

**Petrophysical Investigation of the Secondary Recovery
Potential in the Cherry Canyon Formation
NE Lea Field
Lea County, New Mexico**

Final Technical Report

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ABSTRACT

Read & Stevens has proposed the evaluation of the waterflood potential from the Cherry Canyon formation in the NE Lea Field in Lea County, New Mexico. Much of the development in this area is approaching primary recovery limitations; additional recovery of remaining oil reserves by waterflood needs to be evaluated.

The Cherry Canyon formation is composed of fine grained sandstone, containing clay material which results in high water saturation, and also has the tendency to swell and reduce reservoir permeability – the ability of fluid to flow through the rock pores and fractures. There are also abundant organic materials that interfere with obtaining reliable well logs. These complications have limited oil in place calculations and identification of net pay zones, presenting a challenge to the planned waterflood.

Core analysis of the Cherry Canyon should improve the understanding of existing well logs and possibly indicate secondary recovery measures, such as waterflood, to enhance field recovery. Lacking truly representative core to provide accurate analyses, Read and Stevens will obtain and preserve fresh core. The consulting firm of T. Scott Hickman and Associates will then collaborate on special core analyses and obtain additional well logs for a more detailed analysis of reservoir properties. The log interpretation will be compared to the core analysis results, and the entire collected data set will be used to assess the potential and economic viability of successfully waterflooding the identified oil zones. Successful results from the project will improve accuracy of log interpretation and establish a methodology for evaluating secondary recovery by waterflood.

TECHNICAL PROGRESS REPORT

INTRODUCTION

The Northeast Lea Cherry Canyon represents a significant oil accumulation. On the Read & Stevens-operated leases a total of 2.9 MMBO has been produced through June 2001, the majority of which has been from the Cherry Canyon. Many individual wells will have ultimate primary reserves in excess of 100 MBO and 40-acre volumetric calculations indicate primary recoveries in excess of 15% of the OOIP. Such performance indicates good permeability and reservoir continuity, suggesting that the reservoir is a waterflood prospect. On the other hand the Cherry Canyon is an extremely fine grained sand with a significant clay content that has a high water saturation. Cherry Canyon wells usually produce at a high water cut and it is difficult to determine from log and core analysis whether a zone is water or oil productive. Even if the oil productive zone can be identified, it is usually necessary to fracture treat the well upon completion to get beyond wellbore damage; hence the oil zones can not be isolated.

Industry has had very little experience with water flooding the Cherry Canyon. A literature search prior to undertaking this study revealed a few projects in New Mexico that were reported to be Cherry Canyon waterfloods. Only one, Indian Draw, had any extensive performance history. Although response to injection has occurred, the reservoir was several thousand feet shallower than that at Northeast Lea and probably is not a good analogy. In all cases there was confusion as to exactly what formation was being injected into. Most projects were injecting into both the Cherry Canyon and Brushy Canyon and in some cases the Upper Delaware, i.e. Bell and/or Ramsey Sands, was opened. The Bell and Ramsey Sands are proven waterflood prospects and are not analogous to the Cherry Canyon.

Read & Stevens commissioned T. Scott Hickman & Associates to conduct a waterflood study on the Northeast Lea Cherry Canyon reservoir. A detailed geological description was obtained on unpreserved cores from two wells which indicated a large amount of fine layered shale/sand lamination which would affect log response and calculate erroneously high water saturation (S_w) values. The prediction of waterflood performance in an untried formation would require accurate S_w values and valid relative permeability data for each rock type that might be present. It was decided that a preserved core would be cut for petrophysical analysis on the next well Read & Stevens drilled. Since the project was expanding in scope and complexity beyond what was originally envisioned, application was successfully made for a \$75,000 grant from the DOE under a special program for small independent operators.

The core was cut in early 2000 and the rest of the year was spent on conducting and interpreting special core analysis to define the reservoir's petrophysical relationship by rock types. A detailed core description with thin section petrography and depositional environment and sequence interpretation was performed by Fred Behnken. This report showed that shale lamination was not a problem and the study procedure was adjusted accordingly.

Both conventional and special logs suites had been run on the test well. The log interpretation results were combined with the petrophysical relationships from core to create a reservoir model for simulation. History matching with the simulator started in the spring of 2001. By early summer the model was calibrated and ready for waterflood predictive runs. Belatedly it was discovered that the commercial simulator being utilized did not have an oil hysteresis option which is needed to predict waterflood performance in a strongly water wet rock. Without this feature the results would be too optimistic. The software company acknowledged their omission, but development and inclusion of the hysteresis feature would take about a month. It was decided to go ahead with the waterflood predictive runs. If the results were not economic then there would be no need to run the hysteresis option.

However, the results were marginally economic so the hysteresis feature was used once it became available. Unfortunately, in the process of installing the new feature the programmer also made some change in the PVT processor and a couple of weeks were lost in reestablishing the original PVT relationships in the model. The simulator results were run through the OGRE economic model and the resulting cash flow clearly showed that waterflooding was not a viable option.

CONCLUSIONS

1. Within the study area the Northeast Lea Cherry Canyon reservoir has demonstrated good primary performance with individual wells estimated to have primary recovery on the order of 15% of their OOIP on a 40-acre basis.
2. The Cherry Canyon producing formation is a fine grained sand that is strongly water wet due to a coating of non-swelling clay around the individual sand grains. Due to the fine grain size and presence of certain types of clay, the average pore throat size is about 1.5 microns.
3. Even though both core analysis and performance indicate good oil permeability, the combination of water wetness and small pore throats creates unfavorable water relative permeability conditions for the recovery of secondary oil by waterflood.

4. The unfavorable conditions are manifested in low water injection rates, lack of sufficient banking of oil and extremely long reservoir pressure build up and oil response time.
5. Pressure maintenance by water injection initiated early in the reservoir producing life might have been economically successful. The simulation predictions indicate that reservoir voidage is now too large for pressure maintenance to be effective.
6. The simulation results predicted that infill drilling without water injection would not be economically successful.
7. Experience in history matching the primary performance during simulation suggests that there may be some unrecognized compartmentalization in the model area. Such a situation would not improve the waterflood potential, but might impact primary infill drilling in terms of undrained areas.
8. The irregular spacing of wells in the Northeast Lea Cherry Canyon reservoir prevents development of uniform injection patterns. This situation decreases the sweep and increases the costs. However, the results from the simulation of idealized uniform patterns still show that waterflooding is not economically viable.
9. The injection pressure in the simulator was held below formation parting pressure. Historically many operators in the Permian Basin have injected above parting pressure to increase injection rates. It is doubtful that such a practice at Northeast Lea would improve waterflood performance.
10. Secondary recovery by miscible CO₂ flooding has not been investigated. Such a technology might have much better relative permeability than water which would allow higher injection rates and faster processing of the pore volume. However, since the reservoir could not be effectively repressured initially with water or the miscible bank driven by water, the volume of CO₂ required would be much greater in relative terms than for a conventional tertiary CO₂ project.

RESERVOIR MODEL

A reservoir model was constructed for the southwest quarter-section area of Section 3, Township 20S, Range 34E for use in a three dimensional, black oil numeric simulator (Figure 1). The active wells in the model area are the Mark Federal Nos. 1, 2, 5 and 6. These wells were selected for the model based on the quality of the Cherry Canyon in the area in addition to the understanding that these wells have never produced from a reservoir other than the Cherry Canyon. Three Cherry Canyon sand members, "A", "B" and "C", were set up as individual layers in the model. Due to its low structural position and limited productivity, it was assumed that no water would be injected into the "C" sand. The rock and fluid properties assigned to each layer were based on the extensive petrophysical study conducted on preserved cores from the North Lea Federal No. 11 well. Although this test well was on the edge of the structure and exhibited limited productivity, the petrophysical relationships developed from it appeared to be applicable to the main reservoir based on a comparison of conventional core porosity and permeability values.

The reservoir model was calibrated by matching the reported primary performance. The history matching process is dependent on the allocation of production to individual wells. It has been our experience that the allocations in New Mexico, where per well allocations are required monthly, are reasonable when reported by a responsible operator. A usable match was obtained on three of the four wells. The lack of a match on the fourth well appears to be due to compartmentalization or zonation, but the impact is not sufficient to change the conclusion about waterflooding.

PATTERNS

Numerous waterflood scenarios for four different pattern configurations - five-spot, line drive, conversions and 20-acre infill drilling - were investigated with the simulator. Two additional cases were also simulated: 1) an "ideal" five-spot in which the producers were centered within each injection pattern and 2) an infill drilling case without water injection. Although the reservoir is developed more or less on 40 ac /well density, the actual spacing is highly irregular. This not only creates a problem with areal sweep due to non-uniform injection patterns, but necessitates the drilling of extra wells to give continuous development. With uniform spacing, five-spot or line drive patterns can be created either by well conversion or infill drilling with all but the interior producer being shared in common with other patterns, greatly reducing the investment per pattern. This is not the case in parts of the Northeast Lea Cherry Canyon reservoir including the model area. It was necessary to look at a large number of pattern options, most of which required drilling numerous wells. However, well cost sharing was assumed on most scenarios since there would be some cost sharing if the reservoir was developed for waterflooding.

A five-spot pattern scenario was evaluated that used the current wells as interior producers and drilled nine injectors (Figure 2). This is referred to as the "As-Is" five-spot pattern. Some cost sharing with offset patterns was assumed so drilling costs were based on four net wells. The predicted performance from the simulator is shown on Figure 3. Although the repressuring effects of injection start moderating the primary decline within the first year, the secondary increase over primary performance is not significant until ten years after injection starts. The cash flow projection (Table 2) gives negative economics. To study the impact of irregular spacing an "ideal" scenario was created in which the four existing producers were centered within uniform five-spot injection patterns (Figure 4). The drilling of nine (four net) injectors was required. Theoretically this would result in a more balanced sweep and higher recovery. As seen on the performance projection (Figure 5) the recovery was increased, but the response time was delayed by an extra two years so the economics remained negative (Table 3). The response delay is due to all of the injectors being further from producers than is the case with irregular spacing.

A line drive pattern scenario was investigated that required the drilling of nine (six net) injectors (Figure 6). The line drive secondary response is similar to the five-spot in that response is slow and amounts to little more than arresting the primary decline (Figure 7). As a result the economics are negative (Table 4).

Three well conversion scenarios - diagonal, north/south and east/west - were developed to investigate the effect of minimizing capital expenditure. Each pattern yielded two producers and two injectors for the quarter-section pattern (Figure 8). The performance projection for all three conversion scenarios resulted in the loss of production for six plus years from converting two wells to injection. The best response of the three scenarios was the east/west conversion (Figure 9), but its economics on a present worth basis were negative (Table 5).

An infill drilling scenario was modeled that required the drilling of four producers and seven injectors (Figure 10). The simulator generated performance projection (Figure 11) shows an initial increase in oil rate due to primary production from infill producers. The impact of reservoir repressuring due to water injection is felt within two years in the form of lessening the primary decline. A production response is experienced within five years, which is sooner than for the other patterns tested due to reduced spacing. However, this scenario is very capital intensive and the economics are negative (Table 6).

To look at the economics of infill drilling under primary conditions, the injectors were omitted and the scenario rerun through the simulator (Figure 12). The performance projection (Figure 13) shows how rapidly the initial infill producers' rates decline without any type of pressure support. The dropping of the "existing + infill" rate below the existing rate after seven years indicates that the infill wells are being

drilled within the drainage areas of existing wells. The economics for the scenario were negative (Table 7) and none of the four infill locations were individually economical.

ECONOMIC CRITERIA

Table 8 outlines the capital costs assumed for the cash flow analysis. The price and escalation scheme and primary discount rate are in accord with current industry practices. The use of assumed rather than existing economic parameters affects the cash flow projections by the difference in prices and expenses and can have a major effect on the economic viability of undeveloped reserves. We express no opinion as to future oil and gas prices, but rather depend on the NYMEX oil and gas future strip prices to establish prices over the next several years and the trend of prices into the future as discussed below.

Future product prices were based on the NYMEX (WTI spot) oil and NYMEX (HH) gas five-year strip futures as of July 27, 2001 after adjusting for gravity and transportation. The oil price was not adjusted for the differential between spot and posted prices. Using a more current five-year strip futures basis and making the price differential adjustment would result in a slightly lower oil price than input for this cash flow analysis. The prices were not revised since it would result in even less favorable economics. Lease operating expenses were adjusted from historical data provided by the operator. Investments were also adjusted from historical data provided by the operator. Investment costs for injection wells near the pattern edges were allocated, assuming adjacent patterns would be completed. Expenses and investments were held constant for the life of the properties. Costs of 20¢/bbl for acquiring makeup injection water are based on experience. No salvage value or abandonment costs were included for the properties.

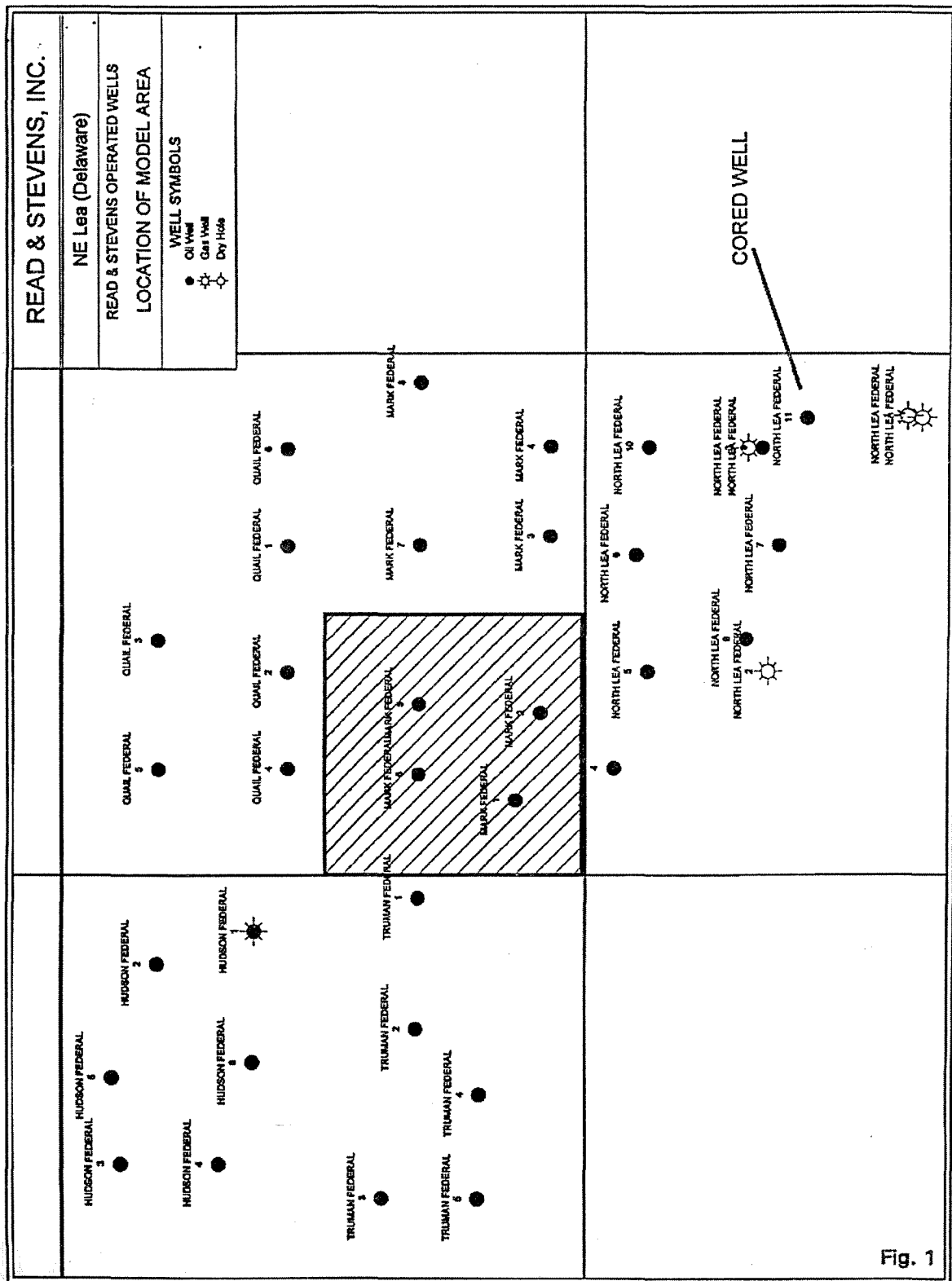


Fig. 1

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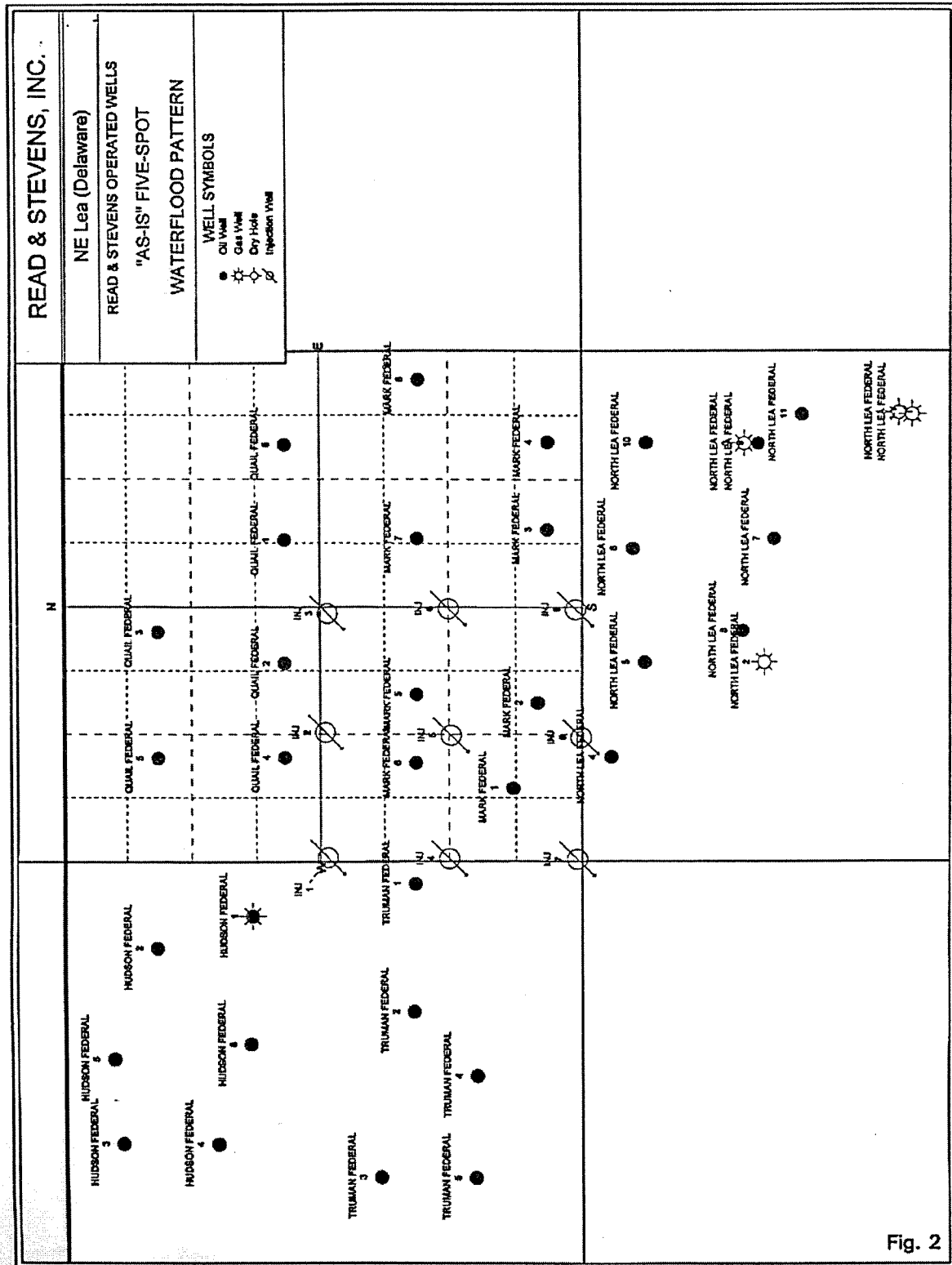


Fig. 2

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40-ACRE 5-SPOT
LEA NE (DELAWARE)
LEA, NM

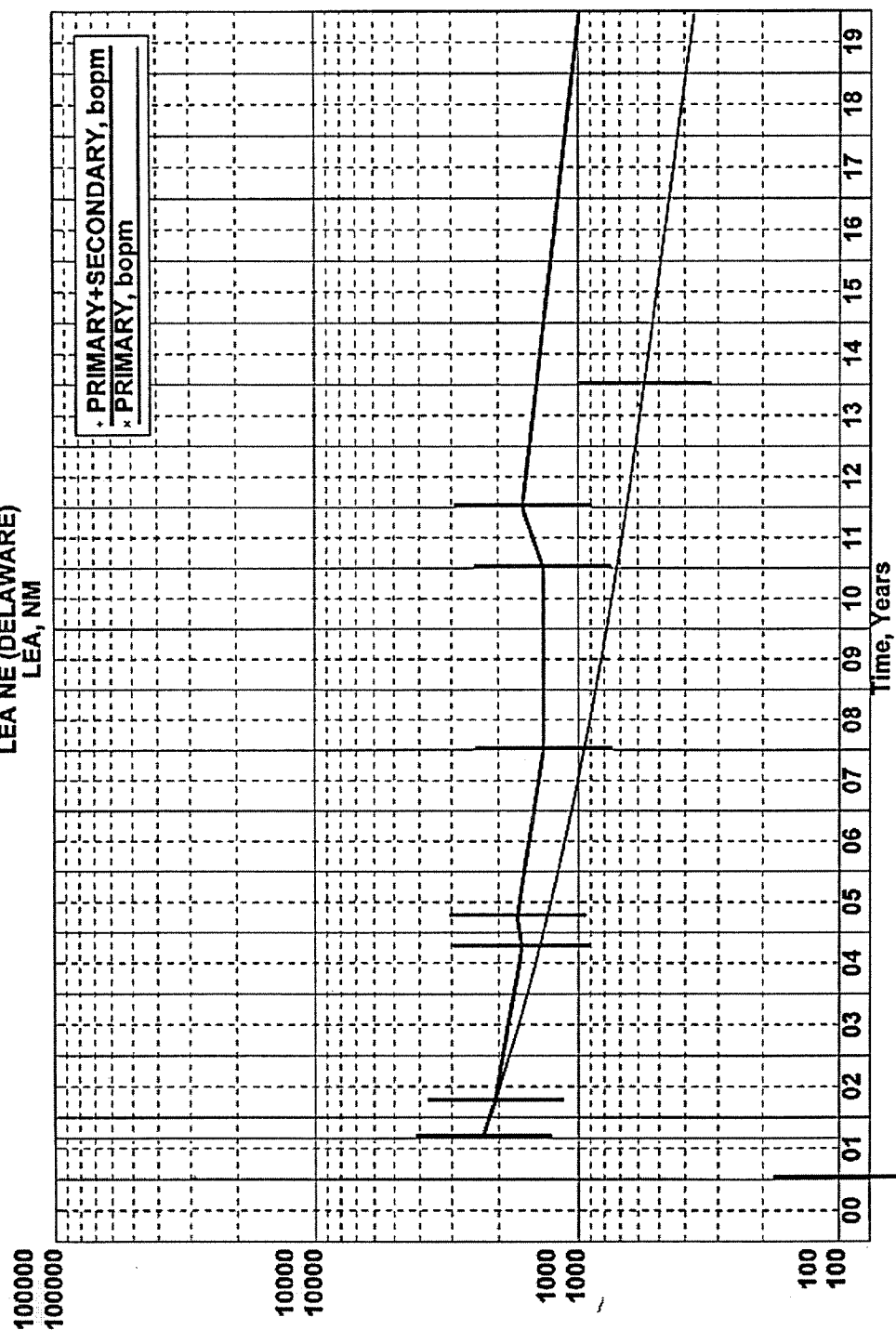


Fig. 3

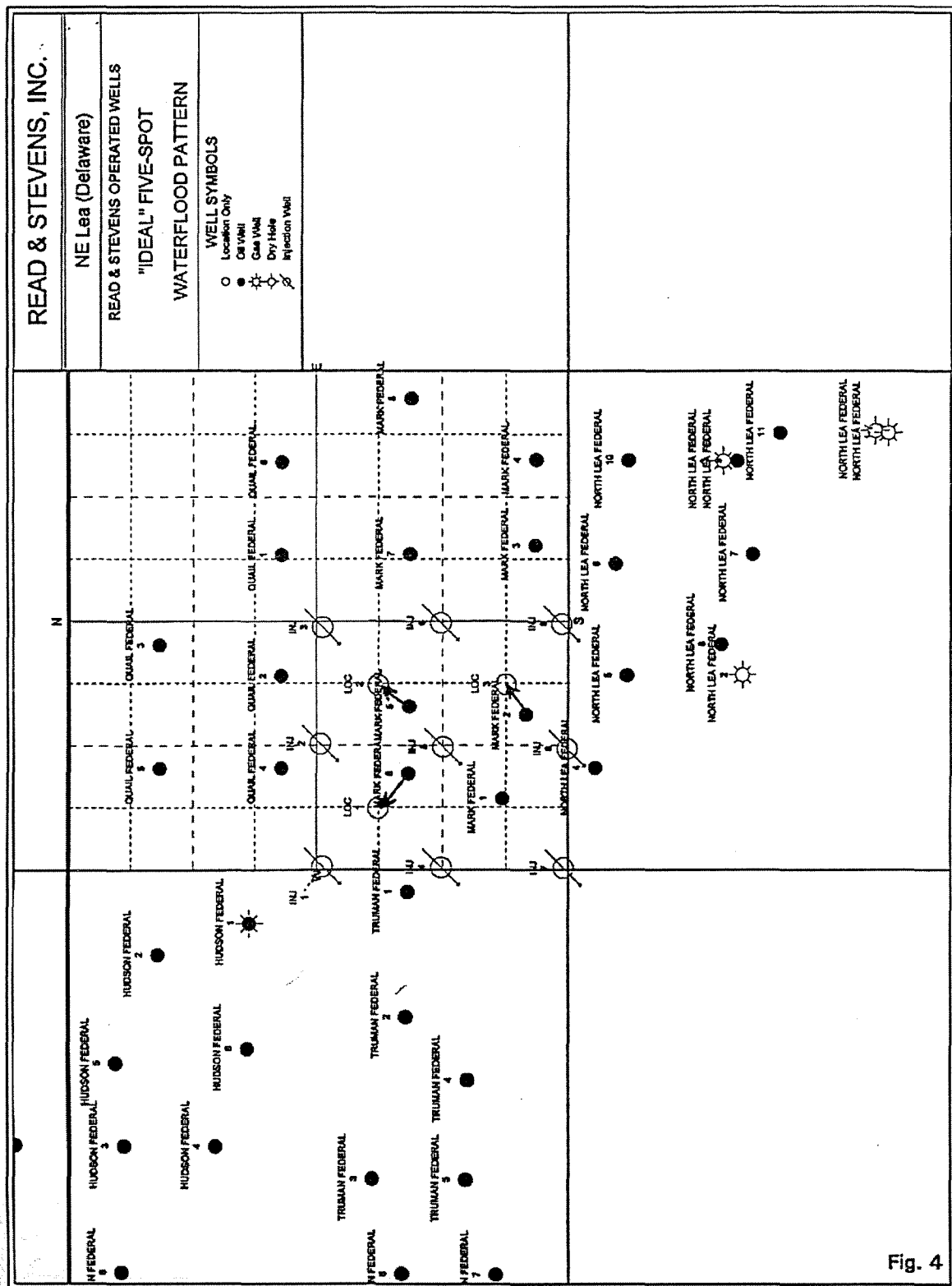


Fig. 4

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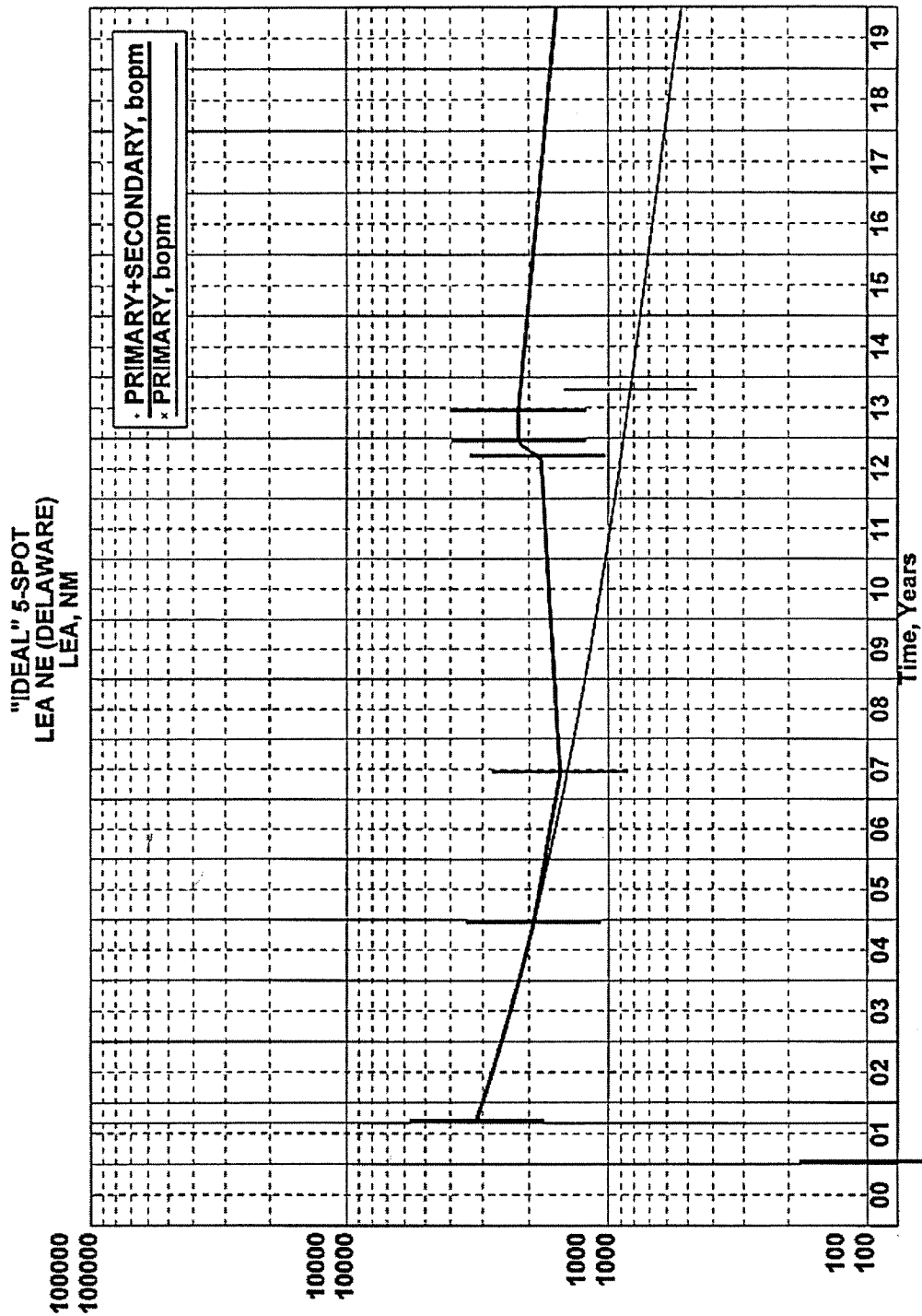
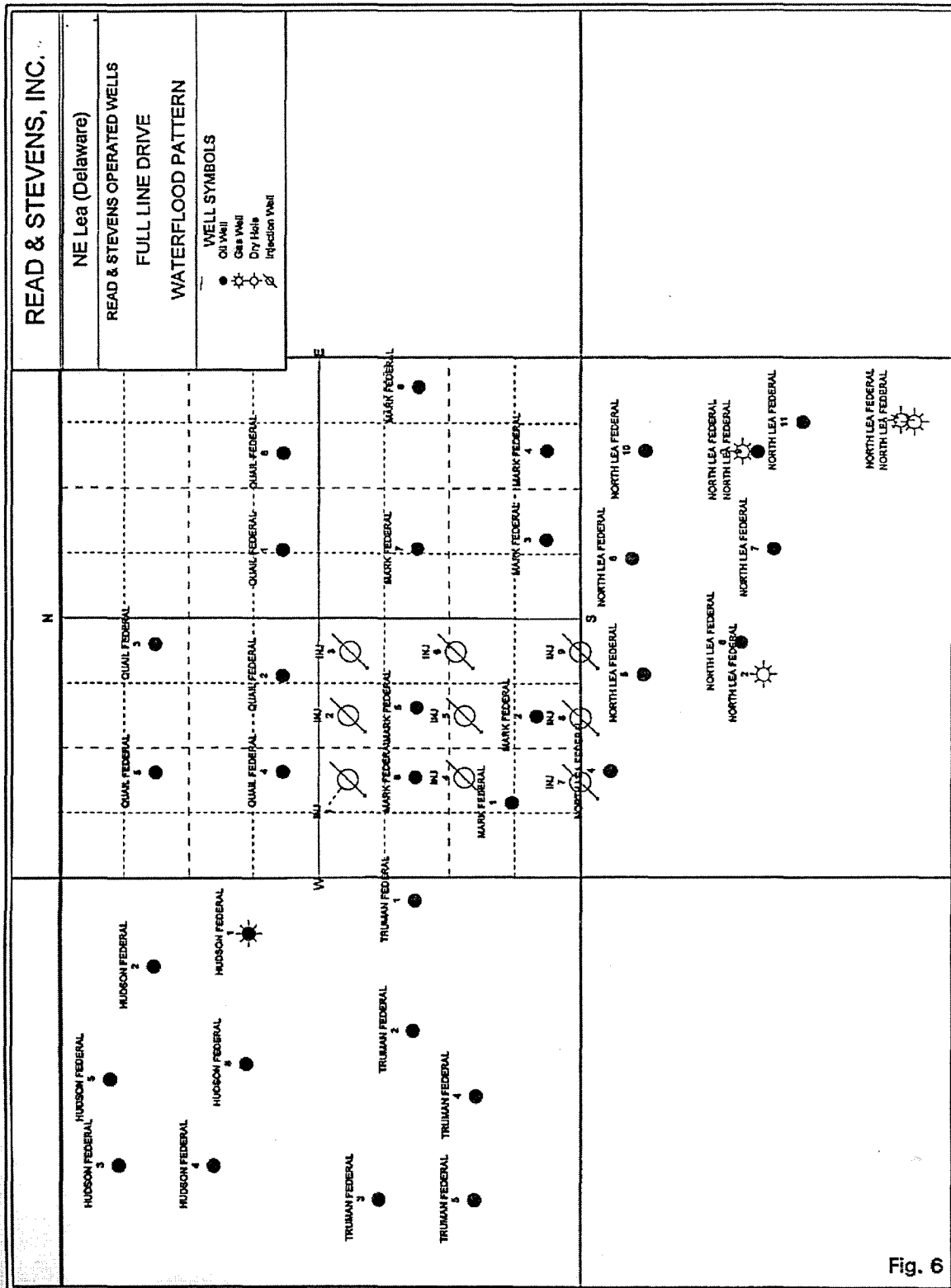


Fig. 5



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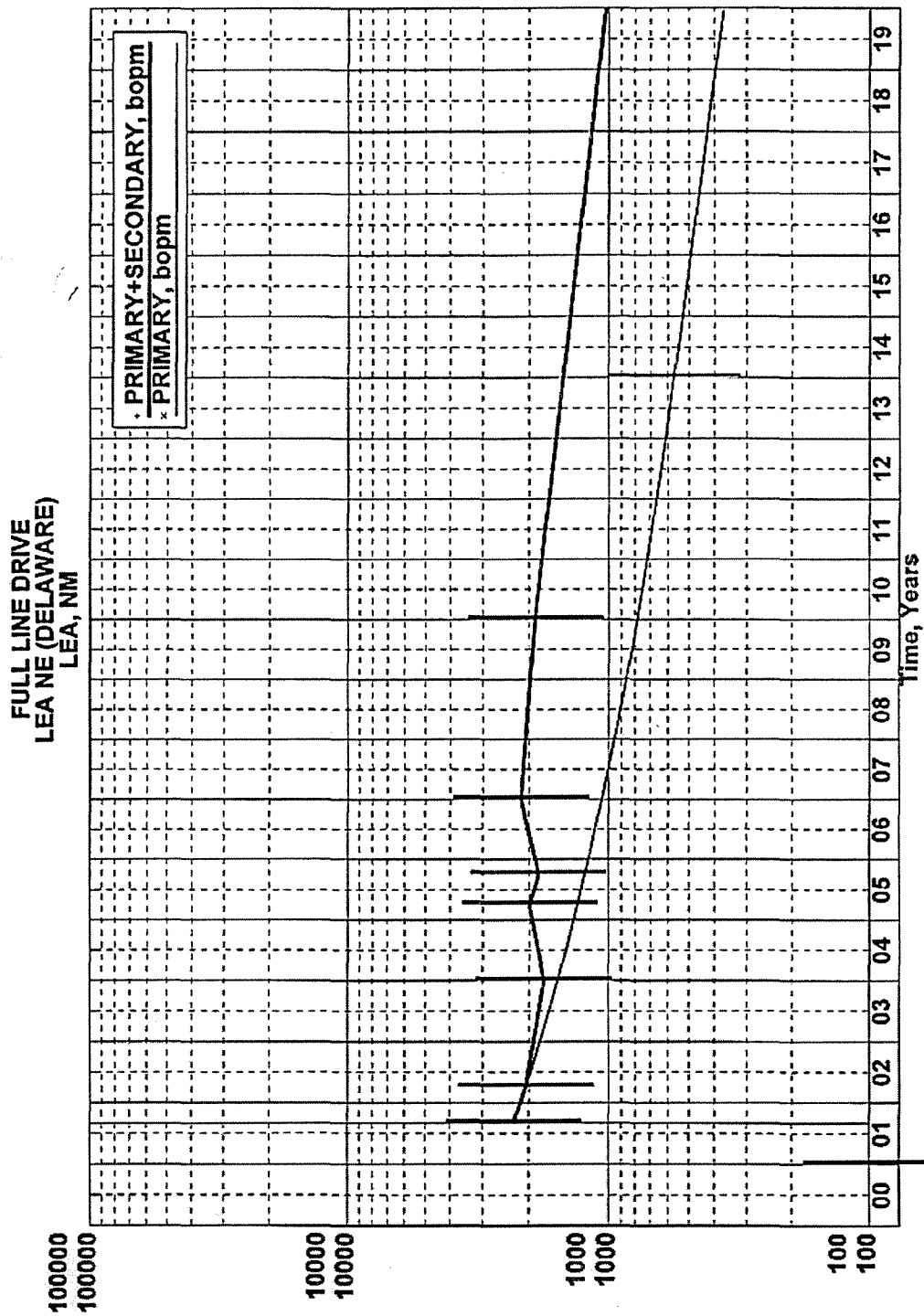


Fig. 7

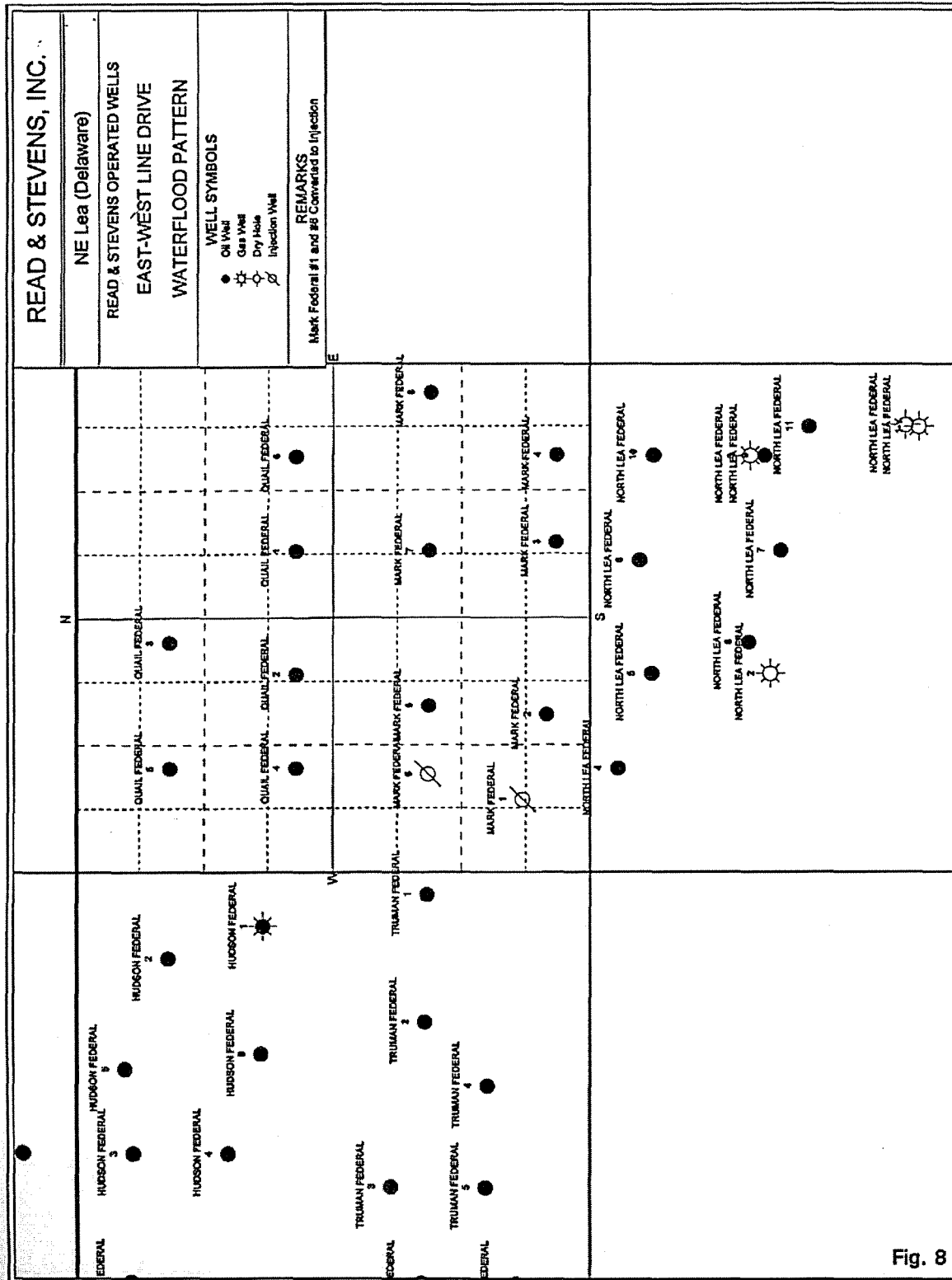


Fig. 8

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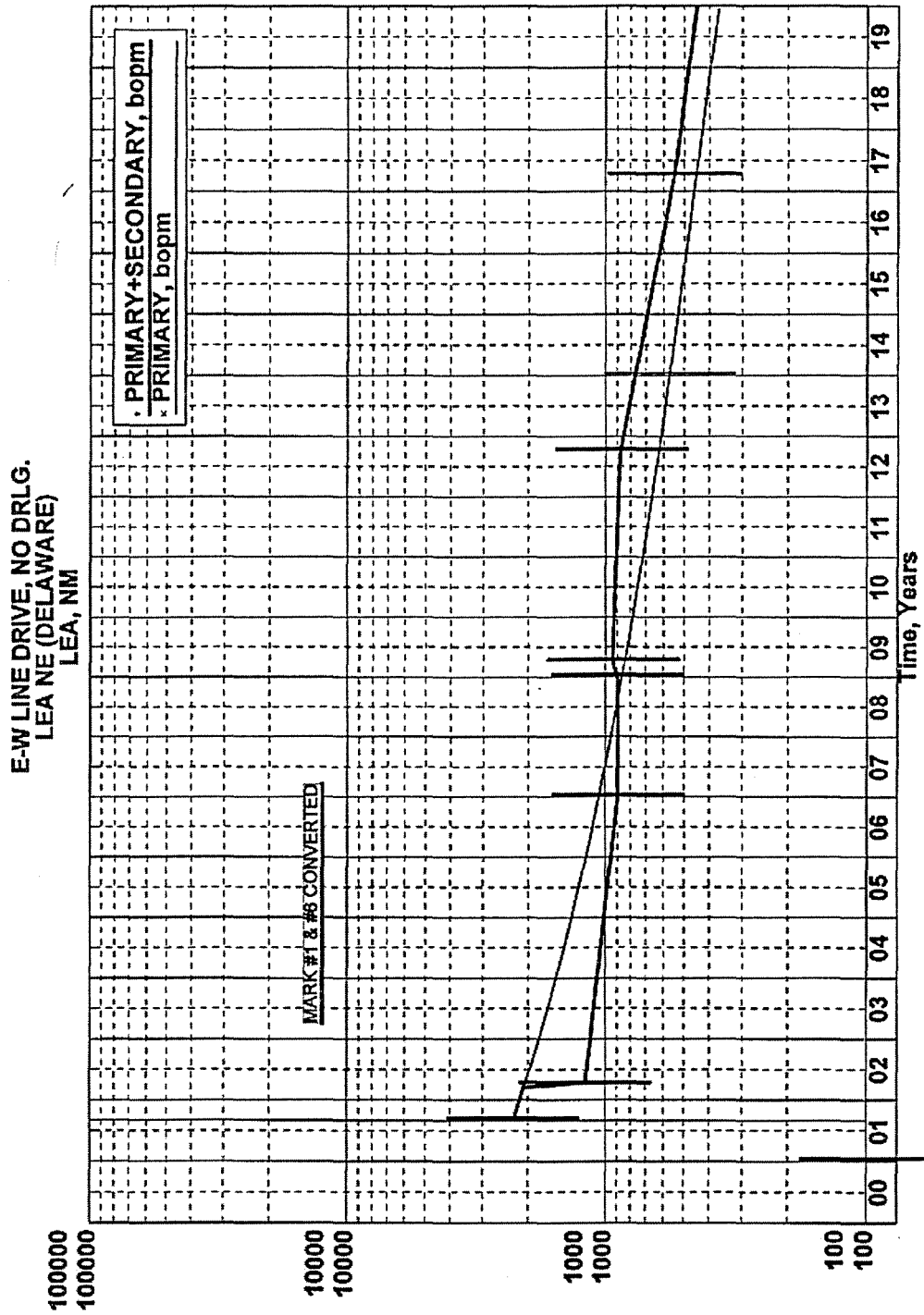


Fig. 9

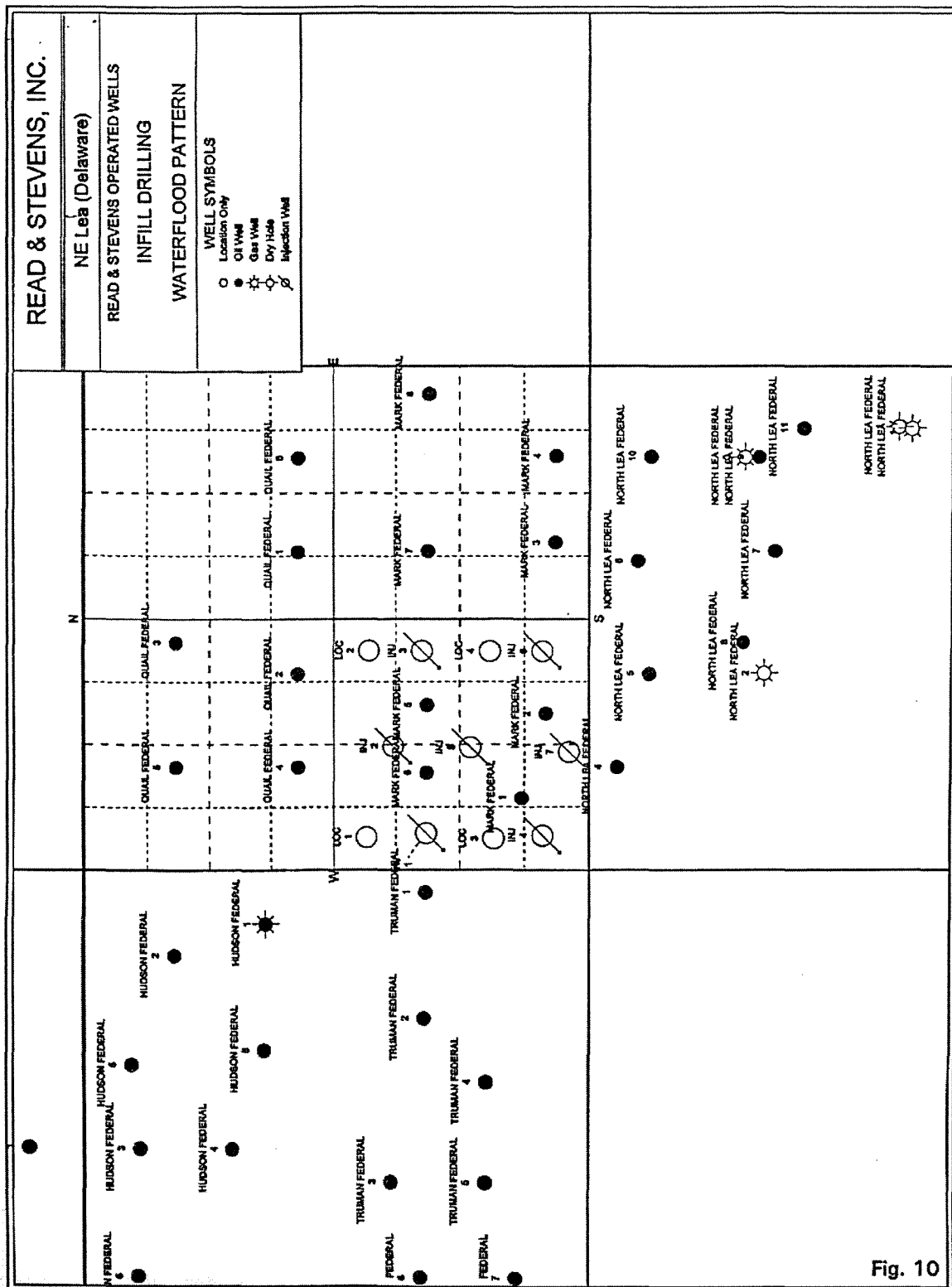


Fig. 10

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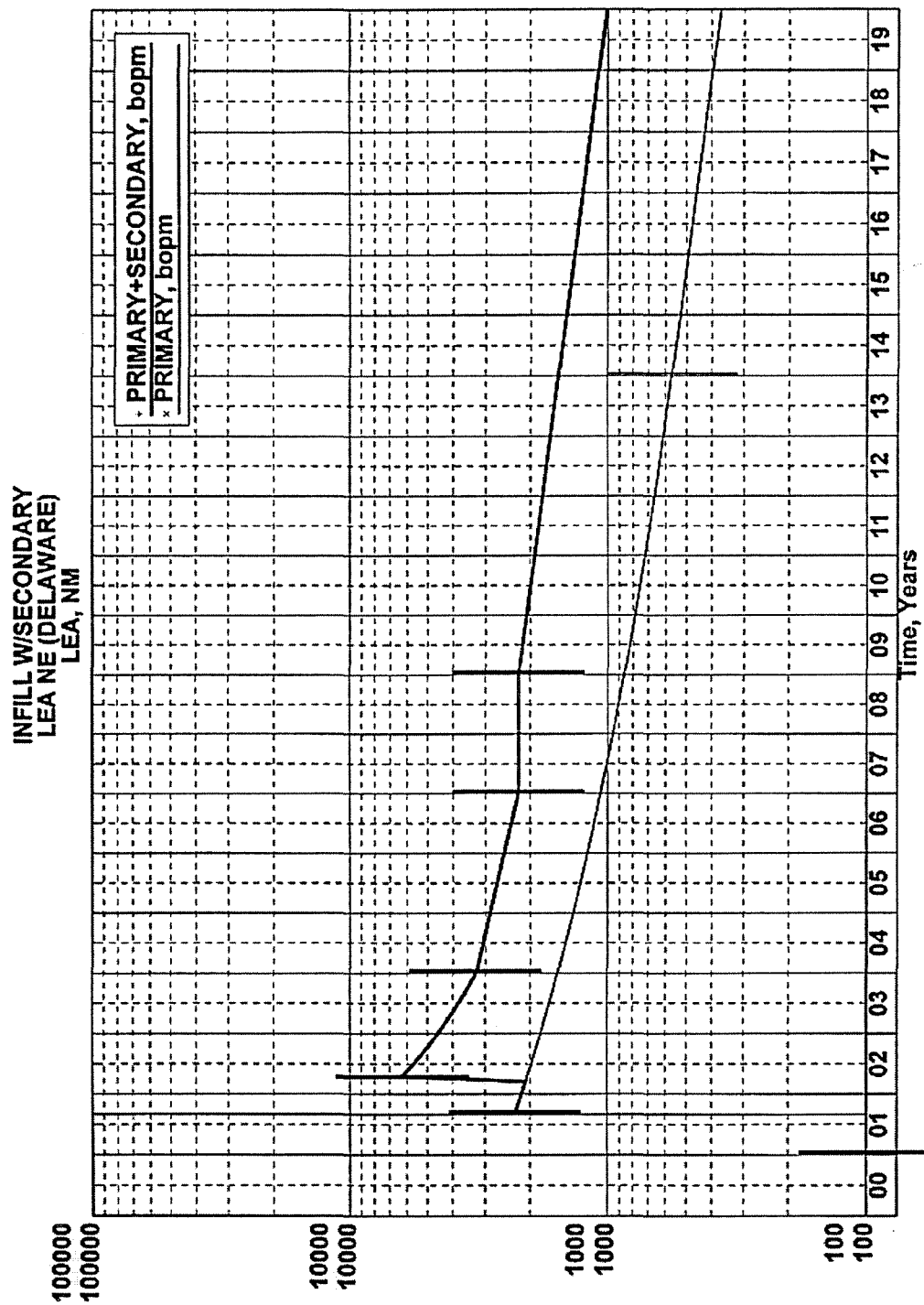


Fig. 11

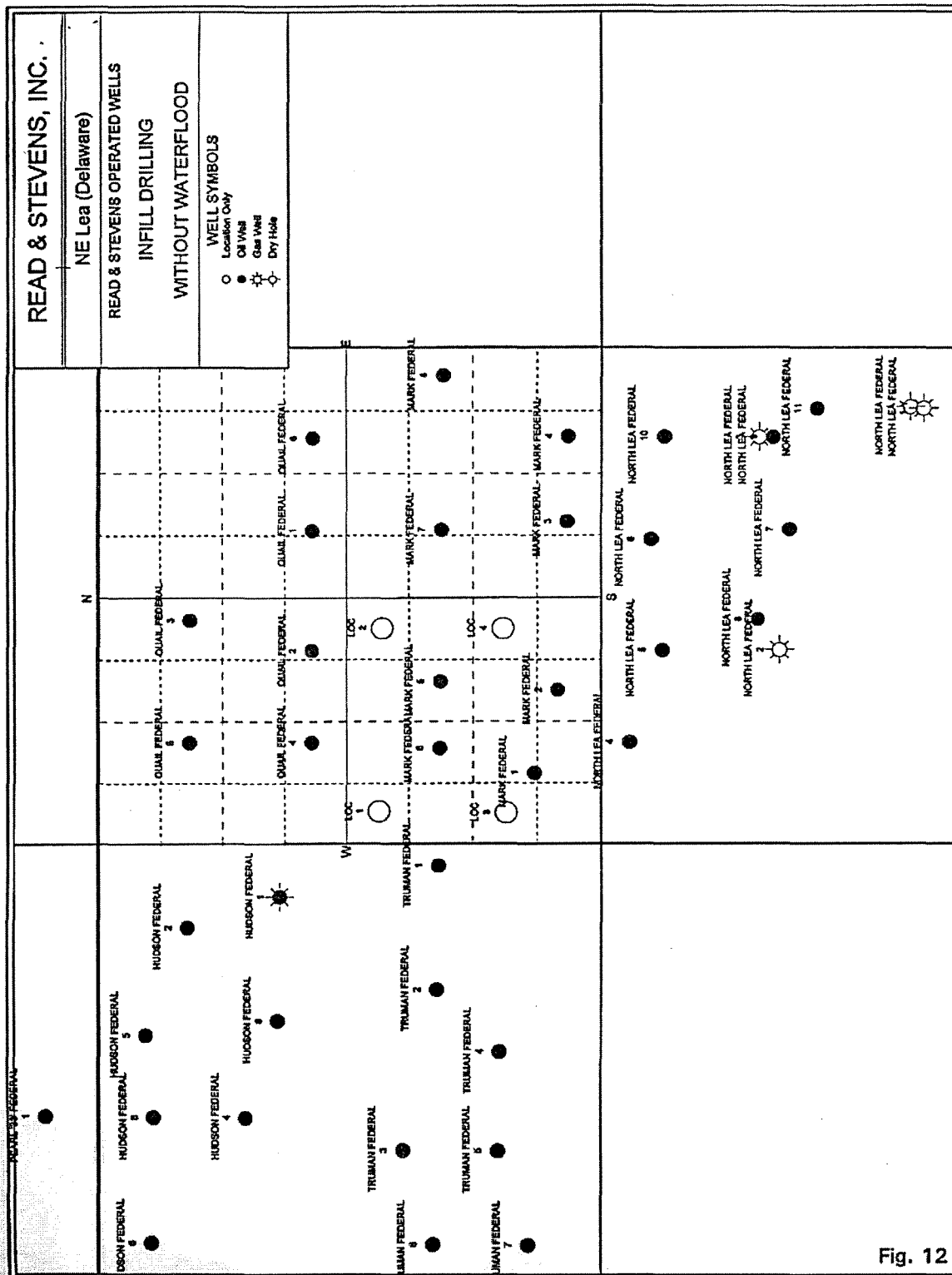


Fig. 12

PATNA 02001 14120 AL

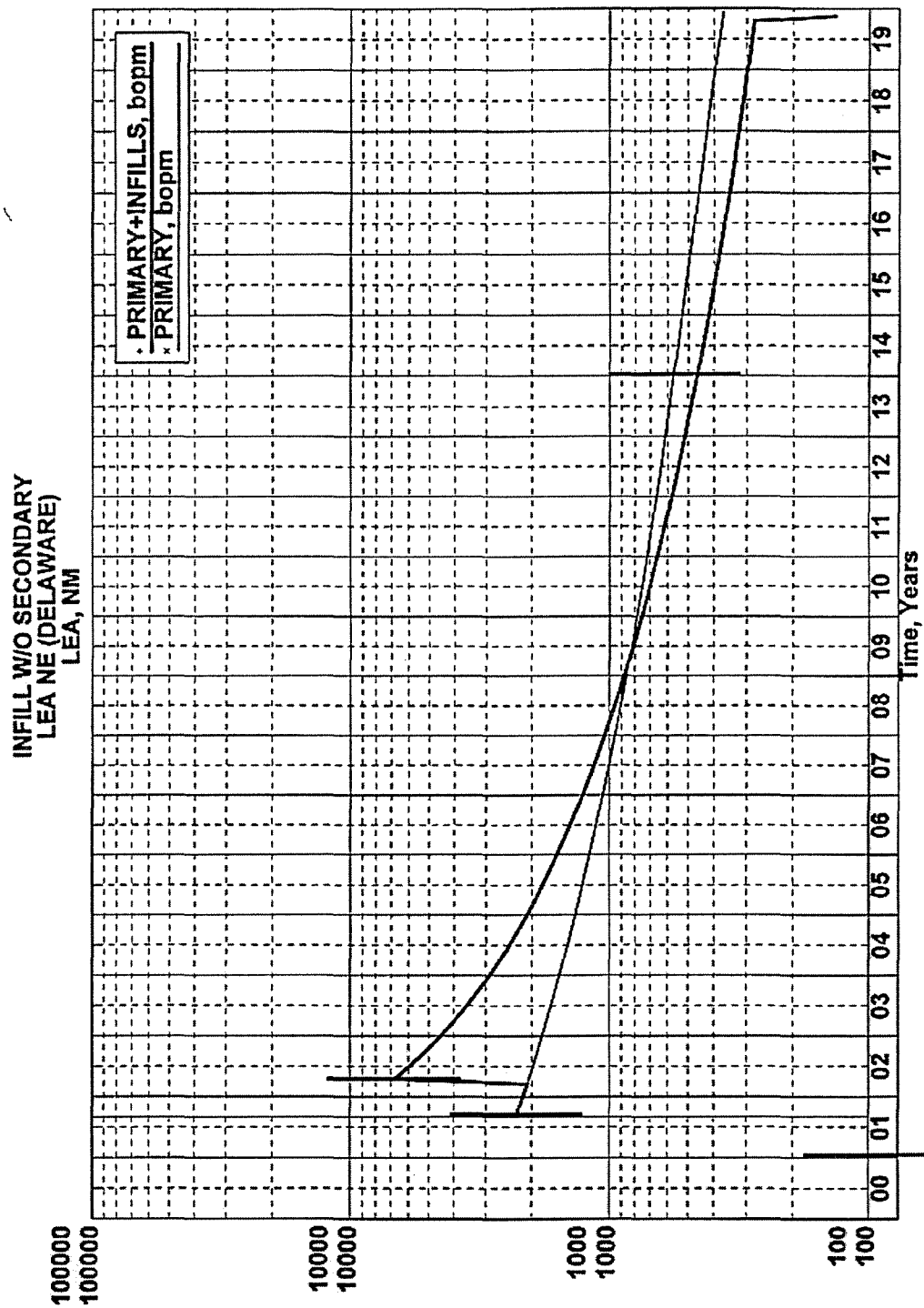


Fig. 13

TABLE 1.

COMPARISON OF RESERVES & ECONOMICS
PROPOSED WATERFLOOD PROJECT
NORTHEAST LEA (DELAWARE) FIELD
LEA COUNTY, NEW MEXICO

SCENARIO	RESERVES, MBO	RECOVERY FACTOR, % OOIP ⁽¹⁾	S:P RATIO	8/8THS DEVELOPMENT COST, \$M	UNDISCOUNTED FUTURE NET REVENUE, \$M
PRIMARY	689.5	14.7	--	--	2,281
"AS-IS" FIVE-SPOT	127.2	2.7	0.18	1,890	(1,712)
"IDEAL" FIVE- SPOT	233.3	5.0	0.34	1,890	(2,019)
FULL LINE DRIVE	149.1	3.2	0.22	2,835	(2,943)
E/W LINE DRIVE	20.9	0.4	0.03	100	55
INFILL W/ WATERFLOOD	140.7	3.0	0.20 ⁽²⁾	5,878	(5,213)
INFILL W/O WATERFLOOD	28.2	0.6	--	2,520	(1,569)

(2) Percent of Model Area Original Oil-in-Place

(3) Primary = 689.5 + 28.2 MBO from Infills

TABLE 2

PROBABLE "AS IS" 5-SPOT

DATE: 09/21/01

TIME: 09:31:56

FILE: LEA

GET#: 0

RESERVES AND ECONOMICS

READ & STEVENS

7/27/01 NYMEX FUTURE STRIP

AS OF SEPTEMBER 1, 2001

T. SCOTT HICKMAN & ASSOC., INC

PETROLEUM ENGINEERS CRV/00.004

-END- MO-YR	---GROSS PRODUCTION---		----NET PRODUCTION----		--PRICES--		-----OPERATIONS, M\$-----			10.00 PCT		
	OIL, MMBL	GAS, MMCF	OIL, MMBL	GAS, MMCF	OIL \$/B	GAS \$/M	NET OPER REVENUES	SEV+ADV TAXES	NET OPER EXPENSES	CAPITAL COSTS, M\$	CASH FLOW BTAX, M\$	CUM. DISC BTAX, M\$
12- 1	.000	.099	.000	.075	.00	4.39	.329	.026	.000	.000	.303	.298
12- 2	.514	2.314	.386	1.736	24.03	4.76	17.538	1.403	56.700	1890.000	-1930.565	-1868.082
12- 3	1.855	4.206	1.391	3.155	22.28	4.90	46.454	3.717	75.600	.000	-32.863	-1895.687
12- 4	2.735	1.945	2.051	1.459	21.38	4.97	51.095	4.087	75.600	.000	-28.592	-1917.521
12- 5	4.632	1.910	3.474	1.432	20.88	5.00	79.704	6.377	75.600	.000	-2.273	-1919.099
12- 6	4.887	-.535	3.666	-.401	20.80	5.08	74.216	5.938	75.600	.000	-7.322	-1923.720
12- 7	4.848	-2.989	3.636	-2.241	20.80	5.16	64.073	5.126	75.600	.000	-16.653	-1933.274
12- 8	5.344	-4.450	4.008	-3.338	20.80	5.23	65.896	5.272	75.600	.000	-14.976	-1941.085
12- 9	6.349	-5.286	4.762	-3.965	20.80	5.31	77.988	6.239	75.600	.000	-3.851	-1942.911
12-10	7.206	-6.362	5.404	-4.772	20.80	5.39	86.672	6.934	75.600	.000	4.138	-1941.127
12-11	9.504	-6.525	7.128	-4.893	20.80	5.47	121.485	9.718	75.600	.000	36.167	-1926.954
12-12	11.214	-6.180	8.410	-4.635	20.80	5.55	149.181	11.935	75.600	.000	61.646	-1904.993
12-13	10.643	-5.994	7.982	-4.495	20.80	5.64	140.683	11.254	75.600	.000	53.829	-1887.560
12-14	10.079	-5.853	7.559	-4.390	20.80	5.72	132.105	10.569	75.600	.000	45.936	-1874.036
12-15	9.539	-5.711	7.154	-4.283	20.80	5.81	123.925	9.914	75.600	.000	38.411	-1863.756
S TOT	89.349	-39.411	67.011	-29.556	20.87	5.66	1231.344	98.509	1039.500	1890.000	-1796.665	-1863.756
REM.	37.882	-8.995	28.412	-6.746	20.80	5.84	551.594	44.129	422.400	.000	85.065	-1845.021
TOTAL	127.231	-48.406	95.423	-36.302	20.85	5.69	1782.938	142.638	1461.900	1890.000	-1711.600	-1845.021
CUM.	.000	.000					NET OIL REVENUES (M\$)	1989.573	-----PRESENT WORTH PROFILE-----			
							NET GAS REVENUES (M\$)	-206.635	DISC	PW OF NET	DISC	PW OF NET
ULT.	127.231	-48.406					TOTAL REVENUES (M\$)	1782.938	RATE	BTAX, M\$	RATE	BTAX, M\$
									----	-----	----	-----
BTAX RATE OF RETURN (PCT)			.00	PROJECT LIFE (YEARS)			18.333	.0	-1711.600	30.0	-1794.505	
BTAX PAYOUT YEARS			18.33	DISCOUNT RATE (PCT)			10.000	2.0	-1763.392	35.0	-1771.969	
BTAX PAYOUT YEARS (DISC)			18.33	GROSS OIL WELLS			.000	5.0	-1811.760	40.0	-1749.509	
BTAX NET INCOME/INVEST			.09	GROSS GAS WELLS			.000	8.0	-1836.833	45.0	-1727.593	
BTAX NET INCOME/INVEST (DISC)			-.01	GROSS WELLS			.000	10.0	-1845.021	50.0	-1706.431	
								12.0	-1848.443	60.0	-1666.641	
								15.0	-1847.283	70.0	-1630.161	
								18.0	-1841.050	80.0	-1596.682	
								20.0	-1835.039	90.0	-1565.842	
								25.0	-1816.167	100.0	-1537.310	

TABLE 3

PROBABLE "IDEAL" 5-SPOT

DATE: 09/21/01

TIME: 09:31:56

FILE: LEA

GET#: 0

RESERVES AND ECONOMICS

READ & STEVENS

7/27/01 NYMEX FUTURE STRIP

AS OF SEPTEMBER 1, 2001

T. SCOTT HICKMAN & ASSOC., INC

PETROLEUM ENGINEERS CRV/00.004

						--PRICES--		-----OPERATIONS, M\$-----					10.00 PCT		
-END-	---GROSS PRODUCTION---		----NET PRODUCTION----				OIL	GAS	NET OPER	SEV+ADV	NET OPER	CAPITAL	CASH FLOW	CUM. DISC	
MO-YR	OIL, MMBL	GAS, MMCF	OIL, MMBL	GAS, MMCF	\$/B	\$/M			REVENUES	TAXES	EXPENSES	COSTS, M\$	BTAX, M\$	BTAX, M\$	
----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	
12- 1	.000	-1.263	.000	-.948	.00	4.39			-4.160	-.333	.000	.000	-3.827	-3.766	
12- 2	.000	-3.609	.000	-2.706	.00	4.76			-12.879	-1.031	56.700	1890.000	-1958.548	-1898.002	
12- 3	.000	-3.374	.000	-2.530	.00	4.90			-12.398	-.992	75.600	.000	-87.006	-1971.087	
12- 4	.003	-4.218	.003	-3.163	21.67	4.96			-15.638	-1.251	75.600	.000	-89.987	-2039.804	
12- 5	.404	-9.589	.303	-7.191	20.88	5.01			-29.665	-2.373	75.600	.000	-102.892	-2111.233	
12- 6	.853	-14.475	.639	-10.856	20.80	5.08			-41.859	-3.349	75.600	.000	-114.110	-2183.248	
12- 7	1.435	-18.159	1.076	-13.619	20.80	5.16			-47.843	-3.827	75.600	.000	-119.616	-2251.876	
12- 8	3.483	-19.356	2.612	-14.517	20.80	5.23			-21.649	-1.732	75.600	.000	-95.517	-2301.695	
12- 9	5.496	-20.691	4.122	-15.518	20.80	5.31			3.302	.264	75.600	.000	-72.562	-2336.101	
12-10	7.323	-21.415	5.492	-16.061	20.80	5.39			27.634	2.211	75.600	.000	-50.177	-2357.730	
12-11	9.005	-22.473	6.754	-16.855	20.80	5.47			48.241	3.859	75.600	.000	-31.218	-2369.964	
12-12	11.515	-23.194	8.636	-17.395	20.80	5.55			83.002	6.640	75.600	.000	.762	-2369.693	
12-13	16.048	-20.181	12.036	-15.136	20.80	5.64			165.009	13.201	75.600	.000	76.208	-2345.012	
12-14	15.564	-18.763	11.673	-14.073	20.80	5.72			162.263	12.981	75.600	.000	73.682	-2323.319	
12-15	14.973	-17.488	11.229	-13.116	20.80	5.81			157.378	12.591	75.600	.000	69.187	-2304.801	
S TOT	86.102	-218.248	64.575	-163.684	20.80	5.39			460.738	36.859	1039.500	1890.000	-2505.621	-2304.801	
REM.	147.198	-111.820	110.400	-83.866	20.80	6.20			1776.095	142.086	1147.200	.000	486.809	-2221.672	
TOTAL	233.300	-330.068	174.975	-247.550	20.80	5.67			2236.833	178.945	2186.700	1890.000	-2018.812	-2221.672	
CUM.	.000	.000							NET OIL REVENUES (M\$)	3639.510	-----PRESENT WORTH PROFILE-----				
									NET GAS REVENUES (M\$)	-1402.677	DISC	PW OF NET	DISC	PW OF NET	
ULT.	233.300	-330.068							TOTAL REVENUES (M\$)	2236.833	RATE	BTAX, M\$	RATE	BTAX, M\$	
BTAX RATE OF RETURN (PCT)			.00	PROJECT LIFE (YEARS)					26.333	.0	-2018.812	30.0	-2003.665		
BTAX PAYOUT YEARS			26.33	DISCOUNT RATE (PCT)					10.000	2.0	-2131.309	35.0	-1953.889		
BTAX PAYOUT YEARS (DISC)			26.33	GROSS OIL WELLS					.000	5.0	-2209.667	40.0	-1909.240		
BTAX NET INCOME/INVEST			-.07	GROSS GAS WELLS					.000	8.0	-2227.716	45.0	-1869.151		
BTAX NET INCOME/INVEST (DISC)			-.21	GROSS WELLS					.000	10.0	-2221.672	50.0	-1832.994		
											12.0	-2207.366	60.0	-1770.204	
											15.0	-2177.237	70.0	-1717.210	
											18.0	-2142.303	80.0	-1671.473	
											20.0	-2118.159	90.0	-1631.273	
											25.0	-2058.774	100.0	-1595.416	

TABLE 4

PROBABLE FULL LINE DRIVE

DATE: 09/21/01

TIME: 09:31:56

FILE: LEA

GET#: 0

RESERVES AND ECONOMICS

READ & STEVENS

7/27/01 NYMEX FUTURE STRIP

AS OF SEPTEMBER 1, 2001

T. SCOTT HICKMAN & ASSOC., INC

PETROLEUM ENGINEERS CRV/00.004

						--PRICES--		-----OPERATIONS, M\$-----					10.00 PCT	
-END-	---GROSS PRODUCTION---		----NET PRODUCTION----				OIL	GAS	NET OPER	SEV+ADV	NET OPER	CAPITAL	CASH FLOW	CUM. DISC
MO-YR	OIL, MMBL	GAS, MMCF	OIL, MMBL	GAS, MMCF	\$/B	\$/M			REVENUES	TAXES	EXPENSES	COSTS, M\$	BTAX, M\$	BTAX, M\$
----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
12- 1	.000	.064	.000	.048	.00	4.38			.210	.016	.000	.000	.194	.191
12- 2	.514	1.843	.386	1.382	24.03	4.76			15.853	1.268	94.500	2835.000	-2914.915	-2819.998
12- 3	1.855	-.999	1.391	-.749	22.28	4.90			27.321	2.186	126.000	.000	-100.865	-2904.724
12- 4	4.748	-6.996	3.561	-5.247	21.38	4.96			50.084	4.006	126.000	.000	-79.922	-2965.755
12- 5	7.753	-9.939	5.815	-7.455	20.88	5.01			84.104	6.729	126.000	.000	-48.625	-2999.512
12- 6	10.723	-10.107	8.043	-7.580	20.80	5.08			128.787	10.303	108.000	.000	10.484	-2992.896
12- 7	13.213	-11.297	9.910	-8.472	20.80	5.16			162.443	12.996	108.000	.000	41.447	-2969.116
12- 8	13.393	-13.922	10.045	-10.442	20.80	5.23			154.286	12.343	108.000	.000	33.943	-2951.412
12- 9	13.428	-13.675	10.071	-10.256	20.80	5.31			154.996	12.400	108.000	.000	34.596	-2935.008
12-10	13.120	-12.537	9.840	-9.403	20.80	5.39			153.972	12.318	108.000	.000	33.654	-2920.501
12-11	12.530	-11.661	9.397	-8.745	20.80	5.47			147.598	11.807	108.000	.000	27.791	-2909.611
12-12	11.920	-10.924	8.940	-8.193	20.80	5.55			140.441	11.236	108.000	.000	21.205	-2902.057
12-13	11.308	-10.300	8.481	-7.725	20.80	5.64			132.850	10.628	108.000	.000	14.222	-2897.451
12-14	10.704	-9.757	8.028	-7.318	20.80	5.72			125.104	10.009	108.000	.000	7.095	-2895.362
12-15	10.127	-9.245	7.595	-6.933	20.80	5.81			117.705	9.417	108.000	.000	.288	-2895.285
S TOT	135.336	-129.452	101.503	-97.088	20.86	5.37			1595.754	127.662	1552.500	2835.000	-2919.408	-2895.285
REM.	13.723	-30.026	10.293	-22.520	20.80	6.00			79.038	6.323	96.000	.000	-23.285	-2900.469
TOTAL	149.059	-159.478	111.796	-119.608	20.85	5.49			1674.792	133.985	1648.500	2835.000	-2942.693	-2900.469
CUM.	.000	.000							NET OIL REVENUES (M\$)	2331.195	-----PRESENT WORTH PROFILE-----			
									NET GAS REVENUES (M\$)	-656.403	DISC	PW OF NET	DISC	PW OF NET
ULT.	149.059	-159.478							TOTAL REVENUES (M\$)	1674.792	RATE	BTAX, M\$	RATE	BTAX, M\$
BTAX RATE OF RETURN (PCT)			.00	PROJECT LIFE (YEARS)					17.333	.0	-2942.693	30.0	-2751.041	
BTAX PAYOUT YEARS			17.33	DISCOUNT RATE (PCT)					10.000	2.0	-2938.764	35.0	-2713.128	
BTAX PAYOUT YEARS (DISC)			17.33	GROSS OIL WELLS					.000	5.0	-2927.889	40.0	-2676.392	
BTAX NET INCOME/INVEST			-.04	GROSS GAS WELLS					.000	8.0	-2912.525	45.0	-2641.034	
BTAX NET INCOME/INVEST (DISC)			-.06	GROSS WELLS					.000	10.0	-2900.469	50.0	-2607.115	

TABLE 5

PROBABLE E/W LINE DRIVE

DATE: 09/21/01

TIME: 09:31:56

FILE: LEA

GET#: 0

RESERVES AND ECONOMICS

READ & STEVENS

7/27/01 NYMEX FUTURE STRIP

AS OF SEPTEMBER 1, 2001

T. SCOTT HICKMAN & ASSOC., INC

PETROLEUM ENGINEERS CRV/00.004

					--PRICES--		-----OPERATIONS, M\$-----					10.00 PCT
-END-	---GROSS PRODUCTION---		----NET PRODUCTION----		OIL	GAS	NET OPER	SEV+ADV	NET OPER	CAPITAL	CASH FLOW	CUM. DISC
MO-YR	OIL, MBBL	GAS, MMCF	OIL, MBBL	GAS, MMCF	\$/B	\$/M	REVENUES	TAXES	EXPENSES	COSTS, M\$	BTAX, M\$	BTAX, M\$
----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
12- 1	.000	1.586	.000	1.190	.00	4.39	5.221	.417	.000	.000	4.804	4.728
12- 2	-6.871	-14.904	-5.153	-11.178	24.03	4.76	-177.029	-14.162	-37.800	100.000	-225.067	-207.706
12- 3	-6.842	-17.989	-5.131	-13.491	22.28	4.90	-180.434	-14.434	-50.400	.000	-115.600	-304.810
12- 4	-4.887	-14.738	-3.666	-11.053	21.38	4.96	-133.255	-10.661	-50.400	.000	-72.194	-359.940
12- 5	-3.469	-12.335	-2.601	-9.252	20.88	5.01	-100.616	-8.049	-50.400	.000	-42.167	-389.213
12- 6	-2.427	-10.769	-1.820	-8.076	20.80	5.08	-78.883	-6.310	-50.400	.000	-22.173	-403.207
12- 7	-1.334	-10.461	-1.000	-7.845	20.80	5.16	-61.252	-4.900	-55.200	.000	-1.152	-403.868
12- 8	-.143	-10.234	-.107	-7.676	20.80	5.23	-42.400	-3.392	-55.200	.000	16.192	-395.422
12- 9	1.276	-9.866	.957	-7.400	20.80	5.31	-19.404	-1.552	-55.200	.000	37.348	-377.713
12-10	1.985	-10.390	1.488	-7.793	20.80	5.39	-11.069	-.885	-55.200	.000	45.016	-358.309
12-11	2.502	-11.112	1.876	-8.334	20.80	5.47	-6.589	-.527	-55.200	.000	49.138	-339.054
12-12	2.899	-11.068	2.174	-8.301	20.80	5.55	-.891	-.071	-55.200	.000	54.380	-319.682
12-13	2.639	-10.649	1.979	-7.987	20.80	5.64	-3.868	-.310	-55.200	.000	51.642	-302.958
12-14	2.167	-10.423	1.625	-7.817	20.80	5.72	-10.935	-.874	-55.200	.000	45.139	-289.669
12-15	1.752	-10.175	1.314	-7.631	20.80	5.81	-16.994	-1.359	-55.200	.000	39.565	-279.080
S TOT	-10.753	-163.527	-8.065	-122.644	24.09	5.25	-838.398	-67.069	-736.200	100.000	-135.129	-279.080
REM.	31.617	-11.013	23.714	-8.258	20.80	5.35	449.103	35.927	223.200	.000	189.976	-242.406
TOTAL	20.864	-174.540	15.649	-130.902	19.10	5.26	-389.295	-31.142	-513.000	100.000	54.847	-242.406
CUM.	.000	.000					NET OIL REVENUES (M\$)	298.927	-----PRESENT WORTH PROFILE-----			
							NET GAS REVENUES (M\$)	-688.222	DISC	PW OF NET	DISC	PW OF NET
ULT.	20.864	-174.540					TOTAL REVENUES (M\$)	-389.295	RATE	BTAX, M\$	RATE	BTAX, M\$
BTAX RATE OF RETURN (PCT)			1.06	PROJECT LIFE (YEARS)			23.333	.0	54.847	30.0	-289.865	
BTAX PAYOUT YEARS			18.60	DISCOUNT RATE (PCT)			10.000	2.0	-48.808	35.0	-282.563	
BTAX PAYOUT YEARS (DISC)			23.33	GROSS OIL WELLS			.000	5.0	-152.107	40.0	-274.139	
BTAX NET INCOME/INVEST			1.55	GROSS GAS WELLS			.000	8.0	-214.992	45.0	-265.419	
BTAX NET INCOME/INVEST (DISC)			-1.50	GROSS WELLS			.000	10.0	-242.406	50.0	-256.814	

TABLE 6

PROBABLE INFILL (WITH FLOOD)

DATE: 09/21/01

TIME: 09:31:56

FILE: LEA

GET#: 0

RESERVES AND ECONOMICS

READ & STEVENS

7/27/01 NYMEX FUTURE STRIP

AS OF SEPTEMBER 1, 2001

T. SCOTT HICKMAN & ASSOC., INC

PETROLEUM ENGINEERS CRV/00.004

-END- MO-YR	---GROSS PRODUCTION---		----NET PRODUCTION----		--PRICES--		-----OPERATIONS, M\$-----			10.00 PCT		
	OIL, MBBL	GAS, MMCF	OIL, MBBL	GAS, MMCF	OIL \$/B	GAS \$/M	NET OPER REVENUES	SEV+ADV TAXES	NET OPER EXPENSES	CAPITAL COSTS, M\$	CASH FLOW BTAX, M\$	CUM. DISC BTAX, M\$
12- 1	.000	-.285	.000	-.213	.00	4.39	-.935	-.075	.000	.000	-.860	-.847
12- 2	31.022	49.842	23.267	37.382	24.03	4.76	737.028	58.962	173.250	5877.500	-5372.684	-5228.104
12- 3	25.992	34.081	19.494	25.561	22.28	4.90	559.592	44.768	231.000	.000	283.824	-4989.693
12- 4	19.396	18.446	14.547	13.835	21.38	4.96	379.703	30.376	231.000	.000	118.327	-4899.335
12- 5	17.150	10.981	12.863	8.235	20.88	5.00	309.795	24.784	231.000	.000	54.011	-4861.840
12- 6	15.010	4.730	11.258	3.548	20.80	5.08	252.191	20.176	231.000	.000	1.015	-4861.200
12- 7	14.659	1.214	10.995	.911	20.80	5.16	233.393	18.672	219.000	.000	-4.279	-4863.655
12- 8	15.849	-.640	11.887	-.480	20.80	5.23	244.737	19.579	219.000	.000	6.158	-4860.443
12- 9	15.908	-3.475	11.931	-2.606	20.80	5.31	234.322	18.746	219.000	.000	-3.424	-4862.067
12-10	14.960	-6.763	11.220	-5.072	20.80	5.39	206.028	16.482	219.000	.000	-29.454	-4874.763
12-11	14.020	-9.493	10.515	-7.119	20.80	5.47	179.751	14.380	219.000	.000	-53.629	-4895.778
12-12	-7.637	-18.005	-5.728	-13.504	20.80	5.55	-194.155	-15.532	-120.000	.000	-58.623	-4916.662
12-13	-7.077	-17.016	-5.308	-12.762	20.80	5.64	-182.360	-14.589	-120.000	.000	-47.771	-4932.133
12-14	-6.577	-16.125	-4.933	-12.094	20.80	5.72	-171.817	-13.745	-120.000	.000	-38.072	-4943.342
12-15	-6.118	-15.283	-4.589	-11.462	20.80	5.81	-162.029	-12.962	-120.000	.000	-29.067	-4951.122
S TOT	156.557	32.209	117.419	24.160	21.77	2.87	2625.244	210.022	1712.250	5877.500	-5174.528	-4951.122
REM.	-15.900	-41.178	-11.925	-30.884	20.80	5.98	-432.768	-34.621	-360.000	.000	-38.147	-4959.913
TOTAL	140.657	-8.969	105.494	-6.724	21.88	17.14	2192.476	175.401	1352.250	5877.500	-5212.675	-4959.913
CUM.	.000	.000					NET OIL REVENUES (M\$)	2307.746	-----PRESENT WORTH PROFILE-----			
							NET GAS REVENUES (M\$)	-115.270	DISC	PW OF NET	DISC	PW OF NET
ULT.	140.657	-8.969					TOTAL REVENUES (M\$)	2192.476	RATE	BTAX, M\$	RATE	BTAX, M\$
									----	-----	----	-----
BTAX RATE OF RETURN (PCT)		.00	PROJECT LIFE (YEARS)				17.333	.0	-5212.675	30.0	-4742.494	
BTAX PAYOUT YEARS		17.33	DISCOUNT RATE (PCT)				10.000	2.0	-5141.628	35.0	-4702.227	
BTAX PAYOUT YEARS (DISC)		17.33	GROSS OIL WELLS				.000	5.0	-5058.566	40.0	-4663.851	
BTAX NET INCOME/INVEST		.11	GROSS GAS WELLS				.000	8.0	-4994.908	45.0	-4626.855	
BTAX NET INCOME/INVEST (DISC)		.13	GROSS WELLS				.000	10.0	-4959.913	50.0	-4590.943	
								12.0	-4929.254	60.0	-4521.807	
								15.0	-4889.293	70.0	-4455.825	
								18.0	-4854.519	80.0	-4392.757	
								20.0	-4833.411	90.0	-4332.471	
								25.0	-4785.622	100.0	-4274.847	

TABLE 7

PROBABLE INFILL (NO FLOOD)

DATE: 09/21/01

TIME: 09:31:56

FILE: LEA

GET#: 0

RESERVES AND ECONOMICS

READ & STEVENS

7/27/01 NYMEX FUTURE STRIP

AS OF SEPTEMBER 1, 2001

T. SCOTT HICKMAN & ASSOC., INC

PETROLEUM ENGINEERS CRV/00.004

-END- MO-YR	---GROSS PRODUCTION---		----NET PRODUCTION----		---PRICES---		-----OPERATIONS, M\$-----			10.00 PCT		
	OIL, MMBL	GAS, MMCF	OIL, MMBL	GAS, MMCF	OIL \$/B	GAS \$/M	NET OPER REVENUES	SEV+ADV TAXES	NET OPER EXPENSES	CAPITAL COSTS, M\$	CASH FLOW BTAX, M\$	CUM. DISC BTAX, M\$
12- 1	.000	2.096	.000	1.572	.00	4.39	6.897	.551	.000	.000	6.346	6.246
12- 2	32.884	77.545	24.663	58.159	24.03	4.76	869.462	69.557	67.500	2520.000	-1787.595	-1758.212
12- 3	23.075	53.577	17.306	40.183	22.28	4.90	582.502	46.601	90.000	.000	445.901	-1383.657
12- 4	12.082	31.996	9.061	23.997	21.38	4.96	312.866	25.029	90.000	.000	197.837	-1232.582
12- 5	6.592	20.786	4.944	15.589	20.88	5.01	181.255	14.501	90.000	.000	76.754	-1179.299
12- 6	3.544	14.274	2.658	10.706	20.80	5.08	109.675	8.774	90.000	.000	10.901	-1172.420
12- 7	1.733	10.199	1.300	7.650	20.80	5.16	66.486	5.319	90.000	.000	-28.833	-1188.962
12- 8	.608	7.511	.456	5.633	20.80	5.23	38.965	3.117	90.000	.000	-54.152	-1217.206
12- 9	-.112	5.662	-.084	4.246	20.80	5.31	20.809	1.665	90.000	.000	-70.856	-1250.803
12-10	-.582	4.351	-.437	3.263	20.80	5.39	8.503	.680	90.000	.000	-82.177	-1286.226
12-11	-8.277	-19.127	-6.208	-14.345	20.80	5.47	-207.633	-16.611	-120.000	.000	-71.022	-1314.057
12-12	-7.637	-18.005	-5.728	-13.504	20.80	5.55	-194.155	-15.532	-120.000	.000	-58.623	-1334.941
12-13	-7.077	-17.016	-5.308	-12.762	20.80	5.64	-182.360	-14.589	-120.000	.000	-47.771	-1350.412
12-14	-6.577	-16.125	-4.933	-12.094	20.80	5.72	-171.817	-13.745	-120.000	.000	-38.072	-1361.621
12-15	-6.118	-15.283	-4.589	-11.462	20.80	5.81	-162.029	-12.962	-120.000	.000	-29.067	-1369.401
S TOT	44.138	142.441	33.101	106.831	24.15	4.49	1279.426	102.355	187.500	2520.000	-1530.429	-1369.401
REM.	-15.900	-41.178	-11.925	-30.884	20.80	5.98	-432.768	-34.621	-360.000	.000	-38.147	-1378.192
TOTAL	28.238	101.263	21.176	75.947	26.04	3.89	846.658	67.734	-172.500	2520.000	-1568.576	-1378.192
CUM.	.000	.000					NET OIL REVENUES (M\$)	551.388	-----PRESENT WORTH PROFILE-----			
							NET GAS REVENUES (M\$)	295.270	DISC	PW OF NET	DISC	PW OF NET
ULT.	28.238	101.263					TOTAL REVENUES (M\$)	846.658	RATE	BTAX, M\$	RATE	BTAX, M\$
									----	-----	----	-----
BTAX RATE OF RETURN (PCT)			.00	PROJECT LIFE (YEARS)			17.333	.0	-1568.576	30.0	-1356.894	
BTAX PAYOUT YEARS			17.33	DISCOUNT RATE (PCT)			10.000	2.0	-1504.507	35.0	-1365.256	
BTAX PAYOUT YEARS (DISC)			17.33	GROSS OIL WELLS			.000	5.0	-1438.130	40.0	-1373.842	
BTAX NET INCOME/INVEST			.38	GROSS GAS WELLS			.000	8.0	-1396.468	45.0	-1381.956	
BTAX NET INCOME/INVEST (DISC)			.44	GROSS WELLS			.000	10.0	-1378.192	50.0	-1389.251	
								12.0	-1365.422	60.0	-1400.930	
								15.0	-1353.835	70.0	-1408.795	
								18.0	-1348.581	80.0	-1413.356	
								20.0	-1347.503	90.0	-1415.214	
								25.0	-1350.125	100.0	-1414.919	

TABLE 8.
ECONOMIC DATA USED FOR
CASH FLOWS
NORTHEAST LEA (DELAWARE) FIELD
LEA COUNTY, NEW MEXICO

Completed well cost (producer)	\$630,000
Completed well cost (injector)	\$472,500
Conversion cost	\$ 50,000
Per-well monthly operating cost (producer)	\$ 2,500
Per-well monthly operating cost (injector)	\$ 1,250
Makeup water cost	20¢/barrel