TUNDRA OIL AND GAS LTD.

KOLA FIELD

BAKKEN 'A' POOL

PRESSURE
MAINTENANCE
APPLICATION

JULY, 1993

TABLE OF CONTENTS

TABLE OF CONTENTS (CONTINUED)

July 8, 1993

Manitoba Energy and Mines
Petroleum Branch
555 - 330 Graham Avenue
Winnipeg, Manitoba
R3C 4E3

Attention: Mr. C. Moster
Deputy Chairman

Dear Mr. Moster,

RE: Kola Field
Pressure Maintenance Application

A. EXECUTIVE SUMMARY

A.1 Introduction

The Kola Field is located approximately 32 kilometres west of the town of Virden, Manitoba (refer to Attachment No.1). The principal producing formation in the Kola Field is the Bakken 'A' Pool which was discovered in October, 1985 by the drilling of well 13-21-10-29 W1M. Current oil production is about 20 m3/day at a field watercut of 45%. The purpose of the pressure maintenance program is to install a waterflood recovery scheme, in order to maximize oil recovery from the Bakken 'A' Pool.

A.2 Conclusions

1. The Bakken 'A' pool has been determined to be a good reservoir for waterflooding based on comprehensive geological and engineering evaluations.

2. Engineering studies have indicated that the installation of a waterflood program in the Bakken 'A' Pool will provide an ultimate recovery of 35.8% of the original oil-in-place.

3. The waterflood program will be staged in the Kola Field with the initial installation in the highest reservoir quality area. Staging is recommended to evaluate the commercial feasibility of the project. The initial waterflood area will provide incremental oil recovery of 42,395 m3 (267,000 STB).

4. The waterflood program will be expanded to other areas of the Unit pending a favourable production response from the the initial area of installation. Attachment No.2 and Attachment No.3 outline the Unit lands and the initial area of waterflooding, respectively.

A.3 Discussion

The following highlights have been summarized from the subsequent sections of the pressure maintenance application:

UNIT NAME

Tundra suggests that the official unit name of the Kola Field shall be the Kola Unit No.1.

OPERATORSHIP

Tundra Oil and Gas Ltd. will be the operator of record for the the Kola Unit No.1.

TRACT FACTORS

The tract factors for the the Kola Unit No.1 lands are outlined in Table No.7. The Unit working interest owners have agreed to determine the tract factors based on current production during the last 90 well operating days.

WORKING INTEREST OWNERS

The major working interest owners in the Kola Unit No.1 will be Tundra Oil and Gas Ltd.(78.13%), and Corvair Oils Ltd(16.22%). The minor working interest owners will have a total working interest of 5.65% in the Kola Unit No.1. Table No.7 outlines the Kola Unit No.1 working interest owners.

TECHNICAL STUDIES

The waterflood predictions for the Bakken 'A' Pool in the Kola Unit No.1 are based on geological and engineering reviews.

Geological work has included developing a suite of mapping to establish reservoir development and continuity. A review of the available core data was also undertaken to determine reservoir quality in the Bakken 'A' Pool. Section B of the pressure maintenance application outlines the mapping available for the Bakken 'A' Pool.

Engineering reviews included reserve estimation, historical production assessment, ultimate recovery predictions, and relative permeability tests to establish waterflood performance and secondary oil recovery. The engineering studies predict that waterflood performance in the Bakken 'A' Pool will involve piston displacement of the oil by the displacing fluid(water bank). The piston displacement process in this reservoir has been assessed as providing effective oil sweep and recovery.

HISTORICAL PRODUCTION

Figure No.1 outlines the production history of the Kola Bakken 'A' Pool. The production decline during 1992 was arrested primarily due to workover programs. Remaining primary production(proved producing reserves) has been estimated at 80,000 m3 (500,000 STB). The ultimate primary recovery is estimated(based on log derived reservoir parameters) at 18.5 % of the original oil-in-place(refer to Figure No.2).

WATERFLOOD RECOVERY

Core flooding during relative permeability testing has indicated that the ultimate recovery from the Bakken 'A' Pool with waterflooding will be 35.8% of the original oil-in-place. The ultimate primary recovery in the initial area for waterflooding has been estimated at 23.9% of the original oil-in-place. Incremental recovery of 17.8% of the original oil-in-place with incremental reserves of 267,000 STB are estimated in the initial area of waterflooding.

WATERFLOOD PATTERN

The waterflood pattern in the initial area of waterflooding will be an incomplete inverted 9-spot. This type of waterflood pattern, as a first application, has provided commercial waterflood recovery in the North Ebor Units No.1 and No.2. Well 13-21-10-29 W1M has been selected as the injection well in the initial area of waterflooding in the Kola Unit No.1.

RECOVERABLE RESERVE AND RECOVERY FACTOR SUMMARY

Table No.12 provides an outline of the recoverable reserves and recovery factor summary for the Kola Unit No.1.

FACILITIES

The central battery facility will be located at 4-28-10-29 W1M. The water injection pumps will be located at injection well 13-21-10-29 W1M. Makeup injection water will be obtained that is compatible with Bakken produced water. Attachment No.4 outlines the location of the facilities and wells that will be initially tied into the central battery facilities at 4-28-10-29 W1M.

NOTIFICATION OF MINERAL AND SURFACE RIGHTS OWNERS

Tundra is in the process of notifying all mineral rights and surface owners of the unitization of the Kola Bakken 'A' Pool and subsequent commencement of waterflood operations.

Respectfully Submitted,

TUNDRA OIL AND GAS LTD.

George Czyzewski, P.Eng.
Senior Reservoir Engineer

C.M. Finn, P.Geol
Chief Geologist

B. GEOLOGY

B.1 Description

The Kola Bakken 'A' Pool produces from a 1 to 3 metre thick, fine to medium grained dolomitic sandstone developed at the base of the Middle Bakken Member (refer to Attachment No.5). The productive interval has an average porosity of 16.6%, using a log porosity cutoff of 12% on the Limestone Density Scale. This porosity cutoff approximates a permeability cutoff of 1 md, based on log-core relationships. Core permeabilities in the productive interval range from 1 to 100 md and average 10 md.

Potential reservoir exists within a 1 metre thick sandstone developed at the top of the Middle Bakken Member. Average porosity in this upper zone is 13.7% and average permeability is 1 to 2 md. The productive capability of the upper zone is uncertain, as no independent production testing has been done to date.

Top seal for the reservoir is provided by the overlying black shale of the Upper Bakken Member. Seat seal is the red and green dolomitic shales of the Devonian Lyleton Formation. Lateral changes in porosity, permeability and depositional texture provide an important component of the trapping mechanism for the Middle Bakken sandstones.

The Middle Bakken reservoir has a gentle regional dip to the southwest (refer to Attachment No.6). Local structural closure is developed to the north and west and is attributed to the differential salt solution.

B.2 Mapping

The following suite of mapping has been prepared to determine the areal extent of the Bakken 'A' Pool and to define the reservoir quality:

* Attachment No.6: Structural Top Middle Bakken Member
* Attachment No.7: Total Hydrocarbon Pore Volume Middle Bakken Member
* Attachment No.8: Kh Map Middle Bakken Member Lower Zone
* Attachment No.9: Kh Map Middle Bakken Member Upper Zone

Attachment No.6 indicates that the Middle Bakken Member dips gently to the southwest.

Attachment No.7 indicates that the highest pore volume is contained within the initial area selected for waterflooding in the Bakken 'A' Pool.

Attachment No.8 indicates that the best and most continuous flow capacity(Kh) is contained in the lower zone of the Middle Bakken Member. The area selected for initial waterflooding in the Kola Unit No.1 contains the highest flow capacity in the Bakken reservoir. Attachment No.9 indicates that the upper zone of the Middle Bakken Member has lower flow capacity, and is discontinuous in the Kola Field.

B.3 Reservoir Fence Diagram

A reservoir fence diagram was prepared to determine the continuity of the Middle Bakken Member. The correlation of the lower and upper zones between wells in the Middle Bakken Member was done using compensated neutron-density logs, and where core data was available. The reservoir fence diagram indicates that there is good connectivity in the Middle Bakken Member in both an east - west direction, and also in a northeast - southwest direction. The fence diagram also illustrates the relative thickness of the lower and upper zones in the Middle Bakken Member. The lower zone is consistently thicker throughout the Bakken 'A' Pool than the upper zone. The reservoir fence diagram supports the selection of 13-21-10-29 W1M as the best well to maximize waterflood sweep in the initial area selected for waterflooding. Appendix A outlines the reservoir fence diagram for the Bakken 'A' Pool.

B.4 Core Analysis

Core data was available for the following wells in the Bakken 'A' Pool: (a) 9-20-10-29, (b) 5-21-10-29, (c) 10-21-10-29, (d) 11-21-10-29, (e) 3-28-10-29, (f) 4-28-10-29, (g) 5-28-10-29, and (h) 9-29-10-29. Core data was used in conjunction with open-hole logs to prepare all mapping contained within this pressure application. Analysis of the core data indicates that at least within the wellbore region, the permeability within each zone is fairly uniform. This should minimize the amount of fingering that will occur during waterflood operations.

C. RESERVOIR PARAMETERS

C.1 Rock Parameters

Rock parameters and minimum cutoffs such as porosity and permeability were determined initially from available core. Core data was then calibrated to log response to provide parameters for non-cored wells. Considerable manipulation of the raw log data was required to achieve fair correlation to the available core data.

C.2 Fluid Parameters

Table No.1 summarizes the fluid parameters for the Bakken 'A' Pool. The fluid parameters were determined from PVT analysis and correlation charts. The only available PVT test for the Bakken 'A' Pool was at well 3-28-10-29 W1M (refer to Appendix B).

D. PRESSURE SURVEYS

D.1 Field History

The Bakken 'A' Pool initial reservoir pressure was 8604 kPa, based on the DST at well 13-21-10-29 W1M. The reservoir drive mechanism in the Bakken 'A' Pool is primarily solution gas and expansion drive. There is no pressure support evident from bottom water. Fracturing into the Lodgepole formation which overlies the Bakken formation, may be providing some local pressure support. The rapid decline in production capability and annual pressure surveys support the conclusion that the Bakken 'A' Pool generally has no pressure support. New wells (10-20-10-29; 15-21-10-29; 16-29-10-29) drilled during the first quarter of 1993 indicate that offsetting production is draining the reserves at these locations. DST's run at these new locations indicated an average static reservoir pressure of 6400 kPa. This information supports the existing mapping that the Bakken 'A' Pool has good continuity and connectivity. As a result, the Bakken 'A' Pool should respond well to waterflooding. The 1993 average reservoir pressure in the Bakken 'A' Pool is estimated at 6000 kPa. Figure No.3 outlines the historical pressure in the Bakken 'A' Pool.

E. RESERVES AND PRODUCTION HISTORY

E.1 Original Oil-In-Place

Two methods were used to calculate the original oil-in-place in the Bakken 'A' Pool. The volumetric approach was based on log derived parameters of net pay, porosity, and initial formation water saturation. The volumetric method was further augmented with formation wettability information from the relative permeability tests. A material balance procedure was also used to determine the original oil-in-place using actual production and pressure history from the Bakken 'A' Pool. The objective of the material balance approach was to review the reliability of the volumetrically estimated original oil-in-place. The following sub-sections outline the results obtained using each method.

E.1.1 Volumetric Estimate

As previously mentioned, two volumetric methods were used to determine the original oil-in-place. The first approach involved using only log derived parameters for net pay, porosity, and initial formation water saturation. The initial formation water saturations used in the calculation were obtained from Manitoba EMR publication "Evaluation of the Daly Field, Bakken Formation, Southwestern Manitoba", by M. Arbez. Based on this approach, the total oil-in-place in the lower and upper middle Bakken member was 648,338 m3 and 266,143 m3, respectively. Total original oil-in-place for the Bakken 'A' Pool using only log derived reservoir parameters was 915 e3m3. Table No.2 and Table No.3 outline the original oil-in-place estimates (log derived parameters only) by well for the lower and upper Middle Bakken Member, respectively.

The second volumetric method of determining the original oil-in-place utilized the wettability information from the relative permeability study. The core from well 4-28-10-29 W1M was used in the test. An initial formation water saturation of 32% was derived from open-hole logs at 4-28 in the lower zone of the Middle Bakken Member (refer to Table No.2). An initial formation water saturation of 57.8% was obtained from the relative permeability tests at 4-28 (refer to Figure No.4). The large difference is attributable to the consideration that in the log derived approach a constant cementation factor is used in the Archie equation to derive the initial formation water saturation. Under in situ conditions, the cementation factor varies throughout the oil column. As a result, the log derived initial formation water saturation in the lower zone of the Middle Bakken Member is considered to be optimistic. On this basis, the original oil-in-place estimates were recalculated in the lower zone using only the higher intial formation water saturation of 57.8%. The upper zone of the Middle Bakken Member was not adjusted, since an initial formation water saturation of 60% was used to calculate the original oil-in-place in this zone. The original oil-in-place in the lower zone using this approach is 468,999 m3. The total original oil-in-place in the Bakken 'A' Pool using the higher initial formation water saturations is 735 e3m3. Table No.4 outlines the revised volumetric original oil-in-place estimates for the lower zone of the Middle Bakken Member.

E.1.2 Material Balance Estimate

A material balance estimate of the original oil-in-place in the Bakken 'A' Pool was performed to check on the reliability of the volumetric estimates of oil-in-place. The Fetkovich limited acquifer support model was used to determine the material balance estimate of original oil-in-place. The process involved reviewing the available PVT data, production, and pressure history for the Bakken 'A' Pool. This was followed by first determining the effective oil compressibility and then calculating the expansibility of the reservoir fluids. The change in reservoir pressure over time with expansibility of reservoir fluids was then calculated. This allowed the calculation of reservoir fluid withdrawals, and the apparent oil-in-place with each successive time step. The final step in the material balance calculation involved using least squares analysis to back out the original oil-in-place in the Bakken 'A' Pool. An original oil-in-place of 610 e3m3 was calculated for the Bakken 'A' Pool using the aforementioned material balance method.

The material balance calculation suggests that the Bakken 'A' Pool may have less original oil-in-place than the volumetric estimates predict. This may be attributable to the following reasons. First, the initial formation water saturation in the upper zone of the Middle Bakken Member may be higher than used in the volumetric calculation. Secondly, the upper zone may have less connectivity between wells, and as a result, less moveable oil than the volumetric estimates predict. The material balance estimate further suggests that the initial formation water saturation determined from the wettability studies is more likely to prevail than the log derived equivalent. The material balance technique used in this pressure maintenance application is not considered rigorous, since there was an absence of pressure data between 1987 and 1992. The material balance derived original oil-in-place, however, is considered to be accurate within the limits of the data that was available to perform this analysis. Appendix C outlines the methodology to generate the material balance estimate of original oil-in-place for the Bakken 'A' Pool.

E.2 Production History

Figure No.1 outlines the production history for the Bakken 'A' Pool. Peak oil production of 45 m3/day was achieved in February, 1988. Oil production declined 41% during the balance of 1988. Between 1989 and early 1992, the average annual decline in oil production was 21% / year. A workover program initiated during the first quarter of 1992 arrested the production decline and increased field oil production capability by 6 m3/day. Current oil production capability is about 20 m3/day at an average field water-cut of 46%. Appendix D outlines the total production history for the Bakken 'A' Pool. Appendix E outlines the production time plots for the individual wells in the Bakken 'A' Pool.

E.3 Ultimate Primary Recovery

Figure No.2 outlines the remaining proved reserves for the Bakken 'A' Pool. The ultimate recoverable primary oil reserves are estimated at 136,000 m3. Cumulative oil production to 93.03.31 was 59,474.10 m3. Remaining proved oil reserves are estimated at 76,525 m3. Appendix F provides oil rate vs cumulative production plots estimating the remaining proved reserves in the individual wells.

The ultimate primary oil recovery factor was estimated by using both the volumetrically(initial Sw = 57.8%) calculated oil-in-place, and the material balance estimate of oil-in-place. An ultimate primary oil recovery of 18.5% of the original oil-in-place is estimated using volumetric methodology. The material balance technique estimates that 22.3% of the original oil-in-place will be recovered from the Bakken 'A' Pool. Cumulative recovery(93.03.31) of 8.1% of the original oil-in-place is estimated from the Bakken 'A' Pool using volumetric methods. Similarly, cumulative recovery of 9.7% of the original oil-in-place is estimated using material balance practices.

E.4 Primary Production Forecast

The primary production forecast for the remaining proved reserves in the Bakken 'A' Pool is outlined in Table No.5.

F. WATERFLOOD PROGRAM

F.1 Unit Lands and Wells

The Kola Unit No.1 lands are outlined in Attachment No.2. The Kola Unit No.1 will comprise a total land area of 259 hectares (640 acres). The initial area for waterflooding is outlined in Attachment No.3, and will comprise a total area of 113.3 hectares (280 acres). The initial waterflood area represents 44% of the total Kola Unit No.1 lands. Table No.6 outlines the total Kola Unit No.1 wells, and the initial wells in the Unit selected for waterflood operations.

F.2 Tract Factors and Working Interests

The major working interest owners in the Kola Unit No.1 have agreed to use current oil production during the last 90 well operating days for each well as the basis to determine the Unit tract factors. Current production has been assessed as the most reliable indicator of a wells production potential in the Kola Bakken 'A' Pool. The working interest owners have also addressed the consideration of using pore volume in the determination of Unit tract factors. This approach has been assessed as not being indicative of a wells production capability, since wells with good and poor pore volume have experienced similar production problems(fracturing out of zone and subsequent watering out) after initial completion. Initial completion in this context includes such programs as perforating, acidizing, and fracturing. As a result, the most equitable approach in assigning working interest participations in the Kola Unit No.1 was on the basis of using current well production during the last 90 well operating days.

The last 90 well operating days for the majority of the Unit wells was satisfied during the period December 1, 1992 to April 30, 1993. Wells 10-21-10-29 W1M and 5-28-10-29 W1M required going back to January 1, 1992, in order to obtain the last 90 well operating days. Although well 14-21-10-29 W1M has not produced since August, 1988, installation of high volume lift equipment during Unit operations should restore productivity at this location. On this basis, a tract factor similar to well 12-21-10-29 W1M was assigned to LSD 14-21-10-29 W1M, since well 14-21 had a similar production profile to 12-21 prior to watering out after fracture treatment.

Table No.7 outlines the Kola Unit No.1 tract factors and working interest participations that have been agreed upon by the major working interest owners.

F.3 Relative Permeability Data

A relative permeability testing program was initiated in the Kola Bakken 'A' Pool in order to determine the following information:

1. Determine wettability of the Bakken 'A' reservoir (initial formation water saturation)
2. Determine waterflood displacement mechanism in the Bakken 'A' Pool
3. Determine the recovery factor with waterflooding the Bakken 'A' Pool
4. Determine the residual oil saturation after waterflood operations

The core from well 4-28-10-29 W1M was selected as representative of both the Bakken 'A' Pool in the Unit, and the initial area for waterflooding in the Kola Unit No.1. The relative permeability study was done on core with porosities and permeabilities primarily representative of the lower zone of the Middle Bakken Member. The four objectives of the relative permeability testing program are addressed under the following items:

i. Mobility Ratio

The mobility ratio essentially represents how well oil moves in the presence of water recognizing in this situation that water is the displacing fluid. The mobility ratio concept also recognizes that there is a viscosity difference between the oil and water, which will impact on the displacement efficiency of oil in the reservoir. The mobility ratio can be summarized by the following equation:

$$\text{Mobility Ratio} = M = \frac{u_o}{u_w} * \frac{K_{rw}}{K_{ro}}$$

where:

K_{rw} = relative permeability to water
K_{ro} = relative permeability to oil
u_w = water viscosity
u_o = oil viscosity

Field studies in Western Canada have shown that oil reservoirs with mobility ratios of less than one (reservoirs with light oil) show preferential movement of oil in the reservoir. Reservoirs with mobility ratios of greater than one(heavy oil) generally favour the preferential movement of water in the reservoir. Reservoirs with mobility ratios equal to one do not indicate preferential movement of one fluid over the other. Analysis of the k_{ro} and k_{rw} curves in Figure No.4 prior to water breakthrough indicates that the

Kola Bakken 'A' Pool has a mobility ratio of less than one(using u_w = 1 mPa.s, and u_o = 2.8 mPa.s). Mobility ratios of less than one will also impact on injection pressures which will be discussed in a later item.

ii. K_{ro} and K_{rw} Curves

Figure No.4 outlines the relative permeability of oil and water flow in the Bakken 'A' Pool during waterflood operations. All four objectives previously stated can be addressed from the k_{ro} and k_{rw} curves. Figure No.4 indicates that the initial or irreducible formation water saturation(S_{wirr}) of the Bakken 'A' Pool = 57.8% at well 4-28. On this basis the initial oil saturation(S_{oi}) in the pore space is 42.2%. This indicates that the Bakken 'A' Pool is a highly water wet reservoir. The displacement mechanism evident from Figure No.4 is that fluid movement in the reservoir will be in the form of piston displacement. The sharp concave downward shape of the k_{ro} curve supports this conclusion that the displacement mechanism during waterflood operations will be piston displacement. The significance of piston displacement is that recovery at breakthrough is generally equivalent to ultimate recovery. Residual oil saturation (S_{or}) = 19.7% at the end of waterflood operations(final S_w = 80.3%) in the Bakken 'A' Pool. This results in an ultimate secondary recovery of 53.3% of the original oil-in-place(OOIP) after waterflooding. The recovery factor of 53.3% of the OOIP is representative of the lower zone of the Middle Bakken Member only. As previously stated in Section B.1, the production potential of the upper zone of the Middle Bakken Member is uncertain. As a result, a nominal recovery factor of 5% of the OOIP was assigned to the upper zone of the Middle Bakken Member with waterflood operations. The k_{ro} / k_{rw} curves indicate that at water breakthrough(formation S_w = 70%) the oil production drops off dramatically. However, the majority of the oil has been recovered at this point, as will be discussed in a later item in this subsection of the pressure maintenance application.

iii. Cumulative Production vs Cumulative Injection

Figure No.5 outlines the cumulative production vs the the cumulative water injection profile obtained from the core during the relative permeability study. Water breakthrough occurs at approximately at 0.15 pore volumes of cumulative water injection resulting in a recovery of 70% (0.15/0.225) of the total recoverable oil in the pore space. Current economic recovery is complete between 0.5 to 0.70 pore volumes of cumulative injection. Ultimate recovery of 53.3% of the original oil-in-place is achieved at 1.67 pore volumes of cumulative injection. Waterflooding beyond this point does not yield any further oil recovery. Table No.8 outlines the cumulative injection, cumulative production, and differential pressure data obtained during the relative permeability tests.

iv. Pressure vs Cumulative Injection

Figure No.6 outlines the differential pressure across the core with successively higher cumulative injection. This profile indicates that injection pressures will continue to rise with higher cumulative injection until water breakthrough is achieved at the producing well. Injection pressures will begin to drop off after breakthrough has ocurred in all the producing wells in a given waterflood pattern. Although injection pressures will begin to falloff after water breakthrough, high injection pressures will prevail during the economic life of the waterflood operation. Successively higher injection pressures during waterflooding are characteristic of oil reservoirs that have a mobility ratio of less than one.

v. Sweep Efficiency

The lower zone of the Kola Middle Bakken Member has a very good waterflood sweep efficiency. This is evident from the total oil recovery at water breakthrough. At breakthrough, 70% of the total recoverable oil has been recovered. This recovery is achieved after only 0.15 pore volumes have been displaced in the reservoir. Current economic oil recovery reaches its peak after about 0.5 pore volumes have been displaced. As a result of the low cumulative injection required to achieve this high oil recovery, the Bakken 'A' Pool is a good reservoir for waterflooding. As previously mentioned, the waterflood front will act as a piston in the displacement of oil to the producing wells.

F.4 Waterflood Pattern Selection

An inverted 9-spot waterflood pattern has been selected in the initial area for waterflooding in the Kola Unit No.1. The initial application of this type of waterflood pattern has provided good waterflood recovery in the North Ebor Units No.1 and No.2. Since the Bakken 'A' Pool is a similar reservoir to the Bakken 'D' Pool(North Ebor Units), an inverted 9-spot will be installed as the initial waterflood pattern in the Kola Unit No.1. Attachment No.3 indicates that the initial waterflood pattern will not be a symmetrical inverted 9-spot, since corner wells 1-29-10-29 W1M and 11-21-10-29 W1M have been abandoned. This, however, will not have a negative impact on waterflood recovery, since the permeability trends in the reservoir are in an east - west and northeast - southwest direction.

F.5 Incremental Reserves

Incremental oil reserves of 267,000 STB are estimated with waterflooding the initial area of the Kola Unit No.1(refer to Attachment No.3). The following process was used to estimate the incremental oil reserves:

* The volumetric original oil-in-place was first calculated for each well using the irreducible formation water saturation from the relative permeability study.

* A decline analysis was then done for each well in the initial waterflood area to estimate the ultimate primary recovery.

* The primary recovery factor was then calculated for each well in the intial waterflood area.

* Incremental waterflood recovery was then calculated by first recognizing that each well has an ultimate recovery of 53.3% of the original oil-in-place(OOIP) with waterflooding the lower zone of the Middle Bakken Member within its LSD. The difference between this upper limit of 53.3% of the OOIP and the predicted ultimate primary recovery were taken as the estimated incremental oil reserves in the initial waterflood area of the Kola Unit No.1.

* The aforementioned secondary reserve estimation process applied only to the lower zone of the Middle Bakken Member. Since the production potential of the upper zone in the Middle Bakken Member is uncertain at this time, a recovery ceiling of 5% of the OOIP from this zone was estimated as recoverable with waterflood operations.

* Table No.9 outlines the process to estimate incremental oil recovery with waterflooding the initial area of the Kola Unit No.1.

On this basis, implementation of waterflood operations in the remaining areas of the Kola Unit No.1 in the future may provide additional oil reserves of 534,000 STB(84,900 e3m3). Expansion of the waterflood operation to the remaining areas of the Kola Unit No.1 will be contingent on good waterflood response in the initial area of the Unit.

F.6 Incremental Forecast

The incremental oil forecast for the initial area selected for waterflooding in the Kola Unit No.1 was generated through the following process:

* A review was first undertaken of the waterflood production

performance in the North Ebor Units No.1 and No.2.

* A waterflood response generally occurred between 3 to 6 months after water injection commenced.

* The waterflood production performance was characterized by either a flattening of the production decline or a 30 to 50% increase in the oil production rate after waterflood operations had commenced.

* This review served as the basis to predict waterflood performance in the Kola Unit No.1

* Rather than a flattening of the production decline, a 75% increase (average oil increase of 1 m3/day per well) in the current oil rate, as a base case, is expected in the initial area selected for waterflooding in the Kola Unit No.1. Better waterflood production performance is expected in the initial waterflood area in the Kola Unit No.1, since injection well 13-21-10-29 W1M has much better permeability and connectivity with its offsetting producers than the injection wells in the North Ebor Units No.1 and No.2 (refer to Appendix A: Bakken 'A' Pool Reservoir Fence Diagram).

* The initial waterflood area is expected to achieve its peak rate by early 1994, and remain flat for the next 3 years. After the initial 3 years of waterflood operations, the oil rate is expected to decline at 8% / year during the next 6 years, and 20% / year thereafter.

* The aforementioned predictions will be reviewed on an annual basis, and adjustments will be made based on actual waterflood performance.

* Table No.10 outlines the current oil rates and watercuts of the wells in the initial waterflood area in the Kola Unit No.1.

* Table No.11 outlines the current production forecast, and the incremental production rate in the intial waterflood area of the Kola Unit No.1. The water
flood production forecast includes the primary production component.

* Table No.12 provides a summary of the recoverable reserves and recovery factors for the Kola Unit No.1.

F.7 Water Injection Rate

The water injection rate recommended at injection well 13-21-10-29 W1M has been determined as follows:

* Initial water injection rate = [9.04 / 0.6(oilcut)] * 1.25
= **19 m3/day**

* Peak water injection rate = [15.75 / 0.6(oilcut)] * 1.15
= **30 m3/day**

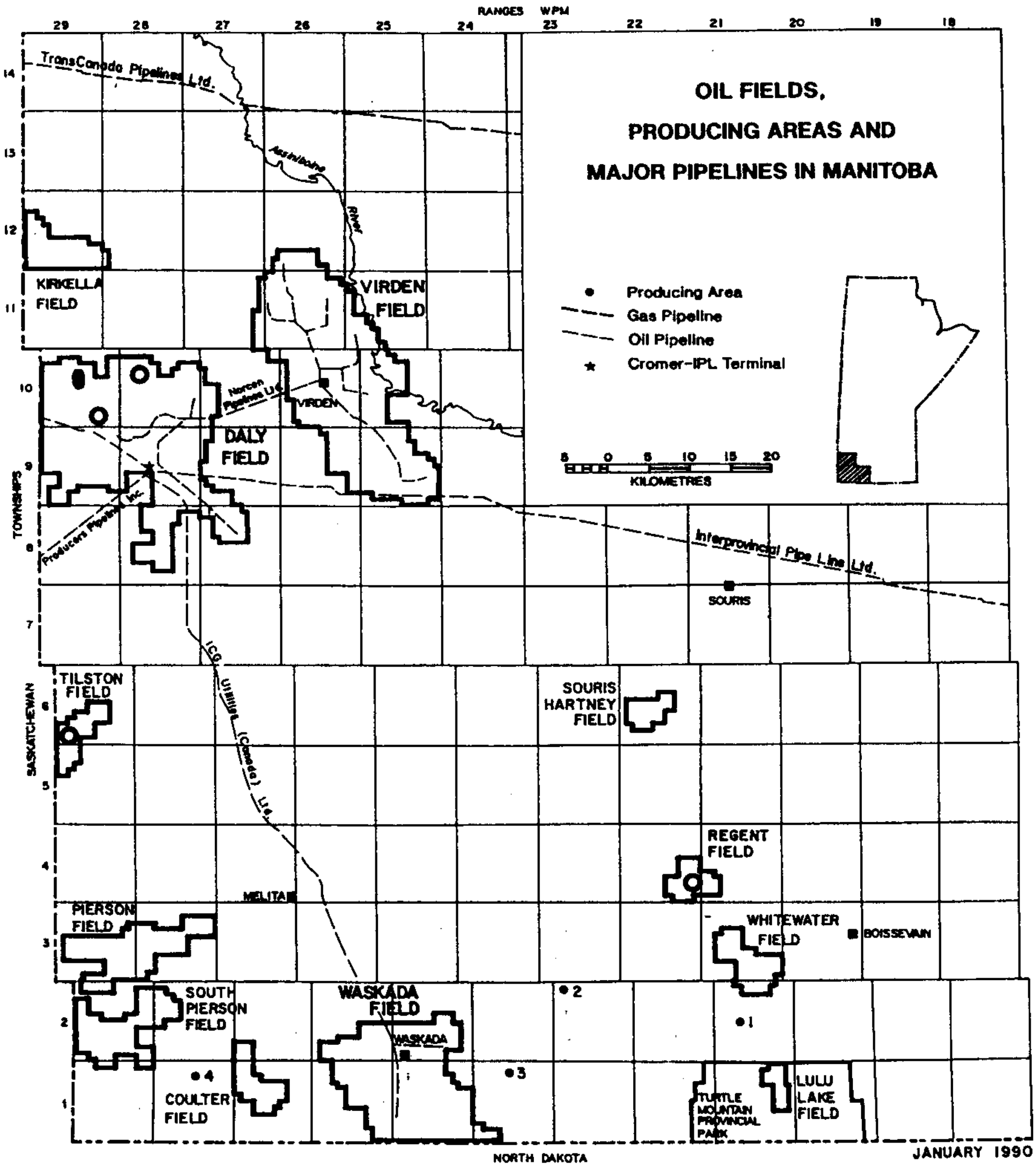
* The actual peak injection rate will be dependent on waterflood performance and the injectivity capability of well 13-21-10-29 W1M.

F.8 Facilities

Attachment No.4 outlines the location of the central battery facilities, and the wells that will be initially tied into the central battery at 4-28-10-29 W1M. Water treatment facilities will also be located at the central battery with the injection pump at injector 13-21-10-29 W1M. Wells that are not scheduled to be tied in at this time will continue to produce to their existing lease tanks.

G. ATTACHMENTS

ATTACHMENT NO. 1



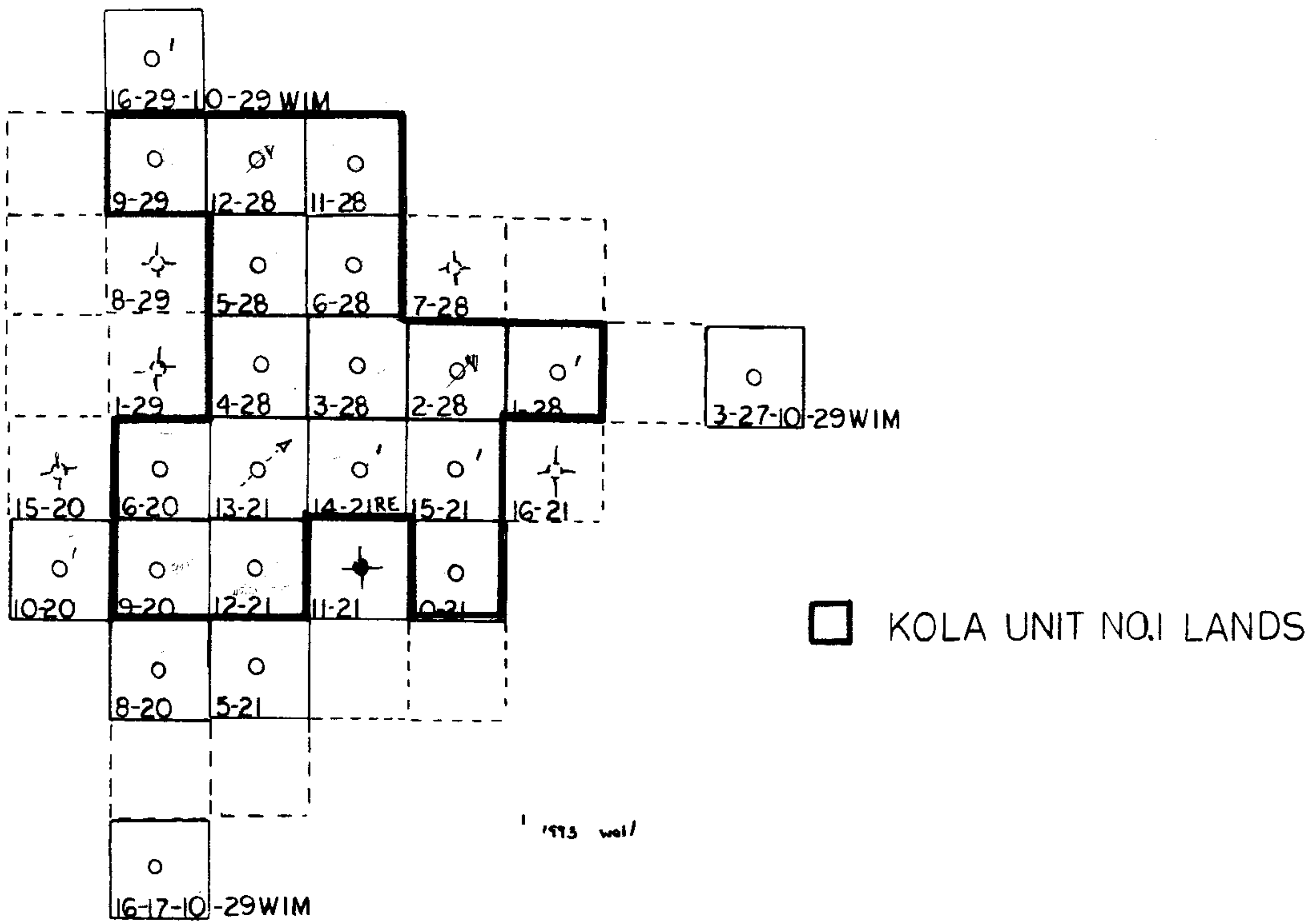
OTHER PRODUCING AREAS

1. Mountainside
2. Deloraine
3. Goodlands
4. Lyleton

■ KOLA BAKKEN 'A' POOL

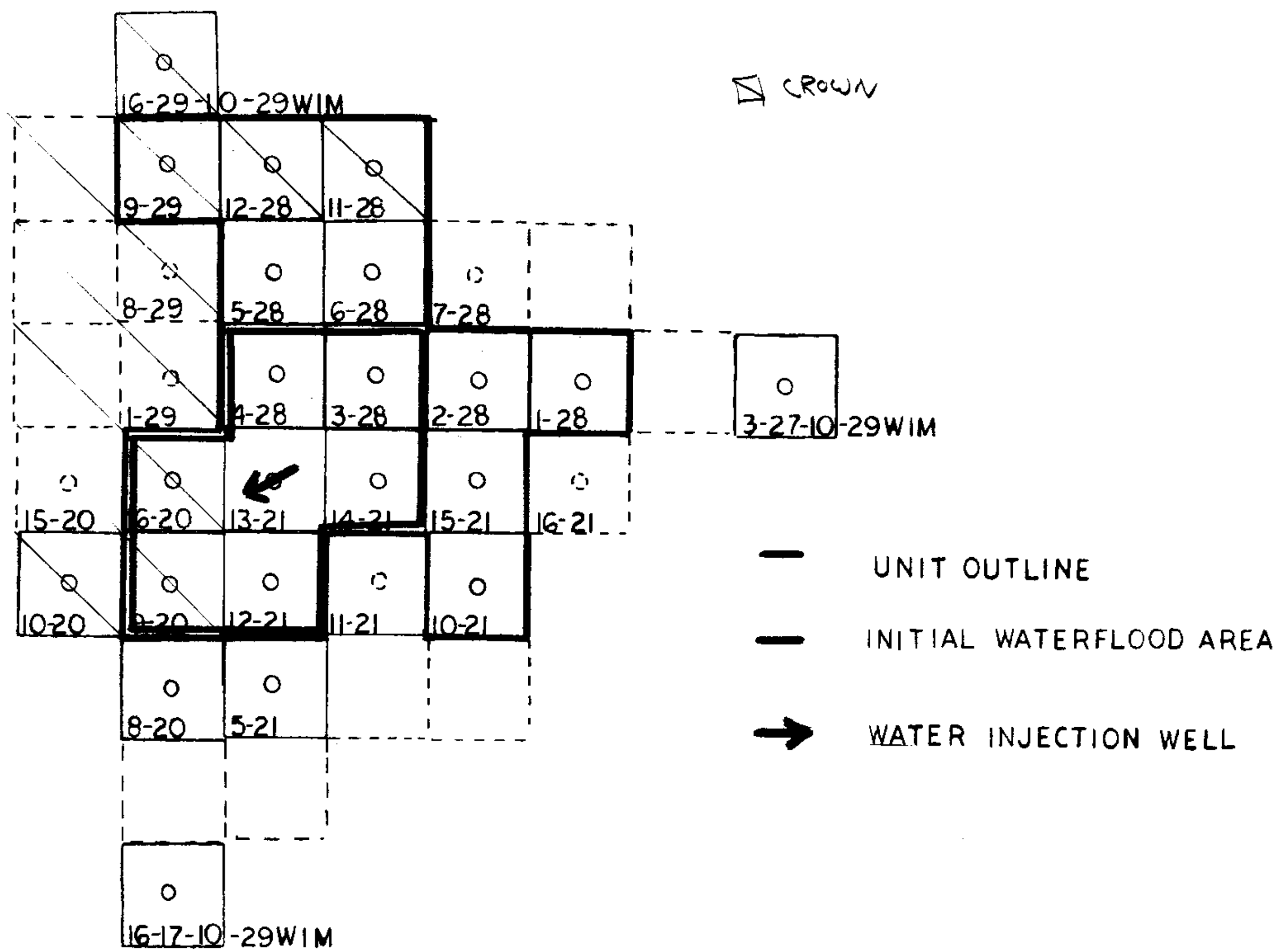
ATTACHMENT NO. 2

BAKKEN 'A' POOL



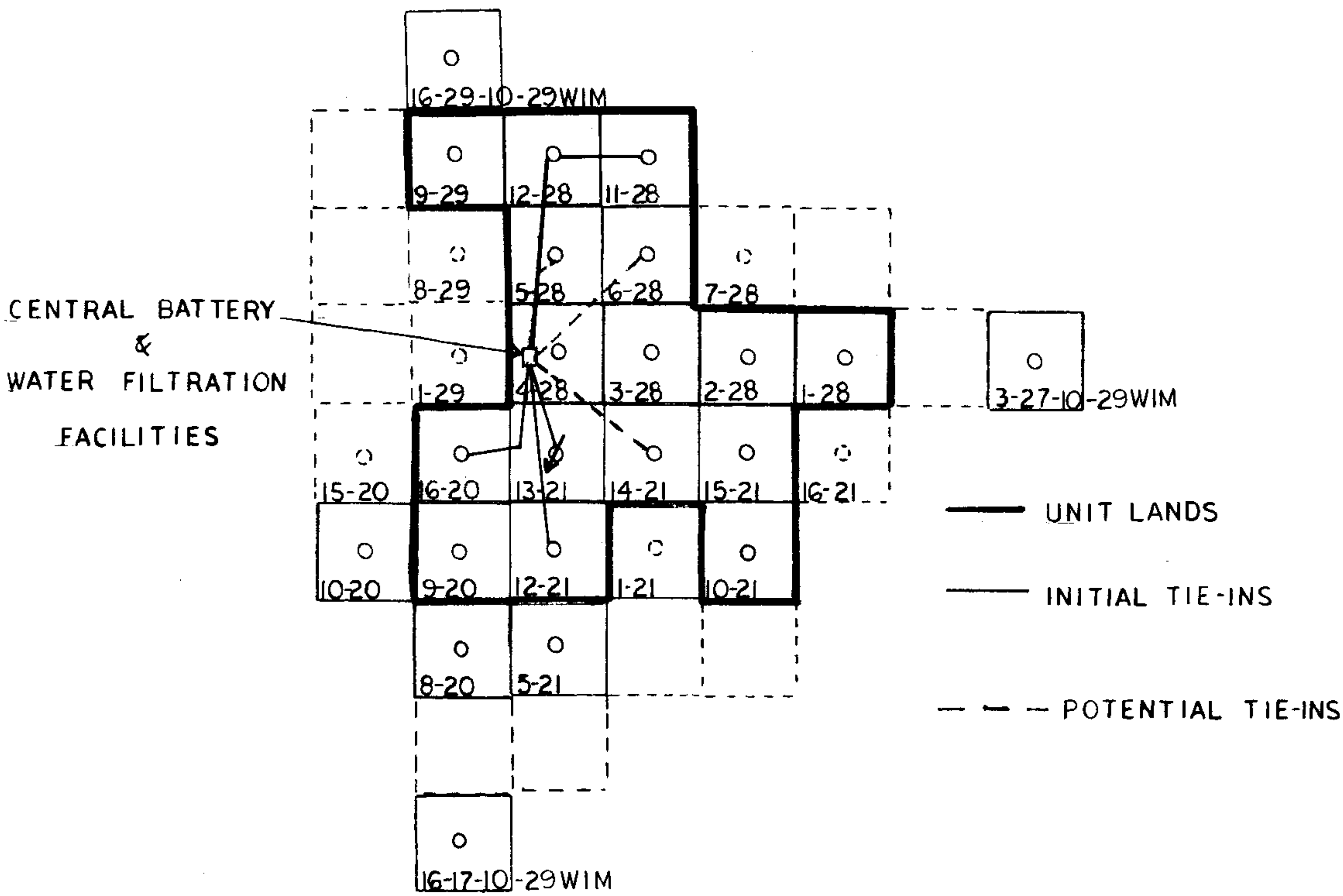
ATTACHMENT NO. 3

BAKKEN 'A' POOL



ATTACHMENT NO.4

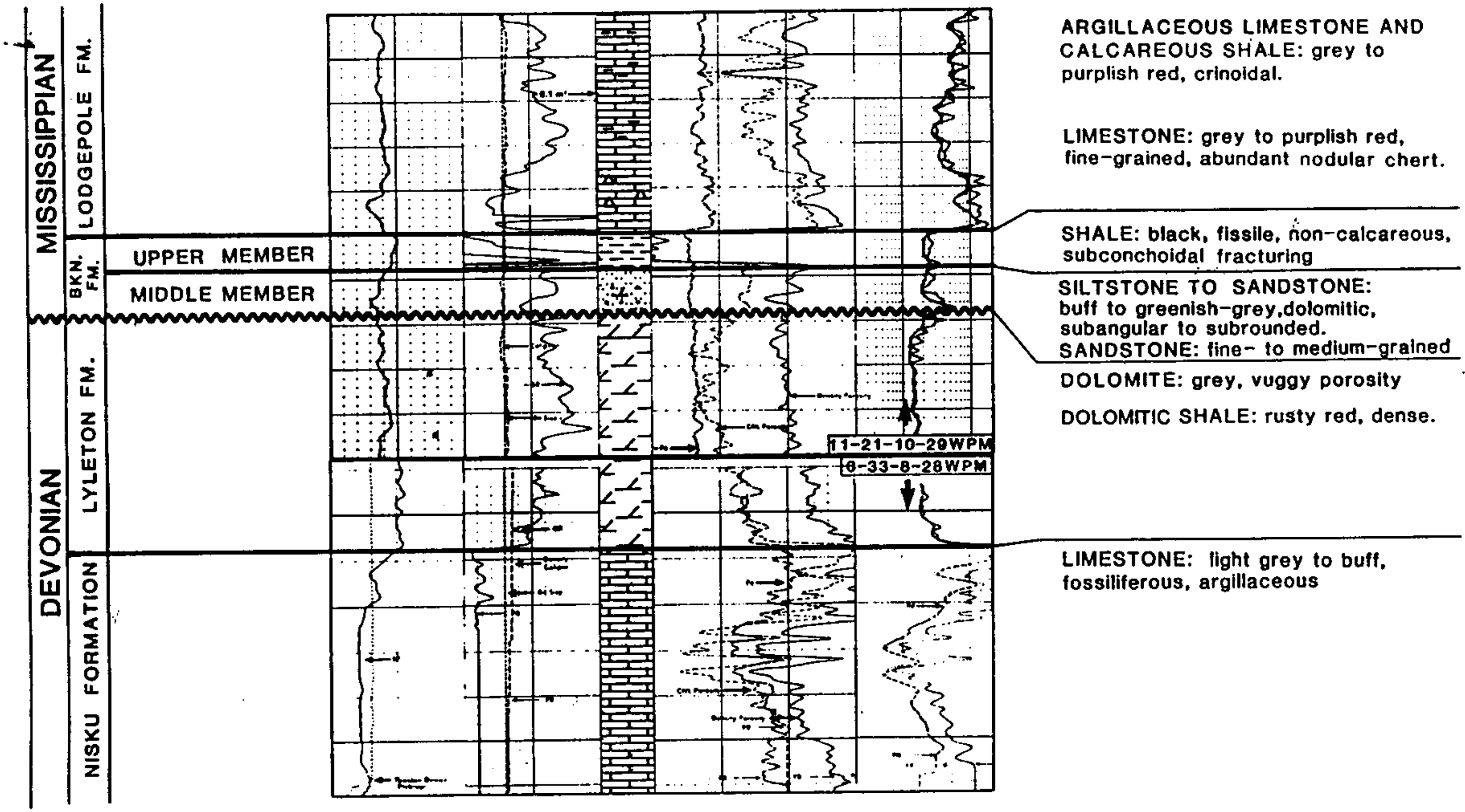
BAKKEN 'A' POOL



ATTACHMENT NO.5

BAKKEN FORMATION STRATIGRAPHIC COLUMN

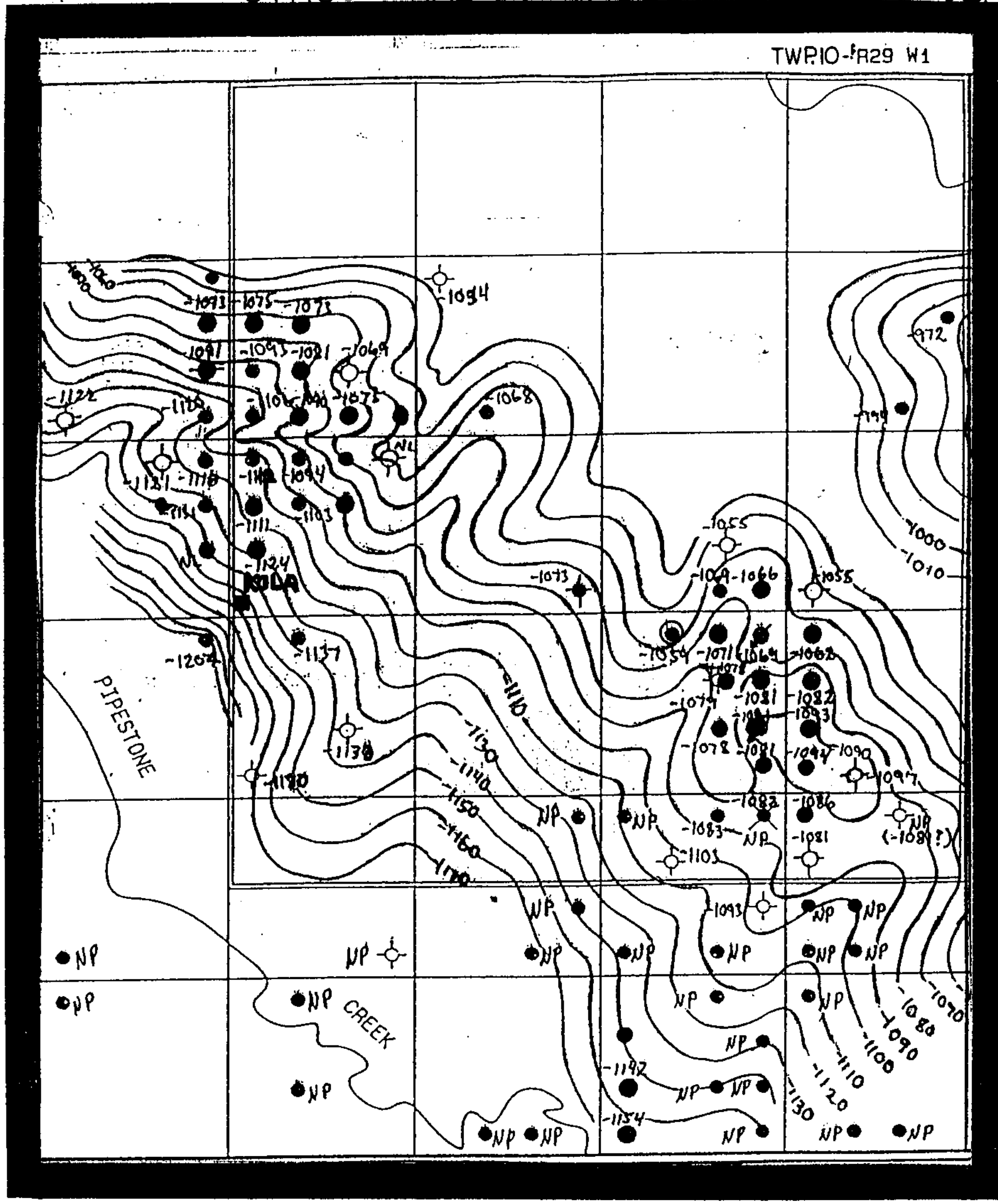
COMPOSITE LOGS: NEWSCOPE OPINAC DALY 11-21-10-29 WPM
ANDEX et al DALY 6-33-8-28 WPM



Composite reference section for areas where the lower member of the Bakken is absent, showing generalized stratigraphic column.

ATTACHMENT NO.6

STRUCTURAL TOP MIDDLE BAKKEN MEMBER



Tundra oil and gas ltd.

SCM TOP Mid Bakken

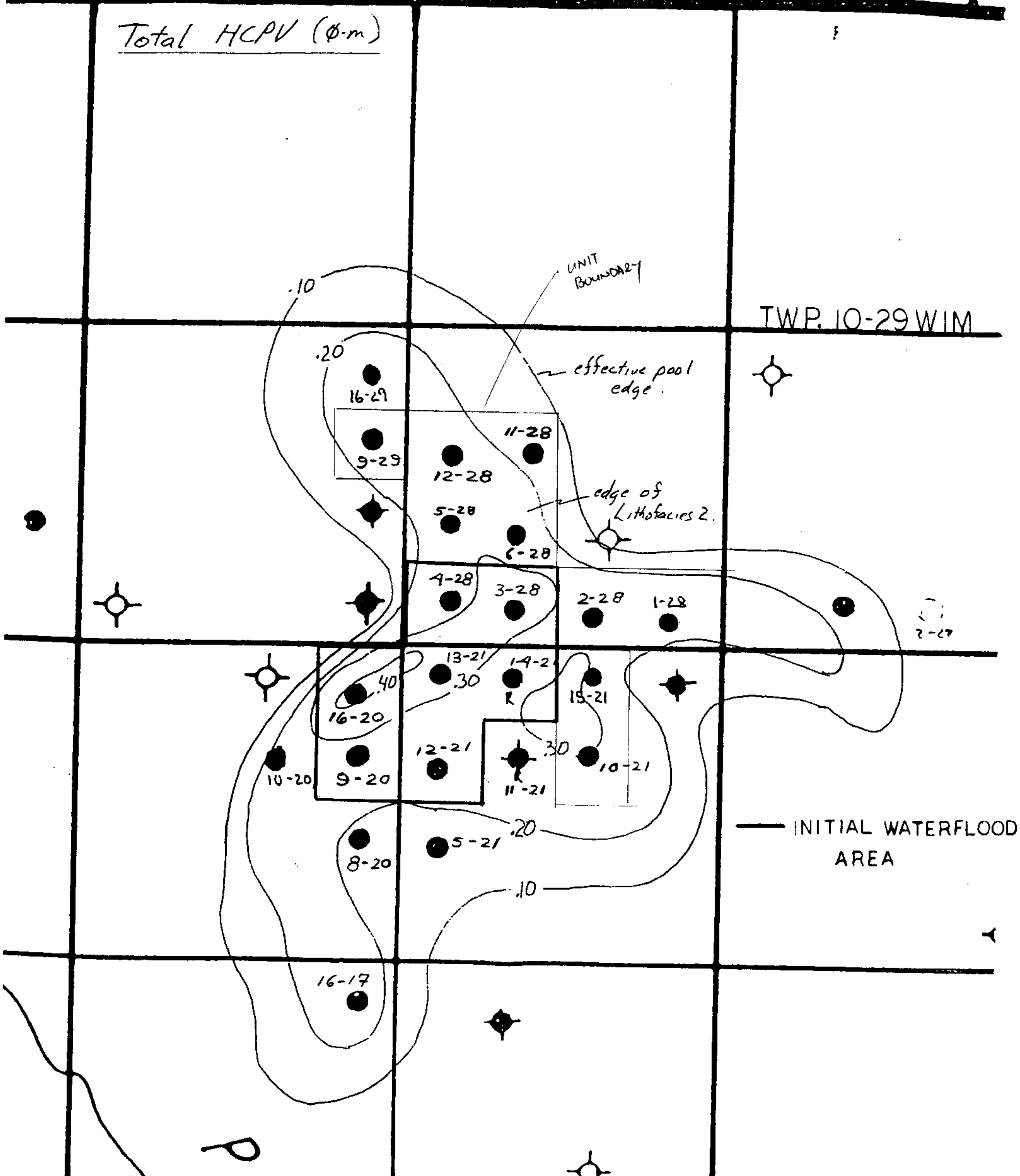
Contour Interval: 10' | Date: 92 | By: MT

Daly Bakken A Pool

ATTACHMENT NO.7

TOTAL HYDRO-CARBON PORE VOLUME

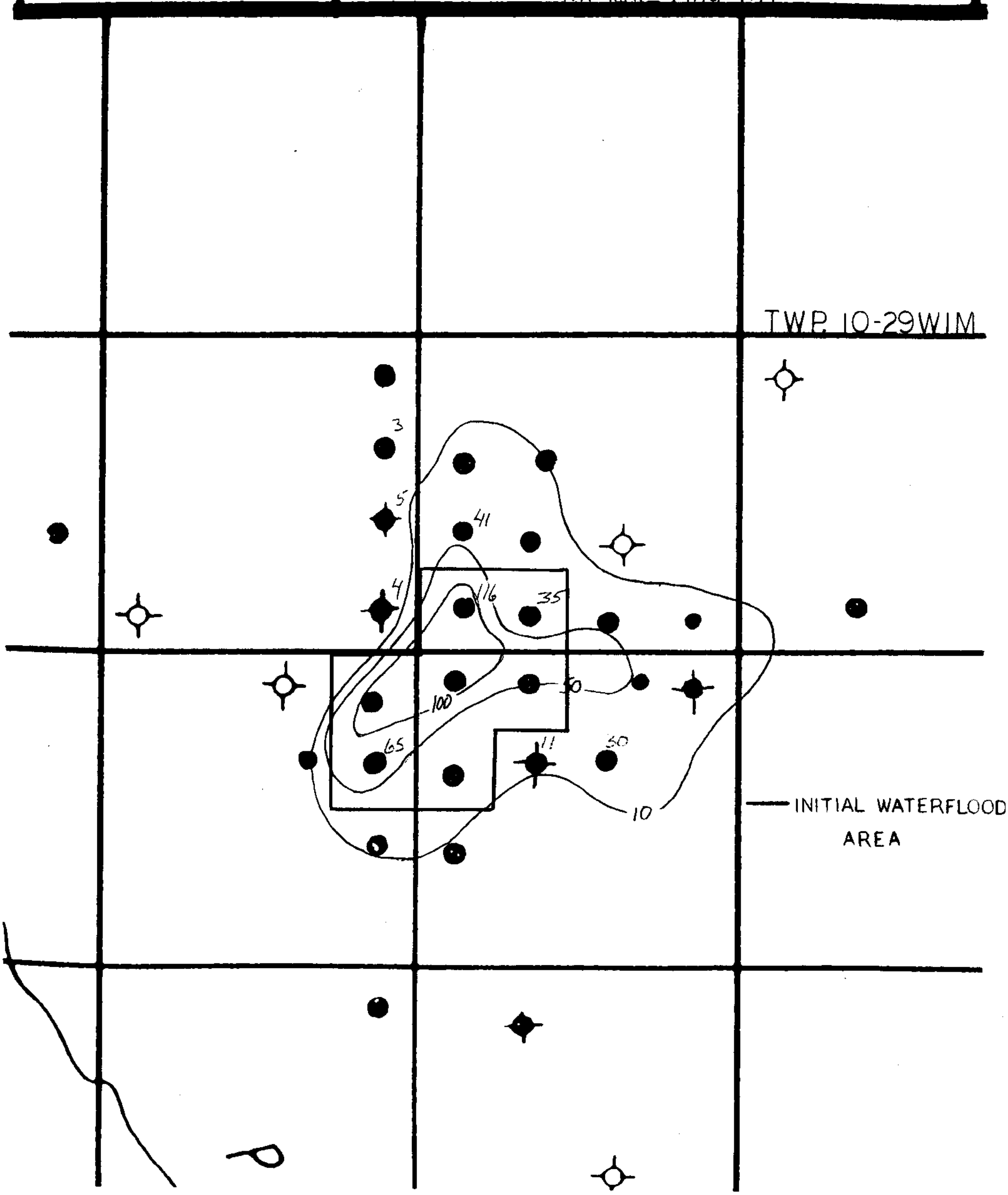
MIDDLE BAKKEN MEMBER



ATTACHMENT NO.8

MIDDLE BAKKEN LOWER ZONE

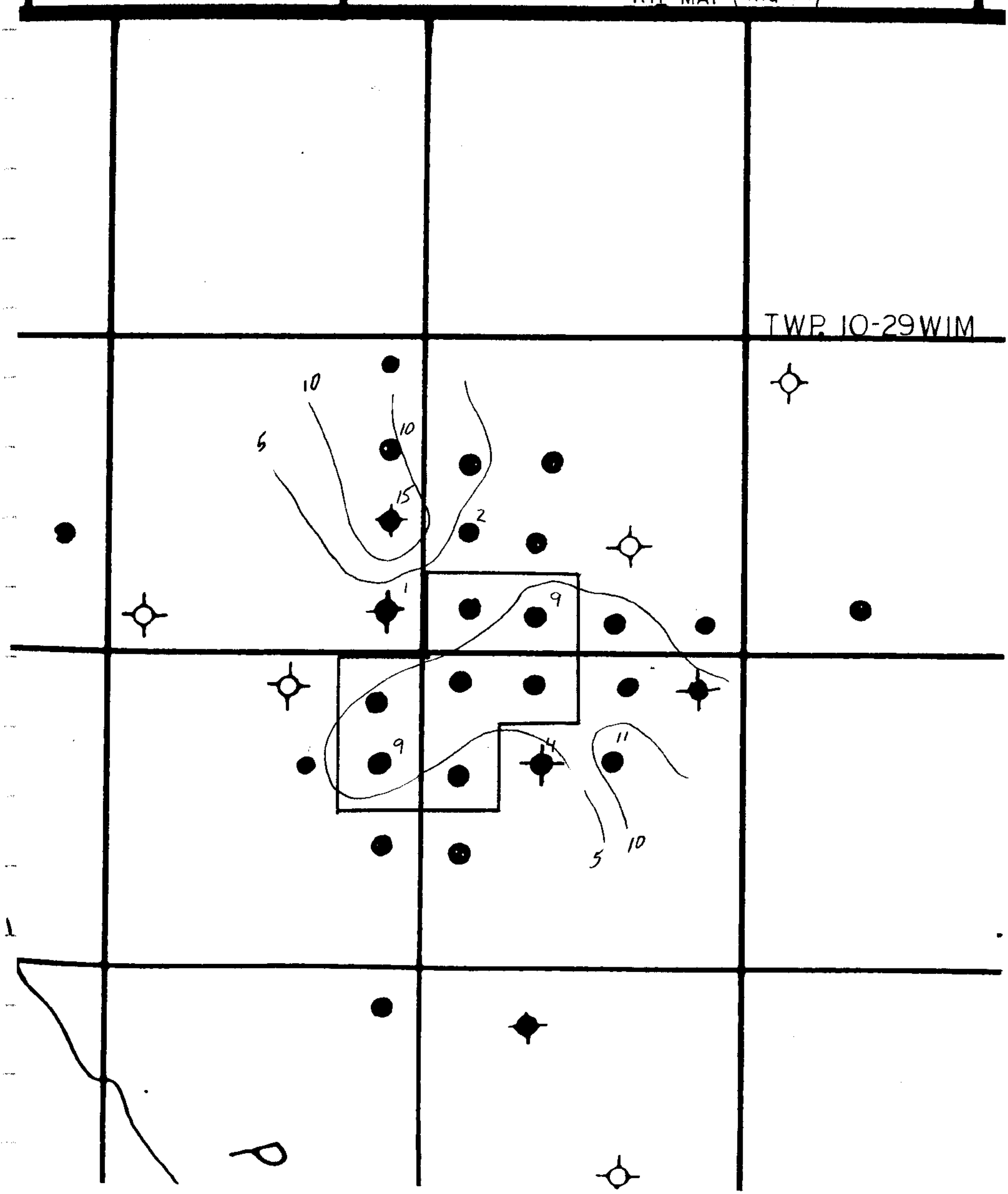
KH MAP (md-m)



ATTACHMENT NO.9

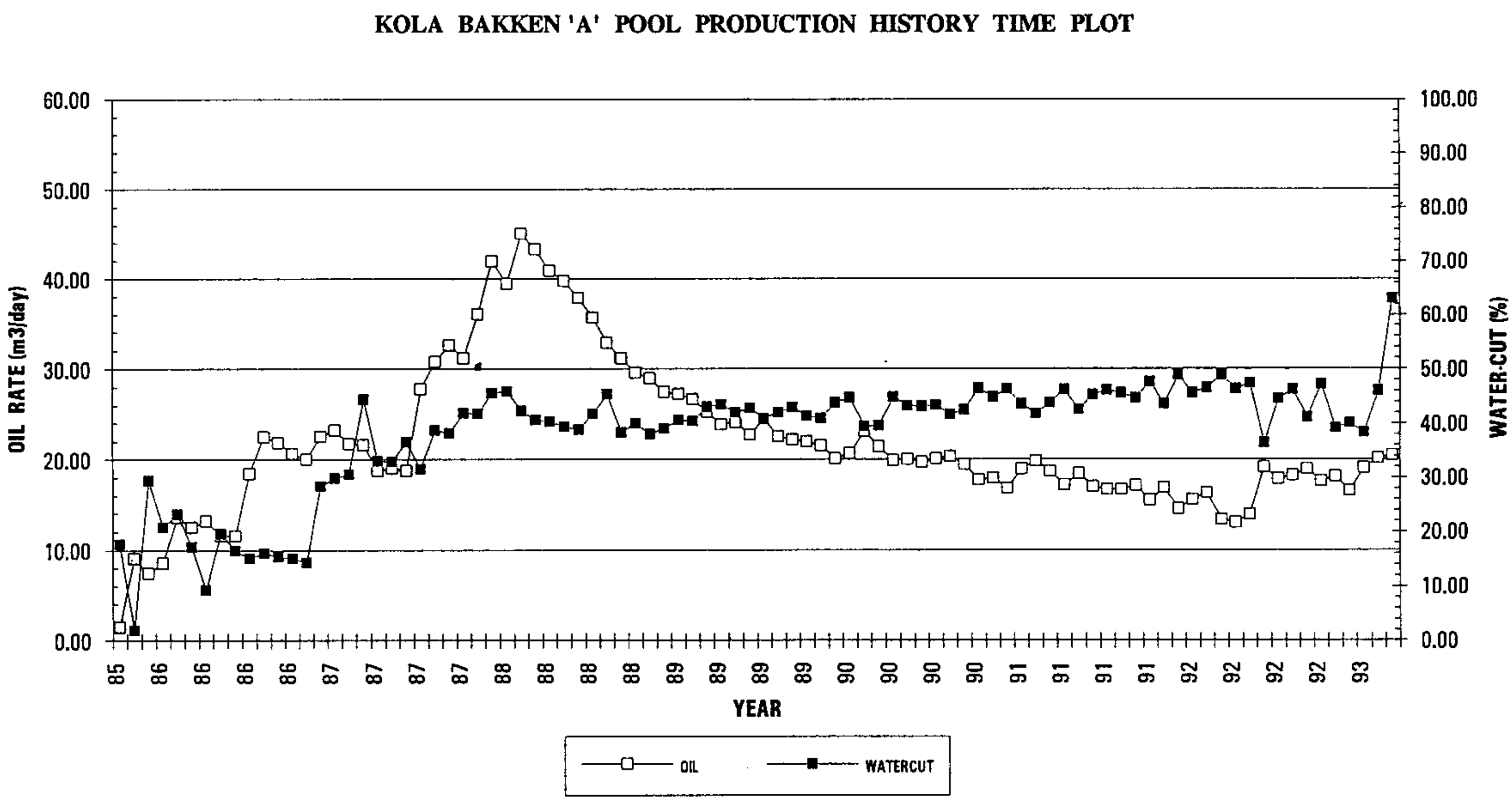
MIDDLE BAKKEN UPPER ZONE

KH MAP (md-m)



H. FIGURES

FIGURE NO.I



KOLA BAKKEN 'A' POOL PRODUCTION HISTORY TIME PLOT
OIL RATE (m3/day)
60.00
50.00
40.00
30.00
20.00
10.00
0.00
WATER-CUT (%)
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
85 86 86 86 86 87 87 87 87 88 88 88 88 89 89 89 89 90 90 90 90 91 91 91 91 92 92 92 92 93
YEAR
OIL
WATERCUT

FIGURE NO.2

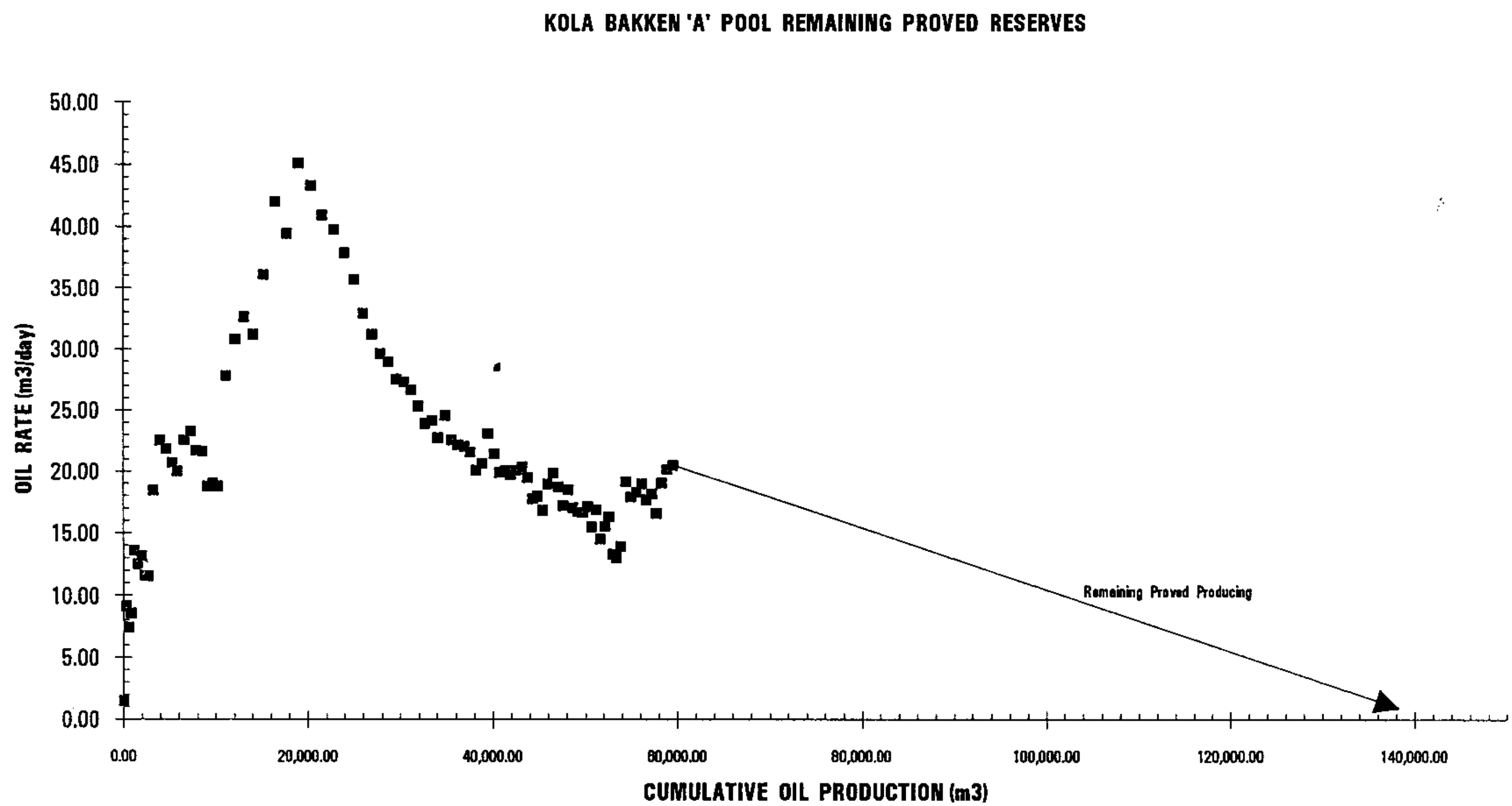

KOLA BAKKEN 'A' POOL REMAINING PROVED RESERVES
OIL RATE (m3/day)
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
0.00
20,000.00
40,000.00
60,000.00
80,000.00
100,000.00
120,000.00
140,000.00
CUMULATIVE OIL PRODUCTION (m3)
Remaining Proved Producing

FIGURE NO.3

BAKKEN 'A' POOL PRESSURE HISTORY

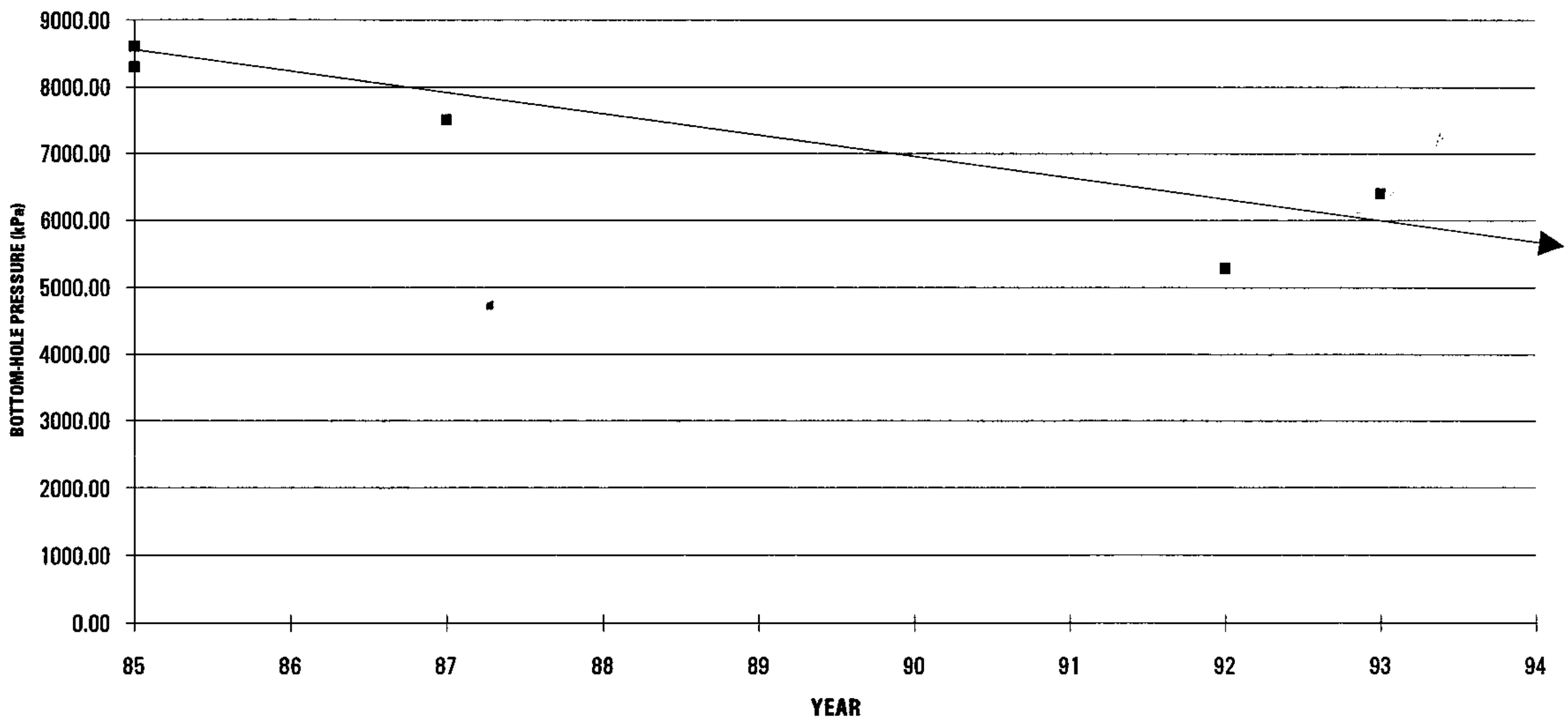


FIGURE NO.4

TUNDRA - BAKKEN "A" POOL
RELATIVE PERMEABILITY STUDY
CORE STACK #1 - WATER-OIL RELATIVE PERMEABILITY
RELATIVE PERMEABILITY vs WATER SATURATION

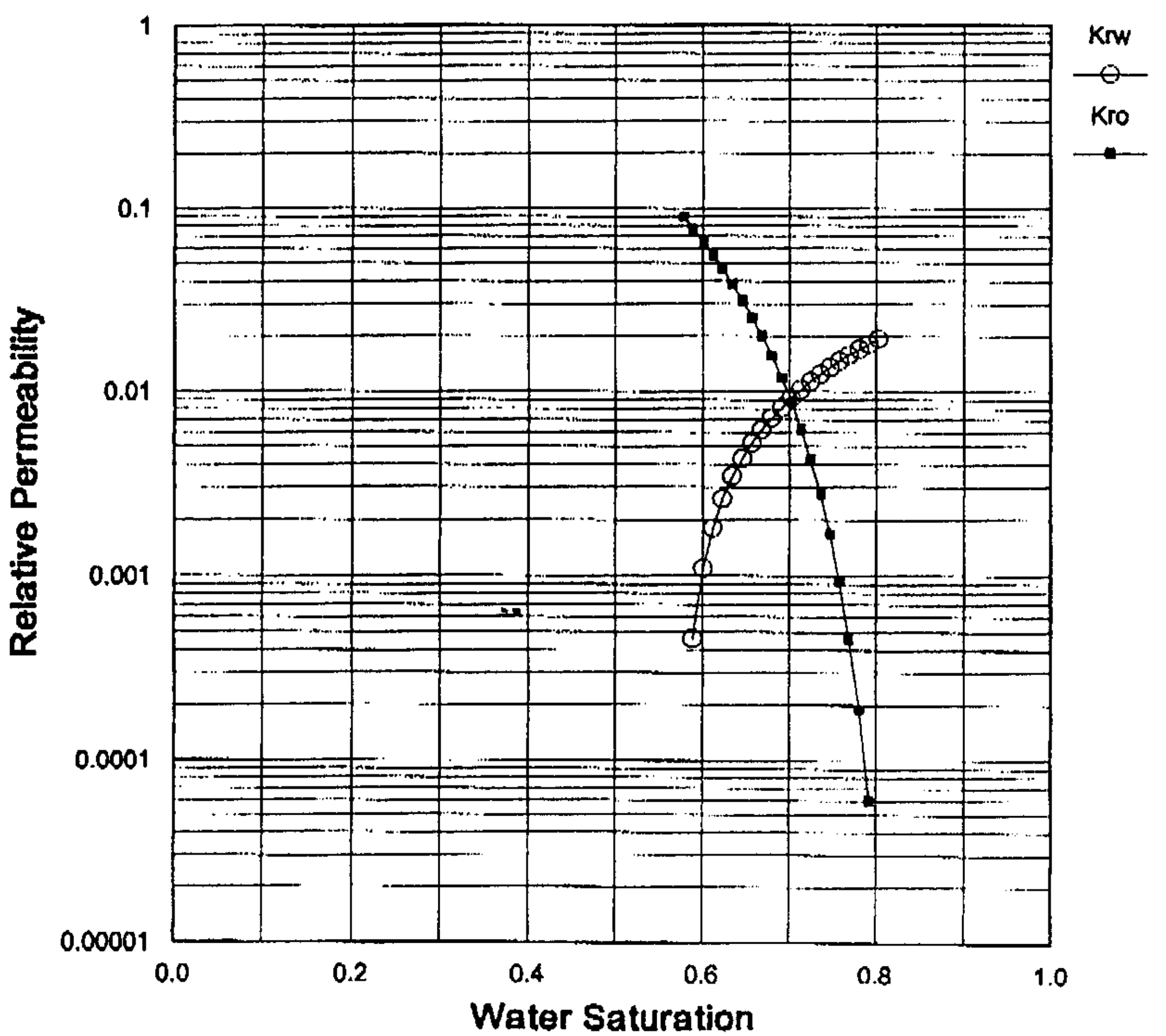


FIGURE NO.5

TUNDRA - BAKKEN "A" POOL
RELATIVE PERMEABILITY STUDY
CORE STACK #1 - WATER-OIL RELATIVE PERMEABILITY
CUML PRODUCTION vs CUML INJECTION

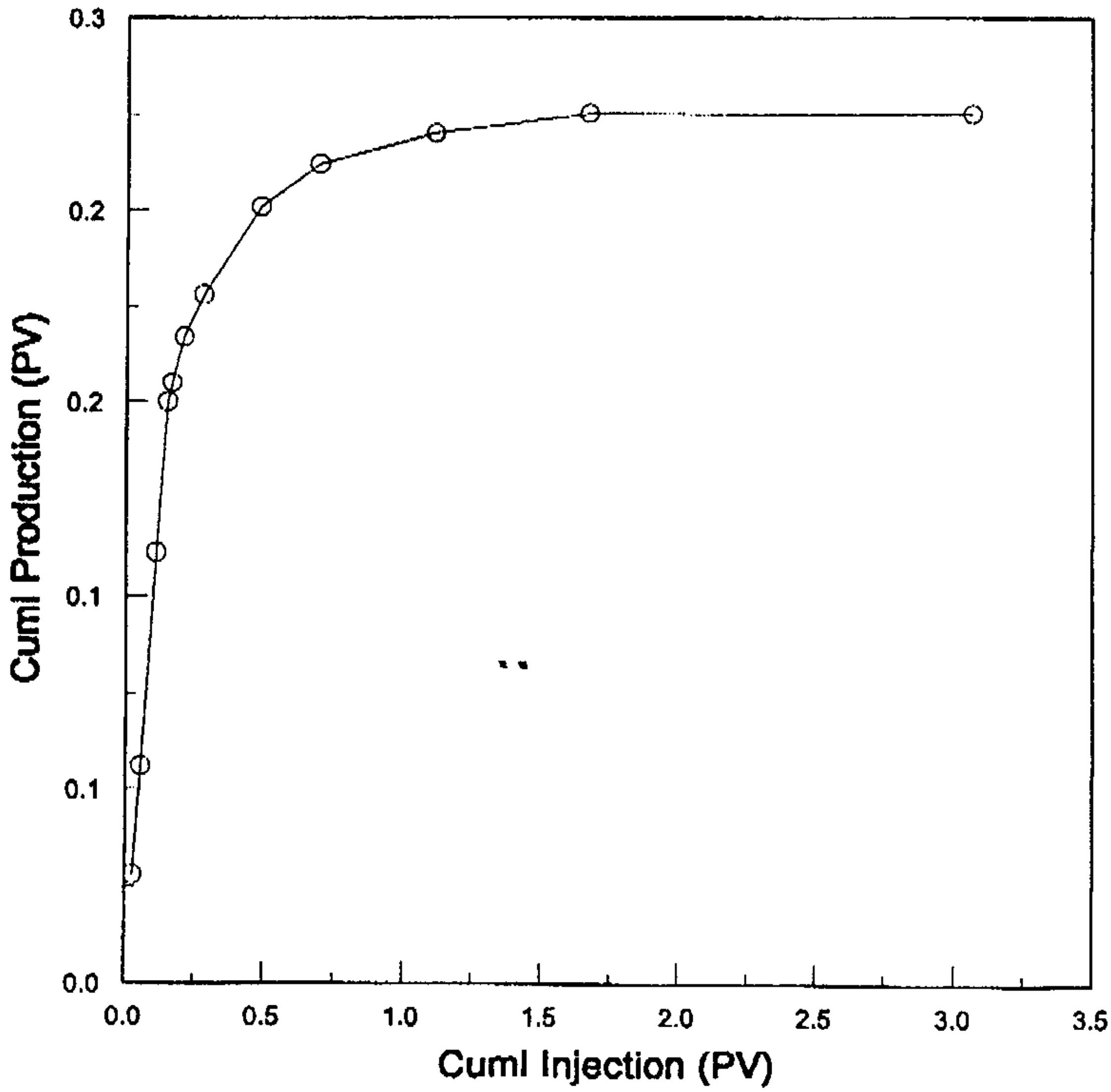
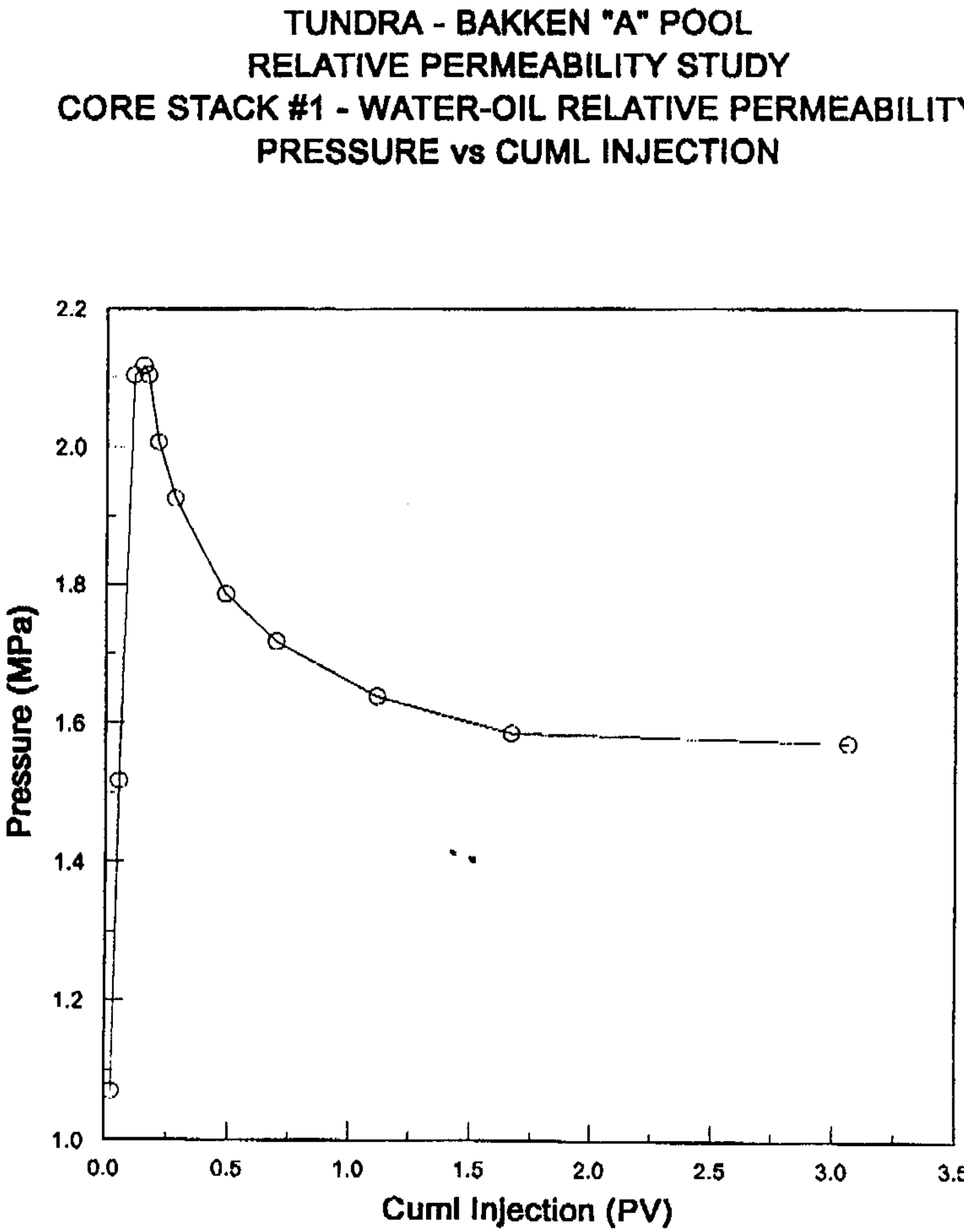


FIGURE NO.6



Hycal

I. TABLES

TABLE NO.1

BAKKEN 'A' POOL FLUID PARAMETERS

Bakken 'A' Pool	
Reservoir temperature	31 deg. C
Bubble point pressure	2101 kPa
Oil API	41 deg. API
Boi	1.063 Rm3/m3
Solution GOR	27 m3/m3
Oil Compressibility @ Pi	1.15 E-6 (1/kPa)
Water Compressibility	4.5 E-7 (1/kPa)
Rock Compressibility	5.8 E-7 (1/kPa)
Water Salinity	90,000 ppm

TABLE NO.2

BAKK | POO

				RESERVOIR PARAMETERS						
				ORIGINAL OIL-IN-PLACE ESTIMATES						
					LOWER ZONE					
WELL	CONSTANT	AREA (ha)	FVF (R m3/m3)	POROSITY (fraction)	NET PAY (m)	PHI-H (m)	Sw* (fraction)	1-Sw (fraction)	HCPV (phi-metres)	OOIP (m3)
16-17-10-29	10,000.00	16.17	1.06	0.15	1.4 1	0.21	0.49	0.51	0.11	16,291.69
8-20-10-29	10,000.00	16.17	1.06	0.15	1.6 2	0.24	0.48	0.52	0.12	18,984.16
9-20-10-29	10,000.00	16.17	1.06	0.15	2.5 3	0.375	0.5	0.5	0.19	28,521.87
10-20-10-29	10,000.00	16.17	1.06	0.14	1.8 4	0.252	0.6	0.4	0.10	15,333.36
15-20-10-29	10,000.00	16.17	1.06	-	-	-	-	-	-	0.00
16-20-10-29	10,000.00	16.17	1.06	0.2	2.8 5	0.56	0.37	0.63	0.35	53,666.75
5-21-10-29	10,000.00	16.17	1.06	0.15	1.4 6	0.21	0.57	0.43	0.09	13,736.13
10-21-10-29	10,000.00	16.17	1.06	0.16	2.2 7	0.352	0.38	0.62	0.22	33,197.94
11-21-10-29	10,000.00	16.17	1.06	0.18	2 8	0.36	0.45	0.55	0.20	30,119.10
12-21-10-29	10,000.00	16.17	1.06	0.17	1.8 9	0.306	0.58	0.42	0.13	19,550.03
13-21-10-29	10,000.00	16.17	1.06	0.19	2.4 10	0.456	0.31	0.69	0.31	47,861.98
14-21-10-29	10,000.00	16.17	1.06	0.16	1.5 11	0.24	0.35	0.65	0.16	23,730.20
15-21-10-29	10,000.00	16.17	1.06	0.17	1.4 12	0.238	0.35	0.65	0.15	23,532.45
16-21-10-29	10,000.00	16.17	1.06	0.15	1.1 13	0.165	0.57	0.43	0.07	10,792.68
1-28-10-29	10,000.00	16.17	1.06	0.17	1.4 14	0.238	0.35	0.65	0.15	23,532.45
2-28-10-29	10,000.00	16.17	1.06	0.19	1.6 15	0.304	0.3	0.7	0.21	32,370.42
3-28-10-29	10,000.00	16.17	1.06	0.18	2.4 16	0.432	0.29	0.71	0.31	46,657.22
4-28-10-29	10,000.00	16.17	1.06	0.18	2 17	0.36	0.32	0.68	0.24	37,238.16
5-28-10-29	10,000.00	16.17	1.06	0.18	1.8 18	0.324	0.46	0.54	0.17	26,614.33
6-28-10-29	10,000.00	16.17	1.06	0.16	1.5 19	0.24	0.31	0.69	0.17	25,190.52
7-28-10-29	10,000.00	16.17	1.06	-	-	-	-	-	-	0.00
11-28-10-29	10,000.00	16.17	1.06	0.15	1.6 20	0.24	0.44	0.56	0.13	20,444.48
12-28-10-29	10,000.00	16.17	1.06	0.14	2 21	0.28	0.51	0.49	0.14	20,870.40
1-29-10-29	10,000.00	16.17	1.06	0.13	0.8 22	0.104	0.63	0.37	0.04	5,853.45
8-29-10-29	10,000.00	16.17	1.06	0.15	1.6 23	0.24	0.47	0.53	0.13	19,349.24
9-29-10-29	10,000.00	16.17	1.06	0.15	2 24	0.3	0.46	0.54	0.16	24,642.90
16-29-10-29	10,000.00	16.17	1.06	0.18	1.7 25	0.306	0.35	0.65	0.20	30,256.00
TOTALS		436.59								648,337.90
				0.163	1.272					
TOTAL OOIP=	914,481.19	m3(5.45 MM STB)								

* Proposed unit tract

* Sw Waxman-Smit, Arbez

TABLE NO.3

BAKKE POOL

RESERVOIR PARAMETERS

ORIGINAL OIL-IN-PLACE ESTIMATES

Upper Zone

UNIT TRACT FACTOR 100% OOIP	WELL	CONSTANT	AREA (ha)	FVF (R m3/m3)	POROSITY (fraction)	NET PAY (m)	PHI-H (m)	Sw (fraction)	1-Sw (fraction)	HCPV (phi-metres)	OOIP (m3)	OOIP UPPER + LOWER
	16-17-10-29	10,000.00	16.17	1.06	0.15	2	0.3	0.6	0.4	0.12	18,254.00	
	8-20-10-29	10,000.00	16.17	1.06	0.14	0.9	0.126	0.6	0.4	0.05	7,666.68	
.0809	9-20-10-29	10,000.00	16.17	1.06	0.14	1.8	0.252	0.6	0.4	0.10	15,333.36	39405
	10-20-10-29	10,000.00	16.17	1.06	0.15	1.9	0.285	0.6	0.4	0.11	17,341.30	
	15-20-10-29	10,000.00	16.17	1.06	0.14	1.1	0.154	0.6	0.4	0.06	9,370.39	
.0917	16-20-10-29	10,000.00	16.17	1.06	0.13	1.1	0.143	0.6	0.4	0.06	8,701.07	44649
	5-21-10-29	10,000.00	16.17	1.06	0.14	1.5	0.21	0.6	0.4	0.08	12,777.80	
.0724	10-21-10-29	10,000.00	16.17	1.06	0.13	1.6	0.208	0.6	0.4	0.08	12,656.11	35252
	11-21-10-29	10,000.00	16.17	1.06	0.14	1.2	0.168	0.6	0.4	0.07	10,222.24	
.0684	12-21-10-29	10,000.00	16.17	1.06	0.15	1.5	0.225	0.6	0.4	0.09	13,690.50	33333
.0763	13-21-10-29	10,000.00	16.17	1.06	0.13	1	0.13	0.6	0.4	0.05	7,910.07	37182
.0491	14-21-10-29	10,000.00	16.17	1.06	0.14	1	0.14	0.6	0.4	0.06	8,518.53	23924
.0501	15-21-10-29	10,000.00	16.17	1.06	0.15	1	0.15	0.6	0.4	0.06	9,127.00	24404
	16-21-10-29	10,000.00	16.17	1.06	0.13	0.9	0.117	0.6	0.4	0.05	7,119.06	
.0539	1-28-10-29	10,000.00	16.17	1.06	0.15	1.2	0.18	0.6	0.4	0.07	10,952.40	26229
.0576	2-28-10-29	10,000.00	16.17	1.06	0.14	1	0.14	0.6	0.4	0.06	8,518.53	28032
.0699	3-28-10-29	10,000.00	16.17	1.06	0.13	0.8	0.104	0.6	0.4	0.04	6,328.05	34059
.0549	4-28-10-29	10,000.00	16.17	1.06	0.12	0.5	0.06	0.6	0.4	0.02	3,650.80	26759
.0633	5-28-10-29	10,000.00	16.17	1.06	0.15	1.1	0.165	0.6	0.4	0.07	10,039.70	30837
.0491	6-28-10-29	10,000.00	16.17	1.06	0.14	1	0.14	0.6	0.4	0.06	8,518.53	23924
	7-28-10-29	10,000.00	16.17	1.06	0.14	1.4	0.196	0.6	0.4	0.08	11,925.95	
.0456	11-28-10-29	10,000.00	16.17	1.06	0.14	0.8	0.112	0.6	0.4	0.04	6,814.83	22220
.0596	12-28-10-29	10,000.00	16.17	1.06	0.14	1.3	0.182	0.6	0.4	0.07	11,074.09	29048
	1-29-10-29	10,000.00	16.17	1.06	0.13	0.3	0.039	0.6	0.4	0.02	2,373.02	
	8-29-10-29	10,000.00	16.17	1.06	0.14	1	0.14	0.6	0.4	0.06	8,518.53	
.0570	9-29-10-29	10,000.00	16.17	1.06	0.14	1	0.14	0.6	0.4	0.06	8,518.53	27775
	16-29-10-29	10,000.00	16.17	1.06	0.14	1.2	0.168	0.6	0.4	0.07	10,222.24	
	TOTALS		436.59								266,143.29	487032 UNIT OOIP

OOIP PB UPPER + LOWER ZONE

TABLE NO.4

				BAKKEN 'A' POOL						
				RESERVOIR PARAMETERS						
				ORIGINAL OIL-IN-PLACE ESTIMATES						
					LOWER ZONE					
WELL	CONSTANT	AREA	FVF	POROSITY	NET PAY	PHI-H	Sw	1-Sw	HCPV	OOIP
		(ha)	(R m3/m3)	(fraction)	(m)	(m)	(fraction)	(fraction)	(phi-metres)	(m3)
16-17-10-29	10,000.00	16.17	1.06	0.15	1.4	0.21	0.578	0.422	0.09	13,480.58
8-20-10-29	10,000.00	16.17	1.06	0.15	1.6	0.24	0.578	0.422	0.10	15,406.37
9-20-10-29	10,000.00	16.17	1.06	0.15	2.5	0.375	0.578	0.422	0.16	24,072.46
10-20-10-29	10,000.00	16.17	1.06	0.14	1.8	0.252	0.6	0.4	0.10	15,333.36
15-20-10-29	10,000.00	16.17	1.06	-	-	-	-	-	-	0.00
16-20-10-29	10,000.00	16.17	1.06	0.2	2.8	0.56	0.578	0.422	0.24	35,948.21
5-21-10-29	10,000.00	16.17	1.06	0.15	1.4	0.21	0.578	0.422	0.09	13,480.58
10-21-10-29	10,000.00	16.17	1.06	0.16	2.2	0.352	0.578	0.422	0.15	22,596.02
11-21-10-29	10,000.00	16.17	1.06	0.18	2	0.36	0.578	0.422	0.15	23,108.56
12-21-10-29	10,000.00	16.17	1.06	0.17	1.8	0.306	0.578	0.422	0.13	19,643.13
13-21-10-29	10,000.00	16.17	1.06	0.19	2.4	0.456	0.578	0.422	0.19	29,272.11
14-21-10-29	10,000.00	16.17	1.06	0.16	1.5	0.24	0.578	0.422	0.10	15,406.37
15-21-10-29	10,000.00	16.17	1.06	0.17	1.4	0.238	0.578	0.422	0.10	15,277.99
16-21-10-29	10,000.00	16.17	1.06	0.15	1.1	0.165	0.578	0.422	0.07	10,591.88
1-28-10-29	10,000.00	16.17	1.06	0.17	1.4	0.238	0.578	0.422	0.10	15,277.99
2-28-10-29	10,000.00	16.17	1.06	0.19	1.6	0.304	0.578	0.422	0.13	19,514.74
3-28-10-29	10,000.00	16.17	1.06	0.18	2.4	0.432	0.578	0.422	0.18	27,731.47
4-28-10-29	10,000.00	16.17	1.06	0.18	2	0.36	0.578	0.422	0.15	23,108.56
5-28-10-29	10,000.00	16.17	1.06	0.18	1.8	0.324	0.578	0.422	0.14	20,798.61
6-28-10-29	10,000.00	16.17	1.06	0.16	1.5	0.24	0.578	0.422	0.10	15,406.37
7-28-10-29	10,000.00	16.17	1.06	-	-	-	-	-	-	0.00
11-28-10-29	10,000.00	16.17	1.06	0.15	1.6	0.24	0.578	0.422	0.10	15,406.37
12-28-10-29	10,000.00	16.17	1.06	0.14	2	0.28	0.578	0.422	0.12	17,974.10
1-29-10-29	10,000.00	16.17	1.06	0.13	0.8	0.104	0.63	0.37	0.04	5,653.45
8-29-10-29	10,000.00	16.17	1.06	0.15	1.6	0.24	0.578	0.422	0.10	15,406.37
9-29-10-29	10,000.00	16.17	1.06	0.15	2	0.3	0.578	0.422	0.13	19,257.97
16-29-10-29	10,000.00	16.17	1.06	0.18	1.7	0.306	0.578	0.422	0.13	19,643.13
TOTALS		436.59								469,998.76

28% reduction in OOIP due to increased Sw estimate

TABLE NO.5

TOTAL BAKKEN 'A' POOL PRIMARY PRODUCTION FORECAST

Year	WELLS	GROSS DAILY OIL	GROSS YEARLY (STB)	CUM. OIL (STB)
1993	16	144 STB/DAY	52,665 STB	52,665 STB
1994	17	149 STB/DAY	54,437 STB	107,102 STB
1995	17	137 STB/DAY	49,897 STB	156,999 STB
1996	17	126 STB/DAY	46,027 STB	203,026 STB
1997	16	117 STB/DAY	42,728 STB	245,754 STB
1998	15	105 STB/DAY	38,148 STB	283,902 STB
1999	15	89 STB/DAY	32,386 STB	316,288 STB
2000	14	75 STB/DAY	27,408 STB	343,696 STB
2001	14	64 STB/DAY	23,506 STB	367,202 STB
2002	14	55 STB/DAY	20,181 STB	387,383 STB
2003	13	47 STB/DAY	17,170 STB	404,553 STB
2004	13	40 STB/DAY	14,604 STB	419,157 STB
2005	11	34 STB/DAY	12,261 STB	431,418 STB
2006	10	28 STB/DAY	10,163 STB	441,581 STB
2007	8	23 STB/DAY	8514 STB	450,095 STB
REMAINING	6	13 STB/DAY		41,759 STB
TOTAL				491,854 STB

$78.2 \times 10^3 m^3$

REMAINING PROVED RESERVES

TABLE NO.6

KOLA UNIT NO.1 WELL LIST

	KOLA UNIT NO.1
TOTAL UNIT WELLS	WELLS IN INITIAL WATERFLOOD AREA
C 9-20-10-29 W1M ?	C 9-20-10-29 W1M
C 16-20-10-29 W1M	C 16-20-10-29 W1M
10-21-10-29 W1M	12-21-10-29 W1M
12-21-10-29 W1M	13-21-10-29 W1M injection
13-21-10-29 W1M	14-21-10-29 W1M
14-21-10-29 W1M	3-28-10-29 W1M
15-21-10-29 W1M	4-28-10-29 W1M
1-28-10-29 W1M	
2-28-10-29 W1M	
3-28-10-29 W1M	
4-28-10-29 W1M	
5-28-10-29 W1M	
6-28-10-29 W1M	
C 11-28-10-29 W1M	
C 12-28-10-29 W1M	
C 9-29-10-29 W1M	

C - CROWN

TABLE NO.7

KOLA UNIT NO.1 WORKING INTEREST OWNERS

AND UNIT TRACT FACTORS

KOLA UNIT NO.1

WORKING INTEREST OWNERS

TRACT FACTORS FOR EACH LSD IN THE UNIT

WELL	Tundra W.I. IN LSD (%)	Corvair W.I. IN LSD (%)	Brandon Prof. W.I. IN LSD. (%)	Kiwi W.I. IN LSD. (%)	Topac W.I. IN LSD. (%)	Mustang W.I. IN LSD. (%)	TOTAL W.I. IN LSD (%)	Total Operating Days	Total Production (m3)	Average Oil Rate Per Operating Day (m3/day)	Tract Factor Per LSD (%)	Tundra Tract Factor (%)	Corvair Tract Factor (%)	Brandon Prof. Tract Factor (%)	Kiwi Tract Factor (%)	Topac Tract Factor (%)	Mustang Tract Factor (%)	Total Unit Tract Factor (%)	100% OOIP
9-20-10-29	100.00	0.00	0.00	0.00	0.00	0.00	100.00	90	51.41	0.57	2.77	2.77	0.00	0.00	0.00	0.00	0.00	2.77	8.09
16-20-10-29	100.00	0.00	0.00	0.00	0.00	0.00	100.00	90	207.33	2.30	11.17	11.17	0.00	0.00	0.00	0.00	0.00	11.17	9.17
10-21-10-29	100.00	0.00	0.00	0.00	0.00	0.00	100.00	90	31.39	0.35	1.69	1.69	0.00	0.00	0.00	0.00	0.00	1.69	7.24
12-21-10-29	100.00	0.00	0.00	0.00	0.00	0.00	100.00	90	37.52	0.42	2.02	2.02	0.00	0.00	0.00	0.00	0.00	2.02	6.84
13-21-10-29	100.00	0.00	0.00	0.00	0.00	0.00	100.00	90	205.27	2.28	11.06	11.06	0.00	0.00	0.00	0.00	0.00	11.06	7.63
14-21-10-29	100.00	0.00	0.00	0.00	0.00	0.00	100.00	0	0.00	0.42	2.02	2.02	0.00	0.00	0.00	0.00	0.00	2.02	4.91
15-21-10-29	100.00	0.00	0.00	0.00	0.00	0.00	100.00	67	86.30	1.29	6.25	6.25	0.00	0.00	0.00	0.00	0.00	6.25	5.01
1-28-10-29	57.00	43.00	0.00	0.00	0.00	0.00	100.00	61	45.10	0.74	3.58	2.04	1.54	0.00	0.00	0.00	0.00	3.58	5.39
2-28-10-29	57.00	43.00	0.00	0.00	0.00	0.00	100.00	90	193.52	2.15	10.43	5.95	4.49	0.00	0.00	0.00	0.00	10.43	5.76
3-28-10-29	33.5625	43.00	12.50	9.68750	1.25	0.00	100.00	90	153.10	1.70	8.25	2.77	3.55	1.03	0.80	0.10	0.00	8.25	6.99
4-28-10-29	35.1250	43.00	0.00	19.37500	2.50	0.00	100.00	90	201.78	2.24	10.87	3.82	4.68	0.00	2.11	0.27	0.00	10.88	5.44
5-28-10-29	7.00	43.00	12.50	9.68750	1.25	26.5625	100.00	90	18.10	0.20	0.98	0.07	0.42	0.12	0.09	0.02	0.26	0.98	6.33
6-28-10-29	33.5625	43.00	12.50	9.68750	1.25	0.00	100.00	90	68.68	0.74	3.61	1.21	1.55	0.45	0.35	0.05	0.00	3.61	4.99
11-28-10-29	100.00	0.00	0.00	0.00	0.00	0.00	100.00	90	233.98	2.60	12.61	12.61	0.00	0.00	0.00	0.00	0.00	12.61	4.56
12-28-10-29	100.00	0.00	0.00	0.00	0.00	0.00	100.00	90	148.31	1.65	7.99	7.99	0.00	0.00	0.00	0.00	0.00	7.99	5.96
8-29-10-29	100.00	0.00	0.00	0.00	0.00	0.00	100.00	90	86.79	0.96	4.68	4.69	0.00	0.00	0.00	0.00	0.00	4.68	5.7
Totals									1766.75	20.61	100.00	78.13	18.22	1.80	3.35	0.44	0.26	100.00	

CROWN SHARE 100% CURRENT PRODUCTION 39.22%

" " " OOIP 33.48%

TABLE NO.8

RELATIVE PERMEABILITY TEST DATA

	KOLA UNIT NO.1	
CUMULATIVE INJECTION, CUMULATIVE PRODUCTION, AND PRESSURE DATA		
CUM. INJECTION (PV)	CUM. PRODUCTION (PV)	DIFFERENTIAL PRESSURE (MPa)
0.028	0.028	1.06873
0.056	0.056	1.51690
0.111	0.111	2.10298
0.150	0.150	2.11677
0.167	0.155	2.10298
0.209	0.167	2.00645
0.279	0.178	1.92508
0.487	0.201	1.78581
0.696	0.212	1.71686
1.114	0.220	1.63825
1.671	0.225	1.58585
3.064	0.225	1.57206

TABLE NO.9

INCREMENTAL OIL RESERVES WITH WATERFLOODING

BAKKEN 'A' POOL

ORIGINAL OIL-IN-PLACE ESTIMATES FOR EACH LSD

ESTIMATION OF INCREMENTAL RECOVERY WITH WATERFLOODING

INITIAL WATERFLOODING AREA

1 INJECTOR

Sw = 57.8%					LOWER ZONE								UPPER ZONE						
WELL	CONSTANT	AREA (ha)	HCPV (phi-metres)	FVF (res m3/m3)	OOIP (m3)	OOIP (STB)	ULTIMATE PRIMARY RECOVERY (m3)	ULTIMATE PRIMARY RECOVERY (STB)	INCREMENTAL SECONDARY RECOVERY (STB)	TOTAL RECOVERY LOWER ZONE (STB)	AREA (ha)	HCPV (phi-metres)	OOIP UPPER ZONE (m3)	OOIP UPPER ZONE (STB)	ESTIMATED RECOVERY LOWER ZONE (STB)	ULTIMATE PRIMARY RECOVERY FACTOR (%)	SECONDARY RECOVERY FACTOR (%)	TOTAL RECOVERY UPPER & LOWER ZONE (STB)	TOTAL RECOVERY RECOVERY FACTOR (%)
3-28-10-29	10,000.00	16.17	0.19	1.06	27,381	172,228	9,751	61,332	30,465	91,797	16.17	0.04	6,085	38,273	1,914	29.14	15.38	93,710	44.52
4-28-10-29	10,000.00	16.17	0.15	1.06	22,817	143,522	10,103	63,550	12,947	76,497	16.17	0.02	3,042	19,136	957	39.07	8.55	77,454	47.62
12-21-10-29	10,000.00	16.17	0.13	1.06	19,775	124,386	3,208	20,177	46,121	66,298	16.17	0.09	13,690	86,113	4,306	9.59	23.96	70,603	33.54
13-21-10-29	10,000.00	16.17	0.19	1.06	28,902	181,795	18,477	116,220	-	116,220	16.17	0.05	7,606	47,841	2,392	50.61	-	118,612	51.85
14-21-10-29	10,000.00	16.17	0.10	1.06	15,212	95,681	734	4,618	46,380	50,998	16.17	0.06	9,127	57,409	2,870	3.02	32.17	53,869	35.19
9-20-10-29	10,000.00	16.17	0.16	1.06	24,339	153,090	5,965	37,522	44,075	81,597	16.17	0.10	15,212	95,691	4,784	15.08	19.84	86,381	34.72
16-20-10-29	10,000.00	16.17	0.24	1.06	36,508	229,635	8,873	55,813	66,582	122,396	16.17	0.06	9,127	57,409	2,870	19.44	24.20	125,266	43.64
TOTALS		113.19			174,934	1,100,336	57,112	359,231	246,571	605,802	113.19		63,889	401,662	20,093	23.91	17.75	625,895	41.67
INCREMENTAL RECOVERY IN INITIAL AREA OF 17.9% OOIP WITH WATERFLOODING																			
	LOWER ZONE =	246,571	STB (39,040 m3)	~Δ22.5% OOIP			32.6%			55.1%					5%				
	UPPER ZONE =	20,093	STB (3190 m3)																
	TOTAL =	266,664	STB (42,395 m3)																

OOIP WF AREA 238323 m^3

TABLE NO. 10

CURRENT OIL RATES INITIAL WATERFLOOD AREA

KOLA UNIT NO.1				
INITIAL WATERFLOOD AREA				
CURRENT WELL RATES				
WELL	Oil Rate (m3/day)	Water-cut (%)	Total Rate (m3/day)	ON PROD
9-20-10-29	0.51	43.12	0.90	86-01
16-20-10-29	2.18	39.23	3.59	87-07
12-21-10-29	0.43	90.36	4.46	87-07
13-21-10-29	2.23	12.18	2.54	85-10
14-21-10-29	-	-	0.00	87-06 RE-ENTERED '93
3-28-10-29	1.57	8.79	1.72	87-11
4-28-10-29	2.12	26.87	2.90	87-06
	9.04	36.76	16.10	

TABLE No. 1

PRIMARY AND WATERFLOOD PRODUCTION FORECASTS

				KOLA UNIT NO.1					
				PRODUCTION FORECAST					
				INITIAL WATERFLOOD AREA					
	Primary Production Forecast					Waterflood Production Forecast			
Year	Total Oil Rate (m3/day)	Annual Prod. (m3)	Cum. Prod. (m3)	Cum. Prod. (STB)		Total Oil Rate (m3/day)	Annual Prod. (m3)	Cum. Prod. (m3)	Cum. Prod. (STB)
			34,551.90	217,331.45				34,551.90	217,331.45
1993	9.04	3,299.60	37,851.50	238,085.94		12.38	4,516.88	39,068.78	245,742.59
1994	8.14	2,969.64	40,821.14	256,764.97		15.75	5,748.75	44,817.53	281,902.23
1995	7.32	2,672.68	43,493.82	273,576.10		15.75	5,748.75	50,566.28	318,061.87
1996	6.44	2,351.95	45,845.77	288,369.90		15.75	5,748.75	56,315.03	354,221.51
1997	5.61	2,046.20	47,891.97	301,240.50		14.96	5,461.31	61,776.34	388,573.16
1998	4.88	1,780.19	49,672.17	312,437.93		14.21	5,188.25	66,964.58	421,207.24
1999	4.15	1,513.17	51,185.33	321,955.74		13.50	4,928.83	71,893.42	452,209.60
2000	3.52	1,286.19	52,471.52	330,045.88		12.15	4,435.95	76,329.37	480,111.74
2001	2.92	1,067.54	53,539.06	336,760.69		10.94	3,992.36	80,321.73	505,223.66
2002	2.43	886.06	54,425.12	342,333.99		9.84	3,593.12	83,914.85	527,824.38
2003	2.01	735.43	55,160.54	346,959.82		7.88	2,874.50	86,789.34	545,904.97
2004	1.67	610.40	55,770.95	350,799.27		6.30	2,299.60	89,088.94	560,369.43
2005	1.39	506.64	56,277.58	353,986.01		5.04	1,839.68	90,928.62	571,941.00
2006	1.15	420.51	56,698.09	356,631.00		3.93	1,434.95	92,363.57	580,966.83
2007	0.96	349.02	57,047.11	358,826.34		3.07	1,119.26	93,482.83	588,006.97
2008						2.39	873.02	94,355.85	593,498.29
2009						1.87	680.96	95,036.81	597,781.51
2010						1.46	531.15	95,567.95	601,122.43
2011						1.14	414.29	95,982.25	603,728.34
2012						0.89	323.15	96,305.40	605,760.95

TABLE NO.12

KOLA UNIT NO.1

RESERVE AND RECOVERY FACTOR SUMMARY

	TOTAL ~~UNIT~~ Pool	INITIAL WATERFLOOD AREA
RESERVES		
CUM. PROD.(93.03.31)	374,092 STB	218,277 STB
REMAINING PRIMARY	481,348 STB	140,953 STB
TOTAL PRIMARY	855,440 STB 135.9 10^3 m^3	359,230 STB 57084
SECONDARY	800,000 STB 127.1 10^3 m3	266,665 STB
TOTAL	1,655,440 STB 263.1 (10^3 m3)	625,895 STB
RECOVERY FACTOR(%)		
CUM. PROD.(93.03.31)	8.1%	14.5%
REMAINING PRIMARY	10.4%	9.4%
TOTAL PRIMARY	18.5%	23.9%
SECONDARY	17.3%	17.8%
TOTAL	35.8%	41.7%

unit as % total pool
ooip
current prod.
est. cumul.
primary prod
cumul. prod

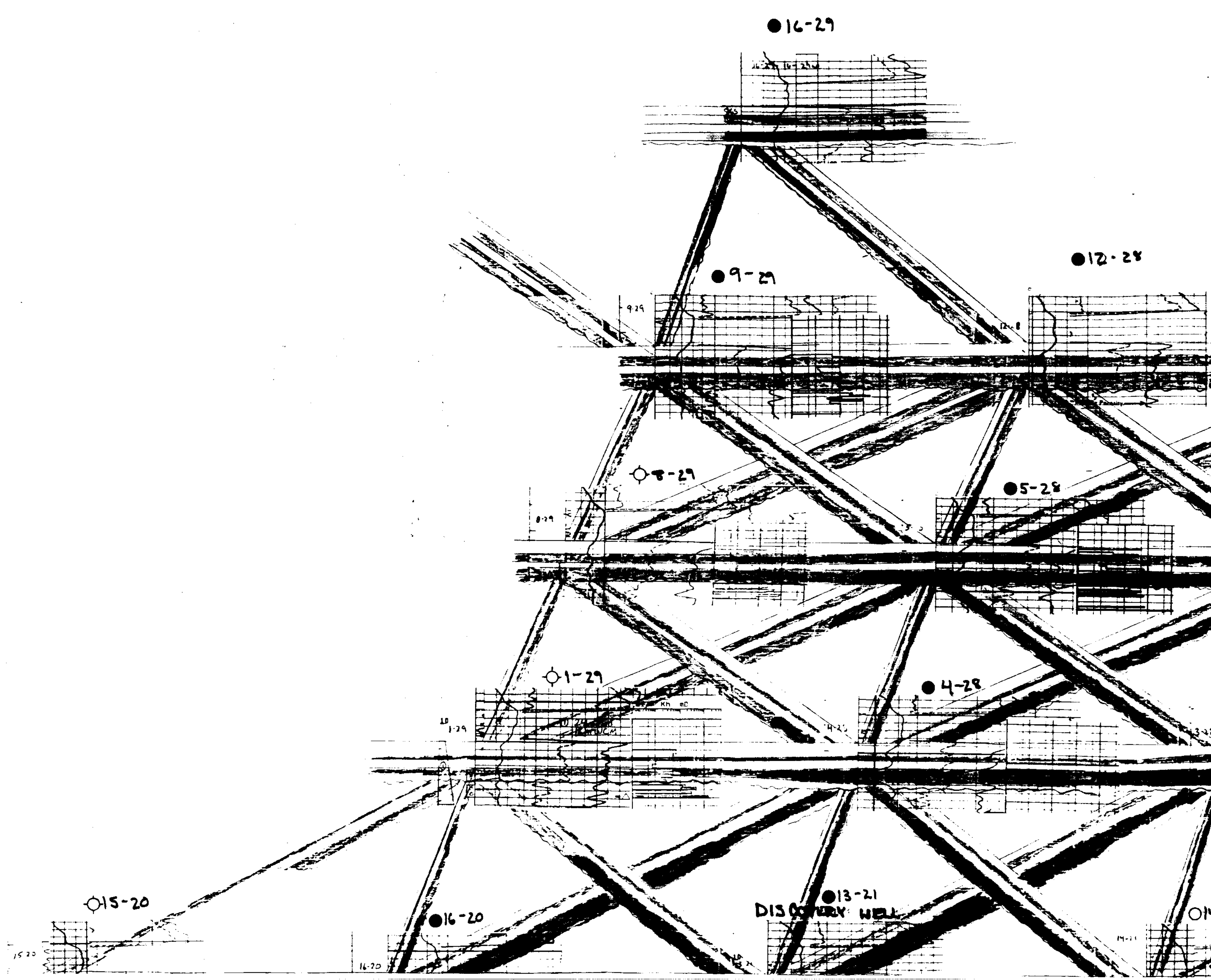
J. APPENDICI

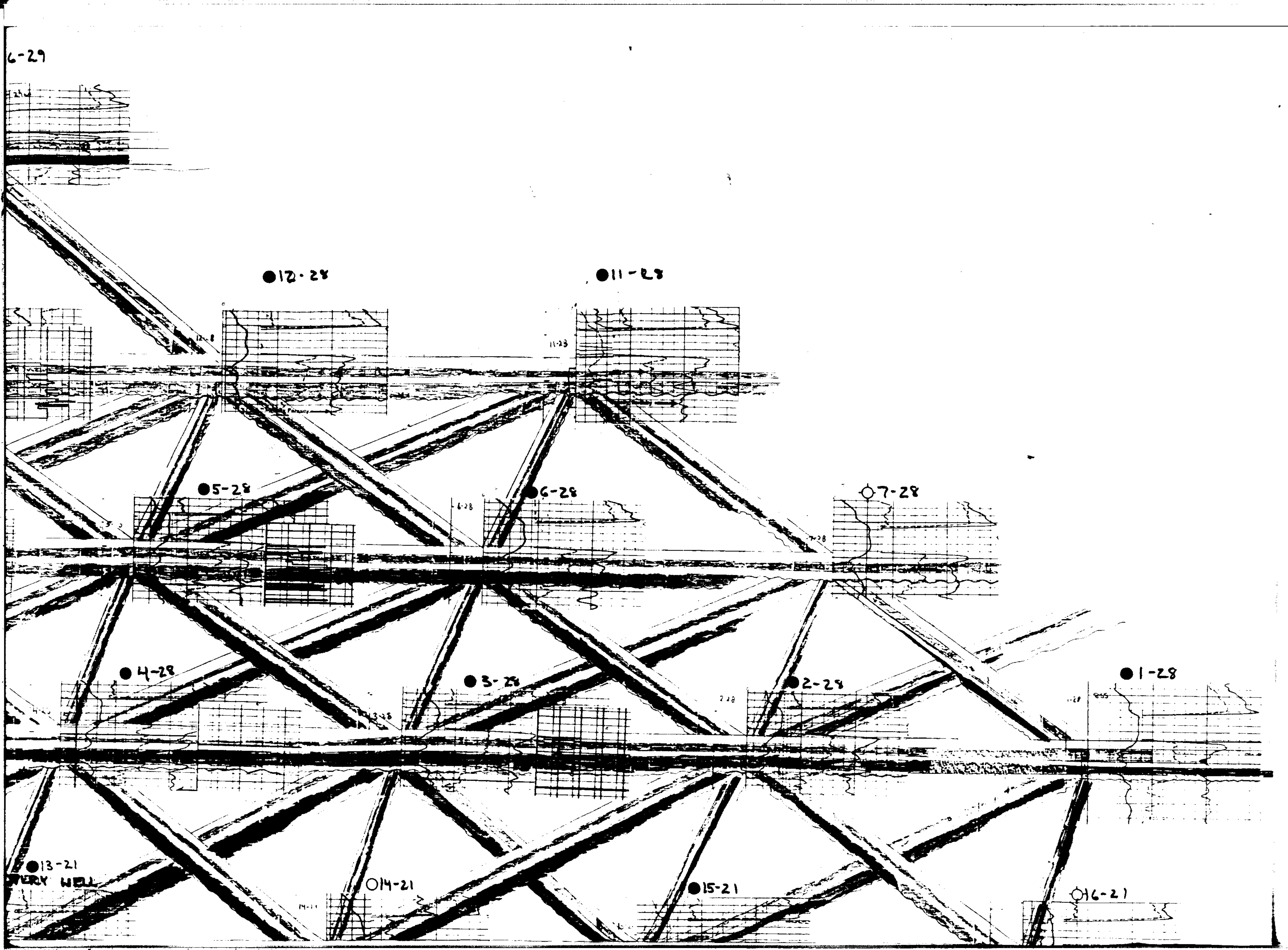
APPENDIX A

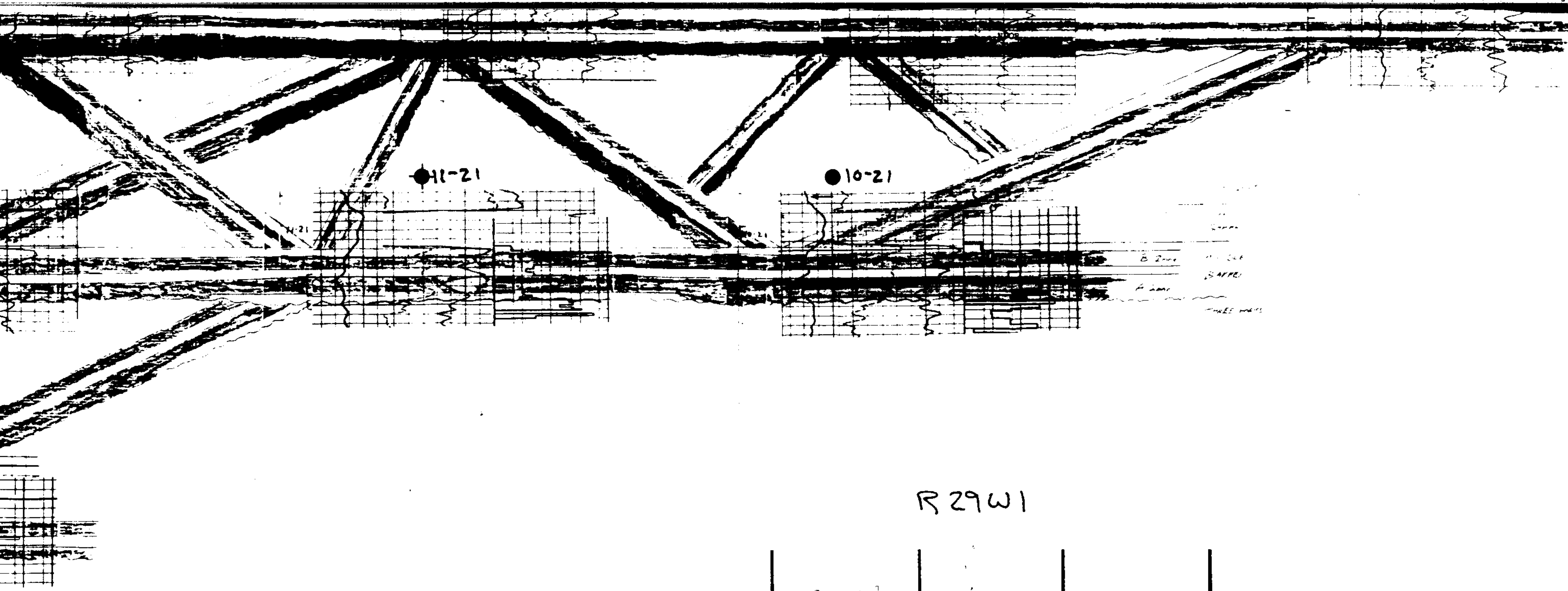
BAKKEN 'A' POOL

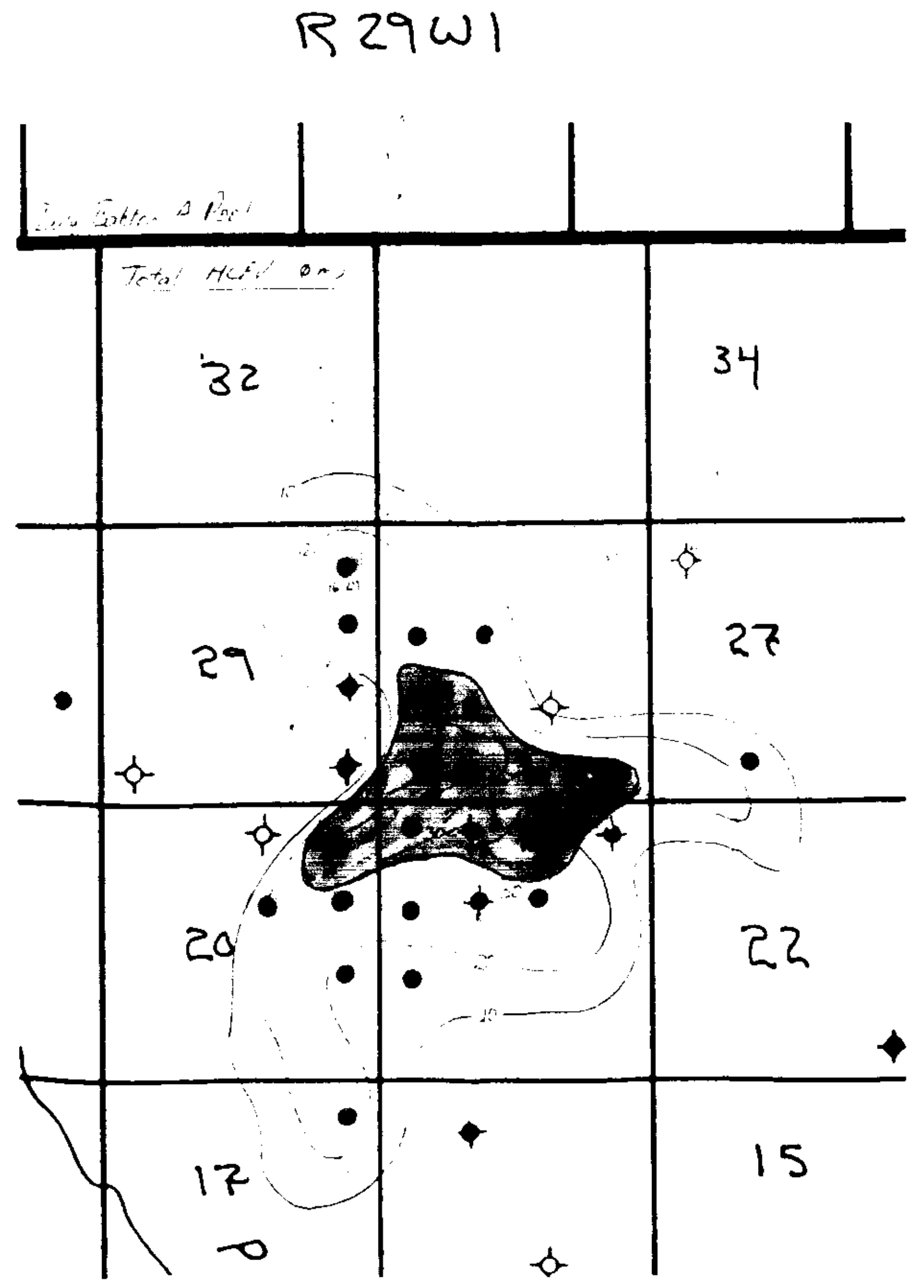
RESERVOIR FENCE DIAGRAM

Appendici


16-29
9-29
12-28
8-29
5-28
1-29
4-28
15-20
16-20
13-21
DISCOVERY WELL


6-29
12-28
11-28
5-28
6-28
7-28
4-28
3-28
2-28
1-28
13-21
VERY WELL
14-21
15-21
16-21





○ Current Locations

R = Re-entry

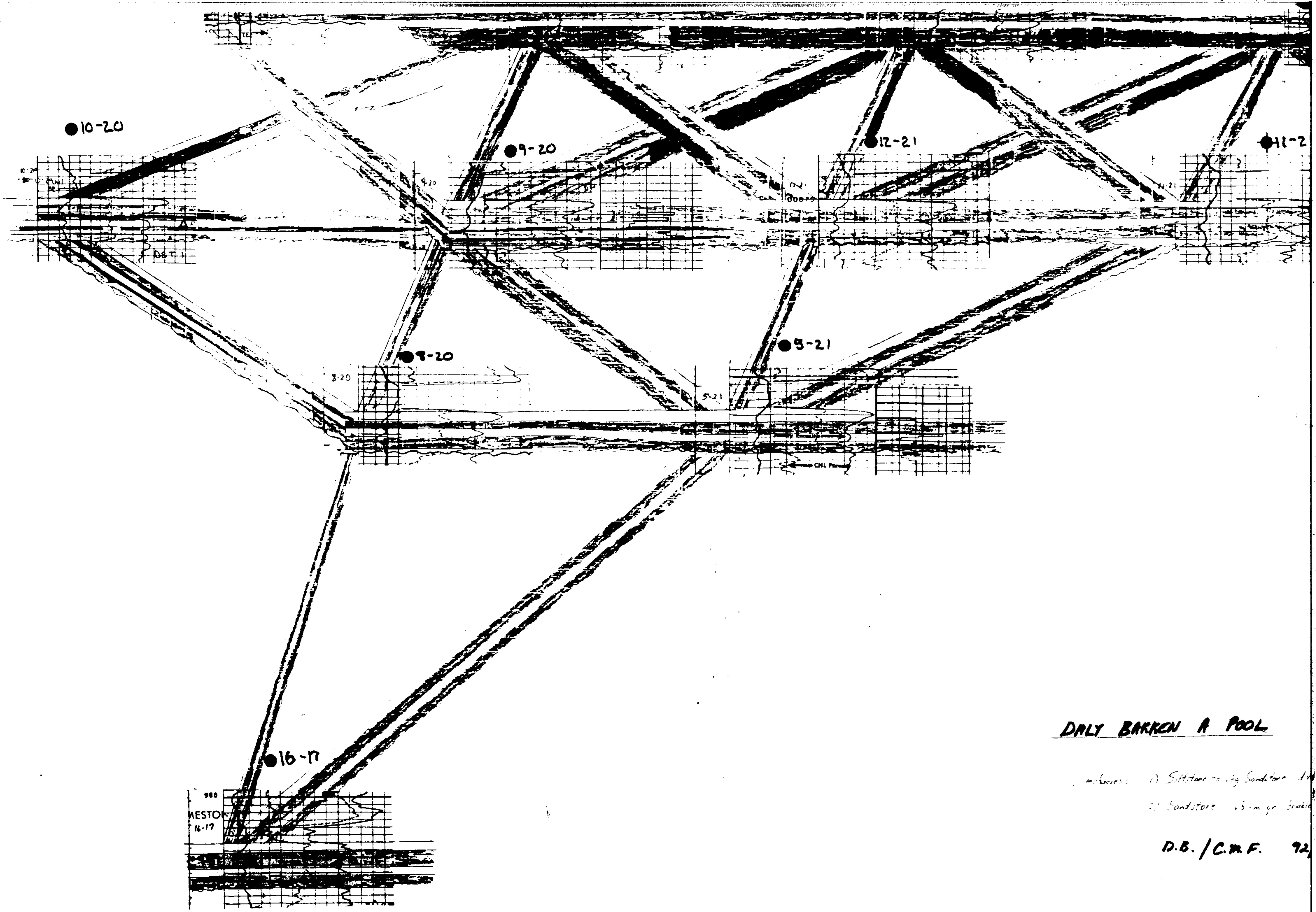
Daly Bakken 'A'

DALY BAKKEN A POOL

Facies: 1) Siltstone to v.f.g. Sandstone dolomitic (1-10 md. ave.)

2) Sandstone v.f.-m.gr. friable (10-100 md. ave.)

D.B. / C.M.F. 92/93



DALY BAKKEN A POOL

lithofacies: 1) Siltstone to v.f.g Sandstone
2) Sandstone v.f.-m.gr. friable

D.B. / C.M.F. 92

APPENDIX B

BAKKEN 'A' POOL
PVT DATA

CHEMICAL & GEOLOGICAL LABORATORIES LTD.

4605-12 STREET N.E. CALGARY ALBERTA T2E 4R3

TELEPHONE
(403) ~~XXXXXXXX~~
291-3024

1988-02-10

Newscope Resources Limited
1600, 700 - 9 Avenue SW
Calgary, Alberta
T2P 3V4

Attention: Mr. Bruce McKay

Dear Sir:

Re: Reservoir Fluid Study
Newscope et al Daly 3-28-10-29 W1

The following pages present the results of a reservoir fluid study on a recombined sample of separator oil and gas taken at the subject well by representatives of Chemical & Geological Laboratories Ltd.

The GOR at time of sampling was measured to be 10.00 m^3/m^3 from a separator operating at 207 kPa (gauge) and 15°C.

The separator oil and gas were recombined using the above ratio and a portion of the recombined sample was flashed through a separator operating at 207 kPa (gauge) and 15°C to verify the GOR. The ratio was found to 9.96 m^3/m^3.

The fluid study was conducted on this mixture which has a saturation pressure of 2 000 kPa (gauge) at the reservoir temperature of 31°C.

Thank you for this opportunity to have been of service to you.

Yours truly,

CHEMICAL & GEOLOGICAL LABORATORIES LTD.

Kevin Brunner
PVT Department

KB/jah

INDEX

CONTENTS	PAGE

GRAPHS

CHEMICAL & GEOLOGICAL LABORATORIES LIMITED

Lab. No. C88-0047

Company: NEWSCOPE RESOURCES LIMITED

Well: Newscope et al Daly 3-28-10-29 W1

Field: Daly Province: Manitoba

FORMATION CHARACTERISTICS

Formation Name	Bakken "A"
Date First Well Completed	October 1986
Original Reservoir Pressure	8646 kPa @ 880 m
Original Produced Gas-Oil Ratio	
Production Rate	9.0 m^3/d
Separator Pressure and Temperature	To Lease Tank kPa °C
Oil Density at 15°C	41° API
Datum	m Subsea
Original Gas Cap	N/A

WELL CHARACTERISTICS

Elevation	KB: 536 m GRD: 531.8 m m
Total Depth	900 m
Producing Interval	871.2 - 873.2 mKB
Tubing Size and Depth	60.3 mm 876.9 mKB
Productivity Index	$m^3/(kPa \cdot d)$
Last Reservoir Pressure	kPa @ m
Date	
Reservoir Temperature	31 °C @ 900 m
Status of Well	Producing Oil Well
Pressure Survey By	
Normal Production Rate	m^3/d
Gas-Oil Ratio	10 m3/m3
Separator Pressure and Temperature	207 kPa 15 °C
Base Pressure	kPa (abs)
Well Making Water	

SAMPLING CONDITIONS

Sampled at	Separator m
Status of Well	Pumping
Gas-Oil Ratio	
Separator Pressure and Temperature	20.7 kPa 15 °C
Tubing Pressure	kPa
Casing Pressure	kPa
Date Sampled	1988-01-18
Sampled by	C & G Labs.

Gregorach Printing Ltd.

Lab. No. C88-0047

Well Newscope et al Daly 3-28-10-29 W1

PVT ANALYSIS SUMMARY

RESERVOIR TEMPERATURE 31 °C

BUBBLE-POINT PRESSURE 2000 kPa at 31 °C

COMPRESSIBILITY of saturated oil at reservoir temperature

FROM 20 685 TO 13 790 kPa = 0.000967 MPa^{-1}
FROM 13 790 TO 6 895 kPa = 0.001075 MPa^{-1}
FROM 6 895 TO 3 448 kPa = 0.001202 MPa^{-1}

THERMAL EXPANSION of saturated oil at 20 685 kPa = 0.0008126 per °C

SPECIFIC VOLUME at bubble-point pressure and reservoir temperature = 1.2880 L/kg

DENSITY at bubble-point pressure and reservoir temperature 776.4 kg/m^3

OIL VISCOSITY 1.239 mPa s at bubble-point pressure and reservoir temperature

RESIDUAL STOCK TANK OIL DENSITY 813.9 kg/m^3 flashed through a separator operating at 311 kPa and 22.2 °C

RELATIVE DENSITY OF SEPARATOR GAS 1.165 Flashed through a separator operating at 311 kPa and 22.2 °C

FORMATION VOLUME FACTOR 1.120 Cubic metres reservoir oil at bubble-point pressure per cubic metre residual oil - by differential liberation at reservoir temperature.

RESIDUAL OIL VOLUME 0.8929 Cubic metres residual oil per cubic metre reservoir oil at bubble point pressure - by differential liberation at reservoir temperature.

SOLUTION GAS OIL RATIO 27.29 by differential liberation at reservoir temperature.

Note: Volume of residual oil is at 15°C

CHEMICAL & GEOLOGICAL LABORATORIES LIMITED

Lab. No. C88-0047

Well Newscope et al Daly 3-28-10-29 W1

PRESSURE - VOLUME RELATIONS AT 31 °C

PRESSURE Pga/kPa	RELATIVE VOLUME OF OIL AND GAS	Y FUNCTION	ABSOLUTE VISCOSITY OF OIL η/mPa.s
20 685	0.9802		
17 237	0.9839		
13 790	0.9868		
10 343	0.9905		
6 895	0.9941		
3 448	0.9982		
2 069	0.9999		
2 000	1.0000		
1 903	1.0066	7.2991	
1 841	1.0115	7.1204	
1 786	1.0167	6.9825	
1 379	1.0705	5.9487	
1 035	1.1675	5.0749	
690	1.3956	4.1855	
345	2.1280	3.2888	

Relative Volume = V/Vsat
V = Volume at given pressure.
Vsat = Volume at saturation pressure at the specified temperature.
Psat = Saturation pressure at the specified temperature

$$\text{Y Function} = \frac{P_{sat} - P}{P_{abs}\left(\frac{V}{V_{sat}} - 1\right)}$$

CHEMICAL & GEOLOGICAL LABORATORIES LIMITED

Lab. No. C88-0047

Well Newscope et al Daly 3-28-10-29 W1

DIFFERENTIAL VAPORIZATION AT 31 °C

Pressure Pga/kPa	Oil Density ρ/kg·m-3	Relative Oil Volume (1)	Relative Total Volume (2)	Solution Gas/Oil Ratio (3)	Incremental Gas Relative Density	Cumulative Gas Relative Density	Deviation Factor Z	Gas Formation Volume Factor (4)	Gas Expansion Factor (5)
2 000	776.4	1.120	1.120	27.29					
1 379	777.2	1.116	1.204	26.06	0.982	0.982	0.974	0.07093	14.10
1 035	777.8	1.114	1.314	25.13	0.987	0.984	0.974	0.09267	10.79
690	778.6	1.111	1.551	24.00	1.013	0.994	0.974	0.13362	7.48
345	779.8	1.106	2.330	22.18	1.085	1.026	0.974	0.23953	4.18
0	807.2	1.013	33.32	0.00	1.641	1.526	1.000(e)	1.18371	0.85

0 818.2 @ 15°C 41.44 API @ 60°F

(1) Cubic metres of oil at indicated pressure and temperature per cubic metre of residual oil at 15°C.
(2) Cubic metres of oil plus liberated gas at indicated pressure and temperature per cubic metre of residual oil at 15°C.
(3) Cubic metres of gas at 101.325 kPa (abs) and 15°C per cubic metre of residual oil at 15°C.
(4) Cubic metres of gas at indicated pressure and temperature per cubic metre at 101.325 kPa (abs) and 15°C.
(5) Cubic metres of gas at 101.325 kPa (abs) and 15°C per cubic metre at indicated pressure and temperature:

VISCOSITY AT 31 °C

Pressure kPa	Oil Viscosity mPa.s	* Gas Viscosity mPa.s	Oil/Gas Viscosity Ratio
20 685	1.604		
17 237	1.534		
13 790	1.461		
10 343	1.391		
6 895	1.322		
3 448	1.263		
2 069	1.240		
2 000	1.239		
1 379	1.243	0.0102	123.82
1 035	1.247	0.0101	125.45
690	1.264	0.0099	129.70
345	1.305	0.0096	138.02
0	2.020	0.0080	252.50

* Calculated from the correlation by Lee, Eakin and Gonzalez:
"The Viscosity of Natural Gases", August 1966 - Journal of Petroleum Technology.

CHEMICAL & GEOLOGICAL LABORATORIES LIMITED

Lab. No. C88-0047

Well Newscope et al Daly 3-28-10-29 W1

SEPARATOR TESTS

SEPARATOR PRESSURE Pga/kPa	SEPARATOR TEMPERATURE t/°C	SEPARATOR GAS/OIL RATIO See Foot Note (1)	STOCK TANK GAS/OIL RATIO See Foot Note (1)	STOCK TANK OIL DENSITY @ 15 C ρ/kg m⁻³	SHRINKAGE FACTOR Vt/Vsat See Foot Note (2)	FORMATION VOLUME FACTOR Vsat/Vt See Foot Note (3)	RELATIVE DENSITY OF FLASHED GAS STAGE 1st	2nd
311	22.2	8.17	14.99	813.9	0.9061	1.104	1.165	1.625
207	23.3	11.94	11.35	814.8	0.9033	1.107	1.200	1.641
104	23.3	16.83	6.13	916.1	0.9009	1.110	1.323	1.643
0	23.3	28.93	-	818.1	0.8900	1.124	1.495	

(1) Separator and stock tank Gas/Oil Ratio in cubic metres of gas @ 101 325 kPa absolute and 15°C per cubic metre of stock tank oil @ 15°C

(2) Shrinkage Factor (Vt/Vsat) is cubic metres of stock tank oil @ 15°C per cubic metre of saturated oil @ 2000 kPa gauge and 31 °C.

(3) Formation Volume Factor (Vsat/Vt) is cubic metres of saturated oil @ 2000 kPa gauge and 31 °C per cubic metre of stock tank oil @ 15°C

Gregorach Printing Ltd

CHEMICAL & GEOLOGICAL LABORATORIES LTD.

GAS ANALYSIS

CONTAINER IDENTITY: LS-1

LABORATORY NUMBER: C88-0047-1

LICENCE NUMBER:

OPERATOR NAME: NEWSCOPE RESOURCES LIMITED

LOCATION: 3-28-10-29 W1

WELL NAME: NEWSCOPE ET AL DALY 3-28-10-29

ELEVATIONS (metres) K.B.: 536 GRD.: 531.8

FIELD OR AREA: DALY

POOL OR ZONE: BAKKEN "A"

NAME OF SAMPLER: I.M.

COMPANY: C & G LABS.

TEST TYPE: NO.:

TEST RECOVERY:

MULTIPLE RECOVERY Y N

SAMPLING POINT: SEPARATOR

AMT. & TYPE OF CUSHION:

MUD RESISTIVITY: @ 25°C

TEST INTERVAL (metres):

PERFORATIONS (metres): 871.2 - 873.2

TYPE OF PRODUCTION: PUMPING / FLOWING / GAS LIFT / SWAB

PRODUCTION RATES: WATER m^3/d / OIL m^3/d / GAS $10^3m^3/d$

	Separator	Treater	Reservoir	Source	Sampled	Received
GAUGE PRESSURE kPa	207					210
TEMPERATURE °C	15					23

DATE SAMPLED (Y-M-D): 88-01-18

DATE RECEIVED (Y-M-D): 88-01-20

DATE REPORTED (Y-M-D): 88-02-10

ANALYST: D. MINIONS

OTHER INFORMATION:

COMP	MOLE FRACTION AIR FREE AS RECEIVED	MOLE FRACTION AIR FREE ACID GAS FREE	PETROLEUM LIQUID CONTENT ml/m³
H_2	0.0002	0.0002	
He	0.0006	0.0006	
N_2	0.2679	0.2699	
CO_2	0.0072	0.0000	
H_2S	0.0000	0.0000	
C_1	0.2166	0.2182	
C_2	0.2258	0.2274	
C_3	0.2006	0.2021	737.5
IC_4	0.0217	0.0219	94.7
NC_4	0.0429	0.0432	180.6
IC_5	0.0055	0.0055	26.9
NC_5	0.0061	0.0061	29.5
C_6	0.0025	0.0025	13.7
C_7	0.0013	0.0013	8.0
C_8	0.0007	0.0007	4.8
C_9	0.0002	0.0002	1.5
C_{10+}	0.0002	0.0002	1.6
TOTAL	1.0000	1.0000	1098.8

GROSS HEATING VALUE MJ/m3 15°C AND 101.325 kPa

MOISTURE AND ACID GAS FREE — MEASURED: ; CALCULATED: 53.17

DETERMINED DEW POINT: °C

VAPOUR PRESSURE PENTANES PLUS: 100. kPa

RELATIVE DENSITY

MOISTURE FREE AS SAMPLED — MEASURED: ; CALCULATED: 1.105

MOISTURE AND ACID GAS FREE — MEASURED: ; CALCULATED: 1.102

PSEUDO CRITICAL PROPERTIES (CALCULATED)

AS SAMPLED — pPc(abs): 4206 kPa; pTc: 255.5 K

ACID GAS FREE — pPc(abs): 4183. kPa; pTc: 254.5 K

H_2S g/m³: 0.00

RELATIVE MOLECULAR MASS — TOTAL GAS: 32.00; C_{7+}: 110.14

C5+ ML/MOL 2.033

GROSS HEATING VALUE AS PER AGA REPORT #5

52.80 MAJ/M3 @ 15C AND 101.325 KPA

THIS SEPARATOR GAS WAS USED IN THE RECOMBINATION OF THE RESERVOIR FLUID.

CHEMICAL & GEOLOGICAL LABORATORIES LTD.

LIQUID ANALYSIS

CONTAINER IDENTITY	PVT #7
LABORATORY NUMBER	C88-0047
LICENCE NUMBER	
OPERATOR NAME	NEWSCOPE RESOURCES LIMITED
LOCATION	3-28-10-29 W1
WELL NAME	NEWSCOPE ET AL DALY 3-28-10-29
ELEVATIONS (metres) K.B.	536
ELEVATIONS (metres) GRD.	531.8
FIELD OR AREA	DALY
POOL OR ZONE	BAKKEN "A"
NAME OF SAMPLER	I.M.
COMPANY	C & G LABS.
TEST TYPE	
NO.	
TEST RECOVERY	
MULTIPLE RECOVERY Y N	
SAMPLING POINT	RECOMBINED RESERVOIR FLUID
AMT. & TYPE OF CUSHION	
MUD RESISTIVITY	@ 25°C
TEST INTERVAL (metres)	
PERFORATIONS (metres)	871.2 - 873.2

TYPE OF PRODUCTION: PUMPING | FLOWING | GAS LIFT | SWAB

PRODUCTION RATES: WATER m^3/d | OIL m^3/d | GAS $10^3 m^3/d$

	SEPARATOR	TREATER	RESERVOIR	SOURCE	SAMPLED	RECEIVED
GAUGE PRESSURE kPa				20685		
TEMPERATURE °C				23.3		

DATE SAMPLED (Y-M-D)	DATE RECEIVED (Y-M-D)	DATE REPORTED (Y-M-D)	ANALYST	OTHER INFORMATION
88-01-18	88-01-20	88-02-10	D. MINIONS	

COMP.	MOLE FRACTION	MASS FRACTION	VOLUME FRACTION
N_2	0.0220	0.0041	0.0040
CO_2	0.0010	0.0003	0.0003
H_2S	0.0000	0.0000	0.0000
C_1	0.0188	0.0020	0.0053
C_2	0.0360	0.0073	0.0160
C_3	0.0798	0.0236	0.0367
IC_4	0.0222	0.0087	0.0121
NC_4	0.0649	0.0253	0.0342
IC_5	0.0247	0.0119	0.0151
NC_5	0.0271	0.0131	0.0164
C_6	0.0507	0.0293	0.0348
C_7+	0.6528	0.8744	0.8251
C_8			
C_9			
C_{10}			
C_{11}			
C_{12+}			
TOTAL	1.0000	1.0000	1.0000

PROPERTIES OF FRACTIONS (CALCULATED)

	MOLE FRACTION	MASS FRACTION	VOLUME FRACTION	DENSITY AT 15°C RELATIVE	DENSITY AT 15°C ABSOLUTE kg/m3	RELATIVE MOLECULAR MASS
C_{12+}						
C_{7+}	0.6528	0.8744	0.8251	0.838	837.	200.0
C_{6+}	0.7035	0.9037	0.8599	0.831	830.	191.8
C_{5+}	0.7553	0.9287	0.8914	0.824	823.	183.6

PROPERTIES OF TOTAL SAMPLE

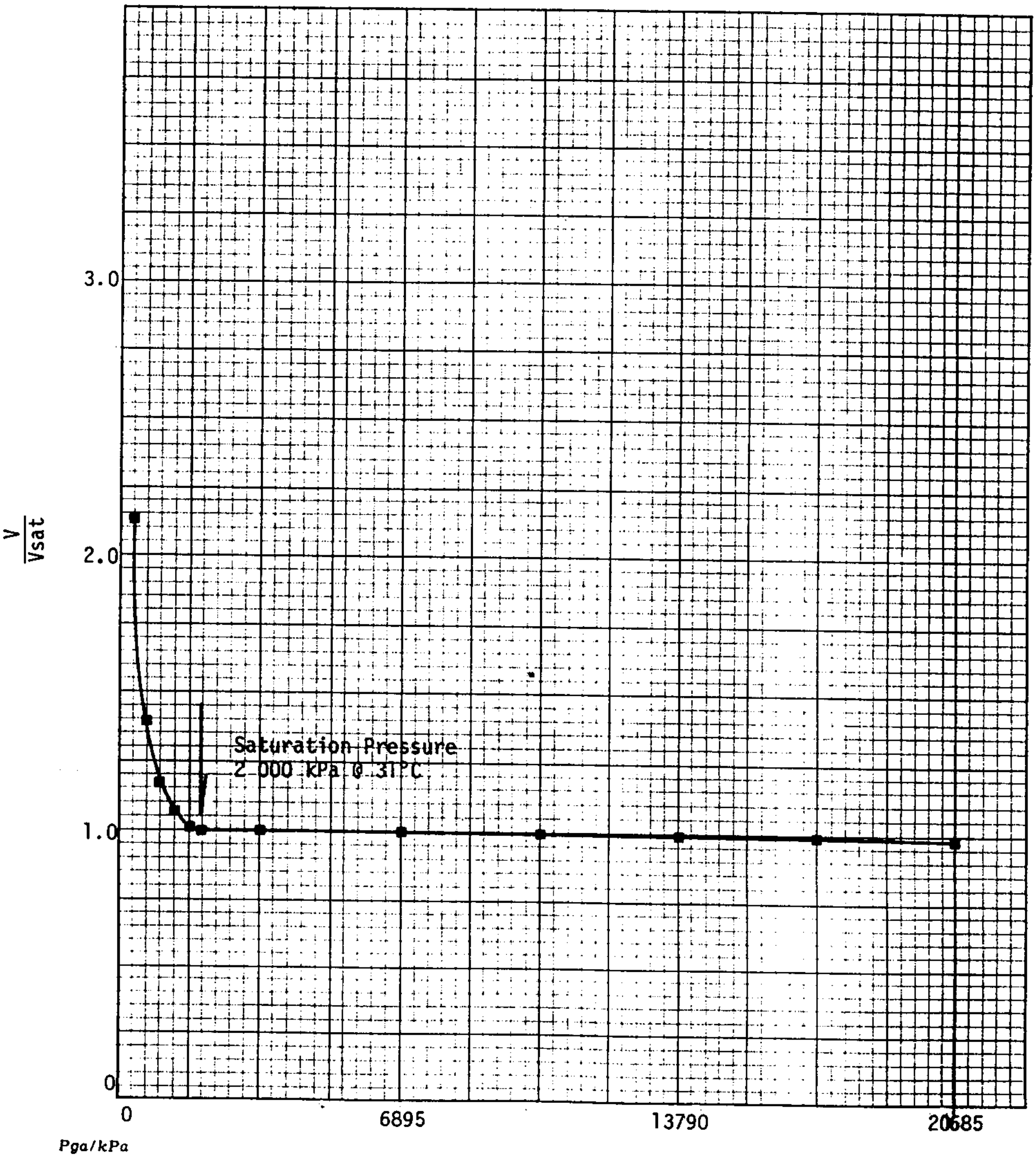
DENSITY AT 15°C RELATIVE DETERMINED	RELATIVE CALCULATED	ABSOLUTE kg/m3 DETERMINED	ABSOLUTE kg/m3 CALCULATED	RELATIVE MOLECULAR MASS DETERMINED	RELATIVE MOLECULAR MASS CALCULATED
	0.790		789.		149.2

CHEMICAL & GEOLOGICAL LABORATORIES LIMITED

Lab. No. C88-0047

Well Newscope et al Daly 3-28-10-29 W1

Relative Volume of Oil & Gas

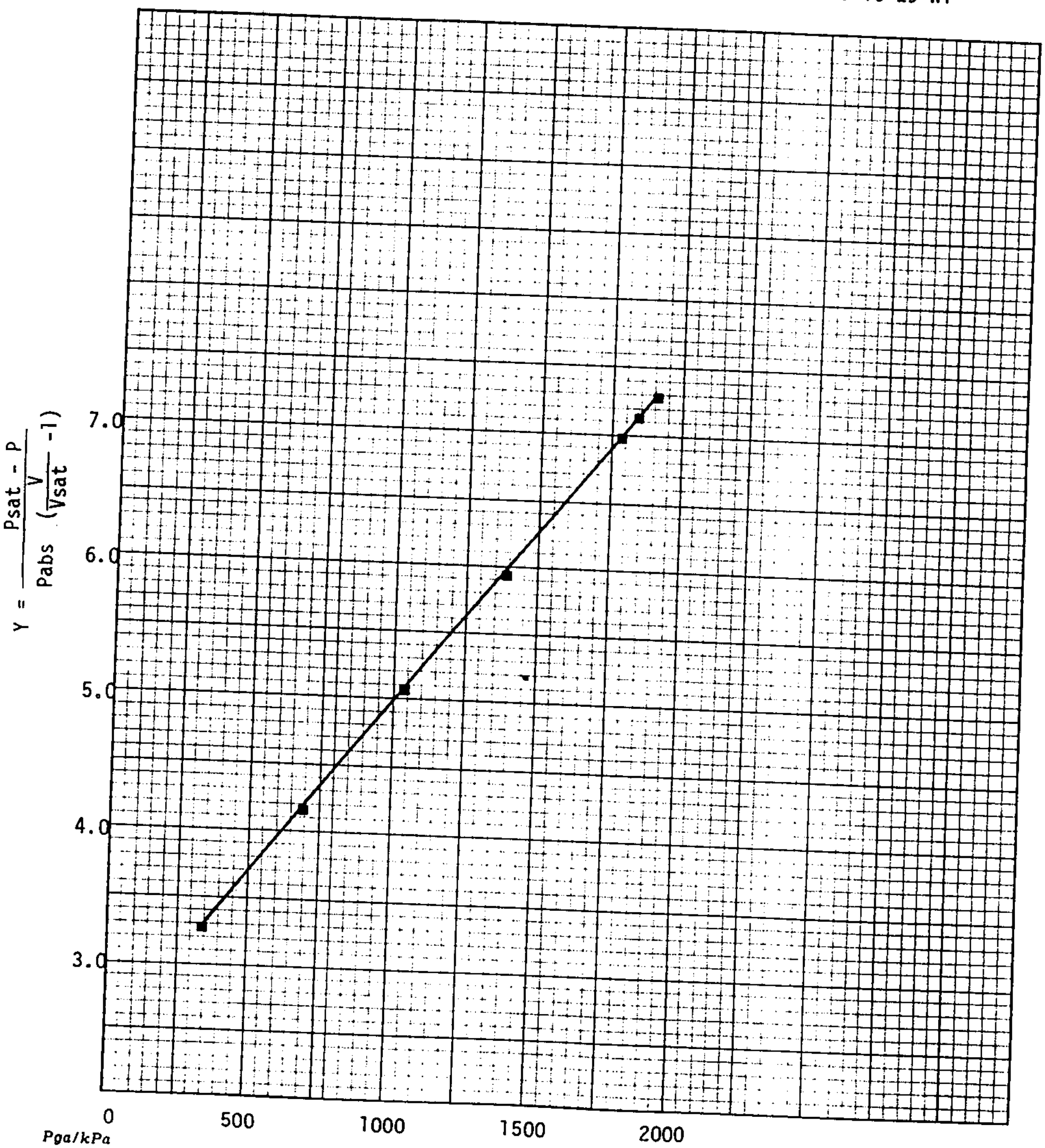


CHEMICAL & GEOLOGICAL LABORATORIES LIMITED

Lab. No. C88-0047

Well Newscope et al Daly 3-28-10-29 W1

Y Function

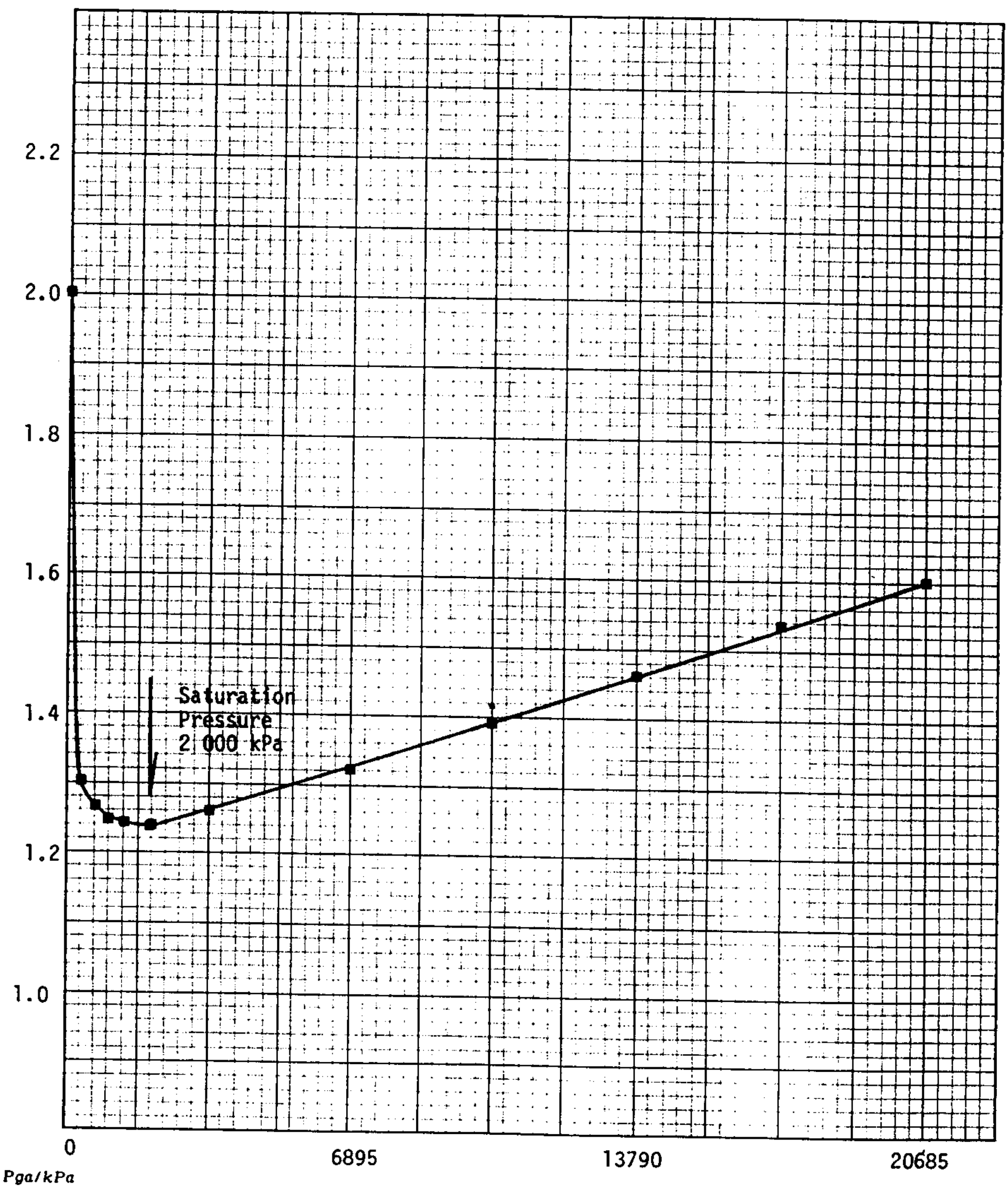


CHEMICAL & GEOLOGICAL LABORATORIES LIMITED

Lab. No. C88-0047

Well Newscope et al Daly 3-28-10-29 W1

Viscosity of Oil @ 31°C

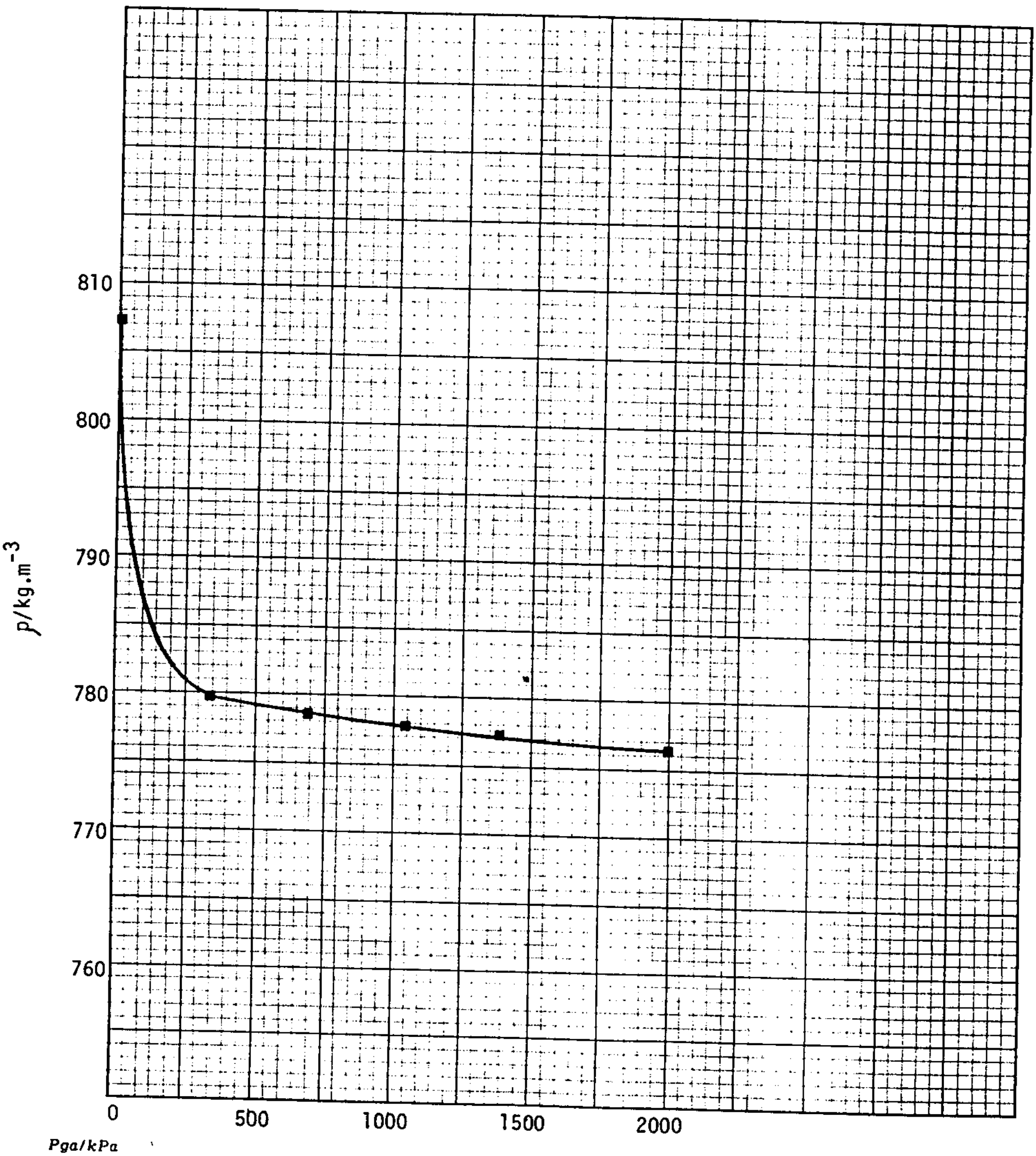


CHEMICAL & GEOLOGICAL LABORATORIES LIMITED

Lab. No. C88-0047

Well Newscope et al Daly 3-28-10-29 W1

Density of Liquid Produced By Differential Vaporization

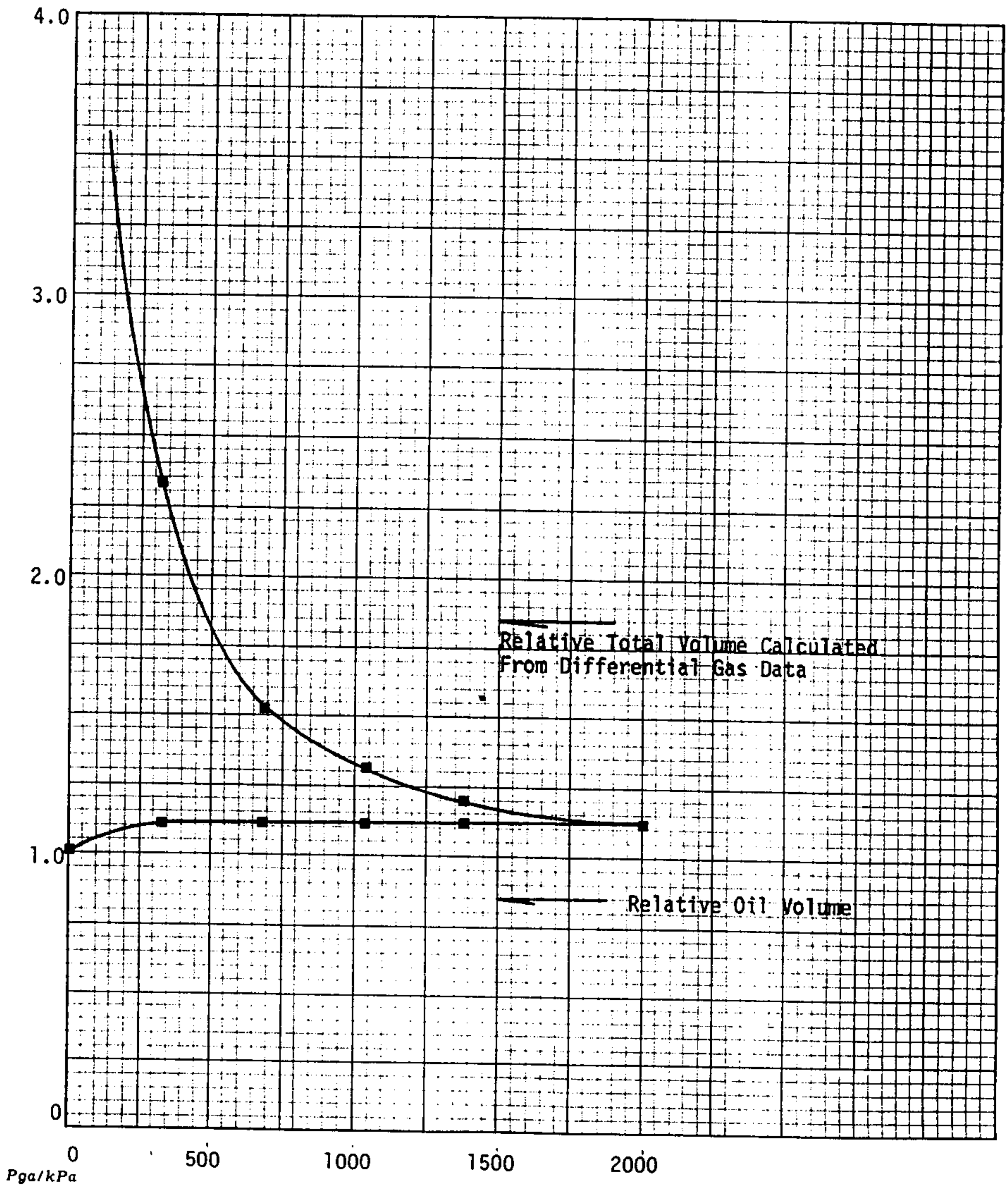


CHEMICAL & GEOLOGICAL LABORATORIES LIMITED

Lab. No. C88-0047

Well Newscope et al Daly 3-28-10-29 W1

Relative Total Volume
Of Oil & Gas Per Cubic Metre
Of Residual Oil (Differential)

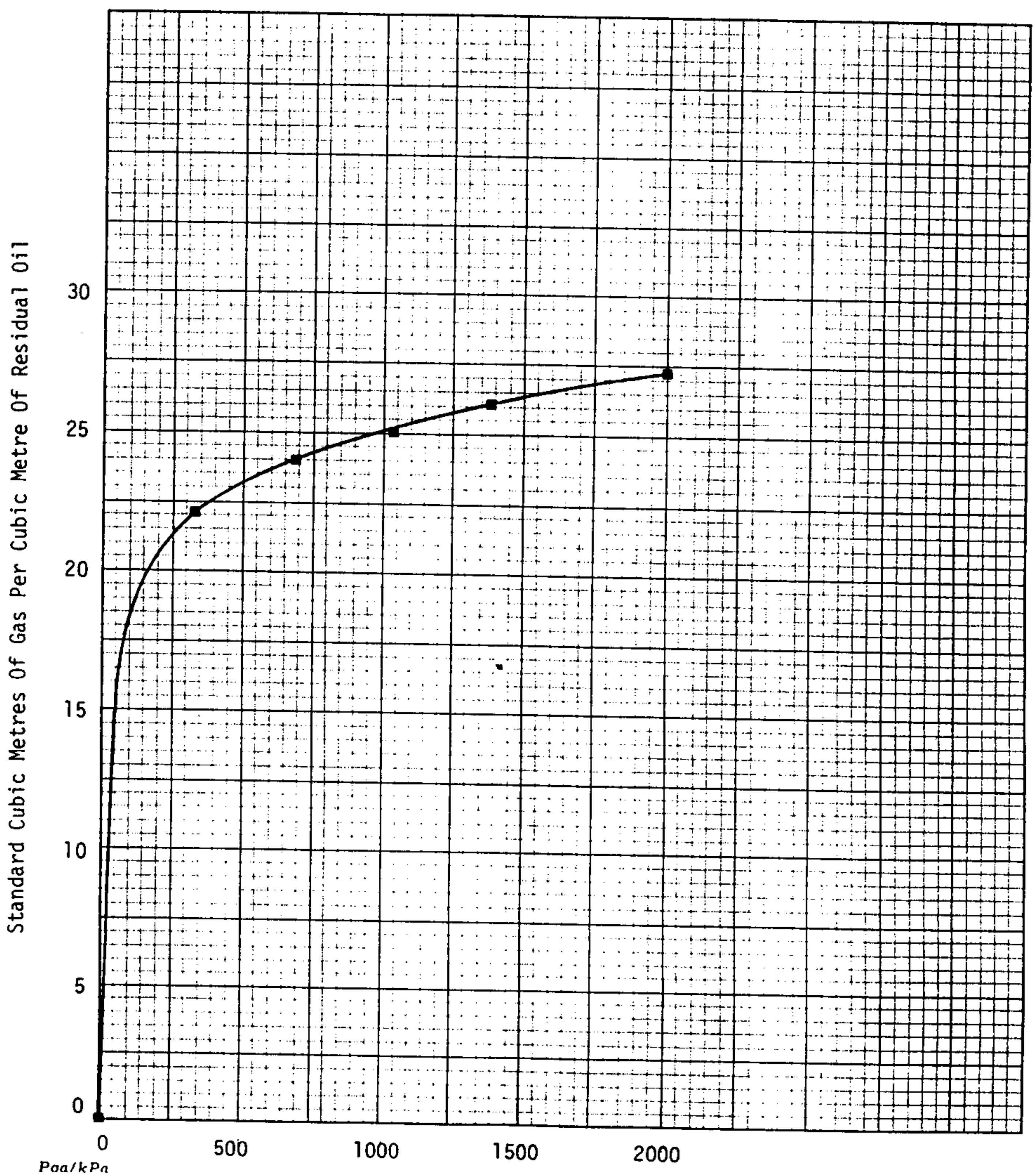


CHEMICAL & GEOLOGICAL LABORATORIES LIMITED

Gas In Solution
By Differential Vaporization

Lab. No. C88-0047

Well Newscope et al Daly
3-28-10-29 W1

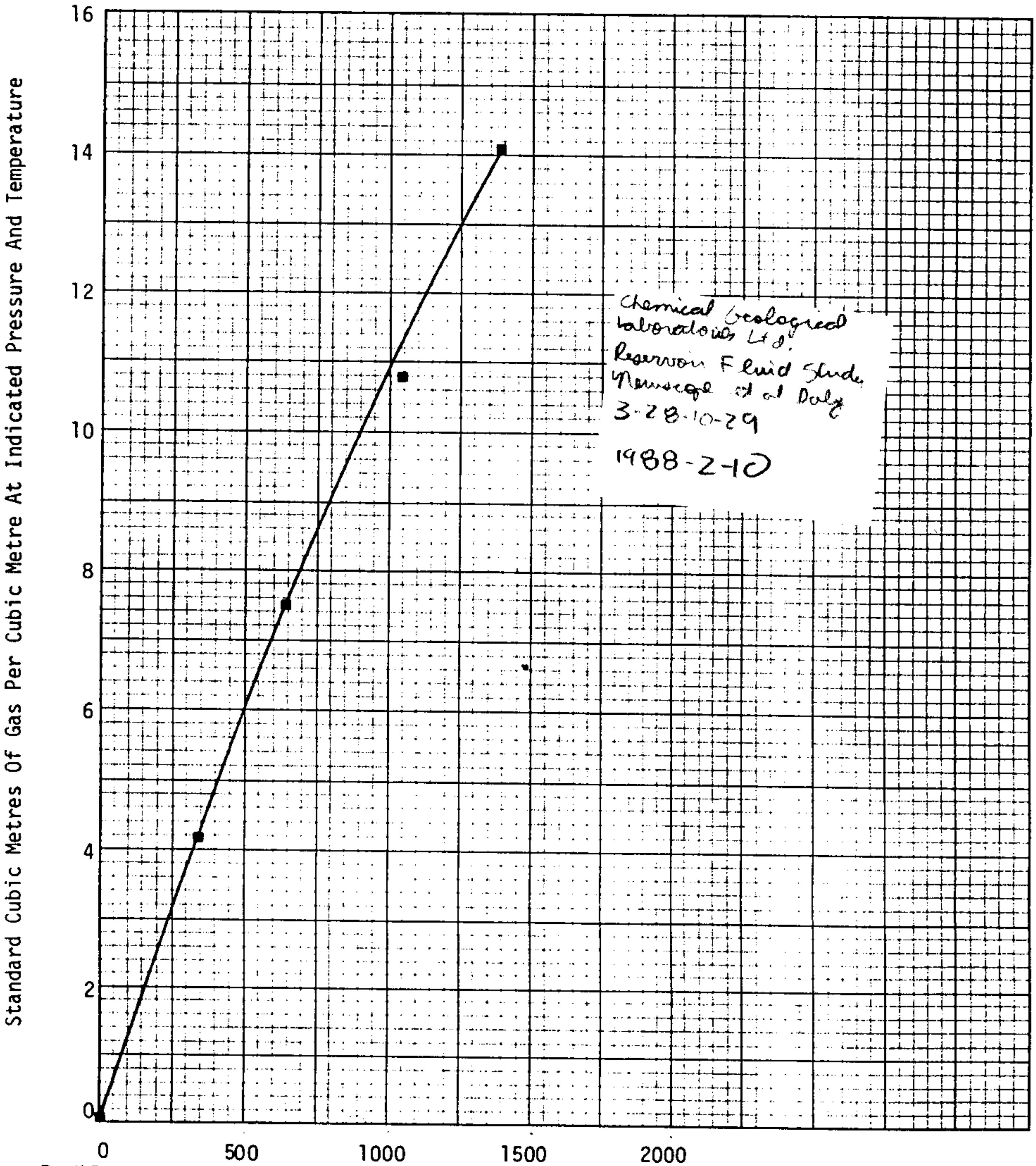


CHEMICAL & GEOLOGICAL LABORATORIES LIMITED

Lab. No. C88-0047

Well Newscope et al Daly
3-28-10-29 W1

Expansion Factor Of Gas
By Differential Vaporization



APPENDIX C

BAKKEN 'A' POOL
MATERIAL BALANCE METHOD OF ESTIMATION OF ORIGINAL OIL-IN-PLACE

MATERIAL BALANCE CALCULATION OF ORIGINAL OIL-IN-PLACE

LIMITED ACQUIFER SUPPORT
(STEADY STATE MODEL)

THE FOLLOWING PROCESS WAS USED TO ESTABLISH THE ORIGINAL OIL-IN-PLACE FOR THE BAKKEN 'A' POOL UNDER LIMITED ACQUIFER SUPPORT:

* REVIEW RESERVOIR FLUID PARAMETERS
* REVIEW PVT, PRODUCTION, AND PRESSURE OF BAKKEN 'A' POOL OVER ENTIRE HISTORY
* DETERMINE EFFECTIVE OIL COMPRESSIBILITY
* CALCULATE EXPANSIBILITY OF RESERVOIR FLUIDS
* DETERMINE CHANGE IN PRESSURE OVER TIME WITH EXPANSIBILITY OF RESERVOIR FLUIDS
* CALCULATE RESERVOIR FLUID WITHDRAWALS AND APPARENT OIL-IN-PLACE WITH EACH TIME STEP
* USE NUMERICAL ANALYSIS TECHNIQUE OF LEAST SQUARES ANALYSIS TO SOLVE MATERIAL BALANCE EQUATION FOR ORIGINAL OIL-IN-PLACE

Material Balance Estimate of Original Oil-In-Place

Limited Acquifer Support Model

$$N = \frac{Sum(Xi*Yi) * Sum(Xi) - Sum(Xi^2) * SumYi}{Sum(Xi) * Sum(Xi) - n * Sum(Xi^2)}$$

= Original Oil-In-Place

where

$$X = \frac{Sum(\text{ Change Pressure } * \text{ Change Time })}{D}$$

where D = Expansibility of reservoir fluids

Y = Apparent oil-in-place (estimate of OOIP based on cumulative production at a given point in time)

n = number of years of production

ACQUIFER STEADY STATE MODEL

Reservoir Parameters

Connate Water Saturation = 35%

Oil compressibility = 1.15 E-6

Water Compressibility = 4.5 E-7

Formation Compressibility = 5.8 E-7

Bw = 1.0 m3/m3

Bubble Point Pressure = 2100 kPa

Initial Pressure = 8604 kPa

PRESSURE PRODUCTION DATA

Time (Years)	Oil Prod (m3)	Water Prod (m3)	Pressure (kPa)	Bo
0	0	0	8604	1.063
1(end85)	319.5	15.1	8300	1.065
2(end87)	16408.2	7521.1	7500	1.07
3(mid92)	54390	35386.5	5286	1.092

All of the static pressures are above the bubble point pressure, so the Bakken 'A' Pool can be analyzed as an undersaturated reservoir.

Therefore, next step is to calculate the effective oil compressibility:

$$Coe = \frac{Co}{} + \frac{Cw*Sw}{So} + \frac{Cf}{So}$$

$$= (1.15 + \frac{0.45*0.35}{0.65} + \frac{0.58}{0.65}) *E-6$$

$$= 2.2846 \text{ E-6}$$

CALCULATION OF EXPANSIBILITY (D)

The expansibility (D) is the denominator of the material balance equation when solved for N.

Therefore, for an undersaturated oil reservoir we have:

* Expansibility = D = (Coe) * (Boi) * (Pi - P)

  = 2.2846 *E-6 * 1.063 * (Pi-P)

  = 2.4285 * E-6 (Pi-P)

Therfore, with each static pressure, an expansibility can be calculated:

Time (Years)	Pressure (kPa)	Pi-P (kPa)	Expansibility (D)
0	8604	0	-
1(end85)	8300	304	0.0007383
2(end87)	7500	1104	0.0026811
7(end92)	5286	3318	0.0080578

CALCULATION OF (SUM[Chge P Chge T]) / D

Time	Press	Pavg	Pi-Pavg	ChgeT	ChgePChgeT
0	8604	8604	0		
1	8300	8452	152	2	304
2	7500	7900	704	25	17600
7	5286	5783	2821	54	152334

Time	(SumChgePChgeT) / D
1	411757
2	6564470
7	18905160

	25881387

Y = Na

Sum Y = 21,597,516

X = Sum Chge P Chge T / D

Sum = 25,881,387

CALCULATION OF WITHDRAWALS

Withdrawals = Np*Bo + Wp   (Bw = 1.0)

$$Na = \frac{\text{Withdrawals}}{\text{Expansibility}} = (\text{ apparent oil-in-place })$$

Time (Yrs)	Np (m3)	Bo	Wp (m3)	Np*Bo	Withdrawals (m3)	Na (m3)
0	0	1.063	0	0	0	-
1	319.5	1.065	15.1	340.3	355.4	481,376
2	16408.2	1.070	7521.1	17556.8	25077.9	9,353,577
7	54390.0	1.092	35386.5	59393.9	94780.4	11,762,563
						21,597,516

LEAST SQUARES FORMULA TO DETERMINE N

$$N = \frac{\text{Sum }(Yi*Xi) * \text{Sum }(Xi) - \text{Sum }(Xi^2) * \text{Sum }(Yi)}{\text{Sum }(Xi) * \text{Sum }(Xi) - n*\text{Sum}(Xi^2)}$$

Time	X	X^2	Y	(Y)*(X)
1	411757	1.695438 E11	481,376	1.982099 E11
2	6564470	4.309226 E13	9,353,577	6.140127 E13
7	18905160	3.574050 E14	11,762,563	2.223731 E14
	--------	------------	----------	------------
	25,881,387	4.006668 E14	21,597,516	2.839725 E14

$$N = \frac{2.839725\text{ E14} * 25{,}881{,}387 - 4.006668\text{ E14} * 21{,}597{,}516}{(25{,}881{,}387)^2 - 7*4.006668\text{ E14}}$$

= 610 E3M3

= 3.8 MM STB

PORE VOLUME WEIGHTED PRESSURES

The Bakken 'A' Pool pore volume weighted reservoir pressure to mid 1992 was determined using the following procedure:

WELL	PRESSURE (kPa)	PHI-H (m)	% of PHI-H (%)	Pore Volume Weighted Pressure (kPa)
11-28	6500	0.1524	12.2	793
16-20	5500	0.4907	39.4	2167
6-28	5500	0.1829	14.7	809
4-28	4500	0.4206	33.7	1517
		1.2466	100.0	5286

APPENDIX D

BAKKEN 'A' POOL
TOTAL PRODUCTION HISTORY

	SUMMARY OF KOLA BAKKEN 'A' POOL TOTAL PRODUCTION HISTORY					
Year	Month Oil (m3)	Cum. Oil (m3)	Oil Rate (m3/day)	Watercut (%)	Month Water (m3)	Cum. Water (m3)
85	46.20	46.20	1.49	17.79	10.00	10.00
85	273.30	319.50	9.11	1.83	5.10	15.10
85	230.20	549.70	7.43	29.49	96.30	111.40
86	265.10	814.80	8.55	20.84	69.80	181.20
86	380.80	1,195.60	13.60	23.21	115.10	296.30
86	386.70	1,582.30	12.47	17.30	80.90	377.20
86	395.10	1,977.40	13.17	9.34	40.70	417.90
86	359.40	2,336.80	11.59	19.69	88.10	506.00
86	346.80	2,683.60	11.56	16.63	69.20	575.20
86	571.40	3,255.00	18.43	15.11	101.70	676.90
86	698.20	3,953.20	22.52	16.14	134.40	811.30
86	655.80	4,609.00	21.86	15.50	120.30	931.60
86	641.40	5,250.40	20.69	15.15	114.50	1,046.10
86	599.90	5,850.30	20.00	14.40	100.90	1,147.00
86	699.60	6,549.90	22.57	28.40	277.50	1,424.50
87	721.70	7,271.60	23.28	29.90	307.80	1,732.30
87	608.20	7,879.80	21.72	30.67	269.00	2,001.30
87	669.40	8,549.20	21.59	44.43	535.30	2,536.60
87	563.00	9,112.20	18.77	33.03	277.70	2,814.30
87	589.40	9,701.60	19.01	32.97	289.90	3,104.20
87	563.20	10,264.80	18.77	36.49	323.60	3,427.80
87	862.00	11,126.80	27.81	31.62	398.60	3,826.40
87	954.80	12,081.60	30.80	38.81	605.70	4,432.10
87	977.60	13,059.20	32.59	38.24	605.30	5,037.40
87	966.20	14,025.40	31.17	41.97	698.80	5,736.20
87	1081.60	15,107.00	36.05	41.85	778.30	6,514.50
87	1301.20	16,408.20	41.97	45.60	1,090.80	7,605.30
88	1222.30	17,630.50	39.43	45.87	1,035.90	8,641.20
88	1261.90	18,892.40	45.07	42.32	925.80	9,567.00
88	1342.10	20,234.50	43.29	40.65	919.40	10,486.40
88	1227.90	21,462.40	40.93	40.32	829.60	11,316.00
88	1232.10	22,694.50	39.75	39.40	801.10	12,117.10
88	1135.50	23,830.00	37.85	38.89	722.60	12,839.70
88	1105.40	24,935.40	35.66	41.81	794.40	13,634.10
88	1018.60	25,954.00	32.86	45.43	847.90	14,482.00
88	935.10	26,889.10	31.17	38.32	581.00	15,063.00
88	917.40	27,806.50	29.59	39.99	611.30	15,674.30
88	868.40	28,674.90	28.95	37.98	531.80	16,206.10
88	853.00	29,527.90	27.52	39.10	547.60	16,753.70
89	845.30	30,373.20	27.27	40.61	578.10	17,331.80

	SUMMARY OF KOLA BAKKEN 'A' POOL TOTAL PRODUCTION HISTORY					
Year	Month Oil (m3)	Cum. Oil (m3)	Oil Rate (m3/day)	Watercut (%)	Month Water (m3)	Cum. Water (m3)
89	746.90	31,120.10	26.68	40.41	506.40	17,838.20
89	784.50	31,904.60	25.31	43.07	593.60	18,431.80
89	716.80	32,621.40	23.89	43.53	552.50	18,984.30
89	747.50	33,368.90	24.11	42.06	542.60	19,526.90
89	682.50	34,051.40	22.75	42.86	512.00	20,038.90
89	760.80	34,812.20	24.54	40.93	527.20	20,566.10
89	699.70	35,511.90	22.57	42.03	507.40	21,073.50
89	665.50	36,177.40	22.18	42.94	500.90	21,574.40
89	682.70	36,860.10	22.02	41.41	482.60	22,057.00
89	647.10	37,507.20	21.57	40.99	449.50	22,506.50
89	622.90	38,130.10	20.09	43.78	485.10	22,991.60
90	641.00	38,771.10	20.68	44.76	519.30	23,510.90
90	647.10	39,418.20	23.11	39.46	421.80	23,932.70
90	664.20	40,082.40	21.43	39.55	434.50	24,367.20
90	596.60	40,679.00	19.89	44.86	485.30	24,852.50
90	621.20	41,300.20	20.04	43.26	473.70	25,326.20
90	591.30	41,891.50	19.71	43.17	449.20	25,775.40
90	622.30	42,513.80	20.07	43.41	477.30	26,252.70
90	631.30	43,145.10	20.36	41.75	452.50	26,705.20
90	584.40	43,729.50	19.48	42.61	433.90	27,139.10
90	550.40	44,279.90	17.75	46.41	476.70	27,615.80
90	538.60	44,818.50	17.95	44.89	438.80	28,054.60
90	521.50	45,340.00	16.82	46.34	450.40	28,505.00
91	587.60	45,927.60	18.95	43.57	453.70	28,958.70
91	555.40	46,483.00	19.84	41.78	398.50	29,357.20
91	580.20	47,063.20	18.72	43.78	451.90	29,809.10
91	515.30	47,578.50	17.18	46.30	444.30	30,253.40
91	572.50	48,151.00	18.47	42.59	424.70	30,678.10
91	509.70	48,660.70	16.99	45.32	422.50	31,100.60
91	517.70	49,178.40	16.70	46.13	443.40	31,544.00
91	516.50	49,694.90	16.66	45.67	434.10	31,978.10
91	513.00	50,207.90	17.10	44.65	413.80	32,391.90
91	480.10	50,688.00	15.49	47.58	435.80	32,827.70
91	505.70	51,193.70	16.86	43.59	390.80	33,218.50
91	451.00	51,644.70	14.55	48.93	432.10	33,650.60
92	481.50	52,126.20	15.53	45.65	404.40	34,055.00
92	456.70	52,582.90	16.31	46.57	398.10	34,453.10
92	411.90	52,994.80	13.29	48.90	394.20	34,847.30
92	389.70	53,384.50	12.99	46.33	336.40	35,183.70
92	431.00	53,815.50	13.90	47.37	387.90	35,571.60
92	574.50	54,390.00	19.15	36.46	329.60	35,901.20

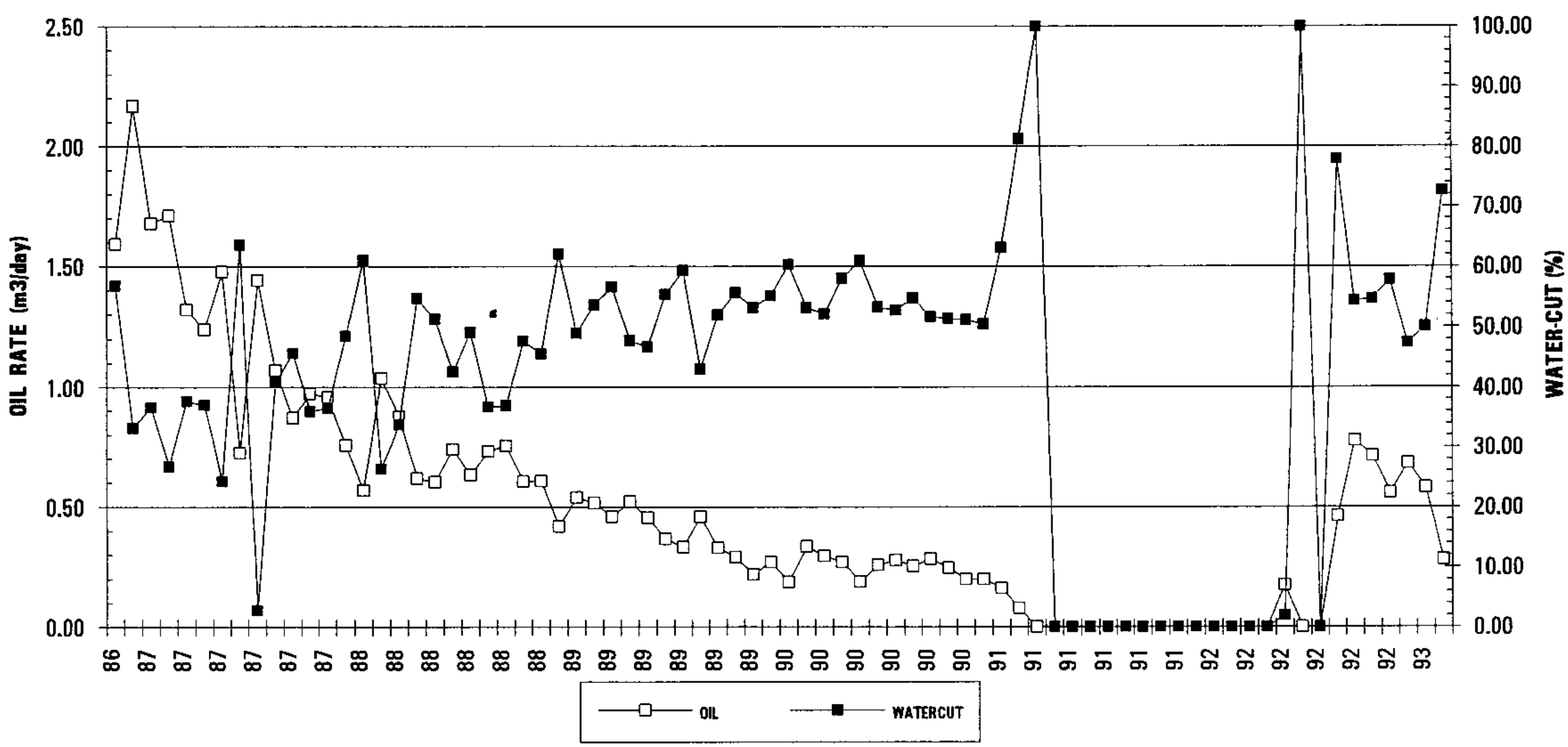
SUMMARY OF KOLA BAKKEN 'A' POOL TOTAL PRODUCTION HISTORY

Year	Month Oil (m3)	Cum. Oil (m3)	Oil Rate (m3/day)	Watercut (%)	Month Water (m3)	Cum. Water (m3)
92	554.70	54,944.70	17.89	44.60	446.50	36,347.70
92	566.50	55,511.20	18.27	46.25	487.40	36,835.10
92	568.10	56,079.30	18.94	41.13	396.90	37,232.00
92	547.20	56,626.50	17.65	47.24	490.00	37,722.00
92	544.30	57,170.80	18.14	39.20	351.00	38,073.00
92	513.20	57,684.00	16.55	40.13	344.00	38,417.00
93	590.80	58,274.80	19.06	38.32	367.00	38,784.00
93	564.60	58,839.40	20.16	46.08	482.50	39,266.50
93	634.70	59,474.10	20.47	63.05	1,083.00	40,349.50

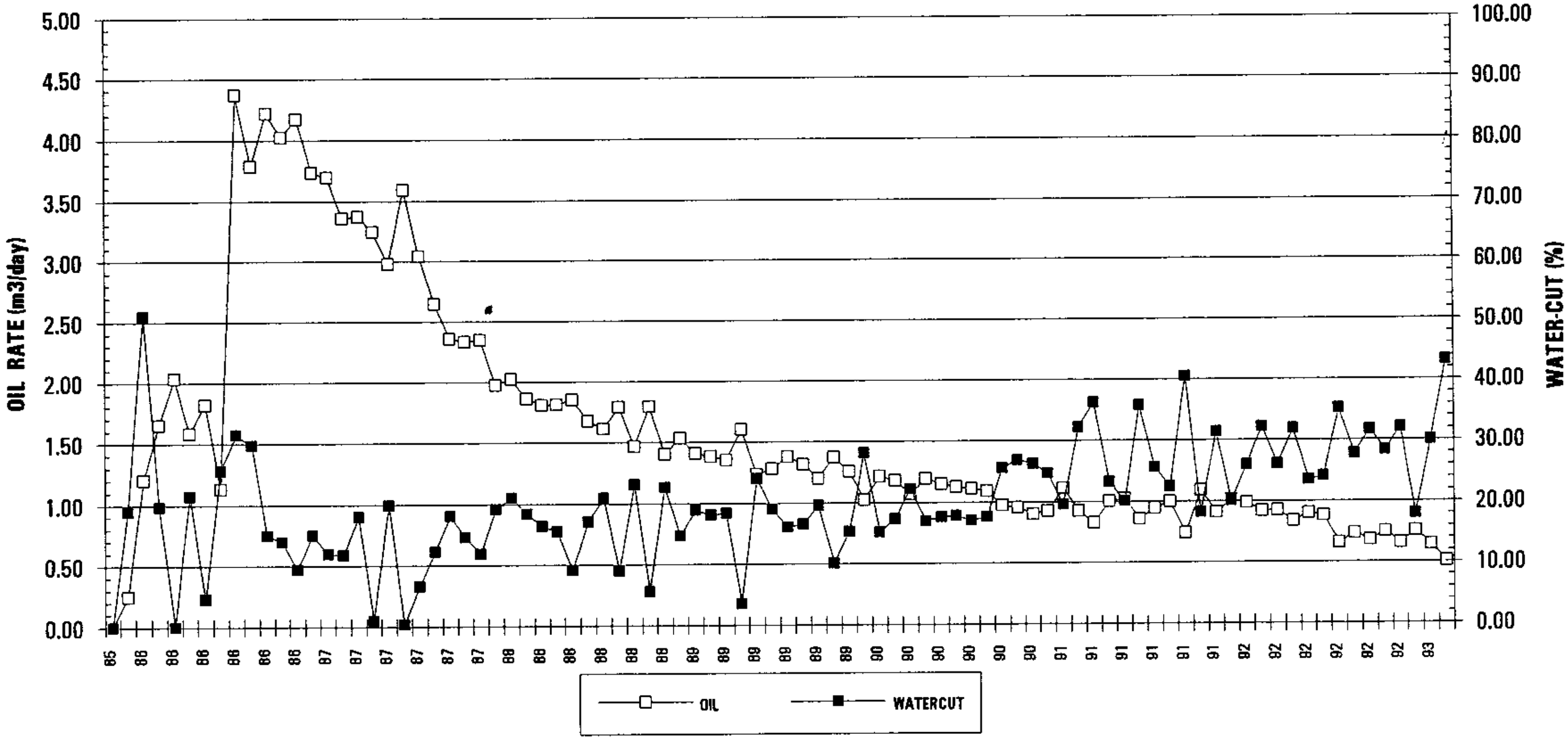
APPENDIX E

BAKKEN 'A' POOL
INDIVIDUAL WELL PRODUCTION TIME PLOTS

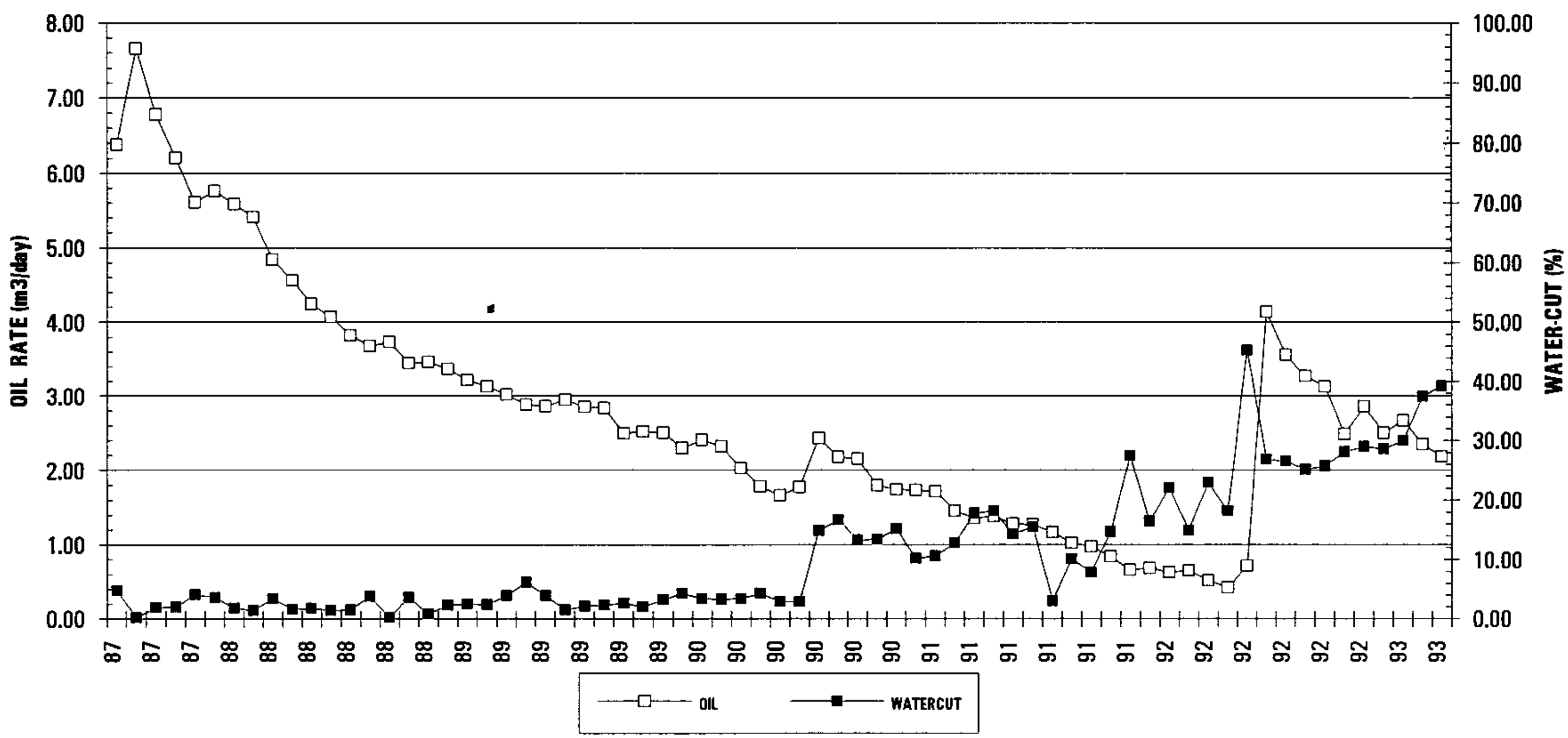
WELL 16-17-10-29 PRODUCTION HISTORY



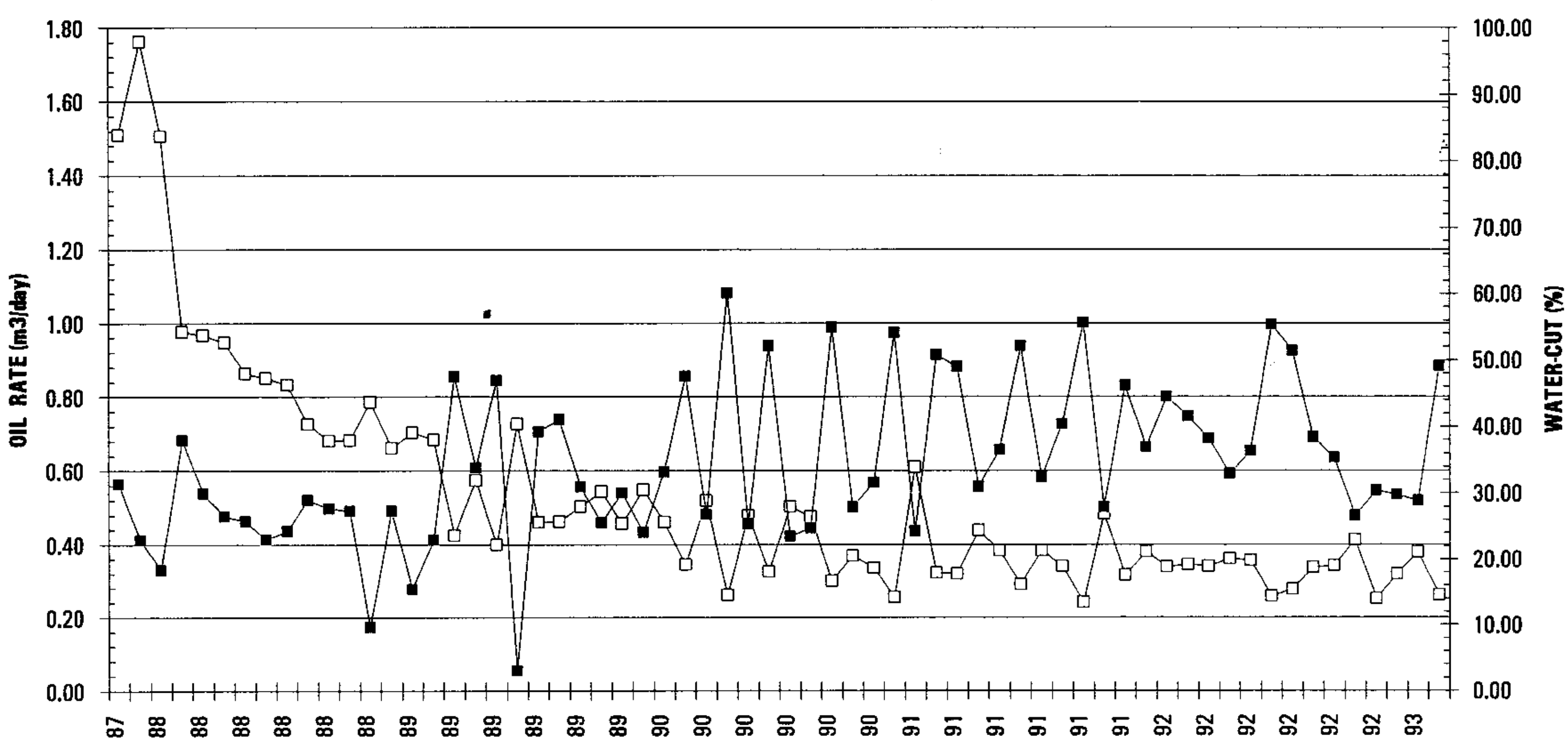
WELL 9-20-10-29 PRODUCTION HISTORY



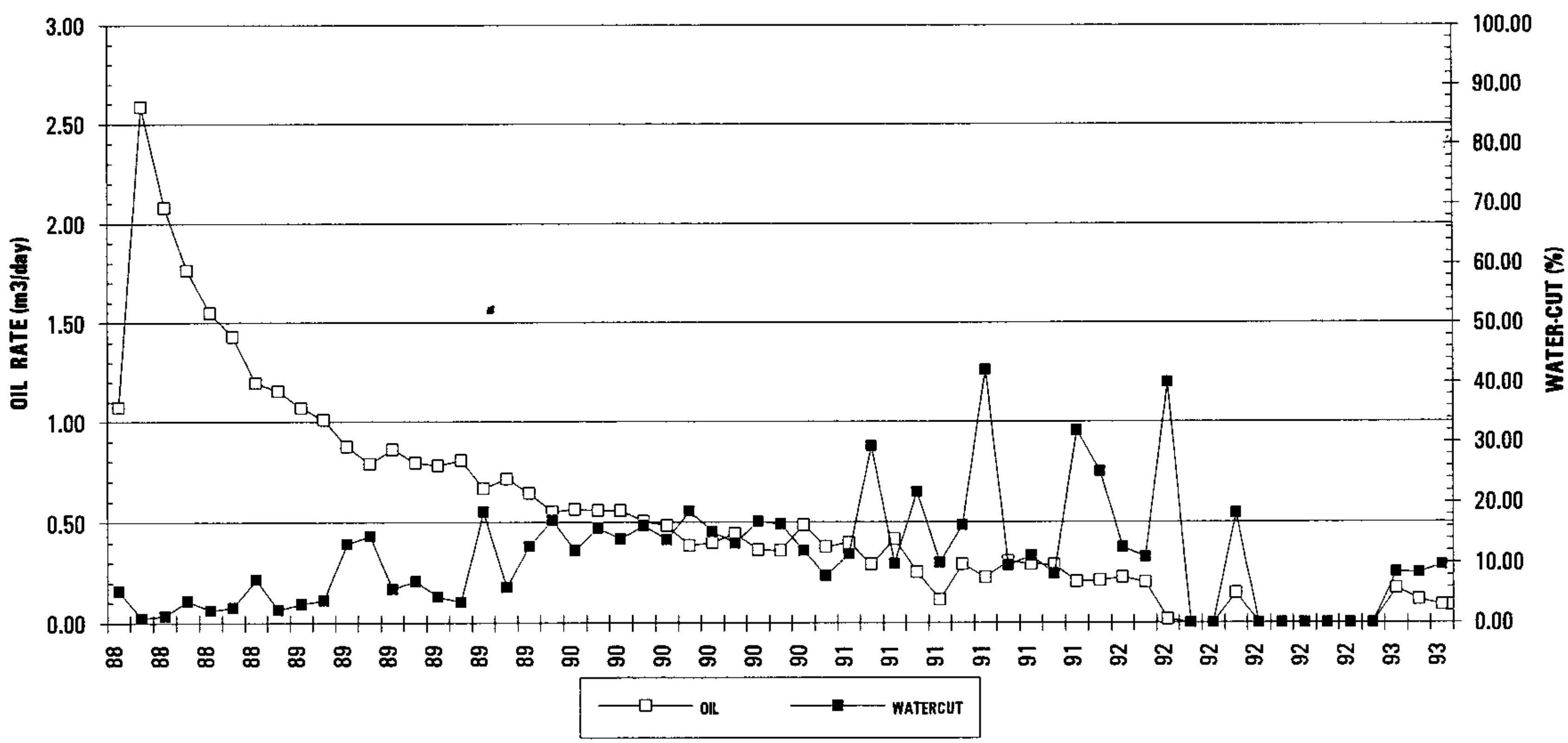
WELL 16-20-10-29 PRODUCTION HISTORY



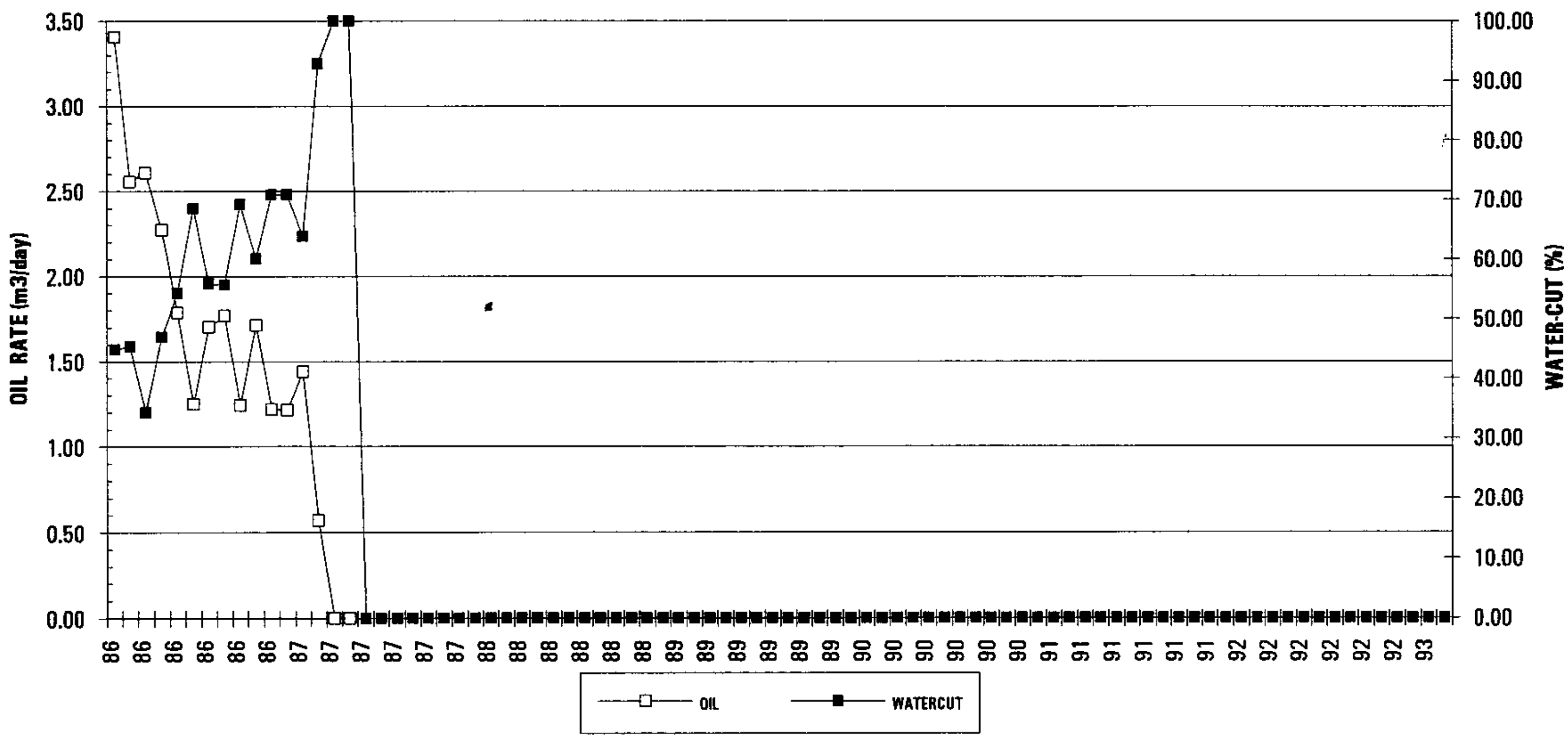
WELL 5-21-10-29 PRODUCTION HISTORY



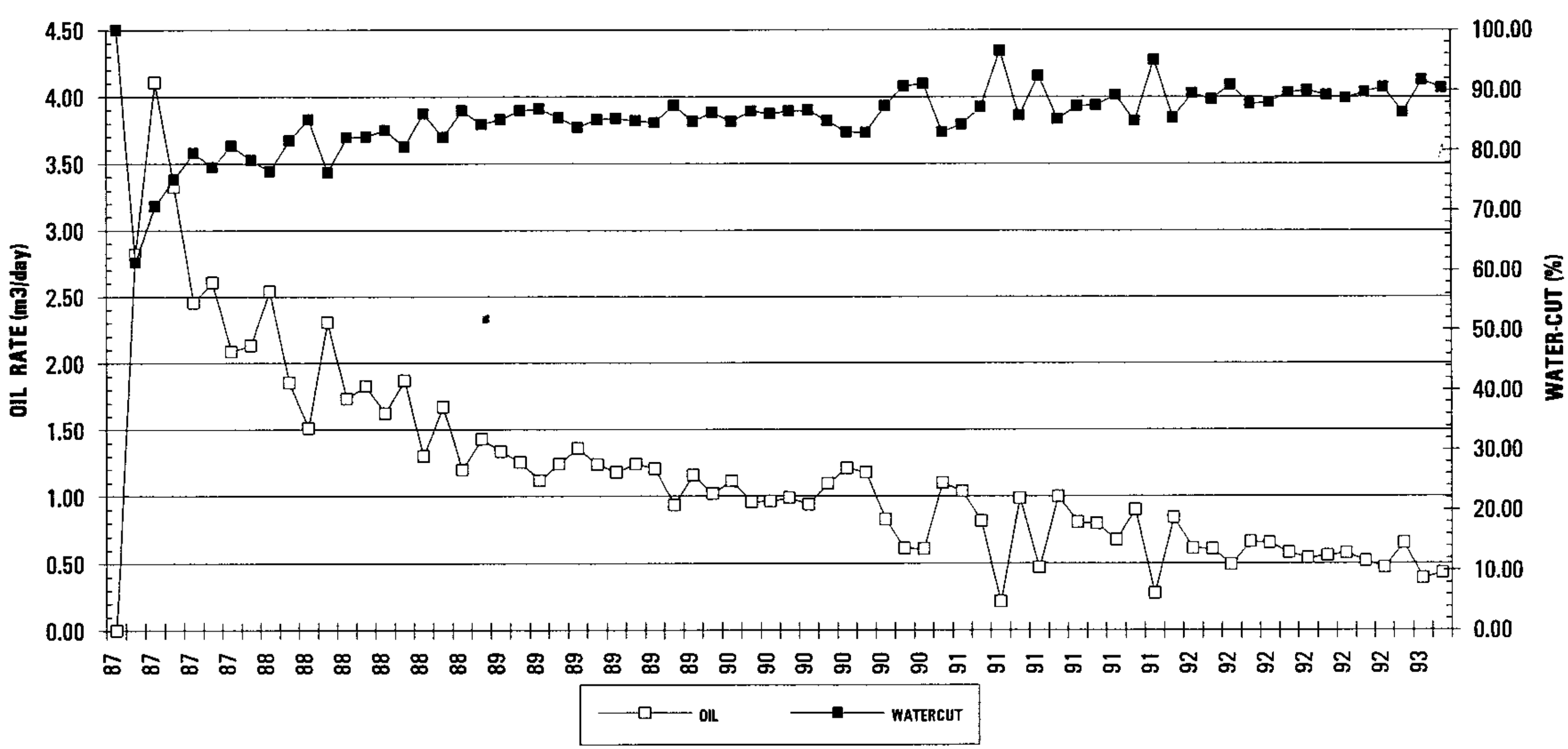
WELL 10-21-10-29 PRODUCTION HISTORY



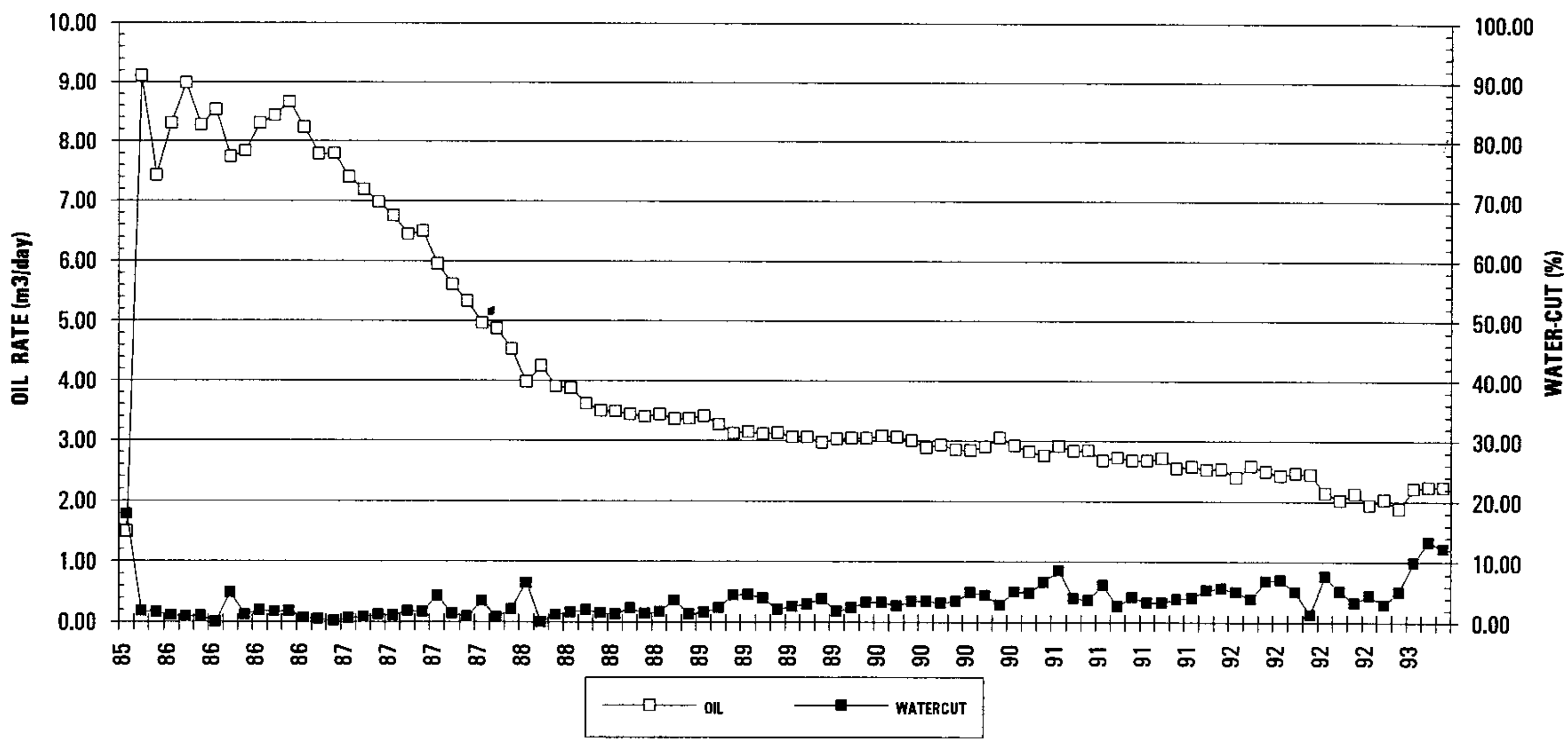
WELL 11-21-10-29 PRODUCTION HISTORY



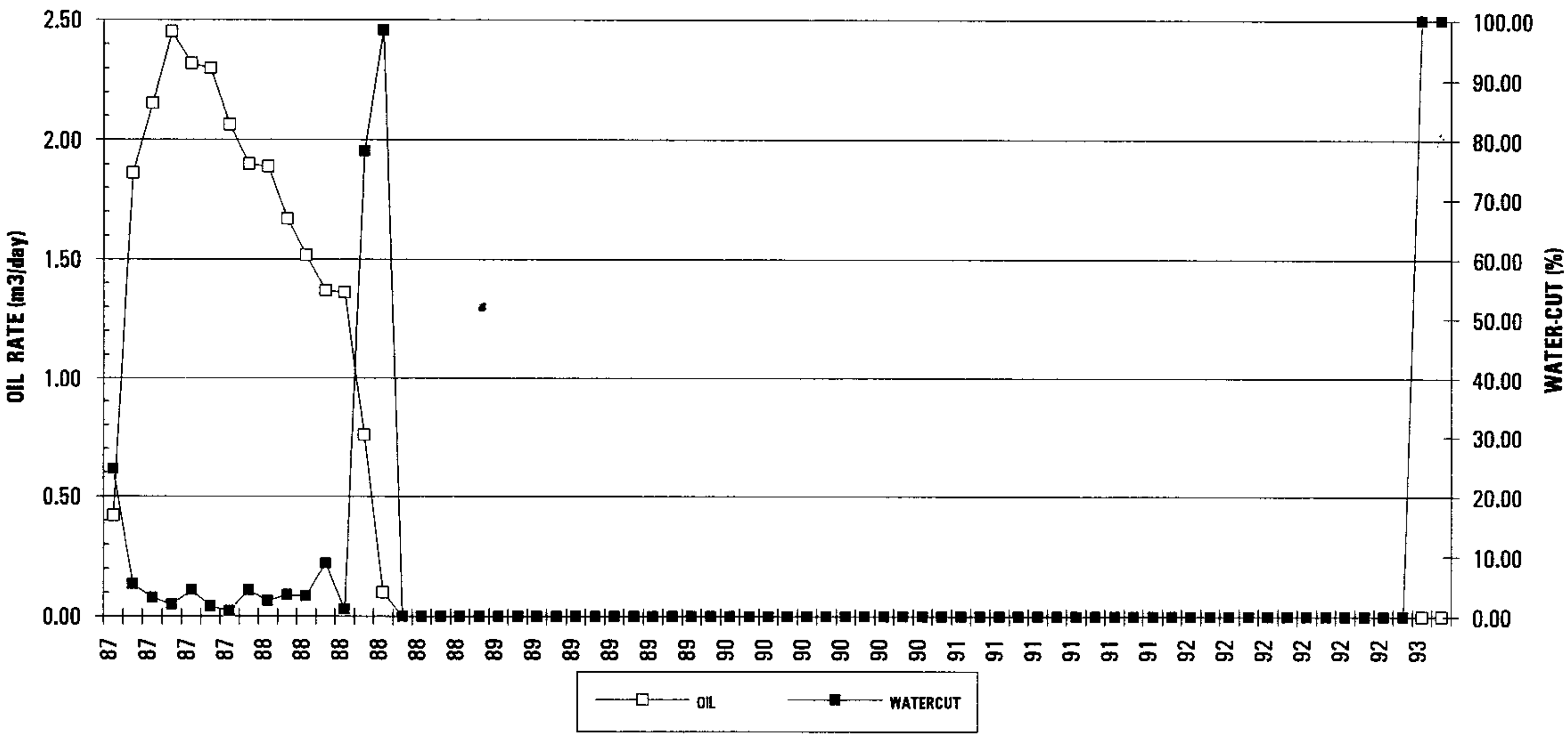
WELL 12-21-10-29 PRODUCTION HISTORY



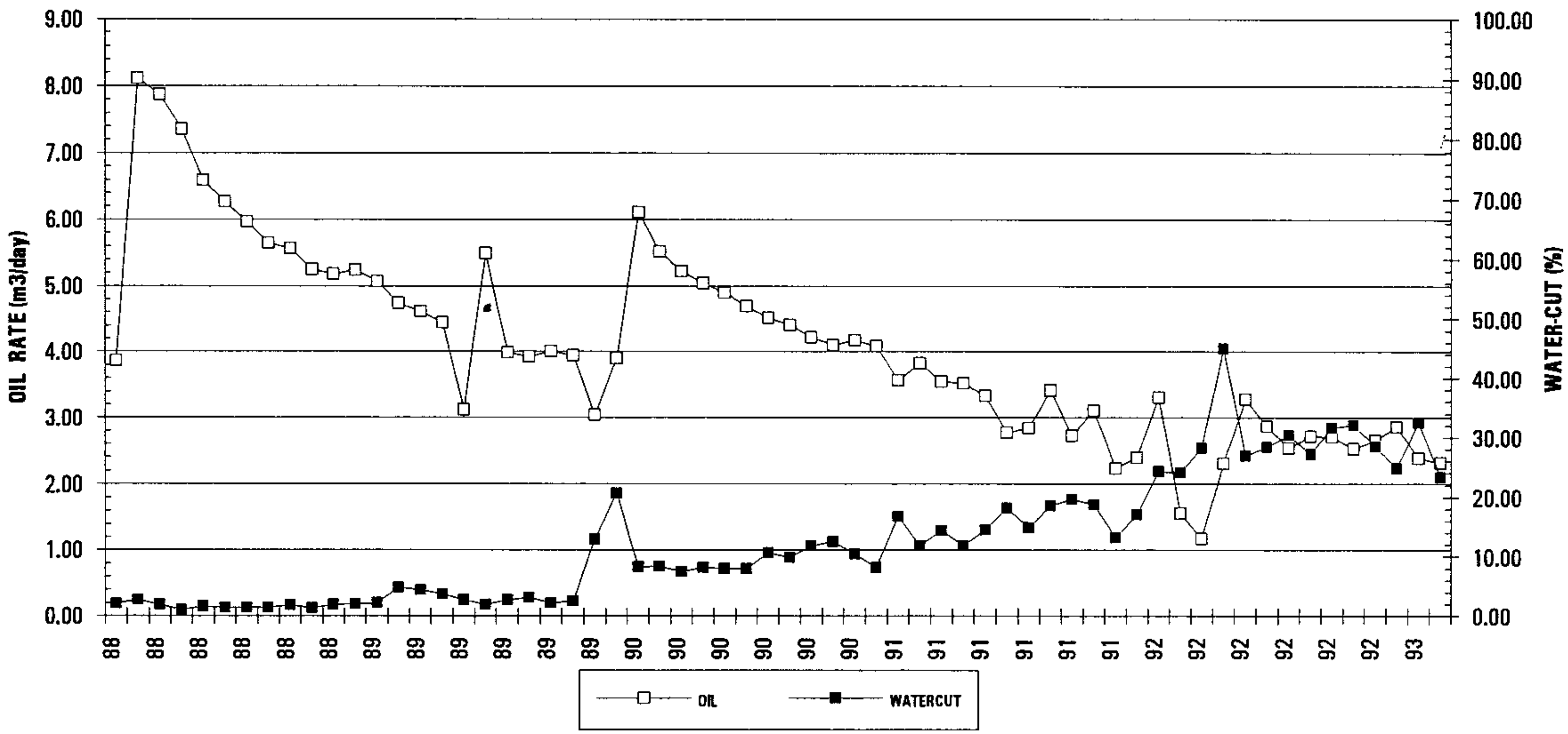
WELL 13-21-10-29 PRODUCTION HISTORY



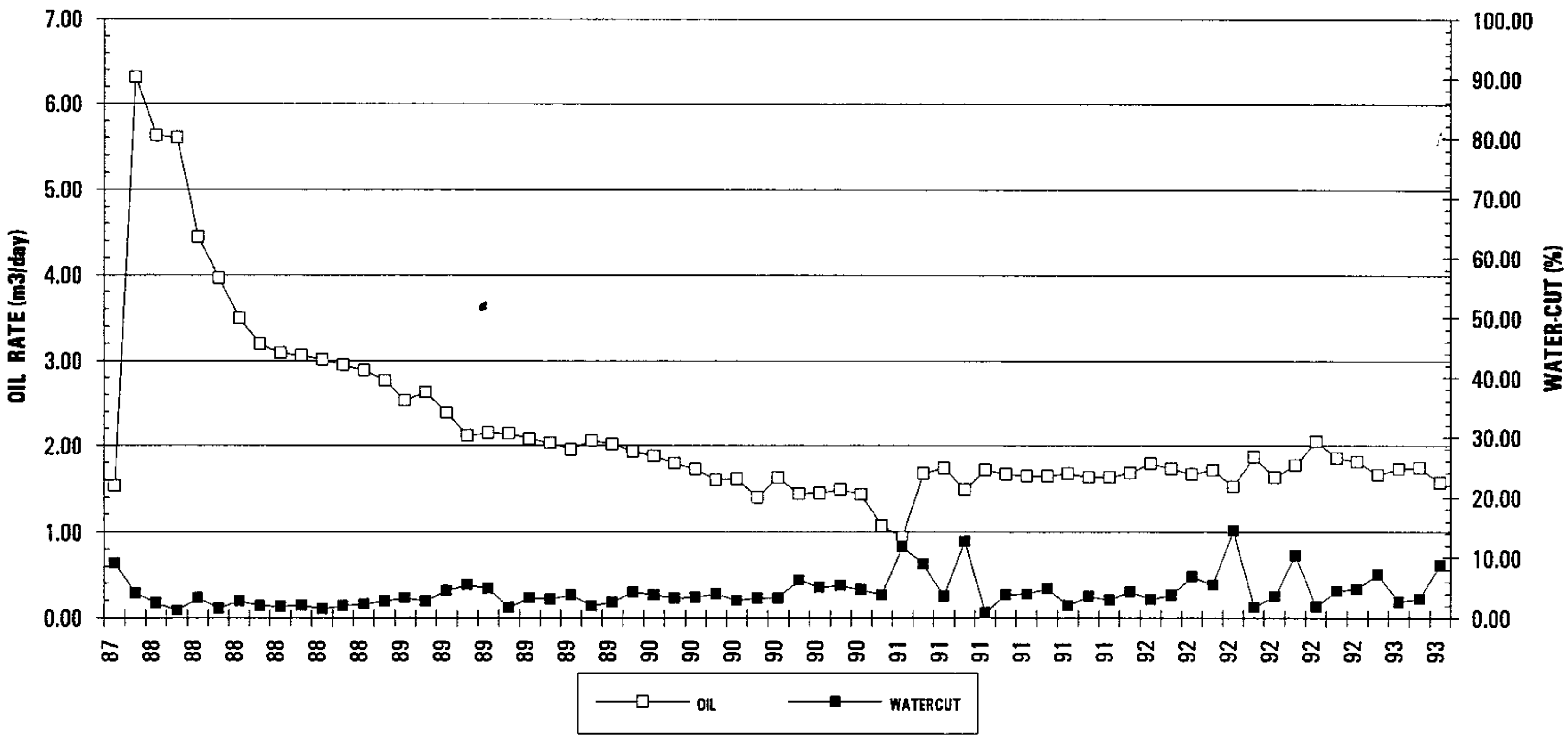
WELL 14-21-10-29 PRODUCTION HISTORY



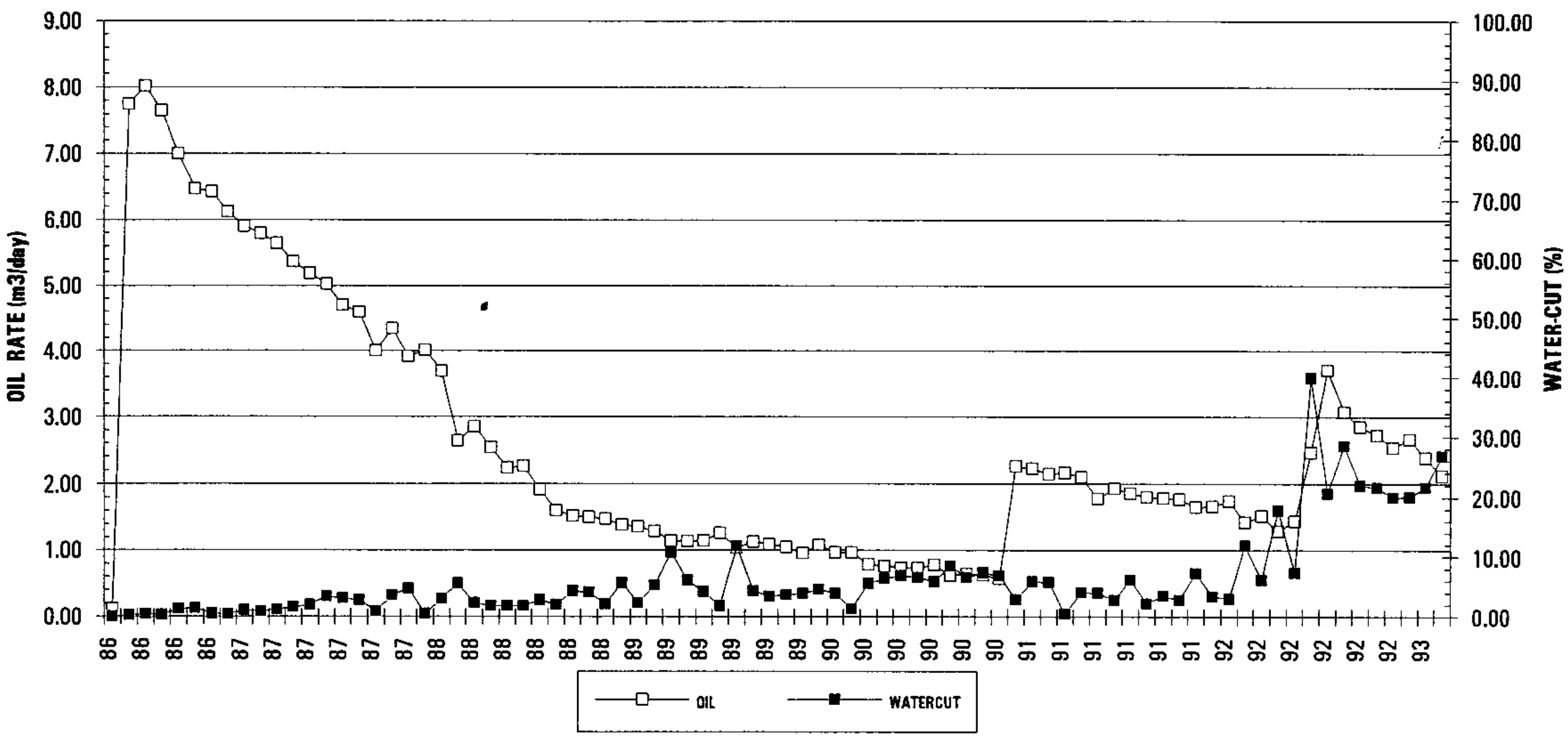
WELL 2-28-10-29 PRODUCTION HISTORY



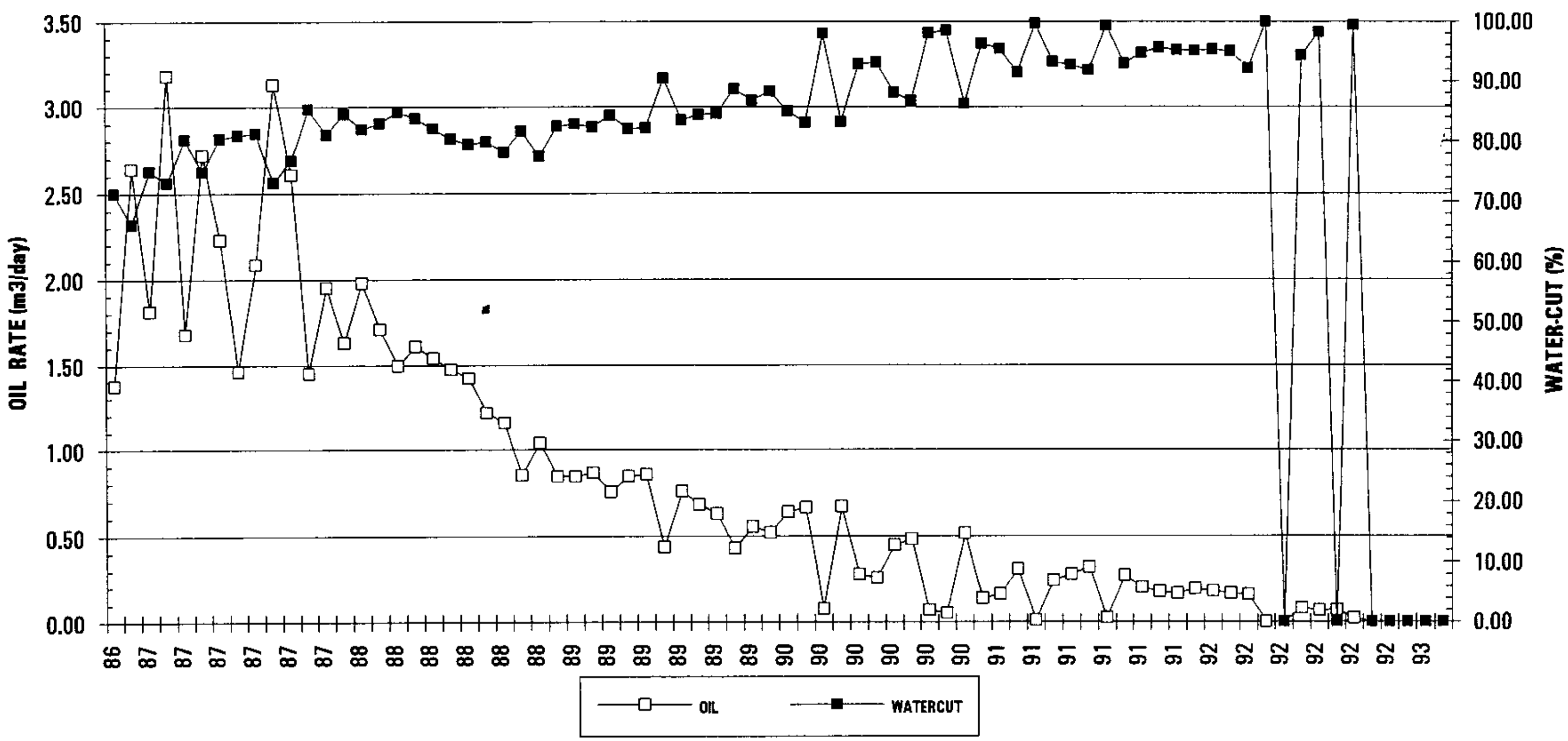
WELL 3-28-10-29 PRODUCTION HISTORY



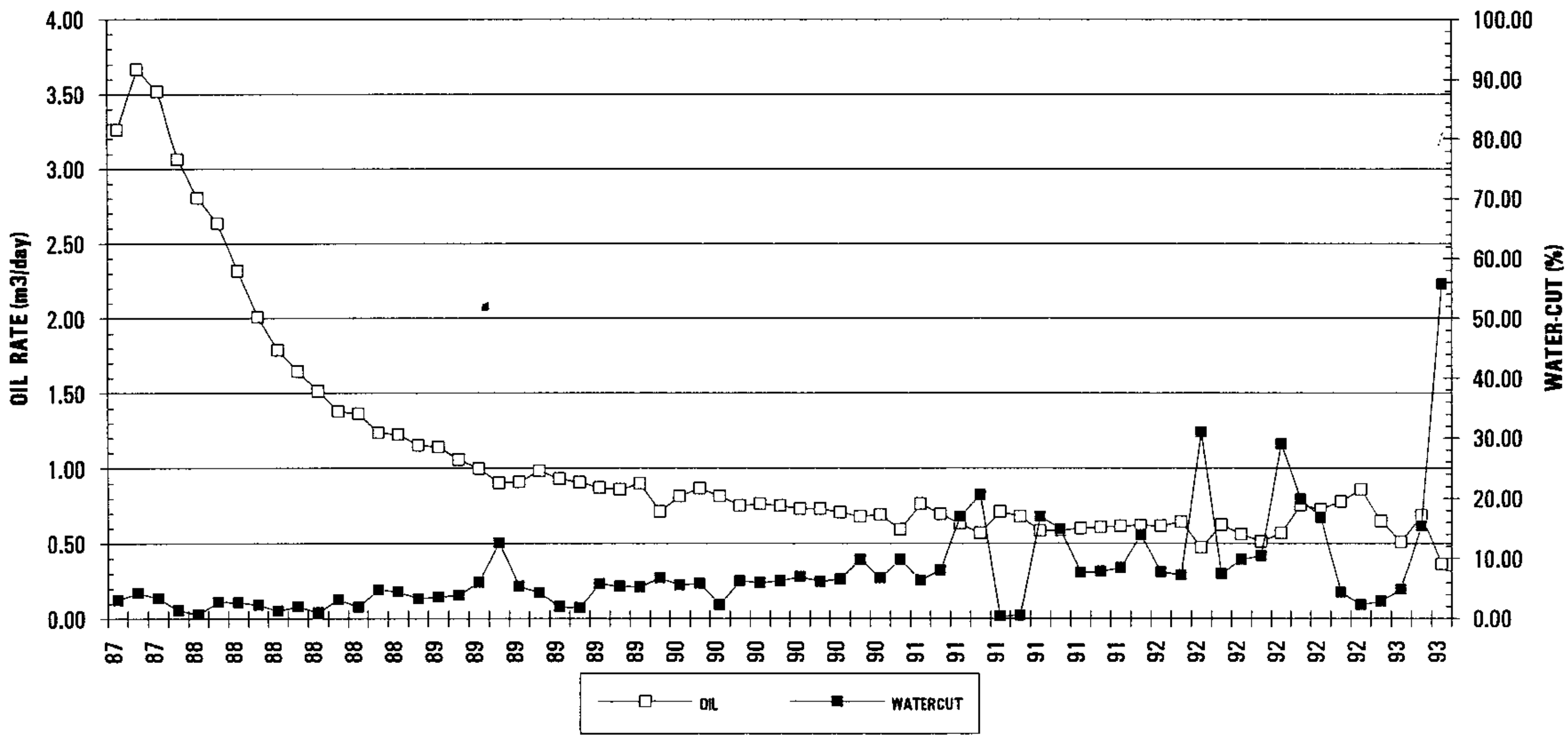
WELL 4-28-10-29 PRODUCTION HISTORY



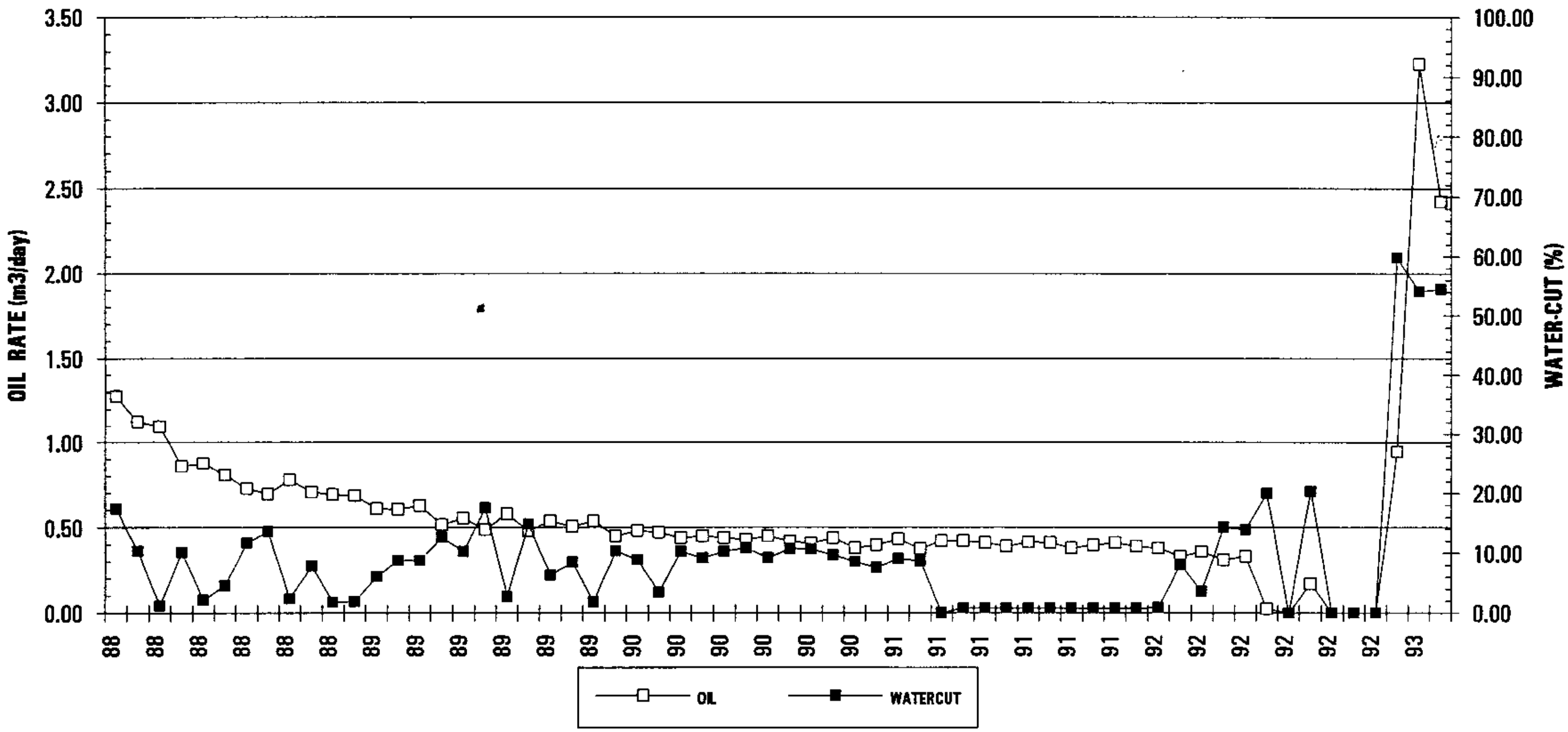
WELL 5-28-10-29 PRODUCTION HISTORY



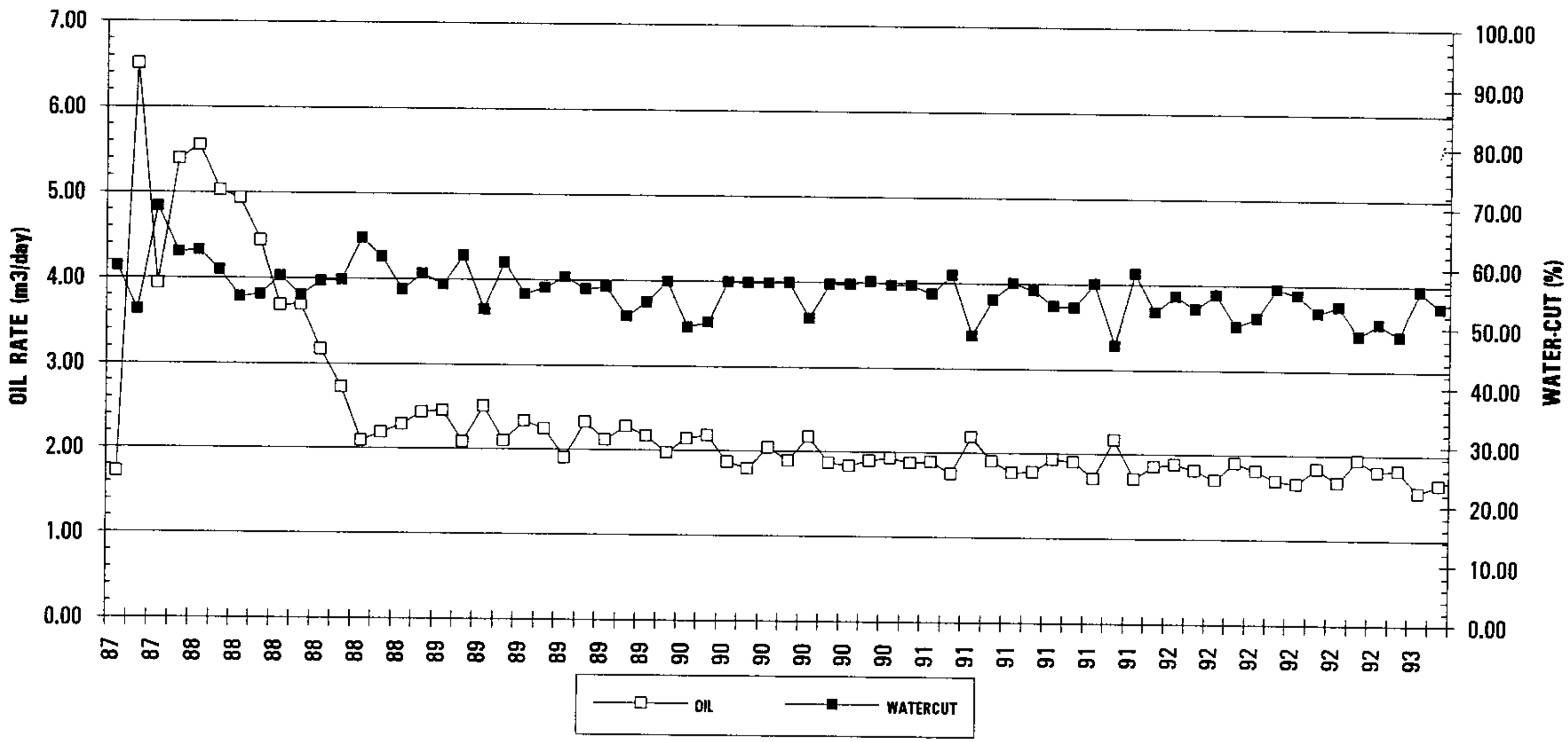
WELL 6-28-10-29 PRODUCTION HISTORY



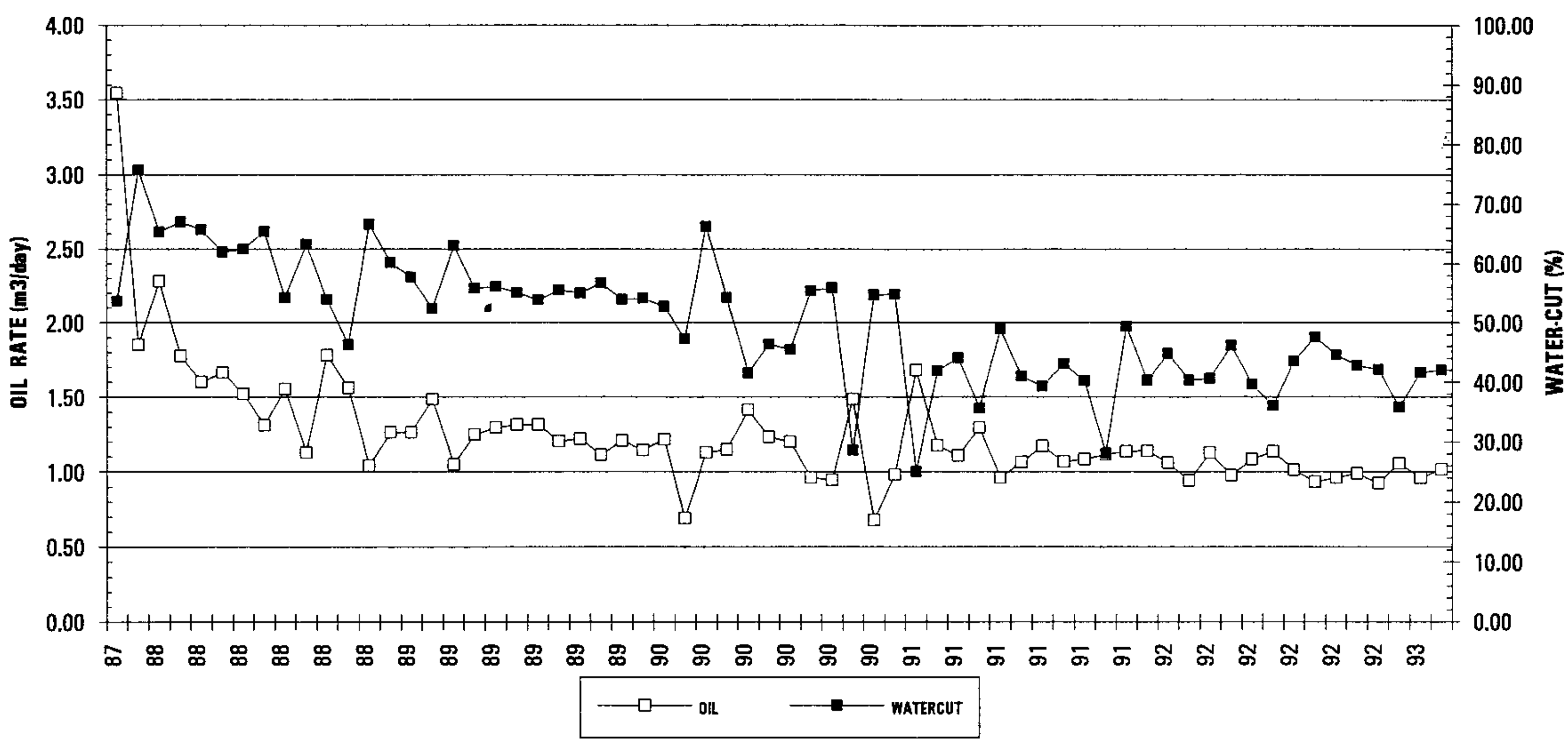
WELL 11-28-10-29 PRODUCTION HISTORY



WELL 12-28-10-29 PRODUCTION HISTORY



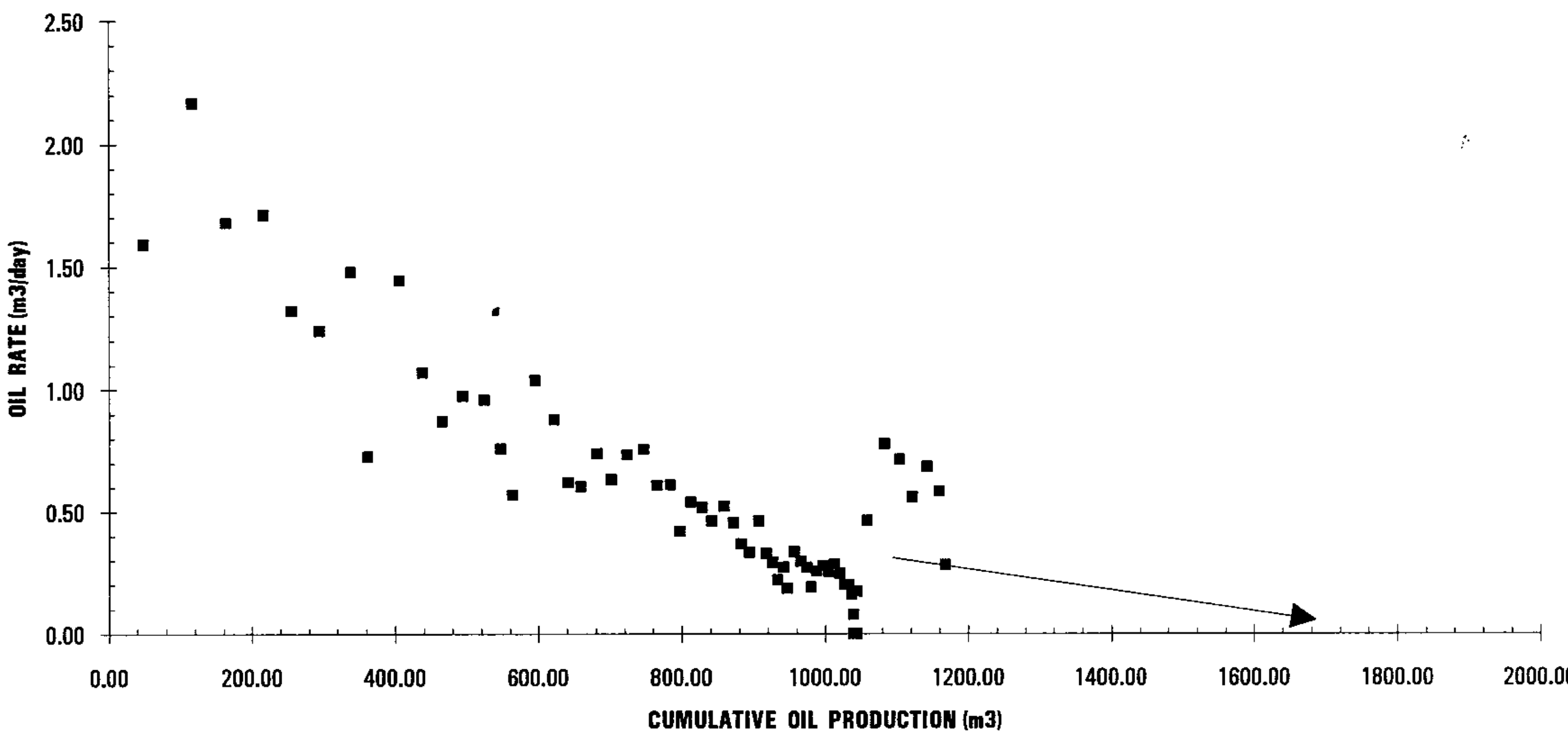
WELL 9-29-10-29 PRODUCTION HISTORY



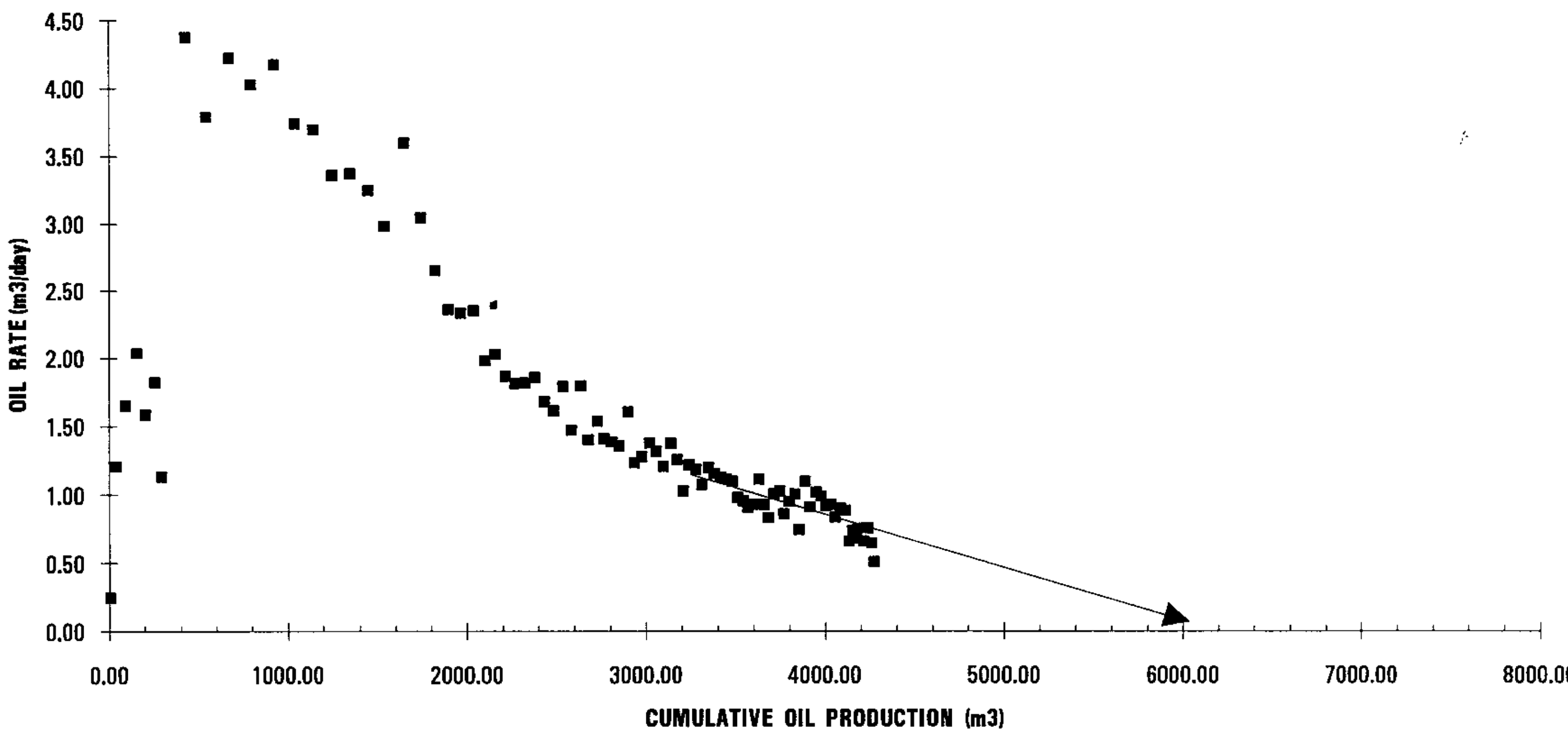
APPENDIX F

BAKKEN 'A' POOL
INDIVIDUAL WELL OIL RATE vs CUMULATIVE PRODUCTION PLOTS
ESTIMATE OF REMAINING PROVED RESERVES

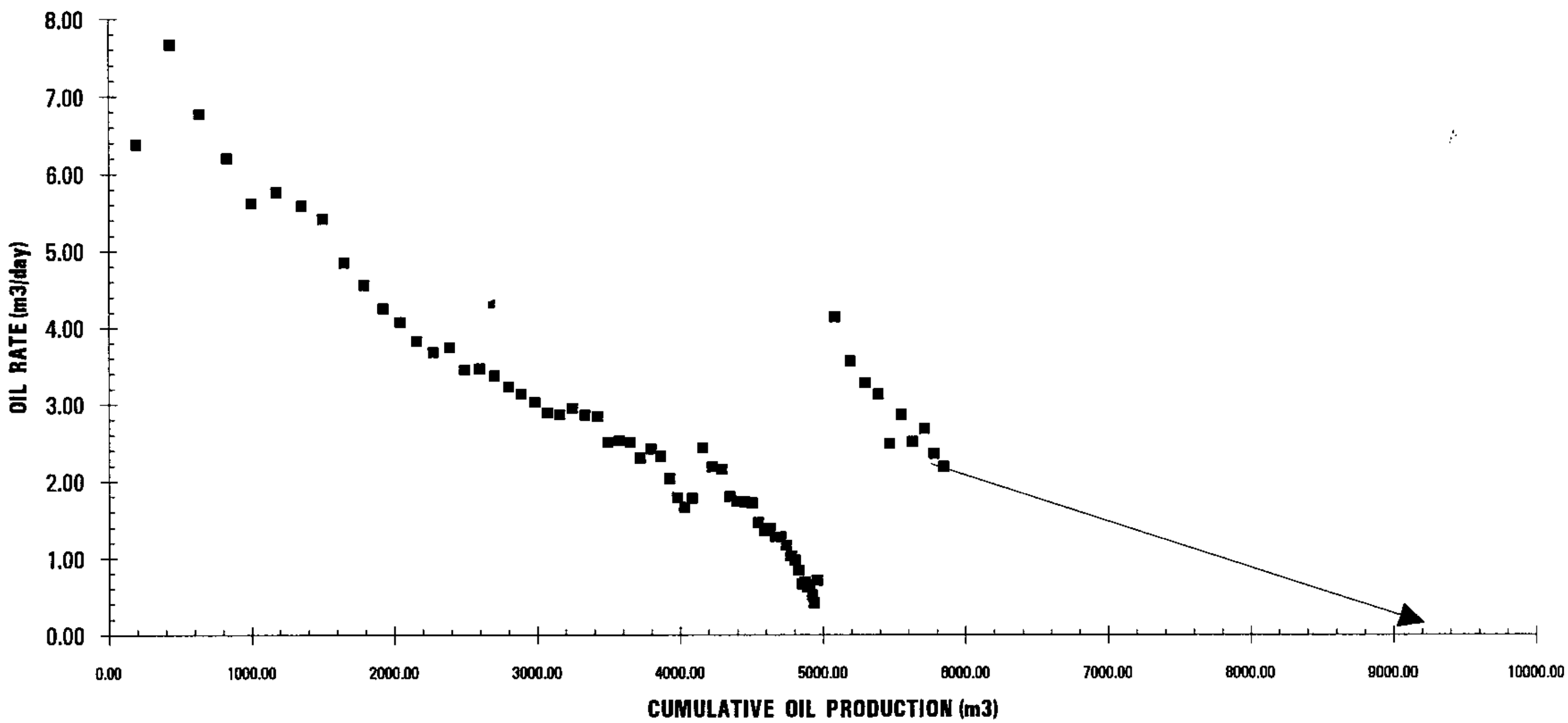
WELL 16-17-10-29 REMAINING PROVED RESERVES



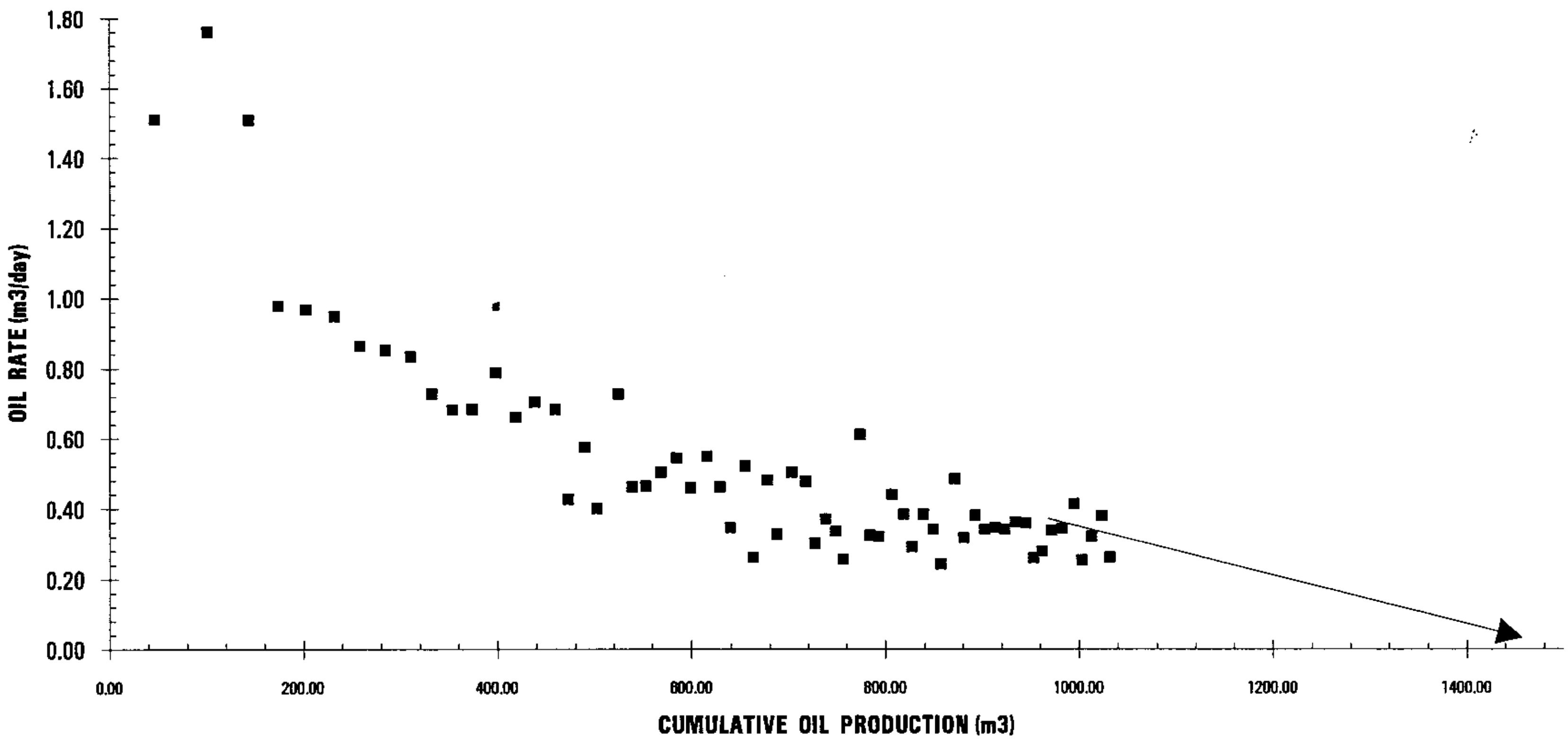
WELL 9-20-10-29 REMAINING PROVED RESERVES



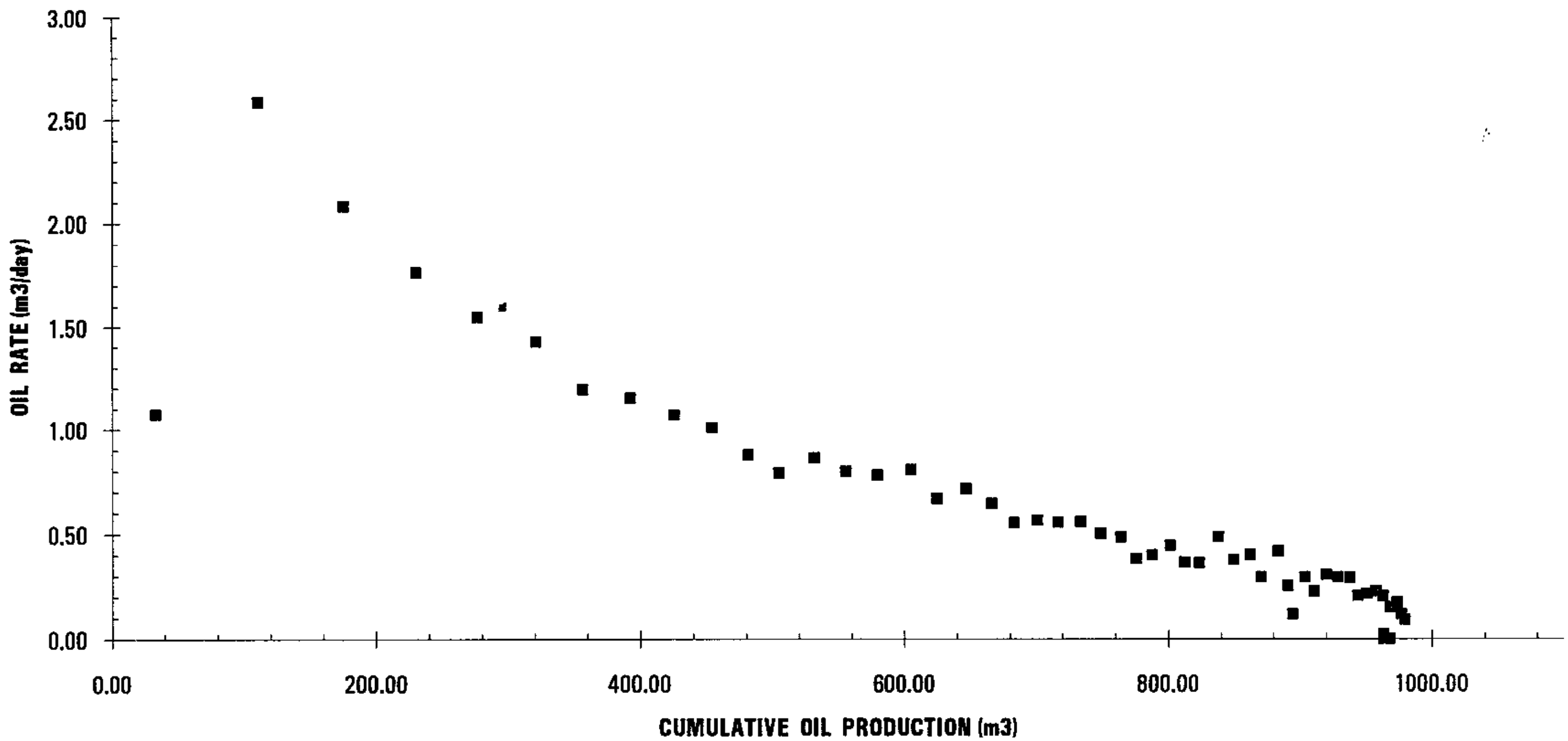
WELL 16-20-10-29 REMAINING PROVED RESERVES



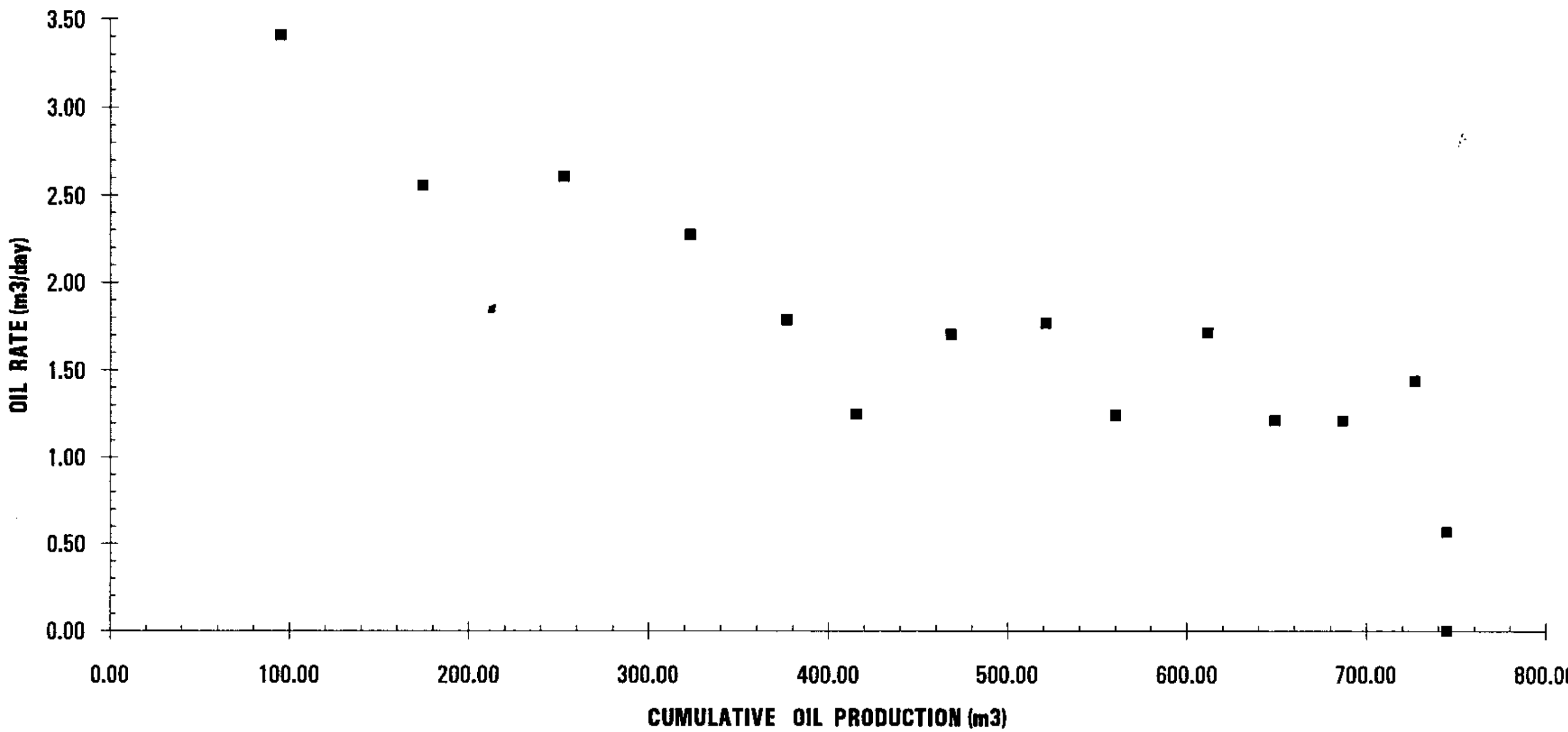
WELL 5-21-10-29 REMAINING PROVED RESERVES



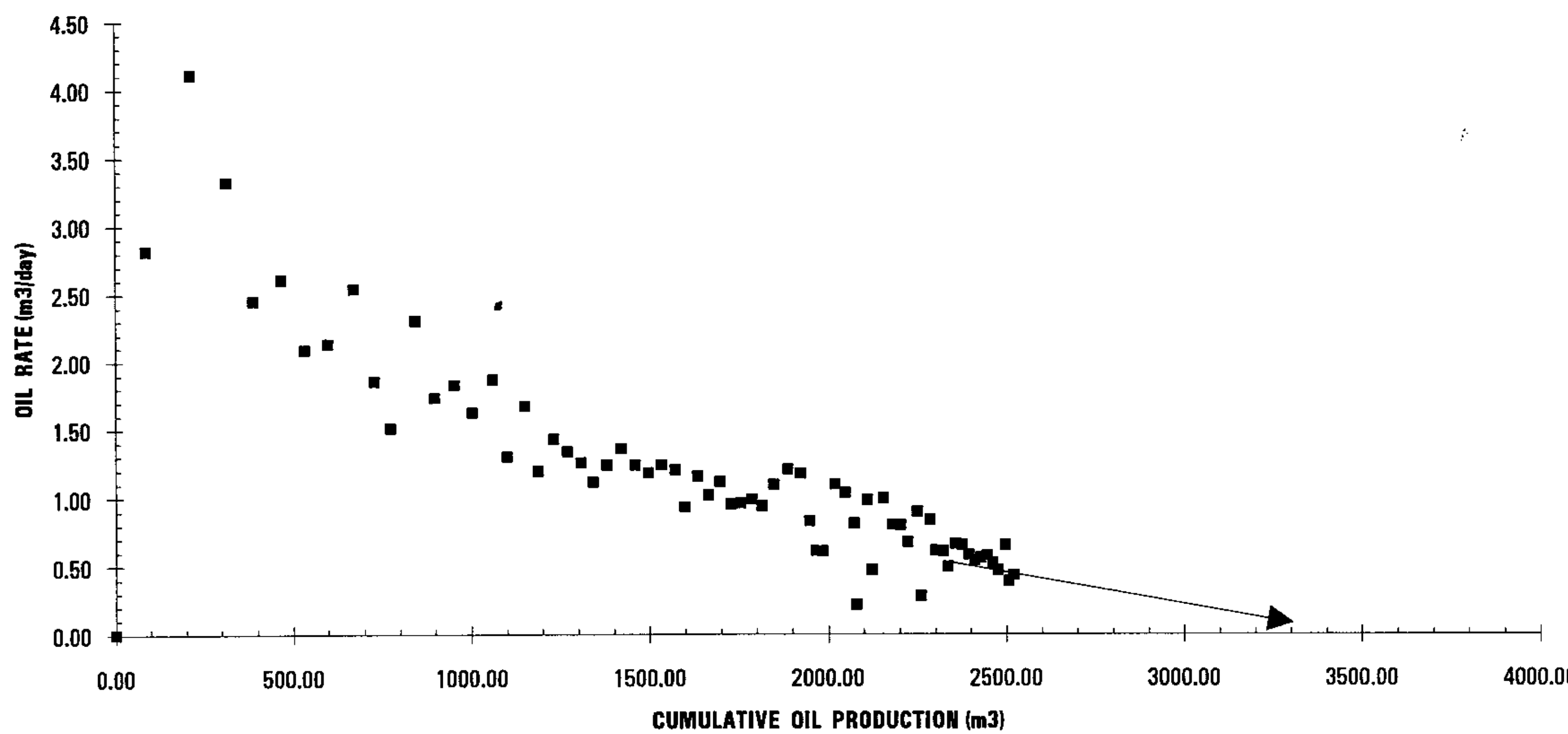
WELL 10-21-10-29 REMAINING PROVED RESERVES



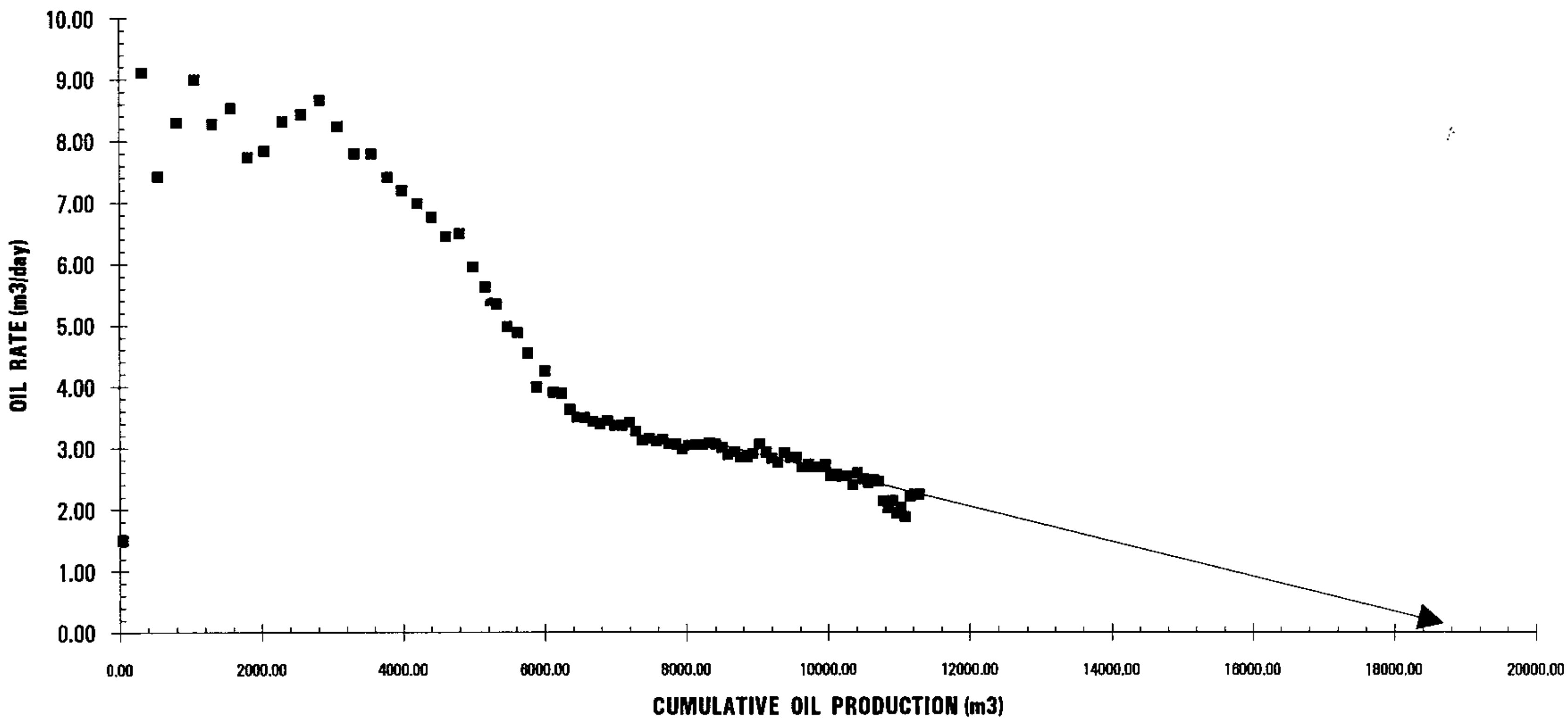
WELL 11-21-10-29 REMAINING PROVED RESERVES



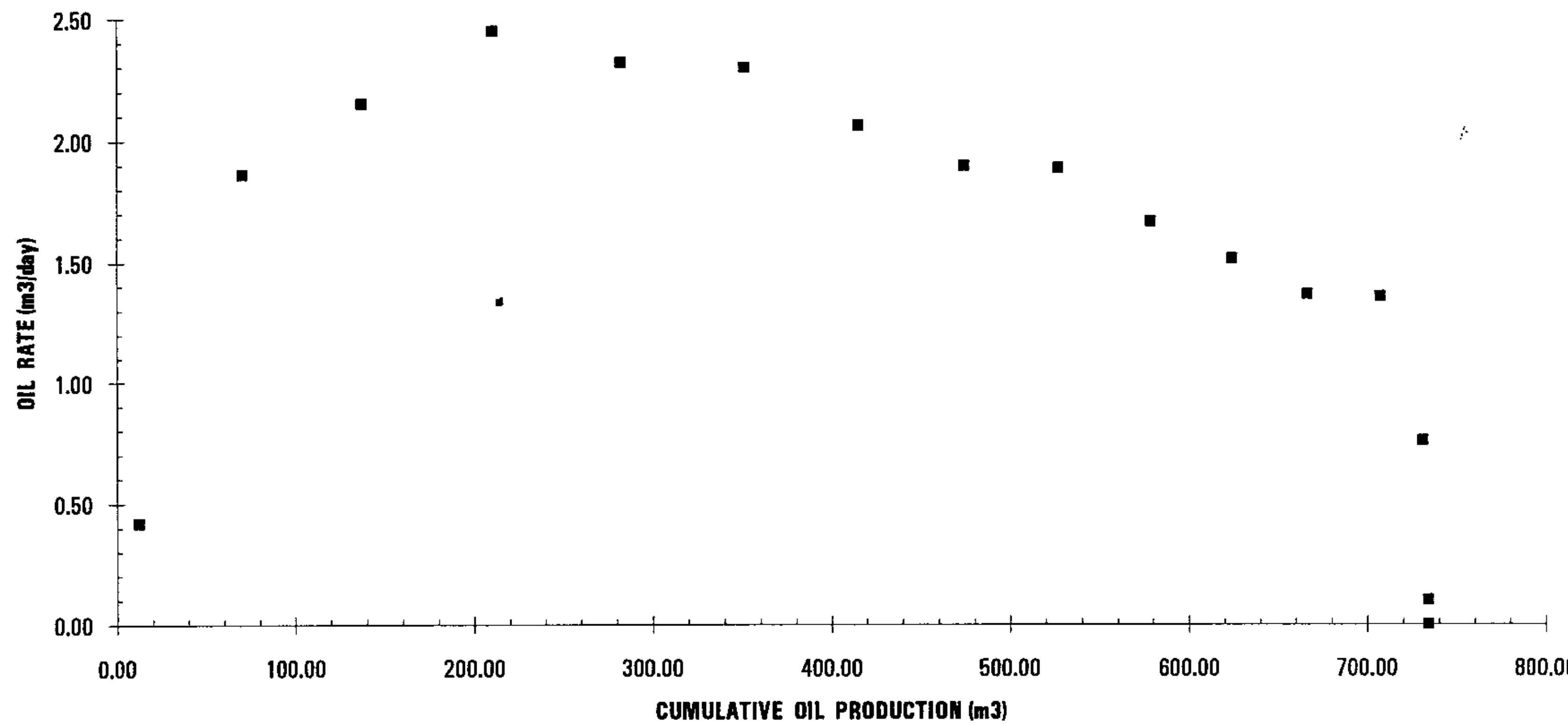
WELL 12-21-10-29 REMAINING PROVED RESERVES



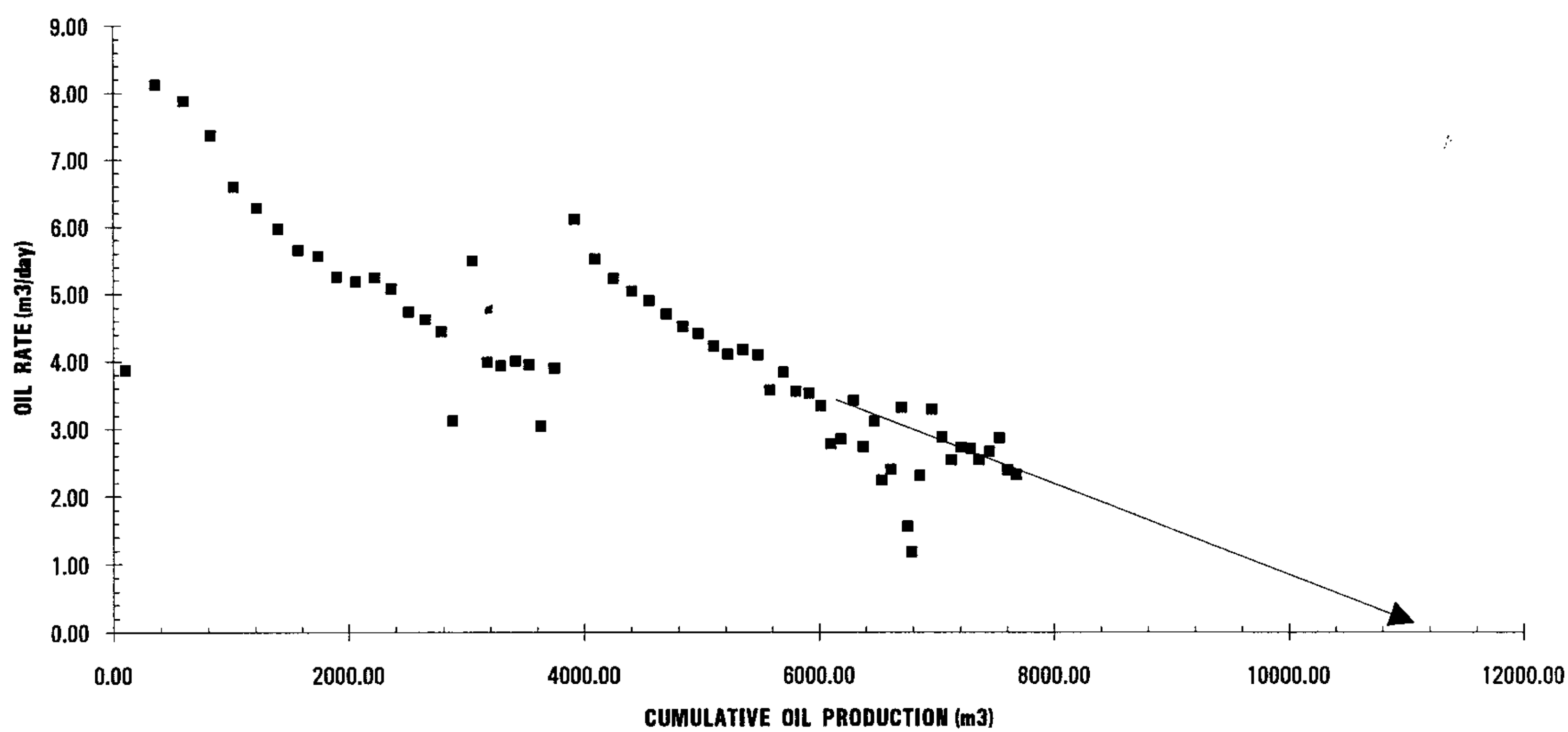
WELL 13-21-10-29 REMAINING PROVED RESERVES



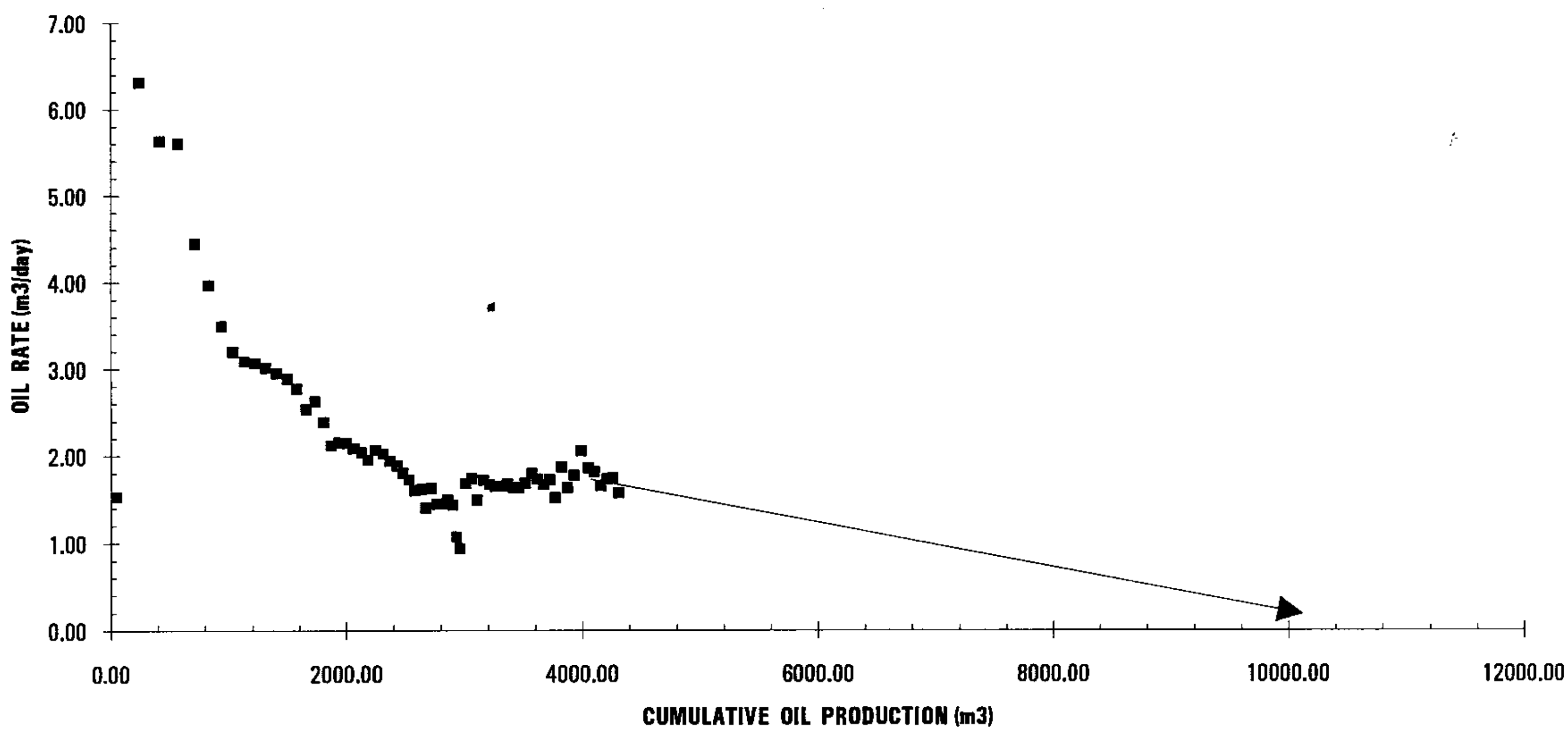
WELL 14-21-10-29 REMAINING PROVED RESERVES



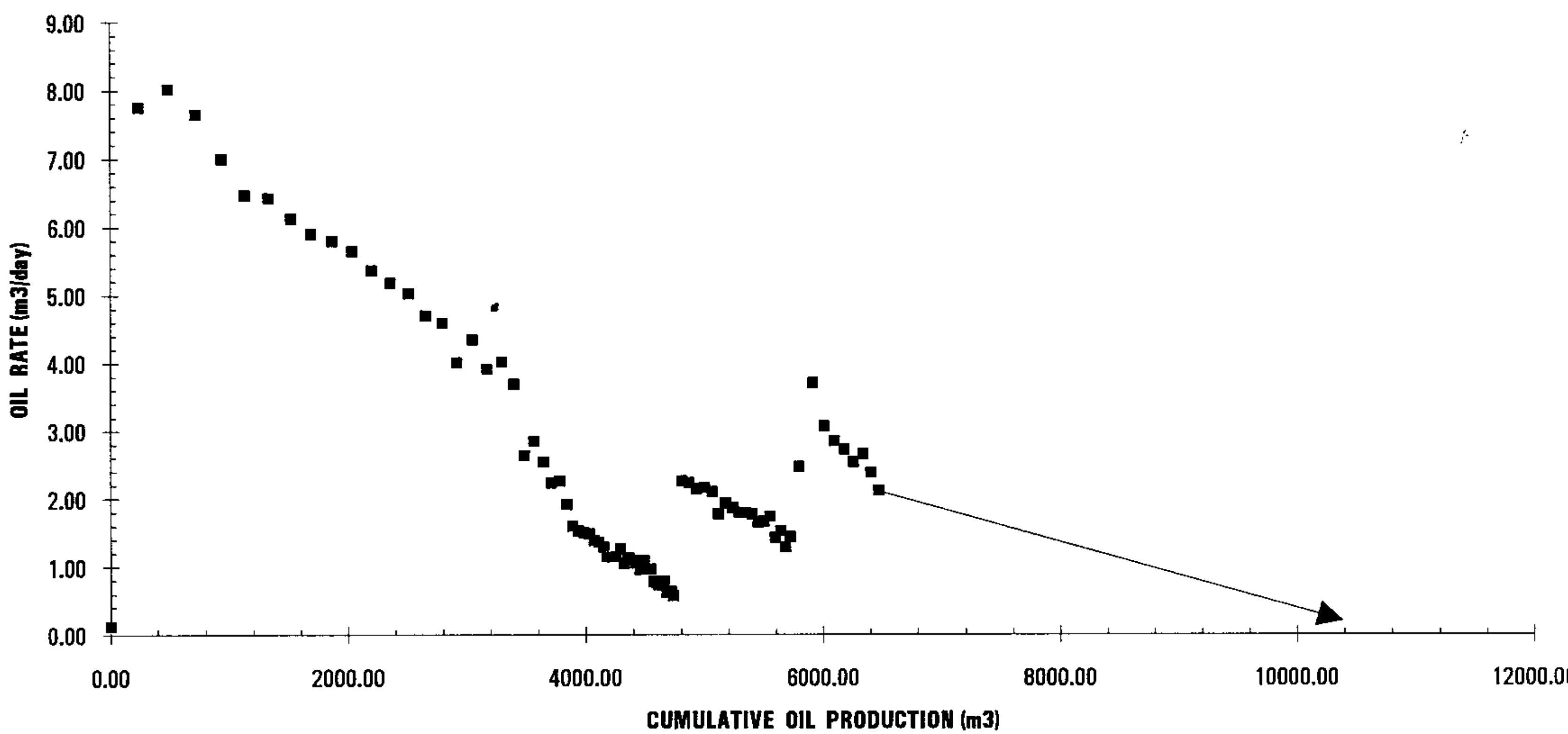
WELL 2-28-10-29 REMAINING PROVED RESERVES



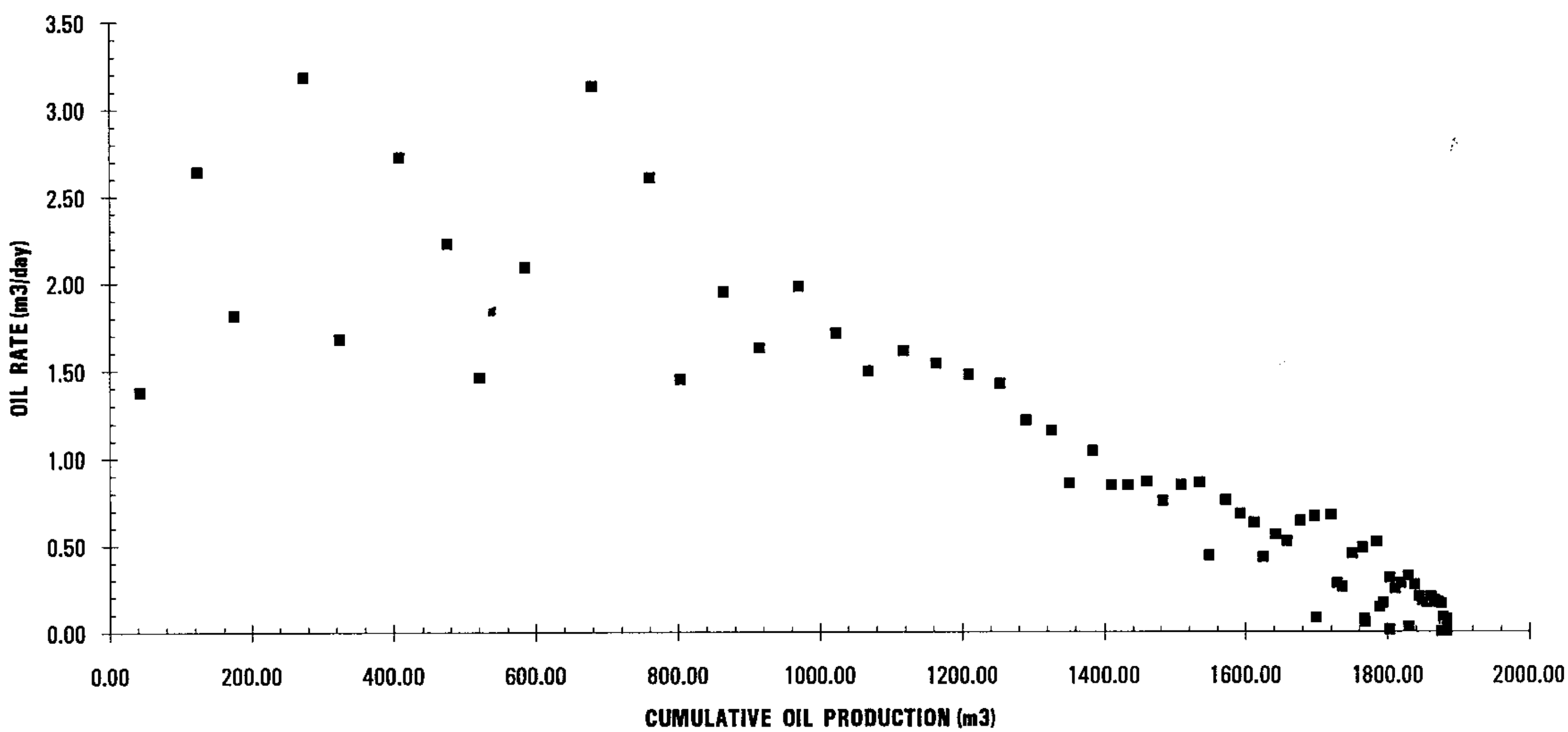
WELL 3-28-10-29 REMAINING PROVED RESERVES



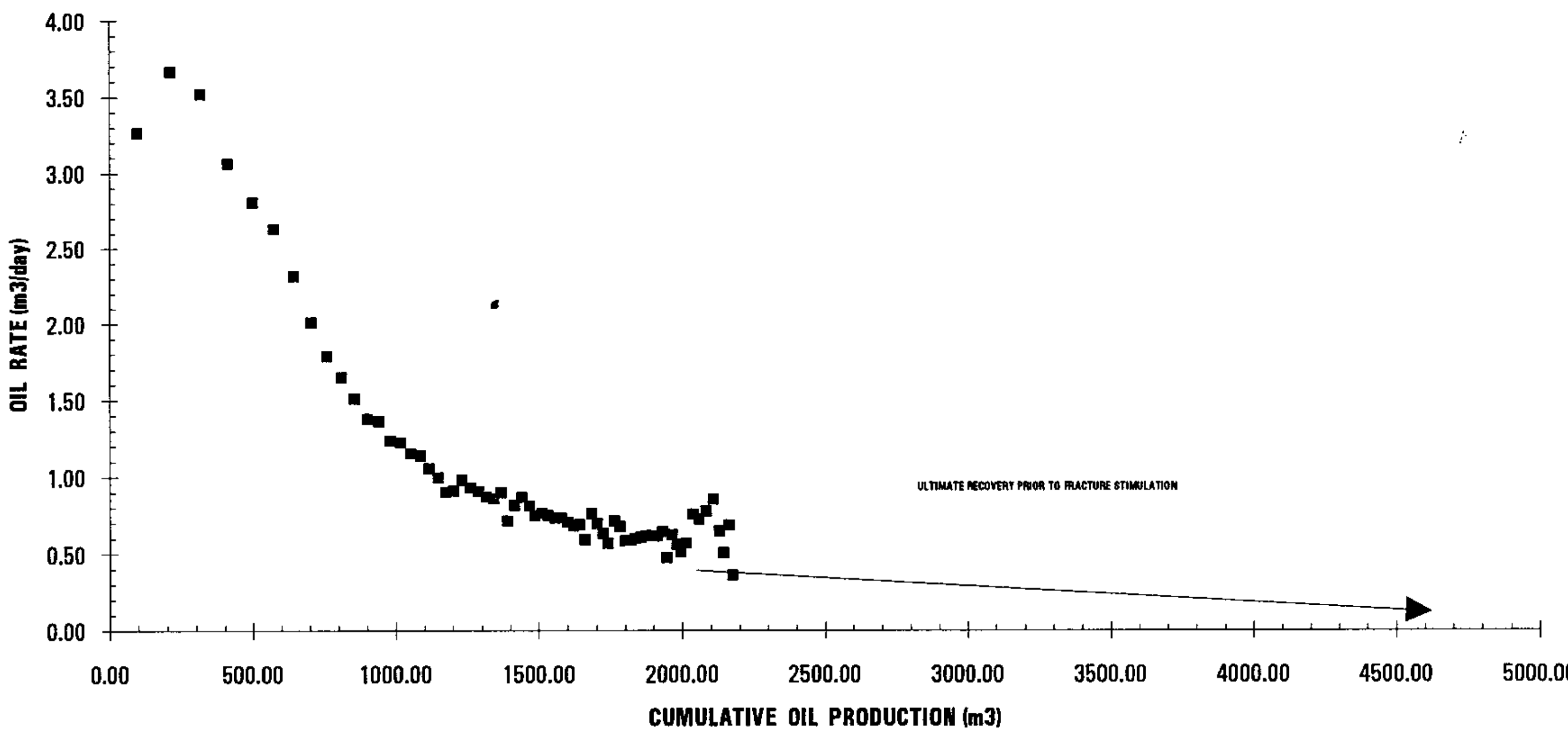
WELL 4-28-10-29 REMAINING PROVED RESERVES



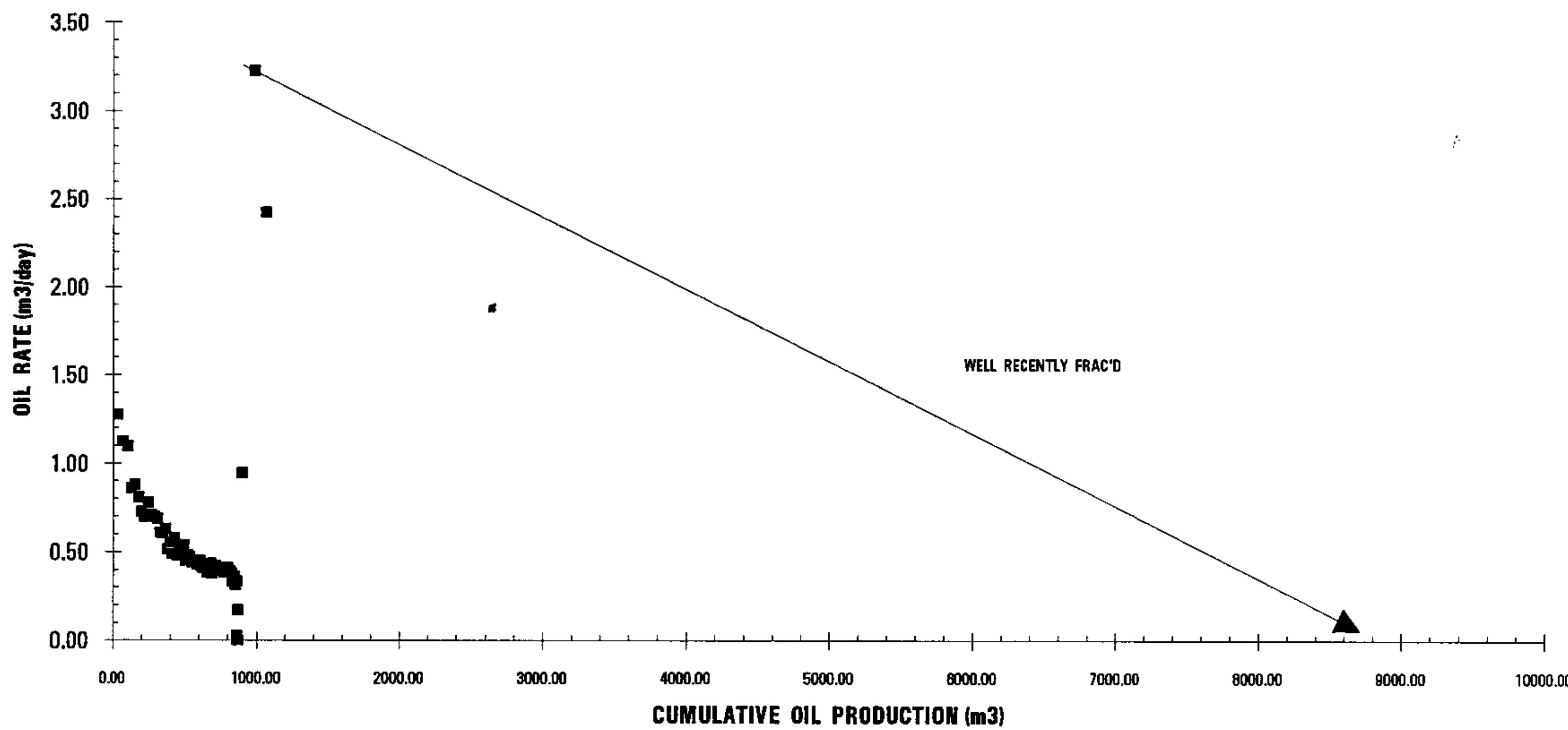
WELL 5-28-10-29 REMAINING PROVED RESERVES



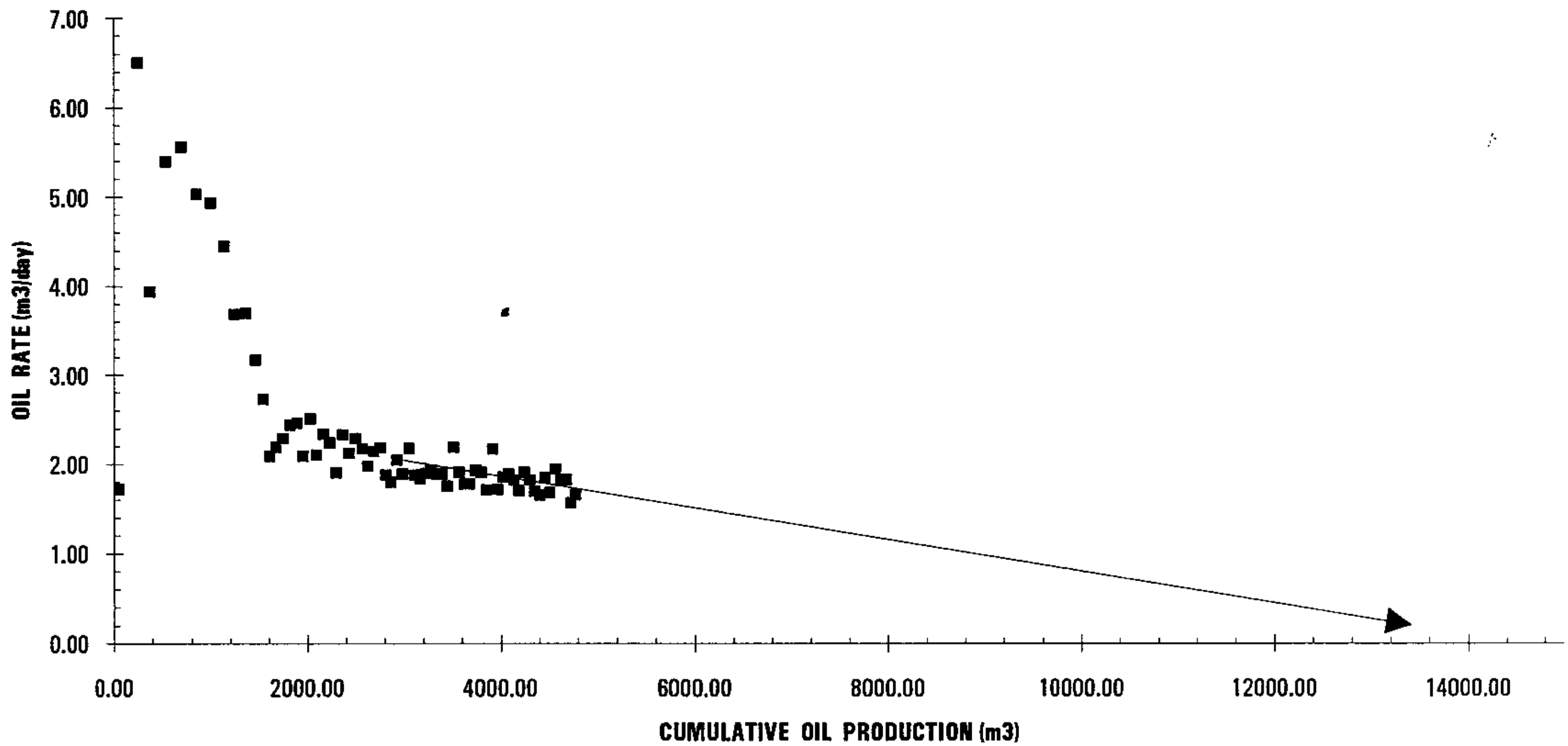
WELL 6-28-10-29 REMAINING PROVED RESERVES



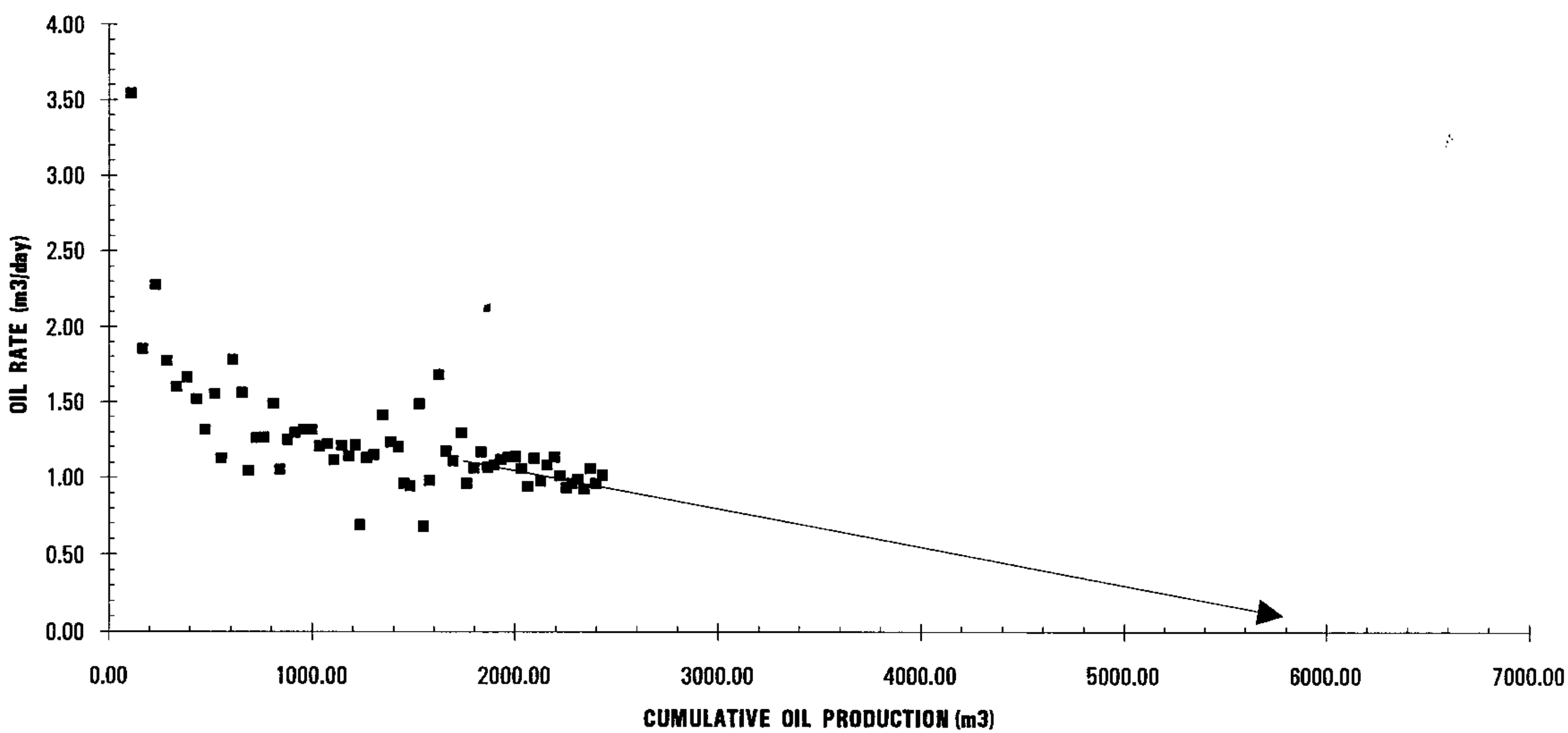
WELL 11-28-10-29 REMAINING PROVED RESERVES



WELL 12-28-10-29 REMAINING PROVED RESERVES



WELL 9-29-10-29 REMAINING PROVED RESERVES



APPENDIX G

BAKKEN 'A' POOL
RELATIVE PERMEABILITY STUDY

Hycal ENERGY RESEARCH LABORATORIES LTD.

TUNDRA - BAKKEN "A" POOL
WELL 4-28-10-29 W1M
RELATIVE PERMEABILITY STUDY

Prepared for

Tundra Oil and Gas Ltd.

Prepared by

Hycal Energy Research Laboratories Ltd.

June 23, 1993

93-028

1338A - 36th Avenue N.E., Calgary, Alberta, Canada T2E 6T6
Telephone (403) 250-5800 Telex 03-821172 CGY Fax: (403) 291-0481

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES

SUMMARY

At the request of Tundra Oil and Gas Ltd. (Tundra), Hycal Energy Research Laboratories Ltd. (Hycal) conducted special core analysis tests on core material from well 4-28-10-29 W1M in the Bakken "A" Pool area. Tests to ascertain water-oil permeability were conducted using restored state core material from the 876 to 877 m interval of well 4-28-10-29 W1M. The relative permeability tests were conducted at the net reservoir overburden pressure of 8246 kPa with no backpressure and utilized dead produced crude oil and well 4-28 tank (formation) water as displacing fluids, at the reservoir temperature of 31°C. Major results of the study are summarized as follows.

Relative Permeability Tests

An ambient pressure condition water-oil permeability test was conducted on a composite core stack consisting of three core samples. Results are summarized in the following table:

Water-Oil Relative Permeability Test						
Core #	**Depth (m)**	**k_{air} (mD)**	**$k_{absolute\ (fluid)}$ @ Reservoir T & P (mD)**	**ϕ (%)**	**k_{oil} @ Sw_i (mD)**	**Sw_i**
2A, 2B, 3A*	876.50	10-73	28.1	19.9	2.58	0.578
So_i	**Sw_{max}**	**So_r**	**% Recovery OOIP**	**k_w (mD)**	**k_{rw}**	
0.422	0.803	0.197	53.3	0.541	0.019	
* Composite stack						

Test results indicated a relatively good waterflood recovery efficiency of 53.3% of the initial oil-in-place, with a relatively low residual oil saturation of 19.7%. Initial water saturation was quite high in the core material. This fact and the configuration of the water-oil relative permeability curves is indicative of a water-wetted system.

INTRODUCTION

At the request of George Czyzewski of Tundra Oil and Gas Ltd., Hycal performed a series of displacement tests on restored state plug core samples from well 4-28-10-29 W1M in the Bakken "A" Pool. The tests were performed for the purpose of determining water-oil permeability characteristics of the reservoir. This report describes the equipment used in the tests, outlines the experimental procedures utilized, and presents the results of the test program.

DESCRIPTION OF EQUIPMENT

Relative Permeability Apparatus

A schematic of the experimental apparatus used in the relative permeability tests conducted on the Bakken "A" Pool core material appears as Figure 1. The core sample is placed in a 3.81 cm ID, 0.692 cm WT heavy lead sleeve. The ductility of the lead sleeve allows a confining overburden pressure to be transferred to the core to simulate reservoir pressure. The core, mounted within the lead sleeve, is placed inside a 7.5 cm ID steel core holder which is capable of simulating reservoir pressures of up to 68.9 mPa. This pressure is applied by filling the annular space between the lead sleeve and the core holder with reconstituted formation water, and then compressing the water with a hydraulic pump to obtain the desired overburden pressure.

The core holder ends each contain two ports. One of these ports is for fluid feed or production and the second set is for pressure measurement. The portions of the core holder directly adjacent to the injection and production ends of the core are equipped with radial distribution plates to ensure evenly distributed fluid flow into and out of the core specimen.

Pressure differential is monitored using a Validyne pressure transducer. The transducer is mounted directly across the core and measures the pressure differential between the injection and production ends. The pressure transducer has a range of 0 to 350 or 0 to 3500 kPa and is accurate to 0.01% of the full scale value.

A Ruska displacement pump is used to inject fluids into the core. The pump is capable of injecting at rates from 0.5 to 8200 cm^3/hr at pressures of up to 68.9 MPa, with an accuracy of ± 0.01 cm^3. The pump is filled with distilled water which displaces live crude oil. This water may also displace varsol which then displaces the brine or gas to be used in the test into the core. This arrangement is used to avoid placing corrosive fluids directly into the pump. The experimental system has been designed to minimize dead volume and to ensure that the entire system is at pressure equilibrium prior to any fluid change.

Backpressure on the system (for full reservoir condition tests) is controlled using a 316 SS controlling backpressure regulator accurate to 0.5% of the setpoint value. This regulator allows for the smooth production of fluids from the system at any desired flowrate and setpoint pressure. Gas production rates are measured using a precision wet test meter.

EXPERIMENTAL PROCEDURE

Core Handling Procedures

Full diameter samples of core from the 876.00 to 877.37 m interval of Bakken "A" Pool area well 4-28-10-29 W1M were supplied to Hycal by Tundra for testing. A total of two (2) full diameter samples were provided. Four (4) 3.81 cm plug samples were drilled from the full diameter cores and subjected o routine air permeability and porosity measurements. Based upon the results of these measurements, samples were specified by Tundra for relative permeability tests. A summary of core parameters and the specific disposition of each sample is contained in Table 1. Wettability restoration was conducted to re-establish the original reservoir condition wettability to provide representative relative permeability and wettability data.

Wettability restoration was conducted by mounting a composite stack of core samples, applying 8246 kPa net overburden pressure and then vacuum saturating the cleaned core samples to be tested with formation brine and flooding with brine for a 7 day period to allow equilibrium to be established. The brine was then slowly displaced by dead reservoir crude oil after which fresh oil was slowly circulated through the core samples over a 42 day (6 week) period. Temperature was maintained at the reservoir value of 31°C during this process.

Once conditioning was completed the individual samples were stored submerged in fresh crude oil in sealed, oxygen-free containers until required for testing.

Fluid Sampling

Tundra supplied Hycal with samples of well 4-28 tank water (formation brine) and samples of produced Bakken "A" pool dead crude oil for use in the study. These fluids were cleaned via pressure filtration to remove any suspended solids prior to being utilized in the test series.

Ambient Pressure Condition Water-Oil Relative Permeability Test

A composite core stack consisting of three core plugs (2A, 2B and 3A) was placed in the oven with an overburden pressure of 8246 kPag, at a temperature of 31°C and with no backpressure. Dead oil was injected into the core and the initial permeability to oil determined. Formation brine was then injected at a low rate until no additional oil was being produced. During this displacement the pressure drop across the core and the water and oil production rates were measured to facilitate saturation and relative permeability calculations (via a computer history matching method). Several higher rate endpoint waterflood tests were conducted to ensure that the water endpoint relative permeability data was representative.

RESULTS AND DISCUSSION

Preliminary Test Preparations

Table 1 contains a summary of initial coreplug parameters and disposition as discussed previously in the "Experimental Procedure" section of the report.

Composite Core Stack #1 (Cores #2A, #2B and #3A)

A composite core stack composed of cores #2A, #2B and #3A was utilized for relative permeability testing. Table 2 provides a summary of core and fluid parameters for the waterflood test conducted on the composite core.

Table 3 provides a summary of the oil and water saturations in the core after each displacement step phase and the measured endpoint permeability and relative permeability for each step. Initial oil and water saturations in the restored state plug had values of 0.422 and 0.578 respectively.

Initial permeability to the displacing oil phase had a value of 2.48 $(\mu m)^2 \times 10^{-3}$ [2.51 mD]. Absolute fluid permeability for the core stack was estimated to be 27.7 $(\mu m)^2 \times 10^{-3}$ [28.1 mD] from the extrapolation of the k_{ro} curve to a 1.00 value at 100% oil saturation. Subsequent water, oil and gas phase relative permeabilities were calculated using this estimated absolute permeability.

Table 4 contains the experimental differential pressure and oil production history from the waterflood. The oil production data and differential pressure data of Table 4 have been plotted as a function of cumulative injection and appear as Figures 2 and 3 respectively.

The waterflood resulted in the production of 0.225 pore volumes of oil from the core resulting in final oil and water saturation values of 0.197 and 0.803. This represents a relatively good recovery of 53.3% of the initial oil-in-place in the core prior to waterflooding. Endpoint permeability to water at this saturation level had a value of 0.534 $(\mu m)^2 \times 10^{-3}$ [0.541 mD] yielding a water endpoint relative permeability value of 0.019. The configuration of the relative permeability curves and high initial water saturation is indicative of a water-wetted system.

The relative permeability data presented in this report was generated by a computer simulation as described in a paper by Bennion et al. A copy of this paper is also included as Appendix "A" of the report. The program required information concerning rock and fluid properties, as well as the differential pressure and production history over the course of the test. The program initially assumed values for the pressure differential and recovery data, and then compared these values to the experimental data and computed the least square error. The program continued to iterate in this fashion until the minimum least square error was obtained. The two-phase flow equation was solved using finite difference techniques, and the model included capillary pressure effects.

Table 5 provides a summary of the oil-water relative permeability data as generated by the simulator for the waterflood conducted on the composite core. The relative permeability data contained in Table 5 have been plotted vs water saturation on both cartesian and semilog co-ordinates and appears as Figures 4 and 5 respectively.

Data Diskette Summary

A 5¼" double sided, double density data diskette is included at the end of the report. This diskette contains all pertinent numerical information from the test series summarized in Lotus 1-2-3 style spreadsheet format. This will facilitate the plotting and manipulation of the data as required. A summary of the worksheet files contained on the data diskette is as follows:

File Name	Contents
TABLE4.WK1	Experimental Pressure and Production History
TABLE5.WK1	Water-Oil Relative Permeability Data

CONCLUSIONS

A water-oil relative permeability test conducted at simulated reservoir conditions of net overburden and temperature on core material from the 876.00 to 877.37 m interval of well 4-28-10-29 W1M in the Bakken "A" Pool indicated:

a) Relatively good sweep efficiency with a 53.3% recovery of the initial oil-in-place.

b) A high initial water saturation of 57.8%.

c) A relatively low So_r of 19.7%. The use of live reservoir crude oil in the tests may have resulted in an additional slight reduction in So_r due to a more favourable mobility ratio between the injection water and the reservoir oil due to the reducing effect of dissolved gas on reservoir oil viscosity. Due to the low solution GOR of the oil, this effect is likely to be relatively small.

d) The high initial water saturation and configuration of the oil-water relative permeability curves is indicative of a water-wet system.

TABLE 1
TUNDRA - BAKKEN "A" POOL
RELATIVE PERMEABILITY STUDY
INITIAL COREPLUG PARAMETER
(WELL 4-28-10-29 W1M)

Plug #	Depth (m)	Air Permeability		Porosity (%)
		$(\mu m)^2 \times 10^{-3}$	mD	
2A	876.00 - 876.20	9.87	10.00	18.3
2B	876.00 - 876.20	16.78	17.00	19.9
3A	877.22 - 877.37	72.05	73.00	22.8
3B	877.22 - 877.37	1.28	1.30	17.1

TABLE 2
TUNDRA - BAKKEN "A" POOL
RELATIVE PERMEABILITY STUDY
CORE STACK #1 - WATER-OIL RELATIVE PERMEABILITY
CORE AND TEST PARAMETERS

Core Stack Number	1
Core Stack Configuration (from inlet)	2A, 2B, 3A
Depth (m)	876.50
Field Name	Bakken "A" Pool
Well Location	4-28-10-29 W1M
Stack Length (cm)	15.74
Diameter (cm)	3.82
Effective Flow Area (cm^2)	11.461
Bulk Volume (cm^3)	180.39
Porosity (fraction)	0.199
Pore Volume (cm^3)	35.9
Initial Water Saturation (fraction)	0.578
Final Water Saturation (fraction)	0.803
Water Viscosity @ 31°C (mPa·s)	1.10
Oil Viscosity @ 31°C (mPa·s)	2.81
Test Temperature (°C)	31
Displacement Rate (cc/hr)	20
Backpressure (kPag)	0.00
Net Overburden Pressure (kPag)	8246

TABLE 3
TUNDRA - BAKKEN "A" POOL
RELATIVE PERMEABILITY STUDY
CORE STACK #1 - WATER-OIL RELATIVE PERMEABILITY
SATURATION AND PERMEABILITY SUMMARY

Test Phase	So	Sw	Permeability		Relative Permeability
			$(\mu m)^2 \times 10^{-3}$	mD	
Absolute Liquid Permeability	1.000	0.000	27.7	28.1	1.000
Initial Oil Permeability (@ Sw_i)	0.422	0.578	2.48	2.51	0.089
Final Water Permeability (@ So_r)	0.197	0.803	0.534	0.541	0.019

* Absolute permeability is determined by extrapolating the k_{ro} curve to 1.0 at Sw = 0.0

TABLE 4
TUNDRA - BAKKEN "A" POOL
RELATIVE PERMEABILITY STUDY
CORE STACK #1 - WATER-OIL RELATIVE PERMEABILITY
DIFFERENTIAL PRESSURE AND PRODUCTION

Cuml Injection (PV)	Cuml Production (PV)	Pressure (MPa)
0.028	0.028	1.06873
0.056	0.056	1.51690
0.111	0.111	2.10298
0.150	0.150	2.11677
0.167	0.155	2.10298
0.209	0.167	2.00645
0.279	0.178	1.92508
0.487	0.201	1.78581
0.696	0.212	1.71686
1.114	0.220	1.63825
1.671	0.225	1.58585
3.064	0.225	1.57206

TABLE 5
TUNDRA - BAKKEN "A" POOL
RELATIVE PERMEABILITY STUDY
CORE STACK #1 - WATER-OIL RELATIVE PERMEABILITY
RELATIVE PERMEABILITY DATA

Water Saturation	Relative Permeability	
	k_{rw}	k_{ro}
0.578	0.00000	0.08950
0.589	0.00046	0.07697
0.601	0.00109	0.06567
0.612	0.00181	0.05553
0.623	0.00259	0.04649
0.634	0.00343	0.03848
0.646	0.00430	0.03145
0.657	0.00521	0.02533
0.668	0.00616	0.02007
0.679	0.00713	0.01559
0.691	0.00813	0.01183
0.702	0.00916	0.00874
0.713	0.01021	0.00624
0.724	0.01128	0.00427
0.736	0.01237	0.00278
0.747	0.01348	0.00169
0.758	0.01461	0.00093
0.769	0.01576	0.00046
0.781	0.01692	0.00019
0.792	0.01810	0.00006
0.803	0.01930	0.00000

FIGURE 1
TUNDRA - BAKKEN "A" POOL
RELATIVE PERMEABILITY STUDY
RESERVOIR CONDITION RELATIVE PERMEABILITY APPARATUS

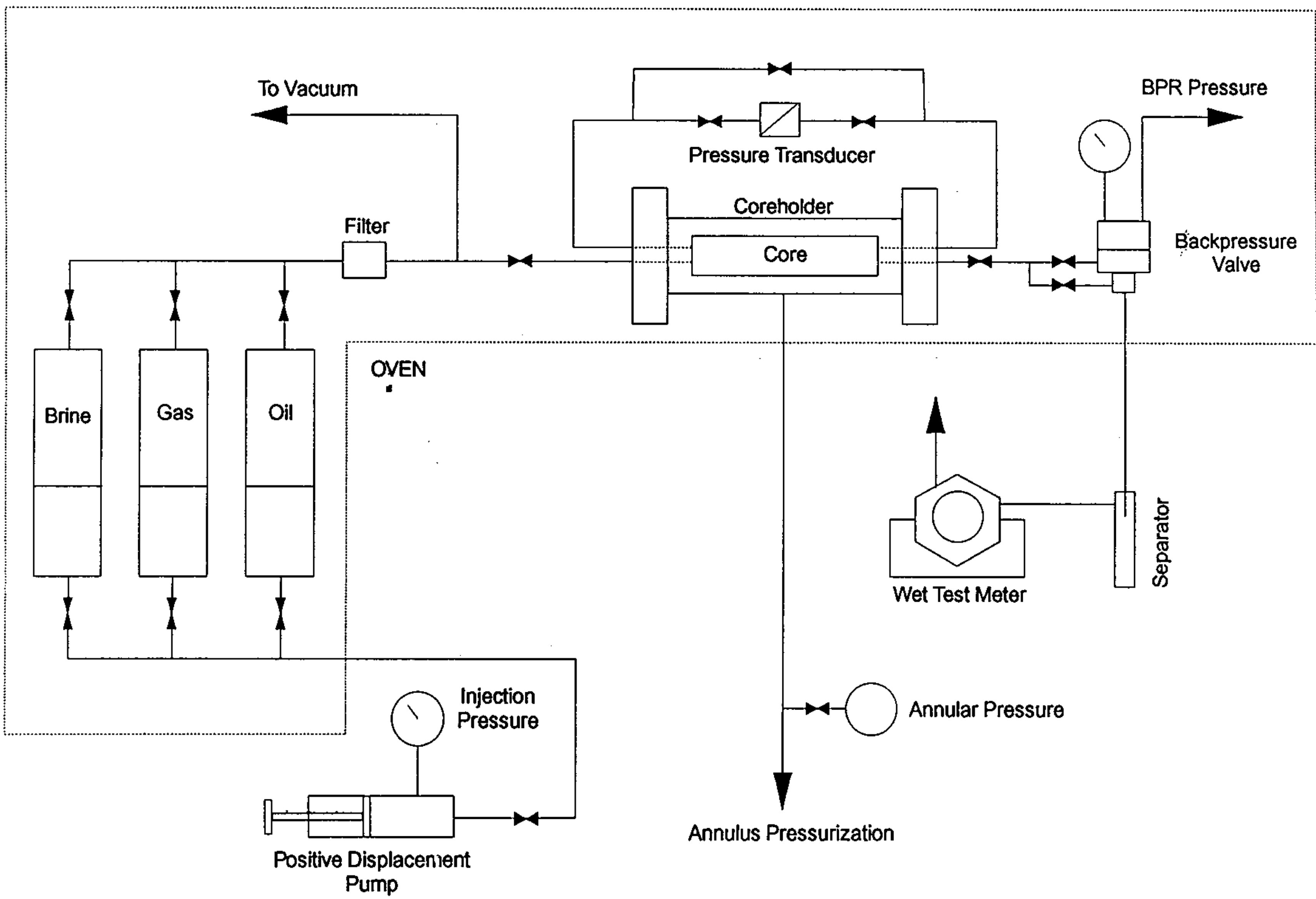


FIGURE 2
TUNDRA - BAKKEN "A" POOL
RELATIVE PERMEABILITY STUDY
CORE STACK #1 - WATER-OIL RELATIVE PERMEABILITY
CUML PRODUCTION vs CUML INJECTION

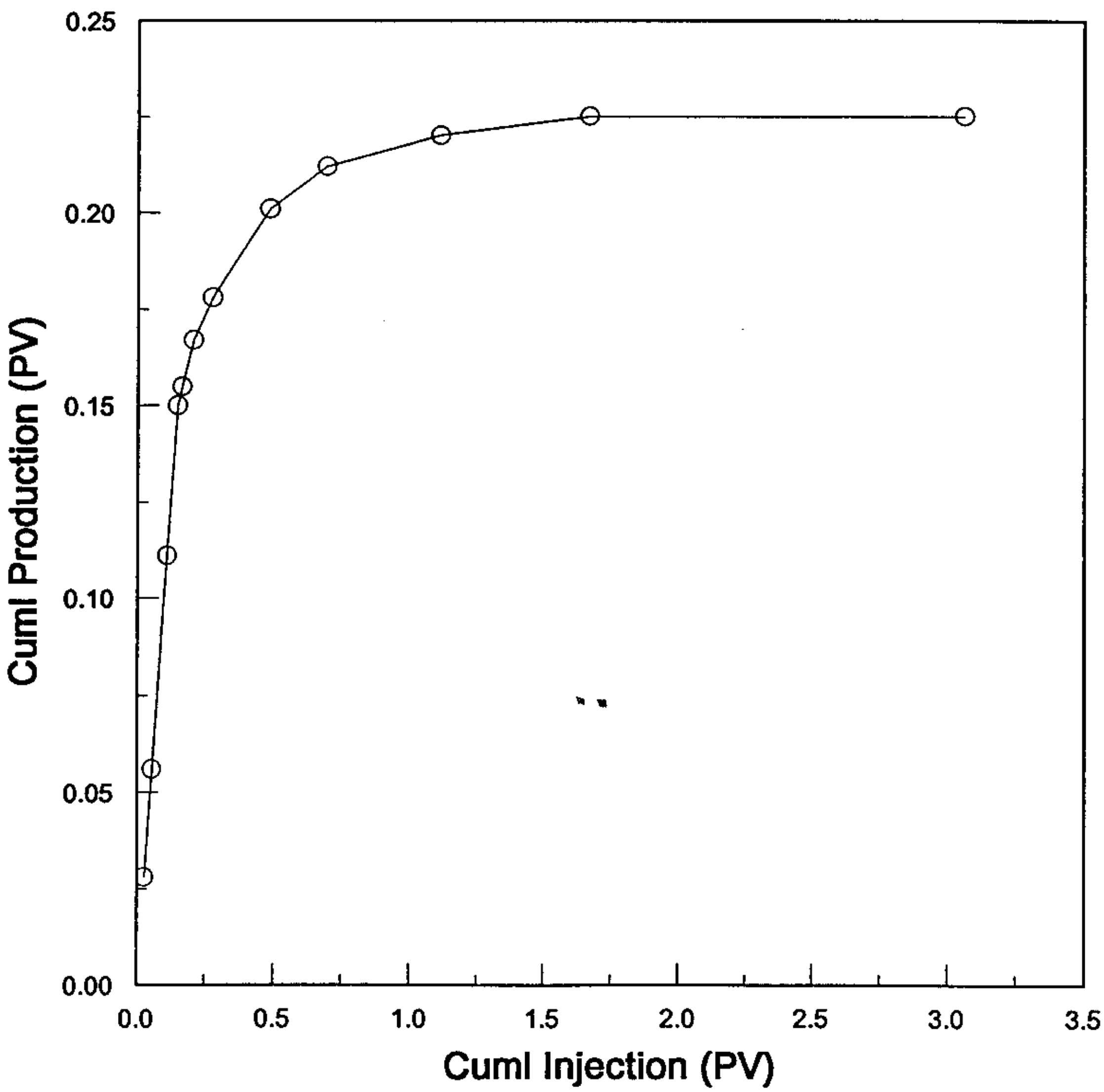


FIGURE 3
TUNDRA - BAKKEN "A" POOL
RELATIVE PERMEABILITY STUDY
CORE STACK #1 - WATER-OIL RELATIVE PERMEABILITY
PRESSURE vs CUML INJECTION

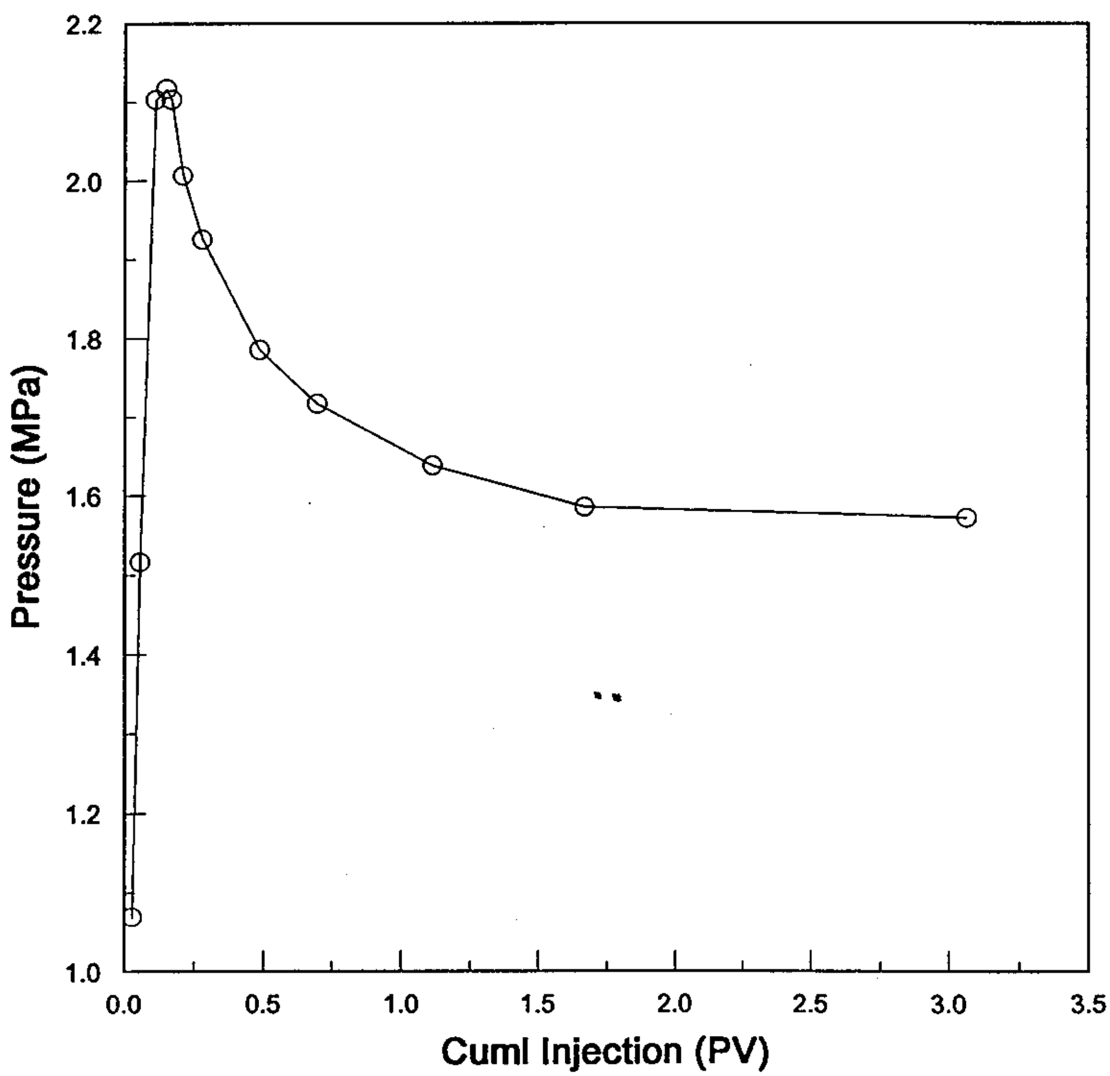


FIGURE 4
TUNDRA - BAKKEN "A" POOL
RELATIVE PERMEABILITY STUDY
CORE STACK #1 - WATER-OIL RELATIVE PERMEABILITY
RELATIVE PERMEABILITY vs WATER SATURATION

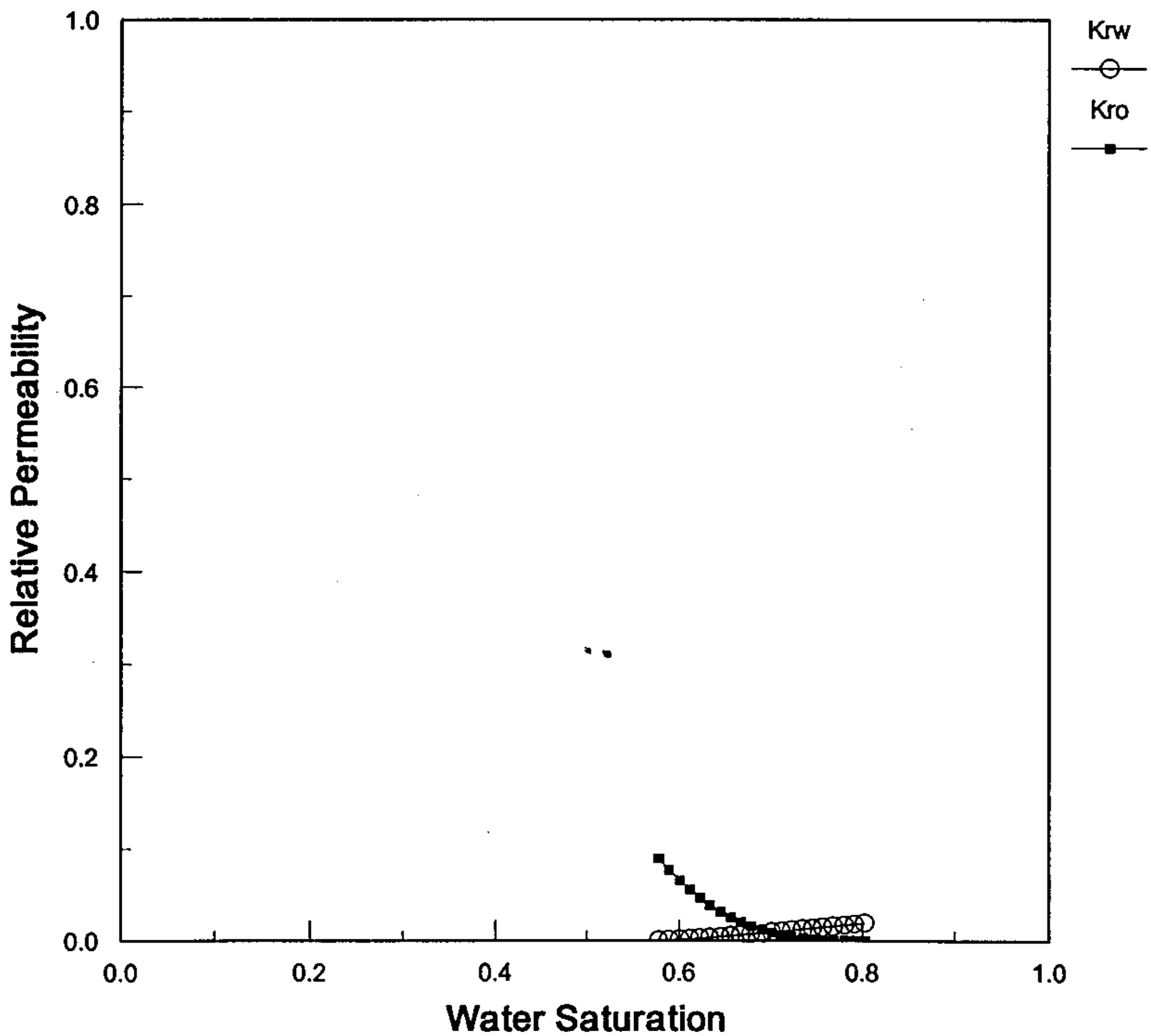
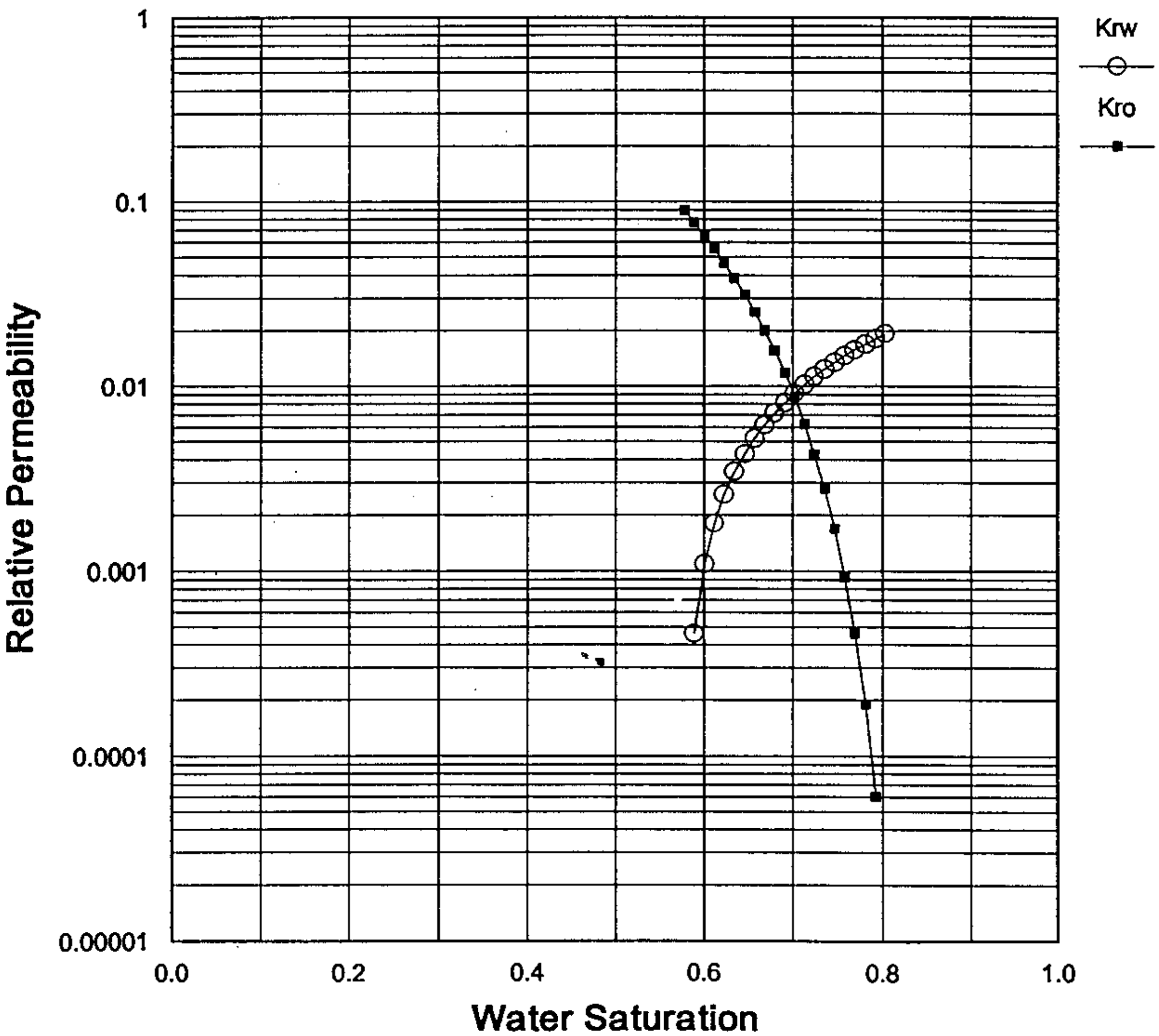


FIGURE 5
TUNDRA - BAKKEN "A" POOL
RELATIVE PERMEABILITY STUDY
CORE STACK #1 - WATER-OIL RELATIVE PERMEABILITY
RELATIVE PERMEABILITY vs WATER SATURATION



Manitoba

Energy and Mines

Petroleum

1395 Ellice Avenue Suite 360
Winnipeg MB R3G 3P2
CANADA

PH: (204) 945-6577
Fax: (204) 945-0586

May 15, 1995

Mr. George Czyzewski, P.Eng.
Sr. Reservoir Engineer
Tundra Oil and Gas Ltd.
1111 - One Lombard Place
Winnipeg MB R3B 0X4

DALY BAKKEN A POOL WATERFLOOD APPLICATION

Dear George:

Re: Kola Unit No. 1
Application to Convert Wells to Water Injection

Your application to convert the 2-28-10-29 (WPM) and 12-28-10-29 (WPM) wells to water injection in Kola Unit No. 1 has been approved. Attached is Waterflood Order No. 2 outlining conditions for operation of the waterflood in Kola Unit No. 1. Waterflood Order No. 2 issued under The Oil and Gas Act replaces Board Order No. PM 71. Also attached are approved copies of the applications to convert the wells.

If you have any questions please don't hesitate to call the undersigned at 945-6574.

Yours truly,

John N. Fox, P.Eng.
Chief Petroleum Engineer

cc. Virden

THE OIL AND GAS ACT

MINISTERIAL ORDER
WATERFLOOD ORDER NO. 2

Pertaining to Waterflood Operations
in Kola Unit No. 1

1.0 The Unit Operator shall conduct waterflood operations by injecting water into the Bakken Formation underlying Kola Unit No. 1 ("the Unit") through the wells listed in Schedule A. The Director may approve the conversion of additional wells in the Unit to water injection.

1.1 Every injection well shall be completed as approved under Section 47 of the Drilling and Production Regulation.

1.2 The maximum wellhead pressure at which water may be injected is 9 000 kPa.

1.3 The Director may, from time to time , establish a maximum or minimum rate at which water may be injected into a well.

1.4 The annulus of each injection well shall be pressure tested in accordance with Section 50 of the Drilling and Production Regulation.

2.0 The Unit Operator shall conduct an annual survey to determine the level and distribution of reservoir pressure in the Unit. A summary of the results of any pressure surveys conducted during the year are to be included in the annual waterflood progress report required under Section 73 of the Drilling and Production Regulation.

2.1 The frequency of pressure surveys may be reduced where the Director is satisfied that annual surveys will not assist the Unit Operator in monitoring the effectiveness of the waterflood.

2.2 The Unit Operator is responsible for monitoring the effectiveness of the waterflood and for collecting such reservoir data and other information as is necessary to evaluate and optimize waterflood performance.

2.3 The Unit Operator is to advise the Petroleum Branch of the suspension of water injection at any well, any indication of channelling or breakthrough of injected water to a producing well or out of zone and any other detrimental effects that may be attributable to waterflood operations.

3.0 The Unit Operator shall file a monthly report of production or injection for each well in the Unit in accordance with Section 120 of the Drilling and Production Regulation.

4.0 The Oil and Natural Gas Conservation Board Order No. PM 71 dated September 30, 1993 is rescinded.

MAY 15, 1995
Date

Director of Petroleum for
Minister of Energy and Mines

Schedule A
Kola Unit No. 1
Water Injection Wells

Kola Unit No. 1 WIW 13-21-10-29 (WPM)

Kola Unit No. 1 WIW 2-28-10-29 (WPM)

Kola Unit No. 1 WIW 5-28-10-29 (WPM)

Kola Unit No. 1 WIW 12-28-10-29 (WPM)

Manitoba

Memorandum

Date May 10, 1995

To Bob Dubreuil
Director
Petroleum Branch

From John N. Fox
Chief Petroleum Engineer
Petroleum Branch

Telephone

Subject **Kola Unit No. 1**
Application to Convert Additional Wells to Water Injection

Tundra Oil and Gas Ltd., operator of Kola Unit No. 1, has applied to convert two additional wells to water injection; 2-28-10-29, and 12-28-10-29.

Recommendations

It is recommended that the application be approved. The owners of offsetting lands are parties to the Unit Agreement. Therefore notice of the application is not required.

It is proposed that the Director (authority delegated under Section 72 of the regulation) issue Waterflood Order No. 2 approving continued waterflood operations in Kola Unit No. 1. Waterflood Order No. 2 rescinds Board Order No. PM 71 (September 30, 1993).

Discussion

The waterflood in the Daly Bakken A Pool was initiated in October 1993 in Kola Unit No. 1 (Figure 1). Initially injection commenced at 13-21-10-29. Waterflood response has been observed in the 13-21 injection pattern. The response has been characterized by an initial increase in production, followed by a flattening of the production decline (Figure 2). Tundra estimates waterflood incremental reserves in the 13-21 injection pattern of 12 000 m^3 (6.9% pattern OOIP).

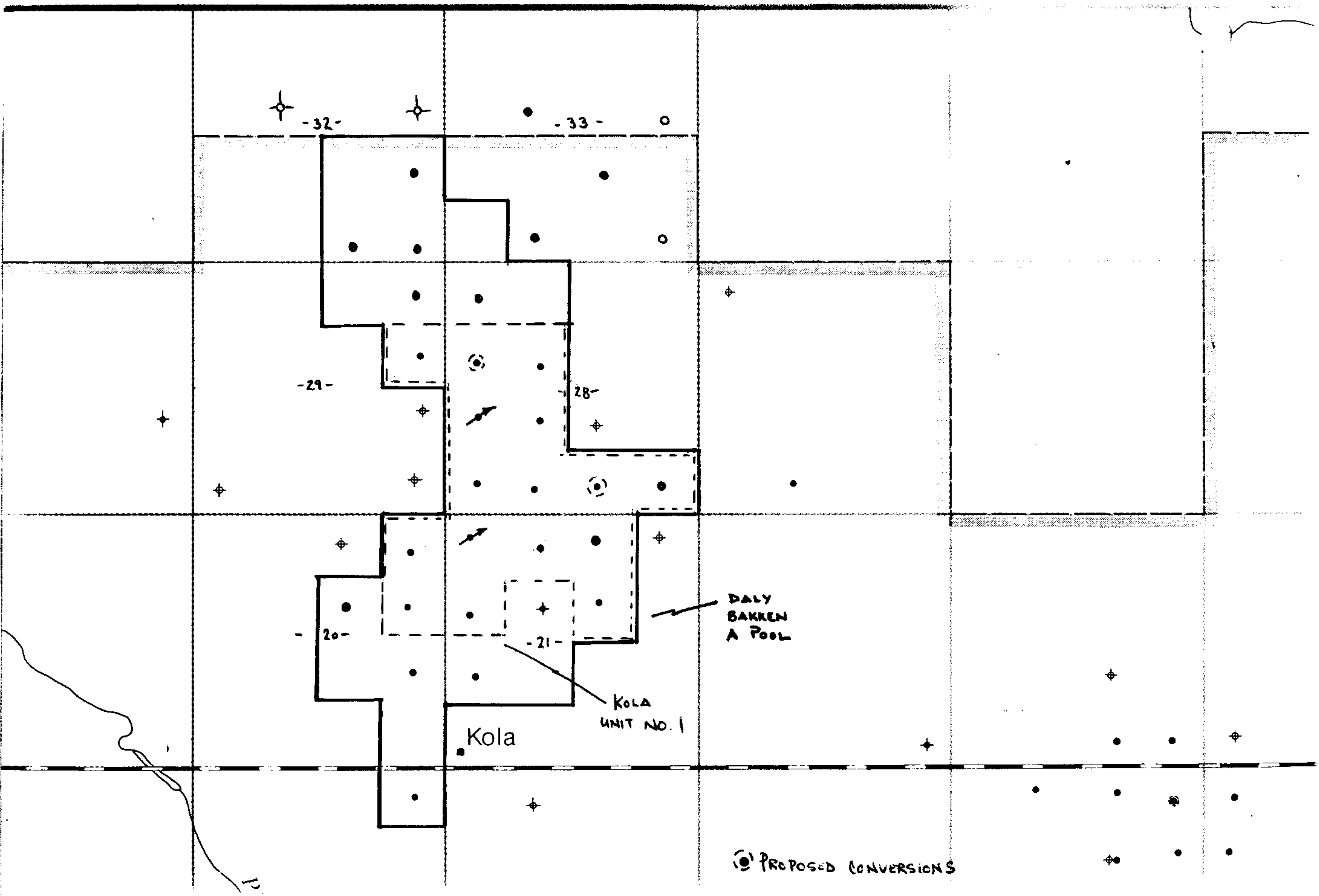
The proposed conversions at 2-28 and 12-28 do not conform to a specific injection pattern, but will provide additional pressure support in the eastern and northern portions of the A pool. Tundra estimates the injector conversions will result in the recovery of 11 760 m^3 or 5% of the OOIP in the injection patterns (see Figure 3).

Note: In November 1994, the 5-28-10-29 well was converted to water injection. The 5-28 well was fractured into the Lodgepole and has been injecting at zero wellhead pressure which suggests no water is entering the Bakken. The 5-28 injector will be suspended when the other wells are converted. Tundra will not be converting the 15-21 well to injection (approved August 1994) because the offsetting producers were fractured out of zone and are shut-in.

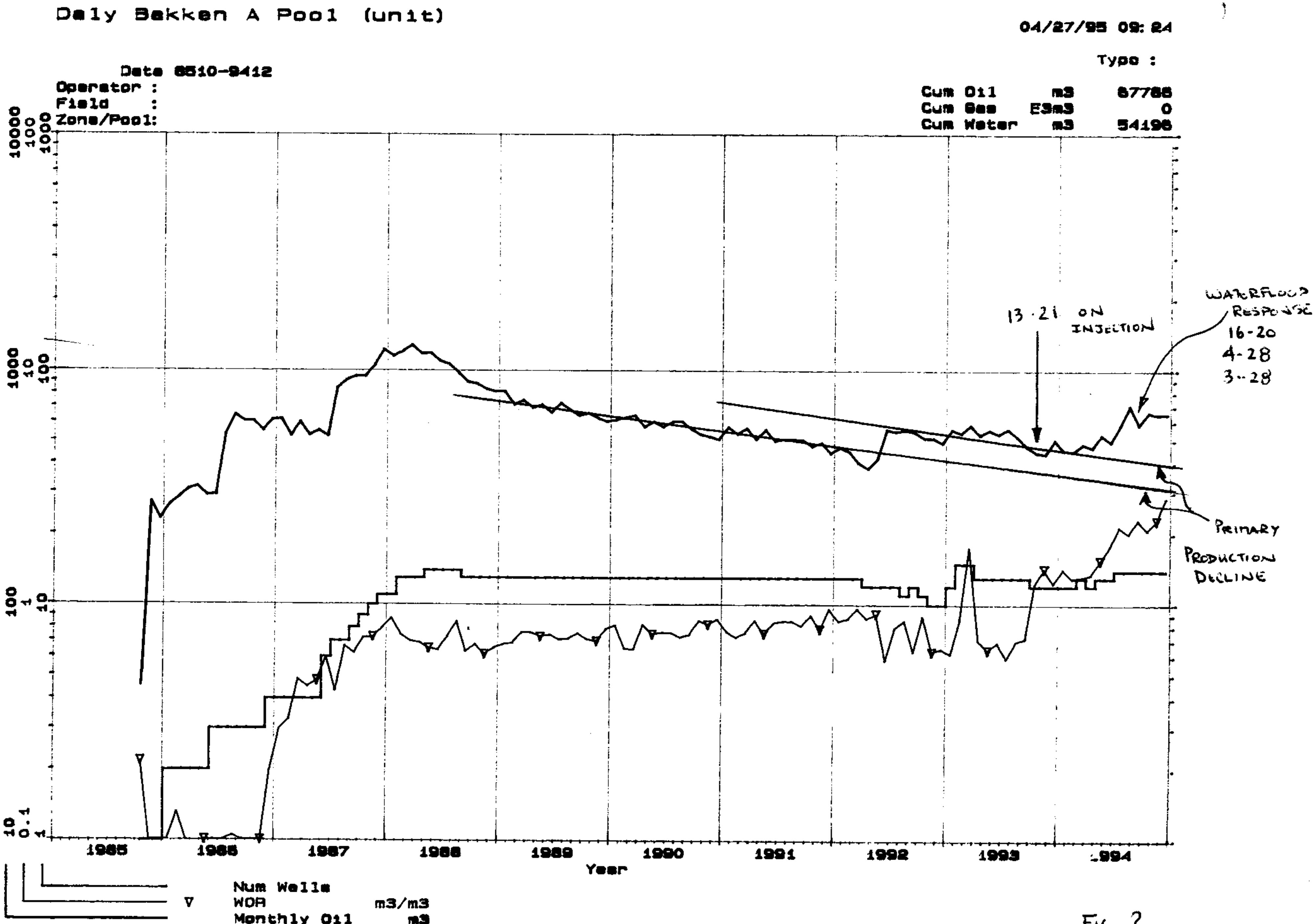
It is proposed to issue Waterflood Order No. 2 in conjunction with the conversion approvals. Waterflood Order No. 2 will rescind Board Order No. PM 71.

John N. Fox

FIGURE 1



-32-
-33-
-29-
-28-
-20-
-21-
DALY BAKKEN A POOL
KOLA UNIT NO. 1
Kola
PROPOSED CONVERSIONS

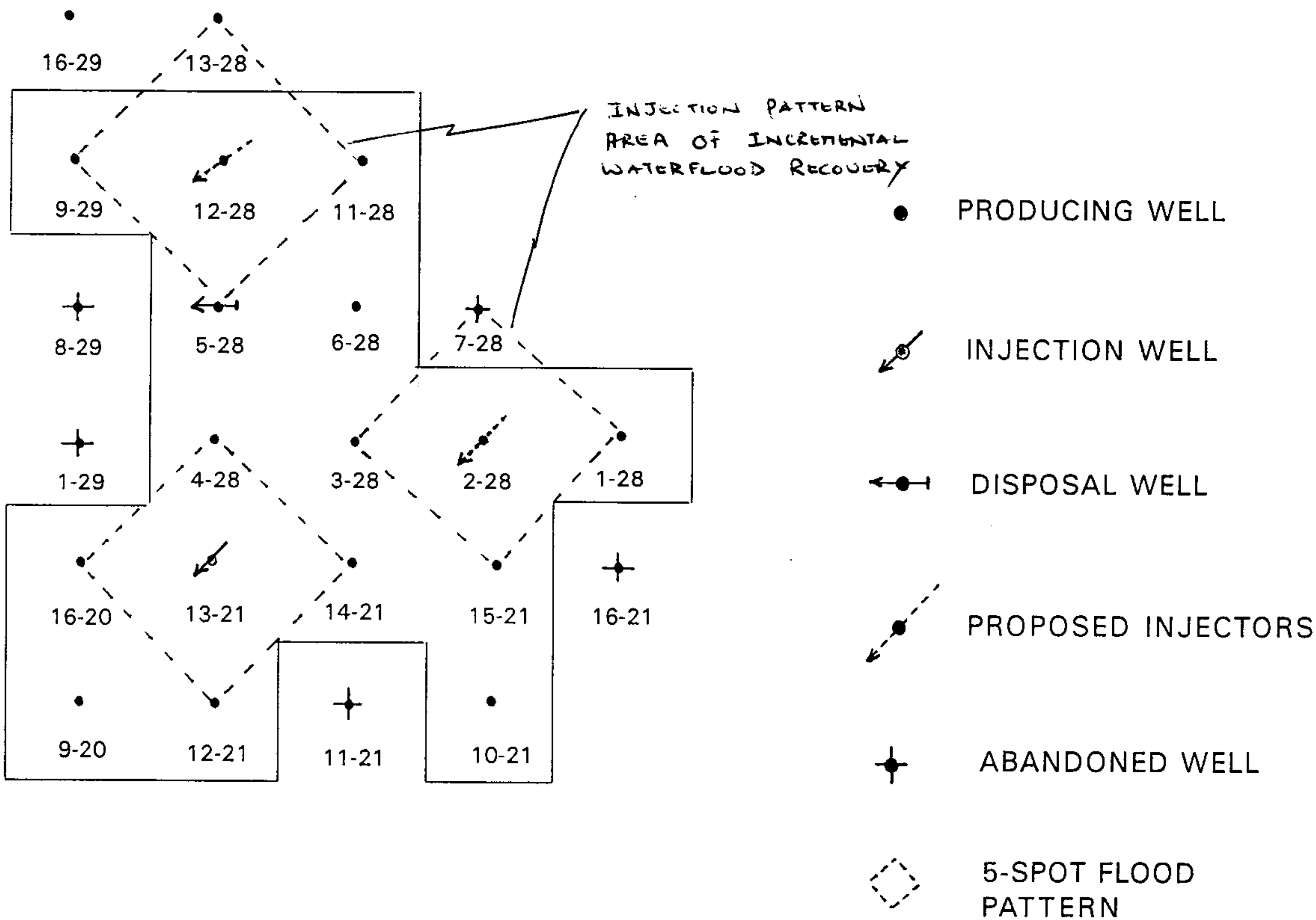


Daly Bakken A Pool (unit)
04/27/95 09:24
Type :
Date 8510-9412
Operator :
Field :
Zone/Pool:
Cum Oil m3 87786
Cum Gas E3m3 0
Cum Water m3 54196
10000
1000
100
10
100
10
1
0.1
1000
100
10
1
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
Year
Num Wells
WOR m3/m3
Monthly Oil m3
13·21 ON INJECTION
WATERFLOOD RESPONSE
16-20
4-28
3-28
PRIMARY PRODUCTION DECLINE

FIG. 2

FIGURE NO. 3

KOLA UNIT NO.1



Tundra
oil and gas ltd.

April 7, 1995

DEPARTMENT OF ENERGY AND MINES
APR 7 1995
PETROLEUM BRANCH

Manitoba Energy and Mines
Petroleum Branch
1395 Ellice Avenue, Suite 360
Winnipeg, Manitoba
R3G OG3

Attention: **Mr. J. Fox, P.Eng.**
Chief Petroleum Engineer

Dear John,

RE: Kola Unit No.1
1994 Progress Report
Application to Convert 2-28-10-29 and 12-28-10-29 to Water Injection Service

---

Please find attached the following information in support of Tundra's application to convert the referenced wells to injection service:

(1) Progress Report January 1, 1994 to December 31, 1994

(2) Individual well applications to convert 2-28-10-29, and 12-28-10-29 to water injection service.

(3) Detailed well operations programs to convert the referenced wells to injection service.

(4) Letters notifying surface owners of proposed operations at the referenced well locations will be forwarded to your attention at a later date.

(5) Lsd 7-28-10-29, outside of the Unit and adjoining the 2-28-10-29 conversion location, are Tundra and Corvair working interest land. Similarly, Lsd 13-28-10-29, again outside of the Unit and adjoining the proposed 12-28-10-29 location, is 100% Tundra working interest land.

I can be reached at 934-5853 for further discussion.

Yours truly,

TUNDRA OIL AND GAS LTD.

George Czyzewski, P.Eng.
Senior Reservoir Engineer

1111 - One Lombard Place, Winnipeg, Manitoba R3B 0X4 Telephone: (204) 934-5850 Fax: (204) 934-5820

LANDS WITHIN 0.5 KL OF PROPOSED
CONVERSIONS 2-28 & 12-28-10-29

LANDS OUTSIDE KOLA UNIT No. 1	OWNERS WIO	RO
16-21		TUNDRA
7-28		CORVAIR
8-28		GAUER
		MAYLEN, R.
13-28		CROWN
14-28		
8-29		CROWN
16-29		

ALL ARE PARTIES TO THE UNIT AGREEMENT

Tundra oil and gas ltd.

FAX TO ROLAND
- 2 COPIES T. HOWELL
FILES TO DAN
- ORIGINAL FILE
DALY FIELD
KOLA UNIT NO. 1
WATERFLOOD APPLICATION

DEPARTMENT OF ENERGY AND MINES
SEP 16 1994
PETROLEUM BRANCH

September 15, 1994

Manitoba Energy and Mines
Petroleum Branch
555 - 330 Graham Avenue
Winnipeg, Manitoba

Attention: Mr. J. Fox, P.Eng.
Chief Petroleum Engineer

Dear John,

RE: Kola Unit No.1
Application to Convert 15-21-10-29 and 5-28-10-29 to Water Injection

Please find attached the following information requested by the Petroleum Branch prior to commencing with operations to convert the referenced wells to injection service:

(1) Detailed programs for converting 15-21-10-29 and 5-28-10-29 to water injection service.

(2) Letters notifying surface owners of proposed operations at the referenced well locations.

I trust this completes the regulatory information requirements, and Tundra will proceed with the conversion programs. Should you have any questions, please contact me at 934-5853.

Yours truly,

TUNDRA OIL AND GAS LTD.

G. Czyzewski

George Czyzewski, P.Eng.
Senior Reservoir Engineer

cc: T. Howell

1111 - One Lombard Place, Winnipeg, Manitoba R3B 0X4 Telephone: (204) 934-5850 Fax: (204) 934-5820

TUNDRA OIL AND GAS LTD.
DALY 5-28-10-29 W1M
CONVERSION PROGRAM

94-08-23

WELL DATA

ELEVATIONS

K.B. - 536.0 M
G.L. - 531.7 M
P.B.T.D. - 887.0 M
T.D. - 901.0 M

PERFORATIONS

872.5 - 874.0 M BAKKEN

CASING

SURFACE - 12 jts, 219.1 MM, 35.72 KG/M, J-55 SET AT 107 M.

PRODUCTION - 75 jts, 114.3 MM, 14.14 KG/M, J-55, SET AT 900 m.

TUBING

90 JTS, 60.3 MM - 861.59 M TALLY
1 - PSN, 0.34 M
1 - TAIL JT - 9.58 M
DELTA K.B. 4.0 M
LANDING DEPTH - 875.31 M

RODS

20-150-RWAC-10-3, CECO 2486
73 - 19 MM PLAIN
37 - 19 MM NYLON SCRAPERED

PROGRAM

1. Inform Dept. of Energy and Mines of impending workover at 748-1557.

2. MIRU service rig c/w pump and tank. Conduct a pre-job meeting reviewing program and safety requirements.

3. Lock out power and remove horsehead. Stroke pump to pressure test tbg to 3500 kPa. If tbg does not pressure test use rig pump for test.

4. POOH with pump and rods. Lay down rods.

5. Install and pressure test B.O.P.'s. Bleed off csg to rig tank. Tag PBTD to check for fill. Circulate well over to clean produced water.

6. POOH and lay down 60.3 mm tbg.

7. RIH with the following string:
1 - 114.3 mm coated AD-1 tension packer
1 - seal tite x-over
60.3 mm PVC lined tbg to surface
1 - seal tite x-over

Land packer at 862 m.

Follow installation instructions as attached.

8. Reverse circulate the annulus over to fresh water inhibited with 0.5 % CRW 132. Do not overcirculate fresh water into tbg. Pump 5 gal diesel into annulus to prevent freezing.

9. Set packer in 5000 daN tension. Exchange dognut for slips. Pressure test annulus to 3500 kPa.

10. Install teflon impregnated nipple on tbg and install a stainless steel ball valve.

11. T.O.T.P.

PREPARED BY______________________________

TUNDRA OIL AND GAS LTD.
DALY 15-21-10-29 W1M
CONVERSION PROGRAM

94-09-14

WELL DATA

ELEVATIONS

K.B. - 533.5 M
G.L. - 529.3 M
P.B.T.D. - 876.6 M
T.D. - 885.0 M

PERFORATIONS

862.8 - 867.0 M BAKKEN

CASING

SURFACE - 10 jts, 219.1 MM, 35.72 KG/M, J-55 SET AT 126 M.

PRODUCTION - 71 jts, 114.3 MM, 14.14 KG/M, J-55, SET AT 885 m.

TUBING

93 JTS, 60.3 MM
1 - 3.05 m pup
1- 2.44 m pup
LANDING DEPTH - 870.91 M

RODS

20-150-RWAC-12-3, ltv 7-93
82 - 19 MM PLAIN
31 - 19 MM NYLON SCRAPERED

PROGRAM

1. Inform Dept. of Energy and Mines of impending workover at 748-1557.

2. MIRU service rig c/w pump and tank. Conduct a pre-job meeting reviewing program and safety requirements.

3. Lock out power and remove horsehead. Stroke pump to pressure test tbg to 3500 kPa. If tbg does not pressure test use rig pump for test.

4. POOH with pump and rods. Lay down rods.

5. Install and pressure test B.O.P.'s. Bleed off csg to rig tank. Tag PBTD to check for fill. Circulate well over to clean produced water.

6. POOH and lay down 60.3 mm tbg.

7. RIH with the following string:
1 - 114.3 mm coated AD-1 tension packer
1 - seal tite x-over
60.3 mm PVC lined tbg to surface
1 - seal tite x-over

Land packer at 852 m.

Follow installation instructions as attached.

8. Reverse circulate the annulus over to fresh water inhibited with 0.5 % CRW 132. Do not overcirculate fresh water into tbg. Pump 5 gal diesel into annulus to prevent freezing.

9. Set packer in 5000 daN tension. Exchange dognut for slips. Pressure test annulus to 3500 kPa.

10. Install teflon impregnated nipple on tbg and install a stainless steel ball valve.

11. T.O.T.P.

PREPARED BY____________________________

Tundra oil and gas ltd.

FILE COPY

September 7, 1994

Mr. Wayne David Plett
General Delivery
Kola, MB
R0M 1B0

Dear Mr. Plett:

RE: Surface Lease Dated July 19, 1986
Twp 10 Rge 29 WPM: LSD 5 Sec 28
Our File: 1412

Further to our recent discussions, this letter will confirm that Tundra Oil and Gas Ltd. intends to convert the well located on the subject Surface Lease to a water injection well in order to conform with the further plans in Kola Unit No. 1.

Should you have any questions or concerns in this regard, please do not hesitate to contact the undersigned at (204) 934-5856.

Sincerely,

TUNDRA OIL AND GAS LTD.

David H. Taylor
Manager, Land and Contracts

DHT/bp

- Wayne requests that site be cleaned

Tundra oil and gas ltd.

September 9, 1994

Mr. Glen Merwin Sharratt
3536 Arbutus Drive South
Cobble Hill, British Columbia
V0R 1L1

Dear Mr. Sharratt:

RE: Surface Lease dated January 26, 1993
TWP 10 RGE 29 WPM: LSD 15 SEC 21
Our File(s): 1267

Further to our recent discussions, this letter will confirm that Tundra Oil and Gas Ltd. intends to convert the well located on the subject Surface Lease to a water injection well in order to conform with further plans in Kola Unit #1.

Should you have any questions or concerns in this regard, please do not hesitate to contact the undersigned at (204) 934-5856.

Sincerely,

TUNDRA OIL AND GAS LTD.

David H. Taylor
Manager, Land and Contracts

DHT/srt

1111 - One Lombard Place, Winnipeg, Manitoba R3B 0X4 Telephone: (204) 934-5850 Fax: (204) 934-5820

Manitoba

Memorandum

Date August 25, 1994

To File

From John N. Fox,
Chief Petroleum Engineer
Petroleum Branch

Telephone

Subject **Application to Convert to WIW**
15-21-10-29 & 5-28-10-29

Tundra has applied to convert the subject wells in Kola Unit No. 1 to water injection.

Recommendations

The application be approved by the Director under Clause 1(1) of Board Order No. PM 71.

Discussion

Injection in Kola Unit No. 1 commenced at 13-21-10-29 in October/93. Water injection at 13-21 has averaged 610 m^3/mon in 1994. The monthly VRR for the 13-21 injection pattern has averaged 1.37 since injection commenced.

Between Oct/93 and Jun/94 production from the 13-21 injection pattern has increased from 210.4 to 271.5 m^3/mon, a 29% increase. Between Oct/93 and Jun/94 production from wells in the Unit outside the 13-21 injection pattern has decreased from 234.4 to 222.7 m^3/mon, a 5% decrease.

Additional injection at 15-21 and 5-28 will allow the whole Unit to be adequately waterflooded.

A review of royalty and working interest owners within 0.5 km of the proposed injectors indicates all parties are participants in the Unit. Tundra is the lessee of Crown oil and gas rights in the SE/4 of Sec. 29 which is not in the Unit. Therefore there is no need to advertise the application.

Tundra must notify the surface owners of it plan to convert the wells. Tundra is to file a detailed program of operations with the district office before commencing operations.

John N. Fox

August 29, 1994

Mr. G. Czyzewski, P.Eng.
Senior Reservoir Engineer
Tundra Oil and Gas Ltd.
1111-One Lombard Place
Winnipeg MB R3B 0X4

Dear George:

Re: Kola Unit No. 1
Application to Convert 15-21-10-29
and 5-28-10-29 to Water Injection

Your application to convert the subject wells to water injection in Kola Unit No. 1 is approved (copies attached). Prior to commencing operations to convert the wells, Tundra is to provide the Branch with the following:

(1) a copy of a notice under Clause 71(e) of the Drilling and Production Regulation, to the surface owners of 15-21 and 5-28 of Tundra's plan to convert the wells;

(2) a detailed program of operations for the two conversions.

Water injection at 15-21 and 5-28 is subject to the conditions contained in Board Order No. PM 71.

If you have any questions in respect of this matter please contact the undesigned at 945-6574.

Yours truly,

John N. Fox, P.Eng.
Chief Petroleum Engineer

cc. Virden

Tundra oil and gas ltd.

August 5, 1994

Manitoba Energy and Mines
Petroleum Branch
555 - 330 Graham Avenue
Winnipeg, Manitoba

Attention: **Mr. L.R. Dubreuil**
Director, Petroleum Branch

DEPARTMENT OF ENERGY AND MINES
AUG 10 1994
PETROLEUM BRANCH

Dear Mr. Dubreuil,

RE: Kola Unit No.1
Conversion to Water Injection Service
Wells 15-21-10-29 W1M and 5-28-10-29 W1M

Tundra Oil and Gas Ltd, as operator of the Kola Unit No.1, makes application here-in to convert the referenced wells to water injection service. The conversion of 15-21-10-29 W1M and 5-28-10-29 to water injection service will expand the existing waterflood operation in the Kola Unit No.1. The initial area of waterflood operations in the Kola Unit No.1 (refer to attached Unit map) has indicated good waterflood response, and on this basis, further expansion of secondary recovery in the Unit is justified.

In support of our application, the following information is attached:

* Outline of Unit area.

* Completed EMR applications outlining proposed program of operations.

* Downhole schematic of water injection service completion.

* Names and addresses of royalty and working interest owners with same outlined on Kola area map.

Tundra would like to convert 5-28 and 15-21 to water injection service during September, 1994, and if any further information is required to process this application, our office will be pleased to provide the Petroleum Branch with the necessary assistance. If you have any questions, I can be reached at 934-5853.

Yours truly,

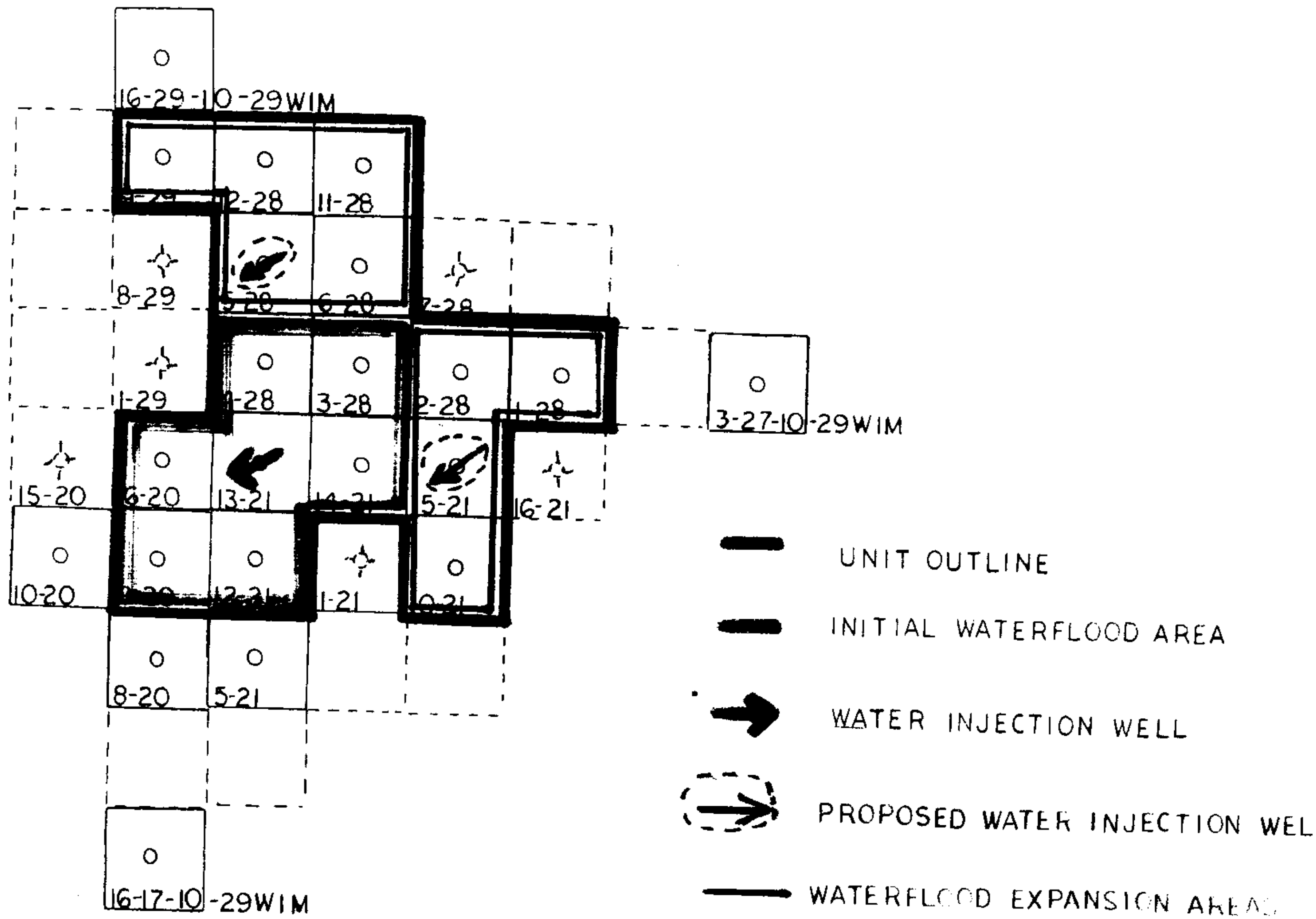
TUNDRA OIL AND GAS LTD.

George Czyzewski, P.Eng.
Senior Reservoir Engineer, P.Eng.

1111 - One Lombard Place, Winnipeg, Manitoba R3B 0X4 Telephone: (204) 934-5850 Fax: (204) 934-5820

BAKKEN 'A' POOL

TUNDRA OIL & GAS
Kola Unit #1 Conversion
to water injection
service



WORKING INTEREST OWNERS

Brandon Professional Investments
P.O. Box 1270
Brandon, Manitoba
R7A 6K4

Corvair Oils Limited
P.O. Box 3827, Station "D"
Edmonton, Alberta
T5L 4J8

Kiwi Resources Ltd.
P.O. Box 908
Virden, Manitoba
ROM 2CO

Mustang Oil Ltd.
P.O. Box 1537
Virden, Manitoba
ROM 2CO

Tundra Oil and Gas Ltd.
1111 One Lombard Place
Winnipeg, Manitoba
R3B 0X4

ROYALTY INTEREST OWNERS

2472 Manitoba Ltd.
1111 One Lombard Place
Winnipeg, Manitoba
R3B 0X4

Corvair Oils Ltd.
P.O. Box 3827, Station "D"
Edmonton, Alberta
T4L 4J8

Edna Rachel Eliza McPhail
336 - 25th Street
Brandon, Manitoba
R7B 1Z3

Naylen Oil Corp.
40 Everett Crescent
Regina, Saskatchewan
S4S 2M7

John Edwin Watson
158 Leslie Street
Sault Ste. Marie, Ontario

Thomas Reginald Watson
P.O. Box 1405
Virden, Manitoba
ROM 2CO

Douglas Harold Wood
P.O. Box 99
Kelwood, Manitoba
ROJ OYO

Department of Energy & Mines
555 - 330 Graham Avenue
Winnipeg, Manitoba
R3C 4E3

Isabel Cotton
2015 Richmond Avenue
Brandon, Manitoba
R7B 0T4

Gauer Oil Company
202 Riverside Drive
Toronto, Ontario
M6S 4A9

Montreal Trust Company
221 Portage Avenue
Winnipeg, Manitoba
R3B 2A6

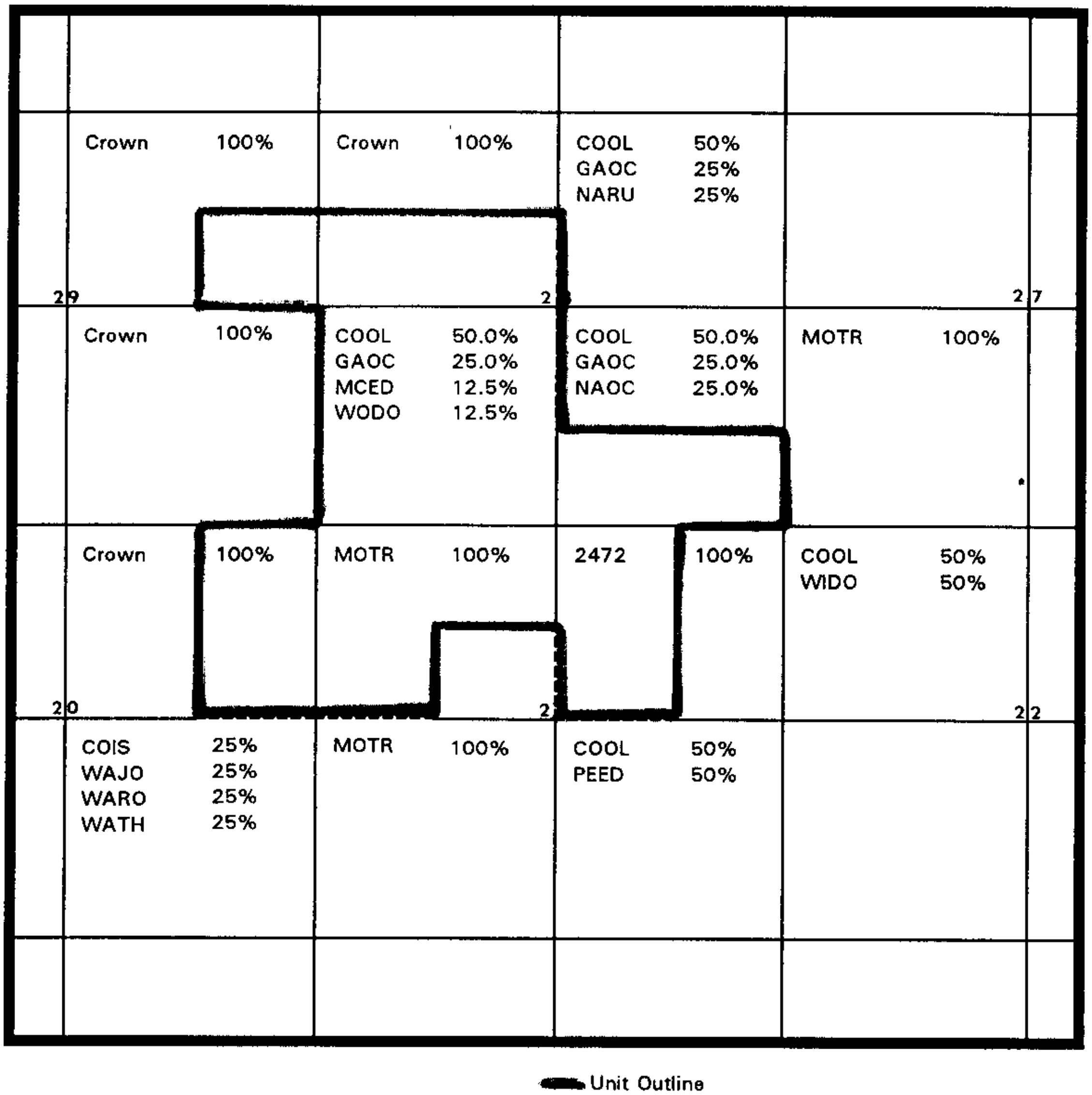
Edgar Penner
General Delivery
Elkhorn, Manitoba
ROM 0NO

Robin Watson
P.O. Box 245
Roblin, Manitoba
ROL 1PO

Donald C. Widger
P.O. Box 68
Elkhorn, Manitoba
ROM 0NO

Poco Petroleums (ORR)
P.O. Box 4365, Station "C"
Calgary, Alberta
T2T 5N2

Ruth Joyce Naylen
General Delivery
Maryfield, Saskatchewan



2472 - 2472792 Manitoba Ltd.
COIS - Isabel Cotton
COOL - Corvair Oils Ltd.
GAOC - Gauer Oil Company
MCED - Edna Rachel Eliza McPhail
MOTR - Montreal Trust
NAOC - Naylen Oil Corp.
NARU - Ruth Joyce Naylen
PEED - Edgar Penner
WAJO - John Edwin Watson
WARO - Robbin Watson
WATH - Thomas Reginald Watson
WIDO - Donald C. Widger
WODO - Douglas Harold Wood

Manitoba
Energy and Mines
Petroleum

APPLICATION TO

~~SUSPEND PRODUCTION~~
~~ABANDON~~
~~RECOMPLETE~~
CONVERT TO ~~SWD~~, WIW, or ________
~~SUSPEND DRILLING~~
~~RESUME DRILLING~~
~~OTHER~~

A WELL

(Stroke Out Operations Which Do Not Apply)

In compliance with the Petroleum Drilling and Production Regulations, 1984 and amendments thereto, approval is hereby applied for the following operations to be commenced on or about the 1, day of September 19 94, on the well known as Tundra Kola Unit No.1 15-21-10-29

located on Lsd. 15 Sec. 21 Twp. 10 Rge. 29 W of First Meridian,

Well Licence No. 4331 Field or Unit Kola Unit No.1

CASING RECORD

	Size O.D. (mm)	Weight (Kg/m)	Amount (m)	Set (m)	Cement (tonnes)	Method
First String	219.1	35.72	126.0	126.0	12.0	pump & plug
Second String	114.3	14.14	885.0	885.0	24.0	pump & plug
Third String						

CONDITION OF WELL

Present Status Producing oil well

Total Depth of Well 885.0 m K.B. Plug Back Total Depth 876.8 m K.B.

Perforations (K.B.): From 862.8 to 867.0; From .... to ....; From .... to ....

Open Hole (K.B.): 533.5 m To

Name of Producing Zone Bakken

Date of Last Production July, 1994

Date of Last Production Test July, 1994 Daily Production 2.8 m^3 / day oil

W.O.R. W.C.% 61% G.O.R.

Reason for Operations Proposed:
Convert 15-21-10-29 to water injection service to expand waterflood operations in the Kola Unit No.1

Program of Operations Proposed:
- Remove existing tubulars and surface pumping equipment from 15-21 well
- Run-in with plastic lined tubing and packer assembly as outlined on attached schematic of water injection service completion.

Operations to be carried out by: T.B.A. Address

Responsible agent in field: T.Howell, P.Eng. Address Virden, MB Phone No. (204) 748-3095

Responsible agent, Co. office: T.Howell, P.Eng. Address Virden, MB Phone No. (204) 748-3095

Signed by [signature], P.Eng. Title Senior Reservoir Engineer

Company Tundra Oil & Gas Ltd. at Winnipeg this 5 day of August 19 94

FOR DEPARTMENT USE ONLY

APPROVAL

This application has been examined and program of operations approved, subject to the following conditions:

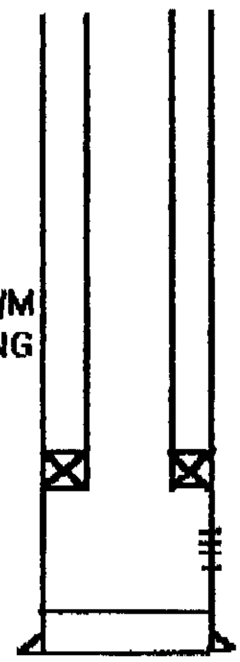
1. Please advise our Virden/Waskada office before approved operations are commenced.
2. This approval expires March 1, 1995.

Date August 29 19 94 Approved:

[signature] Petroleum Engineering Section

for [signature] Director, Petroleum Branch

PROPOSED CONVERSION TO WATER INJECTION
TUNDRA DALY 15-21-10-29 WPM



Manitoba
Energy and Mines
Petroleum

APPLICATION TO { ~~SUSPEND PRODUCTION~~ / ~~ABANDON~~ / ~~RECOMPLETE~~ / CONVERT TO ~~SWD~~, WIW, or ________ / ~~SUSPEND INJECTION~~ / ~~RESUME INJECTION~~ / ~~OTHER~~ } A WELL

(Stroke Out Operations Which Do Not Apply)

In compliance with the Petroleum Drilling and Production Regulations, 1984 and amendments thereto, approval is hereby applied for the following operations to be commenced on or about

the ....1...., day of September... 19 94...., on the well known as .... TUNDRA KOLA UNIT NO.1 . 5-28-10-29 WPM ....

located on Lsd....5...... Sec....28...... Twp.....10..... Rge....29........ W of First Meridian,

Well Licence No. .....3889.................. Field or Unit .. KOLA UNIT NO.1 ....

CASING RECORD

	Size O.D. (mm)	Weight (Kg/m)	Amount (m)	Set (m)	Cement (tonnes)	Method
First String	219.1	35.70	107	107	12.0	pump & plug
Second String	114.3	14.14	900	900	23.7	pump & plug
Third String						

CONDITION OF WELL

Present Status ....Shut - in oil well.............................

Total Depth of Well ......900.0m K.B........ Plug Back Total Depth ..894.87m K.B........

Perforations (K.B.): From .872.5. to .874.0.; From .... to ....; From .... to ....

Open Hole (K.B.): ....536.0 m........... To ....

Name of Producing Zone ..Bakken...

Date of Last Production ....October, 1992...................................

Date of Last Production Test ....------........ Daily Production ....------....................

W.O.R. ....-------..................... W.C.% ...-------...... G.O.R. .....-------...

Reason for Operations Proposed: ..convert 5-28-10-29 to water injection service to... ...expand waterflood operations in the Kola Unit No. 1.............................

Program of Operations Proposed:

- Remove existing tubulars and surface pumping equipment from 5-28 well.
- Run-in with plastic lined tubing and packer assembly as outlined on attached schematic of water injection service completion.

Operations to be carried out by: ...T.B.A.... Address ....

Responsible agent in field: ..T. Howell, P.Eng. Address ..Virden, MB.. Phone No. (204) 748-3095

Responsible agent, Co. office: T. Howell, P.Eng. Address ..Virden, MB.. Phone No. (204) 748-3095

Signed by [signature] .... Title .....Senior Reservoir Engineer......

Company Tundra Oil and Gas Ltd. at Winnipeg this ...5.... day of ...August........ 19 94...

FOR DEPARTMENT USE ONLY

APPROVAL

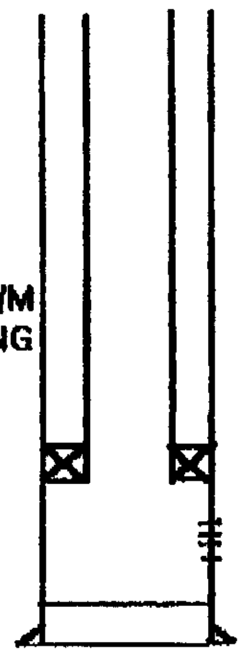
This application has been examined and program of operations approved, subject to the following conditions:

1. Please advise our Virden/Waskada office before approved operations are commenced.
2. This approval expires March 1, 1995.

Date ....August 29....... 19 94.... Approved: [signature]

Petroleum Engineering Section .... for Director, Petroleum Branch

PROPOSED CONVERSION TO WATER INJECTION
TUNDRA ET AL DALY 5-28-10-29 WPM



KOLA UNIT No. 1 AUG 25/94

APPLICATION TO CONVERT 15-21-10-29 &

5-28-10-29 TO WTR INJECTION

ISSUES

(1) NEED FOR NOTIFICATION OF OFFSETTING RO &/WIO
- notification of surface owner re: conversion ✓

(2) MODIFICATIONS REQUIRED TO BOARD ORDER PM 71
- NEED FOR PRESSURE DATA
- PM PROGRESS REPORT
- CURRENT INJ. PRESSURE & RATES @ 13-21-10-29

(3) REVIEW WF PERFORMANCE

MODIFICATIONS TO PM 71

- approved under Clause 1(1) of Order No. PM 71

- 15-21 & 5-28 were future conversions outline in Tundra's PM application Jan/93

- 13-21 injection target 19-30 m3/d VRR = 1-1.15

NEED FOR NOTIFICATION

- S 71 requires notification of ALL RO & WIO WITHIN 0.5 KM of UNIT BOUNDARY

- RO & WIO in the ~~NE/4~~ N/2 of Sec 21, S/2 & NW/4 of Sec 28 WITHIN 0.5 KM of the proposed WIW WELLS 15-21 & 5-28 ARE PARTIES TO THE UNIT AGREEMENT

- the Crown is the mineral owner - the S/E of 29 & the minerals are leased by Tundra

- NO NEED TO ADVERTISE THE CONVERSION

- NEED A copy of the notice to the surface owner of 15-21 & 5 28 re: the proposed conversions under Clause 71 (e)

WF PERFORMANCE REVIEW

13-21-10-29 INJECTION PATTERN

- unit effective Oct 1/93

- 13-21 199~~4~~ aver. inj. 610 m³/mon

- 13-21 injection ~~pattern~~ production Jun/94 271.5 29 % increase
Oct/93 210.4

unit production outside the 13-21 injection pattern Jun/94 222.7 has decreased 5 %
Oct/93 234.4

- pressure data 15-21 Feb/93 6195 kPa

- need detailed program of well operations, prior to commencing operations to convert the well.

13-21 VRR = 1.37

VOIDAGE oil (1517.8 + 648.6) * 1.063 REPLACEMENT ~~3663.8~~
water 1098.5 + 524.5 5380
TOTAL 3926 m^3

Manitoba

The Oil and Natural Gas Conservation Board

555 — 330 Graham Avenue
Winnipeg MB R3C 4E3
CANADA

(204) 945-1111
FAX: (204) 945-0586

FILE:

- BOARD ORDERS
SPACING ORDERS

- COPY FOR
DALY BAKKEN A
POOL - PRESS MAIN. APP'N

Order No. PM 71
An Order Pertaining to Pressure
Maintenance by Water Flooding
Daly Bakken A Pool

WHEREAS, subsection(9)(d) of Section 62 of "The Mines Act", being Chapter M160, of the Continuing Consolidation of the Statutes of Manitoba, provides as follows:

> "62(9) Without restricting the generality of subsection (8) the board, with the approval of the minister, may make orders
>
> (d) requiring the repressuring, recycling, or pressure maintenance, of any pool or portion thereof where it is econonomical so to do, and for that purpose where necessary requiring the introduction or injection into any pool or portion thereof of gas, air, water, or other substance;"

AND WHEREAS, the Board received an application dated July 9, 1993 from Tundra Oil and Gas Ltd. for approval of a project to inject water into the Daly Bakken A Pool ("the pool") in the proposed Kola Unit No. 1 ("the unit area").

AND WHEREAS, upon publication of notice of the application, the Board received no objections to or interventions in the application.

AND WHEREAS, Tundra Oil and Gas Ltd. is the unit operator of the proposed Kola Unit No. 1.

AND WHEREAS, upon due consideration, the Board has found it is reasonable and desirable to approve the application.

NOW THEREFORE, the Board orders that:

1. The unit operator shall conduct pressure maintenance operations by the injection of water into the pool underlying the unit area.

2. The pressure maintenance operations shall be in accordance with, and subject to, the following rules:

PRESSURE MAINTENANCE RULES

1(1) Water shall be injected into the pool through the well:

Tundra Kola Unit No. 1 WIW 13-21-10-29 (WPM)

and such other wells in the unit area as the Board may order or approve.

1(2) After the commencement of injection, the unit operator shall, subject to any remedial work required to be performed on the wells referred to in subsection (1), endeavour to maintain continuous injection.

1(3) Notwithstanding the provisions of subsection (2), the Board may, upon application by the unit operator, approve the suspension of water injection into any well or wells, provided that the Board is satisfied that pressure maintenance operations in the unit area will not be adversely affected.

1(4) The completion of the wells referred to in subsection (1) will be as prescribed by the Director of Petroleum.

2 Upon the request of the Board, the unit operator shall satisfy the Board as to the source, suitability and method of treatment of the water to be injected.

3(1) Before injection of water is commenced, the unit operator shall conduct a survey to determine the static reservoir pressure in the unit area.

3(2) The unit operator shall, not less than six months nor more than 12 months after the commencement of injection, and at yearly intervals thereafter, conduct a survey to determine the static reservoir pressure in the unit area.

3(3) The unit operator shall submit to the Petroleum Branch, within 30 days of the completion date of the surveys described in subsections (1) and (2), the static reservoir pressure data obtained from the survey, corrected to a common datum.

3(4) The Board may, at any time, require the unit operator to carry out such additional reservoir pressure surveys as it deems necessary.

4 The unit operator shall immediately report to the Board any indication of channelling or break-through of injected water to producing wells or any indication of other detrimental effects that may be attributable to the pressure maintenance operations.

5 The maximum wellhead pressure at which water is injected into the wells referred to in subsection 1(1) shall not exceed 9 000 kPa or such other maximum pressure as the Board may prescribe and the Board may, from time to time, prescribe a maximum or minimum rate at which water shall be injected into any well in the unit area.

6 The unit operator shall, before April 30th of each calendar year, file with the Petroleum Branch a report of the pressure maintenance project, setting out such interpretive information as is necessary to evaluate the efficacy of the waterflood.

H. Clare Moster
Deputy Chairman

David Tomasson
Chairman

OIL AND NATURAL GAS CONSERVATION BOARD ORDER NO. PM 71 APPROVED THIS DAY OF Sept. 30 A.D., 1993 AT THE CITY OF WINNIPEG.

APPROVED:

Donald W. Orchard
Minister of Energy and Mines

Manitoba

Memorandum

Date September 8, 1993

To The Oil and Natural Gas Conservation Board
- David Tomasson, Chairman
- H. Clare Moster, Deputy Chairman

From John N. Fox
Chief Petroleum Engineer
Petroleum Branch

Telephone

Subject **DALY BAKKEN A POOL PRESSURE MAINTENANCE APPLICATION**

First | Fold

Tundra Oil and Gas Ltd. has made application to conduct a waterflood in a portion of the Daly Bakken A Pool in the proposed Kola Unit No. 1. Notice of the application was published in the Virden Empire Advance and sent to royalty and working interest owners in and adjoining the proposed unit area. No objections to the application were received.

Recommendations

It is recommended that the Board issue Board Order No. PM 71 approving Tundra's application. A copy of the proposed Board Order and accompanying letter are attached.

Discussion

Tundra has applied to conduct a waterflood in a portion of the Daly Bakken A Pool. The project, in the proposed Kola Unit No. 1, involves the conversion of 13-21-10-29 to water injection. If the waterflood is successful Tundra tentatively plans to convert two additional wells to injection to flood the majority of the pool (Fig.1).

The proposed unit contains 66% of the OOIP in the A Pool (Fig.2). The wells within the unit account for 82% of the current and 92% of the cumulative production from the A Pool. With the exception of the 10-20-10-29 and 16-29-10-29 wells, wells outside the proposed unit are marginal producers.

The shape of the A Pool, 2.4 km long by 1.0 km wide, makes it difficult to implement a pattern waterflood. Tundra's proposal to flood the main portion of the pool is reasonable. When the flood is expanded as outlined in Figure 1, economic recovery from the A pool should be maximized.

Waterflood Performance Predictions

Tundra conducted special core analysis on core from the 4-28-10-29 well. The relative permeability tests indicated; initial water saturation of 57.8% (higher than the Branch's estimate of S_{wi}=45%); residual oil saturation of 19.7%; and a waterflood recovery efficiency of 53.3% OOIP. The analysis confirmed the Bakken is strongly water-wet and displacement will occur in a piston-like manner, with recovery at breakthrough essentially equivalent to ultimate recovery.

Based on the special core analysis and waterflood performance in the Daly Bakken D Pool, Tundra has estimated the waterflood will increase the recovery in the unit from 18.5% OOIP under primary to 35.8% OOIP. The 13-21-10-29 injection pattern is in the best portion of the reservoir, recovery within the pattern is expected to increase from 23.9% OOIP under primary to 42.4% OOIP.

In order to evaluate Tundra's waterflood recovery estimates the Branch reviewed waterflood performance in the Daly Bakken D Pool. Water injection in the D Pool commenced in July 1990 at 16-14-10-29 and in October 1991 at 8-14-10-29 (Fig.3). Under primary recovery, production in the D Pool was characterized by a steep decline in productivity, 40-50%/yr. Response to water injection was almost immediate, and resulted in an arresting of the production decline as shown in Figure 4. It is estimated the waterflood in the D Pool has more than doubled recovery from $59.2 \times 10^3 m^3$ under primary to $127.7 \times 10^3 m^3$. Based on Tundra's OOIP estimates for the D Pool (Tundra - $344.4 \times 10^3 m^3$ vs Branch $503.7 \times 10^3 m^3$) waterflood recovery is 37.1% OOIP, compared to a primary recovery of 17.2% OOIP.

The Branch agrees with Tundra that the A Pool waterflood performance will be similar to the D Pool. Table 1 lists OOIP and primary and secondary recovery estimates for the Bakken A and D Pools.

Reservoir pressure in the A pool is currently 6000 kPa, 2600 kPa less than original reservoir pressure but well above the bubble point pressure of 2100 kPa. Tundra plans to inject at a VRR of 1.15. Water produced from wells in the pool (currently 21 m^3/d) will be adequate to meet voidage replacement requirements.

Injectors in the Daly Bakken D Pool have experienced injectivity problems. Figure 5 is a plot of the injectivity index ($m^3/d/MPa$) for the 8-14 and 16-14-10-29 injection wells. The plot shows steadily decreasing injectivity. In April 1993 the Board approved Tundra's application to increase injection pressure in the D Pool to 9000 kPa, 95% of formation fracture pressure (original maximum injection pressure was 7000 kPa). Tundra anticipates similar injectivity restrictions in the A Pool and has requested a maximum wellhead injection pressure of 9000 kPa. The Branch has some concerns with injection near fracture pressure causing injected fluids to move out of zone. However this does not appear to be a problem in the D Pool. The Branch considers injection at a VRR > 1.0 to be critical for a waterflood to be successful and therefore recommends the Board approve an injection pressure of 9000 kPa.

Implementation of a waterflood in the Daly Bakken A Pool will significantly increase oil recovery. Therefore it is recommended that Tundra's application be approved and Board Order No. PM 71 issued. The proposed Board letter to accompany the order asks Tundra to provide an update of its plans for waterflood expansion by May 1, 1994 and to comment on injection rates and pressures in the A Pool.

John N. Fox

Approved: ______________________
L.R. Dubreuil, Director

TABLE 1

BAKKEN WATERFLOOD

RECOVERY ESTIMATES

	A Pool	Kola Unit No. 1	13-21-10-29 Injection Pattern	D Pool
Original Oil-in-Place ($10^3 m^3$)	735.1	487	238.8	344.4
Primary Recoverable Reserves ($10^3 m^3$)	136	90.1	57.1	59.2
Primary Recovery Factor (%)	18.5	18.5	23.9	17.2
Secondary Recoverable Reserves ($10^3 m^3$)	220.2	174.3	99.5	127.7
Secondary Recovery Factor (%)	30.0*	35.8*	41.7	37.1

* Note : Assumes 3 wells are converted to water injection

Manitoba

The Oil and Natural Gas
Conservation Board

555 — 330 Graham Avenue
Winnipeg MB R3C 4E3
CANADA

(204) 945-1111
FAX: (204) 945-0586

Mr. George Czyzewski, P.Eng.
Sr. Reservoir Engineer
Tundra Oil and Gas Ltd.
1111 One Lombard Place
Winnipeg MB R3B 0X4

Dear Mr. Czyzewski:

Re: Daly Bakken A Pool - Board Order No. PM 71

The Board has completed its review of Tundra's application to conduct a waterflood in the proposed Kola Unit No. 1 in the Daly Bakken A Pool. Attached is Board Order No. PM 71 approving the waterflood.

You are reminded that water injection is not to commence until the Board has approved the Kola Unit No. 1 Unit Agreement.

Tundra is requested to submit to the Board by May 1, 1994, an update of its plans for waterflood expansion in the unit. In the update, Tundra should comment on the injection rate and pressure at 13-21-10-29 (WPM).

If you have any questions, please contact John N. Fox, Chief Petroleum Engineer at (204) 945-6574.

Yours respectfully,

H. Clare Moster
Deputy Chairman

Manitoba

The Oil and Natural Gas
Conservation Board

555 — 330 Graham Avenue
Winnipeg MB R3C 4E3
CANADA

(204) 945-1111
FAX: (204) 945-0586

Order No. PM 71
An Order Pertaining to Pressure
Maintenance by Water Flooding
Daly Bakken A Pool

WHEREAS, subsection(9)(d) of Section 62 of "The Mines Act", being Chapter M160, of the Continuing Consolidation of the Statutes of Manitoba, provides as follows:

> "62(9) Without restricting the generality of subsection (8) the board, with the approval of the minister, may make orders
>
> (d) requiring the repressuring, recycling, or pressure maintenance, of any pool or portion thereof where it is econonomical so to do, and for that purpose where necessary requiring the introduction or injection into any pool or portion thereof of gas, air, water, or other substance;"

AND WHEREAS, the Board received an application dated July 9, 1993 from Tundra Oil and Gas Ltd. for approval of a project to inject water into the Daly Bakken A Pool ("the pool") in the proposed Kola Unit No. 1 ("the unit area").

AND WHEREAS, upon publication of notice of the application, the Board received no objections to or interventions in the application.

AND WHEREAS, Tundra Oil and Gas Ltd. is the unit operator of the proposed Kola Unit No. 1.

AND WHEREAS, upon due consideration, the Board has found it is reasonable and desirable to approve the application.

NOW THEREFORE, the Board orders that:

1. The unit operator shall conduct pressure maintenance operations by the injection of water into the pool underlying the unit area.

2. The pressure maintenance operations shall be in accordance with, and subject to, the following rules:

PRESSURE MAINTENANCE RULES

1(1) Water shall be injected into the pool through the well:

Tundra Kola Unit No. 1 WIW 13-21-10-29 (WPM)

and such other wells in the unit area as the Board may order or approve.

1(2) After the commencement of injection, the unit operator shall, subject to any remedial work required to be performed on the wells referred to in subsection (1), endeavour to maintain continuous injection.

1(3) Notwithstanding the provisions of subsection (2), the Board may, upon application by the unit operator, approve the suspension of water injection into any well or wells, provided that the Board is satisfied that pressure maintenance operations in the unit area will not be adversely affected.

1(4) The completion of the wells referred to in subsection (1) will be as prescribed by the Director of Petroleum.

2 Upon the request of the Board, the unit operator shall satisfy the Board as to the source, suitability and method of treatment of the water to be injected.

3(1) Before injection of water is commenced, the unit operator shall conduct a survey to determine the static reservoir pressure in the unit area.

3(2) The unit operator shall, not less than six months nor more than 12 months after the commencement of injection, and at yearly intervals thereafter, conduct a survey to determine the static reservoir pressure in the unit area.

3(3) The unit operator shall submit to the Petroleum Branch, within 30 days of the completion date of the surveys described in subsections (1) and (2), the static reservoir pressure data obtained from the survey, corrected to a common datum.

3(4) The Board may, at any time, require the unit operator to carry out such additional reservoir pressure surveys as it deems necessary.

4 The unit operator shall immediately report to the Board any indication of channelling or break-through of injected water to producing wells or any indication of other detrimental effects that may be attributable to the pressure maintenance operations.

5 The maximum wellhead pressure at which water is injected into the wells referred to in subsection 1(1) shall not exceed 9 000 kPa or such other maximum pressure as the Board may prescribe and the Board may, from time to time, prescribe a maximum or minimum rate at which water shall be injected into any well in the unit area.

6 The unit operator shall, before April 30th of each calendar year, file with the Petroleum Branch a report of the pressure maintenance project, setting out such interpretive information as is necessary to evaluate the efficacy of the waterflood.

H. Clare Moster
Deputy Chairman

David Tomasson
Chairman

OIL AND NATURAL GAS CONSERVATION BOARD ORDER NO. PM 71 APPROVED THIS DAY OF A.D., 1993 AT THE CITY OF WINNIPEG.

APPROVED:

Donald W. Orchard
Minister of Energy and Mines

FIGURE 1

KOLA UNIT NO. 1

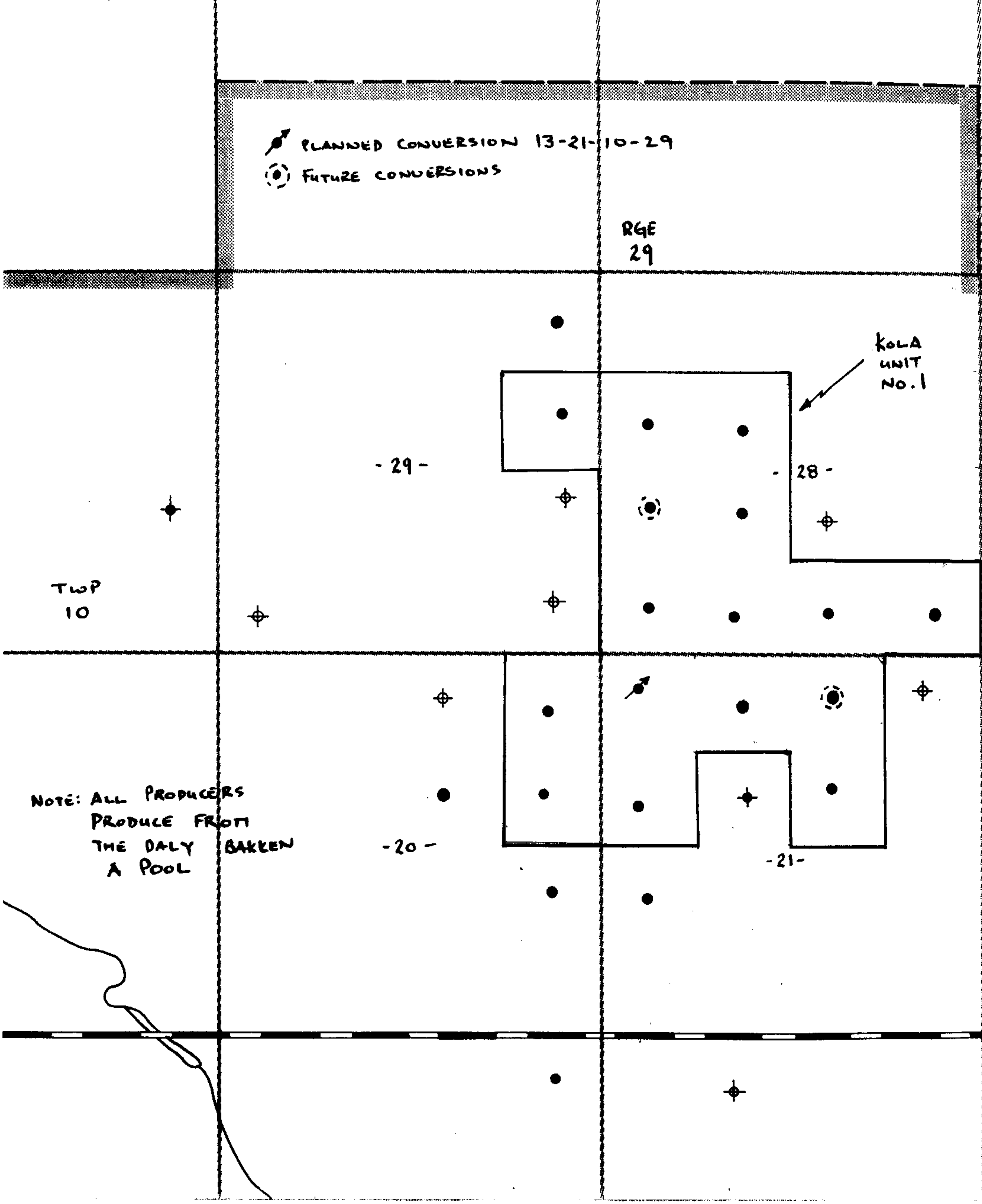
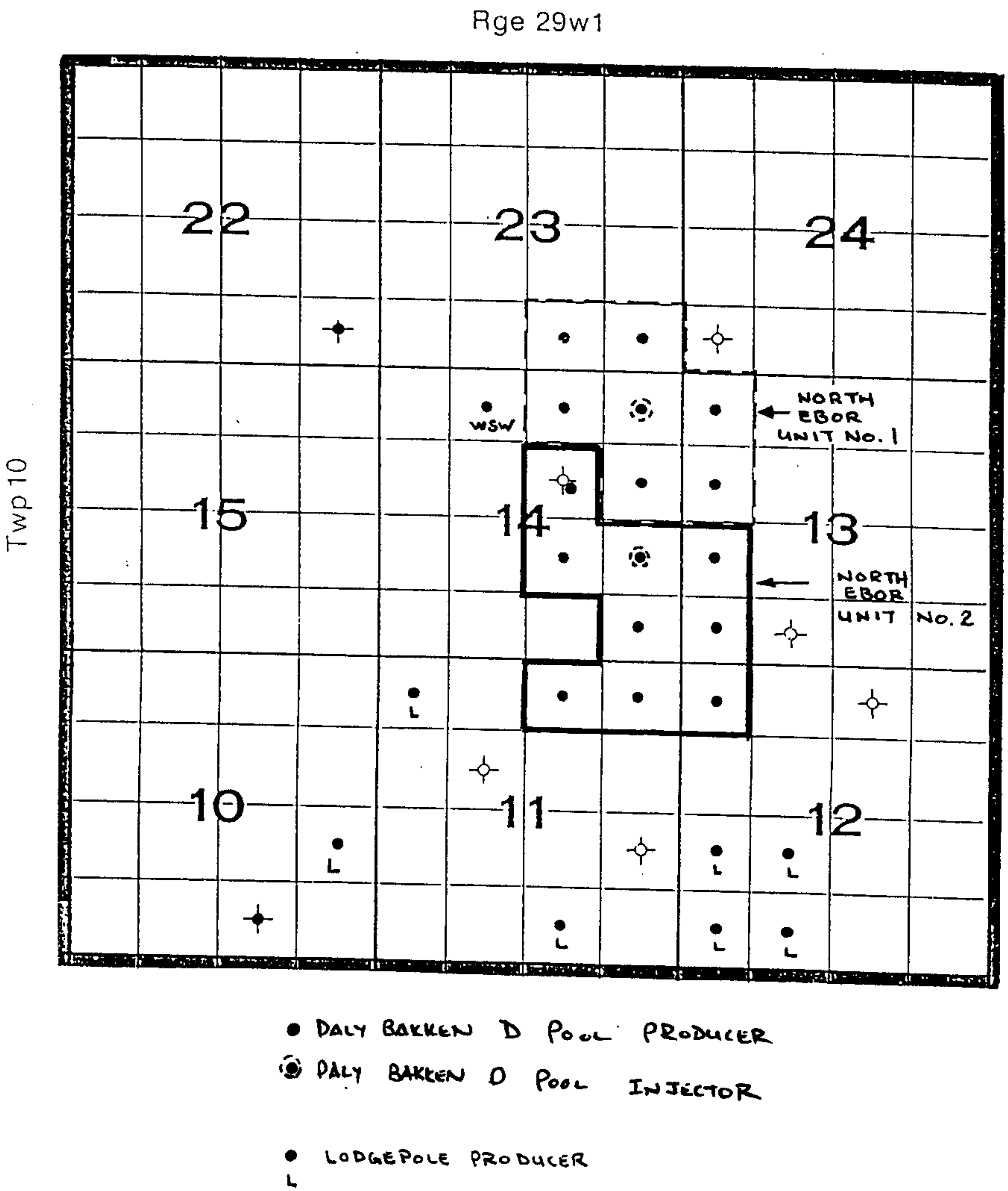


FIGURE 3

DALY BAKKEN D POOL



DALY BAKKEN D POOL

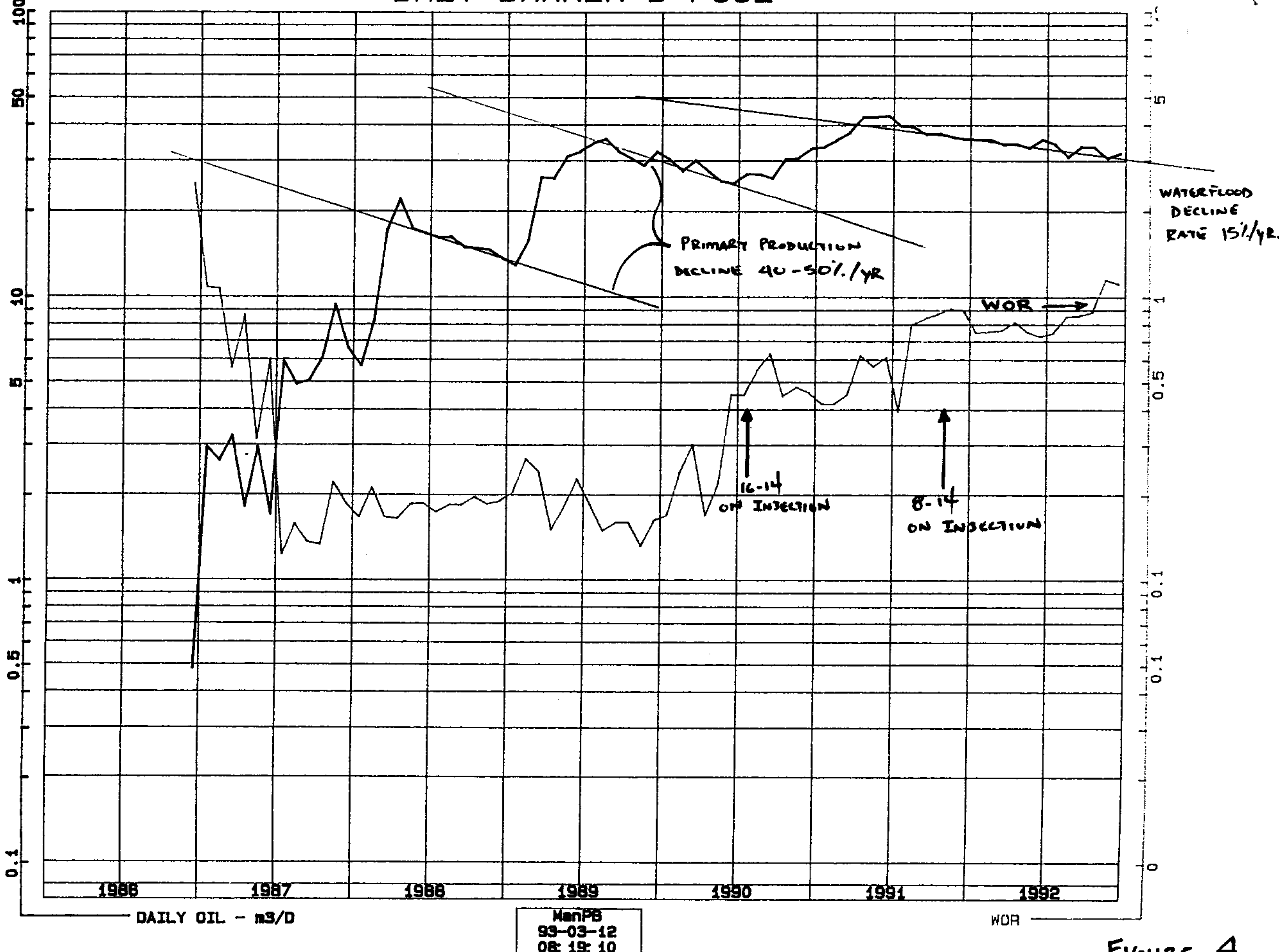
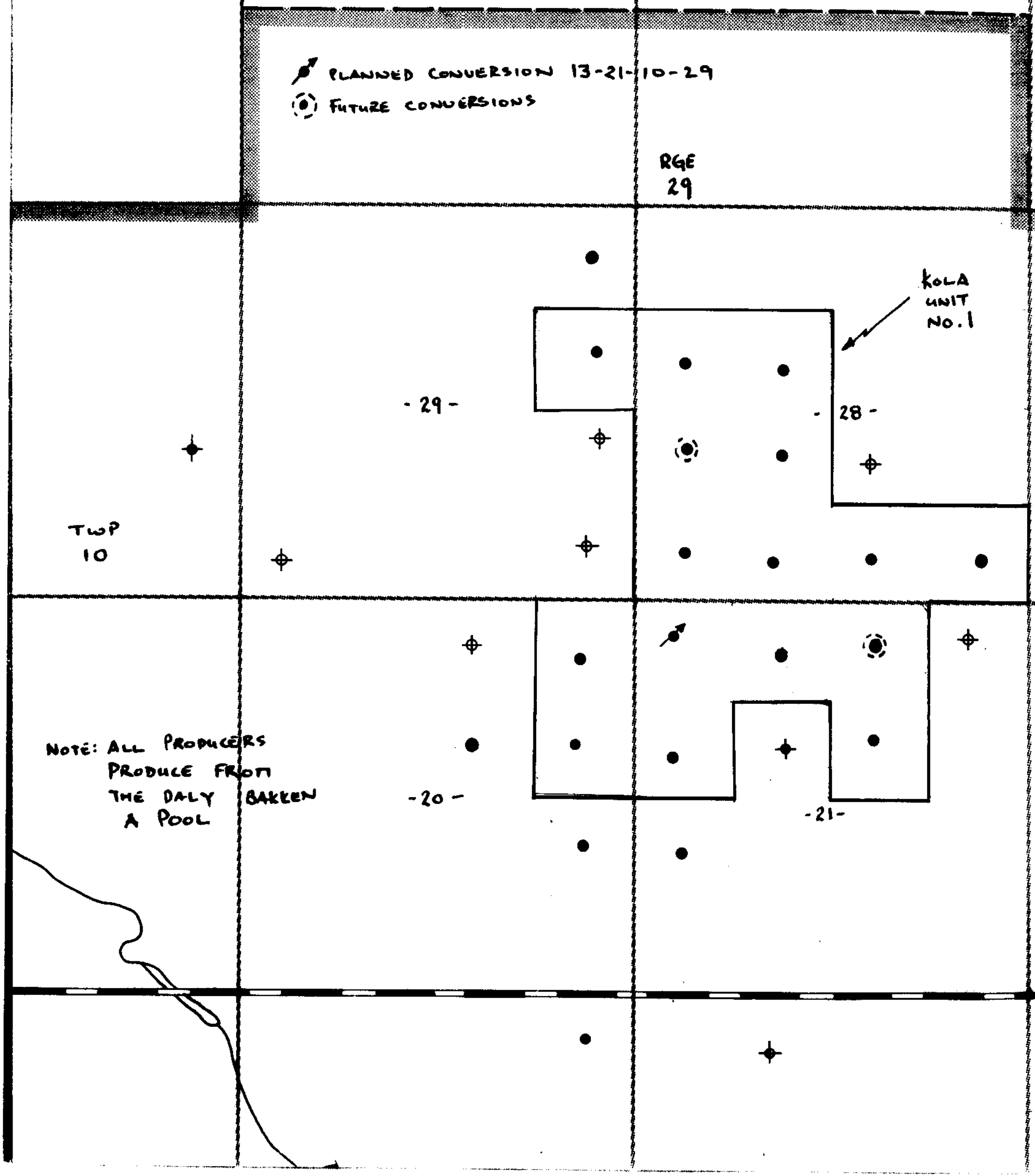


FIGURE 4

FIGURE 1

KOLA UNIT NO. 1



Daly Bakken A Pool

FIGURE 2

TOTAL HYDRO-CARBON PORE VOLUME
MIDDLE BAKKEN MEMBER

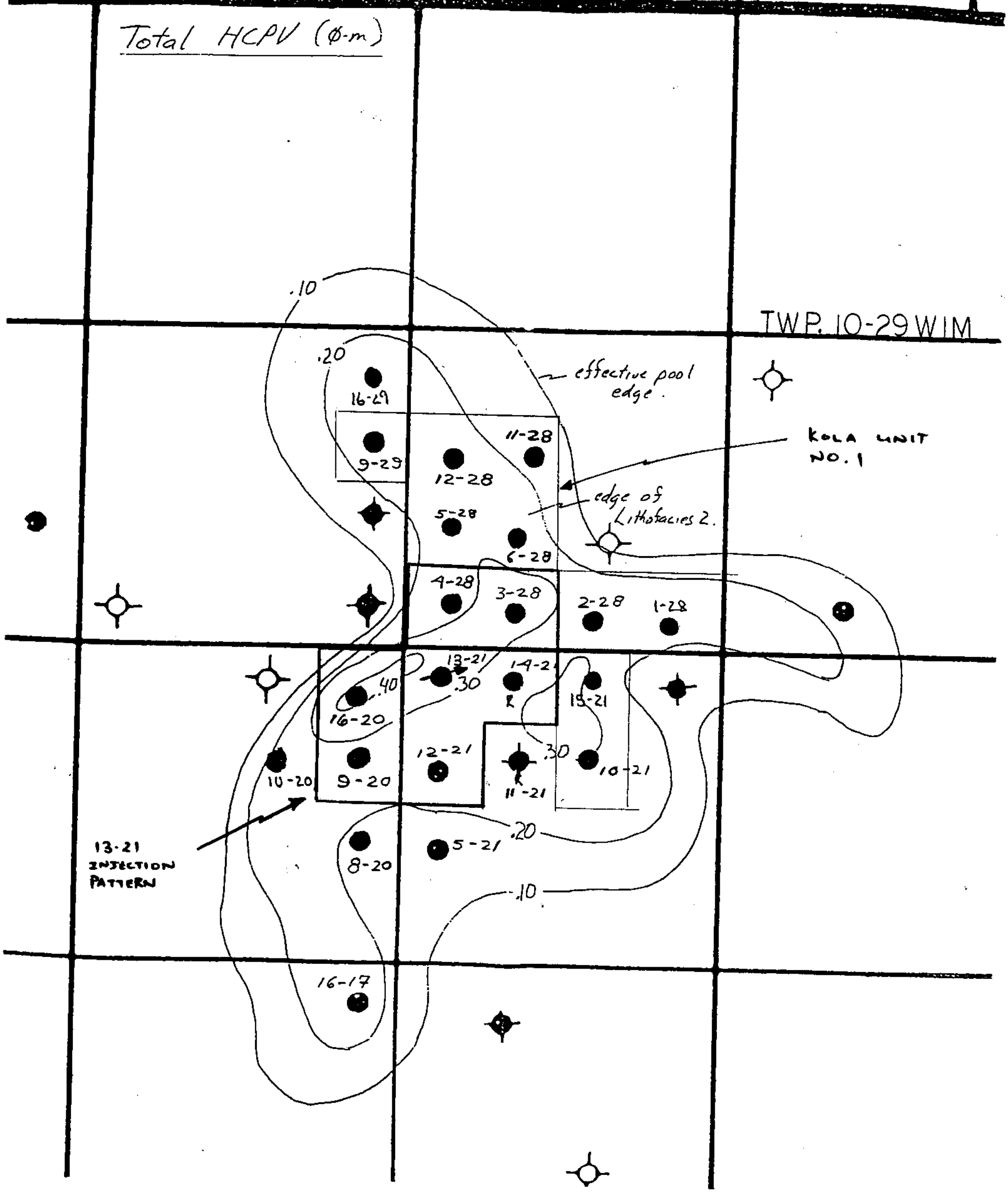
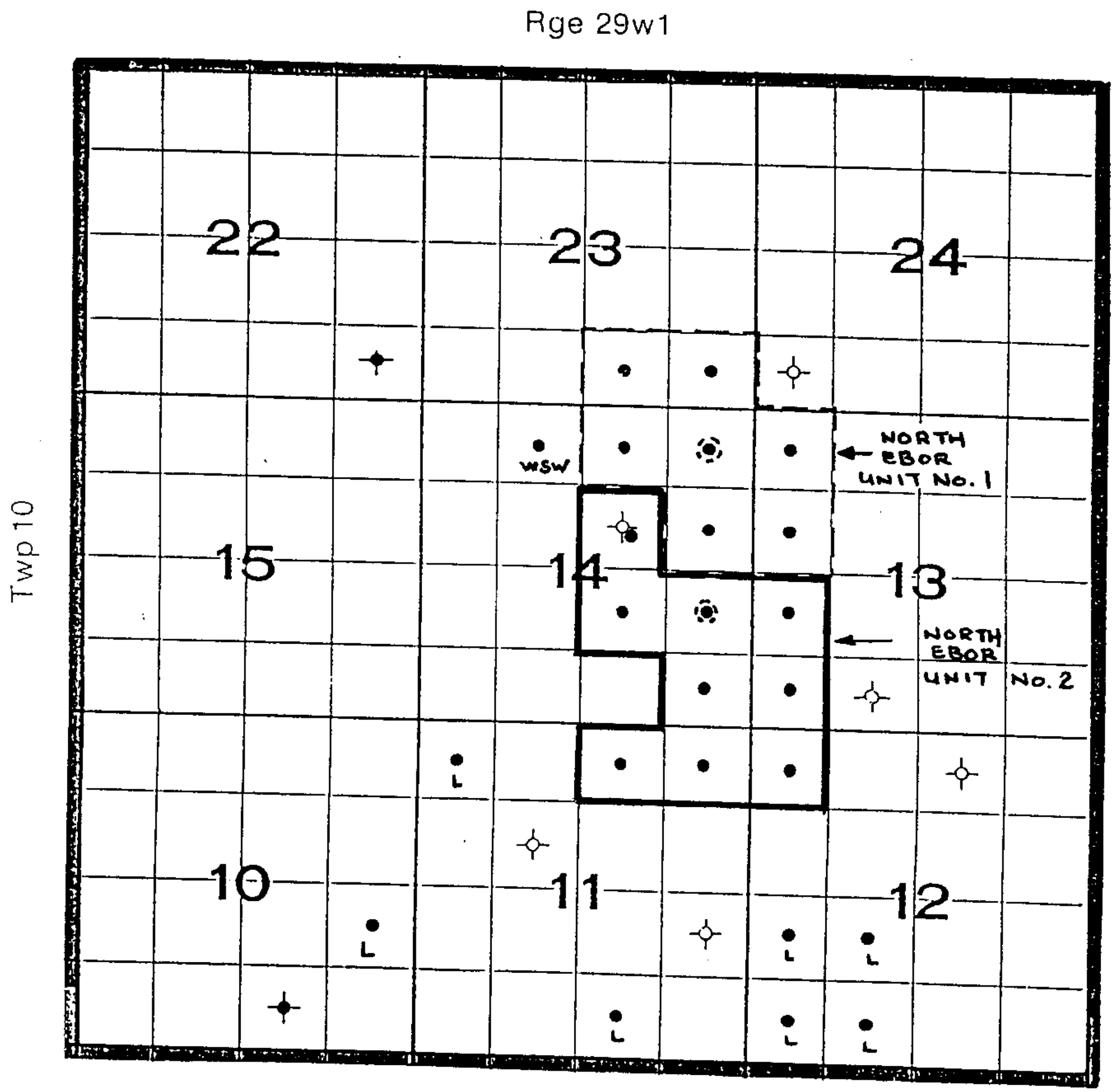


FIGURE 3

DALY BAKKEN D POOL



● DALY BAKKEN D POOL PRODUCER

DALY BAKKEN D POOL INJECTOR

● L LODGEPOLE PRODUCER

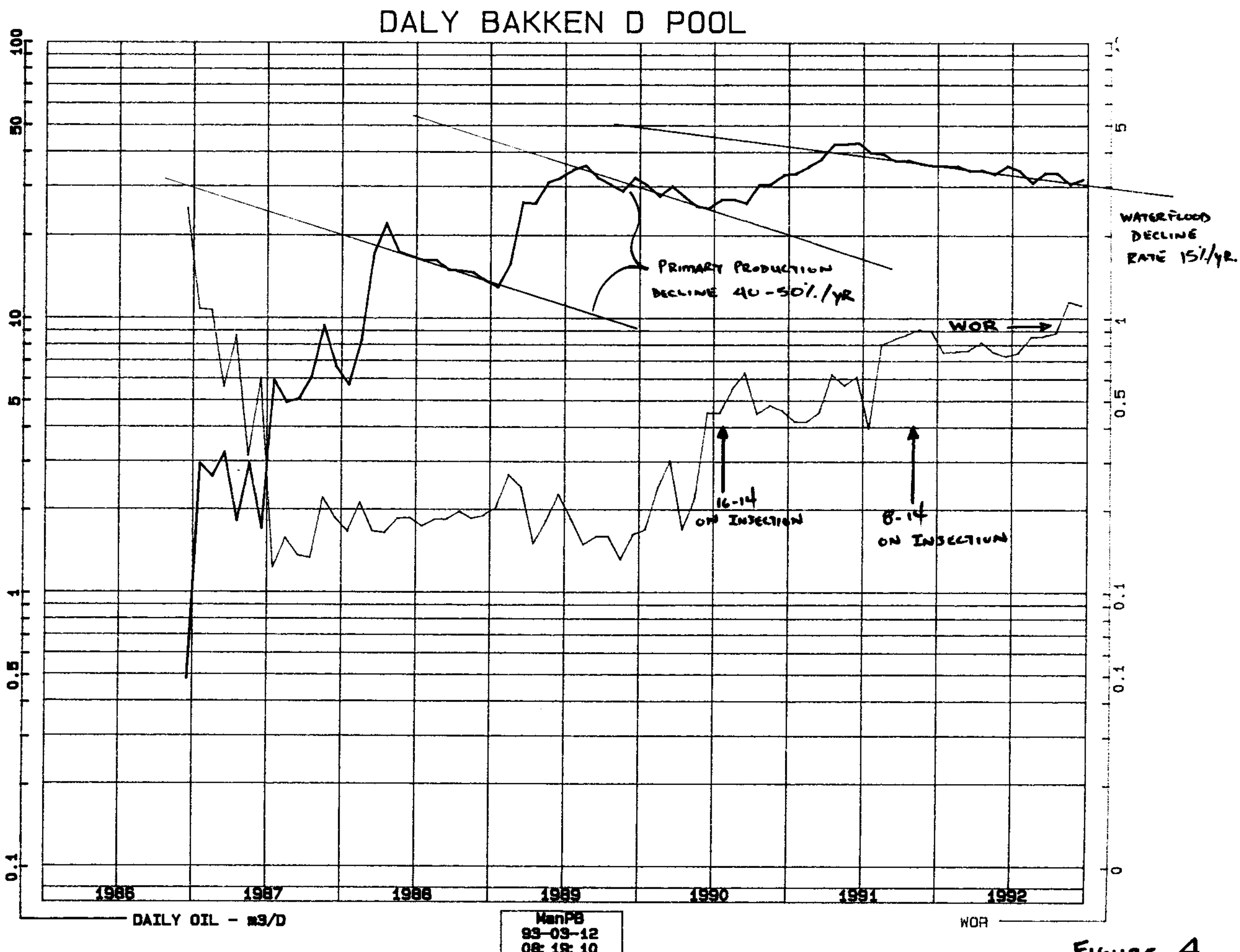
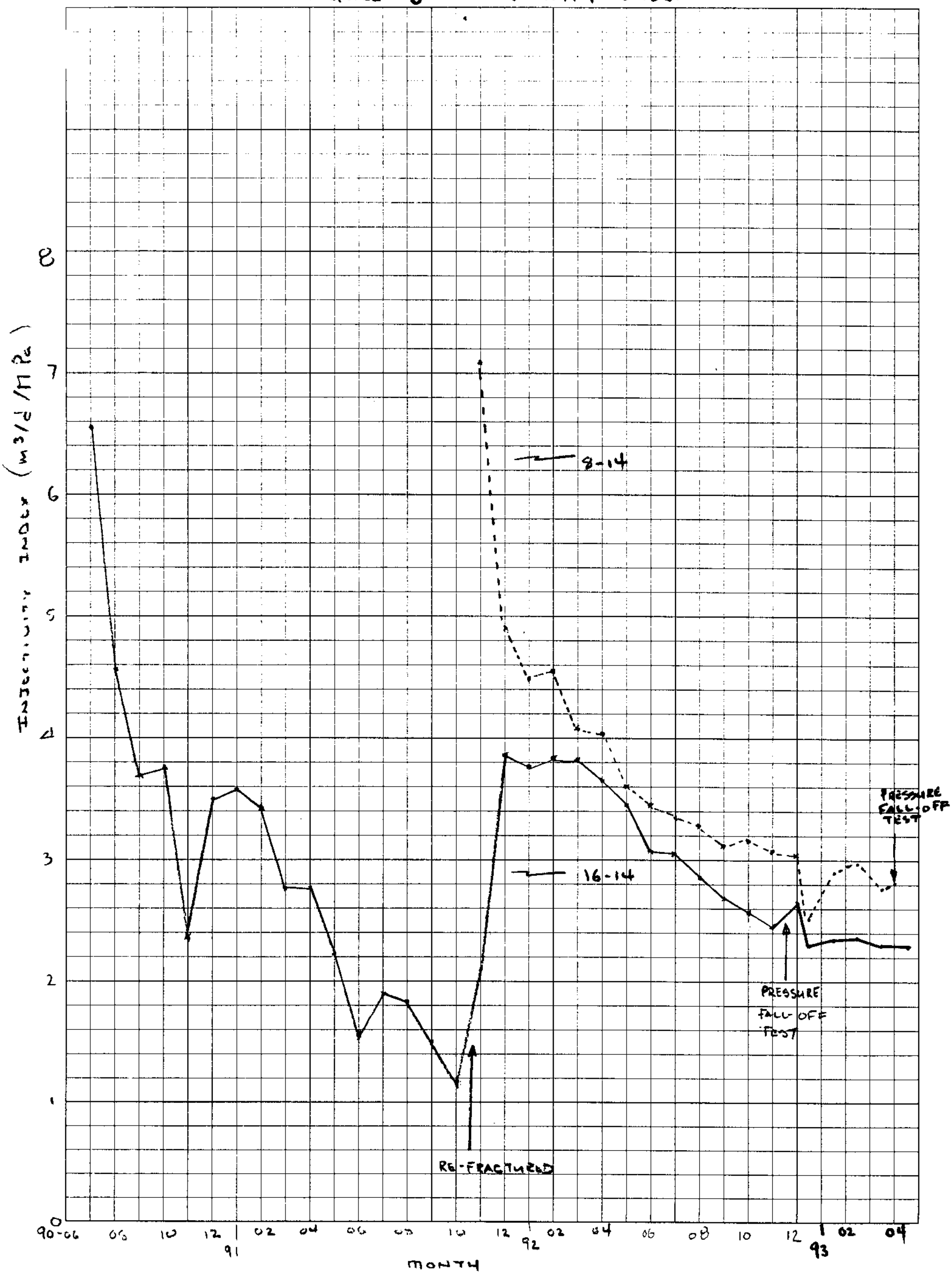

DALY BAKKEN D POOL
100
50
10
5
1
0.5
0.1
5
1
0.5
0.1
0.1
0
1986
1987
1988
1989
1990
1991
1992
DAILY OIL - m3/D
WOR
ManPB
93-03-12
08:19:10
WATERFLOOD DECLINE RATE 15%/YR.
PRIMARY PRODUCTION DECLINE 40-50%/YR
WOR
16-14 ON INJECTION
8-14 ON INJECTION

FIGURE 4

DALY BAKKEN D POOL

FIGURE 5 - INJECTIVITY INDEX



Manitoba

The Oil and Natural Gas
Conservation Board

555 — 330 Graham Avenue
Winnipeg MB R3C 4E3
CANADA

(204) 945-1111
FAX: (204) 945-0586

OCT - 6 1992

FILE
→ Pressure
Maintenance
Appl'n

Mr. George Czyzewski, P.Eng.
Sr. Reservoir Engineer
Tundra Oil and Gas Ltd.
1111 One Lombard Place
Winnipeg MB R3B 0X4

Dear Mr. Czyzewski:

Re: Daly Bakken A Pool - Board Order No. PM 71

The Board has completed its review of Tundra's application to conduct a waterflood in the proposed Kola Unit No. 1 in the Daly Bakken A Pool. Attached is Board Order No. PM 71 approving the waterflood.

Tundra is requested to submit to the Board by May 1, 1994, an update of its plans for waterflood expansion in the unit. In the update, Tundra should comment on the injection rate and pressure at 13-21-10-29 (WPM).

If you have any questions, please contact John N. Fox, Chief Petroleum Engineer at (204) 945-6574.

Yours respectfully,

H. C. Moster

H. Clare Moster
Deputy Chairman

Manitoba randum

John
- Hold.
- I did not have the opportunity to discuss this with the Minister & DM yesterday BL

Date September 17, 1993

To David Tomasson
Chairman
Oil and Natural Gas
Conservation Board

ter

jement Branch
lines

Telephone

Subject **BOARD ORDER NO. PM 71**

Attached and recommended for your signature and the Minister's approval are two (2) copies of the subject pressure maintenance order.

If you and/or Minister wish to discuss this application, this could be done at either of the scheduled "briefing sessions" next week, i.e.:

Moster - Tuesday, September 21 - 2:30 P.M.
Dubreuil Thursday, September 23 - 9:30 A.M.

Clare

H. Clare Moster

Attachments

DEPARTMENT OF ENERGY AND MINES
SEP 20 1993
PETROLEUM BRANCH

cc: L.R. Dubreuil

HCM:p
MemDT124 Doc

First | Fold

PS-f-25 894-01-00930

Manitoba

The Oil and Natural Gas
Conservation Board

555 — 330 Graham Avenue
Winnipeg MB R3C 4E3
CANADA

(204) 945-1111
FAX: (204) 945-0586

Order No. PM 71
An Order Pertaining to Pressure
Maintenance by Water Flooding
Daly Bakken A Pool

WHEREAS, subsection(9)(d) of Section 62 of "The Mines Act", being Chapter M160, of the Continuing Consolidation of the Statutes of Manitoba, provides as follows:

"62(9) Without restricting the generality of subsection (8) the board, with the approval of the minister, may make orders

(d) requiring the repressuring, recycling, or pressure maintenance, of any pool or portion thereof where it is econonomical so to do, and for that purpose where necessary requiring the introduction or injection into any pool or portion thereof of gas, air, water, or other substance;"

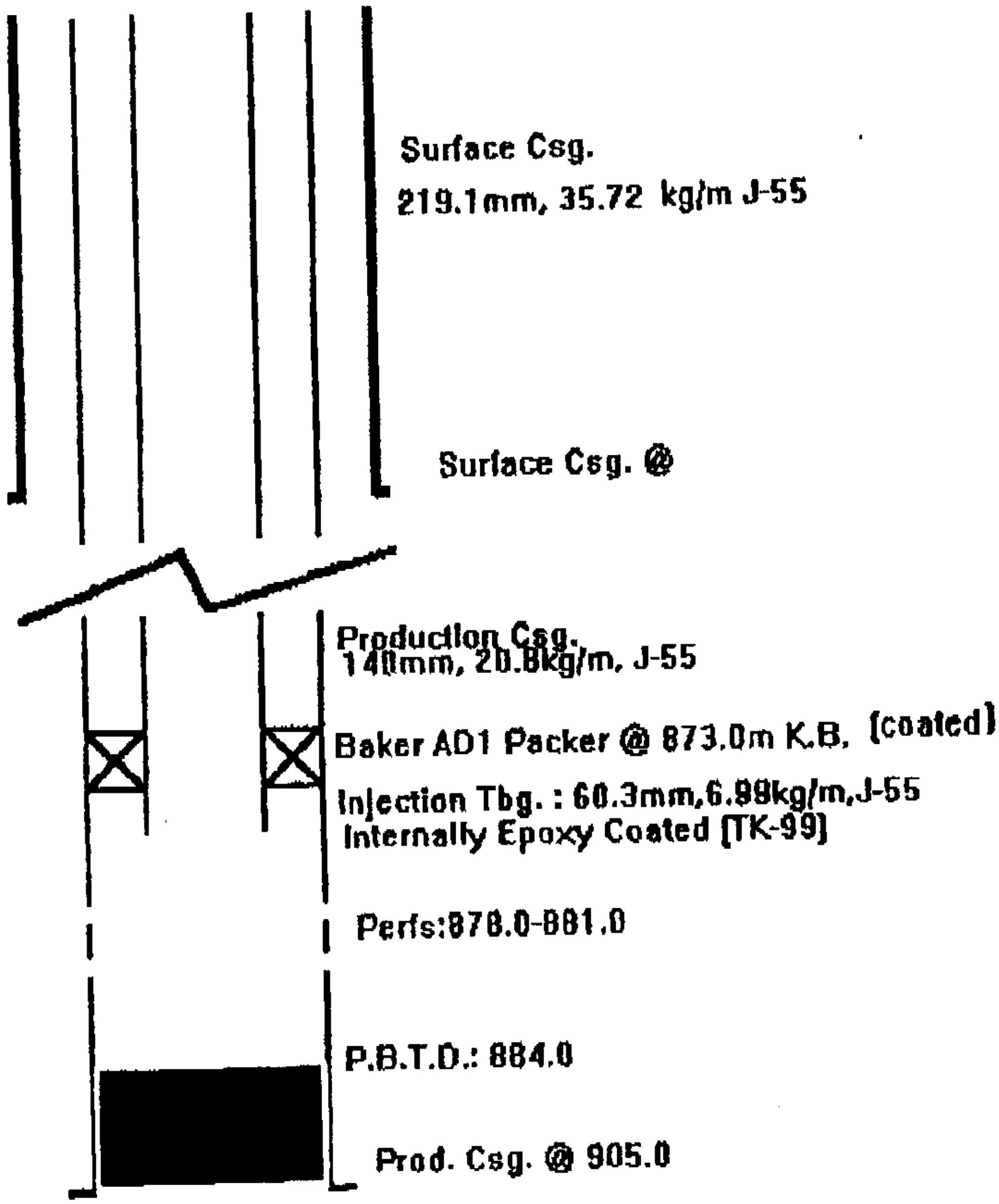
AND WHEREAS, the Board received an application dated July 9, 1993 from Tundra Oil and Gas Ltd. for approval of a project to inject water into the Daly Bakken A Pool ("the pool") in the proposed Kola Unit No. 1 ("the unit area").

AND WHEREAS, upon publication of notice of the application, the Board received no objections to or interventions in the application.

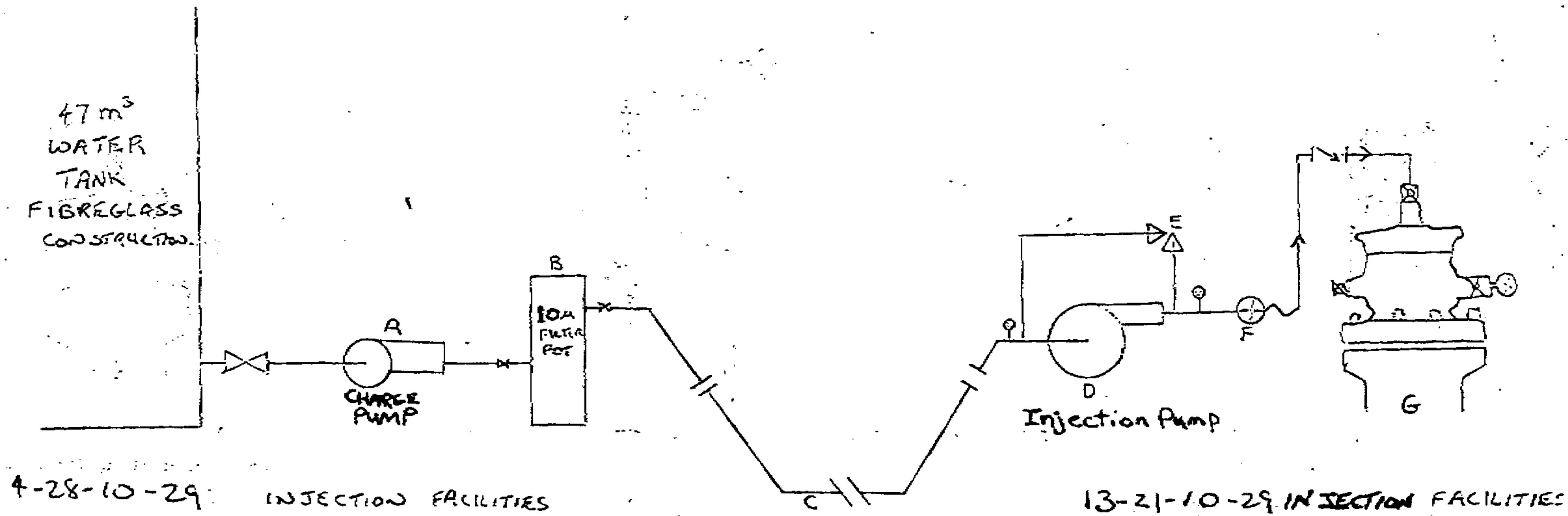
AND WHEREAS, Tundra Oil and Gas Ltd. is the unit operator of the proposed Kola Unit No. 1.

AND WHEREAS, upon due consideration, the Board has found it is reasonable and desirable to approve the application.

TUNDRA ET AL DALY 13-21-10-29 WIW



TUNDRA 4-28 & 13-21-10-29 WATER INJECTION FACILITIES



(SEE ATTACHED EQUIPMENT DETAIL)

TUNDRA DALY 4-28-10-29 WATER INJECTION FACILITIES

PART	EQUIPMENT DETAIL
A	Viking 1-1A540 Centrifugal Pump complete with 1.5 HP X-Proof Driver (1200 rpm) S.S. Trim with bronze impeller Maximum Discharge pressure - 275 kpa
B	Peco Model 55-5-336 Filter pot complete with 10 micron cotton fibre sock type elements. Maximum working pressure - 1900 kpa. Internally epoxy coated
C	A.O. Smith TBS 610 Fibreglass flowline. Rated working pressure - 4200 Kpa 8rd threaded joints

TUNDRA DALY 13-21-10-29 WATER INJECTION FACILITIES

PART	EQUIPMENT DETAIL
D	Wheatley Model P-50A Simplex Pump; - 31.75 mm Ceramic Plunger, 55.5 mm stroke - Al Brz fluid end and S.S. Valves - 5.0 Hp X-proof motor - Maximum Working Pressure - 11,400 kpa
E	Baird Model 7601-1-TB- 25.4mm pressure relief valve set @ 7000 Kpa. Al-Brz with S.S. valve.
F	Barton Turbine water meter - 19 mm
G	Crown Streamflo H series S.O. casing bowl with FCR tubing head. M.W.P.- 14.0 Mpa.

Notes:
1) All Stl. fittings, nipples, etc. shall be forged stl., threaded, and internally epoxy coated
2) All valves upstream of injection pump shall be either bronze or S.S. trim and a M.W.P. of 4100 Kpa or greater.
3) All valves downstream of injection pump shall be S.S. trim and a M.W.P. of 14.0 MPa.
4) Fibreglass stl. x-over accomplished with stl. ASA 150 RF thd. flange to 150 series F/G flange.

CORROSION CONTROL

Wellbore: As shown on the well completion diagram the annulus shall be isolated buy means of a 140 mm epoxy coated tension packer. Prior to setting packer the annulus shall be circulted to fresh inhibited water. Internal tubing corrosion shall be controlled by TK-99 epoxy coating.

Flowlines: All flowlines shall be of fibreglass construction.

Surface Facilities: As indicated on the equipment details, all major components shall be designed for a salt water corrosive application. All minor components and surface piping shall be internally epoxy coated.

SOURCE WATER TREATMENT, CONDITIONING, AND MEASUREMENT

Injection water shall be supplied from production into the battery at 4-28-10-29. Solids shall be removed from the water through settling in the suction tank and filtering through 10 micron cartridges. Biocide and oxygen scavenging treatment is not planned due to the closed nature of the system and absence of Hydrogen Sulphide.

Water volumes shall be metered at 13-21 and recorded on a daily basis.

ADVANCE
npire-Advance, is issued each
pany Limited at its office at the
it, Virden, Manitoba.

t and Publisher
Editor

n advance, are:
tside 40 miles of Virden - $32.10
7.04

Community
the Manitoba
ssociation, and
rculations.

The Audit Bureau

istrict

eporter

n and Helen Peacock enjoyed
at Birtle Fair last week. The
show was especially fine.

EWIS FAMILY REUNION

ere were 205 descendents of es Henry Lewis who gathered Auley Rink on July 17 and 18 weekend of reminiscing and g acquainted.

gistration was Saturday mor- and was looked after by Ken Elaine Lewis and Dale and e Lewis with the 11 families ing the family pictures that ated the walls of the rink. man Lewis was our M.C. for pening ceremonies. Norman nized the remaining members Lewis family: Mary Lowes, aret Santer, John Lewis and Lena. Also the remaining ters-in-law: Mabel (Jimmy), e (Billy), Slim (Bobbie), (Mike), Bertha (George), and -law Harry Carefoot (Dot). was unable to attend. Two es of silence was observed in nbrance of those who are no with us. Following the two es of silence, Son Lowes gave entation on Grandpa Lewis. sia Lewis did a beautiful job orating the tables with rose Dale Lewis made a Lewis r and painted the Lewis Coat s on the flag for the reunion. n Lewis and his family set up e of documents of Charles Lewis and also did a copy of vis Family Tree for all to see joy.

s then to the sports grounds family pictures were taken ore visiting. Huntley Lewis orse and buggy rides for ne.

luck supper was held in the

Kirkella

Mrs. M. Edgar, Reporter

Sympathy is extended to Mr. and Mrs. Pete Nickel on their recent bereavement.

Mrs. Lorna Boyre, Michael and Meagan of Whitecourt, Alberta were recent visitors with Mr. and Mrs. P. Nickel. Greg Nickel was also a recent visitor.

Mr. and Mrs. D. Hunt, Brad and Angie have returned home after holidaying in B.C.

Mrs. Mary Baskerville, Mr. and Mrs. J. Hedison were visitors during the week with Mr. and Mrs. P. Nickel.

A surprise birthday party was held for Katie Edgar last weekend. Those attending were: Amy Bellerive, Winnipeg, Mr. and Mrs. Marc Blais, Ashley and Marc Jr., Mr. and Mrs. J. Edgar of Alexander, Bobbie Guntan of South Carolina, U.S.A., Mr. and Mrs. N. Bowering of Ft. Qu'Apelle, Sask., Mr. and Mrs. T. Bowering of Regina, Lana Rattray, Pam Chrisp, both of Brandon, Annie Beillard, France, Mr. and Mrs. F. Bowering, Mr. and Mrs. D. Oliver, Mr. and Mrs. W. Ruddick, Mr. and Mrs. R. Chrisp, Robbie and Derek, Corinne Chrisp, Mr. and Mrs. Don Edgar, Wolseley, Sask., Mrs. Dot Pomeroy, Wainwright, Alberta, Mrs. Jas. Jamieson, Strasbourg, Sask., Leonard Persson, Mr. and Mrs. R. Martin, Toby, Josh and Chelsey, Filmore, Sask., Mr. Art Edgar, Eden, Man., Mr. Bob Edgar, Winnipeg.

Recent visitors with Mr. and Mrs. A. Turbak were daughter Thelma Hofos, Robert and Janet of Okotoks, Alberta.

Mr. and Mrs. A. Turbak were recent visitors to Vermillion, Alberta. On their way home they visited in Saskatoon with son-in-law and daughter, Jim and Judy Lelond. They also visited with Mrs. Cas Budge at North Battleford and Mr. and Mrs. Bud Schlemmer and Darlene.

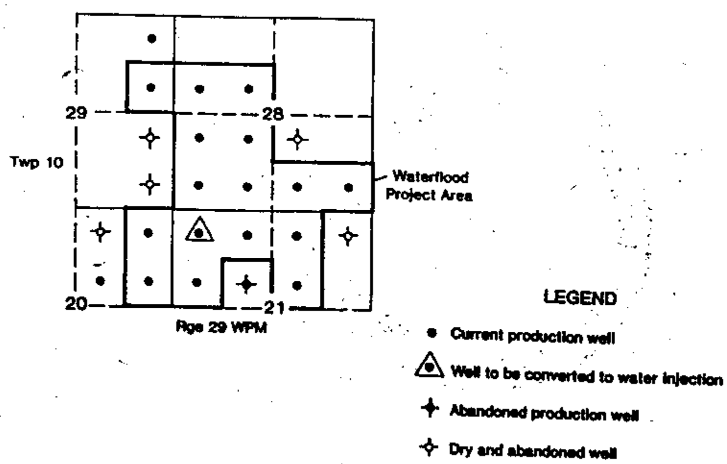
THANK YOU

Carmen and Allison Bailey would like to thank the following buyers for purchasing their 4-H Lambs:

Cargill Nutrena Feeds
Redfern Farm Service
Pipestone Livestock Sales
Jim Martin Livestock

Notice
Under the Mines Act
Daly Oil Field

Tundra Oil & Gas Ltd. has made application under The Mines Act to conduct a waterflood in the Bakken Formation in that portion of the Daly Field referred to as the "waterflood project area" and shown below.



It is proposed to convert the well, Tundra Daly 13-21-10-29 (WPM) to water injection. If no valid objection or intervention in writing is received by The Oil and Natural Gas Conservation Board at 555-330 Graham Avenue, Winnipeg, Manitoba, R3C 4E3 before August 27, 1993, the Board may approve the application.

Copies of the application can be obtained from:

Tundra Oil and Gas Ltd.
1111 - One Lombard Place
Winnipeg, Manitoba R3B 0X4
(204) 934-5850

The application may be viewed at the offices of the Petroleum Branch:

555-330 Graham Avenue
Winnipeg, Man. R3C 4E3
(204) 945-6577

227 King Street
Virden, Man. R0M 2C0
(204) 748-1557

Dated at Winnipeg, this 30th day of July, 1993.

David Tomasson
Chairman

Tundra
oil and gas ltd.

July 27, 1993

Mr. John Fox
Chief Petroleum Engineer
Manitoba Energy and Mines
Petroleum Branch
555 - 330 Graham Avenue
Winnipeg, MB
R3C 4E3

Dear John:

Re: Proposed Kola Unit No. 1

Further to George Czyzewski's letter dated July 26, 1993, please find enclosed the following:

a) the names and addresses of all royalty and working interest owners in, and adjacent to, the proposed Unit;

b) our letter of notification to the surface owner at 13-21-10-29 WPM; and

c) a draft copy of our Unit Agreement. It is identical to the documentation used for North Ebor Unit No. 1 and North Ebor Unit No. 2.

If you have any comments on this material, do not hesitate to call.

Sincerely,

TUNDRA OIL AND GAS LTD.

Robert G. Puchniak

RGP/bp

Enclosures

cc George Czyzewski

Tundra oil and gas ltd.

July 15, 1993

Mr. Leslie Penner
General Delivery
Kola, Manitoba
R0M 1B0

Dear Mr. Penner:

RE: PROPOSED UNITIZATION
INJECTION WELL
TWP 10 RGE 29 WPM: LSD 13, SEC 21
OUR FILE: 1340

Further to our recent conversation, this will confirm and advise that Tundra Oil and Gas Ltd. proposes to unitize the wells which are located on your lands. As discussed, part of the unitization plan would entail converting the well located at LSD 13 of Section 21 to a water injection well. This well will be used to inject water produced and collected from a number of wells in the immediate area and which are located on and off your Section.

We expect to have the unit in operation sometime in the fall of 1993 and I will be in touch with you with regards to Pipeline Right-of-Way agreements prior to that time. However, in order to obtain the required regulatory approvals, Tundra requires your consent to the conversion of the aforementioned well to an injection well.

Should you consent to the aforementioned plan, would you please so indicate by signing in the space provided below and returning the duplicate copy of this letter to my attention. Should you have any questions, please do not hesitate to contact me at 934-5856. Thank you for your prompt attention to this matter.

Sincerely,

TUNDRA OIL AND GAS LTD.

David H. Taylor
Manager, Land and Contracts

DHT/src
Enclosures

CONVERSION OF THE WELL AT 13-21-10-29 WPM TO A WATER INJECTOR WELL IS HEREBY CONSENTED TO THIS 16 DAY OF July, 1993

LESLIE PENNER

1111 - One Lombard Place, Winnipeg, Manitoba R3B 0X4 Telephone: (204) 934-5850 Fax: (204) 934-5820

Tundra
oil and gas ltd.

July 26, 1993

Manitoba Energy and Mines
Petroleum Branch
555 - 330 Graham Avenue
Winnipeg, MB
R3C 4E3

Attention: **Mr. J. Fox, P. Eng.**
Chief Petroleum Engineer

Dear Mr. Fox:

RE: Pressure Maintenance Application
Daly Bakken "A" Pool

Pursuant to your letter of July 26, 1993, Tundra Oil and Gas Ltd. offers the following explanations pertaining to your questions regarding the referenced subject matter.

1. Tundra will provide under separate cover the names and addresses of all royalty and working interest owners in and adjacent to the proposed Kola Unit No. 1. The adjacent lands will extend laterally 16 hectares around the perimeter of the proposed Kola Unit No. 1.

2. a) Tundra plans only to drill 1-32-10-29 W1M in the Bakken "A" Pool during 1993. No re-entries are planned at this time during 1993.

   b) As addressed in our Kola Field Bakken "A" Pool Pressure Maintenance Application dated July 9, 1993, Tundra Oil and Gas Ltd. does not plan to expand the initial waterflood area for a period of six months. We estimate that this time period is required to evaluate the commercial benefits of waterflooding the Bakken "A" Pool. As a result, no waterflood expansion in the proposed Kola Unit No. 1 is envisioned before March 1, 1994 (subject to Unit operations commencing September 1, 1993). In terms of potential injection locations, wells 15-21-10-29 W1M, 2-28-10-29 W1M, and 5-28-10-29 W1M may be selected to achieve two additional inverted nine spot flood patterns in the Unit.

   c) Yes, the Unit may be expanded in the future. This would require working interest approval. Tundra, at this time, has no plans to expand the proposed Unit during 1993.

3. a) As outlined in our Kola Field Bakken "A" Pool Pressure Maintenance Application

1111 - One Lombard Place, Winnipeg, Manitoba R3B 0X4 Telephone: (204) 934-5850 Fax: (204) 934-5820

dated July 9, 1993 (refer to Section F.3, iv, page 14, and Appendix G), high injection pressures are expected to prevail during the economic operating life of the waterflood. This is attributable to the low reservoir permeabilities of the Bakken "A" Pool and the low mobility ratio of the reservoir fluids. A maximum wellhead injection pressure of 9,000 kPa is envisioned as the upper limit for the waterflood operation. Additional injection wells may be required in the future, in order to maintain voidage replacement below an injection pressure of 9,000 kPa.

The initial injection rate of 19 m^3/day has been selected for a VRR of 1.15 based on current total fluid production rates in the initial area of waterflooding. A peak injection rate of 30 m^3/day is estimated to achieve a VRR of 1.0 under peak oil production rates during the waterflood operation. The actual peak injection rate may have to be adjusted based on future waterflood response.

b) Injection wells 8-14-10-29 W1M and 16-14-10-29 W1M are not in the proposed Kola Unit No. 1. Injection pressure data will be provided under separate cover to your attention at a later date.

c) Tundra will provide a schematic of the proposed completion for injection well 13-21-10-29 W1M under separate cover.

4. As outlined in our Kola Bakken "A" Pool Pressure Maintenance Application, no independent production testing of the upper zone of the middle Bakken member has been undertaken to date to establish its production potential. Although the majority of the Bakken "A" Pool wells have been fractured, productivity from the upper zone is quite likely confined to the immediate area around the fracture due to the low permeabilities of this layer. On this basis, total primary and secondary oil recovery from the upper zone has been assigned at 5% of the oil-in-place.

   In our estimation, a primary recovery of 33% of the OOIP is not considered to be exceptionally high, since wells 13-21, 3-28, and 4-28-10-29 W1M indicate ultimate primary recoveries ranging from 29 to 50% of the OOIP. The ultimate primary recovery factor of 33% of the OOIP represents an average of all the wells in the initial waterflooding area. The recovery factor of 33% of the OOIP is also dependent on the laboratory derived irreducible formation water saturation of 57.8% that has been used in the calculation of the OOIP. If the log derived irreducible formation water saturations are used to calculate the OOIP in the initial waterflood area, a primary recovery factor of 22.2% of the OOIP is obtained from the lower zone of the Bakken "A" Pool.

5. Tundra's waterflood estimate of volumetric sweep efficiency in the lower zone is

Tundra
oil and gas ltd.

considered to be less than 100%. An ultimate volumetric sweep efficiency based on industry theoretical correlations is about 85% of the reservoir area will be contacted by the flood front. Taking into consideration that the Bakken "A" Pool is light oil (40 API), and piston displacement is predicted from the 4-28-10-29 W1M relative permeability study, a high volumetric sweep efficiency is expected from this reservoir (refer to Kola Bakken "A" Pool Pressure Maintenance Application, Appendix G, page 10). Exact quantification of the volumetric sweep efficiency would require reservoir simulation. Since this is an expensive and time consuming process, Tundra is comfortable with the prediction from the relative permeability study, and the current waterflood performance in the North Ebor Units.

6. Tundra will provide under separate cover proof that the surface owner of 13-21-10-29 W1M has been notified of the proposed conversion of this well to injection service.

Sincerely,

TUNDRA OIL AND GAS LTD.

G. Czyzewski

George Czyzewski, P. Eng.
Senior Reservoir Engineer

GC/bp

CORRELATION FROM
SPE TEXTBOOK SERIES
VOLUME 3 BY G. PAUL WILLHITE
(WATERFLOODING)

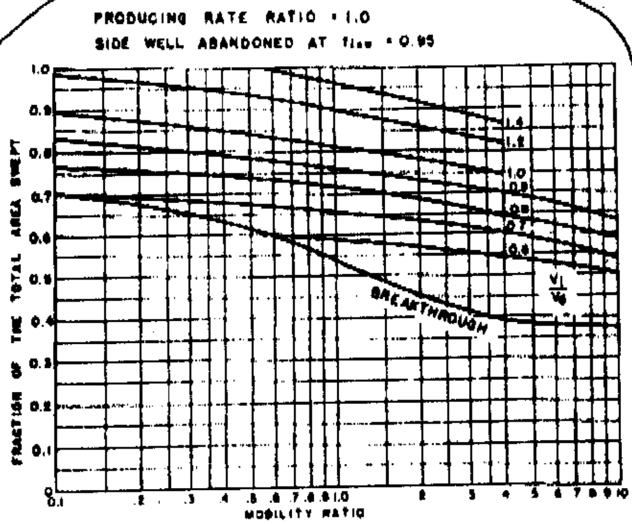


Fig. 6.26—Sweepout pattern efficiency as a function of mobility ratio for the nine-spot pattern at various displaceable volumes injected.[25]

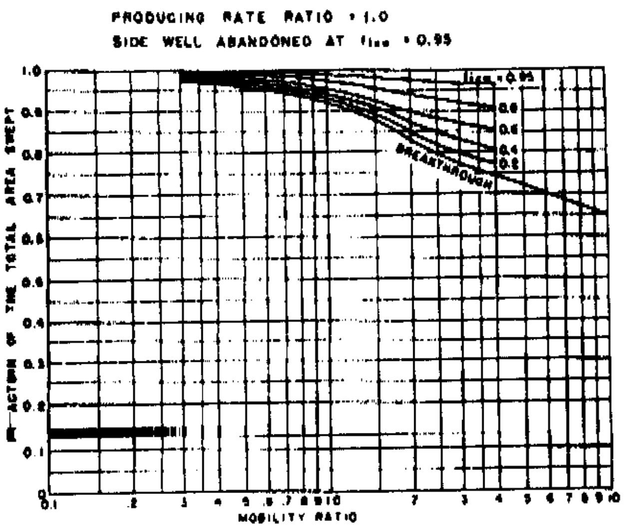


Fig. 6.27—Sweepout pattern efficiency as a function of mobility ratio for the nine-spot pattern at various corner-well producing cuts (f_{cw}).[25]

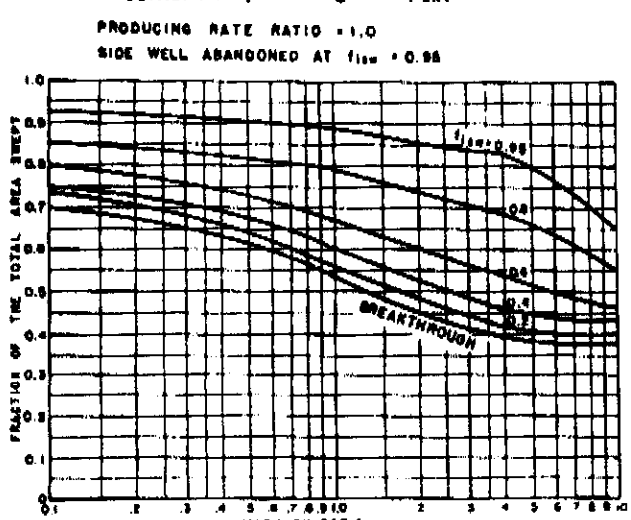


Fig. 6.28—Sweepout pattern efficiency as a function of mobility ratio for the nine-spot pattern at various side-well producing cuts (f_{sw}).[25]

The reservoir engineer is sometimes requested to prepare estimates of waterflood recovery on relatively short notice. A decision must be made about the amount of effort required to produce the estimate. The selection of a displacement model can become a complex process involving time constraints, capabilities of the particular engineer and/or the technical staff, accuracy needed for the decision process, and, finally, the risk the producer is willing to take considering the uncertainties that are present when a displacement model is selected.

The only scaled-model correlation that accounts for immiscible displacement is the Craig, Geffen, Morse (CGM) five-spot model.[24] There are no comparable correlations for linedrive, staggered linedrive, or nine-spot patterns. As mentioned in Chap. 4, correlations from scaled-model experiments with miscible fluids have been developed. These correlations are comparable to waterfloods that behave as piston-like displacements—that is, the average water saturation in the displaced area, $\bar{S}_w$, is equal to $1-S_{or}$. There is no displacement of oil from the swept area after the flood front arrives.

Figs. 6.26 through 6.28 are correlations of displacement performance for a nine-spot flood from scaled-model displacement experiments with miscible fluids.[25] Correlations for a range of mobility ratios (M) are presented in terms of areal sweep efficiency, E_A, displaceable hydrocarbon PV's (V_d), and the fraction of the displacing fluid in the produced fluid (f_D). Eqs. 3.207, 6.72, and 6.73 define these parameters for immiscible displacement.

$$M=\frac{\left(\frac{k_{rw}}{\mu_w}\right)_{S_{or}}}{\left(\frac{k_{ro}}{\mu_o}\right)_{S_{oi}}},$$

where

E_A = area of pattern swept to a residual oil saturation of S_{or},

$$V_d=\frac{W_i}{V_p(1-S_{iw}-S_{or})}, \quad \ldots\ldots\ldots\ldots\ldots\ldots (6.72)$$

and

$$f_D=f_w. \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (6.73)$$

Example 6.3 illustrates the use of these correlations to estimate waterflood performance for a 10-acre [40 469-m^2] nine-spot pattern.

Example 6.3

A waterflood is to be conducted in a nine-spot pattern on 10-acre [40 469-m^2] spacing. Side and corner wells will be operated so that rates are the same. Porosity is 0.2 and the mobility ratio, M, based on the endpoints of the relative permeability curves is 1.0. The reservoir is liquid-saturated with an initial oil saturation of 0.7. Residual saturation is 0.26. Prepare the recovery Q_i and WOR/recovery curves with the miscible correlations of Figs. 6.26 through 6.28.

Manitoba

Energy and Mines

Petroleum

555 — 330 Graham Avenue
Winnipeg, Manitoba, CANADA
R3C 4E3

(204) 945-6577
FAX: (204) 945-0586

July 26, 1993

Mr. George Czyzewski
Tundra Oil and Gas Ltd.
1111 One Lombard Place
Winnipeg MB R3B 0X4

Re: Application for Pressure Maintenance - Daly Bakken A Pool Deficiencies/Technical Question

Dear Mr. Czyzewski:

1) Provide a list of the names and addresses of royalty and working interest owner in and adjacent to the proposed Kola Unit No. 1.

2) Provide the Branch with Tundra's proposed plans for the A Pool

(a) for development drilling including re-entries

(b) for expansion of the waterflood to achieve the secondary recovery of 35.8% OOIP for the unit as indicated in the application (including timing).

(c) Is there a possibility the unit could eventually be expanded?

3) (a) In April/93 the Board approved an increase in injection pressure in the D Pool to 9000 kPa (95% of frac pressure) in order to address injectivity problems. Does Tundra anticipate similar injectivity problems in the A Pool? What maximum allowable wellhead injection pressure does Tundra want for the A Pool? Are the estimated initial and maximum injection rates of 19 and 30 m^3/d at 13-21 based on a VRR of 1.15 at current production rates and a VRR of 1.0 at predicted peak production rates?

(b) Provide 1993 injection pressure data for the 8-14 and 16-14-10-29 injectors.

(c) Tundra has not included in its application the wellbore schematic showing the proposed completion for the 13-21 injection well required under Clause 126(b).

4) Based on the application Tundra appears to have allocated no primary recoverable reserves to the upper zone. If this is the case primary recovery from the lower zone is an exceptionally high 33% OOIP.

5) Does Tundra's waterflood recovery estimate outline below, assume a lower zone volumetric sweep efficiency of 100%?

$$\Delta \text{ Water Flood Rec} = (\text{OOIP/LSD} * .533)_{\substack{\text{lower}\\ \text{zone}}} - (\text{Primary Rec Res})_{\text{decline}} + .05 * \text{OOIP}_{\substack{\text{upper}\\ \text{zone}}}$$

6) In accordance with clause 126(d), proof that the surface owner of 13-21-10-29 has been notified of the conversion is required.

Yours truly,

John N. Fox
Chief Petroleum Engineer

JNF/hw

Manitoba

Memorandum

Date July 26, 1993

To David Tomasson
Chairman, Oil and Natural Gas
Conservation Board

From John N. Fox
Chief Petroleum Engineer
Petroleum Branch
Energy and Mines

Telephone

Subject **PUBLICATION OF NOTICE UNDER THE MINES ACT**
APPLICATION FOR PRESSURE MAINTENANCE - DALY BAKKEN A POOL

First | Fold

Tundra Oil and Gas Ltd. has made application to conduct a waterflood in a portion of the Daly Bakken A Pool. The waterflood project involves conversion of the 13-21-10-29 well to water injection. Tundra estimates the waterflood will significantly increase the recovery of oil from the pool. Tundra hopes to commence water injection on September 1, 1993.

The Branch has completed a preliminary review of the application and there are no deficiencies. It is recommended that notice of the application be published in the Virden Empire Advance and sent directly to lessors and lessees in and adjacent to the proposed waterflood project area. A copy of the standard notice is attached for your signature. To meet the deadline for publication in the August 11, 1993 edition of the Empire Advance, the notice must be submitted to Manitoba Culture, Heritage and Citizenship by August 5, 1993.

John N. Fox

JNF/hw

Attached.

PS-1 25 894-01-00930

Manitoba

The Oil and Natural Gas Conservation Board

555 — 330 Graham Avenue
Winnipeg MB R3C 4E3
CANADA

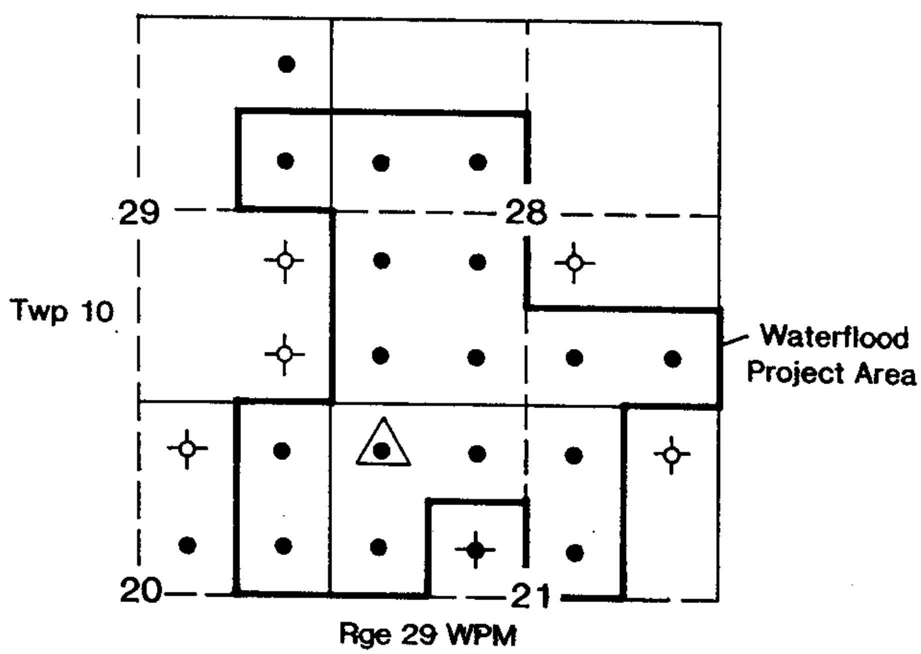
(204) 945-1111
FAX: (204) 945-0586

NOTICE

UNDER THE MINES ACT

DALY OIL FIELD

Tundra Oil and Gas Ltd. has made application under The Mines Act to conduct a waterflood in the Bakken Formation in that portion of the Daly Field referred to as the "waterflood project area" and shown below.



LEGEND

● Current production well

Well to be converted to water injection

Abandoned production well

Dry and abandoned well

It is proposed to convert the well, Tundra Daly 13-21-10-29 (WPM) to water injection.

If no valid objection or intervention in writing is received by The Oil and Natural Gas Conservation Board at 555-330 Graham Avenue, Winnipeg, Manitoba, R3C 4E3 before August 27, 1993, the Board may approve the application.

Copies of the applications can be obtained from:

Tundra Oil and Gas Ltd.
1111 - One Lombard Place
Winnipeg MB R3B OX4

(204) 934-5850

The application may be viewed at the offices of the Petroleum Branch:

555-330 Graham Avenue
Winnipeg MB R3C 4E3

(204) 945-6577

227 King Street
Virden MB ROM 2C0

(204) 673-2472

Dated at Winnipeg, this day of , 1993.

David Tomasson
Chairman

Manitoba

The Oil and Natural Gas Conservation Board

555 — 330 Graham Avenue
Winnipeg MB R3C 4E3
CANADA

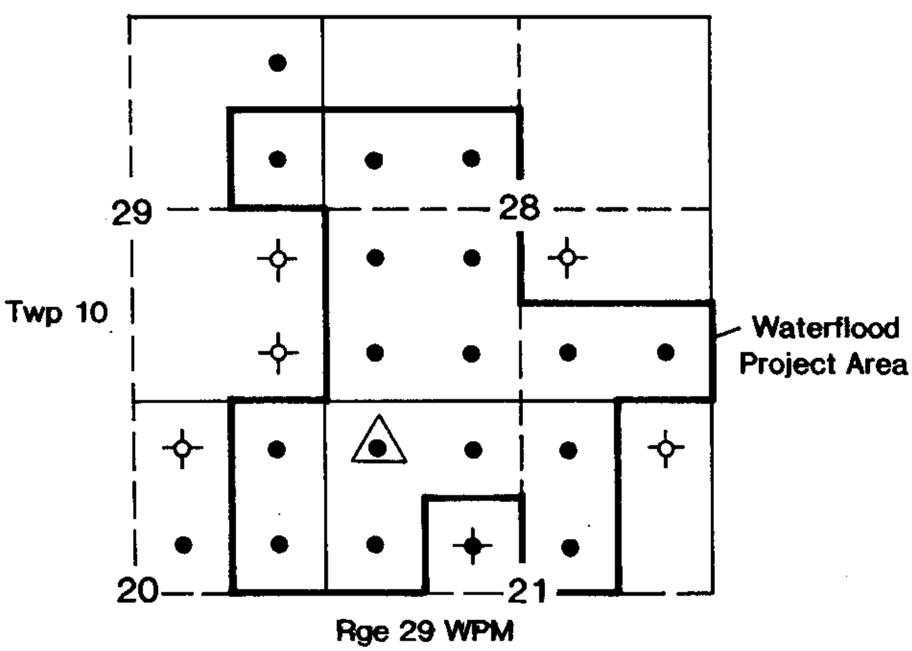
(204) 945-1111
FAX: (204) 945-0586

NOTICE

UNDER THE MINES ACT

DALY OIL FIELD

Tundra Oil and Gas Ltd. has made application under The Mines Act to conduct a waterflood in the Bakken Formation in that portion of the Daly Field referred to as the "waterflood project area" and shown below.



LEGEND

- Current production well
- Well to be converted to water injection
- Abandoned production well
- Dry and abandoned well

It is proposed to convert the well, Tundra Daly 13-21-10-29 (WPM) to water injection.

If no valid objection or intervention in writing is received by The Oil and Natural Gas Conservation Board at 555-330 Graham Avenue, Winnipeg, Manitoba, R3C 4E3 before August 27, 1993, the Board may approve the application.

Copies of the applications can be obtained from:

Tundra Oil and Gas Ltd.
1111 - One Lombard Place
Winnipeg MB   R3B OX4

(204) 934-5850

The application may be viewed at the offices of the Petroleum Branch:

555-330 Graham Avenue
Winnipeg MB   R3C 4E3

(204) 945-6577

227 King Street
Virden MB   ROM 2C0

(204) 748-1557

Dated at Winnipeg, this 30th day of July , 1993.

David Tomasson
Chairman

WORKING INTEREST OWNERS

Brandon Professional Investments
P.O. Box 1270
Brandon, Manitoba
R7A 6K4

Corvair Oils Limited
P.O. Box 3827, Station "D"
Edmonton, Alberta
T5L 4J8

Kiwi Resources Ltd.
P.O. Box 908
Virden, Manitoba
R0M 2C0

Mustang Oil Ltd.
P.O. Box 1537
Virden, Manitoba
R0M 2C0

Tundra Oil and Gas Ltd.
1111 One Lombard Place
Winnipeg, Manitoba
R3B 0X4

ROYALTY INTEREST OWNERS

2472 Manitoba Ltd.
1111 One Lombard Place
Winnipeg, Manitoba
R3B 0X4

Corvair Oils Ltd.
P.O. Box 3827, Station "D"
Edmonton, Alberta
T4L 4J8

Edna Rachel Eliza McPhail
336 - 25th Street
Brandon, Manitoba
R7B 1Z3

Naylen Oil Corp.
40 Everett Crescent
Regina, Saskatchewan
S4S 2M7

John Edwin Watson
158 Leslie Street
Sault Ste. Marie, Ontario
P6B 5C7

Thomas Reginald Watson
P.O. Box 1405
Virden, Manitoba
R0M 2C0

Douglas Harold Wood
P.O. Box 99
Kelwood, Manitoba
R0J 0Y0

Department of Energy & Mines
555 - 330 Graham Avenue
Winnipeg, Manitoba
R3C 4E3

Isabel Cotton
2015 Richmond Avenue
Brandon, Manitoba
R7B 0T4

Gauer Oil Company
202 Riverside Drive
Toronto, Ontario
M6S 4A9

Montreal Trust Company
221 Portage Avenue
Winnipeg, Manitoba
R3B 2A6

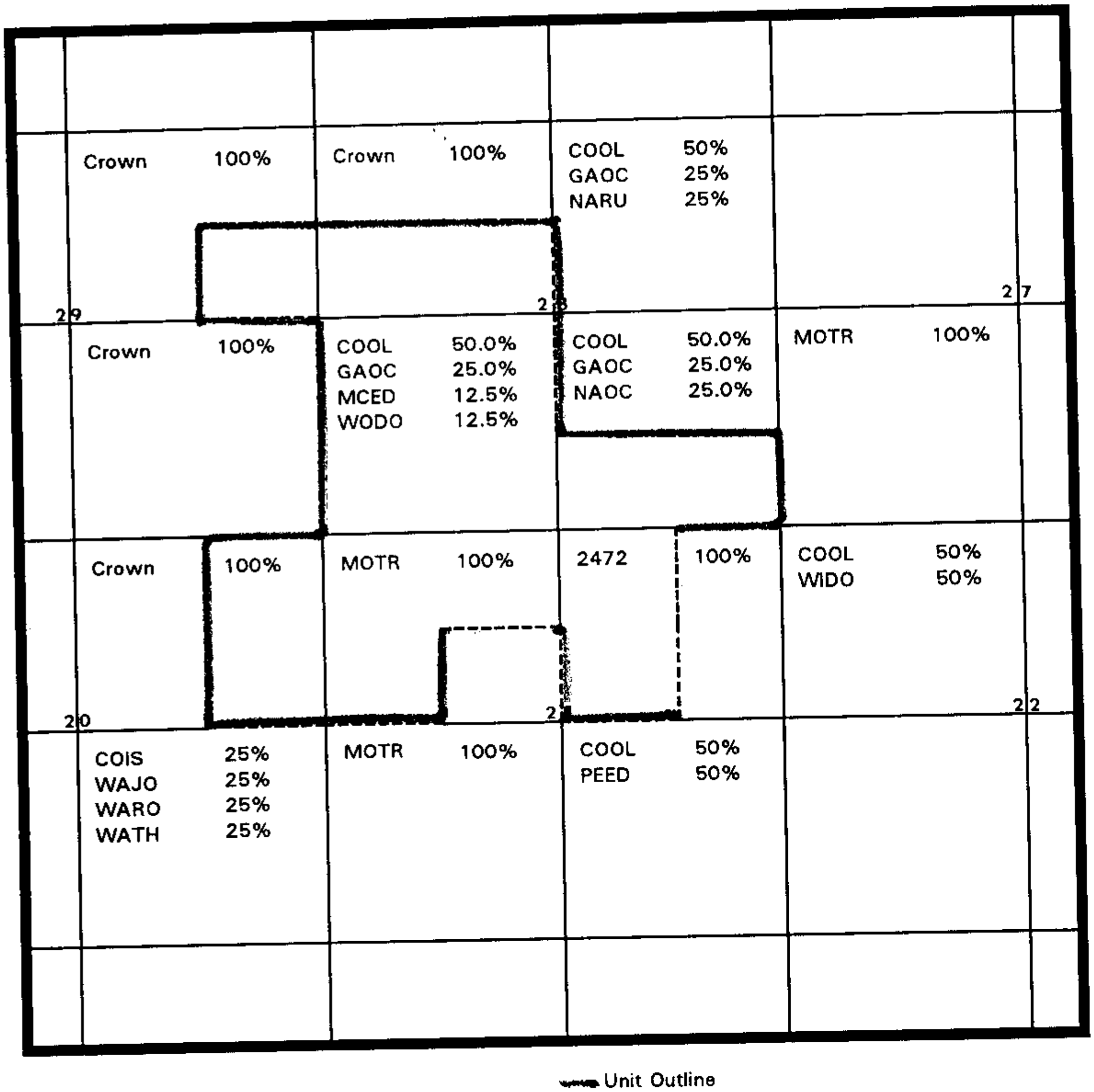
Edgar Penner
General Delivery
Elkhorn, Manitoba
R0M 0N0

Robin Watson
P.O. Box 245
Roblin, Manitoba
R0L 1P0

Donald C. Widger
P.O. Box 68
Elkhorn, Manitoba
R0M 0N0

Poco Petroleums (ORR)
P.O. Box 4365, Station "C"
Calgary, Alberta
T2T 5N2

Ruth Joyce Naylen
General Delivery
Maryfield, Saskatchewan
S0G 3K0



2472 - 2472792 Manitoba Ltd.
COIS - Isabel Cotton
COOL - Corvair Oils Ltd.
GAOC - Gauer Oil Company
MCED - Edna Rachel Eliza McPhail
MOTR - Montreal Trust
NAOC - Naylen Oil Corp.
NARU - Ruth Joyce Naylen
PEED - Edgar Penner
WAJO - John Edwin Watson
WARO - Robbin Watson
WATH - Thomas Reginald Watson
WIDO - Donald C. Widger
WODO - Douglas Harold Wood

Manitoba

The Oil and Natural Gas Conservation Board

555 — 330 Graham Avenue
Winnipeg MB R3C 4E3
CANADA

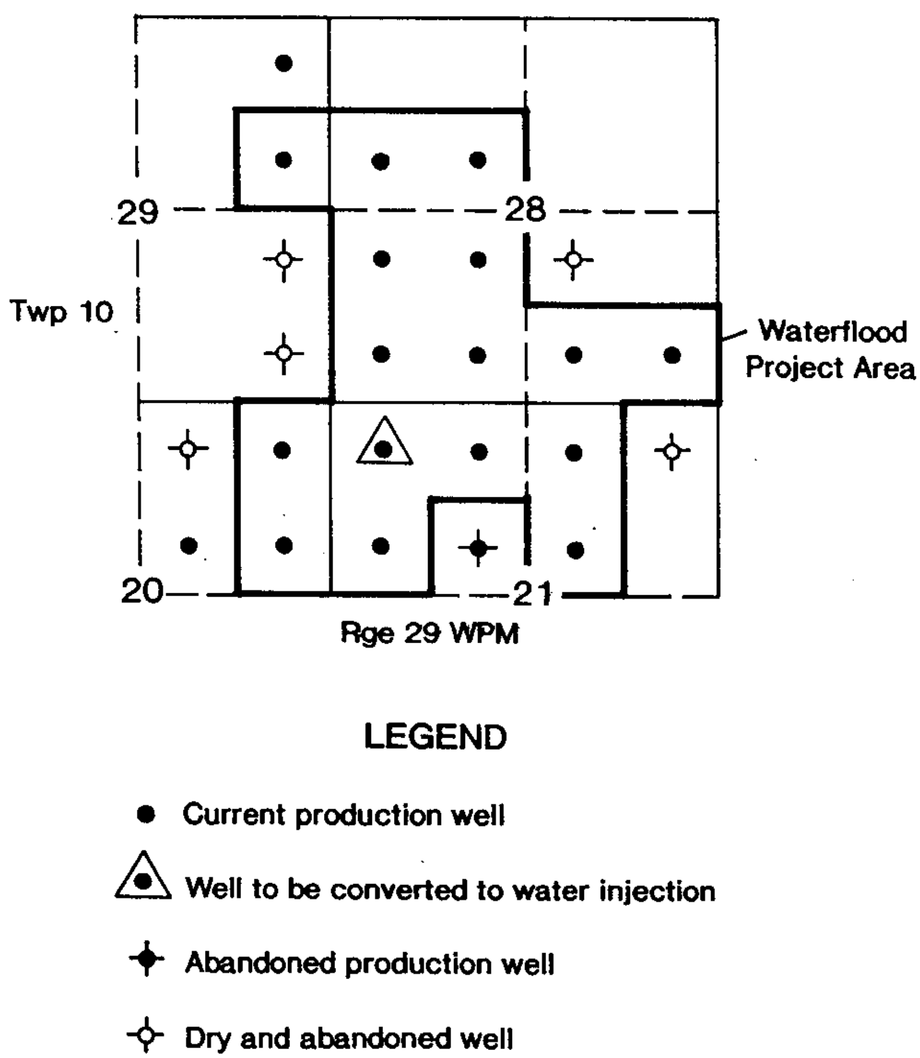
(204) 945-1111
FAX: (204) 945-0586

NOTICE

UNDER THE MINES ACT

DALY OIL FIELD

Tundra Oil and Gas Ltd. has made application under The Mines Act to conduct a waterflood in the Bakken Formation in that portion of the Daly Field referred to as the "waterflood project area" and shown below.



It is proposed to convert the well, Tundra Daly 13-21-10-29 (WPM) to water injection.

If no valid objection or intervention in writing is received by The Oil and Natural Gas Conservation Board at 555-330 Graham Avenue, Winnipeg, Manitoba, R3C 4E3 before August 27, 1993, the Board may approve the application.

Copies of the applications can be obtained from:

Tundra Oil and Gas Ltd.
1111 - One Lombard Place
Winnipeg MB R3B OX4

(204) 934-5850

The application may be viewed at the offices of the Petroleum Branch:

555-330 Graham Avenue
Winnipeg MB R3C 4E3

(204) 945-6577

227 King Street
Virden MB ROM 2C0

(204) 748-1557

Dated at Winnipeg, this 30th day of July , 1993.

David Tomasson
Chairman

Tundra
oil and gas ltd.

JOHN
- FOR YOUR LATE NIGHT
READING ENJOYMENT
Bob

July 9, 1993

- DRAFT LETTER OF
ACKNOWLEDGEMENT
FOR MY SIGNATURE
IN THE BOARD'S (HCM'S)
ABSENCE
BR

Manitoba Energy and Mines
Petroleum Branch
555 - 330 Graham Avenue
Winnipeg, MB
R3C 4E3

Attention: **Mr. C. Moster**
Deputy Chairman

Dear Mr. Moster:

RE: Kola Field
Pressure Maintenance Application

Tundra Oil and Gas Ltd., as Operator of the referenced property, submits the attached pressure maintenance application for Crown approval. The installation of the pressure maintenance scheme in the Kola Field will allow waterflood operations to significantly improve oil recovery from the Bakken 'A' Pool.

The major participants have currently agreed to the Unit land tract factor participations, and preparation of Unit agreements has been initiated. Tundra envisions an effective date for Unit Operations to commence as of September 1, 1993, and any additional assistance or information that Tundra can provide to expedite approval of the application will be made available from our office.

Should you have any questions, please call me at 934-5853.

Yours truly,

TUNDRA OIL AND GAS LTD.

G. Czyzewski

George Czyzewski, P. Eng.
Senior Reservoir Engineer

GC/bp

cc Mr. L. R. Dubreuil, Director, Petroleum Branch
Mr. R. A. Delbaere, P. Eng., Corvair Oils Ltd.

BAKKEN A POOL - PM APPLICATION

- ROIP - 35.8 % ✓ UNDER WF

- PHASE I - area of highest reservoir quality
13-21 inj. incremental recovery (Phase I) - 42,395 m^3 ✓
inverted 9-spot

- KOLA UNIT NO. 1 WIO agreement to participation factors
(current productivity - 100 %.

✓ - pool decline arrested in 1992 by workovers (review)

✓ - rem. rec. res. 80000 m^3 (78.2 $\times 10^3 m^3$) (pool) . prim. rec. factor - 18.5 % OOIP

✓ rel. K. testing indicated ult. rec. (WF) = 35.8 % OOIP
Sor = 19.7 %

PHASE I - primary recovery 23.9 % OOIP
✓ WF recovery 41.7 %* OOIP

*(35.8 % - 18.5 % = Δ_{WF} 17.3 % ≈ 23.9 % + 17.3 % = 41.2 % OOIP)

✓ - inverted 9-spot injectivity problems in N. Ebon Unit's 1 & 2 - DETAIL

- battery to be constructed @ 4-28-10-29 , inj. pump @ 13-21

- production from base of Middle Bakken Mbr 1-3 m thick (highest kh & continuity)

- $\phi_{aver} = 16.6\%$ ($\phi_D = 12\%$ cutoff limestone scale)
  $\approx k = 1$ md

$1 < k < 100$, $K_{aver} = 10$ md.

- maybe reservoir developed at top of Middle Bakken mbr $h = 1$ m, $\phi_{aver} \approx 13.7\%$ $k = 1\text{-}2$ md
  (floodable reserves included in calculations ?)
  13-21 have both porous zones.

- dip SW

PVT - 3-28-10-29

$\bar{P}_R = 8604$ kPa (DST 13-21)

- recovery mechanism soln gas drive

- new wells 10-20, 15-21 & 16-29-10-29 show depletion
  $P_{aver} = 6400$ kPa

- average reservoir pressure 1993 - 6000 kPa

- favourable mobility ratio $M = \dfrac{\mu_o^{\approx 2.8}}{\mu_{w \sim 1.0}} \times \dfrac{K_{rw}}{K_{ro}}$

- highly water wet reservoir $S_{or} = 19.7\%$ = ~~with sec.~~ displacement efficiency 53.3%

- 5% OOIP WF recovery assigned to upper zone

OOIP ESTIMATE

VOLUMETRIC

ooip (based Arbez) - optimistic

lower zone 648338 m^3

upper zone 266143 m^3

$915 \times 10^3 m^3$

ooip (based rel. k study 4-28-10-29) Sw = 57.8% lower zone

log SW lower zone 32%

rel k. Sw " " 57.8%

lower zone 468999 m^3

upper zone 266143 m^3 → optimistic based on Arbez

$735 \times 10^3 m^3$.

note: no primary recovery attributed to upper zone

actual lower zone primary recovery ~ 33% oo.p

Material MBalance

610000 m^3

PRODUCTION

1989 to 1992 dec. rate 21% / yr.

RESERVES

PRIM REC RES - 136000 m^3

CUM. PROD. (MAR 31/93) 59474 m^3

$RF_{VOL\ OOIP}$ ~ 18.5% OOIP

$RF_{MB\ OOIP}$ = 22.3% OOIP

UNITIZATION

- proposed unit 640 ac.
- Phase I WF 280 ac

- current productivity - sole tract participation factor
  - HCPV not indicative of productivity

14-21-10-29 SI Aug/88 - candidate for high volume lift equipment

tract factor for 12-21 assigned to 14-21 as wells had similar production profile

- inj. press. will continue to increase with increasing cumul. inj. volumes until wh. breakthrough

- incomplete inverted 9-spot — actually 7-spot pattern — using 13-21 corner wells 1-29 & 11-21 have been abandoned (no "-ve" effect as k trends E-W & NE-SW)

INCREMENTAL WF RECOVERY (Phase 1)

- Vol. OOIP (S_w=57%) /well
- decline curve analysis /well

} primary recovery estimate

- assumed incremental WF recovery
  (OOIP/LSD * .533 displacement efficiency)* + .05 * OOIP upper zone — lower zone

$\frac{1-.573-.197}{1-.573}$ *

~~[illegible]~~

PHASE I ΔROIP

REMAINDER ΔROIP 84900 (WF EXPANSION)
KOLA UNIT NO. 1

WF PRODUCTION FORECAST

- based on N. Ebon Units # 1 & 2

  - WF response in 3-6 months characterized by either a flattening of production decline or a 30-50% increase in production

- prediction for Phase 1 75% increase in production based k & ϕ continuity of lower zone @ 13-21

  - production to peak in early 94 & remain flat for 3 yrs., decline at 8%/yr. for 6 yrs & 20%/yr thereafter

- estimate injection at 13-21 initial 19 m³/d
  max. 30 m³/d

Is 11-21 a re-entry candidate ϕh (HCPV) within 0.2 (ϕ·m) contour interval

ϕh & kh maps suggest Phase I best WF potential

- review unit boundaries ϕh
  kh
  current productivity

· can it be assumed that upper & lower zones are in communication ī that wellbore either perfs or frac'd

- poor pressure data suggests M.B. estimates maybe inaccurate (check P.B. records.)

- TABLE 3 UPPER ZONE PRESENT IN ALL WELLS
OOIP RGE ~~3650~~ 2373 - 18254 m^3 AVER. 9857 m^3/well

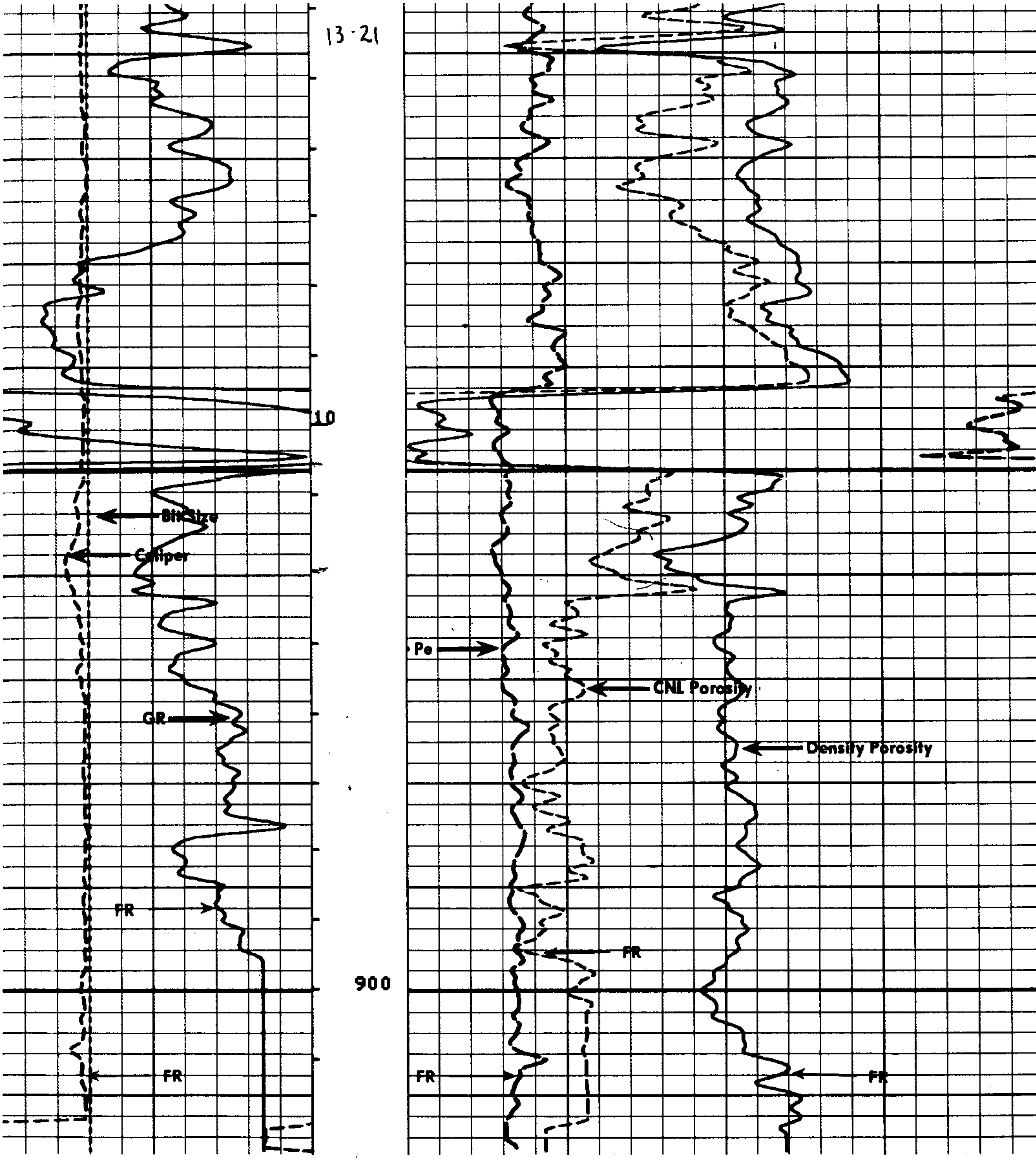
FROM ARBEZ - UPPER & LOWER ZONES SEPARATED BY 1.4 - 3 m

ARBEZ - Sw upper zone > 75%. did not consider upper zone to have meaningful volume of OOIP

BAKKEN A POOL

RECENT WORKOVERS

WELL	STIMULATION	DATE
16-17-10-29	1500 l 15% XFWL ACID	SEP 17/92
16-20-10-29	500 l 15% MDA 1000 l 15% STABILIZED ACID	MAY 28/92
13-21-10-29	1500 l 15% HCl	JAN 11/93
2-28-10-29	1000 l 15% STABILIZED ACID	MAY 20/92
3-28-10-29	500 l 15% MDA + 1500 l 15% HCl	AUG 27/92
4-28-10-29	1.5 m^3 15% HCL	JULY 10/92
6-28-10-29	2 m^3 15% STABILIZED ACID 5 t FRAC	JUL 14/92 MAR 21/93
11-28-10-29	2 m^3 15% HCl 5 t FRAC	JAN 14/93 JAN 19/93



LIMESTONE FILE 7 29-SEP-85 06:43 LIMESTONE

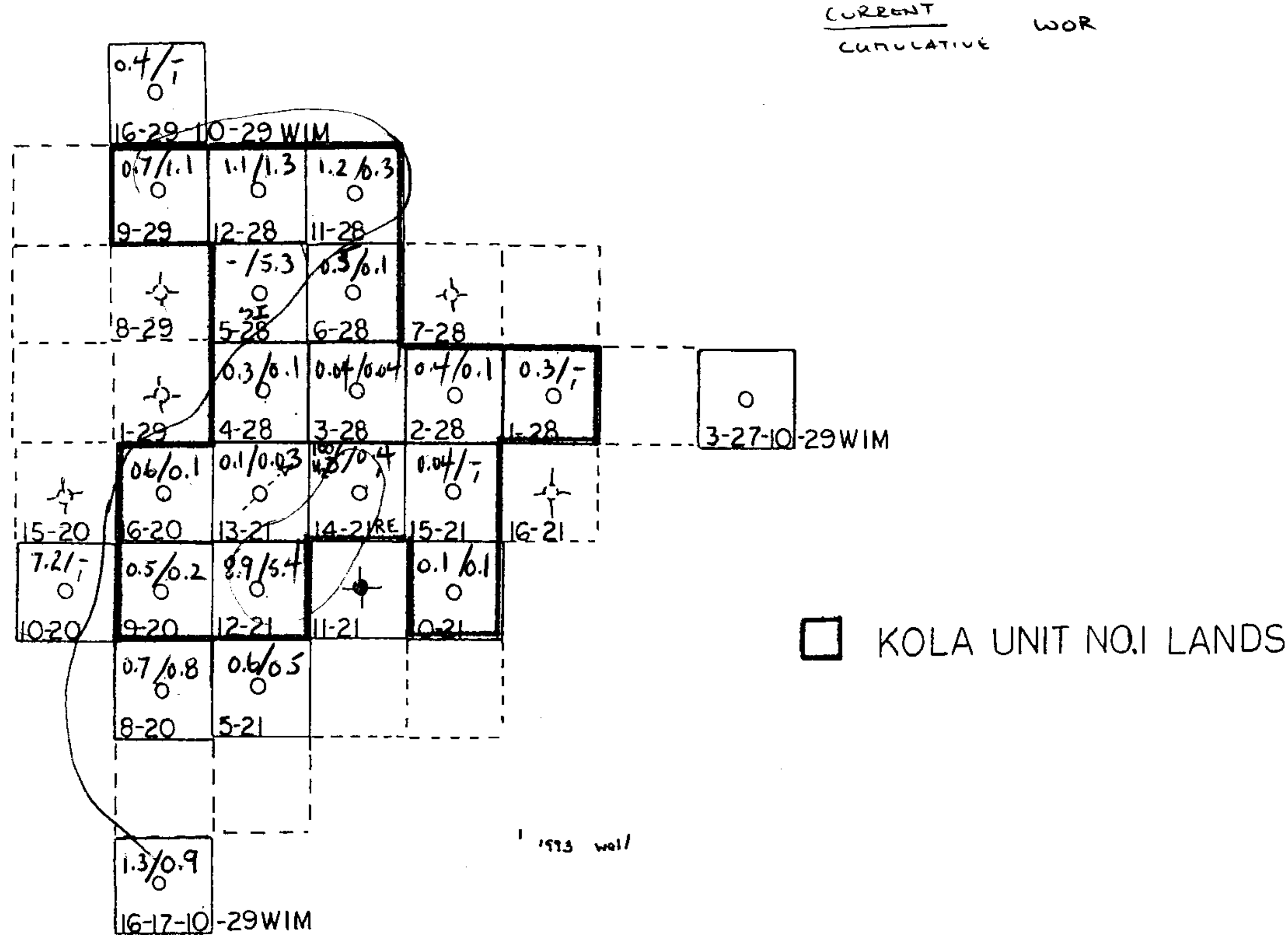
CALI(MM) 125.00 375.00		PEF 0.0 10.000
GR (GAPI) 0.0 150.00		DPHI .45000 -.1500
BS (MM) 125.00 375.00		NPHI .45000 -.1500

RECENT PRESSURE DATA - BAKKEN A POOL

10-20-10-29	DST	MAR 7/93	6062 KPa
16-29-10-29	DST	FEB 23/93	6723 KPa
15-21-10-29	DST	FEB 13/93	5988 KPa

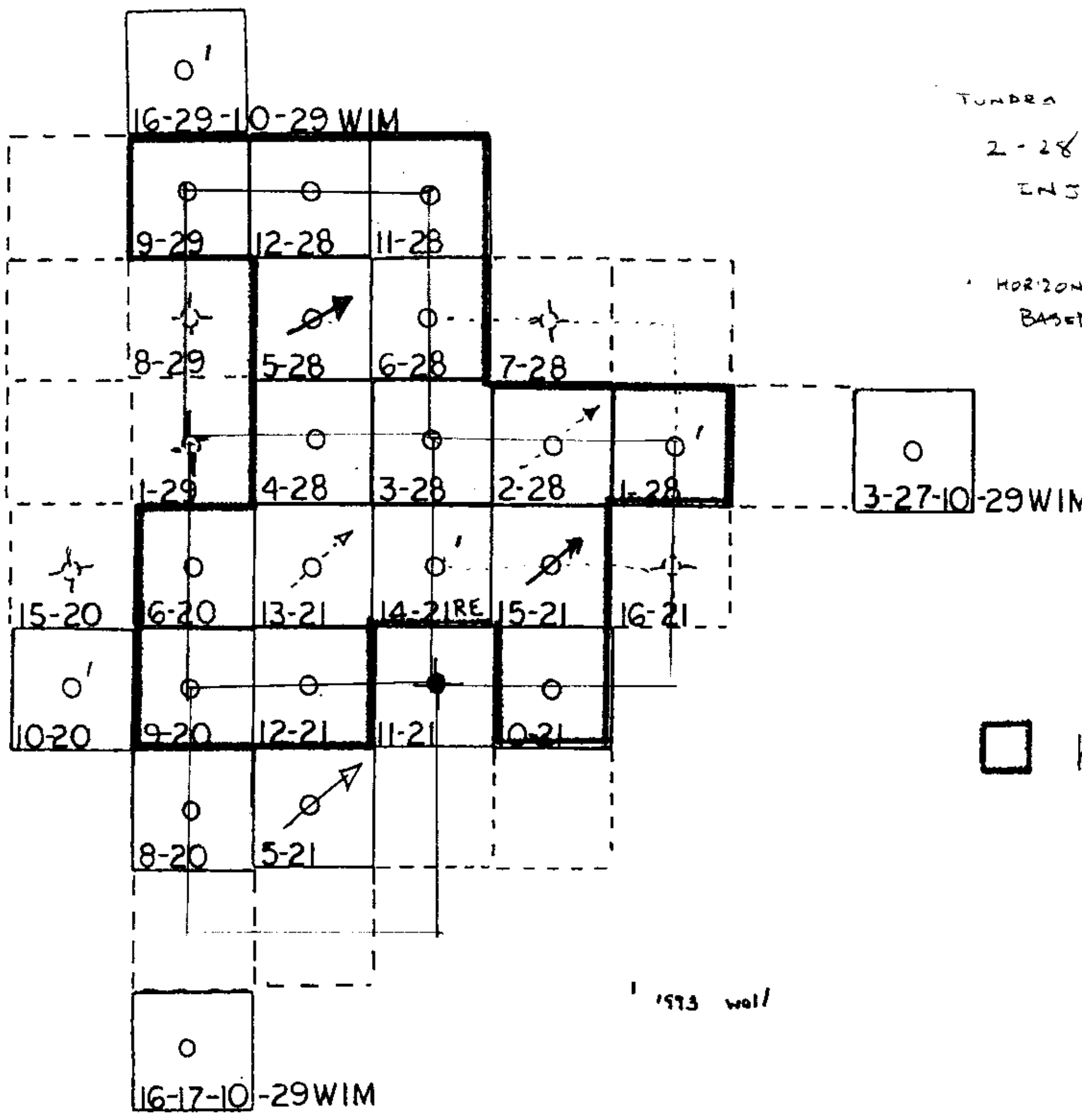
ATTACHMENT NO. 2

BAKKEN 'A' POOL



ATTACHMENT NO. 2

BAKKEN 'A' POOL



TUNDRA CONSIDERING
2-28 AS POSSIBLE
INJECTOR IN NEXT PHASE

' HORIZONTAL DRILLING PROSPECT
BASED ON 1993 VERT. WELLS

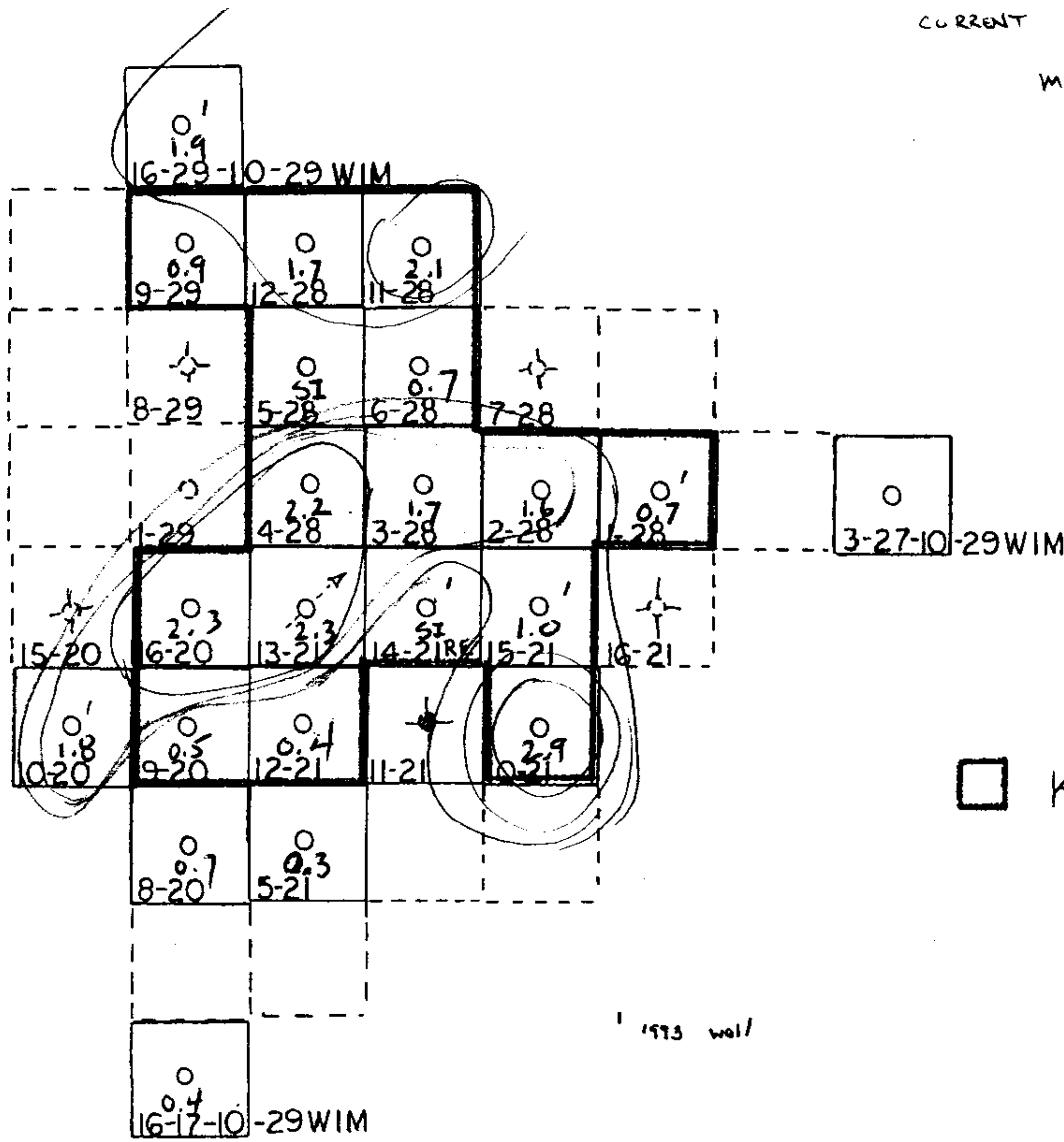
' 1993 well

☐ KOLA UNIT NO.1 LANDS

ATTACHMENT NO. 2

BAKKEN 'A' POOL

CURRENT PRODUCTION
m3/d



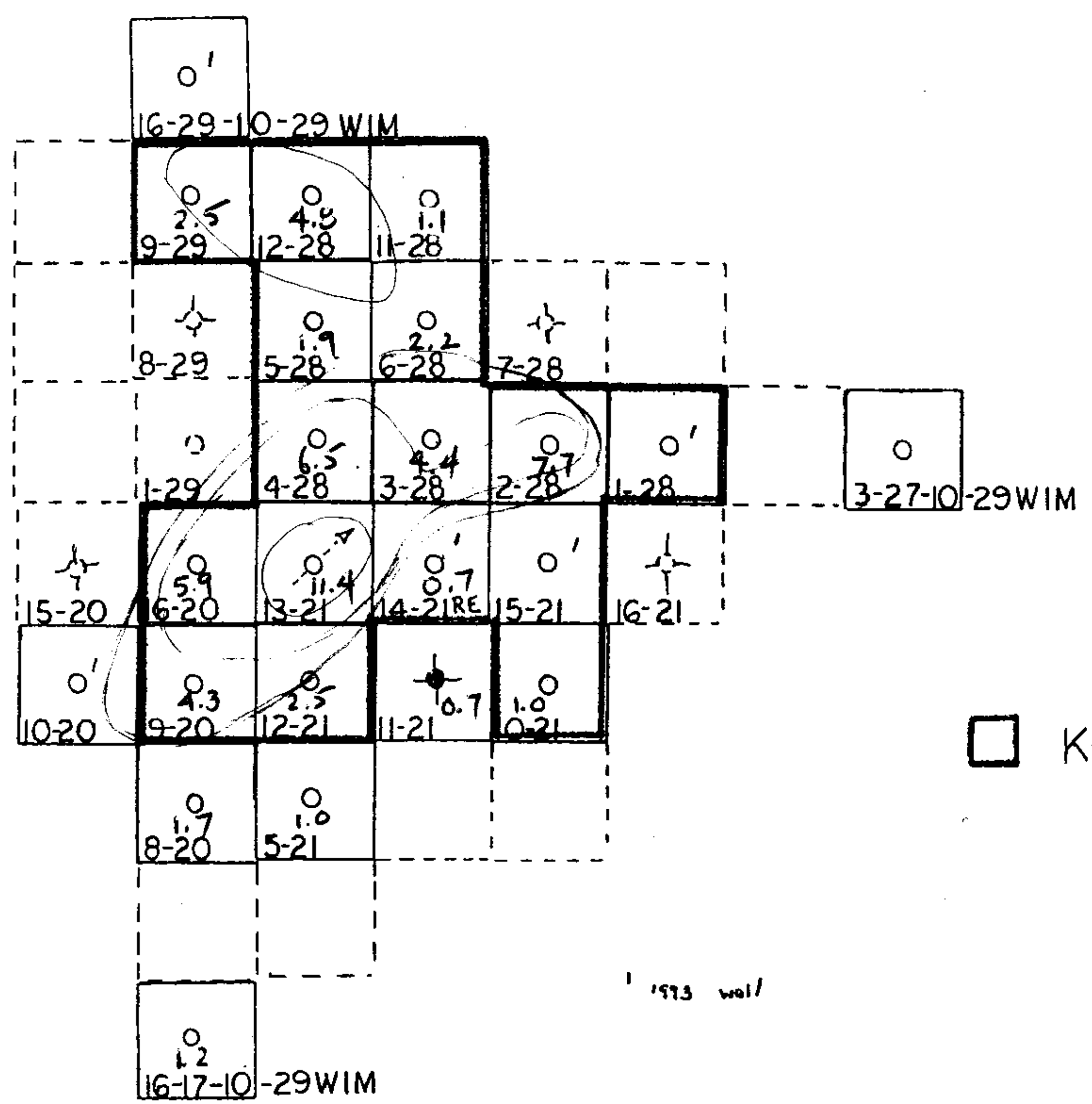
' 1993 well

KOLA UNIT NO.1 LANDS

ATTACHMENT NO. 2

BAKKEN 'A' POOL

CUMULATIVE PRODUCTION
10^3 m^3

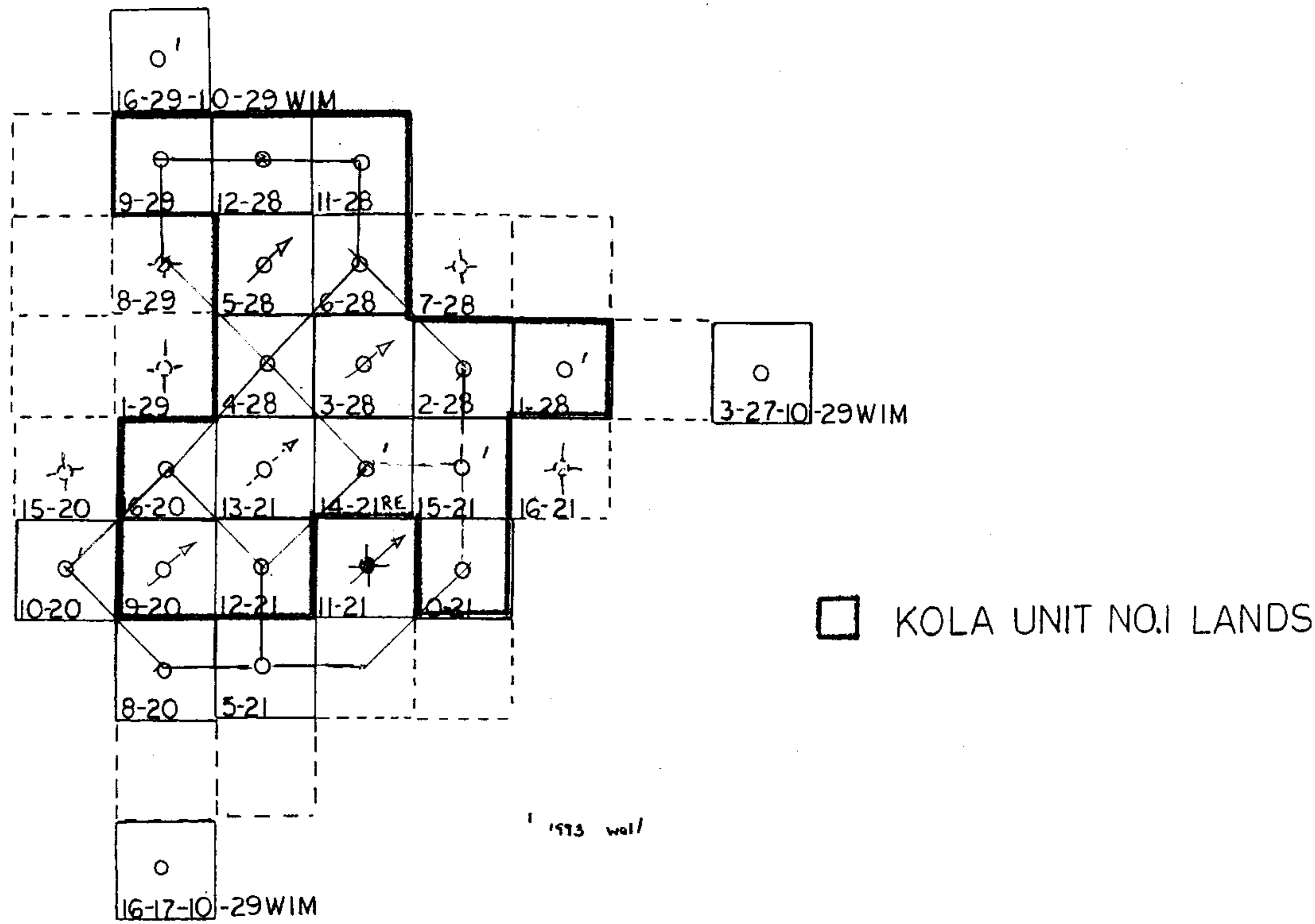


KOLA UNIT NO. 1 LANDS

8-20 Poco
5-28 Kiwi

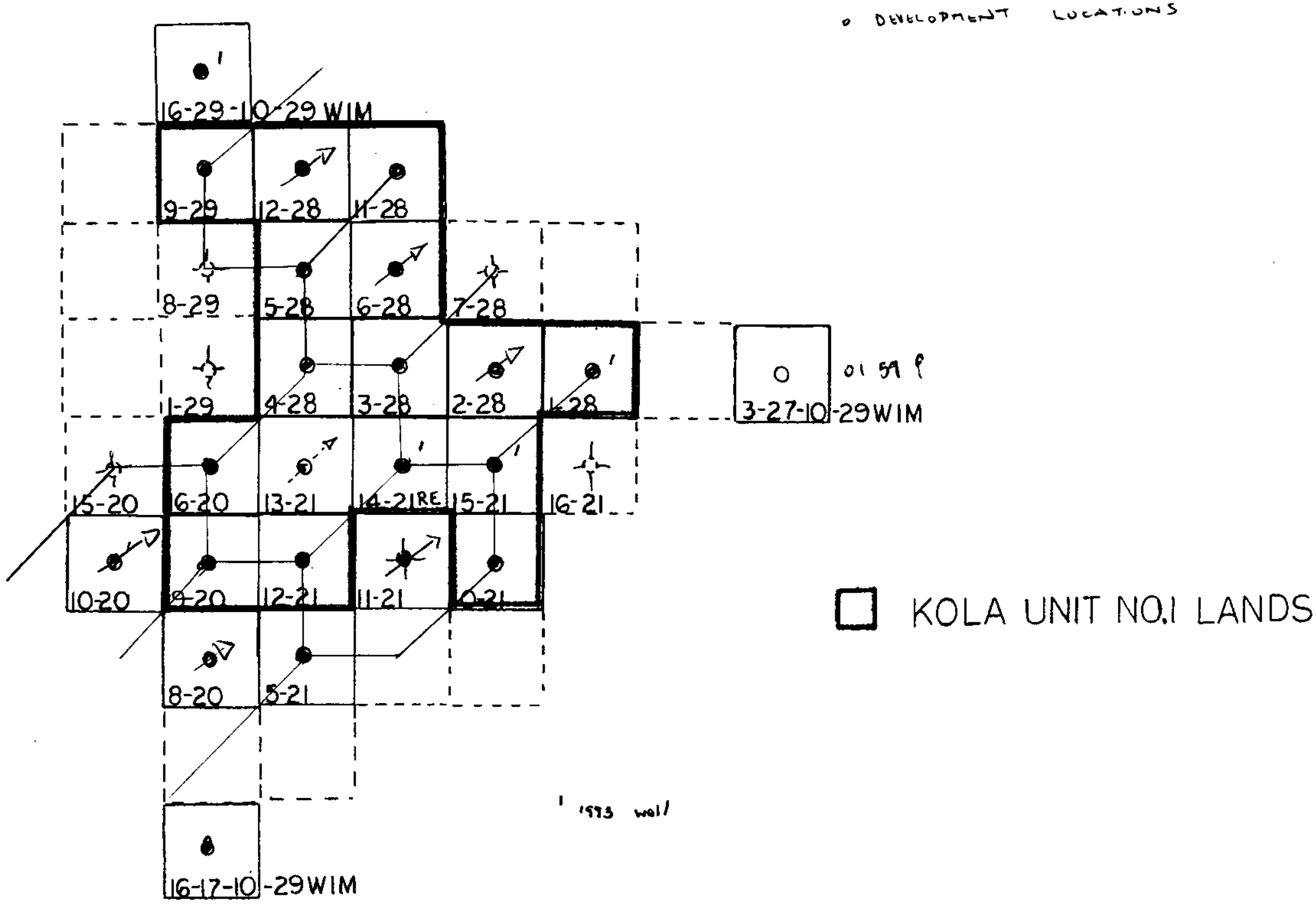
ATTACHMENT NO.2

BAKKEN 'A' POOL



ATTACHMENT NO. 2

BAKKEN 'A' POOL



BAKKEN D POOL - WF PERFORMANCE

N. Ebon Unit No. 1 inj commenced June /90

- WF response characterized by an arresting of prod decline

- rem. recoverable reserves 26950 m³
  cumulative prod. (92-12-31) 28255.3 m³

  total 55203 m³ (35.7% OOIP)

VRR > 1.0 actual 1992 VRR : 1.29

16 14-10-29 injector performance (plot of inj press vs cumul. inj.

initial inj. press 750 psi increased to 1200 psi

mid-1991 cum. inj <8000 m³ refrac successful in temporarily reducing injectivity (aver. inj rate 19.3 m³/d)

- noted that due to low mobility ratio (displacing to displaced fluid

- production performance increased water-cut 1992

N Eban Unit No. 2 inj commenced Oct/91

cumul. prod. 25911.5 m^3
92-12-31
rem. rec. res. 46580 m^3

total 72495 m^3 (38.2% OOIP)

8-14-10-29
injection pres ~~increasing~~ Dec/92 1222 psig
1992 aver. inj. rate 25.1 m^3/d

D'' Pool OOIP ≈
estimated ult. rec. res. 127698 m^3