

Reduced Spacing Application  
for  
North Virden Scallion Unit No. 1  
Virden Lodgepole **A** Pool

Chevron Canada Resources  
July 1991



## **Chevron Canada Resources**

500 - Fifth Avenue S.W., Calgary, Alberta T2P 0L7  
Phone (403) 234-5000 Fax (403) 234-5947

Calgary, Alberta  
July 12, 1991

### **North Virden Scallion Unit No. 1 Reduced Spacing Project**

Oil and Natural Gas Conservation Board  
Room 309  
Legislative Building  
Winnipeg, Manitoba  
R3C 0V8

Attention: Dr. Ian Haugh, Chairman

Gentlemen:

Chevron Canada Resources, a Partnership by its managing partner, Chevron Canada Resources Limited, as operator of North Virden Scallion Unit No. 1 (NVSU No. 1) hereby request:

1. Pursuant to sections 20(1) and 21(3) of the Manitoba Petroleum Drilling and Production Regulations, approval to decrease the size of drilling spacing units from 16 hectares (40 acres) to 8 hectares (20 acres), within the SE $\frac{1}{4}$ -21-11-26W1, SW $\frac{1}{4}$ -27-11-26W1, and SE $\frac{1}{4}$ -4-12-26W1. Chevron proposes to drill 3 infill wells to improve oil recovery and to confirm the validity of the new infill well selection criteria at NVSU # 1. It is understood that the target areas will be square with sides sixty-five metres from the sides of the 8 hectare drilling spacing units (Attachment 13).

The proposed reduced spacing project area is part of North Virden Scallion Unit No. 1 which is wholly contained within the Virden Lodgepole "A" pool.

The following sections and attachments contain all the supporting information associated with the above requests.

#### **A. Technical Details**

1. The three proposed infill wells will increase Unit production by 13 m<sup>3</sup>/d and increase reserves by 17 200 m<sup>3</sup>.
2. Attachment 1 shows the North Virden Scallion Unit and location of the proposed infill locations.

3. Attachment 2 contains a list of the proposed infill wells.
4. Attachment 3 contains the following geological information for the reduced spacing project areas:
  - a) type log showing reservoir units;
  - b) 3 cross sections illustrating pay continuity and well completion;
  - c) structure map (Top of cherty zone);
  - d) maps of porosity-thickness;
  - e) maps of permeability-thickness;
  - f) net effective pay maps;
  - g) map showing distribution of porosity types.
5. Attachment 4 outlines the technical justification for the reduced spacing project.
6. Attachment 5 is a compilation of the 1987 and 1990 reservoir pressure surveys for North Virden Scallion Unit No. 1.

**B. Benefits to Crown and Lessors**

1. All royalty and Mineral tax payments will be calculated in the same manner as used in the North Virden Scallion Unit No. 1 (1989-02-24 application for reduced spacing, Attachment 6). Production from infill wells will be classified as new oil. Attachment 6 shows plots of the Crown royalties, freehold royalties, and mineral tax payments for the base and infill cases.

**C. Surface Consideration**

1. Attachment 7 is an environmental impact assessment of the proposed project.
2. Attachment 8 contains an analysis of the design of flow lines, tie-ins and injection lines. An aerial photograph for each infill location is included. Maps showing the locations of the pipelines are also included.

D. Correspondence with Surface Owners

1. Attachment 9 shows the name of surface owners on land impacted by the infill locations.
2. Attachment 10 contains the consent to survey forms signed by the landowners who will have proposed infill wells located on their property.

E. Drilling Precautions

Attachment 11 contains a list of precautions that will be taken during drilling operations.

F. Corrosion Control

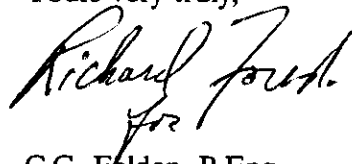
Attachment 12 summarizes the methods of corrosion control that will be used.

G. Equity Considerations for Non-Unit Producers

The infill project will not cause any equity concerns for non-unit producers.

If there are any questions regarding this application, please contact R. Forest at (403) 234-5397, or Len Marchand at (403) 234-5046 in our Calgary office, or Jim Causgrove at (204) 748-1334 in our Virden office. Additional copies of the Application may be requested from our Information Centre (403) 234-5580.

Yours very truly,

A handwritten signature in black ink, appearing to read "Richard Forest".

C.G. Folden, P.Eng.  
Manager  
Reservoir Engineering

RCF/slw

**PostFax**

MONTREAL, H1J 2K9  
CR213-31

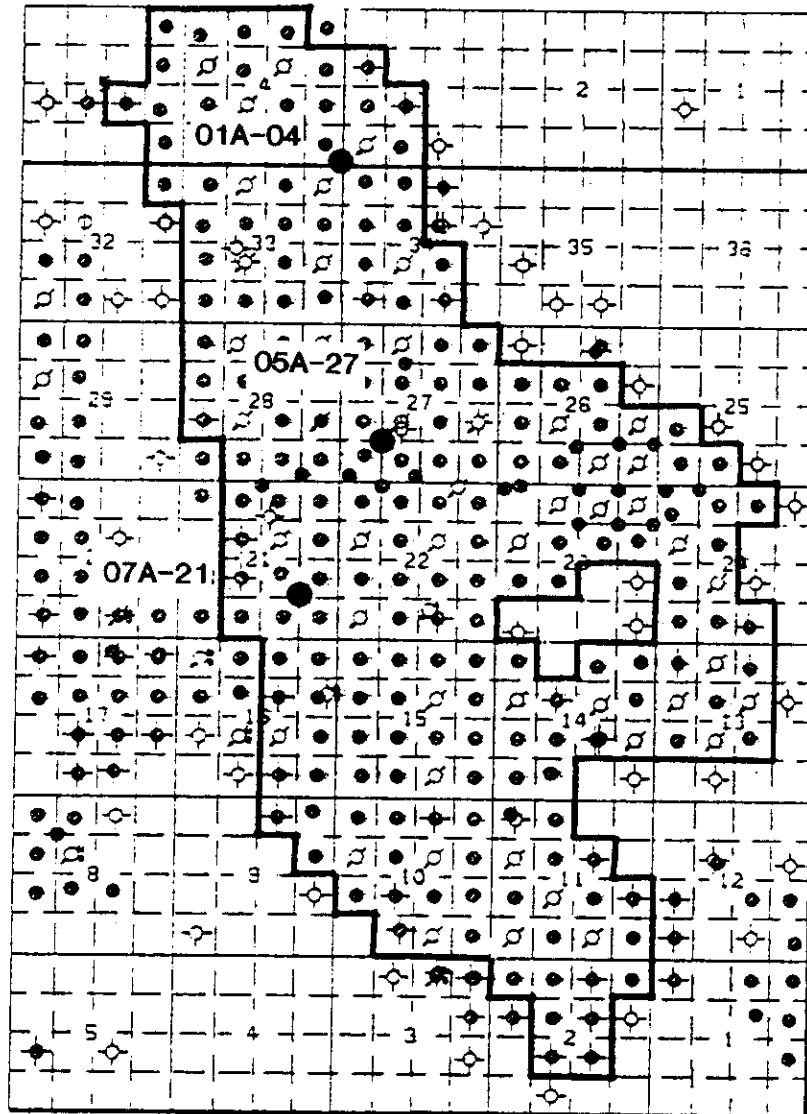
R.26W1M

T.12

T.12

T.11

T.11



R.26W1M

- INFILL WELL
- PRODUCING WELL
- ◆ INJECTION WELL
- ⊕ ABANDONED WELL

**NORTH VIRDEN SCALLION UNIT 1**





**PROPOSED INFILL WELLS  
NORTH VIRDEN SCALLION UNIT No.1 REDUCED SPACING PROJECT**

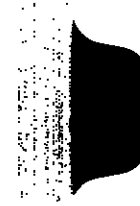
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**Proposed Infill Producing Wells**

1. Chevron NVSU No. 1 07a-21-11-26W1
2. Chevron NVSU No. 1 05a-27-11-26W1
3. Chevron NVSU No. 1 01a-04-12-26W1

(No injection well conversions)





12-24-11-26WPM

TYPE LOG

ANHYDRITE

LODGEPOLE

1900

CRINOIDAL

← ZERO  
5.8"

1 OOLITES

2

3

4

CHERTY

2000

GAMMA RAY

2039

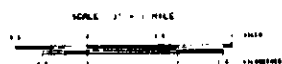
NEUTRON

R.25W1M

T.12

T. 11

R.25W1M

[illegible]

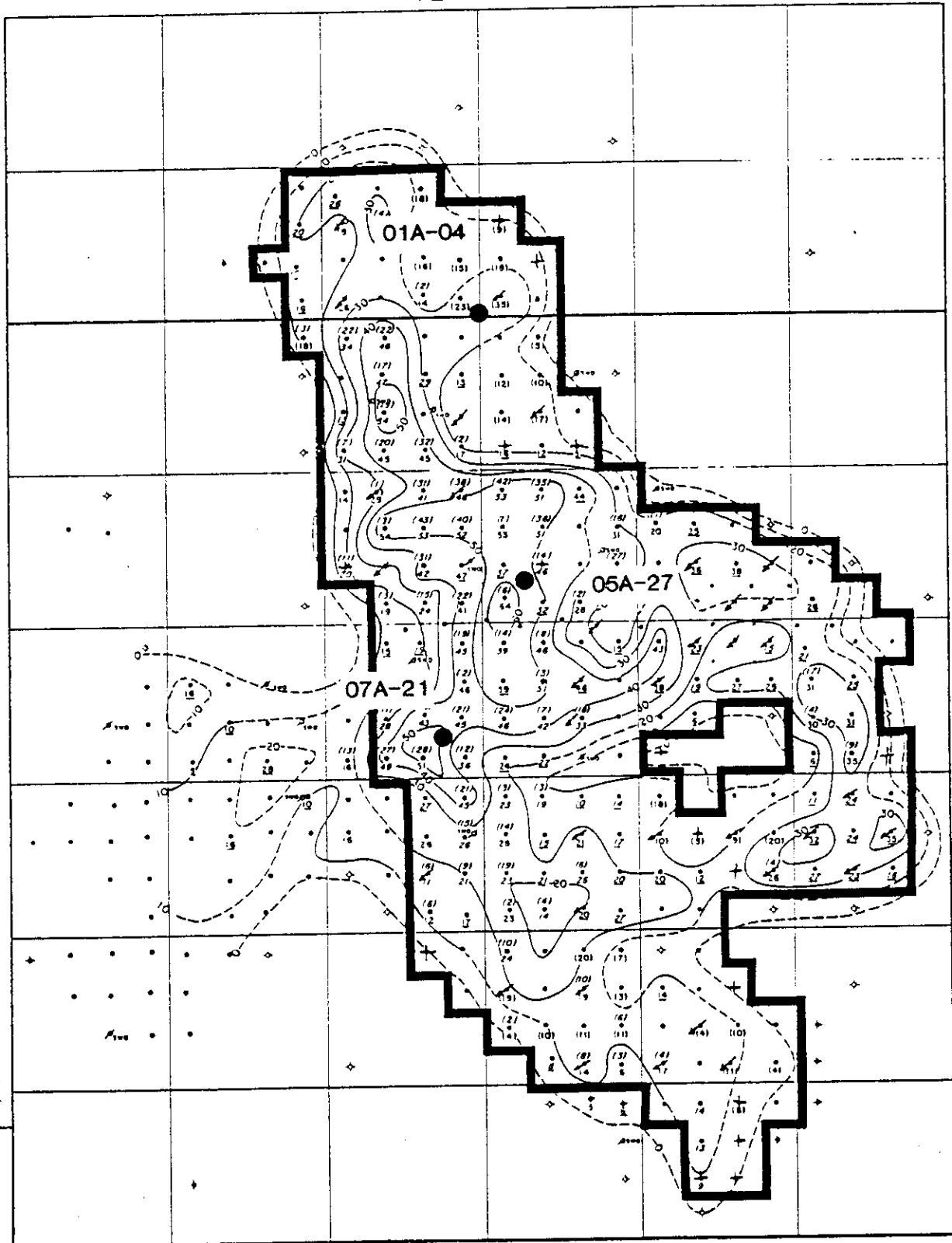


FIGURE 12  
NORTH VIRDEN SCALLION FIELD  
CHERTY ZONE  
ISOPACH OF  
ESTIMATED NET EFFECTIVE PAY

C.I. 10 FT.

SCALE IN MILES

REVISED JULY 1961

## LEGEND

- 20 CORE ANALYSIS VALUE EXTRAPOLATED TO BASE OF EFFECTIVE OIL SATURATION.
- 18 WELL VALUES EXTRAPOLATED TO BASE OF EFFECTIVE OIL SATURATION.
- 16 MEASURED CORE ANALYSIS VALUE NO EXTRAPOLATION REQUIRED.
- 14 WELL VALUE - NO EXTRAPOLATION REQUIRED
- 12 EXTRAPOLATED PAY.
- 10 VALUE OBTAINED BY OTHER MEANS

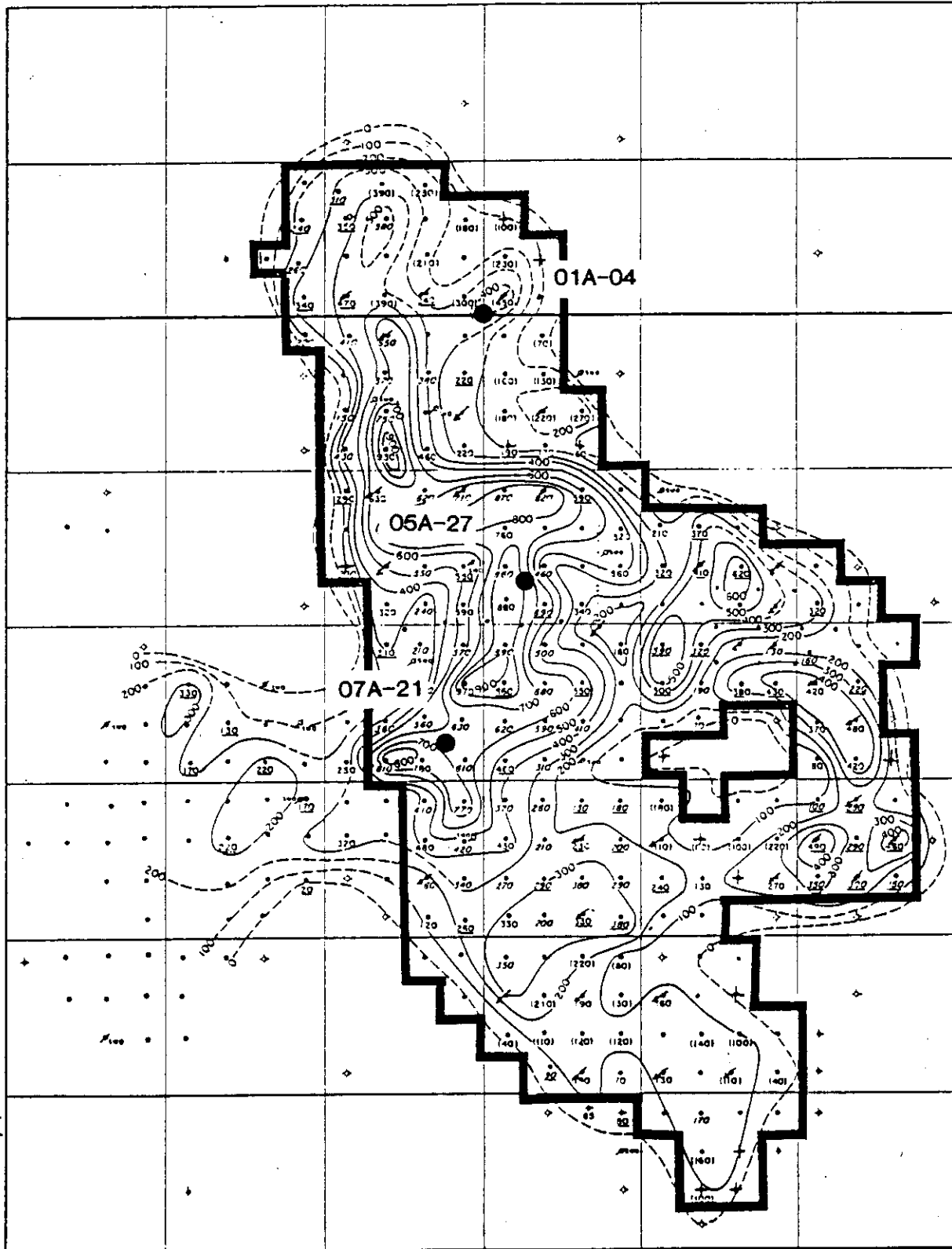


FIGURE 9  
 NORTH VIRDEN SCALLION FIELD  
 CHERTY ZONE  
 ESTIMATED NET POROSITY THICKNESS

C.I. 100 POROSITY FEET

SCALE IN MILES.

REVISED JULY 1981

## LEGEND

- 240 CORE ANALYSIS VALUE
- 180 MLL VALUE
- 120 CORED AND ANALYZED THROUGH BASE OF EFFECTIVE OIL SATURATION (NO EXTRAPOLATION REQUIRED)
- 60 MLL VALUES - NO EXTRAPOLATION REQUIRED
- (121) VALUE OBTAINED BY OTHER MEANS

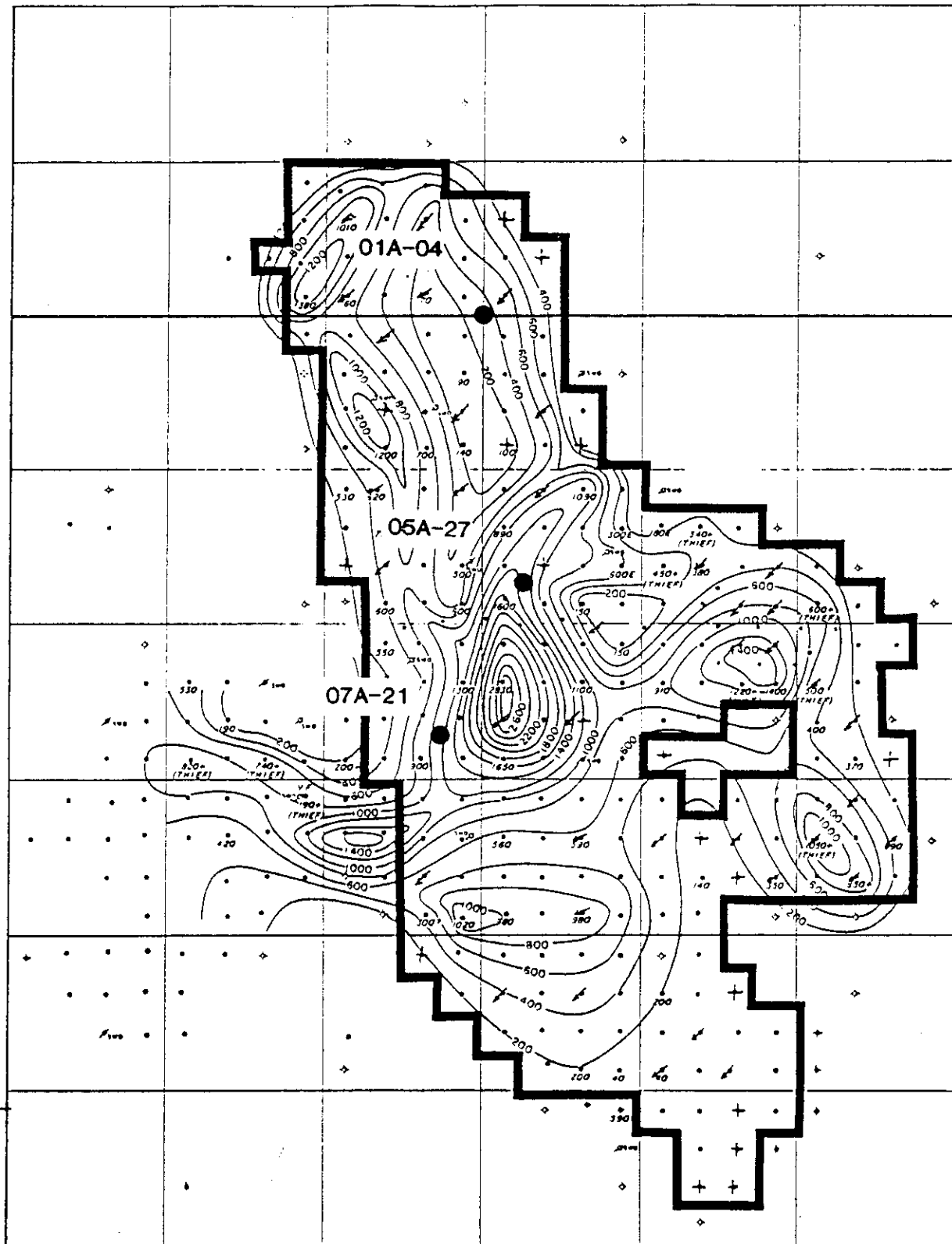


FIGURE  
 NORTH VIRDEN SCALLION FIELD  
 CHERTY ZONE  
 ESTIMATED PERMEABILITY CAPACITY  
 ( $K_{max} \times h$ )  
 MILLIDARCIES x FEET  
 (1.0 MD. CUTOFF)  
 C.I. 200 MD. FT.  
 SCALE IN MILES

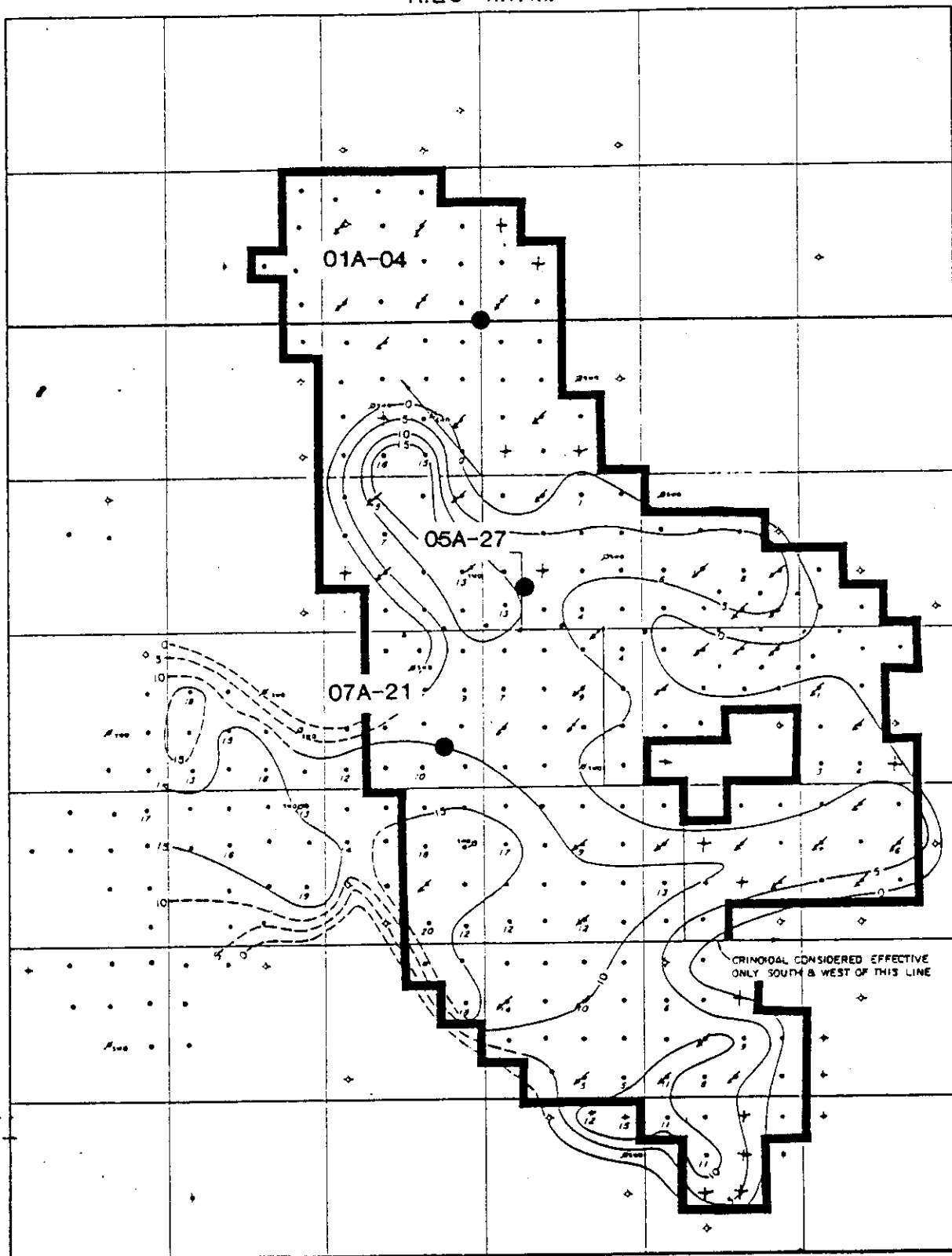
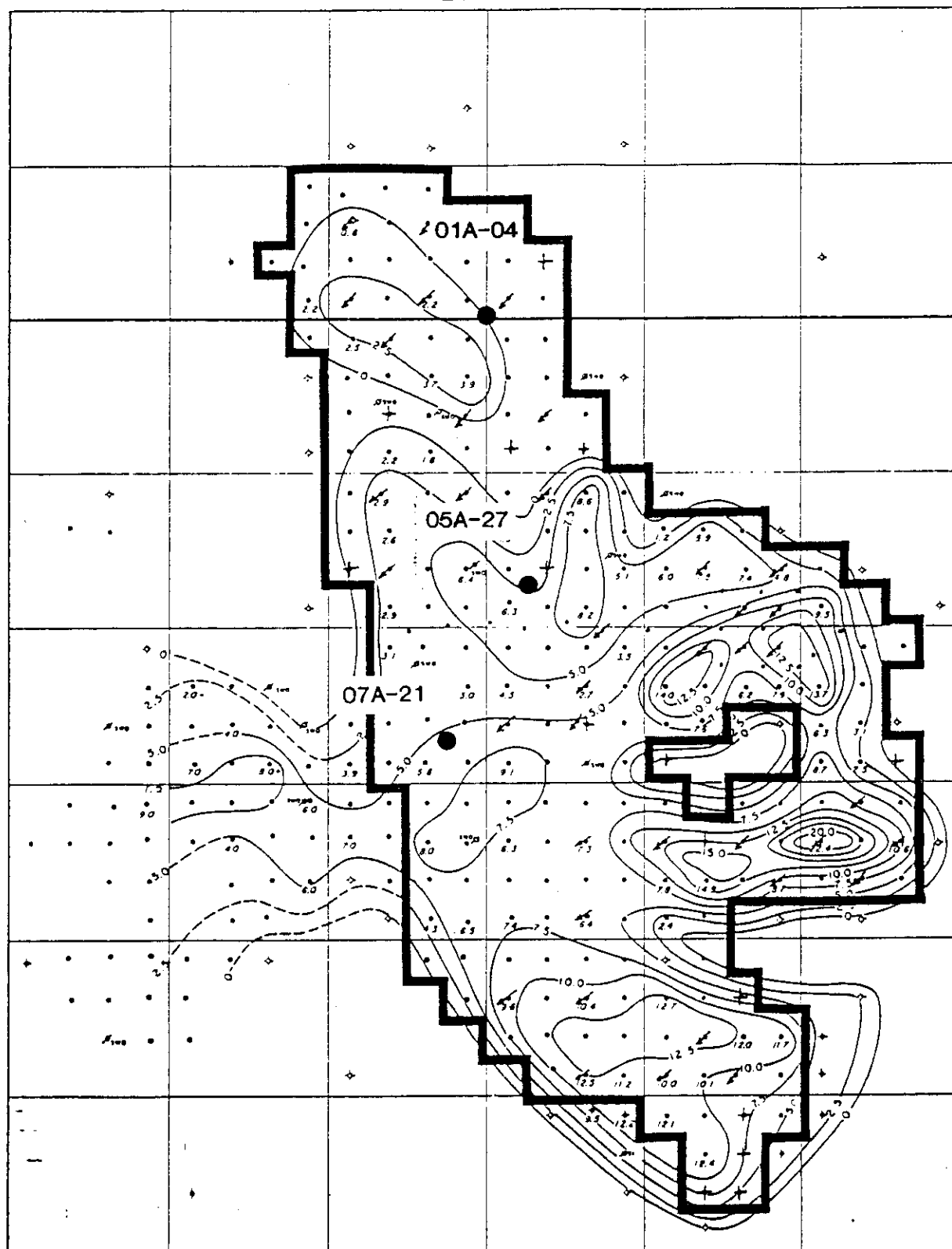


FIGURE 14

NORTH VIRDEN SCALLION FIELD  
 CRINOIDAL MEMBER  
 ISOPACH OF ESTIMATED NET EFFECTIVE PAY  
 (FROM CORE ANALYSIS)

C.I. 5 FT.

SCALE IN MILES



C.1. 2.5 FT.

SCALE IN MILES



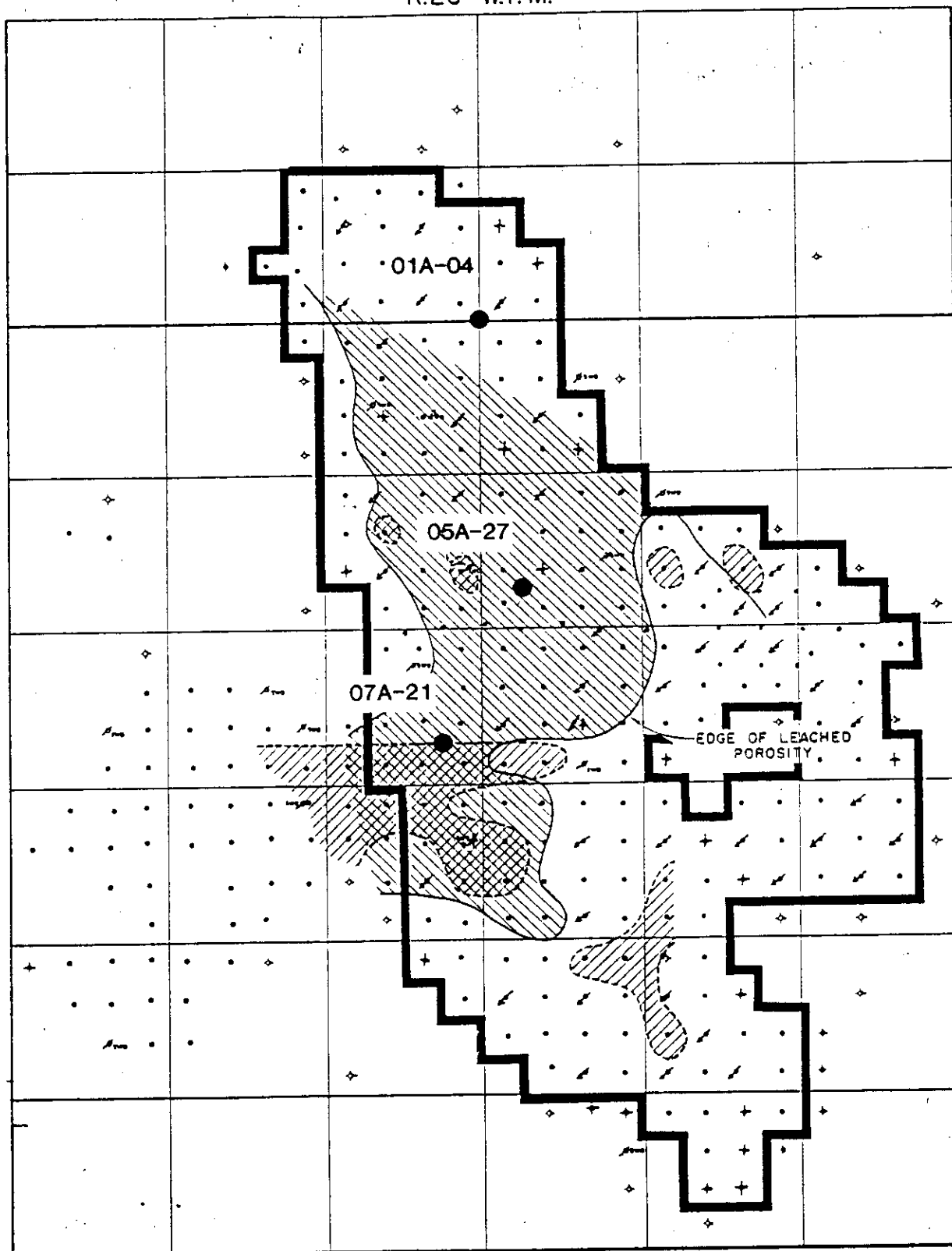


FIGURE 4

NORTH VIRDEN SCALLION FIELD  
 CHERTY. ZONE  
 SHOWING AREAS OF OPEN FRACTURING  
 AND LEACHED POROSITY

-LEGEND-

- OPEN FRACTURES
- LEACHING

SCALE IN MILES

CHEVRON SCALLION 3 21 11 26

KB: 1518  
FTD: 2078  
RR: 55-06-24  
STATUS: PUMPING OIL

03-21-011-26W1

B.O.P.D: 63.9  
CUM. OIL PROD: 1,114,440 BBLs

CHEVRON SCALLION 7 21 11 26

KB: 1512  
FTD: 2054  
RR: 55-07-02  
STATUS: PUMPING OIL

07-21-011-26W1

B.O.P.D: 13.1  
CUM. OIL PROD: 634,160 BBLs

CHEVRON

02-

CUM. OIL

USER DEFINED

NOTE: 40 MAY SP SHIFT

NOTE: 28 MAY SP SHIFT

NOTE: 3 AND MAY SP SHIFT

LODGEPOLE

CRINOIDAL

OOLITES

CHERTY

O  
W



02-21-011-26W1

08-21-011-2671

**B.O.P.D: 33.7**

**CUM. OIL PROD: 927,000 BBL/S**

**B.O.P.D. 18.1**

01-21-011-2671

[illegible][illegible][illegible]

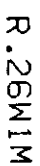


FTD: 2061

STATUS: PUMPING OIL

**B.O.P.D. 18.1**

~~NOTE 40MV B.R. SHIFT~~



T.11

R.26W1M

1=MEGA    2=COSA    3=DEV.GLCY

VERTICAL SCALE -- 1 IN. = 20 FT

WELL SPACING -- 1.000 INCHES (FIXED)

INDEX MAP: NATURAL SCALE = 15840, 1 INCH = 0.25 MILE(S)

[illegible]

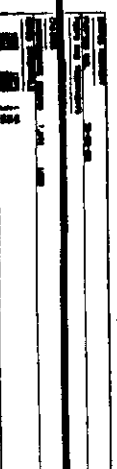
**CUM. OIL PROD: 392,780**

B.O.P.D: 27.4

**CUM. OIL PROD: 7 12,480**

B.O.I.

**CUM. OIL PR**



CHEVRON SCALLION 4 27 11 26

KB: 1516  
FTD: 2056  
RR: 55-08-08  
STATUS: PUMPING OIL

04-27-011-26W1

B.O.P.D: 66.1

CUM. OIL PROD: 883240

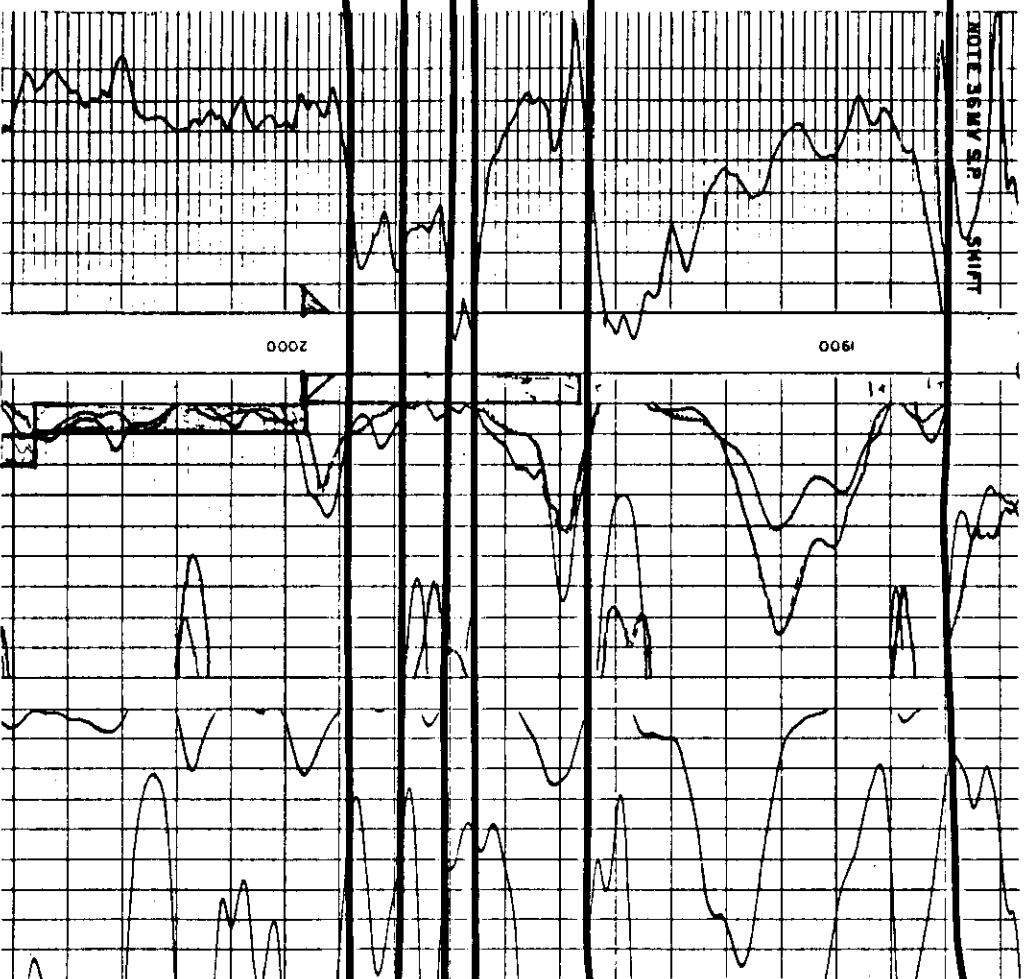
PROPOSED  
LOCATION

5A-27

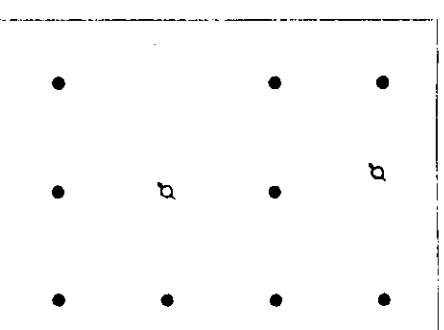
CHEVRON SCALLION WIM 6-27-11-26

KB: 1505  
FTD: 2022  
RR: 55-09-17  
STATUS: WATER INJECTOR

06-27-011-26W1



T.11



STICK PLOT CROSS SECTION, STRATIGRAPHIC SEC  
DATUM -- USER INPUT DEPTHS FOR ALL WELLS  
INTERVAL -- USER INPUT INTERVALS FOR ALL W  
HORIZON PREFERENCE SOURCES --  
1=MEGA 2=COSA  
VERTICAL SCALE -- 1 IN. = 20 FT  
WELL SPACING -- 1,000 INCHES (FIXED)  
INDEX MAP: NATURAL SCALE = 15840, 1 INCH

DATE	TIME
04-27-011-26W1	11:26
06-27-011-26W1	11:26
04-27-011-26W1	11:26
06-27-011-26W1	11:26
04-27-011-26W1	11:26
06-27-011-26W1	11:26
04-27-011-26W1	11:26
06-27-011-26W1	11:26
04-27-011-26W1	11:26
06-27-011-26W1	11:26

W O



CHEVRON SCALLION MIM 6-27-11-26

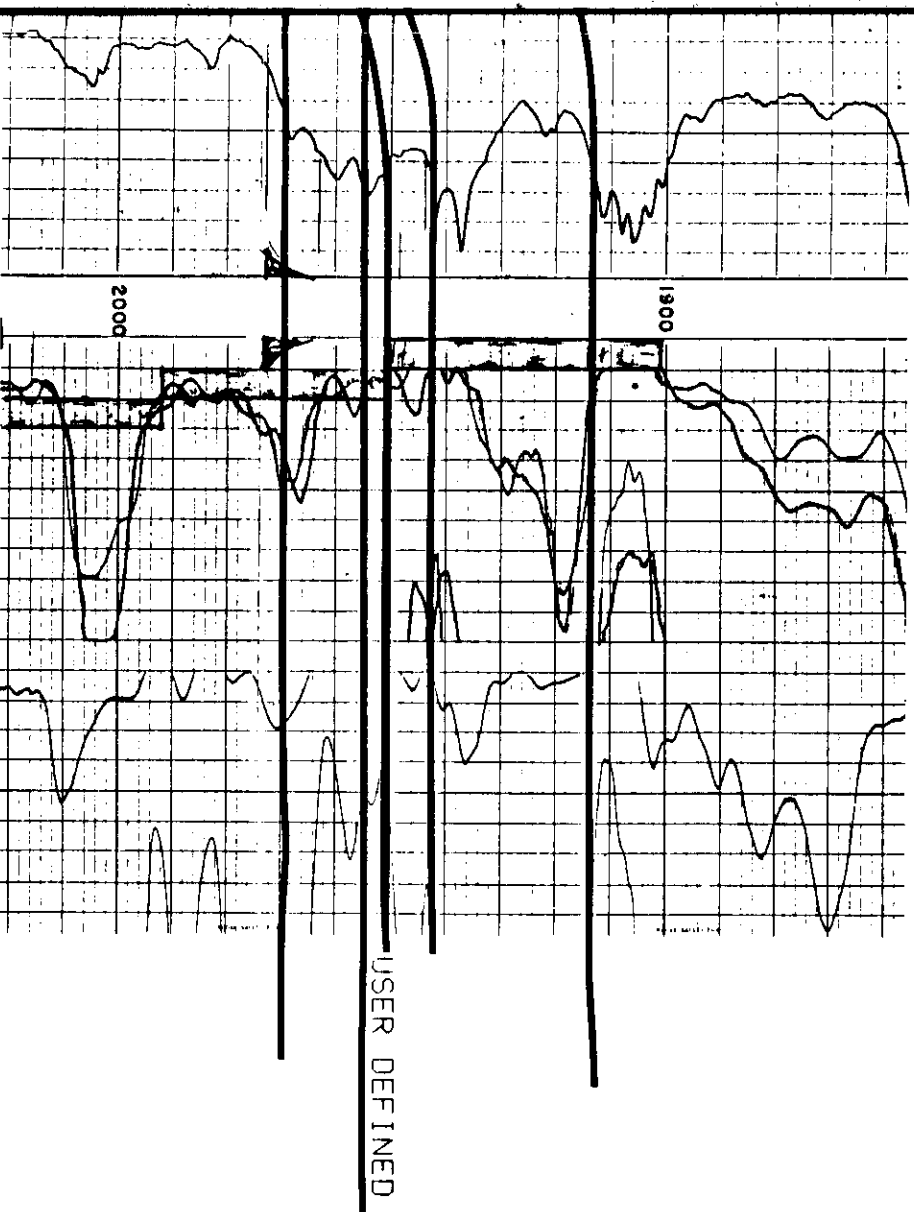
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FTD: 2022

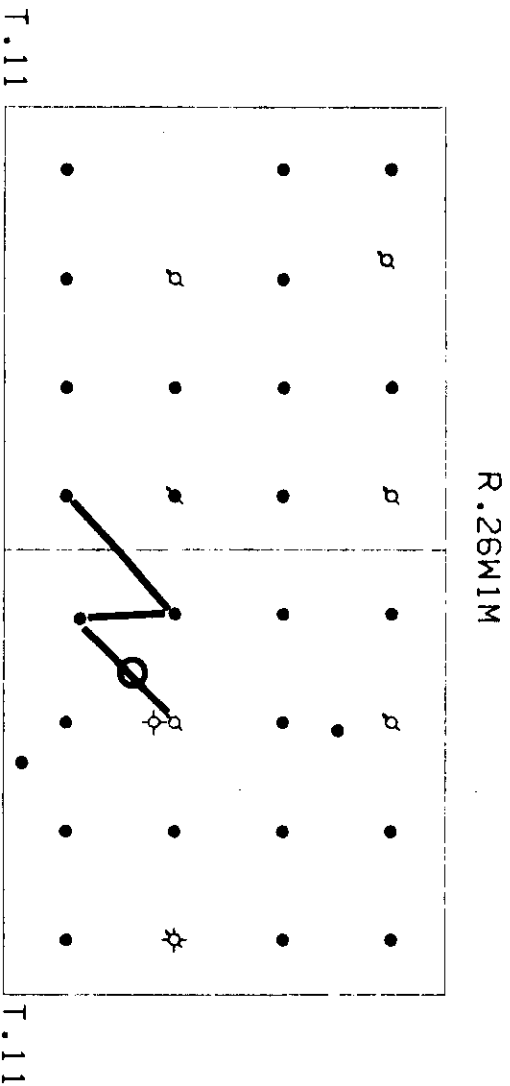
RR: 55-09-17

STATUS: WATER INJECTOR

06-27-011-26W1



DATE	06-27-11
TIME	15:05
USER	06-27-011-26W1
WELL	06-27-011-26W1
STATUS	WATER INJECTOR
RR	55-09-17
FTD	2022
KB	1505
PROJECT	06-27-011-26W1



STICK PLOT CROSS SECTION, STRATIGRAPHIC SECTION, IMPERIAL UNITS  
DATUM -- USER INPUT DEPTHS FOR ALL WELLS  
INTERVAL -- USER INPUT INTERVALS FOR ALL WELLS  
HORIZON PREFERENCE SOURCES --  
1=MEGA 2=COSA  
VERTICAL SCALE -- 1 IN. = 20 FT  
WELL SPACING -- 1.000 INCHES (FIXED)  
INDEX MAP: NATURAL SCALE = 15840.1 INCH = 0.25 MILE(S)

DIGITAL INFORMATION			
TYPE	DESCRIPTION	SOURCE	DATE
WELLS	GENERAL WELL DATA	CAD	31-06-04
MANUAL INFORMATION			
TYPE	DESCRIPTION	SOURCE	DATE
BASIC DATA OVERLAYS			
SYNTH	DESCRIPTION	FILE NO.	LOC. NO.
LOC.			
Chevron Canada Resources			
PROJECT	MAN	CURRENT	SEC/ACT. AREA
NORTH VIRIDEN SCALLION			
INFILL PROGRAM			
SECURITY LEVEL			
CREATED BY FOREST RICHARD			
DATE 31-06-04			
DRAWN BY MITCHELL L. DOWLING			
DATE 31-06-04			
PROJECT 06-27-011-26W1			
DATE 06-27-11			

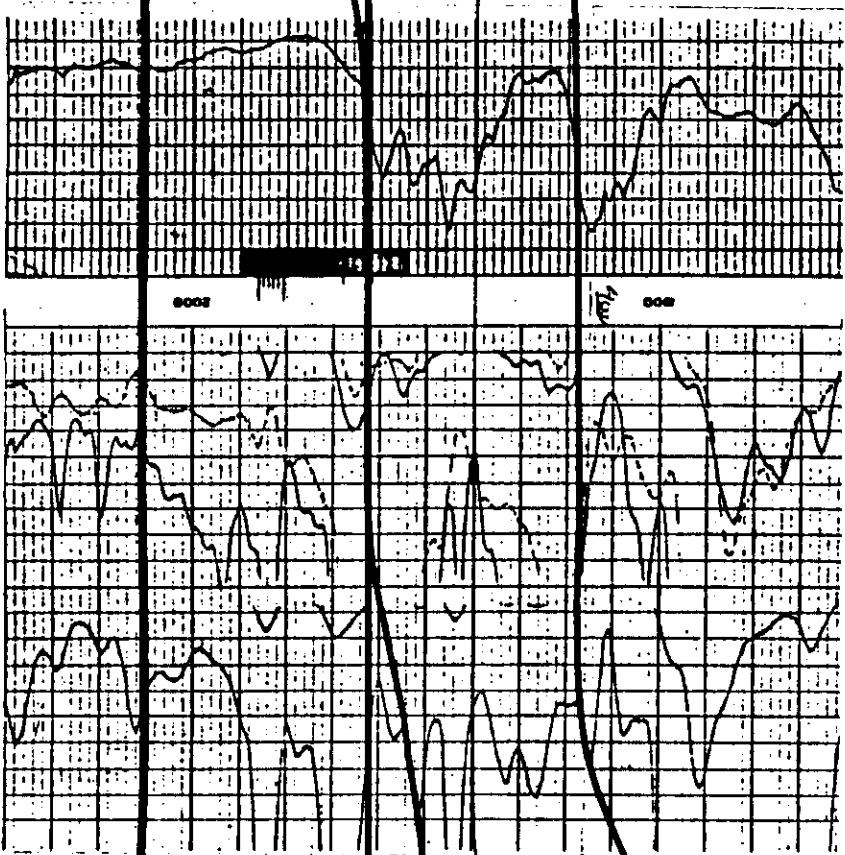
USER DEFINED

DATE	91-06-04
TIME	10:00
BY	ESS
REMARKS	

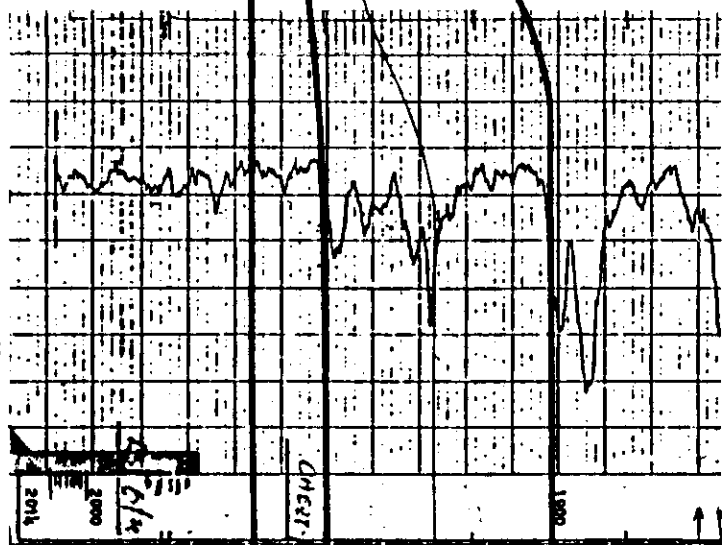
ESSO SCALLION 15-33-11-26  
KB: 1521  
FTD: 2010  
RR: 56-11-17  
STATUS: PUMPING OIL  
15-33-011-26W1  
B.O.P.D. 222  
CUMUL. OIL PROD: 671,290

DOMO CDN SUP SCALLION 1 4 12 26  
KB: 1512  
FTD: 2040  
RR: 58-02-07  
STATUS: PUMPING OIL  
01-04-012-26W1  
B.O.P.D. 283  
CUMUL. OIL PROD: 328,460

VALLAT ET AL SCALLION 1  
KB: 1516  
FTD: 2018  
RR: 58-11-11  
STATUS: WATER  
16-33-011-  
B.O.P.D. 283  
CUMUL. OIL PROD: 328,460



DATE	91-06-04
TIME	10:00
BY	ESS
REMARKS	



DATE	91-06-04
TIME	10:00
BY	ESS
REMARKS	



VALLAT ET AL SCALLION MIM 16-33-11-2

KB: 1516  
FTD: 2018  
RR: 58-11-16  
STATUS: WATER INJECTOR

16-33-011-26W1

PROPOSED  
LOCATION

1a-04

DOME SCALLION MIM 4 3 12 26

KB: 1515  
FTD: 2063  
RR: 58-01-31  
STATUS: WATER INJECTOR

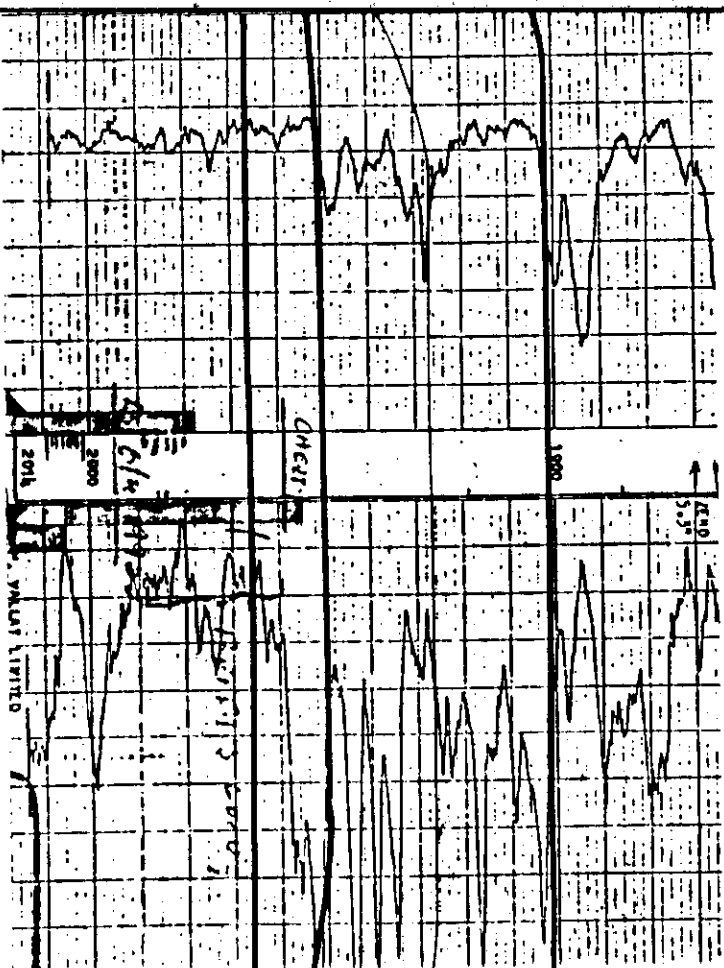
04-03-012-26W1

VALLAT ET AL SCALLION 13 34 11 26

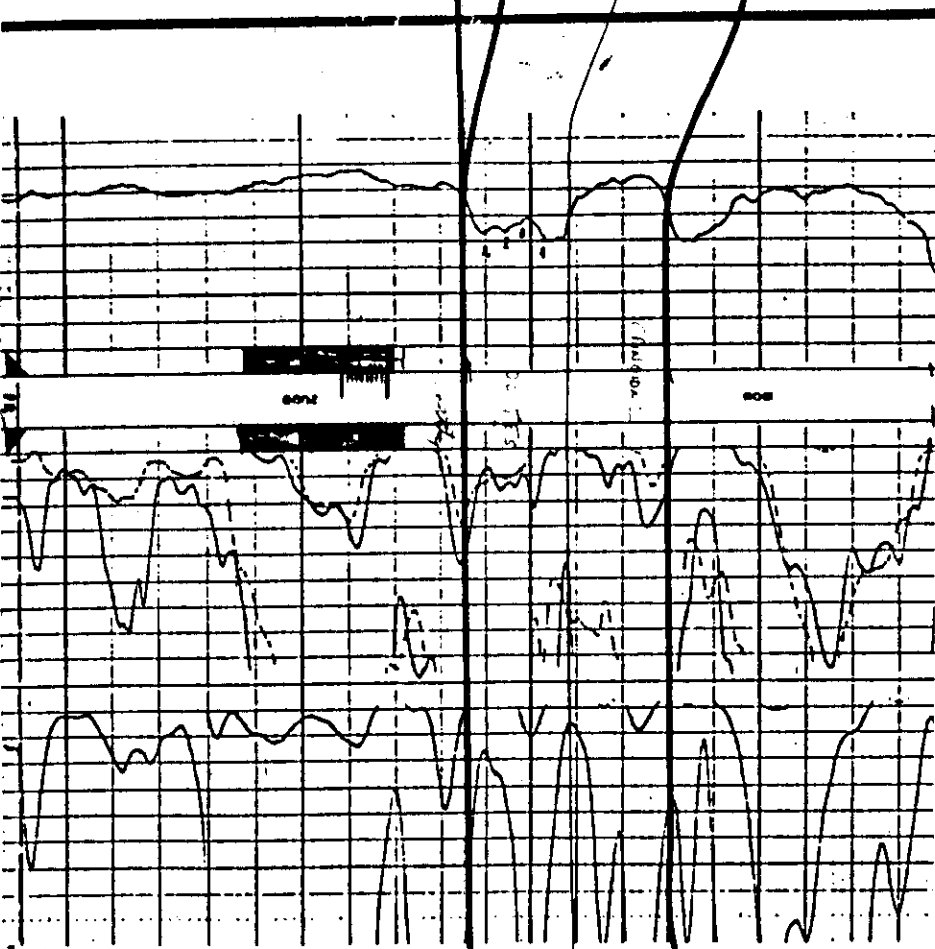
KB: 1516  
FTD: 2006  
RR: 58-10-16  
STATUS: PUMPING OIL

13-34-011-26W1

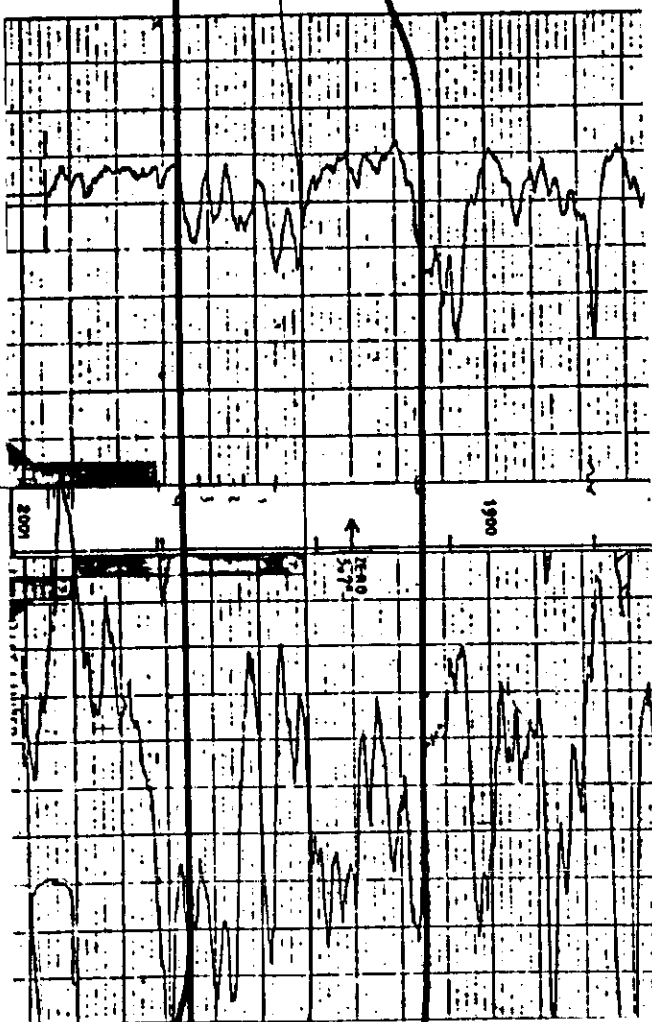
BOPD: 283  
CUMUL OIL PROD: 308,790



TIME	PRESS
0	1850
100	1900
200	1850



TIME	PRESS
0	1850
100	1900
200	1850



TIME	PRESS
0	1850
100	1900
200	1850

11 26

MILESTONE SCALLION 3 3 12 26

KB: 1516

FTD: 2060

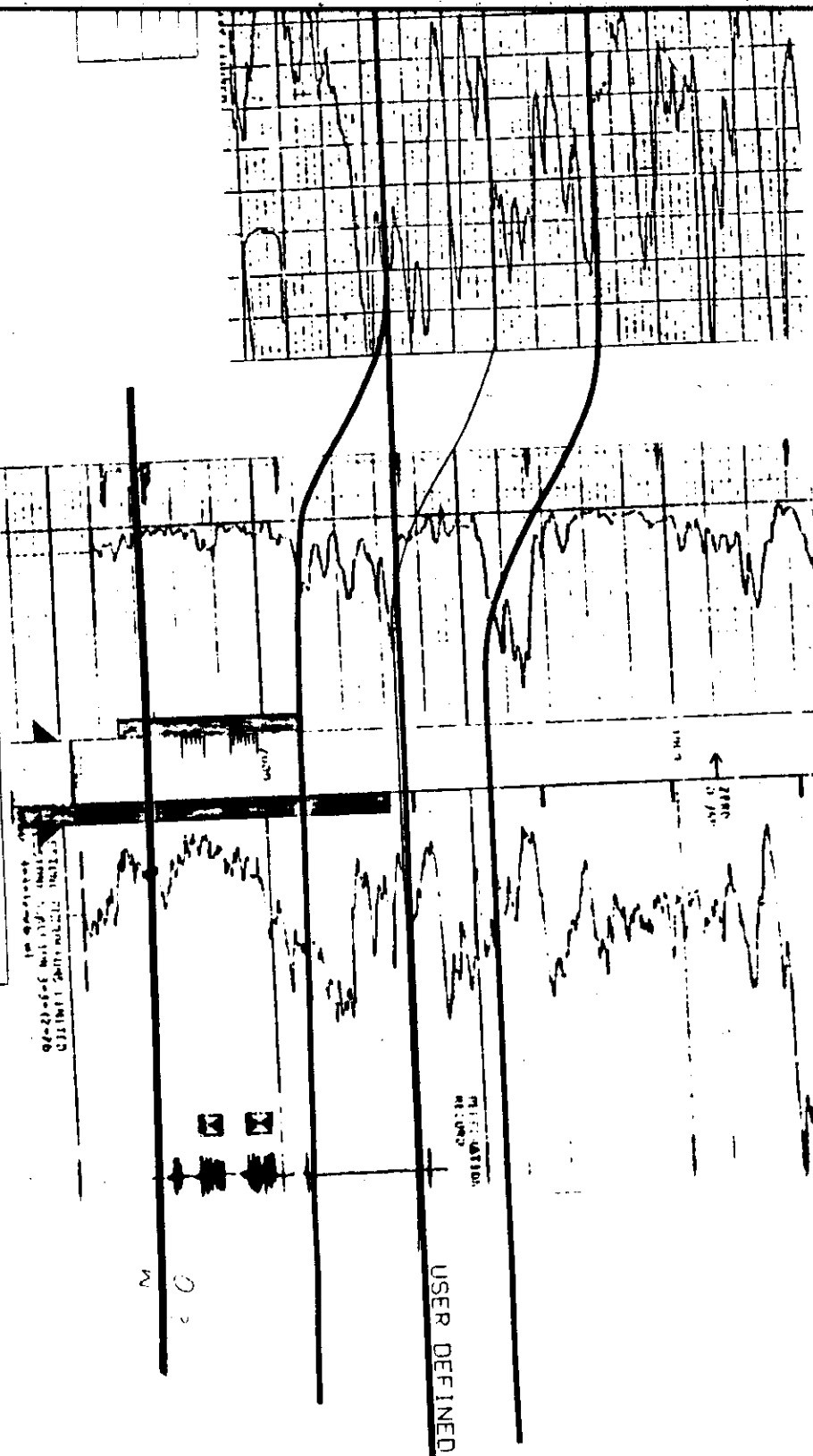
RR: 62-10-19

STATUS: PUMPING OIL

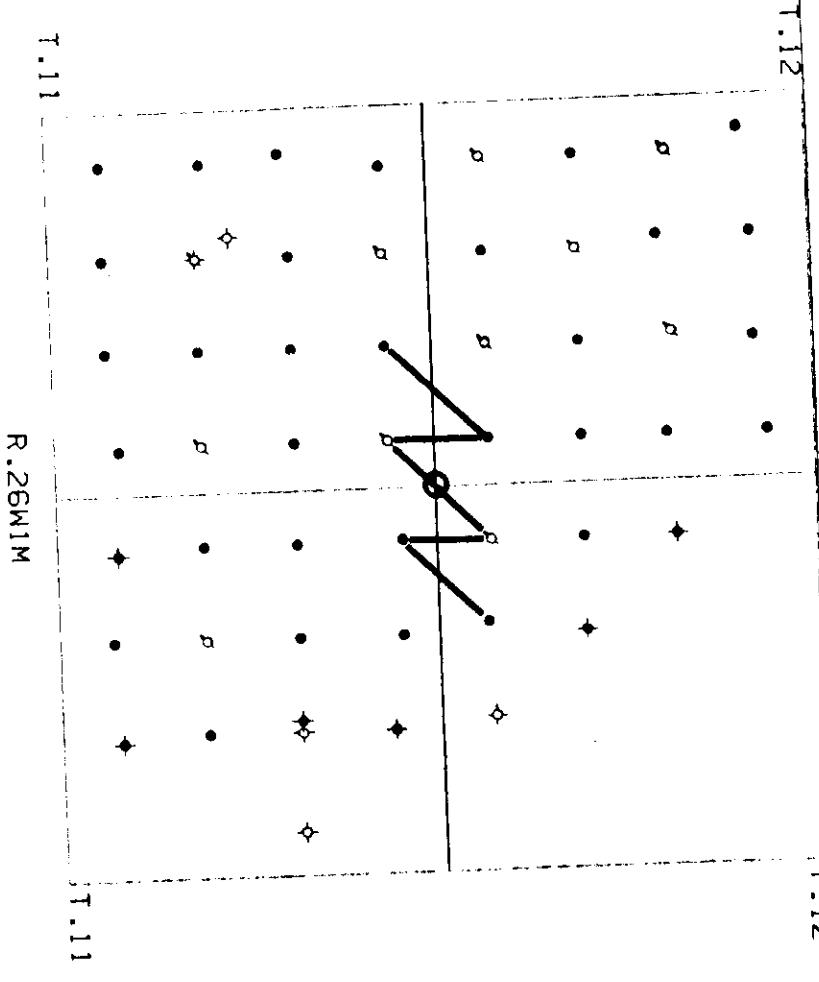
03-03-012-26W1

B.O.P.D: 17.1

CLAMM OIL PROD: 398,250

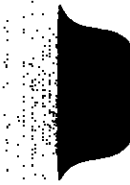


DATE	03/03/01
TIME	15:16
USER	MAN
WELL	03-03-012-26W1
STATUS	PUMPING OIL
RR	62-10-19
FTD	2060
KB	1516



STICK PLOT CROSS SECTION, STRATIGRAPHIC SECTION, IMPERIAL UNITS  
UNIT -- USER INPUT DEPTHS FOR ALL WELLS  
INTERVAL -- USER INPUT INTERVALS FOR ALL WELLS  
HORIZON PREFERENCE SOURCES --  
1=MEGA 2=COSA  
VERTICAL SCALE -- 1 IN. = 20 FT  
WELL SPACING -- 1,000 INCHES (FIXED)  
INDEX MAP: NATURAL SCALE = 15840, 1 INCH = 0.25 MILES

Chevron Canada Resources	
MAN	CURRENT
WELL NAME: 03-03-012-26W1	
WELL TYPE: OIL	
WELL STATUS: PUMPING OIL	
WELL DEPTH: 2060	
WELL KB: 1516	
WELL RR: 62-10-19	
WELL FTD: 2060	
WELL B.O.P.D: 17.1	
WELL CLAMM OIL PROD: 398,250	



## TECHNICAL DISCUSSION OF THE NORTH VIRDEN SCALLION UNIT No. 1 INFILL PROGRAM

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### HISTORY

North Virden Scallion Unit No. 1 was discovered in 1954 and was developed on 40 acre spacing. In 1962, the pool was unitized and waterflooding of the pool started. Between 1974 and 1978, six "corridor" wells were drilled on 20 acre spacing. In 1989, nine 20 acre infills were drilled on the east side of the field.

Current unit recovery is 28% and ultimate recovery is forecasted to be 32% of OOIP. At pool abandonment, North Virden Scallion will have over 130 MM bbls of remaining oil in place. Infill drilling on 20 acre spacing has been evaluated as a method of improving oil recovery from the unit.

### INFILL LOCATION SELECTION

A review of the North Virden Scallion Unit No. 1 has showed that productivity of the wells is somewhat influenced by structure. Usually, downdip wells have higher water cuts and better aquifer support whereas, updip wells have low water cuts and poor aquifer support.

The proposed infills locations are all structurally high except for one location, 7a-21, which is located at the Southwest edge of the field where a natural fracture system is providing excellent oil rates. At this location, surrounding wells have produced more than their recoverable 40 acre OOIP and oil migration must be taking place due to an active aquifer.

The infill locations were selected based on the following criteria:

- 1) areas of the reservoir with better than pool average oil rate
- 2) areas of the reservoir with lower than pool average water cuts
- 3) structurally high areas of the reservoir
- 4) areas of the reservoir which are likely to have incremental oil in all of the Lodgepole members.

These criteria are different from those used to select the Scallion nine 20-acre infills drilled in 1989. An analysis of the pilot is given in Virden Roselea Unit # 1 reduced spacing application, Attachment 5. The Scallion infill pilot was unsuccessful. The performance of the 9 wells has deteriorated further since the analysis was done.

## DISCUSSION

### A. Producing Zones

North Virden Scallion Unit No. 1 produces from two to three members of the Lodgepole Formation. In the Southern part of the pool, the Crinoidal, oolites and Cherty members of the Lodgepole Formation are the producing intervals. In the central and northern part of the pool only the Oolites and the Cherty members are producing. The Cherty reservoir is by far the best reservoir at North Virden Scallion.

The Cherty reservoir has significant permeability variation causing a reduction in sweep efficiency. The reduced well spacing in selected areas will increase both, vertical and areal sweep efficiency. This will result in incremental oil production.

### B. Reservoir Parameters

1. The infill wells have the following reservoirs parameters:

	<u>Average Porosity</u>	<u>Original † Net Pay m</u>	<u>Cherty Sw</u>
7a-21	21%	12.0	34%
05a-27	15%	19.8	34%
01a-04	16%	12.2	34%
Average	12%	12.2	34%

2. The  $\Phi_h$  and Kh maps for the Cherty, Oolites and Crinoidal were constructed using core porosity and permeability where available, and log data for wells without core data (see Attachment 3)

3. The porosity, permeability and water saturation cutoffs used to generate the  $\Phi_h$  and Kh maps for each members are:

$\Phi$ cutoff:	7%
K cutoff:	1mD
Sw cutoff:	55%

4. List of individual OOIP by zone for the offset well surrounding the proposed infill location and reservoir parameter used in Reserves calculation.

	<u>Crinoidal (bbls.)</u>	<u>Oolites (bbls.)</u>	<u>Cherty (bbls.)</u>
7a-21 † OOIP	453,953	284,000	6.5 MM
5a-27 † OOIP	567,440	284,000	7.6 MM
01a-04 † OOIP	0	0	4.9 MM
1-SW	48%	50%	66%
FVF	1.05	1.05	1.05
$\Phi_{Av}$	10%	10%	12-18%

K > 1md

† OOIP by zone using 160 acres and data from 4 surrounding wells to infill location.

### C. Proposed Completion

The infill wells will be completed such that the Crinoidal, Oolites and Cherty zones will be left open for production. The following tables summarize the current offset well and proposed infill well completion.

↓ cross the ground and down to Table 1

	Production BOPD	Depth of Casing Shoe	Casing Shoe Landed at	Producing Zones					Cherty Thickness Drilled
				Crinoidal	1st	2nd	3rd	4th & Cherty	
07a-21†	66	1980	Crinoidal	✓	✓	✓	✓	✓	40'
02-21	224	2019	Cherty	--	--	--	--	✓	39'
08-21	34	2020	Cherty	--	--	--	--	✓	53'
01-21	18	2031	Cherty	--	--	--	--	✓	30'
07-21	13	2020	Cherty	--	--	--	--	✓	34'
ORIGINAL O/W CONTACT @ -560 FT.									
05a-27†	38	1920	Crinoidal	✓	✓	--	✓	✓	50'
05-27	27	1998	Cherty	--	--	--	--	✓	64'
04-27	66	1996	Cherty	--	--	--	--	✓	58'
03-27		Cased	Bakken	--	--	--	--	✓	Perf.
06-27	W.I.	1973	Cherty	--	--	--	--	✓	50'
06A-27	Ab.	--	--	--	--	--	--	✓	--
ORIGINAL O/W CONTACT @ -525 FT.									

† Recommended Completion

	Current Production BOPD	Depth of Casing Shoe	Casing Shoe Landed at	Producing Zones					Cherty Thickness Drilled
				Crinoidal	1st	2nd	3rd	4th & Cherty	
01a-04†	25	1900	Crinoidal	Tight	✓	✓	--	✓	45'
01-04	28	2020	Below O/W	--	--	--	--	5 ft.	86'
04-03	W.I.	T.D.	T.D.	--	--	--	--	10 ft.	95'
16-33	W.I.	T.D.	T.D.	--	--	--	--	8 ft.	60'
13-34	28	T.D.	T.D.	--	--	--	--	5 ft.	33'
ORIGINAL O/W CONTACT @ -500 FT.									

† recommended completion

✓ indicate zone is open or perforated for production

#### **D. Present Performance of Proposed Infill Areas**

Recoveries, current oil rates, and WORs are shown in Table I for each infill area.

#### **E. Incremental Reserves**

The incremental recovery for the four proposed infill wells will be 17 200 m<sup>3</sup>. This represents 2.3% of the total OOIP for the three infill wells.

#### **F. Pressure Maintenance**

All water injectors surrounding the proposed infills are completed in the cherty member. Chevron has not run any injection profile logs to evaluate the vertical distribution of injected fluids.

Reservoir pressure is increasing throughout the unit as shown in Attachment 5, so no additional injection will be required initially. Pressure will continue to be monitored throughout the unit.

#### **G. Production Forecast**

##### **1. Base Case Production Forecast**

The base case production forecast was developed using decline analysis on the production history for the entire unit. This is shown in Figure 7. Oil production is declining at 6.4% per year. ✓  
Table II and Figure 8 show the base case production forecast for the entire unit.

##### **2. Reduced Spacing Production Forecast**

The reduced spacing project production forecast has been developed based on incremental and accelerated production from infill drilling. The following assumptions were made:

- 1 - 1992-01 start date.
- 2 - Project forecast is for thirty years. Incremental recovery for each infill well will be 2.3% of the OOIP in the area affected by the infill well.
- 3 - The water cut forecast is the same for both the base case and infill case.
- 4 - Predicted oil rates and WOR for the infill wells were based on the performance of the adjacent producers.
- 5 - The adjacent producers will experience accelerated decline in 1993-01.
- 6 - Accelerated production associated with each infill well was assumed to be 1/4 of the adjacent producers' reserves.

The production forecast for the infill wells was developed based on the performance of the 14a-27-11-26W1M infill well and predicted incremental recovery of 17 200 m<sup>3</sup> during the project forecast period.

a) - Performance of 14a-27-11-26W1M

Infill well 14a-27 came on stream on January 28th, 1971. Figure 1 shows the oil rate, cumulative oil, WOR and water rate vs. time graphs. It came on with a rate of 9 m<sup>3</sup>/day and WOR of 0. The average rate for the surrounding wells was 11 m<sup>3</sup>/day and the average WOR was 0.3. Plots for these surrounding wells are shown in Figures 2 to 6. It is expected that the 3 infill wells will also have a rate and WOR close to the average values of the adjacent wells.

The adjacent wells to 14a-27 experienced interference within one year. Accelerated decline after one year was used in this project.

b) - Predicted incremental recovery of 17 200 m<sup>3</sup>

Based on the project constraints listed above, the expected incremental production will be 2.3% of OOIP for each infill well for the project period. This is a reasonable number based on the work done for the Daly Unit # 3 reduced spacing application.

Infill well reserves were determined using a process of constraints. The infill well incremental and accelerated reserves were calculated. New reserves were calculated for the adjacent wells by subtracting the accelerated production. The infill and existing well production were then declined to generate calculated reserves. The calculated decline rates were used to generate the reduced spacing forecast, shown in Table II and Figure 8.



UNIT: ALT. REC. = 32% OIL

Table I - Performance of Producers in Infill Areas

7a-21-11-26-W1M Area

Expected Initial Rate = 5.0 m<sup>3</sup>/dayDRAINAGE  
AREA  
ASSUMED  
AVER. ALT. REC.

WELL	OIL RATE (m <sup>3</sup> /day)	WOR	OOIP (m <sup>3</sup> )	CURRENT RECOVERY (%)	ULTIMATE RECOVERY BASE CASE
7-21	1.8	15.3	260 519	38.79	41.71
2-21	36.8	6.7	260 519	64.26	110.70
8-21	4.9	5.2	260 519	62.86	71.71
1-21	2.8	4.5	260 519	56.69	59.73
AVG/SUM	11.59	7.93	1 042 076	55.65	70.76

HA.

21

55

30

30

127.70

NO INJECT INJECTION

RTH REC RES  
157568

5a-27-11-26-W1M Area

Expected Initial Rate = 4.0 m<sup>3</sup>/day

ADP 6955

WELL	OIL RATE (m <sup>3</sup> /day)	WOR	OOIP (m <sup>3</sup> )	CURRENT RECOVERY (%)	ULTIMATE RECOVERY BASE CASE
5-27	4.3	4.2	302 389	37.63	41.87
3-27	3.2	1.9	302 389	23.31	33.20
4-27	9.7	0.9	302 389	46.89	58.07
AVG/SUM	5.73	2.33	907 167	35.95	44.38
5-27 W1W	5.73	2.33	302 389		

21

17

29

209356

RTH REC RES  
76568

1a-21-11-26-W1M Area

Expected Initial Rate = 4.0 m<sup>3</sup>/day

ADP 4855

WELL	OIL RATE (m <sup>3</sup> /day)	WOR	OOIP (m <sup>3</sup> )	CURRENT RECOVERY (%)	ULTIMATE RECOVERY BASE CASE
1-04	4.3	0.9	198 491.3	26.65	44.28
13-34	4.4	3.3	198 491	25.04	31.79
AVG/SUM	4.35	2.10	396 982.3	25.84	38.04
16-33 W1W	4.35	2.10	198 491		
4-3 W1W	4.35	2.10	198 491		

22

16

793964

RTH REC RES  
48392

Table II

**NORTH VIRDEN SCALLION UNIT # 1**  
**REDUCED SPACING FORECASTS FOR ENTIRE UNIT**

YEAR	BASE CASE (m <sup>3</sup> /day)	UNIT NEW OIL %†	INFILL CASE (m <sup>3</sup> /day)	UNIT NEW OIL %†	INFILL WELL PRODUCTION
1992	319.20	0.84	332.20	4.74	12.96
1993	298.64	0.40	305.92	4.45	12.00
1994	279.41	0.20	284.56	4.33	11.75
1995	261.42	0.11	264.76	4.31	11.12
1996	244.58	0.00	246.76	4.27	10.54
1997	228.83	0.00	230.02	4.34	9.98
1998	214.10	0.00	214.55	4.41	9.46
1999	200.31	0.00	200.24	4.48	8.97
2000	187.41	0.00	187.00	4.55	8.51
2001	175.34	0.00	174.72	4.62	8.07
2002	164.05	0.00	163.33	4.69	7.66
2003	153.49	0.00	152.76	4.76	7.27
2004	143.60	0.00	142.94	4.83	6.90
2005	134.36	0.00	133.81	4.89	6.56
2006	125.70	0.00	125.30	4.96	6.21
2007	117.61	0.00	117.39	5.03	5.86
2008	110.03	0.00	110.01	5.10	5.51
2009	102.95	0.00	103.13	5.17	5.16
2010	96.32	0.00	96.72	5.24	4.81
2011	90.12	0.00	90.72	5.31	4.46
2012	84.31	0.00	85.13	5.38	4.11
2013	78.88	0.00	79.90	5.45	3.76
2014	73.80	0.00	75.01	5.52	3.41
2015	69.05	0.00	70.43	5.59	3.06
2016	64.60	0.00	66.15	5.67	2.71
2017	60.44	0.00	62.14	5.74	2.36
2018	56.55	0.00	58.39	5.82	2.01
2019	52.91	0.00	54.87	5.89	1.66
2020	49.50	0.00	51.58	5.97	1.31
2021	46.31	0.00	48.48	6.05	0.96
2022	43.33	0.00	45.59	6.12	0.61

† Unit production that will incur new oil royalty.

1576676  
 TOTAL NEW OIL

74759.3

Figure 1  
Infill Well 14-27 A

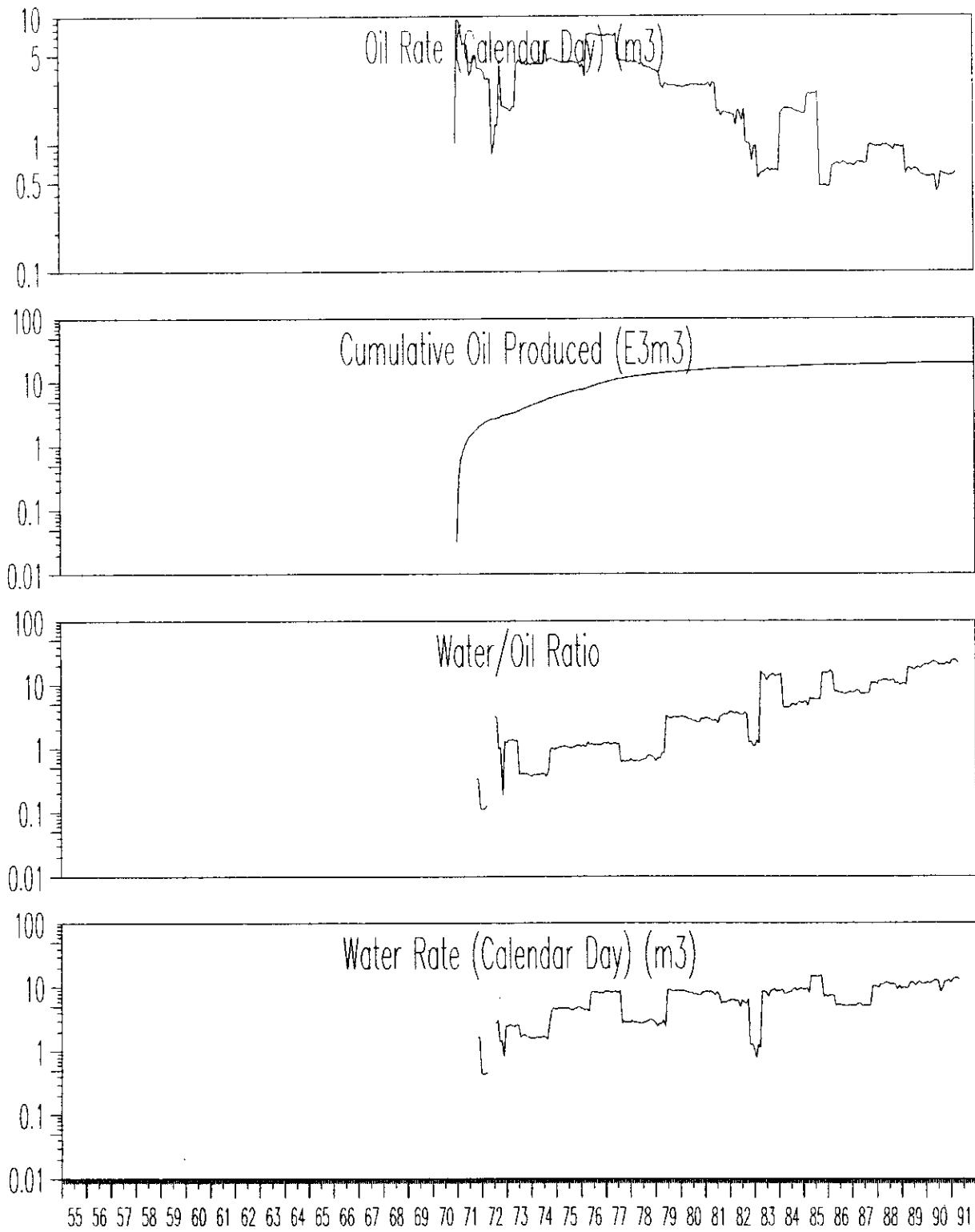


Figure 2

10-27

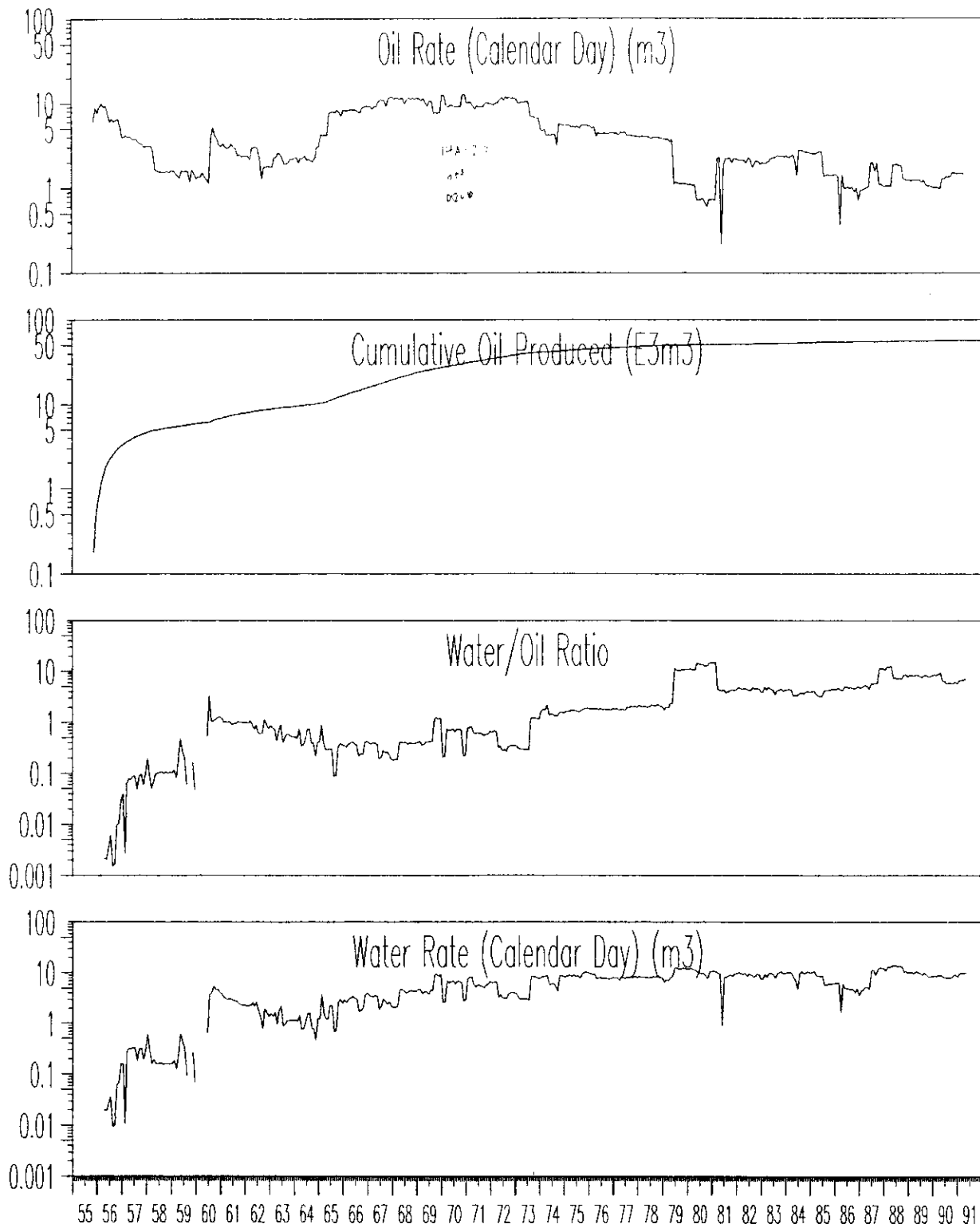


Figure 3

11-27

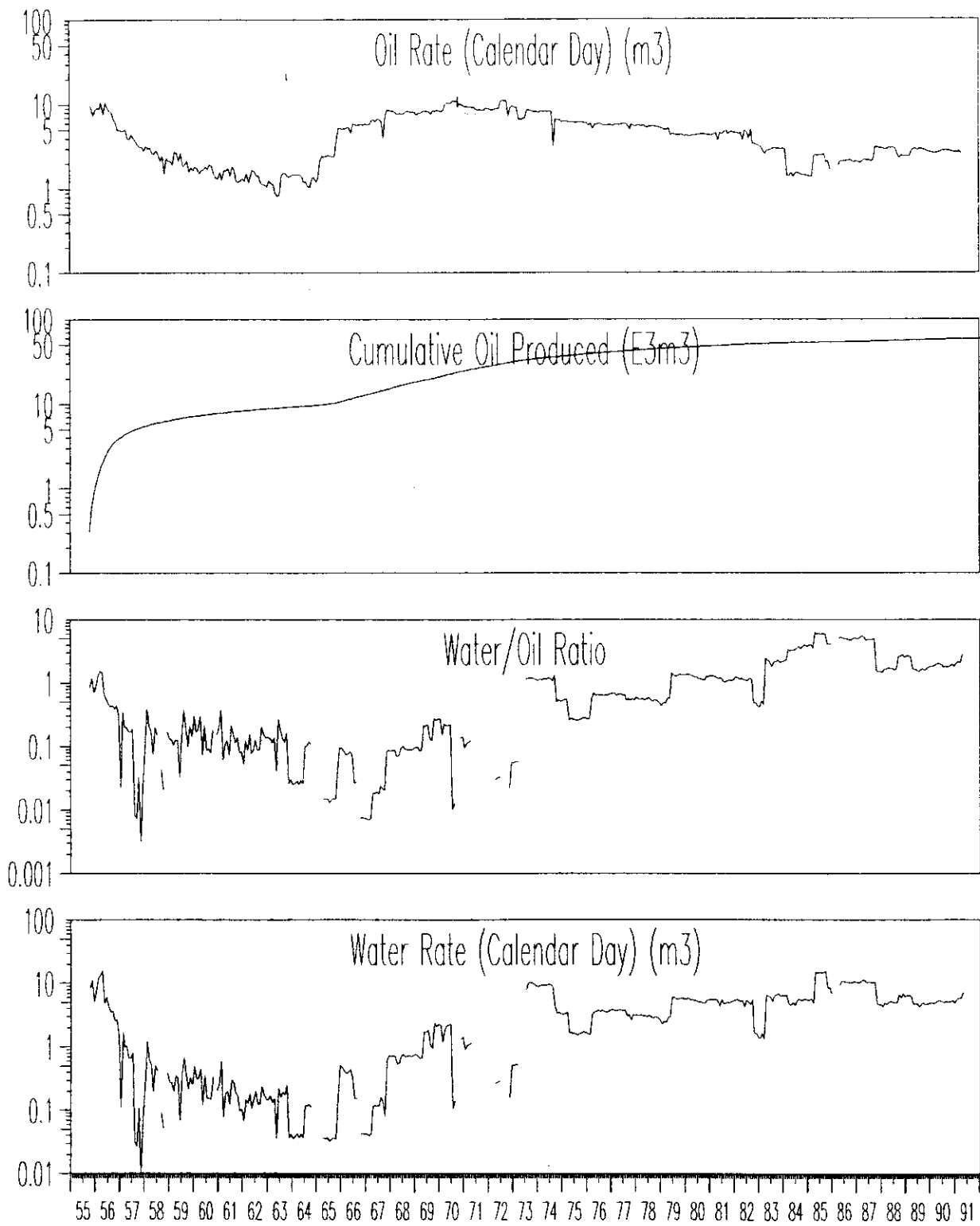


Figure 4

12-27

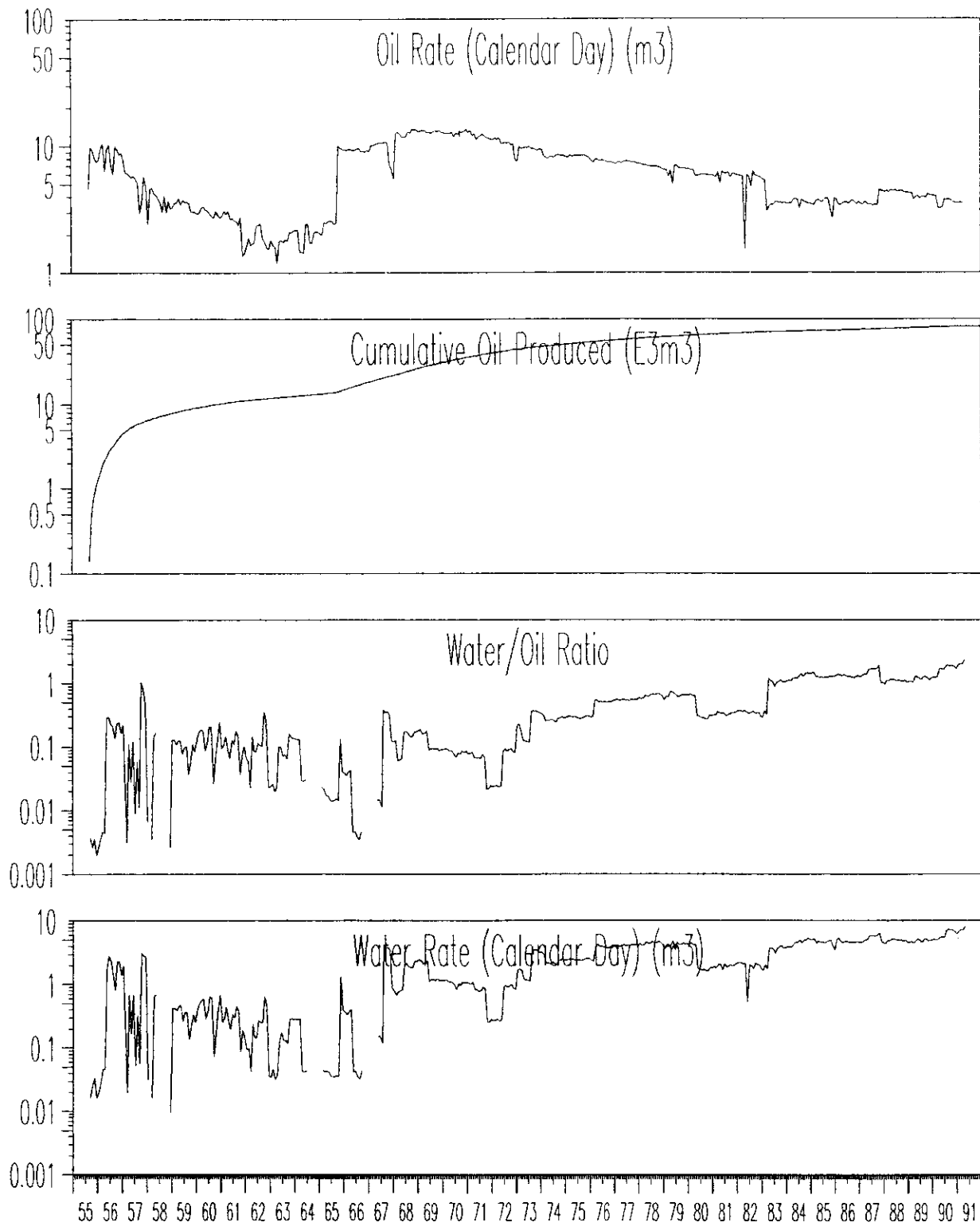


Figure 5

13-27

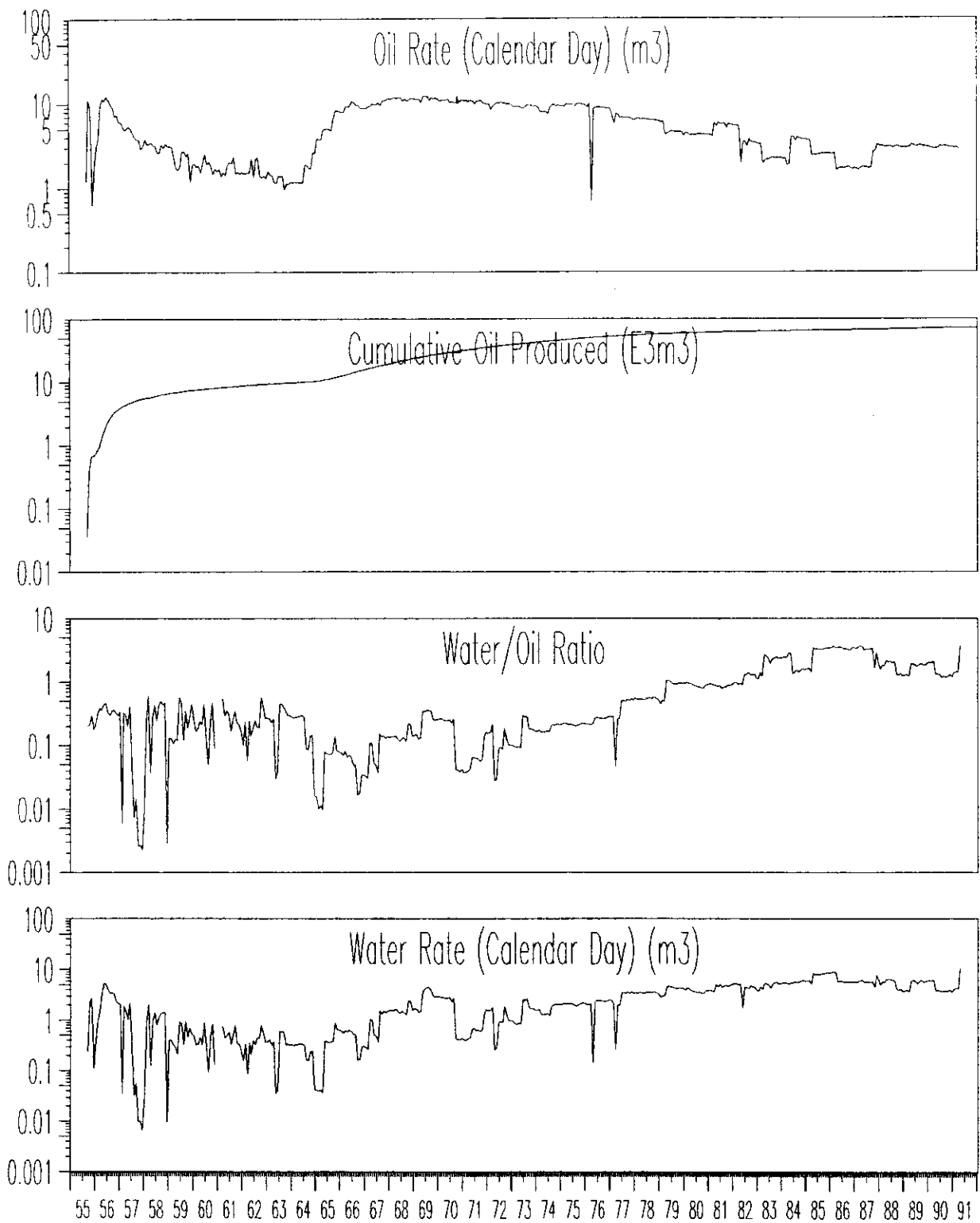


Figure 6

15-27

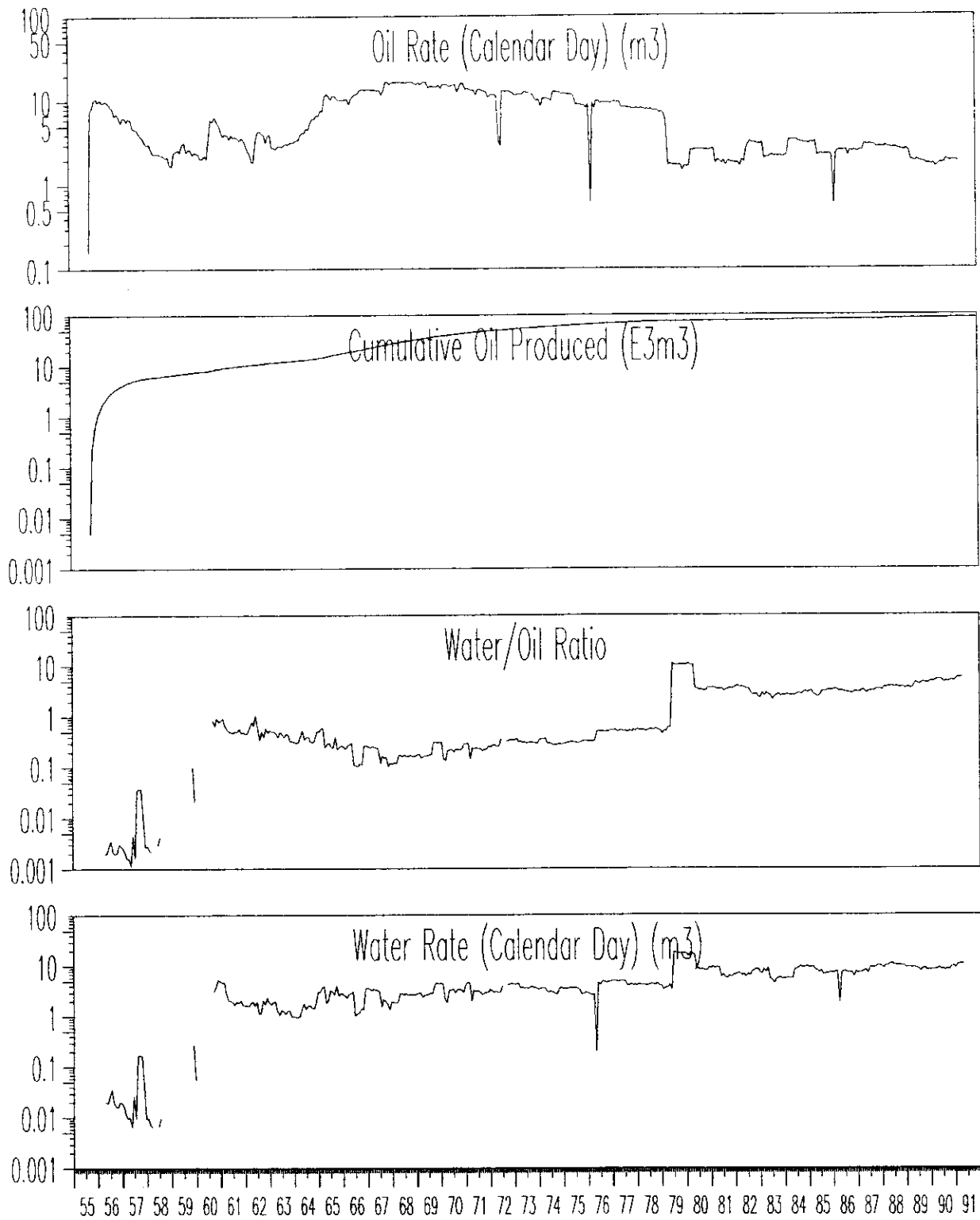
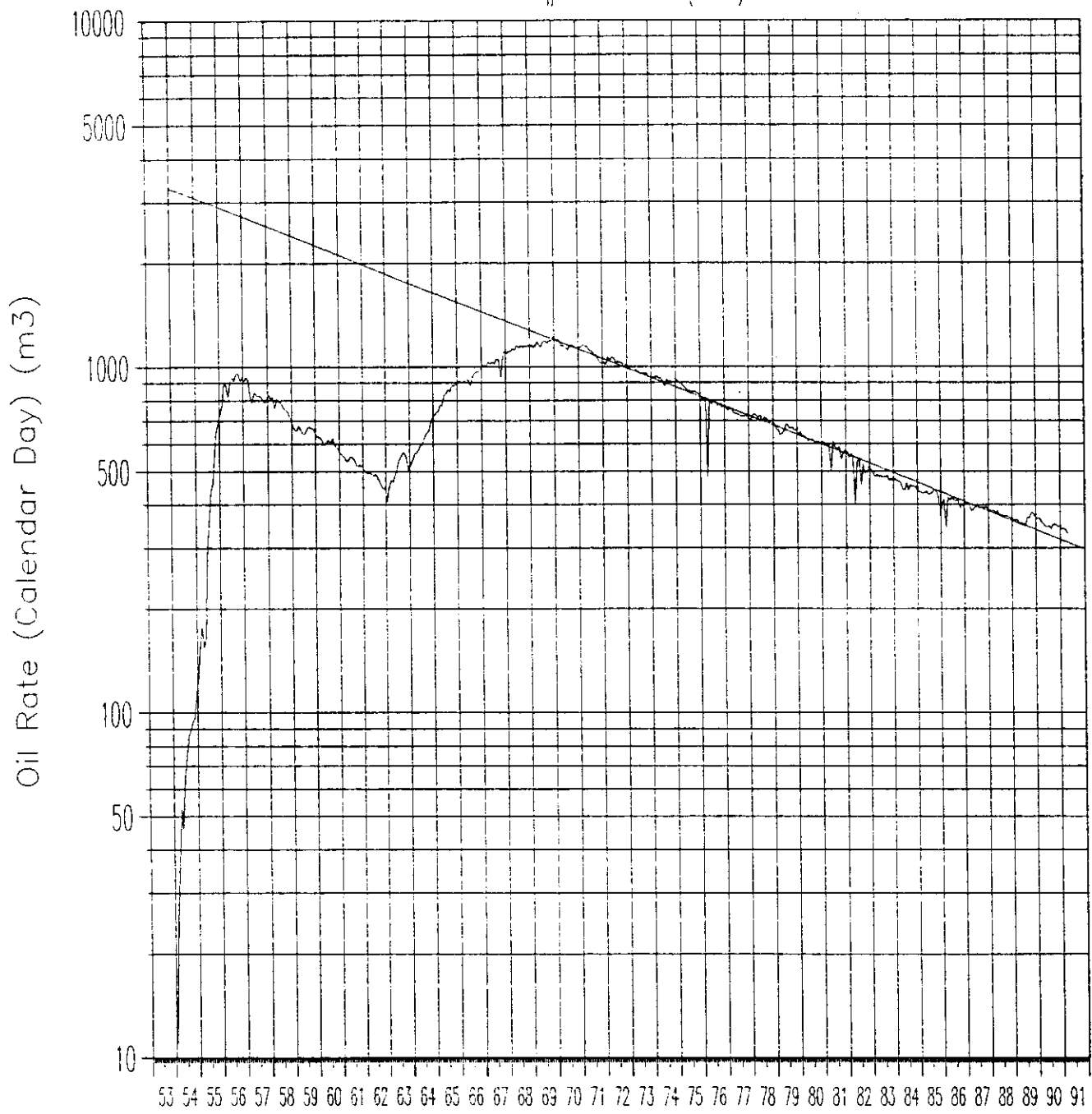


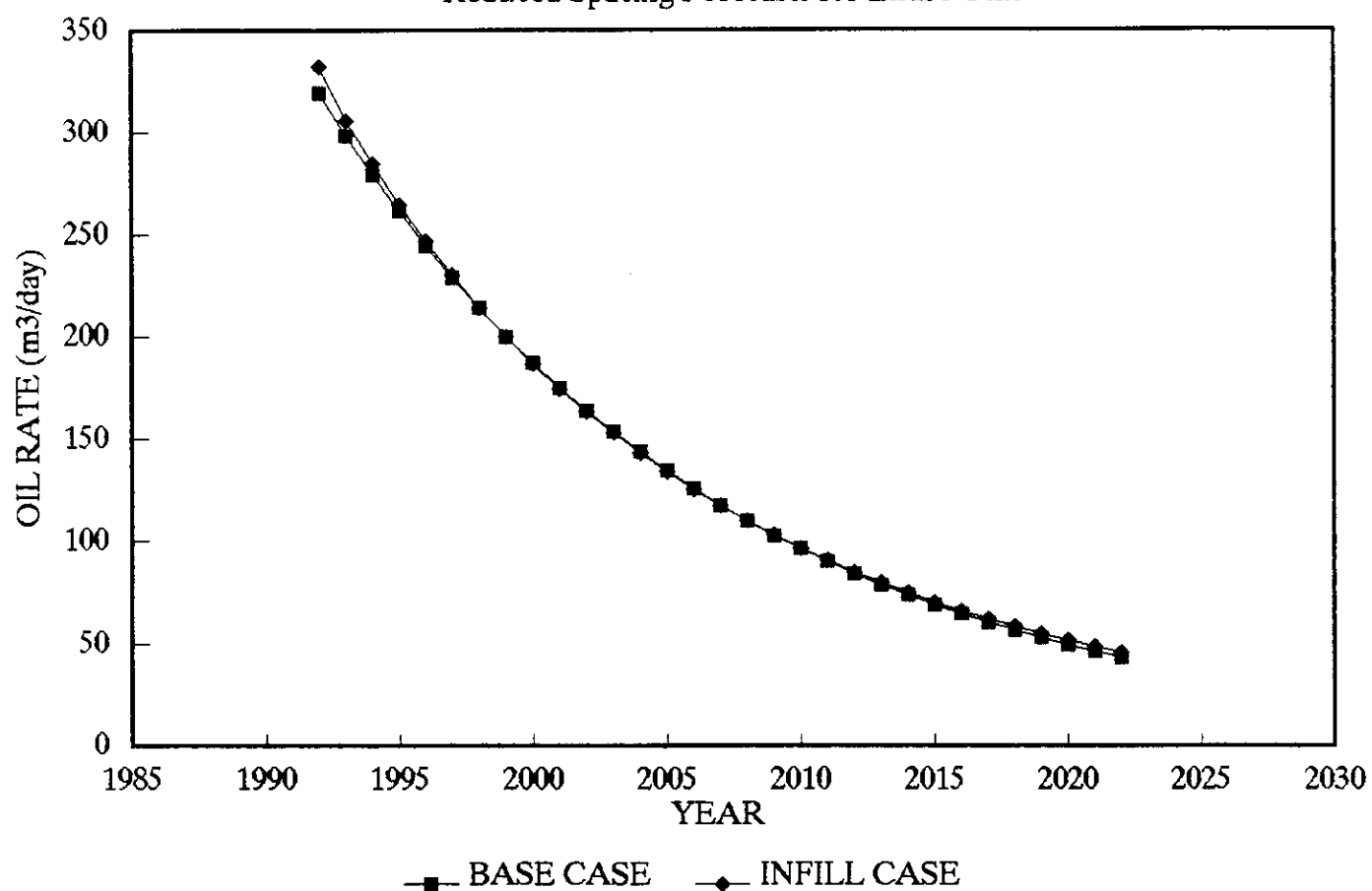


Figure 7  
NVSU #1 All Wells (248)



## Figure 8 – NVSU #1

Reduced Spacing Forecasts for Entire Unit



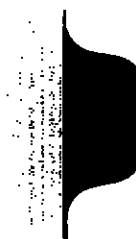


**PRESSURE SURVEY RESULTS**  
**NORTH VIRDEN SCALLION UNIT NO. 1**

<u>WELL LOCATION</u>	<u>DATUM DEPTH PRESSURES (kPa)</u>		
	1990	1989	1987
11-02-11-26W1	10054		7667
6-10			8420
13-10	5905		
10-11	10257		9768
13-11	10320		
10-13	10257		11270
11-13			11357
4-14			8233
9-14			8212
10-14	8618		7425
2-15			8655
10-15	10049		
8-16			5106
10-21	8209		
11-21			7149
4-22	7753		7560
12-22			6130
9D-23	7680	7680	
11D-23	8541	8271	
12-23-1	10054		7240
14d-23	8914		
15-23	8854		
15d-23	10291	8163	
16-23		9045	
6-24		8265	
12-24	9153		
13-24		9176	

**WELL LOCATION****DATUM DEPTH PRESSURES (kPa)**

	<b>1990</b>	<b>1989</b>	<b>1987</b>
13c-24		7715	
1-26		9045	
1d-26	9388	8066	
2d-26		8142	
3-26	8661	8518	8220
3d-26		7894	
6-26	10285	9216	7120
1-27			8174
2-27	7870		7709
14-27	9505		7125
8-28	9998		7625
14-28	9823		7985
16-32	6196		6086
6-33	6869		
6-34	10593		7565
4-03-12-26W1	7118		
6-03			7500
6-04	8218		7030
7-05-12-26W1			6020



NORTH VIRDEN SCALLION UNIT #1 INFILL PROJECT  
CROWN ROYALTIES AND MINERAL TAXES

DATE	BASE CASE			INFILL CASE		
	CROWN ROYALTY (E3 \$)	MINERAL TAX (E3 \$)	FREEHOLD ROYALTY (E3 \$)	CROWN ROYALTY (E3 \$)	MINERAL TAX (E3 \$)	FREEHOLD ROYALTY (E3 \$)
1992	255	2267	1940	202	1682	2021
1993	240	2088	1892	241	2076	1934
1994	229	1944	1877	228	1909	1908
1995	219	1808	1868	216	1753	1890
1996	205	1656	1841	202	1589	1855
1997	193	1500	1804	188	1422	1812
1998	181	1357	1774	176	1273	1777
1999	170	1217	1741	163	1132	1740
2000	158	1084	1704	151	999	1701
2001	149	971	1691	142	885	1685
2002	140	864	1680	134	783	1674
2003	132	764	1667	126	689	1661
2004	124	672	1656	118	601	1650
2005	117	587	1646	111	524	1641
2006	108	506	1624	103	450	1621
2007	107	465	1604	96	386	1603
2008	99	395	1580	88	327	1582
2009	90	334	1559	86	292	1565
2010	83	280	1540	80	245	1549
2011	76	230	1501	73	201	1514
2012	69	187	1462	67	161	1480
2013	63	150	1426	62	130	1448
2014	57	117	1389	57	100	1415
2015	52	91	1354	52	79	1385
2016	48	69	1319	48	58	1354
2017	43	50	1285	44	43	1324
2018	40	36	1251	40	29	1295
2019	36	23	1218	37	20	1267
2020	33	15	1186	34	13	1239
2021	30	10	1155	31	8	1212
2022	0	0	1125	0	0	1187
TOTAL	3546	21737	48359	3396	19859	48989

(Base Case) 1992

loss of royalties - 150 - 53  
" " taxes - 1212 - 585

1992

Freehold Royalties  
increase \$630

1

1992  
1993  
1994  
1995  
1996  
1997  
1998  
1999  
2000  
2001  
2002  
2003  
2004  
2005  
2006  
2007  
2008  
2009  
2010  
2011  
2012  
2013  
2014  
2015  
2016  
2017  
2018  
2019  
2020  
2021  
2022

CROWN ROYALTIES AND MINERAL TAXES DISCOUNTED AT 10%

CASE	TOTAL CROWN ROYALTY (E3M3)	DISCOUNTED CROWN ROYALTY (E3M3)	TOTAL MINERAL TAX (E3M3)	DISCOUNTED MINERAL TAX (E3M3)
BASE	3546	1758	21737	13061
INFILL	3396	1669	19859	11954

Loss

-150

-89

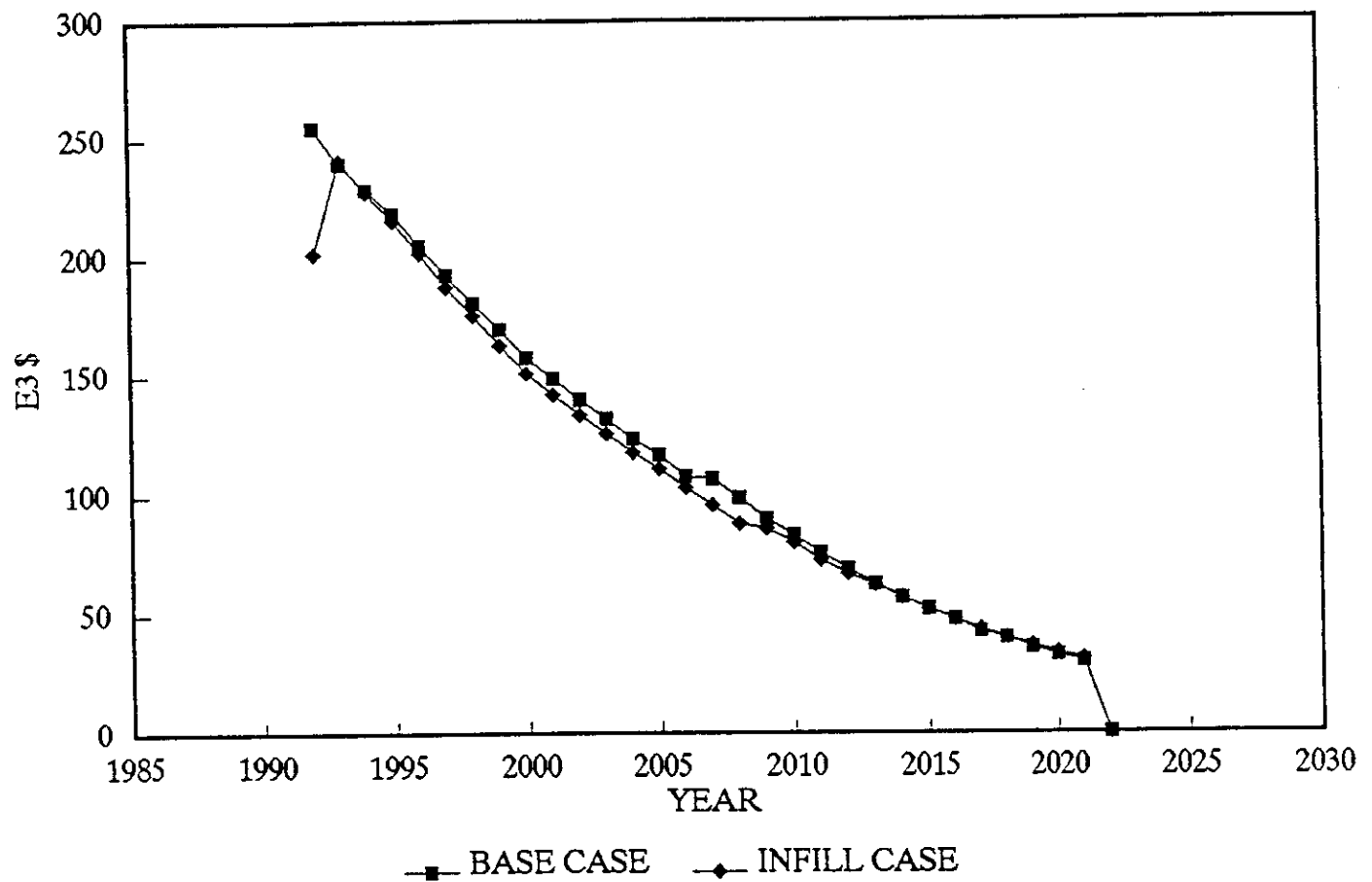
-1876

-1107



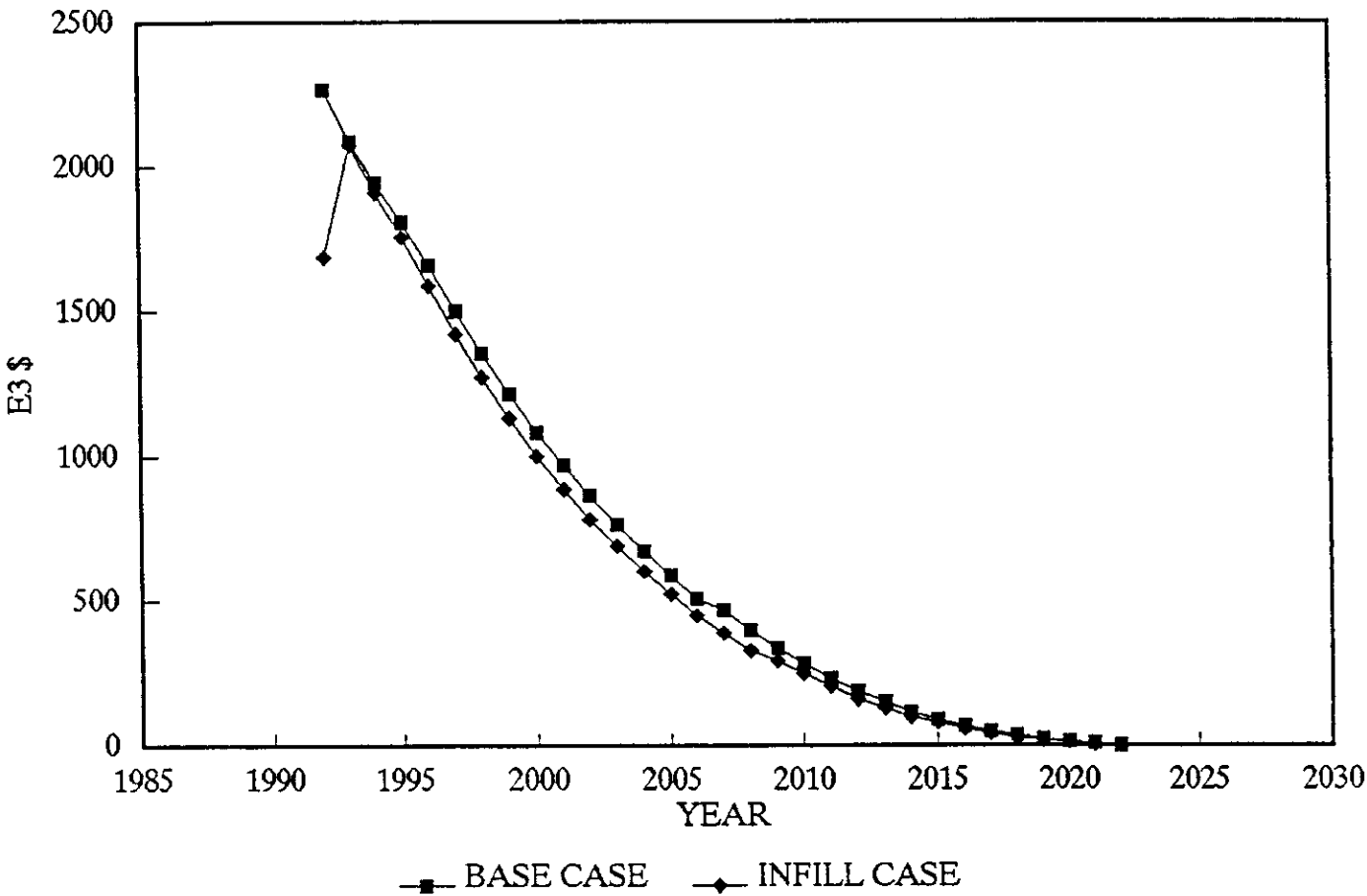
# NORTH VIRDEN SCALLION UNIT #1

Crown Royalties vs. Time



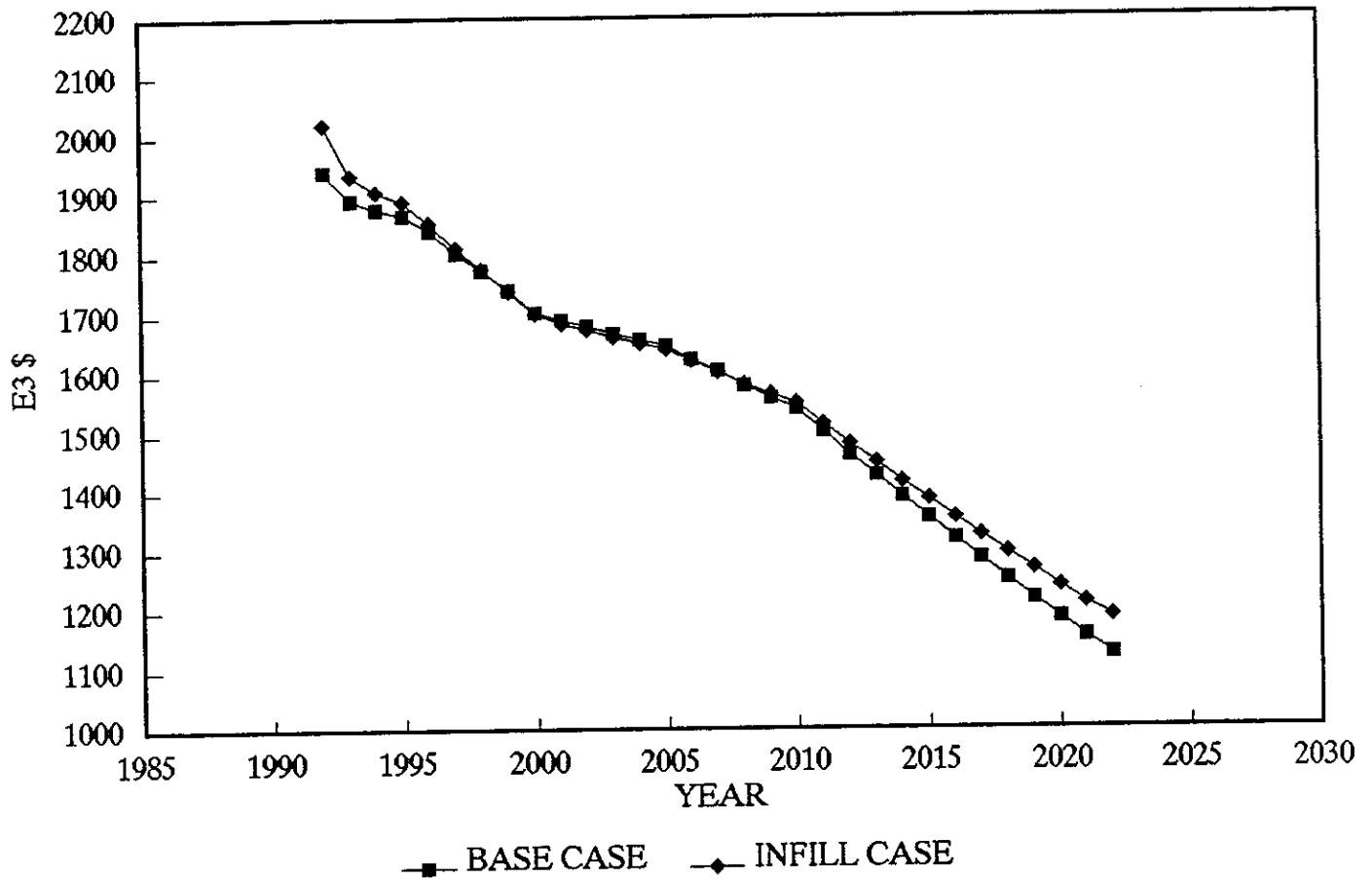
# NORTH VIRDEN SCALLION UNIT #1

Mineral Taxes vs. Time



# NORTH VIRDEN SCALLION UNIT #1

Freehold Royalties vs. Time





17

**ENVIRONMENTAL IMPACT ASSESSMENT OF THE  
CHEVRON REDUCED SPACING PROJECT IN  
NORTH VIRDEN SCALLION UNIT NO. 1**

**Prepared By**

**Chevron Canada Resources  
Environment, Safety and Regulations Division**

**July, 1991**

**ENVIRONMENTAL IMPACT ASSESSMENT OF THE  
CHEVRON REDUCED SPACING PROJECT IN  
NORTH VIRDEN SCALLION UNIT NO. 1**

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The purpose of this assessment is to evaluate impacts which may result on the surrounding environment from the proposed Chevron Canada Resources reduced spacing project in North Virden Scallion Unit No. 1.

The following are the main issues which must be addressed:

1. Disposal of drilling fluids on drill sites;
2. Risk to water supplies from drilling operations;
3. Surface impact from the installation of flowlines;
4. Oil and salt water spills from flowline and water injection line failures;
5. Risk to water supplies from oil and salt water spills;
6. Control of weed growth around production facilities;
7. Impact on Surface Operations.

The following preventative measures and contingency actions will be employed by Chevron to address these impacts:

**1. DISPOSAL OF DRILLING FLUIDS ON DRILL SITES**

Chevron and our contractors will strictly adhere to the Manitoba Energy and Mines Petroleum Drilling and Production Regulations in the reduced spacing project which ensure that drilling fluids are disposed of in an environmentally safe manner and that the drill site is fully restored. As with other existing wells in North Virden Scallion Unit No. 1, water based drilling muds will be used in the reduced spacing project and the use of oil and salt based muds is not anticipated.

**2. RISK TO WATER SUPPLIES FROM DRILLING OPERATIONS**

It is the policy of Chevron and our contractors to strictly adhere to surface casing requirements and cementing procedures during drilling operations as are presented in the Manitoba Energy and Mines Petroleum Drilling and Production Regulations. These requirements during drilling operations ensure the protection of shallow aquifers used for domestic potable water.

3. **SURFACE IMPACT FROM LEASE CONSTRUCTION AND FLOWLINE INSTALLATION**

The possible impacts to agricultural soil during lease construction and flowline installation are mixing of topsoil with subsoil, compaction of the topsoil and loss of topsoil. To address these concerns, Chevron will institute procedures, in consultation with the landowner, to strip and stockpile the topsoil during lease construction and before the flowline is installed. The topsoil will be replaced after the well is drilled and the flowline is in place. These procedures will prevent soil mixing and topsoil compaction and will ensure topsoil is conserved so that the productive capability of the soil is maintained. To minimize ground disturbance a wheel ditcher will be utilized for flowline trench construction wherever possible and Chevron, in consultation with the landowner, will ensure construction activities are conducted within the flowline right of way.

4. **SPILLS FROM FLOWLINE AND WATER INJECTION LINE FAILURES**

To repair equipment and to reclaim land damaged by a spill is very costly. It is in the best interest of Chevron to institute programs which will minimize the probability of spills occurring. The major cause of spills in the Virden area is from corrosion of steel in flowlines.

To greatly reduce the probability of corrosion in flowlines in the reduced spacing project, Chevron will utilize top grade construction materials and will employ well qualified inspectors to oversee construction activities and to ensure quality control is maintained throughout construction.

Chevron wherever practical will construct flowlines and water injection lines of non-corrodible fiberglass pipe. Remaining flowlines and water injection lines will be constructed of steel. Steel flowlines and water injection lines will have non-corrodible polyethylene outer jackets and, as an extra safeguard, will be cathodically (electrically) protected from external corrosion. Steel on the inside of the flowline and water injection lines will be protected by corrosion inhibitor chemical. Water injection lines which are to transport highly corrodible product will also be internally lined with corrosion resistant cement.

Another possible cause of spills is through flowline failure from excessive pressure. Wax buildup is the main cause of pressure build-up in the flowline. Flowlines will be installed in the reduced spacing project so that they are able to be cleaned regularly to prevent wax build-up. In addition, high and low pressure shutdown switches will be installed on all producing wells to shut down pumps and to prevent excessive build-up of pressure. As is Chevron's standard practice, close monitoring of facility integrity and production rates will also be a high priority in the reduced spacing project to ensure a spill does not occur.

If a flowline is not buried deep enough, frost heaving of the flowline can sometimes result in breakage of the flowline. Chevron will bury flowlines in the reduced spacing project to a depth of 1.5 metres to stabilize the position of the flowline and to help prevent flowline breakage from frost heaving.

Although unlikely, a spill may occur even though all of the above preventative measures have been implemented. Should a spill occur, it is/will be Chevron's standard practice to conduct the following spill response procedure:

- a. Isolate the pipeline leak by shutting in the well or valves at either end of the line;
- b. Notify the landowner and the Petroleum Branch;
- c. Isolate and remove spilled fluid;
- d. Conduct an on-site inspection and evaluation of the spill damage;
- e. Repair the pipeline and evaluate the cause of the pipeline failure;
- f. Apply first aid chemical treatment to damaged soil;
- g. Complete the required Petroleum Branch spill report;
- h. Conduct an ongoing site reclamation program for the spill area;
- i. Pay annual compensation to the landowner for crop loss of lease caused by the spill.

Chevron will continue its aerial surveillance program to detect a spill early if one should occur. Twice a week a low flying aircraft will fly over the project area. Early detection of a spill will minimize the amount of material spilled and the resulting damage. In addition, signs will be installed at all road crossing fencelines marking the existence of flowlines. Each road sign will state the product type the flowline is transporting and will provide a Chevron emergency number to phone if a flowline leak or other problem is observed.

## **5. RISK TO WATER SUPPLIES FROM SPILLS**

As discussed in Section 4, Chevron will take all preventative measures to ensure a spill does not occur by installing non-corrodible fibreglass flowlines and employing internal and external corrosion protection on water injection lines. The probability of a spill occurring in the reduced spacing project is very low. If a spill should occur, however, such that the use of a landowner's dugout or drinking water is inhibited, Chevron will implement procedures to delineate the extent of damage and will provide assistance to the landowner.

## **6. CONTROL OF WEED GROWTH AROUND PRODUCTION FACILITIES**

An ongoing program to control weeds around production facilities in the reduced spacing project will be instituted to ensure weeds do not infest surrounding land areas.



## **7. IMPACT ON SURFACE OPERATIONS**

### **Introduction**

Much of the proposed North Virden Scallion Unit No. 1 reduced spacing project area will be on cultivated lands. The intent of this assessment is to highlight Chevron's efforts to minimize the impact of the project on surface operations in the area.

### **Discussion**

#### **A. Project Location**

The location of the proposed North Virden Scallion Unit No. 1 reduced spacing project area is discussed in the "Technical Justification" section of the application. The area was chosen primarily on the basis of favourable geologic and reservoir characteristics for evaluating eight hectare well spacing on ultimate recovery. Other considerations in choosing the area were the degree of impact on surface operations and the expected reaction of the affected landowners.

#### **B. Well Spacing**

A map showing the orientation and size of drilling spacing units within the proposed reduced spacing area is shown in Attachment 13. Target areas within the eight hectare DSUs will be consistent with target areas established by The Oil and Natural Gas Conservation Board in previous reduced spacing orders such that the target areas will be square areas having sides 65 m from and parallel to the sides of the DSUs.

#### **C. Well Locations**

##### **1. 7a-21-11-26 W1M**

The 7a-21 well is to be located on scrub bush/pasture land. The well is to be located next to the CPR railway to minimize driving on cropland. Access to the 7a-21 well will be from the 8-21 well. No drainage problems exist in this area. Production from the 7a-21 well will be tied into the 2-21 well through an underground flowline.

##### **2. 5a-27-11-26 W1M**

The 5a-27 well is to be located on pasture land. Some of the lease will be on cropland. Access to the 5a-27 well will be from the 4-27 well. To eliminate any disturbance to cropland, production from the 5a-27 well will be tied into the 5-27 battery through an underground flowline. No drainage problems exist at this site.

3. 1a-04-12-26 W1M

The 1a-04 well is to be located in a low-lying, poorly drained grassland slough situated on the corner of cropland. The lease will be built to avoid drainage problems and will be bermed to prevent spillage of material into the surrounding slough area. Production from the 1a-04 well will be tied into the 01-04 well through an underground flowline.

**D. Minimization of Surface Impacts**

1. Location Access

With the well locations fixed by the constraints discussed above, Chevron will endeavour to minimize the disruption of surface operations in the area by maximizing the use of existing lease roads to access new locations.

2. Pad Drilling

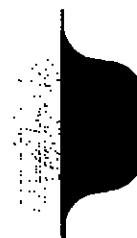
With eight hectare spacing and well depths which average 650 metres, Chevron does not consider directionally drilling the proposed locations from existing wellsites to be feasible. Though surface impacts would be reduced, the increased drilling and operating costs would make the project uneconomic.

**E. Land Owner Consent**

Chevron has discussed the proposed infill drilling program with the affected landowners. The landowners will be compensated for the impact Chevron's installations will have on their land.

**F. Conclusion**

Chevron believes that agricultural and petroleum operations are able to coexist on the same lands. Such coexistence of activities will maximize development of Manitoba's resources above and below the surface. Chevron will make every reasonable effort to minimize the impact of the proposed North Virden Scallion Unit No. 1 reduced spacing project on surface operations and will not proceed without the full consent of affected landowners.



1/2

## SURFACE FACILITIES FOR NORTH VIRDEN SCALLION UNIT 1 REDUCED SPACING WELLS

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7A-21-11-26W1M  
5a-27-11-26W1M  
1a-4-12-26W1M

### **INTRODUCTION**

NVSU1 currently consists of producing wells and water injection wells in 16 hectare and 8 hectare spacing patterns.

A network of flowlines and field headers tie the producing wells into unit batteries, where fluids are separated and metered. Produced water is processed at pumping plants and re-injected.

In Fall of 1991, four reduced spacing infill wells will be drilled within NVSU1. These will be tied-in to the existing gathering system at the closest existing wellheads. No other surface facilities construction will be required. Existing facilities are adequate for the added fluids.

Proposed tie-ins are shown on the attached maps and aerial photos (Figures 1 - 6).

### **TIE-IN DETAILS**

#### **Pipelines**

New pipelines will be 88.9 mm (3") OD.

Based on positive experience with existing pipelines in the Scallion unit, new pipelines will be anhydride epoxy fibreglass. Fibreglass linepipe has superior corrosion resistance.

#### **Metering and Testing**

No changes will be made to the existing setup.

Individual well metering will be done with portable test apparatus (portable gauged tank or 'Net Oil Computer' at each wellhead or tie-in point.

Flow will be transferred via existing common flowlines to unit batteries. Overall oil production will be metered with level gauges on oil storage tanks. Overall water production will be measured with turbine meters at the battery.

### **Summary**

<b>New Well</b>	<b>Tie-in location</b>	<b>Destination of fluids</b>
7a-21-11-26W1M	2-21-11-26W1M well	4-22-11-26W1M battery
5a-27-11-26W1M	5-27-11-26W1M battery	5-27-11-26W1M battery
1a-4-12-26W1M	1-4-12-26W1M well	5-27-11-26W1M battery

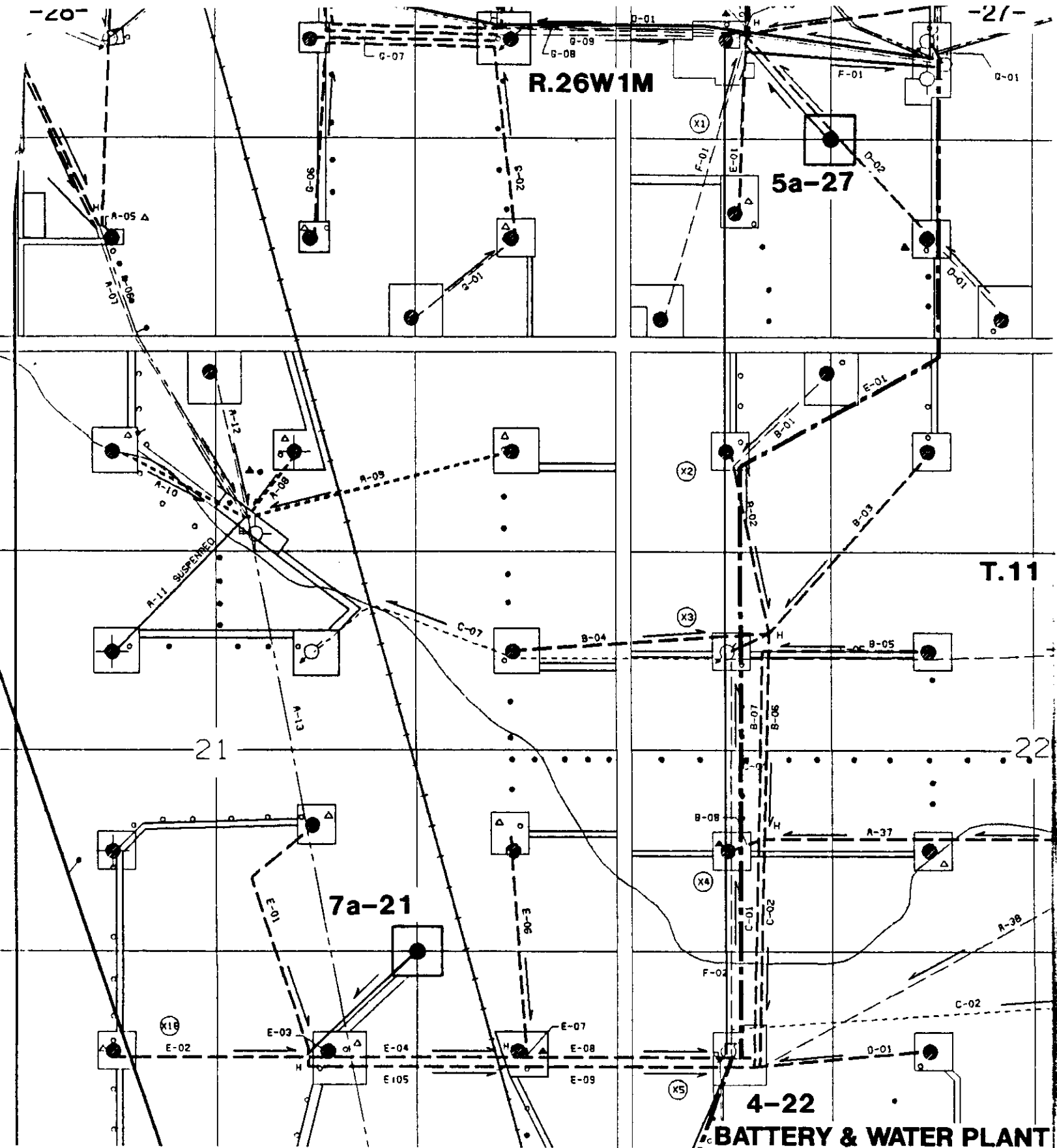


FIGURE 1

**NORTH VIRDEN SCALLION UNIT NO.1**  
**7a-21-11-26W1M INFILL WELL**  
**100 m x 100 m LEASE SHOWN**

**LEGEND**

————— ROADS/TRAILS  
 ..... POWER POLES  
 - - - - - OTHER LINES PIPELINES

**SCALE**

400 m  
 1/4 MILE

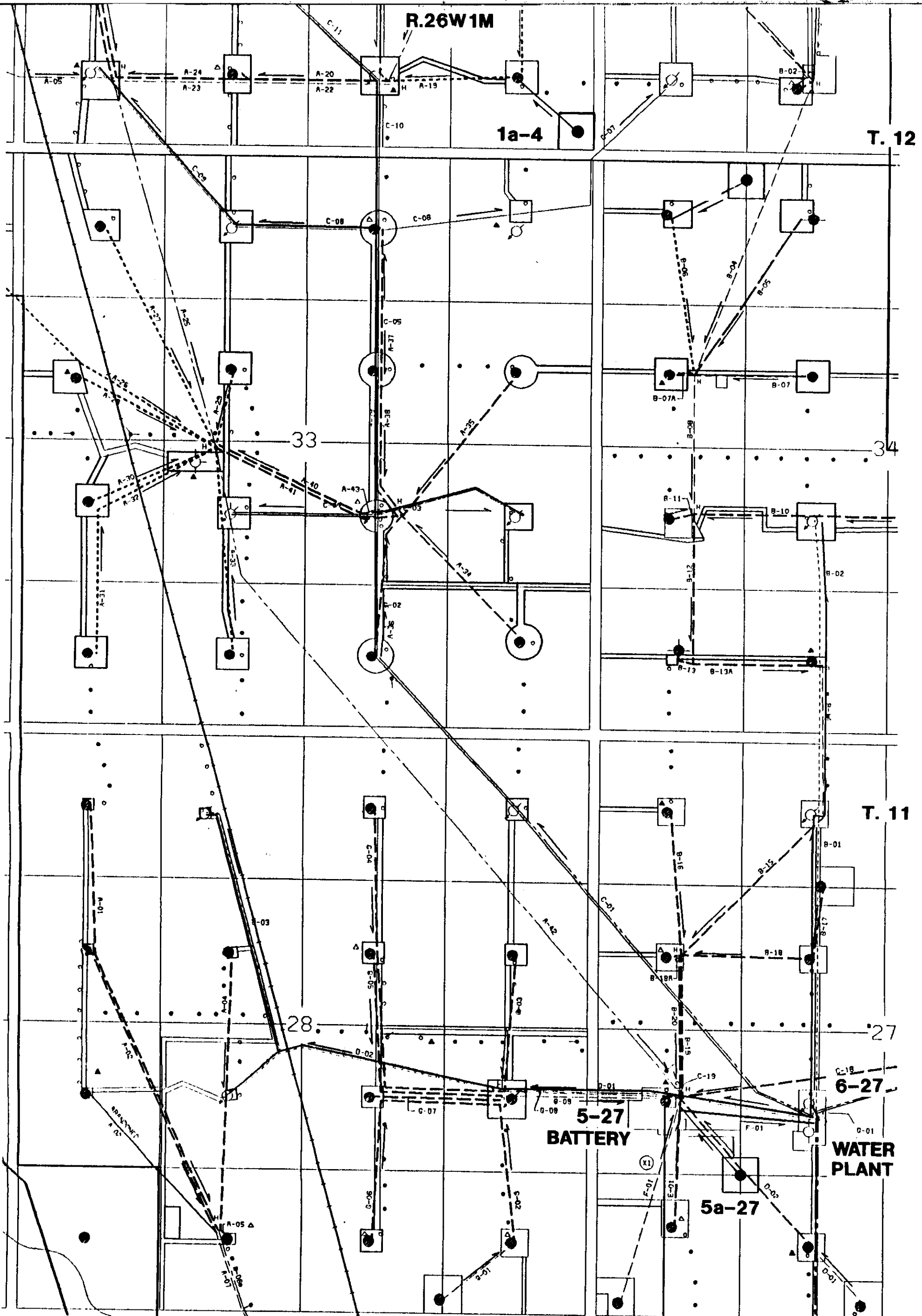


FIGURE 2  
 NORTH VIRDEN SCALLION UNIT NO. 1  
 5a-27-11-26W1M INFILL WELL  
 1a-4-12-26W1M INFILL WELL  
 100 m x 100 m LEASES SHOWN

LEGEND  
 ROADS/TRAILS

SCALE  
 400 m

FIGURE 3

7a-21-11-26W1M



FIGURE 4

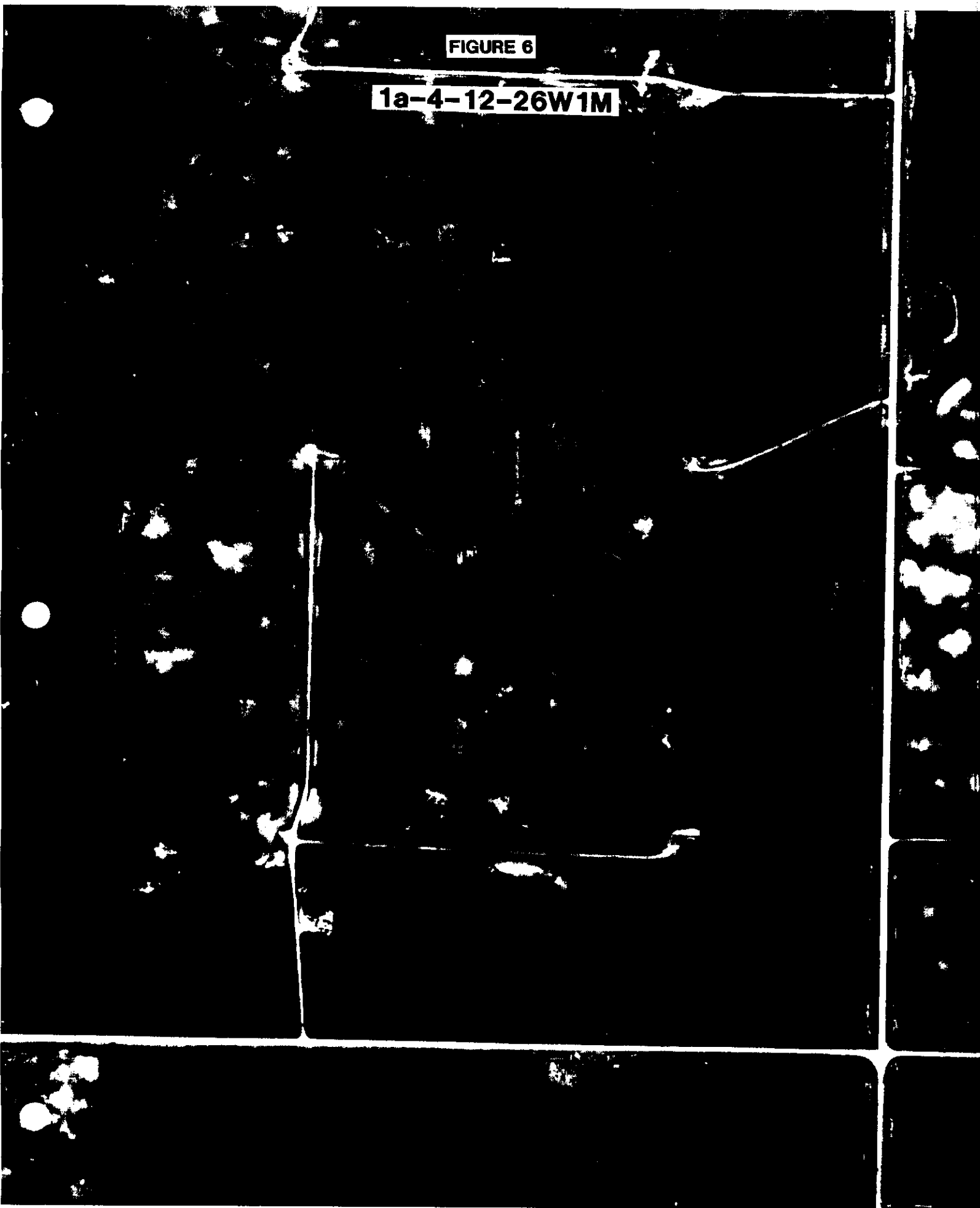
5a- 27-11-26W1M





FIGURE 6

1a-4-12-26W1M





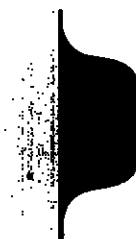
7/6

## **NORTH VIRDEN SCALLION INFILL PROJECT**

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### **Names of Surface Owners on Land Impacted by the Infill Project**

<b>Owner</b>	<b>Land</b>
Donald Collier	SE¼-4-12-26W1
Colin & Trudy Campbell	SW¼-27-11-26W1
Gaylin Eilers	SE¼-21-11-26W1



20 JUNE 19 91.

Chevron Canada Resources Limited  
500 - 5th Avenue S.W.  
Calgary, Alberta  
T2P 0L7

Landowner Contact Report

I, the undersigned, hereby grant you permission to do survey-work and the removal of trees where necessary on the following lands (owned, leased, purchased) by me and described as follows:

SE 1/4-4-12-26 WPM

This permission is granted in consideration of your promise as follows:

All work under this permit will be conducted at the risk  
and expense of Chevron Canada Resources Limited

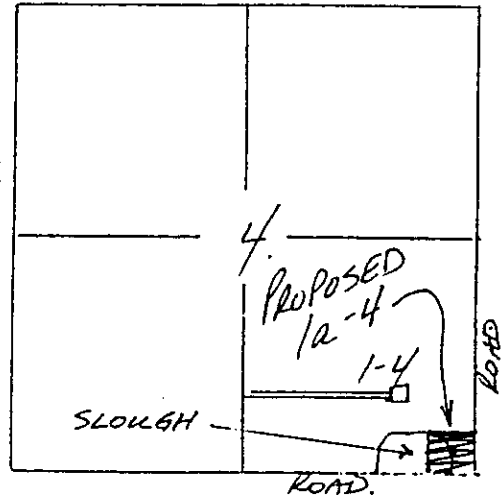
Also I, the undersigned, hereby acknowledge that I am in agreement with  
the proposed route as shown on the sketch.

Special Requirements:

*Contact owner prior to  
entry to discuss location.*

Nature of land likely to be crossed:

*Slough & cultivated.  
Leave no stakes in field.*



Registered Owner: DONALD COLLIER Address: Box 1228 VIRDEN, MAN. R0M 2C0.  
PH-748-1390.

Occupant: N/A. Address: \_\_\_\_\_

*[Signature]*  
Witness

*[Signature]*  
(Person Granting Permit)

1 copy to Landowner  
1 copy to Contractor  
1 copy to District Office

20 JUNE 19 91

Chevron Canada Resources Limited  
500 - 5th Avenue S.W.  
Calgary, Alberta  
T2P 0L7

Landowner Contact Report

I, the undersigned, hereby grant you permission to do survey work and the removal of trees where necessary on the following lands (owned, leased, purchased) by me and described as follows:

SE 1/4-21-11-26 WPM

This permission is granted in consideration of your promise as follows:

All work under this permit will be conducted at the risk and expense of Chevron Canada Resources Limited

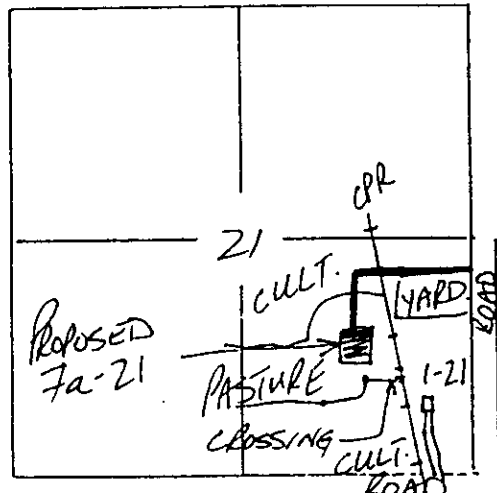
Also I, the undersigned, hereby acknowledge that I am in agreement with the proposed route as shown on the sketch.

Special Requirements:

*Contact owner prior to entry to discuss access route.*

Nature of land likely to be crossed:

*Pasture & cultivated*



Registered Owner: Gaylin Eilers Address: Box 1765 VIRDEN, MAN.  
Rm 200 PH-746-1776.

Occupant: N/A Address: \_\_\_\_\_

*[Signature]*  
Witness

*[Signature]*  
(Person Granting Permit)

- 1 copy to Landowner
- 1 copy to Contractor
- 1 copy to District Office

JUNE 20<sup>th</sup> 91

Chevron Canada Resources Limited  
500 - 5th Avenue S.W.  
Calgary, Alberta  
T2P 0L7

Landowner Contact Report

I, the undersigned, hereby grant you permission to do survey-work and the removal of trees where necessary on the following lands (owned, leased, purchased) by me and described as follows:

SW 1/4-27-11-26 W1M

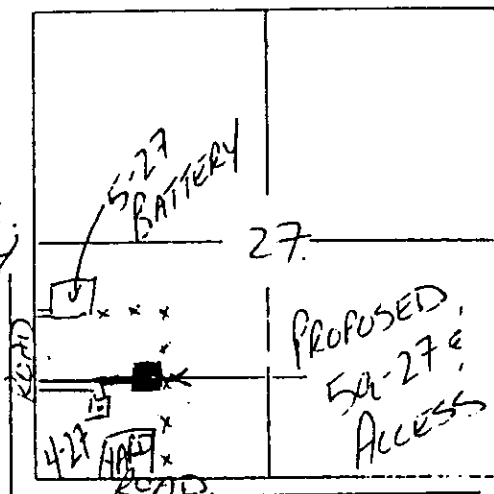
This permission is granted in consideration of your promise as follows:

All work under this permit will be conducted at the risk  
and expense of Chevron Canada Resources Limited

Also I, the undersigned, hereby acknowledge that I am in agreement with  
the proposed route as shown on the sketch.

Special Requirements:

Place lease along fence.  
Caution! It is electric.  
Line up wellhead straight east  
of 4-27 access road.  
Nature of land likely to be crossed:  
TAME PASTURE.



Registered Owner: COLIN & RUDY CAMPBELL

Address: Box 237 VIRDEN, MAN.  
PH 748-3242 Room 200

Occupant: N/A.

Address: \_\_\_\_\_

[Signature]  
Witness

[Signature]  
(Person Granting Permit)

- 1 copy to Landowner
- 1 copy to Contractor
- 1 copy to District Office





**DRILLING PRECAUTIONS**     ✓  
**SCALLION REDUCED SPACING PROJECT**

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The following precautions will be taken during drilling operations:

- a. The wells will initially be drilled to a maximum of 5 m into the Mississippian (Lodgepole).
- b. A 178 mm casing string will then be run and cemented in place at this depth.     7 "
- c. A heavy mud system of approximately 1900 kg/m<sup>3</sup> will be used to drill the Lodgepole Zone (an overbalance of approximately 700 to 1000 kPa will be used).
- d. The drilling mud will remain in the wellbore until the well is completed (open hole completion).
- e. The wells will be secured prior to moving the drilling rig.

These procedures are similar to those used during the 1989 North Virden Scallion Unit. No. 1 Reduced Spacing Project.



**CORROSION CONTROL**  
**NORTH VIRDEN SCALLION UNIT No.1 REDUCED SPACING PROJECT**

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1. Corrosion of injection wellbores will be controlled by:
  - a. installing a coated packer above the injection zone,
  - b. installing plastic-coated or cement-lined tubing,
  - c. filling the annulus with inhibited fresh water,
  - d. cathodically protecting casing,
  - e. using stainless steel surface fittings,
  - f. installing cement-lined surface pipe.
  
2. Corrosion of producing wellbores will be controlled by cathodically protecting and chemically inhibiting the casing.
  
3. Corrosion of flowlines will be controlled by:
  - a. cathodically protecting and chemically inhibiting steel lines, or
  - b. installing fibreglass flowlines.
  
4. Corrosion of surface facilities will be controlled by:
  - a. using corrosion resistant piping and fittings (fibreglass, stainless steel and cement lined),
  - b. inhibiting with corrosion chemical,
  - c. internally coating all vessels,
  - d. installing sacrificial anodes in all vessels.



FIGURE 1  
REDUCED SPACING AREA  
NORTH VIRDEN SCALLION UNIT NO. 1

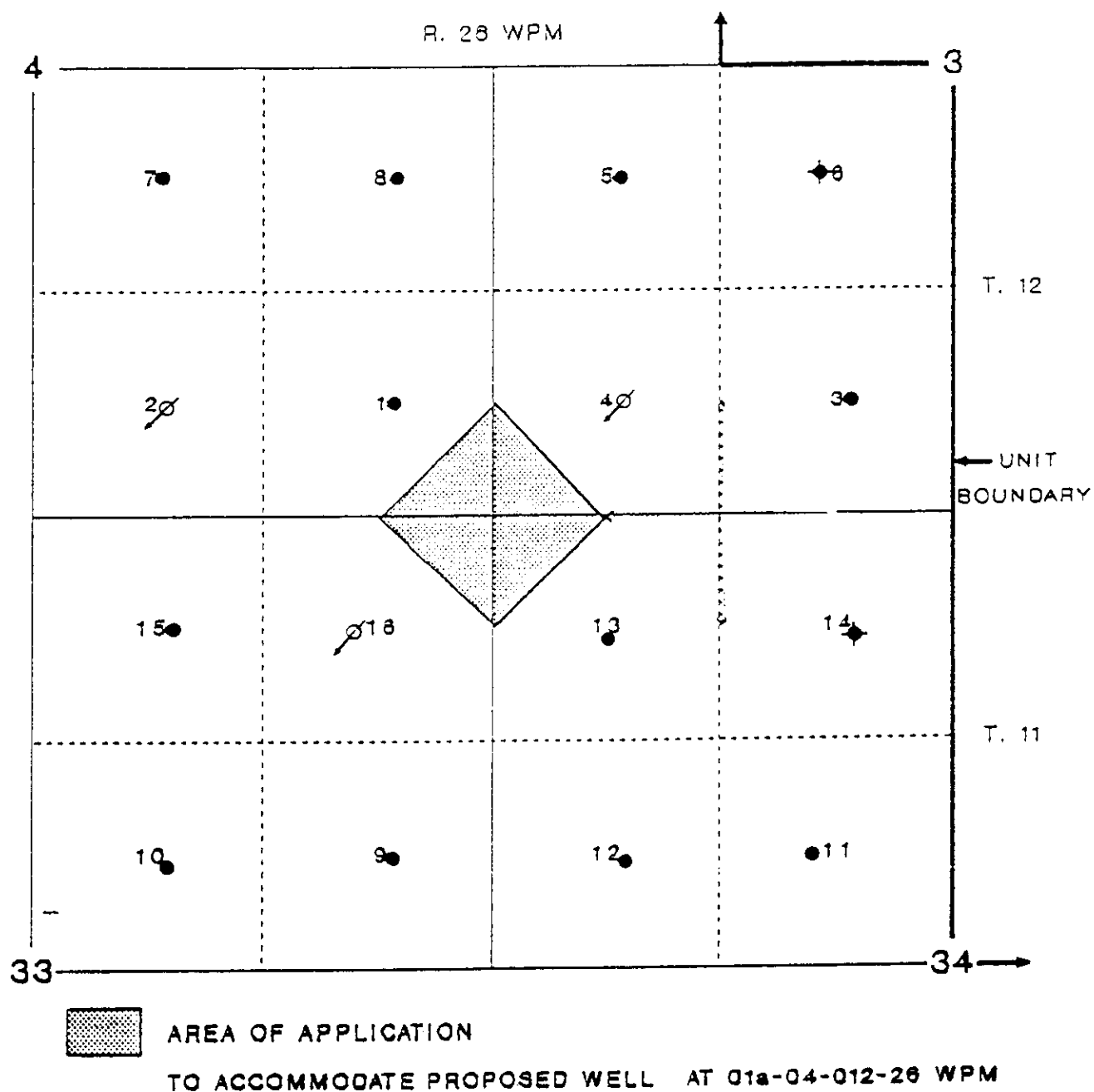
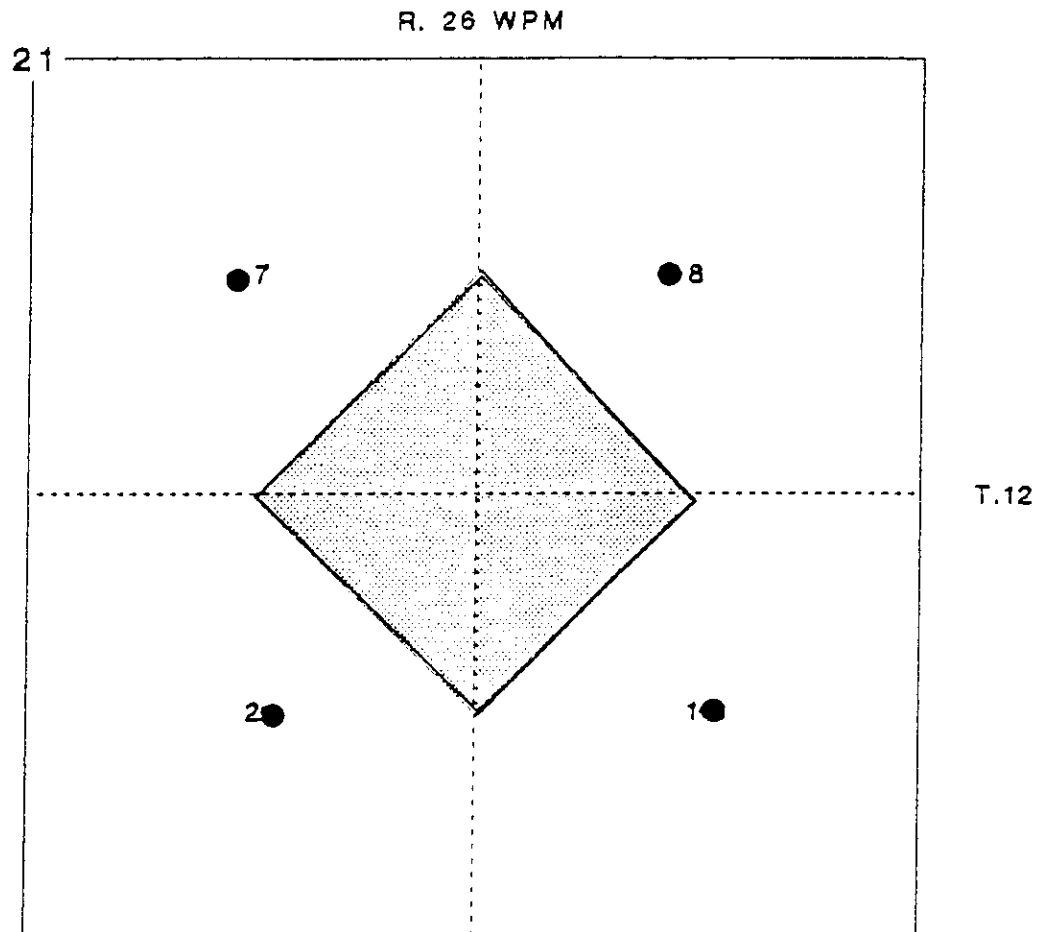


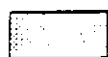
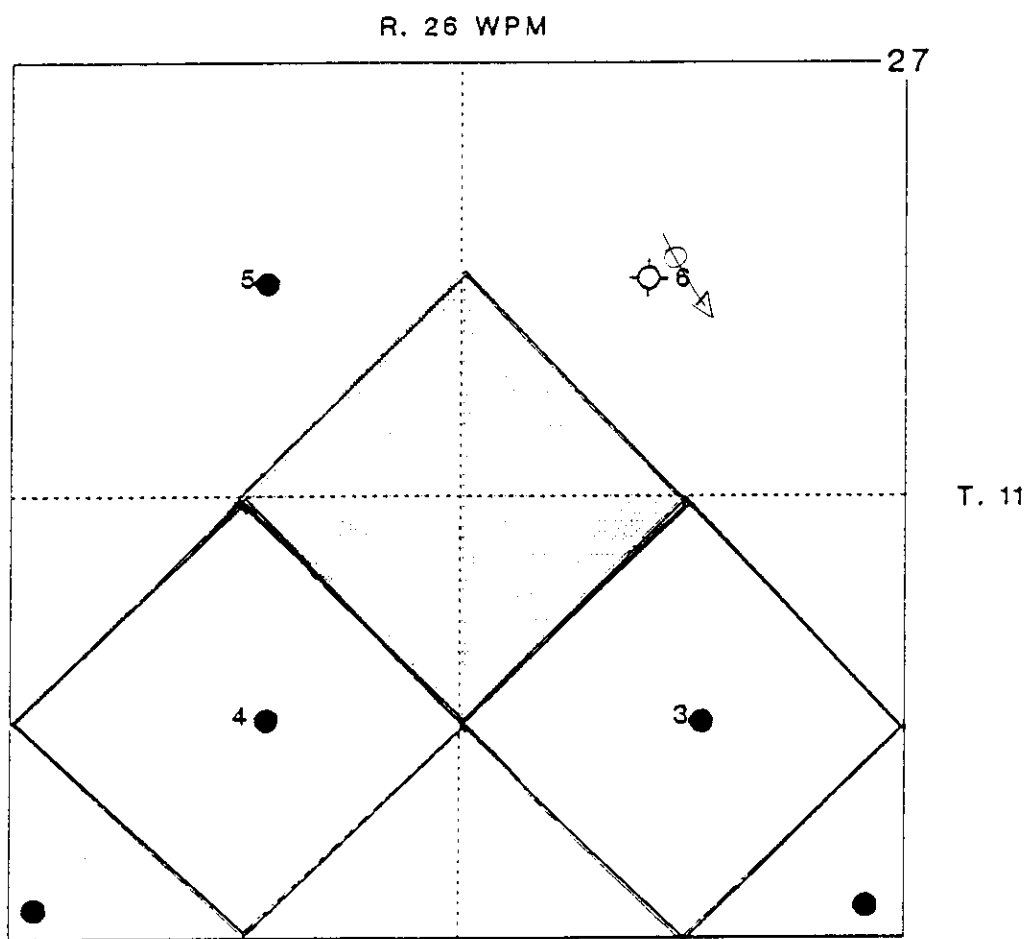
FIGURE 2  
REDUCED SPACING AREA  
NORTH VIRDEN SCALLION UNIT NO. 1



AREA OF APPLICATION

TO ACCOMMODATE PROPOSED WELL AT 07a-21-011-26 WPM

FIGURE 3  
REDUCED SPACING AREA  
NORTH VIRDEN SCALLION UNIT NO. 1



AREA OF APPLICATION

TO ACCOMMODATE PROPOSED WELL AT 05a-27-011-26 WPM







## Chevron Canada Resources

500 - Fifth Avenue S.W., Calgary, Alberta T2P 0L7  
Phone (403) 234-5900 Fax (403) 234-6212

December 12, 1991

K.G. Matieshin  
Manager  
Environment, Safety and Regulations

### NVSU No. 1 Application for Reduced Spacing

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

Attention: Mr. H. Clare Moster

Dear Mr. Clare Moster,

Further to previous discussions with the Manitoba Petroleum Branch (the MPB) and further to your letter of October 2, 1991, Chevron Canada Resources (Chevron) wishes to confirm that we will be unable to proceed with the MPB's modified version of the infill well program outlined in the captioned application. In evaluating the MPB's response to the application, we identified the following points which we believe warrant further discussion:

1. The captioned application included a three-infill well proposal. All three wells were necessary to determine different reservoir characteristics and evaluate forecasted performance. Further, the economics for the three well package were marginal, making it impossible for Chevron to proceed with the 1A-04-12-26 W1M well alone.
2. From a technical perspective, we believe there is potential for infill drilling in Manitoba. That potential may be difficult to reach, however, under the present royalty regime.
3. We are interested in the possibility of a base-decline method of calculating royalties which was suggested in one of our earlier discussions. While we were unable to address this issue well enough to incorporate it into our fall/winter drilling program, we would like to take an opportunity to look into the matter further and respond to you in due course.

While both Chevron and the province of Manitoba would benefit from more oil and gas activity, we are having difficulty developing infill drilling programs with favourable economics given the present royalty structure. We will continue to seek out prospects however, and look forward to programs the province of Manitoba may offer to enhance development opportunities.

We trust the foregoing to be in order. If you have any questions or comments, or wish to discuss any of these matters further, please do not hesitate to contact Trish Steele at (403) 234-5321.

Yours very truly,

K. G. MATIESHIN, P.Eng.

/pjs

October 2, 1991

Mr. C.G. Folden  
Manager, Reservoir Engineering  
Chevron Canada Resources  
500 - 5th Avenue S.W.  
Calgary, Alberta  
T2P 0L7

Dear Mr. Folden:

RE: North Virden Scallion Unit No. 1  
Application for Reduced Spacing

The Board has completed its review of your application for approval of special drilling spacing units in a part of North Virden Scallion Unit No. 1 (NVSU No. 1).

The Board recognizes that at abandonment over  $23 \times 10^6 \text{m}^3$  of oil will remain unrecovered in NVSU No. 1 and infill drilling is a powerful means of recovering this resource. The Board also realizes Chevron is looking for appropriate areas in NVSU No. 1 to infill drill after failure of the 1989 reduced spacing pilot project. However, the Board has two serious concerns with the application; the accuracy of the incremental recovery estimate for the reduced spacing project and the negative impact of the project on Crown revenues.

The Board recognizes the difficulty estimating incremental recoverable reserves from reduced spacing. Though Chevron's incremental recovery estimate of 2.3% OOIP is in line with values quoted in the literature, there is little technical support provided in the application.

With the exception of the 1A-4 location, the current and predicted ultimate recovery for wells adjacent to the proposed reduced spacing locations exceed the unit average. The high recovery levels and above average productivity of wells adjacent to the proposed reduced spacing locations, suggests above average reservoir characteristics and in turn raises questions as to whether significant incremental reserves will be recovered.

Typically in a mature waterflood, infill drilling is accompanied by the conversion of producers to injectors resulting in an increase in total connected and floodable pore volume. An increase in volumetric sweep efficiency and recovery results from improved continuity, pattern alignment and modification of production streamlines. A project of this nature increases the probability of recovering incremental reserves when compared to this application of selectively drilling infill locations.

The small volume of incremental recoverable reserves and large volume of accelerated production (1/4 of the remaining recoverable reserves of adjacent wells) associated with the proposed project results in the Crown losing an estimated \$1.3 million in Crown royalties and production tax over the life of the project.

A review of the economic sensitivity runs provided by Chevron indicated that incremental Crown revenue from the project would be negative even if the estimated incremental recovery were doubled to 4.6% OOIP. The sensitivity runs also indicated the estimated incremental recoverable reserves of 17 200 m<sup>3</sup> were not enough to support any level of accelerated production from the reduced spacing wells without a net loss in Crown revenue.

It is the Board's opinion, that in respect of this project, any additional Crown revenue from the recovery of incremental reserves will be exceeded by the loss of Crown revenue from accelerated production. The Board also believes economic benefits from the project accruing to freehold royalty owners, surface owners, and contractors does not compensate for the significant loss in Crown revenue.

The Board is also of the opinion that this application more closely resembles an infill drilling project resulting in production acceleration than a reduced spacing project that results in significant incremental oil recovery.

It is the Board's position that it is in the public interest that all parties with an interest in an application, whether that interest is direct or indirect, should benefit from approval of the application or as a minimum not be adversely effected by the approval.

For these reasons, the Board has decided to deny the application.

If Chevron wishes to proceed with the drilling of the proposed wells, the company may wish to consider two other options:

- (a) make application for well licences to the Petroleum Branch in which case the wells would be considered infill wells and would be classified as old oil wells for royalty and tax purposes; or
- (b) apply to the Minister under Section 9 of The Petroleum Crown Royalty and Incentive Regulation and Section 5 of The Oil and Gas Production Tax Regulation for special Crown royalty and production tax treatment.

If you have any questions in respect of the Board's decision, please contact the undersigned at (204) 945-1111.

Yours respectfully,

ORIGINAL SIGNED BY  
**H. CLARE MOSTER**

H. Clare Moster  
Deputy Chairman

bcc: Ian Haugh  
Wm. McDonald

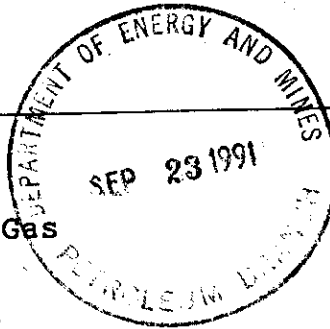
Ma itoba

JOHN  
NVS #1 File



Date September 19, 1991

To The Oil and Natural Gas  
Conservation Board  
Ian Haugh, Chairman  
Wm. McDonald, Member



From H. Clare Moster  
Deputy Chairman  
The Oil and Natural Gas  
Conservation Board

## Memorandum

Subject REDUCED SPACING APPLICATION - NORTH VIRDEN  
SCALLION UNIT No. 1 (CHEVRON CANADA)

The attached memo from the Petroleum Branch provides a thorough evaluation of the subject application.

I concur with the recommendation to deny the application and with the drafted letter of decision notification.

As the recommended decision may become controversial, I would suggest you also review it in detail so we can ensure this is a decision agreed to by the entire Board.

If you would like a presentation of the Branch's evaluation by L.R. Dubreuil and/or J. Fox, please advise.

I will await your advice on this before proceeding with further action on behalf of the Board.

H.C. Moster

Attachment

2240T

b.c.c. L.R. Dubreuil

First Fold

September 17, 1991

The Oil and Natural Gas  
Conservation Board

- Ian Haugh, Chairman
- H. Clare Moster, Deputy Chairman
- Wm. McDonald, Member

John N. Fox  
Chief Petroleum Engineer  
Petroleum Branch

RE: North Virden Scallion Unit No. 1  
Reduced Spacing Application

Chevron Canada Resources application to drill 3 infill wells in North Virden Scallion Unit No. 1 (NVSU No. 1) was advertised in the Virden Empire Advance and the Manitoba Gazette. No objections to the application were received.

#### RECOMMENDATIONS

It is recommended that the Board deny Chevron's application. A copy of the proposed Board letter denying the application, with reasons, is attached.

It is also recommended that the Board advise Chevron if it wishes to proceed with the proposed wells it can either:

- (a) make application for well licences to the Branch in which case the wells would be considered infill wells and be classified as old oil wells for royalty and tax purposes; or
- (b) apply to the Minister under Section 9 of The Petroleum Crown Royalty and Incentive Regulation and Section 5 of The Oil and Gas Production Tax Regulation for special royalty and tax treatment.

#### DISCUSSION

Chevron has applied to drill 3 wells on reduced 8 ha spacing in NVSU No. 1; 7A-21-11-26, 5A-27-11-26 and 1A-4-12-26 (Figure 1). The infill well locations, which have very different geological, reservoir and performance characteristics, were all selected based on the following criteria:

- (1) higher than average oil productivity,
- (2) lower than average WOR,
- (3) structurally high (except 7A-21), and
- (4) likelihood of incremental oil in all Lodgepole members.

The criteria are identical to those used to select the Virden Roselea Unit No. 1 (VRU No. 1) reduced spacing project area. Different criteria, primarily low current and predicted ultimate recovery, were used to select the unsuccessful 1989 NVSU No. 1 reduced spacing project area (Figure 1).

It appears that productivity of the offsetting wells was the main criteria for selection of the infill locations. In May, 1991 the 11 producing wells offsetting the proposed infill locations which represent 7% of the total producing wells in NVSU No. 1, (highlighted in Figure 1) accounted for 23.5% of the total unit production and 12% of the cumulative unit production.

Chevron has forecast incremental recoverable reserves of 17 200 m<sup>3</sup> or 2.3% OOIP over the 30 year project evaluation period (Table 1). For each infill location incremental recovery was determined using 1/4 of the OOIP from each of the four offsetting wells. If the analysis is continued until each infill well reaches its economic limit (33 to 70 years) the incremental recovery increases to 24 400 m<sup>3</sup> or 3.2% OOIP.

Chevron also forecasts the infill wells to recover 1/4 of the remaining recoverable reserves of the adjacent wells, a total of 55 105 m<sup>3</sup> over the 30 year project evaluation period (Table 1). Accelerated decline of adjacent producers is predicted to occur one year after the infill wells go on production.

The ratio of accelerated production to total infill well production is 0.76, which is substantially higher than predicted by Chevron for its previous reduced spacing projects (Table 2). The limited incremental recovery and large volume of accelerated production, which would be reclassified from old oil to new oil for royalty and tax purposes, results in the Crown losing an estimated \$1.3 million in royalties and taxes over the project life.

Though Chevron's incremental recovery prediction of 2.3 - 3.2% OOIP is in line with values quoted in the literature, there is little technical justification provided in the application.

Current and ultimate recovery estimates for the wells adjacent to the proposed infill locations are shown in Table 3. The Branch's recovery estimates differ from Chevron's because for the 5A-27 location, the 6-27 injector and the 3A-27 and 4B-27 infill wells were included in the analysis, and for the 1A-4 location, the 16-33 and 4-3 injectors were included.

With the exception of the 1A-4 location, the current and predicted ultimate recoveries for wells adjacent to the proposed infill locations exceed the unit average; current unit recovery - 28% OOIP and predicted ultimate unit recovery - 32% OOIP.

The high current and predicted ultimate recoveries and high productivity of wells adjacent to the proposed infill locations suggests above average reservoir characteristics and in turn raises questions as to whether significant incremental reserves will be recovered.

Typically in a mature waterflood, infill drilling is accompanied by the conversion of producers to injectors resulting in an increase in total connected and floodable pore volume. An increase in volumetric sweep efficiency and recovery results from the improved continuity, pattern realignment and modification of production streamlines. Chevron's proposal does not involve conversion of wells from production to injection.

Chevron in its application stated reduced spacing will increase the vertical and areal sweep efficiency in the Cherty because of the permeability variation in this zone. Incremental reserves are also attributed to the Crinoidal and Oolites which are essentially untested in the proposed infill locations.

There is no doubt that the proposed infill wells will result in a more thorough sweep of the reservoir and recover some incremental oil. However the volume of incremental oil is difficult to assess. The Branch is also of the opinion that completion of bypassed pay in the uphole Crinoidal and Oolite Members in existing wells could recover significantly more reserves than limiting completion of these zones to the infill wells. Infill wells do however offer an excellent opportunity to selectively evaluate the potential of these zones.

It is recognized that at abandonment, remaining oil-in-place in NVSU No. 1 will exceed  $23 \times 10^6 \text{ m}^3$  and infill drilling is a powerful means of recovering this resource. Chevron is still looking for the appropriate areas in NVSU No. 1 to infill drill after failure of the 1989 reduced spacing project (Figure 1). The current project appears designed to accomplish just that, targeting 3 very different areas of the reservoir. Chevron is also minimizing its risk by selecting high productivity areas of the reservoir. The result is a project that regardless of its technical success will be economic.

Over the next 30 years, 1992-2022, Chevron forecasts the Crown will receive \$25.1 million (Base Case) in royalties and taxes from NVSU No. 1. The infill wells are predicted to produce  $72\,350 \text{ m}^3$  ( $17\,246 \text{ m}^3$  incremental reserves and  $55\,105 \text{ m}^3$  accelerated reserves). As a result of the high percentage of accelerated production, the project economics show a decline in Crown revenue to \$23.8 million, a net loss of \$1.3 million when compared to the Base Case. The foregone Crown revenue is a result of the infill well holiday volume ( $1\,500 \text{ m}^3/\text{well}$ ) and the reclassification from old oil to new oil, of accelerated infill well production.

A plot of cumulative incremental Crown revenues (Figure 2) for the project shows a slight benefit to the Crown in the first year with cumulative Crown benefits becoming negative after approximately 22 months.

Recognizing that there is some merit in continued evaluation of the infill drilling potential in NVSU No. 1, Chevron was requested to run additional economics to illustrate the sensitivity of Crown revenues to changes in incremental recoverable reserves and accelerated production estimates.

In general, an increase in incremental recovery and a decrease in accelerated production will have a positive impact on incremental Crown revenue. Additional economic runs were made increasing the volume of incremental recovery from the infill wells, while holding the total infill well production constant. The economic runs are summarized in Table 4 and shown graphically in Figure 2.

A plot of net Crown benefits versus recoverable reserves (Figure 3) was used to determine at what level of incremental recovery, net Crown revenue from the project, would be zero. It is estimated that incremental reserves of approximately 44 000 m<sup>3</sup> or 5.8% OOIP would have to be recovered by the infill wells for the Crown not to lose revenue.

An additional economic run was made to determine what reduction in accelerated production is required for Crown revenue to equal zero (incremental recovery was held constant at 17 200 m<sup>3</sup>, Table 4 and Figure 3). By reducing the accelerated production by half, from 55 105 m<sup>3</sup> to 27 550 m<sup>3</sup>, the net loss in Crown revenue was halved from \$1.3 million to \$0.65 million. Further extrapolation of this case (Figure 4) suggests there is not enough incremental oil to support any significant level of accelerated production without a net loss in Crown revenue.

It is the Branch's conclusion, after reviewing the economic runs, that any additional Crown revenue from the recovery of incremental reserves will be exceeded by the loss in Crown revenue from accelerated production. For this reason it is recommended that reduced 8 ha spacing not be approved for the 3 proposed infill locations.

The Branch has reviewed the merits of each infill location on a stand alone basis and has the following comments:

(a) 7A-21-11-26 (WPM)

The proposed 7A-21 well is located near the southwest edge of the unit in an area where natural fractures are evident. There is no offset injection as pressure support is provided by the downdip aquifer.

The proposed 7A-21 well offsets the best well in NVSU No. 1, 2-21, which produces 36.8 m<sup>3</sup> OPD. Chevron has no explanation for the anomalous performance of the 2-21 well.

Because of the high current and predicted ultimate recovery from adjacent wells, 55.7% and 70.8% OOIP respectively, and high ratio of accelerated production, 82% of total infill production, approval of this location is not recommended.

(b) 5A-27-11-26 (WPM)

The proposed 5A-27 well is located on a NW-SE trending structural high, just north of the "corridor" infill wells drilled between 1974-78. As a result of previous infill drilling, the well density in the SE/4 of Section 27 is 10.7 ha/well.

Because of the high current and predicted ultimate recovery, 30.7% OOIP and 38% OOIP respectively and high ratio of accelerated production, 70% of total infill production, approval of this location is not recommended.



(c) 1A-4-12-26 (WPM)

The proposed 1A-4 well is located between two injection wells near the apex of a structural high. The area surrounding the proposed 1A-4 well is currently developed on 5-spot injection patterns.

Current and predicted ultimate recovery from adjacent wells is only 15.7% OOIP and 21.8% respectively. Though the forecast ratio of accelerated to total infill production is high, 75%, the Branch feels the low recovery, structural position and offset injection increases the likelihood of additional incremental recovery. It is recommended, if Chevron is prepared to drill a single infill well, that reduced spacing be approved for the 1A-4 well. In discussions with Chevron, the company indicated it is not prepared to drill only the 1A-4 well.

It is suggested that Chevron has two options if it wishes to proceed with the drilling of the proposed wells. Because no objections to the application were received, the Branch would be prepared to licence the wells as infill wells which would not qualify for new oil status. The other alternative is to apply to the Minister for approval of special royalty and tax treatment as provided for under Section 9 of The Petroleum Crown Royalty and Incentive Regulation and Section 5 of The Oil and Gas Production Tax Regulation. One option would be to use the same methodology for determining new oil as approved for Daly Unit No. 3 - new oil status is granted for all oil produced from the unit in excess of the historical production decline. A plot of historical unit production is shown in Figure 5.

ORIGINAL SIGNED BY  
JOHN N. FOX

John N. Fox

Att'd.

Approved:

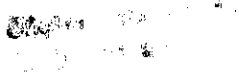
  
L.R. Dubreuil, Director

TABLE 1  
INFILL WELL PRODUCTION FORECAST

Well	Incremental Recoverable Reserves (10 <sup>3</sup> m <sup>3</sup> )	Accelerated Production (10 <sup>3</sup> m <sup>3</sup> )	Total Infill Well Production (10 <sup>3</sup> m <sup>3</sup> )	Percentage of Accelerated Production (%)
7A-21-11-26	5.9	26.5	32.4	82
5A-27-11-26	6.9	16.0	22.9	70
1A-4-12-26	<u>4.5</u>	<u>12.6</u>	<u>17.1</u>	<u>74</u>
Total	17.3	55.1	72.4	76

TABLE 2  
REDUCED SPACING PROJECT FORECASTS

Reduced Spacing Project	Forecast Incremental Recoverable Reserves (10 <sup>3</sup> m <sup>3</sup> )	Forecast Accelerated Production (10 <sup>3</sup> m <sup>3</sup> )	Total Infill Well Production (10 <sup>3</sup> m <sup>3</sup> )	Percentage of Accelerated Production (%)
1989 NVSU No. 1	88.0	67.7	155.7	43
1991 VRU No. 1	91.5	46.4	137.9	34
1991 NVSU No. 1	17.2	55.1	72.4	76

TABLE 3

## CURRENT AND ULTIMATE RECOVERY

Well	Oil-in-Place ( $10^3\text{m}^3$ )		Cumulative Production ( $10\text{m}^3\text{m}^3$ )		Current Recovery (%)		Ultimate Recovery (%)	
	Chevron	Branch	Chevron	Branch	Chevron	Branch	Chevron	Branch
7A-21	1041.1	1041.1	581.2	581.2	55.8	55.8	70.8	71.1
5A-27	907.2	1209.6	334.6	371.2	36.0	30.7	44.4	38.0
1A-4	397.0	794.0	73.1	124.7	25.8	15.7	38.0	20.2
					Current Unit Recovery		Predicted Ultimate Unit Recovery	
					- 28%		- 32%	

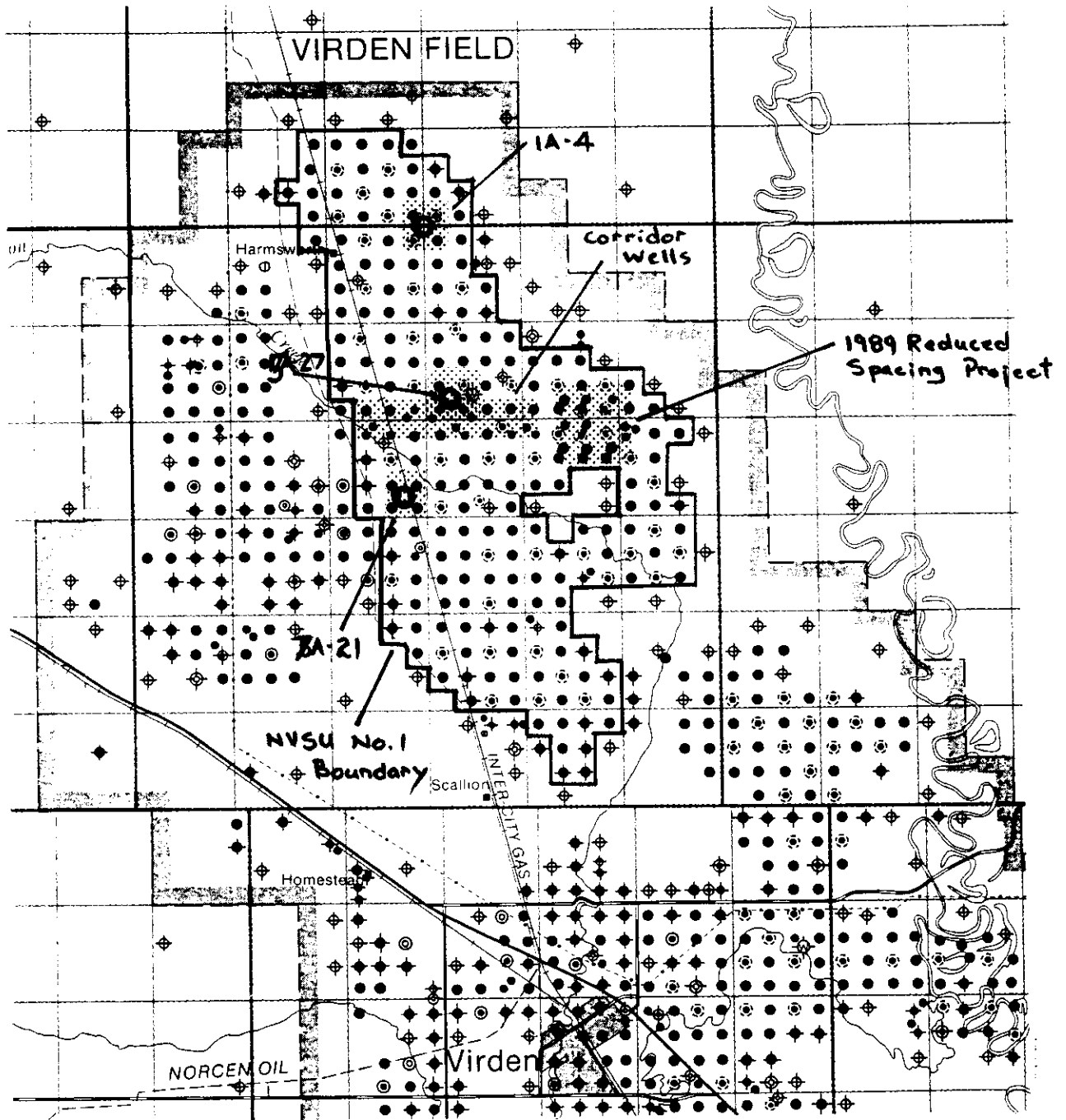
TABLE 4

## ECONOMIC RESULTS

	Incremental Recoverable Reserves (10 <sup>3</sup> m <sup>3</sup> )	Total Infill Production (10 <sup>3</sup> m <sup>3</sup> )	Net Crown Revenue (\$M) (Undiscounted)	Net Crown) Revenue (\$M) (Discounted at 10%)
Incremental*				
Recovery - 2.3% OOIP	17.2	74.0	- 1296	- 531
Incremental				
Recovery - 3.2% OOIP	24.4	74.0	- 937	- 95
Incremental				
Recovery - 9.5% OOIP	74.0	74.0	817	44
Accelerated*				
Production - 55 105 m <sup>3</sup>	17.2	74.0	- 1296	- 531
Accelerated				
Production - 27 552m <sup>3</sup>	17.2	55.1	- 642	- 279

\* This is the same case, which is presented in Chevron's application.

FIGURE 1



○ PROPOSED INFILL LOCATIONS

CUMULATIVE  
NET CROWN  
REVENUE

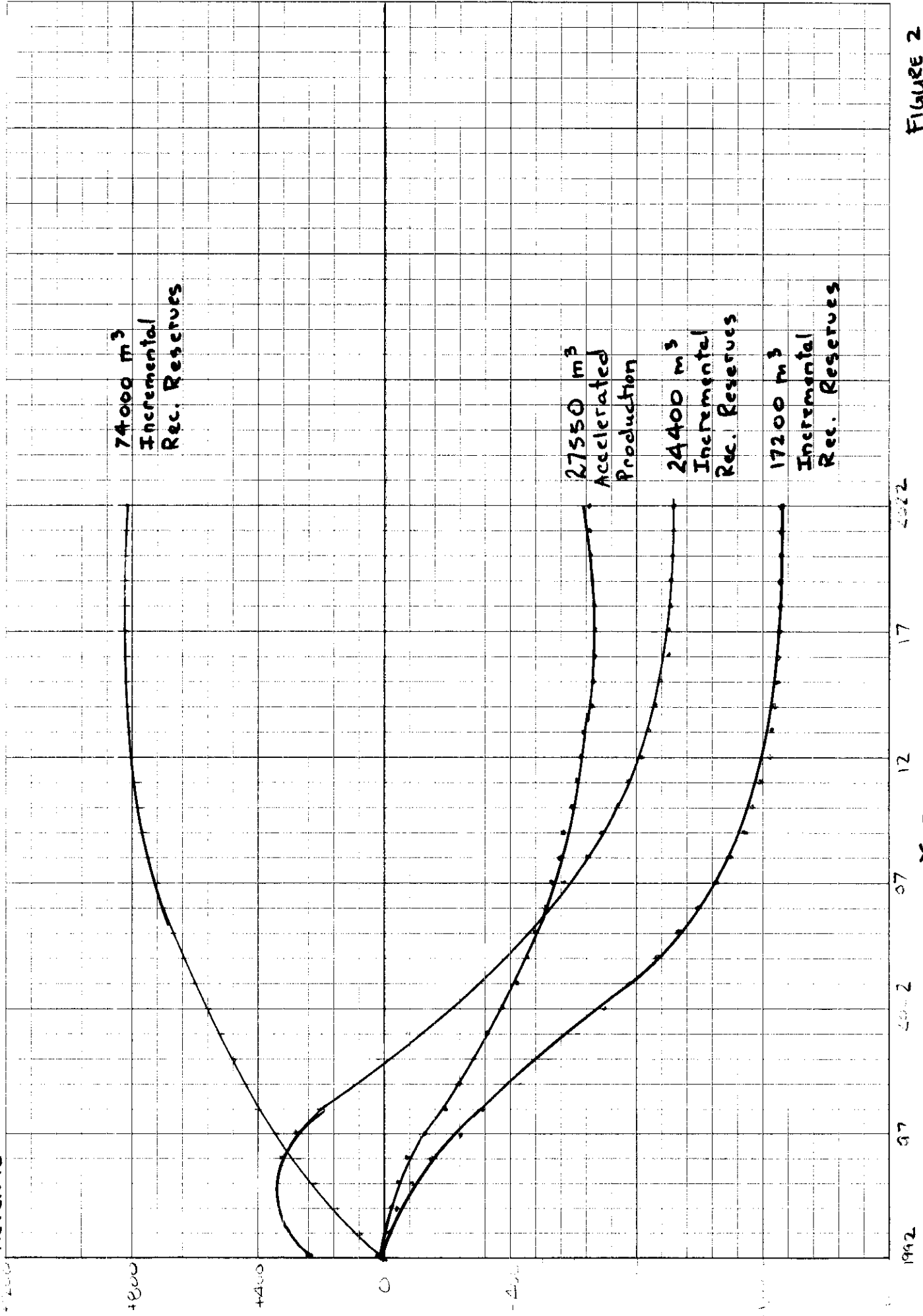


FIGURE 2

NET  
CROWN  
BENEFITS (\$M)

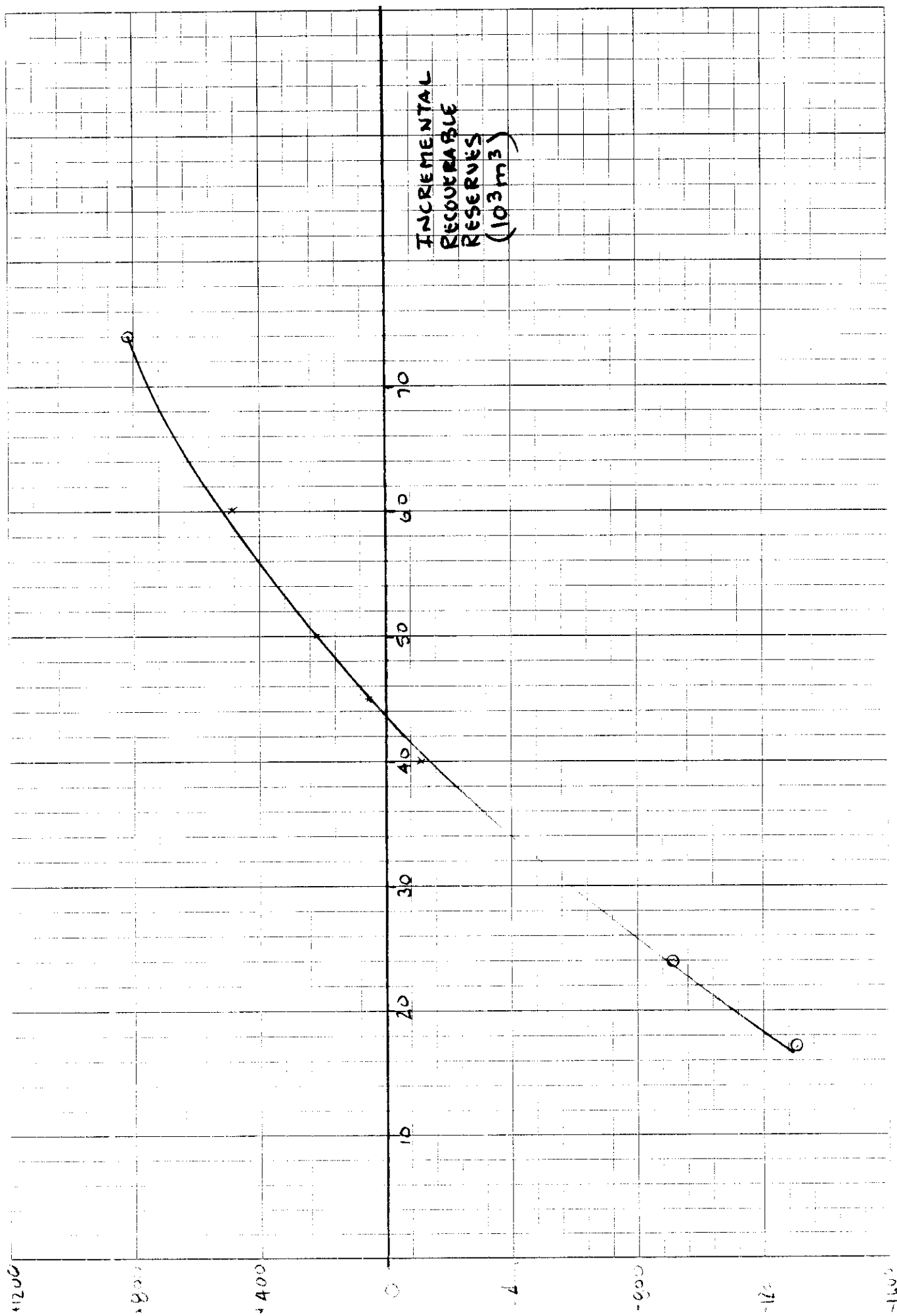


Figure 3

46 0410

5 X 5 TO THE INCH • 7 X 10 INCHES  
KEUFFEL & ESSER CO. MADE IN U.S.A.

NET  
CROWN  
BENEFITS

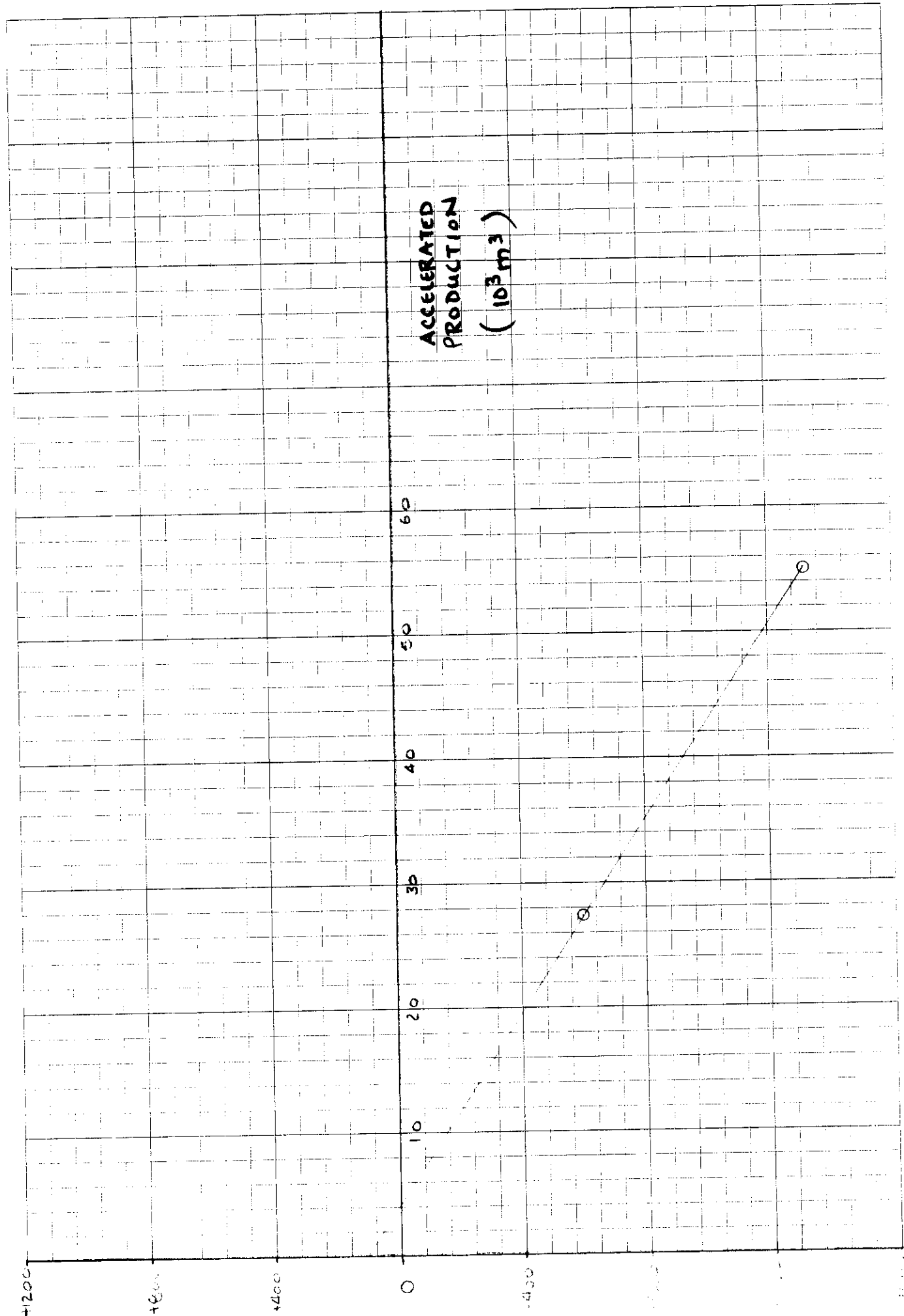


Figure 4



# HISTORICAL PRODUCTION DECLINE

NVSU #1 All Wells (246)

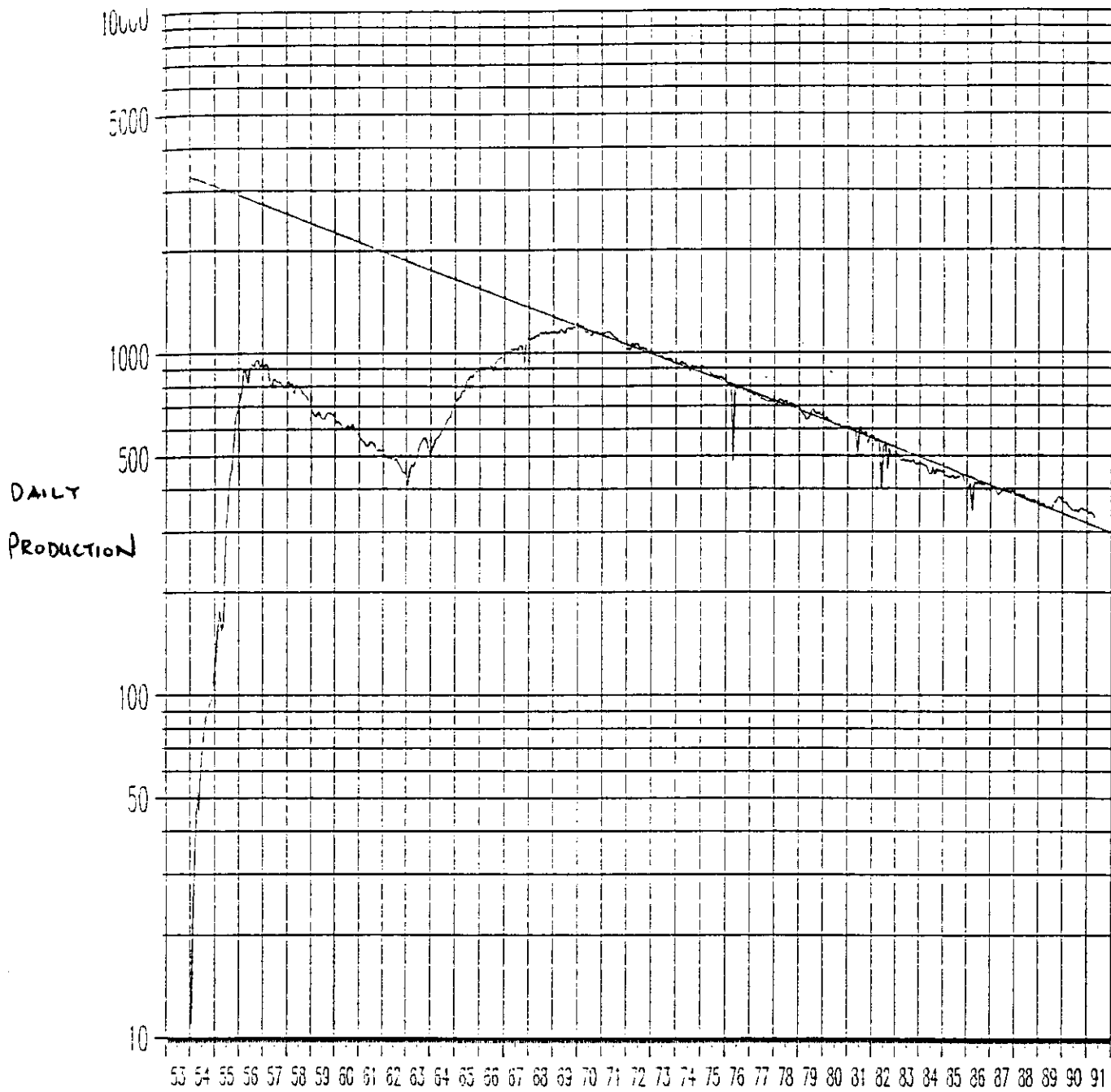


FIGURE 5



The Oil and Natural Gas  
Conservation Board

Room 309  
Legislative Building  
Winnipeg, Manitoba, CANADA  
R3C 0V8

(204) 945-3130

Mr. C.G. Folden  
Manager, Reservoir Engineering  
Chevron Canada Resources  
500 - 5th Avenue S.W.  
Calgary, Alberta  
T2P 0L7

Dear Mr. Folden:

RE: North Virden Scallion Unit No. 1  
Application for Reduced Spacing

The Board has completed its review of your application for approval of special drilling spacing units in a part of North Virden Scallion Unit No. 1 (NVSU No. 1).

The Board recognizes that at abandonment over  $23 \times 10^6 \text{m}^3$  of oil will remain unrecovered in NVSU No. 1 and infill drilling is a powerful means of recovering this resource. The Board also realizes Chevron is looking for appropriate areas in NVSU No. 1 to infill drill after failure of the 1989 reduced spacing pilot project. However, the Board has two serious concerns with the application; the accuracy of the incremental recovery estimate for the reduced spacing project and the negative impact of the project on Crown revenues.

The Board recognizes the difficulty estimating incremental recoverable reserves from reduced spacing. Though Chevron's incremental recovery estimate of 2.3% OOIP is in line with values quoted in the literature, there is little technical support provided in the application.

With the exception of the 1A-4 location, the current and predicted ultimate recovery for wells adjacent to the proposed reduced spacing locations exceed the unit average. The high recovery levels and above average productivity of wells adjacent to the proposed reduced spacing locations, suggests above average reservoir characteristics and in turn raises questions as to whether significant incremental reserves will be recovered.

Typically in a mature waterflood, infill drilling is accompanied by the conversion of producers to injectors resulting in an increase in total connected and floodable pore volume. An increase in volumetric sweep efficiency and recovery results from improved continuity, pattern alignment and modification of production streamlines. A project of this nature increases the probability of recovering incremental reserves when compared to this application of selectively drilling infill locations.

The small volume of incremental recoverable reserves and large volume of accelerated production (1/4 of the remaining recoverable reserves of adjacent wells) associated with the proposed project results in the Crown losing an estimated \$1.3 million in Crown royalties and production tax over the life of the project.

A review of the economic sensitivity runs provided by Chevron indicated that incremental Crown revenue from the project would be negative even if the estimated incremental recovery were doubled to 4.6% OOIP. The sensitivity runs also indicated the estimated incremental recoverable reserves of 17 200 m<sup>3</sup> were not enough to support any level of accelerated production from the reduced spacing wells without a net loss in Crown revenue.

It is the Board's opinion, that in respect of this project, any additional Crown revenue from the recovery of incremental reserves will be exceeded by the loss of Crown revenue from accelerated production. The Board also believes economic benefits from the project accruing to freehold royalty owners, surface owners, and contractors does not compensate for the significant loss in Crown revenue.

The Board is also of the opinion that this application more closely resembles an infill drilling project resulting in production acceleration than a reduced spacing project that results in significant incremental oil recovery.

It is the Board's position that it is in the public interest that all parties with an interest in an application, whether that interest is direct or indirect, should benefit from approval of the application or as a minimum not be adversely effected by the approval.

For these reasons, the Board has decided to deny the application.

If Chevron wishes to proceed with the drilling of the proposed wells, the company may wish to consider two other options:

- (a) make application for well licences to the Petroleum Branch in which case the wells would be considered infill wells and would be classified as old oil wells for royalty and tax purposes; or
- (b) apply to the Minister under Section 9 of The Petroleum Crown Royalty and Incentive Regulation and Section 5 of The Oil and Gas Production Tax Regulation for special Crown royalty and production tax treatment.

If you have any questions in respect of the Board's decision, please contact the undersigned at (204) 945-1111.

Yours respectfully,

H. Clare Moster  
Deputy Chairman



## Memorandum

Date August 23, 1991

To Mr. John Fox  
Chief Petroleum Engineer  
Petroleum Branch  
555-330 Graham Avenue  
Winnipeg, Mb.

From T. Pearce, Planner  
Rural Development  
Community Development Branch  
112-340-9th Street  
Brandon, Mb.  
Telephone

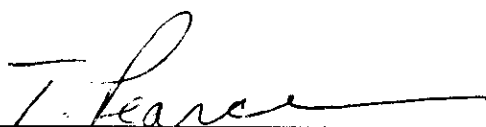
Subject NORTH VIRDEN SCALLION REDUCED SPACING PROJECT

Our office has reviewed this proposal and find the following concerns:

1. The proposed wells in S.E.  $\frac{1}{4}$  Sec. 21, Twp. 11, Rge. 26W and S.W.  $\frac{1}{4}$  Sec. 27, Twp. 11, Rge. 26W are to be located close to existing residences. We recommend that, if this project is approved, the wells be separated from residential sites as far as possible, given your regulations and the geological constraints. Also, we recommend that all mitigating measures be taken to avoid groundwater pollution, air pollution, noise, and drilling and maintenance activity that could adversely affect the nearby residences. Finally, regarding this concern, we recommend that the oil company obtain final site approval from the residents prior to the commencement of drilling work.

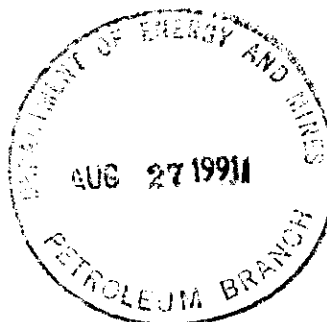
(It should be noted here that the third well on S.E.  $\frac{1}{4}$  Sec. 4, Twp. 12, Rge. 26W is proposed directly across the road from a rural cemetery. It may be that these uses should be separated to some extent.)

2. If the project proceeds the oil company should minimize the disturbance of natural vegetation, revegetate the wellsite including the berm and construct a berm around the wellsite.
3. It has come to our attention that the R.M. of Wallace has not received this application. We recommend that the R.M. of Wallace Council be given an opportunity to comment on this proposal.

  
T. Pearce,  
Planner 726-6273

TP/lm

cc: S. Scrafield,  
Acting Director





## **Chevron Canada Resources**

500 - Fifth Avenue S.W., Calgary, Alberta T2P 0L7  
Phone (403) 234-5000 Fax (403) 234-6212

K.G. Matieshin  
Manager  
Environment, Safety and Regulations

August 22, 1991

North Virden Scallion Unit No. 1  
Application for Reduced Spacing  
Deficiency Letter Meeting

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

Attention: Mr. John Fox

Dear Mr. Fox,

Chevron Canada Resources would like to thank you for participating in the conference call meeting of August 15, 1991, to address the subject Applications' deficiencies outlined in the Manitoba Conservation Board letter dated August 2, 1991.

As agreed, a copy of the minutes from the meeting are attached, as well as a table of Roselea Unit 1 Preliminary Results. Also, please find enclosed, one diskette containing various economic forecasts regarding the subject infill program.

If you have any questions or require any additional information, please call Mr. J. D. Tucker at 234-6102.

Yours very truly,

  
for K. G. MATIESHIN, P.Eng.

JDT/lat  
Attachment



Calgary, Alberta  
August 22, 1991

NVSU No. 1 Application for Reduced Spacing  
Minutes of Conference Call  
Meeting - August 15, 1991

ATTENDEES: J. D. Tucker - Chevron  
P. J. Steele - Chevron  
B. J. Elysee-Collen - Chevron  
K. A. Edwards - Chevron  
John Fox - MEB

Dean Tucker introduced everyone and went over the agenda for the meeting.

The purpose of the meeting was to address the deficiencies outlined by the Manitoba Conservation Board in their letter dated August 2, 1991.

The deficiency letter was reviewed point by point:

1.0 Incremental Recovery Predictions:

1.1 Information sent by BJE.

1.2 Graphs sent.

1.3 Corridor wells were in a special situation between two waterfloods. The 1989 pilot targeted an area of lower recovery under the assumption this is where we would find incremental oil. This was determined not to be true. Present or ultimate recovery is not the best indicator of where to infill drill.

*low current/ultimate recovery, no longer deemed a good reason for selecting infill locations*

1.4 1) Calculated oil recovery may not mean much. 2) Porosity and water saturation may not be correct. 3) 7A-21 produces from an area that is naturally fractured. 4) We have seen this in Roselea where good infill results were obtained in areas of "high" recovery. The same results may be possible at 7A-21. *- questions regarding accuracy of OIP determination*

1.5 Do not feel this is likely in the Cherty. Have to wait to evaluate 1A-4 for uphole potential. May not be enough reserves to make completion worthwhile.

*due to gas. of Cherty injection*

1.6 Have not identified any more specific locations. However, potential exists for future drilling in sections 21, 22, 27, 28 and 33 and section 4-12-26 WPM. Twelve locations possible.

2.0 Reduced Spacing Production Forecast:

2.1 Felt that an arithmetic average was weighting the rate from 2-21 too much. Our final rate was what we believed to be realistic.

2.2 Information sent. Was okay for JF. Will forward diskette.

don't know why  
2-21 is so  
productive

3.0 Project Economics:

3.1 Statement correct. Attachment 6 revised and sent.

3.2 Estimated portion of Project Capital Costs that remain in Manitoba

$$\begin{aligned} &= \$127\,000/\text{well} \times 3 \\ &= \$381\,000 \end{aligned}$$

\$ 70,000 ~~completion~~ completion/equipping  
\$ 37,000 drilling  
\$ 20,000 tie-in

3.3 (a) Sent one forecast already. Sixty-five percent or 48 600 m<sup>3</sup> is amount of total infill well production that would need to be incremental for crown to be revenue neutral.

- (b) 1/4 accelerated reserves leaves Crown in negative position.  
1/8 accelerated reserves leaves Crown in negative position.  
0% accelerated reserves leaves Crown in basically a neutral position.

Therefore, there is not enough incremental oil to carry project without acceleration.

Royalty holiday of 5 000 m<sup>3</sup> and lower rates on remaining oil work against revenue neutral position with 0% accelerated reserves.

JF to review 1/8 acceleration case. If he has any questions, he will talk to BJE.

- (c) Forecasting supplied left the total infill production the same and varied only the base case by  $\pm 5\%$ . JF informed us this was not what was required. What was needed was forecasts where the base case were varied by  $\pm 5\%$ , but only "incremental" infill production was kept constant not "total" infill production. *see revised economics Aug 21/91*

New forecasting will be carried out by BJE and forwarded to JF.

3.4 There are no others that have not already been identified.

4.0 Other matters:

4.1 Infill wells will be tested four times a year, most likely using net oil computer. Adjacent producers will be tested one to two times per year using portable test tank.

4.2 Chevron will use non-built up trails and power lines will be buried.

4.3 Logging program will consist of neutron density porosity log, dual induction S.P. and gamma ray. Most likely a core will be cut in each well but this may change as program progresses.

4.4 Pressure surveys will not be conducted specifically on infill wells.

4.5 Yes, will try to shut-in injectors prior to and during drilling, if possible.

JF is happy with the information provided thus far. Has enough information to formulate revenue neutral possibilities for discussion with Bob Dubreuil.

Will call if any other questions arise. Will try to fast track the whole operation of approval. Confirmed earliest go ahead will be August 30. All agreed conference call worked well.

J. D. TUCKER

JDT/lat

cc: Attendees  
Producing Records



Roselea Unit 1 - Preliminary Results - encouraging results  
 good IP, low WOR  
 unflooded pay adjacent to  
 wells with high recovery

	Predicted	Actual	Rise in O/W	Predicted	Actual
	Pay (ft.)	Pay (ft.)	(ft.)	IP's (Bbls.)	IP's (Bbls.)
Roselea 10b-30	25	7	33	25	3
10c-30	20	32	13	25	105
11b-30	30	36	34	25	No Data
8b-30	25	> 48	Nil	25	120
8c-30	30	47	Nil	25	No Data
7b-30	35	40	25	25	No Data
12d-30	30			25	
TOTAL				175 Bbls.	228 Bbls.

10:25:12.02 Fri 08-09-1991

E:\>DIR A:

Volume in drive A is CHVRONNVSU1  
Directory of A:\

BASECASE WK3	24615	08-09-91	8:49a	- Individual Base Case Forecast	
INFILLCA WK3	29157	08-09-91	9:47a	- Infill Well Forecasts + Individual Infill Case	Forecast
GROUPI WK3	6155	08-09-91	8:53a	- Base Case Forecasts for Group(i)	
GROUPII WK3	6144	08-09-91	8:51a	" " " (ii)	
GROUPIII WK3	6142	08-09-91	8:50a	" " " (iii)	
INFILLI WK3	6209	08-09-91	9:52a	- Infill Case Forecasts for Group (i)	
INFILLII WK3	6203	08-09-91	9:53a	" " " (ii)	
INFILLIII WK3	6208	08-09-91	9:49a	" " " (iii)	
CONSOLID WK3	35256	08-09-91	10:24a	- Consolidation of all files	

9 file(s) 126089 bytes  
1329152 bytes free

E:\>

RESPONSE TO BOARD  
DEFICIENCY LETTER (91-08-02)

- 1.1 How long does it take to recover remainder of reserves?
- |       |      |                 |
|-------|------|-----------------|
| 7a-21 | 70.3 | years from 1992 |
| 5a-27 | 51.3 | yrs             |
| 1a-04 | 33.3 | yrs.            |
- 1.2 Production history for each of the producers adjacent to the infill locations.  
- attached.

GROUP II - Base Case

FILE : GROUPII.WK3

3-27,4-27,5-27

Year	Oil Rate (m3/day)	Oil Rate (m3/year) calculated
1991-04	16.80	3976.75
1992	15.91	5576.15
1993	14.68	5145.14
1994	13.55	4751.05
1995	12.52	4390.60
1996	11.57	4060.80
1997	10.71	3758.93
1998	9.91	3482.52
1999	9.19	3229.31
2000	8.52	2997.26
2001	7.92	2784.49
2002	7.36	2589.31
2003	6.85	2410.18
2004	6.38	2245.70
2005	5.94	2094.57
2006	5.55	1955.64
2007	5.18	1827.84
2008	4.84	1710.21
2009	4.54	1601.87
2010	4.25	1502.02
2011	3.99	1409.92
2012	3.75	1324.92
2013	3.52	1246.41
2014	3.31	1173.83
2015	3.12	1106.68
2016	2.95	1044.50
2017	2.78	986.88
2018	2.63	933.43
2019	2.49	883.81
2020	2.36	837.70
2021	2.24	794.81
2022	2.12	754.87

TOTAL 74588.11

GROW II  
INFILL CASE 3-27, 4-27, 5-27

FILE : INFILLII

Year	Oil Rate (m3/day)	Oil Rate (m3/year) calculated
1991-04	16.80	3976.75
1992	15.91	5576.15
1993	14.58	5026.98
1994	13.01	4489.37
1995	11.63	4014.44
1996	10.41	3594.59
1997	9.32	3223.15
1998	8.37	2894.26
1999	7.52	2602.82
2000	6.77	2344.33
2001	6.10	2114.84
2002	5.51	1910.90
2003	4.98	1729.47
2004	4.51	1567.90
2005	4.09	1423.84
2006	3.72	1295.24
2007	3.39	1180.29
2008	3.09	1077.42
2009	2.82	985.22
2010	2.58	902.48
2011	2.37	828.11
2012	2.18	761.17
2013	2.00	700.82
2014	1.84	646.33
2015	1.70	597.04
2016	1.57	552.39
2017	1.46	511.88
2018	1.35	475.05
2019	1.25	441.51
2020	1.17	410.92
2021	1.09	382.98
2022	1.01	357.39
TOTAL		58596.04

INFILE

Well 5a-27-11  
Forecast 30 years

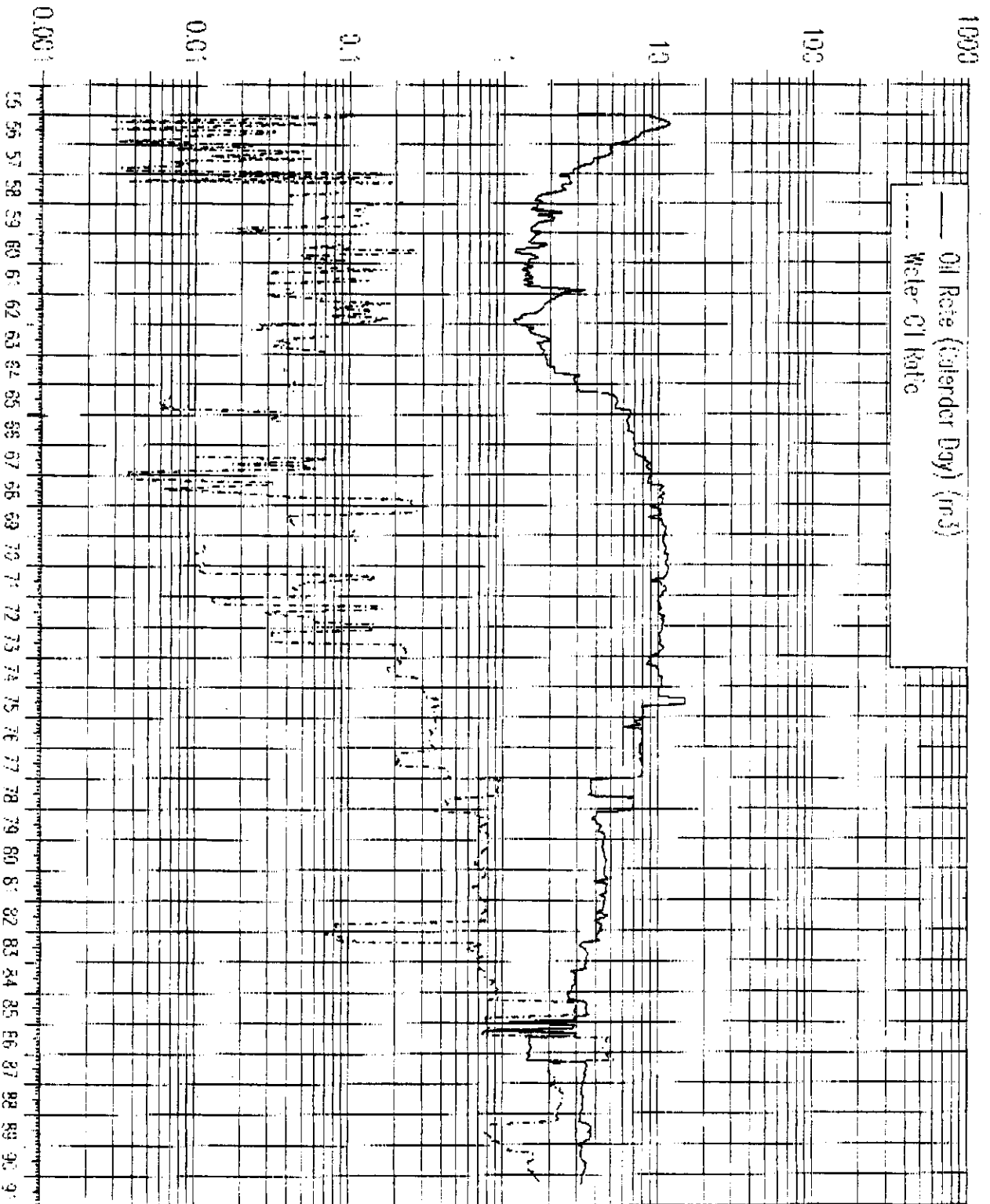
Year	Oil Rate (m3/day)	Oil Rate INCREMENTAL (m3/year) RECOVERY calculated	(M3)
1992	4.00	1423.00	1422.99
1993	3.80	1352.97	1234.81
1994	3.62	1286.40	1024.72
1995	3.44	1223.09	846.94
1996	3.27	1162.91	696.70
1997	3.11	1105.68	569.89
1998	2.96	1051.28	463.02
1999	2.81	999.54	373.05
2000	2.67	950.36	297.43
2001	2.54	903.59	233.94
2002	2.41	859.13	180.72
2003	2.30	816.85	136.14
2004	2.18	776.66	98.86
2005	2.08	738.44	67.71
2006	1.97	702.10	41.70
2007	1.88	667.55	20.01
2008	1.78	634.70	1.91
2009	1.70	603.47	-13.18
2010	1.61	573.78	-25.76
2011	1.53	545.54	-36.27
2012	1.46	518.70	-45.05
2013	1.39	493.17	-52.41
2014	1.32	468.90	-58.59
2015	1.25	445.83	-63.80
2016	1.19	423.89	-68.21
2017	1.13	403.03	-71.97
2018	1.08	383.20	-75.18
2019	1.02	364.34	-77.96
2020	0.97	346.42	-80.36
2021	0.93	329.37	-82.47
2022	0.88	313.16	-84.32

TOTAL

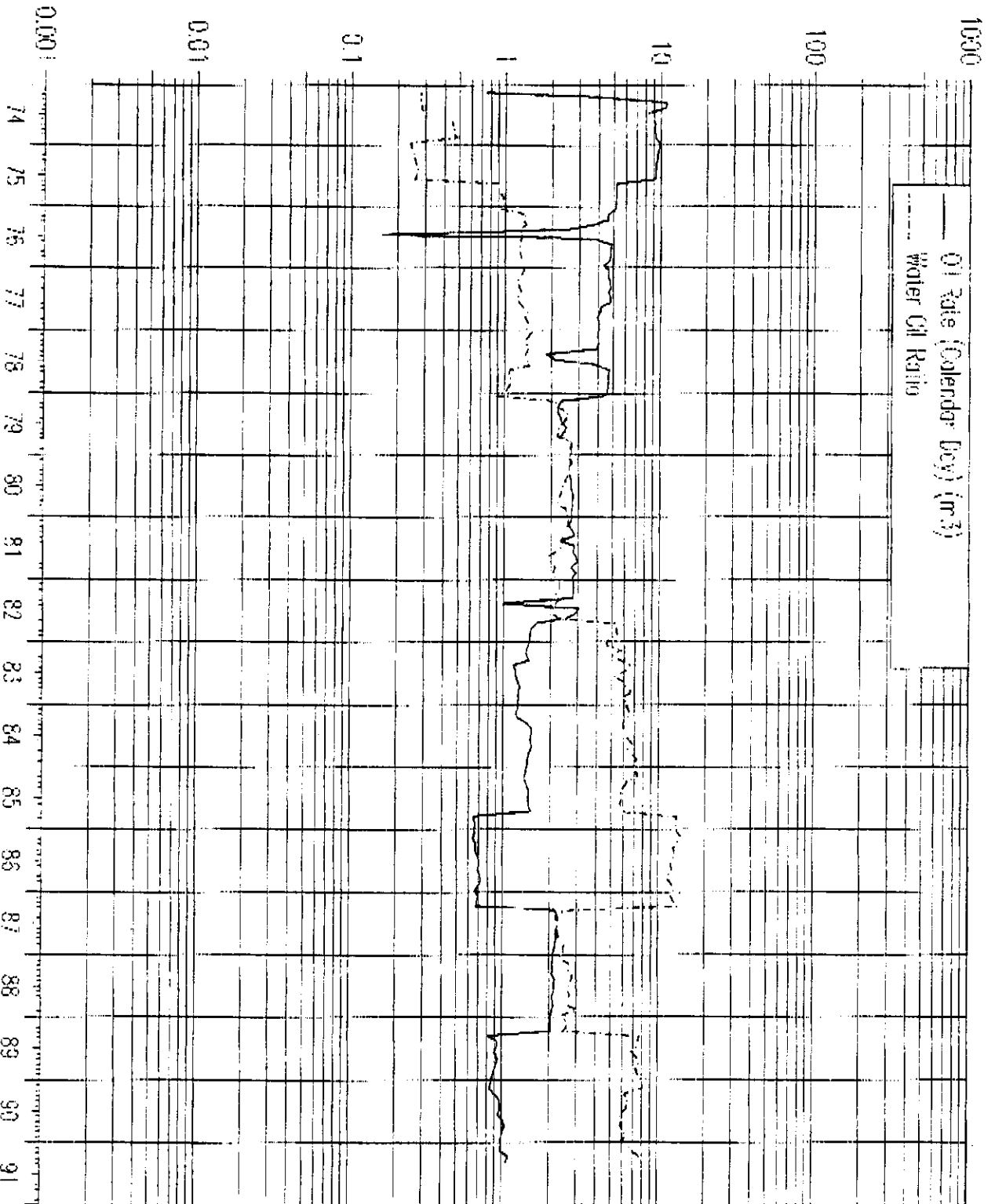
22867.08 6875.01 M3

70% acceleration

WELL: 03-27-011-26W1/



WELL 03-27-01'-26W1/A





WELL: 04-27-011-26W1 /

1000

Oil Rate (Calendar Day) (m3)

Water:Oil Ratio

100

10

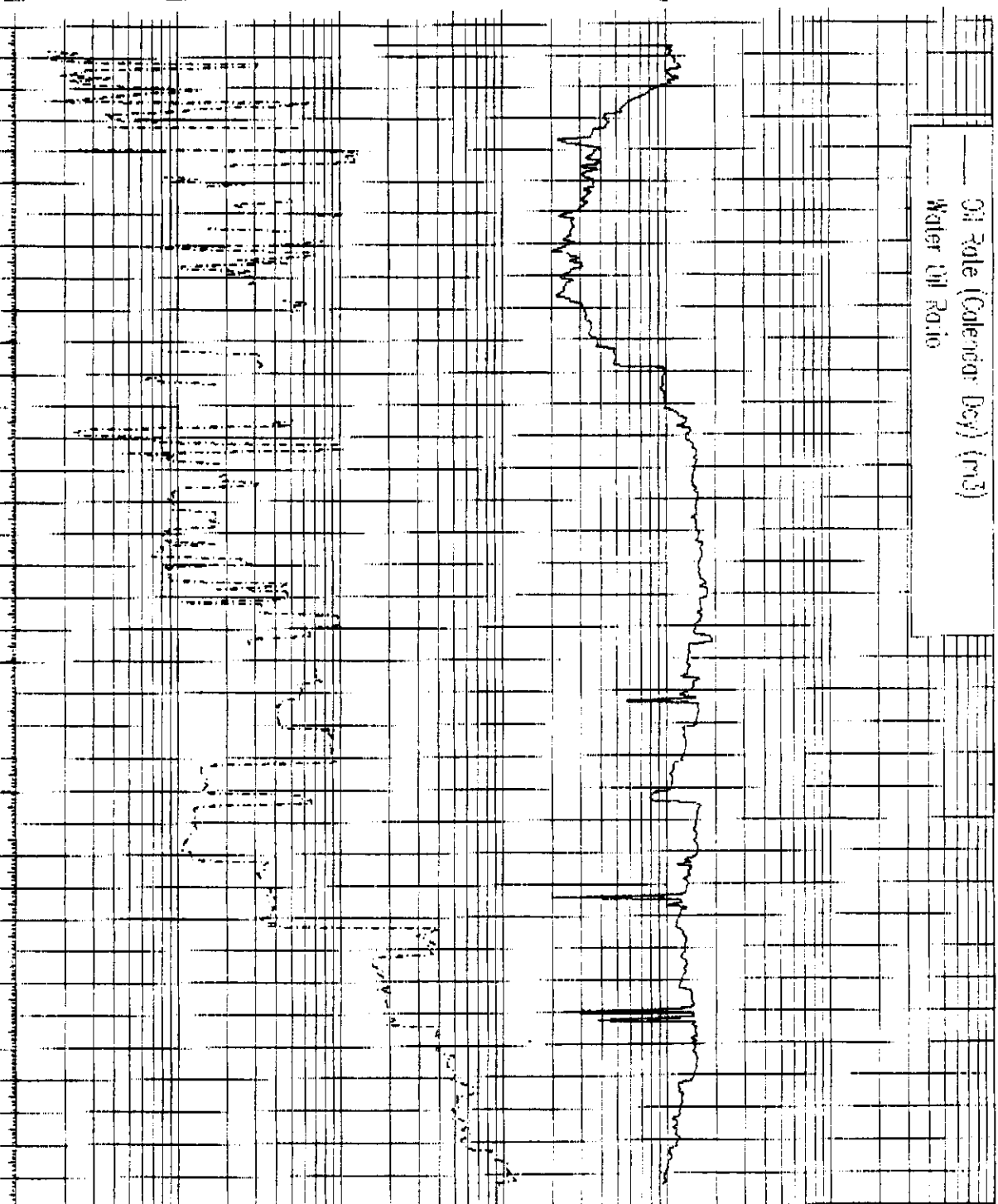
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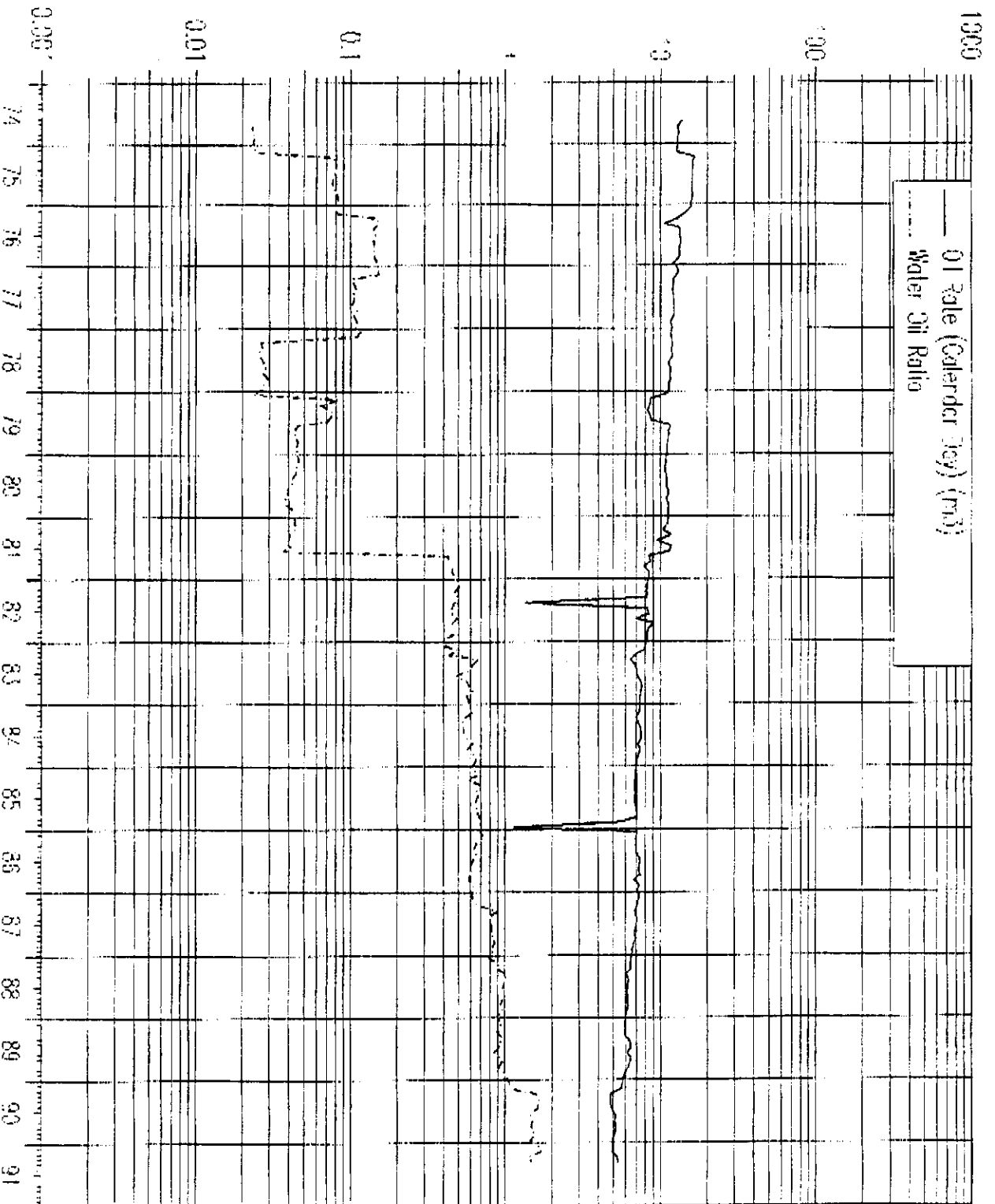
0.01

0.001

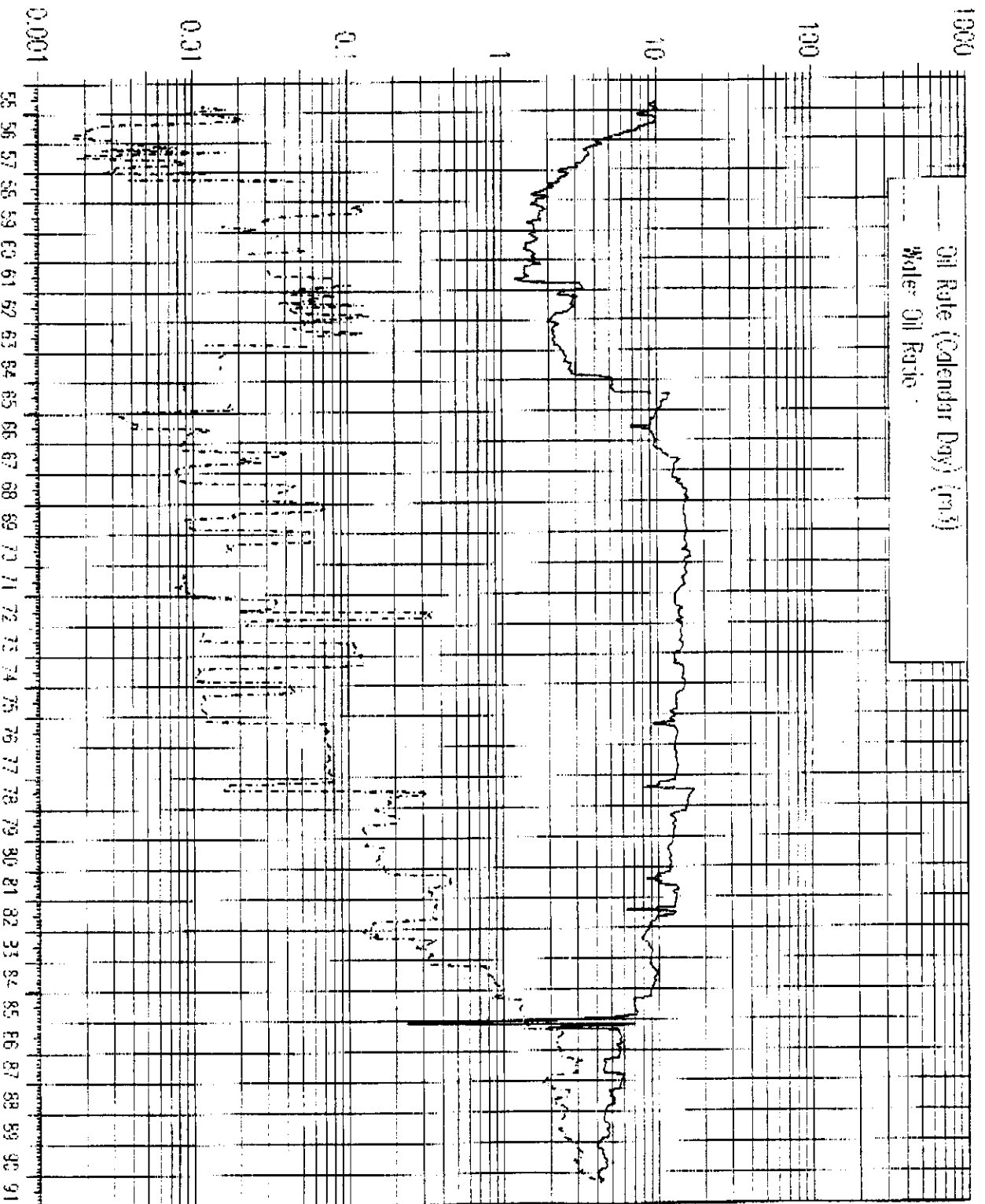
55 56 57 58 59 60 61 62 63 64 65 66 67 68 69 70 71 72 73 74 75 76 77 78 79 80 81 82 83 84 85 86 87 88 89 90 91



WELL: 04-27-011-26W1/A



WELL: 05-27-011-25W1/



GROUP I - *Base Case*

FILE : GROUPI.WK3

1-21, 2-21, 7-21, 8-21

Year	Oil Rate (m3/day)	Oil Rate (m3/year) calculated
1991-04	45.94	10802.46
1992	42.93	14892.10
1993	38.79	13455.25
1994	35.05	12158.62
1995	31.67	10988.43
1996	28.62	9932.23
1997	25.88	8978.82
1998	23.39	8118.10
1999	21.15	7340.97
2000	19.13	6639.24
2001	17.30	6005.51
2002	15.65	5433.13
2003	14.16	4916.10
2004	12.81	4448.99
2005	11.60	4026.95
2006	10.50	3645.56
2007	9.50	3300.88
2008	8.61	2989.31
2009	7.80	2707.65
2010	7.06	2452.97
2011	6.40	2222.67
2012	5.80	2014.38
2013	5.26	1825.97
2014	4.76	1655.51
2015	4.32	1501.26
2016	3.92	1361.67
2017	3.55	1235.31
2018	3.22	1120.92
2019	2.93	1017.34
2020	2.66	923.54
2021	2.41	838.57
2022	2.19	761.59

TOTAL	159712
-------	--------

GROL I  
INFILL CASE 1-21, 2-21, 7-21, 8-21

FILE : INFILLI

Year	Oil Rate (m3/day)	Oil Rate (m3/year) calculated
1991-04	45.94	10802.46
1992	42.93	14892.10
1993	38.56	13192.80
1994	33.87	11587.47
1995	29.75	10180.25
1996	26.14	8946.43
1997	22.98	7864.42
1998	20.20	6915.32
1999	17.77	6082.63
2000	15.63	5351.89
2001	13.75	4710.47
2002	12.11	4147.29
2003	10.66	3652.70
2004	9.39	3218.22
2005	8.28	2836.44
2006	7.30	2500.88
2007	6.43	2205.84
2008	5.68	1946.36
2009	5.01	1718.08
2010	4.42	1517.19
2011	3.91	1340.34
2012	3.45	1184.60
2013	3.05	1047.40
2014	2.70	926.50
2015	2.39	819.92
2016	2.11	725.92
2017	1.87	643.00
2018	1.66	569.81
2019	1.47	505.19
2020	1.30	448.11
2021	1.16	397.67
2022	1.03	353.08
TOTAL		133230.80

1/3

## INFILL WELL FORECASTS

FILE : INFILLCA.WK3

Well 7a-21-11

Forecast 30 years

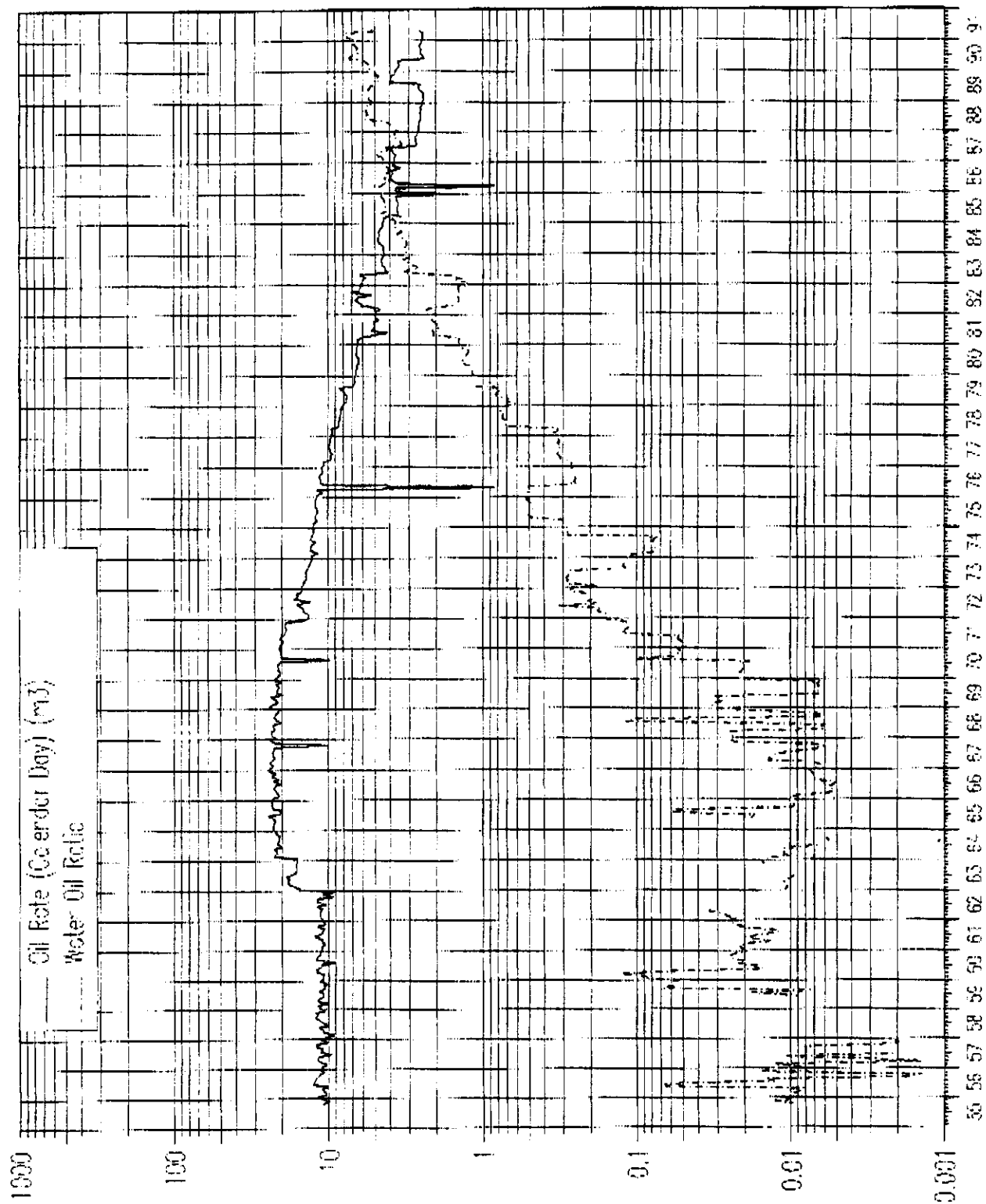
Year	Oil Rate (m3/day)	Oil Rate INCREMENTAL (m3/year) RECOVERY calculated	(M3)
1992	5.00	1787.98	1787.98
1993	4.80	1717.84	1455.39
1994	4.62	1650.45	1079.30
1995	4.43	1585.70	777.52
1996	4.26	1523.50	537.70
1997	4.09	1463.73	349.33
1998	3.93	1406.31	203.53
1999	3.78	1351.14	92.80
2000	3.63	1298.14	10.79
2001	3.49	1247.21	-47.84
2002	3.35	1198.28	-87.56
2003	3.22	1151.27	-112.12
2004	3.09	1106.11	-124.66
2005	2.97	1062.72	-127.79
2006	2.86	1021.03	-123.66
2007	2.74	980.97	-114.06
2008	2.64	942.49	-100.46
2009	2.53	905.52	-84.05
2010	2.43	869.99	-65.79
2011	2.34	835.86	-46.47
2012	2.25	803.07	-26.71
2013	2.16	771.57	-7.00
2014	2.07	741.30	12.29
2015	1.99	712.22	30.87
2016	1.91	684.28	48.53
2017	1.84	657.43	65.12
2018	1.77	631.64	80.53
2019	1.70	606.86	94.71
2020	1.63	583.06	107.63
2021	1.57	560.18	119.29
2022	1.51	538.21	129.70

TOTAL

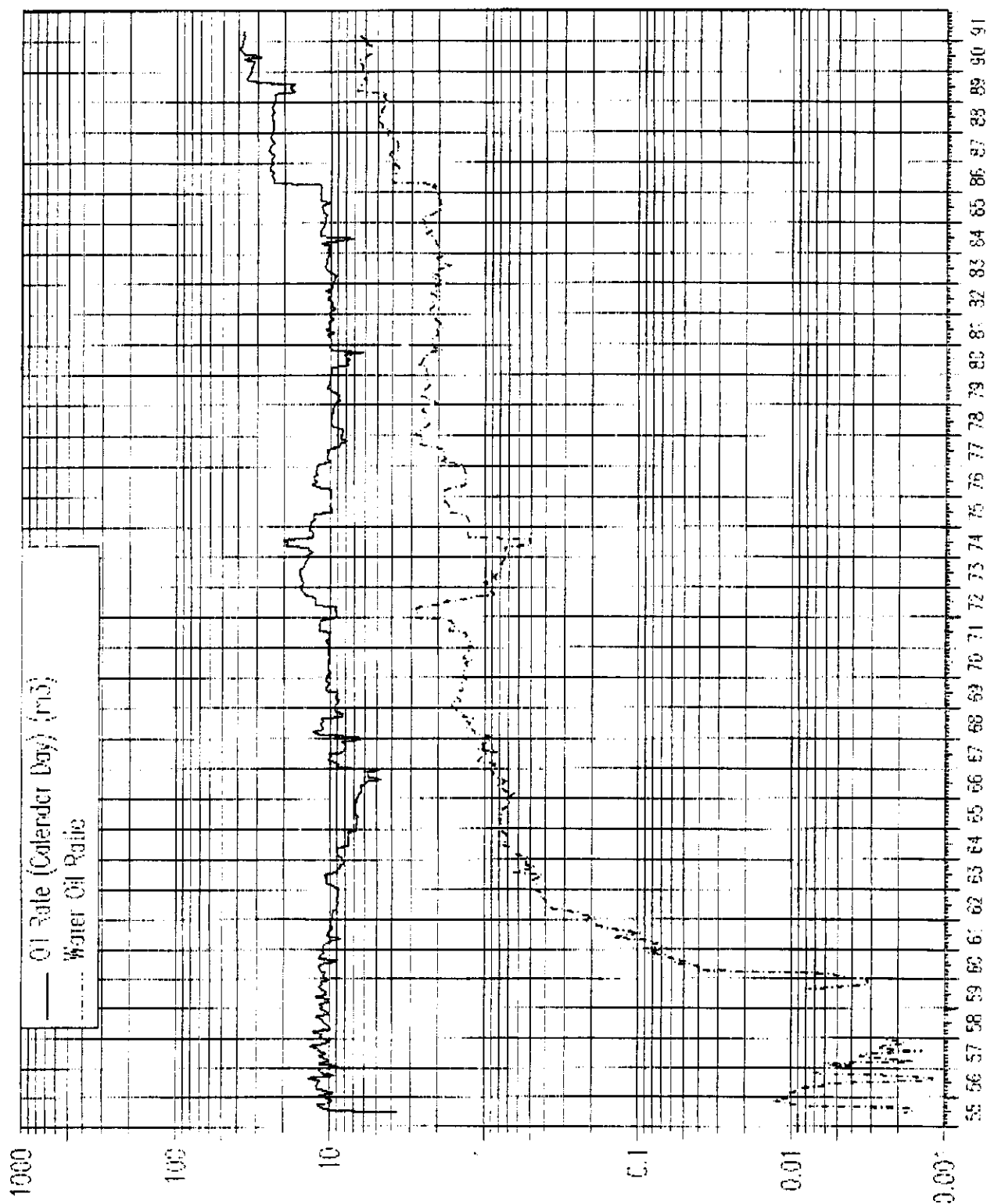
32396.06 5914.84 M3

~ 18.3%

WELL: 01-21-011-26W1/

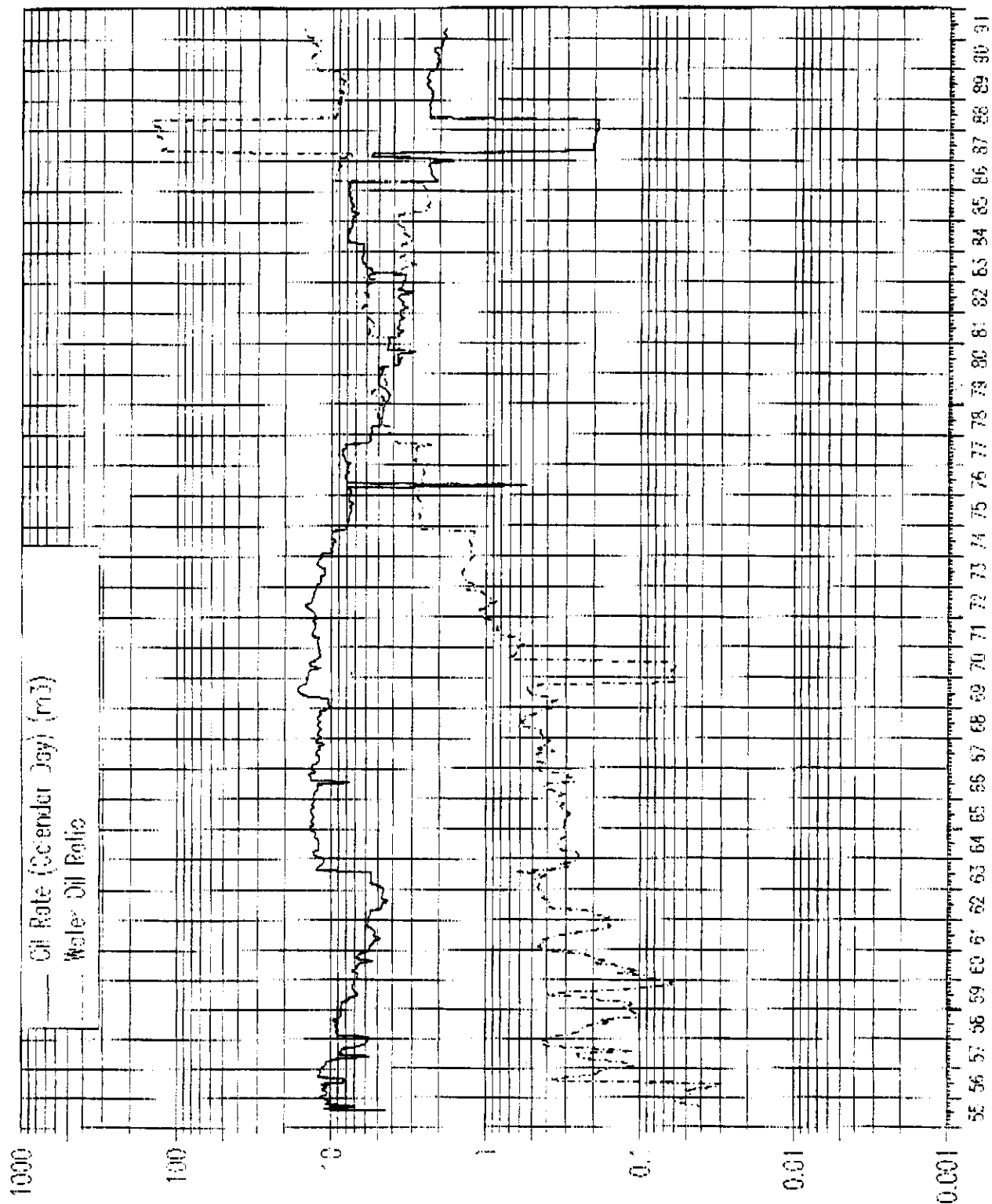


WELL: 02-21-0'-26W1/

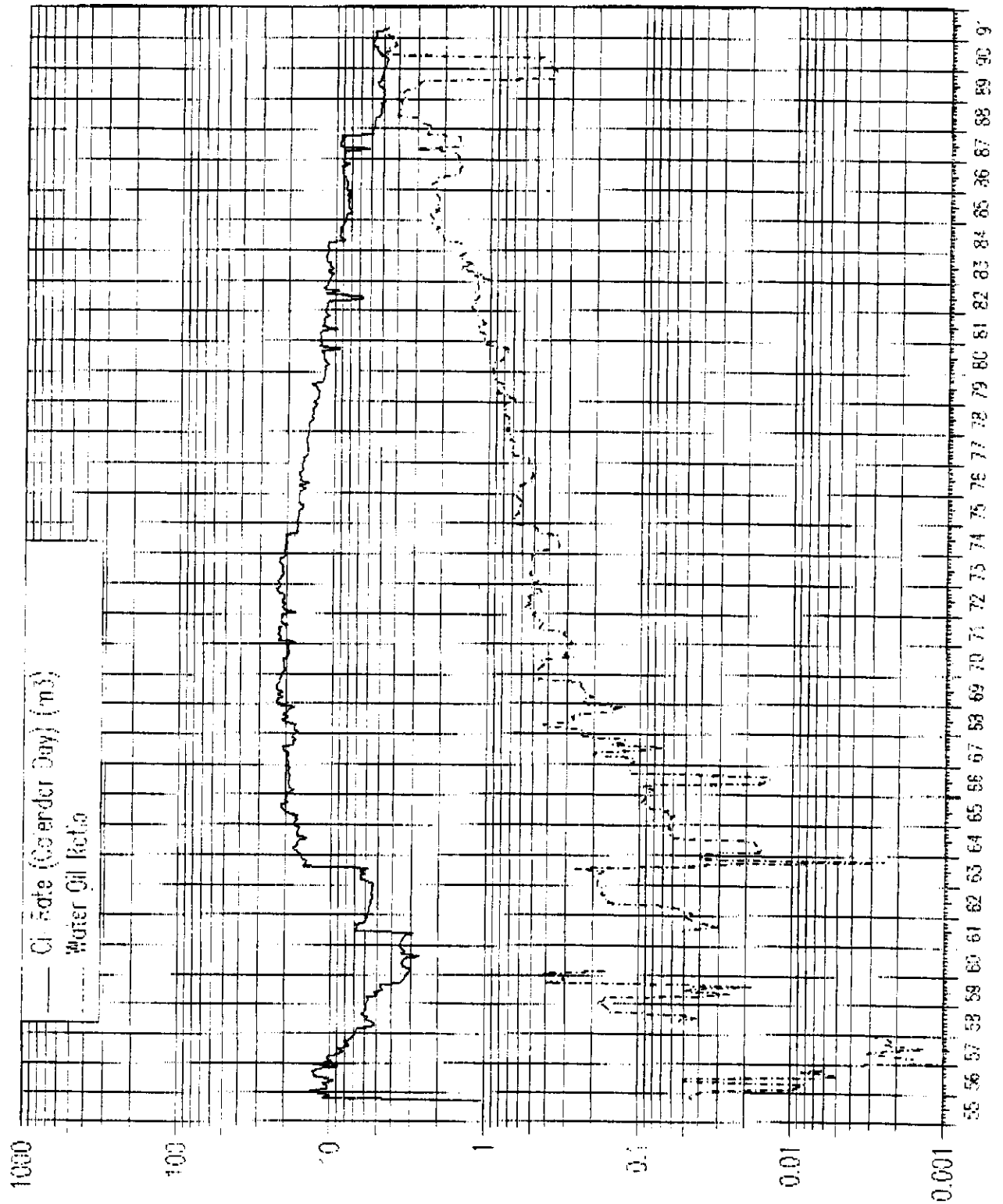




WELL: 07-21-0' 1-26W1 /



WELL: 08-21-011-26W1/



GROL. III - Base Case

FILE : GROUPIII.WK3

13-34,1-04

Year	Oil Rate (m3/day)	Oil Rate (m3/year) calculated
1991-04	8.60	2048.09
1992	8.25	2916.53
1993	7.75	2742.85
1994	7.29	2582.67
1995	6.87	2434.81
1996	6.48	2298.20
1997	6.12	2171.85
1998	5.79	2054.88
1999	5.48	1946.48
2000	5.19	1845.91
2001	4.93	1752.51
2002	4.68	1665.66
2003	4.45	1584.83
2004	4.24	1509.50
2005	4.04	1439.22
2006	3.85	1373.57
2007	3.68	1312.17
2008	3.52	1254.68
2009	3.36	1200.78
2010	3.22	1150.18
2011	3.09	1102.63
2012	2.96	1057.89
2013	2.84	1015.74
2014	2.73	975.98
2015	2.62	938.43
2016	2.52	902.92
2017	2.43	869.31
2018	2.34	837.45
2019	2.25	807.23
2020	2.17	778.52
2021	2.10	751.22
2022	2.02	725.23

TOTAL		48047.9
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GROL III  
INFILL CASE 13.34, 1-4

FILE : INFILIII

Year	Oil Rate (m3/day)	Oil Rate (m3/year) calculated
1991-04	8.60	2048.09
1992	8.25	2916.53
1993	7.58	2634.65
1994	6.88	2395.85
1995	6.26	2182.99
1996	5.71	1992.94
1997	5.22	1822.93
1998	4.78	1670.57
1999	4.39	1533.77
2000	4.03	1410.71
2001	3.71	1299.79
2002	3.42	1199.61
2003	3.16	1108.95
2004	2.92	1026.74
2005	2.71	952.06
2006	2.51	884.06
2007	2.34	822.04
2008	2.17	765.36
2009	2.02	713.46
2010	1.89	665.85
2011	1.76	622.09
2012	1.65	581.81
2013	1.54	544.65
2014	1.44	510.33
2015	1.35	478.58
2016	1.27	449.15
2017	1.19	421.84
2018	1.12	396.47
2019	1.05	372.85
2020	0.99	350.85
2021	0.93	330.33
2022	0.88	311.17

TOTAL 35417.06

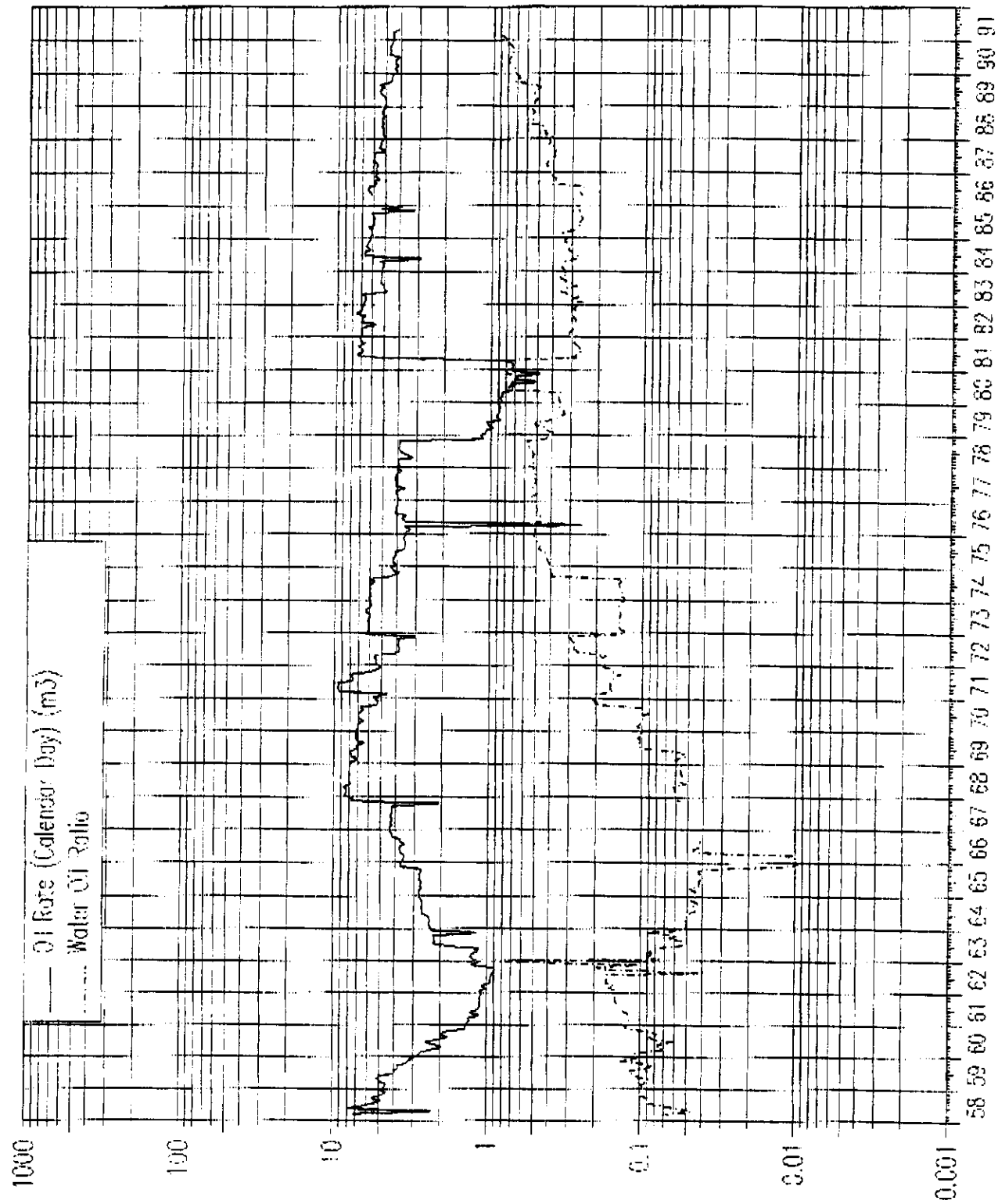
Well 1a-04-12  
Forecast 30 years

Year	Oil Rate (m3/day)	Oil Rate INCREMENTAL (m3/year) RECOVERY calculated	(M3)
1992	4.00	1403.93	1403.94
1993	3.70	1298.95	1190.75
1994	3.42	1201.81	1014.99
1995	3.17	1111.94	860.12
1996	2.93	1028.79	723.53
1997	2.71	951.86	602.93
1998	2.51	880.68	496.37
1999	2.32	814.82	402.12
2000	2.15	753.89	318.69
2001	1.99	697.51	244.79
2002	1.84	645.35	179.29
2003	1.70	597.09	121.21
2004	1.57	552.44	69.68
2005	1.46	511.13	23.97
2006	1.35	472.91	-16.60
2007	1.25	437.54	-52.58
2008	1.15	404.82	-84.49
2009	1.07	374.55	-112.76
2010	0.99	346.54	-137.79
2011	0.91	320.63	-159.91
2012	0.85	296.65	-179.43
2013	0.78	274.47	-196.62
2014	0.72	253.94	-211.70
2015	0.67	234.95	-224.90
2016	0.62	217.38	-236.39
2017	0.57	201.13	-246.34
2018	0.53	186.09	-254.90
2019	0.49	172.17	-262.21
2020	0.45	159.30	-268.37
2021	0.42	147.38	-273.51
2022	0.39	136.36	-277.71
TOTAL		17086.98	4456.16 M3

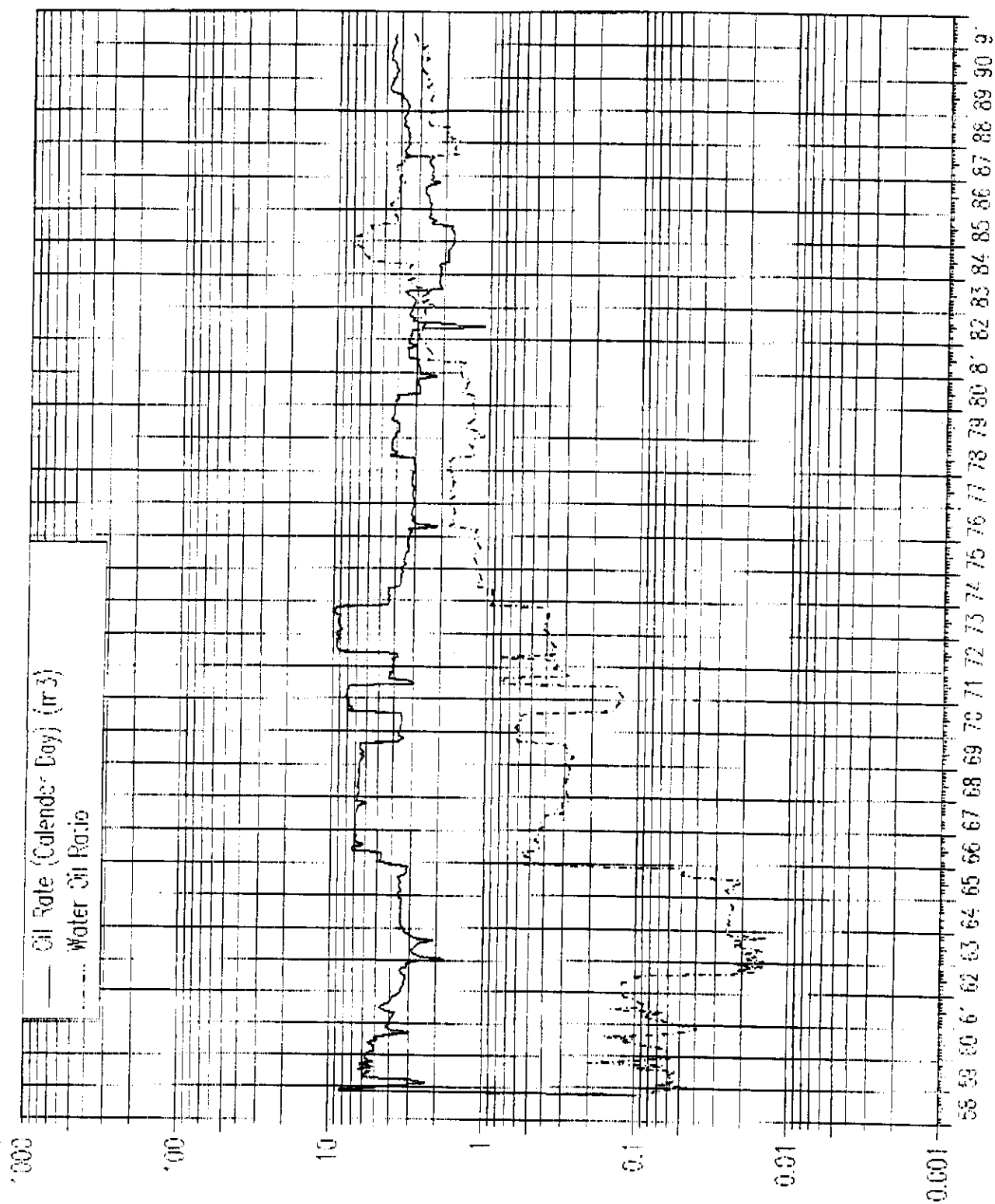
TOTAL INCREMENTAL 17246.01 M3  
RECOVERY

accelerated prod.  
74%

WELL: 01-04-012-26W1/



WELL: 13-34-0'1-26W1/



Calgary, Alberta  
August 26, 1991

Ncl Oil Computer

MARK BORN

At present, the N.O.C. is working satisfactorily. Tests from the N.O.C. are accurate and this machine has enabled us to test more frequently. There are, however, two problems with this machine; one is power supply and the second is gas break out.

The N.O.C. needs a steady supply of 120 V AC power (i.e. no fluctuations) to operate properly. At most of our existing leases, 120 V is not readily available so we have used a transformer to connect across the jack starter. This installation does not meet safety codes, and therefore has been discontinued. At our new locations, such as the 1989 North Scallion infill, this is not a problem and the N.O.C. is working very well. We should ensure that all future leases have 120 V power readily accessible to the N.O.C.

Gas breaking out of solution causes wide fluctuations in density leading to erroneous total fluid produced numbers and cuts. This is especially true at field headers, where more gas breaks out. The tests at wellheads seem to have eliminated this problem in most cases, but not in all cases. RoseMount Instruments is currently working on inputting a program into the computer so that it will ignore densities outside a specified range, thereby eliminating slug flow problems. We hope to have this problem fixed by late fall. Once this is done, we should be able to test any well up to 200 m<sup>3</sup> FPD and hopefully beyond.

TOM RUMML

MWB/pmf

pc: Manitoba Petroleum Branch





The Oil and Natural Gas  
Conservation Board

Room 309  
Legislative Building  
Winnipeg, Manitoba, CANADA  
R3C 0V8

(204) 945-3130

August 2, 1991

Mr. C. G. Folden, P. Eng.  
Manager, Reservoir Engineering  
Chevron Canada Resources  
500 - 5th Avenue S.W.  
Calgary, Alberta  
T2P 0L7

Dear Sir:

Re: North Virden Scallion Unit No. 1  
Application for Reduced Spacing

Your application dated July 12, 1991 for approval of special drilling spacing units in a part of North Virden Scallion Unit No. 1 (NVSU No. 1) is acknowledged.

The Board has completed a preliminary review of the subject application. The Board has some questions with respect to the incremental recovery estimates, infill well production forecast and project economics presented in the application and discussed with representatives of the Petroleum Branch.

## 1.0 Incremental Recovery Predictions

Each of the proposed infill locations is estimated to recover an additional 2.3% OOIP over the 30 year project life despite very different geological, reservoir and performance characteristics. The Board recognizes the difficulty estimating incremental recoverable reserves from infill drilling. The intent of the following questions is to enhance the Board's understanding of the mechanisms contributing to the incremental recovery and the upside potential and downside risk associated with each location.

1.1 The Board understands Chevron has estimated an incremental recovery of 3.2% OOIP for each of the infill locations of which only 2.3% OOIP will be recovered over the 30 year project life used to evaluate the project economics. How long does it take to recover the remainder of the incremental reserves?

1.2 Please provide graphs showing the production history (daily oil and WOR versus time) for each of the producers adjacent to the infill locations.

1.3 Between 1974 and 1978 a total of 6 "corridor" wells were drilled on 8 ha spacing in NVSU No. 1. Chevron in a previous reduced spacing application stated the incremental recovery for the corridor wells was 6.1% OOIP. The 1989 NVSU No. 1 reduced spacing pilot project was estimated to recover an additional 1.7% OOIP. Briefly discuss why neither of these reduced spacing projects accurately models the expected performance of the three proposed infill wells.

1.4 The four wells offsetting the proposed 7A-21-11-26 infill location have currently recovered 55.7% OOIP and are estimated to ultimately recover 70.8% OOIP. Why does Chevron think an additional well at 7A-21 will recover any incremental oil?

1.5 The two injectors 16-33-11-26 and 4-3-12-26 offsetting the 1A-4-12-26 location are only completed over limited intervals near the top of the Cherty. Would incremental recovery at 1A-4 be increased by full-face completion and injection profile modification of the injectors?

1.6 Assuming each infill well encounters incremental reserves, what potential future infill drilling locations are there in NVSU No. 1?

## 2.0 Reduced Spacing Production Forecast

2.1 One of the assumptions used to develop the reduced spacing production forecast was predicted oil rates and WOR for the infill wells were based on the performance of adjacent producers. This appears to hold true for 5A-27 and 1A-4, but the average productivity of producers adjacent to 7A-21 is 11.6 m<sup>3</sup>/d, not 5.0 m<sup>3</sup>/d. Please explain the reasons for using a lower initial productivity for the 7A-21 well. What is the explanation for the high productivity of the 2-21-11-26 well?

2.2 Table II in the application lists the NVSU No. 1 Base Case and Infill Case production forecasts. The Infill Case production forecast is obviously the summation of a number of individual production forecasts. Please provide in tabular form and on diskette in ASCII file format if possible, the following individual production forecasts:

(a) the Base Case (assuming no infill drilling) production forecast for the following groups of wells;

- (i) 1-21-11-26, 2-21-11-26, 7-21-11-26 and 8-21-11-26,
- (ii) 3-27-11-26, 4-27-11-26 and 5-27-11-26, and
- (iii) 13-34-11-26 and 1-4-12-26.

(b) the production forecast for each of the infill wells, listing separately the incremental and acceleration volumes produced, and

(c) the Infill Case (showing the impact of interference by the infill wells) production forecast for the groups of wells listed in (a).

## 3.0 Project Economics

Of particular concern to the Board are the project economics. According to the application, the Crown stands to lose \$2 028 M over the 30 year project evaluation period. The Board in its review of applications not only considers the technical merits of the project but also the economic benefits

and the distribution of those benefits. The following questions may help to clarify the economic impact of the project on the Crown. However, Chevron may wish to consider alternative methods for determining Crown royalties and production tax that would see the project benefits shared more equitably among the unit working interest owners and royalty owners including the Crown. Special royalty and production tax treatment is provided for under Section 9 of The Petroleum Crown Royalty and Incentive Regulation and Section 5 of The Oil and Gas Production Tax Regulation. As suggested by the Petroleum Branch at the July 23, 1991 meeting, one option would be to use the same methodology for determining new oil as approved for Daly Unit No. 3 - new oil status is granted for all oil produced from the unit in excess of the historical production decline.

3.1 If the adjacent producers do not experience an accelerated decline until 1993-01, Crown royalties and production tax revenue should not change appreciably between the Base Case and Infill Case economics in Attachment No. 6. The Board believes Chevron has classified the initial production from the infill wells as both holiday oil and new oil, this double accounting is incorrect. Production from the infill wells is classified as holiday oil until the calculated holiday oil volume is produced, thereafter, infill well production is classified as new oil. Please revise Attachment No. 6 to reflect this correction.

3.2 What are the estimated project capital costs? What portion of the capital costs will be spent in Manitoba for local services and supplies?

3.3 The Board is interested in the sensitivity of Crown revenues to various economic assumptions used in the project economics. Please discuss the following scenarios and provide an economic summary in the form used in Attachment No. 6 for each:

(a) Assuming the total production from the infill wells is held constant (the Board has calculated total infill well production from Table II of 74 759.3 m<sup>3</sup>), what proportion of this production would have to be incremental reserves to have Crown revenues remain unchanged between the Base Case and Infill Case? This scenario will result in an increase in total unit production over the present Infill Case, as adjacent producers will recover more oil.

(b) Assuming the incremental recoverable reserves from the infill wells is held constant at 17 200 m<sup>3</sup>, how much would the accelerated production associated with the infill wells have to be reduced to have Crown revenues remain unchanged between the Base Case and Infill Case? This scenario will result in no change in total unit production over the present Infill Case because the drop in infill well accelerated production will be offset by a similar increase in adjacent well production.

(c) Assuming the total production from the infill wells is held constant, an increase or decrease in the NVSU No. 1 Base Case production forecast will effect the percentage of total unit production that is classified as new oil. What effect does a +5% variation in the Base Case production forecast have on the Infill Case Crown revenues?

3.4 Are there any other economic assumptions that contribute significantly to the difference in Crown revenues between the Base Case and the Infill Case?

4.0 Other Matters

4.1 How frequently does Chevron plan to production test the infill wells using either a portable tank or the net oil computer? Will the adjacent producers be tested at the same frequency?

4.2 Does Chevron plan to use non built-up trails and bury power lines underground for the infill locations?

4.3 Please provide a summary of well data that will be obtained during drilling of the infill wells (ie: logs, cores, tests, etc.).

4.4 Does Chevron plan to conduct pressure surveys on the infill wells?

4.5 Does Chevron plan to shut-in the offsetting injectors during the drilling of the infill wells?

If you have any questions in respect of these matters, please contact L. R. Dubreuil, Director of Petroleum or John N. Fox, Chief Petroleum Engineer at (204) 945-6573 or 945-6574, respectively.

Yours respectfully,

A handwritten signature in dark ink, appearing to read 'H. Clare Moster', with a large, sweeping flourish at the end.

H. Clare Moster  
Deputy Chairman

Attachment 6  
Revised August 13, 1991

NORTH VIRDEN SCALLION UNIT #1 INFILL PROJECT  
CROWN ROYALTIES AND MINERAL TAXES

DATE	BASE CASE			INFILL CASE		
	CROWN ROYALTY (E3 \$)	MINERAL TAX (E3 \$)	FREEHOLD ROYALTY (E3 \$)	CROWN ROYALTY (E3 \$)	MINERAL TAX (E3 \$)	FREEHOLD ROYALTY (E3 \$)
1992	255	2267	1940	255	2276	2021
1993	240	2088	1892	241	2076	1934
1994	229	1944	1877	228	1909	1908
1995	219	1808	1868	216	1753	1890
1996	205	1656	1841	202	1589	1855
1997	193	1500	1804	188	1422	1812
1998	181	1357	1774	176	1273	1777
1999	170	1217	1741	163	1132	1740
2000	158	1084	1704	151	999	1701
2001	149	971	1691	142	885	1685
2002	140	864	1680	134	783	1674
2003	132	764	1667	126	689	1661
2004	124	672	1656	118	601	1650
2005	117	587	1646	111	524	1641
2006	108	506	1624	103	450	1621
2007	100	434	1604	96	386	1603
2008	92	370	1580	88	327	1582
2009	84	312	1559	81	274	1565
2010	78	262	1540	75	229	1549
2011	71	215	1501	69	188	1514
2012	65	175	1462	63	151	1480
2013	59	140	1426	58	122	1448
2014	54	113	1389	53	94	1415
2015	49	85	1354	49	73	1385
2016	45	65	1319	45	55	1354
2017	41	47	1285	41	40	1324
2018	37	33	1251	38	27	1295
2019	34	21	1218	35	19	1267
2020	31	15	1186	32	12	1239
2021	28	9	1155	29	8	1212
2022	26	5	1125	27	5	1187
TOTAL	3514	21586	48359	3433	20371	48989

INCREMENTAL -  
CROWN  
BENEFITS  
ANN.

+9 -  
-11 -2  
-36 -3  
-58 -9

\$ 25100(n)

\$ 23804(n)

Δ 1296n

Revised Aug 13, 1991

## CROWN ROYALTIES AND MINERAL TAXES DISCOUNTED AT 10%

CASE	TOTAL CROWN ROYALTY (E3M3)	DISCOUNTED CROWN ROYALTY (E3M3)	TOTAL MINERAL TAX (E3M3)	DISCOUNTED MINERAL TAX (E3M3)
BASE	3514	1751	21586	13033
INFILL	3433	1718	20371	12535

Δ - 817

Δ - 337

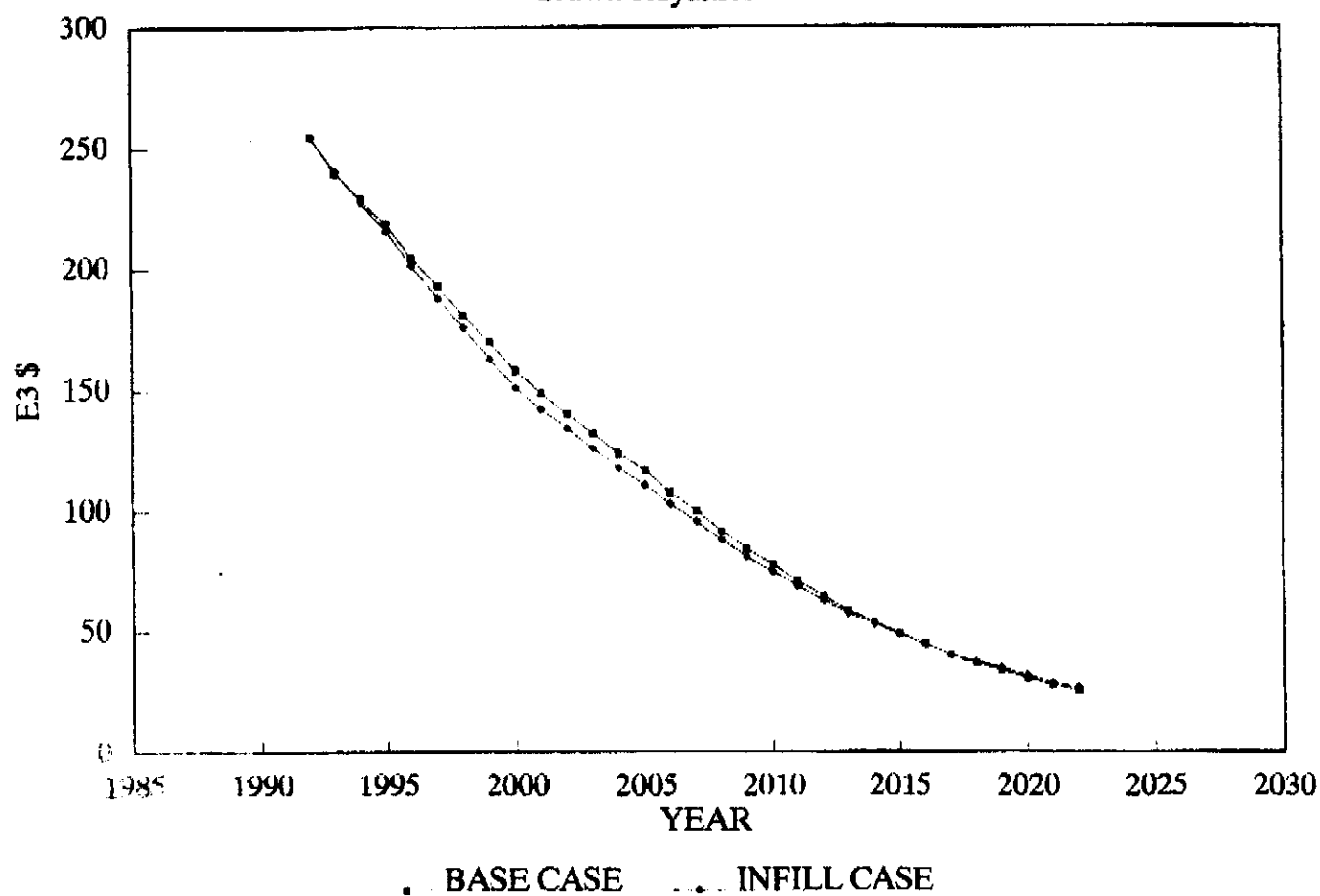
-1215 Δ

- 498

UNDISC. <sup>8</sup> - 12967DISC. <sup>4</sup> - 5317

# NORTH VIRDEN SCALLION UNIT #1

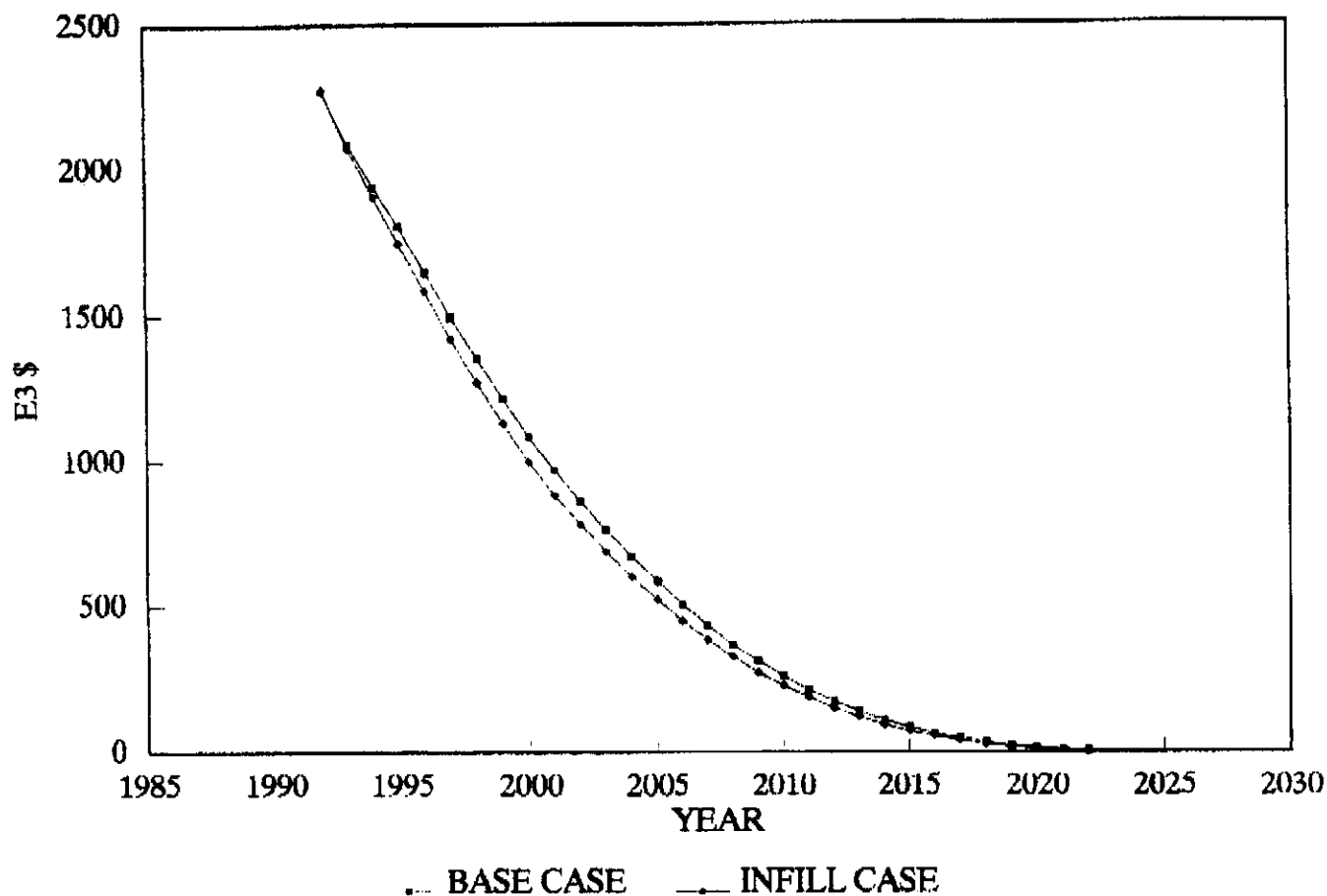
Crown Royalties vs. Time



Revised Aug 13, 1991

# NORTH VIRDEN SCALLION UNIT #1

Mineral Taxes vs. Time

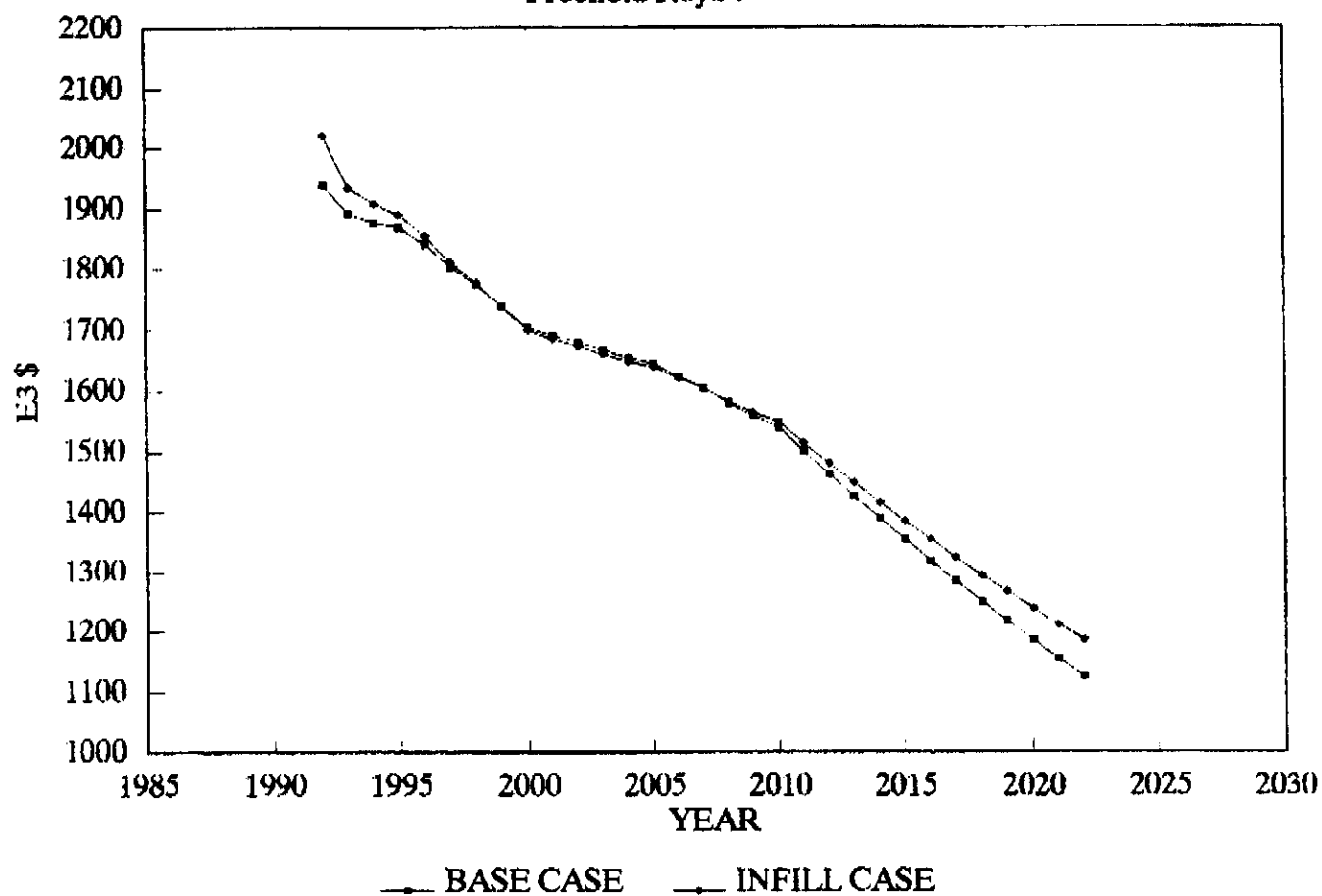




Revised Aug 13, 1991

# NORTH VIRDEN SCALLION UNIT #1

Freehold Royalties vs. Time



CASE 3.3(a) see Board  
deficiency letter  
91-08-02

# NORTH VIRDEN SCALLION UNIT #1

## REDUCED SPACING FORECASTS FOR ENTIRE UNIT

SENSITIVITY CASE: 100% INCREMENTAL OIL 74000 m<sup>3</sup>

YEAR	BASE CASE (E3M3/YEAR)	UNIT % NEW OIL	INFILL CASE (E3M3/YEAR)	UNIT % NEW OIL
1992	309.6	113	117	3.90
1993		105	110	4.10
1994		99	103	4.15
1995		92	96	4.20
1996		86	90	4.25
1997		81	84	4.31
1998		76	79	4.36
1999		71	74	4.42
2000		66	69	4.48
2001		62	65	4.54
2002		58	61	4.61
2003		54	57	4.67
2004		51	53	4.74
2005		47	50	4.81
2006		44	47	4.85
2007		41	44	4.95
2008		39	41	5.03
2009		36	38	5.11
2010		34	36	5.19
2011		32	33	5.27
2012		30	31	5.35
2013		28	29	5.44
2014		26	27	5.53
2015		24	26	5.62
2016		23	24	5.72
2017		21	23	5.82
2018		20	21	6.02
2019		19	20	6.13
2020		17	19	6.24
2021		16	17	6.35
2022		15	16	6.46
sum		1526		1600

INFILL  
production  
(10<sup>3</sup> L/D)

4.56  
4.51  
4.27  
4.03  
3.83  
3.62  
3.44  
3.27  
3.09  
2.93  
2.81  
2.66  
2.51  
2.41  
2.28  
2.18  
2.06  
1.94  
1.87  
1.74  
1.66  
1.58  
1.49  
1.46  
1.37  
1.34  
1.26  
1.23  
1.19  
1.08  
1.03

NOTE: MUST BE REDUCED  
53,000 m<sup>3</sup> FROM  
BASE CASE (ORIG)  
THIS ASSUMES  
EXISTING WELLS  
RECOVER ONLY  
3/4 OF THEIR  
ESTIMATED  
ROT. REC. RES.

IS AND SHOULD BE  
ESSENTIAL UNCHANGED  
FROM INFILL CASE (ORIG)

NOTE: CHEVRON ASSUMES WELLS PRODUCE  
350 DAYS PER YEAR

NOTE: 53400 m<sup>3</sup> ROT. REC. RESERVES  
CHEVRON ESTIMATES WILL  
BE DRAINED FROM EXISTING  
WELLS BY INFILL  
WELLS

NORTH VIRDEN SCALLION UNIT #1 INFILL PROJECT  
CROWN ROYALTIES AND MINERAL TAXES  
SENSITIVITY CASE: 100% INCREMENTAL OIL

DATE	BASE CASE			INFILL CASE		
	CROWN ROYALTY (E3 \$)	MINERAL TAX	FREEHOLD ROYALTY (E3 \$)	CROWN ROYALTY (E3 \$)	MINERAL TAX (E3 \$)	FREEHOLD ROYALTY (E3 \$)
1992	255	2267	1940	255	2273	2019
1993	240	2088	1892	249	2161	1971
1994	229	1944	1877	237	2009	1956
1995	219	1808	1868	227	1868	1948
1996	205	1656	1841	214	1711	1920
1997	193	1500	1804	201	1550	1883
1998	181	1357	1774	189	1403	1853
1999	170	1217	1741	177	1259	1819
2000	158	1084	1704	164	1122	1782
2001	149	971	1691	155	1007	1769
2002	140	864	1680	147	896	1759
2003	132	764	1667	138	795	1746
2004	124	672	1656	130	699	1736
2005	117	587	1646	122	612	1726
2006	108	506	1624	114	527	1705
2007	100	434	1604	106	451	1685
2008	92	370	1580	97	383	1660
2009	84	312	1559	90	325	1640
2010	78	262	1540	82	270	1621
2011	71	215	1501	75	222	1581
2012	65	175	1462	68	179	1542
2013	59	140	1426	63	142	1505
2014	54	113	1389	57	111	1467
2015	49	85	1354	52	85	1431
2016	45	65	1319	48	64	1396
2017	41	47	1285	43	46	1361
2018	37	33	1251	39	33	1326
2019	34	21	1218	36	22	1293
2020	31	15	1186	33	14	1260
2021	28	9	1155	30	8	1228
2022	26	5	1125	27	5	1198
TOTAL	3514	21586	48359	3665	22252	50786

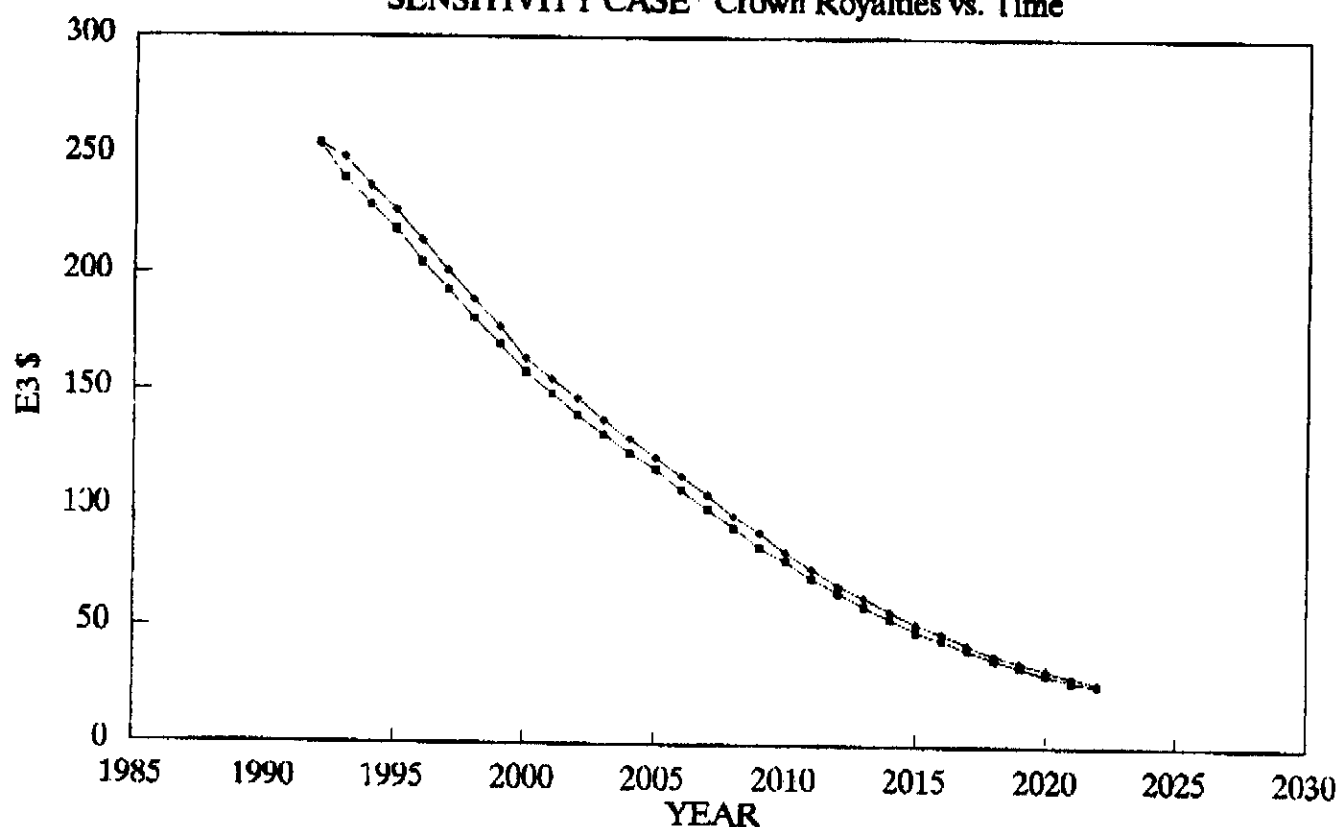
THESE NUMBERS  
ARE WRONG - USE ONLY  
FOR COMPARISON  
PURPOSES  
DON'T REFLECT  
REDUCED PRODUCTION  
VOLUMES - HOWEVER CAN BE USED FOR  
COMPARISON WITH CASES  
EVALUATED AGAINST  
ORIGINAL  
BASE CASE

**CROWN ROYALTIES AND MINERAL TAXES DISCOUNTED AT 10%**  
**SENSITIVITY CASE: 100% INCREMENTAL OIL**

<b>CASE</b>	<b>TOTAL CROWN ROYALTY (£3 \$)</b>	<b>DISCOUNTED CROWN ROYALTY (£3 \$)</b>	<b>TOTAL MINERAL TAX (£3 \$)</b>	<b>DISCOUNTED MINERAL TAX (£3 \$)</b>
<b>BASE</b>	<b>3514</b>	<b>1751</b>	<b>21586</b>	<b>13033</b>
<b>INFILL</b>	<b>3665</b>	<b>1814</b>	<b>22252</b>	<b>13410</b>

# NORTH VIRDEN SCALLION UNIT #1

SENSITIVITY CASE\* Crown Royalties vs. Time

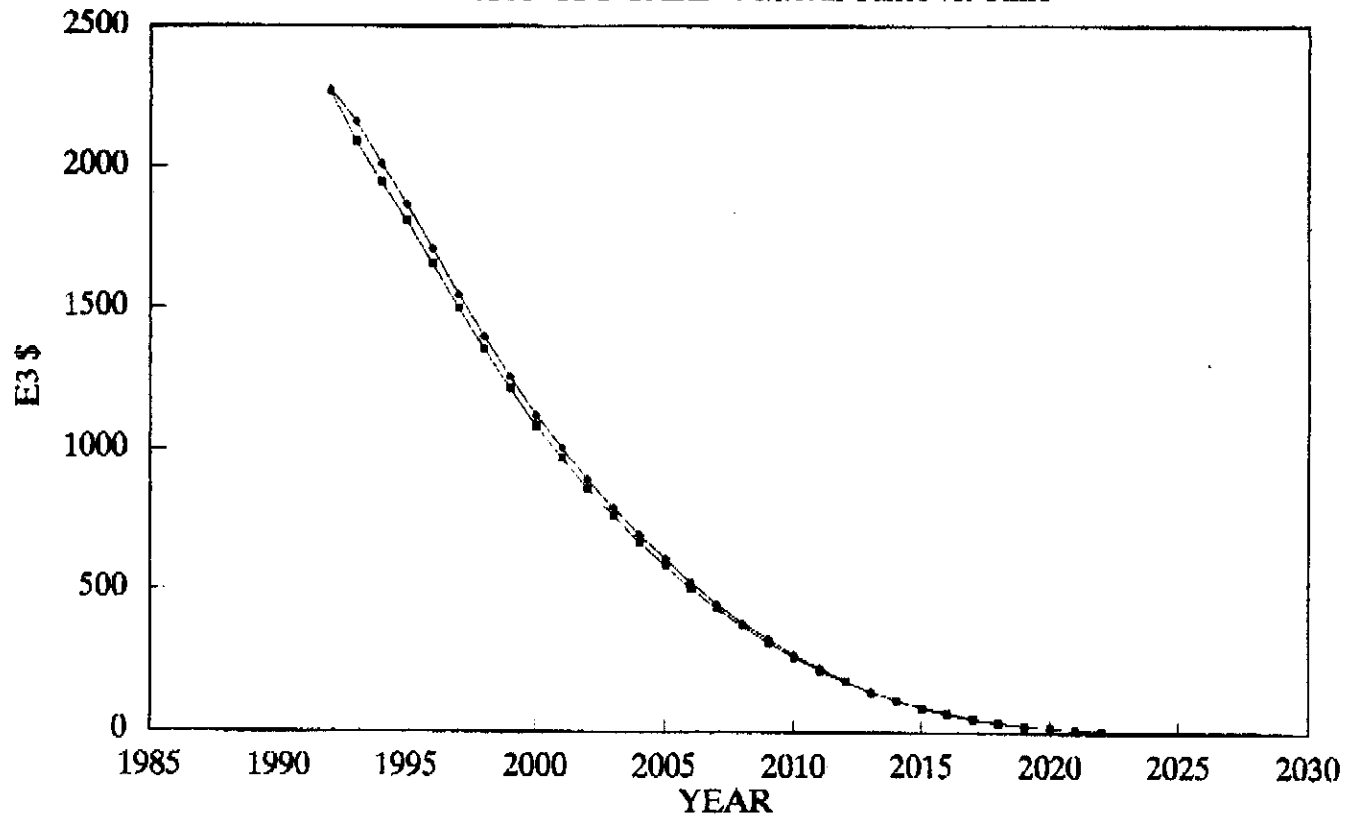


—■— BASE CASE      -○- INFILL CASE

\* 100% INCREMENTAL OIL

# NORTH VIRDEN SCALLION UNIT #1

SENSITIVITY CASE\* Mineral Taxes vs. Time

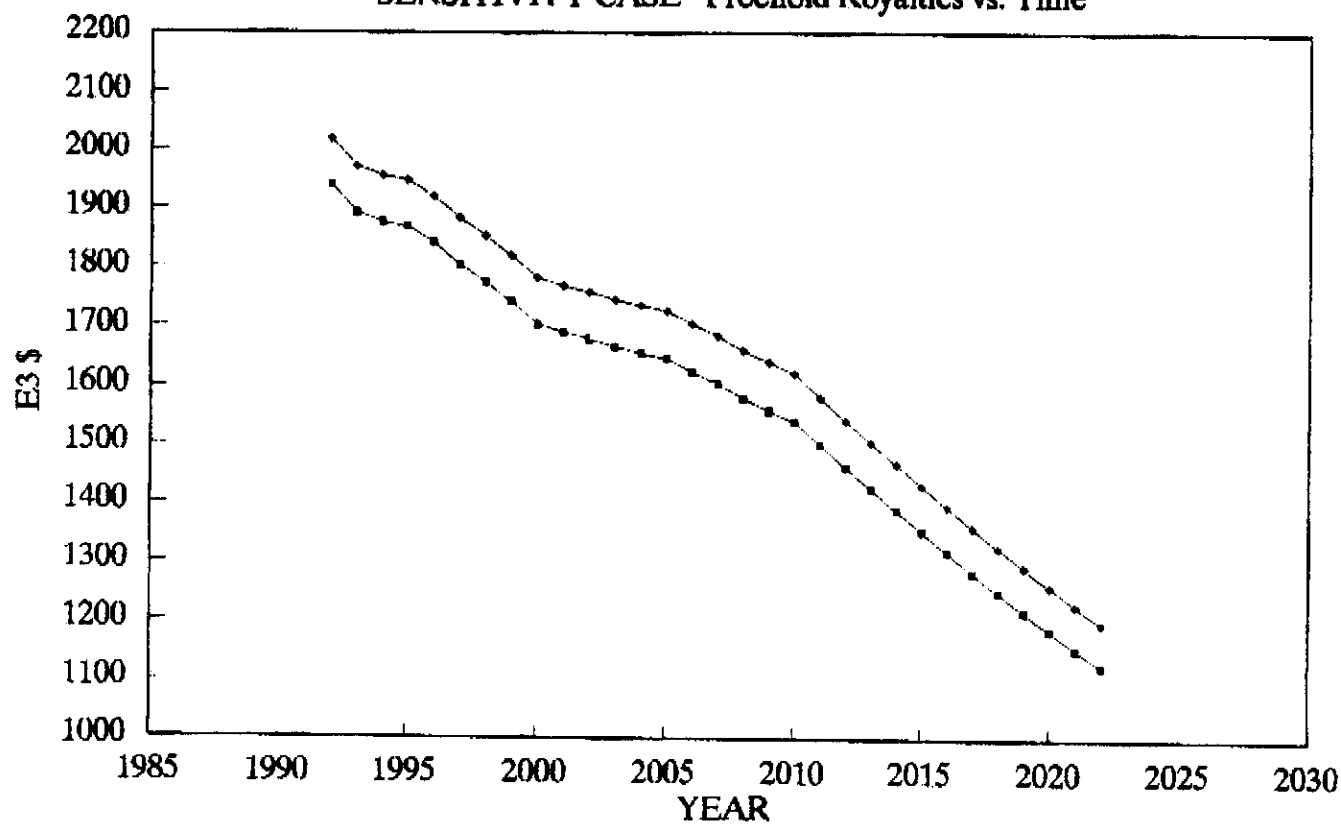


—■— BASE CASE    -▲- INFILL CASE

\* 100% INCREMENTAL OIL

# NORTH VIRDEN SCALLION UNIT #1

SENSITIVITY CASE\* Freehold Royalties vs. Time



—•— BASE CASE    —•— INFILL CASE

\* 100% INCREMENTAL OIL

CASE 3.3(b) see Board deficiency  
letter 91-08-02

BELINDA 403 234 5484

NORTH VIRDEN SCALLION UNIT #1  
REDUCED SPACING FORECASTS FOR ENTIRE UNIT  
SENSITIVITY CASE: 1/8 ACCELERATED PRODUCTION

YEAR	BASE CASE (E3M3/YEAR)	UNIT % NEW OIL	INFILL CASE (E3M3/YEAR)	UNIT % NEW OIL
1992	113	0.84	117	4.69
1993	105	0.40	108	4.28
1994	99	0.20	100	4.04
1995	92	0.11	94	3.90
1996	86	0.00	87	3.74
1997	81	0.00	82	3.69
1998	76	0.00	76	3.65
1999	71	0.00	71	3.60
2000	66	0.00	67	3.55
2001	62	0.00	62	3.51
2002	58	0.00	58	3.46
2003	54	0.00	54	3.42
2004	51	0.00	51	3.38
2005	47	0.00	48	3.33
2006	44	0.00	45	3.29
2007	41	0.00	42	3.32
2008	39	0.00	39	3.21
2009	36	0.00	37	3.17
2010	34	0.00	34	3.14
2011	32	0.00	32	3.10
2012	30	0.00	30	3.06
2013	28	0.00	28	3.02
2014	26	0.00	26	3.01
2015	24	0.00	25	2.58
2016	23	0.00	23	2.56
2017	21	0.00	22	2.54
2018	20	0.00	20	2.52
2019	19	0.00	19	2.50
2020	17	0.00	18	2.49
2021	16	0.00	17	2.47
2022	15	0.00	16	2.45
sum	1526		1548	

INFILL PROD.

5.49  
4.62  
4.04  
3.67  
3.25  
3.03  
2.77  
2.56  
2.38  
2.18  
2.01  
1.85  
1.72  
1.60  
1.46  
1.39  
1.25  
1.17  
1.07  
0.99  
0.92  
0.85  
0.78  
0.65  
0.59  
0.56  
0.50  
0.48  
0.45  
0.42  
0.39

$$\text{INFILL} = \text{BASE (ACCELERATED)} + \text{INCREMENTAL}$$

$$(27552) + 17200$$

55110 (NOTE: SHOULD  
BE 22552 L3  
LESS THAN  
ORIGINAL INFILL  
CASE)

ACCELERATION PRODUCTION  
EQUAL  $\frac{55105}{2} = 27552$

WITH DECREASE IN  
ACCELERATION PRODUCTION,  
SLIGHT 5000 M3 INCREASE  
IN INCREMENTAL RECOVER  
DURING 30 YR PROJECT  
LIFE



NORTH VIRDEN SCALLION UNIT #1 INFILL PROJECT  
CROWN ROYALTIES AND MINERAL TAXES  
SENSITIVITY CASE: 1/8 ACCELERATED PRODUCTION

DATE	BASE CASE			INFILL CASE		
	CROWN ROYALTY (E3 \$)	MINERAL TAX	FREEHOLD ROYALTY (E3 \$)	CROWN ROYALTY (E3 \$)	MINERAL TAX (E3 \$)	FREEHOLD ROYALTY (E3 \$)
1992	255	2267	1940	255	2273	2019
1993	240	2088	1892	241	2080	1934
1994	229	1944	1877	229	1923	1912
1995	219	1808	1868	218	1776	1897
1996	205	1656	1841	205	1617	1865
1997	193	1500	1804	191	1455	1823
1998	181	1357	1774	179	1310	1790
1999	170	1217	1741	167	1171	1754
2000	158	1084	1704	155	1038	1715
2001	149	971	1691	146	924	1700
2002	140	864	1680	138	821	1688
2003	132	764	1667	130	725	1675
2004	124	672	1656	122	636	1665
2005	117	587	1646	115	556	1655
2006	108	506	1624	106	479	1634
2007	100	434	1604	99	412	1616
2008	92	370	1580	91	351	1593
2009	84	312	1559	84	297	1575
2010	78	262	1540	77	247	1553
2011	71	215	1501	70	204	1517
2012	65	175	1462	65	166	1482
2013	59	140	1426	59	135	1449
2014	54	113	1389	53	102	1404
2015	49	85	1354	49	80	1368
2016	45	65	1319	45	61	1337
2017	41	47	1285	41	45	1307
2018	37	33	1251	38	31	1277
2019	34	21	1218	35	22	1249
2020	31	15	1186	32	15	1220
2021	28	9	1155	29	9	1193
2022	26	5	1125	27	6	1168
TOTAL	3514	21586	48359	3491	20967	49034

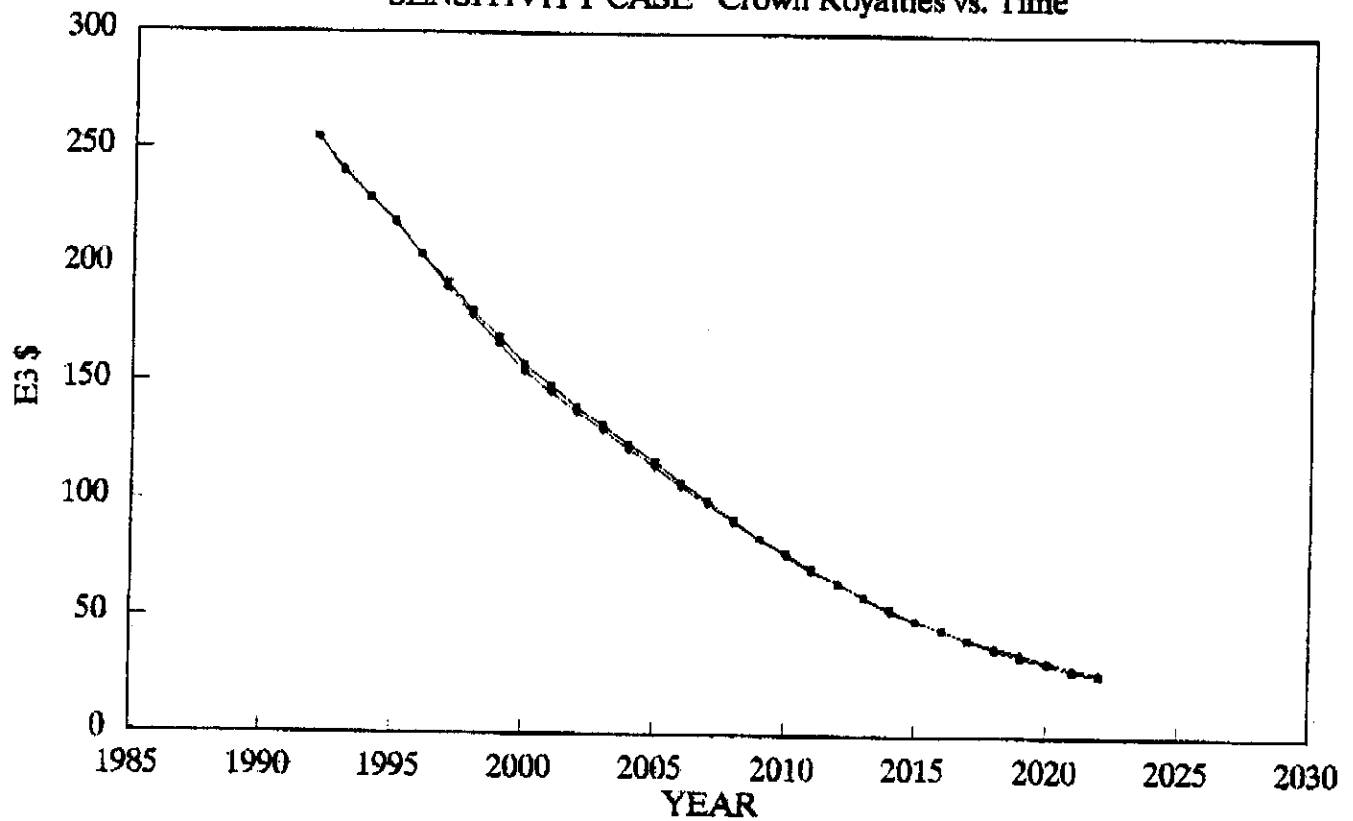
-642

CROWN ROYALTIES AND MINERAL TAXES DISCOUNTED AT 10%  
SENSITIVITY CASE: 1/8 ACCELERATED PRODUCTION

CASE	TOTAL CROWN ROYALTY (E3 \$)	DISCOUNTED CROWN ROYALTY (E3 \$)	TOTAL MINERAL TAX (E3 \$)	DISCOUNTED MINERAL TAX (E3 \$)
BASE	3514	1751	21586	13033
INFILL	3491	1740	20967	12765

# NORTH VIRDEN SCALLION UNIT #1

SENSITIVITY CASE\* Crown Royalties vs. Time

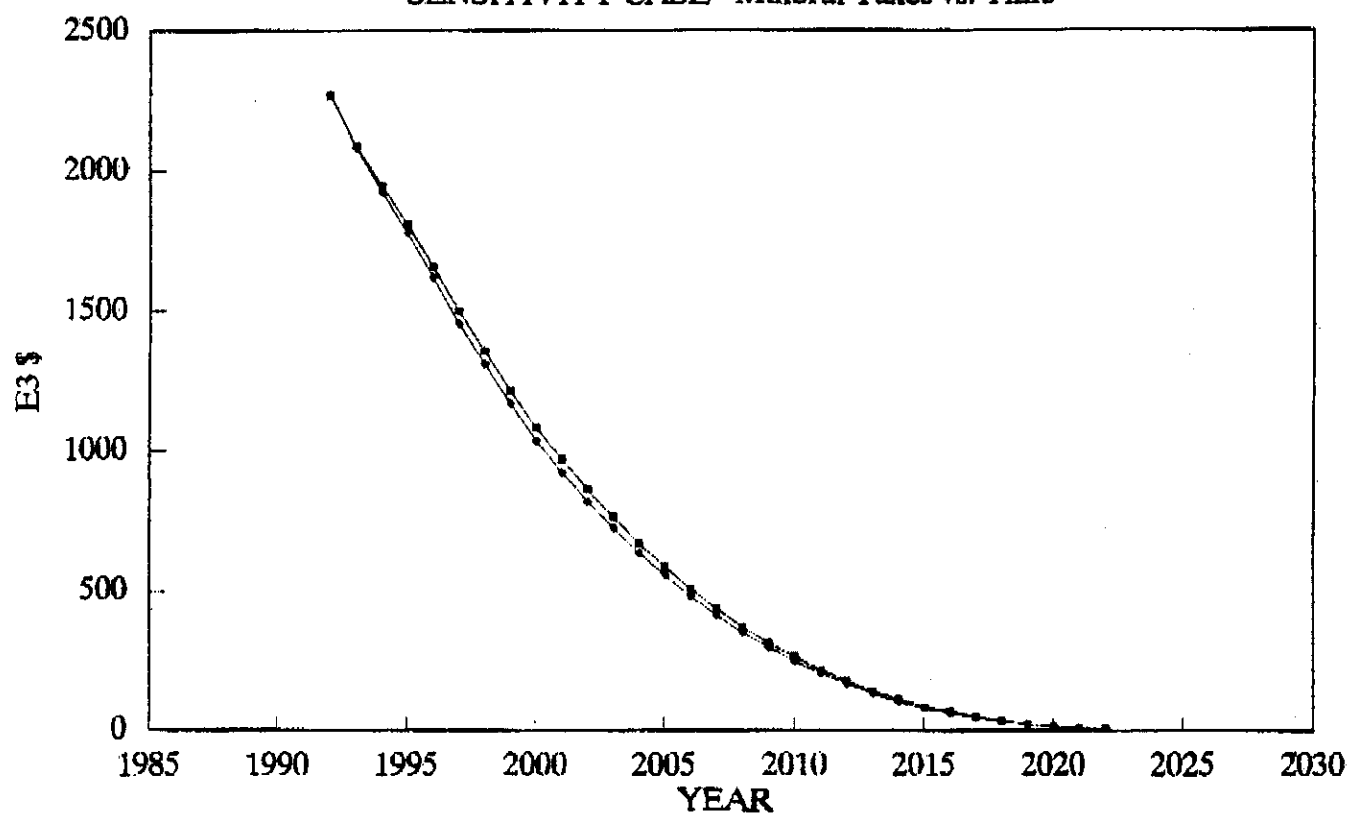


--- BASE CASE    — INFILL CASE

\* 1/8 ACCELERATED PRODUCTION

# NORTH VIRDEN SCALLION UNIT #1

SENSITIVITY CASE\* Mineral Taxes vs. Time

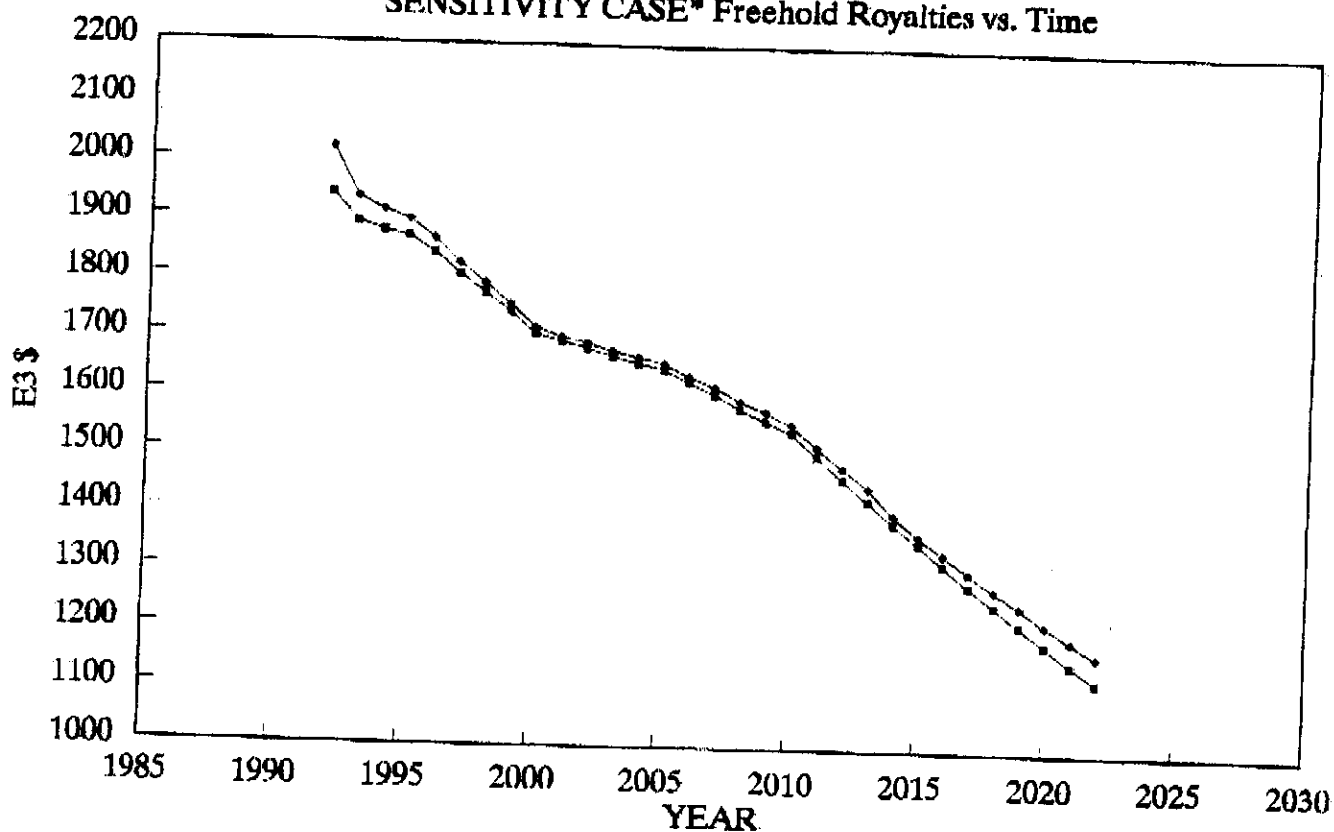


—■— BASE CASE    —●— INFILL CASE

\* 1/8 ACCELERATED PRODUCTION

# NORTH VIRDEN SCALLION UNIT #1

SENSITIVITY CASE\* Freehold Royalties vs. Time



--- BASE CASE    - - - INFILL CASE

\* 1/8 ACCELERATED PRODUCTION



**Chevron Canada Resources**

500 - Fifth Avenue S.W., Calgary, Alberta T2P 0L7 • Phone (403) 234-5000

**FACSIMILE TRANSMITTAL  
COVER PAGE**

PAGE 1 OF 11

DATE: August 21 1991

TIME: \_\_\_\_\_

TO: John Fox

COMPANY: Manitoba Petroleum Branch

CITY: Winnipeg

FAX NO: 204-945-0586

FROM: Belinda Elysée-Collen Rm 1159  
403-234-5484

NUMBER OF PAGES INCLUDING COVER 11

IF ALL PAGES ARE NOT RECEIVED PLEASE CALL (403) 234-5953.

FAX NUMBER (403) 234-5947

CANON FAX-730

CONFIRMATION (403) 234-5953

NOTES: Here are the revised  $\pm 5\%$  forecasts  
Please discard the ~~prev~~ previous  $\pm 5\%$  forecasts

NORTH VIRDEN SCALLION UNIT #1 INFILL PROJECT  
CROWN ROYALTIES AND MINERAL TAXES  
SENSITIVITY CASE: -5% FROM BASE CASE FORECAST

DATE	BASE CASE			INFILL CASE		
	CROWN ROYALTY (£3 \$)	MINERAL TAX (£3 \$)	FREEHOLD ROYALTY (£3 \$)	CROWN ROYALTY (£3 \$)	MINERAL TAX (£3 \$)	FREEHOLD ROYALTY (£3 \$)
1992	235	2050	1843	227	1944	1922
1993	221	1884	1798	222	1873	1839
1994	211	1750	1783	210	1716	1814
1995	201	1621	1775	198	1569	1797
1996	189	1480	1749	185	1414	1763
1997	177	1336	1714	172	1261	1721
1998	166	1203	1686	160	1123	1688
1999	155	1075	1654	149	993	1653
2000	137	950	1619	138	868	1615
2001	129	847	1606	130	768	1601
2002	121	751	1596	122	676	1590
2003	114	661	1584	115	589	1577
2004	106	577	1573	107	514	1567
2005	99	503	1564	100	445	1559
2006	91	432	1543	93	379	1540
2007	84	368	1524	86	324	1523
2008	77	312	1501	79	271	1503
2009	71	261	1481	73	227	1487
2010	66	219	1463	68	189	1472
2011	60	178	1426	62	152	1439
2012	55	143	1389	57	123	1406
2013	50	113	1355	52	95	1377
2014	45	87	1320	48	74	1346
2015	41	67	1286	44	57	1317
2016	38	50	1253	40	41	1288
2017	34	35	1220	37	29	1260
2018	31	23	1188	34	19	1232
2019	29	15	1157	31	13	1206
2020	26	10	1126	29	8	1180
2021	24	6	1097	27	5	1155
2022	22	2	1069	24	2	1130
TOTAL	3105	19009	45942	3119	17761	46567

-1234

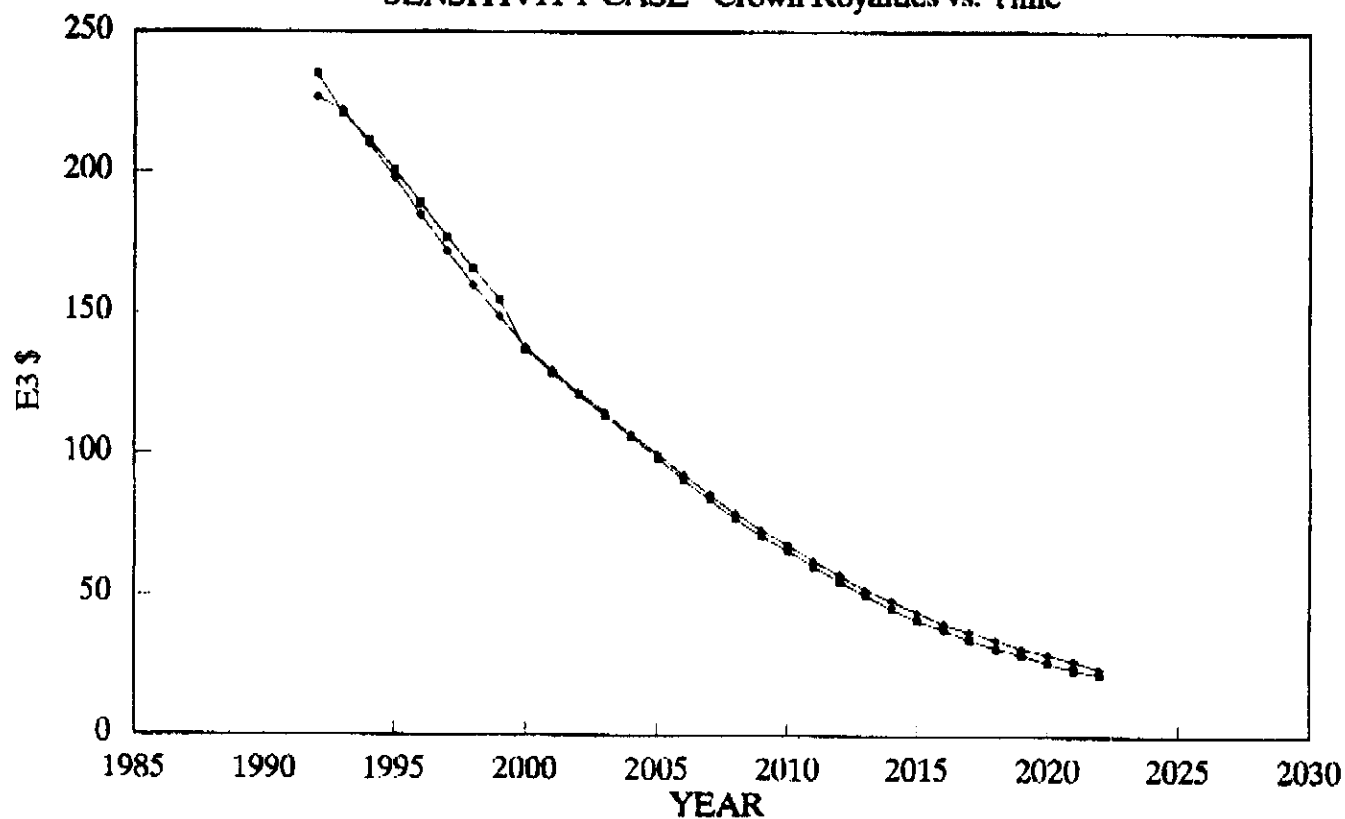
**CROWN ROYALTIES AND MINERAL TAXES DISCOUNTED AT 10%**  
**SENSITIVITY CASE: -5% FROM BASE CASE FORECAST**

CASE	TOTAL CROWN ROYALTY (E3 \$)	DISCOUNTED CROWN ROYALTY (E3 \$)	TOTAL MINERAL TAX (E3 \$)	DISCOUNTED MINERAL TAX (E3 \$)
BASE	3105	1579	19009	11608
INFILL	3119	1564	17761	11023



# NORTH VIRDEN SCALLION UNIT #1

SENSITIVITY CASE\* Crown Royalties vs. Time

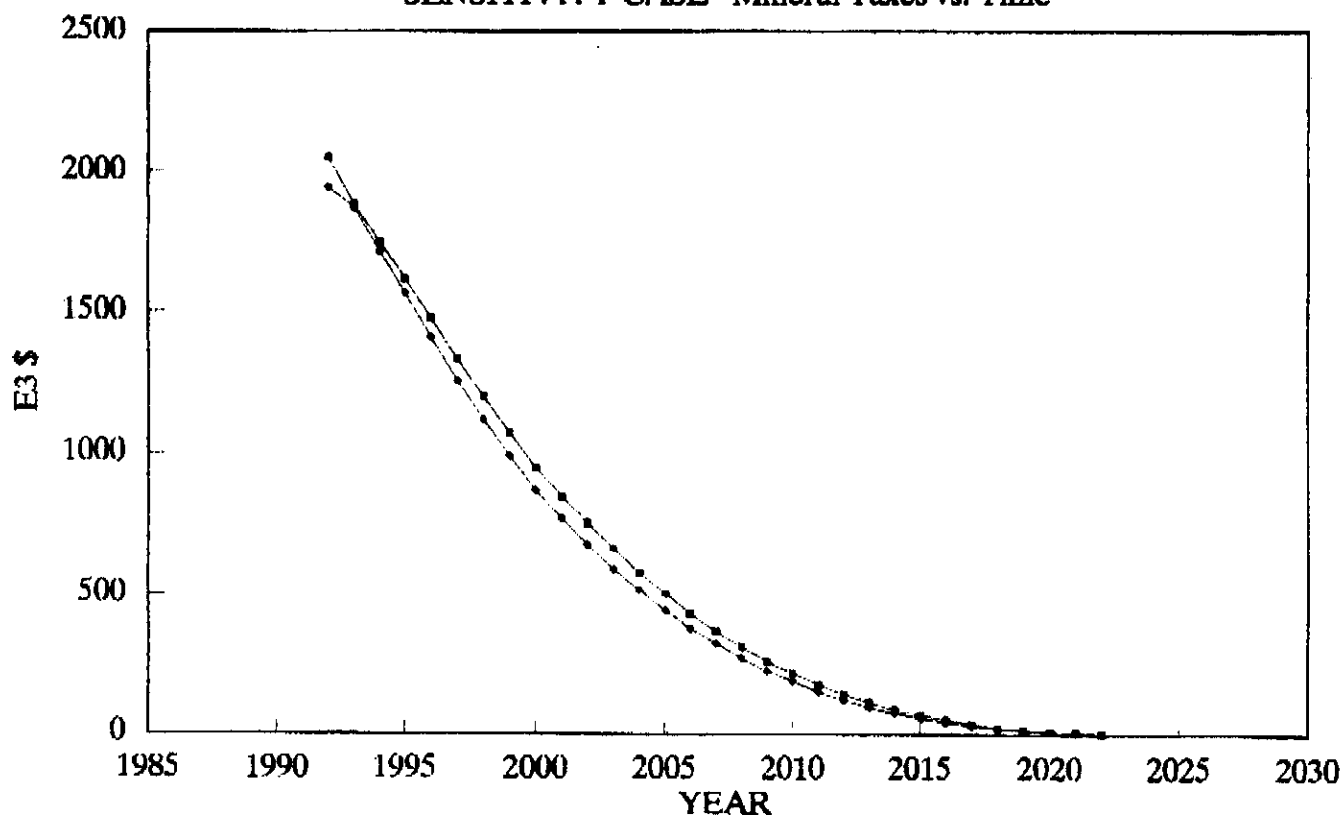


—■— BASE CASE    - - - ■ - - - INFILL CASE

\* -5% FROM BASE CASE FORECAST

# NORTH VIRDEN SCALLION UNIT #1

SENSITIVITY CASE\* Mineral Taxes vs. Time

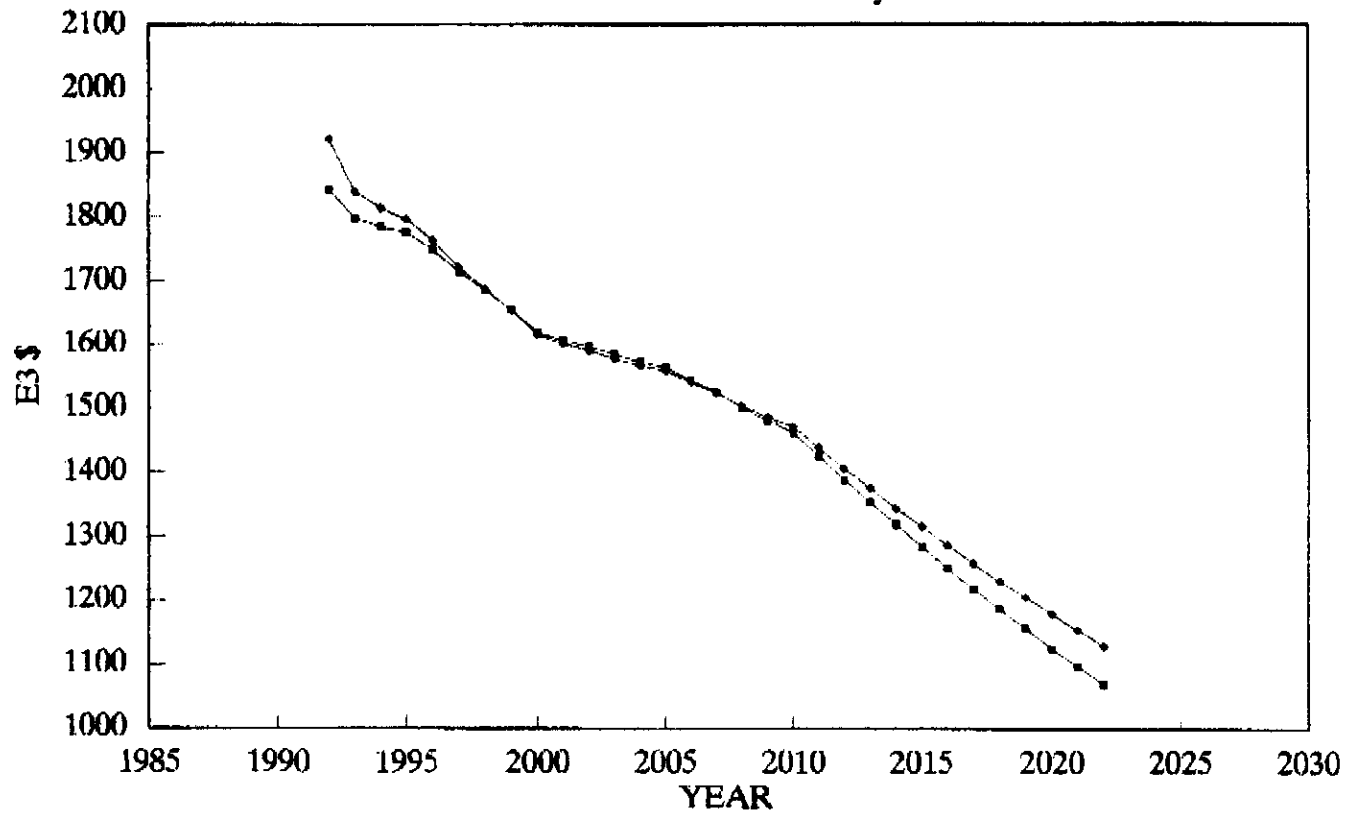


—•— BASE CASE      - - - • - - - INFILL CASE

\* -5% FROM BASE CASE FORECAST

# NORTH VIRDEN SCALLION UNIT #1

SENSITIVITY CASE\* Freehold Royalties vs. Time



—■— BASE CASE    - - - ■ - - - INFILL CASE

\* -5% FROM BASE CASE FORECAST

**NORTH VIRDEN SCALLION UNIT #1 INFILL PROJECT**  
**CROWN ROYALTIES AND MINERAL TAXES**  
**SENSITIVITY CASE: +5% FROM BASE CASE FORECAST**

DATE	BASE CASE			INFILL CASE		
	CROWN ROYALTY (£3 \$)	MINERAL TAX (£3 \$)	FREEHOLD ROYALTY (£3 \$)	CROWN ROYALTY (£3 \$)	MINERAL TAX (£3 \$)	FREEHOLD ROYALTY (£3 \$)
1992	275	2482	2037	267	2377	2118
1993	259	2293	1987	260	2285	2029
1994	247	2140	1971	247	2107	2002
1995	237	1996	1962	234	1942	1964
1996	224	1835	1933	220	1768	1947
1997	210	1667	1894	205	1591	1902
1998	197	1514	1863	191	1430	1866
1999	184	1365	1828	178	1275	1827
2000	172	1219	1790	165	1132	1786
2001	162	1098	1776	155	1012	1770
2002	153	983	1764	147	898	1758
2003	144	873	1751	138	795	1744
2004	136	771	1739	130	698	1733
2005	128	678	1728	122	611	1723
2006	119	586	1705	114	528	1702
2007	110	507	1684	106	453	1684
2008	102	431	1659	98	387	1661
2009	94	368	1637	90	328	1643
2010	86	310	1617	83	276	1626
2011	78	256	1576	76	228	1589
2012	71	211	1535	70	186	1553
2013	65	170	1498	64	149	1520
2014	59	135	1459	59	120	1485
2015	54	106	1422	54	92	1452
2016	49	82	1385	49	72	1420
2017	45	62	1349	45	53	1389
2018	41	44	1313	42	39	1357
2019	37	30	1279	38	26	1328
2020	34	20	1245	35	18	1298
2021	31	13	1212	32	12	1270
2022	28	8	1181	30	8	1243
TOTAL	3831	24253	50779	3744	22896	51409

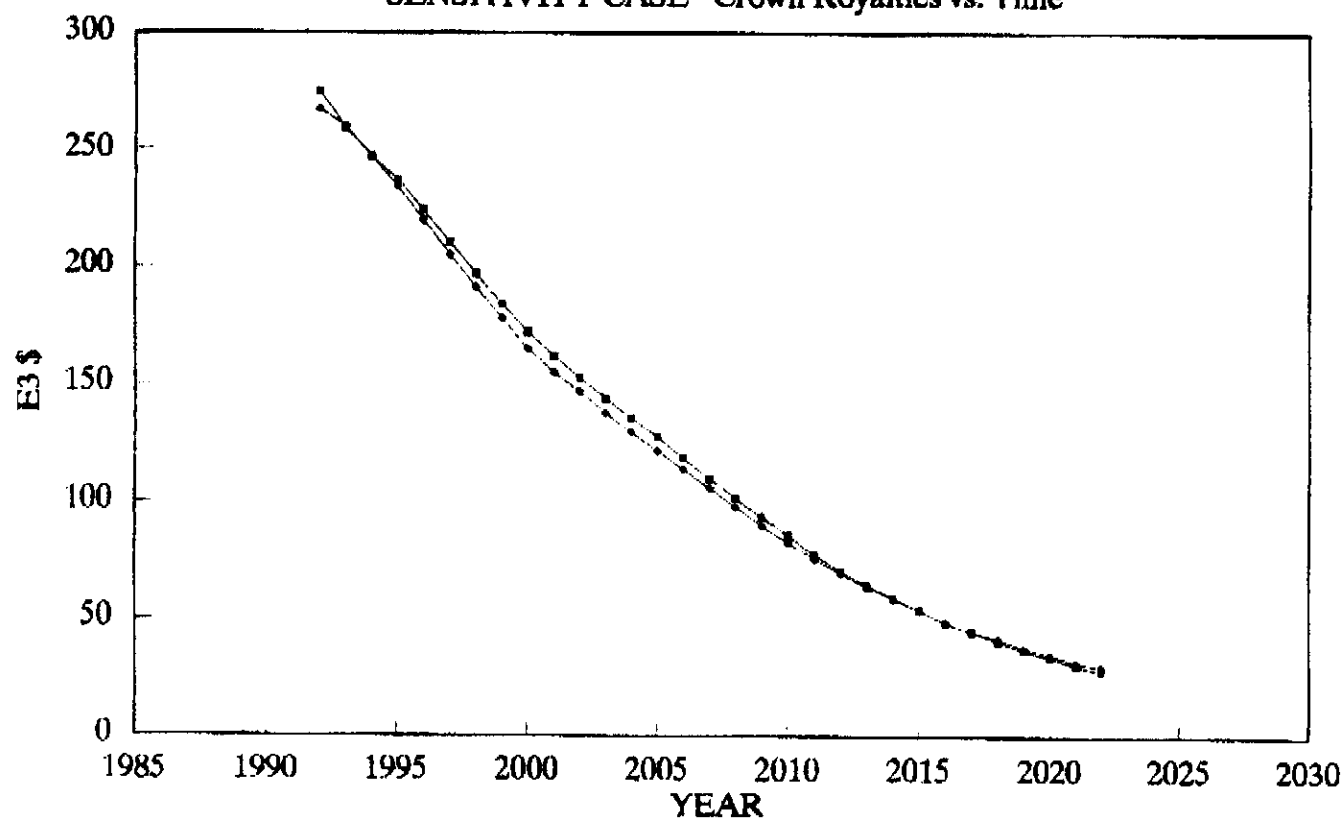
7444

**CROWN ROYALTIES AND MINERAL TAXES DISCOUNTED AT 10%**  
**SENSITIVITY CASE: +5% FROM BASE CASE FORECAST**

CASE	TOTAL CROWN ROYALTY (E3 \$)	DISCOUNTED CROWN ROYALTY (E3 \$)	TOTAL MINERAL TAX (E3 \$)	DISCOUNTED MINERAL TAX (E3 \$)
BASE	3831	1901	24253	14485
INFILL	3744	1860	22896	13869

# NORTH VIRDEN SCALLION UNIT #1

SENSITIVITY CASE\* Crown Royalties vs. Time

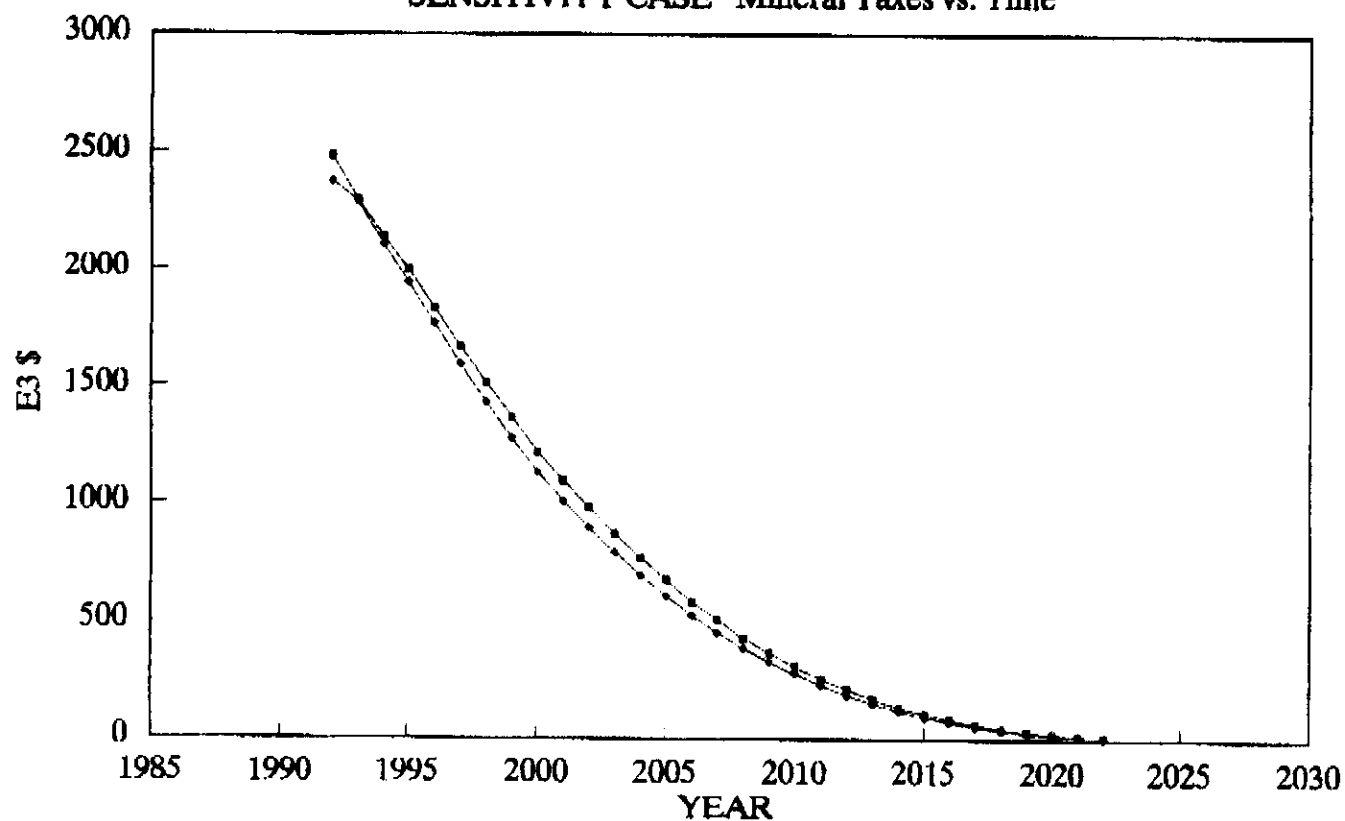


--- BASE CASE    — INFILL CASE

\* +5% FROM BASE CASE FORECAST

# NORTH VIRDEN SCALLION UNIT #1

SENSITIVITY CASE\* Mineral Taxes vs. Time

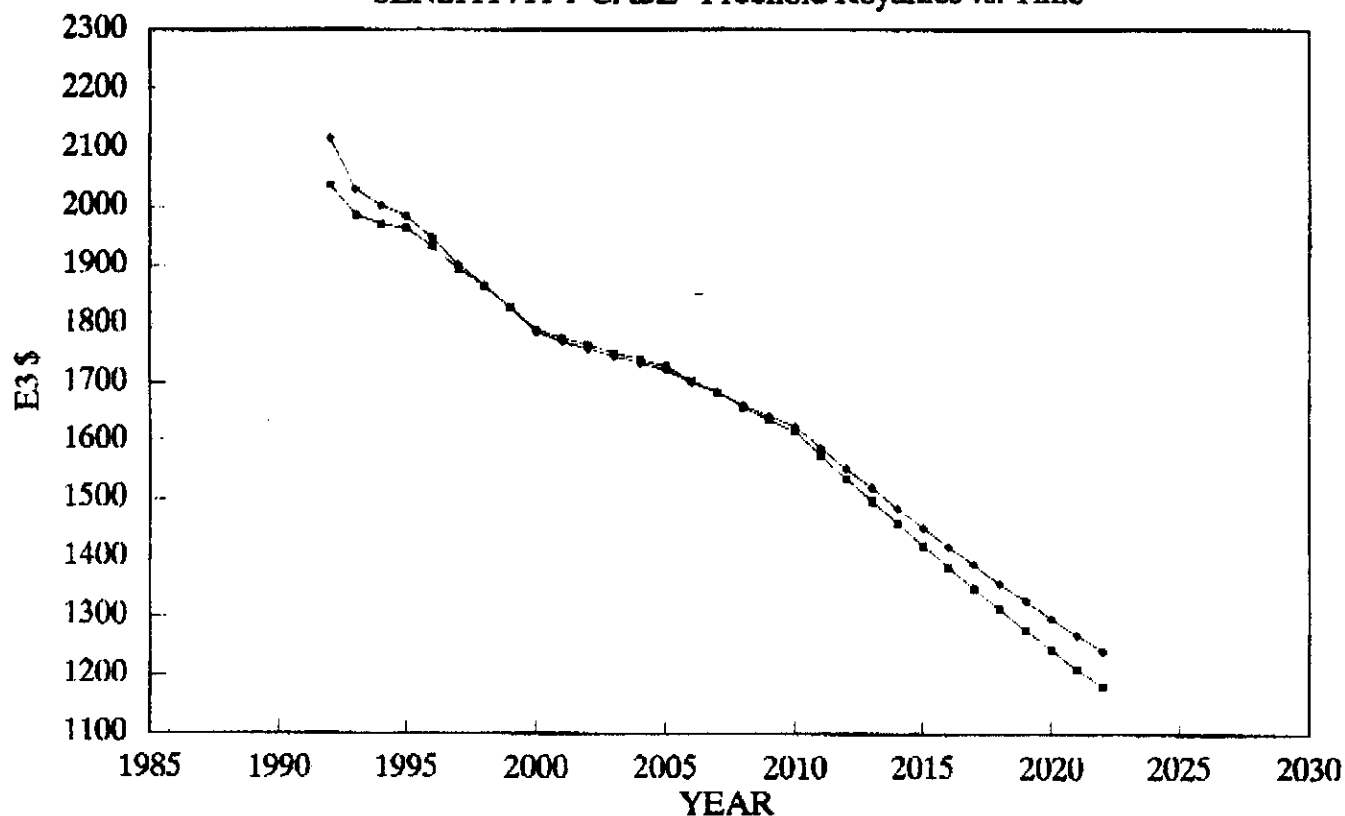


--- BASE CASE    — INFILL CASE

\* +5% FROM BASE CASE FORECAST

# NORTH VIRDEN SCALLION UNIT #1

SENSITIVITY CASE\* Freehold Royalties vs. Time



— BASE CASE      . INFILL CASE

\* +5% FROM BASE CASE FORECAST



# NORTH VIRDEN SCALLION UNIT #1 INFILL PROJECT

## CROWN ROYALTIES AND MINERAL TAXES

SENSITIVITY CASE – RECOVER ALL 24.4 E3M3 INCREMENTAL OIL IN 30 YEARS

(3.2% OOIIP)

DATE	BASE CASE			INFILL CASE		
	CROWN ROYALTY (E3 \$)	MINERAL TAX (E3 \$)	FREEHOLD ROYALTY (E3 \$)	CROWN ROYALTY (E3 \$)	MINERAL TAX (E3 \$)	FREEHOLD ROYALTY (E3 \$)
1992	255	2267	1940	273	2489	2106
1993	240	2088	1892	249	2203	2007
1994	229	1944	1877	235	1961	1972
1995	219	1808	1868	222	1794	1945
1996	205	1656	1841	207	1620	1902
1997	193	1500	1804	192	1443	1849
1998	181	1357	1774	178	1287	1807
1999	170	1217	1741	165	1139	1762
2000	158	1084	1704	152	1001	1716
2001	149	971	1691	143	882	1695
2002	140	864	1680	134	778	1677
2003	132	764	1667	125	681	1658
2004	124	672	1656	117	592	1642
2005	117	587	1646	110	513	1627
2006	108	506	1624	102	439	1602
2007	100	434	1604	93	373	1580
2008	92	370	1580	86	315	1554
2009	84	312	1559	78	263	1532
2010	78	262	1540	72	219	1512
2011	71	215	1501	66	180	1473
2012	65	175	1462	60	144	1436
2013	59	140	1426	55	115	1401
2014	54	113	1389	50	89	1366
2015	49	85	1354	46	69	1333
2016	45	65	1319	42	52	1300
2017	41	47	1285	39	37	1269
2018	37	33	1251	35	26	1237
2019	34	21	1218	32	18	1207
2020	31	15	1186	30	11	1178
2021	28	9	1155	27	7	1150
2022	26	5	1125	25	3	1123
TOTAL	3514	21586	48359	3440	20723	48618

CROWN BENEFIT

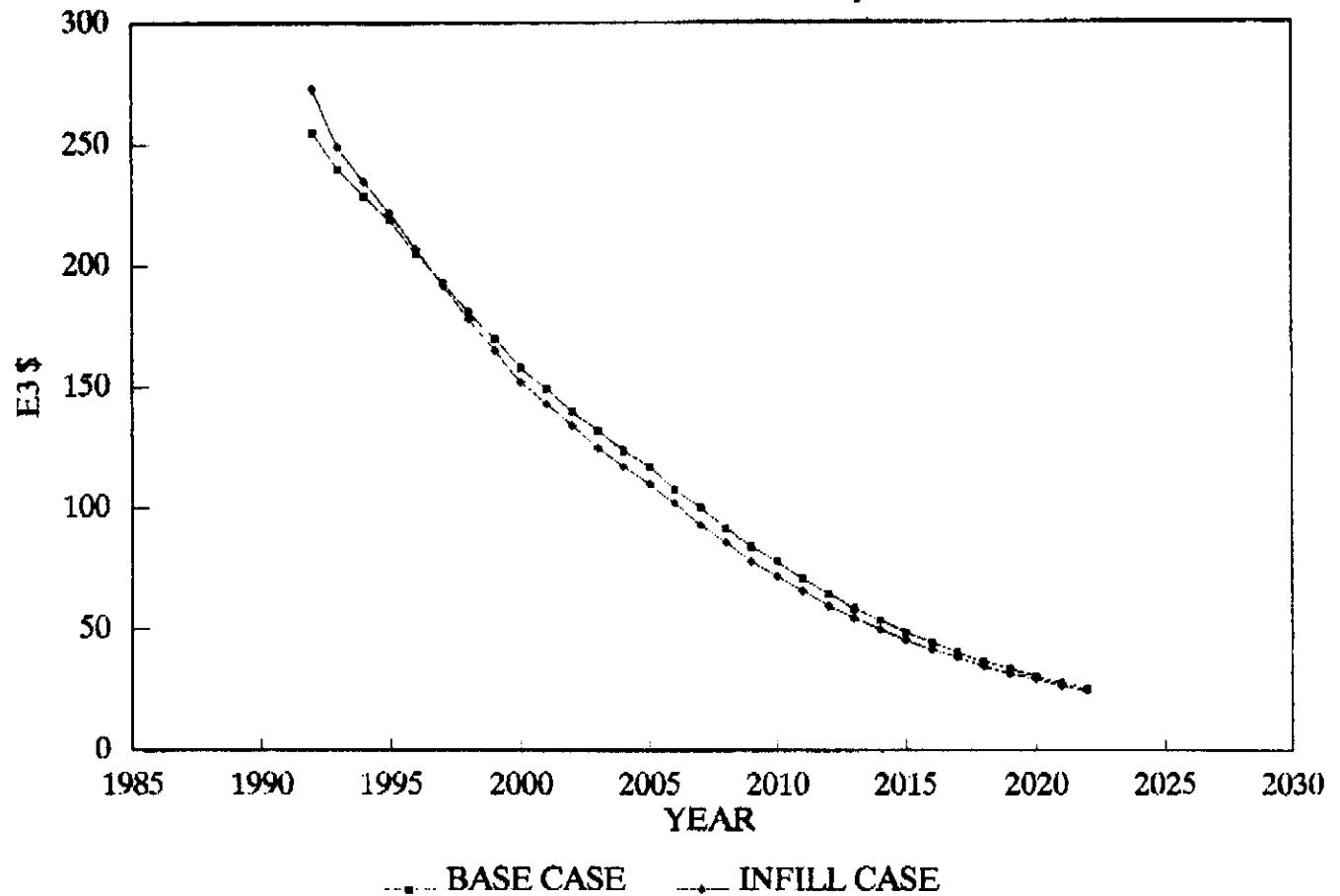
ANN	CUT
+220	+220
+124	+340
+23	+300
-11	+350
-30	+300
-50	
-73	+100
-83	+100
-89	+9
-	-

**CROWN ROYALTIES AND MINERAL TAXES DISCOUNTED AT 10%**  
**SENSITIVITY CASE – RECOVER ALL 24.4 E3M3 INCREMENTAL OIL IN 30 YEARS**

CASE	TOTAL CROWN ROYALTY (E3M3)	DISCOUNTED CROWN ROYALTY (E3M3)	TOTAL MINERAL TAX (E3M3)	DISCOUNTED MINERAL TAX (E3M3)
BASE	3514	1751	21586	13033
INFILL	3440	1755	20723	12934

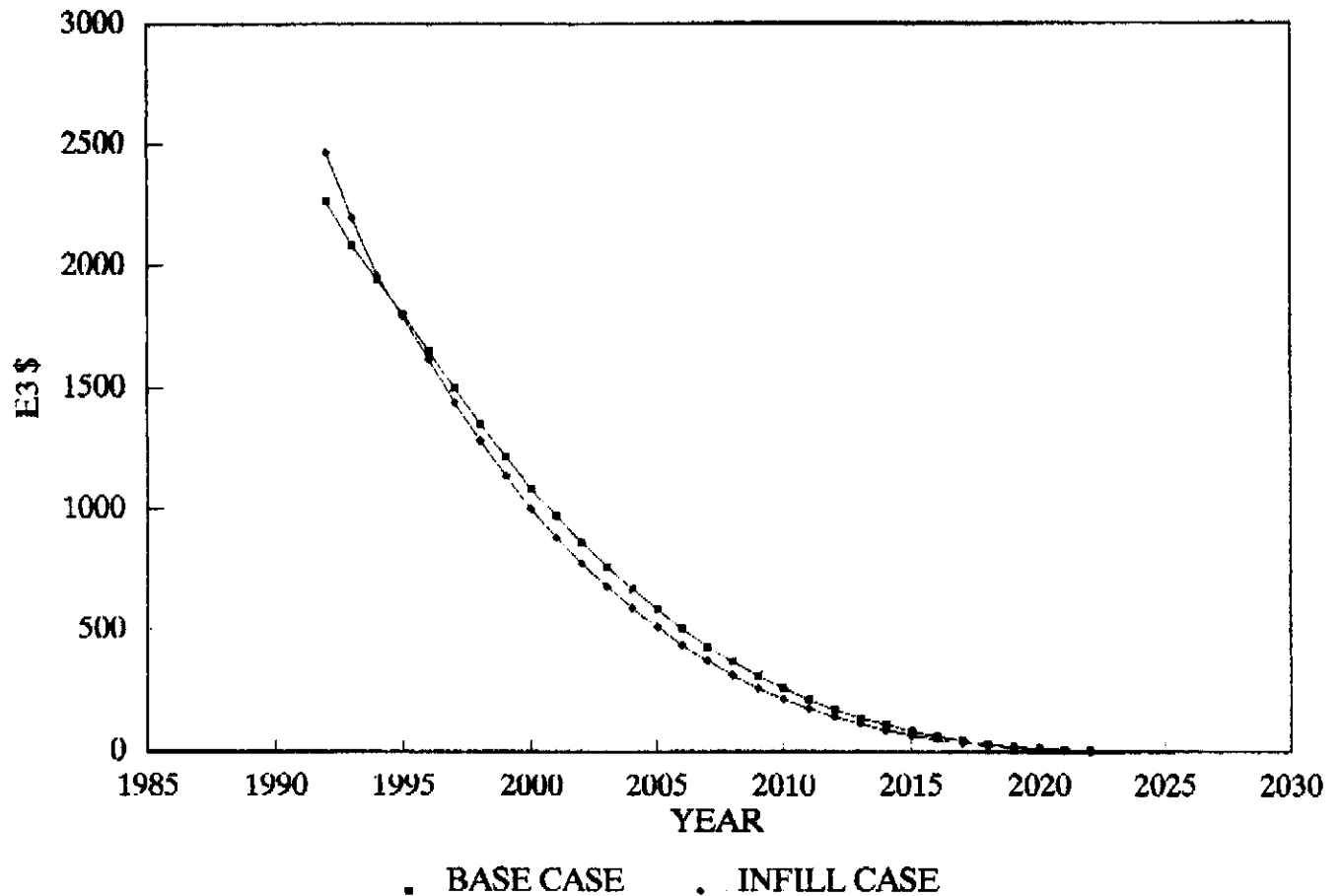
# NORTH VIRDEN SCALLION UNIT #1

SENSITIVITY CASE #1 Crown Royalties vs. Time



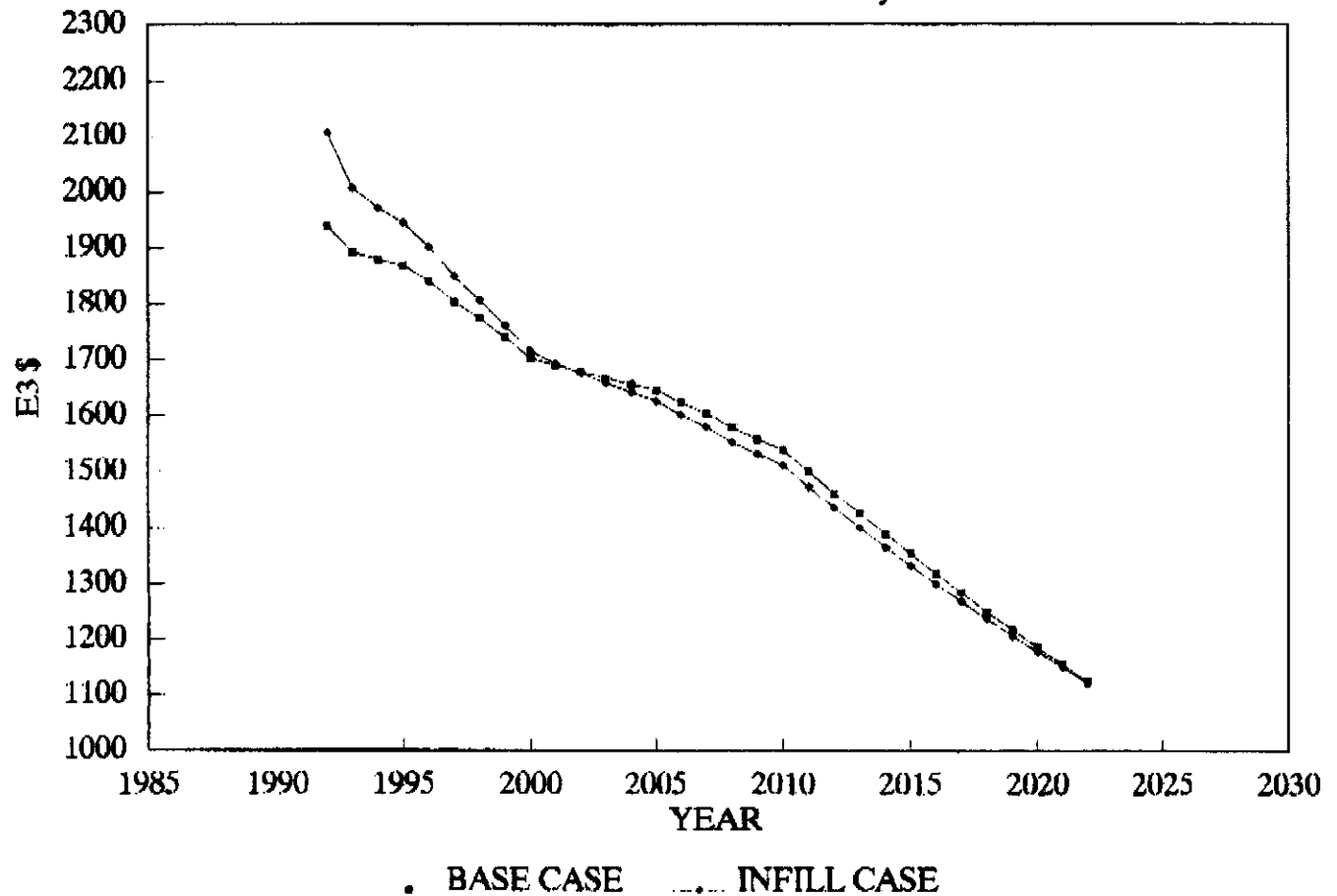
# NORTH VIRDEN SCALLION UNIT #1

SENSITIVITY CASE #1 Mineral Taxes vs. Time



# NORTH VIRDEN SCALLION UNIT #1

SENSITIVITY CASE #1 Freehold Royalties vs. Time





## Memorandum

Date August 1, 1991

To The Oil and Natural Gas  
Conservation Board  
- Ian Haugh, Chairman  
- H. Clare Moster, Deputy Chairman  
- Wm. McDonald, Member

From John N. Fox  
Chief Petroleum Engineer  
Petroleum Branch

Telephone

Subject

Re: North Virden Scallion Unit No. 1  
Reduced Spacing Application

Chevron Canada Resources has made application to drill 3 infill wells on 8 ha spacing in North Virden Scallion Unit No. 1 (NVSU No. 1).

### Recommendation:

It is recommended that notice of the application be published in the Virden Empire Advance and the Manitoba Gazette. A copy of the proposed notice is attached. The surface owners of the proposed infill well locations will be notified directly by the Branch.

It is also recommended that the Board request Chevron file additional information in support of the incremental recovery estimate, production forecast and economics provided in the application. A copy of the proposed Board deficiency letter is attached.

The Departments of Rural Development, Agriculture and Environment have been sent a copy of the application and requested to provide their comments before August 27, 1991.

### Discussion:

Chevron has applied to drill 3 infill wells at 7A-21-11-26, 5A-27-11-26 and 1A-4-12-26 in NVSU No. 1 (Figure 1). Branch representatives met with Chevron to discuss the application on July 23, 1991.

There are 3 main areas of concern with the application; lack of technical support for the incremental recovery estimate of 2.3% OOIP per well; no detailed breakdown of the incremental and acceleration components of the production forecast; and no discussion of the economic assumptions and sensitivity of the project economics to various parameters.

Of particular concern to the Branch are the project economics. Chevron has estimated that the accelerated production from the infill wells will total 1/4 of the remaining recoverable reserves from the adjacent producers. The accelerated production which results in the reclassification of oil from old to new has a negative impact on Crown royalties and production tax. Chevron forecasts the Crown will lose \$2 028 M in royalties and production tax over the 30 year life of the project.

Chevron has been advised that the Branch and the Board do not look favourably on projects that result in a loss in Crown revenues. It was suggested to Chevron that use of a similar royalty/tax treatment used in Daly Unit No. 3 as a result of waterflood expansion and modifications carried out by Chevron in 1984, may be beneficial to both Chevron and the Crown. In Daly Unit No. 3 the Board approved new oil status for all oil produced in excess of the unit's historical production performance.

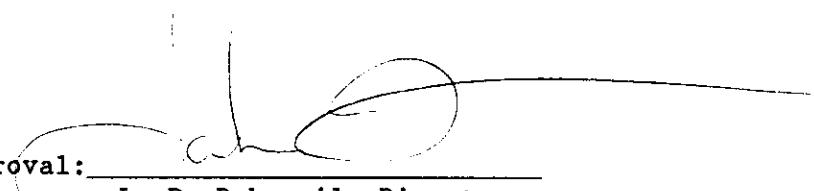
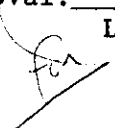
The proposed Board deficiency letter attached addresses these matters.



John N. Fox  
Chief Petroleum Engineer

JNF/sml

Attachments

Recommended for Approval:   
 L. R. Dubreuil, Director



## **Chevron Canada Resources**

500 - Fifth Avenue S.W., Calgary, Alberta T2P 0L7  
Phone (403) 234-5000 Fax (403) 234-6212

J.E. Spring  
Manager,  
Marketing Division

**July 31, 1991**

### **Reduced Spacing Application** **North Virden Scallion Unit No. 1**

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

**Attention: L.R. Dubreuil  
J. Fox**



**Gentlemen:**

We would like to take this opportunity to thank you for taking time to meet with us to discuss the issues related to our application for reduced spacing in North Virden Scallion Unit No. 1. We found the discussion and exchange of ideas that took place to be very useful and it will undoubtedly benefit the present and future applications.

We look forward to interacting with you in the future. In the meantime, if you have any questions or comments, please do not hesitate to contact Trish Steele at (403) 234-5321.

**Yours very truly,**

**P.J. Steele**

**PJS:ajs  
cc: H. Clare Moster**



NOTES FROM JULY 23/91  
Meeting with Cleave - edg

NSU No. 1 (1990) Summary

91-07-23

- continue monitor system - 2 different parts of a monitor - in terms of volume of 1989 pilot
  - 20 potential future well limits
  - targeting whole Member
- will swap test results - VRU #1
- previously for the purpose of setting a well volume limit (based on 1989)

PRODUCTION FORECASTING

- 5.2% incremental recovery for life of well over 30 year forecast life (based on 1989 reserves recovery)
- NEW DECLINE FOR EXISTING WELLS BASED RATE @ 1993.01 is 1.4% R.P.R. R.P.R.
- 0.3 economic limit used

2.2) WOR < UNIT AVER. INDICATION OF LOWER THAN AVERAGE RECOVERY

- corridor wells drilled between abandoned & field front (from N & S) probably not applicable for these wells -  $\Delta$  recovery, optimistic
- 14A-L7 used as a production well - 2001

DATA UNIT NO. 2 4-97. 0010  
 NVSU 100. 1 1997. 0010 02  
 100. 1 1997. 0010 02

## ECONOMICS

- WHAT PORTION OF COSTS ASSOCIATED WITH A NEW WELL ARE NORMALLY SPENT IN PARITIBA
- CHEVRON TARGET APPROVAL DATE  $\rightarrow$  END OF SEP/91 TO COME TO BE DRILLING  $\rightarrow$  WELLS TIED-IN BEFORE NOV 1/91
- COMMIT TO PUBLIC OFFER - NOW
- RUN NEW OIL PERCENTAGE THROUGH BRAD'S NVSU NO. 1 CALCULATION TO CONFIRM CHEVRON'S POTENTIAL TAX INCENTIVES
- KELLY EDWARDS  $\rightarrow$  PRIMARY CONTACT

- Enhanced Oil Recovery?
- 130 000 000 BBL of oil at abandonment
- 20 additional potential infill locations
- structural high
- low work.
- Uphole targets      5A-27  
                                    7A-21

in Virden Rosalea - 10000 - 15000 m<sup>3</sup>  
incremental reserves

Crisoidal recompletions -

- poor cement
- and goes to Cherty

---

Rosalea

3 wells drilled

pay ~~to~~ 32-34 a little more  
good porosity + water sat.

2.3 % recovered over 30yr.

3.2 % recovered at depletion  
from VR - lower than Dealy

= 17 000

-  $\frac{1}{4}$  of surrounding well perm.  
reserve is acceleration

- 1600 m<sup>3</sup> royalty / tax holiday,

7-21 essentially ignored 2-21

14A-27 - confirm production results  
- adjacent wells show interf.  
in about 1 year time.

Target - end of Sept - October

Double check royalty / tax payments through  
our program.



Date July 30, 1991

## Memorandum

To Serge Scrafield  
Senior Planner  
Provincial Planning Branch  
Rural Development  
4th Floor - 800 Portage Avenue

From John N. Fox  
Chief Petroleum Engineer  
Petroleum Branch  
555 - 330 Graham Avenue

Subject Re: North Virden Scallion  
Reduced Spacing Project

Telephone

Chevron Canada Resources, the operator of North Virden Scallion Unit No. 1, has made application to reduce well spacing from 16 ha to 8 ha in a portion of the unit.

The pilot project, which requires the approval of The Oil and Natural Gas Conservation Board, involves the drilling of 3 infill wells at different locations throughout the unit.

Attached is a copy of Chevron's application. The Branch has requested Chevron file additional information in support of the application. The additional information will be forwarded to you when we receive it. I ask that you review the application and provide me with your comments before August 27, 1991. If you have any questions, please contact me at 945-6574.

*Original signed*

John N. Fox

JNF/sml

Attachment

cc: Dale Partridge  
Manitoba Agriculture

Floyd Phillips  
Manitoba Environment

first foot



The Oil and Natural Gas  
Conservation Board

Room 309  
Legislative Building  
Winnipeg, Manitoba, CANADA  
R3C 0V8

(204) 945-3130

## NOTICE

### UNDER THE MINES ACT

Chevron Canada Resources, Operator of North Virden Scallion Unit No. 1 ("the unit area") has made application under Section 20 of the Petroleum Drilling and Production Regulation for approval of special drilling spacing units in a portion of the unit area. It is proposed that drilling spacing units would be reduced from 16 hectares to 8 hectares to permit the drilling of wells at the following locations:

7A-21-11-26 (WPM)  
5A-27-11-26 (WPM)  
1A-4-12-26 (WPM)

If no valid objection or intervention in writing is received by The Oil and Natural Gas Conservation Board at Room 309, Legislative Building, Winnipeg, Manitoba, R3C 0V8, on or before August 27, 1991, the Board may approve the application.

Copies of the application may be obtained from:

Information Centre  
Chevron Canada Resources  
500 - 5th Avenue S.W.  
Calgary, Alberta  
T2P 0L7  
(403) 234-5580

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

555 - 330 Graham Avenue  
Winnipeg, Manitoba  
(204) 945-6577

227 King Street West  
Virden, Manitoba  
(204) 748-1557

Dated at Winnipeg, this *1<sup>st</sup>* day of *August*, 1991.

H. Clare Moster  
Deputy Chairman



The Oil and Natural Gas  
Conservation Board

Room 309  
Legislative Building  
Winnipeg, Manitoba, CANADA  
R3C 0V8

NOTICE

(204) 945-3130

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H. Clare Moster  
Deputy Chairman

Chevron Canada Resources Limited  
500 - 5th Avenue S.W.  
Calgary, Alberta  
T2P 0L7

Landowner Contact Report

I, the undersigned, hereby grant you permission to do survey-work and the removal of trees where necessary on the following lands (owned, leased, purchased) by me and described as follows:

SW 1/4-27-11-26 WPM

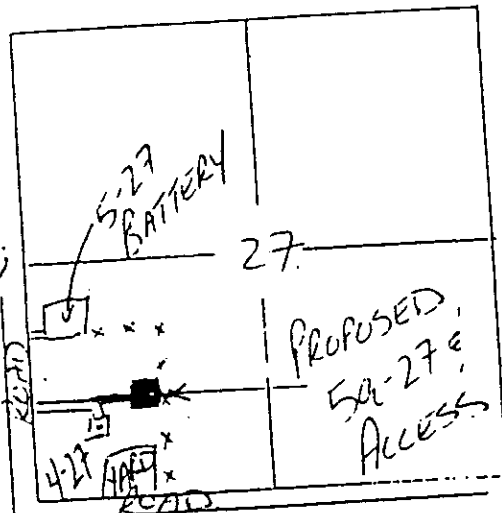
This permission is granted in consideration of your promise as follows:

All work under this permit will be conducted at the risk and expense of Chevron Canada Resources Limited

Also I, the undersigned, hereby acknowledge that I am in agreement with the proposed route as shown on the sketch.

Special Requirements:

Place lease along fence.  
Caution! It is electric.  
Line up wellhead straight east of 4-27 access road.  
Nature of land likely to be crossed:  
TAME PASTURE.



Registered Owner: COLIN & TRUDY CAMPBELL

Address: Box 237 VIRIDEN, MAN  
PH. 748-3242 RUM 200

Occupant: N/A

Address:

*[Signature]*  
Witness

*[Signature]*  
(Person Granting Permit)

- 1 copy to Landowner
- 1 copy to Contractor
- 1 copy to District Office

SHAW

JUNE 20<sup>th</sup> 91

PLEASE SEND  
A COPY OF  
THE NVSU No. 1  
BOARD NOTICE  
TO ATTACHED  
ADDRESSES

Sent August  
7/91

11

12

1



20 JUNE 19 71.

Chevron Canada Resources Limited  
500 - 5th Avenue S.W.  
Calgary, Alberta  
T2P 0L7

Landowner Contact Report

I, the undersigned, hereby grant you permission to do survey work and the removal of trees where necessary on the following lands (owned, leased, purchased) by me and described as follows:

SE 1/4 - 4 - 12 - 26 WPM

This permission is granted in consideration of your promise as follows:

All work under this permit will be conducted at the risk  
and expense of Chevron Canada Resources Limited

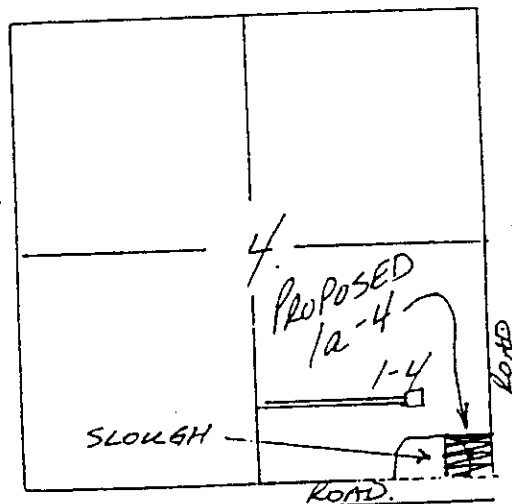
Also I, the undersigned, hereby acknowledge that I am in agreement with  
the proposed route as shown on the sketch.

Special Requirements:

Contact owner prior to  
entry to discuss location.

Nature of land likely to be crossed:

Slough & cultivated.  
Leave no stakes in field.



Registered Owner: DONALD COLLIER Address: Box 1228 VIRDEN, MAN. R0M 2C0.  
PH-748-1390.

Occupant: N/A. Address: \_\_\_\_\_

[Signature]  
Witness

Donald Collier  
(Person Granting Permit)

1 copy to Landowner  
1 copy to Contractor  
1 copy to District Office

20 JUNE 19 91

Chevron Canada Resources Limited  
500 - 5th Avenue S.W.  
Calgary, Alberta  
T2P 0L7

Landowner Contact Report

I, the undersigned, hereby grant you permission to do survey work and the removal of trees where necessary on the following lands (owned, ~~leased~~, ~~purchased~~) by me and described as follows:

SE 1/4-21-11-26 W.P. 117

This permission is granted in consideration of your promise as follows:

All work under this permit will be conducted at the risk  
and expense of Chevron Canada Resources Limited

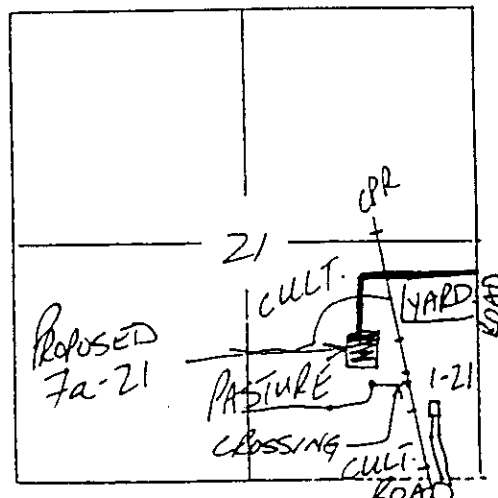
Also I, the undersigned, hereby acknowledge that I am in agreement with  
the proposed route as shown on the sketch.

Special Requirements:

Contact owner prior to  
entry to discuss  
access route.

Nature of land likely to be crossed:

Pasture & cultivated



\* Registered Owner: Gaylin Eilers Address: Box 1765 VIRDEN, MAN  
Box 200 PH-748-1776.

Occupant: N/A Address: \_\_\_\_\_

[Signature]  
Witness

[Signature]  
(Person Granting Permit)

- 1 copy to Landowner
- 1 copy to Contractor
- 1 copy to District Office

## PROJECT ECONOMICS - IMPACT ON CROWN REVENUES

- FOR NVSU NO.1 OVER THE NEXT 30 YEARS, 1992-2022, CHEVRON FORECASTS THE CROWN WILL COLLECT \$25,100M IN ROYALTIES AND PRODUCTION TAX. CHEVRON HAS ESTIMATED THE 3 INFILL WELLS WILL PRODUCE 72350 M<sup>3</sup> (17246 M<sup>3</sup> INCREMENTAL RESERVES + 55105 M<sup>3</sup> ACCELERATED RESERVES). THE RATIO OF ACCELERATED PRODUCTION TO TOTAL INFILL WELL PRODUCTION IS 0.76, WHICH IS SUBSTANTIALLY HIGHER THAN PREDICTED BY CHEVRON FOR ITS OTHER REDUCED SPACING PROJECTS (TABLE ).

WHEN RESERVES RECOVERABLE BY EXISTING WELLS ARE RECOVERED BY INFILL WELLS (ACCELERATED PRODUCTION) ROYALTIES AND TAXES ARE PAID AT NEW OIL RATES, AS OPPOSED TO OLD OIL RATES AS WOULD BE THE CASE IN NVSU NO.1. THE PROJECT ECONOMICS AS A RESULT OF THE HIGH PERCENTAGE OF ACCELERATED PRODUCTION SHOWS CROWN REVENUES OVER THE 30 YEAR PROJECT LIFE OF \$23804M, A NET LOSS OF \$1296M WHEN COMPARED TO THE BASE CASE.

## CASE II - INCREASED INCREMENTAL RECOVERY - 3.2% OOIP

CHEVRON IN THE APPLICATION QUOTED <sup>AN</sup> INCREMENTAL RECOVERY OF 2.3% OOIP. THIS VALUE ACTUALLY REPRESENTS THE INCREMENTAL RECOVERY DURING THE 30-YEAR PROJECT EVALUATION PERIOD, OVER THE PRODUCING LIFE OF THE WELLS, (7A-21; 70 YEARS, 5A-27; 50 YEARS, AND 1A-4; 33 YEARS) CHEVRON ESTIMATED INCREMENTAL RECOVERY OF 3.2% OOIP.

AN ECONOMIC RUN ASSUMING <sup>AN</sup> INCREMENTAL RECOVERY OF 24,400 M<sup>3</sup> (3.2% OOIP) OVER THE 30-YEAR PROJECT EVALUATION PERIOD RESULTED IN A SLIGHT DECREASE IN <sup>THE</sup> NET LOSS TO THE CROWN, - \$937 M. A PLOT OF ANNUAL AND CUMULATIVE CROWN REVENUE FOR THIS CASE SHOWS CUMULATIVE CROWN BENEFITS ARE POSITIVE FOR 9 YEARS

## CASE III - ALL INFILL WELL PRODUCTION INCREMENTAL

TO ASSIST IN DETERMINING WHAT PROPORTION OF <sup>TOTAL</sup> INFILL WELL PRODUCTION WOULD HAVE TO BE INCREMENTAL RESERVES TO HAVE CROWN REVENUES REMAIN UNCHANGED, AN ECONOMIC RUN ASSUMING ALL INFILL WELL PRODUCTION OF <sup>74000 M<sup>3</sup> (9.5% OOIP)</sup> WAS INCREMENTAL RESERVES WAS MADE. THE ECONOMIC RESULTS SHOW INCREMENTAL CROWN BENEFITS OF \$317 M.

THIS CASE IS CONSIDERED UNREALISTIC BUT WAS USED TO GENERATE A GRAPH

OF CROWN BENEFITS VERSUS INCREMENTAL RECOVERABLE RESERVES (FIGURE ) TO DETERMINE AT WHAT LEVEL OF INCREMENTAL RECOVERY FROM THE INFILL WELLS, CROWN BENEFITS FROM THE PROJECT WERE REVENUE NEUTRAL. IT IS ESTIMATED THAT IF THE INFILL WELLS RECOVER INCREMENTAL RESERVES OF  $48750 \text{ m}^3$  (6.5% OOI<sub>P</sub>) < OVER 30 YEARS, 3\* PREDICTED CROWN REVENUE WILL BE UNCHANGED

CASE IV - INFILL WELL ACCELERATED PRODUCTION REDUCED FROM 55105  $\text{m}^3$  TO 27552  $\text{m}^3$

THE SOLE REASON FOR THE LOSS IN CROWN REVENUE FROM THE PROJECT IS THE HIGH VOLUME OF ACCELERATED PRODUCTION ESPECIALLY WHEN COMPARED TO THE INCREMENTAL RECOVERY. TO DETERMINE WHAT REDUCTION IN ACCELERATED PRODUCTION IS REQUIRED FOR THE CROWN BENEFITS TO REMAIN REVENUE NEUTRAL, ECONOMICS WERE RUN REDUCING ACCELERATED PRODUCTION VOLUMES IN HALF FROM 55105  $\text{m}^3$  TO 27552  $\text{m}^3$ . REDUCING <sup>INFILL WELL</sup> ACCELERATED PRODUCTION BY HALF, ESSENTIALLY HALVES THE NET LOSS IN CROWN REVENUES FROM  $-\$1296 \text{ M}$  TO  $-\$642 \text{ M}$ . FURTHER EXTRAPOLATION OF THIS CASE SUGGESTS

# ANNUAL AND CUMULATIVE

A PLOT OF INCREMENTAL CROWN REVENUES FOR THE PROJECT SHOWS A SLIGHT BENEFIT TO THE CROWN IN THE FIRST YEAR \$9,000 (EACH INFILL WELL RECEIVES A ROYALTY AND TAX FREE HOLIDAY VOLUME OF WHICH IS PRODUCED DURING THE FIRST YEAR) AND CUMULATIVE BENEFITS BECOMING NEGATIVE AFTER APPROXIMATELY 22 MONTHS.

INCREMENTAL CROWN REVENUES ARE SENSITIVE TO THE VOLUME OF INCREMENTAL RECOVERABLE RESERVES AND THE VOLUME OF ACCELERATED PRODUCTION. AN INCREASE IN INCREMENTAL RECOVERY HAS A POSITIVE IMPACT ON INCREMENTAL CROWN REVENUES, AS DOES A DECREASE IN ACCELERATED PRODUCTION.

THE BOARD REQUESTED CHEVRON RUN ADDITIONAL ECONOMICS TO SHOW THE SENSITIVITY OF CROWN REVENUES TO A CHANGE IN INCREMENTAL RECOVERY AND ACCELERATED PRODUCTION.

# INFILL PRODUCTION FORECAST

WELL	INCREMENTAL	ACCELERATED	TOTAL PRODUCTION
7A-21-11-26	5915	26482	32396
5A-27-11-26	6875	15992	22867
1A-4-12-26	4456	12631	17087
	<u>17246</u>	<u>55105</u>	<u>72350</u>

REDUCED SPACING PROJECT	INCREMENTAL	ACCELERATED	TOTAL PRODUCTION	<u>ACCELERATED</u> <u>TOTAL</u>
1989 NVSU No.1	88000	67721	155721	0.43
1991 VRU No.1	91458	46439	137897	0.34
1991 NVSU No.1	17246	55105	72350	0.76

WELL	CUMULATIVE PRODUCTION 103L3	
3-27	70.6	
4-27	142.1	
5-27	114.0	
6-27	7.9	SUBTOTAL 334.6
3A-27	17.7 x 1/2	36.6
4B-27	5.0 x 1/2	
		<hr/>
		TOTAL 371.2

16-33	1.7
13-34	49.9
4-3	20.1
1-4	53.0
	<hr/>
	124.7
Per Rec. Res.	<hr/>
	48.4

$$\text{OOR} = 4 * 198.5 = 794 \times 10^3 \text{L3}$$

$$\text{current recovery} = 15.7\%$$

$$\text{ult. recovery} = 21.8\%$$



THERE ARE A NUMBER OF CONCERNS WITH THE INCREMENTAL  
RECOVERY PREDICTIONS

(a) THE INCREMENTAL RECOVERY MECHANISMS

(b) THE CURRENT AND PREDICTED ULTIMATE RECOVERY FOR  
WELLS ADJACENT TO THE PROPOSED INFILL WELLS (RECOVERY  
MAP  
- doesn't adequately describe a significantly larger portion of reservoir  
- sweep

(c) THE EXISTING OF BYPASSED PAY IN EXISTING WELLS

(d) % OUIP IN CHERTY AND GEOLOGICAL PROPERTIES OF CHERTY  
AND CONTINUED lateral

## BASE CASE

	UNDISC.	DISC.
CROWN ROYALTY (\$M)	-81	-33
PROD. TAX (\$M)	-1215	-498

## SENSITIVITY CASES

### (1) ACCELERATE RECOVERY OF INCREMENTAL RESERVES

RECOVERY OF 32% OOIIP IN 30 YR  
 VS. BASE CASE - RECOVERY OF 2.3% OOIIP IN  
 30 YR.

#### INCREASE IN RECOVERABLE RESERVES

$$24400 - 17200 = 7200 \sim 3$$

#### HOW WAS THE INCREMENTAL RECOVERY ACCELERATED

- does this case require an increase in initial well productivity, a decrease in decline rate, or both?
  - (1) increase in initial well productivity
  - (2) decrease in decline rate
  - (3) over 30 yr. what is total well prod.
- does production decline curve remain unchanged in this case

#### - REVENUE ACCELERATED FOR 1ST 10 YRS.

	UNDISC.	DISC.
ROY.	-74	-4
TAX.	-863	-99

WHY DO ROYALTIES BETWEEN THIS CASE AND ORIGINAL INITIAL CASE INCREASE 0.2% AND TAXES INCREASE 1.7%.

CASE	INCREMENTAL RECOVERY	TOTAL INFILL PRODUCTION	NET CROWN * INCOME
INFILL <sup>2</sup> 2.3% OOI <sup>2</sup>	17,200	74760	-1296 <sup>2</sup>
INFILL <sup>2</sup> 3.2% OOI <sup>2</sup>	24,400	(2)	-937 <sup>2</sup>
INFILL <sup>2</sup> 9.5% OOI <sup>2</sup>	74000		+817

<sup>2</sup> NOTE = ASSUMING NO CHANGE IN ACCELERATE PRODUCTION  
(55100 - 3) IT IS ESTIMATED THAT INCREMENTAL  
RECOVERABLE RESERVES (IN 30 YRS) OF 43200 (5.7% OOI<sup>2</sup>)  
WILL RESULT IN REVENUE NEUTRAL FOR THE CROWN

\* INFILL CASE - BASE CASE

OOI<sup>2</sup> = 1705% 3 1 2 1

~~Well No. 1~~ Incremental Recovery Estimate

VRU No. 1 3.2 % OOIP - 87300 m<sup>3</sup> 7 wells

NVSU No. 1 corridor - All wells - 6.1%

1989 Pilot (estimate) = 7.6%

actual = 1.7%

100000 m<sup>3</sup>  
36800 m<sup>3</sup>

9 wells

VRU No. 1 initial prod 137897

incremental 91458 (87300)

accelerated 46439

IP 2.2 - 2.6 / well

14% new oil unit base

7% new oil unit

OOIP spread area 2700 (can. prod 585 x 10<sup>2</sup>)

Ret. Rec RES Procs. AREA P.B 166440

Churn 250,903

CROWN BENEFITS

VRU No. 1 BASE CASE (REVENUE) 28679 + 2996.1

INFLU CASE CASE (REVENUE) 3208.8 + 3013.3

Figure NVSA No. 1 showing 1989 pilot, comm. area

NVSA No. 1

- 30 yr. project life <sup>net benefit</sup> Gross ~~revenue~~ 7240 m<sup>3</sup> with the capacity of benefits occurring over the 1st 5 yrs

see plot Gross benefit annual & cumulative plot vs. time

incremental recovery 100000 m<sup>3</sup> (88000 within project area)  
 $\frac{88000}{100000} = 7.6\%$

NVSA No. 1 incremental recovery was estimated as 100000 m<sup>3</sup> of which 88000 m<sup>3</sup> was <sup>recovered</sup> ~~estimated~~ within the ~~infill~~ wells project area & 12000 m<sup>3</sup> was ~~estimated~~ recovered outside the project area. ~~of the 88000 m<sup>3</sup>~~

76%  
001P

The total production from the infill wells was estimated to be 155721 m<sup>3</sup> for a incremental to accelerated production ratio of  $\frac{88000}{155721} = 56.5\%$  incremental

% in fill well  
 recover of Rot. Rec. RCS.  $\frac{155721 - 88000}{123351} = 56\%$

## CONCERNS NVSU No. 1 INFILL WELLS

- REVOLVE AROUND INCREMENTAL RECOVERY ESTIMATES, INFILL WELL PRODUCTION FORECAST AND PROJECT ECONOMICS

INCREMENTAL RECOVERY - 2.3%

- ✓ ① PREDICTION MODELS - ONLY THE 14A-27 WELL PERFORMANCE IS USED, ONLY NO INCREMENTAL RECOVERY IS STATED FOR THE WELL

- ✓ - PAST PREDICTIONS NVSU #1 1989 RULES SPACING PROJECT, PREDICTED 7.1%, ACTUAL 1.7%, URU No. 1 PREDICTED 3.2%

PERFORMANCE OF

- ✓ - NO REFERENCE TO "CORRIDOR" WELLS DRILLED 1974-78 IN SEC 27 & 28 - 11-26 - A RECOVERY 6.1%

- ✓ ② EACH PROPOSED INFILL LOCATION IS ESTIMATED TO RECOVERY AN ADDITIONAL 2.3% OGP DESPITE VERY DIFFERENT GEOLOGY / RESERVOIR / PERFORMANCE CHARACTERISTICS

7A-21 NATURAL FRACTURE <sup>SYSTEM</sup>, DOWN DIP AQUIFER SUPPORT, ANOMALOUSLY HIGH PRODUCTIVITY AND CURRENT RECOVERY - 56% OGP

14A-27 STRUCTURAL HIGH, THICKEST CHERT SECTION IN THE UNIT, PAY IN ALL LODGEPOLE MEMBERS

1A-4 THOUGH ALSO ON A STRUCTURAL HIGH,  
LOCATED BETWEEN TWO INJECTORS, LOW  
CURRENT RECOVERIES (25% OOIP)

- ③ VARIOUS FACTORS THAT CONTRIBUTE TO INCREMENTAL RECOVERY  
IN A NATURAL WATERFLOOD SUCH AS STIPPLES  
CONTINUITY, PATTERN REMAINING, IMPROVED SWEPT  
EFFICIENCY - AREA / VOLT. , WHICH FACTORS CONTRIBUTE  
TO THE 2.3% INCREMENTAL RECOVERY PRODUCTION

### PRODUCTION FORECAST

#### WORK THROUGH CHEVRON'S ASSUMPTIONS

- ① PREDICTED OIL RATE & WOR FOR INFILL WELLS WERE  
BASED ON THE PERFORMANCE OF ADJACENT PRODUCTIONS, THIS  
APPEARS TO HOLD TRUE FOR SA-27 & 1A-4 BUT  
THE AVERAGE PRODUCTIVITY OF ADJACENT PRODUCTIONS IS  
11.6 m<sup>3</sup>/d NOT 5.0 m<sup>3</sup>/d — WHAT IS THE  
EXPLANATION FOR THE HIGH PRODUCTIVITY @ 2-21?

- ② ADJACENT WELLS WILL EXPERIENCE ACCELERATED  
DECLINE IN 1993-01 — ECONOMICS INDICATED  
A SIGNABLE LOSS IN CROWN ROYALTY & TAX IN  
THE 1992, IF THERE IS NO ACCELERATION  
UNTIL 1993-01 YOU WOULDN'T EXPECT THIS  
NOTE: EACH INFILL WELL RECEIVES A HOLIDAY IN  
VOLUME OF 1500 RECOVERED IN 1ST YEAR @ 4.5 m<sup>3</sup>/d  
(CHEVRON USED 1600 m<sup>3</sup>)

③ ACCELERATED PRODUCTION ASSOCIATED WITH EACH INFILL WELL = 1/4 OF ADJACENT PRODUCTION RESOURCES  
ASSUMPTION → REMAINING RECOVERABLE RESERVES 284 SCAL  
✓ ACCELERATED PRODUCTION = 71100 L3 P.B.  
CHEVRON TOTAL INFILL PRODUCTION 74800 L3  
- INCREMENTAL RECOVERY  $\frac{17200 L3}{57600 m^3}$   
?   
↓  
terminated

④ NEED ELABORATION OF THE INCREMENTAL & AGGREGATION COMPONENTS OF THE INFILL WELL PRODUCTION FORECAST & HOW THE INFILL PRODUCTION IMPACTS ON THE PRODUCTION OF OFFSET WELLS

✓ NOTE: BASE CASE DECLINE - 6.4% / YR  
INFILL<sup>UNIT</sup> CASE DECLINE STARTS @ ≈ 8.0% / YR (92) AND STEADILY DECREASES TO ≈ 6.0% / YR (2020)  
INFILL WELL CASE DECLINE STARTS @ ≈ 4.5% / YR 92 AND INCREASES TO 5.5% EARLY 90'S THEN SLOWLY DECLINES < 5.0%

### ECONOMICS

① PREVIOUS REDUCED SPACING PROJECTS HAVE HAD A (REDUCED) NET BENEFIT TO THE CROWN, EXPLAIN WHY THIS PROJECT RESULTS IN AN LOSS OF CROWN ROYALTIES/TAXES  
UNDISCOUNTED \$2026 M  
DISCOUNTED \$1196



② WHAT IS THE CAPITAL COST ESTIMATE FOR THE 3 WELLS (DRILL CONDUIT, CABLE TIE IN

③ WHAT FACTORS RESULT IN A LESSENING OF THE CROWN'S LOSS OR A NET BENEFIT TO THE CROWN,

④ ALTERNATIVE ROYALTY / TAX DETERMINATION

- USE BASE CASE UNIT PRODUCTION IE. DECLINING @ 6.4 % / YR, PRODUCTION ABOVE BASE CASE IS NEW OIL SIMILAR TO OILY UNIT NO. 3
- ADVANTAGES INVEST IN WATERFLOO OPTIMIZATION IE. RECOMPLECTIONS, INJECTOR CONVERSION, PRODUCTION OPTIMIZATION MAY RESULT IN NEW OIL STATUS

- OLD OIL
- NEW OIL ONLY FOR INCREMENTAL PRODUCTION

OTHER

① IS THERE ANY TECHNICAL / ECONOMIC INCENTIVE TO RECOMPLETING CRINOIDAL / OOILITES IN EXISTING WELLS OR PERFORATING ADDITIONAL CHERRY PAY IN BOTH PRODUCERS & INJECTORS (FULL FACE CONNECTIONS AS PLANNED FOR THE INFILL WELLS

PROPOSED  
QUESTIONS

1. PLEASE PROVIDE A RECOVERY MAP (% OGP) FOR THE AREA OUTLINED FOR EACH WELL.

2. IT APPEARS THAT EACH <sup>INFILL</sup> WELL IS ESTIMATED TO RECOVERY ~~INCREMENTAL~~ RESERVES OF 2.3%.

WELL CONFIGURATION PLEASE EXPLAIN HOW WITH THE DIFFERENT GEOLOGY / RESERVOIR CHARACTERISTICS FOR EACH LOCATION; 9A-21 LOCATED DOWNDIP IN AN AREA OF A NATURAL FRACTURE SYSTEM WITH ACTIVE AQUIFER SUPPORT; 9A-27 LOCATED ON A STRUCTURAL HIGH, WITH THE THICKEST CHERTY PAY SECTION IN THE UNIT ON A STRUCTURAL HIGH; 1A-4 <sup>ON A STRUCTURAL HIGH</sup> BETWEEN TWO INJECTORS NEAR THE EDGE OF THE UNIT.

3. THE ONLY PERFORMANCE MODEL USED TO

DEVELOP THE INFILL WELL PRODUCTION FORECAST WAS THE 14A-27-11-26 WELL. IN ORDER TO CLARIFY THE EXPECTED <sup>INFILL</sup> AND INCREMENTAL RECOVERY WELL PRODUCTION FORECAST, ESPECIALLY THE INCREMENTAL AND ACCELERATION <sup>EVALUATE AND</sup> COMPONENTS OF THE FORECAST, PLEASE <sup>EVALUATE AND</sup> DISCUSS THE FOLLOWING

(a) THE INCREMENTAL RESERVES RECOVERED BY THE 14A-27 WELL

(b) THE NVSU NO. 1 "CORRIDOR" WELLS DRILLED BETWEEN 1974 AND 1978  $\rightarrow$   <sup>$\Delta$  RECOVERY</sup> 6% OGP

(c) THE 1989 NUSU NO. 1 REDUCED SPACING PROJECT

4. IT IS RECOGNIZED THAT IN THE PROJECT AREA(S) 92% OF THE OOIIP IS IN THE CHERT, BUT IS THERE ANY TECHNICAL/ECONOMIC MERIT IN COMPLETING THE CRINOIDAL/OOLITES AND ADDITIONAL CHERT PAY IN THE EXISTING WELLS.

5. TYPICALLY IN A NATURE WATERFLOOD REDUCED SPACING RESULTS IN INCREMENTAL RECOVERY DUE TO ONE OR A COMBINATION OF THE FOLLOWING FACTORS;

- (a) Improved continuity
- (b) pattern realignment
- (c) Improved sweep efficiency - early channel/vein
- (d) removal of "wedges" early in life
- (e) increasing permeability and reducing the permeability contrast

WHAT FACTORS CONTRIBUTE <sup>TO</sup> THE INCREMENTAL RECOVERY FROM THIS PROPOSED INFILL WELLS.

6. PLEASE PROVIDE <sup>THE FOLLOWING</sup> COMPOSITE PRODUCTION PLOT TO FIGURE CLEARLY ILLUSTRATE THE PERFORMANCE OF 14A-27 AND THE ADJACENT WELLS

(a)

1A 4-12-26

• NO CONCERN WITH THIS LOCATION LOCATED BETWEEN TWO INJECTORS ON A STRUCTURAL HIGH (192 ha), STRUCTURALLY HIGHER THAN THE OFFSETTING PRODUCERS 1-4-12-26 & 13-34-11-26, POTENTIAL FOR A NUMBER OF OTHER INFILL WELLS, CURRENT RECOVERIES ARE MODERATE 25-26% OOIIP, ULTIMATE RECOVERIES 32-44% OOIIP. QUITE POSSIBLE REFLECT THE RECOVERY OF OIL SWEEP FROM 4-3-12-26 & 16-33-11-26

• THE 1A-4-12-26 INFILL WELL HAS PAY IN THE 1ST, 2ND & 4TH COALITES AND 45' OF EXPECTED CHERTY PAY. ALL THE OFFSET, INJECTORS ARE ONLY PRODUCERS AND COMPLETED IN TOP 5' TO 10' OF THE 4TH COALITE/CHERTY. WHAT INCREMENTAL RESERVE/ADDITIONAL PRODUCTION COULD BE REALIZED BY FULL FACE COMPLETION OF THESE WELLS.

7A-21-11-26

- ACCORDING TO THE APPLICATION, THE FOUR WELLS OFFSETTING THE PROPOSED 7A-21-11-26 INFILL LOCATION, HAVE <sup>CURRENTLY</sup> RECOVERED 75.7% OOIP AND ARE ESTIMATED <sup>TO</sup> ULTIMATELY RECOVER 70.8% OOIP. WHY DOES CHEVRON THINK AN ADDITIONAL WELL AT 7A-21 WILL RECOVER ANY INCREMENTAL OIL. (NOTE: 7A-21 IS NOT IN A STRUCTURAL HIGH)

- THE PROPOSED 7A-21 INFILL LOCATION OFFSETS THE BEST WELL IN THE POOL, 2-21-11-26 WHICH PRODUCES 36.8 m<sup>3</sup>/d. WHAT IS THE EXPLANATION FOR THE HIGH PRODUCTIVITY OF 2-21?

- CHEVRON IN THE APPLICATION STATES 4.2.4 "PREDICTED OIL RATES & WOR FOR THE INFILL WELLS WERE BASED ON THE PERFORMANCE OF THE ADJACENT PRODUCERS. THIS APPEARS TO HOLD TRUE FOR THE SA-27 & 1A-4 LOCATIONS BUT FOR 7A-21 THE AVERAGE PRODUCTIVITY OF THE ADJACENT PRODUCERS IS 11.6 m<sup>3</sup>/d, NOT 5.0 m<sup>3</sup>/d.

5-27-11-26

- 5A-27 INFILL LOCATION IS OFFSET BY AN INJECTOR AT 6-27 AND IS LOCATED ON A STRUCTURAL HIGH WHICH EXTENDS NW-SE  
NOTE: 5A-27 IS DOWNDIP OF THE 6-27 INJECTOR
- 5A-27 IS JUST NORTH OF THE CORRIDOR INFILL WELLS DRILLED IN 1974-78
- THE 14A-27 PERFORMANCE MODEL USED BY CHEVRON IS PROBABLY APPLICABLE FOR THE 5A-27 LOCATION  
NO INCREMENTAL RECOVERY WAS ASSIGNED THE 14A-27 WELL

## ACCELERATION VS. INCREMENTAL RECOVERY AND THE IMPACT ON PROJECT ECONOMICS

THE FOLLOWING ASSUMPTIONS WERE USED BY  
CHEVRON TO GENERATE THE INFILL WELL PRODUCTION  
FORECAST

(1) INCREMENTAL RECOVERY 2.3% O.O.D. OR  $17200 \text{ m}^3$   
APPROXIMATELY DIVIDED BETWEEN THE WELLS AS  
FOLLOWS

7A-21 —  $5992 \text{ m}^3$

5A-27 —  $6955 \text{ m}^3$

1A-4 —  $4565 \text{ m}^3$

(2) OIL RATES & WOR BASED ON ADJACENT  
PRODUCER PERFORMANCE

(3) ADJACENT PRODUCERS WILL EXPERIENCE ACCELERATED  
DECLINE IN 1993-01 (ONE YR AFTER WELLS  
ON PRODUCTION)

(4) ACCELERATED PRODUCTION ASSOCIATED WITH EACH  
INFILL WELL =  $1/4$  OF ADJACENT PRODUCERS  
RESERVES.  $\rightarrow$  RETAINING RECOVERABLE RESERVES  $284528 \text{ m}^3$

P.B. ESTIMATE  $1/4$  OF RET. REC. RES =  $71132 \text{ m}^3$

CHEVRON BASED INFILL WELL FORECAST

$$\begin{aligned} (\text{TOTAL} - \text{INCREMENTAL}) &= 74759 - 17200 \text{ m}^3 \\ &= 57559 \text{ m}^3 \end{aligned}$$

# PERCENTAGE OF INFILL WELL PRODUCTION (NEW OIL)

1992 - 2022	TOTAL UNIT PRODUCTION	1,596,696
	TOTAL INFILL WELL PROD.	74,759
		4.68 %

% OF INCREMENTAL PRODUCTION

$$\frac{17200}{1596696} * 100 = 1.08 \%$$

- OF TOTAL INFILL WELL PRODUCTION ONLY  
 $\frac{17200}{74759} * 100 = 23 \%$  IS INCREMENTAL  
REBORND

THIS COMPARES WITH 45%\* IN 1989  
NUSU NO. 1 REDUCED SPACING PROJECT AND  
63% DRU NO. 1 REDUCED SPACING PROJECT  
\* LISTED IN APPEN

PLEASE LIST THE DECLINE RATE(S) USED IN DEVELOPING  
THE INFILL WELL, PRODUCTION FORECAST AND  
UNIT FORECAST AFTER INFILL DRILLING,

OR

PLEASE PROVIDE A PLOT OF DAILY PRODUCTION  
VERSUS TIME FOR THE INCREMENTAL PRODUCTION &  
ACCELERATION COMPONENTS OF THE INFILL  
PRODUCTION FORECAST



## ECONOMIC EVALUATION

NVSU No. 1 1989 Reduced Spacing Project Forecasted  
Incremental Royalties & Taxes - 7240 m<sup>3</sup>  
(\$94/(\$11) using \$130/m<sup>3</sup>)

VRU No. 1 Reduced Spacing Project Forecasted  
Incremental Royalties & Taxes = 360 (\$11)

NVSU No. 1 1991 Reduced Spacing Project  
Forecasted Incremental Royalties & Taxes  
undiscounted (\$11) - 2026 } WHY  
discounted (\$11) - 1196

- WHAT ARE THE ESTIMATE PROJECT COSTS - DRILL, COMPLETE, EQUIP, TIE-IN?
- IF THERE IS NO ACCELERATION OF PRODUCTION  
(CHEVRON, <sup>REDUCED SPACING</sup> PRODUCTION FORECAST CRITERIA 4.2.2.5 - THE  
ADJACENT PRODUCERS WILL EXPERIENCE ACCELERATED  
DECLINE IN 1993-01) IN 1992 WHY DO  
THE ECONOMICS SHOW A LOSS IN CROWN  
ROYALTIES AND PRODUCTION TAX IN 1992 -

## OTHER MATTERS

PLEASE PROVIDE A SUMMARY OF WELL DATA THAT WILL BE OBTAINED DURING DRILLING OF THE INFILL WELLS (E. LOGS, CORES, TESTS, ETC.)

✓ WHAT IS CHEVRON'S PROPOSED PROGRAM FOR MONITORING RESERVOIR PRESSURE

WHAT WILL FREQUENCY OF PROPOSED WELL TESTS USING A PORTABLE TANK OR NOL - IS IT PROPOSED TO  
✓ TEST THE WELLS OFFSETTING THE INFILL LOCATIONS AT THE SAME FREQUENCY

✓ - WILL CHEVRON BE USING NON-BUILT-UP TENDS AND BURYING POWER LINES UNDERGROUND

PROPOSED LOCATIONS

SE/4-4-12-2601 - SINGLE SPACING UNIT

16-33-11-26

- BETWEEN TWO INJECTORS 4-3-12-26

- OFFSET PRODUCERS 1-4-12-26 & 13-34-11-26

- STRUCTURAL HIGH  $\approx 192$  ha, APOX OF STRUCTURE 16-33-11-26

$h = 20' +$   
only

NO CRINOIDAL PAY, MINIMAL DOLOMITE PAY  $h = 2.5'$

- OFFSET PRODUCERS (INJECTORS) COMPLETED ONLY IN  
CHERTY, PERFORATED INTERVAL 5 to 10' @ TOP OF CHERTY (?)  
40' to 60' OF CHERTY PAY ABOVE O/W CONTACT  
- IS THIS AN EFFECTIVE WAY TO DEplete THE  
CHERTY

✓ recovery map shows fill location -  $< 30\%$   
recovery

PROPOSED LOCATION 7A-21-11-26

SINGLE WELL 7A-21-11-26 between 4 Producers  
1 DSU

1-21, 2-21, 7-21, 8-21

• 2-21 IS THE BEST WELL IN THE POOL @ 30+ W3/C

- NEAREST WTR INJ 4-22, 12-22 & 10-21

$h = 50'$   
CHERTY

$h_{\text{CRINOIDAL}} = 10'$

$h_{\text{GOLITE}} = 5'$

• LOCALIZED THICKENING OF CRINOIDAL BETWEEN  
142 OF SEC 21 & 748 OF SEC 21

• STRATIGRAPHIC INCREASE IN TOP OF CHERTY BETWEEN  
142 OF SEC 21 & 748 OF SEC 21

- NOTE HIGH RECOVERIES @ OFFSETS

- southwest edge, natural fracture system. →  
enhances productivity & provides effective pressure  
support (?) → CHERTY ONLY OR ALL MBES

- OFFSET WELLS ONLY COMPLETED OH IN CHERTY?

- recovery map INVSU #1 advised spacing approx  
09-02-24 shows area of 30% + recovery

PROPOSED LOCATION SE/4 - 27 - 11 - 2001

SA-27-11-26 OFFSET BY PRODUCERS AT  
3, 4 & 5-27, 6-27 W.W

- large structural feature
- offset wells only completed in CHERTY (OK)

NOTE: ADJACENT TO EXISTING INFILL WELLS @ 3A-27 & 4B-27

- REVIEW PERFORMANCE OF INFILL WELLS & EXISTING WELLS IN  
N/2 OF SEC 21 & 22 & S/2 OF SEC 27 & 28 <CORRIDOR WELLS DRILLED>  
1974-78

h: 50' +  
(CHERTY)

h: 10' CRINOIDAL DIPS OUT TO EAST @ 1-28

h: 000.75'

- \* IS INSULATOR @ 6-27 COMPLETED IN CRINOIDAL & IS  
THERE ANY INJECTION INTO THIS INTERVAL (NO)

- infill selection criteria → unchanged
  - (1) better than average productivity
  - (2) lower than average WOR
  - (3) structural high
  - (4)

- incremental oil expected in all Lodgepole members

- recovery map indicates <30% recovery surrounding  
infill location

# PART IV

## TECHNICAL EVIDENCE

• 1989 INFILL PROJECT NET DAY  $\leq 30'$

• 7A-21 & SA-27 IN AREAS MAX.  $\phi H$  & KH

- well productivity, <sup>exponent</sup> influenced by structure

- WOULD LIKE TO SEE A RECOVERY MAP

- 8709 recovery map included

TOTAL OOIP PROPOSED PROJECT AREAS  $3.3 \times 10^6 \text{ L}^3 \Rightarrow 761.4 \times 10^2 \text{ L}^3$  3 wells

92% OOIP IN CHERTY  $\rightarrow$  VERY CONTINUOUS

NOTE: CRITICAL & COLLECTED NOT COMPLETED IN ANY WELLS  
OFFSETTING PROPOSED INFILL WELLS

B.1.1) FURTHER PARAMETER - CHERTY ONLY?

• AVERAGE - UNIT?

TOTAL INFILL PRODUCTION - 13 L3/D

OOIP

1A-2 4.0 L3/D

19640

7A-21 10.5 L3/D

260312

SA-27 6.0 L3/D

362382

INITIAL PRODUCTION 20.5 L3/D OF WHICH 7.5 L3/D  $\pm$  ACCELERATION

$\Delta$  recovery 2.3% OOIP < compared with 1.7% OOIP

1989 NVSU reduced recovery amount

$\rightarrow$  typically reduced spacing results in an improvement (poorly swept area) in areal & wellbore sweep eff., with waterflooding

FIGURE 7 - HISTORICAL PRODUCTION - NOTE INFILL DRILLING IN

1974-78 NO NOTICEABLE IMPACT ON PRODUCTION

$\Rightarrow$  6 CORRIDOR WELLS DRILLED

## RECOVERY VS ACCELERATION

$$OOIP = 747.8 \times 10^3 m^3$$

$$INCREMENTAL RECOVERY = 17200 m^3 \quad (2.3 \% OOIP)$$

(1) ACCELERATION COMPONENT STARTS 1 YR. AFTER NEW WELLS ON PRODUCTION

(2) ACCELERATED PRODUCTION =  $1/4$  OF ADJACENT PRODUCERS' RESERVES REMAINING RECOVERABLE (?)

- 14A-27-11-26 PERFORMANCE  $\rightarrow$  ON PRODUCTION JAN/71  
INTERFERENCE WITH OFFSET WELLS COMMENCED ALMOST IMMEDIATELY TO 2-3 YRS LATER, TOTAL ACCELERATION DIFFICULT TO QUANTIFY FROM FIGURES 2-5

NO INFILL WELL DECLINE RATE

NYSU No. 1 - NEW OIL

% NEW OIL		% NEW OIL	
1991		1989	
APR	1.05		
MAR	1.04	DEC	5.2
FEB	1.28	NOV	4.8
JAN	1.27	OCT	4.5
1990		SEP	1.2
DEC	1.22		6 WELLS
NOV	1.26		
OCT	1.16		
SEP	0.78		
AUG	1.02		
JULY	0.31 (ERROR)		
JUNE	2.99		
MAY	2.9		
APR	1.43		
MAR	6.0		
FEB	5.9		
JAN	6.3		



ENVIRONMENTAL IMPACTS - WORK THROUGH AIR PHOTOS

## LOCATIONS

7A-21 NO CONCERNS

5A-27 " "

1A-4 - will require approval of RM for  
for relocation of minimum offset to ROW  
50m setback

from ROW as required under  
reg<sup>n</sup> - possibility of moving the well  
into one of the other quadrants  
out of the slough

→ Will Clever and new built up needs of heavy hydro  
underground. - power lines installed

## WELL TESTING

→ What will the frequency of proposed well tests  
using a portable tank or NOC be?

→ is it proposed to test the wells affecting  
the 1A-4 location @ the same frequency

→ large volume of water

## PREVIOUS APPINS

### NVSU No. 1

#### — INCREMENTAL CROWN ROTATIONS & TAXES

in a mature WF

- Typical LAH projects, incremental recovery is a fn of improved volumetric sweep eff.
- pattern waterflooding, locating wells in poorly swept areas/zones, conversions
- A recovery eff. diff. required w/ different comp.

6 "CORRIDOR" WELLS wells drilled 0-8 ha spacing between 1974 & 78 - ANALYSIS IN PPT OUTLINED.

14D-21	13C-23
14C-22	4B-27
16C-22	1B-28

- discuss performance - initial work 70% lower than offsetting locations, oil rates constant for 1-2 yrs, minimal interference

- applicable to the analysis of 5A-29

OFFSET  
INDIVIDUAL, well & COMBINED PRODUCTION PLOTS

- typically initial well decline @ greater than the unit production decline

INFILL PRODUCTION FORECAST DEC INFILL WELLS 152/yd.

INFILL WELL TOTAL PROD 223250 L3  
 $\Delta$  RECOVERY = 99899 L3 (45%)  
 ACCELERATION = 123351 L3 (55%)

	YR				
STARTING	21	62%	incremental	4	69
	2	68%	—	5	66
	3	72		6	62
				7	58
				8	54
				9	49

FOR EACH WELL / PROJECT AREA

BASE CASE	REDUCING SPACING PROJECT
TOTAL	INCREMENTAL

ROYALTIES & TAX

Forecast NGL 1. 7240 m<sup>3</sup> incremental royalties & taxes

- evaluation NVSU #1 1st project - evaluate pattern waterflogging - 3 to spacing  
 1. structurally high, moderate to high oil rate, relatively low water cut, low to moderate maximum displacement

What were final well location selection criteria

Check acceleration analysis VRU No. 1

NVSU No. 1 - initial well analysis

$$105000 = \frac{365 (42.2 - 17 \times 0.2)}{1} = 0.69 \text{ per acre}$$

$$21800 = \frac{365 (16.2 - 6 \times 0.2)}{1} = .09$$

$$36200 = \frac{365 (16.2 - 6 \times 0.2)}{1} = .149$$

- In the analysis of the results of the NVSU No. 1 Sec 23, ~~26~~ initial project, the performance of the 7-26 well which had produced 54% of the 16 la reserves and had swept the offsetting well location

$$q_t = q_i \cdot e^{-D \cdot t}$$

4B-27

3A-27

	m <sup>3</sup> /d
1990	5.10
89	6.15
88	6.22
87	6.92
86	7.21
85	6.92
84	7.32
83	7.39
82	8.36
81	10.2
80	11.1
79	10.1
78	11.76
77	12.24
76	13.6
75	15.6

u <sup>2</sup> /d
0.97
1.2
1.8
2.1
0.7
1.3
1.4
1.3
2.4
2.9
2.7
2.6
4.3
4.5
4.8
7.6

DECLINE D = 7%

DECLINE D = 10.7 %

$$Q_t = \frac{365(5.1 - 0.3)}{.07} = 25029 \text{ m}^3$$

$$Q_t = \frac{365(0.97 - 0.3)}{.107} = 2294$$

$$Q_t = \frac{1}{2} (25029 + 2294) =$$

NORTH VIRDEN SCALLOP UNIT #1

CROWN ROYALTY CALCULATION

A Old Crown Royalty (m<sup>3</sup>) = Old oil portion of production calculated at the old oil royalty rate.

B New Crown Royalty (m<sup>3</sup>) =  $\left( \left( \text{total production at the old oil rate} \right) - \left( \text{old oil production at the old oil rate} \right) \right) \times 0.55 \text{ new oil factor}$

Total Crown Royalty (m<sup>3</sup>) = A + B

OIL & GAS PRODUCTION TAX CALCULATION

A Old Oil Tax Rate (%) = Old oil tax rate as determined on the old oil portion of production.

B New Oil Tax Rate (%) = New oil tax rate as determined on the total production minus new oil tax rate as determined on the old oil production.

Total Oil & Gas Production Tax Rate (m<sup>3</sup>) = A + B  
(converted to %)

1.

4.0 % new

4.2 % new

3.8 % new

5.0 m<sup>3</sup>/hr

47.5

52.5

A

B

8.69

0.41

A

B

7.81

0.39

A

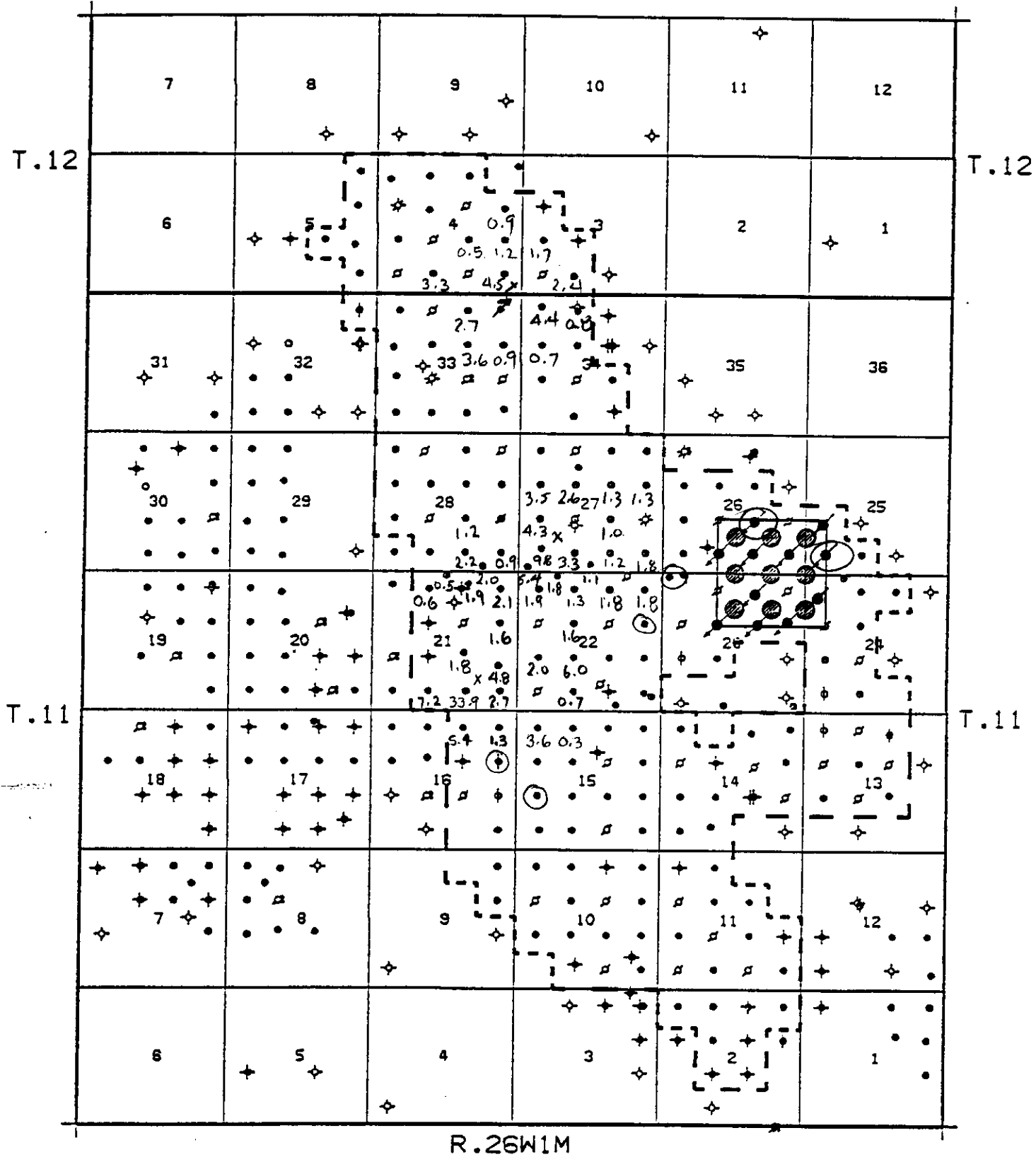
B

9.66

0.49

# FIGURE 1

## NVSU #1 INFILL PROJECT



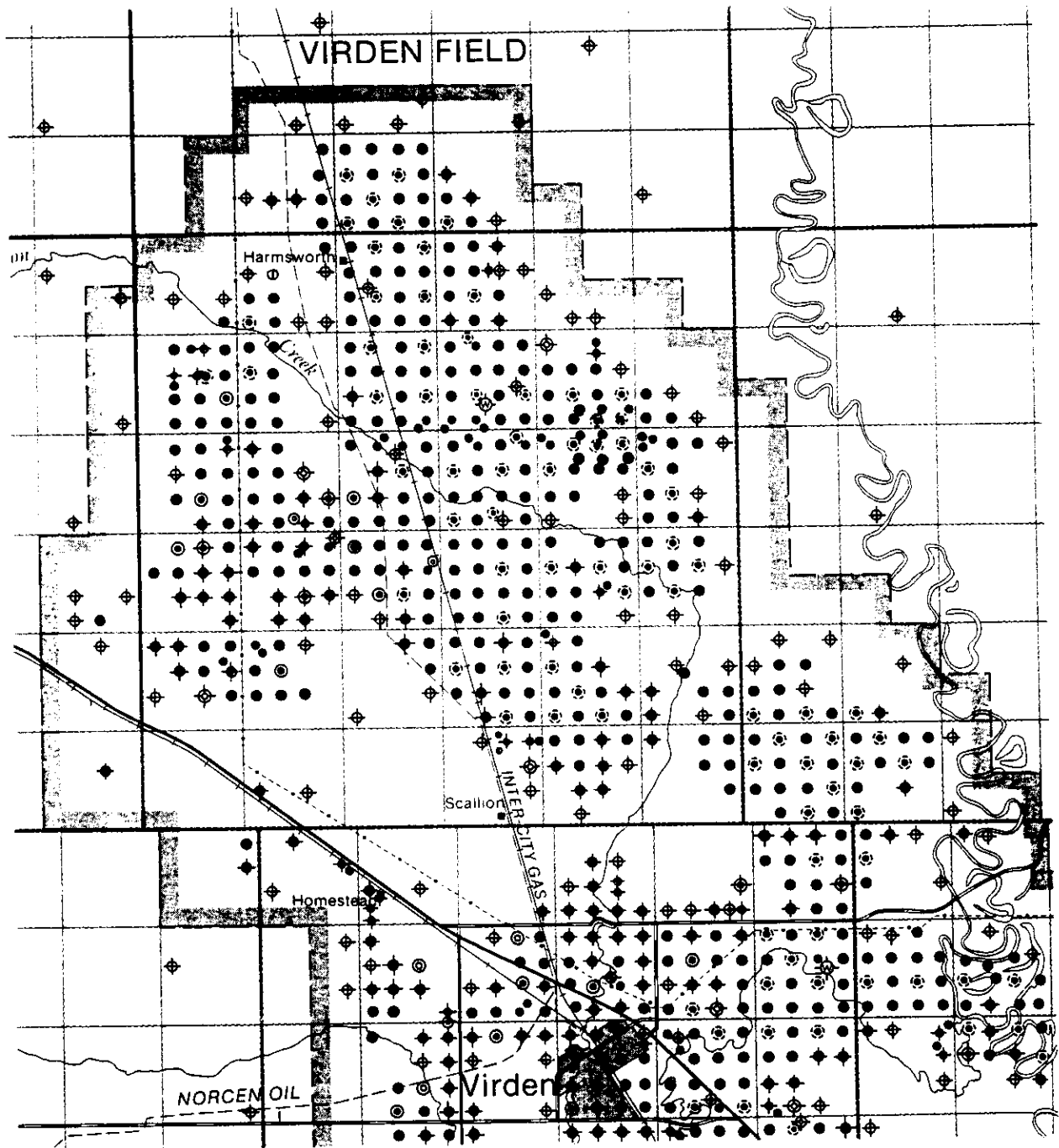
NORTH VIRDEN SCALLION UNIT NO. 1

AS OF 1989-01-25

SCALE 1" = 1 MILE

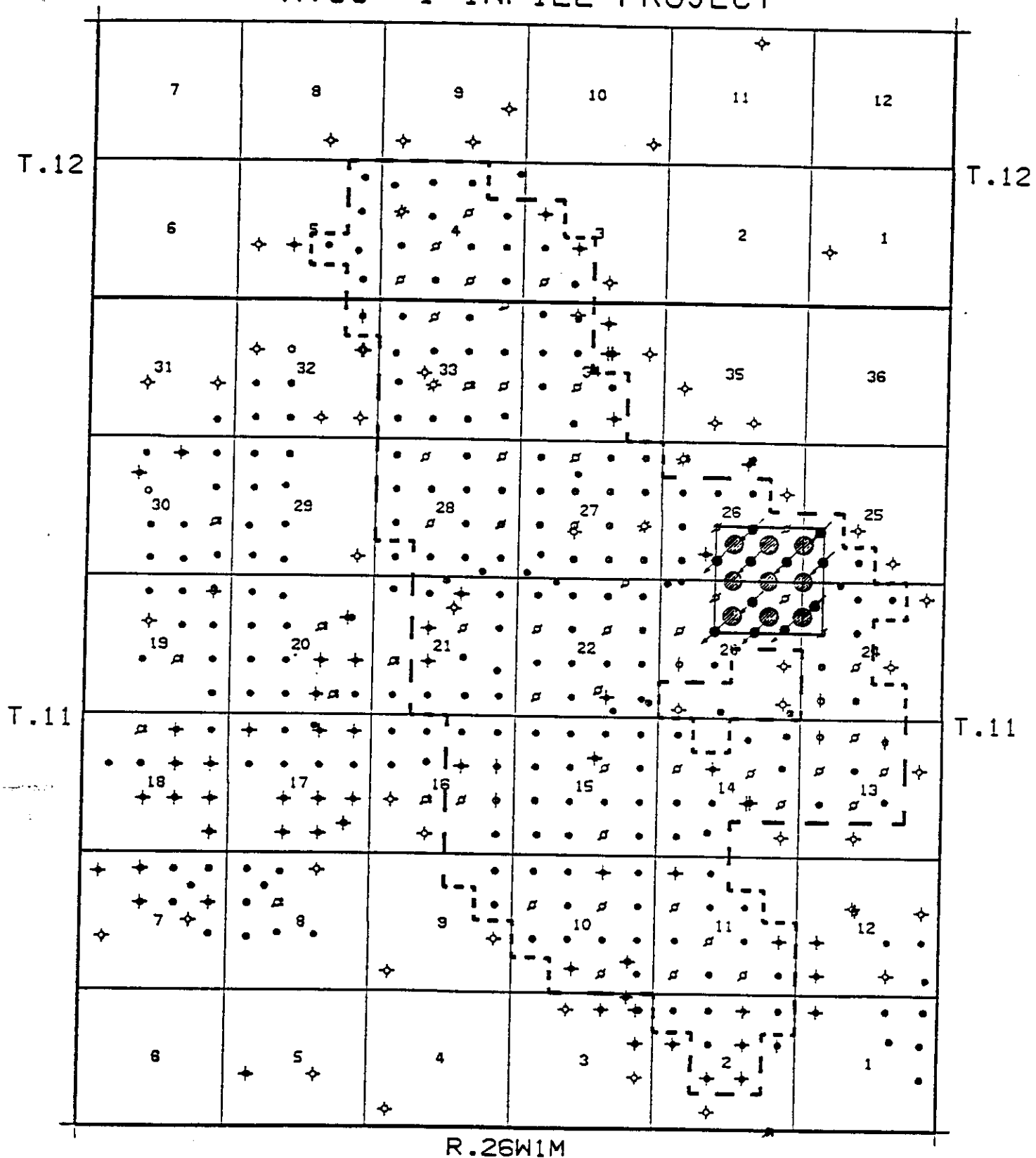
- PROJECT BOUNDARY
- PROPOSED INFILL SITES
- PROPOSED CONVERSIONS





# FIGURE 1

## NVSU #1 INFILL PROJECT



NORTH VIRDEN SCALLION UNIT NO. 1

AS OF 1989-01-25

SCALE 1" = 1 MILE

- PROJECT BOUNDARY
- PROPOSED INFILL SITES
- ⊗ PROPOSED CONVERSIONS



## **Chevron Canada Resources**

500 - Fifth Avenue S.W., Calgary, Alberta T2P 0L7 • Phone (403) 234-5000  
Fax 234-5947

K.E. Godard  
Chief Engineer

1989-04-19

North Virden Scallion Unit No. 1  
Reduced Spacing Project  
Additional Information

Oil and Natural Gas Conservation Board  
Room 309  
Legislative Building  
Winnipeg, Manitoba  
R3C 0V8

Attention: Mr. H. C. Moster, Deputy Chairman

Gentlemen:

Chevron Canada Resources, a Partnership by its managing partner, Chevron Canada Resources Limited, as operator of the North Virden Scallion Unit No. 1, submits additional information to our application of 1989-02-24 for a reduced spacing project. The information is in response to the Board's letter of 1989-03-17 outlining concerns and questions regarding the subject application.

### New Oil Status

Chevron agrees with the Board's proposal for amending the Petroleum Crown Royalty and Incentives Regulation and the Oil and Gas Production Tax Regulation to modify the definition of a "new oil well." Chevron understands the proposed modification along with Board approval of reduced drilling spacing units (to 8 hectares) will result in new oil status for the proposed infill wells.

### Section 3 - Geological Information

The requested list of completion intervals for project area wells and the requested net pay maps (Oolite and Cherty members) are included as Attachments 1, 2, 3, 4, 5, and 6 of this document. In general, the planned approach for the pilot area is to perforate all pay within the Lodgepole Formation.

### Section 4 - Technical Justification

a) Page 1, paragraph 3, sentence 1 should read:

"Current unit recovery is 27% OOIP."



- b) The assumed economic limit for decline calculations is 0.2 m<sup>3</sup>/d/well (see page 7 of application). This value represents the approximate break-even point between revenue and operating costs. It was used in the determination of the project area infill forecast termination point. The base project area forecast was terminated in the year 2020 just prior to reaching the 0.2 m<sup>3</sup>/d/well cut-off. Likewise, the Unit forecast was terminated in 2020 at which point most wells would be reaching the cut-off. The amount and value of production beyond 2020 for the base and Unit cases is insignificant.
- c) The individual effects of vertical and areal sweep are difficult to identify when assessing the proposed project. Both need to be considered together as integral and related parts of the overall volumetric sweep. The reduction in well spacing and the conversion of producers to injectors will increase the total connected and floodable pore volume of the project area. The improvement will largely be the result of two main factors: pattern realignment and improved continuity. Literature provides abundant evidence of cases where incremental recoveries of 5.0 to 10.0% OOIP were realized through improved continuity and/or pattern realignment. One such article written by A. F. van Everdigen<sup>1</sup> (Attachment 7) points to infill drilling as a powerful means for oil recovery enhancement. The heterogeneous nature of the various members of the Lodgepole Formation lends well to realization of similar recovery improvements.

Pattern realignment is anticipated to play a major role in improving oil recovery. Attachment 8 and 9 of this document are simple streamtube depictions of existing and expected flow patterns for the project area. Overlaying Attachment 8 onto Attachment 9 reveals a significant change in flow paths caused by pattern realignment with previous areas of low sweep being swept much more thoroughly under the proposed infill scheme.

Infill drilling will result in a general improvement in continuity. Although the Cherty zone is correlative from well to well as a whole, because of the vertical heterogeneity within the Cherty member, it may be visualized as by a Dykstra-Parsons model of a series of variable permeability "layers." These "layers" are stacked upon each other and may not be continuous between all wells. By increasing well density, a greater percentage of these "layers" will be connected to the effective waterflood system. The Crinoidal and Oolite members, on the other hand, exhibit very definite vertical stratification and limited continuity. Likewise, infill drilling will connect a larger percentage of those pay horizons to the waterflood system. Attachment 9A illustrates conceptually how infill drilling will improve continuity.

- d) The determination of the fraction of oil production being produced from within the project area (55%) was made using edge well allocation factors. The factors were selected by geometric distribution of the produced fluids (eg., a corner well factor is 0.25). Slight modifications were made where significantly different injection rates exist at the supporting injectors offset to the edge wells.

<sup>1</sup>. van Everdigen, A. F., 'A Proposal to Improve Recovery Efficiency,' Journal of Petroleum Technology, p. 1164, July, 1980.

The allocation only plays a role in the estimation of recovery factors. Cumulative production to date and forecasted base case production of the project area were factored by the 55% to come up with the project area recovery factor of 30.5% presented in Table 1 on page 2. Allocation was unnecessary for the generation of a forecast.

- e) The geographical area used to generate the oil in place number of 1 758 900 m<sup>3</sup> in Table 4, page 8 of the application is shown in Attachment 10 of this document. The OOIP determination was made simply for the interwell portion of the reservoir between the project boundary injectors and the nearest surrounding row of offset producers. The net pay over the subject area was planimetered to yield a (h·A) value which was used along with the reservoir properties listed in Attachment 5 of the original application to calculate OOIP.
- f) The last line on page 8 should read:  
  
"The total unit production forecasts are shown in Figure 10 and Table 3."
- g) A copy of the referenced article "Laboratory Comparison of Oil Recovery in Five-Spot and Nine-Spot Waterflood Patterns" is included as Attachment 11 for your information. Further discussion of the spacing options is presented in the following paragraphs.

Attachment 12 of this document presents a pictorial representation of the spacing options available for the project area. The pattern configuration presented in the top left shows nine-spot patterns on 16 ha spacing. The configuration is approximately representative of the existing waterflood. With no further drilling and through conversion of producers to injectors, as shown in the top right diagram, a 16 ha, five-spot configuration is possible. Although a small degree of incremental production is possible through realignment, the 16 ha, five-spot option is not attractive for two main reasons. First, the improvement in continuity is not achieved because well spacing is unaffected. And second, total fluid throughput (injection and production) would not increase. That is, it would be expected that the loss in production through conversion of producers to injectors would, at best, be balanced by productivity increases at remaining producers.

The two bottom configurations of Attachment 12 illustrate nine-spot and five-spot, 8 ha patterns. Both benefit from improvements in continuity through infill drilling and an increase in fluid throughput because of increased well density. However, differences exist between the two. First, the nine-spot development involves drilling three new producers for each injector conversion. Pressure maintenance may be difficult for such a case because of the high ratio of producers to injectors. The five-spot development involves the drilling of approximately one new producer for each injector conversion. Under that scenario, fluid throughput should be maximized. The two configurations also differ with respect to improved sweep expected as a result of pattern realignment. Attachment 13 compares expected flow paths for the two configurations with the previous 16 ha, nine-spot flow paths. More new flow paths are evident for the five-spot development configuration.

#### Section 7 - Royalty and Tax Calculations

- a) Chevron agrees with the descriptive wording suggested by the Board for royalty calculations.
- b) Chevron agrees with the descriptive wording proposed for the calculation of the Oil and Gas Production Tax. The requested tax calculation program has been discussed between Jim Foster of our office (403-234-5911) and Brad Thiessen of your office. Please contact Jim if you have any further requests.

#### Section 8 - Incremental Crown Revenue

- a) Attachment 14 presents a table of the annual benefits to the Crown.
- b) The freehold mineral holders will gain 11 500 m<sup>3</sup> incremental royalty from the expected 100 000 m<sup>3</sup> incremental reserves. They will also benefit from the acceleration of recovery of total reserves.

#### Section 9 - Areal Photograph

A revised areal photograph is attached (Attachment 15) and reflects the changes requested. Specifically, the wells in Lsd. 4 and 5 of Section 25-11-26 WPM have been correctly labelled. In addition, the "ideal location" for each well is shown.

Two of the proposed wells have been moved slightly. Well number 1 has been moved south by 50 metres to locate the lease on only one surface owner's land. Well number 8 has been moved south back to the ideal location. As shown on the revised photograph, the bush to the northwest has been cleared on the land cultivated.

#### Section 10 - Environmental Impact Assessment

- a) The planned frequency for the following items is provided:
  - (i) Cleaning flow lines - Paraffin accumulation in flow lines is cleaned out by running a pig down each line approximately once each month. The frequency can be greater depending on the characteristics of each well. Wellhead pressure helps identify the onset or development of paraffin buildup.
  - (ii) High pressure shut down switches are tested at the time flow line pigs are run (at least once per month).
  - (iii) Wells are monitored in several different ways and with varying frequency:
    - operators inspect each well site daily and can detect any abnormalities in producing behaviour. In addition, they conduct frequent checks of a well's polish rod and stuffing box.

- production batteries are inspected twice each day at which time fluid production rates are observed and any discrepancies with normal operating rates will be noted.
- aerial surveillance of facilities and flow lines are conducted twice each week.
- b) Chevron plans to build up the well site at 13C-24-11-26 WPM and to berm it in order to prevent contamination of surface water. It will be built up to a level consistent with the adjacent high ground.
- c) Chevron will expand its ongoing weed control program to include the new production and injection facilities associated with the reduced spacing project. Weed control will be accomplished as follows:
  - a) Hand removal by weed-eaters and/or shovel of all vegetation immediately surrounding the well.
  - b) Mowing will be used to control annual and perennial broadleaf weeds along lease trails and well sites while promoting grass growth and preventing erosion.
  - c) Noxious weeds requiring chemical control will be treated as recommended by the Manitoba Agriculture Guide to Chemical Weed Control under the supervision of a licensed pesticide applicator. Chemical weed control will not be applied on areas adjacent to susceptible crops.
  - d) Soil sterilants may occasionally be used inside bermed areas unless requested not to by the landowner.

#### Section 11 - Surface Land Use Impact Assessment

At present, Chevron has no need to move the proposed well locations within the 50 metre minimum distance from a road allowance. However, the need may arise in the future as locations are finalized. At that time, Chevron will obtain and submit to the Board supporting evidence to relax the restriction from 50 metres to 38 metres.

#### Section 16 - Landowner Notification

- a) A letter has been forwarded to the Department of Natural Resources (Attachment 16) concerning the conversion of Chevron Scallion 5-25-11-26 (WPM). A letter had mistakenly been sent to the R. M. of Wallace.
- b) Mr. Heaman has been notified by phone of the mistake on the letter originally sent to him. The well at 3-26-11-26 (WPM) was mistakenly included and the well at 2-26-11-26 (WPM) was mistakenly excluded from his letter.

### Section 18 - Water Injection Details

The proposed maximum injection pressure of 8 000 kPag is in accordance with the value approved for the existing waterflood scheme. Although no definite work in terms of step rate testing has been done to determine a formation failure (breakdown) pressure or fracture closure pressure, waterflood performance to date reveals no evidence of poor sweep or water channelling attributable to fracturing. The current field injection pressure and expected injection pressure for the proposed conversions fall in the range of 6 500 to 7 000 kPag, significantly below the maximum. Either no fracturing is occurring or very short, limited fractures have been created. In the event of fracturing, the low rate of water injection and high rate of fluid leakoff would not support fracture propagation to lengths that would jeopardize sweep efficiency.

A review of fracture stimulation data reveals a typical formation breakdown pressure of 13 500 kPag (2 000 psig) and a treating pressure of 9 000 kPag (1 300 psig). The breakdown pressure is the pressure necessary to cause the rock to fail and a fracture to be created. The treating pressure is that pressure required for continued growth of the fracture.

Following is a theoretical interpretation of the field observed breakdown and treating pressures based on current fracture stimulation theory:

- 1) The fracture geometry for NVSU wells is somewhat unknown with the well depth falling in the transition range between vertical and horizontal fracturing. Typically, wells below 600 m (2 000 ft) have a vertical fracture geometry and a closure pressure gradient of 17.0 to 19.2 kPa/m (0.75 to 0.85 psi/ft). Wells shallower than 450 m (1 500 ft) have a horizontal fracture geometry. The closure pressure gradient required to lift overburden and create a horizontal fracture is 22.6 to 25.0 kPa/m (1.0 to 1.1 psi/ft). A mid-point gradient of 20 kPa/m (0.9 psi/ft) and an average depth of 590 m (1 935 ft) have been assumed:

$$\begin{aligned} \text{- Closure Pressure (Bottomhole)} &= 590 \text{ m} \times 20 \text{ kPag/m} = 11\,800 \text{ kPag (1 710 psig)} \\ \text{- Closure Pressure (Surface)} &= 11\,800 \text{ kPag - hydrostatic column} \\ &= 11\,800 \text{ kPag - } 5\,750 \text{ kPag} = 6\,050 \text{ kPag (880 psig)} \end{aligned}$$

- 2) Treating pressure is the closure pressure plus the net fracturing pressure. The latter is the additional pressure required to open and propagate a fracture and is typically in the range of 3 500 kPag (500 psig) or greater based on fracture stimulation experience.

$$\begin{aligned} \text{Treating (Fracturing) Pressure} &= 6\,050 \text{ kPag} + 3\,500 \text{ kPag} \\ &= 9\,550 \text{ kPag} \end{aligned}$$

In summary, the proposed maximum injection pressure 8 000 kPag poses no problem to waterflood sweep efficiency. Current and expected future injection pressure range from 6 500 to 7 000 kPag. However, a maximum pressure of 8 000 kPag is needed for operating flexibility. Even if pressures reach 8 000 kPag, the formation breakdown pressure is much higher at 13 500 kPag based on hydraulic fracture stimulation history and the propagation pressure is above 9 500 kPag.



Section 21

a) The well data to be obtained during drilling is listed below:

- i) Dual Induction - Laterlog or Phaser Induction  
BHC Sonic Log  
CNL-CDL-GR  
Microlog
- ii) Two 18 m cores
- iii) Possible DST after logging
- iv) see Attachment 17

Chevron is also presently considering a special core program to gather additional data and to better define reservoir parameters such as porosity and permeability distribution, initial water saturations, oil/water relative permeability, and capillary pressure.

b) Chevron plans to determine the production rates of wells inside the project area at least four times each year. Other unit wells producing to the same battery as the project wells will be tested as close to four times each year as is possible. Chevron is very hopeful the net oil computer will provide a successful test method and result in an overall improvement in the quality and frequency of well production testing. To date, calibration of the net oil computer has not been conducted. However, Chevron intends to run side-by-side tests comparing it to tank test results.

c) Chevron plans to conduct the following steps for gathering pressure information from within the project area:

- i) Perform static pressure measurements on existing wells in the project area prior to infill drilling. The wells selected are as follows:

15-23-11-26 W1M  
16-23-11-26 W1M (WIW)  
13-24-11-26 W1M  
01-26-11-26 W1M  
03-26-11-26 W1M  
06-26-11-26 W1M (WIW)

Sonolog measurements will be made at producers and the fall-off of surface pressure will be measured at injectors.

- ii) Perform static pressure measurements using pressure bombs on all infill wells immediately after completion and prior to commencement of production.
- iii) Conduct annual static pressure measurements on a representative cross-section of project area producers and injectors.

Please contact Scott Robinson at 403-234-5388 if you have any additional questioning regarding the subject application.

Yours very truly,

A handwritten signature in cursive script, appearing to read "Scott Robinson".

*for* C. G. FOLDEN, P.Eng.  
Manager  
Reservoir Engineering

DSR/kt  
Attach.

cc: C. S. Kang, Chairman  
W. McDonald, Member  
S. Scrafield (Municipal Affairs)  
D. Partridge (Agriculture)  
D. Wotton (Environment)  
L. R. Dubreuil (Petroleum Branch)

## SECTION 3 - GEOLOGICAL INFORMATION

- a) Current and proposed completion intervals for all existing wells in the project area (OH - open hole, P - Perf, all depths reported in feet from KB)

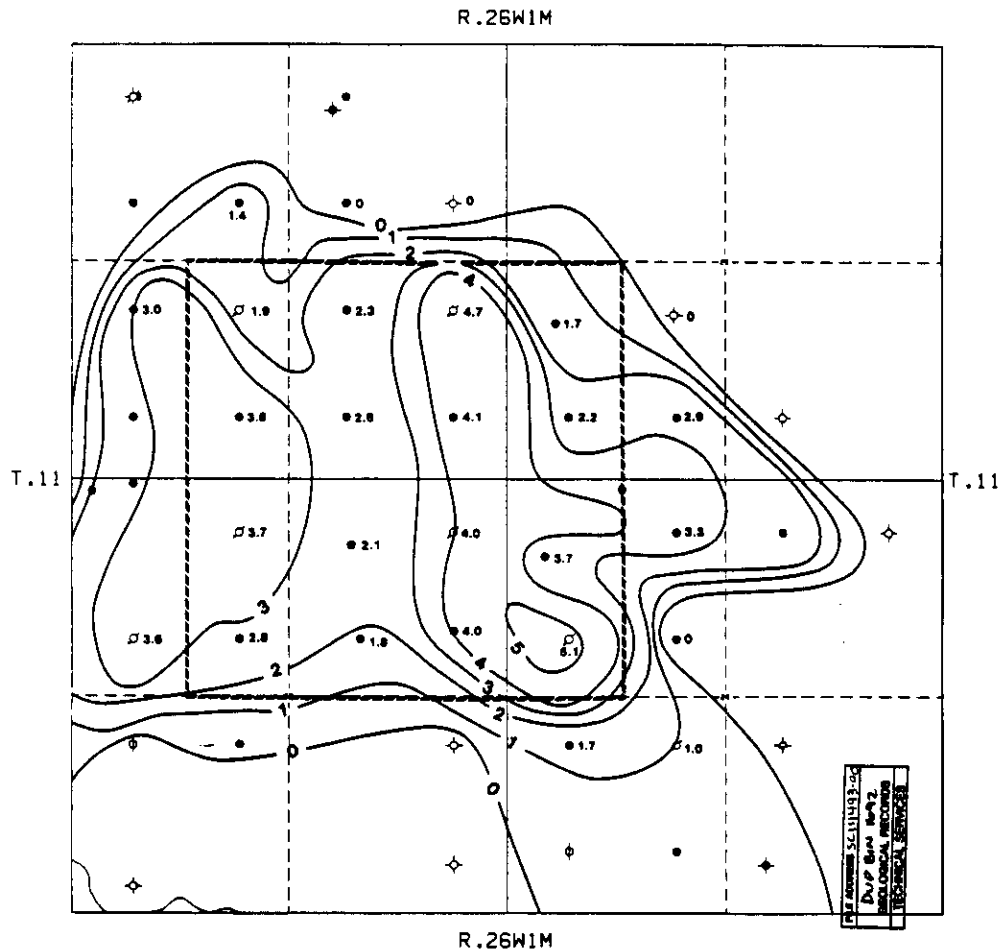
<u>WELL LOCATION</u>	<u>CURRENT COMPLETION INTERVAL</u>		<u>ADDITIONAL INTERVALS TO BE COMPLETED</u>
9-23-11-26 W1	OH	1967 - 2033 1st Oolite - Cherty	None
10-23-11-26 W1	P	2004 - 2006.5 } 2008 - 2009 } 2009 - 2027 } 4th Oolite Cherty	P 1965 - 1967 } 1970 - 1972 } 1983 - 1985 } 1994 - 1996 } Crinoidal 1st Oolite 3rd Oolite
11-23-11-26 W1	P	2026 - 2029 } 2046 - 2027 } Cherty	P 2003 - 2005 1st Oolite 2010 - 2014 3rd Oolite 2017 - 2019 4th Oolite
14-23-11-26 W1	P	2039 - 2044 Cherty	P 2018 - 2022 3rd Oolite 2026 - 2030 4th Oolite
15-23-11-26 W1	P	1998 - 2002 2002 - 2008 4th Oolite Cherty	P 1955 - 1958 Crinoidal 1973 - 1978 1st Oolite 1984 - 1985 2nd Oolite 1989 - 1991 3rd Oolite
16-23-11-26 W1	P	1985.5 - 1987.5 1991 - 1997 2001.5 - 2004.5 3rd Oolite 4th Oolite Cherty	None

<u>WELL LOCATION</u>	<u>CURRENT COMPLETION INTERVAL</u>	<u>ADDITIONAL INTERVALS TO BE COMPLETED</u>
12-24-11-26 W1	P    1956 - 1958    Crinoidal 1958 - 1966.5   1st & 2nd Oolite 1975 - 1979    3rd oolite 1985 - 1988    4th Oolite 1989.5 - 1996   } 2000 - 2008    Cherty	None
13-24-11-26 W1	P    1945 - 1948    1st Oolite 1958 - 1960    3rd Oolite 1971 - 1973   } 1980 - 1981   Cherty	None
4-25-11-26 W1	P    1960 - 1961    4th Oolite 1964 - 1965   } 1969 - 1970   Cherty 1974.5 - 1975.5 }	P    1939 - 1943    1st Oolite 1946 - 1948    2nd Oolite 1951 - 1953    3rd Oolite
5-25-11-26 W1	P    1942 - 1944    } 1955 - 1956   Cherty 1962 - 1963   }	P    1892 - 1894    Crinoidal 1924 - 1926    3rd Oolite 1931 - 1933    4th Oolite
1-26-11-26 W1	P    1971 - 1975    3rd Oolite 1980 - 1982    4th Oolite 1982 - 1993   } 1994 - 2000   Cherty	None
2-26-11-26 W1	P    1964 - 1967    3rd Oolite 1972 - 1974    4th Oolite 1977 - 1999.5 } Cherty	None

<u>WELL LOCATION</u>	<u>CURRENT COMPLETION INTERVAL</u>	<u>ADDITIONAL INTERVALS TO BE COMPLETED</u>
3-26-11-26 W1	P 2015 - 2022 Cherty	P 2000 - 2004 3rd Oolite 2007 - 2011 4th Oolite
6-26-11-26 W1	P 1969 - 1972 3rd Oolite 1976 - 1981 4th Oolite 1984 - 1989 } 1993 - 1998 Cherty	None
7-26-11-26 W1	P 1952 - 1954 4th Oolite 1960 - 1970 Cherty	P 1906 - 1918 Crinoidal 1930 - 1933 1st Oolite 1943 - 1946 3rd Oolite
8-26-11-26 W1	P 1932 - 1936 2nd & 3rd 1948 - 1962 Oolite Cherty	P 1902 - 1904 Crinoidal 1920 - 1921 1st Oolite 1941 - 1944 4th Oolite

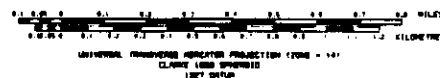






DIGITAL INFORMATION				Chevron Canada Resources	
NAME	DESCRIPTION	SOURCE	DATE	MANI	VIRIDEN SCALLION
WELLS		SWD	25-02-99		
CULTURE	DIGITIZED AT 1:50 000 BY AUTO-TRAC TECH. LTD.	ATL	06-01-01		
				ISOPACH OF NET PAY THIRD OOLITE MEMBER <b>ATTACHMENT 4</b>	
				B-12935 5	
				VIRIDEN	

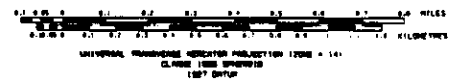


[illegible][illegible]

0.26 Miles

Legend:

- Contour lines (solid lines)
- Spot elevations (circles with numbers)
- Spot elevations (diamonds with numbers)
- Spot elevations (circles with numbers)
- Spot elevations (diamonds with numbers)

[illegible]

# A Proposal To Improve Recovery Efficiency

To substantiate our recommendations for secondary recovery by infill drilling and waterflooding, it was necessary to show that there is some relationship between spacing and ultimate recovery. This is a problem that has perplexed the industry since the 1920's. The last serious attempt to find such a relationship was made in 1967 by the API Subcommittee on Recovery Efficiency. The 103 reservoirs analyzed by Craze and Buckley<sup>1</sup> in 1945 were expanded to 312, and relationships between recovery efficiency, reservoir characteristics, and fluid characteristics were established for depletion-drive as well as water-drive reservoirs; however, a spacing/ultimate-recovery relationship could not be determined, possibly because heterogeneity was not considered.<sup>2</sup>

Our recommendations for secondary recovery of oil do not involve new technology; however, they do require larger capital investments than do tertiary-recovery projects of similar size. Oil recovered by tertiary methods gets upper-tier prices because of the magnitude of the investment required. If size of investment is the criterion used to obtain world prices, then modern infill-drilling programs more than meet this requirement. When mentioned in this paper, secondary recovery or infill drilling always means infill drilling combined with waterflooding to maintain pressures at or above saturation pressure. Such infill drilling easily could result in spacing as dense as 20 acres per unit, where a unit consists of one production well and one injection well. This means that, with 20-acre spacing, there would be four times as many wells in a field as there are now with 40-acre spacing. Because one well now costs three times as much as it did in the early 1970's, requirements for receiving world prices for this method appear fully satisfied.

The only methods effective for large-scale improvement of oil recovery are the secondary method of infill drilling as proposed here and the application of heat in viscous-oil reservoirs. There is at present no tertiary method ready to be used on a large scale.

The CO<sub>2</sub>-WAG project in the SACROC Unit is the only CO<sub>2</sub> project in operation on a large scale; a close look at the data on this unit causes considerable doubt about claims regarding the success of the project.

Infill drilling, if done properly, can be used to recover at least as much oil as the U.S. already has produced. All reservoirs are heterogeneous to some degree — i.e., not all portions of the reservoir are connected to one another. Infill drilling will permit production of oil from parts of the reservoir that might be bypassed by standard, low-density well spacing. Water must be injected in all portions of the reservoir simultaneously to keep the entire reservoir contents at least at, and preferably above, bubble-point pressure. The water produced must be collected and cleaned for recirculation, and "short circuits" between injectors and producers must be located and repaired if possible. During production, some producers must be converted to injectors, and vice versa, depending on productive behavior in a particular portion of the reservoir. At all times, the engineer should determine the particular section of the formation into which water should be injected; the water's path from the injector to the producer should not be left up to formation permeability. For successful recovery, the number of producers should be equal to or less than the number of injectors, and the wells should be spaced on a regular pattern. Obviously, if the injection wells are widely spaced, only the most permeable channels are used. With regularly and densely spaced injectors, water will be forced into the less-permeable portions of the reservoir and will push the oil out. Openhole completions of water-injection wells never should be made, and such wells should not be fractured. If secondary recovery is carried out in this manner, operating costs will be far above normal; however, production also will be far above normal.

Although waterflooding is applicable everywhere except where heat is required to reduce oil viscosity, the most logical places to begin flooding operations are the limestone/dolomite reservoirs of New Mexico and west Texas. There are four reasons for this.

1. Any serious attempt to waterflood on short notice requires large unitized areas such as are present in the New Mexico and west Texas oil fields.

2. Limestone/dolomite reservoirs contain 30% of all the oil in the U.S.

3. Limestone/dolomite porosity is recognized as notoriously variable.

4. Many of these reservoirs are the depletion-drive type – i.e., there is little or no water present along the flanks of the structure to expand and help keep up the pressure.

We have reviewed data on four fields – Slaughter, Levelland, Wasson, and Kelly-Snyder SACROC – to substantiate our opinion. All four fields are limestone/dolomite depletion-type reservoirs. They all have extensive unitized areas; thus, modern secondary recovery could start at once.

It is clear that the rate of fluid produced from a closed reservoir eventually should equal the rate of water injected into the reservoir. Normally, this occurs when reservoir pressure is at or above bubble point. When output is lower than input – as in the Slaughter, Levelland, and Wasson fields as late as 1976 and 1977 – this means the injected fluid still is filling the spaces emptied by gas and oil production during the 35 years the fields were in operation. Even by 1977, bubble-point pressure probably had not been reached in all portions; therefore, free gas still could exist in the fine pores of the formation. This free gas blocks off less-permeable portions of the formation, causing what in the past was called a Jamin effect. Today, instead of the Jamin effect, we talk about relative permeability, although such a characteristic cannot be defined for a formation. However, the effect of creating relative-permeability conditions is the same – a sharp reduction in permeability and probably in recovery efficiency. Obviously, waterflooding techniques that have not restored pressure to at least the bubble point have not yet reached their maximum efficiency, and the results still can be improved. This demonstrates the need for periodic determination of fully built-up reservoir pressures.

Water injection in Slaughter, Levelland, and Wasson fields has been carried out on a sizable scale since the mid-1960's and already has resulted in an average increase in recovery efficiency of about 50% or from 18 to 30% OIP. A modern infill-drilling program should double the efficiency to about 60%. Everyone recognizes that flooding is necessary in depletion-type reservoirs such as these, but few realize that water must be injected simultaneously in all parts of the structure. Hence, whenever the density of the oil producers significantly exceeds that of the injectors, denser drilling is necessary because water injected easily could miss some productive portions of the formation.

To determine the effect of dense drilling on the recovery efficiency of these reservoirs, we plotted the recovery efficiency of each unit against the number of acres per active well as of Jan. 1, 1978. All data are from Ref. 3. The units are numbered in the order in which they are mentioned in the 1978 publication so that the data can be checked and verified. For

units not shown on the graphs, no efficiency could be computed because information was incomplete. In computing the efficiency of each unit, we used the volumetric method to determine the OIP. It is our experience that, for heterogeneous reservoirs, material-balance computations invariably give OIP volumes that are too low because this method fails to include all portions of the reservoir. To obtain effective well spacing (acres per well), we used the total number of injectors plus producers. Because injectors drive the oil to the producers, it appears that the injectors must be spaced as densely as the producers. Fig. 1 indicates the results of the study for Slaughter field. The Levelland field results, which are not included here, are similar to those for Slaughter field. For Slaughter field, Dist. 8A, the productive area is 99,000 acres, average thickness is 51.0 ft, average porosity is 10.8%, and OIP volume is 2.8 billion bbl vs. 1.81 billion bbl given by the API.<sup>4</sup> Out of the 53 units, 46 data points were obtained and are shown in the figure.

The figure shows that denser spacing results in a trend of higher recovery efficiency; the efficiency increases almost continuously when the acres per well are decreased. In some instances, several recovery efficiencies are shown for the same well density. This could be caused by differences in reservoir conditions under the different units and by a change in the ratios of producers to injectors.

To stress the importance of flooding, we used Ref. 2 to obtain an average recovery efficiency for depletion-type reservoirs. Using the known reservoir characteristics, we get an efficiency of 19.2%. Hence, during the 15-year period that waterflooding has been done, recovery efficiency was increased to 30%. Almost any trend line through the points indicates that, with infill drilling, the 40-acre efficiency at least can be doubled by going to 20-acre spacing. This poses a further question: Why should the maximum efficiency be reached at 20 acres? Furthermore, it is interesting that the recovery efficiencies estimated for wide spacing (with waterflooding) are barely above the efficiencies for depletion-type reservoirs where secondary recovery is not used. In our opinion, it shows that flooding on 40-acre spacing is highly, if not totally, inefficient.

In Wasson field, Dist. 8A, (Fig. 2) the productive area is 63,500 acres, average thickness is 166.9 ft, and OIP is 5.671 billion bbl vs. 4.754 billion bbl given by the API.<sup>4</sup> There are only seven units in the field. According to a study by Ghauri *et al.*,<sup>5</sup> up to 10 productive members can be recognized under the Wasson Denver Unit; the members are contained in a section whose gross thickness varies from 300 to 500 ft. Ghauri *et al.* show that several of these pay members are discontinuous and would not be flooded on 40-acre spacing. Moreover, an illustration in that article shows several impermeable barriers between the productive members. All the foregoing made us think we could establish a reliable spacing/recovery relationship. However, we were not able to establish even a trend for such a relationship. For six of the seven units, recovery efficiency is from 20 to 29% for spacing between 15 and 30 acres per

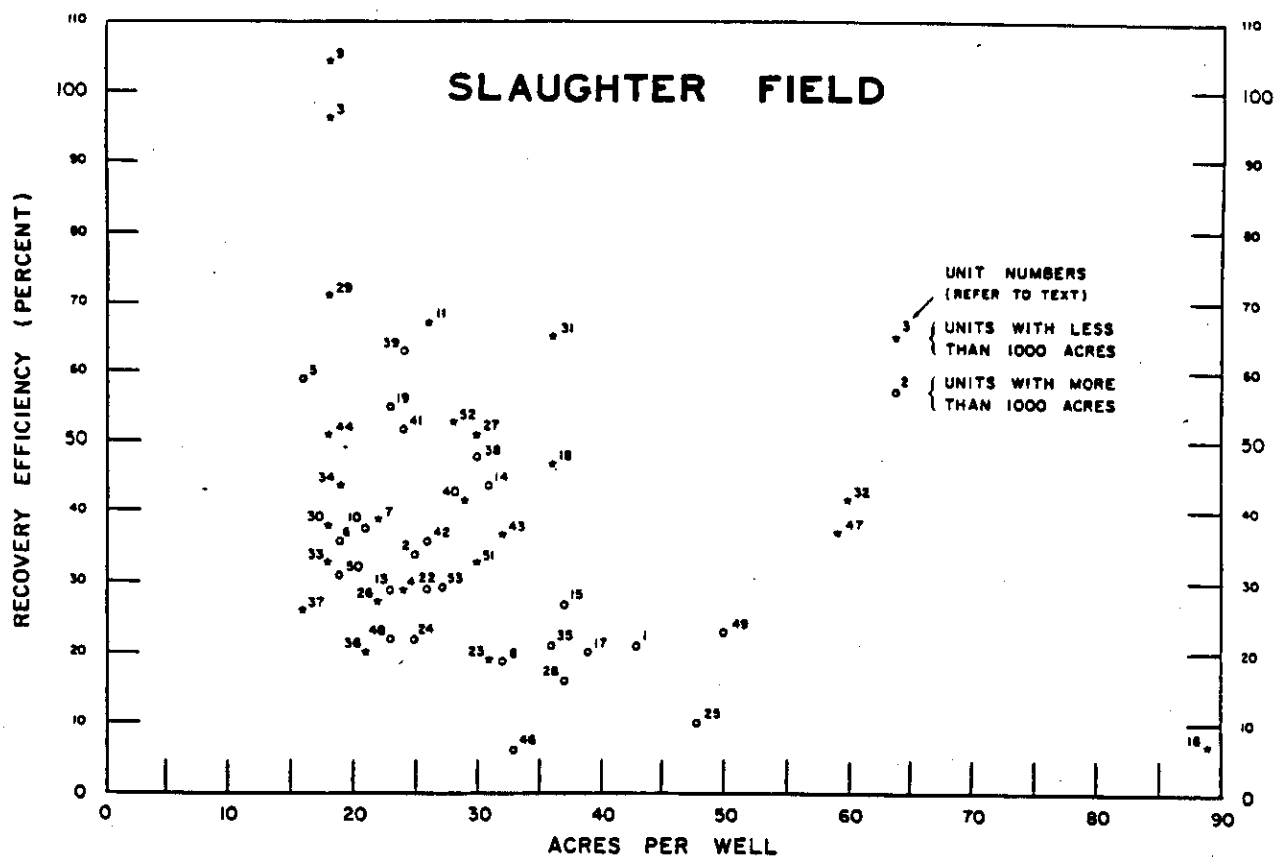


Fig. 1 - Recovery efficiency vs. well density at Slaughter field.

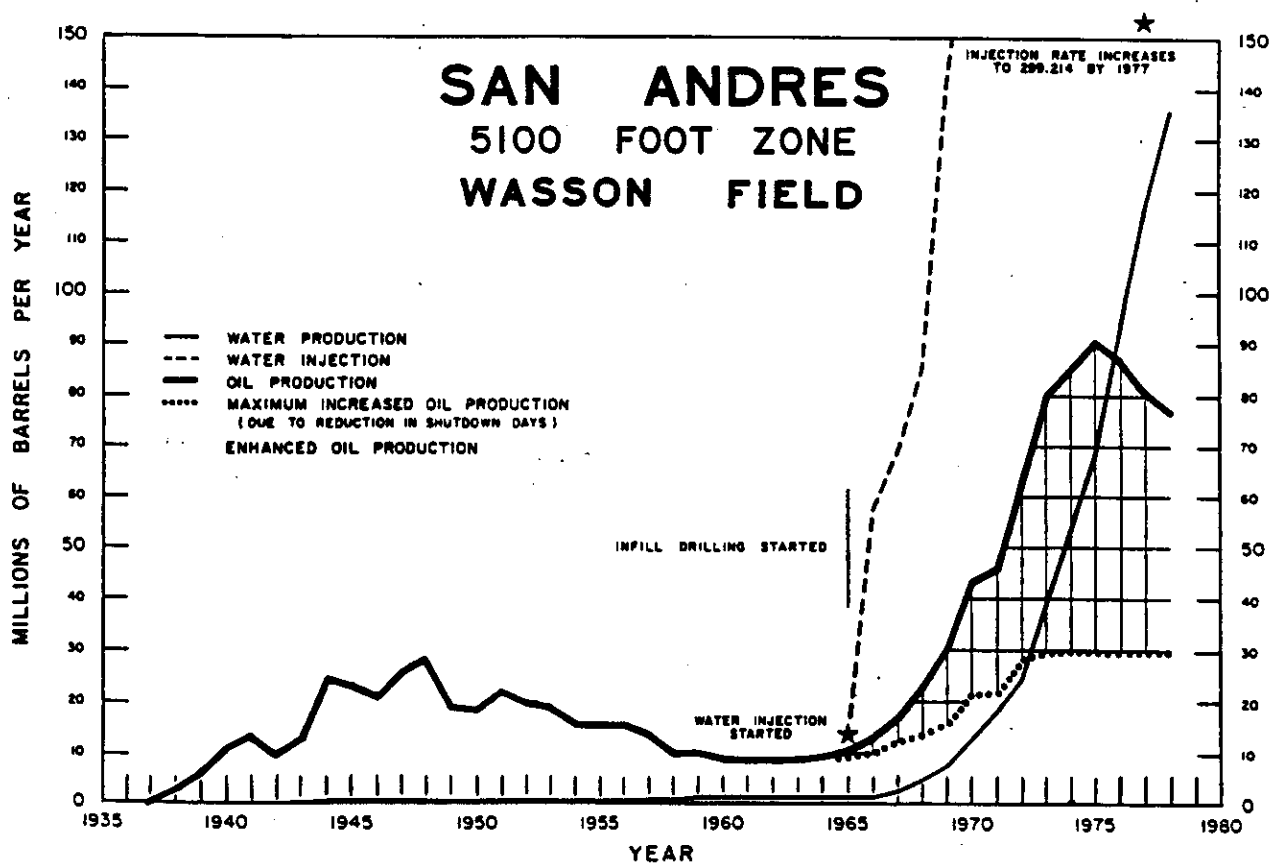


Fig. 2 - Production history of Wasson field.

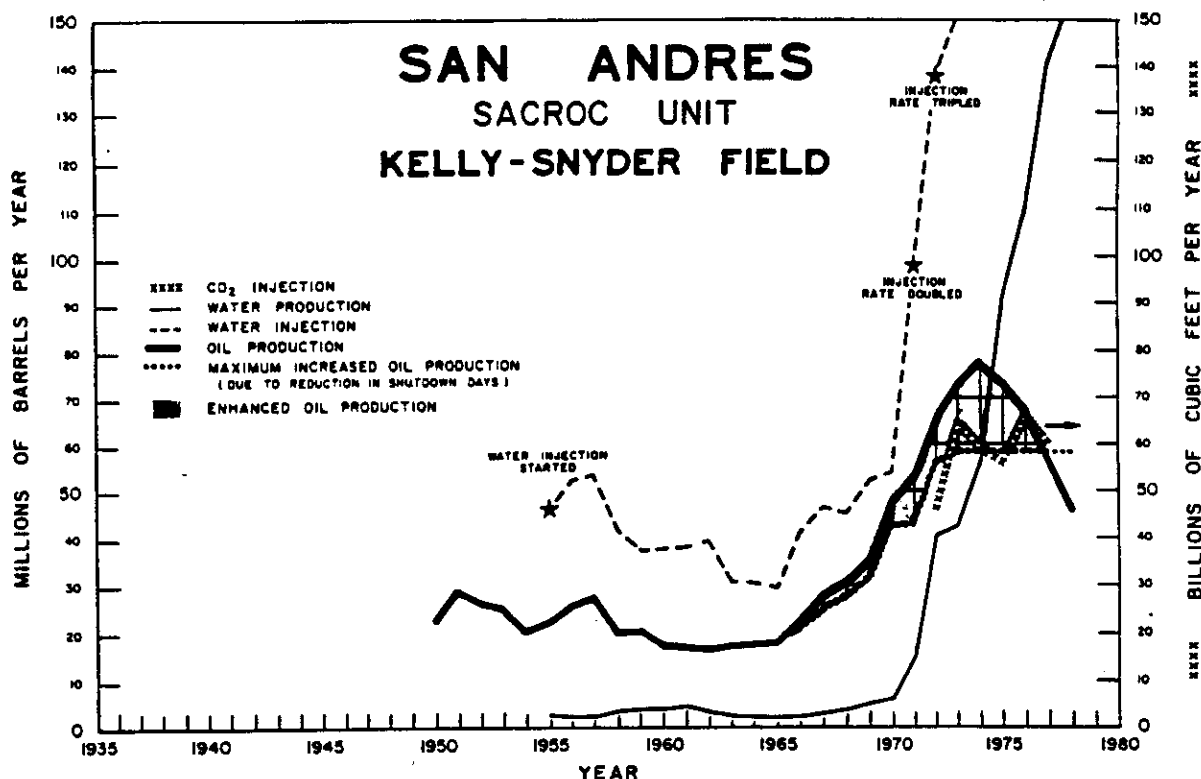


Fig. 3 - Production history of SACROC Unit.

well, and we can only surmise that the great thickness, the widely varying porosities, and the many productive intervals make displacement of oil in the seven units extremely variable. For this reason, we have not included a graph of the same type as we have included for Slaughter field.

The Wasson production history is shown in Fig. 2. It shows the minimum increase in production obtained with infill drilling and waterflooding. The dotted line shows the maximum possible increase in production that could be caused by a reduction in shutdown days. Thus, the volume of oil obtained with infill drilling and waterflooding (shaded area) could have been even greater. Volumetric data indicate that the Wasson field could have contained close to 6 billion bbl of OOIP; based on this volume, the ultimate recovery efficiency still will be 30%.

Many more production data are required before a firm opinion can be given on the ultimate production from this field as it is being produced to date. It would not be at all surprising if producing the top 250 ft and the bottom 250 ft of the formation separately would provide a significant increase in both production rate and ultimate recovery from the field.

In the SACROC Unit, Kelly-Snyder field, Dist. 8A, (Fig. 3) the productive area is 49,900 acres, average gross thickness is 268 ft, and OIP is 3.172 billion bbl vs. 2.113 billion bbl given by the API.<sup>4</sup> The OIP volume of 3.172 billion bbl that we used is a volumetric estimate; it is explained in Ref. 6. We fully agree with that explanation of the way the figure was derived. For an estimated ultimate

recovery of 1.2 billion bbl, the recovery efficiency would be 37.8%. An article by Kane<sup>7</sup> contains an OOIP estimate of 2.1 billion bbl. We have not accepted that estimate because it was made using material-balance calculations and, therefore, does not allow for all the producing pays in a heterogeneous reservoir such as this one. Kane used figures prepared by Brummett *et al.*,<sup>8</sup> who decreased the porosity and permeability to obtain a history match.

As of Jan. 1, 1978, the average well spacing was 52 acres per well for the combined active producers and injectors in the SACROC Unit. Despite this low well density, the recovery efficiency has been an adequate 37.8% because water injection was begun early in the producing life of the field, making it possible to keep reservoir pressure close to bubble point. We believe that at least an additional 1 billion bbl of oil can be recovered from this field with water injection if the well density is doubled, if injectors and producers are spaced equally and in a regular pattern over the entire reservoir, and if water-injection wells are cased and then perforated so that water injection can be directed by engineers. Currently, the injectors are concentrated in the central portion of the field; injectors also should be drilled on the flanks of the reservoir.

Fig. 3 is similar to Fig. 2 for the Wasson field. The shaded area shows the minimum amount recovered by infill drilling and waterflooding; the dotted line is the maximum production that could be caused by the increase in allowable days. Water injection began in 1955; in 1971, the 1970 injection rate was doubled; in

1972, the 1970 rate was tripled. The gradual disappearance of shutdown days and the increased injection rate caused the oil production to increase to 68 million bbl in 1972. We believe that the injection of CO<sub>2</sub>, which was started in 1972, had no effect on the 1972 oil rate.

After reviewing the data on the four major fields, we are more convinced than ever that waterflooding (to maintain pressures at or above saturation pressure) combined with infill drilling will enable the U.S. to increase its rate of production by at least 2 million B/D within 2 to 3 years. In fact, production probably would be even better as long as bottlenecks do not develop in the supply of necessary materials and manpower. There is a good chance that such an increase will put a stop to the upward trend in oil prices. In many cases our OOIP estimates are higher than API estimates.<sup>7</sup> This observation makes our estimate of ultimate recovery that much more reliable.

## References

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2. "A Statistical Study of Recovery Efficiency," *Bull. D14*, API (1967).
3. "Survey of Secondary and Enhanced Recovery Operations in

Texas," Railroad Commission of Texas (1966, 1968, 1970, 1972, 1974, 1976, 1978).

4. "Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada as of December 31, 1978," API, AGA, and CPA (June 1979) 33, 78.
5. Ghauri, W.K., Osborne, A.F., and Magnuson, W.L.: "Changing Concepts in Carbonate Waterflooding - West Texas Denver Unit Project - An Illustrative Example," *J. Pet. Tech.* (June 1974) 595-606.
6. "Oil and Gas Resources, Reserves and Productive Capacities," PB 246355, National Technical Information Service, U.S. Dept. of Commerce (Oct. 1975) II, 101.
7. Kane, A.V.: "Performance Review of a Large-Scale CO<sub>2</sub>-WAG Enhanced Recovery Project, SACROC Unit - Kelley-Snyder Field," *J. Pet. Tech.* (Feb. 1979) 217-231; *Trans.*, AIME, 267.
8. Brummett, W.M. Jr., Emanuel, A.S., and Ronquille, J.D.: "Reservoir Description by Simulation at SACROC - A Case History," *J. Pet. Tech.* (Oct. 1976) 1241-1255.

## SI Metric Conversion Factors

$$\text{acre} \times 4.046\,873\,E+03 = \text{m}^2$$

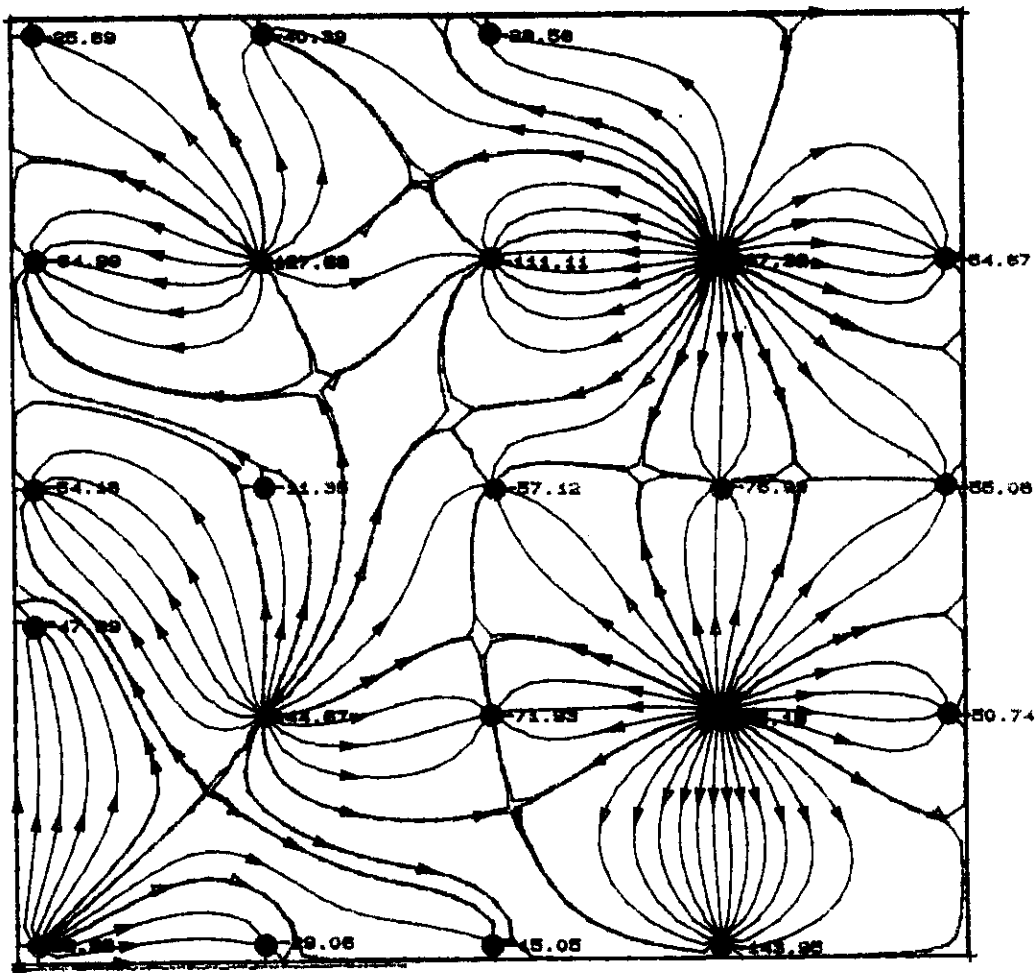
$$\text{bbl} \times 1.589\,873\,E-01 = \text{m}^3$$

$$\text{ft} \times 3.048\,E-01 = \text{m}$$

\*Conversion factor is exact.

A.F. van Everdingen, SPE  
Hyla Swesnik Kriss  
DeGolyer and MacNaughton

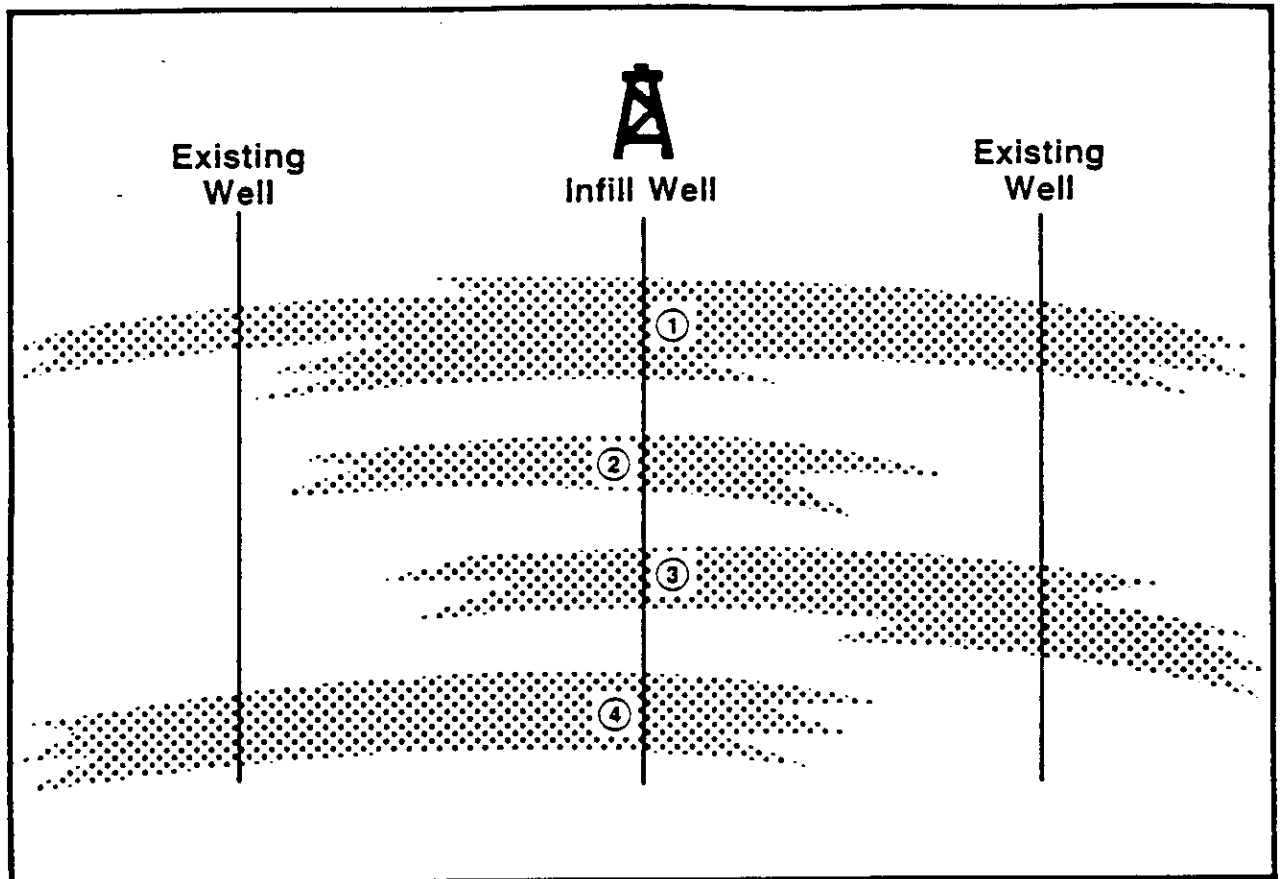
Original manuscript received in Society of Petroleum Engineers office March 28, 1980. Paper (SPE 8088) accepted for publication May 10, 1980. Revised manuscript received May 20, 1980.



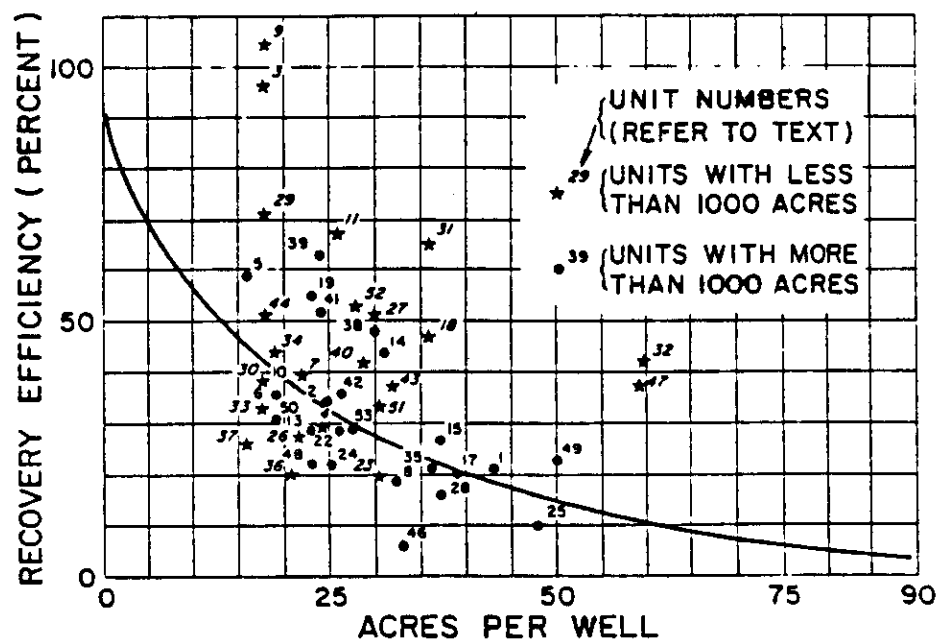
● PRODUCERS  
 ★ INJECTORS



## INFILL DRILLING FOR IMPROVED CONTINUITY

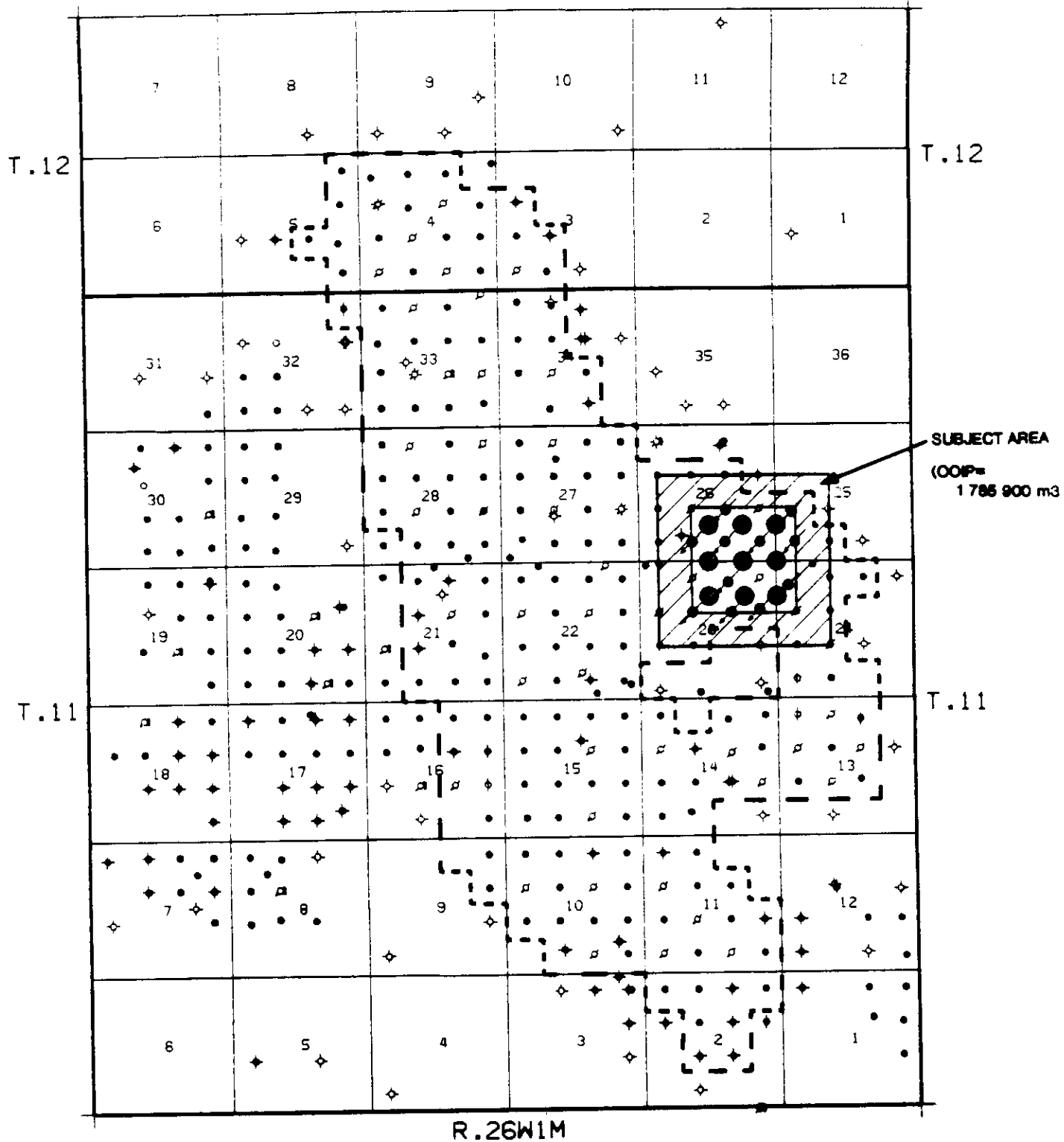


## SLAUGHTER FIELD



# ATTACHMENT 10

## NVSU #1 INFILL PROJECT



## NORTH VIRDEN SCALLION UNIT NO. 1

AS OF 1989-04-06

SCALE 1" = 1 MILE

- PROJECT BOUNDARY
- PROPOSED INFILL SITES
- ▣ PROPOSED CONVERSIONS

# Laboratory Comparison of Oil Recovery In Five-Spot and Nine-Spot Waterflood Patterns

By Nathan T. Cotman, Gerald R. Still\* and Paul B. Crawford

## Abstract

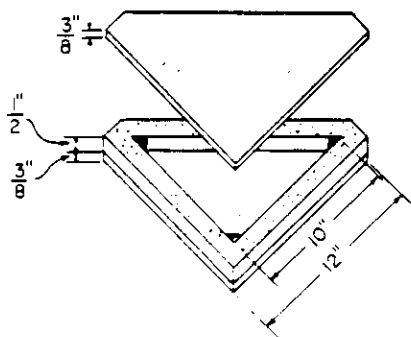
Steady-state theoretical calculations indicate that the sweep efficiency of the nine-spot pattern may vary from 45 to 90 percent compared with 72 percent for the five-spot pattern. A laboratory study has been made to compare the performance of five-spot and nine-spot patterns during the transient conditions of water flooding. A small reservoir model was constructed which could be operated either as a five-spot pattern or as a nine-spot pattern. The model was packed with an unconsolidated sand. Connate water was present. Two synthetic crude oils were used, one having a viscosity of 1.6 times that of water and a second oil having a viscosity of ten times that of water. The initial oil saturations were varied with each crude but ranged from 30 to 60 percent of the pore space.

The results of these tests show very little difference in the ultimate oil recovery for the five or nine-spot pattern. For low oil saturations and when the oil-water viscosity ratio was ten the nine-spot pattern was slightly superior to the five-spot pattern. These data indicate that pattern displacements under the transient conditions of water flooding are substantially different than the steady-state displacements.

## 1. Introduction

Several papers have been prepared describing the calculated or theoretical performance of the nine-spot water flooding pattern under various conditions. The

\*Present address — John W. Mecom, Hitchcock, Texas.  
Texas Petroleum Research Committee, A. and M. Division, College Station, Texas.



Sketch of Reservoir Model

Figure 1

work of Krutter<sup>1</sup> showed that the sweep efficiency of a nine-spot pattern may be only 52 percent compared with 72 percent for the five-spot and 74 percent for the seven-spot pattern. Krutter's work indicates that a nine-spot flood might

result in poorer performance than either a five or seven-spot pattern. Krutter's work indicates that the sweep efficiency of 52 percent resulted from the assumption that the permeability of all wells were the same.

## Injection Schedules

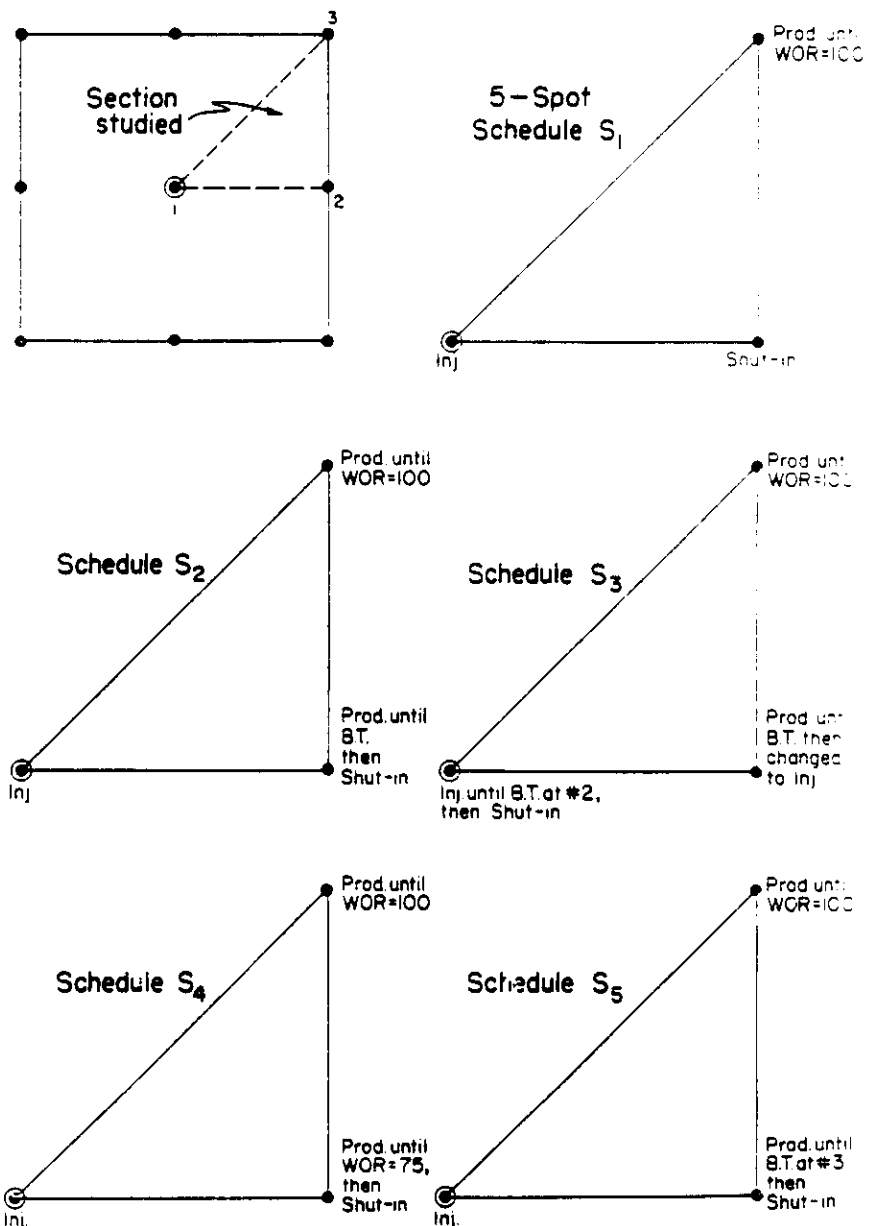


Figure 2

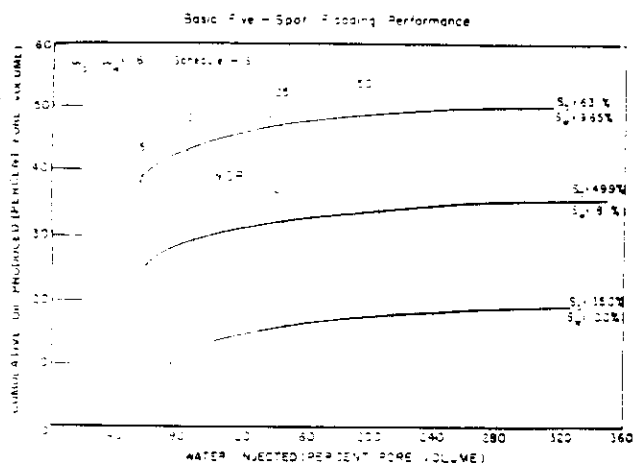


Figure 3

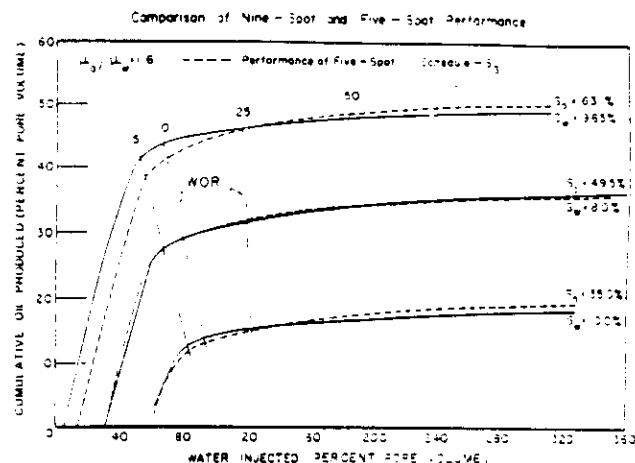


FIGURE 5

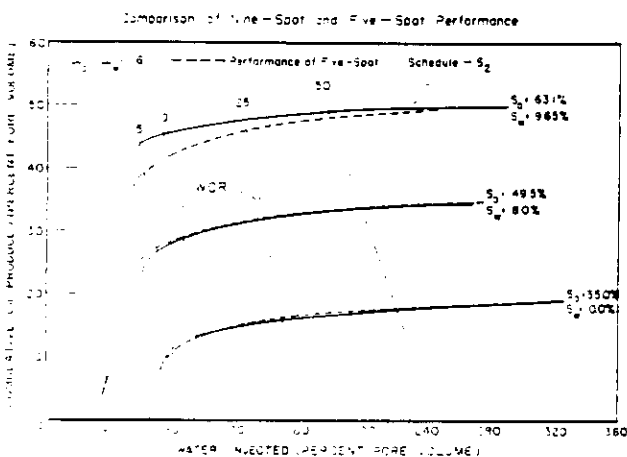


Figure 4

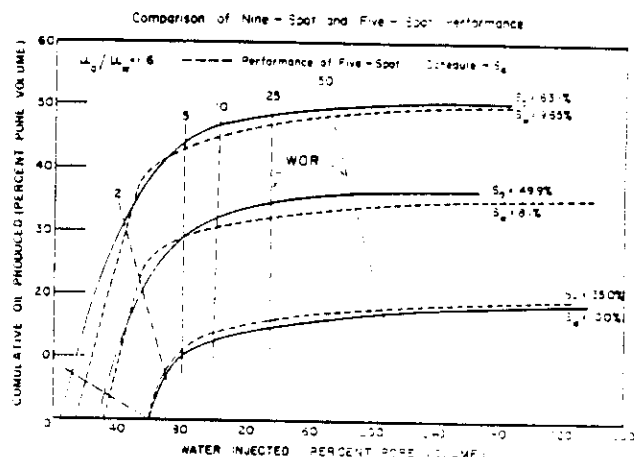


Figure 6

In 1940 Muskat et al.<sup>1</sup> in the theory of linear flow and networks for the case in which the ratio of the rate of flow at the outside wells was varied. Wells 2 and 3 in Figure 1, Muskat noted that the sweep efficiency depended heavily on the ratio of flow at these two wells. The minimum sweep efficiency of 45.6 percent resulted from shutting-in Well No. 3. Muskat pointed out that the nine-spot pattern generates into series of 12 of five-spots of normal size. Each one of the nine-spots was enclosed by adjacent similar five-spot shapes but lacking a characteristic well. When the flow ratios were 10 and 40 the sweep efficiencies were 50 and 63 percent, respectively. If the rate of production at Well No. 3 was about 1/6 that of Well No. 2, the sweep efficiency of the nine-spot attained a maximum of 73 percent. When this rate ratio exceeded 30, it was equivalent to shutting-in Well No. 2, and the sweep efficiency approached that of the five-spot or 72 percent.

The works of Krutter and Muskat were based on steady-state injection and producing schedules. In steady-state operations the streamlines and isopotentials are unchaned from the initiation of the injection fluid until breakthrough.

A two-stage modified nine-spot injection program was studied by Smith and

Nobles using an electrical network. In their two-stage technique the streamlines and isopotentials were constant for a single stage, but in the second stage of the injection program a separate field of streamlines and isopotentials existed. By use of a two-stage nine-spot displacement method Smith and Nobles found that a sweep efficiency of 90 percent could be obtained. This high sweep efficiency resulted when in the initial stage Well No. 1 was an injection well and in the final stage Well No. 2 was the sole injection well.

From a review of the literature it is apparent that the sweep efficiency of the nine-spot pattern may range from near 45 percent to 90 percent depending on the producing-injection scheduling techniques. However, these theoretical results may have limited application to water flooding in depleted reservoirs as it is well known that the mobility ratio is not unity, that water flooding results in the creation of a flooded zone and an oil bank, and the oil is displaced in a transient potential field. In a discussion of flooding, Muskat points out that "while the steady-state theory gives an instructive picture of the tendencies for differential fluid movement over the different parts of a fluid-injection system and does have applicability to cycling operations in condensate-producing res-

ervoirs, it will hardly ever give a semiquantitative treatment of the motion of fluids directed for secondary recovery." In view of the possible limited application of steady-state results to depleted waterfloods, it appeared desirable that actual laboratory flow and programs be conducted in porous media to evaluate several nine-spot injection-producing schedules in order to supplement the theoretical work and provide additional information on the relative efficiency of the five-spot compared with the nine-spot pattern in a transient displacement program.

## II. Apparatus

The reservoir model was constructed of lucite in the shape of a 45-degree triangle with the shorter sides 10 inches long. The model was 1/2" deep and 1/2" wide to assure a good seal with the top strips of 1/2" thick cork were cemented around the top of the base.

Lucite cylinders 1/2" in diameter and 1/2" high were used for the wells. A well was placed in each of the three corners of the reservoir over threaded holes in the bottom of the base. Small holes had been drilled through the spacers to allow fluid passage to or from the well bore. Figure 1 illustrates the construction of the model.

A lucite cylindrical tank of 1100 cc ca-

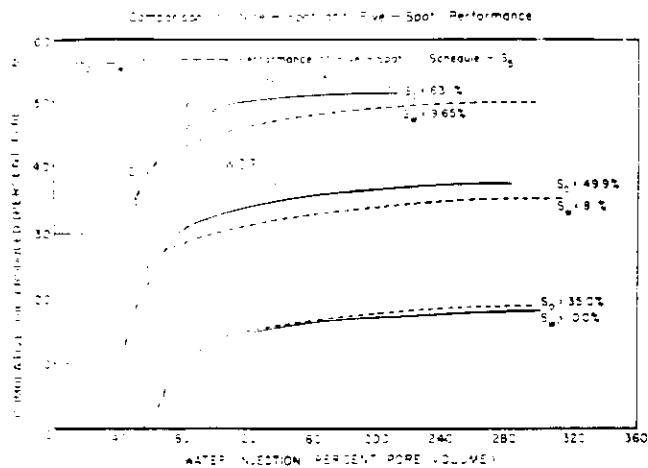


Figure 7

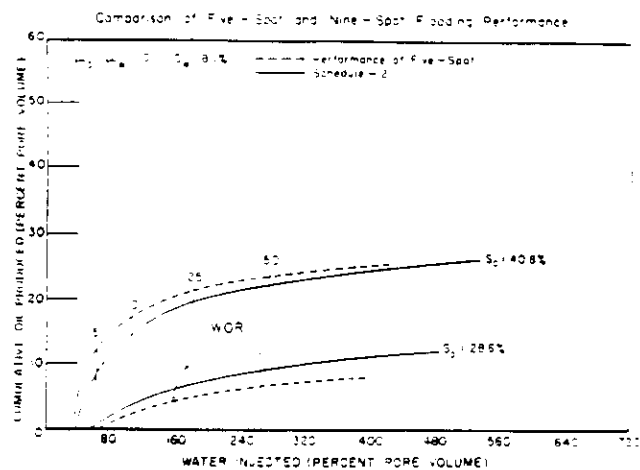


Figure 9

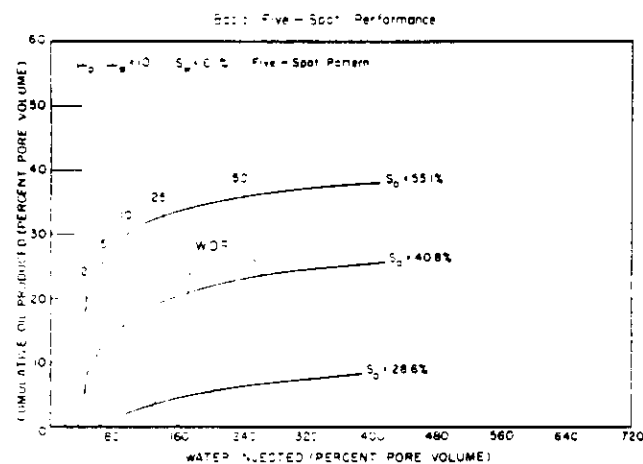


Figure 8

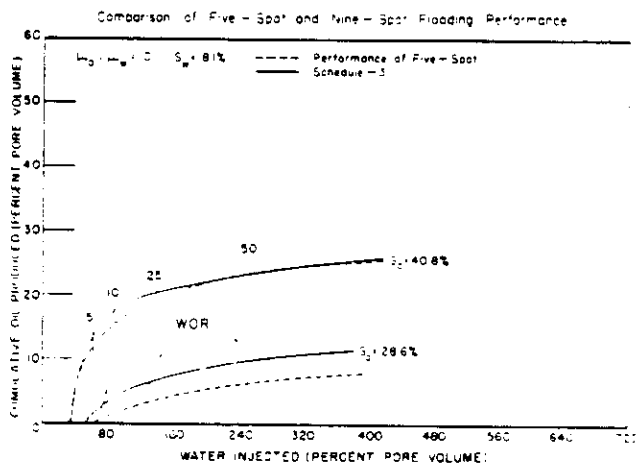


Figure 10

capacity was used to hold the colored injection water, and a pump set at a rate near 250 cc per hour was used to inject the water into the reservoir. Graduated cylinders were used to collect the produced fluids. Connections were made using copper and plastic tubing. A mercury manometer was connected to the outlet end of the pump.

### III. Procedure

A sand believed to be 100 percent water wet, was used for the study. Two different oil-water viscosity ratios were studied; the ratios were 1.6 and 10 to one. Kerosene was used as oil to obtain the oil-water viscosity ratio of 1.6. A mixture of 40 percent kerosene and 60 percent Cetus oil was used to obtain an oil-water viscosity ratio of 10. Tap water was used both for the initial connate water and the water flood.

Several different oil saturations were studied at each viscosity ratio. At the oil-water viscosity ratio of 1.6 the initial oil saturations were 35.6, 50 and 63 percent of the pore space. The connate water was near 10 percent. At the oil-water viscosity ratio of 10 the water saturation was kept constant at 8.1 percent, and the oil saturations were 28.6 and 40.8 percent.

The three wells in the model were numbered 1, 2, and 3. See Figure 2. The five-spot pattern of Schedule S<sub>1</sub> was simulated by shutting-in Well No. 2, injecting into No. 1, and producing through Well No. 3. Except for that condition which will be explained, Well No. 1 was always the injection well and No. 3 always a production well.

Four schedules for water injection and production were selected for operating the nine-spot pattern. The first nine-spot pattern, designated by Schedule S<sub>1</sub>, produced through Wells No. 2 and No. 3 until water breakthrough at No. 2, at which time No. 2 was shut in and No. 3 was produced to a WOR of 100:1. The next nine-spot schedule studied was designated S<sub>2</sub>. It was similar to S<sub>1</sub> except that on breakthrough at No. 2, Well No. 1 was shut in and No. 2 was changed to an injection well. Schedules S<sub>3</sub> and S<sub>4</sub> were similar to S<sub>2</sub>, except Well No. 2 was shut in at a WOR of 75:1 in the case of Schedule S<sub>3</sub>, and Well No. 2 was shut in at water breakthrough at Well No. 3 in the case of Schedule S<sub>4</sub>. Diagrams of the various flooding schedules are shown in Figure 2.

In making each run the dyed, injected water front was traced on top of the model every few minutes until water

breakthrough. The water injection volume and fluid production were recorded at various intervals. At water breakthrough and after every 100 cc of fluid produced thereafter, the time, pressure, cumulative water injected, oil produced, and water produced were recorded.

The injection water was to be held constant at a rate near 250 cc per hour, although at the beginning of the flood the rate was sometimes higher as the pump output was greater at very low pressures.

### IV. Discussion of Results

Figure 3 shows the basic five-spot water flood performance for an oil-water viscosity ratio of 1.6. The curves show the cumulative oil produced in percent pore volume for various quantities of water injected. The solid lines show the oil recovery curves for the case of initial oil saturations of 35.6, 49.9 and 63.1 percent, respectively. The dashed lines show the injected water-oil ratios. Note the increase in oil recovery as the water injected increases up until approximately 120 percent of a pore volume of water had been injected after which there was only a slight increase in oil recovery.

Figures 4, 5, 6 and 7 show a comparison of the five-spot performance to the

nine-spot pattern operated according to Schedules 1, 2, 4, and 5. The five-spot performance is at well 7. The water-oil ratio on the surface. In all cases there was some difference in the water-oil ratio between the nine-spot and five-spot patterns.

Five-spot water-oil ratio was about 1.50 to 1.00 water-oil ratio. The water-oil ratio was nearly independent of the water-oil ratio schedule for the 4, 5, and 6, of these tests.

Figures 8, 9, 10, 11, and 12 show a comparison of the performance of the five-spot and nine-spot patterns when the water-oil ratio was varied. The initial water-oil ratios were near 20, 40, and 55 percent of pore volume. The water-oil ratio was varied at the end of the test. The water-oil ratio was varied at the end of the test. The water-oil ratio was varied at the end of the test.

From a study of the displacement of the water-oil interface, it was found that the sweep efficiency was much greater than obtained for steady-state conditions. This should be expected since in a depleted flood, radial flow occurs for a longer time than occurs under steady-state displacement.

## V. Conclusions

For the conditions of these tests, it appeared that the five-spot and nine-spot patterns may be expected to yield substantially the same recovery when flooding depleted fields. The initial oil recovery may be greater for the five-spot than the nine-spot, but the ultimate recovery was about the same.

The sweep efficiency for the transient conditions observed in the field is expected to be greater than for the steady-state conditions.

## References

1. Krutter, "Nine-spot Flooding Programs," Oil and Gas Journal, Vol. 35, p. 10, August 17, 1958.
2. Muskat, "The Theory of Nine-spot Flooding Networks," Producers Monthly, March 1958, Vol. 1, p. 10.
3. H. W. Smith and M. A. Santos, "Five-spot Modified Nine-spot Flooding Procedure," Producers Monthly, Dec. 1958, p. 10.
4. Muskat, "Physical Principles of Oil Production," McGraw-Hill Book Co., Inc., 1949.
5. A. B. Dees, B. H. Faudel, and R. A. Erickson, "Oil Production After Breakthrough is Influenced by Mobility Ratio," AIME Trans., Vol. 281, p. 51, 1954.

Comparison of Five - Spot and Nine - Spot Flooding Performance

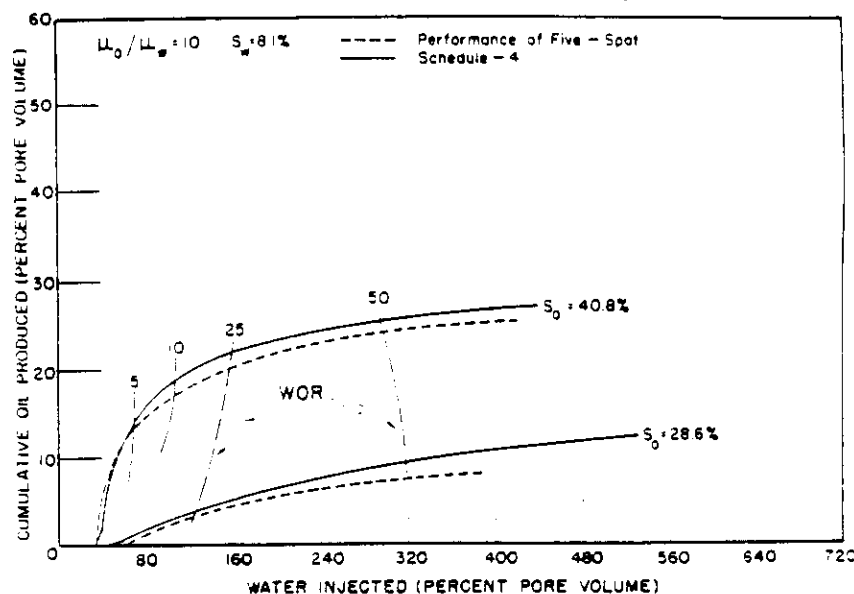


Figure 11

Comparison of Five - Spot and Nine - Spot Flooding Performance

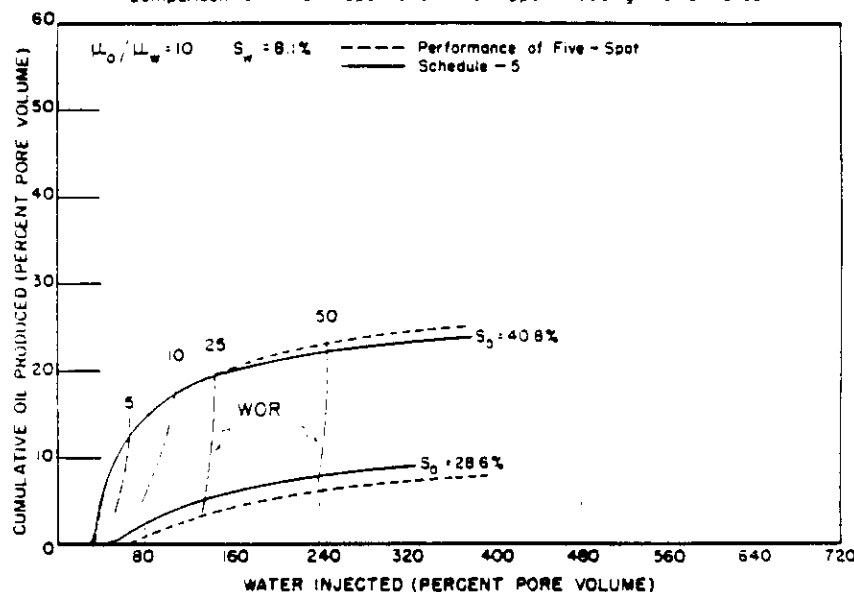


Figure 12



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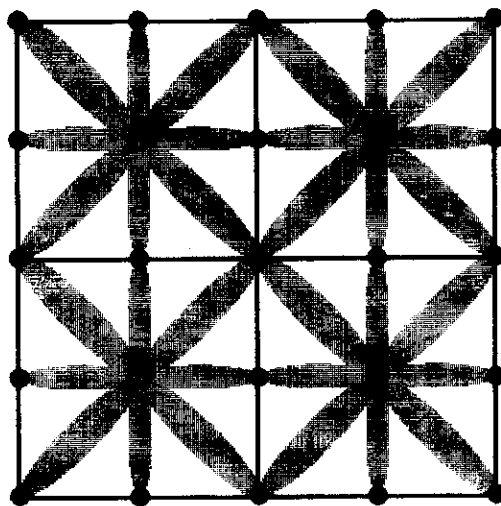
NAME \_\_\_\_\_

ADDRESS \_\_\_\_\_

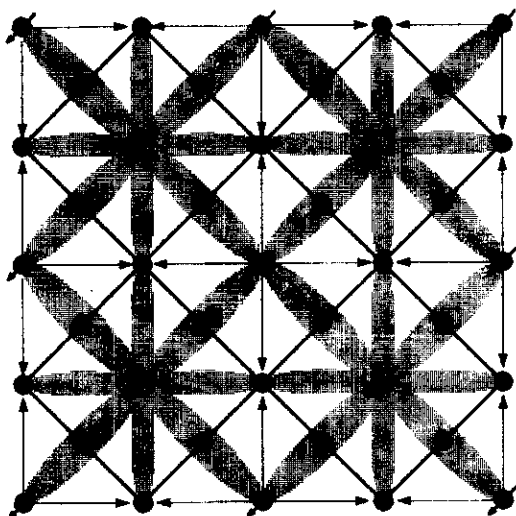
CITY & STATE \_\_\_\_\_

Mail to: Producers Monthly, Box 368, Bradford, Penna.

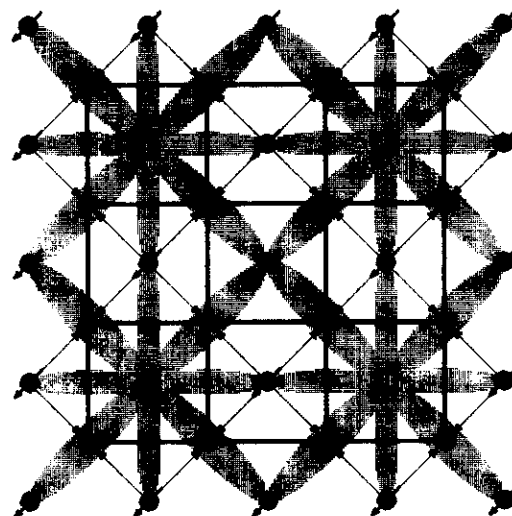
# FIVE-SPOT VERSUS NINE-SPOT INFILL DEVELOPMENT



EXISTING 16 HECTARE 9-SPOT



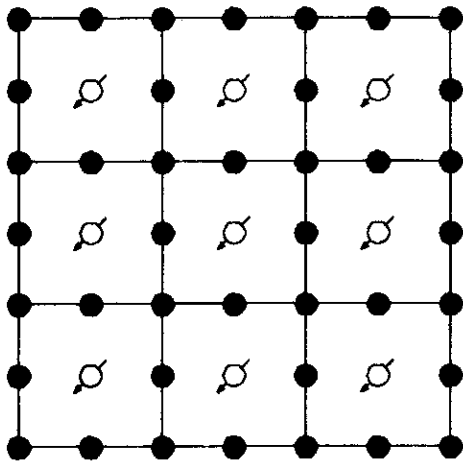
8 HECTARE 9-SPOT



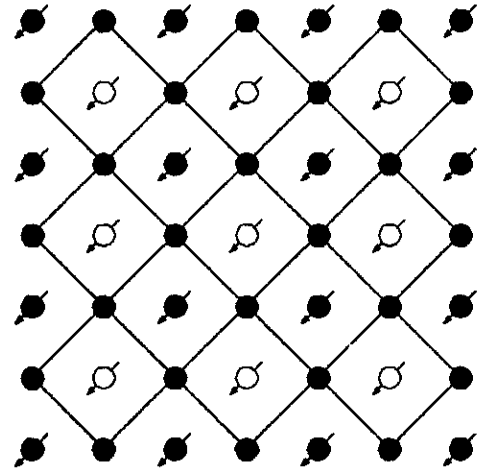
8 HECTARE 5-SPOT

- EXISTING PRODUCER
- ⊗ EXISTING INJECTOR
- NEW PRODUCER
- ⊗ CONVERSION
- PATTERN BOUNDARY
- ▨ PREVIOUS FLOW PATHS
- NEW FLOW PATHS

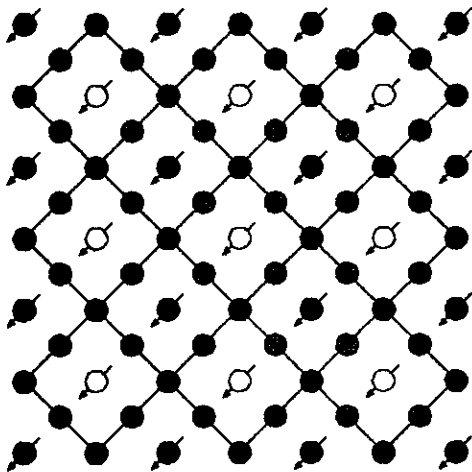
## PATTERN CONFIGURATION OPTIONS



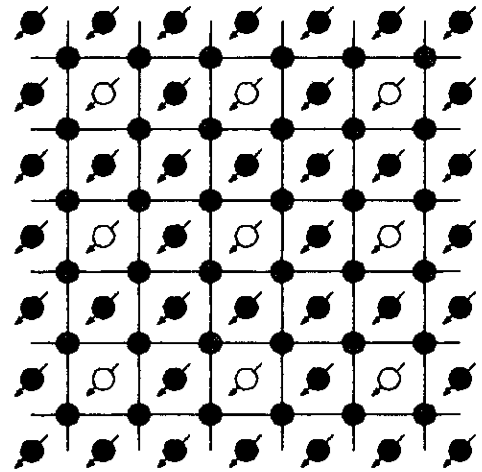
CURRENT NINE-SPOT  
16 HECTARE (40 ACRE)



FIVE-SPOT  
16 HECTARE (40 ACRE)



NINE-SPOT  
8 HECTARE (20 ACRE)



FIVE-SPOT  
8 HECTARE (20 ACRE)

- NEW PRODUCER
- CONVERSION TO INJECTION



ATTACHMENT 14  
Crown Benefits

<u>Year</u>	<u>Total Unit Prod. (10<sup>3</sup> m<sup>3</sup>)</u>	<u>Base Unit Prod. (10<sup>3</sup> m<sup>3</sup>)</u>	<u>Royalty/Tax (m<sup>3</sup>)</u>	
			<u>Total Prod.</u>	<u>Base Prod.</u>
1989	138.0*	124.1	21 568	23 835
1990	133.5	116.0	23 147	21 082
1991	128.0	108.5	21 860	18 583
1992	117.4	101.4	18 750	16 327
1993	107.7	94.8	16 025	14 295
1994	99.0	88.7	13 665	12 462
1995	91.1	82.9	11 604	10 817
1996	84.0	77.5	9 806	9 347
1997	77.5	72.5	8 259	8 034
1998	71.5	67.8	6 930	6 873
1999	66.1	63.4	5 776	5 842
2000	61.2	59.3	4 781	4 931
2001	56.6	55.4	3 946	4 146
2002	52.5	51.8	3 238	3 464
2003	48.6	48.4	2 642	2 878
2004	45.1	45.3	2 143	2 377
2005	41.9	42.3	1 733	1 959
2006	38.9	39.6	1 395	1 602
2007	36.2	37.0	1 108	1 303
2008	33.6	34.6	884	1 049
2009	31.3	32.4	700	849
2010	29.1	30.3	548	679
2011	27.1	28.3	429	538
2012	24.6	26.5	326	425
2013	23.0	24.7	251	330
2014	21.5	23.1	191	256
2015	20.0	21.6	143	196
2016	18.7	20.2	107	148
2017	17.5	18.9	81	111
2018	16.3	17.7	63	85
2019	15.2	16.5	48	65
2020	<u>14.2</u>	<u>15.5</u>	<u>37</u>	<u>52</u>
TOTALS	1 786.9	1 687.0	182 184	174 910

\* Includes 18.2 10<sup>3</sup> m<sup>3</sup> royalty holiday on infill production.

NORTH

ATTACHMENT 15

AERIAL PHOTOGRAPH  
OF  
REDUCED SPACING  
PROJECT AREA  
(REVISED 89-04)

KEY:



EXISTING WELLS



PROPOSED WELLS



IDEAL LOCATIONS



8 ha TARGET AREAS

3

WELL NUMBER

SCALE:



7-26

8-26

5-25

2-26

1-26

4-25

16-23

15-23

13D-24

13-24

1989-04-11

Infill and Conversion Project  
SW-1/4 25-11-26 WPM

Department of Natural Resources  
Land, Leases and Permits  
Box 2  
600 - 1495 St. James Street  
Winnipeg, Manitoba  
R3H 0W9

Gentlemen:

Chevron Canada Resources Limited is in the process of applying for reduced spacing in the North Virden Scallion Unit #1. As part of this Infill and Conversion Project, Chevron will be converting some existing producing wells to water injection wells.

This letter is to inform you, the landowner, that upon approval of the proposed project the following well will be converted.

5-25-11-26 WPM

Yours very truly,



H. H. POCKRANT  
Supervisor  
Field Land Operations

RDB/sp

cc: S. Robinson


**Chevron Canada Resources**

500 - Fifth Avenue S.W., Calgary, Alberta T2P 0L7  
 Phone (403) 234-5000 Fax (403) 234-5947

DATE:

**WELL DATA REQUIREMENT SHEET**

WELL:

1. **INFORMATION REQUIRED PRIOR TO DRILLING**
  - SURVEY PLAT 2
  - APPLICATION FOR WELL LICENSE AND WELL LICENSE 2
  - DRILLING PROGRAM AND CORING & TESTING PROGRAM 2
2. **NOTICES REQUIRED**
  - 24 HOURS' NOTICE OF INTENT TO SPUD
  - 24 HOURS' NOTICE OF INTENT TO LOG, CORE, TEST, OR CONDUCT ANY NON-ROUTINE OPERATIONS
  - IMMEDIATE NOTICE OF ANY OIL OR GAS SHOW
  - 48 HOURS' NOTICE OF INTENT TO ABANDON. APPROVAL TO ABANDON WILL BE GRANTED ONLY AFTER CHEVRON HAS EVALUATED ONE RESISTIVITY LOG AND ONE POROSITY LOG REPRESENTING THE ENTIRE OPEN HOLE INTERVAL.
3. **INFORMATION REQUIRED DURING DRILLING**
  - DAILY 8:30 A.M. TELEPHONE/FAX DRILLING REPORTS yes
  - DAILY/WEEKLY DRILLING TOUR REPORTS 2
  - DAILY/WEEKLY LITHOLOGY (CORE AND SAMPLE DESCRIPTIONS) 2
  - DRILL STEM TEST REPORTS 2
4. **INFORMATION REQUIRED REGARDING GEOLOGY**
  - ACCESS TO CORE yes
  - ACCESS TO OPERATOR'S SAMPLES yes
  - BAGGED SAMPLES AS PER ERCB REQUIREMENTS** 1
  - LITHOLOGY LOG 2
  - CORE AND SAMPLE DESCRIPTIONS 2
  - OIL, WATER, GAS AND CORE ANALYSES 2
  - FINAL DST REPORTS AND CHARTS 2
  - LOGS AND SURVEYS - FIELD PRINTS 2
  - FINAL PRINTS 2
  - L.I.S. TAPES** 1
  - CORE DATA TAPE 1
  - WELL SUMMARY REPORT 2
5. **INFORMATION REQUIRED DURING COMPLETION**
  - COMPLETION PROGRAM 2
  - COMPLETION REPORTS (DAILY) 2
  - BOTTOM HOLE PRESSURE REPORTS 2
  - AOFP AND IP REPORTS 2
  - ALL REGULATORY GOVERNMENT REPORTS 2
  - FINAL COMPLETION OR ABANDONMENT REPORTS 2
6. **CONTACTS**
  - DAILY DRILLING REPORTS TO: **Juliana Wadia** FAX 234-5512 Phone 234-5510
  - ON CALL:
  - Geoff Perry** Aurora 560-6600 Home 282-0466  
Office 234-5514
  - Alan Lishman** Aurora 560-6600 Home 249-9569  
Office 234-5511

MAIL THE ABOVE DATA TO THE ATTENTION OF: **Juliana Wadia**