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Medicine Hat Glauconitic C Pool
CO_2 Flood Study

VIKOR ENERGY INC.

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I. Summary 1

II. Conclusion 3

III. Recommendations 4

IV. Introduction 5

V. Study Details 6
- A. Reservoir Characteristics 6
  - 1. Geology 6
  - 2. Rock Properties 6
  - 3. Reservoir Conditions 7
  - 4. Fluid Properties 7
- B. Immiscible CO_2 Flood of the Field 9
  - 1. Key Assumptions 9
  - 2. Fractional Flow Curves 10
  - 3. Cases 10
- C. Pool Wide Waterflood Predictions 13
- D. Pattern Development 14
  - 1. Input 14
  - 2. CO_2 Source 15
  - 3. Pattern Layout 15
  - 4. Injection/Production Determination 15
  - 5. Prediction Method 15
  - 6. Output 16
- E. Vapex Application 16
- F. Economics 18
  - 1. Product Price 19
  - 2. Inflation 19
  - 3. Royalty 19
  - 4. Source CO_2 Price 20
  - 5. Recycle CO_2 20
  - 6. Capital Expenditures (CAPEX) 19
  - 7. Operating Costs 21
  - 8. Net CO_2 Stored

Appendices

- A. Performance of the Glauconitic C Pool Waterflood Pilot A1
- B. Immiscible CO_2 Flood Predictions B1
- C. Analog Pools C1

Tables:

Table 1A - Economic Results (Case 1 - 8MPa 1)
Table 1B - Economic Results (Case 2 - 8MPa 2)
Table 1C - Economic Results (Case 3 - 8MPa 2)
Table 1D - Economic Results (Case 4 - 6MPa 2)
Table 2 - Assumption Common to all Cases
Table 3 - Reservoir Properties
Table 4 - PVT Properties (7-4-13-5W4)
Table 5 - PVT Properties (14-10-13-5W4)
Table 6 - Capital Cost Assumptions
Table 7 - Individual Pattern Information
Table 8 - CO_2 Generated by Medicine Hat Glauc C Flood

Figures:

Figure 1 - Proposed CO_2 Pipeline Layout
Figure 1A - Pattern Layout
Figure 2A - Case 1 - 8MPa 1 HCPV 1.5 Layer Graph
Figure 2B - Case 2 - 8MPa 2 HCPV 1.5 Layer Graph
Figure 2C - Case 3 - 8MPa 2 HCPV 2 Layer Graph
Figure 2D - Case 4 - 6MPa 2 HCPV 1.5 Layer Graph
Figure 3 - Porosity Thickness Map - C1 Sand
Figure 4 - Porosity Thickness Map - C2 Sand
Figure 5 - Porosity Thickness Map - C3 Sand
Figure 6 - Porosity Thickness Map - B Sand
Figure 7 - API Gravity Distribution Map
Figure 8 - Live Oil Viscosity Distribution Map

Study

Medicine Hat Glauconitic C Pool

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I. Summary

The Medicine Hat Glauconitic C Pool is located very close to the City of Medicine Hat in S.E. Alberta. It contains 30,920 e^3m^3 (200 MMBbls) of original oil in place at a depth of 826 m, with an average density of 960 kg/m^3 (15.9 °API). The pool was discovered in 1981 and heavily drilled up with many horizontal wells, primarily to accelerate production in the mid 1990's before waterflood of the pool commenced in 2001. The oil recovery factor is expected to range from 12% to 18%, depending on the amount of water injection. At the end of the waterflood, there will still be a significant amount of oil left in the reservoir. Figures 1 and 1A show the pool and the area analyzed in this study.

The subject study investigates the economic feasibility of implementing an immiscible CO_2 flood in the pool. The motivation behind the investigation is the availability of CO_2 from an adjacent CO_2 source that previously supplied CO_2 for another EOR pilot. It is believed that CO_2 can be obtained at a reasonable cost and within the desired time frame. The benefits of immiscible flood of CO_2 lie in the solution of CO_2 in the oil thus reducing the viscosity as well as swelling the reservoir oil. However, our investigation showed that water injection with CO_2 is crucial in the success of an immiscible CO_2 injection. CO_2 is important in making the reservoir oil more susceptible to flow. CO_2 is not an efficient displacement fluid due to its low viscosity. Our investigation recommended a simultaneous injection of water to displace the CO_2 saturated oil as well as to deliver the CO_2 into the reservoir. Appendix B documents the pool sensitivity to different flooding strategies. A high water/CO_2 ratio is also needed to improve the reservoir conformance.

For the four cases evaluated, CO_2 injection of about 50% HCPV at a water/CO_2 ratio of 2.2 - 3.2 Rm^3/Rm^3 would be economic, (see Tables 1A-1D) based on the investment assumptions shown on Table 2. Figures 2A-2D show the purchased and recycle CO_2 injected, the predicted oil production, from the CO_2 floods and the comparable waterfloods, for the four cases. The base case (Case 2) for the project would require an injection of 7.1×10^6 tonnes of CO_2 and could result in an addition recovery of about 7.5 MMBbls of oil incremental to waterflood. An incremental

capital investment of $18 million is needed to implement a 37 pattern CO_2 – waterflood for the east side of the pool. Because the sunk capital utilized in the development to date is not included in the capital, realistic rates of return cannot be calculated. However, operating at 8,000 kPa would generate an incremental $21 million discounted cash flow at 15% before tax. Reducing the operating pressure to 6,000 kPa under no free gas condition could improve the incremental discounted cash flow @15% before tax, to $24 million. However, it may be difficult to achieve no free gas condition at 6,000 kPa.

II. Conclusions

A. The simultaneous injection of CO_2 and water at a high water/gas ratio has good economic potential in the Medicine Hat Glauconitic C pool.

B. The mechanism used is for the CO_2 to dissolve in the oil reducing the viscosity and swelling the oil. The lower viscosity oil is then displaced more efficiently by the waterflood. A classic immiscible CO_2 flood will be ineffective in Medicine Hat Glauconitic C pool. The injected CO_2 will have to dissolve in the reservoir oil to reduce the oil viscosity to within the 14 cp to 25 cp range. Water injection at high water/CO_2 ratio is effective in displacing the CO_2 saturated oil and controlling the reservoir conformance of injected CO_2.

C. In order for a CO_2 injection test to be initiated it is crucial that a portion of the field be re-pressured to eliminate free gas saturation.

D. Laboratory testing under idealized conditions will confirm the effect of dissolving CO_2 in the oil on oil properties, however, laboratory testing will not answer the question of how effectively and efficiently the CO_2 will dissolve in the oil in the field.

E. Approximately 15% of the pool has a pay greater than 15m with apparent good vertical permeability. This portion of the pool may be suitable for a gravity stable VAPEX type of process. The gravity stable process could increase the oil recovery above the predicted recovery used in this study economics.

F. The reservoir temperature is slightly below the critical temperature of CO_2 making it possible to operate at a pressure very close to the CO_2 dew point, a key requirement for VAPEX.

G. The pool has been extensively drilled with horizontal wells in a very haphazard orientation. Developing effective patterns to optimize both vertical and horizontal sweep conformance with the existing wells will be extremely difficult.

H. Apparent productivity and injectivity in the pool is low. The study assumes that increasing the reservoir pressure to eliminate the free gas and provide a greater differential pressure to drive fluids into the well bore will permit satisfactory processing rates.

I. Injection system and wells must be designed for simultaneous injection of water and CO_2.

(1) Investigate the use of CO_2 in a VAPEX process.

III. Recommendations

A. Investigate ways to increase voidage replacement ratio to re-pressure the reservoir and eliminate free gas saturation as soon as possible.

B. Accurately determine the reservoir temperature, especially in the potential VAPEX region.

C. Laboratory measurements of the PVT properties of a CO_2 – reservoir mixture should be carried out to confirm the effect of CO_2 on the reservoir oil. These tests should be conducted at pressures above and below the liquid/vapor saturation pressure at reservoir temperature.

D. Run a small field test with trucked CO_2 to confirm the effectiveness of CO_2 and water injection in selected part of the pool. The injection area must have relatively high reservoir pressure and no free of gas saturation. Currently, the most prospective candidate is the oil waterflood pilot area because it is probably the area that can achieve the necessary operating conditions sooner than other areas. Careful design of this test is recommended to gather as much data as possible to improve the evaluation of parameters for both the CO_2 enhanced waterflood and the VAPEX process.

E. A possibility exists to increase the oil recovery through a VAPEX process in approximately 15% of the pool. These areas have pay thickness and vertical permeability suitable for such an application. It is also possible to achieve an operating pressure close to the CO_2 dew point temperature. However, VAPEX process is still in an experimental stage. It is recommended that the operator closely monitor the research and development of VAPEX process by participating in the VAPEX consortium. If the operator is satisfied with the progress and potential of the VAPEX process, a pilot could be contemplated.

F. Investigate best alternatives to simultaneously inject CO_2 and water, and to maximize the CO_2 saturated in the water at the point of highest operating pressure and lowest temperature to maximize the transport of the CO_2 to the reservoir.

G. Confirm available CO_2 volumes and cost for both short term trucked CO_2 for field test and longer tern CO_2 compressed and delivered by pipeline to the field.

IV. Introduction

Medicine Hat Glauconitic C Pool is situated next to the City of Medicine Hat, with part of the pool lying under the city. The pool was discovered in 1981 with 30.92 e^6m^3 (200 MMBbls) OOIP of 946 - 978 kg/m^3 (18.1 – 13.2 °API) heavy oil at a depth of 826 m. A total of over 230 wells were drilled in the pool with a peak production of 1,256 m^3/d from 125 wells achieved in August 1996. After twenty years of primary depletion, a waterflood was implemented in part of the pool in June 2001; based on a pilot waterflood that commenced in 1992, see Appendix A. The current pool consists of the Medicine Hat Glauconitic C Pool Unit, which covers approximately one half of the pool and the non-unit area (Figure 1). The unitization of the non-unit area is in progress, and an agreement is expected in 2002. At the end of 2001, the unit was producing at 150 m^3/d or approximately 50% of the total pool production. Water injection into the unit area was 1,500 m^3/d in December 2001. Though under waterflood for the second half of 2001, the unit's gas oil ratio at approximately 258 m^3/m^3 for the last three months of 2001. This is similar to that for the non-unit GOR of 230 m^3/m^3, both higher than the EUB recognized solution GOR of 45 m^3/m^3. The cumulative oil production to the end of 2001 was 2,428 e^3m^3, or 7.8% of the OOIP. The current reservoir pressure for most of the pool is under 4,000 kPa, down significantly from the initial pressure of 10,175 kPa.

Previous reservoir studies predict oil recovery under primary and waterflood, to range between 12% and 18%, depending on injection and reservoir performance of the pool. Due to the high amount of oil remaining after secondary recovery, the pool could attract a tertiary recovery scheme. Several tertiary methods were contemplated, including CO_2, polymer and steam. The pool is very close to a CO_2 source and CO_2 could be available at a reasonable cost. The objective of the study is to evaluate the economic feasibility of implementing a CO_2 flood in conjunction with the developing waterflood. Appendix C outlines the performance of analog pools under both waterflood and immiscible CO_2 flood. As part of the pool is lying under the City of Medicine Hat, the CO_2 flood is assumed to operate in the higher reservoir quality east side of the river only (Figure 1A). This area contains approximately 73.5% of the OOIP of the pool. If actual performance of a CO_2 flood meets expectations, the feasibility of expanding it to the full pool could be investigated at a later date. As the feasibility study indicated that a CO_2 enhanced waterflood could be economic, it is recommended that the reservoir pressure be increase to permit field injection testing. Pilot test design, laboratory measurement, and numerical reservoir simulation should be completed.

V. Study Details

A. Reservoir Characteristics

1. Geology

The Medicine Hat Glauconitic C Pool is formed by accreted fluvial sandstone bodies deposited in a valley. Meandering and braided stream channels cut into the pre-existing sediments. Individual channel sands have a fining upward sequence of a point bar deposit. Higher rate of contemporaneous subsidence in the east resulted in cleaner and coarser-grained channel sands along the eastern margin. Sands in the west are more argillaceous. The reservoir is heterogeneous and the pool could be separated into regions of various fluid properties, which appeared to be structurally controlled. The reservoir dips to the SW, with a water leg on the down dip end. The sand pinches out to the east and is eroded by a Mannville channel in the north. The sand is unconsolidated and has good porosity and permeability.

The sands can be divided into the lower fluvial channel infill (B sand) and the middle channel (C sand). Channel B consists of moderately to poorly sorted chert litharenites with good inter-granular porosity and good permeability. Channel C consists of sandstone, mudstone and siltstones displaying wavy bedding. The changes in grain size, layer thickness and lamination result in porosity and permeability variation between the beds and laminae. Argillaceous laminae could be vertical barriers in the Channel C sand.

The top sand (C sand) can be further divided into three separate sequences (bottom C1, C2, and top C3 sands) and the lower sand (B sand) was divided into two sands (B1 and B2 sands). All these sands were mapped by PRI in 1998. The individuals sand have separate mapping of gross pay, net pay, porosity, saturation and permeability.

2. Rock Properties

Based on the Adams Pearson study pool porosity varies from 19.5% to 28%, with an average of 24.3%. The net pay of the pool ranges from 2 m to 18 m, with an average of 9 m. The largest pore volumes are in Section 33-012-05W4M, Section 4-013-05W4M and Section 9-013-05W4M. AEUB assigned a porosity of 22% and an average pay thickness of 9 m. Permeability derived from well performance ranged from 100 md to 1300 md, with a most likely permeability of 690 md. The water saturation for the pool was investigated in the previous studies. The average saturation discussed varied between 26% and 30%. In this evaluation, an uniform average water saturation of 30% was assumed, consistent with the AEUB recognized average water saturation. The reservoir properties recognized by AEUB are tabulated in Table 3.

For this study the net pay and porosity maps for top separate sands were combined to form a ϕh map for each sand. For the purpose of this study, the lower sands (B1 and B2 sand) are treated as one unit. The ϕh maps for C1, C2, C3 and B sands are depicted in Figures 3 to 6.

3. Reservoir Conditions

Published reservoir temperatures range from 26 degrees C to 30 degrees C. The reservoir temperature is very close to the carbon dioxide critical temperature of 31 degrees C. The original reservoir pressure at discovery was 10,175 kPa (1,476 psi). However, the pressure of the reservoir has been depleted to a current pressure of less than 4,000 kPa in a majority of the area. Re-pressuring of the reservoir is expected with the waterflood. However, this would require a number of years due to the current strategy of restraining water injection to avoid early water breakthrough and about half of the pool is still on primary production. Re-pressuring the pool to between 6,000 kPa and 8,000 kPa, to eliminate free gas, will cause the pool to operate very close to the critical pressure of CO_2, 7,383 kPa{a} (1,071 psia). The requirement for the pool to operate close to the critical point creates some uncertainty in the density of CO_2 because a small change of temperature or operating pressure could alter the CO_2 density by a factor greater than three.

4. Fluid Properties

The pool contains heavy oil with API gravity ranging from 13 to 18 $^{\circ}$API with dead oil viscosity from 240 cp to 3,000 cp. In 1991, the interpretation of the oil characteristics of the pool was that the southern part of the pool contains higher viscosity, heavier but saturated oil while the northern part of the pool contains lower viscosity, lighter but under-saturated oil with initial gas saturation. The lower structure area has higher viscosity oil, probably due to biodegradation proximal to underlying water.

In the southern area, based on the oil analysis of the 7-4-013-05W4M well, the oil was saturated at the initial pressure of 9,750 kPa. The stock tank oil density was 970 kg/m^3 (14.4 °API). A solution gas oil ratio of 22 m^3/m^3 produces a formation volume factor of 1.09 Rm^3/m^3. With the solution gas and a reservoir temperature of 30 degrees C, the oil viscosity is reduced from a stock tank value of 888 cp to 259 cp. Table 4 summaries the oil properties for the heavier oil in the 7-4 well.

For the northern area, based on the oil analysis of the 14-10-013-05W4M well, the oil is under-saturated at 5,500 kPa and the solution gas oil ratio ranges from 16 to 19 m^3/m^3. Oil density is lighter at 947 kg/m^3 (17.8 °API). The formation volume factor is 1.062 Rm^3/m^3. The oil viscosity of 14-10 well at original reservoir condition was 62 cp, an 80% reduction from the stock tank oil density of 316 cp. Table 5 summaries the oil properties for the lighter oil from the 14-10 well.

In 1996, Adams Pearson Associates had another interpretation of the oil characteristics of the pool. The interpretation was that the initial solution-gas-oil ratio was 10 m^3/m^3 with a much lower bubble point (average 3,620 kPa). This conclusion was based on the well production behavior, which rapidly declined to 20 to 30% of the initial rate with high gas oil ratio. The live oil viscosity based on 71 samples has almost half of the wells below 300 cp, with a most likely live oil viscosity of 250 cp. A relationship of API gravity and live oil viscosity was developed and the API gravity map developed by Adams Pearson is shown on Figure 7. The median oil viscosity is very similar to that from the 7-4 well oil analysis. The live oil viscosity map is shown on Figure 8. These maps appear to have incorrect scales as neither the gravity or viscosity is expected to approach zero. This was corrected in the study but the Figures are a duplicate of the Adams Pearson's map without correction.

In this study we used three oil types. The first oil type is similar to the lighter oil from 14-10. The second oil type is similar to the oil from 4-7 and the third oil type is a heavier oil with a live oil viscosity of 450 cp as shown in the Adams Pearson Associates report.

B. Immiscible CO_2 Flood of the Field

Many sensitivity studies were conducted on different strategies to CO_2 flood the pool as outlined in Appendix B. These studies indicated that simultaneous CO_2 and water injection at a high water to CO_2 ratio would be the most effective flooding strategy. In this evaluation, the base case assumed that the immiscible CO_2 would operate at approximately 8 MPa (1,160 psi). At a reservoir temperature of 26 degree C (79 degree F), the injected CO_2 would have a density of 700 kg/m^3, significantly lower than the reservoir oil density. If the operating pressure is reduced to 6 MPa (870 psi), CO_2 would have a density of 190 kg/m^3, a gaseous phase. At both pressures, CO_2 is expected to gravity override the reservoir oil and water. The gravity override phenomenon is quite well known even in CO_2 miscible flooding of light oil. CO_2 gravity override was observed at the immiscible CO_2 flood of Retlaw Upper Mannville V Pool where the oil gravity was 922 kg/m^3. Therefore, we inferred that CO_2 would rise to the top of the formation. The time required for CO_2 to rise to the top of the formation is dependent on several factors, such as the injection intervals, the ratio of viscous force and gravity force, injection rate and the vertical heterogeneity of the reservoir.

In the laboratory experiment, the mixing of CO_2 and heavy oil requires as long as 12 days to achieve equilibrium. The experiment is conducted in perfect controlled environment where human intervention to ensure equilibrium is common (e.g. shaking). In the field, CO_2 gravity override, reservoir heterogeneity, gas saturation and direct channeling of CO_2 from injector to producers could severely limited the mixing of CO_2 and heavy oil. A mathematical model cannot accurately predict the effect of these factors, until some history of field performance is available. Based on our experience and our examination of several CO_2 numerical simulations, the following assumptions were made for this study:

1. Key Assumptions

   a. The reservoir is to be divided into four layers.

   b. CO_2 override will occur.

   c. Top Layer

      CO_2 and heavy oil full equilibrium would be achieved in the top layer and the CO_2 saturated oil would reflect the full effect of CO_2 solubility, swelling factor and lower viscosity. The majority of the injected CO_2 will enter the top layer.

d. Second Layer

CO_2 will enter the second layer but cause less effect as it will not achieve full equilibrium with the heavy oil. It is assumed that only half of the solubility of CO_2 in the heavy oil is achieved resulting in a lower swelling factor and oil viscosity reduction.

e. Bottom Layers

CO_2 is not expected to affect the oil properties in the bottom two layers and these layers would only reflect the performance of water injection.

2. Fractional Flow Curves

Fractional flow curves are used to predict the produced oil and CO_2 flow as a fraction of total production as a function of the percentage hydrocarbon pore volume of CO_2 plus water injection. Different fractional flow curves were developed in order to run sensitivities for different water/ CO_2 injection strategies.

Due to a variation of thickness of the different layers, the pool was separated into four layer types. The first layer type has the top two layers accounting for 56% of the total layer ϕh. The second layer type has the top two layers accounting for 47% of the total layer ϕh. The third and fourth layer types have the top two layers consisting of 40% and 27% of the total layer ϕh, respectively. Combining different layer types with the variation of three oil types, a total of 10 different performance curves were required to forecast the different patterns in the pool. A total of 60 fractional flow curves were needed to run the four CO_2 and two waterflood cases.

3. Cases

The injected CO_2 is immiscible with the reservoir oil at initial reservoir conditions. A review of the oil viscosity at various CO_2 saturation pressures showed that good viscosity reduction could be achieved at about 8,000 kPa (Case 2). Due to the time required to achieve 8,000 kPa in the reservoir, a sensitivity was run at 6,000 kPa, Case 4 (Table 1D). However, the result of 6,000 kPa, though appearing to be more economic than the comparable Case 2 (Table 1B), should be used with caution because considerable amount of free gas might still be in the reservoir at this pressure. In general, free gas saturation will reduce the amount of CO_2 dissolving in the oil, thus reducing or even eliminating the viscosity reduction benefit. In addition, the tendency of gravity override will be more severe at 6,000 kPa due to the gaseous phase of CO_2.

The predictive model does not include the volume of CO_2 dissolved in the injected water (significant at high water/ CO_2 ratios) and the volume that remains dissolved in the oil left in the reservoir. Vikor adjusted the injected and produced CO_2 volume to reflect these dissolved volumes. The oil response was also adjusted to allow time for the CO_2 to contact the oil, to provide realistic predictions for all Cases.

a. Case 1

Case 1 involved the injection of 0.266 HCPV of CO_2 at a water/CO_2 ratio of 2.9 Rm^3 of water per Rm^3 of CO_2. A total of one HCPV of CO_2 and water was injected into the formation. The operating pressure is assumed to be 8,000 kPa. At this pressure, the oil viscosity in the top layer is reduced to 14 cp for type 1 oil, 20 cp for type 2 oil and 25 cp for type 3 oil. For the second layer, due to only half of the CO_2 being dissolved in the oil, the viscosities of the three oil types are 49 cp, 60 cp and 70 cp respectively. For the oil not affected by the CO_2, the viscosity remained at 98 cp, 287 cp and 450 cp.

This case involved the injection of 26.6 % HCPV of CO_2 at a water/CO_2 ratio of 2.9 m^3/m^3, including a follow-up injection of 10% HCPV of water. Due to the high water/CO_2 ratio required to displace the CO_2 saturated oil and for conformance control, the small slug size resulted in a large total amount of fluid injection. Of this amount, 9.4% HCPV would be purchased and the remaining recycled. The oil recovery for this case is 9.9% OOIP, about 3.3% OOIP higher than the waterflood case. However, this is equivalent to an increase of 50% of the waterflood recovery factor.

b. Case 2

The second case is a repeat of Case 1, but with the slug size increased to 0.46 HCPV and the total fluid injected was 2 HCPV. The water/CO_2 ratio during the CO_2 injection period was approximately 3.1 m^3/m^3.

This case involved the injection of 46% HCPV of CO_2 at a water/CO_2 ratio of 3.1 m^3/m^3 including the follow-up 10% HCPV of water. The amount of CO_2 and water injected are almost twice as much as that for Case 1. The amount of CO_2 purchased is 11.4% HCPV. The oil recovery for this case is 14.1% OOIP, about 58% higher than the waterflood recovery of 8.9% OOIP.

c. Case 3

The third case is an upside sensitivity case of Case 2. In this case, the solubility of CO_2 in layer 2 oil was increased to the saturation level. Therefore, the viscosities of the oil for layer 2 were the same as those for layer 1. The water/CO_2 ratio during the CO_2 injection period was approximately 3.2 m^3/m^3.

The injected CO_2 is totally dissolved in the oil and as a result both C1 and C2 sands are effectively contacted by the injected CO_2. The amount of CO_2 required is 48.2% HCPV, with 12.6% HCPV of this amount purchased. The oil recovery for this case is 16.4% OOIP, 85% higher than the 8.9% OOIP waterflood recovery. The amount of purchase increased due to the higher amount of CO_2 dissolved and stored in the oil.

d. Case 4

The fourth case is a repeat of Case 2, but the operating pressure was at 6,000 kPa. At this pressure, the viscosities of the oil in the first layer were 20 cp, 25 cp and 30 cp respectively for the three oil types. The CO_2 shrinkage factor is about 3.25 times as great in the high-pressure cases as in this case but the percentage of CO_2 dissolved in the oil and water is very similar. The water/CO_2 ratio during the CO_2 injection period was approximately 2.2 m^3/m^3. The water / CO_2 ratio is lower and the apparent HCPV injected higher in this case because the CO_2 dissolved in the water and oil is a larger percentage of the total CO_2 injected.

At this pressure, the CO_2 will exist as a gas phase at reservoir condition. The oil recovery for this case, at 12.8% OOIP, is slightly less than Case 2. The CO_2 injected and purchased for this case is less than one half that of Case 2 because of the CO_2 shrinkage. The incremental oil recovery for this case is 45% higher than the 8.9% OOIP waterflood recovery reflecting the less efficient process.

C. Pool Wide Waterflood Prediction

In order to be able to evaluate the benefit of immiscible CO_2 flood, two waterflood forecasts were generated to serve as the base cases, for the different total HCPV injected cases. Both the CO_2 flood and waterflood forecasts are assumed to start at the same point in time. In this evaluation, it is assumed that the whole pool is under waterflood and the reservoir is re-pressured to the desired operating pressure for the CO_2 flood. It is also assumed that at that time, the free solution gas is all completely re-dissolved or produced. As the pool is still at low pressure and the water injection is constrained, it would require several years before the reservoir would reach the operating pressure for CO_2 flood.

As the pool pressure is well below 4 MPa in many part of the field, significant amount of solution gas has been liberated from the oil. As a consequence, the oil viscosity is higher than at the original conditions. As part of the liberated gas was produced, the free gas, even when re-dissolved will not return the reservoir to it original state. It is assumed that after re-pressuring, the oil viscosity would remain at approximately the lower pressure level.

Because of the low reservoir pressure and the high voidage created by the primary production, a significant amount of excess water (water beyond replacing the voidage created by current production) must be injected. The estimated voidage created so far from production is 9 e^6m^3. The current voidage created per day is approximately 2,800 m^3/d. If the injection capacity is 10,000 m^3/d, there would be only 6,200 m^3/d of water available to re-pressure the reservoir. At this rate, it would require 4 years to replace all the voidage created. To reach 6,000 kPa or 8,000 kPa instead of the original 10,175 kPa, less time and volume of water would be needed. However, this assumption is based on unrestrained water injection at a voidage replacement ratio of more than 3 m^3/m^3. If the water injection is restrained, the number of years required to re-pressure the pool will be higher.

In addition to raising the reservoir pressure to a level that significant viscosity reduction can be realized, an equally important reservoir condition is the reduction of gas saturation (to zero if possible). This is necessary because gas saturation reduces the amount of CO_2 soluble in the reservoir oil. At high gas saturation, CO_2 could not dissolve in a sufficient amount to be effective in reducing the viscosity of reservoir oil. There is a range of saturation pressures for the pool, from the low estimate between 3,620 kPa to 9,750 kPa and significant amount of gas has been produced. It might be possible that part of the pool would be resaturated at 6,000 kPa to 8,000 kPa. Since the oil is almost incompressible, once the gas saturation disappears, the amount of water required to raise the reservoir pressure is minor. In order to obtain the reservoir conditions necessary for CO_2 injection, one of the prime objectives of the field operation is to reduce the free gas in the reservoir as quickly as possible.

Since the subject evaluation is to investigate the feasibility of the CO_2 flood, we make the assumption that required operation pressure would be achieved at approximately 10% oil recovery, 2.2% above the current recovery.

In order to achieve quick fill-up, the number of water injection wells is assumed to be higher than what is now planned by EnerMark. The assumed water injection patterns and wells are depicted in Figure 1A. We believe that quick re-pressurization and good horizontal waterflood performance is best realized by using a high injector to producer ratio. Another reason is that for strict comparison of the effectiveness of the CO_2 – water injection, we maintain a similar development scenario for the waterflood and CO_2 flood. Hence the waterflood plan in this study is different than EnerMark's current plan and is intended only as a base to compare CO_2 flood and waterflood performance.

D. Pattern Development

The Pattern model is used to determine development by starting new patterns to fully utilize available purchased and produced CO_2 within the limits of injectivity and productivity of the operating patterns.

1. Input Data

OOIP was calculated by planimetering the phi-H contour of each sand in each pattern. The maximum allowed injection and production rate in reservoir m^3 per day is specified for each well. Production wells are assigned to the appropriate patterns in a matrix with the injection wells. Production wells common to several patterns have their production allocated to each operating pattern.

2. CO_2 Source

Available purchased CO_2 volume is specified and can be varied quarterly over the project life. The CO_2 source volume used in these predictions was selected for quick development of the project area. Once the last patterns are developed the program reduces the required CO_2 source rate to match the maximum required injection of CO_2 and preferentially recycles produced CO_2.

3. Pattern Layout

Pattern layout in the Medicine Hat Glauconitic C pool was very difficult, as the pool has been developed with horizontal wells drilled in a very haphazard manner. Where possible patterns were selected to use existing waterflood patterns with water injection wells converted to water/CO_2 injectors. Existing producing wells were converted to injectors as required to develop a pattern flood. The pattern layouts have not been optimized and the same layout is used in all Cases. Final flood design may require drilling new wells to ensure horizontal conformance in the field.

4. Injection/Production Determination

Production and injection rate is an important parameter in enhanced oil recovery economics. In order to get a reasonable estimate of the maximum productivity and injectivity for the pools, the maximum production rate for each well was determined by reviewing the past performance of each of the production wells on a monthly basis. Because the wells have not had pressure support, and the flood will be operated at increased pressure and the maximum months' productivity was selected for the wells in the 6Mpa (Case 4) and the water flood cases. For the 8MPa cases, the productivity was further increased by the ratio of the pressure increase. In spite of the aggressive selection of productivity, the cases with 2 HCPV injection results in a life of more that 40 years. The cost to stimulate wells in selected patterns to increase productivity was included in the economics.

5. Prediction Method

A sufficient number of patterns for the specified injection rate begin to operate at the start of the project. The program injects the available purchased CO_2 and the volume of

CO_2 produced in the previous time step, at the specified water/CO_2 ratio and the percentage of hydrocarbon pore volume injected at the end of the specified time (3 months) is determined. The fractional flow curve for this percentage of hydrocarbon pore volume is then used to predict the volume of oil and CO_2 produced. The status of injection for each pattern is tracked independently for each time step.

The maximum injection rate is determined by the pattern injectivity and productivity, assuming a voidage replacement ratio of one. The available productivity is calculated from the productivity of the specified wells producing from the pattern. The producing well productivity is divided equally among the number of operating patterns from which the well produces.

A new pattern is added when the existing patterns are unable to take the available CO_2. Once all of the patterns are operating the source CO_2 purchases are limited to match the demand assuming 100% of the produced CO_2 is recycled. CO_2 injection terminates into a pattern when the specified % HCPV of CO_2 is reached and the pattern remains in operation, including any producing wells associated with it, until the total CO_2 and water injection volume is reached.

6. Output

The program tracks the number of patterns and wells operating at any given time. The new injection and production wells, required with a new pattern, are determined and the specified well completion and tie-in cost added when the pattern comes on stream.

The production well starts up when the first pattern it is associated with begins injection and is shut in when the last pattern it is associated with ceases injection. The number of operating injection and production wells is tracked in order to estimate well operating costs. The oil, water, and CO_2 production and the volume of source and recycled CO_2 and water injected are calculated quarterly.

E. VAPEX Application

In some areas of the pool where the pay thickness is exceeding 15 m (east half of Section 33-012-5W5M and south half of Section 09-013-5W5M) could be very good candidates for

VAPEX operation. This area of the pool contains approximately 30 MMBbls of OOIP and may be suitable for a gravity stable process such as VAPEX.

VAPEX is a potential process that could recover some of the remaining oil in the reservoir. VAPEX is similar in concept to SAGD with the exception that solvent is used instead of steam to reduce the viscosity of the heavy oil. A vapor chamber is formed at the top of the formation with the producer situated at the base of the formation. The reduced viscosity oil that formed close to the solvent – oil interface, flows to the producer through a gravity drainage process.

In May 1997, Gravdrain Inc. conducted a VAPEX evaluation on the use of solvent in E1, E2 and E3 wells. At 20 degree C, Gravdrain estimated that the viscosity of oil containing 30% volume fraction of butane could be reduced from 300 to 1,200 cp to a range of 10 to 40 cp. It also showed that recovery could be as much as 48% of the OOIP in about 12 to 15 years. Oil rate declined from 50 m^3/d in the early years to 6 m^3/d after 15 years for a 1,000 m long horizontal well. Using the analogy from the laboratory model of non-Medicine Hat oil, the amount of solvent injection required was 45% of the oil produced with 40% of which is makeup solvent. The purchased make up solvent is 18% of the oil produced. Buying one barrel of butane or propane to produce 5 barrels of heavy oil is unlikely to be economic.

Though Gravdrain found the reservoir quality of Medicine Hat Glauconitic C Pool suitable for VAPEX, the E1 to E3 wells were not suitable for VAPEX due to their high or above the zones trajectories. Gravdrain recommended additional investigation and scaled physical model tests be conducted using with Medicine Hat oil.

There is a possibility to use CO_2 as solvent instead of hydrocarbon liquids. The carbon dioxide critical temperature is 31.1 °C and the critical pressure of CO_2 is 7,383 kPa{a} (1,071 psia). Data for the Medicine Hat Glauconitic C Pool shows a temperature range from 26 °C to 30 °C. The original reservoir pressure at discovery was 10,175 kPa{g} (1,476 psig) has been depleted to less than 4,000 kPa (580 psig). Therefore the reservoir operating conditions can be adjusted to be very close to the CO_2 dew point line, which is one of the conditions for a successful VAPEX. The viscosity reduction effect of CO_2 appears to be similar to the reduction in Gravdrain's work. Therefore, the performance should be similar. However, CO_2 dissolves more slowly into the oil at the oil solvent interface than hydrocarbon liquids due to its lower diffusivity. The lower reaction rate would probably reduce the performance of a CO_2 VAPEX process when compared with a hydrocarbon liquid VAPEX process. Since VAPEX is still at a development stage, laboratory and field experiments need to be completed and evaluated before a reliable prediction of performance can be prepared. It is also recommended that the reservoir temperature be accurately determined so that the operating pressure can be adjusted to the optimum condition.

The VAPEX recovery may be about double the anticipated recovery from the high water/ CO_2 ratio injection analyzed for the pool. Therefore for the portion of the pool with sufficient pay and vertical permeability, consideration should be given to a VAPEX process. The information learned from the laboratory and recommended field test should help analyze the VAPEX potential.

The economics considered in this proposal do not include any upside for potentially higher recovery from a gravity drainage process in a portion of the pool. It is recommended that EnerMark monitor the current VAPEX development and, if appropriate, participate in some of the current industry funded consortium.

F. Economics

The original oil in place for target area of the Medicine Hat Glauconitic C is 22.7 e^6m^3 (143 MMBbls.) Recovery of up to 23.5 million barrels of oil is predicted. Recovery ranged from 9.9% to 16.4% OOIP, for the CO_2 enhanced waterflood. The gross CO_2 utilization ranged from 3.3 to 6.7 mcf/Bbl. The net CO_2 utilization ranged from 0.9 to 1.7 mcf/Bbl. An estimated 1.9 million tonnes (37 bcf) of source CO_2 could be stored. The gross CO_2 injected ranged from 26% to 48% HCPV in the 8,000 kPa operating pressure Cases.

The injection and production forecasts from the pattern model are incorporated into an economic spreadsheet to determine the feasibility of the project. The source and recycle CO_2 rates, oil production rates, and oil rates under comparable waterflood are shown on the Figures 2A to 2D for the four development cases analyzed.

The economic model runs for a maximum of 40 years and terminates earlier if the net operating income becomes negative. Thus the oil recovery may be lower than predicted from the fractional flow curves. The main economic assumptions for the waterflood and CO_2 flood are summarized on Table 2 and briefly described below.

1. Product Price

The Sproule 02/04/01 Hardisty Bow River crude oil price forecast, reduced by \$3.00/Bbl for quality and \$1.50/Bbl for transportation, is used in all of the economics resulting in a \$21.85/Bbl Cdn wellhead oil price (2002 dollars).

2. Inflation

All capital and operating costs, CO_2 and oil prices were inflated from the 2002 base year by 1.5% per annum per Sproule prediction.

3. Royalty

   a. Crown Royalty

   The Unit is 51.6% Crown and the non-unit area 68% Crown land. The developed area was calculated on the basis of OOIP resulting in 59.6% Crown for the project. Crown royalty is based on the old Section 11 Royalty Relief calculations. It is assumed that all capital costs and injection and corrosion control operating costs are allowed for relief. The enhanced production above the waterflood, results in a "T" factor of about 35%. To reflect the use of horizontal wells the producing well count was increased by a factor of 2.5 to calculate the royalty rate. To more accurately reflect production response in an EOR scheme the economics assume that one third of the wells produce two thirds of the oil, increasing the Crown Royalty payable.

   b. Freehold Royalty

   The freehold land is subject to a negotiated royalty of between 20% and 22.5%. Based on the ratio of OOIP, the weighted average rate was 21% applicable to 40.4% of the project.

   c. Other

   GORR's of 0.2% to 0.65% on non-unit and unit land. The weighted average GORR of 0.43% was added to the freehold royalty in the economics.

4. Source CO_2 Price

A CO_2 price of $25.00/tonne (2002 dollars Cdn) is assumed for the CO_2 at the Canadian Fertilizer Limited plant. Up to 500 tonnes/d (9,500 mcf/d) of CO_2 could be required for the flood. Information on CO_2 sources available to Vikor suggests that this volume of pure CO_2 is available from the Canadian Fertilizer Limited plant. However, EnerMark were unable to confirm availability with Canadian Fertilizer Limited so Vikor assumed the required volume would be available and require only compression to injection pressure. The capital and operating cost to deliver a high pressure, high quality CO_2 to the pipeline, is assumed to be covered in the $25/tonne price. A pipeline from the plant to the field is included in the CAPEX, see Figure 1. The line from the plant to the east side of the river follows an existing pipeline route and the installation cost has been doubled to reflect construction inside city limits.

5. Recycle CO_2

It is assumed that in the future a project will not be allowed to vent CO_2, therefore, the economics model assumes a complete recycle of all produced CO_2 over the life of the project. The pattern spreadsheet automatically shuts in the CO_2 injection when the specified hydrocarbon pore volume of CO_2 is reached in the last pattern. The economics have some conservatism as they include the cost to recycle the CO_2 to the end of the project without any additional oil production from this additional CO_2 injection. This can lead to a slightly higher CO_2 injection in the economic runs than specified. For low GOR pools, the most economic recycle is to re-inject the full produced gas stream. The Recycle CAPEX is shown on Table 1A-1D for each case.

6. Capital Expenditures (CAPEX)

In order to phase the field capital expenditures correctly the CAPEX is determined for each pattern and included when the pattern is developed. The pattern layout is analyzed to determine the wells and pipelines required in the field. Costs are assigned to upgrade, convert or drill new wells as required based on current well status. The well and pipeline costs used to generate the pattern cost estimate are shown on Table 6 for both the CO_2 and waterflood cases.

The existing operating oil gathering and water injection pipelines can continue to be used in the same service. A new pipeline system for CO_2 is installed to all injection wells and a water injection system is added, if it does not exist. Multi-phase group pipelines are used to flow all of the oil, water, and CO_2 production back to the existing batteries. The field has three batteries so a pipeline to gather the CO_2 from the batteries at 6-16-13-5W4M and 7-4-13-5W4M to the battery at 4-2-13-5W4M is included in the costs. It is assumed that the existing battery and waterflood plants are used with minimal upgrades. New inlet gas separators at each of the three batteries are installed at a total cost of $1,500,000 (2002 dollars) in the CO_2 cases. It is assumed that the battery modifications are expended the year before the project commences.

Compression, calculated to meet peak recycle demand for the following three years, is installed in the first year of project operation. Thereafter incremental compression is installed in the year that existing compression is fully utilized, designed to meet peak recycle demand for the following three years. Compression requirements are determined as 140 HP/mmcf/d at a cost of $500,000 plus $1,500/HP (2002 dollars) for electric drive compressors. It includes allowance for the low-pressure compression of treater and stock tank vapor gas. The oil in place, number of wells and costs assigned to each pattern are shown on Table 7. Note the high facility cost for pattern 1 includes the pipeline from the CO_2 source.

The internal rate of return for the project is misleading as it ignores all the sunk capital.

7. Operating Cost (OPEX)

The Unit operating costs used in the economics has been developed for the key cost centers in an EOR project. The unit costs used to generate the cost estimate are shown on Table 2. The cost estimates are based on the analysis of three years of Lease Operating Statements, adjusted for the addition of CO_2 based on the author's experience.

a. Well Operating Costs

Well operating costs are assigned based on a fixed monthly cost for injection wells and production wells. Because of the Section 11 Royalty a separate fixed monthly corrosion control cost is also assigned to production wells in the CO_2 cases.

b. Battery Operating Costs

Battery operating costs are assigned on a fixed monthly cost and a variable treating cost based on a dollar per barrel of oil treated.

c. Water Injection Costs

Water injection operating costs are assigned variable cost based on a dollar per barrel of water injected into the reservoir.

d. Recycle Operating Costs

The cost to recycle the CO_2 is dominated by the energy cost, with operators and maintenance costs being less costly. It is assumed that electric power calculated at $0.06/kW-hr. is used.

e. Overhead Fee:

An overhead fee of 0% is applied to the purchase price of the solvent, water and power. A 10% overhead fee is applied to all other plant operating costs and a $150/well month for producing wells as per Unit Agreement is used in the economics.

f. Abandonment Costs

It is assumed that the wells are abandoned when they finish operating. The net cost after recovery of equipment of $20,000/well is used to generate the abandonment cost estimate.

8. Net CO_2 Stored

At the request of AERI, Vikor has completed a rough estimate of the net CO_2 stored in tonnes per m^3 of oil production as shown on Table 8. The results show that the waterflood might generate 0.29 Mg/m^3 (0.9 mcf/Bbl) of CO_2 while the comparable CO_2 floods would store a net of 0.30 Mg/m^3 (0.9 mcf/Bbl).

Tables

Table 1 A

Vikor Energy Inc.

Medicine Hat Glauconitic C Pool CO_2 Flood Feasibility Study

Economic Results

		Case 1 - 8 MPa 1 HCPV 1.5 layer	Case WF1 - 6 MPa 1 HCPV	Incremental
Production =	k Bbls	14,094	9,343	4,751
Recovery	% OOIP	9.9%	6.5%	3.3%
CO2 Injection	% HCPV	26.6%	0.0%	26.6%
CO2 Stored	% HCPV	9.4%	0.0%	9.4%
Total CO2 Injected	M tonnes	4.1	0	4.1
Total CO2 Stored	M tonnes	1.4	0.0	1.4
Total CO2 Stored	bcf	28	0	28
Peak Source CO2	tonne/d	460	0	460
Peak Source CO2	mcf/d	8,800	0	8,800
Solvent/Oil Ratio	mcf/Bbl.	5.55	0.00	5.55
Purchase SOR	mcf/Bbl.	1.96	0.00	1.96
Water / CO2 Ratio	Rm3/Rm3	2.9		
Crown Royalty Rate		7.49%	6.05%	
Recycle CO2 Capital (2002 M $)		$3.2	$0.0	$3.2
As Spent Undiscounted				
Gross Revenue overlife =	/Bbl.	$25.74	$25.84	($0.10)
Burdens =	/Bbl.	$3.74	$3.58	$0.16
Capital =	/Bbl.	$2.52	$2.05	$0.47
Purchase CO2 =	/Bbl.	$2.86	$0.00	$2.86
Recycle CO2 OPEX =	/Bbl.	$1.23	$0.00	$1.23
Other Field OPEX =	/Bbl.	$6.19	$9.34	($3.15)
Net Income =	/Bbl.	$9.19	$10.87	($1.68)
Gross Revenue	M $	$362.8	$241.4	$121.3
Capital	M $	$35.6	$19.1	$16.4
Source CO2	M $	$40.3	$0.0	$40.3
Operating Costs	M $	$104.7	$87.2	$17.4
Burdens	M $	$52.7	$33.5	$19.2
Cash Flow BT @ 0%	M $	$129.6	$101.6	$28.0
Cash Flow BT @ 10%	M $	$60.6	$51.4	$9.2
Cash Flow BT @ 15%	M $	$44.1	$39.1	$5.0
Cash Flow BT @ 20%	M $	$33.0	$30.7	$2.4
Cash Flow BT @ 25%	M $	$25.3	$24.7	$0.6

Table 1 B

Vikor Energy Inc.

Medicine Hat Glauconitic C Pool CO2 Flood Feasibility Study

Economic Results

		Case 2 - 8 MPa 2 HCPV 1.5 layer	Case WF2 - 6 MPa 2 HCPV	Incremental
Production =	k Bbls	20,111	12,667	7,444
Recovery	% OOIP	14.1%	8.9%	5.2%
CO2 Injection	% HCPV	46.1%	0.0%	46.1%
CO2 Stored	% HCPV	11.4%	0.0%	11.4%
Total CO2 Injected	M tonnes	7.1		
Total CO2 Stored	M tonnes	1.8	0.0	1.8
Total CO2 Stored	bcf	34	0	34
Peak Source CO2	tonne/d	480	0	480
Peak Source CO2	mcf/d	9,200	0	9,200
Solvent/Oil Ratio	mcf/Bbl.	6.74	0.00	6.74
Purchase SOR	mcf/Bbl.	1.67	0.00	1.67
Water / CO2 Ratio	Rm3/Rm3	3.1		
Crown Royalty Rate		6.63%	4.99%	
Recycle CO2 Capital (2002 M $)		$4.5	$0.0	$4.5
As Spent Undiscounted				
Gross Revenue overlife =	/Bbl.	$26.87	$27.46	($0.59)
Burdens =	/Bbl.	$3.72	$3.57	$0.15
Capital =	/Bbl.	$1.86	$1.55	$0.31
Purchase CO2 =	/Bbl.	$2.47	$0.00	$2.47
Recycle CO2 OPEX =	/Bbl.	$1.88	$0.00	$1.88
Other Field OPEX =	/Bbl.	$7.81	$13.02	($5.20)
Net Income =	/Bbl.	$9.12	$9.32	($0.20)
Gross Revenue	M $	$540.4	$347.8	$192.6
Capital	M $	$37.4	$19.6	$17.8
Source CO2	M $	$49.7	$0.0	$49.7
Operating Costs	M $	$194.9	$164.9	$30.0
Burdens	M $	$74.9	$45.3	$29.6
Cash Flow BT @ 0%	M $	$183.4	$118.0	$65.4
Cash Flow BT @ 10%	M $	$86.4	$57.6	$28.8
Cash Flow BT @ 15%	M $	$64.2	$43.3	$20.9
Cash Flow BT @ 20%	M $	$49.3	$33.8	$15.5
Cash Flow BT @ 25%	M $	$38.9	$27.2	$11.7

Table 1 C

Vikor Energy Inc.

Medicine Hat Glauconitic C Pool CO2 Flood Feasibility Study

Economic Results

		Case 3 - 8 MPa 2 HCPV 2 layer	Case WF2 - 6 MPa 2 HCPV	Incremental
Production =	k Bbls	23,485	12,667	10,818
Recovery	% OOIP	16.4%	8.9%	7.6%
CO2 Injection	% HCPV	48.2%	0.0%	48.2%
CO2 Stored	% HCPV	12.6%	0.0%	12.6%
Total CO2 Injected	M tonnes	7.4		
Total CO2 Stored	M tonnes	1.9	0.0	1.9
Total CO2 Stored	bcf	37	0	37
Peak Source CO2	tonne/d	490	0	490
Peak Source CO2	mcf/d	9,300	0	9,300
Solvent/Oil Ratio	mcf/Bbl.	6.04	0.00	6.04
Purchase SOR	mcf/Bbl.	1.58	0.00	1.58
Water / CO2 Ratio	Rm3/Rm3	3.2		
Crown Royalty Rate		7.07%	4.99%	
Recycle CO2 Capital (2002 M $)		$4.4	$0.0	$4.4
As Spent Undiscounted				
Gross Revenue overlife =	/Bbl.	$27.19	$27.46	($0.27)
Burdens =	/Bbl.	$3.82	$3.57	$0.24
Capital =	/Bbl.	$1.60	$1.55	$0.05
Purchase CO2 =	/Bbl.	$2.31	$0.00	$2.31
Recycle CO2 OPEX =	/Bbl.	$1.69	$0.00	$1.69
Other Field OPEX =	/Bbl.	$7.48	$13.02	($5.54)
Net Income BT =	/Bbl.	$10.29	$9.32	$0.97
Gross Revenue	M $	$638.5	$347.8	$290.7
Capital	M $	$37.5	$19.6	$17.9
Source CO2	M $	$54.3	$0.0	$54.3
Operating Costs	M $	$215.4	$164.9	$50.5
Burdens	M $	$89.6	$45.3	$44.4
Cash Flow BT @ 0%	M $	$241.6	$118.0	$123.6
Cash Flow BT @ 10%	M $	$111.9	$57.6	$54.4
Cash Flow BT @ 15%	M $	$83.4	$43.3	$40.1
Cash Flow BT @ 20%	M $	$64.5	$33.8	$30.7
Cash Flow BT @ 25%	M $	$51.3	$27.2	$24.1

Table 1 D
Vikor Energy Inc.
Medicine Hat Glauconitic C Pool CO2 Flood Feasibility Study
Economic Results

		Case 4 - 6 MPa 2 HCPV 1.5 layer	Case WF2 - 6 MPa 2 HCPV	Incremental
Production =	k Bbls	18,354	12,667	5,687
Recovery	% OOIP	12.8%	8.9%	4.0%
CO2 Injection	% HCPV	66.0%	0.0%	66.0%
CO2 Stored	% HCPV	18.8%	0.0%	18.8%
Total CO2 Injected	M tonnes	3.2		
Total CO2 Stored	M tonnes	0.9	0.0	0.9
Total CO2 Stored	bcf	17	0	17
Peak Source CO2	tonne/d	260	0	260
Peak Source CO2	mcf/d	5,000	0	5,000
Solvent/Oil Ratio	mcf/Bbl.	3.28	0.00	3.28
Purchase SOR	mcf/Bbl.	0.93	0.00	0.93
Water / CO2 Ratio	Rm3/Rm3	2.2		
Crown Royalty Rate		6.44%	4.99%	
Recycle CO2 Capital (2002 M $)		$2.7	$0.0	$2.7
As Spent Undiscounted				
Gross Revenue overlife =	/Bbl.	$26.82	$27.46	($0.63)
Burdens =	/Bbl.	$3.69	$3.57	$0.12
Capital =	/Bbl.	$1.92	$1.55	$0.37
Purchase CO2 =	/Bbl.	$1.39	$0.00	$1.39
Recycle CO2 OPEX =	/Bbl.	$0.87	$0.00	$0.87
Other Field OPEX =	/Bbl.	$8.57	$13.02	($4.45)
Net Income =	/Bbl.	$10.38	$9.32	$1.06
Gross Revenue	M $	$492.3	$347.8	$144.5
Capital	M $	$35.3	$19.6	$15.7
Source CO2	M $	$25.6	$0.0	$25.6
Operating Costs	M $	$173.2	$164.9	$8.3
Burdens	M $	$67.8	$45.3	$22.6
Cash Flow BT @ 0%	M $	$190.4	$118.0	$72.4
Cash Flow BT @ 10%	M $	$89.8	$57.6	$32.2
Cash Flow BT @ 15%	M $	$67.4	$43.3	$24.0
Cash Flow BT @ 20%	M $	$52.4	$33.8	$18.5
Cash Flow BT @ 25%	M $	$41.8	$27.2	$14.5

Table 2
Vikor Energy Inc.
Medicine Hat Glauconitic C Pool CO2 Flood Feasibility Study
Assumptions Common to all Cases

		CO2	Waterflood
OOIP =	k Bbls	142,975	
OOIP =	e3m3	22,731	
Number Injection Wells		37	
Number Producing Wells		89	
Oil Price Forecast		Sproule 02/04/01	
Project Injection Start Date		2004	
Project Crown Leases =		59.61%	
Project Freehold Leases =		40.39%	
Freehold & GORR Rate		22.03%	
Common Capital Costs (in 2002 $)			
Intangible Well Cost	k $	$6,780	$6,340
Tangible Well Cost	k $	$6,500	$3,480
Field Facilities & Pipelines	k $	$12,436	$4,950
Battery Upgrades	k $	$1,500	$0
Net Abandonment	k $/Well	$20	$20
Common Operating Costs (in 2002 $)			
Source CO2 Cost @ Plant	/Mg	$25.00	$0.00
Recycle Solvent	/Mg	$5.00	$0.00
Source Solvent Payment	/MCF	$1.31	$0.00
Recycle Solvent	/MCF	$0.26	$0.00
Production Well fixed	/well-mo.	$1,250	$1,250
Corrosion Control	/well-mo.	$250	$0
Injection Well	/well-mo.	$750	$750
Fixed Production	/mo.	$32,500	$32,500
Treating Costs	/bbl oil	$0.50	$0.50
Fixed H2O Injection	/mo.	$15,000	$15,000
Waterflood/disposal	/bbl H2O	$0.20	$0.20

Table 3

Medicine Hat Glauconitic C Pool

Reservoir Properties

KB (m)	716.1
Formation Depth (m)	825.9
Datum (m)	-109.8
Area (ha)	2576
Average Net Pay (m)	8.66
Average Porosity (%)	22
Average Water Saturation (%)	30
Oil FVF (Rm^3/m^3)	1.11
API Gravity	15.9
Initial GOR (m^3/m^3)	45
Initial Pressure (kPa)	10,175
Temperature (degree C)	26
OOIP (e^3m^3)	30,920

Table 4

PVT Properties from Well 07-04-013-05W5M

Pressure	GOR	FVF	Bg	Oil Visc.
(kPa)	(m3/m3)	(Rm3/m3)	(Rm3/M3)	cp
90	0.0	1.0221	2.3472	887
676	2.8	1.0554	0.1997	496
1076	4.3	1.0599	0.1097	453
1524	5.8	1.0628	0.0752	420
1993	7.4	1.0654	0.0585	388
2482	9.0	1.0681	0.0500	360
2958	10.2	1.0704	0.0422	340
3434	11.5	1.0730	0.0368	324
3930	12.7	1.0749	0.0330	307
4385	13.7	1.0763	0.0303	295
4874	14.6	1.0772	0.0286	287
6000	17.0	1.0800	0.0238	280
8000	20.3	1.0850	0.0217	265
10000	22.3	1.0890	0.0208	257

Bubble Point 9,750 kPa

Solution GOR 22.1 m3/m3

Oil Density 970 kg/m3 (14.4 °API)

Data based on Simtech Study, July 1991

Table 5

PVT Properties from Well 14-10-013-05W5M

Pressure	GOR	FVF	Bg	Oil Visc.
(kPa)	(m3/m3)	(Rm3/m3)	(Rm3/M3)	cp
90	0.0	1.006	1.0000	316
876	3.9	1.018	0.1176	205
1889	7.5	1.028	0.0538	153
2950	11.2	1.035	0.0338	127
3875	14.2	1.041	0.0253	110
4881	17.4	1.046	0.0197	98
5895	19.7	1.050	0.0160	88
6895	22.5	1.054	0.0134	77
7901	24.8	1.058	0.0115	73
8901	27.6	1.062	0.0098	67
9901	29.3	1.065	0.0085	61
11000	31.6	1.068	0.0079	56

Bubble Point 5,500 kPa

Solution GOR 18.8 m3/m3

Oil Density 947.2 kg/m3 (17.8 °API)

Data based on Simtech Study, July 1991

Vikor Energy Inc.
Table 6
Medicine Hat Glauc C
Capital Cost Assumptions

** Thousands of 2002 dollars*

CO2 Well Capital Costs *(Includes 20% Contingency)*

		Injector			*Producer*	
Current Status	# wells	**Intang**	**Tang**		**Intang**	**Tang**
Injector	11	$40	$40	0	$40	$100
Producer	17	$60	$80	67	$0	$20
vert with stimulation				2	$50	$20
Suspended	8	$160	$80	13	$180	$130
Abandoned	1	$200	$80	7	$200	$130
	37	$2,940	$2,520	89	$3,840	$3,980
	126	**$6,780**	**$6,500**			

Wtrfld Well Capital Costs *(Includes 20% Contingency)*

		Injector			*Producer*	
Current Status	# wells	**Intang**	**Tang**		**Intang**	**Tang**
Injector	11	$0	$0	0	$40	$90
Producer	17	$60	$40	67	$0	$0
vert with stimulation				2	$50	$20
Suspended	8	$160	$40	13	$180	$120
Abandoned	1	$200	$40	7	$200	$120
	37	$2,500	$1,040	89	$3,840	$2,440
	126	**$6,340**	**$3,480**			

Pipeline and Tie In Capital Costs

PipeLine	$/m		Buried Lines /ditch	$/m
Wtr (3")	$30.00		1	$30.00
CO2 (3")	$20.00		CO2 in City	$60.00
Oil or test (3")	$17.50		2	$40.00
Recycle (8")	$80.00		3	$50.00
Recycle (4")	$40.00		Easements	$20.00
Contingency -	20%		Tie-in - Injector(CO2)	$40
Satellite -	$250		Tie-in - Producer(CO2)	$25
River Crossing -	$500		Tie-in - Injector(Wtrfld)	$20
Road Crossing -	$10	/crossing	ie-in - Producer(Wtrfld)	$20

Plant Capital Cost (CO2 Cases)

Recycle Compression Cost:

- phased installation to compress peak in next three years.
- $500,000 + $1,500/HP-140HP/MMSCF/d *

Battery Upgrades:

New battery at $1,500,000

Vikor Energy Inc.

Table 7

Med Hat Glauc C

Individual Pattern Information

thousands of dollars - 2002 $

OOIP k Bbl.	Injectivity Rm3/d	OOIP e3 m3	Injection Well	pat #	new prod wells	CO2 Pattern Capital Costs Intang	CO2 Pattern Capital Costs Tang	CO2 Pattern Capital Costs Facility	Wtrfld Pattern Capital Costs Intang	Wtrfld Pattern Capital Costs Tang	Wtrfld Pattern Capital Costs Facility
142,975	8,774	22,731	Total =		89	$6,780	$6,500	$12,436	$6,340	$3,480	$4,950
3,907	100	621	09-09-13-5	1	5	$290	$290	$3,714	$290	$180	$292
6,763	158	1,075	02-09-13-5	2	5	$420	$360	$222	$380	$240	$145
4,297	341	683	15-04-13-5	3	2	$60	$140	$472	$60	$40	$268
6,973	425	1,109	02-04-13-5	4	6	$340	$350	$531	$340	$160	$361
5,351	710	851	11-09-13-5	5	2	$220	$190	$126	$180	$120	$64
2,911	341	463	12-09-13-5	6	2	$60	$120	$189	$60	$40	$116
2,633	513	419	13-10-13-5	7	3	$40	$100	$200	$0	$0	$84
4,251	100	676	04-16-13-5	8	1	$160	$100	$251	$160	$40	$118
4,091	100	650	02-16-13-5	9	1	$160	$100	$107	$160	$40	$56
2,064	281	328	08-16-13-5	10	3	$220	$210	$270	$180	$120	$96
2,256	199	359	10-16-13-5	11	2	$40	$80	$295	$0	$0	$194
486	482	77	13-16-13-5	12	0	$60	$80	$306	$60	$40	$143
3,434	438	546	09-17-13-5	13	2	$60	$120	$393	$60	$40	$183
718	204	114	12-17-13-5	14	1	$400	$210	$132	$400	$160	$73
1,884	244	300	11-15-13-5	15	2	$60	$120	$149	$60	$40	$71
220	81	35	11-15-13-5	16	2	$260	$230	$241	$260	$160	$207
2,441	173	388	06-10-13-5	17	4	$40	$100	$168	$0	$0	$96
2,928	100	466	06-03-13-5	18	3	$40	$100	$138	$0	$0	$84
5,123	100	815	11-04-13-5	19	3	$340	$250	$292	$340	$160	$168
5,027	100	799	15-05-13-5	20	2	$240	$230	$201	$240	$160	$134
7,802	401	1,240	03-04-13-5	21	4	$420	$360	$329	$420	$280	$235
4,383	290	697	05-03-13-5	22	3	$40	$80	$153	$0	$0	$64
1,585	199	252	07-02-13-5	23	2	$40	$80	$109	$0	$0	$64
5,157	286	820	05-34-12-5	24	4	$440	$380	$203	$440	$280	$104
5,788	147	920	12-33-12-5	25	2	$160	$120	$362	$160	$40	$75
6,479	199	1,030	10-33-12-5	26	2	$60	$120	$209	$60	$40	$113
6,564	199	1,044	02-33-12-5	27	4	$60	$160	$254	$60	$40	$138
3,619	100	575	10-34-12-5	28	1	$60	$100	$202	$60	$40	$51
3,127	471	497	09-34-12-5	29	2	$110	$120	$200	$110	$60	$105
4,341	272	690	04-35-12-5	30	3	$460	$360	$323	$460	$280	$240
5,045	100	802	03-34-12-5	31	4	$520	$380	$263	$520	$280	$167
403	100	64	10-35-12-5	32	0	$40	$40	$158	$0	$0	$24
2,119	100	337	16-27-12-5	33	1	$160	$100	$317	$160	$40	$178
1,516	100	241	02-35-12-5	34	0	$40	$40	$181	$0	$0	$36
4,189	100	666	11-27-12-5	35	3	$340	$250	$319	$340	$160	$188
4,506	318	716	10-28-12-5	36	0	$60	$80	$109	$60	$40	$66
8,595	204	1,366	05-09-13-5	37	3	$260	$250	$351	$260	$160	$147

Table 8
Vikor Energy Inc.

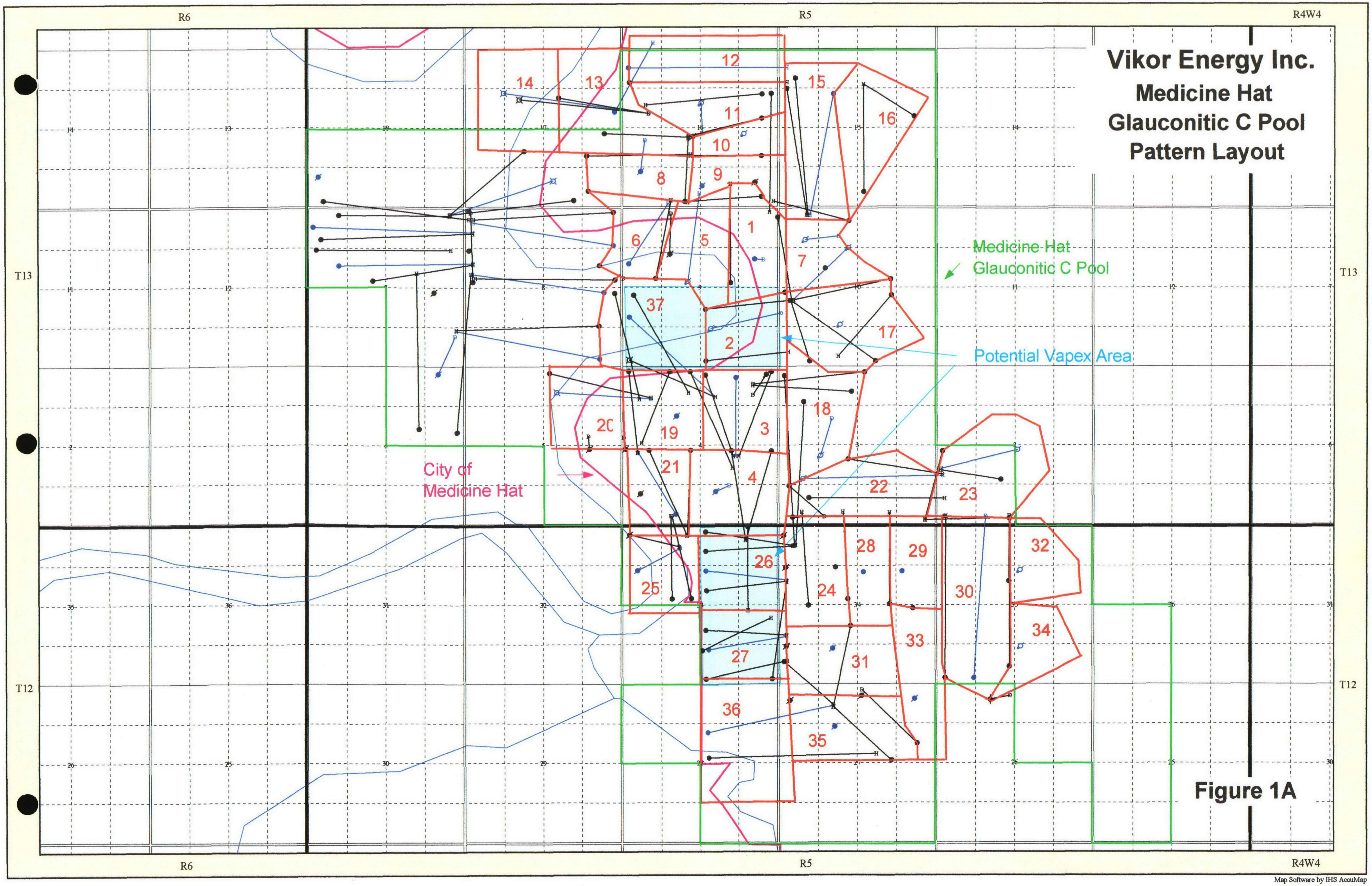
CO2 Generated by Medicine Hat Glauc C Flood

		Case 1	Case 2	Case 3	Case 4	Case WF1	Case WF2
Oil Produced	m3	2,240,767	3,197,394	3,733,817	2,918,053	1,485,418	2,013,892
Oil Produced	Bbl.	14,094,000	20,111,000	23,485,000	18,354,000	9,343,000	12,667,000
Source CO2 Injected	Mg	1,450,028	1,757,783	1,944,707	898,619	0	0
Recycle CO2 Injected	Mg	2,652,642	5,355,015	5,491,464	2,256,315	0	0
Water	m3	18,611,244	35,006,778	36,733,666	34,967,603	23,061,982	42,709,855
Source	kW/Mg	110	110	110	110	110	110
Recycle	kW/Mg	45	45	45	45	45	45
Water	kW/m3	3.4	3.4	3.4	3.4	3.4	3.4
Source	MW	159,503	193,356	213,918	98,848	0	0
Recycle	MW	119,369	240,976	247,116	101,534	0	0
Water	MW	63,278	119,023	124,894	118,890	78,411	145,214
Pump jacks etc. estimated	MW	60,000	120,000	120,000	120,000	80,000	150,000
Total	MW	402,150	673,355	705,928	439,272	158,411	295,214
Treating	TJ	2,476,632	4,596,376	4,846,208	4,574,417	2,990,162	5,492,715
CO2 Generated @ 0.7 Mg/MW	Mg	281,505	471,348	494,150	307,491	110,888	206,649
CO2 Generated treating oil	Mg	169,783	315,100	332,227	313,594	204,987	376,547
	Mg/m3	0.201	0.246	0.221	0.213	0.213	0.290
	Mg/Bbl.	0.032	0.039	0.035	0.034	0.034	0.046
Net CO2 Stored	Mg	998,740	971,335	1,118,330	277,534	(315,875)	(583,197)
	Mg/m3	0.446	0.304	0.300	0.095	(0.213)	(0.290)
	mcf/Bbl.	1.4	0.9	0.9	0.3	(0.6)	(0.9)

4t

Note: Pure source no capture emissions only compression

Figures



Vikor Energy Inc.
Medicine Hat
Glauconitic C Pool
Pattern Layout
Medicine Hat
Glauconitic C Pool
Potential Vapex Area
City of
Medicine Hat
R6
R5
R4W4
T13
T12
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
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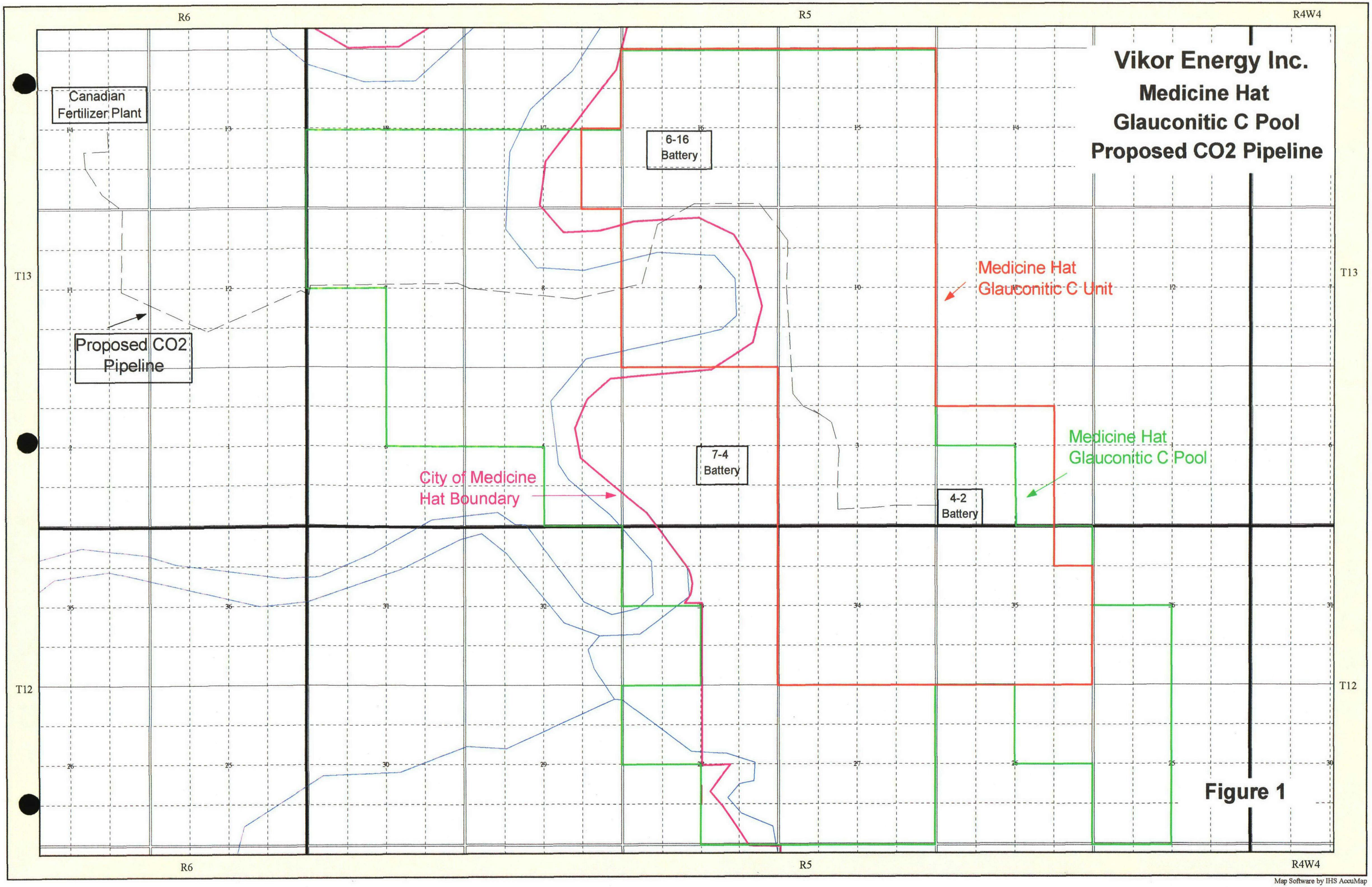
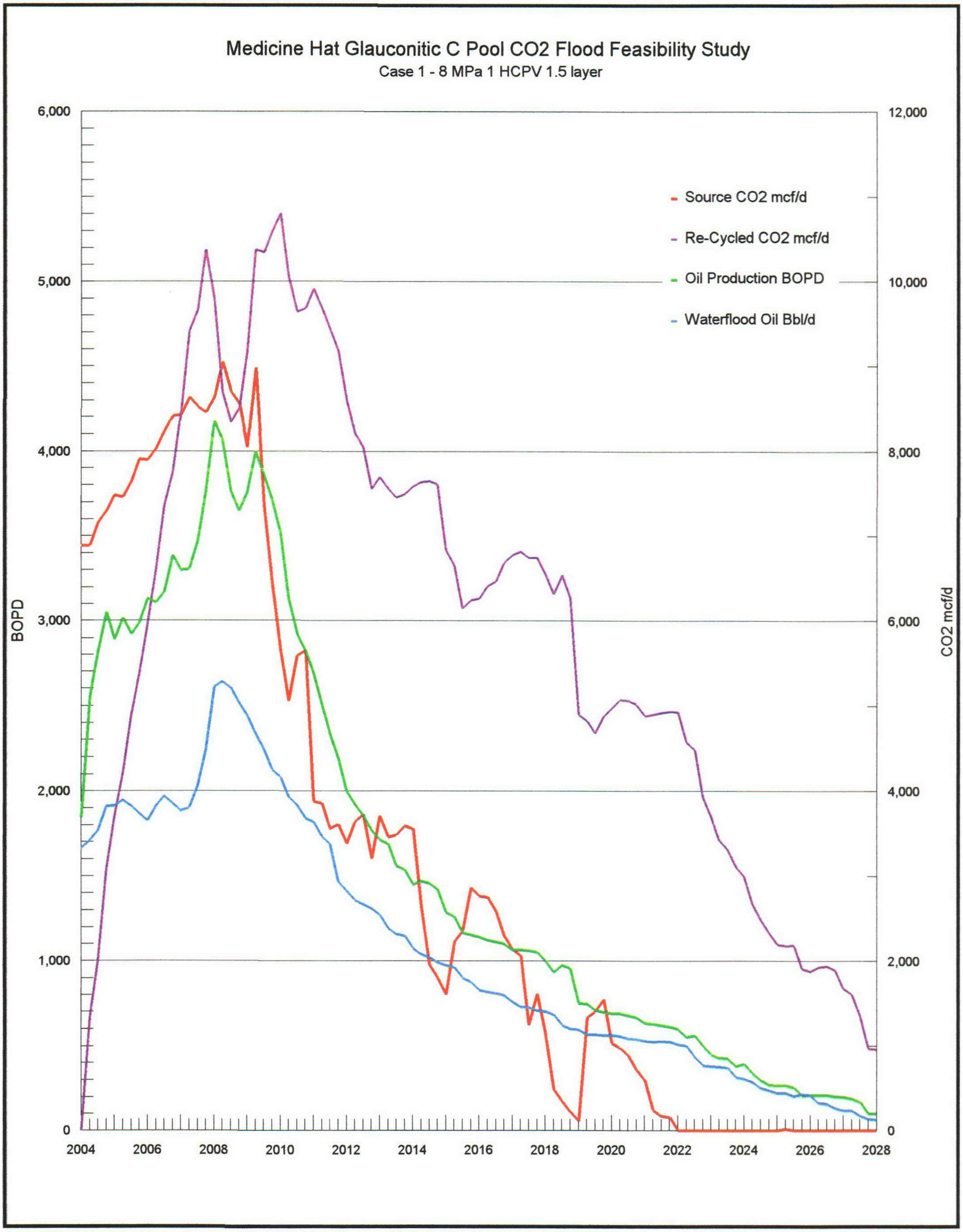
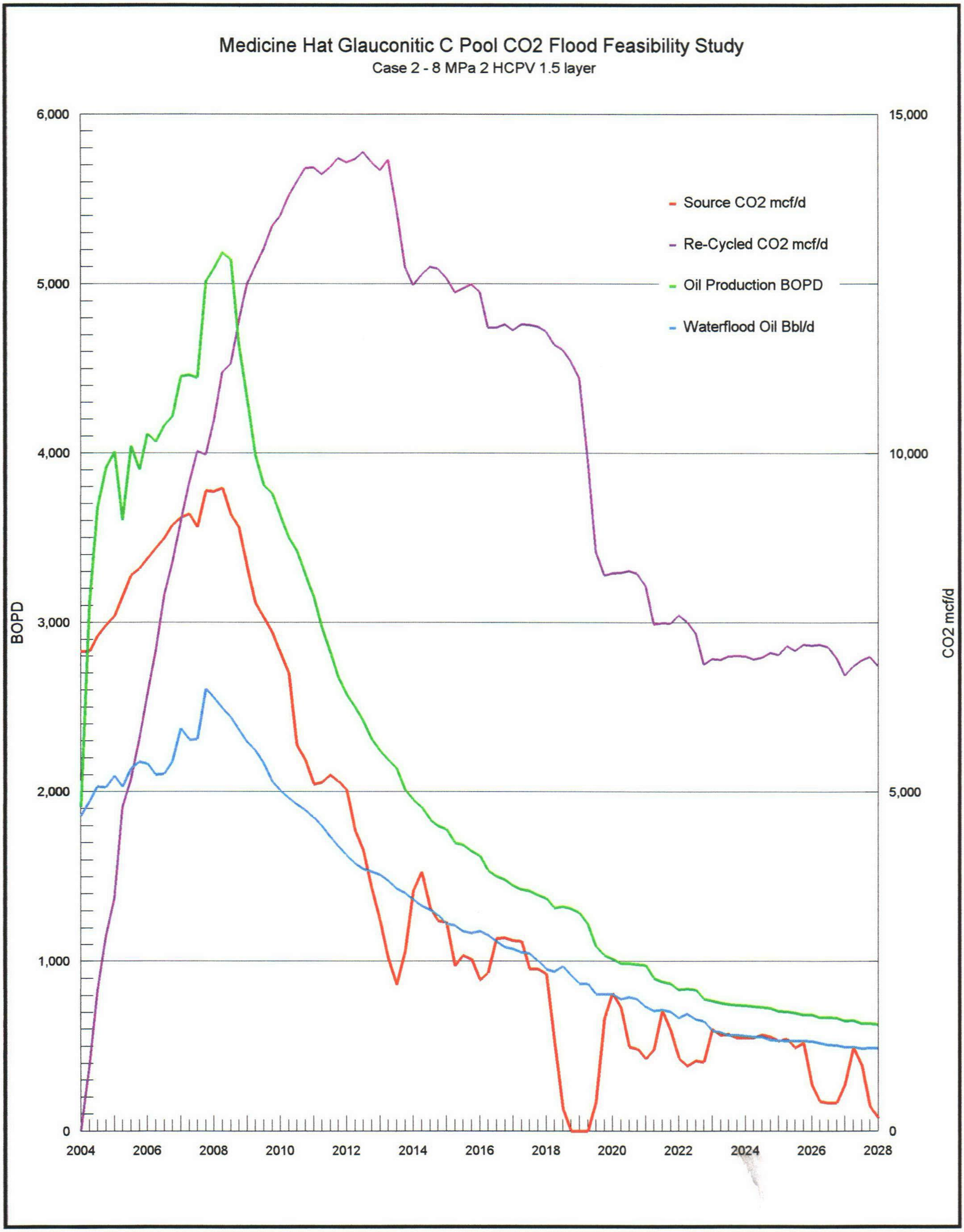
Figure 1A
Map Software by IHS AccuMap

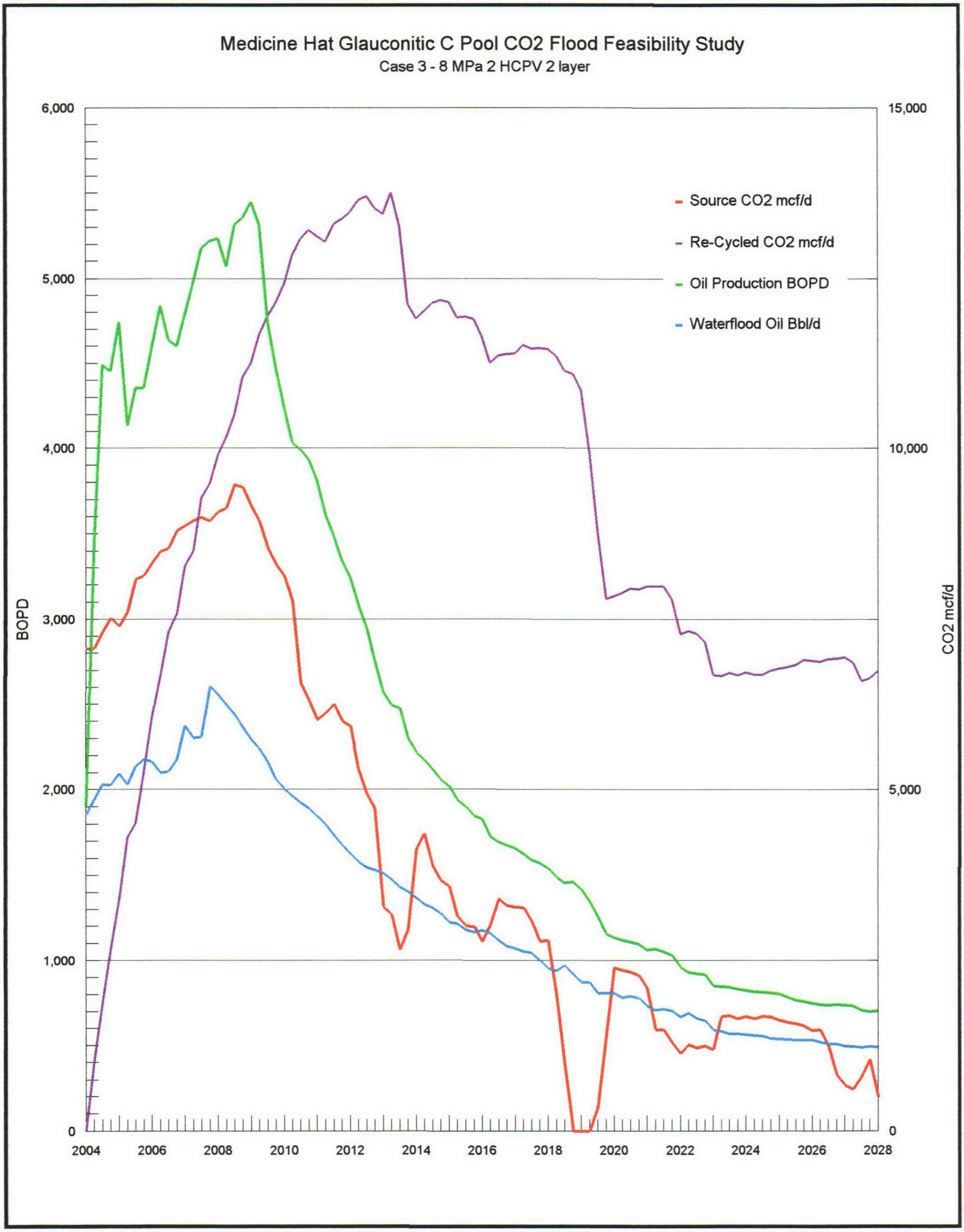


Vikor Energy Inc.
Medicine Hat
Glauconitic C Pool
Proposed CO2 Pipeline
R6
R5
R4W4
T13
T12
Canadian Fertilizer Plant
Proposed CO2 Pipeline
6-16 Battery
7-4 Battery
4-2 Battery
Medicine Hat Glauconitic C Unit
Medicine Hat Glauconitic C Pool
City of Medicine Hat Boundary
Figure 1
Map Software by IHS AccuMap

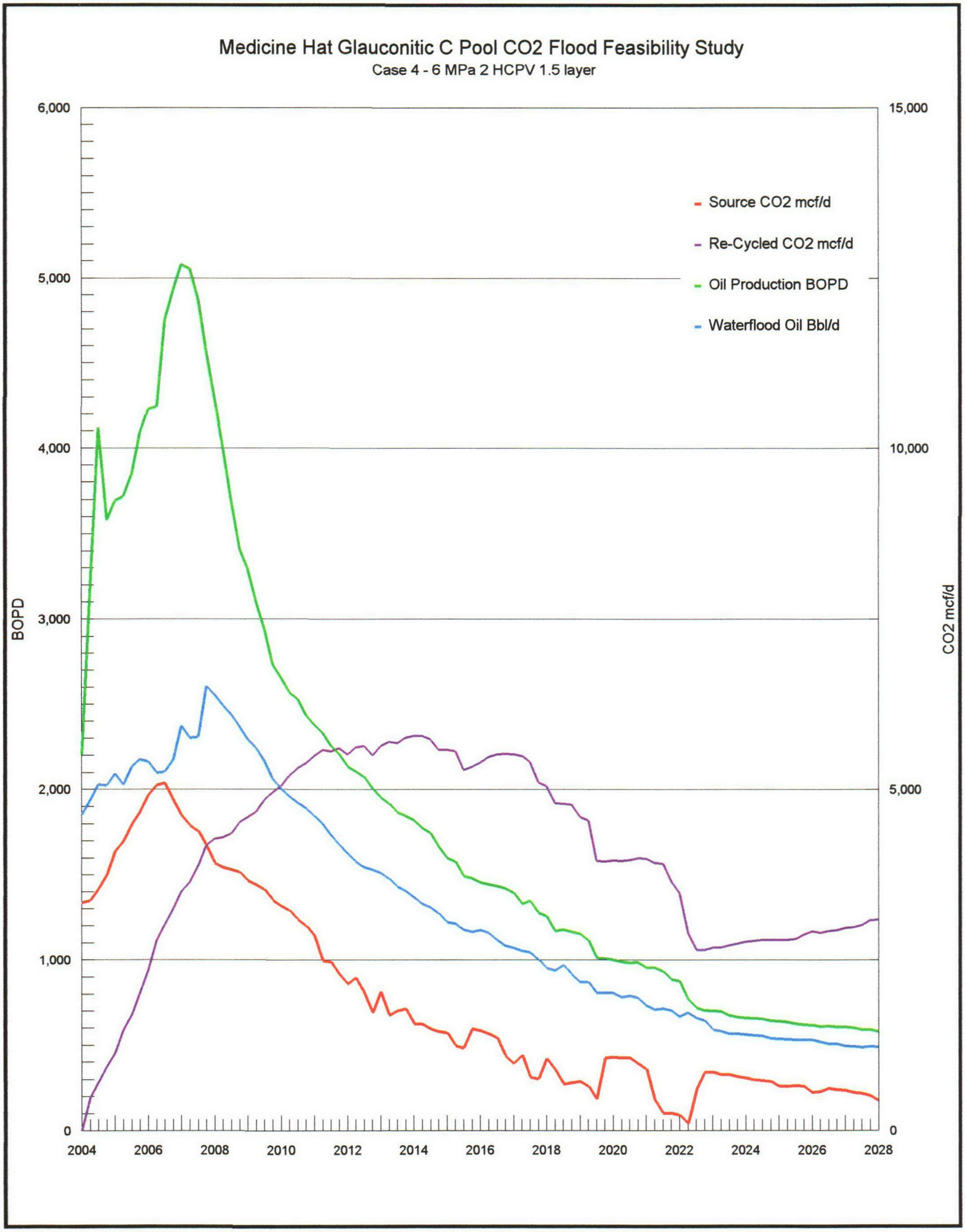

Medicine Hat Glauconitic C Pool CO2 Flood Feasibility Study
Case 1 - 8 MPa 1 HCPV 1.5 layer
Source CO2 mcf/d
Re-Cycled CO2 mcf/d
Oil Production BOPD
Waterflood Oil Bbl/d
BOPD
CO2 mcf/d
6,000
5,000
4,000
3,000
2,000
1,000
0
12,000
10,000
8,000
6,000
4,000
2,000
0
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028



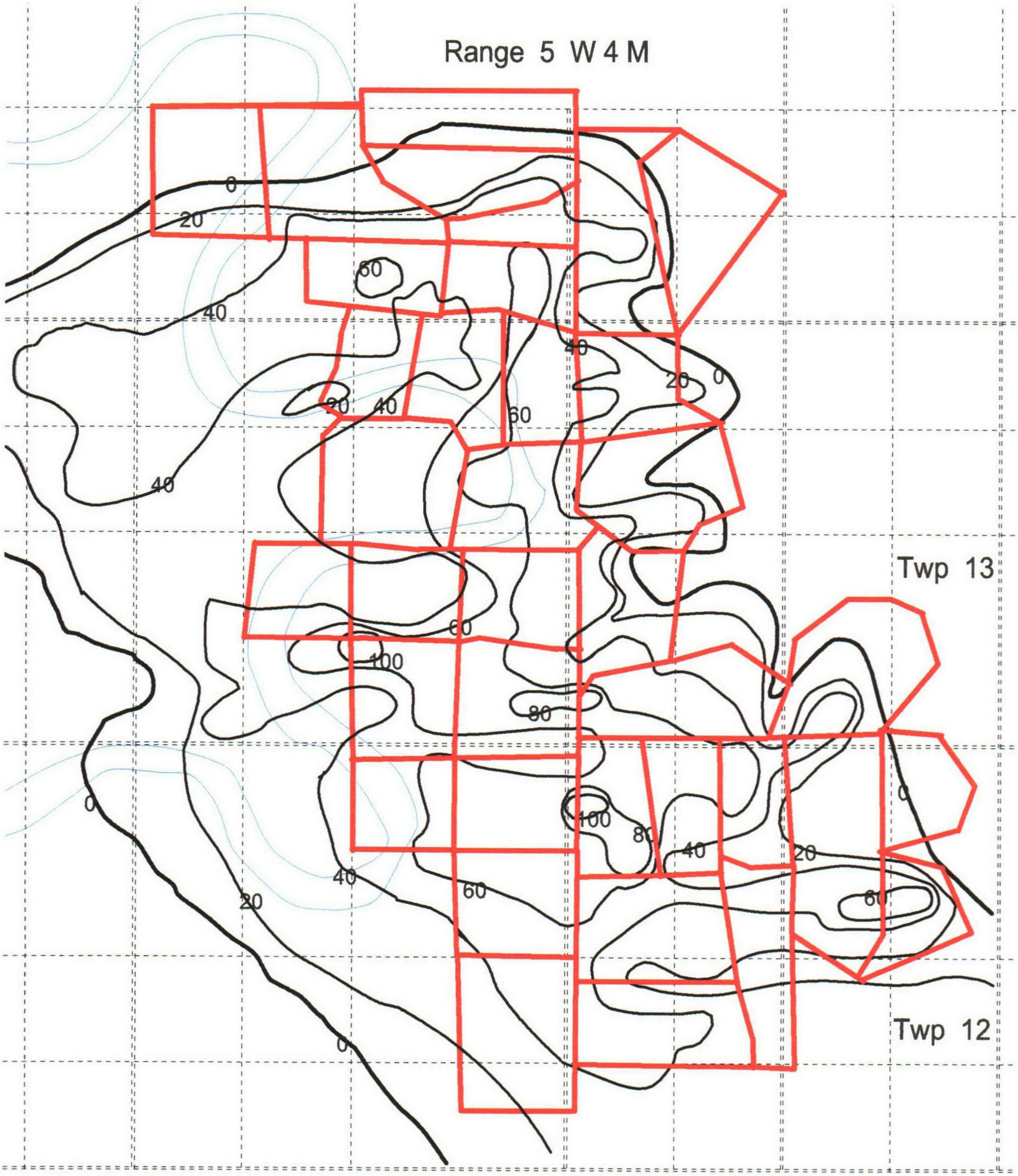
Medicine Hat Glauconitic C Pool CO2 Flood Feasibility Study
Case 2 - 8 MPa 2 HCPV 1.5 layer
Source CO2 mcf/d
Re-Cycled CO2 mcf/d
Oil Production BOPD
Waterflood Oil Bbl/d
BOPD
CO2 mcf/d
6,000
5,000
4,000
3,000
2,000
1,000
0
15,000
10,000
5,000
0
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028



Medicine Hat Glauconitic C Pool CO2 Flood Feasibility Study
Case 3 - 8 MPa 2 HCPV 2 layer
Source CO2 mcf/d
Re-Cycled CO2 mcf/d
Oil Production BOPD
Waterflood Oil Bbl/d
BOPD
CO2 mcf/d
6,000
5,000
4,000
3,000
2,000
1,000
0
15,000
10,000
5,000
0
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028



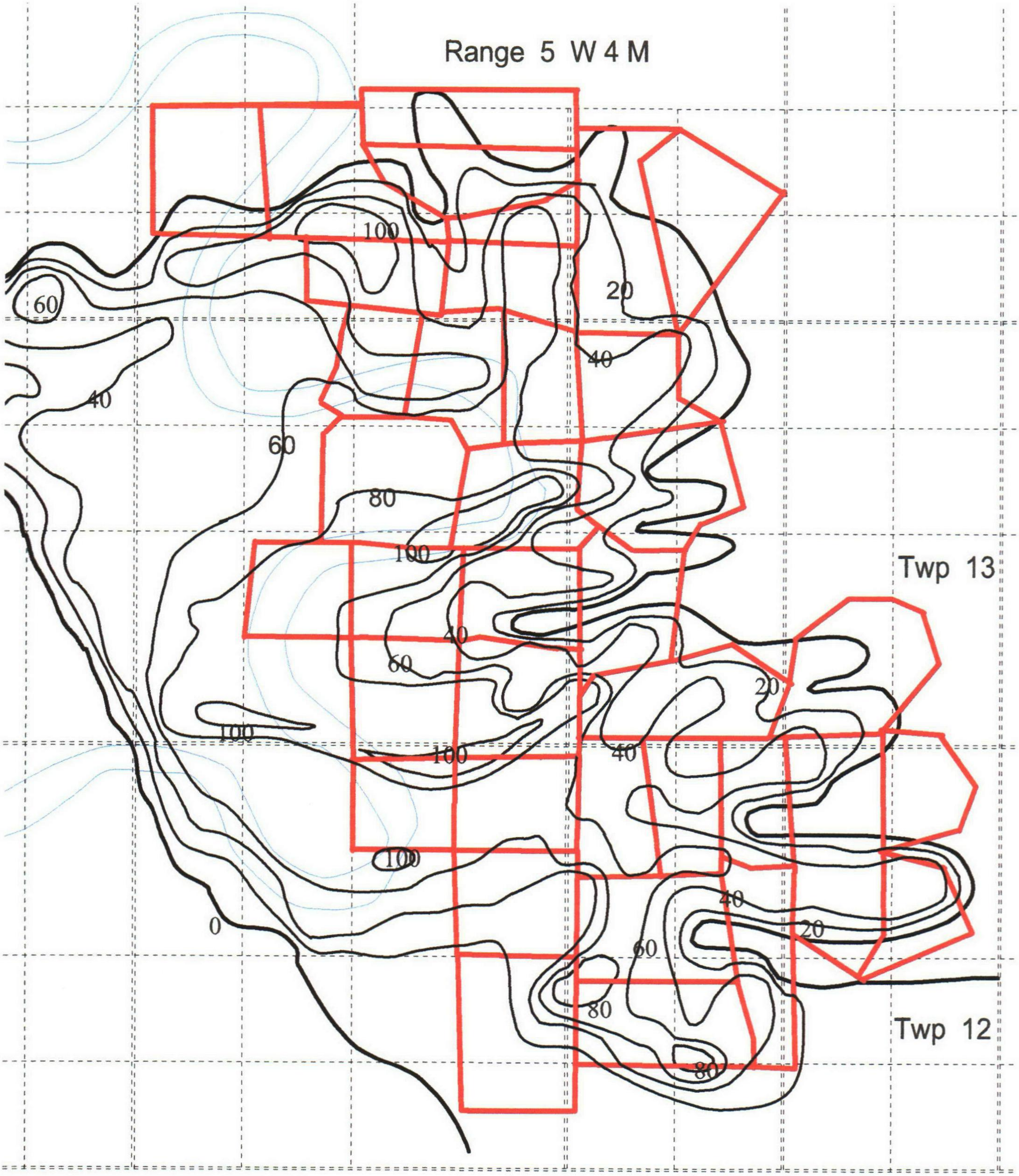
Medicine Hat Glauconitic C Pool CO2 Flood Feasibility Study
Case 4 - 6 MPa 2 HCPV 1.5 layer
Source CO2 mcf/d
Re-Cycled CO2 mcf/d
Oil Production BOPD
Waterflood Oil Bbl/d
BOPD
CO2 mcf/d
6,000
5,000
4,000
3,000
2,000
1,000
0
15,000
10,000
5,000
0
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028



Vikor Energy Inc.

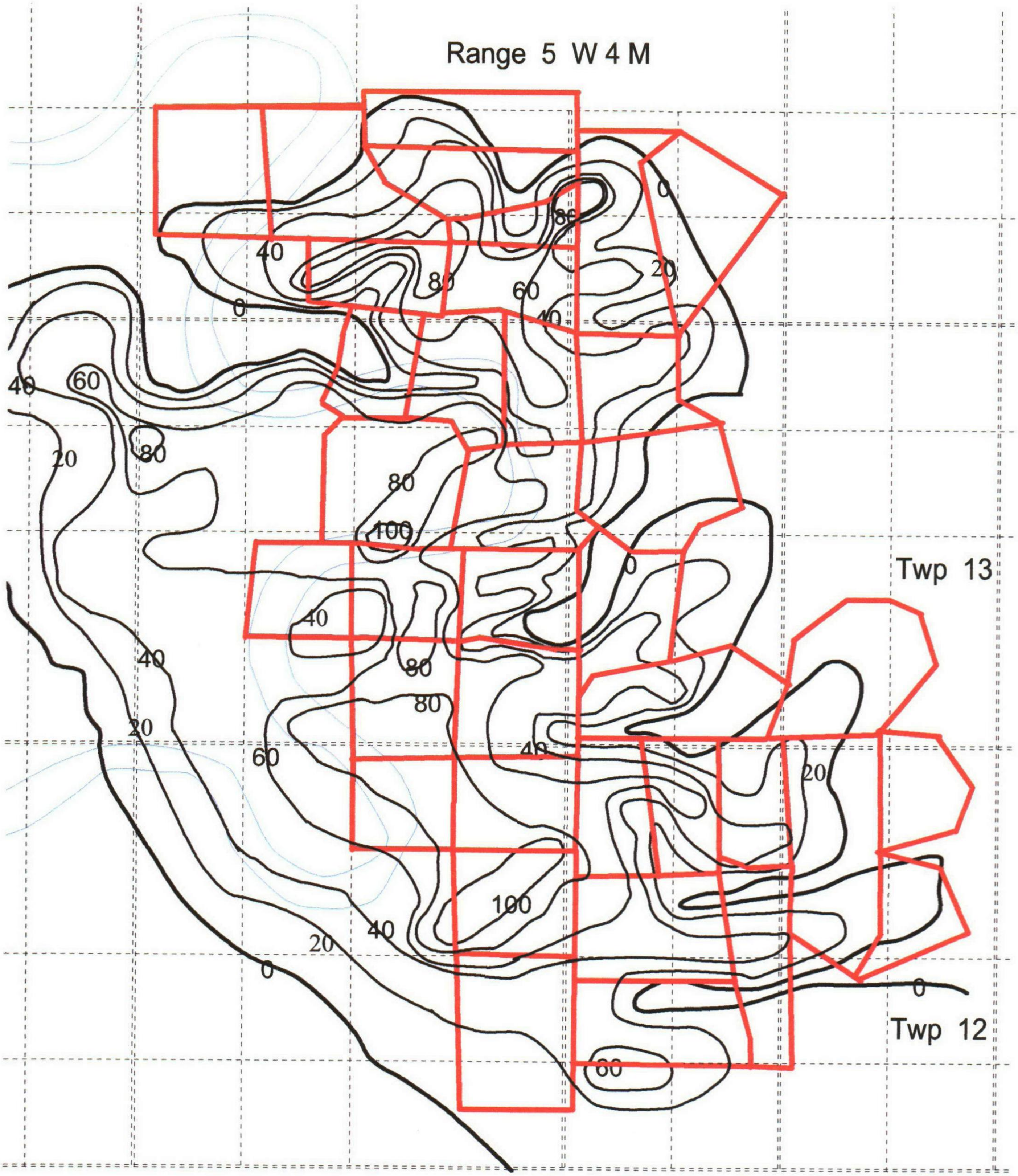
Medicine Hat
Glauconitic C Pool
C1 Sand Phi H Map
Figure 3

Phi H in Percent Meters



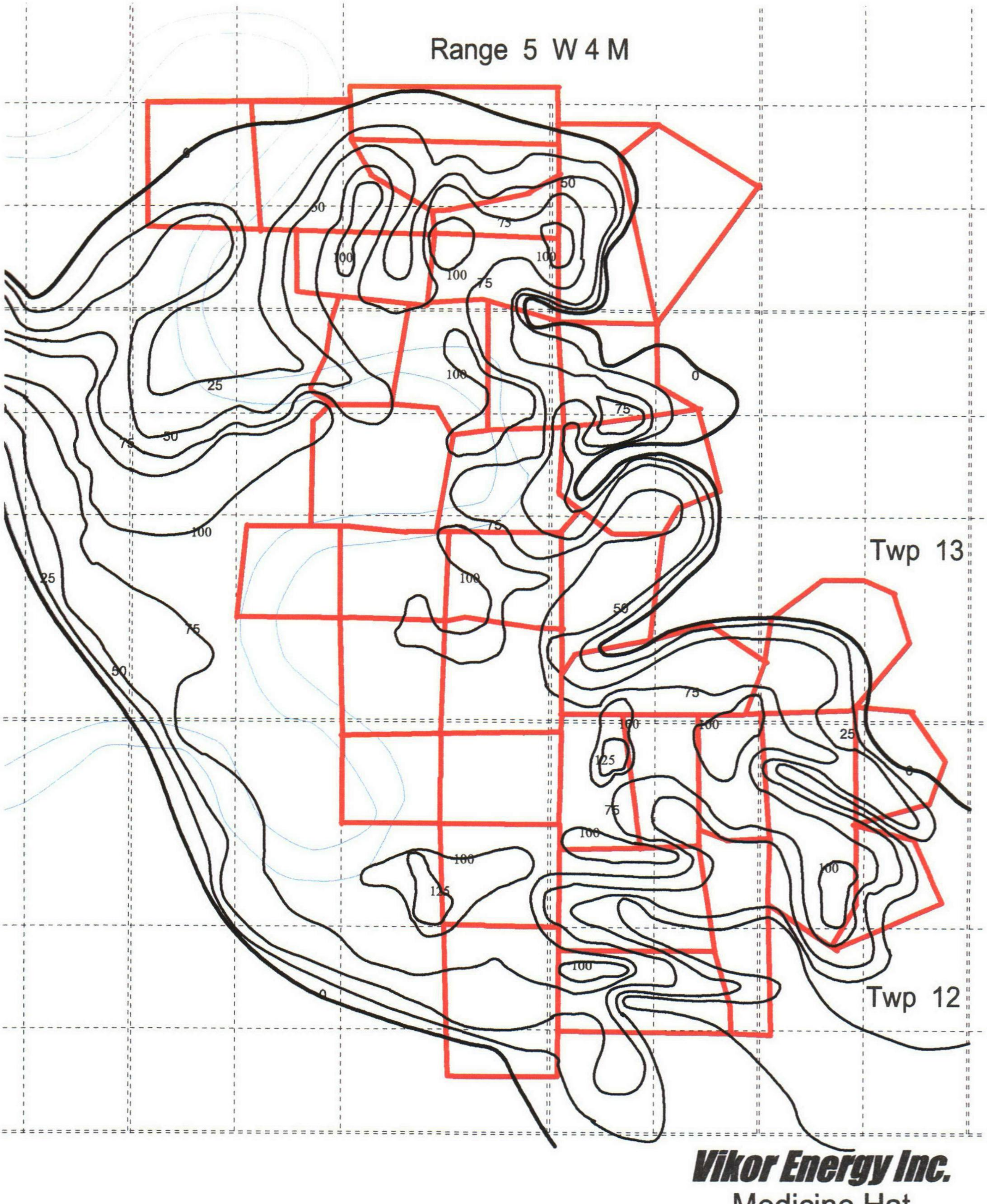
Vikor Energy Inc.
Medicine Hat
Glauconitic C Pool
C2 Sand Phi H Map
Figure 4

Phi H in Percent Meters



Phi H in Percent Meters

Vikor Energy Inc.
Medicine Hat
Glauconitic C Pool
C3 Sand Phi H Map
Figure 5



Vikor Energy Inc.

Medicine Hat

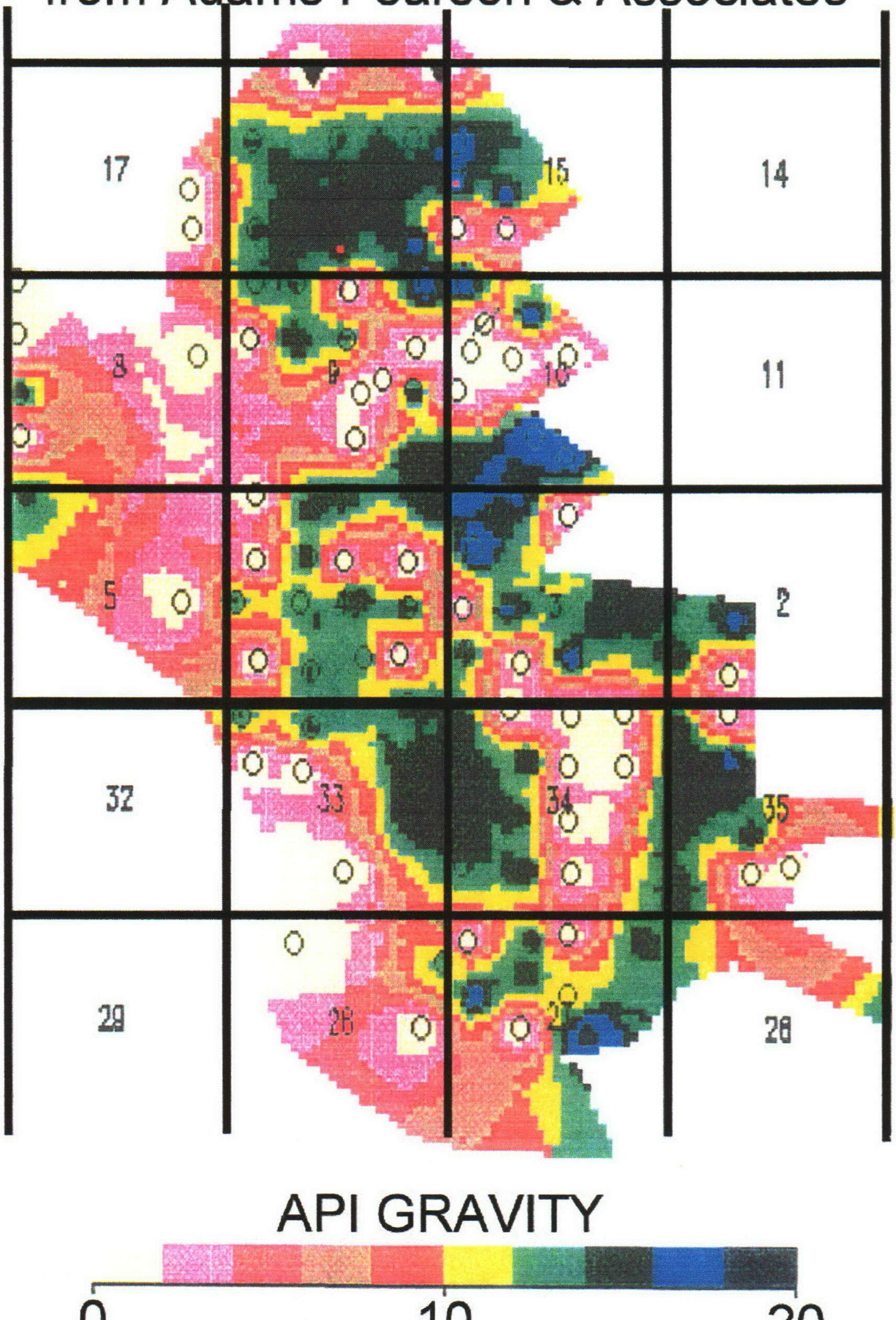
Glauconitic C Pool

B1 Sand Phi H Map

Figure 6

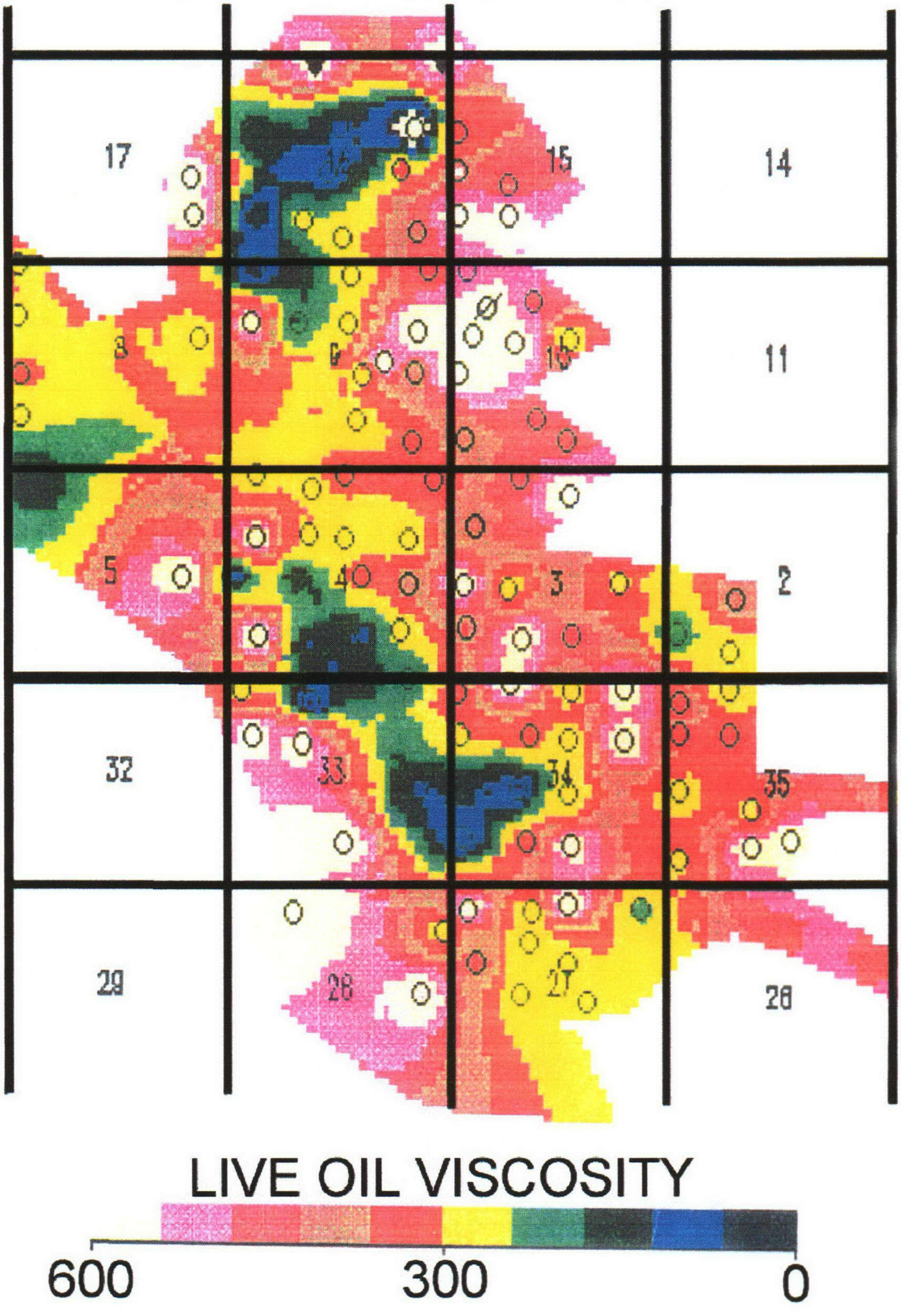
Phi H in Percent Meters

AREAL VARIATION of API GRAVITY
from Adams Pearson & Associates



Medicine Hat Glauconitic C Pool
Figure 7

AREAL VARIATION of LIVE OIL VISCOSITY
from Adams Pearson & Associates



Medicine Hat Glauconitic C Pool
Figure 8

Appendix A

Medicine Hat Glauconitic C Pool
CO_2 Flood Study

Appendix A Performance of the Glauconitic C Pool Waterflood Pilot A1

Figures:

Figure A1 - Map of Waterflood Pilot
Figure A2 - Performance of Vertical Pilot Producer 13-10
Figure A3 - Performance of Vertical Pilot Producer 14-10
Figure A4 - Performance of Vertical Pilot Producer 12-10
Figure A5 - Performance of Vertical Pilot Producer 11-10
Figure A6 - Performance of Waterflood Pilot, Vertical Wells
Figure A7 - Performance of Waterflood Pilot, All Wells
Figure A8 - Performance of Horizontal Pilot Producer 03/14-10
Figure A9 - Performance of Horizontal Pilot Producer W0/13-10
Figure A10 - Performance of Horizontal Pilot Producer 02/14-10
Figure A11 - Waterflood Pilot History Match
Figure A12 - Water Oil Relative Permeabilities
Figure A13 - Waterflood Performance of Various Viscosity Oil

Appendix A - Performance of the Glauconitic C Pool Waterflood Pilot

Although the Medicine Hat Glauconitic C was on primary production until 2001, a pilot waterflood injecting into 02-010-013-05W4M well has operated since November 1992. The injector was surrounded by four vertical wells (11-10, 12-10, 13-10 and 14-10) to form a non-symmetrical inverted 5 spot pattern, as shown in Figure A1. This pilot area has the lightest API gravity and the lowest oil viscosity in the pool. Injection and production appeared to cover both the upper and lower sand. The waterflood for the pilot area appeared to be very successful. This waterflood pilot has a cumulative injection of 9% HCPV of the area enclosed by the vertical wells before significant water production was observed. All four wells responded to water injection with increasing oil rate and water oil ratio, as shown in Figures A2 to A5.

From 1996 to 1997, three horizontal wells were drilled in the north, west and south, slightly beyond the original inverted 5 spot pattern, thus enlarging the pattern area. The higher withdrawal from the horizontal wells quickly pulled the waterfront beyond the vertical wells, which were watered out and ceased production shortly after the horizontal wells were on stream. At the time of the shut-in of the interior vertical wells, a total of almost 14% of the OOIP of the inside vertical well pattern area was produced by the vertical wells, as shown in Figure A6.

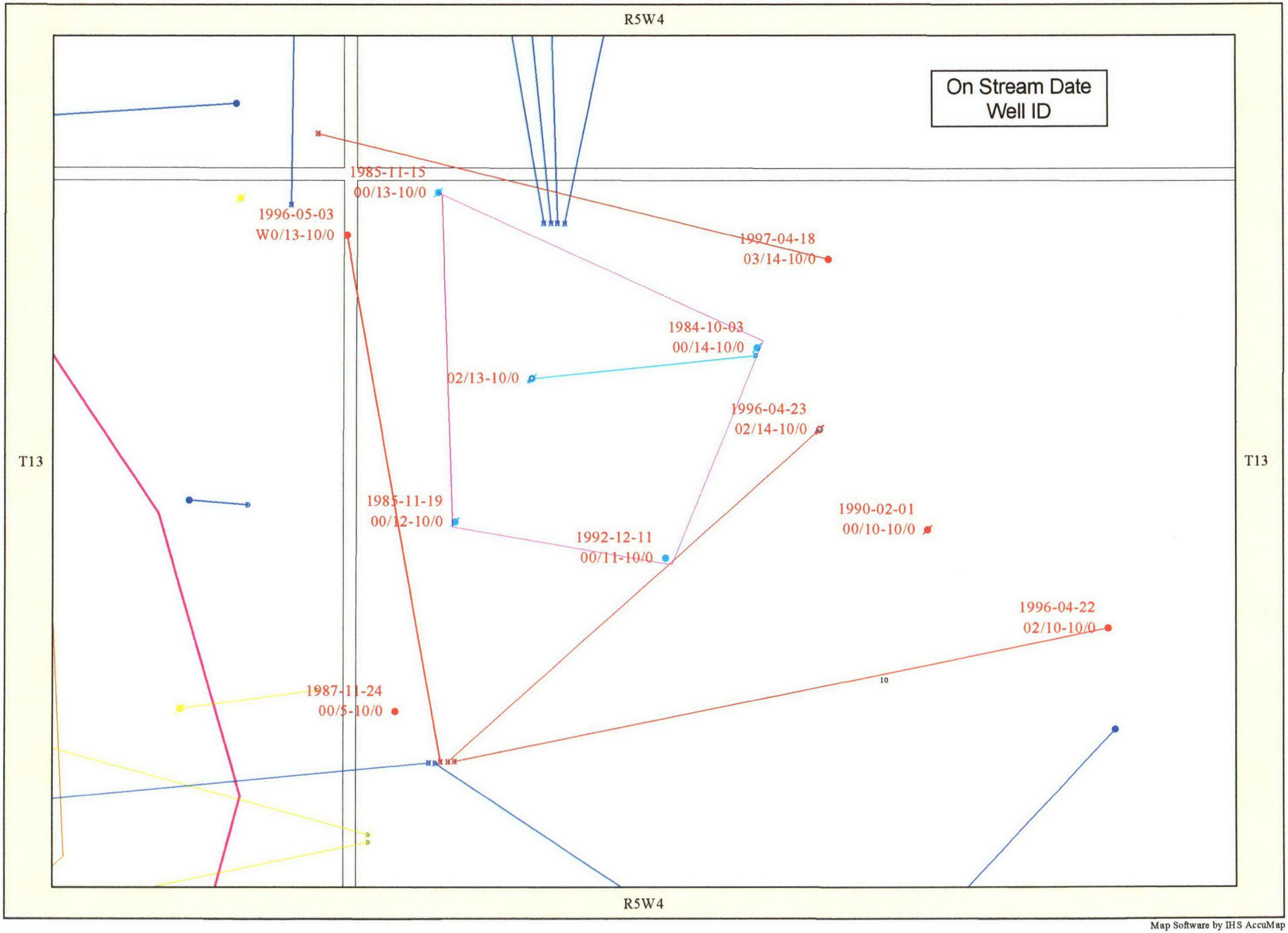
The enlarged pattern continued to produce to the current date. Using an estimated oil volume of 554,000 m^3 for the larger pilot area, the injected water volume to-date is 39% HCPV and the recovery factor is approaching 14% for the larger horizontal well pattern area. The current water-cut is approximately 86%. Depending on the economics of producing at high water-cut, the final recovery for the pilot area could reach over 20%. Figure A7 shows the production performance of the total pilot including the vertical and horizontal wells. Individual horizontal well performances for the pilot are depicted in Figures A8 to A10.

The good performance of the pilot area with the smaller vertical well patterns and the larger horizontal well patterns is encouraging and it demonstrated high recovery can be achieved, at least for the lighter oil of the pool.

The area under waterflood contains some of the best quality oil in the pool with live oil viscosity in the range of 60 cp at initial pressure of 10 MPa. However, pressure depletion during the primary stage reduced the pressure of the area to 3.5 MPa or less. The live oil viscosity, based on the PVT analysis of the well 14-10 as summarized in Table 5, is assumed to be 98 cp for the waterflood area.

The performance of the waterflood pilot was history matched by small modifications of the relative permeability curves used in the previous simulation studies. A plot of the actual and simulated cumulative oil production versus water injection is shown in Figure A11. At one HCPV of cumulative water injection, the recovery factor is in the order of 18%. The oil and water relative permeability curves used, to obtain this match is shown in Figure A12.

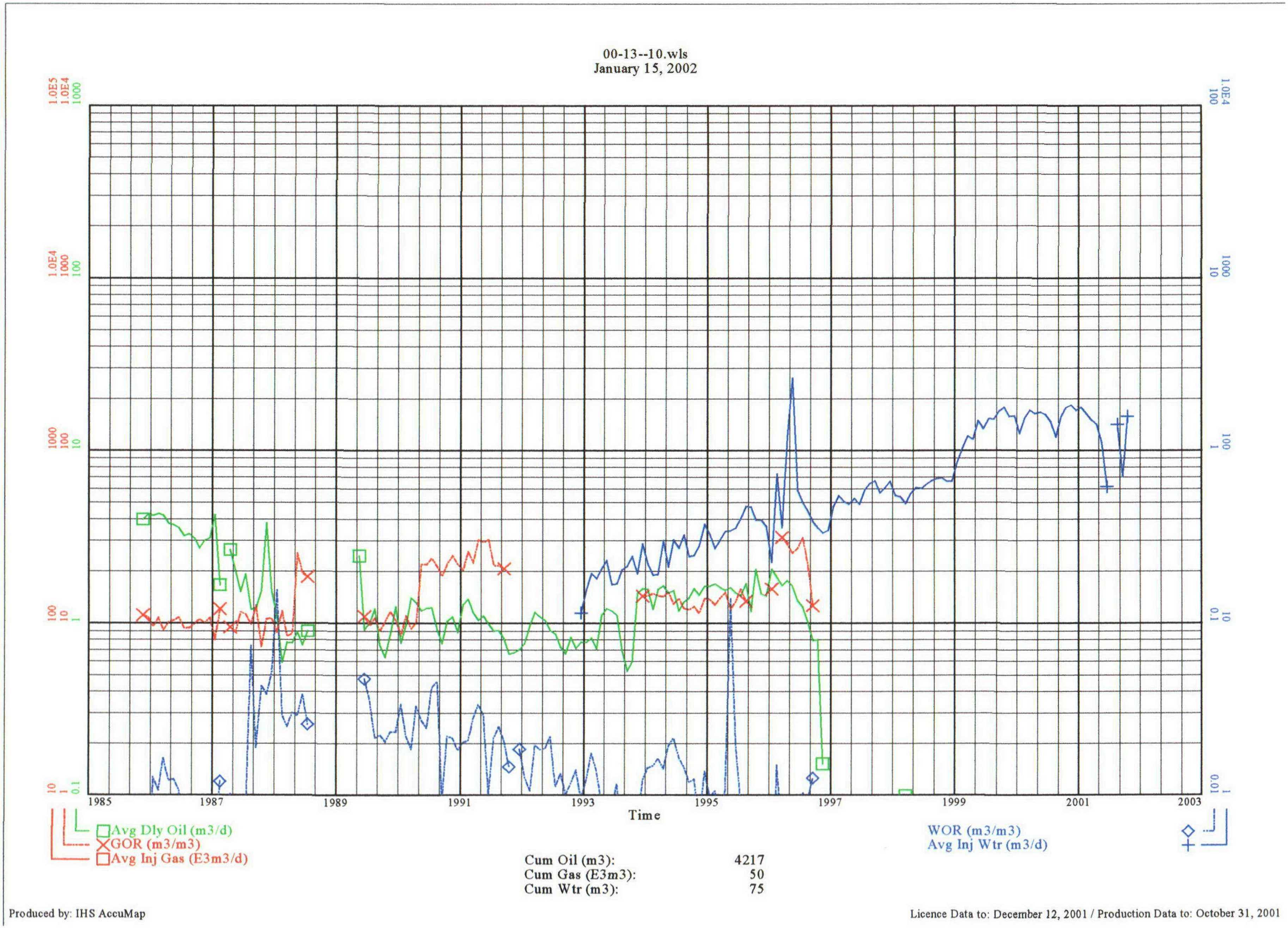
Using the matched relative permeability curves, the effect of various oil viscosity was evaluated. The curves showed the effect of viscosity of two types heavier oil on the oil recovery rate. The heavier oil would have a live oil viscosity of 287 cp and 450 cp, respectively. The 287cp oil is very close to the median viscosity of 250 cp in the Adams Pearson's 1996 report. For the 287 cp oil, the recovery factor at one HCPV of water injection is 14%. For the more viscous 450 cp oil the oil recovery is reduced to 12%, see Figure A13.



Vikor Energy Inc.

Medicine Hat Glau. C Pool WF Pilot Area

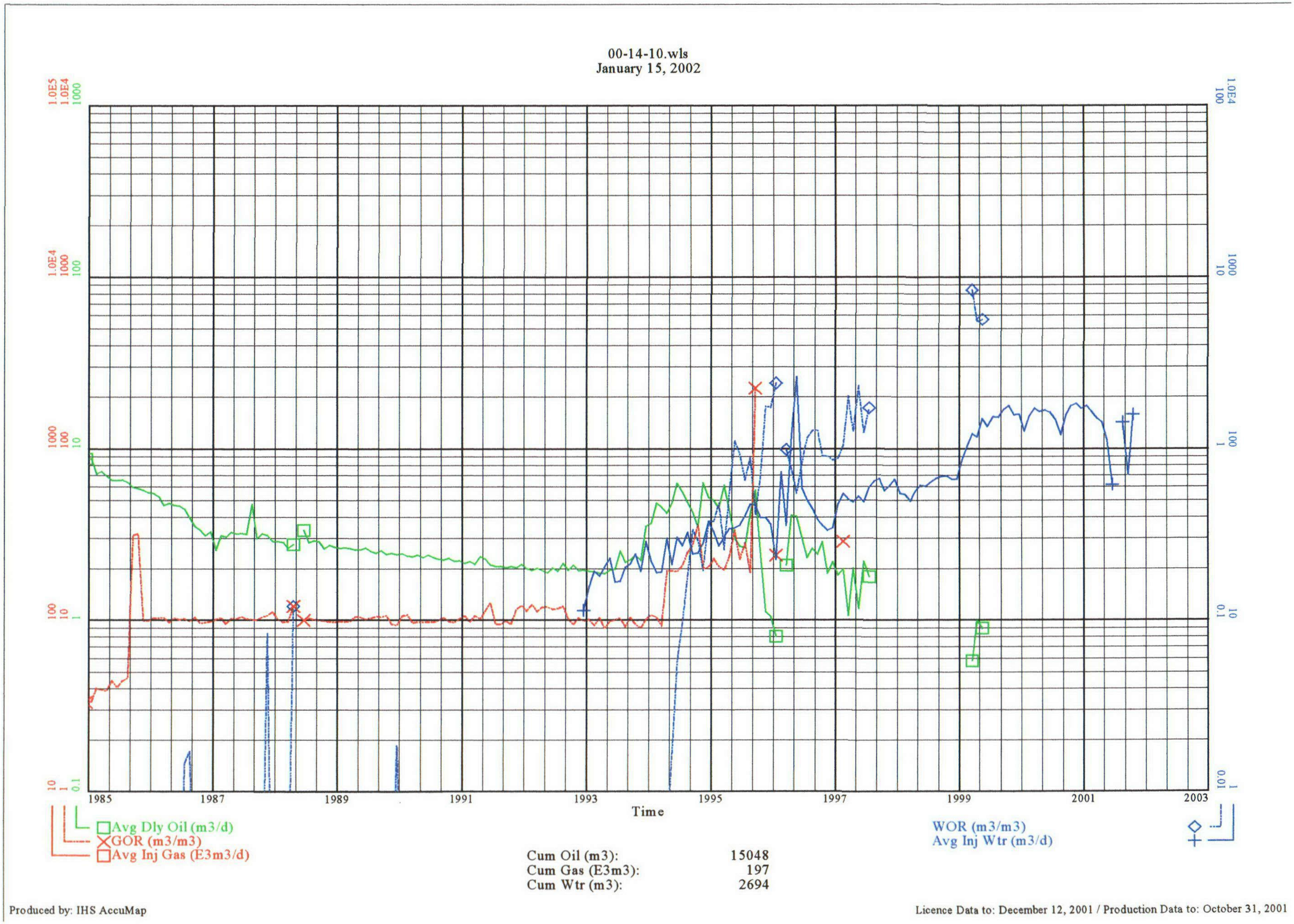
Figure A1



Vikor Energy Inc.

Medicine Hat Glauconitic C Pool
Pilot vertical well (13-10) northwest of injector

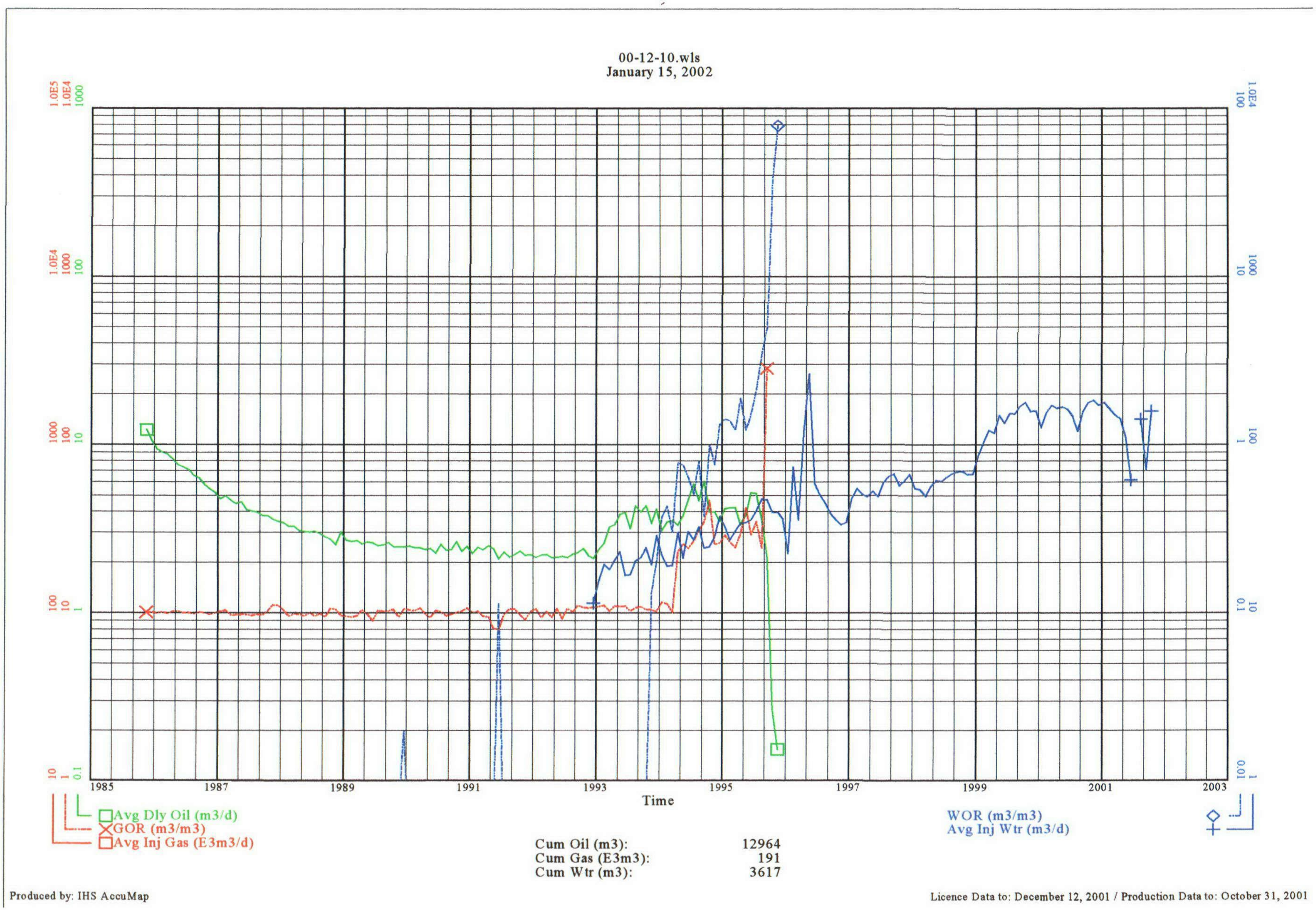
Figure A2



Vikor Energy Inc.

Medicine Hat Glauconitic C Pool
Pilot vertical well (14-10) east of injector

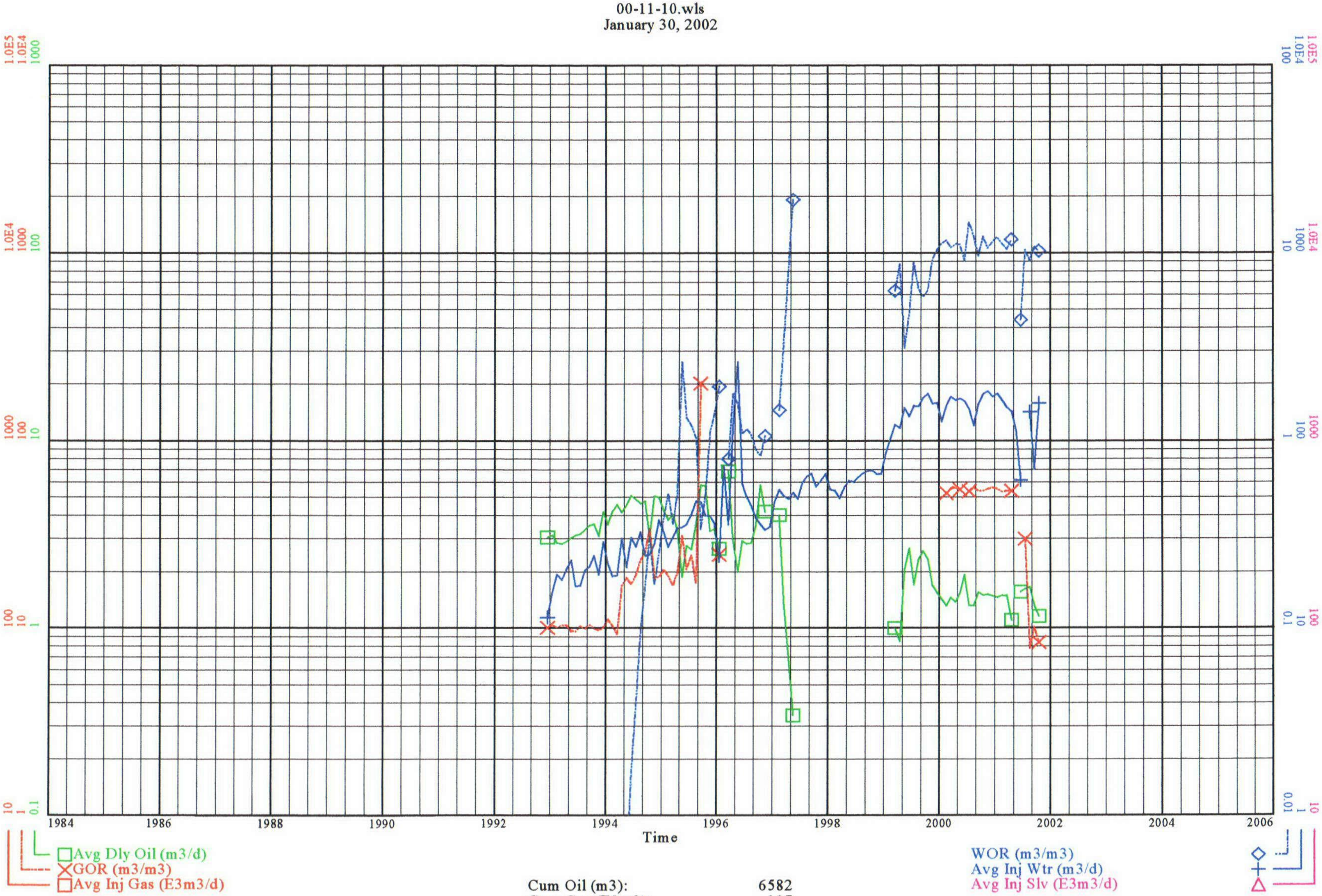
Figure A3



Vikor Energy Inc.

Medicine Hat Glauconitic C Pool
Pilot vertical well (12-10) southwest of injector

Figure A4



Cum Oil (m3): 6582
Cum Gas (E3m3): 127
Cum Wtr (m3): 15869

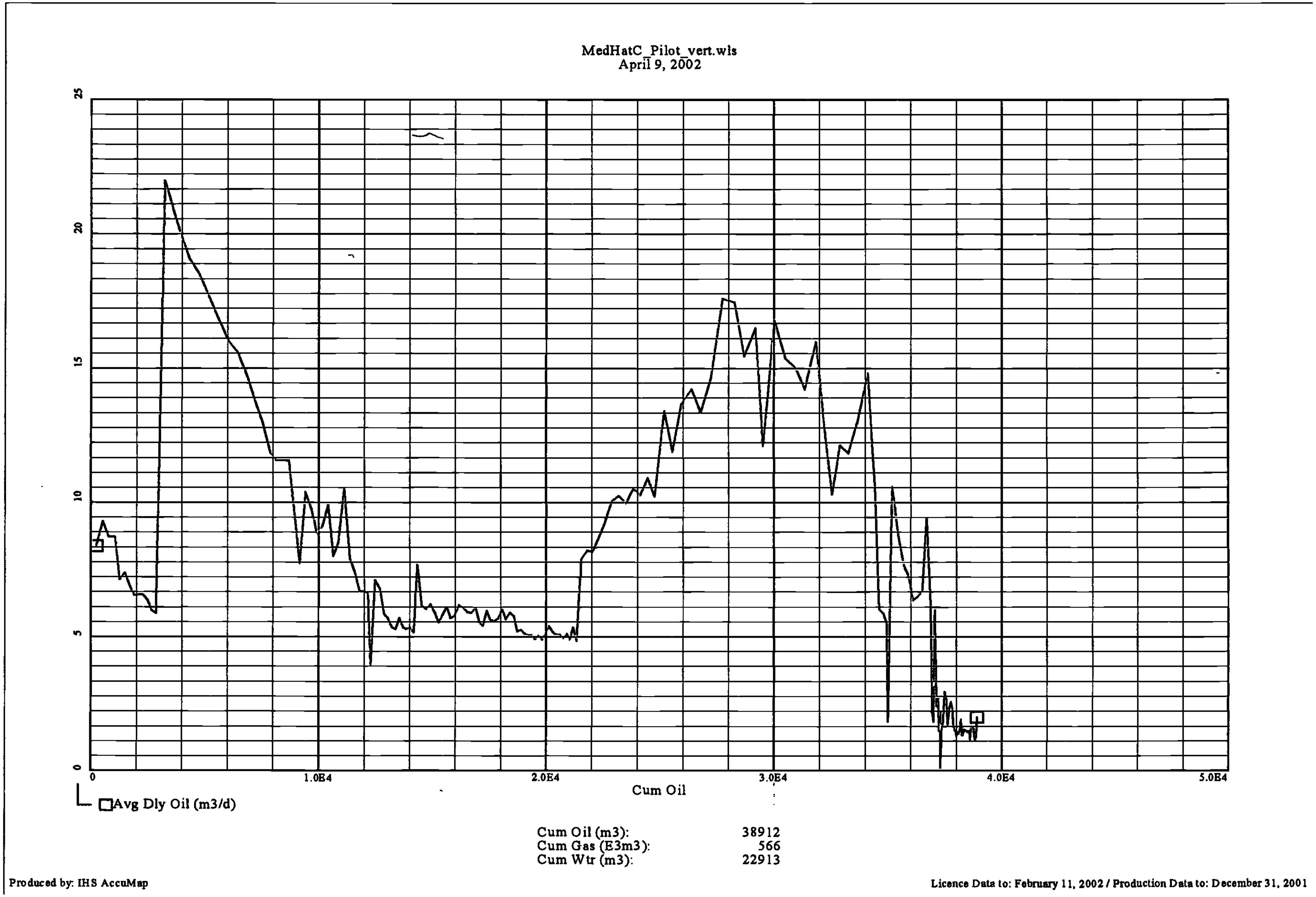
Produced by: IHS AccuMap

Licence Data to: December 12, 2001 / Production Data to: October 31, 2001

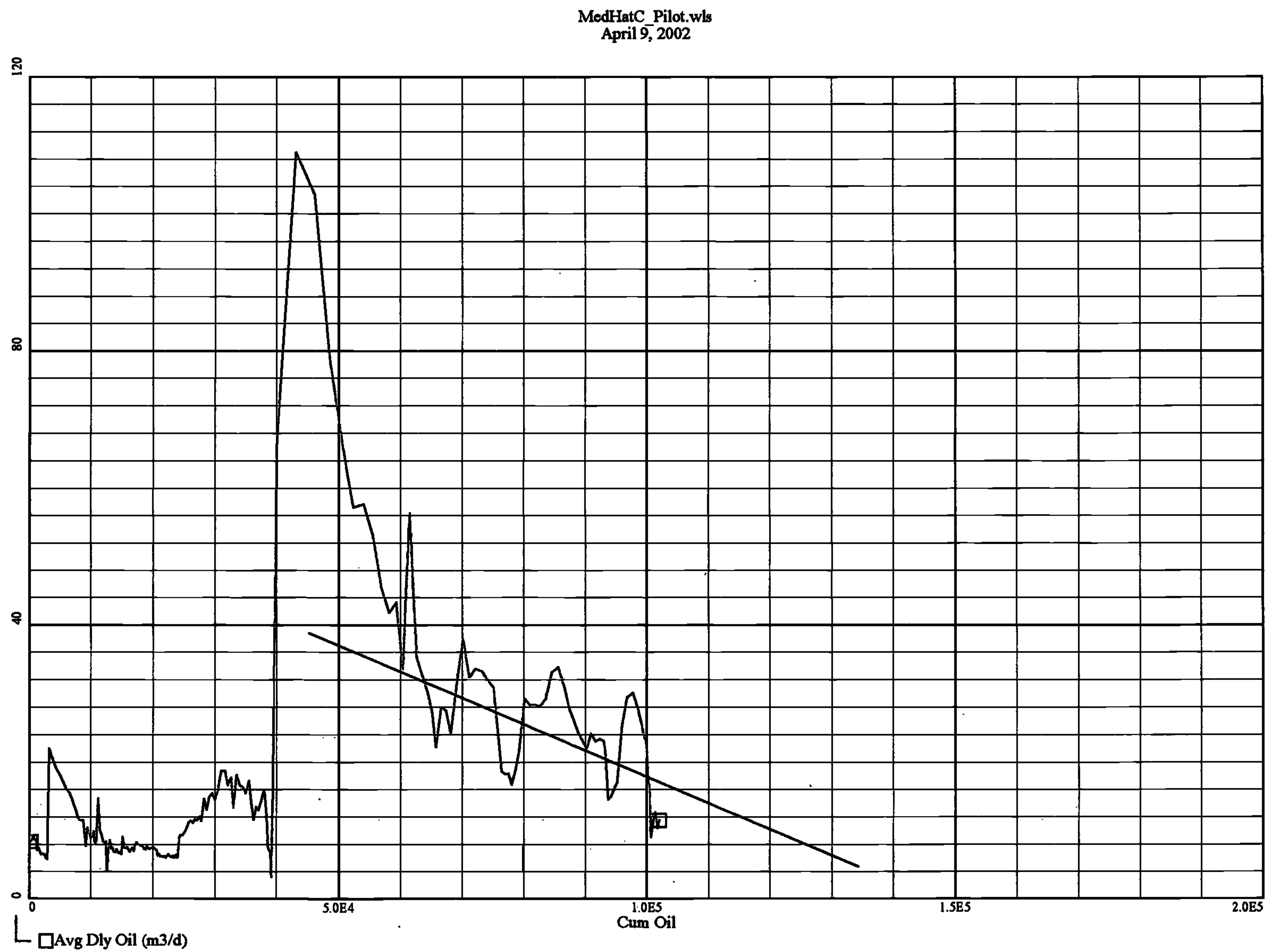
Vikor Energy Inc.

Medicine Hat Glauconitic C Pool
Pilot vertical well (11-10) southeast of injector

Figure A5



Vikor Energy Inc. Performance of Waterflood Pilot, Vertical Wells Figure A6

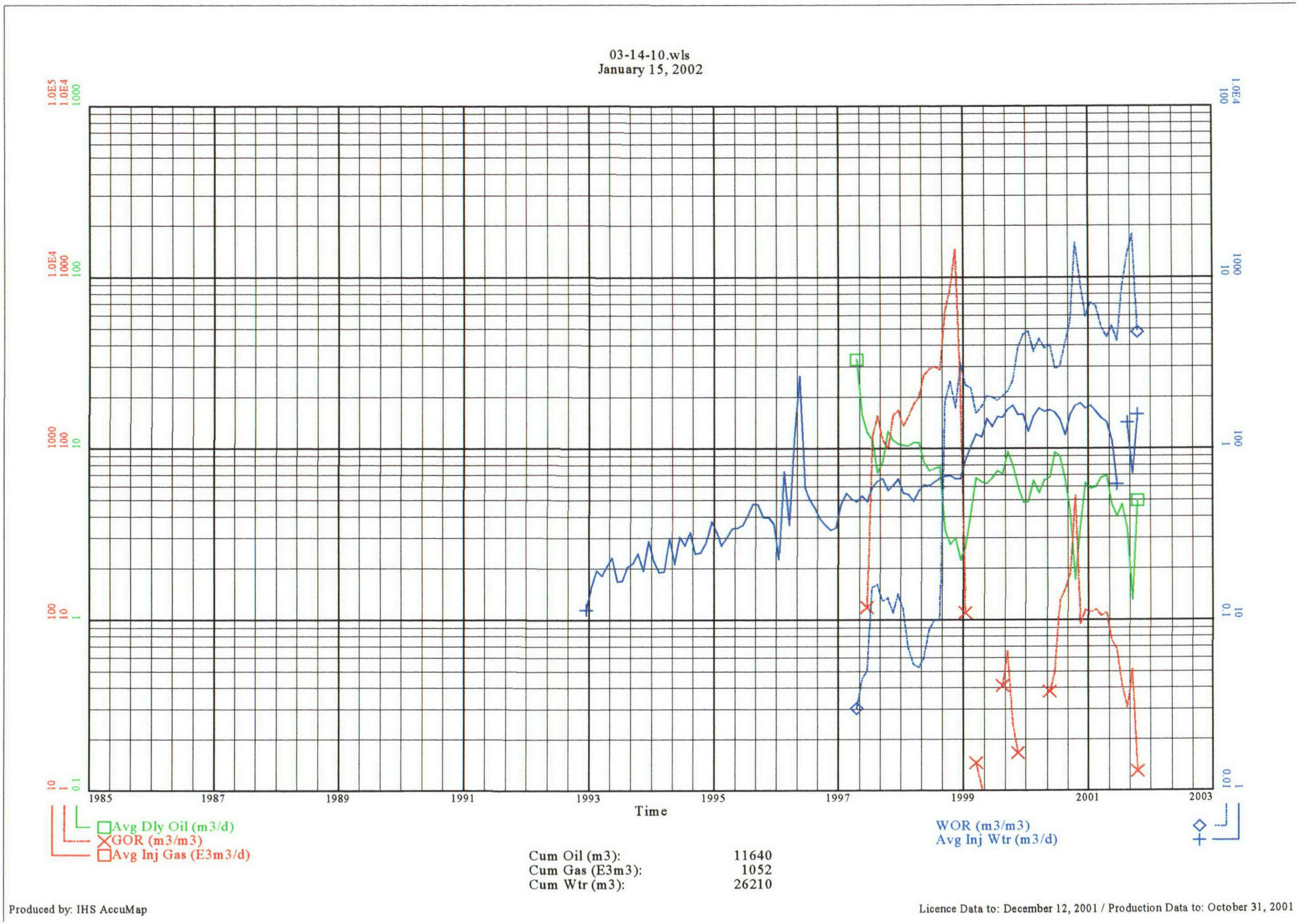


Cum Oil (m3):	101993
Cum Gas (E3m3):	4551
Cum Wtr (m3):	133726

Produced by: IHS AccuMap

Licence Data to: February 11, 2002 / Production Data to: December 31, 2001

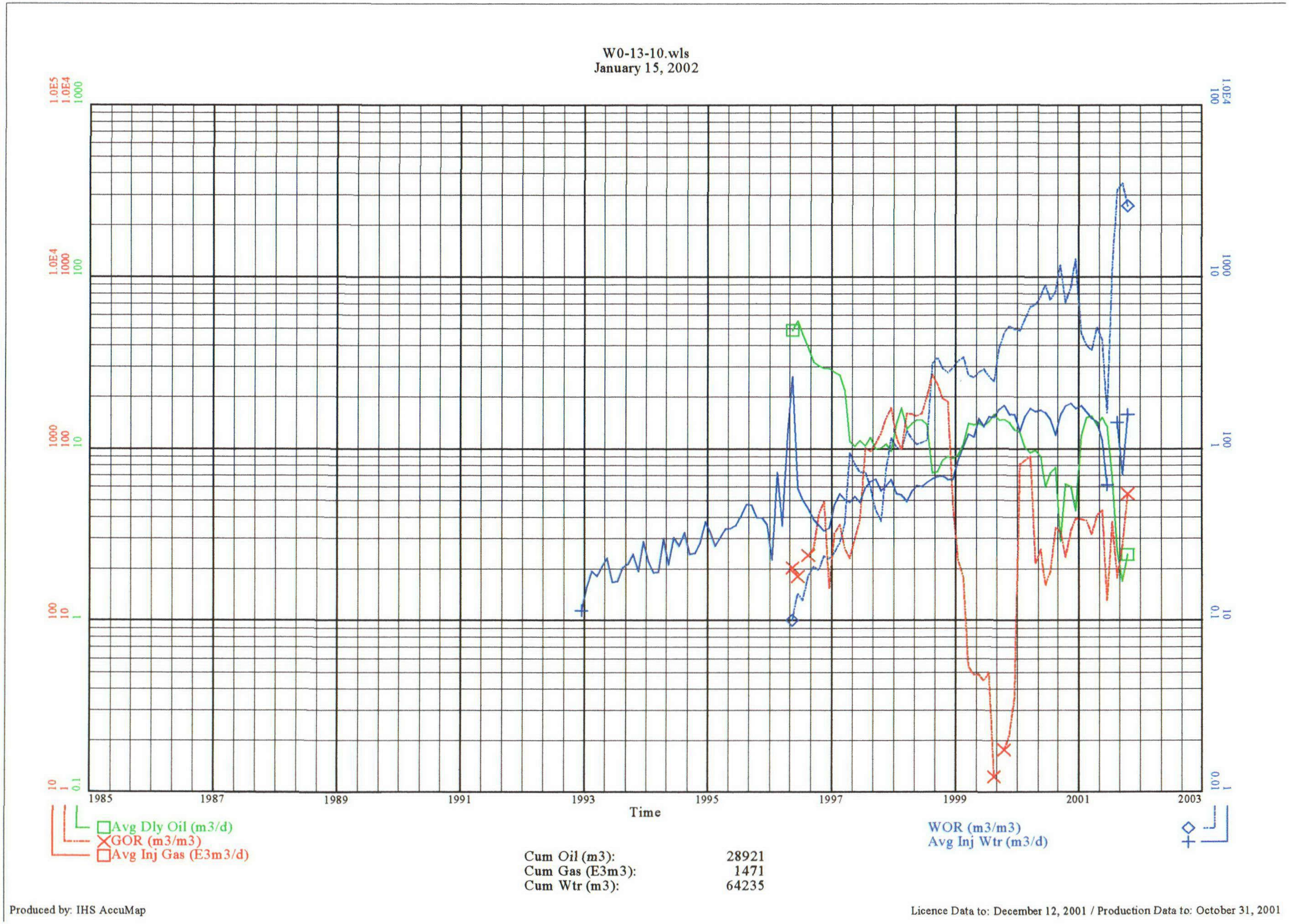
Vikor Energy Inc. Performance of Waterflood Pilot, All Wells Figure A7



Vikor Energy Inc.

Medicine Hat Glauconitic C Pool
Pilot horizontal well (03/14-10) north of injector

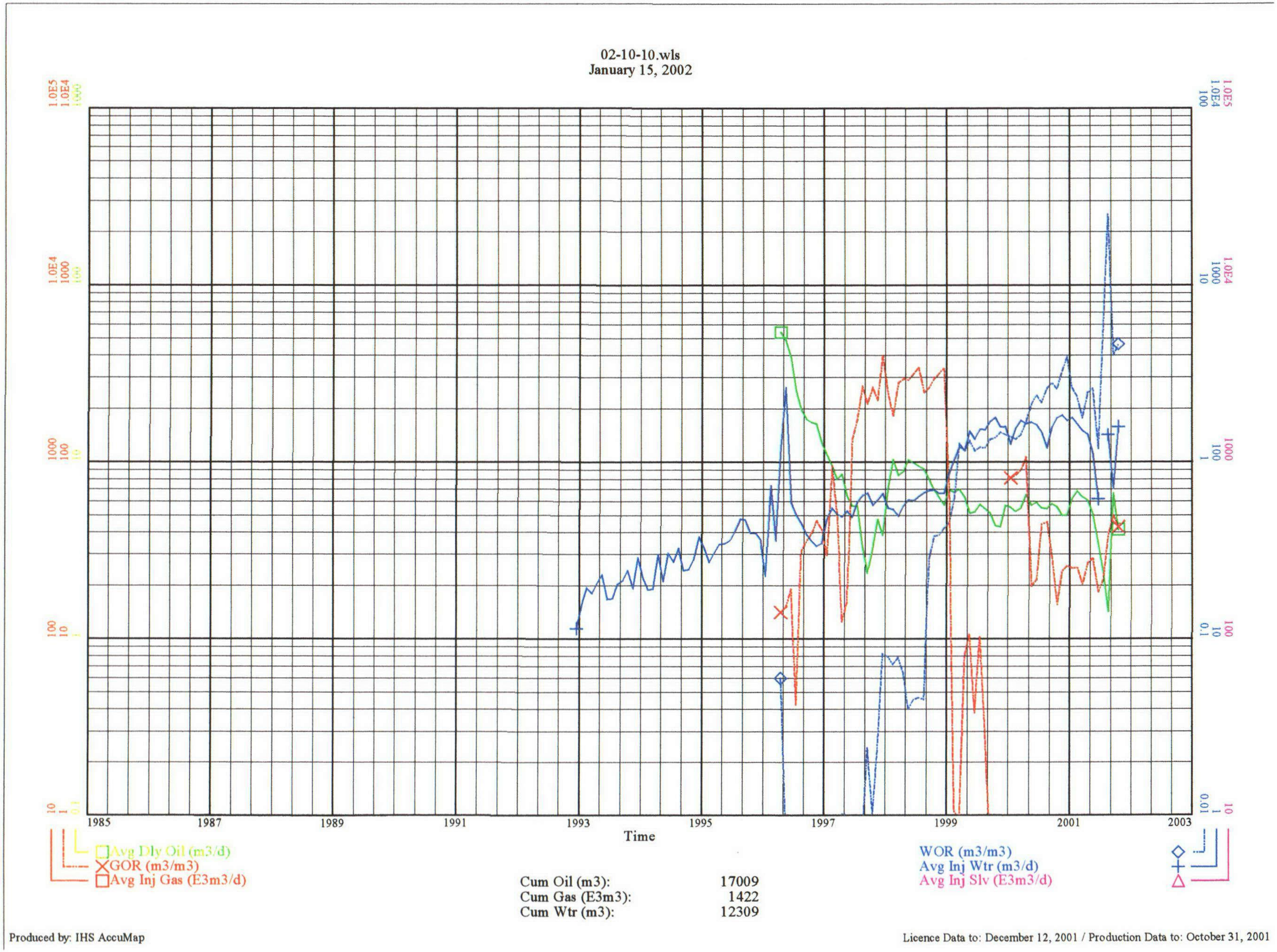
Figure A8



Vikor Energy Inc.

Medicine Hat Glauconitic C Pool
Pilot horizontal well (W0/13-10) west of injector

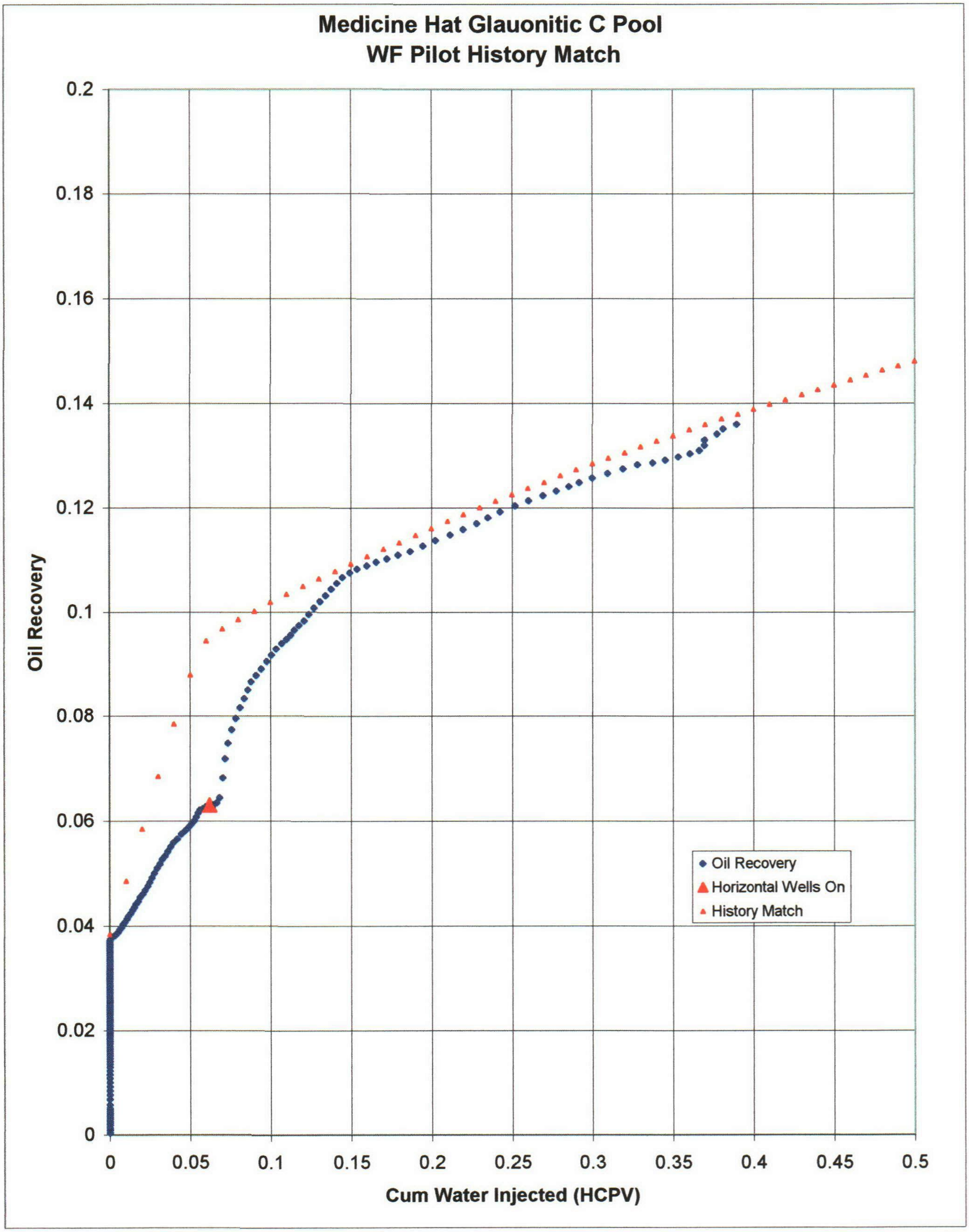
Figure A9

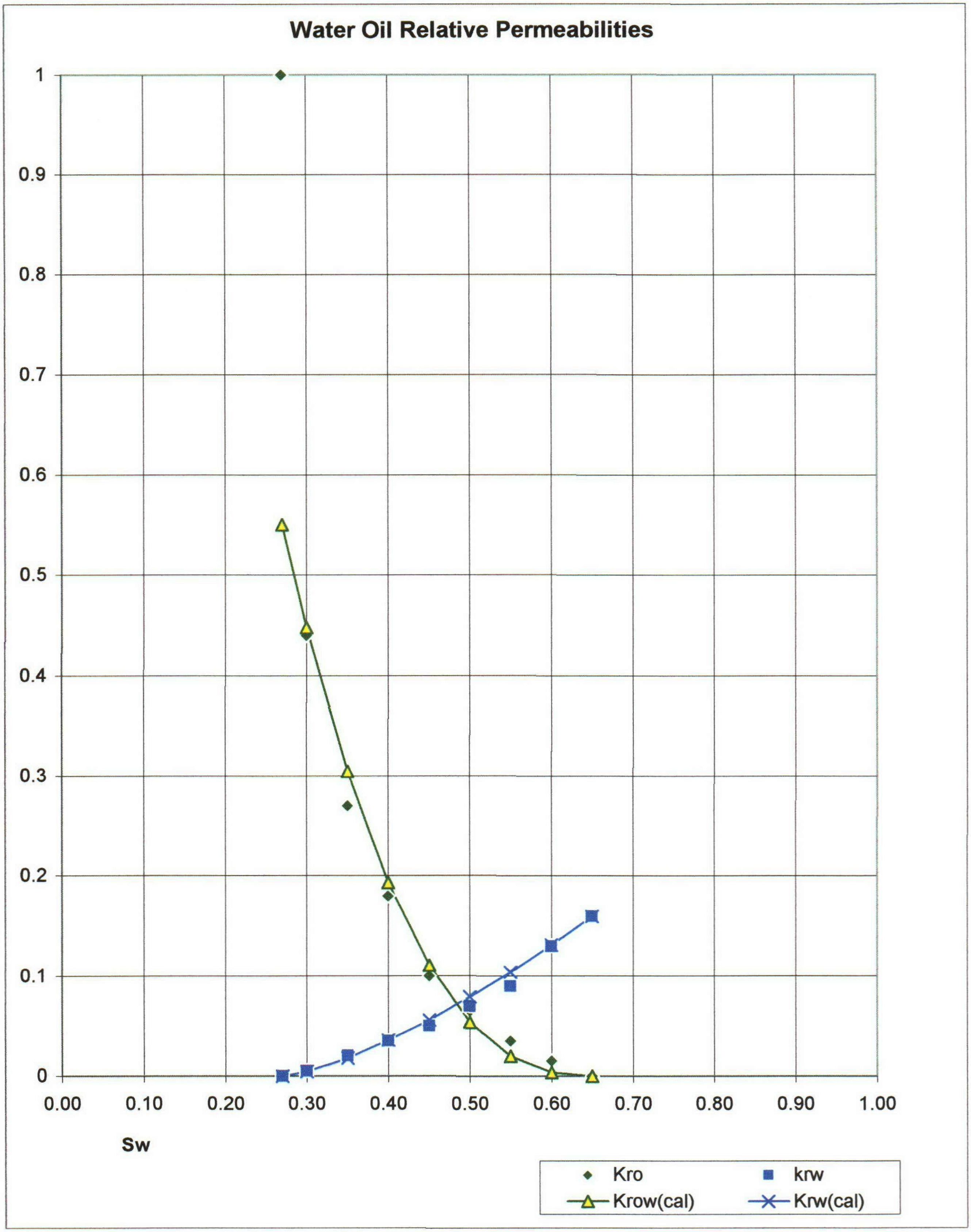


Vikor Energy Inc.

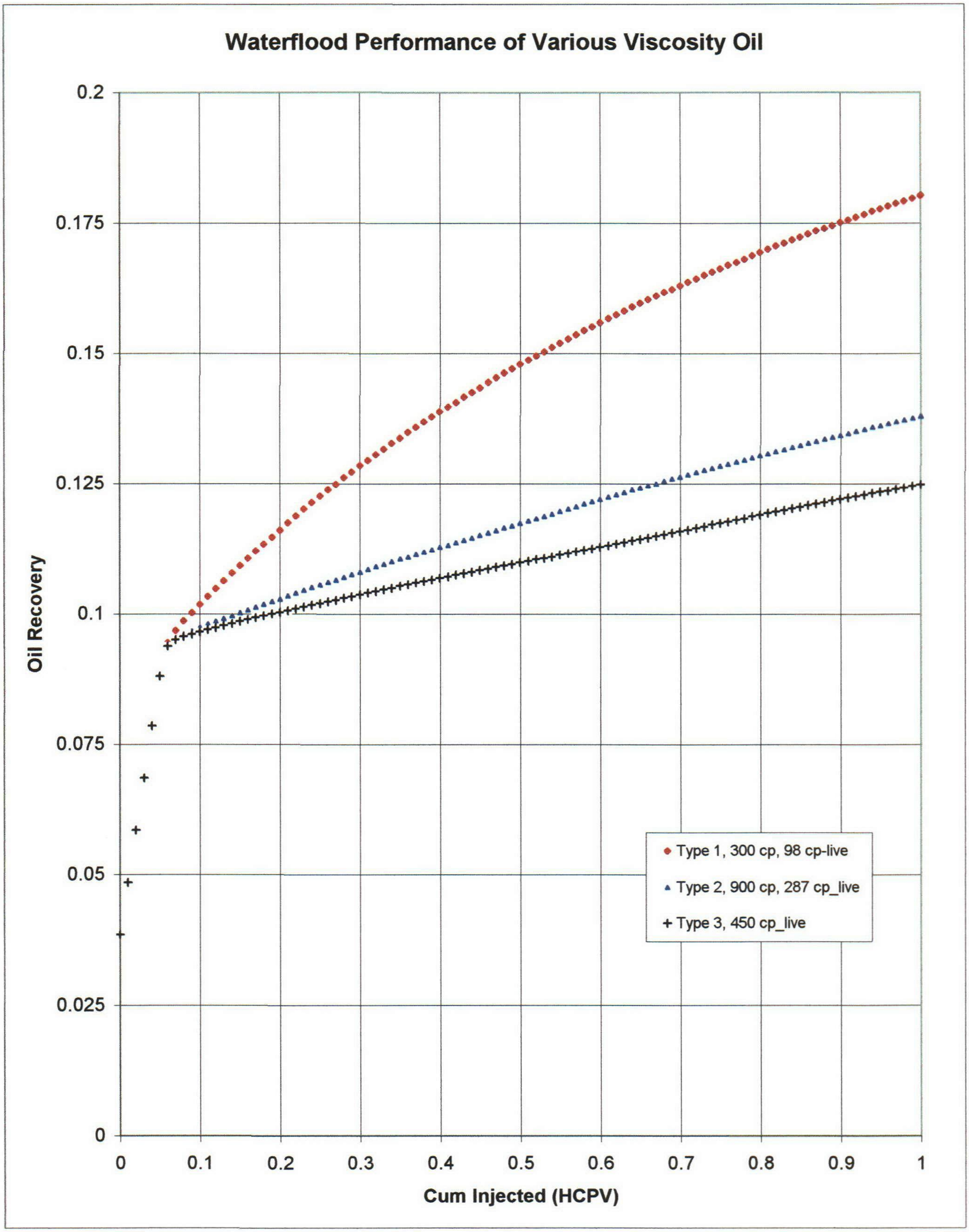
Medicine Hat Glauconitic C Pool
Pilot horizontal well (02/10-10) 1/2 mile south of injector

Figure A10


Medicine Hat Glauonitic C Pool
WF Pilot History Match
Oil Recovery
Cum Water Injected (HCPV)
0.2
0.18
0.16
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
0.05
0.1
0.15
0.2
0.25
0.3
0.35
0.4
0.45
0.5
Oil Recovery
Horizontal Wells On
History Match



Water Oil Relative Permeabilities
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0.00
0.10
0.20
0.30
0.40
0.50
0.60
0.70
0.80
0.90
1.00
Sw
Kro
krw
Krow(cal)
Krw(cal)



Waterflood Performance of Various Viscosity Oil
Oil Recovery
0.2
0.175
0.15
0.125
0.1
0.075
0.05
0.025
0
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Cum Injected (HCPV)
Type 1, 300 cp, 98 cp-live
Type 2, 900 cp, 287 cp_live
Type 3, 450 cp_live

Appendix B

Medicine Hat Glauconitic C Pool
CO_2 Flood Study

Appendix B Oil Displacement Process by CO_2 B1

I. CO_2 Medicine Hat Glauconitic C Oil Interaction B1

II. Immiscible CO_2 Flood Predictions B2
- A. Prophet Screening Model B2
- B. Sensistivity Cases B3
  - Case A - Waterflood of Original Oil B3
  - Case B - Waterflood of CO_2 Saturated Oil B4
  - Case C - CO_2 Injection Only in CO_2 Saturated Oil B4
  - Case D - Slug of CO_2 Inj. into CO_2 Saturated Oil, Followed by Water B5
  - Case E - Small Slug of CO_2 Injection into CO_2 Saturated Oil, Followed by Water B5
  - Case F - WAG Cycles of Small Slugs of CO_2 Injection into CO_2 Saturated Oil B5
  - Case G - Simultaneous Injection into CO_2 Saturated Oil B6
  - Case H - Simultaneous Water/CO_2 into CO_2 Saturated Oil with Oil Swelling Ignored B6

Tables:
- Table B1 Properties of CO_2 Saturated Oil (Simtech)
- Table B2 Properties of CO_2 Saturated Oil (Mungan)
- Table B3 Properties of CO_2 Saturated Oil for Three Oil Types

Figures:
- Figure B1 CO_2 Saturated Oil Viscosity vs. CO_2 Solubility
- Figure B2 Case A - Waterflood of Three Oil Types
- Figure B3 Case B - Waterflooding of CO_2Saturated Oil
- Figure B4 Case C - CO_2 Displacement of CO_2 Saturated Oil
- Figure B5 Case D - 0.2 HCPV CO_2 Injected, followed by water
- Figure B6 Case E - 0.1 HCPV CO_2 Injected, followed by water
- Figure B7 Case F - 2 WAG Cycles of 0.1 HCPV CO_2 Injection
- Figure B8 Case G - Simultaneous WAG into CO_2 Saturated Oil
- Figure B9 Case H - Simultaneous WAG into CO_2 Saturated Oil with Oil Swelling Ignored

Appendix B - Oil displacement Process by CO_2

The displacement of oil by CO_2 is strongly related to the phase behavior of the CO_2 oil mixture, which is related to the composition of oil, reservoir pressure and reservoir temperature. At high reservoir pressure and temperature, the CO_2 reacts with the oil through extraction of hydrocarbon from the oil by the CO_2. Under certain conditions, miscibility of CO_2 and crude oil is obtained when enough C_2-C_4 fractions are vaporized. At lower reservoir temperature (below 50 degree C), the vaporization of the crude oil is replaced by the condensation of CO_2 into the oil to form a CO_2-rich liquid. Under certain conditions, miscibility of CO_2 and crude oil can be obtained.

In the immiscible region of CO_2 and oil mixture, there would not be sufficient mass transfer between the CO_2 and the oil phase to form a miscible liquid. In this region, the mechanisms that contribute to increased oil recovery are swelling of crude oil, oil viscosity reduction and the energy from solution gas drive during the blow down phase. Medicine Hat Glauconitic C Pool oil falls in this region.

Depending on the reservoir temperature and pressure and the composition of the crude oil, significant amount of CO_2 could dissolve in oil. The solution of CO_2 could yield an increase in volume of as high as 40%. If we assume the residual oil to water is unchanged, the stock tank oil that remains in the reservoir will be correspondingly reduced by the inverse of the swelling factor. There would be an increase in oil recovery due to CO_2 swelling of oil.

As CO_2 dissolves in the oil, the viscosity of crude oil is significantly reduced. The reduction could be in the order of ten fold to one hundred fold of the original oil viscosity. The higher the original oil viscosity, the larger would be the percentage of viscosity reduction. The reduced viscosity improves the mobility of the oil and it would flow easier to the producer. Displacement of the CO_2 saturated oil by water would be more efficient due to the much improved mobility ratio.

I. Medicine Hat Glauconitic CO_2 - Oil Interaction

The benefits of CO_2 immiscible flood lie in the reduced viscosity of the oil and the swelling factor. The lower viscosity would improve the mobility of the heavy oil and make it easier to flow to the producer. The viscosity reduction is more significant for a more viscous oil than a less viscous oil. Viscosity reduction of 20 fold or more of the dead oil viscosity is not uncommon.

Though there is no laboratory measurement of the effect of CO_2 on Medicine Hat Glauconitic C Pool oil, there are two estimates done in the previous studies. Simtech did the first estimate and the data is duplicated in Table B1. The estimated was based on the correlations developed by Simon and Gaue. Dr. Nick Mungan did the second estimate, the data is shown in Table B2. The two estimates are similar at low pressure but Dr. Mungan's estimate predicts lower viscosity at high pressure. A CO_2 saturated oil viscosity versus CO_2 solubility plot is shown in Figure B1. It shows that the viscosity properties derived by Simtech and Dr. Mungan are similar, though Dr. Mungan predicts a slightly higher CO_2 solubility at the higher pressure. For the pressure range of this study (6 MPa to 8 MPa), the differences are quite small. Hycal developed a CO2 oil general correlation in 1988, with support of industry and AOSTRA. This correlation predicts a much more viscous oil and therefore predicts that CO_2 injection is less beneficial for the Glauconitic C Pool oil. This is probably because the original Hycal experimental data was based on a much more viscous oil. The Hycal correlations were not used for this study.

In this study, the CO_2 oil properties developed by Simtech was used for the light oil and new sets of properties were developed for the heavier oil, see Table B3. The properties were estimated base on the Simon and Gaue approach.

Depending on the crude oil characteristics, mixing CO_2 with crude oil could precipitate asphaltene. These phenomena have be observed in a number of laboratory measurement of Alberta and Saskatchewan heavy oil. However, it appears that no detrimental effect was observed either in the laboratory or in field operation.

II. Immiscible CO_2 Flood Predictions

In order to understand the effect of the different mechanism of the immiscible CO_2 displacement on the recovery of oil, a number of sensitivities runs were make using Prophet. These sensitivities are simple to run and since they do not have the geological and compositional complexity of a full numerical simulation model, it is easier to understand what is necessary to make an immiscible CO_2 flood work.

A. Prophet Screening Model

The Model is a three-phase stream-tube model that allows the displacement of oil by either water or a combination of CO_2 solvent and water. The model is strictly written for a CO_2 flood so the solvent properties are hardwired for CO_2 only. Oil and water properties, such as density, viscosity and formation volume factors are input by the user. In conjunction with specified reservoir temperatures and pressures, the reservoir oil density is estimated by using input shrinkage and stock tank oil density. The calculated oil, water, CO_2 density and viscosity are displayed in the output table. Being a stream-tube model, Prophet runs at constant pressure, thus the voidage replacement ratio is assumed to be one at all time. The program allows free CO_2 to flow in the reservoir but since it is not a compositional model, CO_2 does not dissolve into the oil during the run. The effect of CO_2 on the oil viscosity and swelling is manually adjusted in the run.

The flow efficiency is governed by relative permeability curves. The effect of CO_2 viscous fingering and gravity instability is simulated by a mixing parameter. For the immiscible mode, a gas flood residual oil can be assigned. A gas residual saturation to oil can also be assigned. Reservoir heterogeneity is handled by using a Dykstra-Parsons coefficient factor (VDP). The higher the Dykstra-Parsons coefficient, the more heterogeneous the reservoir. The model can have up to 10 layers but migration between the layers in the reservoir due to gravity effect is not simulated.

The model can be configured into several common pattern types such as 5 spot, 7 spot, 9 spot, line drive, etc. A custom irregular injector-producer configuration can be input if desired. Stream-tubes are constructed by the model for calculation of breakthrough time and fluid saturation between the injector and producers.

The model can be run in waterflood mode or in a CO_2 mode with different WAG schedule. Up to four injection schedules can be accommodated. This allows the testing of different WAG strategy for optimization purpose. Injection rates are input in standard surface conditions.

Initial oil saturation can be input to simulate various stages of reservoir depletion and the result of the simulation can be reported monthly, quarterly or yearly. The output table consists of rate and cumulative production data for all the fluids involved on a time basis.

B. Sensitivity Cases

1. Case A - Waterflood of Original Oil

In this sensitivity case, the effect of oil viscosity of Medicine Hat Glauconitic C oil was evaluated. The pool contains a spectrum of oil gravity and viscosity and it would be impossible to simulate all of them. Three oil type viscosities were evaluated for this sensitivity. The viscosities are 98 cp, 287 cp, and 450 cp. They represent the viscosities of the original live-oil viscosity of 60 cp (Type 1), 257 cp (Type 2),and 500 cp (Type 3) depleted to 5,000 kPa. The oil was waterflooded by the injection of one HCPV of water.

The waterflood efficiencies of these three oil types are shown in Figure B2. As expected, it can be seen that the recovery of oil is a function of oil viscosity and the recovery factors range from 18 % for the lighter oil (Type 1) to 12 % for the heavier oil (Type 3) after one HCPV of water injection.

2. Case B – Waterflood of CO_2 Saturated Oil

In this sensitivity case, the three oil types used in Sensitivity Case A were assumed to have the viscosity of the CO_2 saturated oil. The viscosities were reduced from 98 cp, 287 cp and 450 cp to 14 cp, 20 cp and 25 cp respectively. The oil was waterflooded by the injection of one HCPV of water.

In Figure B3, the performance of the waterflood of the original oil and CO_2 saturated oil for the lighter oil (Type 1) and the heavier oil (Type 3) is compared. The heavier oil, though with a lower recovery factor of 28% at CO_2 saturated condition, has a more dramatic incremental improvement of 20%, when compared with the improvement value of 17.5% for the lighter oil.

3. Case C - CO_2 Injection Only in CO_2 Saturated Oil

In this sensitivity case, one HCPV of CO_2 was injected into the CO_2 saturated oil. Type 2 oil was used for this case.

The recovery of the CO_2 only injection, as plotted in Figure B4, is only 57% of the waterflood at one HCPV injected. The result demonstrates that for the immiscible CO_2 flood, the injected CO_2 is a much less efficient displacing fluid than water. Though CO_2 is crucial in reducing the viscosity of oil, it is ineffective in driving the oil to the producers because the CO_2 injection is similar to a gas flood with a very adverse mobility ratio. Therefore, for a successful immiscible CO_2 flood, it is crucial that water is injected to displace the CO_2 saturated oil.

4. Case D - Slug of CO_2 Injection into CO_2 Saturated Oil, Followed by Water

In this sensitivity case, a CO_2 slug of 20% HCPV was injected into the Type 2 CO_2 saturated oil, followed by 0.8 HCPV of water. The slug size selected is similar to those actually used for the Retlaw Upper Mannville V Pool CO_2 flood.

The result of this sensitivity case, plotted in Figure B5, showed that after the injection of a 20% HCPV slug of CO_2, the performance is very similar to the result from the strictly gas injection in Sensitivity Case C. The follow-up water injection did not appear to return the reservoir to the efficiency of the pure waterflood. Injection of a large slug of CO_2 followed by water is not an effective process.

5. Case E - Small Slug of CO_2 Injection into CO_2 Saturated Oil, Followed by Water

In this sensitivity case, a CO_2 slug of 10% HCPV was injected into the Type 2 CO_2 saturated oil, then followed by 90% HCPV of water. The CO_2 slug size selected is half of the slug size used in Sensitivity Case 4.

The result of this sensitivity case, plotted in Figure B6, showed that after the injection of a small slug of CO_2, the performance improve over the results obtained from using a larger slug size. This shows that beyond dissolving CO_2 into the reservoir oil, a large gas saturation of free CO_2 could reduce the oil recovery.

6. Case F – WAG Cycles of Small Slugs of CO_2 Injection into CO_2 Saturated Oil

This sensitivity case is an extension of Sensitivity Case E. The 10% HCPV CO_2 slug used in Sensitivity Case 5 was followed by a 10% HCPV of water to complete a WAG cycle. Two WAG cycles were used for this sensitivity case.

The result of this sensitivity case showed improved performance using a WAG process. It improves the performance of the process above the single slug of CO_2 followed by a waterflood approach. A comparison of the performances is shown in Figure B7.

7. Case G - Simultaneous Injection into CO_2 Saturated Oil

This sensitivity case used simultaneous water/CO_2 injection of CO_2 and water into Type 2 oil. Two water/CO_2 ratios, one at unity and another at four were used. The cumulative injection is one HCPV.

The result showed that the performance of the simultaneous unity water/CO_2 injection is slightly better than the 10% HCPV slug WAG obtained in Sensitivity Case F. It also showed that a wetter ratio of 4 has performance approaching the waterflood performance on lower viscosity oil (Figure B8).

8. Case H - Simultaneous water/CO_2 into CO_2 Saturated Oil with Oil Swelling Ignored

In all the previous cases, CO_2 was assumed to be fully saturated in the oil, resulting in a reduction of reservoir oil viscosity. The oil swelling factor is close to 20% at the 8,000 kPa operating condition. This swelling factor reduces the amount of original oil left in the reservoir. In this sensitivity case, the effect of this 20% swelling factor is investigated.

A plot of the results shown in Figure B9 shows the performance of CO_2 floods with and without the benefit of the oil swelling by CO_2. The incremental oil production due to oil swelling at 150% HCPV total injection at a water/ CO_2 ratio of four is less than 4%, compared to the improvement of 20% by oil viscosity reduction.

As a result of the sensitivity analysis the CO_2 flood performance was predicted assuming a high water / CO_2 ratio simultaneous injection strategy with 20% oil swelling and a viscosity reduction of between 7 and 18 fold for a fully CO_2 saturated oil.

Table B1

Properties of CO_2 Saturated Oil

Based on Simtech Interpretation

Pressure (kPa)	GOR (m3/m3)	FVF (Rm3/m3)	Bg (Rm3/M3)	Oil Visc. cp
101	1.8	1.093	1.0899	257
2000	25.0	1.137	0.0516	77
4000	48.0	1.191	0.0230	31
6000	65.0	1.246	0.0121	21
8000	78.0	1.266	0.0063	14
10000	90.0	1.290	0.0028	13

Data based on Simtech Study, July 1991

Table B2

Properties of CO_2 Saturated Oil

Based on Dr. Mungan's Interpretation

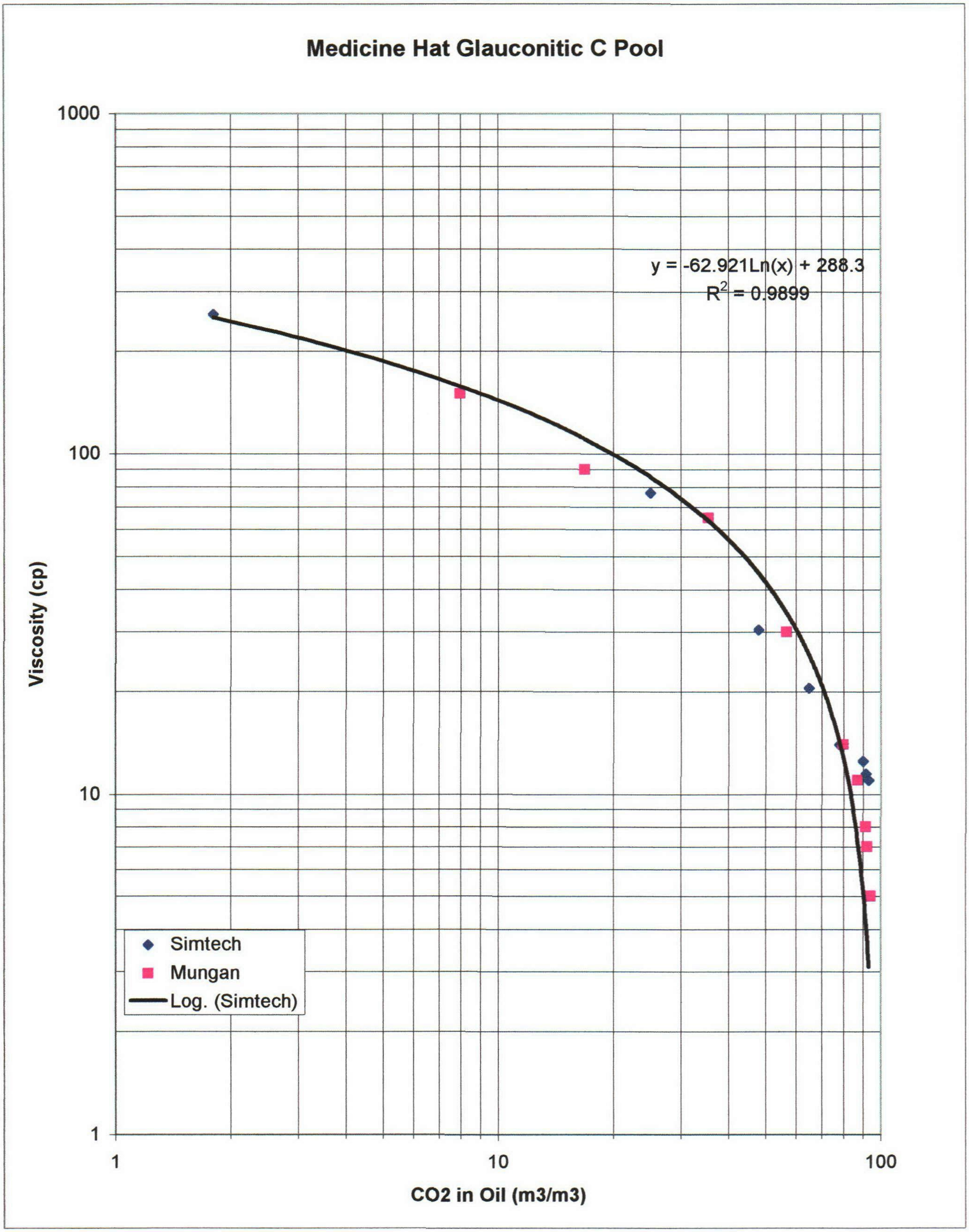
Pressure (kPa)	GOR (m3/m3)	Swelling Factor (m3/m3)	Oil Visc. cp
680	8.0	1.012	150
1379	16.8	1.025	90
2068	26.6	1.050	80
2758	35.5	1.060	65
3447	46.1	1.070	45
4136	56.7	1.117	30
4826	67.4	1.125	20
5515	79.8	1.170	14
6205	84.2	1.200	12
6894	86.9	1.230	11
7584	89.5	1.250	9
8273	91.3	1.270	8
8963	92.2	1.300	7
10342	94.0	1.350	5

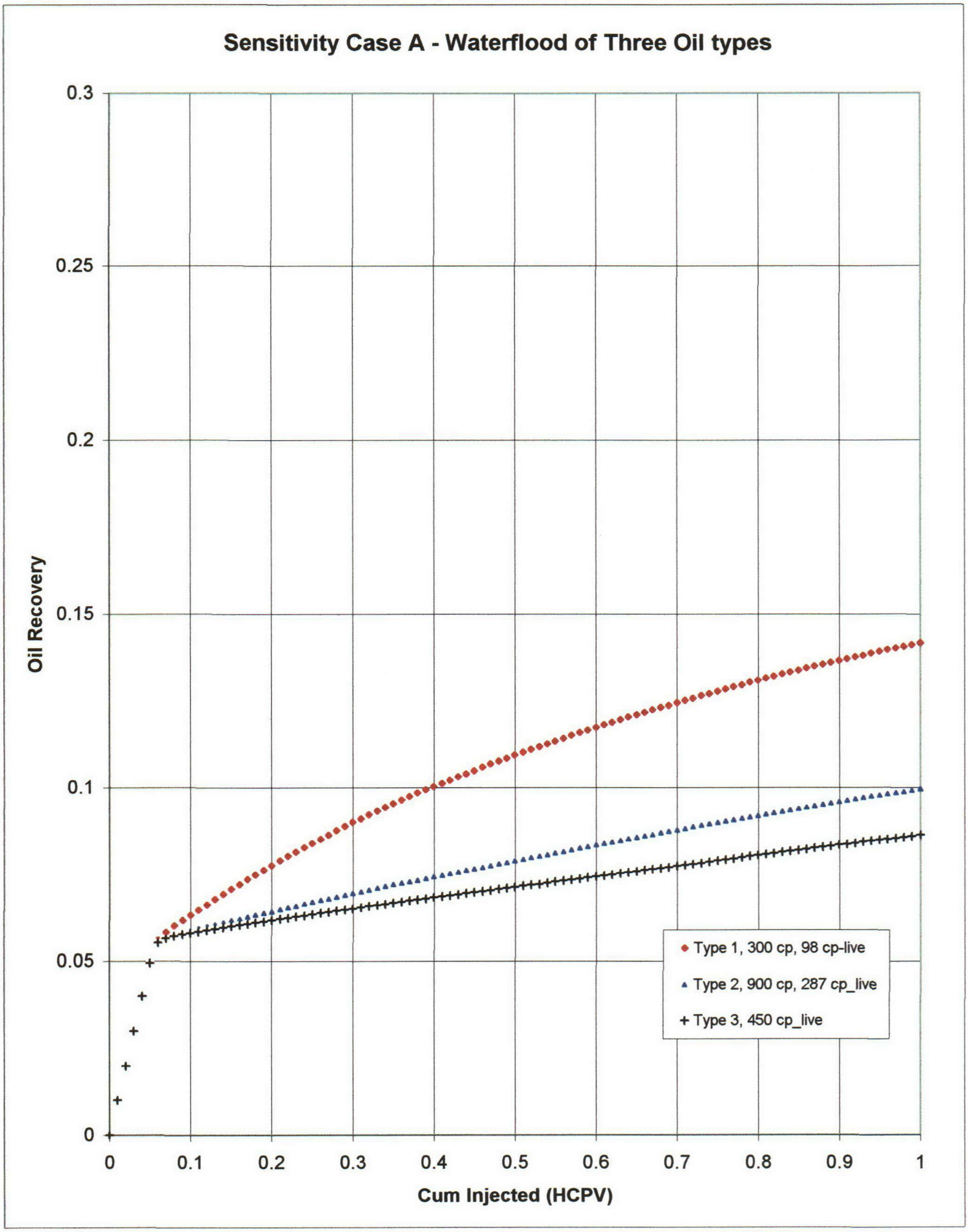
Data based on report by Mungan Petroluem Consultants Ltd., December 16, 1997

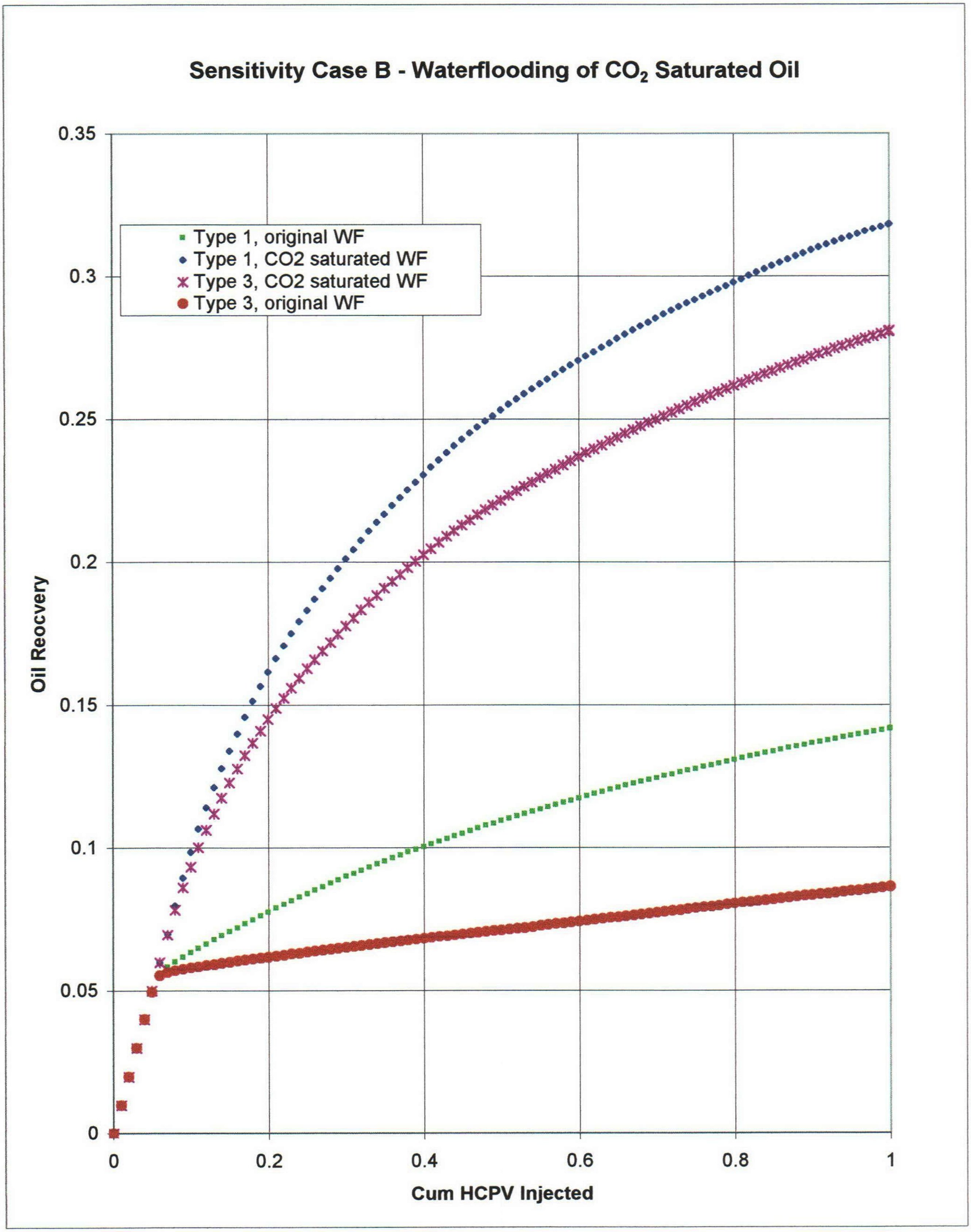
Table B3

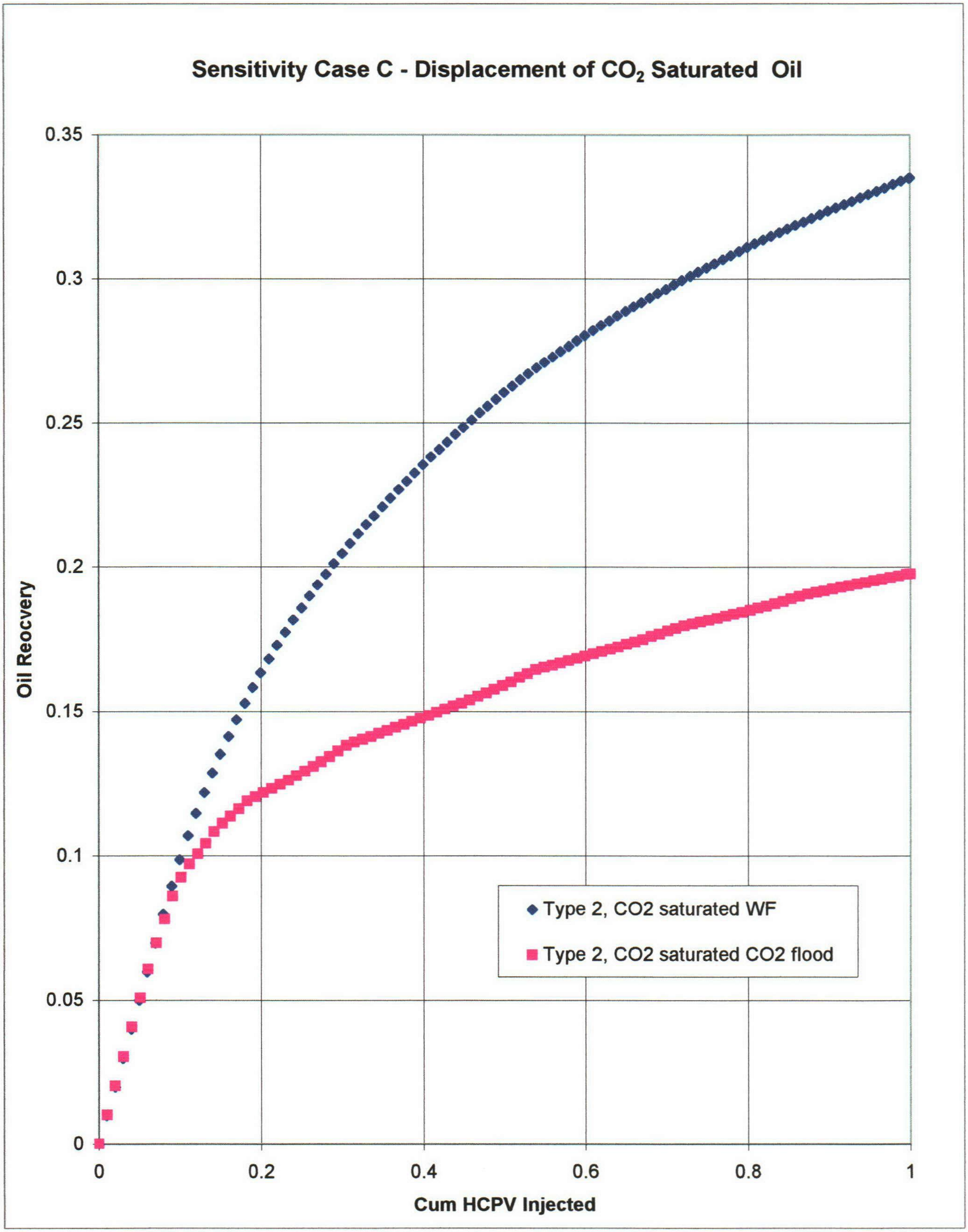
Properties of CO_2 Saturated Oil for Three Oil Types

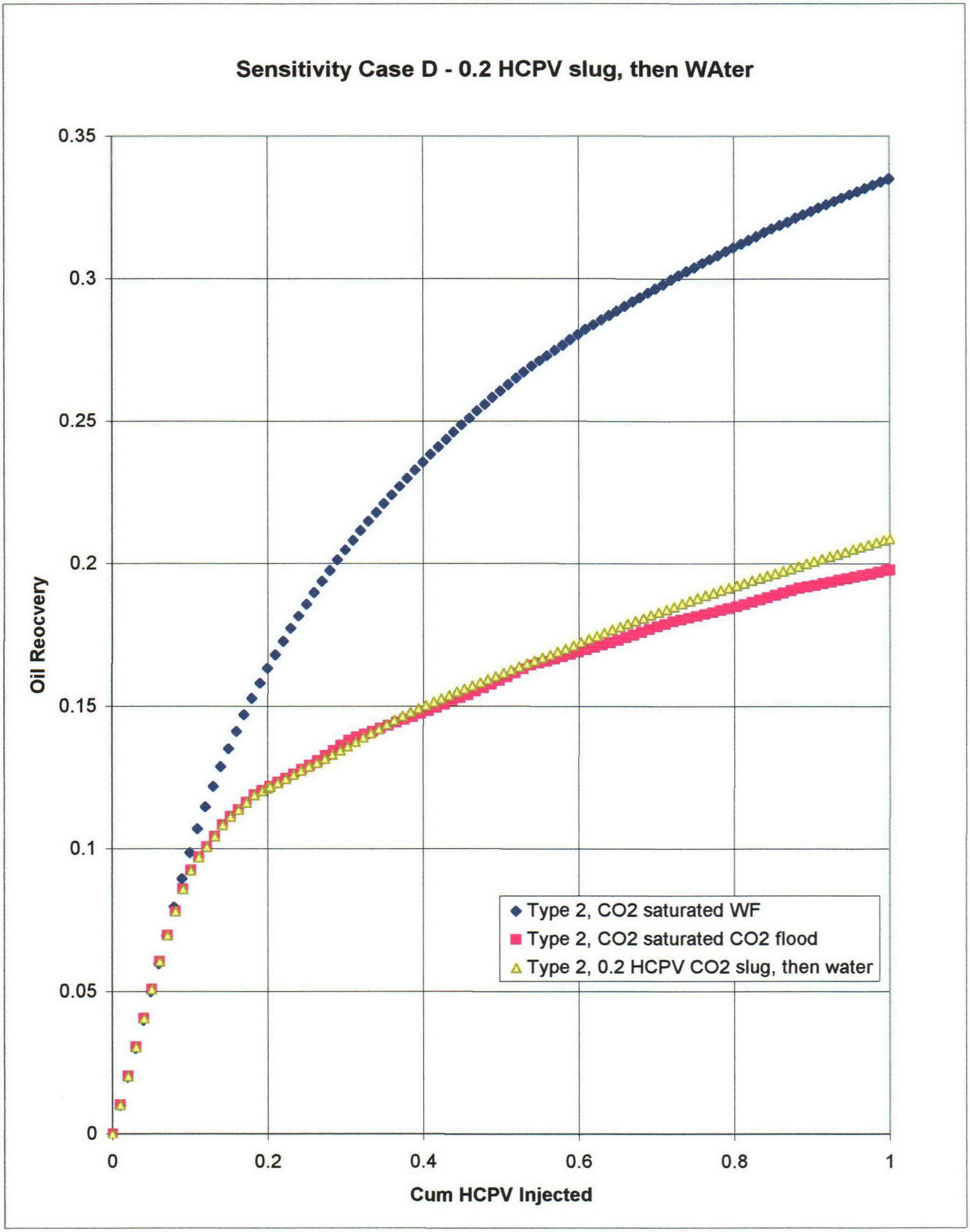
	Pressure (kPa)	Oil Visc. cp
Type 1 Oil (no CO2)	8,000	98
Type 1 Oil (fully saturated)	8,000	14
Type 1 Oil (half saturated)	8,000	49
Type 2 Oil (no CO2)	8,000	287
Type 2 Oil (fully saturated)	8,000	20
Type 2 Oil (half saturated)	8,000	60
Type 3 Oil (no CO2)	8,000	450
Type 3 Oil (fully saturated)	8,000	25
Type 3 Oil (half saturated)	8,000	70
Type 1 Oil (no CO2)	6,000	98
Type 1 Oil (fully saturated)	6,000	20
Type 1 Oil (half saturated)	6,000	62
Type 2 Oil (no CO2)	6,000	287
Type 2 Oil (fully saturated)	6,000	25
Type 2 Oil (half saturated)	6,000	72
Type 3 Oil (no CO2)	6,000	450
Type 3 Oil (fully saturated)	6,000	30
Type 3 Oil (half saturated)	6,000	82

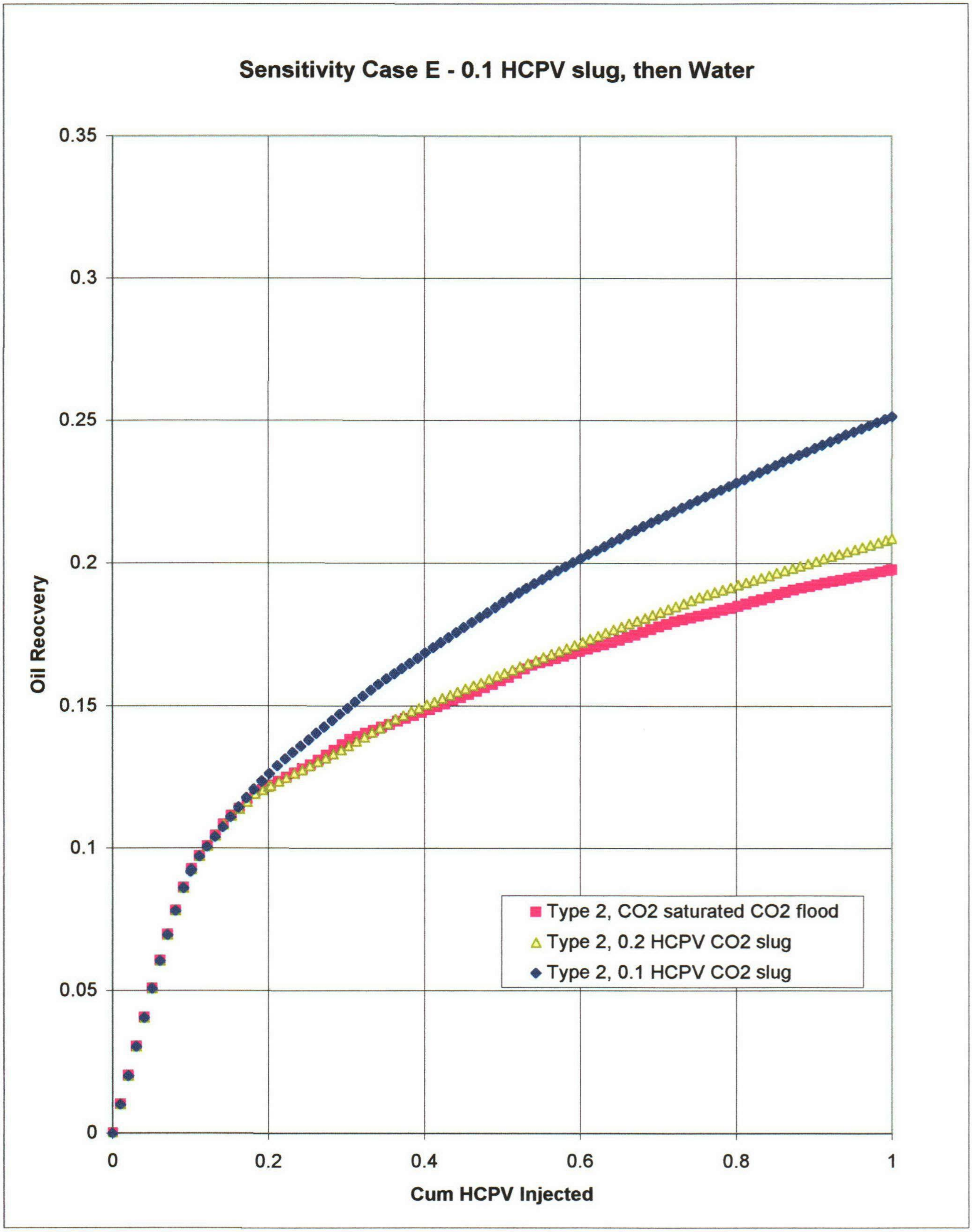

Medicine Hat Glauconitic C Pool
y = -62.921Ln(x) + 288.3
R2 = 0.9899
Viscosity (cp)
CO2 in Oil (m3/m3)
1000
100
10
1
1
10
100
Simtech
Mungan
Log. (Simtech)

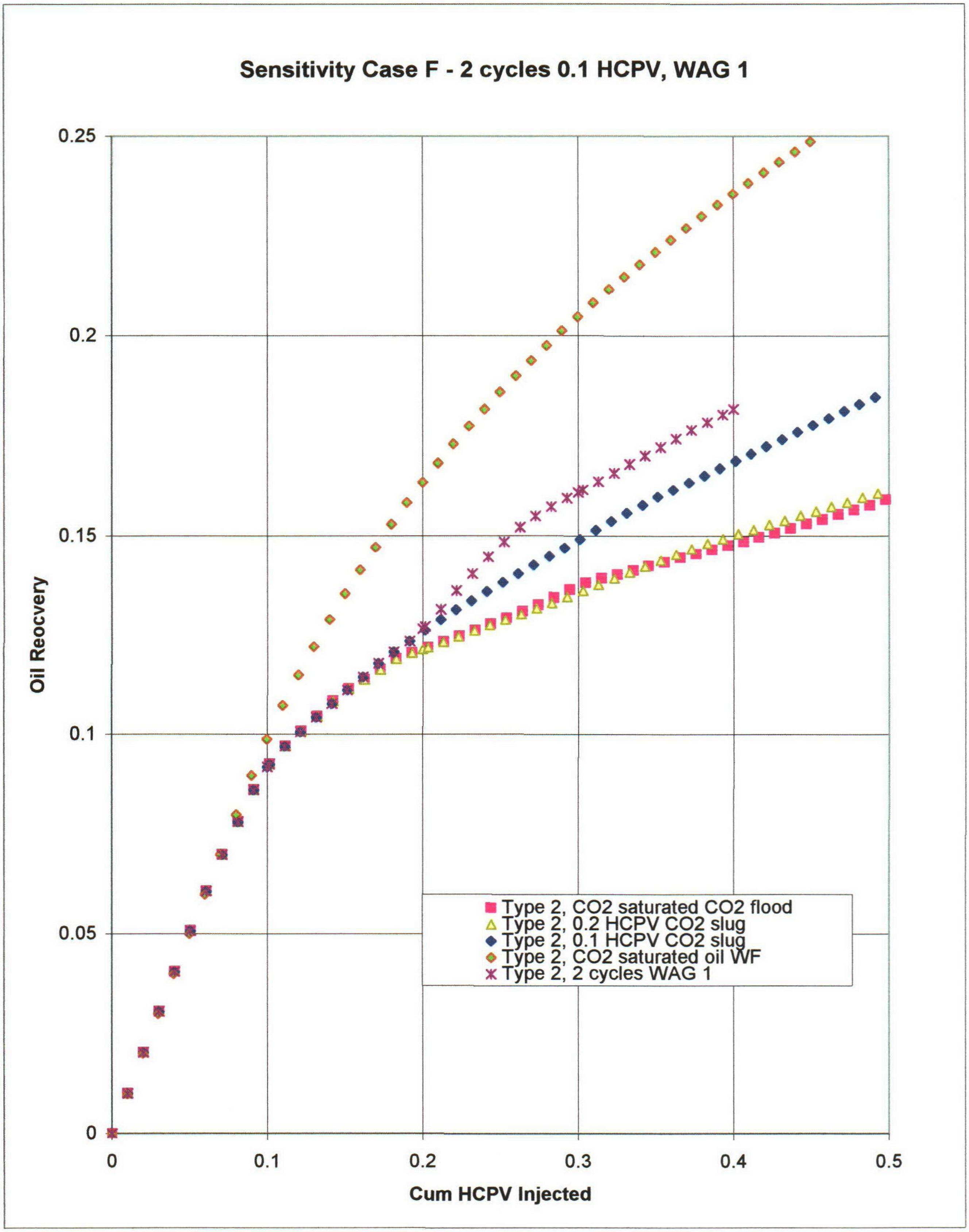

Sensitivity Case A - Waterflood of Three Oil types
0.3
0.25
0.2
0.15
0.1
0.05
0
Oil Recovery
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Cum Injected (HCPV)
Type 1, 300 cp, 98 cp-live
Type 2, 900 cp, 287 cp_live
Type 3, 450 cp_live


Sensitivity Case B - Waterflooding of CO_2 Saturated Oil
Type 1, original WF
Type 1, CO2 saturated WF
Type 3, CO2 saturated WF
Type 3, original WF
Oil Reocvery
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
0
0.2
0.4
0.6
0.8
1
Cum HCPV Injected

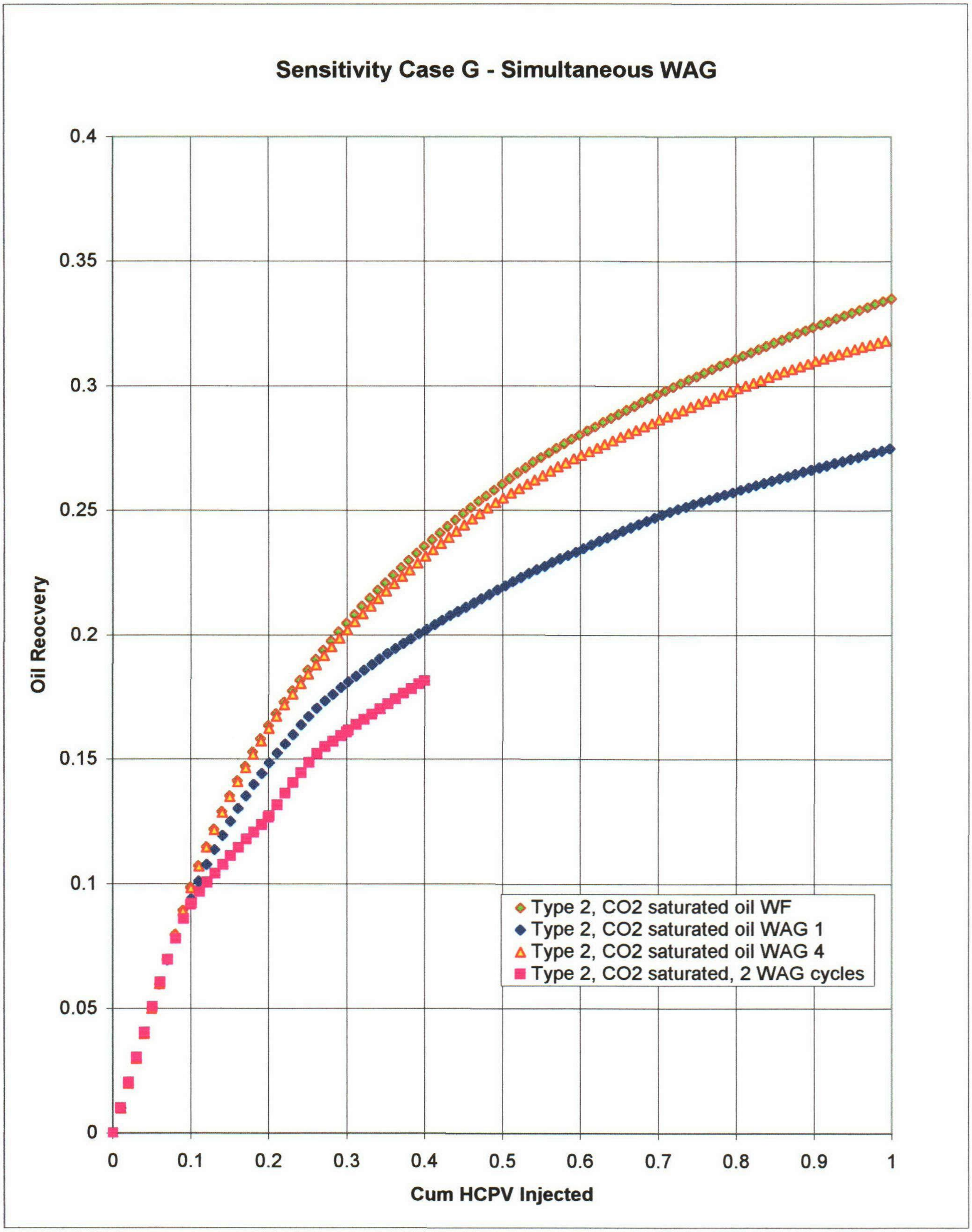

Sensitivity Case C - Displacement of CO2 Saturated Oil
Oil Reocvery
Cum HCPV Injected
Type 2, CO2 saturated WF
Type 2, CO2 saturated CO2 flood
0
0.05
0.1
0.15
0.2
0.25
0.3
0.35
0
0.2
0.4
0.6
0.8
1

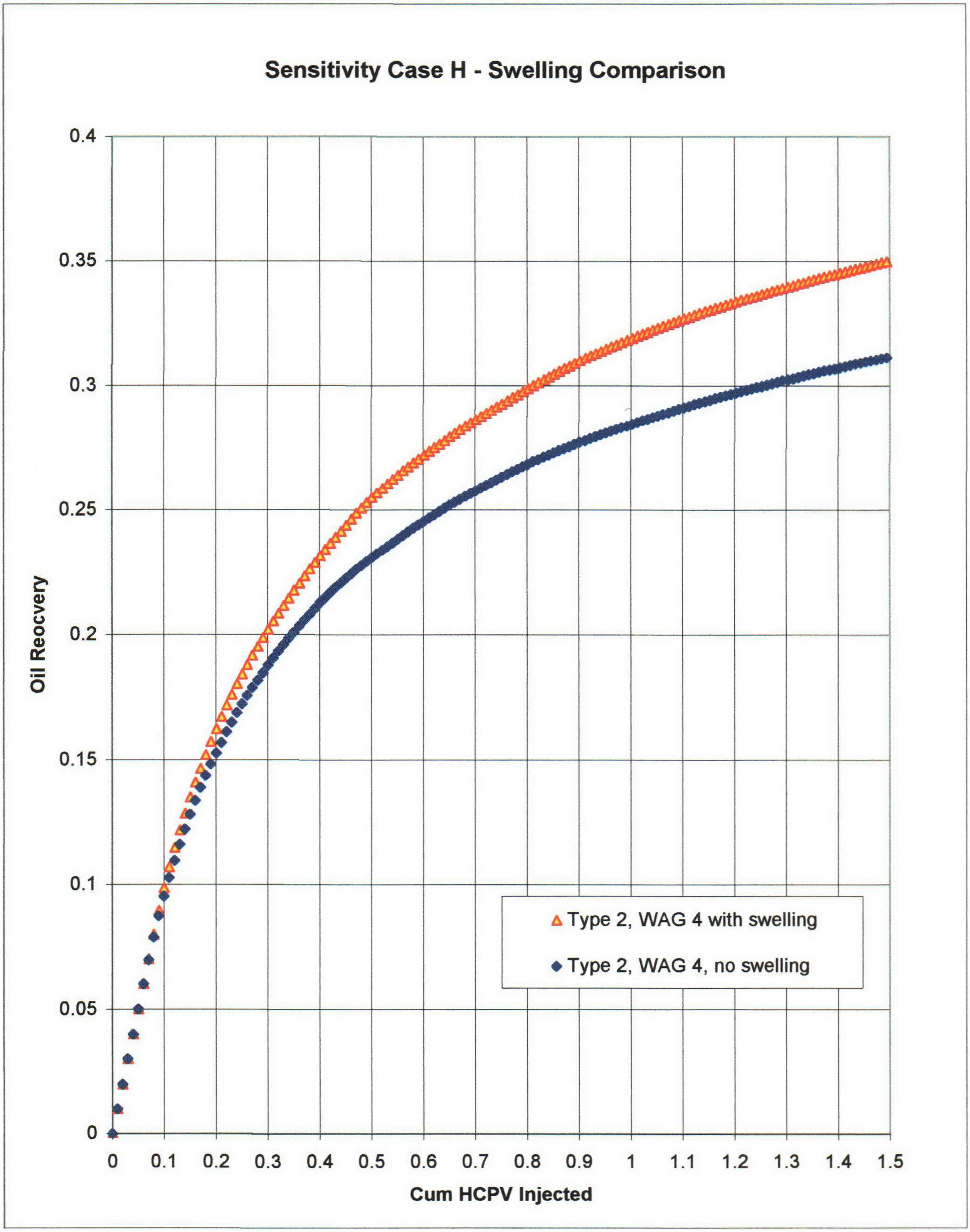

Sensitivity Case D - 0.2 HCPV slug, then WAter
Oil Reocvery
Cum HCPV Injected
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
0
0.2
0.4
0.6
0.8
1
Type 2, CO2 saturated WF
Type 2, CO2 saturated CO2 flood
Type 2, 0.2 HCPV CO2 slug, then water


Sensitivity Case E - 0.1 HCPV slug, then Water
Oil Reocvery
Cum HCPV Injected
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
0
0.2
0.4
0.6
0.8
1
Type 2, CO2 saturated CO2 flood
Type 2, 0.2 HCPV CO2 slug
Type 2, 0.1 HCPV CO2 slug



Sensitivity Case F - 2 cycles 0.1 HCPV, WAG 1
Oil Reocvery
Cum HCPV Injected
0.25
0.2
0.15
0.1
0.05
0
0
0.1
0.2
0.3
0.4
0.5
Type 2, CO2 saturated CO2 flood
Type 2, 0.2 HCPV CO2 slug
Type 2, 0.1 HCPV CO2 slug
Type 2, CO2 saturated oil WF
Type 2, 2 cycles WAG 1


Sensitivity Case G - Simultaneous WAG
Oil Reocvery
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Cum HCPV Injected
Type 2, CO2 saturated oil WF
Type 2, CO2 saturated oil WAG 1
Type 2, CO2 saturated oil WAG 4
Type 2, CO2 saturated, 2 WAG cycles


Sensitivity Case H - Swelling Comparison
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
Oil Reocvery
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
1.1
1.2
1.3
1.4
1.5
Cum HCPV Injected
Type 2, WAG 4 with swelling
Type 2, WAG 4, no swelling

Appendix C

Medicine Hat Glauconitic C Pool
CO_2 Flood Study

Appendix C Analog Pools C1

I. Medicine Hat Glauconitic H Pool C1
II. Retlaw Mannville V Pool C2

Tables: Table C1 Comparison of Glauconitic C and H Pools - Reservoir Properties

Figures: Figure C1 Medicine Hat Glauconitic H Pool
Figure C2 Performance of Medicine Hat Glauconitic H Pool
Figure C3 Retlaw Upper Mannville V Pool

Appendix C - Analog Pools

The Medicine Hat Glauconitic H Pool and Retlaw Upper Mannville V Pool are analog Glauconitic pools that could add to the understanding of the waterflood and CO_2 injection in the Medicine Hat Glauconitic C Pool.

I. Medicine Hat Glauconitic H Pool

The Medicine Hat Glauconitic H Pool (Figure C1), 30 kilometres northwest of the Glauconitic C Pool, initiated a waterflood in February 1999. The Glauconitic C Pool and the H Pool have many similar characteristics. In general, the Glauconitic H Pool is slightly deeper, thinner, slightly colder and about one tenth the OOIP of the Glauconitic C Pool. The initial pressure is very similar but the H pool contains more viscous (2000 cp) dead oil and has higher water saturation. A comparison of reservoir rock and fluid properties is tabulated in Table C1.

The Medicine Hat Glauconitic H Pool was discovered in 1996. The pool is a north trending channel sand body containing very fine to medium grained well-sorted sand with common shale interbeds. Permeability average approximately 1,000 md. The sand can be split into three cycles: the uppermost A sand of highest porosity and permeability, middle B sand and lower C sand of poor quality. Shale and tight intervals generally separate the cycles. In the thin basal bottom sand, all wells are wet except for wells (10-36, 9-36, 16-36-014-8W4M) and are located on a slight structure high. A and B sands contains 2,650 e^3m^3 (85% of the total OOIP of 3,090 e^3m^3).

The waterflood originally started with two injectors (5-36-014-8 and 5-31-014-7W4M) in the C sand only with the intention of utilizing a vertical bottom waterflood by taking advantage of the high horizontal permeability and low vertical permeability. The primary recovery estimate was 10.6% and waterflood was expected to add 6.3% recovery for a total of 16.7%.

The water injection initially did not meet expectation with low injection rate into the initial two wells. 02/1-36 horizontal well was recompleted into the B sand. Injection wells required fracturing before reasonable amount of water could be injected. Injection rate was ramped up in September 2001 to 400 m^3/d by adding two vertical injectors 5-31 and 6-31. The injection and production history of the Glauconitic H Pool is depicted in Figure C2. Extrapolation of the pool performance showed a primary and waterflood recovery factor of 4.2% and 7.2% using exponential decline. The recovery factors would be slightly higher using hyperbolic decline. So far 5.3% HCPV of water was injected into the pool, with 5% of oil produced and another 5% HCPV of water produced. Since waterflood response is evident in this pool, the secondary recovery scheme is successful. Currently the low injector to producer ratio and the strategy of bottom waterflood limit the pool performance. A change of strategy by increasing the injector to producer ratio of a pattern waterflood and injection into all layers could significantly improve the waterflood performance.

II. Retlaw Upper Mannville V Pool

The Retlaw Upper Mannville V Pool was discovered in 1976 (Figure C3). With the support of AOSTRA, a carbon dioxide immiscible injection project utilizing 32 ha spacing commenced in 1983. The injected CO_2 was obtained from the nearby Turin gas plant. CO_2 was injected into 7 wells surrounded by 27 producers in the Unit. Approximately 20 to 25% HCPV of CO_2 was injected into the patterns. To the end of 1993, a total of 132 e^6m^3 (245,670 tonnes, 4.7 bcf) of CO_2 was injected into the project area. The oil recovery was 229 e^3m^3 (1.44 MMBbls), approximately 12% of the OOIP.

The Retlaw Upper Mannville V Pool, is a reworked Glauconitic splay sand that developed from nearly fluvial channels and the sand is bounded by shale and or tight sand. The bar sand in a north-south direction is divided into Upper and Lower members. The sands are layered and contain randomly intermittent shale barriers. The Upper member is thicker and more permeable and is higher in quality than the lower sand. A region of poor permeability in the middle of the pool effectively separates it into a northern and a southern part. A gas cap exists in the northern section of the pool. The pool has an average thickness of 2.4 m, an average porosity of 18% and permeability in the range of 50 md.

The Retlaw Upper Mannville V Pool, at a depth of 1,100 m, contains 22 to 24 API oil. The initial pressure for the pool was 11,342 kPa and the initial gas oil ratio was 56.6 m^3/m^3. Reservoir temperature is 35.5 degrees C. The dead oil viscosity is 41 cp.

Extensive laboratory measures, including first contact and multi contact fluid properties, slim tube measurement and core flood tests were conducted in 1982. The reservoir oil can absorb 135 m^3/m^3 of CO_2 and swells by 30% at reservoir temperature and pressure. The oil viscosity is reduced to 9 cp by the dissolved CO_2, which is in a liquid like state.

Carbon dioxide was found to have microscopic displacement efficiency in the neighborhood of 70 to 75%, which is significantly higher than a typical immiscible displacement efficiency of 30%. During the core flood, a methane bank advanced ahead of the main CO_2 front indicating the presence of oil swelling. A significantly high amount of C_5-C_{11} in produced oil after the arrival of CO_2 front indicated extraction of lighter end of the reservoir oil into the flowing CO_2 phase. Both extraction and condensation were found to be important mechanism in the Retlaw CO_2 flood. A separate core test with 20% methane in the core was found not detrimental to recovery.

A simulation study in 1982 indicated waterflood would recover only 17.5% of the oil while a CO_2 followed by water injection scheme would recovery 38%. The study recommended that 15% PV of CO_2 be injected, followed by water at a reservoir pressure of 13,800 kPa.

Carbon dioxide injection into the pool commenced in one well in November 1983. Additional wells were put on CO_2 injection in 1983, 1985 and 1986 until all 7 wells had the designed CO_2 slug injected. Initially, there was not enough CO_2 from the Turin Plant and additional CO_2 was trucked in. Gas-oil ratio kept rising after injection until production was cut in April 1984.

In 1986, oil price dropped and it was no long economic to operate the pool with trucked CO_2, which was terminated. Production peaked at 128 m^3/d in April 1986 but voidage was less than one until January 1988, when water injection commenced. Pressure was consistently well below the design pressure of 13,800 kPa. It was as low as 8,000 kPa and always below 10,000 kPa.

Due to its poor performance, a number of studies were conducted on the project. The 1987 study by BRTR matched the history from 1982 to 1986 and concluded that CO_2 performed satisfactorily when pool pressure was above 9,653 kPa and when oil saturation was high. In the low pressure area, due to a low voidage replacement ratio or high gas saturation, the result was poor. The 1989 AOSTRA study concluded that gravity override was significant and pressure maintenance was the dominant oil recovery mechanism. However, this study used only a fraction of the CO_2-Oil interaction properties due to simulation program stability problem. An evaluation conducted by J.D. Griffith in 1991 concluded that the field performance was closely following a gas drive-water flood combination with no indication of CO_2 extraction. Another simulation study done by AOSTRA in 1993 again concluded that the injected CO_2 rose to the top layer of the model and it appeared to go to previously swept upper layer and was only marginally beneficial. However, the model concluded a WAG waterflood could improve the performance and can accelerate the waterflood recovery.

Since the termination of CO_2 injection in 1993, waterflooding of the pool continued. The current waterflood decline curve indicated a possible recovery factor of 29%, much higher than the original estimate of 17.5%.

The original prediction of excellent contact between CO_2 and reservoir oil with large proportion of CO_2 dissolved into the oil was not observed in the field performance. Breakthrough of CO_2 was predicted in 7.5 years. In reality, CO_2 broke through in 1 to 2 years.

There could be several reasons why the CO_2 flood in Retlaw performed poorly. The CO_2-oil equilibrium observed in the laboratory experiment was never achieved in the field. One reason could be that geological condition and dynamic field operation may prevent the creation of ideal equilibrium condition, such as good CO_2-oil contact and mixing. The CO_2-oil interaction observed in the laboratory could not be fully achieved in the field at prescribed conditions.

The other explanation could be that the ideal equilibrium condition is fully achievable in the field but the project failed to reach the prescribed reservoir pressure (13,800 kPa) as pointed out by the designer of the CO_2 flood. As a result the reduced density of the CO_2 led to a poor mobility ratio and the injected CO_2 bypassed the oil.

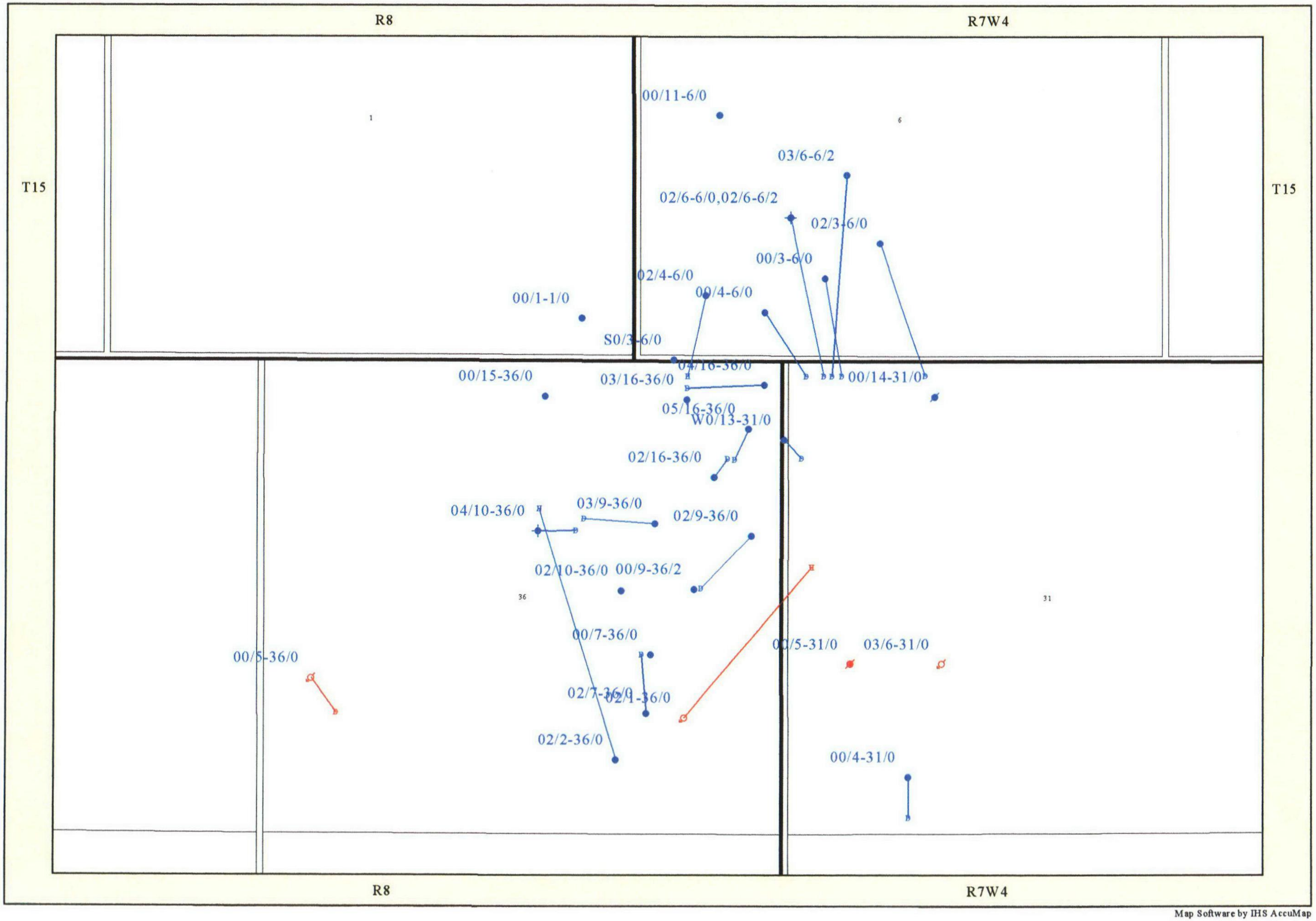
When CO_2 gravity override occurred, there was no attempt to modify the fluid conformance. No water was injected until after the full slug of 20 to 25% HCPV of CO_2 was injected. The mode of operation was unchanged even when the injected CO_2 was just recycled after the CO_2 breakthrough was observed.

Table C1

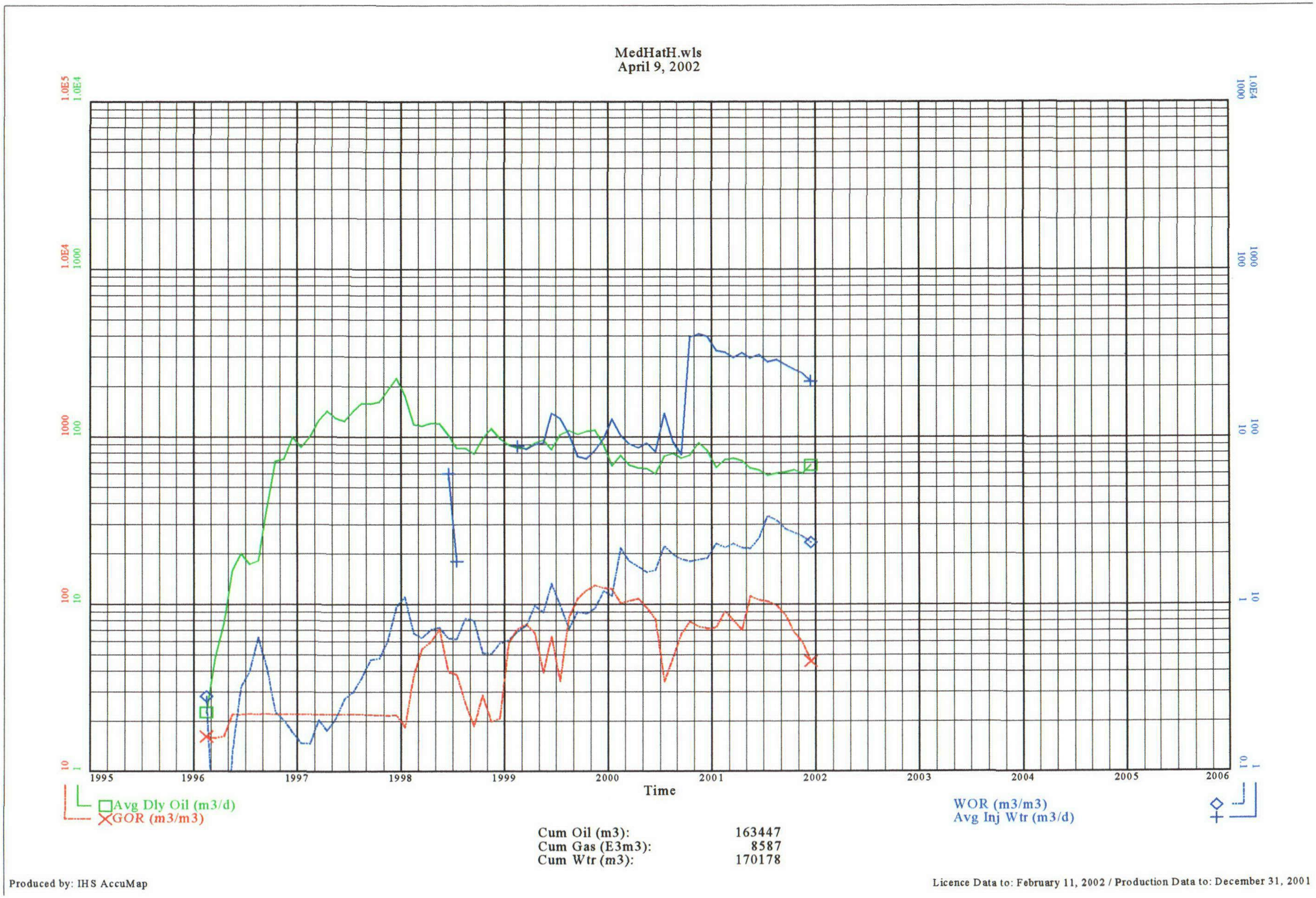
A Comparison of Medicine Hat Glauconitic C Pool and H Pool

Reservoir Properties

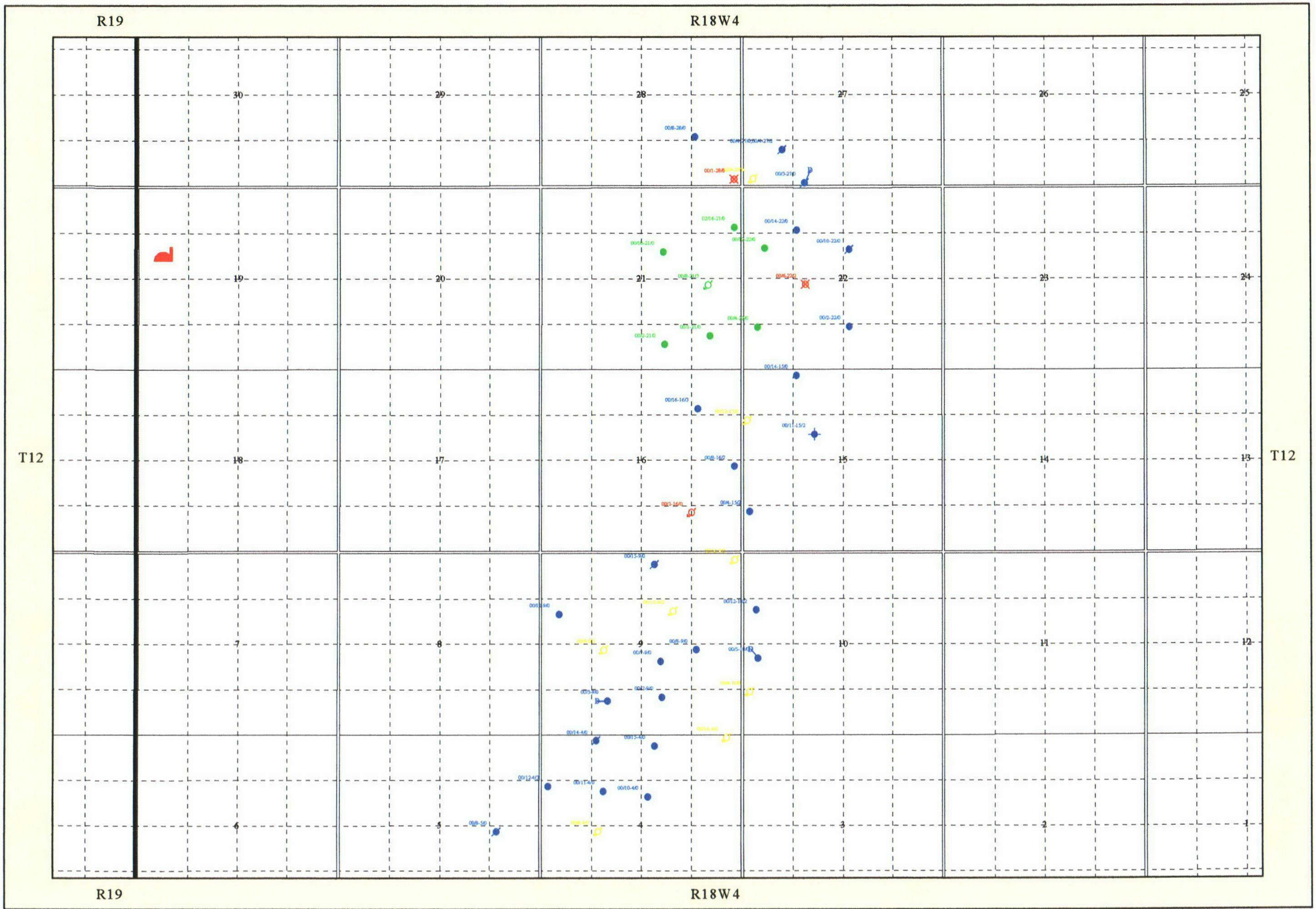
	Glauconitic C Pool	Glauconitic H Pool
Pool Area (ha)	2576	369
Formation Depth (m)	826	902
Average Net Pay (m)	8.66	5.38
Average Porosity (%)	22	26
Average Permeability (md)	1000	690
Average Water Saturation (%)	30	37
Average Shrinkage (m^3/Rm^3)	0.9	0.95
Average Oil Density (kg/m^3)	960	965
Average API Gravity	15.9	15.1
Solution Gas Oil Ratio (m^3/m^3)	45	28
Initial Pressure (kPa)	10,175	10,452
Reservoir Temperature (degree C)	26	24
Dead Oil Viscosity (cp)	2,000	500
Live Oil Viscosity (cp)	715	250
OOIP (e^3m^3)	30,920	3,089



Vikor Energy Inc. Medicine Hat Glauconitic H Pool Figure C1



Vikor Energy Inc. Performance of Medicine Hat Glauconitic H Pool Figure C2



Map Software by IHS AccuMap

Vikor Energy Inc.

Retlaw Upper Mannville V Pool

Figure C3