Manitoba

The Oil and Natural Gas
Conservation Board

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

(204) 945-3130

May 15, 1991

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

Dear Mr. Folden:

Re: Virden Roselea Unit No. 1
<u>Reduced Spacing Project Approval</u>

The Board has considered your application for reduced 8 ha spacing and conversion of two wells to water injection in a portion of Virden Roselea Unit No. 1. Attached are copies of Board Order No. SU 8 and Board Order No. PM 65 approving the application.

Board Order No. SU 8 establishes 8 ha drilling spacing units for the project area. The location of the infill wells in the project area shall conform to the conditions of this order and the requirements of Section 17 of the Petroleum Drilling and Production Regulation.

The Petroleum Branch is concerned with the 7D-30 and 8B-30 locations on the side slope of the Assiniboine River Valley. In order to minimize soil erosion, the following measures listed in Chevron's application will be required:

(1) minimize disturbance of natural vegetation,

(2) construct a contoured berm around the wellsite to divert run-off water, and

(3) revegetate the wellsite including the berm.

In addition, Manitoba Environment has requested that a survey for rare or endangered plant species be conducted by a professional botanist at the proposed 7D-30 and 8B-30 locations before the wells are licenced. If rare or endangered plants are present at the proposed wellsites the wells will have to be relocated. If you require any additional information regarding the survey, please contact Floyd Phillips, Chief, Terrestrial Quality Management, Manitoba Environment at (204) 945-7003.

Board Order No. PM 65 covers pressure maintenance operations in Virden Roselea Unit No.'s 1, 2 and 3 and supercedes Board Order No. PM 55. The order includes a provision for annual pressure surveys in the project area.

Plans for the following activities, as outlined by Chevron in the application, are acceptable:

(1) spill mitigation,
(2) housekeeping,
(3) facility inspection, and
(4) well and reservoir data acquisition.

The Board requests Chevron submit a detailed drilling program for the infill wells and a copy of its contingency plan in the event of a well kick, blowout or other loss of well control situation. Chevron is also directed to conduct a leak-off test after drilling out the surface casing on the first of the seven infill wells drilled.

The Board recognizes that there is a great deal of uncertainty regarding incremental reserve estimates for reduced spacing projects. The difficulty is compounded when an attempt is made to further assign those reserves to individual producing zones. In order to improve incremental reserves estimates for future projects the Board requests Chevron comment on the technical and economic feasibility of collecting zonal reservoir and waterflood performance data by, for example, selective swabbing, zonal pressure measurement or injection profile logging. In addition, the Board requests Chevron submit, within two years of completion of the reduced spacing project, a detailed evaluation of the project. The report should be similar in scope and content to the North Virden Scallion Unit No. 1 reduced spacing project analysis included in the application for this project. The report should also discuss the feasibility of deepening existing wells in the project area.

Please provide the Petroleum Branch with a proposed schedule of drilling, conversion and facility construction activities.

Chevron, in its response to the Board's deficiency letter (February 15, 1991), indicated it thought many of the questions asked by the Board were unwarranted. The Board requests companies provide additional information in support of an application for two reasons. Firstly, for clarification of the public record. Often a company's application and the Board's decision are the only information on the public record. Therefore, it is important where material in the application appears unclear that further clarification is provided by the company.

Secondly, it is incumbent on the Board to ensure it has the information necessary to properly evaluate the application and make the appropriate decision. By requesting this information by letter, the Board's goal is to avoid the time consuming and costly hearing process.

The Board has reviewed its deficiency letter and believes the questions asked of Chevron were appropriate. The Board hopes Chevron is satisfied with this explanation and that the spirit of cooperation established between Chevron and the Board continues to the mutual benefit of both parties.

If you have any questions 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,

H. Clare Moster
Deputy Chairman

cc: S. Scrafield, Rural Development
D. Partridge, Manitoba Agriculture
F. Phillips, Manitoba Environment

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Order No. PM 65

An Order Pertaining to Pressure Maintenance by Water Flooding
Virden Lodgepole B Pool

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

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

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

AND WHEREAS, Chevron Canada Resources is the unit operator of Virden Roselea Unit No. 1, Virden Roselea Unit No. 2 and Virden Roselea Unit No. 3 ("the unit areas").

AND WHEREAS, the Board received an application dated January 18, 1991 from Chevron Canada Resources for approval to convert two additional wells in Virden Roselea Unit No. 1 to water injection.

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

AND WHEREAS, upon due consideration of the said application, the Board has found it is reasonable and desirable to convert the said wells to water injection in the Virden Lodgepole B Pool ("the pool").

NOW THEREFORE, the Board orders that:

1. Board Order No. PM 55 is hereby rescinded.

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

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

PRESSURE MAINTENANCE RULES

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

Chevron South Virden CPR WIW 10-7-10-25 (WPM)
Chevron South Virden CPR WIW 12-7-10-25 (WPM)
Chevron South Virden CPR WIW 14-7-10-25 (WPM)
Chevron Virden Prov. WIW A2-18-10-25 (WPM)
Sun I. Welch Virden WIW 4-18-10-25 (WPM)
Chevron Virden WIW 9-20-10-25 (WPM)
Sun M. Welch Virden WIW 13-20-10-25 (WPM)
Chevron Virden WIW 15-20-10-25 (WPM)
Chevron Virden WIW 11-21-10-25 (WPM)
Chevron Virden WIW 13-21-10-25 (WPM)
Chevron East Virden Prov. WIW 5-28-10-25 (WPM)
Chevron East Virden Prov. WIW 5-29-10-25 (WPM)
Chevron Virden Prov. WIW 7-29-10-25 (WPM)
Placer Virden WIW 5-30-10-25 (WPM)
Placer Virden WIW 7-30-10-25 (WPM)
Virden Roselea Unit No. 1 WIW 9-30-10-25 (WPM)
Virden Roselea Unit No. 1 WIW 15-30-10-25 (WPM)
Continental Virden WIW 12-31-10-25 (WPM)
Chevron South Virden CPR WIW 6-1-10-26 (WPM)
Chevron South Virden CPR WIW 14-1-10-26 (WPM)
Chevron South Virden Prov. WIW 8-2-10-26 (WPM)
Chevron South Virden WIW 14-2-10-26 (WPM)
Mineraloid Virden WIW 16-2-10-26 (WPM)
Chevron South Virden WIW 16-3-10-26 (WPM)
Gulf Duncan Virden WIW 6-10-10-26 (WPM)
Chevron South Virden Prov. WIW 8-10-10-26 (WPM)
Chevron South Virden Prov. WIW 6-11-10-26 (WPM)
Chevron South Virden Prov. WIW 8-11-10-26 (WPM)
Chevron South Virden Prov. WIW 12-11-10-26 (WPM)
Chevron South Virden Prov. WIW 14-11-10-26 (WPM)
Chevron South Virden Prov. WIW 16-11-10-26 (WPM)
Chevron South Virden WIW 6-12-10-26 (WPM)
Chevron South Virden WIW 14-12-10-26 (WPM)
Placer Virden WIW 6-13-10-26 (WPM)
Gulf Union Welch Virden WIW 9-13-10-26 (WPM)
Mineraloid Virden WIW 14-13-10-26 (WPM)
Rundle Williams Virden WIW 4-14-10-26 (WPM)
Rundle Williams Virden WIW 11-14-10-26 (WPM)
Murphy Virden WIW 1-23-10-26 (WPM)
Esso Virden WIW 3-23-10-26 (WPM)
Teck Hepburn Virden WIW 15-23-10-26 (WPM)
Chevron Virden WIW 13-24-10-26 (WPM)
Chevron Virden WIW 15-24-10-26 (WPM)

Chevron Virden WIW 5-25-10-26 (WPM)
Chevron Virden CPR WIW 7-25-10-26 (WPM)
Chevron Virden WIW 11-25-10-26 (WPM)
Chevron Virden WIW 13-25-10-26 (WPM)
Chevron Virden CPR WIW 15-25-10-26 (WPM)
Chevron Virden WIW 3-26-10-26 (WPM)
Chevron Virden Prov. WIW 10-36-10-26 (WPM)
Chevron Virden WIW 4-5-11-25 (WPM)
Chevron Virden WIW 10-5-11-25 (WPM)
Chevron Virden Prov. WIW 12-5-11-25 (WPM)
Chevron Virden Prov. WIW 14-5-11-25 (WPM)
Chevron Virden Prov. WIW 2-6-11-25 (WPM)
Chevron Virden Prov. WIW 8-6-11-25 (WPM)
Chevron Virden Prov. WIW 10-6-11-25 (WPM)
Chevron Virden Prov. WIW 12-6-11-25 (WPM)
Chevron Virden Prov. WIW 14-6-11-25 (WPM)
Chevron Virden Prov. WIW 16-6-11-25 (WPM)
Murphy Virden WIW 2-7-11-25 (WPM)
Murphy Virden WIW 4-7-11-25 (WPM)
Chevron Virden WIW 4-8-11-25 (WPM)

and such other wells in the unit areas as the Board may approve.

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

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

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

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

3(1) At least once every three years commencing in 1981, unless otherwise directed by the Board, the unit operator shall conduct a survey to determine the static reservoir pressure in the unit areas.

3(2) Notwithstanding the provisions of subsection (1), the unit operator shall, at yearly intervals until such time as the Board approves otherwise, conduct a survey to determine the static reservoir pressure in Section 30, Township 10, Range 25 (WPM).

3(3) The unit operator shall submit to the Petroleum Branch, the details of the surveys described in subsections (1) and (2), including a list of the wells to be surveyed, the measurement technique to be used, and the intended shut-in periods for each well, and approval shall be obtained from the Director of Petroleum before the program is carried out.

3(4) The unit operator shall submit to the Petroleum Branch, within 30 days of the completion date of the surveys described in subsections (1) and (2), a report which shall include:

(a) the static reservoir pressure data obtained from the survey, corrected to a common datum;

(b) an isobaric map of the pool within the unit areas based on the data obtained; and

(c) a discussion of the survey results and pressure distribution within the pool.

3(5) The Board may, at any time, require the unit operator to carry out such additional reservoir pressure surveys as it deems necessary.

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

5 The maximum wellhead pressure at which water is injected into the wells referred to in subsection 1(1) shall not exceed 8 000 kPa or such other maximum pressure as the Board may prescribe and the Board may, from time to time, prescribe a maximum or minimum rate at which water shall be injected into any well in the unit areas.

6(1) The unit operator shall, not later than the last day of each month, file with the Petroleum Branch, a report of the quantity, source and pressure of water injected during the preceding month into each well referred to in subsection 1(1).

6(2) The unit operator shall, not later than the last day of each month, file with the Petroleum Branch a summary report of production and injection operations during the preceding month, which report shall include:

(a) a tabulation of total oil, total water and total gas produced;

(b) a tabulation of the number of producing wells and injection wells which were active; and

(c) a summary of any remedial operations carried out on any well in the unit areas.

7. The unit operator, shall, within 60 days of the end of each calendar year, file with the Petroleum Branch a report of the pressure maintenance program, setting out graphically such interpretive information necessary to evaluate the efficacy of the waterflood, including a discussion of the performance of the reduced spacing project area outlined in Board Order No. SU 8.

Wm. McDonald
Member

H. Clare Moster
Deputy Chairman

OIL AND NATURAL GAS CONSERVATION BOARD ORDER NO. PM 65 APPROVED THIS 14 DAY OF MAY A.D. 1991 AT THE CITY OF WINNIPEG.

APPROVED:

Harold Neufeld
Minister of Energy and Mines

Manitoba

The Oil and Natural Gas
Conservation Board

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

(204) 945-3130

<u>Order No. SU 8</u>

An Order Pertaining to Drilling Spacing Units
Virden Lodgepole B Pool

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

> "62(9) Without restricting the generality of subsection (8) the board, with the approval of the minister, may make orders
>
> (b) respecting the designation of the area that shall be allocated to a well in connection with fixing allowable production;"

AND WHEREAS, subsection (1)(f) of section 63 of "The Mines Act" being Chapter M160 of the Continuing Consolidation of the Statutes of Manitoba, provides as follows:

> "63(1) For the purpose of carrying out the provisions of this Part and Part III according to their intent, the Lieutenant Governor in Council may make such regulations and orders as are ancillary thereto, and are not inconsistent therewith; and every such regulation or order made under, and in accordance with the authority granted by, this section has the force of law; and, without restricting the generality of the foregoing, the Lieutenant Governor in Council may make regulations and orders, not inconsistent with any other provision of this Part of Part III,
>
> (f) prescribing spacing units and the size and shape of spacing units;"

AND WHEREAS, subsection (1) of Section 20 of Manitoba Regulation 430/87R under The Mines Act ("the Petroleum Drilling and Production Regulation") provides as follows:

"20(1) Notwithstanding section 19, the board may, after a public hearing or after publication of notice, prescribe by order special drilling spacing units which may differ from normal drilling spacing units in size, shape or target area."

AND WHEREAS, subsection (3) of Section 21 of the Petroleum Drilling and Production Regulation provides as follows:

"21(3) Where a special drilling spacing unit is prescribed under section 20, the board may prescribe the target area within which a well shall be completed in order to qualify for a maximum permissible production rate based on the area of the special drilling spacing unit."

AND WHEREAS, the Board received an application dated January 18, 1991 from Chevron Canada Resources as unit operator of Virden Roselea Unit No. 1 ("the unit area") for approval to reduce the size of drilling spacing units in a portion of the unit area outlined in Schedule A ("the project area").

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

AND WHEREAS, the Board considers that establishment of smaller drilling spacing units within the project area will result in an increase in recovery of crude oil from the project area.

NOW THEREFORE, the Board orders that:

1. Subject to clause 2 and 4 herein, the spacing unit for each well drilled, or to be drilled, for the purpose of obtaining oil from or injecting salt water into the Mississippian Lodgepole Formation within the project area is a square, 8 hectares in area, with corners located at the midpoints of the boundaries of each legal subdivision, as illustrated in Schedule A.

2. Where a spacing unit established by clause 1 intersects the boundary of the unit area, the unit boundary shall truncate the spacing unit and form part of the spacing unit boundary as illustrated in Schedule A.

3. The target area of each drilling spacing unit shall be an area having sides sixty-five metres from the sides of the drilling spacing unit and parallel to them.

4. Notwithstanding clause 3, no well shall be completed nearer to any boundary of the unit area than 100 metres or nearer to any other well than 130 metres.

Wm. McDonald
Member

H. Clare Moster
Deputy Chairman

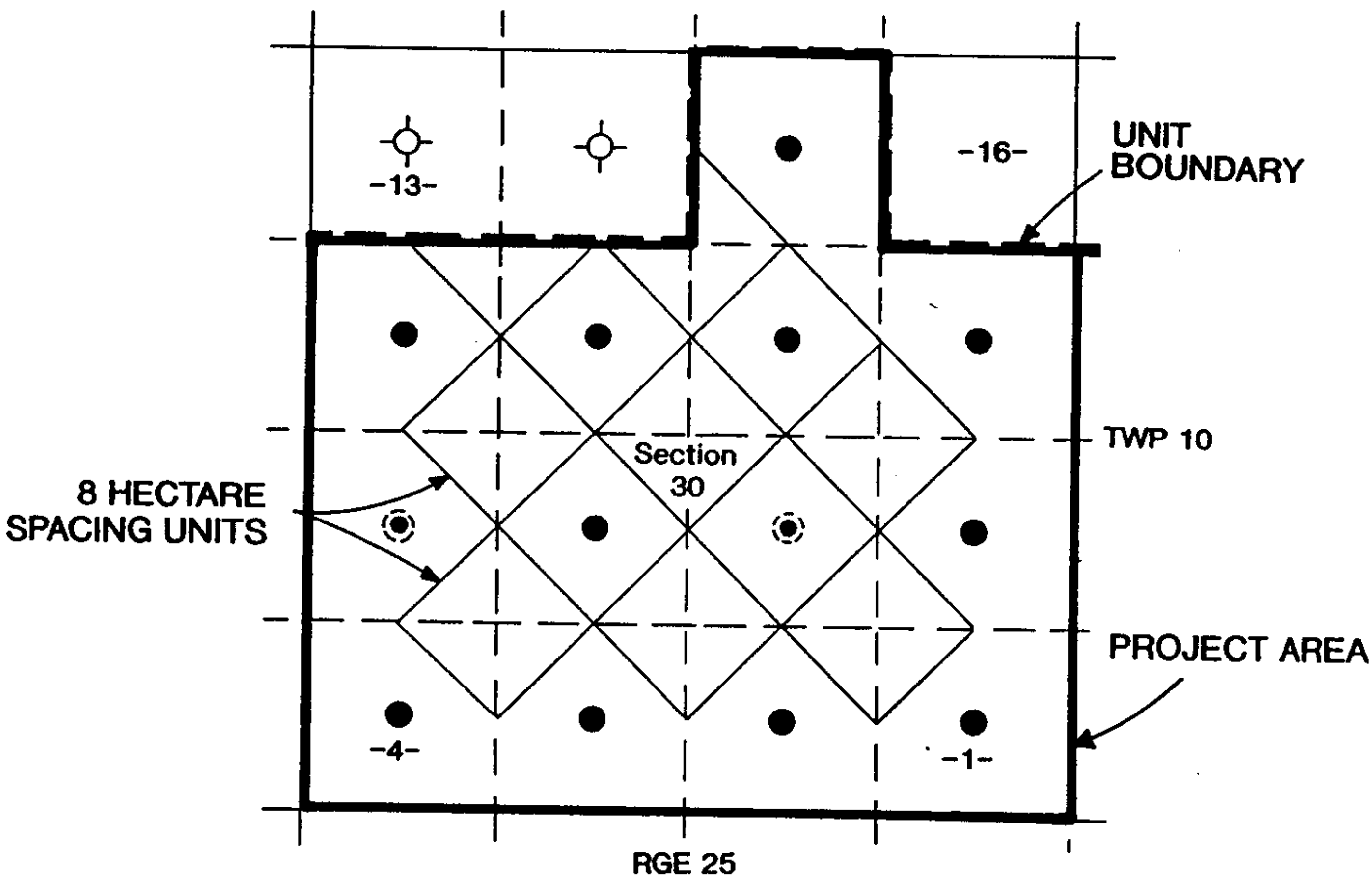
OIL AND NATURAL GAS CONSERVATION BOARD ORDER NO. SU 8 APPROVED THIS 14 DAY OF MAY A.D., 1991 AT THE CITY OF WINNIPEG.

APPROVED:

Harold Neufeld
Minister of Energy and Mines

SCHEDULE A

BOARD ORDER NO. SU 8
VIRDEN ROSELEA UNIT NO. 1
8 Hectare Drilling Spacing Units



LEGEND:

- ● Producer
- Water injector
- Dry and abandoned

Chevron

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

Calgary, Alberta
March 7, 1991

ASSISTANT DEPUTY MINISTER
ENERGY
MAR 8 1991
DEPARTMENT OF
ENERGY and MINES

Mr. H. Clare Moster
Deputy Chairman
Manitoba, The Oil and Natural Gas
Conservation Board
Room 309
Legislative Building
Winnipeg, Manitoba
R3C 0V8

Dear Sir:

Virden Roselea Unit No. 1
Application for Reduced Spacing

We are providing you with an additional 3 copies of the original application and 6 copies of our response to your letter dated February 15, 1991. In regards to your letter, we feel that many of the questions asked of Chevron were not warranted because either they did not deal with the type of information required under section 115 of the Petroleum Drilling and Production Regulations or required detail beyond that normally submitted in such an application. In fact, we feel that we went beyond the intent of section 115 in providing our analysis of the North Virden Scallion infill project.

If there are any additional questions, please contact Kelly Edwards (403) 234-5388 or Richard Forest at (403) 234-5397 in our Calgary Office, or Lyle Martinson at (204) 748-1334 in our Virden office.

Yours very truly,

R. Forest

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

RCF/slw

Virden Roselea Unit No.1
Application for Reduced Spacing
Additional Information

To the best of our knowledge, the names and addresses of the royalty owners in LSD's. 13, 14 and 16 of section 30 are:

LSD's 13 & 14

Mr. Messuaski
Family
Reduced VR#1
NW 1/4 - 30-10-25

- Canada Trust Company
  c/o Montreal Trust
  411 - 8 Avenue S.W.
  Calgary, Alberta
  T2P 1E7

- John Wesley Clarke
  Box 999
  Virden, Manitoba

- Saul Katz
  Winnipeg, Manitoba

LSD 16

- Canada Trust Company
  c/o Montreal Trust
  411 - 8 Avenue S.W.
  Calgary, Alberta
  T2P 1E7

- Richard Henry Stevens
  Fannystelle, Manitoba

- Alexander Garfield Sissons
  Portage LaPrairie, Manitoba

- Frank Osborne Meighen
  c/o 119 - 9 Street
  Brandon, Manitoba

To the best of our knowledge, the working interest owner of LSD's 13, 14, and 16 is Placer CEGO (Amerada Hess). They are also Unit participants.

Geological Information

(1) **In the cross-section, what do the numbers posted for each well on the map in the upper right-hand corner represent?**

The upper right-hand corner numbers represent the daily oil rate averaged over the life of the well. two sets of #'s

(2) **The Φh and Kh maps for the 1st, 2nd and 3rd Oolite have identical numerical values for all wells except 15-30. Is this correct?**

The Φh and Kh maps were constructed by multiplying the pay thickness by the average weighted porosity and permeability determined by all core analyses.

The average weighted porosity of the 1st, 2nd, and 3rd Oolite for section 30 is 12%. The average weighted permeability of the same zone for section 30 is 12 mD. Therefore, by multiplying the net pay by the porosity value, it will give the same result as multiplying the net pay by the permeability value.

(3) **Are the Φh maps based on core data or a combination of core and log data?**

The Φh maps are constructed using a combination of core and log data.

(4) **What porosity, permeability and water saturation cut-offs have been used to determine the Φh and Kh maps for each member?**

The cut-offs are as follows:			
	SW	=	50%
	Φ	=	7%
	K	=	1 mD

N.B. for the wells that Td'ed above the oil-water interface, the Δh was determined by subtracting the cherty structure from the assumed oil/water interface.

(5) **The Φh maps for the various members indicate there is no net pay in the dry holes at 13-30 and 14-30. Explain the reasons for the sudden loss in reservoir quality at these locations.**

The reservoir has no porosity and permeability due to 'deep' dolomitization caused by fresh water percolation during the "Flossie Time" erosion.

Attachment 4 - Technical Justification

(6) **The current recovery from the unit and project area is 27.3% OOIP and 21.9% OOIP, respectively. Why is the current recovery in the project area so much lower than the current unit recovery? What is the estimated ultimate recovery from the unit and project area with and without infill drilling? What abandonment conditions are assumed and on what parameters are the conditions based?**

The recovery factor is calculated as follows:

$$RF = \frac{\text{Cum. Production}}{\text{OOIP}}$$

The OOIP for section 30 is high due to a structural dome which provides additional reservoir storage and a thicker oil leg in the Cherty beds. This dome is not present elsewhere in the Unit (see structural cross-section, Alta. chart 3 in attachment No.3). ? Also, wells located on the apex of the structure are not completed in the Cherty, which is the best reservoir.

Ultimate recoveries can be calculated from information supplied in Attachment 4. A time limit of 30 years was imposed on the forecasts.

(7) **Please provide a list or a map showing current completion intervals and zones for all existing wells in the project area.**

CRIN SAND CHERT

T.D.	CASING SHOE DEPTH	PRODUCTIVE ZONE (Yes/No)							PERF DEPTH
		C	S	1	2	3	4	C	
1-30 3′ in cherty	below 3rd Oolite	N	N	N	N	N	N	Y	Open hole
2-30 25′ in cherty	4 Oolite	N	N	Y	Y	Y	Y	Y	Open hole
3-30 33′ in cherty	below Cr.	N	Y	Y	Y	Y	Y	Y	Open hole
4-30 18′ in cherty	below Crinoidal	N	Y	Y	Y	Y	Y	Y	Open hole
5-30 T.D. above cherty	below Crinoidal	N	Y	Y	Y	Y	Y	Y	Open hole
6-30 T.D. above cherty	below Crinoidal	N	Y	Y	Y	Y	Y	Y	Open hole
7-30 4′ in cherty	above Crinoidal	Y	Y	Y	Y	Y	Y	Y	Open hole
8-30 36′ in cherty	below Sandhill	N	N	Y	Y	Y	Y	Y	Open hole
9-30 20′ in cherty	below 3rd	N	N	Y	Y	Y	Y	Y	Open hole
10-30 6′ in cherty	above cherty	N	N	Y	Y	Y	Y	Y	Open hole
11-30 5′ in cherty	below Crinoidal	N	Y	Y	Y	Y	Y	Y	Open hole
12-30 40′ in cherty	below Crinoidal	N	N	Y	Y	Y	Y	Y	Open hole
15-30 4′ in cherty	below Crinoidal	N	N	Y	Y	Y	Y	N	Open hole

(8) Were the water saturation values determined from log analysis or special core studies or a combination of both?

The water saturation were estimated using log analyses only.

(9) Please provide a list of individual well OOIP by zone in the project area.

OOIP BY ZONE
in Bbls

CRINOIDAL		SANDHILL	1ST	2ND	3RD	4TH	CHERTY
1-30	dolomitized	460,000	40,726	40,784	76,841	39,898	514,000
2-30	dolomitized	dolomitized	77,225	47,789	86,062	57,190	533,000
3-30	227,568	631,000	47,641	28,963	86,890	0	323,000
4-30	390,116	344,000	47,641	33,691	107,580	0	0
5-30	189,000	287,000	77,225	43,444	112,542	66,497	495,000
6-30	186,783	460,000	44,567	52,015	80,683	58,517	628,000
7-30	0	344,000	114,760	44,600	44,600	114,000	780,000
8-30	0	460,000	0	0	0	132,403	970,000
9-30	0	0	0	0	57,098	11,112	285,000
10-30	0	0	0	0	115,852	33,337	894,000
11-30	244,700	258,000	99,893	57,926	53,788	62,773	1,028,000
12-30	251,625	230,000	53,483	43,444	107,577	45,750	609,000
15-30	231,700	344,000	44,500	28,900	114,900	0	0

(10) Is the net pay map (Figure 2) a summation of the net pay in all members?

Yes.

(11) What is the source, cause and estimated volume of oil migration into the project area?

Undrained Cherty in LSD's 5, 6, 7, 10 & 11 estimated at 3.8 MM Bbls OOIP.

(12) Why is the 4D-30 location not included in the list of proposed infill wells for the reduced spacing project? Does Chevron plan to drill this location in the future?

A well at this location is structurally low, downdip, and at proximity to a water injector. The structure on top of the Cherty is −560 feet subsea, therefore no or very little Cherty pay is expected at this location. Depending on the results of the infill program, this location could be considered as part of a different infill project at a later date.

(13) In the application, Chevron gives a zonal breakdown of OOIP and indicates that production within the project area has been mainly from the Sandhill and Cherty Members with some additional production from the Oolites. Has Chevron tried to determine zonal oil production and current zonal recoveries? Will Chevron be evaluating inflow from individual zones in the infill wells, by selective swabbing or other means, to assist in waterflood evaluation and optimization?

Chevron has not tried to determine zonal oil production and current zonal recoveries. Chevron may evaluate inflow from individual zones in the infill wells to assist in waterflood optimization as determined on a well-by-well basis.

(14) List the six wells in the project area that have penetrated the Cherty Member. Is the deepening of existing producing wells an option for recovering undrained Cherty reserves? What percentage of the estimated incremental recovery of 3.2% OOIP is associated with production of undrained Cherty reserves?

02-30	T.D.'ed 25′ in cherty
03-30	T.D.'ed 33′ in cherty
04-30	T.D.'ed 18′ in cherty
08-30	T.D.'ed 36′ in cherty
09-30	T.D.'ed 20′ in cherty
12-30	T.D.'ed 40′ in cherty

After drilling the infill wells and reviewing the data, Chevron will consider deepening some of the existing wells. The 3.2% OOIP incremental recovery is associated with <u>all</u> of the undrained cherty reserves.

i.e. there are no incremental reserves in the Crinoidal Oolite + Sandhill?

(15) According to the application, there has been no production from the Crinoidal Member, which contains 10% of the OOIP in the project area. Does Chevron plan to complete the Crinoidal Member in the infill wells and if so, what is the estimated contribution of Crinoidal production to the total incremental recovery?

Yes, Chevron plans to complete the Crinoidal Member in the infill wells. The Crinoidal member has yet to be proved productive. Therefore, Crinoidal reserves were not included in the total incremental recovery.

Potential for Crinoidal completion in existing wells?

(16) **According to the application, all water injection in the project area is into the Sandhill and Oolites Members. What degree of pressure support has the Cherty Member received from the injectors adjacent to the project area and has the Cherty Member within the project area been effectively waterflooded? If not, how will the proposed injector conversions improve the effectiveness of waterflooding the Cherty? Which zones will the proposed injectors be completed in? Will Chevron be deepening either of the existing injectors in the project area into the Cherty?**

The 05-25 well is the closest water injector well outside the infill area. The well was drilled to a depth of 2057 feet subsea. The well T.D.'ed above the Cherty and casing was landed at a depth of 2005 feet, just above the Sandhill. Therefore, the Sandhill and the Oolites are effectively waterflooded, but not the Cherty zone.

9-30 20' in Cherty
15-30 4' in Cherty
deepening?

The two proposed injection wells 9-30 and 15-30 are located on the flank of the structure. Water injection from these wells is likely to displace the oil towards the apex of the structure where the oil can be produced. Water injection on the apex of the structure could prematurely increase the WOR in downdip wells. The existing water injector will not be deepened into the Cherty. 5-30 - Has it not already been deepened?

(17) **Has Chevron run any injection profile logs to evaluate the vertical distribution of injected fluids in the project area? Can incremental recovery in the project area be increased economically, by controlling/modifying zonal injection rates?**

No injection profile logs have been run. All wells are open hole and modifying zonal injection rates could be a problem.

(18) **Chevron noted that if injection at 9-30 and 15-30 could not meet the increased voidage from the infill wells, an additional injector conversion may be necessary. Which well(s) is Chevron considering converting?**

1-30 or
3-30 lower
2-30
12-30
other

Another well located on the flank of the structure like 04-30 or 12-30 could be considered as an additional water injector.

(19) **It is apparent from the infill well production forecast (Figure 7) that there is a significant acceleration component. Please provide a plot of daily production versus time for the incremental production and acceleration components of the infill production forecast.**

Separate incremental and accelerated forecasts were not developed.

Attachment 5 - Analysis of Reduced Spacing
North Virden Scallion Unit No.1 (NVSU No.1)

(20) Explain the reasons for the difference in estimated (7.6% OOIP) and actual (1.7% OOIP) incremental recovery for the NVSU No.1 reduced spacing project and the estimated incremental recovery (3.2% OOIP) for the VRU No.1 reduced spacing project.

The estimated 7.6% OOIP incremental reserves forecasted for the NVSU No.1 infill program was determined after analyzing the results of the "corridor" infill drilling. The incremental recovery as a result of infill drilling in the "corridor" area was estimated at 6.1% OOIP based on decline analysis.

The 7.6% OOIP incremental reserves factor was overly optimistic for NVSU #1 infill program. The corridor infill wells were drilled on a dome structure centered on section 27 & 28-11-26W1. The NVSU #1 infill wells were drilled in structural lows resulting in a 1.7% OOIP incremental reserves.

The 3.2% OOIP incremental reserves for the VRU No.1 area is established as follows:

5-30	Cherty reserves OOIP	=	495,000
6-30		=	628,000
7-30		=	780,000
10-30		=	894,000
11-30		=	1,028,000
	TOTAL	=	3,825,000 bbls
Rec @ 15%	3,825,000 bbls	=	574,000 bbls

OOIP number from P 4

PROJECT AREA OOIP FROM APPLICATION PAGE 4-2 2 695 800 m3 16 956, 600 bbl = 3.4% OOIP

or 3.2% of OOIP

574 000 bbl

N.B. The other 15% of Cherty reserves might have been produced from existing wells.

without deepening ?

(21) Should Point 3 on page 5 be prefaced with "avoid"?

Yes

(22) Chevron estimated reservoir continuity in the NVSU No.1 reduced spacing project to be 82% on 16 ha spacing. Post-drilling project analysis indicated the project area had been depleted/swept by existing producers/injectors and the Oolite and Cherty Members were more laterally continuous than predicted. What is the revised estimate of reservoir continuity on 8 ha and 16 ha spacing in the NVSU No.1 reduced spacing project? Are these numbers applicable to the VRU No.1 reduced spacing project? Is there a concern that good lateral continuity will have a detrimental impact on incremental recovery in the VRU No.1 reduced spacing project as was the case in the NVSU No.1 reducing spacing project?

Reservoir continuity was determined for the Scallion infill area using the following equation:

Continuity	=	Pay thickness (above cut-offs)
		Gross Pay
		Total thickness (above & below cut-offs)

This equation should not be used to determine reservoir continuity because it is not a measure of lateral continuity. Therefore, a quantitative estimation of reservoir continuity can not be determined for NVSU #1 or VRU #1. The reservoir continuity at VRU # 1 is probably similar to NVSU #1.

Lateral continuity is good but vertical permeability/continuity is very low, therefore, incremental recovery from the Cherty is likely to be high, whereas incremental recovery in higher members (Sandhill to Oolites) is likely to be low.

(23) Chevron indicated the high cumulative production at 7-26-11-26 and depleted a significant portion of the NVSU #1 reduced spacing project area, resulting in the poor performance of the offsetting infill wells. A similar argument could be made for the 6-30 and 10-30 wells in the VRU No.1 reduced spacing project area. Does Chevron have any concerns that these wells may have drained a disproportionate share of the reservoir?

07-26-11-26W1 (40′ cherty pay only) structurally highest well in area.

$$\text{Rec} = \frac{\text{Cum. oil}}{\text{OOIP}} = \frac{1{,}048{,}000 \text{ bbls} \times 100}{777{,}000 \text{ bbls}} = 140\%$$

Rates 37 BOPD, WOR = 2.4

06-30-10-25W1 OOIP = 1,303,940 bbls

$$\text{Rec} = \frac{\text{Cum. oil}}{{}^{*}\,\text{OOIP}} = \frac{679{,}890 \text{ bbls} \times 100}{1{,}324{,}000 \text{ bbls}} = 51\%$$

Rates 25 BOPD, WOR = 6

* including Cherty pay

10-30-10-25W1 OOIP = $\underline{55 \cdot 40 \cdot 7758 \cdot .13 \cdot .50}$ = 1,027,000 bbls

$$\frac{\text{Cum. oil}}{{}^{*}\,\text{OOIP}} = \frac{660{,}060 \text{ bbls} \times 100}{1{,}043{,}200 \text{ bbls}} = 63\%$$

Rates 45 BOPD, WOR = 0.43

* including Cherty pay

The above calculations demonstrate the difference between the 07-26 Scallion recovery and the Roselea 06-30 and 10-30 recoveries.

The 07-26 well has produced 140% of OOIP whereas 06-30 and 10-30 wells have produced 60% of OOIP. The higher-than-usual recovery at 06-30 and 10-30 is due to enhance sweep efficiency created by the 05 & 07-30 water injectors.

The 07-26 well has obviously drained more than 40 acres. **The 06 and 10-30 have also drained more than 40 acres, but only in the Sandhill and Oolites.** The oil might have migrated from the Sandhill and Oolite Members at 05 & 07-30.

The OOIP for spacing 05 & 07-30 are:

05-30	OOIP	=	586,700 bbls (exc. Cherty OOIP)
07-30	OOIP	=	661,900 bbls (exc. Cherty OOIP)
	TOTAL	=	1,248,600 bbls (exc. Cherty OOIP)

A portion of this oil has probably been produced from the existing wells due to the sweep created by the 07-30 & 5-30 water injector. However, a portion of the Cherty oil has not been swept due to the 05-30 & 7-30 completion above the Cherty zone. The undrained Cherty oil reserves for lsd's 05 & 07-30 are 1,275,000 bbls.

$$05\text{-}30 \text{ Cherty OOIP} = \frac{26 \cdot 40 \cdot 7758 \cdot .13 \cdot .5}{1.06} = 495{,}000 \text{ bbls}$$

$$07\text{-}30 \text{ Cherty OOIP} = \frac{41 \cdot 40 \cdot 7758 \cdot .13 \cdot .5}{1.06} = \underline{766{,}000} \text{ bbls}$$

Depletion effects from 6-30 and 10-30 are of some concern to Chevron, although they are not likely to be as severe as those caused by 7-26. This is one of the reasons for doing a pilot project.

Attachment 7 - Benefits to Crown and Lessors

(24) Please provide the information shown in the three graphs in Attachment 7 in tabular form.

Attached.

(25) Has Chevron contacted working interest owners in VRU No.1 with respect to the special treatment of royalties and taxes that will be necessary if the project is approved?

Only with two partners (Suncor and Amerada Hess) who had requested the information CCR intent to provide the information to all partners as soon as the reduce spacing application is approved.

(26) Please provide a topographic map of the project area showing the well locations, access roads and flowline and injection line routes.

A topographic map has not been provided. As discussed in a telephone conversation between Mr. John Fox and Mr. John Fulton on March 4, 1991, the only available topographic map has a scale of 1:50000. This scale is much too small to provide any useful elevation information relative to the proposed well locations or road and pipeline routings.

(27) Please provide an outline on the aerial photograph of agricultural land use (i.e. cultivated and pasture) and areas with little topsoil.

The area where the infill is occurring is on marginal land for agricultural purposes. The whole area has little topsoil especially the areas on the side of the hill. See attached map for agricultural land use.

(28) In the aerial photograph there is evidence of a network of trails running north and northeast from 6-30. Does Chevron use these trails to access the existing wells?

There is a walkaccess in ~~a~~ the fence N of 6-30

The trails running north and northeast from 6-30 are no longer used.

(29) **The access road to 11D-30 as shown on the aerial photograph is through a forested area. Would it be feasible to access 11D-30 from the south, off the access road to 10B-30 and thereby avoid destruction of trees which would result from the proposed access?**

Yes, instead of accessing 11-D-30 from the north it could be accessed from the east off the existing road to 10B-30. See attached map.

(30) **Please provide a summary of potable groundwater resources in the project area including the location of all potable water supply wells and dugouts.**

Location of [illegible] farm well?

There appears to be only one dugout in the infill area which is filled by runoff in the spring only. It dries up in the summer and the cattle get there water from the river. There are no water wells in the infill area. See attached map.

(31) **Will electrical power be run underground to the infill wells?**

Electrical power will be run underground to areas that are cultivated. In pasture areas, overhead power lines will be used. This area is extremely rocky and it is difficult to bury power lines.

(32) **What lease construction precaution will be taken to minimize erosional concerns at the 7D-30 and 8B-30 locations on the slope of the river valley and what measures will be taken to confine drilling and produced fluids to the wellsite? Is there any merit in directionally drilling these wells?**

What is impact? Drainage experience?

Firstly, directional drilling was not reviewed in detail because it negatively affects the economics. To minimize erosion at these leases, the following will be observed:

1. minimum amount of disturbance of lease site and road
2. clear minimum amount of bush
3. restore and seed lease
4. attempt to detour water around lease area
5. continue to monitor and take further action as required

(33) **Where in the project area does Chevron plan to use fibreglass pipe and where will steel pipe be used? What is the reason for using the different materials?**

Fiberglass pipe is used for its corrosion resistance which reduces inhibitor cost. Steel pipe is used for its durability in rock areas. Because we are confident in our inhibition protection and cathodic protection programs, we propose to use steel pipe mainly in the infill area because of the rocks. Fiberglass pipe requires proper sand padding and rock shielding making steel pipe more economical and easier to install. Fiberglass pipe will be used only where practical.

(34) **It is recognized that Chevron has in place preventative measures to help reduce flowline leaks and closely monitors its flowlines to ensure a leak is detected as quickly as possible. However, what spill reduction equipment such as check valves and pressure shutdowns does Chevron plan for the high volume flowlines in the project area to minimize spill volumes in the event of a flowline failure?**

There are high pressure shutdown valves at all well sites and all new flowlines will have check valves installed at the headers.

Attachment 13 - Drilling Program

(35) **Does Chevron plan to shut-in the water injectors in and surrounding the project area before and during the drilling of the infill wells?**

The Chevron drilling plan is designed to handle the present reservoir pressure. We do not anticipate having any problems; therefore, our intention is not to shut in injection wells because production would have to be suspended because of a lack of water handling capacity. However, we will be in close contact with the drilling group and if needed, water injection could be stopped.

(36) **What is the additional cost, if any, to drill the infill wells using lease tanks instead of drilling pits? Are there any other concerns with the use of lease tanks?**

The additional cost to drill infill wells using lease tanks instead of drilling pits would be $12,000.

(37) **Historically, wells drilled on the Assiniboine Valley floor have encountered water flows in the Swan River and other aquifers due to lower ground elevation. What contingency measures does Chevron propose to address this potential problem for the 7D-30 and the 8B-30 locations which are close to the valley floor?**

Offsets to the proposed 7D-30 and 8B-30 locations include three wells drilled in 1955/56; 9-30-10-25, 8-30-10-25 and 1-30-10-25. All three wells were drilled in the Assiniboine Valley. In this area the valley floor is 61 m lower than the surrounding land. There is no record of any water flow encountered during the drilling of these wells. However, if a water flow from the Swan River were encountered during the drilling of one of the proposed wells, the well would be shut-in on the surface Csg which will be set at sufficient depth to withstand shut-in pressures. The mud weight would then be increased to overbalance and shut off the flow.

What depth - need to evaluate this, inter- Drilling program coming in

Miscellaneous Comments

(38) **As required under clause 115(b) of the regulations, provide the names of the royalty and working interest owners within one kilometre of the project area (excluding those lands within VRU No.1).**

Royalty Owners 10-25-WPM

SE¼19 David Fefchak and Marilyn Fefchak, Virden
Jim Latham, Virden

SW¼19 David Fefchak and Marilyn Fefchak, Virden
John Alexander Forrest and Judith Irene Forrest, Virden
Marilyn Fefchak, Box 1403, Virden, R0M 2C0
Beverly Gay Waller, Box 981, Lenore, Manitoba, R0M 1E0

NE¼19 Beverly Gay Waller, Box 981, Lenore, Manitoba, R0M 1E0
Marilyn Fefchak, Box 1403, Virden, Manitoba, R0M 2C0

Toronto General Trusts, 283 Portage Avenue, Winnipeg, Manitoba
(is now Canada Trust Company, c/o Montreal Trust Company,
411 - 8 Avenue S.W., Calgary, Alberta, T2P 1E7)

NW¼19 Beverly Gay Waller (address above)
Marilyn Jean Fefchak (address above)

NW¼31 Naco Limited, c/o Aikens MacAulay, Winnipeg, Manitoba

North Canadian Trust, 209 Bank of Nova Scotia Building, Winnipeg
(may be bought out by Sun Life - (204) 994-0021)

John Spelliscy, Brandon, Manitoba

NE¼31 Beverly Gay Waller (address above)
Marilyn Jean Fefchak (address above)
Deno Fontana, Virden, Manitoba, R0M 2C0 Phone (204) 748-2117
Kate Gorzala, Virden, Manitoba, R0M 2C0 Phone (204) 748-2453

SE¼31 Beverly Gay Waller (address above)
Marilyn Jean Fefchak (address above)

SW¼31 See Notes

S½, NE¼ 32 CROWN LAND

NW¼32 Elizabeth Anne Forsyth (Calgary) & Jacqueline Sylvia Brayfield (Toronto), c/o Buckingham, Toews & Swelty (Barristers - Virden)
Kate Gorzala, Virden, Manitoba
John Wesley Clarke, Winnipeg, Manitoba
Marilyn Jean Fefchak (address previous page)
Beverly Gay Waller (address previous page)

NOTES

SW¼31 does not appear in Field Title's records (abstracts), although their map shows it as being CPR land.

Companies (WI)

Murphy Oil (SW31, AID) 1700, 800 - 6 Ave. S.W., Calgary
Omega Hydrocarbons (S½32) 1300, 112 - 4 Ave. S.W., Calgary
Petro Canada (Gulf) (NW31) 150 - 6 Ave. S.W., Calgary
Possibly PanCanadian if CPR land on SW31 is controlled by them (150 - 9 Ave. S.W., Calgary).

(39) **Please provide a summary of well data that will be obtained during drilling of the infill wells (i.e. logs, cores, tests, etc.) Will Chevron be conducting any special core studies or any other reservoir tests or surveys?**

2a-30	1 x 18 m core at first sign of Sandhill porosity
7d-30	1 x 18 m core cut at top of first Oolite
8b-30	1 x 18 m core cut first sign of Sandhill porosity
6c-30	1 x 18 m core cut at first sign of Sandhill porosity
11d-30	1 x 18 m core cut at top of first Oolite
12d-30	1 x 18 m core cut at top of first Oolite
10b-30	1 x 18 m core cut at top of Crinoidal in cubic. ?

All infill wells will be logged with Microlog, Gamma-Ray, Phasor Induction, Compensated Density and Neutron. Chevron will not be conducting any special core studies or any other reservoir tests.

40) What is Chevron's proposed program of monitoring reservoir pressure in the project area?

Chevron monitors reservoir pressure once every 3 years and this should be sufficient. JDL comments?

(41) What are Chevron's views on the use of horizontal drilling as an alternative method of recovering incremental reserves in the project area?

Horizontal wells were not evaluated for this infill project. However, several problems of using horizontal wells in a 20 acre infill can be identified:

a) increased costs for horizontal wells
b) the horizontal section would be drilled in only one of the seven Lodgepole members
c) on 8-ha spacing vertical wells will be almost as effective as a horizontal well for producing the incremental reserves.

RCF/slw
(REF:\DAILY\GEO-INFO.RCF)

INFILL CASE

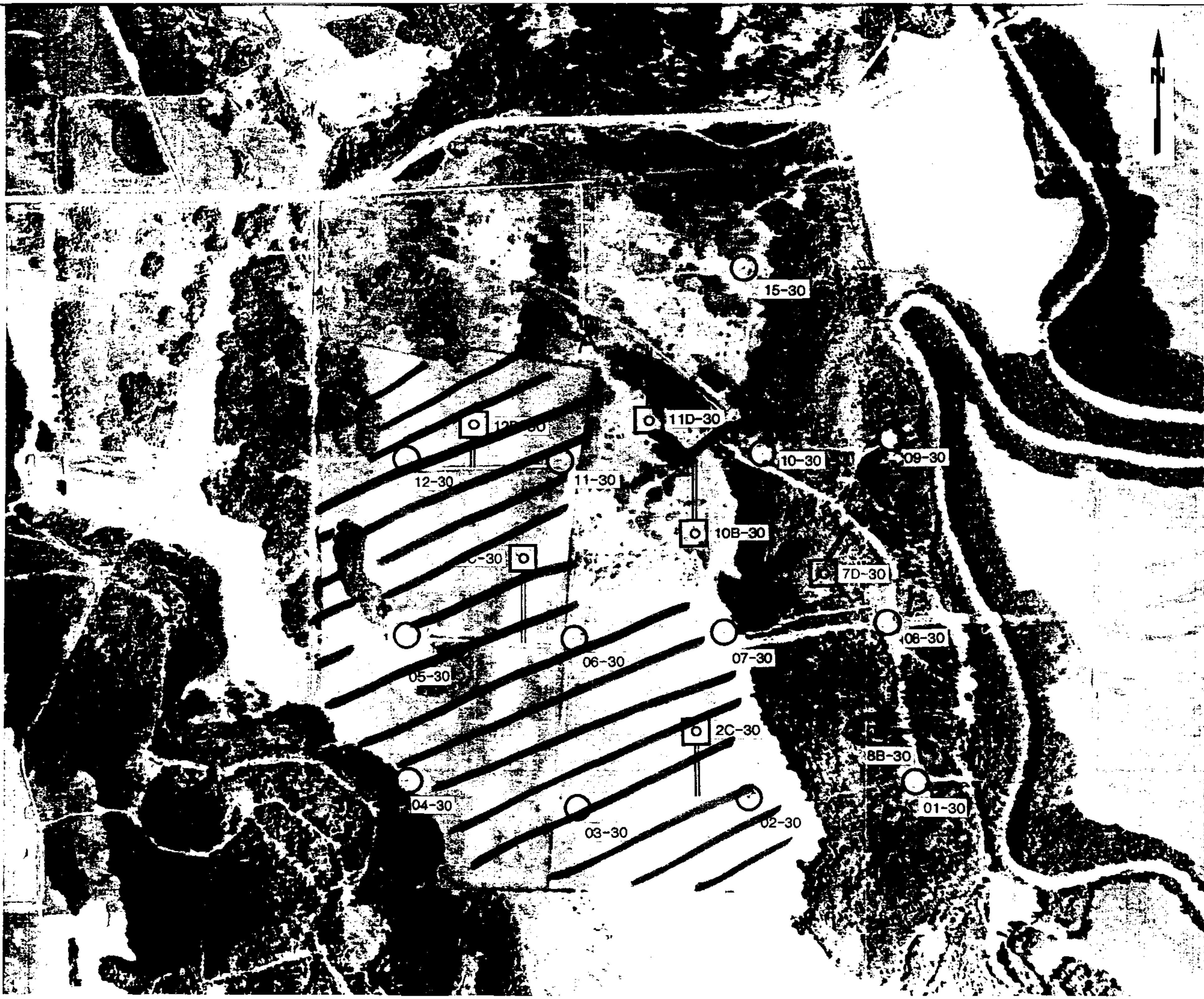
Year	FH ROY (M $)	CR ROY (M $)	MIN TAX (M $)
91	342.7	98.1	116.5
92	581.4	199.5	255.8
93	570.1	238.0	333.6
94	560.4	226.0	300.1
95	546.0	211.9	267.3
96	540.2	201.3	239.6
97	537.9	192.3	215.4
98	534.3	182.8	192.9
99	533.6	174.4	173.0
2000	535.2	166.8	153.4
01	542.4	161.3	136.5
02	547.2	154.9	119.1
03	553.0	148.7	103.6
04	556.5	141.7	90.0
05	560.9	135.4	78.8
06	560.3	127.8	67.9
07	558.0	121.0	57.4
08	556.6	113.9	47.6
09	556.1	112.1	37.8
10	553.5	100.9	29.0
	10826.5	3208.8	3015.3

BASE CASE

FH ROY (M $)	CR ROY (M $)	MIN TAX (M $)
265.6	120.6	184.9
456.7	200.4	296.6
451.5	191.3	272.5
447.6	182.3	250.0
439.8	172.4	226.6
438.8	165.3	208.0
440.7	159.8	190.7
441.6	153.8	173.6
444.9	148.6	158.6
450.3	144.0	145.6
460.6	141.2	134.5
468.9	137.0	123.2
478.4	134.0	112.5
486.1	130.2	101.8
494.7	126.4	92.2
499.1	121.5	82.5
501.9	116.0	72.8
505.9	111.8	64.1
510.5	107.6	56.3
513.7	103.6	49.1
9197.4	2867.9	2996.1

FIGURE 4

AERIAL PHOTOGRAPH OF REDUCED SPACING PROJECT AREA



pasture – rest is cultivated

A dugout

cultivated.

KEY:

EXISTING WELLS

PROPOSED WELLS

PROPOSED LEASE TRAILS

SCALE

0 100 200 300 400 500

METRES

100 m

100 m

DRILLING LEASE SIZE (TO SCALE)

Chevron

Chevron Canada Resources

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

D.M. Clementz
Manager, Engineering

April 26, 1991

Virden Roselea Unit No. 1
Additional Information for
Reduced Spacing Application

Mr. H. Clare Moster
Deputy Chairman
The Oil and Natural Gas Conservation Board
Room 309
Legislative Building
Winnipeg, Manitoba
R3C 0V8

Gentlemen:

In response to the questions raised in your letter of April 24, 1991 on the allocation of incremental reserves and the advantages of infill drilling compared to deepening existing wells, Chevron offers the following:

1. The incremental target of 87 300 m^3 will be produced from all Lodgepole members. The statement in our previous reply that this incremental target would be produced only from the Cherty was incorrect. We feel, as does the Board, that incremental reserves exist in all members of the Lodgepole formation. As stated in the application, this target of 87 300 m^3 represents 3.2% of the project-area OOIP and is considered a reasonable value.

2. The incremental reserves can be allocated to the various members approximately on the basis of that member's fraction of OOIP to the total OOIP. Thus, the portion of the incremental reserves allocated to the Cherty is approximately 60% (52 380 m^3). The remaining 40% (34 920 m^3) would be allocated to the other Lodgepole members.

   The incremental recovery in the Sandhill and Oolite members will result from improved sweep. Figures 1 and 2 show streamtube maps generated for the infill area. The area covered by the streamtube maps is outlined on the Unit Map in Figure 3. In Figure 1 the streamtubes were generated for the existing project. In Figure 2 the streamtubes were generated for the proposed infill project. Better sweep of the infill area is noted in Figure 2, especially in the eastern portion.

3. The case for incremental reserves in the Cherty is more complex. The incremental oil volume to be recovered by deepening existing wells would be much the same as the incremental oil volume (52 380 m^3) recovered by the infill wells, assuming the Cherty has not been drained by the existing wells. This incremental volume may be in the order of 60-70% of the total incremental reserves that could be produced from the Cherty by both deepening existing wells

and infill drilling. However, if the Cherty has been drained by existing wells through natural fracturing up into the Oolites, the incremental oil recovered by the infill wells would be only 30-40% of the total Cherty incremental reserves. The best recovery in the Cherty would result from both deepening existing wells and infill drilling.

4. Chevron believes now is the best time to infill drill for the following reasons:

   a. There is some concern that the Cherty reserves have been drained. Deepening the existing wells would not achieve results in this case.

   b. The economic incentive to infill drill in the future would be less than it is now. At least several years of production data would be required before an estimate of incremental volumes from the deepened wells could be made. At that time we would be considering an infill project in a more mature area with higher WORs in the upper Lodgepole members, and less incremental reserves to be recovered in the Cherty because 60-70% of the total incremental reserves would be produced by the deepened wells.

5. The only way to properly test our theories on displacement mechanism and expected incremental oil recovery is to do a pilot project. Success in this pilot project will open opportunities of additional infill projects in other areas of Roselea and also in NVSU No. 1.

We trust this answers your concerns so that drilling can start in May as scheduled. Please contact Kelly Edwards at (403) 234-5388 if you have further questions.

Yours very truly,

for Kelly Edwards P-Eng.

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

KAE/er
Attach.

FIGURE 1

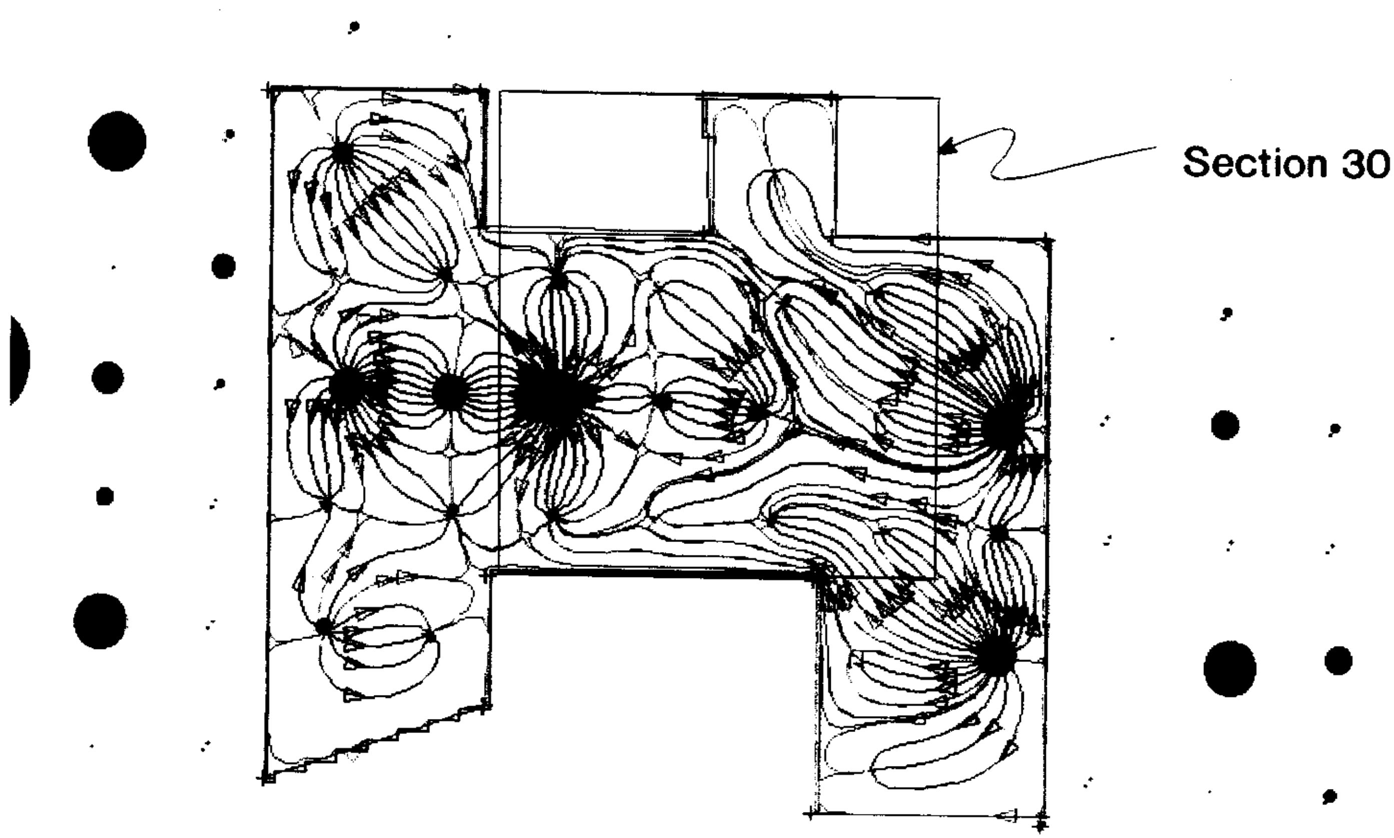
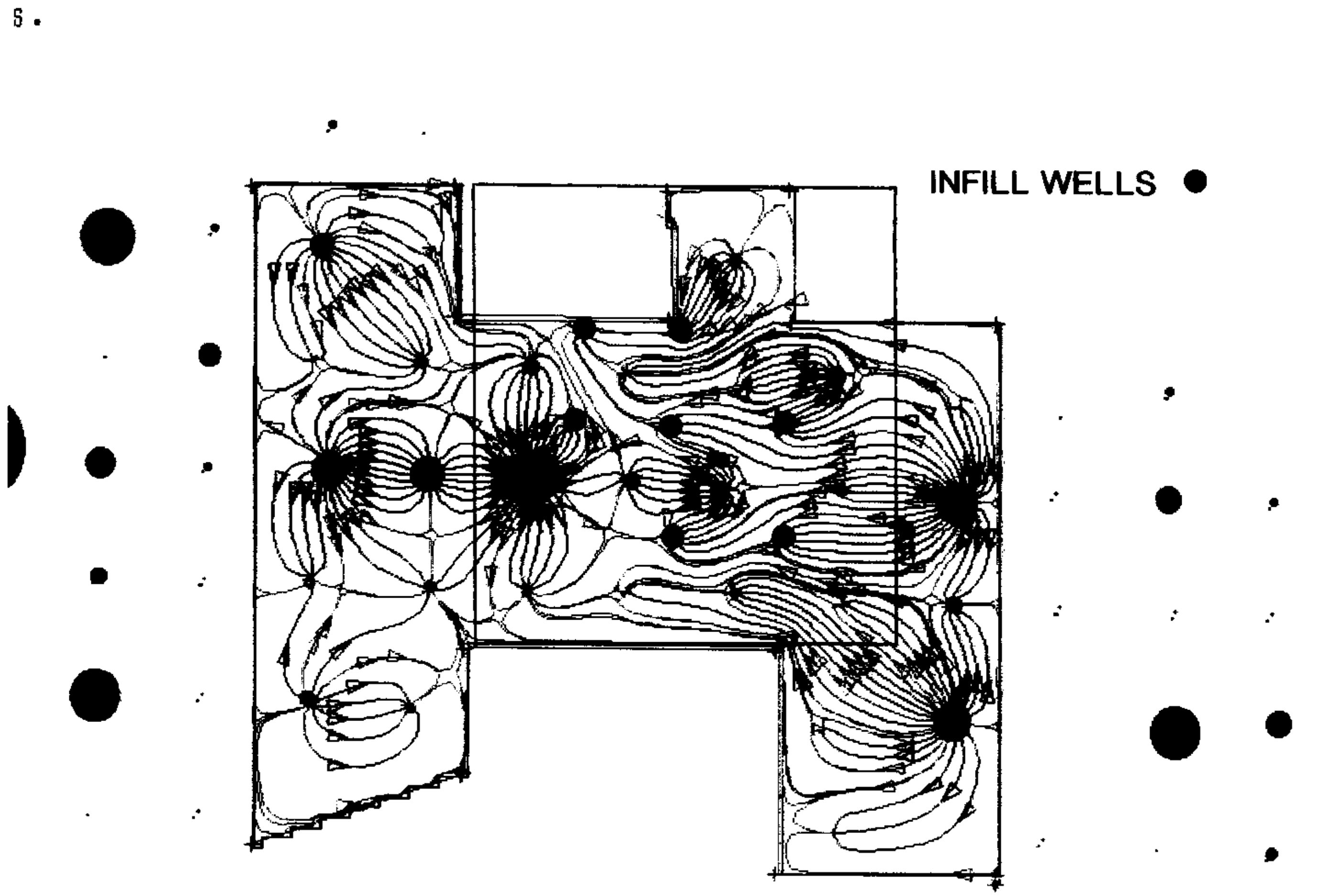
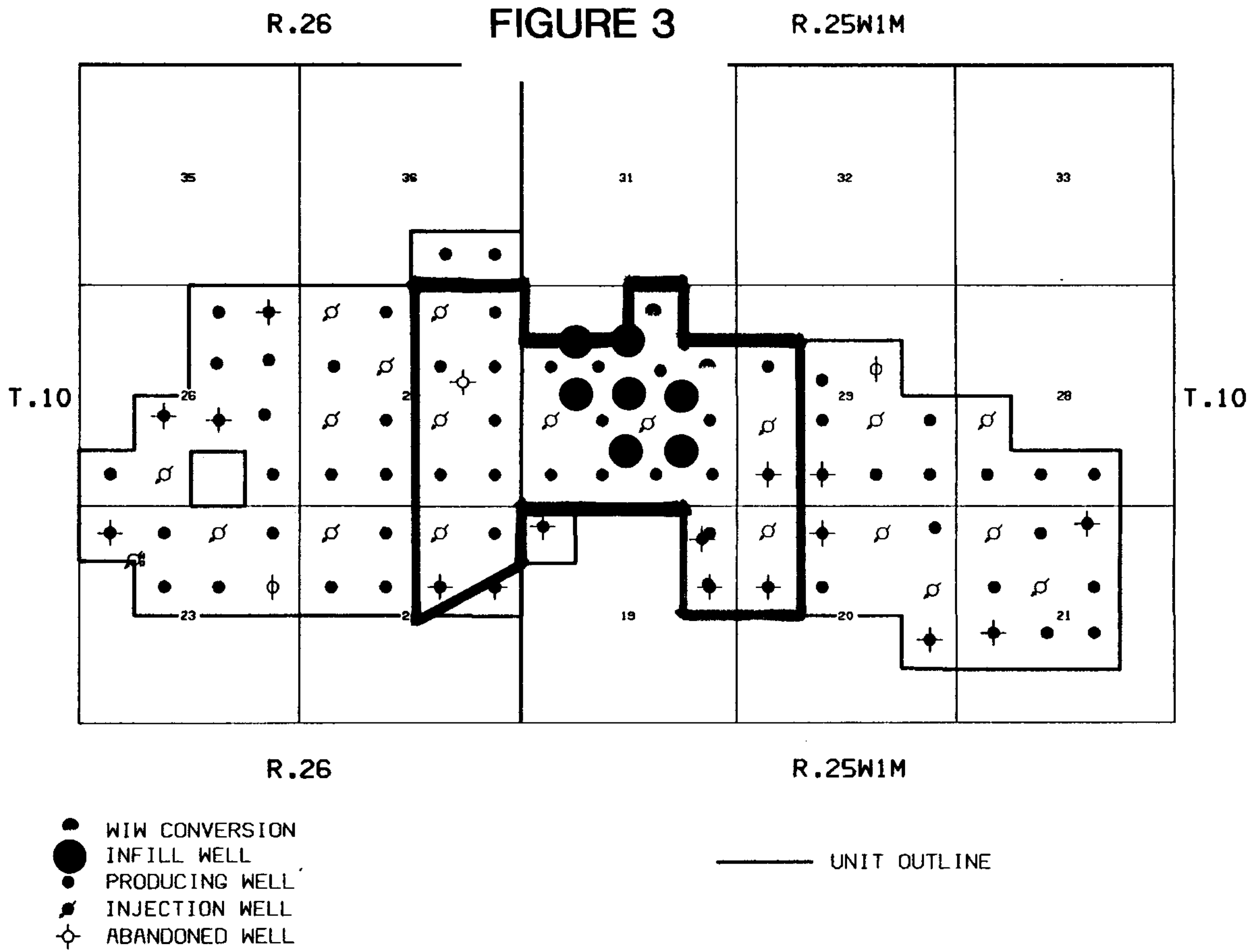


FIGURE 2



VIRDEN ROSELEA UNIT NO.1
UNIT AREA MAP

FIGURE 3



G0337

REDUCED SPACING APPLICATION

~~ALLOWABLE EXEMPTION APPLICATION~~

UNIT VIRDEN ROSELEA UNIT NO. 1 APPLICATION NO. 91 SU

APPLICATION RECEIVED JAN 25 /91

MEMO TO BOARD

DEFICIENCY LETTER

PUBLICATION OF NOTICE

MANITOBA GAZETTE

LAST DATE FOR OBJECTION

OBJECTIONS RECEIVED

MEMO TO BOARD W/ORDER

ORDER NO. _______ SIGNED

APPROVED ORDER TO COMPANY

ORDER AND OTHER MATERIAL FILED

OTHER COMMENTS:

ROUTE SLIP - BOARD CORRESPONDENCE

APPLICATION NO. 91 SU 1

DATE: MAY 2/91

TITLE: VRU #1 - REDUCED SPACING

ROUTING: Draft (Reviewed) | Final Draft (Reviewed and Signed)

	Draft (Reviewed)		Final Draft (Reviewed and Signed)
John Fox	✓	John Fox	✓
Bob Dubreuil	✓	Bob Dubreuil	✓

DO NOT SEND TO BOARD UNLESS BOARD BELOW IS CHECKED.

☑ DATE SENT TO BOARD: May 3/91

BOARD ACTION REQUIRED:

	Date Returned to Petroleum
Board Order	
Board Letter	
Other (Specify)	

DATE SENT TO APPLICANT

OTHER ACTION (SPECIFY)

Manitoba

Memorandum

Date May 2, 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

First | Fold

Re: Virden Roselea Unit No. 1
<u>Reduced Spacing Project</u>

Chevron, in response to the Board's deficiency letter dated April 24, 1991, has revised its previous estimates of the source of incremental reserves recovered by the infill wells.

(1) Original Incremental Reserves Estimate - 87 300m^3
All recovered from undrained Cherty reserves under Lsd's 5, 6, 7, 10, and 11 of Section 30-10-25 (WPM).

(2) Revised Incremental Reserves Estimate - 87 300m^3
34 910m^3 - Crinoidal, Sandhill and Oolite Members, and
52 380m^3 - Cherty

In its revised incremental reserves estimate, Chevron has allocated the incremental reserves to the various members on the basis of the members' fraction of OOIP within the project area.

The incremental recovery in the Sandhill and Oolites will result from improved areal sweep, especially on the northeast flank of the structural high where the 9-30 and 15-30 wells will be converted.

Chevron has estimated that incremental reserves recoverable from the Cherty by both deepening existing wells and infill drilling is 104.8 x 10^3m^3 or 9.3% OOIP. The company indicated that 50 - 70% of the incremental reserves may be recovered by deepening existing wells. Chevron believes recovery will be maximized by both infill drilling and deepening existing wells.

The volume of incremental reserves recoverable from the Cherty is uncertain and there is a risk that the Cherty may be drained by existing wells. If 70% of the incremental reserves in the Cherty are recovered by deepening existing wells, the overall reduced spacing project incremental recovery is still 66.4 x 10^3m^3 or 2.5% OOIP.

It is recommended that the application be approved and Board Order No.'s SU 8 and PM 65 be issued (see previous Petroleum Branch recommendations, April 25, 1991).

In addition, the Board in its letter of approval, should require Chevron to submit, within 2 years of completion of the reduced spacing project, a report evaluating the project results, including the feasibility of deepening existing wells. A copy of the proposed Board letter of approval is attached.

John N. Fox
Chief Petroleum Engineer

JNF/sml

Attachments

Recommended for Approval: ______________________
L. R. Dubreuil, Director

Manitoba

The Oil and Natural Gas
Conservation Board

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

(204) 945-3130

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

Dear Mr. Folden:

Re: Virden Roselea Unit No. 1
<u>Reduced Spacing Project Approval</u>

The Board has considered your application for reduced 8 ha spacing and conversion of two wells to water injection in a portion of Virden Roselea Unit No. 1. Attached are copies of Board Order No. SU 8 and Board Order No. PM 65 approving the application.

Board Order No. SU 8 establishes 8 ha drilling spacing units for the project area. The location of the infill wells in the project area shall conform to the conditions of this order and the requirements of Section 17 of the Petroleum Drilling and Production Regulation.

The Petroleum Branch is concerned with the 7D-30 and 8B-30 locations on the side slope of the Assiniboine River Valley. In order to minimize soil erosion, the following measures listed in Chevron's application will be required:

(1) minimize disturbance of natural vegetation,

(2) construct a contoured berm around the wellsite to divert run-off water, and

(3) revegetate the wellsite including the berm.

In addition, Manitoba Environment has requested that a survey for rare or endangered plant species be conducted by a professional botanist at the proposed 7D-30 and 8B-30 locations before the wells are licenced. If rare or endangered plants are present at the proposed wellsites the wells will have to be relocated. If you require any additional information regarding the survey, please contact Floyd Phillips, Chief, Terrestrial Quality Management, Manitoba Environment at (204) 945-7003.

Board Order No. PM 65 covers pressure maintenance operations in Virden Roselea Unit No.'s 1, 2 and 3 and supercedes Board Order No. PM 55. The order includes a provision for annual pressure surveys in the project area.

Plans for the following activities, as outlined by Chevron in the application, are acceptable:

(1) spill mitigation,
(2) housekeeping,
(3) facility inspection, and
(4) well and reservoir data acquisition.

The Board requests Chevron submit a detailed drilling program for the infill wells and a copy of its contingency plan in the event of a well kick, blowout or other loss of well control situation. Chevron is also directed to conduct a leak-off test after drilling out the surface casing on the first of the seven infill wells drilled.

The Board recognizes that there is a great deal of uncertainty regarding incremental reserve estimates for reduced spacing projects. The difficulty is compounded when an attempt is made to further assign those reserves to individual producing zones. In order to improve incremental reserves estimates for future projects the Board requests Chevron comment on the technical and economic feasibility of collecting zonal reservoir and waterflood performance data by, for example, selective swabbing, zonal pressure measurement or injection profile logging. In addition, the Board requests Chevron submit, within two years of completion of the reduced spacing project, a detailed evaluation of the project. The report should be similar in scope and content to the North Virden Scallion Unit No. 1 reduced spacing project analysis included in the application for this project. The report should also discuss the feasibility of deepening existing wells in the project area.

Please provide the Petroleum Branch with a proposed schedule of drilling, conversion and facility construction activities.

Chevron, in its response to the Board's deficiency letter (February 15, 1991), indicated it thought many of the questions asked by the Board were unwarranted. The Board requests companies provide additional information in support of an application for two reasons. Firstly, for clarification of the public record. Often a company's application and the Board's decision are the only information on the public record. Therefore, it is important where material in the application appears unclear that further clarification is provided by the company.

Secondly, it is incumbent on the Board to ensure it has the information necessary to properly evaluate the application and make the appropriate decision. By requesting this information by letter, the Board's goal is to avoid the time consuming and costly hearing process.

The Board has reviewed its deficiency letter and believes the questions asked of Chevron were appropriate. The Board hopes Chevron is satisfied with this explanation and that the spirit of cooperation established between Chevron and the Board continues to the mutual benefit of both parties.

If you have any questions 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,

H. Clare Moster
Deputy Chairman

cc: S. Scrafield, Rural Development
D. Partridge, Manitoba Agriculture
F. Phillips, Manitoba Environment

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

D M. Clementz
Manager, Engineering

April 26, 1991

Virden Roselea Unit No. 1
Additional Information for
<u>Reduced Spacing Application</u>

Mr. H. Clare Moster
Deputy Chairman
The Oil and Natural Gas Conservation Board
Room 309
Legislative Building
Winnipeg, Manitoba
R3C 0V8

Gentlemen:

In response to the questions raised in your letter of April 24, 1991 on the allocation of incremental reserves and the advantages of infill drilling compared to deepening existing wells, Chevron offers the following:

1. The incremental target of 87 300 m^3 will be produced from all Lodgepole members. The statement in our previous reply that this incremental target would be produced only from the Cherty was incorrect. We feel, as does the Board, that incremental reserves exist in all members of the Lodgepole formation. As stated in the application, this target of 87 300 m^3 represents 3.2% of the project-area OOIP and is considered a reasonable value.

2. The incremental reserves can be allocated to the various members approximately on the basis of that member's fraction of OOIP to the total OOIP. Thus, the portion of the incremental reserves allocated to the Cherty is approximately 60% (52 380 m^3). The remaining 40% (34 920 m^3) would be allocated to the other Lodgepole members.

   The incremental recovery in the Sandhill and Oolite members will result from improved sweep. Figures 1 and 2 show streamtube maps generated for the infill area. The area covered by the streamtube maps is outlined on the Unit Map in Figure 3. In Figure 1 the streamtubes were generated for the existing project. In Figure 2 the streamtubes were generated for the proposed infill project. Better sweep of the infill area is noted in Figure 2, especially in the eastern portion.

3. The case for incremental reserves in the Cherty is more complex. The incremental oil volume to be recovered by deepening existing wells would be much the same as the incremental oil volume (52 380 m^3) recovered by the infill wells, assuming the Cherty has not been drained by the existing wells. This incremental volume may be in the order of 60-70% of the total incremental reserves that could be produced from the Cherty by both deepening existing wells

and infill drilling. However, if the Cherty has been drained by existing wells through natural fracturing up into the Oolites, the incremental oil recovered by the infill wells would be only 30-40% of the total Cherty incremental reserves. The best recovery in the Cherty would result from both deepening existing wells and infill drilling.

4. Chevron believes now is the best time to infill drill for the following reasons:

   a. There is some concern that the Cherty reserves have been drained. Deepening the existing wells would not achieve results in this case.

   b. The economic incentive to infill drill in the future would be less than it is now. At least several years of production data would be required before an estimate of incremental volumes from the deepened wells could be made. At that time we would be considering an infill project in a more mature area with higher WORs in the upper Lodgepole members, and less incremental reserves to be recovered in the Cherty because 60-70% of the total incremental reserves would be produced by the deepened wells.

5. The only way to properly test our theories on displacement mechanism and expected incremental oil recovery is to do a pilot project. Success in this pilot project will open opportunities of additional infill projects in other areas of Roselea and also in NVSU No. 1.

We trust this answers your concerns so that drilling can start in May as scheduled. Please contact Kelly Edwards at (403) 234-5388 if you have further questions.

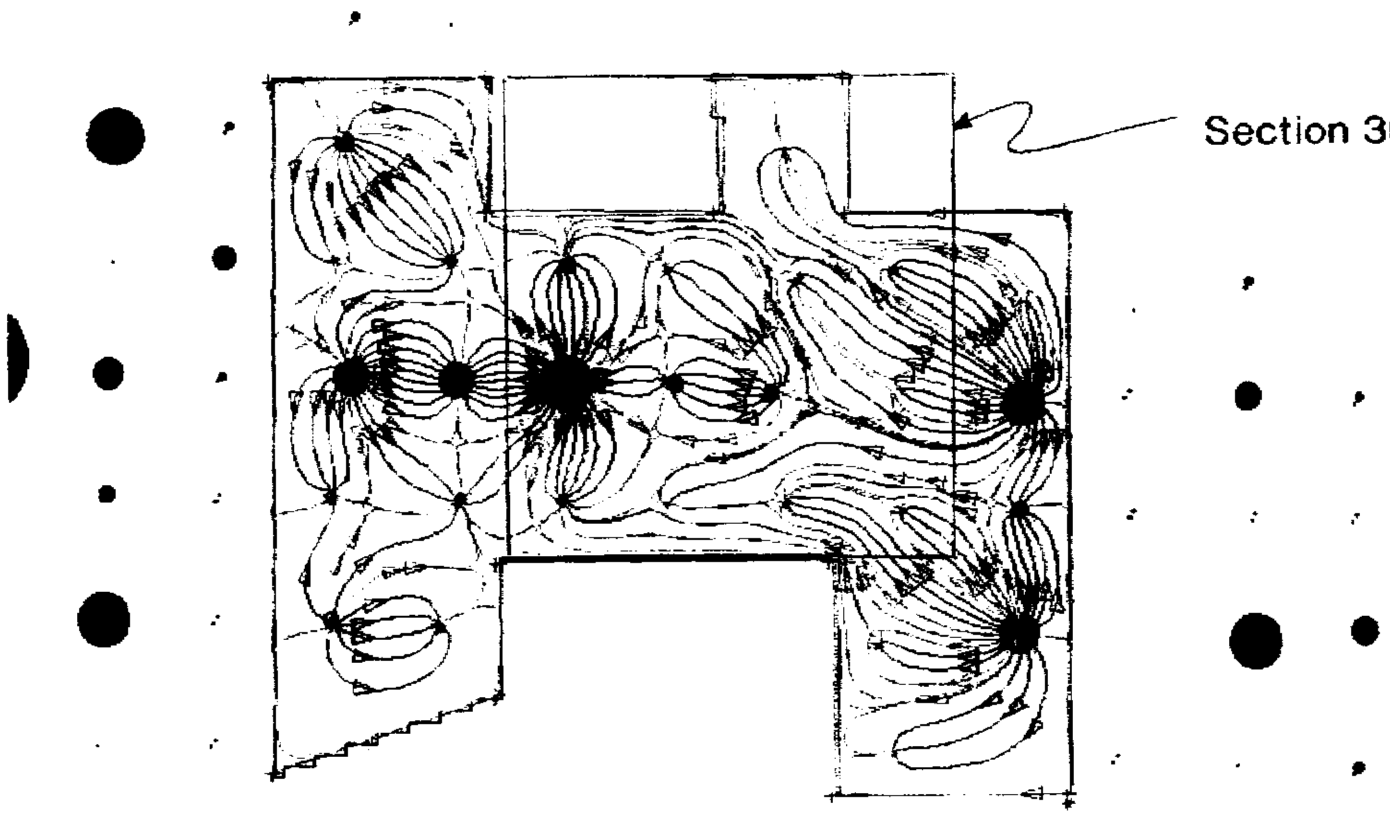
Yours very truly,

Kelly Edwards P.Eng.

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

KAE/er
Attach.

FIGURE 1



Section 30

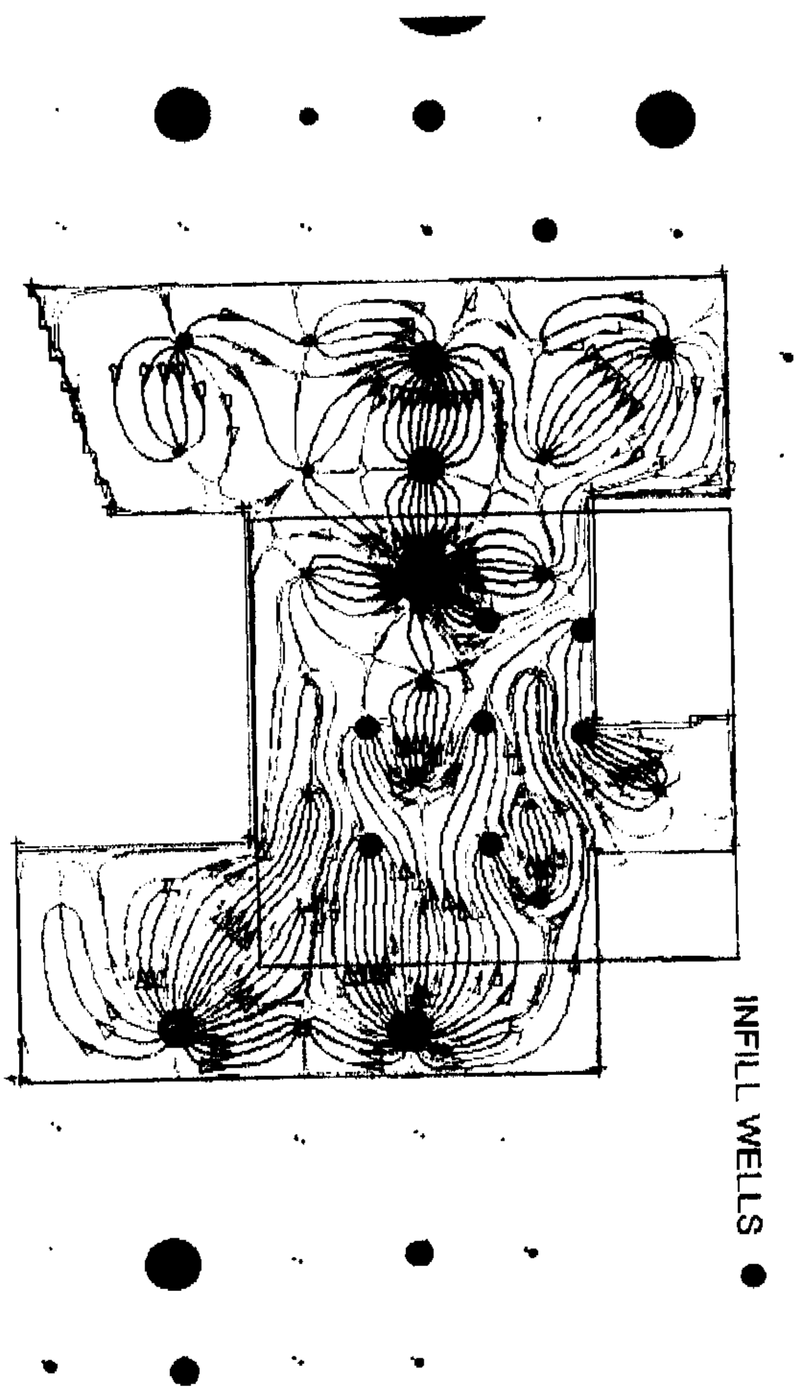
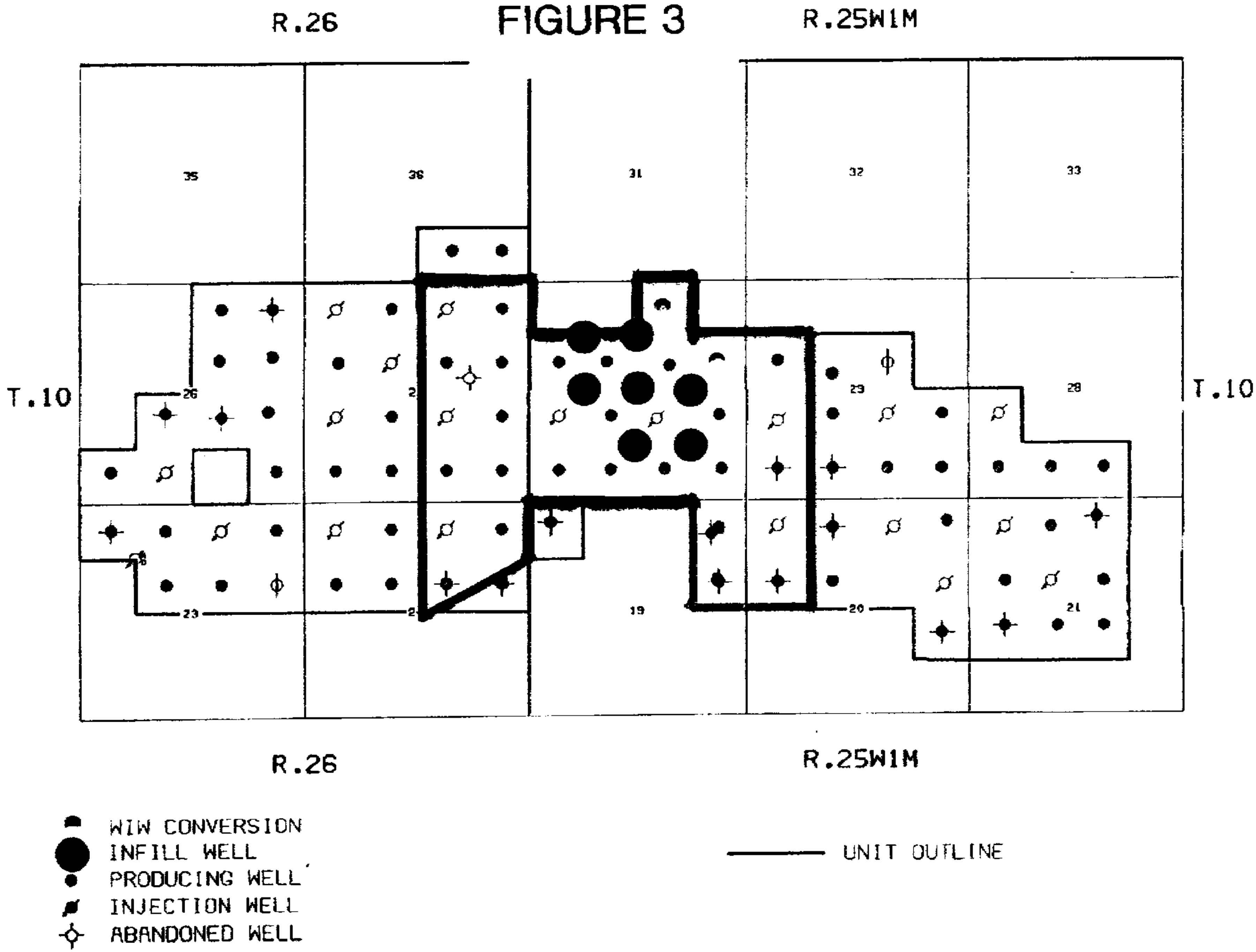


FIGURE 2

VIRDEN ROSELEA UNIT NO.1
UNIT AREA MAP

FIGURE 3



Manitoba

Memorandum

Date: April 25, 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:

First | Fold

Re: Virden Roselea Unit No. 1
<u>Reduced Spacing Project</u>

Chevron has applied to reduce spacing from 16 ha to 8 ha in a portion of Section 30-10-25 (WPM) in Virden Roselea Unit No. 1 (VRU No. 1) and drill 7 infill wells and convert 2 wells to water injection. Figure 1 shows the outline of the project area and the location of the infill wells and injector conversions. Notice of the application was published in the Virden Empire Advance and Manitoba Gazette. No objections were received.

<u>Recommendations</u>

It is recommended that the Board request Chevron comment on what portion of the estimated incremental reserves recovered by the infill wells could be recovered by deepening existing wells. A copy of the proposed Board letter is attached. If Chevron can demonstrate that the reduced spacing project will result in some incremental recovery above that which would result from deepening the wells, it is recommended that the application be approved and the following Board Orders issued:

1) Board Order No. SU 8 - approving 8 ha drilling spacing units for the project area, and

2) Board Order No. PM 65 - approving the conversion of 2 producers in the project area to water injection.

Copies of the proposed Board Orders are attached.

<u>Project Area - Waterflood Performance</u>

VRU No. 1 produces from the Virden Lodgepole B Pool. In the project area the main producing members are the Sandhill and Cherty, with additional production from the Oolites. The Crinoidal has production potential but has only been completed in one well in the project area. The distribution of original oil-in-place ("OOIP") by zone within the project area is shown in Table 1.

The project area overlies a NW-SE structural high centered on Lsd's 6, 7, 8, 9, 10, & 11 of Section 30. Figure 2 is a structure map on the top of the Cherty showing the extent of the structural high.

The Crinoidal, Sandhill and Oolites are continuous over the structural high, though in wells at the apex of the structure some of these zones have been dolomitized and are tight. The Cherty pay above the estimated oil/water contact (-171.6 m subsea) thickens from zero on the flanks of the structure to 13.7 m at the apex of the structure. Figure 3 is a net pay map showing the total net pay thickness for all zones.

Structure has had a significant effect on waterflood performance in the project area. There is a direct correlation between productivity, WOR and structure (Figure 2). The wells at the apex of the structure furthest remove from the oil/water contact have the highest productivity and lowest WOR.

In January, 1991, production from the 11 wells in the project area ranged from 0.4 to 7.1 m^3/d and averaged 2.7 m^3/d/well, compared to the average unit productivity of 1.5 m^3/d/well. In addition, 3 of the 4 highest productivity wells in VRU No. 1 are in the project area.

The WOR in the project area in January, 1991 was 4.7 m^3/m^3 compared to the unit average WOR of 12.4 m^3/m^3. Figure 4 which shows cumulative WOR, clearly illustrates the impact of structure on water production.

The current recovery in VRU No. 1 is 2 208 x $10^3 m^3$ or 27.8% OOIP. The current recovery in the project area is 585 x $10^3 m^3$ or 21.7% OOIP. The predicted ultimate recovery for VRU No. 1 is 34.8% OOIP, compared to an ultimate recovery of between 27.8% (Petroleum Branch) to 31% (Chevron) for the project area. The difference in recovery estimates is based on different decline curve interpretations. Chevron has estimated an exponential decline rate of 2.6%/year for the project area, compared to a 5.0%/year decline estimated by the Petroleum Branch. Figure 5 is a plot of the project area production history.

The difference in current and ultimate recovery between VRU No. 1 and the project area is a function of the volume of OOIP that is presently not effectively completed in the existing wells in the project area. This will be discussed in further detail in the following section.

Predicted Reduced Spacing Project Performance

It appears that the criteria used by Chevron to select the reduced spacing project area in VRU No. 1 are a direct result of the evaluation of Chevron's marginally successful reduced spacing project in North Virden Scallion Unit No. 1 (NVSU No. 1) completed in 1989.

The NVSU No. 1 reduced spacing project included the drilling of 9 infill wells and the conversion of 11 producers to water injection to develop a number of 8 ha 5-spot injection patterns (Figure 6). The predicted incremental recovery, based on improved zonal continuity and improved areal sweep efficiency was 100,000 m^3 or 7.6% OOIP.

After drilling, logging and producing the NVSU No. 1 infill wells, it was apparent that the producing zones - the Oolites and Cherty were more continuous than anticipated and the reduced spacing project area was generally well swept and depleted by the existing producers and injectors. To avoid the project becoming uneconomic, only 3 of the proposed 11 wells were converted to injection. The predicted and actual NVSU No. 1 reduced spacing project results are shown in Table 2.

The following infill drilling criteria were used by Chevron to select the VRU No. 1 reduced spacing project area:

1) infill wells to be located on structural highs to maximize net pay thickness and minimize rapid water encroachment,

2) above average porosity and permeability,

3) areas where all potentially productive zones have not been completed in the existing wells,

4) favourable producing characteristics - high productivity and low WOR, and

5) minimize the number of conversions and convert wells that are structurally low.

The two most important criteria for the success of the VRU No. 1 reduced spacing project are favourable structure and the potential undrained reserves in zones not completed in existing wells.

The 7 proposed infill locations are all located near the apex of the structural high in Section 30-10-25 (WPM) where the top of the Cherty is a minimum of 7.0 m above the estimated oil/water contact (Figure 2). The importance of structural position can be measured by the estimated 4 800 m^3 recoverable reserves per metre of Cherty pay (based on 16 ha spacing) that may be trapped as an "attic loss" if wells are not drilled at the apex of the structure.

Chevron plans to convert the 9-30 and 15-30 wells to water injection. The wells are on the NE flank of the structural high near the unit boundary where there is presently no water injection. The 9-30 well is completed in the 4th Oolite and Cherty and has no pay above the 3rd Oolite. The 15-30 well is openhole below the Crinoidal and TD'd 1.2 m in the Cherty which is wet. The combination of zones completed in the proposed injectors should result in the effective waterflooding of the Sandhill, Oolites and Cherty.

Chevron has indicated that if necessary to replace voidage, a third conversion may be necessary. The proposed location of the third injector would be on the flank of the structure such as 4-30 or 12-30.

Another option would be to waterflood the project area using a 8 ha 5-spot or 9-spot injection pattern. Either of these options would involve converting one or more of the high productivty wells 6-30, 10-30 or 11-30 located at the apex of the structural high. There are two major disadvantages to converting one of these wells. Firstly, the negative impact on the project economics due to the loss of production. Secondly, Chevron's contention that water injected in the project area flows down structure, possibly causing premature water breakthrough in downdip wells. Figure 4 is a cumulative WOR map which supports Chevron's conclusion.

All the wells in the project area are completed openhole with most having casing set below the Crinoidal. The Crinoidal which is potentially productive has only been completed in the 12-30 well. Two wells have unperforated Sandhill or Oolite pay behind casing. Seven wells have TD'd less than 3 m into the Cherty. The total volume of OOIP not completed or penetrated in the project area is 1 007.7 x $10^3 m^3$ or 37% of the total project area OOIP. A well by well breakdown of potentially undrained reserves is listed in Table 3.

Chevron has predicted an incremental recovery of 87 300 m^3 or 3.2% OOIP for the reduced spacing project. The incremental recovery is based solely on the recovery of 15% of the undrained Cherty reserves underlying Lsd's 5, 6, 7, 10, and 11 of Section 30. Chevron assumes the other 15+% of recoverable Cherty reserves have been or will be recovered by existing wells.

Chevron has assigned no incremental reserves to the Crinoidal, Sandhill or Oolites. The two existing injectors in the project area, 5-30 and 7-30, are completed only in the Sandhill and Oolites (5-30 was deepened to the base of the Cherty in March, 1991). The cumulative volume of water injected into the two wells is 1 477.7 x $10^3 m^3$, 1.3 times the hydrocarbon pore volume of the Sandhill and Oolite zones within the project area. As a result of the volume of zonal injection, Chevron feels the laterally continuous Sandhill and Oolite zones have probably been effectively waterflooded in the project area and are probably at an advanced stage of depletion. Recovery as a percentage of OOIP on 16 ha spacing for wells completed only in these zones is anomalously high; 4-30 - 38%, 6-30 - 98%, 10-30 - 64%, 11-30 - 81%. In general, this supports Chevron's conclusion and also indicates that individual wells in the project area can effectively drain more than 16 ha in the Sandhill and Oolites. However, there may be oil trapped updip in these zones where dolomitization has reduced the porosity and permeability. The trapped oil may be recovered by the 7D-30, 10B-30, 11D-30 and 12D-30 infill wells.

If the volume of OOIP in the project area not completed or penetrated is excluded, the current and predicted ultimate recovery in the project area is 34.6% OOIP and 44.4% OOIP, respectively. The anomalously high recovery is either a result of the recovery of a significant volume of oil that has migrated up structure (further confirming individual wells effectively drain in excess of 16 ha) or the production by existing wells of non-penetrated Cherty reserves or most likely, a combination of both.

Chevron indicated in its application that there is a risk that the "incremental" Cherty reserves may have been drained. The company also indicated it will consider deepening some of the existing wells after reviewing the data from the infill wells.

In view of the above, the Petroleum Branch recommends that the Board request Chevron answer the following questions.

1) What portion of the incremental Cherty reserves could be recovered by deepening the existing wells?

2) Are there any incremental reserves in the Crinoidal, Sandhill or Oolites?

3) Are there any technical or economic advantages to drilling the infill wells versus deepening the existing wells?

A copy of the proposed Board deficiency letter is attached.

It is recommended that if Chevron can demonstrate that infill drilling will result in the recovery of incremental reserves above those reserves recovered by deepening existing wells, the project should be approved.

Drilling and Reservoir Evaluation Program

The only change in Chevron's infill drilling program from NVSU No. 1 is that because of a lack of water handling capacity the company does not plan to shut-in the injectors in the project area.

Chevron should be requested to forward a copy of its contingency plans in the event of a well kick, blowout or other loss of well control situation. Chevron will also be requested to conduct a leak-off test after drilling out the surface casing on the first of the 7 infill wells.

Chevron plans to run an extensive suite of well logs and cut a 18 m core on each well.

Pressure surveys are only required in VRU No. 1 once every 3 years, with the next survey due in 1993. In 1990 the only reservoir pressure measured in the project area was at 12-30. It is recommended that Chevron be required to measure the reservoir pressure in Section 30 annually until at least 1993.

Royalty and production tax calculations depend on a determination of the portion of unit production assigned to the infill wells, which is classified as new oil. Therefore, it is recommended that Chevron be requested to production test the infill wells monthly.

Environmental and Land Use Concerns

The reduced spacing project area is located partially atop the Assiniboine River Valley and on the side slope of the river valley (Figure 7). Five of the infill wells are located on cultivated or pasture land at the top of the river valley. Except for the 11D-30 well which is on the edge of cultivated land, it is impractical from a reservoir stand point, to move any of the five wells off cultivated or pasture land.

The Departments of Agriculture, Environment and Rural Development were provided copies of the application for comment. Agriculture, in its review of the application, asked that consideration be given to aligning the infill and existing wells in a similar manner to Waskada Unit No. 4, where the wells were drilled on 4 ha spacing targets. Agriculture was satisfied with the Branch's explanation of the differences in the projects.

To minimize the impact on agricultural activities, as in previous infill projects, Chevron plans to:

1) maximize the use of existing access roads and use non-built up trails into infill locations,

2) run electrical power underground on cultivated land where soil conditions permit, and

3) minimize the actively used portion of the lease area.

Rural Development and Environment expressed concerns regarding soil erosion (especially on the side slope locations 7D-30 and 8B-30) and soil, groundwater and surface water contamination. Chevron, in its application, reiterated the preventative measures and contingency plans the company employs in all phases of its Manitoba operations to minimize the risk of a spill. The Petroleum Branch is satisfied with the effectiveness of these measures.

Environment listed a number of measures to minimize soil erosion at the 7D-30 and 8B-30 side slope locations. These measures will be incorporated in the drilling licence conditions for the wells,

1) minimize disturbance of natural vegetation,

2) install a contoured berm to divert run-off water around the wellsite, and

3) revegetate the wellsite including the berm.

Environment has also recommended that due to the potential for the occurrence of rare or endangered plant species in undisturbed, naturally vegetated river valleys, a survey by a professional botanist be required prior to licencing the 7D-30 or 8B-30 locations. It is proposed that the Board letter of approval require Chevron to conduct such a survey and submit the results with the well licence applications.

Board Orders

The main conditions of the proposed Board Order No.'s SU 8 and PM 65 are outlined below.

Board Order No. SU 8 establishes the orientation of the 8 ha drilling spacing units, the size of the target area and the setback from the unit boundary.

The 8 ha spacing units for the 11D-30 and 12D-30 wells are truncated by the unit boundary. The royalty and working interest owners in Lsd's 13 & 14 of Section 30 were notified of the application directly by the Board. No objections were received.

In previous spacing unit orders, a minimum setback of 200 m from the unit boundary has been required. It is proposed to reduce the setback to 100 m to accommodate the 11D-30 and 12D-30 wells. The 100 m setback is more than the 65 m target area setback for 8 ha spacing units in other pools and is equivalent to the 16 ha spacing unit target area setback.

Board Order No. PM 65 rescinds Board Order No. PM 55 which covers pressure maintenance operations in Virden Roselea Unit No.'s 1, 2, and 3. The order sets out the rules for pressure maintenance within the three units and includes special provisions for annual pressure surveys within the reduced spacing project area and annual reporting requirements, specific to the project area. The order also grants approval to convert the 9-30-10-25 and 15-30-10-25 wells to water injection.

ORIGINAL SIGNED BY
JOHN N. FOX

John Fox
Chief Petroleum Engineer

JNF/sml

Attachments

Recommended for Approval:______________________________
L. R. Dubreuil, Director

Manitoba

The Oil and Natural Gas
Conservation Board

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

(204) 945-3130

Order No. PM 65

An Order Pertaining to Pressure Maintenance by Water Flooding
Virden Lodgepole B Pool

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

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

AND WHEREAS, Chevron Canada Resources is the unit operator of Virden Roselea Unit No. 1, Virden Roselea Unit No. 2 and Virden Roselea Unit No. 3 ("the unit areas").

AND WHEREAS, the Board received an application dated January 18, 1991 from Chevron Canada Resources for approval to convert two additional wells in Virden Roselea Unit No. 1 to water injection.

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

AND WHEREAS, upon due consideration of the said application, the Board has found it is reasonable and desirable to convert the said wells to water injection in the Virden Lodgepole B Pool ("the pool").

NOW THEREFORE, the Board orders that:

1. Board Order No. PM 55 is hereby rescinded.

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

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

PRESSURE MAINTENANCE RULES

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

Chevron South Virden CPR WIW 10-7-10-25 (WPM)
Chevron South Virden CPR WIW 12-7-10-25 (WPM)
Chevron South Virden CPR WIW 14-7-10-25 (WPM)
Chevron Virden Prov. WIW A2-18-10-25 (WPM)
Sun I. Welch Virden WIW 4-18-10-25 (WPM)
Chevron Virden WIW 9-20-10-25 (WPM)
Sun M. Welch Virden WIW 13-20-10-25 (WPM)
Chevron Virden WIW 15-20-10-25 (WPM)
Chevron Virden WIW 11-21-10-25 (WPM)
Chevron Virden WIW 13-21-10-25 (WPM)
Chevron East Virden Prov. WIW 5-28-10-25 (WPM)
Chevron East Virden Prov. WIW 5-29-10-25 (WPM)
Chevron Virden Prov. WIW 7-29-10-25 (WPM)
Placer Virden WIW 5-30-10-25 (WPM)
Placer Virden WIW 7-30-10-25 (WPM)
Virden Roselea Unit No. 1 WIW 9-30-10-25 (WPM)
Virden Roselea Unit No. 1 WIW 15-30-10-25 (WPM)
Continental Virden WIW 12-31-10-25 (WPM)
Chevron South Virden CPR WIW 6-1-10-26 (WPM)
Chevron South Virden CPR WIW 14-1-10-26 (WPM)
Chevron South Virden Prov. WIW 8-2-10-26 (WPM)
Chevron South Virden WIW 14-2-10-26 (WPM)
Mineraloid Virden WIW 16-2-10-26 (WPM)
Chevron South Virden WIW 16-3-10-26 (WPM)
Gulf Duncan Virden WIW 6-10-10-26 (WPM)
Chevron South Virden Prov. WIW 8-10-10-26 (WPM)
Chevron South Virden Prov. WIW 6-11-10-26 (WPM)
Chevron South Virden Prov. WIW 8-11-10-26 (WPM)
Chevron South Virden Prov. WIW 12-11-10-26 (WPM)
Chevron South Virden Prov. WIW 14-11-10-26 (WPM)
Chevron South Virden Prov. WIW 16-11-10-26 (WPM)
Chevron South Virden WIW 6-12-10-26 (WPM)
Chevron South Virden WIW 14-12-10-26 (WPM)
Placer Virden WIW 6-13-10-26 (WPM)
Gulf Union Welch Virden WIW 9-13-10-26 (WPM)
Mineraloid Virden WIW 14-13-10-26 (WPM)
Rundle Williams Virden WIW 4-14-10-26 (WPM)
Rundle Williams Virden WIW 11-14-10-26 (WPM)
Murphy Virden WIW 1-23-10-26 (WPM)
Esso Virden WIW 3-23-10-26 (WPM)
Teck Hepburn Virden WIW 15-23-10-26 (WPM)
Chevron Virden WIW 13-24-10-26 (WPM)
Chevron Virden WIW 15-24-10-26 (WPM)

Chevron Virden WIW 5-25-10-26 (WPM)
Chevron Virden CPR WIW 7-25-10-26 (WPM)
Chevron Virden WIW 11-25-10-26 (WPM)
Chevron Virden WIW 13-25-10-26 (WPM)
Chevron Virden CPR WIW 15-25-10-26 (WPM)
Chevron Virden WIW 3-26-10-26 (WPM)
Chevron Virden Prov. WIW 10-36-10-26 (WPM)
Chevron Virden WIW 4-5-11-25 (WPM)
Chevron Virden WIW 10-5-11-25 (WPM)
Chevron Virden Prov. WIW 12-5-11-25 (WPM)
Chevron Virden Prov. WIW 14-5-11-25 (WPM)
Chevron Virden Prov. WIW 2-6-11-25 (WPM)
Chevron Virden Prov. WIW 8-6-11-25 (WPM)
Chevron Virden Prov. WIW 10-6-11-25 (WPM)
Chevron Virden Prov. WIW 12-6-11-25 (WPM)
Chevron Virden Prov. WIW 14-6-11-25 (WPM)
Chevron Virden Prov. WIW 16-6-11-25 (WPM)
Murphy Virden WIW 2-7-11-25 (WPM)
Murphy Virden WIW 4-7-11-25 (WPM)
Chevron Virden WIW 4-8-11-25 (WPM)

and such other wells in the unit areas as the Board may approve.

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

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

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

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

3(1) At least once every three years commencing in 1981, unless otherwise directed by the Board, the unit operator shall conduct a survey to determine the static reservoir pressure in the unit areas.

3(2) Notwithstanding the provisions of subsection (1), the unit operator shall, at yearly intervals until such time as the Board approves otherwise, conduct a survey to determine the static reservoir pressure in Section 30, Township 10, Range 25 (WPM).

3(3) The unit operator shall submit to the Petroleum Branch, the details of the surveys described in subsections (1) and (2), including a list of the wells to be surveyed, the measurement technique to be used, and the intended shut-in periods for each well, and approval shall be obtained from the Director of Petroleum before the program is carried out.

3(4) The unit operator shall submit to the Petroleum Branch, within 30 days of the completion date of the surveys described in subsections (1) and (2), a report which shall include:

(a) the static reservoir pressure data obtained from the survey, corrected to a common datum;

(b) an isobaric map of the pool within the unit areas based on the data obtained; and

(c) a discussion of the survey results and pressure distribution within the pool.

3(5) The Board may, at any time, require the unit operator to carry out such additional reservoir pressure surveys as it deems necessary.

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

5 The maximum wellhead pressure at which water is injected into the wells referred to in subsection 1(1) shall not exceed 8 000 kPa or such other maximum pressure as the Board may prescribe and the Board may, from time to time, prescribe a maximum or minimum rate at which water shall be injected into any well in the unit areas.

6(1) The unit operator shall, not later than the last day of each month, file with the Petroleum Branch, a report of the quantity, source and pressure of water injected during the preceding month into each well referred to in subsection 1(1).

6(2) The unit operator shall, not later than the last day of each month, file with the Petroleum Branch a summary report of production and injection operations during the preceding month, which report shall include:

(a) a tabulation of total oil, total water and total gas produced;

(b) a tabulation of the number of producing wells and injection wells which were active; and

(c) a summary of any remedial operations carried out on any well in the unit areas.

7. The unit operator, shall, within 60 days of the end of each calendar year, file with the Petroleum Branch a report of the pressure maintenance program, setting out graphically such interpretive information necessary to evaluate the efficacy of the waterflood, including a discussion of the performance of the reduced spacing project area outlined in Board Order No. SU 8.

Wm. McDonald
Member

H. Clare Moster
Deputy Chairman

OIL AND NATURAL GAS CONSERVATION
BOARD ORDER NO. PM 65 APPROVED THIS
DAY OF A.D. 1991
AT THE CITY OF WINNIPEG.

APPROVED:

Harold Neufeld
Minister of Energy and Mines

Manitoba

The Oil and Natural Gas
Conservation Board

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

(204) 945-3130

Order No. SU 8

An Order Pertaining to Drilling Spacing Units
Virden Lodgepole B Pool

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

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

(b) respecting the designation of the area that shall be allocated to a well in connection with fixing allowable production;"

AND WHEREAS, subsection (1)(f) of section 63 of "The Mines Act" being Chapter M160 of the Continuing Consolidation of the Statutes of Manitoba, provides as follows:

"63(1) For the purpose of carrying out the provisions of this Part and Part III according to their intent, the Lieutenant Governor in Council may make such regulations and orders as are ancillary thereto, and are not inconsistent therewith; and every such regulation or order made under, and in accordance with the authority granted by, this section has the force of law; and, without restricting the generality of the foregoing, the Lieutenant Governor in Council may make regulations and orders, not inconsistent with any other provision of this Part of Part III,

(f) prescribing spacing units and the size and shape of spacing units;"

AND WHEREAS, subsection (1) of Section 20 of Manitoba Regulation 430/87R under The Mines Act ("the Petroleum Drilling and Production Regulation") provides as follows:

"20(1) Notwithstanding section 19, the board may, after a public hearing or after publication of notice, prescribe by order special drilling spacing units which may differ from normal drilling spacing units in size, shape or target area."

AND WHEREAS, subsection (3) of Section 21 of the Petroleum Drilling and Production Regulation provides as follows:

"21(3) Where a special drilling spacing unit is prescribed under section 20, the board may prescribe the target area within which a well shall be completed in order to qualify for a maximum permissible production rate based on the area of the special drilling spacing unit."

AND WHEREAS, the Board received an application dated January 18, 1991 from Chevron Canada Resources as unit operator of Virden Roselea Unit No. 1 ("the unit area") for approval to reduce the size of drilling spacing units in a portion of the unit area outlined in Schedule A ("the project area").

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

AND WHEREAS, the Board considers that establishment of smaller drilling spacing units within the project area will result in an increase in recovery of crude oil from the project area.

NOW THEREFORE, the Board orders that:

1. Subject to clause 2 and 4 herein, the spacing unit for each well drilled, or to be drilled, for the purpose of obtaining oil from or injecting salt water into the Mississippian Lodgepole Formation within the project area is a square, 8 hectares in area, with corners located at the midpoints of the boundaries of each legal subdivision, as illustrated in Schedule A.

2. Where a spacing unit established by clause 1 intersects the boundary of the unit area, the unit boundary shall truncate the spacing unit and form part of the spacing unit boundary as illustrated in Schedule A.

3. The target area of each drilling spacing unit shall be an area having sides sixty-five metres from the sides of the drilling spacing unit and parallel to them.

4. Notwithstanding clause 3, no well shall be completed nearer to any boundary of the unit area than 100 metres or nearer to any other well than 130 metres.

Wm. McDonald
Member

H. Clare Moster
Deputy Chairman

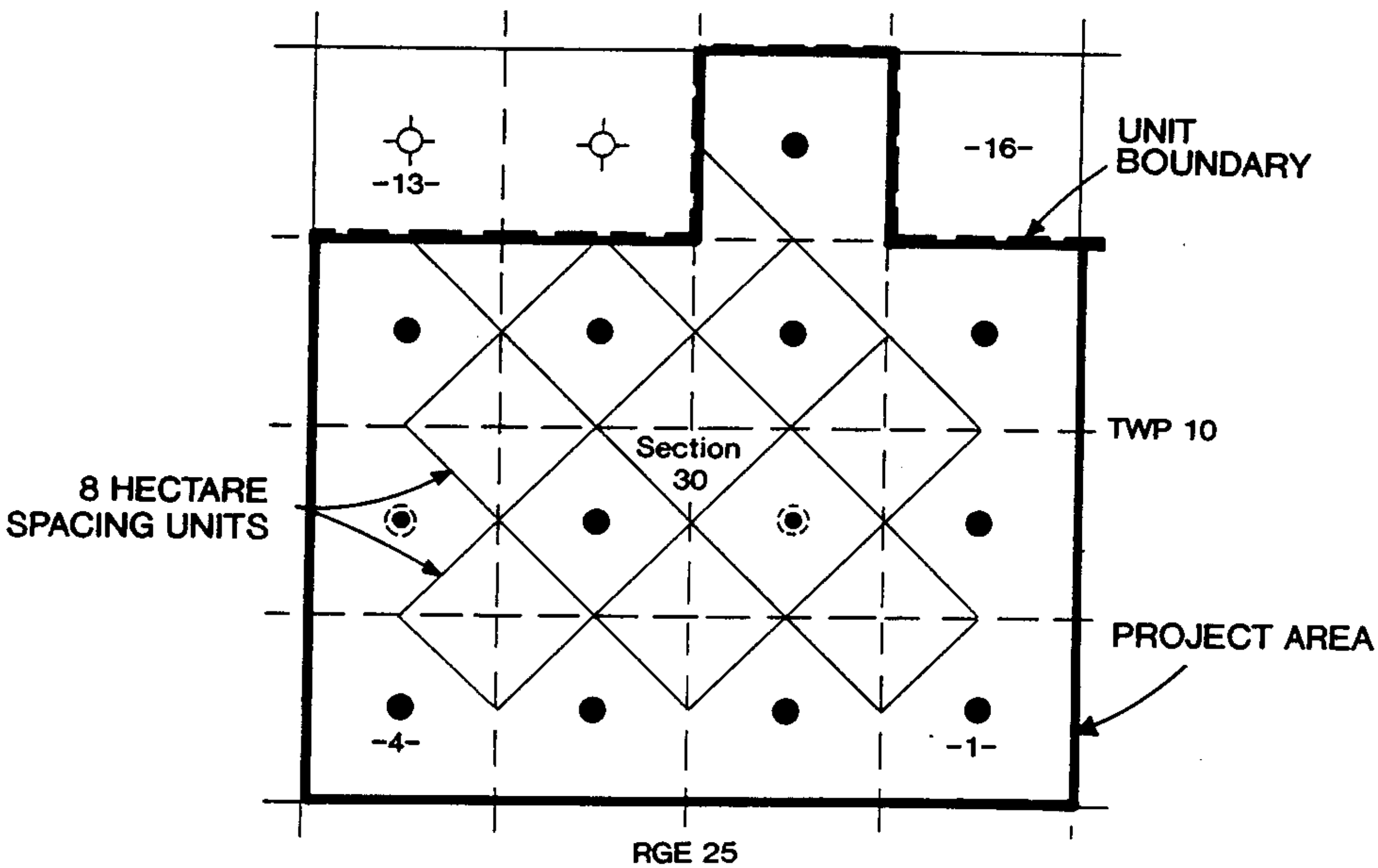
OIL AND NATURAL GAS CONSERVATION
BOARD ORDER NO. SU 8 APPROVED THIS
DAY OF A.D., 1991
AT THE CITY OF WINNIPEG.

APPROVED:

Harold Neufeld
Minister of Energy and Mines

SCHEDULE A

BOARD ORDER NO. SU 8
VIRDEN ROSELEA UNIT NO. 1
8 Hectare Drilling Spacing Units



LEGEND:

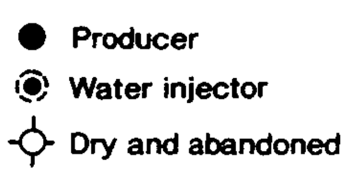


TABLE 1

Member	Project Area Original Oil-in-Place ($10^3 m^3$)	% of Project Area Original Oil-in-Place
Crinoidal	268.0	10
Sandhill	689.6	26
Oolites	270.6	10
Cherty	1 467.6	54
	2 695.8	

TABLE 2

North Virden Scallion Unit No. 1
Reduced Spacing Project

	Forecast	Actual
No. of Wells Drilled	9	9
No. of Wells Converted	11	3
Average Initial Oil Rate (m^3/d/well)	6.8	2.2
Average Water-cut (%)	57	82
Incremental Recovery (m^3)	100,000	36 800
Incremental Recovery Factor (% of OOIP)	7.6	1.7

TABLE 3

Undrained Potential Reserves
Within the Project Area

Well	Member	Original Oil-in-Place (10^3m^3)
1-30	Cherty	81.7
3-30	Crinoidal	36.2
4-30	Crinoidal	62.0
5-30	Crinoidal	30.1
	Cherty	78.7
6-30	Crinoidal	29.7
	Cherty	99.8
7-30	Cherty	124.0
8-30	Sandhill	73.1
9-30	3rd Oolite	9.1
10-30	Cherty (5.2m of 8.5m Cherty pay penetrated)	142.1
11-30	Crinoidal	41.0
	Cherty	163.4
15-30	Crinoidal	36.8
	Total	1 007.7 x 10^3m^3

Undrained Reserves	Crinoidal	235.8 x 10^3m^3
	Sandhill	73.1 x 10^3m^3
	Oolite	9.1 x 10^3m^3
	Cherty	689.7 x 10^3m^3

VIRDEN ROSELEA UNIT NO.1
UNIT AREA MAP

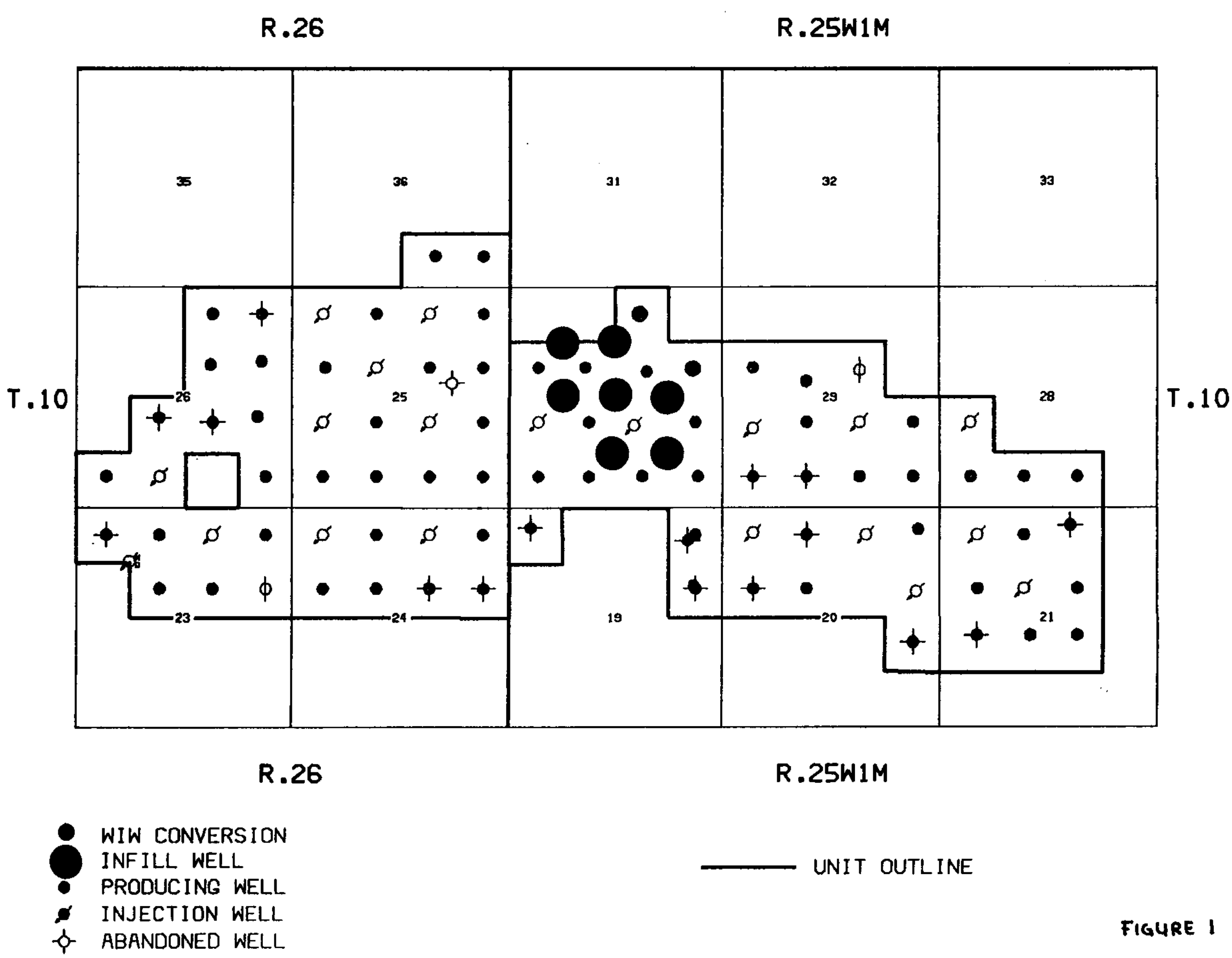
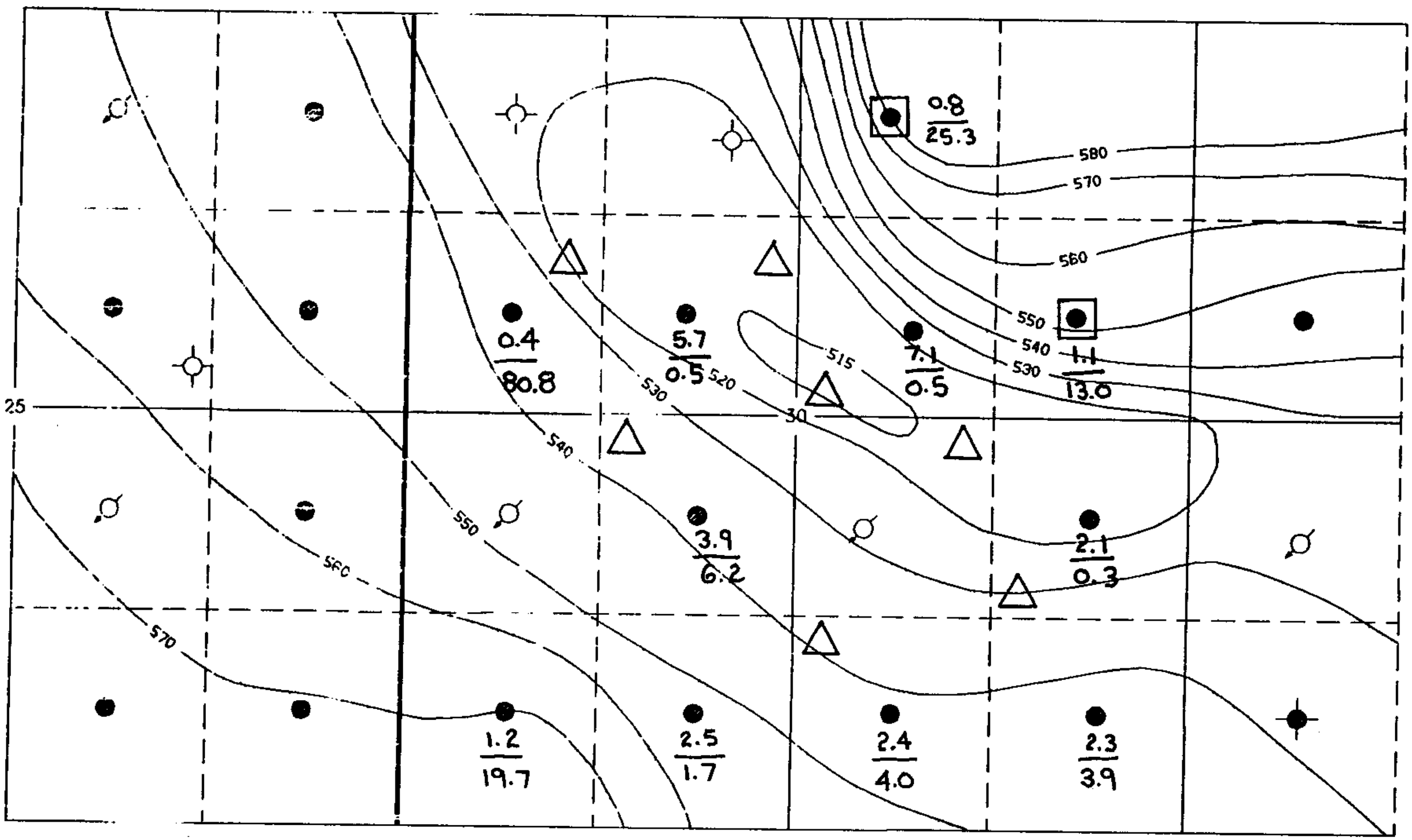


FIGURE 1



INFILL DRILLING LOCATION

PROPOSED INJECTOR CONVERSION

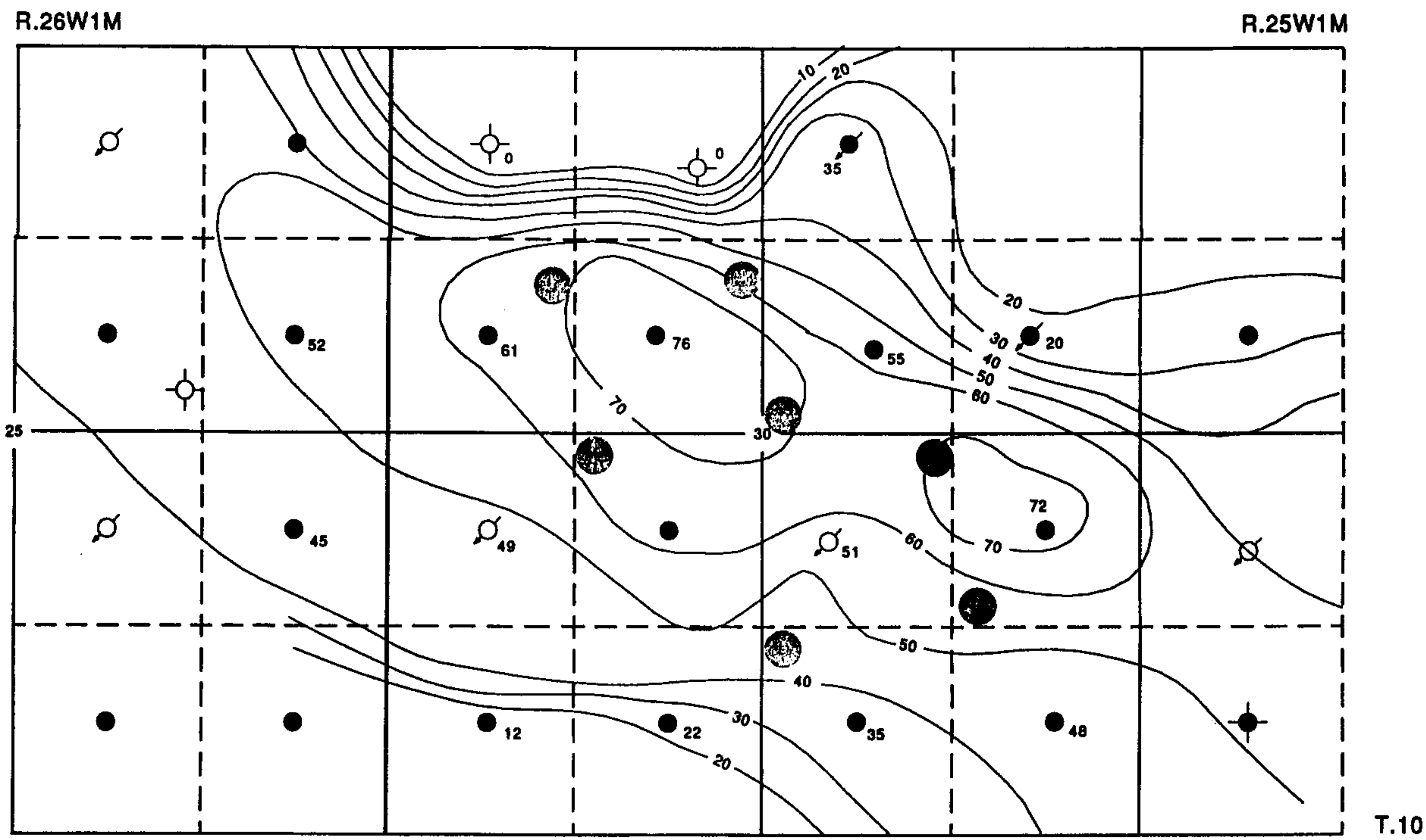
$\frac{2.3}{3.9}$ - $\frac{\text{DAILY OIL } (m^3/d)}{\text{WOR } (m^3/m^3)}$

C.I. - 10'

FIGURE 2

STRUCTURE ON TOP OF CHERTY
(FEET SUBSEA)

VIRDEN ROSELEA UNIT NO. 1



INFILL WELLS

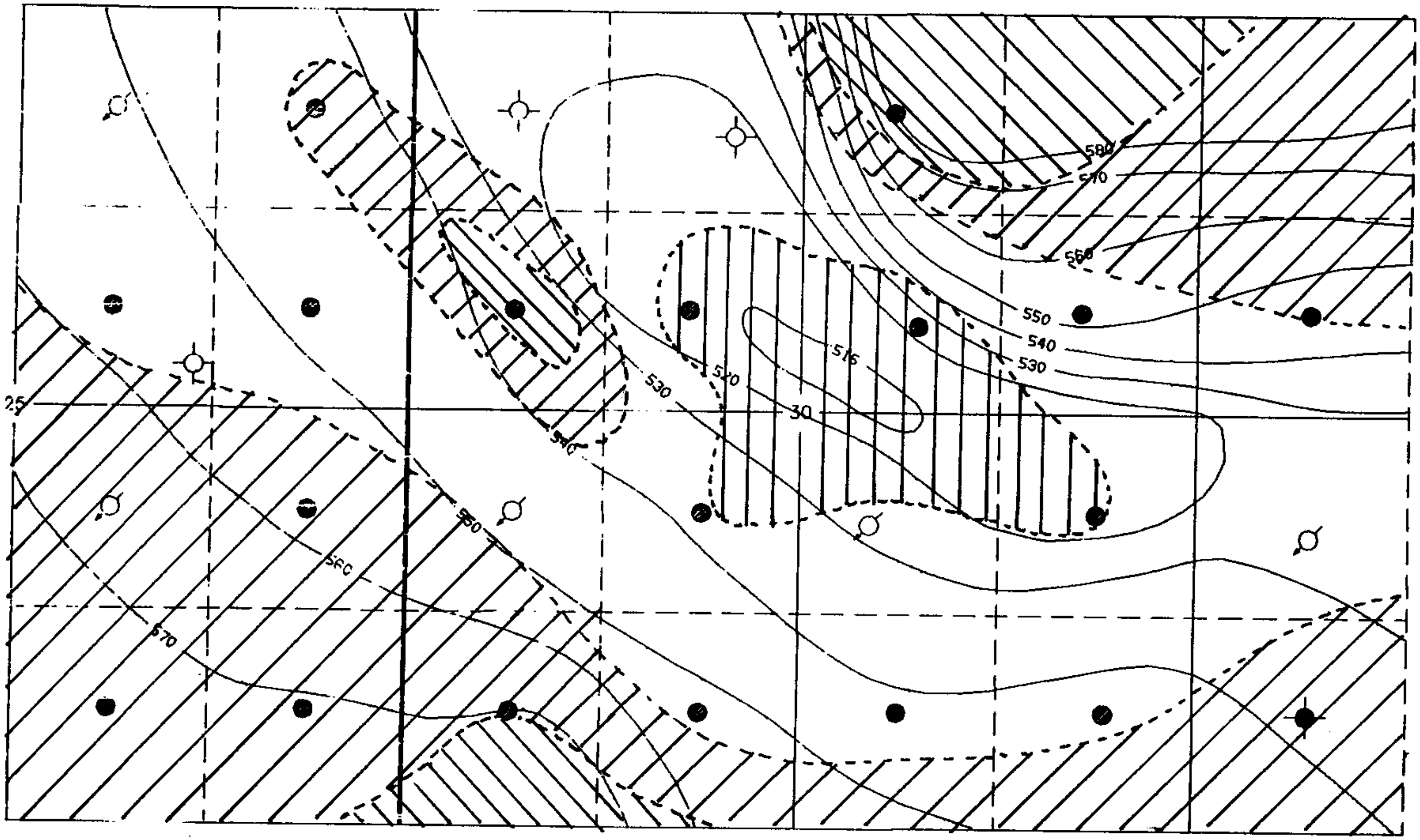
CONVERTED TO WATER INJECTION

ORIGINAL NET PAY MAP
(FEET)

FIGURE 3

G04540_04

CUMULATIVE WOR



CUMULATIVE WOR m^3/m^3

- 0 - 1
- 1 - 2
- 2 - 4
- > 4

C.I. - 10'

STRUCTURE ON TOP OF CHERTY
(FEET SUBSEA)

FIGURE 4

REDUCED SPACING PROJECT

PRODUCTION HISTORY

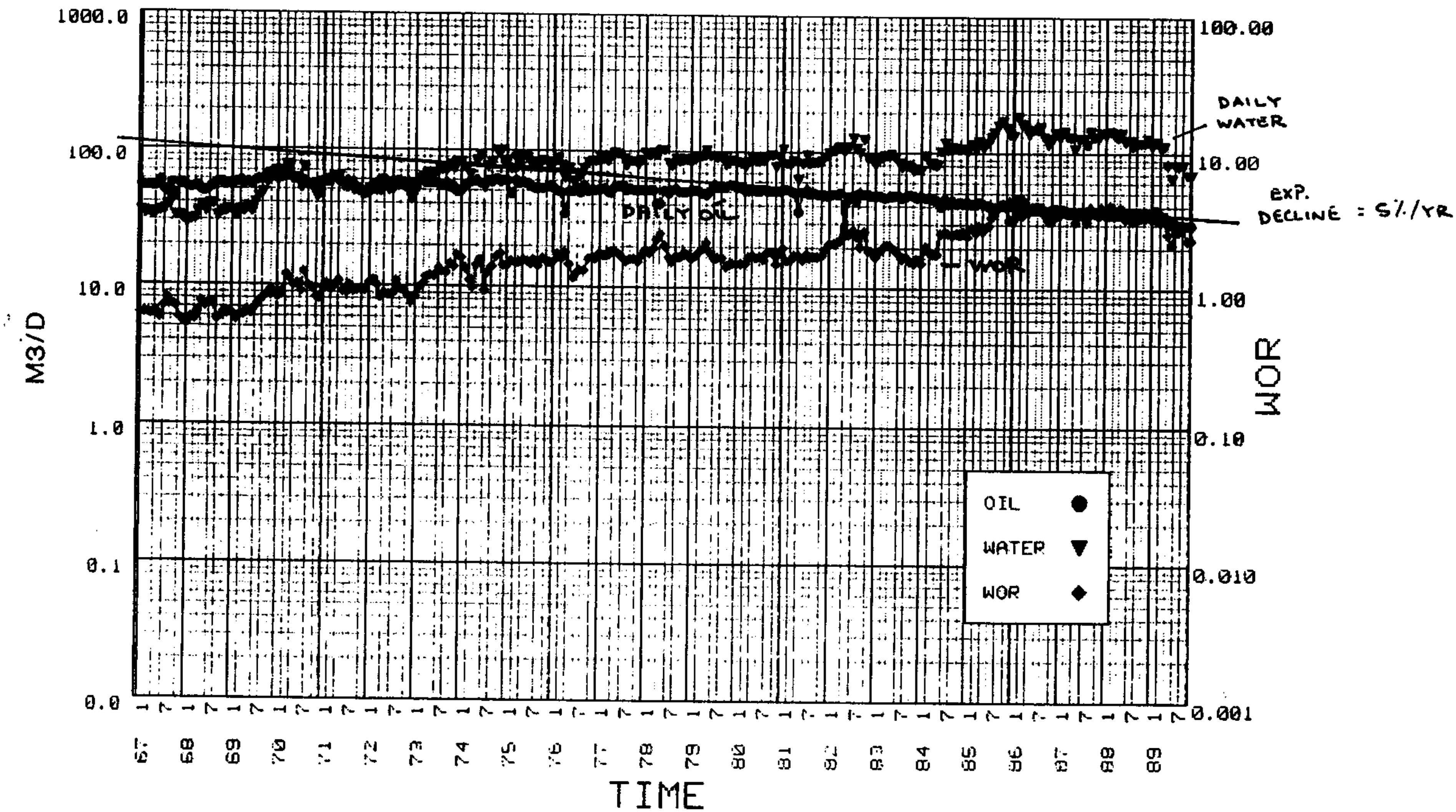
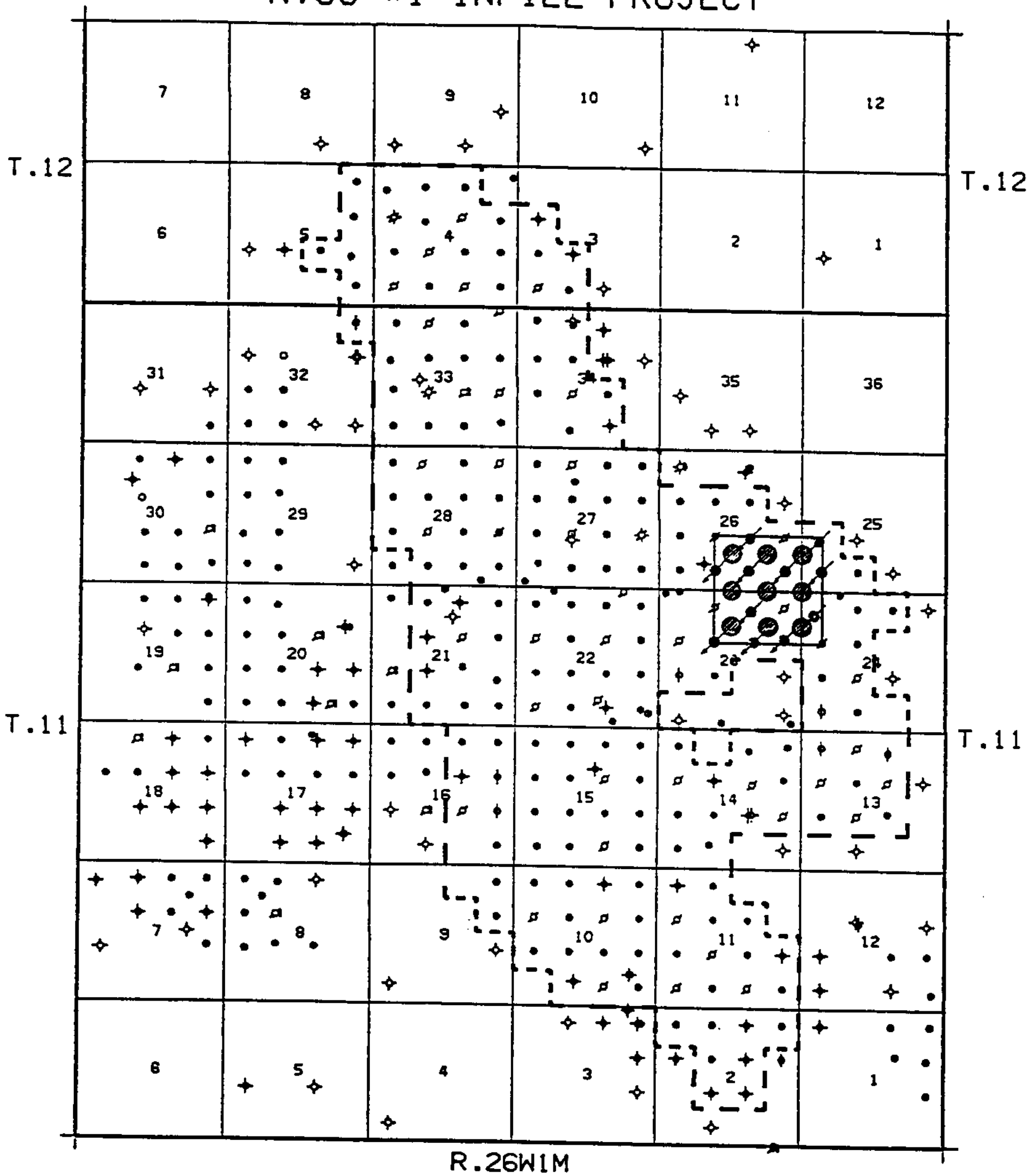


FIGURE 5

FIGURE 6

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

C034

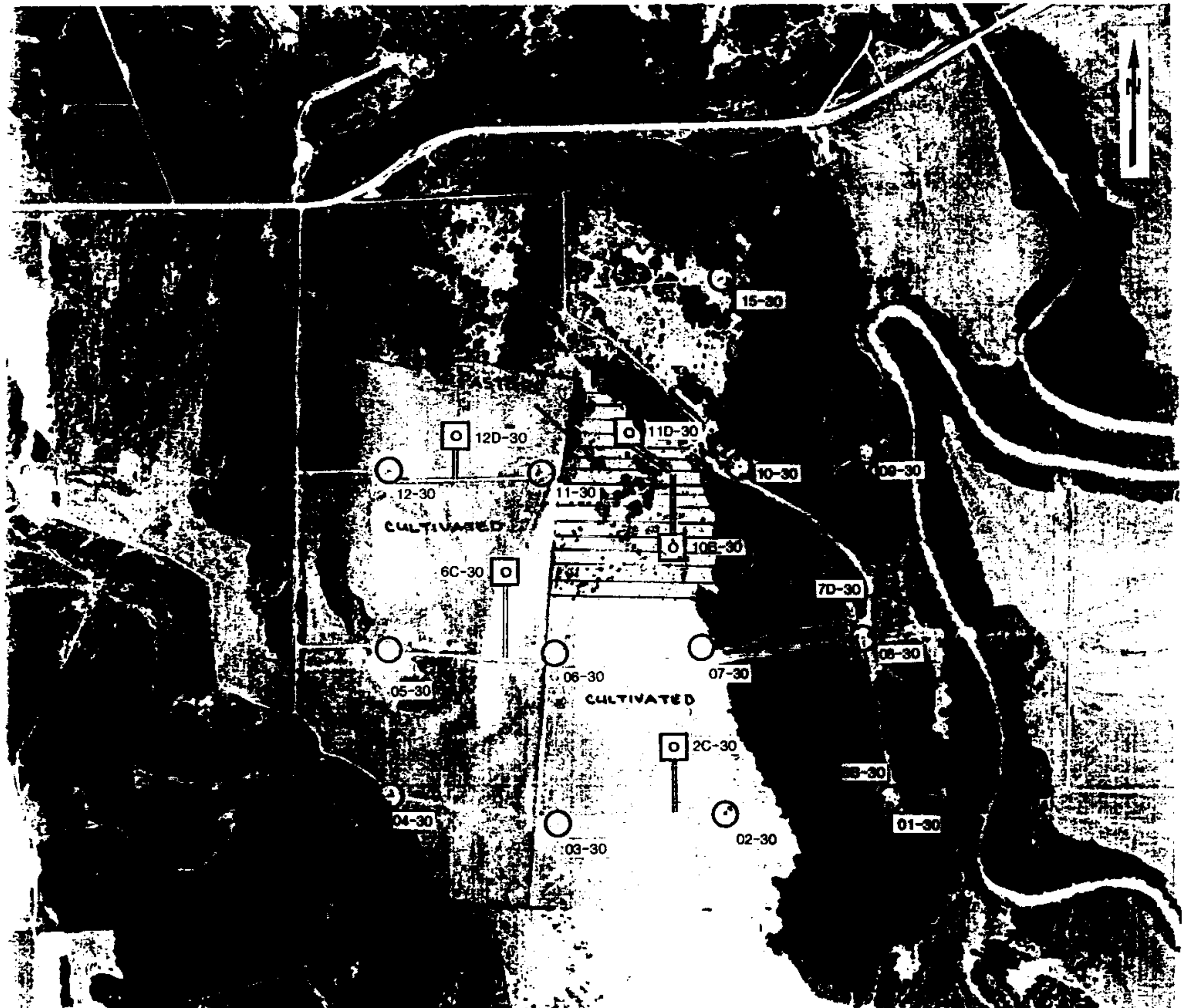


FIGURE
7

AERIAL PHOTOGRAPH
OF
REDUCED SPACING
PROJECT AREA

KEY:

EXISTING WELLS

PROPOSED WELLS

PROPOSED LEASE TRAILS

SCALE
0 100 200 300 400 500
METRES

100 m
100 m
DRILLING LEASE SIZE
(TO SCALE)

Manitoba

The Oil and Natural Gas Conservation Board

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

(204) 945-3130

April 24, 1991

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

Dear Mr. Folden:

Re: Virden Roselea Unit No. 1
<u>Application for Reduced Spacing</u>

Based on its technical review of the subject application, the Board is of the opinion that, within the project area, incremental reserves exist in the Cherty, and to a lesser extent, in the Crinoidal, Sandhill and Oolite Members. There is also evidence that existing wells can effectively drain in excess of 16 ha.

In response to the Board's deficiency letter (February 15, 1991), Chevron indicated incremental recovery was based solely on production of undrained Cherty reserves underlying Lsd's 5, 6, 7, 10, and 11 of Section 30 and that after drilling the infill wells and reviewing the data, the company will consider deepening some of the existing wells.

In view of the above, the Board requests Chevron address the following questions before final disposition of the application:

1) What portion of the incremental reserves of 87 300 m^3, predicted to be recovered from the Cherty by the infill wells, could be recovered by deepening the existing wells further into the Cherty?

2) What is the magnitude of incremental recovery from the Crinoidal, Sandhill and Oolite Members anticipated as a result of the proposed infill project?

3) What are the technical or economic advantages to drilling the infill wells as opposed to deepening the existing wells?

Yours respectfully,

H. Clare Moster
Deputy Chairman

Manitoba

Energy and Mines Petroleum

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

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

December 11, 1990

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

Dear Len:

RE: Virden Roselea Unit No. 1
Reduced Spacing Proposal

The Petroleum Branch has reviewed your proposed 8 ha spacing unit boundaries.

With respect to the 8 ha spacing units for the proposed 11D-30-10-25 and 12D-30-10-25 infill wells, for the purpose of the application, the Petroleum Branch is not concerned with truncation of the spacing units at the unit boundary (please note the proposed modifications on the attached Figure). The Petroleum Branch anticipates however, that the Board will be concerned with the effect of the reduced spacing project on the correlative rights of the lessors and lessees adjacent to the unit. It is suggested that Chevron address this matter in its application.

Yours truly,

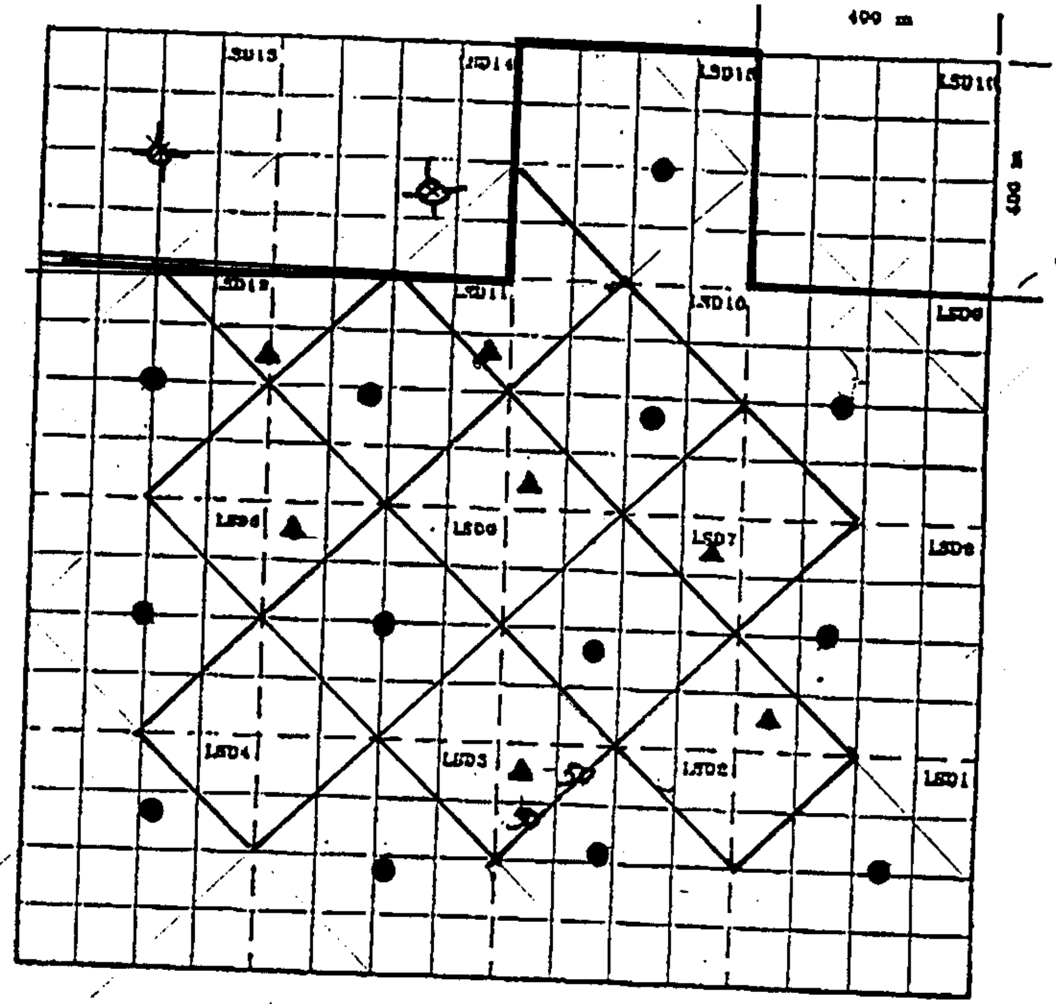
John N. Fox, P. Eng.
Chief Petroleum Engineer

JNF:cvs

Chevron Canada Resources

BOTTOM HOLE LOCATION FORM

Proposed Well Location NV Roselea Unit No 1
LSD 2C SEC. 30 TWP. 10 RGE. 25 W. OF 1 MER.
Mark on Gas Target and Oil Target



UNIT BOUNDARY

BOTTOM HOLE COORDS. 1250 metres South of North Boundary
750 metres West of East Boundary

Estimated Ground Elevation 426 metres
Estimated K.B. 430 metres
Estimated Total Depth 614 metres

Restrictions:

FACSIMILE TRANSMITTAL COVER PAGE

Chevron Canada Resources
500 - Fifth Avenue S.W., Calgary, Alberta
Phone (403) 234-5000 Fax 234-6212

Page 1 of 2
Date: 90-12-07

Canon Fax-730
Fax Number (403) 234-6212
Confirmation (403) 234-5646

FROM: LEN MARCHAND
REGULATORY AFFAIRS

TO: JOHN FOX

COMPANY: MANITOBA PETROLEUM BRANCH

CITY: WINNIPEG

FAX NO.: (204) 945-0586

JOHN,

Here's a map of how I envision the DSUs within the reduced spacing area. The north half of the DSUs which would normally be comprised of 11c/12d/13a/14b and 10c/11d/14a/15b will be truncated as shown (i.e. the DSUs will consist of 11c/12d and 10c/11d only). All the other DSUs will be "normal." I assume the target areas for the truncated DSUs will also be truncated and that we will have to stay 100m away from the Unit boundary.

Could you please confirm that this configuration will be acceptable to the P-Branch for application / advertisement purposes.

Thanks very much.

Len Marchand
(phone: 234-5046)

Chevron

PAGE OF

FILE BY DATE

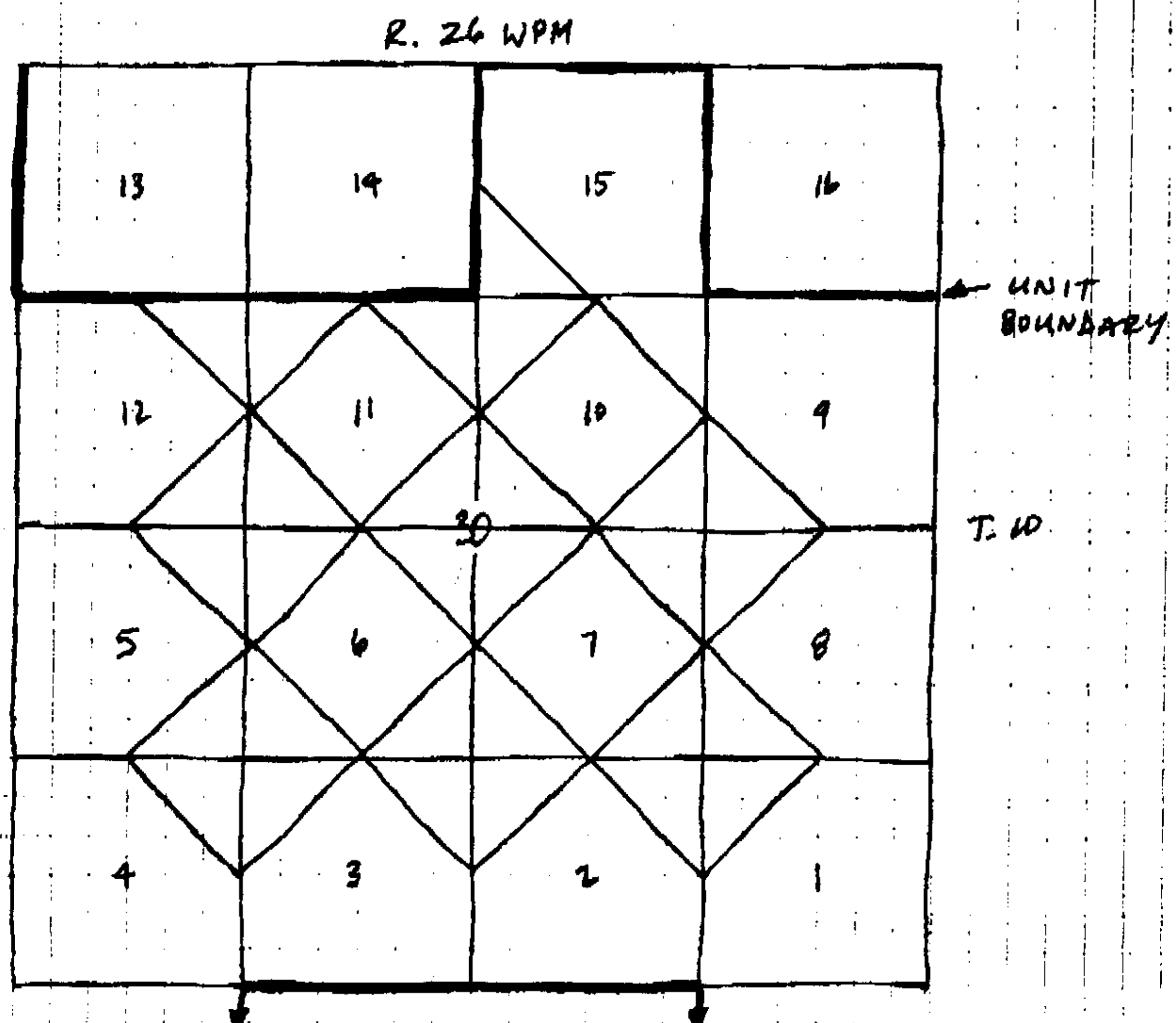
PROJECT SUBJECT

FIGURE 1

REDUCED SPACING AREA

VIRDEN ROSELEA UNIT NO. 1

SECTION 30 - 10 - 26 WPM



Manitoba

Energy and Mines Petroleum

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

(204) 945-6577

September 10, 1990

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

Attention: Mr. Len Marchand

Dear Len:

Re: Virden Roselea Unit No. 1
Reduced Spacing Proposal

The Petroleum Branch has reviewed your request regarding the location of proposed infill wells in Virden Roselea Unit No. 1.

The decision regarding special drilling spacing and target areas is under the jurisdiction of the Board. Board Order No.'s SU 3 & SU 4 dealing with 8 ha spacing in Daly Unit No. 1 and North Virden Scallion Unit No. 1 have a setback requirement of 200 m from the unit boundary. However the normal 16 ha spacing target area is only setback 100 m from the side of the spacing unit. Not wanting to prejudge the Board, the only comment the Branch can make at this time is that a 100 m setback from the unit boundary is not unreasonable given the prescribed target area for normal 16 ha spacing units.

With respect to directional survey requirements, under normal 16 ha spacing a directional survey is required if a well is drilled outside the central 100 m^2 area of the spacing unit. It is likely that a directional survey would be required for the 11D-30 and 12D-30 wells.

If you have any questions please contact the undersigned at (204) 945-6574.

Yours truly,

John N. Fox
Chief Petroleum Engineer

JNF:cvs

FACSIMILE TRANSMITTAL COVER PAGE

Chevron Canada Resources
500 - Fifth Avenue S.W., Calgary, Alberta
Phone (403) 234-5000 Fax 234-6212

Page 1 of 8
Date: 90-09-06

Canon Fax-730
Fax Number (403) 234-6212
Confirmation (403) 234-5646

FROM: LEN MARCHAND
REGULATIONS DIVISION
TO: JOHN FOX
COMPANY: PETROLEUM BRANCH
CITY: WINNIPEG, MANITOBA
FAX NO.: (204) 945-0586

JOHN,

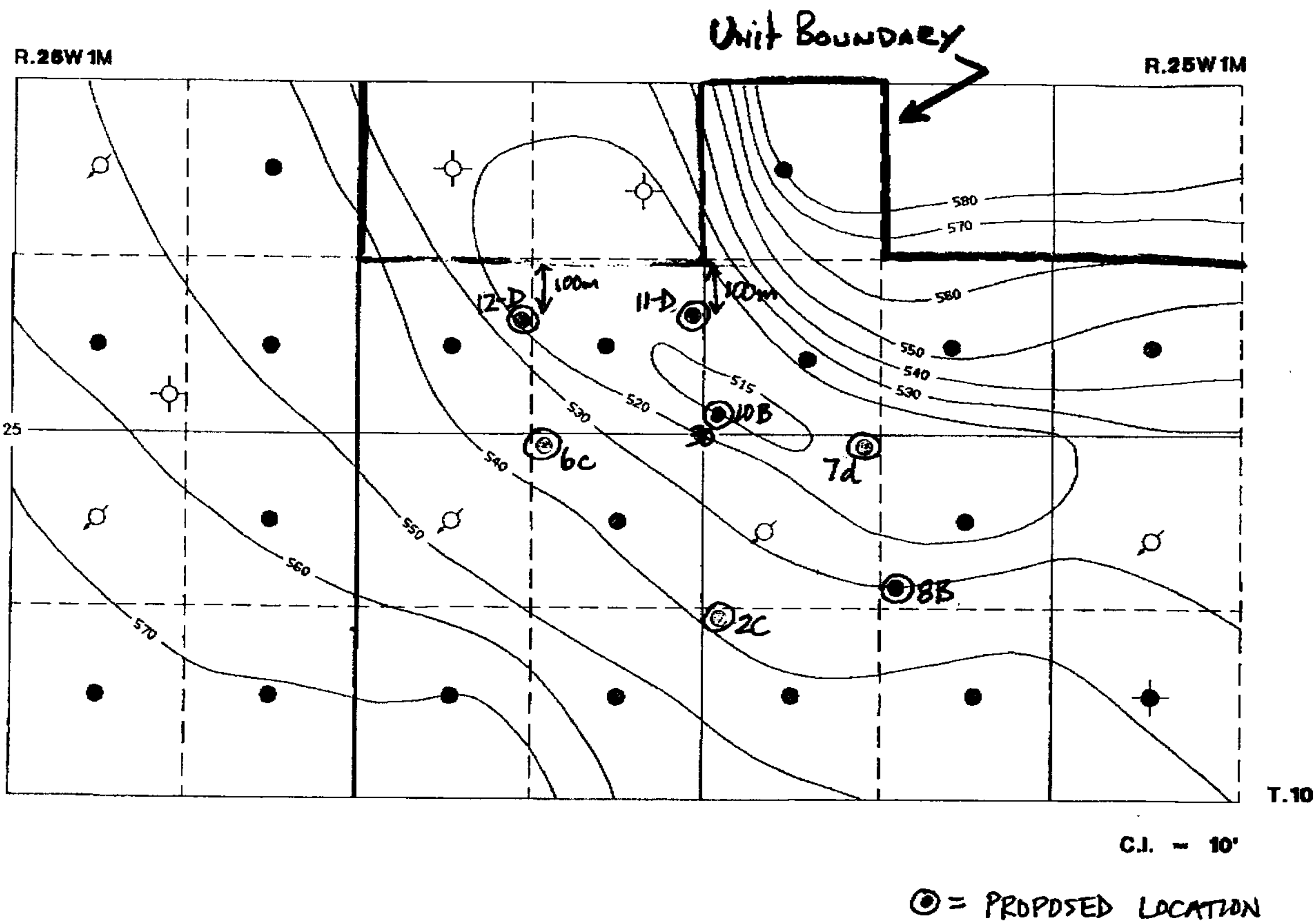
ATTACHED IS A MAP SHOWING EXISTING AND PROPOSED WELL LOCATIONS IN VIRDEN-ROSELEA UNIT NO. 1. ALSO ATTACHED ARE DIAGRAMS SHOWING THE PROPOSED COORDS OF THE INFILL WELLS. WE HOPE TO CONFIRM THAT ALL OF THE PROPOSED LOCATIONS WILL MEET WITH REDUCED SPACING REQUIREMENTS — OF COURSE, SURFACE CONDITIONS AND IMPACTS MAY ~~CAUSE~~ FORCE US TO MOVE SOME OF THESE LOCATIONS SLIGHTLY.

THESE WELLS HAVE BEEN RECOMMENDED TO CCR MANAGEMENT FOR APPROVAL. WE HOPE TO HAVE A FORMAL APPLICATION BEFORE THE P-BRANCH BY XMAS WITH DRILLING COMMENCING IN THE SPRING.

THANKS, Len Marchand
(403) 234-5046

P.S. ONE OTHER GENERAL QUESTION: UNDER NORMAL 40 ACRE SPACING, HOW FAR INSIDE THE TARGET AREA WOULD A WELL HAVE TO BE SPUDDED TO WAIVE DIRECTIONAL SURVEY REQUIREMENTS?

VIRDEN ROSELEA UNIT NO. 1



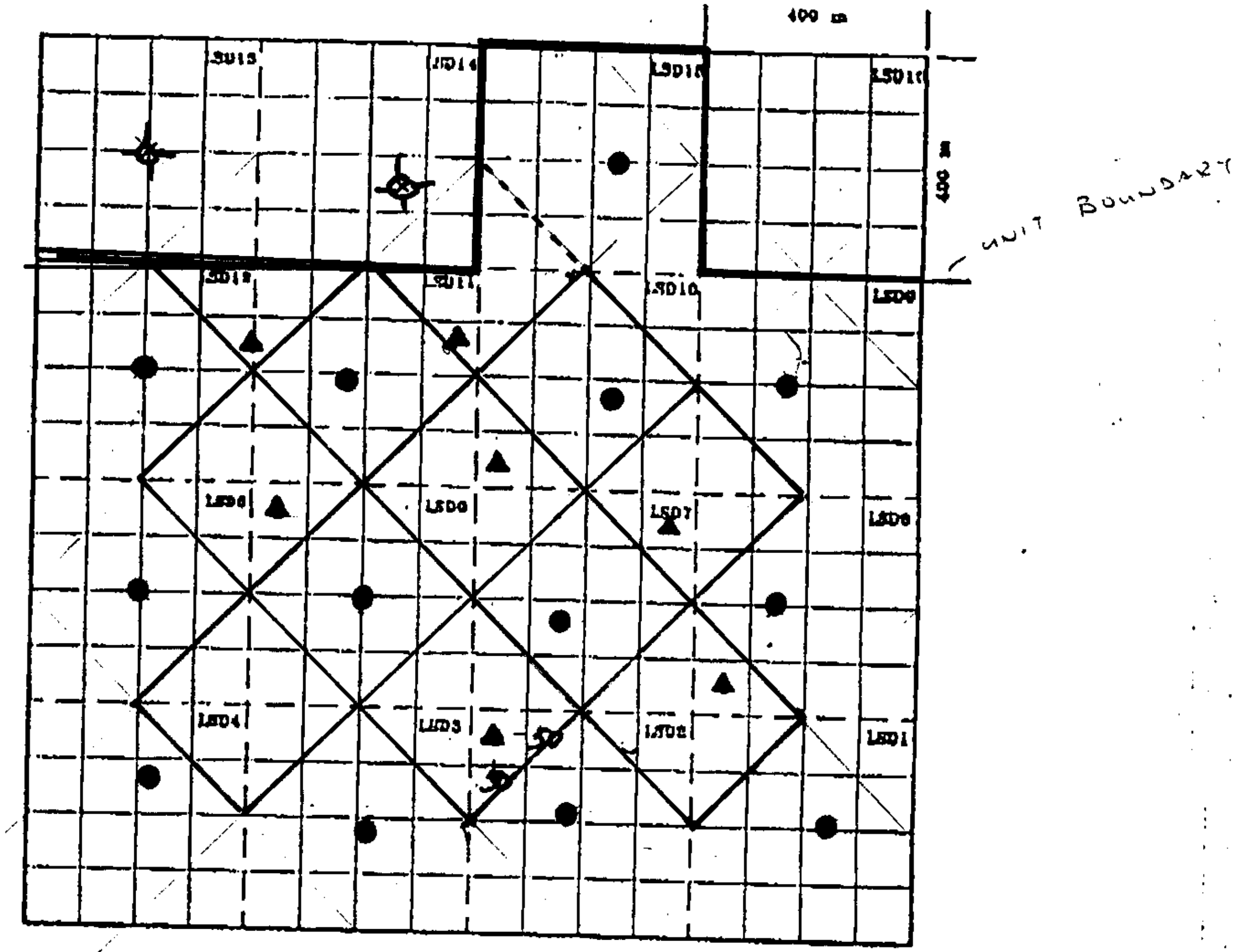
STRUCTURE ON TOP OF CHERTY
(FEET SUBSEA)

BOTTOM HOLE LOCATION FORM

Proposed Well Location NV Roselea Unit No 1 CROSSED FIELD

LSD 2C SEC. 30 TWP. 10 RGE. 25 W. OF 1 MER.

Mark on Gas Target and Oil Target



BOTTOM HOLE COORDS. 1250 metres South of North Boundary

750 metres West of East Boundary

Estimated Ground Elevation 436 metres

Estimated K.B. 439 metres

Estimated Total Depth 614 metres

Restrictions:

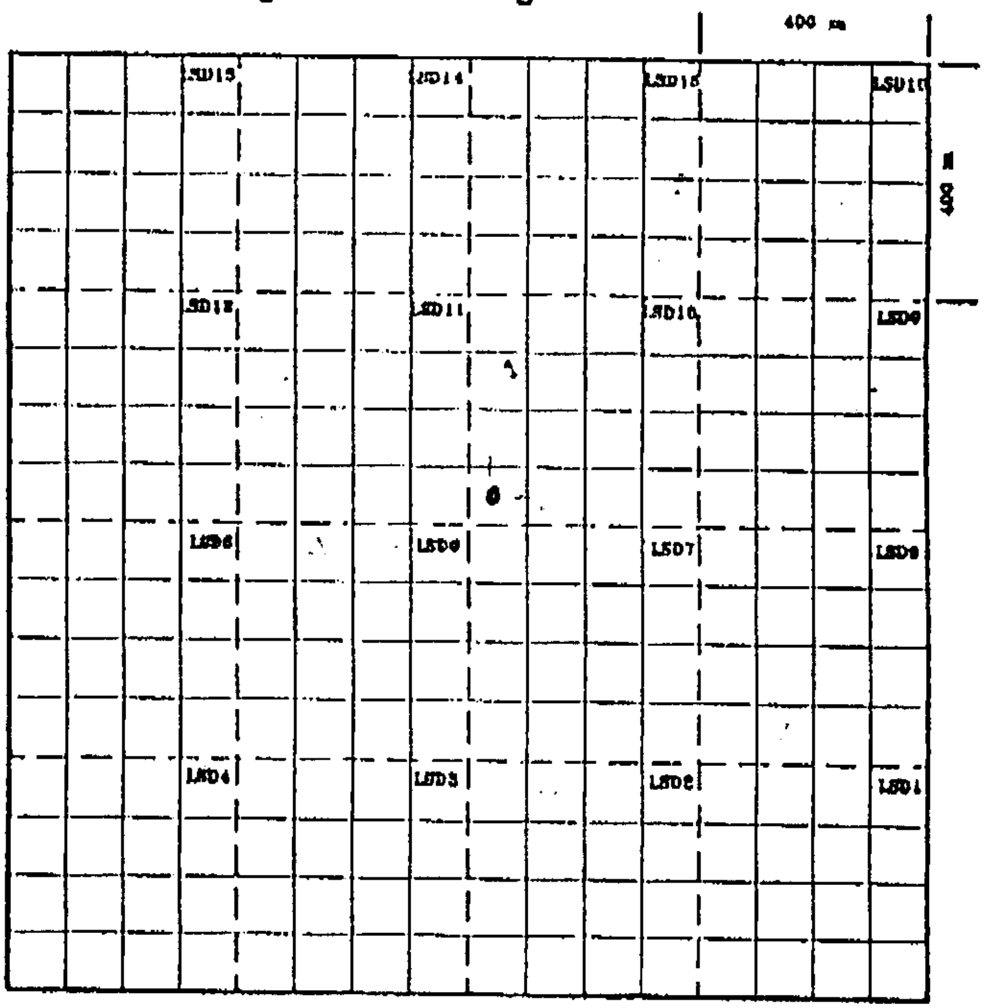
Chevron Canada Resources

BOTTOM HOLE LOCATION FORM

Proposed Well Location NV Roselea Unit 1 PASTURE

LSD 10B SEC. 30 TWP. 10 RGE. 25 W. OF 1 MER.

Mark on Gas Target and Oil Target



BOTTOM HOLE COORDS. 750 metres South of North Boundary
750 metres West of East Boundary

Estimated Ground Elevation 436 metres
Estimated K.B. 439 metres
Estimated Total Depth 616 metres

Restrictions:

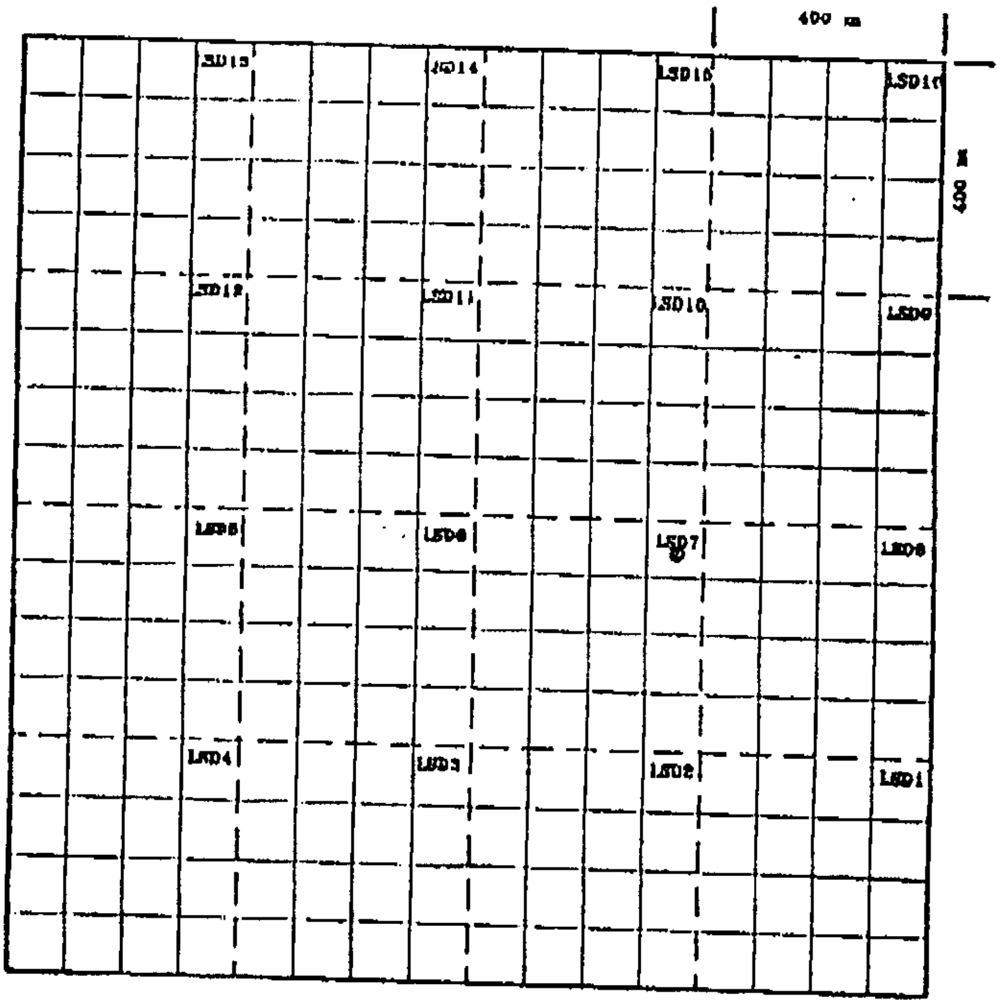
Chevron Canada Resources

BOTTOM HOLE LOCATION FORM

Proposed Well Location NV Roselea Unit 1
LSD 7d SEC. 30 TWP. 10 RGE. 25 W. OF 1 MER.

BRUSH HILL SIDE
DYKING + EROSION
CONTROL

Mark on Gas Target and Oil Target



BOTTOM HOLE COORDS. 850 metres South of North Boundary
450 metres West of East Boundary

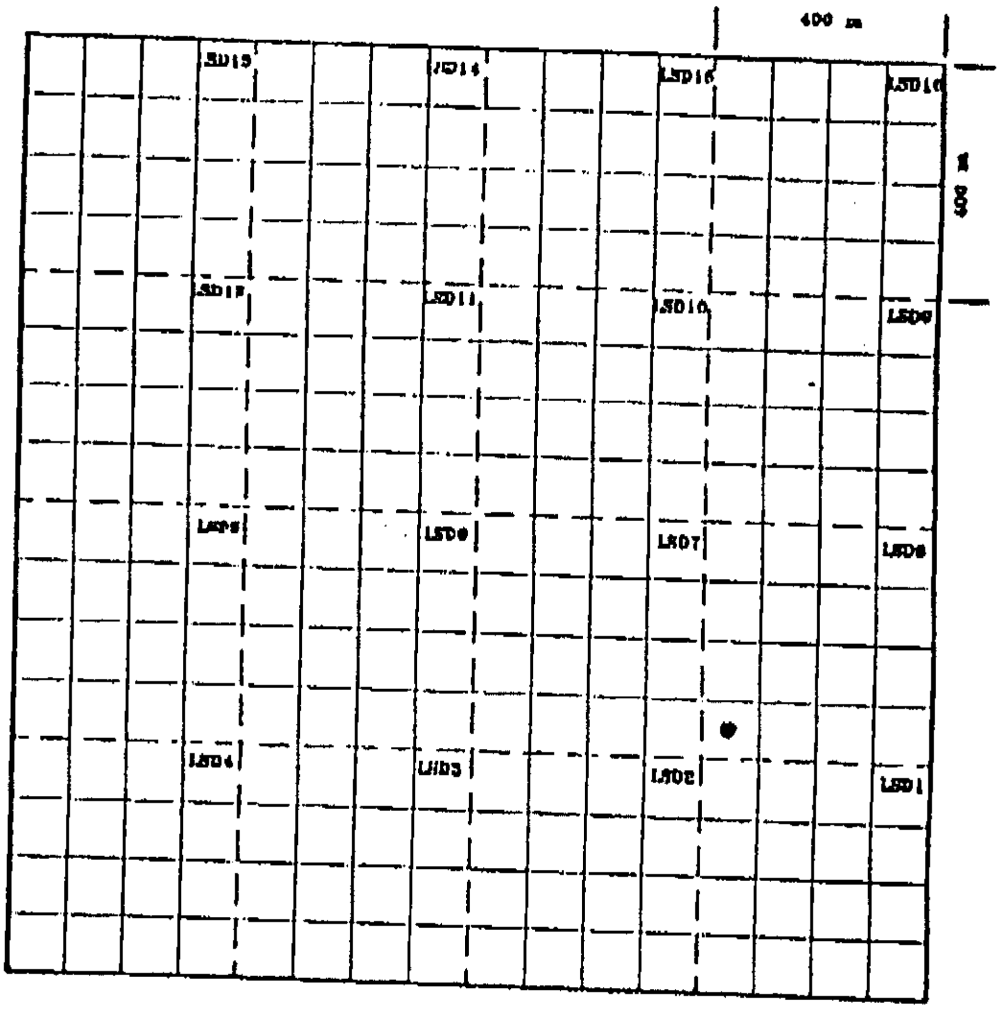
Estimated Ground Elevation 399 metres
Estimated K.B. 402 metres
Estimated Total Depth 590 metres

Restrictions:

Chevron Canada Resources

BOTTOM HOLE LOCATION FORM

Proposed Well Location NV Roselea Unit n=1
LSD 8b SEC. 30 TWP. 10 RGE. 25 W. OF 1 MER. See 7d-30
Mark on Gas Target and Oil Target



BOTTOM HOLE COORDS. 1150 metres South of North Boundary
350 metres West of East Boundary

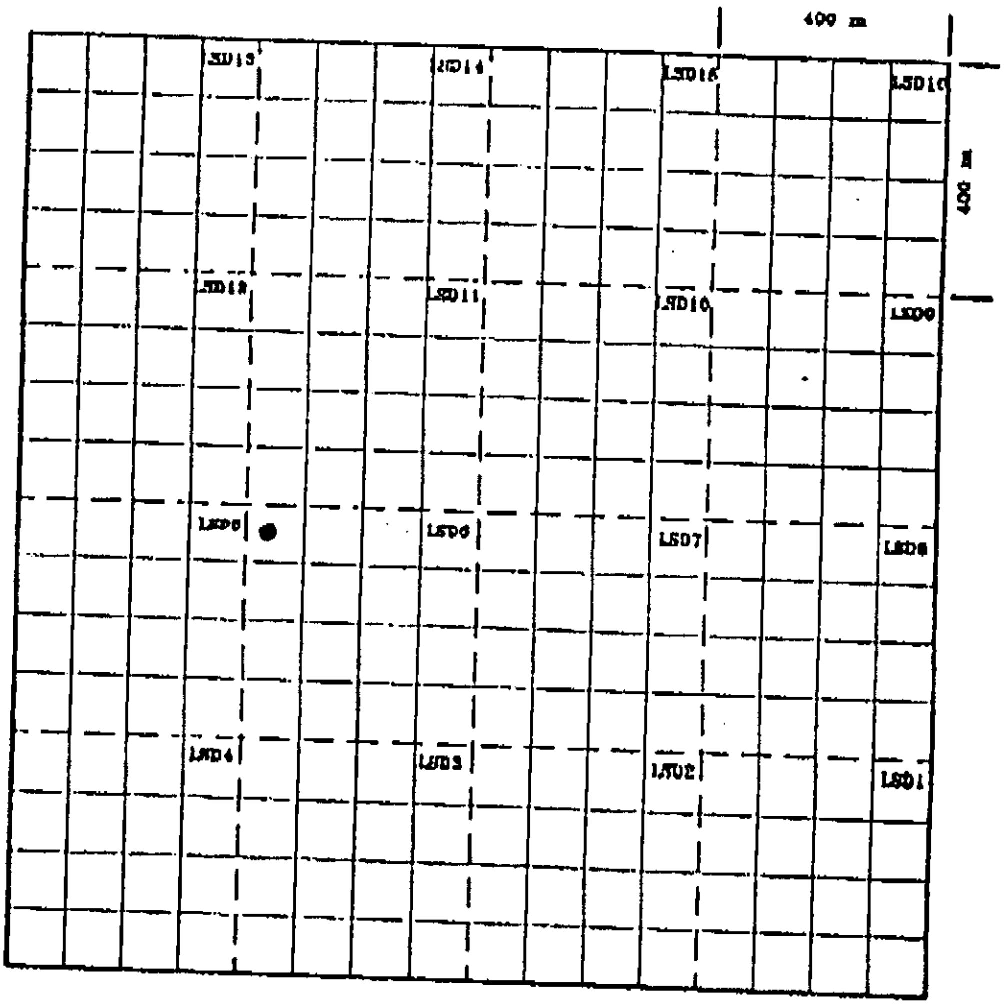
Estimated Ground Elevation 398 metres
Estimated K.B. 402 metres
Estimated Total Depth 580 metres

Restrictions:

Chevron Canada Resources

BOTTOM HOLE LOCATION FORM

Proposed Well Location NV Roselea Unit 1
LSD 6C SEC. 30 TWP. 10 RGE. 25 W. OF 1 MER.
Mark on Gas Target and Oil Target



BOTTOM HOLE COORDS. 850 metres South of North Boundary
1150 metres West of East Boundary

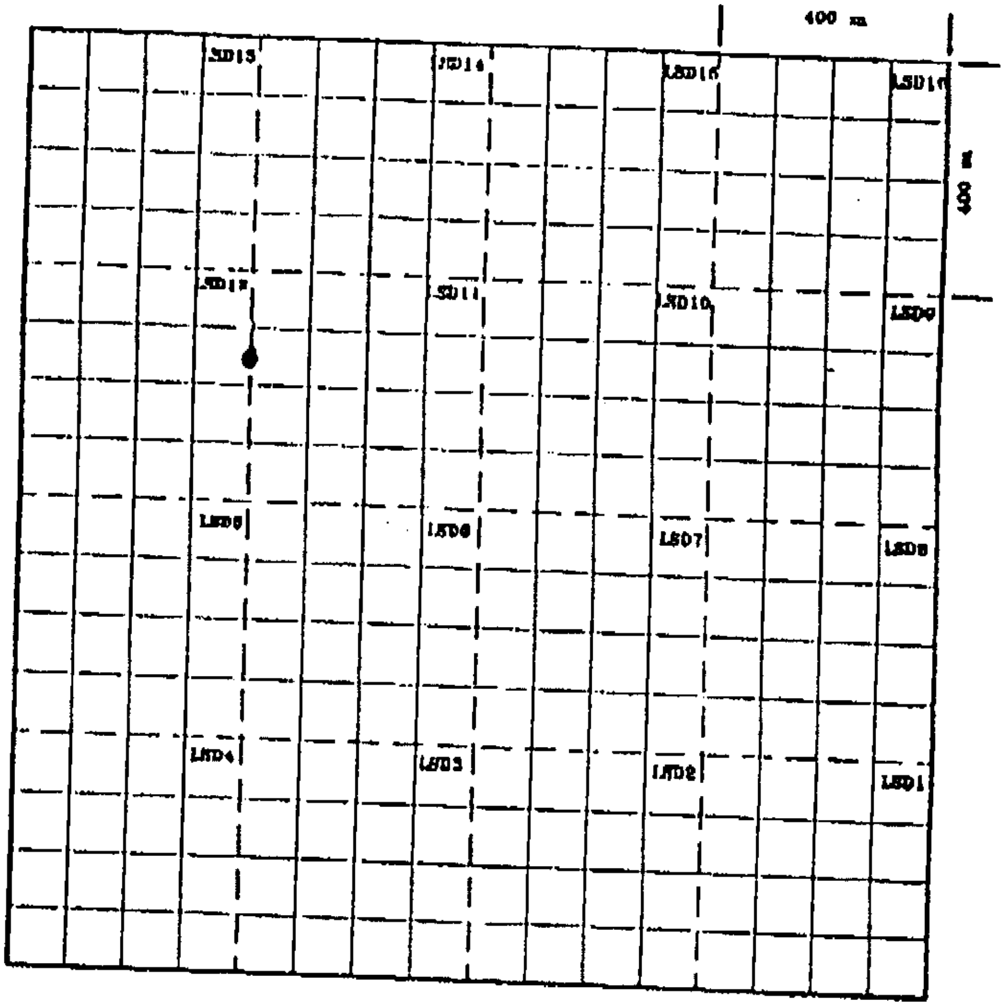
Estimated Ground Elevation 436 metres
Estimated K.B. 439 metres
Estimated Total Depth ______ metres

Restrictions:

Chevron Canada Resources

BOTTOM HOLE LOCATION FORM

Proposed Well Location NV Roselea Unit No 1
LSD 12D SEC. 30 TWP. 10 RGE. 25 W. OF 1 MER.
Mark on Gas Target and Oil Target



CROPPED FIELD

BOTTOM HOLE COORDS. 550 metres South of North Boundary
1200 metres West of East Boundary

Estimated Ground Elevation 428 metres
Estimated K.B. 430 metres
Estimated Total Depth 605 metres

Restrictions:

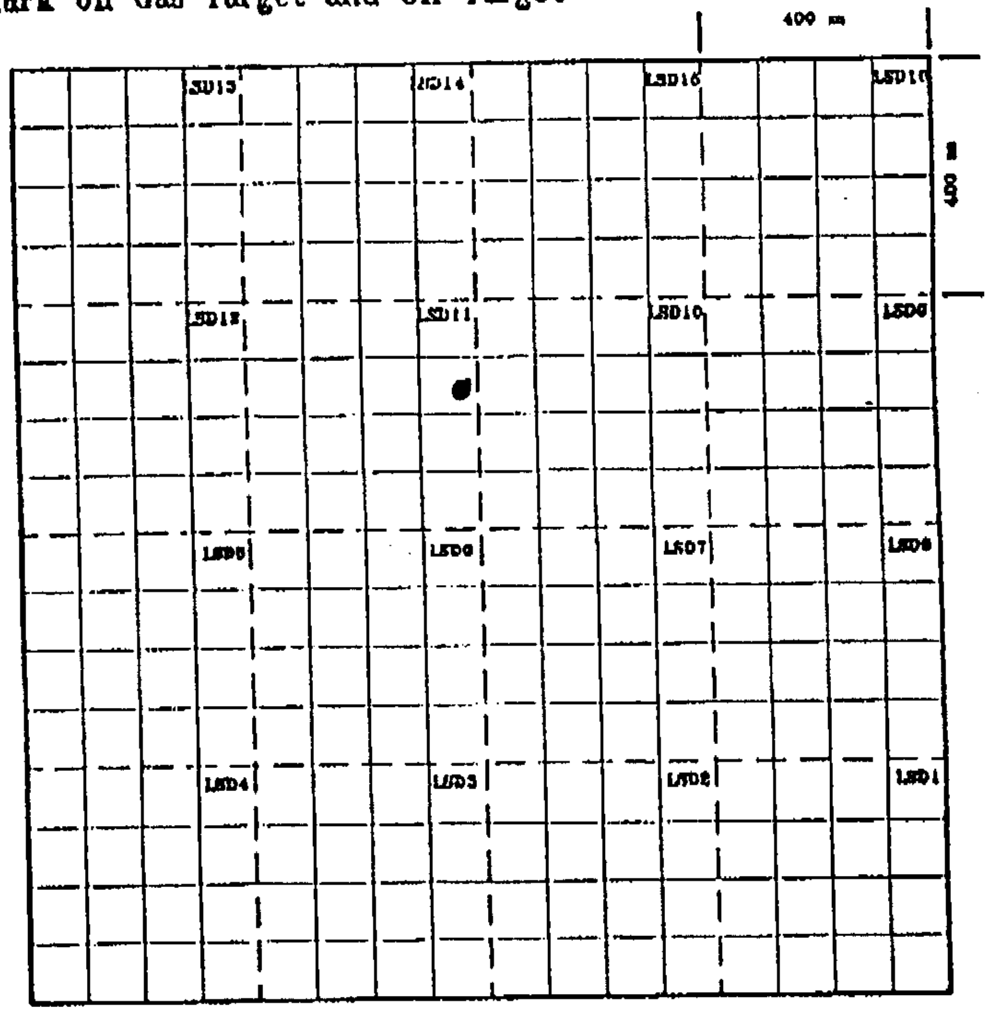
Chevron Canada Resources

BOTTOM HOLE LOCATION FORM

Proposed Well Location NV Roselea Unit 1

LSD 11d SEC. 30 TWP. 10 RGE. 25 W. OF 1 MER.

Mark on Gas Target and Oil Target



SMALL BUSH ON RIDGE IN PASTURE

BOTTOM HOLE COORDS. 550 metres South of North Boundary
800 metres West of East Boundary

Estimated Ground Elevation ________ metres
Estimated K.B. 430 metres
Estimated Total Depth 602 metres

Restrictions:

MEMORANDUM

TO ______ CC ______ DATE ______

FROM ______ FILE ______ ______ NUMBER PAGE ______ OF ______

SUBJECT ______ JOB

______ TAG

LEGEND

new injection flowline
(cement lined ferrous)

well conversion to water injection/disposal

new production flowline

intill well (new)

access roads

<u>Note</u>: all new flowlines / injection lines are to be tied in at existing headers.

Manitoba

Memorandum

Date March 22, 1990

To John N. Fox
Chief Petroleum Eng.
Petroleum Branch
555-330 Graham Ave.

From J.R.D. Partridge, Chief
Land Utilization Section
Manitoba Agriculture
908 - 401 York Ave.
Winnipeg, MB.

Subject Virden Roselea Unit #1 - Reduced Spacing Project

Telephone 945-3837

We have reviewed the proposed reduced spacing of oil wells on 30-10-25W and offer the following comments. We note that several of the existing wells are located off-centre to significant degrees, and that all seven of the proposed new wells are considerable distances off-target. This leads us to question the so-often-mentioned importance of drilling new wells as close as possible to the target locations. It appears there is much more latitude and flexibility in moving surface locations around to suit conditions than the text of the proposal admits to. Such being the case, it appears to us in Agriculture that where reduced spacing is to be implemented on cultivated lands that alignment of new wells with existing ones should be practiced as was done in the Waskada Unit #4 Pilot Project. Of course, in specific situations, where surface placements can be made in native or non-productive areas, alignment would not be as crucial.

In summary, we would request that the proposal be re-examined to determine if some alignments might be accomplished for this project.

Attach.

Dale Partridge

J.R.D. Partridge

cc. B.G. Todd
T.L. Pringle
W. Digby
A. Toews
J. Hollinger
S. Scrafield

First | Fold

PS I 25 894-01-00271

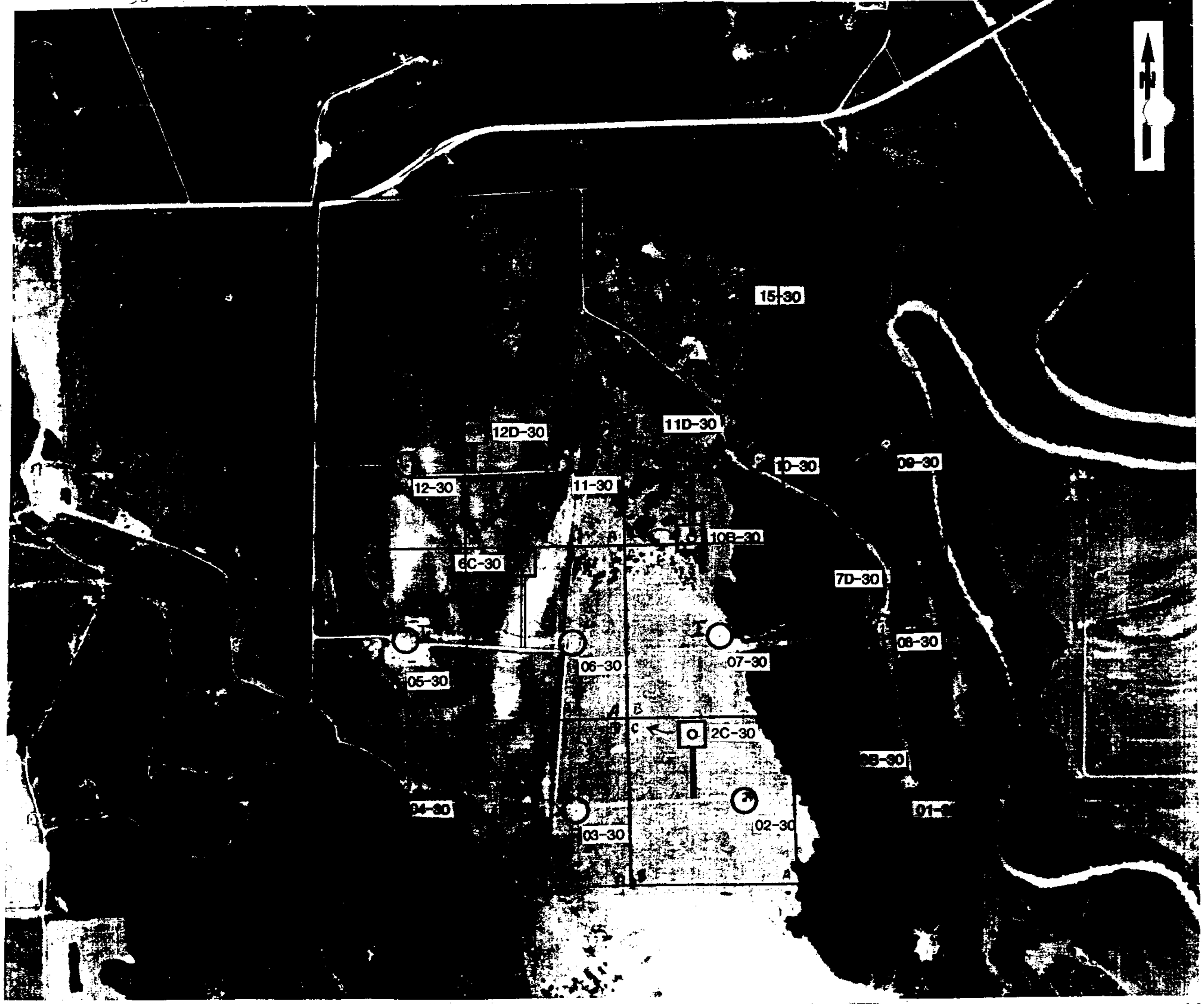


FIGURE 4

AERIAL PHOTOGRAPH
OF
REDUCED SPACING
PROJECT AREA

30-10-6 W.

KEY:

EXISTING WELLS

PROPOSED WELLS

PROPOSED LEASE TRAILS

SCALE
0 100 200 300 400 500
METRES

100 m
100 m

DRILLING LEASE SIZE
(TO SCALE)

Manitoba

Memorandum

Date	March 21, 1991		
To	John N. Fox Chief Petroleum Engineer Petroleum Branch 555-330 Graham Avenue	From	Floyd Phillips Chief, Terrestrial Quality Management Manitoba Environment
Subject	Virden Roselea Unit No. 1 Reduced Spacing Project	Telephone	945-7003

PETROLEUM BRANCH

The Terrestrial Quality Section of Manitoba Environment has concerns about the following potential impacts of this reduced spacing pilot project:

1. Erosion on the Assiniboine Valley Slope

   The air photo indicates that well locations 7D-30 and 8B-30 are on the slope of the Assiniboine River Valley. Concerns are for the disruption of the natural vegetation during well installation, and the subsequent increased potential for soil erosion once the vegetation is removed. Measures must be implimented to prevent erosion impacts. These will include, but are not limited to, minimizing the amount of vegetation which is removed, installation of a berm to divert runoff water around each site, installation of a berm on the downslope side of each site to prevent uncontrolled runoff, and revegetating each site as soon as possible after the well is completed. The berms would have to be contoured and vegetated to prevent their erosion.

2. Rare or Endangered Plants

   There is increased potential for the occurrence of rare or endangered plant species in undisturbed, naturally vegetated river valleys. A survey by a professional botanist is needed, to determine if rare or endangered plants are present at these proposed well locations or along proposed access trail routes. If any are present, well site or road locations should be adjusted to avoid disturbing them.

3. Potential Contamination of Soil, Groundwater and Assiniboine River with Drilling Fluids and Lubricating and Hydraulic Oils

   Spillage or careless disposal of drilling fluids as well as lubricating and hydraulic oils must be prevented at all sites, but especially at 7D-30 and 8B-30.

   Soil contamination could preclude the establishment of the vegetation cover needed for erosion control.

   Contaminants may also seep down through the soil and contaminate local shallow aquifers which may be present. In addition to the obvious potential effect on potable water, there could also be effects on surface water if a contaminated aquifer discharges (e.g. springs) directly into rivers, ponds or lakes.

First | Fold

3. cont

Contaminants could also be transported to the Assiniboine River by runoff. This is another reason for constructing a berm on the downslope side of each well site.

If reduced spacing proves to be viable and is expanded in the future, Manitoba Environment is concerned about the potential loss of agricultural land and natural habitat. We realize that it is really up to the land owner to decide whether economic benefits adequately compensate for the loss of productive land and the inconvenience of more obstructions in the fields. Nevertheless we would want the proponent to make every effort to avoid positioning wells in agricultural fields. The company should make every effort to minimize natural habitat losses by avoiding locations within natural bush or grassland habitat. Wells should be located at the edge of fields, preferably along property boundaries and fence lines or at the edge of natural grassland or bush areas. The high water zone of potholes or creeks should also be avoided to prevent the contamination of surface water by drilling fluids or in the event of accidental spills during operation of the well.

Thank you for giving us the opportunity of commenting on this proposal.

S. Floyd Phillips.

S. Floyd Phillips

P 4070401

Reference / Référence

Re: Notice/John Fox

Received by / Reçu par

AMD

Delivered by / Livré par · Date

D. Chartrand 91-03-18

To / À

Man. Energy and Mines
Petroleum Branch
555 - 330 Graham Ave
Winnipeg, Manitoba
R3C 4E3

Canada Post · Postes Canada

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2 Proof of Delivery · Avis de livraison

Manitoba

The Oil and Natural Gas
Conservation Board

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

(204) 945-3130

Certified Mail P407'914

March 14, 1991

Canada Trust Company
c/o Montreal Trust
411 - 8 Avenue S.W.
Calgary, Alberta
T2P 1E7

Dear Sir:

Re: Application for Reduced Spacing
<u>Virden Roselea Unit No. 1 - Chevron Canada Resources</u>

This letter is to notify you of an application by Chevron Canada Resources for reduced 8 ha drilling spacing units in a portion of Virden Roselea Unit No. 1 adjacent to lands in which you have a royalty or working interest.

For your information, a copy of the Board's notice is attached. The date listed in the notice for filing of an intervention has been extended to April 2, 1991.

Yours respectfully,

H. Clare Moster
Deputy Chairman

Attachment

P4070402

Reference

Notice/ ..m Fox

Received by / Reçu par

X

Delivered by / Livré par / Date

18/03/91

To / À

Man. Energy and Mines
Petroleum Branch
555 - 330 Graham Ave
Winnipeg, Manitoba
R3C 4E3

Canada Post / Postes Canada

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VIRDEN PM 18 III 91 MAN

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Manitoba

The Oil and Natural Gas
Conservation Board

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

(204) 945-3130

Certified Mail P407040 2

March 14, 1991

John Wesley Clarke
Box 999
Virden, Manitoba
ROM 2CO

Dear Mr. Clarke:

Re: Application for Reduced Spacing
<u>Virden Roselea Unit No. 1 - Chevron Canada Resources</u>

This letter is to notify you of an application by Chevron Canada Resources for reduced 8 ha drilling spacing units in a portion of Virden Roselea Unit No. 1 adjacent to lands in which you have a royalty or working interest.

For your information, a copy of the Board's notice is attached. The date listed in the notice for filing of an intervention has been extended to April 2, 1991.

Yours respectfully,

H. Clare Moster
Deputy Chairman

Attachment

P 4070404

Notice John Fox

Received by / Reçu par

W. Stevens

Delivered by / Livré par / Date

K.P Hamel March 18/91

To / A

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

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The Oil and Natural Gas
Conservation Board

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

(204) 945-3130

Certified Mail 4070404

March 14, 1991

Richard Henry Stevens
General Delivery
Fannystelle, Manitoba
ROG OPO

Dear Mr. Stevens:

Re: Application for Reduced Spacing
<u>Virden Roselea Unit No. 1 - Chevron Canada Resources</u>

This letter is to notify you of an application by Chevron Canada Resources for reduced 8 ha drilling spacing units in a portion of Virden Roselea Unit No. 1 adjacent to lands in which you have a royalty or working interest.

For your information, a copy of the Board's notice is attached. The date listed in the notice for filing of an intervention has been extended to April 2, 1991.

Yours respectfully,

H. C. Moster

H. Clare Moster
Deputy Chairman

Attachment

P 4070408

Reference Référence

Notice John Fox

Received by Reçu par

Anne Kal

CANADA
18 III
1991
R3C 0J0

To

Man. Energy and Mines
Petroleum Branch
555 - 330 Graham Ave
Winnipeg, Manitoba
R3C 4E3

POSTAL CODE
CODE POSTAL
Certified Mail
Poste certifiée

MAR 19 1991

531227

MAR 18 1991

WINNIPEG
MANITOBA

2 Proof of Delivery Avis de livraison

Manitoba

The Oil and Natural Gas
Conservation Board

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

(204) 945-3130

Certified Mail P46704 08

March 14, 1991

Saul Katz
158 Arrowwood Dr. S.
Winnipeg, Manitoba
R2V 2P1

Dear Mr. Katz:

Re: Application for Reduced Spacing
<u>Virden Roselea Unit No. 1 - Chevron Canada Resources</u>

This letter is to notify you of an application by Chevron Canada Resources for reduced 8 ha drilling spacing units in a portion of Virden Roselea Unit No. 1 adjacent to lands in which you have a royalty or working interest.

For your information, a copy of the Board's notice is attached. The date listed in the notice for filing of an intervention has been extended to April 2, 1991.

Yours respectfully,

H. Clare Moster
Deputy Chairman

Attachment

P 4070406

Reference Reference

Neeig John Fox

Received by Reçu par

[signature]

Delivered by Livré par Date

[signature] 91/03/19

CANADA 1991

POSTAL

Canada Post Postes Canada

Certified Mail Poste certifiée

DEPARTMENT OF ENERGY AND MINES

MAR 21 1991

PETROLEUM BRANCH

To A

Man. Energy and Mines
Petroleum Branch
555 - 330 Graham Ave
Winnipeg, Manitoba
R3C 4E3

2 Proof of Delivery Avis de livraison

Manitoba

The Oil and Natural Gas
Conservation Board

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

(204) 945-3130

Certified Mail P40 70 006

March 14, 1991

Alexander Garfield Sissons
General Delivery
Portage La Prairie, Manitoba
R1N 3A7

Dear Mr. Sissons:

Re: Application for Reduced Spacing
Virden Roselea Unit No. 1 - Chevron Canada Resources

This letter is to notify you of an application by Chevron Canada Resources for reduced 8 ha drilling spacing units in a portion of Virden Roselea Unit No. 1 adjacent to lands in which you have a royalty or working interest.

For your information, a copy of the Board's notice is attached. The date listed in the notice for filing of an intervention has been extended to April 2, 1991.

Yours respectfully,

H. Clare Moster

H. Clare Moster
Deputy Chairman

Attachment

P4070407

Reference Référence

Notice John Fox

Reçu par

Livré par Date

19-3-91

Man. Energy and Mines
Petroleum Branch
555 - 330 Graham Ave
Winnipeg, Manitoba
R3C 4E3

CANADA PM 19 III 1991

POSTAL CODE

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DEPARTMENT OF ENERGY AND MINES PETROLEUM BRANCH MAR 21 1991

2 Proof of Delivery Avis de livraison

Manitoba

The Oil and Natural Gas
Conservation Board

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

(204) 945-3130

Certified Mail P 4070407

March 14, 1991

Frank Osborne Meighen
110 - 11th Street
Brandon, Manitoba
R7A 5Y6

Dear Mr. Meighen:

Re: Application for Reduced Spacing
<u>Virden Roselea Unit No. 1 - Chevron Canada Resources</u>

This letter is to notify you of an application by Chevron Canada Resources for reduced 8 ha drilling spacing units in a portion of Virden Roselea Unit No. 1 adjacent to lands in which you have a royalty or working interest.

For your information, a copy of the Board's notice is attached. The date listed in the notice for filing of an intervention has been extended to April 2, 1991.

Yours respectfully,

H. Clare Moster
Deputy Chairman

Attachment

Manitoba

The Oil and Natural Gas
Conservation Board

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

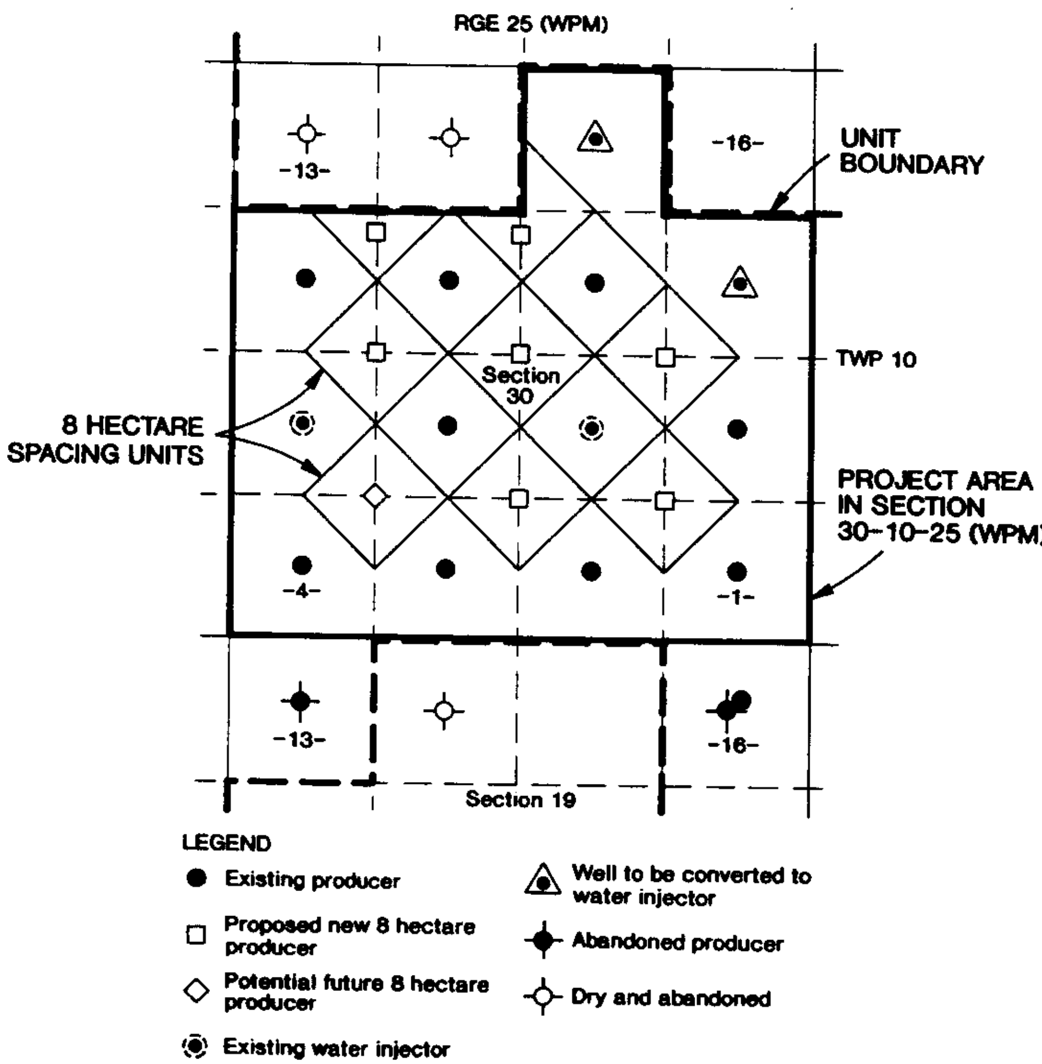
(204) 945-3130

NOTICE

UNDER THE MINES ACT

Chevron Canada Resources, Operator of Virden Roselea Unit No. 1 ("the unit area") has made application:

1. 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 (40 acres) to eight hectares (20 acres) in the project area outlined below. If the application is approved and the area is fully developed on eight hectare spacing, eight additional oil wells, located as indicated would be drilled.



2. Under Section 64 of the Petroleum Drilling and Production Regulation for approval to convert the following wells to water injection.

Placer Virden 9-30-10-25 (WPM)
Placer Virden 15-30-10-25 (WPM)

If no intervention in writing is received by the Board at Room 309, Legislative Building, Winnipeg, Manitoba, R3C OV8 on or before March 18, 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 OL7
(403) 234-5580

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

555-330 Graham Avenue Winnipeg, Manitoba (204) 945-6577	247 Wellington Street West Virden, Manitoba (204) 673-2472

Dated at Winnipeg, this 15th day of FEBRUARY, 1991.

H.C. Moster

H. Clare Moster
Deputy Chairman

Manitoba

Memorandum

DEPARTMENT OF ENERGY AND MINES
MAR 15 1991
PETROLEUM BRANCH

Date March 13, 1991

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

From T. Pearce
Planner
Municipal Planning Branch
112-340-9th Street
Brandon, Mb.

Telephone

Subject VIRDEN ROSELEA UNIT NO. 1 - REDUCED SPACING PROJECT

First | Fold

Based on the application regarding the above identified project and our Brandon Field Office review of this material with the R.M. of Woodworth Council and the local District Petroleum Engineer, our comments are as follows:

CONCERNS:

- The additional wells can not help but present a somewhat greater degree of risk for environmental damage and a reduction in agricultural use of the land.

RECOMMENDATIONS:

- The company locate the new wells on sites that, with proper development will minimize soil erosion and prevent groundwater and surface water (Assiniboine River) contamination.

- The company make an extra effort to inspect and keep each well site clean and the pumps in good maintenance order so that soil contamination is minimized.

- That the company undertake effective and prompt remedial actions should there be any spills.

- That the company use existing roads and flowlines where possible to service the new wells, and that as much land as possible be returned to agricultural production once the new wells have been developed.

- That the company make every effort to reach satisfactory lease arrangements with the landowners involved.

- That the company abide by the Provincial Pertoleum Regulations.

- That the company make available results of this Pilot Project to the Municipality and the Brandon Field Office of the Municipal Planning Branch.

Thank you very much for your attention.

T. Pearce

T. Pearce, Planner

TP/lm

cc: Serge Scrafield

Chevron

Chevron Canada Resources

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

Calgary, Alberta
March 7, 1991

Mr. H. Clare Moster
Deputy Chairman
Manitoba, The Oil and Natural Gas
Conservation Board
Room 309
Legislative Building
Winnipeg, Manitoba
R3C 0V8

Dear Sir:

Virden Roselea Unit No. 1
Application for Reduced Spacing

We are providing you with an additional 3 copies of the original application and 6 copies of our response to your letter dated February 15, 1991. In regards to your letter, we feel that many of the questions asked of Chevron were not warranted because either they did not deal with the type of information required under section 115 of the Petroleum Drilling and Production Regulations or required detail beyond that normally submitted in such an application. In fact, we feel that we went beyond the intent of section 115 in providing our analysis of the North Virden Scallion infill project.

If there are any additional questions, please contact Kelly Edwards (403) 234-5388 or Richard Forest at (403) 234-5397 in our Calgary Office, or Lyle Martinson at (204) 748-1334 in our Virden office.

Yours very truly,

T. Forest

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

RCF/slw

Virden Roselea Unit No.1
Application for Reduced Spacing
Additional Information

To the best of our knowledge, the names and addresses of the royalty owners in LSD's. 13, 14 and 16 of section 30 are:

LSD's 13 & 14

- Canada Trust Company
  c/o Montreal Trust
  411 - 8 Avenue S.W.
  Calgary, Alberta
  T2P 1E7

- John Wesley Clarke
  Box 999
  Virden, Manitoba

- Saul Katz
  Winnipeg, Manitoba

LSD 16

- Canada Trust Company
  c/o Montreal Trust
  411 - 8 Avenue S.W.
  Calgary, Alberta
  T2P 1E7

- Richard Henry Stevens
  Fannystelle, Manitoba

- Alexander Garfield Sissons
  Portage LaPrairie, Manitoba

- Frank Osborne Meighen
  c/o 119 - 9 Street
  Brandon, Manitoba

To the best of our knowledge, the working interest owner of LSD's 13, 14, and 16 is Placer CEGO (Amerada Hess). They are also Unit participants.

Geological Information

(1) **In the cross-section, what do the numbers posted for each well on the map in the upper right-hand corner represent?**

The upper right-hand corner numbers represent the daily oil rate averaged over the life of the well.

(2) **The φh and Kh maps for the 1st, 2nd and 3rd Oolite have identical numerical values for all wells except 15-30. Is this correct?**

The φh and Kh maps were constructed by multiplying the pay thickness by the average weighted porosity and permeability determined by <u>all</u> core analyses.

The average weighted porosity of the 1st, 2nd, and 3rd Oolite for section 30 is 12%. The average weighted permeability of the same zone for section 30 is 12 mD. Therefore, by multiplying the net pay by the porosity value, it will give the same result as multiplying the net pay by the permeability value.

(3) **Are the φh maps based on core data or a combination of core and log data?**

The φh maps are constructed using a combination of core and log data.

(4) **What porosity, permeability and water saturation cut-offs have been used to determine the φh and Kh maps for each member?**

The cut-offs are as follows:

SW	=	50%
φ	=	7%
K	=	1 mD

N.B. for the wells that Td'ed above the oil-water interface, the Δh was determined by subtracting the cherty structure from the assumed oil/water interface.

(5) **The φh maps for the various members indicate there is no net pay in the dry holes at 13-30 and 14-30. Explain the reasons for the sudden loss in reservoir quality at these locations.**

The reservoir has no porosity and permeability due to `deep' dolomitization caused by fresh water percolation during the "Flossie Time" erosion.

Attachment 4 - Technical Justification

(6) **The current recovery from the unit and project area is 27.3% OOIP and 21.9% OOIP, respectively. Why is the current recovery in the project area so much lower than the current unit recovery? What is the estimated ultimate recovery from the unit and project area with and without infill drilling? What abandonment conditions are assumed and on what parameters are the conditions based?**

The recovery factor is calculated as follows:

$$RF = \frac{\text{Cum. Production}}{\text{OOIP}}$$

The OOIP for section 30 is high due to a structural dome which provides additional reservoir storage and a thicker oil leg in the Cherty beds. This dome is not present elsewhere in the Unit (see structural cross-section, Alta. chart 3 in attachment No.3). Also, wells located on the apex of the structure are not completed in the Cherty, which is the best reservoir.

Ultimate recoveries can be calculated from information supplied in Attachment 4. A time limit of 30 years was imposed on the forecasts.

(7) **Please provide a list or a map showing current completion intervals and zones for all existing wells in the project area.**

T.D.	CASING SHOE DEPTH	PRODUCTIVE ZONE (Yes/No)							PERF DEPTH
		C	S	1	2	3	4	C	
1-30 3′ in cherty	below 3rd Oolite	N	N	N	N	N	N	Y	Open hole
2-30 25′ in cherty	4 Oolite	N	N	Y	Y	Y	Y	Y	Open hole
3-30 33′ in cherty	below Cr.	N	Y	Y	Y	Y	Y	Y	Open hole
4-30 18′ in cherty	below Crinoidal	N	Y	Y	Y	Y	Y	Y	Open hole
5-30 T.D. above cherty	below Crinoidal	N	Y	Y	Y	Y	Y	Y	Open hole
6-30 T.D. above cherty	below Crinoidal	N	Y	Y	Y	Y	Y	Y	Open hole
7-30 4′ in cherty	above Crinoidal	Y	Y	Y	Y	Y	Y	Y	Open hole
8-30 36′ in cherty	below Sandhill	N	N	Y	Y	Y	Y	Y	Open hole
9-30 20′ in cherty	below 3rd	N	N	Y	Y	Y	Y	Y	Open hole
10-30 |6′ in cherty	above cherty	N	N	Y	Y	Y	Y	Y	Open hole
11-30 5′ in cherty	below Crinoidal	N	Y	Y	Y	Y	Y	Y	Open hole
12-30 40′ in cherty	below Crinoidal	N	N	Y	Y	Y	Y	Y	Open hole
15-30 4′ in cherty	below Crinoidal	N	N	Y	Y	Y	Y	N	Open hole

(8) Were the water saturation values determined from log analysis or special core studies or a combination of both?

The water saturation were estimated using log analyses only.

(9) Please provide a list of individual well OOIP by zone in the project area.

OOIP BY ZONE
in Bbls

current recovery

CRINOIDAL		SANDHILL	1ST	2ND	3RD	4TH	CHERTY
1-30	dolomitized	460,000	40,726	40,784	76,841	39,898	514,000
2-30	dolomitized	dolomitized	77,225	47,789	86,062	57,190	533,000
3-30	227,568	631,000	47,641	28,963	86,890	0	323,000
4-30	390,116	344,000	47,641	33,691	107,580	0	0
5-30	189,000	287,000	77,225	43,444	112,542	66,497	495,000
6-30	186,783	460,000	44,567	52,015	80,683	58,517	628,000
7-30	0	344,000	114,760	44,600	44,600	114,000	780,000
8-30	0	460,000	0	0	0	132,403	970,000
9-30	0	0	0	0	57,098	11,112	285,000
10-30	0	0	0	0	115,852	33,337	894,000
11-30	244,700	258,000	99,893	57,926	53,788	62,773	1,028,000
12-30	251,625	230,000	53,483	43,444	107,577	45,750	609,000
15-30	231,700	344,000	44,500	28,900	114,900	0	0

18
38
7,059,000

(10) Is the net pay map (Figure 2) a summation of the net pay in all members?

Yes.

(11) What is the source, cause and estimated volume of oil migration into the project area?

604.1×10³ m³

Undrained Cherty in LSD's 5, 6, 7, 10 & 11 estimated at 3.8 MM Bbls OOIP.

all ... wells
Δ recovery 87.3×10³ m³
= 6.9% of Cherty OOIP of ...

(12) Why is the 4D-30 location not included in the list of proposed infill wells for the reduced spacing project? Does Chevron plan to drill this location in the future?

A well at this location is structurally low, downdip, and at proximity to a water injector. The structure on top of the Cherty is −560 feet subsea, therefore no or very little Cherty pay is expected at this location. Depending on the results of the infill program, this location could be considered as part of a different infill project at a later date.

(13) In the application, Chevron gives a zonal breakdown of OOIP and indicates that production within the project area has been mainly from the Sandhill and Cherty Members with some additional production from the Oolites. Has Chevron tried to determine zonal oil production and current zonal recoveries? Will Chevron be evaluating inflow from individual zones in the infill wells, by selective swabbing or other means, to assist in waterflood evaluation and optimization?

Chevron has not tried to determine zonal oil production and current zonal recoveries. Chevron may evaluate inflow from individual zones in the infill wells to assist in waterflood optimization as determined on a well-by-well basis.

(14) List the six wells in the project area that have penetrated the Cherty Member. Is the deepening of existing producing wells an option for recovering undrained Cherty reserves? What percentage of the estimated incremental recovery of 3.2% OOIP is associated with production of undrained Cherty reserves?

02-30	T.D.'ed 25′ in cherty
03-30	T.D.'ed 33′ in cherty
04-30	T.D.'ed 18′ in cherty
08-30	T.D.'ed 36′ in cherty
09-30	T.D.'ed 20′ in cherty
12-30	T.D.'ed 40′ in cherty

After drilling the infill wells and reviewing the data, Chevron will consider deepening some of the existing wells. The 3.2% OOIP incremental recovery is associated with <u>all</u> of the undrained cherty reserves. ?

(15) According to the application, there has been no production from the Crinoidal Member, which contains 10% of the OOIP in the project area. Does Chevron plan to complete the Crinoidal Member in the infill wells and if so, what is the estimated contribution of Crinoidal production to the total incremental recovery?

Yes, Chevron plans to complete the Crinoidal Member in the infill wells. The Crinoidal member has yet to be proved productive. Therefore, Crinoidal reserves were not included in the total incremental recovery.

upside potential

(16) According to the application, all water injection in the project area is into the Sandhill and Oolites Members. What degree of pressure support has the Cherty Member received from the injectors adjacent to the project area and has the Cherty Member within the project area been effectively waterflooded? If not, how will the proposed injector conversions improve the effectiveness of waterflooding the Cherty? Which zones will the proposed injectors be completed in? Will Chevron be deepening either of the existing injectors in the project area into the Cherty?

The 05-25 well is the closest water injector well outside the infill area. The well was drilled to a depth of 2057 feet subsea. The well T.D.'ed above the Cherty and casing was landed at a depth of 2005 feet, just above the Sandhill. Therefore, the Sandhill and the Oolites are effectively waterflooded, but not the Cherty zone.

The two proposed injection wells 9-30 and 15-30 are located on the flank of the structure. Water injection from these wells is likely to displace the oil towards the apex of the structure where the oil can be produced. Water injection on the apex of the structure could prematurely increase the WOR in downdip wells. The existing water injector will not be deepened into the Cherty.

(17) Has Chevron run any injection profile logs to evaluate the vertical distribution of injected fluids in the project area? Can incremental recovery in the project area be increased economically, by controlling/modifying zonal injection rates?

No injection profile logs have been run. All wells are open hole and modifying zonal injection rates could be a problem.

(18) Chevron noted that if injection at 9-30 and 15-30 could not meet the increased voidage from the infill wells, an additional injector conversion may be necessary. Which well(s) is Chevron considering converting?

Another well located on the flank of the structure like 04-30 or 12-30 could be considered as an additional water injector.

(19) It is apparent from the infill well production forecast (Figure 7) that there is a significant acceleration component. Please provide a plot of daily production versus time for the incremental production and acceleration components of the infill production forecast.

Separate incremental and accelerated forecasts were not developed.

Attachment 5 - Analysis of Reduced Spacing
North Virden Scallion Unit No.1 (NVSU No.1)

(20) Explain the reasons for the difference in estimated (7.6% OOIP) and actual (1.7% OOIP) incremental recovery for the NVSU No.1 reduced spacing project and the estimated incremental recovery (3.2% OOIP) for the VRU No.1 reduced spacing project.

The estimated 7.6% OOIP incremental reserves forecasted for the NVSU No.1 infill program was determined after analyzing the results of the "corridor" infill drilling. The incremental recovery as a result of infill drilling in the "corridor" area was estimated at 6.1% OOIP based on decline analysis.

The 7.6% OOIP incremental reserves factor was overly optimistic for NVSU #1 infill program. The corridor infill wells were drilled on a dome structure centered on section 27 & 28-11-26W1. The NVSU #1 infill wells were drilled in structural lows resulting in a 1.7% OOIP incremental reserves.

The 3.2% OOIP incremental reserves for the VRU No.1 area is established as follows:

5-30	Cherty reserves OOIP	=	495,000	
6-30		=	628,000	
7-30		=	780,000	
10-30		=	894,000	
11-30		=	1,028,000	
	TOTAL	=	3,825,000 bbls	
Rec @ 15%	3,825,000 bbls	=	574,000 bbls	(91256 m³)

or 3.2% of OOIP

N.B. The other 15% of Cherty reserves might have been produced from existing wells.

(21) Should Point 3 on page 5 be prefaced with "avoid"?

Yes

(22) Chevron estimated reservoir continuity in the NVSU No.1 reduced spacing project to be 82% on 16 ha spacing. Post-drilling project analysis indicated the project area had been depleted/swept by existing producers/injectors and the Oolite and Cherty Members were more laterally continuous than predicted. What is the revised estimate of reservoir continuity on 8 ha and 16 ha spacing in the NVSU No.1 reduced spacing project? Are these numbers applicable to the VRU No.1 reduced spacing project? Is there a concern that good lateral continuity will have a detrimental impact on incremental recovery in the VRU No.1 reduced spacing project as was the case in the NVSU No.1 reducing spacing project?

Reservoir continuity was determined for the Scallion infill area using the following equation:

Continuity = $\frac{\text{Pay thickness (above cut-offs)}}{\text{Total thickness (above \& below cut-offs)}}$

Gross Pay

This equation should not be used to determine reservoir continuity because it is not a measure of lateral continuity. Therefore, a quantitative estimation of reservoir continuity can not be determined for NVSU #1 or VRU #1. The reservoir continuity at VRU # 1 is probably similar to NVSU #1. ✓

Lateral continuity is good but vertical permeability/continuity is very low, therefore, incremental recovery from the Cherty is likely to be high, whereas incremental recovery in higher members (Sandhill to Oolites) is likely to be low. ✓

(23) **Chevron indicated the high cumulative production at 7-26-11-26 and depleted a significant portion of the NVSU #1 reduced spacing project area, resulting in the poor performance of the offsetting infill wells. A similar argument could be made for the 6-30 and 10-30 wells in the VRU No.1 reduced spacing project area. Does Chevron have any concerns that these wells may have drained a disproportionate share of the reservoir?**

07-26-11-26W1 (40′ cherty pay only) structurally highest well in area.

Rec = $\frac{\text{Cum. oil}}{\text{OOIP}}$ = $\frac{1{,}048{,}000 \text{ bbls} \times 100}{777{,}000 \text{ bbls}}$ = 140%

Rates 37 BOPD, WOR = 2.4

06-30-10-25W1 OOIP = 1,303,940 bbls

Rec = $\frac{\text{Cum. oil}}{\text{* OOIP}}$ = $\frac{679{,}890 \text{ bbls} \times 100}{1{,}324{,}000 \text{ bbls}}$ = 51% excluding Cherty 98 %

Rates 25 BOPD, WOR = 6

* including Cherty pay

10-30-10-25W1 OOIP = $\underline{55 \cdot 40 \cdot 7758 \cdot .13 \cdot .50}$ = 1,027,000 bbls must be significant Cherty recovery from 10-30

Cum. oil / * OOIP = $\frac{660{,}060 \text{ bbls} \times 100}{1{,}043{,}200 \text{ bbls}}$ = 63%

Rates 45 BOPD, WOR = 0.43

Oolite recovery 42 %

* including Cherty pay

The above calculations demonstrate the difference between the 07-26 Scallion recovery and the Roselea 06-30 and 10-30 recoveries.

The 07-26 well has produced 140% of OOIP whereas 06-30 and 10-30 wells have produced 60% of OOIP. The higher-than-usual recovery at 06-30 and 10-30 is due to enhance sweep efficiency created by the 05 & 07-30 water injectors.

The 07-26 well has obviously drained more than 40 acres. The 06 and 10-30 have also drained more than 40 acres, but only in the Sandhill and Oolites. The oil might have migrated from the Sandhill and Oolite Members at 05 & 07-30.

The OOIP for spacing 05 & 07-30 are:

05-30 OOIP = 586,700 bbls (exc. Cherty OOIP)

07-30 OOIP = 661,900 bbls (exc. Cherty OOIP)

TOTAL = 1,248,600 bbls (exc. Cherty OOIP)

A portion of this oil has probably been produced from the existing wells due to the sweep created by the 07-30 & 5-30 water injector. However, a portion of the Cherty oil has not been swept due to the 05-30 & 7-30 completion above the Cherty zone. The undrained Cherty oil reserves for lsd's 05 & 07-30 are 1,275,000 bbls.

$$05\text{-}30 \text{ Cherty OOIP} = \frac{26 \cdot 40 \cdot 7758 \cdot .13 \cdot .5}{1.06} = 495{,}000 \text{ bbls}$$

$$07\text{-}30 \text{ Cherty OOIP} = \frac{41 \cdot 40 \cdot 7758 \cdot .13 \cdot .5}{1.06} = \underline{766{,}000} \text{ bbls}$$

Depletion effects from 6-30 and 10-30 are of some concern to Chevron, although they are not likely to be as severe as those caused by 7-26. This is one of the reasons for doing a pilot project.

Attachment 7 - Benefits to Crown and Lessors

(24) **Please provide the information shown in the three graphs in Attachment 7 in tabular form.**

Attached.

(25) **Has Chevron contacted working interest owners in VRU No.1 with respect to the special treatment of royalties and taxes that will be necessary if the project is approved?**

Only with two partners (Suncor and Amerada Hess) who had requested the information CCR intent to provide the information to all partners as soon as the reduce spacing application is approved.

(26) **Please provide a topographic map of the project area showing the well locations, access roads and flowline and injection line routes.**

A topographic map has not been provided. As discussed in a telephone conversation between Mr. John Fox and Mr. John Fulton on March 4, 1991, the only available topographic map has a scale of 1:50000. This scale is much too small to provide any useful elevation information relative to the proposed well locations or road and pipeline routings.

(27) **Please provide an outline on the aerial photograph of agricultural land use (i.e. cultivated and pasture) and areas with little topsoil.**

The area where the infill is occurring is on marginal land for agricultural purposes. The whole area has little topsoil especially the areas on the side of the hill. See attached map for agricultural land use.

(28) **In the aerial photograph there is evidence of a network of trails running north and northeast from 6-30. Does Chevron use these trails to access the existing wells?**

The trails running north and northeast from 6-30 are no longer used.

(29) **The access road to 11D-30 as shown on the aerial photograph is through a forested area. Would it be feasible to access 11D-30 from the south, off the access road to 10B-30 and thereby avoid destruction of trees which would result from the proposed access?**

Yes, instead of accessing 11-D-30 from the north it could be accessed from the east off the existing road to 10B-30. See attached map.

(30) **Please provide a summary of potable groundwater resources in the project area including the location of all potable water supply wells and dugouts.**

There appears to be only one dugout in the infill area which is filled by runoff in the spring only. It dries up in the summer and the cattle get there water from the river. There are no water wells in the infill area. See attached map.

(31) **Will electrical power be run underground to the infill wells?**

Electrical power will be run underground to areas that are cultivated. In pasture areas, overhead power lines will be used. This area is extremely rocky and it is difficult to bury power lines.

(32) **What lease construction precaution will be taken to minimize erosional concerns at the 7D-30 and 8B-30 locations on the slope of the river valley and what measures will be taken to confine drilling and produced fluids to the wellsite? Is there any merit in directionally drilling these wells?**

Firstly, directional drilling was not reviewed in detail because it negatively affects the economics. To minimize erosion at these leases, the following will be observed:

1. minimum amount of disturbance of lease site and road
2. clear minimum amount of bush
3. restore and seed lease
4. attempt to detour water around lease area
5. continue to monitor and take further action as required

(33) **Where in the project area does Chevron plan to use fibreglass pipe and where will steel pipe be used? What is the reason for using the different materials?**

Fiberglass pipe is used for its corrosion resistance which reduces inhibitor cost. Steel pipe is used for its durability in rock areas. Because we are confident in our inhibition protection and cathodic protection programs, we propose to use steel pipe mainly in the infill area because of the rocks. Fiberglass pipe requires proper sand padding and rock shielding making steel pipe more economical and easier to install. Fiberglass pipe will be used only where practical.

(34) It is recognized that Chevron has in place preventative measures to help reduce flowline leaks and closely monitors its flowlines to ensure a leak is detected as quickly as possible. However, what spill reduction equipment such as check valves and pressure shutdowns does Chevron plan for the high volume flowlines in the project area to minimize spill volumes in the event of a flowline failure?

There are high pressure shutdown valves at all well sites and all new flowlines will have check valves installed at the headers.

Attachment 13 - Drilling Program

(35) Does Chevron plan to shut-in the water injectors in and surrounding the project area before and during the drilling of the infill wells?

The Chevron drilling plan is designed to handle the present reservoir pressure. We do not anticipate having any problems; therefore, our intention is not to shut in injection wells because production would have to be suspended because of a lack of water handling capacity. However, we will be in close contact with the drilling group and if needed, water injection could be stopped.

(36) What is the additional cost, if any, to drill the infill wells using lease tanks instead of drilling pits? Are there any other concerns with the use of lease tanks?

The additional cost to drill infill wells using lease tanks instead of drilling pits would be $12,000.

(37) Historically, wells drilled on the Assiniboine Valley floor have encountered water flows in the Swan River and other aquifers due to lower ground elevation. What contingency measures does Chevron propose to address this potential problem for he 7D-30 and the 8B-30 locations which are close to the valley floor?

Offsets to the proposed 7D-30 and 8B-30 locations include three wells drilled in 1955/56; 9-30-10-25, 8-30-10-25 and 1-30-10-25. All three wells were drilled in the Assiniboine Valley. In this area the valley floor is 61 m lower than the surrounding land. There is no record of any water flow encountered during the drilling of these wells. However, if a water flow from the Swan River were encountered during the drilling of one of the proposed wells, the well would be shut-in on the surface Csg which will be set at sufficient depth to withstand shut-in pressures. The mud weight would then be increased to overbalance and shut off the flow.

Miscellaneous Comments

(38) **As required under clause 115(b) of the regulations, provide the names of the royalty and working interest owners within one kilometre of the project area (excluding those lands within VRU No.1).**

Royalty Owners 10-25-WPM

SE¼19 David Fefchak and Marilyn Fefchak, Virden
Jim Latham, Virden

SW¼19 David Fefchak and Marilyn Fefchak, Virden
John Alexander Forrest and Judith Irene Forrest, Virden
Marilyn Fefchak, Box 1403, Virden, R0M 2C0
Beverly Gay Waller, Box 981, Lenore, Manitoba, R0M 1E0

NE¼19 Beverly Gay Waller, Box 981, Lenore, Manitoba, R0M 1E0
Marilyn Fefchak, Box 1403, Virden, Manitoba, R0M 2C0

Toronto General Trusts, 283 Portage Avenue, Winnipeg, Manitoba
(is now Canada Trust Company, c/o Montreal Trust Company,
411 - 8 Avenue S.W., Calgary, Alberta, T2P 1E7)

NW¼19 Beverly Gay Waller (address above)
Marilyn Jean Fefchak (address above)

NW¼31 Naco Limited, c/o Aikens MacAulay, Winnipeg, Manitoba

North Canadian Trust, 209 Bank of Nova Scotia Building, Winnipeg
(may be bought out by Sun Life - (204) 994-0021)

John Spelliscy, Brandon, Manitoba

NE¼31 Beverly Gay Waller (address above)
Marilyn Jean Fefchak (address above)
Deno Fontana, Virden, Manitoba, R0M 2C0 Phone (204) 748-2117
Kate Gorzala, Virden, Manitoba, R0M 2C0 Phone (204) 748-2453

SE¼31 Beverly Gay Waller (address above)
Marilyn Jean Fefchak (address above)

SW¼31 See Notes

S½, NE¼ 32 CROWN LAND

NW¼32 Elizabeth Anne Forsyth (Calgary) & Jacqueline Sylvia Brayfield (Toronto), c/o Buckingham, Toews & Swelty (Barristers - Virden)
Kate Gorzala, Virden, Manitoba
John Wesley Clarke, Winnipeg, Manitoba
Marilyn Jean Fefchak (address previous page)
Beverly Gay Waller (address previous page)

NOTES

SW¼31 does not appear in Field Title's records (abstracts), although their map shows it as being CPR land.

Companies (WI)

Murphy Oil (SW31, AID) 1700, 800 - 6 Ave. S.W., Calgary
Owega Hydrocarbons (S½32) 1300, 112 - 4 Ave. S.W., Calgary
Petro Canada (Gulf) (NW31) 150 - 6 Ave. S.W., Calgary
Possibly PanCanadian if CPR land on SW31 is controlled by them (150 - 9 Ave. S.W., Calgary).

(39) **Please provide a summary of well data that will be obtained during drilling of the infill wells (i.e. logs, cores, tests, etc.) Will Chevron be conducting any special core studies or any other reservoir tests or surveys?**

2a-30	1 x 18 m core at first sign of Sandhill porosity
7d-30	1 x 18 m core cut at top of first Oolite
8b-30	1 x 18 m core cut first sign of Sandhill porosity
6c-30	1 x 18 m core cut at first sign of Sandhill porosity
11d-30	1 x 18 m core cut at top of first Oolite
12d-30	1 x 18 m core cut at top of first Oolite
10b-30	1 x 18 m core cut at top of Crinoidal in cubic.

All infill wells will be logged with Microlog, Gamma-Ray, Phasor Induction, Compensated Density and Neutron. Chevron will not be conducting any special core studies or any other reservoir tests.

40) What is Chevron's proposed program of monitoring reservoir pressure in the project area?

Chevron monitors reservoir pressure once every 3 years and this should be sufficient.

(41) What are Chevron's views on the use of horizontal drilling as an alternative method of recovering incremental reserves in the project area?

Horizontal wells were not evaluated for this infill project. However, several problems of using horizontal wells in a 20 acre infill can be identified:

a) increased costs for horizontal wells
b) the horizontal section would be drilled in only one of the seven Lodgepole members
c) on 8-ha spacing vertical wells will be almost as effective as a horizontal well for producing the incremental reserves.

RCF/slw
(REF:\DAILY\GEO-INFO.RCF)

INFILL CASE

FH ROY (M $)	CR ROY (M $)	MIN TAX (M $)
342.7	98.1	116.5
581.4	199.5	255.8
570.1	238.0	333.6
560.4	226.0	300.1
546.0	211.9	267.3
540.2	201.3	239.6
537.9	192.3	215.4
534.3	182.8	192.9
533.6	174.4	173.0
535.2	166.8	153.4
542.4	161.3	136.5
547.2	154.9	119.1
553.0	148.7	103.6
556.5	141.7	90.0
560.9	135.4	78.8
560.3	127.8	67.9
558.0	121.0	57.4
556.6	113.9	47.6
556.1	112.1	37.8
553.5	100.9	29.0
10826.5	3208.8	3015.3

BASE CASE

FH ROY (M $)	CR ROY (M $)	MIN TAX (M $)
265.6	120.6	184.9
456.7	200.4	296.6
451.5	191.3	272.5
447.6	182.3	250.0
439.8	172.4	226.6
438.8	165.3	208.0
440.7	159.8	190.7
441.6	153.8	173.6
444.9	148.6	158.6
450.3	144.0	145.6
460.6	141.2	134.5
468.9	137.0	123.2
478.4	134.0	112.5
486.1	130.2	101.8
494.7	126.4	92.2
499.1	121.5	82.5
501.9	116.0	72.8
505.9	111.8	64.1
510.5	107.6	56.3
513.7	103.6	49.1
9197.4	2867.9	2996.1

FIGURE 4

AERIAL PHOTOGRAPH
OF
REDUCED SPACING
PROJECT AREA

pasture – rest is cultimted

A dugout

cultivated.

KEY:

EXISTING WELLS

PROPOSED WELLS

PROPOSED LEASE TRAILS

SCALE

0 100 200 300 400 500

METRES

100 m

100 m

DRILLING LEASE SIZE
(TO SCALE)

February 26, 1991

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

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

RE: Virden Roselea Unit No. 1
Reduced Spacing Project

Chevron Canada Resources, the operator of Virden Roselea 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 7 infill wells and the conversion of 2 producing wells to water injection wells.

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 March 18, 1991. If you have any questions, please contact me at 945-6574.

ORIGINAL SIG...
JOHN N. ...

John N. Fox

cc: Dale Partridge
Manitoba Agriculture

cc: Floyd Phillips
Manitoba Environment

(Note: Extra copies of the application are not available at this time. Once copies are received, a copy will be forwarded to you.

THE HIGHWAY TRAFFIC BOARD

Notice is hereby given that a hearing of the Highway Traffic Board will be held on Thursday, March 7, 1991 at 09:00 hours in Swan River Council Chambers, 216 Main Street West, Swan River, Manitoba.

Permits — Part I — Section 9 H.P.A. and Part III — Section 17 H.P.A.

13/006/202/A/90 — Repap Manitoba Inc.

An application for a permit for a Temporary Access Driveway (Logging Road) onto P.T.H. No. 6, S.E. ¼, Section 11-59-12 West, The Pas Unorganized Territory.

09/083/081/S/90 — Ed Yaknovich

An application for a permit for an Off-Premise Sign (Commercial) adjacent to P.T.H. No. 83, S.W. ¼, Section 17-31-29 West, Swan River Unorganized Territory.

Speed Zones — Sections 97 and 98 H.T.A.

010-S — Provincial Traffic Engineer

Consideration to be given to shortening the existing 60 Km/h speed zone on portions of P.T.H. No. 10 to a point 100 metres north of Park Drive and the approval of an 80 Km/h modified speed zone for a distance of 650 metres beginning at the point 100 metres north of Park Drive, Town of Swan River.

366-S — Provincial Traffic Engineer

Consideration to be given to a modified speed zone of 70 Km/h on portions of P.R. No. 366 beginning at the point 700 metres south of P.T.H. No. 10 and continuing southerly for 700 metres in the R.M. of Minitonas and the Village of Minitonas.

366-S — Provincial Traffic Engineer

Consideration to be given to a modified speed zone of 70 Km/h on portions of P.R. No. 366 beginning at the point 50 metres north of Isable Avenue and continuing southerly for a distance of 250 metres, Village of Minitonas.

366-S — Provincial Traffic Engineer

Consideration to be given to exclude a portion of P.R. No. 366 from the restricted speed area beginning at the point where the southern boundary of the Village of Minitonas crosses the highway and continuing northerly for 400 metres, Village of Minitonas.

010-S — Little Athapap Cottage Owners Association

Consideration to be given to easterly and northerly extension of the existing modified speed zone of 70 Km/h on portions of P.T.H. No. 10 in the vicinity of Baker's Narrows and Sally's Beach, Flin Flon Unorganized Territory.

The Highway Traffic Board will be prepared to consider all submissions written or oral on the above applications by contacting the Secretary prior to or at the hearing.

206-301 Weston Street
Winnipeg, Manitoba
R3E 3H4
Phone: 945-8912

A. POLTARUK, MMM CD
Secretary,
The Highway Traffic Board.

2617—8

UNDER THE MINES ACT

NOTICE

Chevron Canada Resources, Operator of Virden Roselea Unit No. 1 ("the unit area") has made application:

1. 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 (40 acres) to eight hectares (20 acres) in the project area outlined below. If the application is approved and the area is fully developed on eight hectare spacing, eight additional oil wells, located as indicated would be drilled.
2. Under Section 64 of the Petroleum Drilling and Production Regulation for approval to convert the following wells to water injection.

Placer Virden 9-30-10-25 (WPM)
Placer Virden 15-30-10-25 (WPM)

If no intervention in writing is received by the Board at Room 309, Legislative Building, Winnipeg, Manitoba, R3C 0V8 on or before March 18, 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

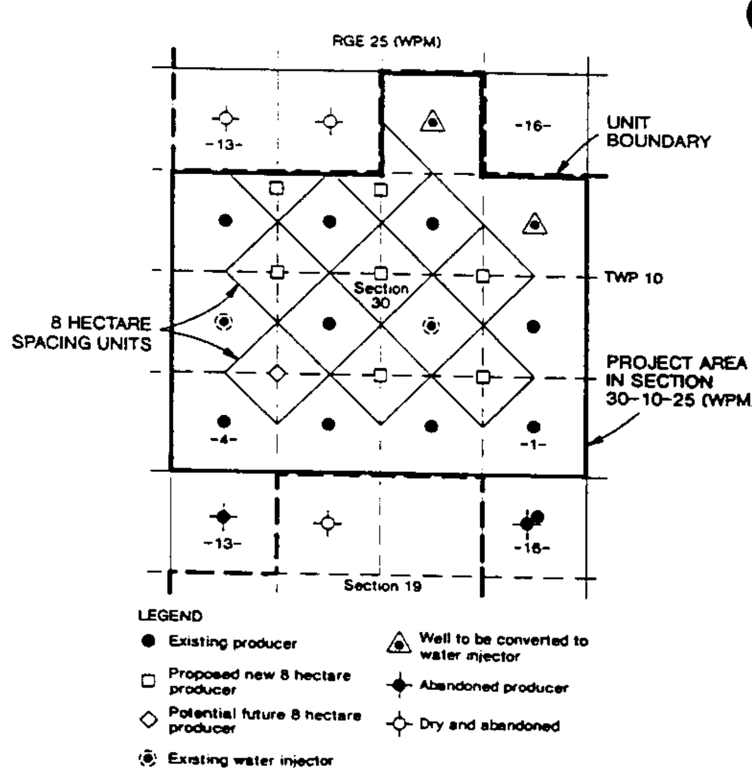
The application may be viewed at the offices of the Petroleum Branch:

555-330 Graham Avenue	247 Wellington Street West
Winnipeg, Manitoba	Virden, Manitoba
(204) 945-6577	(204) 673-2472

Dated at Winnipeg, this 15th day of February, 1991.

H. CLARE MOSTER,
Deputy Chairman.

2655—8



February 14, 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: Virden Roselea Unit No. 1
Application for Reduced Spacing

Chevron Canada Resources has applied (91-01-18) for approval of reduced 8 ha spacing and modification to pressure maintenance operations in a portion of Section 30-10-25 (WPM) in Virden Roselea Unit No. 1. The Petroleum Branch has completed its preliminary review of the application and has identified a number of areas that require further information, clarification or comment.

RECOMMENDATIONS

It is recommended that notice of the application (attached) be published in the Virden Empire Advance and the Manitoba Gazette, as well as sent directly to the following:

(1) the surface owners in Section 30,
(2) the royalty and working interest owners of Lsds 13, 14 and 16 of Section 30,
(3) the Departments of Rural Development, Agriculture and Environment, and
(4) the Surface Rights Association.

Chevron will be requested by phone to supply the names and addresses of the persons listed in Item (2) as quickly as possible.

A copy of the proposed Board deficiency letter is attached.

John N. Fox

Approved: ______________________________
L.R. Dubreuil, Director

Manitoba

The Oil and Natural Gas
Conservation Board

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

(204) 945-3130

February 15, 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: Virden Roselea Unit No. 1
Application for Reduced Spacing

Your application dated January 18, 1991 for approval of special drilling spacing units and modification to pressure maintenance operations in a part of Virden Roselea Unit No. 1 (VRU No. 1) is acknowledged.

The application has been reviewed and a few areas have been identified that require further information, clarification or comment. These are outlined below in the order each subject appears in the application.

Before notice of the application is published, the Board requires the names and addresses of the royalty and working interest owners in Lsds. 13, 14 and 16 of Section 30. Are these parties also participants in VRU No. 1? Upon receipt of the names and addresses, notice of the application will be published in the Virden Empire Advance and the Manitoba Gazette.

Please provide the Board with an additional 3 copies of the original application and 6 copies of your response to this letter.

Attachment 3 - Geological Information

(1) In the cross-section, what do the numbers posted for each well on the map in the upper right-hand corner represent?

(2) The Øh and kh maps for the 1st, 2nd and 3rd Oolite have identical numerical values for all wells except 15-30. Is this correct?

(3) Are the Øh maps based on core data or a combination of core and log data?

(4) What porosity, permeability and water saturation cut-offs have been used to determine the Øh and kh maps for each member?

(5) The Øh maps for the various members indicate there is no net pay in the dry holes at 13-30 and 14-30. Explain the reasons for the sudden loss in reservoir quality at these locations.

Attachment 4 - Technical Justification

(6) The current recovery from the unit and project area is 27.3% OOIP and 21.9% OOIP, respectively. Why is the current recovery in the project area so much lower than the current unit recovery? What is the estimated ultimate recovery from the unit and project area with and without infill drilling? What abandonment conditions are assumed and on what parameters are the conditions based?

(7) Please provide a list or a map showing current completion intervals and zones for all existing wells in the project area.

(8) Were the water saturation values determined from log analysis or special core studies or a combination of both?

(9) Please provide a list of individual well OOIP by zone in the project area.

(10) Is the net pay map (Figure 2) a summation of the net pay in all members?

(11) What is the source, cause and estimated volume of oil migration into the project area?

(12) Why is the 4D-30 location not included in the list of proposed infill wells for the reduced spacing project? Does Chevron plan to drill this location in the future?

(13) In the application, Chevron gives a zonal breakdown of OOIP and indicates that production within the project area has been mainly from the Sandhill and Cherty Members with some additional production from the Oolites. Has Chevron tried to determine zonal oil production and current zonal recoveries? Will Chevron be evaluating inflow from individual zones in the infill wells, by selective swabbing or other means, to assist in waterflood evaluation and optimization?

(14) List the six wells in the project area that have penetrated the Cherty Member. Is the deepening of existing producing wells an option for recovering undrained Cherty reserves? What percentage of the estimated incremental recovery of 3.2% OOIP is associated with production of undrained Cherty reserves?

(15) According to the application, there has been no production from the Crinoidal Member, which contains 10% of the OOIP in the project area. Does Chevron plan to complete the Crinoidal Member in the infill wells and if so, what is the estimated contribution of Crinoidal production to the total incremental recovery?

(16) According to the application, all water injection in the project area is into the Sandhill and Oolites Members. What degree of pressure support has the Cherty Member received from the injectors adjacent to the project area and has the Cherty Member within the project area been effectively waterflooded? If not, how will the proposed injector conversions improve the effectiveness of waterflooding the Cherty? Which zones will the proposed injectors be completed in? Will Chevron be deepening either of the existing injectors in the project area into the Cherty?

(17) Has Chevron run any injection profile logs to evaluate the vertical distribution of injected fluids in the project area? Can incremental recovery in the project area be increased economically, by controlling/modifying zonal injection rates?

(18) Chevron noted that if injection at 9-30 and 15-30 could not meet the increased voidage from the infill wells, an additional injector conversion may be necessary. Which well(s) is Chevron considering converting?

(19) It is apparent from the infill well production forecast (Figure 7) that there is a significant acceleration component. Please provide a plot of daily production versus time for the incremental production and acceleration components of the infill production forecast.

Attachment 5 - Analysis of Reduced Spacing
North Virden Scallion Unit No. 1 (NVSU No. 1)

(20) Explain the reasons for the difference in estimated (7.6% OOIP) and actual (1.7% OOIP) incremental recovery for the NVSU No. 1 reduced spacing project and the estimated incremental recovery (3.2% OOIP) for the VRU No. 1 reduced spacing project.

(21) Should Point 3 on page 5 be prefaced with "avoid"?

(22) Chevron estimated reservoir continuity in the NVSU No. 1 reduced spacing project to be 82% on 16 ha spacing. Post-drilling project analysis indicated the project area had been depleted/swept by existing producers/injectors and the Oolite and Cherty Members were more laterally continuous than predicted. What is the revised estimate of reservoir continuity on 8 ha and 16 ha spacing in the NVSU No. 1 reduced spacing project? Are these numbers applicable to the VRU No. 1 reduced spacing project? Is there a concern that good lateral continuity will have a detrimental impact on incremental recovery in the VRU No. 1 reduced spacing project as was the case in the NVSU No. 1 reducing spacing project?

(23) Chevron indicated the high cumulative production at 7-26-11-26 had depleted a significant portion of the NVSU No. 1 reduced spacing project area, resulting in the poor performance of the offsetting infill wells. A similar argument could be made for the 6-30 and 10-30 wells in the VRU No. 1 reduced spacing project area. Does Chevron have any concerns that these wells may have drained a disproportionate share of the reservoir?

Attachment 7 - Benefits to Crown and Lessors

(24) Please provide the information shown in the three graphs in Attachment 7 in tabular form.

(25) Has Chevron contacted working interest owners in VRU No. 1 with respect to the special treatment of royalties and taxes that will be necessary if the project is approved?

Attachment 8 - Environmental Impact

(26) Please provide a topographic map of the project area showing the well locations, access roads and flowline and injection line routes.

(27) Please provide an outline on the aerial photograph of agricultural land use (i.e. cultivated and pasture) and areas with little topsoil.

(28) In the aerial photograph there is evidence of a network of trails running north and northeast from 6-30. Does Chevron use these trails to access the existing wells?

(29) The access road to 11D-30 as shown on the aerial photograph is through a forested area. Would it be feasible to access 11D-30 from the south, off the access road to 10B-30 and thereby avoid destruction of trees which would result from the proposed access?

(30) Please provide a summary of potable groundwater resources in the project area including the location of all potable water supply wells and dugouts.

(31) Will electrical power be run underground to the infill wells?

(32) What lease construction precautions will be taken to minimize erosional concerns at the 7D-30 and 8B-30 locations on the slope of the river valley and what measures will be taken to confine drilling and produced fluids to the wellsite? Is there any merit in directionally drilling these wells?

(33) Where in the project area does Chevron plan to use fibreglass pipe and where will steel pipe be used? What is the reason for using the different materials?

(34) It is recognized that Chevron has in place preventative measures to help reduce flowline leaks and closely monitors its flowlines to ensure a leak is detected as quickly as possible. However, what spill reduction equipment such as check valves and pressure shutdowns does Chevron plan for the high volume flowlines in the project area to minimize spill volumes in the event of a flowline failure?

Attachment 13 - Drilling Program

(35) Does Chevron plan to shut-in the water injectors in and surrounding the project area before and during the drilling of the infill wells?

(36) What is the additional cost, if any, to drill the infill wells using lease tanks instead of drilling pits? Are there any other concerns with the use of lease tanks?

(37) Historically, wells drilled on the Assiniboine Valley floor have encountered water flows in the Swan River and other aquifers due to lower ground elevation. What contingency measures does Chevron propose to address this potential problem for the 7D-30 and the 8B-30 locations which are close to the valley floor?

Miscellaneous Comments

(38) As required under clause 115(b) of the regulations, provide the names of the royalty and working interest owners within one kilometer of the project area (excluding those lands within VRU No. 1).

(39) Please provide a summary of well data that will be obtained during drilling of the infill wells (i.e. logs, cores, tests, etc.). Will Chevron be conducting any special core studies or any other reservoir tests or surveys?

(40) What is Chevron's proposed program of monitoring reservoir pressure in the project area?

(41) What are Chevron's views on the use of horizontal drilling as an alternative method of recovering incremental reserves in the project area?

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

Yours respectfully,

HC Moster

H. Clare Moster
Deputy Chairman

** TX CONFIRMATION REPORT **   AS OF FEB 15 '91 14:09 PAGE.01

ENERGY AND MINES

	DATE	TIME	TO/FROM	MODE	MIN/SEC	PGS	STATUS
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Manitoba

Energy and Mines Petroleum

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Winnipeg, Manitoba, CANADA
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TELECOPIER NUMBER: (204) 945-0586

FAX MESSAGE

DATE: February 15, 1991

SENT TO: Mr. C. G. Folden
Chevron Canada Resources

FROM:

Manitoba

Energy and Mines
Petroleum

555-330 Graham Avenue
Winnipeg, Manitoba
R3C 4E3

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

(204) 945-6574

REGARDING: Virden Roselea Unit No. 1
Application for Reduced Spacing

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P.O. Box 1403
Virden, Manitoba
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1

1.0 TECHNICAL DETAILS

- 7 infill wells   incremental recovery = 87300 m^3 (3.2% OOIP)
incremental recovery/well = 12,500 m^3
initial production : 27 m^3/d
initial production/well : 3.86 m^3/d/well

estimated unit recovery 2.76×10⁶ m^3

- current recovery 27.3% OOIP VRU #1
estimate unit decline rate D = 4.1 %/yr.

			YEAR TO YEAR DECLINE
1990	PROD	34229.7 m^3	- 7.2
1989		36802.9 m^3	- 4.5
88		38501.4 m^3	- 1.8
87		39213.6 m^3	- 3.0
86		40392.5 m^3	- 9.0
85		44177.2 m^3	- 7.4
84		47571.6 m^3	

DECLINE 1985 to 1990 - 5.1 %
1986 to 1990 - 4.1 % USE

REMAINING RECOVERABLE RESERVES 1990 AVER DAILY PROD - 93.8 m^3/d

$q_{t=30} = q_i \cdot e^{-Dt} = 93.8 \cdot e^{-.041 \cdot 30} = 27.4\ m^3/d$

$Q_{30} = \frac{365\,(q_i - q_{t30})}{.041} + 2{,}202{,}340 = 2.79 \times 10^6\ m^3$

OOIP in VRU #1 - 7930 $\times 10^3 m^3$

RF VRU #1 $\frac{2790}{7930} = 35.2\ \%$

CHEVRON'S ESTIMATES IN APPLICATION
decline rate = 4.6 %
recovery factor = 34.8 %

1.1 PROJECT AREA

SELECTION

1. STRUCTURALLY HIGH
2. MODERATE TO HIGH OIL RATE
3. LOW WATER-CUT
4. LOW TO MODERATE DEPLETION

- INFILL DRILLING TARGETS (a) undrained Cheaty reserves (b) migrated / trapped oil @ apex of structure
  represents both incremental / accelerated production

1. STRUCTURAL HIGH - structural difference (Top of Cheaty) of 65' between 15-30 & 11-30 (apex) and 55' between 4-30 & 11-30

2. MODERATE TO HIGH OIL RATE - PROJECT AREA JAN / 91 AVERAGE DAILY OIL - 2.67 m^3/d /well

UNIT AVERAGE DAILY OIL JAN/91 - 1.51 m^3/d /well

3. LOW WATER-CUT

PROJECT AREA JAN/91 WOR - $\frac{4314.9}{910.1} = 4.7\ m^3/m^3$

UNIT JAN/91 WOR - 12.4 m^3/m^3

4/ LOW TO MODERATE DEPLETION

CURRENT UNIT RECOVERY $\frac{2205}{7930}$ = 27.8 %

CURRENT PROJECT AREA RECOVERY = $\frac{585}{2700}$ = 21.7%

OOIP /HA UNIT = 5324 m^3 / ha
PROJECT AREA = 14063 m^3 / ha

PROJECT AREA RECOVERABLE RESERVES

	PRODUCTION	YEAR TO YEAR DECLINE
1990	11105	10.1 %
1989	12346	12.4 %
1988	14092	0.4%
1987	14154	3.4 %
1986	14659	5.5%
1985	15516	8.0 %
1984	16861	

ESTIMATED DECLINE 1985-1990 - 6.7 %
ESTIMATED DECLINE 1984-1990 - 7.0 %
CHEVRON'S DECLINE FROM APPLICATION - 2.6 % / yr.

CHECK DECLINE USING DAILY PRODUCTION JAN/91 - 29.7 m^3/d
JAN/86 42.86 m^3/d
JAN/84 - 49.52 m^3/d

DECLINE 86.01 to 91.01 - 3 %
DECLINE 84.01 to 91.01 - 7.3

REMAINING RECOVERABLE RESERVES - PROJECT AREA

$q_{i_{1991-01}} = 29.3\ m^3/d$

$q_{30} = q_{i_{1991-01}} \cdot e^{-Dt} = 29.3 * e^{(-0.05 * 30)} = 6.5\ m^3/d$

$Q_{30} = \frac{365 (29.3 - 6.5)}{0.05} = 166,440\ m^3$

ULTIMATE RECOVERABLE RESERVES - PROJECT AREA

585,000 + 166440 = 751,440 m^3

ULTIMATE RECOVERY = $\frac{751.4}{2700}$ = 27.8%

CHEVRONS PREDICTION

$Q_{30} = \frac{365 (33 - 15.1)}{.026} = 250,903$

ULTIMATE RECOVERY = $\frac{836}{2700}$ = 31 %

NOTE : THE DIFFERENCE IN UNIT VS. PROJECT AREA ULTIMATE RECOVERY AS PREDICTED BY CHEVRON IS 34.8 - 31 = 3.8% VS CHEVRONS PREDICTED INCREMENTAL INFILL RECOVERY OF 3.2 %

REVIEW COMPLETION INFORMATION

PRODUCING ZONES

separated by ... there ... UNIT

		OOIP
PRIMARY –	[illegible]	54%
	[illegible]	26%
SECONDARY	[illegible]	10%
POTENTIAL	PRINCIPAL	10%

[illegible] 20' [illegible] 285,000 [illegible]

[illegible] – of [illegible] question

[illegible] core –

[illegible] – [illegible] H

only [illegible] porosity [illegible]

2000 [illegible] –

[illegible] 4 [illegible] have [illegible]

[illegible] – POTENTIAL RESERVES

BEHIND CASING OR NOT PENETRATED 1267 × 10³ m³ or 47% of OOIP

[illegible] additional [illegible]

[illegible]

TD' < 10' [illegible]

[illegible] have been

produced [illegible]

[illegible] 16 ha spacing

[illegible] 11 – [illegible] average – 40%

suggests drainage of [illegible] ha

(b) production performance like current recovery is quite variable & difficult to analyze for example high-permeability 10-30 well which produces primarily from the [illegible] [illegible] no appreciable production decline since WF response was observed in 1966.

Chevron expresses concern in application that Sandhill & Oolites may be swept & drained

INFILL LOCATIONS VS. DEEPENING

[illegible] logs - evaluation [illegible] [illegible] [illegible] to assist WF evaluation

[illegible] 20-30 [illegible] near [illegible] = [illegible] [illegible]
7 D-30
10B-30 [illegible] [illegible] [illegible] [illegible] [illegible]

11 D-30

12 9+30

[illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [illegible]

(d) unaccess [illegible] [illegible] in [illegible] [illegible] [illegible] injection wells

(e) permitted [illegible] [illegible] existing [illegible] [illegible] [illegible] NW [illegible]

4. GEOLOGY — favourable geologic & reservoir characteristics

✓ [illegible] project area overlies a NW-SE structural high centred [illegible] of Sec 30

✓ [illegible] zones are continuous over the structural high, [illegible] in some wells all or some of these zones have been infilled by dolomite & anhydrite and are tight. [illegible] of these zones has its own down dip O/W contact and edge water drive.

– [illegible] has an estimated O/W contact of -563' ft [illegible] in the project. [illegible] wells drilled high on the structure have a thicker net pay section. For example

WELL	TOP OF CHERRY	CHERRY [illegible] NET PAY ABOVE O/W CONTACT @ -563' SS
1-30	[illegible]	[illegible]
2-30	[illegible]	[illegible]
3-30	[illegible]	[illegible]
4-30	-510	–
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	-523	[illegible]
	-537	4[illegible]
	-552	[illegible]

WELL	TOP of [illegible]	[illegible]
11-30	-517	45
12-30	[illegible]	[illegible]
13-30	[illegible]	∅

- two cores [illegible] Clearly [illegible]
8-30 (36' [illegible]) & 9-30 (20' [illegible]),
[illegible] a large variation in k_h

	$k_{h\,min}$	$k_{h\,max}$	$k_{aver.}$	$k_{v\,AVER}$
8-30	1.2	25	7.6	
9-30	2.6	242	53	

minimal [illegible] observed in core

- lateral continuity is not a concern

- all Δ recovery based on recovery of 10% of [illegible] Clearly [illegible]
[illegible] in LSU: [illegible]
[illegible] OOIP = 3225 $\times 10^3$ bbls
[illegible] 10% recovery [illegible]
= Well #1 [illegible] 20% [illegible]

- lateral continuity good
[illegible] low k_v & [illegible], [illegible] Clearly Δ recovery high

WF PERFORMANCE

- cumulative water production clearly illustrates that impact of structure on water production

- down structure injection acts as an edge water drive in all zones (except Cherty) which drape over the structural high

- all injection in project area 5-30 & 7-30 has been into Crinoidal & Oolite members
  Chevron's opinion these zones effectively waterflooded

- regardless of proximity to injection wells WF response in project area was observed in most wells in June/66 to Oct/66
  8 wells after injection commenced in 5-30, 7-30 was offsetting injectors at 5-29-10-25, 7-29-10-26,
  15-[illegible] [illegible], 13-25-10-26, 13-24-10-26
  all of which commenced injection in OCT/65

WELL	INJECTION INTERVALS
13-20-10-25	PERF'D OOLITES + TOP 6' CHERTY 1968 - 600 injection into Cherty
7-29-10-25	PERF'D OOLITES & 6' CHERTY
15-24-10-26	OH below Crinoidal, TD 20' into Cherty
7-25-10-26	OH below Crinoidal, crinoidal perf'd TD 30' into Cherty
15-25-10-26	OH below Crinoidal, TD 4' into Cherty,

Clearly injection @ 15-24-10-25, 7-25-10-26 supporting Clearly production in project area

Project VRR

Voidage edge well tract factor = 0.5

VOIDAGE to JAN 31 /91

WELL	TF	OIL * 1.06 $\frac{m^3}{m^3}$ ($10^3 m^3$)	WATER * 1.0 ($10^3 m^3$)
1-30	0.5	24.7	26.3
2-30	1.0	47.4	79.9
3-30	1.0	34.1	44.3
4-30	1.0	34.5	145.9
1-25-10-26	0.25	12.3	35.6
8-25-10-26	0.5	63.3	208.9
9-25-10-26	0.25	18.6	33.8
12-30	1.0	30.9	221.8
11-30	1.0	72.6	33.7
10-30	1.0	111.8	35.0
15-30	1.0	10.3	75.9
9-30	0.5	21.7	41.6
8-30	0.5	25.2	19.6
5-30	1.0	8.9	2.2
7-30	1.0	11.6	2.9
6-30	1.0	114.9	117.5

TOTAL VOIDAGE 642.8 + 1124.9 = 1767.7 m^3 VOIDAGE

WELL	CUMULATIVE INJECTION (10^3 m^3)
5-30	1082.5
7-30	395.1
TOTAL REPLACEMENT	1477.6

$$VRR = \frac{1477.6}{1767.0} = 0.84$$

INFILL LOCATIONS & INJECTOR CONVERSIONS

- 2C-30 5' structurally higher that 2-30
  15' " " 3-30

8B-30 15' structurally higher that 1-30 & 2-30

7B-30 10' structurally higher than 7-30
<5' " " 8-30
<5' " " 10-30
20' " " 9-30

6C-30 10' structurally higher than 5-30
<5' " " 6-30 & 12-30

10B-30 20' structurally higher than 6-30
10' " " 7-30
<5' " " 11-30
5' " " 10-30

120-30 15' structurally higher than 12-30

110-30 7' " " " 10-30
>60' " " " 15-30

note: 120-30 & 110-30 max recovery oil trapped against updip edge of pool

Crude estimate of OOIP/ft of Cherty pay is

WELL	CHERTY GROSS PAY THICKNESS (Ft)	CHERTY RESERVES PER FT OF NET PAY 1000 bbl/ft
1-30	12	28.6
[illegible]	18	29.6
[illegible]	[illegible]	40.4
4-30	[illegible]	—
[illegible]	[illegible]	27.5
[illegible]	[illegible]	22.4
7-30	[illegible]	20.5
8-30	45	21.6
9-30	11	25.9
10-30	27	31.9
11-30	47	22.8
12-30	26	21.7
13-30	~	0
		266 30 bbl/ft of Cherty net pay

based on 16 ha spacing

- wells [illegible] [illegible] [illegible] interval, straddle [illegible] [illegible] with packers

[illegible] conversions [illegible] edge-water / bottom water [illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [illegible] apex [illegible] [illegible] [illegible] pattern [illegible] the [illegible] [illegible], whether [illegible] [illegible] 8-ha [illegible] [illegible] [illegible], obvious candidates for [illegible] 6-30, 10-30, 11-30 all high productivity wells [illegible] [illegible] [illegible]

- proposed conversions 9-30 & 5-30 [illegible] [illegible]

9-30 [illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [illegible] 5-30 [illegible] [illegible] [illegible] [illegible] [illegible], [illegible] [illegible] candidate

Test 5
NVSU ... (Table 2)

6. ... ... recovery - 100,000 m³
... good net pay
(2) low oil production - WOR existing ... wells - ...
... poor ult. recovery

... ... producers ...
only 3 conversions ... ...

recovery based ... + WF ...

... IP ... ... IP of ...
... WOR I.P = 19.8 ... vs IP = 61.2 ...
... 6.3 ...

NVSU ... ...
continuous
WOR 219.6 ... ... 264 3 ...

large portion of project area swept of depleted by
existing producers & injectors

actual incremental recovery 36,260m³
Δ RF = 1.7 %
vs 7.0% ... ...
predicted incremental recovery 100000

conclusion; ... ... low wells -> ex...
... ...

(2) 7-26 has produced 34% of 16 Ls [illegible] due excellent reservoir perm [illegible] & sweep [illegible] essentially draining LSD's 1 & 2 & [illegible] dispositional [illegible] of reservoir

RECOMMENDATIONS

(1) locate wells on structural highs to maximize net pay thickness, minimize WOR & avoid rapid water encroachment

(2) identify areas were productive zones not completed

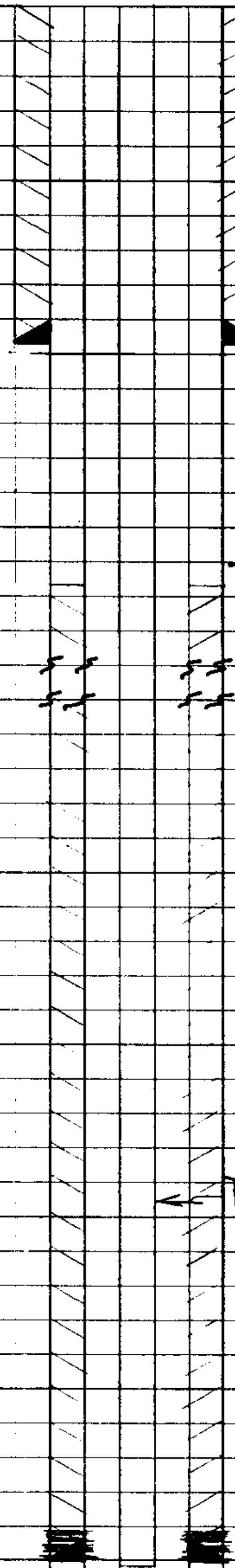
[illegible] conversion because of the impact [illegible] production [illegible] major [illegible] risk of not [illegible] or [illegible] response

YEAR	BASE CASE (M3/D)	INFILL PRODUCTION (M3/D)	INFILL PROJECT (M3/D)	INCREMENTAL PRODUCTION (PROJECT - BASE)	ACCELERATED PRODUCTION (BASE + INFILL - PROJECT)	EXISTING WELL PRODUCTION (BASE-ACCELERATED)	VRU #1 PRODUCTION (INFILL CASE)	INFILL PRODUCTION (% NEW OIL VRU #1)	INCREMENTAL PRODUCTION (% NEW OIL VRU #1)
1991-6	31.68	27.72	58.4	26.72	1	30.68	118.84	0.233254	0.224840
1992	30.85	25.98	54.88	24.03	1.55	28.9	112.01	0.231943	0.214534
1993	30.04	24.34	52.11	22.07	2.27	27.77	106.1	0.229406	0.208011
1994	29.26	22.81	49.49	20.23	2.58	26.68	100.48	0.227010	0.201333
1995	28.49	21.37	47	18.51	2.86	25.63	95.15	0.224592	0.194534
1996	27.75	20.03	44.66	16.91	3.12	24.57	90.11	0.222283	0.187659
1997	27.02	18.77	42.43	15.41	3.36	23.66	85.31	0.220021	0.180635
1998	26.31	17.59	40.32	14.01	3.58	22.73	80.77	0.217778	0.173455
1999	25.26	16.48	38.32	13.06	3.42	21.84	76.46	0.215537	0.170808
2000	24.95	15.44	36.43	11.48	3.96	20.99	72.37	0.213348	0.158629
2001	24.3	14.47	34.63	10.33	4.14	20.16	68.48	0.211302	0.150846
2002	23.67	13.56	32.93	9.26	4.3	19.37	64.8	0.209259	0.142901
2003	23.05	12.71	31.32	8.27	4.44	18.61	61.31	0.207307	0.134888
2004	22.44	11.91	29.79	7.35	4.56	17.88	58	0.205344	0.126724
2005	21.86	11.16	28.34	6.48	4.68	17.18	54.86	0.203426	0.118118
2006	21.29	10.46	26.97	5.68	4.78	16.51	51.89	0.201580	0.109462
2007	20.73	9.8	25.66	4.93	4.87	15.86	49.06	0.199755	0.100489
2008	20.19	9.18	24.42	4.23	4.95	15.24	46.38	0.197930	0.091203
2009	19.66	8.6	23.24	3.58	5.02	14.64	43.83	0.196212	0.081679
2010	19.15	8.06	22.13	2.98	5.08	14.07	41.43	0.194545	0.071928
2011	18.64	7.55	21.07	2.43	5.12	13.52	39.14	0.192897	0.062084
2012	18.16	7.08	20.07	1.91	5.17	12.99	36.97	0.191506	0.051663
2013	17.68	6.63	19.11	1.43	5.2	12.48	34.92	0.189862	0.040950
2014	17.22	6.22	18.21	0.99	5.23	11.99	32.97	0.188656	0.030027
2015	16.77	5.82	17.34	0.57	5.25	11.52	31.12	0.187017	0.018316
2016	16.33	5.46	16.53	0.2	5.26	11.07	29.37	0.185903	0.006809
2017	15.9	5.11	15.74	-0.16	5.27	10.63	27.7	0.184476	0
2018	15.49	4.79	15	-0.49	5.28	10.21	26.12	0.183384	0
2019	15.08	4.49	14.3	-0.78	5.27	9.81	24.63	0.182298	0
2020	14.69	4.21	13.64	-1.05	5.26	9.43	23.22	0.181309	0
									0
TOTAL	242327.1	137897	333785.2	91458.05	46438.95	195888.2	651037	0.211795	0.140469
ECONOMIC LIMIT	1.33 m3/d	0.60 m3/d	0.85 m3/d						
DECLINE	2.6%/YR	6.3%/YR							

LIC# 1052
PLACER VIRDEN
1-30-10-25
K.B. - 385.57m
G.L. - 381.61m

DATE ON PROD - JULY 25/56

CORES:



100

219.1m - 35.72 kg/m @ 96.3m / 7.5t + 2% $CaCl_2$ - RETURNS (3m^3)

CORES: #1 - 524.3m - 542.5m } w/FULL RECOVERY
#2 - 542.5m - 554.7m

TOC - 166.3m (CALC)

D.S.T.'S: NONE RUN

300

PERFORATIONS: OPEN HOLE - 550.2m - 554.7m

BLAIRMORE

Nov 4/87 - 541.3m - 544.4m } w/13 SPM
- 545.6m - 546.8m
- 547.4m - 548.9m

DEPTH
(METRES)

400

STIMULATION: Nov 5/58 - 1137 L MUD ACID & 2273 L
15% HCL ACID

APRIL 9/60 - 3410 L 15% HCL ACID

TUBING - 60.3 @ 551.74m

Nov 3/87 - 2.8m^3 15% HCL ACID

Nov 5/87 - 3.6m^3 28% HCL ACID

500

MISS
CRIN
COL

1
2

139.7m - 20.83 kg/m @ 550.2m / 8.2t + 3% Gel

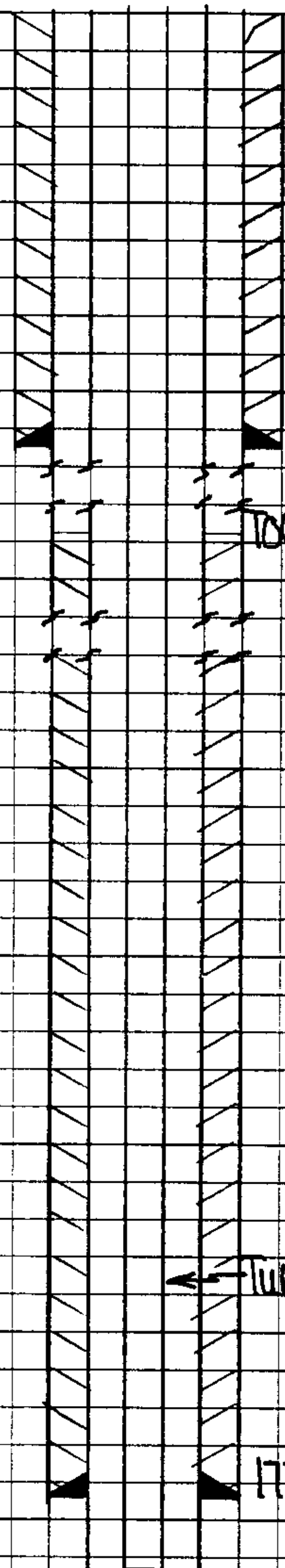
T.D. - 554.7m

46 0410

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

Lic# 150
PLACER VIRDEN
2-30-10-25
K.B. - 441.50m
G.L. - 438.30m

DATE ON PROD. - JUNE 22/55



CORES:

100

273.1mm - 48.73 kg/m @ 114.6m w/ 7.5t + 2% CaCl2

TOC - 137.2m (CALC)

250

CORES: #1 - 581.6m - 596.8m
#2 - 596.8m - 607.2m
w/ FULL RECOVERY

BLAIRMORE
400

D.S.T.'S: NONE RUN

PERFORATIONS: OPEN HOLE - 594.1m - 607.2m
Nov 22/56 - DRILL OUT TO 614.2m

DEPTH
(METRES)

500

STIMULATION: MAR 7/55 - 1137 l. MCA & 2275 l. 15% XFAW
JAN 17/59 - 4546 l. 15% HCl ACID
MAY 26/62 - 4546 l. 15% HCl ACID
MAR 28/70 - 1137 l. 15% HCl & 2275 l. 28% HCl ACID

TUBING - 60.3mm @ 612.01m

MISS
CRIN
DOL
600

1
2

177.8mm - 29.76 kg/m @ 594.1m w/ 7.6t + 2% GEL

T.D. - 607.2m
NEW T.D. - 614.2m

46 0410

2 30

OH OOLITES + CHERTY all [illegible] [illegible] [illegible]

deepen 2" [illegible] [illegible] Nov/66 negligible increase in productivity

WF response JUN/66

PROD. TO 91-01 44692 m^3

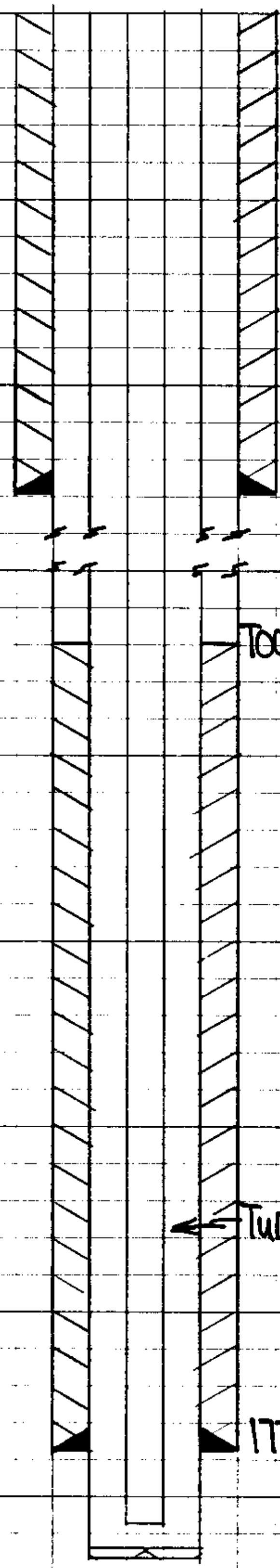
OOIP 127.3 × 10^3 m^3 (all zones)

CURRENT REC = 35%

WF response JUN/66

LIC. # 726
PLACER VIRDEN
3-30-10-25
K.B. - 438.00m
G.L. - 434.95m

DATE ON PROD. - FEB. 21/55



100

273.1mm - 48.73 kg/m @ 129.54m w/ 7.53t. + 2% $CaCl_2$ - RETURNS

250

CORES: NONE

TOC - 270.0m (CALC)

BLAIRMORE -

D.S.T.'s: NONE RUN

400

PERFORATIONS: OPEN HOLE - 587.65m - 609.6m

JUNE 25/56 - DRILL OUT TO 616.61m

DEPTH

(METRES)

500

STIMULATION: JUNE 25/56 - 9092 l. 15% XFMW ACID

TUBING - 60.3mm @ 606.65m

FEB. 5/59 - 2273 l. 15% XFMW ACID

JULY 4/62 - 4546 l. 15% HCL ACID

JUNE 10/70 - 1137 l. 15% HCL & 3410 l. 15% CRA ACID

LODGEPOLE -

CRIN. - 177.8mm - 29.76 kg/m @ 587.65m w/ 6.8t. + 3% $CaCl_2$.

DOL. - 600 -

T.D. - 616.61m
PBTD - 613.56m

177.7 [illegible] EXCLUDING [illegible]

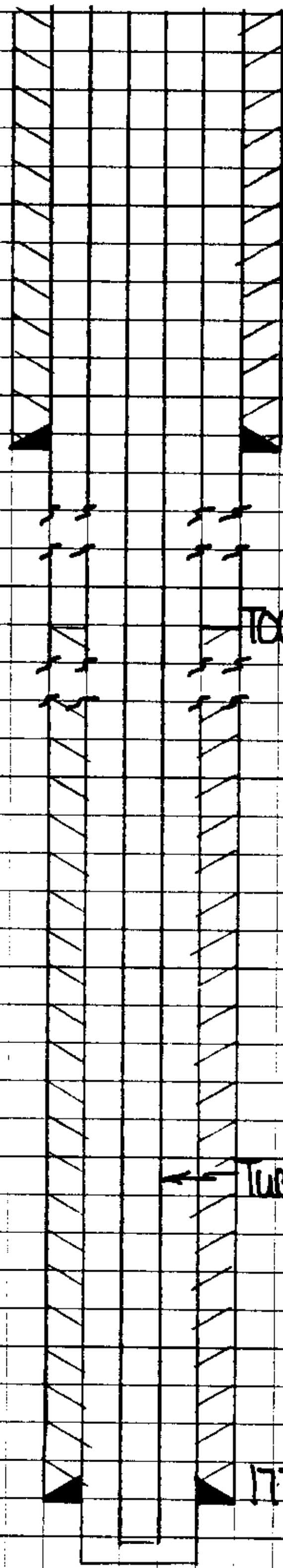
URGENT [illegible] - 32212 m^3 18'

WF response Jul /66

LIC# 094
PLACER VIRDEN
4-30-10-25
K.B. - 428.85m
G.L. - 425.30m

DATE ON PROD. - JAN 9/55

CORES:



100

273.1mm - 48.73 kg/m @ 113.7m w/ 7.5t + 3% CaCl2 - RETURNS

CORES: #1 - 576.07m - 588.26m
#2 - 588.26m - 598.93m
#3 - 598.93m - 601.98m
} w/ FULL RECOVERY

200

TOC - 210.5m (CALC)

BLAIRMORE

D.S.T.'s: NONE RUN

400

PERFORATIONS: OPEN HOLE - 590.4m - 601.98m
OCT 20/56 - DRILL OUT TO 606.6m

DEPTH

(METRES)

500

STIMULATION: DEC 31/54 - 1500 L. MUD ACID & 3000 L. 15% HCL ACID

TUBING - 73.0mm @ 601.17m

OCT 20/56 - 2275 L. MUD ACID & 6820 L. 15% XFAW ACID

DEC 17/59 - 2275 L. 15% HCL ACID

MISS

NOV 21/62 - 4546 L. 15% HCL ACID

CRIN
COL.

1
2

177.8mm - 29.76 kg/m @ 590.4m w/ 8.1t + 3% GEL

600

NOV 23/73 - 4546 L. 28% HCL ACID

T.D. - 601.98m
NEW T.D. - 606.6m

46 0410

4-30

OH all zones except [illegible]
no [illegible] 4th [illegible] - wet
O/W [illegible]

JAN - [illegible] /56 PRODUCTION 6.6 b/d WOR 0.d2
1 - DEC /5[illegible] 13 b/d WOR 0.42

well [illegible] OCT/56 [illegible]
[illegible] be [illegible]

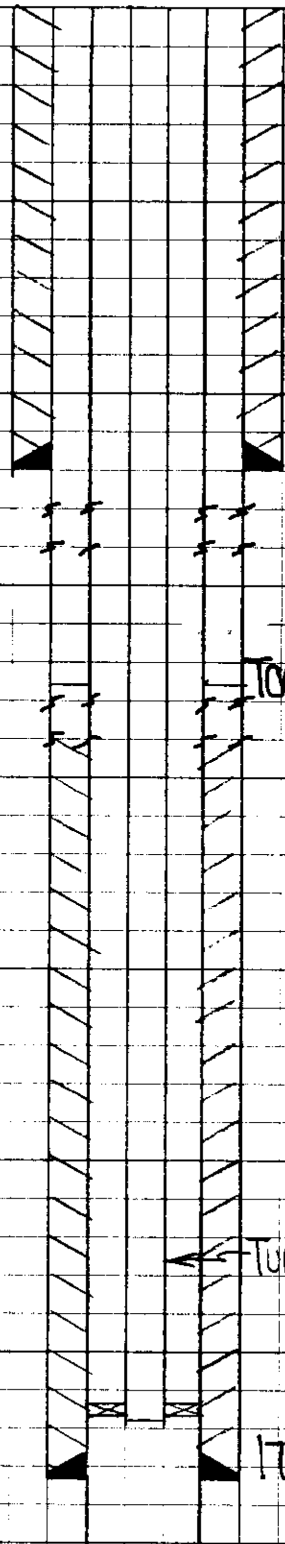
[illegible] 2 [illegible]
[illegible] x 4697
CURRENT RECOVERY 38%

WF RESPONSE MAY/66

LIC# 623
PLACER VIRDEN WIW
5-30-10-25
K.B. - 428.40m
G.L. - 425.20m

DATE ON PROD - NOV 26/54
DATE ON INJ - OCT 27/65

D.S.T.'s:
CORES:



100

273.1m - 48.73 kg/m @ 119.8m w/ 8.6t + 2% CaCl2 - RETURNS

CORES: #1 - 573.0m - 580.64m
#2 - 580.64m - 586.74m
#3 - 586.74m - 592.84m
#4 - 592.84m - 594.36m
w/ FULL RECOVERY

200

0410

BLAIRMORE

TOC - 227m (CALC)

400

D.S.T.'s: #1 - 573.6m - 586.74m VO 25 SI 35 - REC. 18.3m DM
#2 - 573.6m - 586.74m VO 60 - REC 10.7m DFM
#3 - 586.1m - 594.4m VO 60 - REC. 45.7m O&GCM

DEPTH

(METRES)

PERFORATIONS: OPEN HOLE - 583.4m - 594.36m

500

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

MAR 4/56 - DRILL OUT TO 601.98m

TUBING - 60.3m @ 567.37m
w/ SA 2 TENSION PACKER

STIMULATION: NOV 19/54 - 1137 L. MCA & 22731 L. 15% HCL ACID

MISS

CRIN
COL

177.8m - 29.76 kg/m @ 583.4m w/ 7.6t + 3% GEL

600

JULY 25/56 - 9100 L. 15% XFMW ACID
NOV 26/59 - 2273 L. 15% XFMW ACID
NOV 19/62 - 4546 L. 15% XFMW ACID
JULY 5/89 - 3 m³ 15% HCL ACID

T.D. - 601.98m

[illegible]-30 INJECTION WELL

converted to injection OCT/65

on prod. Nov/54 to OCT/65

OH below Crinoidal, deepened 7 m into Clarity in 1956
deepened 40 m to base of Clarity 1991-03 (TD 6385)

[illegible] primary

		Decline rate	
1967	8.2 b/d	18%	
[illegible]	10 b/d	6%	average decline rate
[illegible]	10.6 b/d	5%	8.5% /yr
[illegible]	11.1 b/d	3%	
[illegible]	11.5		

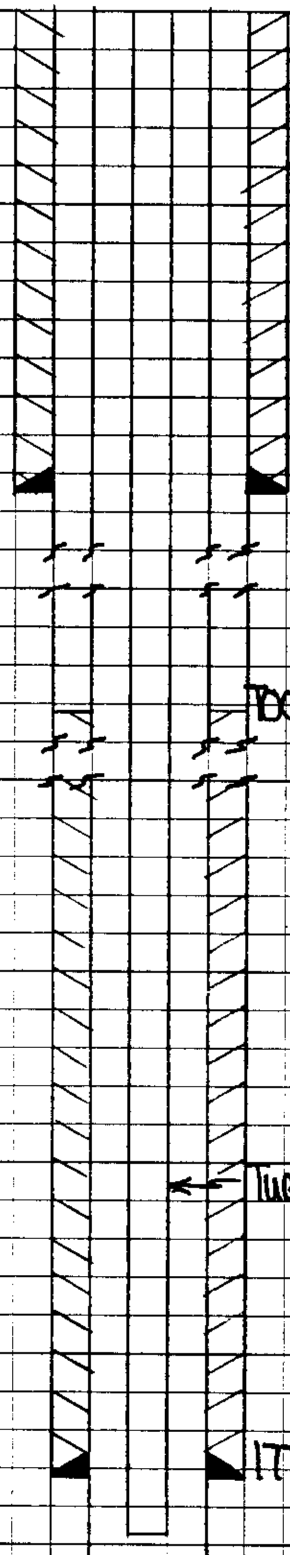
$$Q_t = [illegible] \text{ bbl} + 365 \left(\frac{8.2 - 3}{.085} \right) = 77202 \text{ bbl}$$

OOIP excluding Crinoidal [illegible] = 586000 bbl

Est. Ult. Primary Rec. = 13% – [illegible]
[illegible]
[illegible]

LIC# 712
PLACER VIRDEN
6-30-10-25
KB - 436.93m
G.L. - 433.73m.

DATE ON PROD - JAN 29/55



100

273.1mm - 48.73 kg/m @ 124.7m / 10.75t + 2% $CaCl_2$ - RETURNS

CORES: NONE

200

D.S.T.'s: NONE RUN

TOC - 232.7m (CALC)

BLAIR - 400

PERFORATIONS: OPEN HOLE - 581.9m - 603.5m

DEPTH

(METRES)

STIMULATION: JAN 23/55 - 2275 L. 15% XFMW ACID

500

TUBING - 73.0mm @ 597.75m

JUNE 5/59 - 2275 L. 15% HCL ACID

SEPT 27/63 - 1137 L. MUD ACID & 3410 L. 15% XFMW ACID

JUNE 15/78 - 2275 L. 28% HCL ACID

MISS

CRW

177.8mm - 29.76 kg/m @ 581.9m / 7.5t + 2% GEL

DOL

600

T.D. - 603.5m

46 0410

6-30-10-25

TD above Charity
OH : Sandhill + Oolites, possibly 4' of Charity

Cumulative Production 91.01 108407 m3 (39 m3/c

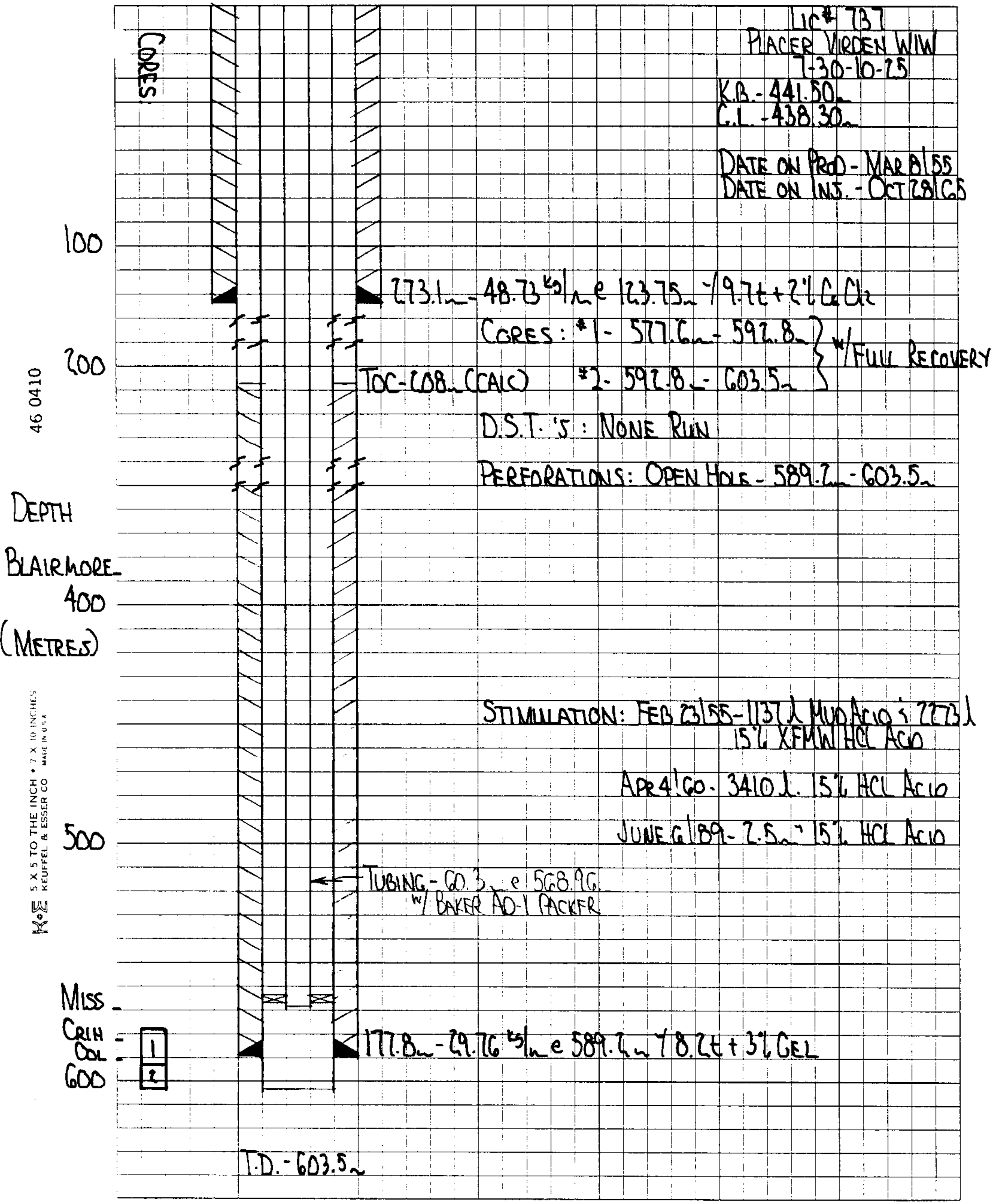
OOIP (Sandhill + Oolites) - 110620 m3

Current Recovery - 98 %

WF Response June/66 Prod increase 345 b/mon
to 3043 b/mon

Assuming 32 ha Drainage - estimate Recovery
(Sandhill + Oolites) OOIP 6-30 110620
5-30 (* 1/2) 46630
7-30 (* 1/2) 52620
Total 209870 m3
Current Recovery = 52 %

WF Response Jun/66



46 0410

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

7-30

TD 4' into Cherty
oil below Crinoidal

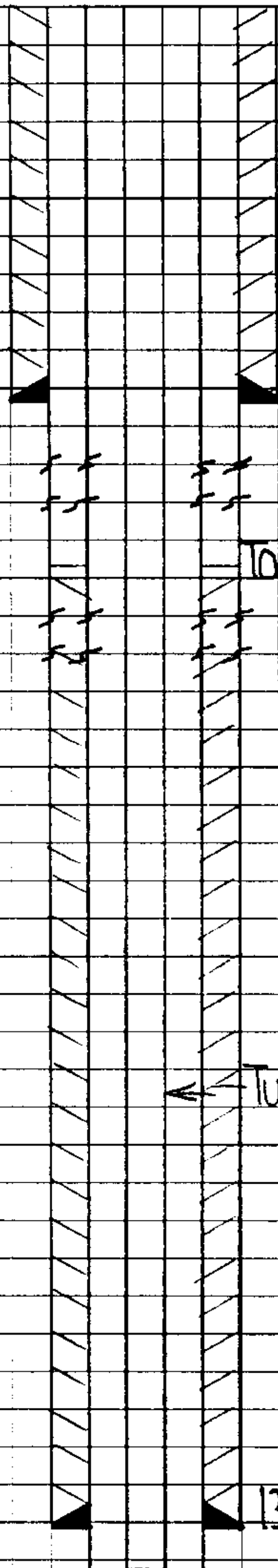
ON PROD MAR/55
CONVERTED TO INJECTION OCT/65

EST PRIMARY RECOVERY - 85200 bbl
OOIP (SANDHILL - OOLITES) 662000 bbl
PRIM. RECOVERY FACTOR - 13% indicates minimal
Cherty recovery

LIC# 1053
PLACER VIRDEN
8-30-10-25
K.B. - 391.67m
G.L. - 387.71m

DATE ON PROD - JAN 25/56

CORES:



100 — 219.1mm - 35.72 kg/m e 103.3m w/ 8.6t + 2% $CaCl_2$ - RETURNS (.6 m^3)

CORES: #1 - 533.4m - 551.7m - REC. 18m

200 — TOC - 197.1m (CALC)   #2 - 551.7m - 563.9m - w/ FULL RECOVERY

D.S.T.'s: NONE RUN

BLAIRMORE

PERFORATIONS: OPEN HOLE - 551.7m - 563.9m

DEPTH
400
(METRES)

STIMULATION: DEC 13/55 - SANDFRAC w/ 4546 L. GEL ACID + 1.3t SAND

TUBING - 60.3mm e 562.1m

JAN 5/59 - 2273 L. 15% HCL ACID

MAY 25/62 - 4546 L. 15% HCL ACID

FEB 28/74 - 6820 L. 28% HCL ACID

500
MISS
CRIN
OOL
CHERTY

1
2

139.7mm - 20.83 kg/m e 551.7m w/ 7.5t POZMIX + 2% GEL

600

T.D. - 563.9m

46 0410

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

8 - 30

RESERVES ONLY IN SANDHILL, 4th oolite & Cherty

Completed OH in Oolites + Cherty (36')

CUMULATIVE PROD 91-01 47 557 m³
OOIP (excluding Sandhill) = 175 260 m³

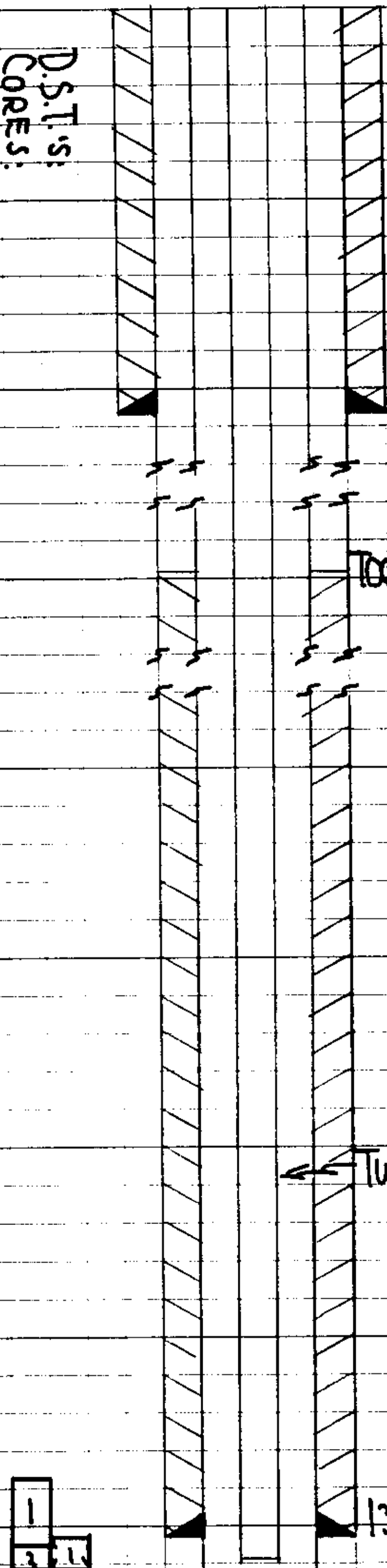
CURRENT RECOVERY = 27 %

WF RESPONSE - MAY/66 FROM 264 b/mon to 1260 b/mon
MAR/74 FROM 581 b/mon to 1537 b/mon

LIC. # 1070
PLACER VIRDEN
9-30-10-25
K.B.- 384.66m.
G.L.- 380.54m.

DATE ON PROD.- JAN.25/56

D.S.T.'S:
CORES:



100 — 219.1mm - 35.72 kg/m @ 106.68m. w/ 8.6t. + 2% CaCl2 - RETURNS

CORES: #1 - 536.45m - 554.74m - REC. 17.37m
#2 - 554.74m - 560.83m - FULL RECOVERY

200 — TOC - 198.0m (CALC)

D.S.T.'S: #1 - 552.60m - 560.83m VO GO SI GO - REC.
18.3m GOCM & 118.9m GMCO

BLAIRMORE

PERFORATIONS: OPEN HOLE 552.6m - 563.27m

DEPTH
400
(METRES)

TUBING - 60.3mm @ 559.0m

STIMULATION: DEC.19/55 - 2273 l. 15% XFMW ACID
APR.5/60 - 2273 l. 15% XFMW ACID

500

LODGEPOLE
CRIN
OOL
CHERTY

139.7mm - 20.83 kg/m @ 552.6m w/ 7.54t. 1:1 Poz + 2% GEL

600

T.D. - 563.27m

46 0410

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

)-30

[illegible] TD' 20' into Clearly

4" [illegible] (NO PAY ABOVE 3RD OO · [illegible])

CURRENT RECOVERY 40966 m³ [illegible])

OOIP ([illegible] 56156 [illegible]

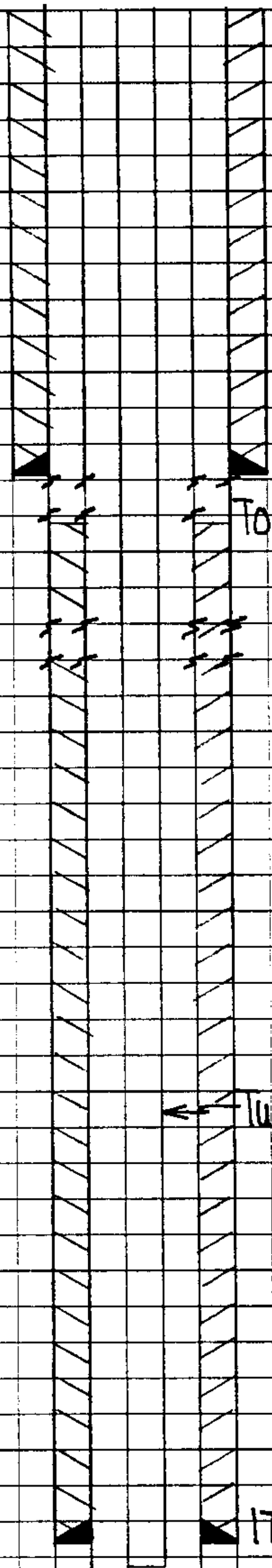
CURRENT RF = 73%

WF RESPONSE JUN/66 FROM 211 b/d to 1004 b/d

D.S.T.'s:
CORES:

LIC # 7C8
PLACER VIRDEN
10-30-10-25
K.B. - 420.62m
G.L. - 417.42m

DATE ON PROD. - MAY 28/55



100

273.1mm - 48.73kg/m @ 128.0m w/ 8.6t + 2% $CaCl_2$ - RETURNS

TOC - 242.7m (CALC)

250

CORES: #1- 556.26m - 565.4m
#2- 565.4m - 574.55m
#3- 574.55m - 580.64m
w/ FULL RECOVERY

BLAIRMORE

DEPTH

(METRES)

D.S.T.'s: #1- 566.0m - 574.55m VO 25 SI 45 - REC. 18.3m DRLG. MUD

400

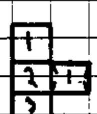
PERFORATIONS: OPEN HOLE - 575.5m - 580.6m
FEB 26/57 - DRILL OUT TO 583.7m

TUBING - 60.3mm @ 583.1m

500

STIMULATION: MAY 21/55 - 910 L. MCA & 2275 L. XFLW ACID
FEB 27/57 - 1137 L. MCA & 2275 L. 15% XFMW ACID
NOV 20/62 - 4546 L. 15% HCL ACID
MAY 11/71 - 680 L. 28% HCL ACID

MISS
CRIN
DOL



177.8mm - 29.76kg/m @ 575.5m w/ 7.1t + 3% GEL

600

T.D. - 580.6m
NEW T.D. - 583.7m

46 0410

10-30

[illegible] ONLY IN 3^{RD} & 4^{TH} OOLITES & CHERT

OH below 2^{ND} OOLITE

MAY/55 ORIGINALLY TD'D 6' into [illegible]

FEB/57 [illegible] additional 10' [illegible]

increase in [illegible] from 29.4 b/d to 43.5 b/d

CUMULATIVE PRODUCTION - 105549 m^3

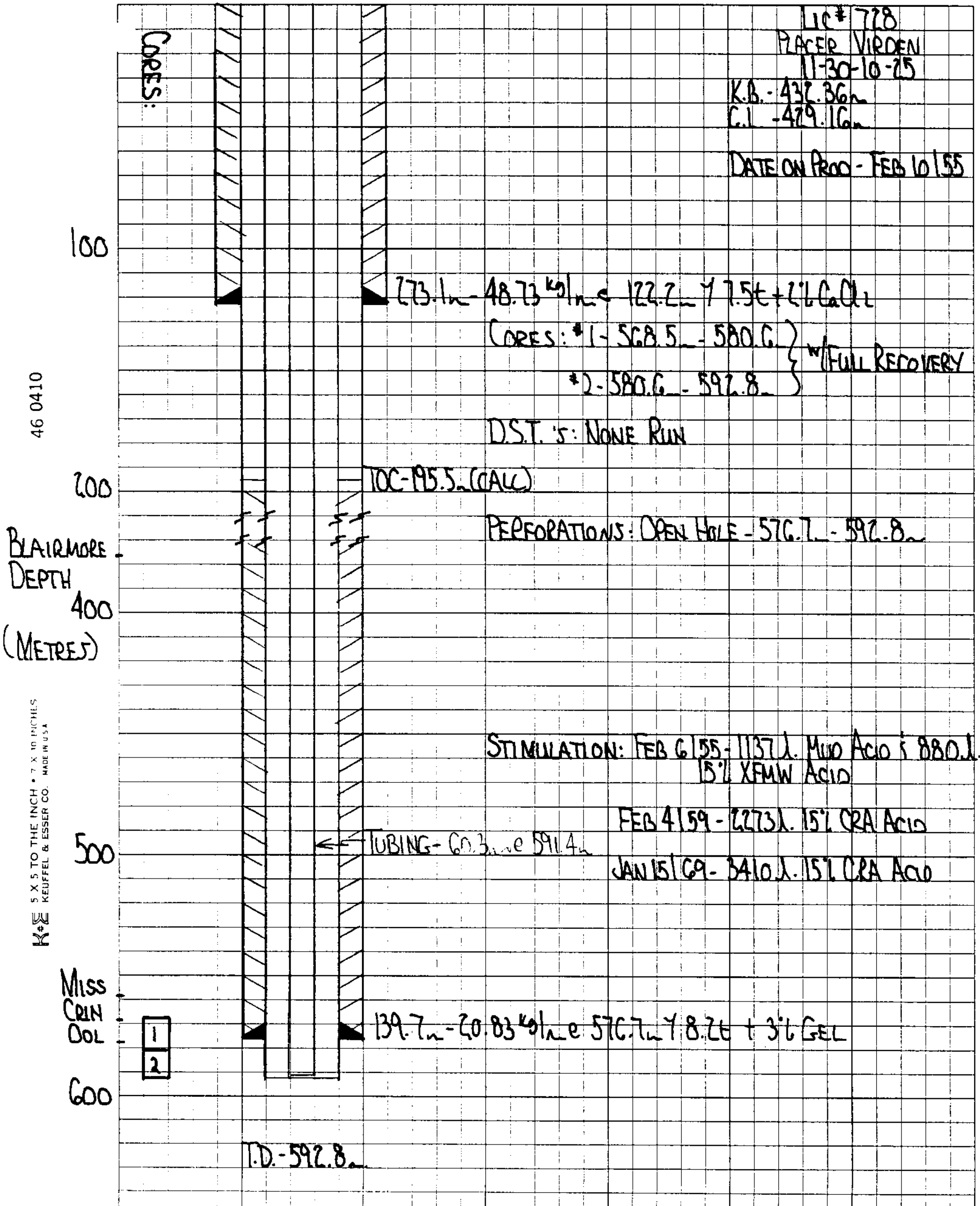
OOIP - 165800 m^3

CURRENT RECOVERY - 64 %

WF RESPONSE JUN/66 FROM 643 b/mo to 132[illegible] b/mo

INCREASING & REMAINING RELATIVELY CONSTANT AT

1700 - 2200 b/mo SINCE 1966-1988



Lic# 728
PLACER VIRDEN
11-30-10-25
K.B. - 432.36m
G.L. - 429.16m
DATE ON PROD - FEB 10/55
CORES:
100
273.1mm - 48.73 kg/m @ 122.2m w/ 7.5t + 2% CaCl2
CORES: #1 - 568.5m - 580.6m
#2 - 580.6m - 592.8m
w/ FULL RECOVERY
D.S.T.'S: NONE RUN
200
TOC - 195.5m (CALC)
PERFORATIONS: OPEN HOLE - 576.7m - 592.8m
BLAIRMORE
DEPTH
400
(METRES)
STIMULATION: FEB 6/55 - 1137 l. MUD ACID & 880 l. 15% XFMW ACID
FEB 4/59 - 2273 l. 15% CRA ACID
500
TUBING - 60.3mm @ 591.4m
JAN 15/69 - 3410 l. 15% CRA ACID
MISS
CRIN
DOL
1
2
139.7mm - 20.83 kg/m @ 576.7m w/ 8.2t + 3% GEL
600
T.D. - 592.8m

11-30

OH IN ALL ZONES EXCEPT CRINOIDAL
TD'D 5' into Cherty

OOIP EXCLUDING CRINOIDAL + CHERTY) - 84640 m^3
OOIP (CHERTY) 163434 m^3

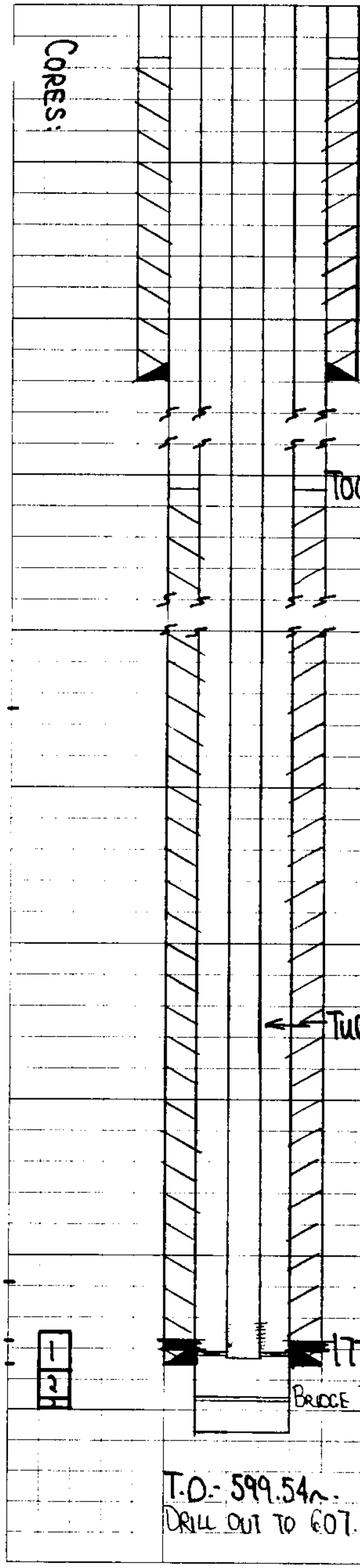
CUM. PROD. (91-01) 68541 m^3

CURRENT RECOVERY (SANDHILL + OOLITES) - 81%

WF RESPONSE OCT/66 PRODUCTION INCREASE
342 bbl/mon to 613 b/mon
FEB/69 from 753 b/mon to 1601 b/mon

LIC.# 643
PLACER VIRDEN
12-30-10-25
K.B.- 431.14m.
G.L.- 427.94m.

DATE ON PROD.- DEC.9/54



46 0410

273.1m - 48.73 kg/m @ 119.2m - 6.45 t. + 2% $CaCl_2$ - NO RETURNS

CORES: #1 - 574.85m - 587.65m
#2 - 587.65m - 596.80m
#3 - 596.80m - 599.54m
FULL RECOVERY

D.S.T.'s: NONE RUN

PERFORATIONS: OPEN HOLE - 585.83m - 599.54m
MAR. 5/56 - DRILL OUT TO 600.15m
AUG. 6/69 - DRILL OUT TO 607.16m.
AUG 14/90 - SET BRIDGE PLUG W/O.H. @ 595.3m
AUG 14/90 - 577.29m - 580.34m - 13 SPM

STIMULATION: DEC. 2/54 - 1137 L. MUD ACID & 2273 L. 15% XFMW ACID
MAR. 7/56 - 9092 L. 15% XFMW ACID
FEB. 16/60 - 2273 L. 15% XFMW ACID
OCT. 21/69 - 9092 L. 15% CRA ACID
AUG 15/90 - $3m^3$ 15% HCL ACID

177.8m - 29.76 kg/m @ 585.83m - 8.2t. + 3% GEL

T.D.- 599.54m.
DRILL OUT TO 607.16m

12-30

OH below CRINOIDAL

ORIGINAL TD 22' into [illegible] DEC/54

DEEPENED 2' MAR/56

DEEPENED 23' AUG/69 PRODUCTION INCREASE FROM 748 b/[illegible]
to 1562 b/[illegible], WOR - 1.06 to WOR - 1.76

AUG/90 set BP [illegible] [illegible] [illegible] perforated
[illegible] increase [illegible] production
[illegible] production increased from
12.6 [illegible] to 24.7 [illegible] questionable
[illegible]

- CUMULATIVE PRODUCTION - 29 55[illegible]
[illegible] 31600 [illegible]

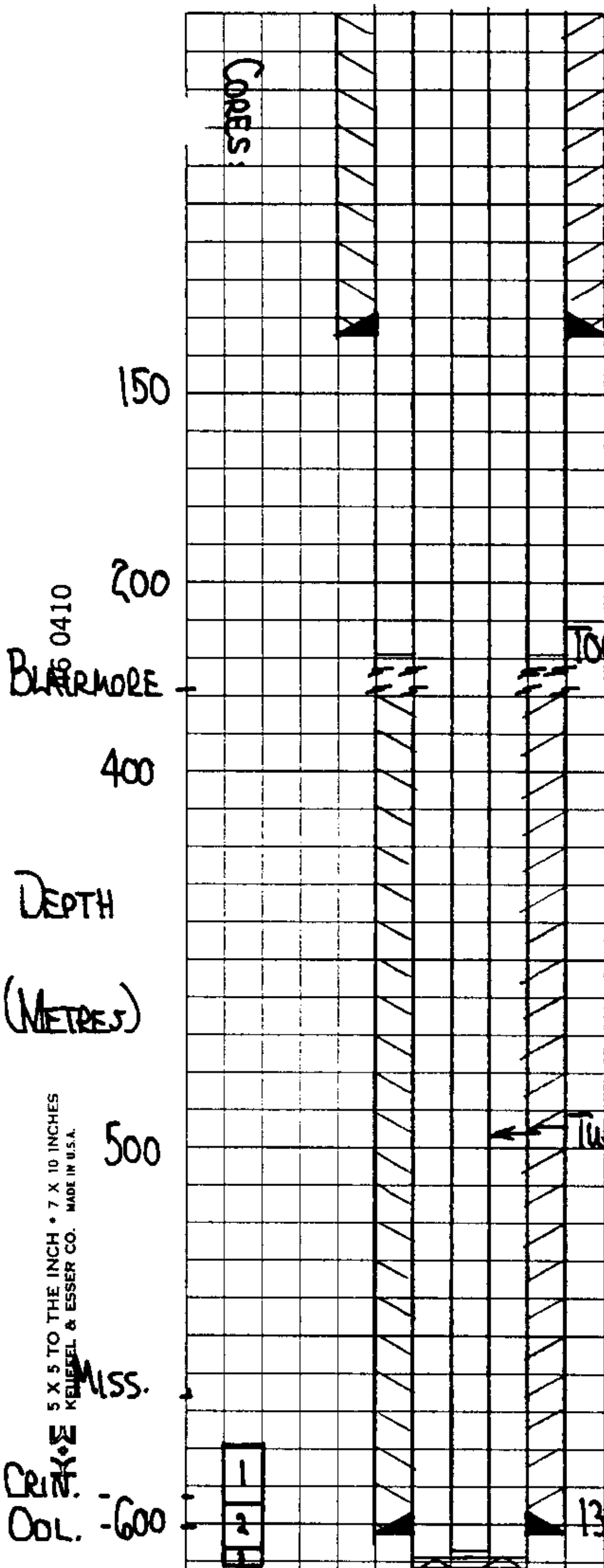
CURRENT [illegible] — [illegible] %

WF RESPONSE NOV/86 PRODUCTION INCREASE FROM
[illegible] to 1430 b/[illegible]

LIC. #1110
PLACER VIRDEN
15-30-10-25

K.B. - 432.51m.
G.L. - 428.55m.

DATE ON PROD. - MAR. 2/56



219.1m - 35.72 kg/m @ 134.4m w/ 9.7t. + 2% $CaCl_2$ - RETURNS

CORES: #1 - 579.73m - 594.97m.
#2 - 594.97m - 607.16m
#3 - 607.16m - 611.43m.
} FULL RECOVERY

TOC - 219.3m (CALC)

D.S.T.'s: NONE RUN

PERFORATIONS: OPEN HOLE - 601.98m - 611.42m.

TUBING - 60.3m @ 607.0m

STIMULATION: ACIDFRAC w/ 4546 l. GEL ACID & .9t. SAND
MAR 1/56 - ACIDFRAC w/ 4546 l. GEL ACID & .9t. SAND
AUG. 20/55 - 3.55 m³ 28% HCL ACID

139.7m - 20.83 kg/m @ 601.98m w/ 8.1t. + 2% GEL

T.D. - 611.42m
PBTD - 608.4m

12:30

OH below [illegible]

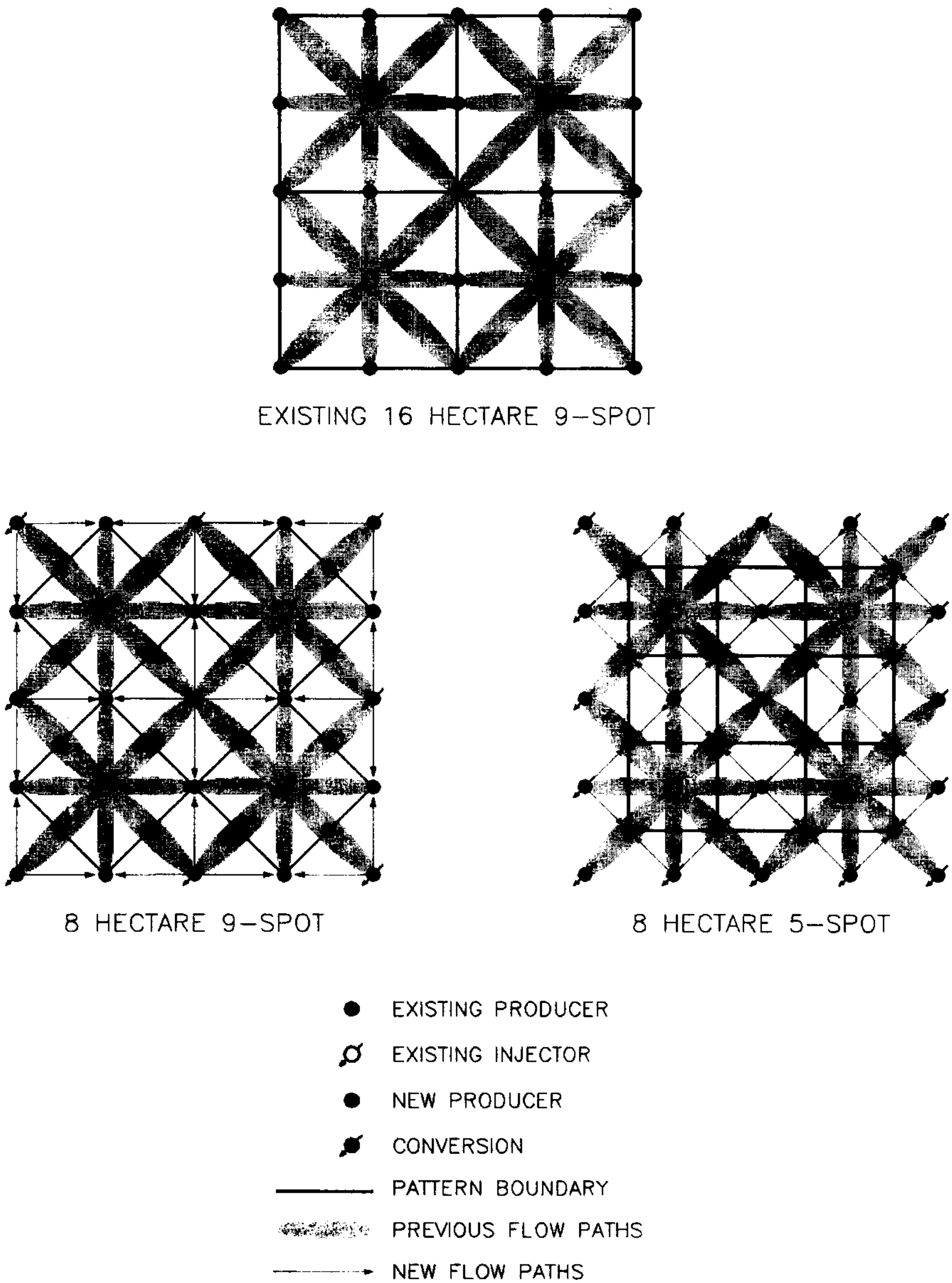
TD 4' into Chalky, no chalky [illegible]

CUMULATIVE PRODUCTION - 9697 LB

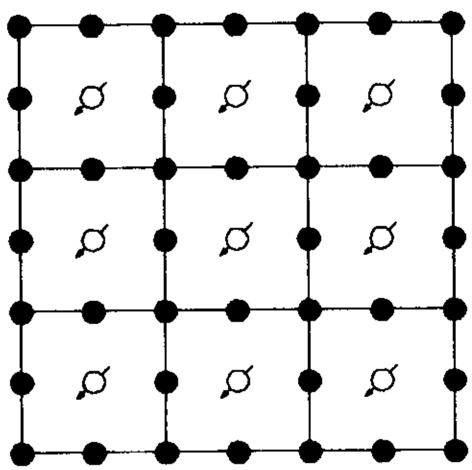
[illegible] - 84630 LB

CURRENT RECOVERY - 11 %

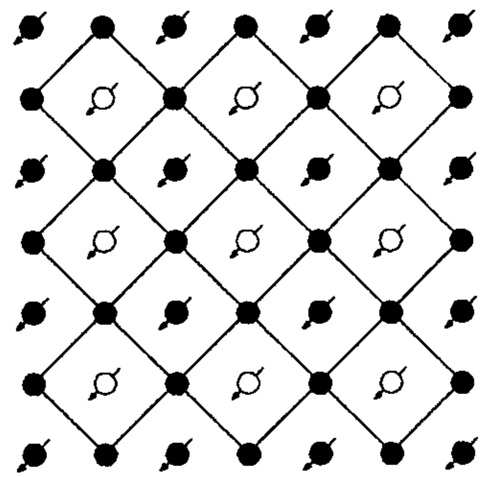
FIVE-SPOT VERSUS NINE-SPOT INFILL DEVELOPMENT



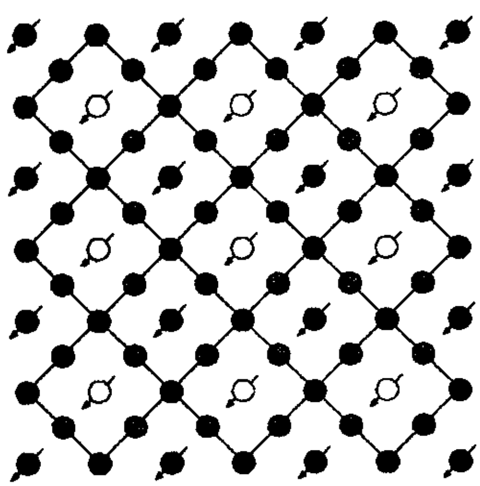
PATTERN CONFIGURATION OPTIONS



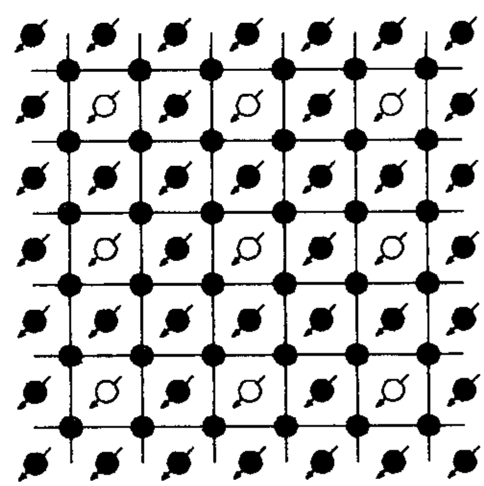
CURRENT NINE-SPOT
16 HECTARE (40 ACRE)



FIVE-SPOT
16 HECTARE (40 ACRE)



NINE-SPOT
8 HECTARE (20 ACRE)



FIVE-SPOT
8 HECTARE (20 ACRE)

● NEW PRODUCER

● CONVERSION TO INJECTION

VRU No. 1 - INFILL DRILLING APPL'N

1. CONVERSION APPEAR DESIGN TO PROVIDE WATER FENCE AT UNIT BOUNDARY → WHAT ARE ANTICIPATED EDGE LOSSES

✓2. CONCERN MINERAL OWNER IN LSD'S 13, 14 & 16-30-10-25

3. WHICH MBR'S ARE PRODUCTIVE

O/W CONTACT -563' SS in Cherty

			Ø	K
MBRS	CRINOIDAL	producing zones		
	SANDHILLS		14	56
	OOLITES (1-3)		12	12
	4th OOLITE CHERTY		13	28

4. structural high in Sec. 30

✓5. X-SECTION (ATTACHMENT 3) what are numbers associated with wells in small map on RHS of x-section

6. NET PAY CUT-OFFS

7. PROJECT AREA SELECTION

NVSU #1

VRU #1
1. structurally high
2. moderate to high oil rate
3. low water-cut
4. low to moderate reservoir depletion

- good lateral reservoir continuity
- vertically no. of tight stringers

infill well selection - undrained Cherty reserves
- access migrated oil to top of structure

8. ATTACHMENT 4

✓ - source of oil migration into Sec 30

- Clarity injection in project area — Sandhill Oolites only

- Clarity completions in project area (list of)

9. Review Abd wells in 13-30 & 14-30 → ∅ net pay attributed by Chevron → structure on top of Clarity (Fig. 5) above wells on crest of structure → dolomitized tight on high structure

10. Cumulative production map VRU #1 need

11. Are there any plans to test the Crinoidal 10% of OOIP in project area

12 NOTE 6-30 & 10-30 which have recovered >50% OOIP are not only near apex of structure but also between injectors in EW direction

13. Noted both incremental & accelerated production

14 POSSIBLE CONVERSIONS — 11-30, 6-30, 10-30

- concern → well productivity

- updip water injection - fingering & premature water breakthrough

· no concern voidage - replacement

- essentially 9-30, 15-30 form line drive along edge of pool, also 30' down structure from offset producers in project area

16. completions OH - discussion of merits wrt NVSU#1
use dual inflatable packers in OH to isolate
wet zones

17. merit in using RFT to evaluate zonal
pressures & zonal watercuts

18 infill IP = 3.96 m³/d @ a WOR = 1.5
Δ recovery = 87,300 m³

ATTACHMENT #5 - NVSU #1

19. NVSU #1 infill project selected basis good net pay, low WC,
low current recovery & poor ult. recovery + landowner support
(1) infill WOR = 30% current WOR
(2) infill IP = existing well IP - 15% dec after one yr.
(3) Δ recovery = 7.6% OOIP
actual Δ recovery 1.0%
- Cherty & Oolite units more continuous than anticipated
large portion of project ~~area~~ depleted / swept by
existing prod/inj.
→ minimize conversions due to loss of production
20. given little change in OOIP assume original porosity and
Sw estimates were correct
21. Any comments on continuity in NVSU #1
infill area after results of infill wells analyzed

22. attachment No. 6 - need more pressure data in project
area

23. Attachment 7 does Brad want actual incremental crown/freehold royalty & tax numbers

24 Attachment 8 no mention of spill mitigation equipment

25 SURFACE IMPACTS

CULTIVATED LAND - CROPPED VS PASTURE PLEASE LIST USES

FEB 15 '91 8:26 FROM PETROLEUM VIRDEN TO WPG-PETRO PAGE.001

Manitoba

Energy and Mines

WELL	DRILLING DATE	WELL	DRILLING DATE
1-29	MAR/57	12-29	MAR/57
2-29	FEB/57	14-29	SEP/67
3-29	FEB/57	1-30	NOV 55
4-29	FEB/56	2-30	FEB/55
5-29	DEC/56	3-30	JAN/55
6-29	JAN/57	4-30	DEC/54
7-29	FEB/57	5-30	NOV/54
8-29	MAR/57	7-30	FEB/55
* F6 9-29	SEP/67	8-30	NOV/55
10-29	FEB/66	9-30	NOV/55
11-29	JUL/65	10-30	MAY/55
		11-30	JAN/55
		12-30	NOV/54

DATE: FEB 13, 1991

TO: PETROLEUM
JOHN FOX

FR: BRUCE

RE: Town Well #9 SW/4 of Sec. 29-10-25
LSD 5 on opposite side of river to infill project
DRILLED 1958
H₂S Gas In #8 DRILLED FEB/57

TOTAL PAGES SENT: 12 (includes route slip)

IF YOU DO NOT RECEIVE THE ABOVE NUMBER OF PAGES,
PLEASE CALL THE SENDER AT THE ABOVE TELEPHONE NUMBER.
THANK YOU.

Manitoba

Natural Resources

Water Resources Branch
1577 Dublin Avenue
Winnipeg, Manitoba
R3E 3J5

July 22, 1987

File: 5.7.2

Mr. K. Lowden
Petroleum Inspector
Energy and Mines
Box 1359
Virden, Manitoba
R0M 2C0

Dear Keith:

Attached are two well logs for the Virden town well in SW 29-10-25W. It appears that the 1957 well was drilled as a test hole before the town well was eventually drilled in 1958. Gravel under shale perhaps implies a large slump block of shale has slid into the valley in the geologically recent past.

More information on water chemistry is available from K. Kjartanson with Environment.

Just call if we can provide any more data.

Yours truly,

Bob

R.N. Betcher, P. Eng.
Aquifer Definition Geologist

Attachments

RNB:spr

Checking w/town records it appears the well is approx 91-92 feet below existing ground level which roughly corresponds w/ground water data obtained when well was drilled in 1958.

File - Town Water Well

Petroleum Engineering Division

Virden Field Office

Water Test Well Drilling for
The Town of Virden 1956-57

Winnipeg — Mines Branch

Mr. M. J. Gobert,

March 31st, 1960.

Attached hereto, please find the report on water test wells drilled for the Town of Virden in the years 1956 and 1957.

Grady E. Johnson,
District Petroleum Engineer.

GEJ/mf

Enc.

WATER TEST WELL DRILLING FOR TOWN OF VIRDEN
1956-1957

Seeing the need for an additional water well for the Town of Virden the Town Council had a portable drilling rig of International Water Supply Limited, come in and drill test holes for water.

As shown in Schedule "A" International moved a rig in on November 10th, 1956. The rig was a small rotary type probably a Failing "500" or "750". The first hole was on lot #1, Block 94, on Ashburton Street.

Water was encountered in this well at around the 70' level but the well was drilled on to 181' when mechanical difficulties forced the abandonment of the hole. Well #1A was spudded nearby and drilling continued to 71'. A screen was set and pumping test taken, however the volume of water obtained was too small.

Test holes were then drilled as shown on Map #1.

Well #2 was drilled on an unsurveyed lot, Block 153 on Seymour Street. It was drilled to 71'.

Number 3 well on LSD 14-15-10-26 was drilled to 86', well #4 on LSD 15-15-10-26 to 101', well #5 on LSD 4-23-10-26 to 80', well #6 on LSD 1-26-10-26 to 71', and well #7 on LSD 1-20-10-25 to 56'.

All wells encountered water sand but none in sufficient quantities to warrant completion.

Oil wells drilled in section 29-10-25 had encountered a strong water flow at shallow depths. The council decided to drill a test hole in Section 29-10-25 and on January 19th, 1957 International Water Supply moved the rig back to Virden (See Schedule "B").

The hole was drilled to 35', reamed to 30' and 6" casing set. It was then drilled on to a total depth of 81' and tested. The hole was back filled to 28' and a cement plug put in the casing on February 12th, 1957.

The above well (No. 8) is the only one which appears to have been abandoned properly.

Having given #8 well a satisfactory test the present well (No. 9) was drilled by International Water Supply 100' north of No. 8 well. This well was drilled with cable tools during the spring of 1957.

The well was drilled (See Schedule "C") to 86' with 80'1" of 20" casing being cemented at a depth of 70'. 10'1" of the casing being above ground level. The same amount of 10" casing was hung in the well with 15' of 10" screen pipe being on the bottom.

Tests were run on the well indicating a capacity of 325 imperial gallons per minute.

After the construction of a new reservoir, the well went on production on May 9th, 1959.

Schedule "A"

INTERNATIONAL WATER SUPPLY, LIMITED
Water Supply Contractors
London, Ontario.

DATE: December 31, 1956

SOLD TO: Town of Virden

Invoice No. 61244

TO: Test Well Drilling

Time of Crew and Equipment: 195½ hrs.	$17.50	$3421.25
Mobilization and Demobilization		900.00
Amount Due		$4321.25

cc: Vancouver
Saskatoon

TOWN OF VIRDEN
Virden, Manitoba
Test Well Drilling

TIME OF CREW AND EQUIPMENT

Nov.	10	4 hours	Setting up
	12	8	Drilling to 74'
	13	8	Drilling to 120'
	14	8	Drilling to 181'
	15	8	Drilling on boulder at 120'
	16	8	Jarring boulder down, reaming, stopping at 168', preparing to blast.
	19	8	Pulling pipe, plugging test hole, moving to No. 1A setting up, drilling 3 holes to 10' trying to get past boulders.
	20	8	Drilling to 71', setting screen
	21	8	Blizzard
	22	8	Trying to drill gauge hole
	23	8	Drilling to gauge hole to 70', setting screen
	24	4	Developing
	27	7	Running pumping test
	28	4½	Pulling pipe and screen, moving to No. 2
	29		Waiting for instructions
	30	8	Drilling to 61' moving to No. 3 setting up
Dec.	1	8	Drilling to 86' moving to No. 4
	3	8	Drilling to 101'
	4	8	Moving to No. 5 setting up
	5	8	Drilling to 80'
	6	8	Moving to No. 6, setting up, delayed by cold
	7	8	Too cold to attempt drilling, checking iron removal plant.
	8	8	Drilling to 71'
	10	8	Moving to No. 7, setting up
	11	8	Storming
	12	8	Drilling to 56', preparing to move
	13	4	Preparing to move
	15	4	Loading out
		195½ hours.	

Schedule "D"

INTERNATIONAL WATER SUPPLY? LIMITED
Water Supply Contractors
London, Ont.

SOLD TO: Town of Virden DATE: February 28, 1957.

to: Test Well Drilling, to February 12/57

Time of Crew and Equipment: 109 Hours.	$17.50	$2907.50
Mobilizing and Demobilizing		900.00
Cement - $2.90 & 15%		3.34
Rental of Mixer - $12.00 & 15%		13.80
Amount Due		$3,824.64

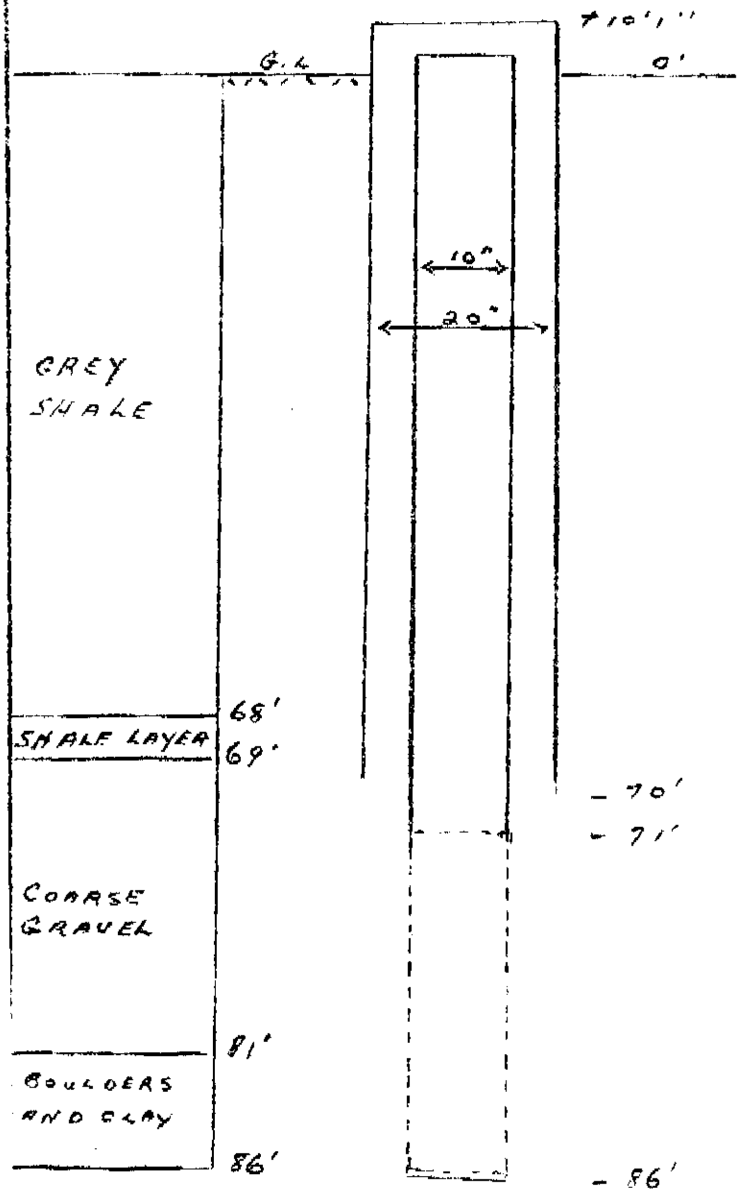
cc: H. N. Hainstock
Saskatoon Office

TOWN OF VIRDEN
Virden, Manitoba
Test Well Drilling

TIME OF CREW AND EQUIPMENT

Jan.	19	8 hours	Clearing site, preparing to dig pit
	20	4	Preparing site
	21	8	Setting up at test hole No. 8
	22	8	Finishing setting up-too cold to attempt drilling
	23	8	Too cold- -26°
Feb.	1	8	" "
	4	12	Drilling to 35', reaming out hole, setting 6" casing to 30', pouring cement grout
	5	8	Cleaning out hole, drilling to 69', setting 6" valve, capping well
	6	8	Drilling to 72'
	7	8	Drilling to 78'
	8	1	Drilling to 80'
	9	8	Drilling to 81', developing, preparing to run test
	10	8	Running pumping test, checking recovery
	11	8	Backfilling hole to 28', pouring cement plug
	12	4	Loading out
		109 hours.	

Schedule "C"



Well Material

Outer Casing 80' 1" of 20"
Inner Casing 81' 1" of 10"
Screen 15' of 10"
Plug Cement Plug
Gravel

Pump

No. 39801	Setting BP-MB 20'
No. Stages 9	Length Bowl 7'6"
Bowl 10" RKLC	Size & Lgth. Suction 10'-6"
Head TF 618	Size Column 6" x 1- 3/16"

Materials or setting details other than standard: Impellers: Trim

Motor

Make U.S.	Phase 3
H. P. 40	Cycles 60
R. P. M. 1800	Volts 220-440
Type CFV	Ampts. 49-98
Frame 404P	Serial 2585011

Bearing Nos. Upper-7220M, Lower-6212J

Special Equipment

Well No. 2

B.P. referred to original ground level + 10' 1"
Clear depth below B.P. 96' 1"
Started 5/9/59 **Final Test**
Preliminary Test 6/6/58 Static Level 1' 10"
Final Test 11-13/58 Pumping Level 4'3
Guarantee ---- IGPM Capacity 325 IGPM
Contract Pressure____# Pressure Pump____#
Length Air Line 22'8" Main________#

INTERNATIONAL WATER SUPPLY LIMITED
Montreal London, Canada Saskatoon
~~Oakville Water supply contractors Vancouver~~

VIRDEN, MANITOBA.

Drilled by L. Slack Drawn by J.W.
Installed by F. Hopper Approved by

PROVINCE OF MANITOBA
GROUND WATER DATA

YEAR | 1. QUARTER OR LEGAL SUB-DIVISION (SE SW NW NE) | SECTION | TOWNSHIP | RANGE | MER. (E W)

LOG

FROM FEET	TO FEET	DESCRIPTION
0	67	GREY CLAY
67	68	BRITTLE SHALE & CLAY
68	81	VERY COARSE GRAVEL, SMOOTH, NO FINE
81	—	LARGE BOULDERS, CLAY PACKED

Test Readings

			Pump Level
9 AM – 12 AM		@ 45 IGPM	Ground
12	AM	95 IGPM	6'5"
1	PM	95	5'11"
2		105	5'9"
3		100	5'9"
4		100	5'8"
5		100	5'7"

M P - Ground Level

LOCATION

L.S.D. OR ¼ SW SEC. 29 TP. 10 R. 25 E. ☐ W. ☒ OF P. MER.

REMARKS T.H. #9 - VIRDEN 3mi E. OF TOWN - ASSINIBOINE RIVER VALLEY

DATE COMPLETED: DAY 11 MONTH FEB 1957

OWNER'S NAME TOWN OF VIRDEN

ADDRESS VIRDEN

DRILLER'S NAME IWS (Peguequat)

ADDRESS SASKATOON

GROUND ELEV. 1225 FT. (M.S.L.) MEAS. ☐ ESTIM. ☒

LOCATION SKETCH

WELL CONSTRUCTION

CASING

LENGTH 30 FEET, DIAMETER 6 IN.

OUTSIDE CASING

LENGTH ______ FEET, DIAMETER ______ IN.

PERFORATIONS

TYPE ______

MAKE ______

MATERIAL ______

SLOT SIZE ______

LENGTH ______ FEET

DIAMETER ______ INCHES

DEPTH TO TOP OF PERF. ______ FEET

GRAVEL PACK

TYPE ______ GRAIN SIZE ______

LENGTH ______ FEET

DIAMETER ______ INCHES

PUMPING TEST

STATIC L. 4 FT. ABOVE ■ BELOW ☐ G.L. D. 11 M. 2 1957

PUMPING RATE 100 I.G.P.M.

PUMPING TIME 8 HOURS ______ MINUTES

PUMPING LEVEL 6 FEET ABOVE ☐ BELOW ■ G.L.

WATER TEMP. ______ °F D. ______ M. ______ 19 ______

SPECIFIC CAPACITY ~~20~~ 10 I.G.P.M./FT.

AQUIFER PROPERTIES

STORAGE COEFFICIENT ______

TRANSMISSIBILITY ______ I.G.P.D./FT.

SATURATED THICKNESS ______ FEET

PERMEABILITY ______ I.G.P.D./SQ.FT.

OTHER DATA

FILE, REPORT, ETC. ______

GOWN 62F15W045

REMARKS:

AFTER SHUT DOWN - RECOVERY IMMEDIATE - FLOWING 20 IGPM.

CASING CEMENTED IN AND PLUGGED @ 20' LEVEL w/ CEMENT

H2S gas bubbling and water greenish color

R

WATER USE	DOMESTIC	☐
	MUNICIPAL	☐
	INDUSTRIAL	☐
	IRRIGATION	☐
	AIR COND.	☐
	OTHER	☐
WELL USE	PRODUCTION	☐
	RECHARGE	☐
	OBSERVATION	☐
	TEST WELL	☒
WELL DEPTH, FEET	1 - 50	☐
	51 - 150	☒
	151 - 300	☐
	> 300	☐
STATIC L. FEET	ABOVE GROUND	☒
	0 - 10	☐
	> 10	☐
SPECIFIC CAPACITY	< 1	☐
	1 - 10	☐
	> 10	☒
AQUIFER MATERIAL	SAND AND / OR GRAVEL	☒
	SHALE	☐
	SANDSTONE	☐
	LIMESTONE AND / OR DOLOMITE	☐
	OTHER	☐
	BEDROCK	☐
	AQUIFER TEST	☐
	ELECTRIC LOG	☐
	FORMATION SAMPLES	☐

HD-gw-5

CHEMICAL ANALYSIS

SAMPLE COLLECTED BY ______ DAY ______ MONTH ______ 19 ______

REMARKS: ______

LABORATORY ANALYSIS

LABORATORY: ______ LAB. No. ______

BY ______ DAY ______ MONTH ______ 19 ______

APPEARANCE ______
COLOUR ______
HAZEN UNITS ______
TURBIDITY ______
pH ______
EC MICROMHOS/CM 25°C ______
SATURATION INDEX AT 42°F ______
SATURATION INDEX AT 170°F ______
% Na ______
S A R ______

CATIONS	mgs. / l.	me / l.	% RV	ANIONS	mgs. / l.	me / l.	% RV
Ca				HCO_3			
Mg				CO_3			
Na				SO_4			
K				Cl			
Fe				F			
Mn				NO_3			
TOTAL				TOTAL			

B ______ mgs./l. SUSP. SOLIDS ______ mgs./l.
SiO_2 ______ mgs./l. DISS. SOLIDS ______ mgs./l.
TOTAL SOLIDS ______ mgs./l.
ALKALINITY, Ca CO_3 ______ mgs./l.
NON CARBONATE HARDNESS, Ca CO_3 ______ mgs./l.
TOTAL HARDNESS, Ca CO_3 ______ mgs./l.

REMARKS:

Virden
Roth 2CO

FIELD ANALYSIS

BY I. W. S.
D 11 M. FEB 1957

HACH KIT

Na Cl ______ p.p.m.
Fe 1.0 p.p.m.
HARDNESS 102 p.p.m.
pH 8.0

H2S GAS BUBLING
STEADY
WATER GREENISH

SOLUBRIDGE

______ MICROHMOS/CM
______ GR./GAL. NaCl.
p.p.m.

REMARKS: ______

BACTERIOLOGICAL ANALYSIS

SAMPLE COLLECTED BY ______ DAY ______ MONTH ______ 19 ______

REMARKS: ______

COLI A GROUP M.P.N. ______
STANDARD PLATE COUNT ______
NITRATE (AS ______) ______ p.p.m.

REMARKS: ______

	LABORATORY ANALYSIS	☐
	FIELD ANALYSIS	☐
	BACT. ANALYSIS	☐
DISSOLVED SOLIDS, mgs / l.	0 - 500	☐
	501 - 1,000	☐
	1,001 - 2,000	☐
	2,001 - 5,000	☐
	5,001 - 10,000	☐
	> 10,000	☐
TOTAL HARDNESS Ca CO_3, mgs. / l.	0 - 150	☐
	151 - 300	☐
	301 - 500	☐
	501 - 1,000	☐
	> 1,000	☐
IRON mgs. / l.	< 0.50	☐
	0.50 - 5.0	☐
	> 5.0	☐
NITRATE NO_3, mgs. / l.	0 - 45	☐
	46 - 100	☐
	> 100	☐
BORON mgs / l.	0 - 0.5	☐
	0.6 - 2.5	☐
	> 2.5	☐
% Na	< 60	☐
	> 60	☐
S.A.R.	< 26	☐
	> 26	☐
COLIF. M.P.N.	< 10	☐
	> 10	☐

YEAR	1. QUARTER OR LEGAL SUB-DIVISION	SECTION	TOWNSHIP	RANGE	MER.
7 4 2 1 7 4 2 1	SE SW NW NE 1 7 4 2 1	2 1 7 4 2 1	7 4 2 1 7 4 2 1	2 1 7 4 2 1	E W

PROVINCE OF MANITOBA
GROUND WATER DATA

LOG

FROM FEET	TO FEET	DESCRIPTION
0	68	GREY SHALE
68	69	SHALE LAYER
69	81	COARSE GRAVEL
81	86	BOULDERS & CLAY

LOCATION

L.S.D. OR ¼ SW SEC. 29 TP. 10 R. 25 E. ☐ W. ☒ OF P. MER.

REMARKS: TOWN WELL #2 VIRDEN (T.H. #9 - VIRDEN)

DATE COMPLETED: DAY 13 MONTH 11 19 58

OWNER'S NAME: TOWN OF VIRDEN

ADDRESS: VIRDEN

DRILLER'S NAME: IWS

ADDRESS: SASKATOON

GROUND ELEV. 1225 FT. (M.S.L.) MEAS. ☐ ESTIM. ☒

LOCATION SKETCH

WELL CONSTRUCTION

CASING

LENGTH 81.08 FEET DIAMETER 10 IN.

OUTSIDE CASING

LENGTH 80.08 FEET, DIAMETER 20 IN.

PERFORATIONS

TYPE

MAKE

MATERIAL

SLOT SIZE

LENGTH 15 FEET

DIAMETER 10 INCHES

DEPTH TO TOP OF PERF. 81 FEET

Cement Plug

GRAVEL PACK

TYPE GRAIN SIZE

LENGTH FEET

DIAMETER INCHES

PUMPING TEST

STATIC 8 FT. ABOVE / BELOW G.L. D. 13 M. 11 19 58

PUMPING RATE 325 I.G.P.M.

PUMPING TIME HOURS MINUTES

PUMPING LEVEL 4.5 FEET ABOVE ☐ BELOW ☒ G.L.

WATER TEMP. °F D. M. 19

SPECIFIC CAPACITY 26.1 I.G.P.M./FT.

AQUIFER PROPERTIES

STORAGE COEFFICIENT

TRANSMISSIBILITY I.G.P.D./FT.

SATURATED THICKNESS FEET

PERMEABILITY I.G.P.D./SQ.FT.

OTHER DATA

FILE, REPORT, ETC.

GOWN 62F15W046

REMARKS:

$SO_4 + 2H_2CO$ (organ) → $2HCO_3 + H_2S$

pH 7.8

WATER USE	
DOMESTIC	☐
MUNICIPAL	☒
INDUSTRIAL	☐
IRRIGATION	☐
AIR COND.	☐
OTHER	☐

WELL USE	
PRODUCTION	☒
RECHARGE	☐
OBSERVATION	☐
TEST WELL	☐

WELL DEPTH, FEET	
1 - 50	☐
51 - 150	☒
151 - 300	☐
> 300	☐

STATIC L. FEET	
ABOVE GROUND	☒
0 - 10	☐
> 10	☐

SPECIFIC CAPACITY	
< 1	☐
1 - 10	☐
> 10	☒

AQUIFER MATERIAL	
SAND AND / OR GRAVEL	☒
SHALE	☐
SANDSTONE	☐
LIMESTONE AND / OR DOLOMITE	☐
OTHER	☐

BEDROCK	☐
AQUIFER TEST	☐
ELECTRIC LOG	☐
FORMATION SAMPLES	☐

CHEMICAL ANALYSIS

SAMPLE COLLECTED BY DEPT. OF HEALTH DAY ______ MONTH JAN. 19 70

REMARKS: Int. water Supply 11-1-64
Sampled @ Valley Pump House (Sample No. 64574)

LABORATORY ANALYSIS

LABORATORY: ENV. HEALTH LAB. No. ______
BY ______ DAY ______ MONTH ______ 19 ______

APPEARANCE ______
COLOUR 45
HAZEN UNITS ______
TURBIDITY 7
pH 8.0 7.5
EC MICROMHOS/CM 25°C. 1800
SATURATION INDEX AT 42°F. ______
SATURATION INDEX AT 170°F. ______
% Na ______
S.A.R. ______

CATIONS	mgs. / l.	me / l.	~~[illegible]~~	ANIONS	mgs. / l.	me / l.	~~[illegible]~~
Ca	19.2	0.96	50	HCO_3	830	13.6	
Mg	4.5	0.36	26	CO_3	0		40
Na	447	19.40	100.1	SO_4	2		8
K				Cl	275	7.25	405
Fe	1.2		1.0	F	.72		
Mn			0	NO_3	0		
TOTAL	471.9	20.72		TOTAL	1107.72	20.85	

B ______ mgs./l.
SiO_2 16 mgs./l.
SUSP. SOLIDS ______ mgs./l.
DISS. SOLIDS ______ mgs./l.
TOTAL SOLIDS ______ mgs./l.
ALKALINITY, Ca CO_3 680 / 664 mgs./l.
NON CARBONATE HARDNESS, Ca CO_3 0 mgs./l.
TOTAL HARDNESS, Ca CO_3 76 / 66 mgs./l.

REMARKS: Sam

FIELD ANALYSIS

BY ______
D. ______ M. ______ 19 ______

HACH KIT

Na Cl ______ p.p.m.
Fe ______ p.p.m.
HARDNESS ______ p.p.m.
pH ______

SOLUBRIDGE

______ MICROHMOS/CM
______ GR./GAL. NaCl.
______ p.p.m.

REMARKS: ______

BACTERIOLOGICAL ANALYSIS

SAMPLE COLLECTED BY ______ DAY ______ MONTH ______ 19 ______
REMARKS ______

COLIFORM GROUP M.P.N. ______
STANDARD PLATE COUNT ______
NITRATE (AS ______) ______ p.p.m.

REMARKS: ______

LABORATORY ANALYSIS	☐
FIELD ANALYSIS	☐
BACT. ANALYSIS	☐
DISSOLVED SOLIDS, mgs. / l. 0 - 500	☐
501 - 1,000	☐
1,001 - 2,000	☐
2,001 - 5,000	☐
5,001 - 10,000	☐
> 10,000	☐
TOTAL HARDNESS Ca CO_3, mgs. / l. 0 - 150	☐
151 - 300	☐
301 - 500	☐
501 - 1,000	☐
> 1,000	☐
IRON mgs. / l. < 0.50	☐
0.50 - 5.0	☐
> 5.0	☐
NITRATE NO_3, mgs. / l. 0 - 45	☐
46 - 100	☐
> 100	☐
BORON mgs. / l. 0 - 0.5	☐
0.6 - 2.5	☐
> 2.5	☐
% Na < 60	☐
> 60	☐
S.A.R. < 26	☐
> 26	☐
COLIF. M.P.N. < 10	☐
> 10	☐

131-1-30-10-

CORE LABORATORIES-CANADA LTD.
CALGARY ALBERTA

Company	- CANADIAN PROSPECT LTD.	Date Report	- March 7, 1955	Page	- 1 of 3
Well	- CANADIAN PROSPECT ROSELEA No. 7-30	Location	-	File	- EL-1341
Field	- VIRDEN-ROSELEA	Formation	- MISSISSIPPIAN	Analysts	- DA-LM
Province	- MANITOBA	Cores	- DIAMOND	Remarks	-

SAMPLE NUMBER	DEPTH REPRESENTED FEET	FOOTAGE REPRESENTED	PERMEABILITY TO AIR HORIZONTAL K MAX	PERMEABILITY TO AIR HORIZONTAL K 90°	PERMEABILITY TO AIR VERTICAL	POROSITY PER CENT	VISUAL EXAMINATION
Depth of Core Analyzed 1895' - 1980'							
CORE NO. 1 1895' - 1945' (Rec. 50.0')							
-	1895.0-1905.9	10.9	-	-	-	-	Not received
-	1905.9-1930.1	24.2	-	-	-	-	Dense, no sample
1	1930.1-1930.8	0.7	0.84	0.81	0.59	6.5	Intergranular
2	1930.8-1932.8	2.0	0.46	0.32	0.21	4.3	Intergranular
-	1932.8-1933.1	0.3	-	-	-	-	Dense, shaly
3	1933.1-1934.6	1.5	0.63	0.56	0.29	3.8	Intergranular
-	1934.6-1935.9	1.3	-	-	-	-	Dense, no sample
4	1935.9-1936.6	0.7	3.0	2.9	1.0	11.6	Intergranular
5	1936.6-1937.9	1.3	3.3	3.0	1.7	9.2	Intergranular
6	1937.9-1939.4	1.5	56.0	51.0	21.0	17.6	Intergranular
7	1939.4-1940.9	1.5	23.0	22.0	11.0	14.1	Intergranular
8	1940.9-1941.6	0.7	22.0	20.0	2.8	13.2	Intergranular
9	1941.6-1943.0	1.4	22.0	21.0	11.0	14.5	Intergranular
10	1943.0-1944.1	1.1	3.0	2.4	1.3	9.5	Intergranular
11	1944.1-1945.0	0.9	154.0	128.0	86.0	20.0	Intergranular
CORE NO. 2 1945' - 1980' (Rec. 35.0')							
12	1945.0-1946.3	1.3	36.0	50.0	24.0	23.0	Intergranular
13	1946.3-1948.0	1.7	150.0	42.0	14.0	16.8	Intergranular, fractured
14	1948.0-1949.5	1.5	2.1	2.0	<0.01	11.3	Intergranular
15	1949.5-1950.3	0.8	2.5	2.2	0.33	11.2	Intergranular

CORE LABORATORIES-CANADA LTD.
CALGARY ALBERTA

CANADIAN PROSPECT LTD.
CANADIAN PROSPECT ROSELEA #7-30

SAMPLE NUMBER	DEPTH REPRESENTED FEET	FOOTAGE REPRESENTED		PERMEABILITY TO AIR HORIZONTAL K MAX	K 90°)	VERTICAL	POROSITY PER CENT	VISUAL EXAMINATION
Core No. 2 - Cont'd.			1st					
16	1950.3-1951.5	1.2		2.4	1.9	1.7	13.2	Pin-point vugs, intergr
17	1951.5-1952.9	1.4		1.0	1.0	0.13	10.5	Intergranular
18	1952.9-1954.8	1.9		2.3	2.2	0.86	13.9	Intergranular
-	1954.8-1955.5	0.7		-	-	-	-	Dense, shaly
19	1955.5-1956.9	1.4		65.0	39.0	8.0	13.2	Intergranular
-	1956.9-1957.3	0.4	2nd	-	-	-	-	Dense, shaly
20	1957.3-1958.6	1.3		2.1	2.0	0.72	10.0	Intergranular
21	1958.6-1959.9	1.3		7.7	5.9	5.0	13.3	Intergranular
22	1959.9-1961.0	1.1		1.9	1.8	0.94	8.0	Intergranular, pin poin
-	1961.0-1963.8	2.8	3rd	-	-	-	-	Dense, shaly
23	1963.8-1965.4	1.5		1.2	1.2	0.23	9.4	Pin point vugs, intergr
24	1965.4-1966.4	1.0		23.0	22.0	14.0	13.0	Intergranular
25	1966.4-1967.7	1.3		56.0	47.0	17.0	15.5	Intergranular
-	1967.7-1971.9	4.2		-	-	-	-	Dense, shaly
26	1971.9-1972.7	0.8		0.56	0.38	0.37	4.2	Intergranular
27	1972.7-1973.7	1.0		4.4	4.3	1.7	9.4	Intergranular
28	1973.7-1975.4	1.7	4th	2.7	2.7	0.58	9.0	Intergranular
29	1975.4-1976.6	1.2		46.0	21.0	7.7	11.7	Intergranular
30	1976.6-1977.9	1.3		24.0	21.0	11.0	12.9	Intergranular
31	1977.9-1978.9	1.0		89.0	87.0	62.0	16.1	Intergranular
32	1978.9-1980.0	1.1		27.0	26.0	12.0	14.5	Intergranular

CORE LABORATORIES-CANADA LTD.
CALGARY ALBERTA

CANADIAN PROSPECT LTD.
CANADIAN PROSPECT ROSEIRA #7-30

Core with Permeability 0.0 to 1.0 Millidarcys

Total footage of core with 0.0 to 1.0 millidarcys permeability	5.0'
Weighted average porosity of core with 0.0 to 1.0 millidarcys permeability	4.44%
Per cent of analyzed core having 0.0 to 1.0 millidarcys permeability	12.4%
Weighted average horizontal permeability of core with 0.0 to 1.0 millidarcys	0.58 md.

Core with Permeability 1.0 to 10 Millidarcys

Total footage of core with permeabilities 1.0 to 10 millidarcys permeability	17.9'
Weighted average porosity of core with permeabilities 1.0 to 10 millidarcys	10.74%
Per cent of analyzed core having permeabilities 1.0 to 10 millidarcys	44.5%
Weighted average horizontal permeability of core with permeability 1.0 to 10 md.	2.8 md.

Core with Permeability Greater than 10 Millidarcys

Total footage of core with permeabilities greater than 10 millidarcys	17.3'
Weighted average porosity of core with permeabilities greater than 10 millidarcys	15.49%
Per cent of analyzed core having permeabilities greater than 10 millidarcys	43.1%
Weighted average horizontal permeability of core with permeability greater than 10 md.	61 md.

Depth of core analyzed	1895' - 1980'
Total footage	85.0'
Footage analyzed	40.2'
Footage not analyzed .... Dense 33.9' .... Not Received 10.9'	44.8'
Weighted average porosity of core analyzed	12.00%
Weighted average horizontal permeability of core analyzed	28 md.

CORE LABORATORIES-CANADA LTD
CALGARY ALBERTA

Company	- THE CALIFORNIA STANDARD COMPANY	Date Report	- OCTOBER 9, 1962	Page	- 1 of 4
Well	- CANADIAN PROSPECT ROSELEA 8-30	Formation	- MISSISSIPPIAN	File	- CNP-3-2601
Field	- ROSELEA AREA, MANITOBA	D. Fluid	- GYP BASE	Analysts	- JB:KG
Location	- LSD 8-30-10-25 W1	Analysis	- FULL DIAMETER	Cores	- DIAMOND

SAMPLE NUMBER	DEPTH REPRESENTED FEET	FOOTAGE REPRESENTED	PERMEABILITY TO AIR HORIZONTAL K MAX	PERMEABILITY TO AIR HORIZONTAL K 90°	PERMEABILITY TO AIR VERTICAL	POROSITY PER CENT	POROSITY X FEET	DENSITY BULK	DENSITY GRAIN	VISUAL EXAMINATION
CORED INTERVAL RECEIVED 1810' - 1850'										
CORE NO. 1 Not received										
CORE NO. 2 1810' - 1850' (Rec. 42.3')										
1	1810.0-1811.0	1.0	3.7	3.3	0.93	7.5	7.50	2.49	2.70	Intergran. anhydr. pin p vugs, stylolite
2	1811.0-1811.9	0.9	15.	13.	7.1	13.6	12.24	2.35	2.72	Intergran. pin pt. vugs, anhydr. few small vugs
3	1811.9-1812.8	0.9	22.	21.	2.3	13.5	12.15	2.35	2.72	Intergran. few pin pt.v few small vugs, anhydr.
4	1812.8-1813.7	0.9	2.[illegible]	2.4	1.2	10.1	9.09	2.45	2.73	Intergran.pin pt.vugs, anhydritic
5	1813.7-1814.6	0.9	10.	10.	5.2	12.1	10.89	2.38	2.71	Intergran. anhydr. pin point vugs
6	1814.6-1815.2	0.6	0.20	0.83	0.40	11.5	6.90	2.47	2.79	Intergran. few pin pt. vugs, anhydritic
7	1815.2-1816.1	0.9	5.3	5.3	1.7	12.0	10.80	2.44	2.78	Intergran.few pin pt.vug
8	1816.1-1816.8	0.7	1.1	1.0	0.06	9.1	6.37	2.50	2.75	Intergran.few pin pt.vug
9	1816.8-1817.4	0.6	3.2	2.5	0.75	9.3	5.58	2.45	2.71	Intergran.few pin pt.vug
-	1817.4-1817.6	0.2 Chalky	-	-	-	-	-	-	-	No stain
10	1817.6-1818.6	1.0	2.1	2.0	0.81	10.5	10.50	2.44	2.72	Intergran. pin pt. vugs
11	1818.6-1819.1	0.5	4.5	4.0	2.2	12.6	6.30	2.36	2.71	Intergran. vert. fractur. few pin pt.vugs, anhydr.
12	1819.1-1819.6	0.5	3.7	3.3	1.7	11.7	5.85	2.41	2.72	Intergran. anhydr. few p pt. vugs, vert. fractur.
13	1819.6-1820.3	0.7	10.	9.9	5.1	12.7	8.89	2.38	2.73	Intergran. pin pt. vugs anhydritic

SAMPLE NUMBER	DEPTH REPRESENTED FEET	FOOTAGE REPRESENTED	PERMEABILITY TO AIR (HORIZONTAL) K MAX	PERMEABILITY TO AIR (HORIZONTAL) K 90°	PERMEABILITY TO AIR VERTICAL	POROSITY PER CENT	POROSITY X FEET	DENSITY BULK	DENSITY GRAIN	VISUAL EXAMINATION
CORE NO. 2 con't.										
14	1820.3-1821.3	1.0	5.6	3.1	0.79	8.7	8.70	2.48	2.72	intergran. pin pt.vugs, anhydr.
15	1821.3-1821.8	0.5	6.1	4.8	0.57	15.6	7.80	2.35	2.79	intergran. few pin pt. vugs
16	1821.8-1822.8	1.0	3.1	3.0	1.0	9.9	9.90	2.49	2.76	Intergranular
17	1822.8-1823.7	0.9	1.2	1.2	0.29	9.6	8.64	2.53	2.79	Intergran. few small vugs
18	1823.7-1824.5	0.8	2.4	1.9	0.74	8.3	6.64	2.49	2.72	Intergran. anhydr. few small v
19	1824.5-1826.1	1.6	13.	11.	0.17	14.0	22.40	2.37	2.76	Intergran. anhydr. pin pt.vugs
20	1826.1-1827.5	1.4	14.	13.	5.4	14.6	20.44	2.34	2.74	Intergran. few small vugs, anhydritic
21	1827.5-1828.9	1.4	11.	10.	4.7	11.2	15.68	2.41	2.72	Intergran. pin pt.vugs, anhydr.
22	1828.9-1829.9	1.0	2.9	2.8	0.79	10.3	10.30	2.45	2.73	Intergran. pin pt.vugs, anhydr
23	1829.9-1830.5	0.6	21.	17.	9.0	15.5	9.30	2.36	2.79	Intergran.few small vugs,anhyd
24	1830.5-1831.4	0.9	10.	10.	2.9	13.0	11.70	2.36	2.71	Intergran.pin pt.vugs, few sma vugs, anhydritic
25	1831.4-1832.3	0.9	6.3	6.1	1.0	12.2	10.98	2.38	2.71	Intergran. pin pt. vugs, few small vugs
26	1832.3-1833.1	0.8	12.	11.	4.7	13.9	11.12	2.35	2.73	Intergran. pin pt. vugs,anhydr
27	1833.1-1834.2	1.1	11.	9.4	2.7	12.4	13.64	2.37	2.71	Intergran. few pin pt.vugs, anhydritic
28	1834.2-1835.7	1.5	6.6	6.2	1.6	9.9	14.85	2.45	2.72	Intergran. pin pt.vugs,few small vugs
29	1835.7-1836.7	1.0	2.5	2.6	0.93	8.9	8.90	2.48	2.72	Intergran. pin pt. vugs
30	1836.7-1837.6	0.9	2.8	2.5	0.61	10.0	9.00	2.44	2.72	Intergran. anhydr. pin pt.vugs few small vugs
31	1837.6-1838.4	0.8	8.5	8.0	2.7	13.0	10.40	2.39	2.75	Intergran. anhydr. few small v
32	1838.4-1839.2	0.8	1.9	1.9	0.56	9.1	7.28	2.43	2.67	Intergran. few small vugs, pin point vugs
33	1839.2-1840.5	1.3	8.0	7.3	2.4	12.6	16.38	2.39	2.72	Intergran. few pin pt. vugs, anhydritic
34	1840.5-1841.5	1.0	9.6	7.8	3.6	14.3	14.30	2.31	2.72	Intergran. anhydritic
35	1841.5-1842.5	1.0	7.8	7.5	2.2	13.6	13.60	2.35	2.72	Intergran. few small vugs
36	1842.5-1843.5	1.0	17.	16.	2.1	15.5	15.50	2.30	2.72	Intergran. pin pt.vugs, few small vugs, anhydritic

CORE LABORATORIES CANADA LTD.
CALGARY ALBERTA

THE CALIFORNIA STANDARD COMPANY
CANADIAN PROSPECT ROSELEA 8-30

File - CNP-3-2601

SAMPLE NUMBER	DEPTH REPRESENTED FEET	FOOTAGE REPRESENTED	PERMEABILITY TO AIR HORIZONTAL K MAX.	PERMEABILITY TO AIR HORIZONTAL K 90°	PERMEABILITY TO AIR VERTICAL	POROSITY PER CENT	POROSITY x FEET	DENSITY BULK	DENSITY GRAIN	VISUAL EXAMINATION
CORE NO. 2 con't.										
37	1843.5-1844.2	0.7	11.	9.1	0.99	15.2	10.64	2.28	2.69	Intergran. pin pt. vugs, anhydritic
38	1844.2-1845.1	0.9	12.	11.	2.5	13.3	16.47	2.22	2.70	Intergran. few small vugs, pin point vugs
39	1845.1-1846.1	1.0	4.3	4.1	0.76	14.7	14.70	2.31	2.70	Intergran. few small vugs
40	1846.1-1847.1	1.0	1.6	1.4	0.79	12.6	12.60	2.36	2.72	Intergran. few small vugs
41	1847.1-1848.2	1.1	6.4	5.4	0.74	15.0	16.50	2.30	2.71	Intergran. few small vugs
-	1848.2-1848.4	0.2	-	-	-	-	-	-	-	No stain
42	1848.4-1849.3	0.9	5.3	5.0	1.3	14.6	13.14	2.38	2.73	Intergran. few pin pt. vugs small vugs
43	1849.3-1850.6	1.3	5.3	5.0	1.8	15.3	19.89	2.34	2.76	Intergran. few small vugs
44	1850.6-1851.7	1.1	5.8	3.9	2.3	12.3	13.53	2.38	2.71	Intergran. few small vugs, anhydr. vertical fracture
SS 1	1851.7-1852.0	0.3	3.7	3.1	0.9	19.4	5.82	-	-	Intergranular
45	1852.0-1952.3	0.3	25.	23.	11.	17.8	5.34	2.26	2.75	Intergran. few small vugs

SS - Small sample due to broken core.

CORE LABORATORIES-CANADA LTD.
CALGARY ALBERTA

THE CALIFORNIA STANDARD COMPANY
CANADIAN PROSPECT ROSELEA 3-30

Core with Permeability 0.0 to 0.9 Millidarcys

Total footage of core with 0.0 to 0.9 millidarcys permeability	0.6'	
Weighted average porosity of core with 0.0 to 0.9 millidarcys permeability	11.50%	(6.90)
Per cent of analyzed core having 0.0 to 0.9 millidarcys permeability	1.43%	
Weighted average horizontal permeability of core with 0.0 to 0.9 millidarcys	0.90 md.	(0.54)

Core with Permeability 1.0 to 9.9 Millidarcys

Total footage of core with permeabilities 1.0 to 9.9 millidarcys permeability	27.2'	
Weighted average porosity of core with permeabilities 1.0 to 9.9 millidarcys	11.63%	(316.34)
Per cent of analyzed core having permeabilities 1.0 to 9.9 millidarcys	64.92%	
Weighted average horizontal permeability of core with permeability 1.0 to 9.9 millidarcys	4.6 md.	(126.43)

Core with Permeability 10 Millidarcys and Greater

Total footage of core with permeabilities 10 millidarcys and greater	14.1'	
Weighted average porosity of core with permeabilities 10 millidarcys and greater	13.93%	(196.40)
Per cent of analyzed core having permeabilities 10 millidarcys and greater	33.65%	
Weighted average horizontal permeability of core with permeabilities 10 millidarcys & greater	14. md.	(131.40)

Cored interval received	1810' - 1850'	
Total footage	42.3'	
Footage analyzed	41.9'	
Footage not analyzed — No stain 0.4'	0.4'	
Weighted average porosity of core analyzed	12.40%	(519.64)
Weighted average horizontal permeability of core analyzed	7.6 md.	(318.77)

Note: Figures in parentheses indicate porosity feet and permeability feet.

Company	- THE CALIFORNIA STANDARD COMPANY	Date Report	- October 10, 1962
Well	- CANADIAN PROSPECT ROSELEA 9-30	Formation	- MISSISSIPPIAN
Field	- ROSELEA AREA, MANITOBA	D. Fluid	- GYP BASE
Location	- LSD 9-30-10-25 W1	Analysis	- FULL DIAMETER
Page	[illegible]	File	- CNP-3-2602
		Analysts	- JB:KG
		Cores	- DIAMOND

SAMPLE NUMBER	DEPTH REPRESENTED FEET	FOOTAGE REPRESENTED	PERMEABILITY TO AIR HORIZONTAL K MAX	PERMEABILITY TO AIR HORIZONTAL K 90°	PERMEABILITY TO AIR VERTICAL	POROSITY PER CENT	POROSITY X FEET	DENSITY BULK	DENSITY GRAIN	VISUAL EXAMINATION
CORED INTERVAL 1760' - 1840'										
CORE NO. 1 1760' - 1820' (Rec. 57.4')										
-	1760.0-1807.6	47.6	-	-	-	-	-	-	-	Not received
-	1807.6-1811.8	4.2	-	-	-	-	-	-	-	No stain
1	1811.8-1812.8	1.0	2.9	2.5	0.45	8.3	8.30	2.49	2.71	Intergran. anhydr. few small vugs, pin point vugs
2	1812.8-1813.4	0.6	12.	10.	3.1	8.1	4.86	2.47	2.69	Intergran. anhydr. small vugs
3	1813.4-1814.0	0.6	0.92	0.66	0.14	7.3	4.38	2.51	2.70	Intergran. anhydr. small vugs
4	1814.0-1815.0	1.0	3.0	2.0	1.1	6.2	6.20	2.53	2.69	Intergran. anhydr. few small vugs
5	1815.0-1815.9	0.9	7.2	3.5	3.4	7.3	6.57	2.51	2.71	Intergran. stylolite, vertica[l] fracture
6	1815.9-1816.8	0.9	*	23.	*	11.0	9.90	2.41	2.71	Intergran. open vertical frac[ture] pin point vugs
7	1816.8-1817.4	0.6	241.	62.	45.	11.4	6.84	2.40	2.71	Intergran. anhydr. pin pt.vu[gs] vertical fracture
-	1817.4-1820.0	2.6	-	-	-	-	-	-	-	Lost Core
CORE NO. 2 1820' - 1840' (Rec. 23.3')										
8	1820.0-1821.0	1.0	3.8	3.3	0.53	11.2	11.20	2.44	2.75	Intergran. anhydr. pin pt.vu[gs]
9	1821.0-1822.1	1.1	5.7	5.7	2.1	11.6	12.76	2.42	2.74	Intergran. pin pt. vugs,anhy[dr.]
10	1822.1-1822.8	0.7	37.	21.	6.6	22.3	15.61	2.11	2.71	Intergran. pin pt.vugs, anhy[dr.]
11	1822.8-1824.2	1.4	242.	206.	48.	17.4	24.36	2.24	2.71	Intergran. anhydr. pin pt.vu[gs]
12	1824.2-1825.3	1.1	23.	22.	9.3	13.5	14.35	2.35	2.72	Intergran. anhydr. few pin point vugs

SAMPLE NUMBER	DEPTH REPRESENTED FEET	FOOTAGE REPRESENTED	PERMEABILITY TO AIR HORIZONTAL K MAX	K 90°)	VERTICAL	POROSITY PER CENT	POROSITY λ FEET	DENSITY BULK	GRAIN	VISUAL EXAMINATION
CORE NO. 2 con't.										
13	1825.3-1826.2	0.9	75.	70.	17.	13.5	12.15	2.35	2.71	Intergran. pin pt. vugs, f small vugs
14	1826.2-1827.1	0.9	3.7	2.6	0.29	10.6	9.54	2.46	2.75	Intergranular
SS 1	1827.1-1828.6	1.5	2.6	2.0	1.1	16.4	24.60	-	-	Intergranular
15	1828.6-1829.9	1.3	20.	19.	3.1	12.1	15.73	2.40	2.73	Intergran. few pin pt.vugs anhydr. few small vugs
16	1829.9-1831.1	1.2	6.3	6.1	2.7	13.3	15.96	2.37	2.74	Intergranular, anhydritic
17	1831.1-1832.5	1.4	20.	16.	7.3	13.0	18.20	2.38	2.73	Intergran. anhydr. few pin vugs
18	1832.5-1834.1	1.6	30.	26.0	3.6	11.0	17.60	2.41	2.71	Intergran.anhydr.pin pt.v
19	1834.1-1835.6	1.5	67.	67.	17.	14.0	21.00	2.33	2.71	Intergran.anhydr.pin pt.v
20	1835.6-1836.9	1.3	140.	132.	38.	16.6	21.58	2.26	2.71	Intergran.anhydr pin pt.v
21	1836.9-1838.0	1.1	35.	33.	3.6	12.7	13.97	2.37	2.71	Intergran.anhydr.few pin vugs
22	1838.0-1839.0	1.0	132.	116.	7.2	14.7	14.70	2.31	2.71	Intergran.pin pt.vugs, an
-	1839.0-1839.2	0.2	-	-	-	-	-	-	-	No stain
23	1839.2-1840.0	0.8	85.	59.	7.6	13.1	10.48	2.36	2.71	Intergran.pin pt.vugs, fe vugs, anhydritic
24	1840.0-1840.8	0.8	26.	23.	4.7	9.8	7.84	2.44	2.71	Intergran. pin pt. vugs, small vugs, anhydritic
25	1840.8-1841.3	0.5	8.5	6.1	1.6	8.7	4.35	2.47	2.70	Intergran. pin pt.vugs, f small vugs, anhydritic
-	1841.3-1841.5	0.2	-	-	-	-	-	-	-	No stain
26	1841.5-1842.3	0.8	144.	121.	42.	10.9	8.72	2.41	2.71	Intergran.pin pt.vugs, an
27	1842.3-1843.3	1.0	68.	65.	31.	14.5	14.50	2.33	2.75	Intergranular

* Broken or fractured core. K 90° used for summary purposes.

SS - Small sample due to broken core.

Core with Permeability 0.0 to 0.9 Millidarcys

Total footage of core with 0.0 to 0.9 millidarcys permeability	0.6'	
Weighted average porosity of core with 0.0 to 0.9 millidarcys permeability	7.30%	(4.38)
Per cent of analyzed core having 0.0 to 0.9 millidarcys permeability	2.11%	
Weighted average horizontal permeability of core with 0.0 to 0.9 millidarcys	0.92 md.	(0.55)

Core with Permeability 1.0 to 9.9 Millidarcys

Total footage of core with permeabilities 1.0 to 9.9 millidarcys permeability	9.1'	
Weighted average porosity of core with permeabilities 1.0 to 9.9 millidarcys	10.93%	(99.48)
Per cent of analyzed core having permeabilities 1.0 to 9.9 millidarcys	31.93%	
Weighted average horizontal permeability of core with permeability 1.0 to 9.9 millidarcys	4.6 md.	(41.49)

Core with Permeability 10 Millidarcys and Greater

Total footage of core with permeabilities 10 millidarcys and greater	18.8'	
Weighted average porosity of core with permeabilities 10 millidarcys and greater	13.45%	(252.89)
Per cent of analyzed core having permeabilities 10 millidarcys and greater	65.96%	
Weighted average horizontal permeability of core with permeabilities 10 millidarcys & greater	78. md.	(1457.00)

Cored interval	1760.0' - 1843.3'	
Total footage	83.3'	
Footage analyzed	28.5'	
Footage not analyzed ---- Not received 47.5' ---- No stain 4.4' ---- Lost Core 2.6'	54.8'	
Weighted average porosity of core analyzed	12.52%	(356.75)
Weighted average horizontal permeability of core analyzed	53. md.	(1499.04)

Note: Figures in parentheses indicate porosity feet and permeability feet.

VIRDEN ROSELEA UNIT NO. 1

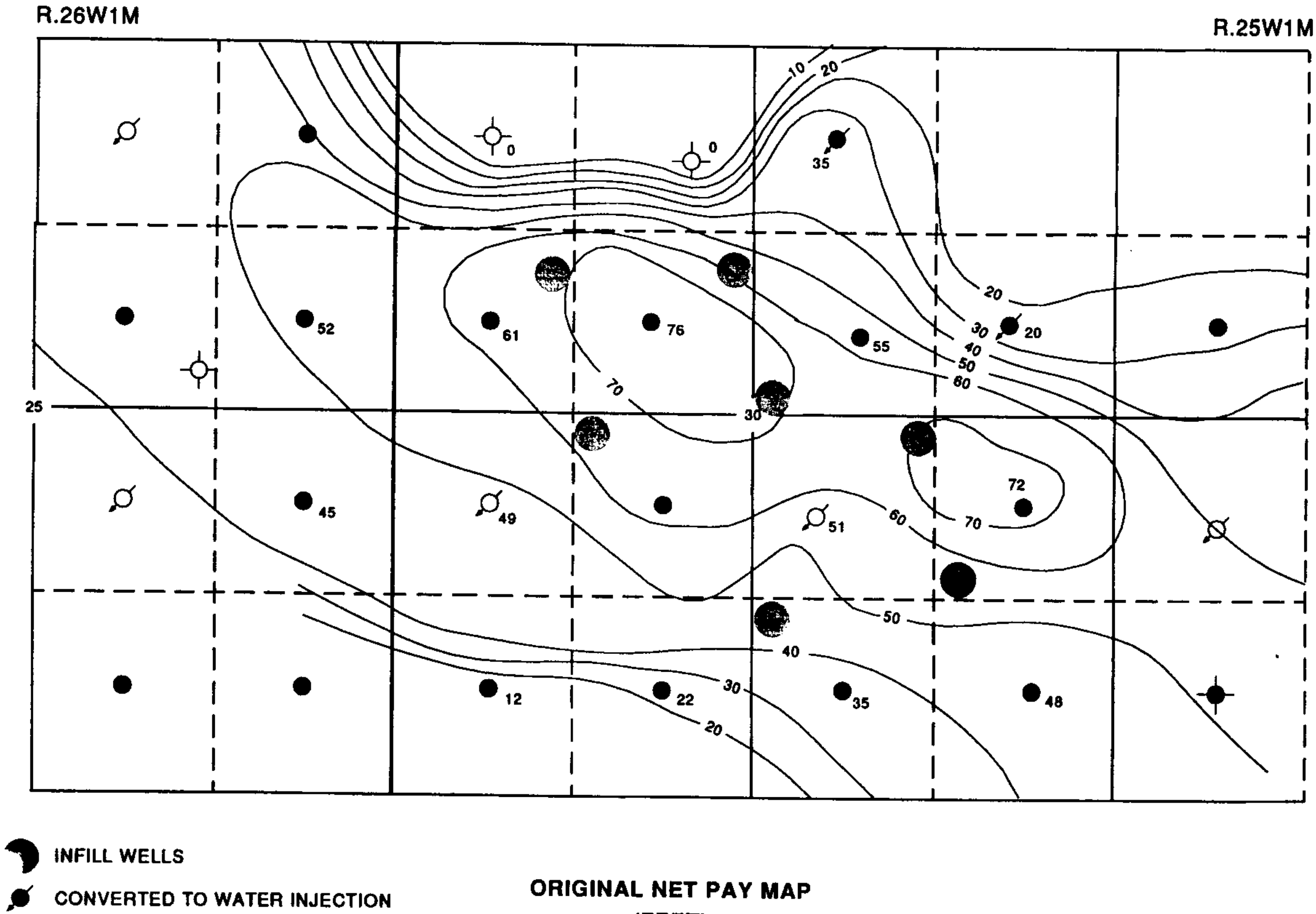


FIGURE 2

ORIGINAL NET PAY MAP
(FEET)

G04540_04

FIGURE 4

AERIAL PHOTOGRAPH OF REDUCED SPACING PROJECT AREA

KEY:

- ○ EXISTING WELLS
- ▣ PROPOSED WELLS
- ═ PROPOSED LEASE TRAILS

SCALE

0 100 200 300 400 500

METRES

100 m × 100 m — DRILLING LEASE SIZE (TO SCALE)

FIGURE 4

AERIAL PHOTOGRAPH
OF
REDUCED SPACING
PROJECT AREA

KEY:

EXISTING WELLS

PROPOSED WELLS

PROPOSED LEASE TRAILS

SCALE

0 100 200 300 400 500

METRES

100 m

100 m

DRILLING LEASE SIZE (TO SCALE)

VIRDEN ROSELEA UNIT NO. 1

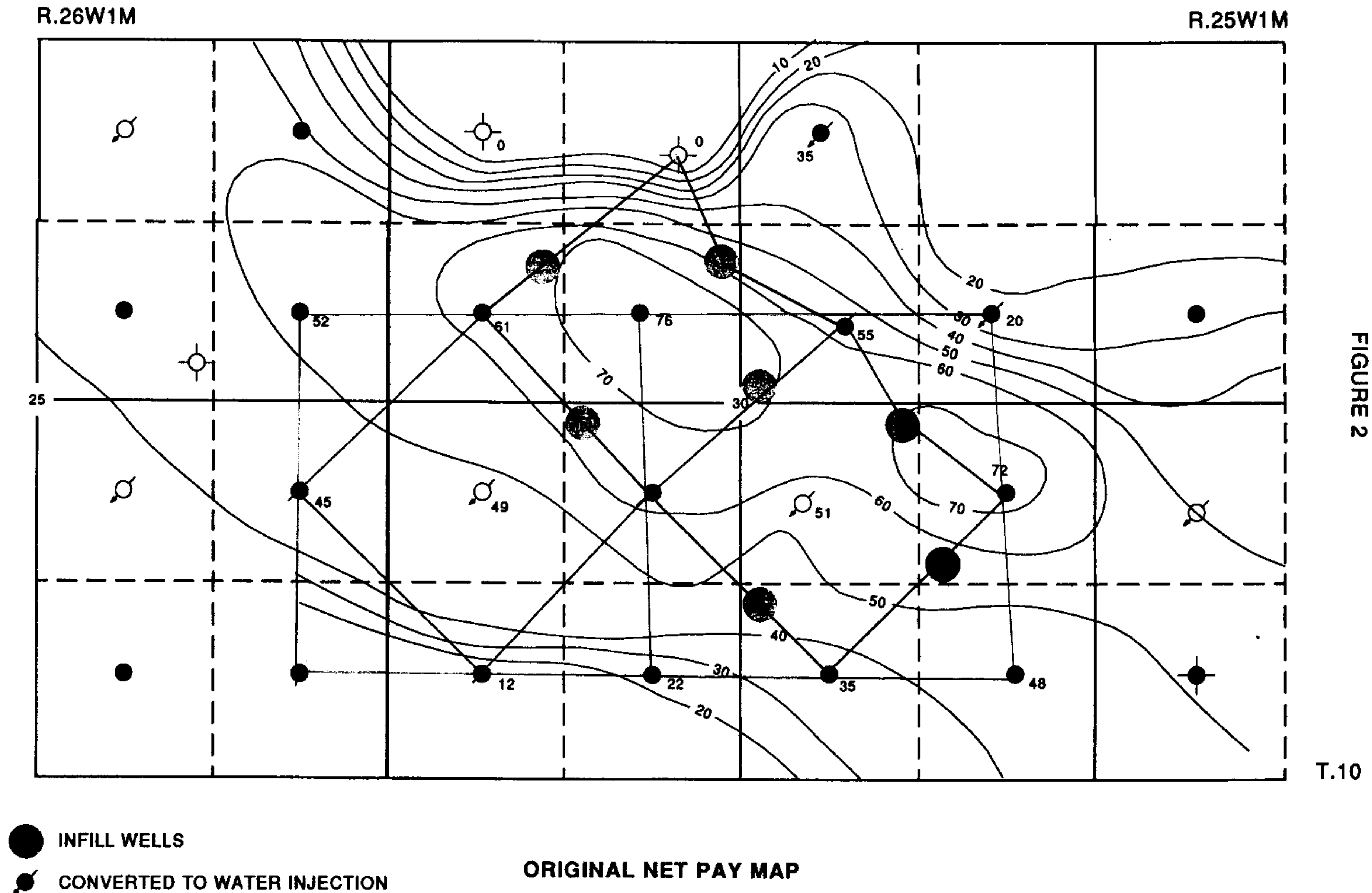


FIGURE 2

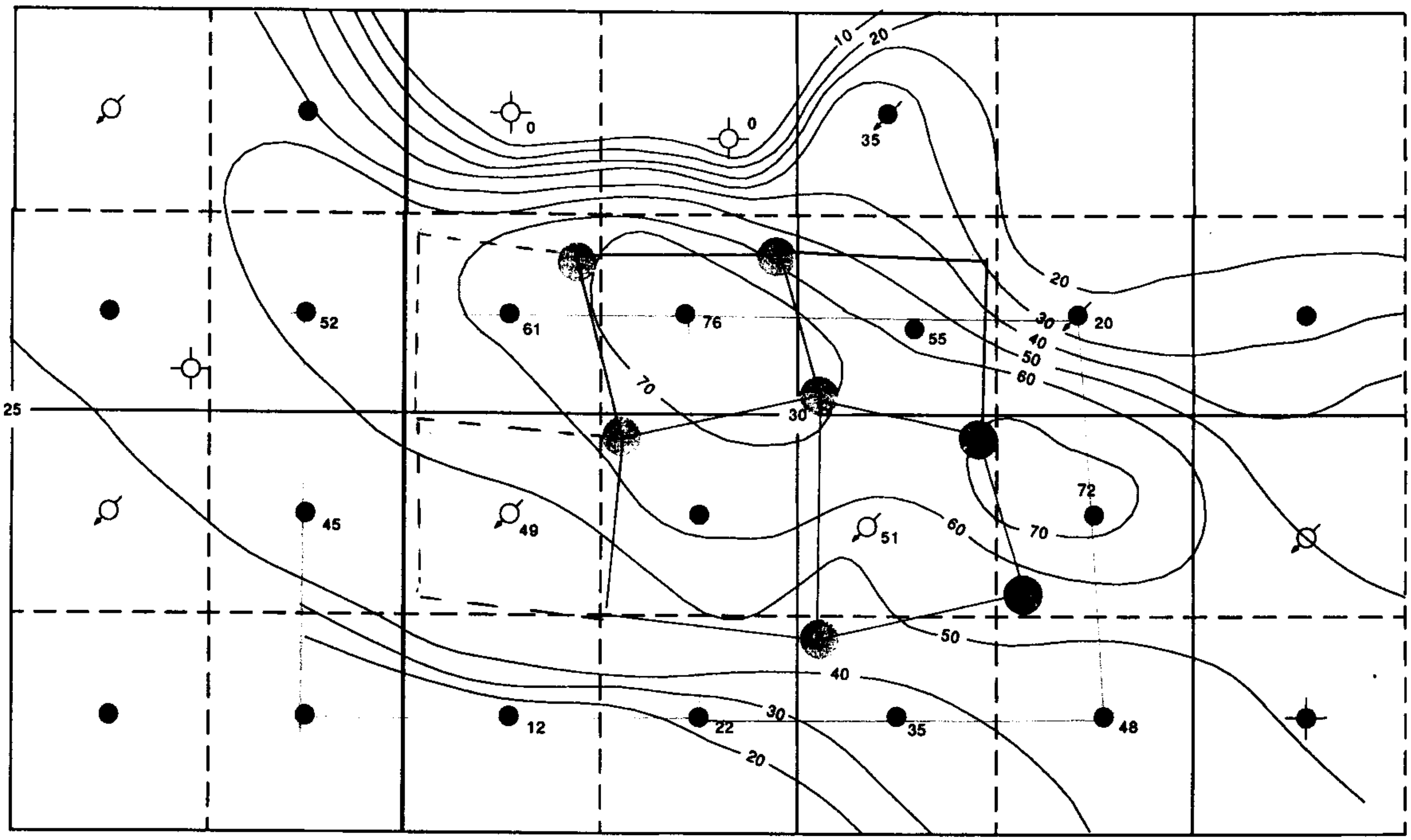
ORIGINAL NET PAY MAP
(FEET)

G04540_04

— VRU #1 ESSENTIALLY
DEVELOPED 16 HA INVERTED 9 SPOT

— PROJECT AREA DEVELOPMENT
ON 8 HA - Inverted 5 spot

VIRDEN ROSELEA UNIT NO. 1



INFILL WELLS

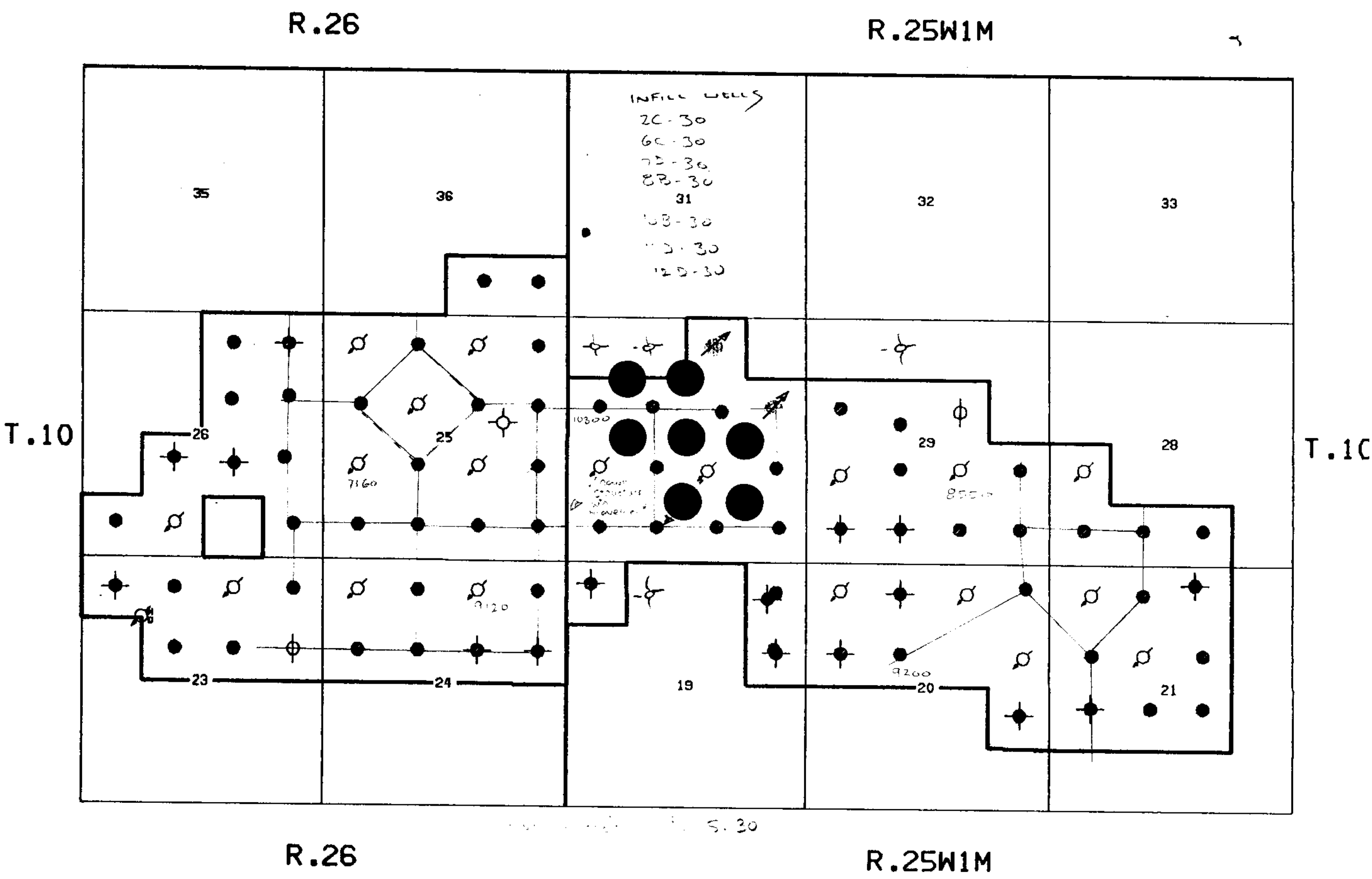
CONVERTED TO WATER INJECTION

ORIGINAL NET PAY MAP
(FEET)

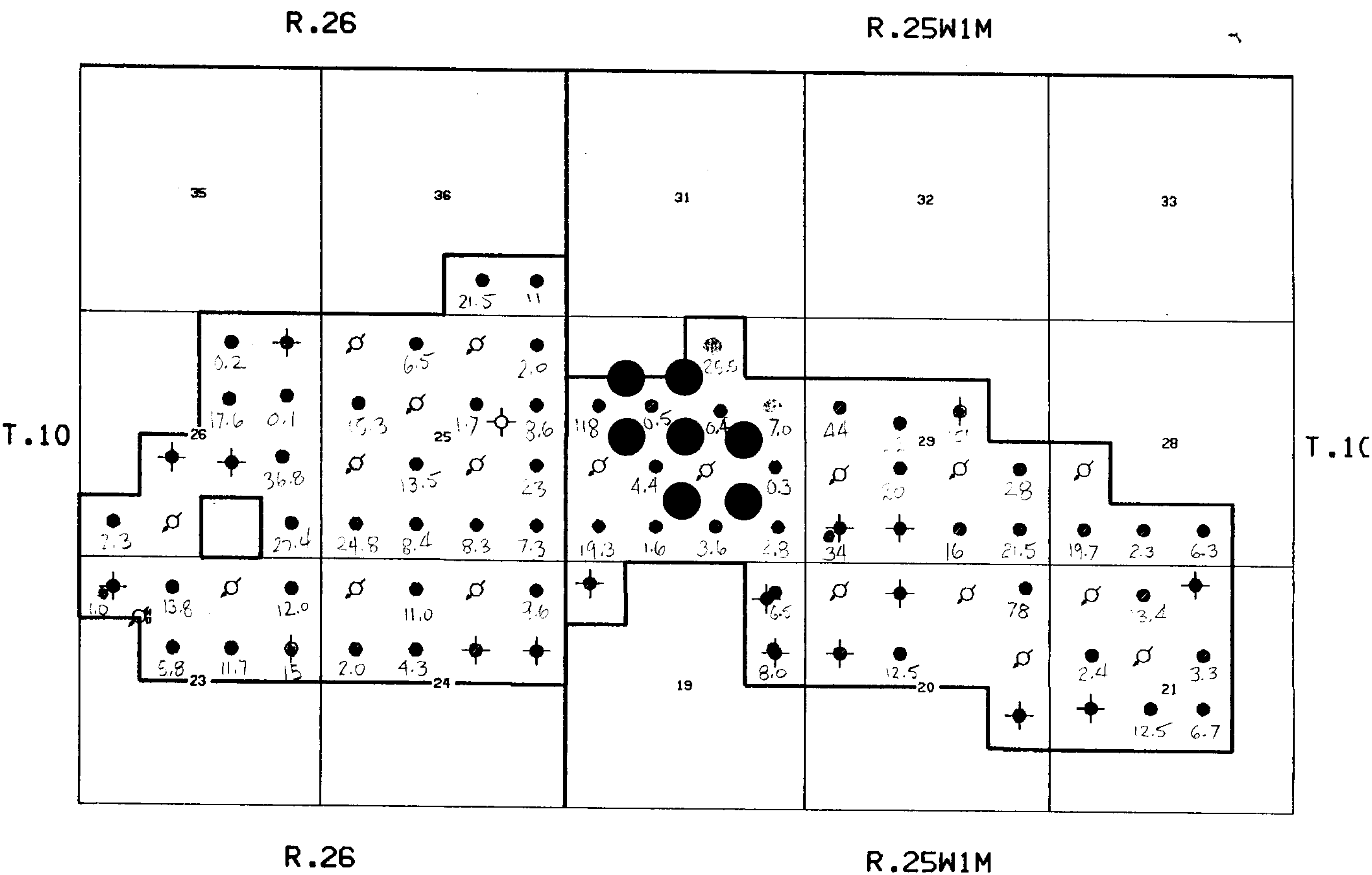
G04540_04

VIRDEN ROSELEA UNIT NO.1
UNIT AREA MAP

PROJECT AREA S. 30-10-25

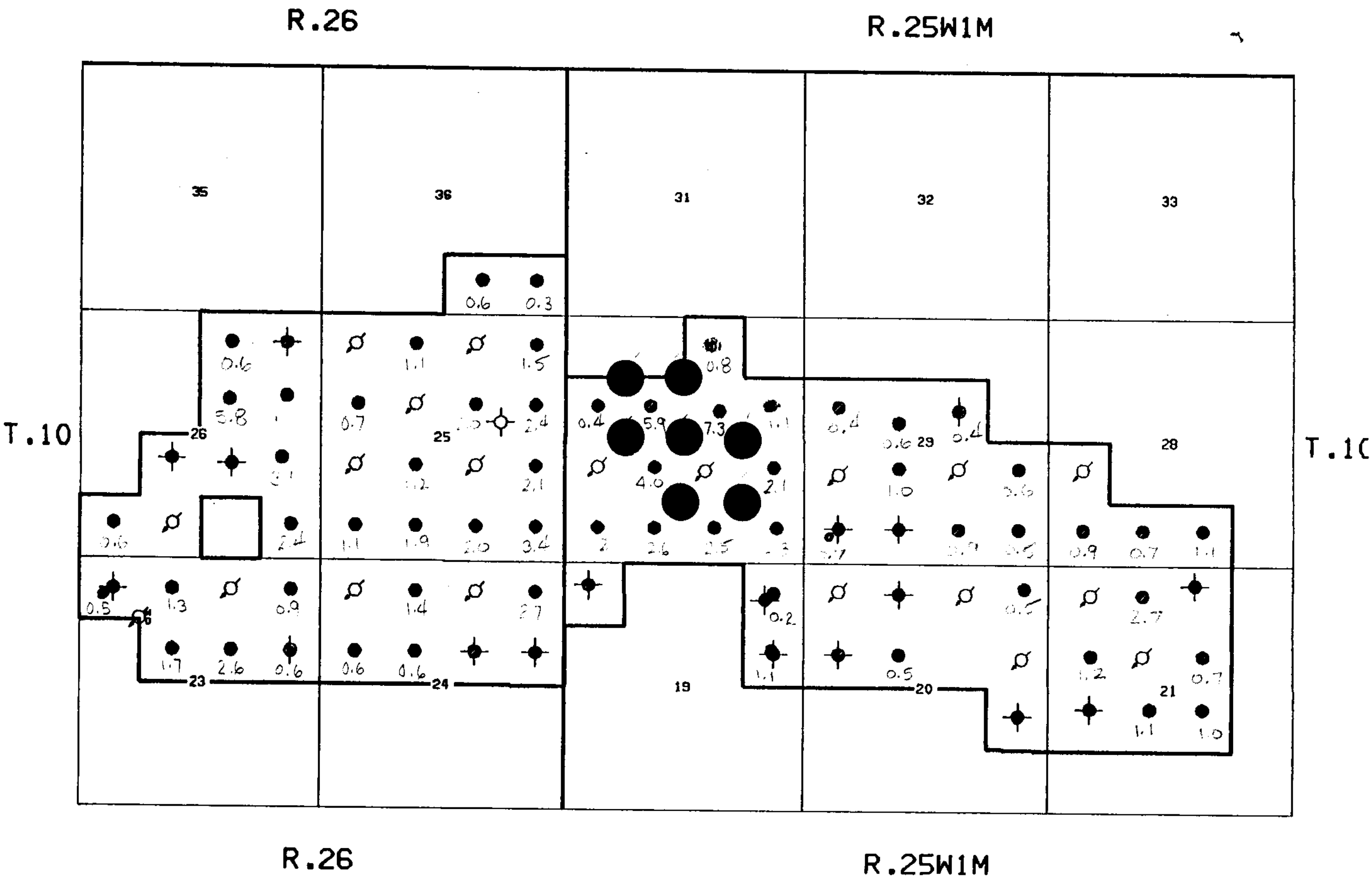


VIRDEN ROSELEA UNIT NO.1
UNIT AREA MAP

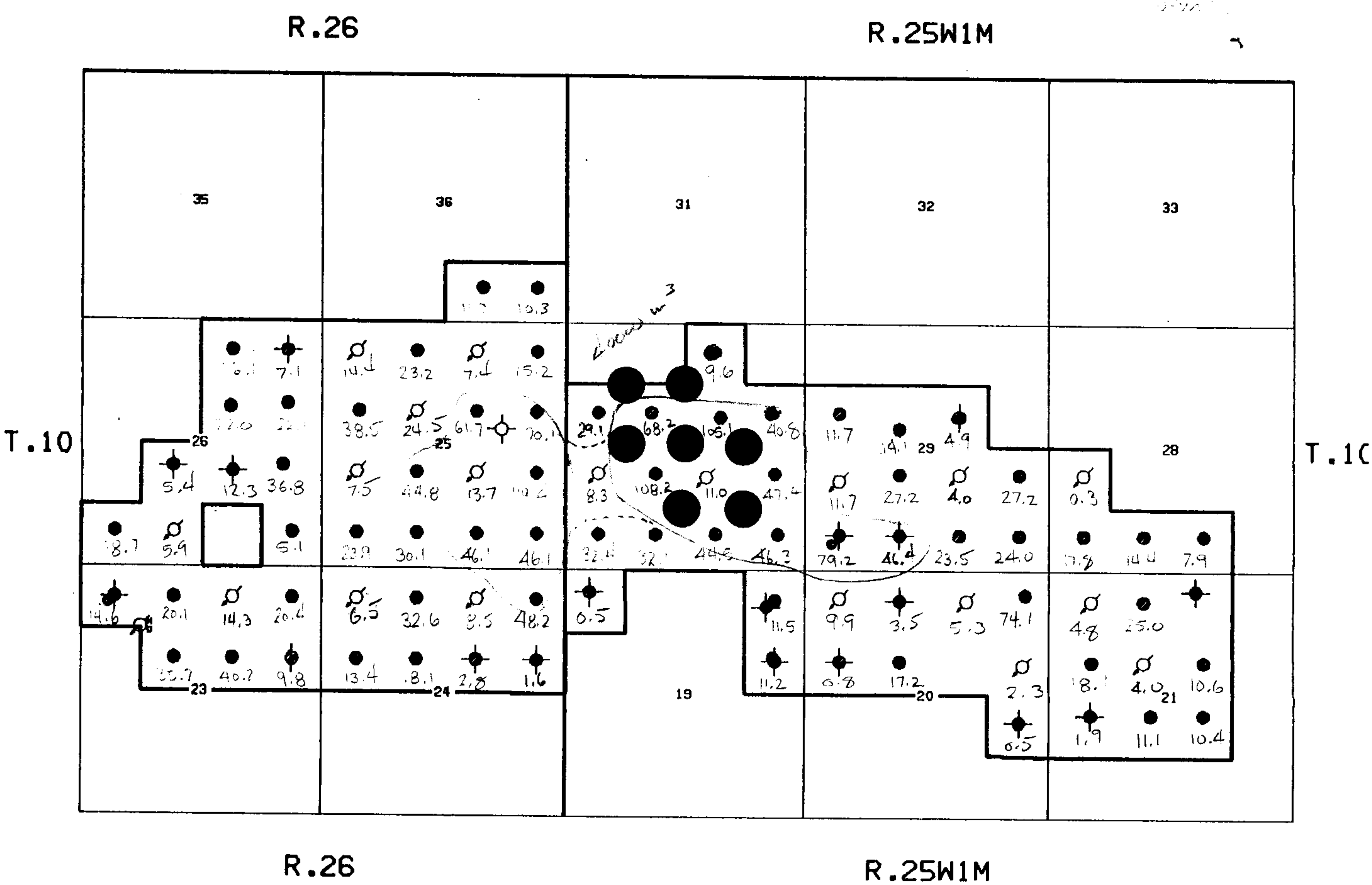


VIRDEN ROSELEA UNIT NO.1
UNIT AREA MAP

DAILY
OIL



VIRDEN ROSELEA UNIT NO.1
UNIT AREA MAP



VIRDEN ROSELEA UNIT NO. 1

..... structure on top of Cherty
CI = -520' ss

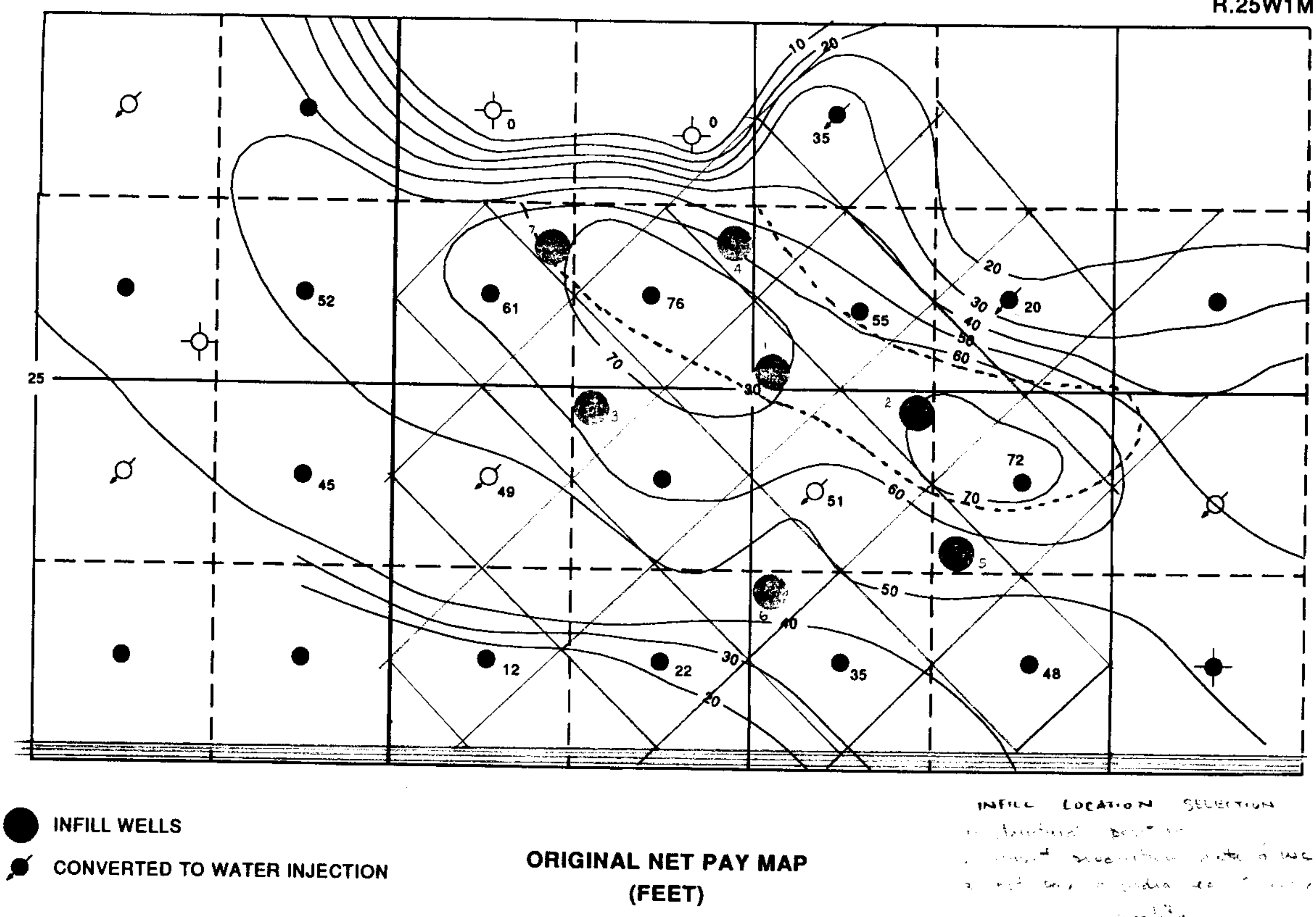


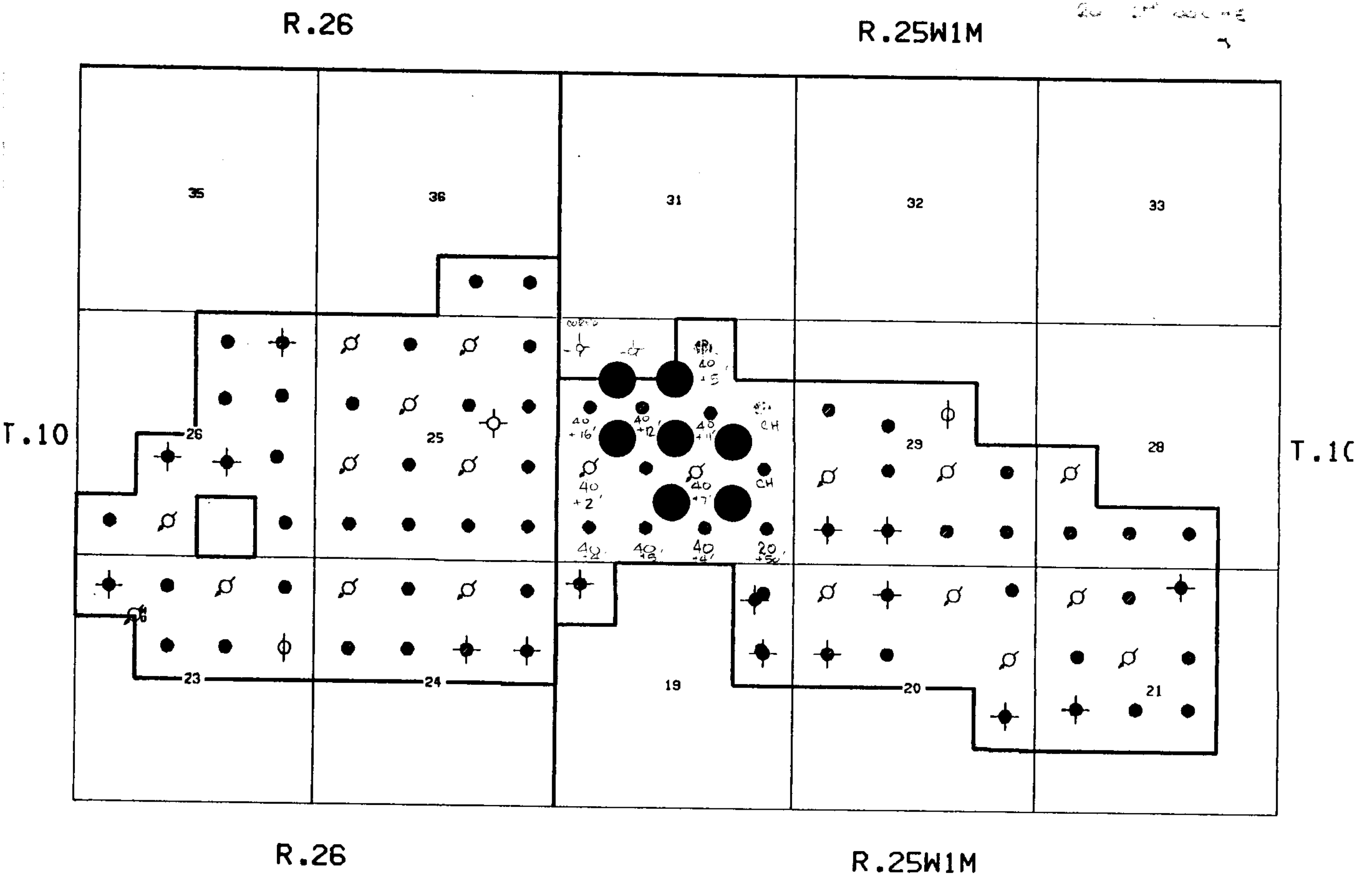
FIGURE 2

ORIGINAL NET PAY MAP
(FEET)

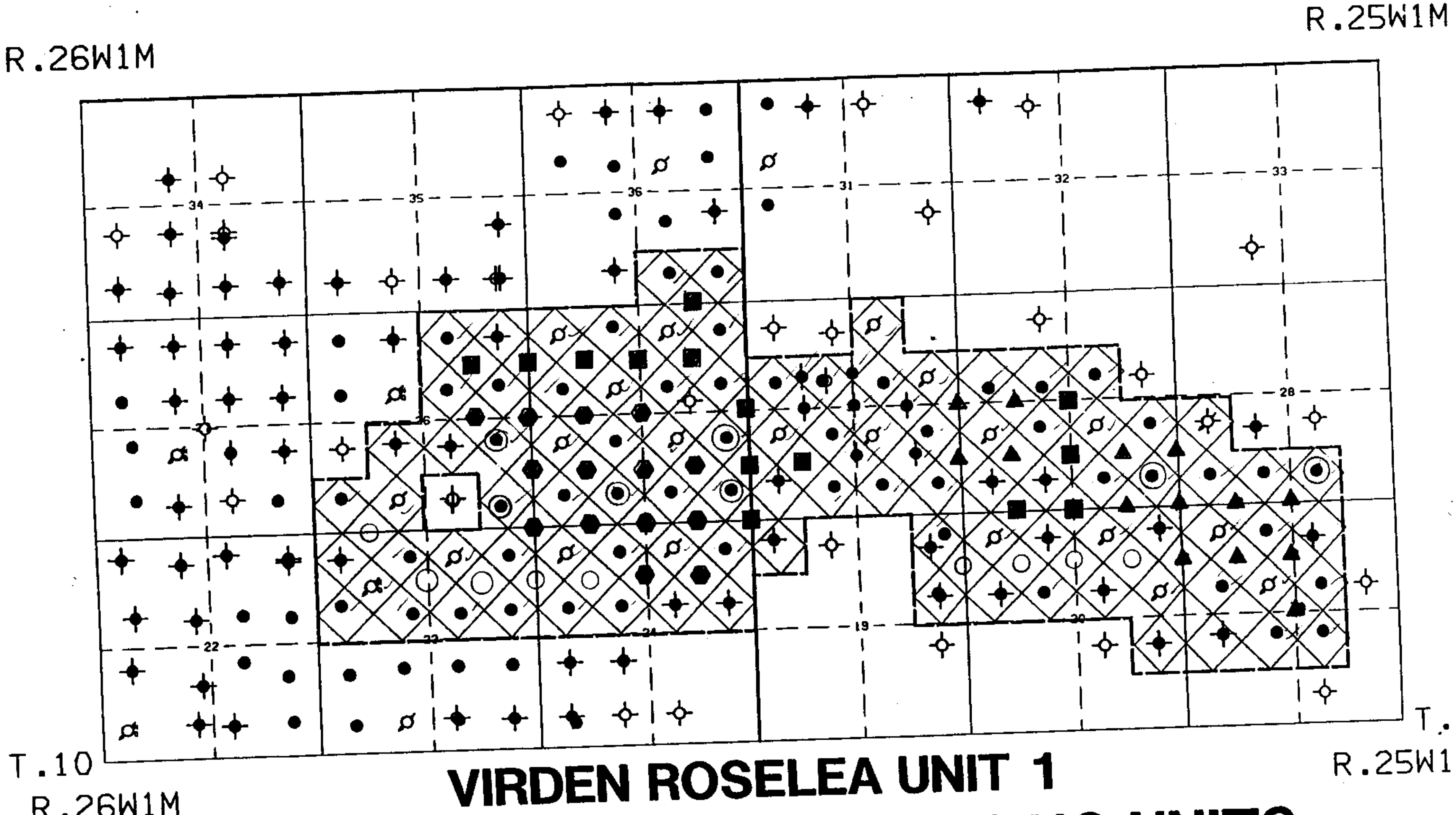
INFILL LOCATION SELECTION

G04540_04

VIRDEN ROSELEA UNIT NO.1
UNIT AREA MAP



APPENDIX 1



VIRDEN ROSELEA UNIT 1
8 HECTARE DRILLING SPACING UNITS

- 1991 INFILL WELLS
- ▲ 1994 INFILL WELLS
- ■ 1995 INFILL WELLS
- ⬢ 1996 INFILL WELLS
- ◉ PROPOSED WIW CONVERSIONS

1993 PRODUCERS/INJECTORS 61/20 : 3.05

1994 73/22 : 3.32

1995 85/24 : 3.54

1996 : 96/27 : 3.56

1997 105/27 : 3.89

DRILLING PROGRAM

1300 kg/m³ drilling mud density is proposed

Chevron believes infills, even if subject to water breakthrough, will exhibit low enough inflow rates that there is adequate time to circulate weighted mud into the well to kill it.

4#-29 4.7 m³/hr. SI wellhead pressure 4800-5200 kPa

- Chevron will submit a detailed contingency plan for well control at the well licensing stage

P_R: 8100-9600 kPa

- recognition @ 1300 kg/m³ underbalanced drilling system

Chevron stated original application 700 kPa overbalanced, actually (12.69 kPa/m × 550-600 m) 1100-2000 kPa underbalanced

BOARD ORDERS

· amend PM 65

· rescind SU 8 , approved SU

- review copy of Board letter of approval (1991)

VIRDEN ROSELEA UNIT NO. 1 - REDUCED SPACING APPL'N

The Board has received Chevron's response to the Board's deficiency letter (Jan 20/94). Comments on the application have been received from Rural Development, Agriculture and Environment.

RECOMMENDATIONS

DISCUSSION

PHASE 2 PERFORMANCE PREDICTIONS

INCREMENTAL RECOVERY PHASE I OOIP ~~2696~~ 2728 × 10³ m³

VRU #1 OOIP ~~7920~~ 7942 10³ m³

PHASE I current recovery 29% (Jul/93), ult. rec 34%

- Chevron has reduced its estimate

Decline curve analysis - rate vs. time, rate vs. cum prod and WOR vs cumul. prod. conducted by Chevron and the Board yield incremental recoverable reserves of between 45.7 - 143 10³m³. Based on two years of infill well production a reasonable incremental recovery estimate for Phase I is 60 - 70 10³ m³ or 8570-10000 m³/well. Chevron predicts based on streamtube analysis that the Phase I infill project will improve sweep efficiency by 1.7% from 36.4% to 38.1% for 0.4 pore volumes injected.

- incremental recovery 2.2 - 2.6% OOIP

If there is (component associated with) Acceleration ~~of~~ production ~~associated with~~ from the infill wells is not apparent at this time.

An analysis of Crown royalties & freehold production tax paid in VRU #1 from Jan 1/91 to Dec 31/93 (Fig. *) shows no negative impact from infill well production (infill wells ~~producing~~ then holiday oil & then oil is classified as new oil.)

- Comparison - Crown revenue curve should mirror production decline curve when oil price normalized

Phase I

It is apparent from Phase I that reduced 8 ha spacing in VRU [illegible] will result in the recovery of incremental reserves. It is also apparent that there is some downside technical risk

Chevron's Phase II incremental recovery prediction is based on the results observed in Phase I. The company has predicted Phase II incremental recoverable reserves of $125 \times 10^3 m^3$ or 8930 m^3/well.

Phase II OOIP = 2496 $10^3 m^3$ (75.5% in Chevy). Incremental recoverable reserves represent a 5% OOIP incremental recovery.

Current recovery in the Phase II project area is 25.7% OOIP, compared to current unit recovery of ___ % OOIP and a Phase I project area recovery of ___ % OOIP @ the commencement of infill drilling

(in and adjacent to the project area.
- In Phase II, 6 of the producers offsetting proposed infill wells have been abandoned, offers an increase opportunity to increase sweep efficiency (review - Fig of "project area) ✓

Phase 1 producer to injector ratio 4
Phase 2 " " " " 3.1

→ It is suggested that initial productivity and recoverable reserves estimates are based on (1) the performance of the Phase I infill wells; and (2) the current performance of existing wells in the Phase II area. This is a reasonable approach and appears to have yielded reasonable estimates though there are some inconsistencies.

FUTURE PHASES

Chevron plans on drilling 14 infill wells per year to complete 8 ha development of VRU #1 in 1997. The proposed schedule of infill drilling is shown in Fig ___

The company also indicated it expects to convert an additional 5 wells to wtr inj.

compare producer - injector ratio pre & post - infill drilling ~~ratios~~

Chevron is predicting a 5% OOIP increase in ultimate recovery for VRU #1 as a result of infill drilling & pattern realignment.

TABLE COMPARING PHASES

Chevron has noted that future plans are dependent on a number of factors, in particular, Phase II infill well performance, oil prices, and unit WIO approval.

- 1993 Injection patterns (16 ha)
  - inverted 9 spot in general, irregularly located injectors create 5 spot & incomplete patterns

  1-28, 12-23, 10-26 & 5-26 wells do not receive direct pressure support

- 1994 all infill wells will receive direct pressure support from offsetting injection (ie within 282 m of an injector)

- 1995 inverted 9 spot (8 ha) with following WIW location remaining as producers

  3-29-10-25

  incomplete along pattern unit boundaries 1-30-10-25

  11-29-10-25

  3-30-10-25

  11-30-10-25

  1996 9-23-10-26

  11-24-10-26

  11-20-10-26

Project Costs & Benefits.

UNIT-WIDE VS. PHASE 2 APPROVAL

- proposed future phases are reasonable, options are

(1) to approve only Phase 2

or

(2) to approve unit wide reduced spacing

ISSUES: (1) determination of incremental recovery from infill drilling costs & benefits
(2) environmental & land use impacts

- future appl'n refine incremental recovery estimates. if Chevron's current incremental recovery estimate 2-5% OOIP is not met it is unlikely future phases will be developed

- to ensure this data is available for review, the Board should ask that Chevron provide a project technical summary at year-end.

- future injector conversions could be monitored & approved under the Board PM Orders.

- well siting is an issue - well siting for future phases will have to be approved by the P.B., Environment & Agriculture. Both Environment & Agriculture have established infill well siting criteria which should be included as part of the SU order

- the SU order should include time lines for well licence review & approval.

INFILL WELL SITING

ENVIRONMENT & AGRICULTURE HAD 4 siting criteria

Chevron has submitted air photos showing the proposed locations for the 14 infill wells including access roads & f/l ROW's. The infill wells have been sited to minimize environmental & land use impacts.

Infills wells located on the slopes of the Assiniboine river valley have been moved to as close to the bottom of the slope as possible (4B-28, 4C-28 & 8A-30). Chevron will conduct a survey for rare & endangered flora & fauna. Disturbance of natural vegetation will be minimized and the wellsite will be bermed & revegetated to divert run-off & minimize erosion

- Chevron has had discussion with the landowners in SE/4 of Sec 25-10-26 who objected to the application. Chevron (Attachment 1&2) appears to have satisfied the landowners concerns regarding infill wells/drilling causing noise & aesthetic concerns, impacting natural habitat, affecting domestic water supply well

- where an infill location cannot meet the siting criteria or otherwise has a significant (adverse) impact on adjacent land use, the Board may not permit the well to be licensed