KANSAS GEOLOGICAL SURVEY
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Short-Listing Mississippian Carbonate Files for Horizontal Drilling
(DOE Contract # DE-PS26-00BC15304)

by

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Disclaimer

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Introduction

This report summarizes the initial screening studies carried out to select candidate reservoirs/fields for spotting an infill horizontal well as a part of the DOE sponsored PUMP (Preferred Upstream Management Practices) project (USDOE Contract # DE-PS26-00BC15304). It starts with the application of quick screening tools to identify prospective Mississippian carbonate reservoirs in an area of West Central Kansas. A short-list was generated from the selected fields by further screening them for the availability and quality of data (petrophysical log, core, production) and operational concerns. Based on petrophysical data from a type well, the production performance of an infill horizontal well was estimated in each field by using a homogenous closed-tank single-phase simulator (RESMOD – Maurer Engineering Inc.). Published records on previously drilled horizontal wells in Kansas were researched and operators involved in these projects were informally approached to summarize drilling practices that need to be either avoided or preplanned in order to drill a successful horizontal well.

Study Area

The area considered for this study extended from Township 16S Range 26W to Township 27S Range 20W. This area was selected because

a) most of the fields are charged by a strong bottom water drive,
b) the industry partner Mull Drilling Company Inc. (MDCI) has some holdings here and holds operational interests in some of the fields, and
c) some of the successful horizontal wells, drilled in Kansas till date, are located here.

Initial Screening Studies

The initial screening criterion was reservoir pressure. Infill horizontal wells drilled in under-pressured reservoirs require significant drawdowns to maintain economic production rates and such high drawdowns result in water coning. Thus, horizontal wells are most effective in undepleted reservoirs.

Initially, 29 fields were selected for the initial screening studies. Final shut-in pressures, recorded by DST in discovery, developmental and infill wells, were plotted over time for each field. In all cases, drilling activity, in and around the field, has continued over the life of the field. This helped to quickly determine the pressure support available in each field. Based on the reservoir pressure histories, 13 fields were selected for further analysis (Map 1). MDCI recommended adding one more field, namely Fralick West, to this list. Previous studies and available pressure data indicate that this field has suffered from pressure depletion. However, MDCI's interest in this field was due to high production volumes recorded in vertical wells, large well spacing, and significant ownership rights. Thus, a group of 14 fields were taken up for comparative screening studies.

For each field, a type well was selected. In some cases, 2 type wells were selected to represent two major regions of the field. Petrophysical logs from the type well were analyzed to estimate the pay height, porosity and initial water saturation. Table 1 lists the results from this log analysis. An average drainage area was calculated for each field by dividing the area of the field by the number of wells that produced or are producing. The initial petrophysical analyses and the cumulative production data were in the volumetric calculation of original-oil-in-place (OOIP) and also the minimum and maximum range of recovery factors (R.F.) in each field. Volumetric calculations were also used to estimate minimum and maximum volumes of remaining-oil-in-place (ROIP) per acre-ft. These results are listed in Table 2.

The gross pay thickness was mapped in each field. Based on this map, the minimum and maximum pay thickness of the undrilled (interwell) areas was estimated. Also, the best-fit line through the final shut-in pressure data versus time was used to approximate the original reservoir pressure and the current pressure. The ratio of the difference between the original and current pressure with the production life of the field was taken as the proxy for aquifer support available to the field in each case. These data are tabulated in Table 3.

Additional screening criteria used include ranking the fields on the basis of minimum pay (gross) thickness in the undrilled areas, average well spacing, R.F., and ROIP per gross acre-ft. The intent of the above ranking was to identify fields with high gross pay in undrilled areas, where the ROIP/acre-ft and average well spacing was high, and the average R.F. for vertical wells was low. Tables 4 to 6 list the fields in a descending order as per their average well spacing, the minimum gross pay in the undrilled infill areas, and the ROIP/acre-ft. Table 7 lists the fields in an ascending order in accordance to the average R.F. from vertical wells. It is expected that infill horizontal wells would be more effective (as compared to vertical infills) in fields where reservoir heterogeneity limited the drainage of vertical wells. The above rankings are based on the analysis carried out on data from only one or at most two type-wells per field. Hence, it important to note that it is more meaningful to compare the relative values of different screening criteria rather than emphasizing on their absolute values.

Table 8 shows the relative rankings of the fields after taking into account their average well spacing, minimum gross pay in undrilled areas, ROIP/acre-ft and R.F. of vertical wells. Fralick West is the top ranked field with a score of 6. However as will be discussed later, previous studies on this field and available pressure data indicate that central parts of the reservoir has produced under a solution gas drive while the periphery has produced under a weak water drive. For the last 37 years, the field has produced without any pressure support and this has resulted in significant pressure depletion. It is because of this severe pressure depletion that Fralick West failed to receive a rank (Table 9). The Mississippian reservoirs in the study area produce from 3 major rock units (Map 1) namely Osage, Warsaw and Spergen. The strong bottom water aquifer, that charges many of the Mississippian reservoirs in this area, communicates with the Osage (the oldest) rocks. Most reservoirs producing out of Warsaw and Spergen rocks, that overlie the Osage, therefore have relatively weaker aquifer support. Fralick West produces from the Warsaw and this may be one of the reasons for its weak edge water drive.

Table 9 includes the ratings that MDCI provided as a proxy measure of the degree of difficulty that it anticipates in order to strike a deal with the major operators/owners of each of these fields. A value of 1 signifies little difficulty on part of MDCI to implement a horizontal infill well in the field while a score of 4 signifies that it will be very difficult for MDCI to come to a consensus with the current operator(s) and/or owner(s). This is a common problem in the Midcontinent, as independent operators like MDCI often do not own the whole field but select leases and/or hold operating interests in the field/leases. Thus, the initial problem of locating prospective fields/leases and mapping pockets of residual reserves in them is further compounded by the fact that only a select few of these screened locations will be viable candidates because of various operational difficulties encountered by the interested independent operators.

Six fields were selected, in consultation with MDCI, for second round of screening studies, and they include:

a) Lippoldt
b) Riverside
c) Arnold SW
d) McDonald
e) Ness City North
f) Judica

MDCI wanted to include Fralick West in the second round of evaluation studies in order to compare the estimated recoveries from infill locations in other fields with that from Fralick West. Also, available data from Fralick West was researched in order to confirm pressure depletion of the field.

Screening studies on Short-listed fields

The secondary screening studies on the short listed fields included:

a) Application of a single-phase closed tank homogenous model (RESMOD, Maurer Engineering Inc.) to analytically estimate the performance of horizontal infill wells in each of the short listed fields.

b) Detailed inventory of available data for each of the 6 short listed fields. The listing included mention about the quality and quantity of production, pressure (fluid level), wire line log and core data that are available for each of the 6 fields.

c) Outline possible reasons that were crucial to the success or failure of previously drilled horizontal wells in Kansas by researching publicly available data and reports.

d) Inventory available Mississippian cores from the study area, and identify cores taken from the short listed fields or analog cores taken from the neighborhood of the short listed fields.

e) Research available data on Fralick West to confirm depletion of reservoir pressure.

RESMOD studies

Assumptions inherent in the RESMOD model are:

a) Darcy's radial equation is used to model flow into the well.
b) Single phase (oil) fluid flow is modeled.
c) The drainage area of the modeled well is assumed to be homogenous and there is no-flow across the boundary.
d) The modeled well is located at the center of the drainage area.
e) A conservative skin factor (Hall's skin factor) is applied to wells in the model.
f) The model ignores the flush production. This makes the estimated production volumes conservative. However, such an assumption has little effect on the cumulative production volumes estimated.

The intent of this study was to approximate the productive potential (in terms of IPs and cumulative volumes) of petrophysical properties estimated from type well(s) in each field, i.e., estimate the production from both vertical and horizontal infill wells in each of the fields provided the petrophysical properties of the drainage areas (of the infill wells) were similar to that obtained from type-well analyses. Such an exercise would enable one to relatively rank the synergistic effects (in terms of estimated production volumes) of the petrophysical properties assigned to each field.

Tables 10a-10g list the basic petrophysical data that was used to model production performance of infill (horizontal and vertical) wells in each of the 6 fields. At this initial screening stage, lacking information that comes from a detailed geomodel development, the formation thickness assigned to each field is the gross pay of the productive zone in type well(s). At this stage, information about horizontal and vertical permeability and oil saturations in prospective inter well regions. Based on the available data from routine analyses carried out on Mississippian cores, an assumption was made that 10 md of permeability can be considered as a conservative estimate for Mississippian pay sections. Most of these fields have been under primary production for more than 30 years, and thus remaining oil saturations in the inter well regions can only be estimated by mapping the results of a full-field reservoir simulation study. Based on experience from previous simulation studies on Mississippian fields, it was assumed that for infill wells to be economically successful, they have to be located in pockets where the oil saturation were at least 45%. A positive skin of 1 was applied to both horizontal and vertical wells modeled.

In RESMOD, the reservoir drive mechanism in each field is described with the help of drive mechanism scaling factor (DMSF). Strong water drives, bottom and/or edge, correspond to highest recovery efficiencies and in this model it carries a DMSF = 1. Solution gas driven reservoirs are the least efficient and the model assigns a DMSF = 0 to them. The DMSF factor was assigned in a relative sense based on the rate of decline of reservoir pressure that has observed in each of the fields. The flowing bottom hole pressures (BHPs) have been kept a few hundred psi below the initial reservoir pressures. In each field, both the horizontal and vertical wells have been produced under the same draw down. Along with this data set, some uniform cost parameters were provided. These included, $400,000 to drill and complete a horizontal well and $125/day fixed well operating costs. The discount rate was assumed as 17.5% and the net sale price for produced oil was assumed to be $19/barrel. The horizontal well in each field was assumed to have a productive length of 600 ft.

Table 11 compares the estimated IPs and cumulative production (after 5 years) for an infill vertical and an infill horizontal well in each field. The results tabulated have been calculated using the base case values for each of the input parameters (Table 10a to 10g). The relevance of this exercise lies not in the absolute values of the listed numbers but rather in interpreting the results (IPs and cumulative production volumes) in a relative manner. Also, RESMOD models single-phase flow, and it, therefore, does not include the effects of relative permeability between oil and water. All but one of short listed fields have produced both oil and water. Fralick West field has produced oil, gas, and water and thus relative permeability effects assume importance in modeling flow in these fields. Exercises using RESMOD enables one to get a feel for the expected range of oil production volumes based on the input of a set (range) of rock and fluid properties. As this model does not predict water production volumes, any economic evaluation minus the water pumping and disposal costs is only approximate.

RESMOD is a quick screening tool, and a calibration process enhances its application to be field specific. During the calibration process, the production history and petrophysical properties of a vertical well in a field are input in order to obtain a history match. The history matching process is iterative, wherein different petrophysical values are varied within the maximum and minimum ranges. This helps to obtain a better quantitative feel for the different field specific parameters such as average drainage radius, draw down, DMSF, and skin. Then, the petrophysical properties for the infill horizontal well location are adjusted in a similar manner as that required to history match the vertical well. Finally, the production from the infill horizontal well is estimated by inputting the set of field specific parameters determined from the history match.

Inventory of available data on 6 short-listed fields

Riverside

Logs – available for 16 wells out of 29
Cores – None are available.
Production data – Individual well production data is available for 7 wells. Six leases have more than one producing well and thus the lease production can be allocated to the constituent wells only if barrel test information is available with the current (past) operator.

This field has 2 horizontal wells already drilled in it, and neither of them has turned out to be a good performer. MDCI has a bias against this field because neither vertical nor horizontal wells have been economically successful in this field. Vertical wells have produced water too early shortening the economic life of wells. There is a possibility that a horizontal well in this field will be beset with similar early water breakthrough problems, and thus production may be limited to the first 100 feet (from the heel) of the horizontal leg. Also, the shaly-conglomerate section, atop the Mississippian reservoir, presents an operational problem. Both the horizontal wells encountered this shaly-conglomerate problem during the drilling of the curve. (Most Mississippian fields, in the study area, have a conglomerate over the dolomite. However, the thickness of the conglomerate layer varies.) Production histories from both horizontal and vertical wells in this field appear to indicate that early water breakthrough occurs due to the presence of a fracture network in the reservoir and strong underlying aquifer.

Ness City North

Logs – logs are available in 8 wells out of 9 in the field. Most wells have RAG (resistivity and gamma) logs.
Cores – available from 4 wells.
Production data – Oil production data is available at the well level. However, barrel tests data (showing volumes of oil and water produced) are available for only 3 wells.

One horizontal well has been drilled in this field. The well was producing at rates close to what a previous simulation study had predicted but it suddenly collapsed (and stopped producing fluids) after 60 days due to mechanical reasons. Production in this field appears to be related to the structure. MDCI would like to use this field's potential for exploitation by infill horizontal drilling as the "base case" to compare the productive potential of the other short-listed fields. Characterization and simulation studies have already been completed on this field. The dolomite reservoir has interbedded shale, which, perhaps, limits the role of fractures in transporting significant volumes of water from the strong aquifer at the bottom.

Lippoldt

Logs – available for all the wells.
Cores – Available from 2 wells (3 boxes).
Production data – Lease level production data is available. Most leases have multiple producing wells and so allocation of lease production to constituent wells is possible if barrel test data is available with current and/or past operators.

It is perceived that the reservoir rock has interbedded shale and this may help mitigate the early water breakthrough problem.

McDonald

Logs – available for most wells. Wells have good penetration and some of the infill wells have modern suite of logs.
Cores – Available from 1 well (3 boxes).
Production data – Bulk of field production comes from 2 leases. However, this field is owned by MDCI and history of barrel test data is available.

Overall, this field has a relatively small pool size. However, the well spacing increases in the eastern side of the field. Also, MDCI has 3D seismic data shot and analyzed over sections 4 and 5 (including the eastern part of the field). MDCI may consider deepening a non-producing well in section 5 to obtain a core if this field selected for field demonstration study.

Judica

Logs – Most wells have good logs showing penetration into the Mississippian.
Cores – None
Production data – All leases, but one, have only one constituent well. Thus, oil production data is available for all wells. However, water production records or barrel test data have yet to be traced.

This field produces from a stratigraphic trap. It is thought that the depositional environment affects reservoir permeability, and this increases the uncertainties related to mapping the permeability distribution in the field. There are dry wells right in the middle of the field. The dolomite reservoir has significant lateral heterogeneity and this adds to complexity associated to modeling the reservoir. Wells in this field have produced limited volumes of water. The flowing shut-in pressures (FSIPs) recorded in the DSTs show little variation. This field is sparsely drilled, and has productive and dry wells interspersed all over. This makes the field heterogeneous both laterally and vertically. It was noted that a 3D survey would help clarify the uncertainties related to characterization of this field. A long infill horizontal well can be drilled in this field. Such a horizontal well in a thin reservoir as this will have significant advantages over a vertical infill well.

Arnold SW

Logs – Most wells have RAG logs. There are a few wells with resistivity and sonic logs. Few wells have good penetration and therefore it is difficult to characterize the reservoir.
Cores – Available from 1 well.
Production data – Most leases have more than one producing well, and thus barrel test data is required to allocate lease production amongst constituent wells. The list of operators indicates that barrel test data may be available for wells in one of sections (Section 31).

This is the biggest field amongst those short-listed, and extends over 9 sections. This field has a producing horizontal well that appears to be well placed. This well was drilled 30-40' beneath the Mississippian top. This well has been a low fluid well having a cumulative production of 27,000 bbls and currently producing 17 bopd & 17 bwpd. It is possible that the major portion of the lateral is too low and, therefore, is not located in the reservoir rock. The chances of high water production are low in this field given the fact that vertical wells have not produced significant quantities of water. There are many leaseholders in this field and MDCI has no lease holdings here.

Operational Notes on previously drilled horizontal wells in Kansas

a) One of the major problems noted in the reports on previously drilled horizontal wells in Kansas is that pipe stuck-ups occurred 14 times in the first 2 wells because the drillers did not mud-up early.

b) A few of the wells had a curve radius of 660 ft and used slotted liners. However, such a "tight" radius prevented running and placing lateral horizontal sub pumps.

c) Most of the wells failed to stay consistently at the top of the best reservoir rock. Production testing indicated predominance of oil producing from the heels in most cases. Well steering in accordance to the Mississippian structure appears to be absent.

d) External packers, for zone isolation, did not work in most of the wells.

e) Ideal candidate for a horizontal well in the Mississippian carbonates should meet as many of the following criteria:

> i) Field producing from Osage reservoirs where vertical wells produce significant volumes of fluid. Most Osage reservoirs have strong water drives and often times early breakthrough of water results in limited drainage by vertical wells and significant fluid production.
>
> ii) Incorporation of 3D data into reservoir model or application of some method that enables excellent well control would go a long way in steering the well in a manner such that it stayed at the top of the reservoir.

iii) The horizontal leg should be started within proven reservoir and then extended into unproven regions if needed.

iv) The well should be steered such that it stayed in top 10' of the reservoir consistently.

v) A large curve radius should be used if there are plans to place down hole horizontal separator.

vi) Salt-water disposal costs ranged over $11,000/month in several wells. Thus, horizontal wells that produce significant volumes of water often become economic failures though remaining technical successes because of the varying oil prices prevalent in Kansas.

Some of the mechanical concerns that were mentioned in the records include:

i) An appropriate mud strategy needs to be designed such that formation damage was minimized and lost circulation was controlled.

ii) The well has to be planned and designed from the bottom to the top such that the selected curve radius would not come in the way in case intervention is required to solve of future anticipated problems.

iii) The economics and benefits of using a liner in the horizontal leg of the well against open hole completion needs to thoroughly evaluated. MDCI prefers to initiate production from a lateral section that is kept open hole. It expects that the bottom-up design and large diameter of the vertical section will ensure tool re-entry to rectify problems if and when they occur.

The operator of the Antrim-Cossman #1HZ well believes that fractures present in the Mississippian chert reservoir resulted in high water production at the well. MDCI's has significant operational experience in the study area, and in certain fields (such as the Riverside) it appears that the fracture porosity in the reservoir rock is the major contributor to Mississippian production. However, the high attendant vertical permeability results in early breakthrough and high water production in vertical wells. It has been noted by the operators in this area that fractures in Osage rocks have at times extended into the dolomite (Warsaw) on top. Also, it is believed that the Osage was exposed over a longer period of time than the overlying dolomite (Warsaw), and this perhaps resulted in higher vertical permeabilities in Osage as compared to the Warsaw.

Inventory of Mississippian cores

Table 12 lists all known Mississippian cores in the study region, lying between Townships 16 South and 27 South and between Ranges 20 West and 26 West, which are available at the Kansas Geological Survey Core Repository. Basic and various advanced rock properties have been recorded on plugs taken from the Mississippian intervals in wells marked in yellow. Properties measured on selected samples include: porosity, air permeability, grain density, capillary pressure, electrical resistivity, waterflood susceptibility, and water-oil imbibition relative permeability. These cores represent cores from within fields that are considered candidate fields for the demonstration or are considered analogue fields. Data are being entered into the GEMINI rock catalog database for web-based access from the KGS website.

Fralick West

Logs – Most wells have good logs.
Cores – Available from 1 well.
Production data – Oil production data available for most wells. Wells in this field have produced water and gas also. No well level gas production data could be traced.

Wells have good penetration in the south. Individual vertical wells have been good producers. The reservoir truncates in the direction of North-Northeast. The initial reservoir pressure is estimated to be close to 1600 psi, and the available data of initial shut-in pressures (ISIPs) and final shut-in pressures (FSIPs) from DSTs indicate that severe pressure depletion has occurred in the reservoir (Figure 1). Current reservoir pressure is estimated to be close to 200 psi.

Reports are available detailing some of the past reservoir evaluation studies that have been conducted on this field. Relevant sections from some of these reports are quoted below.

Alfred James report -
"The field produces under a combination drive of gas cap expansion and edge water drive. Formation pressures have been observed to drop rather rapidly in the early years."

Walton & Preston report (1986) –
"Water-cut maps indicate that there is some water influx occurring in the reservoir. Major increases in water production have occurred primarily in the edge wells – specifically in the southern and northeastern wells. There is little increase, if any, in the center wells where the major oil production takes place. Other evidence, which would disprove a strong active water drive, is that over the past 20+ years of production, the pressure has dropped over 1200 psi. It also appears as though the center part of the reservoir, in effect, is "sealed" from a limited water drive acting aquifer because all water influx has taken place at the edge wells and that the center wells have not shown a substantial increase in water production."

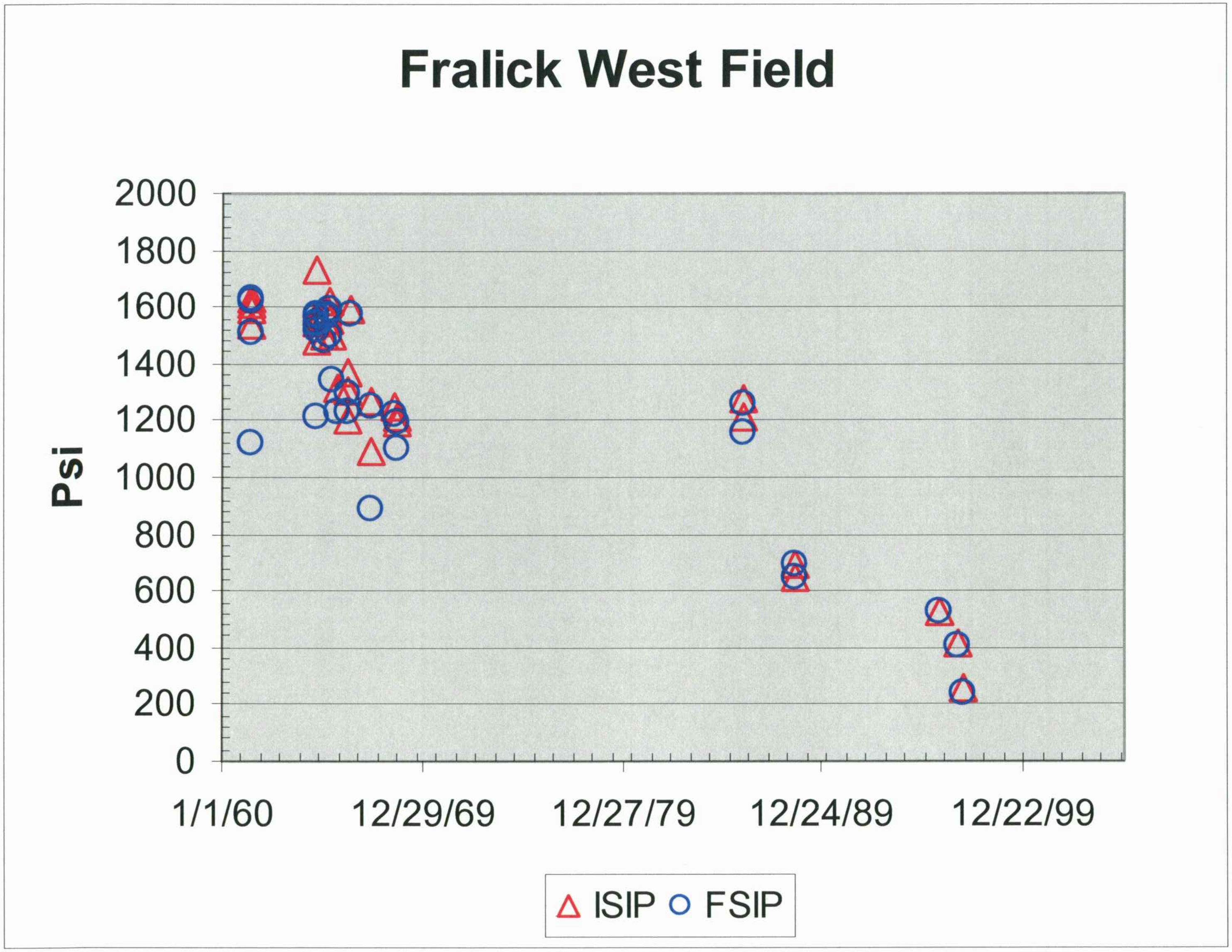
Parker report (1995) –
"The primary drive mechanism for the field is a combination of solution gas, gas cap expansion, and edge water drive encroaching from the south-southwest. Original aquifer energy was perceived as minimal due to the considerable decrease in reservoir pressure with corresponding fluid withdrawals. Original reservoir pressure, as measured by DST at the Falcon-Seaboard Brensing #1, approximated 1625 psi. The average pressure

depletion across the field was 40% from inception (Apr 1961) to Apr 1968. Reservoir heterogeneities, including permeability barriers, both horizontal and vertical, prohibit pressure support in many areas of the field. However, several wells including Zeigler #A1, #3, Bissitt #1, and Einsel #B1 experienced less depletion primarily due to the Spergen dolomite in direct contact with either the gas cap, the underlying aquifer, or vertically fractured to one or both."

All the above previous studies indicate that pressure depletion has occurred in this reservoir. Given the low current reservoir pressure, the question that needs to be addressed is: "What is the lowest BHP under which one produce a horizontal well?" Also, this field has recorded significant cumulative gas production over the course of its life. Thus, low reservoir pressures coupled with free gas in the reservoir are expected to adversely affect oil recovery from an infill horizontal well due to relative permeability effects.

Permeability values prevalent in Fralick W are higher than what commonly occurs in other Mississippian reservoirs of Kansas and this makes it a unique Mississippian field. It is believed that the reservoir rock is located close to a valley, and this resulted in significant leaching of the dolomite, which in turn has enhanced permeability. As such, this field cannot be considered to be representative of Mississippian reservoirs of the Midcontinent. Project demonstration in this field will, therefore, have limited applications elsewhere. This field appears to be a good potential candidate for a waterflood. In this context, a horizontal well will sure help future studies on the waterflooding feasibility. Also, the high permeability present in this field may lead to interference at the surrounding vertical wells due to production from an infill horizontal well.

Figure 1



Fralick West Field
Psi
2000
1800
1600
1400
1200
1000
800
600
400
200
0
1/1/60
12/29/69
12/27/79
12/24/89
12/22/99
ISIP
FSIP

Table 1

No.	Field Name	Sec	Miss Top	Miss Base	Low Por	High Por	Net Pay	Low Sw	High Sw	Reservoir	Phi min	Phi max	Sw min	Sw max
1	Aldrich N	7	-1894	-1915	12	12	4	35	60	Dolomite	12.0	12.0	35.0	60.0
	Aldrich S	13	-1910	-1923	18	18	5	25	58	Dolomite				
	Aldrich S	23	-1907	-1960	15	18	53	36	52	Dolomite				
2	Arnold SW	31	-1923	-1950	16	16	8	41	50	Dolomite	12.5	17.0	40.5	52.0
		29	-1897	-1949	9	18	26	40	54	Dolomite				
3	Fralick W	28	-2544	-2569	20	23	10	37	37	Dolomite	20.0	23.0	37.0	37.0
4	Stairett	13	-2089	-2117	8	12	17	31	47	Dolomite	8.0	12.0	31.0	47.0
5	Riverside	13	-2091	-2121	13	18	30	38	48	Dolomite	13.0	18.0	38.0	48.0
6	Judica	3	-1914	-1933	24	28	19	28	50		24.0	28.0	28.0	50.0
7	Stutz E	8	-1944	-1961	18	18	17	35	60	Dolomite	18.0	18.0	35.0	60.0
8	Laird	36	-1994	-2030	10	16	8	19	47	Dolomite	12.5	15.5	27.5	47.0
		36	-1999	-2039	15	15	10	36	47	Dolomite				
9	Lippoldt	14	-2218	-2240	14	16	22	17	37	Dolomite	14.0	17.0	25.5	51.0
		13	-2218	-2252	14	18	34	34	65	Dolomite				
10	Arnold	23	-1961	-1976	16	16	8	41	50	Dolomite	16.0	16.0	41.0	50.0
11	Arnold N	10	-1946	-1975	10	20	12	35	40	Dolomite	10.0	20.0	35.0	40.0
12	Steffen W	25	-2142	-2166	18	18	24	51	62	Chery-dol	18.0	18.0	51.0	62.0
13	McDonald	5	-2021	-2050	18	18	29	36	66		18.0	18.0	36.0	66.0
14	Ness City North	23	-2001	-2001	10	14	16	45	60	Dolomite	12.0	17.5	32.5	55.5
		24	-1998	-2022	14	21	10	20	51					

Table 2

Field Name	Acre	Ac-ft	well #	Avg Spacing, ac	PV (bbls)	Boi	STB, min OOIP	STB, max OOIP	Cum Prod	Min R.F.	Max R.F.	Min ROIP/ac-ft	Max ROIP/ac-ft	Avg R.F.	Avg ROIP/ac-ft
Aldrich N	1337	29,053	44	30.4	225,528,986	1.05	10,309,897	16,753,582	4,394,950	0.26	0.43	204	425	0.34	314
Arnold SW	3030	93,334	88	34.4	724,521,475	1.05	41,401,227	69,795,569	5,742,599	0.08	0.14	382	686	0.11	534
Fralick W	1619	59,733	23	70.4	463,687,844	1.05	55,642,541	63,988,922	5,322,647	0.08	0.10	842	982	0.09	912
Stairett	1591	61,694	39	40.8	478,910,449	1.05	19,338,860	37,765,510	3,595,005	0.10	0.19	255	554	0.14	405
Riverside	854	32,846	19	44.9	254,972,811	1.05	16,415,392	27,099,967	1,833,454	0.07	0.11	444	769	0.09	607
Judica	216	3638	7	30.8	28,240,610	1.05	3,227,498	5,422,197	1,621,847	0.30	0.50	441	1045	0.40	743
Stutz E	1160	29,255	23	50.4	227,097,047	1.05	15,572,369	25,305,099	1,231,799	0.05	0.08	490	823	0.06	657
Laird	607	14,495	11	55.2	112,519,969	1.05	7,099,474	12,042,316	1,222,114	0.10	0.17	405	746	0.14	576
Lippoldt	766	32,906	14	54.7	255,438,572	1.05	16,688,653	30,810,757	1,217,343	0.04	0.07	470	899	0.06	685
Arnold	259	4,300	8	32.4	33,379,501	1.05	2,543,200	3,000,976	1,157,276	0.39	0.46	322	429	0.42	376
Arnold N	369	7675	10	36.9	59,578,528	1.05	3,404,487	7,376,389	902,785	0.12	0.27	326	843	0.19	585
Steffen W	451	11,856	12	37.6	92,034,271	1.05	5,995,375	7,730,879	814,064	0.11	0.14	437	583	0.12	510
McDonald	245	7006	12	20.4	54,385,299	1.05	3,169,886	5,966,844	585,355	0.10	0.18	369	768	0.14	569
Ness City N	290	6600	8	36.3	51,233,653	1.05	2,605,597	5,763,786	445,616	0.08	0.17	327	806	0.12	567

Table 3

Field Name	Pay min	Pay max	Pr Initial	Yrs prod	Latest pr
Aldrich N	15	50	1000	45	1000
Arnold SW	25	60	1000	45	800
	15	50			
Fralick W	20	45	1400	37	400
Stairett	20	50	1100	40	800
Riverside	20	50	1300	30	1100
Judica	8	32	1100	25	900
Stutz E	23	53	1100	25	1100
Laird	20	40	1100	32	1000
Lippoldt	25	55	1300	35	1250
Arnold	15	25	1100	40	900
Arnold N	20	35	1000	30	900
Steffen W	20	47	1100	35	800
McDonald	28	49	1200	35	1000
Ness City North	17	32	1100	40	900

Table 4

No.	Field Name	Acre	well #	Avg Spacing, ac
1	Fralick W	1619	23	70.4
2	Laird	607	11	55.2
3	Lippoldt	766	14	54.7
4	Stutz E	1160	23	50.4
5	Riverside	854	19	44.9
6	Stairett	1591	39	40.8
7	Steffen W	451	12	37.6
8	Arnold N	369	10	36.9
9	Ness City North	290	8	36.3
10	Arnold SW	3030	88	34.4
11	Arnold	259	8	32.4
12	Judica	216	7	30.8
13	Aldrich N	1337	44	30.4
14	McDonald	245	12	20.4

Table 5

No.	Field Name	Pay min	Pay max
1	McDonald	28	49
2	Lippoldt	25	55
3	Stutz E	23	53
4	Arnold SW	20	60
4	Fralick W	20	45
4	Stairett	20	50
4	Riverside	20	50
4	Laird	20	40
4	Arnold N	20	35
4	Steffen W	20	47
5	Ness City North	17	32
6	Aldrich N	15	50
6	Arnold	15	25
7	Judica	8	32

Table 6

No.	Field Name	Pr Initial	Yrs prod	Latest pr	Avg psi/yr decline
1	Stutz E	1100	25	1100	0.0
2	Aldrich N	1000	45	1000	0.0
3	Lippoldt	1300	35	1250	1.4
4	Laird	1100	32	1000	3.1
5	Arnold N	1000	30	900	3.3
6	Arnold SW	1000	45	800	4.4
7	Ness City North	1100	40	900	5.0
8	Arnold	1100	40	900	5.0
9	McDonald	1200	35	1000	5.7
10	Riverside	1300	30	1100	6.7
11	Stairett	1100	40	800	7.5
12	Judica	1100	25	900	8.0
13	Steffen W	1100	35	800	8.6
14	Fralick W	1400	37	400	27.0

Table 7

No.	Field Name	Avg R.F.
1	Lippoldt	0.06
2	Stutz E	0.06
3	Fralick W	0.09
4	Riverside	0.09
5	Arnold SW	0.11
6	Steffen W	0.12
7	Ness City North	0.12
8	Laird	0.14
9	Stairett	0.14
10	McDonald	0.14
11	Arnold N	0.19
12	Aldrich N	0.34
13	Judica	0.40
14	Arnold	0.42

Table 8

Field Name	Rank --				
	Avg ROIP/ac-ft	Avg R.F.	Avg Well spacing	Min Pay ft above OWC	Total Score
Fralick W	1	2	1	2	**6**
Lippoldt	3	1	2	1	**7**
Stutz E	3	1	2	1	**7**
Riverside	3	2	3	2	**10**
Laird	4	4	2	2	**12**
Arnold SW	4	3	4	2	**13**
McDonald	4	4	5	1	**14**
Stairett	5	4	3	2	**14**
Steffen W	4	4	4	2	**14**
Arnold N	4	5	4	2	**15**
Ness City North	4	4	4	3	**15**
Judica	2	7	4	4	**17**
Aldrich N	6	6	4	3	**19**
Arnold	6	8	4	3	**21**

Table 9

Field	Score	Rank	Mull's operational difficulty	Final score	Final Rank
Fralick W	6		1	7	
Lippoldt	7	1	2.5	9.5	1
Stutz E	7	1	4	11	2
Riverside	10	2	3	13	3
Arnold SW	13	4	2	15	4
McDonald	14	5	1	15	4
Laird	12	3	4	16	5
Ness City North	15	5	1	16	5
Stairett	14	5	3	17	6
Steffen W	14	5	3	17	6
Arnold N	15	5	3	18	7
Judica	17	6	1	18	7
Aldrich N	19	7	4	23	8
Arnold	21	8	3	24	9

Table 10a

Field - McDonald			
	Base	**Min**	**Max**
Rock Properties			
Drainage Radius, ft	660	330	990
Formation Thickness, ft	38.5	28	49
Horizontal K, md	10	1	100
Vertical K, md	1	0.1	10
Porosity, %	18	17	19
External Drainage Pr, psi	800	700	900
Fluid Properties			
Oil Viscosity, cp	2	1.8	2.1
Initial oil saturation, %	45	40	55
Formation volume factor, RB/STB	1.05	1.03	1.07
Drive Mechanism Scaling factor (DMSF)	0.6	0.5	0.8
(DMSF = 1 for active water drive, DMSF = 0 for solution gas drive)			
Vertical well data			
Skin factor	1	-1	3
BHP, psi	300	200	400
Residual oil saturation, %	30	25	35
Well bore radius, inch	3.5		
Well cost, 1000 $	200		
Fixed Operational cost/day, $	100		
Horizontal well data			
Skin factor	1	-1	3
BHP, psi	300	200	400
Residual oil saturation, %	30	25	35
Well bore radius, inch	3.5		
Horizontal well length, ft	600		
Well cost, 1000 $	400		
Fixed Operational costs, $/day	125		

Table 10 b

Field - Ness City N			
	Base	Min	Max
Rock Properties			
Drainage Radius, ft	629	314	943
Formation Thickness, ft	24.5	17	32
Horizontal K, md	10	1	100
Vertical K, md	1	0.1	10
Porosity, %	14.8	12	17.5
External Drainage Pr, psi	700	600	800
Fluid Properties			
Oil Viscosity, cp	2	1.8	2.1
Initial oil saturation, %	45	40	55
Formation volume factor, RB/STB	1.05	1.03	1.07
Drive Mechanism Scaling factor (DMSF)	0.6	0.5	0.8
(DMSF = 1 for active water drive, DMSF = 0 for solution gas drive)			
Vertical well data			
Skin factor	1	-1	3
BHP, psi	300	200	400
Residual oil saturation, %	30	25	35
Well bore radius, inch	3.5		
Well cost, 1000 $	200		
Fixed Operational cost/day, $	100		
Horizontal well data			
Skin factor	1	-1	3
BHP, psi	300	200	400
Residual oil saturation, %	30	25	35
Well bore radius, inch	3.5		
Horizontal well length, ft	600		
Well cost, 1000 $	400		
Fixed Operational costs, $/day	125		

Table 10c

Field - Arnold SW			
	Base	**Min**	**Max**
Rock Properties			
Drainage Radius, ft	612	306	918
Formation Thickness, ft	37.5	20	55
Horizontal K, md	10	1	100
Vertical K, md	1	0.1	10
Porosity, %	14.8	13	17
External Drainage Pr, psi	600	500	700
Fluid Properties			
Oil Viscosity, cp	2	1.8	2.1
Initial oil saturation, %	45	40	55
Formation volume factor, RB/STB	1.05	1.03	1.07
Drive Mechanism Scaling factor (DMSF)	0.6	0.5	0.8
(DMSF = 1 for active water drive, DMSF = 0 for solution gas drive)			
Vertical well data			
Skin factor	1	-1	3
BHP, psi	300	200	400
Residual oil saturation, %	30	25	35
Well bore radius, inch	3.5		
Well cost, 1000 $	200		
Fixed Operational cost/day, $	100		
Horizontal well data			
Skin factor	1	-1	3
BHP, psi	300	200	400
Residual oil saturation, %	30	25	35
Well bore radius, inch	3.5		
Horizontal well length, ft	600		
Well cost, 1000 $	400		
Fixed Operational costs, $/day	125		

Table 10d

Field - Judica			
	Base	Min	Max
Rock Properties			
Drainage Radius, ft	579	290	869
Formation Thickness, ft	20	8	32
Horizontal K, md	10	1	100
Vertical K, md	1	0.1	10
Porosity, %	20	18	22
External Drainage Pr, psi	700	600	800
Fluid Properties			
Oil Viscosity, cp	2	1.8	2.1
Initial oil saturation, %	45	40	55
Formation volume factor, RB/STB	1.05	1.03	1.07
Drive Mechanism Scaling factor (DMSF)	0.55	0.5	0.7
(DMSF = 1 for active water drive, DMSF = 0 for solution gas drive)			
Vertical well data			
Skin factor	1	-1	3
BHP, psi	300	200	400
Residual oil saturation, %	30	25	35
Well bore radius, inch	3.5		
Well cost, 1000 $	200		
Fixed Operational cost/day, $	100		
Horizontal well data			
Skin factor	1	-1	3
BHP, psi	300	200	400
Residual oil saturation, %	30	25	35
Well bore radius, inch	3.5		
Horizontal well length, ft	600		
Well cost, 1000 $	400		
Fixed Operational costs, $/day	125		

Table 10e

Field - Riverside			
	Base	Min	Max
Rock Properties			
Drainage Radius, ft	699	350	1049
Formation Thickness, ft	35	20	50
Horizontal K, md	10	1	100
Vertical K, md	1	0.1	10
Porosity, %	15.5	13	18
External Drainage Pr, psi	900	800	1000
Fluid Properties			
Oil Viscosity, cp	2	1.8	2.1
Initial oil saturation, %	45	40	55
Formation volume factor, RB/STB	1.05	1.03	1.07
Drive Mechanism Scaling factor (DMSF)	0.6	0.5	0.75
(DMSF = 1 for active water drive, DMSF = 0 for solution gas drive)			
Vertical well data			
Skin factor	1	-1	3
BHP, psi	300	200	400
Residual oil saturation, %	30	25	35
Well bore radius, inch	3.5		
Well cost, 1000 $	200		
Fixed Operational cost/day, $	100		
Horizontal well data			
Skin factor	1	-1	3
BHP, psi	300	200	400
Residual oil saturation, %	30	25	35
Well bore radius, inch	3.5		
Horizontal well length, ft	600		
Well cost, 1000 $	400		
Fixed Operational costs, $/day	125		

Table 10f

Field - Lippoldt			
	Base	Min	Max
Rock Properties			
Drainage Radius, ft	772	385	1157
Formation Thickness, ft	40	25	55
Horizontal K, md	10	1	100
Vertical K, md	1	0.1	10
Porosity, %	15.5	14	17
External Drainage Pr, psi	1050	950	1150
Fluid Properties			
Oil Viscosity, cp	2	1.8	2.1
Initial oil saturation, %	45	40	55
Formation volume factor, RB/STB	1.05	1.03	1.07
Drive Mechanism Scaling factor (DMSF)	0.7	0.6	0.9
(DMSF = 1 for active water drive, DMSF = 0 for solution gas drive)			
Vertical well data			
Skin factor	1	-1	3
BHP, psi	450	350	550
Residual oil saturation, %	30	25	35
Well bore radius, inch	3.5		
Well cost, 1000 $	200		
Fixed Operational cost/day, $	100		
Horizontal well data			
Skin factor	1	-1	3
BHP, psi	450	350	550
Residual oil saturation, %	30	25	35
Well bore radius, inch	3.5		
Horizontal well length, ft	600		
Well cost, 1000 $	400		
Fixed Operational costs, $/day	125		

Table 10g

Field - Fralick W			
	Base	Min	Max
Rock Properties			
Drainage Radius, ft	876	437	1313.4
Formation Thickness, ft	32.5	20	45
Horizontal K, md	10	1	100
Vertical K, md	1	0.1	10
Porosity, %	21.5	20	23
External Drainage Pr, psi	200	100	300
Fluid Properties			
Oil Viscosity, cp	2	1.8	2.1
Initial oil saturation, %	45	40	55
Formation volume factor, RB/STB	1.05	1.03	1.07
Drive Mechanism Scaling factor (DMSF)	0.2	0.1	0.5
(DMSF = 1 for active water drive, DMSF = 0 for solution gas drive)			
Vertical well data			
Skin factor	1	-1	3
BHP, psi	75	15	90
Residual oil saturation, %	30	25	35
Well bore radius, inch	3.5		
Well cost, 1000 $	200		
Fixed Operational cost/day, $	100		
Horizontal well data			
Skin factor	1	-1	3
BHP, psi	75	15	90
Residual oil saturation, %	30	25	35
Well bore radius, inch	3.5		
Horizontal well length, ft	600		
Well cost, 1000 $	400		
Fixed Operational costs, $/day	125		

Table 11

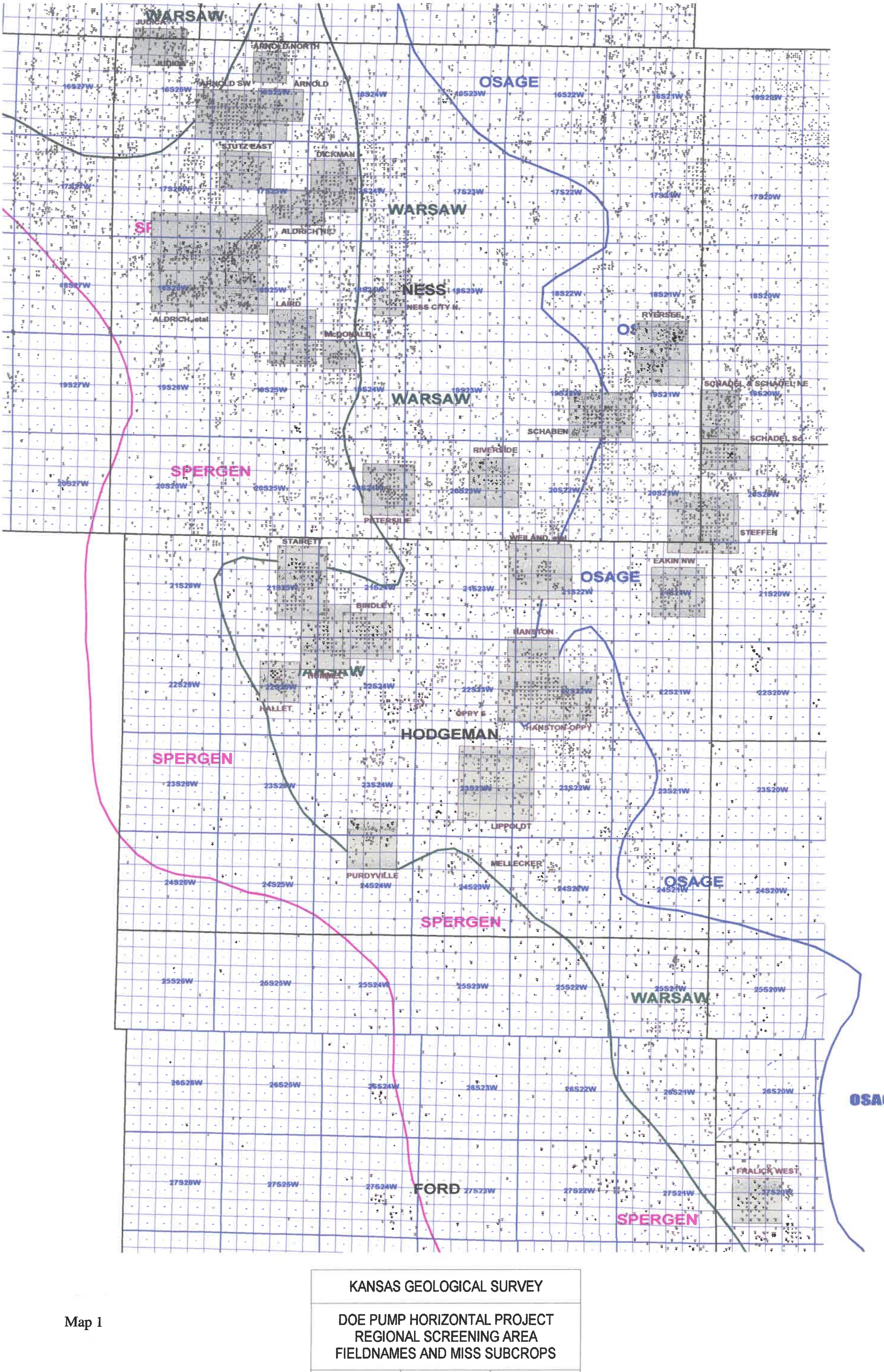
Field	Vertical IP rate BBl/d	Horizontal IP rate BBl/d	Vertical Rate after 5 yrs BBl/d	Horizontal Rate after 5 yrs BBl/d	Vertical Cum Recovery After 5 yrs, Mbbl	Horizontal Cum Recovery After 5 yrs, Mbbl
Lippoldt	90	268	56.5	72	131	273
Riverside	80.7	268	34.8	20.4	99.8	176
Ness City N	38	149	19	12	50	100
Arnold SW	43.9	147	25	27.2	61	130
Judica	31.4	134	16	10	42	88
McDonald	74.5	241	38.7	34.9	100	195
Fralick W	15	49	13.8	36	26.5	77

Table 12
Summary of KGS Mississippian Cores in the Study Area Region

Field	ID	OPERATOR_NAME	LEASE_NAME	Well #	Twn	Twn	Rng	Rng	Sec	SPOT	COUNTY	TOP	BOTTOM	LOCATION	STATUS
Arnold SW	507	EXETER	BOYD	6-23	16	S	26	W	23	SE-SE-NW	Ness	4545	4571	G-E5, UB2	L
	1711	WALTERS DRLG.	TILLEY	2	17	S	24	W	8	SE-SW-	Ness	4446	4461	1176-1178	0
	1712	WALTERS DRLG.	KLITZKE	1	17	S	24	W	12	C-SE-SE	Ness	4483	4496	2145-2146	L
	1713	WALTERS DRLG.	LYNCH	1	17	S	24	W	13	C-NE-NE	Ness	4475	4495	2152-2154	L
	27	ANADARKO	WEGELE A	1	18	S	22	W	21	C-SE-	Ness	4298	4316	GG-E4, PA1	L
	999	MOBIL	ELSASSER HRS	1	18	S	22	W	29	C-SE-SW	Ness	4321	4351	72-76	W
	29	ANADARKO	ENDICOTT A	1	18	S	23	W	13	SW-SE-SE	Ness	4310	4324	QB7	L
Ness City	1551	SUN	UMMEL	1	18	S	24	W	23	C-SE-NE	Ness	4290	4298	733	L
Ness City	1552	SUN	PFANNENSTIEL	1	18	S	24	W	24	SE-SW-	Ness	4265	4284	736	L
Ness City	1553	SUN	PFANNENSTIEL	2	18	S	24	W	24	C-NW-SW	Ness	4266	4290	736	L
Ness City	1716	WALTERS DRLG.	MAIER	1	18	S	24	W	25	C-SW-SW	Ness	4252	4267	1235-1236	L
	761	KERN LANDES	STIEBEN	1	19	S	21	W	17	NE-SW-	Ness	4343	4354	733	L
Schaben	2009	RITCHIE EXPLORATION	REIN A-P	7	19	S	21	W	29		Ness	4385	4399	KD7	0
Schaben	228	CITIES SERVICE	MOORE C	1	19	S	21	W	30	C-SE-SW	Ness	4423	4445	4078-4080	L
Schaben	2007	RITCHIE EXPLORATION	MOORE D-P	6	19	S	21	W	30		Ness	4354	4376	KD7	L
Schaben	2003	RITCHIE EXPLORATION	MOORE BP TWIN	4	19	S	21	W	30		Ness	4370	4450	KD6, KD5	L
Schaben	2008	RITCHIE EXPLORATION	MOORE C-P	4	19	S	21	W	30		Ness	4421	4435	KD7	L
Schaben	229	CITIES SERVICE	FOOS A	1	19	S	21	W	31	C-SW-SW	Ness	4401	4413	3566-3567	L
Schaben	2004	RITCHIE EXPLORATION	FOOS AP TWIN	1	19	S	21	W	31		Ness	4387	4440	KD6, KD5	L
Schaben	2005	RITCHIE EXPLORATION	LYLE SCHABEN "P"	2	19	S	21	W	31		Ness	4382	4465	KC6	L
Schaben	763	KERN LANDES	MOORE	1	19	S	21	W	34	C-NW-NW	Ness	4421	4439	1433-1436	L
	3566	RITCHIE EXP.	HUMBERG AP#3		19	S	22	W	25		Ness	4376	4385	KD7	0
	230	CITIES SERVICE	HUMBURG A	2	19	S	22	W	25	C-SE-SE	Ness	4389	4409	NC2	0
McDonald	956	MCCLURE	ATENEN	1	19	S	24	W	6	C-NE-NE	Ness	4393	4414	270-272	W
	1557	SUNRAY DX	BONDURANT	1	19	S	25	W	12	C-NW-NE	Ness	4396	4449	1439-1447	L
	2006	RITCHIE EXPLORATION	HUMBURG AP	3	19	S	25	W	25		Ness	4373	4382	KD7	0
	1001	MOBIL	H. MOORE A	1	20	S	21	W	5	C-NE-SW	Ness	4420	4424	102-103	W
	231	CITIES SERVICE	ANTENEN A	1	20	S	21	W	6	C-NE-SE	Ness	4384	4399	NC2	U
	232	CITIES SERVICE	O'BRIEN A	2	20	S	21	W	7	C-SE-NW	Ness	4355	4375	LB3	U
	1003	MOBIL	M.SCHNEIDER	2	20	S	22	W	12	C-NW-NE	Ness	4366	4384	558-560	U
	1005	MOBIL	SCHNEIDER	3	20	S	22	W	12	C-SE-NE	Ness	4333	4371	1937-1943	L
	991	MIDCONTINENT	J.G.COLLINS	1	20	S	26	W	24	NW-NW-NW	Ness	4527	4555	382-385	L
	127	BEARDMORE	SHELTON A	1	21	S	24	W	28	SE-SE-	Hodgeman	4616	4641	1901-1905	L
	1102	OASIS	ADAMS	1	21	S	24	W	33	C-NE-SW	Hodgeman	4665	4674	1364-1365	L
Bindley	1105	OASIS	BINDLEY	3	21	S	24	W	33	C-NE-NE	Hodgeman	4594	4643	1366-1374	L
Bindley	1884	OASIS	BINDLEY	2	21	S	24	W	33	C-SW-NE	Hodgeman	4636	4669	OA3, MB0	L
Bindley	1103	OASIS	DEUTSCH	1	21	S	24	W	33	C-NE-SE	Hodgeman	4609	4694	1304-1319	L
Bindley	1106	OASIS	DEUTSCH	5	21	S	24	W	33	C-SW-SE	Hodgeman	4622	4682	1341-1351	L
Bindley	1885	OASIS	DEUTSCH	2	21	S	24	W	33	C-NW-SE	Hodgeman	4602	4655	OA2, MA0	L
Bindley	1887	OASIS	DEUTSCH	3	21	S	24	W	33	C-NW-SW	Hodgeman	4625	4683	OA3	L
Bindley	1888	OASIS	DEUTSCH	4	21	S	24	W	33	C-SE-SE	Hodgeman	4636	4688	OA1, MB0	L
Bindley	1104	OASIS	SCHAUVLIEGE	1	21	S	24	W	33	C-SE-NW	Hodgeman	4654	4711	1320-1329	L
Bindley	1109	OASIS	DEUTSCH	7	21	S	24	W	34	C-SE-SW	Hodgeman	4637	4696	1330-1340	L
Bindley	3136	OASIS	DEUTSCH	3	21	S	24	W	34	C-NW-SW	Hodgeman	4625	4683	MA 0	L
Bindley	3138	OASIS	DEUTSCH	6	21	S	24	W	34	C-SW-SW	Hodgeman	4639	4696	MA0, OA2, OA0	L
Bindley	1107	OASIS	EVERTON	1	21	S	24	W	34	C-SW-SE	Hodgeman	4663	4708	1608-1615	L
Bindley	1108	OASIS	EVERTON	2	21	S	24	W	34	C-SE-SE	Hodgeman	4642	4700	1390-1399	L
Bindley	3137	OASIS	MARIE	1	21	S	24	W	34	C-NW-SW	Hodgeman	4625	4683	MA 0, OA3	L
Bindley	1886	OASIS	SMITH	1	21	S	24	W	34	C-SW-NW	Hodgeman	4621	4668	OA3, MA0	L
	1009	MOBIL	SALMANS A	1	22	S	22	W	3	C-SE-SE	Hodgeman	4432	4470	235-239	W
	1554	SUNRAY DX	GUS MILLER	1	22	S	22	W	8	C-SE-NW	Hodgeman	4520	4547	686-690;557	L
	1080	NORTHERN NATURAL	EWY A	1	22	S	22	W	17	C-NW-SE	Hodgeman	4460	4461	2178	L
Bindley	1110	OASIS	WALTER	1	22	S	24	W	3	C-NW-NW	Hodgeman	4642	4718	1375-1389	L
Bindley	1111	OASIS	WALTER	2	22	S	24	W	3	C-NE-NW	Hodgeman	4652	4685	1616-1621	L
Bindley	1112	OASIS	DIXON	1	22	S	24	W	4	C-NE-NE	Hodgeman	4642	4700	1352-1361	L
Bindley	128	BEARDMORE	FEHRENBACH	1	22	S	25	W	1	C-NE-NE	Hodgeman	4513	4532	1105-1107	L
Lippoldt	129	BEARDMORE	CLIFTON	1	23	S	23	W	1	NW-NE-	Hodgeman	4422	4446	8	W
Lippoldt	130	BEARDMORE	CLIFTON	2	23	S	23	W	1	SW-NE-	Hodgeman	4443	4463	327-328	W
	3403	AMERICAN ENERGY	KNOEFLER	1	23	S	24	W	11		Hodgeman	4520	4530	WB7	L
	1151	PENDLETON	V.GLEASON B	1	24	S	21	W	5	SW-NW-SE	Hodgeman	4654	4660	NB5	U
Fralick	1087	NORTHERN NATURAL	FRALICK A	2	27	S	20	W	14	C-NE-SW	Kiowa	4818	4876	793-804 / QB0	L
	1024	MULL & WALTERS	BRENSING G	1	27	S	20	W	20	C-NW-SE	Kiowa	4874	4907	286-289	W
	32	ANADARKO	BRENSING A	1	27	S	20	W	33	SE-NW-	Kiowa	4910	4941	573-578	L
	1023	MULL & MOBIL	MATKIN	1	27	S	21	W	16	C-NE-NW	Ford	4904	4931	107-112	W
	1863	MOBIL	MATKIN	1	27	S	21	W	16	C-NE-NW	Ford	4904	4931	BB4	0
	1488	SINCLAIR PRAIRIE	YOUNG	1	27	S	21	W	34	C-SL-NE	Ford	4890	5355	252	W

Core in Wichita - status must be checked
Cores already sampled and have some data

L - Cores in Lawrence
W - Cores in Wichita
0 - Cores missing



Map 1

KANSAS GEOLOGICAL SURVEY

DOE PUMP HORIZONTAL PROJECT
REGIONAL SCREENING AREA
FIELDNAMES AND MISS SUBCROPS

Paul Gerlach		1/7/2003
	Scale 1:344916.44	