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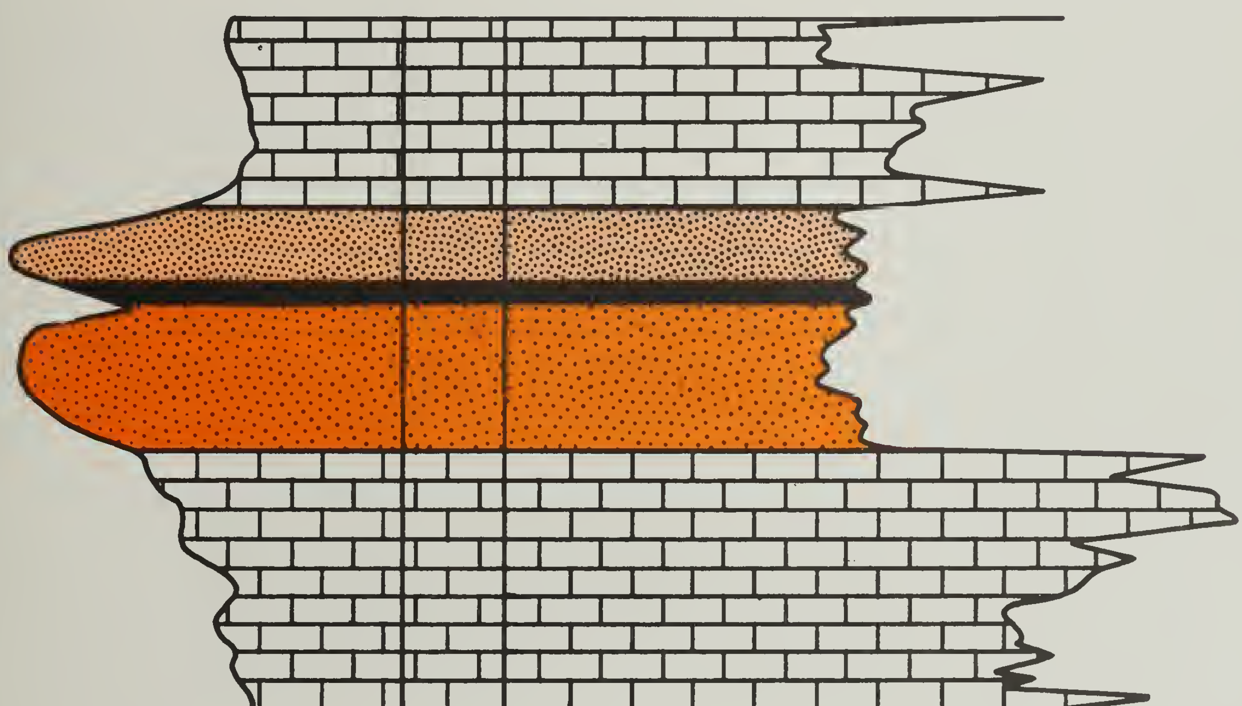
Integrated Geologic and Engineering Model for Improved Reservoir Development and Management at Energy Field, Williamson County, Illinois

Emmanuel O. Udegbunam and Bryan G. Huff



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ABSTRACT

A three-dimensional (3-D) reservoir model, developed from geologic and petrophysical data, was used to estimate the original oil in place (OOIP), simulate historical field development, and investigate strategies for improving recovery of oil from Energy Field in Williamson County, Illinois.

The Aux Vases Sandstone reservoirs at Energy Field are two stacked sandstone bars separated by an interval of impermeable, calcareous siltstone and shale. Descriptions of the reservoirs were made on the basis of geologic interpretations of reservoir sandstone distribution, structure, depositional history, porosity, permeability, and correlation of core data with wireline logs.

A 3-D geologic model, generated with a stratigraphic computer modeling program, was input for the 3-D full-field, black oil, reservoir simulation model. The estimated OOIP is 2,208,000 stock tank barrels of oil (STBO). About 15% of the OOIP was recovered after 23 years of primary production. The estimated volume of unproduced mobile oil (UMO), about 50% of the OOIP, provides strong motivation for considering future oil recovery opportunities from Energy Field through improved waterflood strategies and strategic location of infill wells.

Past pressure maintenance programs of reservoir simulation models were analyzed, and the results showed that these programs were not optimal and could not sustain reservoir pressure above the bubble-point. Various strategies for improved waterflooding were also investigated, including (1) no further development of Energy Field, (2) development of the A.B. Vaughn unit alone, (3) development of the Budmark unit alone, and (4) field unitization. Reservoir simulation results showed that optimum cumulative oil recovery from waterflooding any of the units always involved more than one injection well. The simulations also showed that migration of oil across lease boundaries occurred when the units were independently developed in an unsynchronized manner. Comparisons among various simulated strategies for future development showed that field unitization and waterflooding with two or more carefully placed infill wells would be the optimum approach.

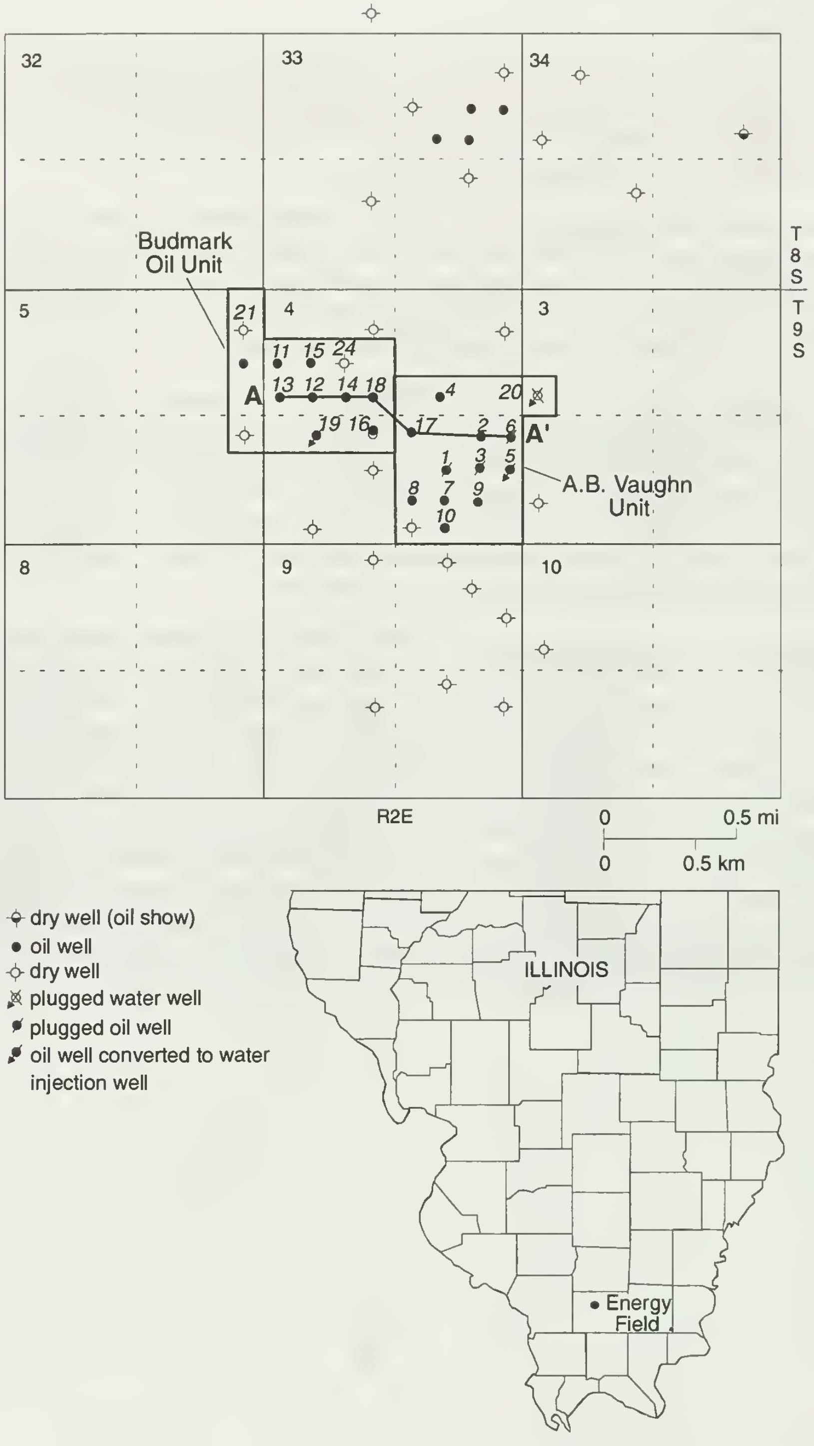

Figure 1 Location map and field map of the Energy Field study area showing line of cross section A–A′ and numbered wells (see table 2).

INTRODUCTION

Energy Field in Williamson County, Illinois, consists of 220 proven productive acres in Sections 3, 4, and 5, T9S, R2E, and Section 33, T8S, R2E. The study area (fig. 1) consists of two leases that have produced more than 300,000 barrels of oil since 1968. The pay zone comprises two sandstone bars stacked one atop the other within the upper Valmeyeran (Mississippian) Aux Vases Sandstone at depths of approximately 2,400 feet. These sandstone bars, separated by thin, impermeable, calcareous, argillaceous sandstone and shale, are encased in shale and limestone. The upper sandstone bar is replaced by shale in the western part of the field (Huff 1993).

The initial phase of development in Energy Field began when the A.B. Vaughn unit was discovered and began producing from the Eovaldi Fairchild no. 1 (fig. 1, well 1) in June 1968, after hydraulic fracturing. Well no. 1 produced 40 barrels of oil per day (BOPD) (table 1) and 40 barrels of water per day (BWPD). Eight more oil-producing wells were drilled and completed in the A.B. Vaughn unit between November 1968 and November 1969. Average production in Energy Field peaked at about 200 BOPD in 1969 but began to decline thereafter because of a lack of adequate reservoir energy (fig. 2). In October 1971, water injection for pressure maintenance was initiated using an offset well, the Eigenrauch Armstrong no. 3 (fig. 1, well 20; table 2). Water injection rates were variable but averaged about 50 BWPD. In October 1987, the Morgan Coal Eigenrauch no. 2 (fig. 1, well 5) was converted to water injection after the Eigenrauch Armstrong no. 3 was abandoned (fig. 1, well 20). About 288,000 barrels of oil were produced from the A.B. Vaughn unit between 1968 and 1991. By December 1991, the A.B. Vaughn unit was producing only 8 BOPD (H. Hughes, Budmark Oil Company, Inc., personal communication 1992).

Development of the sandstone bars in the Aux Vases Formation in the Budmark unit west of the A.B. Vaughn unit began with the discovery of oil in the Williamson County Airport no. 1 (fig. 1, well 11) by the Budmark Oil Company in 1988. The well extended Energy Field more than 1/2 mile to the west. This unit produced more than 43,000 barrels of oil between July 1988 and December 1991. A marginal producer, the Morgan Coal no. 4 (fig. 1, well 19), was converted to water injection in 1990. It injected water at an average of 63 BWPD.

Well development in both units followed a similar pattern: drilling with freshwater mud, wireline logging, casing completions, perforations, acid cleanout, hydraulic fracturing, and oil production. Formation damage, reportedly resulting from the use of mud cleanout acid containing 15% hydrochloric acid in the Budmark Morgan Coal no. 2 (fig. 1, well 14), is discussed in another Illinois State Geological Survey (ISGS) publication (Haggerty and Seyler, in preparation).

Oil production rates have declined in the past 24 years from 200 BOPD to less than 25 BOPD. The southern part of Energy Field (the study area) is approaching the economic limits of oil production. The unit operators are facing the choice of continuing oil production at present marginal rates or initiating field development to recover incremental oil.

Most Illinois operators continue production until oil production rates become marginal and then begin a waterflood program. Selection of wells to be used as water injectors, time to start the waterflood, and rates at which to inject are not usually guided by detailed reservoir simulation studies. Many mature Illinois fields are thus in danger of being abandoned despite the fact that several million barrels of producible oil still remains in the reservoirs. This same situation probably exists in

Table 1 Nomenclature used in this report.

BOPD	barrels of oil per day
BWPD	barrels of water per day
DST	drill stem test
GOR	gas-to-oil ratio
K	absolute permeability, md
Kh	permeability × thickness
MSTBO	thousand stock tank barrels of oil
OOIP	original oil in place
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PVT	pressure–volume–temperature
S	fluid saturation (fraction)
scf	standard cubic feet
STB or stb	stock tank barrels
STBO	stock tank barrels of oil
STOOIP	stock tank original oil in place
UMO	unproduced mobile oil
OWC	oil–water contact
Symbols	
ϕ	porosity (fraction)
Subscripts	
o	oil
ro	residual oil
rw	residual water
w	water or brine
t	true
g	gas

other oil-producing fields operated by independent operators throughout the United States.

The major objective of this study was to use limited available field data to develop a simulation reservoir model for a small field, such as Energy Field. The model would then be used to evaluate past field performance and test potential strategies for improved oil recovery. Energy Field was selected because it is representative of small fields with multiple independent and nonunitized operations, and because developments in the leases were consistently recorded. Futhermore, operators were very cooperative. This study may serve as an analog to other unit operators because Energy Field is typical of many Illinois fields.

RESERVOIR CHARACTERIZATION

Geologic Characteristics

A complete discussion of the reservoirs of Energy Field, including petrography, depositional environments, and exploration strategy, can be found in Huff (1993). A brief discussion of the geology of the study area follows.

The Aux Vases Formation at Energy Field consists of a sequence of overlapping and interfingering layers of shale and sandstone that range from 6 to 35 feet thick. Within this succession, four separate sandstone reservoirs are present. The four reservoirs consist of two complexes of upper and lower sand bodies, one complex in the northern part of the field and another in the southern part. Only the south

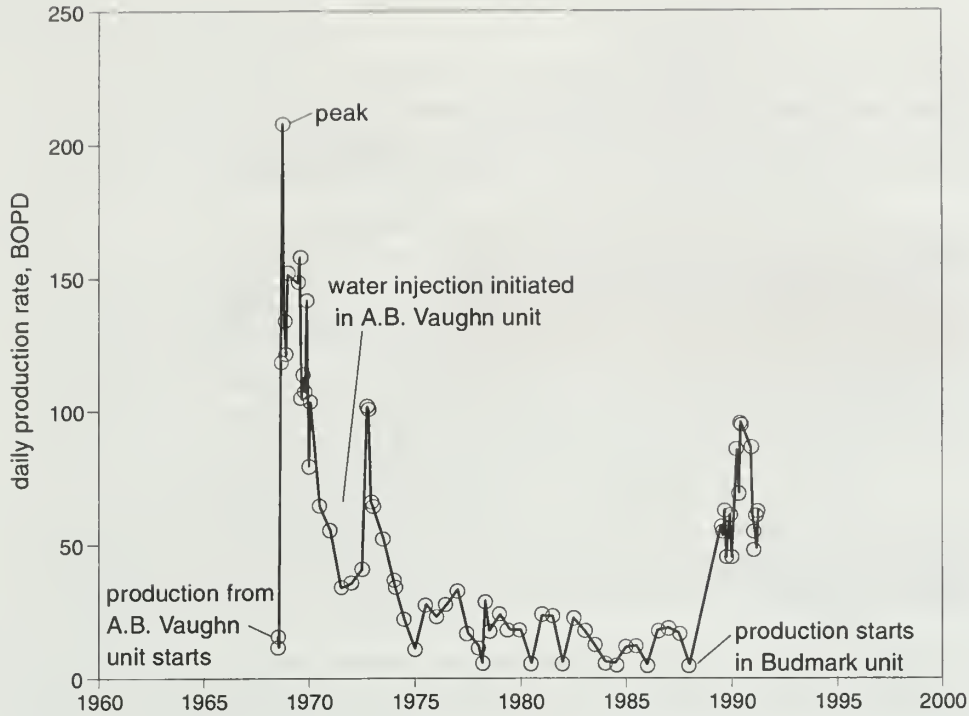

Figure 2 Summary of oil production history in the Energy Field.

Table 2 Well names, API numbers, and simulated well numbers (see fig. 1).

Well name	Well API no.	Well no. (simulated well)
Eovaldi Fairchild no. 1	2336	1
Eigenrauch Armstrong no. 1	2345	2
Morgan Coal Eigenrauch no. 1	2344	3
Eovaldi Fairchild no. 2	2358	4
Morgan Coal Eigenrauch no. 2	2369	5
Eigenrauch Armstrong no. 2	2370	6
Hill Zoller no. 1	2377	7
Hill Zoller no. 2	2395	8
Morgan Coal no. 1	2397	9
Hill Zoller no. 3	23268	10
Williamson Cty no. 1	23455	11
Morgan Coal no. 1	23456	12
Williamson Cty no. 2	23457	13
Morgan Coal no. 2	23465	14
Morgan Coal no. 3	23466	15
Morgan Coal no. 5A	23472	16
Eigenrauch Fairchild no. 3	23477	17
Morgan Coal no. 6	23481	18
Morgan Coal no. 4	23467	19 (injector)
Eigenrauch Armstrong no. 3	2387	20 (injector)
Williamson Cty Airport no. 1	23420	21 (dry)
Infill (simulated) well	New	22
Infill (simulated) well	New	23
Morgan Coal no. 7	23482	24 (dry)

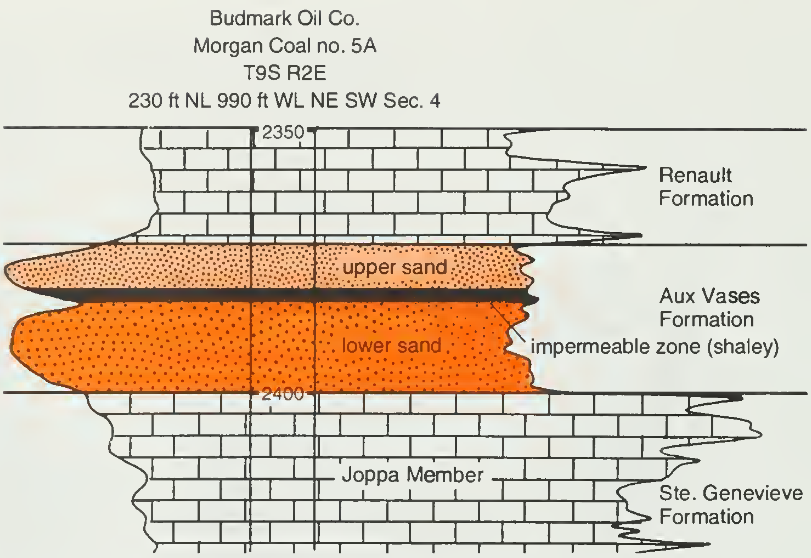

Figure 3 Typical electric log of a well from the Energy Field.

complex is covered in this study because the northern reservoirs, discovered in December 1991, are a relatively recent development (Huff 1993).

The reservoir sandstones are sealed laterally and vertically from each other by impermeable shale, siltstone, and sandstone. Although the trapping mechanism at Energy Field is stratigraphic, structural modification has added significant complexity to the reservoir geometery. This complexity makes it difficult for any company operating without the benefit of a detailed reservoir study to develop a reservoir management strategy for the southern part of the field.

A typical electric log from the field (fig. 3) shows the major lithofacies within the Aux Vases Formation: an upper sandstone body, a thin impermeable zone of interfingering shales, and a lower sandstone body. A cross section of the field (fig. 4) correlates these units and illustrates the reservoir geometry.

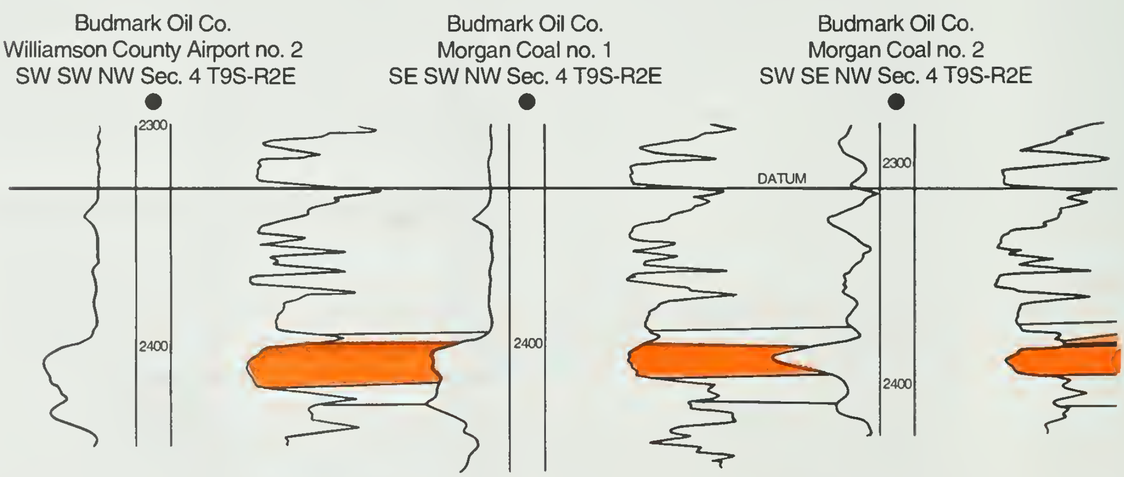

Figure 4 Cross section A–A′ shows vertical relationships of Aux Vases siliciclastic units in southern bar complex, Energy Field. Well spacing is not proportional; datum is indicated. See figure 1 for line of cross section.

Data Availability

Data used for reservoir characterization and simulation included depth to the top of the Aux Vases Sandstone, sand thickness (Huff 1993), porosity, permeability, lithology, initial water saturation, and depth to the oil–water contact (OWC). Values of these parameters were obtained from geophysical and/or drilling logs or from core analyses.

Huff (1993) interpreted the depths to the top of the Aux Vases Sandstone and productive pay thickness of the reservoir in each well directly from the drilling and geophysical logs available in the repository at the ISGS Geological Records Unit. Porosity, absolute permeability, and initial water saturation data were directly evaluated from core analysis reports of three wells: the Hill & Zoller no. 1 and Eigenrauch Armstrong no. 1 in the A.B. Vaughn unit, and the Morgan Coal no. 2 in the Budmark unit (appendix A). Unit operators provided core analysis reports, as well as oil production and water injection records.

Data that are useful for reservoir studies but unavailable for this study included (1) reservoir pressure data at various times, (2) detailed drill stem test (DST) data instead of the test summaries, (3) transient field tests for better reservoir definition, and (4) gas-to-oil ratios (GOR).

Analyses of Rock Data for Geologic Modeling and Reservoir Simulation

The A.B. Vaughn unit has only two cored wells, the Hill & Zoller no. 1 and Eigenrauch Armstrong no 1. Old electric logs are available for the unit, but there are no porosity logs. Consequently, the in situ porosity values of uncored wells could not be evaluated. The average values of permeability, porosity, and water saturations from the cored wells were used in the initialization of the reservoir simulation model of the A.B. Vaughn unit (table 3). The permeability, porosity, and water saturation values of the cored wells were averaged in each interval present in the A.B. Vaughn unit (table 3).

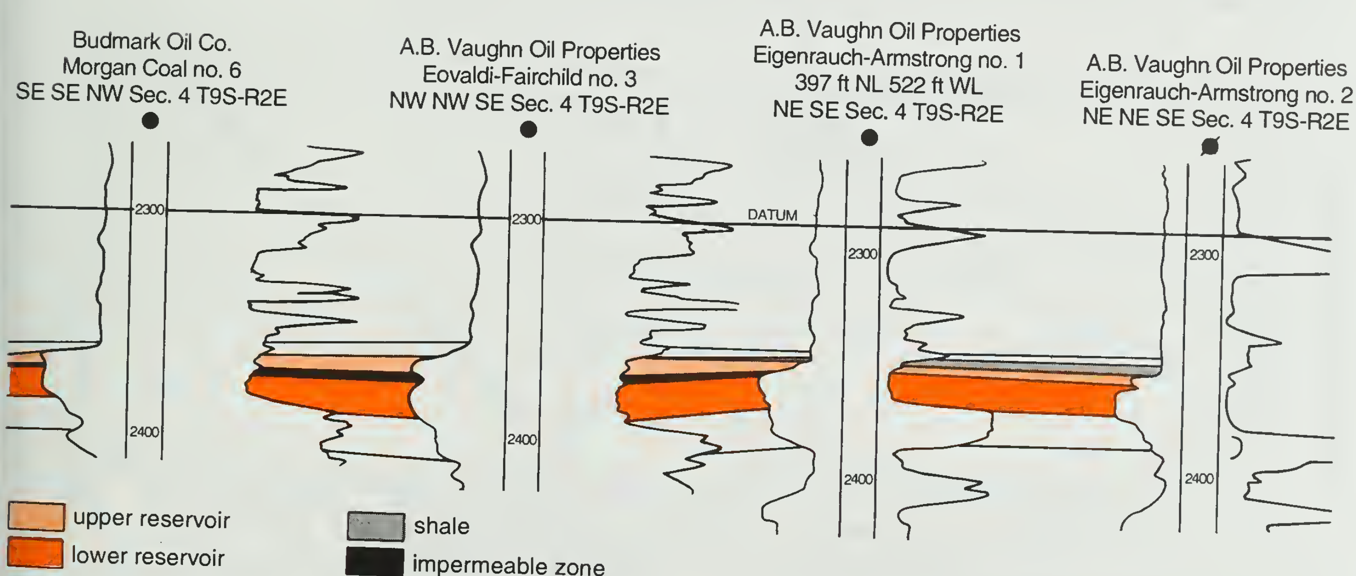

Table 3 Ranges of porosity (ϕ), permeability (K), and water saturation (Sw) data for two wells in the A.B. Vaughn unit.

Reservoir intervals	Eigenrauch Armstrong no. 1			Hill Zoller no. 1			Average		
	ϕ	K	Sw	ϕ	K	Sw	ϕ	K	Sw
Upper sandstone bar	n/a	n/a	n/a	15–20	15–103	38–59	18.8	74.9	52.2
Middle shaley zone	n/a	n/a	n/a	5–14	0.5–49	48–63	13.6	8.7	55.1
Lower sandstone bar	19–24	75–431	42–64	13–21	36–190	42–59	19.0	103.0	47.7

In the Budmark unit, however, all the wells had complete suites of induction and density/neutron porosity logs. The Morgan Coal no. 2 well was cored. This larger data set made it possible to

- develop a log permeability versus porosity (ϕ) crossplot from the core analysis of the Morgan Coal no. 2 (fig. 5);
- develop a ϕ_{core}/ϕ_{log} crossplot from corresponding log-derived and core-derived porosity values from the Morgan Coal no. 2 (fig. 6);
- determine permeability values at uncored wells by interpreting ϕ_{log} values from neutron/density logs, and by using figure 6 to obtain ϕ_{core} and figure 5 to obtain permeability.

The fluid saturation values measured when the Budmark unit was discovered were not original values. The low reservoir pressures in the Budmark unit at discovery are indicative of pressure bleed-off due to production in the A.B. Vaughn unit. For this reason, it was not possible to interpret preproduction water saturation values from either the core analyses of the Morgan Coal no. 2 or from corrected true resistivity values of all Budmark unit wells. The average initial water saturation values, determined from core analyses of the Eigenrauch Armstrong no. 1 and Hill Zoller no.1 wells, were 52.2% for the upper sand bar, 55.1% for the intermediate shaley/silty zone, and 47.7% for the lower sand bar (table 3). These values were used throughout the study area.

Oil–water contact The original OWC interpreted from geophysical logs lay between -1,923 and -1,928 feet subsea. The geophysical log interpretations were confirmed by a whole core sample taken from the Burr Oak no. 3, a well north of the study area. The isopach map of the net thickness of the lower reservoir sandstone

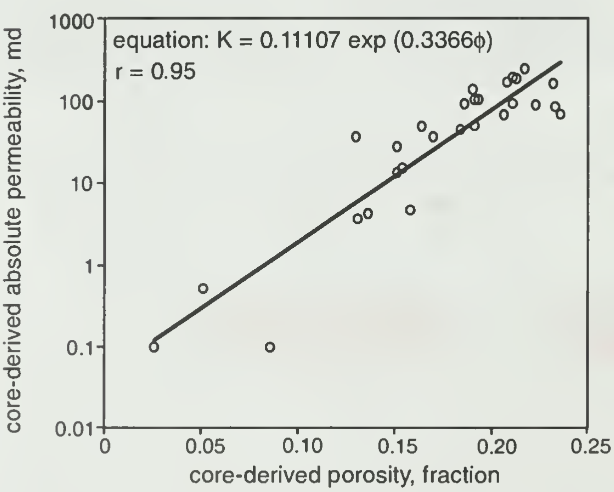

Figure 5 Crossplot of core-derived porosity versus core-derived permeability.

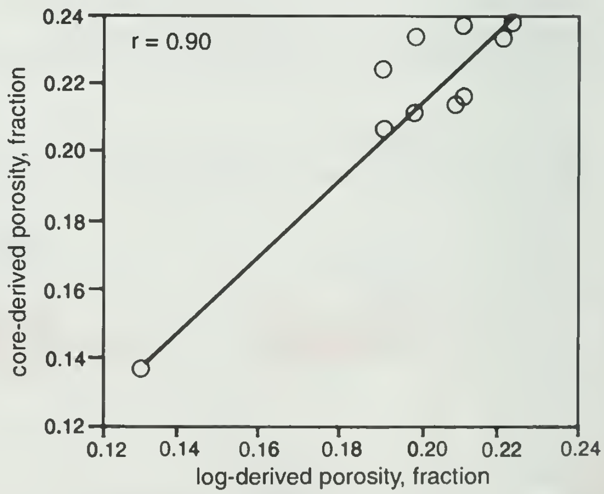

Figure 6 Crossplot of log-derived porosity versus core-derived porosity.

above the conservative OWC elevation of -1,923 feet shows that the lower sandstone interval consists of two separate pods of productive reservoir sandstones, one in the Budmark unit and the other in the A.B. Vaughn unit, connected at a saddle below the oil–water interface (fig. 7). Oil-producing wells located at the saddle, such as the Eovaldi Fairchild no. 2, Eovaldi Fairchild no. 3, and Morgan Coal no. 5A, produce oil from the upper sandstone.

Fluid properties Surface samples of oil and gas from Energy Field were recombined at various ratios and analyzed in the ISGS PVT laboratory to determine their characteristic properties (table 4). Because the compositions of the oil and gas samples are not the same as those originally in the reservoir, the PVT properties of each mixture were determined, and oil and gas were recombined in three different ratios—210, 279.5, and 419.4 scf/stb. The saturation (bubble-point) pressure of hydrocarbon fluid samples increases with the oil and gas mixing ratios (fig. 8). A bubble-point of 910 psig was selected for the simulation because it was known that no primary gas cap was present at the original reservoir pressure of 923 psig (Moore 1969).

Whether the original bubble-point pressure was actually 910 psig or some lesser value is not known. Bubble-point pressures of Aux Vases reservoirs could be much less than 910 psig (G.A. Payne, petroleum engineering consultant, personal communication 1992). We investigated the effects of bubble-point pressure on the simulation model by comparing simulated cumulative oil production, reservoir pressures, water cut ratios, and gas/oil ratios at 910 psig and 375 psig (table 5).The average percentage deviations of cumulative oil production, reservoir pressure, and water cut ratios are 2.1, 4.5, and 1.6, respectively, in 24 years of simulated production (1978–2002). The simulations show that 36% more gas would have been produced with a bubble-point pressure of 375 psig than with 910 psig. However, the GOR could not be used as a test of the history match for the simulations because the field gas production has not been measured.

Geologic modeling A geologic framework consisting of sandstone thicknesses, depths to the top of sandstones, porosities, permeabilities, and fluid saturations is required by the reservoir simulation model. A 3-D geologic model of the study area was created with Stratigraphic Geocellular Modeling Software (SGM™), a computer

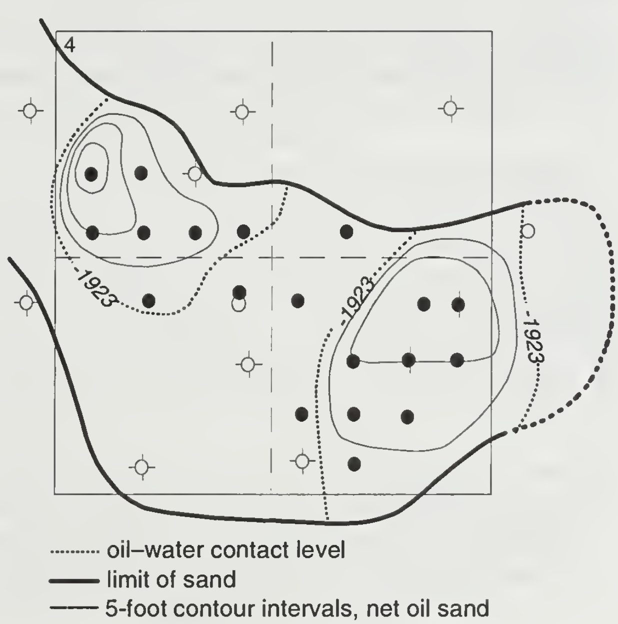

Figure 7 Isopach map of the net thickness of the lower reservoir sandstone interval above the oil–water contact of -1,923 feet.

Table 4 PVT analyses of Energy Field fluid samples of three GORs.

GOR values, scf/stb	419.4	279.5	210.0
Saturation pressure, psia	1600.0	1160.0	910.0
Reservoir temperature, °F	84.0	84.0	84.0
API gravity	38.0	38.0	38.0

program that subdivides the gross rock volume into layers and cells within stratigraphic sequences. The program is not only capable of creating an accurate 3-D model from the field geometrical data, but it also allows a large number of rock attributes (e.g., porosity, permeability, lithology, or water saturation) to be assigned to each cell within the model. Attribute values for the interwell regions are determined by interpolation of data given at the wells.

The detailed stratigraphic model of the reservoir from the modeling program was exported to the GeoLink™ program. GeoLink™ interactively creates a layered fluid-flow simulation model from the detailed stratigraphic reservoir model. The three fluid-flow layers, thus constructed, correspond to the upper sandstone bar, the middle silty/shaley zone, and the lower sandstone bar (fig. 3). The fluid-flow simulation model was then transferred to the reservoir simulator for subsequent model initialization and field simulation.

RESERVOIR SIMULATION OF THE ENERGY FIELD

Background of Energy Field Development

Aux Vases reservoirs are typically solution-gas driven and have weak or no water drive energy. As a consequence, reservoir pressures and oil production rates commonly decline precipitously. Two ways of maintaining the reservoir pressure, and thus enhancing primary recovery, are gas injection and water injection (Dake 1978). As noted by Moore (1969), the produced-gas volumes at Energy Field were not sufficient to justify the costs of gas gathering and injection operations. Gas-to-oil ratios in Aux Vases fields commonly are rather low because of the high nitrogen content of the Aux Vases crude oil. The feasibility of reservoir pressure maintenance through gas reinjection is doubtful in such cases. Water injection for pressure maintenance was clearly the more feasible option for Energy Field.

Preliminary engineering studies of Energy Field were commissioned by A.B. Vaughn, Inc. (Moore 1969) and by Budmark Oil Company (Walker 1989). Moore's study of the A.B. Vaughn unit noted rapidly declining reservoir pressure due to the low GOR,

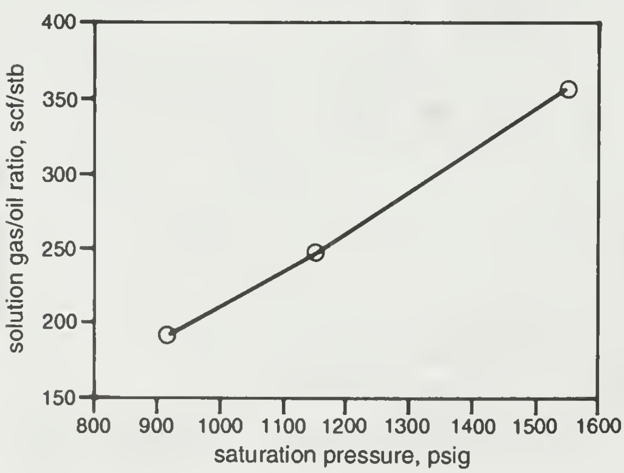

Figure 8 Variations of mixing gas-to-oil ratios with saturation pressure.

Table 5 Comparison of simulated results for two bubble-point pressures (910 psig and 375 psig).

Simulated parameters	Pressure 375 psig	910 psig	% deviation $100\,(R_{375}-R_{910})/R_{910}$
Cumulative oil production, MSTB	249.3	245.2	2.1
Avg. reservoir pressure	10.0	105.2	4.5
Water cut ratio	0.67	0.66	1.6
GOR	567.3	417.1	36.0

inefficient gas drive, and weak water drive. The study recommended that water injection be initiated "as early as possible" to raise the reservoir pressure above the bubble-point pressure and that "pressure be maintained throughout the future life of the project." It was also recommended that water be injected into the Eigenrauch Armstrong no. 3 well (fig. 1, well 20) at a rate of 300 to 350 BWPD.

A.B. Vaughn, Inc. responded to Moore's report by initiating water injection into the Eigenrauch Armstrong no. 3 in 1971. Production rose initially but declined to pre-waterflood levels soon thereafter (fig. 2). The Eigenrauch Armstrong no. 3 well was shut-in June 1987 and the Morgan Coal Eigenrauch no. 2 (fig. 1, well 5) was converted to water injection, but there was no discernible oil production response after this conversion (fig. 2). It seems likely that the water injection rates used in the Morgan Coal Eigenrauch no. 2 were not sufficient to maintain reservoir pressure.

Walker's (1989) report on the development of the Budmark unit suggested an anticipated primary recovery of 12,000 barrels of oil per well, but "only by virtue of oil [being] forced to the producing wells." According to the report, an estimated 10,000 barrels of oil per well could be produced if only two or three injection wells were used. After Walker's report was released, Budmark Oil Company converted a marginal oil-producing well, the Morgan Coal no. 4 (fig. 1, well 19), to water injection in August 1990. The average water injection rate into the unit is about 65 BWPD.

The data on past reservoir performance in Energy Field (fig. 2) clearly indicate that water injection rates were not optimal. The reservoir simulations conducted for this study show that water injection volumes in both units were not sufficient to maintain reservoir pressure in the field (fig. 9). Neither unit has undergone a properly patterned multi-well waterflood program. The simulations indicate that Energy Field could still produce substantial volumes of oil if such a waterflood program were implemented.

Study Area for Reservoir Simulation Modeling

The study area consisted of 11 oil producers and one water injector in the A.B. Vaughn unit, and seven oil producers and one water injector in the Budmark unit (fig. 1). Oil production rates were available on a per well basis in the A.B. Vaughn unit until November 1971 when water injection into the Eigenrauch Armstrong no. 3 well commenced and all produced oil was directed into a common tank battery. In the Budmark unit, oil production volumes are documented on a single well basis, but water production and injection volumes are documented on a field-wide basis.

Gridblock Selection

The model was constructed using 28 x 16 x 3 gridblocks containing at least two grid cells between adjacent wells (fig. 10), following the recommendation of Mattax and Dalton (1990). The region within the outline is, according to current interpretations, the extent of the permeable and porous sandstone interval of the Aux Vases in the study area.

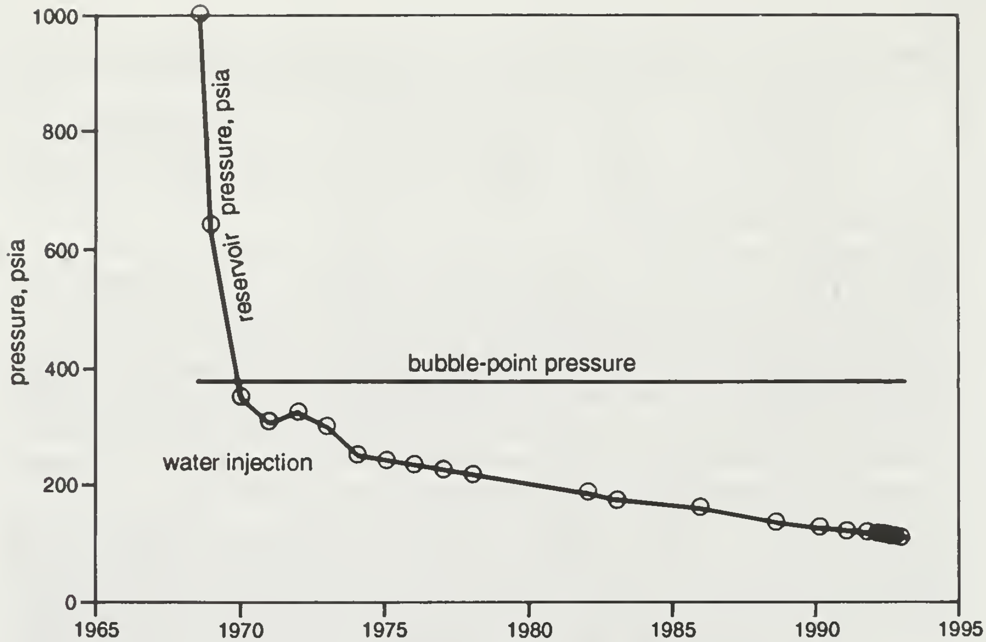

Figure 9 Comparison of bubble-point pressure with simulated reservoir pressure shows ineffectiveness of the pressure maintenance program.

Initialization of the Fluid-Flow Simulation Model

Most of the data needed to describe the reservoir simulation model originated from the geological model. The end-point relative permeabilities and saturations used for the simulations were obtained from two sandstone reservoirs in the Aux Vases in the South East Jordan School and Feller units, Wayne County, Illinois (Sandiford and Eggebrecht 1972). Experimental data on relative permeability versus water saturation for Aux Vases Sandstone reservoirs are sparse. The relative permeability versus water saturation data used in the reservoir simulation of the A.B. Vaughn and Budmark units are shown in figure 11. Capillary pressure data were not necessary for calculating the original oil in place (OOIP) because the initial water saturation distribution was available.

Estimation of Reserves and Oil Recovery Factors

Original oil in place was determined by the volumetric method during the initialization of the reservoir simulation model. The OOIP is the summation of the preproduction hydrocarbon volumes in the gridblocks (fig. 10) and is represented by the following equation:

$$STOOIP = 7758 \sum \frac{\phi_i (Ah)_i S_{o_i}}{B_o}$$

where:

7758	=	conversion factor for acre-feet to barrels
$STOOIP$	=	original oil in place in stock tank barrels
ϕ_i	=	porosity of the i-th gridblock, fraction
$(Ah)_i$	=	reservoir volume of the i-th gridblock in acre-feet
S_{o_i}	=	oil saturation of the i-th gridblock, fraction
B_o	=	oil formation volume factor, rb/STB

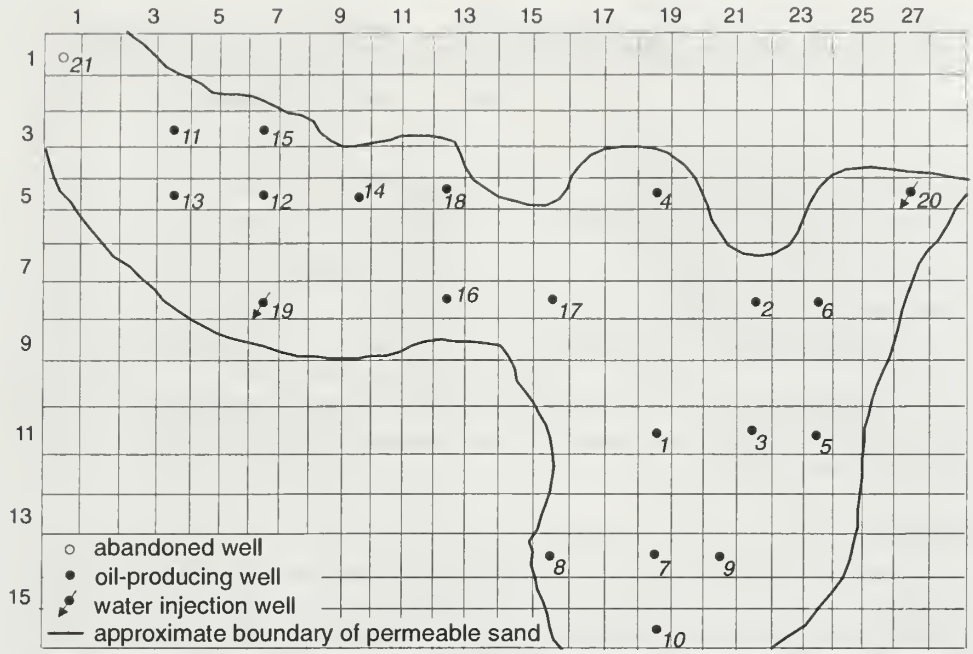

Figure 10 Gridblocks for reservoir simulation modeling.

We estimated the STOOIP to be 1,290,000 barrels in the A.B. Vaughn unit and 918,000 barrels in the Budmark unit, totaling 2,208 MSTBO. We also estimated from core analyses that the average residual oil saturation in Energy Field is 15%. Hence, the immobile oil volume is 472 MSTBO in the A.B. Vaughn unit and 294 MSTBO in the Budmark unit.

By December 1991, about 15% of the total estimated reserves in the Energy Field had been produced: 13% by the A.B. Vaughn unit and 2% by the Budmark unit (table 6). Consequently, about 50% (1.1 million barrels) of the OOIP in the Energy Field is unproduced mobile oil, which is the target for an improved waterflooding and infill drilling program.

Reservoir Simulation Techniques

Reservoir modeling of the Energy Field was performed using VIP CORE™, a 3-D black oil reservoir simulator developed by Western Atlas Integrated Technologies.

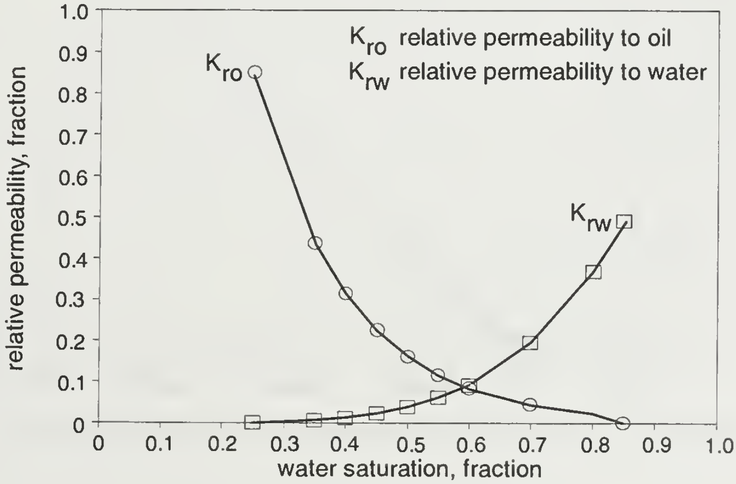

Figure 11 Relative permeability versus water saturation data in the simulation model.

Table 6 Estimated reserves and recovery factors for the Energy Field (December 1991).

	A.B. Vaughn unit	Budmark unit	Total
Estimated OOIP, MSTBO	1,290	918	2,208
Est. immobile oil, MSTBO (S_{or} = 15%)	472	294	766
Oil recovery, MSTBO (12/91)	288	43	331
Recovery factors (% OOIP)	22.3	4.6	15
Waterflood reserves, MSTBO	530	581	1,111
Waterflood reserves (UMO as % OOIP)	41.1	63.3	50.3

The simulator was run on an *Iris 4D/310* Silicon Graphics workstation. The VIP's BLITZ solution technique was used for solving the algebraic equations (Western Atlas Software 1991).

History Match

Several history match runs were used to test the reservoir simulation model's capability to reproduce observed field performance. Through the history match testing, significant adjustments were made to the model parameters controlling the permeability-thickness (Kh) product and the oil–water relative permeability at the producing wells. No adjustments were required on areal and vertical permeability distribution within the producing intervals, interblock saturation distributions, PVT properties, and liquid flow rates from the wells. To evaluate the quality of the match,

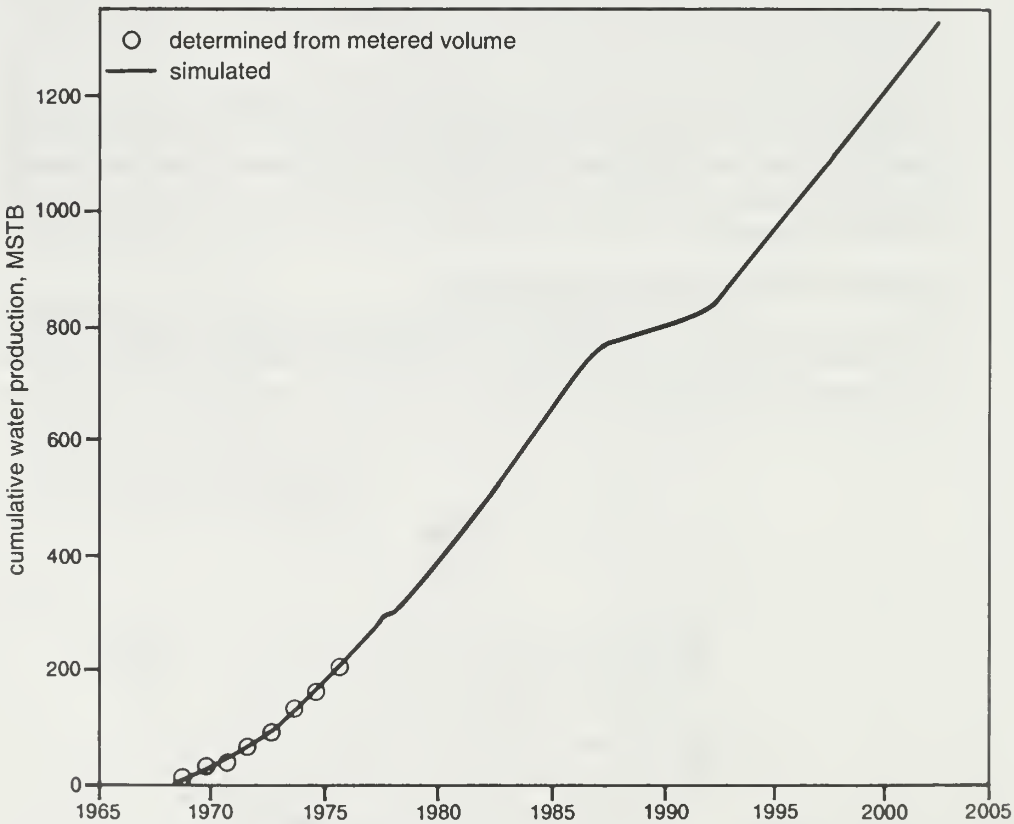

Figure 12 Water production history match for the A. B. Vaughn unit.

we used the following historical field data: pressure values from DST of some wells at various times, total oil production, and field water production. Field gas production data were not available and could not be matched.

The permeability-thickness values at the wells and the curvatures of the relative permeability-water saturation curves were gradually altered around the well bores to bring the simulated reservoir performance as close as possible to the known 23-year history from August 1968 to December 1991. The adjustment of the Kh values around well bores was justified by changes that occurred during the drilling and well completion stages, such as mud invasion of the formation, acid treatment, and hydraulic fracturing. The net effect of these changes can increase the permeability around the well bore (Allen and Roberts 1989). Figures 12 and 13 show the simulated and actual water production for the A.B. Vaughn and Budmark units, respectively. Observed DST pressures also compared well with the values computed by the simulation model (fig. 14).

Evaluation of Future Development Opportunities at Energy Field

The analysis of current oil reserves in the A.B. Vaughn and Budmark leases at Energy Field showed that about 50% of the estimated OOIP (1.11 million barrels of oil) is mobile. Exploration of field development opportunities is worthwhile in Energy Field because the present recovery strategies have approached their ultimate production and, most likely, their economic limits. Water injection into both units was through single wells at rates that were insufficient to halt the precipitous pressure decline in the reservoirs.

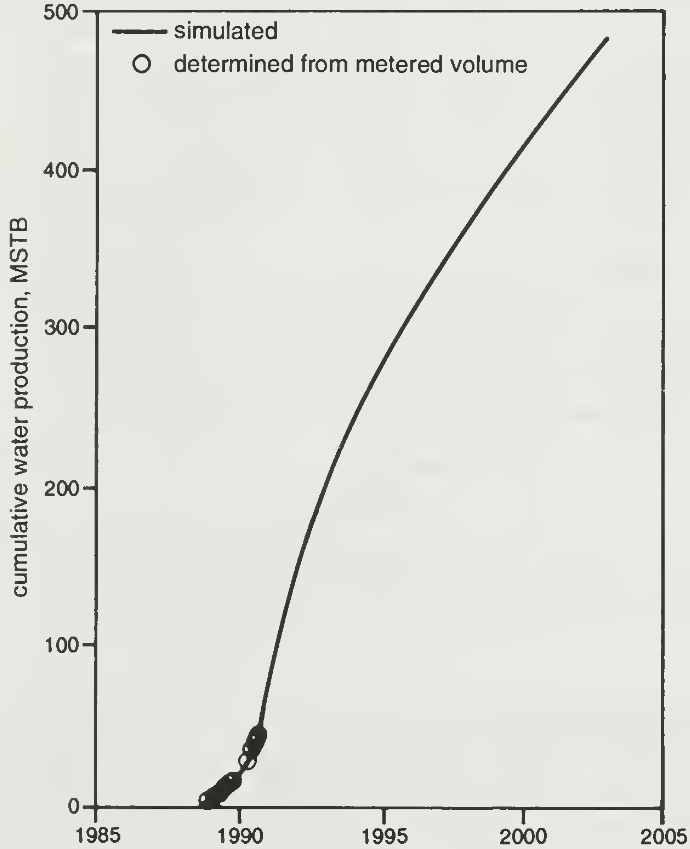

Figure 13 Water production history match for the Budmark unit.

Several strategies for reservoir management were investigated to maximize recovery at Energy Field. These included multi-well waterflooding, infill drilling, and/or field unitization. The following options were independently investigated and compared:

- base-case option — no new developments at Energy Field
- A.B. Vaughn unit development
- Budmark unit development
- unitization of A.B. Vaughn and Budmark leases.

A 5-year (1993–1998) waterflood life was assumed in each waterflooding case. Each water injection well was assumed to inject 250 BWPD per well.

Because developmental costs of the various strategies differ, the optimal recovery strategy depends on both the incremental amount of oil recovered and on the project economics over a given period of time. A cursory economic analysis of each alternative used, the cost elements, and costs are given in appendix B. These values were provided by Hiram Hughes, the operator of the Budmark unit, in February 1993. The four options were ranked on the basis of profitability for an oil price at $20 per barrel for 5 years. Detailed economic analyses of these projects are beyond the scope of this study.

Base-case option The base-case simulations assume that there are no further developments at Energy Field and that the present scenario in the field, including the water injection rates, is maintained. This simulation involved eight oil producers and one water injector, injecting at the rate of 50 BWPD in the A.B. Vaughn unit, and seven

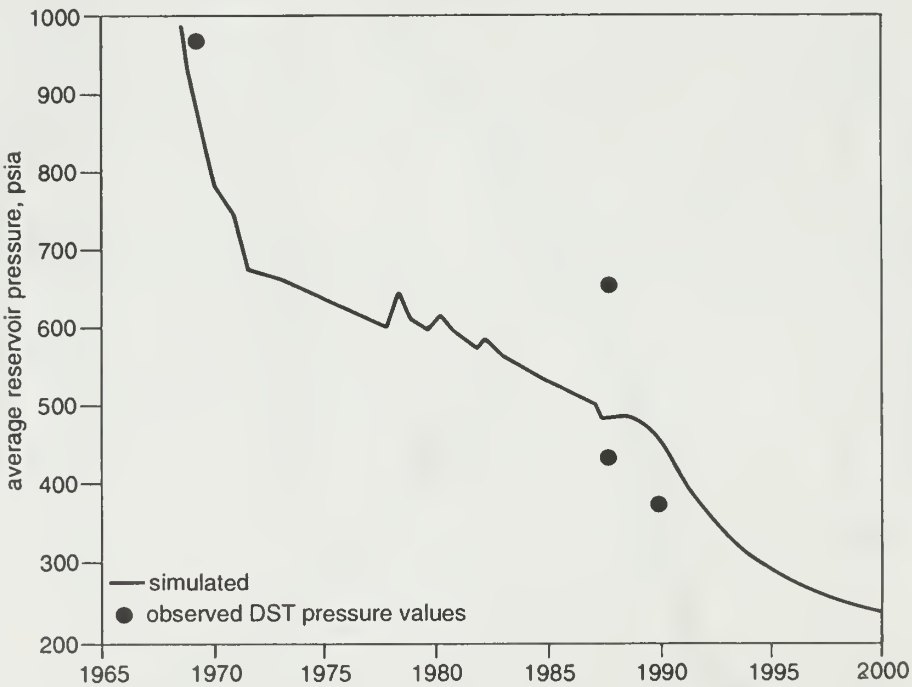

Figure 14 Field pressure match for Energy Field.

oil producers and one water injector, injecting at 62.5 BWPD in the Budmark unit. The simulated results for the base-case are as follows.

- The A.B. Vaughn unit would reach its economic limit in mid-1993, with an incremental recovery of 2.7 MSTB. The model predicts that, without regard to production economics, this unit would yield a total of 23.4 MSTB of additional oil in the next 5 years (1993–1998).
- Although recovery of an additional 15 MSTB is predicted through 1998, the net income from this alternative in the Budmark unit would be negative.
- If the field were abandoned in mid-1993, the estimated remaining UMO at that time would be 1,106,000 barrels.

Because only about 15% of the OOIP was recovered during previous operations, and a waterflood reserve as high as 50% of the OOIP remains, redevelopment of Energy Field through well planned waterflooding and unitization is necessary for improved oil recovery.

Choice of well arrangement The arrangement of injection and production wells depends on the geology and geometry of the reservoir and the volume of the hydrocarbon-bearing rock required to be swept within a time frame limited by economics (Latil et al. 1980). The reservoir simulator was used to evaluate several plausible options for injection and production wells for the A.B. Vaughn and Budmark units.

As discussed in Huff (1993), the reservoir sandstones at Energy Field are elongate in the northwest-southeast direction. Also, the two lower sandstone pods in the Budmark and A.B. Vaughn units are surrounded by an aquifer (fig. 7). As a consequence, peripheral and line-direct arrangements of injection wells seem best suited for waterflood recovery from Energy Field. For the best effect, line-drive injection wells should be arranged approximately perpendicular to the elongation axis of the sandstone bodies. Existing water injectors were not converted to producers in the simulations because of the likelihood of water blockage around their well bore regions. Plugged wells are simulated as plugged.

Development of the A.B. Vaughn unit The following options of water injection and oil-producing wells were investigated (fig. 15).

1 Inject water into peripheral wells 5 and 17. Well 5 is the existing water injection well. Well 17 is an existing oil producer to be converted to water injection. Produce wells 1, 2, 4, 7, 8, 9, and 10.

2 Inject water in a line-drive pattern into wells 5, 9, and 10; inject water into 17. Produce wells 1, 2, 4, 7, and 8.

3 Inject water in a line-drive pattern into wells 5, 9, 10, 4, and 17 (fig. 15). Place infill well 23 between wells 3 and 17, and infill well 22 between plugged wells 3 and 6. Produce the two infill wells and wells 1, 2, 7, and 8.

The results of the model simulations show that option 3 would result in the highest additional oil recovery among the alternatives considered for development of the A.B. Vaughn unit (table 7). A cursory economic analysis of these options also indicates that option 3 would give the highest rate of return on invested dollars. Option 3 is ranked as the first economic choice, followed by option 2.

Development of the Budmark unit The following options of water injection wells and production wells were investigated (fig. 16).

1 Inject in a line-drive pattern into wells 12, 15, and 19. Produce wells 11, 13, 14, 16, and 18.

2 Inject water in a line-drive pattern into wells 12, 15, and 19, and into a peripheral well, 21 (fig. 16). Produce wells 11, 12, 13, 14, 16, and 18.

3 Increase the water injection rate to 250 BWPD into the existing injector 19. This option represents the minimum cost water injection development in the Budmark unit.

The results of the simulations show that in terms of cumulative incremental oil recovery, option 2 may be optimal among the alternatives considered in the model (table 8). A cursory economic analysis of the alternatives shows that it costs more to develop option 2 than option 1 because of the additional peripheral well (no. 21) in option 2, which might also require recompletions and additional monthly operating expenses. Options 1 and 2 would be ranked equally economically (table 8), but option 1 involves less development and lower operating costs. Option 1 would have a higher rate of return on invested dollars. These results clearly indicate that more than one water injection well is needed for successful waterflooding of the Budmark unit.

Across lease-line migration of oil The model indicates that oil production increased in one unit when waterflooding operations were simulated in the other (figs. 17 and 18). These results are dependent on the present understanding of the reservoir architecture, which assumes that the lower sandbar is continuous between the two units. On the basis of these results, it would be essential that the field be fully unitized prior to waterflooding. The results of reservoir simulations such as this can be useful in decision making, but an operator should also consider other technical and business factors when deciding how best to proceed.

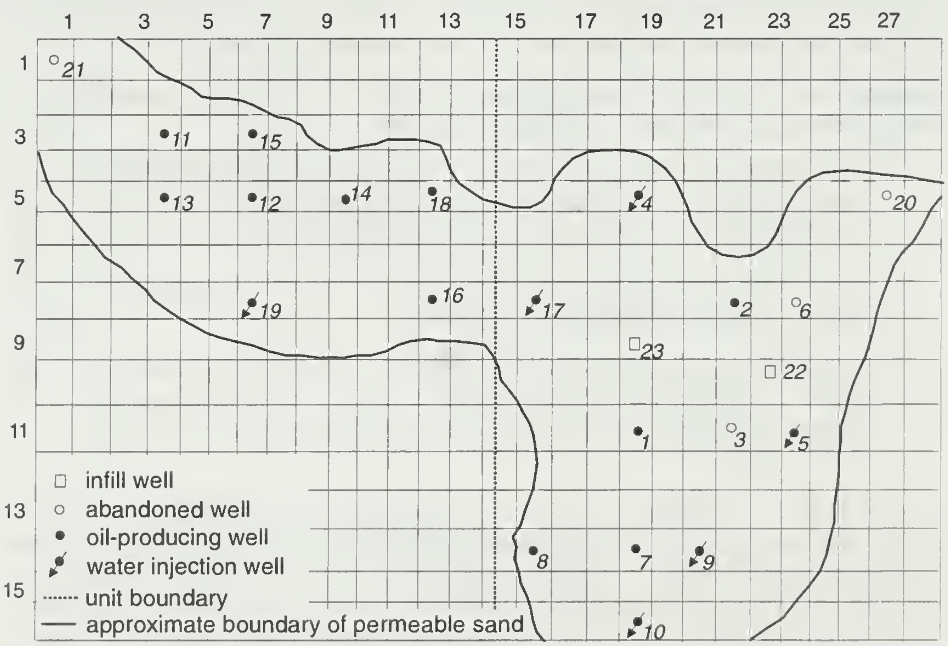

Figure 15 Well location map shows the optimal simulated waterflood plan for the A.B. Vaughn unit.

Table 7 Predictions of 5-year incremental oil recovery from the A.B.Vaughn waterflood unit (see fig. 17).

Options	Incremental oil production MSTBO	No. of injectors
Base case	23.4	1
1	70.7	2
2	96.1	4
3	127.6	5

Unitization of Energy Field In simulating the unitization of Energy Field, the following four possible arrangements of water-injection and oil production wells were investigated (fig. 16).

1 Inject water into wells 5, 7, and 17 in the A.B. Vaughn lease and wells 13, 14, 15, and 19 in the Budmark lease. Produce wells 1, 2, 4, 8, 9, 10, 11, 12, 16, and 18. There is no infill well in this option (fig. 16).

2 Same as option 1, except that production is from infill well 23 in the A.B. Vaughn lease.

3 Inject water into wells 5, 7, and 17 in the A.B. Vaughn lease and wells 15, and 19 in the Budmark lease. Produce wells 1, 2, 4, 8, 9, 10, 11, 12, 13, 14, 16, and 18 (fig. 16). Also produce from infill well 23 in the A.B. Vaughn lease.

4 Similar to option 3, except that there is production from two infill wells (22 and 23) in the A.B. Vaughn lease.

The results show that option 4 offers the greatest cumulative incremental oil recovery among the alternatives considered (table 9). The difference in cumulative recovery

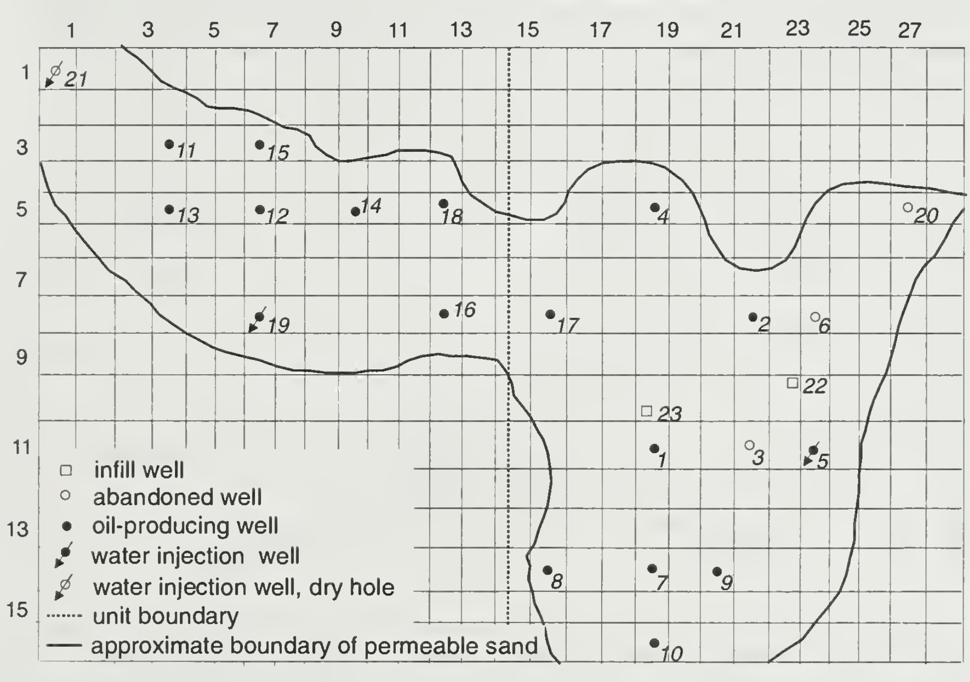

Figure 16 Well location gridblock shows the optimal simulated waterflood plan for the Budmark unit.

Table 8 Predictions of 5-year incremental oil recovery from the Budmark waterflood unit.

Options	Incremental oil production MSTBO	No. of injectors
Base case	15.3	1
1	59.8	3
2	61.8	4
3	31.4	1

between options 3 and 4 is only 8,000 barrels of oil, which is attributed to the extra infill well and may not provide sufficient incentive to drill the additional infill well.

Participatory factors were determined by computing the ratios of net waterflood oil recoveries from the two leases. Net waterflood oil recovery is the difference between the simulated waterflood oil recovery from a given option and the oil recovery without waterflood (base case) over a period of time. The participatory factors resulting from predicted recoveries in options 3 and 4 are also shown in table 9. Cursory economic analyses of options 3 and 4 show that both options are equally attractive and both produce more oil than the combined results of the best options from separate development of the leases.

SUMMARY AND CONCLUSIONS

A 3-D fluid-flow model, developed from geologic and petrophysical data, was used to estimate the OOIP, to simulate historical field development, and to investigate strategies for improved future recovery of oil from Energy Field. The estimated OOIP in Energy Field was 2,208,000 barrels of oil. About 15% of that amount has been recovered after 23 years of primary production, 13% from the A.B. Vaughn unit and 2% from the Budmark unit. The estimated volume of UMO in Energy Field, about 1,111,000 barrels or 50% of the OOIP, provides strong motivation for considering future oil recovery opportunities from the field through improved waterflood strategies and drilling infill wells.

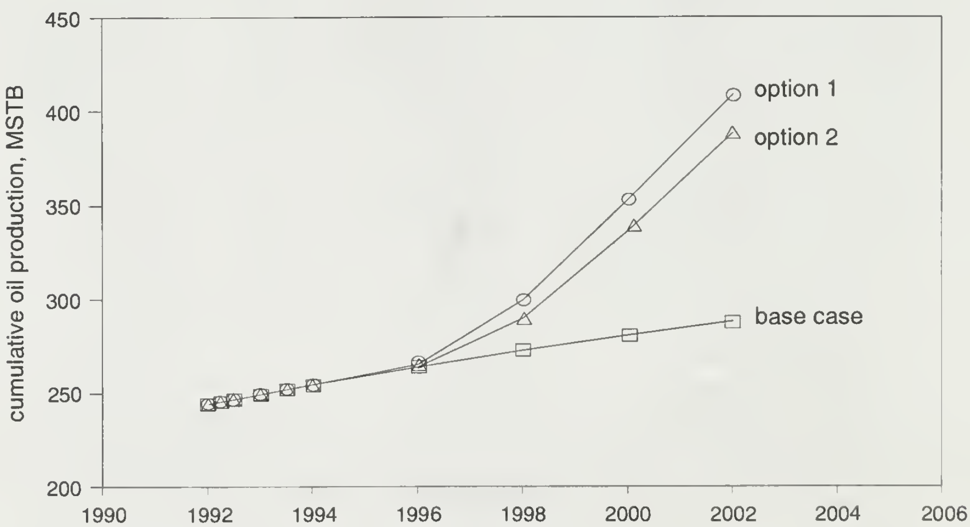

Figure 17 Predicted A.B. Vaughn oil production during simulated Budmark unit waterflood (options 1 and 2).

Table 9 Predictions of 5-year incremental oil recovery from unitization of the Energy Field waterflood.

Options	Incremental oil production MSTBO	No. of injectors	Participatory factors % Vaughn	Budmark
Base case	38.7	2	-	-
1	164.0	7	-	-
2	184.0	7	-	-
3	195.0	5	62	38
4	203.0	5	64	36

The outcome of various strategies for improved waterflooding in Energy Field was predicted using a reservoir simulation model. The strategies investigated included no further development of Energy Field, development of the A.B. Vaughn unit alone, development of the Budmark unit alone, and field unitization. Apart from the first strategy, the others included simulations of three different optional arrangements in the number and location of injection and production wells, and of strategically located infill production wells. Simulated water injection rates were held constant at 250 BWPD per well. Within the two independent development strategies for the Budmark and A.B. Vaughn leases, the options that offered the greatest cumulative incremental oil production always involved more than one water injection well.

The simulations showed that migration of oil across lease boundaries occurred when the units were independently developed in an unsynchronized manner. Across-lease migration of oil necessitates field unitization. Comparisons among the various simulated strategies for future development of Energy Field showed that field unitization and waterflooding with one or two carefully placed infill wells, would be the optimum approach for improving recovery at Energy Field.

This case study for Energy Field demonstrates that, despite the limited data available, computer simulations can be used to characterize and manage reservoirs, to evaluate the performance of past development practices, and to identify future opportunities for improving recovery. Increased utilization of similar integrated

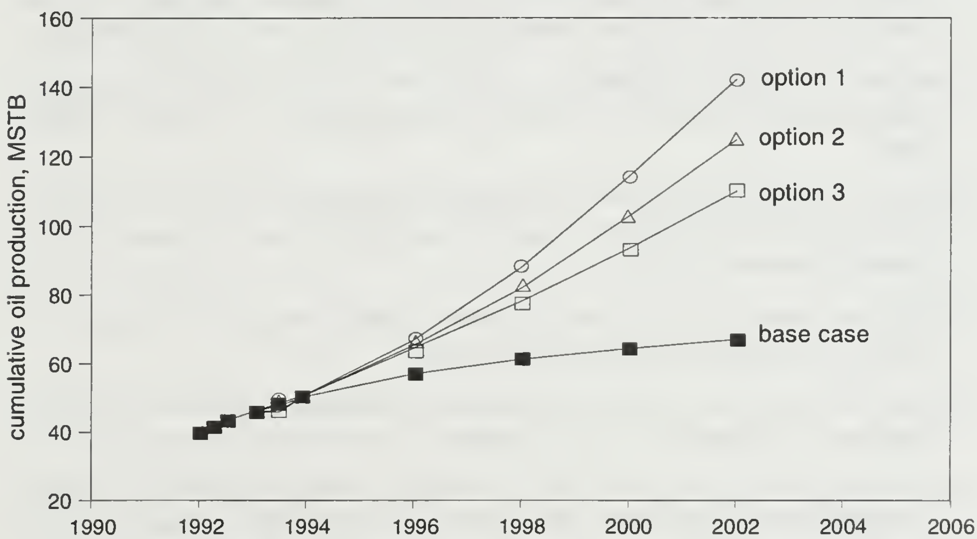

Figure 18 Predicted Budmark oil production during simulated A.B. Vaughn unit waterflood (options 1, 2, 3).

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geologic and engineering studies will allow oil producers to make prudent choices among possible field development strategies. Many of the techniques and results of this study are transferrable and can be used as analogs for studying similar reservoirs.

ACKNOWLEDGMENTS

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APPENDIX A CORE ANALYSES OF ENERGY FIELD

Company: Budmark Oil
Well: Morgan Coal no. 2, API no. 23465
Formation: Aux Vases

Depth (ft)	Permeability (md) horizontal	Porosity (%)	Residual saturation (%) Oil	Water
2,387.5	184	21.3	17.0	57.4
2,388.5	246	21.7	13.7	49.5
2,389.5	161	23.2	13.9	43.4
2,390.5	69	23.6	16.2	53.4
2,391.5	92	21.1	12.8	50.0
2,392.5	85	23.3	15.1	47.2
2,393.5	88	22.3	11.9	46.5
2,394.5	69	20.6	13.0	43.5
2,395.5	4.3	13.6	9.6	55.4

Company: A.B. Vaughn Oil Properties
Well: Hill and Zoller no. 1, API no. 2377
Formation: Aux Vases

Depth (ft)	Permeability (md) horizontal	Porosity (%)	Residual saturation (%) Oil	Water
2,356.5	91.5	18.6	12.4	59.4
2,357.5	103.0	19.3	13.2	59.1
2,358.5	44.5	18.4	12.4	38.1
2,359.5	15.2	15.4	22.9	51.0
2,360.5	4.72	15.8	20.6	48.1
2,361.5	49.3	16.4	15.0	54.6
2,362.5	0.52	5.1	15.2	63.2
2,363.5	27.7	15.1	18.9	58.8
2,364.5	36.4	17.0	17.9	54.8
2,365.5	103.0	19.1	15.0	53.8
2,367.5	139.0	19.0	15.5	48.7
2,368.5	190.0	21.1	11.9	42.0
2,369.5	169.0	20.8	10.8	48.6
2,370.5	36.4	13.0	13.0	55.4
2,371.5	13.4	15.1	14.0	46.8
2,372.5	3.62	13.1	14.8	64.1
2,380.5	<0.1	8.6	0.0	50.0
2,381.5	<0.1	2.6	0.0	72.4

APPENDIX A *(continued)*

Company: A.B. Vaughn Oil Properties
Well: Eigenrauch Armstrong no. 1, API no. 2336
Formation: Aux Vases

Depth (ft)	Permeability (md) horizontal	Porosity (%)	Residual saturation (%) Oil	Water
2,350.5	223	20.2	10.0	61.0
2,351.5	431	23.7	11.1	51.0
2,352.5	350	22.5	19.2	47.1
2,353.5	380	21.2	15.8	46.1
2,354.5	350	22.3	10.8	49.1
2,355.5	210	22.7	7.7	41.8
2,356.5	75	21.0	11.8	50.0
2,357.5	135	20.0	12.5	49.1
2,358.5	187	19.9	11.6	64.1

APPENDIX B COST ANALYSES OF ENERGY FIELD

Installation Cost Elements

Conversion of oil producers to water injectors
Injection lines and installation
Development of water supply
Construction of water plant facilities
Consolidation of central tank battery
Cost of engineering services
Cost of drilling and completion of infill well
Electrification (none–gas used)
Miscellaneous

Total Estimated Costs:

without infill well	$150,000.00
with one infill well	$190,000.00
with two infill wells	$230,000.00

Estimated Monthly Operating Expenses

Average estimated monthly operating expenses per well $800.00

Expenditure (5 years)

Installation costs + operating cost × number of wells × 60 months

Income

Income at $20/barrel (with 19.3% royalty interest)

Income ($) = $0.807 \times Q_o \times 20$

where: Q_o = *60 month period of oil production*