PROPOSAL FOR PRESSURE MAINTENANCE BY WATERFLOODING

The applicants propose to unitize a portion of the Virden-Roselea Field. The proposed Unit Area consists of 108 wells, one of which is dually completed as a producer from the Mississippian formation and a salt water disposal in the Devonian formation. (See Figure 1). The primary purpose for unitizing this portion of the Virden-Roselea Field is to facilitate the operation of a waterflood in the subject area. An engineering report entitled "Waterflood Evaluation, Proposed Virden-Roselea Unit No. 3, Virden-Roselea Field, Manitoba" and dated February, 1966, has been included in support of this submission.

The estimated original oil in place from volumetric calculations was 51,000,000 barrels. The indicated ultimate primary recovery from the proposed Unit Area is 8,100,000 barrels. By comparison, waterflood calculations indicate an estimated total ultimate primary plus secondary recovery of 17,850,000 barrels from the same area. A waterflood project is planned for the subject area in order to recover the estimated 9,750,000 barrels of additional oil. Appendix I contains a summary of the investigation of the feasibility of waterflooding. An inverted 160 acre nine-spot pattern with some modification in the northeast portion of the area is planned for the proposed Unit Area. A detailed outline of the proposed waterflood program is presented in Appendix II.

Unitization of the area under application would enable all interest in the area to be merged so that this portion of the reservoir may be operated as a single property. Maximum recovery efficiency and

reduced production costs may be attained under unit operation when waterflooding is applied to a large tract. This would be achieved by selecting injection wells without regard to property lines and by controlling injection and production rates to obtain a high degree of recovery efficiency.

Certain wells in the proposed waterflood scheme are required for conversion to water injection. The owners must be ensured of a continued income from currently producing wells, including those that would be converted to water injection. Additional production will be obtained from the waterflood project and the Unit must provide a fair and equitable basis for the sharing of this benefit. The applicants submit that the participation formula provides a fair and equitable basis for sharing the unitized production.

By referring to Figure 1, it is noted that the western edge of the proposed Virden-Roselea Unit No. 3 is bounded by producing wells which have been excluded from the Unit and waterflood area. It is apparent from the high water production that the excluded area is operating under a strong natural water drive, therefore, inclusion of this portion of the field in the proposed Unit Area is considered unnecessary. The proposed Unit Area is bounded on the north by Virden-Roselea Unit No. 1 and by producing wells on the NW$\frac{1}{4}$ of Section 23. If sufficient incentive is evident, the NW$\frac{1}{4}$ of Section 23 could be brought into Virden-Roselea Unit No. 1 by enlargement. If future development indicates that any lands currently excluded from the proposed Unit Area should be included, the Board may, at any

time, under Section 76 of the Mines Act, hold a further hearing to consider the admission of these or any other lands to the Unit Area. Therefore, should any outside acreage be subsequently developed and proven productive, it could enter and participate in the Unit by order of the Board. Similarly, should it be deemed necessary or advantageous to waterflood any of the currently proven and developed acreage which is presently excluded, it could also enter and participate in the Unit.

APPENDIX I

INVESTIGATION OF THE FEASIBILITY OF WATERFLOODING

The majority of the wells in the proposed Virden-Roselea Unit No. 3 area were drilled during 1955 and 1956. The rapid production decline of individual wells indicated that some form of secondary recovery mechanism was necessary to increase the ultimate oil recovery from the field. Both geological and reservoir studies were therefore initiated to properly evaluate methods of secondary recovery.

Flood tests have not been conducted on cores from the Virden-Roselea Field, however, it is felt that the results of the laboratory tests conducted on North Virden Scallion cores would be reasonably representative. These laboratory tests indicated that substantial additional oil could be recovered by waterflooding.

The report "Waterflood Evaluation, Proposed Virden-Roselea Unit No. 3, Virden-Roselea Field, Manitoba" dated February, 1966 may be briefly summarized as follows:

(a) The size and structure of the reservoir was studied to obtain an estimate of original oil in place.

(b) An estimate of the ultimate primary oil reserves as a percentage of the estimated original oil in place was determined from decline curves.

(c) The approximate amount of oil that could be obtained by waterflooding the field was calculated using the laboratory waterflood test data with consideration given to displacement efficiency and vertical and areal sweep efficiencies.

(d) An estimate of the possible gain which may result from waterflooding was obtained by comparing the ultimate primary with the ultimate waterflood reserves estimate.

SUMMARY OF PRIMARY RESERVES ESTIMATE

	CRINOIDAL ZONE	SANDHILL ZONE	OOLITE ZONE	CHERTY ZONE	TOTAL
Est. Surface Area (Acres)	3,210	3,800	4,320	4,080	4,320
Est. Average Pay Thickness (Ft.)	8.50	6.07	7.61	9.14	31.32
Est. Average Porosity (%)	9.6	12.7	11.5	12.6	
Est. Average Water Saturation (%)	52	48	52	52	
Est. Average Initial Oil Saturation (%)	48	52	48	48	
Formation Volume Factor (Res. Bbls./S.T. Bbl.)	1.05	1.05	1.05	1.05	
Est. Original Oil-in-Place (Bbls./Acre-Ft.)	340	487	407	446	
Total Est. Original Oil-in-Place (Barrels)	9,800,000	11,200,000	13,400,000	16,600,000	51,000,000
Total Est. Primary Recovery Oil (Barrels)					8,100,000
Est. Primary Recovery (% of Original Oil-in-Place)					15.9%

SUMMARY OF ESTIMATE OF WATERFLOOD RESERVES

A summary of the waterflood tests conducted on North Virden Scallion cores is presented since it is on the basis of these tests that the waterflood project for the proposed Virden-Roselea Unit No. 3 is considered feasible.

Twenty-five core plugs were selected on the basis of permeability distribution plots. The distribution of plugs by zones was as follows:

ZONE	NUMBER OF SAMPLES SELECTED	NUMBER OF SAMPLES WATERFLOODED BY CRC
Cherty	17	7
Oolitic	5	3
Crinoidal	3	2
TOTAL	25	12

In the laboratory, one inch diameter plugs were cut and resaturated to simulate reservoir oil and water saturations and viscosities. The plugs were then flooded with brine solution until production of oil had practically ceased. The results are tabulated below:

	CRINOIDAL ZONE	OOLITIC ZONE	CHERTY ZONE
Initial Oil Saturation (Fraction of pore volume)	0.67	0.79	0.76
Average Oil Saturation at Breakthrough (Fraction of pore volume)	0.42	0.62	0.48
Average Oil Saturation at Infinite WOR (Fraction of pore volume)	0.25	0.40	0.34
Average Oil Recoveries at Breakthrough (Percent of original oil-in-place)	38%	20%	36%

Using the above-mentioned laboratory data and calculation procedures which take into account such factors as areal and vertical sweep efficiencies, it has been estimated that a properly engineered waterflood might increase the ultimate recovery for the proposed Unit Area to 35% of the original oil-in-place or 17,850,000 barrels. This is more than twice the estimated 8,100,000 barrels expected under natural depletion.

APPENDIX II

DETAILS OF OPERATION TO BE CONDUCTED IN PROPOSED UNIT AREA

INTRODUCTION

The basic objective of the waterflood proposal is to recover the greatest amount of oil economically. Injectivity to a large degree controls the choice of flood pattern which is desirable in initiating a waterflood. Injectivity calculations have been made which indicate an average zone capacity of 1.84 BWPD/md. ft. This suggests injection rates ranging up to 475 barrels per day, with an average of approximately 220 barrels per day. These rates should be considered as illustrating the anticipated order of magnitude rather than the absolute values. The injectivity calculations indicate that the proposed Unit area can be flooded using the flood pattern proposed. The applicants propose to waterflood each of the Crinoidal, Sandhill, Oolitic, and Cherty Zones simultaneously. Completions are to be conducted in both injection wells and producing wells, with this in mind.

It is estimated that approximately 5,500 barrels of water per day will be injected into the reservoir through twenty-five injection wells. Figure 1 indicates the proposed Unit outline and the proposed injection wells. The flood pattern is such that it can be converted almost entirely into a five-spot pattern throughout the Unit area if injectivity should prove to be much lower than anticipated.

Producing wells have been excluded on the western edge of the proposed Unit area. These wells are influenced by a strong natural water drive which is maintaining the reservoir pressure. Water oil ratios have increased pronouncedly due to water encroachment, consequently, it is not considered desirable or necessary to include these wells in the water-

flood project. Virden-Roselea Unit No. 1 and producing wells on the northwest quarter of Section 23-10-26 lie immediately north of the proposed Unit area. If sufficient incentive is evident, the northwest quarter of Section 23-10-26 could more suitably be brought into Virden-Roselea Unit No. 1 by enlargement.

A. Source of Water for Injection

The water supply for the injection system will initially consist of produced Mississippian water from the Unit area plus water from a Devonian water supply well located on Lsd. 2-11-10-26. The two sources would be handled separately by two injection plants such that the Mississippian and Devonian water would not be mixed at surface. As the supply of produced Mississippian water increases, more of the system would operate on Mississippian water such that ultimately the entire injection system will be supplied with produced Mississippian water. It is estimated that in excess of 7,000 barrels of water per day will be initially available for the injection system, which should be sufficient for the calculated stabilized injectivity of the system.

B. Injection Plants

Two similar water injection plants will be located at Lsd. 2-11-10-26. Each plant will consist of two reciprocating injection pumps. One plant will handle only produced Mississippian water, the other will handle only Devonian water. At such time as there is sufficient produced Mississippian water for the entire system, the plant initially handling only Devonian water, will be converted to a salt water disposal system.

C. High Pressure Injection System

It is proposed that all injection lines be cement lined nominal sized Grade A line pipe, coated and wrapped and tested to a pressure greater than the anticipated injection pressure. Line losses were obtained from a set of flow curves for water based on the Hazen and Williams formula. A coefficient of friction of 130 was used for all cement lined steel pipe. The interior diameter of all steel pipe was reduced by 0.4 inches to allow for cement lining. In general, pipe sizes were selected to maintain line losses below 2 psi/1,000 feet. Line sizes and calculated injection rates are shown in Figure 2. Line sizing has been selected to provide for increased capacity should it be required.

D. Conversion of Wells to Water Injection

It is the applicant's intention to flood the four oil bearing horizons, namely Crinoidal, Sandhill, Oolitic and Cherty, simultaneously. A schematic diagram of a typical injection well is shown in Figure 3. The following procedure outlines the program to be carried out in converting the wells to water injection. Additional remedial work such as restimulation, addition of plugging materials, etc., may be required at a later date to rectify difficulties which cannot presently be anticipated.

(a) Pull rods, pump and tubing.

(b) Run casing scraper.

(c) Re-run open-end tubing and reverse circulate well bore to total depth.

(d) Perform salt water injection test at maximum surface pressure of 1,000 psi.

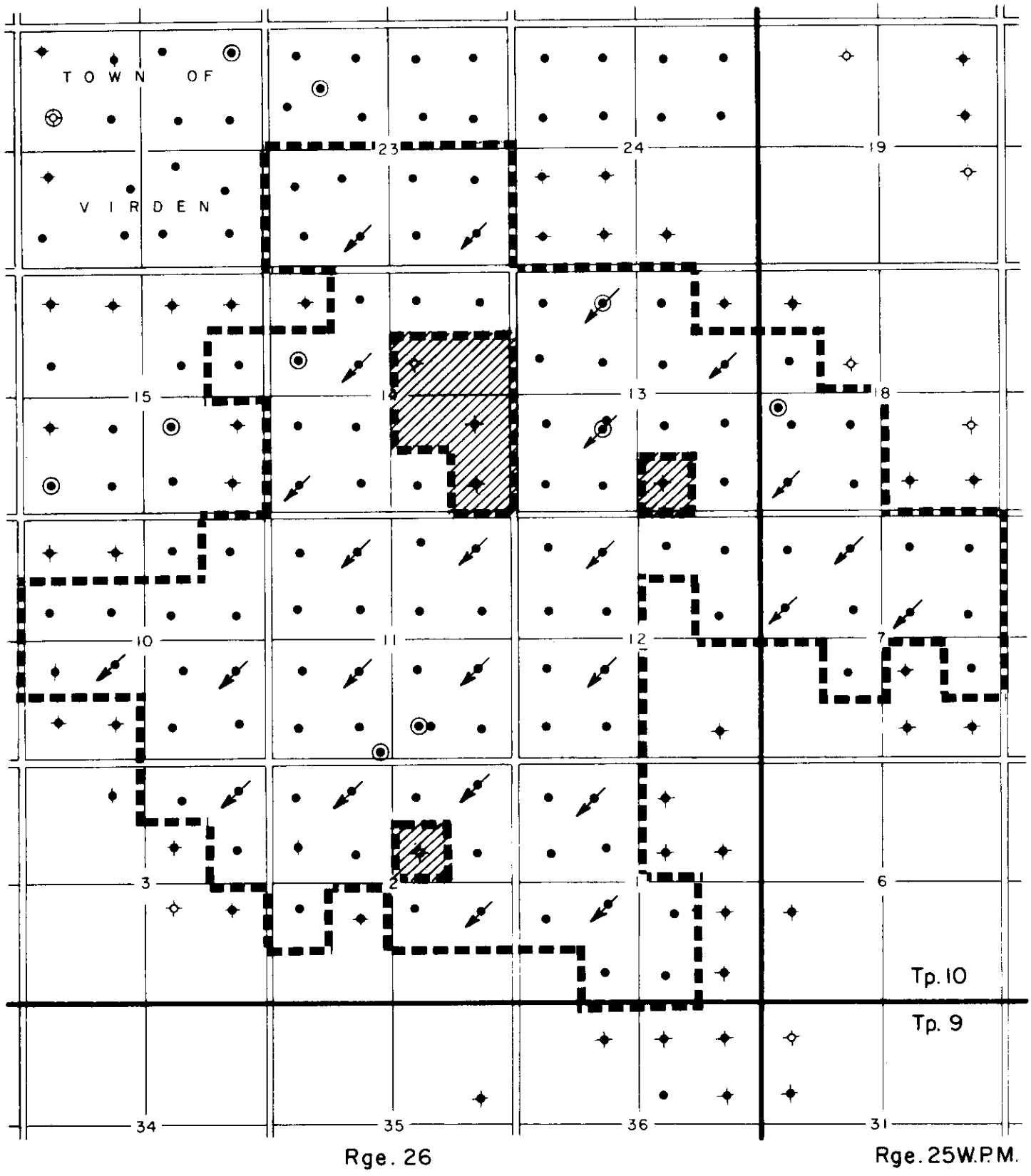


FIG. 1

PROPOSED VIRDEN ROSELEA UNIT No. 3

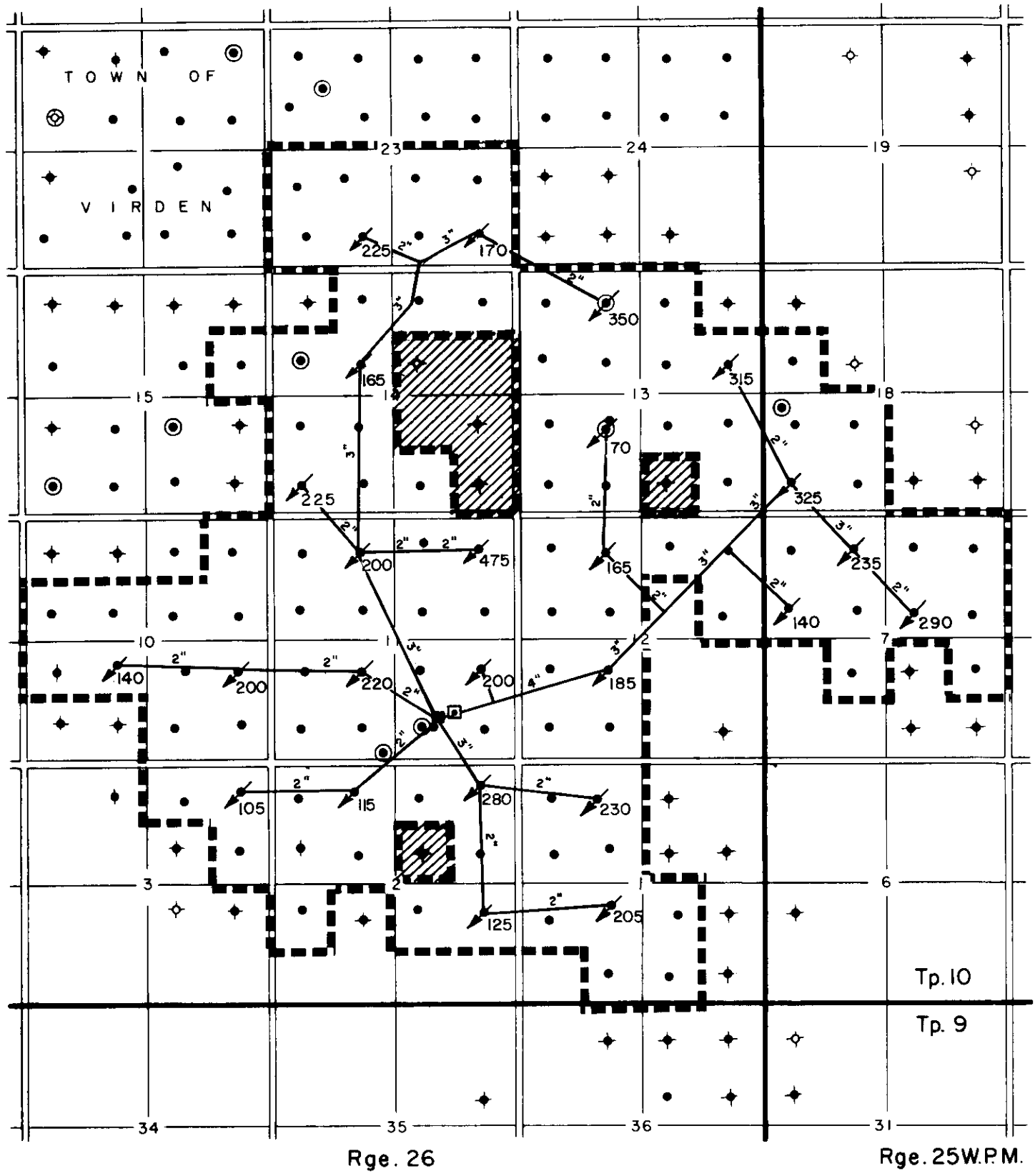
WATERFLOOD PATTERN

INJECTION WELL

S.W.D. WELL

UNIT BOUNDARY

Scale 1" = 3000'



200 INJECTION WELL & RATE

S.W.D. WELL

2" INJECTION LINE & SIZE

INJECTION PLANT

WATER SUPPLY WELL

UNIT BOUNDARY

FIG. 2

PROPOSED VIRDEN ROSELEA UNIT No. 3 WATER INJECTION SYSTEM

Scale 1" = 3000'

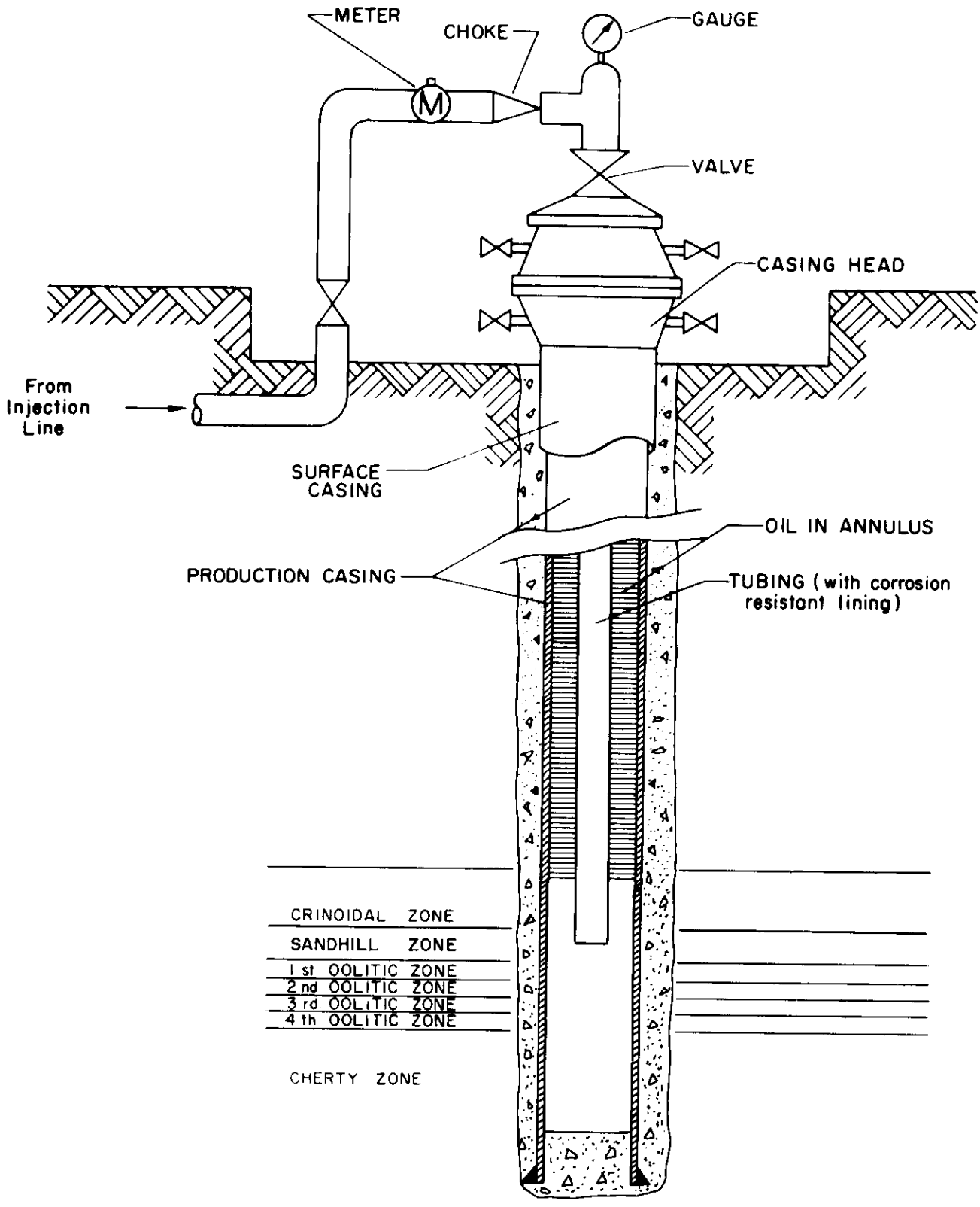


FIGURE 3

PROPOSED VIRDEN ROSELEA UNIT No 3
TYPICAL INJECTION WELL

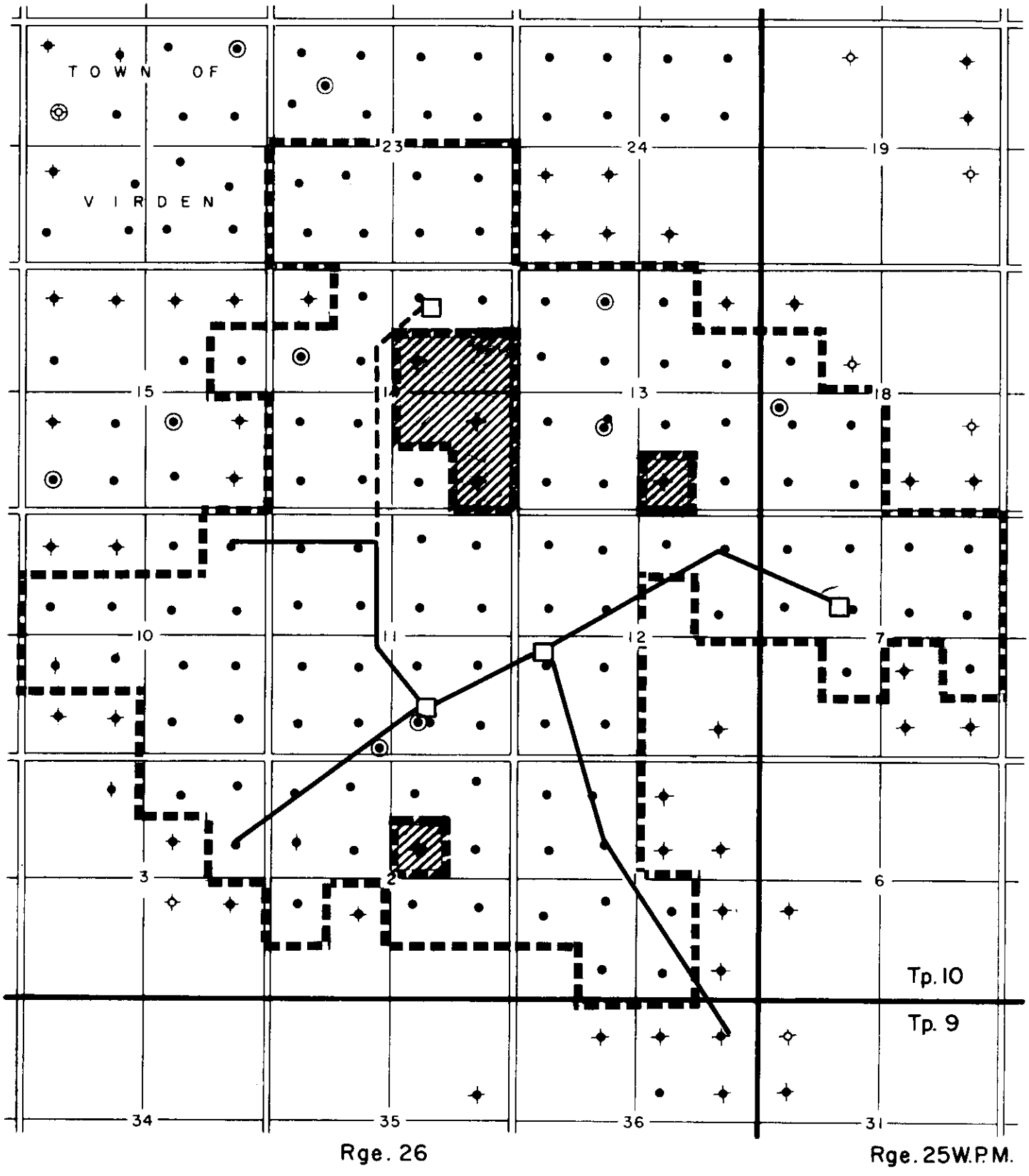


FIG. 4

PROPOSED VIRDEN ROSELEA UNIT No. 3
SALT WATER GATHERING SYSTEM

- CONSOLIDATED BATTERIES
- EXISTING SALT WATER GATHERING LINE
- PROPOSED SALT WATER GATHERING LINE
- UNIT BOUNDARY

Scale 1"= 3000'

APPLICATION FOR A UNIT MAXIMUM PERMISSIBLE RATE OF PRODUCTION

The applicants propose that a degree of production flexibility which is consistent with good engineering practice be provided for the Unit.

At the present time, production may be considered to be unrestricted since the majority of the Virden-Roselea wells are being produced at capacity. It is the applicant's contention that no reservoir damage has resulted from producing these wells at capacity.

During the proposed waterflood program, it is anticipated that water injection rates will be such that reservoir fluid withdrawals will be completely replaced. It is anticipated that the productive capacity of certain wells will be significantly increased. There is no reason to believe that reservoir damage would result from producing these increased capacity wells at unrestricted rates.

It is the applicants' contention that Unit producing wells, where offset by non-unit producing wells should also be allowed to produce at unrestricted rates in order to fulfill the basic objective of the waterflood, i.e., to recover the greatest amount of oil economically. There is no reason to believe that reservoir damage within the Unit area would result by producing these wells at capacity, nor is there any reason to believe that non-unit oil would be produced within the Unit since the Unit well capacities would increase only as a direct result of the unitized waterflood and therefore the increased production would be made up of oil from within the Unit Area only. There is also no reason to believe that reservoir damage outside the Unit Area would result or that the production at offsetting non-

unit wells would be in any way affected by the production of Unit boundary wells at unrestricted rates.

The applicants respectfully request that, on and after the first day that the Virden-Roselea Unit No. 3 becomes effective, the Unit be excluded from any provisions governing the limitations and allocation of production of oil.

EXTRA COPY.

PROPOSED VIRDEN-ROSELEA UNIT NO. 3

FINAL TRACT PARTICIPATION FACTORS BASED ON A CURRENT PRODUCTION FACTOR
(JUNE 1, 1965 TO NOVEMBER 30, 1965 INCLUSIVE) AND A PENALIZED AVERAGE MONTHLY FACTOR
(PENALTY FACTOR BASED ON WATER CUT DURING ABOVE SIX MONTH PERIOD)

TRACT NUMBER	MONTHS ON PRODUCTION TO 12/1/65	CUMULATIVE PRODUCTION TO 12/1/65	6/1/65 TO 11/30/65 PRODUCTION	6/1/65 TO 11/30/65 WATER CUT	100% PEN. AVG. MONTHLY PRODUCTION FACTOR	100% CURRENT PRODUCTION FACTOR	TRACT FACTOR A*	TRACT FACTOR B**
B.A.								
5-10	102	33,457	1,574	.9181700	.14303	.79131	.53200	.40234
6-10	105	21,611	727	.4905396	.55876	.36549	.44280	.48145
9-13	126	83,842	4,060	.3873548	2.17235	2.04111	2.09361	2.11986
10-13	129	98,858	4,375	.3476964	2.66379	2.19948	2.38520	2.47806
15-13	126	51,465	3,216	.6753810	.70655	1.61680	1.25270	1.07065
CHEVRON								
6-7	115	76,515	2,457	.8948607	.37277	1.23523	.89025	.71776
8-7	117	19,413	633	.8765119	.10918	.31823	.23461	.19280
9-7	116	26,428	311	.6858586	.38138	.15635	.24636	.29137
10-7	119	142,786	4,304	.6359022	2.32803	2.16378	2.22948	2.26233
11-7	120	36,229	513	.0968310	1.45302	.25790	.73595	.97497
12-7	112	47,424	632	.9653033	.07829	.31773	.22195	.17407
13-7	122	29,564	269	.0000000	1.29131	.13524	.59767	.82888
14-7	119	71,504	1,928	.4199759	1.85721	.96928	1.32445	1.50204
15-7	116	47,801	1,025	.4462453	1.21598	.51531	.79557	.93571
16-7	114	37,851	830	.5146199	.85878	.41727	.59388	.68218
3-1	106	33,692	1,905	.6927915	.52034	.95771	.78276	.69529
5-1	106	10,998	-	.8155300	.10199	.00000	.04080	.06120
6-1	106	10,013	-	.9272137	.03664	.00000	.01466	.02198
11-1	111	24,752	1,640	.6864245	.37261	.82449	.64374	.55336

TRACT NUMBER	MONTHS ON PRODUCTION TO 12/1/65	CUMULATIVE PRODUCTION TO 12/1/65	6/1/65 TO 11/30/65 PRODUCTION	6/1/65 TO 11/30/65 WATER CUT	100% PEN. AVG. MONTHLY PRODUCTION FACTOR	100% CURRENT PRODUCTION FACTOR	TRACT FACTOR A*	TRACT FACTOR B**
CHEVRON (Cont'd)								
12-1	107	63,042	957	.7693420	.72418	.48112	.57834	.62695
13-1	110	30,956	1,405	.6669037	.49952	.70635	.62361	.58225
14-1	111	17,242	-	.6969093	.25088	.00000	.10035	.15053
5-2	105	52,621	1,380	.7107525	.77245	.69378	.72525	.74098
7-2	105	16,357	-	.8750000	.10377	.00000	.04151	.06226
8-2	105	28,176	-	.7771186	.31871	.00000	.12748	.19123
11-2	110	46,101	1,831	.9286910	.15925	.92051	.61601	.46376
12-2	107	1,793	-	.9001640	.00891	.00000	.00357	.00535
13-2	109	82,786	2,961	.9124198	.35446	1.48861	1.03495	.80812
14-2	112	141,899	2,232	.8743668	.84820	1.12211	1.01255	.95776
9-3	106	32,263	906	.6942288	.49594	.45548	.47166	.47976
15-3	106	48,172	1,874	.5899344	.99306	.94213	.96250	.97269
16-3	106	112,705	2,293	.6436121	2.01926	1.15278	1.49937	1.67267
1-10	107	108,918	5,302	.6862908	1.70166	2.66551	2.27997	2.08720
2-10	107	64,120	2,510	.3290564	2.14252	1.26187	1.61413	1.79026
7-10	107	45,771	1,564	.6899286	.70680	.78628	.75449	.73860
8-10	107	62,684	1,794	.9610271	.12167	.90191	.58981	.43376
9-10	108	76,673	3,068	.7105387	1.09507	1.54240	1.36347	1.27400
11-10	104	58,924	923	.9797486	.06114	.46403	.30287	.22230
12-10	102	89,671	2,942	.8864531	.53193	1.47905	1.10021	.91078
16-10	109	44,653	444	.5668293	.94561	.22322	.51217	.65665
1-11	113	50,205	686	.4225589	1.36712	.34488	.75378	.95823
2-11	113	55,319	4,919	.3893992	1.59289	2.47297	2.12093	1.94492
3-11	113	108,963	3,785	.6904645	1.59053	1.90286	1.77793	1.71546
4-11	110	141,534	5,087	.0945176	6.20837	2.55743	4.01780	4.74799
5-11	110	99,628	3,966	.8624731	.66375	1.99386	1.46181	1.19579
6-11	111	79,558	1,747	.4931825	1.93572	.87828	1.30126	1.51274

TRACT NUMBER	MONTHS ON PRODUCTION TO 12/1/65	CUMULATIVE PRODUCTION TO 12/1/65	6/1/65 TO 11/30/65 PRODUCTION	6/1/65 TO 11/30/65 WATER CUT	100% PEN. AVG. MONTHLY PRODUCTION FACTOR	100% CURRENT PRODUCTION FACTOR	TRACT FACTOR A*	TRACT FACTOR B**	
CHEVRON (Cont'd)									
7-11	112	42,899	389	.5057179	1.00887	.19556	.52089	.68355	-
8-11	112	20,420	830	.7065064	.28515	.41727	.36442	.33800	-
9-11	111	42,757	963	.6657411	.68611	.48414	.56493	.60532	-
10-11	111	50,781	963	.5541667	1.08688	.48414	.72523	.84578	-
11-11	111	68,998	3,823	.6188055	1.26267	1.92197	1.65825	1.52639	-
12-11	111	67,686	1,604	.1923464	2.62440	.80639	1.53360	1.89720	-
13-11	111	106,114	3,706	.5581784	2.25074	1.86314	2.01819	2.09570	-
14-11	111	70,554	1,916	.7055931	.99719	.96324	.97682	.98361	-
15-11	108	48,240	1,477	.1224005	2.08887	.74254	1.28108	1.55034	-
16-11	109	45,082	1,496	.1753032	1.81761	.75210	1.17830	1.39140	F
3-12	110	15,147	-	.7426108	.18887	.00000	.07555	.11332	
4-12	110	7,918	-	.8577320	.05457	.00000	.02183	.03274	
5-12	112	29,690	783	.6532329	.48985	.39364	.43213	.45137	
6-12	109	20,803	-	.7552553	.24891	.00000	.09956	.14935	
9-12	110	746	-	.4699140	.01916	.00000	.00766	.01149	
11-12	110	825	-	.8873164	.00450	.00000	.00180	.00270	
12-12	111	37,166	1,873	.6553184	.61499	.94163	.81097	.74565	
13-12	110	25,437	1,574	.2723070	.89671	.79131	.83347	.85455	
14-12	111	5,228	-	.8072382	.04838	.00000	.01935	.02903	
15-12	113	5,814	-	.9342767	.01802	.00000	.00721	.01081	
16-12	113	58,894	1,446	.8610284	.38597	.72696	.59056	.52236	
15-14	121	108,117	3,024	.7527796	1.17713	1.52028	1.38302	1.31439	
16-14	124	35,750	1,071	.4623494	.82601	.53843	.65346	.71098	
CEGO									
2-1	110	45,641	1,609	.8333333	.36850	.80890	.63274	.54466	
7-1	109	25,691	1,619	.7982806	.25336	.81393	.58970	.47759	

TRACT NUMBER	MONTHS ON PRODUCTION TO 12/1/65	CUMULATIVE PRODUCTION TO 12/1/65	6/1/65 TO 11/30/65 PRODUCTION	6/1/65 TO 11/30/65 WATER CUT	100% PEN. AVG. MONTHLY PRODUCTION FACTOR	100% CURRENT PRODUCTION FACTOR	TRACT FACTOR A*	TRACT FACTOR B**
CEGO (Cont'd)								
1-13	120	64,706	3,050	.2422360	2.17734	1.53335	1.79094	1.91974
3-13	121	15,647	530	.5354952	.32009	.26645	.28791	.29863
4-13	117	133,638	5,162	.1439469	5.21044	2.59513	3.64125	4.16432
5-13	121	40,119	2,399	.2815214	1.26943	1.20607	1.23141	1.24409
6-13	128	25,748	1,677	.3599237	.68611	.84309	.78030	.74890
7-13	127	27,968	943	.4410196	.65597	.47408	.54684	.58321
8-13	121	67,147	2,648	.2877891	2.10611	1.33125	1.64119	1.79617
2-14	115	29,669	1,435	.3262911	.92621	.72143	.80334	.84430
FARGO								
10-10	109	42,808	58	.9891771	.02265	.02916	.02656	.02525
IMPERIAL								
2-23	126	61,010	2,982	.7536148	.63573	1.49916	1.15379	.98111
3-23	129	56,797	5,257	.6886032	.73060	2.64289	1.87797	1.49551
4-23	132	112,378	1,963	.6396843	1.63464	.98687	1.24598	1.37554
5-23	132	116,159	5,267	.6653323	1.56937	2.64792	2.21650	2.00079
6-23	132	32,660	1,984	.6655992	.44090	.99743	.77482	.66351
7-23	130	68,052	1,466	.8117133	.52523	.73701	.65230	.60994
MINERALOID								
11-13	130	78,177	4,406	.5831599	1.33578	2.21506	1.86335	1.68749
12-13	127	8,363	-	.7899741	.07370	.00000	.02948	.04422
13-13	129	32,468	2,222	.7578466	.32478	1.11708	.80016	.64170

TRACT NUMBER	MONTHS ON PRODUCTION TO 12/1/65	CUMULATIVE PRODUCTION TO 12/1/65	6/1/65 TO 11/30/65 PRODUCTION	6/1/65 TO 11/30/65 WATER CUT	100% PEN. AVG. MONTHLY PRODUCTION FACTOR	100% CURRENT PRODUCTION FACTOR	TRACT FACTOR A*	TRACT FACTOR B**
MINERALOID (Cont'd)								
14-13	130	52,102	3,648	.6450671	.75803	1.83399	1.40360	1.18841
14-14	122	75,257	2,552	.7945415	.67537	1.28299	1.03994	.91841
9-15	118	76,696	1,946	.9107503	.30912	.97833	.71064	.57680
9-2	117	84,385	5,311	.5580428	1.69859	2.67004	2.28146	2.08717
15-2	119	85,725	3,263	.5245519	1.82514	1.64043	1.71431	1.75126
16-2	117	75,806	3,966	.5044978	1.71077	1.99386	1.88062	1.82401
PARADISE								
1-23	126	3,888	1,729	.6690909	.05441	.86923	.54331	.38034
8-23	130	7,723	1,990	.9070137	.02944	1.00045	.61204	.41784
RUNDLE								
12-18	125	37,785	612	.8619134	.22243	.30768	.27358	.25653
3-14	119	29,104	1,451	.7635267	.30819	.72947	.56096	.47670
4-14	119	36,223	1,724	.7472141	.41004	.86672	.68405	.59271
5-14	119	44,661	1,469	.6789773	.64202	.73852	.69992	.68062
6-14	121	29,011	1,215	.6983615	.38539	.61083	.52065	.47556
11-14	124	34,175	1,548	.6191882	.55928	.77824	.69065	.64686
12-14	125	17,726	-	.9595061	.03060	.00000	.01224	.01836
SUN								
3-18	118	69,209	2,320	.4597112	1.68864	1.16635	1.37527	1.47972
4-18	123	41,869	1,382	.6737488	.59179	.69478	.65359	.63299
5-18	124	97,877	2,226	.5478367	1.90188	1.11909	1.43221	1.58877
6-18	112	45,104	1,969	.8066195	.41499	.98989	.75993	.64495

PROPOSED VIRDEN-ROSELEA UNIT NO. 3

WORKING INTEREST OWNER PARTICIPATION IN PROPOSED UNIT

Working Interest Owner	Unit Participation A*	Unit Participation B**
Chevron Standard Limited	52.43617	54.22855
Canadian Export Gas & Oil Ltd.	11.94563	12.62161
Canadian Superior Oils Ltd.	2.93820	2.83122
Fargo Oils Limited	.44857	.45965
Imperial Oil Limited	7.92136	7.12640
Mineraloid Limited	8.78537	7.88826
Paradise Petroleums Ltd.	1.15535	.79818
Rundle Petroleums Ltd.	3.44205	3.14734
Sun Oil Company	4.22099	4.34643
The British American Oil Company Ltd.	3.84055	3.71808
Union Oil of Canada Ltd.	2.86576	2.83428
	100.00000	100.00000

* Unit Participation and Tract Factor "A": Factor Based on 40% Penalized Average Monthly Production Factor plus 60% Current Production Factor (i.e. factors in effect for first million STB of Unit production or three years, whichever occurs first).

** Unit Participation and Tract Factor "B": Factor Based on 60% Penalized Average Monthly Production Factor plus 40% Current Production Factor (i.e. factors in effect at the expiration of Tract Participation Factors "A").