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EXPLORATION AND PRODUCTION PROGRAM FOR LOCATING AND PRODUCING PROSPECTIVE AQUIFERS CONTAINING SOLUTION GAS AND FREE GAS— TEXAS GULF COAST

ANNUAL REPORT

(February 1981 - February 1982)

Gas Research Institute
8600 West Bryn Mawr Avenue
Chicago, Illinois 60631

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For

GAS RESEARCH INSTITUTE

Contract No. 5080-321-0398

GRI Project Manager
Leo A. Rogers
Geopressured Methane

August 1982

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16. Abstract (Limit: 200 words)

The Port Arthur field, Jefferson County, Texas, was selected as a prospective watered-out gas field that is favorable for application of secondary enhanced gas recovery methods. This field contains multiple watered-out gas reservoirs, multiple thick aquifers, and gas stringer sandstones at depths from 10,850 to 11,700 ft. Sidewall core data show that the average porosity is 30 percent and average permeability is 60 md. Reservoir simulation studies predict that 3.91×10^9 standard cubic feet of unconventional gas can be recovered by natural flow from the "C" sandstone over a 10-year period by reducing reservoir pressure from 6,500 to 4,018 psig. The break-even gas price is $3.45 per thousand standard cubic feet for a 15-percent rate of return.

Substantial additional gas recovery can be obtained by co-production from other sandstones and by further reduction of reservoir pressure by artificial lift. It is recommended that a design test well be drilled to a depth of 11,650 ft on a site near the Meredith no. 2 Doornbos (well no. 14).

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RESEARCH SUMMARY

Title	Exploration and Production Program for Locating and Producing Prospective Aquifers Containing Solution Gas and Free Gas--Texas Gulf Coast
Contractor	Bureau of Economic Geology The University of Texas at Austin GRI Contract No. 5080-321-0398 Accession Code: GRI-80/0141
Principal Investigator	A. R. Gregory
Time Span	February 1981-February 1982 Annual Report
Objective	This project was designed to locate and evaluate a prospective watered-out gas reservoir in the Texas Gulf Coast inland area. The prospective reservoir should be suitable for application of enhanced gas recovery methods for producing the unconventional gas that remained in the reservoir after primary gas production ceased. The methodology employed would be evaluated, and a test well site would be located within a favorable prospect area.
Technical Perspective	Previous related work conducted by the Bureau of Economic Geology included geological studies for the U.S. Department of Energy that focused on the selection of test well sites in the Frio Formation and Wilcox Group of the Texas Gulf Coast where temperatures are at least 300°F. Initially these studies were intended to make use of thermal energy, mechanical energy, and gas dissolved in formation waters by producing large volumes of hot water from deep highly pressured formations. In later projects funded by the Gas Research Institute, interest shifted to solution gas and free gas because of increases in the price of gas and even higher prices projected for future gas. The present project, funded by the Gas Research Institute, shows a continuing interest in unconventional gas and the development of prospects that are favorable for producing solution gas and free gas remaining in watered-out gas fields.

Results

The guidelines set up for screening gas fields along the Texas Gulf Coast resulted in the selection of the Port Arthur field, Jefferson County, Texas, as a suitable prospect for application of enhanced gas recovery methods. Several watered-out gas sandstones in this field have excellent reservoir characteristics. All 18 wells in the field have been plugged and abandoned by previous operators; hence, leasing problems should be simplified. Abundant shallow Miocene sands in the area are available for saltwater disposal.

The "C" reservoir interval, located at an average depth of 11,132 ft, received the most extensive evaluation. Predicted gas recovery by natural flow is 3.9 billion standard cubic feet as reservoir pressure declines from 6,500 to 4,018 psig. The break-even gas price of $3.45 per thousand standard cubic feet obtained for a 15-percent rate of return is encouraging.

Use of gas lift increases the predicted gas recovery from the "C" reservoir to a total value of 11.7 billion standard cubic feet as reservoir pressure declines from 6,500 to 1,700 psig. It is probable that production from the "C" reservoir would be commingled with production from other reservoirs in the field. Preliminary results show that solution gas represents only 4 percent of the total predicted gas recovery.

Recommendation

It is recommended that a design test well be drilled to a depth of 11,650 ft on a site near the Meredith no. 2 Doornbos (well no. 14).

Technical Approach

The first task was to locate a prospective watered-out gas field where free gas and water containing solution gas could be co-produced in economic quantities. Guidelines and test criteria were established for screening gas fields in the Texas Gulf Coast. Eventually the Port Arthur field was selected as the most favorable prospect for further study and evaluation.

The second task was to collect different types of data for the Port Arthur field and to analyze the data using various methods that are broadly classified as geological, reservoir engineering, geophysical, well log analysis, and economic analysis.

The Port Arthur field, which covers about 3 square miles, produced gas and condensate from the lower Hackberry (Frio) sandstones; the sandstones are interpreted as submarine fan deposits. The field contains multiple watered-out gas reservoirs, multiple thick aquifers, and gas stringer sandstones at depths from 10,850 to 11,700 ft. Core data and well log analyses show that porosity averages 30 percent and permeability averages 60 md. Initial pressure gradients average 0.73 psi/ft but fall to an average of 0.45 psi/ft when the reservoirs water out.

The amount of gas dissolved in formation waters was estimated from known values of pressure and temperature and calculated values of salinity. Pressures were obtained from drill-stem tests or from wellhead shut-in measurements. Borehole temperatures were obtained from well logs and corrected to equilibrium values. Salinities were determined from spontaneous potential well logs.

Water saturation, used to help locate gas/water contacts in the field, was determined from resistivity ratios obtained from induction logs. The original gas in place was determined by a volumetric method; parameters required for the volumetric calculation were evaluated by analyzing induction logs.

A computer reservoir simulation study was initiated for the "C" reservoir in the lower Hackberry sandstones using a two-dimensional gas/water areal simulator and "dynamic pseudo functions" to approximate a three-dimensional model. A history match was performed, and a 10-year gas recovery forecast was made. An economic analysis of the "C" reservoir gave encouraging results.

More than 31 miles of seismic data are being processed to supplement geological interpretations of structure in areas with poor well control. Reprocessed data will be used to help define reservoir boundaries, locate faults that might isolate reservoirs from sandstones downdip, map suspected submarine channels, and apply special amplitude analysis to help identify the extent of free gas in the "C" sandstone.

Project Implications

One of the important aspects of the GRI unconventional natural gas supply research program is to identify field test prospects of interest to industry and GRI. In a 1981 assessment, geopressured watered-out gas reservoirs were identified as the most promising R&D prospects for the co-production of gas and water. This project by the Bureau of Economic Geology has been successful in identifying many prospects in Texas, and for the specific search criterion of watered-out reservoirs, the Port Arthur field appears to be a good selection. Work will be continued to further assess the resource and identify other possible field test sites that will meet the needs of well tests having different R&D objectives.

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INTRODUCTION

Description and Objectives of Project

This project is a comprehensive exploration and reservoir engineering program designed to locate and evaluate a prospective inland test area on the Texas Gulf Coast that will produce gas and water at a ratio that exceeds the solution-gas-to-water ratio. The search for suitable test areas was focused on watered-out gas fields. The types of reservoirs considered include hydropressured and geopressured reservoirs that are suitable for application of enhanced gas recovery methods for producing unconventional gas after primary production ceases. Unconventional gas consists of solution gas, mobile and producible free gas remaining in the gas cap (fig. 1), immobile dispersed free gas trapped in the water-invaded zone, and mobile and producible free gas located in thin noncommercial stringer sandstones. Some of the dispersed gas may be recovered by withdrawing large volumes of water to depressure the reservoir. The reduction in pressure causes expansion of the immobile dispersed gas, which then becomes mobile and migrates more easily to the production well. Lower pressure in the aquifer also allows the release of some of the gas that is dissolved in formation waters. A portion of the released gas may migrate upward to form a gas cap or expand an existing gas cap and be produced from one or more wells. The volume of producible free gas depends on the existing reservoir pressure, reservoir pore volume, water saturation, permeability, and other reservoir characteristics. If the prospective watered-out gas field also contains noncommercial virgin stringer gas sandstones, this free gas may also be commingled and produced with unconventional gas from other sources discussed above. A noncommercial stringer gas sandstone is defined as a thin gas sandstone that was passed over or ignored by previous operators in the field. Normally a stringer gas sandstone has little or no aquifer associated with it (fig. 2).

The objective of the first phase of the project was to establish guidelines for screening and selecting a favorable prospect. This objective was attained when the Port Arthur field, Jefferson County, Texas, was selected from over 150 gas fields that were screened. After selection, a geological study of the field was completed.

The objective of the second phase of the project covered in this report was to collect different types of data and to analyze the data using various methods that are broadly classified as reservoir engineering, geophysical interpretation, well log analysis, and economic analysis. More than 31 miles of raw seismic data obtained for lines located in or near the Port Arthur field are currently being processed, and the results

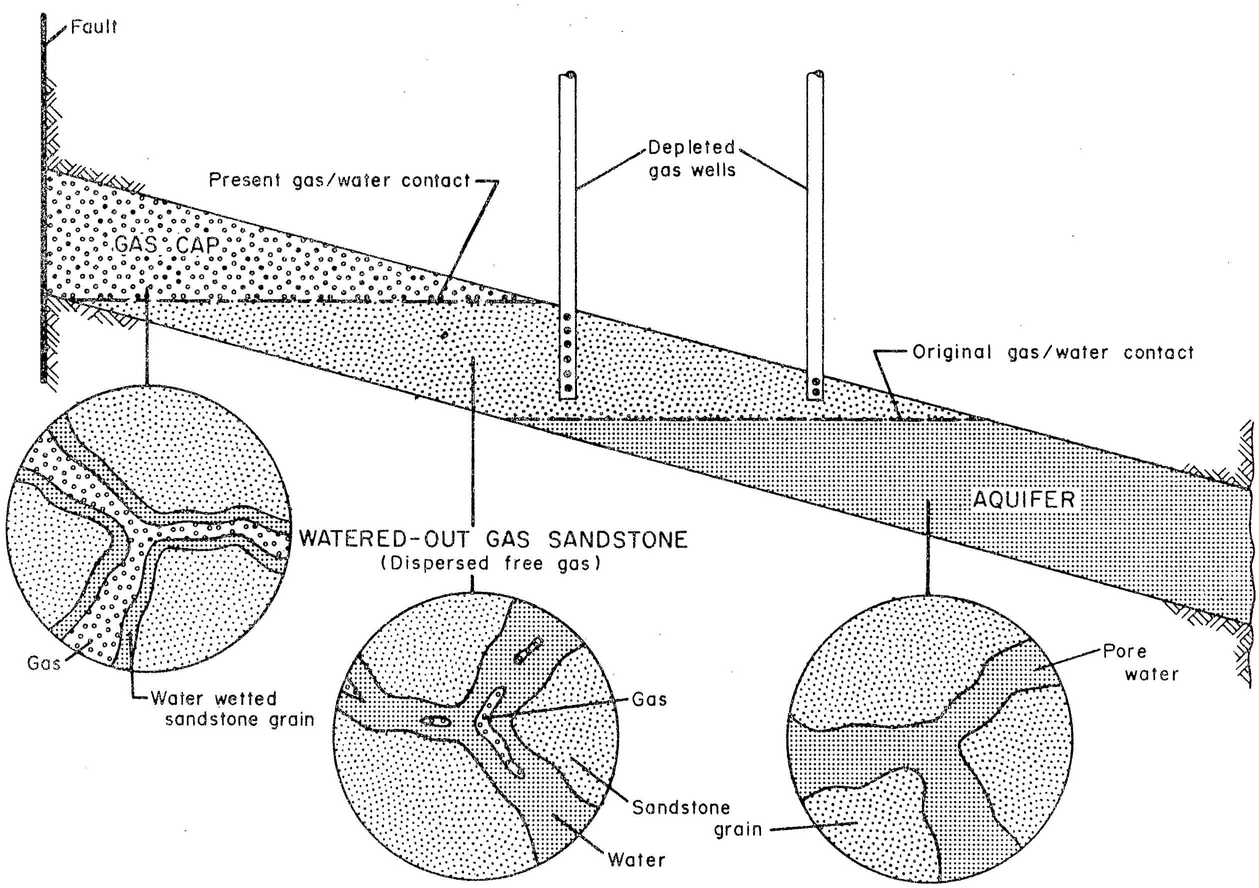

Figure 1. Model of a hypothetical watered-out gas reservoir.

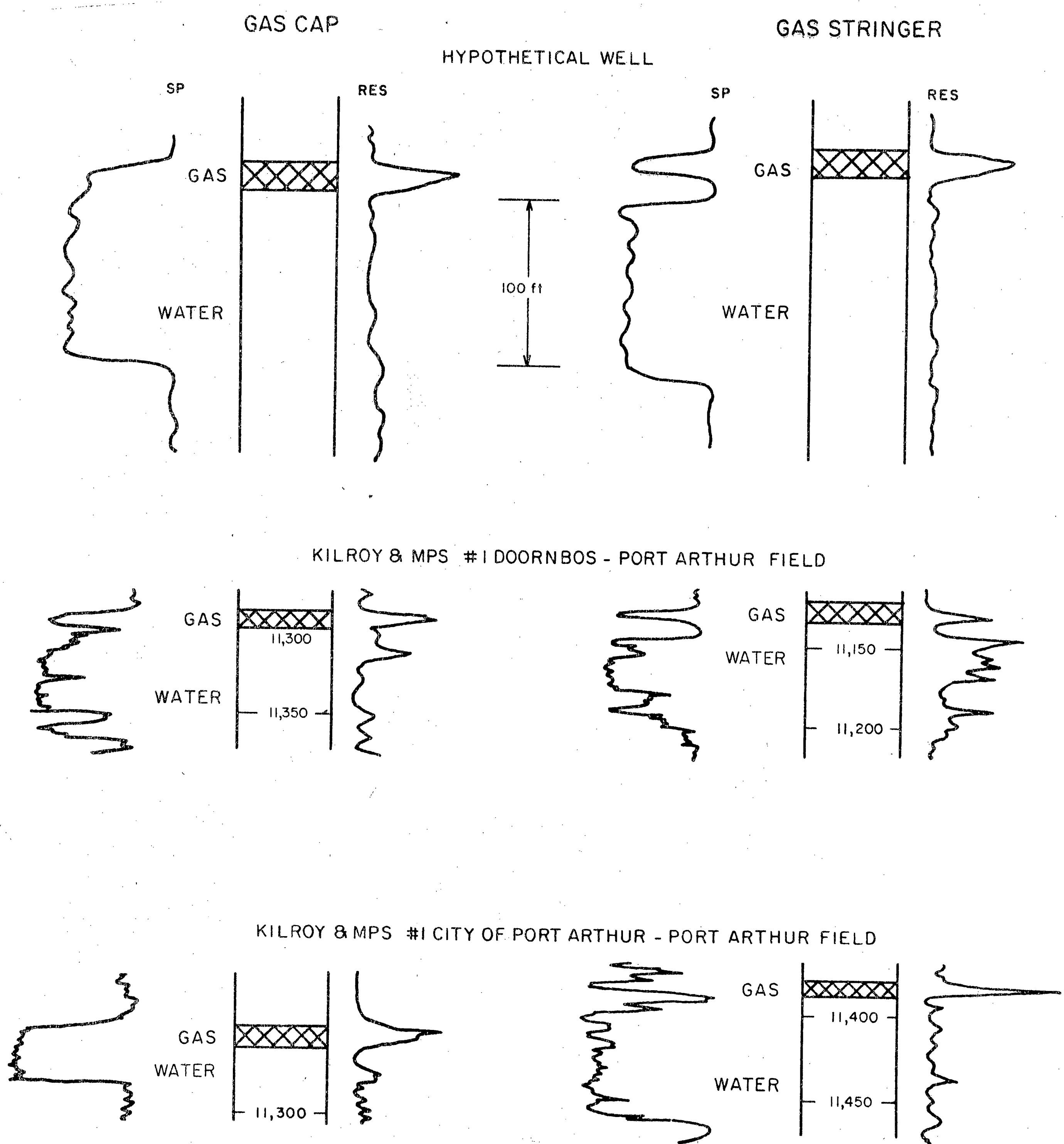

Figure 2. Typical well-log response for types of reservoirs considered in this project.

will be given in the final report. A computer reservoir simulation study was done on the "C" reservoir in the lower Hackberry sandstone interval. History matches were performed, and predictions of reservoir performance and additional gas recovery were made for specified rates of gas and water production over a 10-year period. An economic analysis indicates that the results are encouraging. Well log analyses were completed for the "B-2" and "C" reservoirs. Gas-water contacts were established, and hydrocarbon pore volume maps were prepared for this report.

Formation fluid properties of pressure, temperature, and salinity have a significant influence on the amount of methane gas that can be held in solution. Solution gas, however, is of less importance in this project because it represents a relatively small part of the total gas resource. As a result, the influence of high salinity on the resource is minor, but high-salinity waters may cause scaling and corrosion of production equipment.

An important objective of the third and final phase of this project is to evaluate the relative effectiveness and economic impact of the methods used to evaluate the prospect. This evaluation will be discussed in the final report, and the proposed test well site will be delineated in more detail.

Previous Related Work

Previous geological studies by the Bureau of Economic Geology, funded by the U.S. Department of Energy (DOE), concentrated on the development of prospects in the Texas Gulf Coast area. These prospects were intended to produce large volumes of water from deep geopressured zones where fluid temperatures were at least 300°F* (Bebout and others, 1978a, 1978b, and 1979). Later studies, funded by the Gas Research Institute (GRI), were directed toward the location of prospective areas that were favorable for producing solution gas from deep hydropressured and shallow geopressured zones where formation fluid temperatures were less than 300°F (Weise and others, 1981a). The GRI studies included the A, B, and C Zones that were defined on the basis of pressure gradients and temperatures (fig. 3). The A Zone is the deep hydropressured zone below a depth of 4,500 ft, in which the pressure gradient is hydrostatic (0.465 psi/ft). The B Zone is a relatively thin zone of transition from hydrostatic pressure gradients (0.465 psi/ft) to abnormally high pressure gradients of

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*Metric conversion factors are given in appendix F; nomenclature and abbreviations used in this report are given in appendix G.

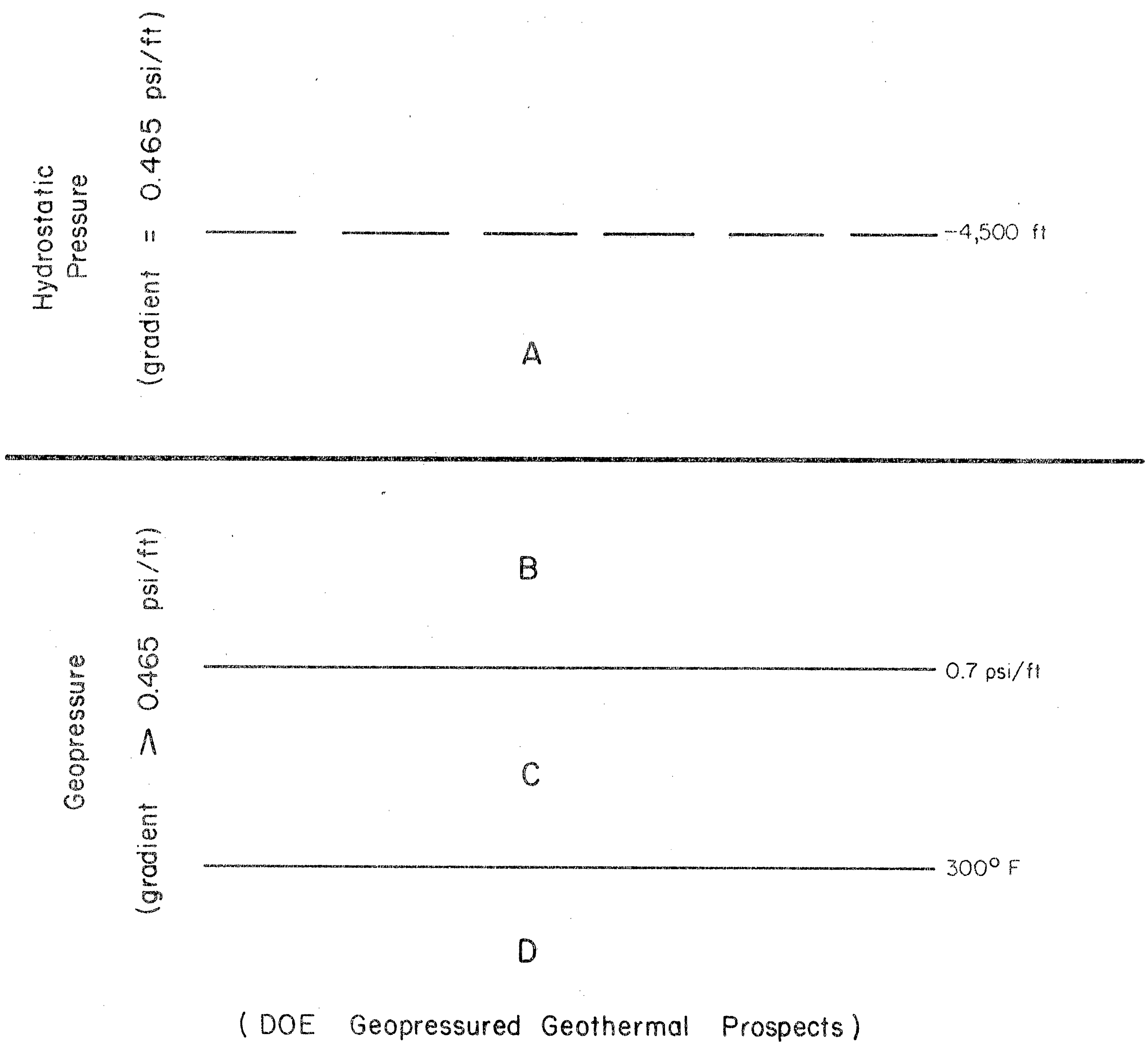

Figure 3. Definition of geopressured and deep hydropressured zones.

about 0.7 psi/ft. The C Zone has fluid pressure gradients greater than 0.7 psi/ft and fluid temperatures less than 300°F. In the D Zone, fluid pressure gradients are greater than 0.7 psi/ft and fluid temperatures are greater than 300°F. Broad sandstone corridors following trends of the Wilcox Group and Frio Formation were outlined. Areas with maximum net sandstone within these corridors were identified as the Matagorda, Corpus Christi, Kenedy, Cameron, and Montgomery fairways. Several areas within these fairways were considered to be favorable for testing the solution gas resource and were identified as prospects.

A continuation of the above work was later redirected to supplement the DOE conventional geopressured geothermal program and the GRI dispersed gas project (Weise and others, 1981b). Reconnaissance for conventional geopressured prospects of the interfairway Frio/Vicksburg and Wilcox sandstone trends showed that only five fault blocks had enough potential for further study. These fault blocks were identified as Point Comfort, Blue Lake, Devillier, and Port Arthur in the Frio/Vicksburg trend and Holzmark South in the Wilcox trend (fig. 4). A large number of watered-out gas fields located in most of the Wilcox and Frio/Vicksburg trends and in fairways were screened as possible test areas for the project described in this report.

PROSPECT SELECTION AND EVALUATION

Guidelines for Selecting Test Area

Guidelines for selecting favorable test reservoirs in watered-out gas fields are listed below.

1. The area of the watered-out gas field, fault block, or aquifer should be equal to or greater than 5 mi^2.
2. There should be at least five watered-out gas wells.
3. It is desirable that there be few or no active producing gas or oil wells.
4. Multiple prospective sands have some advantage, but one thick sand with a gas cap or a thin gas sand associated with a thick aquifer with good lateral continuity should be adequate.
5. Approximate minimum thickness of the sand should be 5 ft of gas sand associated with a 40-ft aquifer.
6. Formation pressures of abandoned gas reservoirs may vary from less than 0.3 psi/ft to more than 0.7 psi/ft. Normally, gas reservoirs with high pressure gradients are not abandoned without good reason; therefore,

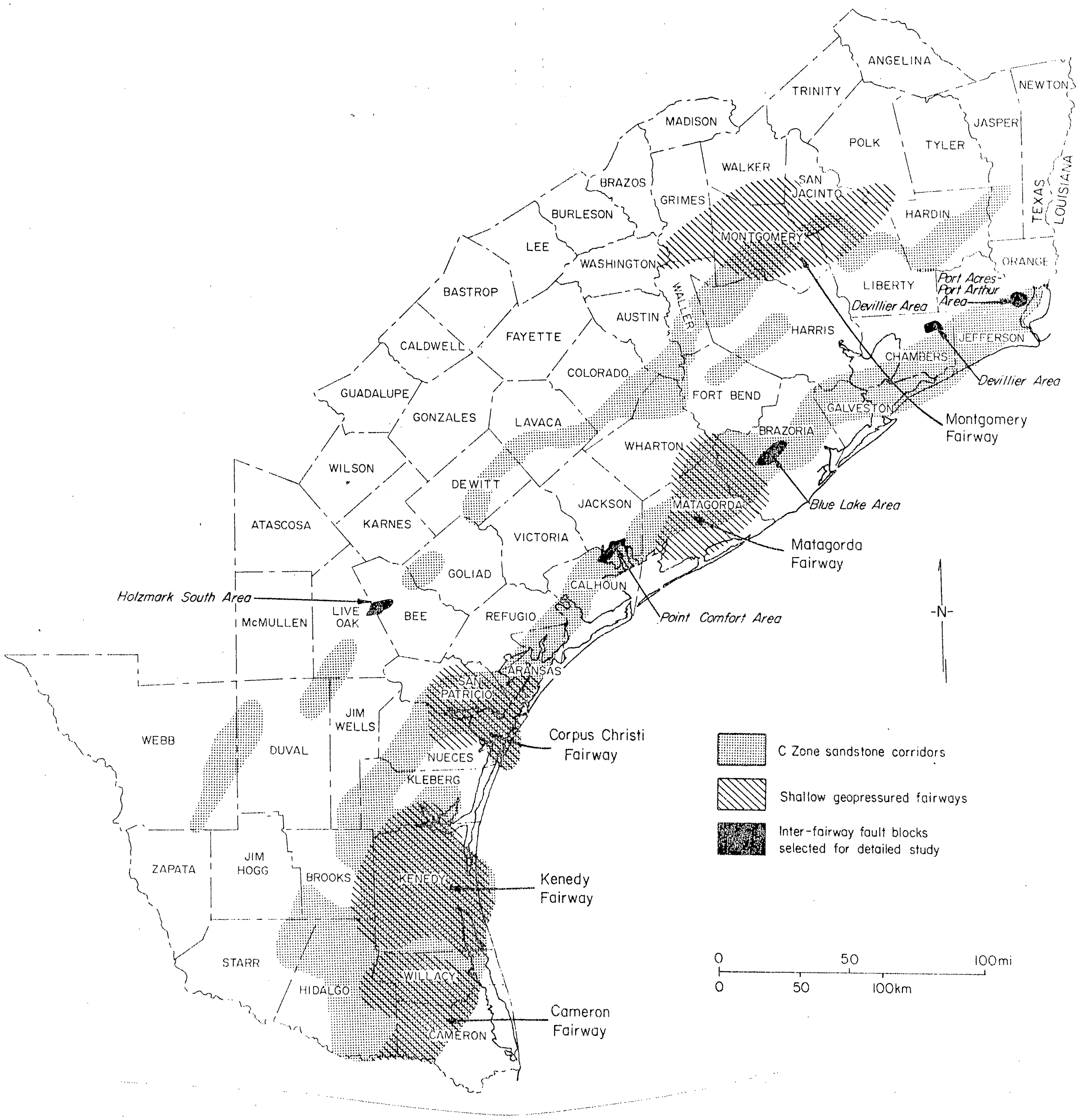

Figure 4. Fault blocks selected for detailed study along C Zone sandstone corridors between fairways (from Weise and others, 1981b).

mechanical problems, sand or shale production, casing partings, and other production problems should be noted. These problems do not necessarily detract from the value of the prospect. High abandonment pressure means that more gas remains in the reservoir and increases the value of the prospect.

7. High temperature increases the methane solubility in formation water and adds to the value of the prospect. A temperature of $200^{\circ}F \pm 15^{\circ}F$ may be considered a practical lower limit for hydropressured reservoirs in Texas.

8. Permeability, which is particularly important for the aquifer because large volumes of water must be produced at high rates, should be at least 20 md. High porosity (20 percent) may or may not indicate good permeability.

9. Low salinity increases methane solubility in formation water and adds to the value of the prospect. Salinities below 100,000 ppm NaCl are preferred. Water samples recovered from the formation by an approved technique and analyzed for total dissolved solids give the most credible values of salinity. The SP well log is less credible but often is the only alternative for estimating salinity.

10. Existing seismic lines located in or near the field are very desirable. It is also desirable that some wells in the field have sonic and/or density logs as well as induction logs. A very good prospect should have strike and dip seismic lines and sonic and density logs for at least four wells in the field.

It is emphasized that these guidelines are not strict criteria. Most likely no field would meet all requirements, and compromises must be made.

Screening of Gas Fields

Numerous gas fields in the Frio/Vicksburg and Wilcox sandstone trends were screened initially. Attention was given to reservoirs in wells that were listed by Doherty (1981) as (1) watered-out geopressured gas cap wells (pressure gradient greater than 0.65 psi/ft), (2) wells that lacked shut-in pressure data but had high water production rates, and (3) rejected wells that had pressure gradients between 0.60 and 0.65 psi/ft. Many fields were rejected in the initial screening if factors such as too small an area or large numbers of wells actively producing could be readily determined. Fields that showed some potential in the initial evaluation or that needed more specific work to determine field area or production status were referred to a special study group for additional evaluation and determination of less readily available information. This information consisted of permeability, porosity, salinity, methane solubility, pressure and production history, sandstone continuity, and availability of seismic data and sonic and density logs.

Reservoir evaluation checklists (example in table 1) were prepared for individual wells in fields of interest. After final evaluation of a field, favorable and unfavorable factors and a recommendation were given on a short form such as that given in appendix A. The potential prospects were then classified in three categories: (1) a class A field is most favorable for a dispersed gas test area; (2) class B fields have marginal potential or lack certain data needed for full evaluation; and (3) class C fields were rejected.

Selection of Potential Test Areas

Class A Field

The screening of gas fields along the Frio/Vicksburg and Wilcox sandstone trends resulted in the selection of the Port Arthur field, Jefferson County, Texas, as the most favorable test area. The short form evaluation sheet (table 2) lists both favorable and unfavorable criteria. The favorable features clearly predominate, making the field a prime prospect (class A).

Class B Fields

Two fields were classified as class B because they have some attractive characteristics but are thought to have marginal potential because of negative features such as small area, active production, shaly sands, and low permeability. The class B fields are Port Acres, Jefferson County, Texas, and Algoa, Brazoria and Galveston Counties, Texas. Evaluation sheets (appendix A, tables A1 and A2) summarize the favorable and unfavorable features of these fields.

The Port Acres field previously produced gas distillate primarily from a single interval (10,350-10,600 ft) in the lower Hackberry (Frio) sandstone units. Sandstone thickness in the producing interval varies from 30 to 120 ft. Porosity is high (28-35 percent), and permeability ranges from 5 to 1,000 md. Most wells have been plugged and abandoned. Pressures recorded before abandonment were low. The field might be considered a viable hydropressured prospect, but the economics are questionable.

The Algoa field produces gas from the Frio 37 sandstone in the depth interval from 10,350 to 10,750 ft. The target sandstone is 150 to 300 ft thick, including gas cap and aquifer. There are five active wells in the field; three are recent completions.

Table 1. RESERVOIR EVALUATION CHECKLIST

Dispersed Gas Project

(1) Name of operator: Meredith and Co.

(2) Well no. and name: #2 W. Doornbos (well #14)

(3) County: Jefferson

(4) Tobin Grid: 1S-49E-4

(5) Located in gas field — Yes X No ____

- Field name: Port Arthur
- Active gas well: No
- Inactive (P & A), date: 10/72
- Inactive (shut-in), date: ____

(6) Total depth: 12,200 ft

(7) SS thickness: 63 ft

(8) SS interval (ft): Upper 11,117 Lower 11,160

(9) Perforation depths "C" sandstone: 11,136-11,144 ft

(10) Porosity ____ %

- Whole core: ____
- SWC: 34.8 (average)
- Computed: 23
- (Identify method used): $F=0.62/\phi^{2.15}$ (HUMBLE)

(11) Permeability ____ md

- Whole core: ____
- SWC: 218 (avg)
- BU/DD tests: ____
- Other: ____

(12) List types of logs available:

induction	X	sonic	
SP	X	density	
gamma ray		other (identify)	

(13) Temperature at reservoir depth:

- Well bore temp. 210 °F
- Equilibrium temp. 243 °F
- Temp. gradient 1.55 °F/100 ft
- Annual mean surface temp. 70 °F

Table 1. continued

(14) Fluid pressure in reservoir

a. Well head shut-in pressure (WHSIP)

Initial 7593 psig

Last 3215 psig

b. Bottom-hole shut-in pressure (BHSIP)

DST 9284 psig

Avg. perf. depth 11,140 ft

Gradient 0.833 psi/ft

c. Bottom-hole static pressure

Computed from WHSIP 9,166 (initial) psig; 4,211 psig (last)

(15) Salinity of formation water

From SP 32,000 ppm, NaCl

R_{mf} method 80,000 Mud type Lime-base oil emulsion

Total solids from water analysis not available ppm NaCl

(16) Methane solubility 26.7 SCF/bbl

(17) a. Formation resistivity factor 14.66 ($F = R_o/R_w = \frac{0.48}{0.033}$)

b. Water resistivity (from SP) 0.033 ohm-m; Res. Index (I) 6.94 .

($I = R_t/R_o = \frac{3.33}{0.48}$)

(18) Cumulative gas produced 12,362 MMscf

Years of production December 1959 through October 1972

(19) Last production date Aug. 1972

(20) Gas gravity 0.67 (separator)

(21) Gas compressibility factor (Z) 0.855 (last)

Table 1. continued

(22) Free gas & water saturations S_w 32% S_g 68%

Any oil in reservoir? Condensate GOR -- SCF/bbl

Irreducible water saturation (S_{wirr}) --

(23) Water production - last rate reported -- bbl/day

- cumulative -- bbl

(24) Area of reservoir 4.09 mi^2

(25) Free gas in-place ("C" reservoir) 26.24 Bscf

(26) Primary gas produced 13.752 (all wells) MMscf

(27) Predicted gas recovery 11.667* Bscf

(28) BHP/Z at abandonment 4,925 psia

(29) Seismic data in area Yes X No

(30) Sonic logs in area Yes X No

How many? one

*value includes gas recovery from artificial lift ("C" reservoir)

Table 2. EVALUATION OF GAS FIELDS

DISPERSED GAS PROJECT

(Short form)

Field name: Port Arthur, 59 Hackberry sands, Frio (10,850-11,700 ft)

Location: Jefferson County, Texas 1S-49E

Favorable Criteria:

1. 15 watered-out gas-distillate wells, no active wells in field
2. Multiple watered-out gas sands
3. Multiple thick aquifers: 30-150 ft
4. Abandonment pressure gradients: 0.4-0.74 psi/ft
5. Temp: 200°F, Porosity: 25-35%, Perm: 60-300 md
6. Recent (1973-1979) seismic lines in or near field
7. Pertinent geological and engineering data have been published

Unfavorable Criteria:

1. Productive area: 3 mi^2 (1,900 acres)
2. Possible sand and shale production problems
3. Only two sonic logs run in field (one available)
4. Salinity averages 90,400 ppm NaCl
5.
6.

Recommendation:

Favorable, because of multiple thick aquifers and watered-out gas sands with excellent reservoir properties. All wells in field have been plugged and abandoned, and all or most leases have expired. Some gas reservoirs remain geopressured, and some aquifers appear to be geopressured. This is considered to be a prime prospect and is rated as class A.

Core data are unavailable. Pressure gradients are low, but the reservoir might become a viable hydropressured prospect at some later date when active wells are abandoned.

Both Algoa and Port Acres fields are definitely less favorable prospects than Port Arthur field. Considerable additional work would be required to evaluate their producibility and economic potential.

Class C Fields

Short form evaluation sheets have been prepared for eight gas fields that were previously considered candidates for the more favorable class B rating (appendix B, tables B1-B8). Further investigation showed that these fields were not good prospects. The most common unfavorable criteria are (1) active wells in target reservoir interval, (2) shaly sandstones, (3) poor aquifers, (4) presence of oil, (5) small area, (6) no core data, and (7) low porosity and permeability. Only the Lake Creek field, Montgomery County, Texas, might be upgraded to class B in the future when active production diminishes or ceases. Available core data for one well (Prairie Producing Company no. 1 E. G. Frost) in the Lake Creek area show high permeabilities ranging up to 1,050 md in the perforated interval from 11,558 to 11,575 ft. A second interval from 11,269 to 11,297 ft has a maximum permeability of 10.2 md. Bottom-hole pressures are very low in this well. Although the sandstone bodies range from 80 to 100 ft thick, the permeable zones are thin and their lateral extent is unknown. In general, permeabilities in the Lake Creek area are very low. Appendix B also lists 134 class C gas fields that were rejected as prospects because of unfavorable criteria (table B9). This list does not include the large number of fields rejected during the initial screening.

Many gas fields were rejected as prospects because they contained active gas-producing wells. Gas production in these fields will eventually decline as wells water out and are abandoned by the operators. When all wells that produce from a target reservoir are abandoned, the field may need to be reevaluated as a candidate for secondary gas recovery. If operators of active wells cooperate, some of these gas fields could become good prospects for secondary gas recovery before they water out.

STUDIES OF PORT ARTHUR FIELD

Geological Background

The Port Arthur field is located in east-central Jefferson County immediately west of the town of Port Arthur (fig. 5). The field is adjacent to the Port Acres field

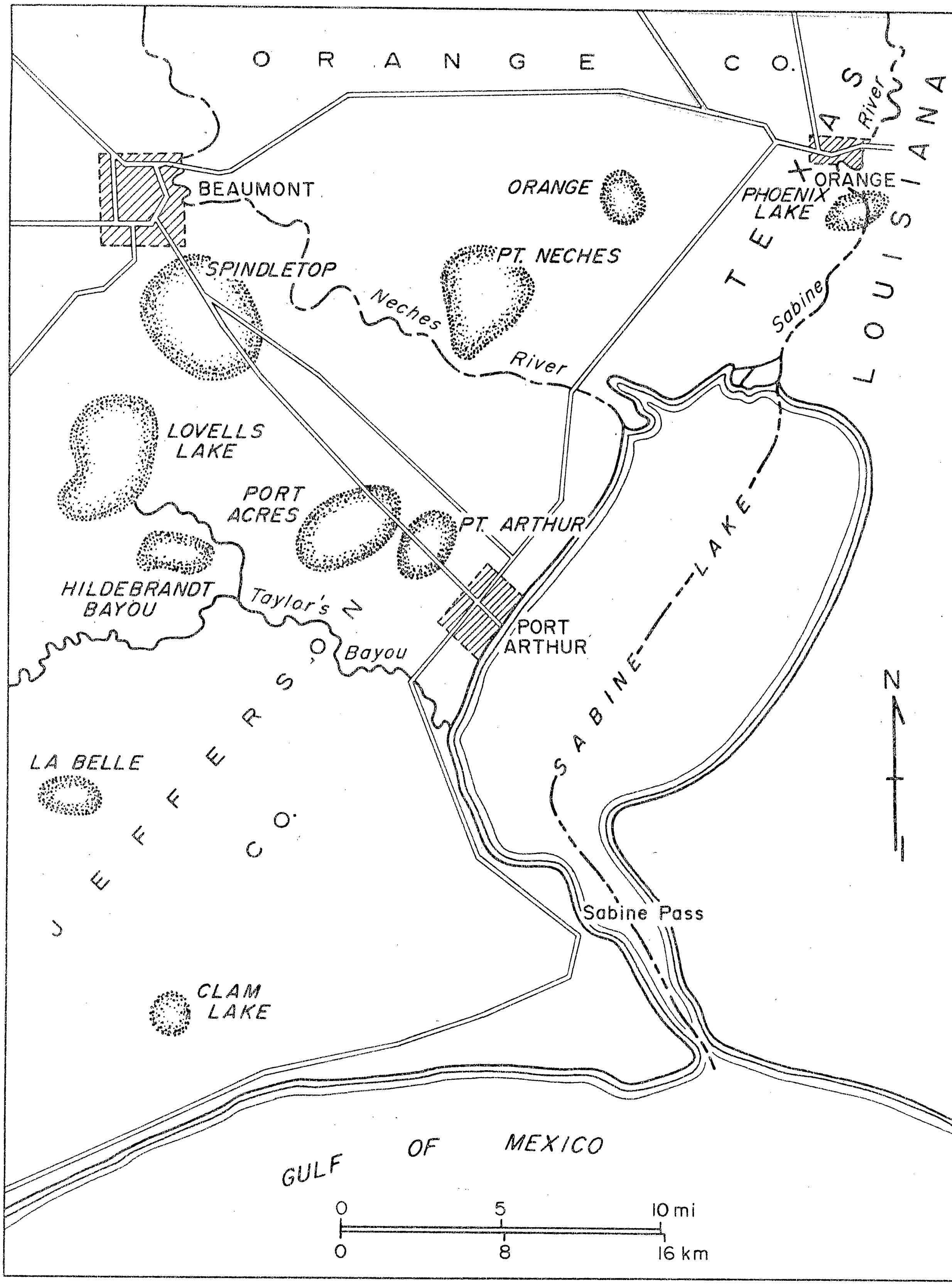

Figure 5. Location plat showing position of Port Arthur field with respect to other nearby fields and points of interest (after Halbouty and Barber, 1961).

on the west; the two fields are separated by a major fault (fig. 6). The major sandstone accumulation and productive area of the Port Arthur field covers about 1,900 acres (3.0 mi^2). The field produces gas and condensate from the lower Hackberry (Frio) sandstone units that are interpreted to have been deposited in a submarine fan environment (Weise and others, 1981b). The Nodosaria sandstone and the Vicksburg Formation are also gas producers in this field. The downdip structure of the field is a northeast-trending anticline caused by the rollover into a major fault (Weise and others, 1981b). Closure on the structure is about 100 ft in all directions, but structure to the east is uncertain because of poor well control. Seismic data from the area are currently being reprocessed and may help clear up these structural uncertainties.

The area cross section A-A' (fig. 7) and net sandstone map (fig. 8) show the continuity of the lower Hackberry interval in the dip direction and illustrate that the best sandstone development occurs in fairly narrow dip-aligned bands. The area is characterized by large variations in interval thickness; the channel-fill geometry supports the concept of deposition within a submarine fan system (Weise and others, 1981b).

Geologic cross sections Z-Z' (fig. 9) and X-X' (fig.10) were constructed to show the structure at the lower Hackberry interval and the presence of high net sandstone and reservoir continuity in the lower Hackberry sands in Port Arthur field. The productive reservoirs include thick sandstones with gas caps and thin stringer gas sandstones. The type log, well no. 14 on the structure map (fig. 6, identifies these reservoirs (fig. 11).

Electric logs indicate the presence of a normal fault located at a depth of 8,840 ft in well no. 28 (fig. 6). Apparent expansion of the lower Hackberry sandstone units in well no. 36 suggested that the fault extended through the target zone; however, newly acquired maps show that well no. 36 and well no. 37 were directionally drilled. The deviation of the hole caused the apparent expansion in well no. 36. Further study also indicated that the fault at -8,840 ft was a small antithetic fault that did not extend as deep as the lower Hackberry interval. Well logs also show a fault at the Vicksburg interval. It will not be possible to determine the validity and extent of these faults until a thorough study of seismic data is completed.

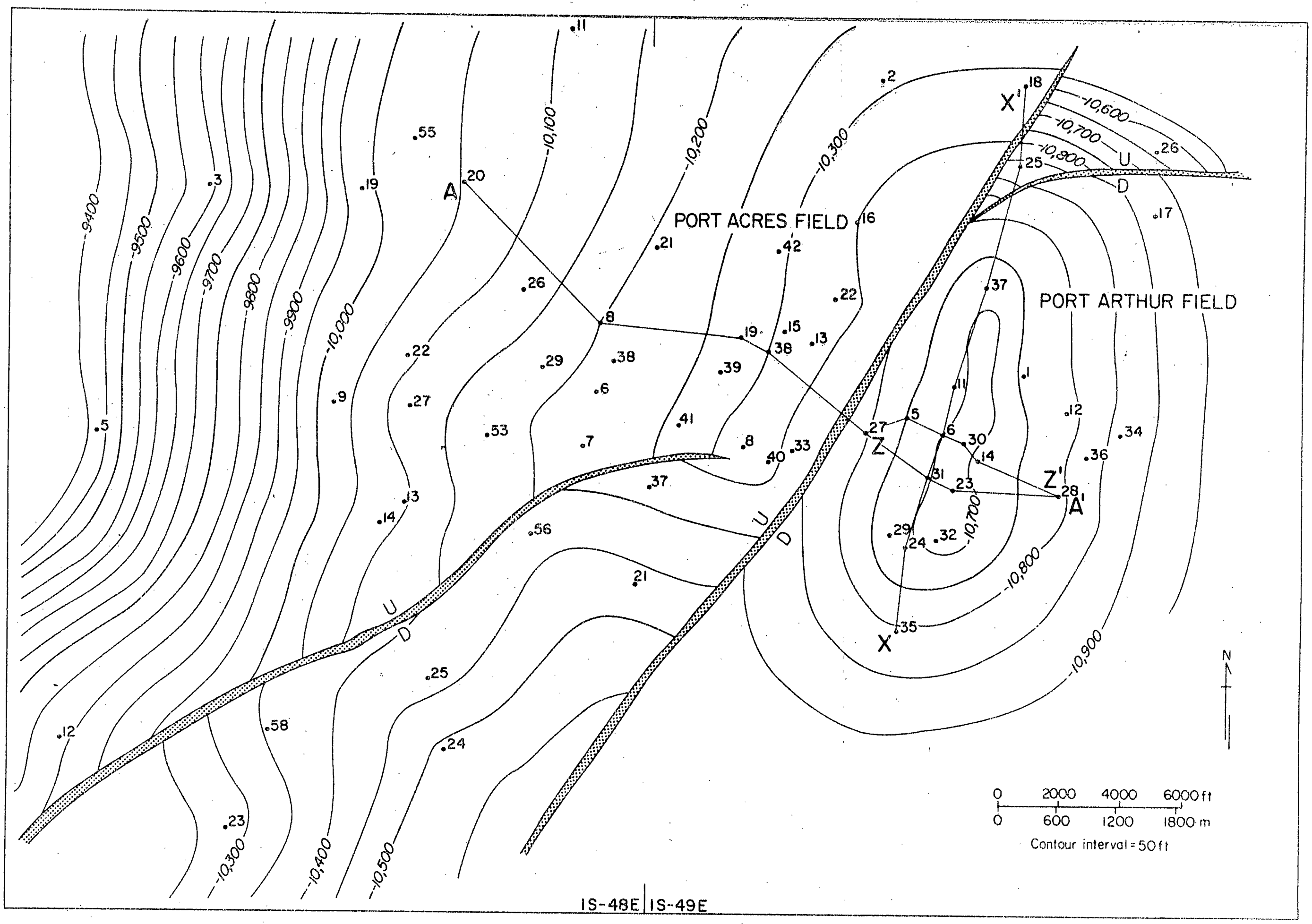

Figure 6. Well locations, lines of cross section, and structure on top of the lower Hackberry, Port Arthur-Port Acres area.

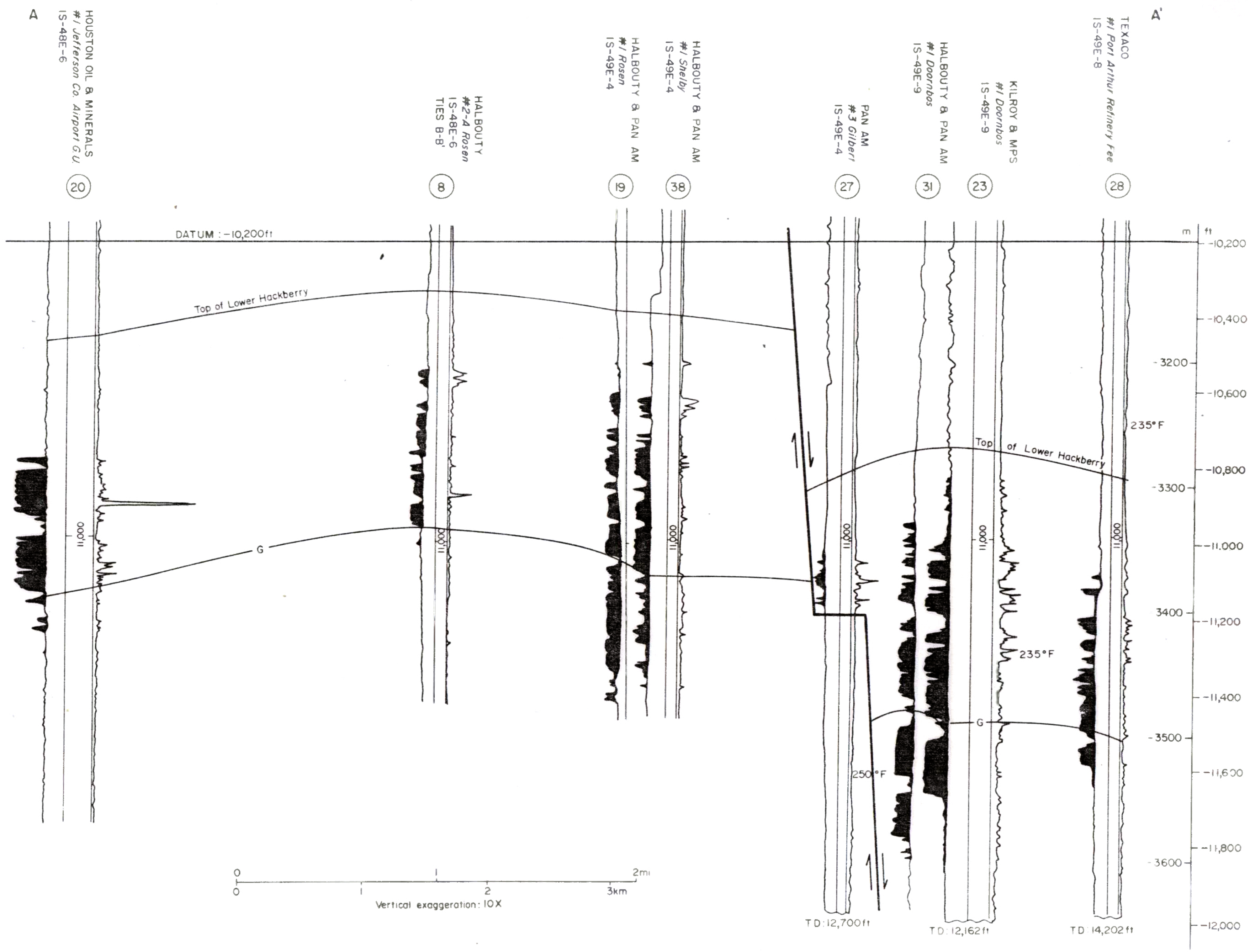

Figure 7. Structural dip section A-A', Port Arthur-Port Acres area (from Weise and others, 1981b).

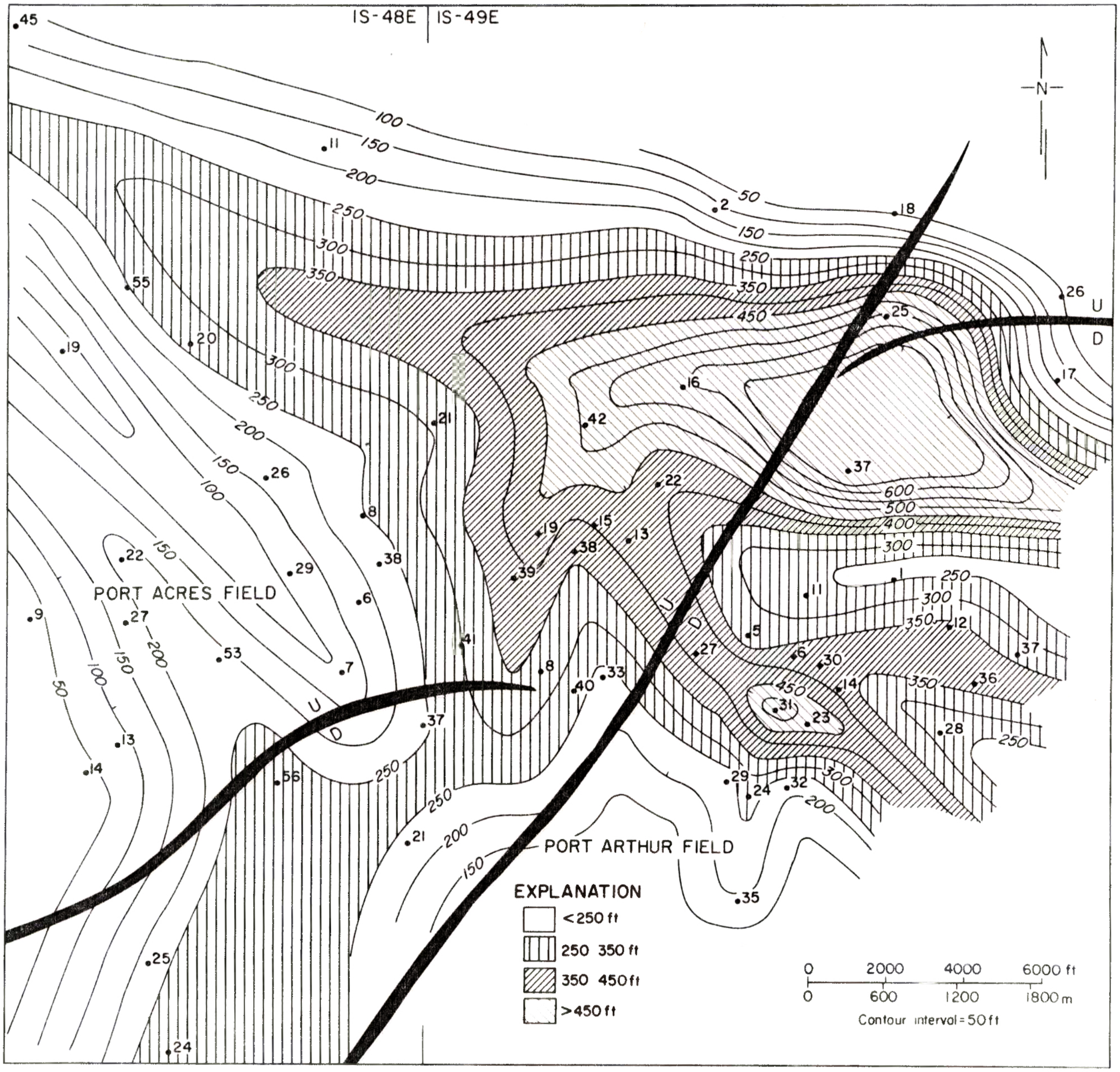

Figure 8. Net sandstone of the lower Hackberry, Port Arthur-Port Acres area.

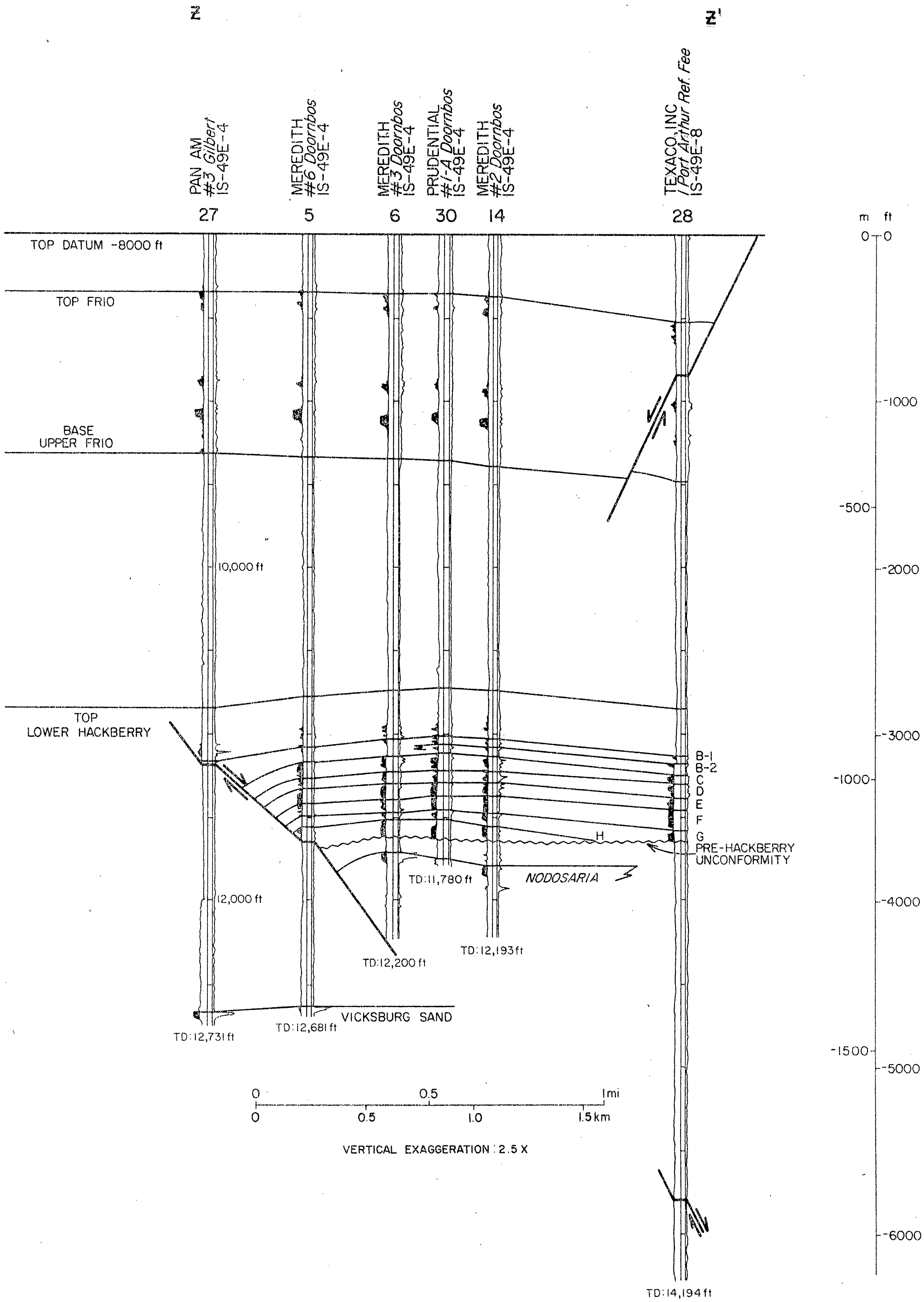

Figure 9. Structural dip section Z-Z', Port Arthur field.

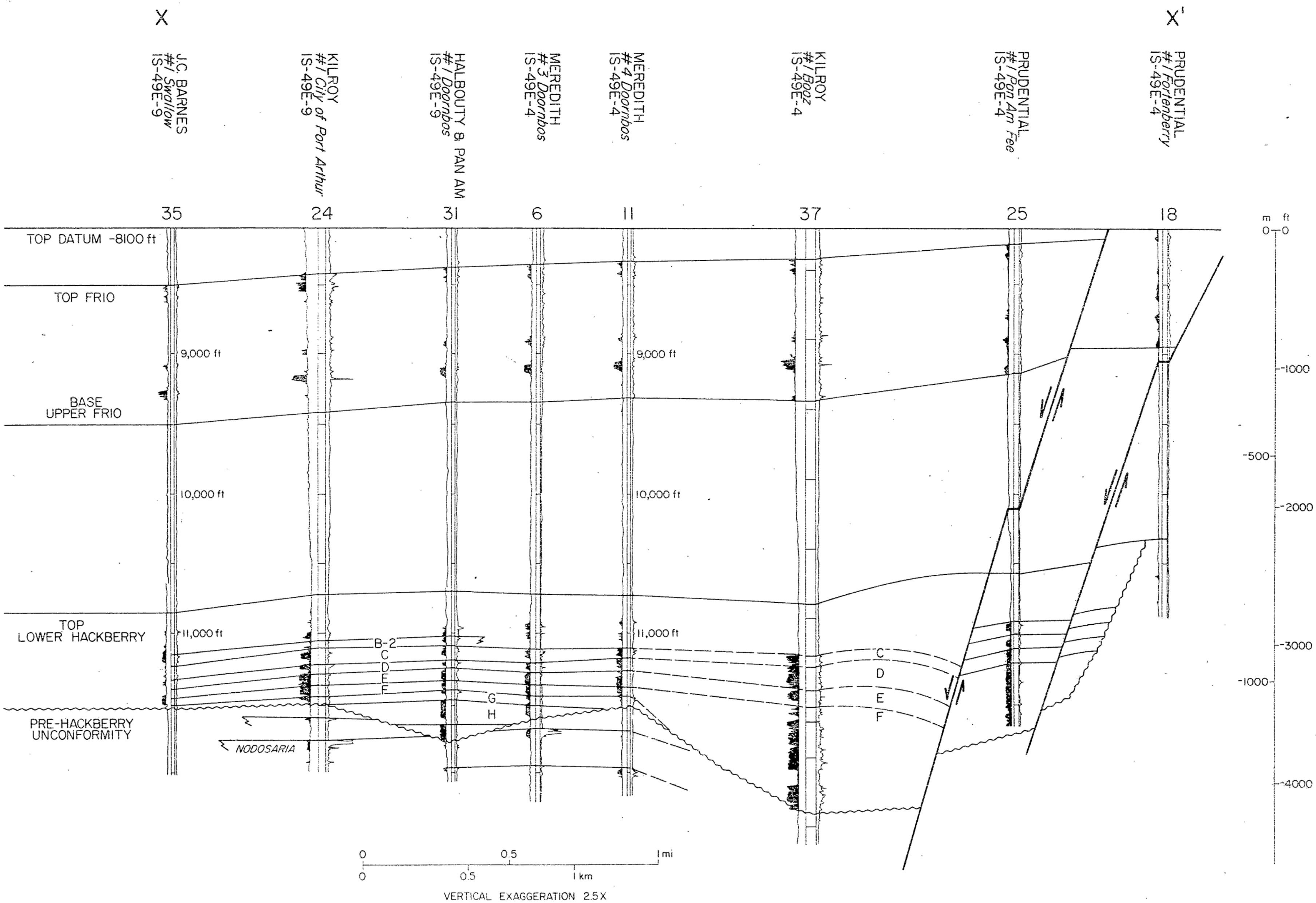

Figure 10. Stratigraphic strike section X-X', Port Arthur field.

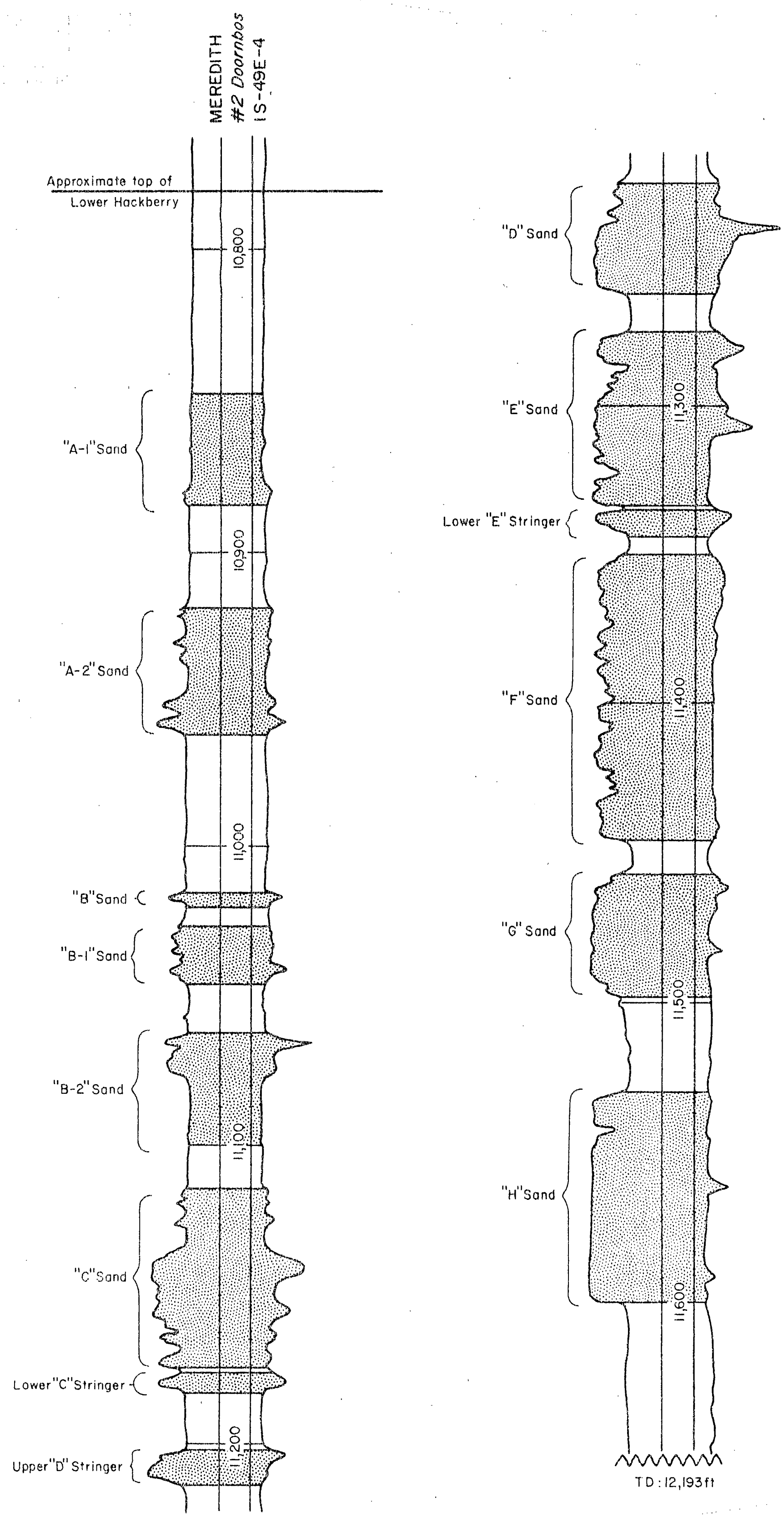

Figure 11. Type log showing reservoir intervals, Port Arthur field. The well is no. 14 on cross section Z-Z', figures 6 and 9 (from Weise and others, 1981b).

Potential Saltwater Disposal Sands

The predicted production of 8.82 million bbl of saltwater for natural flow conditions and an additional 10.25 million bbl for artificial lift conditions over a 10-year period requires that suitable disposal sands be located near the test well site. Formation waters from the lower Hackberry sandstones have an average salinity of 90,400 ppm NaCl and an average equilibrium temperature of 231°F.

Shallow Miocene sands in the depth interval from 2,000 to 6,200 ft are abundant in the Port Arthur field (fig. 12) and appear to be good potential saltwater disposal sands. Fresh ground water in the area is from the Chicot aquifer, where the base of usable quality water is -500 ft. There is no hydrocarbon production above the lower Hackberry (Frio) sandstones. Previous saltwater disposal in the field was in the depth interval from 2,406 to 3,520 ft in well no. 29, located about 0.7 mi southwest of well no. 14. Since the test well site will be located near well no. 14, it may be possible to reopen well no. 14 or to use one of the existing nearby plugged and abandoned wells for an injection well. Well numbers 14, 6, 30 and 23 are potential candidates for injection. The average salinity of waters in the Miocene sands in the depth interval from 2,000 to 7,000 ft is substantially higher than that of the lower Hackberry sandstones. For example, the average calculated salinity for Miocene sands from -2,200 to -7,000 ft in well no. 14 is 180,400 ppm NaCl (table D-6, appendix D) compared with 90,400 ppm NaCl for the lower Hackberry sandstones. The average equilibrium temperature in the same depth interval is 144°F. Before moderately saline water (90,400 ppm NaCl) can be safely injected into highly saline water (180,400 ppm NaCl), the effects of this mixing on the stability of clays in the Miocene sands will have to be evaluated.

Well Locations, Status, and Reservoir Properties

There are 18 wells located in the Port Arthur field (table 3 and fig. 6). Eleven of these wells produced gas and condensate from one or more lower Hackberry reservoirs (table 4); four wells (numbers 1, 6, 24, and 32) produced from the Nodosaria sandstone; three wells (numbers 5, 27, and 36) produced from the Vicksburg interval; two wells (numbers 28 and 34) were dry holes; and well no. 37 was reported as suspended (table 3).

Gas is produced in the lower Hackberry (Frio) sandstones in the depth interval from 10,850 to 11,700 ft. Reservoirs designated as "C," "D," and "E" are laterally continuous and have the best characteristics for producing gas and water. Cumulative

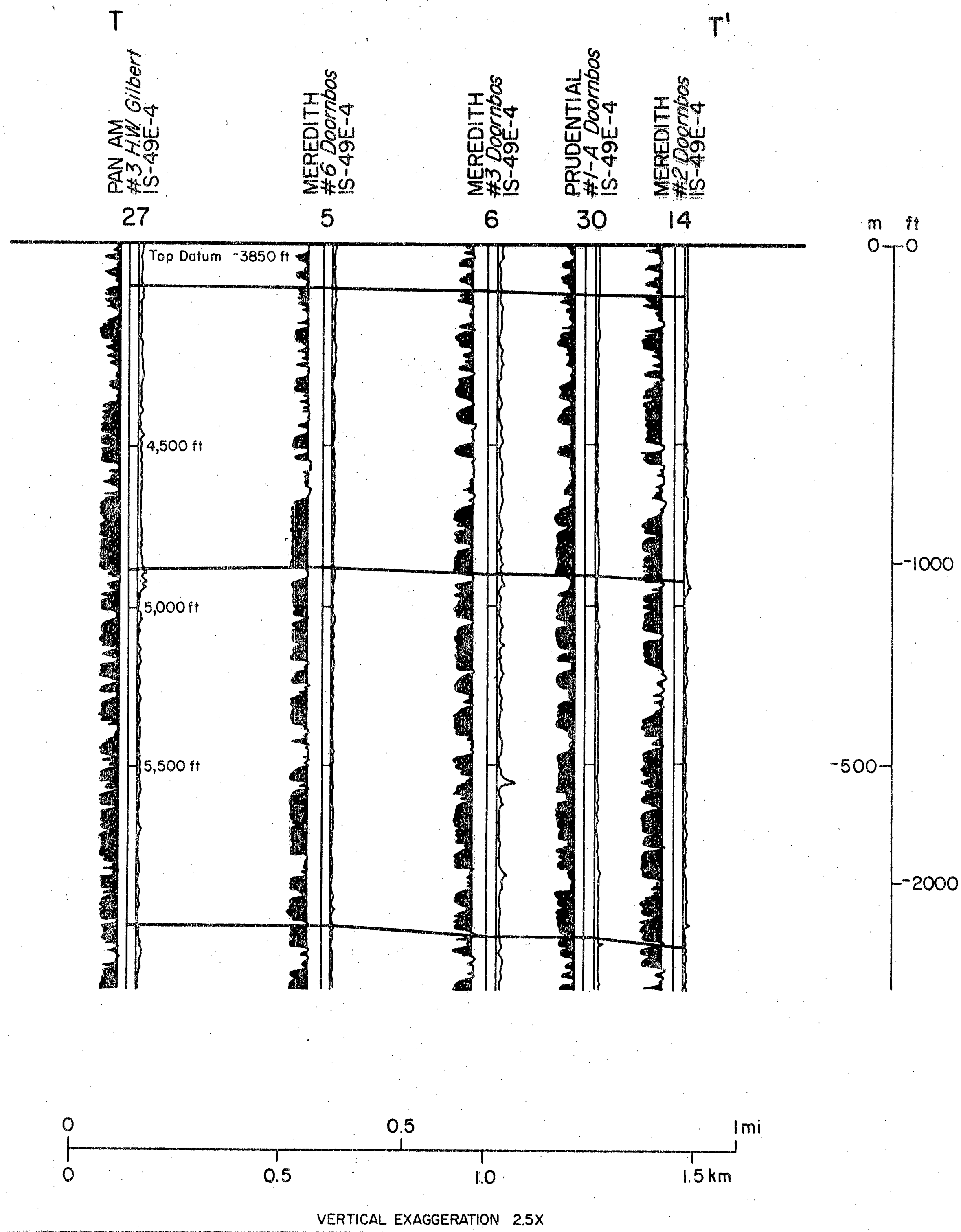

Figure 12. Thickness of Miocene sands in the shallow subsurface suitable for disposal of waste saltwater.

Table 3. Identification, Location, and Status of Wells, Port Arthur Field, Jefferson County, Texas

Well No.	Original Operator and Well Name	(Current Operator and Well Name)	Tobin Grid	Well Status	Total Depth (ft)
1	Meredith no. 1 Doornbos	(Prudential no. 1 Doornbos Loidold)	1S-49E-4	P & A	12,290
5	Meredith no. 6 Doornbos	(Prudential no. 6 Doornbos)	1S-49E-4	P & A	12,681
6	Meredith no. 3 Doornbos	(Prudential no. 3 Port Arthur Hack. Unit)	1S-49E-4	P & A	12,200
11	Meredith no. 4 Doornbos	(Prudential no. 4 Port Arthur Hack. Unit)	1S-49E-4	P & A	12,175
12	Meredith no. 5 Doornbos	(Prudential no. 5 Port Arthur Hack. Unit)	1S-49E-5	P & A	12,352
14	Meredith no. 2 Doornbos	(Prudential no. 2 Port Arthur Hack. Unit)	1S-49E-4	P & A	12,200
23	Kilroy & M.P.S. no. 1 Doornbos	(Prudential no. 1 Port Arthur Hack. Unit)	1S-49E-9	P & A	12,160
24	Kilroy & M.P.S. no. 1 City of Port Arthur	(Prudential no. 9 Port Arthur Hack. Unit)	1S-49E-9	P & A	12,001
27	Pan Am. no. 3, H. W. Gilbert	(Amoco no. 3 H. W. Gilbert)	1S-49E-4	P & A	12,751
28	Texaco, Inc. no. 1 Port Arthur Refinery Fee	(no change)	1S-49E-8	Dry	14,200
29	Halbouty & Pan Am. no. 2 Doornbos	(Prudential no. 7 Port Arthur Hack. Unit)	1S-49E-9	P & A	12,202
30	Prudential no. 1-A Doornbos	(no change)	1S-49E-4	P & A	11,809
31	Halbouty & Pan Am. no. 1 Doornbos	(Prudential no. 6 Port Arthur Hack. Unit)	1S-49E-9	P & A	12,103
32	Kilroy & M.P.S. no. 2 Doornbos	(Kilroy & M.P.S. no. 1 Doornbos *Nodosaria* G.U. 1)	1S-49E-9	P & A	12,208
34	Meredith no. 1 Doornbos-Port Arthur Vicksburg Gas Unit 1	(no change)	1S-49E-5	Dry	14,125
35	J. C. Barnes no. 1 Swallow	(Tex-Star Oil & Gas no. 1 Swallow)	1S-49E-9	P & A	12,000
36	Texaco, Inc. no. 1 Park Place Gas Unit	(no change) (slanted hole)	1S-49E-8	P & A	14,050
37	Kilroy no. 1 Booz	(no change) (slanted hole)	1S-49E-4	Sus.	12,641

Table 4. Pressure Gradients and Production History by Reservoir and Well, Port Arthur Field, Jefferson County, Texas

Lower Hackberry Reservoirs	Well No.*	Perforated Interval (ft)	Pressure Gradient (psi/ft) Initial	Last	Production Period	Cumulative Production Gas (Bscf)	Cond. (bbl)
A-1	12	10,946-10,956	0.84	-	12/59-7/68	0.989	93,934
	35	10,966-10,978	0.83	-	8/60-5/61	0.138	-
A-2	29	10,925-10,955	0.82	0.57	9/59-2/62	0.054	228
	6	10,936-10,946	0.83	0.41	3/66-8/71	0.784	31,492
	11	10,934-10,950	0.82	0.55	12/59-1/72	7.644	365,794
Upper B Stringer	31	10,986-10,944	0.83	0.74	3/66-1/72	0.200	8,115
B	6	10,995-11,000	0.81	0.47	5/67-5/79	0.088	4,952
	30	10,994-11,002	0.73	-	8/78-2/80	0.002	387
B-1	24	11,052-11,058	0.71	0.36	9/68-3/70	0.003	148
	23	11,021-11,029	0.80	0.74	6/62-9/65	3.323	172,158
B-2	31	11,077-11,101	0.84	0.61	9/59-1/66	13.343	720,286
C	23	11,128-11,131	0.75	0.32	7/65-8/71	1.291	33,637
	14	11,136-11,144	0.84	0.36	12/59-10/72	12.362	563,091
	6	11,130-11,135	0.70	0.44	8/71-10/72	0.099	2,310
Upper D Stringer	30	11,204-11,208	0.73	0.58	5/75-5/79	0.616	27,963
D	14	11,225-11,243	0.83	0.36	6/68-10/72	0.517	19,719
	6	11,218-11,228	0.83	0.35	3/60-4/66	4.310	174,229
	23	11,251-11,256	0.67	0.33	7/65-8/71	1.881	66,583
	24	11,250-11,257	0.70	0.44	1/68-8/68	0.126	6,430
E	14	11,276-11,286	0.83	-	5/59-12/60	1.620	87,638
	23	11,290-11,299	0.83	-	11/59-6/62	2.072	109,115
	6	11,296-11,301	0.80	0.74	3/66-4/67	0.398	21,352
Lower E Stringer	24	11,377-11,381	0.70	-	11/67-12/67	0.034	1,225
F	14	11,350-11,359	0.81	-	7/61-6/68	6.212	224,288
G	31	11,458-11,463	0.77	0.48	3/66-1/67	0.449	17,606
					Total	58.556	2,752,680

*Well locations shown in figure 6; tobin grid given in table 3.

production from the lower Hackberry sandstones from 1959 to 1980 was 58.6 Bscf of gas and about 2.75 million bbl of condensate (table 4). The last producing well watered out and was plugged and abandoned in March 1981.

The listing of average reservoir properties (table 5) shows that the lower Hackberry sandstones have high porosity, fairly high permeability, moderate temperature, and high salinity. Pressure gradients in abandoned reservoirs vary from 0.32 to 0.74 psi/ft. Initial pressure gradients in the "C," "D," and "E" reservoirs averaged 0.73 psi/ft, and the last recorded pressure gradients average 0.45 psi/ft. Equilibrium temperatures range from 222° to 249°F and average 231°F for all Hackberry production intervals. Salinities determined from SP well logs average 90,400 ppm NaCl in aquifers associated with gas reservoirs. Methane solubility varies from 18.2 to 30.1 scf/bbl (table 6) and averages 23.6 scf/bbl. This means that only 472 Mscf/d of solution gas will be obtained from a well producing methane-saturated formation water at a rate of 20,000 bbl/d. It is essential, therefore, to produce a substantial amount of free gas, in addition to solution gas, to make the drilling of a test well economically viable. Multiple thick aquifers in the Hackberry sandstone units should simplify the tasks of finding suitable combinations of gas and water reservoirs that will produce at a gas/brine ratio that greatly exceeds the solution gas/brine ratio.

Production History

The "C" Reservoir

Cumulative production from the "C" reservoir was 13.752 Bscf of gas and 599,038 bbl of condensate. Well no. 14 produced 90 percent of the gas and 94 percent of the condensate from perforations in the depth interval from 11,136 to 11,144 ft over a period of about 13 years from December 1959 to July 1972 (table 4 and fig. 13). The well was plugged and abandoned in October 1972. The rest of the cumulative production was from well numbers 6 and 23 (table 4). Peak production of hydrocarbons occurred from 1961 until 1965 when water production started to increase (fig. 14). Production of water peaked in 1967 at 2,400 bbl/d. Bottom-hole shut-in pressures decreased from an initial value of 9,320 psi in 1959 to 4,313 psi in 1972. A plot of P/Z versus cumulative gas production does not give a straight line because there was a significant amount of water production (fig. 15a). A new plot of P/Z versus x (fig. 15b), where x is defined by equation (1), takes into consideration the water production from the well and water encroachment into the gas reservoir.

Table 5. Average Reservoir Properties, Lower Hackberry (Frio) Sandstone Units, Port Arthur Field, Jefferson County, Texas

Depth to top	10,850 ft
Net sandstone	350 ft
Bed thickness	30 to 150 ft
Porosity[1]	30%
Permeability[1]	60 md
Equilibrium temperature	231°F
Pressure gradient (initial)	0.78 psi/ft
Salinity[2]	90,400 ppm NaCl
Methane solubility[3]	23.6 scf/bbl
Productive area[1]	3 mi^2

[1]Modified from Halbouty and Barber (1961)

[2]Calculated from SP well logs using method of Dunlap and Dorfman (1981).

[3]Calculated at initial pressure, temperature, and salinity, using equation of Price and others (1981).

Table 6. Salinity, Temperature, Pressure, and Methane Solubility for Lower Hackberry Reservoirs, Port Arthur Field, Jefferson County, Texas

Lower Hackberry Reservoirs	Well No.[1]	Perforated Interval (ft)	Salinity (ppm NaCl)[2]	Equilibrium Temperature (°F)	DST Initial Pressure (psi)[3]	Methane Solubility (scf/bbl)[4]
A-1	12	10,946-10,956	28,300	214	9,192	30.10
	35	10,966-10,978	45,900	224	9,127	28.80
A-2	29	10,925-10,955	37,000	208	8,917	27.99
	6	10,936-10,946	77,300	212	9,059	23.96
	11	10,934-10,950	55,900	217	8,934	26.60
Upper B Stringer	31	10,986-10,944	95,000	219	9,171	22.76
B	6	10,995-11,000	60,500	214	8,955	25.84
	30	10,994-11,002	98,600	232	8,029	21.91
B-1	24	11,052-11,058	110,000	237	7,894	20.91
	23	11,021-11,029	89,900	230	8,783	23.69
B-2	31	11,077-11,101	112,000	223	9,302	21.47
C	23	11,128-11,131	95,100	232	8,398	22.78
	14	11,136-11,144	80,000	243	9,284	26.70
	6	11,130-11,135	88,100	218	7,775	21.57
Upper D Stringer	30	11,204-11,208	144,000	238	8,180	18.20
D	14	11,225-11,243	88,600	247	9,324	26.12
	6	11,218-11,228	74,700	222	9,068	25.08
	23	11,251-11,256	112,000	234	7,540	20.08
	24	11,250-11,257	134,000	246	7,877	19.30
E	14	11,276-11,286	87,500	249	9,400	26.56
	23	11,290-11,299	108,000	235	9,395	22.94
	6	11,296-11,301	87,600	224	9,023	23.76
Lower E Stringer	24	11,387-11,391	129,000	250	8,012	20.24
F	14	11,350-11,359	83,500	252	9,231	27.11
G	31	11,458-11,463	121,000	237	8,820	21.05
H	30	11,782-11,792	107,000	251	9,041	23.98

[1]Well locations shown in figure 6; tobin grid given in table 3.
[2]From SP log using method of Dunlap and Dorfman (1981).
[3]From completion cards.
[4]Calculated from equation of Price and others (1981) at initial conditions of pressure, temperature, and salinity.

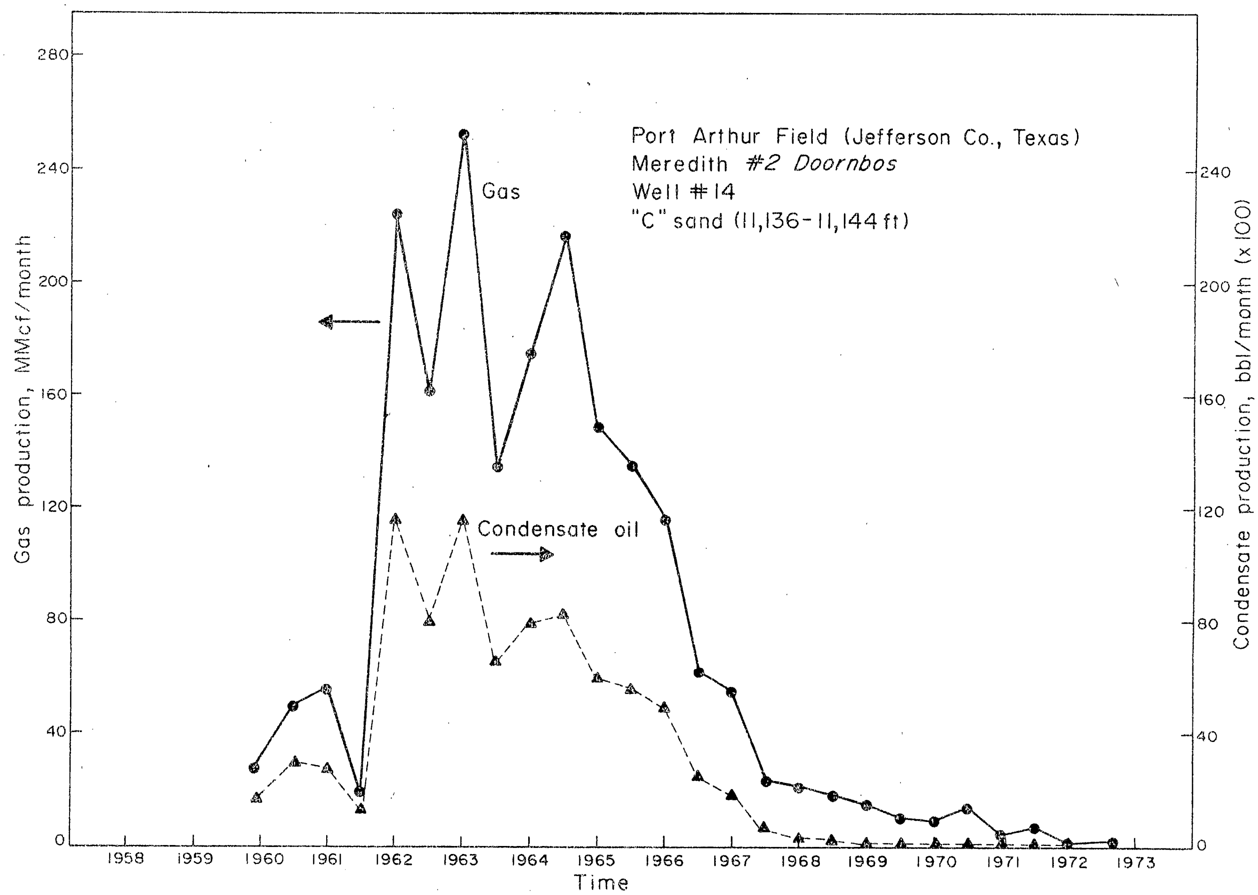

Figure 13. Gas and condensate production rates, "C" sandstone.

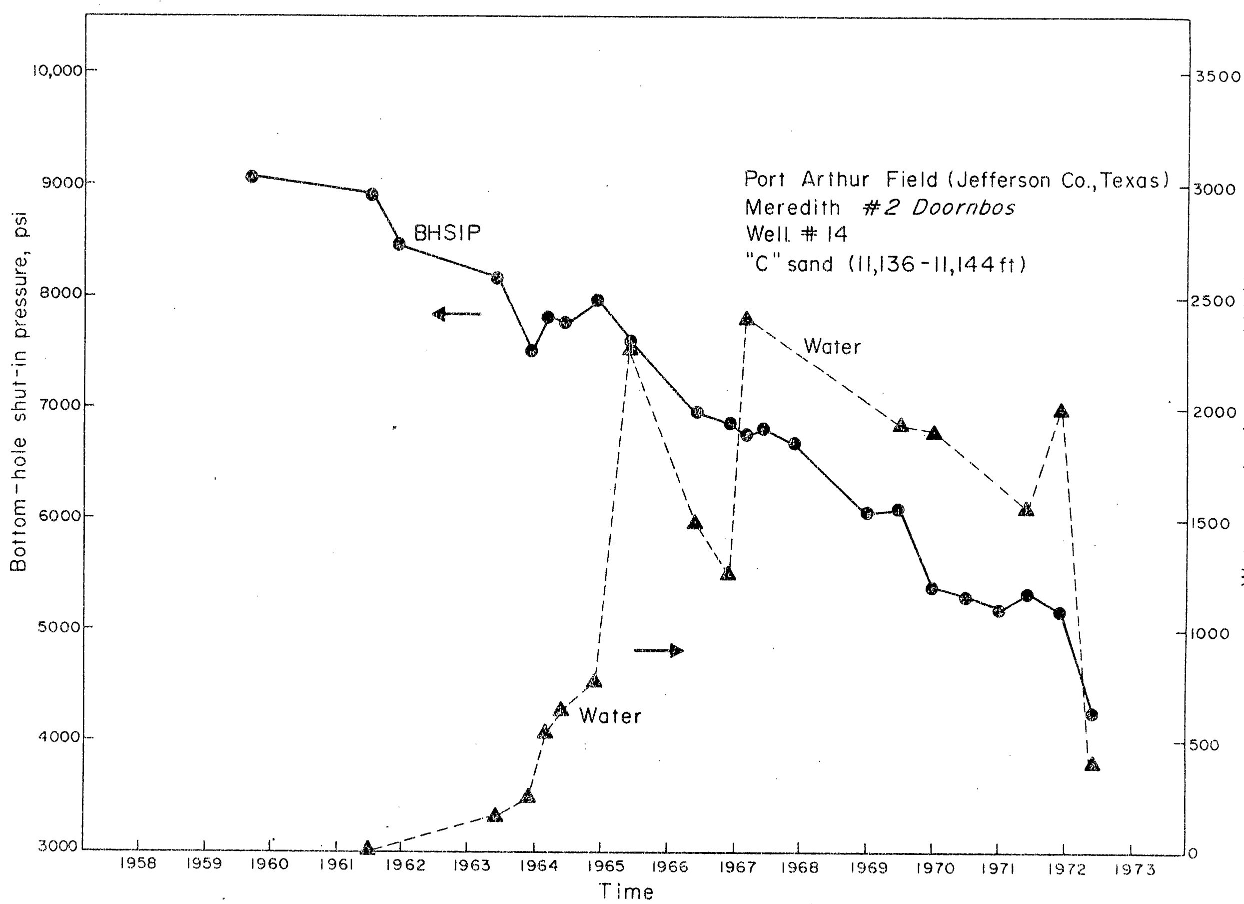

Figure 14. Bottom-hole shut-in pressure decline and water production rates, "C" sandstone.

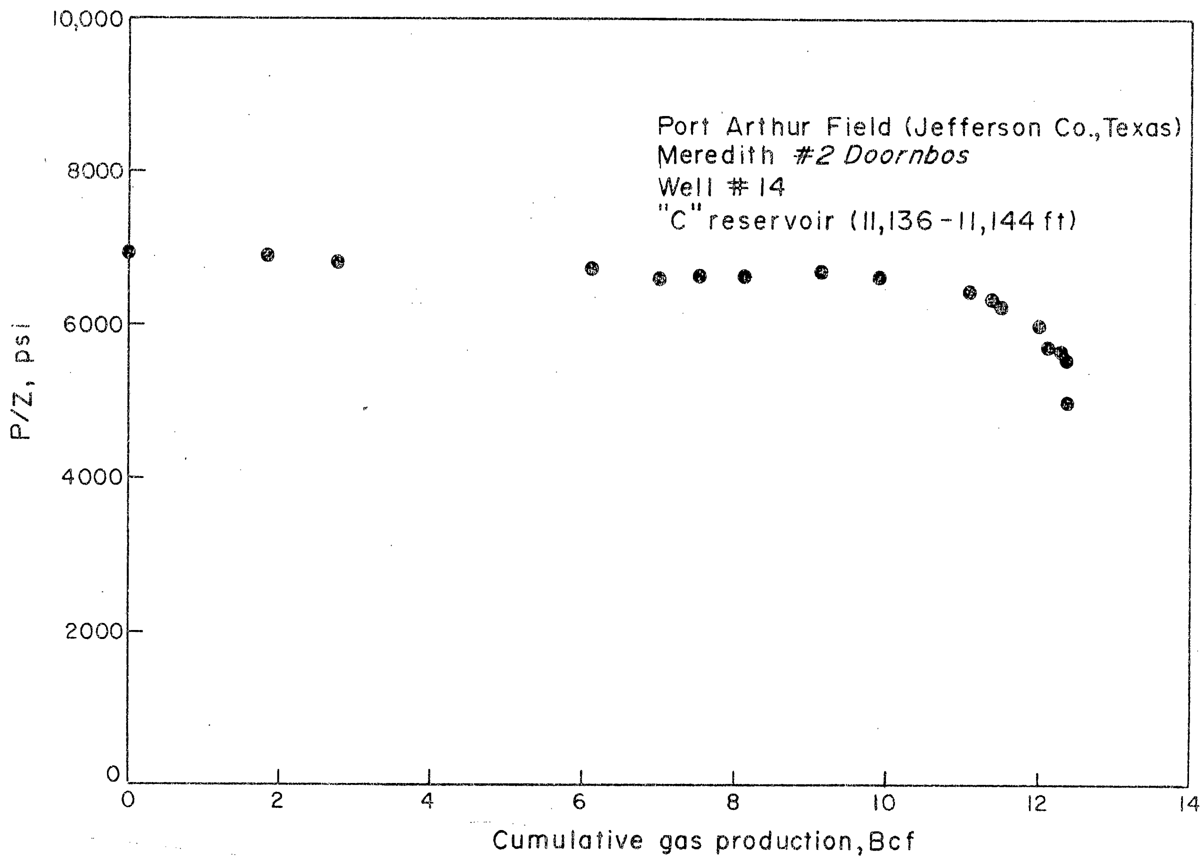

Figure 15a. P/Z versus cumulative gas production, "C" sandstone.

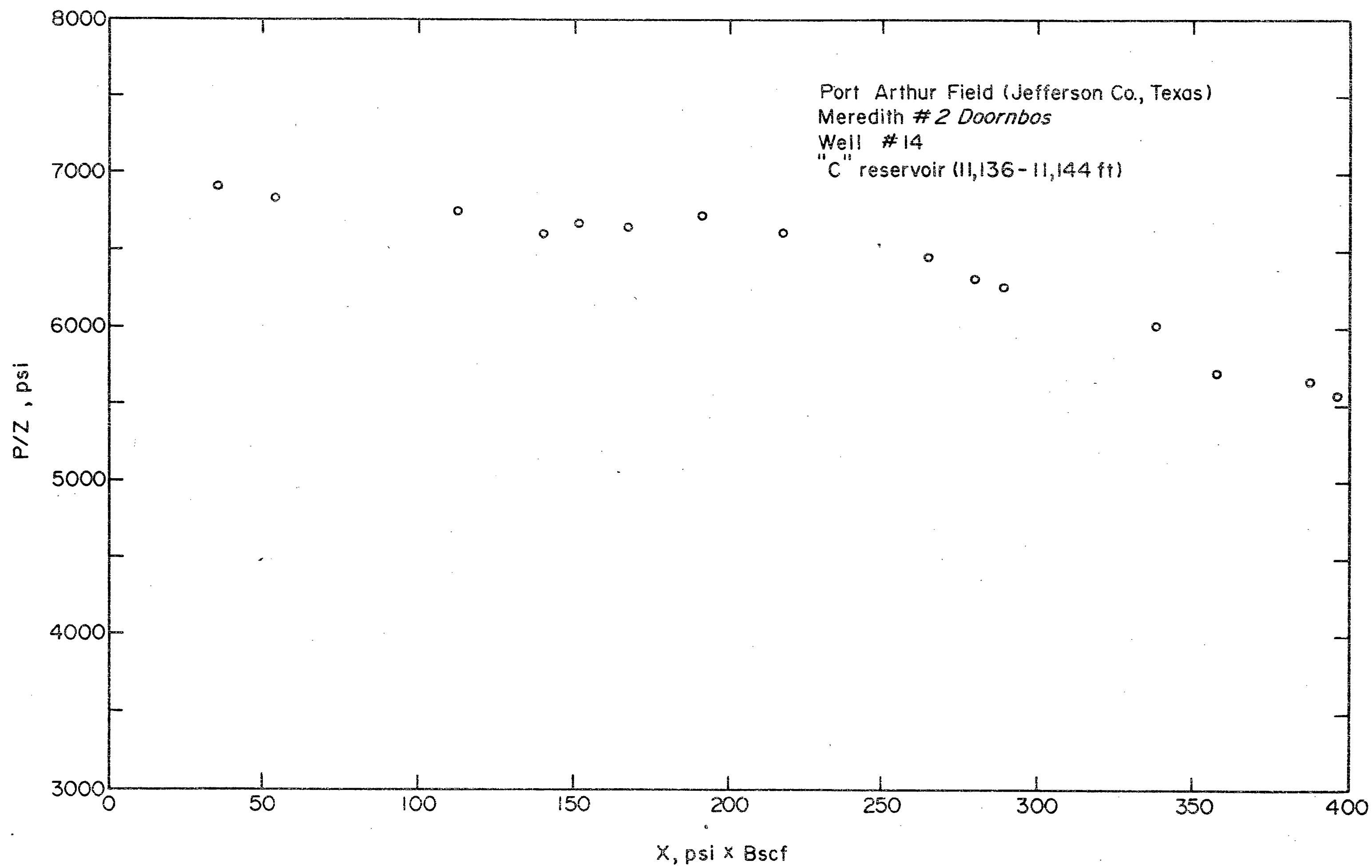

Figure 15b. P/Z versus x, where x is defined by equation (1).

$$x = \left(\frac{TP_{sc}}{T_{sc}} \; G_p + \frac{P_f B_w}{Z_f} \; W_p \right) \qquad (1)$$

where G_p = cumulative gas production, Mscf
T = reservoir temperature, ^oR
T_{sc} = temperature at standard conditions, ^oR
P_{sc} = pressure at standard conditions, psi
W_p = cumulative water production, Mscf
P_f = final pressure, psi
Z_f = gas compressibility factor at P_f, dimensionless
B_w = water formation volume factor, dimensionless

The data points in figure 15b give a better approximation of a straight line than those in figure 15a. It should be possible to estimate the initial gas in place and the original size of the aquifer from the new plot.

An isopach map (fig. 16) shows sandstone accumulations of 60 ft or more for the "C" reservoir in two areas of the Port Arthur field. The structure map (fig. 17) constructed on top of the "C" reservoir shows that well numbers 6, 14, 23, 24, 30, and 32 are located near the top of the structure. However, only well numbers 6, 14, and 23 produced from this reservoir, as stated above.

Sidewall cores from seven wells show that permeabilities range from 0.0 to 314 md and porosities vary from 12.9 to 36.5 percent in the "C" reservoir (table 7). Two cores from the perforated interval of well no. 14 had an average permeability of 156.5 md and an average porosity of 33.4 percent. Average water saturation and oil saturation in the perforated interval was 65.2 percent and 1.55 percent, respectively.

The "B-2" Reservoir

The "B-2" reservoir, located in the lower Hackberry sandstones, produced 13.34 Bscf of gas and 720,286 bbl of condensate from the perforated depth interval from 11,077 to 11,101 ft in well no. 31 (Halbouty and Pan American no. 1 Doornbos, 1S-49E-9). Production started in September 1959; the well watered out and was plugged and abandoned in January 1966. The gas production rate peaked at 10,500 Mscf/d in December 1961, then declined steadily to the last recorded rate of 5,600 Mscf/d in June 1965 (fig. 18). Condensate was also produced at rates that varied from a maximum of 629.7 bbl/d in 1960 to the lowest recorded rate of 228.4 bbl/d in 1965.

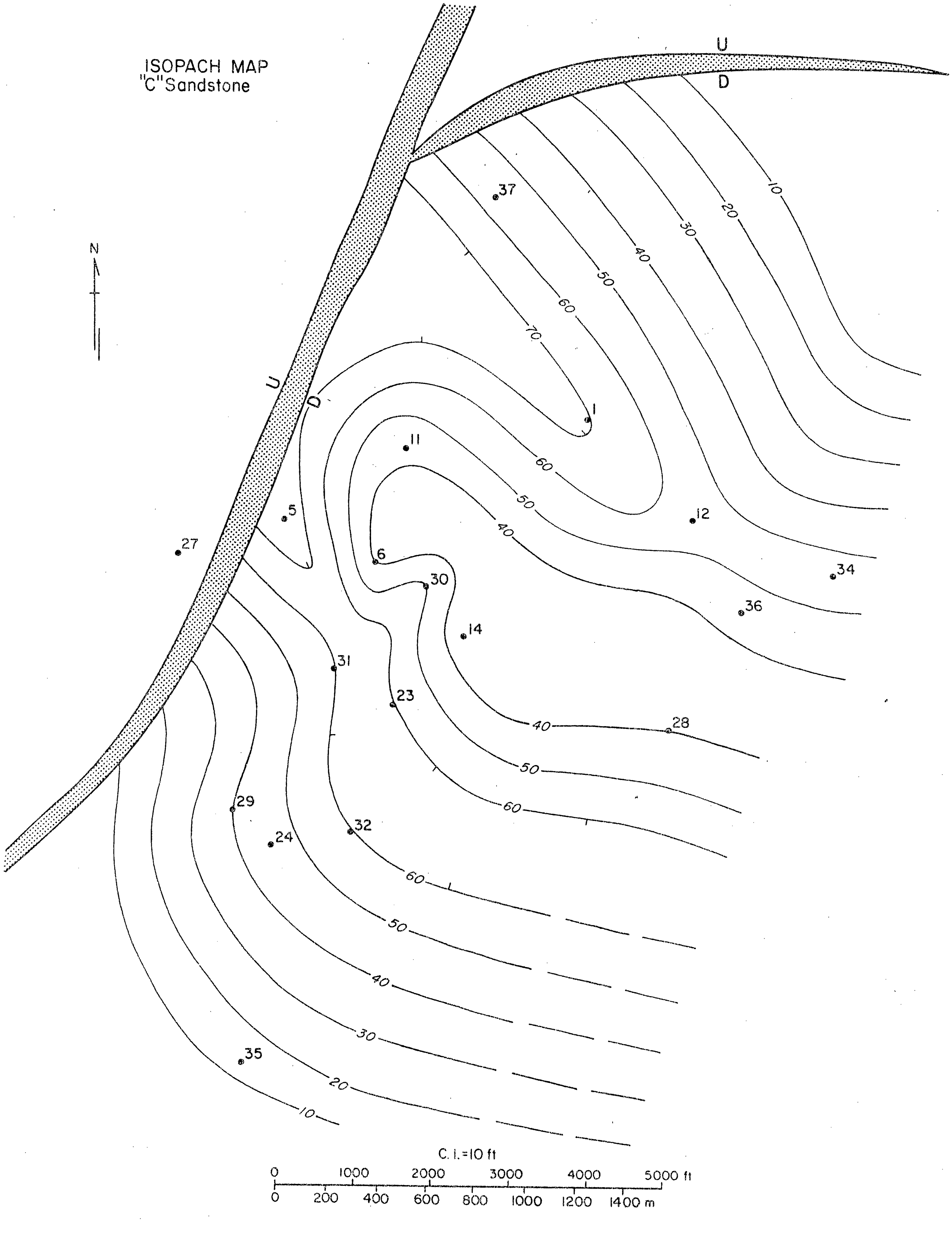

Figure 16. Isopach map, "C" sandstone, Port Arthur field.

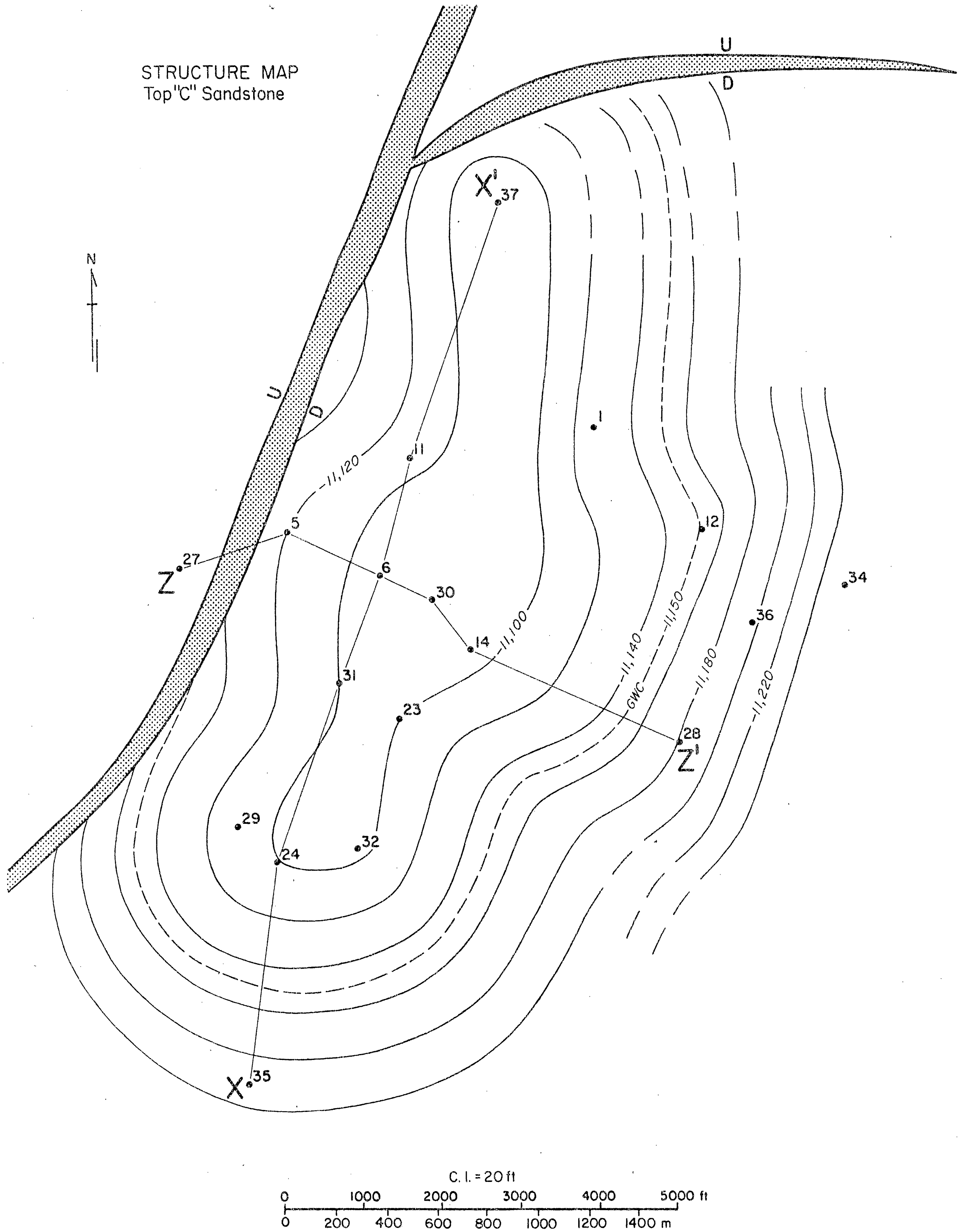

Figure 17. Structure map, "C" sandstone, Port Arthur field.

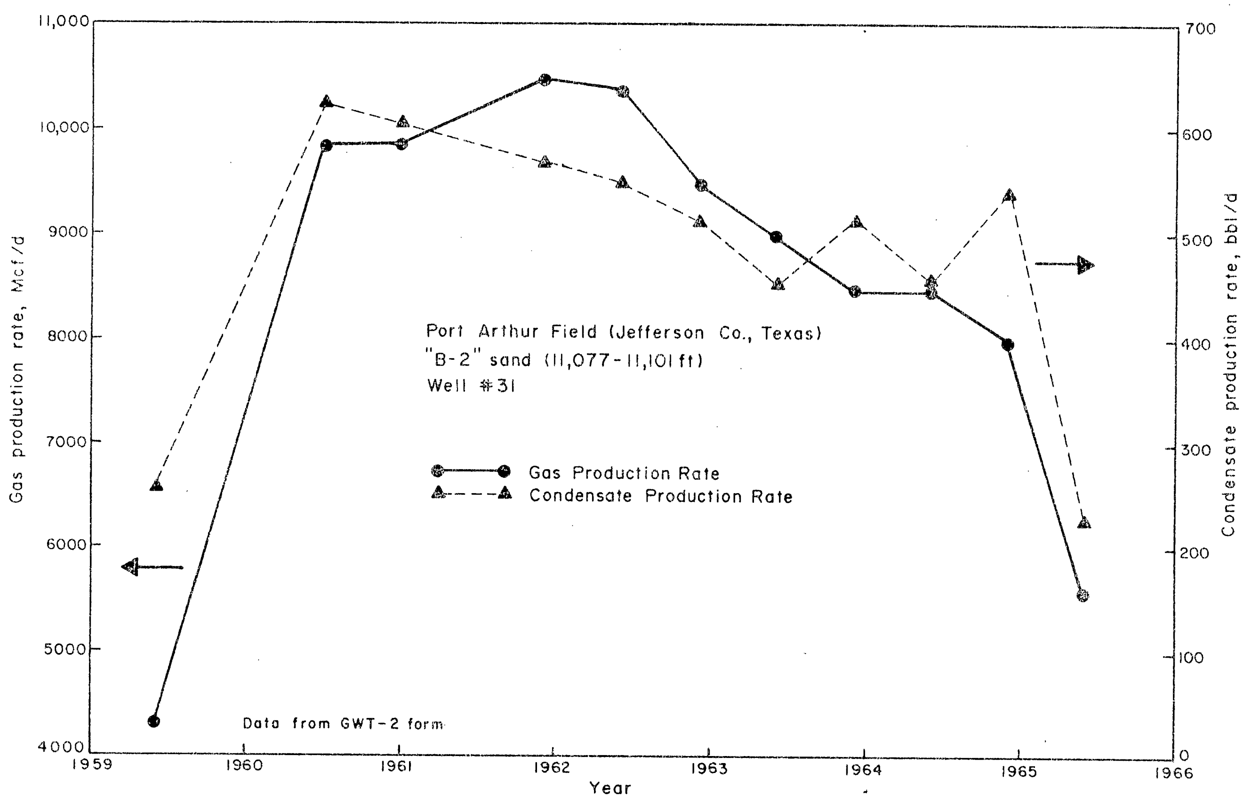

Figure 18. Gas and condensate production rates, "B-2" sandstone.

Table 7. Sidewall core data

Well No.	Depth (ft)	K (md)	ϕ (%)	Sw (%)	So (%)	Gas (by vol.)
			"A-1" Reservoir			
14	10,882	52.8	27.9	64.9	tr	9.8
			"A-2" Reservoir			
6	10,938†	7.1	27.3	82.0	0.0	4.9
	10,947	12.6	27.9	71.6	0.0	7.9
	10,951	335.0	32.6	49.7	tr	16.4
11	10,937†	84.5	27.5	61.8	0.4	10.4
	10,948†	58.2	27.2	63.1	0.7	9.8
14	10,923	41.9	27.5	63.3	tr	10.1
	10,960	238.0	30.8	60.4	tr	12.2
24	10,930	*	24.2	62.3	0.4	9.0
	10,945	11.0	24.4	77.9	0.4	5.3
	10,948	14.0	25.2	64.3	0.4	8.9
	10,951	0.0	19.6	64.6	0.5	6.8
29	10,927	15.2	24.1	63.2	0.0	8.9
	10,933.5	0.0	12.1	76.9	0.0	2.8
	10,938.5	1.3	15.2	67.2	0.0	5.0
	10,944	2.9	16.3	62.6	0.0	6.1
	10,961	0.0	11.2	81.2	0.0	2.1
			"B" Reservoir			
11	11,022	104.0	29.0	57.2	8.6	9.9
24	11,032	0.0	24.0	89.5	0.0	2.6
29	11,051	2.9	19.1	87.4	0.0	2.2
31	11,025.5	*	31.8	74.7	0.1	6.9
	11,029	*	30.9	63.7	3.9	10.0
	11,032	*	31.2	68.3	0.4	9.8
	11,034	*	30.3	79.3	3.6	5.2
	11,044	*	33.7	63.3	8.9	9.4
	11,045	*	34.1	63.7	9.3	10.2
			"B-1" Reservoir			
6	11,022	21.2	28.4	51.0	tr	13.9
11	11,041	0.0	15.7	70.6	0.0	4.6
	11,042	7.6	17.3	71.1	0.0	5.0
14	11,043	141.0	28.1	64.1	tr	10.1
24	11,040	*	24.9	54.3	0.4	11.3
	11,045	5.4	26.1	58.2	0.0	6.9
	11,048	0.0	25.6	83.2	0.0	4.3

Table 7 (cont.)

Well No.	Depth (ft)	K (md)	ϕ (%)	Sw (%)	So (%)	Gas (by vol.)
			"B-2" Reservoir			
31	11,078.5	*	29.4	75.4	1.4	6.8
	11,091	*	32.6	71.3	0.3	9.4
	11,097	*	27.2	76.5	1.5	6.0
14	11,067	182.0	30.7	61.6	1.1	11.8
29	11,071	0.0	14.3	77.6	0.0	3.2
	11,074	127.0	31.1	68.6	0.8	9.6
	11,087	0.0	12.1	83.5	0.0	2.0
			"C" Reservoir			
1	11,147.5	60.0	28.9	76.4	0.0	6.8
	11,149	95.2	30.0	71.1	0.3	8.9
	11,152	74.3	31.2	69.2	0.2	9.6
	11,156	110.0	30.7	66.2	0.3	10.4
	11,162	88.0	29.6	60.3	0.1	11.8
	11,168	132.0	30.8	59.3	0.2	11.6
	11,173.5	120.0	31.4	76.6	0.0	7.4
6	11,131	*	32.4	44.5	15.4	13.3
11	11,157	41.2	22.0	64.0	3.2	7.2
	11,160	10.8	19.4	73.7	0.0	5.1
14	11,142†	207.0	33.3	60.1	1.5	12.7
	11,144†	106.0	33.5	70.2	1.6	9.5
	11,147	248.0	35.7	66.1	1.4	11.6
	11,148	310.0	36.5	63.3	2.7	12.4
	11,157	122.0	31.1	63.2	tr	11.4
	11,164	0.0	28.8	83.7	1.2	4.8
	11,174	35.2	27.1	57.1	3.2	10.6
	11,182	262.0	30.5	56.7	3.0	12.2
24	11,122	4.2	23.3	35.6	0.4	11.2
	11,161	0.0	25.0	83.1	0.0	2.8
	11,165	4.6	29.7	66.0	1.1	9.3
	11,170	113.0	31.6	67.6	0.3	10.1
	11,189	67.0	29.6	48.1	0.3	15.3
	11,200	226.0	31.9	56.2	0.3	13.9
29	11,129	0.0	12.9	69.0	0.0	4.0
31	11,132	*	28.6	75.0	1.1	6.8
	11,152	*	28.3	71.3	0.2	8.1
	11,155	13.1	26.4	78.0	0.0	5.8
	11,163	84.3	31.2	61.2	1.3	11.7
	11,165	314.0	33.3	58.9	1.5	13.2
			Upper "D" Reservoir			
14	11,206	15.2	20.7	56.1	4.5	8.1
	11,209.5	176.0	34.4	58.7	2.9	13.2

Table 7 (cont.)

Well No.	Depth (ft)	K (md)	ϕ (%)	Sw (%)	So (%)	Gas (by vol.)
			"D" Reservoir			
6	11,231	67.0	28.8	70.1	tr	8.6
	11,240	49.2	29.7	70.8	5.4	7.1
	11,244	*	28.0	57.5	8.6	9.5
11	11,205	12.1	19.7	59.0	0.3	8.1
	11,211	18.5	22.0	70.5	0.0	6.5
	11,219	*	22.6	65.5	0.0	7.8
14	11,232†	285.0	32.5	66.2	3.0	10.1
	11,238†	101.0	28.2	57.1	2.8	11.0
	11,249	89.7	31.8	65.6	3.0	10.0
	11,255	241.0	38.4	64.7	2.6	12.6
	11,261	187.0	35.1	63.7	1.4	12.2
24	11,250†	*	34.2	58.7	0.3	14.0
	11,255†	110.0	31.0	60.3	0.3	12.2
	11,260	173.0	32.3	52.9	0.3	15.1
29	11,240	8.1	13.7	67.1	0.0	4.5
	11,253	98.1	26.0	53.2	0.4	12.2
	11,267	3.2	18.4	62.1	0.0	7.0
31	11,250	149.0	30.7	61.3	0.2	11.8
	11,252	*	29.9	45.8	3.7	15.1
	11,253	310.0	31.1	58.8	0.2	11.8
			"E" Reservoir			
11	11,303	*	27.7	59.5	0.0	11.2
14	11,281†	327.0	37.5	63.3	1.3	13.3
	11,283†	119.0	32.5	61.1	tr	12.6
	11,285†	137.0	31.5	66.0	1.5	10.9
	11,302	128.0	32.6	64.1	tr	10.6
	11,305.5	89.7	36.7	68.1	1.3	12.2
	11,315	122.0	32.7	68.2	tr	12.0
	11,339	27.5	26.5	70.1	1.9	7.4
	11,341	91.9	33.8	66.5	1.5	10.8
24	11,309	44.0	24.3	56.6	0.3	12.3
	11,310	11.0	26.6	67.0	0.4	8.7
	11,318	44.0	33.4	58.5	0.3	15.4
	11,322	35.0	31.4	68.9	0.3	9.7
	11,327	112.0	31.4	67.3	0.3	10.2
	11,333	29.0	31.4	59.9	0.3	12.5
	11,362	27.0	29.7	65.0	0.3	10.3
	11,369	12.0	29.8	78.2	0.3	6.4
	11,380	51.0	34.7	65.2	0.3	12.0
29	11,312	69.1	27.1	55.3	0.0	12.1

Table 7 (cont.)

Well No.	Depth (ft)	K (md)	ϕ (%)	Sw (%)	So (%)	Gas (by vol.)
			"E" Reservoir (cont.)			
31	11,289	4.7	24.3	85.2	0.0	4.1
	11,296	80.9	29.2	44.5	0.7	16.2
	11,300.5	64.3	28.7	61.3	0.7	10.9
	11,306	71.1	28.2	69.6	0.3	7.8
			"F" Reservoir			
14	11,359†	182.0	35.0	62.3	tr	14.2
	11,364	137.0	38.7	65.5	2.6	12.5
	11,370	218.0	38.0	62.9	2.4	*
	11,385	87.2	33.2	62.0	tr	12.6
24	11,394	37.0	32.5	75.5	0.3	7.9
	11,400	69.0	31.0	72.3	0.3	8.5
29	11,413	7.6	17.1	46.9	0.0	9.1
31	11,386.5	7.4	24.4	88.0	0.0	3.1
	11,390	27.6	28.3	73.3	0.0	7.0
	11,440	*	26.1	81.8	0.0	4.7
			"G" Reservoir			
14	11,463	167.0	36.5	59.4	2.7	*
	11,467	151.0	38.8	59.2	2.1	15.0
	11,470	139.0	34.8	64.2	tr	2.4
	11,479	119.0	38.3	69.9	tr	11.5
24	11,478	74.0	31.2	73.6	0.3	8.1
	11,482	101.0	32.8	68.9	0.3	9.1
	11,489	16.0	29.2	50.6	0.4	14.3
	11,493	8.0	27.9	60.0	0.3	11.1
	11,499	*	29.8	74.0	0.3	8.4
	11,528	2.5	23.4	67.8	0.0	7.5
29	11,480	54.1	21.1	48.8	0.0	10.8
	11,481	29.7	25.1	53.7	0.0	10.7
	11,490	2.7	17.9	70.9	0.0	5.2
	11,496	16.8	18.1	46.4	0.0	9.7
	11,501	23.1	24.2	54.1	0.0	11.1
	11,502	73.9	23.4	40.6	0.4	13.9
	11,503	31.4	20.9	42.1	0.6	12.1
	11,525	47.3	21.8	46.8	0.9	11.2
	11,527	15.1	24.2	58.3	0.0	10.1
31	11,461†	*	31.3	63.0	3.8	10.4
	11,464	112.0	32.6	72.0	0.2	9.1
	11,468	184.0	32.9	66.0	0.2	11.2
	11,474	8.7	26.8	82.8	0.1	4.6

Table 7 (cont.)

Well No.	Depth (ft)	K (md)	ϕ (%)	Sw (%)	So (%)	Gas (by vol.)
			Nodosaria Reservoir			
1	12,043	6.7	27.2	69.4	0.0	8.3
	12,045	16.8	28.6	68.7	tr	9.0
	12,048	14.3	27.4	76.3	0.0	6.5
	12,050	15.2	27.9	71.4	0.0	8.0
	12,053	5.3	26.3	81.3	0.0	4.9
	12.063	14.9	28.5	67.4	0.1	9.3
	12,067	8.8	27.2	72.4	0.0	7.5
6	11,708	*	28.9	45.8	2.1	14.3
	11,723	238.0	28.4	37.0	10.9	14.8
	11,733	*	29.6	44.6	11.5	13.0
	11,738	341.0	30.6	49.3	7.5	13.2
14	11,787	16.5	31.4	62.8	tr	11.6
	11,797	42.8	30.5	65.1	tr	10.6
	11,804	452.0	34.3	64.1	tr	12.3
24	11,802	132.0	34.8	64.6	0.3	12.2
	11,806	135.0	34.0	57.0	0.3	14.5
	11,810	171.0	34.6	63.7	0.6	12.3
	11,815	256.0	33.0	54.0	0.3	15.1
	11,820	15.0	28.9	56.2	0.4	12.2
	11,824	*	29.4	56.9	0.7	12.5
	11,852	97.0	33.3	34.8	0.3	14.5

* No test
† Depths fall within perforated intervals.
tr = trace

The initial pressure gradient measured by drill-stem tests in the "B-2" reservoir was 0.84 psi/ft in June 1959. The last pressure gradient in June 1965 was calculated to be 0.61 psi/ft. The bottom-hole shut-in pressure dropped rapidly from an initial value of 9,320 psi to 7,258 psi during the first 19-month period of production (fig. 19). The decline in pressure was more gradual from 1961 to 1965. The P/Z data plotted versus cumulative gas production (fig. 20) is nonlinear in the early production period where pressure decline was rapid. Water production was very low until 1965, when the well began to water out (fig. 19).

Salinity of formation water in the "B-2" reservoir was determined to be 112,000 ppm NaCl from the SP log. Equilibrium temperature was 223°F, and methane solubility was 21.5 scf/bbl at the initial reservoir pressure of 9,302 psi. Solubility declined to 18.3 scf/bbl in 1965 at the last recorded pressure of 6,761 psi.

No conventional whole-core data are available for the "B-2" reservoir. A few sidewall cores were tested from "B-2" zones that are identified in three different wells in the Port Arthur field (table 7). Permeabilities range from 0 to 182 md; porosities range from 12.1 to 32.6 percent; water saturation (S_w) ranges from 61.6 to 83.5 percent; oil saturation (S_o) varies from 0 to 1.5 percent; and the amount of gas, by volume, ranges from 2 to 11.8.

The isopach map (fig. 21) shows that the "B-2" reservoir is about 30 ft thick in well no. 31. The sand body is thicker at the locations of well numbers 23 and 35, but these wells did not produce from the "B-2" reservoir. The structure map (fig. 22) shows that the productive well (well no. 31) lies slightly updip from the structural high.

Other Reservoirs

Several other lower Hackberry reservoirs ("A-2," "B-1," "D," "E," and "F") produced enough hydrocarbons to merit some attention in evaluating the Port Arthur field (table 4). Some of these reservoirs do not have substantial lateral continuity but may have sufficient production potential to influence the economic feasibility of an enhanced gas recovery test. Salinity, pressure, temperature, and methane solubility data for these reservoirs are listed in table 6. Sidewall core data are given in table 7. These reservoirs will be further evaluated before this project is completed. Several wells produced gas and condensate from three or four different sandstones. Some of the perforated (hatched) intervals of production (figs. 23 and 24) occur in isolated thin gas stringer sandstones. Other productive intervals occur as gas caps associated with underlying aquifers. Several potentially productive gas-capped aquifers and thin gas stringer sandstones that were not perforated can be identified in these wells. A new

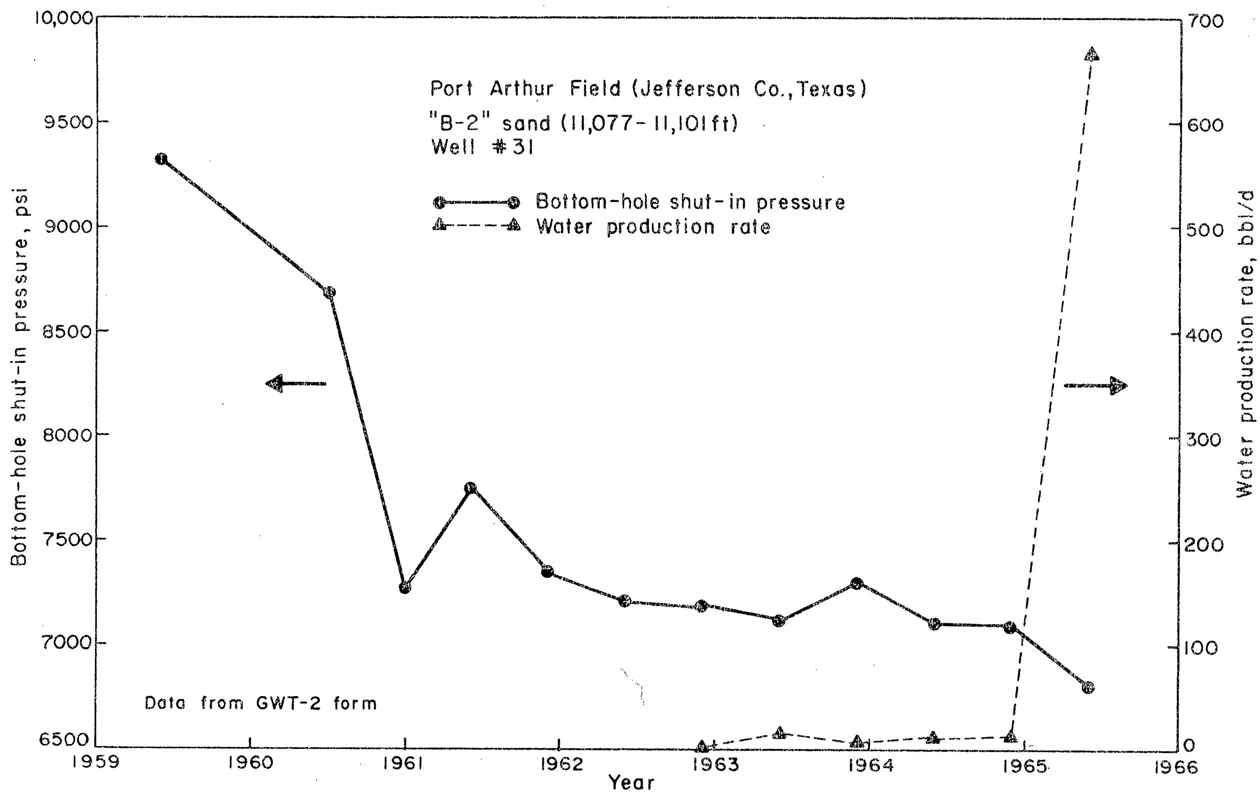

Figure 19. Bottom-hole shut-in pressure decline and water production rates, "B-2" sandstone.

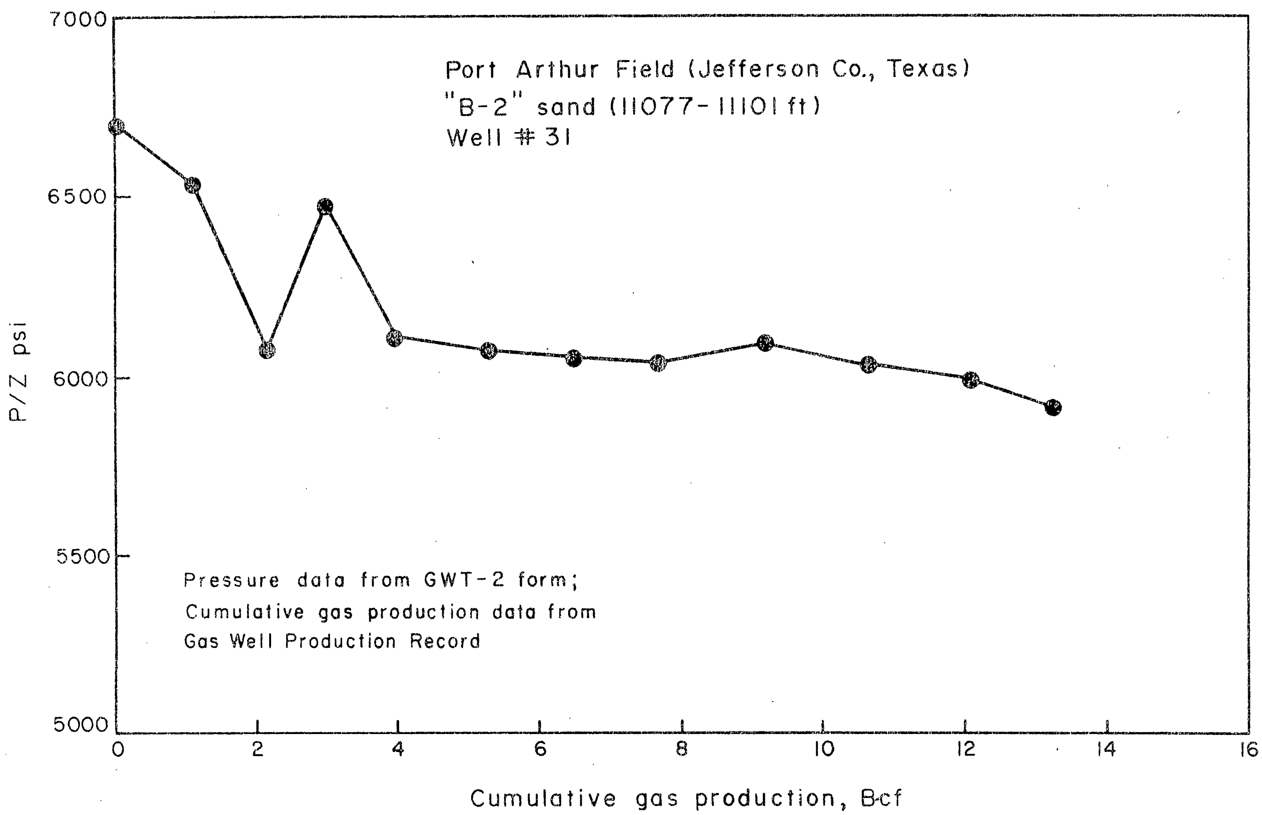

Figure 20. P/Z versus cumulative gas production, "B-2" sandstone.

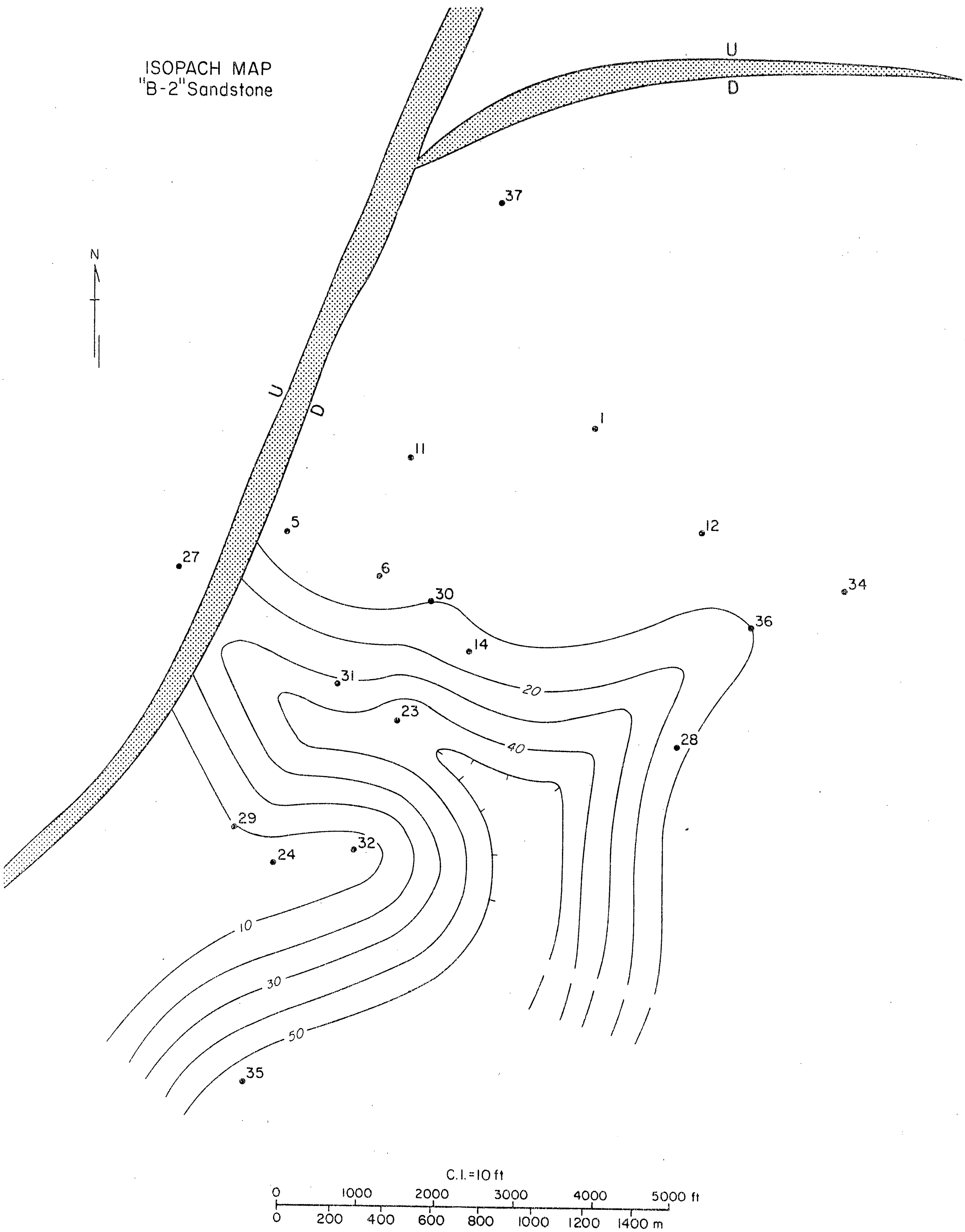

Figure 21. Isopach map, "B-2" sandstone, Port Arthur field.

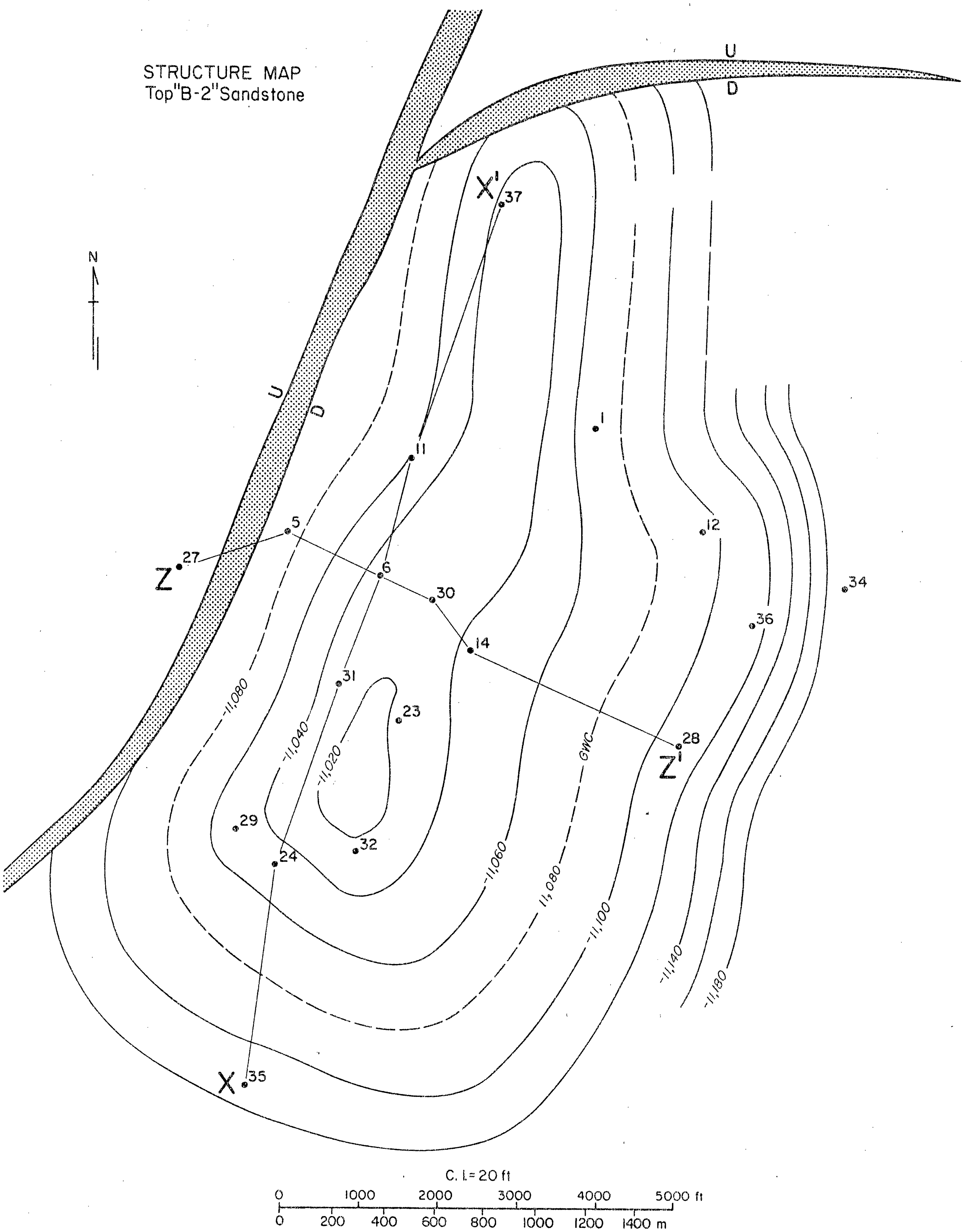

Figure 22. Structure map, "B-2" sandstone, Port Arthur field.

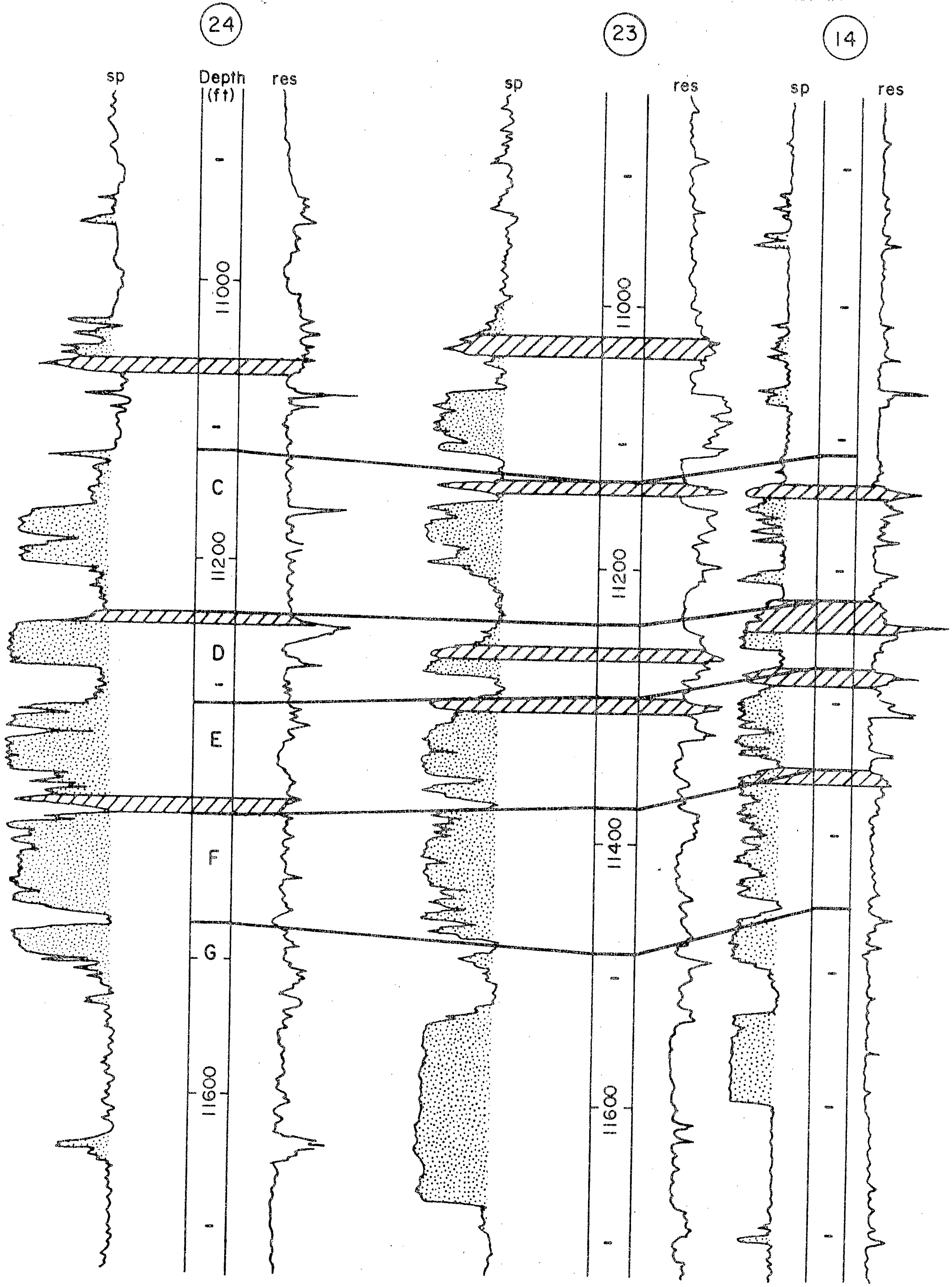

Figure 23. Well logs for 3 wells along strike direction show perforated gas-cap sandstones and gas stringer sandstones (hatched areas) and aquifers, lower Hackberry, Port Arthur field.

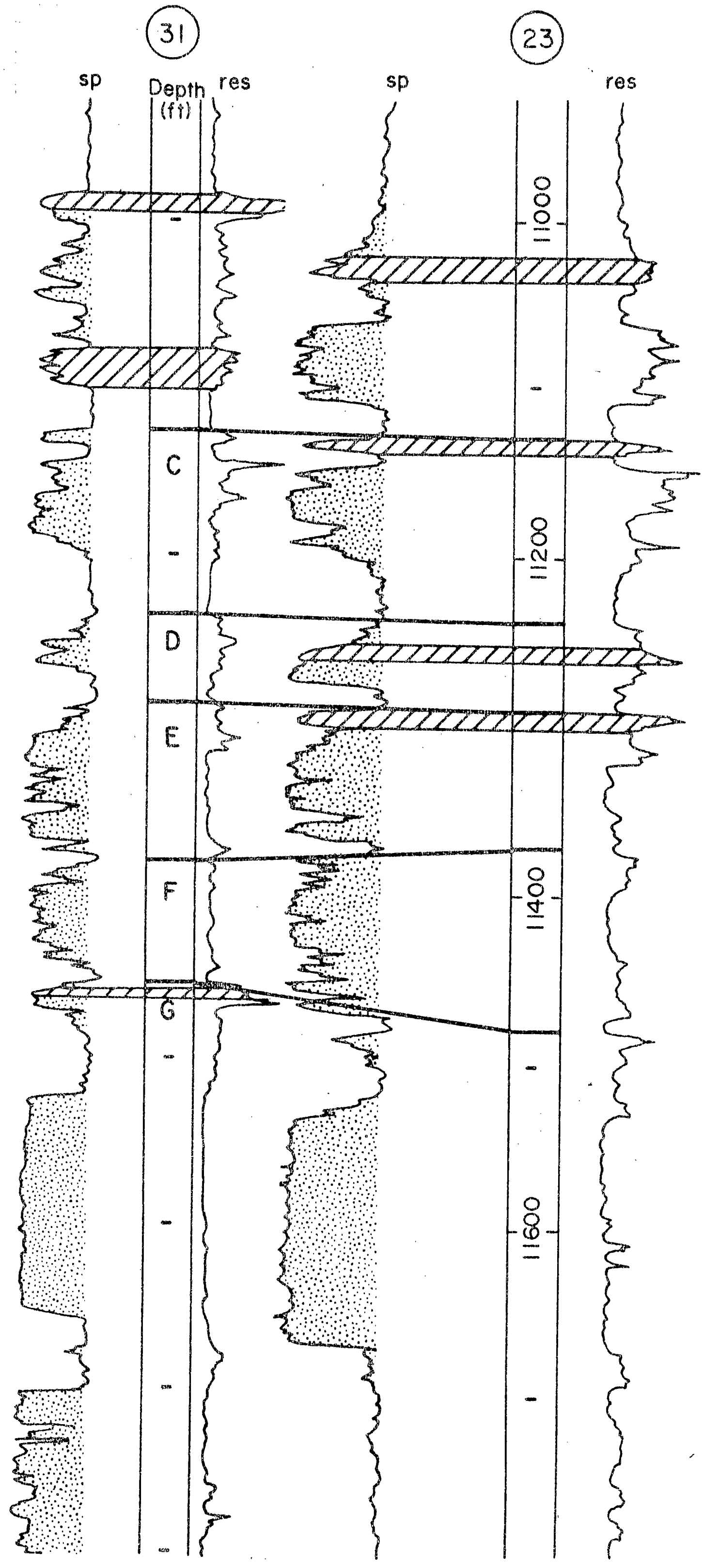

Figure 24. Well logs for 2 wells along dip direction near top of structure show perforated gas sandstones and gas stringer sandstones (hatched areas) and aquifers, lower Hackberry, Port Arthur field.

well drilled near the top of the structure in the Port Arthur field would offer numerous potentially productive lower Hackberry sandstones for the testing and completion programs. If a new well is drilled deeper, a Nodosaria sandstone and Vicksburg interval would become potential producers.

Well Log Analyses

The main objective of log analyses in the "B-2" and "C" sandstones in the Port Arthur field was to provide a basis to determine original gas in place. To do this it was necessary to establish net gas sandstone thickness, porosity, and water saturation at each penetration. The major findings of this study (Ausburn, 1981) are summarized below; details of the computation methods are given in appendix C.

Only one porosity log was available for the field (sonic log for well no. 37). The interval transit times and the correlative induction log resistivities provided a basis to estimate formation factor relationships. The apparent relationship between formation factor (F) and porosity ($\emptyset$) was found to be:

$$F = 1.75 \times \emptyset^{-1.81} \tag{2}$$

and water saturation (S_w) was related to the resistivity ratio (R_o/R_t) by the equation

$$S_w = (R_o/R_t)^{-1/n} \tag{3}$$

where R_t = true resistivity of rock obtained from the induction log in the zone of interest, ohm-meters.

R_o = resistivity of rock obtained from the induction log in a zone that is interpreted to be 100 percent saturated with water, ohm-meters.

n = saturation exponent, assumed to be 1.8.

Using the established formation factor relation (equation 2) and resistivity values in zones interpreted to be wet ($S_w = 100$), it was possible to estimate porosity from resistivity values for zones near the intervals of interest in each wellbore. For example, the porosity $\emptyset_w$ of the wet zone was computed from the relation

$$\emptyset_w = \frac{a\,R_w}{R_o}^{1/m} \tag{4}$$

where a = 1.75

m = 1.81

R_w = resistivity of water computed from salinity data, ohm-meters.

These wet-zone porosities were usually assigned to nearby zones of interest, but sidewall core data, when available, were used as a guide in the assignments.

The gas-water contact (GWC) was determined by inspection of the computed values of S_w. When values of S_w were consistently above 65 percent, a possible GWC was noted. These individual well values were compared and the best estimate of GWC was determined by finding the subsea depth compatible with the individual well determinations and existing structure and stratigraphic interpretations. The apparent GWC was determined to be -11,150 ft for the "C" sandstone and -11,080 ft for the "B-2" sandstone, as indicated on the structure maps (figs. 17 and 22).

Values of net feet of gas in place obtained from the relation ($\phi h (1-S_w) = \phi h S_g$) are computed for each penetration and are listed in table C-5 (appendix C). These values were plotted on maps for the "B-2" and "C" sandstones (figs. 25 and 26) and then contoured and planimetered to obtain in-place gas volumes. Values for the "B-2" sandstone are 969 acre-ft (42.210×10^6 ft^3). Dividing by the gas volume factor (2.8×10^{-3}) yields the estimated 15.07 Bscf in-place gas compared with 13.34 Bscf that was produced from this reservoir by conventional primary production methods. The apparent recovery efficiency of 88.5 percent seems high for this type of reservoir.

In a similar manner, in-place gas values for the "C" sandstone are found to be 1,789 acre-ft (77.929×10^6 ft^3) and dividing by the gas volume factor yields 26.24 Bscf in-place gas compared with 13.752 Bscf produced by primary methods. The apparent recovery efficiency of 52.4 percent appears to be reasonable and compares favorably with results from reservoir simulation studies.

Other average parameters for the "B-2" and "C" reservoirs are listed below.

Parameter (avg.)	"B-2" SS	"C" SS
temp. (^{o}F)	226	230
R_w (ohm-m)	0.026	0.024
R_o (ohm-m)	0.430	0.430
porosity (%)	28.4	27.3
S_w (%)	53.8	50.6
thickness (ft)	9.8	19.6

Wells that show some net sandstone thickness are numbers 1, 6, 14, 23, 29, 30, 31, and 32 for the "B-2" sandstone and numbers 1, 5, 6, 11, 14, 23, 24, 30, 31, and 32 for the "C" sandstone. Information sheets and log calculation sheets were prepared for each of 17 wells in the Port Arthur field; however, these sheets were considered too bulky to be included in this report.

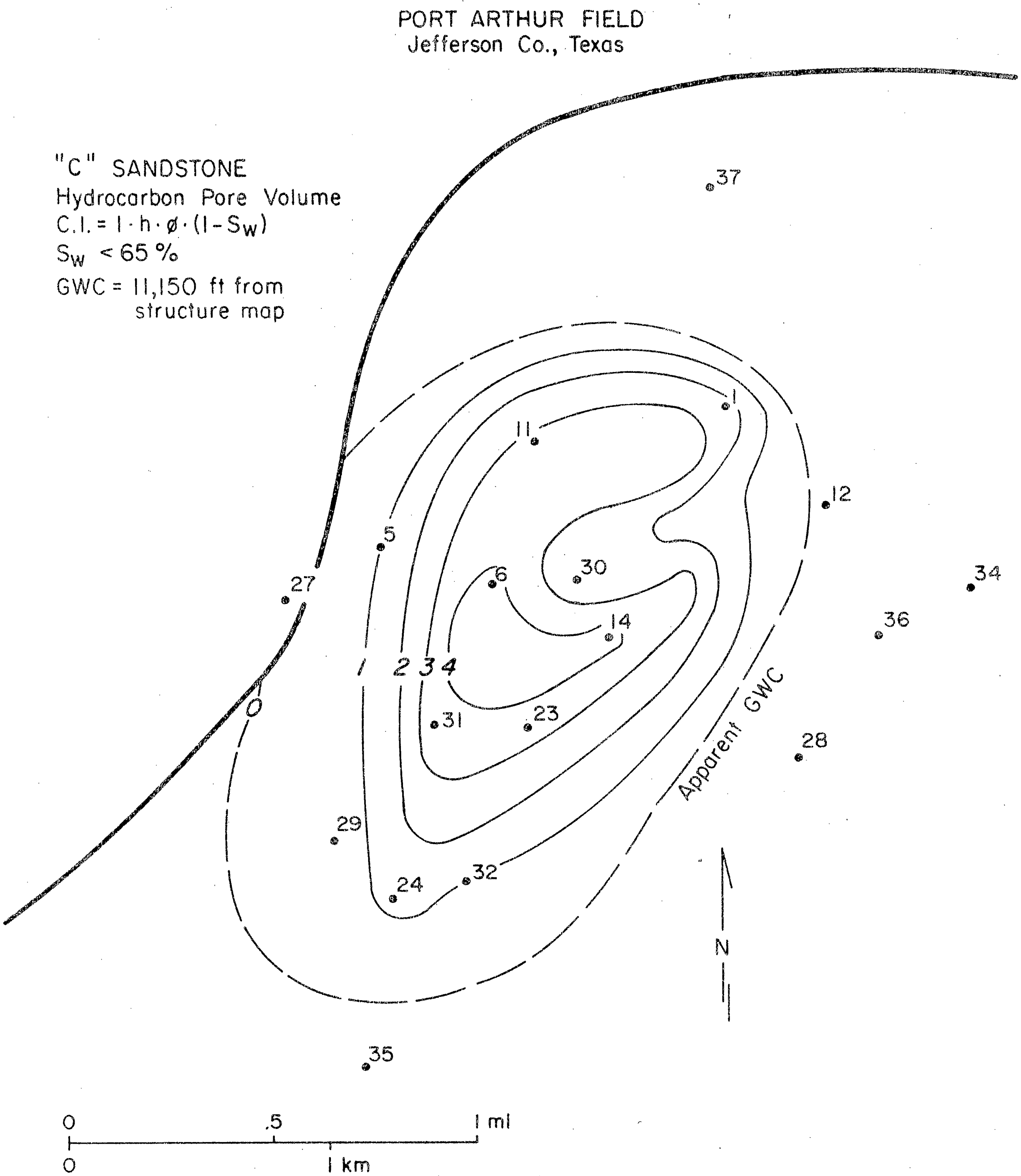

Figure 25. In-place gas volume map; contours show thickness (ft) of "B-2" sandstone where $S_g > 35$ percent ($S_w < 65$ percent), Port Arthur field.

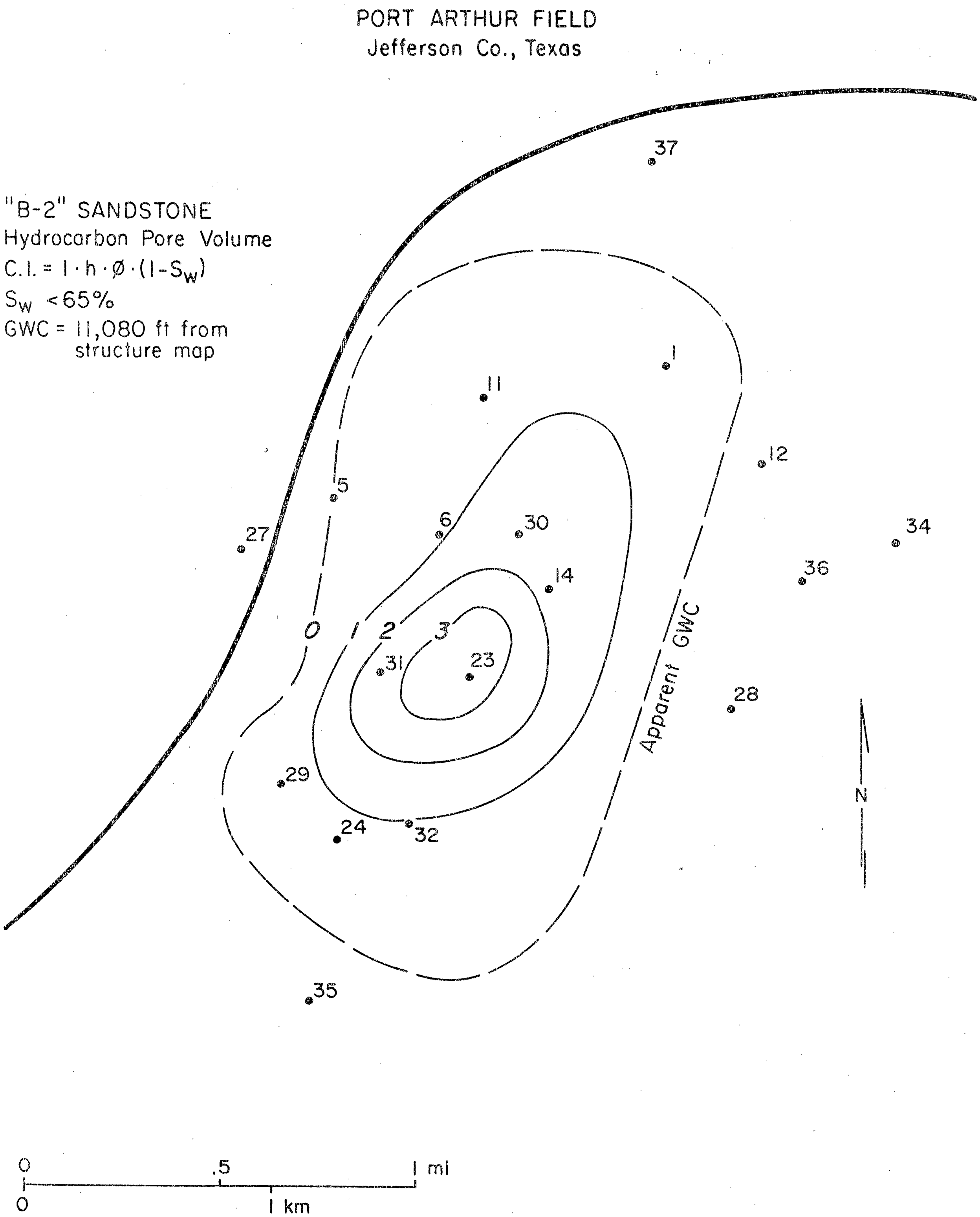

Figure 26. In-place gas volume map; contours show thickness (ft) of "C" sandstone where $S_g > 35$ percent ($S_w < 65$ percent), Port Arthur field.

Predicted Reservoir Performance and Economic Analysis

Reservoir Simulation Results

This part of the project was designed to estimate production of dissolved gas, dispersed gas, and water by natural flow in a high water-cut field. The Port Arthur field was abandoned in 1981 and was not considered to be commercial under the reservoir conditions and economic climate that existed at that time.

The results presented here summarize reservoir simulation studies of the "C" sandstone (Wattenbarger, 1981b); additional details of methodology, production history, and history match are given in appendix E. A history match was performed to understand and to model the reservoir performance of the "C" sandstone. Production was then predicted over a 10-year period.

Table 8 contains a summary of reservoir model data. Some of the data came from previous publications (Halbouty and Barber, 1961, 1962), and some of the data were estimated. The initial pressure of 9,425 psi was calculated from the initial wellhead shut-in pressure and a tubing gradient correction for the original gas having a specific gravity of 0.8. The specific gravity for the raw reservoir gas was calculated by estimating the recombination of the separator fluids.

The results of the prediction run are shown in figure 27 and are also tabulated in table 9. The predicted production is 3.908 Bscf of gas, 58,620 bbl of condensate, and 8,825,000 bbl of water. The predicted recovery is mostly from the free gas phase under natural flow conditions. The gas and water production rates stabilize to a constant percent depletion performance after 2 years. The gas production rate then declines at 21 percent per year, whereas the water production rate declines at 20 percent per year. The stabilized water/gas ratio is about 2.7 bbl/Mscf, or a gas/water ratio of about 375 scf/bbl. This stabilized behavior indicates that the ratio of gas expansion to water expansion is about the same as the producing gas/water ratio.

The producing rates are proportional to the drawdown between the reservoir pressure and the 3,800 psig flowing bottom-hole pressure. During the run the gas production rate has declined from 5,100 Mscf/d to 200 Mscf/d, whereas the reservoir pressure has declined from 6,489 to 4,488 psig.

The gas production rates have been adjusted to account for 15 scf of solution gas being produced with each barrel of water produced. This represents the amount of gas dissolved in water as it enters the wellbore.

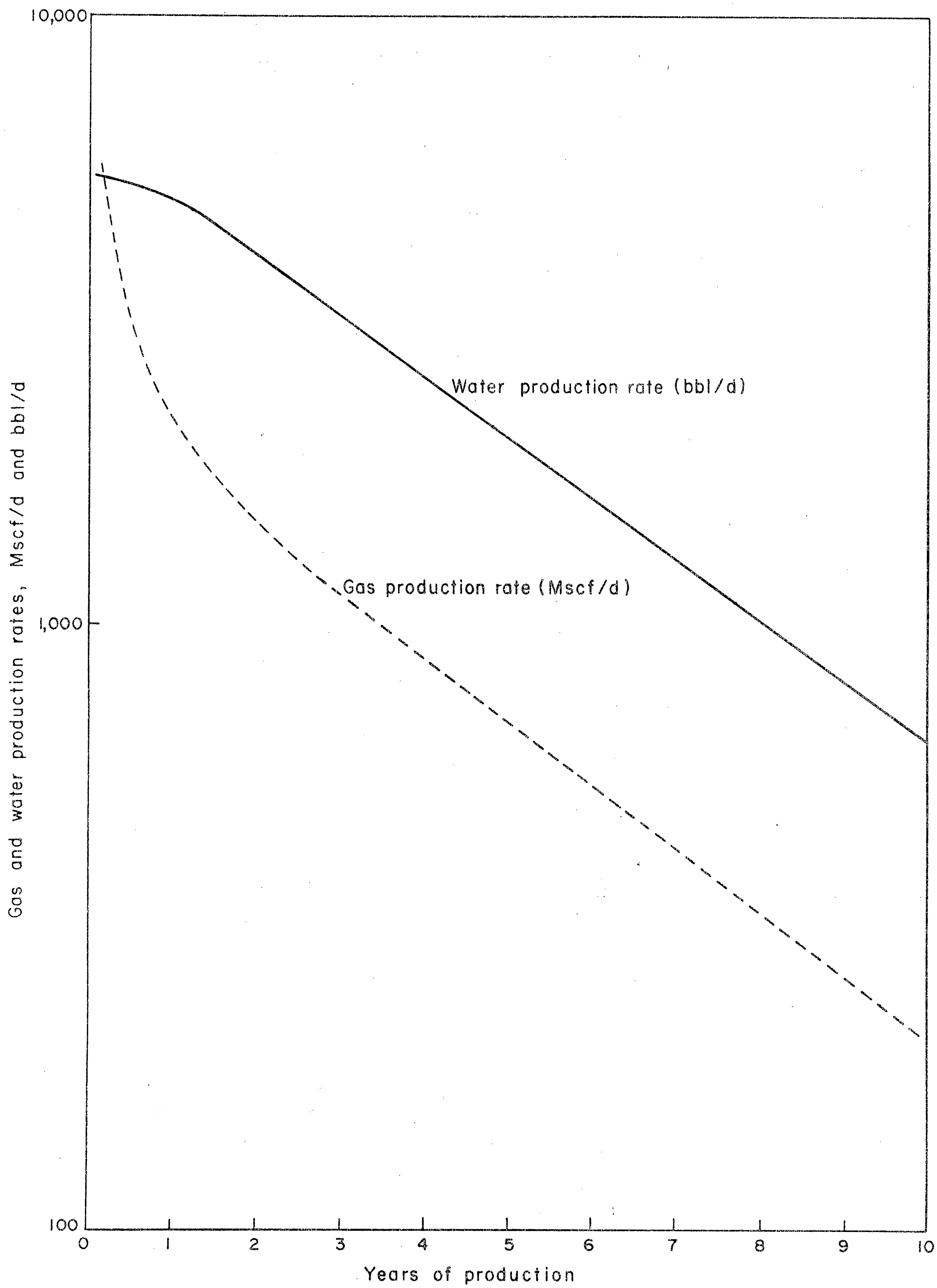

Figure 27. Predicted gas and water production rates, "C" reservoir, Port Arthur field.

Table 8. Summary of Model Data

Original water-in-place*	656.312	MMbbl
Original free gas-in-place*	29.479	Bscf
Reservoir temperature	235	Degrees F
Initial pressure	9,425	psig
Reservoir gas gravity	0.80	
Separator gas gravity	0.67	
Initial gas formation-volume-factor	0.00297	res. cf/scf
Initial gas viscosity	0.0365	cp
Water viscosity	0.40	cp
Permeability	60	md
Porosity	30	percent
Connate water saturation	35.0	percent
Gross thickness*	33	ft
Net gas sand thickness*	16	ft
Water compressibility	2.5×10^{-6}	psi^{-1}
Rock compressibility*	3.0×10^{-6}	psi^{-1}

*These values were determined as a result of the history match.

Table 9. Predicted Production and Pressure Performance

Prediction Year	Gas Prod. (Bscf)	Cond. Oil Prod. (Mbbl)	Water Prod. (Mbbl)	Average Reservoir Pressure (psig)
1	1.369	20.54	1,952	5571
2	0.658	9.87	1,625	5190
3	0.477	7.16	1,291	4899
4	0.369	5.54	1,024	4675
5	0.289	4.33	811	4496
6	0.229	3.44	642	4355
7	0.179	2.68	508	4239
8	0.140	2.10	402	4148
9	0.111	1.66	318	4075
10	0.087	1.30	252	4018
Total	3.908	58.62	8,825	

It is probable that production from the "C" sandstone would be commingled with that from other sands in the lower Hackberry for the test well. The forecast has been made with a constant bottom-hole flowing pressure so that it can be added to similar forecasts for other sands.

Additional work was done recently to address the reservoir mechanics of producing unconventional gas from different sources that may be present in a watered-out gas reservoir (table E-2, appendix E). It is shown that the previous predicted gas production of 3.908 Bscf may be increased to 3.977 Bscf by considering factors (solution gas from water that is invading gas sands and from connate water) that were ignored in previous work. The use of artificial lift increases recovery from 3.977 Bscf to 11.667 Bscf (an increase of 193 percent). The main reason for this increase in recovery is the expansion of trapped gas. A more detailed discussion is given by Wattenbarger (1982) in appendix E, addendum 1.

Economic Analysis

The predicted gas rates for the "C" sandstone lie between the optimistic and pessimistic cases in the preliminary economic evaluation (Wattenbarger, 1981a). The results of those evaluations were a break-even gas price of $0.32/Mscf for the optimistic case and $8.38/Mscf for the pessimistic case. Those cases were for all lower Hackberry sandstones commingled. A more recent economic analysis of the "C" reservoir was based on the gas and water production rates shown in figure 27. The break-even gas price of $1.95/Mscf for the optimistic case and $3.45/Mscf for the pessimistic case for a 15-percent rate of return is encouraging (table 10 and fig. 28). The decrease in the break-even price for the pessimistic case from $8.38/Mscf to $3.45/Mscf is attributed to the more realistic gas and water production rates used for the "C" reservoir. When the increased gas recovery from artificial lift (appendix E, addendum 1) is taken into account, the economic prediction will change. A new economic analysis that takes artificial lift into account has not been completed at this time.

Temperature and Pressure Gradients

Temperatures from well log headers were corrected to equilibrium values and plotted versus depth (fig. 29). A geothermal gradient of $2.58^{\circ}F/100$ ft was determined by least squares fit to the data below a depth of 10,500 ft in the geopressured zone. The top of the lower Hackberry sandstones near the structural high occurs at an average depth of about 10,850 ft.

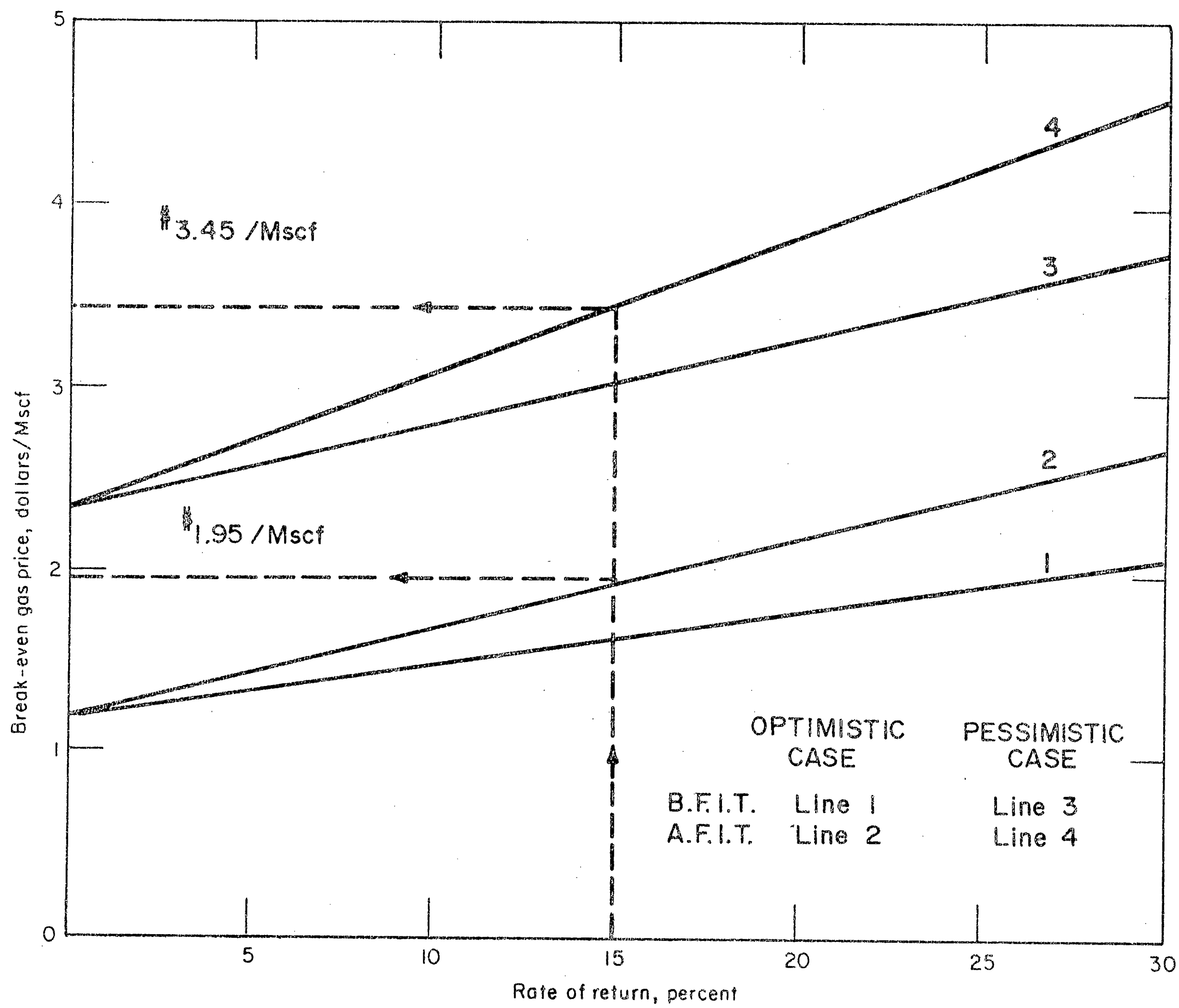

Figure 28. Break-even gas price versus rate of return (B.F.I.T. and A.F.I.T. refer to before and after federal income tax).

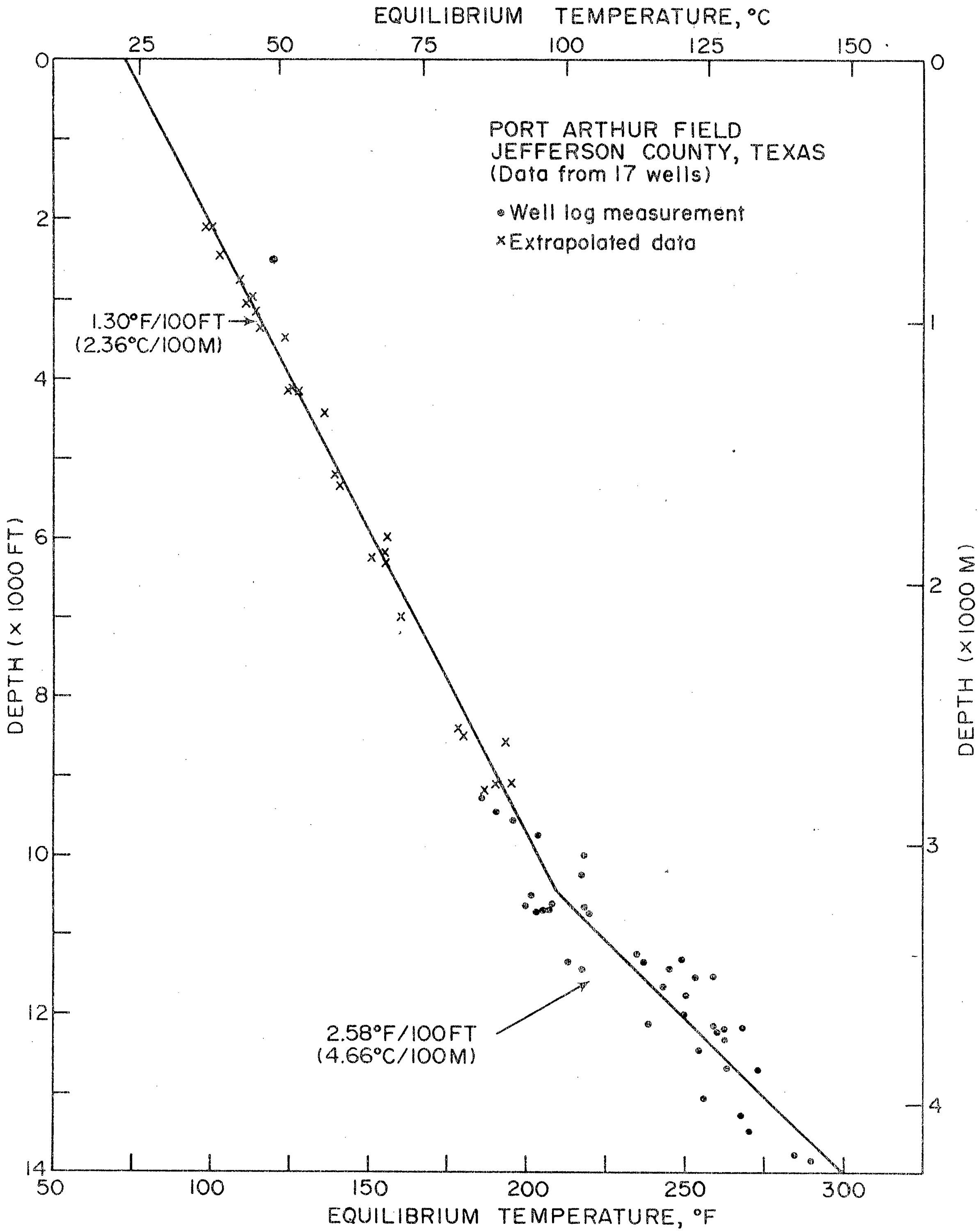

Figure 29. Geothermal gradients, Port Arthur field.

Table 10. Cost Estimates to Produce "C" Reservoir, Port Arthur Field

Physical Parameters:

Permeability	60 md
Net sand thickness	16 ft
Total thickness of sand	33 ft
Water viscosity	0.4 cp
Porosity	30%
Total rock compressibility	3×10^{-6} psi^{-1}
Gas and water flow rate	(see figure 27)
Oil/gas ratio	10 bbl/MMscf

Costs:*	Optimistic	Pessimistic
Producing well	$2,000,000	$3,000,000
Other capital costs	600,000	1,200,000
Operating costs	10,000/month	20,000/month

Other:

Royalty	25.0%	25.0%
Severance tax, oil	4.6%	4.6%
Severance tax, gas	7.5%	7.5%
Ad valorem tax	4.0%	4.0%
Federal income tax	46.0%	46.0%
Oil price	$30/bbl	$30/bbl

Result:

Break-even gas price (at 15% rate of return)	$1.95/Mscf	$3.45/Mscf

*Based on cost estimates of Wattenbarger (1981a).

Temperature data from well logs in the Port Arthur field were very limited at depths less than 10,500 ft. Additional temperature data from other wells in Jefferson County were used to extrapolate the temperature trend in the depth interval above 10,500 ft to a mean surface temperature of 72°F. A geothermal gradient of 1.3°F/100 ft was established for the shallow section.

The original formation fluid pressures in the Port Arthur field were obtained from bottom-hole shut-in pressures (BHSIP) measured by drill-stem tests (DST) and from shale resistivity (R_{sh}) data using the method of Hottmann and Johnson (1965). The top of geopressure in the lower Hackberry sandstones was estimated to be 8,900 ft by plotting BHSIP from DST versus depth and using average pressure gradients from shale resistivity data to extrapolate the trend line until it crosses the pressure gradient line of 0.465 psi/ft (fig. 30). Top of geopressure (8,900 ft) appears to be deeper in the Port Arthur field, compared with 8,000 ft estimated for Jefferson County (fig. 31).

Reservoir Fluid Properties

Parameters That Control Methane Solubility

The solubility of methane in water and NaCl solutions has been determined from laboratory measurements for salinities of 0 to 300 grams per liter, a temperature range of 160 to 464°F, and a pressure range from 3,500 to 22,500 psi (Price and others, 1981). Equations (5) and (6) below give the "best fit" to the average experimental data. Either equation can be used.

$$\log_e CH_4^* = -1.4053 - 0.002332t + 6.30 \times 10^{-6}t^2 - 0.004038S - 7.579 \times 10^{-6}p + 0.5013 \log_e p + 3.235 \times 10^{-4} t \log_e p \tag{5}$$

Standard deviation of residuals = 0.0706
Multiple R = 0.9944

$$\log_e CH_4^* = -3.3544 - 0.002277t + 6.278 \times 10^{-6}t^2 - 0.004042S + 0.9904 \log_e p - 0.0311 (\log_e p)^2 + 3.204 \times 10^{-4}t \log_e p \tag{6}$$

Standard deviation of residuals = 0.0709
Multiple R = 0.9943

t is temperature in ° Fahrenheit

S is salinity in grams per liter

p is pressure in psi.

*CH_4 is in standard cubic feet (scf) per petroleum barrel (42 gallons) at 25°C (77°F) and one atmosphere.

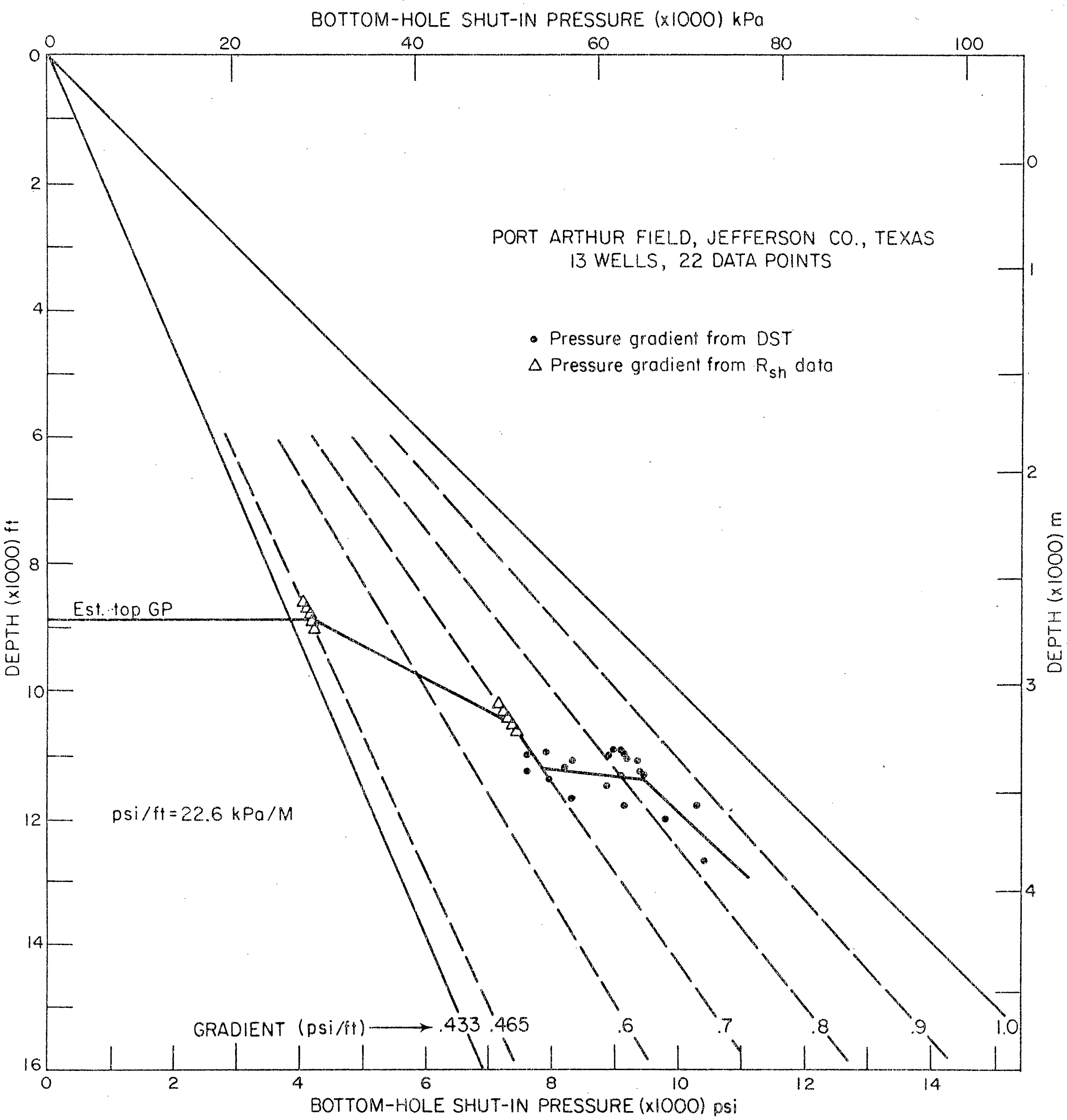

Figure 30. Bottom-hole shut-in pressure versus depth for 13 wells in Port Arthur field.

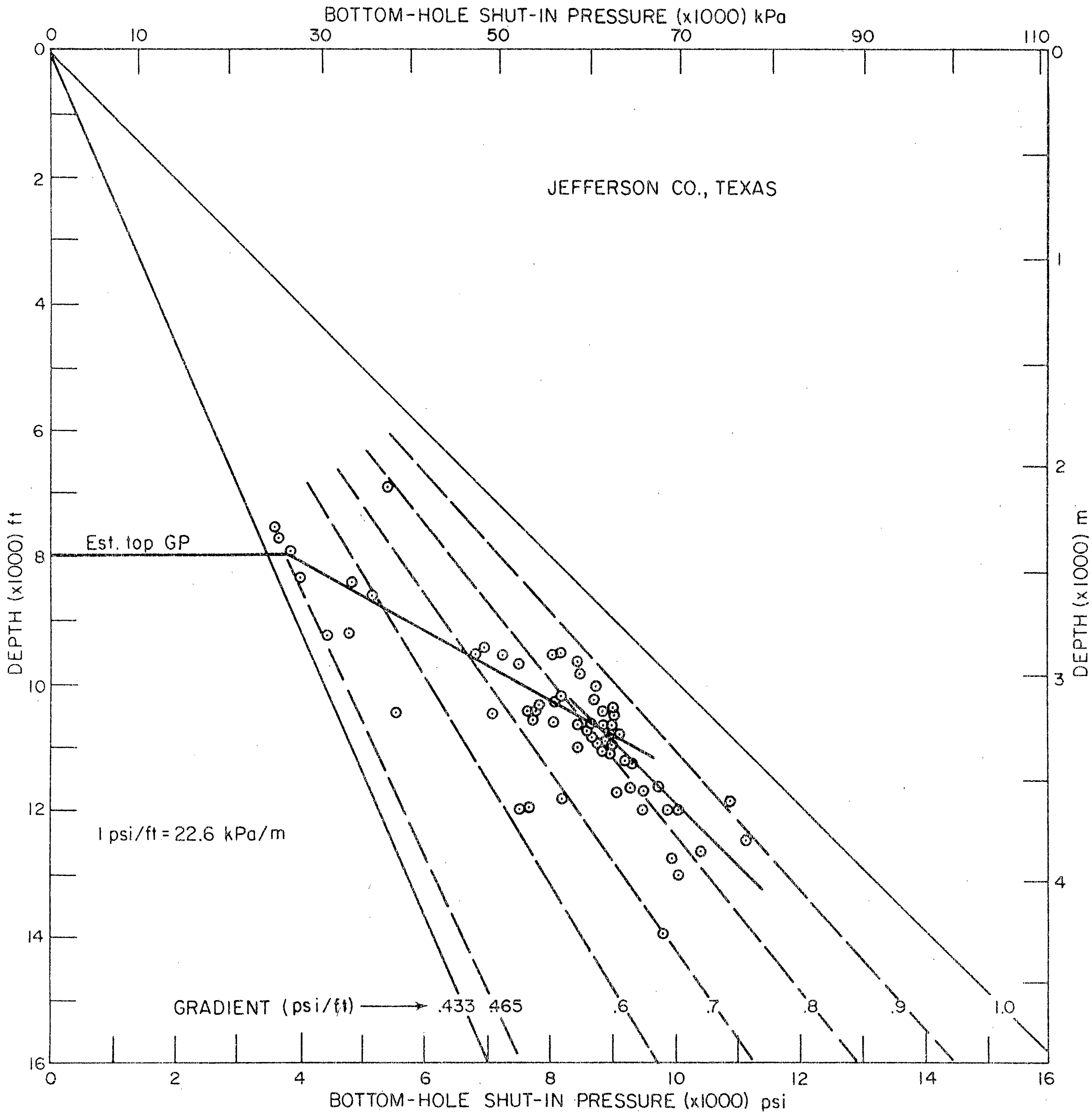

Figure 31. Bottom-hole shut-in pressure (from DST) versus depth for wells in Jefferson County, Texas.

The equations show that methane solubility in water and NaCl solutions is a function of pressure, temperature, and salinity. An increase in pressure or temperature causes an increase in solubility. An increase in salinity reduces solubility. Pressure and temperature are more predictable than salinity, which varies greatly throughout the Gulf Coast area. Because of this variability and the difficulty of determining salinities accurately by indirect methods such as the well log analyses discussed below, salinity values generally are the least reliable of the three parameters that control methane solubility.

Several potential sources of error exist for salinities determined from the SP log. Recent work by Dunlap and Dorfman (1981) points out that a major source of error lies in the use of incorrect values of R_{mf} that are listed on well log headers when high-density lignosulfonate muds and certain other types of mud are used (R_{mf} is too large). Lignosulfonate muds have been in use for over 15 years; thus, the scope of the problem is large. Also, the method of determining R_{mf} from mud resistivity using the Schlumberger Limited (1978) chart, Gen 7, should not be applied to lignosulfonate muds, as clearly stated on the chart. The chart was based on the work of Overton (1958), which took place before the widespread use of lignosulfonate muds began. The present method of correcting R_{mf} from surface to downhole temperature, using resistivity versus temperature variations for NaCl solutions, may not be applicable to modern muds and mud filtrates, thus introducing further errors into salinity determinations.

Salinities in this report were determined from the SP log by the improved method of Dunlap and Dorfman (1981) and are commonly higher than those obtained from previous well log methods; these higher salinities result in lower estimates of methane solubility.

As stated earlier, formation fluid temperature influences methane solubility. In this report, wellbore temperatures taken from well logs are corrected to equilibrium values that represent formation fluid temperatures by the following equation of Kehle (1971):

$$T_E = T_L - 8.819 \times 10^{-12} D^3 - 2.143 \times 10^{-8} D^2 + 4.375 \times 10^{-3} D - 1.018 \qquad (7)$$

where T_E = equilibrium temperature (^oF)

T_L = temperature recorded on well log header (^oF)

D = depth (ft).

Formation fluid pressures can be derived from shale resistivity or acoustic travel time data using the method of Hottmann and Johnson (1965). Shale resistivity values (R_{sh}) from amplified short normal resistivity curves of induction logs are plotted as a function of depth for both hydropressured and geopressured zones. The normal compaction curve is drawn by a least-squares regression method. All R_{sh} data fall near this curve when shales are normally pressured or slightly geopressured; R_{sh} data falling to the left of this curve are lower than normal, indicating that pressure gradients are significantly greater than normal and may approach 1 psi/ft in highly geopressured zones. Deviations of R_{sh} data points from the normal compaction curve are calibrated in terms of pressure or pressure gradient by bottom-hole shut-in pressures measured by drill-stem tests in wells located in the area of interest. Details of the method are explained in previous reports (Gregory and others, 1980; Weise and others, 1981a).

Gas/Brine Ratios versus Methane Solubility

Recent studies of reservoir gas content in relation to methane saturation show a poor correlation between produced gas/brine ratio and methane solubility determined by laboratory measurements (Randolph, 1981). Produced gas/brine ratios are influenced by a complex relation between compositions of gas and brine, reservoir characteristics, and producing conditions. After considering the results of five well tests, Randolph concludes that the correlation between salinity and hydrocarbon energy content of produced brine is so poor that salinity is of questionable value as a criterion for selecting reservoirs to be tested. These findings are more pertinent to the DOE geothermal program than to the GRI program. The reason is that solution gas represents a large portion of the DOE geothermal resource but is a small portion of the GRI gas resource in watered-out gas fields such as the Port Arthur field. No great error will be made in this project, therefore, if we continue to estimate potential production of solution gas from methane solubility data until the observations of Randolph are better understood.

Methane Solubility in Aquifers

Aquifers in the lower Hackberry sandstones in the Port Arthur field initially contained waters characterized by high geopressures, high salinities, moderate temperatures, and moderate methane solubilities. During the production period, the amount of methane dissolved in formation waters decreased as reservoir pressures declined (as discussed in the next section).

Values of pressure, pressure gradient, salinity, temperature, and methane solubility for the best thick aquifers are plotted and tabulated versus depth at original reservoir conditions for 18 wells in the Port Arthur field (appendix D). Solubility values increase with depth; typical data vary from 4 or 5 scf/bbl at a depth of 2,000 ft and from 24 to 30 scf/bbl at about 12,000 ft. In the lower Hackberry sandstone units the average methane solubility is 23.6 scf/bbl, based on a pressure gradient of 0.78 psi/ft, a salinity of 90,400 ppm, a temperature of 231°F, and an average depth of 11,150 ft (table 5).

Effect of Reservoir Pressure Decline on Methane Solubility

There is a substantial decrease in the aqueous solubility of methane as pressure declines in a producing reservoir. An example is the "C" reservoir (11,136 to 11,144 ft) in the Meredith no. 2 Doornbos, where the pressure decreased 54 percent over a period of about 13 years (fig. 32 and table 11). The corresponding decrease in methane solubility was 33 percent, changing from 26.75 scf/bbl in 1959 to 17.87 scf/bbl in 1972. It was assumed that reservoir temperature and formation water salinity remained constant at 243°F and 80,000 ppm NaCl, respectively.

Seismic Data

The reasons for obtaining seismic data for this project are to (1) provide structural information to supplement geological interpretations in areas with poor well control, (2) determine location and geometry of faults, (3) locate boundaries of gas reservoirs and aquifers, and (4) evaluate seismic reflection response to low saturations of free gas dispersed in the water-invaded zones of watered-out gas reservoirs.

Seismic data were purchased from three different companies that conducted surveys that cross the Port Arthur field or provide regional control in adjacent areas. The first set of data was obtained from Mobil Exploration and Producing Services, Inc., for lines 1, 2, and 3, which were shot by Western VI in 1973. Six nine-track (800 BPI) reels of 1/2-inch tape and three microfiche copies of supporting documentation were received. These correlated vibroseis data are in Western's Code 4, 32-bit floating point format, 4 mil sample rate, and 6.2 second record length. Line 3 runs through the Port Arthur field in a northwest-southeast direction for a distance of 4.38 mi (fig. 33) and is potentially the most valuable data for evaluating the field. Line 2 is almost perpendicular to line 1 and runs in a northeast-southwest direction for a distance of 4.06 mi. Line 1 (4.19 mi in length) is located about 2.5 mi southwest of line 3; the

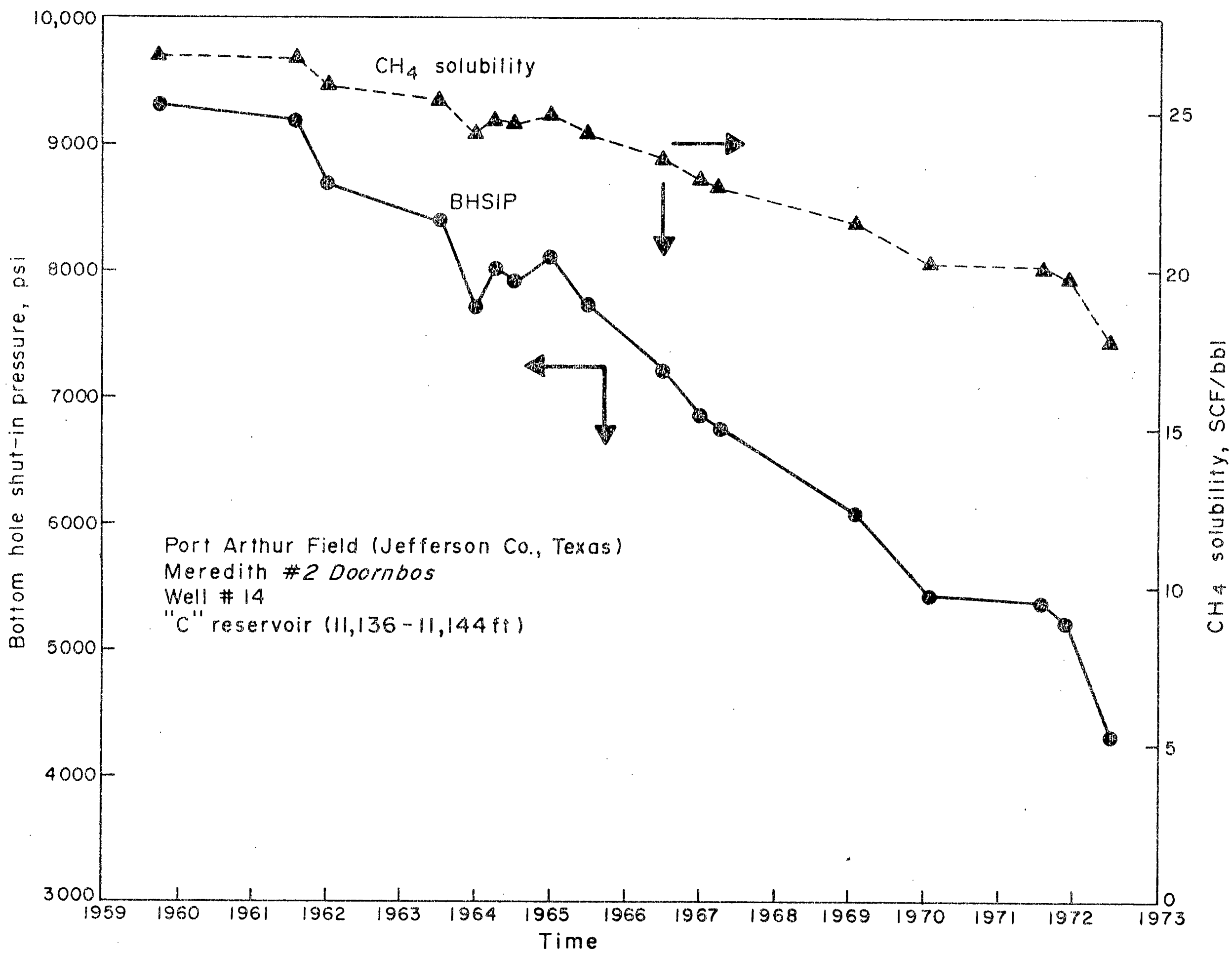

Figure 32. Bottom-hole shut-in pressure and methane solubility versus time (years), "C" reservoir, Port Arthur field.

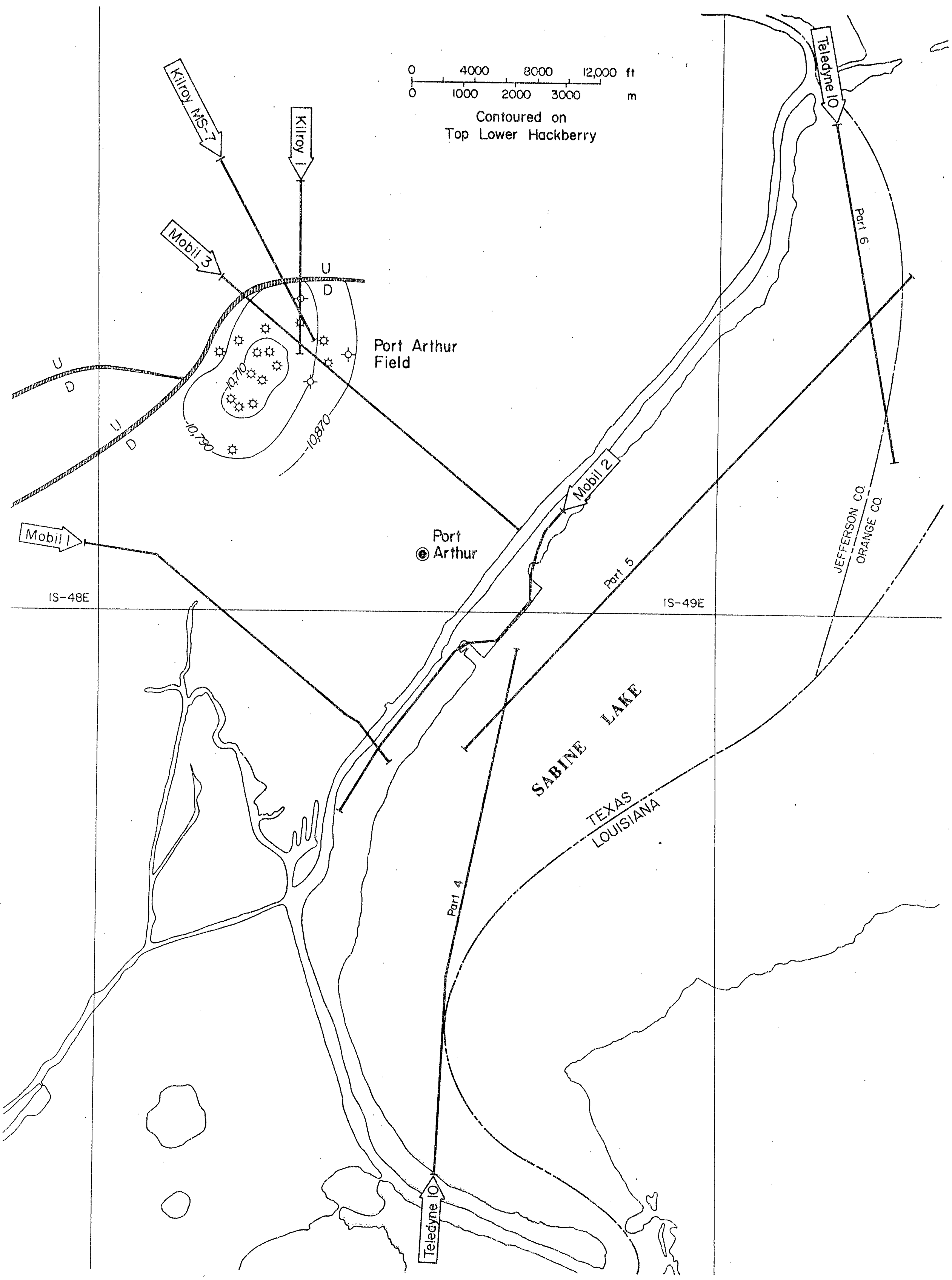

Figure 33. Location of available seismic lines in and near the Port Arthur field.

Table 11. Effect of pressure decline on solubility of methane in formation water at constant equilibrium temperature of 243°F and constant salinity of 80,000 ppm NaCl, Meredith #2 Wm. Doornbos, "C" reservoir, 11,136-11,144 ft, Port Arthur field, Jefferson County, Texas.

Date (year-month)	WHSIP (psia)	BHSIP* (psia)	CH_4 Solubility (scf/bbl)
59-09	7,608	9,320	26.75
61-07	7,454	9,217	26.61
61-12	7,015	8,719	25.87
63-06	6,715	8,394	25.38
63-12	6,115	7,712	24.31
64-03	6,415	8,009	24.78
64-06	6,315	7,937	24.67
64-12	6,502	8,107	24.93
65-06	6,165	7,736	24.35
66-06	5,615	7,227	23.51
66-12	5,515	6,859	22.88
67-03	5,415	6,750	22.69
69-01	4,815	6,091	21.51
70-01	4,215	5,441	20.26
71-06	4,165	5,379	20.14
71-12	4,015	5,216	19.81
72-06	3,215	4,313	17.87

*Converted from WHSIP (assumed only gas in wellbore pipe) southeastern portions of these lines are roughly parallel. Total length of lines 1, 2, and 3 is 12.63 mi.

The second set of lines, obtained from Kilroy Company of Texas, Inc., intersect in the northeast part of Port Arthur field (fig. 33). Line MS-7 is 6-fold and 12-fold CDP coverage shot in 1979 and runs in a northwest-southeast direction for a distance of about 2 mi. Line 1 was shot in 1980 and runs for about 2 mi in a north-south direction to tie into Mobil's line 3. Two wells in or near the field are located on line 1; well no. 1, the Meredith no. 1 Doornbos, is located near the south end, and well no. 37, the Kilroy no. 1 Booz, is located farther north on the line.

The third and last set of available seismic data is line 10, which was obtained from Teledyne Exploration. Line 10, shot in 1969, provides regional coverage in the area southeast of the Port Arthur field and consists of three intersecting segments, parts 4, 5, and 6, with a combined length of 15 mi (fig. 33). Total length of seismic lines from all sources is 31.67 mi. Magnetic tapes containing the raw (unprocessed) digital seismic data will be processed by GeoQuest International, Inc., of Houston, Texas. Processing work began in early January 1982. Preliminary results indicate that the quality of the seismic data is poor and that many of the original objectives of the seismic study may not be attainable.

TECHNICAL PROBLEMS ENCOUNTERED

A problem that is common for this type of project is the unavailability of certain data or well logs that are necessary or desirable for evaluating the prospect. The reasons for unavailability of data may be that the key measurements were not made or the data were destroyed, misplaced, or considered proprietary. Reliable porosity and permeability data are commonly lacking. Whole-core porosity and permeability data were not available for the Port Arthur field. In situ permeability could not be calculated because pressure buildup data were lacking. However, sidewall core porosity and permeability data were found for several zones of interest in the lower Hackberry sandstones. Sidewall core data are much better than no data at all but usually overestimate both porosity and permeability.

Only one sonic log and no density logs were available in the field. Normally several sonic and density logs are needed to develop acoustic impedance trends in the subsurface and to calibrate seismic response to lithology and fluid content by using synthetic seismograms and models.

Reservoir simulation computer programs for modeling the reservoir mechanics of a watered-out gas field were not readily available at the beginning of this project. The development of suitable programs has been slow and has caused delay in evaluating individual reservoirs in the Port Arthur field. We hope to model the "C" and "B-2" sandstones satisfactorily before this contract expires.

Initially, we were unable to convert wellhead shut-in pressure (WHSIP) to bottom-hole shut-in pressure (BHSIP) unless it was assumed that the only fluid in the wellbore was gas. This conversion technique has since been modified to include the presence of both liquid and gas in the borehole. We still have some problems in converting wellhead flowing pressure (WHFP) to bottom-hole flowing pressure (BHFP) with multiphase flow in a vertical pipe; however, this problem can be solved with additional work.

RESULTS AND CONCLUSIONS

It was shown in this report that the guidelines adopted for screening gas fields resulted in the selection of a viable test area (the Port Arthur field, Jefferson County, Texas). This field contains multiple watered-out gas reservoirs with excellent reservoir characteristics. Thick aquifers and potentially productive thin gas stringer sandstones are also present. All wells in the field have been plugged and abandoned by previous operators. Presumably the area can be leased for the drilling of a design well in which enhanced gas recovery methods can be used. Abundant shallow Miocene sands in the area are available for saltwater disposal. Possibly one of the plugged and abandoned wells could be worked over and used for saltwater disposal.

The "C" reservoir interval in the lower Hackberry (Frio) sandstones has received the most extensive evaluation and currently ranks first among potential candidates for enhanced gas recovery. Other reservoirs are potentially good producers but have not been evaluated in detail. Primary gas production from the "B-2" reservoir was large (13.343 Bscf), but the apparent high recovery efficiency (88.5 percent) reduces the amount of in-place gas remaining for secondary recovery. It is probable that production from the "C" sandstone would be commingled with production from the "B-2" sandstone and other sandstones after an extensive formation testing program in the new well has been completed.

In-place gas volume in the "C" reservoir was determined from well log analysis to be 1,789 acre-ft (77.929 x 10^6 ft^3), which translates into 26.24 Bscf in-place within the interconnected gas accumulation. Similar gas-volume values found for the "B-2" reservoir are 969 acre-ft (42.210×10^6 ft^3), which yields an estimated 15.07 Bscf in place. Apparent recovery efficiencies are 52.4 percent for the "C" reservoir and 88.5 percent for the "B-2" reservoir.

The gas-water contact (GWC) was determined from water-saturation (S_w) values computed by a well log analysis technique. The water saturation "cutoff" was assumed to be 65 percent, based on available relative permeability curves for Miocene sands at a depth of 11,100 ft. These curves show that the permeability to gas approaches zero when S_w approaches 60 to 65 percent. The apparent GWC for the "C" and "B-2" sandstones is -11,150 ft and -11, 080 ft, respectively.

Predicted gas recovery from the "C" reservoir by natural flow is 3.977 Bscf as the pressure declines from 6,500 to 4,018 psig. This recovered gas includes solution gas separated from water produced at the surface, free gas previously immobile and trapped in the water-invaded zone, and other mobile gas remaining in the watered-out gas reservoir. A break-even gas price of \$1.95/Mscf for an optimistic case and \$3.45/Mscf for a pessimistic case for a 15-percent rate of return is encouraging. An additional gas recovery of 7.690 Bscf is obtained by using artificial lift and drawing down the reservoir pressure from 4,018 to 1,700 psig. The above gas volume also includes minor contributions of solution gas from connate water and from water invading the gas sandstones. The total predicted gas recovery of 11.667 Bscf includes gas recovered by natural flow and by artificial lift from the "C" reservoir.

Evaluation of relative effectiveness of methodology employed in this project will be delayed until all studies are completed.

It is recommended that a design test well be drilled on a site about 200 ft southwest of well no. 14. The exact location may be determined by the location of good elevated roads and by the condition of the old surface site of well no. 14, which is located in a swampy area. Projected depths of the well are 11,650 ft to penetrate all of the lower Hackberry sandstones, 11,850 ft to penetrate the Nodosaria sandstone, and about 13,500 ft to penetrate the Vicksburg interval.

WORK REMAINING IN CURRENT CONTRACT

Reprocessing and interpretation of seismic lines in and near the Port Arthur field are currently in progress, and the results will be included in the final report. The original objectives of this work were to (1) correlate the top of the "C" sandstone to obtain a time structure map, (2) map the suspected submarine channels in the lower Hackberry sandstones if they can be identified, (3) identify faults, giving special attention to those that separate the Port Arthur field from the Port Acres field, and look for faults that may isolate the reservoir from sandstones downdip, (4) attempt to identify "fluid contacts," possibly in the "C" sandstone, assuming that the original gas-water contact has been preserved acoustically, and (5) apply special amplitude analysis on at least one line to help identify the extent of free gas in the "C" reservoir.

If all of the original objectives listed above are not attained because of poor quality of data, some additional work may be done to build a two-dimensional model of the Port Arthur reservoir along one seismic line to generate a synthetic section to (1) show to what extent the presence of dispersed free gas in the reservoir configuration of the Port Arthur field can be recognized in seismic sections, (2) attempt to identify the extent of the field by modeling the original fluid contact, and (3) show the variability of seismic imaging of this type of reservoir with changing seismic parameters such as bandwidth, signal-to-noise ratio, and possibly attenuation. This additional work should demonstrate the kind of seismic data quality that is needed to delineate reservoirs like those in the Port Arthur field.

In this report, well log analysis was shown to be an effective method for determining the original gas in place and for locating gas-water contacts in the "B-2" and "C" sandstones. Similar additional log analyses will be done for the "D," "E," "F," "G," and "H" sandstones.

Evaluation of methodology used in this project for locating and evaluating a prospective watered-out gas field that is suitable for application of enhanced gas recovery methods will be discussed in the final report.

Additional reservoir simulation work will be done to incorporate into the model the reservoir mechanics of gas lift and solution gas recovered by both natural flow and artificial lift. Curves for new gas and water production rates will be established, and an economic analysis will be made to take into account the new production rates as well as the additional operating costs incurred by using gas lift.

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Lombeida, Evans Jegbefume, Jackson Yoong, Wahiduzzaman Mirza, Yueming Chen, and Sam Cho were responsible for calculating numerous reservoir parameters.

Certain types of work required in support of this project were subcontracted from the Gas Research Institute and the Bureau of Economic Geology to J. R. Butler and Company, oil and gas consultants, Houston, Texas. Other Houston consulting firms (GeoQuest International, Inc., and Wattenbarger and Associates) were also available to the project through the subcontract agreement. The well log analytical work for the "B-2" and "C" sandstones, described in appendix C, was supervised by Brian E. Ausburn, J. R. Butler and Company. Reservoir simulation studies of the "C" sandstone, described in appendix E, were done by Robert A. Wattenbarger, Wattenbarger and Associates. Seismic data processing and analysis are being done by GeoQuest International, Inc.

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APPENDIX A

CLASS B FIELDS

EVALUATION SHEETS

CONTENTS

TABLES A-1 AND A-2

Table A-1. EVALUATION OF GAS FIELDS

DISPERSED GAS PROJECT

(Short form)

Field name: Port Acres, 57 Hackberry sands, Frio (10,350-10,600 ft)

Location: Jefferson County, Texas, 1S-48E, 1S-49E

Favorable Criteria:

1. Reservoir area: 5 mi^2, multiple Hackberry sands (Frio)
2. Essentially one producing sand; 30-120 ft thick
3. Porosity: 28-35%, Permeability: 5-1,000 md
4. Seismic lines penetrate field
5. 5 sonic logs in general area
6. Geological and engineering data have been published

Unfavorable Criteria:

1. Active wells in field: one in Hackberry @ 10,600 ft; two in Frio 5 sand
2. Possible sand/shale production problems
3. Limited seismic coverage
4. Abandonment pressure gradients average 0.25 psi/ft
5.
6.

Recommendation:

Favorable, because good sand, most wells P & A, good porosity and permeability (Rated: Class B)

Unfavorable, because low pressure gradients

Table A-2. EVALUATION OF GAS FIELDS

DISPERSED GAS PROJECT

(Short form)

Field name: Algoa, 49 (Frio 37 sd, 10,350-10,750 ft interval)

Location: Brazoria-Galveston Counties, Texas, 5S-39E

Favorable Criteria:

1. Fault block: 6.6 mi^2, anticlinal structure
2. Average equilibrium temperature: 227°F @ 10,400 ft
3. One thick sand (gas stringer + aquifer) 150-300 ft
4. Three gas wells in target zone P & A
5. Range of salinities: 62,000 - 150,000 ppm NaCl
6.

Unfavorable Criteria:

1. Core data unavailable; possible core data in files of Superior Oil for their #1 Evans unit
2. Reservoir area <5 mi^2
3. Five active wells in field (3 comp. 1978-1979)
4. 2 sonic logs, 1 density log in area
5. Abandonment pressure gradients: 0.3 to 0.4 psi/ft
6.

Recommendation:

Favorable, because good sand (Rated: Class B)

Unfavorable, because field is still active, might become viable prospect when active wells are abandoned.

APPENDIX B

CLASS C FIELDS

EVALUATION SHEETS

CONTENTS

Table B-1. EVALUATION OF GAS FIELDS

DISPERSED GAS PROJECT

(Short form)

Field name: Blessing (F-19 sand at 8,500 ft)

Location: Matagorda County, Texas, 10S-31E

Favorable Criteria:

1. Located in large fault block (35 mi^2) but producing area is small
2. Target sand 100 ft thick (35 ft gas sand, 65 ft aquifer)
3. No active wells in target sand
4. 8 wells P & A in target sandstone
5. Seismic lines through field
6. At least 4 sonic logs in immediate area

Unfavorable Criteria:

1. Oil production primarily from F-14 sand which is above the F-19 sand.
2. 8 active gas wells in field, shallower than target sand
3. Recent completions 1978, 1979
4. Average abandonment pressure gradient $\doteq$ 0.25 psi/ft
5. No core data for target sand
6. Target sand is shaly in much of area

Recommendation:

Favorable, because

Unfavorable, because active oil and gas production occurs near target sand. Sands are shaly (Rated: Class C).

Table B-2. EVALUATION OF GAS FIELDS

DISPERSED GAS PROJECT

(Short form)

Field name: Blue Lake, 45 (Frio 10,280 ft sand)

Location: Brazoria County, Texas, 7S-37E

Favorable Criteria:

1. Seven inactive wells (P & A)
2. Sand thickness = 30-70 ft with 10-30 ft of gas sand
3. Equilibrium temperature of reservoir is about 230°F
4.
5.
6.

Unfavorable Criteria:

1. Estimated reservoir size: <2 square miles
2. Only two sonic logs in area
3. There are two active wells which produce from intervals that bracket the target sand: one is in 8,900 ft sand, the other is in 10,500 ft sand
4. Average abandonment pressure gradient = 0.24 psi/ft
5. No core data available in target sand interval

Recommendation:

Favorable, because

Unfavorable, because area is small and sands are shaly (Rated: Class C).

Table B-3. EVALUATION OF GAS FIELDS

DISPERSED GAS PROJECT

(Short form)

Field name: Devillier, 75 (Vicksburg, 10,750-10,920 ft interval)

Location: Chambers County, Texas, 2S-44E, 2S-45E

Favorable Criteria:

1. Gas productive area: 4 to 5 square miles
2. Four wells P & A
3. Conv. core data (Gulf no. 1 Hankamer) avg. perm. >300 md, range 25-980 md, avg. porosity 29% in interval 10,850-10,875 ft. Avg. perm. = 200 md, avg. porosity = 26% from 10,876-10,888 ft.
4. Five sonic logs run in area; BHT >200°F.

Unfavorable Criteria:

1. Gas sand thickness: 10-30 ft
2. 3 active wells producing from Vicksburg
3. Thin aquifer sands, very shaly
4. Oil produced from reservoir
5.
6.

Recommendation:

Favorable, because

Unfavorable, because thin shaly aquifer sands not laterally extensive, considerable oil production from reservoir (Rated: Class C).

Table B-4. EVALUATION OF GAS FIELDS

DISPERSED GAS PROJECT

(Short form)

Field name: Harris, 47 (Wilcox, Luling and Massive sands in depth interval 7,600-8,600 ft

Location: Live Oak County, Texas, 14S-16E

Favorable Criteria:

1. Located in fault block, 25 mi^2 area
2. Structure--fault-bounded anticline with 200 ft closure
3. More than one sand
4.
5.
6.

Unfavorable Criteria:

1. At least 12 active wells (most in target sand zone)
2. Perforated intervals range from 2 to 30 ft
3. Recent completion - 1979
4. Core data not available
5. Only two sonic logs in area
6. Abandonment pressures average 0.3 psi/ft from 7,600-8,600 ft

Recommendation:

Favorable, because

Unfavorable, because field is still active (Rated: Class C).

Table B-5. EVALUATION OF GAS FIELDS

DISPERSED GAS PROJECT

(Short form)

Field name: Lake Creek, Wilcox 11,508-11,758 ft sand

Location: Montgomery County, Texas, 3N-36E, 2N-36E

Favorable Criteria:

1. Fault block size is 14.4 square miles
2. 6 inactive wells in target sand; all P & A
3. 75 ft gas cap associated with 150 ft aquifer (Delhi Taylor, #1 Sealy Smith
4. Permeability varies from 0 to 1,050 md and averages 234 md in interval from 11,537 to 11,564 ft in Prairie Prod. #1 Frost
5. Salinity averages 72,000 ppm NaCl in aquifers nearest target gas sands

Unfavorable Criteria:

1. 9 active wells producing from above and below target sand.
2.
3.
4.
5.

Recommendation:

vorable, because

Unfavorable, because field is too active (Rated: Class C). Reservoir might become viable prospect when production ceases.

Table B-6. EVALUATION OF GAS FIELDS

DISPERSED GAS PROJECT

(Short form)

Field name: NADA (67) & NADA, NE (62) Wilcox 9,700 ft sand

Location: Colorado County, Texas, 5S-29E-8/9

Favorable Criteria:

1. Reservoir size: ≥4.5 mi^2
2. Fault block, anticlinal structure
3. 9 inactive wells (P & A)
4. Sand thickness: 45-260 ft
5. Average salinity = 45,000 ppm NaCl
6.

Unfavorable Criteria:

1. Two active wells near top of anticline with last pressure gradient = 0.06-0.07 psi/ft
2. Average porosity = 15.2%, and permeability = 10.7 md, based on conv. core data from Shell Oil, no. 1 Engstrom.
3. Only two sonic logs (for Shell, no. 1 Engstrom and Chambers and Kenedy, #1 Dalco Oil Co.)
4. Abandonment pressure grad. ≥ 0.3 psi/ft

Recommendation:

Favorable, because

Unfavorable, because the target reservoir has low porosity and permeability, shaly sand, low pressure gradients, and active wells near top of structure (Rated: Class C).

Table B-7. EVALUATION OF GAS FIELDS

DISPERSED GAS PROJECT

(Short form)

Field name: Petronilla (8,000-8,100 ft sand interval)

Location: Nueces County, Texas, 19S-20E-3

Favorable Criteria:

1. Area of field is about 5 mi^2
2. There are 19 gas wells P & A
3. Five sonic logs, one density log
4. Average equilibrium temperature at 8,050 ft = 192°F
5. Average sand thickness in depth interval 8,000-8,100 ft = 90 ft
6.

Unfavorable Criteria:

1. 4 gas wells active from sands near target sand
2. 12 oil wells active from sand near target sand
3. No core data
4. Abandonment pressure gradients: 0.3 to 0.4 psi/ft
5.
6.

Recommendation:

Favorable, because

Unfavorable, because the field is very active (Rated: Class C).

Table B-8. EVALUATION OF GAS FIELDS

DISPERSED GAS PROJECT

(Short form)

Field name: Sarah White, 58 (Frio 9,200 ft sand)

Location: Galveston County, Texas, 6S-40E

Favorable Criteria:

1. Field is essentially abandoned with the exception of one well
2. Target sand is abandoned (originally contained gas, oil, and H_2O)
3. Target area >12 mi^2
4. Equilibrium temperature: 216°F

Unfavorable Criteria:

1. No core data available, but core taken in Tex East Trans. #1 Sadie Henck
2. Only one sonic log in fault block
3. Fault cuts target sand and reduces thickness from 80 to 30 ft
4. Area of aquifer is reduced by fault
5. Salinity: Indeterminate from SP log
6. Reservoir originally produced oil in western part of field and gas distillate from eastern part.
7. Pressure gradient in abandoned sand = 0.05-0.16 psi/ft

Recommendation:

Favorable, because

Unfavorable, because thin isolated gas sand, oil production, poor aquifer (Rated: Class C).

Table B-9. Gas fields rejected as non-prospective for dispersed gas test areas.

County	Field Name, Discovery Year	Area <5 mi^2	Active Field	<5 Watered-Out Gas Wells	Recent Gas Completions Since 1975
Aransas	[3]Nine Mile Pt., 65		x		
	Rattlesnake Pt., 68	x	x		
	Rockport W., 54				x
	Salt Lake, 48	x			
Bee	[2]Caesar S., 42		x		
	Holzmark S., 56		x		x
	Karon S., 49		x		x
	Mosca, 59			x	
	Norbee, 65		x		x
	Orangedale, 63		x		
	Ragsdale, 52		x		x
	[2]Tuleta N., 61	x			
	Tuleta W., 37		x		
Brazoria	[2]Angleton, 39		x		x
	Bailey's Prairie, 40				No Aquifer
	Bell Lake, 76		x	x	
	Bonney, 50	x			
	Bonney N., 54			x	
	Collins Lake, 49		x		x
	Drum Point, 53			x	
	Lake Alaska, 63			x	
	Manor Lake, 55		x		
	Oyster Creek, 75			x	
	Peach Point, 48			x	
	Rattlesnake Mound, 61		x		
	Rowan, 40				x
	Rowan N., 53	x			
Chambers	Anahuac E., 64			x	
	[1,3]Devillier, 75		x		x
	Fig Ridge N.W., 44	x			
	Fishers Reef, 40		x		
	Mayes S., 46		x		x
	Red Fish Reef, 46		x		
	Umbrella Point, 57		x		x
	Willow Slough N., 51	x	x		

[1]One or more wells in field were classified by Doherty (1981) as watered-out geopressured gas cap wells.
[2]One or more field wells reported by Doherty (1981) as having high water production rates but lacked shut-in pressure data.
[3]One or more wells classified by Doherty (1981) as bottom hole rejects (pressure gradient between 0.6 and 0.65 psi/ft).

Table B-9 continued

County	Field Name, Discovery Year	Area <5 mi^2	Active Field	<5 Watered-Out Gas Wells	Recent Gas Completions Since 1975
Colorado	Altair, 45		x		No Aquifer
	Buck Snag, 42		x		x
	Cecil Noble, 50		x		x
	[2]Chesterville, 43		x		x
	Columbus, 44		x		x
	Eagle Lake S., 69		x		x
	Frelsburg, 44				x
	Glasscock, 44		x		x
	Hamel, 45		x		x
	Lissie, 50		x		
	New Ulm, 45				x
	Orangehill, 42				x
	Ramsey, 43		x		x
	Rock Island, 45		x		
	[2]Sheridan, 40		x		
	Tait, 50			x	
De Witt	Anna Barre, 54				x
	Arneckeville, 51		x		x
	Arneckeville S., 53		x		x
	Helen Gohlke, 51		x		
	Hix Green, 65		x		x
	Jennie Bell, 52		x		x
	Nordheim, 42		x		
	Smith Creek, 61		x		
	Sucher, 78				x
	Thomaston, 40				x
	Tinsley, 64			x	
	[2]Yorktown, 54		x		x
Goliad	Cabeza Creek S., 44		x		x
	Dallas Husky E., 53		x		x
	Dial, 44		x		
	Karen Beauchamp, 57		x		x
	Marshall, 48			x	x
	[2]Soleberg, 62			x	x
Hardin	Hickory Creek, 69			x	
	Longs Station, 60			x	
Karnes	[2]Burnell, 44		x		

Table B-9 continued

County	Field Name, Discovery Year	Area <5 mi^2	Active Field	<5 Watered-Out Gas Wells	Recent Gas Completions Since 1975
Kleberg	Baffin Bay, 66	x		x	
	Bina, 76		x		
	Kings Inn, 77		x		x
	[2]Laguna Larga, 49		x		x
	May, 55		x		
	Yeary, 58		x		
Liberty	Blanding, 75		x		
	Hull, 18		x		
	McCoy, 46				No Aquifer
	Raywood, 53		x		
	Rich Ranch, 60			x	
Live Oak	[2]Braslau S., 58		x		
	Clayton, 44		x		x
	Dunn, 56	x		x	
	George West, 62		x		x
	Karon, 51		x		
	Katz-Slick, 59	x			x
	[2]Sierra Vista, 67	x			x
Matagorda	Bay City, 34		x		
	Duncan Slough, 60		x		
	El Maton, 59				No Aquifer
	Old Ocean, 34		x		
	Pheasant S., 61		x		
	Pheasant S.W., 59		x		
	Sugar Valley, 43		x		
	Sugar Valley N., 66		x		
	[3]Tidehaven, 46		x		
	Trull, 57		x		x
	Van Vleck N., 62			x	
	Wilson Creek, 52			x	
Montgomery	Conroe N., 53			x	
	Fostoria, 42		x		No Aquifer
	Grand Lake, 52			x	
Newton	Quicksand Creek, 59		x		x

Table B-9 continued

County	Field Name, Discovery Year	Area $<5\ mi^2$	Active Field	<5 Watered-Out Gas Wells	Recent Gas Completions Since 1975
Nueces	[2]Agua Dulce, 28		x		x
	Bobby Lynn King, 78		x		x
	Bohemian Colony, 64			x	
	Chapman Ranch, 37		x		x
	Corpus Channel, 53		x		
	Corpus Christi, 35		x		x
	[3]Encinal Channel, 65		x		x
	Flour Bluff S.S.E., 78		x		x
	Nor Am., 70			x	
	Ransom Island, 53			x	
	[3]Red Fish Bay, 50		x		x
	[3]Red Fish Bay N., 59		x		x
	Stedman Island, 51		x		
Refugio	Bayside, 57			x	
	Bonnie View, 76		x		x
	Roche N., 62		x		
	Rooke Ranch, 75		x		
	Woodsboro S., 75		x		x
San Jacinto	Cold Springs, 40		x		x
	Urbana, 59		x	x	x
San Patricio	Enos Cooper, 53		x		x
	Gregory E., 60			x	
	Mary Lou Patrick, 68			x	
	Patrick, 51			x	
Tyler	Hillister E., 48		x	x	x
	Hyatt S., 45			x	
Victoria	Mission Valley N., 51		x		x
	Mission Valley W., 49		x		x

Appendix C

Well Log Analysis of "B-2" and "C" Sandstones, Port Arthur Field, Jefferson County, Texas

Contents

Appendix C

Procedure

This study was confined to the "B-2" and "C" sandstones of the lower Hackberry sandstone units (10,500 to 11,200 ft). Seventeen IES logs, one sonic log, and limited core data were available. To estimate original gas-in-place for the selected sandstones, petrophysical parameters were established and approximate pay thicknesses were determined from resistivity values and assumed log parameters.

The pattern-recognition technique (Pickett, 1973) was used to establish a formation factor-porosity relationship on well no. 37 (Dual Induction-Sonic). No attempt was made to calculate porosity for every interval analyzed. Instead, porosity was derived directly from resistivity readings in nearby zones assumed to be wet. To use this approach, R_w was obtained from the salinity value and equilibrium formation temperature. Using resistivity ratios R_t/R_o (Ransom, 1974, and Lang, 1973), S_w was calculated for each separate interval.

Identification and Evaluation of the Sands

Based on structure maps, each sand was posted on the IES Log. Approximate bed boundaries were identified by searching the SP curve for deviations from the shale base line. Beds were selected for analysis which were at least 2 ft thick. True resistivity (R_t) was obtained by reciprocating conductivity instead of reading resistivity directly. Corrections were applied only for thin beds, whereas tight limy streaks were eliminated because of the uncertainties in porosity and logging parameters "a" and "m". No attempts were made to correct for invasion.

To determine water saturation, the conventional ratio (R_t/R_o) method was used. To identify original gas in place in the connected gas column, a 65-percent S_w cutoff was used as a guide line.

Since well elevations were not always available, all depths were reported by log depth. If there were no elevation values, subsea depth was assumed by subtracting 20 ft from log depth. This elevation uncertainty makes it difficult to determine a precise subsurface gas water contact (GWC).

Following the above rules, sand thickness and apparent GWC's were estimated and are shown in table C-1. Gas/water contacts for the "B-2" sandstone are not obvious. However, it is estimated that the lowest known gas occurs at 11,080 ft subsea (from well no. 31). The best estimate of GWC for the "C" sandstone is 11,150 ft subsea. It should be noted, however, that well no. 14 and well no. 34 had good resistivity development below -11,150 ft. These zones could be tight streaks, or there could be some geologic separation (fault/stratigraphic) from the main accumulation.

Log Parameters

(a) Matrix Interval Transit Time (Δtm)

Ninety-five sets of data (R_t vs. Δt) were extracted from well no. 37 and used to approximate matrix transit time for several thousand feet of water-bearing section (4,000 - 12,000 ft).

$$\text{Log } R_t = m \cdot \text{Log } \phi_s + \text{Log } A \qquad \text{(C-1)}$$

where

$$A = a \cdot R_w \cdot I \qquad \text{(C-2)}$$

$$\phi = \frac{\Delta t - \Delta tm}{\Delta tf - \Delta tm} \cdot \frac{1}{C_p} \qquad \text{(C-3)}$$

Sonic derived porosity (ϕs) was calculated in the conventional manner. Compaction factor C_p was approximated by the magnitude of Δtsh and was considered a function of depth as demonstrated by the following relationship:

$$C_p = 1.54 - (6 \times 10^{-5} \times \text{depth}) \qquad \text{if depth} < 9000 \text{ ft}$$

ie. $C_p = 1.36$ @ 3000 ft

$C_p = 1.00$ @ 9000 ft

and

$$C_p = 1.15 \qquad \text{if depth} > 9000 \text{ ft}$$

Using the above C_p value and assumed Δtf (189 μsec/ft.), a series of computer runs were made by varying Δtm from 40 to 60 μsec/ft.

To select the best fit line regression coefficient, R_c, was calculated (table C-2). The highest degree of correlation was found when Δtm = 53 μsec/ft. In this phase only the applicable Δtm value was determined without calculating cementation constant "m."

TABLE C-1

SANDSTONE THICKNESS

Well #	KB ft.	SS ID	Interval Log-Depth (ft)	Thickness (h) ft. Gross	Net	Gas	GWC Subsea (ft)	Remarks
1	20	B-2	11070 - 073	3	3	3		
		C	11144 - 230	86	69	16	11150	
5	20	B-2	11107 - 111	4	4	0		Needs geologic study
		C	11158 - 248	90	63	9	11153	
6	19	B-2	11058 - 061	3	3	0		
		C	11120 - 181	61	38	27	11150	Produced from C (.099Bscf)
11	20	B-2	11056 - 066	10	6	6		
		C	11130 - 187	57	42	22	11150	
12	20	B-2	None					
		C	11180 - 239	59	46	0		
14	20	B-2	11063 - 078	15	13	13		
		C	11117 - 180	63	38	26	11150	Produced from C (12.362Bscf)
23	20	B-2	11060 - 107	47	41	30	11070	
		C	11128 - 200	72	50	29	11150	Produced from C (1.291Bscf)
24	20	B-2	11074 - 087	13	5	5		
		C	11120 - 205	85	45	12	11149	
27	37	B-2	11160 - 180	20	10	0		
		C	None					
28	20	B-2	11130 - 142	12	10	0		
		C	11200 - 248	48	40	0		

Table C-1 (con'd)

Well #	KB ft.	SS ID	Interval Log-Depth (ft)	Thickness (h) ft. Gross	Net	Gas	GWC Subsea (ft)	Remarks
29	19	B-2	11072 - 095	23	13	3		
		C	11132 - 212	80	44	0		
30	26	B-2	11065 - 078	13	12	12		Needs geologic study
		C	11111 - 190	79	51	20	11149	
31	20	B-2	11077 - 100	23	19	19	11080	Produced from B-2 (13.343Bscf)
		C	11125 - 193	68	56	25	11150	
32	37	B-2	11060 - 093	33	17	5		
		C	11138 - 234	96	54	10	11162	
34	20	B-2	11208 - 211	3	3	0		Needs geologic study
		C	11272 - 350	78	50	0		
35	18	B-2	11130 - 187	57	52	0		
		C	11216 - 292	76	20	0		
37	26	B-2	11150	0	0	0		
		C	11288 - 354	66	45	0		

TABLE C-2

REGRESSION COEFFICIENTS

Δtm	Rc
41	.8516
43	.8521
45	.8526
47	.8530
49	.8534
51	.8536
53	.8538; Best Fit
55	.8537
57	.8534
59	.8525

(b) Formation Factor-Porosity Relation

The sonic log for well no. 37 was the only porosity log available in the field. The interval transit times and the correlative induction log resistivities provided a basis to estimate formation factor relationships. The results of the following analysis compare favorably with published data (table C-4).

Using a value of 53 μsec/ft for Δtm to compute porosity and 63 sets of data points below 11,000 ft (zones of interest in well no. 37), two regression analyses were made to determine "a" and "m" for the equation $F = a\phi^{-m}$. Figure C-1 shows a linear bivariate relationship between R_t and ϕ_s represented by two lines. These two lines are the result of the two regression analyses. One considers porosity as the independent variable. The other considers porosity as the dependent variable. The spread between the lines is a measure of random error and heterogeneity effects operating on each variable. The equations for the two lines are:

Run 1 (ϕ independent): $R_t = A \cdot \phi^m$

Run 2 (R_t independent): $\phi_s = A* \cdot R_t^{m*}$, or $R_t = A*^{-1/m} \cdot \phi^{1/m*}$

If $m = {}^1/m*$ and $A = A*^{(-m)}$,

then $R_t = A \cdot \phi^m$

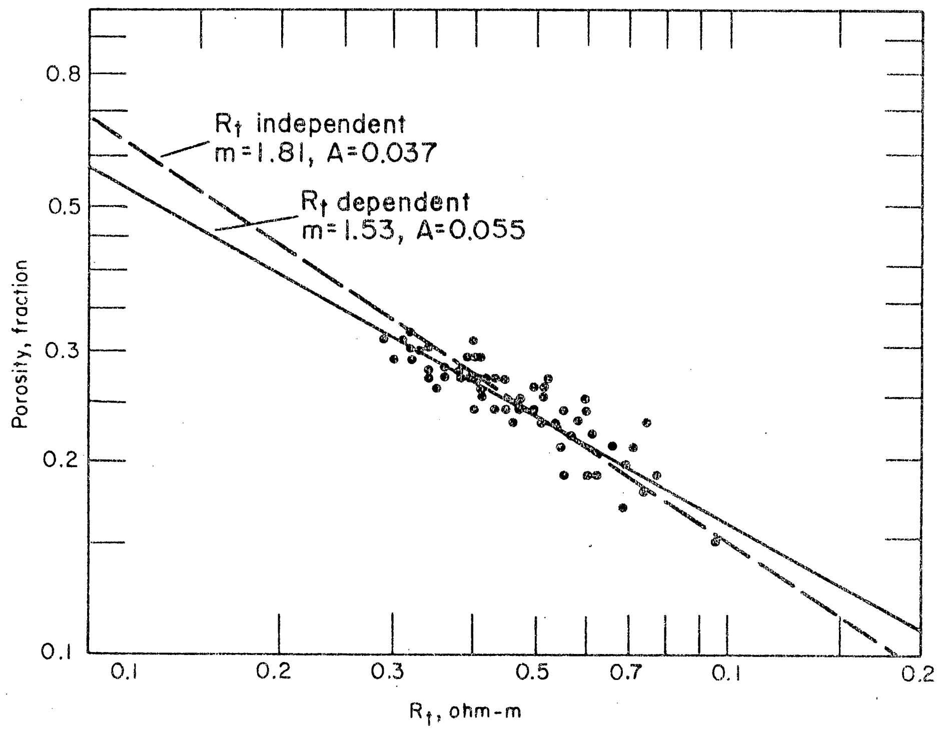

Figure C-1. Plot of R_t versus sonic porosity (well no. 37) $\Delta t_m = 53$ μ sec/ft and $\Delta t_f = 189$ μ sec/ft.

Assuming the saturation index I = 1 and $R_w = 0.0212$ (136,000 ppm @ 217°F) constant "a" was obtained by:

$$a = \frac{A}{R_w \cdot I} = \frac{A}{R_w}$$

It is recognized that a saturation index of 1.00 produces a value of "a" that may be too high. Therefore, instead of attempting a reduced regression (Collins and Piles, 1981), values obtained by regressing R_t as the independent variable were selected. Table C-3 shows "a" and "m" obtained by the pattern recognition technique.

TABLE C-3

COMPUTED "a" AND "m"

Run	m*	A*	m	A	a	
#1			-1.532	.0549	2.59	Ø independent
#2	-.5527	.1619	-1.809	.0371	1.75	R_t independent

Therefore, based on well no. 37, the apparent formation factor-porosity relationship is $F = 1.75 \cdot \phi^{-1.81}$.

Since the quality of porosity data in well no. 37 is unknown, determining the true functional relationship between Ø and R_t is difficult. However, by noting the intersection of the two lines in figure C-1, an approximation of average porosity and water-bearing formation resistivity can be made:

Porosity	=	0.243 fraction of bulk volume
R_o	=	0.479 ohm-meters.

These values may be used as a reference when there are insufficient data to determine specific values for an interval.

(c) Saturation Exponent

According to the previous study on well no. 1 (Ausburn, 1981) and a study of the Vicksburg Formation (Ritch and Kozik, 1971), the value of 1.8 for "n" was chosen.

At this point, working parameters for this area were fixed as follow:

Δtm	=	53	m	=	1.81
Δtf	=	189	n	=	1.8
a	=	1.75	C_p	=	1.1 - 1.2

Table C-4, which contains laboratory-measured values of "m" and "n," was reproduced from Coats and Dumanoir (1974) and Porter and Carothers (1970) is included for reference.

Resistivity Values

(a) Temperature

Instead of interpolating bottom-hole temperature (BHT), nearby equilibrium temperature was adopted as the formation temperature (T_f).

(b) Mud Resistivities

Mud and mud-filtrate resistivities were converted to formation temperature.

(c) Formation Water Resistivity

R_w was calculated from salinity data according to the conversion formula of Bateman and Konen (1977).

$$R_w \ @ \ 75^{o}F = 10^{(3.562 - .955 \ \text{Log (ppm)})} + .0123 \tag{C-4}$$

$$R_w \ @ \ T_f = R_w \ @ \ 75^{o}F \times \frac{82}{T_f + 7} \tag{C-5}$$

(d) R_o

R_o was assumed from conductivity of a nearby apparent wet zone. Their ranges were:

Item	Range	Average
R_w	.017 - .036	.025
R_o	.37 - .50	.44

Porosity

Instead of finding the porosity of each interval, one wet zone porosity ($\emptyset_w$) was used for each sand of a given well and is expressed as follows:

$$\phi_w = \left(\frac{a \cdot R_w}{R_o}\right)^{1/m} . \qquad \text{(C-6)}$$

As a guide in the calculation it was noted that 60 percent of the 42 sidewall samples from the "B-2" and "C" sandstones had porosities that ranged from 28 to 32 percent. The effect of clay content was ignored at this time since insufficient information was available to compute clay volume (V_{clay}) with any accuracy.

Water saturation

A simple resistivity ratio (R_t/R_o) was utilized in the Archie equation to compute S_w:

$$S_w = \left(\frac{R_t}{R_o}\right)^{-1/n} \qquad \text{(C-7)}$$

Gas saturation was obtained by $1-S_w$, considering S_o equal to zero.

Original gas in place ($\phi_w \cdot h_g \cdot S_g$)

To map the gas-filled pore volume (OGIP), table C-5 was constructed.

TABLE C-4

LABORATORY MEASURED "m" AND "n"

	Litho.	Average m	Average n	a
Wilcox, Gulf Coast	SS	1.9	1.8	
Government Wells, South Texas	SS	1.7	1.9	
Frio, South Texas	SS	1.8	1.8	
Miocene, South Texas	SS	1.95	2.1	
Rodessa, East Texas	LS	2.0	1.6	
Woodbine, East Texas	SS	2.0	2.5	
Ellenberger, West Texas	LS, DOL	2.0	3.8	
Ordovician, West Texas	SS	1.6	1.6	
Pennsylvanian, West Texas	LS	1.9	1.8	
Permian, West Texas	SS	1.8	1.9	
Frio, Agua Dulce, South Texas	SS	1.71	1.66	
Frio, Edinburg, South Texas	SS	1.82	1.5	
Frio, Hollow Tree, South Texas	SS	1.83	1.66	
Jackson, Cole, South Texas	SS	2.01	1.66	
Navarro, Olmos, South Texas	SS	1.89	1.49	
Viola, Bowie, North Texas	LS	1.77	1.15	
*Miocene, Gulf Coast	SS	1.35		1.8
*Miocene, Gulf Coast	SS	1.35		1.6
*Miocene, Gulf Coast	SS	1.3		2.0
*Miocene, Gulf Coast	SS	1.2		2.0
*Miocene, Gulf Coast	SS	1.29		1.97

*Data taken from Porter and Carothers (1970).

TABLE C-5

GAS SANDSTONE THICKNESS BY WELL

			Net Sandstone			Gas Sandstone		
Well	SS	Ø	h (ft)	S_w	Gas Tk.* (ft)	h_g(ft)	S_w	Gas Tk.* (ft)
1	B-2	.26	3	.41	0.46	3	.41	0.46
	C	.26	69	.74	4.70	16	.46	2.25
5	B-2	.30	4	.69	0.37	0		0
	C	.30	63	.88	2.31	9	.65	0.95
6	B-2	.30	3	.76	0.22	0		0
	C	.30	38	.51	5.54	27	.45	4.45
11	B-2	.26	6	.59	0.64	6	.59	0.64
	C	.26	42	.62	4.11	22	.43	3.25
12	B-2	None						
	C	.27	46	.85	1.73	0		0
14	B-2	.31	13	.55	1.81	13	.55	1.81
	C	.31	38	.49	6.05	26	.42	4.70
23	B-2	.29	41	.59	4.92	30	.56	3.82
	C	.28	50	.63	5.25	29	.56	3.60
24	B-2	.27	5	.50	0.68	5	.50	0.68
	C	.25	45	.82	1.99	12	.46	1.61
27	B-2	.24	10	.66	0.82	0		0
	C	None						
28	B-2	.25	10	.84	.40	0		0
	C	.25	40	.85	1.48	0		0
29	B-2	.32	13	.71	1.20	3	.66	0.33
	C	.28	44	.87	1.64	0		0
30	B-2	.26	12	.46	1.67	12	.46	1.67
	C	.25	51	.82	2.34	20	.53	2.34
31	B-2	.28	19	.50	2.68	19	.50	2.68
	C	.25	56	.65	4.87	25	.45	3.44

Table C-5 (cont'd)

Well	SS	Ø	Net Sandstone h (ft)	Net Sandstone S_w	Net Sandstone Gas Tk.* (ft)	Gas Sandstone h_g(ft)	Gas Sandstone S_w	Gas Sandstone Gas Tk.* (ft)
32	B-2	.31	17	.82	0.96	5	.61	0.61
	C	.27	54	.89	1.56	10	.65	0.94
34	B-2	.29	3	.86	0.12	0		0
	C	.25	50	.83	2.09	0		0
35	B-2	.31	52	.84	2.55	0		0
	C	.31	20	.77	1.42	0		0
37	B-2	None						
	C	.29	45	.82	2.30	0		0

*Equivalent thickness of sandstone containing 100 percent gas.

Appendix D

Methane Solubility Profiles for Wells in the Port Arthur Field

Contents

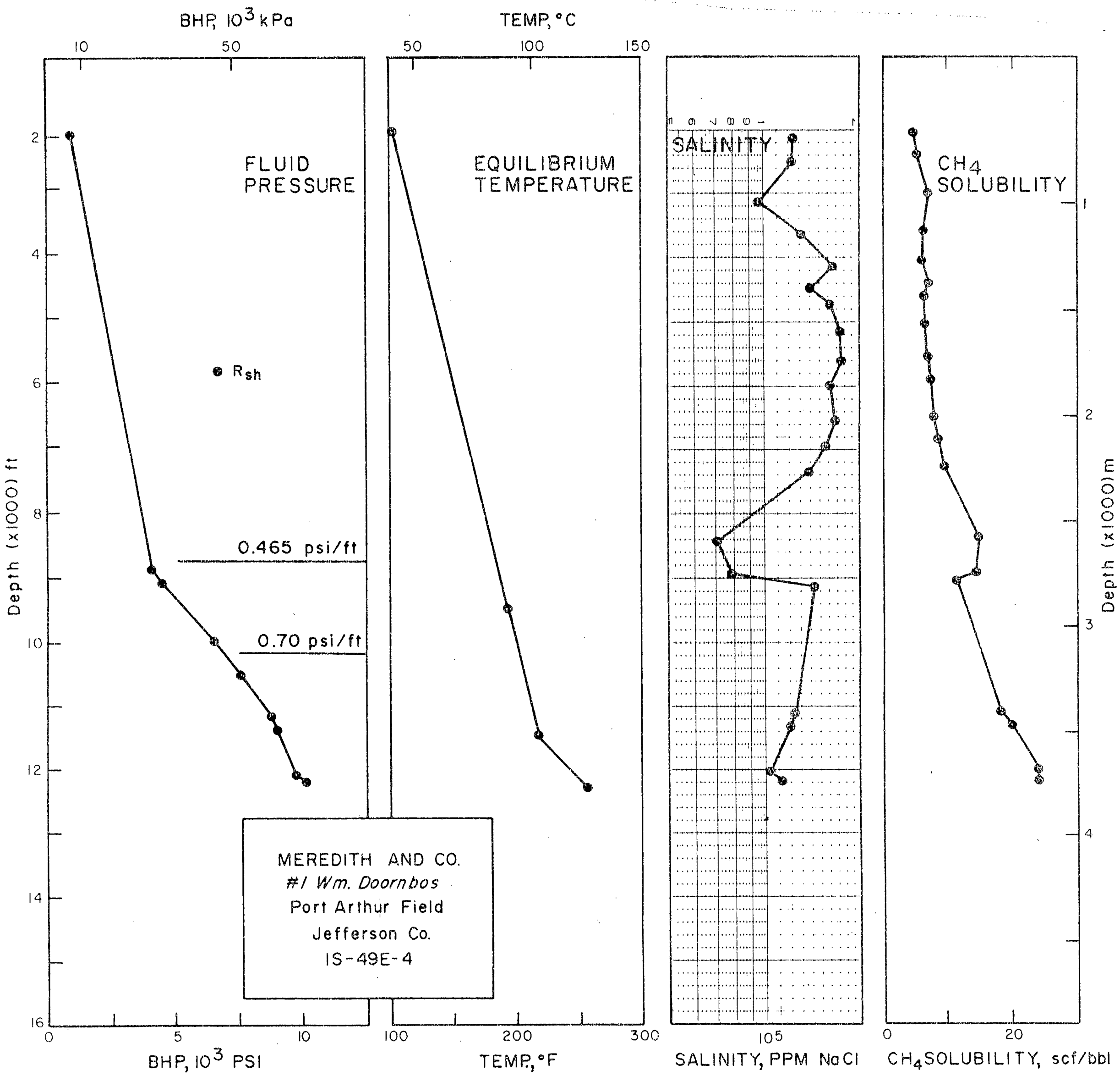

Figure D-1. Pressure, temperature, salinity, and methane solubility, well no. 1.

Table D-1, Well No. 1

Fluid pressure, equilibrium temperature, salinity, and methane solubility versus depth at original reservoir conditions, Meredith #1 Wm. Doornbos, Port Arthur field, Jefferson County, Texas.

Depth (ft)	Pressure (psi)	Pressure Gradient (psi/ft)	Salinity (ppm NaCl)	Temperature (°F)	CH_4 Solubility (scf/bbl)
2,100	977	0.465	126,000	100	4.4
2,500	1,163	0.465	124,000	105	5.0
3,140	1,460	0.465	97,200	113	6.5
3,660	1,702	0.465	132,000	120	6.1
4,150	1,930	0.465	167,000	127	5.6
4,500	2,093	0.465	141,000	132	6.7
4,750	2,209	0.465	164,000	135	6.2
5,150	2,395	0.465	174,000	141	6.2
5,650	2,627	0.465	176,000	147	6.6
6,000	2,790	0.465	163,000	154	7.4
6,550	3,046	0.465	168,000	159	7.6
6,950	3,232	0.465	159,000	164	8.3
7,350	3,418	0.465	141,000	170	9.5
8,410	3,911	0.465	70,800	183	14.7
8,890	4,134	0.465	79,700	188	14.7
9,110	4,555	0.500	145,000	191	11.5
11,150	8,363	0.750	126,000	215	18.5
11,340	9,072	0.800	121,000	217	19.9
12,050	9,761	0.810	107,000	243	24.2
12,150	10,085	0.830	113,000	247	24.2

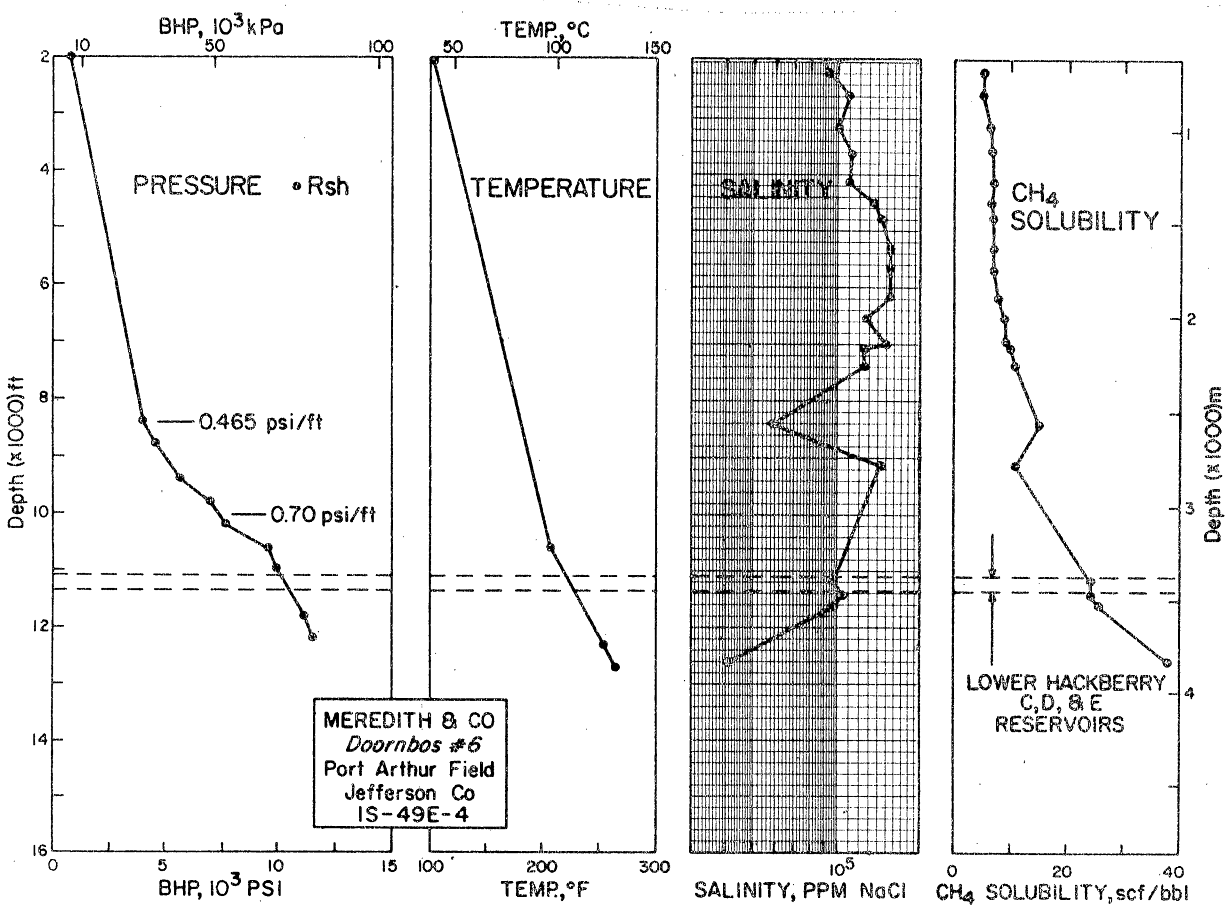

Figure D-2. Pressure, temperature, salinity, and methane solubility, well no. 5.

Table D-2, Well No. 5

Fluid pressure, equilibrium temperature, salinity, and methane solubility versus depth at original reservoir conditions. Meredith #6 Wm. Doornbos, Port Arthur field, Jefferson County, Texas.

Depth (ft)	Pressure (psi)	Pressure Gradient (psi/ft)	Salinity (ppm NaCl)	Temperature (°F)	CH_4 Solubility (scf/bbl)
2,200	1,023	0.465	92,800	100	5.25
2,600	1,209	0.465	111,000	106	5.41
3,130	1,455	0.465	102,000	113	6.24
3,650	1,697	0.465	113,000	120	6.46
4,150	1,930	0.465	111,000	127	7.05
4,500	2,092	0.465	135,000	132	6.74
4,850	2,255	0.465	146,000	137	6.79
5,300	2,464	0.465	156,000	143	7.02
5,750	2,674	0.465	155,000	149	7.45
6,200	2,883	0.465	153,000	155	7.78
6,550	3,046	0.465	128,000	159	9.21
6,950	3,231	0.465	150,000	164	8.67
7,080	3,292	0.465	126,000	167	9.98
7,350	3,417	0.465	125,000	169	10.40
8,430	3,920	0.465	59,100	183	15.24
9,100	4,231	0.465	143,000	191	11.54
11,200	10,000	0.890	97,500	226	24.05
11,400	10,300	0.900	105,000	231	23.99
11,580	10,600	0.920	99,600	236	25.41
12,650	11,800	0.930	41,600	262	38.31

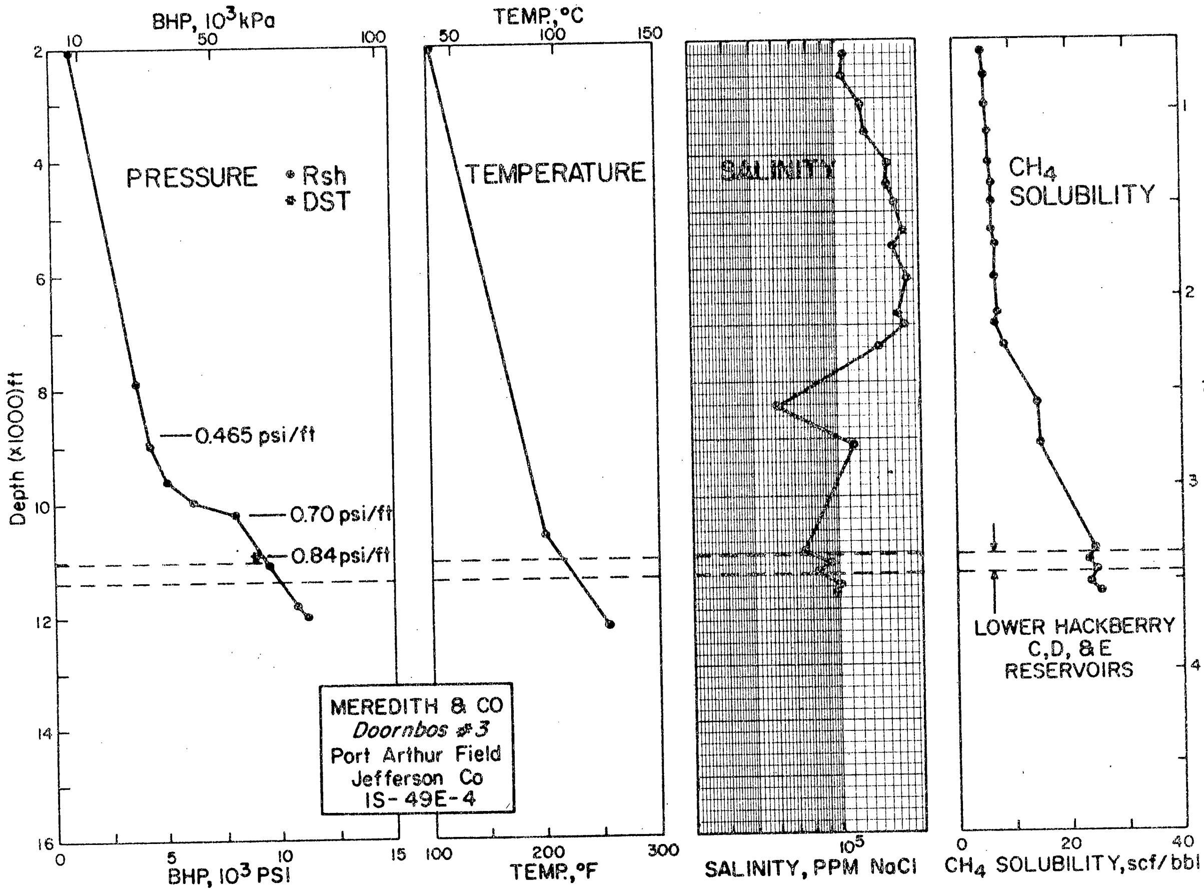

Figure D-3. Pressure, temperature, salinity, and methane solubility, well no. 6.

Table D-3, Well No. 6

Fluid pressure, equilibrium temperature, salinity, and methane solubility versus depth at original reservoir conditions, Meredith #3 Wm. Doornbos, Port Arthur field, Jefferson County, Texas.

Depth (ft)	Pressure (psi)	Pressure Gradient (psi/ft)	Salinity (ppm NaCl)	Temperature (°F)	CH_4 Solubility (scf/bbl)
2,200	1,023	0.465	108,000	98	4.89
2,600	1,209	0.465	107,000	104	5.64
3,100	1,441	0.465	124,000	109	5.82
3,650	1,697	0.465	129,000	118	6.18
4,150	1,920	0.465	153,000	124	6.08
4,500	2,092	0.465	152,000	129	6.50
4,850	2,255	0.465	163,000	134	6.36
5,350	2,487	0.465	173,000	139	6.39
5,600	2,604	0.465	160,000	143	7.32
6,200	2,883	0.465	181,000	150	6.93
6,750	3,138	0.465	168,000	157	7.90
7,000	3,255	0.465	178,000	161	7.72
7,350	3,417	0.465	143,000	164	9.41
8,450	3,929	0.465	63,300	177	15.14
9,100	4,231	0.465	115,000	184	12.96
10,950	9.300	0.850	75,800	212	24.43
11,180	9,700	0.870	94,300	220	23.56
11,330	9,800	0.860	85,800	225	25.04
11,550	10,200	0.880	102,000	233	24.38
11,740	10,500	0.890	98,700	239	25.68

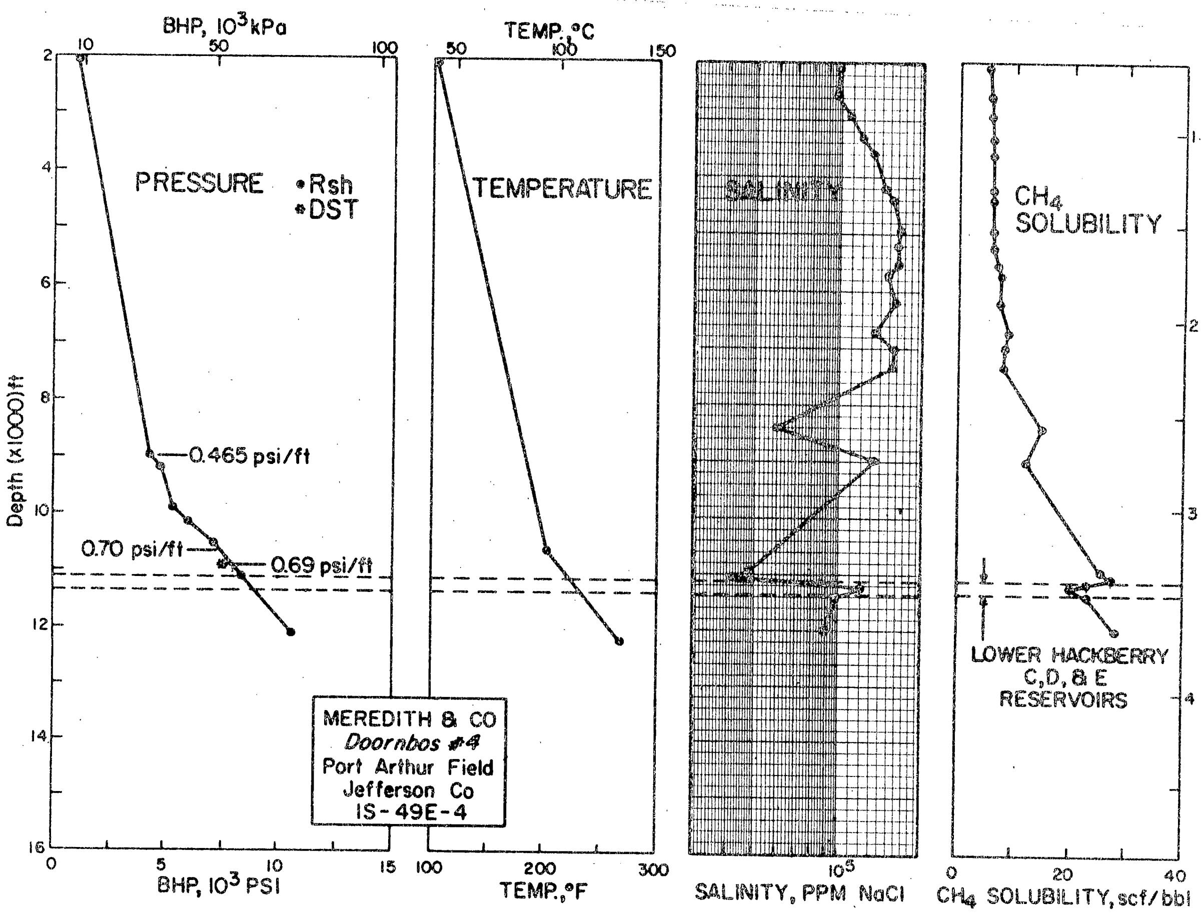

Figure D-4. Pressure, temperature, salinity, and methane solubility, well no. 11.

Table D-4, Well No. 11

Fluid pressure, equilibrium temperature, salinity, and methane solubility versus depth at original reservoir conditions. Meredith #4 Wm. Doornbos, Port Arthur field, Jefferson County, Texas.

Depth (ft)	Pressure (psi)	Pressure Gradient (psi/ft)	Salinity (ppm NaCl)	Temperature (°F)	CH_4 Solubility (scf/bbl)
2,100	976.5	0.465	97,600	98	5.07
2,600	1,209	0.465	96,100	105	5.80
2,940	1,367	0.465	107,000	109	5.93
3,300	1,534	0.465	119,000	114	6.00
3,650	1,697	0.465	130,000	118	6.15
4,150	1,930	0.465	141,000	125	6.09
4,400	2,046	0.465	152,000	129	6.16
4,850	2,255	0.465	162,000	135	6.33
5,200	2,418	0.465	161,000	139	6.64
5,470	2,543	0.465	160,000	143	6.92
5,750	2,674	0.465	147,000	146	7.70
6,200	2,883	0.465	157,000	151	7.56
6,700	3,115	0.465	131,000	158	9.22
6,950	3,231	0.465	154,000	161	8.58
7,320	3,403	0.465	153,000	165	8.10
8,430	3,920	0.465	61,300	179	14.94
9,080	4,222	0.465	130,000	186	11.73
10,950	7,800	0.710	49,000	217	25.62
11,070	8,250	0.740	41,700	222	27.65
11,170	8,500	0.760	87,300	226	23.25
11,240	8,600	0.770	120,000	229	20.30
11,380	8,800	0.770	98,800	235	23.17
12,010	10,250	0.850	90,300	261	28.69

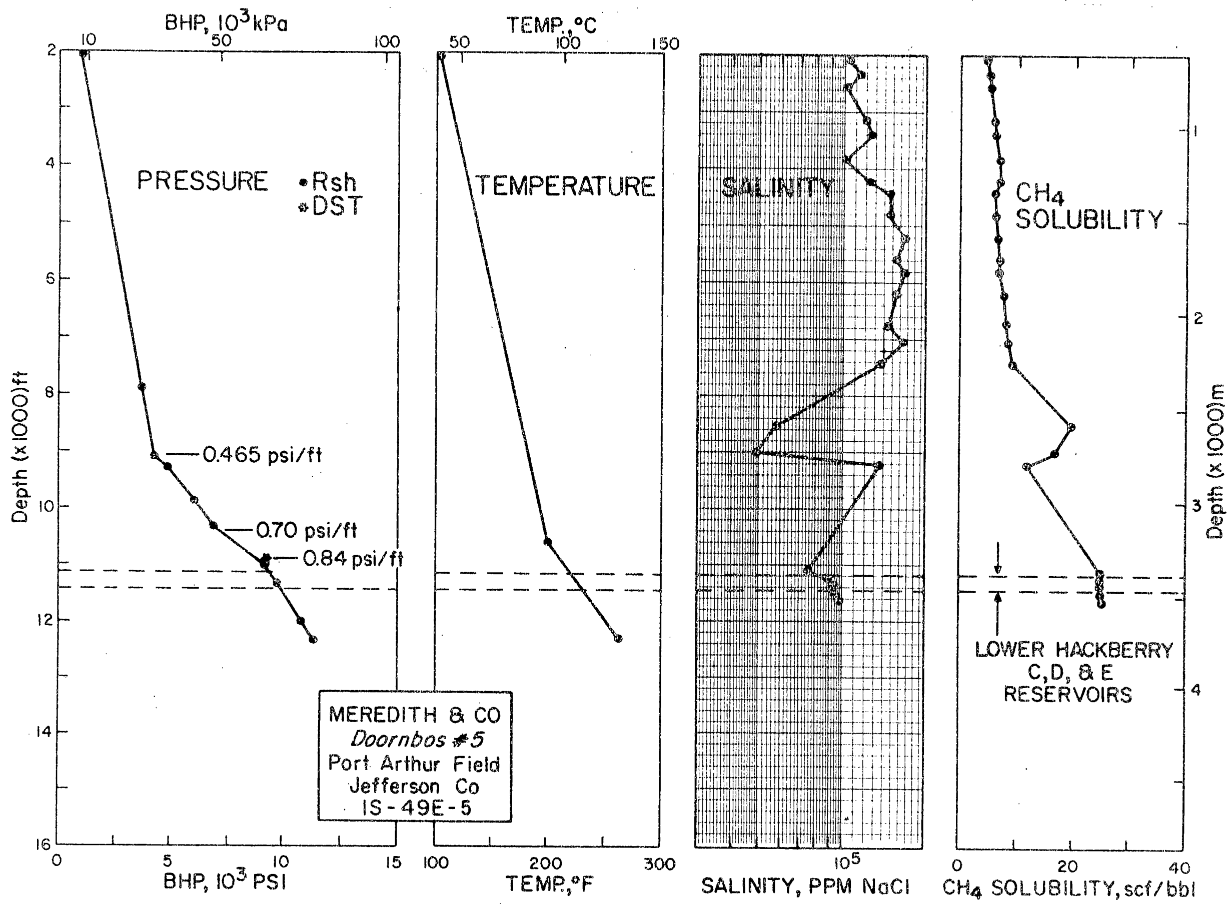

Figure D-5. Pressure, temperature, salinity, and methane solubility, well no. 12.

Table D-5, Well No. 12

Fluid pressure, equilibrium temperature, salinity, and methane solubility versus depth at original reservoir conditions, Meredith #5 Wm. Doornbos, Port Arthur field, Jefferson County, Texas.

Depth (ft)	Pressure (psi)	Pressure Gradient (psi/ft)	Salinity (ppm NaCl)	Temperature (°F)	CH_4 Solubility (scf/bbl)
2,000	930	0.465	105,000	97	4.74
2,350	1,093	0.465	116,000	101	5.13
2,550	1,186	0.465	103,000	104	5.61
3,080	1,432	0.465	119,000	111	5.97
3,450	1,604	0.465	126,000	115	6.03
3,800	1,767	0.465	100,000	120	7.34
4,170	1,939	0.465	124,000	125	7.01
4,350	2,023	0.465	148,000	128	6.36
4,800	2,232	0.465	148,000	134	6.41
5,200	2,418	0.465	169,000	139	6.38
5,530	2,571	0.465	151,000	143	7.10
5,800	2,697	0.465	167,000	146	6.97
6,250	2,906	0.465	154,000	151	7.96
6,700	3,116	0.465	148,000	158	8.48
7,050	3,278	0.465	163,000	162	8.15
7,400	3,441	0.465	138,000	166	9.54
8,480	3,943	0.465	59,800	178	19.83
8,990	4,180	0.465	50,000	184	16.74
9,170	4,500	0.490	133,000	186	11.95
11,090	9,400	0.850	76,300	219	25.09
11,230	9,500	0.850	88,400	224	24.29
11,330	9,750	0.860	92,600	227	24.39
11,470	9,900	0.860	95,300	232	24.70
11,600	10,200	0.880	98,400	237	26.16

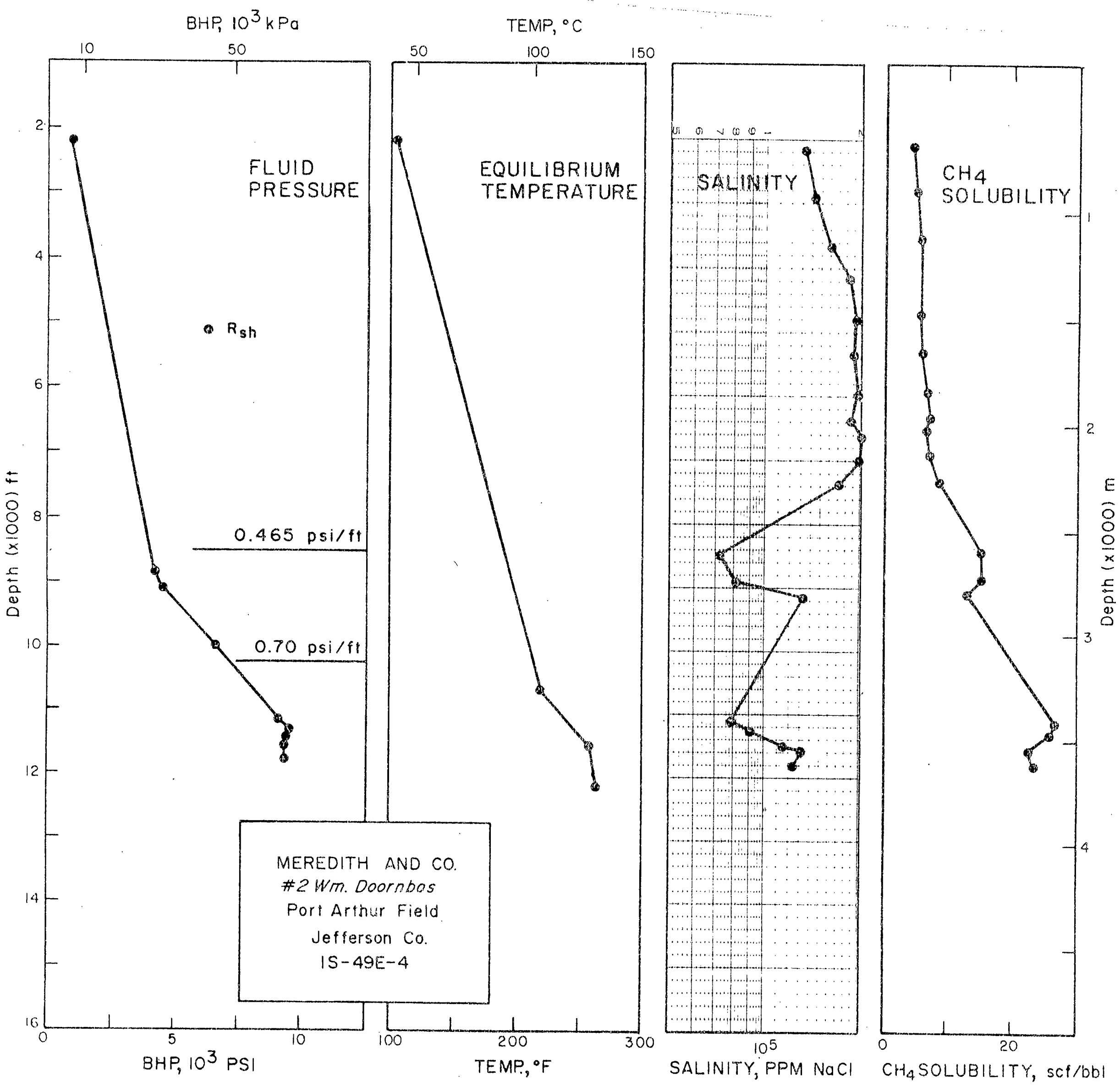

Figure D-6. Pressure, temperature, salinity, and methane solubility, well no. 14.

Table D-6, Well No. 14

Fluid pressure, equilibrium temperature, salinity, and methane solubility versus depth at original reservoir conditions, Meredith #2 Wm. Doornbos, Port Arthur field, Jefferson County, Texas.

Depth (ft)	Pressure (psi)	Pressure Gradient (psi/ft)	Salinity (ppm NaCl)	Temperature (°F)	CH_4 Solubility (scf/bbl)
2,200	1,023	0.465	134,000	104	4.4
2,920	1,358	0.465	144,000	113	5.0
3,650	1,697	0.465	162,000	125	5.3
4,160	1,934	0.465	187,000	135	5.1
4,800	2,232	0.465	195,000	142	5.4
5,350	2,488	0.465	193,000	150	5.9
6,000	2,790	0.465	196,000	161	6.3
6,400	2,976	0.465	189,000	166	6.9
6,600	3,069	0.465	204,000	169	6.5
7,000	3,255	0.465	200,000	175	6.9
7,350	3,418	0.465	174,000	179	8.2
8,480	3,943	0.465	72,300	195	15.2
9,120	4,560	0.500	135,000	203	12.5
11,150	9,255	0.830	80,000	244	26.8
11,250	9,338	0.830	90,100	247	26.0
11,360	9,656	0.850	91,900	252	26.7
11,470	9,520	0.830	116,000	256	24.0
11,550	9,471	0.820	130,000	259	22.7
11,800	9,440	0.800	124,000	261	23.5

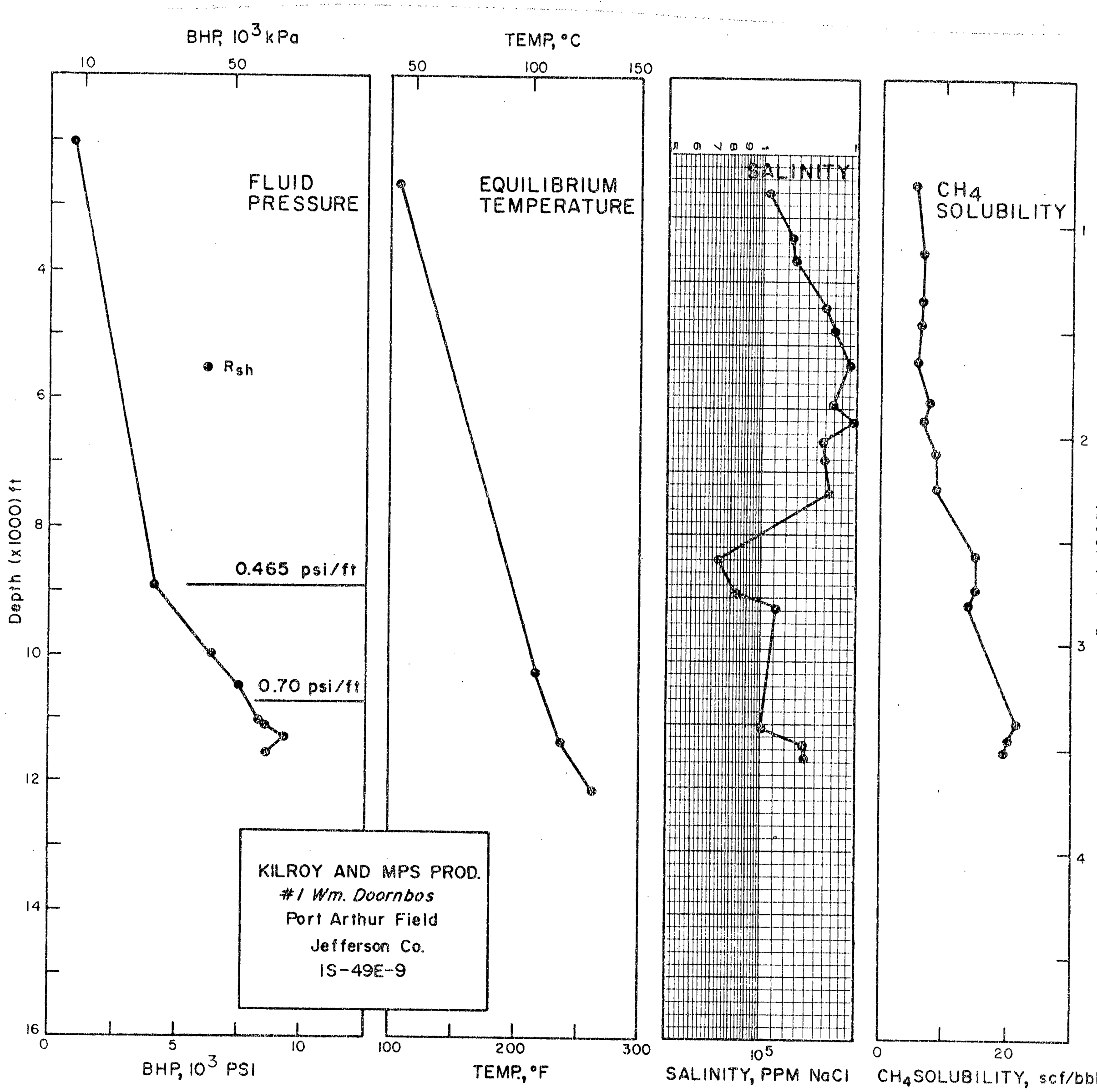

Figure D-7. Pressure, temperature, salinity, and methane solubility, well no. 23.

Table D-7, Well No. 23

Fluid pressure, equilibrium temperature, salinity, and methane solubility versus depth at original reservoir conditions, Kilroy and MPS Production #1 Wm. Doornbos, Port Arthur field, Jefferson County, Texas.

Depth (ft)	Pressure (psi)	Pressure Gradient (psi/ft)	Salinity (ppm NaCl)	Temperature (°F)	CH_4 Solubility (scf/bbl)
2,610	1,214	0.465	107,000	110	5.6
3,310	1,539	0.465	125,000	121	6.0
3,660	1,702	0.465	129,000	125	6.2
4,400	2,046	0.465	161,000	136	6.0
4,800	2,232	0.465	173,000	142	6.0
5,330	2,478	0.465	193,000	150	5.8
5,970	2,776	0.465	169,000	159	7.2
6,250	2,906	0.465	196,000	164	6.5
6,520	3,032	0.465	156,000	168	8.2
6,800	3,162	0.465	160,000	171	8.3
7,370	3,427	0.465	165,000	179	8.6
8,400	3,906	0.465	73,800	194	14.9
8,940	4,157	0.465	82,900	201	15.1
9,150	4,575	0.500	114,000	204	13.9
11,080	8,421	0.760	106,000	231	21.6
11,160	8,593	0.770	113,000	232	21.2
11,340	9,412	0.830	144,000	248	20.2
11,550	8,432	0.730	139,000	251	19.8

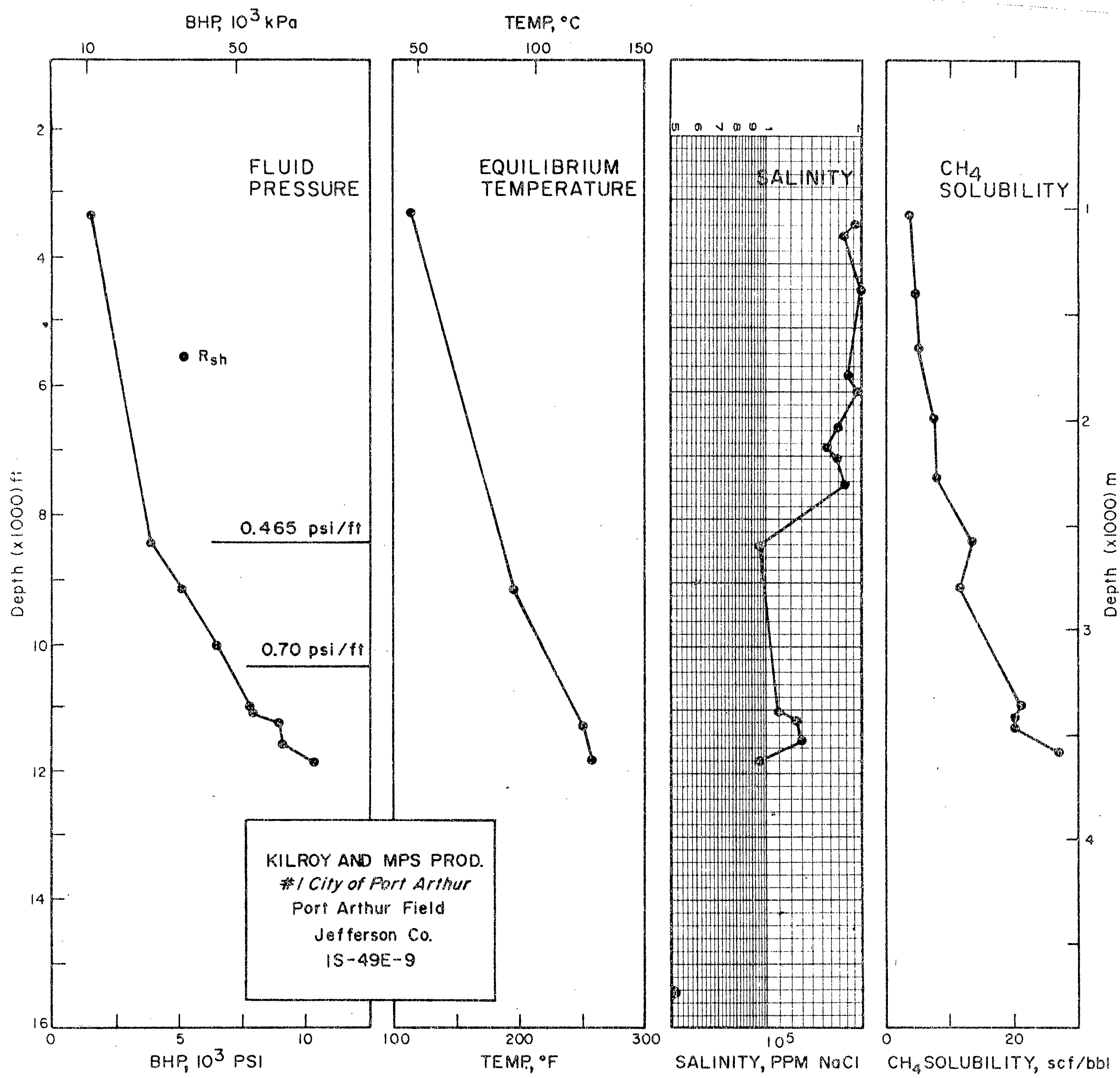

Figure D-8. Pressure, temperature, salinity, and methane solubility, well no. 24.

Table D-8, Well No. 24

Fluid pressure, equilibrium temperature, salinity, and methane solubility versus depth at original reservoir conditions, Kilroy and MPS Production #1 City of Port Arthur, Port Arthur field, Jefferson County, Texas.

Depth (ft)	Pressure (psi)	Pressure Gradient (psi/ft)	Salinity (ppm NaCl)	Temperature (°F)	CH_4 Solubility (scf/bbl)
3,330	1,548	0.465	193,000	116	4.2
3,510	1,632	0.465	181,000	119	4.6
4,360	2,027	0.465	200,000	131	4.9
5,400	2,511	0.465	189,000	146	5.5
5,700	2,651	0.465	184,000	150	6.4
6,000	2,790	0.465	194,000	156	6.3
6,530	3,306	0.465	170,000	161	7.6
6,850	3,185	0.465	158,000	165	8.3
7,030	3,269	0.465	169,000	168	8.0
7,410	3,446	0.465	178,000	173	8.0
8,425	3,918	0.465	95,800	186	13.2
9,100	5,100	0.560	105,000	196	12.7
11,055	7,849	0.710	110,000	240	21.1
11,175	8,158	0.730	125,000	246	20.5
11,250	9,000	0.800	134,000	249	20.8
11,400	7,980	0.700	129,000	250	20.2
11,485	9,188	0.800	129,000	251	21.8
11,800	10,266	0.870	95,500	253	27.2

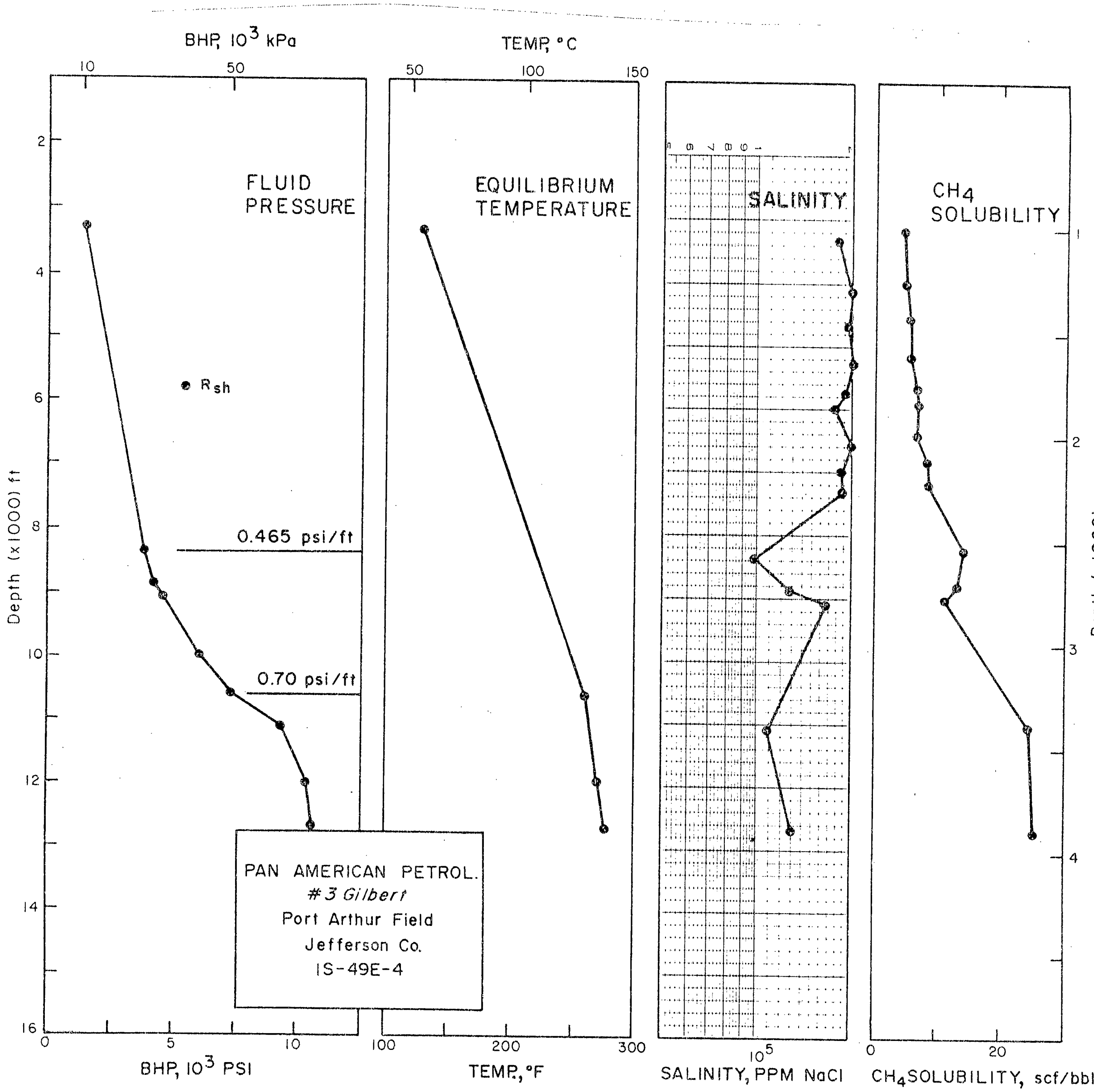

Figure D-9. Pressure, temperature, salinity, and methane solubility, well no. 27.

Table D-9, Well No. 27

Fluid pressure, equilibrium temperature, salinity, and methane solubility versus depth at original reservoir conditions, Pan American Petroleum #3 Gilbert, Port Arthur field, Jefferson County, Texas.

Depth (ft)	Pressure (psi)	Pressure Gradient (psi/ft)	Salinity (ppm NaCl)	Temperature (°F)	CH_4 Solubility (scf/bbl)
3,300	1,535	0.465	183,000	129	4.5
4,130	1,920	0.465	200,000	145	4.8
4,700	2,186	0.465	198,000	155	5.4
5,300	2,465	0.465	205,000	166	5.7
5,750	2,674	0.465	194,000	172	6.4
6,000	2,790	0.465	183,000	177	7.0
6,550	3,046	0.465	200,000	188	6.9
6,950	3,232	0.465	179,000	195	8.1
7,320	3,404	0.465	178,000	201	8.6
8,360	3,887	0.465	99,100	219	14.3
8,890	4,267	0.480	130,000	227	13.3
9,060	4,530	0.500	171,000	230	11.3
11,110	9,221	0.830	109,000	259	24.7
12,680	10,400	0.820	128,000	272	25.3

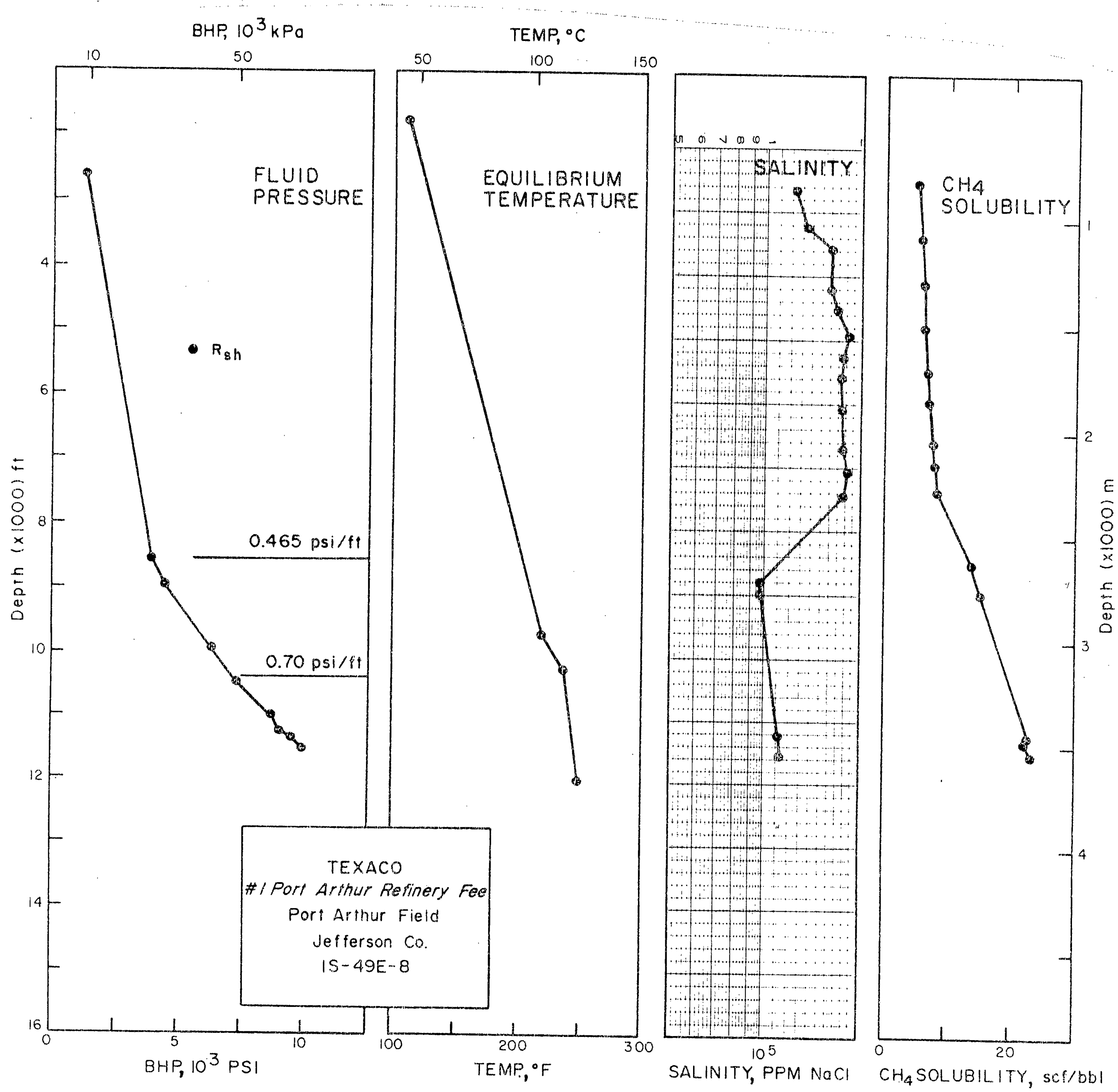

Figure D-10. Pressure, temperature, salinity, and methane solubility, well no. 28.

Table D-10, Well No. 28

Fluid pressure, equilibrium temperature, salinity, and methane solubility versus depth at original reservoir conditions, Texaco #1 Port Arthur Refinery Fee, Port Arthur field, Jefferson County, Texas.

Depth (ft)	Pressure (psi)	Pressure Gradient (psi/ft)	Salinity (ppm NaCl)	Temperature (°F)	CH_4 Solubility (scf/bbl)
2,710	1,260	0.465	125,000	109	5.2
3,250	1,511	0.465	136,000	117	5.6
3,570	1,660	0.465	159,000	124	5.3
4,200	1,953	0.465	157,000	132	6.0
4,500	2,093	0.465	168,000	136	5.9
4,900	2,279	0.465	182,000	142	5.8
5,550	2,581	0.465	175,000	151	6.6
6,050	2,813	0.465	177,000	160	7.0
6,700	3,116	0.465	175,000	168	7.6
7,050	3,278	0.465	180,000	173	7.9
7,450	3,464	0.465	175,000	178	8.2
8,600	4,000	0.465	97,000	193	13.6
9,010	4,505	0.500	95,900	198	14.7
11,270	9,096	0.810	112,000	235	22.1
11,360	9,429	0.830	118,000	236	22.0
11,550	9,818	0.850	113,000	239	23.2

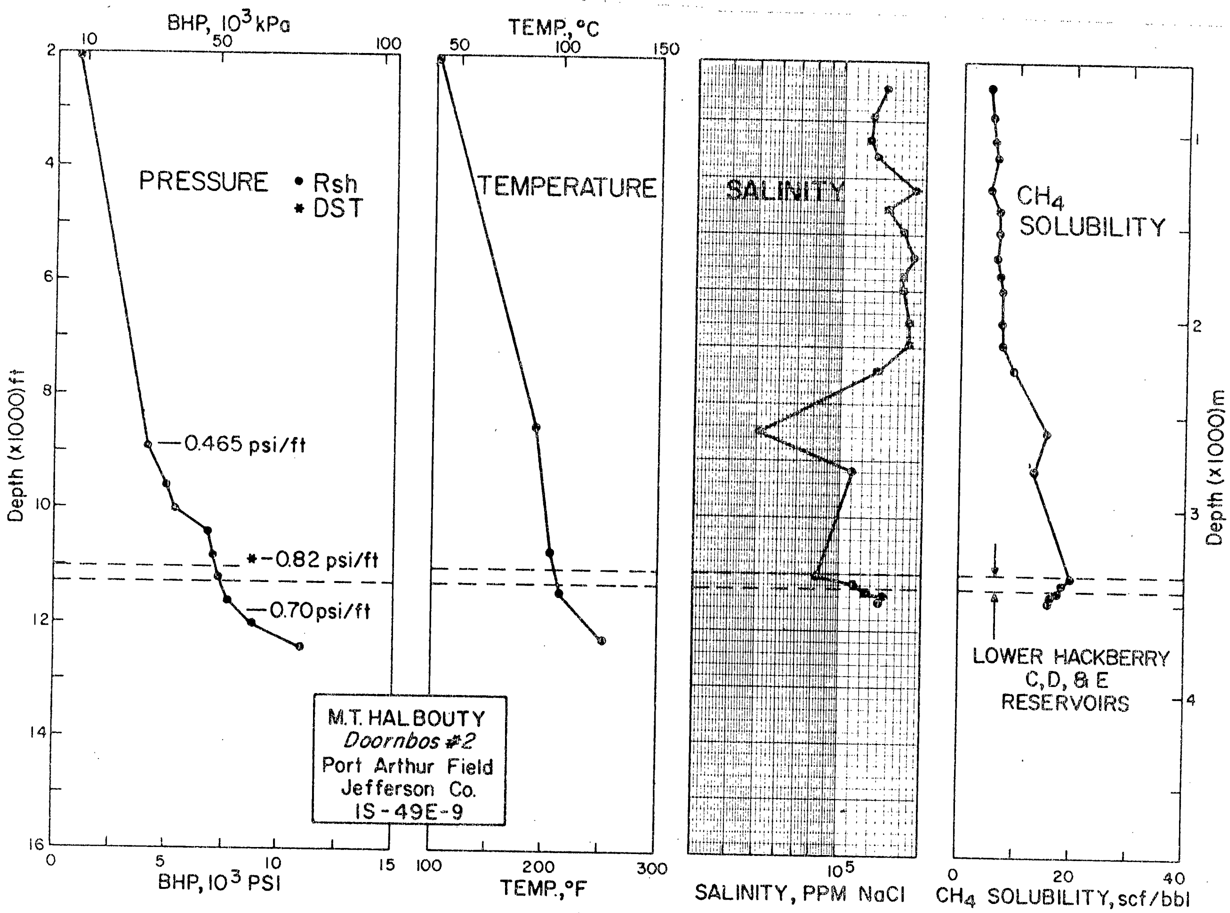

Figure D-11. Pressure, temperature, salinity, and methane solubility, well no. 29.

Table D-11, Well No. 29

Fluid pressure, equilibrium temperature, salinity, and methane solubility versus depth at original reservoir conditions, M. T. Halbouty #2 Wm. Doornbos, Port Arthur field, Jefferson County, Texas.

Depth (ft)	Pressure (psi)	Pressure Gradient (psi/ft)	Salinity (ppm NaCl)	Temperature (°F)	CH_4 Solubility (scf/bbl)
2,450	1,139	0.465	142,000	102	4.64
2,900	1,348	0.465	128,000	108	5.25
3,270	1,520	0.465	127,000	114	5.77
3,600	1,674	0.465	131,000	118	6.12
4,180	1,943	0.465	184,000	126	4.91
4,550	2,115	0.465	147,000	131	6.34
4,900	2,278	0.465	163,000	136	6.31
5,350	2,488	0.465	180,000	141	6.05
5,690	2,646	0.465	167,000	146	6.68
6,030	2,803	0.465	166,000	150	7.07
6,530	3,036	0.465	176,000	156	7.21
6,850	3,185	0.465	175,000	160	7.37
7,400	3,441	0.465	138,000	167	9.72
8,500	3,952	0.465	51,100	180	15.44
9,160	4,375	0.480	110,000	187	13.18
11,050	7,200	0.650	84,100	210	20.58
11,200	7,250	0.650	112,000	211	18.21
11,330	7,375	0.650	126,000	213	17.30
11,400	7,500	0.660	143,000	216	16.22
11,450	7,500	0.660	139,000	218	16.65

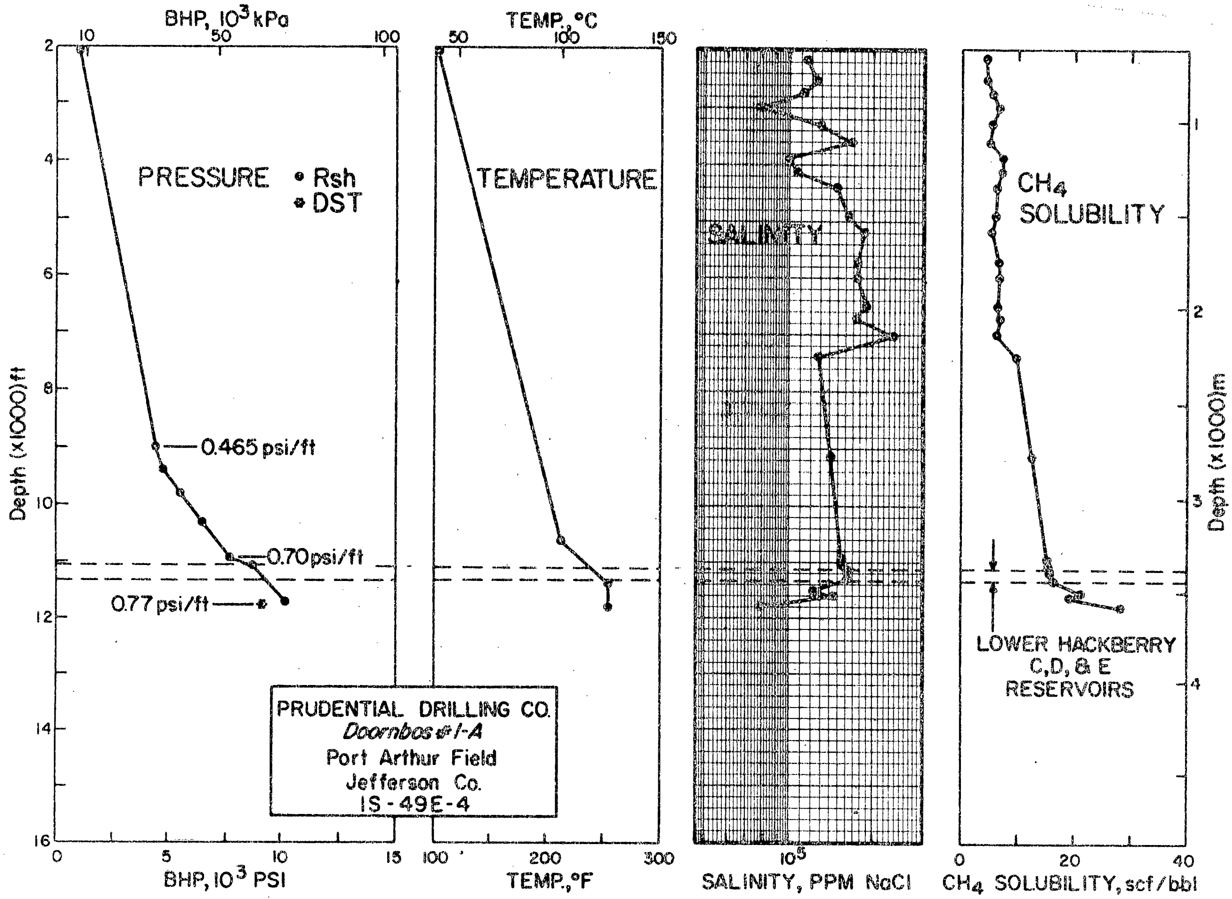

Figure D-12. Pressure, temperature, salinity, and methane solubility, well no. 30.

Table D-12, Well No. 30

Fluid pressure, equilibrium temperature, salinity, and methane solubility versus depth at original reservoir conditions, Prudential Drilling Co. #1-A Doornbos, Port Arthur field, Jefferson County, Texas.

Depth (ft)	Pressure (psi)	Pressure Gradient (psi/ft)	Salinity (ppm NaCl)	Temperature (°F)	CH_4 Solubility (scf/bbl)
2,200	1,023	0.465	125,000	101	4.79
2,550	1,185	0.465	135,000	106	4.83
2,750	1,279	0.465	120,000	110	5.47
3,000	1,395	0.465	85,000	113	6.74
3,300	1,535	0.465	140,000	117	5.65
3,650	1,697	0.465	178,000	122	4.87
3,900	1,814	0.465	110,000	125	7.08
4,150	1,930	0.465	115,000	129	7.37
4,400	2,046	0.465	160,000	133	6.05
4,900	2,279	0.465	175,000	140	6.05
5,200	2,418	0.465	195,000	144	5.63
5,700	2,650	0.465	185,000	151	6.42
6,000	2,790	0.465	185,000	155	6.61
6,500	3,022	0.465	200,000	161	6.43
6,700	3,115	0.465	185,000	164	7.13
7,000	3,255	0.465	225,000	169	5.93
7,350	3,417	0.465	135,000	172	9.98
9,100	4,500	0.490	150,000	194	11.25
10,970	7,700	0.700	165,000	225	15.18
11,040	8,000	0.720	165,000	227	15.59
11,150	9,000	0.810	175,000	230	15.88
11,330	9,250	0.820	175,000	236	16.45
11,470	9,800	0.850	130,000	241	21.56
11,600	10,000	0.860	155,000	245	19.55
11,770	10,200	0.870	85,000	251	28.20

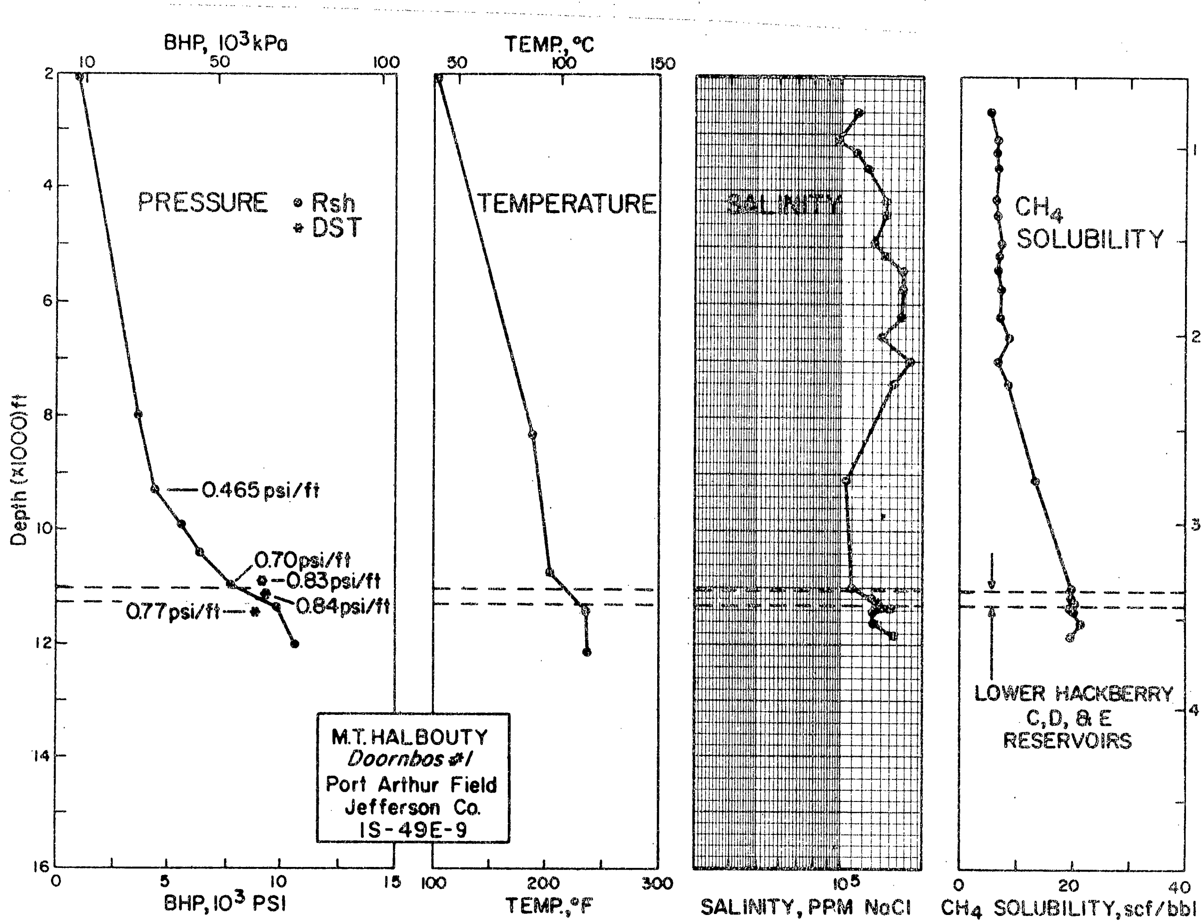

Figure D-13. Pressure, temperature, salinity, and methane solubility, well no. 31.

Table D-13, Well No. 31

Fluid pressure, equilibrium temperature, salinity, and methane solubility versus depth at original reservoir conditions, M. T. Halbouty #1 Wm. Doornbos, Port Arthur field, Jefferson County, Texas.

Depth (ft)	Pressure (psi)	Pressure Gradient (psi/ft)	Salinity (ppm NaCl)	Temperature (°F)	CH_4 Solubility (scf/bbl)
2,600	1,209	0.465	115,000	104	5.43
3,090	1,437	0.465	98,700	111	6.57
3,300	1,535	0.465	113,000	114	6.29
3,670	1,707	0.465	125,000	118	6.30
4,160	1,934	0.465	148,000	125	6.24
4,430	2,060	0.465	147,000	128	6.39
4,900	2,279	0.465	133,000	134	7.38
5,100	2,372	0.465	145,000	137	7.08
5,430	2,525	0.465	168,000	141	6.58
5,770	2,683	0.465	167,000	146	6.83
6,220	2,892	0.465	165,000	151	7.26
6,580	3,060	0.465	140,000	155	8.76
7,000	3,255	0.465	174,000	161	7.63
7,360	3,422	0.465	154,000	165	8.59
9,130	4,245	0.460	106,000	185	13.23
11,040	8,000	0.720	110,000	221	19.97
11,180	9,000	0.810	128,000	228	19.91
11,270	9,500	0.840	134,000	232	20.15
11,350	9,800	0.860	150,000	236	19.20
11,400	9,850	0.860	128,000	237	20.10
11,600	10,000	0.860	130,000	237	21.46
11,800	10,300	0.870	151,000	238	19.72

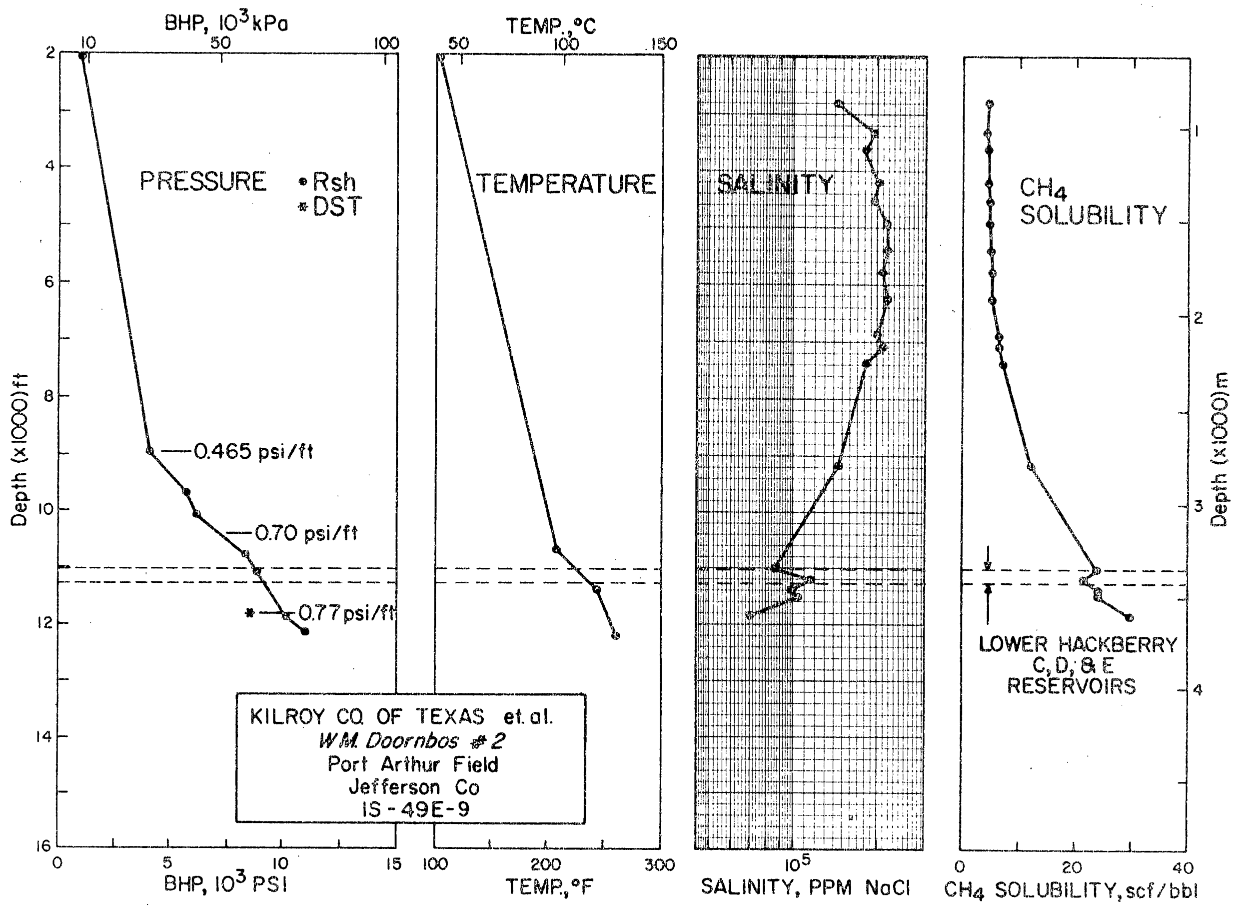

Figure D-14. Pressure, temperature, salinity, and methane solubility, well no. 32.

Table D-14, Well No. 32

Fluid pressure, equilibrium temperature, salinity, and methane solubility versus depth at original reservoir conditions, Kilroy Company of Texas #2 Wm. Doornbos, Port Arthur field, Jefferson County, Texas.

Depth (ft)	Pressure (psi)	Pressure Gradient (psi/ft)	Salinity (ppm NaCl)	Temperature (°F)	CH_4 Solubility (scf/bbl)
2,770	1,288	0.465	142,000	108	5.12
3,330	1,548	0.465	191,000	106	4.22
3,660	1,702	0.465	180,000	120	4.64
4,200	1,953	0.465	202,000	127	4.61
4,500	2,092	0.465	195,000	131	5.03
4,900	2,279	0.465	213,000	137	4.87
5,400	2,511	0.465	217,000	144	5.01
5,800	2,697	0.465	210,000	149	5.49
6,300	2,929	0.465	218,000	155	5.55
6,850	3,185	0.465	198,000	162	6.75
7,100	3,301	0.465	206,000	166	6.64
7,430	3,455	0.465	179,000	170	7.78
9,200	4,500	0.490	147,000	191	11.32
11,070	8,700	0.790	84,900	227	23.87
11,200	9,000	0.800	115,000	233	21.57
11,350	9,250	0.810	98,200	241	24.35
11,450	9,300	0.810	103,000	246	24.26
11,860	9,800	0.830	71,500	256	29.94

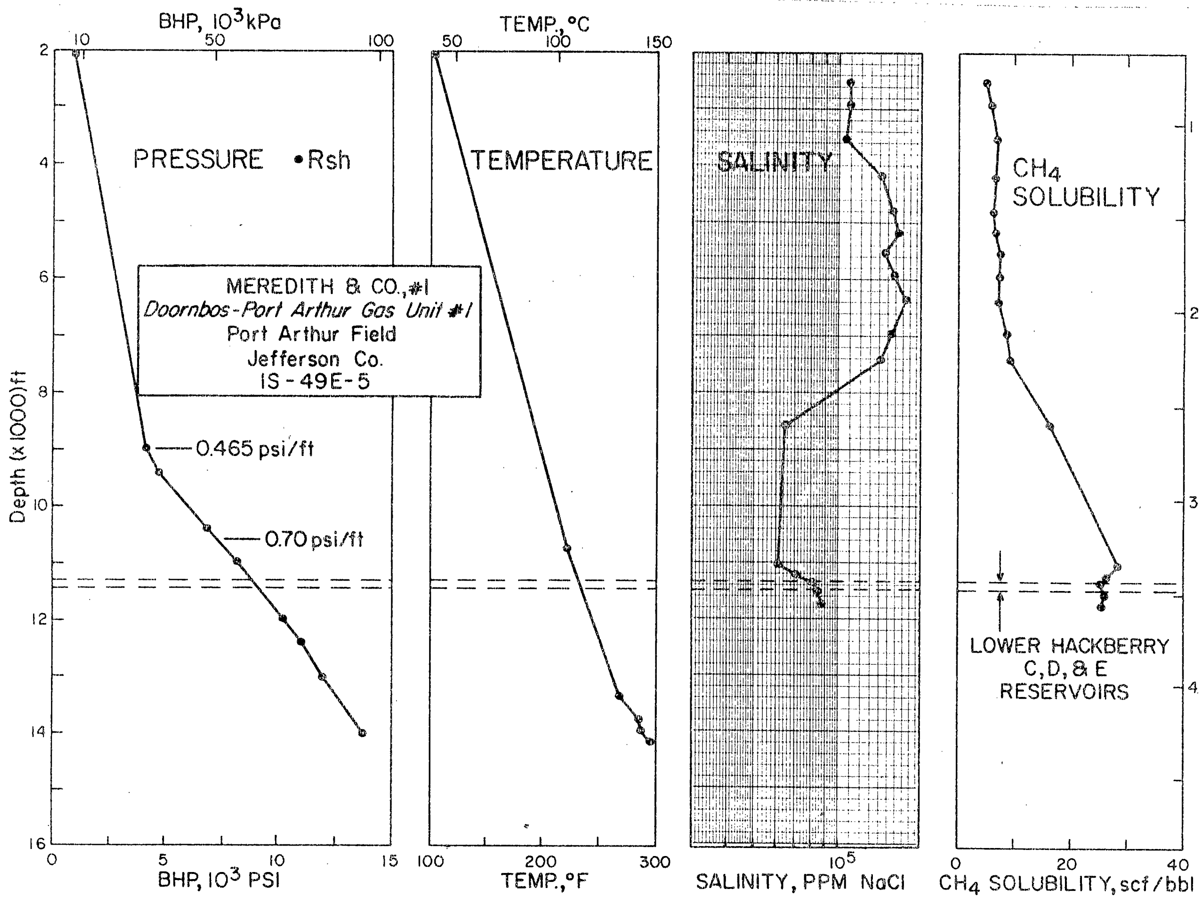

Figure D-15. Pressure, temperature, salinity, and methane solubility, well no. 34.

Table D-15, Well No. 34

Fluid pressure, equilibrium temperature, salinity, and methane solubility versus depth at original reservoir conditions, Meredith #1 Wm. Doornbos, Port Arthur Gas Unit #1, Port Arthur field, Jefferson County, Texas.

Depth (ft)	Pressure (psi)	Pressure Gradient (psi/ft)	Salinity (ppm NaCl)	Temperature (°F)	CH_4 Solubility (scf/bbl)
2,550	1,186	0.465	110,000	108	5.42
2,930	1,362	0.465	109,000	114	5.95
3,520	1,637	0.465	107,000	123	6.77
4,200	1,953	0.465	141,000	133	6.46
4,830	2,246	0.465	156,000	143	6.61
5,200	2,418	0.465	161,000	148	6.79
5,550	2,580	0.465	148,000	153	7.59
5,850	2,720	0.465	159,000	157	7.46
6,400	2,976	0.465	172,000	165	7.47
6,870	3,195	0.465	155,000	171	8.59
7,440	3,460	0.465	141,000	180	9.83
8,540	3,971	0.465	54,400	194	16.42
11,060	9,000	0.810	50,900	226	28.14
11,170	9,250	0.830	61,100	230	27.66
11,310	9,400	0.830	81,700	233	25.71
11,500	9,600	0.830	84,400	236	25.94
11,670	9,750	0.840	86,200	239	26.22

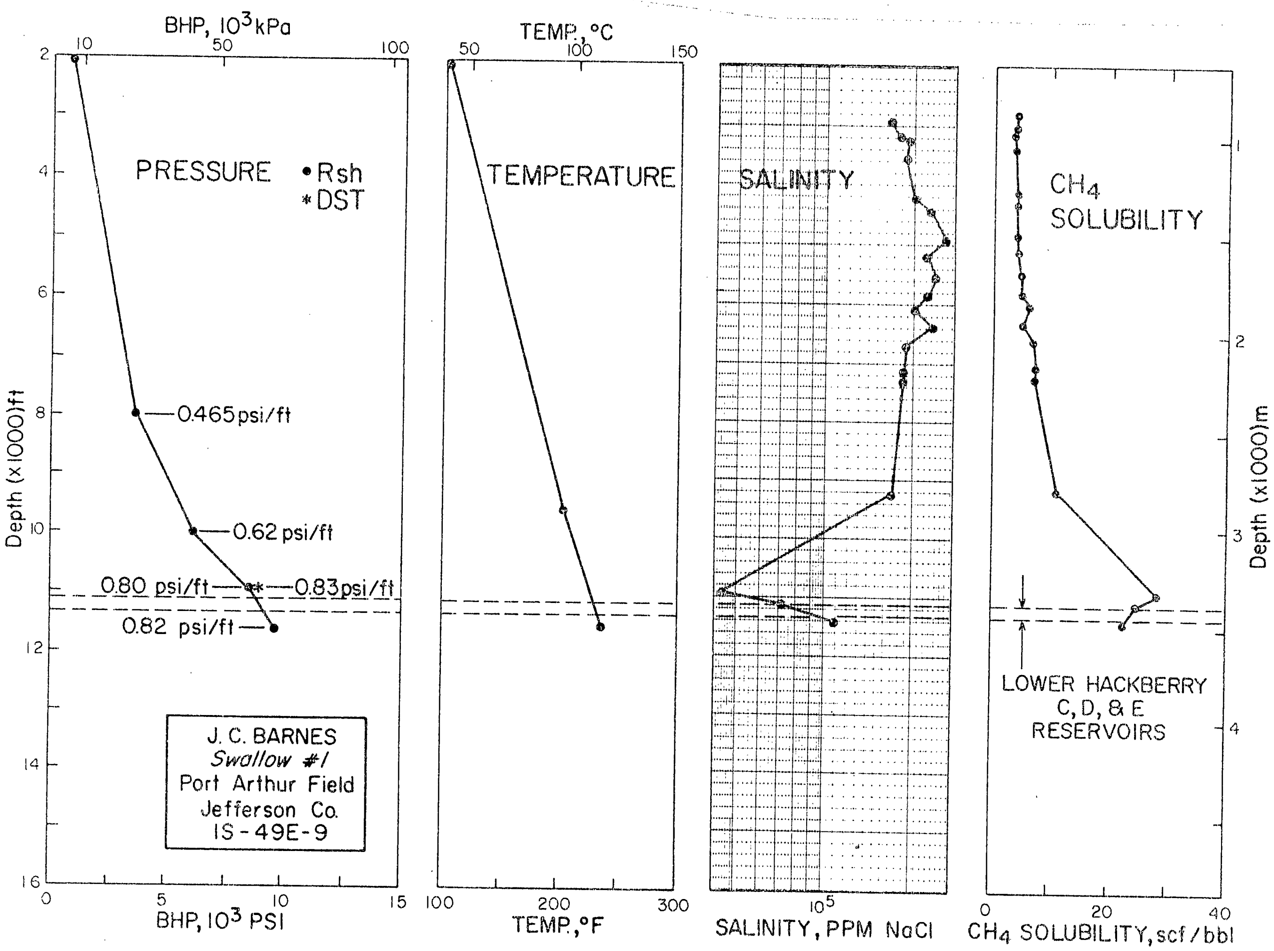

Figure D-16. Pressure, temperature, salintiy, and methane solubility, well no. 35.

Table D-16, Well No. 35

Fluid pressure, equilibrium temperature, salinity, and methane solubility versus depth at original reservoir conditions, J. C. Barnes #1 Swallow, Port Arthur field, Jefferson County, Texas.

Depth (ft)	Pressure (psi)	Pressure Gradient (psi/ft)	Salinity (ppm NaCl)	Temperature (°F)	CH_4 Solubility (scf/bbl)
2,950	1,372	0.465	164,000	113	4.56
3,200	1,488	0.465	175,000	115	4.54
3,280	1,525	0.465	188,000	116	4.31
3,540	1,646	0.465	185,000	119	4.59
4,230	1,967	0.465	203,000	130	4.70
4,420	2,055	0.465	212,000	132	4.61
4,950	2,302	0.465	227,000	141	4.60
5,210	2,423	0.465	209,000	144	5.25
5,600	2,604	0.465	217,000	151	5.31
5,900	2,744	0.465	210,000	154	5.72
6,120	2,846	0.465	196,000	157	6.32
6,440	2,995	0.465	214,000	160	5.94
6,770	3,148	0.465	183,000	166	7.30
7,190	3,343	0.465	182,000	171	7.68
7,320	3,404	0.465	181,000	173	7.82
9,270	5,200	0.560	164,000	198	11.40
11,170	8,700	0.780	72,000	229	25.50
11,470	9,250	0.810	108,000	237	22.90

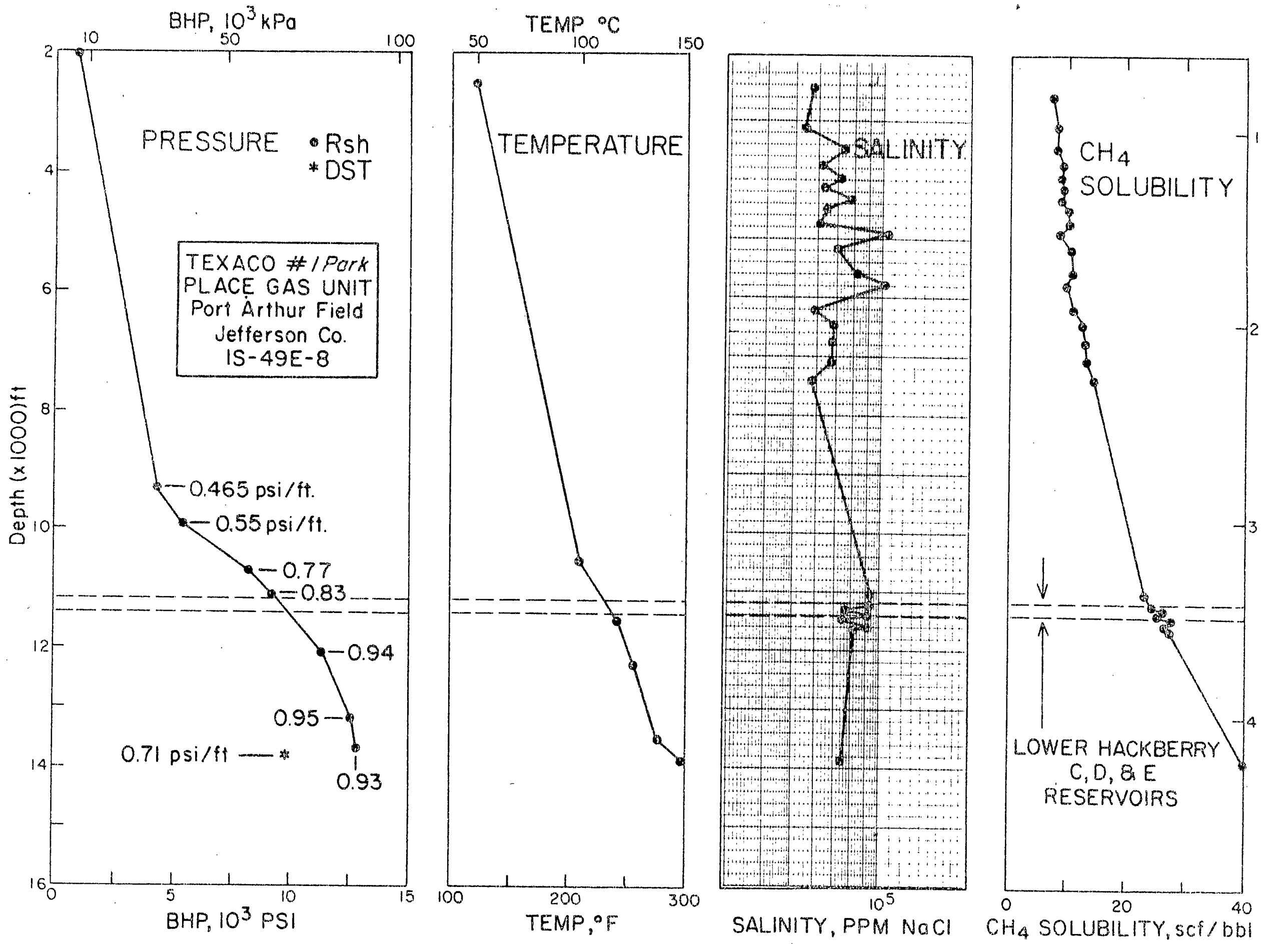

Figure D-17. Pressure, temperature, salinity, and methane solubility, well no. 36.

Table D-17, Well No. 36

Fluid pressure, equilibrium temperature, salinity, and methane solubility versus depth at original reservoir conditions, Texaco #1 Park Place Gas Unit, Port Arthur field, Jefferson County, Texas.

Depth (ft)	Pressure (psi)	Pressure Gradient (psi/ft)	Salinity (ppm NaCl)	Temperature (°F)	CH_4 Solubility (scf/bbl)
2,560	1,190	0.465	56,000	120	7.05
3,200	1,488	0.465	55,100	127	8.16
3,580	1,665	0.465	74,400	132	8.06
3,820	1,776	0.465	63,700	135	8.81
4,020	1,869	0.465	73,500	138	8.73
4,200	1,953	0.465	63,100	139	9.39
4,400	2,046	0.465	79,200	142	9.03
4,590	2,134	0.465	62,500	145	10.02
4,800	2,232	0.465	62,100	147	10.33
4,980	2,316	0.465	105,000	149	8.72
5,249	2,441	0.465	71,300	152	10.53
5,673	2,638	0.465	81,100	157	10.64
5,845	2,718	0.465	103,000	159	9.82
6,273	2,917	0.465	60,000	163	10.52
6,515	3,029	0.465	69,000	166	12.37
6,805	3,164	0.465	68,500	169	12.78
7,095	3,299	0.465	68,000	173	13.23
7,435	3,457	0.465	58,100	177	14.32
11,065	9,132	0.825	92,500	225	23.46
11,215	9,444	0.842	91,500	231	24.47
11,284	9,583	0.849	77,600	233	26.44
11,395	9,810	0.861	90,500	237	25.60
11,445	9,913	0.866	75,000	239	27.80
11,534	10,098	0.875	91,000	242	26.39
11,614	10,266	0.884	82,800	244	27.82
13,842	12,873	0.930	74,800	297	40.13

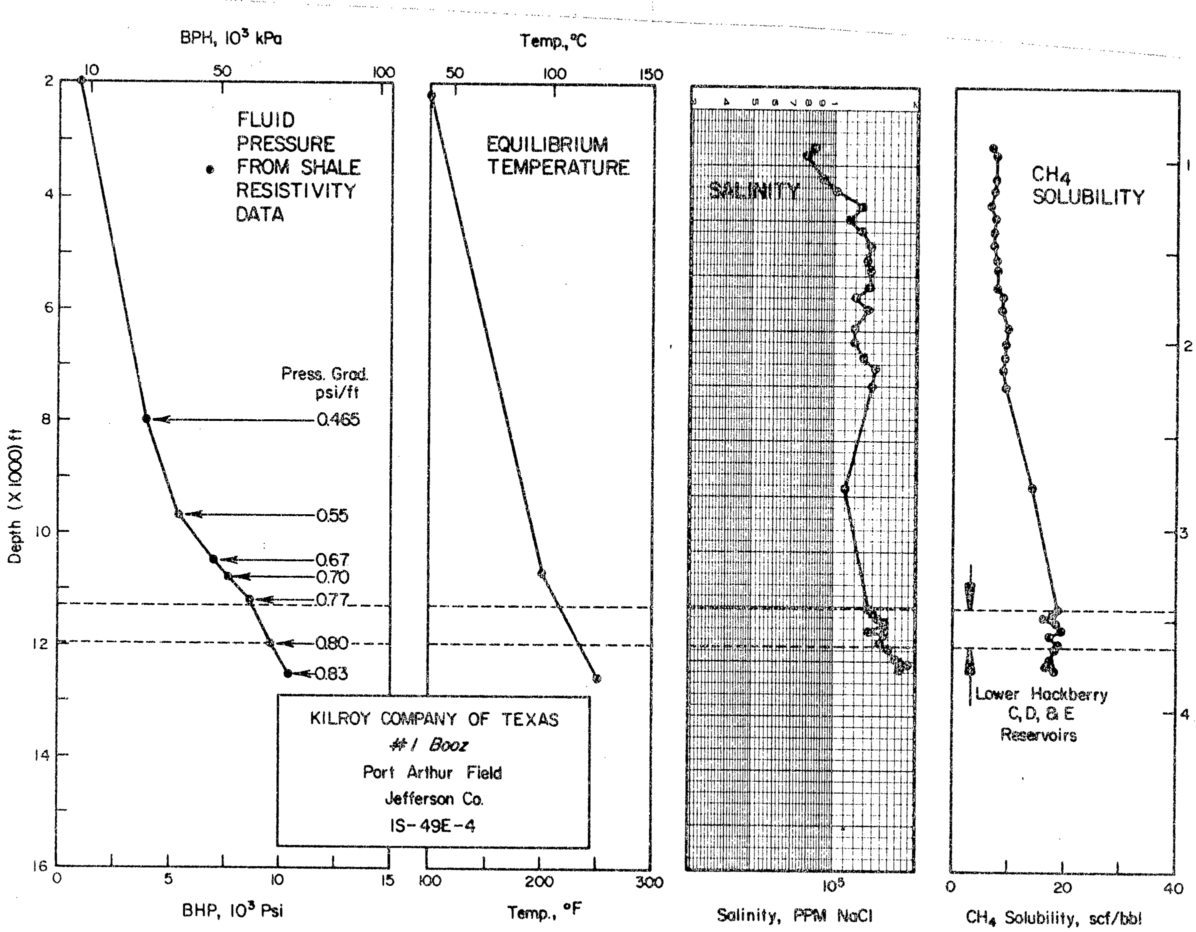

Figure D-18. Pressure, temperature, salinity, and methane solubility, well no. 37.

Table D-18, Well No. 37

Fluid pressure, equilibrium temperature, salinity, and methane solubility versus depth at original reservoir conditions, Kilroy Company of Texas #1 Booz, Port Arthur field, Jefferson County, Texas.

Depth (ft)	Pressure (psi)	Pressure Gradient (psi/ft)	Salinity (ppm NaCl)	Temperature (°F)	CH_4 Solubility (scf/bbl)
3,045	1,416	0.465	84,600	110	6.77
3,200	1,488	0.465	79,700	111	7.13
3,620	1,683	0.465	90,200	117	7.36
3,870	1,800	0.465	102,000	120	7.26
4,100	1,907	0.465	126,000	122	6.73
4,350	2,023	0.465	112,000	127	7.50
4,550	2,116	0.465	124,000	130	7.30
4,800	2,232	0.465	135,000	133	7.17
5,050	2,348	0.465	130,000	135	7.59
5,250	2,441	0.465	134,000	138	7.65
5,550	2,581	0.465	133,000	142	7.98
5,750	2,674	0.465	120,000	145	8.72
5,980	2,781	0.465	131,000	147	8.48
6,280	2,920	0.465	118,000	151	9.35
6,560	3,050	0.465	118,000	154	9.64
6,800	3,162	0.465	129,000	157	9.39
7,000	3,255	0.465	140,000	160	9.10
7,380	3,432	0.465	139,000	165	9.52
9,160	4,791	0.523	110,000	184	13.71
11,300	8,694	0.769	136,000	217	18.14
11,380	8,795	0.773	140,000	219	18.01
11,460	8,897	0.776	145,000	221	17.79
11,580	9,051	0.782	151,000	224	17.60
[illegible],700	9,206	0.787	136,000	227	19.31
11,7[illegible]	9,245	0.788	152,000	228	17.95
11,900	9,468	0.791	148,000	233	18.85
12,000	9,600	0.800	155,000	235	18.14
12,050	9,676	0.803	168,000	237	17.49
12,220	9,937	0.813	172,000	241	17.62
12,300	10,061	0.818	183,000	243	16.88
12,380	10,186	0.823	177,000	245	17.65

Appendix E

Reservoir Simulation, "C" Sandstone, Port Arthur Field, Jefferson County, Texas

Contents

Appendix E

General

The Port Arthur field is located near the city of Port Arthur in Jefferson County, Texas. The field is an anticline which is faulted on the northwest side. The geology and discovery of the Port Arthur field are discussed by Halbouty and Barber (1961, 1962). Figure E-1 shows a structure map of the lower Hackberry sandstones. The well numbering system shown on the structure map is currently being used.

The Port Arthur field was discovered in 1958 and found to produce gas condensate from the lower Hackberry sandstones and a Nodosaria sandstone. Only the lower Hackberry is covered in this report. The lower Hackberry produced from 1959 until abandonment in 1979. No wells are currently producing in the field.

Production History

Total production from the lower Hackberry was about 56.8 Bscf of gas and 2,752,680 bbl of condensate oil. The lower Hackberry "C" sandstone was selected for this reservoir simulation study because it represented a significant share of the total production: 13.752 Bscf of gas and 599,038 bbl of condensate oil. The "C" sandstone produced from 1959 to 1972. The major portion of this production was from well no. 14 (originally Meredith no. 2 Doornbos). Well no. 23 (originally Kilroy and M.P.S. no. 1 Doornbos) produced a smaller amount and well no. 6 (originally Meredith, no. 3 Doornbos) produced a negligible amount. Well no. 6 was not included in the reservoir simulation. A summary of the total production is as follows:

	Cumulative Production	
	Gas (Bscf)	Cond. Oil (bbl)
Well no. 6	0.099	2,310
Well no. 14	12.362	563,091
Well no. 23	1.291	33,637
Total "C" sandstone	13.752	599,038
Total lower Hackberry	58.556	2,752,680

There are eleven sandstones which produced from the lower Hackberry. Other than the "C" sandstone, the "B-2" sandstone, "A-2" sandstone, "F" sandstone, and "D"

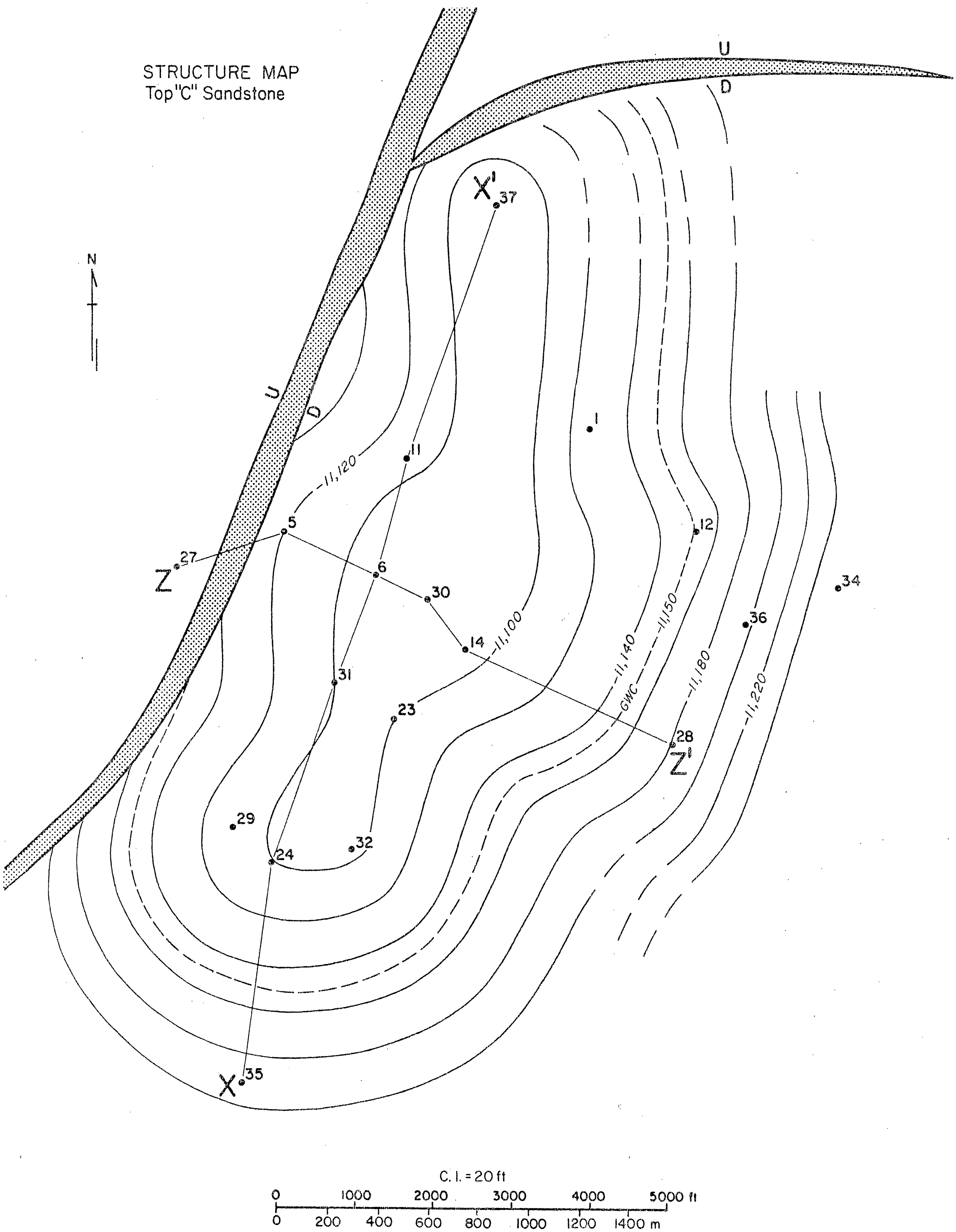

Figure E-1. Structure map, "C" sandstone, Port Arthur field.

sandstone were also significant producers. The sandstones are all believed to be separated in the producing area and in the aquifer. The partial depletion of the "C" sandstone was, therefore, believed to be independent from the depletion of the other sandstones.

Figures E-2 and E-3 show the production histories from well no. 14 and well no. 23. The rates shown are averaged over six month periods, as was done in the simulation runs. Well no. 14 was the best producer from the "C" sandstone. The peak gas rate was over 8,000 Mscf/d in 1960 and again in 1963. The peak condensate oil rate was 469 bbl/d in 1960. The condensate/gas ratio for well no. 14 was about 50 bbl/MMscf until 1964, when it began declining toward its ultimate value of around 15 bbl/MMscf. It is estimated that the dew point for the gas was about 7,500 psig. The dew point is the pressure at which liquid condenses in the reservoir and stays immobile in the reservoir rock rather than flowing into the wellbore. This, of course, results in lower liquid recovery at the surface. Well no. 23 apparently began producing after the dew point had been reached. Its average condensate/gas ratio was 26 bbl/MMscf.

No water production was reported for well no. 14 until June, 1963. Water rates increased and the water/gas ratio was as high as 5.0 bbl/Mscf before abandonment. Well no. 23 was producing water in its first year. Both wells were abandoned because of high water/gas ratios which caused low gas rates and high operating costs. The wells would have been produced longer if the gas price had been higher in 1972, according to the operator.

The production and pressure data were all taken from State files. The water rates were reported for the tests but otherwise the water was not reported. The test gas rates were usually much higher than the average monthly production rates. It was assumed that the water/gas ratios were more representative of water production than were the test rates.

Reservoir Simulation

It was decided to model the "C" sandstone since it was a relatively large producer and seemed to represent the reservoir mechanics of the Port Arthur field, i.e. aquifer expansion. The following describes the reservoir simulation model.

A two-dimensional gas/water simulator was used for the study. All of the important reservoir properties were included in the simulator: gravity, multi-phase flow, compressibility, etc. Solution gas was not included in the water. This was a minor factor and the results were corrected exogenously. The condensate oil

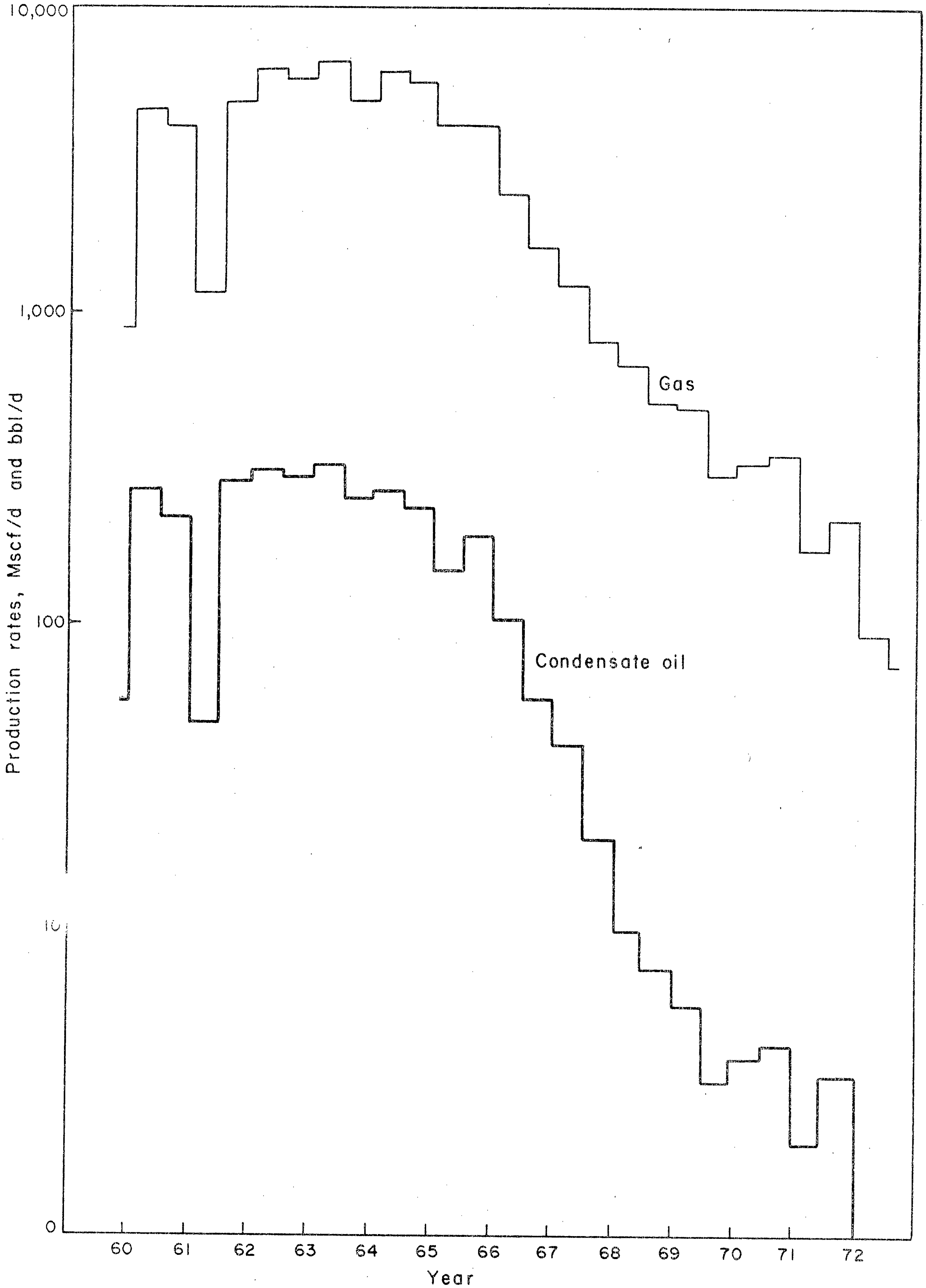

Figure E-2. Production history, "C" sandstone, well no. 14.

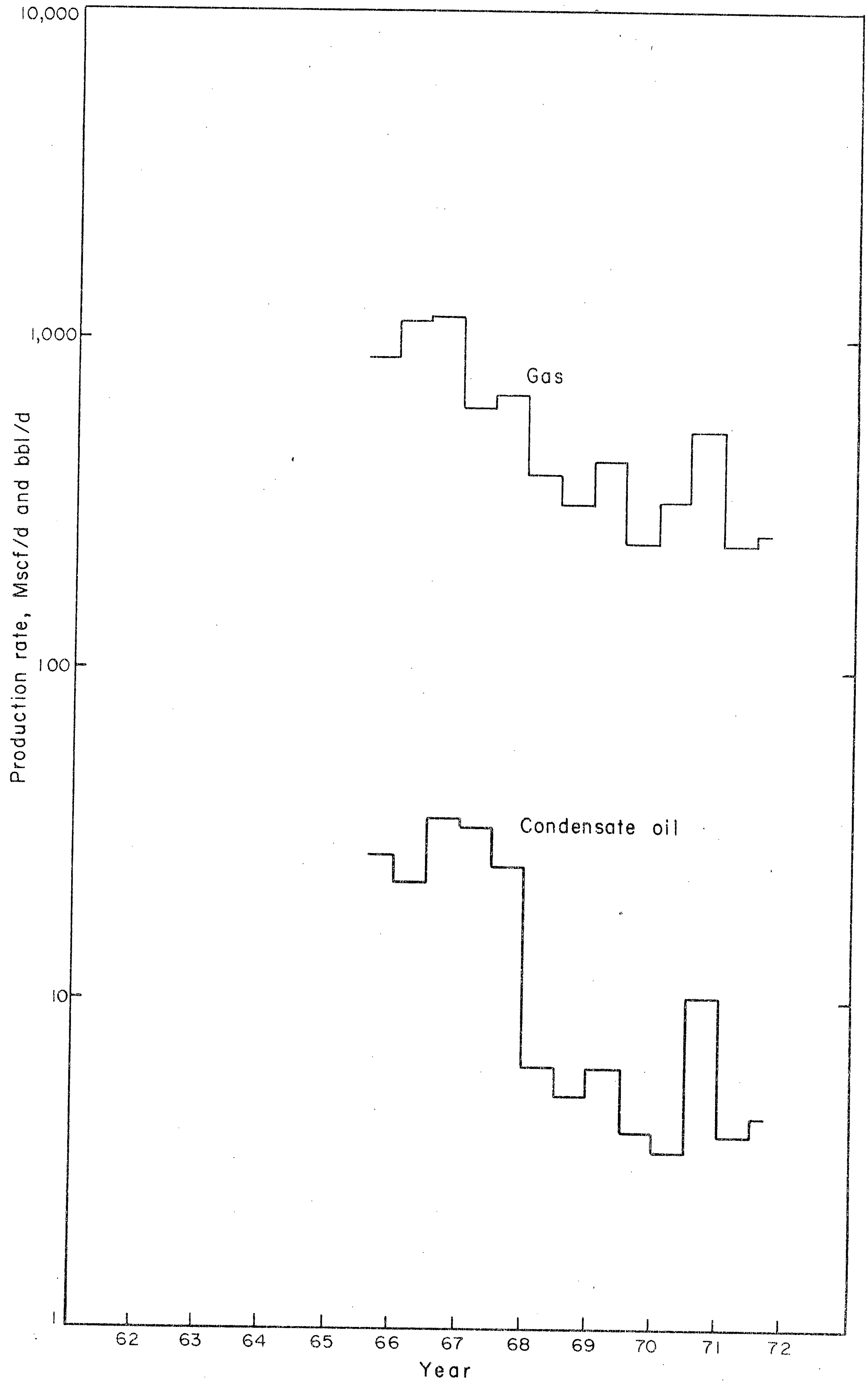

Figure E-3. Production history, "C" sandstone, well no. 23.

saturations were also not modeled directly, but the formation volume factors and pseudo relative permeabilities were modified to account for the retrograde condensation. These modifications are described later.

Figure E-4 shows the final 10 x 13 grid used for the "C" sandstone. The grid blocks in the gas cap are 800 ft by 800 ft in size. The overall grid covers an area 18,400 ft (3.48 mi) north-south and 20,700 ft (3.92 mi) east-west. The gas cap is contained in grid blocks I=1 through 5 and J=4 through 10. The outermost ring of these grid blocks contains the gas/water contact. The interior grid blocks all contain free gas saturation. The rest of the grid blocks comprise the aquifer.

The History Match

A total of fifty-eight runs were made to obtain the final history match. This is a relatively large number of runs, due to (1) the difficulty of modeling the reservoir mechanics and (2) inaccuracies in the historical data. We feel that the final history match does represent the performance of the "C" sandstone and that the model can be used for predictions.

Figure E-5 shows the history match of pressure for well no. 14. Well no. 23 is similar. Overall, this seems to be a reasonable match, although there is no direct comparison between the model pressures and field data. Only well-head pressures are reported in the field, both flowing and shut-in. Bottom-hole flowing pressures were calculated using the reported well-head pressures and flow rates. These are shown on Figure E-5 as flowing bottom-hole pressures but there is some indication that these pressures may be too high.

The well-head shut-in pressures are also corrected to bottom-hole pressures, but with the assumption of no liquids in the tubing. Before 1963, when water production began, these bottom-hole shut-in pressures on Figure E-5 should be compared to the model pressures. At later times, increasing amounts of liquids would have been standing in the tubing during shut-in, making the bottom-hole shut-in pressures too low in Figure E-5.

Figure E-5 shows that the general shape of the pressure decline is similar to history even though there is no direct comparison between the model pressures and estimated history pressures. The pressure data problem is usually solved by obtaining pressure build-up tests with a bottom-hole pressure bomb.

The match of the pressure history tends to confirm that the overall size of the aquifer and gas cap is about right. The only direct conclusion of the pressure match,

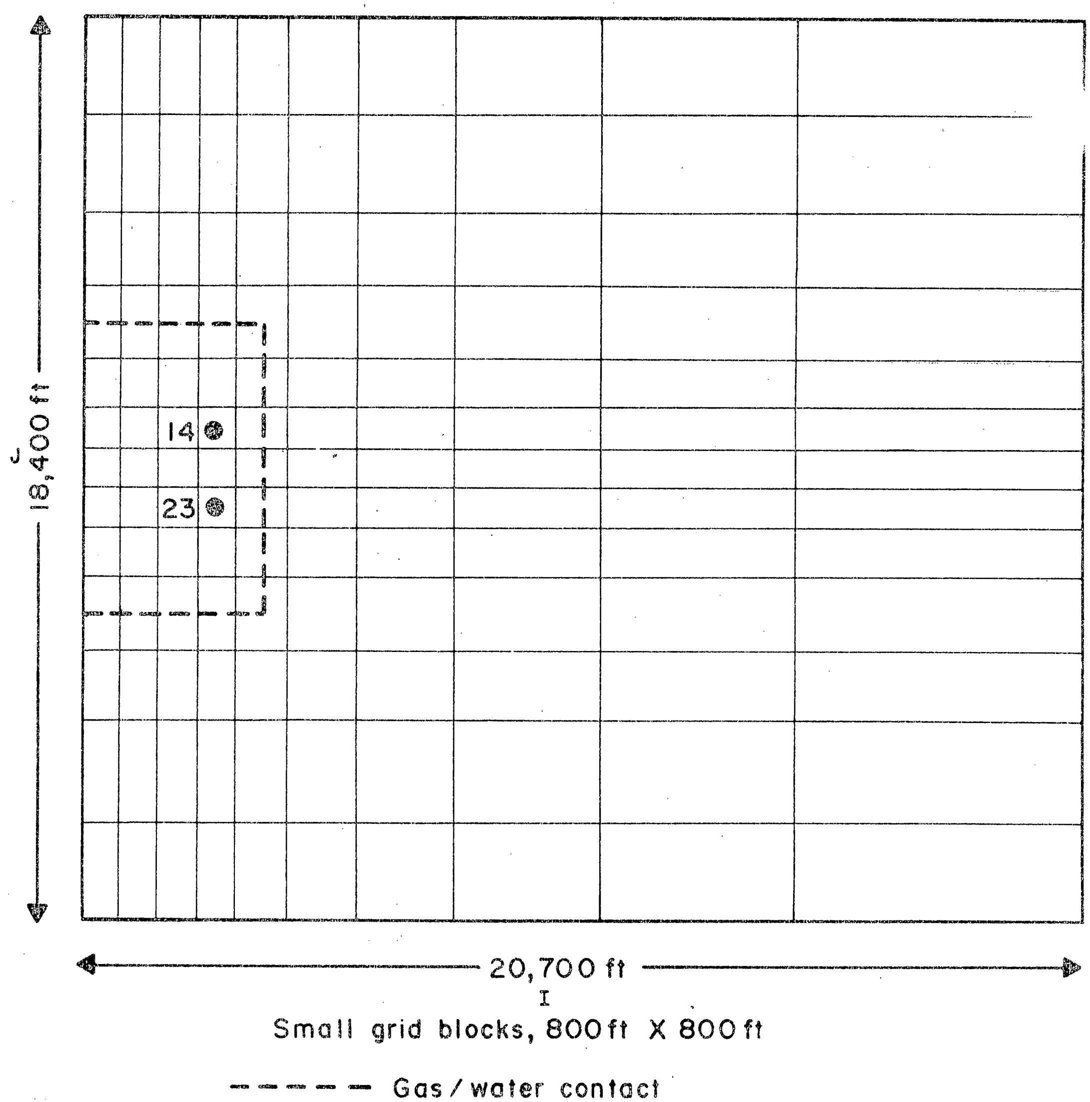

Figure E-4. Simulator grid.

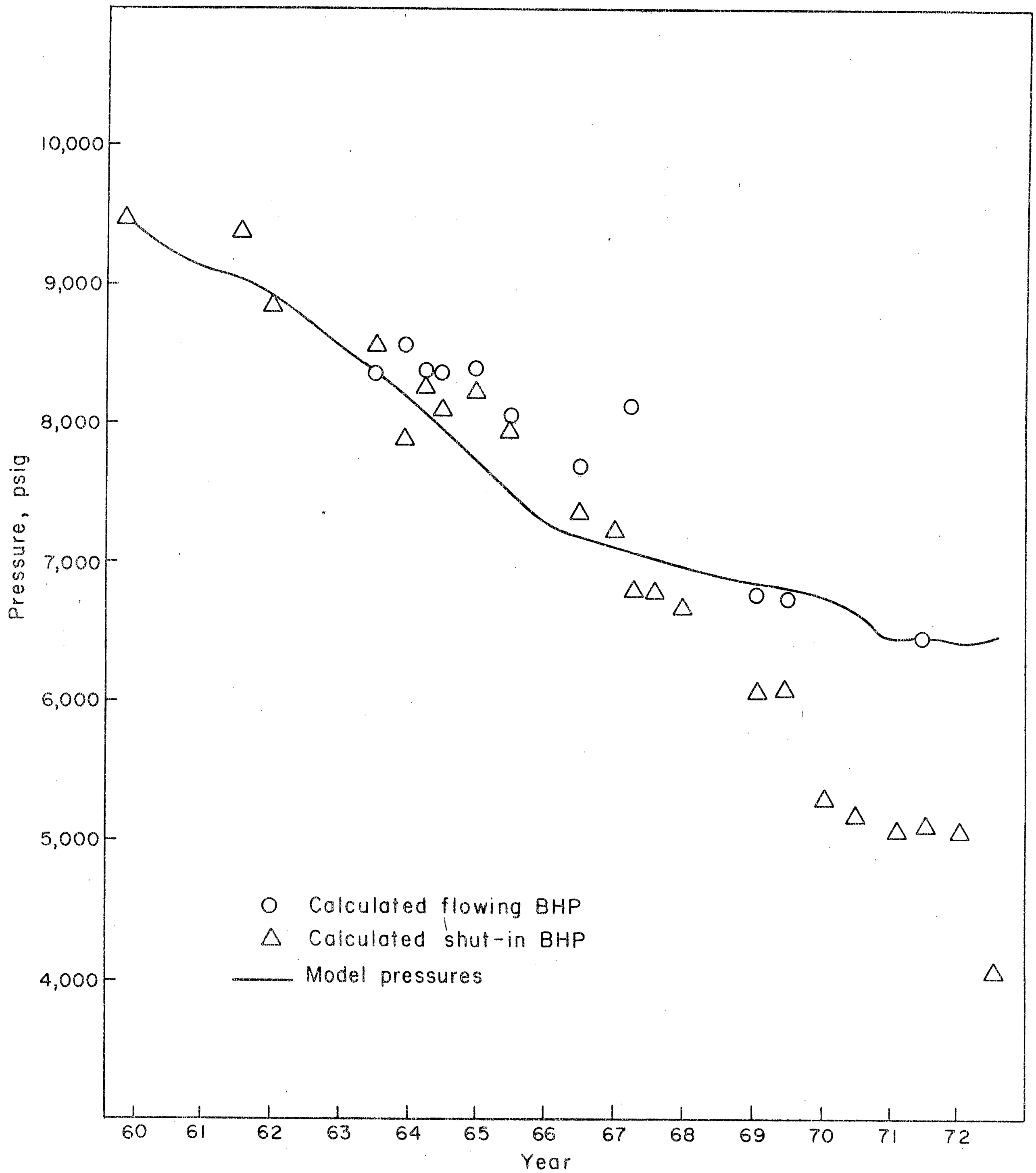

Figure E-5. Pressure history match, well no. 14.

however, is that the total compressibility-volume product for rock, gas, and water expansion is modeled correctly.

Rock Compressibility

Considerable effort was spent in trying to estimate rock compressibility. Initially, the model was set up with a high rock compressibility, 15.0×10^{-6} psi^{-1}, to represent a "soft" rock. Several technical papers have indicated that this is applicable to deep Gulf Coast reservoirs. However, it was difficult to match history on this basis, particularly the water/gas ratio. This high rock compressibility necessitated the modeling of a small aquifer in order to achieve the same amount of pressure support. There is field evidence in support of a larger aquifer, as finally modeled. This, plus various communications with others that are knowledgeable on the subject convinced us that the low compressibility (3.0×10^{-6} psi^{-1}) is more plausible.

Water/Gas Ratio

The water/gas ratio was matched for both wells. Figure E-6 shows the water/gas ratio match of model ratios plotted against test ratios reported on the state forms.

The water/gas ratio trends were matched by modifying (1) gas viscosity below the dew point (table E-1), (2) pseudo relative permeability curves, (3) formation thickness, and (4) the gas/water contact. Another major factor was the rock compressibility mentioned above. The water/gas ratio was much better when it was decided to use the lower rock compressibility value. This modification resulted in stronger aquifer expansion which held the water/gas ratios closer to the values reported in the field.

The pseudo relative permeability curves are shown in Figure E-7. These curves do not represent laboratory behavior, but are a composite of vertical behavior which allows a two-dimensional simulator to model three-dimensional flow (Coats and others, 1967; Hearn, 1971). The main effect which is modeled with pseudo relative permeability curves is the effect of water invading the higher permeability streaks as water encroaches. This drastically reduces the effective flow to gas and increases the effective flow to water. This invasion is modeled by reducing the relative permeability to gas with relatively small decreases in gas saturation. The curves of Figure E-7 were obtained by trial-and-error matching of history and were then applied to the prediction.

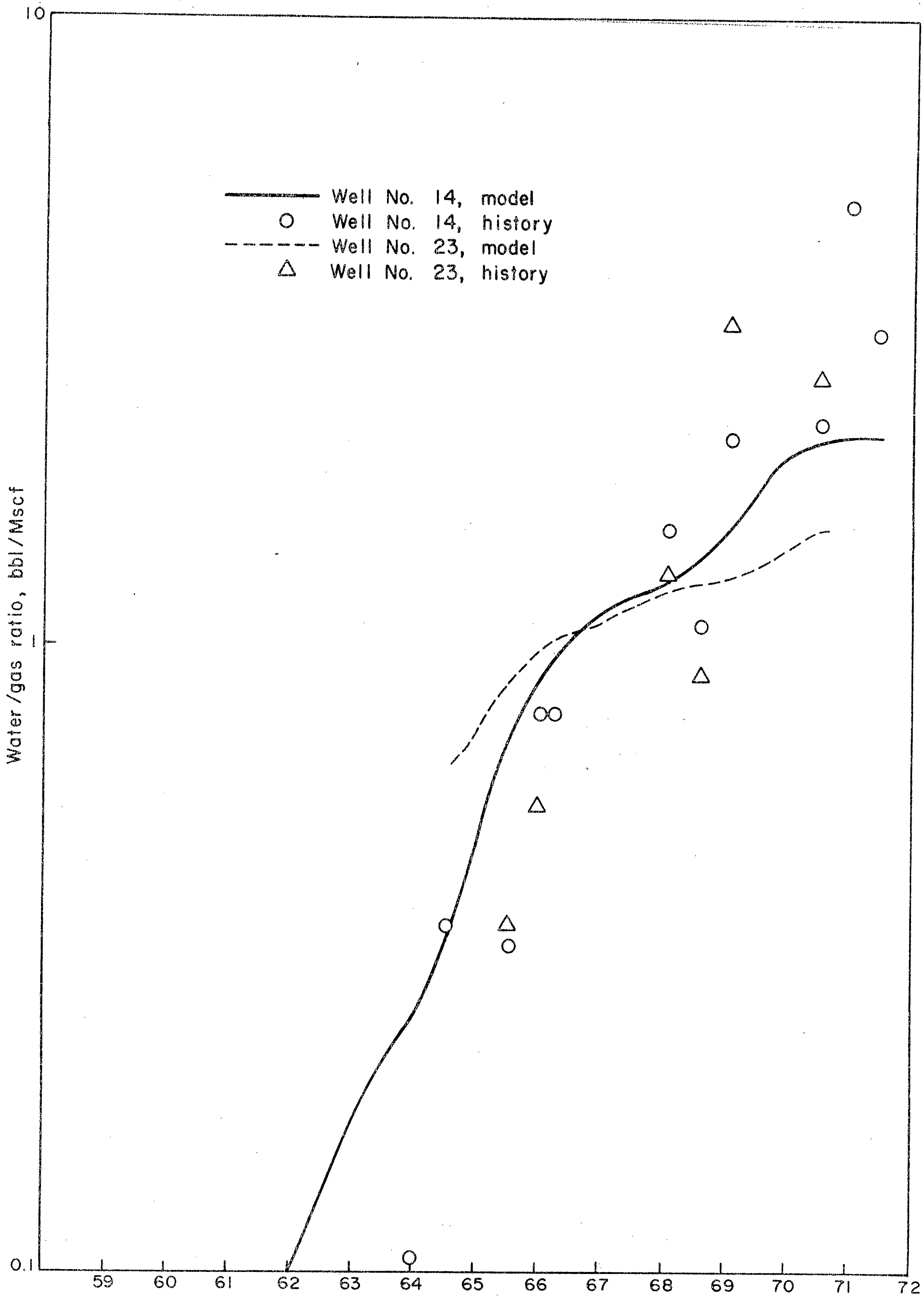

Figure E-6. History match of water/gas ratio.

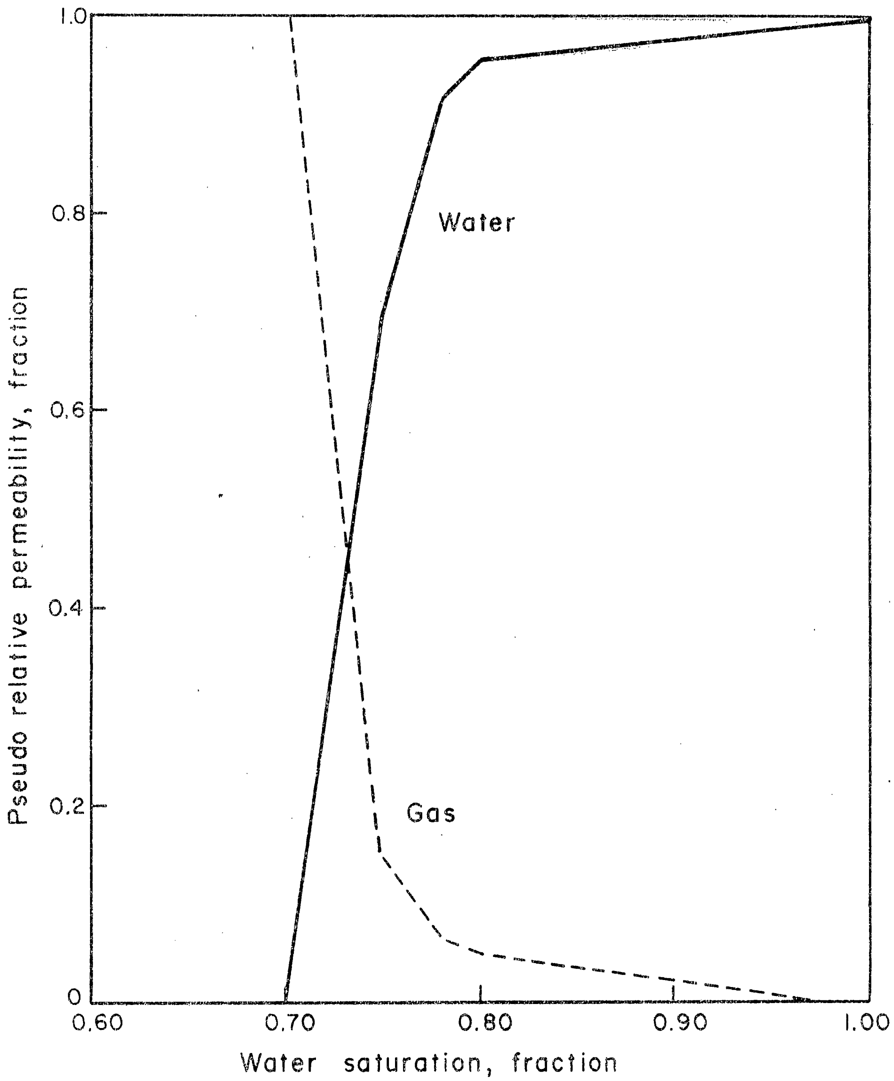

Figure E-7. Pseudo relative permeability curves.

Table E-1

Model Gas Formation Volume Factors
and Gas Viscosity

Pressure (Psig)	B_g (rescf/scf)	μ_g (cp)
10,000	0.00290	0.0375
9,000	0.00303	0.0357
8,000	0.00318	0.0322
7,500(dew point)	0.00327	0.0311
7,000	0.00335	0.06
6,000	0.00363	0.12
5,000	0.00403	0.12
4,000	0.00463	0.12
3,000	0.00573	0.12

Note - Values below 7,500 psig were modified to account for oil saturation in the reservoir.

Predicted Performance

After matching history with sufficient accuracy, the model was then used to predict future performance. A 10-year shut-in period was modeled, then followed by a 10-year prediction.

The prediction was for a single well located midway between well no. 14 and well no. 23. It was assumed that this new well would have the same deliverability as well no. 14.

The flowing bottom-hole pressure was held constant at 3,800 psig. This pressure should be achievable over the 10-year period of prediction. Lower pressures can be achieved under ideal conditions (Wattenbarger, 1981a), but the pressure will tend to increase as the reservoir pressure depletes and rates decrease. It will probably be necessary to change the tubing size and depth to maintain this bottom-hole pressure. The 3,800 psig flowing bottom-hole pressure can also be a plausible value if production from other sandstones is commingled with production from the "C" sandstone.

Conclusions

The following conclusions are made as a result of the reservoir simulation of the "C" sandstone:

1. The available data are sufficient for history matching, but correction of well-head pressures to reservoir pressures is only approximate.
2. The dew point appeared to occur at about 7,500 psig.
3. A reasonable history match was obtained with the use of pseudo relativity permeability curves.
4. The history match indicates that the reservoir behavior is dominated by a strong, but depleting, water drive with water encroachment into the higher permeability streaks.
5. A low rock compressibility matches past performance.
6. The "C" sandstone contains 29.479 Bscf of gas-in-place and 656.312 MMbbl of water-in-place.
7. Recovery for past and predicted performance is:

	Gas (Bscf)	% In-place	Cond. Oil (Mbbl)	Water (Mbbl)
Past production	13.752	46.7	599.04	4,700
Predicted production	3.908	13.3	56.62	8,825

8. The results for the "C" sandstone appear to be encouraging.

Addendum 1 - Port Arthur Field, "C" Sandstone, Reservoir Mechanics

The different categories for unconventional gas recovery are covered in this report. This is intended to clarify and supplement our reservoir simulation report of November 1981.

The following categories refer to the BEG outline of unconventional gas (table E-2). Each item on the outline is discussed and the results are summarized in table E-3.

1. Solution gas

(a) Gas separated from water produced at the surface.

This is included in the reported total recovery of 3.908 Bscf. The amount of gas in the produced water was 15 scf/bbl for 8,825,000 bbl of water, giving a gas production of 0.132 Bscf. For artificial lift, the additional recovery will be at 12.1 scf/bbl giving an additional 0.124 Bscf from an estimated additional water production of 10,250,000 bbl.

(b) Gas released in reservoir during pressure depletion.

This is negligible for the Port Arthur field for sands with initial water saturation of 100 percent. Using gas solubility values shown below, the gas liberated from the water gives the gas saturation shown in the following table.

p (psig)	R_s (scf/bbl)	B_g (rcf/scf)	S_g (%)	
9425	26.4	0.00297	0	(initial condition)
6500	22.4	0.00349	0.25	(begin project)
4018	17.0	0.00463	0.78	(end natural flow)
1700	7.2	0.01014	3.47	(end artificial lift)

The saturation values shown at the beginning and end of the project are much too small to allow flow of gas toward the wells.

If the invading water releases gas in the area, we can calculate an approximate amount of gas released. The average water saturation does not increase during the prediction period so we can estimate the released gas as that gas released by the produced water before it is produced. The average producing pressure is between 6500 psig and 4018 psig, i.e. 5,259 psig. The gas released from 6,500 psig to 5,259 is about 0.5 x (22.4 - 17.0) = 2.7 scf/bbl. For 8,825,000 bbl of produced water, this would

TABLE E-2

Dispersed Gas Project, Bureau of Economic Geology

Unconventional gas in a watered-out gas field with multiple gas reservoirs, multiple aquifers, and isolated virgin gas stringer sandstones includes the following:

1. Solution gas
   (a) gas separated from water produced at the surface
   (b) gas released in reservoir during pressure depletion

2. Immobile free gas trapped in the water-invaded zone

3. Bonus free gas
   (a) mobile and producible free gas remaining in the watered-out gas reservoir
   (b) mobile and producible free gas located in noncommercial* virgin stringer gas sandstones

*A noncommercial stringer gas sandstone is defined as a thin gas sandstone that was passed over or ignored by previous operators in the field. It is assumed that the stringer sandstone has little or no aquifer associated with it.

TABLE E-3

Port Arthur Field, "C" Sandstone
Summary of Predicted Recovery by Different
Categories of reservoir Mechanics

		Natural Flow (Bscf)	Artificial Lift Additional (Bscf)	Total Artificial Lift (Bscf)
	Pressure depletion	6500-4018 psig	4018-1700 psig	6500-1700 psig
1.	Solution gas			
	(a) Gas separated from producing water at surface	0.000	0.000	0.000
	(b) Gas released in reservoir during pressure depletion			
	(1). from aquifer and water saturated zones	0.000	0.000	0.000
	(2). from water invading gas sandstones	0.024	0.050	0.074
	(3). from connate water	0.045	0.082	0.127
2.	Immobile free gas trapped in the water-invaded zone	3.776*	7.434	11.210
3.	Bonus free gas			
	(a) Mobile and producible free gas remaining in the watered-out gas reservoir	included in 2.	included in 2.	
	(b) Mobile and producible gas located in non-commercial virgin stringer gas sands	not included	not included	
	Total	3.977	7,690	11.667

*Combined for 3.908 Bscf in our previous report.

be 0.024 Bscf of gas released. Some of this gas would be released in layers with gas saturation near zero and will not flow. The amount of 0.024 Bscf that would be produced at the wells would be very small, compared with the total gas production of 3.908 Bscf. For artificial lift, we can estimate gas released of 0.5 x (17.0 - 7.2) = 4.9 scf/bbl. This would add an additional 0.050 Bscf using the produced water value of 10,250,000 bbl.

There will be gas released from connate water in the gas sands estimated at 0.045 Bscf for natural flow and an additional 0.082 Bscf for artificial lift.

2. Immobile free gas trapped in the water-invaded zone

This factor is included in the 3.908 Bscf reservoir simulation recovery prediction. As gas zones are invaded, the gas saturation will be left at the imbibition residual gas saturation. This is called dispersed free gas in the Transco patent. A key part of the Exxon and Transco patents and the Exxon field tests is the expansion of this residual gas as the reservoir pressure is reduced. The expansion yields higher gas saturations and allows the gas to flow into the well. The remaining gas, at the residual saturation, contains fewer scf because of the lower B_g at the lower pressure. Artificial lift is estimated to yield an additional 7.434 Bscf.

This effect is modeled in the simulator. The remaining gas is at low pressure. The expanded gas is assumed to flow according to the pseudo relative permeability curves. This effect, however, is blended with the flow and expansion of mobile gas, and it is not known how much each factor contributes to the ultimate recovery.

3. Bonus free gas

(a) Mobile and producible free gas remaining in the watered-out gas reservoir. This effect is included in the 3.908 Bscf and is indistinguishable in the reservoir simulation from factor no. 2. The mobile gas continues to flow toward the producing well. As the pressure decreases with time, the mobile gas expands and flows more easily at the higher gas saturation. This higher average gas saturation due to expansion and the lower average gas saturation due to gas production and water invasion tend to offset each other.

(b) Mobile and producible free gas located in noncommercial virgin stringer gas sands.

Such virgin stringer gas sandstones may exist in the Port Arthur field but were not included in the reservoir simulation.

APPENDIX F: METRIC CONVERSION FACTORS

Customary Unit		Conversion Factor		Preferred Metric Unit
acre	x	0.4046856	=	ha (hectares)*
acre-ft	x	1,233.482	=	m^3
acre-ft	x	0.1233482	=	ha-m
bbl (42 gals)	x	0.158983	=	m^3
bbl/acre-ft	x	0.0001288931	=	m^3/m^3
bbl/d	x	0.1589873	=	m^3/d
°C	+	273.1500	=	°K
°F		(°F - 32)/1.8	=	°C
ft	x	0.3048	=	m
gal	x	0.003785412	=	m^3
lb/gal	x	119.8264	=	kg/m^3
md	x	0.0009869233	=	μm^2
mi	x	1.609344	=	km
mi^2	x	2.589988	=	km^2
psi	x	6.894757	=	kPa
psi/ft	x	22.62059	=	kPa/m
scf (std ft^3)	x	0.02831685	=	m^3
scf/bbl	x	0.1801175	=	std m^3/m^3

*1 ha (hectare) = 10,000 m^2 (2.47 acres)

APPENDIX G: NOMENCLATURE

A.F.I.T.	=	after federal income tax
bbl	=	barrel, 42-gallon capacity
B.F.I.T.	=	before federal income tax
BHP	=	bottom-hole pressure, psi
BHSIP	=	bottom-hole shut-in pressure, psi
BHT	=	bottom-hole temperature, °F
Bscf	=	billion standard cubic feet
B_w	=	water formation volume factor, dimensionless
°C	=	degrees Celsius (Centigrade)
CH_4	=	methane
C_p	=	compaction correction factor
D	=	depth, feet
d	=	day
DST	=	drill stem test
F	=	formation factor
°F	=	degrees Fahrenheit
FPG	=	formation pressure gradient, psi/ft
GOR	=	gas-to-oil ratio
GP	=	geopressure
Gp	=	cumulative gas production, Mscf
GWC	=	gas/water contact
m	=	cementation factor
md	=	millidarcy
mi	=	mile or miles
MMscf	=	million standard cubic feet

Appendix G: (continued)

Mscf	=	thousand standard cubic feet
n	=	see appendix C
NaCl	=	sodium chloride
OGIP	=	original gas in place
P	=	pressure, psi
ϕ	=	porosity, percent or fraction
P & A	=	plugged and abandoned
P/Z	=	pressure/gas compressibility factor, ratio
P_f	=	final pressure, psi
P_{sc}	=	pressure at standard conditions, psi
ppm	=	parts per million, weight/weight
psi	=	pounds per square inch
psia	=	pounds per square inch absolute
psig	=	pounds per square inch gage
°R	=	degrees Rankine (°F + 460 = °R)
R_{mf}	=	mud filtrate resistivity, ohm-meter
R_o	=	resistivity of rock that is fully saturated with water, ohm-meter
R_{sh}	=	shale resistivity, ohm-meter
R_t	=	true resistivity of rock, ohm-meter
R_w	=	formation water resistivity, ohm-meter
scf/bbl	=	standard cubic feet per barrel
S_g	=	gas saturation, percent or fraction
S_o	=	oil saturation, percent or fraction
SP	=	spontaneous potential

Appendix G: (continued)

S_w	=	water saturation, percent or fraction
SWC	=	sidewall core
T	=	reservoir temperature, °R
T_E	=	equilibrium temperature, °F
T_L	=	temperature measured in borehole and recorded on well log header, °F
T_{sc}	=	temperature at standard conditions, °R
ΔT_f	=	transit time of fluid contained in pore spaces of rock, μsec/ft
ΔT_{log}	=	transit time from acoustic log, μsec/ft
ΔT_m	=	transit time of solid matrix material of rock, μsec/ft
WHSIP	=	wellhead shut-in pressure, psi
W_p	=	cumulative water production, Mscf
Z	=	gas compressibility factor, dimensionless
Z_f	=	gas compressibility factor at P_f, dimensionless