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FOSSIL ENERGY

THE "200" SAND STEAMFLOOD DEMONSTRATION PROJECT

Fourth Annual Report
June, 1979 – June, 1980

Work Performed for the Department of Energy
Under Contract DE-AC03-79ET12059

Date Published—February 1981

Santa Fe Energy Company — Chanslor Division
(Formerly Chanslor—Western Oil and Development Company)
Santa Fe Springs, California

DEPARTMENT OF ENERGY UNITED STATES OF AMERICA

U. S. DEPARTMENT OF ENERGY

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THE "200" STEAMFLOOD DEMONSTRATION PROJECT

Fourth Annual Report
June, 1979 – June, 1980

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U.S. DEPARTMENT OF ENERGY

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INTRODUCTION

The "200" Sand Steamflood Demonstration Project, a jointly funded venture between Santa Fe Energy Company - Chanslor Division (formerly Chanslor-Western Oil and Development Company) and the United States Department of Energy (DOE), is testing an enhanced steamflooding technique in the Midway-Sunset Field, Kern County, California (Figure I-1). The project was initiated in July, 1975, by Santa Fe Energy Company - Chanslor Division (SFE) and was followed by the DOE Cost-Sharing Contract which commenced on June 16, 1976, and will expire on June 30, 1983. At contract initiation the total cost of the work to be performed under the contract was estimated to be $8,247,266. Of this estimated amount, the Government will fund a maximum amount of $1,700,000 (21%). Actual cost will be approximately 2.5 times the original estimate, because of increased fuel cost, delay in expanding project area which caused capital expenditures to rise, and the unpredictably high inflation rates. Likewise, the revenue stream has and will increase dramatically.

The "200" Sand Pool produced very little primary production and responded poorly to cyclic steam stimulation. Therefore, this project was initiated to demonstrate the operational, recovery, and economic aspects of steamflooding a typical heavy oil reservoir which had unfavorable response to cyclic steam stimulation. A pilot test was conducted in four (4) 2.35 acre inverted seven-spot steam drive patterns, which were not fully developed with producers (Figure I-2). As a result of the response shown by the pilot, in April 1980, work began to expand the pilot area to a total of fourteen (14) fully developed 2.35 acre inverted seven-spot patterns (Figure I-2). Expansion to a full-scale steamflood test will consist of drilling and completing 30 producing wells and 10 steam injection wells. The reservoir contains approximately 50 million barrels of oil-in-place in a structure that lies between 400 and 700 feet in depth.

SCOPE OF WORK

The scope of the "200" Sand Steamflood Demonstration Project is being done in five phases, which are: (1) pilot site monitoring and evaluation, (2) pilot area expansion, (3) site selection for expansion to full-scale project, (4) expansion to full-scale steamflood, and (5) production monitoring.

The pilot site monitoring and evaluation phase consisted of a comprehensive evaluation of all available reservoir and production data such as well logs, sidewall cores, radioactive surveys, temperature surveys, and production and injection data. Two enclosed producers are the key wells in the evaluation of the pilot project. The two interior wells were completed with two types of completion techniques, a conventional gravel-pack slotted liner and a cemented cased-through-zone completion with only the steam drive interval being jet perforated. The purpose of the jet perforated completion was to determine if the steam injection can be restricted to the drive interval. This is accomplished by restricting production to the steam drive interval only. All other producers in the pilot are conventional gravel-pack slotted liner completions. The logs run in the producers and injectors were the formation density compensated log (FDC), compensated neutron log (CNL) and the dual induction log (DIL). Sidewall cores were taken and tested for permeability, porosity, saturation along with lithological description of samples. A minimum of two radioactive surveys are run in each of the injection wells, and a minimum of three temperature surveys are run in each of the producing wells each year. Surface equipment was installed including automatic gauging of production and injection data.

The pilot area expansion phase consisted of two step-out wells and two observation (information) wells. The step-out producers were drilled and completed in February, 1977, and in January, 1979, the information wells were drilled and completed. The step-out wells helped delineate and define the limits of the reservoir. The information wells were drilled to determine the degree of channeling, sweep efficiency, and to evaluate advancement of the flood front from an injector. The suite of logs run in the four wells were DIL, FDC, and CNL. A minimum of twenty (20) sidewall core samples were taken from each step-out well and analyzed for permeability, porosity, saturations and description of samples. Each information well was conventionally cored through the entire producing zone with a minimum of ten (10) sidewall core samples taken from each well.

The site selection for expansion to full-scale project was based on data obtained during Phase 1 and Phase 2. A pilot evaluation report was prepared in September, 1979, and after it was reviewed by SFE and DOE, both parties agreed that the pilot merited expansion. The expansion area was selected from the economics, production, and reservoir data.

The expansion to a full-scale steamflood phase consists of drilling and completing 10 continuous steam injection wells and 30 producing wells. Concurrent with this development drilling program, the surface equipment and facilities are being designed and constructed. A minimum of twenty sidewall cores per well were taken in twelve of the wells drilled, with permeability, porosity, and saturation being obtained. Two producers were conventionally cored. A suite of logs consisting of DIL, FDC and CNL was obtained in twelve wells drilled during this phase. The remaining wells will be logged with DIL as a minimum. Mud logs are being run on all wells. When the patterns are under normal operations, the expansion wells will have steam injected continuously in the injection wells and steam injected intermittently, as needed, in the production wells until there is a response to the steam drive process. The reason for the cyclic injection is to remove any wellbore's viscous oil preventing steam breakthrough and production. Response of all ten patterns is expected by January 1982.

The production monitoring phase will consist of three years of data gathering and reporting to complete the demonstration project. The project area will be monitored and evaluated monthly. During this phase of the project, two information wells will be drilled to determine sweep efficiency and permit evaluation of the advancement of the flood front in one of the ten expansion patterns. Each well will be conventionally cored through the entire producing zone, and DIL, FDC, and CNL logs will be run. A final report containing an evaluation of the total project will be prepared at the completion of the project.

Estimated steamflood and cyclic recovery for the total demonstration area is 4.5 million barrels of oil for the 200 foot sand reservoir. If the "200" Sand Steamflood Demonstration Project, which covers 32.9 acres, proves to be economically feasible, steamflooding can be expanded to the entire "200" Sand reservoir, which is approximately 250 acres and contains approximately 50 million barrels of oil-in-place. Likewise, methods and economics could be applied to other reservoirs in the Midway-Sunset Field as well as other fields with similar characteristics.

PROJECT DESCRIPTION

Reservoir and Geological Data

The reservoir is located in Section 17, T32S, R23E, Midway-Sunset Field, Kern County, California. The Spellacy formation, designated the "200" Sand of Upper Miocene Age, contains approximately 50 million barrels of oil-in-place. The crude oil is very viscous with ambient viscosities in the range of 6500 centipoise. However, the oil viscosity reduces rapidly with elevated temperatures. Figure I-3 shows as the temperature increases from 90°F (reservoir temp.) to approximately 200°F, the 12° API oil has an approximately 110-fold reduction in viscosity. With the same increased temperature, the oil-water viscosity ratio has a 35-fold reduction and an 18-fold mobility ratio reduction at original saturations.

The reservoir pressure in the "200" pool is very low, in the range of 20-60 psi. This pressure range does not provide sufficient energy for a producing mechanism. Most of the project area is located on top of a monoclinal structure where dips range from 5 to 15 degrees. With the low dips, gravity drainage does not provide an effective mechanism to obtain economical production rates and effectively deplete the reservoir. Herein lies the necessity of steamflooding, to not only reduce the oil viscosity, but also increase the displacement process, so the crude can flow to the wellbore.

Based on previous well data, and most recent drilling and coring data, the "200" Sand is a series of submarine fan-channels with the source area to the northwest of the project area. The reservoir consists of interbedded sands, conglomerates, silts and diatomite. Figure I-4 is a north-south cross-section map of the project. Contrary to initial analysis, these lower permeability layers of silts, diatomite or conglomerate, do not have continuity over long distances to allow the reservoir to be broken into discrete sand units. However, there are enough lower permeability layers so that lateral transmissibility is better than vertical transmissibility. Detailed correlation studies will be required to make sure all sand units are swept by the steam drive.

The sand is fine to medium grained, with scattered coarse to very coarse grains and pebbles. Usually the sand is clean and extremely friable with the grains being held together by the heavy viscous crude.

The average petrophysical properties for all productive sands are 2,250 millidarcies permeability, 30 percent porosity, and an oil saturation before steamflooding of 59 percent, equivalent to an average oil content of 1,373 barrels per acre foot. Table I-1 has a summary of reservoir data obtained from the pilot wells and surrounding core holes in Section 17, T32S, R23E.

Well Completions

The pilot injection wells are completed with 5-1/2" O.D. casing strings cemented in 8-3/4" holes at total depth. To maintain good steam injection profiles, the steam drive interval was restricted to approximately the bottom 50 feet of the reservoir with selectively jet perforated 1/2" holes every 2 feet. The First Annual Report[1] has further discussion on injection wells, drilling and completion procedures.

Two types of producing well completions are used in the pilot area. All, except one, of the producing wells are completed with 7" O.D. casing cemented from surface to top of producing sand, and 5-1/2" O.D. liner 60 mesh, 2" slots, run from 9 feet above the 7" casing shoe to 2 feet off bottom. The liner is gravel flow packed with 6 x 9 gravel

[1]Chanslor-Western Oil and Development Company: "The "200" Sand Steamflood Demonstration Project, First Annual Report, June, 1976 - June, 1977" DOE Report No. SAN/1277-1.

in a 9-7/8" hole. Producing conditions in unconsolidated sands generally require that producing wells be completed with sand control liners. One producing well, 255, had a limited perforated cased-through completion to determine if steam injection can be confined to the drive interval by restricting production in the producer to the steam drive interval. Conclusion of this test is discussed on Page 13. Also, the well has been closely observed for excessive sand production and after 4.5 years of production, there have been no sand problems. The well was completed with 7" cemented casing, jet perforated with four, 1/2" holes per foot.

The two observation wells are completed with 2-7/8" O.D. tubing strings run to 2 feet off bottom and cemented in the open hole. Temperature response is monitored in the observation wells by using a surface recording downhole thermocouple tool. Temperature profiles are recorded every three months to define the position of the heat front and steam and hot water zones. Neutron logs are being used in monitoring the movement of reservoir fluids thus observing the depletion growth as the steam drive progresses.

Surface Facilities

Steam Generators

Two 20-million Btu/Hr. steam generators were used in the pilot area, and the site for the generators was within the pilot area. The units provided approximately 1,800 B/D steam for the four injectors, and each unit has the capability of heating 900 B/D of water to between 500 and 600 Farenheit. The generators have 1500 psi discharge pressures. Both generators can be fired on either natural gas or oil, but due to the limited supply of fuel gas available, the generators are fired with crude oil. Each generator uses fuel at a rate of 4 barrels/hour when operating at full capacity. The fuel oil was stored in a 500-barrel tank near the generators and was delivered to the generators by a centrifugal pump.

Since project start-up, the two 20-million Btu/Hr. steam generators have had normal shutdown for cleaning every 4 months which takes approximately one week. There has been no problem with fuel oil supply or significant electrical problems throughout the facilities. Additional descriptions and functions are available in The First Annual Report.

Water Softeners

The project is supplied with fresh water from the West Kern Water District. Water with total dissolved solids of 246 parts per million (ppm) is treated at Santa Fe Energy's South Midway soft water plant located on Section 8, T32S, R23E, approximately 1-1/2 miles northeast of the project. This plant is capable of handling approximately 20,000 barrels of water per day. The water system services numerous oil production areas and has operated with only minor problems. The system allows the steam generators to be operated without any appreciable scaling problem, and costs approximately $.01 to treat one barrel of water, or about .5% of the total costs of steam production.

Oil Treating Plant

Treating the fluid production is a major problem because an estimated 90% or greater of all Midway heavy oil is produced as an emulsion. Between 5 and 10 percent of the oil is rejected and has to be pumped back through the treating system with emulsion breaking chemicals. The treating plant, located 1-3/4 miles northeast of the project on Section 9, T32S, R23E, has operated with minor problems throughout the project life.

PROJECT PERFORMANCE

Steam Injection

Continuous injection was initiated in October, 1975. As of June 1, 1980, 2.07 million barrels of steam had been injected into the four injection wells at an average sand face injection temperature and quality of 350°F. and 72%,respectively. Steam at the generator outlets is 420°F. with 80% quality. The total project injection and injection for each of the four input wells are shown in Figures II-1 through II-5.

Results from laboratory and field tests by several oil companies indicate a steam drive should be initiated with 3-5 barrels per day per gross Ac-Ft. injection rate until response occurs. Once temperature and production responses have occurred, the rate can then be reduced to 1.5-3 B/D/Ac.-Ft. Unfortunately, the pilot averaged less than 2 B/D/Ac.-Ft. during the first two years which allowed for lower oil viscosity reduction and heat transfer and thus delayed favorable response. During this period, the injection wells were averaging only 220 B/D/well. Due to the lag in response time, estimated at 18 to 24 months, injection rate was increased to 450 B/D/well until September, 1979.

In September 1979, one of the two 20-million BTU/Hr. steam generators in the pilot was shut down. Since the operational, recovery, and economic performance had been determined, it was more advantageous to discontinue with the high injection rates that allows valuable BTU's to flow from the small pilot area. In June 1980, the second steam generator was shut down and all steam injection will be suspended until late 1980. The generators are being moved to a centralized steam plant. The plant is currently under construction in the NW/4 of Section 17, T32S, R23E, and it will be able to accommodate expansion of the pilot area and other companies' projects as well.

Production

Production from the ten pilot producers (exclude two step-out producers) have averaged 158 B/D oil and 237 B/D water the last year (Figures II-6 to II-19). Total pilot area production is shown in Figure II-7. Over half of the producers have shown very good response from the drive. The highest oil production rate was in Well 254 and its peak production was 67 B/D oil in March 1978.

One of the major limitations to the effectiveness of steam drive recovery are patterns not fully developed with producers. Fully developed patterns would have improved control of frontal movement and volumetric recovery, but capital availability did not permit additional drilling.

Since injection was reduced in September 1979, oil production from the pilot has shown a continuous decline. Of course this was expected since a relatively flat formation doesn't allow for gravity drainage. The decline is expected to continue until the new steam plant is completed.

The discontinuous impervious layers have complicated the problem in predicting the reservoir performance. Had the barriers separating the sands been competent and laterally continuous, controlling the flood front and gravity override would have been easier, thus making production prediction less complicated. At the onset of the project, data from the small pilot area allowed us to believe that the reservoir was divided into separate zones by continuous barriers. However additional drilling and coring have indicated the reservoir to contain many small discontinuous barriers. With these conditions there is no known standard or proven method that can be used to describe and predict the oil recovery.

Because of these factors, production rate and recovery are calculated from the empirical relationship between ultimate tertiary oil recovery and ultimate steam injection requirements.

Randomly distributed, discontinuous barriers will cause significant reduction in vertical transmissivity because of the tortuous path the fluid must follow. Yet while lateral transmissibility is better than vertical transmissibility, steam will eventually work around the discontinuous barriers and migrate upward to higher horizons. As the steam invades these regions, the oil will tend to flow vertically downward by gravity until it reaches the impervious rocks, whereto it will accumulate in a layer of high oil saturation. As the oil layer builds up above a barrier, it will begin lateral movement and move off the edge to lower regions. The driving force for lateral oil movement through the layer is the gravity head from the middle of the barrier where the oil layer is thicker. The oil layer will become thinner toward the edge of the barrier. Unfortunately it is not known just how fast this oil will drain laterally and vertically from barrier to barrier after invasion from steam override. Since there is no conceptualization of the time involved, perforations will be restricted in the expansion's injectors to the lower 20 feet of the sand. If recovery time becomes excessive, additional perforating will be considered.

PILOT EXPANSION PROGRAM

Results of the pilot demonstration project were sufficiently encouraging to justify expansion to a full scale project utilizing continuous steam injection. Ten additional 2.35 acre inverted seven-spot steam drive patterns are being drilled. The seven-spot pattern was retained because of the greater sweep and recovery efficiency that can be attained in the displacement of oil reserves in the shallow dipping reservoir. The configuration has an injector spaced approximately 210 feet from the pattern producers (Figure I-2).

Well Completions

From the initial geologic study, the zone barriers were believed to be laterally continuous. Therefore, producing Well 255 was completed with a jet perforated cased-through completion to determine if steam injection could be confined to the drive interval by restricting production in a producer only to the steam drive interval. Since additional information indicates the silt interbeds are not laterally continuous, which prevent vertical flow between zones, this type of completion will cease.

With the steam overriding almost as soon as it leaves the injector, it will be more advantageous to complete future producing wells with 5-1/2" O.D. slotted liners open across the entire producing sand. Since the steam cannot be confined to the 50' drive interval, Well 255 will be reperforated over the entire sand and evaluation will be made on the production and sanding problem under those conditions. The limited perforations did very well in controlling the sand production since it was put on production in 1975.

The expansion's injection wells will have the same completions as the pilot's injection wells. Injectors will be completed with 5-1/2" O.D. casing string cemented in 8-3/4" holes at total depth.

The expansion wells consist of 30 producers and 10 injectors. With the reservoir's complexities, Mud Logs and Induction Logs will be run on all wells. Density-Neutron Logs and sidewalls were run and taken only on injectors. Two producers were conventionally cored to get original conditions so that when two core holes are drilled later in the project life to evaluate the steam drive performance, SFE will be able to evaluate more fully.

Surface Facilities

Steam Generators and SO_2 Scrubber Systems

The pilot expansion project will require an additional 5500 B/D steam for 18 months, then the demand will be reduced to approximately 3800 B/D steam. To make up the additional steam requirement, two new 50-million Btu/Hr. generators are being installed. Each generator is capable of producing about 2800 B/D steam. When the steam demand is reduced, at least one of the 20-million Btu/Hr. generators will be used elsewhere. The generators will be grouped together in the NW/4 of Section 17, T32S, R23E, as part of a central steam plant for this area. After some delays from the Kern County Air Pollution Control District (KCAPCD), we did get approval to start the construction in June, 1980.

Since the concentrations of sulphur dioxide by law cannot increase in the general area, 95% efficient SO_2 scrubber systems that can scrub two, 50-million Btu/Hr. and one, 20-million Btu/Hr. steam generators will be installed. The law requires that one of the two existing 20's be scrubbed. To make operation easier, each generator will have its own scrubbing system. The non-regenerative sulphur dioxide removal system can use aqueous solutions of sodium carbonate, sodium hydroxide or sodium sulfite as the scrubbing agent. At this time sodium hydroxide will be the chemical used. The disposal material will consist of sodium sulfite, sodium bisulfite and sodium carbonate. Design of the system will allow for expansion to accommodate more steam generators.

Water Softeners

The additional steam will require installing one new water softener that will handle about 5500 barrels of water per day. West Kern Water District will supply adequate water to be treated and used for the project. The soft water plant is located on Section 8, T32S, R23E.

Oil Treating Plant

The pilot production and a significant amount of other SFE's production comes from the field to the treating plant on Section 9, T32S, R23E. Until recently the treating plant was operating near maximum capacity. A heater treater and free water knockout have been installed and can handle 5,000 BFPD and 7,000 BWPD, respectively. This will accommodate an expected production increase of 1100 B/D oil and 2500 B/D water from the expansion project.

Oil Recovery

Ultimate recovery of oil is estimated at 50% with project life of 13 years. The steamflood life and oil production schedule of the proposed expansion was calculated from the empirical relationship between ultimate tertiary oil recovery and ultimate steam injection requirements. Due to the present state of the art of heavy oil recovery, it is felt that estimates from field experience and observation would be better than theory or principle. Therefore, based on field experience, it is estimated that a cumulative steam/oil ratio of 5 with a 50% of the OOIP recovered is attainable. Figure I-5 shows the estimated oil production schedule.

PROJECT ECONOMICS

At the beginning of the project, the unavailability of an additional 20-million BTU/Hr. steam generator delayed production and temperature response. As a result, the project is behind schedule and the milestone chart has been revised from Figure III-1 to Figure III-2. Every effort is being made to bring it as close as possible to the original timetable.

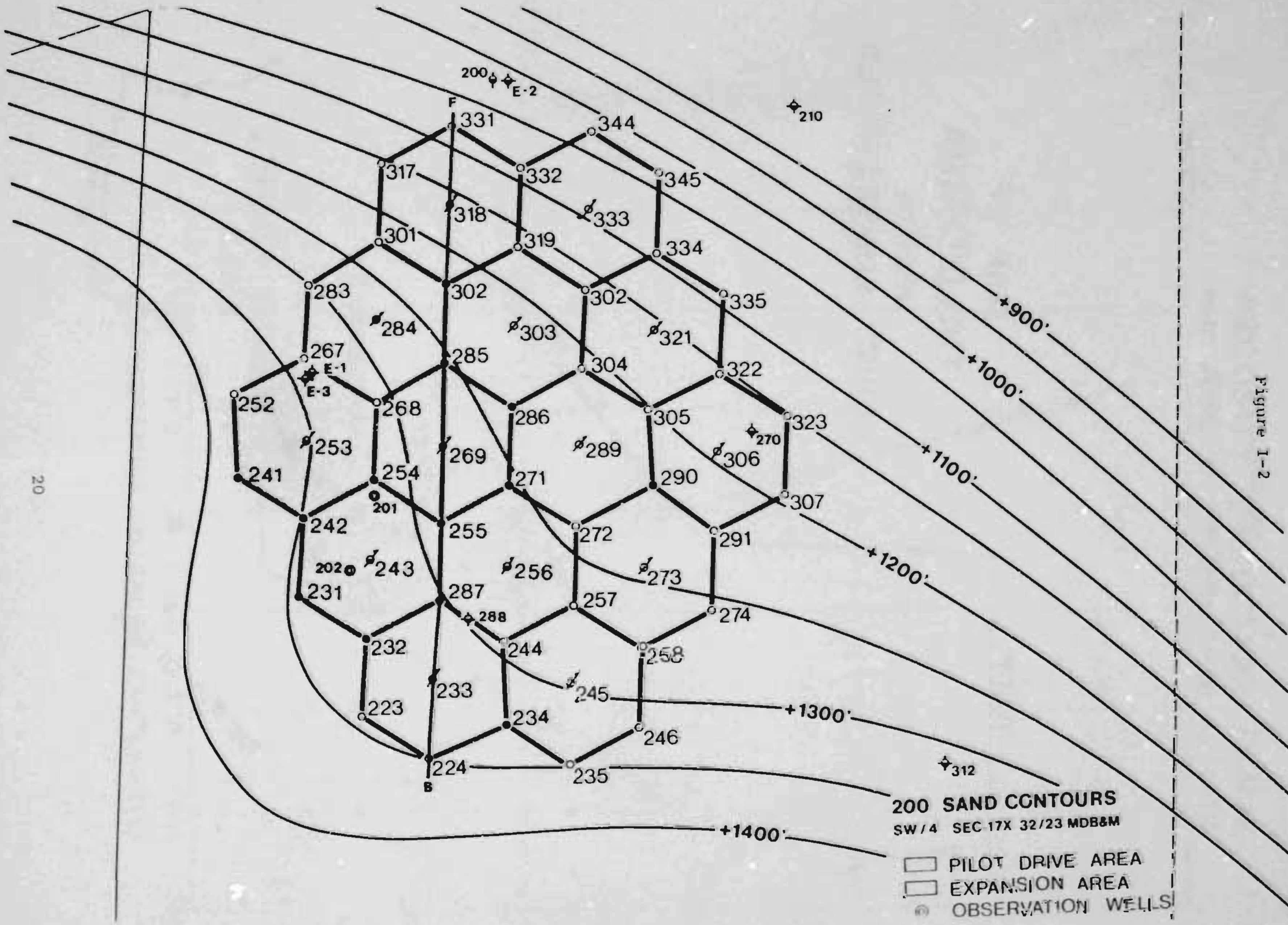
The total estimated cost for the seven-year project has been revised to over $21,000,000. Actual cost will be approximately 2.5 times the original estimate, because of increased fuel cost, delay in expanding project area which caused capital expenditures to rise, and the unpredictably high inflation rates. Likewise, the revenue stream has and will increase dramatically. Cumulative expenditures to date have been $3,059,962, of which DOE's share has been $1,244,538.

Table III-1 summarizes the pilot project economics from October, 1975 through May 1980, and that is because continuous steam injection started in October, 1975. In the table, a comparative is made with the economic posture of existing development vs. an estimated economic posture that has all patterns developed with producers vs. an estimated economic posture that has all patterns fully developed with producers and ideal steam injection rate. Based on the cumulative production of 167,826 barrels, the total operating cost was $8.74 per barrel of oil. Current operating cost was $3.88 per barrel of oil. It is estimated with fully developed patterns, the cumulative oil production, total operating cost, and current operating cost would be 262,554, $6.14, and $2.43, respectively. It is estimated with fully developed patterns and ideal steam injection rate, the cumulative oil production, total operating cost, and current operating cost, would be 584,008, \$3.31, and \$1.53, respectively.

APPENDIX I

RESERVOIR INFORMATION

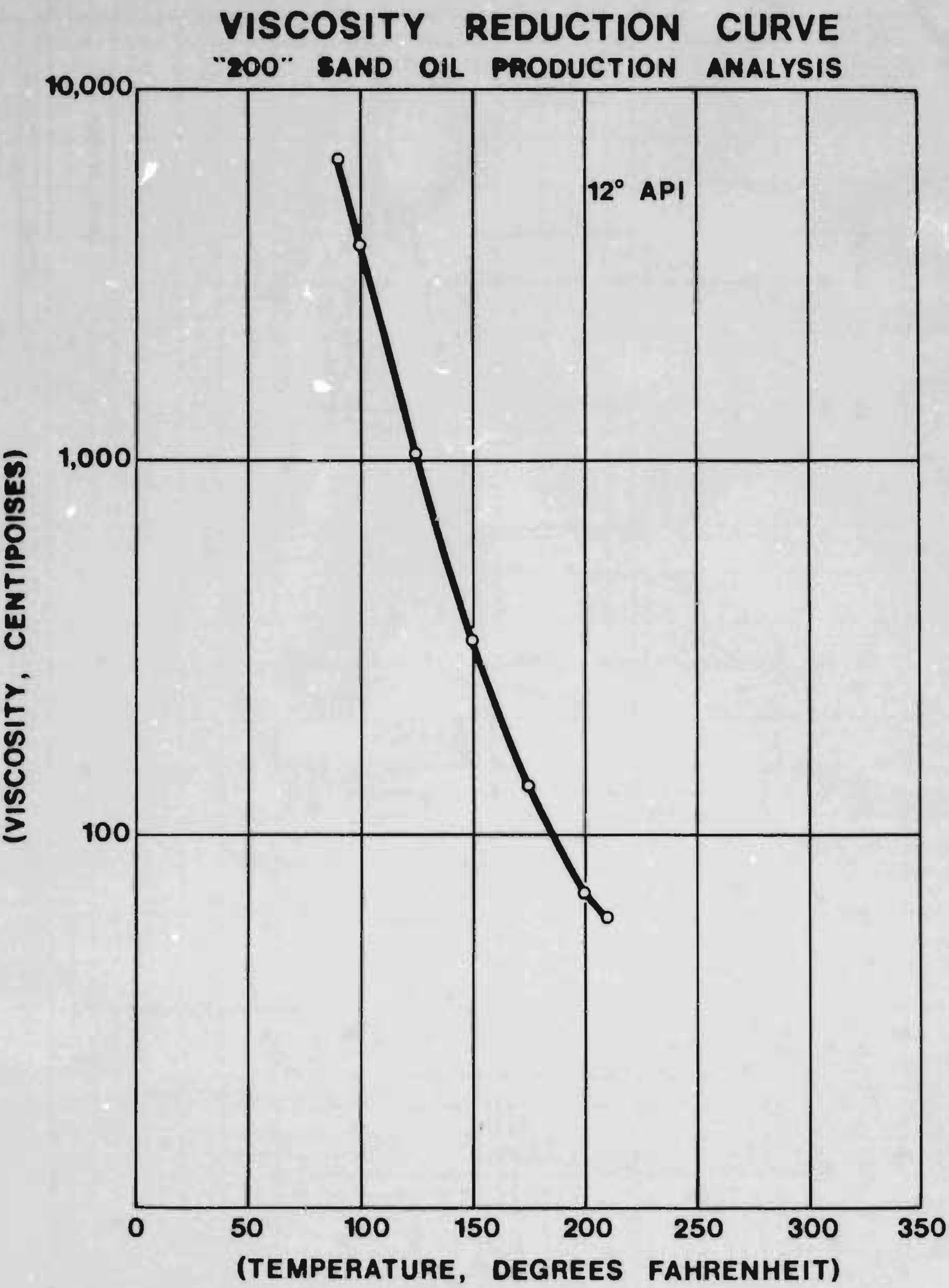
Figure I-1



200 SAND CONTOURS
SW/4 SEC 17X 32/23 MDB&M
PILOT DRIVE AREA
EXPANSION AREA
OBSERVATION WELLS
+900'
+1000'
+1100'
+1200'
+1300'
+1400'
F
B
E-1
E-2
E-3
200
201
202
210
270
288
312
331 344 317 332 345 318 333 301 319 334 283 302 302 335 284 303 321 267 285 304 322 252 268 286 305 323 253 269 289 306 241 254 271 290 307 242 255 272 291 243 256 273 231 287 257 274 232 244 258 233 245 223 234 246 224 235

Figure I-2

Figure I-3


VISCOSITY REDUCTION CURVE
"200" SAND OIL PRODUCTION ANALYSIS
10,000
1,000
100
12° API
(VISCOSITY, CENTIPOISES)
0
50
100
150
200
250
300
350
(TEMPERATURE, DEGREES FAHRENHEIT)

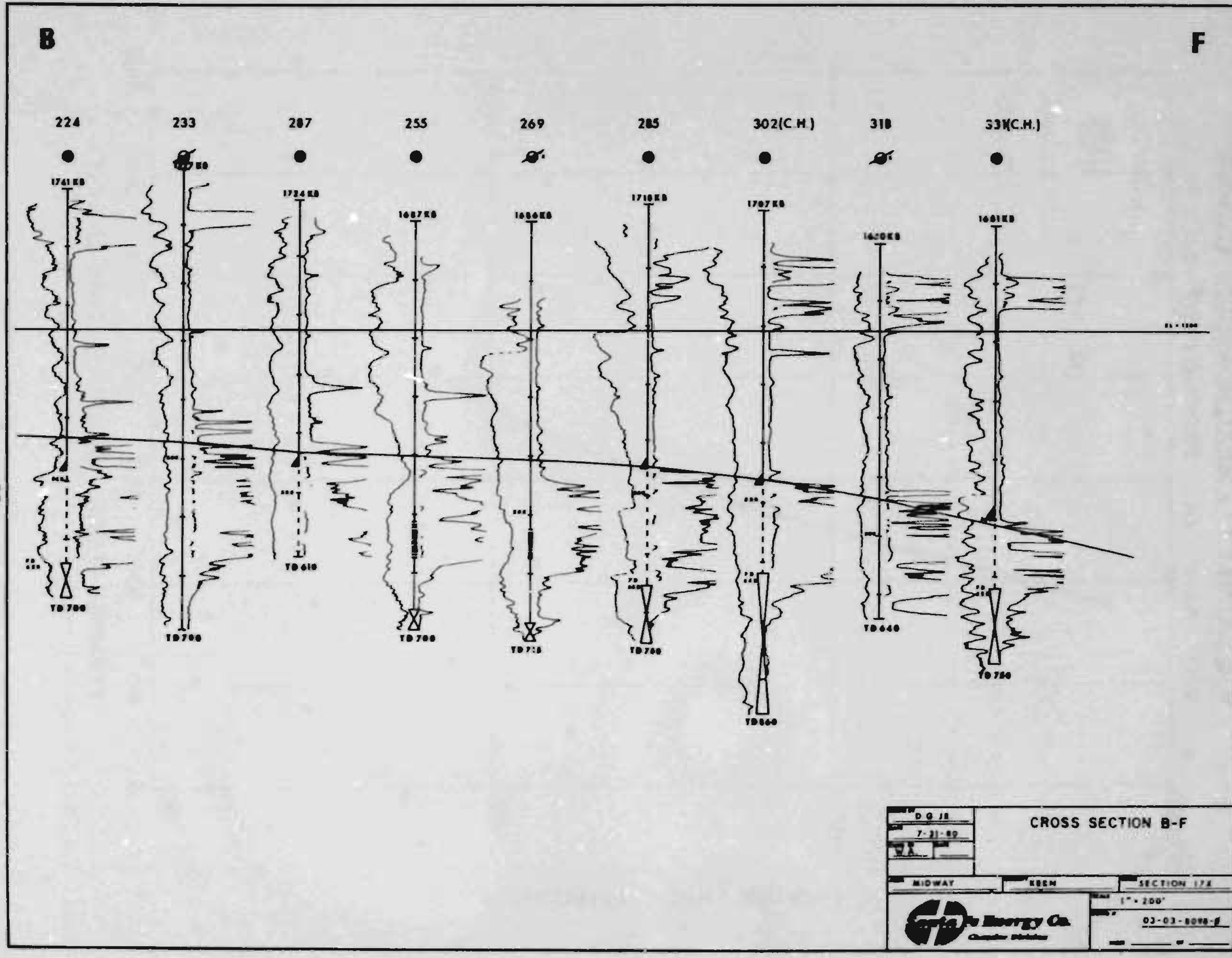
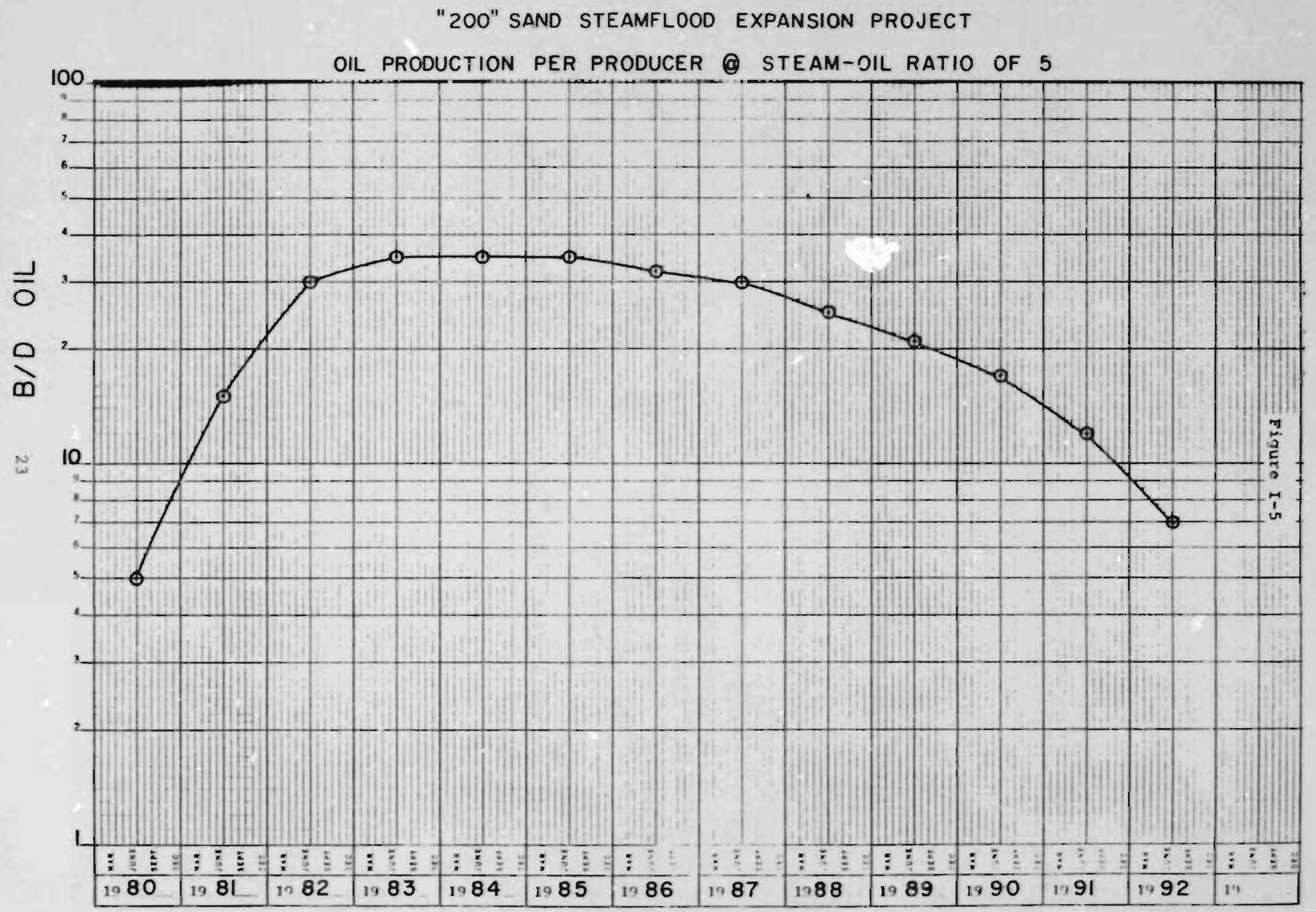

B
F
224
233
287
255
269
285
302(C.H.)
318
331(C.H.)
1761 KB
1724 KB
1687 KB
1686 KB
1718 KB
1707 KB
1681 KB
TD 700
TD 700
TD 610
TD 700
TD 700
TD 860
TD 640
TD 750
D G JR.
7-21-80
CROSS SECTION B-F
MIDWAY
KERN
SECTION 17X
1" = 200'
03-03-8098-0

Figure I-4


"200" SAND STEAMFLOOD EXPANSION PROJECT
OIL PRODUCTION PER PRODUCER @ STEAM-OIL RATIO OF 5
B/D OIL
100
10
1
1980
1981
1982
1983
1984
1985
1986
1987
1988
1989
1990
1991
1992
19

23

Figure I-5

Table I-1

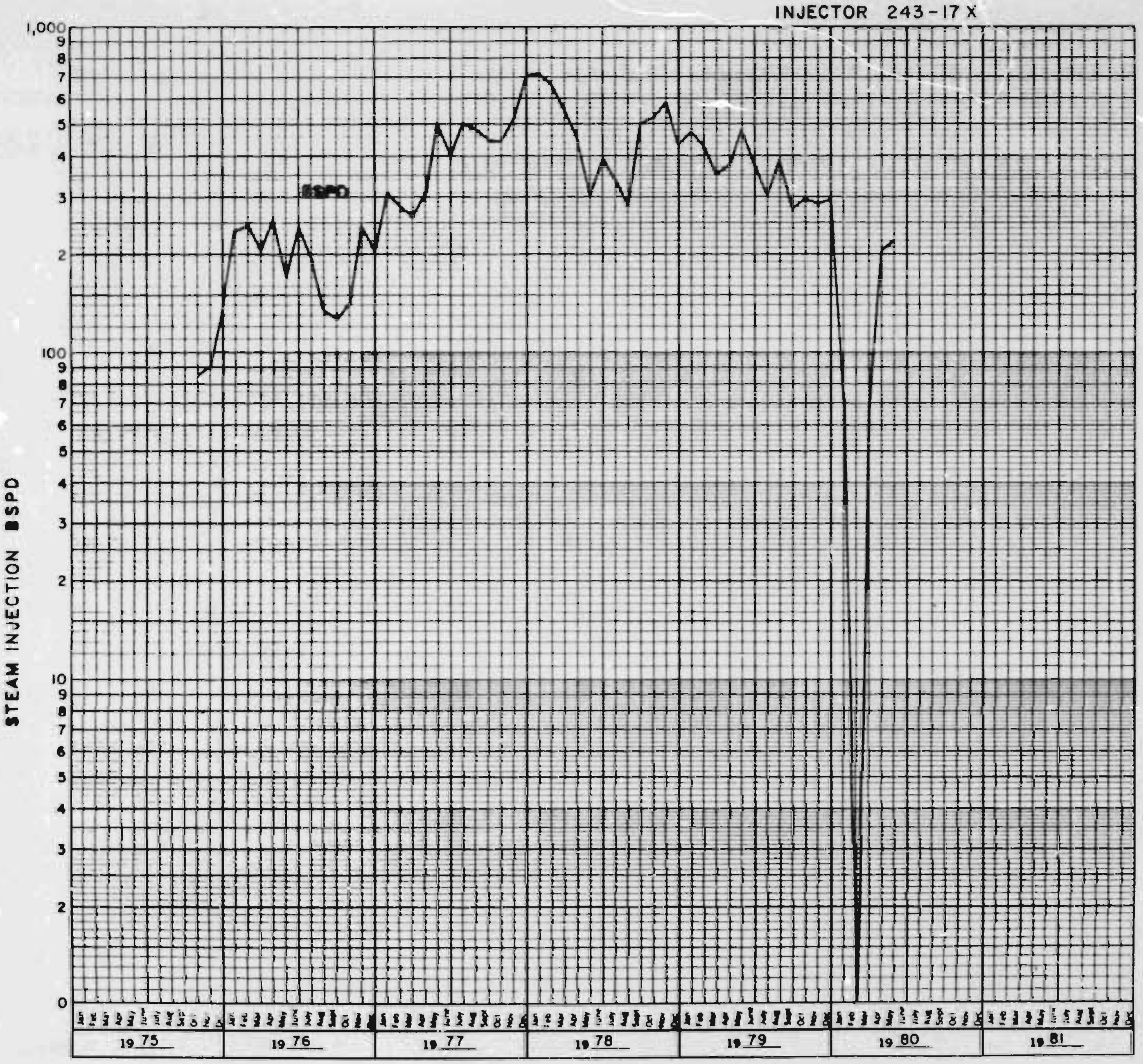
SUMMARY OF RESERVOIR DATA

DEPTH, FEET	400-700
AREAL EXTENT, ACRES (EST.)	250
OIL GRAVITY, °API	12
RESERVOIR PRESSURE, PSI (EST.)	40
RESERVOIR TEMPERATURE, °F	90
AVERAGE FORMATION DIP, DEGREES	12
AVERAGE GROSS THICKNESS, FEET	200
AVERAGE NET THICKNESS, FEET	150
PERMEABILITY TO AIR, MD	1,050-3,440
AVERAGE POROSITY, PERCENT	30
AVERAGE OIL SATURATION, PERCENT	59
AVERAGE OIL CONTENT, BBL/ACRE-FT.	1,373
OIL VISCOSITY @ 90° F, CP	6,500
OIL VISCOSITY @ 212° F, CP	60

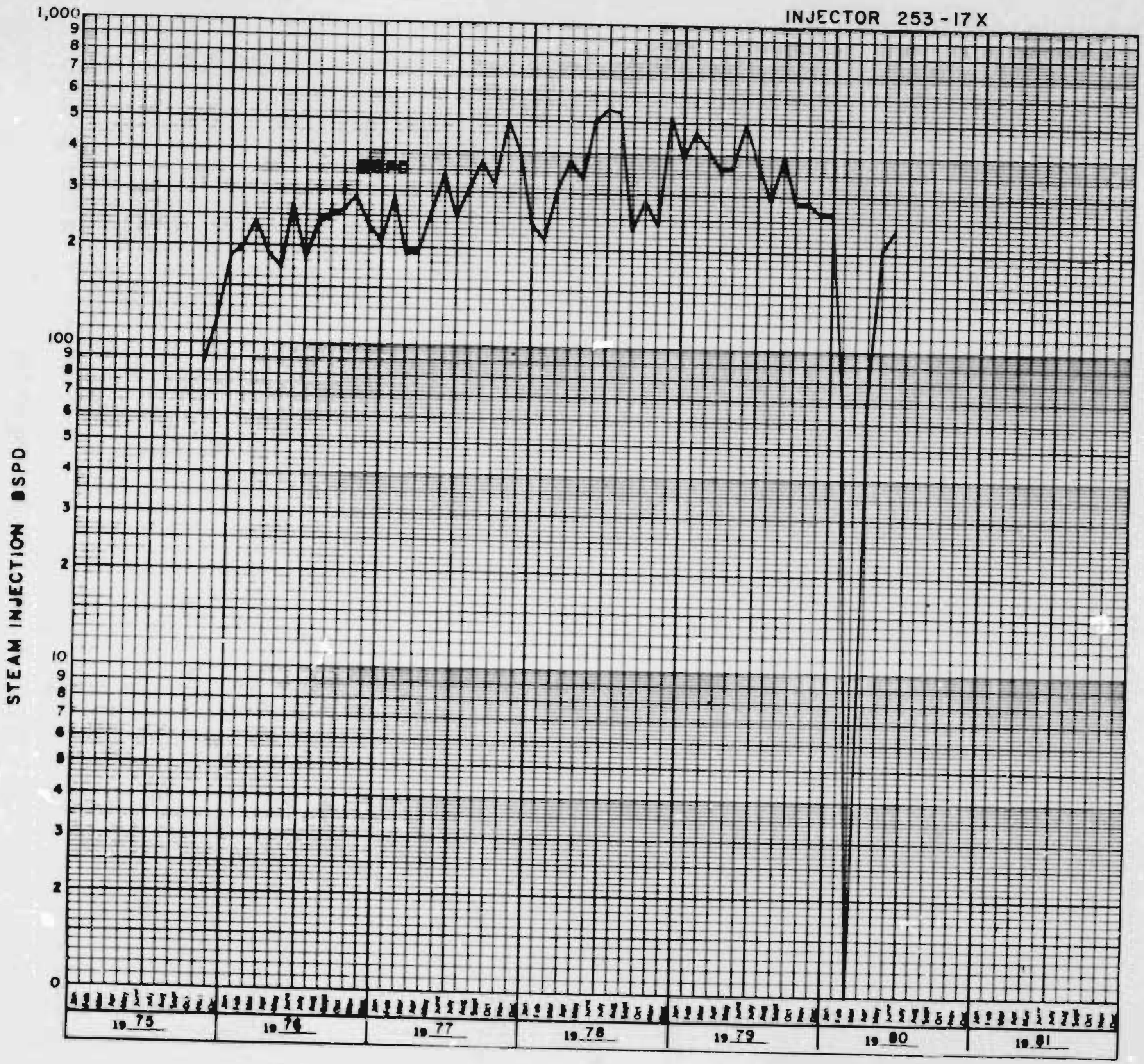
APPENDIX II

INJECTION AND PRODUCTION GRAPHS

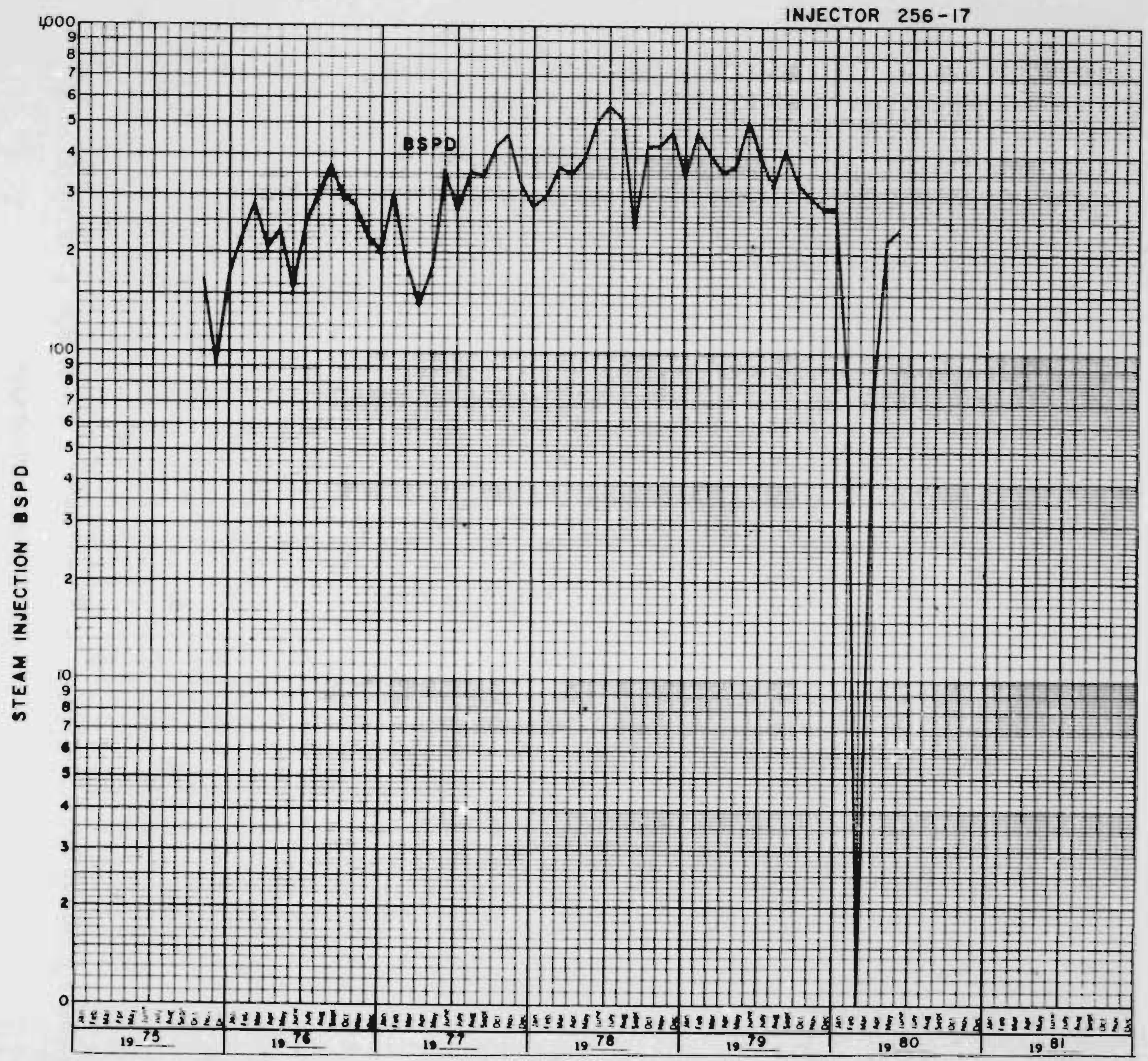
Steam Injection
Figure II-1



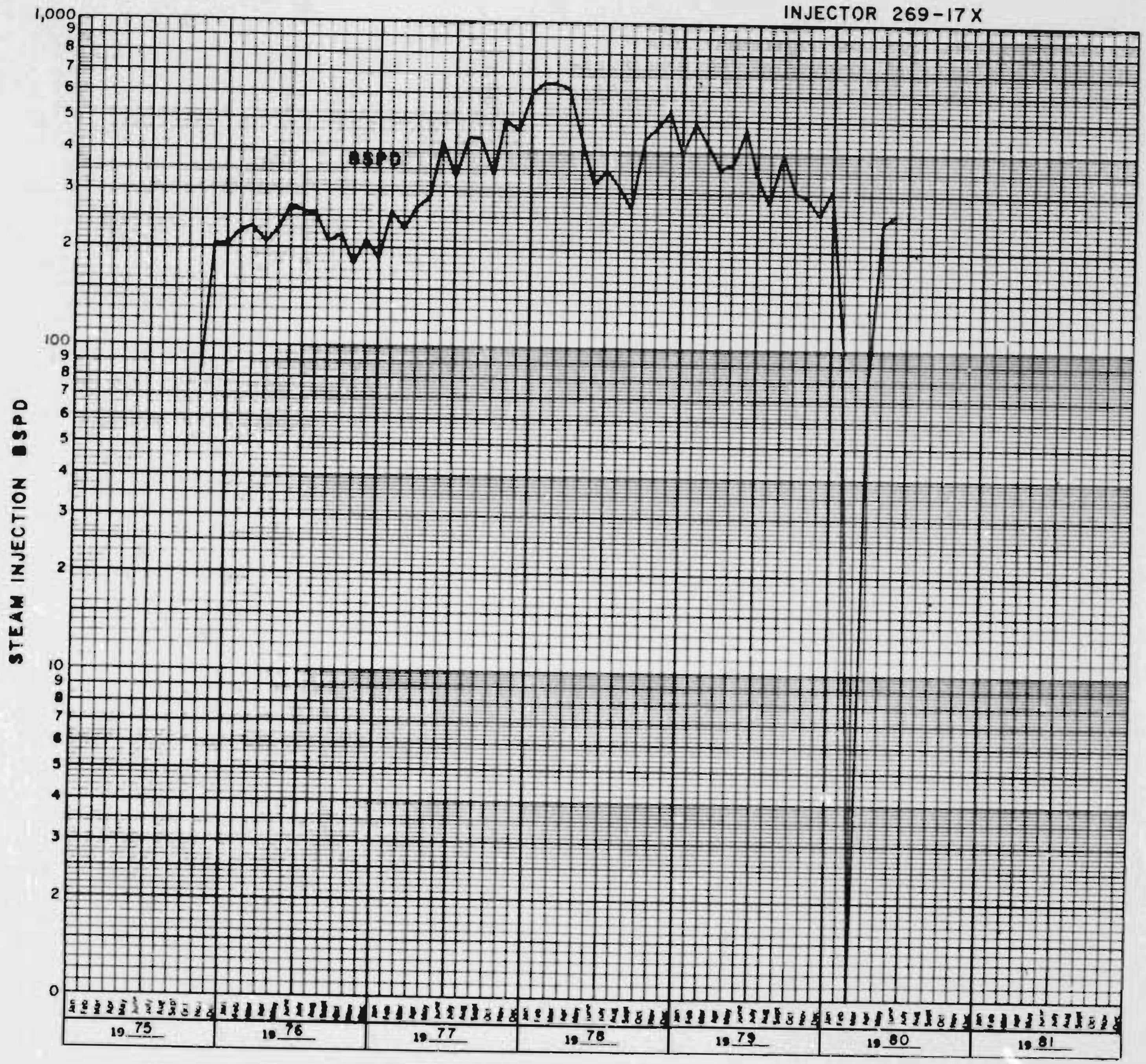
Steam Injection
Figure II-2



Steam Injection
Figure II-3



Steam Injection
Figure II-4

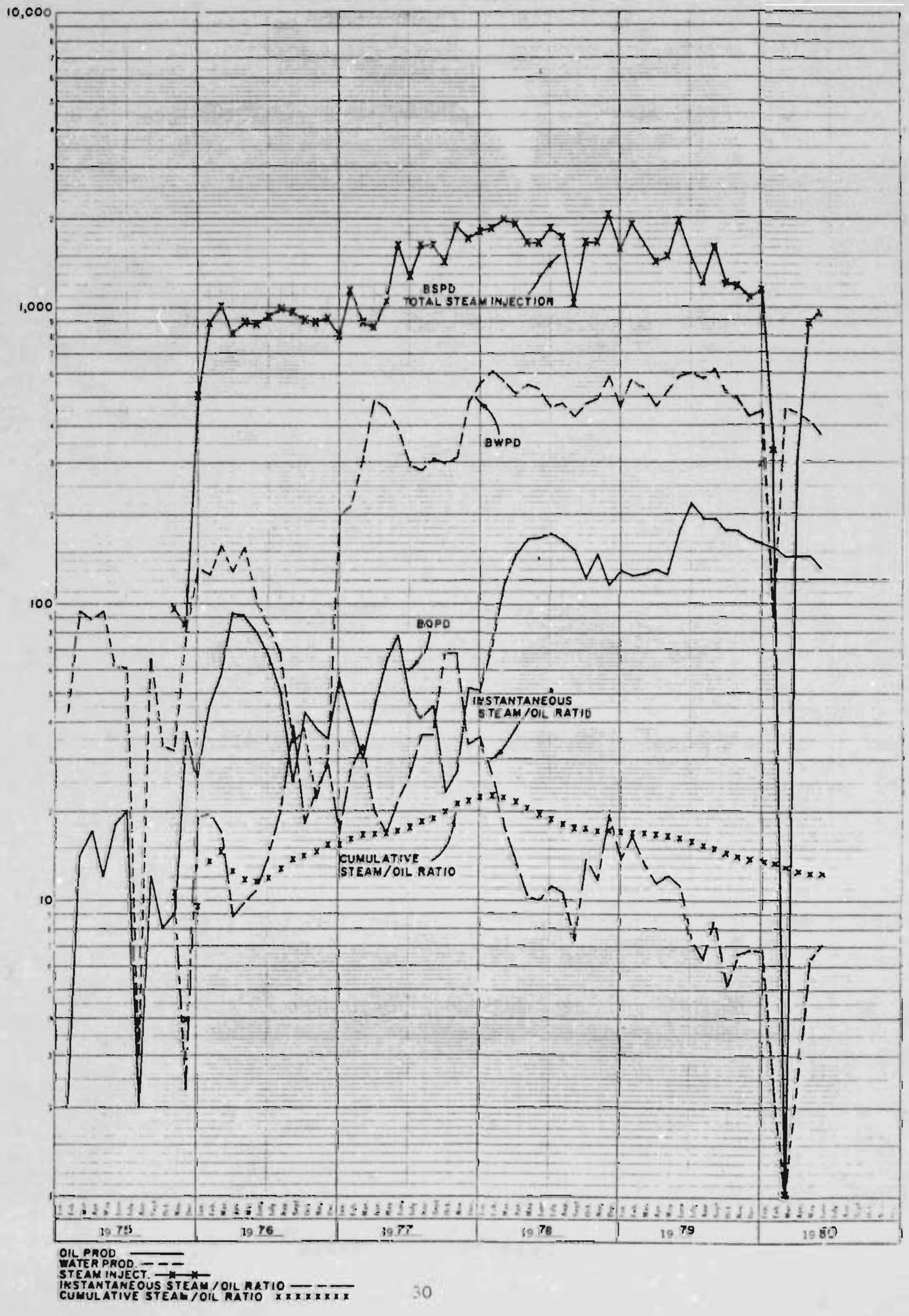


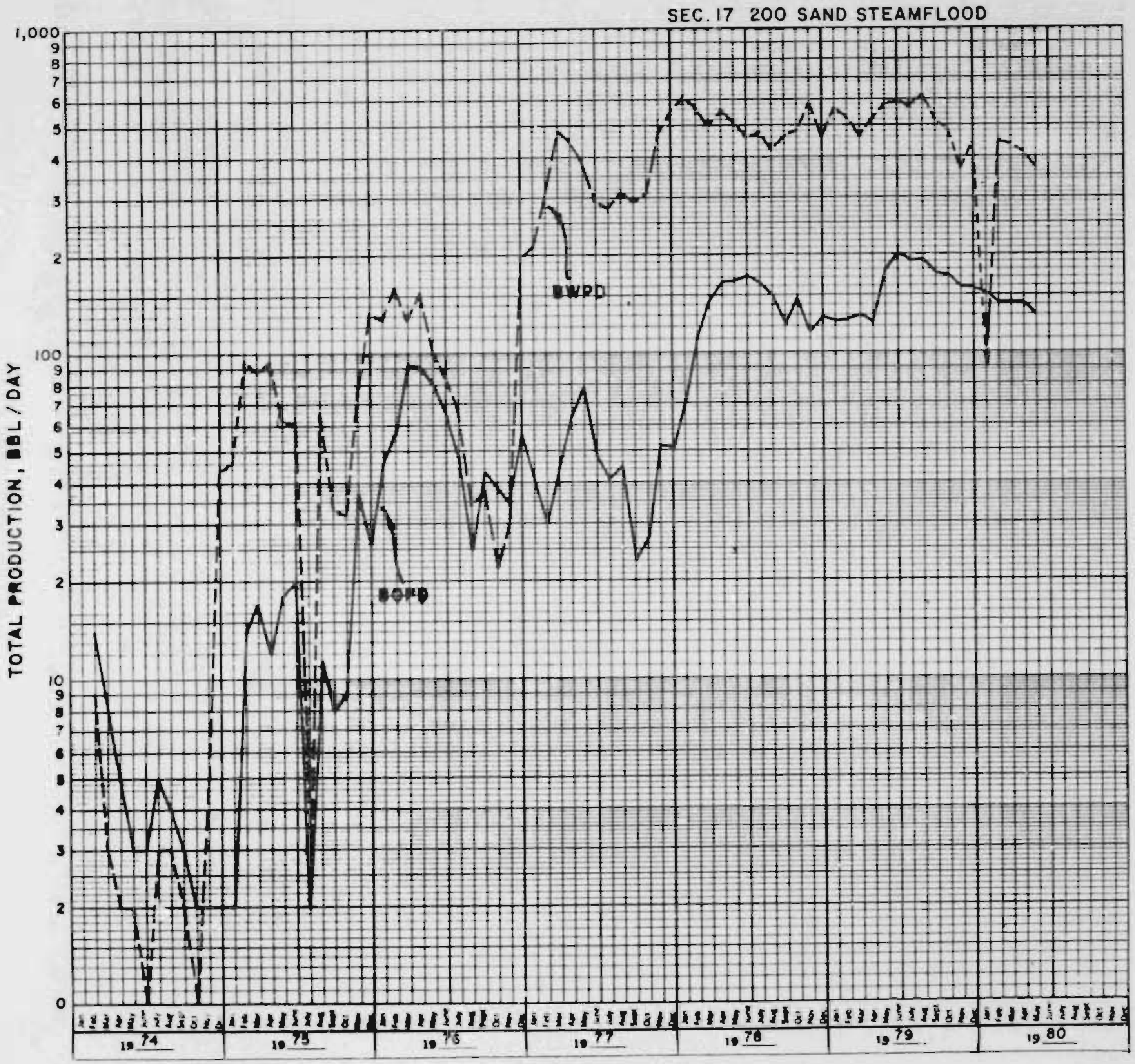
Steam Injection
Figure II-5

Figure II-6

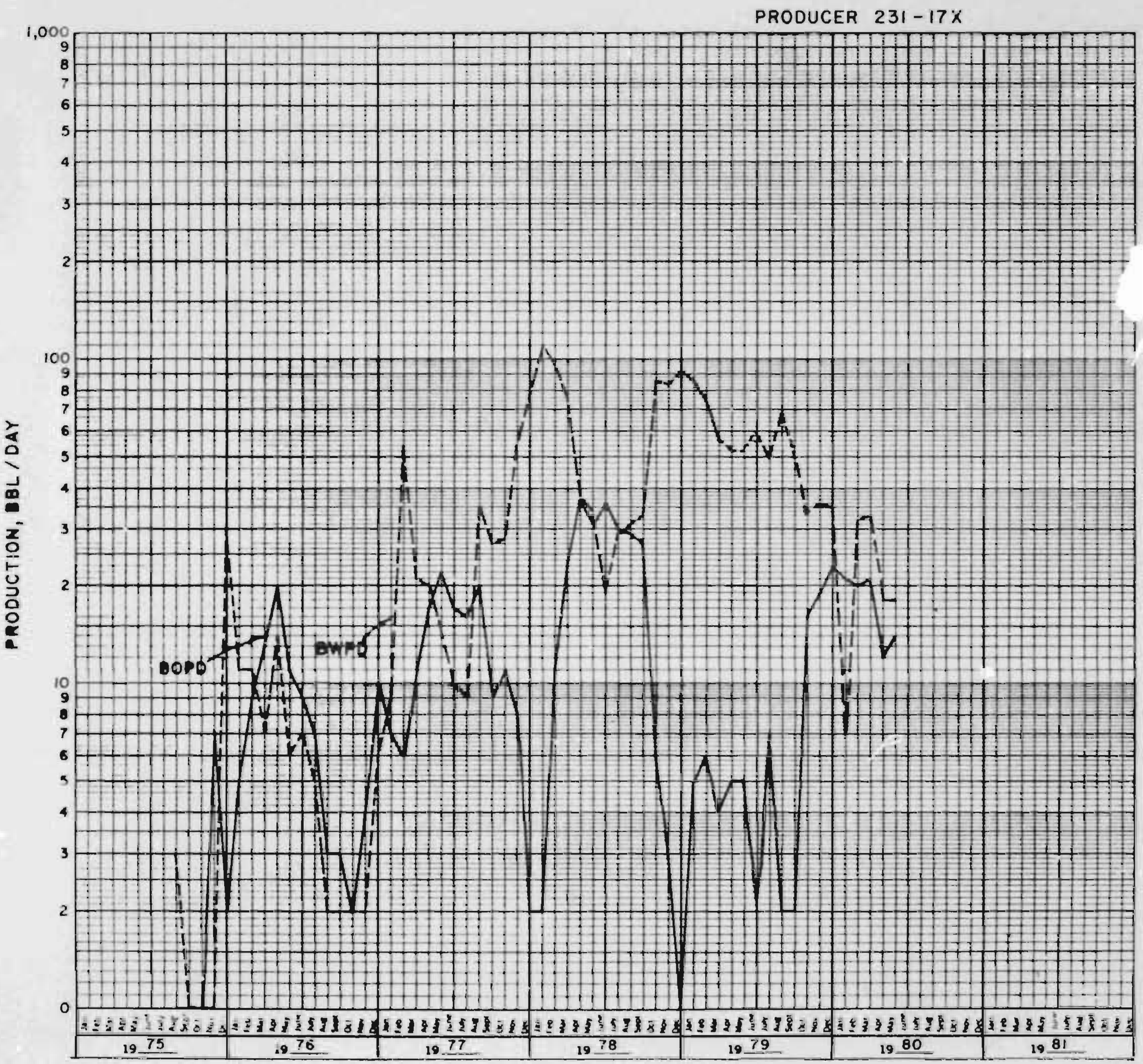
"200" SAND STEAMFLOOD DEMONSTRATION PROJECT

PRODUCTION AND INJECTION HISTORY

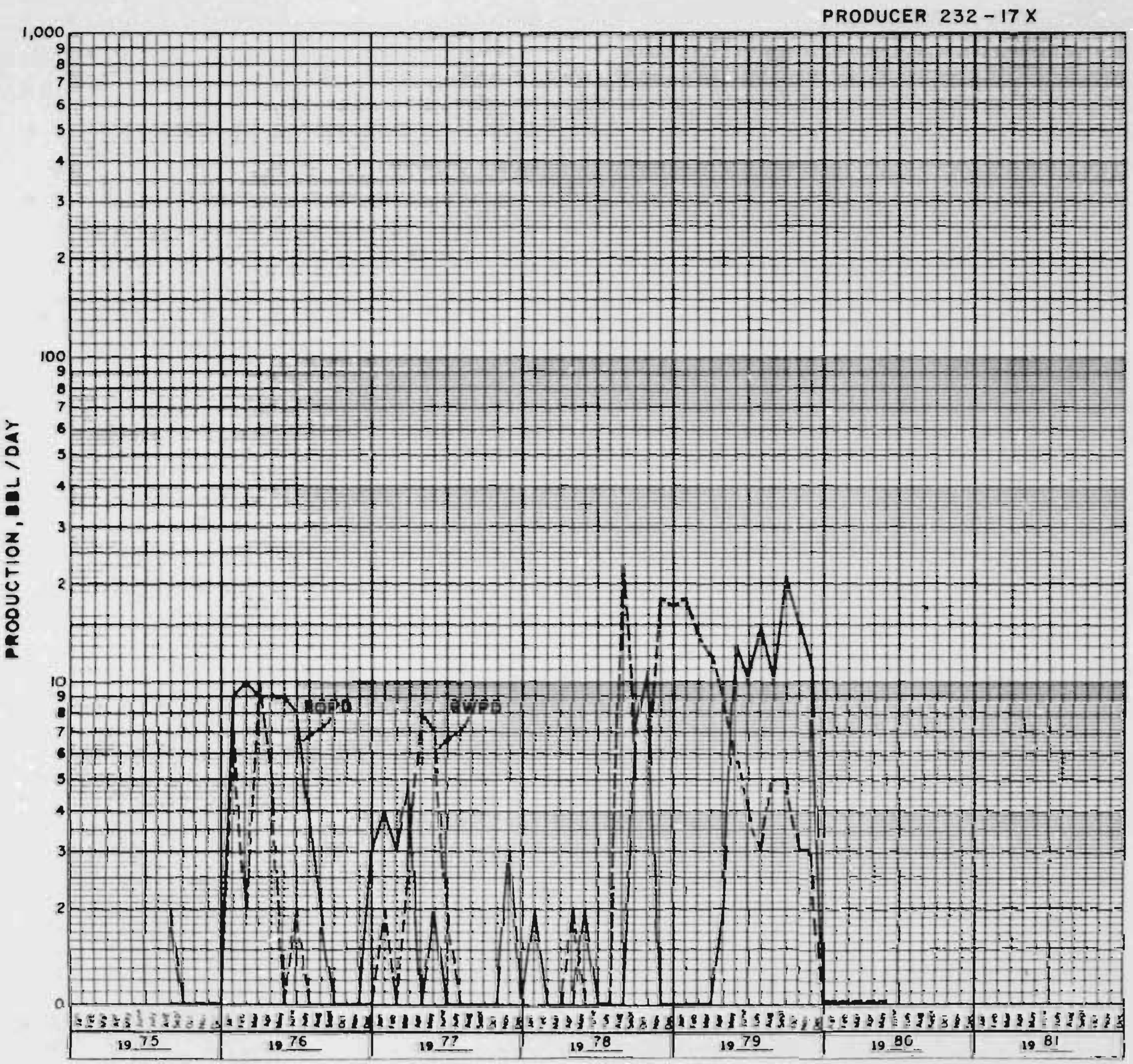




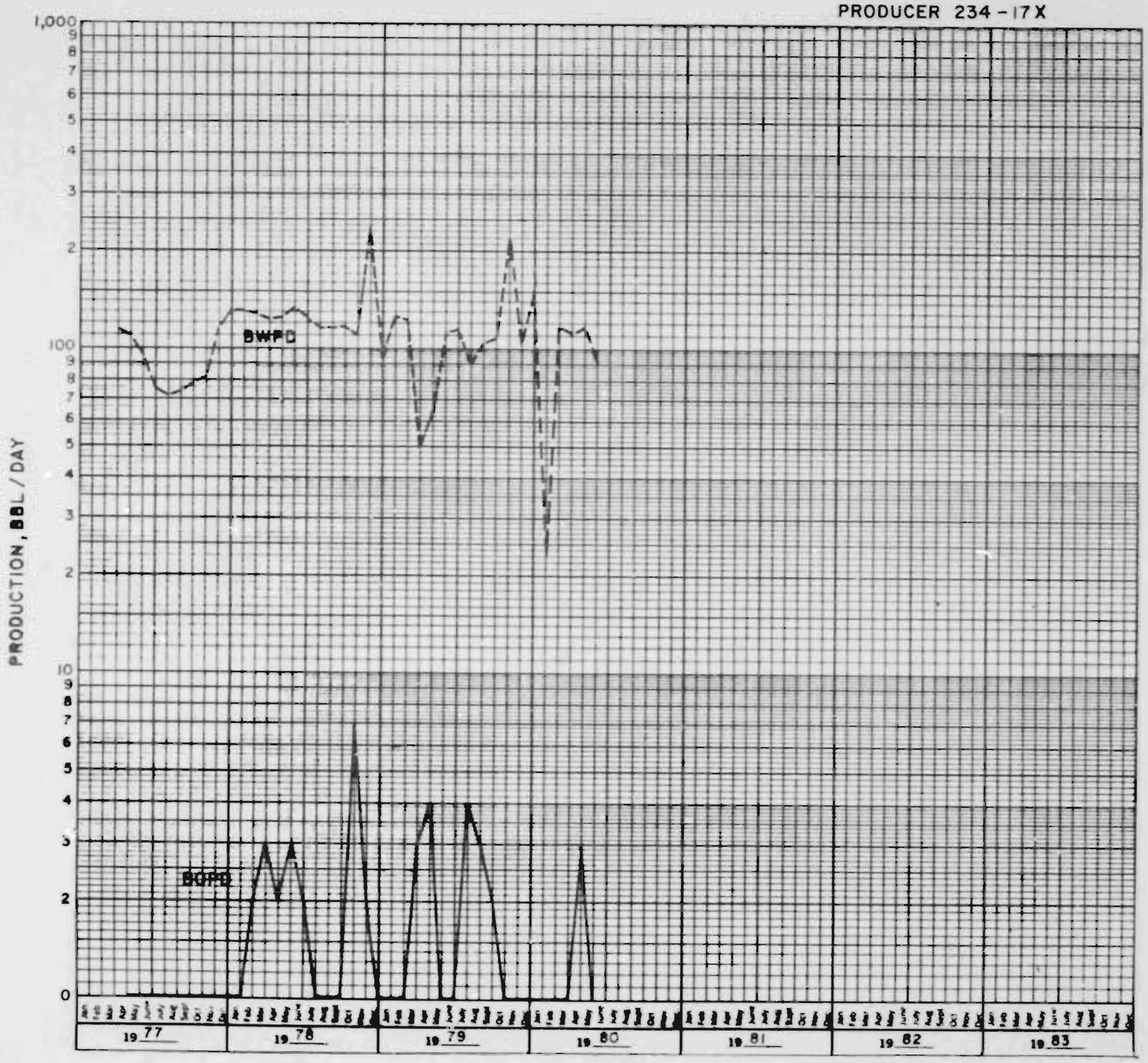
Oil and Water Production
Figure II-7



Oil and Water Production
Figure II-8



Oil and Water Production
Figure II-9



Oil and Water Production
Figure II-10

Oil and Water Production
Figure II-11

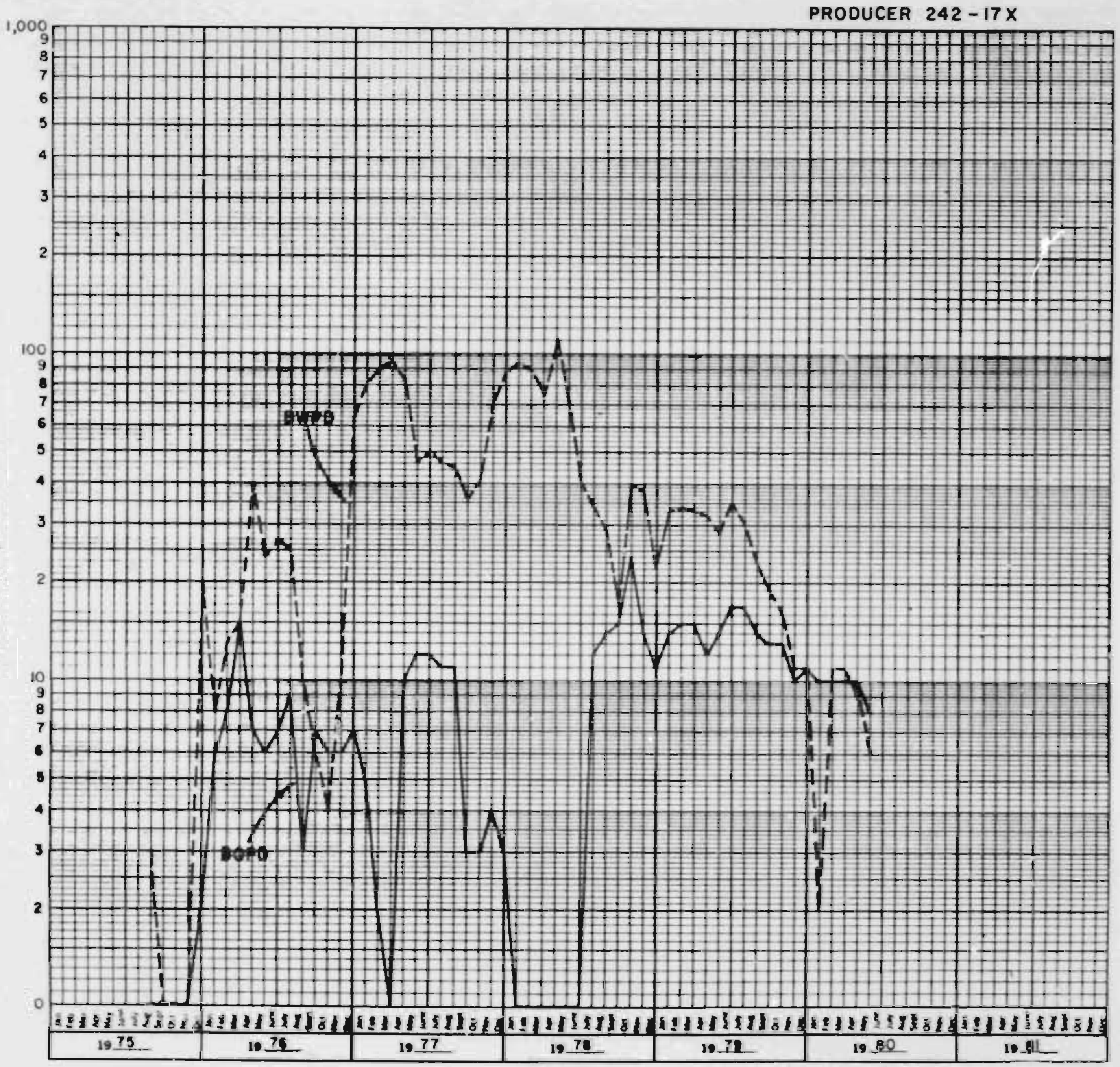
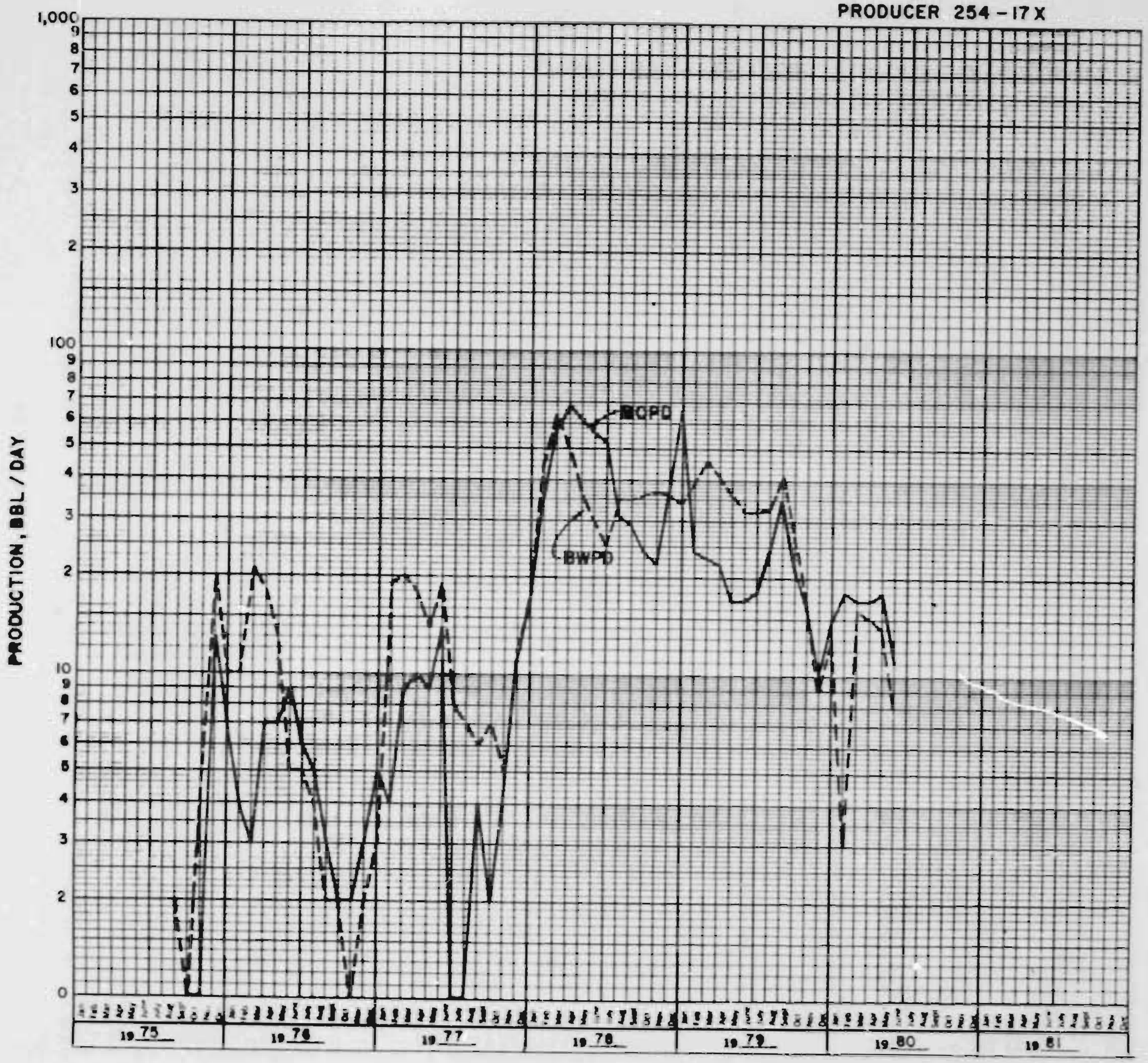
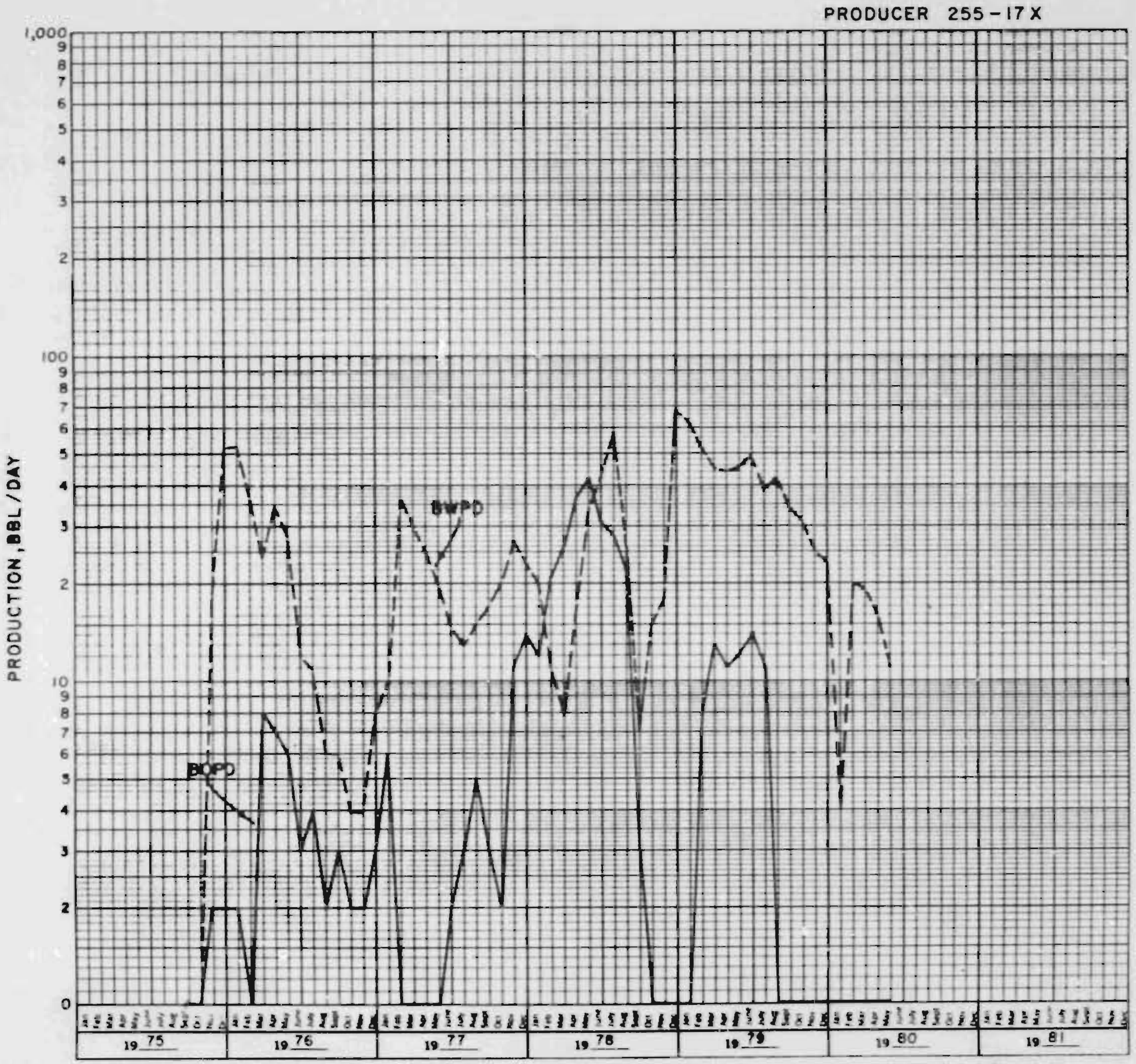


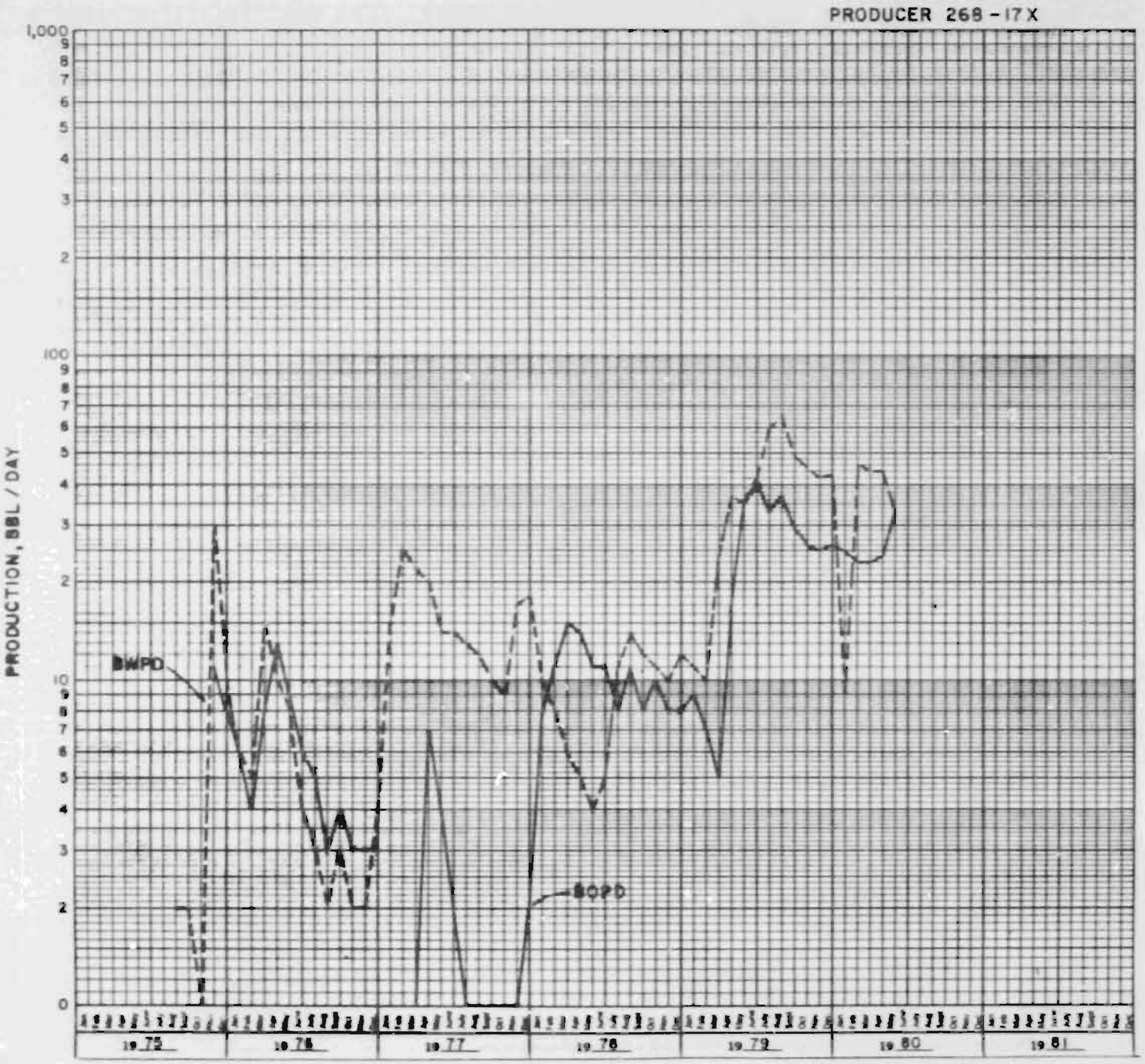
Figure II-12
Oil and Water Production



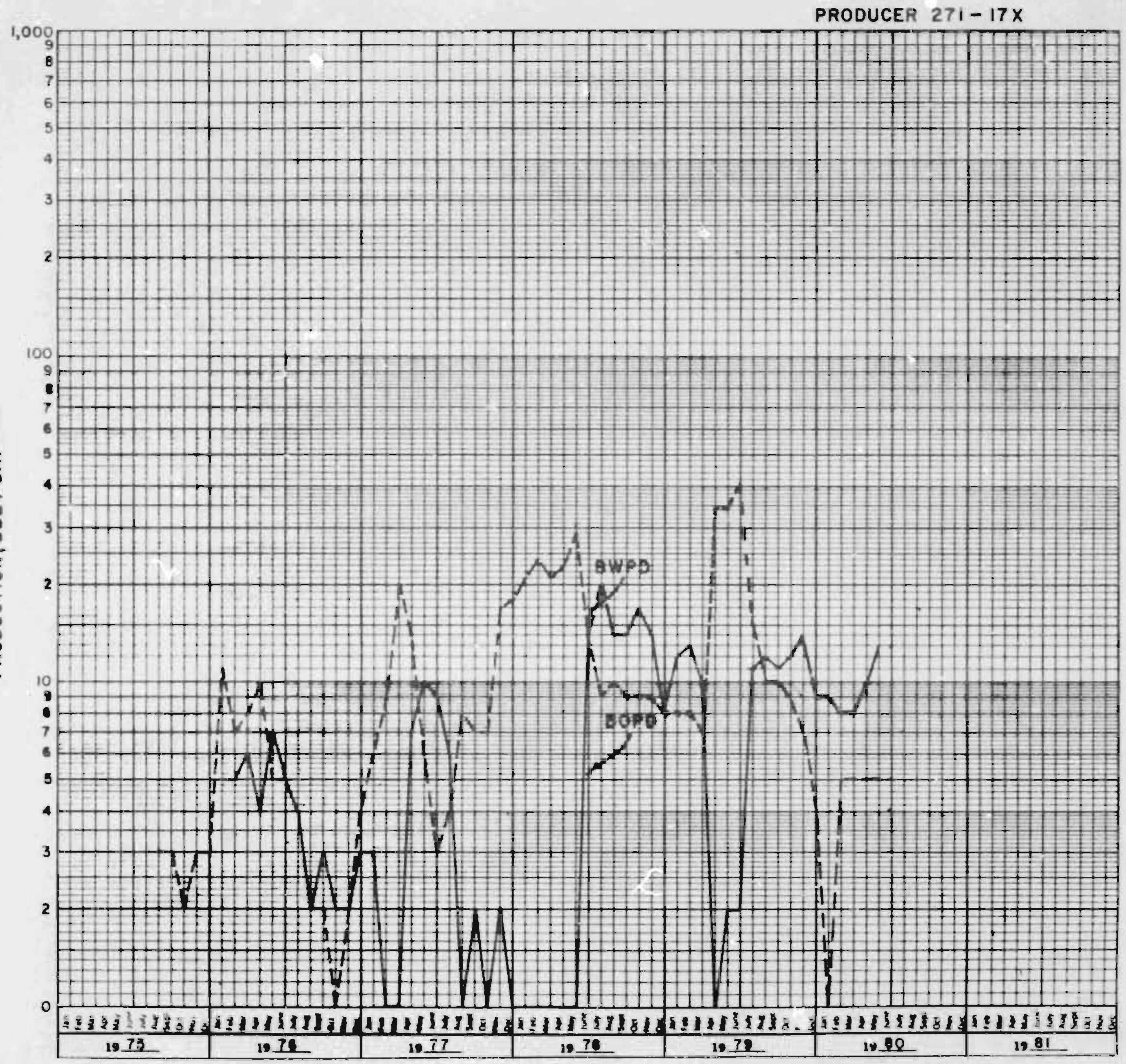
Oil and Water Production
Figure II-13



Oil and Water Production
Figure II-14



Oil and Water Production
Figure II-15



Oil and Water Production
Figure II-16

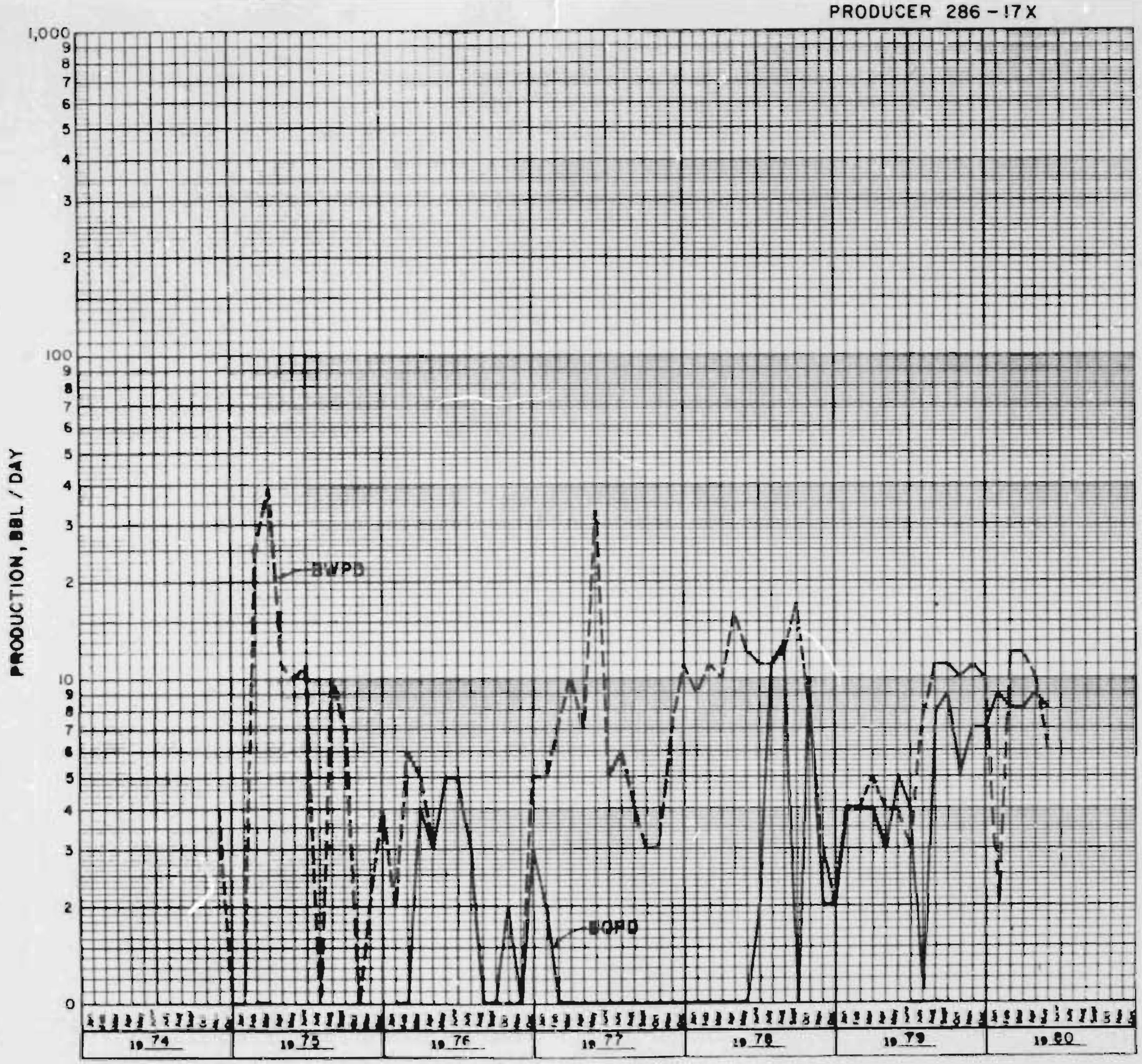
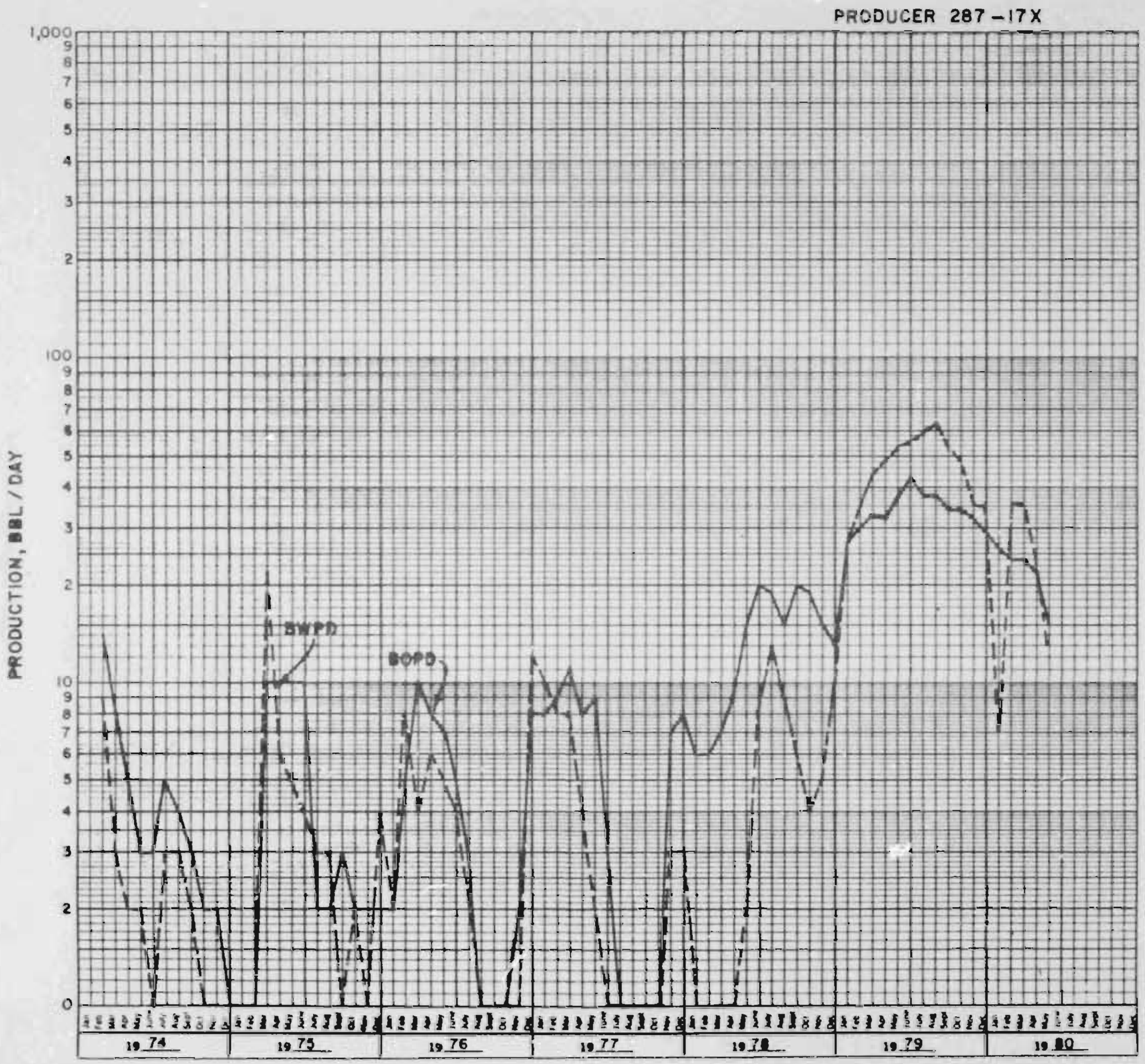


Figure II-17
Oil and Water Production



Oil and Water Production
Figure II-18

Oil and Water Production
Figure II-19

APPENDIX III

MILESTONE CHARTS AND FINANCIAL SUMMARIES

MILESTONE CHART - 200 SAND STEAMFLOOD DEMONSTRATION PROJECT

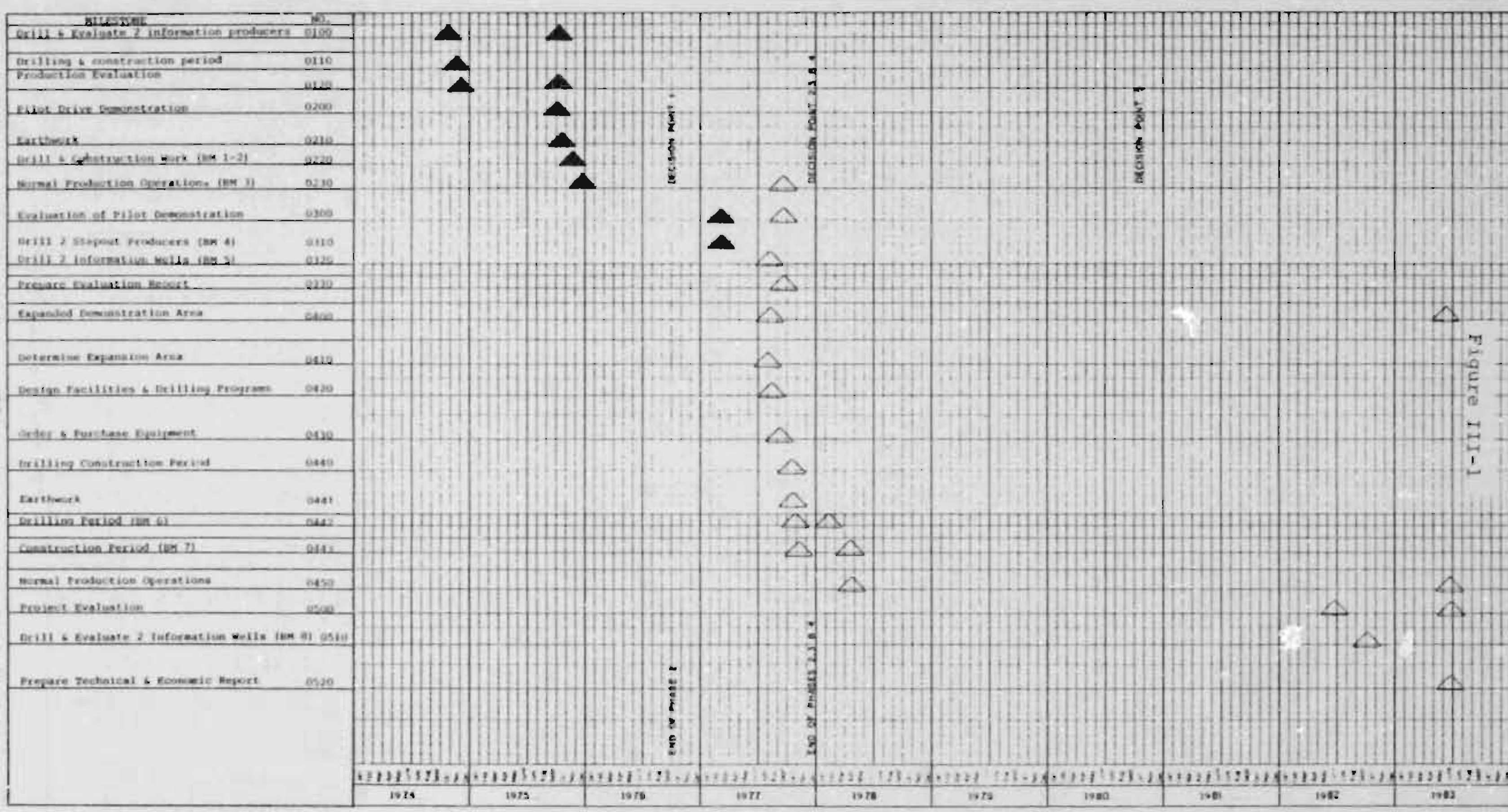


Figure III-1

REVISED (7-10-80) MILESTONE CHART - 200X SAND STEAMFLOOD DEMONSTRATION PROJECT

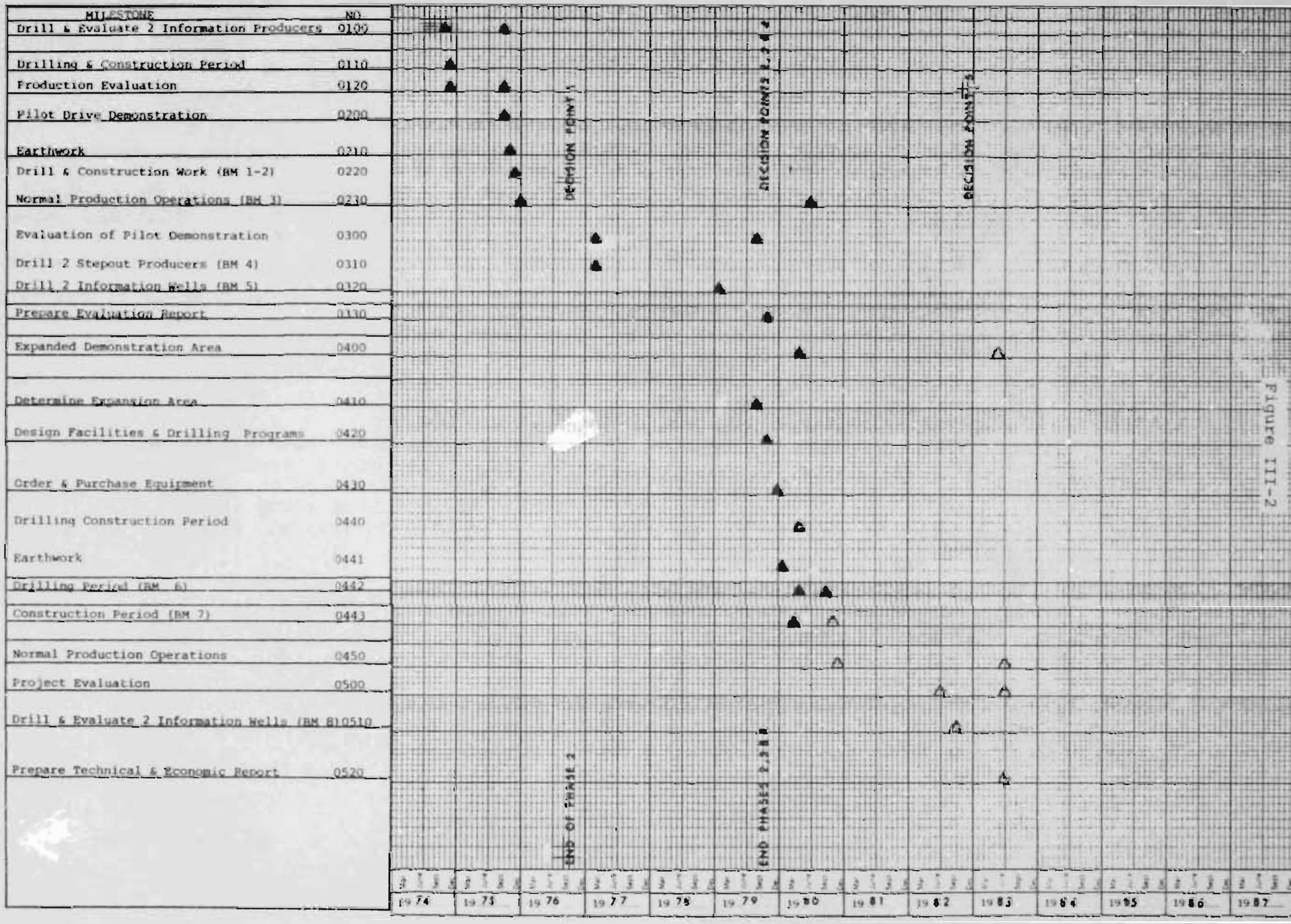


Figure III-2

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Table III-1

PROJECT ECONOMIC POSTURE
OCTOBER, 1975 THRU MAY, 1980

	ECONOMIC POSITION WITH EXISTING PATTERN'S DEVELOPMENT	ESTIMATED ECONOMIC POSITION WITH FULLY DEVELOPED PATTERNS	ESTIMATED ECONOMIC POSITION WITH FULLY DEVELOPED PATTERNS AND IDEAL STEAM INJECTION RATE
REVENUE	$2,026,869	$3,242,542	$7,335,140
OPERATING EXPENSES			
POWER (PRIME MOVERS FOR PUMPING UNITS)	25,213	40,341	40,341
LABOR (AT WELLS AND CONNECTING ELECTRIC AND PIPE LINES)	85,917	137,467	137,467
MATERIAL (AT WELLS AND CONNECTING ELECTRIC AND PIPE LINES)	130,433	208,693	208,693
WATER FACILITIES (POWER, LABOR, AND MATERIAL)	154,170	154,170	194,254
SECONDARY RECOVERY (LABOR AND MATERIAL)			
POWER	92,736	92,736	116,347
FUEL	979,256	979,256	1,233,862
TOTAL EXPENSES	$1,467,725	$1,612,663	$1,931,464
NET REVENUE	$559,144	$1,629,879	$5,403,676
TOTAL OIL PRODUCTION	167,826	262,554	584,008
REVENUE/BARREL OIL	$12.08	$12.35	$12.56
TOTAL OPERATING COST/BARREL OIL	$8.74	$6.14	$3.31
CURRENT OPERATING COST/BARREL OIL	$3,88	$2.43	$1.53
TOTAL CAPITAL EXPENDITURE	$977,538	$1,196,538	$1,196,538

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