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TUNDRA OIL AND GAS LTD.

2000 N Ebor #2

NORTH EBOR UNIT NO. 2

PROGRESS REPORT

January 1 - December 31, 2000

FEBRUARY, 2001

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APPENDICES

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NORTH EBOR UNIT NO.2

INTRODUCTION

The North Ebor Unit No.2 was unitized in October, 1991 for the purposes of waterflooding. Water injection commenced during the same month through well 8-14-10-29. During July, 1994, a second injector was added at 1-14-10-29. Table No.1 outlines the Unit well list. The subject Progress Report covers the operating period from January 1, 2000 thru to December 31, 2000.

DISCUSSION

1. Production Performance

Oil production averaged 3.8 m3/day during the month of January, 2000 and increased to 4.0 m3/day by December 31, 2000. Annual daily oil production increased by 5% over the aforementioned period. The average daily oil rate during 2000 was 4.1 m3/day. Total oil production during 2000 was 1,501.5 m3 (down 9% from 1999). Cumulative oil production in the Unit to 2000.12.31 was 51,338.2 m3. Table No.2 summarizes the 2000 production statistics of the North Ebor Unit No.2.

Water-cut averaged 86% during January, 2000 and remained unchanged by December 31, 2000. The average monthly water-cut during 2000 was 85%. Water-cut remained relatively flat in the Unit during 2000. The current Unit water-cut is not representative of the unitized zone (Bakken "D" Pool), since the majority of the water is produced from wells 16-11, and 13-12-10-29. These wells have been fracture stimulated, which resulted in water influx from the overlying Lodgepole formation. This has been confirmed through salinity tests. Appendix B outlines the 2000 production data of the individual wells in the Unit. Figure No.2 outlines the historical production of the Unit.

Remaining recoverable oil reserves of 10,000 m3 are estimated from the North Ebor Unit No.2. Figure No.2 outlines the ultimate oil recovery prediction estimated from the Bakken formation in the Unit.

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2. Reserves

The total oil-in-place in the Unit in both the upper and lower zone of the Middle Bakken Member is estimated at 173,585 m3. The oil-in-place estimates for the individual wells are outlined in Table No.3.

3. Recovery Profiles

Current oil recovery to 2000.12.31 is estimated at 29.6% of the oil-in-place (includes both upper and lower layers). Ultimate oil recovery in the Unit is estimated at 61,340 m3 or 35.3% of the oil-in-place. This is considered as the upper end of the recovery spectrum from the Bakken formation under 16 hectare spacing with pressure maintenance. Table No.3 outlines the current and ultimate oil recoveries of the individual wells in the Unit. Appendix C outlines the 2000 individual well ultimate oil recovery predictions.

4. Injector Performance

Figures No.3 and No.4 outline the wellhead injection pressures vs cumulative injection volume for injection wells 8-14-10-29 and 1-14-10-29, respectively. In both cases, even with re-fracturing, the wellhead injection pressures have continued to increase over the cumulative injection period. This is attributable to low matrix permeability associated with the Bakken formation. The injection capacity is further impacted by the low mobility ratio identified from relative permeability testing. As a result, during a pressure maintenance operation in the Bakken formation, as reservoir fill-up is approached, it will become progressively more difficult to maintain injection. On this basis, a higher ratio of injectors is required in the Bakken to maximize oil recovery with waterflood operations. More recently, injection pressures at 8-14 have flattened out in the 1,100 psig range with higher injection pressure of about 1550 psig at 1-14 (refer to Figures No.3 and No.4).

Hall Plots were also prepared for injection wells 8-14 and 1-14-10-29 to further confirm that injection cannot be improved on a long term basis with

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additional stimulation programs. Figures No.5 and No.6 outline the Hall Plots for injectors 8-14 and 1-14, respectively. Both plots, as in the North Ebor Unit No.1 injectors, indicate that there is no significant change in the slope over the majority of the injection profiles. As a result, remedial work will not significantly improve injection or reduce wellhead injection pressures over the long term. These profiles confirm from a reservoir engineering standpoint that the high injection pressures are due to the low reservoir permeability conditions of the Bakken "D" Pool.

In summary, total injection during 2000 was 9,353.3 m3 (down 1% from 1999). The average daily injection in the Unit during 2000 was 25.5 m3/day (unchanged from 1999). Cumulative injection to 2000.12.31 was 88,779 m3 (up 15% from 1999). Tables No.4a and No.4b summarize the 2000 injection data for injectors 8-14-10-29 and 1-14-10-29, respectively. Tables No.5a and No.5b outline the historical injection profiles for injection wells 8-14 and 1-14-10-29, respectively.

5. Voidage Replacement

Table No.6a outlines the voidage calculations for the Unit. Total voidage in the Unit during 2000 was 5,671.5 Rm3 (down 1% from 1999). In calculating the annual voidage, an adjustment was required to the water production, since two wells (16-11, and 13-12-10-29) are fractured into the overlying Lodgepole, which is water bearing. Table No.6b outlines the method that was used to determine the volume of water that is being contributed by the Bakken formation. Based on our assessment, 80% of the historical produced water in the two aforementioned wells is a direct contribution from the Lodgepole formation. Both wells have produced at high water-cuts from initial production. A typical Bakken well produces at a water-cut below 20% over the majority of it's life under primary production. Since waterflood response in this area of the Unit has been weak, Tundra considers that the majority of produced water is still coming from the Lodgepole formation.

Based on the aforementioned methodology, the resulting voidage replacement ratio in the Unit during 2000 was 1.65. A cumulative voidage replacement ratio of 1.0 Rm3/m3 has been achieved in the Unit to 2000.12.31.

6. Individual Well Performance

A review of the production performance of each individual well is presented here-after. The analysis is referenced to the wells outlined in Appendices B and C.

a. 15-11-10-29

The 15-11 well was abandoned in November, 1996.

b. 16-11-10-29

Oil production at the beginning of 2000 was 0.41 m3/day at a water-cut of 67%. By year end, oil production had marginally declined to 0.3 m3/day with water-cut increasing to 74%. Oil production at this location has been relatively flat during 2000. Waterflood response at 16-11 is being received from the injector at 1-14. This observation is supported by the progressive decrease in water-cut and a stabilization in the total fluid production during 1995 at 16-11. The 16-11 well has been fractured out of zone into the Lodgepole formation, which has contributed to the historically high water-cut at this well. Since the reservoir quality is lower at 16-11, waterflood response at this location will lag the higher quality wells in the Unit. Operations will continue at 16-11-10-29 during 2001, however, if the oil rate continues to decline, this location will be abandoned.

c. 13-12-10-29

Oil production at the beginning of 2000 was 2.13 m3/day at a water-cut of 87%. By year end, oil production remained relatively unchanged at 2.07 m3/day at a water-cut of 88%. Based on well testing, oil production at 13-12 has remained relatively flat at this location during 2000. The 13-12 well has had a high water-cut from initial production due to the hydraulic fracture treatment breaking into the overlying water bearing Lodgepole formation.

The high water-cut has not adversely impacted oil productivity at this location. Since oil productivity has remained fairly flat throughout the producing life of this well, this suggests that the 13-12 well is draining a large area. The contribution of waterflood response from the initial injector at 8-14 is unlikely at 13-12 due to this well being outside of the initial inverted 9-spot waterflood pattern. With the installation of the 1-14-10-29 injector, pressure maintenance should maintain productivity at 13-12. The 13-12 well, at this time, is the best producing well in the Unit.

d. 4-13-10-29

Oil production at the beginning of 2000 was 0.86 m3/day at a water-cut of 86%. By the end of 2000 oil production increased slightly to 1.01 m3/day with a water-cut of 84%. During 2000, based on well testing, the oil production profile at 4-13 has been flat with a slight decrease in water-cut. The 4-13 well has had the best waterflood response in the Unit. The 1-14 injector has been the prime contributor in improving oil recovery at 4-13. This conclusion is supported by both the significant increase in oil production (refer to Appendix C) and water-cut after injector 1-14 went into operation. Based on a review of all the wells in the southern sector of the Unit, the majority of waterflood support provided by injector 1-14 has manifested itself at 4-13. Although water breakthrough has occurred at 4-13, the well is still economic to operate, and operations will continue at 4-13 during 2001. It appears based on the current production performance of the 4-13 well that the majority of water injection at 1-14 is going to 4-13.

e. 5-13-10-29

Oil production at the beginning of 2000 was 0.2 m3/day at a water-cut of 91%. Oil production was relatively flat during the year with a December, 2000 oil rate of 0.4 m3/day at a water-cut of 86%. A review of the total fluid production (refer to Appendix C) indicates that the 5-13 well has received additional waterflood response from the 1-14 injector. This conclusion is supported by both an increase in total fluid and oil production, with a progressively increasing water-cut. During the last 3 years total fluid production has been relatively flat, and water-cut has continued to increase. The 5-13 well has the highest cumulative oil production in the Unit.

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Although the 5-13 well is in an advanced state of depletion and water breakthrough, this location is still economic in the current oil price environment. The 5-13 oil production will be monitored during 2001, and if oil productivity continues to decline, the 5-13 well will be abandoned during 2001.

f. 1-14-10-29

Since the 1-14 well was sub-economic, this location was converted to injection service in July, 1994 to improve voidage replacement and oil recovery in the Unit. Previous pressure surveys also indicated that the prevailing pool pressures were low in the southern sector of the Unit. Based on the cumulative injection from 1-14, good waterflood response has been observed only at 4-13 and 5-13-10-29, with weaker response at 16-11-10-29. The continuing strong production performance at 13-12 may in part also be due to the pressure maintenance contribution from injector 1-14. Injection operations will continue at 1-14 during 2001.

g. 7-14-10-29

The 7-14 well was abandoned during July, 1996, since oil productivity at this location was sub-economic with no further optimization opportunities.

h. 8-14-10-29

The 8-14 well was the initial injector in the Unit. Injection operations at 8-14 will continue during 2001.

i. A10-14-10-29

Oil production at the beginning of 2000 was 0.2 m3/day at a water-cut of 88%. By year end, oil production remained relatively unchanged at 0.25 m3/day at a water-cut of 86%. Although there was waterflood support historically from injector 9-14, there does not appear to be any significant impact on the total fluid production at A10-14 after 9-14 injector was abandoned. The A10-14 well has basically watered-out, since oil productivity is presently at the economic limit. The A10-14 well will be abandoned during 2001 if oil production continues to decline.

7. Bakken Waterflood Performance Parameters

A discussion of the analysis of the Bakken relative permeability testing completed in an analogous reservoir to the Bakken "D" Pool is outlined in the North Ebor Unit No.1 2000 Progress Report. The aforementioned document outlines the fractional flow curve, and flood front advancement expected in a typical Bakken reservoir under pressure maintenance. For further information, please refer to the North Ebor Unit No.1, 2000 Progress Report.

As reservoir fill-up is approached (Cum. VRR=1.0), the injection life of additional injectors will be considerably shorter (a pore volume replacement of only 0.5 is required to maximize oil recovery) than in the initial injection wells. This conclusion is supported by laboratory testing and actual field performance of the new injectors added in both the North Ebor Units No.1 and No.2 during 1994. In the final stages of the producing life of the Unit, the addition of more injectors beyond 1-14 and 9-14 will not result in a significant increase in the total injection volume because of the high wellhead injection pressures that will be encountered immediately (high interfacial tension between the water and oil phases increases as waterflood matures in a Bakken reservoir). The only benefit will be the capbaility to reduce injection volumes at the existing injectors, which will reduce wellhead injection pressures. However, the total Unit injection volume will not increase significantly over the long term.

8. Pressure Surveys

There were no pressure surveys completed in the North Ebor Unit No.2 during 2000. As outlined in the North Ebor Unit No.1 2000 Progress Report, Bakken reservoirs require long shut-in periods to obtain reliable estimates of static reservoir pressures (radial flow period) and their associated formation parameters. On this basis, as outlined in the aforementioned document,

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pressure surveys (DST's) in the future will only be done if new wells are drilled adjacent to the Unit (substitute for conventional pressure buildup tests). Running pressure surveys in Bakken wells with more than three months of production history is not economic and impacts on the profitability of the Unit (a shut-in period of at least 6 months is required to obtain reliable data in a low permeability reservoir where the production period exceeds 3 months). The Manitoba Petroleum Branch has acknowledged this reservoir phenomenon in a previous submission by Tundra Oil and Gas Ltd., and exempted the Company from running further annual pressure surveys in Bakken pressure maintenance schemes.

9. Enhanced Recovery

Laboratory testing was completed during 1995 to determine if chemical flooding would improve Unit oil recovery from a mature Bakken waterflood. Chemical flooding would involve the addition of surfactant to the injection water to lower the interfacial tension (IFT) between the oil and formation water. After testing a suite of commercially available surfactants, two potential chemicals were identified that would substantially reduce formation IFT. However, both surfactants indicated significant adsorption by the reservoir rock. As a result, under in-situ conditions, this would significantly reduce the effectiveness of the chemicals in reducing IFT in the reservoir fluids and not increasing oil recovery. A preliminary benefit/cost analysis suggested that it would not be economic to install enhanced recovery operations in the Bakken "D" Pool, relative to the incremental oil recovery attributable to chemical flooding.

10. Summary

The North Ebor Unit No.2 is a mature pressure maintenance scheme with current recovery estimated at about 35.9 M STB/well (does not include D&A's. Ultimate oil recovery is estimated at 42.9 M STB/well. Since three D&A's were drilled south and east of the Unit, to define the southern extent of the Bakken "D" Pool, an ultimate oil recovery of 32 M STB/well is projected under full cycle development scenario (primary and secondary operations) for this production entity. Drainage is quite likely greater than 16 hectares in several wells (16-11, 13-12, 5-13, and A10-14-10-29) in the Unit based on high ultimate oil recoveries and low reservoir pressures (4-13-10-29) from DST's after drilling operations. The reserve life index of the Unit is estimated at 6.9 years.

CONCLUSIONS

The following conclusions are offered by Tundra Oil and Gas Ltd. in our efforts to maximize oil recovery from the North Ebor Unit No.2:

1. Tundra will continue to monitor production and carry out the required remedial work to achieve the recovery predictions outlined in this Progress Report.

2. The Unit has achieved a cumulative voidage replacement ratio of 1.0 with the existing pressure maintenance program.

3. The addition of further injectors in the Unit is not economic under 16 hectare spacing.

4. Similarly, consideration of infill drilling would not be economic without attractive government incentives.

5. Horizontal drilling would not be an economic venture in the Unit due to the advanced state of depletion in this production entity. The application of horizontal drilling in the Bakken formation must be justified on using the horizontal wellbore both for production and injection operations. Due to the low mobility ratio in the Bakken formation, an extended wellbore would result in lower injection pressures and provide better waterflood sweep. This concept may be attempted with the horizontal presently in Kola Unit No.2.

6. As in the North Ebor Unit No.1, future conventional pressure buildup testing has been discontinued. The Bakken formation requires extended shut-in periods to obtain reliable data. The extended shut-in times are not

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economic and will negatively impact on the profitability of this pressure maintenance scheme. Fluid levels will be taken periodically to ensure that all wells are pumping at their optimum rates.

7. Laboratory testing of chemical flooding indicated that this type of enhanced recovery would not be economic in the Bakken formation at the North Ebor Units.

8. Well A10-14-10-29 is at it's economic limit and will be abandoned in Year 2001.

LIST OF TABLES

Table No.1

North Ebor Unit No.2

Well List

The following wells are included in the North Ebor Unit No.2

Well	Status
15-11-10-29	Abandoned
16-11-10-29	Producing
13-12-10-29	Producing
4-13-10-29	Producing
5-13-10-29	Producing
1-14-10-29	Injector
7-14-10-29	Abandoned
8-14-10-29	Injector
A10-14-10-29	Producing

TABLE NO. 2

NORTH EBOR UNIT NO.2

2000 PRODUCTION DATA

	JAN	FEB	MARCH	APRIL	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC
OIL (m3)	117.0	115.9	136.3	121.6	129.5	123.3	129.8	127.5	125.7	127.6	123.3	124.0
WATER (m3)	738.5	688.2	739.4	710.5	696.0	624.3	650.2	668.0	631.5	656.6	742.9	773.1
TOTAL FLUID (m3)	855.5	804.1	875.7	832.1	825.5	747.6	780.0	795.5	757.2	784.2	866.2	897.1
DAILY OIL (m3/day)	3.8	4.0	4.4	4.1	4.2	4.1	4.2	4.1	4.2	4.1	4.1	4.0
WATER-CUT (%)	86	86	84	85	84	84	83	84	83	84	86	86

AVERAGE MONTHLY OIL =	125.1	m3
AVERAGE MONTHLY WATER =	693.3	m3
AVERAGE MONTHLY TOTAL FLUID =	818.4	m3
AVERAGE ANNUAL DAILY OIL =	4.1	m3/day
AVERAGE MONTHLY WATER-CUT =	84.7	%
2000 CUM. OIL PRODUCTION =	1,501.5	m3
2000 CUM. WATER PRODUCTION =	8,319.2	m3
CUM. OIL PRODUCTION TO 2000.12.31	51,338.2	m3

TABLE NO.3

North Ebor Unit No.2

Recovery Profiles

(Based on Cumulative Production to 2000.12.31)

Well	Cum. Prod. to Dec.31/2000 (m3)	Cum. Prod. to Dec.31/2000 (STB)	Lower Zone OOIP (STB)	Upper Zone OOIP (STB)	Total OOIP (STB)	Ultimate Recoverable Oil (STB)	Remaining Proved Producing Oil (STB)	Current Rec. Fac. Lower & Upper Zone (%)	Ultimate Rec. Fac. Lower & Upper Zone (%)
15-11-10-29	2,211.2	13,908	0	96,566	96,566	13,908	0	14.4	14.4
16-11-10-29	4,387.8	27,599	74,724	0	74,724	29,420	1,821	36.9	39.4
13-12-10-29	11,255.7	70,798	114,960	89,669	204,628	109,630	38,832	34.6	53.6
4-13-10-29	9,125.8	57,401	232,793	0	232,793	75,320	17,919	24.7	32.4
5-13-10-29	14,426.2	90,741	77,598	52,307	129,904	94,195	3,454	69.9	72.5
1-14-10-29	2,386.9	15,014	77,621	29,890	107,510	15,014	0	14.0	14.0
7-14-10-29	1,417.6	8,917	13,795	18,394	32,189	8,917	0	27.7	27.7
8-14-10-29	2,080.2	13,084	100,877	42,918	143,795	13,084	0	9.1	9.1
A10-14-10-29	4,046.8	25,454	69,742	0	69,742	26,345	891	36.5	37.8
Totals	51,338.2	322,917	762,110	329,743	1,091,852	385,833	62,916	29.6	35.3

NOTE: REMAINING PROVED RESERVES HAVE BEEN ESTIMATED FROM DECLINE ANALYSIS

TABLE NO.4a

NORTH EBOR UNIT NO.2

2000 WATER INJECTION SUMMARY

WELL 8-14-10-29

	JAN	FEB	MARCH	APRIL	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC
TOTAL (m3)	429.7	401.6	424.8	410.5	420.3	393.4	426.3	419.6	408	411.5	396.9	411.6
DAILY (m3/day)	13.9	13.8	13.7	13.7	13.6	13.1	13.8	13.5	13.6	13.3	13.2	13.3

2000 AVERAGE ANNUAL DAILY INJECTION =	13.5	m3/day
CUMULATIVE INJECTION TO 99.12.31 =	49,536.2	m3
TOTAL 2000 ANNUAL INJECTION =	4,954.2	m3
CUMULATIVE INJECTION TO 2000-12-31 =	54,490.4	m3

TABLE NO.4b

NORTH EBOR UNIT NO.2

2000 WATER INJECTION SUMMARY

WELL 1-14-10-29

	JAN	FEB	MARCH	APRIL	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC
TOTAL (m3)	384.9	348.4	374.7	361.4	377.6	350	360.7	377.7	365.2	369.9	355.4	373.2
DAILY (m3/day)	12.4	12.0	12.1	12.0	12.2	11.7	11.6	12.2	12.2	11.9	11.8	12.0

2000 AVERAGE ANNUAL DAILY INJECTION =	12.0	m3/day
CUMULATIVE INJECTION TO 99.12.31 =	27,954.3	m3
TOTAL 2000 ANNUAL INJECTION =	4,399.5	m3
CUMULATIVE INJECTION TO 2000-12-31 =	32,353.8	m3

TABLE NO.5a

NORTH EBOR UNIT NO.2

8-14-10-29 HISTORICAL INJECTION DATA

YEAR	MONTH	Qinj (m3/day)	MONTHinj (Rm3)	CUMinj (Rm3)	Pinj (psig)
1991	10	-	668.5	668.5	166
	11	25.9	777.4	1,445.9	530
	12	25	775.7	2,221.6	744
1992	1	24.7	764.6	2,986.2	800
	2	25.2	731.7	3,717.9	830
	3	26	763.1	4,481.0	875
	4	26.3	788.2	5,269.2	941
	5	24.4	756.2	6,025.4	983
	6	24.2	701.1	6,726.5	1,013
	7	24.3	753.9	7,480.4	1,061
	8	24.9	777.3	8,257.7	1,098
	9	24.3	729.8	8,987.5	1,135
	10	25.6	794.1	9,781.6	1,172
	11	25.5	763.8	10,545.4	1,196
	12	25.6	791.7	11,337.1	1,222
1993	1	21.9	679.7	12,016.8	1,244
	2	25.2	706.8	12,723.6	1,259
	3	25.1	778.1	13,501.7	1,265
	4	25.0	750.4	14,252.1	1,282
	5	24.8	99.1	14,351.2	801
	6	0.0	0	14,351.2	244
	7	24.6	73.8	14,425.0	-
	8	21.7	671.3	15,096.3	983
	9	25.5	766.1	15,862.4	1,129
	10	25.3	783	16,645.4	1,210
	11	25.1	754	17,399.4	1,275
	12	25.0	776.1	18,175.5	1,321
1994	1	24.7	765.9	18,941.4	1,367
	2	24.8	694.7	19,636.1	1,398
	3	21	649.7	20,285.8	1,406
	4	17.2	516.5	20,802.3	1,399
	5	18.1	72.2	20,874.5	1,375
	6	21.2	127.3	21,001.8	1,167
	7	14	434.3	21,436.1	1,045
	8	16	495.8	21,931.9	1,057
	9	17.2	514.6	22,446.5	1,103
	10	18.6	575.2	23,021.7	1,110
	11	18.8	565	23,586.7	1,136
	12	15.5	480.5	24,067.2	1,149
1995	1	19	588.8	24,656.0	1,153
	2	19	531	25,187.0	1,164
	3	18.5	572	25,759.0	1,192
	4	16.6	496.9	26,255.9	1,212
	5	17.9	304.2	26,560.1	1,205
	6	16.1	129	26,689.1	1,066
	7	14.4	447.9	27,137.0	1,165
	8	14.3	443.9	27,580.9	1,182
	9	13.9	418	27,998.9	1,197
	10	13.8	316.7	28,315.6	1,173

TABLE NO.5a					
NORTH EBOR UNIT NO.2					
8-14-10-29 HISTORICAL INJECTION DATA					
YEAR	MONTH	Qinj (m3/day)	MONTHinj (Rm3)	CUMinj (Rm3)	Pinj (psig)
	11	14	418.5	28,734.1	1,151
	12	13.8	429.1	29,163.2	1,170
1996	1	13.7	424	29,587.2	1,498
	2	14.2	397	29,984.2	1,527
	3	13.8	428	30,412.2	1,468
	4	13.9	416	30,828.2	1,478
	5	14.3	272	31,100.2	1,484
	6	14.1	423	31,523.2	1,289
	7	13.7	426	31,949.2	1,426
	8	13.3	307	32,256.2	1,557
	9	14	420	32,676.2	1,228
	10	14.2	440	33,116.2	1,139
	11	15.6	469	33,585.2	1,182
	12	15.9	491.6	34,076.8	1,219
1997	1	14.5	449.6	34,526.4	1,182
	2	14	391.7	34,918.1	1,176
	3	16.4	508.9	35,427.0	1,160
	4	18	541.2	35,968.2	1,168
	5	16	494.6	36,462.8	1,168
	6	14.1	424	36,886.8	1,197
	7	13.5	419.1	37,305.9	1,198
	8	14.2	438.7	37,744.6	1,200
	9	13.8	414.8	38,159.4	1,206
	10	13.6	421.4	38,580.8	1,199
	11	13.7	411.8	38,992.6	1,199
	12	27.5	852.1	39,844.7	1,200
1998	1	14.2	440	40,284.7	1,200
	2	14.1	393.5	40,678.2	1,200
	3	14.2	438.8	41,117.0	1,205
	4	14.1	423.9	41,540.9	1,221
	5	13.7	423.9	41,964.8	1,229
	6	14.1	422.2	42,387.0	1,276
	7	7.9	243.7	42,630.7	1,142
	8	13.8	428.3	43,059.0	1,185
	9	12.3	475.5	43,534.5	1,197
	10	13	402.8	43,937.3	1,201
	11	10.3	308.6	44,245.9	1,217
	12	13.3	412	44,657.9	1,219
1999	1	13.3	412.1	45,070.0	1,232
	2	12.9	373	45,443.0	1,240
	3	13.2	409.8	45,852.8	1,240
	4	11.8	353.4	46,206.2	1,210
	5	12.9	401	46,607.2	1,148
	6	13.9	417.5	47,024.7	1,149
	7	12.6	391	47,415.7	1,135
	8	13.5	417	47,832.7	1,104
	9	14.1	422.9	48,255.6	1,100
	10	14	435.2	48,690.8	1,099
	11	13.9	416.4	49,107.2	1,080
	12	13.8	429	49,536.2	1,088

TABLE NO.5a					
NORTH EBOR UNIT NO.2					
8-14-10-29 HISTORICAL INJECTION DATA					
YEAR	MONTH	Qinj	MONTHinj	CUMinj	Pinj
		(m3/day)	(Rm3)	(Rm3)	(psig)
2000	1	13.9	429.7	49,965.9	1,104
	2	13.8	401.6	50,367.5	1,121
	3	13.7	424.8	50,792.3	1,126
	4	13.7	410.5	51,202.8	1,123
	5	13.6	420.3	51,623.1	1,121
	6	13.1	393.4	52,016.5	1,189
	7	13.8	426.3	52,442.8	1,121
	8	13.5	419.6	52,862.4	1,125
	9	13.6	408	53,270.4	1,120
	10	13.3	411.5	53,681.9	1,120
	11	13.2	396.9	54,078.8	1,135
	12	13.3	411.6	54,490.4	1,126

Inj114hi.xls

TABLE NO.5b					
NORTH EBOR UNIT NO.2					
1-14-10-29 INJECTION HISTORY					
YEAR	MONTH	Qinj (m3/day)	MONTHinj (Rm3)	CUMinj (Rm3)	Pinj (psig)
1994	Jan	0	0	0.0	0
	Feb	0	0	0.0	0
	Mar	0	0	0.0	0
	April	0	0	0.0	0
	May	0	0	0.0	0
	June	0	0	0.0	0
	July	18.6	501.8	501.8	941
	Aug	16.5	430.1	931.9	983
	Sept	19.9	596	1,527.9	1013
	Oct	22	594	2,121.9	1061
	Nov	23.1	693.5	2,815.4	1098
	Dec	21.2	635.6	3,451.0	1135
1995	Jan	22.3	692.7	4,143.7	1252
	Feb	22.3	624.1	4,767.8	1323
	Mar	21.7	673.7	5,441.5	1372
	April	21.5	645.7	6,087.2	1490
	May	26.3	367.5	6,454.7	1465
	June	20.4	612.6	7,067.3	1524
	July	17.6	546.1	7,613.4	1554
	Aug	17.8	552.3	8,165.7	1587
	Sept	16.6	498.1	8,663.8	1618
	Oct	17.5	524.1	9,187.9	1623
	Nov	16	479.8	9,667.7	1569
	Dec	20.4	224.9	9,892.6	1370
1996	Jan	17.9	556	10,448.6	1498
	Feb	16.8	471	10,919.6	1527
	Mar	9.5	295	11,214.6	1468
	April	13.9	418	11,632.6	1478
	May	13.5	216	11,848.6	1484
	June	13.9	250	12,098.6	1289
	July	13.1	407	12,505.6	1426
	Aug	13	403	12,908.6	1557
	Sept	13.5	404	13,312.6	1228
	Oct	12.3	370	13,682.6	1139
	Nov	12.3	369	14,051.6	1182
	Dec	13	389	14,440.6	1219
1997	Jan	12.7	395	14,835.2	1254
	Feb	13.2	370	15,205.0	1278
	Mar	12.7	393	15,597.6	1266
	April	14.1	422	16,019.8	1306
	May	14.2	439	16,459.0	1321
	June	13.2	397	16,856.4	1354
	July	12.6	389	17,245.5	1366
	Aug	12.9	401	17,646.8	1379
	Sept	12.9	375	18,021.8	1382
	Oct	13.1	405	18,426.7	1397
	Nov	12.6	378	18,804.4	1414
	Dec	6.8	212	19,016.3	1290

TABLE NO.5b					
NORTH EBOR UNIT NO.2					
1-14-10-29 INJECTION HISTORY					
YEAR	MONTH	Qinj	MONTHinj	CUMinj	Pinj
		(m3/day)	(Rm3)	(Rm3)	(psig)
1998	Jan	13	401.6	19,417.9	1364
	Feb	12.8	359.3	19,777.2	1418
	Mar	12.4	384.8	20,162.0	1430
	April	12.9	387.4	20,549.4	1423
	May	12.5	386.7	20,936.1	1436
	June	12.4	372	21,308.1	1445
	July	5.7	177.3	21,485.4	1454
	Aug	11.4	354.8	21,840.2	1342
	Sept	12.3	369	22,209.2	1427
	Oct	12.9	398.4	22,607.6	1454
	Nov	12.6	378.9	22,986.5	1466
	Dec	12.6	390.8	23,377.3	1474
1999	Jan	12.8	396.5	23,773.8	1,487
	Feb	12.5	361.1	24,134.9	1,497
	Mar	12.3	381.2	24,516.1	1,494
	April	11.9	356.9	24,873.0	1,498
	May	12	373.5	25,246.5	1,479
	June	13	390	25,636.5	1,500
	July	12.5	387.5	26,024.0	1,505
	Aug	12.1	375	26,399.0	1,487
	Sept	12.6	379	26,778.0	1,499
	Oct	13	401.5	27,179.5	1,520
	Nov	13	389.3	27,568.8	1,527
	Dec	12.4	385.5	27,954.3	1,534
2000	Jan	12.4	384.9	28,339.2	1548
	Feb	12	348.4	28,687.6	1555
	Mar	12.1	374.7	29,062.3	1557
	April	12	361.4	29,423.7	1566
	May	12.2	377.6	29,801.3	1562
	June	11.7	350.4	30,151.7	1551
	July	11.6	360.7	30,512.4	1537
	Aug	12.2	377.7	30,890.1	1547
	Sept	12.2	365.2	31,255.3	1550
	Oct	11.9	369.9	31,625.2	1553
	Nov	11.8	355.4	31,980.6	1541
	Dec	12	373.2	32,353.8	1551

TABLE NO.6a

NORTH EBOR UNIT NO.2

VOIDAGE CALCULATIONS

FROM JAN 1,2000 TO DEC. 31, 2000

OIL FORMATION VOLUME FACTOR = 1.063 Rm3

MONTH	OIL PRODUCTION m3	WATER PRODUCTION m3	ADJUSTED WATER PRODUCTION m3	OIL VOIDAGE Rm3	TOTAL VOIDAGE Rm3	TOTAL INJECTION Rm3	NET VOIDAGE Rm3	VOIDAGE REPLACEMENT RATIO VRR
JAN.	117	738.5	368	124.4	492.1	815	-322.53	1.66
FEB.	115.9	688.2	340	123.2	462.7	750	-287.30	1.62
MARCH	136.3	739.4	356	144.9	501.2	799.5	-298.31	1.60
APRIL	121.6	710.5	344	129.3	473.6	771.9	-298.34	1.63
MAY	129.5	696.0	341	137.7	478.8	797.9	-319.14	1.67
JUNE	123.3	624.3	306	131.1	437.4	743.4	-306.03	1.70
JULY	129.8	650.2	318	138.0	456.4	787	-330.62	1.72
AUG.	127.5	668.0	331	135.5	466.8	797.3	-330.47	1.71
SEPT.	125.7	631.5	309	133.6	442.5	773.2	-330.68	1.75
OCT.	127.6	656.6	317	135.6	452.8	781.4	-328.56	1.73
NOV.	123.3	742.9	363	131.1	493.8	752.3	-258.53	1.52
DEC.	124	773.1	382	131.8	513.5	785	-271.29	1.53
TOTAL	1,501.5	8,319.2	4,075	1,596.1	5,671.5	9,353.3	-3,681.8	1.65

CUM. POOL VOIDAGE (to 2000.12.31) =	86,138	Rm3
CUM. POOL INJECTION (2000.12.31) =	88,779	Rm3
CUM. NET VOIDAGE (2000.12.31) =	-2,641.6	Rm3
CUMULATIVE VRR (2000.12.31) =	1.0	Rm3 /m3

TABLE NO. 6b

North Ebor Unit No.2

2000 Water Production

Procedure to Calculate out of Zone Water Production

Year		16-11	13-12	Total Water	Out of Zone Water	Adjusted Water
		(m3)	(m3)	(m3)	(m3)	(m3)
2000	Jan	25	438.5	463.5	370.8	93
	Feb	25.4	410.5	435.9	348.72	87
	Mar	25.8	453.1	478.9	383.12	96
	Apr	24.6	433.1	457.7	366.16	92
	May	24.9	418.7	443.6	354.88	89
	June	23	374.5	397.5	318	80
	July	23	391.8	414.8	331.84	83
	Aug	23.4	397.5	420.9	336.72	84
	Sept	21	382.2	403.2	322.56	81
	Oct	22.3	402	424.3	339.44	85
	Nov	26.1	449.2	475.3	380.24	95
	Dec	25.7	463.5	489.2	391.36	98

Note: 80% of total water production is estimated in coming from Lodgepole formation

TABLE NO.7

PRESSURE SURVEYS

There were no pressure surveys conducted in the North Ebor Unit No.2 during 2000. As outlined in previous North Ebor Unit No.2 Progress Reports, long shut-in periods are required to obtain reliable static pressure estimates (reach radial flow conditions) in the Bakken formation. As an alternative, reservoir pressure measurements will be obtained in the future from DST's in new wells offsetting the existing Unit. In low permeability formations, such as the Bakken formation, the shut-in period generally has to be twice the previous production period, in order to achieve radial flow conditions. On this basis, a well with more than 3 months of production history would require on average a shut-in period of at least 6 months to obtain a reliable estimate of the static reservoir pressure and associated formation parameters.

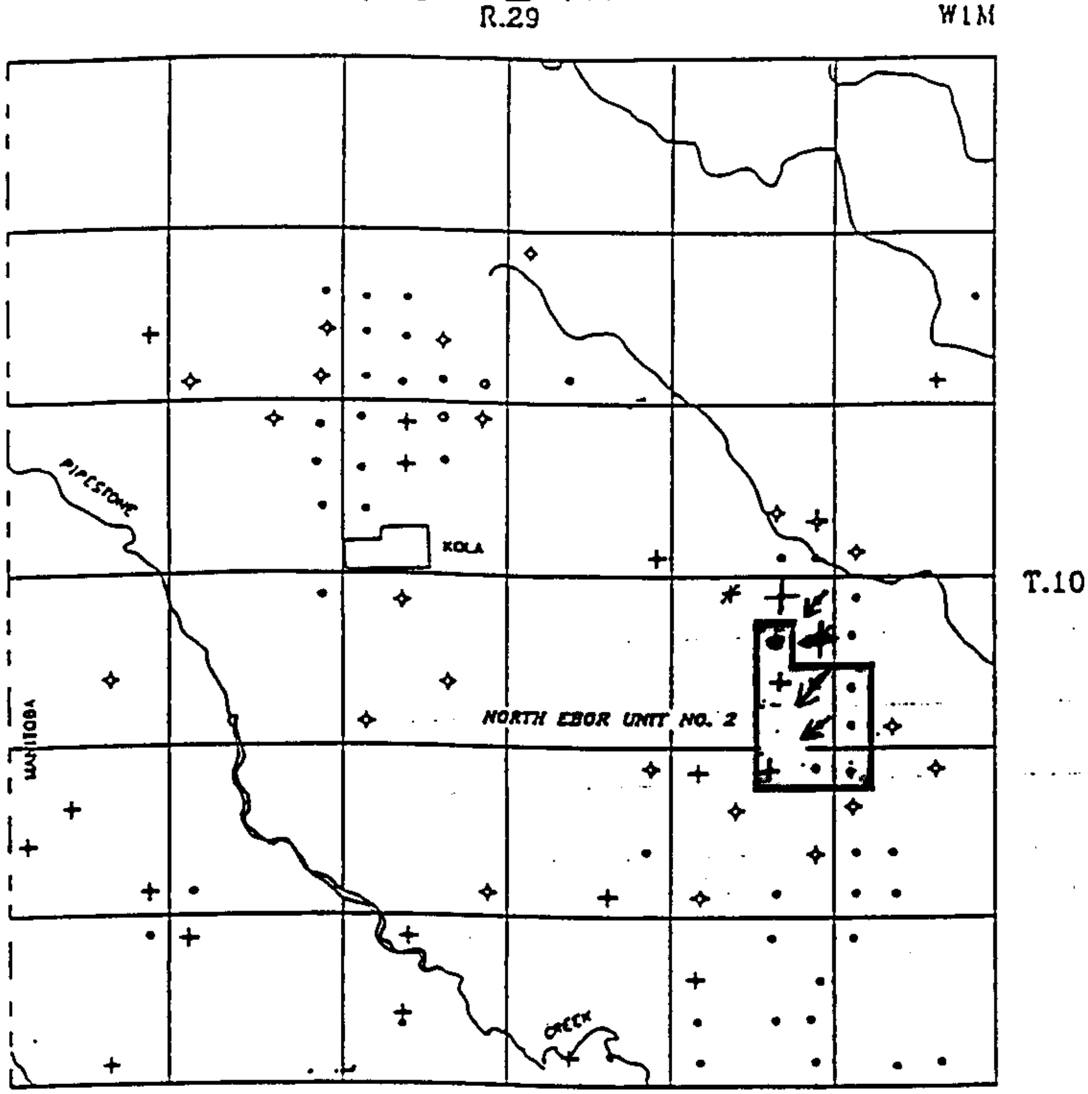
TABLE NO.8

WORKOVERS

During 2000 there were only maintenance activities in the Unit.

LIST OF FIGURES

FIGURE NO.1



UNIT OUTLINE

TUNDRA OIL AND GAS LTD.

NORTH EBOR UNIT NO 2

LAND MAP

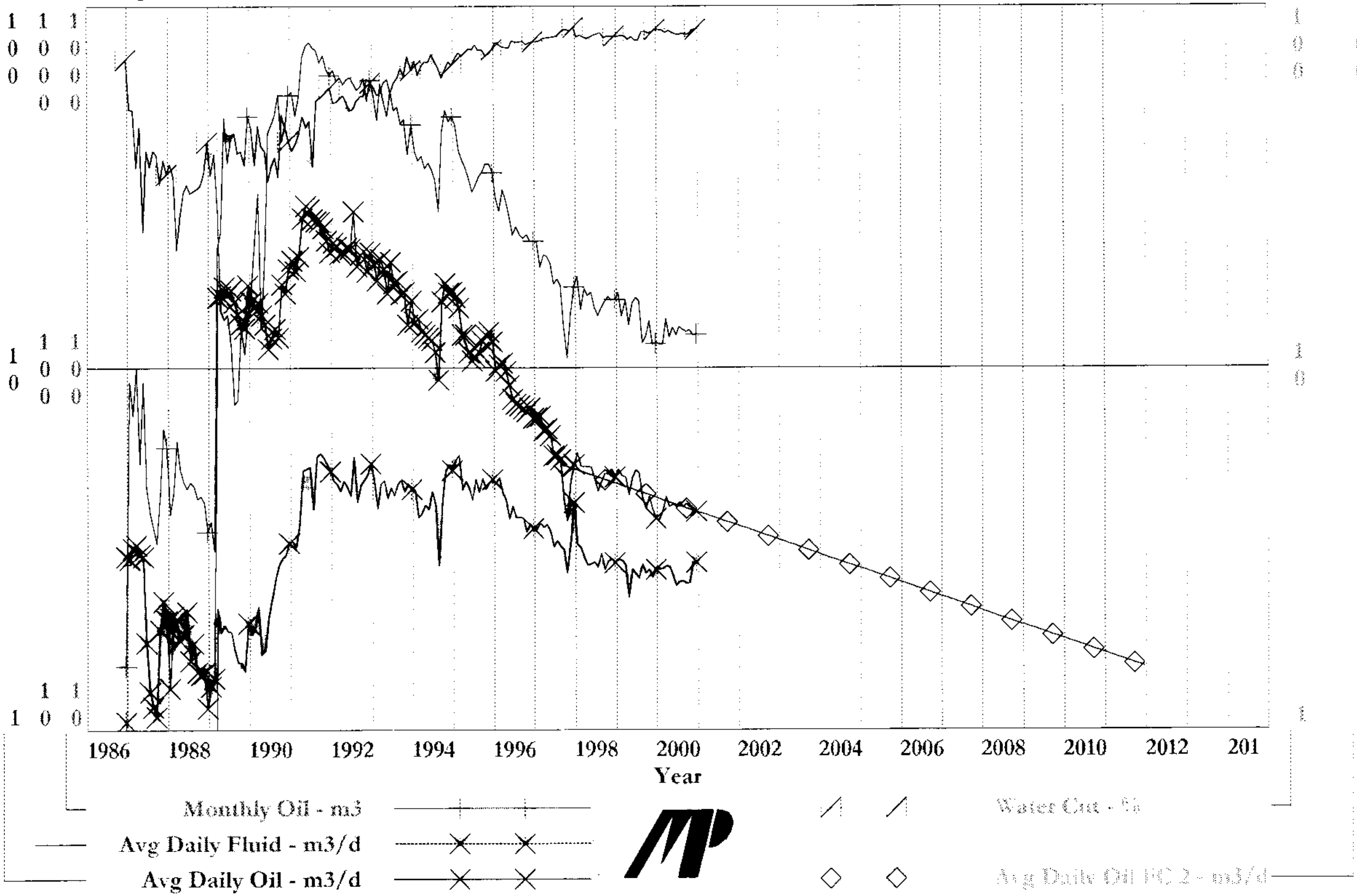
SCALE. 1:75,000	DATE. January 1, 1993
SOURCE. 9931846/XHSM01	DRAWING. MAP-1

FIGURE NO.2

neun2 Data 01/86-12/00
Avg Daily Oil FC 2 (Rate-Time)
qi: 5.3956 m3/d, Sep, 1997
qf: 1.48988 m3/d, Dec, 2011
di(Exp): 8.587 CTD: 51338.2 m3
RR: 10029.9 m3 Tot: 61368.1 m3

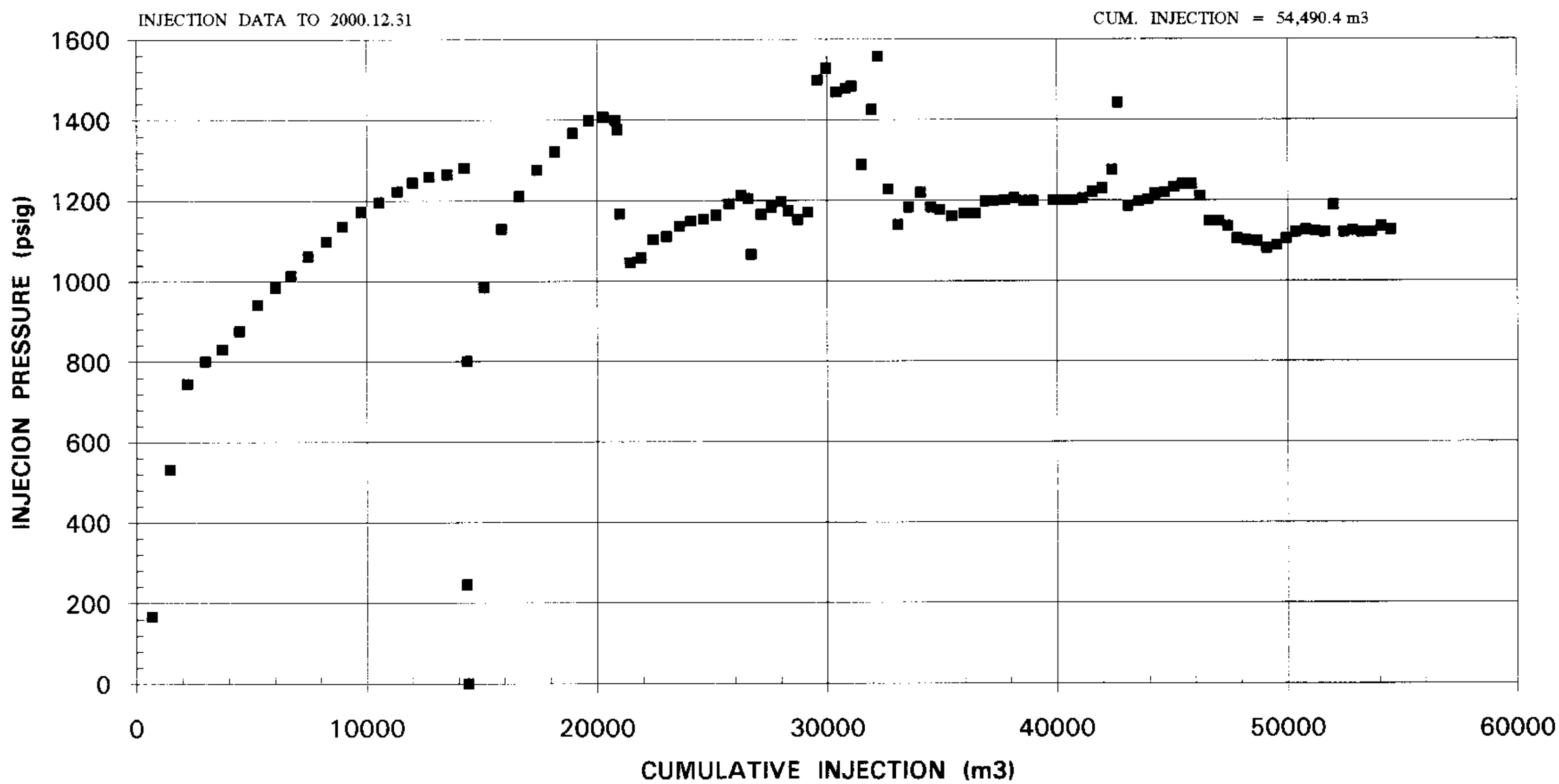
Operator:
Field:
Zone:
Type: Oil
Group: neborun2

Production Cums
Oil: 51338.2 m3
Gas: 0 E6m3
Water: 103066 m3
Cond: 0 m3



C814INJP.XLC

FIGURE NO.3
INJECTION PERFORMANCE OF WELL 8-14-10-29



C114INJP.XLC

FIGURE NO.4

INJECTION PERFORMANCE OF WELL 1-14-10-29

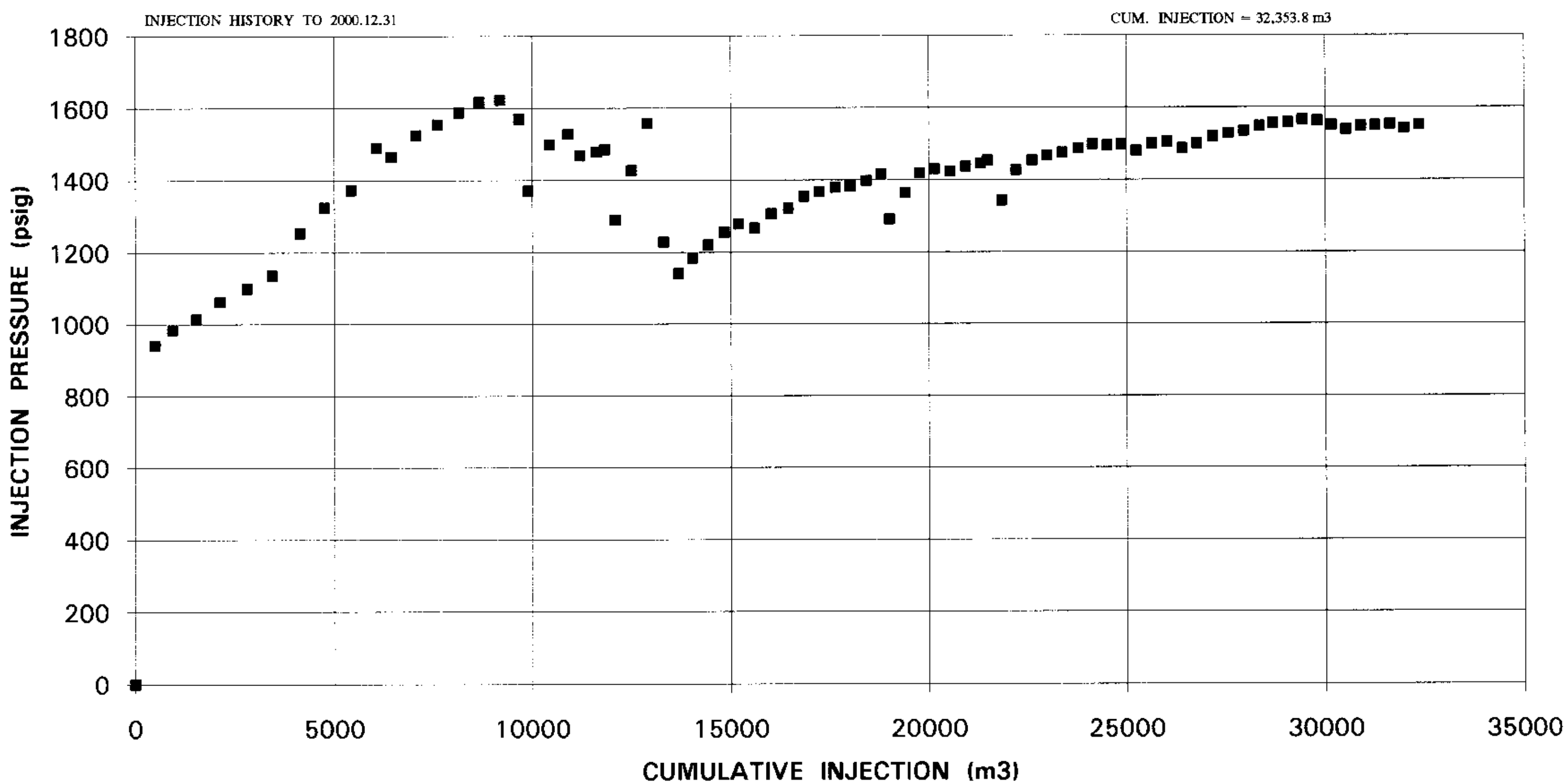


FIGURE NO.5

HALL PLOT INJECTION WELL 8-14-10-29

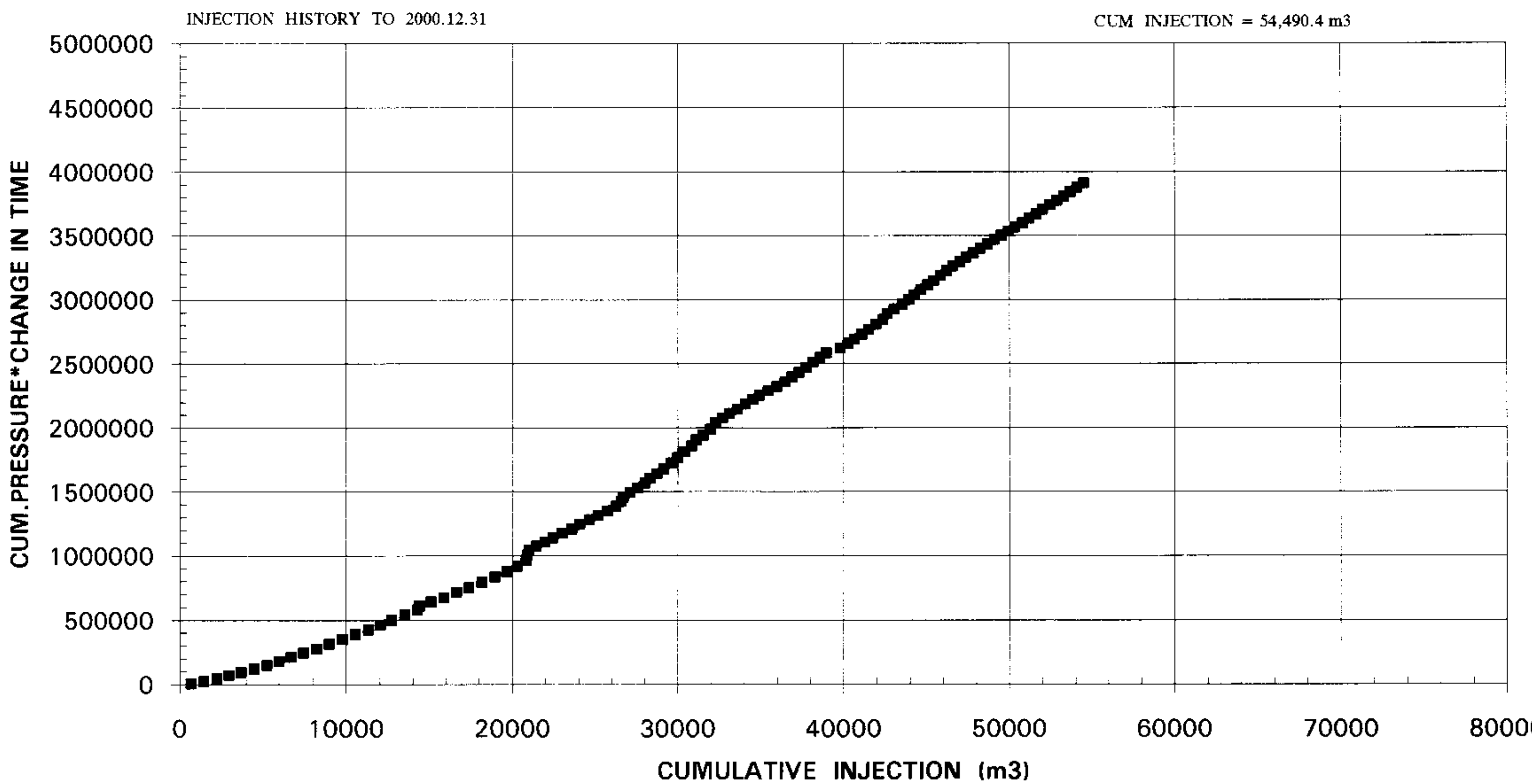


FIGURE NO.6

HALL PLOT INJECTION WELL 1-14-10-29

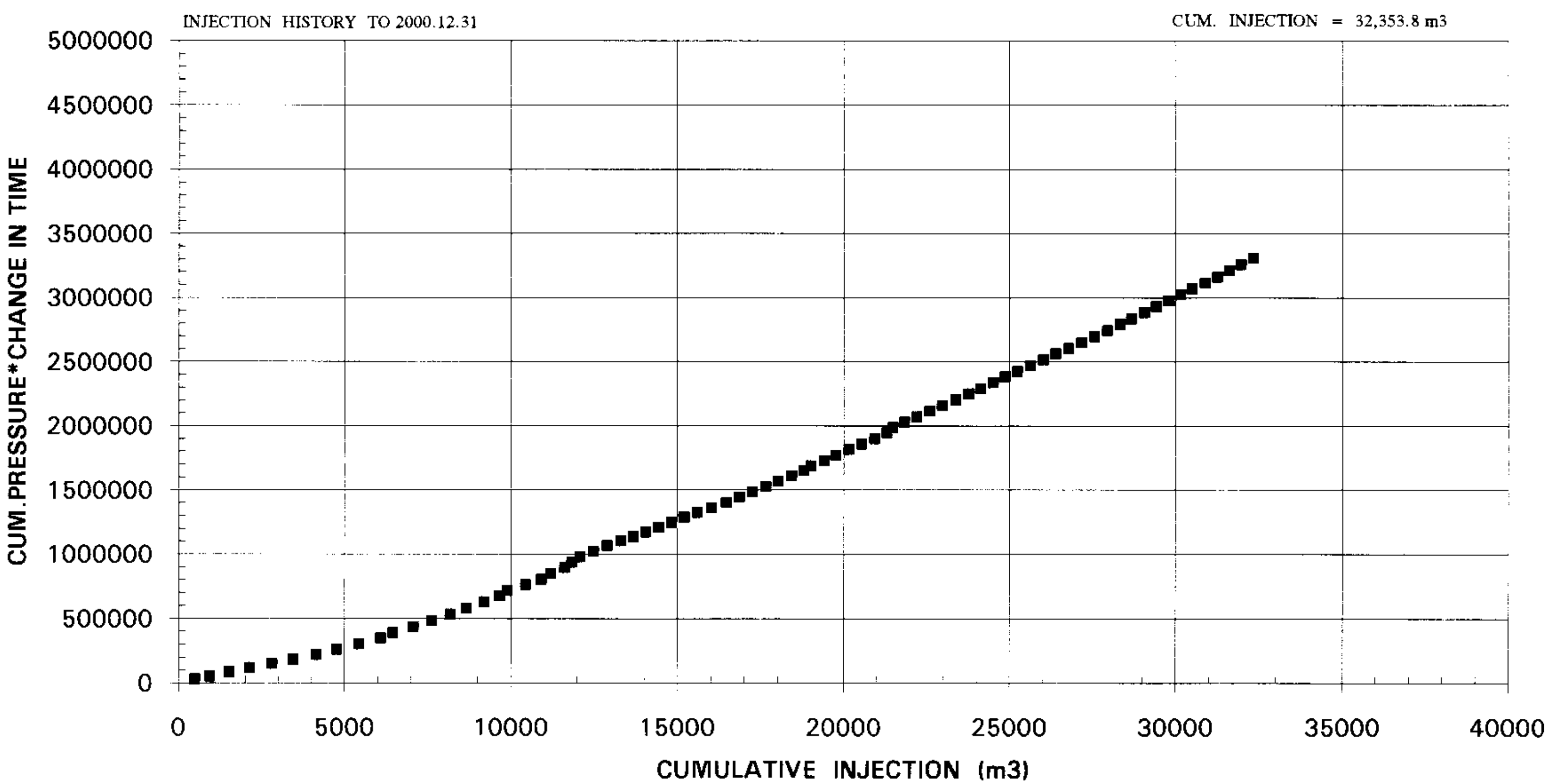
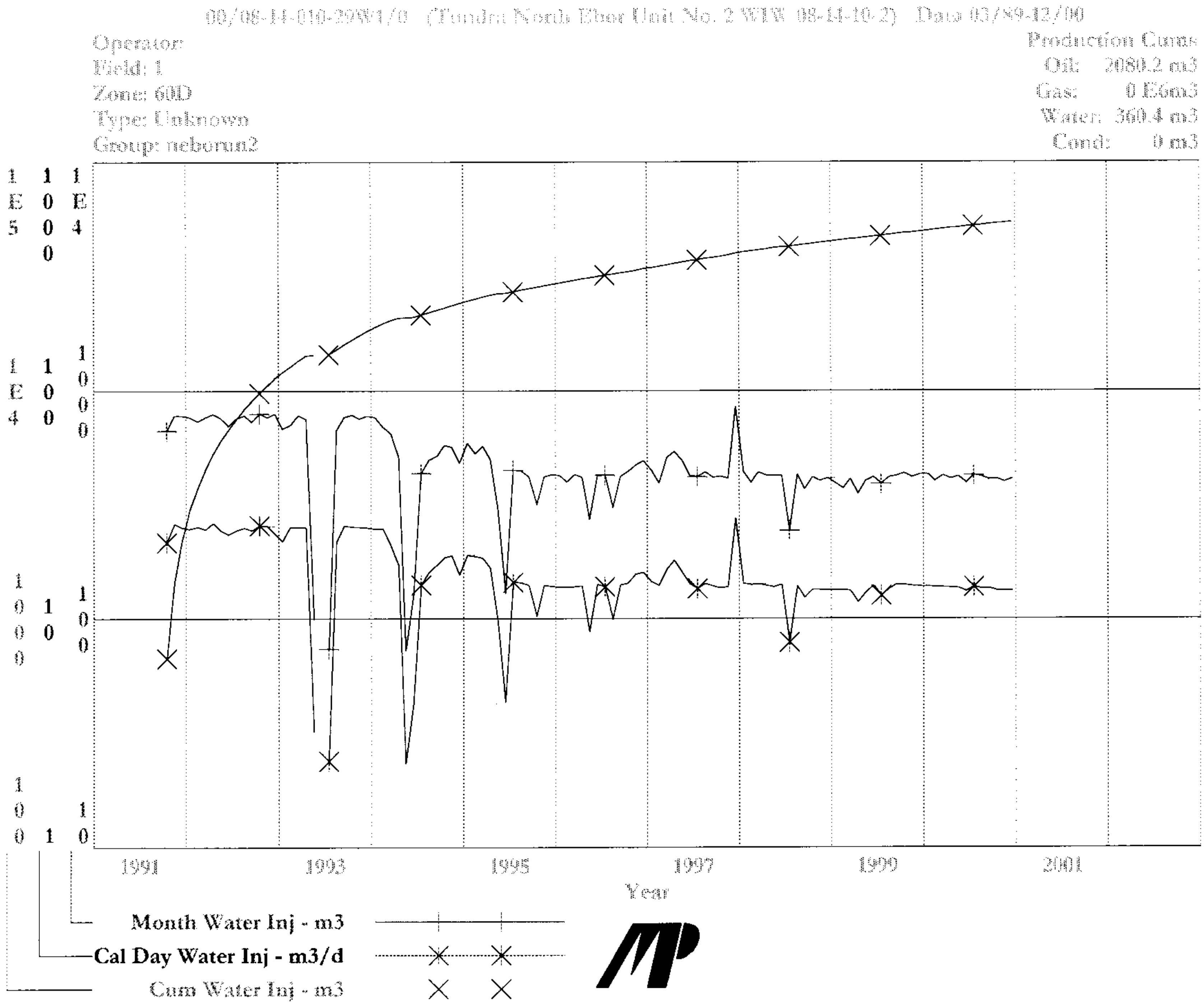


FIGURE NO.8



00/08-14-010-29W1/0 (Tundra North Ebor Unit No. 2 WIW 08-14-10-2) Data 03/89-12/00
Operator:
Field: 1
Zone: 60D
Type: Unknown
Group: neborun2
Production Cums
Oil: 2080.2 m3
Gas: 0 E6m3
Water: 360.4 m3
Cond: 0 m3
1E5
1000
1E4
1E4
100
1000
1000
10
100
100
1
10
1991
1993
1995
1997
1999
2001
Year
Month Water Inj - m3
Cal Day Water Inj - m3/d
Cum Water Inj - m3

LIST OF APPENDICES

APPENDICES

APPENDIX A

HISTORICAL UNIT PRODUCTION DATA

Production Report

Group	:	neborun2	Date	:	July 27, 2006 3:49:39 am
Well	:	neun2	User	:	George
	:	000000006			
Hist.Data	:	01/86-12/00	On Prod	:	02/09
Operator	:		Status	:	Oil
Field	:		Zone	:	

Production Data from January, 1986 to December, 2000

Year	Monthly Oil m3	Cum Oil m3	Avg Daily Oil m3/d	Water Cut %	Monthly Water m3	Cum Water m3
Jan., 1986						
Feb., 1986						
Mar., 1986						
Apr., 1986						
May., 1986						
Jun., 1986						
Jul., 1986						
Aug., 1986						
Sep., 1986						
Oct., 1986						
Nov., 1986						
Dec., 1986	14.9995	14.9995	2.9999	71.4204	37.5002	37.5002
Jan., 1987	91.7006	106.7	2.95808	51.8776	98.8999	136.4
Feb., 1987	73.9011	180.601	3.16719	51.6248	78.9002	215.3
Mar., 1987	100.199	280.8	3.23223	35.8418	56.0007	271.301
Apr., 1987	54.4013	335.202	3.05054	46.34	47.0008	318.302
May., 1987	91.4003	426.602	3.00494	23.8891	28.7007	347.002
Jun., 1987	46.3	472.902	1.73625	40.0161	30.9009	377.903
Jul., 1987	39.4001	512.302	1.27097	36.1325	22.3001	400.203
Aug., 1987	35.7992	548.101	1.15481	39.9221	23.7993	424.003
Sep., 1987	32.6004	580.702	1.08668	38.8269	20.7008	444.704
Oct., 1987	44.3995	625.101	1.88266	32.3077	21.2	465.904
Nov., 1987	67.9007	693.002	2.26336	37.6383	40.9994	506.903
Dec., 1987	60.0998	753.102	2.00055	34.4507	31.6005	538.503
Jan., 1988	39.3	792.402	1.30097	36.8059	22.8995	561.403
Feb., 1988	45.3005	837.702	2.05911	33.7632	23.1014	584.504
Mar., 1988	62.5994	900.301	2.01934	21.2502	16.8996	601.404
Apr., 1988	52.0001	952.302	1.75775	26.1282	18.4003	619.804
May., 1988	48.2991	1000.6	1.83414	30.4946	21.2	641.004
Jun., 1988	46.3	1046.9	2.11657	32.2009	21.9997	663.004
Jul., 1988	48.1005	1095	1.55163	30.4816	21.0998	684.104
Aug., 1988	47.1009	1142.1	1.73112	30.9284	21.0998	705.203
Sep., 1988	43.2998	1185.4	1.44333	31.3704	19.801	725.004
Oct., 1988	44.0991	1229.5	1.42255	32.0411	20.8009	745.805
Nov., 1988	42.3003	1271.8	1.43594	34.5102	22.3001	768.105
Dec., 1988	35.2002	1307	1.14783	42.1886	25.6991	793.805
Jan., 1989	37.4996	1344.5	1.31963	34.0856	19.4003	813.205

Group : neborun2
Well : neun2
: 000000006

Date : July 27, 2006 3:49:39 am
User : George

Production Data from January, 1986 to December, 2000 (cont.)

Year	Monthly Oil m3	Cum Oil m3	Avg Daily Oil m3/d	Water Cut %	Monthly Water m3	Cum Water m3
Feb., 1989	31.1003	1375.6	1.38737	39.1279	19.9997	833.205
Mar., 1989	215.8	1591.4	15.7423	27.3066	81.0991	914.304
Apr., 1989	237.999	1829.4	15.8666	14.3832	40.0002	954.304
May., 1989	492.401	2321.8	16.7626	13.6393	77.8011	1032.1
Jun., 1989	370.101	2691.9	16.0622	14.0449	60.5004	1092.61
Jul., 1989	430.6	3122.5	16.456	11.6128	56.5995	1149.2
Aug., 1989	446.2	3568.7	15.2547	7.92093	38.4004	1187.61
Sep., 1989	393.499	3962.2	14.0955	8.14315	34.8993	1222.5
Oct., 1989	398.4	4360.6	13.28	12.856	58.8002	1281.3
Nov., 1989	364.1	4724.7	12.9075	10.9084	44.6	1325.9
Dec., 1989	497.8	5222.5	16.9705	13.6611	78.8	1404.7
Jan., 1990	462.001	5684.5	15.2727	16.495	91.3003	1496.01
Feb., 1990	363.9	6048.4	14.7527	22.8129	107.599	1603.6
Mar., 1990	467.9	6516.3	15.1751	30.4559	205.001	1808.6
Apr., 1990	411	6927.3	14.0313	12.9189	61.0007	1869.61
May., 1990	399.2	7326.5	13.2331	20.1049	100.499	1970.1
Jun., 1990	329.4	7655.9	11.2937	44.6465	265.801	2235.91
Jul., 1990	362.699	8018.6	12.09	47.2404	324.901	2560.81
Aug., 1990	382.6	8401.2	12.8605	50.2814	387.101	2947.91
Sep., 1990	338.4	8739.6	12.1763	56.9522	447.9	3395.81
Oct., 1990	502.7	9242.3	17.0648	42.3667	369.701	3765.51
Nov., 1990	458.801	9701.1	16.0983	46.764	403.201	4168.71
Dec., 1990	568.401	10269.5	18.816	42.5577	421.301	4590.01
Jan., 1991	580.1	10849.6	19.8892	39.9811	386.599	4976.61
Feb., 1991	498.699	11348.3	18.5851	41.6003	355.398	5332.01
Mar., 1991	563.101	11911.4	20.3531	44.1869	446	5778.01
Apr., 1991	727.5	12638.9	26.0208	49.7473	720.5	6498.51
May., 1991	776.999	13415.9	28.2118	46.2732	669.5	7168.01
Jun., 1991	794.699	14210.6	27.5618	48.2002	739.8	7907.81
Jul., 1991	769.599	14980.2	25.9052	36.0908	434.799	8342.61
Aug., 1991	755.5	15735.7	25.538	54.9223	920.901	9263.51
Sep., 1991	699.501	16435.2	25.475	56.059	892.8	10156.3
Oct., 1991	732.1	17167.3	24.4713	56.6414	956.8	11113.1
Nov., 1991	668.5	17835.8	22.5337	58.403	938.999	12052.1
Dec., 1991	644	18479.8	20.9715	59.4709	945.4	12997.5
Jan., 1992	668.2	19148	22.2733	54.156	789.701	13787.2
Feb., 1992	622.401	19770.4	21.7117	54.3652	741.8	14529
Mar., 1992	636.099	20406.5	20.7706	54.4591	761	15290
Apr., 1992	607.8	21014.3	20.9586	56.8553	801.301	16091.3
May., 1992	626.8	21641.1	21.521	53.9076	733.401	16824.7
Jun., 1992	636.099	22277.2	21.4415	51.4911	675.501	17500.2

Production Report

Group	:	neborun2	Date	:	July 27, 2006 3:49:39 am
Well	:	neun2	User	:	George
	:	000000006			

Production Data from January, 1986 to December, 2000 (cont.)

Year	Monthly Oil m3	Cum Oil m3	Avg Daily Oil m3/d	Water Cut %	Monthly Water m3	Cum Water m3
Jul., 1992	637.899	22915.1	27.1929	52.0627	693.1	18193.3
Aug., 1992	587.899	23503	19.1706	54.8736	715.2	18908.5
Sep., 1992	599.1	24102.1	20.6586	56.2273	769.9	19678.4
Oct., 1992	633.301	24735.4	21.11	56.6866	829.201	20507.6
Nov., 1992	550.099	25285.5	18.5427	63.1987	945.1	21452.7
Dec., 1992	626.001	25911.5	20.8667	61.6058	1004.9	22457.6
Jan., 1993	564.7	26476.2	19.4445	59.8087	840.7	23298.3
Feb., 1993	486.001	26962.2	17.5135	56.8888	641.601	23939.9
Mar., 1993	607.6	27569.8	20.0859	57.7919	832.3	24772.2
Apr., 1993	545.299	28115.1	18.7764	61.515	871.999	25644.2
May., 1993	497.4	28612.5	16.1101	62.9257	844.601	26488.8
Jun., 1993	585.1	29197.6	19.7225	57.649	796.799	27285.6
Jul., 1993	515.8	29713.4	17.1695	61.26	816	28101.6
Aug., 1993	527.5	30240.9	17.4621	63.2686	908.999	29010.6
Sep., 1993	473.8	30714.7	15.9932	67.2851	974.901	29985.5
Oct., 1993	487.7	31202.4	16.2341	64.1296	872.3	30857.8
Nov., 1993	391.5	31593.9	13.1781	72.4828	1031.7	31889.5
Dec., 1993	471.9	32065.8	15.3672	66.7016	945.701	32835.2
Jan., 1994	399.6	32465.4	13.4508	70.6344	961.6	33796.8
Feb., 1994	374.001	32839.4	13.6621	64.4925	679.6	34476.4
Mar., 1994	386.5	33225.9	12.6376	67.9131	818.4	35294.8
Apr., 1994	356.5	33582.4	12.3463	70.327	845.299	36140.1
May., 1994	369.8	33952.2	12.1412	69.9501	861.2	37001.3
Jun., 1994	353.9	34306.1	11.946	73.7572	995.101	37996.4
Jul., 1994	331.201	34637.3	11.04	73.6702	927.1	38923.5
Aug., 1994	271.299	34908.6	9.26199	67.276	558	39481.5
Sep., 1994	449.1	35357.7	15.3102	63.3824	777.7	40259.2
Oct., 1994	515.999	35873.7	17.2	66.6634	1032.3	41291.5
Nov., 1994	480.3	36354	16.1672	70.0581	1124.3	42415.8
Dec., 1994	496.5	36850.5	16.2565	68.7366	1092.1	43507.9
Jan., 1995	469.4	37319.9	15.6902	71.6576	1187.3	44695.2
Feb., 1995	400.7	37720.6	14.7046	74.2975	1158.8	45854
Mar., 1995	375.701	38096.3	12.3688	73.011	1016.8	46870.8
Apr., 1995	357.1	38453.4	12.3493	74.4863	1043	47913.8
May., 1995	334.4	38787.8	11.0091	76.1794	1069.9	48983.7
Jun., 1995	307.599	39095.4	10.4566	75.6256	954.8	49938.5
Jul., 1995	320.599	39416	10.6866	78.1934	1150.1	51088.6
Aug., 1995	337.699	39753.7	11.0721	75.4711	1039.5	52128.1
Sep., 1995	349	40102.7	11.864	75.9628	1103.4	53231.5
Oct., 1995	367.8	40470.5	12.3457	73.1916	1004.6	54236.1
Nov., 1995	366.101	40836.6	12.588	73.7383	1028.4	55264.5

Production Report

Group	:	neborun2	Date	:	July 27, 2006 3:49:39 am
Well	:	neun2	User	:	George
	:	000000006			

Production Data from January, 1986 to December, 2000 (cont.)

Year	Monthly Oil m3	Cum Oil m3	Avg Daily Oil m3/d	Water Cut %	Monthly Water m3	Cum Water m3
Dec., 1995	347.901	41184.5	11.8267	75.9241	1097.6	56362.1
Jan., 1996	295.301	41479.8	9.80251	79.4402	1141.5	57503.6
Feb., 1996	271.699	41751.5	10.1887	79.422	1049.1	58552.7
Mar., 1996	311.3	42062.8	10.3193	77.0654	1046.5	59599.2
Apr., 1996	290.401	42353.2	9.81636	77.1117	978.801	60578
May., 1996	264.301	42617.5	8.97201	76.4254	857.201	61435.2
Jun., 1996	233.6	42851.1	8.19649	80.2081	947.1	62382.3
Jul., 1996	246.1	43097.2	7.93871	79.3208	944.4	63326.7
Aug., 1996	233.1	43330.3	7.86835	79.5741	908.5	64235.2
Sep., 1996	228.5	43558.8	7.70225	79.8217	904.3	65139.5
Oct., 1996	234.5	43793.3	7.56452	78.4234	852.7	65992.2
Nov., 1996	224.7	44018	7.74828	79.028	847.1	66839.3
Dec., 1996	224.9	44242.9	7.25484	79.7626	886.8	67726.1
Jan., 1997	223.1	44466	7.29482	79.5249	866.9	68593
Feb., 1997	190.5	44656.5	7.36232	80.0974	767	69360
Mar., 1997	205.6	44862.1	6.71347	81.4055	900.5	70260.5
Apr., 1997	203.7	45065.8	6.79	81.5757	902.3	71162.8
May., 1997	195	45260.8	6.5	81.585	864.3	72027.1
Jun., 1997	170.8	45431.6	5.70125	82.1293	785.3	72812.4
Jul., 1997	176.1	45607.7	5.74239	82.6883	841.5	73653.9
Aug., 1997	169.1	45776.8	5.57473	82.5912	802.6	74456.5
Sep., 1997	128.2	45905	4.27333	86.3449	811	75267.5
Oct., 1997	106.8	46011.8	3.77496	85.9936	656	75923.5
Nov., 1997	141.7	46153.5	4.85136	85.2968	822.4	76745.9
Dec., 1997	167.6	46321.1	5.40645	87.2022	1142.5	77888.4
Jan., 1998	179.6	46500.7	5.817	82.0515	821.4	78709.8
Feb., 1998	145	46645.7	5.32925	83.1549	716.1	79425.9
Mar., 1998	165.5	46811.2	5.33871	82.0706	757.9	80183.8
Apr., 1998	158.7	46969.9	5.31955	81.2011	685.8	80869.6
May., 1998	161.7	47131.6	5.30889	81.4093	708.4	81578
Jun., 1998	146.9	47278.5	4.91715	82.9777	716.4	82294.4
Jul., 1998	139.3	47417.8	4.54857	83.7244	716.9	83011.3
Aug., 1998	146.4	47564.2	4.81315	84.2505	783.5	83794.8
Sep., 1998	152.6	47716.8	5.08667	81.5389	674.3	84469.1
Oct., 1998	157.6	47874.4	5.08387	82.4747	742	85211.1
Nov., 1998	153.9	48028.3	5.23173	82.31	716.4	85927.5
Dec., 1998	154.7	48183	4.99032	82.6972	739.7	86667.2
Jan., 1999	161.9	48344.9	5.22258	82.2472	750.4	87417.6
Feb., 1999	139.3	48484.2	5.02737	82.8512	673.3	88090.9
Mar., 1999	153.8	48638	4.96129	82.5481	727.8	88818.7
Apr., 1999	131.3	48769.3	4.44457	80.7381	550.6	89369.3

Production Report

Group : neborun2
Well : neun2
: 000000006

Date : July 27, 2006 3:49:39 am
User : George

Production Data from January, 1986 to December, 2000 (cont.)

Year	Monthly Oil m3	Cum Oil m3	Avg Daily Oil m3/d	Water Cut %	Monthly Water m3	Cum Water m3
May., 1999	150.9	48920.2	4.95431	82.057	690.4	90059.7
Jun., 1999	156.2	49076.4	5.20667	80.5846	648.6	90708.3
Jul., 1999	153.2	49229.6	5.10667	80.3922	628.4	91336.7
Aug., 1999	117.2	49346.8	4.3677	84.712	649.7	91986.4
Sep., 1999	122.1	49468.9	4.07	84.9054	687.1	92673.5
Oct., 1999	134.6	49603.5	4.40109	84.0708	710.7	93384.2
Nov., 1999	116.3	49719.8	4.05698	84.5165	635.1	94019.3
Dec., 1999	116.9	49836.7	3.81714	86.1555	727.8	94747.1
Jan., 2000	117	49953.7	3.77419	86.3186	738.5	95485.6
Feb., 2000	115.9	50069.6	3.99655	85.5809	688.2	96173.8
Mar., 2000	136.3	50205.9	4.39677	84.4295	739.4	96913.2
Apr., 2000	121.6	50327.5	4.11042	85.3809	710.5	97623.7
May., 2000	129.5	50457	4.17742	84.3067	696	98319.7
Jun., 2000	123.3	50580.3	4.11	83.5012	624.3	98944
Jul., 2000	129.8	50710.1	4.24414	83.3529	650.2	99594.2
Aug., 2000	127.5	50837.6	4.1129	83.9664	668	100262
Sep., 2000	125.7	50963.3	4.19	83.3933	631.5	100894
Oct., 2000	127.6	51090.9	4.11613	83.7226	656.6	101550
Nov., 2000	123.3	51214.2	4.11	85.76	742.9	102293
Dec., 2000	124	51338.2	4	86.1724	773.1	103066

APPENDIX B

2000 INDIVIDUAL WELL PRODUCTION DATA

3.10.6.2 DATE: 0?/30/01
TIME: 9.76

TUNDRA OIL AND GAS LTD.
Fluid Production Report
Year: 2000

WELL: 16111029W1 DALY 16-11-10-29 WPM (UNIT #2)

MONTH	M3 OIL / DAY	M3 OIL / MTH	M3 H2O / MTH	M3 FLUID / MONTH	% H2O	# DAYS OF PROD./MTN	M3 FLUID / DAY	PROD. TEST OIL	WTR	HRS	DATE
01	0.41	12.5	25.0	37.5	66.67	31	1.22	0.44	0.89	24.0	23
02	0.3	8.8	25.4	34.2	74.27	29	1.18	0.33	0.93	24.0	15
03	1.38	42.9	25.8	68.7	37.55	31	2.22	0.32	0.96	24.0	17
04	0.3	8.8	24.6	33.4	73.65	29	1.15	0.32	0.93	24.0	24
05	0.3	9.3	24.9	34.2	72.81	31	1.1	0.35	0.89	24.0	22
06	0.32	9.6	23.0	32.6	70.55	30	1.09	0.34	0.93	24.0	3
07	0.31	9.3	23.0	32.3	71.21	30	1.08	0.33	0.88	24.0	26
08	0.28	8.7	23.4	32.1	72.9	31	1.04	0.36	0.83	24.0	27
09	0.33	9.9	21.0	30.9	67.96	30	1.03	0.35	0.85	24.0	12
10	0.33	10.3	22.3	32.6	68.4	31	1.05	0.3	0.86	24.0	25
11	0.28	8.3	26.1	34.4	75.87	30	1.15	0.29	0.91	24.0	5
12	0.3	9.2	25.7	34.9	73.64	31	1.13	0.31	0.85	24.0	13
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	0.41	147.6	290.2	437.8	66.29	364	1.2				

3.10.6.2 DATE: 0?/?0/01
TIME: 9.76

TUNDRA OIL AND GAS LTD.
Fluid Production Report
Year: 2000

WELL: 13121029W1 DALY 13-12-10-29 WPM (UNIT #2)

MONTH	M3 OIL / DAY	M3 OIL / MTH	M3 H2O / MTH	M3 FLUID / MONTH	% H2O	# DAYS OF PROD./MTN	M3 FLUID / DAY	PROD. TEST OIL	WTR	HRS	DATE
01	2.13	65.6	438.5	504.1	86.99	31	16.39	2.55	15.63	24.0	27
02	2.3	66.6	410.5	477.1	86.04	29	16.45	2.49	15.27	24.0	22
03	1.85	56.8	453.1	509.9	88.86	31	16.63	2.67	16.4	24.0	20
04	2.36	70.9	433.1	504.0	85.93	30	16.8	2.69	15.26	24.0	14
05	2.33	71.3	418.7	490.0	85.45	31	15.98	2.32	15.55	24.0	26
06	2.27	68.0	374.5	442.5	84.63	30	14.75	2.47	15.19	24.0	19
07	2.39	73.3	391.8	465.1	84.24	31	15.19	2.62	14.83	24.0	17
08	2.32	71.8	397.5	469.3	84.7	31	15.18	2.69	15.23	24.0	14
09	2.3	69.1	382.2	451.3	84.69	30	15.04	2.16	15.81	24.0	21
10	2.19	67.6	402.0	469.6	85.6	31	15.19	2.33	15.57	24.0	11
11	2.18	65.3	449.2	514.5	87.31	30	17.2				
12	2.07	63.9	463.5	527.4	87.88	31	17.06	2.21	14.82	24.0	24
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	2.22	810.2	5014.6	5824.8	86.09	366	15.99				

TUNDRA OIL AND GAS LTD.
Fluid Production Report
Year: 2000

WELL: 04131029W1 DALY 4-13-10-29 WPM (UNIT #2)

MONTH	M3 OIL / DAY	M3 OIL / MTH	M3 H2O / MTH	M3 FLUID / MONTH	% H2O	# DAYS OF PROD./MTN	M3 FLUID / DAY	PROD. TEST OIL	WTR	HRS	DATE
01	0.86	26.5	169.6	196.1	86.49	31	6.36				
02	0.86	24.9	153.5	178.4	86.04	29	6.15	0.94	5.75	24.0	11
03	0.7	21.6	159.5	181.1	88.07	31	5.84	0.88	5.89	24.0	25
04	0.83	24.0	156.8	180.8	86.73	29	6.23	0.94	5.81	24.0	16
05	0.92	28.5	155.8	184.3	84.54	31	5.95	0.99	5.62	24.0	19
06	0.9	27.0	140.7	167.7	83.9	30	5.59	0.91	5.59	24.0	22
07	0.93	28.0	146.6	174.6	83.96	30	5.82	1.0	5.69	24.0	21
08	0.93	28.7	153.8	182.5	84.27	31	5.89	1.04	5.87	24.0	21
09	0.93	28.0	142.6	170.6	83.59	30	5.69	1.0	5.67	24.0	6
10	0.94	29.2	143.3	172.5	83.07	31	5.58	0.98	5.58	24.0	20
11	0.98	29.3	158.8	188.1	84.42	30	6.27	1.04	5.49	24.0	1
12	1.01	31.0	165.0	196.0	84.18	31	6.36	1.03	5.4	24.0	6
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	0.9	326.7	1846.0	2172.7	84.96	364	5.98				

TUNDRA OIL AND GAS LTD.
Fluid Production Report
Year: 2000

WELL: 05131029W1 DALY 5-13-10-29 WPM (UNIT #2)

MONTH	M3 OIL / DAY	M3 OIL / MTH	M3 H2O / MTH	M3 FLUID / MONTH	% H2O	# DAYS OF PROD./MTN	M3 FLUID / DAY	PROD. TEST OIL	WTR	HRS	DATE
01	0.2	6.3	60.4	66.7	90.55	31	2.16	0.17	2.29	24.0	23
02	0.33	9.5	56.2	65.7	85.54	29	2.27	0.29	2.1	24.0	22
03	0.25	7.8	58.1	65.9	88.16	31	2.13	0.38	2.0	24.0	14
04	0.34	9.9	55.4	65.3	84.84	29	2.25	0.42	2.04	24.0	14
05	0.34	10.6	56.1	66.7	84.11	31	2.15	0.36	2.03	24.0	25
06	0.33	9.8	50.0	59.8	83.61	30	1.99	0.36	2.02	24.0	16
07	0.33	9.8	51.7	61.5	84.07	30	2.05	0.32	2.02	24.0	13
08	0.31	9.5	54.8	64.3	85.23	31	2.07	0.34	2.09	24.0	4
09	0.32	9.7	50.0	59.7	83.75	30	1.99	0.35	2.0	24.0	1
10	0.37	11.3	52.4	63.7	82.26	31	2.06	0.41	2.35	24.0	25
11	0.39	11.6	68.0	79.6	85.43	30	2.65				
12	0.4	12.3	73.4	85.7	85.65	31	2.76	0.39	2.42	24.0	7
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	0.32	118.1	686.5	804.6	85.32	364	2.21				

TUNDRA OIL AND GAS LTD.
Fluid Production Report
Year: 2000

WELL: 10141029W1 DALY A10-14-10-29 WPM (UNIT #2)

MONTH	M3 OIL / DAY	M3 OIL / MTH	M3 H2O / MTH	M3 FLUID / MONTH	% H2O	# DAYS OF PROD./MTN	M3 FLUID / DAY	PROD. TEST OIL	WTR	HRS	DATE
01	0.2	6.1	45.0	51.1	88.06	31	1.66	0.23	1.67	24.0	20
02	0.21	6.1	42.6	48.7	87.47	29	1.68	0.26	1.57	24.0	15
03	0.23	7.2	42.9	50.1	85.63	31	1.62	0.31	1.5	24.0	25
04	0.28	8.0	40.6	48.6	83.54	29	1.68	0.31	1.51	24.0	9
05	0.32	9.8	40.5	50.3	80.52	31	1.62	0.31	1.5	24.0	21
06	0.3	8.9	36.1	45.0	80.22	30	1.52	0.34	1.41	24.0	27
07	0.31	9.4	37.1	46.5	79.78	30	1.55	0.29	1.52	24.0	21
08	0.28	8.8	38.5	47.3	81.4	31	1.53	0.33	1.42	24.0	14
09	0.3	9.0	35.7	44.7	79.87	30	1.49	0.31	1.43	24.0	19
10	0.3	9.2	36.6	45.8	79.91	31	1.48	0.31	1.42	24.0	16
11	0.29	8.8	40.8	49.6	82.26	30	1.65	0.28	1.45	24.0	21
12	0.25	7.6	45.5	53.1	85.69	31	1.71	0.21	1.52	24.0	17
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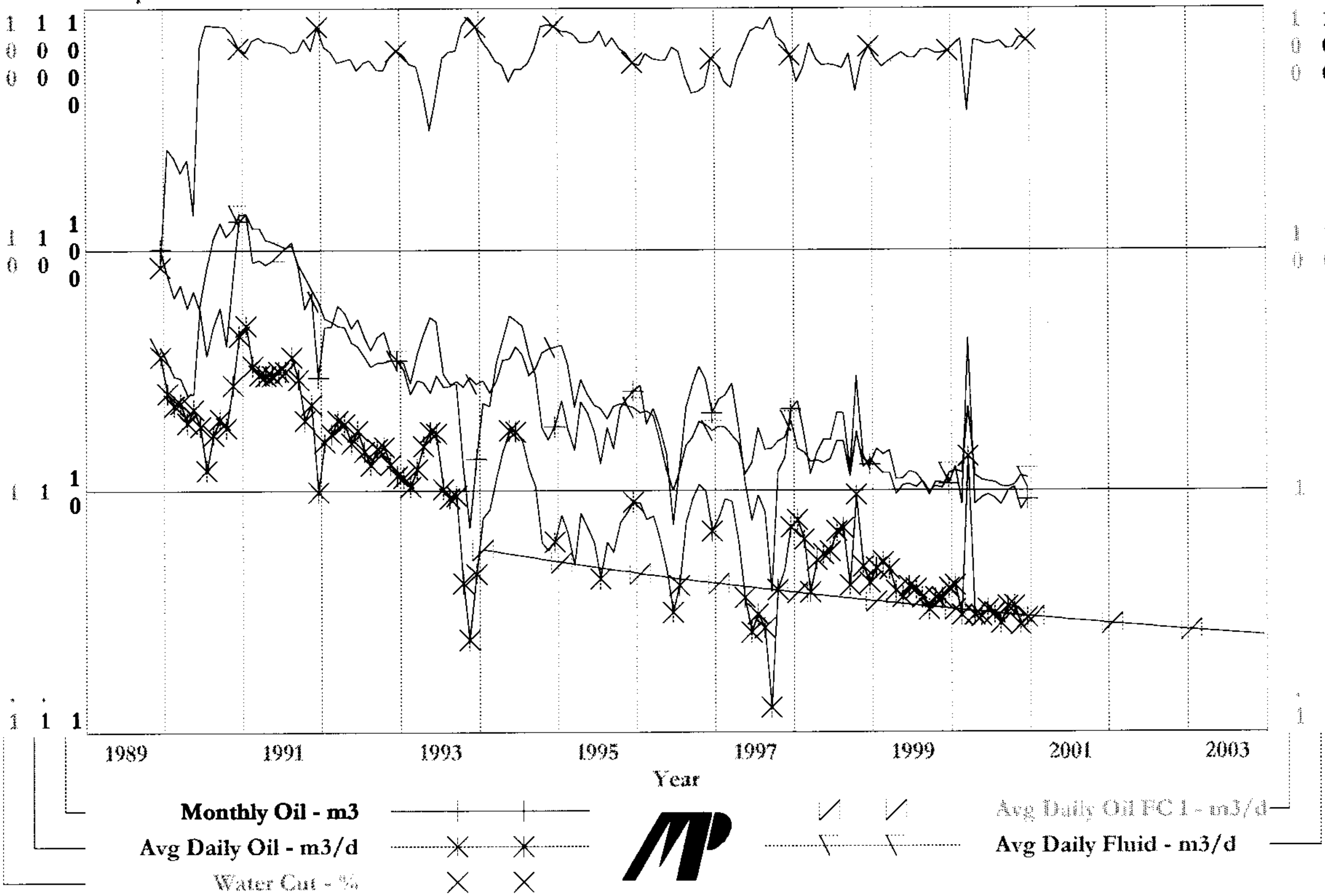
	0.27	98.9	481.9	580.8	82.97	364	1.6				

APPENDIX C

INDIVIDUAL WELL ULTIMATE RECOVERY PREDICTIONS

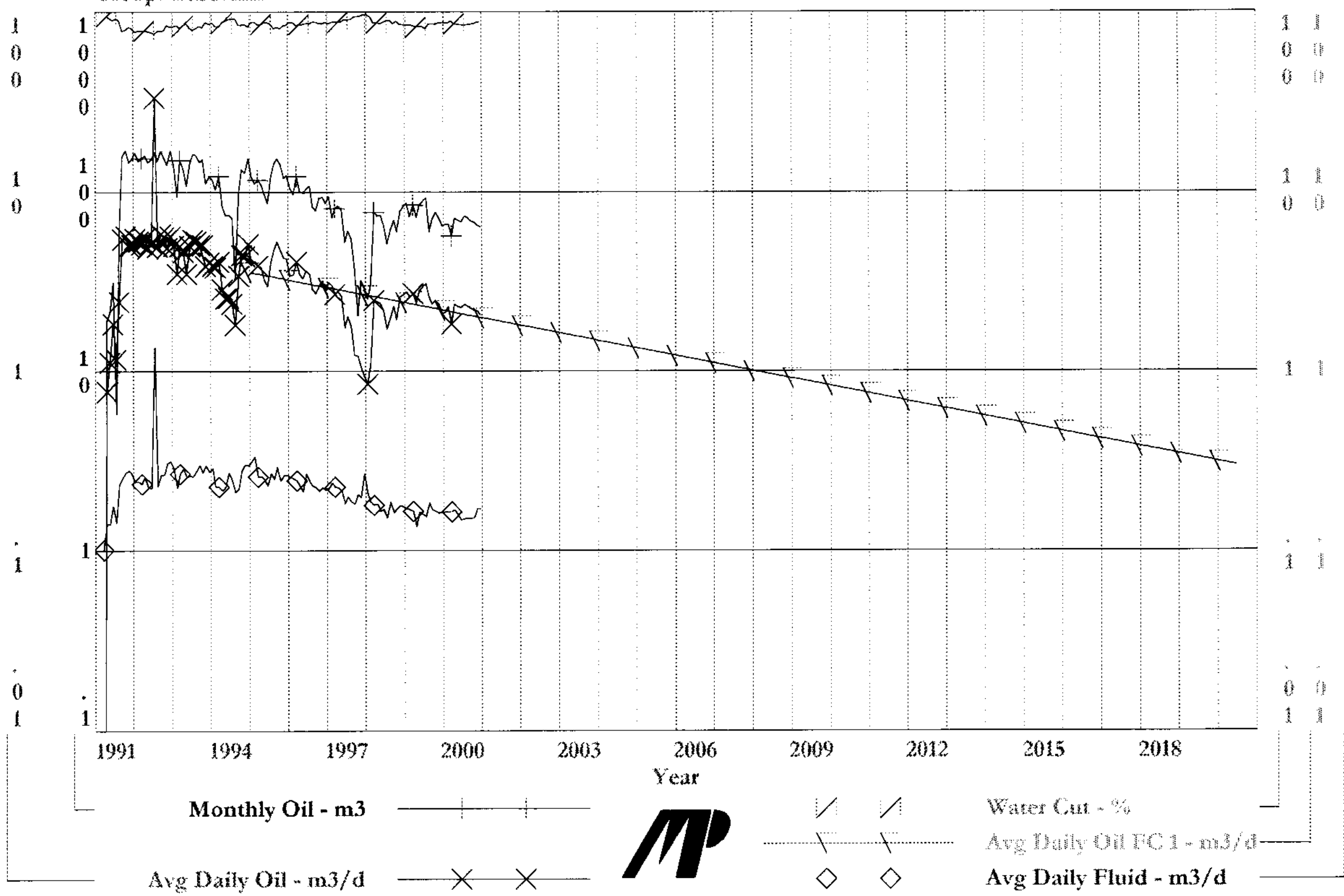
00/16-11-010-29W1/2 (Tundra North Ebor Unit No. 2 Prov. 16-11-10) Data 01/89-12/00

Operator:	Avg Daily Oil FC 1 (Rate-Time)	Production Cums
Field: 1	qi: 0.5753 m3/d, Jan, 1994	Oil: 4387.8 m3
Zone: 60D	qf: 0.249729 m3/d, Dec, 2003	Gas: 0 E6m3
Type: Unknown	di(Har): 11.5334 CTD: 4387.8 m3	Water: 8822.7 m3
Group: neborun2	RR: 289.256 m3 Tot: 4677.06 m3	Cond: 0 m3



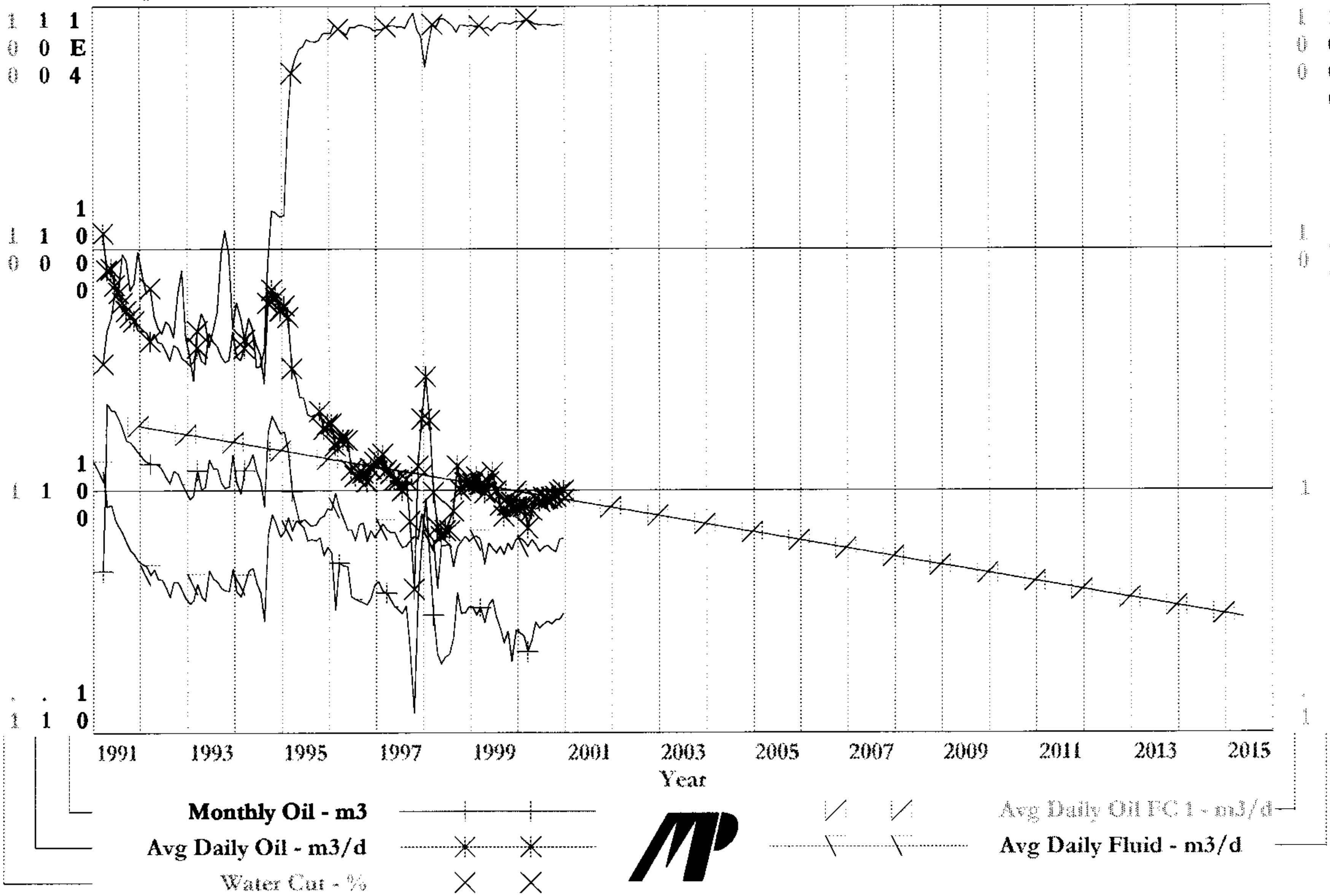
00/13-12-010-29W1/0 (Tundra North Ebor Unit No. 2 13-12-10-29W1) Data 03/91-12/00

Operator:	Avg Daily Oil FC 1 (Rate-Time)	Production Cums
Field: 1	qi: 3.5817 m3/d, Jan, 1995	Oil: 11255.7 m3
Zone: 60D	qf: 0.298646 m3/d, Jun, 2020	Gas: 0 E6m3
Type: Unknown	di(Exp): 9.27322 CTD: 11255.7 m3	Water: 63614.1 m3
Group: neborun2	RR: 6173.81 m3 Tot: 17429.5 m3	Cond: 0 m3



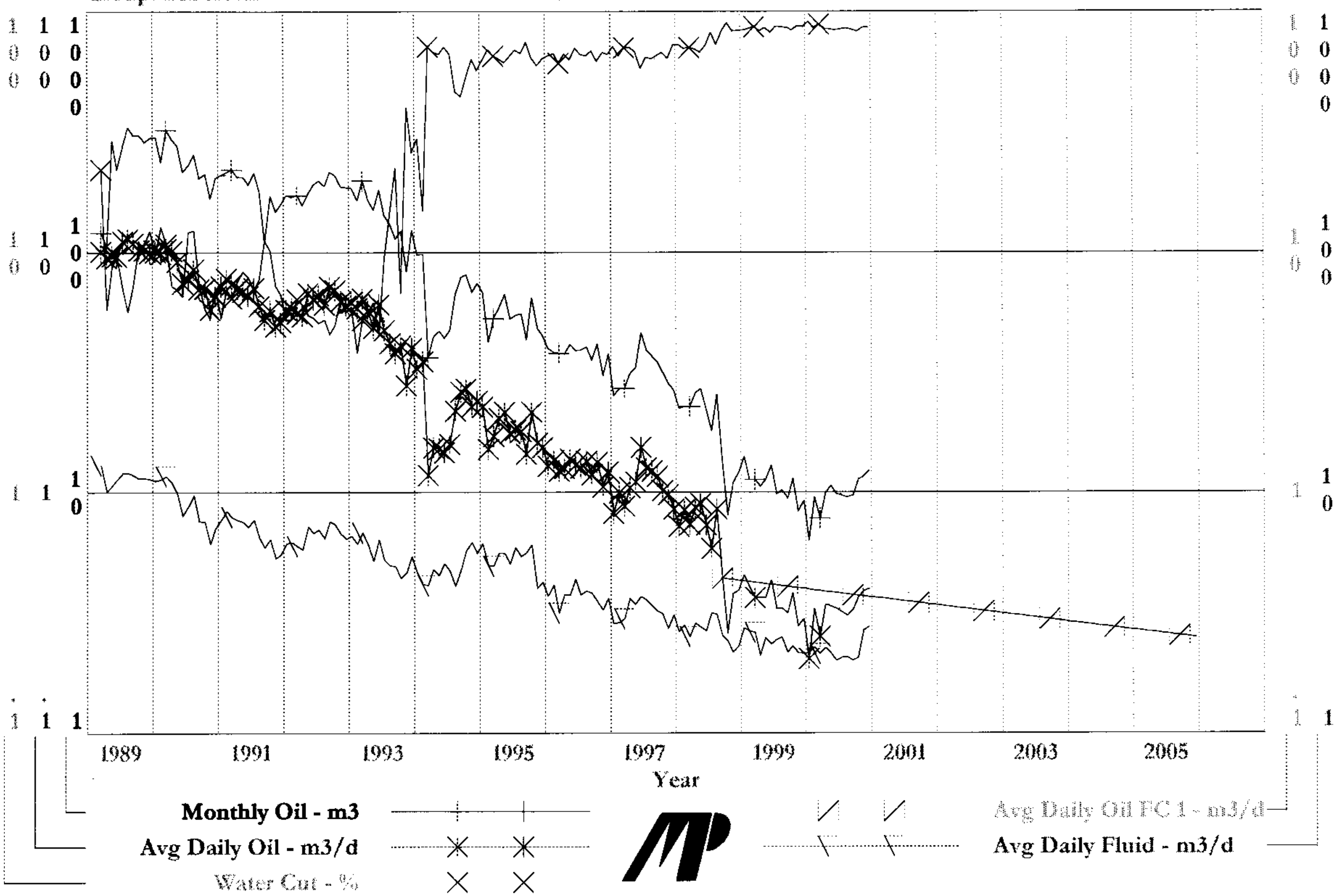
00/04-13-010-29W1/0 (Tundra North Ebor Unit No. 2 04-13-10-29W1) Data 03/91-12/00

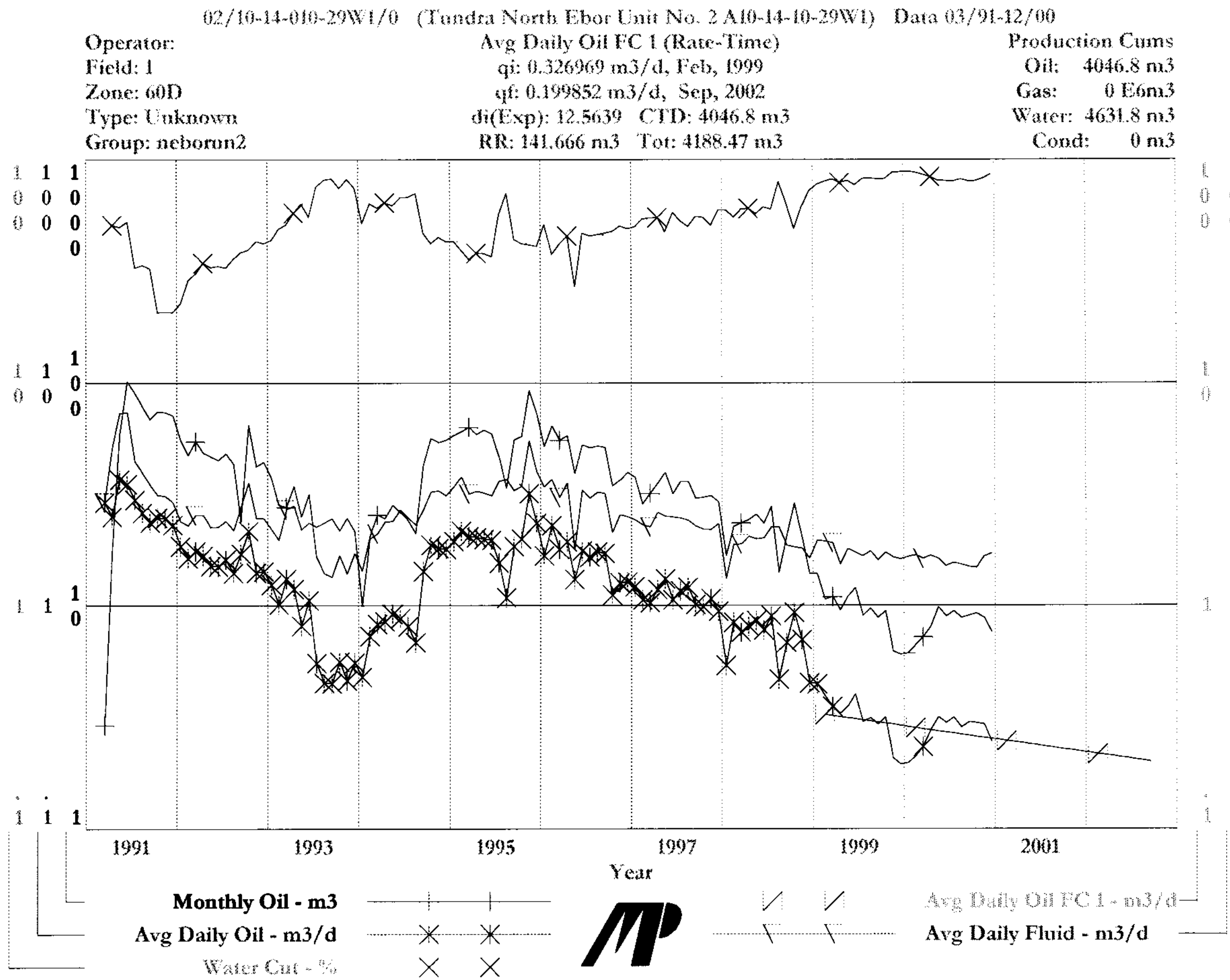
Operator:	Avg Daily Oil FC 1 (Rate-Time)	Production Cums
Field: 1	qi: 1.86055 m3/d, Dec, 1991	Oil: 9125.8 m3
Zone: 60D	qf: 0.298533 m3/d, May, 2015	Gas: 0 E6m3
Type: Unknown	di(Exp): 7.49074 CTD: 9125.8 m3	Water: 11431.3 m3
Group: neborun2	RR: 2848.72 m3 Tot: 11974.5 m3	Cond: 0 m3



00/05-13-010-29W1/0 (Tundra North Ebor Unit No. 2 05-13-10-29W1) Data 03/89-12/00

Operator:	Avg Daily Oil FC 1 (Rate-Time)	Production Cums
Field: 1	qi: 0.440544 m3/d, Sep, 1998	Oil: 14426.2 m3
Zone: 60D	qf: 0.24886 m3/d, Dec, 2005	Gas: 0 E6m3
Type: Unknown	di(Exp): 7.49239 CTD: 14426.2 m3	Water: 7096.2 m3
Group: neborun2	RR: 549.364 m3 Tot: 14975.6 m3	Cond: 0 m3





02/10-14-010-29W1/0 (Tundra North Ebor Unit No. 2 A10-14-10-29W1) Data 03/91-12/00
Operator:
Field: 1
Zone: 60D
Type: Unknown
Group: neboron2
Avg Daily Oil FC 1 (Rate-Time)
qi: 0.326969 m3/d, Feb, 1999
qf: 0.199852 m3/d, Sep, 2002
di(Exp): 12.5639 CTD: 4046.8 m3
RR: 141.666 m3 Tot: 4188.47 m3
Production Cums
Oil: 4046.8 m3
Gas: 0 E6m3
Water: 4631.8 m3
Cond: 0 m3
1991
1993
1995
1997
1999
2001
Year
Monthly Oil - m3
Avg Daily Oil - m3/d
Water Cut - %
Avg Daily Oil FC 1 - m3/d
Avg Daily Fluid - m3/d

APPENDIX D

1-14-10-29 HISTORICAL INJECTION DATA

Production Report

Group	:	neborun2	Date	:	July 22, 2006 4:59:22 am
Well	:	Tundra North Ebor Unit No. 2 01-14-10-29W1	User	:	George
	:	00/01-14-010-29W1/0			

Production Data from September, 1990 to December, 2000 (cont.)

Year	Month Water Inj m3	Cal Day Water Inj m3/d	Cum Water Inj m3
Oct., 1993			
Nov., 1993			
Dec., 1993			
Jan., 1994			
Feb., 1994			
Mar., 1994			
Apr., 1994			
May., 1994			
Jun., 1994			
Jul., 1994	501.8	16.1871	501.8
Aug., 1994	430.1	13.8742	931.9
Sep., 1994	596	19.8667	1527.9
Oct., 1994	594	19.1613	2121.9
Nov., 1994	693.5	23.1167	2815.4
Dec., 1994	635.6	20.5032	3451
Jan., 1995	692.7	22.3452	4143.7
Feb., 1995	624.1	22.2893	4767.8
Mar., 1995	673.7	21.7323	5441.5
Apr., 1995	645.7	21.5233	6087.2
May., 1995	367.5	11.8548	6454.7
Jun., 1995	612.6	20.42	7067.3
Jul., 1995	546.1	17.6161	7613.4
Aug., 1995	552.3	17.8161	8165.7
Sep., 1995	498.1	16.6033	8663.8
Oct., 1995	524.1	16.9065	9187.9
Nov., 1995	479.8	15.9933	9667.7
Dec., 1995	224.9	7.25484	9892.6
Jan., 1996	556.2	17.9419	10448.8
Feb., 1996	471.1	16.2448	10919.9
Mar., 1996	295.4	9.52903	11215.3
Apr., 1996	417.5	13.9167	11632.8
May., 1996	216.2	6.97419	11849
Jun., 1996	250.3	8.34333	12099.3
Jul., 1996	406.6	13.1161	12505.9
Aug., 1996	402.6	12.9871	12908.5
Sep., 1996	404	13.4667	13312.5
Oct., 1996	369.6	11.9226	13682.1
Nov., 1996	368.5	12.2833	14050.6
Dec., 1996	378.9	12.2226	14429.5
Jan., 1997	394.6	12.729	14824.1
Feb., 1997	369.8	13.2071	15193.9

Production Report

Group	:	neborun2	Date	:	July 22, 2006 4:59:22 am
Well	:	Tundra North Ebor Unit No. 2 01-14-10-29W1	User	:	George
	:	00/01-14-010-29W1/0			

Production Data from September, 1990 to December, 2000 (cont.)

Year	Month Water Inj m3	Cal Day Water Inj m3/d	Cum Water Inj m3
Mar., 1997	392.6	12.6645	15586.5
Apr., 1997	422.2	14.0733	16008.7
May., 1997	439.2	14.1677	16447.9
Jun., 1997	397.4	13.2467	16845.3
Jul., 1997	389.1	12.5516	17234.4
Aug., 1997	401.7	12.9581	17636.1
Sep., 1997	385.7	12.8567	18021.8
Oct., 1997	404.9	13.0613	18426.7
Nov., 1997	377.7	12.59	18804.4
Dec., 1997	211.9	6.83548	19016.3
Jan., 1998	401.6	12.9548	19417.9
Feb., 1998	359.3	12.8321	19777.2
Mar., 1998	384.8	12.4129	20162
Apr., 1998	387.4	12.9133	20549.4
May., 1998	386.7	12.4742	20936.1
Jun., 1998	371.9	12.3967	21308
Jul., 1998	177.3	5.71936	21485.3
Aug., 1998	354.8	11.4452	21840.1
Sep., 1998	369	12.3	22209.1
Oct., 1998	398.5	12.8548	22607.6
Nov., 1998	378.9	12.63	22986.5
Dec., 1998	390.8	12.6065	23377.3
Jan., 1999	396.5	12.7903	23773.8
Feb., 1999	361.1	12.8964	24134.9
Mar., 1999	381.2	12.2968	24516.1
Apr., 1999	356.9	11.8967	24873
May., 1999	373.5	12.0484	25246.5
Jun., 1999	389.5	12.9833	25636
Jul., 1999	387.5	12.5	26023.5
Aug., 1999	375.5	12.1129	26399
Sep., 1999	379	12.6333	26778
Oct., 1999	401.5	12.9516	27179.5
Nov., 1999	389.3	12.9767	27568.8
Dec., 1999	385.5	12.4355	27954.3
Jan., 2000	384.9	12.4161	28339.2
Feb., 2000	348.4	12.0138	28687.6
Mar., 2000	374.7	12.0871	29062.3
Apr., 2000	361.4	12.0467	29423.7
May., 2000	377.6	12.1806	29801.3
Jun., 2000	350.4	11.68	30151.7
Jul., 2000	360.7	11.6355	30512.4

Production Report

Group	:	neborun2	Date	:	July 22, 2006 4:59:22 am
Well	:	Tundra North Ebor Unit No. 2 01-14-10-29W1	User	:	George
	:	00/01-14-010-29W1/0			

Production Data from September, 1990 to December, 2000 (cont.)

Year	Month Water Inj m3	Cal Day Water Inj m3/d	Cum Water Inj m3
Aug., 2000	377.7	12.1839	30890.1
Sep., 2000	365.2	12.1733	31255.3
Oct., 2000	369.9	11.9323	31625.2
Nov., 2000	355.4	11.8467	31980.6
Dec., 2000	373.2	12.0387	32353.8

APPENDIX E

8-14-10-29 HISTORICAL INJECTION DATA

Production Report

Group	:	neborun2	Date	:	July 22, 2006 5:02:33 am
Well	:	Tundra North Ebor Unit No. 2 WIW 08-14-10-2	User	:	George
	:	00/08-14-010-29W1/0			
Hist.Data	:	03/89-12/00	On Prod	:	02/09
Operator	:		Status	:	Unknown
Field	:	1	Zone	:	60D

Production Data from January, 1991 to December, 2000

Year	Month Water Inj m3	Cal Day Water Inj m3/d	Cum Water Inj m3
Jan., 1991			
Feb., 1991			
Mar., 1991			
Apr., 1991			
May., 1991			
Jun., 1991			
Jul., 1991			
Aug., 1991			
Sep., 1991			
Oct., 1991	668.5	21.5645	668.5
Nov., 1991	777.4	25.9133	1445.9
Dec., 1991	775.7	25.0226	2221.6
Jan., 1992	764.6	24.6645	2986.2
Feb., 1992	731.7	25.231	3717.9
Mar., 1992	763.1	24.6161	4481
Apr., 1992	788.2	26.2733	5269.2
May., 1992	756.2	24.3935	6025.4
Jun., 1992	701.1	23.37	6726.5
Jul., 1992	753.9	24.3194	7480.4
Aug., 1992	777.3	25.0742	8257.7
Sep., 1992	729.8	24.3267	8987.5
Oct., 1992	794.1	25.6161	9781.6
Nov., 1992	763.8	25.46	10545.4
Dec., 1992	791.7	25.5387	11337.1
Jan., 1993	679.7	21.9258	12016.8
Feb., 1993	706.8	25.2429	12723.6
Mar., 1993	778.1	25.1	13501.7
Apr., 1993	750.4	25.0133	14252.1
May., 1993	99.1	3.19677	14351.2
Jun., 1993			
Jul., 1993	73.8	2.38065	14425
Aug., 1993	671.3	21.6548	15096.3
Sep., 1993	766.1	25.5367	15862.4
Oct., 1993	783	25.2581	16645.4
Nov., 1993	754	25.1333	17399.4
Dec., 1993	776.1	25.0355	18175.5
Jan., 1994	765.9	24.7065	18941.4

Production Report

Group	: neborun2	Date	: July 22, 2006 5:02:33 am
Well	: Tundra North Ebor Unit No. 2 WIW 08-14-10-2	User	: George
	: 00/08-14-010-29W1/0		

Production Data from January, 1991 to December, 2000 (cont.)

Year	Month Water Inj m3	Cal Day Water Inj m3/d	Cum Water Inj m3
Feb., 1994	694.7	24.8107	19636.1
Mar., 1994	649.7	20.9581	20285.8
Apr., 1994	516.5	17.2167	20802.3
May., 1994	72.2	2.32903	20874.5
Jun., 1994	127.3	4.24333	21001.8
Jul., 1994	434.3	14.0097	21436.1
Aug., 1994	495.8	15.9935	21931.9
Sep., 1994	514.6	17.1533	22446.5
Oct., 1994	575.2	18.5548	23021.7
Nov., 1994	565	18.8333	23586.7
Dec., 1994	480.5	15.5	24067.2
Jan., 1995	588.8	18.9935	24656
Feb., 1995	531	18.9643	25187
Mar., 1995	572	18.4516	25759
Apr., 1995	496.9	16.5633	26255.9
May., 1995	304.2	9.8129	26560.1
Jun., 1995	129	4.3	26689.1
Jul., 1995	447.9	14.4484	27137
Aug., 1995	444	14.3226	27581
Sep., 1995	418	13.9333	27999
Oct., 1995	316.7	10.2161	28315.7
Nov., 1995	418.5	13.95	28734.2
Dec., 1995	429.1	13.8419	29163.3
Jan., 1996	424	13.6774	29587.3
Feb., 1996	397	13.6897	29984.3
Mar., 1996	427.7	13.7968	30412
Apr., 1996	416.2	13.8733	30828.2
May., 1996	271.5	8.75806	31099.7
Jun., 1996	422.8	14.0933	31522.5
Jul., 1996	426.4	13.7548	31948.9
Aug., 1996	306.7	9.89355	32255.6
Sep., 1996	419.8	13.9933	32675.4
Oct., 1996	440.7	14.2161	33116.1
Nov., 1996	469	15.6333	33585.1
Dec., 1996	491.8	15.8645	34076.9
Jan., 1997	449.6	14.5032	34526.5
Feb., 1997	391.7	13.9893	34918.2
Mar., 1997	508.9	16.4161	35427.1
Apr., 1997	541.2	18.04	35968.3
May., 1997	494.6	15.9548	36462.9
Jun., 1997	423.9	14.13	36886.8

Production Report

Group	:	neborun2	Date	:	July 22, 2006 5:02:33 am
Well	:	Tundra North Ebor Unit No. 2 WIW 08-14-10-2	User	:	George
	:	00/08-14-010-29W1/0			

Production Data from January, 1991 to December, 2000 (cont.)

Year	Month Water Inj m3	Cal Day Water Inj m3/d	Cum Water Inj m3
Jul., 1997	419.1	13.5194	37305.9
Aug., 1997	438.7	14.1516	37744.6
Sep., 1997	414.8	13.8267	38159.4
Oct., 1997	421.4	13.5935	38580.8
Nov., 1997	411.8	13.7267	38992.6
Dec., 1997	852.1	27.4871	39844.7
Jan., 1998	440	14.1935	40284.7
Feb., 1998	393.5	14.0536	40678.2
Mar., 1998	438.8	14.1548	41117
Apr., 1998	423.9	14.13	41540.9
May., 1998	423.9	13.6742	41964.8
Jun., 1998	422.2	14.0733	42387
Jul., 1998	243.7	7.86129	42630.7
Aug., 1998	428.3	13.8161	43059
Sep., 1998	370	12.3333	43429
Oct., 1998	415.9	13.4161	43844.9
Nov., 1998	401	13.3667	44245.9
Dec., 1998	412	13.2903	44657.9
Jan., 1999	412.1	13.2935	45070
Feb., 1999	373	13.3214	45443
Mar., 1999	409.8	13.2194	45852.8
Apr., 1999	353.4	11.78	46206.2
May., 1999	401	12.9355	46607.2
Jun., 1999	417.5	13.9167	47024.7
Jul., 1999	391	12.6129	47415.7
Aug., 1999	417	13.4516	47832.7
Sep., 1999	422.9	14.0967	48255.6
Oct., 1999	435.2	14.0387	48690.8
Nov., 1999	416.4	13.88	49107.2
Dec., 1999	429	13.8387	49536.2
Jan., 2000	429.7	13.8613	49965.9
Feb., 2000	401.6	13.8483	50367.5
Mar., 2000	424.8	13.7032	50792.3
Apr., 2000	410.5	13.6833	51202.8
May., 2000	420.3	13.5581	51623.1
Jun., 2000	393.4	13.1133	52016.5
Jul., 2000	426.3	13.7516	52442.8
Aug., 2000	419.6	13.5355	52862.4
Sep., 2000	408	13.6	53270.4
Oct., 2000	411.5	13.2742	53681.9
Nov., 2000	396.9	13.23	54078.8