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EROMANGA AND COOPER BASINS

BIG LAKE FIELD STUDIES

OPEN FILE TECHNICAL REPORTS AND DATA

Submitted by

South Australian Oil and Gas Corp. Pty Ltd, Delhi Petroleum Pty Ltd and Santos Ltd
1998

Enquiries: Customer Services
Ground Floor
101 Grenfell Street, Adelaide 5000

Telephone: (08) 8463 3000
Facsimile: (08) 8204 1880

PRIMARY INDUSTRIES AND RESOURCES SA

HYDRAULIC FRACTURING FEASIBILITY
PATCHAWARRA AND TIRRAWARRA SANDS -

BIG LAKE FIELD

COOPER BASIN - SOUTH AUSTRALIA

OCTOBER, 1981

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HYDRAULIC FRACTURING FEASIBILITY

PATCHAWARRA AND TIRRAWARRA SANDS

BIG LAKE FIELD

COOPER BASIN - SOUTH AUSTRALIA

PREPARED FOR

SOUTH AUSTRALIAN OIL AND GAS CORPORATION PTY. LTD.

OCTOBER 1981

C. L. LOVE
MANAGER, EXPLORATION AND
PRODUCTION SERVICES

SCIENTIFIC SOFTWARE CORPORATION

October 14, 1981

Mr. S. B. Devine
South Australian Oil and Gas Corp.
226 Melbourne Street
North Adelaide, South Australia 5006

Dear Mr. Devine:

Enclosed are five copies of our report on the fracture simulation study of the Big Lake Field. This version is complete except for log analysis trace plots which will be sent separately. One copy of Exhibits of computer analysis printout are furnished separately.

We see the engineering, geological and well log analysis as being essentially complete for the limited amount of data available at this time. As more data becomes available the project should be updated to improve field applications and reserves/economic estimates.

We appreciate the opportunity to be of service to you and anticipate being of further service during the fracture job design and evaluation.

Sincerely,

Chester L. Love
Manager
Exploration and Production Services

CLL:kab

Enclosures

First of Denver Plaza Building-18th Floor, 633-17th Street, Denver, Colorado 80202 / (303) 571-1111 / Cable: Bugler / Telex: 45-80

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INTRODUCTION

INTRODUCTION

An economic feasibility and preliminary treatment design study was made for developing the tight gas sand reserves of the Patchawarra and Tirrawarra sands of the Big Lake Field, Cooper Basin, South Australia. The analysis was based on performance results from a single well simulation model for massive hydraulic fracture completions combined with economic evaluation. The analysis was made on the basis of individual models for five separate layers in the Patchawarra and one model for the Tirrawarra sands. Performance was evaluated at two field locations based on the reservoir layer properties indicated by existing wells (Big Lake #1 and Big Lake #3) at the two locations.

To support the preliminary treatment design the following special efforts were undertaken: (1) a limited amount of special core testing was performed by the Halliburton Co., (2) limited geological review was made of the core samples and available core/sample description information, and (3) log analysis was made on two wells to evaluate in-place rock properties such as fracture gradients, clay contents and gas saturation in the sands.

The project develops a recommended completion, treatment and testing program which will be further modified as additional information is available. The project is designed to be a continuing effort with a field trip to Australia for report presentation and development of the detailed completion/testing schedule with follow-up consulting during the evaluation of the next well.

SUMMARY

SUMMARY

The economic and physical feasibility of hydraulic fractured completions in the Patchawarra and Tirrawarra sands of the Big Lake Field were evaluated using engineering/geologic design considerations and computer simulation to yield predictions of flow results under a range of treatment volumes. The analysis is based on design studies only as just one well in the Big Lake Field has been hydraulic fracture treated in the subject zone and it has not been tested for an extended period. The evaluation was made based on reservoir properties from logs, limited cores and drill stem tests in four wells in the field. The reservoir properties and test results are listed in Tables 1 and 2. Rock strength properties are assumed constant for all intervals. The analysis was based on 320 acre spacing only and no attempt was made to optimize spacing.

The study results indicate that hydraulically fractured treatments are a practical completion method for significantly increasing flow rates from the zones but that the completion interval and treatment design will need to be carefully tailored because of the high reservoir temperature (325° - 360°F) and the presence of interbedded, low compressive strength coals. The results using $0.60/MCF gas price indicated a range of optimum treatment volumes from 50,000 to 300,000 gallons (Table 3). The optimum treatment volume appears to be primarily a function of gas pore volume to be drained (Sg porosity for a constant drainage area of 320 acres) and the well location (separate volume versus Sg porosity trends for Location #1 and Location #3). (Fig. 2).

The summation of cash flow from all intervals based on $0.60/MCF gas price indicates that Location #1 would yield $1.3MM present value profit (PVP) based on 20% discount factor and 20 years of production. However under the same conditions, Location #3 is in a minor negative position (-$0.08MM). At Location #1, only one of the six intervals is in a negative PVP position and the PVP is strongly a function of the permeability x thickness product, Kgh (Fig. 4). At location #1, the PVP is also a reasonable function of kg·h except for the Tirrawarra where the low gas permeability relative to the larger treatment volume

apparently reduces the PVP (Fig. 5). At Location #3, three of the six intervals are in a negative PVP position with the Patchawarra intervals all in a low PVP position (-$.092MM to $0.136MM) that appears to be permeability-thickness dependent (Kgh) Fig. 4.

Evaluation at a gas price of $1.20/MCF significantly alters the PVP results in that both locations are in a positive position (except one interval at Location #1). Tirrawarra at Location #1 is somewhat better thant the overall trend when PVP is plotted agains kgh (Fig. 4). The PVP results appear to be a function of either gas pore volume or permeability thickness as indicated by Figs. 4 and 5. At this price overall PVP ranges from $6.27MM at Location #1 to $2.986MM at Location #3.

The results of the economics-simulation study indicate that the rock characteristics have a major impact on the treatment design and the economic results. The areal and interval variation in rock properties are strong enough that a field testing program needs to be undertaken in two or more locations to evaluate the probable economics of the overall field development. Detailed evaluation of the rock properties and the treatment design/results needs to be undertaken on a very complete basis that includes coring/log evaluation during the drilling and complete pre- and post-fracture evaluation by pressure transient production testing. A recommended test program is included in the Recommendations section.

RECOMMENDATIONS

RECOMMENDATIONS

1. Evaluate field development potential by completing new wells at Locations #1 and #3 with extensive pre- and post-fracture evaluation by specific intervals. These results should provide a realistic evaluation of the Patchawarra and Tirrawarra potential in the Big Lake Field.

2. Core the sand interval of interest. Analyze cores in all key intervals for porosity, permeability, relative permeability to gas with connate water saturations, clay content, clay type, strength characteristics such as Young's modulus, Poisson's ratio, shear modulus and embedment tendencies.

3. Run a log suite of DIL, Gamma Ray, SP, BHC, CNL and FDC. Analyze logs for effective porosity, clay content, gas saturation and fracture pressure gradient.

4. Ensure hole is kept in-gauge as well as possible for log evaluation and cement bonding purposes. Utilize critical review of mud program, drilling hydraulics and past field experience to reduce washouts.

5. Review cementing practices to ensure segregation between completion zones. Interfaces between sand-coal-shale should be critically evaluated and squeezed if cement bonds are questionable.

6. Complete and test zones of interest sequentially from bottom to top using these guidelines:

   a. Run acoustic cement bond log and squeeze above/below treatment interval if poor bonding is indicated.

   b. Run base temperature log.

   c. Perforate limited intervals 2 holes per foot using casing type guns. Keep perforations at least 5 feet from sand-coal and sand-shale interfaces.

d. Breakdown perfs with cleanup acid and ball sealers under packer.

e. Flow test for 1 to 5 days.

f. Shut-in for pressure buildup for a period of at least twice the flow time.

g. Evaluate drawdown/PBU transient data and combine with log/core analysis to determine net pay, porosity and permeability to integrate into hydraulic fracture treatment design.

h. Run mini-frac by injecting 10,000 gallons Hygel 500 fluid down 3-1/2" tubing with 7" to 3-1/2" annulus open to monitor bottom hole fracturing pressure.

i. Run temperature log to evaluate frac height.

j. Fine tune frac design based on mini-frac results and interval gas pore volume ($SG \cdot \phi \cdot h$). Frac fluid using Howco Hygel 500 is recommended based on the 300+°F temperature. Use 20/40 sand with sand concentrations to be based on mini-frac and field test data. Pad volume should be approximately 30% of total fluid. Total fluid volume should be based on optimization results of this study combined with new data developed from the new wells.

k. Frac down 3-1/2" tubing while monitoring annulus bottom hole fracturing pressure on the annulus.

l. Run post-frac temperature log to evaluate frac height.

m. Pull out of hole with frac string.

n. Set drillable retainer above perfs using wireline.

o. Run 3-1/2" tubing with N, R nipples and sting into retainer.

p. Flow to cleanup and test for 21+ days.

q. Run bombs while flowing well. Shut-in two hours after on bottom. Leave shut-in at least twice the flow period. Run tubing plug above bombs if wellbore storage becomes serious. ?

r. Evaluate commerciality of zone.

s. If zone is indicated to be commercial, evaluate the place cement on top of the retainer and test next higher zone using the same guidelines. If zone is non-commercial, squeeze off zone below retainer before proceeding to next test interval. After upper zone is evaluated clean out wellbore to expose all final completion zones in commingled state. Complete with tubing shoe set above highest producing zone.

7. Evaluate reserves and fracture job effectiveness after final completion by simulation matching of pressure transient/production data and cumulative production/static reservoir pressure data.

Estimated reservoir propeties at the Big Lake #1 and #3 evaluation locations are listed in Table 1.

Well Log Analysis

Twelve samples of core from four wells (Big Lake #1, #3, #4, #5) were examined for sedimentary structures and lithologic description. The limited number and distribution of samples is not a good representation of the Patchawarra section because they were taken in lithologies with a high gamma ray response. Both the Patchawarra and the Tirrawarra have sand units with a much lower gamma response suggesting that those sands may have better porosity.

From this core material it is believed that the sands were deposited in a fluvial and deltaic environment. Most sands are quartzose with the usual quartz grain overgrowths, but quartz crystal growth in the form of "Herkimer Diamonds" seems prevalent below 9400'. "Herkimer Diamond" growth requires leaching and re-deposition of materials; thus, secondary porosity and diagenetic clay formation would occur simultaneously creating new porosity on one hand and reducing it to microporosity on the other.

Two samples from below 8600' Big Lake #1, in the upper Patchawarra, indicate that the environment of deposition is deltaic and the sand is lithic, composed of 10% quartz, 60% feldspar, and 30% lithic grains and clay. These samples are very fine grained and are probably not representative of sands with a lower gamma ray response. Kaolinite pore plugging reduces all porosity to microporosity.

"Herkimer Diamonds" were found in samples from Big Lake #3 and #5 at depth of 9400' and deeper. The "diamonds" appear to be a typical occurrence in the lower Patchawarra where they grow within a silty clay matrix containing medium to coarse lithic grains, and appear to nucleate as a blade within a feldspar crystal (possibly a graphic granite). As connate waters decompose the feldspar, the quartz grows and the residue becomes kaolinite. Secondary porosity is formed by the decomposition process, but whatever space is available, after the quartz crystal growth and the prior cementation, it is subsequently filled with kaolinite. In addition, coals and beach sand deposits are also part of the lower Patchawarra. Sand composition is 72% quartz, 25% feldspar and 3% carbonaceous material with the primary porosity being plugged by kaolinite.

Conglomerates in Big Lake #4 below 9800' are representative of beds in the Tirrawarra, and are believed to be braided stream deposits. They are very quartzose, being composed of quartzite clasts and quartz sand lenses. Sand grains in the lenses exhibit abundant quartz overgrowth and silty clay cement. Any remaining primary pore space is filled with kaolinite and minor quartz crystal growth.

In his thin section study for South Australian Oil and Gas Corporation, Almon indicates that illite is also present as a pore lining. This is common in high temperature gradient areas, as indicated by Big Lake #5 (~ 3°F/100'), where diagenetic clay formation probably began to form when the sediments were buried to a depth of 2000'. Considerable time has elapsed since the onset of diagenetic clay formation (2000') and the present depth of ~ 9000' for the formation of diagenetic clays; however, this clay has abundant microporosity which can be tapped by fracturing the reservoir.

In summary, conglomerates and medium-coarse sands of the Tirrawarre Formation appear to be a braided stream deposit, overlain by delta plain, cravasse splays, beach ridges, and point bars of the younger Patchawarra section. Microporosity within the diagenetic clays can contain hydrocarbons which may be produced by fracturing the reservoir.

Prior Completion/Production Data

Prior DST/completion/production data are listed in Table 2. The DST data indicated flow rates of 100 to 2,300 MCFD from relatively long test intervals. However, completion testing, after acidizing, of short intervals (8' to 60') through jet perforations yielded no gas production in Big Lake #3 and only 300 to 500 MCFD from specific intervals in the Big Lake #1, #3 and #5 wells. One well, Big Lake #4, was hydraulic fracture treated with 64,000 pounds of 20/40 sand in 43,000 gallons of fluid. After fracing the well tested 500 MCFD. The small treatment volume may make this job unrepresentative of results to be achieved with larger frac jobs.

Poor cement bonds, test tool failures and inadequate breakdown volumes make the production/test data unconclusive. These problems are accentuated by the high bottom hole temperatures (300+°F), and severe hole washouts.

DISCUSSION

DISCUSSION

Field Description

Big Lake Field is a fault bounded anticlinal block trending SW-NE in South Australia's Cooper Basin (Fig. 1). To date, commercial production in Big Lake is from the Toolache and Epsilon formations which produce without fracture stimulation. Four wells have penetrated the deeper Patchawarra and Tirrawarra horizons and tests have shown these sections to be gas bearing but tight (Table 2). A detailed geologic study by South Australian Oil and Gas indicated significant accumulations of gas in the Patchawarra and Tirrawarra. The subject sequences are 2,000'± of fluviatile sandstones with interbedded coals and dense shales.

Project Description

This project was initiated to evaluate the feasibility of developing the Big Lake Patchawarra/Tirrawarra reserves by completions utilizing massive hydraulic fracturing to develop permeable drainage channels. The three key elements to a project of this nature are pre-job planning, detailed monitoring and control during the treatment and post-frac analysis. This report focuses on the planning stage with emphasis on evaluation of expected simulation performances based on the fractured well production rates and evaluation of project economics.

Fracture Job Simulation And Economic Analysis

The project concentrated on estimating interval rock properties and then optimizing fracture design, predicting gas flow rates and calculating present value profit (PVP) economics for selected Patchawarra (zones 85-1, 86-8, 89-3, 92-1 and 93-2) and Tirrawarra completions at two, 320 acre sites (Locations #1 and #3). The reservoir properties used in the evaluation are listed in Table 1. A computer model that combines fracture dimension calculations, infinite conductivity type curve flow rate predictions and present value economics (U.S. tax basis) was used for preliminary optimization of the size of fracture simulation jobs for each zone at Locations #1 and #3 (Table 3). The comparative use of this technique is valid but the actual numbers may be high for three reasons: (1) calculated fracture lengths based on fluid rheology and rock property data have been shown to be about 40% optimistic to those inferred from post-frac simulator history matching, (2) infinite conductivity type curves tend to give inflated early time production rates which adversely affect present value production rates, and (3) Australian and U.S. tax law differ in the depreciation treatment of tangible expenditures thereby causing the U.S. calculation of present value dollars to be optimistic compared to Australian tax treatment. The job size optimization results of this analysis for $0.60/MCF gas price for the specific completion intervals are plotted in Figures 6-31 and are summarized in Table 3. The optimum job sizes range from 50,000 gallons to 300,000 gallons. The optimum job size is plotted versus net gas pore volume and permeability x thickness in Figs. 2 and 3. These plots indicate that the optimum job size appears to be a function of net gas pore volume with specific trends for each location. The data does not show a clear relationship to permeability x thickness although permeability contrasts probably strongly affect the two trends in the Sg x porosity crossplot.

To account for the historical/theoretical frac length comparison a 40% reduction in calculated fracutre length was applied and decline curves (Figures 30-31) were generated for the zones under consideration by use of a finite difference, fractured gas well simulator which handles finite capacity fractures. These production data were then incorporated into a separate, rigorous economic model set up to handle the prevailing economic conditions. The economic results of the analysis for casing $0.60/MCF gas ($.427 net) and $1.20/MCF gas ($.867 net) are shown in Table 4. The present value profit (PVP is shown as a function of gas pore volume and gas permeability thickness in Figs. 4 and 5. These plots indicate that either parameter could be used to estimate well economics.

The economic performance data for the $0.60/MCF gas price indicate that, Location #1 is profitable in all intervals except the 85-1 sand and that at Location #3 only two of the significant intervals show a profit. The difference in performance is probably a function of the lower permeability x thickness values at Location #3 which control drainage rate into the fracture flow system. PVP appears to be a directly related function to permeability-thickness as shown in Fig. 4. PVP is shown versus Sg x porosity in Fig. 5 and shows a reasonable trend for the Patchawarra.

Economics run at $1.20 gas price indicate that both locations would have satisfactory economies at this price. PVP at $1.20 price is shown as a function of $\$S\phi h$ and Kgh in Figs. 4 and 5. PVP data is shown in Table 4 for each interval and location.

Well And Fracture Treatment Design

Several formation or borehole conditions posing significant hazards to effective fracturing are: (1) washouts, (2) poor cement bonding, (3) closely interbedded sand, shale and coal with distinct interfaces and strongly constrasting strengths, (4) relatively low strength and high embedment characteristics of the sands, (5) potential rock sensitivity to completion fracture fluid chemistry, and (6) high bottom hole temperatures with resultant limitations on tool performance and frac gel stability.

The problem of washouts affects log interpretations and obtaining good cement jobs and can best be attacked by control of mud properties and drilling hydraulics. The need for competent interval segregation is high so that good cement bonding is essential. Maintaining gauge hole, using a scavenger slurry, equipping the casing with centralizing and scratches at key points and reciprocating the casing during cementing are keys to obtaining a good cement job. Evaluation of the bond by CBL and remedial squeezing, if necessary, are secondary keys to obtaining a good bond. Use of "rough coat" on casing should be considered.

Coal commonly occurs at the base of objective sands. The low compressive strength of the coal presents a potential escape point for the fluids at pressures below the frac gradient of the sand bodies. Historically, fracture treatment success ratio is not high where coals are interbedded. Probably the best ways to minimize the coal effects are to (1) keep perfs at least 5' away from coal, (2) keep treating rates and pressures relatively low, and (3) ensure that coal/sand interface has a good casing cement bond.

The high bottom hole temperatures (320°+F) primarily have an effect on the frac gel stability and the gels' ability to carry sand. Field and lab experience indicate that a crosslinked system becomes very unpredictable at -300'. Recent work with thermodynamic models predicting formation temperatures during and after fracturing (Exhibit D) show less cooling than previously thought. Therefore, a non-crosslinked frac fluid, such as Howco Hygel 500 is recommended. The presence of CO_2 in the reservoir gas may also affect the gel stability.

A controlled pre- and post-frac testing program is essential for evaluating individual interval performance and determining the overall reservoir potential. A program listed in the Recommendations section is designed to evaluate frac job results and provide a basis for improving future frac jobs.

Special Core Tests For Fracturing Or Stimulation

The Halliburton Company performed strength tests on four selected core samples including one coal sample. The strength parameter data is shown in Table 5. The coal properties are in strong contrast to the sands, e.g. the shear modulus is 0.2 compared to 1.0 for the sands. Acid flow tests were incomplete due to rock being too tight for testing in all except one sample. The one sample tested did not show any detrimental effects from acidizing. Previous test reports indicated that sand embedment might be a problem but no embedment tests were run for this project. The Halliburton detail report is shown in Table 6.

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*Exhibits are furnished as one separate copy only and are not bound with the report.

TABLE 1

Reservoir Properties

Location #1	Zone	Depth (FT)	ϕg	Kg (md)	h (FT)	ϕgh (FT)	Kgh (md)	Pi (psi)	BHT°F
Patchawarra	85-1	8515	.039	.016	22	0.80	0.30	4163	325
	86-8	8684	.07	.065	20	1.40	1.30	4246	330
	89-3	8934	.074	.105	90	6.66	9.45	4368	338
	92-1	9232	.053	.045	50	2.65	2.25	4543	350
	93-2	9342	.08	.175	38	3.04	6.65	4560	350
Tirrawarra		9629	.072	.03	100	7.20	3.00	4600	360
Location #3									
Patchawarra	85-1	8714	.063	.065	37	2.33	2.40	4261	331
	86-8	8893	.071	.130	32	2.27	4.16	4349	336
	89-3	9206	.069	.062	64	4.41	3.97	4502	346
	92-1	9499	.050	.045	20	1.00	0.90	4706	359
	93-2	9622	.050	.045	20	1.00	0.90	4706	350
Tirrawarra		9780	.090	.030	40	3.60	1.20	4720	360

* ϕg = gas pore volume fraction
= Sg x porosity

** Net feet of reservoir

TABLE 2

DST and Completion Review - Big Lake #1, #3, #4, and #5

A. DST

Well	Depth, Ft.	Zone	Qg (MCFD)
BL #1	8965-9162	89-3,90-0, 90-4	300
	9326-9418	93-2	560
	9447-9702	Tirrawarra	3100
BL #3	9170-9297	89-3, 90-0	121
	9835-10020	Tirrawarra	1300
BL #4	9003-9200	89-3	425
	9765-9905	Tirrawarra	507
BL #5	9370-9550	Tirrawarra	2300

Note: Several other zones were tested at rates "too small too measure" (TSTM). Tool malfunctions, short flow times and short shut-in times made qualitative evaluation of open hole DST data questionable.

B. Completion

Well	Perforated Depth, Ft.	Comments
BL #1	9600-9660 (Tirrawarra)	31 of 48 shots misfired. Acidized with 400 gallons 9% HCL - 6% HF at .25 BPM. Tested at 430 MCFD.
	9497-9505 (94-9)	Acidized with 550 gallons HCL-HF. Tested at 1.7 MMCFD declining to 340 MCFD.
	9336-9360 (93-2)	Broke down with 315 gallons diesel, 105 gallons 9% HCL - 6% HF. Tested at 500 MCFD.

TABLE 2 - (CONT'D)

Well	Perforated Depth, Ft.	Comments
BL #3	9930-9939 9915-9925 9898-9908 (Tirrawarra)	Acidized with 500 gallons 7-1/2% MCA, 1,000 gallons HF, 500 gallons 7-1/2 MCA. Tested no gas.
	9490-9520 (92-1)	Acidized with 1,000 gallons MCA, 500 gallons 12% HCL - 3% HF at 1 BPM at 2,200 psi. Tested no gas.
BL #4	9854-9887 9840-9851 (Tirrawarra)	No acid breakdown made. Fracture treated under RTTS tool set at 9802. Blender and packer failed. Left rubbers in hole. Redressed packer. Fracture treated as follows: 25M gal. pre-pad 25M gal. Hygel pad 43M gal. Hygel with 64,000 pounds of 20/40 mesh sand. Tested at 9 BPM. Screened out at 9,600 psi. Tested 500 MCFD. No cleanup details.
BL #5	8554-8581 (86-8)	No details available.

TABLE 3

Fracture Optimization

Location #1	Zone	Opt. Job Size (MGAL)	Propped Length* (FT)
Patchawarra	85-1	50	360
	86-8	100	543
	89-3	300	460
	92-1	200	683
	93-2	150	716
Tirrawarra		300	569
Location #3			
Patchawarra	85-1	150	435
	86-8	150	602
	89-3	300	464
	92-1	50	361
	93-2	50	373
Tirrawarra		200	616

* Radial fracture length away from well. (Sometimes referred to as fracture half-length).

TABLE 4

Economic Summary*

Location #1	Zone	$0.60/MCF Present Value Profit (MM$)	$0.60/MCF DCFROR	$1.20/MCF Present Value Profit (MM$)	$1.20/MCF DCFROR	Investment (MM$)
	85-1	-.129	3.80	-.044	13.68	.232
	86-8	0.006	18.64	0.255	49.12	.264
	89-3	0.739	61.36	2.161	672.50	.668
	92-1	0.073	22.37	0.604	67.96	.480
	93-2	0.449	83.70	1.235	>1000.00	.350
	TR	0.186	24.35	1.127	68.90	.760
Total Well		1.324	29.07	6.270	183.20	2.754
Location #3						
	85-1	-.010	17.32	0.413	49.06	.441
	86-8	.136	29.09	0.680	113.80	.417
	89-3	.066	20.40	0.876	59.15	.753
	92-1	-.092	8.89	0.073	25.34	.260
	93-2	.089	9.15	0.078	25.80	.260
	TR	.191	13.75	0.311	33.91	.516
Total Well		-.082	16.00	2.986	58.89	2.647

* 20% Discount Factor

DCFROR - Discounted Cash Flow Rate of Return

TABLE 5

Special Core Analysis

A. Rock Mechanics

Well	Depth Ft	Zone	Young's Modulus (10^6 psi)	Poisson's Ratio	Shear Modulus (10^6 psi)
BL #3	9862	16' Above Tirrawarra	2.26	.24	0.91
BL #4	9791	Tirrawarra	3.16	.41	1.12
BL #5	9413	24' Above Tirrawarra	2.40	.28	0.94
BL #5	9276	Coal Base of 93-2 sd.	0.52	.33	0.20

B. Acid Flow Tests - 7-1/2% HCL with Fe Agent

Well	Depth Ft	Zone	Kg (md) Before	Kg (md) After
BL #3	9862	16' Above Tirrawarra	4.8	6.6
BL #1	8616	26' Below 85-1 Series		
BL #4	9791	Tirrawarra		
BL #5	9426	11' Above Tirrawarra	Kg too low for flow test	
BL #5	9578	Tirrawarra		
BL #5	9276	Coal Base of 93-2 sd.		

FORM 1012 R-6

TABLE 6

CHEMICAL RESEARCH AND DEVELOPMENT DEPARTMENT

HALLIBURTON SERVICES
DUNCAN, OKLAHOMA

No. F12-T064-81

LABORATORY REPORT

Date October 6, 1981

Mr. Bill Wilkinson
Halliburton Manufacturing & Services Ltd.
Malvern, South Australia

give below results of our examination of the submitted core samples.

Submitted by South Australian Oil and Gas Company

Marked

Well:	Big Lake 1,3,4,5 and Tirrawarra 5
Location:	Australia
Formation:	Patcharra and Tirrawarra
Depth:	8,616 - 9,862.5 feet

Purpose

These formation cores were submitted for the following tests and examinations: x-ray diffraction, acid solubility, rock properties, and immersion.

Conclusion

Laboratory testing was completed on the submitted core samples. The x-ray diffraction indicated the presence of a large quantity of clay minerals. Due to the presence of the clay minerals if an aqueous base fluid is used as a stimulation fluid, protection from possible clay swelling or particle migration should be considered.

The results of the laboratory testing has been reported in the Data Section of this report.

Testing conducted by Chemical Services is reported in Laboratory Report S30-B084-81.

Data

Immersion Tests

Effects of immersion under vacuum at 200°F (test temp.) for one hour in the following:

Sample No.	Depth (feet)	Fresh Water	2% KCl	2% KCl*	2% KCl**	7 1/2% MCA	6% HF	Kero-sene
1	8,616	NFR	NFR	NFR	NFR	VSAF	MAF	NFR
3	9,862.5	VSAF	VSAF	VSAF	VSAF	SAF	MAF	NFR
4	9,791	VSAF	VSAF	VSAF	VSAF	VSAF	SAF	NFR
9	9,426	NFR	NFR	NFR	NFR	VSAF	VSAF	NFR
11	9,578	NFR	NFR	NFR	NFR	VSAF	SAF	NFR
12	9,276	NFR	NFR	NFR	NFR	NFR	NFR	NFR

NFR = No fines released.
VSAF = Very small amount fines.
SAF = Small amount fines.
MAF = Moderate amount fines.
LAF = Large amount fines.

PD = Partially disintegrated.
CD = Completely disintegrated.
GR = Gelatinous residue formed.
PDis = Partially dissolved.
C = Completely dissolved.

* 0.5 gallon CLA-STA II compound per 1,000 gallons.
** Adjusted pH with 10 lb K-34 per 1,000 gallons.

Qualitative X-ray Diffraction and Acid Solubility Analyses

Sample No.	1	3	4	8
Depth (ft)	8,616	9,862.5	9,791	9,413
Acid Solubility, %*	0	0.1	0	0
Quartz	MJ	LG	MJ	MJ
Feldspar	TR	--	--	--
Calcite	--	--	--	--
Dolomite	--	--	--	--
Kaolinite	SM-MD	LG	MD-LG	LG
Illite	SM-MD	SM	SM-MD	SM
Smectite	--	--	--	--
Mixed Layer Clay	VS	VS	VS	VS
Chlorite	--	--	MD	--
Siderite	VS	VS	VS	VS-TR

Data (Cont'd)

Qualitative X-ray Diffraction and Acid Solubility Analyses (Cont'.

Sample No.	9	11	12**
Depth (ft)	9,426	9,578	9,276
Acid Solubility, %*	0.2	0	0
Quartz	LG	MJ	
Feldspar	--	--	
Calcite	--	--	
Dolomite	--	--	
Kaolinite	LG	MD	
Illite	VS	SM	
Smectite	--	--	
Mixed Layer Clay	VS	VS	
Chlorite	SM-MD	SM	
Siderite	VS	VS	

Coding	Reported Amount	Approximate Percentage Range
--	None Detected	Less than 0.1
TR	Trace	0.1 to 1.0
VS	Very Small	1.0 to 3.0
SM	Small	3.0 to 10.0
MD	Moderate	10.0 to 20.0
LG	Large	15.0 to 40.0
MJ	Major	40.0 to 100.0

* This is solubility in dilute hydrochloric acid as calcium carbonate only.

** This sample was primarily amorphous material.

Data (Cont'd)

Regained Permeability Tests (Nitrogen)

Sample Depth: No. 3, 9,862.5 feet
No. 8, 9,413 feet

PROCEDURE: The core plugs were oven dried prior to the initial nitrogen permeability measurements. The core plugs were then saturated in the test fluids and a measured volume was flowed through the core plug in the opposite direction. Fluid temperature 180°F. The plugs remained in their respective fluids for one hour prior to regained nitrogen flow for four hours and final permeability measurements in the original direction.

Sample No.	Initial Permeability (N_2), md	Fluid Flowed	Final Permeability (N_2), md	Test Pressure (psig)
3A	2.54	2% KCl Water*	3.02	200
8A		Fractured during testing		
3B	2.48	Kerosene	2.34	200
8B	0.181	Kerosene	0.109	800

* 0.5 gallon CLA-STA II per 1,000 gallons.

Rock Properties Tests

Sample No.	Depth (feet)	Young's Modulus (psi)	Poisson's Ratio
3	9,862.5	2.26×10^6	0.24
4	9,810	3.16×10^6	0.41
8	9,413	2.40×10^6	0.28
12	9,276	0.52×10^6	0.33

Remarks

The data in this report were given to Mr. Steve Marchang by Mr. M. A. McCabe during a telephone conversation on September 30, 1981.

The remaining cores from this project were stored in the Core Library.

Data Book Reference

The data presented in this report are recorded in Fracturing Book No. 4495, page 6; Fracturing Book No. 4479, pages 35 and 36; Materials Engineering Book No. 4449, pages 64 - 67; Analytical Book No. 4483, page 47; and Analytical Book No. 4496, page 6.

cc: Mr. A. B. Waters
Mr. R. M. Lasater
Mr. A. R. Jennings, Jr.
Mr. V. V. Hill
Mr. L. G. Moffatt
Mr. R. M. Johnson
Mr. W. K. Ott
Mr. Chester Love ✓
Mr. Steve Marchang

Respectfully submitted,

HALLIBURTON SERVICES

Laboratory Analyst
McCabe-Phelps-Rice-Blanton-Meiers
Ketchum-Anderson-Fitzgerald-pc

By M. A. McCabe
M. A. McCabe

TABLE 7

Core Descriptions

Big Lake #1 Core 3? 8616'
Upper Patchawarra

Hand specimen:

Sedimentary structures include: wave and current ripples, festoon crossbeds, clay clasts, sharp basal contact with black shale which contains wave ripples, horizontal burrows and sand streaks. (Cravasse splay over lagoonal shales).

Binocular:

Lithic sandstone, medium grained grading upward to very-fine grained, subrounded grains, 15% quartz, 75% feldspar, 10% mica and carbonaceous material, with kaolinite cement. Kaolinite fills the primary porosity and reduces it to microporosity.

Note: In the Core Laboratory report of October 6, 1981, X-ray analysis reports little or no feldspar content. It is believed that the binocular examination sees the feldspar grain, but that the internal structure is decomposed enough to reflect the secondary structures of quartz and kaolinite.

Big Lake #3 Core 3 9862.5'
Lower Patchawarra

Hand specimen:

Sedimentary structures include: festoon crossbeds, cut and fill within the black siltstone at the base. Grain size is granule to conglomerate. (Point bar?)

Binocular:

"Herkimer diamond" (quartz crystal) growth throughout the silty clay matrix with kaolinite intimately associated. The development of the crystal seems to be the result of decomposition of feldspar with the conversion of material to kaolinite and quartz crystals. Probably correlates to Big Lake #5, Core 1, 9396'.

Big Lake #4 Core 1 9791'
Upper Tirrawarra

Hand specimen:

Sedimentary structures include: flaser structure, shale clasts, some festoon crossbedding. (Braided stream)

Binocular:

Lithic sandstone, fine to very coarse, massive, poor sorting, subrounded grains, 50% quartz, 30% feldspar, 20% mica and lithic grains, with kaolinite cement. Only microporosity present in this rock. Trace oil stain?

Big Lake #4 Core 2 9810'
Upper Tirrawarra

Hand specimen:

Sedimentary structures are: wave ripples, poor sorting and massive bedding. (Braided stream?)

Binocular:

Quartose sand, fine to granule sized grains, medium gray, 85% quartz, 5% feldspar, and 10% lithic grains. Kaolinite fills in voids left between quartz overgrowths leaving only microporosity. Slight oil stain?

Big Lake #4 Core 2 9812'
Upper Tirrawarra

Hand specimen:

Sedimentary structures include: grading finer upward, micro-faulting, and healed fractures. (Braided stream)

Binocular:

Conglomerate composed of quartzite clasts, well rounded, sand lenses and streaks cemented with silty clay. Sand lenses are quartz grains with abundant quartz overgrowth. All pore space is filled with kaolinite. Some "herkimer diamond" growth noted. Grains are 95% quartz, 5% feldspar, and the pore space is filled with kaolinite leaving only microporosity.

Big Lake #5 Core 1 9426'
Upper Tirrawarra

Hand specimen:

Sedimentary structures are: parallel banding, 1/4 - 1/2" layers of similar grain size, dip is 10°. (Beach)

Binocular:

Medium gray, well sorted in thin layers, grains subrounded, 65% quartz, 25% feldspar, 10% lithic grains, with siderite and kaolinite cement. All primary porosity is plugged with kaolinite and siderite.

Big Lake #5 Core 1 9413'
Lower Patchawarra

Hand specimen:

Sedimentary structures include: parallel bedding, 10° dip. (Beach sand)

Binocular:

One-half inch layers of well sorted, subrounded grains, 72% quartz, 25% feldspar, and 3% carbonaceous material. All primary porosity is plugged by kaolinite.

Big Lake #5 Core 1 9396' (9336?)
Lower Patchawarra

Hand specimen:

Dark gray silty clay with "herkimer diamonds" developed throughout the matrix. (Delta plain?)

Binocular:

Medium to coarse lithic grains imbedded in silty clay matrix sprinkled with "herkimer" crystals growing in all directions. Kaolinite pods filling dissolved voids around the "herkimer" crystals, and plugs the secondary porosity. The quartz grows in opal like fashion.

Big Lake # 5 9276'
Lower Patchawarra

Hand specimen:

Bituminus coal, concoidal fracture, dense. (Delta plain)

Big Lake #1 Core 3 8633'
Upper Patchawarra

Hand specimen:

Sedimentary structures include: wave ripples, cut and fill, climbing ripples, current ripples, fine carbonaceous and micaceous streaks. (Delta Front)

Binocular:

Lithic sandstone, medium gray, very-fine to fine grained, 15% quartz, 75% feldspar, 10% mica and carbonaceous material, with kaolinite cement. Kaolinite reduces primary porosity to microporosity.

Big Lake #5 Core 2 9578'
Upper Tirrawarra

Hand specimen:

Sedimentary structures include: cross bedding, massive bedding, and parallel bedding. (Braided stream)

Binocular:

Medium to coarse grained, well sorted, subrounded, 90% quartz, 2% feldspar, 8% clasts and lithic grains. Quartz overgrowths, kaolinite and siderite combine to completely cement the rock leaving only microporosity.

FIGURES

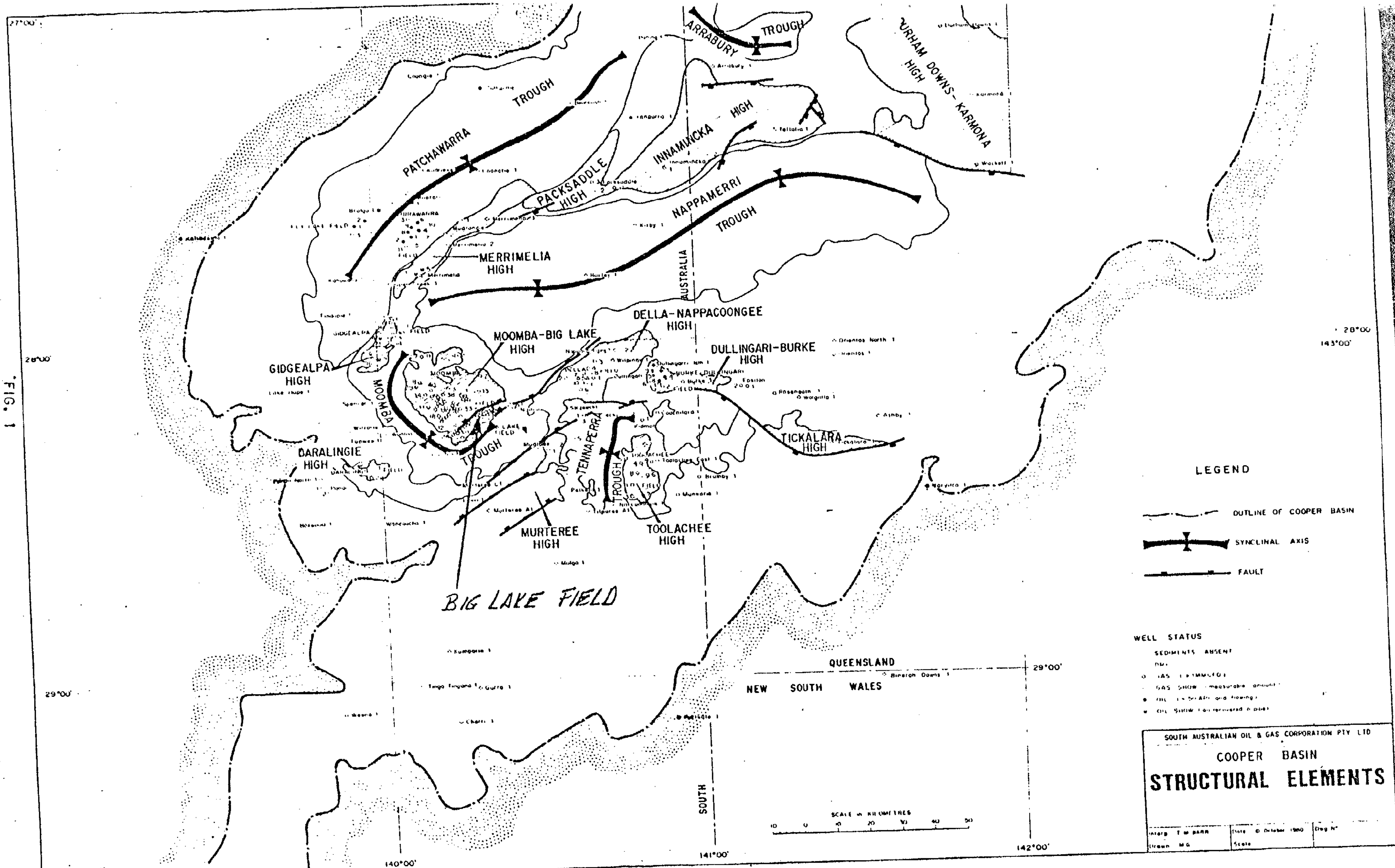
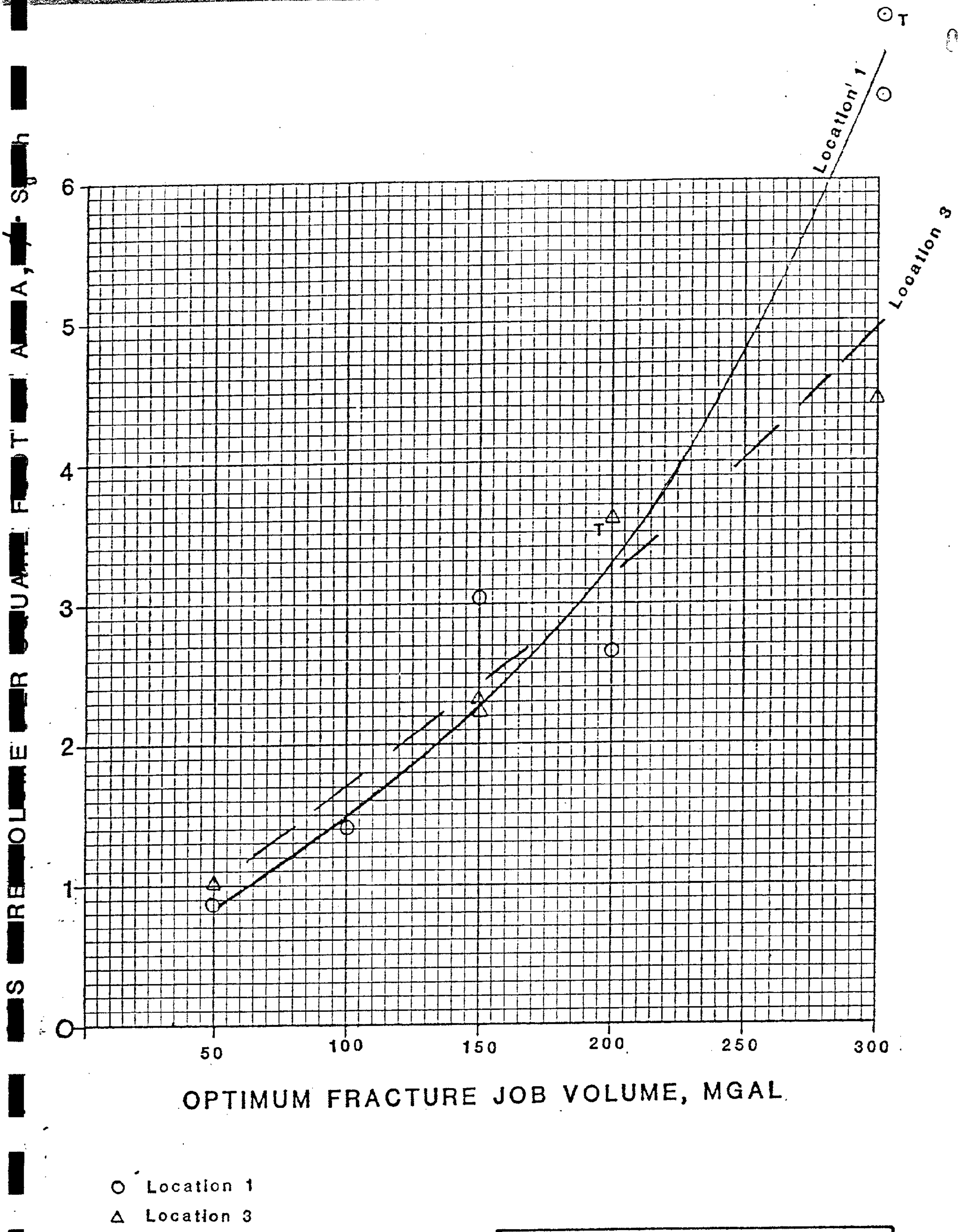

ARRABURY TROUGH
DURHAM DOWNS-KARMONA HIGH
PATCHAWARRA TROUGH
INNAMINCKA HIGH
PACKSADDLE HIGH
NAPPAMERRI TROUGH
MERRIMELIA HIGH
AUSTRALIA
DELLA-NAPPACOONGEE HIGH
MOOMBA-BIG LAKE HIGH
DULLINGARI-BURKE HIGH
GIDGEALPA HIGH
MOOMBA TROUGH
TICKALARA HIGH
DARALINGIE HIGH
TENNAPERRA TROUGH
MURTEREE HIGH
TOOLACHEE HIGH
BIG LAKE FIELD
LEGEND
OUTLINE OF COOPER BASIN
SYNCLINAL AXIS
FAULT
WELL STATUS
QUEENSLAND
NEW SOUTH WALES
SOUTH
SCALE IN KILOMETRES
10 0 10 20 30 40 50
27°00'
28°00'
29°00'
139°00'
140°00'
141°00'
142°00'
143°00'
SOUTH AUSTRALIAN OIL & GAS CORPORATION PTY LTD
COOPER BASIN
STRUCTURAL ELEMENTS

Fig. 1

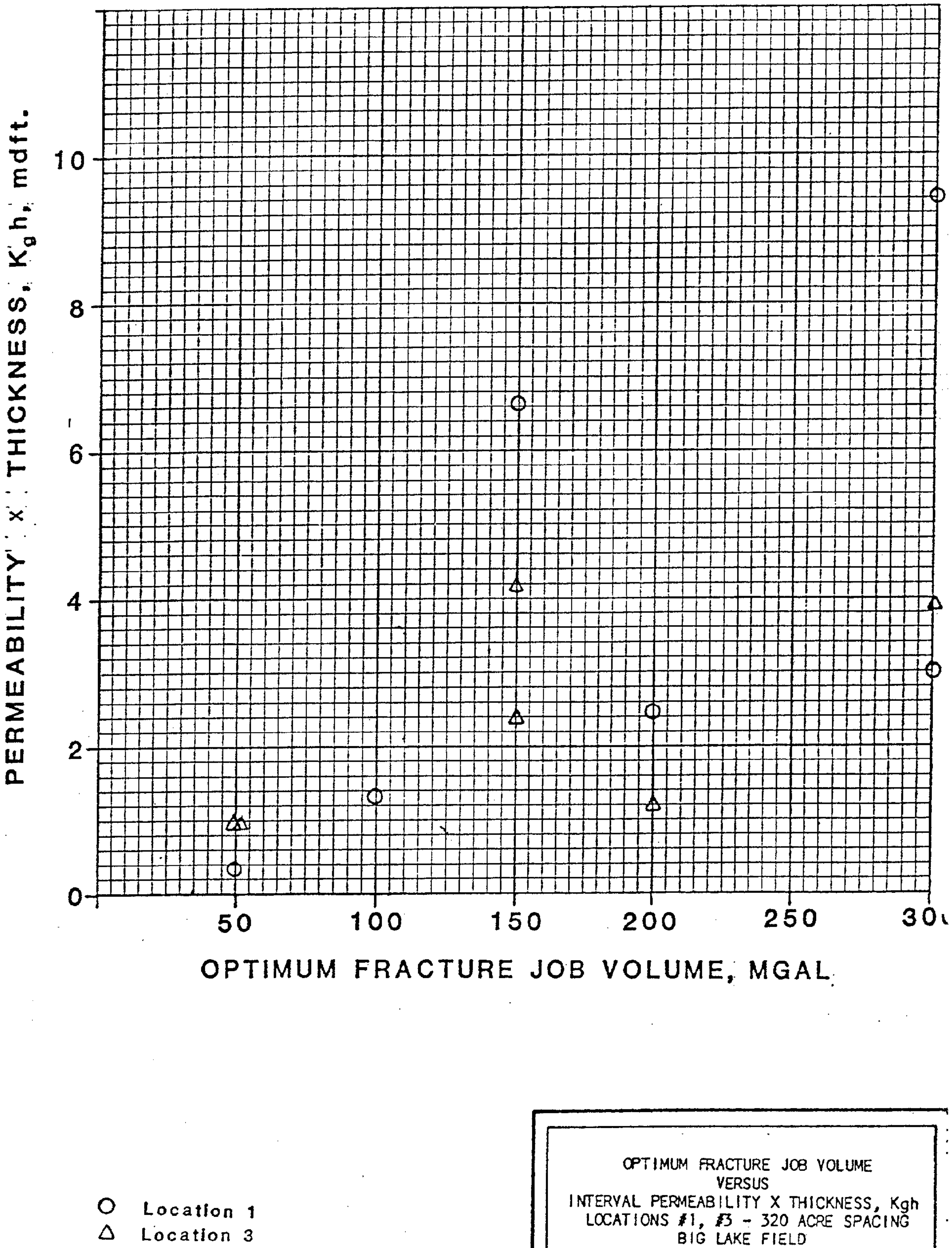
00942



OPTIMUM FRACTURE JOB VOLUME
VERSUS
INTERVAL GAS PORE VOLUME, Sgϕ h
LOCATIONS #1, #3 - 320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, SOUTH AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

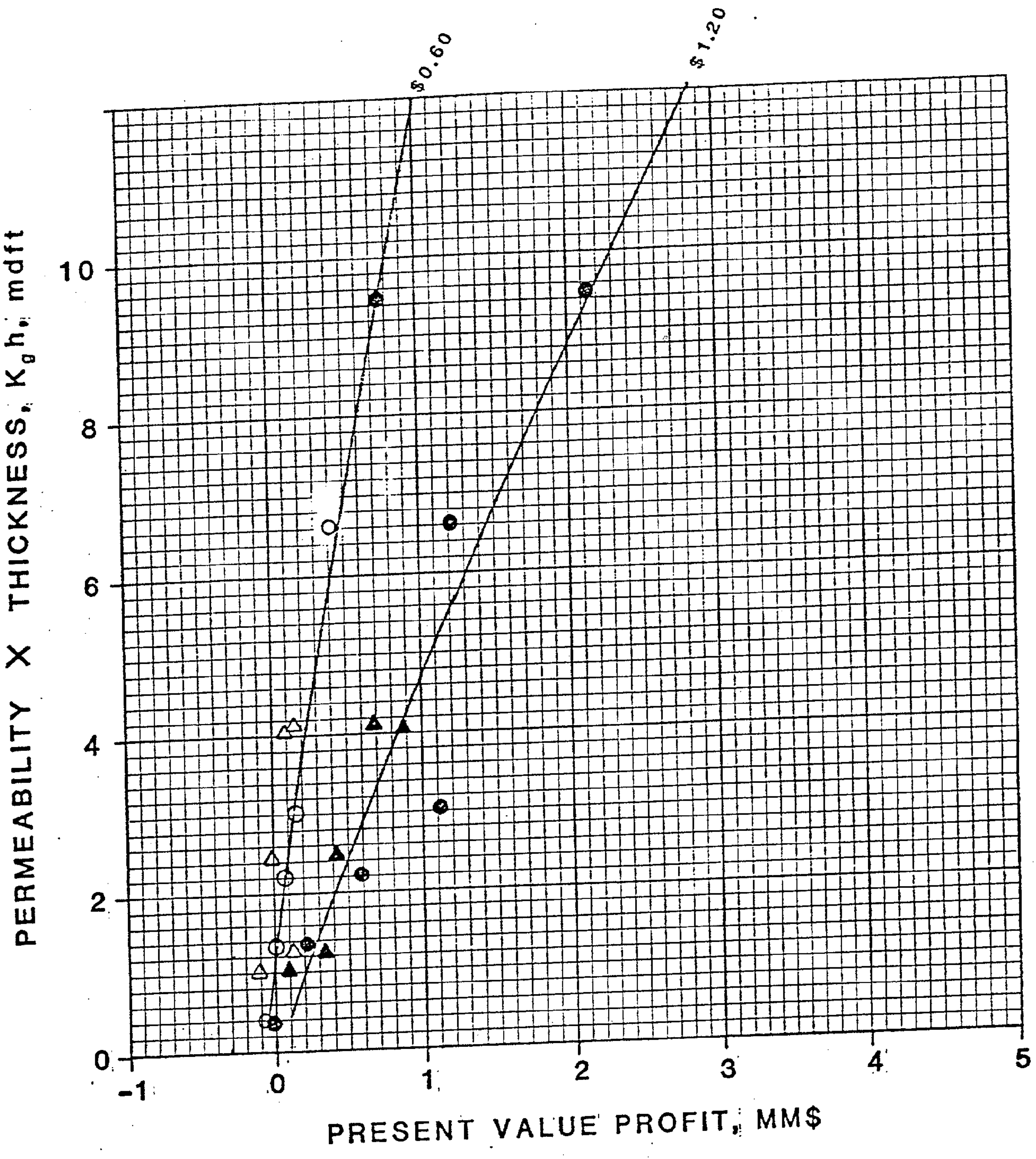
FIG. 2



OPTIMUM FRACTURE JOB VOLUME
VERSUS
INTERVAL PERMEABILITY X THICKNESS, Kgh
LOCATIONS #1, #3 - 320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, SOUTH AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

FIG. 3



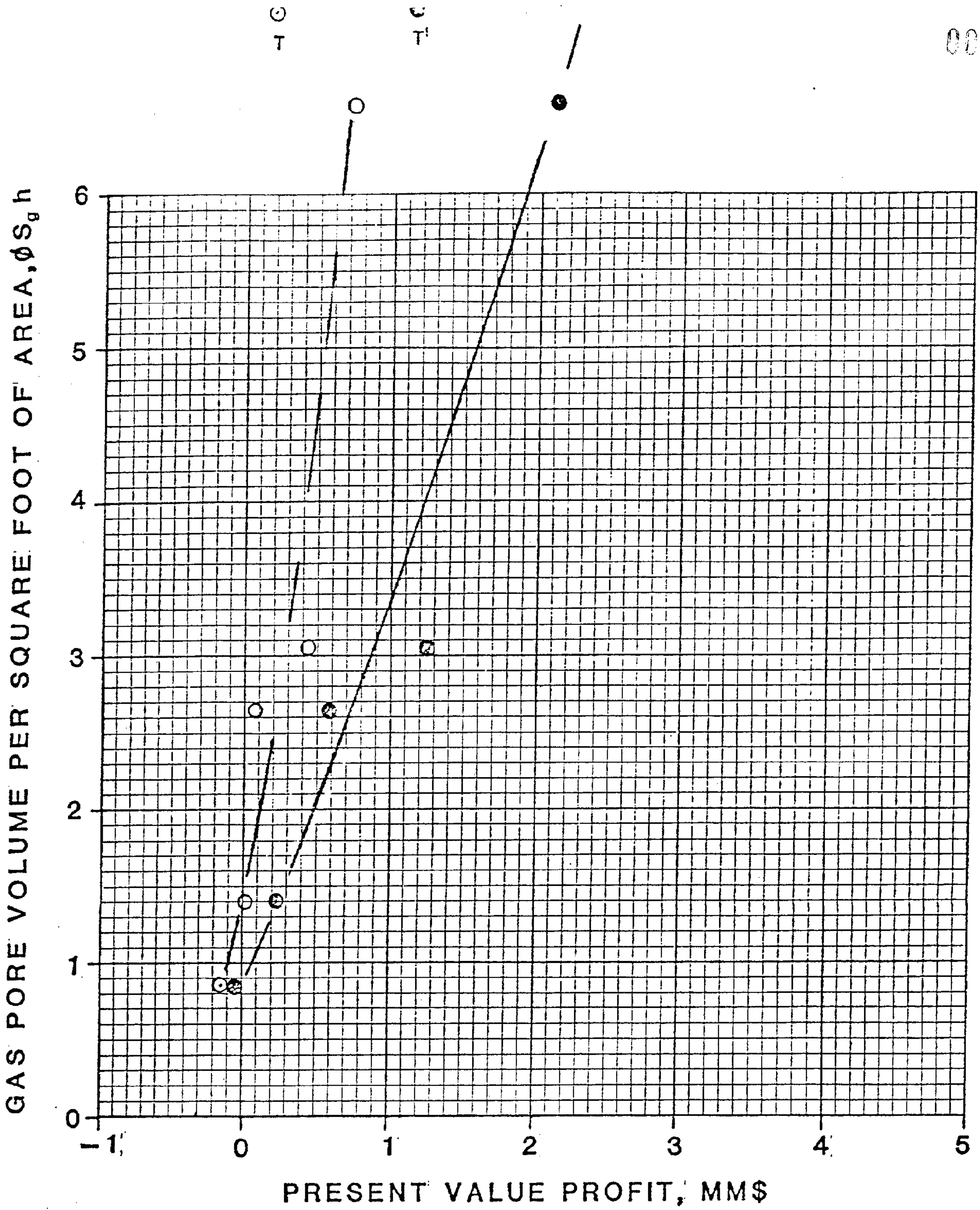
○ Location 1, $0.60
● Location 1, $1.20
△ Location 3, $0.60
▲ Location 3, $1.20

T Tirrawarra

PRESENT VALUE PROFIT
VERSUS
INTERVAL PERMEABILITY THICKNESS, Kgh
LOCATIONS #1, #3 - 320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, SOUTH AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

FIG. 4



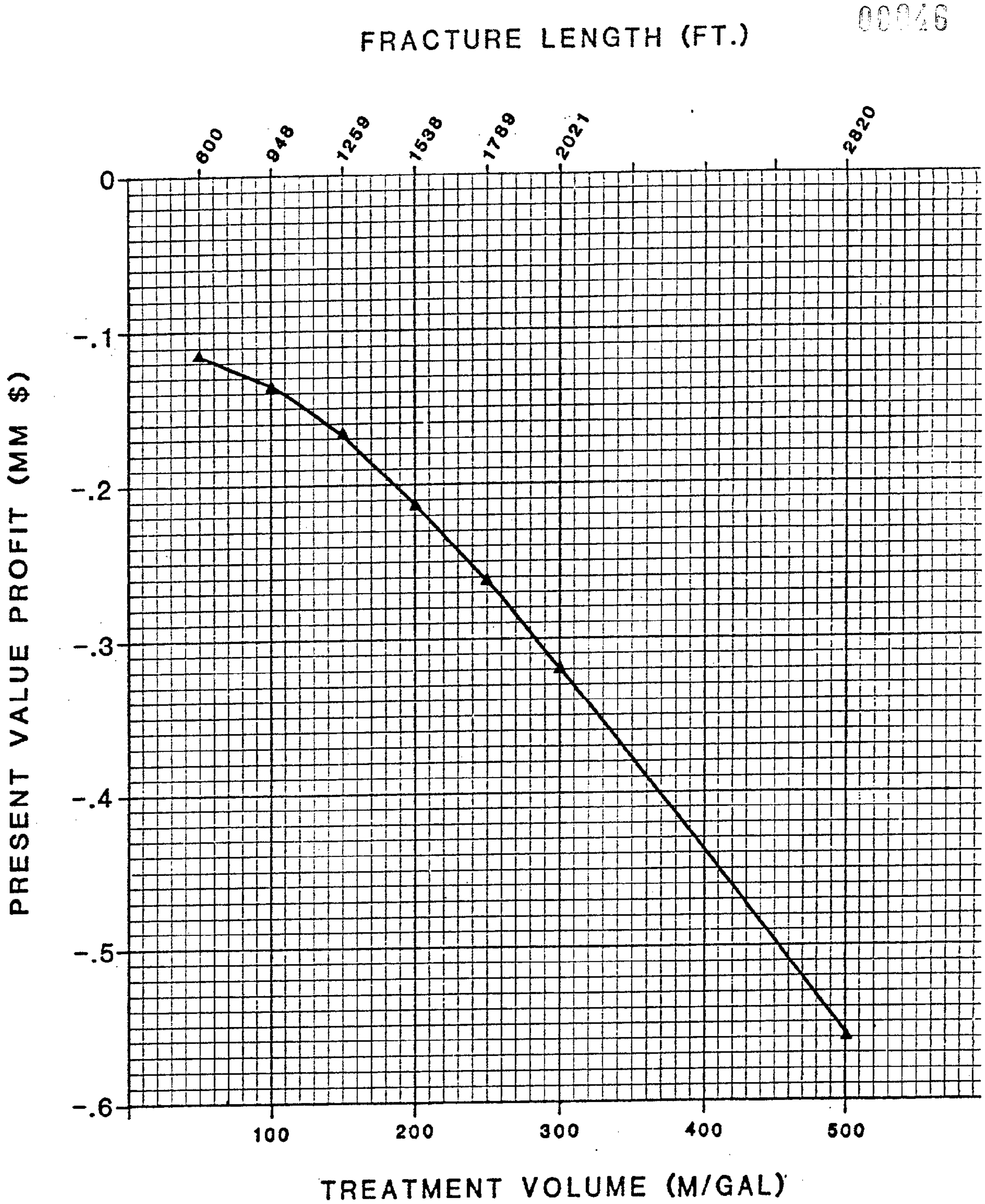
○ Location 1, $0.60
● Location 1, $1.20
△ Location 3, $0.60
▲ Location 3, $1.20

T Tirrawarra

PRESENT VALUE PROFIT
VERSUS
INTERVAL GAS PORE VOLUME, Sg ϕ h
LOCATIONS #1, #3 - 320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, SOUTH AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

FIG. 5

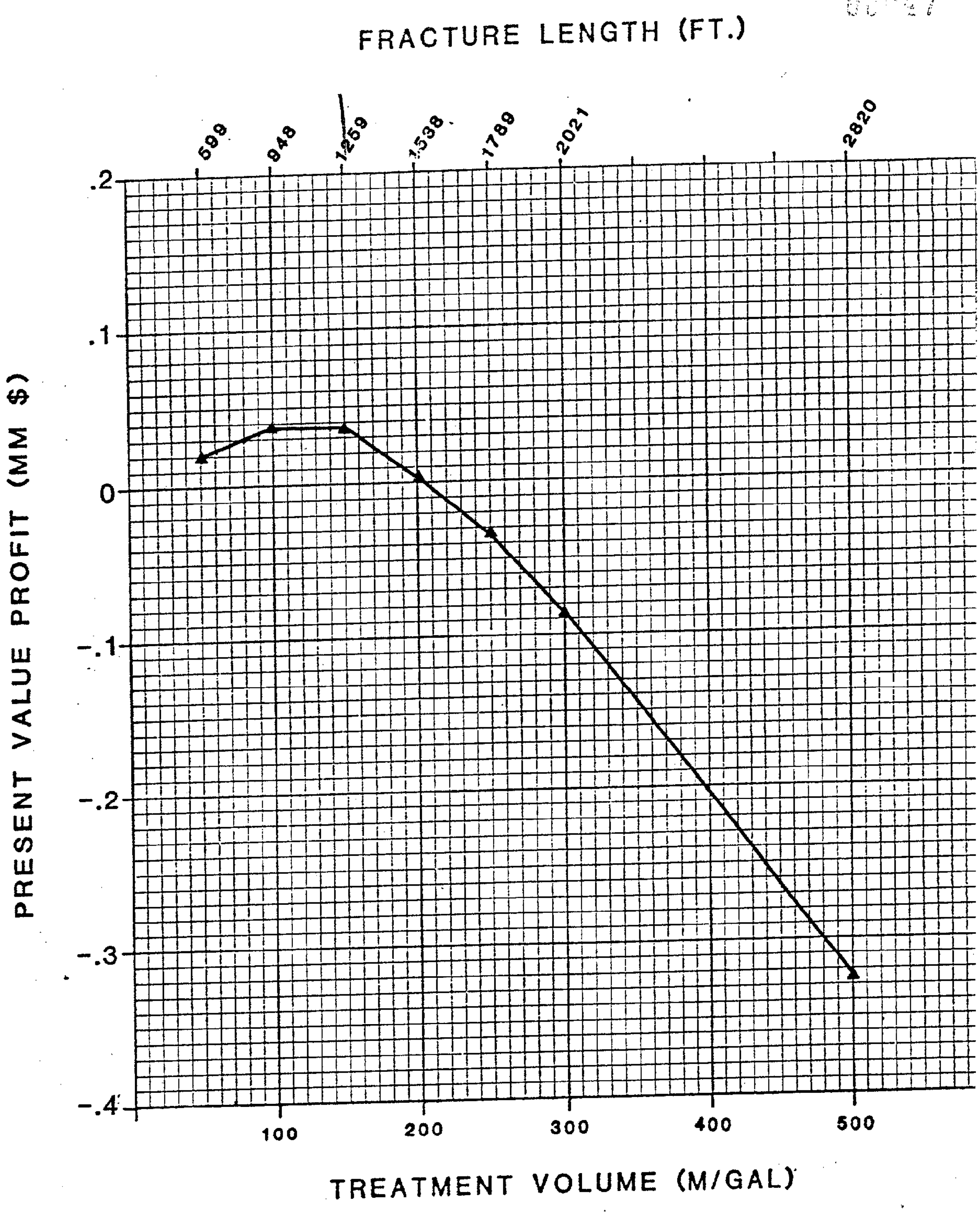


PRESENT VALUE PROFIT
VERSUS FRACTURE LENGTH
AND FRAC TREATMENT VOLUME
85-1 INTERVAL
LOCATION #1
$.60 GAS/320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

FIG. 6

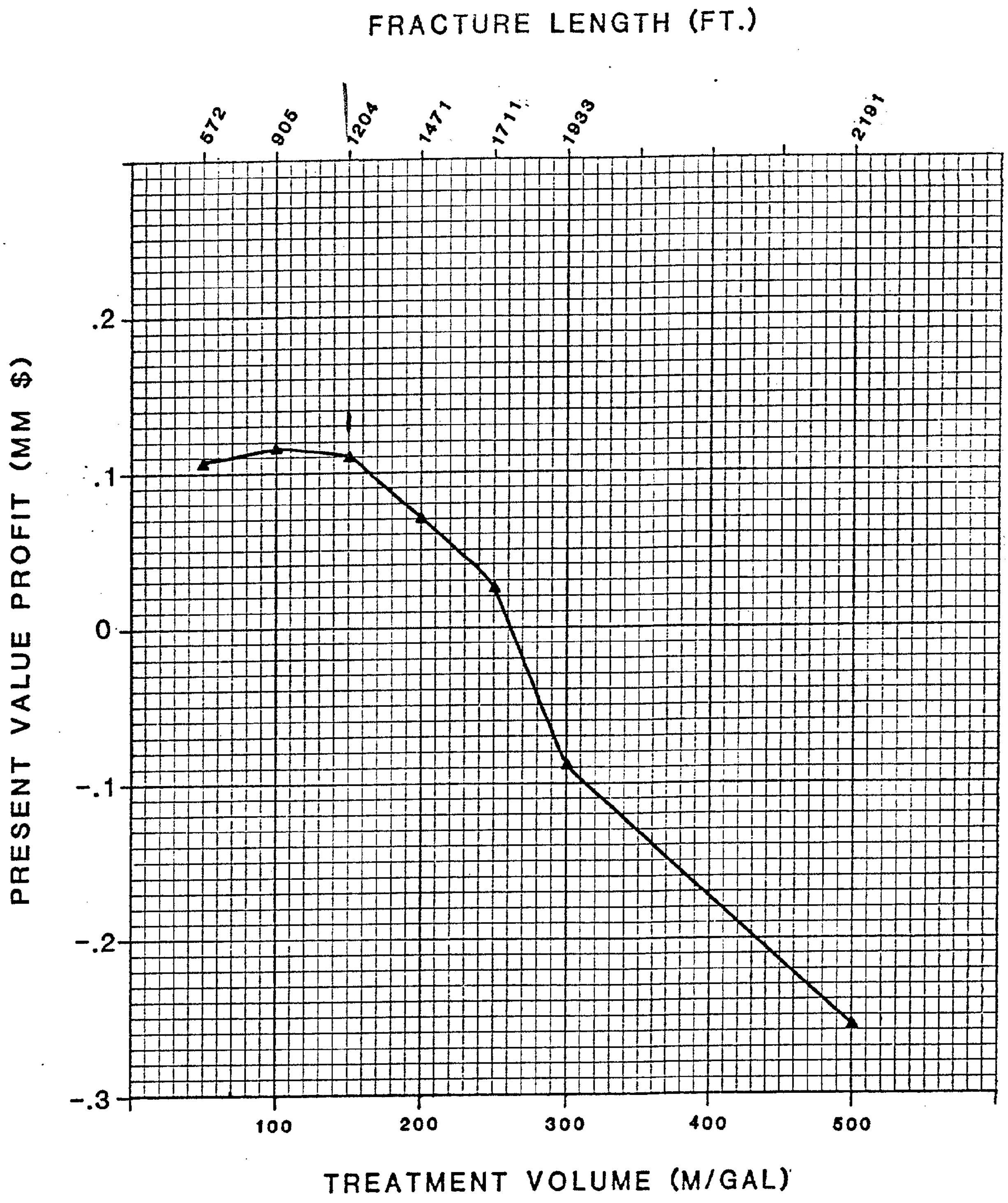
00047



PRESENT VALUE PROFIT
VERSUS FRACTURE LENGTH
AND FRAC TREATMENT VOLUME
85-1 INTERVAL
LOCATION #1
$1.20 GAS/320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

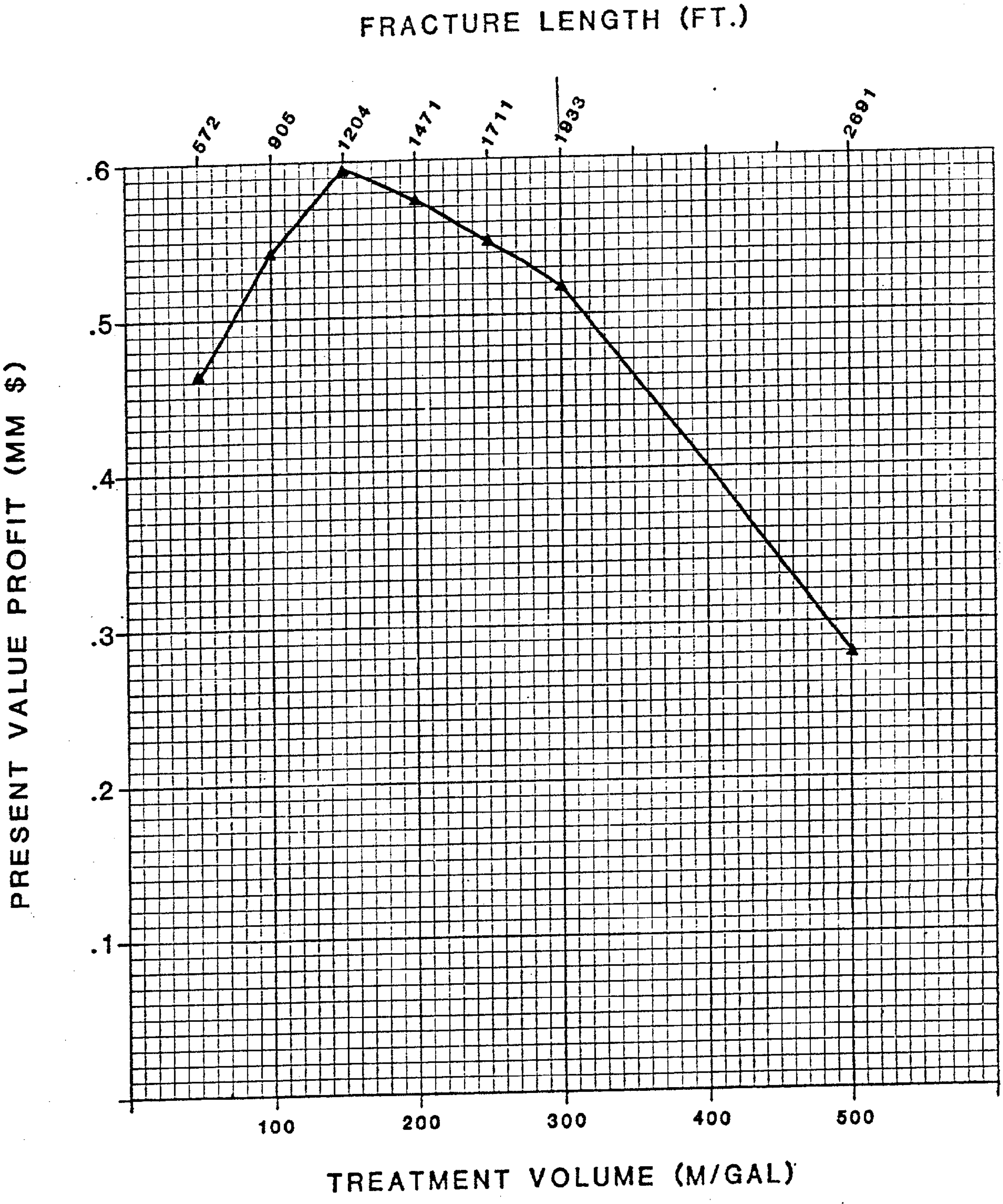
FIG. 7



PRESENT VALUE PROFIT
VERSUS FRACTURE LENGTH
AND FRAC TREATMENT VOLUME
86-8 INTERVAL
LOCATION #1
$.60 GAS/320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

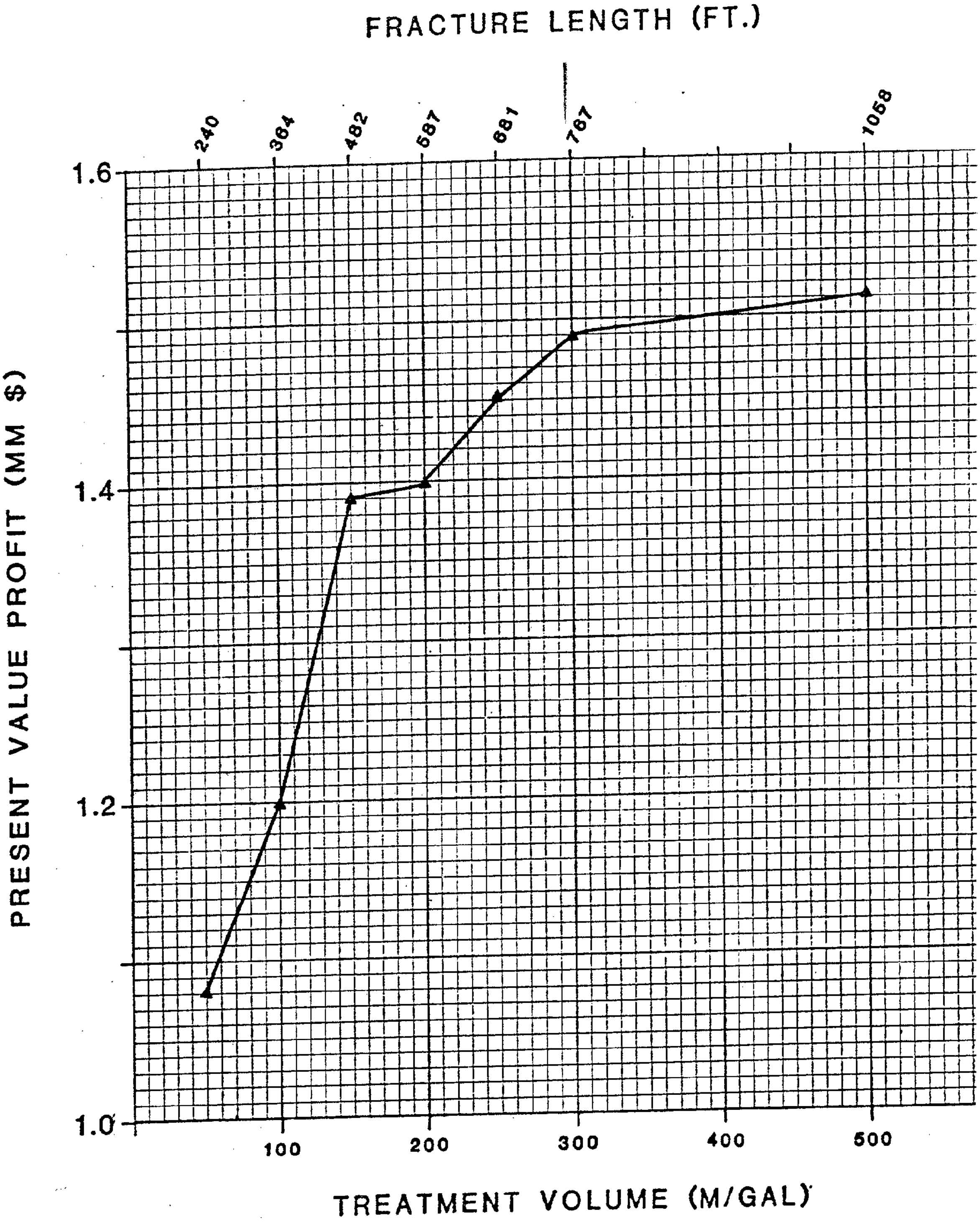
FIG. 8



PRESENT VALUE PROFIT
VERSUS FRACTURE LENGTH
AND FRAC TREATMENT VOLUME
86-8 INTERVAL
LOCATION #1
$1.20 GAS/320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

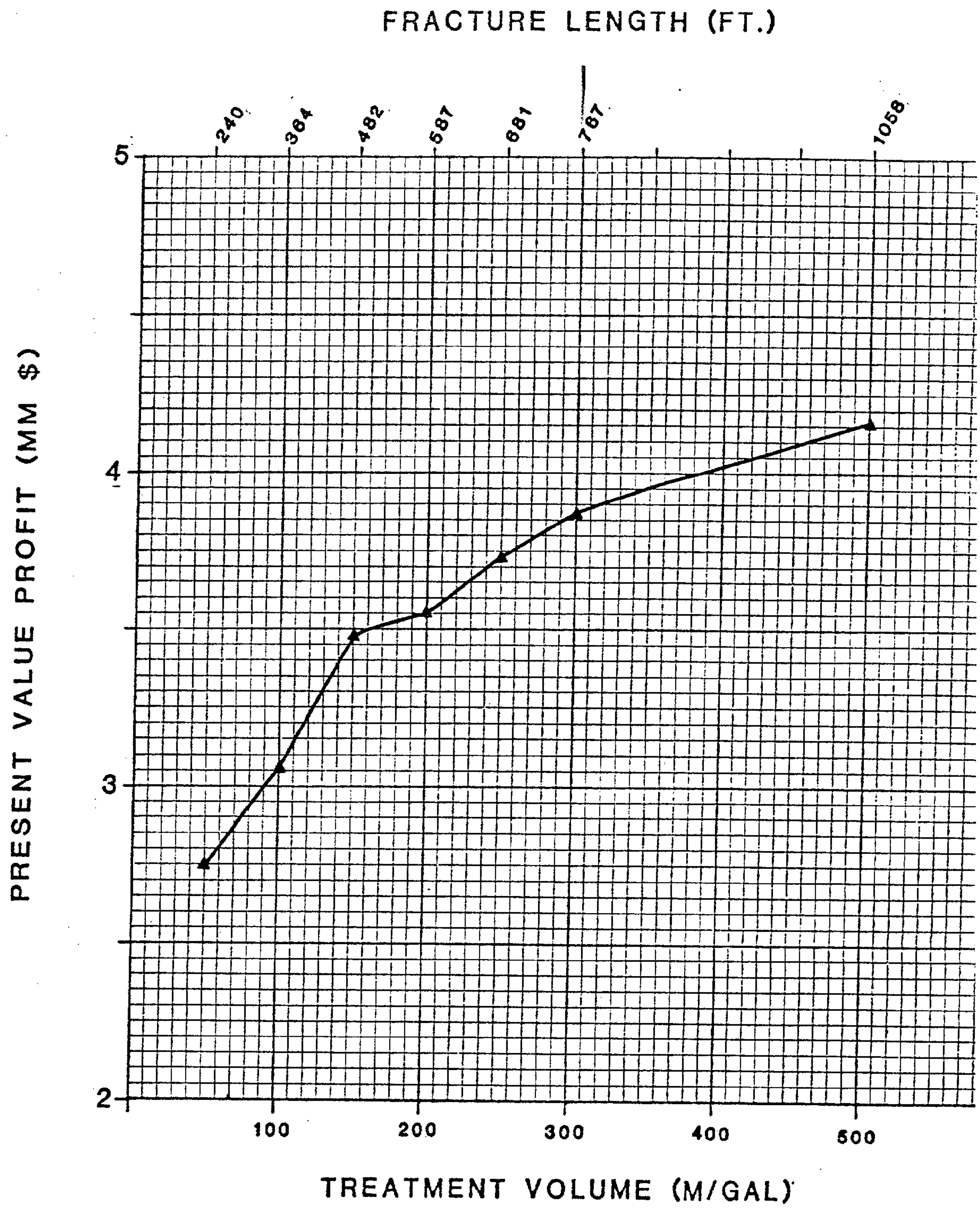
FIG. 9



PRESENT VALUE PROFIT
VERSUS FRACTURE LENGTH
AND FRAC TREATMENT VOLUME
A89-3 INTERVAL
LOCATION #1
$.60 GAS/320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

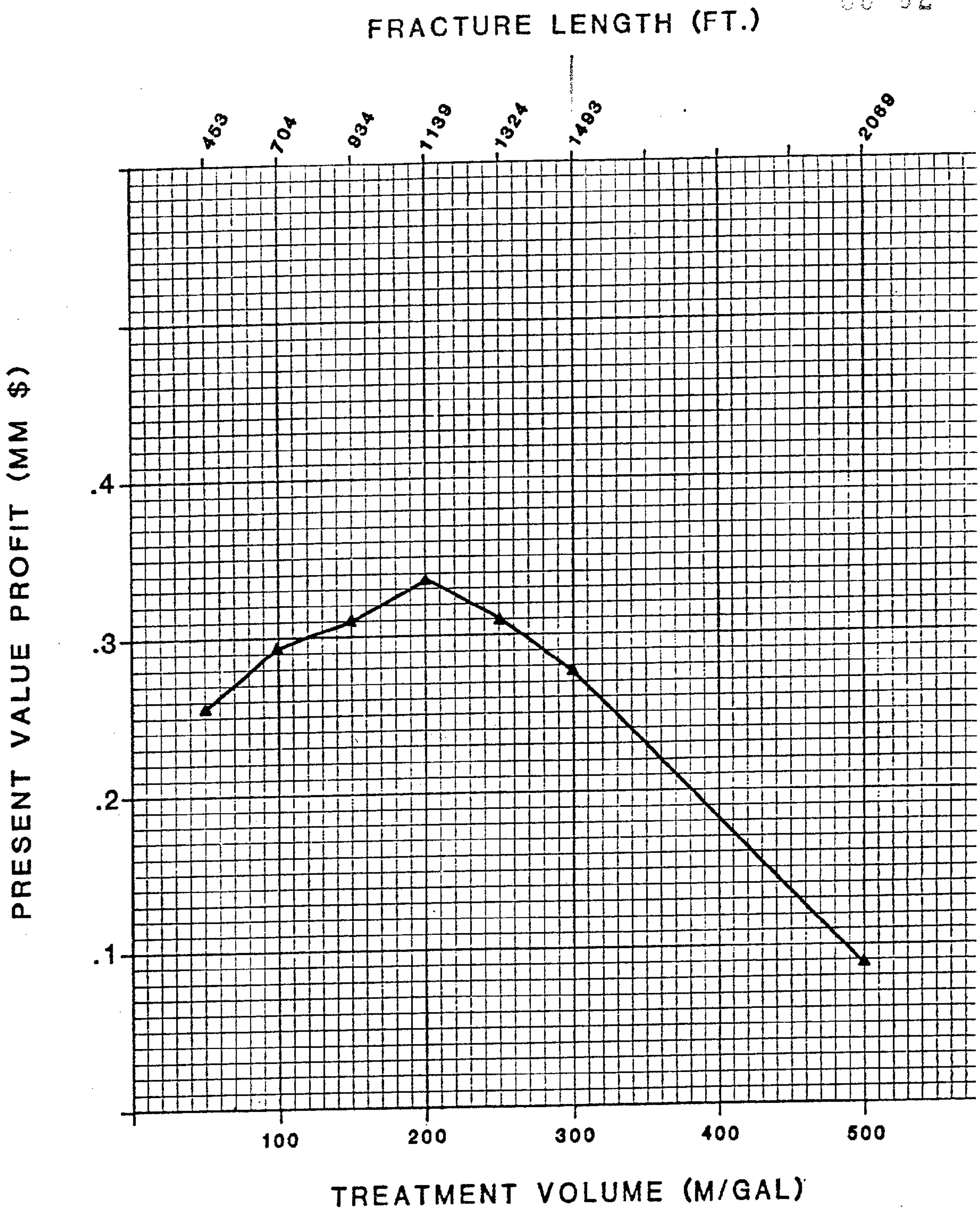
FIG. 10



PRESENT VALUE PROFIT
VERSUS FRACTURE LENGTH
AND FRAC TREATMENT VOLUME
A89-3 INTERVAL
LOCATION #1
$1.20 GAS/320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

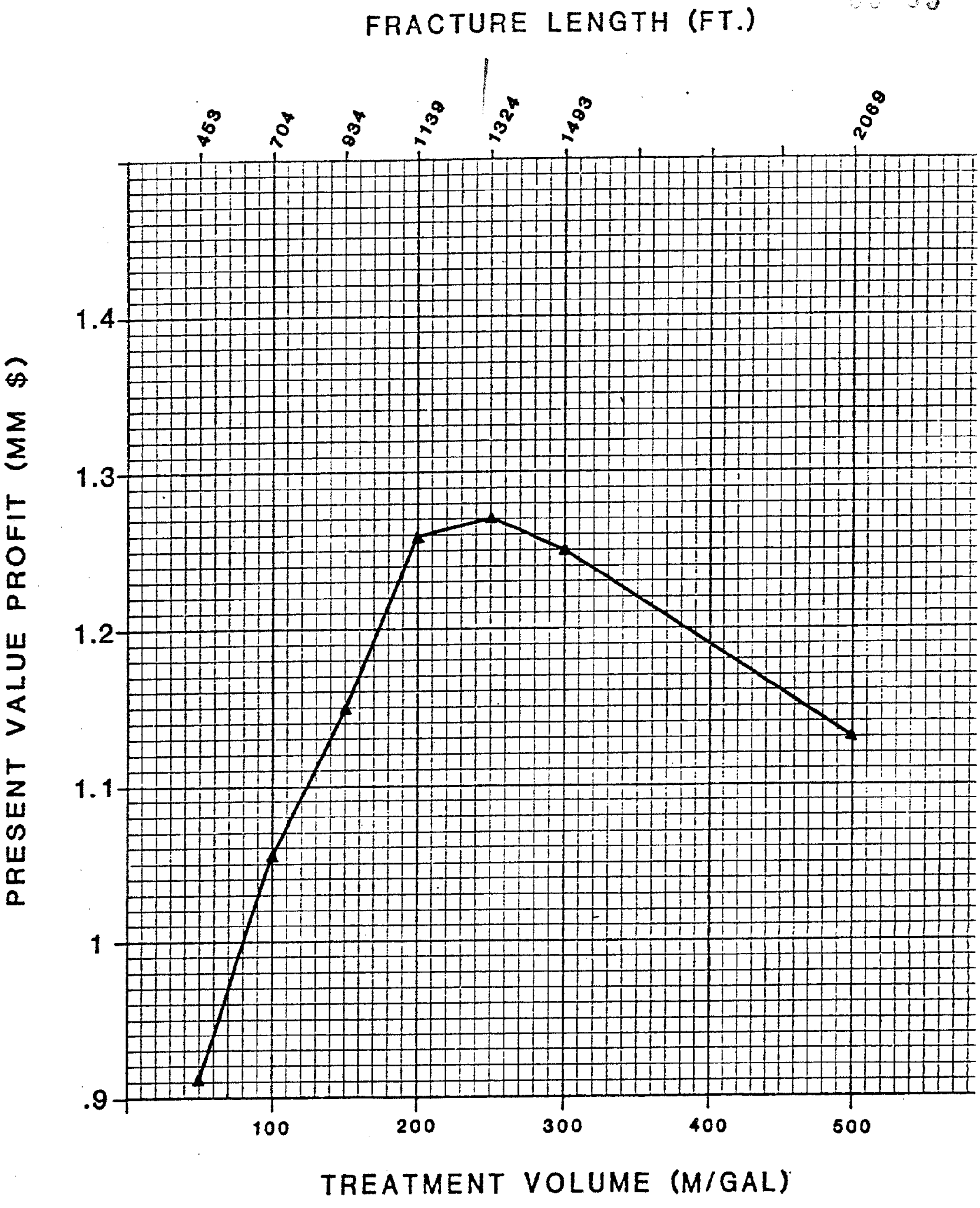
FIG. 11



PRESENT VALUE PROFIT
VERSUS FRACTURE LENGTH
AND FRAC TREATMENT VOLUME
A92-1 INTERVAL
LOCATION #1
$.60 GAS/320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

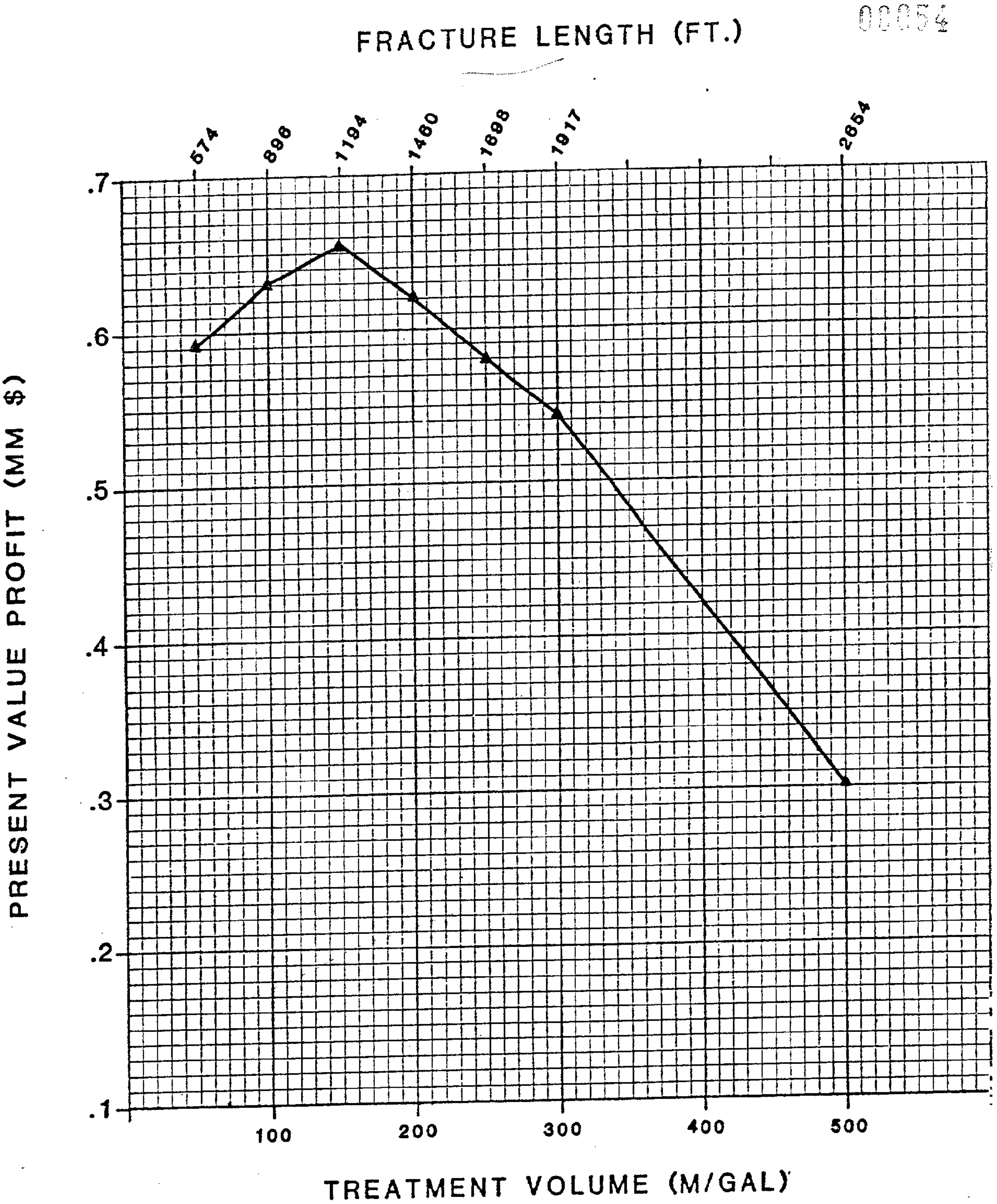
FIG. 12



PRESENT VALUE PROFIT
VERSUS FRACTURE LENGTH
AND FRAC TREATMENT VOLUME
A92-1 INTERVAL
LOCATION #1
$1.20 GAS/320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

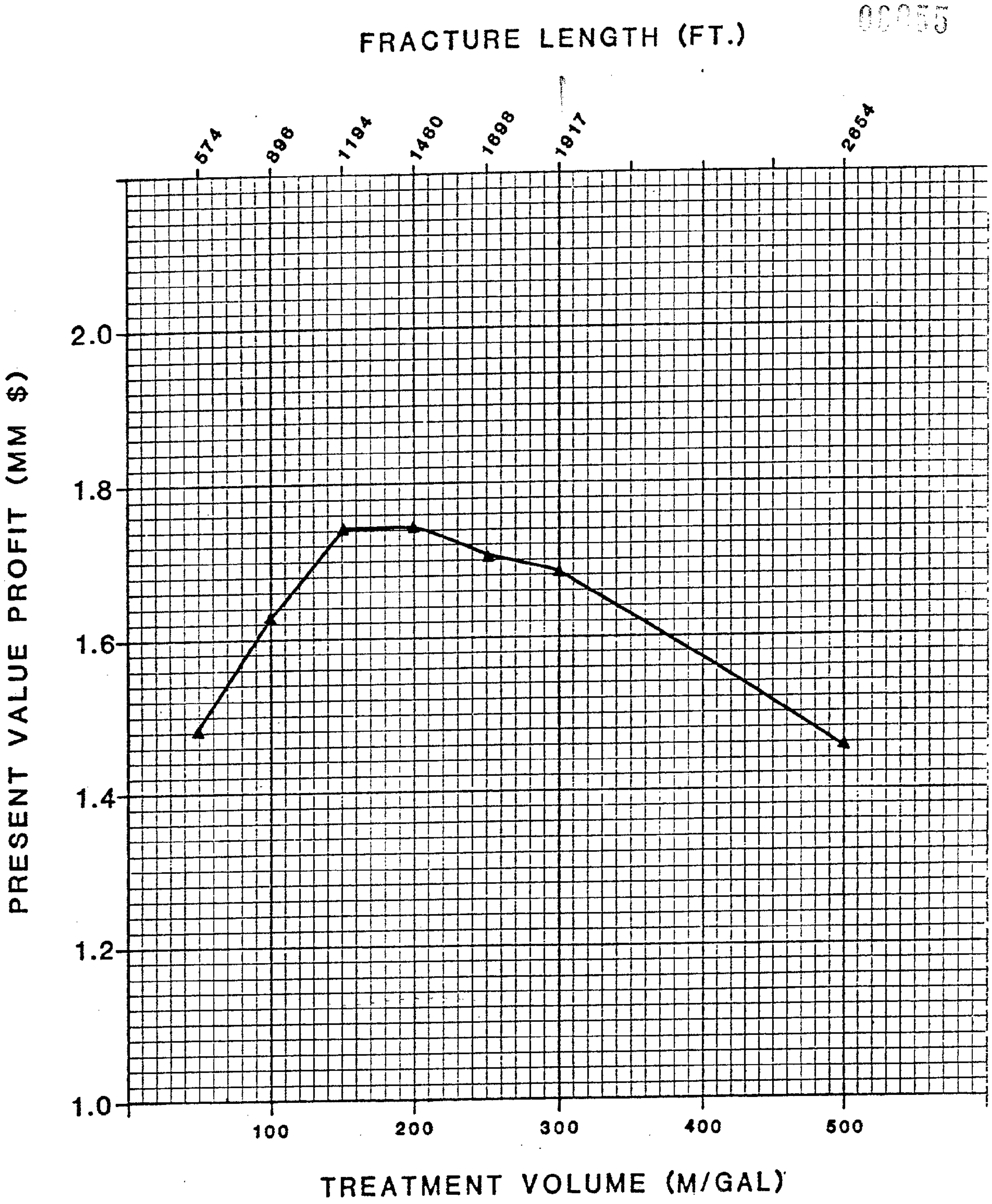
FIG. 13



PRESENT VALUE PROFIT
VERSUS FRACTURE LENGTH
AND FRAC TREATMENT VOLUME
A93-2 INTERVAL
LOCATION #1
$.60 GAS/320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

FIG. 14



PRESENT VALUE PROFIT
VERSUS FRACTURE LENGTH
AND FRAC TREATMENT VOLUME
A93-2 INTERVAL
LOCATION #1
$1.20 GAS/320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

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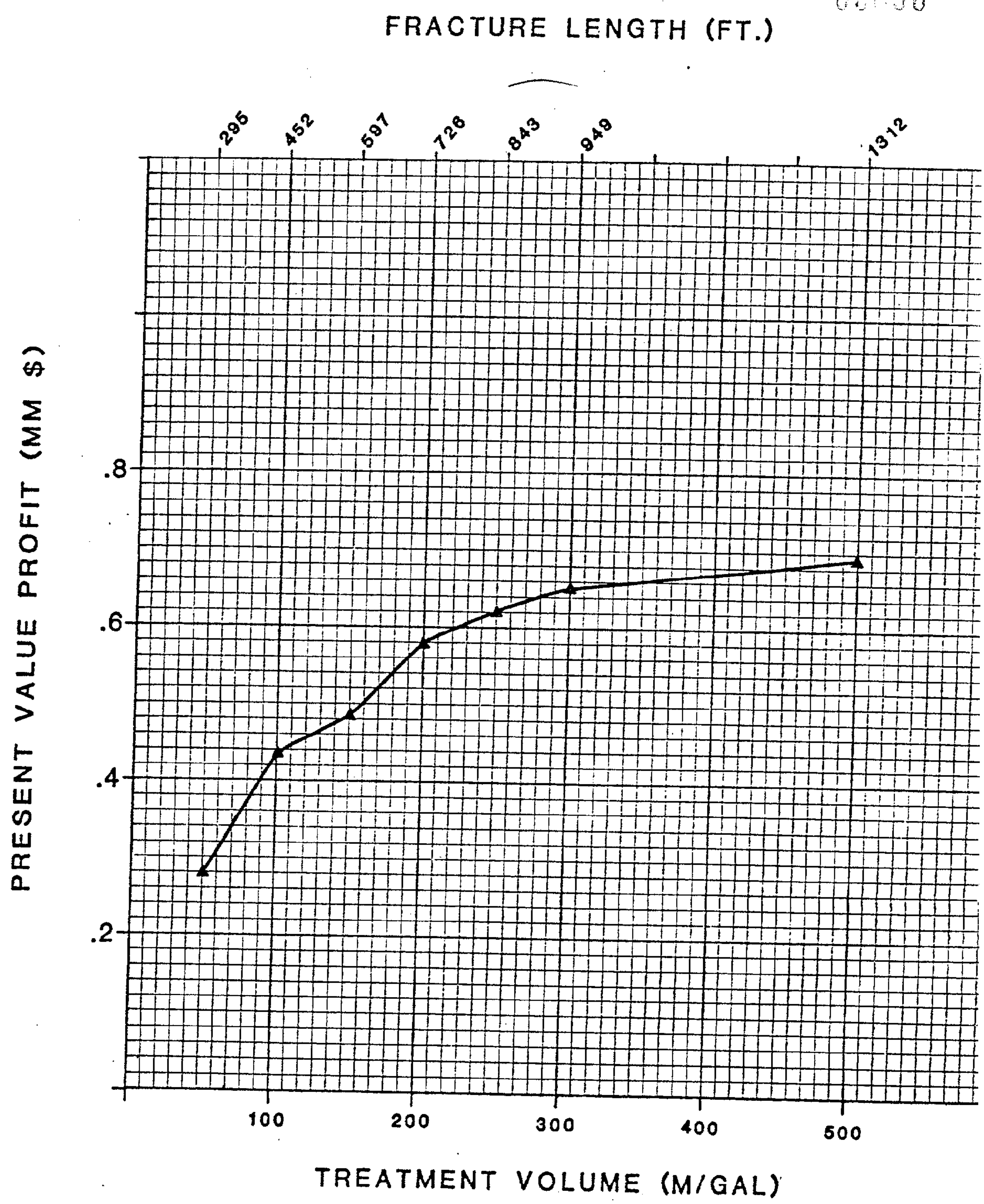
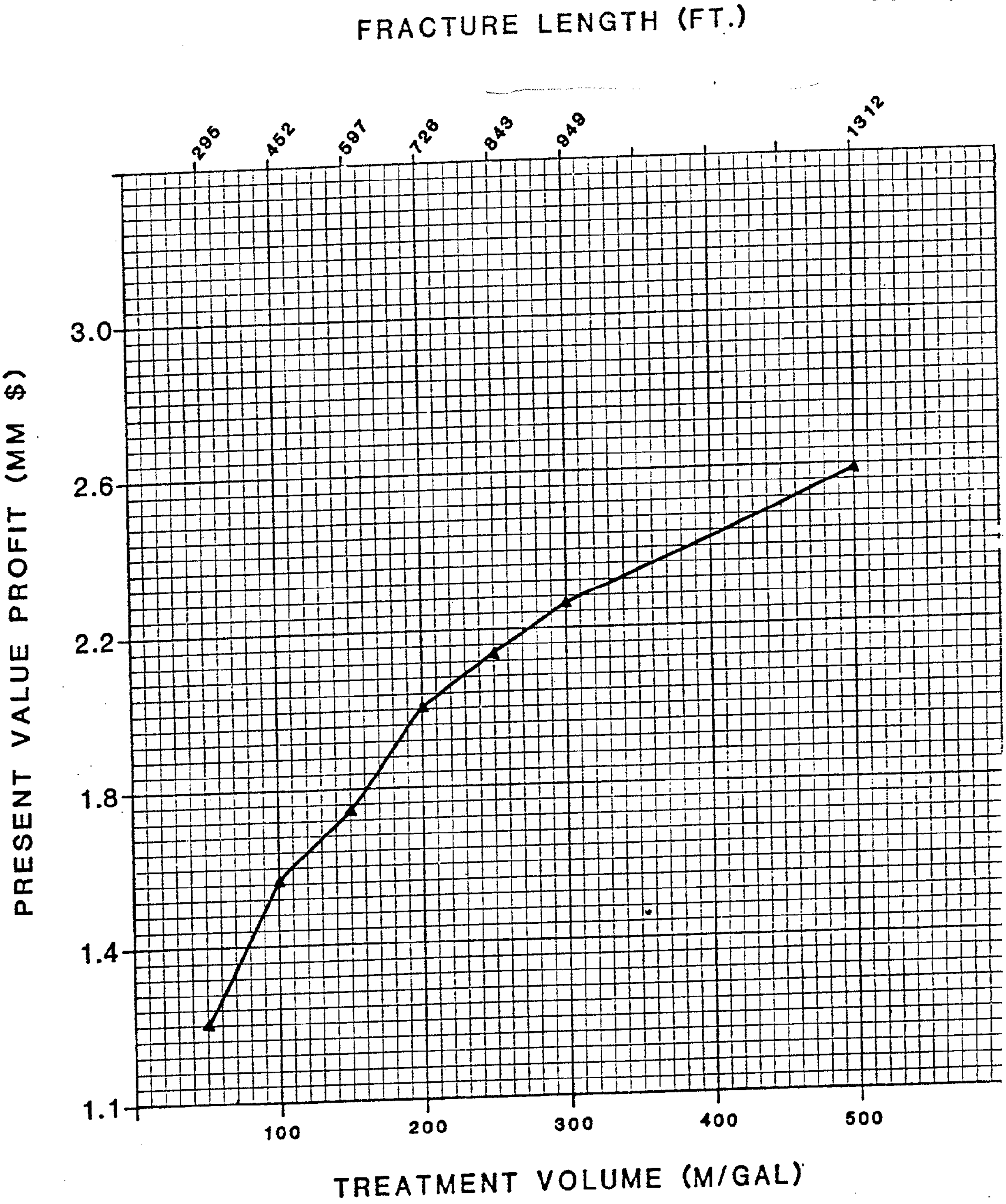
FIG. 15



PRESENT VALUE PROFIT
VERSUS FRACTURE LENGTH
AND FRAC TREATMENT VOLUME
TR1 INTERVAL
LOCATION #1
$.60 GAS/320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

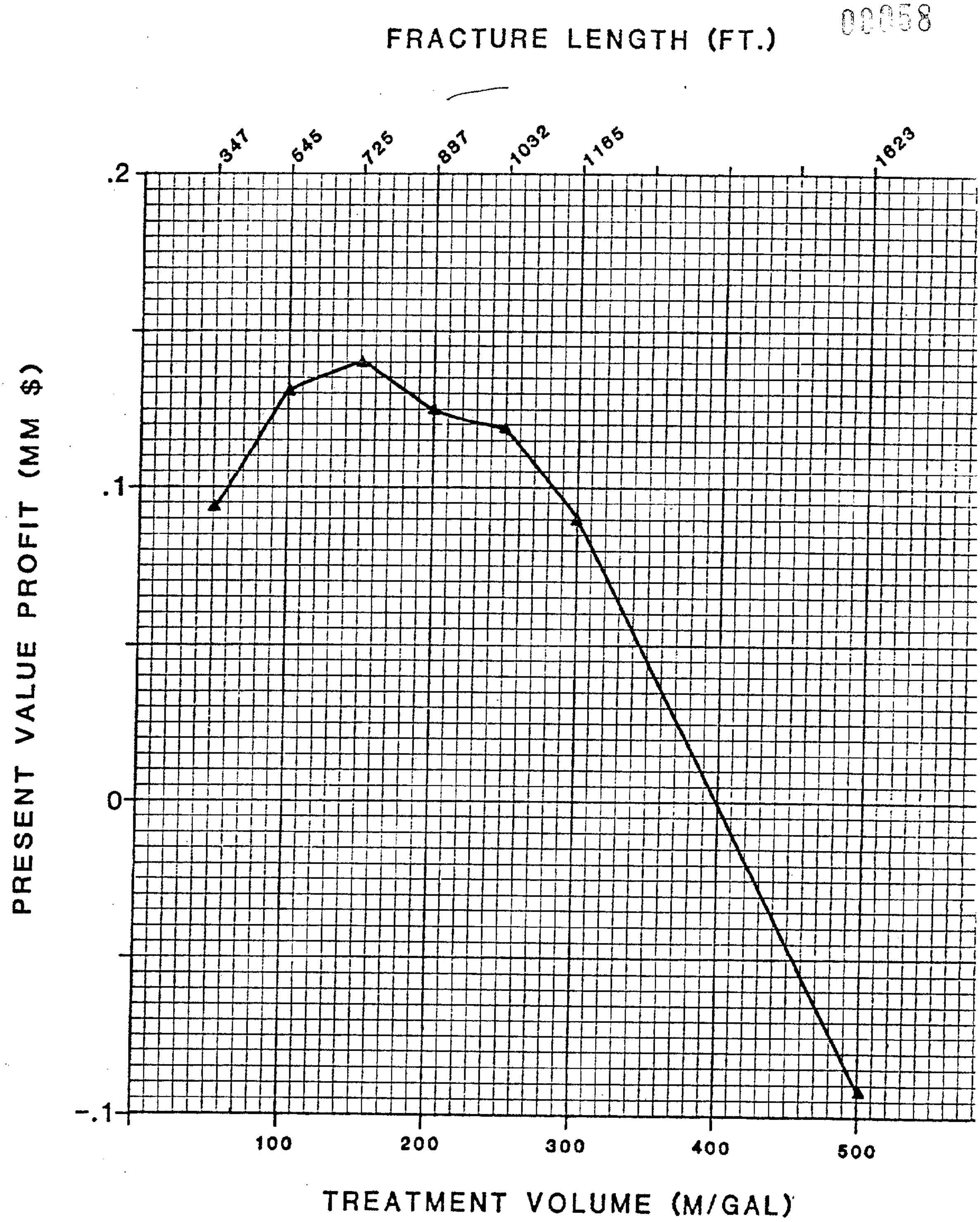
FIG. 16



PRESENT VALUE PROFIT
VERSUS FRACTURE LENGTH
AND FRAC TREATMENT VOLUME
TRI INTERVAL
LOCATION #1
$1.20 GAS/320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

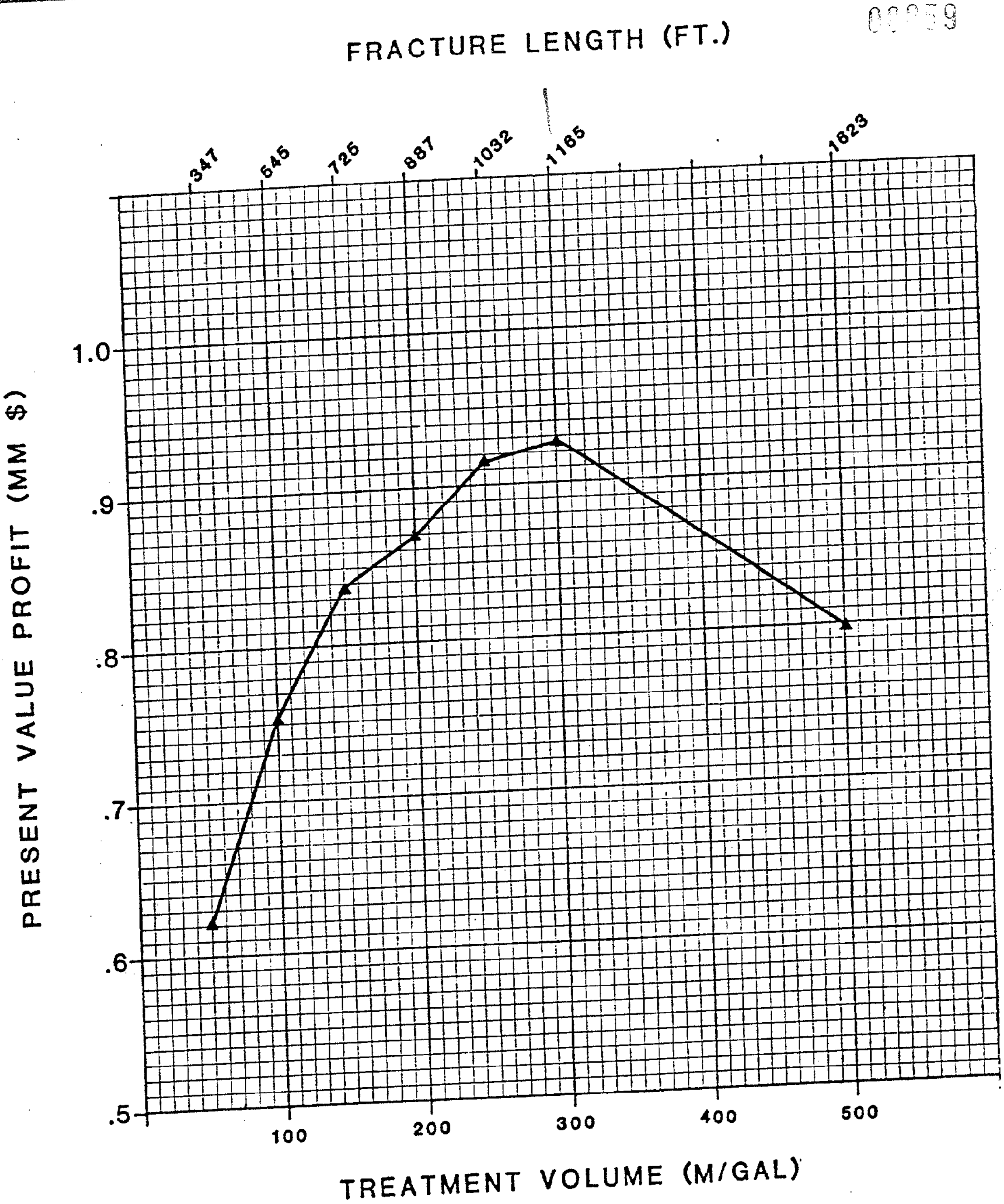
FIG. 17



PRESENT VALUE PROFIT
VERSUS FRACTURE LENGTH
AND FRAC TREATMENT VOLUME
85-1 INTERVAL
LOCATION #3
$.60 GAS/320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

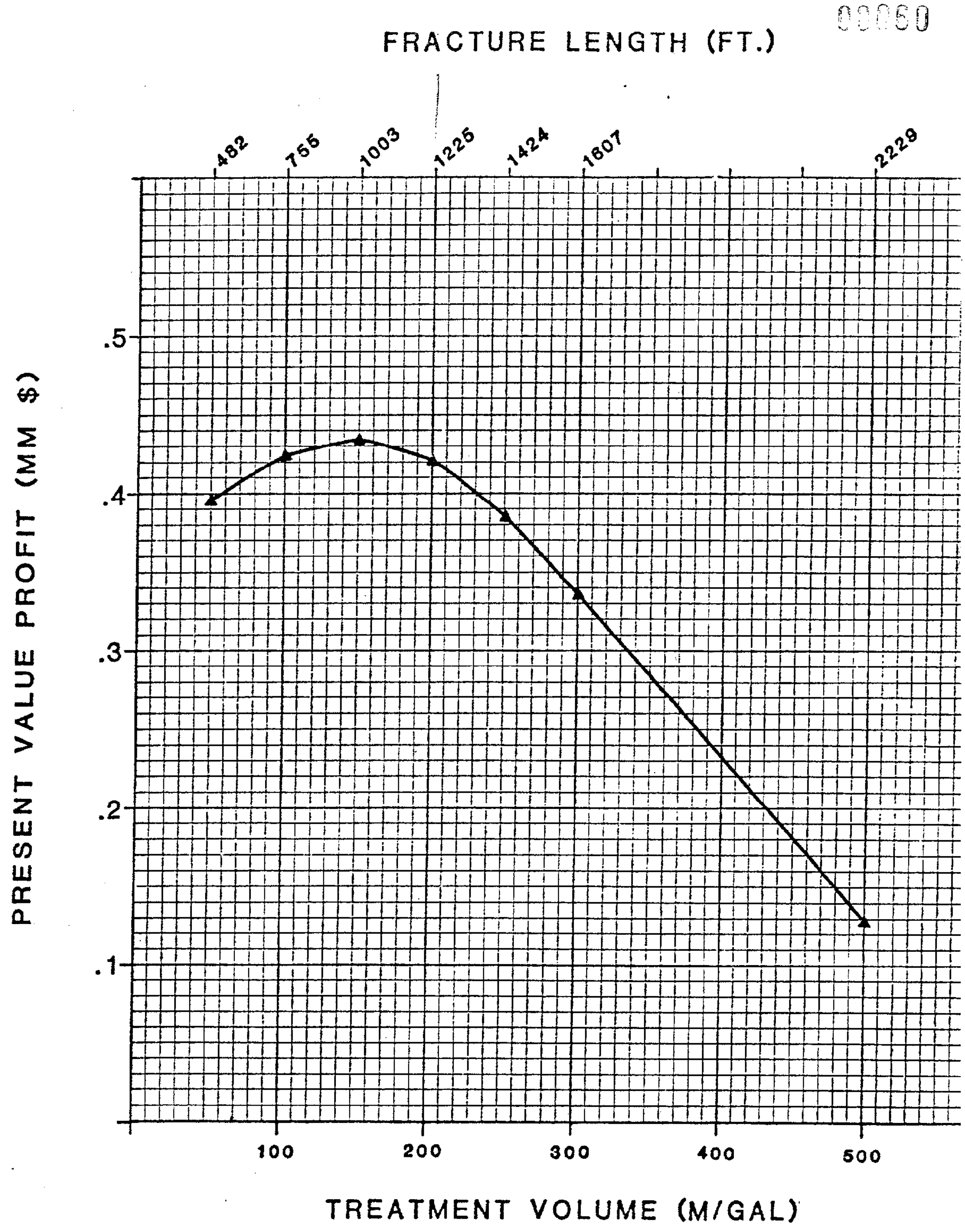
FIG. 18



PRESENT VALUE PROFIT
VERSUS FRACTURE LENGTH
AND FRAC TREATMENT VOLUME
85-1 INTERVAL
LOCATION #3
$1.20 GAS/320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

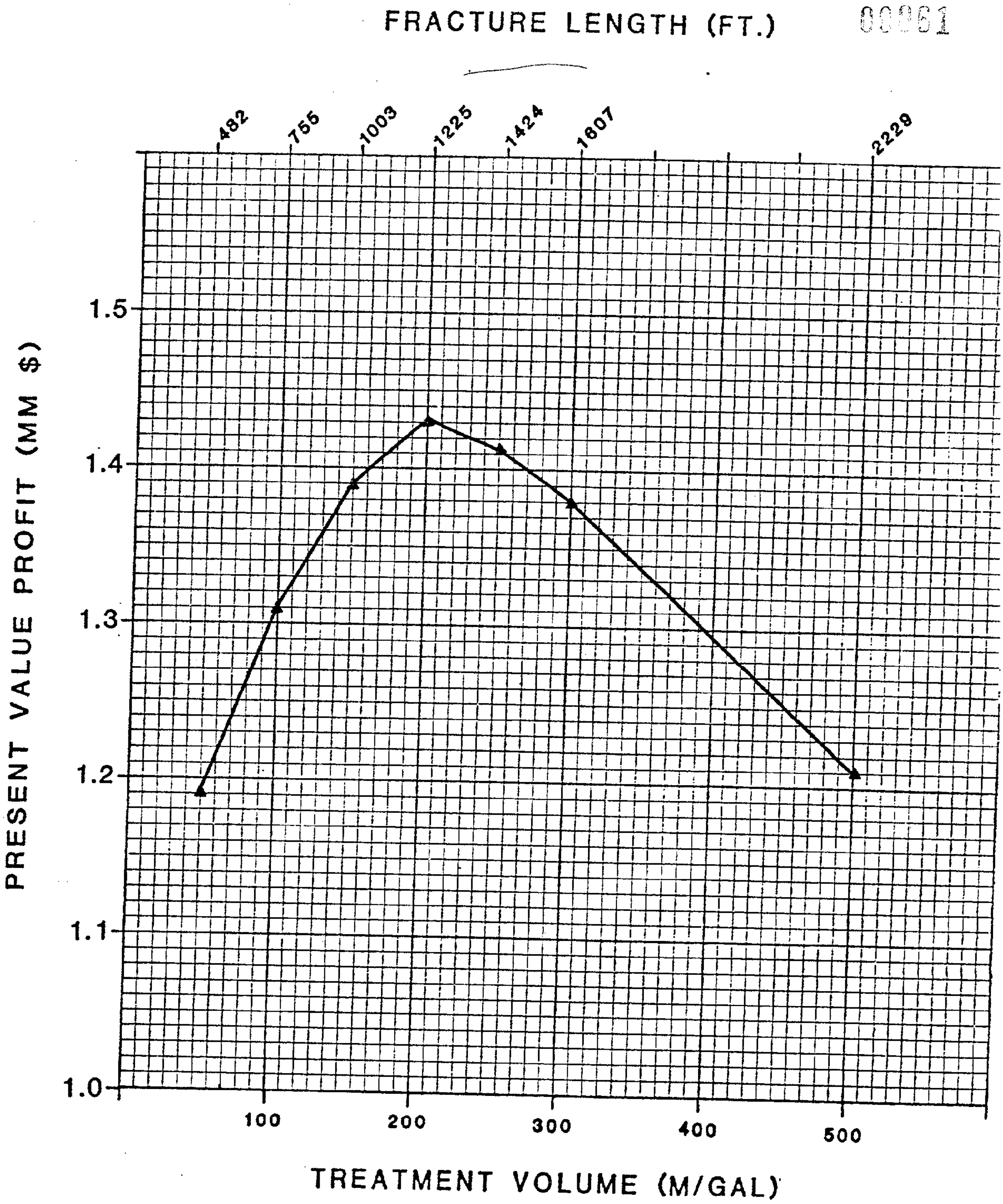
FIG. 19



PRESENT VALUE PROFIT
VERSUS FRACTURE LENGTH
AND FRAC TREATMENT VOLUME
86-8 INTERVAL
LOCATION #3
$.60 GAS/320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

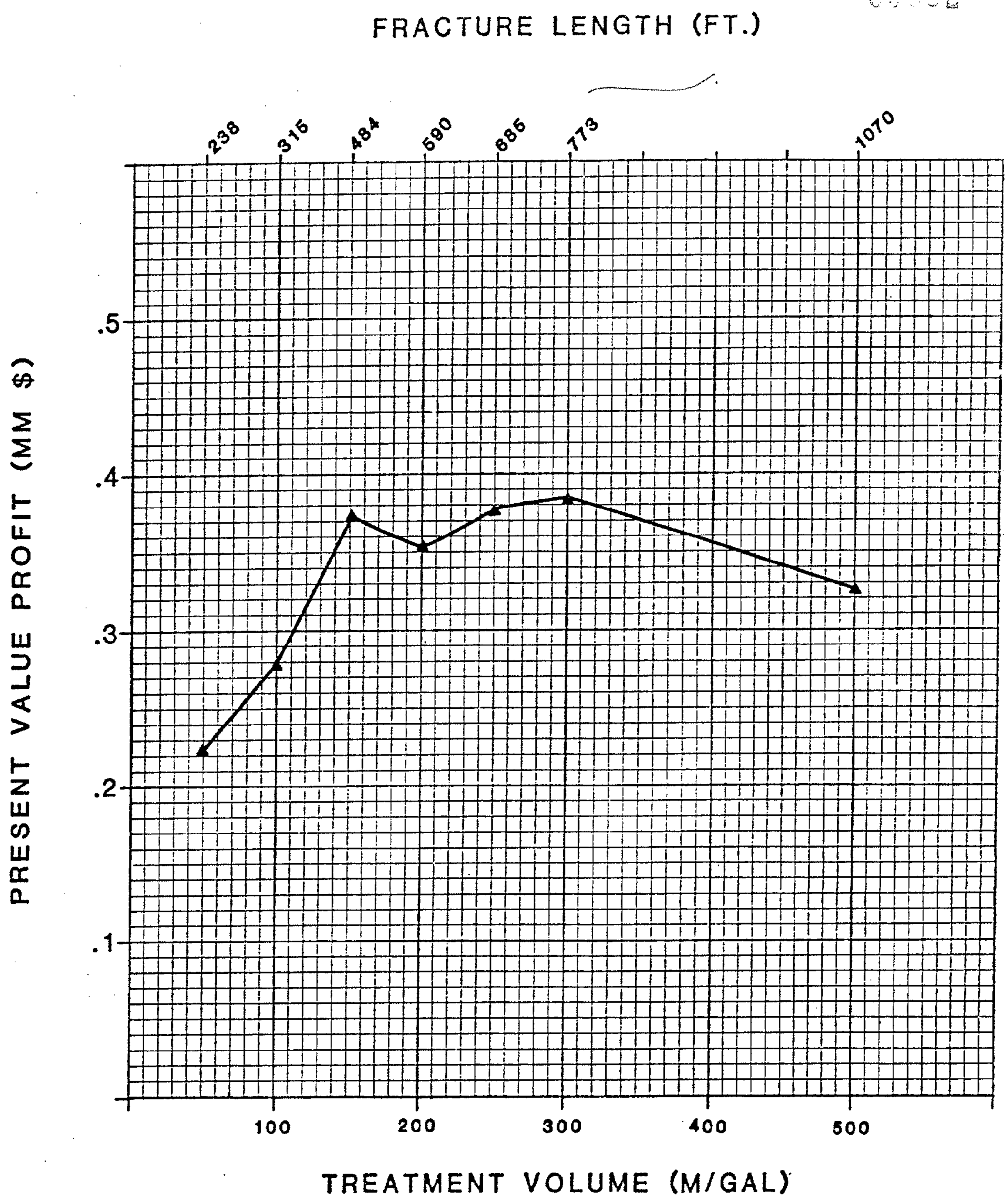
FIG. 20



PRESENT VALUE PROFIT
VERSUS FRACTURE LENGTH
AND FRAC TREATMENT VOLUME
86-8 INTERVAL
LOCATION #3
$1.20 GAS/320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

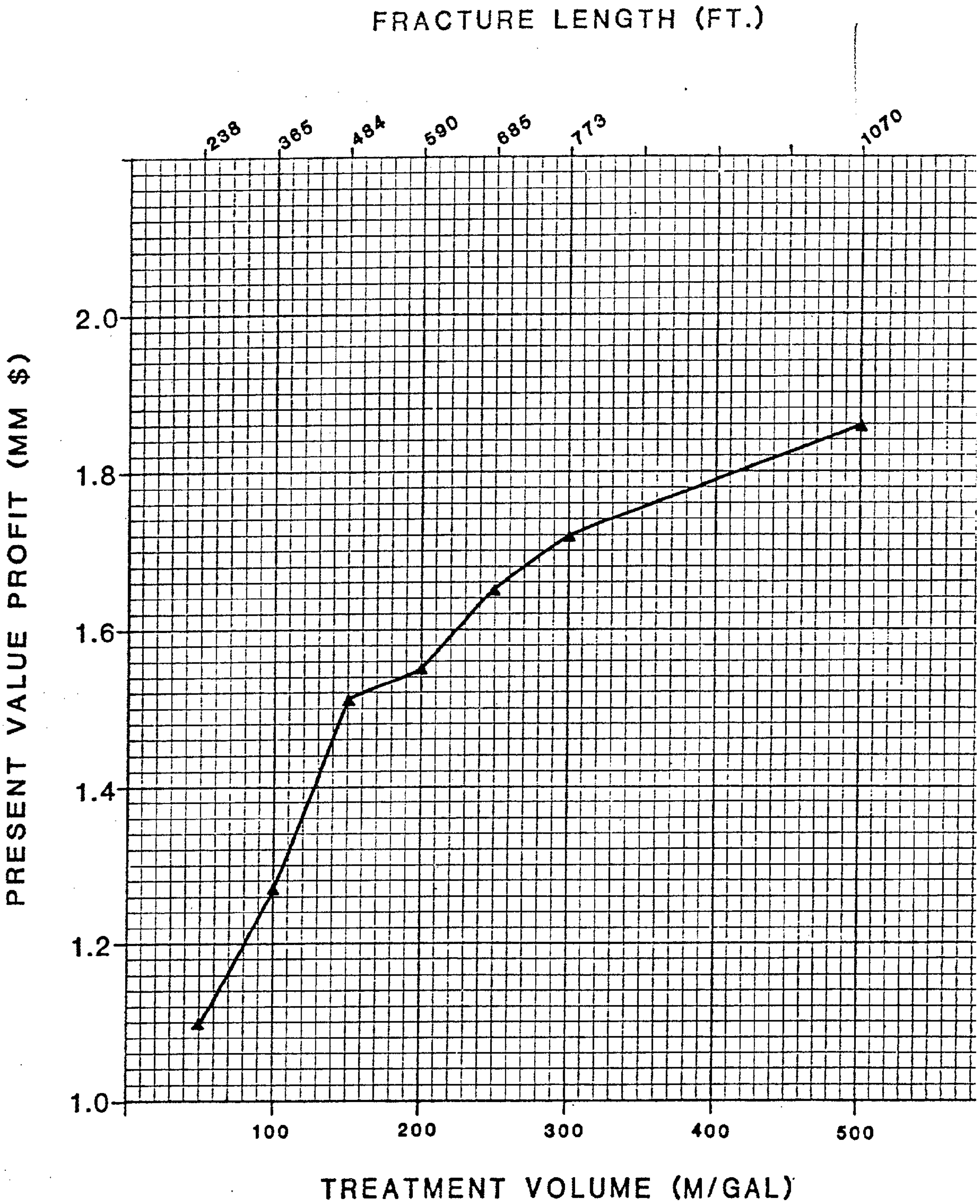
FIG. 21



PRESENT VALUE PROFIT
VERSUS FRACTURE LENGTH
AND FRAC TREATMENT VOLUME
89-3 INTERVAL
LOCATION #3
$.60 GAS/320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

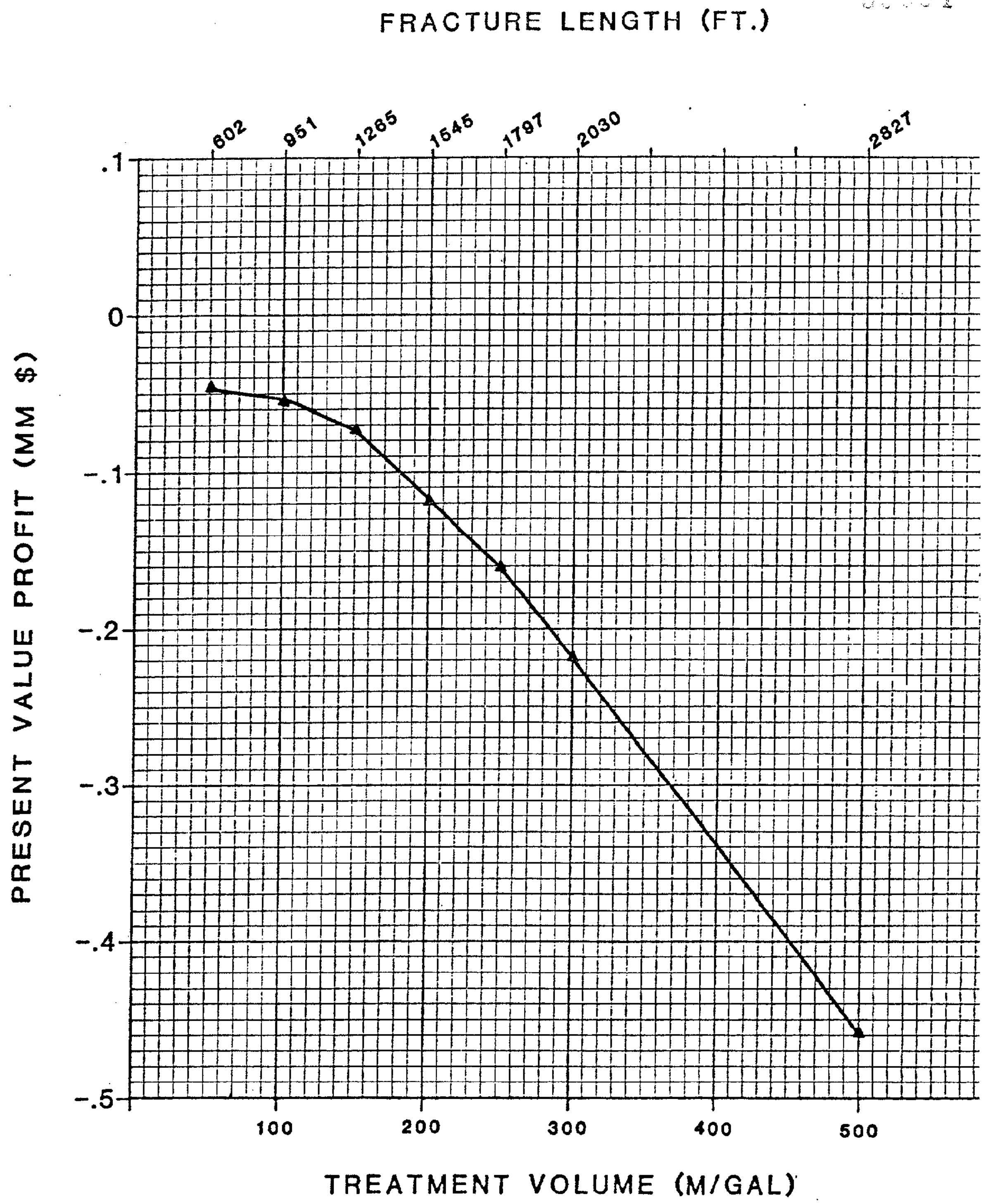
FIG. 22



PRESENT VALUE PROFIT
VERSUS FRACTURE LENGTH
AND FRAC TREATMENT VOLUME
89-3 INTERVAL
LOCATION #3
$1.20 GAS/320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

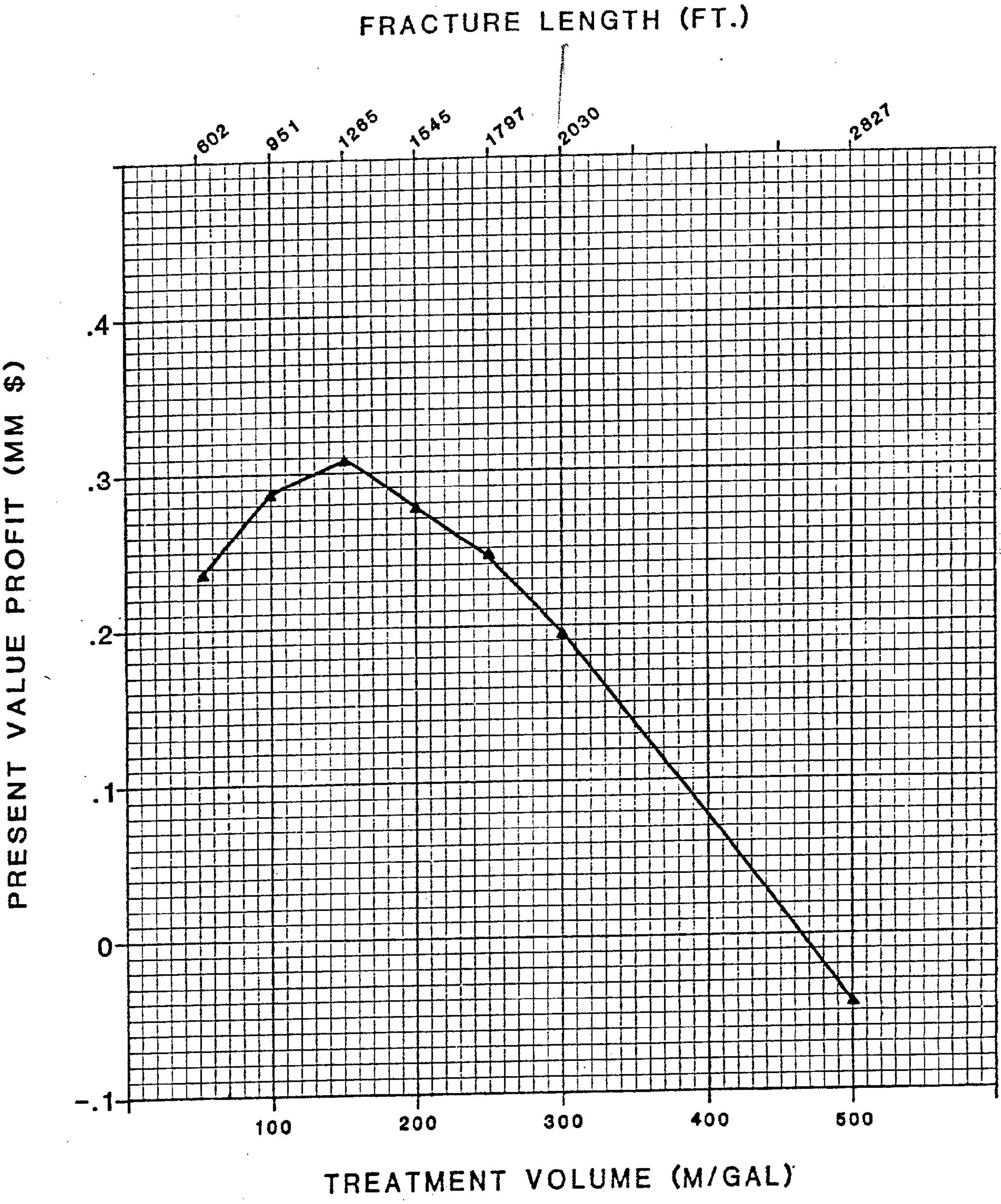
FIG. 23



PRESENT VALUE PROFIT
VERSUS FRACTURE LENGTH
AND FRAC TREATMENT VOLUME
92-1 INTERVAL
LOCATION #3
$.60 GAS/320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

FIG. 24



PRESENT VALUE PROFIT
VERSUS FRACTURE LENGTH
AND FRAC TREATMENT VOLUME
92-1 INTERVAL
LOCATION #3
$1.20 GAS/320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

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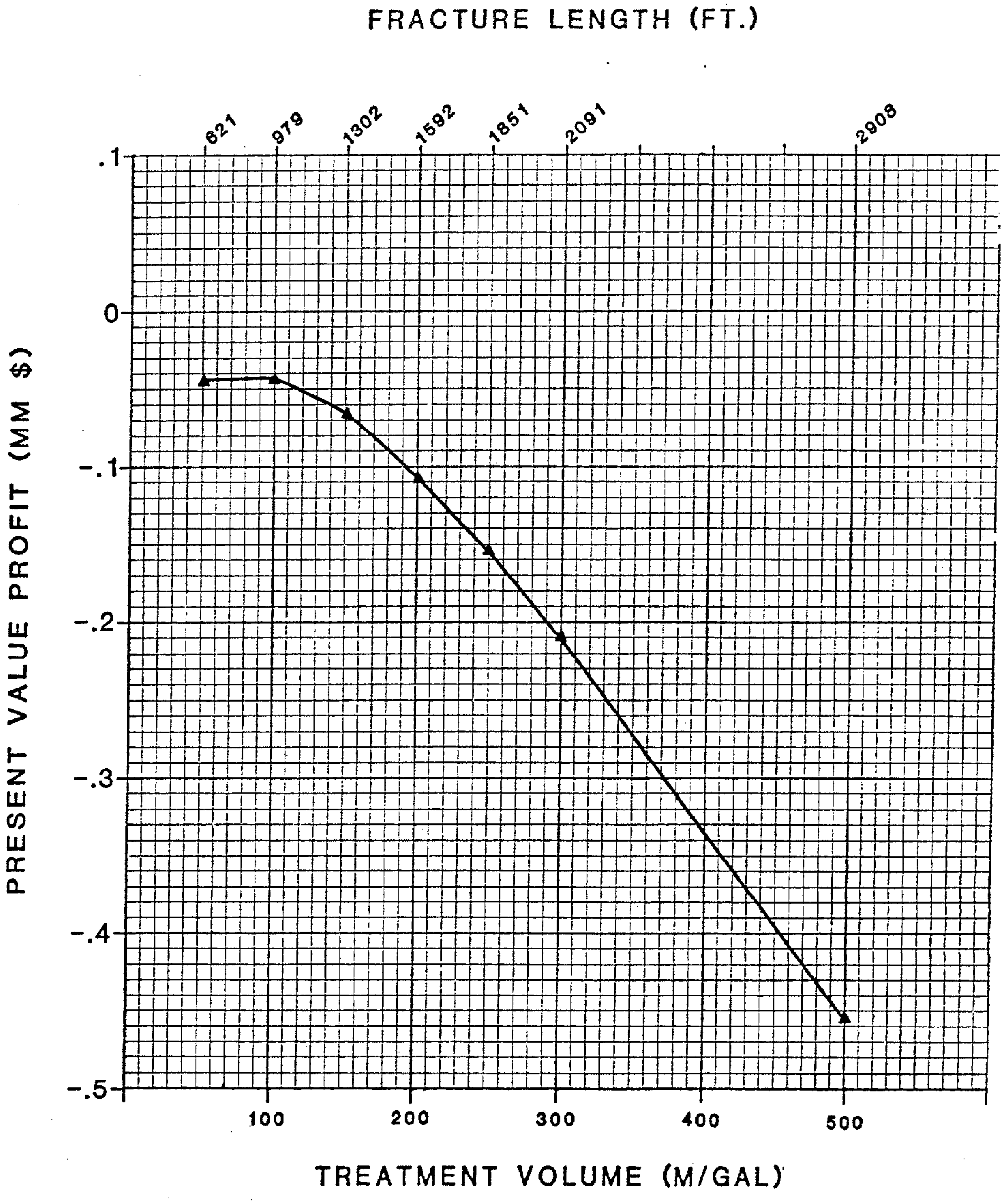
FIG. 25



PRESENT VALUE PROFIT
VERSUS FRACTURE LENGTH
AND FRAC TREATMENT VOLUME
93-2 INTERVAL
LOCATION #3
$.60 GAS/320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

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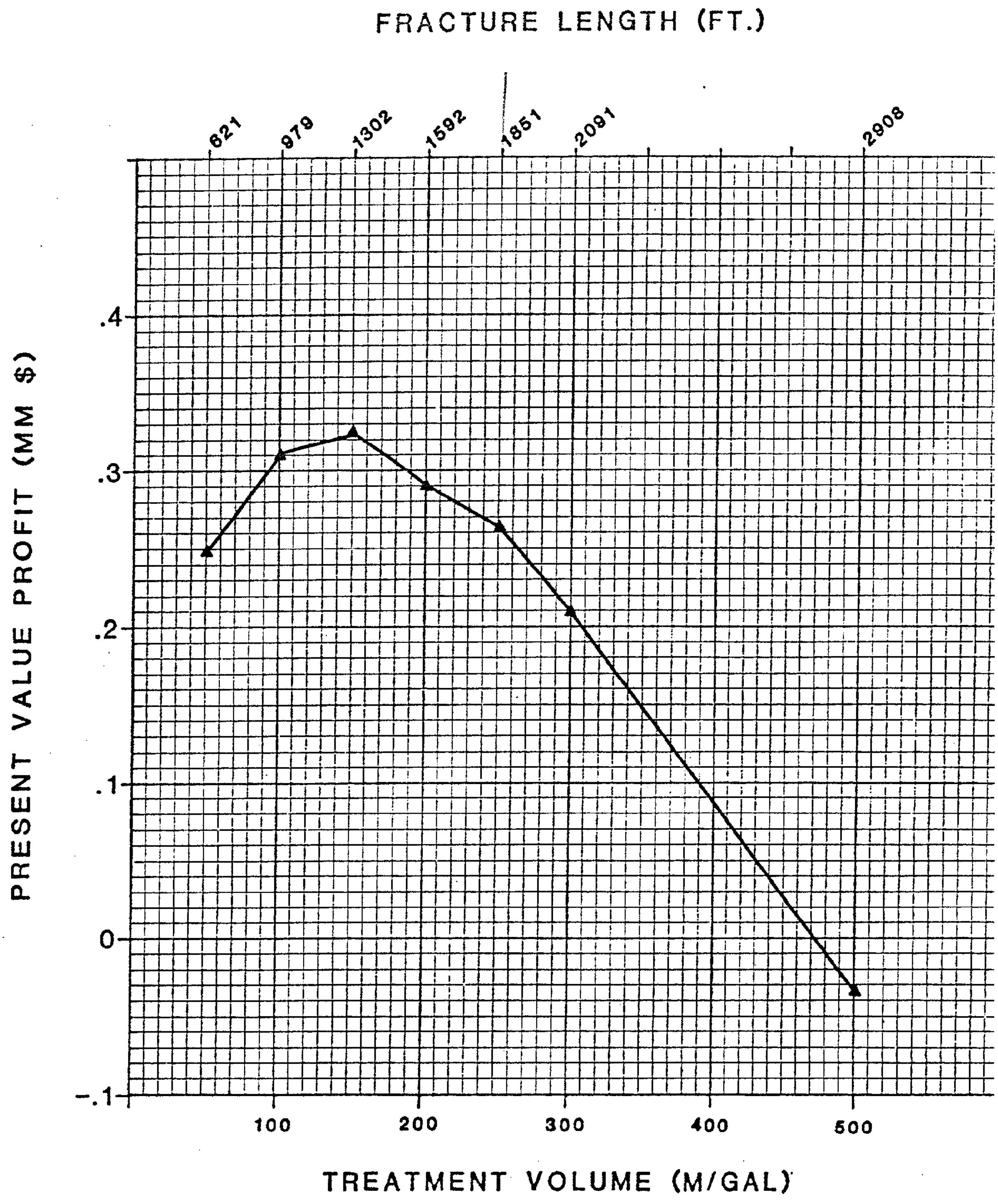
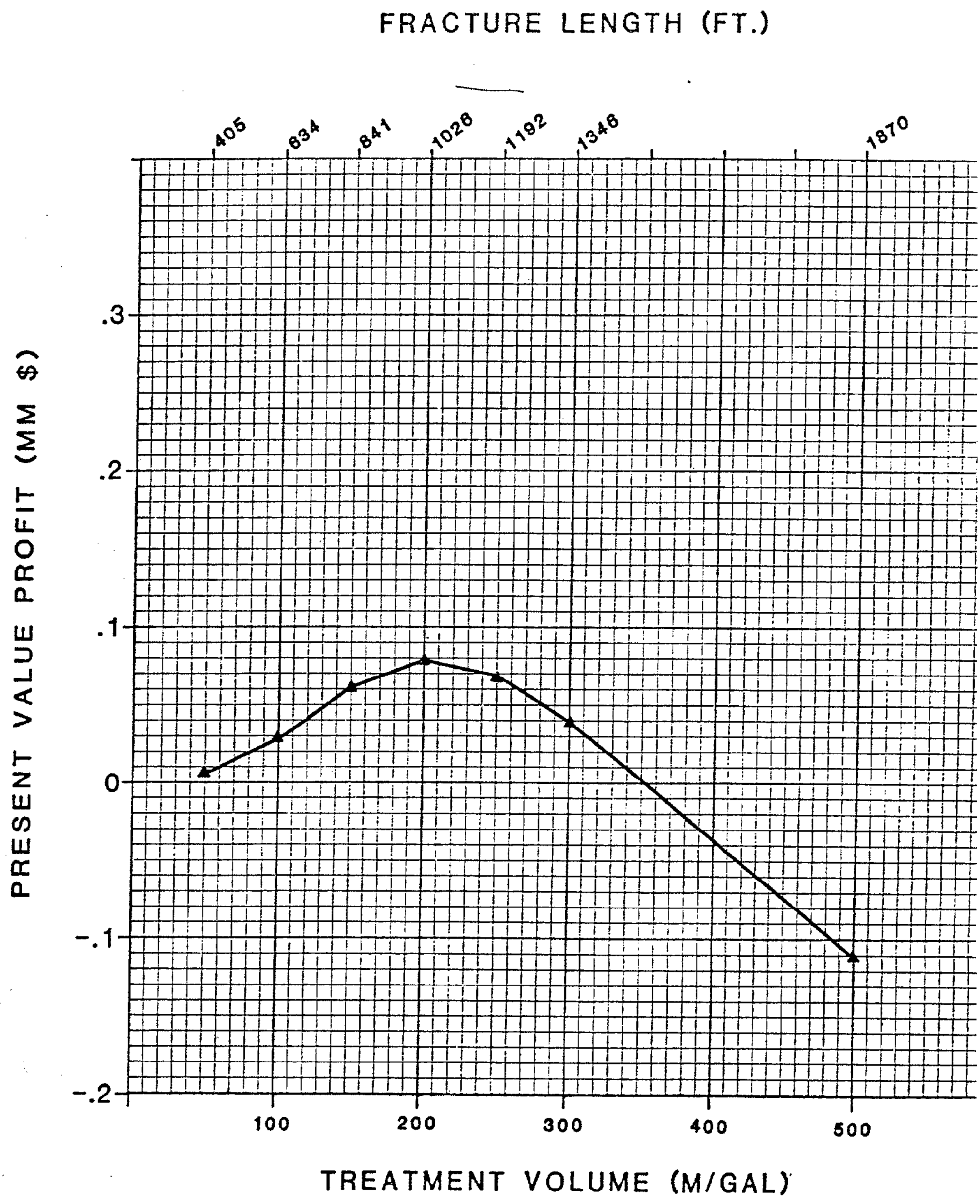
FIG. 26



PRESENT VALUE PROFIT
VERSUS FRACTURE LENGTH
AND FRAC TREATMENT VOLUME
93-2 INTERVAL
LOCATION #3
$1.20 GAS/320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

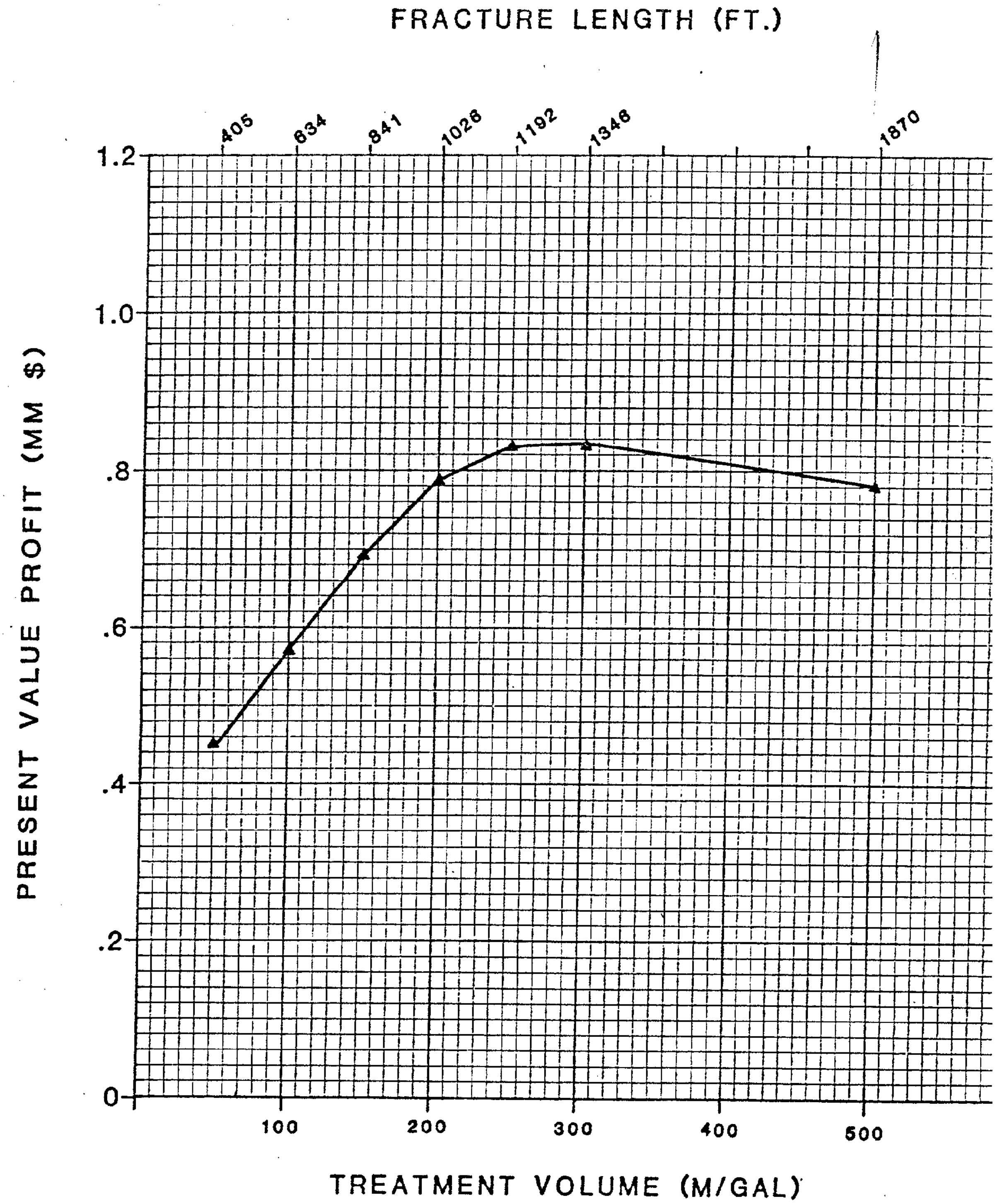
FIG. 27



PRESENT VALUE PROFIT
VERSUS FRACTURE LENGTH
AND FRAC TREATMENT VOLUME
TR-3 INTERVAL
LOCATION #3
$.60 GAS/320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

FIG. 28



PRESENT VALUE PROFIT
VERSUS FRACTURE LENGTH
AND FRAC TREATMENT VOLUME
TR-3 INTERVAL
LOCATION #3
$1.20 GAS/320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

FIG. 29

00070

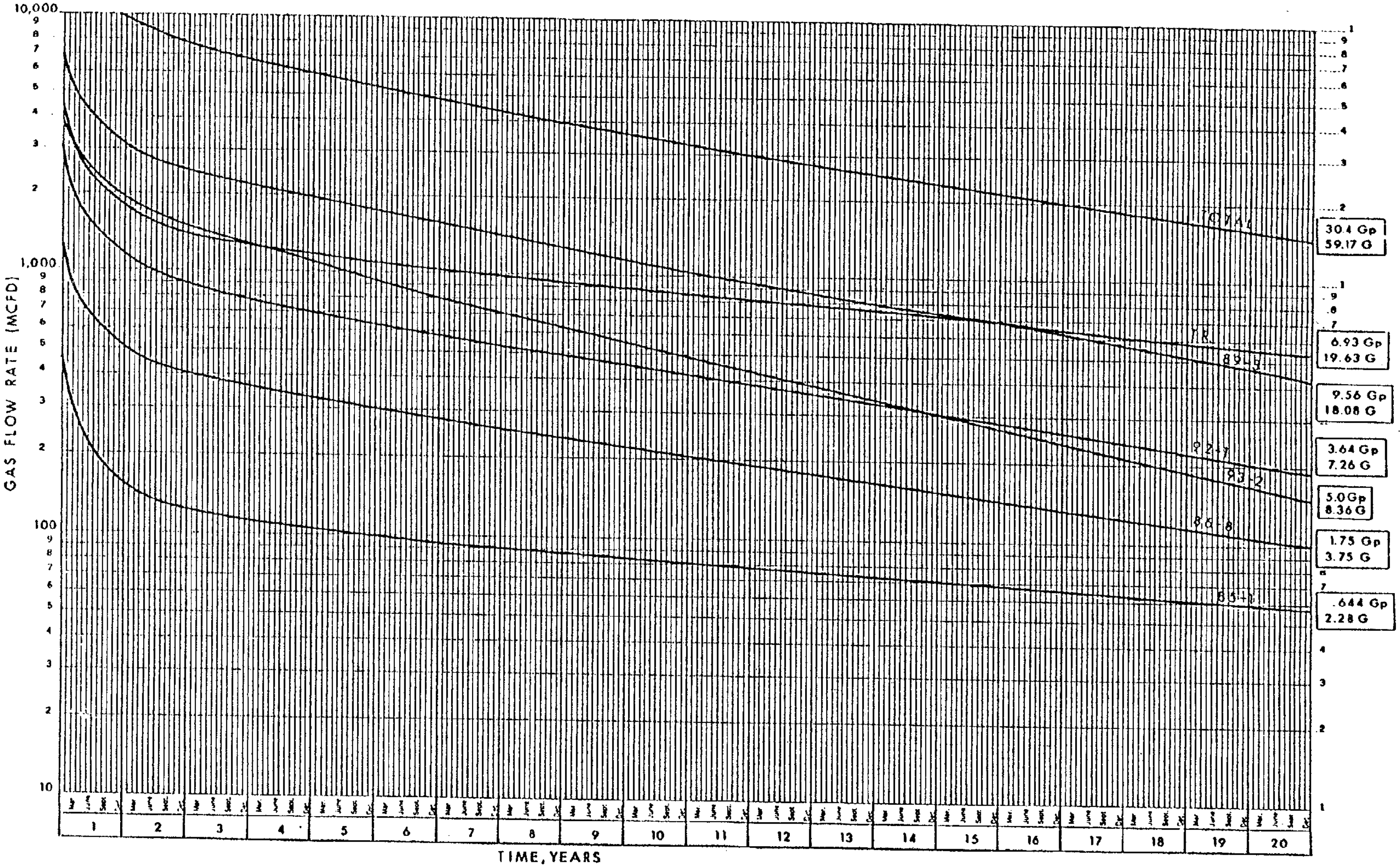


FIG. 30

LEGEND

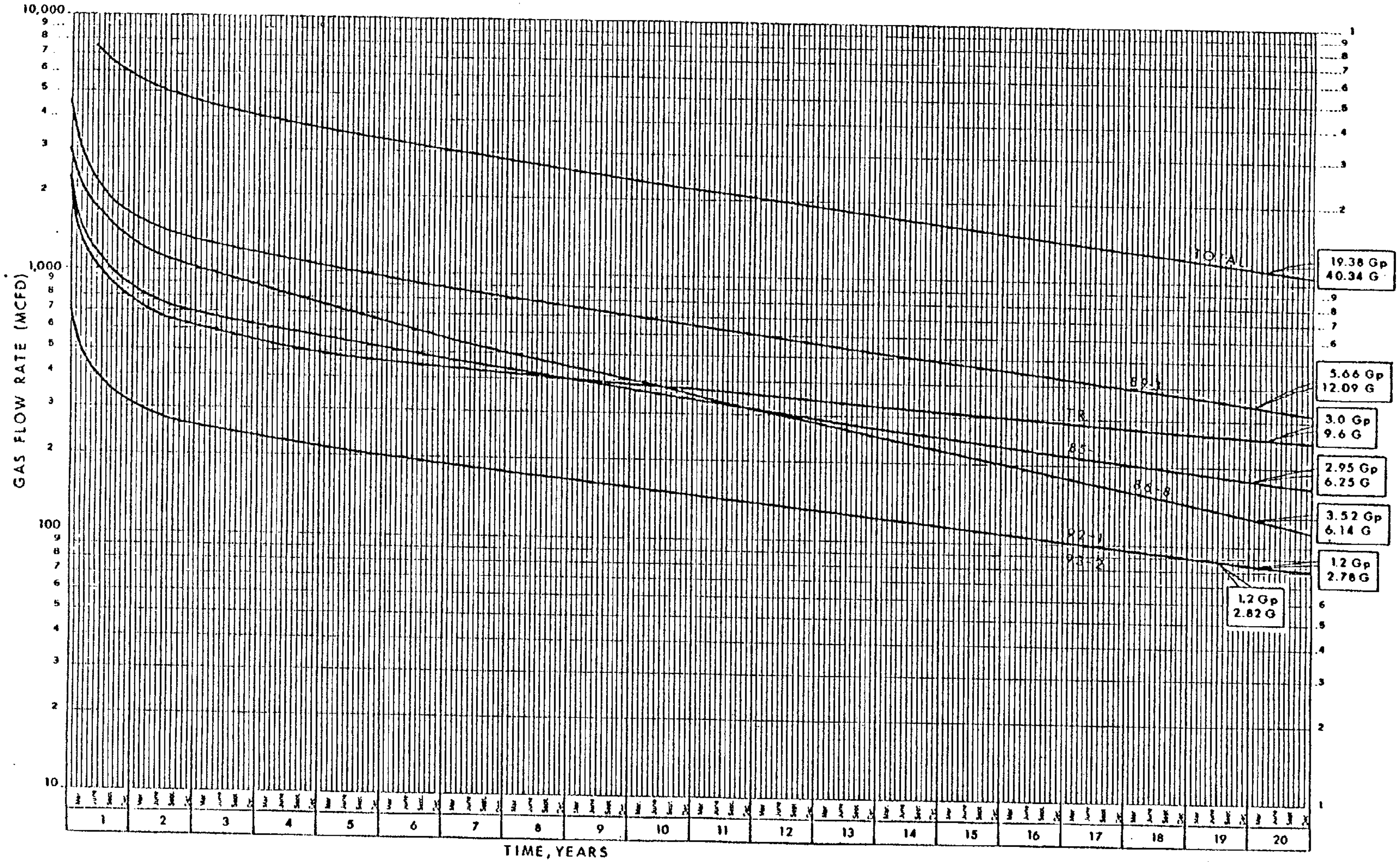
GP = BCF of Gas Produced
G = BCF of Gas-In-Place

92-1 - Interval Produced

FIG. 30

GAS PRODUCTION VERSUS TIME
BY COMPLETION ZONE
BASED ON FRACTURED WELL SIMULATOR
WELL #1 - 320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION



LEGEND

GP = BCF of Gas Produced
G = BCF of Gas-In-Place

92-1 - Interval Produced

FIG. 31

GAS PRODUCTION VERSUS TIME
BY COMPLETION ZONE
BASED ON FRACTURED WELL SIMULATOR
WELL #3 - 320 ACRE SPACING
BIG LAKE FIELD
COOPER BASIN, AUSTRALIA
SOUTH AUSTRALIAN OIL AND GAS

SCIENTIFIC SOFTWARE CORPORATION

FIG. 31

LOGGING ADDENDUM

Due to the availability of more complete logging suites, log evaluation was concentrated on Wells Big Lake No. 1 and Big Lake No. 3. Both wells have resistivity and two porosity devices which is sufficient to determine the effective porosity, fluid saturations, and estimates of the fracture pressure gradient in a good borehole and known petrophysical environment. These data must be graded in any circumstance. Where borehole conditions are adverse and where various amounts of dispersed shale, clays, heavy minerals, and two- or three-phase pore fluid systems exist, the effectiveness of this suite is limited. Wells in the Big Lake Field may exhibit all of these conditions.

Where the borehole is unduly rugose or enlarged, data from certain logging devices should not be used: the values may not be representative of the rocks near the bore wall. The Compensated Density device (FDC of Schlumberger) must maintain intimate contact with a smooth borewall or mud cake to make adequate corrections. Where the hole can be recognized as rugose or unduly enlarged, the bulk density values are suspect at best.

An analysis model was used to identify depth levels where possible bad hole conditions exist. The caliper and correction curve ($\Delta \rho$) from the density log were used for this determination. Where the borehole size is greater than a maximum for the tool, a bad hole condition of "1" is assigned. Where the $\Delta \rho$ curve is greater than a maximum that is reliable, a bad ~~hold~~ hole condition of "2" is assigned. Where both conditions exist, a bad hole condition of "3" is assigned.

All calculations are performed and results available regardless of the probable bad ~~hold~~ hole condition. However, it is mandatory to consider the borehole condition grade within any zone of interest before adjudging the credibility of the results for engineering or economic use.

Determination of Fracture Pressure Gradient

Fracture pressure gradient at any depth level within the overall zone of interest was calculated using a method proposed in SPE paper 4135. The method uses a function of overburden pressure, pore pressure, porosity, Poisson's ratio, and depth of zone.

Poisson's ratio may be derived from wireline porosity logs. It is affected by the shaliness, an index for which is also derived from wireline log data. As the log data become more suspect (due to bad hole conditions) the evaluation of Poisson's ratio, porosity and subsequent calculation of fracture pressure gradient become less useful.

The calculation of reservoir porosity and shaliness index from log data are also dependent upon knowledge of the reservoir rock type and shale types within the zone, i.e. porosity evaluation within a limestone reservoir using sandstone matrix parameters is meaningless. Since the evaluation of shale index and porosity from log data are rock-type dependent, the resultant fracture pressure gradient calculation will only apply where the assumed rock type is present in the well.

A shaly sand reservoir rock type has been assumed for these reservoir intervals for the project study. Fracture pressure gradient calculations in shaly sand intervals where the borehole is regular and under 12" in diameter should be usable. Outside these rock types and limits, the present results should not be used.

Any efforts expended to improve overall reliability of future log data and the accuracy of porosity and volume of shale evaluation will improve all calculations made during log analysis. The following recommendations are offered.

1. New holes should be drilled as smooth as possible. Use of drilling fluids, additives, and drilling techniques to minimize washouts will be effective in increasing the reliability of log data.

2. A gamma ray log should be run with the density log.

3. A Sidewall Neutron porosity (SNP) or Compensated Neutron porosity (CNL) should be added to the logging suite. This would improve the rock type and shale/clay determinations measureably.

4. Whole core and subsequent physical testing would support calibration of the log data.

5. Additional bad hole logic should be developed to further enhance the grading of the data. This work can be done by SSC in Denver.

Integration of additional whole core data from a few wells with new carefully collected log data should improve the overall reliability of all log analysis in the Big Lake Field.

RESULTS OF COMPUTER AIDED LOG ANALYSIS

Tables 1 and 2 summarize the averages from log evaluation in the six zones studied in wells #1 and #3. The summary used any depth level within a zone which calculated a shale volume (V_{sh}) less than 50%, and effective porosity (ϕ_e) less than 20% and more than 4%. Therefore, the number of levels used for averages represents the number of porosity feet over 4% within each zone.

The remarks column contain the analysts' appraisal of the borehole conditions throughout the interval. The numbers used 0,1,2,3 indicate increasing lack of confidence in the density log if used. Where the program has interpreted a coal lithology the number has been set to "9".

Two trace plots for each well accompany this addendum. An appraisal of V_{sh}, ϕ_e, S_w, Fracture Pressure Gradient, and general grade of the data may be made. In addition, the shading between traces HYCVOL and HYCWT indicates a qualitative interpretation of the presence of gas. An additional calculation of Fracture Pressure Gradient (FRAPGE) is shown on the trace plot. This calculation is valid only within the reservoirs where the borehole condition is good.

The computer program evaluates the log data on a depth level by depth level basis. Boundary effects (relationships between values of adjacent depth levels) are not taken into consideration. In addition to evaluating the mechanical condition of the hole for "bad hole", the logic also grades the usability of the two porosity devices and gamma-ray data at each level or depth point. As a value from a device is judged "out of bounds" with relationship to the other log values at the same depth, it is excluded from the evaluation at that depth level.

The hierarchy is as follows:

1. Where density, sonic and gamma-ray data are acceptable, tests for coal and shale are made. No additional calculations are performed in these lithologies.

2. Where both density and sonic log data are acceptable, ϕ_e is derived from the density-sonic crossplot relationship and corrected for shale and light hydrocarbons, if necessary.

3. Where sonic log data are rejected, ϕ_e is derived from the density log, corrected for shale if necessary.

4. Where density log data are rejected, ϕ_e is derived from the sonic log, corrected for shale if necessary.

5. Where both porosity logs are rejected, no calculations are made. A shale lithology is assumed.

6. Volume of shale (V_{sh}) is derived from the density-sonic crossplot where (a) both logs are acceptable, and (b) the calculated V_{sh} is less than that calculated from the gamma-ray.

7. Where either density or sonic data are rejected, V_{sh} is derived from the gamma-ray.

Crossplots of log porosity and log R_t were used to derive values for formation water resistivity, R_w, and cementation factor, m, for use in the Archie equation. Matrix values of Δt_m = 56.0 μ/ft. and ρ_g = 2.67 gm/cc were used. Values of $(A \times R_w)$ = .14 and n = 2.0 were used for this analysis. Due to the high percentage of unusable density log levels, descrete rock typing for each zone was not attempted.

Computer aided log analysis on future wells where our previous recommendations are followed should result in the following:

1. Precise rock typing in each zone to derive more reliable matrix values.

2. A higher confidence level in ϕ_e, V_{sh}, and pore fluid calculations due to an additional porosity device and fewer number of bad hole levels.

3. More reliable fracture pressure gradient calculations.

TABLE 1

Tabulation of Computer-Aided Log Analysis
Big Lake #1

Formation	Zone	Depth (FT)	ϕ_e Avg %	S_w Avg %	V_{sh} %	Fracture Pres. G. psi/ft.	Remarks
Patchawarra	85-1	8515-29 14	5.1	35.8	21.6	0.89	Hole condition 2. FDC had poor contact with borewall. ϕ_e from ϕ_s corrected for shale. Seven levels used.
	86-8	8681-93 12	4.4	45.5	18.3	1.05	Hole condition 0,2. High V_{sh} calculations near top and base of zone eliminate potential porosity. Five levels used.
845	89-3	8934-65 31	7.0	13.0	22.9	0.80	Hole condition 2,3. Frac pressure data reliable. ϕ_e mostly from ϕ_s corrected for shale. Twenty-seven levels used.
	92-1	9213-51 38	7.3	15.9	15.7	0.81	Hole condition 3,2. Frac pressure data reliable. ϕ_e mostly from ϕ_s corrected for shale. Thirty-one levels used.
	93-2	9328-60 32	10.4	13.1	17.2	0.81	Hole conditions 2,3. Frac pressure data reliable ϕ_e from ϕ_s corrected for shale and light hydrocarbons. Twenty-three levels used.
Tirrawarra		9571-9688 117	10.2	16.8	25.1	0.88	Hole conditions 3,1,2. Coal encountered. Frac pressure gradient probably slightly high. ϕ_e from ϕ_s and ϕ_d combination. Forty-eight levels used.