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# EVALUATION OF THE BODCAU (BELLEVUE) IN SITU COMBUSTION PROJECT

Work Performed for the Department of Energy
Under Contract No. DE-AC19-80BC10033

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Keplinger and Associates, Inc.
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## SUMMARY


Operating under Department of Energy Contract DE-AC03-76ET12057, Cities Service Oil Company conducted a cost-shared commercial scale demonstration in situ combustion project in the Bodcau Fee lease of the Bellevue Nacatoch Reservoir near Shreveport, Louisiana. The 19-acre, five-pattern project was started in July, 1976, following successful pilot operations in nearby leases.

Following extensive reservoir studies and concurrent laboratory combustion tube experiments, the five injection wells were ignited in August and September, 1976, with an electrical heater. Six months of dry burning was followed by simultaneous air and water injection and finally, late in the project, heat scavenging water injection was carried out.

As of February 28, 1982, 667,609 barrels of tertiary oil had been produced, compared with 700,00 barrels predicted. It is anticipated that the project will ultimately produce slightly more than the predicted 700,000 if the economic limit permits it to be operated long enough. The operation has already paid out and yielded attractive economics under the economic climate in which it was conducted. Operation under the economic conditions of the 1981-82 period would reduce the attractiveness of the project, but it would still yield a profit.

In spite of considerable care in design and operation, an explosion occurred in the air compression/injection system. Since explosions of this type are not uncommon, it is particularly important that a rigid program of preventive maintenance be set up to eliminate this hazard.

The project was carefully designed and operated in an expert manner, but there are some areas in which improvements would be desirable including:

1. Better technique of maintaining simultaneous air and water injection.

2. Improvements in operating and working over producing wells to increase capture efficiency.

3. Increased accuracy in estimating the original oil saturation.

4. Greater sophistication in laboratory combustion tests.

5. Reservoir simulation of the combustion process to aid in design of patterns and injection schedules.

6. Improvements in techniques used in making observation well measurements to justify the expense of providing these wells.

## INTRODUCTION

Beginning in 1976, a 19-acre demonstration in situ combustion project was conducted in the Bodcau Fee lease of the Bellevue Field by Cities Service Oil Company with support of the United States Department of Energy (then known as ERDA) under Contract Number E(04-3) - 1189 (now DE-AC03-76ET12057). The project was preceded by a 10-acre dry combustion pilot in an adjacent area started in 1971 using heat scavenging by water injection after the combustion phase was completed. Encouraging results led to a side-by-side comparison test of dry and wet combustion beginning in 1974. The current 19-acre test, which is nearing completion, is an out-growth of the successful series of pilots and has the objective of demonstrating the efficiency and economics of a simultaneous water-air in situ combustion process on a reasonably large scale. An additional objective was to demonstrate techniques of increasing vertical sweep efficiency while reducing overall project time.

The purposes of this report are to review the project, evaluate the degree of technical success of the operation, evaluate the economic feasibility of exploiting similar reservoirs by wet in situ combustion, and delineate areas in which additional investigation is needed.

The Bellevue Field is located 18 miles northeast of Shreveport, Louisiana (Figure 1). The field, discovered in 1921, is in the Upper Cretaceous Nacatoch Sand at a depth of 300-400 feet and occupies a total of approximately 900 productive acres. The 19° API oil has a viscosity of 676 cp at the reservoir temperature of 75°F, and contained so little gas at discovery that primary production was by liquid expansion and, later, gravity drainage. No significant secondary recovery operations were conducted because of the high viscosity of the oil. A number of stimulation techniques were applied in unsuccessful attempts to increase the production rate, and by the late sixties, production had decreased to a few barrels per day per well. A fireflood test run by Getty Oil Company beginning in 1966 on an adjacent property was successful and encouraged Cities Service to begin thermal recovery testing.

## RESERVOIR DESCRIPTION

The Upper Cretaceous Nacatoch reservoir is one of many such heavy oil reservoirs located in Northern Louisiana and Southern Arkansas. The reservoir is an unconsolidated sand and contains a 19° API oil with a (reservoir) viscosity of 676 cp (75°F). The total reservoir is a dome occupying an area of approximately 900 acres, lying at a depth of 300-400 feet. It is estimated that primary production has recovered less than 15 percent of the original oil-in-place, resulting mainly from liquid expansion and gravity drainage.

To assist in selecting the site of the demonstration project, five evaluation wells were drilled and logged, and one was also cored with a rubber sleeve core barrel. Information from these wells and previous operations was used in developing the isopach and structure maps (Figures 2 and 3). Figure 2 shows all the wells drilled for the project, including four diagnostic wells drilled late in the life of the project to estimate the coverage of the combustion zone.

Within the area of the project, the Nacatoch Reservoir is a highly unconsolidated fine to very fine-grained calcareous sandstone with numerous thin, dense, fossiliferous limestone beds. The sand is predominantly quartzose, dark brown to dark gray in color, commonly silty and fossiliferous. The Nacatoch contains some clay minerals, dominantly kaolinite with some illite and smectite. The inferred depositional environment for the Nacatoch Sand at the Bellevue Field is nearshore shallow marine, probably an offshore bar or a strandline deposit.

The Nacatoch Sand is confined by a dense limestone at the top and a water-oil contact at the base. Interspersed in the pay are several dense limestone layers ranging from a few inches up to two or three feet in thickness. These appear to be continuous across the project area and subdivide the reservoir into four discrete sands. There are no known faults in the project area and there is no gas cap. The presence of the limestone layers was probably beneficial in helping to confine the injected air to the productive sand intervals.

The project area is located on the northeast flank of the dome so that it dips towards the northeast at about 4.5°. The average net thickness in the 19-acre project is approximately 56 feet. The actual bulk volume is 1039 acre-feet. The maximum thickness of the pay in the pattern area is about 60 feet in the southwest corner, thinning down-dip to 20 feet in the northeast corner.

The formation permeability averages 700 md (absolute) and appears to be relatively uniform. Considerable transient pressure testing, including both pulse and pressure falloff tests, was conducted to detect any channeling tendencies or strong directional permeability trends. No significant channels were detected, but there is a significant directional permeability favoring fluid flow in a north-south direction.

Pressure falloff measurements made on all the injectors indicated effective permeabilities to air ranging from 6 md in Pattern 14 to 32 md in Pattern 16. In all cases, negative skin factors (ranging from -0.2 to -3.4) were calculated. The operator does not associate any of these negative skin factors with fracturing at these wells, but no type curve analyses were performed to establish the near-well geometry or to identify the correct point of the onset of the semilog straightline.

Porosities were determined by log analysis. The maximum value reported for the pattern area is an average of 34.4 percent at Well 2-8 and the minimum is 32.4 percent at Well 15-3. The average for the pattern is 33.9 percent. Due to the shallow depth, it is unlikely that the effects of overburden on porosity are significant.

Relatively little effort appears to have been expended on determination of the oil saturation within the project area. In view of the importance of determining the potential oil recovery, this is surprising. Unfortunately, the operator has made many shifts of personnel since the initiation of the project, and it was impossible to obtain a clear picture of the techniques and parameters used in the log analysis. The oil saturation problem will be discussed in depth in later sections of this report.

## PROJECT DESIGN

All aspects of pattern development and construction of surface facilities were conducted according to original plans which are reviewed below.

### Pattern

A common problem with *in situ* combustion projects is that, in many cases, the oil is too viscous to produce at the rate it is being displaced by the thermal process until the heat begins to arrive at the producer. This can lead to the loss of oil outside the boundaries of the pattern. The reservoir was particularly favorable in this project, having a net thickness of 56 feet and lying at a depth of about 400 feet. This permitted the use of 9-spot patterns which, in thinner, deeper reservoirs might have been too expensive. A common practice in the latter case is to use fewer producing wells, with cyclic steaming to stimulate production until heat arrives from the *in situ* combustion process. Using the 9-spot patterns, the operator did not consider cyclic stimulation necessary.

Another design factor considered by the operator is the tendency of the combustion zone to overrun the oil due to gravity segregation. The operator dealt with this problem in two ways:

(1) by elongating the patterns up-structure, injecting air down-structure, and
(2) injecting air through perforations near the bottom and water through perforations near the top of the pay.

The well array consisted of five inverted 9-spot patterns with each one occupying approximately four acres (Figure 2). The total area in the project was slightly less than 19 acres. To provide information on the movement of the combustion zone and hot fluids, a temperature observation well was located in each 9-spot.

### Completion Practices

The wells were cased and cemented through the pay to the surface using materials and techniques which are standard in thermal recovery projects. Initially, the injectors were perforated in the bottom 10 to 20 feet of net pay, and all air injection was through these perforations until the dry burn was completed. As planned, additional perforations were then made in the upper portion of the pay. A packer set on tubing between the two sets of perforations permitted air to be injected at the bottom at the same time water was injected in the upper part of the pay.

Production wells were perforated selectively across the entire pay. During the burning phases of the project, production was carried out by pumping through hollow sucker rods, allowing the injection of cooling "quench" water down the annulus between the sucker rods and the 2 7/8-inch tubing. Gas was produced through the casing-tubing annulus. As air injection was completed in each pattern, water was injected as a heat scavenger, using a schedule tailored to each pattern. This served the dual function of making use of the heat stored in the burned-over rock and also minimized any tendency toward resaturation of the burned-over rock by oil from adjacent areas which might not be as far advanced in the displacement process.

Temperature observation wells were completed by cementing 5 1/2-inch casing from the bottom of the hole to the surface. Use of 5 1/2-inch casing permitted remedial work (cementing smaller tubing inside the 5 1/2-inch) in the event the well became damaged by the combustion temperatures.

## Surface Facilities

The surface facilities were not very different from those used in *in situ* combustion projects discussed in the literature over the years. Most of the earlier projects were small pilots and required smaller air compressors. The Bodcau project was equipped with three compressors furnishing a total of 20 MMSCFD at 250 psig, shared with an on-going Cities Service project on adjacent acreage. This permitted a maximum air injection rate of 3 MMSCFD at each of the five injection wells.

Produced liquids were handled in the usual way, with facilities to separate free water, break emulsions, and meter production prior to transferring the oil to a LACT unit. Produced gas was vented at concrete-lined pits where the entrained liquids were separated. Pumps and lines were provided to transfer the liquids to the main battery facilities for processing.

Water for simultaneous injection with air was furnished by a supply well in a fresh water sand 70 feet deep. Injection wells were also equipped to accept produced water so that it could be diverted from the disposal well for injection during the waterflood (heat scavenging) phase after combustion ended.

## Schedule of Operations

Preignition Testing - Air injection tests, with associated pressure falloff and pulse tests, were conducted prior to ignition. These tests were designed to provide data on formation flow capacity, wellbore damage, average reservoir pressure, faults and directional permeabilities.

Ignition - An electric heater was run to a point above the perforated interval of an injection well. The first step in ignition was a preheating period, during which air was injected at 250 MSCFD and heated to 300°F. After several hours, the heating rate was increased to the maximum safe heater temperature (1,000°F), heating the injected air to 600°F. Temperature profiles along the injection wellbore (using a 1-inch thermowell inside the casing), together with gas analyses at offset producers, furnished evidence of successful ignition.

Dry Burn - After well ignition, the heater was pulled and air injection continued through perforations in the bottom 10 feet of pay, raising the air injection rate to the maximum level of 3 MMSCFD in a series of steps. Dry combustion continued until a well-stabilized combustion zone was established (about six months).

Wet Burn - The upper 10-12 feet of pay was perforated, a packer set between the upper and lower perforations, and air injected at the bottom of the pay through tubing and water injected at the top of the pay through casing.

Target water-air ratios of 200-500 B/MMSCF were selected on the basis of laboratory combustion tube runs. An important objective of the project was to find the best practical water/air ratio.

Post-Burn Waterflood - When pattern performance, temperature observation well data, and gas analysis indicated that a sufficient fraction of the reservoir had been burned, air injection stopped and produced water was injected through perforations across the entire pay. Thus, the project will be completed as a conventional waterflood.

## PRODUCTION FORECAST

The oil production schedule was based on the operator's previous pilot experience in the Bellevue Field. The reports are rather vague in explaining how the timing of the oil production was scaled. It is assumed that the rate of oil production was based on the relationship between the air and water injection rates in proportion to the reservoir volume in the pilot and the demonstration project. A total of 700,000 barrels of tertiary oil was projected over a six-year period. The production forecast is shown in Figure 4.

## ACTUAL PROJECT PERFORMANCE

### Injection

A comparison of the planned and realized injection rates (Figure 5) shows that there was considerable deviation from the planned injection schedule. Initially, injectivity was reduced by the tendency for scale to form in the injection wells due to the fresh water injection which took place between May, 1977 and October, 1980. This problem was corrected by acidizing the wells and use of a scale inhibitor. Injectivity was not a problem during the remainder of the project and the original target rates could have been maintained if the producing wells could have captured the displaced oil. Unfortunately, capture became a serious problem and served as the limiting factor in determining the injection rate. This emphasizes the importance of careful planning in both injection and production facilities to obtain properly sized equipment. In the present case, the operator had much flexibility because the project was sharing injection facilities with an adjacent project.

The simultaneous water/air injection into upper and lower intervals of the pay was facilitated by the presence of the thin, dense limestone layers which subdivide the reservoir. These layers appear to be fairly continuous across the project area and may have made a significant contribution to the operator's measure of success in controlling air/water segregation.

### Burning Front Breakthrough

*In situ* combustion in a totally homogeneous reservoir would result in initial breakthrough at the top of the pay due to gravity override of the oil by the injected air. It was for this reason that air was injected at the base of the pay instead of the entire interval. In the case of Well 15-2 (Figure 2), 165 feet north of its injector, breakthrough occurred about five months after ignition and was considered premature. Analysis of the well performance suggested that the early breakthrough was caused by channeling of air through a water zone below the oil.

Squeeze cementing, followed by reperforating, was not very effective in this well, which was squeezed a total of seven times during the first two years of operations.

Well 12-2 (Figure 2) also showed early breakthrough due to a high permeability streak near the top of the pay. Squeezes were much more effective in shutting off the hot combustion gases in this well than in Well 15-2. A possible explanation is that the water zone present at Well 15-2 was thicker than the high permeability streak in Well 12-2.

During the course of the project to February 28, 1981, a total of 123 squeeze jobs had been performed. The average number of jobs per well is three; the largest number is 17 on Well 13-14. Nine wells had not been squeezed.

Overall, the operator's management of the remedial program has been good. One of the most critical factors in successful *in situ* combustion is hot well operation. To be able to keep the wells producing oil after hot fluids appear is a challenge which confronts all operators of *in situ* combustion projects.

## Oil Production

Figure 14 of Reference (1) shows that an increase in oil production rate began as early as September, 1976, while ignitions were taking place. Since there had been insufficient time for any appreciable oil displacement by heat, this increase must have been caused by the gas drive induced by the injected air prior to, and during, ignition. This behavior is not unusual for *in situ* combustion projects where the oil has some mobility at reservoir conditions. Examination of the oil production graphs of Reference (1) for individual producing wells shows that significant increases began to occur at many of them in November, 1976, suggesting good areal sweep.

The maximum response to thermal displacement occurred when the oil production rate reached 601 BOPD in March, 1978 (Figure 4). This was a short term excursion from an average level of about 525 BOPD and was accompanied by a peak in water production, suggesting that this was a month during which well problems happened to be fewer than usual. The highest oil production rate for any single well, to which significance could be attached, occurred at Well 12-6 in March, 1978, (Figure 6) when the production reached a daily average slightly greater than 60 BOPD. Although two other wells peaked at slightly higher rates, these are not representative and the averages for them are lower. All three are updip from their injection wells, in the direction of the preferential air flow.

Figure 4 shows the actual oil production compared with the original forecast. Although the two graphs do not track each other in every detail, the agreement is quite good; and it appears that the projected oil production for the life of the project should be slightly better than the forecast. To provide oil production data for economic studies carried to project completion, a decline curve was drawn for the period from January 1, 1980, through February 28, 1982. Linear regression analysis gave a good fit to an exponential decline (Figure 4), and integration of the decline equation

$$q = 382e^{-0.001619t}$$

where q = production rate, BOPD
t = time in days (1-1-80=0)

provided the estimate of remaining oil reserves. From this calculation, the expected total project oil production as of the June 30, 1982, contract completion date is 683,719 barrels. If the economic limit is reached June 30, 1983, instead of 1982, an additional 24,048 barrels of incremental tertiary oil may be recovered. Of course, the actual economic limit will be determined by costs and oil prices.

## Production Equipment Performance

The main difficulty in lifting heavy oil displaced by *in situ* combustion is that the production wells are required to lift viscous oil, water, and large volumes of exhaust gas. During the early phases of a project, the oil at the producers is at normal reservoir temperature and its viscosity has not been reduced by heating. There may be some slight viscosity reduction due to carbon dioxide dissolution in the oil, but this is not usually a major effect. After heat arrives at a producer, the oil becomes less viscous and easier to produce but gas production increases, making pumping less efficient. Also, sand production frequently becomes a problem. Ultimately, as the temperature rises and combustion gas production increases and contains more and more oxygen, it becomes increasingly difficult to protect the well tubulars; and the well must be squeezed off and reperforated, as discussed previously.

The production well completions used in this project worked reasonably well. Hollow sucker rods were used to help lift the small amounts of sand being produced along with the heat-thinned oil and water from the combustion process. Also, cooling water was injected down the rod-tubing annulus. The completion was also successful in allowing the gas to separate from most of the oil and be produced with steam from the vaporizing water up the casing-tubing annulus. Foaming of the oil, with resulting high fluid levels, was thus minimized. In spite of these measures and the high well density of the 9-spot patterns, the wells were unable to capture all the displaced oil; and when the operator of the lease to the south of the project drilled wells along the lease line, Cities Service had to increase the well density in the south row by drilling a total of nine additional producers. This raised the number of production wells to 38 in the 19 acre project.

## Explosion in Air Injection System

On February 17, 1980, an explosion occurred in the air injection system causing about $100,000 in damages to the piping, meter runs, and air compressors. The operator conducted a very detailed investigation to determine the cause of the explosion and the results of the study are well documented in the Fourth Annual Report (2). Therefore, no detailed discussion will be included in this report.

The explosion appears to have resulted from autoignition of lubricant in a cylinder of Compressor No. 2, which had been shut down and restarted a short time before the explosion took place. Although it was apparently a "low order" explosion, it must have generated a shock wave in the air distribution lines which, in turn, caused a larger oil film detonation to propagate throughout the system causing considerable damage. Fortunately, no one was injured.

The operator adopted an expanded program of preventive maintenance to prevent explosions in the future. The steps included:

(1) Periodic washing of the air distribution system with 5 percent (by weight) solution of sodium hydroxide and sodium nitrite, with frequent checks of possible lubricant collection points made between washes. The chemical wash is designed to destroy oxidized residues in the lines.

(2) Careful checks for buildup of carbonaceous residues on discharge valves and cylinders during routine maintenance.

(3) Settings of high-temperature shut down switches lowered to activitate at 300°F and discharge pressure held at minimum levels.

(4) Elimination of mineral oil as cylinder lubricant in all air compressors.

Although explosions in compressed air systems are uncommon, they continue to happen. No *in situ* combustion project should be undertaken without first conducting a careful study of the potential hazards, and setting up a rigorous program of preventive maintenance to eliminate or reduce the possibility of such explosions.

## ANALYSIS AND SIGNIFICANCE OF ACTUAL PERFORMANCE

### Displacement and Sweep Efficiency

The recovery mechanism in underground combustion involves a variety of processes such as hot water drive, steam drive, hot gas drive, vaporization, miscible phase displacement, expansion and gravity drainage. Since the entire pay interval is never subjected to actual burning throughout the pattern, some of these processes will be active only in certain areas, but not in others. Accordingly, it is common to attempt to estimate the burned volume and to allocate recoveries to the burned and unburned portions of the pay. The oil displaced from the burned zone is calculated as the oil-in-place minus the oil consumed as fuel. Gates and Ramey (3) provided a useful approach by correlating volume percent burned *vs* oil displacement. Thus, the total oil displaced (from burned and unburned zones) will range from zero at zero percent burned up to oil-in-place minus fuel at 100 percent burned.

An attempt was made to correlate oil production in the Bellevue project using Gates and Ramey's method. This was done by applying the algorithm of Fassihi, *et al.* (4), for a series of different values of volume percent burned, and attempting to match the oil production, time, and air requirements experienced in the project.

The first trial used parameters obtained from combustion tube runs made by Cities Service (5). There is considerable variation in the data for fuel deposition ($C_f$) and air-fuel ratio (AFR); but as a first trial, the former was taken as 1.5 lb/ft$^3$ rock and the latter as 175 SCF/lb of fuel. These and other parameters used in the calculation are listed in Table 1 (Case A).

It became quickly obvious that these data led to anomalously high oil production. For example, the first year's oil production is more than six times the amount actually produced. After several attempts to reduce the oil and extend the time by increasing the fuel deposition and air-fuel ratio, it became clear that more drastic measures would be required. Accordingly, these values were set at 2.0 $lb/ft^3$ and 200 SCF/lb, respectively, as the highest reasonable values that are useful to consider and the oil-in-place and gas saturation were varied until the production at the end of the first year was matched. The values used are given in Table 1 (Case B).

The operator reported that the gas saturation was less than 3 percent and made calculations assuming it to be zero. It appears probable that the gas saturation was near zero prior to air injection. Field experience has shown, however, that injection of air into reservoirs containing highly viscous oil and water tend to develop gas (air) saturation at the expense of water saturation. Accurate determination of oil saturation is extremely difficult in these heavy oil reservoirs. It appears likely that the actual oil saturation may have averaged closer to 50 percent, rather than the 72.6 percent estimated by the operator. If it is assumed that the oil saturation was 54.0 percent and the water saturation prior to air injection was 46.0 percent and further, that preignition air injection produced a gas saturation of 18.6 percent, the first year's oil production can be matched by the calculation. Production data for the project prior to ignition (Figure 14, Reference 1) shows a producing water cut of about 95 percent, suggesting some mobile water was present. Moreover, Getty Oil Company, as operator of a large project in another part of this field, reported an average oil saturation of 52 percent (6).

When the calculations were extended to the oil production at the end of succeeding project-years, a new problem appeared (Table 1, Case B). By the end of the second year, the actual production lagged behind the calculated value by 48 percent, and by 46 percent as of the end of the third project year. It is difficult to accept that such a large volume of displaced oil was lost across lease lines, although the operator was aware of losses, and drilled nine wells to increase capture efficiency. Of course, the discrepancy would be worse if the lower fuel requirement and high oil saturation values of Case A are used. To gain some additional understanding, the actual volume burned was estimated from the diagnostic well data.

## Burned Volume

The burned volume was calculated by assuming that portions of the pay with a residual oil saturation of 5 percent or less had been burned. This is somewhat arbitrary since the oil saturation in burned sand should be zero. The value of 5 percent was chosen to allow for the fact that the sand would have to be brought to a very high temperature to reduce the saturation to 5 percent and because the saturation profiles were very difficult to read near zero saturation. Since high accuracy is not possible anyway, this was considered an acceptable approximation. Next, the net sand thickness with saturation of 5 percent or less was calculated for each diagnostic well and a contour map was drawn (Figure 7). The map was then planimetered to determine the volume of rock burned. This resulted in a burned volume estimate of 41 acre-feet, or 23 percent of the pattern volume.

Recently, the operator presented a paper (SPE 10766) at the California Regional meeting of the Society of Petroleum Engineers (7) in which the burned volume was estimated to be 49 percent. In arriving at this figure, a more sophisticated approach, involving extensive laboratory measurements was used. These included thermogravimetric analysis and differential scanning calorimetry as well as core and log analysis. Comparing the contour map of burned sand thickness presented as Figure 15 of SPE 10766 with our Figure 7 shows that our estimate is much more conservative than that of the operator. This may be due to several reasons including a more conservative definition of burned sand. Also, the operator's contours are drawn to include a larger sand volume for which there is no direct evidence of burning. Thus, the sand lying beyond the 15-foot contour in the northern sector of Pattern 15 is assigned a burned thickness between 10 and 15 feet. In our judgment, the saturation profiles given in the Fourth Annual Report (2) do not justify such thicknesses, but information unavailable to us may make such assignments more reasonable.

In considering what percentage of the reservoir volume was actually burned, four values have been taken into account: (1) 78.8 percent calculated from data in Table 5 of the Fourth Annual Report, (2) 23 percent estimated using the net burned sand isopach (Figure 7) as discussed above, (3) 55.6 percent based on the Gates and Ramey method for the volume of air actually injected (Table 1), and (4) 49 percent estimated by the operator. The result from the Fourth Annual Report seems much too high when compared with the data from the diagnostic wells, although the definition of "burned-over" reservoir allows considerable room for discussion. Also, the method of Gates and Ramey may not be totally applicable to the Nacatoch reservoir since their method was derived from data mostly from California reservoirs.

For the entire project area, assuming the starting oil saturation is 54 percent, the oil production may be expressed by

$$(1)\quad N_p = 1039 \times (1420 - \text{Fuel}) \times V_B / 100$$
$$+\ 1039 \times 1420 \times (1 - V_B / 100) \times ((S_{oi} - S_{or})/S_{oi})u - \text{Uncaptured Oil}$$

where 1039 is the bulk volume, $V_B$ = % of bulk volume burned, and $((S_{oi} - S_{or})/S_{oi})_u$ is the fractional recovery from the unburned zones. The fuel burned is estimated by making a Gates and Ramey calculation for 1 acre-foot and assigning a 100 percent volume burned. This gave a value of 249 BPAF for fuel.

SPE 10766 gives a value of 32 percent for the average residual oil saturation in the unburned zones. Applying equation (1), using $V_B = 49$, $S_{or} = 32$, $S_{oi} = 54$ and 249 BPAF for fuel and substituting the oil recovery of 667,609 barrels as of February 28, 1982, we have

$$1039 \times (1420 - 249) \times .49 + 1039 \times 1420 \times (1 - .49) \times ((54/32)/54)$$
$$- \text{Uncaptured Oil} = 667{,}609$$

which gives a value of 235,110 bbls. or 15.9% of oil-in-place for the uncaptured oil. Similar calculations were made for the other three values listed above. The results are shown below.

| Burned Volume, % of Bulk Volume | Estimated Loss, % of OIP |
|---|---|
| 49 | 15.9 |
| 23 | 5.0 |
| 78.8 | 28.4 |
| 55.6 | 18.7 |

SPE 10766 concludes that the capture efficiency is only 42.5 percent for Pattern 15, implying that 57.5 percent of the displaced oil is lost outside the pattern. This large quantity results from the assumption of an original oil-in-place of 1909 BPAF. All factors considered, it seems that reasonable values would be about 50 percent for the burned volume, 32 percent for the residual oil in the unburned zones and a corresponding loss of 16.4 percent.

Comments on Actual Sweep

Although there was premature breakthrough to Wells 12-2 and 15-2, as discussed previously, the behavior of the combustion process was close to that expected. The tendency for the combustion front to move to the top of the pay is demonstrated by the temperature profiles in the observation wells and by the oil saturation profiles in the diagnostic wells drilled in Pattern 15.

Figures 13 through 17 of the Fourth Annual Report (2) show that maximum temperatures tend to occur in the upper portions of the pay. In the case of Well 12-7, temperatures are much lower than they are in the other patterns, particularly those in Well 13-7. In fact, only in the latter well is there clear temperature evidence that the combustion zone traversed the well location. This is probably due primarily to the fact that Well 13-7 lies up-dip from the injection well. The combination of a north-south directional permeability trend and local formation dip to the north favors the movement of the combustion front towards the south (up-dip) and restrains its movement towards the north. For this reason, the operator located the injectors closer to the north line of the patterns.

More information was gained on the displacement process from the four diagnostic wells in Pattern 15. Because of the unconsolidated nature of the sand, particularly after the thermal process, conventional coring was not satisfactory. Rubber sleeve coring gave full recovery in two of the wells, however, and sidewall coring, used in one well, gave satisfactory results.

Saturation data for the four wells are presented in Figures 8 through 11 in the form of depth-saturation profiles. These show that the entire pay section had been burned out to a distance of 50 feet in the southwesterly direction (Figure 10), in general agreement with the observation well data in Pattern 13. The saturation profiles also reveal the tendency for the thermal process to move through the upper portions of the pay at greater distances from the injection wells. Thus, in Well 15-10 (100 feet to the northwest of the injector) several thin zones in the upper portion were reduced to near zero oil saturation while saturations in the lowest 13 feet remained above an average 40 percent (Figure 8). It was evident that some oil displacement had occurred in this zone, however, since the original saturation had been much higher.

The up-dip *vs* down-dip effect on the combustion process is shown by comparison of the saturation profiles of Wells 15-11 (Figure 9) and 15-13 (Figure 11). In the former, only a thin zone a few feet thick near the center of the pay had an oil saturation approaching zero even though this well is 50 feet closer to the injection well than is Well 15-13. The latter well contains a 25-foot zone near the center with no residual oil.

Both gravity and stratification appear to be involved at Well 15-13. Gravity segregation would explain the relatively high residual oil in the lower 30 feet. Also, the upper portion has not been as well stripped as the middle zone. This appears to be due to lower than average porosity (and permeability) than the zone at the middle. Thus, the fire apparently burned through the highest available path.

Evidence from the observation wells and the diagnostic wells is consistent with the expected tendencies for the gravity segregation in the combustion process. There was, however, no clear demonstration of the expected beneficial effect of water injection with air as far as improved sweep efficiency is concerned. More data on this idea would have been useful, and might have been obtained if there had been temperature profiles more clearly associated with dry *vs* wet combustion. Keeping the observation wells completely dry would have helped, and use of rubber sleeve coring on all the diagnostic wells would have been advisable.

It seems clear that the oil recovery at the completion of the project will be at least as good as was predicted. Some improvement might be possible by applying cyclic steam stimulation at the producing wells prior to the arrival of the combustion front. All things considered, however, it appears that the various aspects of channeling, gravity override, and so forth were anticipated and properly dealt with. The main shortcoming appears to have been loss of displaced oil outside the project; and the operator made a strong, though probably not completely successful, effort to cope with this problem.

It is instructive to examine the oil production response curves on an areal basis. Figure 12 shows the oil production curves of all the project wells superimposed on the structure map. This figure demonstrates qualitatively the effect of the position of the wells on the structure. Wells toward the lower left (top of structure) tend to give stronger responses than those toward the upper right. Some of the wells drilled late in the project to reduce loss of oil across the south boundary did not have a long enough producing history to give very much information, but the others show a very striking effect of location on structure. The full impact of this cannot be observed on the production curves of Figure 12 because the curves are plotted on a logarithmic vertical scale to conserve space on the map; and this flattens the curves, reducing the contrast between wells of good and poor response. To make comparisons on a semi-quantitative basis, a point scoring system was devised, rating response on a scale of 1 to 10 in each of the following categories: (1) early response, (2) cumulative oil at time of confirmed response, (3) cumulative oil at peak oil rate, and (4) cumulative oil from June 1, 1976, to February 28, 1982. Confirmed response was defined as the third of three successive months of increasing oil production. Each of these four categories was assigned a weight: 10% for (1), 20% for (2), 30% for (3), and 40% for (4). This recognizes the fact that wells where channeling may be a problem will respond quickly, but the response will not last long. Also, wells in thicker sections will tend to respond more slowly but give more oil in the longer run. Finally, the score was taken as the sum of the weighted scoring categories multiplied by 10 to give a maximum possible score of 100. The resulting values are listed in Table 2, along with the corresponding elevation of the sand top in each well above a 200' subsea datum and the net pay thickness.

The position of the wells on structure was compared with the quality of response by correlating the elevation of the sand top above a 200' subsea datum with the "quality of response" as defined above. Because the isopach map (Figure 2) and the structure map (Figure 3) are similar, it was possible that both would correlate with the response. Therefore, correlations were run for response vs position on structure and vs net pay thickness. Also, correlation of net pay thickness vs position of structure was calculated. The results of these correlations are tabulated below.

| Case | $r^2$ | r | Significance |
|---|---|---|---|
| 1) Resp. vs struct. pos. | 0.62 | 0.79 | < 0.01 |
| 2) Resp. vs. thickness | 0.44 | 0.66 | < 0.01 |
| 3) Struct. pos. vs thickness | 0.69 | 0.83 | < 0.01 |

These results show that a good correlation exists between response and structural position (Case (1)) and for structural position vs thickness (Case (3)). The correlation of response vs thickness is only fair. The probability that the r value could be obtained by chance is less than 1%. The correlation for Case (1) is interpreted to mean that the effect of position on structure is very strong, perhaps nearly dominant. The fact that the correlation with thickness is not strong, even though the thickness correlates well with position on structure, suggests that the thickness factor is probably acting in the opposite direction from the position on structure. Were it not for gravitational effects, responses should be quickest, but shortest-lived, in the portions of the sand toward the bottom, because the amount of sand to be traversed would be smaller in the thinner portions. The tendency for the combustion zone to move up-structure due to gravity segregation may offset the faster movement in the thinner portions, so it will be very difficult to predict what the net effect will be. Reservoir simulation, using a sophisticated in situ combustion model, might provide some useful conclusions regarding these competing effects. Such simulation is beyond the scope of this report. The most important conclusion to be drawn at this time is that the response appears to be very sensitive to these physical reservoir characteristics, emphasizing the importance of an awareness of all facets of the reservoir description in designing and operating a project of this type. In any future projects in similar reservoirs, it would be highly desirable to run such simulations and use the results to optimize the pattern configuration and injection schedule.

## Summary of Overall Project Performance

Careful study of this project leads to the conclusion that the operator should be commended for having devoted considerable effort to the design and operation of the project. The results show that very little was left to chance, and that virtually all difficulties were foreseen and strong efforts made to deal with them.

Since the oil recovery appears to be headed for the level forecasted and the costs have been held fairly close to the projected amount, it is clear that the process is economically applicable to reservoirs of this type when the economic and regulatory climate is favorable. Detailed economics are discussed in the next section.

Technology for in situ combustion is relatively mature. Most advances were made in the period from the late fifties to the early seventies. The most important tasks in its further application are to make certain that adequate reservoir description (including oil-in-place) and reservoir engineering design are performed. Since economic trends and government policies are highly uncertain, these may overwhelm even the best available technology and cause a favorable reservoir to be the site of an economically unsuccessful project.

Four areas of work which should be pursued are:

(1) More careful estimation of the fluid saturations in the reservoir.

(2) Refinement of laboratory combustion parameters. The reported data show so much scatter that useful trends may have been masked.

(3) In situ combustion process simulation of the reservoir. Simulation studies using a model which permits gravitational effects should permit the design of a project to be optimized with respect to the well configuration and the injection schedule, and should minimize loss of oil outside the project boundaries.

(4) Consideration of cyclic steam stimulation to aid production of heavy oil prior to arrival of heat from the combustion zone.

## ECONOMIC ANALYSIS

Four economic cases were run.

(1) Actual performance -- oil prices and all costs actually incurred.

(2) Potential performance -- same as (1) except excluded R&D costs and diagnostic wells.

(3) Hypothetical case -- assumed the same inputs as (1) except costs were projected into the future to simulate the same project beginning in 1982 instead of 1976.

(4) Modified hypothetical case -- same as (3) except excluded R&D costs and diagnostic wells.

The basis of the input data for the economics is discussed below.

Investments: Wells and Surface Facilities - In developing the five inverted 9-spot patterns which constituted this project, initial investments were made in three evaluation wells, five injection wells, twenty-nine production wells, five temperature observation wells and one salt water disposal well. The three evaluation wells were included in this category because they were completed and used in the project. Additional investments were made in surface facilities for air compression and injection, water injection, tank battery modifications for emulsion treating, and exhaust gas handling. An investment was made in the second year to replace an injection well which had suffered a casing failure, apparently due to excessive heat during ignition. Also electrification costs were required for one of the compressors which had been powered by natural gas. A projected shortage of gas was the reason for this expenditure.

The only other investment costs were for nine new producers drilled along the south lease boundary to minimize losses of oil across the lease line. These and other depreciable investments are shown in Tables 3 and 4.

It should be noted that the four evaluation (diagnostic) wells were drilled, cored, and logged in the fourth year, but only one of these, Well 15-13, was completed; the others were plugged and abandoned without completing them. All four of these were added to the operating costs of the fourth year*.

The intangible drilling costs are also listed in Tables 3 and 4. Note that the disposal well is not entitled to intangible drilling cost expensing and the entire cost of all surface facilities is depreciable.

Operating Costs - Tables 3 and 4 also show the operating costs associated with the combustion project. These included all the usual lease operation

*The fact that Well 15-13 was completed as a producer and began operating in July, 1981, came to our attention after the economic calculations were completed. The economics were not rerun because the effect of the late change in the status of this well would be negligible.

and maintenance costs as well as the costs of compressor operation and maintenance. Since air and water were the only fluids injected, no injectant costs are listed as such.

Along with direct lease expenses, the operator includes costs for Louisiana severance taxes, producing well overhead, Exploration and Production Services, Research Services, depletion and depreciation, and beginning in 1981, "Decontrol ('Windfall Profits') Tax". Since the economics program used in this analysis calculates severance taxes, depletion, depreciaton, and "Decontrol Tax" internally, these items were omitted from the costs input to the program. Overhead costs tend to be highly variable from one operator to another. These are identified clearly to permit a prospective user of the data in this report to evaluate his own particular costs in the context of this study. R&D and Exploration and Production Services reflect the costs of performing a highly sophisticated recovery technique and represent manpower charges to the project for activities of the operator's R&D and regional offices. These might be reduced to some degree in a "routine" commercial project, as discussed later.

The values shown in Tables 3 and 4 were calculated from monthly cost reports furnished by the operator. It is difficult to relate these to the tabulations in the annual reports because the latter were for irregular periods and the breakdown of the costs differed in some respects. For the purposes of economic analysis, the annual values shown are most convenient and, accordingly, were used in this study.

Since there will be oil to recover after the official project completion date, the economics were run assuming that the operations would continue through June 30, 1983. This required estimates to be made for oil production, oil prices and operating costs. Oil production was estimated from the decline curve as discussed previously. Oil prices have been on a downward trend for several months, and projections are that they will continue the decline until the current oversupply is alleviated. For Cases (1) and (2), it was assumed that prices would decline from the February, 1982, level at a 5 percent per year rate for the remainder of the project. Figure 13 shows the oil price trend for the life of the project.

Operating costs are particularly difficult to forecast. It would be expected that with the cessation of air injection the operating costs would drop sharply. This did not occur, however, because when the waterflooding phase began, it was necessary to reperforate the wells to open them across the entire pay. Figure 14 shows the trend of direct lease expenses over the life of the project. It will be noted that the <u>trend</u> has flattened out during the past two years, although there have been some large changes in the cost level. It is assumed that with continued waterflooding (heat scavenging), these costs will stabilize at a level of $57,000 per month as of February, 1982, and will escalate at a rate of 5 percent per year from that level.

The other operating expenses were estimated for 1982 by rounding off values for the preceding year. These, in turn, were used as the basis for the estimate for 1983 by escalating one-half of the 1982 amounts (for the six month period of 1983) at 5 percent per year.

## Actual vs Potential Performance

Case (1), which represents the economics of the project as actually performed, was for a commercial scale operation, but included considerable research surveillance, presumably because this was also a demonstration project. In a larger, more routine operation, some of the research activities would probably be eliminated and it is unlikely that diagnostic wells would be drilled. Accordingly, an attempt was made to identify those costs which would not be included in a routine commercial operation so that the economics could be examined on a purely commercial basis. Unfortunately, the R&D costs were not itemized in the reports, and it would require a considerable expenditure of time by the operator to furnish the itemized information necessary to decide which R&D activities would be needed in a routine commercial project. The R&D costs were not very large, so Case (2), excluding them (and diagnostic well costs) completely, was run to furnish an upper limit for the profitability indicators. No operational or design changes were assumed. This project appeared to be operated at close to "the state of the art" and the only way to incorporate such changes would be to make arbitrary assumptions for increased oil recovery (for example, by improved capture efficiency) or reduced costs. Neither of these approaches seemed realistic, so no such changes were explored.

The Bellevue project was carried out during a period of steeply escalating oil prices. The situation has changed markedly during 1981-82, and an operator considering a similar project would face steady, or slightly declining oil prices and continued escalation of costs. Cases (3) and (4) were run in an attempt to investigate these effects. This was done by comparing 1982 costs estimated by the operator with those actually incurred in the project. It was found that the increase varied fairly widely depending on the category of cost, but was roughly doubled from 1976 to 1982. For the purposes of this report, it was considered adequate to assume that the doubling in six years (12.25%/year) would illustrate the point being made. Thus, costs in 1976 were assumed to have been incurred in 1982 at twice the 1976 level. Costs in 1977 were escalated for five years at 12.25%/year and then one year at 8%/year; those in 1978 for four years at 12.25% and then two years at 8%/year, and so on. Oil prices were assumed to be constant at $30/bbl for the duration of the project. Case (4) was the same as Case (3) except that R&D and diagnostic well costs were eliminated.

Table 5 presents a comparison of the results of the four economic cases and Figure 15 shows the present worth profiles. Since Cities Service is a major oil company, the calculations are made from the viewpoint of a major. The economics are on a before Federal income tax basis and the results for an independent would not be greatly different. All of the results indicate attractive economics, with average annual rate of return (AARR) ranging from 40 to 67 percent, and present worth of the (10% discounted) cash flow from $1.25 to $2.2 million. The effect of eliminating the R&D and diagnostic well costs was about 8-10% in AARR. The most significant differences were in the economic life. The combination of rising costs and decreasing oil production in later years caused the cash flow to go negative, cutting off the project to avoid losses. The result was a significant reduction in oil recovery amounting to more than 42,000 bbl (about 6% of prediction) in the best case, and 203,000 bbl (29%) in the worst case. For an isolated project, the negative cash flow would lead to abandonment, but in the Bellevue Field, the operator will probably continue to produce at least some of the wells for a while longer, grouping them with others in expansion areas of the field.

## CONCLUSIONS

1. The Bodcau In Situ Combustion Project was both technically and economically successful, paying out quickly, providing an attractive return on invested capital, and leading to plans for expansion.

2. Although simultaneous air and water injection was conducted, segregation took place so that the performance was more characteristic of dry combustion than wet combustion. Thus, the question of the optimum water/air ratio could not be answered.

3. The limiting factor in the oil production rate was the capture of displaced oil, not the injectivity.

4. As expected, gravity override occurred causing the combustion zone to move through the upper portions of the reservoir.

5. Channeling was not a severe problem, but high operating costs were incurred due to the necessity of repeatedly squeezing off zones through which the combustion front penetrated to the producers. This caused considerable down-time and allowed a significant amount of oil to be lost outside the pattern.

6. The original oil saturation is probably closer to 50-55 percent, rather than 72.6 percent as reported by the operator.

7. The economics were significantly enhanced by the fact that the project was conducted during a period of rapidly escalating oil prices. The same project, conducted under current economic conditions would be commercially feasible, the economic life would be shortened and less oil recovered before the economic limit would be reached.

8. Areas where more research effort is needed include more sophisticated combustion tube runs, combustion simulation to optimize the pattern configuration and injection schedule, more careful estimation of the original oil saturation, and possibly cyclic steam stimulation of producers might be considered.

9. More careful attention to the conditions in the observation wells would provide additional useful data.

10. Before starting an in situ combustion project, a careful study should be made of all hazards involved in compressing and injecting air, and a rigorous program of preventive maintenance should be set up to eliminate the possibility of explosion in the compressed air system.

### General Comment

The main purpose of this study was to identify areas in which technical advances have been made and where additional advances are needed. It is hoped that statements made and conclusions drawn in this report will be interpreted in this light, and not regarded as negative comments on the operation of the project. The project was well-designed and operated. The results will be extremely useful to other operators in evaluating their reservoirs for this recovery process.

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TABLE 1.

GATES & RAMEY CALCULATIONS VS FIELD DATA

| Cum[1] Time Days | Cum. Air Injected MMSCF | Ave. Injection Rate MSCFD[2] | FIELD DATA[3] Cum. Oil Recovery BBL | FIELD DATA[3] Cum AOR MSCF/BBL | CALCULATED[4] CASE A Vol % Burned | CALCULATED[4] CASE A Cum Oil | CALCULATED[4] CASE A Cum AOR | CALCULATED[4] CASE B Vol % Burned | CALCULATED[4] CASE B Cum Oil | CALCULATED[4] CASE B Cum. AOR |
|---|---|---|---|---|---|---|---|---|---|---|
| 365 | 1,842.332 | 5047.48 | 102,192 | 18.03 | 15.50 | 624,556 | 2.95 | 10.18 | 102,882 | 17.91 |
| 730 | 4,435.501 | 6076.03 | 280,245 | 15.83 | 37.35 | 1,154,526 | 3.84 | 24.50 | 415,723 | 10.67 |
| 1,095 | 6,883.359 | 6286.17 | 433,784 | 15.87 | 57.93 | 1,483,077 | 4.64 | 38.03 | 631,662 | 10.90 |
| 1,461 | 9,096.732 | 6226.37 | 562,623 | 16.17 | 76.60 | 1,703,359 | 5.34 | 50.25 | 790,405 | 11.51 |
| 1,734[5] | 10,070.020 | 5807.39 | 627,169 | 16.06 | 84.76 | 1,767,355 | 5.70 | 55.63 | 835,732 | 11.80 |

[1]Starting 7-31-76
[2]Cum. Average
[3]From Computer Print-Out Furnished by Cities Service
[4]Method of Gates and Ramey(2)

Data Used in Calculations:

| | Case A | Case B |
|---|---|---|
| Fuel Deposition, Lb/Ft$^3$ | 1.5 | 2 |
| Air/Fuel Ratio, SCF/Lb Fuel | 175 | 200 |
| Gas Saturation, % | 0 | 18.6 |
| Oil Content, BPAF | 1,909 | 1,420 |
| Pattern Bulk Vol., Acre-Ft | 1,039 | 1,039 |

[5]END OF AIR INJECTION

TABLE 2

DATA FOR CORRELATION OF PRODUCTION RESPONSE

| WELL NO. | RESPONSE SCORE | HT. ABOVE DATUM** | NET PAY FT. |
|---|---|---|---|
| 2-3 | 72 | 67 | 61 |
| 2-4 | 78 | 77 | 63 |
| 2-5 | 67 | 83 | 67 |
| 2-8 | 85 | 92 | 56 |
| 12-2* | - | - | - |
| 12-3 | 69 | 55 | 55 |
| 12-4 | 79 | 72 | 62 |
| 12-5 | 66 | 89 | 56 |
| 12-6 | 86 | 87 | 65 |
| 12-8* | - | - | - |
| 12-9* | - | - | - |
| 13-2 | 50 | 58 | 55 |
| 13-3 | 46 | 53 | 58 |
| 13-4 | 66 | 67 | 62 |
| 13-5 | 73 | 83 | 67 |
| 13-6 | 73 | 88 | 66 |
| 13-8* | - | - | - |
| 13-9* | - | - | - |
| 14-2 | 52 | 46 | 47 |
| 14-3 | 25 | 37 | 39 |
| 14-4 | 60 | 56 | 55 |
| 14-5 | 71 | 73 | 68 |
| 14-6 | 73 | 75 | 64 |
| 14-8* | - | - | - |
| 15-2* | - | - | - |
| 15-3 | 31 | 35 | 38 |
| 15-4 | 45 | 49 | 47 |
| 15-5 | 59 | 59 | 61 |
| 15-6 | 68 | 69 | 60 |
| 15-8* | - | - | - |
| 15-9* | - | - | - |
| 16-2 | 34 | 36 | 39 |
| 16-3 | 56 | 29 | 19 |
| 16-4 | 66 | 41 | 46 |
| 16-5 | 64 | 49 | 49 |
| 16-6 | 63 | 57 | 56 |
| 16-8* | - | - | - |
| 16-9* | - | - | - |
| 15-13* | - | - | - |

* WELLS WITH INSUFFICIENT DATA

** DATUM = 200' SUBSEA

TABLE 3.

ANNUAL COSTS, BELLEVUE IN SITU COMBUSTION

1976 STARTING POINT

| Item | 1976 | 1977 | 1978 | 1979 | 1980 | 1981 | 1982 | 1983 |
|---|---|---|---|---|---|---|---|---|
| DEPRECIABLES | | | | | | | | |
| Wells, Tangible | | | | | | | | |
| Evaluation Wells | 10,301.81 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Development Wells | 216,648.33 | 4,434.33 | 30,953.18 | 39,958.21 | 1,976.66 | 0 | 0 | 0 |
| Observation Wells | 2,972.39 | 10,140.20 | 0 | 0 | 0 | 0 | 0 | 0 |
| Disposal Well | 15,118.47 | 417.51 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal | 245,041.00 | 14,992.04 | 30,953.18 | 39,958.21 | 1,976.66 | 0 | 0 | 0 |
| Surface Facilities | 436,018.43 | 37,832.05 | 26,316.40 | -37.14 | 0 | 0 | 0 | 0 |
| Total Depreciables | 681,059.43 | 52,824.09 | 57,269.58 | 39,921.07 | 1,976.66 | 0 | 0 | 0 |
| INTANGIBLE DRILLING COSTS | | | | | | | | |
| Evaluation Wells | 26,457.45 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Development Wells | 498,834.94 | 10,210.07 | 71,270.01 | 92,004.16 | 4,551.27 | 0 | 0 | 0 |
| Observation Wells | 6,844.97 | 23,346.91 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total I.D.C. | 532,137.36 | 33,556.98 | 71,270.01 | 92,004.16 | 4,551.27 | 0 | 0 | 0 |
| OPERATING EXPENSES | | | | | | | | |
| Direct Lease Expenses | 126,769.53 | 535,217.56 | 765,226.67 | 798,970.77 | 1,010,577.98 | 818,526.52 | 687,000.00 | 361,000.00 |
| Diagnostic Wells | 0 | 0 | 0 | 0 | 3,238.30 | 146,657.59 | (5,687.14) | 0 |
| E&P Services | 97,871.29 | 134,606.38 | 140,194.50 | 133,178.94 | 103,386.06 | 98,183.48 | 100,000.00 | 51,200.00 |
| Research Services | 34,276.45 | 103,797.53 | 54,182.54 | 32,926.22 | 45,600.65 | 23,938.16 | 25,000.00 | 12,800.00 |
| CSC Overhead | 69,200.00 | 186,408.00 | 209,595.96 | 239,031.66 | 282,808.84 | 337,969.68 | 300,000.00 | 154,000.00 |
| Total OP Exp. | $328,117.27 | $960,029.47 | $1,169,199.67 | $1,204,107.59 | $1,445,611.83 | $1,425,275.43 | $1,106,312.86 | $579,000.00 |
| Total Less R&D & Diag. Wells | $293,840.82 | $856,231.94 | $1,115,017.13 | $1,171,181.37 | $1,396,772.88 | $1,254,678.68 | $1,087,000.00 | $566,200.00 |

NOTES:
(1) 30.28% of Well Costs Allocated To Depreciables; Remainder To IDC Except Disposal Wells (100% Depreciable) & Diagnostic Wells (Expensed)
(2) Evaluation Wells Included In These Costs Were Completed & Used In Project.
(3) Development Wells Are Injection & Production Wells.
(4) Surface Facilities Include Air Injection System, Water Systems, Tank Battery, Compression Facilities & Casing Exhaust System.
(5) Direct Lease Expenses Include Materials, Chemicals, Labor, Utilities & Well Service But Exclude Severance Tax, Depreciation & Depletion & WP Tax
(6) Diagnostic Wells Drilled, Cored & Logged Then P & A.
(7) All Costs After 12-31-81 Are Estimated
(8) 1983 Costs Are For Period 1-1-83 To 6-30-83

TABLE 4.

ANNUAL COSTS, BELLEVUE IN SITU COMBUSTION

PROJECTION TO 1982 START

| ITEM | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 | 1989 |
|---|---|---|---|---|---|---|---|---|
| DEPRECIABLES | | | | | | | | |
| Wells, Tangible | | | | | | | | |
| Evaluation Wells | 20,600 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Development Wells | 433,400 | 8,500 | 57,300 | 71,200 | 3,400 | 0 | 0 | 0 |
| Observation Wells | 6,000 | 19,500 | 0 | 0 | 0 | 0 | 0 | 0 |
| Disposal Well | 30,200 | 700 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal | 490,200 | 28,700 | 57,300 | 71,200 | 3,400 | 0 | 0 | 0 |
| Surface Facilities | 872,200 | 72,800 | 48,700 | - 66 | 0 | 0 | 0 | 0 |
| Total Depreciables | $1,362,400 | $101,500 | $106,000 | $71,134 | $3,400 | 0 | 0 | 0 |
| INTANGIBLE DRILLING COSTS | | | | | | | | |
| Evaluation Wells | 52,900 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Development Wells | 997,900 | 19,700 | 132,000 | 163,900 | 7,800 | 0 | 0 | 0 |
| Observation Wells | 13,700 | 44,900 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total IDC | $1,064,500 | $64,600 | $132,000 | $163,900 | $7,800 | 0 | 0 | 0 |
| OPERATING EXPENSES | | | | | | | | |
| Direct Lease Expense | 253,600 | 1,030,100 | 1,417,000 | 1,423,500 | 1,732,400 | 1,350,000 | 1,090,200 | 595,300 |
| Diagnostic Wells | 0 | 0 | 0 | 0 | 5,600 | 241,900 | - 9,000 | 0 |
| E & P Services | 195,800 | 259,100 | 260,000 | 237,300 | 177,200 | 161,900 | 158,700 | 84,400 |
| Research Services | 68,600 | 200,000 | 92,900 | 58,700 | 78,200 | 39,500 | 40,000 | 21,100 |
| CSC Overhead | 138,400 | 358,800 | 388,100 | 425,900 | 484,800 | 557,400 | 476,100 | 254,000 |
| Total Operating Exp. | $656,400 | $1,848,000 | $2,158,000 | $2,145,400 | $2,478,200 | $2,350,700 | $1,756,000 | $954,800 |
| Total Less R&D & Diag. Wells | $587,800 | $1,648,000 | $2,065,000 | $2,086,700 | $2,394,400 | $2,069,300 | $1,725,000 | $933,700 |

All costs assumed to increase 12.25%/year from 1976 to 1982 and then increase at 8%year. i.e. $P = Po \times (1.1225)^m \times (1.08)^n$

Where m = no. yrs. since 1976

n = no. yrs. since 1982

e.g. If an expenditure cost $10,000 in 1976 it would cost $10,000 \times (1.1225)^6$ in 1982. An expenditure of $10,000 in 1979 would be $10,000 \times (1.1225)^3 \times (1.08)^3$ in 1985.

i.e. Each year's costs were moved 6 years into the future.

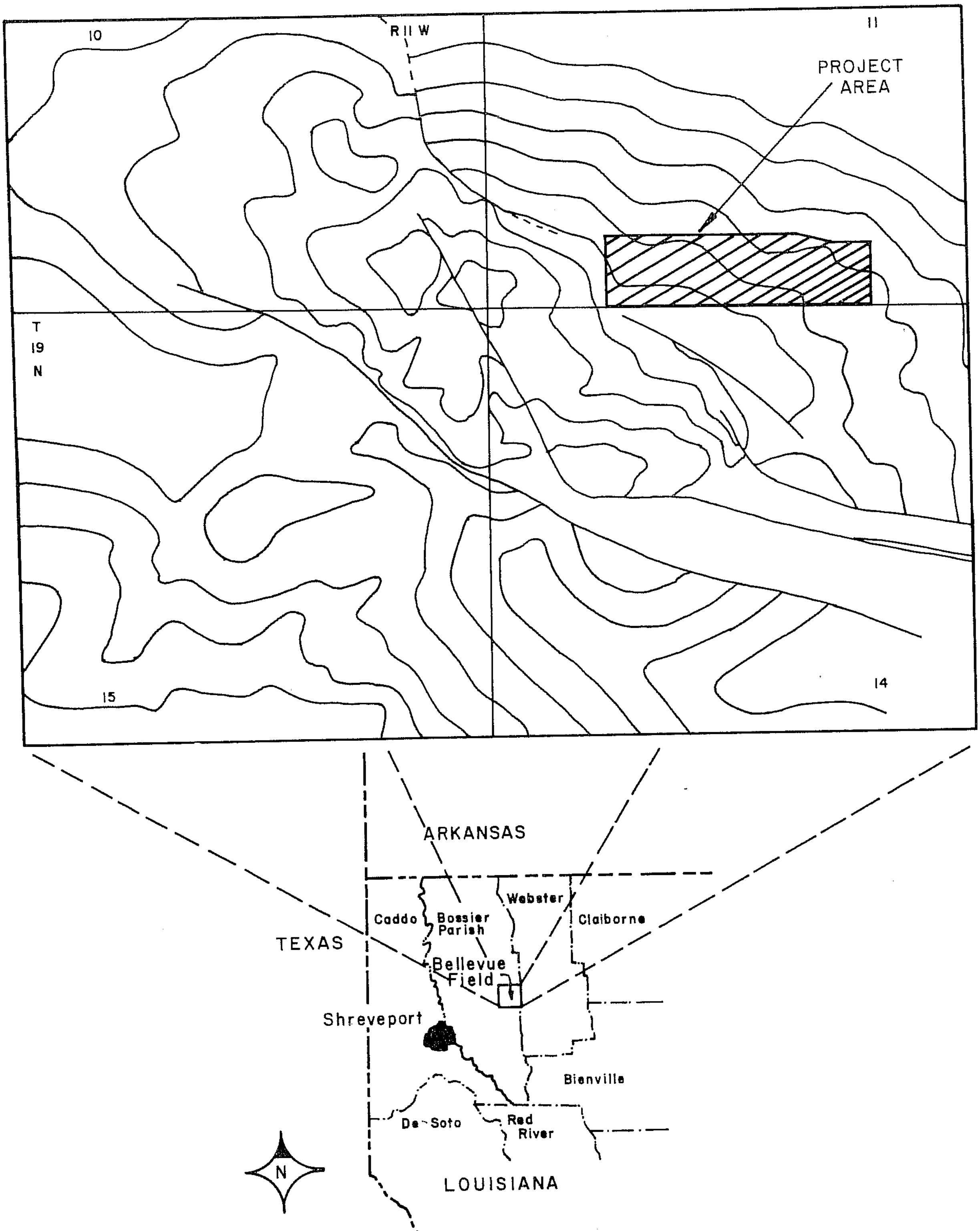
TABLE 5

COMPARISON OF ECONOMIC CASES

| | Case (1) | Case (2) | Case (3) | Case (4) |
|---|---|---|---|---|
| Project Economic Life, Years | 4.58 | 5.58 | 3.58 | 3.58 |
| Gross Oil Produced, BBL | 608,265 | 665,367 | 504,326 | 504,326 |
| Payout (Disc @ 10%), Years | 2.8 | 2.6 | 2.4 | 2.2 |
| Present Worth of Cash Flow (Disc @ 10%) | $1,830,950 | $2,195,364 | $1,258,305 | $1,597,511 |
| Ave. Ann. Rate of Return, % | 59 | 67 | 40 | 50 |

Case (1) As Actually Performed (1976-83)
Case (2) Same As Case (1) Except Excludes R&D & Diag. Well Costs
Case (3) Case (1) Projected to Period 1982-89
Case (4) Same As Case (3) Except Excludes R&D & Diag. Well Costs

FIGURE 1

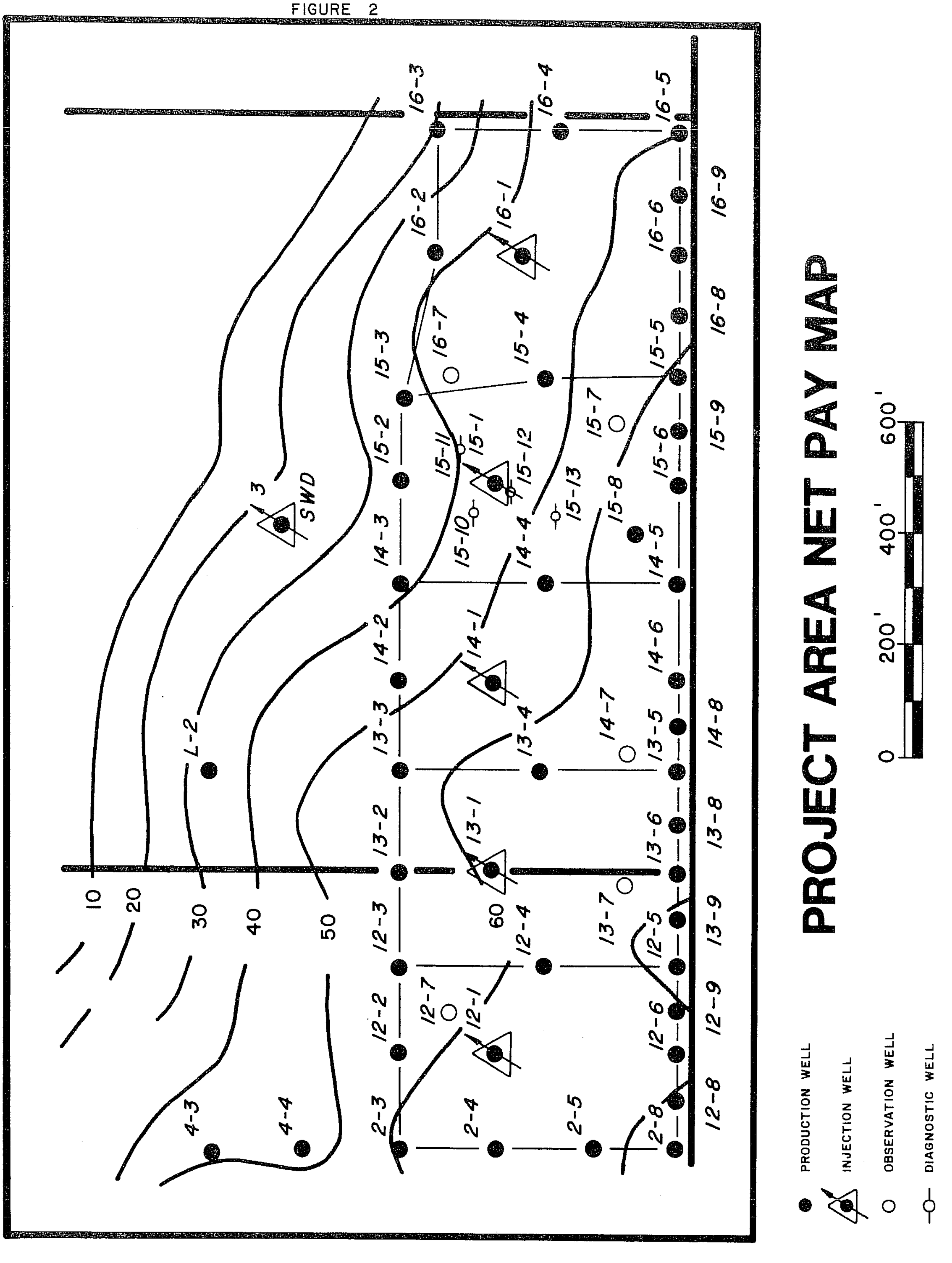



General Location Map

BELLEVUE FIELD

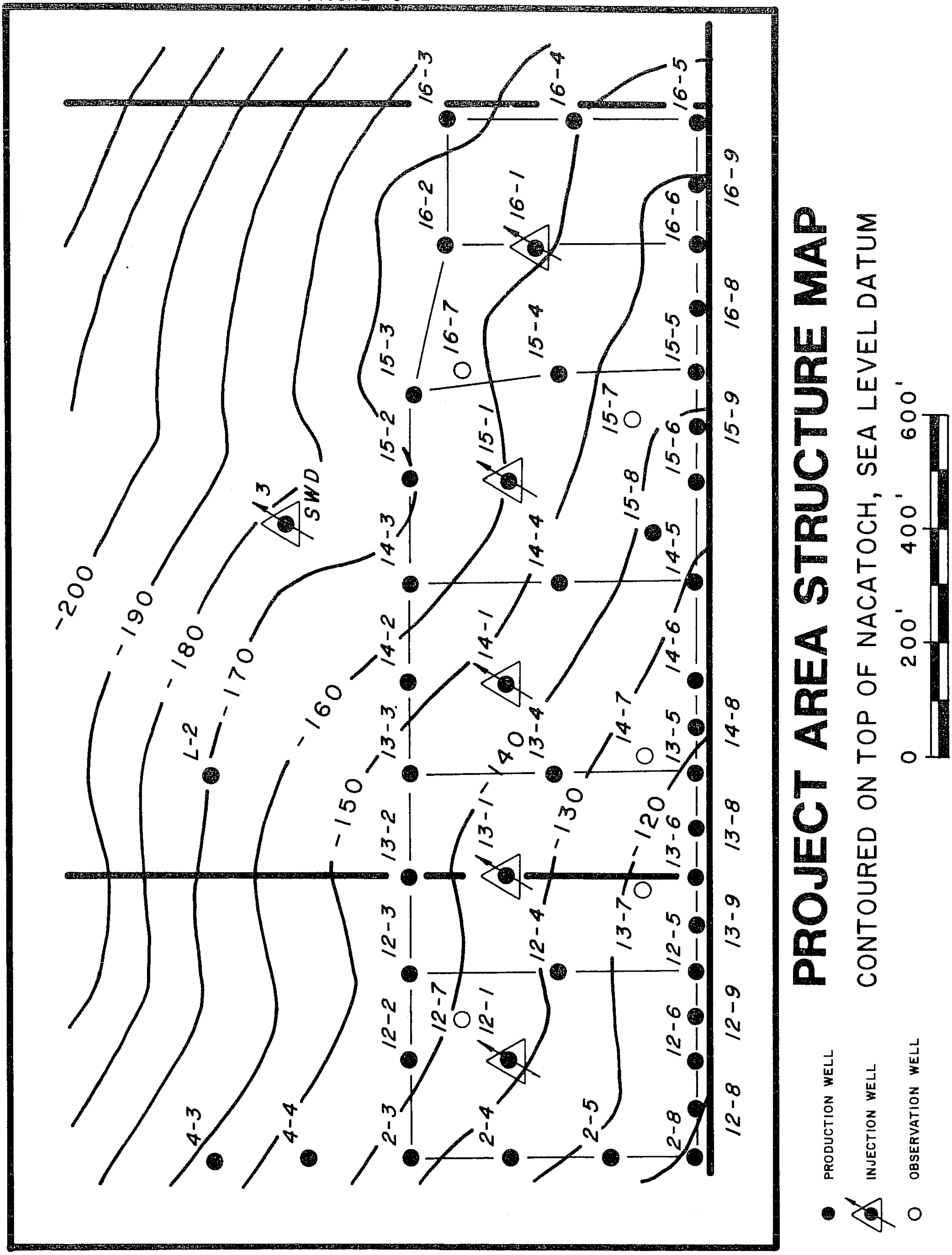
Bossier Parish, Louisiana

FIGURE 2




PROJECT AREA NET PAY MAP

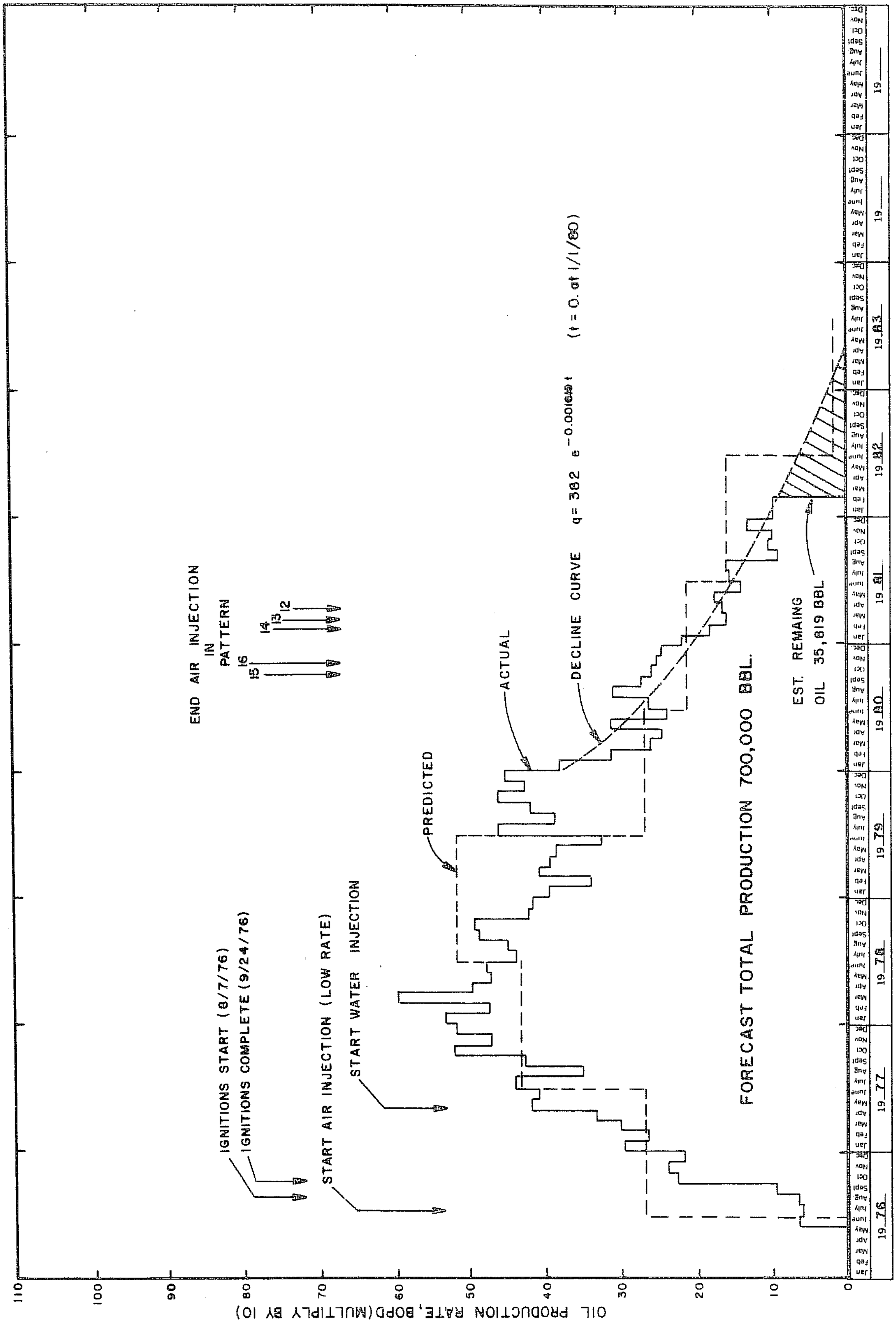
FIGURE 3




**PROJECT AREA STRUCTURE MAP**

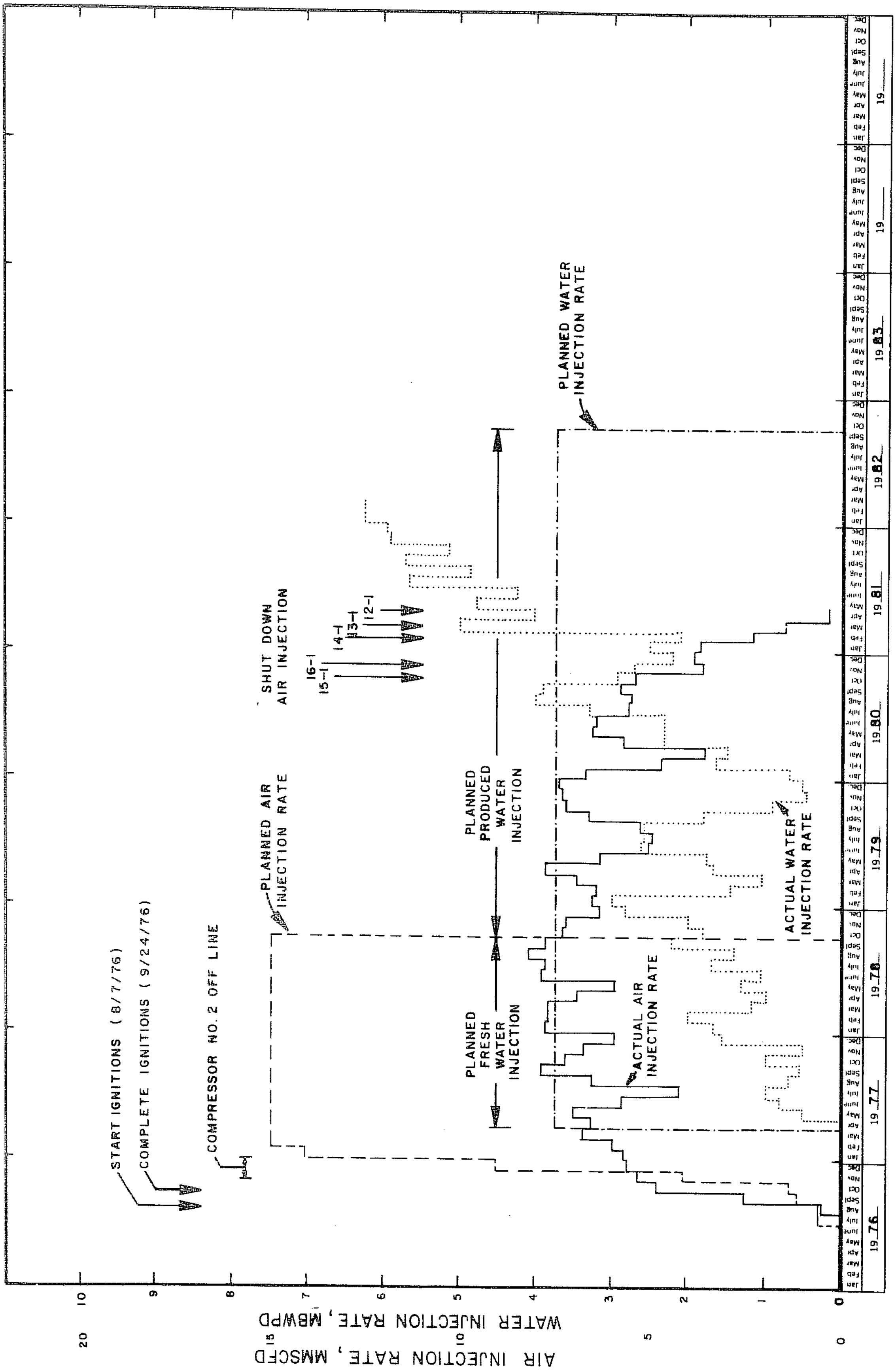
CONTOURED ON TOP OF NACATOCH, SEA LEVEL DATUM

FIGURE 4



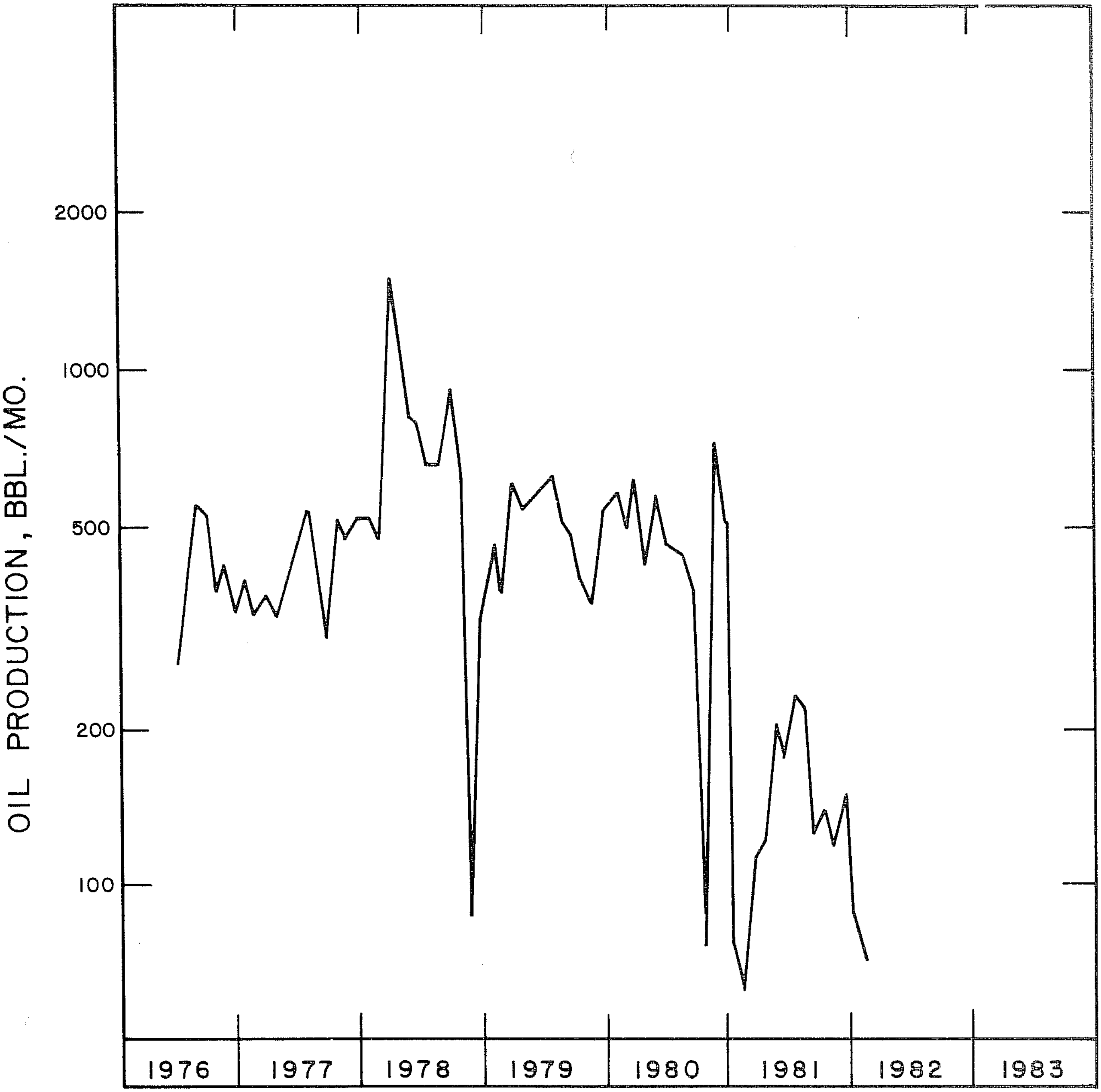

BELLEVUE PROJECT ACTUAL vs PREDICTED OIL PRODUCTION

FIGURE 5



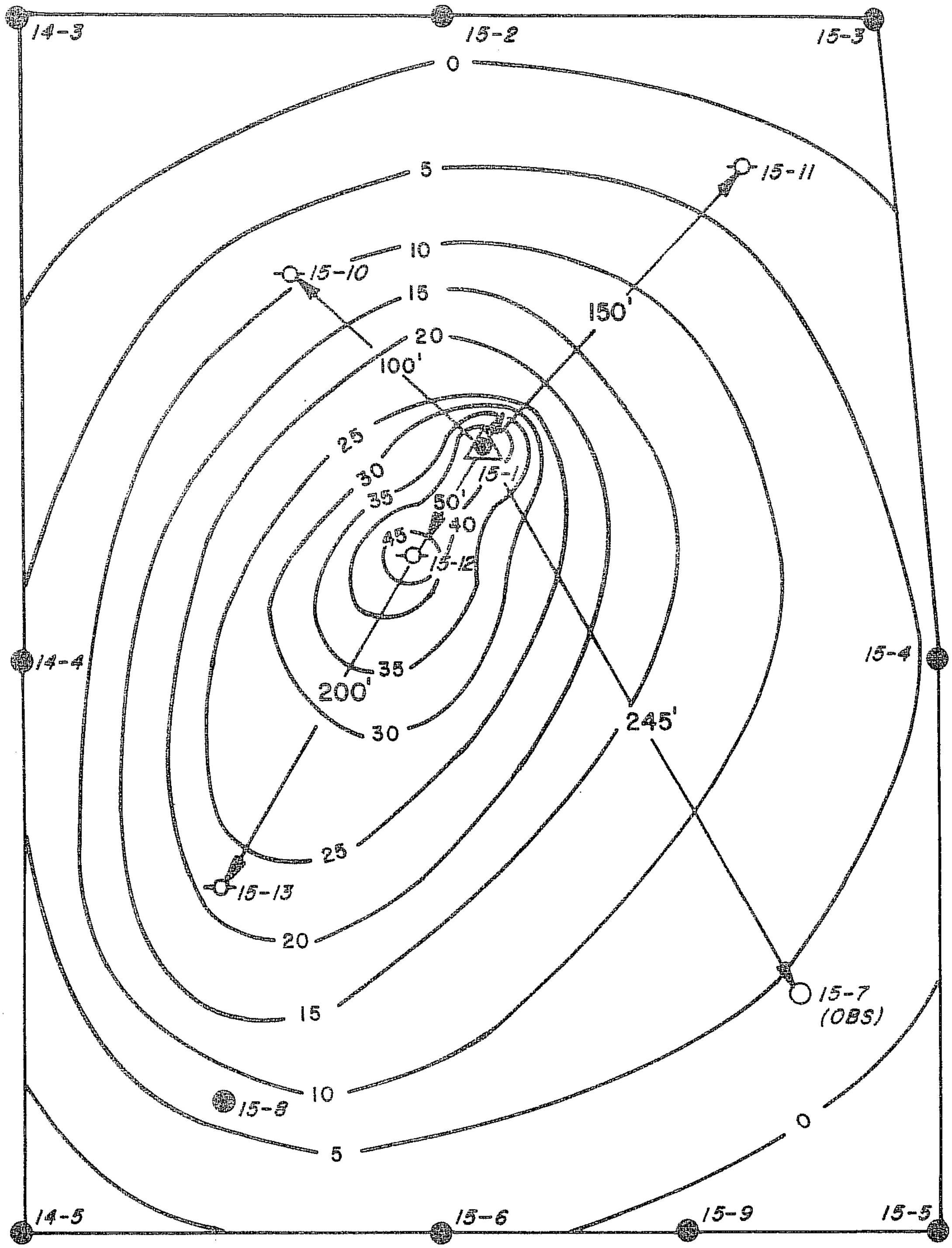

BELLEVUE IN SITU COMBUSTION INJECTION PERFORMANCE

FIGURE 6



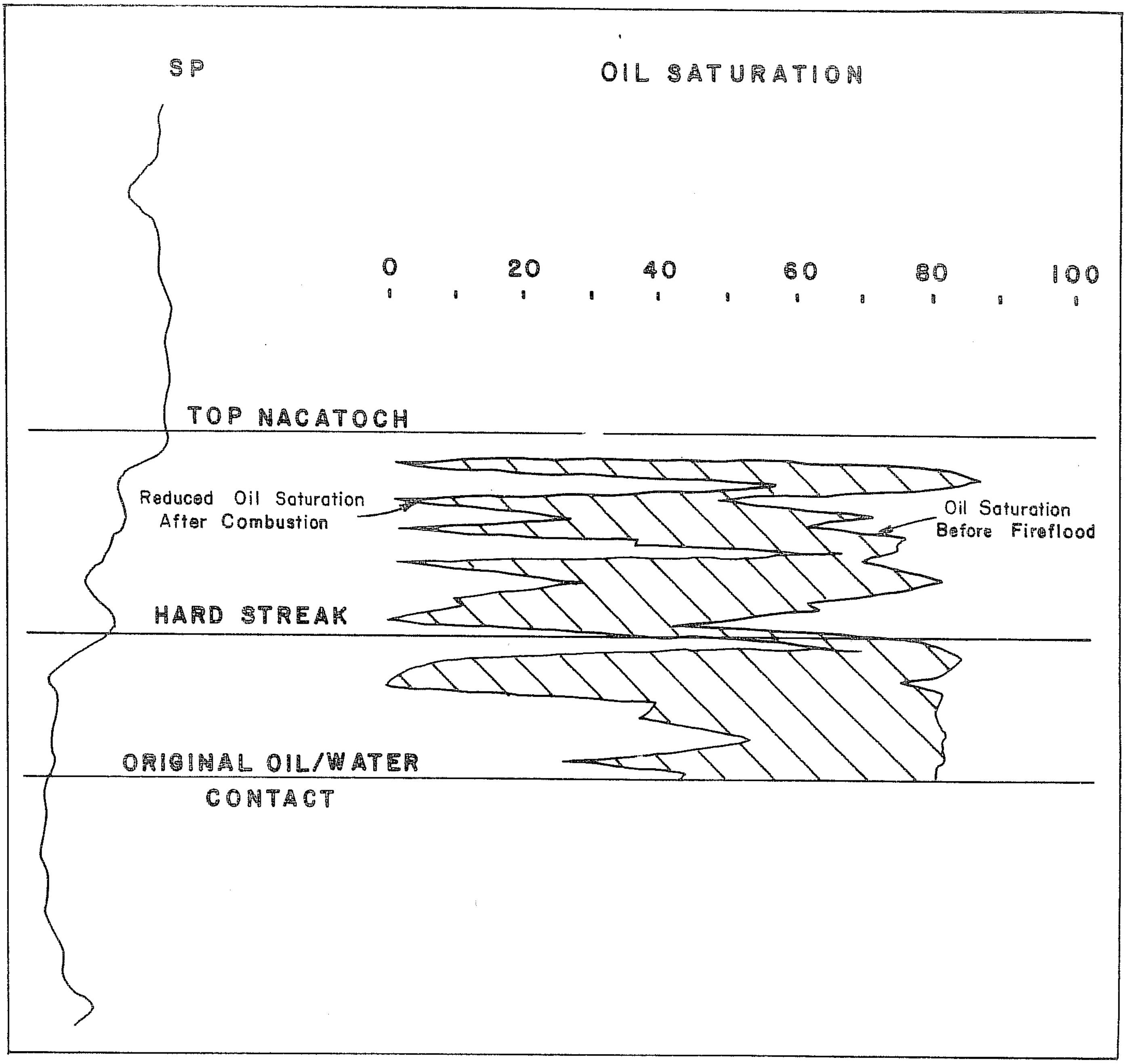

OIL PRODUCTION, WELL 12-6

FIGURE 7



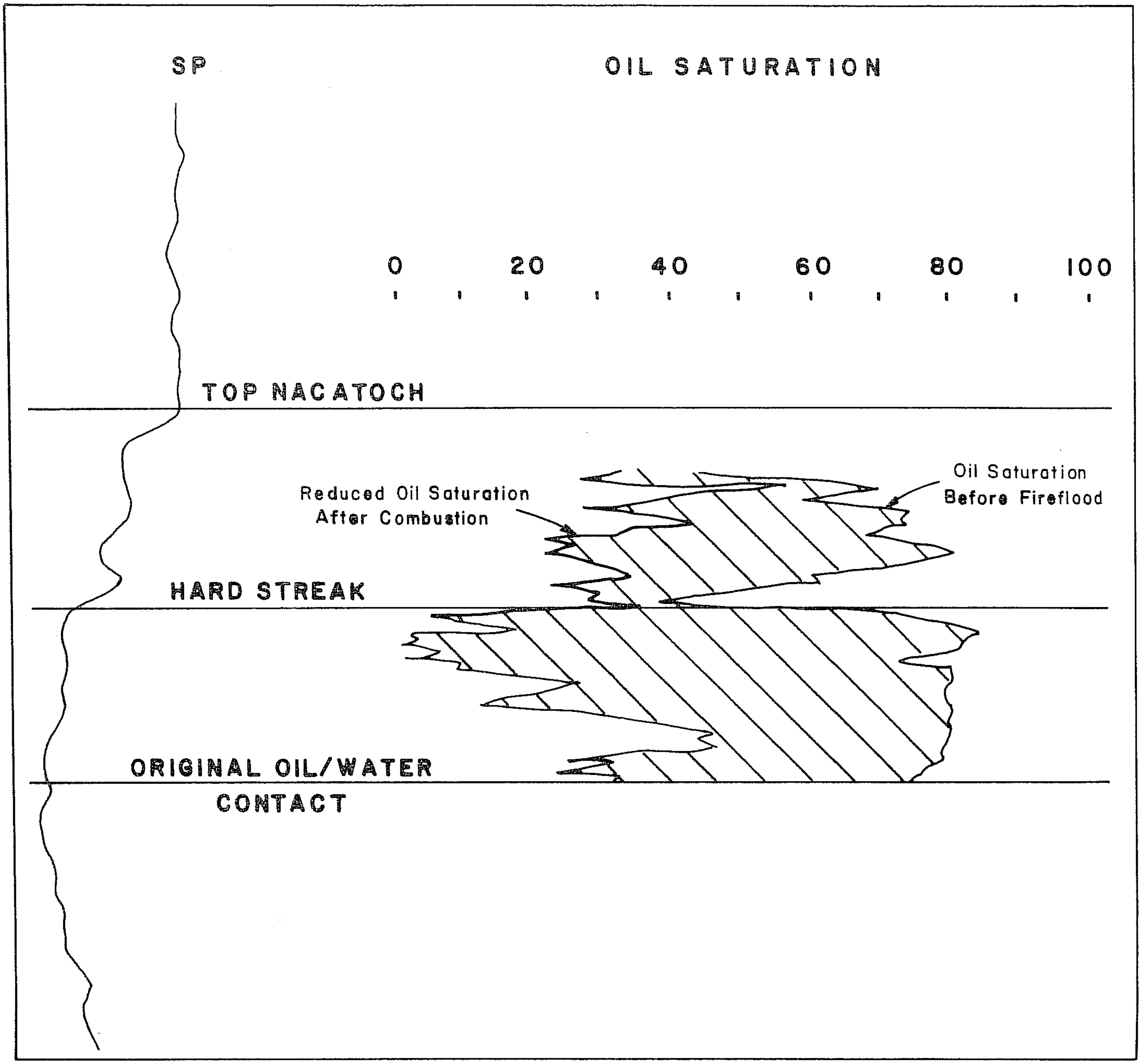

ISOPACH OF NET BURNED SAND
PATTERN 15

FIGURE 8



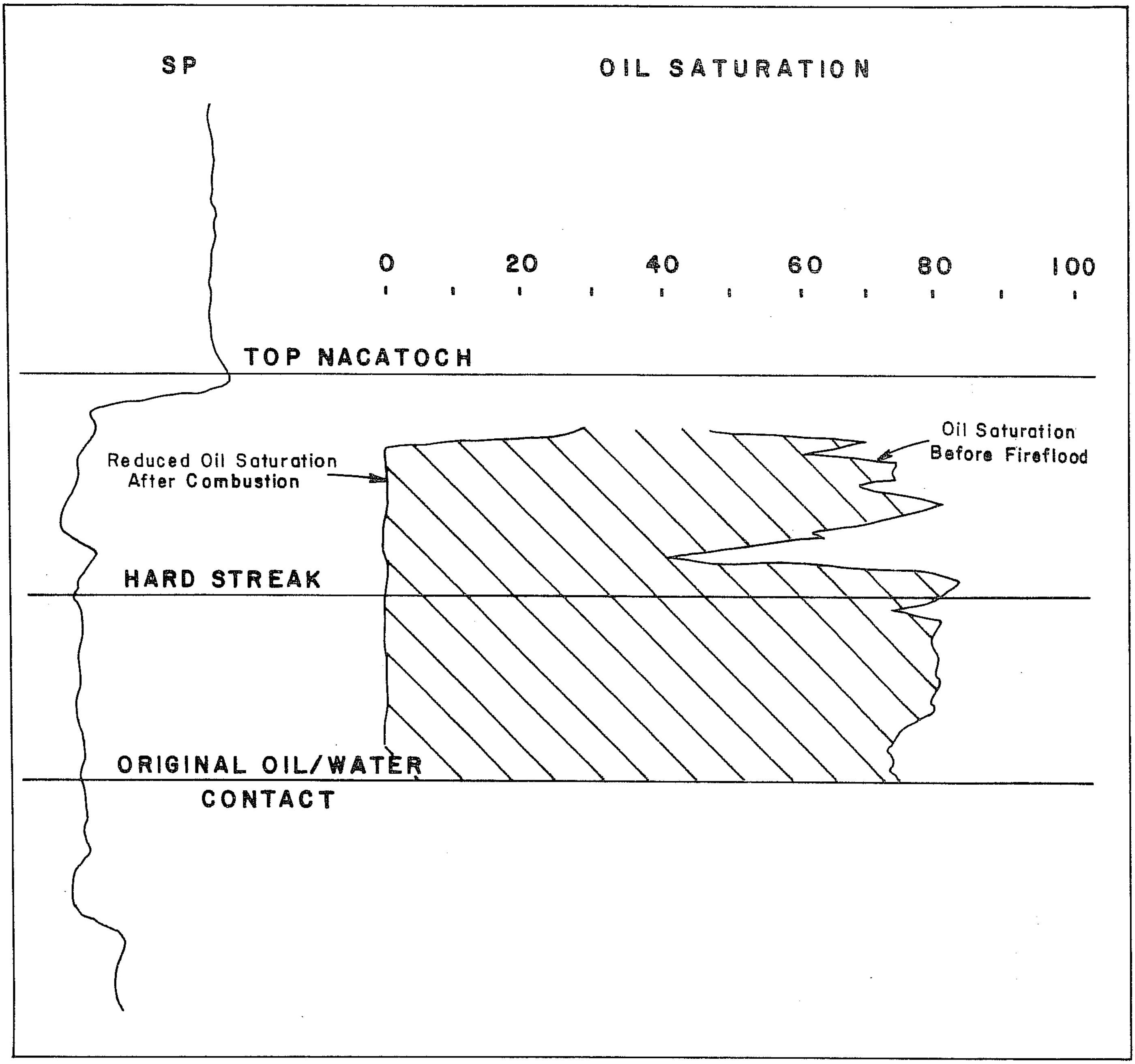

SATURATION PROFILE, WELL 15-10

FIGURE 9



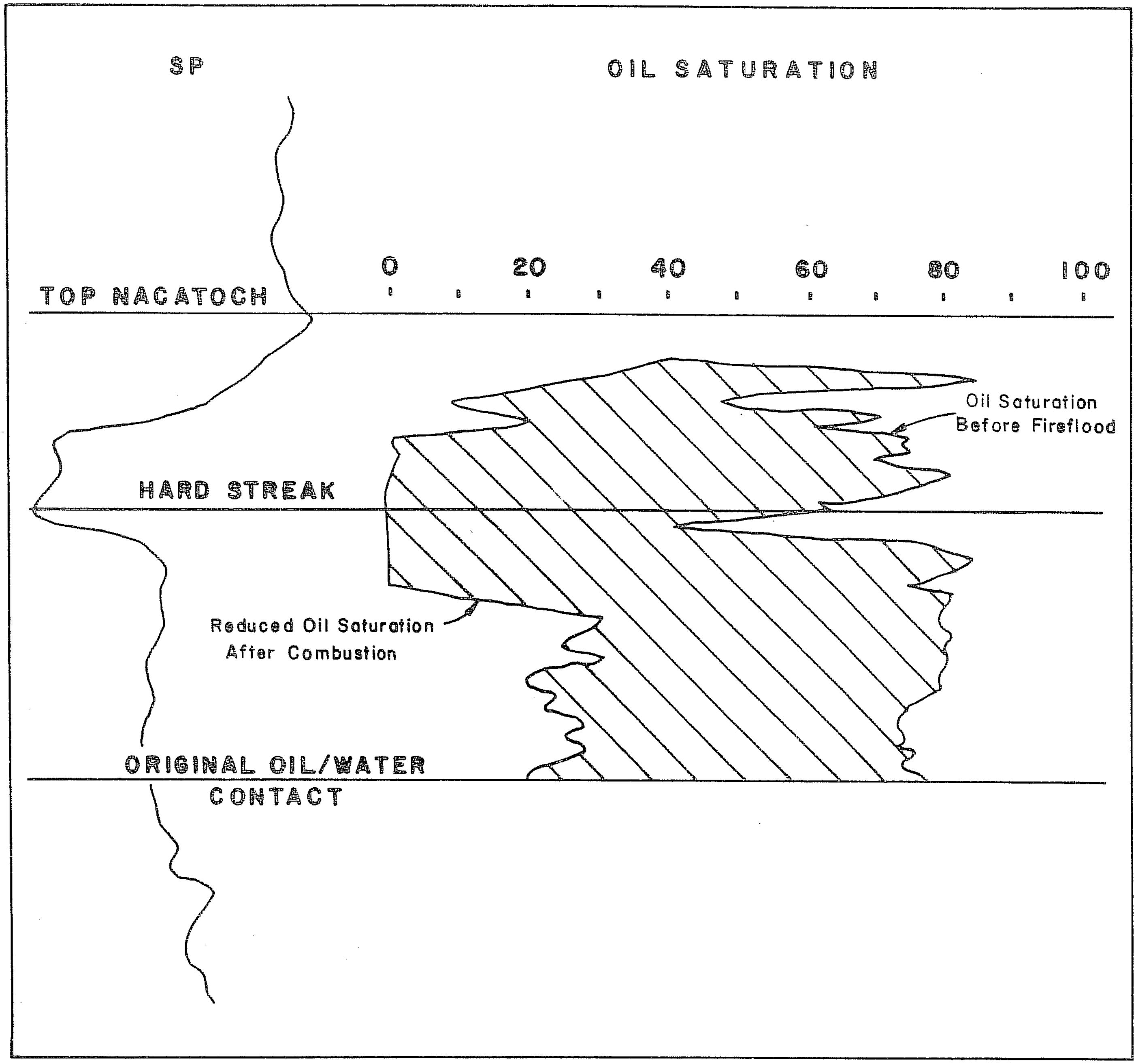

SATURATION PROFILE, WELL 15-11

FIGURE 10



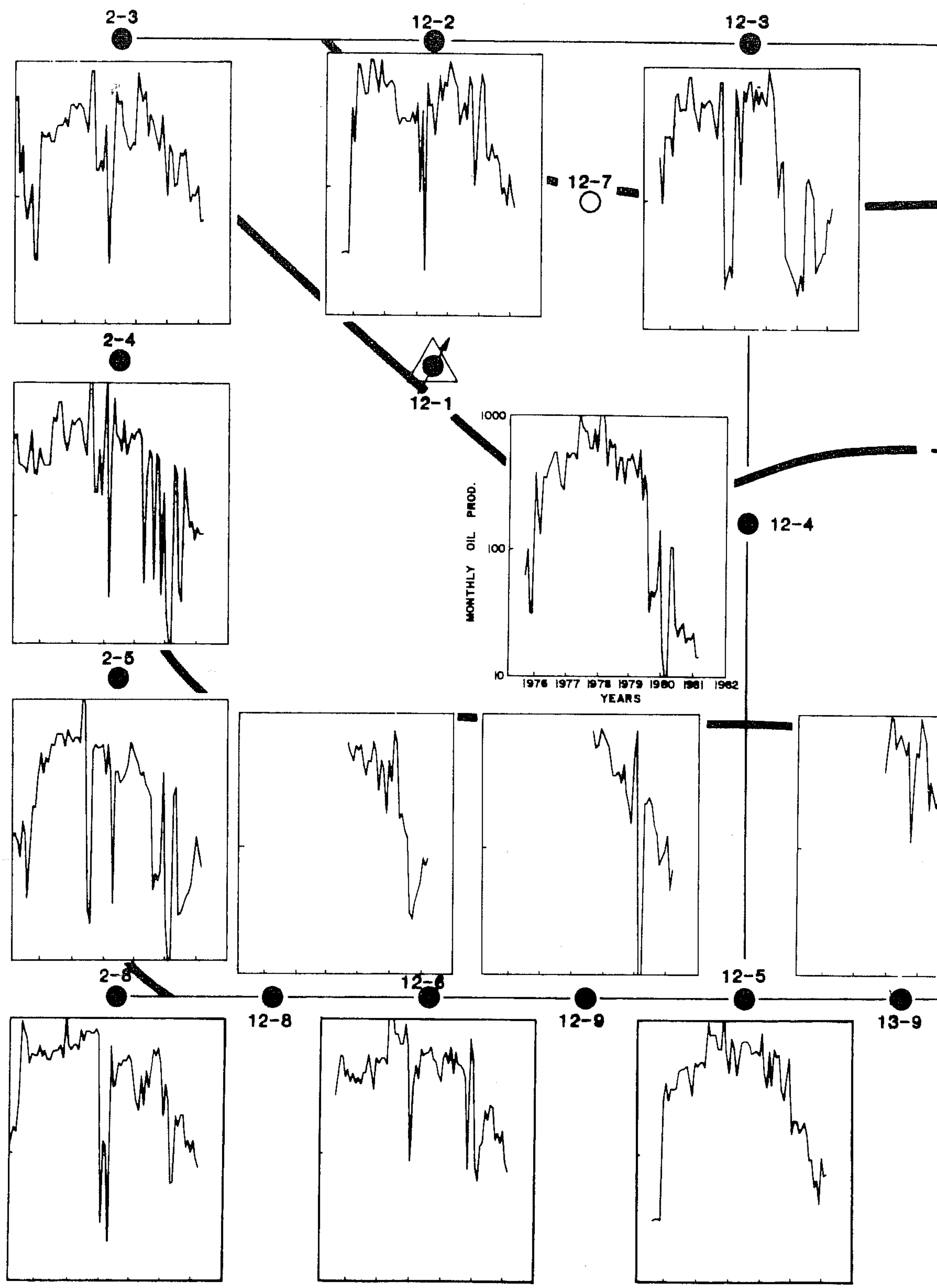

SATURATION PROFILE, WELL 15-12

FIGURE 11




SATURATION PROFILE, WELL 15-13

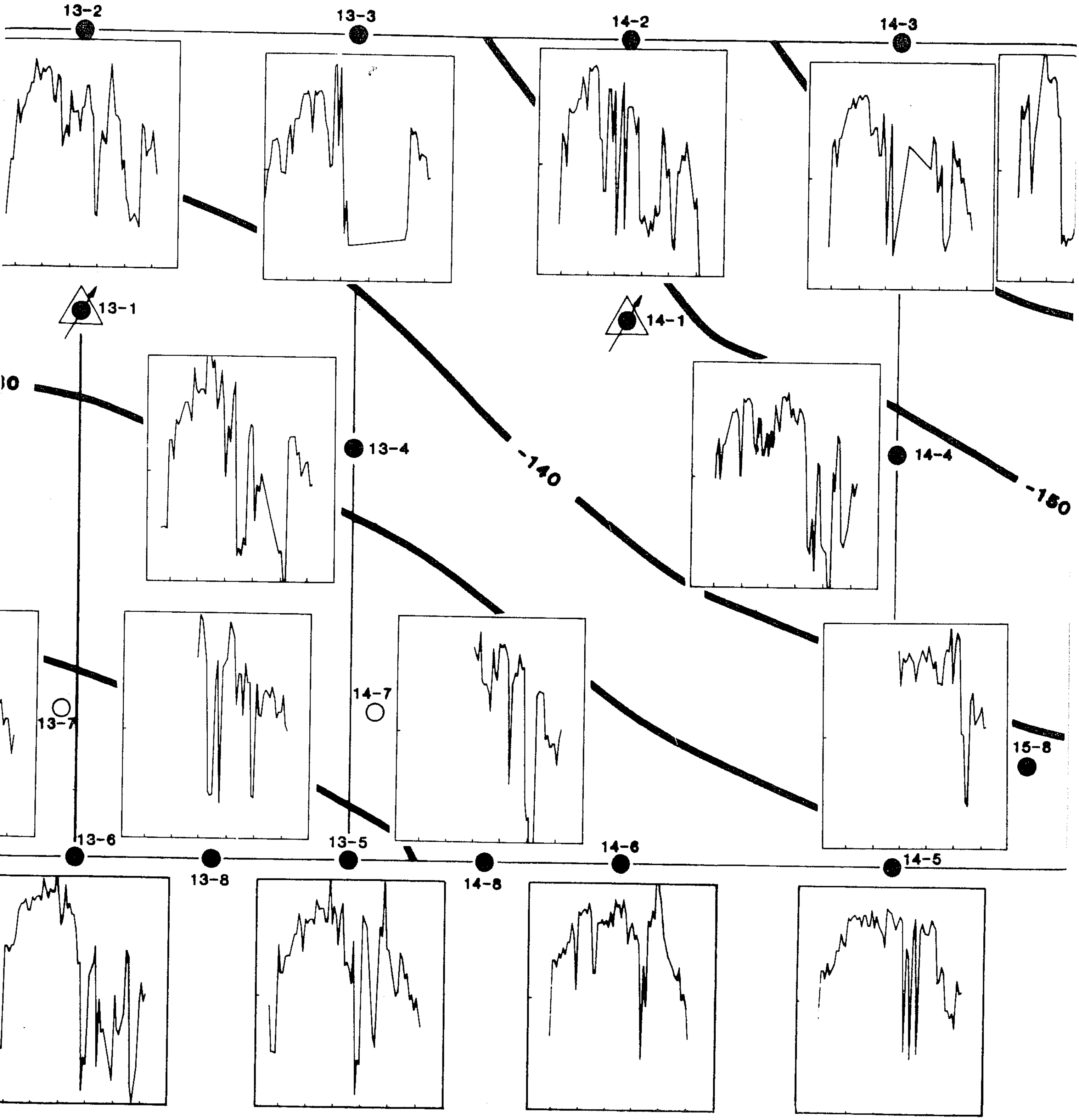
FIGURE 12

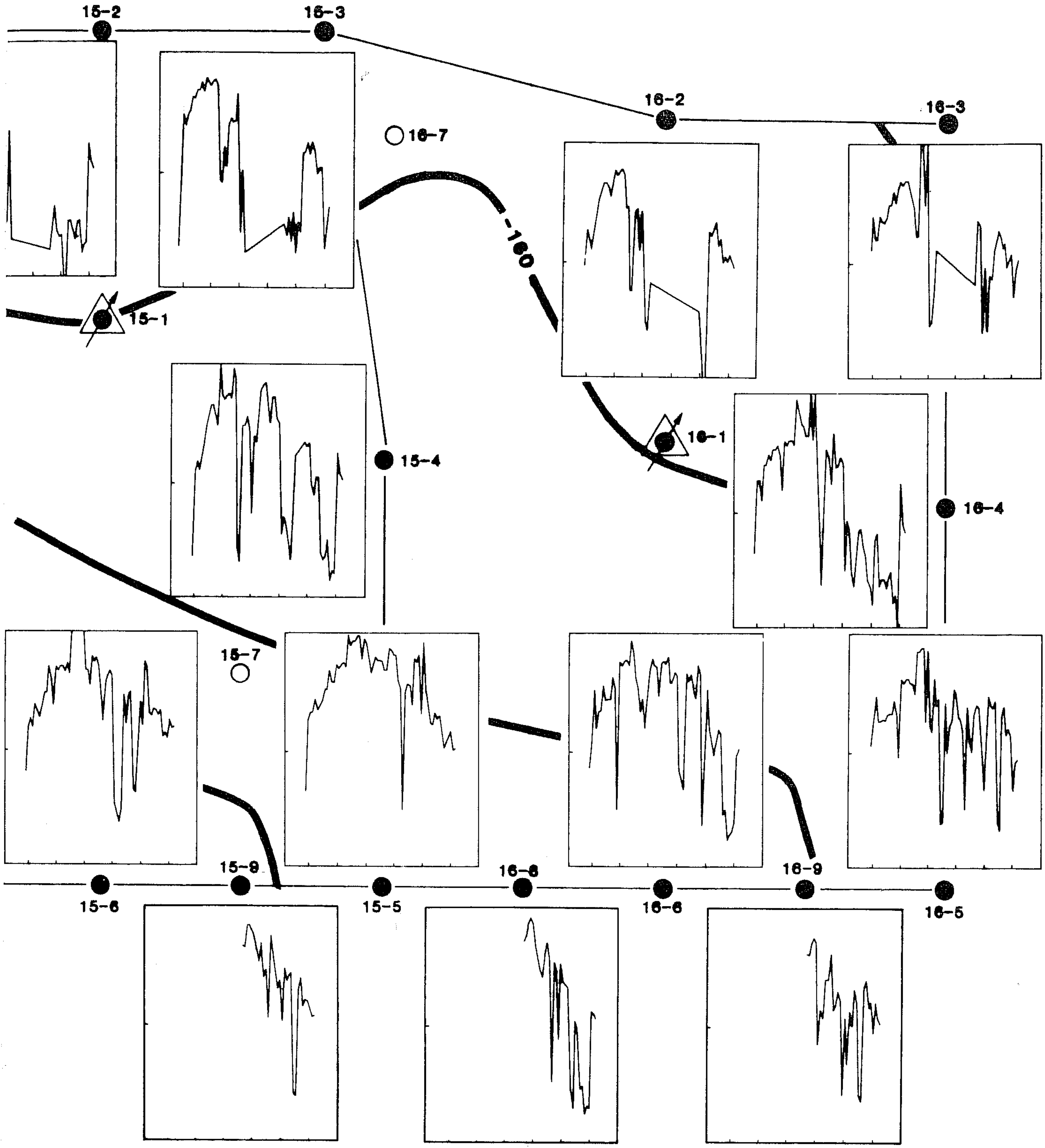



AERIAL DISTRIBUTION OF PRODUCTION RESPONSE

CONTOURED ON TOP OF NACATOCH, SEA LEVEL DATUM

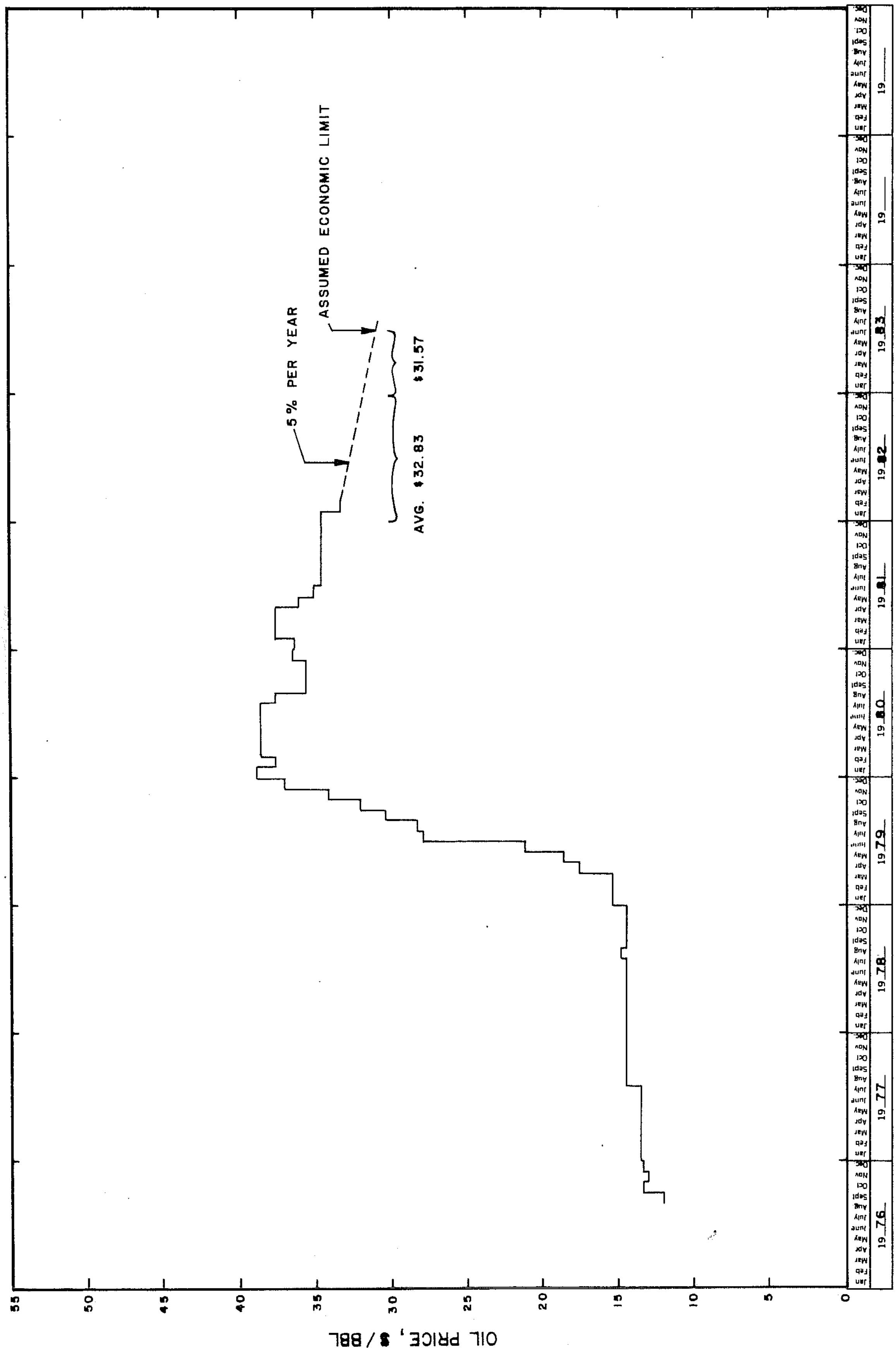
(SEE GRAPH AT WELL 12-4 FOR AXES IDENTIFICATION)


13-2
13-3
14-2
14-3
13-1
14-1
13-4
-140
14-4
-150
14-7
13-7
15-8
13-6
13-8
13-5
14-8
14-6
14-5



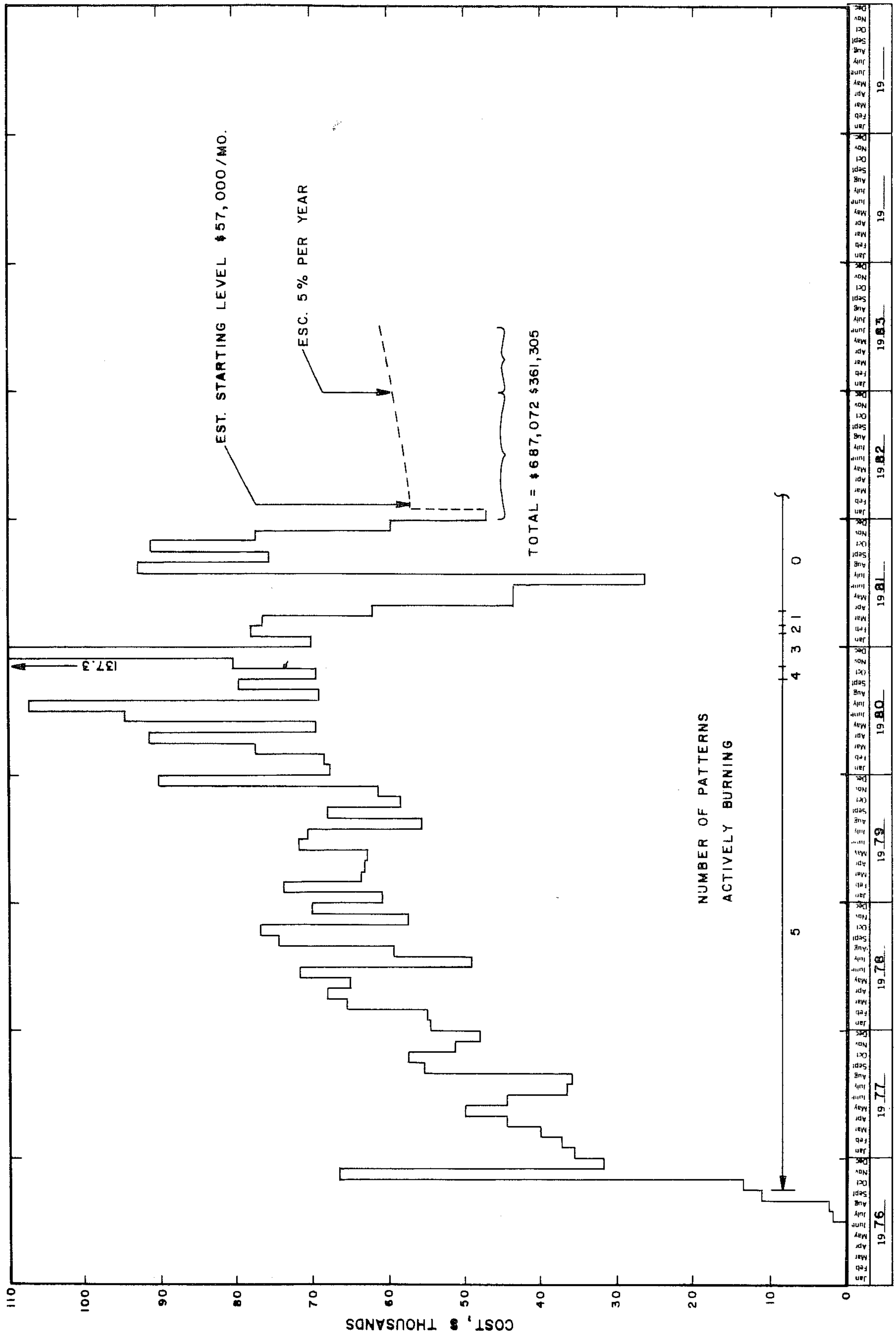
15-2
15-3
16-2
16-3
16-7
-160
15-1
16-1
15-4
16-4
15-7
15-9
16-8
16-9
15-6
15-5
16-6
16-5

FIGURE 13



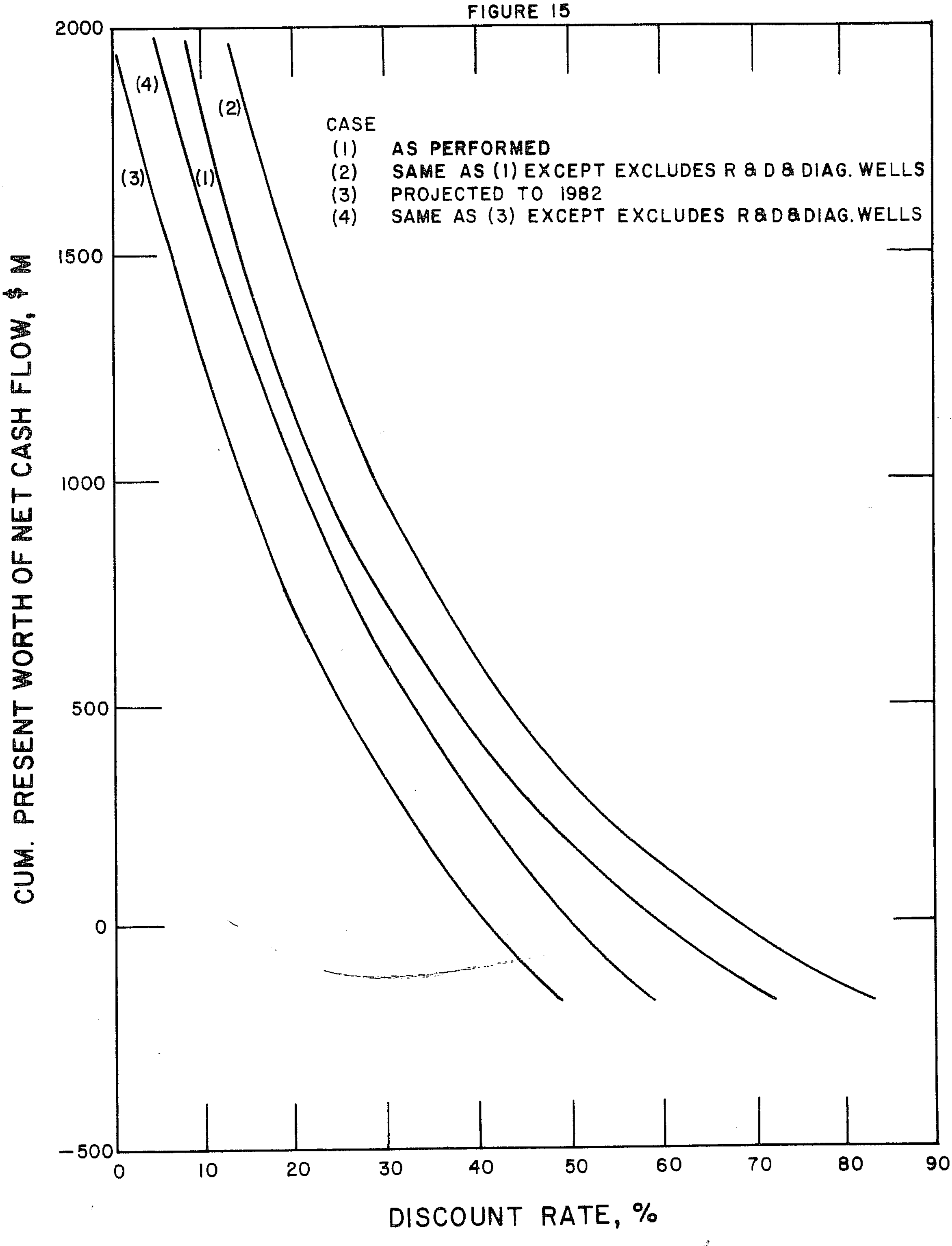

CRUDE OIL PRICE TREND

FIGURE 14




DIRECT LEASE EXPENSES

FIGURE 15




PRESENT WORTH PROFILE