CASE STUDY OF A MULTIPLE SAND WATERFLOOD, HEWITT UNIT, OKLAHOMA

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ABSTRACT

Twenty-two sands in the Hewitt Field have been simultaneously flooded by the Exxon operated Hewitt Unit and a case history of the operations is detailed in this paper. A multiple sand waterflood project requires special optimization methods to improve oil recovery. Highlighted are the injection and production surveillance programs and optimization methods used at the Hewitt Unit. These include injection wellbore design, injection distribution, production stimulation, polymer augmented injection, and infill drilling. Successful application of these techniques has increased the ultimate recovery from this waterflood operation.

INTRODUCTION

The Exxon-operated Hewitt Unit is located 20 miles west of Ardmore in South Central Oklahoma and covers approximately 2600 acres (Figure 1). The Unit became effective march 1, 1968 for the purpose of conducting a waterflood in 22 separate Pennsylvanian age sands.

Currently the Unit has 147 active producing wells and 142 active injectors on a twenty-acre five-spot pattern with each productive sand open in the wellbore. All zones are commingled in the producers and a total of 419 individual injection strings provide waterflood support. The unitized production peaked at 14,000 BOPD in January 1973 and has declined to a current level of 4500 BOPD. Injection rates were as high as 200,000 BWPD but are now reduced to a current level of 160,000 BWPD.

PRIMARY PRODUCTION

Hewitt, one of the older fields in Oklahoma, was discovered in 1919. Development was rapid during the 1920's with primary production peaking at 27,000 BOPD in 1921. The spacing was erratic with approximately 1000 wells drilled for an average of 2.5 acres per well.

The method of completion in the early days was to drill through the first major producing zone and run slotted production casing across the producing interval. Cemented casing was the exception rather than the rule. After the production had declined, the well would be deepened through the next major interval and smaller slotted casing run to total depth. This procedure was repeated in many instances. Initially all casing was hung from the surface and later upper portions of the multiple strings were salvaged, leaving uncemented slotted liners.

Hewitt was a prolific field producing 98.5 million barrels prior to unitization or an average of 37,800 barrels per acre. After 39 years of life, operations had declined to the stripper stage and several hundred wells had been shut down or abandoned. Production prior to unitization was 2700 BOPD from 600 active wells or 4.5 BOPD per well. The average decline in production was four percent per year and some leases had a projected life beyond the year 2000.

Recovery was principally by solution-gas drive augmented by gravity drainage on down-structure leases. Water/oil contacts were located to the south, southeast, and west of the field but no active water drive was present. Gas caps were present initially in some sands but no effective gas drive was realized because the gas caps were dissipated rapidly during early development.

GEOLOGY

The geologic section and nomenclature adopted in identifying individual sands is shown on a type log, Figure 2. The section is a sand/shale sequence of the Hoxbar and Deese formation of Pennsylvanian age. Gross interval between the top and lowermost sands is 1500 to 1600 feet. The average depth of the sands ranges from 1200 to 2900 feet subsurface. The pay interval is divided into five major zones, the 1st Hewitt through the 5th. The sands within a zone are termed "A", "B", etc., with the exception of the Stearns and Chubbee at the top. Four sands comprise 73% of the total acre feet: the Chubbee, 2C, 3C, and 3E.

The Hewitt structure contoured on the Chubbee is shown in Figure 3. It is a northwest to southeast trending anticline with a 12° dip to the west and south. The productive limits of the field are bounded by water-oil contacts to the west, south, and southeast, by a major fault to the north, and by steep dip and faulting to the east. Figure 4 shows a plat of the Unit with the water-oil contacts of the major sands. Most of the 22 sands contain water-oil contacts, and they occur at about the same subsea elevation. Moving from low to high on the structure, the number of sands within the oil column increases, and inside the 3E productive limit a maximum net sand thickness of up to 225 feet occurs.

WATERFLOOD DEVELOPMENT

Exxon began evaluating Hewitt as a waterflood prospect in the mid-1950's. As the major acreage owner, Exxon did a major portion of the geological and engineering work during negotiations with 47 other operators. A summary of the Unit's reservoir data is shown in Table I.

The waterflood was developed in three stages (Figure 5). The initial flooding began in 1969 in the southern and southwest portions of the Unit. This portion of the field was favored because of the structurally lower position of the sands and the anticipated higher oil saturations due to gravity drainage. In addition, the south end was closer to a source water supply. By the end of 1970, the north half of Section 22, all of Section 9, and the top of Section 16 were under flood. The final expansion occurred in 1971 when 600 acres were added in Section 10, 15, and the balance of Section 16.

The flood pattern is a 20-acre five-spot with some irregulatities. The Unit drilled 53 of the 147 active producers and 86 of the 142 active injectors with the balance being older primary wells brought into the Unit. These old wells were utilized as much as possible to minimize costs. Many new wells and major workovers of old wells were necessary to provide cemented casing strings for injection wells. Flood development included the plugging of 680 wells. Plugging costs total 4.5 MM$ or approximately 25% of the flood development cost. The total waterflood investment of 18.5 MM$ was paid out in 1974.

Ninety-two of the 147 producing wells utilize electric submersible pumps and the other 55 are conventional rod pumps. Production is monitored through 11 automatic well test stations and sold through a central tank battery. Initially source water was supplied by five wells completed in a 1200' salt water sand eight miles south of the Unit. Currently only two of the wells are maintained for makeup requirements. Produced water is treated in coalescers and sand filters before reinjection. Source water has been commingled with produced water since 1975 without any adverse effects.

OPERATIONS

Unit operations, shown in Figure 6, commenced with injection in April of 1969 and approximately six months later oil response occurred. Production increased steadily during 1970 to 9000 BOPD and then leveled off during the next 20 months to an average of 9500 BOPD through August 1972. Response from the 1971 expansion area combined with the remainder of the unit to peak production at 14,000 BOPD during January of 1973. The unit production declined at a constant rate of 24% per year from 1974 until 1977 when the decline began to shift to the current decline rate of 12% per year.

Water production rose rapidly along with early flood gains and by 1972 exceeded 90,000 B/D for a water cut in excess of 90 percent. This high water cut behavior was expected. Pre-Unit engineering studies had predicted this type of behavior due primarily to permeability variation.

Injection rose rapidly during the early development to 190,000 B/D, which is essentially plant capacity. Input remained at that level through the 3rd quarter of 1975. The drop in injection after 1975 to the current level of 160,000 B/D was due to selective injection cutbacks which will be discussed later under flood optimization.

Cumulative withdrawals since unitization to 1-1-80 total 36 million barrels of oil and 472 million barrels of water. A total of 702 million barrels of water has been injected which equates to a 1.5 reservoir pore volume throughput.

INJECTION WELL DESIGN

Initial waterflood studies indicated a large permeability variation in the sands at the Hewitt field. This fact, along with the large number of sands proposed to waterflood, pointed to the need for injection water control to efficiently flood the field.

Figure 7 illustrates a triple completion utilized at the Hewitt Unit to mechanically segregate injection. Surface casing was cemented below fresh water sands and three staggered lengths of 2-7/8" casing were then run and cemented to the surface. The short string or "A" completion was set through the 1st Hewitt sand, the "B" string through the 2nd Hewitt sand, and the "C" string included the 3rd, 4th, and 5th Hewitt sands. Each completion string was perforated to include at least one of the four major sands (Chubbee, 2C, 3C, and 3E). This method of injection well completion enabled a majority of the reserves to be flooded simultaneously. State regulatory approval was received to inject down cemented casing.

INJECTION SURVEYS

In a multiple sand waterflood, regularly scheduled injection profiles give information necessary to achieve control of water distribution and improve recovery efficiency. An average of 200 radioactive tracer profiles are run annually at Hewitt. Water injection is allocated to individual sands based on these profiles. From the tracer surveys, injection allocations are set for each completion string. Profiles also identify theif zones, stimulation candidates, tubing and casing leaks, and channeling between zones.

TUBING AND PACKER INSTALLATIONS

When an imbalance of injection volumes is indicated between zones by well tracer profiles, tubing and packer installations can be used to improve distribution. As shown in Figure 7, 1-1/4" tubing and packers are installed in the 2-7/8" casing to allow injection down the tubing and tubing-casing annulus. This method is applicable only when there is sufficient pressure to inject water into the lower permeability zone. Presently in the Unit there are 132 tubing and packer installations. These installations have enabled the Unit to increase the number of separate injection streams to allow timely flooding of the less permeable producing sands.

Early profiling in the 1971 Expansion Area indicated the need for improved distribution. Of the 51 tubing and packer installations in this area, 41 or 80% were completed by 1-1-73 before and during early flood response. Table 2 summarizes the flood results of the Unit and 1971 Expansion Area. As shown, the 1971 area projected recovery of 174 barrels per acre foot is expected to exceed the old area by 19 barrels per acre foot. Of equal significance is the comparison in flood efficiency. The 1971 area has produced one barrel of oil per 13.8 barrels of injected water compared to the old area's one barrel of oil produced per 22 barrels of water injected. This difference indicates a more efficient flood in the 1971 expansion area. Exxon credits a major part of the increased flood efficiency in the expansion area to the early installation of the tubing and packer strings.

WATERFLOOD PERFORMANCE PREDICTIONS

Utilizing the injection profiles, an accurate account of injection into each sand is recorded to aid in predicting areas of low cumulative injection throughput and corresponding high oil saturations. A computer analysis run with the injection data models and predicts the injection and production from individual producing sands at the Unit. The producing wells at the Unit have all of the sands commingled in the wellbore. Because of the commingled status, oil recovery from any individual sand is virtually impossible to determine and a prediction of oil recovery potential is made with injection data.

The computer analysis used at the Hewitt Unit to model waterflood performance is based upon articles published by Dr. B. H. Caudle (1,2). The program, written by Exxon, provides a simplified model bridging the gap between three dimensional reservoir simulators and rule-of-thumb prediction techniques. The program assumes steady-state flow, piston displacement, and non-communicating layers. Within the limitations of the assumptions the model accounts for areal sweep efficiency, vertical stratification, mobility ratio, initial gas saturation, and changing injectivity. The program output used at Hewitt is a comparison of cumulative injection to cumulative recovery and reserves. These reserve estimates are used to evaluate work programs on injections wells.

SELECTIVE INJECTION

Another optimization approach at the Unit has been the selective decrease or increase of injection into individual sands. The purpose of the injection changes is to optimally allocate the injection water into the sands with the highest oil saturation. These injection changes result in larger oil cut production due to less water cycling through depleted sands. The water injection cutbacks prevent a more depleted oil sand from flooding out a less depleted sand in the commingled producing well. Fluid levels are monitored on a regular basis in all producing wells in the field. The wells with a high fluid level are considered for the possibility of a decrease in offset injection. Conversely, low fluid level producers which could potentially benefit from injection increases are identified. The producing sand cumulative throughput of water and corresponding oil reserves are analyzed for the potential of injection changes.

During 1975 and 1976 several injection cutbacks were used to decrease injection into high water cut sands. The first injection cutback, in October of 1975, amounted to 12,000 B/D in the Chubbee and was followed by an increase in production of approximately 200 BOPD. The other two injection cutbacks were initiated in September and November of 1976 and totaled 17,800 B/D. These injection decreases lowered injection costs while oil production remained unchanged. The decreases in injection did not alter the field decline but successfully lowered fluid levels. Figure 8 depicts the Unit production levels during year 1976 following the injection cutback.

In the second half of 1977 the field decline began to change from a 24% per year rate to a 1980 decline rate of 12% per year. Selective injection increases were initiated in June of 1977 and are credited as a principal reason for the gradual shift in field decline. A total increase of 12,250 BWPD has been implemented to date. Figure 9 shows an example of the effect of selective injection increases into less depleted sands during 1977-1980. As shown, the injection increase in Section 15 resulted in increased oil production of as much as 350 BOPD.

POLYMER TREATMENTS

The Hewitt Unit has had three polymer-augmented injection projects. The projects have involved the injection of a high molecular weight, water soluble polyacrylamide that becomes gelatinous when mixed with water. A cross-linking agent is injected and activates the polyacrylamide to form a viscous gel. The material will enter the most permeable section of the sand and build up yield strength to block and/or divert flow. The resulting pressure buildup diverts the injection water to less permeable flow channels that are less depleted and contain a higher oil saturation. This diversion of injection water improves the vertical sweep efficiency of the flood.

A map of three polymer project areas is shown in Figure 10, and a summary of the three projects is presented in Table 3. Each of the projects injected polymer into the Chubbee sand, one of the four major sands in the Hewitt Unit. Treatments were sized to inject polymer at a 500 ppm concentration for 30 days. The objective was to increase the injection wellhead pressure to as near plant injection pressure (1080 psig) as possible while maintaining a constant rate of injection water. This increase in pressure indicates plugging of the most permeable streaks in the Chubbee sand and corresponding water diversion.

The polymer projects have been credited with increasing tract recovery from a 1972 project high of 32 bbls/ac.ft. to a low in 1979 of 6.5 bbls/ac.ft. These figures correspond to 20%-4% of the 162 bbls/ac.ft. projected Unit recovery. The variation in the project oil recoveries is attributed to differences in the project timing and areas. Two factors were found to correlate well with the project recovery. These are:

1. Cumulative injection into the sand prior to project initiation.

2. Percentage of the sand receiving injection support as indicated on injection profiles.

Figure 11 illustrates this relationship of oil recovery to the cumulative injection and percentage of pay taking water.

The 1972 project area had less cumulative injection prior to start up and a smaller percentage of the Chubbee sand taking water injection than the 1977 or 1979 areas. With less cumulative injection, the 1972 project diverted water to sand with a higher oil saturation. Additionally, the 1972 project had a larger percentage of the pay not being injection supported. These factors resulted in increased diversion and efficiency.

PRODUCER STIMULATIONS

Selective stimulation of producing wells has proved to be a successful method of improving recovery at the Hewitt Unit. Ninety-seven of the 140 active producers have cemented casing strings which permit the selective fracturing of a producing sand. The other active producing wells were drilled during primary development and have two or more uncemented liners through the pay interval, prohibiting selective stimulation. An average stimulation workover consists of six stages in four selected intervals in a producing well. The largest stimulation workover consisted of 13 stages in 10 producing intervals. A standard frac stage at Hewitt consists of 5000 gallons of emulsion-based fluid and 8800 pounds of sand.

Seventy-one stimulation jobs have been completed at the Hewitt Unit from 1972 to the present. Overall the 71 stimulation jobs have yielded an average first year gain of 64 BOPD. Thirty-five of the fracture jobs were completed by the end of 1973. Criteria for selecting zones for stimulation have included:

1. Individual sand quality.

2. Individual flood performance in relation to other producers.

3. Cumulative and current injection rates by zones in offset inputs.

4. Mechanical condition of the wellbore.

ARTIFICIAL LIFT OPTIMIZATION AND SELECTIVE TESTING

Existing lift equipment does not have the capacity to pump off all of the wells in the Unit. Fluid levels are monitored and equipment is moved to maximize fluid production from the higher oil cut producing sands.

Individual sands have been tested in 15 producing wells to locate watered out zones or zones needing stimulation. Intervals are individually tested by isolation with bridge plug and packer. Producing well wireline surveys have not been used at the Unit for the following reasons:

1. High water-cut production lies outside the accuracy of the tools.

2. The fluid level is below more than half of the producing zones.

3. It is difficult to run the tool past the submersible pump.

Selective testing is expensive in terms of tool rentals, well servicing, and lost production but the results have shown it to be economical. Selective stimulation treatments of 16 producing zones in 10 wells have yielded a 450 BOPD first year buildup. Additionally, 14 uneconomical zones have been squeeze cemented or blanked off.

Drilling

In addition to the 122 wells drilled during the initiation of waterflood operations, nine producers and three injection replacement wells have been drilled in the Unit. Seven of the producing wells were successful, one was marginal, and the ninth well gave very little buildup. Cumulative oil production as of 1-1-80 from the nine replacement wells was 2.38 million barrels or approximately 265,000 barrels per well. Currently the wells produce 600 BOPD or 67 BOPD per well. The three injection inputs were drilled to replace wells with mechanical problems that prevented needed injection distribution.

Three of the wells drilled during 1974 and 1976 resulted in an increase in producing tract ultimate recovery. The old producing wells in these tracts were projected to have recovered 122 barrels per acre foot. The three new wells resulted in an increased projected recovery of 45 barrels per acre foot or a total tract recovery of 167 barrels per acre foot.

The results of replacement well drilling (increased ultimate tract recovery) led to a study of all producing patterns in the Unit with more than one producing well. The study results, shown in Table 4, indicated that multiple well producing patterns are projected to average 85 barrels per acre foot greater recovery than single well patterns. The results of this study initially led to five infill drilling locations shown in Figure 12.

The five infill wells averaged 162 BOPD per well initial potential. These wells should increase tract recovery by an average of 43 barrels per acre foot. The infill drilling program will continue in 1981 with a proposed 30 additional wells.

RECOVERY

The Hewitt Unit is projected to recover 46 million barrels of oil through the life of the Unit. Table 5 summarizes the Unit recovery reflecting 34.9 million barrels of additional oil recovery over primary. Without the optimization work programs outlined above, the Unit would have only produced 41 million barrels of oil. The waterflood optimizing methods will therefore yield an additional five million barrels of oil.

CONCLUSION

The results achieved at the Hewitt Unit waterflood demonstrate the benefits of a thorough surveillance program and the development of measures to optimize recovery. Early programs to increase recovery included triple completion injection wells, tubing and packer installations for further injection distribution, and sand fracture treatments of producing wells. Recent techniques have included the polymer-augmented injection projects and an infill drilling program. These optimization methods have slowed the Unit production decline and increased the ultimate recovery. Methods used at Hewitt should prove to have application in other waterflood operations.

ACKNOWLEDGEMENTS

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TABLE I
HEWITT UNIT RESERVOIR DATA

General		
Unit Area	- Ac	2,610
Floodable Net Sand Volume	- Ac Ft	284,700
Average Composite Thickness (22 Separate Sand Reservoirs)	- Ft	109
Original Oil in Place	- MMB	350.8
Rock Properties		
Permeability	- Md	184
Porosity	- %	21.0
Connate Water	- %	23.0
Lorenz Coefficient	-	.49
Permeability Variation	-	.726
Fluid Properties		
Mobility Ratio	-	4.0
Original Reservoir Pressure	- Psig	905
Reservoir Temperature	- ^{o}F	96
Original FVF	RB/STB	1.13
Flood Start FVF	RB/STB	1.02
Oil Stock Tank Gravity	- ^{o}API	35
Oil Viscosity	- cp	8.7
Original Dissolved GOR	- Ft^3/STB	253
Primary Recovery Mechanism	Solution Gas Drive Gravity Drainage	

TABLE 2
RECOVERY SUMMARY
OLD AREA vs 1971 EXPANSION AREA
HEWITT UNIT
1-01-80

	Old Area	1971 Expansion	Unit/Total
Ac. Ft.	190,664	94,036	284,700
Cumulative Oil - MMB	22.7	10.8	33.5
- Bbls/Ac Ft	119	115	118
Produced Water - MMB	351.3	73.5	424.8
Water Oil Ratio	15.5	6.8	12.7
Injections - MMB	499	149	648.0
- Bbls Inj/Bbl Oil Rec	22	13.8	19.3
Ultimate Unit Oil Rec - MMB	29.6	16.4	46.0*
- Bbls/Ac Ft	155	174	162*

* Does not include pre-unit production

TABLE 3

HEWITT POLYMER PROJECTS

	1972	1977	1979
Injectors Treated	4	9	10
Producers Monitored	11	21	23
No. Producers Responding	6	14	14
Avg Inj Press - Before - psig	210	240	274
Avg Inj Press - After - psig	595	650	780
Treatment Size - M lbs polymer	15.5	29.6	33.0
- M Bbls water	87	182	189
Incremental Recovery - MBO	115	130	33
- Bbl/Ac Ft	32	16	6.5
Cost - M$	37.5	135	115

TABLE 4

MULTIPLE PRODUCING PATTERNS vs REMAINDER OF UNIT

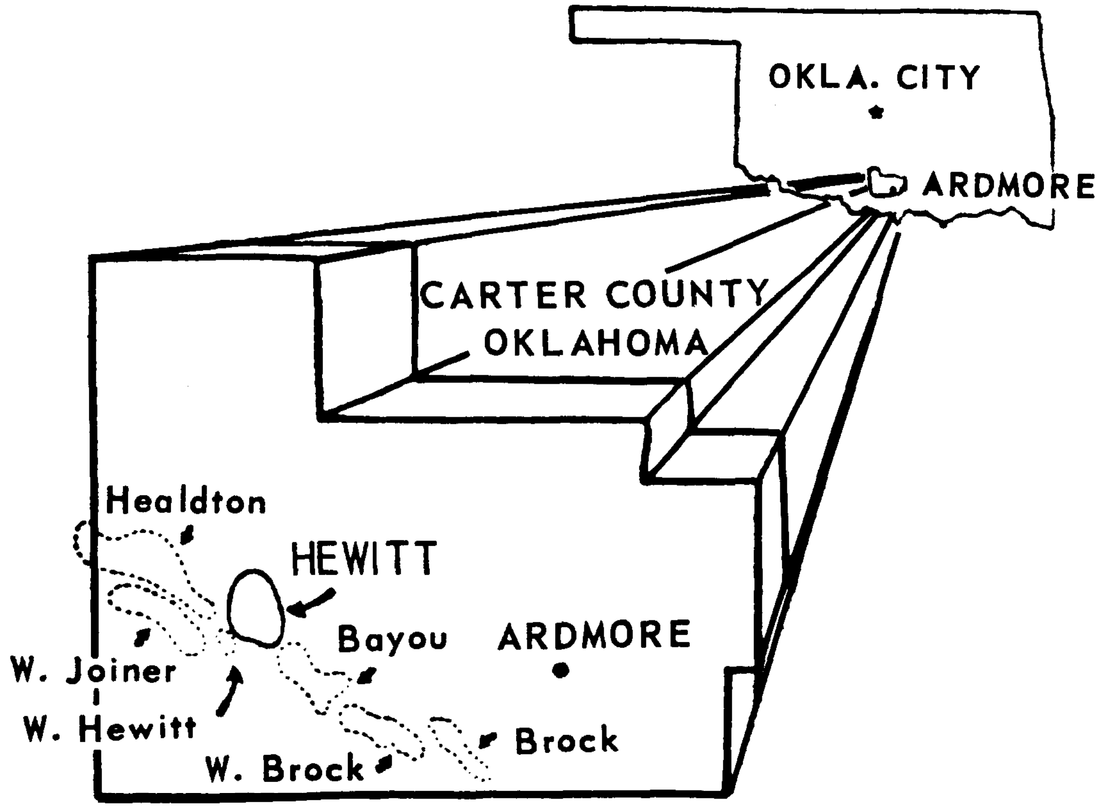
COMPARISON OF PATTERN RECOVERY

	Acres	No. Producing Wells	Ac. Ft.	Pattern Recovery MMBbls	Pattern Recovery Bbls/AcFt	
Producing Patterns with Multiple Wells	466	47	79,009	17.6	223	Δ85
Remainder of Unit	2,144	93	205,691	28.4	138	
Unit Total	2,610	140	284,700	46.0	162	

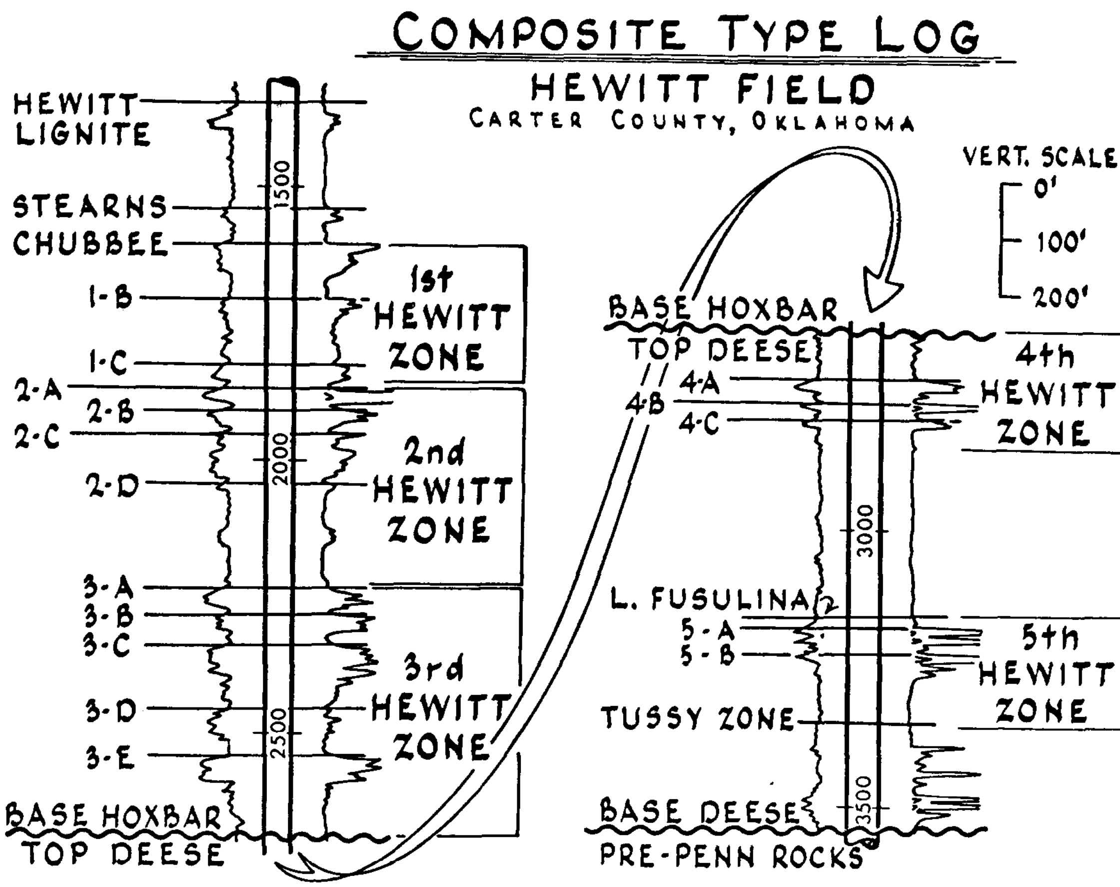
TABLE 5

HEWITT UNIT RECOVERY

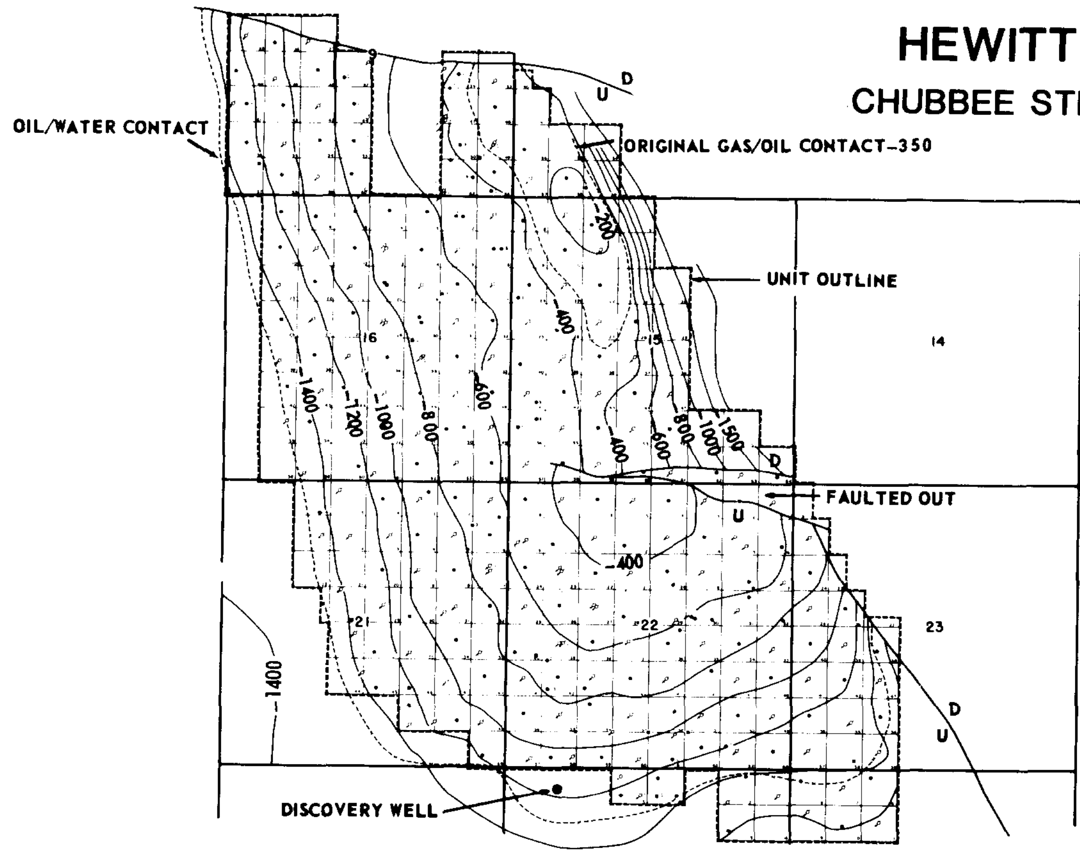
Original Oil in Place	- MMB	350.8
Cumulative Primary to Unitization	- MMB	98.5
	- % OOIP	28.1
Est. Unit Primary from (3-1-68)	- MMB	11.1
Unit Ult. Primary	- MMB	109.6
	- % OOIP	31.2
Est. Unit Ultimate (from 3-1-68)	- MMB	46.0
Unit Area Ult. (Primary & Secondary)	- MMB	144.5
	- % OOIP	41.2
Ult. Flood Gain Over Ult. Primary	- MMB	34.9
Percent of Ult. Primary	- %	31.8



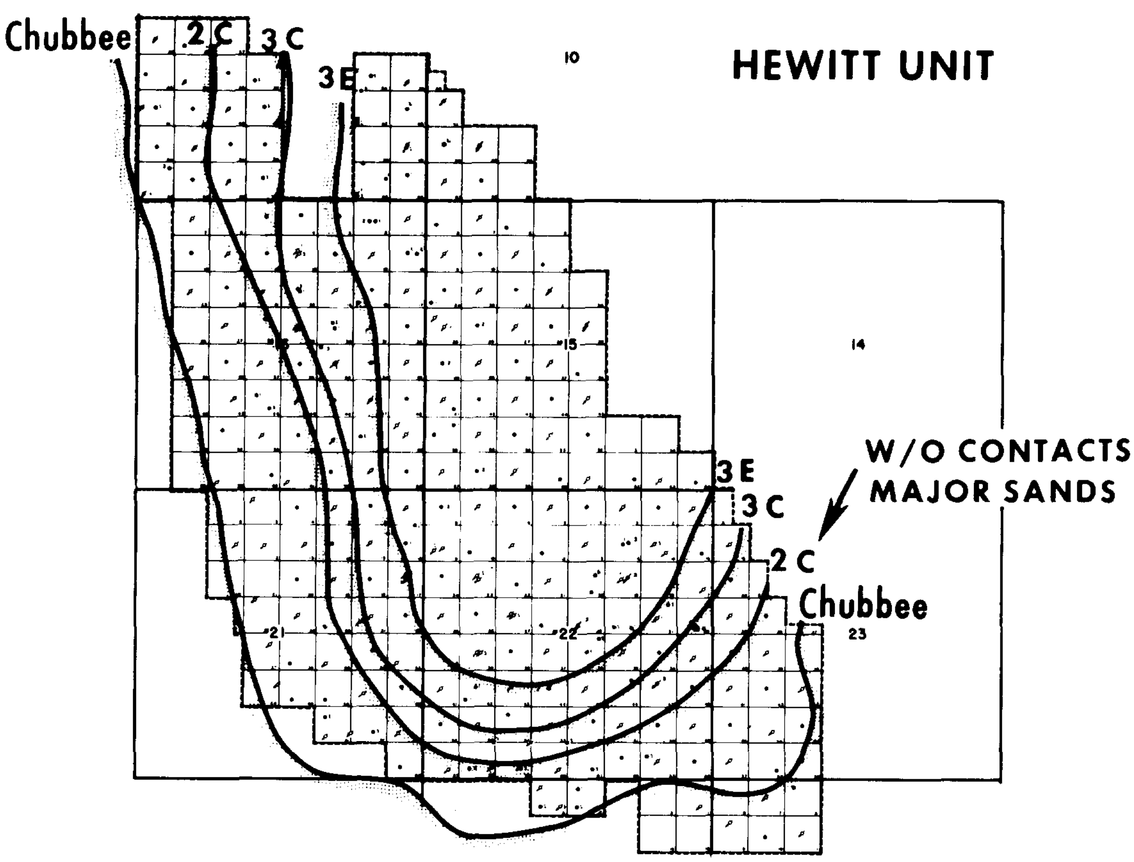
LOCATION MAP, HEWITT UNIT

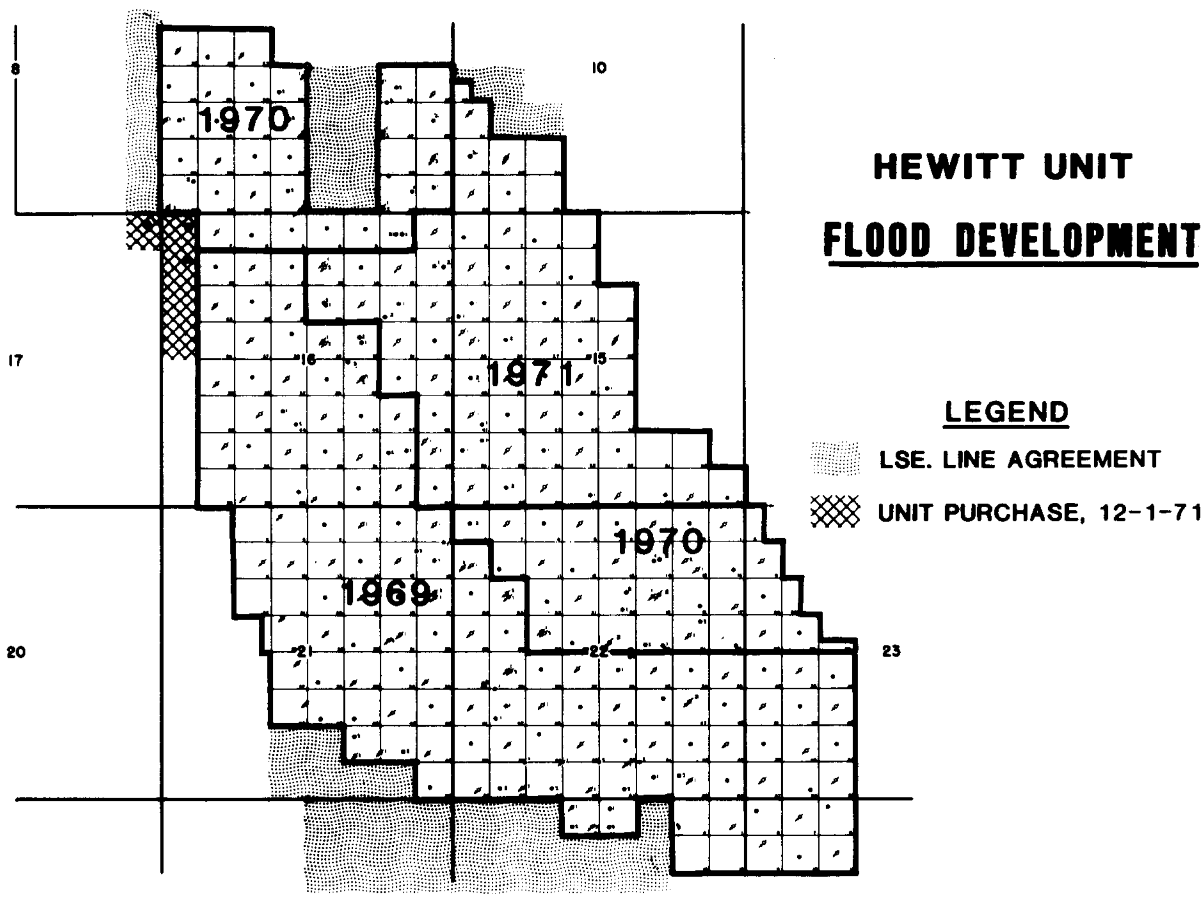


HEWITT UNIT
CHUBBEE STRUCTURE

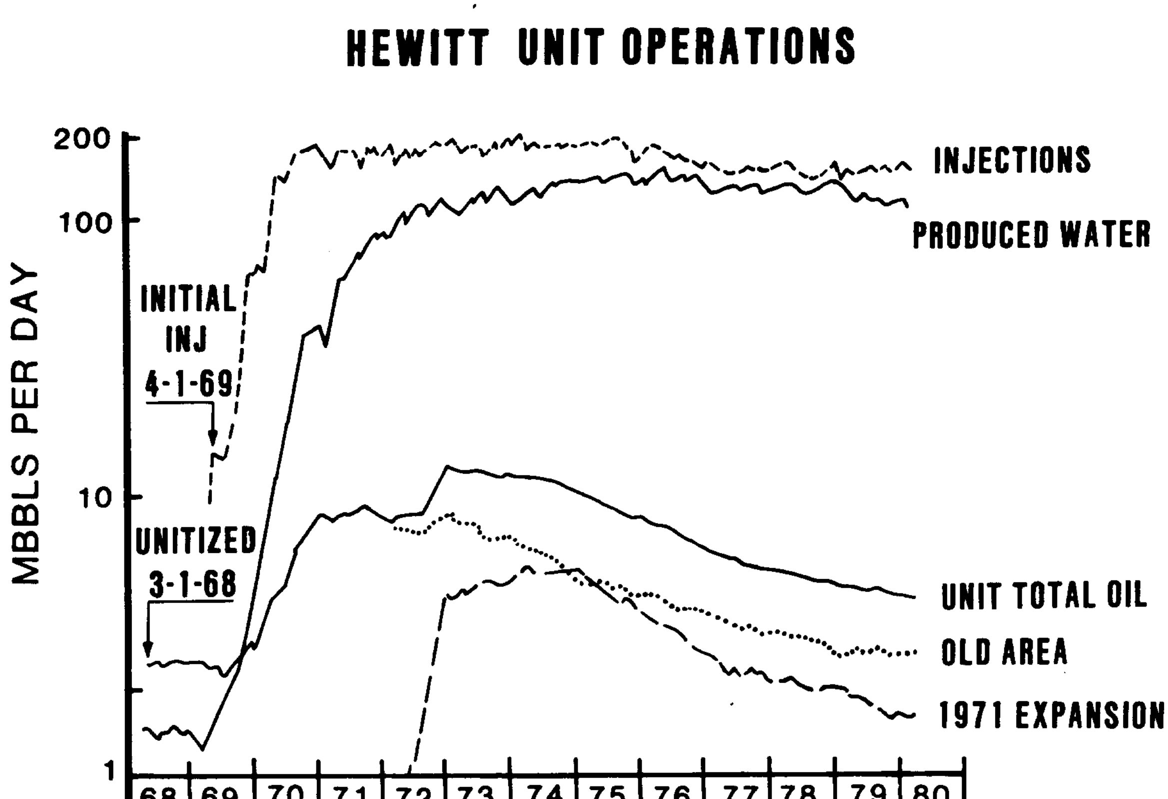


HEWITT UNIT

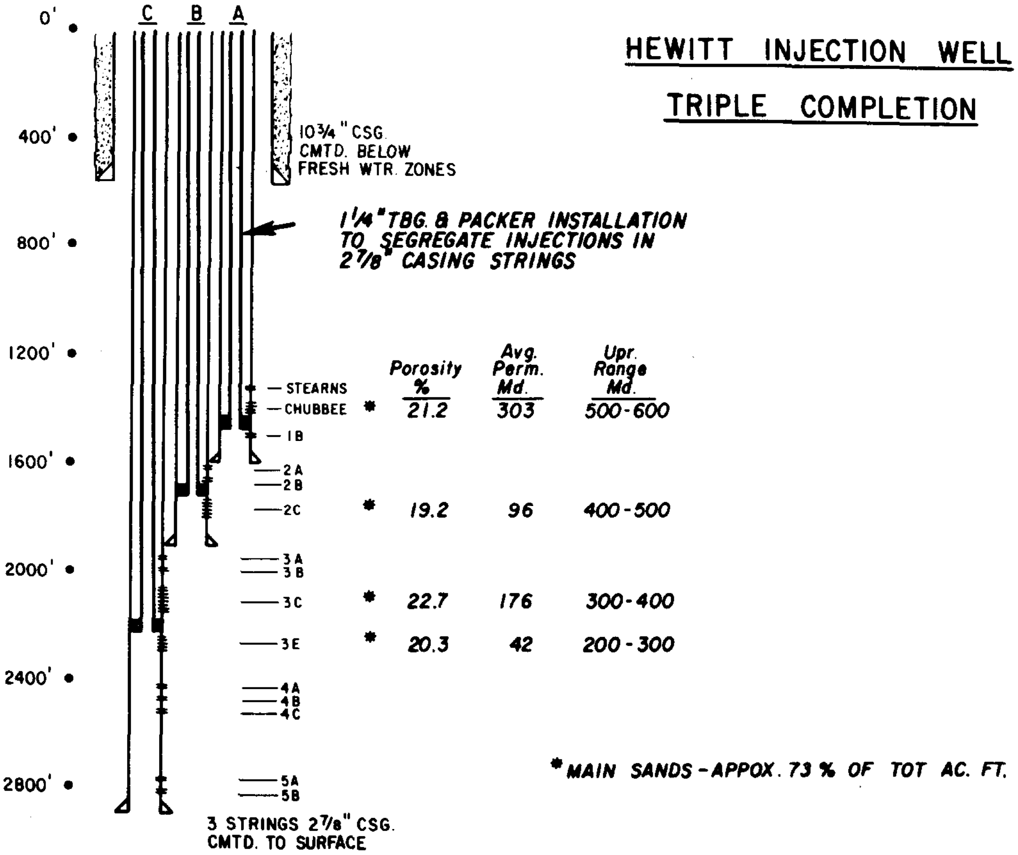




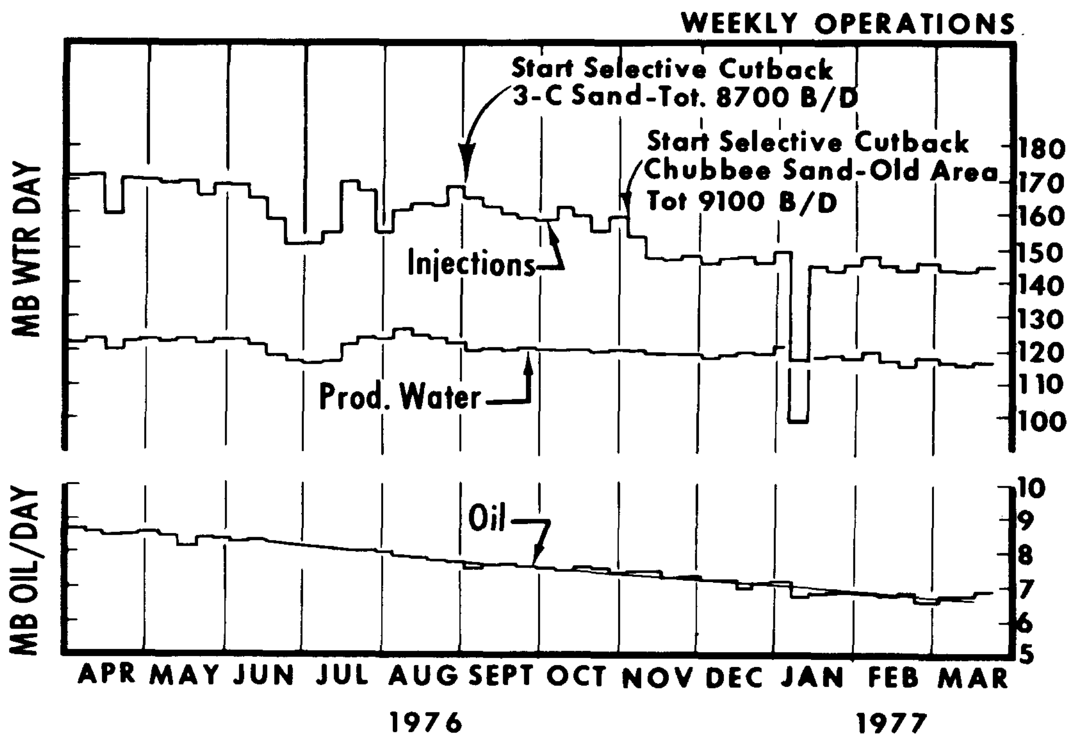
8
10
17
20
23
16
15
21
22
1970
1971
1970
1969
HEWITT UNIT
FLOOD DEVELOPMENT
LEGEND
LSE. LINE AGREEMENT
UNIT PURCHASE, 12-1-71



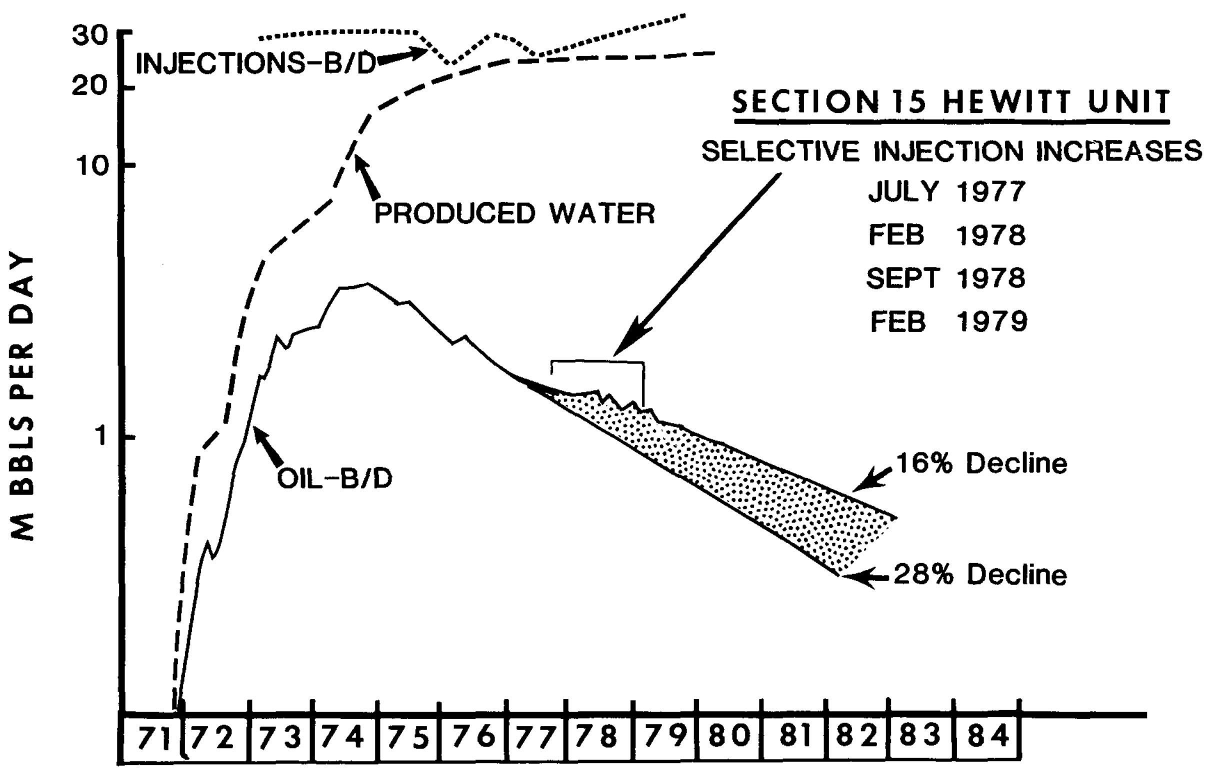
HEWITT UNIT OPERATIONS
200
100
10
1
MBBLS PER DAY
INITIAL INJ 4-1-69
UNITIZED 3-1-68
INJECTIONS
PRODUCED WATER
UNIT TOTAL OIL
OLD AREA
1971 EXPANSION
68
69
70
71
72
73
74
75
76
77
78
79
80



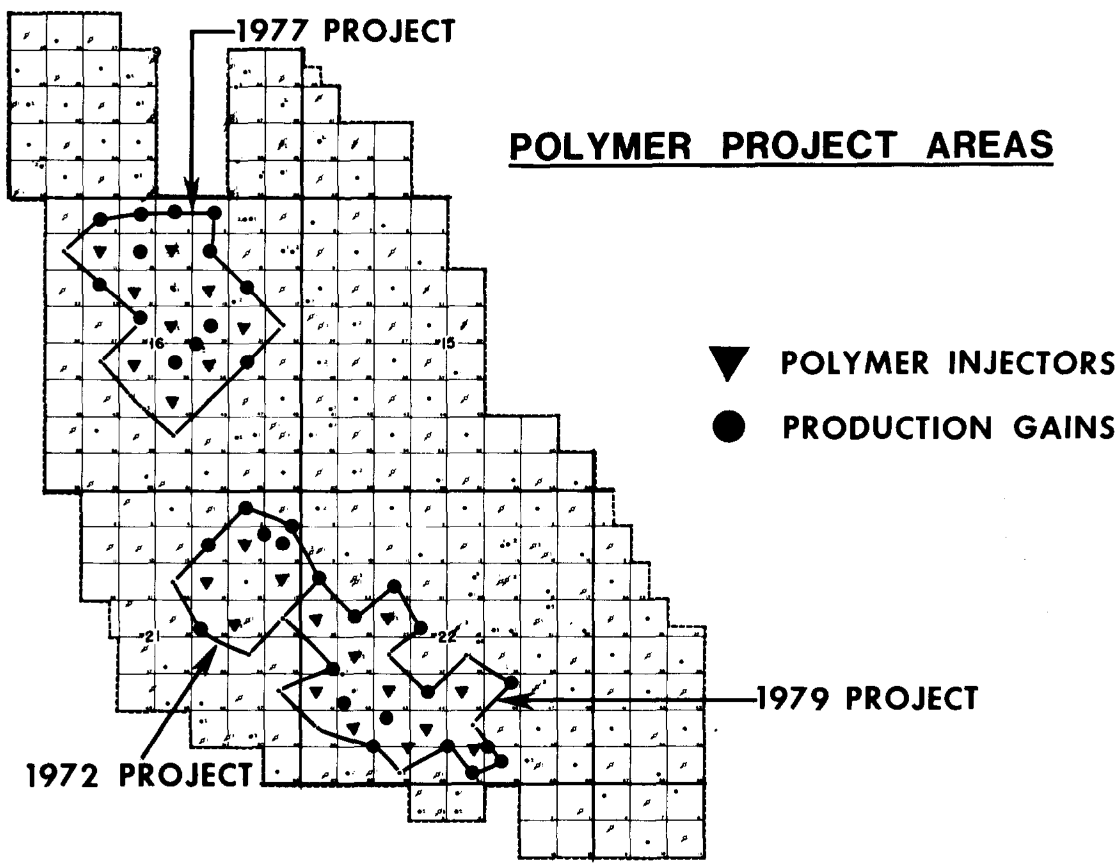
HEWITT UNIT
SELECTIVE INJECTION CUTBACKS
SEPT. & NOV. 1976

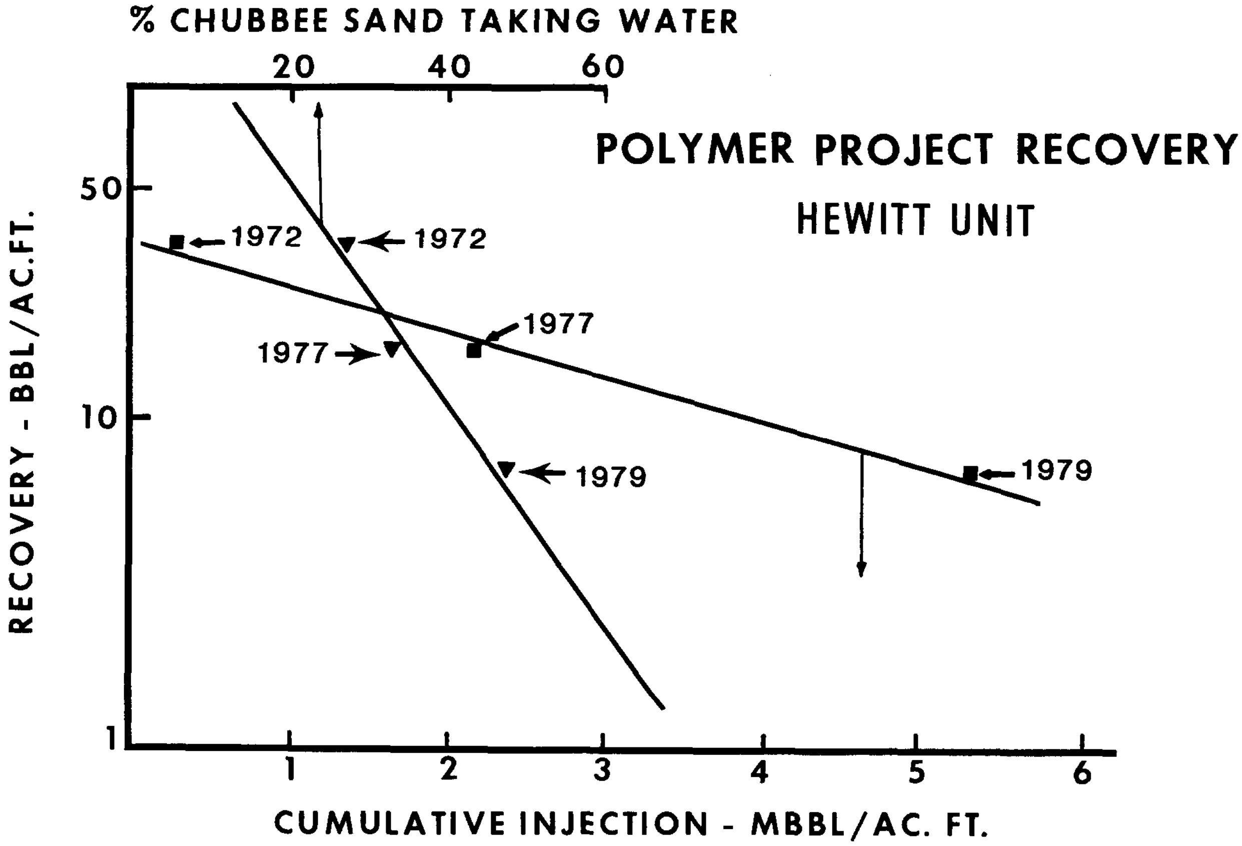


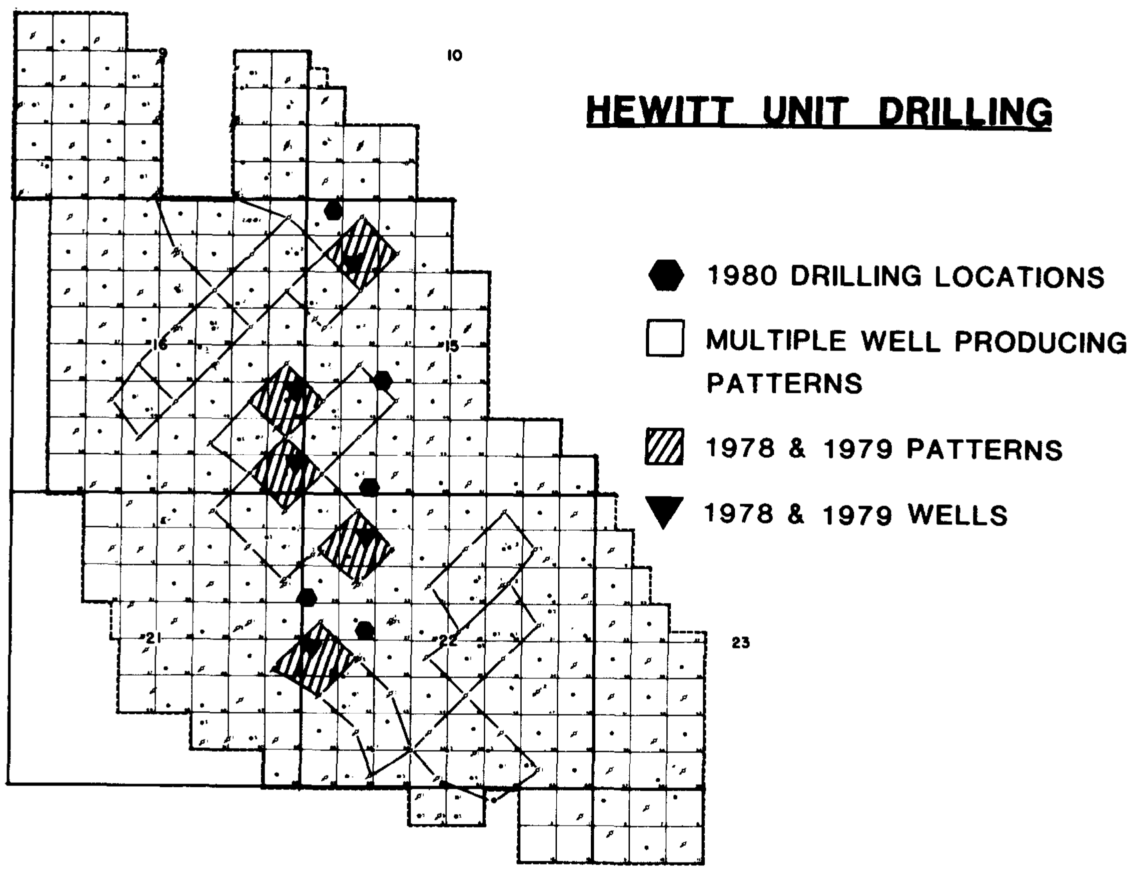
SELECTIVE INJECTION INCREASE RESULTS



POLYMER PROJECT AREAS




% CHUBBEE SAND TAKING WATER
20
40
60
POLYMER PROJECT RECOVERY
HEWITT UNIT
50
10
1
1972
1972
1977
1977
1979
1979
RECOVERY - BBL/AC.FT.
1
2
3
4
5
6
CUMULATIVE INJECTION - MBBL/AC. FT.


HEWITT UNIT DRILLING
1980 DRILLING LOCATIONS
MULTIPLE WELL PRODUCING PATTERNS
1978 & 1979 PATTERNS
1978 & 1979 WELLS
9
10
16
15
21
22
23