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AUSTRALIAN CONTRIBUTION IN EXPENDITURE AND DEVELOPMENT OF ITS INDIGENOUS PETROLEUM RESOURCES

by

J.M. Henry and K. Blair

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Introduction

During the last 2 years or so public interest has developed considerably in the ownership and the present and future use of Australia's petroleum and other natural resources.

This interest has aroused strong national feelings in some quarters. It has led to statements, both verbal and written, ranging from well balanced economic studies to intemperate and emotional comment.

Against this background the following information and thoughts concerning petroleum are offered in an endeavour to present facts that are often overlooked, or little known, particularly by the general public. The paper is in two parts; the first deals with expenditure and Australia's share or equity in petroleum, and the second deals with the development of our hydrocarbons.

Ownership of Petroleum Resources

Initially, we should remember that in Australia and, for the present, in Papua New Guinea, all petroleum is the property of State Governments and Territory Administrations.

The conditions of tenure for a title are set down in legislation by the Government concerned, which always retains the ultimate control.

All farmouts, agreements to participate, etc., must be approved by Government. The position of Australian and overseas companies in this area and hence Australia's share of petroleum production is presented later when dealing with equity.

Expenditure

The petroleum industry is probably one of the most international industries in the world. In many instances the same company, directly or through subsidiaries, operates in Australia, Europe, the Middle East, North and South America, and Africa. The main companies searching and developing the North Sea areas are those which are operating in offshore Texas and Louisiana, Indonesia, and around the Australian coast, where, with only a few exceptions, they are in partnership or working alongside local companies.

The amounts of money needed for exploration are very large by any standard. This money must all be considered high risk capital. In Australia to the end of 1971 $843,813,976[1] had been spent on petroleum exploration. Of this sum $63,424,584[1] had been provided by State and Federal Governments as direct expenditure and $110,92?,244[1] had been paid in subsidies to exploration companies. Private enterprise provided $669,456,148[1].

When the sum spent by private enterprise on the development and the bringing into production of our currently producing fields and on fields being prepared for production is added, the total reaches $1,195,152,254[2].

This sum does not include any major on-shore pipelines or refineries, etc., which represents an additional investment of some $1,716.0 million[3].

In 1971 alone, for example, the industry spent $79,755,095[4] on exploration, $10,181,816[4] on development work, including the drilling of producing wells, and $65,098,669[4] on production installations and activities. Annual details of exploration expenditures are given in Table 1[1].

TABLE 1. EXPENDITURE ON PETROLEUM EXPLORATION[1]

Year	Private Industry Exploration Only $	Subsidy Payments $	State and Fed. Govt. $	Total $
To 31.12.1956	64,906,470	nil	10,111,550*	75,018,020
1957	14,649,894	nil	1,132,200*	15,782,094*
1958	11,093,712	564,728	1,229,800*	12,888,240*
1959	11,771,184	1,197,854	1,486,600*	14,455,638*
1960	12,490,518	1,581,486	1,877,200*	15,949,204*
1961	12,969,756	2,695,800	2,369,400*	18,034,956*
1962	22,892,694	5,930,752	3,029,800*	31,853,246*
1963	26,979,700	10,519,208	3,357,600*	40,856,508*
1964	33,856,010	9,121,910	4,844,534	47,822,454
1965	50,606,566	10,412,832	4,534,936	65,554,334
1966	51,325,552	10,154,169	4,416,412	65,896,133
1967	56,519,964	10,326,475	4,974,238	71,820,677
1968	68,337,069	13,805,484	5,539,515	87,682,968
1969	73,834,898	14,911,351	5,069,879	93,816,128
1970	77,473,066	11,237,019	4,296,325	93,006,410
1971	79,755,095	8,468,176	5,154,595	93,377,966
Totals	669,456,148	110,927,244	63,424,584	843,813,976
		$174,351,828		

The trends in this expenditure are indicated graphically in Figure 1, Appendix A.

In examining the figures for exploration expenditure it is worthy of note that Government expenditure between 1958 and 1971, that is expenditure by State and Federal Governments including the payments made under the Petroleum Search Subsidy Act, amounted to $162,108,078[1] or 27% of the sum spent by private industry during that period. To this must be added the tariff benefits and taxation concessions that have been made available to the industry. The amount of this is difficult to assess but is probably considerable. Figure 1 clearly shows the escalation in private industry funds provided each year. The drop in subsidy since 1969 clearly reflects the exclusion from the scheme of offshore projects with insufficient Australian participation, and this is reflected in the "Total" by the flattening off since 1969.

Source of Funds

The Bureau of Mineral Resources, Geology and Geophysics publishes annually figures on petroleum exploration, development, and production expenditure and the origin of private enterprise funds. The figures quoted are based on confidential individual company returns which are aggregated and published on a State and Territory basis.

In collecting and presenting these figures the following definitions[5] as to the origins of funds are used:

Australian Funds: new domestic capital of Australian origin.

Re-investment: funds derived from the sale of indigenous (Australian) production by any company operating in Australia.

North American: new capital from United States of America or Canadian sources.

Other (non - $): other new capital originating from overseas such as sterling, francs, etc.

Appendix B gives a breakdown of the origin of private enterprise funds since 1965 using these definitions. The trends since 1957 are shown graphically in Figure 2, Appendix C.

Some very interesting and often overlooked trends are apparent. To the end of 1971, 43.01% of the new capital was from Australian sources, and a further 11.81% was "Re-investment" money which is also of Australian origin. Together this represents 54.82% of the total expenditure by private industry. What is often overlooked - in fact rarely mentioned - is the significant gain in the percentage of funds being provided by "re-investment". It is encouraging to see the producing companies returning revenue to the search and development programs which amounted in 1971 to 26.51% of the private enterprise total; this compares very favourably with only 6.15% in 1966. In other words, a large part of the funds which could well have been "exported" remains in Australia and is being put to work to further the search for or the development of our petroleum resources.

The favourable percentage of Australian funds indicates that a corresponding amount of profits or future profits should benefit the country's investors.

Australia's Equity or benefit

Overseas interests have played and do play a considerable part in the exploration for and the development of Australia's natural resources. However, our petroleum resources differ in one important respect from our mineral resources such as iron ore, bauxite and coal: Australia is a net importer of petroleum, but a net exporter of minerals. We still have to import some 28 percent to 30 percent of our petroleum needs.

Almost all our indigenous petroleum production, with the exception of some natural gas liquids, is refined and marketed within Australia. There is provision in the legislation for indigenous production to be refined in Australia and the absorption by each refinery of its allocation of the local production. The price of Australian crude oil is controlled and is less than that for similar crudes from many overseas sources. The price is not affected by overseas influences.

Thus Australia not only benefits by virtue of royalty and other charges levied on the producers, but also by low cost crude and the revenue from the sale of refined products, which are amongst the lowest priced in the world. The saving in overseas exchange and freight must also be recognised.

In terms of Australia's share of petroleum and the part Australian companies have played in the search, it is interesting to note that with one or two exceptions, the petroleum discoveries have been made in titles that were originally wholly Australian owned. Because of the difficulty in raising locally the large amounts of money necessary for the exploration and development of their discoveries, the title holders were forced to seek overseas capital. In return for this participation some of the Australian equity had to be surrendered. It is well known that many Australian investors in oil exploration, particularly in the case of participating shares, are often unwilling to meet calls on their shares, and Australian companies have been left short of funds and with many millions of forfeited shares on their hands as a result of a call.

In the fields currently in production, Australia has an overall share amounting to 50% in the Bass Strait fields, some 14% in the Barrow Island and the Mondarra, Dongara, and Gingin fields, 100% or close to that figure in the Moonie and Alton fields, some 94.0% in the Roma fields, and some 36.5% in the Gidgealpa-Moomba fields. The use of the words "close to" and "some" in respect of the latter fields is deliberate, as the share holding by overseas interests can and does vary by small amounts. The Australian equity in fields to be developed will naturally depend upon the ability of the Australian partners, where present, to provide the required share of the development funds needed and the ultimate Australian equity in the production licence or lease that will have to be applied for and issued before this work can be undertaken. Hopefully these ventures will provide the avenue for greater Australian participation in funding and ultimate equity, but only time will tell. While on this subject it should not be forgotten that much of the exploration work being done by overseas interest under an agreement is dependent on there being a discovery before any overseas interest is gained. Hence, in many instances, when unsuccessful, exploration by an overseas partner does not affect Australian equity in the title.

An indication of Australia's share of production and current reserves in currently producing fields as at 31 December 1972 is given in the following table:

TABLE 2. AUSTRALIA'S SHARE OF PRODUCTION AND RESERVES AS AT 31 DECEMBER 1973

Field	Aust. Equity %	Australia's Share			
		Production		Reserves	
		Oil B/D	Gas MMcf/D	Oil Million Barrels	Gas million million cu.ft.
Bass Strait	50	173,897	52.951	798.1705	5,0544
Roma area	94	-	23.279	-	0.1995
Moonie-Alton-Bennett	100	1851	-	3.854	-
Barrow Island	14	5779	-	17.1262	0.0109
Dongara-Mondarra-Gingin	14	17	11.566	0.2312	0.0665
Gidgealpa-Moomba	36.5	-	36.916	-	0.4988
Total Australian Share		185,544	127.712	819.3819	5.8301
Total Aust. & Overseas		390,928	314.423	1724.4224	12.2405
% Aust. Share		46.44	39.66	47.52	47.63

Future Discovery Needs and Costs

Between now and 1985 it is estimated that new crude oil reserves of 2650 million barrels of recoverable liquids will need to be proved in order to attain full self-sufficiency.

Based on the proved petroleum reserves and exploration expenditure to the end of 1971, the cost of discovering petroleum is calculated to be $0.167 per barrel of oil and $30.0 per million cubic feet of gas. In terms of energy one million cubic feet of gas is equivalent to roughly 185 barrels of crude oil. The cost in terms of total hydrocarbon energy is $0.003 per therm.

On the assumption that the discovery ratio for oil to gas is maintained, and knowing our future estimated crude needs, the exploration costs of satisfying our crude oil requirements over the next 12 years are estimated to be $922 million at present discovery costs. Allowing for a 25 percent escalation in costs over the period the total exploration requirement will be in the order of $1150 million, just over one and one third times the amount spent over the last 70 years. This averages out at $96 million per year, only slightly above the average of $93 million for the last 3 years.

Failure to meet or exceed the discovery rate for liquid hydrocarbons will mean increasing imports or finding alternative energy sources.

Development Costs

To the end of 1971 development drilling and production facilities such as offshore platforms, marine pipe lines, and field gathering systems, but excluding major pipelines and processing units such as stabilization plants, have cost $351 million or roughly $1000 per barrel in terms of the daily production rate at that time.

If we are to reach full self-sufficiency rate the daily rate of production will have to reach some 1,230,000 barrels by 1985. This means an increase of some 800,000 barrels in daily production handling facilities, which could require an investment of a further $800,000,000. Allowing for rising costs this could well reach $1000 million. The cost of other facilities is difficult to estimate but could double this figure to $2000 million.

Development Wells

To the end of 1971, 2468 wells had been drilled in Australia compared with 2,188,295 (about a thousand times as many) in the United States of America, which itself does not now have self-sufficiency in terms of oil or gas production.

Of the 2468 wells, 709 have been drilled as development wells, 158 as service wells, and the balance of 1601 wells as exploration, extension, or appraisal wells. The number of wells completed for production at December 1971 was 668, of which 97 were originally drilled as exploration wells and 571 as development wells.

Development Practices

In the development of any hydrocarbon accumulation, the first concept is, or should be, the maximum efficient recovery for minimum capital investment (i.e. simply that unnecessary wells should not be drilled). The decision as to whether a well is necessary or not depends on the findings from a meticulous scrutiny of all information derived from previous drilling. Careful testing and concomitant interpretation of the results from wildcats and step-outs are essential for the determination of the subsequent production well pattern.

Since the days of extreme well density, when it was erroneously believed that the more wells drilled the greater the ultimate recovery, advances in technological interpretations and understanding of reservoir performances under different production conditions, have proved that:

"- in either solution gas, water drive or combination drive reservoirs, the ultimate production of oil is independent of well density.

- new oil fields could be first developed on wide spacing patterns, the final well density to be determined in the light of geological, geometrical, engineering and economic information, obtained as relevant information accumulates[7]."

Drainage areas may be defined from prolonged stabilized production testing of wildcats and step-outs, and thereafter, depending on structural knowledge, interference tests should be performed. Ideally, well spacing should be symmetrical during such tests. An excellent example of this technique is the H-J (Strawn) field (Humble, West Texas) Figure 3, Appendix D. This operation consisted of a 5-spot interference test, during which 4 wells were produced at constant rates for two weeks, with the fifth (central) well closed in and closely observed for interference effects. The effects on this well by production from the 4 adjacent wells were pronounced (Figure 4, Appendix E). On evidence from these tests, Humble convinced the Railroad Commission of Texas that a well spacing pattern of less than 80-acres was unnecessary. The Railroad Commission accepted this, and as a result, Humble saved drilling 22 wells and the corresponding development and operating costs which were based on a previously proposed 40-acre well spacing. Again, to investigate the concept of unnecessary well density, the API carried out an exhaustive analysis of comprehensive data from 103 reservoirs, both carbonate and sandstone, with both water and gas and combination drives, Figure 5, Appendix F. Although the multitude of data on parameters presented almost a life term career for a sizeable team of technologists, a reasonable conclusion was reached - that ultimate recovery is independent of well density.

In Australia there are six actively producing areas. These are:

Onshore -	Moonie - Alton - Bennett	- oil
	Roma area	- gas
	Gidgealpa - Moomba	- gas
	Dongara - Mondarra - Gingin	- gas
	Barrow Island	- oil
Offshore -	Gippsland Shelf	- oil and gas

With the exception of Barrow Island, the natures of the structural configurations have precluded a symmetrical development pattern.

Barrow Island now has 320 production wells and roughly 200 service wells (i.e. water supply and injection). The production well pattern is 40 acres per well, and the injection pattern a combination of 5 and 9 spot. This is a good example of a reservoir which is in the course of a full efficient development program and evidence of foresight in the early stages is strong.

The only offshore development has been in the Gippsland Shelf, where four fields are on production; Barracouta 1 platform (10 wells), Kingfish 2 platforms A & B (21 wells each), Halibut 1 platform (21 wells) and Marlin 1 platform (21 wells). Further development may be expected at the Tuna and Mackerel accumulations. Of necessity, development wells are drilled from platforms and well drainage spacing is achieved by directional drilling. This of course does not lend itself to the flexibility of well spacing concepts as applied on land, but given a good drilling rig capacity and a rigorous control of pre-determined deviation, a good pattern can be obtained, and this may well prove to be more symmetrical than that adopted on land.

Assessment and development drilling in Australia in the near future will undoubtedly take place in the Gippsland Shelf (Tuna, Mackerel), the Cooper Basin (Tirrawarra etc.), the Northwest Shelf (Goodwyn, Angel, Rankin and N. Rankin), and perhaps on the Mereenie - Palm Valley structures. Unfortunately, some of these structures suffer from severe faulting and/or permeability pinch-outs and it is unlikely that an overall symmetrical well spacing design such as that at Barrow Island, will be achieved. However, structures such as Tirrawarra and Goodwyn could well be subdivided into blocks or cells of reasonable homogeneity within which symmetrical spacing and therefore maximum ultimate recovery can be realised. As soon as a production history of sufficient magnitude (in terms of time, volume, and pressure) to permit definition of the nature of the depletion mechanism has been established, then decisions will be taken on the need for more wells, or better still, whether some of the development wells can be relegated to the status of "observation" wells.

To summarize, the determination of a field development pattern should be established from - in this order -

(a) Reliable seismic coverage.

(b) Prolonged stabilized production testing (not drill stem tests) of the discovery well in order to establish radius of drainage (during the test period and subsequent pressure build-up), the presence of faults and/or permeability pinch-outs, and the water contact and its effectiveness. Static pressure gradients should be run before and after production bottom hole pressure measurements.

(c) Step-out wells located according to structural information and geometrical indications derived from the testing just mentioned.

(d) Prolonged stabilized testing of these step-out wells and, if possible, the observation of the effects of the tests on the original well. Again, radii of drainage should be determined and permeability barriers and/or faults and water contacts located. From this, the field may be separated into blocks or cells, each of which may have to have its own development pattern.

(e) Development drilling with, if conditions permit, a five-spot interference program which, at this stage of correlated information from previous wells, should result in maximum ultimate recovery with minimum drilling.

(f) In all cases, the oil or gas/water contact should be established and its activity if any, assessed. The same applies to a gas/oil contact. Again, static pressure gradients are of utmost importance.

(g) These procedures may appear to be simple, but too often they are not; the maximum amount of information, both field and laboratory, should be obtained from each well - stratigraphic configuration from subsurface contours, electric and other logs, sidewall cores, formation interval tests, cuttings and full cores, extensive laboratory work, and the calculation of skin (turbulence) effect. Correlation should be thorough, but completed as fast as possible.

(h) Finally, in planning the development of a prospect, a priority requisite is laboratory PVT work, preferably on a differential liberation basis. In the absence of this, correlation charts or flash liberation results may be used, but these seldom supply the accuracy desired. With this in mind, it may be of interest to know that the Bureau of Mineral Resources will be fully equipped in the foreseeable future to carry out PVT studies. All PVT studies submitted so far by companies operating in Australia have been performed in the United States and France. It is generally accepted that the shorter the distance and time between sampling and laboratory work, the more representative of reservoir conditions will be the results from the sample. Of about equal importance are full (unslabbed) core analyses which provide permeabilities and residual phase saturations. Slabbed cores are of little use to those outside the spheres of palaeontology, palynology etc; while these disciplines are extremely useful in the long term, the urgency of field development requires full cores, as far as possible protected against external and unnatural damage. Slabbing, of course, negates these requisites and the residual fragments after other needs have been satisfied can only provide parameters such as effective porosity and, with good fortune, Klinkenberg permeability. Parameters based on these fragments contribute very little to the final decisions on field development.

So the initial targets are -

- adequate seismic coverage

- the maximum possible determination of reservoir properties (i.e. full cores, complete suites of logs, extended testing etc.)

- Rigorous mud quality control to minimize formation damage and its inherent "down hole choke" effect.

In other words, the reservoir should be appraised as clearly as possible, and as soon as possible, before a development plan is formulated.

Therefore, to equate maximum ultimate recovery to minimum expenditure, it is essential to spend as much as is necessary in time and money in obtaining, collating, and interpreting all pertinent data obtained during the primary stages of an oil/gas field. As in the Humble example, this can result in substantial savings in the long run.

Conclusion

To summarize, Australia has provided 54.8 percent of the money required so far for the exploration, development, and production of the oil and gas fields currently in production or being proposed for production.

The Australian equity in current production is 46.4% for oil and 39.6% for gas; the equity in the reserves providing that production is 47.5 percent.

To attain self-sufficiency to 1985 a further 2650 million barrels of recoverable oil will need to be proved.

The production rate in 1985 will need to be about 1,230,000 barrels per day.

To meet these discovery and production rates the very heavy demand for high risk exploration capital and for the more secure development capital must be met. This capital will be of the order of $1150.0 million for exploration and $1,000 for development and production facilities. To this total of $2150.0 million must be added the cost of major pipelines, stabilisation plants, compressor stations and other major installations, which could add another $1000 million. However, the final investment will depend greatly on the area and nature of the discovery and the market it is to serve.

References

(1) Australian Mineral Industry 1971 Review
Petroleum Chapter Pre-print Page 27, Table 22

(2) The Petroleum Newsletter Vol. 50, Page 44, Table 1

(3) Oil and Australia 1972, Page 24, Capital Investment in Marketing and Refining in Australia

(4) Australian Mineral Industry 1971 Review
Petroleum Chapter Pre-pring Page 21, Table 13

(5) Australian Mineral Industry 1971 Review
Petroleum Chapter Pre-print Page 26, "Qualifying Notes"

(6) B.M.R. Record 1966/205 Expenditures on Petroleum Exploration and Development to 31 December 1965. Table 9(a) and
The Petroleum Newsletter Nos. 30, 34, 38, 42, 36 and 50

(7) Frick; Petroleum Production Handbook Vol. II p.33-13, 14 & 15

ORIGIN OF PRIVATE ENTERPRISE FUNDS

Year	Source of Funds						Total
	Australian		Re-investment		Overseas		$
	$	%	$	%	$	%	
To 31.12.65	113,039,434	38.00	5,953,700	2.00	174,836,574	60.06	293,829,708
1966	15,936,309	27.09	3,617,356	6.15	39,267,842	66.72	58,819,507
1967	25,030,352	28.21	12,658,851	14.26	51,026,790	57.53	88,715,993
1968	51,880,039	42.20	19,300,124	15.68	51,810,246	42.12	122,999,409
1969	94,443,393	57.30	14,169,909	8.59	56,206,152	34.11	164,810,454
1970	49,533,296	36.29	24,737,963	18.13	62,209,516	45.58	136,480,775
1971	84,034,843	54.20	41,101,850	26.51	29,898,887	19.29	155,035,580
Total to 31.12.71	433,897,666	43.01	121,539,753	11.81	465,265,007	45.18	1,029,641,426

FIG I

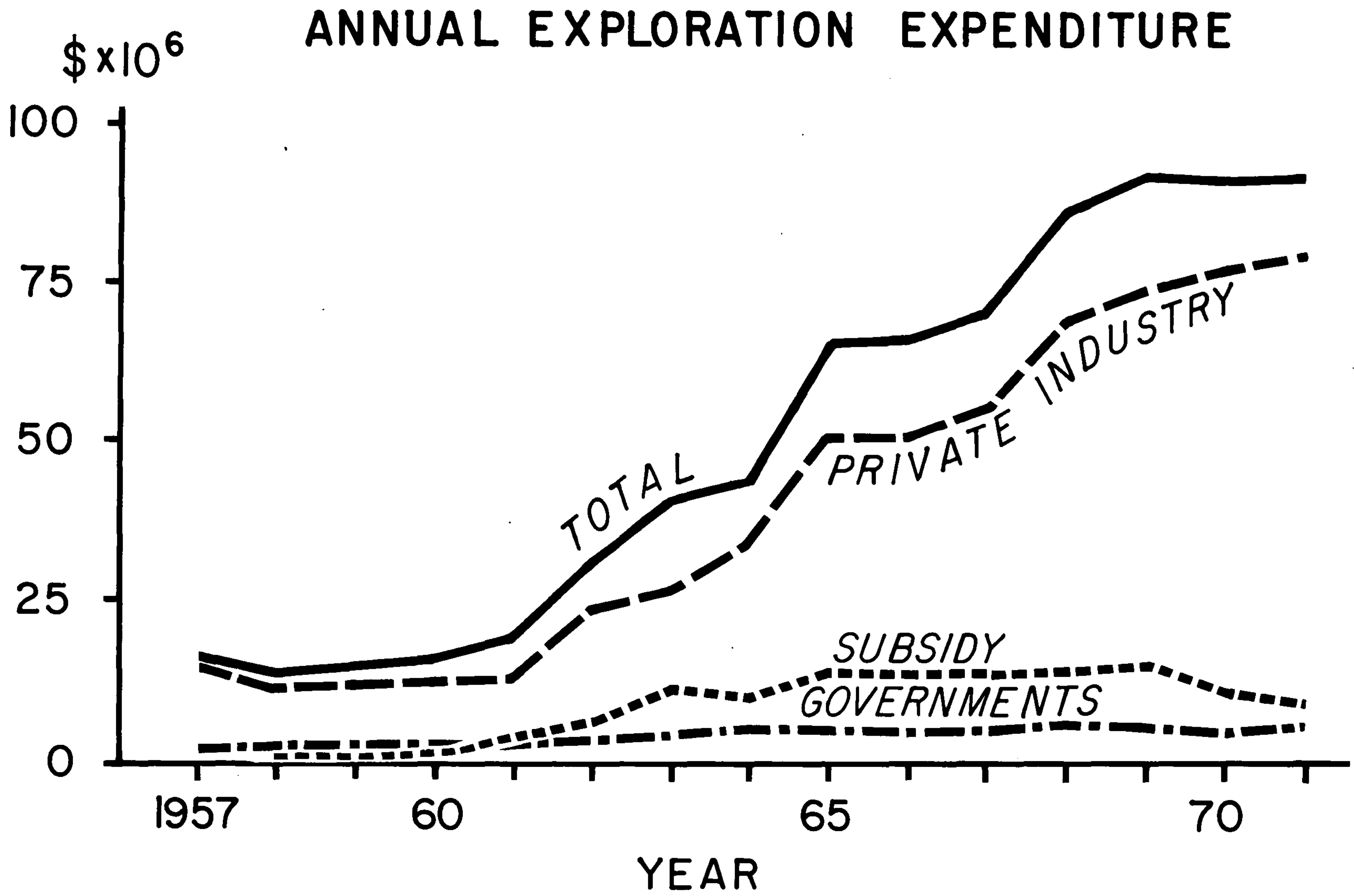

ANNUAL EXPLORATION EXPENDITURE
$ x10^6
100
75
50
25
0
TOTAL
PRIVATE INDUSTRY
SUBSIDY
GOVERNMENTS
1957
60
65
70
YEAR

FIG 2

ORIGIN OF PRIVATE INDUSTRY FUNDS

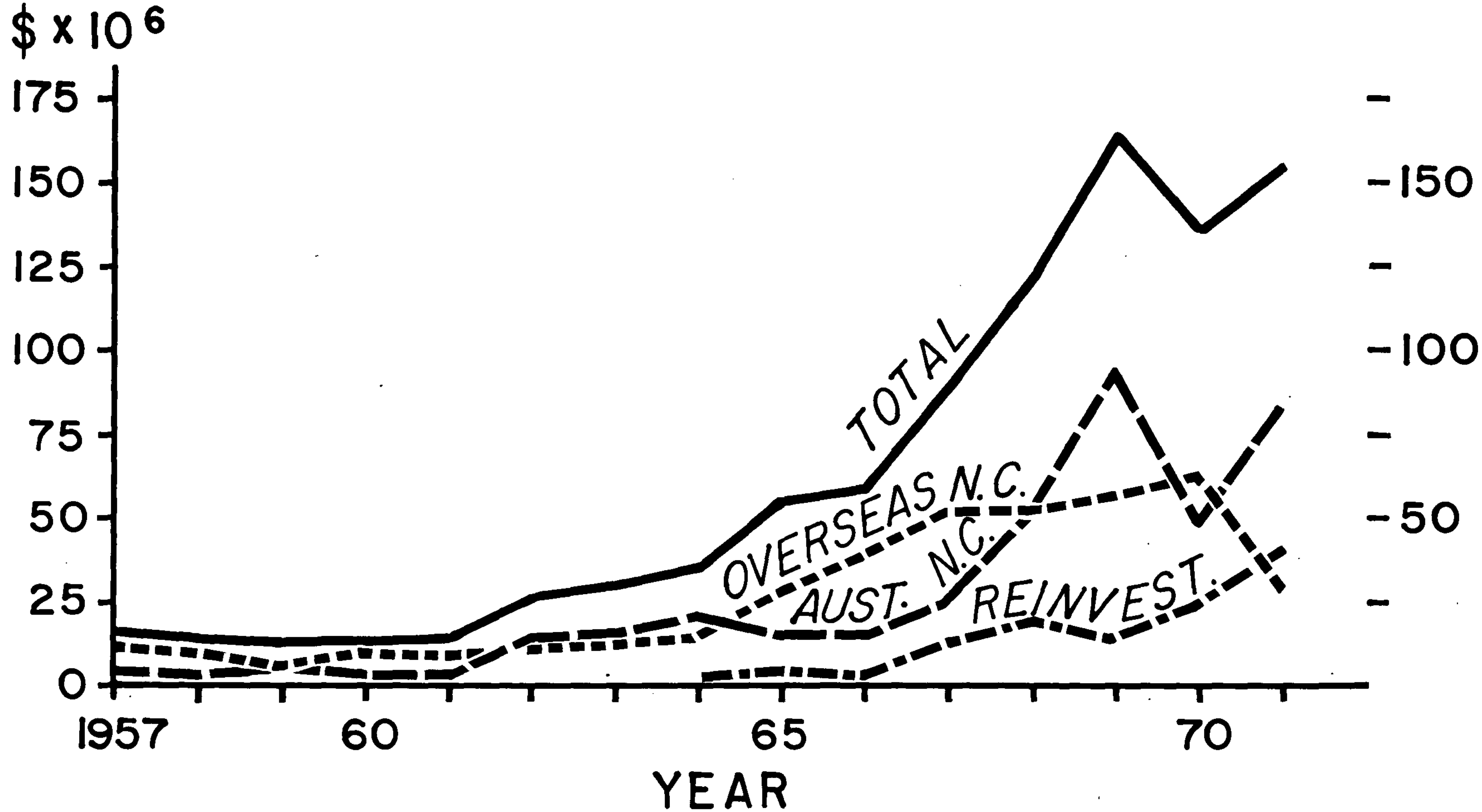
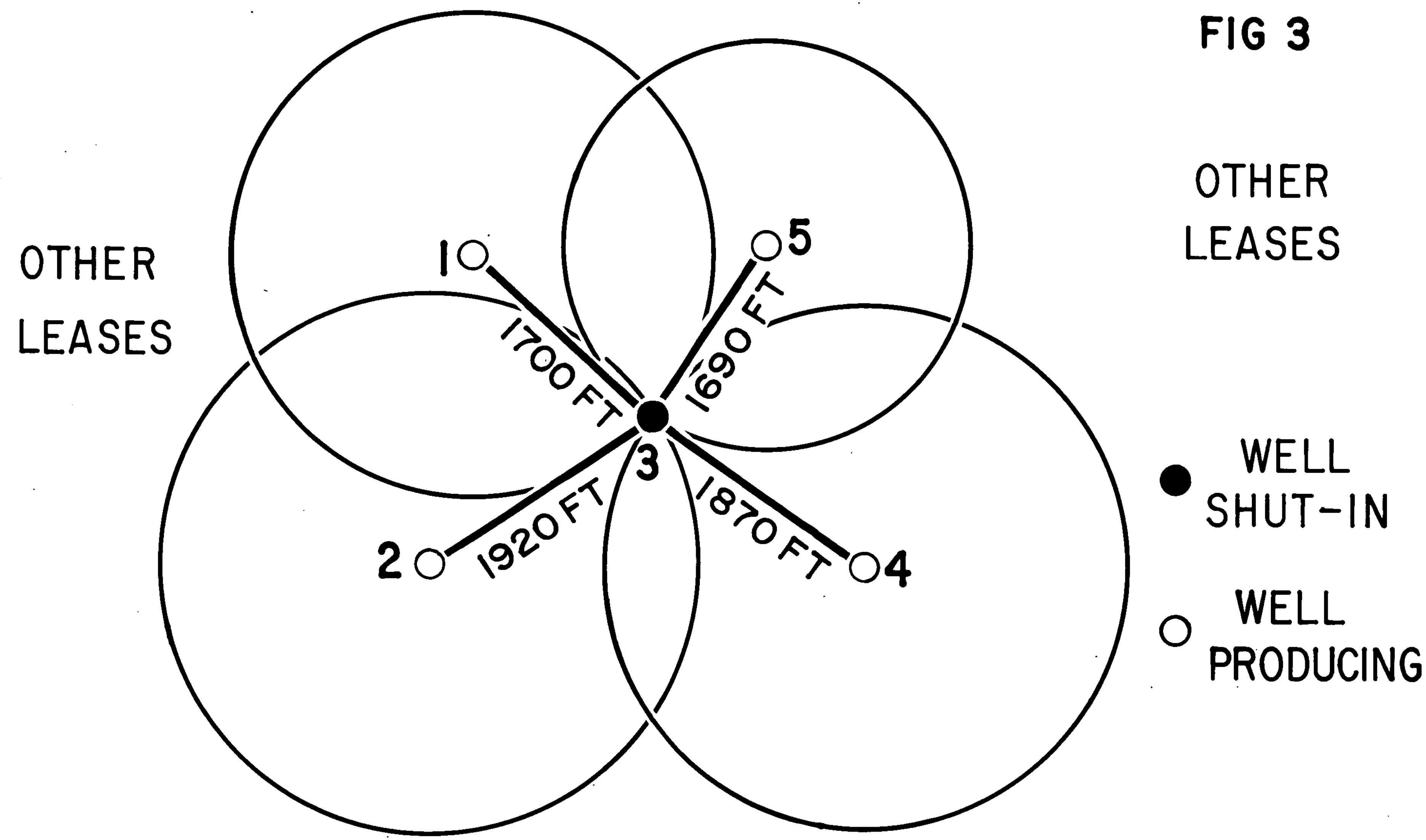


FIG 3



INTERFERENCE TEST — HUMBLE J-F LEASE

FIG 4

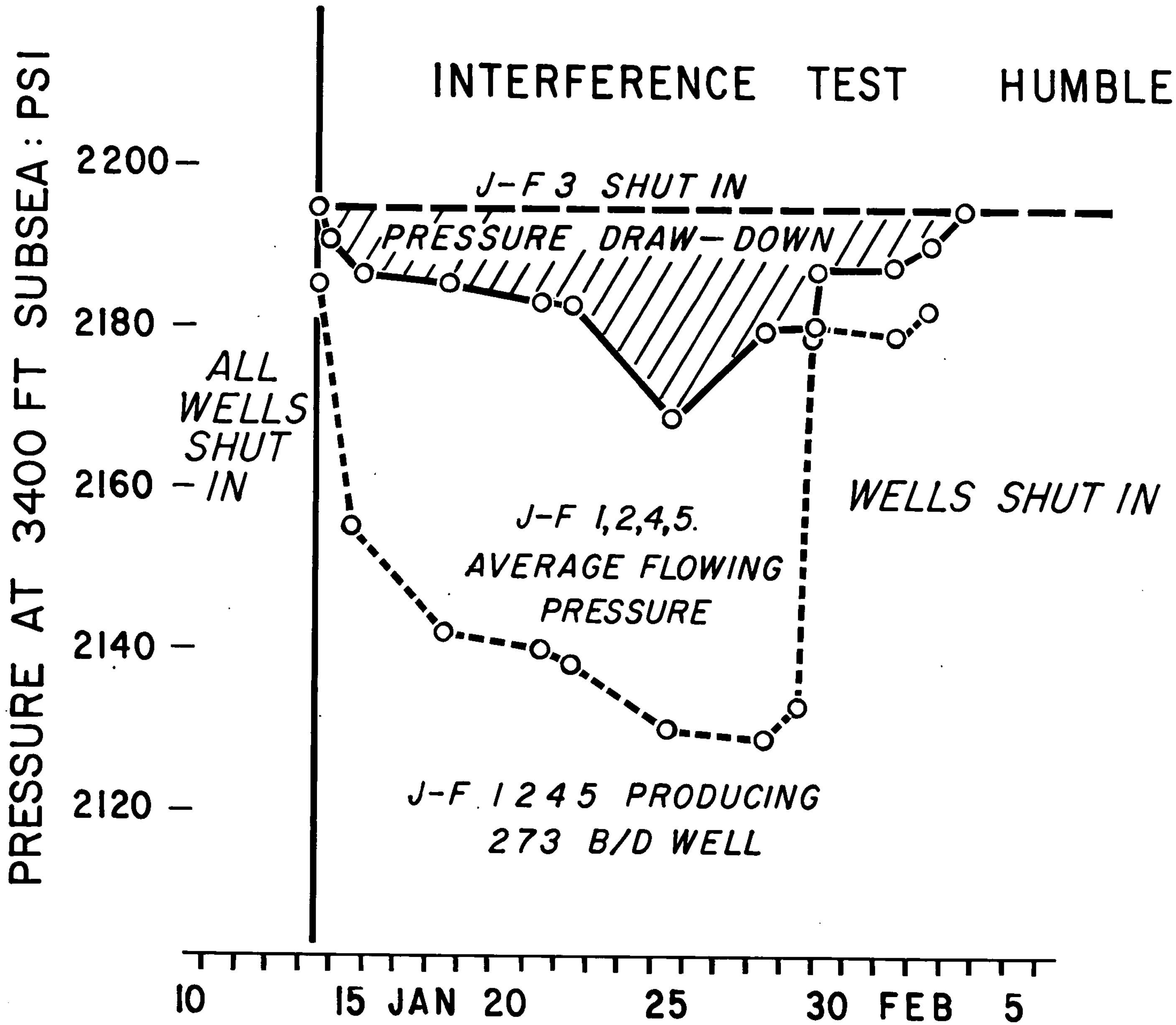
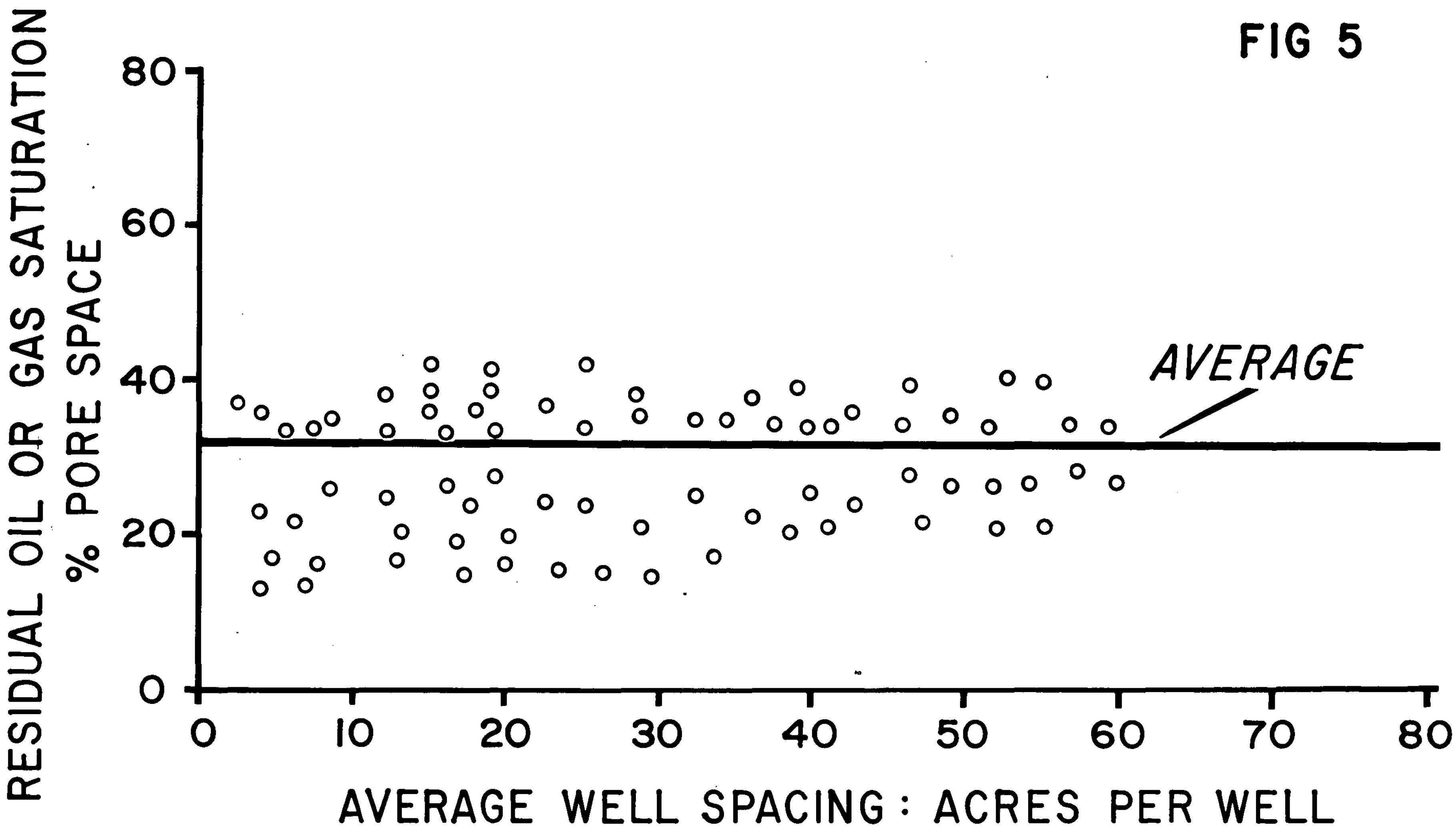

INTERFERENCE TEST HUMBLE J-F LEASE
PRESSURE AT 3400 FT SUBSEA : PSI
2200
2180
2160
2140
2120
J-F 3 SHUT IN
PRESSURE DRAW-DOWN
ALL WELLS SHUT - IN
WELLS SHUT IN
J-F 1,2,4,5.
AVERAGE FLOWING PRESSURE
J-F 1 2 4 5 PRODUCING
273 B/D WELL
10
15 JAN 20
25
30 FEB
5

FIG 5



REFERENCE: SPECIAL STUDY COMMITTEE ON WELL SPACING AND ALLOCATION OF PRODUCTION – API 1945