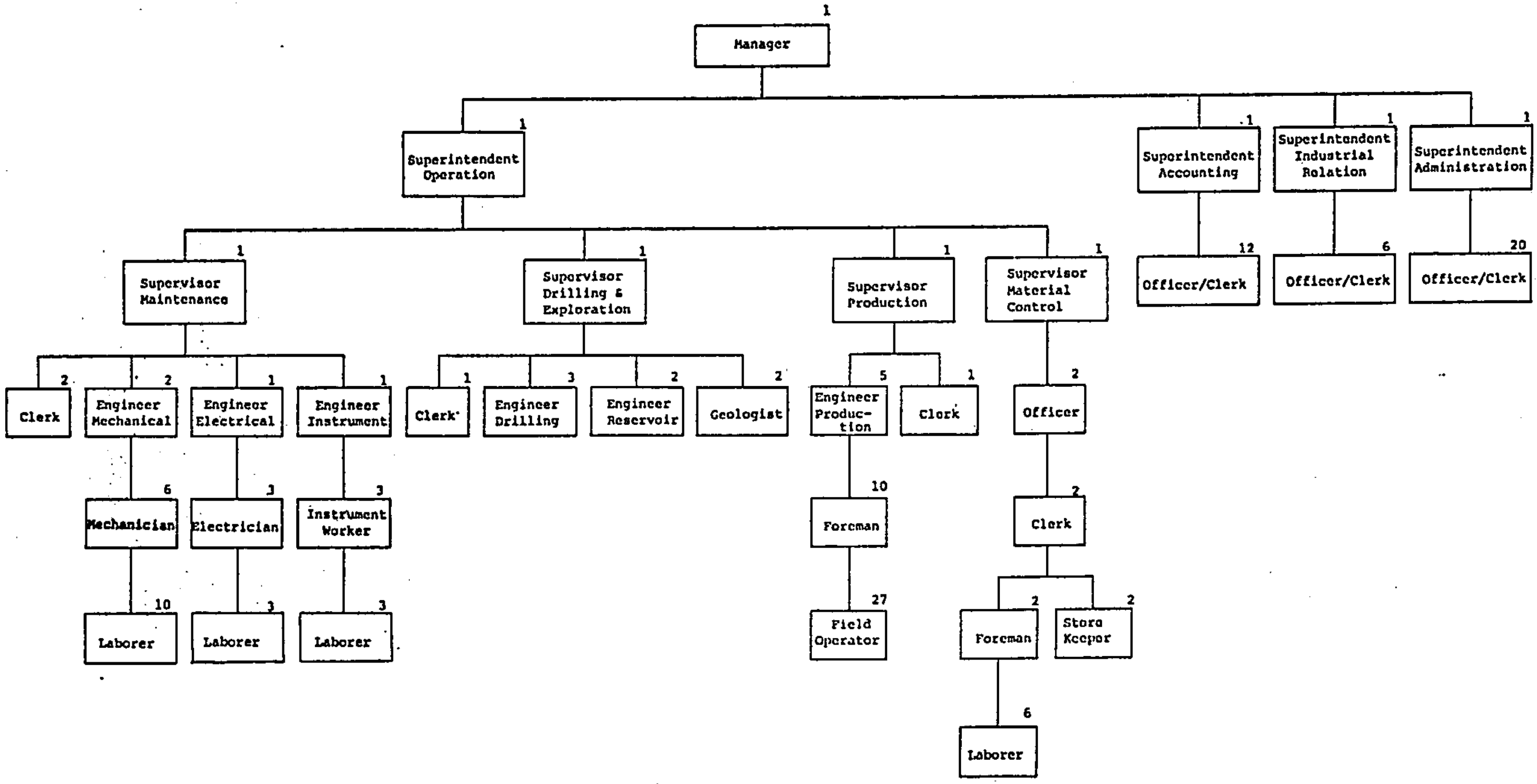
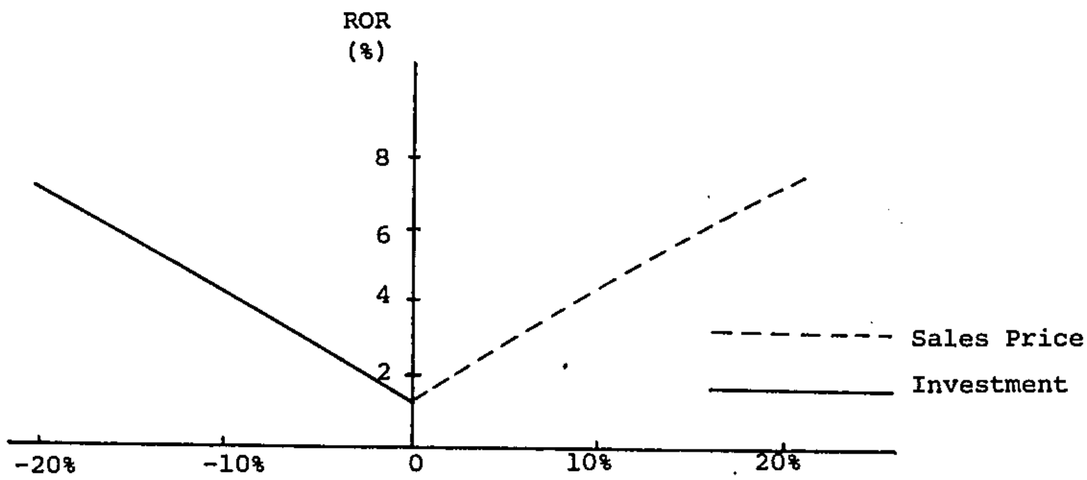


Fig. 31-6-7 **SENSITIVITY CURVE FOR SABAH AREA**
(Vol. III)

Erb West & South Furious Fields

Optimum Case: Erb West, Lab[illegible] Terminal Case - CASE IIA



APPENDIX

APPENDIX

APPENDIX

LOG INTERPRETATION RESULTS

SABAH AREA

1. Sammarang Field

Using the data of formation factor and porosity derived from core analysis the cementation factor and a constant of Archie's formula was gotten. The values are 2.02, 0.36 respectively. But the value of constant a is too low comparing with other field's data. So in this case the general formula as sandstone, $F = 0.62/\phi^{2.15}$ was used.

Logs of well No.2, 3 and 14 to 29 were digitized and analyzed by computer every two feet.

The rest of logs are not analyzed by computer because of scale difficulty. But well No.8 is situated in the important place of the structure, so the log analysis of well No.8 also was done manually. The results was shown as table. The comparison with core analysis data was not done because the number of core analysis data is not sufficient.

2. Tembungo Field

Log data of Tembungo field was analyzed by manual. The results are arranged as table. The water saturation shows somewaht high value.

The comparison between core derived porosity and log derived porosity was not conducted because of no core data.

3. Erb West

0.13 Ω-m @ 145°F for water resistivity value was used.

After core analysis results the relation between formation factor(F) and porosity (ϕ) was $F = 1.1/\phi^{1.21}$

for sandstone was adopted.

Water saturation ranges between 20 to 60%. The core analysis data were not abundant to be able to make compariosn.

4. South Furious Field

0.22 Ω-m @ 155°F was used for water saturation value.

After core analysis results the relation, $F = 1/\phi^{1.69}$ was used. The core analysis was conducted on the cores of well No.2 and well No.3. Among these cores the intervals between 3515' and 3540.5' of well No.2 has sufficient data.

The porosities of core samples corresponding the intervals which are under 20% shale contents were compared with log derived porosity. The average core derived porosity was 20.86%. On the other hand the average log derived porosity was 19.63%. These two values are consistent with each other fairly good.

5. West Emerald Field

For the water resistivity value 0.21 Ω-m @ 135°F and for the relation between formation factor and porosity general formula for sandstone $F=0.62/\phi^{2.15}$ were used.

6. St. Joseph

For the water resistivity value 0.25 Ω-m @ 150°F and for the relation between formation factor and porosity general formula for sandstone $F = 0.62/\phi^{2.15}$ were used.

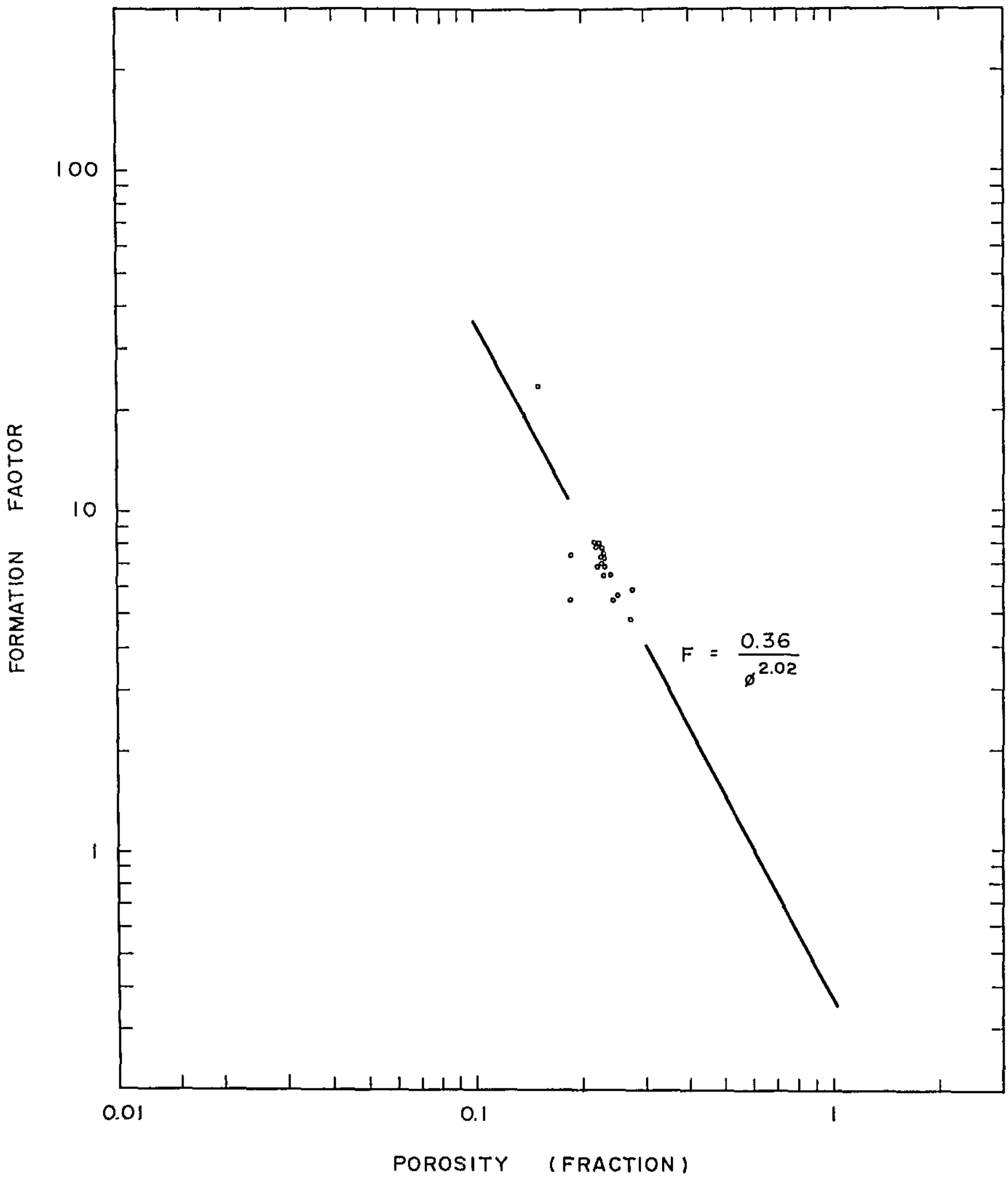
7. Erb South Field

0.3 Ω-m @ 120°F was used for the water resistivity value. This value is higher than that of Sarawaku area. But other fields which belong to Sabah area, that is, South Furious, St. Joseph, West Emerald also show similar values. So this is considered as a regional characteristic. The cores did not recovered. Therefor general formula for sandstone $F = 0.62/\phi^{2.15}$ was applied.

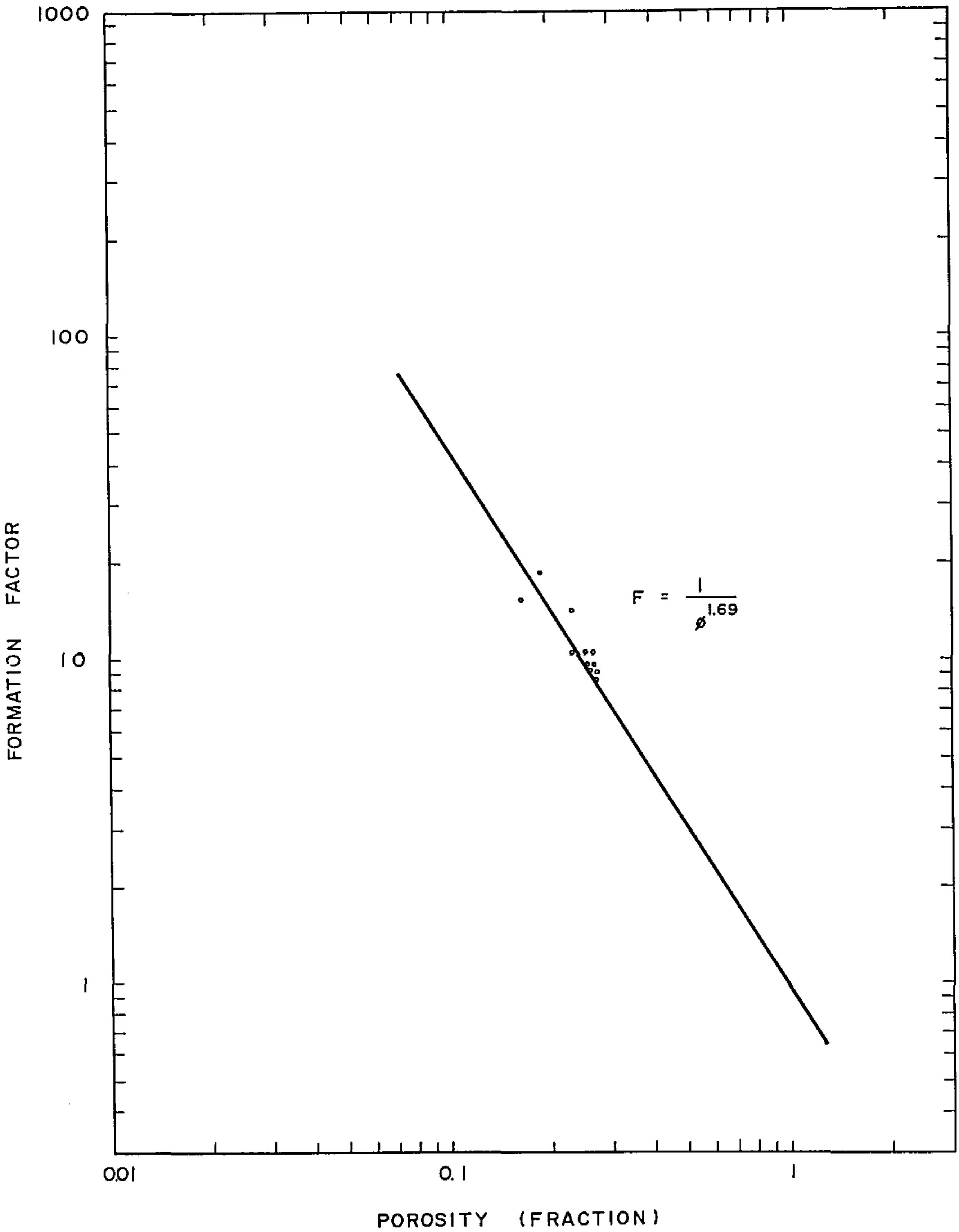
IMPORTANT PARAMETER USED FOR LOG-ANALYSIS

\- SABAH AND SARAWAK -

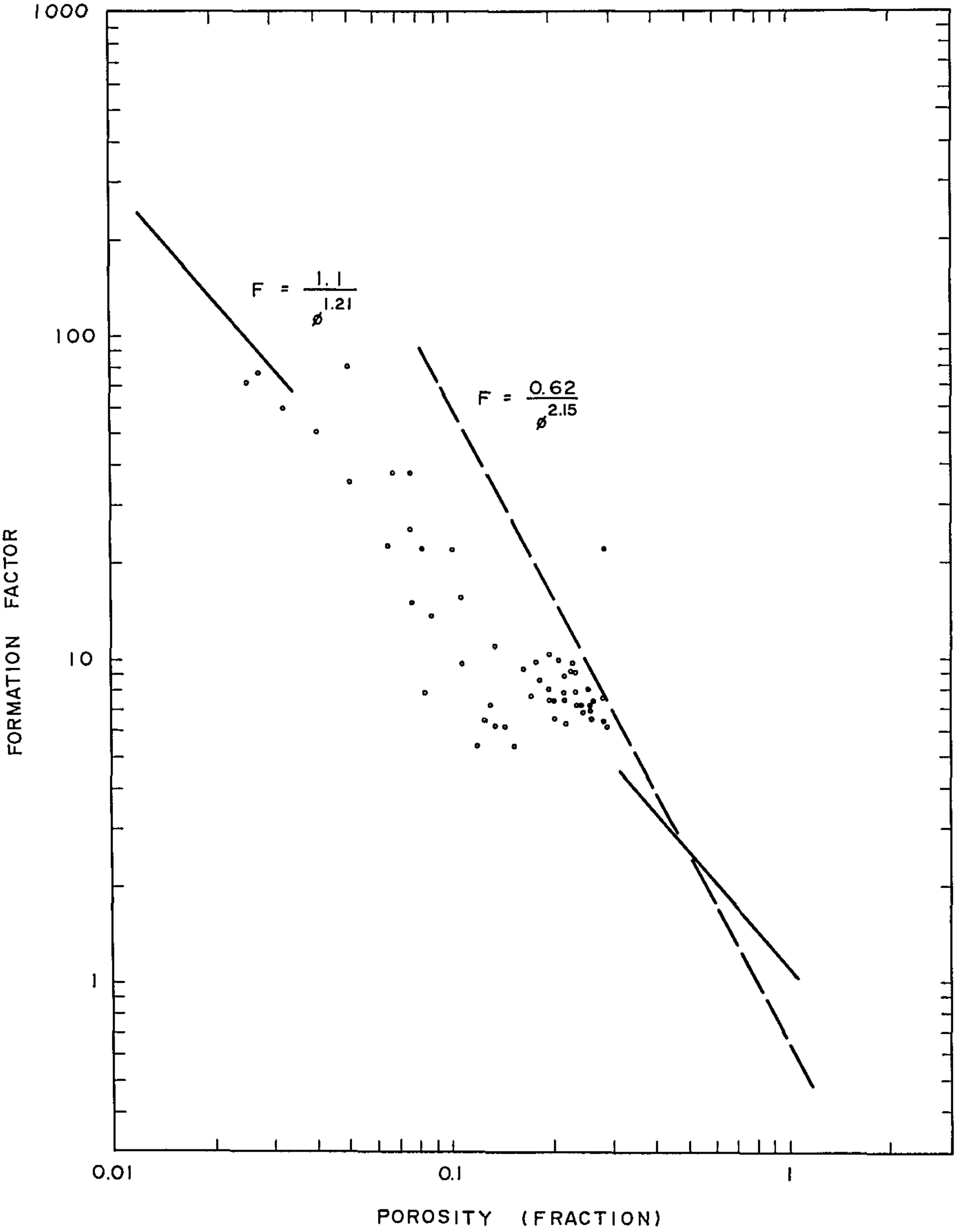
FIELD	CEMENTATION FACTOR (m)	ARCHIE FORMULA'S CONSTANT (a)	SATURATION EXPONENT (n)	WATER RESISTIVITY (Ω-M @ F.T.)
TEMANA	2	1	2	0.15 @ 152°F
SOUTH FURIOUS	1.69	1	2	0.22 @ 155°F
BETTY	2	1	2	0.11 @ 180°F
BOKOR	2.15	0.62	2	0.16 @ 140°F
ERB WEST	2.15	0.62	2	0.13 @ 145°F
ERB SOUTH	2.15	0.62	2	0.3 @ 120°F
ST. JOSEPH	2.15	0.62	2	0.25 @ 150°F
WEST EMERALD	2.15	0.62	2	0.21 @ 135°F
BERYL	1.87	0.7	2	
SIWA	2.15	0.62	2	0.4 @ 120°F
CENTRAL LUCONIA				
B12	1.84	1.04	1.84	0.096@ 240°F
E6	1.84	1.04	1.84	0.23 @ 70°F
E8	1.84	1.04	1.84	0.102@ 148°F
E11	1.84	1.04	1.84	0.096@ 165°F
F6	1.84	1.04	1.84	0.096@ 152°F
F9	2	1	2	0.208@ 170°F
F13	1.84	1.04	0.84	0.25 @ 184°F
F14	1.84	1.04	1.84	0.124@ 148°F
F22	1.84	1.04	1.84	0.2 @ 170°F
F23	1.84	1.04	1.84	0.16 @ 204°F
K4	2	1	2	0.102@ 175°F
M1	1.84	1.04	1.84	0.11 @ 162°F
M3	1.84	1.04	0.84	0.06 @ 203°F
M5	1.84	1.04	1.84	0.06 @ 206°F
BARAM A	1.87	0.7	2	0.135@ 150°F
BARAM B	1.87	0.7	2	0.13 @ 170°F
BAKAU	2.15	0.62	2	0.11 @ 206°F
BARONIA	1.69	1	2.0	0.09 @ 150°F
RAIRLY BARAM	2.15	1	1.49	0.22 @ 70°F
SAMMARANG	1.8	1	1.8	0.111@ 142°F
TEMBUNGO	1.93	1.14	1.93	0.14 @ 150°F
TUKAU	2.15	0.62	2	0.12 @ 140°F
WEST LUTONG	1.84	0.68	2	0.205@ 100°F



FORMATION FACTOR VS POROSITY PLOT
SAMMARANG 1X



FORMATION FACTOR VS POROSITY PLOT
SOUTH FURIOUS 2X



FORMATION FACTOR VS POROSITY PLOT
ERB WEST 4

WELL NAME : SAMARANG 002

CUT OFF OF SW : 90.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 50.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
6444.0	-	6458.0	16	22.8	41.4	SAMARANG 02 'C2' OIL ZONE
6498.0	-	6516.0	20	17.9	59.5	SAMARANG 02 'C3' OIL ZONE

WELL NAME : SAMARANG 03

CUT OFF OF SW : 90.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 50.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
5380.0	-	5478.0	98	18.3	42.5	SAMARANG 03 'B ' OIL ZONE
6184.0	-	6228.0	40	18.7	55.8	SAMARANG 03 'C1' OIL ZONE
6266.0	-	6324.0	60	17.9	40.5	SAMARANG 03 'C2' GAS ZONE
6334.0	-	6398.0	58	18.7	42.6	SAMARANG 03 'C3' GAS ZONE
6400.0	-	6410.0	8	12.4	75.0	SAMARANG 03 'C3' OIL ZONE
6424.0	-	6476.0	24	13.7	63.8	SAMARANG 03 'C4' OIL ZONE
6486.0	-	6616.0	104	19.1	44.6	SAMARANG 03 'C5' OIL ZONE
7312.0	-	7370.0	60	17.0	46.6	SAMARANG 03 'D ' GAS ZONE
7372.0	-	7440.0	64	15.2	66.1	SAMARANG 03 'D ' OIL ZONE

LOG INTERPRETATION RESULTS

- SAMARANG 8 -

INTERVAL	NET SAND	AVERAGE ϕ	AVERAGE Sw	REMARKS
4742 - 4905				
5772 - 5820				
6040 - 6050				
6570 - 6630	38	19.58	48.51	C_1
6704 - 6722	17	23.06	19.39	Gas C_2
6760 - 6800	40	19.83	37.38	Gas C_3
6800 - 6855	55	17.87	29.66	
6856 - 6954	56	18.73	46.22	
6954 - 6965	5	23	57	

WELL NAME : SAMARANG 13

CUT OFF OF SW	:	90.00
CUT OFF OF POROSITY	:	0.0
CUT OFF OF SHALE	:	50.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
5134.0	-	5410.0	244	24.1	31.1	SAMARANG 13 'A ' OIL ZONE
6370.0	-	6404.0	32	23.4	39.1	SAMARANG 13 'B ' GAS ZONE
6414.0	-	6560.0	130	22.1	38.1	SAMARANG 13 'B ' OIL ZONE
7546.0	-	7574.0				SAMARANG 13 'C1' OIL ZONE
7698.0	-	7762.0	44	17.5	40.3	SAMARANG 13 'C2' OIL ZONE
7802.0	-	7908.0				SAMARANG 13 'C3' OIL ZONE
7931.0	-	7984.0				SAMARANG 13 'C4' OIL ZONE

WELL NAME : SAMARANG 14 1

CUT OFF OF SW : 90.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 50.00

INTERVAL TOP (FT)		BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
4920.0	-	5032.0	80	24.4	38.2	SAMARANG 14 'A ' OIL ZONE
5744.0	-	5764.0	20	18.3	64.4	SAMARANG 14 'B ' GAS ZONE
5772.0	-	5894.0	120	22.1	34.8	SAMARANG 14 'B ' OIL ZONE

WELL NAME : SAMARANG 15

CUT OFF OF SW : 90.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 50.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
4914.0	-	5104.0	174	26.6	34.6	SAMARANG 15 'A ' OIL ZONE
5918.0	-	5924.0	8	24.5	37.7	SAMARANG 15 'B ' GAS ZONE
5930.0	-	6028.0	92	23.5	30.4	SAMARANG 15 'B ' OIL ZONE
7040.0	-	7102.0	50	19.8	39.1	SAMARANG 15 'C2' OIL ZONE
7134.0	-	7210.0	66	20.9	42.4	SAMARANG 15 'C3' OIL ZONE

WELL NAME : SAMARANG 16

CUT OFF OF SW : 90.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 50.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
3661.0	-	3683.0	192	26.1	31.1	SAMARANG 16 'A ' OIL ZONE
4678.0	-	4904.0	80	21.0	50.6	SAMARANG 16 'B ' OIL ZONE
5718.0	-	5833.0	42	13.9	60.6	SAMARANG 16 'C1' OIL ZONE
6590.0	-	6634.0	18	17.8	35.1	SAMARANG 16 'C2' GAS ZONE
6723.0	-	6744.0	12	13.4	46.5	SAMARANG 16 'C2' OIL ZONE
6748.0	-	6758.0	28	16.9	38.7	SAMARANG 16 'C3' GAS ZONE
6792.0	-	6818.0	32	16.0	44.5	SAMARANG 16 'C3' OIL ZONE
6842.0	-	6872.0	66	19.1	42.9	SAMARANG 16 'C4' OIL ZONE
6890.0	-	6982.0	34	21.9	60.9	SAMARANG 16 'C5' OIL ZONE
7004.0	-	7036.0				

WELL NAME : SAMARANG 17

CUT OFF OF SW : 90.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 50.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
5087.0	-	5294.0	184	26.2	34.8	SAMARANG 17 'A ' OIL ZONE
6106.0	-	6146.0	20	20.0	70.3	SAMARANG 17 'B ' GAS ZONE
6154.0	-	6248.0	86	24.1	33.4	SAMARANG 17 'B ' OIL ZONE

WELL NAME : SAMARANG 18

CUT OFF OF SW : 90.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 50.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
4682.0	-	4854.0	158	26.8	29.0	SAMARANG 18 'A ' OIL ZONE
5644.0	-	5748.0	88	20.4	38.0	SAMARANG 18 'B ' OIL ZONE
6404.0	-	6460.0	56	19.4	31.9	SAMARANG 18 'C1' GAS ZONE
6532.0	-	6560.0	30	22.4	18.9	SAMARANG 18 'C2' GAS ZONE
6588.0	-	6662.0	76	20.5	23.8	SAMARANG 18 'C3' GAS ZONE
6682.0	-	6710.0	30	19.0	30.5	SAMARANG 18 'C4' GAS ZONE
6720.0	-	6762.0	42	13.4	46.6	SAMARANG 18 'C4' OIL ZONE
6780.0	-	6930.0	144	17.8	43.7	SAMARANG 18 'C5' OIL ZONE

WELL NAME : SAMARANG 19

CUT OFF OF SW : 90.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 50.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
4392.0	-	4436.0	46	20.7	22.3	SAMARANG 19 'A ' GAS ZONE
4438.0	-	4672.0	178	20.2	34.0	SAMARANG 19 'A ' OIL ZONE
5384.0	-	5444.0	56	15.4	38.9	SAMARANG 19 'B ' GAS ZONE
5446.0	-	5576.0	104	18.5	39.5	SAMARANG 19 'B ' OIL ZONE
6540.0	-	6580.0	36	16.1	57.4	SAMARANG 19 'C2' OIL ZONE
6618.0	-	6702.0	30	16.8	72.2	SAMARANG 19 'C3' OIL ZONE

WELL NAME : SAMARANG 21

CUT OFF OF SW : 90.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 50.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
3853.0	-	3897.0	38	25.6	43.5	
3902.0	-	3951.0	50	29.4	30.2	
3953.0	-	3981.0	26	25.5	48.7	
5108.0	-	5298.0	160	22.7	35.4	SAMARANG 21 'A ' OIL ZONE
6086.0	-	6192.0	102	23.9	33.2	SAMARANG 21 'B ' OIL ZONE
7222.0	-	7226.0	6	21.2	74.7	SAMARANG 21 'C2' OIL ZONE
7288.0	-	7296.0	10	19.6	80.9	SAMARANG 21 'C3' OIL ZONE

WELL NAME : SAMARANG 22

CUT OFF OF SW : 90.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 50.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
4616.0	-	4744.0	102	25.1	46.3	SAMARANG 22 'A ' OIL ZONE
5456.0	-	5508.0	38	19.0	63.2	SAMARANG 22 'B ' GAS ZONE
5510.0	-	5630.0	100	24.1	29.7	SAMARANG 22 'B ' OIL ZONE
6372.0	-	6428.0	50	16.6	52.0	SAMARANG 22 'C1' OIL ZONE
6496.0	-	6516.0	20	20.8	28.8	SAMARANG 22 'C2' GAS ZONE
6518.0	-	6526.0	10	16.4	36.0	SAMARANG 22 'C2' OIL ZONE
6560.0	-	6570.0	12	20.8	28.2	SAMARANG 22 'C3' GAS-ZONE
6602.0	-	6630.0	28	18.0	37.8	SAMARANG 22 'C3' OIL ZONE
6648.0	-	6714.0	50	19.2	43.1	SAMARANG 22 'C4' OIL ZONE
6746.0	-	6782.0	34	22.9	56.4	SAMARANG 22 'C5' OIL ZONE

WELL NAME : SAMARANG 23

CUT OFF OF SW : 90.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 50.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
3825.0	-	3860.0	28	25.0	26.9	
3860.0	-	3868.0	8	20.5	44.7	
3867.0	-	3906.0	36	27.8	43.3	
4956.0	-	5088.0	120	22.5	39.7	SAMARANG 23 'A ' OIL ZONE
5762.0	-	5798.0	30	17.9	45.1	SAMARANG 23 'B ' GAS ZONE
5808.0	-	5945.0	90	22.9	23.2	SAMARANG 23 'B ' OIL ZONE

WELL NAME : SAMARANG 24

CUT OFF OF SW : 90.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 50.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
3708.0	-	3757.0	36	24.1	41.0	
3759.0	-	3804.0	46	26.3	30.0	
3804.0	-	3841.0	36	26.4	39.2	
4948.0	-	5066.0	98	25.3	27.2	SAMARANG 24 'A ' OIL ZONE
5822.0	-	5940.0	52	25.0	60.0	SAMARANG 24 'B ' OIL ZONE

WELL NAME : SAMARANG 25

CUT OFF OF SW : 90.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 50.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
4616.0	-	4624.0	10	22.7	59.4	SAMARANG 25 'A ' GAS ZONE
4626.0	-	4852.0	220	26.7	28.1	SAMARANG 25 'A ' OIL ZONE
5538.0	-	5630.0	70	25.5	22.6	SAMARANG 25 'B ' GAS ZONE
5632.0	-	5764.0	126	25.7	23.4	SAMARANG 25 'B ' OIL ZONE

WELL NAME : SAMARANG 26

CUT OFF OF SW : 90.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 50.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
3943.0	-	3986.0	32	27.3	34.5	
3989.0	-	4045.0	56	29.9	28.7	
4047.0	-	4062.0	16	30.3	49.0	
5000.0	-	5016.0	18	23.7	34.2	SAMARANG 26 'A' GAS ZONE
5018.0	-	5270.0	210	24.8	25.5	SAMARANG 26 'B' OIL ZONE

WELL NAME : SAMARANG 27

CUT OFF OF SW : 90.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 50.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
4648.0	-	4814.0	130	25.7	34.8	SAMARANG 27 'A' OIL ZONE

WELL NAME : SAMARANG 28

CUT OFF OF SW : 90.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 50.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
5374.0	-	5458.0	56	25.7	35.1	SAMARANG 28 'A ' OIL ZONE
6412.0	-	6542.0	130	25.4	27.1	SAMARANG 28 'B ' OIL ZONE

WELL NAME : SAMARANG 29

CUT OFF OF SW : 90.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 50.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
4512.0	-	4684.0	134	26.0	30.1	SAMARANG 29 'A ' OIL ZONE
5437.0	-	5452.0	4	18.8	50.7	SAMARANG 29 'B ' GAS ZONE
5458.0	-	5586.0	118	20.8	30.3	SAMARANG 29 'B ' OIL ZONE

LOG INTERPRETATION RESULTS

- TEMBUNGO 1 -

INTERVAL	NET SAND	AVERAGE ϕ	AVERAGE Sw	REMARKS
5916 - 5934	18	27.17	24.44	
5945 - 5956	11	25.86	25.70	
5966 - 5997	28	23.96	33.68	
6045 - 6075	24	25.21	25.64	
6096 - 6060	56	21.98	27.27	
6165 - 6175	10	17.75	53.63	

LOG INTERPRETATION RESULTS

- TEMBUNGO A-1 -

INTERVAL	NET SAND	AVERAGE ϕ	AVERAGE Sw	REMARKS
5535 - 5550	15	16.33	38.33	Oil
5560 - 5570	5	22.0	60.0	Oil
5585 - 5560				Oil
5615 - 5655	35	26.14	26.08	Oil
5670 - 5675	5	33.0	36.0	Oil
5685 - 5730	35	28.14	27.12	Oil
5800 - 5835	35	24.83	25.52	Oil

LOG INTERPRETATION RESULTS

- TEMBUNGO 2 -

INTERVAL	NET SAND	AVERAGE ϕ	AVERAGE Sw	REMARKS
4415 - 4423	8	31	26	
4441 - 4466	25	28	28	
4474 - 4500	26	21	51	WUT 4508
5176 - 5187	8	16	36	
6114 - 6128				Shale
6413 - 6427				Tight
6742 - 6855	83	19	49	Gas,GOC 6800
6922 - 6933	11	19	41	Oil
7033 - 7074	22	21	43	Oil

LOG INTERPRETATION RESULTS

- TEMBUNGO A-2 -

INTERVAL	NET SAND	AVERAGE ϕ	AVERAGE Sw	REMARKS	
7324 - 7338	14	26.94	33.26	Gas	
7358 - 7370	12	19.8	49.85	Gas	GOC 7370
7372 - 7414	8	19.65	56.26	Oil	WDT 7414
7698 - 7724	26	22.84	35.61	Gas	
7784 - 7850	50	18.17	42.83	Oil	
8596 - 8906				Gas	
8746 - 8754					
9160 - 9178	10	18.46	54.78	Gas	
9206 - 9242	4	19.65	58.04	Oil	

LOG INTERPRETATION RESULTS

- TEMBUNGO A-2A -

INTERVAL	NET SAND	AVERAGE ϕ	AVERAGE Sw	REMARKS
4094 - 4122				Tight
4192 - 4205				Oil
4296 - 4312				Tight
7858 - 7973	84	21.65	49.33	Oil (5223.4-5286.9 SS)

LOG INTERPRETATION RESULTS

- TEMBUNGO A-3 -

INTERVAL	NET SAND	AVERAGE ϕ	AVERAGE Sw	REMARKS
5420 - 5435				Tight
6730 - 6790	20	12	63.25	Oil
7930 - 7940	10	20	51	Gas
7965 - 7975	10	22	66	Gas

LOG INTERPRETATION RESULTS
- TEMBUNGO A-4 -

INTERVAL	NET SAND	AVERAGE ϕ	AVERAGE Sw	REMARKS
5510 - 5525	15	17	54	Oil
5912 - 5972	56	24.80	29.70	Oil
6020 - 6128	96	19.32	37.39	Oil
6150 - 6162	9	23.5	44	Oil, OWC 6162
6424 - 6580	134	17.40	64.68	Oil, OWC 6580

LOG INTERPRETATION RESULTS

- TEMBUNGO 5 -

INTERVAL	NET SAND	AVERAGE ϕ	AVERAGE Sw	REMARKS
4276 - 4322				
4687 - 4727				
5244 - 5280	26	23.82	72.52	Oil
5296 - 5306	6.0	21.33	75.28	Gas
5345 - 5427	62	22.88	66.99	Oil
5470 - 5510	4	30.0	71.0	Oil
5536 - 5565	8	19.88	75.02	Oil
5620 - 5642	22	23.66	64.29	Oil
5660 - 5688	19	25.54	64.55	Oil
5697 - 5732	31	26.44	59.71	Oil

LOG INTERPRETATION RESULTS
- TEMBUNGO A-5 -

INTERVAL	NET SAND	AVERAGE ϕ	AVERAGE S_w	REMARKS
4464 - 4470				Tight
4550 - 4583				Tight
4847 - 4860				Tight
5834 - 5892	51	23.24	53.54	Oil
5966 - 5978	12	25	40	Oil
7347 - 7400	9	17	47	Oil
7865 - 7874				Oil
7958 - 7963				Oil
7974 - 7979				Oil
8690 - 8703	12	24.38	39.99	Oil
9054 - 9090	32	18.37	50.77	Oil
9100 - 9138	38	22.94	34.01	Gas
9172 - 9234	58	23.12	27.24	Gas
9273 - 9279	10	28.6	44.93	Oil
9305 - 9394	92	22.11	38.42	Oil

LOG INTERPRETATION RESULTS

- TEMBUNGO A-7 -

INTERVAL	NET SAND	AVERAGE ϕ	AVERAGE Sw	REMARKS
6310 - 6318	13	4	56	
6352 - 6360	12	21	89	
6405 - 6421	18	16.33	49.29	OWC 6421
6477 - 6488	13	22	57	
6512 - 6538	26	25.5	31	
6550 - 6558	14	14	53	OWC 6558
6613 - 6640	36	24.50	28.94	OWC 6640

WELL NAME : ERBWEST 01

CUT OFF OF SW : 80.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 50.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
3796.0	-	3833.0	26	26.5	48.6	
3851.0	-	3872.0	8	28.6	53.9	HWC 3872
3942.0	-	3990.0	26	33.1	28.5	WUT 4000
4093.0	-	4131.0	10	35.8	25.4	WHWC 4131
4196.0	-	4208.0	6	19.6	67.1	
4242.0	-	4248.0	2	40.7	18.3	
4298.0	-	4334.0	18	37.3	41.8	HWC 4334
4459.0	-	4490.0	8	37.2	28.9	
4612.0	-	4624.0	10	22.0	61.0	
4664.0	-	4684.0	20	30.9	42.4	GAS
5004.0	-	5040.0	12	20.0	69.0	
5046.0	-	5053.0	4	32.7	42.1	
5192.0	-	5216.0	18	29.8	48.3	HWC 5218
5860.0	-	5868.0				
6462.0	-	6486.0	24	15.7	34.9	
6542.0	-	6848.0	162	22.7	16.7	GAS
6926.0	-	6970.0	18	15.5	43.5	OIL
7793.0	-	7799.0				

WELL NAME : ERB WEST 02

CUT OFF OF SW	:	80.00
CUT OFF OF POROSITY	:	0.0
CUT OFF OF SHALE	:	50.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
5366.0	-	5376.0				
6278.0	-	6338.0	6	16.4	32.8	
6384.0	-	6412.0	26	23.4	15.3	
6416.0	-	6420.0	2	11.7	46.8	
6428.0	-	6484.0	52	18.7	20.4	
6500.0	-	6528.0	16	16.7	27.6	
6550.0	-	6612.0	58	19.4	19.2	
6628.0	-	6638.0	8	15.2	40.9	
6642.0	-	6736.0	90	22.0	20.7	

WELL NAME : ERB WEST 03

CUT OFF OF SW : 80.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 50.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
5458.0	-	5461.0				GAS
5796.0	-	5802.0				
6164.0	-	6174.0	2	17.6	38.9	
6342.0	-	6372.0				
6444.0	-	6516.0	20	14.8	41.1	
6602.0	-	6690.0	44	15.3	34.9	
6756.0	-	6794.0	34	22.6	32.9	
6816.0	-	6930.0	66	22.4	26.4	
6930.0	-	7032.0	52	20.3	32.1	GAS

WELL NAME : ERB WEST 04

CUT OFF OF SW : 80.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 50.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
3856.0	-	3902.0	48	33.7	20.6	GAS
7100.0	-	7126.0	2	15.8	73.3	
7162.0	-	7204.0	34	21.3	49.0	OIL

WELL NAME : SOUTH FURIOUS 01

CUT OFF OF SW : 60.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 60.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
6634.0	-	6649.0	2	19.6	59.3	OIL
6684.0	-	6735.0				OIL
7054.0	-	7063.0				OIL

WELL NAME : SOUTH FURIOUS 03

CUT OFF OF SW : 60.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 60.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
1076.0	-	1080.0	4	27.0	42.5	GAS
1202.0	-	1214.0				OIL
1540.0	-	1570.0	2	20.3	46.8	GAS
1582.0	-	1692.0	38	23.9	39.3	GAS
1708.0	-	1760.0	16	27.5	36.6	OIL
1782.0	-	1846.0	40	27.5	34.9	GAS
1846.0	-	1858.0	10	26.9	46.8	OIL
2120.0	-	2126.0	6	29.8	35.9	
2164.0	-	2170.0				
2176.0	-	2184.0				
2280.0	-	2292.0	10	28.1	42.5	
2304.0	-	2311.0	4	32.4	44.2	
2326.0	-	2330.0	2	29.7	47.0	
2356.0	-	2368.0	12	31.3	39.1	
2631.0	-	2635.0	4	35.0	39.3	
2838.0	-	2845.0				
2864.0	-	2888.0	16	24.0	41.4	
2916.0	-	2926.0	6	26.5	40.8	
2931.0	-	2938.0	6	22.8	53.4	
2947.0	-	2965.0	2	25.0	56.2	
3132.0	-	3138.0	2	21.7	57.1	
3224.0	-	3247.0	20	23.6	21.7	GAS
3267.0	-	3670.0	112	23.2	36.0	OIL
3906.0	-	3954.0	4	18.5	53.2	
4128.0	-	4160.0	18	19.4	34.6	
4164.0	-	4166.0				
4204.0	-	4210.0				
4216.0	-	4230.0	4	23.2	33.0	

WELL NAME : SOUTH FURIOUS 03

CUT OFF OF SW : 60.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 60.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
4232.0	-	4252.0				
4360.0	-	4364.0				GAS
4374.0	-	4380.0	6	21.1	41.3	
4385.0	-	4394.0				
4698.0	-	5262.0	24	20.6	44.5	OIL
5795.0	-	5803.0	4	20.3	57.8	
5972.0	-	5992.0	18	19.9	37.3	
6008.0	-	6086.0				
6456.0	-	6472.0				
6640.0	-	6644.0				
6690.0	-	7668.0	8	19.3	36.6	GAS
7730.0	-	7814.0				OIL

WELL NAME : SOUTH FURIOUS 04

CUT OFF OF SW : 60.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 60.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
3123.0	-	3298.0	6	19.6	52.4	OIL
3504.0	-	3910.0	48	21.7	28.9	OIL
4014.0	-	4085.0	16	19.0	51.4	OIL
4107.0	-	4118.0	6	25.8	41.6	
4118.0	-	4162.0				
4200.0	-	4269.0	6	17.0	24.2	
4344.0	-	4386.0	4	19.8	46.4	
4405.0	-	4409.0				
4412.0	-	4416.0				
4434.0	-	4476.0	6	17.7	26.4	
4529.0	-	4810.0	34	18.0	43.1	OIL

WELL NAME : SOUTH FURIOUS 05

CUT OFF OF SW : 60.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 60.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
1170.0	-	1213.0	24	27.4	37.0	GAS
1221.0	-	1226.0	2	28.3	54.2	OIL
1348.0	-	1424.0	12	28.8	48.5	OIL
1870.0	-	1878.0	6	29.7	47.2	OIL
1943.0	-	1957.0	8	25.6	47.9	
1992.0	-	2048.0	32	24.8	37.5	
2100.0	-	2105.0	4	19.1	44.6	
2120.0	-	2142.0	8	17.6	47.1	
2184.0	-	2188.0	4	16.3	49.5	
2205.0	-	2346.0	72	23.2	35.8	OIL
2430.0	-	2604.0	64	21.9	29.3	GAS
2634.0	-	2645.0	10	20.5	49.8	OIL
2680.0	-	2798.0	62	26.2	21.2	GAS
2810.0	-	2815.0	4	18.3	32.7	OIL
2822.0	-	2824.0				
2829.0	-	2836.0	6	22.3	34.7	
2843.0	-	2846.0	4	18.3	49.1	
2884.0	-	2904.0	18	21.1	39.9	
2914.0	-	2923.0	2	14.8	57.5	
2948.0	-	2968.0	18	19.6	33.3	
2992.0	-	3004.0	10	23.2	28.3	
3024.0	-	3044.0	6	21.2	31.9	
3066.0	-	3086.0	18	20.0	39.3	
3096.0	-	3106.0	2	17.0	43.1	
3122.0	-	3133.0	8	20.7	20.8	
3152.0	-	3165.0	14	19.2	30.0	
3184.0	-	3380.0	82	20.1	32.0	GAS
3665.0	-	3668.0				OIL

WELL NAME : SOUTH FURIOUS 05

CUT OFF OF SW : 60.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 60.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
3707.0	-	3711.0				GAS
3834.0	-	3915.0	28	20.8	31.2	OIL
3919.0	-	4434.0	70	19.3	36.5	

WELL NAME : SOUTH FURIOUS 06

CUT OFF OF SW : 60.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 60.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS
2288.0	-	2586.0	68	25.1	37.7	OIL
2610.0	-	2748.0	78	26.3	34.9	OIL

WELL NAME : WEST EMERALD B

CUT OFF OF SW	:	80.00
CUT OFF OF POROSITY	:	0.0
CUT OFF OF SHALE	:	50.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS	
1118.0	-	1140.0	20	33.0	19.9	GAS	GOC 1140
1140.0	-	1174.0	32	32.6	32.6	OIL	OWC 1174
4338.0	-	4370.0				TIGHT	
4712.0	-	4720.0	8	16.0	72.2	GAS	GOC 4720
4720.0	-	4728.0	6	18.3	67.7	OIL	OWC 4728

WELL NAME : ST.JOSEPH

CUT OFF OF SW : 80.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 50.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)	REMARKS	
1426.0	-	1447.0					
1483.0	-	1493.0					
1740.0	-	1781.0	6	18.7	68.3		
1890.0	-	1914.0	18	18.1	54.6		
2108.0	-	2119.0	2	12.7	58.3		
2196.0	-	2273.0	72	20.4	38.6		
2304.0	-	2309.0	2	10.8	74.7		
2320.0	-	2360.0	28	18.2	60.7		
2396.0	-	2427.0	12	19.3	61.0	GAS	
2584.0	-	2636.0	6	14.9	65.8	OIL	WUT 2642
2759.0	-	2767.0	2	31.3	65.5	TIGHT	
2840.0	-	2842.0				TIGHT	
2938.0	-	2952.0				TIGHT	
2975.0	-	2981.0	2	3.0	70.5	TIGHT	
2998.0	-	3005.0				GAS	
3114.0	-	3123.0				OIL	
3156.0	-	3188.0	12	2.3	65.4	OIL	OWC 3188
5556.0	-	5592.0	4	23.4	43.7	GAS	GOC 5592

WELL NAME : ERB SOUTH (AX)

CUT OFF OF SW : 80.00
CUT OFF OF POROSITY : 0.0
CUT OFF OF SHALE : 50.00

INTERVAL TOP (FT)		INTERVAL BASE (FT)	NET THICKNESS (FT)	AVERAGE POROSITY (%)	AVERAGE SATURATION (%)		REMARKS
2122.0	-	2148.0				TIGHT	
2388.0	-	2412.0				TIGHT	
2507.0	-	2531.0				TIGHT	
2583.0	-	2594.0				TIGHT	
2606.0	-	2611.0				TIGHT	
2831.0	-	2886.0	50	26.2	47.3	OIL	
2896.0	-	2914.0	10	21.9	74.8	OIL	OWC2914
2934.0	-	2941.0	6	21.5	48.1	OIL	
2952.0	-	2963.0	8	23.4	66.2	OIL	