# IDENTIFICATION OF ENHANCED OIL RECOVERY POTENTIAL IN ALBERTA

## PHASE 2 FINAL REPORT

FOR

ENERGY RESOURCES CONSERVATION BOARD

(March 31, 2012)

Worldwide Petroleum Consultants

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# Introduction

Sproule Associates Limited ("Sproule") has been contracted to conduct a study titled "Identification of Enhanced Oil Recovery Potential in Alberta" at the request of the Energy Resources Conservation Board (ERCB). The study was prepared from March 2011 to March 2012 and was conducted in two phases. This report presents the results of Phase 2.

## Project Objectives

The primary objectives of the study "Identification of Enhanced Oil Recovery Potential in Alberta" are as follows:

### 1.0 Phase 1

- Retrieve information on all EOR schemes in Alberta from the ERCB's Reserves Report and other ERCB and public databases/files;
- Create an inventory of EOR scheme information organized by pertinent characteristics such as geographic area, pool, formation, reservoir properties, scheme type (e.g., $CO_2$, alkali surfactant polymer [ASP]), and recoveries;
- Analyze the inventory of EOR scheme information, focusing on successful EOR operations, existing and emerging trends, and likely short-term EOR prospects;
- Assess the associated potential success factors;
- Write preliminary report on EOR in Alberta oil pools, containing lessons learned and preliminary findings;
- Create an inventory of existing EOR schemes in Alberta organized by pertinent characteristics;
- Initially assess potential success factors.

### 2.0 Phase 2

- Apply knowledge gained from Phase 1, along with information from literature searches and possible industry interviews, to fully develop criteria for the screening of potential future EOR prospects, with consideration for the various types of possible EOR schemes and technologies;
- Apply screening criteria to all oil pools in Alberta;
- Assess and compile potential incremental recoverable volumes for all oil pools under various EOR technologies;

- Provide a progress update on preliminary findings and adjust the study as necessary;
- Prepare a report on the total findings on existing and future potential EOR in Alberta in written, tabular, and graphical formats. The report will include, but is not limited to, the following information:

    a. Field and pool name,
    b. Formation,
    c. EOR type,
    d. Fluid properties,
    e. Reservoir parameters,
    f. Geographic location,
    g. Primary recovery,
    h. Current incremental recovery.

This study considers only the technical factors associated with EOR. For any individual project, the economics are important, however, since the economic factors are variable and highly dependent on the current oil price (and the expectation of future oil prices), these factors are not addressed in this study.

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# Certification

## Report Preparation

The report entitled "Identification of Enhanced Oil Recovery Potential in Alberta Phase 2 Final Report for Energy Resources Conservation Board (March 31, 2012)" was prepared by the following Sproule personnel:

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Project Leader;
Manager, Reservoir Studies and Partner
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## Sproule Executive Endorsement

This report has been reviewed and endorsed by the following Executive of Sproule:

Original Signed by Harry J. Helwerda, P.Eng., FEC

Harry J. Helwerda, P.Eng., FEC
Executive Vice-President and Director
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## Permit to Practice

Sproule International Limited is a member of the Association of Professional Engineers and Geoscientists of Alberta and our permit number is P6151.

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2. I am a registered professional:
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   b. Society of Petroleum Engineers (SPE)

4. My contribution to the report entitled "Identification of Enhanced Oil Recovery Potential in Alberta Phase 2 Final Report for Energy Resources Conservation Board (March 31, 2012)" is based on my engineering knowledge and the data provided to me by the Company, from public sources, and from the non-confidential files of Sproule. I did not undertake a field inspection of the properties.

5. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of the Energy Resources Conservation Board.

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   c. Canadian Heavy Oil Association (CHOA)

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4. My contribution to the report entitled "Identification of Enhanced Oil Recovery Potential in Alberta Phase 2 Final Report for Energy Resources Conservation Board (March 31, 2012)" is based on my engineering knowledge and the data provided to me by the Company, from public sources, and from the non-confidential files of Sproule. I did not undertake a field inspection of the properties.

5. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of the Energy Resources Conservation Board.

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5. I am a qualified reserves evaluator and reserves auditor as defined in National Instrument 51-101.

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7. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of the Energy Resources Conservation Board.

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# Summary


This report is a summary of Phase 2 of the project "Identification of Enhanced Oil Recovery (EOR) Potential in Alberta" (March 31, 2012).

The tasks undertaken for Phase 2 are:

- Discuss screening for EOR, including reviewing the principal EOR methods and selecting EOR screening criteria, taking into account the technical issues and the availability of data;
- Review 72 solvent and 22 chemical floods in Alberta, along with some thermal recovery projects;
- Summarize the findings and discuss success/fail criteria for each method;
- Screen all of the oil pools in Alberta for their potential for EOR. This screening showed that the number of pools with potential for each process is
    - 200 pools for vertical solvent floods,
    - 734 pools for horizontal solvent floods,
    - 382 pools for combination solvent floods,
    - 1,701 pools for sandstone solvent floods,
    - 1,396 pools for ASP floods,
    - 935 pools for polymer floods,
    - 196 pools for cyclic steam,
    - 214 pools for steam floods,
    - 196 pools for SAGD,
    - 1,434 pools for in-situ combustion;
- Estimate the incremental recoverable oil for each process. The total oil recoverable by solvent and chemical floods is between 100 and 300 x $10^6$ $m^3$.

Three principal sources of data were used:

- ERCB Oil Reserves Report (2010),
- ERCB Oil and Gas Experimental Projects Report,
- ERCB Oilsands Schemes Report.

In addition, a set of binary screening criteria was put into the database.

# Discussion

## 1.0 Overview

This report summarizes the results of the work carried out for Phase 2 of the study.

The tasks undertaken for Phase 2 that will be described in the following sections are:

- Developing a set of screening parameters compatible with available data on Alberta oil pools;
- Reviewing individual EOR projects in Alberta;
- Summarizing findings from Alberta EOR projects;
- Establishing success/fail criteria;
- Performing a binary screening of all Alberta oil pools for EOR processes;
- Estimating incremental recoverable oil by EOR in Alberta.

This report is focused on EOR projects in the "conventional" oil areas of Alberta and excludes the "oilsands" areas. However, since there is information from the oilsands that is relevant (or potentially relevant) to conventional oil, some data on oilsands pilot schemes is included. Conventional oil includes light, medium and heavy oil. Bitumen is defined as oil with an in-situ viscosity greater than 10,000 mPa.s. The oilsands areas contain both bitumen and heavy oil and some of the developments for heavy oil in the oilsands areas can be applied to heavy oil in the conventional oil areas.

In addition, waterflooding, which is not normally classed as enhanced oil recovery, is considered in terms of incremental potential recovery. In many cases, waterflooding is a competing process to EOR processes and its inclusion allows for a comparison with the EOR processes.

For completeness, some of the sections from the Phase 1 report have been repeated in this report, with some additions.

## 2.0 Database

The database is the location where all the information gathered over the course of the project is stored. The responsibility of the database development team is to efficiently store large quantities of data in an easy-to-access system. This requires careful design, large amounts of data validation and the creation of an intuitive software interface.

The assignment of the data sources for the database is critical to the database development.

# 3.0 EOR Screening

## 3.1 Review of Process - Solvent Floods

The key to solvent floods is achieving miscibility between the solvent and the reservoir oil, through either a first or multiple contact miscible system. Multiple contact floods can be either vaporizing or condensing gas drives. In a miscible flood, the reservoir oil becomes increasingly solvent rich, so the residual oil phase has a lower oil component (i.e., more of the reservoir oil can be displaced). The solvent also increases the reservoir pressure, swells the oil phase and reduces the oil viscosity—all of which aid in increasing the oil recovery.

A major difficulty with most solvent floods is early solvent breakthrough due to the unfavourable mobility ratio of any gas flood. This leads to the solvent being re-cycled through the reservoir. The most common method of mitigating early solvent breakthrough is to inject water and gas in alternating slugs, which is called water-alternating-gas (WAG) flooding.

The solvent can be of several types:

- Ethane, propane or butane (or mixtures of these),
- Enriched hydrocarbon gas,
- Lean natural gas,
- High pressure lean gas,
- Nitrogen,
- Carbon dioxide.

The selection is usually based on miscibility pressure, reservoir pressure and cost. The solvents in the above list are roughly in order of miscibility pressure, with the exception of carbon dioxide.

Carbon dioxide can be multiple contact miscible at fairly low pressures. It is of particular interest since miscible flooding can also serve to sequester carbon dioxide in the reservoir and thereby reduce the amount of carbon dioxide released into the atmosphere.

A principal cost for a solvent flood comprises the cost of the solvent itself, injection facilities, processing facilities and the cost of transportation of the solvent to the EOR site. As a result, there are considerable economies of scale, and larger projects tend to be much more economic than small projects.

## 3.2 Review of Process - Chemical Floods

The key to chemical floods is to improve the mobility ratio of a waterflood and to reduce the residual oil saturation. Polymer flooding can also improve the vertical conformance of a waterflood. All of these mechanisms can improve the oil recovery factor.

There are a number of different types of chemical floods:

- Polymer,
- Alkali,
- Alkali/polymer,
- Surfactant,
- Alkali/surfactant/polymer (ASP),
- Micellar.

In polymer floods, a polymer, most commonly a polyacrylamide, is added to the injection water to increase its viscosity. This increase in viscosity improves the mobility ratio of the flood. Since the mobility ratio is of most concern in more viscous oil reservoirs, polymer flooding is most often applied to medium and heavy oil pools. The oil-water relative permeability end-points are not changed by the polymer, so, in a sense, there is no incremental oil recovery. However, this is only true if the waterflood is carried out to completion. If there is a maximum water cut limit applied, the polymer flood results in considerable incremental reserves. There is also an acceleration component, meaning that the time to reach a fixed oil recovery factor is greatly decreased. In a heavy oil waterflood, there is usually a long production period (often decades or even centuries) where the water cut is over 95 percent. For reserves purposes, only 50 years of production can be claimed as reserves; therefore, a polymer flood can increase the reserves by producing more oil in 50 years. Fractional flow theory predicts that a polymer flood will have a "plateau" period where water has broken through to a well and the well produces at a constant water cut. Eventually, the waterflood front breaks through to the well, and the well continues to produce as it would under a simple waterflood with viscous water. Plotting the water-oil ratio against cumulative oil production shows a sideways shift of the plot when the polymer is injected into a mature waterflood. The size of this shift can be interpreted as the incremental oil due to the polymer flood.

One of the features of polymer flooding is that the polymer is adsorbed to the rock. This leads to a loss of polymer and determines the amount of polymer solution that is needed to flood the reservoir (and the cost of the flood). The adsorption also results in a reduction of the permeability of the reservoir. In a heterogeneous reservoir, the injected fluids tend to flow preferentially in the highest permeability reservoir, so the permeability reduction is greatest there. This leads to more of the injected fluids going into the less permeable layers, improving the vertical sweep efficiency of the flood. The very successful polymer floods in the Minnelusa trend in Wyoming use this mechanism to improve the recovery of light oil.

In surfactant and micellar floods, a surfactant is added to the injected water to reduce the interfacial tension between the oil and the water. The reduction of the interfacial tension, if great enough, can reduce the residual oil saturation, thereby increasing the oil displacement efficiency and the oil recovery factor.

Like polymer, surfactants tend to adsorb onto the reservoir rock. In order to adequately flood the reservoir, the concentration of the surfactant must be quite high. Surfactants are relatively expensive, so the cost of a surfactant flood is high.

Alkalis such as sodium hydroxide, sodium carbonate and sodium orthosilicate are used instead of surfactants due to their lower costs. The alkali can react with acids in the oil to create in-situ surfactants, which then act in the same way as surfactants injected directly. However, it is usually difficult to sufficiently lower the interfacial tension with alkalis to significantly reduce the residual oil saturation. Both surfactants and alkalis are often used together with polymers for better mobility control.

Combining alkali, surfactant and polymer together (ASP flood) has the added advantage of a synergy between the alkali and the surfactant, significantly reducing the adsorption of the surfactant and bringing the residual oil saturation to very low levels. In the laboratory, ASP floods can reduce the residual oil saturation to less than 3 percent.

## 3.3 Review of Process - Thermal Recovery

The key to thermal recovery is the use of heat to lower the viscosity of oil and thereby make it possible to produce (in the case of bitumen) or to increase the productivity and recovery (in the case of medium or heavy oil).

There are several major thermal processes in use today:

- Cyclic steam stimulation (CSS),
- Steam flood,
- Steam-assisted gravity drainage (SAGD),

- In-situ combustion (ISC),
- High pressure air injection (HPAI).

Other processes which are not as widely implemented are

- Electrical/electromagnetic heating,
- Hot water flooding.

In cyclic steam stimulation, a pre-determined volume of steam is injected into a well, then the well is allowed to “soak” for a period, and then it is brought on production. Typically, the injection period is one month, the soak lasts for a week or two, and the production lasts for several months. The injection/soak/production cycle is repeated until it becomes uneconomic.

A steam flood is exactly like a waterflood, except that steam replaces water as the injection fluid.

In SAGD, two long horizontal wells are used. The production well is located near the base of the reservoir. A second horizontal well is placed directly above the production well and is used for steam injection. A key to the process is that the injection/production rates are sufficiently low that the process is dominated by gravity forces. In this situation, the steam rises to the top of the formation, forming a steam chamber, and the heated oil drains down to the producer.

In in-situ combustion, air or oxygen is injected into the reservoir and ignited. The heat pyrolyses the oil, resulting in part of the oil being reduced to a solid “coke”. The coke is the primary fuel for combustion; the rest of the oil is displaced ahead of the combustion front. Water is often injected as well, to improve the flow of heat ahead of the front. In many cases, the process can be viewed as a steam flood with in-situ steam generation.

### 3.4 Review of Process – Other EOR

Other EOR schemes that have been proposed in the literature or tested in the field include

- Microbial recovery,
- Foam flooding,
- Fresh water flood,
- Immiscible gas vertical floods,
- VAPEX,
- THAI.

None of these has been extensively tested, so none will be considered here. For more information on the methods, references are provided.

## 3.5 Alberta EOR Screening Criteria

Several criteria must be considered when developing screening criteria for Alberta oil pools. One is that the data for screening are readily available or can be easily estimated. With over 10,000 separate oil pools in Alberta, it is impossible to perform a detailed evaluation of each pool.

The screening criteria selected had to be

- Important to at least one EOR process,
- Readily available in public databases or able to be calculated from readily available sources,
- Easily definable.

Criteria used in Phase 1 of this study are listed in that section. This section will examine the usefulness and applicability of each potential criterion.

### Reservoir Depth

The depth of each reservoir is listed in the ERCB Annual Reserves Report. Each reservoir spans a range of depths, which can have a significant impact on temperatures and pressures, but in Alberta, the reservoirs are relatively thin (compared to, for example, the Orinoco Belt in Venezuela, where the developments must take into account productive zones which can be several thousand metres thick) and depth variations are low, with most reservoirs in the Western Canadian Basin having low dip.

The importance of this parameter is with regards to pressure, which is important for miscible floods and temperature, which can limit the applicability of steam injection and chemical flood processes. Since both temperature and pressure are readily available as separate parameters, depth alone is not a necessary parameter, though it is important in determining the cost of drilling. Drilling cost is a major factor in the cost of the wells and can be critical in the economic feasibility of a project. However, the economics of EOR are outside the scope of this project. The most challenging aspect of the economics of EOR is the price of oil, which is highly variable and very unpredictable. For these reasons, although the depth of the reservoir is listed in the tables, depth will not be used as a screening parameter on its own.

### Net Pay

Chemical floods are relatively insensitive to net pay itself, though oil-in-place, which is often important, is dependent on net pay.

For miscible floods, a high net pay is important if the flood is to be a gravity stable, top down flood (e.g., Brazeau River Nisku D), but if it is to be a horizontal flood (e.g., Chigwell Viking I), it is not relevant.

In thermal processes, the net pay is important in that it controls the ratio of heat in the reservoir versus the heat lost to the over- and under-burden. This affects the efficiency of the process as measured by the steam-oil ratio. For SAGD, the net pay is important in that there has to be enough thickness to allow for separation between the injection and production wells and to allow for the formation of the steam chamber or steam chest.

Net pay is listed in the reserves database, so it can easily be used as a screening parameter.

### Net-to-Gross Ratio

The net-to-gross ratio can indicate reservoir stratification and reservoir continuity. For all EOR processes which involve flooding from one well to another, reservoir continuity is essential.

In most Alberta reservoirs, reservoir continuity is not an issue (unlike, for example, waterflood in the Means San Andres Unit carbonate reservoir in West Texas). For this reason, the net-to-gross ratio is not an important parameter. This is fortunate, since the net-to-gross ratio for each reservoir is not readily available.

### Reservoir Permeability

Permeability is an important parameter for most EOR processes, because it controls both injection and production rates. Since the rates control revenue, the return on investment is affected. In tight reservoirs, the low rates can be mitigated to some extent by reducing the well spacing, but this may increase the capital requirements to prohibitive levels.

The average reservoir permeability is not immediately accessible. However, core data for each pool can be obtained from public databases. For this study, the permeability of each pool with an EOR project was approximated by extracting the core data from all of the wells in the pool, filtering the data by producing formation and dominant producing lithologies. The resulting values were then ordered, cut-offs were applied and an arithmetic average was calculated.

The cut-offs selected were a minimum permeability of 1 mD and a maximum of 30,000 mD. The lower limit is somewhat arbitrary, but most reservoir core analyses show a number of very low values which are not representative of the producing zones. The low permeability reservoir may contribute to production under primary recovery, but under any flooding scheme, the high permeability dominates, and contribution from low permeability streaks may be limited to capillary imbibition.

Very high permeability measurements usually reflect fracturing and/or vuggy porosity—both of which can be very important for an EOR process. Where such values are found, the occurrence is noted under "Natural Fractures".

The use of the arithmetic average rather than the geometric or harmonic average is due to the fact that in waterflood calculations, the usual Stiles technique has layers of constant permeability, and combining them is equivalent to calculating an arithmetic average. In developing screening criteria, the choice of averaging technique is not as important as maintaining a consistent methodology.

Another issue with the permeability of a pool is that it may vary significantly geographically and by geologic layer. A good example is the Pembina Cardium reservoir, where some areas are amenable to waterflooding, some only to primary recovery, and some only to primary recovery with multi-fracked horizontal wells.

**Reservoir Pressure**

Reservoir pressure is an important parameter for some thermal processes and for miscible floods, but it is not significant for chemical flooding.

For steam injection processes, it is important to have a relatively low pressure to ensure the steam is in the saturated condition so the latent heat can be used effectively.

The initial reservoir pressure is always recorded, but the current reservoir pressure needs to be determined from pressure tests. For screening purposes, the initial pressure is an adequate parameter, since the reservoir can usually be re-pressured to the initial reservoir pressure.

### Reservoir Temperature

The reservoir temperature affects the minimum miscibility pressure for miscible floods.

For chemical floods, some of the chemicals—in particular, polyacrylamide polymers—break down under high temperatures. For polyacrylamides, the effective maximum temperature is about 90°C. For surfactants, the maximum temperature is somewhat lower, at about 80°C.

### Oil Density

Oil density is not an important parameter in itself, but it is nearly always available and can be correlated to oil viscosity (see section on oil viscosity).

### Oil Viscosity

Oil viscosity is a critical parameter for thermal and chemical floods. Most oils which are suitable for miscible flooding have a low oil viscosity to start with, so they are not sensitive to this parameter.

The oil viscosity is not readily available for most pools. In order to estimate the oil viscosity for each pool, a correlation with oil density and reservoir temperature was developed.

The correlation was created using the following steps:

- Extract assorted oil liquid analyses with three temperature/viscosity readings for a wide variety of Alberta oil;
- Use the ASTM correlation to determine oil viscosity at 15°C for each sample. In this correlation, the log(log(viscosity + 0.8)) is plotted against the log of the absolute temperature. Figure 1 shows the correlation for four Alberta oil samples with different viscosity ranges;
- Plot oil viscosity at 15°C against oil density;
- Develop a correlation that fits the data, with emphasis on high viscosity oil;
- Use the ASTM correlation to calculate oil viscosity at reservoir temperature.

Figure 1 shows the ASTM correlation for several oil samples. The oil viscosity plotted against the oil density is shown in Figure 2. The data come from different parts of the province and different formations. A number of samples do not fit in the general trend, but the vast majority do, suggesting that the ones that do not fit are either contaminated, poorly measured or poorly recorded.

Eliminating some of the points off the trend, a polynomial correlation was applied to the data, as shown in Figure 2. The correlation is based on 3,215 oil samples, ranging from 681.5 to 1,012 kg/m$^3$ or 8.3 to 76.1°API gravity. The correlation is given by:

$$y = 1.5654E\text{-}09x^4 - 5.1019E\text{-}06x^3 + 6.2539E\text{-}03x^2 - 3.4053E{+}00x + 6.9306E{+}02$$

The oil viscosity at reservoir temperature was estimated by applying the ASTM correlation with slope B, estimated by:

$$B = 4.46E\text{-}03x - 7.88E{+}00$$

This procedure gives a good estimate of the dead oil at reservoir temperature. This is, of course, different from the live oil viscosity, but it is adequate for screening purposes.

### Water Salinity and Divalent Ion Concentration

Water analysis for many pools is available in the public database. It is a factor for chemical floods since the efficiency of chemicals, in particular polyacrylamides, is adversely affected by high water salinity and by divalent ion concentration.

The usual limit for polyacrylamides is about 25,000 ppm TDS. There are no published criteria for the maximum divalent ion concentration, so this parameter is not used as a screening criterion.

Other polymers, in particular biopolymers such as xanthum gum, are not as sensitive and can be used to much higher water TDS limits.

### Remaining Oil Saturation / Mobile Oil Saturation

The remaining oil saturation is a measure of the target for EOR. If the remaining oil saturation is low, there is little oil left to recover. Furthermore, a low remaining oil saturation may indicate a high water saturation (if the pool has been on waterflood or if there is a natural water drive) or a high gas saturation (if the pool has been produced to below the bubble point and there is free gas in the reservoir or a secondary gas cap has been formed).

In any case, any injected EOR fluids will have to displace water and gas as well as oil, so the produced oil per unit volume of injected fluid is lower, meaning the process is less efficient. This can have a severely detrimental effect on the economic viability of the project.

The remaining oil saturation can be estimated if more details of the recovery from the pool are known. Since this must be on an individual pool basis, this parameter cannot be used as a general screening criterion.

Even if it is known, the minimum value for a successful project is difficult to determine and can only be found by a detailed study.

These two parameters are related to the question: "what is the incremental recoverable oil by a particular EOR scheme?" An associated question is, "with the current degree of depletion, what is the incremental recoverable oil?" These questions can be approached in two ways, either through saturations or through recovery factors. To maintain some continuity with the previous screening criteria, a saturation-based approach will be used here.

The first thing to determine is the remaining oil saturation. This depends on the following factors:

- Was the pool waterflooded? If yes, and assuming that the waterflood achieved fill-up of any secondary gas, the remaining oil saturation is approximately the initial oil saturation multiplied by the ratio of the remaining OIP to the OOIP.
- If the pool was not waterflooded and only produced under primary, did the pressure fall below the bubble point? Since the bubble point is not available in any accessible database, this question can be answered approximately by comparing the cumulative produced GOR to the solution GOR. Acknowledging that there may have been some gas coming out of solution at the producing wells while the reservoir was above the bubble point on average, the reservoir can be expected to be above the bubble point if the ratio of produced GOR to solution GOR is less than 3. If this is the case, then the remaining oil saturation is equal to the initial gas saturation.
- If, based on the preceding, the reservoir did go below the bubble point, then an estimate of the oil saturation can be calculated by material balance considerations, providing that the current reservoir pressure is known. Since this is rarely the case, it is not possible to do this calculation.

The mobile oil saturation is the difference between the initial or current oil saturation and the residual oil saturation. It is not very useful as a criterion on its own. The residual oil saturation, though, can be important in deciding between different EOR processes, where, based on theoretical considerations, miscible flooding and ASP are more effective at mobilising residual oil than polymer. For the purposes of screening, "typical" values of residual oil saturation for different recovery processes (including primary) can be used, though there is considerable uncertainty in the typical values. The residual oil saturation values that should be used are the "effective" residual oil saturations which take into account the fact that flooding processes, especially with heavier oils, are never carried out to completion, but to some limiting water cut which is less than 100 percent. For this reason, polymer flooding results in incremental oil. The review of the existing EOR projects in Alberta plus a review of laboratory studies Sproule has access to will provide the "typical values" and will be discussed in section 6 of this report.

The incremental oil due to the EOR process is the difference in the effective residual oil saturations. The economics of the EOR scheme are more dependent on the total remaining oil production than on the incremental.

**Oil Content**

The oil content, expressed as "oil per unit area" or "oil column" has a bearing on the well spacing and perhaps the time needed for the EOR flood; however, it is not obvious how it can be used as a screening parameter.

**Reservoir Transmissivity**

Reservoir transmissivity is defined as the ratio of reservoir permeability to oil viscosity. EOR floods can work in high permeability/high viscosity and low permeability/low viscosity systems, but they are much more difficult to carry out in a low permeability/high viscosity situation.

Using this parameter as a criterion is difficult since the statistics are few and there are no theoretical guidelines. It will be examined for the Alberta EOR projects, but it may not yield practical results.

**Lithology**

The lithology provides a simple criterion. In general, chemical floods are not successful in carbonates, but miscible floods can succeed in either sandstones or carbonates. The most successful miscible floods have been in carbonates, but that is often more a function of the geometry, where the shape of pinnacle reefs allows for a gravity-stable displacement which results in very high recovery.

The lithological limitations of EOR processes are being tested in various parts of the world. For example, most successful thermal projects are in sandstones such as the McMurray in Alberta or the Morichal in Venezuela. However, there have been successful tests of CSS in carbonates in the Middle East as well as in the Grosmont formation in Alberta.

### Dip Angle

Dip angle is never known without a geological study, so it cannot be utilised as a screening parameter.

### Clay Content

This parameter is important for chemical floods, since it controls the adsorption of the injected chemicals. However, it requires laboratory investigation and it is rarely publicly available.

### Natural Fractures

This is always important in a flood for two reasons. Firstly, the fractures may connect the injection wells to the production wells, leading to premature breakthrough of the injected fluids and low areal sweep efficiency. Secondly, the natural fractures always enhance the effective permeability of the system and can enable a waterflood or EOR flood in a reservoir that may otherwise be too tight.

If there are natural fractures, the negative impacts can often be avoided by an appropriate well pattern.

### Gas Cap

The presence of a gas cap nearly always has a deleterious effect on an EOR flood. In water-based floods, the gas is the first phase to be displaced, and no production response is seen until "reservoir fill-up" is achieved. In miscible floods, the reservoir gas can dilute the solvent and prevent miscibility from being achieved.

If the gas cap covers a limited area of the pool, the EOR flood can be implemented in areas where there is no gas cap.

As a screening criterion, the gas cap can be identified in pools which have both oil and "associated gas" reserves.

### Minimum Reservoir Size

For an economically successful EOR project, the pool must be of a sufficient size to pay for both the up-front capital required and the operating costs. It must also support at least two wells.

The last criterion suggests that the minimum size should be at least two drilling spacing units (DSUs) in size (i.e., 32 ha over most of Alberta).

For a waterflood, the minimum capital expenses cover a pumping unit to inject the water. For a miscible flood, a compressor is required. A chemical flood requires not only a pumping unit but also a facility to mix the chemicals into the water. Operating costs to be covered include the cost of chemicals for chemical floods and the cost of solvent for miscible floods. There are considerable economies of scale, but the most severe are for thermal projects like the SAGD projects in the oilsands.

Based on some "back of the envelope" estimates, the minimum pool size for an EOR project is about 100,000 $m^3$ (629,000 bbl). This cut-off leaves about 6,000 out of the 11,942 oil pools in Alberta.

### List of Screening Criteria

The final list of screening criteria that will be used is as follows:

- Net pay;
- Permeability;
- Temperature;
- Oil viscosity;
- Water salinity;
- Previous waterflood;
- If no waterflood: pressure below the bubble point;
- Remaining oil saturation;
- Mobile oil saturation;
- Transmissivity;
- Lithology;
- Fractures;
- Gas cap;
- Minimum reservoir size.

# 4.0 Alberta EOR Projects

Alberta EOR projects are divided into four types:

- Solvent floods,
- Chemical floods,
- Thermal recovery,
- Other.

These are discussed in sections 4.1 to 4.4 on an individual project basis.

## 4.1 Solvent Floods

The EOR Project Assessment and reservoir properties for each project are summarized in Tables 1 to 72. These are the key parameters to develop the criteria for successful miscible floods.

### Acheson D-3A

The Acheson D3A pool is a light-medium oil carbonate reservoir at a depth of 1,547 m. The oil gravity is 37.8°API. The average porosity is 0.1, the average pay thickness is 18.4 m, the average water saturation is 0.12 and the initial reservoir pressure is 11,922 kPa. The average permeability is 2,870 mD, and the OOIP in the pool was 9.692 x $10^6$ $m^3$.

The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 3 and 4. The EOR project assessment is shown in Table 1.

The area for Approval 10003 is in Twp 52-53, Range 26W4; the boundaries are shown in Figure 5. This project consists of 5 active producing oil wells, 2 non-active producing oil wells, 2 water disposal injection wells, 78 abandoned wells and 8 suspended oil wells. The current producing rate from Area 2 in Figure 5 is approximately 20 $m^3$/d oil and 145 $m^3$/d water, with an average water cut of 86.2 percent. In the last two years, the GOR has fluctuated between 100 and 140 $m^3/m^3$.

In July 1987, a tertiary hydrocarbon miscible flood scheme was initiated in the northern part of the pool (current Area 2 Township 53 within approval 10003). The miscible flooding was further expanded to the center area of Township 52.  The last continuous solvent injection occurred in November 1996. The total solvent injected was 1,034,762 x $10^3$ $m^3$. Chase gas started in September 1988 in the northern part, which was highly injected (with more than 70 percent of the total gas injected), followed by the southern area in January 1993. The injection of chase gas ended in June 2005. Cumulative gas injection was 1,432,521 x $10^3$ $m^3$. The production and injection histories of Area 2 are shown in Figures 6 and 7, respectively.

The estimated primary recovery factor for the pool was 54 percent. The incremental EOR recovery factor with the solvent/chase gas injection was 18.5 percent. The remaining OIP is 1.454 x $10^6$ $m^3$, and possible future incremental recovery is 0.0291 x $10^6$ $m^3$.

**Reservoir Pressure**

In terms of pressure maintenance, public records do have historical pressure data on some wells in this approval. Public records list the initial pressure of the Acheson D-3A pool when the pool was discovered in 1950 to be 11,922 kPa. The most recent pressure indicates the reservoir pressure was between 10,000 and 12,000 kPa in 1998.

This leads to the conclusion that water and solvent injection provided reasonable pressure support. In terms of pressure maintenance, GeoSCOUT records the last static reservoir pressure for this area for two wells on February and June 2010. Well 00/03-02-053-26W4/0 had a pressure of 11,101 kPag after 259 hours of shut-in and well 00/14-02-053-26W4/0 had a pressure of 9,844 kPag after 332 hours of shut-in. Figure 8 shows a reservoir pressure distribution map as of January, 2011.

The future depletion strategy is to maintain production as it is until the producing wells are no longer economic.

**Voidage Replacement Ratio (Instantaneous and Cumulative)**

Calculations were done using PVT data from well 06-23, pressure history, production history, rock properties (porosity and compressibility) and the application of an aquifer function, which Penn West strongly believes is partially supplying energy to the pool (as mentioned in the main application); otherwise, it would be difficult to match the actual data to the simulated data. In the subject area, there are two disposal wells injecting in the D-3A formation which Penn West had considered when balancing the material balance equation regarding fluids injected into the formation. During pressure history matching, some pressure points were below those pressure data in time where the miscible flooding started, and it was quite difficult to get a better match without affecting other variables. As seen in the PVT analysis, the IRP and the bubble point pressure are close enough to deduce that in Part 2 of the pool, some wells could be below the bubble point after production started. The matching in terms of OOIP and production index was adequate.

In terms of reservoir voidage, InsVRR and CumVRR (as of January 2011) are 4.7 and 0.91, respectively, using an approximation by material balance. The high InsVRR value was expected because of the implementation of the aquifer as a water supply resource.

### References


1. Application to Terminate the Miscible Flood Approval for Acheson Field, April 30, 2011 Submission to the ERCB, D-3A Pool, Approval No.10003, Part 2, Solvent Flood Area.
2. MacLean, D.A. and Edwards, K.A. "Acheson D-3A Pool: Primary to Secondary HCMF-40 Years of Performance". SPE paper# 26616, 1993.


## Ante Creek Beaverhill Lake

The Ante Creek Beaverhill Lake pool is a light-medium oil carbonate reservoir at a depth of 3,433.1 m which was discovered in 1962. The oil gravity is 44°API. The average porosity is 0.1, the average permeability is 20 mD, the average water saturation is 0.27 and the initial reservoir pressure is 35,550 kPa. The OOIP in the pool was 6.218 x $10^6$ $m^3$.

Solvent flooding was started in 1968, and gas injection began in 1985. The EOR project assessment is shown in Table 2. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 9 and 10.

The solvent flood resulted in improved oil recovery, as seen in Figure 10. Following injection, the oil rate remained relatively constant at about 250 $m^3$/d, until 1986, at which point the production started to decline. Solvent flooding was completed in 1989, and gas injection ended in 1991.

The estimated primary recovery factor for the pool was 16 percent. The remaining OIP is 3.855 x $10^6$ $m^3$.

### Summary

Miscible flood is working in terms of incremental oil recovery, but early gas breakthrough has led to bypassed oil.

### References


1. Griffith, J.D., Baiton, N., and Steffensen, R.J. "Ante Creek - A Miscible Flood Using Separator Gas and Water Injection". SPE paper# 2644, 1970.

## Bigoray Nisku B

The Bigoray Nisku B pool is a light-medium oil carbonate reservoir at a depth of 2,337.2 m, discovered in 1978. The oil gravity is 38.16°API. The average porosity is 0.067, the average permeability is 1,068 mD, the average water saturation is 0.22 and the initial reservoir pressure is 21,024 kPa. The OOIP in the pool was 1.5 x $10^6$ $m^3$.

There are six wells in the pool (Figure 11). Production started in 1978, and in 1980, the well 13-09-52-08W5 was converted to solvent injection with an injection rate of about 300,000 $m^3$/d. Water injection into 08-08-52-08W5 was started in 1998, and solvent injection was terminated in 2002. A total of about 450 x $10^6$ $sm^3$ of solvent was injected. The performance of the pool is shown in Figure 12. The oil rate fluctuated between 100 and 200 $m^3$/d until 1994, when it started declining. The GOR had been rising steadily and by 1994 had reached 300 $m^3/m^3$ from the original solution GOR of 40 $m^3/m^3$. The GOR peaked at 4,000 $m^3/m^3$ and then dropped, presumably as a result of the water injection. Figure 12 shows the solvent injection rate and the gas production rate plotted against time. Until 1994, the injection rate was significantly above the production rate. The two then tracked each other until the injection rate was reduced and then stopped, when the production rate exceeded the injection rate. In 2004, the gas production rate dropped dramatically. Well 13-09-52-08W5 was later converted to gas production.

The EOR project assessment is shown in Table 3.

The estimated primary recovery factor for the pool was 31 percent. The incremental EOR recovery factor with the solvent injection was 18 percent. The remaining OIP is 0.498 x $10^6$ $m^3$.

The composition of the solvent has not been found. Nevertheless, the long period with a near constant GOR and the high recovery argue for miscible conditions to have been achieved.

### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010

## Bigoray Nisku F

The Bigoray Nisku F pool is a light-medium oil carbonate reservoir at a depth of 2,404 m. The oil gravity is 38.1°API. The average porosity is 0.11, the average permeability is 2,418 mD, the average water saturation is 0.07 and the initial reservoir pressure is 20,304 kPa. The OOIP in the pool was 2.8 x $10^6$ $m^3$.

Solvent flooding was started in 1987, and the scheme was followed by gas injection in 1989. The EOR project assessment is shown in Table 4. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 13 and 14.

Following injection, the oil rate increased from about 300 $m^3$/d in 1987 to about 600 $m^3$/d in 1993, at which point the production started to decline. This increase in production is likely partially due to the additional well that was brought on during that time period. Solvent flooding was completed in 1989, and gas injection was terminated in 1995.

The estimated primary recovery factor for the pool was 40 percent. The incremental EOR recovery factor with the solvent injection was 23.5 percent.

### References

1. Bigoray Nisku F Pool, Penn West Petroleum Ltd., Annual Progress Report, 22 January 2011, (2010-10658).
2. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Brazeau River Nisku A (Nisku X2X)

The Brazeau River Nisku A pool is a light-medium oil carbonate reservoir at a depth of 3,110.3 m. The oil gravity is 44.06°API. The average porosity is 0.11, the average permeability is 769 mD, the average water saturation is 0.10 and the initial reservoir pressure is 45,803 kPa. The OOIP in the pool was 5.3 x $10^6$ $m^3$.

The pool was discovered in 1978 and placed on primary production with three wells. When the reservoir pressure was close to the bubble point of 21,000 kPa in 1980, the pool was converted to a miscible flood. The northernmost and structurally highest well, 05-06-49-12W5M, was converted to injection with perforations close to the top of the formation. The two producing wells, 11-31-48-12W5M and 15-31-48-12W5M, were perforated near the base of the reservoir, about 50 m lower than the perforations in the injector. The gas injection was first used to re-pressure the reservoir to 1,000-1,500 kPa above the minimum miscibility pressure of 34,500 kPa, and then the pressure was kept roughly constant. The oil production rate rose to about 1,200 $m^3$/d and was limited mainly by facility constraints. After seven years of injection, gas breakthrough occurred when the gas-oil contact was estimated to be 20 m above the top of the producing perforations. In 1991, a horizontal well was drilled in the reef, and it produced until 2006. Production continued with gas injection until the GOR became excessive in 1994. At that time, gas injection was stopped and the pool was operated in a blow-down mode. By 2012, the oil rate had dropped to about 10 $m^3$/d with a water cut between 10 and 50 percent and a gas-oil ratio between 3,000 and 20,000 $m^3/m^3$.

The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 15 and 16. The EOR project assessment is shown in Table 5.

In order to maintain miscibility, the injected gas had to have a composition with an ethane-plus component of over 10 mole percent. The actual injected gas had an ethane-plus component of 12-15 mole percent.

The estimated primary recovery factor for the pool was 40.5 percent, though the conversion to a miscible flood occurred when the recovery was only 6 percent of OOIP. The incremental EOR recovery factor with the solvent injection was 26.5 percent, for a total recovery factor of 77 percent. By the end of January, the pool had produced 4,321,439 $m^3$ of oil and condensate, implying an actual recovery factor of 81.5 percent of OOIP.

### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.
2. Lee, J.L., E. l. Astete and T. F. Jerhoff, "Performance review of Brazeau River Nisku Dry-Gas Miscible Flood Projects", SPE 22896, 1994.
3. Lee, J. I. and T. F. Jerhoff, "Redevelopment of the Brazeau River Nisku A and D Vertical Miscible Floods with Horizontal Wells", JCPT, 356, 60-69, 1996.

## Brazeau River Nisku D

The Brazeau River Nisku D pool is a light-medium oil carbonate reservoir at a depth of 3,069 m. The oil gravity is 42.12°API. The average porosity is 0.065, the average permeability is 50 mD, the average water saturation is 0.12 and the initial reservoir pressure is 34,568 kPa. The OOIP in the pool was 2.7 x $10^6$ $m^3$.

The pool was discovered in 1978. It was operated in a very similar manner to the Nisku A pool, except that under primary, the pressure dropped to below the bubble point pressure of

20,480 kPa from the initial pressure of 34,500 kPa. The miscible flood was implemented and the pressure raised and then kept above the minimum miscibility pressure of 35,000 kPa. Gas breakthrough was much faster than in the Nisku A pool, occurring about six months after the start of injection, when the gas-oil contact was estimated to be 40 m above the top of the producing perforations. The early breakthrough was attributed to the poorer reservoir quality in this pool by Lee, Astete and Jerhoff (1994). A horizontal well was added to the pool in 1993 and was successful in increasing the oil rate and decreasing the gas-oil ratio.

The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 17 and 18. The EOR project assessment is shown in Table 6.

The estimated primary recovery factor for the pool was 50 percent. The incremental EOR recovery factor with the solvent injection was 15 percent.

#### References


1. ERCB Oil Reserves Detailed Report, 31 December 2010.
2. Lee, J.L., E. l. Astete and T. F. Jerhoff, "Performance review of Brazeau River Nisku Dry-Gas Miscible Flood Projects", SPE 22896, 1994.
3. Lee, J. I. and T. F. Jerhoff, "Redevelopment of the Brazeau River Nisku A and D Vertical Miscible Floods with Horizontal Wells", JCPT, 356, 60-69, 1996.


### Brazeau River Nisku E

The Brazeau River Nisku E pool is a light-medium oil carbonate reservoir at depth of 3,199.9 m. The oil gravity is 45.69°API. The average porosity is 0.10, the average water saturation is 0.12 and the initial reservoir pressure is 46,019 kPa. The OOIP in the pool was $2.45 \times 10^6$ $m^3$.

The pool was also discovered in 1978. It was operated in a very similar manner to the Nisku A pool, except that the production wells were perforated about 10 m above the oil-water contact, since there was a water leg in this pool. The pressure dropped to close to the bubble point pressure of 33,990 kPa from the initial pressure of 46,200 kPa. The miscible flood was implemented and the pressure raised and then kept above the minimum miscibility pressure of 37,700 kPa. Gas breakthrough occurred later than expected, in seven years, when the gas-oil contact was estimated to be only 15 m above the top of the producing perforations.

The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 19 and 20. The EOR project assessment is shown in Table 7.

The estimated primary recovery factor for the pool was 45.1 percent. The incremental EOR recovery factor with the solvent injection was 35 percent. At the end of 2010, the remaining OIP is 0.390 x $10^6$ $m^3$.

### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.
2. Lee, J.L., E. l. Astete and T. F. Jerhoff, "Performance review of Brazeau River Nisku Dry-Gas Miscible Flood Projects", SPE 22896, 1994.

## Caroline Cardium E

The Caroline Cardium E pool is a light-medium oil sandstone reservoir at depth of 2,413.6 m. The oil gravity is 46.09°API. The average porosity is 0.12, the average permeability is 41.41 mD, the average water saturation is 0.16 and the initial reservoir pressure is 27,614 kPa. The OOIP in the pool was 4.7 x $10^6$ $m^3$.

Gas injection started in 1978, followed by water injection in 1982 and, finally, solvent flooding in 1986. The EOR project assessment is shown in Table 8. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 21 and 22.

The scheme resulted in improved oil recovery, as seen in Figure 22. From the start of gas injection, the oil rate increased from about 200 $m^3$/d in 1978 to about 500 $m^3$/d by 1989. This increase in production is likely partially due to additional wells coming on production over that time period. Gas injection was completed in 1986, and solvent flooding was terminated in 1997.

The estimated primary recovery factor for the pool was 9 percent. The incremental EOR recovery factor with the solvent injection was 5 percent. The remaining OIP is 3.29 x $10^6$ $m^3$.

### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Chigwell Viking E

The Chigwell Viking E pool is a light-medium oil sandstone reservoir at a depth of 1,385.6 m. The oil gravity is 38°API. The average porosity is 0.13, the average permeability is 72.89 mD, the average water saturation is 0.38 and the initial reservoir pressure is 9,916 kPa. The OOIP in the pool was 4.986 x $10^6$ $m^3$.

The Chigwell Viking E pool has been on a $CO_2$ flooding scheme since 2007. Since the start of injection, the oil production rate has increased from about 10 $m^3$/d to 100 $m^3$/d. It is too early to gauge the full benefits of the $CO_2$ flooding scheme, but the results are positive thus far.

The EOR Project Assessment of Viking E is summarized in Table 9. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 23 and 24.

The pool pressure is much lower than the expected value for its depth of 1,385.6 m. The normal pressure gradient is about 10 kPa/m. With this gradient, the initial pressure should be about 13,800 kPa. Clearly the reservoir is severely under-pressured. This has important implications. Firstly, the reservoir can be pressured to a much higher pressure. The normal fracture gradient is 18 kPa/m, so the maximum pressure is 25,000 kPa. Secondly, $CO_2$ may not be miscible with the oil at the original reservoir pressure, but it may become miscible if the reservoir pressure is increased. This seems to be the case in the Chigwell Viking I pool as well.

The estimated primary recovery factor for the pool was 8 percent. The incremental EOR recovery factor with the solvent injection was 3 percent. The remaining OIP is 4.437 x $10^6$ $m^3$.

### References

1. Chigwell Viking I and E, Glencoe Resources Ltd., Annual Presentation, 27 January 2011, (2010-10392).

## Chigwell Viking I

The Chigwell Viking I pool is a light-medium oil sandstone reservoir at a depth of 1,411 m. The oil gravity is 38.6°API. The average porosity is 0.13, the average permeability is 43.76 mD, the average water saturation is 0.39 and the initial reservoir pressure is 7,372 kPa. The OOIP in the pool was 2.075 x $10^6$ $m^3$.

Solvent flooding with Ethane was started in 1999. The scheme was followed with a miscible $CO_2$ flood started in 2006, which is still in operation at the time of writing. The EOR project assessment is shown in Table 10.

The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 25 and 26.

The pool pressure is much lower than the expected value for its depth of 1,411 m. The normal pressure gradient is about 10 kPa/m. With this gradient, the initial pressure should be about 14,100 kPa. The reservoir is severely under-pressured, which has important implications. Firstly, the reservoir can be pressured to a much higher pressure. The normal fracture gradient is 18 kPa/m, so the maximum pressure is 25,000 kPa.

The minimum miscibility pressure (MMP) for $CO_2$ as determined in lab tests is 13,800 kPa. Pressure surveys from 1997 and 2010 indicate a reservoir pressure above the MMP during the solvent injection periods. The maximum pressure reached is about 16,500 kPa.

A bubble map showing cumulative oil recovery in the Chigwell Viking I pool is given in Figure 27.

The solvent-$CO_2$ floods resulted in improved oil recovery, as indicated in Figures 28 and 29. At the start of ethane injection, the oil rate went from about 20 $m^3$/d to 140 $m^3$/d. After the start of $CO_2$ injection, the oil rate went from about 20 $m^3$/d to 90 $m^3$/d. In both cases, the peak rate was immediately followed by a sharp decline, with a similar decline rate to the earlier primary production (Figure 28).

The ethane and $CO_2$ flood pressure history measurements are plotted in Figure 30. A plot showing the daily production performance and well count can be found in Figure 31, while the 6-33 WAG injection history is given in Figure 32. Finally, the net $CO_2$ volumes injected into the pool are given in Figure 33.

The estimated primary recovery factor for the pool was 8 percent. The incremental EOR recovery factor with the solvent-$CO_2$ injection was 8 percent. The remaining OIP is $1.66 \times 10^6$ $m^3$. From the production data, the primary recovery was about 240,000 $m^3$, the recovery due to ethane injection was 10,000 $m^3$ and the recovery due to $CO_2$ flooding to date was 80,000 $m^3$. This implies recovery factors of 7.2 percent for primary, 4.6 percent for ethane and 3.9 percent for $CO_2$, for a combined incremental recovery for the miscible floods of 8.5 percent to date. Note that the $CO_2$ flood is still in operation.

Currently, the Viking I pool has been converted from a straight $CO_2$ injection to a water-alternating-gas scheme (WAG) for further recovery assessment.

### Overall Performance

$CO_2$ was very effective at mobilizing the oil, and it reduced oil viscosity dramatically. The scheme had a higher-than-anticipated GOR and lower-than-anticipated oil rates and recovery. No containment issues were encountered. All wells had some form of breakthrough. $CO_2$ mobility in the solvent swept the rock higher than expected; the $CO_2$ travelled through the reservoir readily and moved across the pattern to the second line offset. WAG injection results were promising.

### Short- & Long-Term Opportunities

The greatest potential to increase production rates and recoverable reserves is through WAG injection.

Horizontal drilling recovery can be maximized by shortening the period that $CO_2$ must remain in a specific area ($CO_2$ utilization efficiency).

### Summary

Miscible flood is working in terms of incremental oil recovery, but early $CO_2$ breakthrough has led to bypassed oil. A WAG is currently being implemented, but it is too early to tell if it has been successful.

### References

1. Chigwell Viking I and E, Glencoe Resources Ltd., Annual Presentation, 27 January 2011, (2010-10392).

## Enchant Arcs A & B (Commingled 005)

## Miscible Displacement by $CO_2$ and Water

The Enchant Arcs A & B pool, now called the Commingled 005 pool, is a light-medium oil carbonate reservoir at a depth of 1,355.5 m. The oil gravity is 26.07°API. The average porosity is 0.14, the average water saturation is 0.20 and the initial reservoir pressure is 11,905 kPa. The OOIP in the pool was $1.743 \times 10^6$ $m^3$.

The Enchant Arcs A & B pool miscible flood commenced injection of $CO_2$ on September 23, 2004. The pool was switched to water injection on May 9, 2006. Anadarko, the operator at the time of the switch, noticed a reduction in water injection rates, but the production levels were not adjusted. The pool was shut-in after pressure surveys confirmed that the pool pressure was below mandated minimum operating pressure in October. The pool production has remained shut-in, but the injection of water has continued. Ongoing operations are being performed to return the injection rate to initial rates, and the pool pressure is being monitored to determine when the well can be returned to production.

As a result of internal confusion during the time of the sale of Anadarko Canada Corporation to Canadian Natural Resources Limited (CNRL), no samples of gas were taken after the pool was returned to water injection, and no sample can be taken until the pool is returned to production.

The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 34 and 35. The EOR project assessment is shown in Table 11.

The estimated primary recovery factor for the pool was 22 percent. The incremental EOR recovery factor with the solvent injection was 17 percent.

#### References

1. Enchant Arcs A&B Pool, Approval No. 9839 for Miscible Displacement by $CO_2$ and Water Annual Data Submission (IL96-02) for 2006.

### Enchant Arcs F & G (Commingled 017)

#### Miscible Displacement by $CO_2$ and Water

The Enchant Arcs F & G pool, now called the Commingled 017 pool, is a light-medium oil carbonate reservoir at a depth of 1,320.6 m. The oil gravity is 28.03°API. The average porosity is 0.13, the average water saturation is 0.20 and the initial reservoir pressure is 10,374 kPa. The OOIP in the pool was 0.723 x $10^6$ $m^3$.

The Enchant Arcs F & G pool miscible flood commenced injection of $CO_2$ on May 19, 2006. Anadarko completed a pressure survey from September 14 to 29, 2006, while the rest of the pool continued to operate. The extrapolated results of this survey showed a pool pressure well above the 10.5 MPa (gauge) minimum operating pressure for the pool. The final stabilized pressure is interpreted to be 12.0 MPa. The VRR were observed to be greater than 1.0; as of January 2007, the injection volumes have been adjusted to be closer to 1.0. The injector well 0017-22-14-16W4 was not initially shut-in due to internal confusion. The well has not been injected into since February 15, 2007.

Canadian Natural Resources Limited (CNRL), the current operator of this pool as a result of its purchase of Anadarko Canada Corporation, planned to convert the former injector 0017-22-14-16W4W4 into a producer in the second quarter of 2007.

The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 36 and 37. The EOR project assessment is shown in Table 12.

The estimated primary recovery factor for the pool was 25 percent. The incremental EOR recovery factor with the solvent injection was 23 percent.

#### References

1. Enchant Arcs F&G Pool, Approval No. 10523 for Miscible Displacement by $CO_2$ and Water Annual Data Submission (IL96-02) for 2006.

### Fenn-Big Valley Nisku A (Commingled 009)

The Fenn-Big Valley Nisku A pool, now called the Commingled 009 pool, is a light-medium oil carbonate reservoir at a depth of 1,574.4 m, discovered in 1950. The oil gravity is 32.1°API. The average water saturation is 0.14 and the initial reservoir pressure is 11,417 kPa. The OOIP in the pool was 5.804 x $10^6$ $m^3$.

The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 38 and 39. The EOR project assessment is shown in Table 13.

An experimental solvent flood was conducted in the pool from 1987 to 1989 using nitrogen injection.

The estimated primary recovery factor for the pool was 46.8 percent. The incremental EOR recovery factor with the solvent injection was 5.2 percent.

#### Overall Performance

Enriched gas is very effective at mobilizing oil.

### Summary

Miscible flood is working in terms of incremental oil recovery, but early enriched gas breakthrough has led to bypassed oil.

## Golden Spike D-3 A

The Golden Spike D-3 A pool is a light-medium oil dolomite reservoir at a depth of 1,725.3 m, discovered in 1949. The oil gravity is 37.09°API. The average porosity is 0.087, the average water saturation is 0.11 and the initial reservoir pressure is 14,400 kPa. The OOIP in the pool was 49.603 x $10^6$ $m^3$.

Gas injection was started prior to 1962 and ended in 2001. The EOR project assessment is shown in Table 14. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 40 and 41.

The estimated primary recovery factor for the pool was 53 percent. The incremental EOR recovery factor with the solvent injection was 5 percent for a combined incremental recovery for the miscible flood of 58 percent.

### Overall Performance

Enriched gas is very effective at mobilizing oil.

### Summary

Miscible flood is working in terms of incremental oil recovery, but early enriched gas breakthrough has led to bypassed oil.

### References

1. Larson, V. C., Peterson, R. B., and Lacey, J. W. "Technology's Role in Alberta's Golden Spike Miscible Project". SPE paper# 12253, 1967.
2. Reitzel, G.A. and Callow, G.O. "Pool Description and Performance Analysis Leads to Understanding Golden Spike's Miscible Flood". SPE paper# 6140, 1977.

## Goose River Beaverhill Lake A

The Goose River Beaverhill Lake A pool is a light-medium oil carbonate reservoir at a depth of 2,800 m. The oil gravity is 41.08°API. The average porosity is 0.094, the average permeability is 9.89 mD, the average water saturation is 0.19 and the initial reservoir pressure is 24,805 kPa. The OOIP in the pool was 16.16 x $10^6$ $m^3$.

Solvent flooding in the pool commenced in 1987. The EOR project assessment is shown in Table 15. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 42 and 43. The scheme resulted in improved oil recovery, as seen in Figure 43. From the start of solvent injection, the oil rate increased from about 500 $m^3$/d in 1987 to about 1800 $m^3$/d by 1994. This increase in production is likely partially due to additional wells coming on production over that time period. The oil rate began declining rapidly after 1994, and solvent injection was terminated in 2003.

The estimated primary recovery factor for the pool was 16 percent. The incremental EOR recovery factor with the solvent injection was 7 percent. The remaining OIP was 8.726 x $10^6$ $m^3$.

### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Joffre D-3 B

The Joffre D-3 B pool is a light-medium oil carbonate reservoir at a depth of 2,113.3 m. The oil gravity is 38.57°API. The average porosity is 0.09, the average permeability is 434.4 mD, the average water saturation is 0.13 and the initial reservoir pressure is 16,550 kPa. The OOIP in the pool was 1.721 x $10^6$ $m^3$.

Solvent flooding was started in 1989 and was followed by gas injection in 1992. The EOR project assessment is shown in Table 16. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 44 and 45.

The scheme likely improved oil recovery, as seen in Figure 45. The oil rate in 1990 (300 $m^3$/d) was similar to the rate in 1994. Solvent flooding was completed in 1992, and gas injection ended in 2002.

The estimated primary recovery factor for the pool was 33 percent. The incremental EOR recovery factor with the solvent injection was 5 percent. The remaining OIP is 740,000 $m^3$.

### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Joffre Viking Tertiary Oil Unit

### $CO_2$ Miscible Flood

The Joffre Viking pool is a light-medium oil sandstone reservoir at a depth of 1,400.4 m. The oil gravity is 38.2°API. The average porosity is 0.13, the average permeability is 349.2 mD, the average water saturation is 0.36 and the initial reservoir pressure is 6,616 kPa. The OOIP in the pool was 8.215 x $10^6$ $m^3$.

Gas injection in the pool commenced in 1988. The EOR project assessment is shown in Table 17. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 46 and 47.

The pool pressure is much lower than the expected value for its depth of 1,400.4 m. The normal pressure gradient is about 10 kPa/m. With this gradient, the initial pressure should be about 14,000 kPa. The reservoir is severely under-pressured. This has important implications. Firstly, the reservoir can be pressured to a much higher pressure. The normal fracture gradient is 18 kPa/m, so the maximum pressure is 25,000 kPa. Secondly, $CO_2$ may not be miscible with the oil at the original reservoir pressure, but it may become miscible if the reservoir pressure is increased. This seems to be the case in the Chigwell Viking I pool and is probably the case in the Joffre Viking pool as well.

The Joffre Viking $CO_2$ miscible flood area is shown in Figure 48, and plots showing historical performance are given in Figures 49 and 50.

The estimated primary recovery factor for the pool was 16 percent. The incremental EOR recovery factor with the $CO_2$ injection was 18 percent. The remaining OIP is 3.286 x $10^6$ $m^3$.

### References

1. Joffre Viking Tertiary Oil Unit, $CO_2$ Miscible Flood, AEUB Approval No. 9838C, Progress Report No. 15, January1, 2006 - January31, 2006.
2. Ko, S. C. M., Stanton, P. M., and Stephenson, D. J. "Tertiary Recovery Potential Of CO2 Flooding In Joffre Viking Pool, Alberta". JCPT paper# 85-01-01, 1985.

3. Pyo, K., Damian-Diaz, N., Powell, M., and Van Nieuwkerk, J. "CO2 Flooding in Joffre Viking Pool". Canadian International Petroleum Conference paper# 2003-109, 2003.
4. Stephenson, Derril J., Graham, Andrew G., and Luhning, Richard W. "Mobility Control Experience in the Joffre Viking Miscible CO2 Flood". SPE paper# 23598, 1993.

### Judy Creek BeaverHill Lake A

The Judy Creek A pool is a light-medium oil carbonate reservoir at a depth of 2,628.6 m. The oil gravity is 41°API. The average porosity is 0.09, the average permeability is 65.3 mD, the average water saturation is 0.16 and the initial reservoir pressure is 22,564 kPa. The OOIP in the pool was 77.950 x $10^6$ $m^3$.

The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 51 and 52. The EOR project assessment is shown in Table 18.

The historical HC solvent injection was started in February 2002 to August 2003. $CO_2$ injection started in February 2007, and it was supplemented with acid gas injection in April 2007. The Judy Creek $CO_2$ Pilot was ended in December 2010. WAG scheme started in 2007.

A plot of the Judy Creek A pool oil rate versus cumulative oil production is given in Figure 53. The location of the $CO_2$ EOR pilot and a cross-section of the pool can be found in Figure 54. An outline of the pilot is shown in Figure 55 along with a type log for well 07-02-064-11W5. The log shows the target reservoir interval for $CO_2$ injection. Figure 56 shows that the pilot acid gas injection composition did not exceed the maximum $H_2S$ concentration of 7 percent at any time.

The Judy Creek A pool solvent bank size and performance is given in Figure 57, and the $CO_2$ pilot performance to December 31, 2010 is shown in Figure 58. A plot of the voidage replacement ratio can be seen in Figure 59. Finally, the pattern injection and recovery data are given in Figure 60.

The estimated primary recovery factor was 16 percent. The incremental EOR recovery factor with the solvent-$CO_2$ injection was 9 percent. The remaining OIP is 38.970 x $10^6$ $m^3$.

### Summary

The operation is in compliance with ERCB approval. The voidage replacement ratio averaged 0.99 over the review period, and no wells operated below MOP. Three patterns completed solvent injection during the review period: HZ MFI 01-10-64-11W5 and re-floods at 02-35-

63-11W5 and 12-36-63-11W5. Seventeen WAG cycles were completed during the review period, and 14 WAG ratios exceeded 1.2. Higher WAGs resulted from new operational constraints.

**References**


1. Biberdorf, O.C. "Miscible Flood Forecasting Technique at Judy Creek". SPE paper# 12630, 1986.
2. Delaney, R. P., and Fish, A. M., "Judy Creek CO2 Flood Performance Predictions". JCPT paper # 80-31-23, 1980.
3. Judy Creek Beaverhill Lake A (2010-10269) Annual Presentation, Pengrowth, Annual Presentation, 27 January 2011.
4. Judy Creek $CO_2$ Flood Performance Predictions, R. P. Delaney, R. M. Fish, Esso Resources Canada Ltd. Petroleum Society of CIM Paper 80-31-23, May 1980.


## Judy Creek Beaverhill Lake B

The Judy Creek Beaverhill Lake B pool is a light-medium oil carbonate reservoir at a depth of 2,696.2 m, discovered in 1959. The oil gravity is 42.08°API. The average porosity is 0.099, the average permeability is 92.64 mD, the average water saturation is 0.17 and the initial reservoir pressure is 24,442 kPa. The OOIP in the pool was 28.370 x $10^6$ $m^3$.

Solvent flooding was started in 1987 and ended in 2004. The EOR project assessment is shown in Table 19.

The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 61 and 62.

The solvent flood resulted in improved oil recovery, as indicated in Figure 62. At the start of solvent injection, the oil rate went up from about 700 $m^3$/d to 900 $m^3$/d. The peak rate was followed by a shallower decline rate than earlier primary production for the next several years.

The estimated primary recovery factor for the pool was 20 percent, and the incremental EOR recovery factor was 5 percent. The remaining OIP was 14.469 x $10^6$ $m^3$.

**Overall Performance**

Enriched gas is very effective at mobilizing oil.

#### Summary

Miscible flood works in terms of incremental oil recovery, but early enriched gas breakthrough has led to bypassed oil.

#### References

1. Biberdorf, O.C. "Miscible Flood Forecasting Technique at Judy Creek". SPE paper# 12630, 1986.
2. Judy Creek Beaverhill Lake B (2010-10291) Annual Progress Report, Pengrowth, Annual Progress Report, 2010.

### Kaybob Beaverhill Lake A

Kaybob Beaverhill Lake A pool is a light-medium oil carbonate reservoir at a depth of 2,982 m. The oil gravity is 42.98°API. The average porosity is 0.08, the average permeability is 140.31 mD, the average water saturation is 0.21 and the initial reservoir pressure is 31,820 kPa. The OOIP in the pool was 36.830 x $10^6$ $m^3$.

Solvent flooding was started in 1988 and ended in 1994. The EOR project assessment is shown in Table 20. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 63 and 64.

The estimated primary recovery factor for the pool was 16 percent. The incremental EOR recovery factor with the solvent injection was 6.5 percent. The remaining OIP was 19.704 x $10^6$ $m^3$.

#### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.
2. MacLean, D. A., "Design of a Field-Wide Hydrocarbon Miscible Flood for the Kaybob Beaverhill Lake A Pool", JCPT paper# 89-03-01, 1989.

### Kaybob South Triassic A

The Kaybob South Triassic A pool is a light-medium oil carbonate reservoir at a depth of 2,060.4 m. The oil gravity is 39.39°API. The average porosity is 0.13, the average water saturation is 0.17 and the initial reservoir pressure is 16,844 kPa. The OOIP in the pool was 16.880 x $10^6$ $m^3$.

The EOR project assessment is shown in Table 21. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 65 and 66.

The estimated primary recovery factor for the pool was 15 percent. The incremental EOR recovery factor with the solvent injection was 5 percent. The remaining OIP was 9.284 x $10^6$ $m^3$.

**References**

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Leduc D-2A

The Leduc D-2A pool is a light-medium oil carbonate reservoir at a depth of 1,486.6 m. The oil gravity is 38.16°API. The average porosity is 0.034, the average permeability is 297.1 mD, the average water saturation is 0.26 and the initial reservoir pressure is 10,441 kPa. The OOIP in the pool was 62.650 x $10^6$ $m^3$.

The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 67 and 68. The EOR project assessment is shown in Table 22.

The estimated primary recovery factor for the pool was 25 percent. The incremental EOR recovery factor with the solvent injection was 9 percent. The remaining OIP is 23.807 x $10^6$ $m^3$.

**References**

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Mitsue Gilwood A

The Mitsue Gilwood A pool is a light-medium oil sandstone reservoir at a depth of 1,659.1 m. The oil gravity is 43.08°API. The average porosity is 0.144, the average permeability is 234.02 mD, the average water saturation is 0.36 and the initial reservoir pressure is 12,323 kPa. The OOIP in the pool was 63.672 x $10^6$ $m^3$.

Gas injection started in the pool in 1972, and solvent flooding began in 1985. The EOR project assessment is shown in Table 23. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 69 and 70. Solvent flooding ended in 1992. Gas injection was terminated four years later, in 1996.

The estimated primary recovery factor for the pool was 25 percent. The incremental EOR recovery factor with the solvent injection was 15 percent. The remaining OIP is 24.832 x $10^6$ $m^3$.

**References**

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Nipisi Gilwood A

The Nipisi Gilwood A pool is a light-medium oil sandstone reservoir at a depth of 1,711 m. The oil gravity is 41.08°API. The average porosity is 0.15, the average permeability is 479.19 mD, the average water saturation is 0.35 and the initial reservoir pressure is 17,948 kPa. The OOIP in the pool was 69.480 x $10^6$ $m^3$.

Gas injection started in the pool in 1984, and solvent flooding began two years later, in 1986. The EOR project assessment is shown in Table 24. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 71 and 72. Solvent flooding ended in 1994, and gas injection was terminated two years later, in 1996.

The estimated primary recovery factor for the pool was 26 percent. The incremental EOR recovery factor with the solvent injection was 15.9 percent. The remaining OIP was 31.683 x $10^6$ $m^3$.

**References**

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Pembina Cardium A Lease $CO_2$ Project

The Pembina Cardium A pool is a light-medium oil sandstone reservoir at a depth of 1,600 m. The oil gravity is 38.1°API. The average porosity is 0.121, the average permeability is 30 mD, the average water saturation is 0.15 and the initial reservoir pressure is 33,807 kPa. The OOIP in the pool was 3.000 x $10^6$ $m^3$.

The main objectives of the pilot were to demonstrate the technical and economical feasibility of $CO_2$ EOR in Pembina Cardium; improve productivity and sweep by making use of horizontal producers and existing vertical injectors; improve conformance through an off-trend line drive pattern configuration; develop $CO_2$ flood operational experience using horizontal wells; identify operational challenges (i.e., wax, GOR control, corrosion); and validate and tune the simulation model (response profile, recycle, recovery, etc.).

Pembina Cardium A is located adjacent to Penn West's initial "A" Lease vertical $CO_2$ pilot. The project was targeting the residual oil in well flooded areas (those with a high water cut). $CO_2$ injection commenced in September 2008.

The location of the Pembina Cardium A pool is given in Figure 73, and the location of the $CO_2$ pilot is shown in Figure 74. The response of the wells to $CO_2$ injection can be seen in Figures 75 to 77.

The following is the horizontal $CO_2$ pilot summary for June 2010:

- OOIP = 289 $Mm^3$
- Cumulative $CO_2$ injection = 0.45 Bcf
- Cumulative $CO_2$ injection = 8.24% HCPV
- Cumulative oil production (allocated) = 2.45 $Mm^3$
- Cumulative oil production (allocated) = 0.9%
- Ultimate incremental oil production = 31.8 $Mm^3$
- Ultimate incremental oil recovery = 11%

### Main Result Indicators

- Higher current oil rates than pre-$CO_2$ rates in most wells, and increased oil cut;
- Oil production increase at $CO_2$ breakthrough in most wells;
- Change in oil decline curve;
- Increased $CO_2$ concentration in produced gas after one month of $CO_2$ injection (100-12-12-048-09W5);
- Gradual $CO_2$ breakthrough (GOR and $CO_2$ content of produced gas) and good $CO_2$ retention factor;
- Preferential $CO_2$ breakthrough in a NE-SW direction;
- Decent $CO_2$ injectivity in injectors;
- Actual and predicted values are very close.

### Summary

Target fluid production and injection rates were achieved, but target $CO_2$ injectivity was not. Injector/producer communication was identified. Pressure was maintained above the MMP, and miscibility was achieved. Pilot operations were safe and successful for 1.5 years. Direct oil-$CO_2$ response was observed in well 12-11-048-09W5, and better sweep efficiency was observed in the NW-SE direction. No significant operational problems were experienced.

#### Future Plans

- Inject water in both injectors to maintain voidage,
- Continue Geochem and pressure monitoring Pembina A Lease horizontal pilot
- Continue quarterly gas sampling of the pilot and non-pilot wells,
- Design commercial flood around the pilot location.

The vertical well pilot has been under water injection since April 2009 and has ongoing Geochem and pressure monitoring. There is also ongoing quarterly gas sampling of the pilot and non-pilot wells.

The EOR project assessment is shown in Table 25.

The estimated primary recovery factor for the pool was 40.5 percent. The incremental EOR recovery factor with the solvent injection was 30 percent. The remaining OIP is $0.525 \times 10^6$ $m^3$.

#### References

1. Pembina Cardium 'A' Lease $CO_2$ Project, Penn West Energy, Approval 9780H, Energy Resources Conservation Board Update, (5 October 2010).

### Pembina Nisku A

The Pembina Nisku A pool is a light-medium oil carbonate reservoir at a depth of 3,005.7 m. The oil gravity is 44.08°API. The average porosity is 0.08, the average permeability is 954.26 mD, the average water saturation is 0.2 and the initial reservoir pressure is 33,807 kPa. The OOIP in the pool was $3.000 \times 10^6$ $m^3$.

Solvent flooding was started in 1986. The scheme was followed by chase gas injection in 1993, which was terminated in 1994. The EOR project assessment is shown in Table 26. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 78 and 79.

More details on similar Nisku pinnacle reefs can be found in the descriptions of the Brazeau Nisku A, D and E pools and the references cited in those sections.

The estimated primary recovery factor for the pool was 40.5 percent. The incremental EOR recovery factor with the solvent injection was 42 percent. The remaining OIP was 0.525 x $10^6$ $m^3$.

### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.
2. Pembina Nisku A Pool, Penn West Petroleum Ltd., Annual Progress Report, 22 January 2011, (2010-10658).

## Pembina Nisku D

The Pembina Nisku D pool is a light-medium oil carbonate reservoir at a depth of 2,576.6 m. The oil gravity is 36.75°API. The average porosity is 0.12, the average permeability is 1,331.6 mD, the average water saturation is 0.1 and the initial reservoir pressure is 25,808 kPa. The OOIP in the pool was 6.503 x $10^6$ $m^3$.

Solvent flooding was started in 1985. The scheme was followed by chase gas injection in 1989, which was terminated in 1997. The EOR project assessment is shown in Table 27. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 80 and 81.

More details on similar Nisku pinnacle reefs can be found in the descriptions of the Brazeau Nisku A, D and E pools and the references cited in those sections.

The estimated primary recovery factor for the pool was 35 percent. The incremental EOR recovery factor with the solvent injection was 35 percent. The remaining OIP is 1.951 x $10^6$ $m^3$.

### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.
2. Pembina Nisku D Pool, Penn West Petroleum Ltd., Annual Progress Report, 22 January 2011, (2010-10658).

## Pembina Nisku F

The Pembina Nisku F pool is a light-medium oil carbonate reservoir at a depth of 2,549.1 m. The oil gravity is 34.58°API. The average porosity is 0.119, the average permeability is

1,587.86 mD, the average water saturation is 0.28 and the initial reservoir pressure is 21,736 kPa. The OOIP in the pool was 2.201 x $10^6$ $m^3$.

More details on similar Nisku pinnacle reefs can be found in the descriptions of the Brazeau Nisku A, D and E pools and the references cited in those sections.

Solvent flooding was started in 1987. The scheme was followed by chase gas injection in 1993, which was terminated in 2008. The EOR project assessment is shown in Table 28. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 82 and 83.

The estimated primary recovery factor for the pool was 35 percent. The incremental EOR recovery factor with the solvent injection was 45 percent. The remaining OIP is 0.440 x $10^6$ $m^3$.

**References**

1. ERCB Oil Reserves Detailed Report, 31 December 2010.
2. Pembina Nisku F Pool, Penn West Petroleum Ltd., Annual Progress Report, 22 January 2011, (2010-10658).

## Pembina Nisku G

The Pembina Nisku G pool is a light-medium oil carbonate reservoir at a depth of 2,906.3 m. The oil gravity is 43.19°API. The average porosity is 0.08, the average permeability is 2,603.57 mD, the average water saturation is 0.2 and the initial reservoir pressure is 27,547 kPa. The OOIP in the pool was 2.650 x $10^6$ $m^3$.

More details on similar Nisku pinnacle reefs can be found in the descriptions of the Brazeau Nisku A, D and E pools and the references cited in those sections.

Gas injection was started in 1982. The EOR project assessment is shown in Table 29. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 84 and 85. Gas injection was terminated in 2005.

The estimated primary recovery factor for the pool was 40.8 percent. The incremental EOR recovery factor with the solvent injection was 50 percent. The remaining OIP is 0.244 x $10^6$ $m^3$.

### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Pembina Nisku G2G

The Pembina Nisku G2G pool is a light-medium oil carbonate reservoir at a depth of 3,081.6 m. The oil gravity is 41.99°API. The average porosity is 0.08, the average permeability is 390.39 mD, the average water saturation is 0.12 and the initial reservoir pressure is 32,090 kPa. The OOIP in the pool was 2.406 x $10^6$ $m^3$.

More details on similar Nisku pinnacle reefs can be found in the descriptions of the Brazeau Nisku A, D and E pools and the references cited in those sections.

Solvent flooding was started in 1984. The scheme was followed by chase gas injection in 1989, which was terminated in 1994. The EOR project assessment is shown in Table 30. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 86 and 87.

The estimated primary recovery factor for the pool was 35 percent. The incremental EOR recovery factor with the solvent injection was 28 percent. The remaining OIP is 0.890 x $10^6$ $m^3$.

### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.
2. Pembina Nisku G2G Pool, Penn West Petroleum Ltd., Annual Progress Report, 22 January 2011, (2010-10658).

## Pembina Nisku H2H

The Pembina Nisku H2H pool is a light-medium oil carbonate reservoir at a depth of 3,033.3 m. The oil gravity is 40.22°API. The average porosity is 0.11, the average water saturation is 0.14 and the initial reservoir pressure is 31,373 kPa. The OOIP in the pool was 4.000 x $10^6$ $m^3$.

More details on similar Nisku pinnacle reefs can be found in the descriptions of the Brazeau Nisku A, D and E pools and the references cited in those sections.

Solvent flooding was started in 1984. The scheme was followed by chase gas injection in 1990, which was terminated in 1994. The EOR project assessment is shown in Table 31. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 88 and 89.

The solvent flood resulted in improved oil recovery, as seen in Figure 89. Following injection, the oil rate increased from about 700 $m^3$/d in 1984 to about 1,000 $m^3$/d in 1990, at which point the production started to decline. Solvent flooding was completed in 1991, and chase gas injection was terminated in 1994.

The estimated primary recovery factor for the pool was 40 percent. The incremental EOR recovery factor with the solvent injection was 47 percent. The remaining OIP was $0.520 \times 10^6$ $m^3$.

**References**

1. ERCB Oil Reserves Detailed Report, 31 December 2010.
2. Pembina Nisku H2H Pool, Penn West Petroleum Ltd., Annual Progress Report, 22 January 2011, (2010-10658).

## Pembina Nisku K

The Pembina Nisku K pool is a light-medium oil carbonate reservoir at a depth of 2,892.9 m. The oil gravity is 43.62°API. The average porosity is 0.127, the average permeability is 1,784.6 mD, the average water saturation is 0.18 and the initial reservoir pressure is 28,706 kPa. The OOIP in the pool was $2.753 \times 10^6$ $m^3$.

More details on similar Nisku pinnacle reefs can be found in the descriptions of the Brazeau Nisku A, D and E pools and the references cited in those sections.

Gas injection started in 1981, and solvent flooding commenced five years later, in 1986. The EOR project assessment is shown in Table 32. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 90 and 91.

The injection scheme resulted in improved oil recovery, as seen in Figure 91. Following injection, the oil rate slowly increased from about 300 $m^3$/d in 1982 to about 600 $m^3$/d in 1991, at which point the production started to decline. The oil rate increase can likely be partially attributed to an additional well coming on stream. Solvent flooding was completed in 1987, and gas injection was terminated in 2005.

The estimated primary recovery factor for the pool was 40 percent. The incremental EOR recovery factor with the solvent injection was 48 percent. The remaining OIP was 0.330 x $10^6$ $m^3$.

#### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

### Pembina Nisku L

The Pembina Nisku L pool is a light-medium oil carbonate reservoir at a depth of 2,880.6 m. The oil gravity is 40.85°API. The average porosity is 0.105, the average permeability is 2,427.51 mD, the average water saturation is 0.12 and the initial reservoir pressure is 28,222 kPa. The OOIP in the pool was 5.000 x $10^6$ $m^3$.

Solvent flooding was started in 1985. The scheme was followed by gas injection in 1989, which was terminated in 2009. The EOR project assessment is shown in Table 33. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 92 and 93.

The injection scheme resulted in improved oil recovery, as seen in Figure 93. Following injection, the oil rate slowly increased from about 900 $m^3$/d in 1985 to about 1,200 $m^3$/d in 1989, at which point the production started to decline. Solvent flooding was completed in 1989, and gas injection was terminated in 2009.

More details on similar Nisku pinnacle reefs can be found in the descriptions of the Brazeau Nisku A, D and E pools and the references cited in those sections.

The estimated primary recovery factor for the pool was 25 percent. The incremental EOR recovery factor with the solvent injection was 63 percent. The remaining OIP was 0.600 x $10^6$ $m^3$.

#### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

### Pembina Nisku M

The Pembina Nisku M pool is a light-medium oil carbonate reservoir at a depth of 2,850.1 m. The oil gravity is 41.06°API. The average porosity is 0.09, the average permeability is 1,551.53 mD, the average water saturation is 0.09 and the initial reservoir pressure is 27,909 kPa. The OOIP in the pool was 3.120 x $10^6$ $m^3$.

More details on similar Nisku pinnacle reefs can be found in the descriptions of the Brazeau Nisku A, D and E pools and the references cited in those sections.

Gas injection in the pool began in 1983 and ended in 2009. The EOR project assessment is shown in Table 34. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 94 and 95.

The estimated primary recovery factor for the pool was 40 percent. The incremental EOR recovery factor with the solvent injection was 45 percent. The remaining OIP was 468,000 $m^3$.

**References**

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Pembina Nisku O

The Pembina Nisku O pool is a light-medium oil carbonate reservoir at a depth of 2,844 m. The oil gravity is 43.41°API. The average porosity is 0.118, the average permeability is 3,941.39 mD, the average water saturation is 0.16 and the initial reservoir pressure is 26,949 kPa. The OOIP in the pool was 1.900 x $10^6$ $m^3$.

More details on similar Nisku pinnacle reefs can be found in the descriptions of the Brazeau Nisku A, D and E pools and the references cited in those sections.

Gas injection started in 1983, and solvent flooding began three years later, in 1986. The EOR project assessment is shown in Table 35. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 96 and 97.

The injection scheme resulted in improved oil recovery, as seen in Figure 97. Following injection, the oil rate slowly increased from about 300 $m^3$/d in 1983 to about 380 $m^3$/d in 1992, at which point the production started to decline. Solvent flooding was completed in 1990, and gas injection was terminated in 2004.

The estimated primary recovery factor for the pool was 40 percent. The incremental EOR recovery factor with the solvent injection was 40 percent. The remaining OIP is 0.380 x $10^6$ $m^3$.

### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Pembina Nisku P

The Pembina Nisku P pool is a light-medium oil carbonate reservoir at a depth of 2,909.4 m. The oil gravity is 45.49°API. The average porosity is 0.11, the average permeability is 1,477.58 mD, the average water saturation is 0.1 and the initial reservoir pressure is 28,226 kPa. The OOIP in the pool was 4.740 x $10^6$ $m^3$.

More details on similar Nisku pinnacle reefs can be found in the descriptions of the Brazeau Nisku A, D and E pools and the references cited in those sections.

Gas injection started in 1983, and solvent flooding commenced three years later, in 1986. The EOR project assessment is shown in Table 36. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 98 and 99.

The injection scheme resulted in improved oil recovery, as seen in Figure 99. Following injection, the oil rate slowly increased from about 700 $m^3$/d in 1983 to about 1,000 $m^3$/d in 1991, at which point the production started to decline. Solvent flooding was completed in 1989, and gas injection was terminated in 2007.

The estimated primary recovery factor for the pool was 35 percent. The incremental EOR recovery factor with the solvent injection was 45 percent. The remaining OIP was 0.948 x $10^6$ $m^3$.

### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Pembina Nisku P2P

The Pembina Nisku P2P pool is a light-medium oil carbonate reservoir at a depth of 2,932.7 m. The oil gravity is 42.08°API. The average porosity is 0.1, the average permeability is 703.36 mD, the average water saturation is 0.12 and the initial reservoir pressure is 38,036 kPa. The OOIP in the pool was 2.850 x $10^6$ $m^3$.

More details on similar Nisku pinnacle reefs can be found in the descriptions of the Brazeau Nisku A, D and E pools and the references cited in those sections.

Solvent flooding began in 1982, and it was followed by gas injection in 1991. The EOR project assessment is shown in Table 37. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 100 and 101.

The injection scheme resulted in improved oil recovery, as seen in Figure 101. Following injection, the oil rate slowly increased from about 600 $m^3$/d in 1987 to about 700 $m^3$/d in 1991, at which point the production started to decline. Solvent flooding was completed in 1993, and gas injection was terminated in 1994.

The estimated primary recovery factor for the pool was 40 percent. The incremental EOR recovery factor with the solvent injection was 45 percent. The remaining OIP was 0.428 x $10^6$ $m^3$.

**References**

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Pembina Nisku Q

The Pembina Nisku Q pool is a light-medium oil carbonate reservoir at a depth of 2,880.5 m. The oil gravity is 41.27°API. The average porosity is 0.098, the average permeability is 1,024.24 mD, the average water saturation is 0.09 and the initial reservoir pressure is 28,560 kPa. The OOIP in the pool was 2.800 x $10^6$ $m^3$.

More details on similar Nisku pinnacle reefs can be found in the descriptions of the Brazeau Nisku A, D and E pools and the references cited in those sections.

Solvent flooding began in 1986 and was followed by gas injection in 1987. The EOR project assessment is shown in Table 38. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 102 and 103.

The injection scheme resulted in improved oil recovery, as seen in Figure 103. Following injection, the oil rate slowly increased from about 600 $m^3$/d in 1987 to about 700 $m^3$/d in 1990, at which point the production started to decline. Solvent flooding was completed in 1988, and gas injection was terminated in 2005.

The estimated primary recovery factor for the pool was 40 percent. The incremental EOR recovery factor with the solvent injection was 29 percent. The remaining OIP was 0.868 x $10^6$ $m^3$.

**References**

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Provost Cummings I

The Provost Cummings I pool is a heavy oil sandstone reservoir at a depth of 763.3 m. The oil gravity is 23.99°API. The average porosity is 0.28, the average permeability is 384.82 mD, the average water saturation is 0.23 and the initial reservoir pressure is 5,430 kPa.

An experimental solvent flood was conducted in the pool from 1989 to 1991 using gas injection.

The EOR project assessment is shown in Table 39. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 104 and 105.

The estimated primary recovery factor for the pool was 35 percent.

**References**

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Rainbow Keg River A

The Rainbow Keg River A pool is a light-medium oil carbonate reservoir at a depth of 1,833.6 m. The oil gravity is 43.08°API. The average porosity is 0.101, the average permeability is 2007.68 mD, the average water saturation is 0.1 and the initial reservoir pressure is 17,662 kPa. The OOIP in the pool was 14.320 x $10^6$ $m^3$.

Gas injection began in 1966, followed by water injection in 1994. The EOR project assessment is shown in Table 40. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 106 and 107.

The injection scheme resulted in improved oil recovery, as seen in Figure 107. Following gas injection, the oil rate remained fairly stable between 1,200 and 1,500 $m^3$/d, until 1983, at which point the production started to decline. Gas injection was completed by 2002, and water injection was terminated in 2005.

The estimated primary recovery factor for the pool was 50 percent. The incremental EOR recovery factor with the solvent injection was 25 percent. The remaining OIP was $3.580 \times 10^6$ $m^3$.

**References**

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Rainbow Keg River AA

The Rainbow Keg River AA pool is a light-medium oil carbonate reservoir at a depth of 1,682.4 m. It has an oil gravity of 39.11°API, an average porosity of 0.086, an average permeability of 1,485.43 mD, an average water saturation of 0.11 and an initial reservoir pressure of 18,104 kPa. The OOIP in the pool was $14.320 \times 10^6$ $m^3$.

Gas injection began in 1969. The EOR project assessment is shown in Table 41. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 108 and 109.

The estimated primary recovery factor for the pool was 45 percent. The incremental EOR recovery factor with the solvent injection was 22.3 percent. The remaining OIP was $4.683 \times 10^6$ $m^3$.

**References**

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Rainbow Keg River B

The Rainbow Keg River B pool is a light-medium oil carbonate reservoir at a depth of 1,819.7 m. The oil gravity is 38.1°API. The average porosity is 0.09, the average permeability is 1,960.7 mD, the average water saturation is 0.14 and the initial reservoir pressure is 17,173 kPa. The OOIP in the pool was $46.820 \times 10^6$ $m^3$.

Gas injection started in 1982, and solvent flooding began five years later, in 1987. The EOR project assessment is shown in Table 42. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 110 and 111.

Water-alternating-gas (WAG) was also tried, but it was discontinued in one part of the approval area at the end of 2009 due to lack of evidence of its benefit in terms of reducing producing gas-oil ratios (GORs) in that part of the approval area. Husky Energy, the Operator, also decided not to re-institute WAG operations in any part of the pool in the future.

The estimated primary recovery factor for the pool was 40 percent. The incremental EOR recovery factor with the solvent injection was 25 percent. The remaining OIP was 16.387 x $10^6$ $m^3$.

#### References

1. Amendments to Approval No. 8967E for Rainbow Keg River B Pool, January 21, 2011.
2. Betiu, M., Ramler, L., and Barden, I. "Rainbow Keg River B" Pool Hydrocarbon Miscible Flood Project"". Annual Technical Meeting paper# 82-33-29, 1982.
3. ERCB Oil Reserves Detailed Report, 31 December 2010.
4. Fong, D. K., Wong, F. Y., Nagel, R. G., and Peggs, J. K. "Combining A Volumetric Model With A Pseudo-Miscible Field Simulation To Achieve Uniform Fluid Levelling In The Rainbow Keg River B" Pool"". JCPT paper# 91-01-05, 1991.

### Rainbow Keg River D

The Rainbow Keg River D pool is a light-medium oil carbonate reservoir at a depth of 1,905.3 m. The oil gravity is 40.1°API. The average porosity is 0.1, the average permeability is 675.97 mD, the average water saturation is 0.08 and the initial reservoir pressure is 17,710 kPa. The OOIP in the pool was 1.130 x $10^6$ $m^3$.

Gas injection started in 1976 and ended in 1999. The EOR project assessment is shown in Table 43. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 112 and 113.

The estimated primary recovery factor for the pool was 40 percent. The incremental EOR recovery factor with the solvent injection was 28 percent. The remaining OIP is 0.362 x $10^6$ $m^3$.

#### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

### Rainbow Keg River E

The Rainbow Keg River E pool is a light-medium oil carbonate reservoir at a depth of 1,840.6 m. The oil gravity is 39.11°API. The average porosity is 0.117, the average permeability is 194.92 mD, the average water saturation is 0.08 and the initial reservoir pressure is 18,126 kPa. The OOIP in the pool was 5.541 x $10^6$ $m^3$.

Gas injection began in 1972 and was completed by 2007. The EOR project assessment is shown in Table 44. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 114 and 115.

The estimated primary recovery factor for the pool was 29.1 percent. The incremental EOR recovery factor with the solvent injection was 20 percent. The remaining OIP is 2.820 x $10^6$ $m^3$.

#### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

### Rainbow Keg River EEE

The Rainbow Keg River EEE pool is a light-medium oil carbonate reservoir at a depth of 1,847.4 m. The oil gravity is 37.09°API. The average porosity is 0.147, the average permeability is 261.27 mD, the average water saturation is 0.07 and the initial reservoir pressure is 14,253 kPa. The OOIP in the pool was 1.580 x $10^6$ $m^3$.

Gas injection began in 1970 and was completed by 2009. The EOR project assessment is shown in Table 45. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 116 and 117.

The estimated primary recovery factor for the pool was 39.9 percent. The incremental EOR recovery factor with the solvent injection was 9.8 percent. The remaining OIP was 0.795 x $10^6$ $m^3$.

#### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Rainbow Keg River F

Rainbow Keg River F pool is a light-medium oil reef carbonate reservoir at a depth of 1,785.5 m. The oil gravity is 40°API. The average porosity is 0.08, the average permeability is 771 mD, the average water saturation is 0.19 and the initial reservoir pressure is 13,673 kPa. The OOIP in the pool was 37.640 x $10^6$ $m^3$ (Husky reported an OOIP of 39 x $10^6$ $m^3$).

Primary production began in April 1966, and it was followed by gas injection in August 1968 and waterflood in December 1972. Tertiary immiscible gas flood was started in April 1993, and Tertiary hydrocarbon miscible floods were started in the NW lobe and in the whole pool in April 1996 and April 2000, respectively.

### Geologic Description

The pool is an extensively dolomitized carbonate build-up with four major lobes and a heterogeneous pore system characterized by ten different pore types. Overall, it has excellent horizontal and vertical permeability. The original gas-oil contact was at ~1,310 mSS in all lobes, and the original oil-water contact was at 1,408 mSS, giving ~98 m of oil bank.

The EOR project assessment is shown in Table 46. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 118 and 119.

A structure map of the Keg River F pool is shown in Figure 120. The production performance of the pool is given in Figure 121 and a prediction of the ultimate oil can be found in Figure 122. A graph of the historical voidage replacement ratio of the pool is given in Figure 123, and the reservoir pressure history of the pool is shown in Figure 124. Finally, plots showing the injected solvent composition can be seen in Figures 125 to 127.

The estimated primary recovery factor for the pool was 38 percent. The incremental EOR recovery factor with the solvent injection was 15 percent. The remaining OIP was 17.691 x $10^6$ $m^3$.

### Current and Future Plans

Work-overs were conducted as required, to follow the oil bank down-reef either through deepening or re-completing lower, and to maintain mechanical integrity. The 2008 Work-over were on wells 02/14-28-108-07W6, 00/04-33-108-07W6, and 00/03-05-109-07W6. In

2009, they were conducted on wells 00/14-28-108-07W6 and 00/09-28-108-07W6, and 2010 on wells 00/15-05-109-07W6 and 02/14-28-108-07W6.

Temperature from the logs of 8 injection wells was recorded in 2009. Infill drilling was continued. The simulation model was to be updated, and development should continue.

### Conclusions

Husky Oil Operations Limited is in compliance with the requirements and conditions stated in Approval No. 10376B for the enhanced recovery of oil by miscible displacement using solvent and chase gas injection in the Rainbow Keg River F pool.

Husky Oil Operations Limited has no plans to stop the scheme in the foreseeable future, since it makes good economic use of available gas and NGL products.

The ultimate recoverable oil currently assigned by the ERCB for the tertiary scheme (19,946 x $10^3$ $m^3$) is preliminary and attainable.

### References

1. 2010 Energy Resources Conservation Board (ERCB), Performance Review, Rainbow Keg River F Pool, Tertiary Miscible Flood Scheme, Annual Presentation, Husky Oil Operations, January 25, 2011.

## Rainbow Keg River FF

The Rainbow Keg River FF pool is a light-medium oil carbonate reservoir at a depth of 1,718.7 m. The oil gravity is 37.09°API. The average porosity is 0.11, the average permeability is 1,195.13 mD, the average water saturation is 0.1 and the initial reservoir pressure is 15,797 kPa. The OOIP in the pool was 4.177 x $10^6$ $m^3$.

Gas injection began in 1972. The EOR project assessment is shown in Table 47. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 128 and 129.

The injection scheme resulted in improved oil recovery, as seen in Figure 129. Following gas injection, the oil rate increased from 150 $m^3$/d in 1974 to about 200 m3/d in 1985. The rate peaked in 1987 at 500 m3/d after an additional well was brought on stream. The oil rate then began to decline rapidly in 1988, which is also when gas injection was terminated.

The estimated primary recovery factor for the pool was 21 percent. The incremental EOR recovery factor with the solvent injection was 15 percent. The remaining OIP was $2.673 \times 10^6$ $m^3$.

#### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

### Rainbow Keg River G

The Rainbow Keg River G pool is a light-medium oil carbonate reservoir at a depth of 1,909 m. The oil gravity is 39.11°API. The average porosity is 0.08, the average permeability is 218.79 mD, the average water saturation is 0.08 and the initial reservoir pressure is 17,120 kPa. The OOIP in the pool was $2.479 \times 10^6$ $m^3$.

Gas injection began in 1973 and was completed by 2001. The EOR project assessment is shown in Table 48. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 130 and 131.

The estimated primary recovery factor for the pool was 43.4 percent. The incremental EOR recovery factor with the solvent injection was 41.8 percent. The remaining OIP was $0.367 \times 10^6$ $m^3$.

#### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

### Rainbow Keg River H

The Rainbow Keg River H pool is a light-medium oil carbonate reservoir at a depth of 1,913.9 m. The oil gravity is 39.11°API. The average porosity is 0.094, the average permeability is 353.64 mD, the average water saturation is 0.1 and the initial reservoir pressure is 19,805 kPa. The OOIP in the pool was $2.833 \times 10^6$ $m^3$.

Gas injection began in 1974. The EOR project assessment is shown in Table 49. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 132 and 133.

The injection scheme resulted in improved oil recovery, as seen in Figure 133. Following gas injection, the oil rate remained fairly constant at 300 $m^3$/d from 1974 until 1982, at which point another well came on stream. The oil rate began to decline in 1985, three years later. Gas injection was terminated in 1997.

The estimated primary recovery factor for the pool was 39.2 percent. The incremental EOR recovery factor with the solvent injection was 20 percent. The remaining OIP was 1.156 x $10^6$ $m^3$.

#### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

### Rainbow Keg River II

The Rainbow Keg River II pool is a light-medium oil carbonate reservoir at a depth of 1,832.9 m. The oil gravity is 41.08°API. The average porosity is 0.1, the average water saturation is 0.12 and the initial reservoir pressure is 17,106 kPa. The OOIP in the pool was 3.800 x $10^6$ $m^3$.

Gas injection started in 1982 and was followed by a solvent flood in 1987. The EOR project assessment is shown in Table 50. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 134 and 135.

The injection scheme resulted in improved oil recovery, as seen in Figure 135. Following gas injection, the oil rate increased from about 60 $m^3$/d in 1988 to about 100 $m^3$/d in 1990, at which point another well came on stream. The oil rate peaked in 1995 at 200 $m^3$/d, after which point it began to decline rapidly. Gas injection was terminated in 2010.

The estimated primary recovery factor for the pool was 45 percent. The incremental EOR recovery factor with the solvent injection was 15.5 percent. The remaining OIP was 1.501 x $10^6$ $m^3$.

#### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.
2. Todd, M. R., Slotbroom, R. A., and Bates, G. M. "Evaluation Of A Tertiary Miscible Flood In The Keg River II Pool, Rainbow Field". Annual Technical Meeting paper# 84-35-20, 1984.

## Rainbow Keg River O

The Rainbow Keg River O pool is a light-medium oil carbonate reservoir at a depth of 1,854.1 m. The oil gravity is 42.08°API. The average porosity is 0.06, the average permeability is 2,900.89 mD, the average water saturation is 0.13 and the initial reservoir pressure is 16,875 kPa. The OOIP in the pool was 6.200 x $10^6$ $m^3$.

Gas injection started in 1970 and was terminated in 2004. The EOR project assessment is shown in Table 51. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 136 and 137.

The estimated primary recovery factor for the pool was 40 percent. The incremental EOR recovery factor with the solvent injection was 27.7 percent. The remaining OIP was 2.003 x $10^6$ $m^3$.

### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Rainbow Keg River Z

The Rainbow Keg River Z pool is a light-medium oil carbonate reservoir at a depth of 1,609.3 m. The oil gravity is 38.1°API. The average porosity is 0.076, the average permeability is 3,901.61 mD, the average water saturation is 0.27 and the initial reservoir pressure is 11,790 kPa. The OOIP in the pool was 3.904 x $10^6$ $m^3$.

Gas injection began in 1971. The EOR project assessment is shown in Table 52. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 138 and 139.

The injection scheme resulted in improved oil recovery, as seen in Figure 139. Following gas injection, the oil rate remained fairly constant at about 120 $m^3$/d until 1983. The oil rate peaked at about 600 m3/d in 1993, after several more wells came on production. The rate then began to decline. Gas injection was terminated in 2009.

The estimated primary recovery factor for the pool was 32 percent. The incremental EOR recovery factor with the solvent injection was 33 percent. The remaining OIP is 1.366 x $10^6$ $m^3$.

### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Rainbow South Keg River B

The Rainbow South Keg River B pool is a light-medium oil carbonate reservoir at a depth of 1,875.7 m. The oil gravity is 39.81°API. The average porosity is 0.077, the average permeability is 2,237.23 mD, the average water saturation is 0.12 and the initial reservoir pressure is 18,319 kPa. The OOIP in the pool was 7.890 x $10^6$ $m^3$.

Solvent flooding commenced in 1994 and was terminated in 2007. The EOR project assessment is shown in Table 53. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 140 and 141.

The estimated primary recovery factor for the pool was 44 percent. The incremental EOR recovery factor with the solvent injection was 21 percent. The remaining OIP was 2.762 x $10^6$ $m^3$.

### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Rainbow South Keg River E

The Rainbow South Keg River E pool is a light-medium oil carbonate reservoir at a depth of 1,945.9 m. The oil gravity is 40°API. The average porosity is 0.1, the average permeability is 503.88 mD, the average water saturation is 0.1 and the initial reservoir pressure is 18,944 kPa. The OOIP in the pool was 8.775 x $10^6$ $m^3$.

Solvent flooding commenced in 1994 and was terminated in 2007. The EOR project assessment is shown in Table 54. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 142 and 143.

The estimated primary recovery factor for the pool was 26 percent. The incremental EOR recovery factor with the solvent injection was 10 percent. The remaining OIP was 5.616 x $10^6$ $m^3$.

### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Rainbow South Keg River G

The Rainbow South Keg River G pool is a light-medium oil carbonate reservoir at a depth of 1,931 m. The oil gravity is 44.08°API. The average porosity is 0.088, the average permeability is 66.34 mD, the average water saturation is 0.11 and the initial reservoir pressure is 17,946 kPa. The OOIP in the pool was 4.359 x $10^6$ $m^3$.

The EOR project assessment is shown in Table 55. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 144 and 145.

The estimated primary recovery factor for the pool was 20 percent. The incremental EOR recovery factor with the solvent injection was 12 percent. The remaining OIP is 2.964 x $10^6$ $m^3$.

### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Redwater D-3

The Redwater D-3 pool is a light-medium oil dolomite reservoir at a depth of 983.7 m. The oil gravity is 36.09°API. The average porosity is 0.065, the average permeability is 1,411.02 mD, the average water saturation is 0.25 and the initial reservoir pressure is 7,824 kPa.

The EOR project assessment is shown in Table 56. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 146 and 147.

The experimental hydrocarbon miscible flood consisted of four inverted five-spot patterns. It was started in 1985 and continued to at least 1990. By 1990, the incremental oil recovery from pattern 11A was 4.4 percent, and it was 5.6 percent from pattern 9C, for an average of 5.0 percent.

The estimated primary recovery factor for the pool as a whole was 65 percent.

### References


1. ERCB Oil Reserves Detailed Report, 31 December 2010.
2. Redwater D-3 Miscible Flood Experimental Pilot, Esso Resources Canada Limited, Progress report No. 1, January 1, 1985 - June 30, 1986
3. Redwater D-3 Miscible Flood Experimental Pilot, Esso resources Canada Limited, Progress report No. 10, July 1, 1989 - December 31, 1989.


## Rich D-3A

The Rich D-3A pool is a light-medium oil carbonate reservoir at a depth of 1,818.7 m. The oil gravity is 33.61°API. The average porosity is 0.11, the average water saturation is 0.10 and the initial reservoir pressure is 13,616 kPa. The OOIP in the pool was 1.333 x $10^6$ $m^3$.

The EOR project assessment is shown in Table 57. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 148 and 149.

The experimental pilot consisted of a single well sour gas injection scheme which started in September 1995. A total volume of 2,371.2 x $10^3$ $m^3$ was injected into well 9-36-34-21W4M by December 1995. The well was brought on production during February 21 to 25, 1996. Initially, the well flowed at a high GOR. Subsequently, it was put on stable pumping production. During March and April 1996, the well produced a total of 911.7 $m^3$ of oil, 198 x $10^3$ $m^3$ of gas and 5,988 $m^3$ of water in 1,464 hours, which gives a production capability of 14.95 $m^3$/d of oil at a water cut of 86.7 percent and 217 $m^3/m^3$ GOR. Prior to the scheme, the well produced at an average rate of 4 $m^3$/d of oil at a watercut of 98.5 percent and 90 $m^3/m^3$ GOR. These results were interpreted to indicate that there was remaining unrecovered attic oil in the pool.

The original oil was highly undersaturated. Based on the change in the GOR, the operator estimated that the OOIP in the attic was less than 18,670 $m^3$. The estimated primary recovery factor for the pool was 46 percent.

### References


1. ERCB Oil Reserves Detailed Report, 31 December 2010.
2. Rich D-3A Pool EUB Approval No. 7809 Experimental Single Well Sour Gas Injection Scheme, Gulf Canada Resources Limited, Progress Report No. 1, Sept 1, 1995 - April 30, 1996.

## Simonette D-3

The Simonette D-3 pool is a light-medium oil carbonate reservoir at a depth of 3,542 m. The oil gravity is 47.09°API. The average porosity is 0.062, the average permeability is 337.65 mD, the average water saturation is 0.16 and the initial reservoir pressure is 35,520 kPa. The OOIP in the pool was 1.200 x $10^6$ $m^3$.

The EOR project assessment is shown in Table 58. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 150 and 151. No details of the project were located.

The estimated primary recovery factor for the pool was 40 percent. The incremental EOR recovery factor with the solvent injection was 6 percent.

### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Suffield Lower Mannville J

The Suffield Lower Mannville J pool is a heavy oil sandstone reservoir at a depth of 1,004.6 m. The oil gravity is 14.53°API. The average porosity is 0.25, the average water saturation is 0.44 and the initial reservoir pressure is 10,677 kPa. The OOIP in the pool was 0.625 x $10^6$ $m^3$.

The EOR project assessment is shown in Table 59. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 152 and 153.

This project involved gas injection, but it was not designed as a miscible flood test but as an anti-water coning test. Gas injection tests were conducted at eight single well locations, while three of the AWACT wells utilized gas only, five wells had a chemical wetting agent added to the gas treatment program to evaluate its effectiveness in controlling water production. One single well test was conducted utilizing the chemical wetting agent without gas injection to monitor its effect on production rates. The tests have been successful in increasing oil production, reducing water production and extending the production life of several wells.

The estimated primary recovery factor for the pool as a whole was 1.2 percent.

### References


1. ERCB Oil Reserves Detailed Report, 31 December 2010.
2. Suffield Experimental Anti-Water Coning, AEC Oil and Gas Company, Semi-Annual ERCB Report, Aug 1, 1988 - March 31, 1989.


## Suffield Upper Mannville N

The Suffield Upper Mannville N pool is a heavy oil sandstone reservoir at a depth of 961.6 m. The oil gravity is 14.23°API. The average porosity is 0.26, the average water saturation is 0.34 and the initial reservoir pressure is 7,708 kPa. The OOIP in the pool was 2.600 x $10^6$ $m^3$.

An experimental solvent flood was conducted in the pool from 2003 to 2005 using solvent injection. No details of the project were located.

The EOR project assessment is shown in Table 60. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 154 and 155.

The estimated primary recovery factor for the pool was 12 percent.

### References


1. ERCB Oil Reserves Detailed Report, 31 December 2010.


## Swan Hills Beaverhill Lake A & B (Commingled 001)

The Swan Hills Beaverhill Lake A & B pool, now called Commingled 001, is a light-medium oil carbonate reservoir at a depth of 2,425.7 m. The oil gravity is 41.08°API. The average porosity is 0.08, the average water saturation is 0.19 and the initial reservoir pressure is 20,226 kPa. The OOIP in the pool was 163.698 x $10^6$ $m^3$.

Solvent flooding was started in 1986. The EOR project assessment is shown in Table 61. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 156 and 157.

The estimated primary recovery factor for the pool was 17 percent. The incremental EOR recovery factor with the solvent injection was 36 percent.

### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Swan Hills South Beaverhill Lake A

The Swan Hills South Beaverhill Lake A pool is a light-medium oil carbonate reservoir at a depth of 2,536.8 m. The oil gravity is 41.08°API. The average porosity is 0.084, the average water saturation is 0.16 and the initial reservoir pressure is 21,585 kPa.

Solvent flooding commenced in 1994. The EOR project assessment is shown in Table 62. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 158 and 159.

The Swan Hills South $CO_2$ pilot location can be seen in Figure 160, and the pilot scheme can be seen in Figure 161. The performance of injection wells 100/16-19-065-10W5 and 100/14-20-065-10W5 are given in Figures 162 and 163, respectively. The $CO_2$ EOR performance response of wells 04-29-065-10W5 and 02-30-065-10W5 can be seen in Figures 164 and 165, respectively. Forecast and actual pilot performance plots are given in Figure 166. Voidage replacement ratio plots are given in Figure 167, and a plot showing the July and August 2010 gas analyses is shown in Figure 168. Finally, the oil recovery and $CO_2$ injection cumulative values as of December 2010 are summarized in Figure 169.

The estimated primary recovery factor for the pool was 17 percent. The incremental EOR recovery factor with the solvent injection was 28 percent. The remaining OIP is 138.800 x $10^6$ $m^3$.

### Pilot Objectives

The technical and economical feasibility of $CO_2$ EOR in SSHU second generation projects (in the non-reef area) was investigated. Well completion strategies were determined, as well as optimal $CO_2$ slug size, well spacing, WAG ratio and injection rates. Operational challenges such as slugging, GOR control, corrosion were identified, and the simulation model was validated and tuned.

### 2010 Pilot Performance

The oil rate improved in four wells.

Based on a 2010 pressure survey, Penn West was not compliant with the pressure requirements for Approval 11002A. In Penn West's opinion, the 2010 pressure survey was not representative of average pattern reservoir pressure. Penn West planned to conduct a new bottomhole pressure survey early in 2011 with which to demonstrate pressure and VRR compliance. Penn West was also reviewing current allocation factors (particularly for 16-20-065-10W5), as these values have changed as a result of water injection in wells offsetting the pilot. Approximately 12.5 percent of the hydrocarbon pore volume of $CO_2$ was injected by the end of 2010.

Observed $CO_2$ concentrations surrounding non-pilot wells were within the historical limit. $CO_2$ was contained within the pilot area. The target $CO_2$ injection rate was achieved, and successful isolation to below Zl shale was confirmed; however, injection logging clearly identified that $CO_2$ was not evenly distributed over the entire target zone.

Good pressure response between the injectors and most producers was clearly identified.

As of December 2010, oil rate improvement was observed in four wells. Pressure was maintained close to MMP, and miscibility was achieved. The $CO_2$ was contained within the pilot area and not fully distributed to the target interval. Injector–producer communication was established by monitoring flowing bottomhole pressure.

**Compliance**

$CO_2$ concentration in the injection stream was greater than or equal to 98 mole percent. Cumulative and monthly VRR was greater than or equal to 1.0, and minimum operating pressure was 18 MPa (in at least two annual pressure surveys).

Battery oil, water, gas and $CO_2$ concentration were continuously monitored, and pilot wells were tested at least once every week. Real time BHP/T sensors were put on the producers, and monthly gas analysis was performed on both pilot and non-pilot wells. Geochemical analysis was also performed, as well as corrosion monitoring and quarterly fluid analysis from each producer.

There were no plans to inject $CO_2$ into the pilot in 2011. Well 2-29 was planned to be converted into an injector. Geochemical, gas analysis monitoring and pressure surveys were continued in 2011.

### References


1. Approval No. 11002A, Experimental Scheme, SSHU C02 Miscible Flood, Progress Report No.3, Penn West Exploration, January 1, 2010 - December 31, 2010.
2. Derochie, L. J. "Performance Of South Swan Hills Tertiary Miscible Flood". JCPT paper# 87-06-07, 1987.
3. Griffith, James D. and Cyca, Len G. "Performance of South Swan Hills Miscible Flood". SPE Journal of Petroleum Technology paper# 8835, 1981.
4. Griffith, J. D. and Horne, A. L. "PD 14(3) South Swan Hills Solvent Flood". 9th World Petroleum Congress paper# 16328, 1975.
5. SSH $CO_2$ Pilot Review, Experimental Scheme Approval No. 11002A, Penn West Exploration, 25 January 2011.


### Turner Valley Rundle

The Turner Valley Rundle pool is a light-medium oil carbonate reservoir at a depth of 1,480.6 m. The oil gravity is 40.1°API. The average porosity is 0.082, the average water saturation is 0.1 and the initial reservoir pressure is 10,410 kPa.

An experimental solvent flood was conducted in the pool from 2001 to 2005 using nitrogen injection.

The EOR project assessment is shown in Table 63. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 170 and 171.

The estimated primary recovery factor for the pool was 12 percent. The incremental EOR recovery factor with the solvent injection was 2 percent. The remaining OIP is 208.700 x $10^6$ $m^3$.

### Virginia Hills Beaverhill Lake

The Virginia Hills Beaverhill Lake pool is a light-medium oil carbonate reservoir at a depth of 2,815.1 m. The oil gravity is 38.1°API. The average porosity is 0.09, the average permeability is 17.77 mD, the average water saturation is 0.24 and the initial reservoir pressure is 24,988 kPa. The OOIP in the pool was 36.510 x $10^6$ $m^3$.

Solvent flooding was started in 1989 and was terminated in 2006. The EOR project assessment is shown in Table 64. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 172 and 173.

The estimated primary recovery factor for the pool was 23 percent. The incremental EOR recovery factor with the solvent injection was 22 percent. The remaining OIP was 20.081 x $10^6$ $m^3$.

**References:**

1. ERCB Oil Reserves Detailed Report, 31 December 2010.
2. Jones, P.W. and Baker, R.O. "Profile Control in Virginia Hills EOR Injectors". SPE/DOE Enhanced Oil Recovery Symposium paper# 24193, 1992.

### West Pembina Nisku D

The West Pembina Nisku D pool is a light-medium oil carbonate reservoir at a depth of 3,141 m. The oil gravity is 45.82°API. The average porosity is 0.117, the average water saturation is 0.07 and the initial reservoir pressure is 40,479 kPa. The OOIP in the pool was 2.400 x $10^6$ $m^3$.

Solvent flooding was started in 1981. The scheme was followed by chase gas injection in 1987, which was terminated in 1994. The EOR project assessment is shown in Table 65.

More details on similar Nisku pinnacle reefs can be found in the descriptions of the Brazeau Nisku A, D and E pools and the references cited in those sections.

The estimated primary recovery factor for the pool was 40 percent. The incremental EOR recovery factor with the solvent injection was 30 percent. The remaining OIP is 0.480 x $10^6$ $m^3$.

**References:**

1. ERCB Oil Reserves Detailed Report, 31 December 2010.
2. West Pembina Nisku D Pool, Penn West Petroleum Ltd., Annual Progress Report, 22 January 2011, (2010-10658).

### Wizard Lake D-3 A

The Wizard Lake D-3 A pool is a light-medium oil carbonate reservoir at a depth of 1,966.7 m. The oil gravity is 38.1°API. The average porosity is 0.098, the average permeability is 2,380.68 mD, the average water saturation is 0.07 and the initial reservoir pressure is 15,507 kPa. The OOIP in the pool was 63.900 x $10^6$ $m^3$.

Solvent flooding commenced in 1986 and was terminated in 1998. The EOR project assessment is shown in Table 66. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 174 and 175.

The estimated primary recovery factor for the pool was 66 percent. The incremental EOR recovery factor with the solvent injection was 19 percent.

### References


1. ERCB Oil Reserves Detailed Report, 31 December 2010.
2. Backmeyer, L.A., Guise, D.R., MacDonell, P.E., and Nute, A.J., "The Tertiary Extension of the Wizard Lake D-3A Pool Miscible Flood". SPE paper# 13271, 1984.
3. Cook, P.G. "Optimizing the Blowdown of Wizard Lake". SPE paper# 97669, 2005.
4. Douglas, J. L. and Weiss, M. "Wizard Lake: Reservoir Quality As A Key To Successful Miscible Displacement". JCPT paper# 91-02-06, 1991.
5. Hsu, H.H. "Numerical Simulation of Gravity-Stable Hydrocarbon Solvent Flood, Wizard Lake D-3A Pool, Alberta, Canada". SPE paper# 17620, 1988.
6. Martin, William Earl and Young, M.N. "The Wizard Lake D-3A Pool Miscible Flood". International Petroleum Exhibition and Technical Symposium paper# 10026, 1982.
7. Young, Marshall N. and Martin, W. Earl. "The Wizard Lake D-3A Pool Miscible Flood". JCPT paper# 80-02-04, 1980.


## Zama Keg River F

The Zama Keg River F pool is a light-medium oil carbonate reservoir at a depth of 1,494.6 m. The oil gravity is 35.11°API. The average porosity is 0.07, the average permeability is 9,850.13 mD, the average water saturation is 0.13 and the initial reservoir pressure is 14,444 kPa. The OOIP in the pool was 0.532 x $10^6$ $m^3$.

Gas injection began in 2007. The EOR project assessment is shown in Table 67. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 176 and 177.

The estimated primary recovery factor for the pool was 33.1 percent. The incremental EOR recovery factor with the solvent injection was 5 percent. The remaining OIP is 0.329 x $10^6$ $m^3$.

### References


1. ERCB Oil Reserves Detailed Report, 31 December 2010.

### Zama Keg River G2G

The Zama Keg River G2G pool is a light-medium oil carbonate reservoir at a depth of 1,510.3 m. The oil gravity is 36.09°API. The average porosity is 0.08, the average permeability is 161.09 mD, the average water saturation is 0.13 and the initial reservoir pressure is 14,117 kPa. The OOIP in the pool was 0.591 x $10^6$ $m^3$.

Gas injection began in 2006. The EOR project assessment is shown in Table 68. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 178 and 179.

The estimated primary recovery factor for the pool was 22.5 percent. The incremental EOR recovery factor with the solvent injection was 4 percent. The remaining OIP was 0.434 x $10^6$ $m^3$.

#### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

### Zama Keg River NNN

The Zama Keg River NNN pool is a light-medium oil carbonate reservoir at a depth of 1,532.2 m. The oil gravity is 36.09°API. The average porosity is 0.07, the average permeability is 60.95 mD, the average water saturation is 0.15 and the initial reservoir pressure is 15,283 kPa. The OOIP in the pool was 0.562 x $10^6$ $m^3$.

Gas injection began in 2006. The EOR project assessment is shown in Table 69. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 180 and 181.

The estimated primary recovery factor for the pool was 30 percent. The incremental EOR recovery factor with the solvent injection was 5 percent. The remaining OIP is 0.376 x $10^6$ $m^3$.

#### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Zama Keg River RRR

The Zama Keg River RRR pool is a light-medium oil carbonate reservoir at a depth of 1,550.5 m. The oil gravity is 39.11°API. The average porosity is 0.1, the average water saturation is 0.15 and the initial reservoir pressure is 15,250 kPa. The OOIP in the pool was 0.748 x $10^6$ $m^3$.

Gas injection began in 2007. The EOR project assessment is shown in Table 70. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 182 and 183.

The estimated primary recovery factor for the pool was 25 percent. The incremental EOR recovery factor with the solvent injection was 5 percent. The remaining OIP was 0.524 x $10^6$ $m^3$.

### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## Zama Keg River X2X

The Zama Keg River X2X pool is a light-medium oil dolomite reservoir at a depth of 1,479.9 m. The oil gravity is 36.09°API. The average porosity is 0.075, the average permeability is 2,994.26 mD, the average water saturation is 0.16 and the initial reservoir pressure is 12,536 kPa. The OOIP in the pool was 0.538 x $10^6$ $m^3$.

The EOR project assessment is shown in Table 71. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 184 and 185.

The estimated primary recovery factor for the pool was 27.5 percent.

Pennzoil's acid gas injection project is located in Township 116-6W6 in the Zama area of northern Alberta. The project is designed to receive waste acid gas from the Nova Gas Clearinghouse (NCL) gas plant located at 13-12-116-6W6 (Figure 186). The NCL plant processes sour natural gas from the Slave and Sulfur Point formations by removing the $H_2S$ and $C0_2$ from the inlet stream and preparing a pipeline-quality sales gas outlet stream for transmission in the Nova pipeline system.

The NCL plant started delivering acid gas for disposal on May 3, 1995. The waste product from the NCL plant, acid gas, is delivered to Pennzoil's X2X pool for injection into the Zama

Keg River formation using wells 1-25-116-6W6 (the primary injection well) and 2/16-24-116-6W6 (the relief injection well). Voidage in the pool is maintained by production from well 16-24-116-6W6. Well 14-24-116-6W6, also completed in the Keg River X2X pool, is a suspended oil well currently being used to monitor reservoir pressure in the back reef area. The project area is illustrated in Map 1 in Figure 187.

The NCL plant generates approximately 60 x $10^3$ $m^3$/d of acid gas at current throughput levels. Daily activities are summarized graphically in Figure 188. The acid gas stream is averaging approximately 20 percent $H_2S$ and 80 percent $C0_2$. Approval 7732 originally allowed 70,000 $m^3$/d of injection. Pennzoil, at the request of NCL, has applied for and received approval to increase the injection to 120,000 $m^3$/d.

### Scheme Performance

Performance of the scheme is summarized in Figure 189.

As of December 31, 1995, cumulative acid gas injected into the X2X pool was 9,600 $m^3$ (28,900 at reservoir conditions). The cumulative amounts of sulfur and $CO_2$ disposed during this report period are 2,600 tonnes and 14.0103 tonnes, respectively. Wellhead injection pressure averaged 9,000 kPa. An acid gas analysis retrieved during November 1995 indicated the acid gas composition is approximately 20 percent $H_2S$ and 80 percent $C0_2$.

Cumulative production (as of December 31, 1995) from well 16-24-116~6W6 since acid gas injection started in April 1995 was 270 $m^3$ of oil, 43,000 $m^3$ of gas and 55,500 $m^3$ of water. The cumulative reservoir voidage is 57,100 $m^3$.

When well 6-24 was first put back on production, it produced a small amount of oil. This oil was not considered tertiary oil, but rather residual waterflood oil not recovered through the previous production completion. The well is currently flowing formation water with a trace of gas.

As of December 31, 1995, cumulative net reservoir voidage was 28,200 $m^3$. The first representative reservoir pressure of 21,546 kPa was measured at well 16-24 just prior to the scheme start-up. The second representative reservoir pressure of 18,969 kPa was measured in December 1995.

Using the voidage-pressure relationship in Figure 190, the average reservoir pressures were predicted for each month during the report period when the reservoir pressure was not measured. Reservoir voidage is a pressure-dependent function, so an iterative solution was required. The formation volume factor for the acid gas, used to convert volumes injected at standard conditions to reservoir volumes, is determined from the relationship presented in Figure 191.

The data used to prepare Figure 191 were from the PVT properties for the acid gas.

Pennzoil was trying to reduce the reservoir pressure in the X2X pool to the initial reservoir pressure of approximately 15,500 kPa. To achieve that pressure, Pennzoil continued to produce well 16-24 at volumes that exceeded the volumes injected.

### Monitoring

In November, Pennzoil reviewed the operating procedures for the acid gas injection project with the following conclusions:

1. Acid gas composition was determined in only one month of the reporting period. In the future, Pennzoil will perform a tutwieler test on the injection stream every month to determine the $H_2S$ content. The $CO_2$ content was determined by subtraction. Pennzoil continued to retrieve an acid gas sample for complete analysis once per reporting period.

2. Reservoir pressure was measured in only one month of the reporting period. In the future, Pennzoil will perform a dead weight pressure (DWT) survey on the inactive injection well. From this survey, and knowing the composition of the fluid in the tubing, the reservoir pressure will be determined. In addition to the DWT survey, Pennzoil will conduct a fluid level survey on well 14-24 to determine reservoir pressure in the back reef area every three months, or twice per reporting period.

### Corrosion Monitoring

The initial study prepared for this injection project concluded that the acid gas was only corrosive if free water was present in the system. To ensure the acid gas had a water dew point well below the operating conditions of the injection system, a continuous dew point analyzer was installed in late September 1995. Initially, the analyzer indicated the acid gas had a dew point of -20 to -25°C. After the operating staff made slight modifications to the process, the dew point was lowered to between -30 and -40°C. To supplement the dew point monitoring, an inhibitor was injected continuously into the pipeline. The inhibitor used was a Baker Chemicals product, Cronox, and it was mixed with diesel fuel. X-ray shadow shot surveys were used to monitor the corrosion of the pipeline. A survey completed in November 1995 showed that no corrosion was present in the pipeline.

### References

1. Zama Keg River X2X Pool, Acid Gas Injection Scheme, Approval No. 7732, Progress Report No. 1, January 1996.

### Zama Muskeg L

The Zama Muskeg L pool is a light-medium oil evaporite reservoir at a depth of 1,512.8 m. The oil gravity is 36.09°API. The average porosity is 0.1, the average permeability is 2,232.49 mD, the average water saturation is 0.16 and the initial reservoir pressure is 13,885 kPa. The OOIP in the pool was 0.429 x $10^6$ $m^3$.

The EOR project assessment is shown in Table 72. The pool location, wells and recovery performance during the miscible flood scheme are summarized in Figures 192 and 193.

The estimated primary recovery factor for the pool was 20 percent. The incremental EOR recovery factor with the solvent injection was 5 percent.

### References

1. ERCB Oil Reserves Detailed Report, 31 December 2010.

## 4.2 Chemical Floods

The EOR project assessments and reservoir properties for each project are summarized in Tables 73 to 94. These are the key parameters to develop the criteria for successful miscible floods.

### Brintnell Polymer Flood

The Brintnell Upper Wabiskaw pool is a heavy oil sandstone reservoir at a depth of 300 to 425 m TVD. The oil gravity is 10°API. The average porosity is 0.28 to 0.32, the average permeability is 300 to 3,000 mD, the average water saturation is 0.30 to 0.40 and the initial reservoir pressure is 1,900 to 2,600 kPa. Dead oil viscosity ranges from 800 to 80,000 mPa.s at 15°C (reservoir temperature is 13 to 17°C).

This overview of the Brintnell polymer project is largely based on CNRL's 2010 presentation to the ERCB. Brintnell is located in the Wabasca Oil Sands area, and the production formation is the Wabiskaw. The location of the project is shown in Figure 194.

Figure 195 shows a type-log of the reservoir. A map of the viscosity of the produced oil is shown in Figure 196; the majority of the developed area is below 5,000 mPa.s.

Polymer injection began in May 2005, with the first production response noted in March 2006. Average water cuts have increased but are generally less than 60 percent. This behavior conforms to the theory where rapid water breakthrough is expected, but production continues at a moderate and constant water cut for a significant time. The primary oil recovery factor was estimated to be 7.5 percent, while the incremental recovery factor due to polymer was estimated to be 15 to 21 percent. The performance of an average pattern under polymer flooding is shown in Figure 197. The range of oil viscosity in the polymer flooded areas is large, with most areas below 5,000 mPa.s but some areas as high as 50,000 mPa.s.

The EOR project assessment is shown in Table 73.

Approval 10147 is the first area expanded after the pilot. The area is shown in Figure 198. Figure 199 is a graph of Approval 10147 performance. Polymer injection commenced in 2005, and polymer response was observed in January 2007. Average water cuts increased in 2009 to 40 percent. Parts of the area have exceeded the results from the pilot area. The primary recovery factor was 5.75 percent, and in 2010, the incremental polymer recovery factor estimate was 15 to 21 percent.

The polymer flood was expanded to Approval 10423. The area is shown in Figure 200. Figure 201 is a graph of Approval 10423 performance. The polymer flood was started in 2007 and was expanded through 2010. Until the end of 2009, only a small area had responded. A large increase in production is anticipated in late 2010 and early 2011. There is a large range in flooded oil viscosity, with most areas under 5,000 mPa.s but some parts as high as 50,000 mPa.s.

The polymer flood was expanded to Approval 10787, shown in Figure 202. Figure 203 is a graph of Approval 10787 performance. A small area of polymer flood was started in 2007; expansion of the flood area was planned for 2011. This is the first area to have a multilateral well being flooded by several injectors, and results have been excellent to 2010.

The area of Approval 9467 is shown in Figure 204. Approval 9467 was initially approved as a waterflood which began in early 2002. A portion of the approval was converted to polymer flood injection in 2008. The remaining portion was to be converted to polymer flood in late 2010. The conversion to polymer flood will be included in Approval 10423. Figure 205 is a graph of Approval 9467 performance to early 2010. The Approval 9467 area is referred to as the N. Horsetail waterflood.

The area of Approval 9673 is shown in Figure 206. It was initially approved as a waterflood which began in early 2004 and was expanded within the approval area during 2005 and 2006. In 2008 and 2009, additional lands were added to 9673, and polymer flood was implemented in them. In later 2009, the previously waterflooded areas were converted to polymer flood. All areas of the approval which are under flood are being flooded by polymer. The approval area is referred to as the North Brintnell polymer flood. Figure 207 is a performance graph of Approval 9673.

### Short- and Long-Term Opportunities

The aggressive expansion of the polymer flood is planned to continue. Expansion areas will test differing reservoir properties including oil viscosity, water saturation, reservoir permeability and pay thickness. Testing will include reduced inter-well spacing and additional multilateral well configurations. A reduced inter-well spacing pilot is planned for 2010.

Figure 208 shows the entire flood response to 2010. Figure 209 summarizes the major approval area recovery factors.

### Conclusions of the Chemical Flood Performance

The phased introduction of polymer flooding has been successful. Plans are underway to continue the expansion.

The initial reservoir pressure was determined via pressure gradients from gas wells in the pool. The Wabiskaw Sand fracture pressure was challenging to determine in an unconsolidated sandstone. Surface pressures are recorded daily and monitored. Pressure switches are in place on injectors to ensure MAWHIP is not exceeded. Cap Rock testing was done to ensure the limits of injection are 100 times less than rate predicted to initiate vertical fractures.

Conversion is underway to use saline water as part of the mixing process, reducing the amount of non-saline used per unit of polymer. Expansion plans after 2007 were designed for use with saline water only.

### References

1. Approval No. 8988, Experimental Scheme Utilizing an Emulsion for the Enhanced Recovery of Crude Bitumen, Progress Report, CNRL, 2005.

2. Approval No. 9673, North Brintnell Waterflood Enhanced Recovery of Crude Bitumen by Water Injection, Performance Presentation 1, CNRL, 21 January 2005.
3. Approval No. 9673, 9467, 9572 10147, North Brintnell Waterflood and Polymer Flood Performance, Performance Presentation, CNRL, 2006.
4. Approval No. 9673, 9467, 9572, 10147, In Situ Oil Sands Schemes North Brintnell, Performance Presentation, CNRL, 2007.
5. Approval No. 9673, 9467, 9572, 10147, 10423, 10787, In Situ Oil Sands Schemes North Brintnell, Performance Presentation, CNRL, 15 February 2008.
6. Approval No. 9673, 9467, 10147, 10423, 10787, In Situ Oil Sands Schemes Brintnell Area, Annual Presentation, Canadian Natural Resources Limited, 18 March 2009.

## Cessford Basal Colorado A

## Experimental Alkaline/Polymer Flood (#4357A/3692A)

The Cessford Basal Colorado A pool is a heavy oil sandstone reservoir at a depth of 920 m. The oil gravity is 23°API. The average porosity is 0.24, the average permeability is 350 mD, the average water saturation is 0.30 and the initial reservoir pressure is 8,784 kPa. The OOIP in the pool was 17.400 x $10^6$ $m^3$.

Figure 210 shows the pool outline. Figure 211 shows the pool performance.

Recovery using an alkaline/polymer flood was evaluated in three areas (North, Central and South). Figure 212 shows the pool outline and identifies the North, Central and South areas and the wells.

The North area patterns are on the edges of the gas cap, as shown in Figure 213. Figure 214 shows the North area alkali/polymer flood well locations adjacent to the gas cap.

Waterflooding commenced in the three areas in 1981 under Approval 2604. Alkaline flooding commenced in the North and Central patterns on July 19, 1984, under Approval 3692. The North and Central areas were converted to an alkali/polymer flood in May 1985. An alkali/polymer flood was started in the South area in January 1985. The alkali/polymer flood was terminated in the North and South areas in October 1990, and it was terminated in the Center area in February 1991.

The EOR project assessment is shown in Table 74.

A preflush of softened salt water was injected from December 1983 to July 18, 1984 in the North and Central areas to act as a buffer between the caustic (alkali) solution and the Red

Deer River water which had been injected since 1981. Injection of the caustic (alkali) solution, containing 1 weight percent sodium hydroxide and 1.3 weight percent sodium chloride, started on July 19, 1984. In late 1984, it was determined that an alkali/polymer solution would be more efficient than a caustic flood.

There was no period of preflush or caustic injection in the South area before alkali and polymer were injected.

The recovery performance during the primary, waterflood, alkali and alkali/polymer schemes are summarized for the total pool and the North, Central and South areas in Figures 215 to 219.

Poor injectivity at the chemical injection wells was observed. Workovers on the chemical injectors were encouraging but still not in the range of the waterflood injectors. Figures 220 and 221 show injection histories for the seven injectors from 1962 to 1990.

No incremental production attributable to the caustic/polymer injection was observed in the North and South areas of the project, due to poor injectivity. It is estimated that with the injection rates observed, it will take between 6 and 90 years to complete the placement of a 10-percent pore volume slug in each of the five injectors in the North and South areas. The reservoir cannot wait six or more years for the chemical slug to be injected because of the pressure gradient across the pool, caused by gas production in the east and water influx in the west, and the maturity of the surrounding waterflood.

Attempts to improve injectivity have, at best, resulted in temporary increases in the injection capability. Due to poor injection capability, voidage replacement ratios are poor in most of the chemical injection patterns. It is estimated that terminating the chemical injection and conducting workovers will increase the voidage replacement ratios. The continued injection of the caustic/polymer solution at the current low rates is likely to be detrimental to the ultimate recovery of the patterns.

Conclusions of the chemical flood performance are as follows:

- Incremental oil production has been observed in the Central area in response to caustic/polymer injection. The effect of the caustic versus polymer cannot be discerned; however, it is thought that the polymer injection is primarily responsible for the incremental production.
- No incremental production has been observed in the other patterns, probably because of the poor injectivity in them. Workovers have resulted, at best, in temporary increases in injectivity.

- It will take a minimum of six years to inject adequate volumes of the caustic/polymer solution to reasonably expect a production response. At these low rates, the production response may not be easy to discern from the data.
- Low chemical injection rates have resulted in very low voidage replacement ratios. Loss of reservoir pressure will probably offset the potential gain from the use of chemicals. Continued operation of the chemical flood will have a detrimental impact on ultimate oil recovery.
- Continued operation of the waterflood surrounding the caustic/polymer patterns will probably cause the wells to water-out before the response to the chemical injection can be observed.
- Lack of waterflood response at most patterns before the chemical flood began will make any calculation of incremental recovery very difficult and inaccurate.
- There is a significant pressure gradient across the oil leg where the chemical flood is being conducted because of the depletion of the Basal Colorado A pool gas. Possible oil migration into the low pressure gas cap mandates that the oil zone be processed as quickly as possible to minimize the effects of migration and to maximize recovery. The size of the gas cap (in 1990, it produced over 0.5 TCF) precludes it from being repressurized.
- The observed incremental recovery in the one pattern where the chemical injection has been a technical success is not significant compared to the large volume of the injected chemicals.
- The poor injectivity does not appear to be related to the core permeability. Core permeability measurements could be erroneously high, with the fines removed during cleaning or the clays dried out before the samples were tested.
- The poor injectivity could also be because
    - The preflush may have been too small to adequately flush the multivalent ions from the formation. Once the caustic fluid contacted these ions, precipitates formed.
- The adsorption of the polyacrylamide polymer and/or the caustic solution has reduced the effective permeability of the reservoir.
- The formation clays may have reacted with the caustic solution and either hydrated or migrated, causing plugging.

### Overall Performance

- Caustic/polymer flooding is ineffective and potentially detrimental,
- Significant problems were encountered with injection,
- VRR was significantly reduced during the chemical flood,
- Injection issues could not be solved,
- The chemical scheme had lower than anticipated oil rates and recovery,

- Caustic/polymer injection results are not promising.

### Short & Long Term Opportunities

Caustic/polymer flooding was ineffective in improving recovery in the Cessford Basal Colorado A pool, so it was discontinued. Injection problems were encountered, and reduced VRR resulted. Workovers of the injection wells had very limited success. The caustic/polymer flood was terminated, and there are no additional plans to implement chemical recovery.

### References

1. Approval No. 4357, Cessford Basal Colorado 'A' Pool Experimental Alkaline-Polymer Solution Flood Scheme, Progress Report, Hudson's Bay Oil and Gas Limited, July 1, 1984 - December 31, 1984.
2. Approval No. 4357A, Cessford Basal Colorado 'A' Pool Experimental Alkaline/Polymer Flood, Progress Report, Crestar Energy, January 1, 1991 - December 31, 1991.
3. Approval No. 4357, Cessford Basal Colorado 'A' Pool Experimental Alkaline/Polymer Flood, Progress Report, Crestar Energy, January 1, 1992 - December 31, 1992.
4. Edinga, K.J.; McCaffery, F.G.; and Wytrychowski, I.M. "Cessford Basal Colorado A Reservoir Caustic Flood Evaluation". SPE # 8199, 1980.

## Chauvin South Sparky E

## Experimental Polymer Flood (5379)

The Chauvin South Sparky E pool is a heavy oil sandstone reservoir at a depth of 1,400 m. The oil gravity is 21.1°API. The average porosity is 0.24, the average water saturation is 0.30 and the initial reservoir pressure is 8,784 kPa. The OOIP in the pool was 2.075 x $10^6$ $m^3$.

Figure 222 identifies the Chauvin South Sparky E well locations. Figure 223 is a production/injection performance plot of the pool, and Figure 224 is a production/injection performance plot of the polymer pilot. Figure 225 outlines the pilot area.

The polymer flood was implemented in three patterns in an existing waterflood area.

The EOR project assessment is shown in Table 75.

The polymer flood started on February 1, 1988, with the injection of a formaldehyde solution (1,500-2,000 ppm), and was scheduled to continue for approximately two weeks. The formaldehyde solution was reduced to 500 ppm on February 17, 1988. Polymer injection commenced after the formaldehyde solution was reduced to 450 ppm. Continuous injection of the polymer did not occur until February 27, 1988, due to shipment and equipment start-up problems. Polymer injection was terminated April 2, 1991. Formaldehyde injection was discontinued on May 23, 2001.

The experimental life of the pilot was from March 1988 to January 1993. The project consists of 11 oil producers and 3 polymer injection wells in an area of 195 ha. There are three injectors: two polymer injectors and one converted to water injection. The major start-up problem was the maintenance of a consistent polymer injection rate.

The pilot area production performance from 1986 to 1992 is shown in Figure 226.

Figure 227 shows the total injection rate, viscosity, and HCOH concentration from 1988 to 1991.

Figures 228 to 230 show the injection performance to January 31, 1993 for the three injectors.

When the polymer injection was stopped, there was a steady decline in the oil production and a slight increase in water production, as expected. The increasing GOR leveled out as total voidage replacement, which had encountered issues, was nearing 1.

The following table summarizes the pilot production:

| Area | Oil ($m^3$) | Water ($m^3$) | Gas ($10^3m^3$) |
|---|---|---|---|
| Total pilot area | 109,600 | 380,064 | 3,195 |
| NW/4-24-3W4 pattern | 26,182 | 149,018 | 1,239 |
| SW quarter of section 25-42-3W4m | 73,635 | 181,544 | 1,603 |
| NE quarter of section 26-42-3W4 | 9,759 | 49,502 | 354 |

A study that was conducted on the polymer pilot's performance deemed it to be successful.

### References


1. Approval No. 5379, Chauvin South Sparky "E" Experimental Polymer Flood Pilot Scheme, Progress Report No. 1, BP Resources Canada Limited, February 1, 1988 - July 31, 1988.
2. Approval No. 5379, Chauvin South Sparky "E" Experimental Polymer Flood Pilot Scheme, Technical Report, BP Resources Canada Limited, May 31, 1993.


## Countess Upper Mannville H

### Commercial Polymer Flood (11250B)

The Countess Upper Mannville H pool is a light-medium oil sandstone reservoir at a depth of 1,062.5 m. The oil gravity is 26°API. The average porosity is 0.22, the average water saturation is 0.22 and the initial reservoir pressure is 8,234 kPa. The OOIP in the pool was 5.725 x $10^6$ $m^3$.

Recovery using a polymer flood was evaluated. Figure 231 identifies the well locations, and Figure 232 is a production/injection performance plot. The EOR project assessment is shown in Table 76.

The estimated primary recovery factor for the pool is 10.5 percent. The estimated incremental polymer flood recovery factor is 36 percent. No recovery factor was specified for the waterflood. The estimated remaining OIP after primary, waterflood and polymer injection is 0.191 x $10^6$ $m^3$.

The Upper Mannville H is still under polymer injection.

## Countess Upper Mannville H

### Experimental ASP (10640)

The Countess Upper Mannville H pool is a heavy oil sandstone reservoir at a depth of 1,400 m. The oil gravity is 10.9°API. The average porosity is 0.24, the average permeability is 945 mD, the average water saturation is 0.30 and the initial reservoir pressure is 8,784 kPa. The OOIP in the pool was 2.075 x $10^6$ $m^3$.

Recovery using an alkali/surfactant/polymer (ASP) flood was evaluated. The EOR project assessment is shown in Table 77.

## Edgerton Woodbend A

### Experimental Polymer Flood

The Edgerton Woodbend A pool is a heavy oil carbonate reservoir at a depth of 697.4 m. The oil gravity is 16.82°API, the average porosity is 0.2, the average water saturation is 0.25 and the initial reservoir pressure is 4,831 kPa. The OOIP in the pool was 8.789 x $10^6$ $m^3$.

Recovery using a polymer flood was evaluated. Figure 233 identifies the Edgerton Woodbend A wells, and Figure 234 is a production/injection performance plot. The EOR project assessment is shown in Table 78.

## Entice Lower Mannville B

### Commercial ASP Flood (11549)

The Entice Lower Mannville B pool is a light-medium oil sandstone reservoir at a depth of 1,782.8 m. The oil gravity is 34°API. The average porosity is 0.16, the average water saturation is 0.31 and the initial reservoir pressure is 13,645 kPa. The OOIP in the pool was 2.596 x $10^6$ $m^3$.

Recovery using an alkali/surfactant/polymer (ASP) flood was evaluated. Figure 235 identifies the well locations, and Figure 236 is a production/injection performance plot. The EOR project assessment is shown in Table 79.

Three areas were monitored for recovery performance:

- Primary recovery area,
- Waterflood recovery area,
- Total area.

The following table summarizes the area and recovery information available.

| AREA | AREA | % of total area | OOIP | Primary | Enhanced | Initial Primary Reserves | Enhanced Primary Reserves | Total Initial Reserves | Cumulative Production | Remaining |
|---|---|---|---|---|---|---|---|---|---|---|
| | (ha) | (%) | ($E^3m^3$) | (%) | (%) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) |
| Primary | 16 | 1.7 | --- | 4 | --- | 0.6 | --- | 0.6 | --- | --- |
| Waterflood | 355 | 37.6 | --- | 10 | 15 | 79.3 | 119 | 198 | --- | --- |
| TOTAL | 944 | 100 | 2596 | --- | --- | 259 | 556 | 825 | 773.1 | 51.9 |

---Not Reported

The estimated primary recovery factor for the pool was 10 percent, and the incremental waterflood was 15 percent. The incremental EOR recovery factor with the ASP was not specified. The remaining pool OIP was 51,900 $m^3$. The current pool cumulative oil production is 773,100 $m^3$, and the pool recovery is 32 percent.

Reported recoveries indicate that the EOR flood is adding incremental recovery; therefore, expanding the EOR flood should be evaluated. It should be noted that the EOR flood is still in operation.

## Horsefly Lake Lower Mannville

## Experimental Alkali/Polymer Flood (4065)

The Horsefly Lake Lower Mannville pool is a light-medium oil sandstone reservoir at a depth of 964.3 m.

Figure 237 identifies the Horsefly Lake Mannville well locations, and Figure 238 is a production/injection performance plot of the Horsefly Lake Mannville wells.

The pilot is located in a high water area of the reservoir. Figure 239 is a location map of the pilot area. The pattern consists of five wells: one producer and four injectors. Four existing producers outside this pattern are also part of the pilot. The total pilot area including the four outside producers is about 13 ha.

The pilot was terminated on December 31, 1987.

Recovery using an alkali polymer flood was evaluated. The EOR project assessment is shown in Table 80.

### Pilot Performance

Total oil production to the end of 1987 is 14,231 $m^3$ or 12 percent of the OOIP in the pilot area. This represents 94 percent of the expected ultimate incremental oil.

The total incremental oil recovered was 10,042 $m^3$ (8 percent) of the OOIP in the pilot area. Incremental oil represents 94 percent of the expected ultimate incremental oil.

Chemical injection was completed in May 1987.

Cumulative injection totaled 43 percent pore volume; cumulative chase water injection was 16 percent pore volume.

Figure 240 shows incremental pilot caustic/polymer oil recovery from 1985 to 1991, during which period, incremental oil of 15,010 $m^3$ was observed. Figure 241 is a plot of the oil rate and cumulative oil production, and Figure 242 shows the oil rate versus time from 1984 to 1988. Figure 243 shows water and oil cut versus time from 1984 to 1988, and Figure 244 shows injection performance during the same period. Figure 245 is a table summarizing the incremental oil from 1984 to 1990. A plot of oil rate versus cumulative injected pore volume can be seen in Figure 246, and Figure 247 shows the water-oil ratio against the cumulative amount of oil produced.

Total oil production to the end of 1987 is 14,231 $m^3$ or 12 percent of OOIP in the pilot area. This represents 88 percent of the expected total recoverable reserves.

### Conclusions

The alkali/polymer flood did not work due to excessive adsorption because of the high clay content of the reservoir. The improvement in the recovery was attributed to the closer well spacing. The reservoir was found to be more heterogeneous than expected, hence the benefit of the closer well spacing.

### References

1. Approval No. 4065, Horsefly Lake Caustic-Polymer Pilot Project Lower Mannville Pool, Progress Report No. 6, PanCanadian Petroleum Limited, July 1, 1987 - December 31, 1987.

2. Approval No. 4065, Horsefly Lake Caustic-Polymer Pilot Project Lower Mannville Pool, Technical Report, PanCanadian Petroleum Limited, January 20, 1986.
3. Enhanced Recovery Week April 3, 1989, "Horsefy consumed caustic, waterflood may benefit".

## Mooney Bluesky A

### Commercial ASP Flood (11488A)

The Mooney Bluesky A pool is a heavy oil sandstone reservoir at a depth of 913 m. The oil gravity is 16.6°API. The average porosity is 0.26, the average water saturation is 0.35 and the initial reservoir pressure is 5,790 kPa. The OOIP in the pool was 7.883 x $10^6$ $m^3$.

Recovery using an alkali/surfactant/polymer (ASP) flood was evaluated. Figure 248 identifies the Mooney Bluesky A well locations, and Figure 249 is a production/injection performance plot of the Mooney Bluesky A wells. The EOR project assessment is shown in Table 81.

Three areas were monitored for recovery performance:

- The primary recovery area,
- The waterflood recovery area,
- The total area.

The following table summarizes the area and recovery information available:

| AREA | AREA | % of total area | OOIP | Primary | Enhanced | Initial Primary Reserves | Enhanced Primary Reserves | Total Initial Reserves | Cumulative Production | Remaining |
|---|---|---|---|---|---|---|---|---|---|---|
| | (ha) | (%) | ($E^3m^3$) | (%) | (%) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) |
| Primary | 788 | 37.4 | --- | 7 | --- | 200 | --- | 200 | --- | --- |
| Waterflood | 763 | 12.5 | --- | 7 | 7 | 85.6 | 96.6 | 193 | --- | --- |
| TOTAL | 2,108 | 100 | 7,883 | --- | --- | 552 | 556 | 1,087 | 442.7 | 644.3 |

--- Not Reported

No ASP data is reported.

The current field recovery is 14 percent.

## Provost Upper Mannville A

## Commercial Polymer Flood (10529F)

The Provost Upper Mannville A polymer flood is operated by Pengrowth Energy Corporation. The field is in southeastern Alberta. Figure 250 shows the well locations. Wells with red symbols are assigned to the Upper Mannville A pool. Figure 251 shows the production/injection history of the pool. The development is in the Lloydminster formation, which contains heavy oil. The reservoir depth is 778.3 m, and the oil gravity is 15.1°API. The average porosity is 0.3. The average water saturation is 0.25, and the initial reservoir pressure is 4,125 kPa. The OOIP in the pool was 13.190 x $10^6$ $m^3$.

The reservoir properties and the recovery factors are summarized in Table 82. Figure 252 shows the pilot area, and Figure 253 shows the well locations. Finally, Figure 254 shows the production profile of well 14-15-37-01W4M.

The estimated primary recovery factor for the pool is only 3 percent. The estimated incremental EOR recovery factor with polymer injection is 12 percent.

Three areas were monitored for recovery performance:

- The primary recovery area,
- The waterflood recovery area,
- The total area.

The following table summarizes the area and recovery information available

| AREA | AREA | % of total area | OOIP | Primary | Enhanced | Initial Primary Reserves | Enhanced Primary Reserves | Total Initial Reserves | Cumulative Production | Remaining |
|---|---|---|---|---|---|---|---|---|---|---|
| | (ha) | (%) | ($E^3m^3$) | (%) | (%) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) |
| Primary | 435 | 25.8 | --- | 3 | --- | 71.1 | --- | 71.1 | --- | --- |
| Waterflood | 1,252 | 74.2 | --- | 3 | 12 | 325 | 1,298 | 1,623 | --- | --- |
| TOTAL | 1,687 | 100 | 13,190 | --- | --- | 396 | 1,298 | 1,694 | 609.4 | 1,084.6 |

--- Not Reported

Based on production to December 31, 2010, the field recovery factor is 13 percent. Performance data indicate the field should be reviewed for potential opportunities to expand the current EOR.

### References

1. Provost Upper Mannville "A" Pool, Pengrowth Energy Corporation, Annual Progress Report, 23 March 2011, (2011-10529E).

## David Lloydminster DD

## Experimental Alkaline/Polymer Flood (5353F/4263)

The David Lloydminster DD pool, also referred to as the Provost Lloydminster A pool, is a light-medium oil sandstone reservoir at a depth of 760 m. The oil gravity is 22.6°API. The average porosity is 0.29 and the average permeability is 1,400 mD. The OOIP in the pool was 1.486 x $10^6$ $m^3$.

Figure 255 identifies the well locations, and Figure 256 is a production/injection performance plot.

Initially, the David pool (Projects 1 and 2) was under waterflood from November 1978 to March 1986. Project 1 was changed to an alkaline flood and then amended to polymer with alkali on June 1, 1987.

Recovery using an alkaline/polymer flood was evaluated in seven patterns. Figure 257 shows the pool outline, and Figure 258 shows the seven patterns configured for the pilot. Figure 257 is also a net pay isopach map of the David pool, and it identifies the waterflood areas adjacent to the alkaline/polymer flood.

The EOR project assessment is shown in Table 83.

A one-year pre-flush was run from March 1986 to February 1987. Softened fresh water injection for the pre-flush portion of the experimental scheme was started in March 1986, and it lasted until February 1987. Alkali (soda ash) injection on all seven patterns began in March 1987, and alkali/polymer injection began in May 1987.

A total of 307,310 $m^3$ (0.19 pore volume) of fresh water pre-flush and 459,821 $m^3$ (0.4 pore volume) of alkali/polymer were injected. The design was for 0.10 pore volume of fresh water buffer followed by 0.35 pore volume slug of alkali/polymer and finally 0.10 pore volume of tapered polymer.

In September 1989, five of the seven patterns had reached the target of 0.35 pore volume of alkali/polymer injected. Modifications were made to begin the injection of tapered polymer (no alkali) while the injection of alkali/polymer continued into patterns 3 and 5. The five patterns finished their tapered polymer injection on August 31, 1990 and began to inject fresh water. Patterns 3 and 5 finished their target pore volume slug of alkali/polymer on December 10, 1990 and started injecting the tapered polymer slug at that point.

Figure 259 summarizes the slug sizes for each pattern. Figure 260 is a performance plot for the David pool. The graph identifies the primary, waterflood and alkaline/polymer flood productions. Figure 261 shows a comparison of the actual alkaline-polymer flood performance and the alkaline-polymer core flood. Figure 262 is a performance plot of oil cut versus cumulative oil recovery for the alkaline/polymer flood in comparison to the North, South and West waterfloods.

#### Summary

Alkaline/polymer flood was more effective in terms of incremental oil recovery than waterflood. Waterflood in adjacent patterns did not affect the chemical flood performance.

#### References


1. Approval No. 4263 and 2671C, David Lloydminister 'A' Pool, Progress Report No. 3, Dome Petroleum Limited, August 1985 - February 1986.
2. Approval No. 5353B, David Experimental Alkali/Polymer Scheme, Progress Report No. 9, Amoco Canada Petroleum Company Ltd., March 1, 1990 - August 31, 1990.
3. Manji, K. H., and Stasiuk, B. W., "Design considerations for Dome's David Alkali/Polymer flood". JCPT paper # 88-03-04, 1988.
4. Pitts, M. J., Chemical Enhanced Oil Recovery, Surtek Inc., CIM Presentation.
5. Pitts, M.J., Wyatt, K., and Surkalo, H. "Alkaline-Polymer Flooding of the David Pool, Lloydminster Alberta". SPE paper# 89386, 2004.


### Provost Cummings I

The Provost Cummings I pool is a heavy oil sandstone reservoir at a depth of 763.3 m. The oil gravity is 24°API. The average porosity is 0.28, the average water saturation is 0.23 and the initial reservoir pressure is 5,430 kPa. The OOIP in the pool was 12.430 x $10^6$ $m^3$.

Recovery using a polymer flood was evaluated. The EOR project assessment is shown in Table 84. The Provost Cumming I wells are identified in Figure 263, and Figure 264 is a production/injection performance plot.

There is no additional information on the Provost Cummings I pool available publicly.

### Suffield Upper Mannville UU

### Commercial ASP Flood (1249B)

The Suffield Upper Mannville UU is under an ASP flood which is designated as a commercial project. The Glauconitic reservoir is a heavy oil sandstone at a depth of 928.8 m. The oil gravity is 14.1°API. Figure 265 identifies the well locations. The reservoir properties and expected recovery factors are summarized in Table 85. Figure 266 is a production/injection performance plot. Figure 267 identifies the pilot area.

The average porosity is 0.30, the average water saturation is 0.28, and the initial reservoir pressure is 7,538 kPa. The OOIP in the pool was 0.531 x $10^6$ $m^3$. Figure 268 shows a type log for the Suffield Upper Mannville UU. The reservoir is a washover (splay) sand of the main sand at SFB Suffield. No aquifer or bottom water is present.

There are two horizontal chemical injection wells, four horizontal production wells and three vertical production/observation wells. The cumulative injection of alkali/surfactant/polymer (ASP) to August 2010 is 146,000 $m^3$ (0.28 HCPV). The average injection concentrations to October 2010 are

- Alkali = 0.75 percent,
- Surfactant = 0.1 percent,
- Polymer = 0.135 percent.

Figures 269 and 270 show the produced water analysis and a map of the scale activity, respectively. The produced water analysis shows where there has been breakthrough of the chemicals. Scale formation has been observed at some wells and is being monitored carefully. Both calcium carbonate scale and silica scale are present.

Figure 271 shows the production performance of the project, excluding the horizontal well 02/14-10, which was drilled in 2010. Figures 272 and 273 show the water and injection pressure for two injection wells.

Two operational issues have been identified. The first is amorphous silica scale at production wells. The second is injection wells pressuring up to MOP, as of October 2010, limiting injectivity in one injection well. Despite these issues, ASP injection is still reported as economic in the pool.

The success of the scheme can only be determined through several measurements, observations, tests and laboratory investigations. Extended water analysis, pH, residual polymer and surfactant are used to determine breakthrough and estimate reservoir sweep. They also show the path of the injection fluids. They have encountered a backlog in the lab, however, due to the high-end nature of the test.

In the produced water analysis (Figure 269), the large red circles indicate wells with significant chemical breakthrough. The blue arrow indicates predominant injection flow based on well oil-cut increases. The black arrow indicates the least significant oil cut increases, with no chemical breakthrough, but with significant Phase 1 scaling.

The wellbore (scaled in 2009–2010) has scales similar to those in the Taber area ASP floods. In the lab, the Phase 1 scale was found to be calcium carbonate, and the Phase 2 scale was found to be amorphous silica scale. The chemical supplier is working to find new inhibitors; in 2010, it was working on a generation 4 inhibitor. The current solution is to pull rods every six to nine months (or if scale coupons show positive) and mechanically remove any scale. To date, scale does not appear to be forming in the reservoir.

The only significant operations conducted on the production wells were scale inspections and removal. Stimulation is only increased by injectivity after significant operations are conducted on the injection wells.

ASP commenced in May 2007, operating under the maximum allowable concentrations. The ASP solution did not reach less than 135.6 $10^3 m^3$ injection. As of August 2010, 146 x $10^3$ $m^3$ of ASP solution was injected.

Production wells were sampled on a bi-annual to monthly basis, and water, pH, silica, polymer and surfactant were extended as required. There was a backlog in the lab due to the specialized nature of the test, but a program is in place to send water into Corelabs at a minimum bi-monthly frequency (most times monthly), to test for residual polymer, pH, all routine and extended ions, and silica.

Water is also sent to the surfactant manufacturer for residual surfactant analysis once a year or when production data dictate. To date, the only well to have contained surfactant was 00/10V-3, in which a small amount was found in the water when the pH was well over 12.

Oil composition was monitored to see if changes over time occurred and if they could be used to help optimize and evaluate the flood. The best measure of success was the change in oil cut and incremental oil produced. Changes occurred in the characteristics of produced fluid. Produced water was monitored for pH, polymer concentration, all major and extended ions, and silica. An increase in pH and polymer concentration was an indication of breakthrough, chemical effectiveness and adsorption. Produced silica may be an indication of wellbore scaling problems to come.

Overall, the ASP flood was successful.

### Short- & Long-Term Opportunities

A 2011 ASP roll-out in the Suffield Upper Mannville YYY pool was planned. The YYY pool is a commercial scale ASP flood which is currently in the regulatory approval process.

Figure 274 is a location map with the YYY pool and the existing UU pool outlined. Figure 275 illustrates the YYY area geological relationships. Figure 276 is a gross isopach of the YYY pool, and Figure 277 is a forecast for the YYY Pool, comparing the waterflood and ASP prediction.

### Summary

The EOR scheme 11249 worked well. Amorphous silica scale issue at production wells remains, and long-term injectivity is still partially in question, but commercial roll-out of the ASP flooding process was planned for the Suffield UM YYY pool in 2011.

### References

1. Cumulative Voidage Replacement Ratio Suffield Upper Mannville UU Pool, EnCana, 1 September 2009, (2009-11249).
2. Enhanced Oil Recovery Scheme Suffield Upper Mannville UU Pool, EnCana, Annual Presentation, 28 October 2009, (2009-11249).
3. Enhanced Oil Recovery Scheme Suffield Upper Mannville UU Pool, Cenovus Energy, Annual Presentation, 26 October 2010 (2010-11249).
4. Simulation Test Data Suffield Upper Mannville UU Pool, EnCana, 2009, (2009-11249).

## Suffield Upper Mannville U

## Commercial Polymer Flood (11249B & 11485)

The Suffield Upper Mannville U pool is a heavy oil sandstone reservoir at a depth of 957.4 m. The oil gravity is 17.3°API. The average porosity is 0.26, the average water saturation is 0.18 and the initial reservoir pressure is 10,703 kPa. The OOIP in the pool was 3.609 x $10^6$ $m^3$.

Recovery using a polymer flood was evaluated. Figure 278 identifies the well locations, and Figure 279 is a production/injection performance plot. The EOR project assessment is shown in Table 86.

Three areas are monitored for recovery performance:

- Primary recovery area,
- Waterflood recovery area,
- Polymer flood area.

The following table summarizes the area and recovery information available:

| AREA | AREA | % of total area | OOIP | Primary | Enhanced | Initial Primary Reserves | Enhanced Primary Reserves | Total Initial Reserves | Cumulative Production | Remaining |
|---|---|---|---|---|---|---|---|---|---|---|
| | (ha) | (%) | ($E^3m^3$) | (%) | (%) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) |
| Primary | 372 | 100 | 3,609 | --- | --- | 541 | 655 | 1,196 | 878.6 | 317.4 |
| Waterflood | 179 | 48.1 | --- | 15 | 16 | 252 | 269 | 521 | --- | --- |
| Polymer flood | 193 | 51.9 | --- | 15 | 16 | 289 | 386 | 675 | --- | --- |

--- Not Reported

## Taber Glauconite K

### Commercial ASP Flood (10860E)

The Taber Glauconitic K pool is a heavy oil sandstone reservoir at a depth of 963.6 m. The oil gravity is 19°API. The average porosity is 0.26, the average water saturation is 0.15 and the initial reservoir pressure is 7,719 kPa. The OOIP in the pool was 4.529 x $10^6$ $m^3$. This pool is the same as the East Taber Mannville D Unit #1, where a polymer pilot was carried out from 1990 to 1992. The pilot is described in the next section.

Figure 280 identifies the well locations, and Figure 281 is a production/injection performance plot.

Recovery using an alkali/surfactant/polymer (ASP) flood was evaluated.

The EOR project assessment is shown in Table 87.

One area under ASP flood was monitored for recovery performance. The following table summarizes the recovery information available from the area:

| AREA | AREA | % of total area | OOIP | Primary | Enhanced | Initial Primary Reserves | Enhanced Primary Reserves | Total Initial Reserves | Cumulative Production | Remaining |
|---|---|---|---|---|---|---|---|---|---|---|
| | (ha) | (%) | ($E^3m^3$) | (%) | (%) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) |
| ASP Flood | 308 | 100 | 4,529 | 18 | 38 | 815 | 1,721 | 2,536 | 2,047.3 | 438.7 |

--- Not Reported

## East Taber Mannville D Unit #1

### Experimental Polymer Flood (5078C)

The East Taber Mannville D pool is a heavy oil sandstone reservoir. The OOIP in the pool was 2.54 x $10^6$ $m^3$.

Recovery using a polymer flood was evaluated. The EOR project assessment is shown in Table 88.

The pool outline is shown in Figure 282.

Two geological facies exist within Unit 1: a channel sand and a sheet sand. The two facies are distinctly separated by a shale deposit. The sheet sand contains four wells and does not receive pressure support.

There were two polymer injection wells. All of the injection wells replace reservoir voidage for both the polymer flood areas and the waterflood areas.

Figure 283 is a production summary from 1980 to 1992.

The polymer flood has not responded as predicted. Only two wells have shown favourable response. A lack of widespread response implies that the pore volume being swept is less than was originally planned. Based on pool performance, the polymer bank size was reduced.

Figure 284 shows the polymer concentration versus the pore volume injected.

Polymer breakthrough is attributed to polymer flooding attempts from 1971 to 1979. The polymer flood conducted during that period was deemed to be ineffective.

Poor flood response on all but two project wells made it economically and technically unjustifiable to continue with the original slug design. The remaining slugs were redesigned using equations derived by Stoneberger and Claridge to have concurrent breakthroughs of the remaining polymer slugs and drive water.

Polymer flood response was generally disappointing, with limited production response. Polymer injection was completed, and two production wells were sensitive to the level of injection. The operation was then converted to a regular waterflood. There is residual polymer in the produced water which continues to be injected.

Figure 285 shows the actual versus predicted performance of the polymer area recovery curves.

All-unit injection into the two polymer injection wells replaced voidage for the polymer flood and waterflood areas.

The OOIP was 2,540 x $10^3$ $m^3$. Predicted ultimate waterflood and polymer flood recovery for the project area was 1,077 x $10^3$ $m^3$, or 42 percent of OOIP.

Polymer flood response was beginning to respond when it was suspended in 90-08, to allow remedial work to be performed. With polymer injection shut-in, there was a sharp decline in oil production and an increase in the water-oil ratio, indicating that polymer injection affected the sweep efficiency. Polymer injection was placed back on line in July 1991, and oil production returned to pre-shut-in rates.

### Short & Long Term Opportunities

The pilot was converted to a waterflood. There were no plans for future chemical flooding.

### Summary

The polymer flood was not successful.

### References

1. Approval No. 5077 and 5078, East Taber Mannville D Unit No. 1 Conventional Waterflood and Experimental Polymer Flood, Progress Report, Chevron Canada Resources, June 30, 1991 - December 31, 1991.
2. Approval No. 5077 and 5078, East Taber Mannville D Unit No. 1 Conventional Waterflood and Experimental Polymer Flood, Progress Report, Chevron Canada Resources, January 1, 1992 - June 30, 1992.

## Taber South Mannville B

## Commercial ASP Flood (10418B)

The Taber South Mannville B, operated by Husky, is the first field-wide ASP flood in Canada.

Figure 286 identifies the well locations. Figure 287 is a production/injection performance plot.

Injection began in May 2006. The ASP target was to inject 30 percent pore volume. ASP injection ended on October 17, 2008, at 34 percent pore volume injected. Figure 288 identifies the pool order. Figure 289 shows the pool outline.

The Taber South Mannville B pool is a heavy oil sandstone reservoir at a depth of 983.3 m. The oil gravity is 19.1°API. The porosity is 0.22, the average water saturation is 0.39, and the initial reservoir pressure is 7,821 kPa. The OOIP in the pool was 6.843 x $10^6$ $m^3$.

Figure 290 is a map of the Mannville B net oil isopach.

The reservoir properties and expected oil recoveries are summarized in Table 89.

Following ASP injection, polymer-only injection had a target of 40 percent pore volume. At the end of May 2010, 16.3 percent pore volume of polymer was injected. Normal waterflooding followed the polymer injection.

During the ASP portion of injection, all minimum concentrations were maintained. Titrations were performed daily by operations to verify ASP injection fluid. An injection of 2,648 x $10^3$ $m^3$ ASP solution was followed by an injection of 1,270 x $10^3$ $m^3$ of polymer to May 2010 (out of a total planned slug of 2,480 x $10^3$ $m^3$ of polymer).

The objective was to maintain a cumulative VRR of 1.0. On an overall pool basis, cumulative VRR to May 31, 2010 was 0.95. The pool has maintained a constant VRR over the last few years.

Due to operational issues (silicate scale) in 2008/2009, the VRR fell to 0.95. In 2010, there was some progress in scale mitigation, which allowed for stabilization in the VRR. The pool was divided into seven zones to help balance injection throughout. Figure 291 shows the cumulative VRR by area from May 2006 (the beginning of the project) to May 2010, as well as a total pool VRR.

The southern and northern edges of the pool (Areas 2 and 6) have had significant drops in injectivity. Area 2 injectors are on the edges of the area, in poor quality reservoir (low pay). An additional injector was drilled in the centre of Area 2 (12 m pay). Area 6 produced small volumes, so small changes in injection show up as large changes in VRR.

A monitoring program was put in place as follows:

- Monthly water analysis is performed on every producer, including measurements of pH and polymer concentration;
- Targets are reviewed every month to help balance flood and prevent premature breakthrough;
- Injected water is sampled daily for polymer concentration, viscosity, pH, NaOH and surfactant concentrations.

Figures 292 and 293 show the Mannville B polymer concentrations and the pH of the water produced at the producers, respectively.

Figure 294 shows the Mannville B production history and operator's forecast. Figure 295 shows the Mannville B injection volumes and pressures.

### Overall Performance (May 2006 to May 2010)

Significant changes in both total production and oil cut have been observed since injection began. Total production increased from 56 $m^3$/d to a current rate of 250 $m^3$/d. Production peaked at 290 $m^3$/d in October 2008. Production declined from Q4 in 2008 due to the presence of silicate scale and reduced injectivity. This meant significant periods of downtime for the wells, and that offsetting injection had to be shut-in to service most of them. While the oil cut continued to remain constant (or improve), the reduction in injection volumes caused a drop in oil production.

Operation issues are continually being addressed:

- Research and testing with scale inhibitors is ongoing,
- Runtimes have improved from 3 months to 5.5 months for problem wells,
- There are plans to drill an additional injection well,
- The oil cut has improved from 1.6 percent to 13 percent.

### Injection Performance (May 2006 to May 2010)

Average injection pressure for the pool has steadily increased since the switch from ASP to only polymer. This is a result of the increased viscosity of the injected fluid without the caustic. Injection rates have decreased from a combination of the increased viscosity and the operation issues related to silicate scaling.

### Summary

Operational issues associated with the scale are having an impact on production and costs as well as making it difficult to maintain a VRR of 1.0.

Continued improvements in the oil cut show that ASP is working. In addition, in Areas 3, 4 and 5 (the centre of the pool), the incremental recovery is close to the original forecast.

Area 2 (the southern edge of pool) highlights the importance of properly placed injectors. Injector quality and location will be a key factor in future ASP projects.

Figure 296 shows some of the key indicators used to monitor the wells. Figure 297 compares waterflood production and ASP production. Figure 298 compares the oil and fluid forecast to the actual values based on ASP volumes injected. Figure 299 is a performance plot of Mannville B oil production and oil cut. Figure 300 shows injection rates and average wellhead pressures against time. Figure 301 outlines the pool and the 7 areas within it. Figure 302 shows the VRR by area. Figure 303 shows the injection fluid chemical concentration over time.

Three areas were monitored for recovery performance:

- The primary recovery area,
- The waterflood recovery area,
- The total area.

The following table summarizes the area and recovery information available:

| AREA | AREA | % of total area | OOIP | Primary | Enhanced | Initial Primary Reserves | Enhanced Primary Reserves | Total Initial Reserves | Cumulative Production | Remaining |
|---|---|---|---|---|---|---|---|---|---|---|
| | (ha) | (%) | ($E^3m^3$) | (%) | (%) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) |
| Primary | 90 | 13.3 | --- | 10 | --- | 20.2 | --- | 20.2 | --- | --- |
| Waterflood | 105 | 15.6 | --- | 10 | 15 | 43.8 | 65.7 | 110 | --- | --- |
| Total | 675 | 100 | 6,843 | --- | --- | 684 | 2,671 | 3,355 | 3,032.5 | 322.5 |

--- Not Reported

## References

1. Warner ASP Flood Taber South Mannville B Pool, Husky, Annual Presentation, June 2007, (2007-10418B).
2. Warner ASP Flood Taber South Mannville B Pool, Husky, Annual Presentation, June 2008, (2008-10418B).
3. Warner ASP Flood Taber South Mannville B Pool, Husky, Annual Presentation, June 2009, (2009-10418C).
4. Warner ASP Flood Taber South Mannville B Pool, Husky, Annual Presentation, June 2010, (2010-10418D).
5. Warner ASP Flood Taber South Mannville B Pool, Husky, Application 01-023, Annual Report, June 30, 2006.
6. Warner ASP Flood Taber South Mannville B Pool, Husky, Application 01-023, Annual Report, June 28, 2007.
7. Warner ASP Flood Taber South Mannville B Pool, Husky, Application 01-023, Annual Report, June 27, 2008.

## Viking-Kinsella Wainwright B

## Commercial Polymer Flood (11195A) (Sparky)

The Viking-Kinsella Wainwright B pool is a heavy oil sandstone reservoir at a depth of 649 m. The oil gravity is 21.1°API. The average porosity is 0.29, the average water saturation is 0.28 and the initial reservoir pressure is 4,392 kPa. The OOIP in the pool was 23.099 x $10^6$ $m^3$

Recovery using a polymer flood was evaluated. Figure 304 identifies the wells in the pool. Figure 305 is a production/injection performance plot. The EOR project assessment is shown in Table 90. Figure 306 outlines the pool and pilot areas. Figure 307 is a cross-section through the Viking-Kinsella Field and the pilot area. Figure 308 is a type log of well 10D-24-48-9. Figure 309 illustrates the reservoir quality in the Sparky A and the Sparky B Upper and Lower. Figure 310 shows the full field production and injection performance from 1973 to 2010. Figure 311 shows the full field voidage replacement ratio, and Figure 312 identifies the 23 producers and 13 injectors in the pilot area.

The design study involved three phases of laboratory work:

1. Fluid-fluid evaluations

    - Interfacial tension screening;
    - Phase behaviour screening;
    - The effect of un-softened produced water dilution on IFT and phase behaviour, static consumption, and cation exchange;
    - ASP/polymer rheology.

2. Linear corefloods

    - Defining relative permeability, polymer rheology, water and chemical injectivity, and matrix retention of chemical solution.

3. Radial sandpack testing (16 sets)

    - Evaluating the efficiency of various chemical solutions.

Figure 313 shows the results of the laboratory testing.

Polymer injection at a concentration of 2,500 ppm began in June 2009. Injection rate and pressure were limited by the plant discharge pressure control valve. The cumulative voidage replacement ratio was 0.83.

Figure 314 shows the pilot area production and injection performance from June 2009 to July 2010. Figure 315 shows the pilot area voidage replacement ratio. Figure 316 summarizes the production performance from the pilot area, and Figure 317 summarizes the polymer injection performance factors.

In producers, polymer concentrations were tested monthly to find trace amounts of polymer through clay reaction testing for the first 10 months of the flood (until April 2010). Polymer produced fluids were lab tested on the wells which tested positive. As of August 2010, all producers are lab tested on a monthly basis.

Figure 318 summarizes the polymer breakthrough monitoring on producers.

The estimated primary recovery factor for the pool was 14 percent, and 30 percent for the waterflood. The incremental EOR recovery factor with the polymer injection was 5 percent. The remaining OIP was $1.343 \times 10^6$ $m^3$. Note that the polymer flood is still in operation.

Currently, the Viking-Kinsella Wainwright B pool is still under polymer flood.

Four areas were monitored for recovery performance:

- The primary recovery area,
- The waterflood recovery area,
- The polymer flood recovery area,
- The total area.

The following table summarizes the area and recovery information available:

| AREA | AREA | % of total area | OOIP | Primary | Enhanced | Initial Primary Reserves | Enhanced Primary Reserves | Total Initial Reserves | Cumulative Production | Remaining |
|---|---|---|---|---|---|---|---|---|---|---|
| | (ha) | (%) | ($E^3m^3$) | (%) | (%) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) |
| Primary | 160 | 4.4 | --- | 5 | --- | 19.8 | --- | 19.8 | --- | --- |
| Waterflood | 2,989 | 83.1 | --- | 14 | 30 | 2,810 | 6,021 | 8,831 | --- | --- |
| Polymer flood | 450 | 12.5 | --- | 14 | 35 | 369 | 922 | 1,291 | --- | --- |
| Total | 3,599 | 100 | 23,099 | --- | --- | 3,199 | 6,943 | 10,140 | 7,874.1 | 2,265.9 |

--- Not Reported

### Overall Performance

Initial results are encouraging, but there is a large economic pre-investment and technical risk component.

### Short- & Long-Term Opportunities

Expansion is possible through continued evaluation of the Phase 1 pilot project:

- Maintaining current polymer concentration,
- Pattern balancing and control of early breakthrough,
- Waiting on occurrence and magnitude of “oil bank” arrival,
- Continually improving injection,
- Evaluating polymer flood performance on an economic basis.

Expansion plans could include the gradual addition of injection patterns to cover the eastern half of the pool (utilizing existing poly mixing capacity), the evaluation of a surfactant IFT altering component, and possible commitment to a large-scale Phase 2 project.

### Summary

The early stages of the project showed that laboratory studies and bench testing are critical, including:

- Special core analysis, mineralogy, wettability and IFT;

- Oil vs chemical rheology testing, relative permeability, viscosity;
- Polymer type, hydration characteristics, sensitivity to shear;
- Formation, injection and produced water compatibility with polymer.

Project operation required consistent water quality and polymer concentration. There was always the possibility for injectivity decline and necessary injector stimulation. Oil cut and polymer breakthrough measurements were critical for pattern balancing and progress evaluation.

For continued operation, clean and iron-free water for the mother solution and the 2,500 ppm polymer injection solution must be maintained. Injection should be increased, e.g., the pilot injection should be increased from the current 650 m3/d. Capital expansion is possible with two to four new injectors. Injectors should be stimulated; within the pilot area, injectors are already being stimulated in sections 17 and 18.

#### References


1. Viking-Kinsella/Wainwright B Polymer Flood, ERCB, Request for Extension For Presentation, August 7, 2009, (2009-11195).
2. Viking-Kinsella/Wainwright B Polymer Flood, Harvest Energy, Annual Presentation, October 13, 2010, (2010-11195A).
3. Viking-Kinsella/Wainwright B Polymer Flood, Harvest Energy, Polymer Breakthrough Data, 2010, (2010-11195).


### Viking-Kinsella Wainwright B

### Experimental Alkaline Flood (3884)

The Viking-Kinsella Wainwright B pool is a heavy oil sandstone/siltstone/shale reservoir at a depth of 675 m. The oil gravity is 21.1°API. The average porosity is 0.30, the average water saturation is 0.28 and the initial reservoir pressure is 4,825 kPa. The OOIP in the pool was 19.400 x $10^6$ $m^3$.

Approval was issued for polymer flood scheme 2884 in the Wainwright B Pool on December 2, 1983. The existing waterflood project was converted to alkaline injection scheme. When approval was requested, waterflood 2537A was rescinded.

Recovery using an alkaline flood was evaluated, but no results were located.

The EOR project assessment is shown in Table 91.

## Wildmere CMG Pool 003 Sparky E, Lloydminster A

## Commercial Polymer Flood (9336F)

The Wildmere Sparky E/Lloydminster A pool is a heavy oil sandstone reservoir at a depth of 569.7 m. The oil gravity is 18.1°API. The average porosity is 0.30, the average water saturation is 0.21 and the initial reservoir pressure is 3,672 kPa. The OOIP in the pool was 51.700 x $10^6$ $m^3$.

Figure 319 identifies the well locations. Figure 320 is a production/injection performance plot. Recovery using a polymer flood was evaluated. The EOR project assessment is shown in Table 92.

Four areas were monitored for recovery performance:

- The primary recovery area,
- The waterflood recovery area,
- The polymer flood recovery area,
- The total area.

The following table summarizes the area and recovery information available:

| AREA | AREA | % of total area | OOIP | Primary | Enhanced | Initial Primary Reserves | Enhanced Primary Reserves | Total Initial Reserves | Cumulative Production | Remaining |
|---|---|---|---|---|---|---|---|---|---|---|
| | (ha) | (%) | ($E^3m^3$) | (%) | (%) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) |
| Primary | 1,163 | 30.5 | --- | 3.5 | --- | 355 | --- | 355 | --- | --- |
| Waterflood | 2,489 | 65.2 | --- | 11 | 9 | 42,187 | 3,451 | 7,668 | --- | --- |
| Polymer flood | 164 | 4.3 | --- | 11 | 12 | 354 | 386 | 740 | --- | --- |
| Total | 3,816 | 100 | 23,099 | --- | --- | 4,926 | 3,837 | 8,763 | 6,633.1 | 2,129.91 |

--- Not Reported

Opportunities for expanding the polymer flood beyond the current area should be evaluated.

## Wrentham Lower Mannville B & Lower Mannville C

## Commercial Polymer Flood (8716/8715)

The Wrentham Lower Mannville B and Lower Mannville C pools are heavy oil sandstone reservoirs at depths of 943 and 953 m, respectively. The oil gravity is 20.1°API. For the B pool, the average porosity is 0.23, the average water saturation is 0.26 and the initial reservoir pressure is 7,614 kPa. The average porosity is 0.21, the average water saturation is 0.32 and the initial reservoir pressure is 9,591 kPa for the C pool. The OOIP in the B pool was 1.224 x $10^6$ $m^3$ and the C Pool was 2.127 x $10^6$ $m^3$.

Figure 321 identifies the Wrentham Lower Mannville B well locations, and Figure 322 is a production/injection performance plot of the field. Figure 323 identifies the Wrentham Lower Mannville C well locations, and Figure 324 is a production/injection performance plot of the field.

ASP technology was reviewed beginning in April 1998. The chemical system selection was started in June 1999. In October 1999, the facility design of Etzikom began. The facility construction, re-completions, conversions, and tie-ins started in August 2000. Alkali/polymer injection into Etzikom began in December of the same year, with 5 percent wt NaOH and 1,400 ppm polymer in softened water. On April 1, 2001 and June 1, 2001, polymer increased to 1,600 ppm and then to 1,800 ppm to reach target viscosity. Approximately 30 percent pore volume of alkali-polymer solution was to be injected. In March 2003, polymer only slug began, with 1,800 ppm polymer solution. In October 2003, polymer taper started, with 1,800 ppm polymer solution. In May 2005, chemical flood was complete, and waterflood was resumed.

Both pools are combined in the same injection system. The injectors have no chokes—polymer is sheared over the pressure drop. One way of controlling injection volumes is by shutting wells in, which was only done at the start of the project. Eventually, injectivity decreased to such an extent that all wells were open all the time.

The EOR project assessments for the Lower Mannville B and Lower Mannville C are shown in Tables 93 and 94.

The polymer flood areas were monitored for recovery performance in both the B and C pools.

The following table summarizes the area and recovery information available for the Lower Mannville B:

| AREA | AREA | % of total area | OOIP | Primary | Enhanced | Initial Primary Reserves | Enhanced Primary Reserves | Total Initial Reserves | Cumulative Production | Remaining |
|---|---|---|---|---|---|---|---|---|---|---|
| | (ha) | (%) | ($E^3m^3$) | (%) | (%) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) |
| Polymer | 99 | 100 | 1,224 | 15 | 30 | 184 | 367 | 551 | 511.2 | 39.8 |

--- Not Reported

The following table summarizes the area and recovery information available for the Lower Mannville C:

| AREA | AREA | % of total area | OOIP | Primary | Enhanced | Initial Primary Reserves | Enhanced Primary Reserves | Total Initial Reserves | Cumulative Production | Remaining |
|---|---|---|---|---|---|---|---|---|---|---|
| | (ha) | (%) | ($E^3m^3$) | (%) | (%) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) | ($E^3m^3$) |
| Polymer | 379 | 100 | 2,127 | 15 | 30 | 319 | 638 | 957 | 809.3 | 147.7 |

--- Not Reported

Figure 325 is a performance graph of forecast versus actual Etzikom Creek performance under alkali/polymer flood. Figures 326 and 327 are performance graphs of forecast versus actual performance for the B and C pools, respectively. Figures 328 and 329 are graphs of the Etzikom Creek facility injection for both pools. Figure 330 is a graph summarizing the polymer injection data, and Figure 331 summarizes the Etzikom Creek facility breakthrough for both pools. Figures 332 and 333 show the performance well response and breakthrough for individual wells in the B pool, and Figures 334 to 339 show the same plots for wells in the C pool.

### Overall Performance

The B pool showed a dramatic response to injection, with 50 percent of the wells having an oil cut of at least 30 percent. It has a completely different lithofacies than other Glauconitic pools. It could never match simulation, and in it, peak well production was higher than expected and ultimate production was much lower than predicted.

The C pool had a delayed production response. The oil cut continued to increase during chemical injection, and injectivity issues resulted in the polymer tapering decision which probably resulted in a lower ultimate recovery. Ninety-three percent of the wells had an oil cut of at least 10 percent.

#### Short & Long Term Opportunities

To date, 1.5 MMbo (6 percent of OOIP) of incremental oil has been recovered. The expected incremental recovery from alkali/polymer injection is 2.3 MMbo. Ultimate oil recovery is still low in these pools (31 to 36 percent), but some recoverable oil was left behind due to the implementation of the polymer taper and the way the pool was developed. Over the next several years, oil recovery options will be investigated, coinciding with the end of the Warner ASP flood when the polymer facility will become available. Options for recovery include

- Additional geological work;
- Further reservoir development and waterflooding;
- Schemes in one or both pools (evaluation of geologic risk);
- Polymer, $CO_2$ or another EOR method;
- Economics (higher recovery requires higher costs).

#### Summary

The geological model is key to understanding how chemicals interact with the reservoir and how fluids flow through the pore spaces, but additional monitoring resources (human and capital) are necessary to maximize flood performance. Injection is very important; injectors should be added before a project starts, to compensate for the loss of injection rates due to the injection of high viscosity solution. When unexpected loss of injectivity occurs, additional injectors must be drilled or converted.

Chemical flooding results in incremental oil production, and operational issues will occur as produced fluid continually changes. Active management of the flood is required through regional VRR, well optimizations, injection workovers and facility modifications.

#### References

1. Wrentham Lower Mannville B & Lower Mannville C Pools, Husky Energy Inc., Final Presentation, December 22, 2009, (2009-8716).

## 4.3 Thermal Recovery

### Countess Upper Mannville B

The Countess Upper Mannville B pool is a light-medium oil Glauconitic sandstone reservoir consisting of a high quality sand underlain by water. The oil gravity is 28°API.

Located in southeastern Alberta, approximately 20 km west of Brooks, the pool was discovered in 1965. Waterflood operations commenced in 1973, followed in 1983 by a 16-ha inverted five spot in-situ combustion (fireflooding) pilot project. The project was done to evaluate the in-situ combustion process, and it included four existing producing wells (04-16, 01-17, 16-08, and 13-09-16-16W4M) and a new air injection well at A4B-16-19-16W4M. Waterflood operations in the pool continued during the pilot project and were adjusted so that the pressure gradients across the pilot area were minimized. The pilot project was completed in 1995.

It was found in the in-situ combustion pilot project that the combustion gas drive supported by the efficient displacement from the burned volume was the most important mechanism in fireflooding the pool, and the propagation of combustion gas and water ahead of the fire front was of considerable importance for oil recovery. The combustion gas was equally important in recovery before and after breakthrough, and oil production response occurred almost immediately after initiating air injection. A stable high temperature region and low temperature oxidation reaction were found to exist, and analyses of the recombined oil and gas indicated favorable mobility under fireflooding.

In 1991, 15 laboratory fireflood combustion tube tests were performed on the pool using both normal and enriched air injection. The normal air was composed of 21 percent oxygen and the enriched air of 38 percent and 95 percent oxygen. Observation of combustion under dry, normal, and wet conditions was done with a wide range of water injection rates. It was found that the pool doesn't appear to be burning a coke-like fuel, but rather an oxidized asphaltenes fraction. The difficulties seen in sustaining a high temperature combustion for this oil, and thus for oil greater than 25°API, was explained by the low rate of coke deposition.

#### References

1. Metwally, M., "Recovery Mechanisms: Fireflooding a High-Gravity Crude in a Waterflooded Sandstone Reservoir; Countess Field, Alberta", SPE 21536, 1991.
2. Tzanco, E. T., Moore, R. G., Belgrave, J. D. M., Ursenbach, M. G., "Laboratory Combustion Behaviour of Countess B Light Oil", SPE 91-05-03, Sep-Oct 1991.

### Peace River Cyclic Steam

This overview of the Baytex Peace River cyclic steam project is largely based on Baytex's 2010 presentation to the ERCB. The project uses cyclic steam in horizontal wells in the Bluesky formation. There are two single well tests:

- Harmon Valley, a single-cycle test at 100/16-17-084-18W5;
- Cliffdale, a multi-cycle test at 100/05-16-084-17W5.

The location of the Cliffdale well is shown in Figure 340. With a drainage area for 50 m around the well, the original bitumen in-place (OBIP) was 298,000 $m^3$ at Harmon Valley and 331,000 $m^3$ at Cliffdale.

The formation depth varies from 300 to 425 mTVD, with a net pay from 20 to 24 m. Porosity is 28 percent at the base of the sand, decreasing to 26 percent at the top. The permeability varies from 870 to 9,900 mD. Dead oil viscosity ranges from 10,160 to 42,070 mPa.s at 20°C. The oil saturation is up to 72 percent. Figure 341 shows a type log of the reservoir.

Production profiles for the two tests are shown in Figures 342 and 343. The cumulative steam-oil ratio (CSOR) at Harmon Valley is 0.38 $m^3/m^3$, and at Cliffdale, it is 3.98 $m^3/m^3$. The expected recovery factors for ten years of cyclic steam are 27.6 percent for Harmon Valley and 17.1 percent for Cliffdale.

The selection of cyclic steam over SAGD was based on numerical simulation and is primarily due to shale inter-bedding within the Bluesky oil sands, which decreases SAGD efficiency.

## 5.0 Summary of Findings: Success/Fail Criteria

In this section, each of the major EOR processes will be discussed under three sub-headings:

- Alberta Experience,
- Observations,
- Potential Success Factors.

Microbial, foam flooding and other EOR processes are not evaluated, since there are too few projects for a valid sample to draw general conclusions, and the processes are not established worldwide.

## 5.1 Solvent Floods

### Alberta Experience

Hydrocarbon miscible floods have been very successful in selected reservoirs in Alberta. Table 95 lists the commercial solvent floods in Alberta. The miscible floods in Alberta can be divided into four categories:

- Vertical floods, with injection into the structurally highest point in the reservoir and production from as low in the reservoir as possible. These projects usually have a limited area and few wells. All are in carbonate reservoirs.
- Horizontal floods, with injectors and producers at roughly the same level. The pay in these reservoirs can be quite low, and they can cover an extensive area. For the purposes of this report, only carbonate reservoirs are included in this group.
- Combination floods, where a thick reservoir covers a large area. The flooding has elements of both gravity stability and horizontal flow. Any dip in the reservoir can be beneficial. In Alberta, all of these are carbonate reservoirs.
- Sandstone reservoirs, in which several horizontal floods have been successful. The EOR incremental recovery is lower than it is for the carbonate reservoirs. Several have been successful with $CO_2$ injection.

In particular, vertical miscible floods in the Pembina, West Pembina and Brazeau River, Nisku reefs, and Rainbow and Rainbow South Keg River reefs have been successful. The average incremental recovery factor (IRF) for such hydrocarbon miscible floods is 28 percent.

In the Pembina Cardium A Lease, the reservoir is too tight for a successful miscible flood. This puts a lower limit on the permeability for a successful project.

There are also nine terminated experimental projects in Alberta, which are listed in Table 96. These projects are more difficult to assess, since none was carried out on a full-field basis. Some may have been technically successful, but none led to a commercial project.

### Observations

The Keg River and Nisku miscible floods are vertically stable floods that were implemented early in the life of the pools—in most cases, before the reservoir pressure had dropped below the bubble point. The miscible floods in the Keg River reefs in the Zama area have not been as successful as those in the Rainbow area. The reservoir parameters in the Zama area are less favourable for miscible flooding than in the Rainbow pools, but no single parameter stands out. It may be a question of timing with respect to the oil prices when the floods were implemented or smaller volumes of solvent were injected.

None of the pools selected for miscible flooding have a gas cap. Several have bottom water, and at least one, Wizard Lake D3A, has a secondary gas cap.

Carbon dioxide flooding has environmental benefits in sequestering the $CO_{2.}$ However, in most cases, the volume that can be sequestered in an oil pool is limited. Due to early breakthrough, much of the $CO_2$ requirement can be met by recycling. This, of course, means that very little of the $CO_2$ actually escapes into the atmosphere.

The number of miscible floods that haves been implemented in Alberta are low compared to the number of potential pools. Several potential types of candidates have not been tested in the field, including reefal reservoirs with an initial gas cap and an underlying aquifer, where production of the gas cap will have led to the oil sandwich moving up the reservoir, leaving behind residual oil. A miscible flood with injection from down-structure (thereby avoiding the gas cap) could recover some of this residual oil. The use of horizontal wells in vertical floods can delay the onset of coning and increase recovery.

### Potential Success Factors

For hydrocarbon miscible floods, a high initial pressure and low oil gravity are key factors. Vertical floods seem to work extremely well. Another factor which may be critical is the permeability, both vertical and horizontal.

Carbon dioxide floods also require a low oil gravity, though the initial pressure is not as great a concern, largely because multiple-contact miscibility can be achieved at relatively low pressures.

The parameters of the pools with solvent projects were examined, and the minimum and maximum values are listed in Table 97. These provide data for fine-tuning the screening criteria for each process.

## 5.2 Chemical Floods

### Alberta Experience

All of the chemical flood projects, both experimental and commercial, have been implemented in reservoirs in the cretaceous Mannville Group, with the exception of the Edgerton Woodbend A pool, which is in the Upper Devonian Woodbend group.

There are currently eight commercial polymer floods listed in the Alberta Oil Reserves report. The eight projects are listed in Table 98. There are also five ASP floods, which are included in Table 98.

As previously noted, the Edgerton polymer flood is an exception. It also has the lowest incremental recovery factor of only 3 percent. The primary recovery is also low, at 6 percent.

There is currently only one active experimental polymer flood in the Viking-Kinsella Sparky JJ pool. There are also nine terminated experimental projects:

- Three polymer floods,
- Two alkali floods,
- Three alkali/polymer floods,
- One ASP flood.

These are listed in Table 99.

Assessment of the success of each project requires a detailed review of the literature and the progress reports submitted to the ERCB. Most of the experimental projects were terminated in the early 1990s, when low oil prices reduced interest in EOR. The two recent pilots are the Countess Upper Mannville H alkali/polymer pilot and the Suffield Upper Mannville UU ASP pilot, both of which are operated by Cenovus Corporation.

Recent ASP floods such as the Taber Glauconite K and the Taber South Upper Mannville show that ASP floods can be very effective even in pools that have been extensively waterflooded.

In the oilsands areas, two projects in the Wabiskaw formation in the Wabasca area are using polymer flooding on heavy oil. Most screening criteria put the maximum viscosity for a polymer flood at 200 mPa.s. The Wabasca polymer floods are in reservoirs with much higher oil viscosities: 500 mPa.s and higher. This is the result of merging polymer flooding with horizontal well technology. Research carried out at Sproule suggests that the upper limit for the oil viscosity for a chemical flood may be 10,000 mPa.s, i.e., if the oil can be produced without the addition of heat, it can be polymer flooded.

### Observations

The experimental chemical floods appear to have been affected by low oil prices at the time. The current high oil prices should enable many of the technical successes to be converted into commercial successes.

The Wabasca polymer floods have extended the range of applicability of chemical flooding from medium oils to heavy oils. The Chauvin Sparky E polymer flood extended the applicability of polymer flooding to reservoirs with higher water salinity through the use of a biopolymer.

There does not appear to have been any attempt at using polymers for vertical conformance improvement in Alberta. This may be a method which should be examined in future developments, e.g., in some Viking waterfloods where there is a strong decrease in permeability with depth.

The choice between polymer flooding and ASP in Alberta is biased towards ASP due to the favourable Royalty treatment. Since polymer flooding is inherently cheaper that ASP, equal treatment for polymer floods may encourage the expansion of chemical flooding to small oil accumulations.

### Potential Success Factors

Chemical floods appear to be very successful in providing incremental oil recovery in Lower Cretaceous sandstone reservoirs, particularly the Mannville group. For the most part, these have high permeability, high porosity, relatively low salinity water, and oil in the medium/heavy range.

The only chemical flood in a carbonate reservoir appears to have been unsuccessful.

Many other reservoir types have not been tested in Alberta.

The parameters of the pools with chemical projects were examined, and the minimum and maximum values are listed in Table 100. These provide data for fine-tuning the screening criteria for each process.

## 5.3 Thermal Recovery

### Alberta Experience

There are only three experimental projects in the conventional oil areas where thermal recovery was tested (Table 101). In two projects in the Countess and Shekilie fields, in-situ combustion was tested. At Suffield, AEC tested hot-water injection. There are no commercial thermal projects at present.

In the oilsands areas, there have been numerous projects. Currently licensed commercial projects include

- Commercial CSS (6),
- Commercial SAGD (25),
- “Commercial” (5),
- Primary (143),
- “Experimental” (13),
- “Enhanced Recovery” (8).

The ERCB Oilsands report does not specify what is classed as “Commercial”, “Experimental” and “Enhanced Recovery”.

In addition, there have been 401 terminated approvals. These include

- CSS (169),
- SAGD (13),
- Combustion (16),
- Solvent injection/VAPEX (13),
- Electromagnetic (7),
- Single well SAGD (SWSAGD) (6),
- Jet leaching,
- Steam drive (14).

A detailed discussion of these is outside the scope of this study. However, some of the projects will have application to heavy and medium oil in the conventional oil areas. These include

- An extension of polymer flooding to more viscous oil,
- CSS in horizontal wells in heavy oil,
- SAGD in heavy oil.

## Observations

Due to the size of Alberta's oilsands resources, it is only to be expected that thermal recovery would be tested much more extensively in the oilsands areas than in the conventional areas. Note that some of the "oilsands" projects are in areas now designated as "conventional oil and gas". Some examples are SAGD in Provost; CSS in Atlee-Buffalo and Chauvin South; and ISC at Viking-Kinsella, Suffield, Joarcam, and others. Table 102 lists the "oilsands" experimental projects south of Township 52.

SAGD has clearly been very successful in bitumen, but it has only recently been applied to heavy oil in Alberta and Saskatchewan.

In-situ combustion is applicable to many reservoirs. However, it is a complex process which is very difficult to operate. Safety is a major concern with the possibility of oxygen reaching the producing wells. Operating difficulties include high sulphate levels due to the high sulphur content of heavy oils and bitumen, which can lead to high levels of corrosion and scaling.

A variation of in-situ combustion, the "THAI" process (toe-to-heel air injection) is currently being tested at several locations, but performance data are not yet available.

The "HPAI" process (high pressure air injection) is intended for light oil and has been tried with some apparent success in other parts of the world, but there has been no test in Alberta to date.

## Potential Success Factors

Thermal recovery is applicable to many medium and heavy oils. As such, there is competition with primary recovery, waterflood and chemical floods. In general, thermal recovery is costly, so it is not the preferred choice for EOR, except for in bitumen cases, in which it is the only option. Nevertheless, thermal recovery can result in very high recovery factors.

Due to the high capital and operating costs of steam generation, there are significant economies of scale, so the size of the resource is a key factor in success.

# 6.0 Screening of Alberta Oil Pools for EOR Potential

The parameters of the pools listed in the reserves report were compared to the binary screening criteria, and those pools which satisfied the criteria were selected. The OOIP of each selected pool was taken and summed to determine the total OOIP in the pools that met the criteria for the selected process.

## 6.1 Waterflood

Waterflooding is not normally considered an EOR process. It is considered to be secondary recovery, while EOR is tertiary recovery (i.e., it is a follow-up to waterflooding). Nevertheless, EOR techniques are often used instead of waterflooding, and in any case, waterflooding is always a potential competitor to any EOR process in light, medium, and often, heavy oils (except bitumen).

Over 700 waterfloods are listed in Alberta, with a combined OOIP of $3.78 \times 10^9$ $m^3$. The average incremental recovery factor is 0.118, with a maximum of 0.500.

Since most pools over a certain size can be waterflooded, there are a large number of pools which have waterflood potential. A quick scan identified 7,500 pools with OOIP less than $160 \times 10^3$ $m^3$, implying that there are about 4,500 pools which could be waterflooded (i.e., 3,800 pools not on waterflood are potential candidates). Pools with an active water drive or an extensive gas cap should be excluded from these totals.

The pools with an initial OOIP of greater than $160 \times 10^3$ $m^3$ that have not been waterflooded contain $7.0 \times 10^9$ $m^3$ of OOIP. This is very much an upper limit, since closer examination of each pool may detect a large gas cap, poor communication, low permeability, active water drive or excessive primary depletion. Since the total OOIP in Alberta was $11.2 \times 10^9$ $m^3$, the non-waterflooded pools represent a large fraction of the total. Cumulative oil production from all light, medium and heavy crude oil pools in Alberta to the end of 2010 was $2.6 \times 10^9$ $m^3$.

## 6.2 Solvent Floods

The ranges of parameters used for binary screening are listed in Table 103. The table is based on the ranges of parameters for solvent floods in Table 97. Note that considerable judgement was used in setting the values for the screening criteria.

The results in Table 97 were altered in several ways:

- If there was no reason for a parameter to be a limit, a low or high value was substituted. For example, the lowest viscosity for a successful vertical flood was 1.3 mPa.s. However, there is no reason why a lower viscosity would not work, so the limit was set to 0.1 mPa.s.
- If the range of parameters included unsuccessful projects, the upper limit was reduced to include successful projects only. For example, the upper range of the viscosity for sandstone floods was 1,093.9 mPa.s. However, that value was associated with a heavy oil project which was unsuccessful; therefore, the upper limit was set to 15 mPa.s.
- None of the limits are precise, so some rounding—down for lower limits, up for upper limits—was applied.
- Pools with a prior waterflood were excluded. This does not mean that a pool with a prior waterflood will not be successful; it only means that none of the successful projects had a prior waterflood.
- Pools with a gas cap were excluded. As with a prior waterflood, this does not mean that in all cases where there is gas cap, solvent flooding will not work; it only means that none of the successful projects in Alberta had a gas cap.
- The initial pressure is an important parameter for solvent floods. In some cases, no pressure for a pool was available. For these, the depth was used as a proxy for pressure, assuming the normal pressure gradient of 10 kPa/m. Note that for at least three of the sandstone floods, the reservoirs were severely under-pressured and the reservoir pressure had to be increased to above the initial pressure to achieve miscibility.

Screening of the oil pools for solvent floods resulted in the following number of pools satisfying the criteria:

- 200 pools for vertical solvent floods,
- 734 pools for horizontal solvent floods,
- 382 pools for combination solvent floods,
- 1701 pools for sandstone solvent floods.

Table 104 is a summary of these results, including the total OOIP in the pools which meet the criteria.

The five largest pools which meet the criteria in each category are listed in Tables 105 to 107. The five largest pools for a "combination" solvent flood turned out to be identical to those for the vertical flood, so no table is shown for these. This emphasizes that a pool may satisfy the screening criteria for several processes and that the incremental reserves for each process are not additive. A check on these pools confirmed that they are indeed suitable candidates for solvent floods.

The two most successful solvent floods were the vertical miscible floods in the Pembina Nisku and Rainbow Keg River reefs. The Pembina and Rainbow pools, which have not had solvent flooding but have potential, are listed in Tables 108 and 109.

## 6.3 Chemical Floods

The ranges of parameters used for binary screening are listed in Table 110. The table is based on the ranges of parameters for chemical floods in Table 100. Only polymer floods and ASP floods were considered, since there appears to be little benefit to alkali/polymer floods.

The results in Table 100 were altered in a similar manner to the solvent flood screening criteria, except that pools which were previously waterflooded were not excluded.

Screening of the oil pools for chemical floods resulted in the following number of pools satisfying the criteria:

- 1,396 pools for ASP floods,
- 935 pools for polymer floods.

Table 111 is a summary of these results, including the total OOIP in the pools satisfying the criteria.

The five largest pools satisfying the criteria in each category are listed in Tables 112 and 113. Several of these pools are in both categories. In essence, every pool that is conducive to polymer flooding is also a candidate for ASP (though the reverse is not necessarily true). This emphasizes that a pool may satisfy the screening criteria for several processes and that the incremental reserves for each process are not additive. A check on these pools confirmed that they are indeed suitable candidates for solvent floods. All of them are classified as heavy oil.

All of the pools in Tables 112 and 113 are close to having produced their initial reserves. In these cases, the chemical flood would be a true tertiary flood. Two of the pools show high recovery factors of over 40 percent. These are either on waterflood or have a natural waterdrive. The other pools have an ultimate recovery of less than 10 percent. These pools also have oil with a higher density, hence the higher viscosity. This suggests that the viscosity has limited the recovery, making the pools prime targets for EOR. If that is indeed the case, they should be considered for thermal recovery as well.

### 6.4 Thermal Recovery

Since none of the thermal projects in conventional oil have been successful, it is not possible to determine appropriate screening criteria. Applying the screening criteria developed earlier for oilsands and heavy oil worldwide, screening of the oil pools for thermal recovery resulted in the following number of pools satisfying the criteria:

- 196 pools for cyclic steam,
- 214 pools for steam floods,
- 196 pools for SAGD,
- 1,434 pools for in-situ combustion.

Table 114 lists a summary of these results, including the total OOIP in the pools satisfying the criteria.

The large number of pools amenable to in-situ combustion was expected. However, the operational difficulties with in-situ combustion mean that it should be considered as a last resort.

## 7.0 Estimation of Incremental Recoverable Oil by EOR in Alberta

### 7.1 Waterflood

The total OOIP in the waterflood candidate pools is 7 x $10^9$ $m^3$. The average incremental recovery factor is 0.118, with a standard deviation of 0.093. Using one standard deviation to establish a range, the range of the incremental recovery factor is 0.025 to 0.211. The ultimate remaining potential oil recovery for waterfloods is from 0.2 x $10^9$ $m^3$ to 1.5 x $10^9$ $m^3$. Pools which are very tight, or pools with a large gas cap, large natural waterdrive, or complex geometry will reduce this number considerably.

Nevertheless, it appears that the potential for additional waterflooding is probably greater than that of EOR processes.

### 7.2 Solvent Floods

For vertical miscible floods, the incremental recovery factor ranges from 1.5 to 63 percent, with an average of 27 percent. Taking a narrower range, from 13 to 30 percent, the incremental oil recovery for solvent floods is between 8 and 18 x $10^6$ $m^3$.

For horizontal miscible floods, the incremental recovery factor ranges from 5.0 to 37 percent, with an average of 25.7 percent. Taking a narrower range, from 17 to 28 percent, the incremental oil recovery for solvent floods is between 31 and 50 x $10^6$ $m^3$.

For combination miscible floods, the incremental recovery factor ranges from 5 to 34 percent. Taking a narrower range, from 5 to 25 percent, the incremental oil recovery for solvent floods is between 3 and 16 x $10^6$ $m^3$.

For sandstone miscible floods, the incremental recovery factor ranges from 1.0 to 44 percent. Taking a narrower range, from 5.0 to 30 percent, the incremental oil recovery for solvent floods is between 23 and 140 x $10^6$ $m^3$.

The total for all solvent floods is in the range of 65 to 224 x $10^6$ $m^3$.

### 7.3 Chemical Floods

For polymer floods, the range of recovery factors is 12 to 36 percent, with an average of 25 percent. Applying a narrower range, from 16 to 34 percent, to the total OOIP in potential pools, the incremental recovery is 42 to 120 x $10^6$ $m^3$.

For ASP floods, the range of recovery factors is 12 to 42 percent. Applying a narrower range of 16 to 34 percent to the total OOIP in potential pools, the incremental recovery is 71 to 150 x $10^6$ $m^3$.

The recovery factors in the reserves report do not separate the recovery due to waterflood and the chemical flood. Detailed evaluations of several chemical floods indicate that a polymer flood increases the recovery factor over a waterflood by about 50 percent, i.e., one-third of the recovery in a waterflood/polymer flood is due to the polymer. The recovery from an ASP flood is perhaps 50 percent more than from a polymer flood (though the ASP floods are generally more recent than the polymer floods and there are fewer of them). Thus in an ASP flood, 40 to 45 percent of the waterflood/ASP flood recovery is due to the ASP.

The incremental recovery due to the polymer flood is therefore in the range of 14 to 40 x $10^6$ $m^3$, and in the ASP flood, it is in the range of 35 to 75 x $10^6$ $m^3$.

# 8.0 Conclusions

Examination of the records of the EOR projects in Alberta has shown that there have been many technical successes, with significant increased oil recovery. In particular, the vertical miscible floods in the Pembina/Brazeau River Nisku reefs and the Rainbow Keg River reefs have been outstanding, often recovering over 80 percent of the OOIP.

Chemical floods have also been successful, with both polymer and ASP floods providing increased oil recovery. Alkali and alkali/polymer floods have shown some success but very little incremental recovery over simple polymer.

There are a large number of oil pools in Alberta which are amenable for both miscible and chemical flooding. In the current high oil price/low gas price environment, many should be economically viable. The incremental oil potential is in the range of 100 to 300 x $10^6$ $m^3$. The total remaining conventional oil reserves in Alberta at the end of 2010 were 237 x $10^6$ $m^3$, meaning that EOR can potentially have a major impact on Alberta's conventional oil reserves.

# 9.0 Recommendations

As with any study of this type, many ideas are generated, and many gaps in knowledge are identified. Several of these should be investigated:

- The effect of prior depletion on the incremental recovery should be investigated, perhaps through a series of conceptual model studies.
- Generic economics should be generated for each process with guidelines as to costs and prices. These would allow for simple economic screening criteria.
- Although there has been considerable work in Alberta on EOR, many aspects have not been investigated. This study should be extended to include a wider selection of EOR projects from around the world.
- This study used a database which was set up to contain considerable data and to perform most of the screening. A user-friendly front-end should be developed, and the database should be made available to a wider number of users.
- The Alberta Oil Reserves report is a very useful source of information; however, it is not in a computer-friendly format and cannot be put into a spreadsheet easily (e.g., primary, waterflood and total recovery are on three lines). Changing the format would make it much easier to use.

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**EOR Project Assessment** **Table 1**

| | |
|---|---|
| **Field** | Acheson |
| **Pool Name** | D-3 A |
| **Formation** | Leduc |
| **ERCB Approval Nos.** | 10003 |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | CO2 |
| **Flood Type** | Vertical |
| **Group** | Leduc |
| | |
| **Number of Wells** | 91 |
| **Number of EOR Injectors** | 5 |
| **Number of EOR Producers** | 39 |
| | |
| **Date** | |
| Discovery | 1950 |
| Secondary Recovery | |
| EOR 1 | Solvent / HC Miscible Flood (1987 - 1996) |
| EOR 2 | Chase Gas (1988 - 2005) North Area |
| EOR 3 | Chase Gas (1995 - 2005) South Area |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1546.7 |
| Average Pay Thickness (m) | 18.39 |
| Average Permeability (md) | 2870.11 |
| Average Porosity | 0.1 |
| Water Saturation | 0.12 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 11922 |
| Initial Temperature (C) | 61 |
| Oil Gravity (API) | 37.8 |
| Oil Density (kg/m3) | 835.8 |
| Oil Viscosity @ 15C (cp) | 5.72 |
| Oil Viscosity @ Tr (cp) | 2.76 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 788 |
| Primary Recovery Factor (fraction) | 0.54 |
| Incremental WF Recovery Factor (fraction) | 0.125 |
| Incremental EOR Recovery Factor (fraction) | 0.185 |
| Total Recovery Factor (fraction) | 0.85 |
| OOIP (E3m3) | 9692 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 1454 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 2**

| | |
|---|---|
| **Field** | Ante Creek |
| **Pool Name** | Beaverhill Lake |
| **Formation** | Beaverhill Lake |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | Enriched Gas |
| **Flood Type** | Horizontal |
| **Group** | Beaverhill Lake |
| | |
| **Number of Wells** | 30 |
| **Number of EOR Injectors** | 9 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | |
| Secondary Recovery | |
| EOR 1 | |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 3433.1 |
| Average Pay Thickness (m) | 3.27 |
| Average Permeability (md) | 20.38 |
| Average Porosity | 0.1 |
| Water Saturation | 0.27 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 35550 |
| Initial Temperature (C) | 110 |
| Oil Gravity (API) | 44.08 |
| Oil Density (kg/m3) | 805.9 |
| Oil Viscosity (cp) | 2.50 |
| Oil Viscosity @ Tr (cp) | 1.42 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | No |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 3039 |
| Primary Recovery Factor (fraction) | 0.16 |
| Incremental WF Recovery Factor (fraction) | 0.22 |
| Incremental EOR Recovery Factor (fraction) | |
| Total Recovery Factor (fraction) | |
| OOIP (E3m3) | 6218 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 3855 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 3**

| | |
|---|---|
| **Field** | Bigoray |
| **Pool Name** | Nisku B |
| **Formation** | Nisku |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Pembina |
| | |
| **Number of Wells** | 6 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1978 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 2337.2 |
| Average Pay Thickness (m) | 49.24 |
| Average Permeability (md) | 1068.57 |
| Average Porosity | 0.067 |
| Water Saturation | 0.22 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 21024 |
| Initial Temperature (C) | 76 |
| Oil Gravity (API) | 38.16 |
| Oil Density (kg/m3) | 834.0 |
| Oil Viscosity (cp) | 5.44 |
| Oil Viscosity @ Tr (cp) | 2.28 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | No |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 67 |
| Primary Recovery Factor (fraction) | 0.31 |
| Incremental WF Recovery Factor (fraction) | 0.18 |
| Incremental EOR Recovery Factor (fraction) | 0.178 |
| Total Recovery Factor (fraction) | 0.668 |
| OOIP (E3m3) | 1500 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 498 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 4**

| | |
|---|---|
| **Field** | Bigoray |
| **Pool Name** | Nisku F |
| **Formation** | Nisku |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Pembina |
| | |
| **Number of Wells** | 4 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1977 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood (1987) |
| EOR 2 | Chase Gas (1989 - 1995) |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 2404 |
| Average Pay Thickness (m) | 65.79 |
| Average Permeability (md) | 2418.1 |
| Average Porosity | 0.11 |
| Water Saturation | 0.07 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 20304 |
| Initial Temperature (C) | 78 |
| Oil Gravity (API) | 38.1 |
| Oil Density (kg/m3) | 834.3 |
| Oil Viscosity (cp) | 5.48 |
| Oil Viscosity @ Tr (cp) | 2.24 |
| Salinity of Formation Water (ppm) | 148530 |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 52 |
| Primary Recovery Factor (fraction) | 0.4 |
| Incremental WF Recovery Factor (fraction) | 0.24 |
| Incremental EOR Recovery Factor (fraction) | 0.235 |
| Total Recovery Factor (fraction) | 0.875 |
| OOIP (E3m3) | 2800 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 350 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 5**

| | |
|---|---|
| **Field** | Brazeau River |
| **Pool Name** | Nisku A |
| **Formation** | Nisku |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Pembina |
| | |
| **Number of Wells** | |
| **Number of EOR Injectors** | |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1977 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 3110 |
| Average Pay Thickness (m) | 72.9 |
| Average Permeability (md) | 769 |
| Average Porosity | 0.11 |
| Water Saturation | 0.1 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 45803 |
| Initial Temperature (C) | 107 |
| Oil Gravity (API) | 44.06 |
| Oil Density (kg/m3) | 806.0 |
| Oil Viscosity (cp) | 2.51 |
| Oil Viscosity @ Tr (cp) | 1.44 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 108 |
| Primary Recovery Factor (fraction) | 0.405 |
| Incremental WF Recovery Factor (fraction) | 0.15 |
| Incremental EOR Recovery Factor (fraction) | 0.265 |
| Total Recovery Factor (fraction) | 0.82 |
| OOIP (E3m3) | 5300 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 954 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 6**

| | |
|---|---|
| **Field** | Brazeau River |
| **Pool Name** | Nisku D |
| **Formation** | Nisku |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Pembina |
| | |
| **Number of Wells** | 6 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1978 |
| Secondary Recovery | |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 3069 |
| Average Pay Thickness (m) | 44.88 |
| Average Permeability (md) | |
| Average Porosity | 0.065 |
| Water Saturation | 0.12 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 34568 |
| Initial Temperature (C) | 102 |
| Oil Gravity (API) | 42.12 |
| Oil Density (kg/m3) | 815.0 |
| Oil Viscosity (cp) | 3.19 |
| Oil Viscosity @ Tr (cp) | 1.57 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 157 |
| Primary Recovery Factor (fraction) | 0.5 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.15 |
| Total Recovery Factor (fraction) | 0.65 |
| OOIP (E3m3) | 2700 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 945 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 7**

| | |
|---|---|
| **Field** | Brazeau River |
| **Pool Name** | Nisku E |
| **Formation** | Nisku |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Pembina |
| | |
| **Number of Wells** | 4 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1978 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 3199.9 |
| Average Pay Thickness (m) | 42.62 |
| Average Permeability (md) | |
| Average Porosity | 0.1 |
| Water Saturation | 0.12 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 46019 |
| Initial Temperature (C) | 108 |
| Oil Gravity (API) | 45.69 |
| Oil Density (kg/m3) | 798.6 |
| Oil Viscosity (cp) | 2.07 |
| Oil Viscosity @ Tr (cp) | 1.37 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 142 |
| Primary Recovery Factor (fraction) | 0.451 |
| Incremental WF Recovery Factor (fraction) | 0.04 |
| Incremental EOR Recovery Factor (fraction) | 0.35 |
| Total Recovery Factor (fraction) | 0.841 |
| OOIP (E3m3) | 2450 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 390 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 8**

| | |
|---|---|
| **Field** | Caroline |
| **Pool Name** | Cardium E |
| **Formation** | Cardium |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Horizontal |
| **Group** | Sandstone |
| | |
| **Number of Wells** | 81 |
| **Number of EOR Injectors** | 14 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 2413.6 |
| Average Pay Thickness (m) | 2.5 |
| Average Permeability (md) | 41.41 |
| Average Porosity | 0.12 |
| Water Saturation | 0.16 |
| Lithology | Sandstone |
| Initial Pressure (kPa) | 27614 |
| Initial Temperature (C) | 81 |
| Oil Gravity (API) | 46.09 |
| Oil Density (kg/m3) | 796.8 |
| Oil Viscosity (cp) | 1.97 |
| Oil Viscosity @ Tr (cp) | 1.52 |
| Salinity of Formation Water (ppm) | 12210 |
| Presence of Natural Fractures | No |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 3519 |
| Primary Recovery Factor (fraction) | 0.09 |
| Incremental WF Recovery Factor (fraction) | 0.16 |
| Incremental EOR Recovery Factor (fraction) | 0.05 |
| Total Recovery Factor (fraction) | 0.3 |
| OOIP (E3m3) | 4700 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 3290 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 9**

| | |
|---|---|
| **Field** | Chigwell |
| **Pool Name** | Viking E |
| **Formation** | Viking |
| **ERCB Approval Nos.** | 10865D |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | CO2 |
| **Flood Type** | Horizontal |
| **Group** | Sandstone |
| | |
| **Number of Wells** | 61 |
| **Number of EOR Injectors** | 7 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1980 |
| Secondary Recovery | |
| EOR 1 | CO2 Flood (2007 - ) |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1385.6 |
| Average Pay Thickness (m) | 2.85 |
| Average Permeability (md) | 72.89 |
| Average Porosity | 0.13 |
| Water Saturation | 0.38 |
| Lithology | Sandstone |
| Initial Pressure (kPa) | 9916 |
| Initial Temperature (C) | 40 |
| Oil Gravity (API) | 38 |
| Oil Density (kg/m3) | 834.8 |
| Oil Viscosity (cp) | 5.56 |
| Oil Viscosity @ Tr (cp) | 3.70 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 2385 |
| Primary Recovery Factor (fraction) | 0.08 |
| Incremental WF Recovery Factor (fraction) | 0 |
| Incremental EOR Recovery Factor (fraction) | 0.03 |
| Total Recovery Factor (fraction) | 0.11 |
| OOIP (E3m3) | 4986 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 4437 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 10**

| | |
|---|---|
| **Field** | Chigwell |
| **Pool Name** | Viking I |
| **Formation** | Viking |
| **ERCB Approval Nos.** | 10392H |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | CO2 |
| **Flood Type** | Horizontal |
| **Group** | Sandstone |
| | |
| **Number of Wells** | 30 |
| **Number of EOR Injectors** | 8 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1985 |
| Secondary Recovery | Solvent - CO2 Flood |
| EOR 1 | Ethane Flood (1999 - 2006) |
| EOR 2 | CO2 Flood (2006 - ) |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1411 |
| Average Pay Thickness (m) | 1.96 |
| Average Permeability (md) | 43.76 |
| Average Porosity | 0.13 |
| Water Saturation | 0.39 |
| Lithology | Sandstone |
| Initial Pressure (kPa) | 7372 |
| Initial Temperature (C) | 55 |
| Oil Gravity (API) | 38.6 |
| Oil Density (kg/m3) | 831.9 |
| Oil Viscosity (cp) | 5.11 |
| Oil Viscosity @ Tr (cp) | 2.81 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 1467 |
| Primary Recovery Factor (fraction) | 0.08 |
| Incremental WF Recovery Factor (fraction) | 0.04 |
| Incremental EOR Recovery Factor (fraction) | 0.08 |
| Total Recovery Factor (fraction) | 0.2 |
| OOIP (E3m3) | 2075 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 1660 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 11**

| | |
|---|---|
| **Field** | Enchant |
| **Pool Name** | Commingled 005 |
| **Formation** | Arcs |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Horizontal |
| **Group** | |
| | |
| **Number of Wells** | 7 |
| **Number of EOR Injectors** | 2 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1987 |
| Secondary Recovery | |
| EOR 1 | |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1355.5 |
| Average Pay Thickness (m) | 9.42 |
| Average Permeability (md) | |
| Average Porosity | 0.14 |
| Water Saturation | 0.2 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 11905 |
| Initial Temperature (C) | 35 |
| Oil Gravity (API) | 26.07 |
| Oil Density (kg/m3) | 898.0 |
| Oil Viscosity (cp) | 48.51 |
| Oil Viscosity @ Tr (cp) | 20.20 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | |
| Primary Recovery Factor (fraction) | 0.22 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.17 |
| Total Recovery Factor (fraction) | 0.39 |
| OOIP (E3m3) | 1743 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 12**

| | |
|---|---|
| **Field** | Enchant |
| **Pool Name** | Commingled 017 |
| **Formation** | Arcs |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Horizontal |
| **Group** | |
| | |
| **Number of Wells** | 9 |
| **Number of EOR Injectors** | 4 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1985 |
| Secondary Recovery | |
| EOR 1 | |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1320.6 |
| Average Pay Thickness (m) | 5.62 |
| Average Permeability (md) | |
| Average Porosity | 0.13 |
| Water Saturation | 0.2 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 10374 |
| Initial Temperature (C) | 35 |
| Oil Gravity (API) | 28.03 |
| Oil Density (kg/m3) | 887.0 |
| Oil Viscosity (cp) | 31.01 |
| Oil Viscosity @ Tr (cp) | 14.28 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 149 |
| Primary Recovery Factor (fraction) | 0.25 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.23 |
| Total Recovery Factor (fraction) | |
| OOIP (E3m3) | 723 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 13**

| | |
|---|---|
| **Field** | Fenn-Big Valley |
| **Pool Name** | Commingled 009 |
| **Formation** | Nisku A |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Horizontal |
| **Group** | |
| | |
| **Number of Wells** | |
| **Number of EOR Injectors** | |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | |
| Secondary Recovery | |
| EOR 1 | |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1574.4 |
| Average Pay Thickness (m) | 9.93 |
| Average Permeability (md) | |
| Average Porosity | 0.082 |
| Water Saturation | 0.14 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 11417 |
| Initial Temperature (C) | 57 |
| Oil Gravity (API) | 32.1 |
| Oil Density (kg/m3) | 864.9 |
| Oil Viscosity (cp) | 14.09 |
| Oil Viscosity @ Tr (cp) | 4.77 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 1023 |
| Primary Recovery Factor (fraction) | 0.468 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.052 |
| Total Recovery Factor (fraction) | |
| OOIP (E3m3) | 5804 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 14**

| | |
|---|---|
| **Field** | Golden Spike |
| **Pool Name** | D-3 A |
| **Formation** | D-3 |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Combination |
| **Group** | Leduc |
| | |
| **Number of Wells** | 73 |
| **Number of EOR Injectors** | 11 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1949 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1725.3 |
| Average Pay Thickness (m) | 135.71 |
| Average Permeability (md) | |
| Average Porosity | 0.087 |
| Water Saturation | 0.11 |
| Lithology | Dolomite |
| Initial Pressure (kPa) | 14400 |
| Initial Temperature (C) | 60 |
| Oil Gravity (API) | 37.09 |
| Oil Density (kg/m3) | 839.3 |
| Oil Viscosity (cp) | 6.34 |
| Oil Viscosity @ Tr (cp) | 2.94 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 590 |
| Primary Recovery Factor (fraction) | 0.53 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.05 |
| Total Recovery Factor (fraction) | 0.58 |
| OOIP (E3m3) | 49603 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 15**

| | |
|---|---|
| **Field** | Goose River |
| **Pool Name** | Beaverhill Lake A |
| **Formation** | Beaverhill Lake |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Horizontal |
| **Group** | Beaverhill Lake |
| | |
| **Number of Wells** | 75 |
| **Number of EOR Injectors** | 15 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 2800 |
| Average Pay Thickness (m) | 17.93 |
| Average Permeability (md) | 9.89 |
| Average Porosity | 0.094 |
| Water Saturation | 0.19 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 24805 |
| Initial Temperature (C) | 98 |
| Oil Gravity (API) | 41.08 |
| Oil Density (kg/m3) | 819.9 |
| Oil Viscosity (cp) | 3.65 |
| Oil Viscosity @ Tr (cp) | 1.67 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 1600 |
| Primary Recovery Factor (fraction) | 0.16 |
| Incremental WF Recovery Factor (fraction) | 0.23 |
| Incremental EOR Recovery Factor (fraction) | 0.07 |
| Total Recovery Factor (fraction) | 0.46 |
| OOIP (E3m3) | 16160 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 8726 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 16**

| | |
|---|---|
| **Field** | Joffre |
| **Pool Name** | D-3 B |
| **Formation** | Leduc |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Leduc |
| | |
| **Number of Wells** | 7 |
| **Number of EOR Injectors** | 3 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1985 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 2113.3 |
| Average Pay Thickness (m) | 40.74 |
| Average Permeability (md) | 434.4 |
| Average Porosity | 0.09 |
| Water Saturation | 0.13 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 16550 |
| Initial Temperature (C) | 72 |
| Oil Gravity (API) | 38.57 |
| Oil Density (kg/m3) | 832.0 |
| Oil Viscosity (cp) | 5.13 |
| Oil Viscosity @ Tr (cp) | 2.31 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 76 |
| Primary Recovery Factor (fraction) | 0.33 |
| Incremental WF Recovery Factor (fraction) | 0.19 |
| Incremental EOR Recovery Factor (fraction) | 0.05 |
| Total Recovery Factor (fraction) | 0.57 |
| OOIP (E3m3) | 1721 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 740 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 17**

| | |
|---|---|
| **Field** | Joffre |
| **Pool Name** | Viking |
| **Formation** | Viking |
| **ERCB Approval Nos.** | 9838 |
| **EOR Type** | CO2 Miscible Flood |
| **EOR Sub Type** | CO2 |
| **Flood Type** | Horizontal |
| **Group** | Sandstone |
| | |
| **Number of Wells** | 422 |
| **Number of EOR Injectors** | 20 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1953 |
| Secondary Recovery | |
| EOR 1 | CO2 Miscible Flood (1984 - 2006) |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1400.4 |
| Average Pay Thickness (m) | 2.73 |
| Average Permeability (md) | 349.22 |
| Average Porosity | 0.13 |
| Water Saturation | 0.36 |
| Lithology | Sandstone |
| Initial Pressure (kPa) | 6616 |
| Initial Temperature (C) | 46 |
| Oil Gravity (API) | 38.2 |
| Oil Density (kg/m3) | 833.8 |
| Oil Viscosity (cp) | 5.41 |
| Oil Viscosity @ Tr (cp) | 3.30 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | No |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 4465 |
| Primary Recovery Factor (fraction) | 0.16 |
| Incremental WF Recovery Factor (fraction) | 0.26 |
| Incremental EOR Recovery Factor (fraction) | 0.18 |
| Total Recovery Factor (fraction) | 0.6 |
| OOIP (E3m3) | 8215 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 3286 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 18**

| | |
|---|---|
| **Field** | Judy Creek |
| **Pool Name** | Beaverhill Lake A |
| **Formation** | Beaverhill Lake |
| **ERCB Approval Nos.** | 10269 |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | CO2 |
| **Flood Type** | Combination |
| **Group** | Beaverhill Lake |
| | |
| **Number of Wells** | 360 |
| **Number of EOR Injectors** | 108 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1959 |
| Secondary Recovery | |
| EOR 1 | Solvent HC Flood (2002 - 2003) |
| EOR 2 | CO2 Flood (2007 - 2010) |
| EOR 3 | Acid Gas (2007 - 2010) |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 2628.6 |
| Average Pay Thickness (m) | 24.58 |
| Average Permeability (md) | 65.28 |
| Average Porosity | 0.09 |
| Water Saturation | 0.16 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 22564 |
| Initial Temperature (C) | 96 |
| Oil Gravity (API) | 41 |
| Oil Density (kg/m3) | 820.3 |
| Oil Viscosity (cp) | 3.69 |
| Oil Viscosity @ Tr (cp) | 1.69 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | No |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 5908 |
| Primary Recovery Factor (fraction) | 0.16 |
| Incremental WF Recovery Factor (fraction) | 0.25 |
| Incremental EOR Recovery Factor (fraction) | 0.09 |
| Total Recovery Factor (fraction) | 0.5 |
| OOIP (E3m3) | 77950 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 38970 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 19**

| | |
|---|---|
| **Field** | Judy Creek |
| **Pool Name** | Beaverhill Lake B |
| **Formation** | Beaverhill Lake |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Combination |
| **Group** | Beaverhill Lake |
| | |
| **Number of Wells** | 99 |
| **Number of EOR Injectors** | 21 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood (1987) |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 2696.2 |
| Average Pay Thickness (m) | 25.59 |
| Average Permeability (md) | 92.64 |
| Average Porosity | 0.099 |
| Water Saturation | 0.17 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 24442 |
| Initial Temperature (C) | 99 |
| Oil Gravity (API) | 42.08 |
| Oil Density (kg/m3) | 815.2 |
| Oil Viscosity (cp) | 3.21 |
| Oil Viscosity @ Tr (cp) | 1.60 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | No |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 2176 |
| Primary Recovery Factor (fraction) | 0.2 |
| Incremental WF Recovery Factor (fraction) | 0.24 |
| Incremental EOR Recovery Factor (fraction) | 0.05 |
| Total Recovery Factor (fraction) | 0.49 |
| OOIP (E3m3) | 28370 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 14469 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 20**

| | |
|---|---|
| **Field** | Kaybob |
| **Pool Name** | Beaverhill Lake A |
| **Formation** | Beaverhill Lake |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Combination |
| **Group** | Beaverhill Lake |
| | |
| **Number of Wells** | 115 |
| **Number of EOR Injectors** | 20 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1957 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 2982 |
| Average Pay Thickness (m) | 19.11 |
| Average Permeability (md) | 140.31 |
| Average Porosity | 0.08 |
| Water Saturation | 0.21 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 31820 |
| Initial Temperature (C) | 105 |
| Oil Gravity (API) | 42.98 |
| Oil Density (kg/m3) | 811.0 |
| Oil Viscosity (cp) | 2.86 |
| Oil Viscosity @ Tr (cp) | 1.50 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 4918 |
| Primary Recovery Factor (fraction) | 0.16 |
| Incremental WF Recovery Factor (fraction) | 0.24 |
| Incremental EOR Recovery Factor (fraction) | 0.065 |
| Total Recovery Factor (fraction) | 0.465 |
| OOIP (E3m3) | 36830 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 19704 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 21**

| | |
|---|---|
| **Field** | Kaybob South |
| **Pool Name** | Triassic A |
| **Formation** | Triassic |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Horizontal |
| **Group** | |
| | |
| **Number of Wells** | 3 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1986 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 2060.4 |
| Average Pay Thickness (m) | 6.38 |
| Average Permeability (md) | |
| Average Porosity | 0.13 |
| Water Saturation | 0.17 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 16844 |
| Initial Temperature (C) | 86 |
| Oil Gravity (API) | 39.39 |
| Oil Density (kg/m3) | 828.0 |
| Oil Viscosity (cp) | 4.58 |
| Oil Viscosity @ Tr (cp) | 1.95 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 3453 |
| Primary Recovery Factor (fraction) | 0.15 |
| Incremental WF Recovery Factor (fraction) | 0.25 |
| Incremental EOR Recovery Factor (fraction) | 0.05 |
| Total Recovery Factor (fraction) | 0.45 |
| OOIP (E3m3) | 16880 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 9284 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 22**

| | |
|---|---|
| **Field** | Leduc |
| **Pool Name** | D-2A |
| **Formation** | Nisku |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Combination |
| **Group** | |
| | |
| **Number of Wells** | 506 |
| **Number of EOR Injectors** | 4 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1947 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1486.6 |
| Average Pay Thickness (m) | 18.9 |
| Average Permeability (md) | 297.1 |
| Average Porosity | 0.034 |
| Water Saturation | 0.26 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 10441 |
| Initial Temperature (C) | 54 |
| Oil Gravity (API) | 38.16 |
| Oil Density (kg/m3) | 834.0 |
| Oil Viscosity (cp) | 5.44 |
| Oil Viscosity @ Tr (cp) | 2.94 |
| Salinity of Formation Water (ppm) | 249560 |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 9169 |
| Primary Recovery Factor (fraction) | 0.25 |
| Incremental WF Recovery Factor (fraction) | 0.28 |
| Incremental EOR Recovery Factor (fraction) | 0.09 |
| Total Recovery Factor (fraction) | 0.62 |
| OOIP (E3m3) | 62650 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 23807 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 23**

| | |
|---|---|
| **Field** | Mitsue |
| **Pool Name** | Gilwood A |
| **Formation** | Gilwood |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Horizontal |
| **Group** | |
| | |
| **Number of Wells** | 799 |
| **Number of EOR Injectors** | 63 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1964 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1659.1 |
| Average Pay Thickness (m) | 4.98 |
| Average Permeability (md) | 234.02 |
| Average Porosity | 0.144 |
| Water Saturation | 0.36 |
| Lithology | |
| Initial Pressure (kPa) | 12323 |
| Initial Temperature (C) | 60 |
| Oil Gravity (API) | 43.08 |
| Oil Density (kg/m3) | 810.5 |
| Oil Viscosity (cp) | 2.83 |
| Oil Viscosity @ Tr (cp) | 2.00 |
| Salinity of Formation Water (ppm) | 284400 |
| Presence of Natural Fractures | No |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 17500 |
| Primary Recovery Factor (fraction) | 0.25 |
| Incremental WF Recovery Factor (fraction) | 0.21 |
| Incremental EOR Recovery Factor (fraction) | 0.15 |
| Total Recovery Factor (fraction) | 0.61 |
| OOIP (E3m3) | 63672 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 24832 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 24**

| | |
|---|---|
| **Field** | Nipisi |
| **Pool Name** | Gilwood A |
| **Formation** | Gilwood |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Horizontal |
| **Group** | |
| | |
| **Number of Wells** | 552 |
| **Number of EOR Injectors** | 39 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1965 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1711 |
| Average Pay Thickness (m) | 6.92 |
| Average Permeability (md) | 479.19 |
| Average Porosity | 0.15 |
| Water Saturation | 0.35 |
| Lithology | Sandstone |
| Initial Pressure (kPa) | 17948 |
| Initial Temperature (C) | 51 |
| Oil Gravity (API) | 41.08 |
| Oil Density (kg/m3) | 819.9 |
| Oil Viscosity (cp) | 3.65 |
| Oil Viscosity @ Tr (cp) | 2.48 |
| Salinity of Formation Water (ppm) | 237000 |
| Presence of Natural Fractures | No |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 12408 |
| Primary Recovery Factor (fraction) | 0.26 |
| Incremental WF Recovery Factor (fraction) | 0.125 |
| Incremental EOR Recovery Factor (fraction) | 0.159 |
| Total Recovery Factor (fraction) | 0.544 |
| OOIP (E3m3) | 69480 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 31683 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 25**

| | |
|---|---|
| **Field** | Pembina |
| **Pool Name** | Cardium A Lease |
| **Formation** | Cardium |
| **ERCB Approval Nos.** | |
| **EOR Type** | CO2 |
| **EOR Sub Type** | |
| **Flood Type** | |
| **Group** | Sandstone |
| | |
| **Number of Wells** | |
| **Number of EOR Injectors** | |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1977 |
| Secondary Recovery | |
| EOR 1 | |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | |
| Average Pay Thickness (m) | |
| Average Permeability (md) | |
| Average Porosity | 0.121 |
| Water Saturation | 0.15 |
| Lithology | Sandstone |
| Initial Pressure (kPa) | 33807 |
| Initial Temperature (C) | 52 |
| Oil Gravity (API) | 38.1 |
| Oil Density (kg/m3) | 834.3 |
| Oil Viscosity (cp) | 5.48 |
| Oil Viscosity @ Tr (cp) | 3.04 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | |
| Primary Recovery Factor (fraction) | 0.405 |
| Incremental WF Recovery Factor (fraction) | 0.12 |
| Incremental EOR Recovery Factor (fraction) | 0.3 |
| Total Recovery Factor (fraction) | 0.825 |
| OOIP (E3m3) | 3000 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 525 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 26**

| | |
|---|---|
| **Field** | Pembina |
| **Pool Name** | Nisku A |
| **Formation** | Nisku |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Pembina |
| | |
| **Number of Wells** | 4 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1977 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood (1985) |
| EOR 2 | Chase Gas (1993 - 1994) |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 3005.7 |
| Average Pay Thickness (m) | 68.69 |
| Average Permeability (md) | 954.26 |
| Average Porosity | 0.08 |
| Water Saturation | 0.2 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 33807 |
| Initial Temperature (C) | 100 |
| Oil Gravity (API) | 44.08 |
| Oil Density (kg/m3) | 805.9 |
| Oil Viscosity (cp) | 2.50 |
| Oil Viscosity @ Tr (cp) | 1.48 |
| Salinity of Formation Water (ppm) | 146450 |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 105 |
| Primary Recovery Factor (fraction) | 0.405 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.42 |
| Total Recovery Factor (fraction) | 0.825 |
| OOIP (E3m3) | 3000 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 525 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 27**

| | |
|---|---|
| **Field** | Pembina |
| **Pool Name** | Nisku D |
| **Formation** | Nisku |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Pembina |
| | |
| **Number of Wells** | 7 |
| **Number of EOR Injectors** | 2 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1978 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood (1985) |
| EOR 2 | Chase Gas (1989 - 1997) |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 2576.6 |
| Average Pay Thickness (m) | 39.2 |
| Average Permeability (md) | 1331.6 |
| Average Porosity | 0.12 |
| Water Saturation | 0.1 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 25808 |
| Initial Temperature (C) | 82 |
| Oil Gravity (API) | 36.75 |
| Oil Density (kg/m3) | 841.0 |
| Oil Viscosity (cp) | 6.67 |
| Oil Viscosity @ Tr (cp) | 2.34 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | No |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 192 |
| Primary Recovery Factor (fraction) | 0.35 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.35 |
| Total Recovery Factor (fraction) | 0.7 |
| OOIP (E3m3) | 6503 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 1951 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 28**

| | |
|---|---|
| **Field** | Pembina |
| **Pool Name** | Nisku F |
| **Formation** | Nisku |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Pembina |
| | |
| **Number of Wells** | 9 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1978 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood (1987) |
| EOR 2 | Chase Gas (1993 - 2008) |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 2549.1 |
| Average Pay Thickness (m) | 17.51 |
| Average Permeability (md) | 1587.86 |
| Average Porosity | 0.119 |
| Water Saturation | 0.28 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 21736 |
| Initial Temperature (C) | 83 |
| Oil Gravity (API) | 34.58 |
| Oil Density (kg/m3) | 852.0 |
| Oil Viscosity (cp) | 9.31 |
| Oil Viscosity @ Tr (cp) | 2.65 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 193 |
| Primary Recovery Factor (fraction) | 0.35 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.45 |
| Total Recovery Factor (fraction) | 0.8 |
| OOIP (E3m3) | 2201 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 440 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 29**

| | |
|---|---|
| **Field** | Pembina |
| **Pool Name** | Nisku G |
| **Formation** | Nisku |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Pembina |
| | |
| **Number of Wells** | 5 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1978 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 2906.3 |
| Average Pay Thickness (m) | 32.17 |
| Average Permeability (md) | 2603.57 |
| Average Porosity | 0.08 |
| Water Saturation | 0.2 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 27547 |
| Initial Temperature (C) | 96 |
| Oil Gravity (API) | 43.19 |
| Oil Density (kg/m3) | 810.0 |
| Oil Viscosity (cp) | 2.79 |
| Oil Viscosity @ Tr (cp) | 1.56 |
| Salinity of Formation Water (ppm) | 165800 |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 198 |
| Primary Recovery Factor (fraction) | 0.408 |
| Incremental WF Recovery Factor (fraction) | 0 |
| Incremental EOR Recovery Factor (fraction) | 0.5 |
| Total Recovery Factor (fraction) | 0.908 |
| OOIP (E3m3) | 2650 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 244 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 30**

| | |
|---|---|
| **Field** | Pembina |
| **Pool Name** | Nisku G2G |
| **Formation** | Nisku |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Pembina |
| | |
| **Number of Wells** | 4 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1977 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood (1984) |
| EOR 2 | Chase Gas (1989 - 1994) |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 3081.6 |
| Average Pay Thickness (m) | 51.9 |
| Average Permeability (md) | 390.39 |
| Average Porosity | 0.08 |
| Water Saturation | 0.12 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 32090 |
| Initial Temperature (C) | 102 |
| Oil Gravity (API) | 41.99 |
| Oil Density (kg/m3) | 815.6 |
| Oil Viscosity (cp) | 3.24 |
| Oil Viscosity @ Tr (cp) | 1.58 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 89 |
| Primary Recovery Factor (fraction) | 0.35 |
| Incremental WF Recovery Factor (fraction) | 0 |
| Incremental EOR Recovery Factor (fraction) | 0.28 |
| Total Recovery Factor (fraction) | 0.63 |
| OOIP (E3m3) | 2406 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 890 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 31**

| | |
|---|---|
| **Field** | Pembina |
| **Pool Name** | Nisku H2H |
| **Formation** | Nisku |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Pembina |
| | |
| **Number of Wells** | 4 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1979 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood (1984) |
| EOR 2 | Chase Gas (1990 - 1994) |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 3033.3 |
| Average Pay Thickness (m) | 90.35 |
| Average Permeability (md) | |
| Average Porosity | 0.11 |
| Water Saturation | 0.14 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 31373 |
| Initial Temperature (C) | 104 |
| Oil Gravity (API) | 40.22 |
| Oil Density (kg/m3) | 824.0 |
| Oil Viscosity (cp) | 4.09 |
| Oil Viscosity @ Tr (cp) | 1.67 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 60 |
| Primary Recovery Factor (fraction) | 0.4 |
| Incremental WF Recovery Factor (fraction) | 0 |
| Incremental EOR Recovery Factor (fraction) | 0.47 |
| Total Recovery Factor (fraction) | 0.87 |
| OOIP (E3m3) | 4000 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 520 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 32**

| | |
|---|---|
| **Field** | Pembina |
| **Pool Name** | Nisku K |
| **Formation** | Nisku |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Pembina |
| | |
| **Number of Wells** | 4 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1978 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 2892.9 |
| Average Pay Thickness (m) | 73.06 |
| Average Permeability (md) | 1784.6 |
| Average Porosity | 0.127 |
| Water Saturation | 0.18 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 28706 |
| Initial Temperature (C) | 92 |
| Oil Gravity (API) | 43.62 |
| Oil Density (kg/m3) | 808.0 |
| Oil Viscosity (cp) | 2.64 |
| Oil Viscosity @ Tr (cp) | 1.57 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | No |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 54 |
| Primary Recovery Factor (fraction) | 0.4 |
| Incremental WF Recovery Factor (fraction) | 0 |
| Incremental EOR Recovery Factor (fraction) | 0.48 |
| Total Recovery Factor (fraction) | 0.88 |
| OOIP (E3m3) | 2753 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 330 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 33**

| | |
|---|---|
| **Field** | Pembina |
| **Pool Name** | Nisku L |
| **Formation** | Nisku |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Pembina |
| | |
| **Number of Wells** | 7 |
| **Number of EOR Injectors** | 2 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1978 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 2880.6 |
| Average Pay Thickness (m) | 30.12 |
| Average Permeability (md) | 2427.51 |
| Average Porosity | 0.105 |
| Water Saturation | 0.12 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 28222 |
| Initial Temperature (C) | 93 |
| Oil Gravity (API) | 40.85 |
| Oil Density (kg/m3) | 821.0 |
| Oil Viscosity (cp) | 3.76 |
| Oil Viscosity @ Tr (cp) | 1.74 |
| Salinity of Formation Water (ppm) | 20408 |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 253 |
| Primary Recovery Factor (fraction) | 0.25 |
| Incremental WF Recovery Factor (fraction) | 0 |
| Incremental EOR Recovery Factor (fraction) | 0.63 |
| Total Recovery Factor (fraction) | 0.88 |
| OOIP (E3m3) | 5000 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 600 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 34**

| | |
|---|---|
| **Field** | Pembina |
| **Pool Name** | Nisku M |
| **Formation** | Nisku |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Pembina |
| | |
| **Number of Wells** | 4 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1978 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 2850.1 |
| Average Pay Thickness (m) | 51.6 |
| Average Permeability (md) | 1551.53 |
| Average Porosity | 0.09 |
| Water Saturation | 0.09 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 27909 |
| Initial Temperature (C) | 92 |
| Oil Gravity (API) | 41.06 |
| Oil Density (kg/m3) | 820.0 |
| Oil Viscosity (cp) | 3.66 |
| Oil Viscosity @ Tr (cp) | 1.73 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | No |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 107 |
| Primary Recovery Factor (fraction) | 0.4 |
| Incremental WF Recovery Factor (fraction) | 0 |
| Incremental EOR Recovery Factor (fraction) | 0.45 |
| Total Recovery Factor (fraction) | 0.85 |
| OOIP (E3m3) | 3120 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 468 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 35**

| | |
|---|---|
| **Field** | Pembina |
| **Pool Name** | Nisku O |
| **Formation** | Nisku |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Pembina |
| | |
| **Number of Wells** | 3 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1979 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 2844 |
| Average Pay Thickness (m) | 21.06 |
| Average Permeability (md) | 3941.39 |
| Average Porosity | 0.118 |
| Water Saturation | 0.16 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 26949 |
| Initial Temperature (C) | 88 |
| Oil Gravity (API) | 43.41 |
| Oil Density (kg/m3) | 809.0 |
| Oil Viscosity (cp) | 2.71 |
| Oil Viscosity @ Tr (cp) | 1.61 |
| Salinity of Formation Water (ppm) | 152200 |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 140 |
| Primary Recovery Factor (fraction) | 0.4 |
| Incremental WF Recovery Factor (fraction) | 0 |
| Incremental EOR Recovery Factor (fraction) | 0.4 |
| Total Recovery Factor (fraction) | 0.8 |
| OOIP (E3m3) | 1900 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 380 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 36**

| | |
|---|---|
| **Field** | Pembina |
| **Pool Name** | Nisku P |
| **Formation** | Nisku |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Pembina |
| | |
| **Number of Wells** | 5 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1979 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 2909.4 |
| Average Pay Thickness (m) | 37.81 |
| Average Permeability (md) | 1477.58 |
| Average Porosity | 0.11 |
| Water Saturation | 0.1 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 28226 |
| Initial Temperature (C) | 93 |
| Oil Gravity (API) | 45.49 |
| Oil Density (kg/m3) | 799.5 |
| Oil Viscosity (cp) | 2.11 |
| Oil Viscosity @ Tr (cp) | 1.46 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 201 |
| Primary Recovery Factor (fraction) | 0.35 |
| Incremental WF Recovery Factor (fraction) | 0 |
| Incremental EOR Recovery Factor (fraction) | 0.45 |
| Total Recovery Factor (fraction) | 0.8 |
| OOIP (E3m3) | 4740 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 948 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 37**

| | |
|---|---|
| **Field** | Pembina |
| **Pool Name** | Nisku P2P |
| **Formation** | Nisku |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Pembina |
| | |
| **Number of Wells** | 3 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1977 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 2932.7 |
| Average Pay Thickness (m) | 85.63 |
| Average Permeability (md) | 703.36 |
| Average Porosity | 0.1 |
| Water Saturation | 0.12 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 38036 |
| Initial Temperature (C) | 100 |
| Oil Gravity (API) | 42.08 |
| Oil Density (kg/m3) | 815.2 |
| Oil Viscosity (cp) | 3.21 |
| Oil Viscosity @ Tr (cp) | 1.59 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 61 |
| Primary Recovery Factor (fraction) | 0.4 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.45 |
| Total Recovery Factor (fraction) | 0.85 |
| OOIP (E3m3) | 2850 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 428 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 38**

| | |
|---|---|
| **Field** | Pembina |
| **Pool Name** | Nisku Q |
| **Formation** | Nisku |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Pembina |
| | |
| **Number of Wells** | 5 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1980 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 2880.5 |
| Average Pay Thickness (m) | 33.86 |
| Average Permeability (md) | 1024.54 |
| Average Porosity | 0.098 |
| Water Saturation | 0.09 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 28560 |
| Initial Temperature (C) | 91 |
| Oil Gravity (API) | 41.27 |
| Oil Density (kg/m3) | 819.0 |
| Oil Viscosity (cp) | 3.56 |
| Oil Viscosity @ Tr (cp) | 1.73 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 122 |
| Primary Recovery Factor (fraction) | 0.4 |
| Incremental WF Recovery Factor (fraction) | 0 |
| Incremental EOR Recovery Factor (fraction) | 0.29 |
| Total Recovery Factor (fraction) | 0.69 |
| OOIP (E3m3) | 2800 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 868 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 39**

| | |
|---|---|
| **Field** | Provost |
| **Pool Name** | Cummings I |
| **Formation** | Cummings |
| **ERCB Approval Nos.** | |
| **EOR Type** | |
| **EOR Sub Type** | |
| **Flood Type** | Horizontal |
| **Group** | Sandstone |
| | |
| **Number of Wells** | 420 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1984 |
| Secondary Recovery | |
| EOR 1 | 1995-04 |
| EOR 2 | 1996-05 |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 763.3 |
| Average Pay Thickness (m) | 4.83 |
| Average Permeability (md) | 384.82 |
| Average Porosity | 0.28 |
| Water Saturation | 0.23 |
| Lithology | Sandstone |
| Initial Pressure (kPa) | 5430 |
| Initial Temperature (C) | 30 |
| Oil Gravity (API) | 23.99 |
| Oil Density (kg/m3) | 910.0 |
| Oil Viscosity (cp) | 83.31 |
| Oil Viscosity @ Tr (cp) | 38.51 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | No |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | |
| Primary Recovery Factor (fraction) | 0.35 |
| Incremental WF Recovery Factor (fraction) | 0.15 |
| Incremental EOR Recovery Factor (fraction) | |
| Total Recovery Factor (fraction) | |
| OOIP (E3m3) | |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 40**

| | |
|---|---|
| **Field** | Rainbow |
| **Pool Name** | Keg River A |
| **Formation** | Keg River |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Rainbow |
| | |
| **Number of Wells** | 37 |
| **Number of EOR Injectors** | 3 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1965 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1833.6 |
| Average Pay Thickness (m) | 90.22 |
| Average Permeability (md) | 2007.68 |
| Average Porosity | 0.101 |
| Water Saturation | 0.1 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 17662 |
| Initial Temperature (C) | 84 |
| Oil Gravity (API) | 43.08 |
| Oil Density (kg/m3) | 810.5 |
| Oil Viscosity (cp) | 2.83 |
| Oil Viscosity @ Tr (cp) | 1.67 |
| Salinity of Formation Water (ppm) | 241690 |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 253 |
| Primary Recovery Factor (fraction) | 0.5 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.25 |
| Total Recovery Factor (fraction) | 0.75 |
| OOIP (E3m3) | 14320 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 3580 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 41**

| | |
|---|---|
| **Field** | Rainbow |
| **Pool Name** | Keg River AA |
| **Formation** | Keg River |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Rainbow |
| | |
| **Number of Wells** | 23 |
| **Number of EOR Injectors** | 5 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1967 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1682.4 |
| Average Pay Thickness (m) | 68.59 |
| Average Permeability (md) | 1485.43 |
| Average Porosity | 0.086 |
| Water Saturation | 0.11 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 18104 |
| Initial Temperature (C) | 84 |
| Oil Gravity (API) | 39.11 |
| Oil Density (kg/m3) | 829.4 |
| Oil Viscosity (cp) | 4.76 |
| Oil Viscosity @ Tr (cp) | 2.01 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 291 |
| Primary Recovery Factor (fraction) | 0.45 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.223 |
| Total Recovery Factor (fraction) | 0.673 |
| OOIP (E3m3) | 14320 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 4683 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 42**

| | |
|---|---|
| **Field** | Rainbow |
| **Pool Name** | Keg River B |
| **Formation** | Keg River |
| **ERCB Approval Nos.** | 8967 |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Rainbow |
| | |
| **Number of Wells** | 95 |
| **Number of EOR Injectors** | 15 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1965 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent/Miscible Flood (2002 - 2006) |
| EOR 2 | Chase Gas (2002 - 2006) |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1819.7 |
| Average Pay Thickness (m) | 61.73 |
| Average Permeability (md) | 1960.7 |
| Average Porosity | 0.09 |
| Water Saturation | 0.14 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 17173 |
| Initial Temperature (C) | 85 |
| Oil Gravity (API) | 38.1 |
| Oil Density (kg/m3) | 834.3 |
| Oil Viscosity (cp) | 5.48 |
| Oil Viscosity @ Tr (cp) | 2.10 |
| Salinity of Formation Water (ppm) | 46500 |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 1195 |
| Primary Recovery Factor (fraction) | 0.4 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.25 |
| Total Recovery Factor (fraction) | 0.65 |
| OOIP (E3m3) | 46820 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 16387 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 43**

| | |
|---|---|
| **Field** | Rainbow |
| **Pool Name** | Keg River D |
| **Formation** | Keg River |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Rainbow |
| | |
| **Number of Wells** | 5 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1966 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1905.3 |
| Average Pay Thickness (m) | 46.32 |
| Average Permeability (md) | 675.97 |
| Average Porosity | 0.1 |
| Water Saturation | 0.08 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 17710 |
| Initial Temperature (C) | 82 |
| Oil Gravity (API) | 40.1 |
| Oil Density (kg/m3) | 824.6 |
| Oil Viscosity (cp) | 4.16 |
| Oil Viscosity @ Tr (cp) | 1.94 |
| Salinity of Formation Water (ppm) | 211318 |
| Presence of Natural Fractures | No |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 34 |
| Primary Recovery Factor (fraction) | 0.4 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.28 |
| Total Recovery Factor (fraction) | 0.68 |
| OOIP (E3m3) | 1130 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 362 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 44**

| | |
|---|---|
| **Field** | Rainbow |
| **Pool Name** | Keg River E |
| **Formation** | Keg River |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Rainbow |
| | |
| **Number of Wells** | 11 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1966 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1840.6 |
| Average Pay Thickness (m) | 54.66 |
| Average Permeability (md) | 194.92 |
| Average Porosity | 0.117 |
| Water Saturation | 0.08 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 18126 |
| Initial Temperature (C) | 83 |
| Oil Gravity (API) | 39.11 |
| Oil Density (kg/m3) | 829.4 |
| Oil Viscosity (cp) | 4.76 |
| Oil Viscosity @ Tr (cp) | 2.03 |
| Salinity of Formation Water (ppm) | 209970 |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 129 |
| Primary Recovery Factor (fraction) | 0.291 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.2 |
| Total Recovery Factor (fraction) | 0.491 |
| OOIP (E3m3) | 5541 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 2820 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 45**

| | |
|---|---|
| **Field** | Rainbow |
| **Pool Name** | Keg River EEE |
| **Formation** | Keg River |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Rainbow |
| | |
| **Number of Wells** | 4 |
| **Number of EOR Injectors** | 2 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1968 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1847.4 |
| Average Pay Thickness (m) | 75.4 |
| Average Permeability (md) | 261.27 |
| Average Porosity | 0.147 |
| Water Saturation | 0.07 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 14253 |
| Initial Temperature (C) | 86 |
| Oil Gravity (API) | 37.09 |
| Oil Density (kg/m3) | 839.3 |
| Oil Viscosity (cp) | 6.34 |
| Oil Viscosity @ Tr (cp) | 2.20 |
| Salinity of Formation Water (ppm) | 290420 |
| Presence of Natural Fractures | No |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 21 |
| Primary Recovery Factor (fraction) | 0.399 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.098 |
| Total Recovery Factor (fraction) | 0.497 |
| OOIP (E3m3) | 1580 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 795 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 46**

| | |
|---|---|
| **Field** | Rainbow |
| **Pool Name** | Keg River F |
| **Formation** | Keg River |
| **ERCB Approval Nos.** | 10376 |
| **EOR Type** | Solvent / Gas Miscible Flood |
| **EOR Sub Type** | Solvent/ NGL/ Enriched Gas |
| **Flood Type** | Vertical |
| **Group** | Rainbow |
| | |
| **Number of Wells** | 56 |
| **Number of EOR Injectors** | 12 |
| **Number of EOR Producers** | 39 |
| | |
| **Date** | |
| Discovery | 1966 |
| Secondary Recovery | Waterflood (1972) |
| EOR 1 | Gas Injection (1968) |
| EOR 2 | Tertiary Immiscible Gas Flood (1993) |
| EOR 3 | Tertiary HC Miscible Flood in NW Lobe (1996) |
| EOR 4 | Tertiary HC Miscible Flood Total Pool (2000) |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1785.5 |
| Average Pay Thickness (m) | 56.08 |
| Average Permeability (md) | 771 |
| Average Porosity | 0.08 |
| Water Saturation | 0.19 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 13673 |
| Initial Temperature (C) | 85 |
| Oil Gravity (API) | 40 |
| Oil Density (kg/m3) | 825.1 |
| Oil Viscosity (cp) | 4.21 |
| Oil Viscosity @ Tr (cp) | 1.91 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 1501 |
| Primary Recovery Factor (fraction) | 0.38 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.15 |
| Total Recovery Factor (fraction) | 0.53 |
| OOIP (E3m3) | 37640 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 17691 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 47**

| | |
|---|---|
| **Field** | Rainbow |
| **Pool Name** | Keg River FF |
| **Formation** | Keg River |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Rainbow |
| | |
| **Number of Wells** | 7 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1967 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1718.7 |
| Average Pay Thickness (m) | 62.27 |
| Average Permeability (md) | 1195.13 |
| Average Porosity | 0.11 |
| Water Saturation | 0.1 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 15797 |
| Initial Temperature (C) | 87 |
| Oil Gravity (API) | 37.09 |
| Oil Density (kg/m3) | 839.3 |
| Oil Viscosity (cp) | 6.34 |
| Oil Viscosity @ Tr (cp) | 2.18 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 88 |
| Primary Recovery Factor (fraction) | 0.21 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.15 |
| Total Recovery Factor (fraction) | 0.36 |
| OOIP (E3m3) | 4177 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 2673 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 48**

| | |
|---|---|
| **Field** | Rainbow |
| **Pool Name** | Keg River G |
| **Formation** | Keg River |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Rainbow |
| | |
| **Number of Wells** | 9 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1966 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1909 |
| Average Pay Thickness (m) | 69.1 |
| Average Permeability (md) | 218.79 |
| Average Porosity | 0.08 |
| Water Saturation | 0.08 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 17120 |
| Initial Temperature (C) | 83 |
| Oil Gravity (API) | 39.11 |
| Oil Density (kg/m3) | 829.4 |
| Oil Viscosity (cp) | 4.76 |
| Oil Viscosity @ Tr (cp) | 2.03 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 65 |
| Primary Recovery Factor (fraction) | 0.434 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.418 |
| Total Recovery Factor (fraction) | 0.852 |
| OOIP (E3m3) | 2479 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 367 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 49**

| | |
|---|---|
| **Field** | Rainbow |
| **Pool Name** | Keg River H |
| **Formation** | Keg River |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Rainbow |
| | |
| **Number of Wells** | 6 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1966 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1913.9 |
| Average Pay Thickness (m) | 48.68 |
| Average Permeability (md) | 353.64 |
| Average Porosity | 0.094 |
| Water Saturation | 0.1 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 19805 |
| Initial Temperature (C) | 84 |
| Oil Gravity (API) | 39.11 |
| Oil Density (kg/m3) | 829.4 |
| Oil Viscosity (cp) | 4.76 |
| Oil Viscosity @ Tr (cp) | 2.01 |
| Salinity of Formation Water (ppm) | 248512 |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 86 |
| Primary Recovery Factor (fraction) | 0.392 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.2 |
| Total Recovery Factor (fraction) | 0.592 |
| OOIP (E3m3) | 2833 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 1156 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 50**

| | |
|---|---|
| **Field** | Rainbow |
| **Pool Name** | Keg River II |
| **Formation** | Keg River |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Rainbow |
| | |
| **Number of Wells** | 14 |
| **Number of EOR Injectors** | 2 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1967 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1832.9 |
| Average Pay Thickness (m) | 56.9 |
| Average Permeability (md) | |
| Average Porosity | 0.1 |
| Water Saturation | 0.12 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 17106 |
| Initial Temperature (C) | 89 |
| Oil Gravity (API) | 41.08 |
| Oil Density (kg/m3) | 819.9 |
| Oil Viscosity (cp) | 3.65 |
| Oil Viscosity @ Tr (cp) | 1.77 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 104 |
| Primary Recovery Factor (fraction) | 0.45 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.155 |
| Total Recovery Factor (fraction) | 0.605 |
| OOIP (E3m3) | 3800 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 1501 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 51**

| | |
|---|---|
| **Field** | Rainbow |
| **Pool Name** | Keg River O |
| **Formation** | Keg River |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Rainbow |
| | |
| **Number of Wells** | 12 |
| **Number of EOR Injectors** | 2 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1966 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1854.1 |
| Average Pay Thickness (m) | 61.26 |
| Average Permeability (md) | 2900.89 |
| Average Porosity | 0.06 |
| Water Saturation | 0.13 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 16875 |
| Initial Temperature (C) | 84 |
| Oil Gravity (API) | 42.08 |
| Oil Density (kg/m3) | 815.2 |
| Oil Viscosity (cp) | 3.21 |
| Oil Viscosity @ Tr (cp) | 1.75 |
| Salinity of Formation Water (ppm) | 165910 |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 281 |
| Primary Recovery Factor (fraction) | 0.4 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.277 |
| Total Recovery Factor (fraction) | 0.677 |
| OOIP (E3m3) | 6200 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 2003 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 52**

| | |
|---|---|
| **Field** | Rainbow |
| **Pool Name** | Keg River Z |
| **Formation** | Keg River |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Rainbow |
| | |
| **Number of Wells** | 13 |
| **Number of EOR Injectors** | 3 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1967 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1609.3 |
| Average Pay Thickness (m) | 42.87 |
| Average Permeability (md) | 3901.61 |
| Average Porosity | 0.076 |
| Water Saturation | 0.27 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 11790 |
| Initial Temperature (C) | 86 |
| Oil Gravity (API) | 38.1 |
| Oil Density (kg/m3) | 834.3 |
| Oil Viscosity (cp) | 5.48 |
| Oil Viscosity @ Tr (cp) | 2.09 |
| Salinity of Formation Water (ppm) | 226520 |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 216 |
| Primary Recovery Factor (fraction) | 0.32 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.33 |
| Total Recovery Factor (fraction) | 0.65 |
| OOIP (E3m3) | 3904 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 1366 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 53**

| | |
|---|---|
| **Field** | Rainbow South |
| **Pool Name** | Keg River B |
| **Formation** | Keg River |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Rainbow |
| | |
| **Number of Wells** | 29 |
| **Number of EOR Injectors** | 4 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1966 |
| Secondary Recovery | Waterflood |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1875.7 |
| Average Pay Thickness (m) | 50 |
| Average Permeability (md) | 2237.23 |
| Average Porosity | 0.077 |
| Water Saturation | 0.12 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 18319 |
| Initial Temperature (C) | 84 |
| Oil Gravity (API) | 39.81 |
| Oil Density (kg/m3) | 826.0 |
| Oil Viscosity (cp) | 4.32 |
| Oil Viscosity @ Tr (cp) | 1.94 |
| Salinity of Formation Water (ppm) | 233114 |
| Presence of Natural Fractures | No |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 328 |
| Primary Recovery Factor (fraction) | 0.44 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.21 |
| Total Recovery Factor (fraction) | 0.65 |
| OOIP (E3m3) | 7890 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 2762 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 54**

| | |
|---|---|
| **Field** | Rainbow South |
| **Pool Name** | Keg River E |
| **Formation** | Keg River |
| **ERCB Approval Nos.** | 7277 |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Rainbow |
| | |
| **Number of Wells** | 13 |
| **Number of EOR Injectors** | 3 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1966 |
| Secondary Recovery | Waterflood (1972) |
| EOR 1 | Solvent/Miscible Flood (1994 - 2006) |
| EOR 2 | Chase Gas |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1945.9 |
| Average Pay Thickness (m) | 75.37 |
| Average Permeability (md) | 503.88 |
| Average Porosity | 0.1 |
| Water Saturation | 0.1 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 18944 |
| Initial Temperature (C) | 87 |
| Oil Gravity (API) | 40 |
| Oil Density (kg/m3) | 825.1 |
| Oil Viscosity (cp) | 4.21 |
| Oil Viscosity @ Tr (cp) | 1.88 |
| Salinity of Formation Water (ppm) | 239081 |
| Presence of Natural Fractures | No |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 196 |
| Primary Recovery Factor (fraction) | 0.26 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.1 |
| Total Recovery Factor (fraction) | 0.36 |
| OOIP (E3m3) | 8775 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 5616 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 55**

| | |
|---|---|
| **Field** | Rainbow South |
| **Pool Name** | Keg River G |
| **Formation** | Keg River |
| **ERCB Approval Nos.** | 7659 |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Rainbow |
| | |
| **Number of Wells** | 10 |
| **Number of EOR Injectors** | 3 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1967 |
| Secondary Recovery | Waterflood (1972) |
| EOR 1 | Solvent/Miscible Flood (1995 - 2006) |
| EOR 2 | Chase Gas |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1931 |
| Average Pay Thickness (m) | 73.33 |
| Average Permeability (md) | 66.34 |
| Average Porosity | 0.088 |
| Water Saturation | 0.11 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 17946 |
| Initial Temperature (C) | 88 |
| Oil Gravity (API) | 44.08 |
| Oil Density (kg/m3) | 805.9 |
| Oil Viscosity (cp) | 2.50 |
| Oil Viscosity @ Tr (cp) | 1.57 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | No |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 115 |
| Primary Recovery Factor (fraction) | 0.2 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.12 |
| Total Recovery Factor (fraction) | 0.32 |
| OOIP (E3m3) | 4359 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 2964 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 56**

| | |
|---|---|
| **Field** | Redwater |
| **Pool Name** | D-3 |
| **Formation** | Leduc |
| **ERCB Approval Nos.** | |
| **EOR Type** | |
| **EOR Sub Type** | |
| **Flood Type** | Combination |
| **Group** | Leduc |
| | |
| **Number of Wells** | 1074 |
| **Number of EOR Injectors** | 45 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1948 |
| Secondary Recovery | |
| EOR 1 | |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 983.7 |
| Average Pay Thickness (m) | 31.39 |
| Average Permeability (md) | 1411.02 |
| Average Porosity | 0.065 |
| Water Saturation | 0.25 |
| Lithology | Dolomite |
| Initial Pressure (kPa) | 7824 |
| Initial Temperature (C) | 34 |
| Oil Gravity (API) | 36.09 |
| Oil Density (kg/m3) | 844.3 |
| Oil Viscosity (cp) | 7.36 |
| Oil Viscosity @ Tr (cp) | 5.03 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | |
| Primary Recovery Factor (fraction) | 0.65 |
| Incremental WF Recovery Factor (fraction) | 0.05 |
| Incremental EOR Recovery Factor (fraction) | |
| Total Recovery Factor (fraction) | |
| OOIP (E3m3) | |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 57**

| | |
|---|---|
| **Field** | Rich |
| **Pool Name** | D-3A |
| **Formation** | Leduc |
| **ERCB Approval Nos.** | |
| **EOR Type** | |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Leduc |
| | |
| **Number of Wells** | 5 |
| **Number of EOR Injectors** | 2 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1982 |
| Secondary Recovery | |
| EOR 1 | |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1818.7 |
| Average Pay Thickness (m) | 103.2 |
| Average Permeability (md) | |
| Average Porosity | 0.11 |
| Water Saturation | 0.1 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 13616 |
| Initial Temperature (C) | 65 |
| Oil Gravity (API) | 33.61 |
| Oil Density (kg/m3) | 857.0 |
| Oil Viscosity (cp) | 10.89 |
| Oil Viscosity @ Tr (cp) | 3.61 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 15 |
| Primary Recovery Factor (fraction) | 0.46 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | |
| Total Recovery Factor (fraction) | |
| OOIP (E3m3) | 1333 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | |
| Remaining Recoverable Reserves (E3m3) | 1.8 |

**EOR Project Assessment** **Table 58**

| | |
|---|---|
| **Field** | Simonette |
| **Pool Name** | D-3 |
| **Formation** | Leduc |
| **ERCB Approval Nos.** | |
| **EOR Type** | |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Leduc |
| | |
| **Number of Wells** | 36 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1958 |
| Secondary Recovery | |
| EOR 1 | |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 3542 |
| Average Pay Thickness (m) | 42.11 |
| Average Permeability (md) | 337.65 |
| Average Porosity | 0.062 |
| Water Saturation | 0.16 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 35520 |
| Initial Temperature (C) | 105 |
| Oil Gravity (API) | 47.09 |
| Oil Density (kg/m3) | 792.3 |
| Oil Viscosity (cp) | 1.76 |
| Oil Viscosity @ Tr (cp) | 1.33 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | |
| Primary Recovery Factor (fraction) | 0.4 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.06 |
| Total Recovery Factor (fraction) | 0.46 |
| OOIP (E3m3) | 1200 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 59**

| | |
|---|---|
| **Field** | Suffield |
| **Pool Name** | Lower Mannville J |
| **Formation** | |
| **ERCB Approval Nos.** | |
| **EOR Type** | |
| **EOR Sub Type** | |
| **Flood Type** | Horizontal |
| **Group** | Sandstone |
| | |
| **Number of Wells** | 4 |
| **Number of EOR Injectors** | 0 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1978 |
| Secondary Recovery | |
| EOR 1 | |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1004.6 |
| Average Pay Thickness (m) | 2.3 |
| Average Permeability (md) | |
| Average Porosity | 0.25 |
| Water Saturation | 0.44 |
| Lithology | Sandstone |
| Initial Pressure (kPa) | 10677 |
| Initial Temperature (C) | 35 |
| Oil Gravity (API) | 14.53 |
| Oil Density (kg/m3) | 969.0 |
| Oil Viscosity (cp) | 4395.05 |
| Oil Viscosity @ Tr (cp) | 739.99 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | |
| Primary Recovery Factor (fraction) | 0.012 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | |
| Total Recovery Factor (fraction) | 0.012 |
| OOIP (E3m3) | 625 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | |
| Remaining Recoverable Reserves (E3m3) | 1.2 |

**EOR Project Assessment** **Table 60**

| | |
|---|---|
| **Field** | Suffield |
| **Pool Name** | Upper Mannville N |
| **Formation** | |
| **ERCB Approval Nos.** | |
| **EOR Type** | |
| **EOR Sub Type** | |
| **Flood Type** | Horizontal |
| **Group** | Sandstone |
| | |
| **Number of Wells** | 40 |
| **Number of EOR Injectors** | 3 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1978 |
| Secondary Recovery | |
| EOR 1 | |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 961.6 |
| Average Pay Thickness (m) | 3.44 |
| Average Permeability (md) | |
| Average Porosity | 0.26 |
| Water Saturation | 0.34 |
| Lithology | Sandstone |
| Initial Pressure (kPa) | 7708 |
| Initial Temperature (C) | 32 |
| Oil Gravity (API) | 14.23 |
| Oil Density (kg/m3) | 971.0 |
| Oil Viscosity (cp) | 5303.71 |
| Oil Viscosity @ Tr (cp) | 1093.86 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | |
| Primary Recovery Factor (fraction) | 0.12 |
| Incremental WF Recovery Factor (fraction) | 0.1 |
| Incremental EOR Recovery Factor (fraction) | |
| Total Recovery Factor (fraction) | 0.22 |
| OOIP (E3m3) | 2600 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 61**

| | |
|---|---|
| **Field** | Swan Hills |
| **Pool Name** | Commingled 001 |
| **Formation** | Beaverhill Lake |
| **ERCB Approval Nos.** | |
| **EOR Type** | |
| **EOR Sub Type** | |
| **Flood Type** | Combination |
| **Group** | Beaverhill Lake |
| | |
| **Number of Wells** | 1420 |
| **Number of EOR Injectors** | 66 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1957 |
| Secondary Recovery | |
| EOR 1 | |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 2425.7 |
| Average Pay Thickness (m) | 36.31 |
| Average Permeability (md) | . |
| Average Porosity | 0.08 |
| Water Saturation | 0.19 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 20226 |
| Initial Temperature (C) | 95 |
| Oil Gravity (API) | 41.08 |
| Oil Density (kg/m3) | 819.9 |
| Oil Viscosity (cp) | 3.65 |
| Oil Viscosity @ Tr (cp) | 1.70 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | |
| Primary Recovery Factor (fraction) | 0.17 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.36 |
| Total Recovery Factor (fraction) | 0.53 |
| OOIP (E3m3) | 163698 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 62**

| | |
|---|---|
| **Field** | Swan Hills South |
| **Pool Name** | Commingled 001 |
| **Formation** | Beaverhill Lake |
| **ERCB Approval Nos.** | |
| **EOR Type** | |
| **EOR Sub Type** | |
| **Flood Type** | Combination |
| **Group** | Beaverhill Lake |
| | |
| **Number of Wells** | 341 |
| **Number of EOR Injectors** | 56 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1959 |
| Secondary Recovery | |
| EOR 1 | |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 2536.8 |
| Average Pay Thickness (m) | 22.67 |
| Average Permeability (md) | |
| Average Porosity | 0.084 |
| Water Saturation | 0.16 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 21585 |
| Initial Temperature (C) | 101 |
| Oil Gravity (API) | 41.08 |
| Oil Density (kg/m3) | 819.9 |
| Oil Viscosity (cp) | 3.65 |
| Oil Viscosity @ Tr (cp) | 1.64 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | |
| Primary Recovery Factor (fraction) | 0.17 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.28 |
| Total Recovery Factor (fraction) | 0.45 |
| OOIP (E3m3) | |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 138800 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 63**

| | |
|---|---|
| **Field** | Turner Valley |
| **Pool Name** | |
| **Formation** | Rundle |
| **ERCB Approval Nos.** | |
| **EOR Type** | |
| **EOR Sub Type** | |
| **Flood Type** | Combination |
| **Group** | |
| | |
| **Number of Wells** | 901 |
| **Number of EOR Injectors** | 36 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1917 |
| Secondary Recovery | |
| EOR 1 | |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1480.6 |
| Average Pay Thickness (m) | 57.61 |
| Average Permeability (md) | |
| Average Porosity | 0.082 |
| Water Saturation | 0.1 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 10410 |
| Initial Temperature (C) | 60 |
| Oil Gravity (API) | 40.1 |
| Oil Density (kg/m3) | 824.6 |
| Oil Viscosity (cp) | 4.16 |
| Oil Viscosity @ Tr (cp) | 2.39 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 7326 |
| Primary Recovery Factor (fraction) | 0.12 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.02 |
| Total Recovery Factor (fraction) | 0.14 |
| OOIP (E3m3) | 208700 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 64**

| | |
|---|---|
| **Field** | Virginia Hills |
| **Pool Name** | Beaverhill Lake |
| **Formation** | Beaverhill Lake |
| **ERCB Approval Nos.** | 10082 |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Combination |
| **Group** | Beaverhill Lake |
| | |
| **Number of Wells** | 260 |
| **Number of EOR Injectors** | 16 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1957 |
| Secondary Recovery | |
| EOR 1 | Solvent Flood (1989 - 2006) |
| EOR 2 | Chase Gas (1989 - 2006) |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 2815.1 |
| Average Pay Thickness (m) | 21.54 |
| Average Permeability (md) | 17.77 |
| Average Porosity | 0.09 |
| Water Saturation | 0.24 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 24988 |
| Initial Temperature (C) | 98 |
| Oil Gravity (API) | 38.1 |
| Oil Density (kg/m3) | 834.3 |
| Oil Viscosity (cp) | 5.48 |
| Oil Viscosity @ Tr (cp) | 1.90 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | |
| Primary Recovery Factor (fraction) | 0.23 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.22 |
| Total Recovery Factor (fraction) | 0.45 |
| OOIP (E3m3) | 36510 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 20081 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 65**

| | |
|---|---|
| **Field** | Westpem |
| **Pool Name** | Nisku D |
| **Formation** | Nisku |
| **ERCB Approval Nos.** | 7148 |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Pembina |
| | |
| **Number of Wells** | |
| **Number of EOR Injectors** | |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1979 |
| Secondary Recovery | |
| EOR 1 | Solvent Flood (1981) |
| EOR 2 | Chase Gas (1987 - 1994) |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 3141 |
| Average Pay Thickness (m) | 47.29 |
| Average Permeability (md) | |
| Average Porosity | 0.117 |
| Water Saturation | 0.07 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 40479 |
| Initial Temperature (C) | 104 |
| Oil Gravity (API) | 45.82 |
| Oil Density (kg/m3) | 798.0 |
| Oil Viscosity (cp) | 2.04 |
| Oil Viscosity @ Tr (cp) | 1.38 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 88 |
| Primary Recovery Factor (fraction) | 0.4 |
| Incremental WF Recovery Factor (fraction) | 0.1 |
| Incremental EOR Recovery Factor (fraction) | 0.3 |
| Total Recovery Factor (fraction) | 0.8 |
| OOIP (E3m3) | 2400 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 480 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 66**

| | |
|---|---|
| **Field** | Wizard Lake |
| **Pool Name** | D-3A |
| **Formation** | Leduc |
| **ERCB Approval Nos.** | |
| **EOR Type** | |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Leduc |
| | |
| **Number of Wells** | 75 |
| **Number of EOR Injectors** | 9 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1951 |
| Secondary Recovery | |
| EOR 1 | |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1966.7 |
| Average Pay Thickness (m) | 85.96 |
| Average Permeability (md) | 2380.68 |
| Average Porosity | 0.098 |
| Water Saturation | 0.07 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 15507 |
| Initial Temperature (C) | 72 |
| Oil Gravity (API) | 38.1 |
| Oil Density (kg/m3) | 834.3 |
| Oil Viscosity (cp) | 5.48 |
| Oil Viscosity @ Tr (cp) | 2.38 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | Yes |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | |
| Primary Recovery Factor (fraction) | 0.66 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.19 |
| Total Recovery Factor (fraction) | 0.85 |
| OOIP (E3m3) | 63900 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 67**

| | |
|---|---|
| **Field** | Zama |
| **Pool Name** | Keg River F |
| **Formation** | Keg River |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Zama |
| | |
| **Number of Wells** | 4 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1967 |
| Secondary Recovery | |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1494.6 |
| Average Pay Thickness (m) | 51.42 |
| Average Permeability (md) | 9850.13 |
| Average Porosity | 0.07 |
| Water Saturation | 0.13 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 14444 |
| Initial Temperature (C) | 71 |
| Oil Gravity (API) | 35.11 |
| Oil Density (kg/m3) | 849.3 |
| Oil Viscosity (cp) | 8.56 |
| Oil Viscosity @ Tr (cp) | 2.95 |
| Salinity of Formation Water (ppm) | 129480 |
| Presence of Natural Fractures | No |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 20 |
| Primary Recovery Factor (fraction) | 0.331 |
| Incremental WF Recovery Factor (fraction) | 0 |
| Incremental EOR Recovery Factor (fraction) | 0.05 |
| Total Recovery Factor (fraction) | 0.381 |
| OOIP (E3m3) | 532 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 329 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 68**

| | |
|---|---|
| **Field** | Zama |
| **Pool Name** | Keg River G2G |
| **Formation** | Keg River |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Zama |
| | |
| **Number of Wells** | 2 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1968 |
| Secondary Recovery | |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1510.3 |
| Average Pay Thickness (m) | 33.81 |
| Average Permeability (md) | 161.09 |
| Average Porosity | 0.08 |
| Water Saturation | 0.13 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 14117 |
| Initial Temperature (C) | 76 |
| Oil Gravity (API) | 36.09 |
| Oil Density (kg/m3) | 844.3 |
| Oil Viscosity (cp) | 7.36 |
| Oil Viscosity @ Tr (cp) | 2.59 |
| Salinity of Formation Water (ppm) | 157231 |
| Presence of Natural Fractures | No |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 31 |
| Primary Recovery Factor (fraction) | 0.225 |
| Incremental WF Recovery Factor (fraction) | 0 |
| Incremental EOR Recovery Factor (fraction) | 0.04 |
| Total Recovery Factor (fraction) | 0.265 |
| OOIP (E3m3) | 591 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 434 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 69**

| | |
|---|---|
| **Field** | Zama |
| **Pool Name** | Keg River NNN |
| **Formation** | Keg River |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Zama |
| | |
| **Number of Wells** | 3 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1967 |
| Secondary Recovery | |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1532.2 |
| Average Pay Thickness (m) | 69.5 |
| Average Permeability (md) | 60.95 |
| Average Porosity | 0.07 |
| Water Saturation | 0.15 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 15283 |
| Initial Temperature (C) | 80 |
| Oil Gravity (API) | 36.09 |
| Oil Density (kg/m3) | 844.3 |
| Oil Viscosity (cp) | 7.36 |
| Oil Viscosity @ Tr (cp) | 2.48 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | No |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 17 |
| Primary Recovery Factor (fraction) | 0.3 |
| Incremental WF Recovery Factor (fraction) | 0 |
| Incremental EOR Recovery Factor (fraction) | 0.05 |
| Total Recovery Factor (fraction) | 0.35 |
| OOIP (E3m3) | 562 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 365 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 70**

| | |
|---|---|
| **Field** | Zama |
| **Pool Name** | Keg River RRR |
| **Formation** | Keg River |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Zama |
| | |
| **Number of Wells** | 3 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1967 |
| Secondary Recovery | |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1550.5 |
| Average Pay Thickness (m) | 50.31 |
| Average Permeability (md) | |
| Average Porosity | 0.1 |
| Water Saturation | 0.15 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 15250 |
| Initial Temperature (C) | 73 |
| Oil Gravity (API) | 39.11 |
| Oil Density (kg/m3) | 829.4 |
| Oil Viscosity (cp) | 4.76 |
| Oil Viscosity @ Tr (cp) | 2.22 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 25 |
| Primary Recovery Factor (fraction) | 0.25 |
| Incremental WF Recovery Factor (fraction) | 0 |
| Incremental EOR Recovery Factor (fraction) | 0.05 |
| Total Recovery Factor (fraction) | 0.3 |
| OOIP (E3m3) | 748 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | 524 |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 71**

| | |
|---|---|
| **Field** | Zama |
| **Pool Name** | Keg River X2X |
| **Formation** | Keg River |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Zama |
| | |
| **Number of Wells** | 3 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1968 |
| Secondary Recovery | |
| EOR 1 | |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1497.9 |
| Average Pay Thickness (m) | 31.39 |
| Average Permeability (md) | 2994.26 |
| Average Porosity | 0.075 |
| Water Saturation | 0.16 |
| Lithology | Dolomite |
| Initial Pressure (kPa) | 12536 |
| Initial Temperature (C) | 76 |
| Oil Gravity (API) | 36.09 |
| Oil Density (kg/m3) | 844.3 |
| Oil Viscosity (cp) | 7.36 |
| Oil Viscosity @ Tr (cp) | 2.59 |
| Salinity of Formation Water (ppm) | 223460 |
| Presence of Natural Fractures | No |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 34 |
| Primary Recovery Factor (fraction) | 0.275 |
| Incremental WF Recovery Factor (fraction) | 0.212 |
| Incremental EOR Recovery Factor (fraction) | |
| Total Recovery Factor (fraction) | 0.487 |
| OOIP (E3m3) | 538 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 72**

| | |
|---|---|
| **Field** | Zama |
| **Pool Name** | Muskeg L |
| **Formation** | Muskeg |
| **ERCB Approval Nos.** | |
| **EOR Type** | Solvent Flood |
| **EOR Sub Type** | |
| **Flood Type** | Vertical |
| **Group** | Zama |
| | |
| **Number of Wells** | 4 |
| **Number of EOR Injectors** | 1 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1967 |
| Secondary Recovery | |
| EOR 1 | Solvent Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1512.8 |
| Average Pay Thickness (m) | 27.95 |
| Average Permeability (md) | 2232.49 |
| Average Porosity | 0.1 |
| Water Saturation | 0.16 |
| Lithology | Evaporite |
| Initial Pressure (kPa) | 13885 |
| Initial Temperature (C) | 77 |
| Oil Gravity (API) | 36.09 |
| Oil Density (kg/m3) | 844.3 |
| Oil Viscosity (cp) | 7.36 |
| Oil Viscosity @ Tr (cp) | 2.56 |
| Salinity of Formation Water (ppm) | Not Available |
| Presence of Natural Fractures | No |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 22 |
| Primary Recovery Factor (fraction) | 0.2 |
| Incremental WF Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | 0.05 |
| Total Recovery Factor (fraction) | 0.25 |
| OOIP (E3m3) | 429 |
| Remaining Oil in-Place (E3m3) after Primary & EOR Recovery | |
| Remaining Recoverable Reserves (E3m3) | |

**EOR Project Assessment** **Table 73**

| | |
|---|---|
| **Field** | Brintnell Field Horsetail |
| **Pool Name** | Upper Wabiskaw Sand |
| **Formation** | Wabiskaw-McMurray Deposit |
| **ERCB Approval Nos.** | 9673 / 9467 / 10147 / 10423 / 10787 |
| **EOR Type** | Chemical |
| **EOR Sub Type - Experimental** | Polymer |
| | |
| **Number of Wells (Pilot)** | HTLP 6 Polymer Pilot - 5 Wells |
| **Number of EOR Injectors (Pilot)** | HTLP 6 - 2 Wells |
| **Number of EOR Producers (Pilot)** | HTLP 6 - 3 Wells |
| | |
| **Date** | |
| Discovery | |
| Secondary Recovery | |
| EOR 1 | Approval 10147 - Polymer Pilot Wells - HTLP 6 Polymer Flood (May 2005) |
| EOR 2 | Approval 10423 - 1st area expanded after the pilot, polymer started 2007, expanded through 2010 |
| EOR 3 | Approval 10797 - Small area of polymer started in 2007 - 1st area to have multilateral well flooded by several injectors |
| EOR 4 | Approval 9673 |
| EOR 5 | Approval 9467 |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 300 to 425 TVD |
| Average Pay Thickness (m) | 1 to 9 |
| Average Permeability (md) | 300 to 3000 |
| Average Porosity | 0.28 to 0.32 |
| Water Saturation | 0.30 to 0.40 |
| Lithology | Sandstone |
| Initial Pressure (kPa) | 1900 to 2600 |
| Initial Temperature (C) | 15 |
| Oil Gravity (API) | 10 |
| Oil Density (kg/m3) | 1000.0 |
| Oil Viscosity (cp) | 144543.98 |
| Oil Viscosity @ Tr (cp) | 144544.78 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | |
| Primary Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | |
| OOIP (E3m3) | |
| Pool Cumulative Production (E3m3) | |
| Total Remaining Reserves Including EOR (E3m3) | |

**EOR Project Assessment** **Table 74**

| | |
|---|---|
| **Field** | Cessford |
| **Pool Name** | Cessford Basal Colorado 'A' Pool |
| **Formation** | Basal Colorado |
| **ERCB Approval Nos. (wf = #2604)** | 9673 / 9467 / 10147 / 10423 / 10787 |
| **EOR Type** | Chemical |
| **EOR Sub Type - Experimental** | AP |
| | |
| **Number of Wells** | 26 |
| **Number of EOR Injectors** | 7 |
| **Number of EOR Producers** | 19 |
| | |
| **Date** | |
| Discovery | 1958 |
| Secondary Recovery | |
| EOR 1 | Waterflood 81/02 |
| EOR 2 | Inject Preflush 83/12-84/07 North & Central Areas |
| EOR 3 | Alkali Flood North & Central Area 84/07 - 85/05 |
| EOR 4 | Alkali/Polymer Flood in South 85/01 |
| EOR 5 | Alkali/Polymer Flood in North & Central Patterns 85/05 |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 920 |
| Average Pay Thickness (m) | 3 to 8 |
| Average Permeability (md) | 350 |
| Average Porosity | 0.24 |
| Water Saturation | 0.30 |
| Lithology | Sandstone |
| Initial Pressure (kPa) | 8784 |
| Initial Temperature (C) | 26 |
| Oil Gravity (API) | 23 |
| Oil Density (kg/m3) | 915.9 |
| Oil Viscosity (cp) - Initial | 110.95 |
| Oil Viscosity @ Tr (cp) | 1.00 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap (OGIP 650 BCF) | Yes |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 303.5 |
| Primary Recovery Factor (fraction) | Undescernable |
| Incremental EOR Recovery Factor (fraction) | Not Specified |
| OOIP (E3m3) | 17400 |
| Pool Cumulative Production (E3m3) | |
| Total Remaining Reserves Including EOR (E3m3) | |

**EOR Project Assessment** **Table 75**

| | |
|---|---|
| **Field** | Chauvin South |
| **Pool Name** | Sparky E |
| **Formation** | Sparky E |
| **ERCB Approval Nos.** | 9673 / 9467 / 10147 / 10423 / 10787 |
| **EOR Type** | Chemical |
| **EOR Sub Type - Experimental** | Polymer |
| | |
| **Number of Wells** | 14 |
| **Number of EOR Injectors** | 3 |
| **Number of EOR Producers** | 11 |
| | |
| **Date** | |
| Discovery | |
| Secondary Recovery | |
| EOR 1 | Waterflood |
| EOR 2 | Polymer Flood |
| EOR 3 | |
| EOR 4 | |
| EOR 5 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | |
| Average Pay Thickness (m) | |
| Average Permeability (md) | |
| Average Porosity | |
| Water Saturation | |
| Lithology | Sandstone |
| Initial Pressure (kPa) | |
| Initial Temperature (C) | 24 |
| Oil Gravity (API) | 21.1 |
| Oil Density (kg/m3) | 927.3 |
| Oil Viscosity (cp) | 204.95 |
| Oil Viscosity @ Tr (cp) | 115.27 |
| Salinity of Formation Water (ppm) | 87000 |
| Presence of Natural Fractures | |
| Presence of Gas Cap | |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) (3 patterns) | 194.25 |
| Primary Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | |
| OOIP (E3m3) | |
| Pool Cumulative Production (E3m3) | |
| Total Remaining Reserves Including EOR (E3m3) | |

**EOR Project Assessment** **Table 76**

| | |
|---|---|
| **Field** | Countess |
| **Pool Name** | Upper Mannville H |
| **Formation** | Upper Mannville H |
| **ERCB Approval Nos.** | 9673 / 9467 / 10147 / 10423 / 10787 |
| **EOR Type** | Chemical |
| **EOR Sub Type** | Polymer |
| | |
| **Number of Wells** | 48 |
| **Number of EOR Injectors** | 7 |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1968 |
| Secondary Recovery | |
| EOR 1 | Polymer Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| EOR 5 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1062.5 |
| Average Pay Thickness (m) | 5.28 |
| Average Permeability (md) | 945 |
| Average Porosity | 0.218 |
| Water Saturation | 0.22 |
| Lithology | Sandstone |
| Initial Pressure (kPa) | 8234 |
| Initial Temperature (C) | 32 |
| Oil Gravity (API) | 26 |
| Oil Density (kg/m3) | 898.4 |
| Oil Viscosity (cp) | 49.34 |
| Oil Viscosity @ Tr (cp) | 23.00 |
| Salinity of Formation Water (ppm) | 9704 |
| Presence of Natural Fractures | no |
| Presence of Gas Cap | no |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 710 |
| Primary Recovery Factor (fraction) | 0.105 |
| Incremental EOR Recovery Factor (fraction) | 0.36 |
| OOIP (E3m3) | 5725 |
| Pool Cumulative Production (E3m3) | 2471.3 |
| Total Remaining Reserves Including EOR (E3m3) | 190.8 |

**EOR Project Assessment** **Table 77**

| | |
|---|---|
| **Field** | Countess |
| **Pool Name** | |
| **Formation** | Upper Mannville H |
| **ERCB Approval Nos.** | 9673 / 9467 / 10147 / 10423 / 10787 |
| **EOR Type** | Chemical |
| **EOR Sub Type - Experimental ASP** | |
| | |
| **Number of Wells** | |
| **Number of EOR Injectors** | |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | |
| Secondary Recovery | |
| EOR 1 | |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| EOR 5 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1060 |
| Average Pay Thickness (m) | |
| Average Permeability (md) | 945 |
| Average Porosity | 0.218 |
| Water Saturation | |
| Lithology | Sandstone |
| Initial Pressure (kPa) | 11911 |
| Initial Temperature (C) | |
| Oil Gravity (API) | 15 |
| Oil Density (kg/m3) | 965.9 |
| Oil Viscosity (cp) | 3308.18 |
| Oil Viscosity @ Tr (cp) | 18209.34 |
| Salinity of Formation Water (ppm) | 29411 |
| Presence of Natural Fractures | no |
| Presence of Gas Cap | no |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) (3 patterns) | |
| Primary Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | |
| OOIP (E3m3) | |
| Pool Cumulative Production (E3m3) | |
| Total Remaining Reserves Including EOR (E3m3) | |

**EOR Project Assessment** **Table 78**

| | |
|---|---|
| **Field** | Edgerton |
| **Pool Name** | |
| **Formation** | Woodbend A |
| **ERCB Approval Nos.** | 9673 / 9467 / 10147 / 10423 / 10787 |
| **EOR Type** | Chemical |
| **EOR Sub Type - Commercial Polymer** | |
| | |
| **Number of Wells** | |
| **Number of EOR Injectors** | |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | |
| Secondary Recovery | |
| EOR 1 | |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| EOR 5 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 697.4 |
| Average Pay Thickness (m) | 3.75 |
| Average Permeability (md) | |
| Average Porosity | 0.2 |
| Water Saturation | 0.25 |
| Lithology | Carbonate |
| Initial Pressure (kPa) | 4831 |
| Initial Temperature (C) | 25 |
| Oil Gravity (API) | 16.82 |
| Oil Density (kg/m3) | 954.0 |
| Oil Viscosity (cp) | 1227.60 |
| Oil Viscosity @ Tr (cp) | 536.99 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) (3 patterns) | |
| Primary Recovery Factor (fraction) | 0.07 |
| Incremental EOR Recovery Factor (fraction) | 0 |
| OOIP (E3m3) | 8789 |
| Pool Cumulative Production (E3m3) | 360.0 |
| Total Remaining Reserves Including EOR (E3m3) | 255.0 |

**EOR Project Assessment** **Table 79**

| | |
|---|---|
| **Field** | Entice |
| **Pool Name** | Lower Mannville B |
| **Formation** | Lower Mannville B |
| **ERCB Approval Nos.** | 9673 / 9467 / 10147 / 10423 / 10787 |
| **EOR Type** | Chemical |
| **EOR Sub Type** | ASP |
| | |
| **Number of Wells** | |
| **Number of EOR Injectors** | |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1985 |
| Secondary Recovery | |
| EOR 1 | Waterflood Incremental RF |
| EOR 2 | ASP Flood |
| EOR 3 | |
| EOR 4 | |
| EOR 5 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 1782.8 |
| Average Pay Thickness (m) | 2.56 |
| Average Permeability (md) | |
| Average Porosity | 0.16 |
| Water Saturation | 0.31 |
| Lithology | Sandstone |
| Initial Pressure (kPa) | 13645 |
| Initial Temperature (C) | 64 |
| Oil Gravity (API) | 34 |
| Oil Density (kg/m3) | 855.0 |
| Oil Viscosity (cp) | 10.22 |
| Oil Viscosity @ Tr (cp) | 3.55 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | Not Reported |
| Primary Recovery Factor (fraction) | Not Reported |
| Incremental EOR Recovery Factor (fraction) | Not Reported |
| OOIP (E3m3) | 2596 |
| Pool Cumulative Production (E3m3) | 773.1 |
| Total Remaining Reserves Including EOR (E3m3) | |

**EOR Project Assessment** **Table 80**

| | |
|---|---|
| **Field** | Horsefly Lake |
| **Pool Name** | Lower Mannville |
| **Formation** | Lower Mannville |
| **ERCB Approval Nos.** | 9673 / 9467 / 10147 / 10423 / 10787 |
| **EOR Type** | Chemical |
| **EOR Sub Type** | AP |
| | |
| **Number of Wells** | 9 |
| **Number of EOR Injectors** | 4 |
| **Number of EOR Producers (4 outside pilot area)** | 5 |
| | |
| **Date** | |
| Discovery | |
| Secondary Recovery | |
| EOR 1 | Waterflood Incremental RF |
| EOR 2 | Alkali Polymer Flood Incremental RF |
| EOR 3 | |
| EOR 4 | |
| EOR 5 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | |
| Average Pay Thickness (m) | |
| Average Permeability (md) | |
| Average Porosity | |
| Water Saturation | |
| Lithology | |
| Initial Pressure (kPa) | |
| Initial Temperature (C) | |
| Oil Gravity (API) | |
| Oil Density (kg/m3) | 955.4 |
| Oil Viscosity (cp) | 1372.14 |
| Oil Viscosity @ Tr (cp) | 439.23 |
| Salinity of Formation Water (ppm) | 28700 |
| Presence of Natural Fractures | No |
| Presence of Gas Cap | No |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 13 |
| Primary Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | |
| OOIP (E3m3) | |
| Pool Cumulative Production (E3m3) | |
| Total Remaining Reserves Including EOR (E3m3) | |

**EOR Project Assessment** **Table 81**

| | |
|---|---|
| **Field** | Mooney |
| **Pool Name** | Bluesky A |
| **Formation** | Bluesky A |
| **ERCB Approval Nos.** | 9673 / 9467 / 10147 / 10423 / 10787 |
| **EOR Type** | Chemical |
| **EOR Sub Type** | ASP |
| | |
| **Number of Wells** | |
| **Number of EOR Injectors** | |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1986 |
| Secondary Recovery | |
| EOR 1 | Waterflood |
| EOR 2 | ASP Flood |
| EOR 3 | |
| EOR 4 | |
| EOR 5 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 913 |
| Average Pay Thickness (m) | 2.5 |
| Average Permeability (md) | 3000 |
| Average Porosity | 0.26 |
| Water Saturation | 0.35 |
| Lithology | Sandstone |
| Initial Pressure (kPa) | 5790 |
| Initial Temperature (C) | 29 |
| Oil Gravity (API) | 16.6 |
| Oil Density (kg/m3) | 955.4 |
| Oil Viscosity (cp) | 1372.14 |
| Oil Viscosity @ Tr (cp) | 439.23 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | Not Reported |
| Primary Recovery Factor (fraction) | Not Reported |
| Incremental EOR Recovery Factor (fraction) | Not Reported |
| OOIP (E3m3) | 7883 |
| Pool Cumulative Production (E3m3) | 442.7 |
| Total Remaining Reserves Including EOR (E3m3) | |

**EOR Project Assessment** **Table 82**

| | |
|---|---|
| **Field** | Provost |
| **Pool Name** | Upper Mannville A |
| **Formation** | Upper Mannville A |
| **ERCB Approval Nos.** | 9673 / 9467 / 10147 / 10423 / 10787 |
| **EOR Type** | Chemical |
| **EOR Sub Type** | Polymer |
| | |
| **Number of Wells** | |
| **Number of EOR Injectors** | |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1969 |
| Secondary Recovery | |
| EOR 1 | Polymer Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| EOR 5 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 778.3 |
| Average Pay Thickness (m) | 3.96 |
| Average Permeability (md) | |
| Average Porosity | 0.3 |
| Water Saturation | 0.25 |
| Lithology | Sandstone |
| Initial Pressure (kPa) | 4125 |
| Initial Temperature (C) | 30 |
| Oil Gravity (API) | 15.09 |
| Oil Density (kg/m3) | 965.3 |
| Oil Viscosity (cp) | 3137.40 |
| Oil Viscosity @ Tr (cp) | 825.22 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 1252 |
| Primary Recovery Factor (fraction) | 0.03 |
| Incremental EOR Recovery Factor (fraction) | 0.12 |
| OOIP (E3m3) | 13190 |
| Pool Cumulative Production (E3m3) | 609.4 |
| Total Remaining Reserves Including EOR (E3m3) | 1369.1 |

**EOR Project Assessment** **Table 83**

**David Lloydminster A**

| | |
|---|---|
| **Field** | David |
| **Pool Name** | Lloydminster A |
| **Formation** | |
| **ERCB Approval Nos.** | 9673 / 9467 / 10147 / 10423 / 10787 |
| **EOR Type** | Chemical |
| **EOR Sub Type - Experimental** | AP |
| | |
| **Number of Wells (7 patterns)** | 28 |
| **Number of EOR Injectors** | 21 |
| **Number of EOR Producers** | 7 |
| | |
| **Date** | |
| Discovery | 1985 |
| Secondary Recovery | |
| EOR 1 | Waterflood Nov 1978 |
| EOR 2 | Pre Flush March 1986 to Feb 1987, 1 year |
| EOR 3 | Alkali Polymer Flood May 1987 |
| EOR 4 | Alkali Polymer Flood May 1987 |
| EOR 5 | Alkali Polymer Flood May 1987 |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 760 |
| Average Pay Thickness (m) | |
| Average Permeability (md) | 1400 |
| Average Porosity | 0.29 |
| Water Saturation | |
| Lithology | Sandstone |
| Initial Pressure (kPa) | |
| Initial Temperature (C) | 30.6 |
| Oil Gravity (API) | 22.6 |
| Oil Density (kg/m3) | 918.2 |
| Oil Viscosity (cp) | 125.32 |
| Oil Viscosity @ Tr (cp) | 52.58 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | |
| Primary Recovery Factor (fraction) | 0.057 |
| Incremental EOR Recovery Factor (fraction) | 0.463 |
| OOIP (E3m3) | 1486 |
| Pool Cumulative Production (E3m3) | |
| Total Remaining Reserves Including EOR (E3m3) | |

**EOR Project Assessment** **Table 84**

| | |
|---|---|
| **Field** | Provost |
| **Pool Name** | |
| **Formation** | Cummings I |
| **ERCB Approval Nos.** | 9673 / 9467 / 10147 / 10423 / 10787 |
| **EOR Type** | Chemical |
| **EOR Sub Type - Experimental Polymer** | |
| | |
| **Number of Wells** | |
| **Number of EOR Injectors** | |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | |
| Secondary Recovery | |
| EOR 1 | |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| EOR 5 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 763.3 |
| Average Pay Thickness (m) | 4.83 |
| Average Permeability (md) | |
| Average Porosity | 0.28 |
| Water Saturation | 0.23 |
| Lithology | |
| Initial Pressure (kPa) | 5430 |
| Initial Temperature (C) | 30 |
| Oil Gravity (API) | 23.99 |
| Oil Density (kg/m3) | 910.0 |
| Oil Viscosity (cp) | 83.31 |
| Oil Viscosity @ Tr (cp) | 38.51 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) (3 patterns) | |
| Primary Recovery Factor (fraction) | 0.35 |
| Incremental EOR Recovery Factor (fraction) | 0.15 |
| OOIP (E3m3) | 12430 |
| Pool Cumulative Production (E3m3) | 5694.0 |
| Total Remaining Reserves Including EOR (E3m3) | 648.9 |

**EOR Project Assessment** **Table 85**

| | |
|---|---|
| **Field** | Suffield |
| **Pool Name** | UpperMannville UU |
| **Formation** | UpperMannville UU |
| **ERCB Approval Nos.** | 9673 / 9467 / 10147 / 10423 / 10787 |
| **EOR Type** | Chemical |
| **EOR Sub Type** | ASP |
| | |
| **Number of Wells** | Unknown |
| **Number of EOR Injectors (2)** | 2 Hz Chemical Injection Wells |
| **Number of EOR Producers (5)** | 4 Hz production wells<br>3 Vertical Production / Observation Wells |
| | |
| **Date** | |
| Discovery | 1996 |
| Secondary Recovery | |
| EOR 1 | Waterflood |
| EOR 2 | ASP Flood |
| EOR 3 | |
| EOR 4 | |
| EOR 5 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 928.8 |
| Average Pay Thickness (m) | 1.9 |
| Average Permeability (md) | |
| Average Porosity | 0.3 |
| Water Saturation | 0.28 |
| Lithology | Sandstone |
| Initial Pressure (kPa) | 7538 |
| Initial Temperature (C) | 33 |
| Oil Gravity (API) | 14.08 |
| Oil Density (kg/m3) | 972.0 |
| Oil Viscosity (cp) | 5837.84 |
| Oil Viscosity @ Tr (cp) | 1092.19 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 139 |
| Primary Recovery Factor (fraction) | 0.1 |
| Incremental EOR Recovery Factor (fraction) | 0.25 |
| OOIP (E3m3) | 531 |
| Pool Cumulative Production (E3m3) | 125.5 |
| Total Remaining Reserves Including EOR (E3m3) | Production Reported > RF |

**EOR Project Assessment** **Table 86**

| | |
|---|---|
| **Field** | Suffield |
| **Pool Name** | Upper Manville U |
| **Formation** | Upper Manville U |
| **ERCB Approval Nos.** | 9673 / 9467 / 10147 / 10423 / 10787 |
| **EOR Type** | Chemical |
| **EOR Sub Type** | Polymer |
| | |
| **Number of Wells** | |
| **Number of EOR Injectors** | |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1980 |
| Secondary Recovery | |
| EOR 1 | Waterflood |
| EOR 2 | Polymer Flood |
| EOR 3 | |
| EOR 4 | |
| EOR 5 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 957.4 |
| Average Pay Thickness (m) | 5.15 |
| Average Permeability (md) | |
| Average Porosity | 0.26 |
| Water Saturation | 0.18 |
| Lithology | Sandstone |
| Initial Pressure (kPa) | 10703 |
| Initial Temperature (C) | 21 |
| Oil Gravity (API) | 17.29 |
| Oil Density (kg/m3) | 951.0 |
| Oil Viscosity (cp) | 974.82 |
| Oil Viscosity @ Tr (cp) | 593.38 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 193 |
| Primary Recovery Factor (fraction) | 0.15 |
| Incremental EOR Recovery Factor (fraction) includes WF | 0.2 |
| OOIP (E3m3) | 3609 |
| Pool Cumulative Production (E3m3) | 878.6 |
| Total Remaining Reserves Including EOR (E3m3) | 384.6 |

**EOR Project Assessment** **Table 87**

| | |
|---|---|
| **Field** | Taber |
| **Pool Name** | Glauconitic K |
| **Formation** | Glauconitic K |
| **ERCB Approval Nos.** | 9673 / 9467 / 10147 / 10423 / 10787 |
| **EOR Type** | Chemical |
| **EOR Sub Type** | ASP |
| | |
| **Number of Wells** | |
| **Number of EOR Injectors** | |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1942 |
| Secondary Recovery | |
| EOR 1 | ASP Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| EOR 5 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 963.6 |
| Average Pay Thickness (m) | 6.86 |
| Average Permeability (md) | |
| Average Porosity | 0.26 |
| Water Saturation | 0.15 |
| Lithology | Sandstone |
| Initial Pressure (kPa) | 7719 |
| Initial Temperature (C) | 36 |
| Oil Gravity (API) | 19.03 |
| Oil Density (kg/m3) | 940.0 |
| Oil Viscosity (cp) | 449.05 |
| Oil Viscosity @ Tr (cp) | 111.40 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 308 |
| Primary Recovery Factor (fraction) | 0.18 |
| Incremental EOR Recovery Factor (fraction) | 0.38 |
| OOIP (E3m3) | 4529 |
| Pool Cumulative Production (E3m3) | 2047.3 |
| Total Remaining Reserves Including EOR (E3m3) | 488.9 |

**EOR Project Assessment** **Table 88**

| | |
|---|---|
| **Field** | East Taber |
| **Pool Name** | Mannville D |
| **Formation** | 5077 (WF) & 5078 (P) |
| **ERCB Approval Nos.** | 9673 / 9467 / 10147 / 10423 / 10787 |
| **EOR Type** | Chemical |
| **EOR Sub Type - Experimental** | Polymer |
| | |
| **Number of Wells** | |
| **Number of EOR Injectors** | 2 |
| **Number of EOR Producers** | 8 |
| | |
| **Date** | |
| Discovery | |
| Secondary Recovery | |
| EOR 1 | Waterflood Incremental RF |
| EOR 2 | Polymer Flood Incremental RF |
| EOR 3 | Waterflood Incremental RF |
| EOR 4 | Waterflood Incremental RF |
| EOR 5 | Waterflood Incremental RF |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | |
| Average Pay Thickness (m) | |
| Average Permeability (md) | |
| Average Porosity | |
| Water Saturation | |
| Lithology | |
| Initial Pressure (kPa) | |
| Initial Temperature (C) | |
| Oil Gravity (API) | |
| Oil Density (kg/m3) | 1076.0 |
| Oil Viscosity (cp) | 1.3586E+12 |
| Oil Viscosity @ Tr (cp) | 2.0199E+14 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | |
| Primary Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) | |
| OOIP (E3m3) | 2.54 |
| Pool Cumulative Production (E3m3) | |
| Total Remaining Reserves Including EOR (E3m3) | |

**EOR Project Assessment** **Table 89**

| | |
|---|---|
| **Field** | Taber South |
| **Pool Name** | Mannville B |
| **Formation** | Glauconite |
| **ERCB Approval Nos.** | 9673 / 9467 / 10147 / 10423 / 10787 |
| **EOR Type** | Chemical |
| **EOR Sub Type** | ASP |
| | |
| **Number of Wells** | |
| **Number of EOR Injectors (2)** | |
| **Number of EOR Producers (5)** | |
| | |
| **Date** | |
| Discovery | 1963 |
| Secondary Recovery | |
| EOR 1 | Waterflood |
| EOR 2 | ASP Flood |
| EOR 3 | |
| EOR 4 | |
| EOR 5 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 983.3 |
| Average Pay Thickness (m) | 3.31 |
| Average Permeability (md) | |
| Average Porosity | 0.22 |
| Water Saturation | 0.39 |
| Lithology | Sandstone |
| Initial Pressure (kPa) | 7821 |
| Initial Temperature (C) | 31 |
| Oil Gravity (API) | 19.1 |
| Oil Density (kg/m3) | 939.6 |
| Oil Viscosity (cp) | 436.30 |
| Oil Viscosity @ Tr (cp) | 145.64 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | Not Reported |
| Primary Recovery Factor (fraction) | Not Reported |
| Incremental EOR Recovery Factor (fraction) | Not Reported |
| OOIP (E3m3) | 6843 |
| Pool Cumulative Production (E3m3) | 3032.5 |
| Total Remaining Reserves Including EOR (E3m3) | |

**EOR Project Assessment** **Table 90**

| | |
|---|---|
| **Field** | Viking-Kinsella |
| **Pool Name** | Wainwright B |
| **Formation** | Sparky |
| **ERCB Approval Nos.** | 9673 / 9467 / 10147 / 10423 / 10787 |
| **EOR Type** | Chemical |
| **EOR Sub Type** | Polymer |
| | |
| **Number of Wells** | |
| **Number of EOR Injectors** | |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | |
| Secondary Recovery | |
| EOR 1 | Waterflood |
| EOR 2 | Polymer Flood |
| EOR 3 | |
| EOR 4 | |
| EOR 5 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 649 |
| Average Pay Thickness (m) | 2.92 |
| Average Permeability (md) | |
| Average Porosity | 0.29 |
| Water Saturation | 0.28 |
| Lithology | Sandstone |
| Initial Pressure (kPa) | 4392 |
| Initial Temperature (C) | 26 |
| Oil Gravity (API) | 21.08 |
| Oil Density (kg/m3) | 927.4 |
| Oil Viscosity (cp) | 206.38 |
| Oil Viscosity @ Tr (cp) | 103.09 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 450 |
| Primary Recovery Factor (fraction) | 0.14 |
| Incremental EOR Recovery Factor (fraction) includes WF | 0.35 |
| OOIP (E3m3) | 23099 |
| Pool Cumulative Production (E3m3) | 7874.1 |
| Total Remaining Reserves Including EOR (E3m3) | 3444.4 |

**EOR Project Assessment** **Table 91**

| | |
|---|---|
| **Field** | Viking-Kinsella |
| **Pool Name** | Wainwright B |
| **Formation** | Sparky B |
| **ERCB Approval Nos.** | 9673 / 9467 / 10147 / 10423 / 10787 |
| **EOR Type** | Chemical |
| **EOR Sub Type** | Polymer |
| | |
| **Number of Wells** | 36 |
| **Number of EOR Injectors** | 13 |
| **Number of EOR Producers** | 23 |
| | |
| **Date** | |
| Discovery | |
| Secondary Recovery | |
| EOR 1 (Polymer Flood incremental RF) | |
| EOR 2 | N/A |
| EOR 3 | N/A |
| EOR 4 | N/A |
| EOR 5 | N/A |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 675 |
| Average Pay Thickness (m) | 3.5 |
| Average Permeability (md) | 300 |
| Average Porosity | 0.30 |
| Water Saturation | 0.28 |
| Lithology | Quartzose Sandstone & Siltstone with Interbedded Shale |
| Initial Pressure (kPa) | 4,825 |
| Initial Temperature (C) | 27 |
| Oil Gravity (API) | 21.1 |
| Oil Density (kg/m3) | 927.3 |
| Oil Viscosity (cp) | 204.95 |
| Oil Viscosity @ Tr (cp) | 96.74 |
| Salinity of Formation Water (ppm) | Not Specified |
| Presence of Natural Fractures | Not Specified |
| Presence of Gas Cap | None |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | |
| Primary Recovery Factor (fraction) | |
| Incremental EOR Recovery Factor (fraction) includes WF | |
| OOIP (E3m3) | 19400 |
| Pool Cumulative Production (E3m3) | |
| Total Remaining Reserves Including EOR (E3m3) | |

**EOR Project Assessment** **Table 92**

| | |
|---|---|
| **Field** | Wildmere |
| **Pool Name** | Commingled Pool 003 |
| **Formation** | Sparky, Lloydminster A |
| **ERCB Approval Nos.** | 9673 / 9467 / 10147 / 10423 / 10787 |
| **EOR Type** | Chemical |
| **EOR Sub Type** | Polymer |
| | |
| **Number of Wells** | |
| **Number of EOR Injectors** | |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | |
| Secondary Recovery | |
| EOR 1 | Waterflood |
| EOR 2 | Polymer Flood |
| EOR 3 | |
| EOR 4 | |
| EOR 5 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 569.7 |
| Average Pay Thickness (m) | 8.54 |
| Average Permeability (md) | |
| Average Porosity | 0.3 |
| Water Saturation | 0.21 |
| Lithology | Sandstone |
| Initial Pressure (kPa) | 3672 |
| Initial Temperature (C) | 23 |
| Oil Gravity (API) | 18.09 |
| Oil Density (kg/m3) | 945.9 |
| Oil Viscosity (cp) | 672.66 |
| Oil Viscosity @ Tr (cp) | 361.83 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 164 |
| Primary Recovery Factor (fraction) | 0.11 |
| Incremental EOR Recovery Factor (fraction) includes WF | 0.12 |
| OOIP (E3m3) | 51700 |
| Pool Cumulative Production (E3m3) | 6633.1 |
| Total Remaining Reserves Including EOR (E3m3) | 5257.9 |

**EOR Project Assessment** **Table 93**

| | |
|---|---|
| **Field** | Wrentham |
| **Pool Name** | Lower Mannville B |
| **Formation** | Lower Mannville B |
| **ERCB Approval Nos.** | 9673 / 9467 / 10147 / 10423 / 10787 |
| **EOR Type** | Chemical |
| **EOR Sub Type** | Polymer |
| | |
| **Number of Wells** | |
| **Number of EOR Injectors** | |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1967 |
| Secondary Recovery | |
| EOR 1 | Polymer Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| EOR 5 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 943.5 |
| Average Pay Thickness (m) | 7.41 |
| Average Permeability (md) | |
| Average Porosity | 0.23 |
| Water Saturation | 0.26 |
| Lithology | Sandstone |
| Initial Pressure (kPa) | 7614 |
| Initial Temperature (C) | 31 |
| Oil Gravity (API) | 20.08 |
| Oil Density (kg/m3) | 933.5 |
| Oil Viscosity (cp) | 296.62 |
| Oil Viscosity @ Tr (cp) | 105.52 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 99 |
| Primary Recovery Factor (fraction) | 0.15 |
| Incremental EOR Recovery Factor (fraction) includes WF | 0.3 |
| OOIP (E3m3) | 1224 |
| Pool Cumulative Production (E3m3) | 511.2 |
| Total Remaining Reserves Including EOR (E3m3) | 39.6 |

**EOR Project Assessment** **Table 94**

| | |
|---|---|
| **Field** | Wrentham |
| **Pool Name** | Lower Mannville C |
| **Formation** | Lower Mannville C |
| **ERCB Approval Nos.** | 9673 / 9467 / 10147 / 10423 / 10787 |
| **EOR Type** | Chemical |
| **EOR Sub Type** | Polymer |
| | |
| **Number of Wells** | |
| **Number of EOR Injectors** | |
| **Number of EOR Producers** | |
| | |
| **Date** | |
| Discovery | 1967 |
| Secondary Recovery | |
| EOR 1 | Polymer Flood |
| EOR 2 | |
| EOR 3 | |
| EOR 4 | |
| EOR 5 | |
| | |
| **Reservoir Fluid Properties and Reservoir Parameters** | |
| Depth (m) | 953 |
| Average Pay Thickness (m) | 4.01 |
| Average Permeability (md) | |
| Average Porosity | 0.21 |
| Water Saturation | 0.32 |
| Lithology | Sandstone |
| Initial Pressure (kPa) | 9591 |
| Initial Temperature (C) | 31 |
| Oil Gravity (API) | 20.08 |
| Oil Density (kg/m3) | 933.5 |
| Oil Viscosity (cp) | 296.62 |
| Oil Viscosity @ Tr (cp) | 105.52 |
| Salinity of Formation Water (ppm) | |
| Presence of Natural Fractures | |
| Presence of Gas Cap | |
| | |
| **Oil Reserves (as of Dec 31, 2010)** | |
| Area of Project (ha) | 379 |
| Primary Recovery Factor (fraction) | 0.15 |
| Incremental EOR Recovery Factor (fraction) includes WF | 0.3 |
| OOIP (E3m3) | 2127 |
| Pool Cumulative Production (E3m3) | 809.3 |
| Total Remaining Reserves Including EOR (E3m3) | 147.9 |

# Table 95

## SOLVENT FLOODS IN ALBERTA

| Field Code | Field Name | Pool Code | Pool Name | Producing Formation | Recovery Factor Primary | Recovery Factor Enhanced | | Type |
|---|---|---|---|---|---|---|---|---|
| AB0009 | ACHESON | AB00090720001 | LEDUC A | LEDUC | 54.0% | 31.0% | Leduc | Vertical |
| | ANTE CREEK | | BEAVERHILL LAKE | BEAVERHILL LAKE | 16.0% | 22.0% | BHL | Horizontal |
| AB0126 | BIGORAY | AB01260696002 | NISKU B | NISKU | 31.0% | 35.8% | Pembina | Vertical |
| AB0126 | BIGORAY | AB01260696006 | NISKU F | NISKU | 40.0% | 47.5% | Pembina | Vertical |
| AB0168 | BRAZEAU RIVER | AB01680696001 | NISKU A | NISKU | 40.5% | 41.5% | Pembina | Vertical |
| AB0168 | BRAZEAU RIVER | AB01680696004 | NISKU D | NISKU | 50.0% | 15.0% | Pembina | Vertical |
| AB0168 | BRAZEAU RIVER | AB01680696005 | NISKU E | NISKU | 45.0% | 40.0% | Pembina | Vertical |
| AB0194 | CAROLINE | AB01940176005 | CARDIUM E | CARDIUM SAND | 9.0% | 21.0% | sandstone | Horizontal |
| AB0214 | CHIGWELL | | VIKING E | VIKING | 8.0% | | sandstone | Horizontal |
| AB0214 | CHIGWELL | AB02140218009 | VIKING I | VIKING | 3.0% | 12.0% | sandstone | Horizontal |
| AB0336 | ENCHANT | AB03360800560 | CMG POOL 005 - ARCS F,G | NISKU | 22.0% | 17.0% | | Horizontal |
| AB0336 | ENCHANT | AB03360801760 | CMG POOL 017 - ARCS A,B | NISKU | 25.0% | 23.0% | | Horizontal |
| | FENN-BIG VALLEY | | NISKU | NISKU | 46.8% | 5.2% | | Horizontal |
| | GOLDEN SPIKE | | D-3A | LEDUC | 53.0% | 5.0% | LEDUC | Vertical ? |
| AB0425 | GOOSE RIVER | AB04250744001 | BEAVERHILL LAKE A | BEAVERHILL LAKE | 16.0% | 30.0% | BHL | Vertical |
| AB0505 | JOFFRE | AB05050720002 | LEDUC B | LEDUC | 33.0% | 24.0% | Leduc | Vertical |
| AB0505 | JOFFRE | AB05050218000 | VIKING | VIKING | 16.0% | 44.0% | sandstone | Horizontal |
| AB0509 | JUDY CREEK | AB05090744001 | BEAVERHILL LAKE A | BEAVERHILL LAKE | 16.0% | 34.0% | BHL | Vertical ? |
| AB0509 | JUDY CREEK | AB05090744002 | BEAVERHILL LAKE B | BEAVERHILL LAKE | 20.0% | 29.0% | BHL | Vertical ? |
| AB0513 | KAYBOB | AB05130744001 | BEAVERHILL LAKE A | BEAVERHILL LAKE | 16.0% | 30.5% | BHL | Horizontal |
| AB0514 | KAYBOB SOUTH | AB05140500001 | TRIASSIC A | MONTNEY | 15.0% | 30.0% | | Horizontal |
| | LEDUC | | D-2A | NISKU | 25.0% | 25.0 + 9.0% | | Horizontal |
| AB0615 | MITSUE | AB06150765501 | GILWOOD A | GILWOOD | 25.0% | 37.0% | | Horizontal |
| AB0644 | NIPISI | AB06440765501 | GILWOOD A | GILWOOD | 26.0% | 28.4% | | Horizontal |
| AB0685 | PEMBINA | AB06850696001 | NISKU A | NISKU | 40.5% | 42.0% | Pembina | Vertical |
| AB0685 | PEMBINA | AB06850696004 | NISKU D | NISKU | 35.0% | 35.0% | Pembina | Vertical |
| AB0685 | PEMBINA | AB06850696006 | NISKU F | NISKU | 35.0% | 45.0% | Pembina | Vertical |
| AB0685 | PEMBINA | AB06850696833 | NISKU G2G | NISKU | 35.0% | 28.0% | Pembina | Vertical |
| AB0685 | PEMBINA | AB06850696007 | NISKU G | NISKU | 40.8% | 50.0% | Pembina | Vertical |
| AB0685 | PEMBINA | AB06850696834 | NISKU H2H | NISKU | 40.0% | 47.0% | Pembina | Vertical |
| AB0685 | PEMBINA | AB06850696011 | NISKU K | NISKU | 40.0% | 48.0% | Pembina | Vertical |
| AB0685 | PEMBINA | AB06850696012 | NISKU L | NISKU | 25.0% | 63.0% | Pembina | Vertical |
| AB0685 | PEMBINA | AB06850696013 | NISKU M | NISKU | 40.0% | 45.0% | Pembina | Vertical |
| AB0685 | PEMBINA | AB06850696015 | NISKU O | NISKU | 40.0% | 40.0% | Pembina | Vertical |
| AB0685 | PEMBINA | AB06850696842 | NISKU P2P | NISKU | 40.0% | 45.0% | Pembina | Vertical |
| AB0685 | PEMBINA | AB06850696016 | NISKU P | NISKU | 35.0% | 45.0% | Pembina | Vertical |
| AB0685 | PEMBINA | AB06850696017 | NISKU Q | NISKU | 40.0% | 29.0% | Pembina | Vertical |

Sproule

# Table 95 (continued)

## SOLVENT FLOODS IN ALBERTA

| Field Code | Field Name | Pool Code | Pool Name | Producing Formation | Recovery Factor Primary | Recovery Factor Enhanced | | Type |
|---|---|---|---|---|---|---|---|---|
| AB0753 | RAINBOW | AB07530772101 | KEG RIVER A | RAINBOW MEMBER | 50.0% | 25.0% | Rainbow | Vertical |
| AB0753 | RAINBOW | AB07530772102 | KEG RIVER B | KEG RIVER UPPER | 40.0% | 23.0% | Rainbow | Vertical |
| AB0753 | RAINBOW | AB07530772104 | KEG RIVER D | KEG RIVER | 40.0% | 28.0% | Rainbow | Vertical |
| AB0753 | RAINBOW | AB07530772105 | KEG RIVER E | KEG RIVER | 29.1% | 20.0% | Rainbow | Vertical |
| AB0753 | RAINBOW | AB07530772205 | KEG RIVER EEE | KEG RIVER | 39.9% | 9.8% | Rainbow | Vertical |
| AB0753 | RAINBOW | AB07530772106 | KEG RIVER F | KEG RIVER | 38.0% | 15.0% | Rainbow | Vertical |
| AB0753 | RAINBOW | AB07530772132 | KEG RIVER FF | KEG RIVER | 21.0% | 15.0% | Rainbow | Vertical |
| AB0753 | RAINBOW | AB07530772107 | KEG RIVER G | KEG RIVER | 43.4% | 41.8% | rainbow | Vertical |
| AB0753 | RAINBOW | AB07530772108 | KEG RIVER H | KEG RIVER | 39.2% | 20.0% | rainbow | Vertical |
| AB0753 | RAINBOW | AB07530772135 | KEG RIVER II | KEG RIVER | 45.0% | 15.5% | rainbow | Vertical |
| AB0753 | RAINBOW | AB07530772115 | KEG RIVER O | KEG RIVER | 40.0% | 27.7% | rainbow | Vertical |
| AB0753 | RAINBOW | AB07530772126 | KEG RIVER Z | KEG RIVER | 32.0% | 33.0% | rainbow | Vertical |
| AB0753 | RAINBOW | AB07530772127 | KEG RIVER AA | KEG RIVER | 45.0% | 22.3% | rainbow | Vertical |
| AB0754 | RAINBOW SOUTH | AB07540772102 | KEG RIVER B | KEG RIVER | 44.0% | 21.0% | rainbow | Vertical |
| AB0754 | RAINBOW SOUTH | AB07540772105 | KEG RIVER E | KEG RIVER UPPER | 26.0% | 10.0% | rainbow | Vertical |
| AB0754 | RAINBOW SOUTH | AB07540772107 | KEG RIVER G | KEG RIVER | 20.0% | 12.0% | rainbow | Vertical |
| | REDWATER | D-3 | D-3 | LEDUC | 65.0% | | leduc | Horizontal |
| | RICH | D-3A | D-3A | LEDUC | 46.0% | | leduc | Vertical |
| AB0844 | SIMONETTE | AB08440720000 | LEDUC | LEDUC | 40.0% | 6.0% | Leduc | Vertical |
| | SUFFIELD | | LOWER MANNVILLE J | LOWER MANNVILLE | 12.0% | | SANDSTONE | Horizontal |
| | SUFFIELD | | UPPER MANNVILLE N | UPPER MANNVILLE | 12.0% | 1.0% | SANDSTONE | Horizontal |
| AB0887 | SWAN HILLS | AB08870800160 | CMG POOL 001 - BEAVERHILL LAKE A,B | SWAN HILLS | 17.0% | 36.0% | BHL | Horizontal |
| AB0889 | SWAN HILLS SOUTH | AB08890800160 | CMG POOL 001 - BEAVERHILL LAKE A,B | SWAN HILLS | 17.0% | 28.0% | BHL | Horizontal |
| | TURNER VALLEY | | RUNDLE | RUNDLE | 12.0% | 2.0% | RUNDLE | Vertical |
| AB0925 | VIRGINIA HILLS | AB09250744000 | BEAVERHILL LAKE | SWAN HILLS | 23.0% | 22.0% | BHL | Horizontal |
| AB0942 | WESTPEM | AB09420696004 | NISKU D | NISKU | 40.0% | 40.0% | pembina | Vertical |
| AB0985 | WIZARD LAKE | AB09850720001 | LEDUC A | LEDUC | 66.0% | 19.0% | Leduc | Vertical |
| AB0997 | ZAMA | AB09970772106 | KEG RIVER F | KEG RIVER | 33.1% | 5.0% | zama | Vertical |
| AB0997 | ZAMA | AB09970772233 | KEG RIVER G2G | KEG RIVER | 22.5% | 4.0% | zama | Vertical |
| AB0997 | ZAMA | AB09970772214 | KEG RIVER NNN | KEG RIVER | 30.0% | 5.0% | zama | Vertical |
| AB0997 | ZAMA | AB09970772218 | KEG RIVER RRR | KEG RIVER | 25.0% | 5.0% | zama | Vertical |
| AB0997 | ZAMA | AB09970768512 | MUSKEG L | MUSKEG | 20.0% | 5.0% | zama | Vertical |

# Table 96

## EXPERIMENTAL SOLVENT FLOODS IN ALBERTA

| APPROVAL_NO | OPERATOR | FIELD | POOL | RECOVERY METHOD | Start Year | End Year |
|---|---|---|---|---|---|---|
| 5229 | Gulf | Fenn - Big Valley | Nisku A | Nitrogen Injection[1] | 1987 | 1989 |
| 4674A/B | Esso | Leduc-Woodbend | | Solvent/Chase Gas/Water Inject | 1985 | 1988 |
| 6098 | Petro-Canada | Provost | Cummings I | Gas Injection | 1989 | 1991 |
| 4309E | Esso | Redwater | Leduc A | Solvent/Chase Gas/Water Inject | 1984 | 1991 |
| 7809 | Gulf | Rich | Leduc A | Sour Gas Injection | 1995 | 1996 |
| 5023 | AEC | Suffield | Upper Mannville N | Cyclic Injection | 1986 | 1988 |
| 9540B | EnCana | Suffield | Upper Mannville N | Solvent Injection | 2003 | 2005 |
| TVU 4 | Talisman | Turner Valley | Rundle | Nitrogen Injection | 2001 | 2005 |
| 7939 | Pennzoil | Zama | | Sour Gas Injection | 1996 | 1998 |

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Table 97

# RANGES OF RESERVOIR DATA FOR SOLVENT FLOODS IN ALBERTA

| Units | Property | Flood Type | Min | Max | # Recovery Processes In Reserves Database |
|---|---|---|---|---|---|
| m | Average_Pay | VERTICAL | 17.5 | 103.2 | 46 |
| md | Average_Permeability | VERTICAL | 61 | 9850 | 46 |
| fraction | Average_Porosity | VERTICAL | 0.06 | 0.15 | 46 |
| fraction | Water_Saturation | VERTICAL | 0.07 | 0.28 | 46 |
| kPa | Initial_Pressure | VERTICAL | 11790 | 46019 | 46 |
| kg/m3 | Oil Density | VERTICAL | 792.3 | 857.0 | 46 |
| cp | Oil Viscosity | VERTICAL | 1.3 | 3.6 | 46 |
| E3m3 | OOIP | VERTICAL | 429 | 63900 | 46 |
| percent | Incremental RF | VERTICAL | 1.5 | 63.0 | 46 |
| percent | Total RF | VERTICAL | 25.0 | 90.8 | 46 |
| ha | Project Area | VERTICAL | 15.0 | 1501.0 | 46 |
| m | Average_Pay | HORIZONTAL | 3.3 | 17.9 | 6 |
| md | Average_Permeability | HORIZONTAL | 10 | 20 | 6 |
| fraction | Average_Porosity | HORIZONTAL | 0.08 | 0.14 | 6 |
| fraction | Water_Saturation | HORIZONTAL | 0.14 | 0.27 | 6 |
| kPa | Initial_Pressure | HORIZONTAL | 10374 | 35550 | 6 |
| $kg/m^3$ | Oil Density | HORIZONTAL | 805.9 | 898.0 | 6 |
| cp | Oil Viscosity | HORIZONTAL | 1.4 | 20.2 | 6 |
| E3m3 | OOIP | HORIZONTAL | 723 | 16880 | 6 |
| percent | Incremental RF | HORIZONTAL | 5.0 | 23.0 | 6 |
| percent | Total RF | HORIZONTAL | 39.0 | 46.0 | 6 |
| ha | Project Area | HORIZONTAL | 149.0 | 3453.0 | 6 |
| m | Average_Pay | COMBINATION | 18.9 | 135.7 | 10 |
| md | Permeability | COMBINATION | 18 | 1411 | 10 |
| fraction | Porosity | COMBINATION | 0.03 | 0.10 | 10 |
| fraction | Water_Saturation | COMBINATION | 0.10 | 0.26 | 10 |
| kPa | Initial_Pressure | COMBINATION | 7824 | 31820 | 10 |
| kg/m3 | Oil Density | COMBINATION | 811.0 | 844.3 | 10 |
| cp | Oil Viscosity | COMBINATION | 1.5 | 5.0 | 10 |
| E3m3 | OOIP | COMBINATION | 28370 | 208700 | 10 |
| percent | Incremental RF | COMBINATION | 2.0 | 36.0 | 10 |
| percent | Total RF | COMBINATION | 14.0 | 62.0 | 10 |
| ha | Project Area | COMBINATION | 590.0 | 9169.0 | 10 |

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**Table 97 (continued)**

## RANGES OF RESERVOIR DATA FOR SOLVENT FLOODS IN ALBERTA

| Units | Property | Enhanced_Type | Min | Max | # Recovery Processes In Reserves Database |
|---|---|---|---|---|---|
| m | Average_Pay | SANDSTONE | 2.0 | 4.8 | 8 |
| md | Average_Permeability | SANDSTONE | 41 | 385 | 8 |
| fraction | Average_Porosity | SANDSTONE | 0.12 | 0.28 | 8 |
| fraction | Water_Saturation | SANDSTONE | 0.15 | 0.44 | 8 |
| kPa | Initial_Pressure | SANDSTONE | 5430 | 33807 | 8 |
| kg/m3 | Oil Density | SANDSTONE | 796.8 | 971.0 | 8 |
| cp | Oil Viscosity | SANDSTONE | 1.5 | 1093.9 | 8 |
| E3m3 | OOIP | SANDSTONE | 625 | 8215 | 8 |
| percent | Incremental RF | SANDSTONE | 3.0 | 30.0 | 8 |
| percent | Total RF | SANDSTONE | 1.2 | 82.5 | 8 |
| ha | Project Area | SANDSTONE | 1467.0 | 4465.0 | 8 |

## Table 98

## CHEMICAL FLOODS IN ALBERTA

| Field Code | Field Name | Pool Code | Pool Name | Producing Formation | Recovery Factor Primary | Recovery Factor Enhanced | Type |
|---|---|---|---|---|---|---|---|
| AB0339 | ENTICE | AB03390310002 | LOWER MANNVILLE B | ELLERSLIE | 10.0% | 25.0% | ASP Flood |
| AB0902 | MOONEY | AB09020304001 | BLUESKY A | BLUESKY | 7.0% | 12.0% | ASP Flood |
| AB0877 | SUFFIELD | AB08770250047 | UPPER MANNVILLE UU | GLAUCONITIC | 10.0% | 25.0% | ASP Flood |
| AB0893 | TABER | AB08930300011 | GLAUCONITE K | GLAUCONITIC | 18.0% | 38.0% | ASP Flood |
| AB0895 | TABER SOUTH | AB08950248002 | MANNVILLE B | MANNVILLE GRP | 10.0% | 42.0% | ASP Flood |
| AB0259 | COUNTESS | AB02590250008 | UPPER MANNVILLE H | GLAUCONITIC | 10.5% | 36.0% | Polymer Flood |
| AB0318 | EDGERTON | AB03180294018 | WOODBEND A | WOODBEND | 6.0% | 3.0% | Polymer Flood |
| AB0750 | PROVOST | AB07500250001 | UPPER MANNVILLE A | MANNVILLE UPPER | 3.0% | 12.0% | Polymer Flood |
| AB0877 | SUFFIELD | AB08770250021 | UPPER MANNVILLE U | MANNVILLE UPPER | 15.0% | 20.0% | Polymer Flood |
| AB0923 | VIKING-KINSELLA | AB09230278002 | WAINWRIGHT B | WAINWRIGHT | 14.0% | 35.0% | Polymer Flood |
| AB0963 | WILDMERE | AB09630800360 | CMG POOL 003 - SPARKY E,LLOYDMINSTER A | LLOYDMINSTER SS/SPARKY | 11.0% | 12.0% | Polymer Flood |
| AB0992 | WRENTHAM | AB09920310002 | LOWER MANNVILLE B | SUNBURST SS | 15.0% | 30.0% | Polymer Flood |
| AB0992 | WRENTHAM | AB09920310003 | LOWER MANNVILLE C | MANNVILLE LOWER | 15.0% | 30.0% | Polymer Flood |

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# Table 99

## EXPERIMENTAL CHEMICAL FLOODS IN ALBERTA

| APPROVAL_NO | OPERATOR | FIELD | POOL | RECOVERY METHOD | Start Year | End Year |
|---|---|---|---|---|---|---|
| 3884 | Dome | Viking-Kinsella | Wainwright B | Alkaline Flood[2] | 1983 | |
| 4357A/3692A | Amoco | Cessford | Mannville C | Alkaline Flood[2] | 1982 | 1992 |
| 4065 | PanCanadian | Horsefly Lake | | Water/Polymer/Alkaline Flood[2] | 1984 | 1987 |
| 10640 | EnCana | Countess | Upper Mannville H | Water, Alkaline, and Polymer Injection[2] | 2006 | 2008 |
| 5353F/4263 | Amoco | Provost | Lloydminster | Polymer/Alkaline Flood[2] | 1984 | 1992 |
| 10626B | EnCana | Upper Mannville UU | Upper Mannville UU | Water, Alkaline, Polymer, and Surfactant | 2006 | 2008 |
| 5379 | BP | Chauvin South | Sparky E | Polymer Flood[2] | 1987 | 1993 |
| 6097 | Petro-Canada | Provost | Cummings I | Polymerized Water[2] | 1989 | 1991 |
| 5078C | Chevron | Taber | | Water/Polymer[2] | 1986 | 1993 |

Table 100

# RANGES OF RESERVOIR DATA FOR CHEMICAL FLOODS IN ALBERTA

| Units | Property | Flood Type | Min | Max | # Recovery Processes In Reserves Database |
|---|---|---|---|---|---|
| m | Average_Pay | ALKALI-POLYMER | 3.0 | 8.0 | 3 |
| md | Average_Permeability | ALKALI-POLYMER | 350 | 1400 | 3 |
| fraction | Average_Porosity | ALKALI-POLYMER | 0.24 | 0.29 | 3 |
| fraction | Water_Saturation | ALKALI-POLYMER | 0.30 | 0.30 | 3 |
| kPa | Initial_Pressure | ALKALI-POLYMER | 8784 | 8784 | 3 |
| $kg/m^3$ | Oil Density | ALKALI-POLYMER | 915.9 | 955.4 | 3 |
| cp | Oil Viscosity | ALKALI-POLYMER | 1.0 | 439.2 | 3 |
| E3m3 | OOIP | ALKALI-POLYMER | 1486 | 17400 | 3 |
| percent | Incremental RF | ALKALI-POLYMER | 46.3 | 46.3 | 3 |
| percent | Total RF | ALKALI-POLYMER | N/A | N/A | 3 |
| ha | Project Area | ALKALI-POLYMER | 13.0 | 303.5 | 3 |
| m | Average_Pay | ALKALI-SURFACTANT-POLYMER | 1.9 | 6.9 | 5 |
| md | Average_Permeability | ALKALI-SURFACTANT-POLYMER | 3000 | 3000 | 5 |
| fraction | Average_Porosity | ALKALI-SURFACTANT-POLYMER | 0.16 | 0.30 | 5 |
| fraction | Water_Saturation | ALKALI-SURFACTANT-POLYMER | 0.15 | 0.39 | 5 |
| kPa | Initial_Pressure | ALKALI-SURFACTANT-POLYMER | 5790 | 13645 | 5 |
| kg/m3 | Oil Density | ALKALI-SURFACTANT-POLYMER | 855.0 | 972.0 | 5 |
| cp | Oil Viscosity | ALKALI-SURFACTANT-POLYMER | 3.6 | 1092.2 | 5 |
| E3m3 | OOIP | ALKALI-SURFACTANT-POLYMER | 531 | 7883 | 5 |
| percent | Incremental RF | ALKALI-SURFACTANT-POLYMER | 25.0 | 38.0 | 5 |
| percent | Total RF | ALKALI-SURFACTANT-POLYMER | N/A | N/A | 5 |
| ha | Project Area | ALKALI-SURFACTANT-POLYMER | 139.0 | 308.0 | 5 |
| m | Average_Pay | POLYMER | 1.0 | 9.0 | 11 |
| md | Average_Permeability | POLYMER | 300 | 3000 | 11 |
| fraction | Average_Porosity | POLYMER | 0.21 | 0.32 | 11 |
| fraction | Water_Saturation | POLYMER | 0.18 | 0.40 | 11 |
| kPa | Initial_Pressure | POLYMER | 1900 | 10703 | 11 |
| kg/m3 | Oil Density | POLYMER | 898.4 | 1076.0 | 11 |
| cp | Oil Viscosity | POLYMER | 23.0 | 2.02E+14 | 11 |
| E3m3 | OOIP | POLYMER | 2.54 | 51700 | 11 |
| percent | Incremental RF | POLYMER | 12.0 | 36.0 | 11 |
| percent | Total RF | POLYMER | N/A | N/A | 11 |
| ha | Project Area | POLYMER | 99.0 | 1252.0 | 11 |

## Table 101

# EXPERIMENTAL THERMAL RECOVERY PROJECTS IN ALBERTA (NON OILSANDS DESIGNATION)

| APPROVAL NO | OPERATOR | FIELD | LOCATION | RECOVERY METHOD | ACTIVE PERIOD |
|---|---|---|---|---|---|
| 6373 (5789) | AEC | Suffield | 3-20-8 W4M | Hot-water Injection | 1988-1991 |
| 3537E | PanCanadian | Countess | 9-19-16 W4M | Combustion | 1982-1995 |
| 7156 | Petro Canada | Shekilie | 5-5-118-08 W6M | Combustion | 1993-1996 |

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# Table 102

## OILSANDS EXPERIMENTAL PROJECTS IN "CONVENTIONAL OIL" AREAS OF ALBERTA

| APPROVAL NO. | OPERATOR | FIELD | LOCATION | RECOVERY METHOD | ACTIVE PERIOD |
|---|---|---|---|---|---|
| 4632C | CNRL | Lindbergh | 13-55-6-W4M | Central Processing Facility | 1985-2003 |
| 3105D | Amoco | Morgan | 35-51-4 W4M | CTD/Steam Stimulation | 1980-1992 |
| 788 | Husky | Lloydminster | 20/28/29-50-1 W4M | Steam Flood | 1965-1970 |
| 805 | Forgotson & Burk | Wizard Lake | 11,13 & 14-48-28 W4M | Injection Program Various Fluids | 1965-1966 |
| 840 | Husky | Wainwright | 20 & 21 46-6 W4M | Steam Stimulation | 1965-1966 |
| 845 | Husky | Lloydminster | 14A-35-49-2 W4M | Steam Stimulation | 1966-1967 |
| 847 | Kodiak Petroleums Ltd. | Lloydminster | 11/14-50-2 W4M | Steam Stimulation | 1966-1967 |
| 1316 | Canadian Hidrogas | Lloydminster | 12-50-2 W4M | Combustion | 1970-1975 |
| 2145 | Tesoro | Provost | 19-37-1 W4M | Steam Stimulation | 1975-1976 |
| 2707 | Tesoro | Provost | 32-36-1 W4M | Steam Stimulation | 1978-1979 |
| 3086 | AEC | Suffield | 10-20-08 W4M | Fireflood Combustion | 1980-1985 |
| 3341 | Dome | Chauvin South | 26-42-3 W4M | Steam Stimulation | 1981-1982 |
| 3342 | Dome | Hayter | 26-40-1 W4M | Steam Stimulation | 1981-1982 |
| 3374 | Esso | Joarcam | 6/7-48-20 W4M | Combustion | 1979-1984 |
| 3402 | Hudson's Bay | Lloydminster | 23-49-1 W4M | Steam Stimulation | 1981-1982 |
| 3417 | Dome | Rivercourse | 36-47-1 W4M | Steam Stimulation | 1981-1984 |
| 3424 | Husky | Lloydminster | 13-50-3 W4M | Steam Stimulation | 1982 |
| 3635 | Koch | Wildmere | 23-47-5 W4M | Combination Thermal Drive | 1982-1987 |
| 3646 | Husky | Wainwright | 32-45-6 W4M | Steam Stimulation | 1982-1984 |
| 3720 | Dome | Atlee-Buffalo | 18-21-5 W4M | Combination Thermal Drive | 1982-1987 |
| 3991 | Koch | Wildmere | 13/14-47-5 W4M | Steam Stimulation | 1983-1984 |
| 4561 | Dome | Morgan | 35-51-4 W4M | Steam Stimulation | 1985-1986 |
| 4567 | Canadian Occidental | Morgan | 34-51-4 W4M | Combustion | 1985-1990 |
| 4780 | AEC | Suffield | 10-20-8 W4M | Combustion | 1980-1990 |
| 4943 | Can. N.W. Energy | Wildmere | 4-30-48-4 W4M | Electrical Stimulation | 1986-1990 |
| 5802 | PanCanadian | Medicine Hat | 35-12-5 W4M | Steam Stimulation | 1988-1991 |
| 7173 | Koch | Wildmere | 9-23-47-5 W4M | Electromagnetic Stimulation | 1993-1994 |
| 7516 | Probe Exploration | Lloydminster | 2-51-2 W4M | Steam Assisted Gravity Drainage | 1994-1997 |
| 7810 | ELAN | Provost | 33-36-1W4M | Steam Assisted Gravity Drainage | 1995-1998 |
| 7919 | Norcen | Provost | 20-37-1W4M | Single Well Steam Assisted Gravity Drainage | 1996-1999 |
| 8040 | ELAN | Fort Kent | 13&14-62-4W4M | Single Well Steam Assisted Gravity Drainage | 1996-1999 |
| 8059 | PanCanadian | Provost | 4-21-38-1 W4M | Water & Gas Injection | 1996-1997 |
| 2531B | Husky | Lloydminster | 30-50-1 W4M | Steam Stimulation | 1977-1981 |
| 2768D | Petro-Canada | Viking-Kinsella | 30-48-8 W4M | Fireflood | 1978-1985 |
| 3002A | Dome | Morgan | 35-51-4 W4M | Steam Injection | 1980 |

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## Table 102 (continued)

## OILSANDS EXPERIMENTAL PROJECTS IN "CONVENTIONAL OIL" AREAS OF ALBERTA

| APPROVAL NO. | OPERATOR | FIELD | LOCATION | RECOVERY METHOD | ACTIVE PERIOD |
|---|---|---|---|---|---|
| 3250G | Home | Lloydminster | 2-51-2 W4M | Steam Stimulation/Flood | 1981-1992 |
| 3293A | Mobil-GC | Morgan | 27-51-4 W4M | Steam Stimulation | 1981-1982 |
| 3418B (2057,3132) | Norcen | Provost | 17-37-1 W4M | Combustion | 1981-1987 |
| 3638A | Husky | Lloydminster | 13-50-3 W4M | Steam Stimulation | 1982 |
| 3918B | Petro-Canada | Viking-Kinsella | 24-48-9 W4M | Combustion | 1983-1987 |
| 4414C | Norcen | Provost | 20-37-1 W4M | Steam Stimulation/Drive | 1984-1995 |
| 4449A | Mobil | Morgan | 36-51-4 W4M | Steam Stimulation | 1984-1986 |
| 4459 (2144) | Mobil | Lloydminster | 18-51-2 W4M | Steam Stimulation | 1975-1988 |
| 4460B (3229, 2142) | Mobil | Lloydminster | 12-49-1 W4M | Combination Thermal Drive | 1975-1987 |
| 5844B | PanCanadian | Provost | 21-38-1 W4M | Steam Stimulation | 1988-1991 |
| 6010B (5387, 4686,11X, 15X) | Canada Energy N.W. | Atlee-Buffalo | 19-21-5 W4M | Steam Stimulation | 1985-1992 |
| 6968A (3105D) | CNRL | Morgan | 35-51-4 W4M | CTD/Steam Stimulation | 1980-1995 |
| 6975A | PanCanadian | Provost | 4-21-38-1 W4M | Horizontal Well/Steam Flood | 1992-1995 |
| 8006D | AEC | Fisher | 21&22-70-4-W4M | Steam Assisted Gravity Drainage | 1996-2002 |

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## Table 103

# SCREENING PARAMETERS FOR SOLVENT FLOODS IN ALBERTA

| Units | Property | Flood Type | Min | Max |
|---|---|---|---|---|
| m | Average_Pay | VERTICAL | 20.0 | 200.0 |
| m | Depth | VERTICAL | 1000.0 | 10000.0 |
| md | Average_Permeability | VERTICAL | 50 | 10000 |
| fraction | Average_Porosity | VERTICAL | 0.06 | 0.3 |
| fraction | Water_Saturation | VERTICAL | 0.07 | 0.28 |
| kPa | Initial_Pressure | VERTICAL | 10000 | 50000 |
| kg/m3 | Oil Density | VERTICAL | 790.0 | 850.0 |
| cp | Oil Viscosity | VERTICAL | 0.1 | 5 |
| E3m3 | OOIP | VERTICAL | 400 | 100000 |
| ha | Project Area | VERTICAL | 15.0 | 2000.0 |
| | Lithology | VERTICAL | CARB. | CARB. |
| | Prior Waterflood | VERTICAL | None | None |
| | Gas cap | VERTICAL | None | None |
| m | Average_Pay | HORIZONTAL | 3.0 | 20.0 |
| m | Depth | HORIZONTAL | 1000.0 | 10000.0 |
| md | Average_Permeability | HORIZONTAL | 10 | 10000 |
| fraction | Average_Porosity | HORIZONTAL | 0.06 | 0.3 |
| fraction | Water_Saturation | HORIZONTAL | 0.1 | 0.3 |
| kPa | Initial_Pressure | HORIZONTAL | 10000 | 50000 |
| $kg/m^3$ | Oil Density | HORIZONTAL | 800.0 | 900.0 |
| cp | Oil Viscosity | HORIZONTAL | 0.1 | 20 |
| E3m3 | OOIP | HORIZONTAL | 500 | 100000 |
| ha | Project Area | HORIZONTAL | 150.0 | 5000.0 |
| | Lithology | HORIZONTAL | CARB. | CARB. |
| | Prior Waterflood | HORIZONTAL | None | None |
| | Gas cap | HORIZONTAL | None | None |
| m | Average_Pay | COMBINATION | 18.0 | 1000.0 |
| m | Depth | COMBINATION | 1000.0 | 10000.0 |
| md | Permeability | COMBINATION | 20 | 2000 |
| fraction | Porosity | COMBINATION | 3.00 | 30.00 |
| fraction | Water_Saturation | COMBINATION | 0.10 | 0.30 |
| kPa | Initial_Pressure | COMBINATION | 7500 | 50000 |
| kg/m3 | Oil Density | COMBINATION | 750.0 | 850.0 |
| cp | Oil Viscosity | COMBINATION | 0.1 | 5.0 |
| E3m3 | OOIP | COMBINATION | 25000 | 1000000 |
| ha | Project Area | COMBINATION | 600.0 | 25000.0 |
| | Lithology | COMBINATION | CARB. | CARB. |
| | Prior Waterflood | COMBINATION | None | None |
| | Gas cap | COMBINATION | None | None |

Table 103 (continued)

## SCREENING PARAMETERS FOR SOLVENT FLOODS IN ALBERTA

| Units | Property | Enhanced_Type | Min | Max |
|---|---|---|---|---|
| m | Average_Pay | SANDSTONE | 2.0 | 20.0 |
| m | Depth | SANDSTONE | 1000.0 | 10000.0 |
| md | Average_Permeability | SANDSTONE | 40 | 2000 |
| fraction | Average_Porosity | SANDSTONE | 0.1 | 0.3 |
| fraction | Water_Saturation | SANDSTONE | 0.15 | 0.44 |
| kPa | Initial_Pressure | SANDSTONE | 5400 | 35000 |
| kg/m3 | Oil Density | SANDSTONE | 750.0 | 975.0 |
| cp | Oil Viscosity | SANDSTONE | 0.1 | 15 |
| E3m3 | OOIP | SANDSTONE | 600 | 25000 |
| ha | Project Area | SANDSTONE | 1000.0 | 25000.0 |
| | Lithology | SANDSTONE | SAND. | SAND. |
| | Prior Waterflood | SANDSTONE | None | None |
| | Gas cap | SANDSTONE | None | None |

## Table 104

### POOLS WITH POTENTIAL FOR SOLVENT FLOODING

| EOR TYPE | NUMBER OF POOLS | OOIP ($10^3$ $m^3$) | INITIAL ESTALISHED RESERVES ($10^3$ $m^3$) | REMAINING ESTABLISHED RESERVES ($10^3$ $m^3$) | RECOVERY FACTOR TO 2010 (%) |
|---|---|---|---|---|---|
| Solvent Vertical | 200 | 62051.1 | 8714.8 | 805.6 | 12.75 |
| Solvent Horizontal | 734 | 182776.0 | 37602.2 | 3920.1 | 18.43 |
| Solvent Combination | 382 | 95242.8 | 13630.4 | 1256.7 | 12.99 |
| Solvent Sandstone | 1701 | 460548.6 | 62552.3 | 8018.8 | 11.84 |

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## Table 105

### FIVE LARGEST POOLS WITH VERTICAL SOLVENT FLOOD POTENTIAL

| **Field and Pool** | | **Oil In Place** | **Recovery** | **Initial** | **Cumulative Production** | **Reservoir Parameters** | | | | | | | | | **Other Pool Information** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | **Primary** | | **Area** | | | | | | | | | | |
| **Field** | **Pool** | **Pool** | **Primary** | **Pool** | | **Pool** | **Average Pay Thickness** | **Porosity** | **Water Saturation** | **Shrinkage** | **Initial Solution GOR** | **Density** | **Temperatur e** | **Initial Pressure** | **Mean Formation Depth** | **Discovery Year** |
| | | $10^3m^3$ | Fraction | $10^3m^3$ | $10^3m^3$ | ha | m | Fraction | Fraction | Fraction | $m^3m^3$ | $kg/m^3$ | $^oC$ | kPa | m KB | |
| MEDICINE RIVER | D-3 F | 1169.0 | 0.35 | 409.0 | 284.5 | 95 | 24.00 | 0.080 | 0.11 | 0.72 | 127 | 810 | 85 | 16699 | 2992.6 | 2003 |
| RICH | D-3 A | 1333.0 | 0.46 | 613.0 | 611.2 | 15 | 103.20 | 0.110 | 0.10 | 0.87 | 64 | 857 | 65 | 13616 | 1818.7 | 1982 |
| MOOSE | RUNDLE C | 1587.0 | 0.25 | 397.0 | 239.5 | 247 | 30.38 | 0.060 | 0.25 | 0.47 | 450 | 838 | 48 | 14190 | 2475.6 | 1994 |
| FENN WEST | COMMINGLED POOL 001 | 1883.0 | 0.341 | 642.0 | 625.5 | 85 | 48.60 | 0.067 | 0.16 | 0.81 | 73 | 865 | 62 | 12570 | 1726.8 | 1983 |
| RAINBOW SOUTH | KEG RIVER N | 3000.0 | 0.13 | 390.0 | 345.8 | 172 | 36.55 | 0.073 | 0.14 | 0.76 | 159 | 796 | 69 | 18191 | 1999.0 | 1978 |

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## Table 106

### FIVE LARGEST POOLS WITH HORIZONTAL SOLVENT FLOOD POTENTIAL

| Field and Pool | | Oil In Place | Recovery | Initial | Cumulative Production | Reservoir Parameters | | | | | | | | | Other Pool Information | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Primary | | Area | | | | | | | | | | |
| Field | Pool | Pool | Primary | Pool | | Pool | Average Pay Thickness | Porosity | Water Saturation | Shrinkage | Initial Solution GOR | Density | Temperature | Initial Pressure | Mean Formation Depth | Discovery Year |
| | | $10^3m^3$ | Fraction | $10^3m^3$ | $10^3m^3$ | ha | m | Fraction | Fraction | Fraction | $m^3m^3$ | $kg/m^3$ | °C | kPa | m KB | |
| EVI | COMMINGLED POOL 005 | 5494.0 | 0.6 | 3296.0 | 3256.2 | 888 | 5.58 | 0.180 | 0.30 | 0.88 | 53 | 824 | 38 | 15810 | 1503.2 | 1985 |
| GARRINGTON | COMMINGLED POOL 008 | 4230.0 | 0.08 | 338.0 | 320.2 | 2560 | 3.00 | 0.107 | 0.22 | 0.66 | 152 | 843 | 82 | 17861 | 2232.3 | 1982 |
| SLAVE | SLAVE POINT S | 3888.0 | 0.5 | 1944.0 | 1770.1 | 1170 | 6.23 | 0.081 | 0.26 | 0.89 | 32 | 827 | 50 | 17164 | 1702.8 | 1980 |
| SWALWELL | D-1 A | 9562.0 | 0.1 | 956.0 | 574.1 | 3791 | 6.74 | 0.070 | 0.19 | 0.66 | 170 | 828 | 85 | 18216 | 2189.3 | 1996 |
| WAYNE-ROSEDALE | NISKU A | 5636.0 | 0.35 | 1973.0 | 1788.0 | 957 | 9.50 | 0.090 | 0.16 | 0.82 | 78 | 851 | 54 | 13606 | 1754.4 | 1993 |

## Table 107

### FIVE LARGEST POOLS WITH SANDSTONE SOLVENT FLOOD POTENTIAL

| Field and Pool | | Oil In Place | Recovery | | Reservoir Parameters | | | | | | | | | Other Pool Information | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Area | | | | | | | | | | |
| Field | Pool | Pool | Primary | Cumulative Production | Pool | Average Pay Thickness | Porosity | Water Saturation | Shrinkage | Initial Solution GOR | Density | Temperatur e | Initial Pressure | Mean Formation Depth | Discovery Year |
| | | $10^3m^3$ | Fraction | $10^3m^3$ | ha | m | Fraction | Fraction | Fraction | $m^3m^3$ | $kg/m^3$ | $^oC$ | kPa | m KB | |
| EDSON | COMMINGLED POOL 003 | 12950.0 | 0.045 | 530.9 | 5264 | 4.95 | 0.100 | 0.28 | 0.69 | 220 | 813 | 83 | 20730 | 1786.9 | 1962 |
| JAYAR | COMMINGLED POOL 001 | 8218.0 | 0.052 | 354.2 | 2090 | 7.10 | 0.120 | 0.29 | 0.65 | 185 | 752 | 66 | 15275 | 1935.4 | 1979 |
| PINE CREEK | COMMINGLED POOL 005 | 10170.0 | 0.05 | 416.3 | 4201 | 3.70 | 0.110 | 0.15 | 0.70 | 167 | 805 | 68 | 13020 | 1899.4 | 1974 |
| WAPITI | COMMINGLED POOL 001 | 19560.0 | 0.07 | 1068.2 | 3761 | 7.98 | 0.110 | 0.25 | 0.79 | 98 | 810 | 40 | 9337 | 1274.5 | 1969 |
| WILSON CREEK | COMMINGLED POOL 002 | 10650.0 | 0.1 | 788.6 | 4539 | 3.48 | 0.140 | 0.42 | 0.83 | 62 | 833 | 68 | 6844 | 1253.1 | 1979 |

## Table 108

**PEMBINA NISKU REEFS WITH NO MISCIBLE FLOOD**

| | |
|---|---|
| BRAZEAU RIVER | NISKU C |
| BRAZEAU RIVER | NISKU G |
| PEMBINA | BANFF L |
| PEMBINA | NISKU AA |
| PEMBINA | NISKU AAA |
| PEMBINA | NISKU B2B |
| PEMBINA | NISKU BBB |
| PEMBINA | NISKU CCC |
| PEMBINA | NISKU DDD |
| PEMBINA | NISKU FF |
| PEMBINA | NISKU GGG |
| PEMBINA | NISKU JJJ |
| PEMBINA | NISKU OO |
| PEMBINA | NISKU PPP |
| PEMBINA | NISKU QQQ |
| PEMBINA | NISKU TTT |
| PEMBINA | NISKU U |
| PEMBINA | NISKU VVV |
| PEMBINA | NISKU W |
| PEMBINA | NISKU X |

## Table 109

### RAINBOW KEG RIVER REEFS WITH NO MISCIBLE FLOOD

| | |
|---|---|
| RAINBOW | KEG RIVER A2A |
| RAINBOW | KEG RIVER B4B |
| RAINBOW | KEG RIVER B5B |
| RAINBOW | KEG RIVER C3C |
| RAINBOW | KEG RIVER D3D |
| RAINBOW | KEG RIVER D5D |
| RAINBOW | KEG RIVER E4E |
| RAINBOW | KEG RIVER F4F |
| RAINBOW | KEG RIVER G3G |
| RAINBOW | KEG RIVER H4H |
| RAINBOW | KEG RIVER I2I |
| RAINBOW | KEG RIVER K2K |
| RAINBOW | KEG RIVER K4K |
| RAINBOW | KEG RIVER L2L |
| RAINBOW | KEG RIVER L3L |
| RAINBOW | KEG RIVER M4M |
| RAINBOW | KEG RIVER O2O |
| RAINBOW | KEG RIVER P4P |
| RAINBOW | KEG RIVER Q2Q |
| RAINBOW | KEG RIVER R3R |
| RAINBOW | KEG RIVER S2S |
| RAINBOW | KEG RIVER T4T |
| RAINBOW | KEG RIVER V3V |
| RAINBOW | KEG RIVER WWW |
| RAINBOW | KEG RIVER X4X |
| RAINBOW | KEG RIVER XXX |
| RAINBOW | KEG RIVER Y2Y |
| RAINBOW | KEG RIVER Y3Y |
| RAINBOW | KEG RIVER Y4Y |
| RAINBOW | KEG RIVER Z3Z |
| RAINBOW | KEG RIVER Z4Z |
| RAINBOW | KEG RIVER ZZZ |
| RAINBOW SOUTH | KEG RIVER BB |
| RAINBOW SOUTH | KEG RIVER M |
| RAINBOW SOUTH | KEG RIVER N |
| RAINBOW SOUTH | KEG RIVER P |
| RAINBOW SOUTH | KEG RIVER S |
| RAINBOW SOUTH | KEG RIVER V |
| RAINBOW SOUTH | KEG RIVER X |
| RAINBOW SOUTH | KEG RIVER Y |
| RAINBOW SOUTH | KEG RIVER Z |

Table 110

# SCREENING PARAMETERS FOR CHEMICAL FLOODS IN ALBERTA

| Units | Property | Flood Type | Min | Max |
|---|---|---|---|---|
| m | Average_Pay | ALKALI-POLYMER | 3.0 | 25.0 |
| md | Average_Permeability | ALKALI-POLYMER | 350 | 5000 |
| fraction | Average_Porosity | ALKALI-POLYMER | 0.24 | 0.35 |
| fraction | Water_Saturation | ALKALI-POLYMER | 0.10 | 0.30 |
| kPa | Initial_Pressure | ALKALI-POLYMER | 1000 | 15000 |
| $kg/m^3$ | Oil Density | ALKALI-POLYMER | 900.0 | 960.0 |
| cp | Oil Viscosity | ALKALI-POLYMER | 1.0 | 500.0 |
| E3m3 | OOIP | ALKALI-POLYMER | 1400 | 100000 |
| ha | Project Area | ALKALI-POLYMER | 13.0 | 303.5 |
| | Lithology | ALKALI-POLYMER | SAND | SAND |
| | | | | |
| m | Average_Pay | ALKALI-SURFACTANT-POLYMER | 1.0 | 25.0 |
| md | Average_Permeability | ALKALI-SURFACTANT-POLYMER | 500 | 5000 |
| fraction | Average_Porosity | ALKALI-SURFACTANT-POLYMER | 0.16 | 0.35 |
| fraction | Water_Saturation | ALKALI-SURFACTANT-POLYMER | 0.10 | 0.39 |
| kPa | Initial_Pressure | ALKALI-SURFACTANT-POLYMER | 1000 | 14000 |
| kg/m3 | Oil Density | ALKALI-SURFACTANT-POLYMER | 850.0 | 975.0 |
| cp | Oil Viscosity | ALKALI-SURFACTANT-POLYMER | 3.0 | 1100.0 |
| E3m3 | OOIP | ALKALI-SURFACTANT-POLYMER | 500 | 100000 |
| ha | Project Area | ALKALI-SURFACTANT-POLYMER | 100.0 | 25000.0 |
| | Lithology | ALKALI-SURFACTANT-POLYMER | SAND | SAND |
| | | | | |
| m | Average_Pay | POLYMER | 1.0 | 25.0 |
| md | Average_Permeability | POLYMER | 300 | 5000 |
| fraction | Average_Porosity | POLYMER | 0.15 | 0.35 |
| fraction | Water_Saturation | POLYMER | 0.10 | 0.40 |
| kPa | Initial_Pressure | POLYMER | 1000 | 15000 |
| kg/m3 | Oil Density | POLYMER | 875.0 | 1075.0 |
| cp | Oil Viscosity | POLYMER | 20.0 | 1.00E+04 |
| E3m3 | OOIP | POLYMER | 500 | 100000 |
| ha | Project Area | POLYMER | 100.0 | 25000.0 |
| | Lithology | POLYMER | SAND | SAND |
| | | | | |

## Table 111

### POOLS WITH POTENTIAL FOR CHEMICAL FLOODING

| EOR TYPE | NUMBER OF POOLS | OOIP ($10^3$ $m^3$) | INITIAL ESTALISHED RESERVES ($10^3$ $m^3$) | REMAINING ESTABLISHED RESERVES ($10^3$ $m^3$) | RECOVERY FACTOR TO 2010 (%) |
|---|---|---|---|---|---|
| ASP | 1396 | 443177.6 | 88274.8 | 8655.7 | 17.97 |
| POLYMER | 935 | 424882.4 | 66385.2 | 8200.5 | 13.69 |

## Table 112

### FIVE LARGEST POOLS WITH ASP FLOOD POTENTIAL

| Field and Pool | | Oil In Place | Recovery Factor | Initial Established Reserves | Cumulative Production | Reservoir Parameters | | | | | | | | | Other Pool Information | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Primary | | Area | | | | | | | | | | |
| Field | Pool | Pool | Primary | Pool | | Pool | Average Pay Thickness | Porosity | Water Saturation | Shrinkage | Initial Solution GOR | Density | Temperature | Initial Pressure | Mean Formation Depth | Discovery Year |
| | | $10^3m^3$ | Fraction | $10^3m^3$ | $10^3m^3$ | ha | m | Fraction | Fraction | Fraction | $m^3m^3$ | $kg/m^3$ | °C | kPa | m KB | |
| LLOYDMINSTER | COMMINGLED POOL 010 | 9231.0 | 0.07 | 646.0 | 532.9 | 927 | 4.16 | 0.310 | 0.22 | 0.99 | 10 | 958 | 28 | 3518 | 552.8 | 1980 |
| PROVOST | DINA N | 8067.0 | 0.50 | 4034.0 | 3459.3 | 517 | 6.45 | 0.290 | 0.14 | 0.97 | 10 | 934 | 31 | 5969 | 834.9 | 1957 |
| PROVOST | BASAL QUARTZ C | 9937.0 | 0.43 | 4273.0 | 4113.2 | 648 | 7.02 | 0.280 | 0.17 | 0.94 | 25 | 921 | 33 | 6501 | 881.1 | 1975 |
| SUFFIELD | UPPER MANNVILLE TTT | 9234.0 | 0.03 | 277.0 | 185.7 | 659 | 9.10 | 0.260 | 0.37 | 0.94 | 26 | 956 | 34 | 9236 | 946.7 | 2002 |
| WILDMERE | LLOYDMINSTER MM | 8172.0 | 0.01 | 81.7 | 52.3 | 444 | 7.00 | 0.330 | 0.17 | 0.96 | 14 | 956 | 24 | 4761 | 629.1 | 1999 |

## Table 113

### FIVE LARGEST POOLS WITH POLYMER FLOOD POTENTIAL

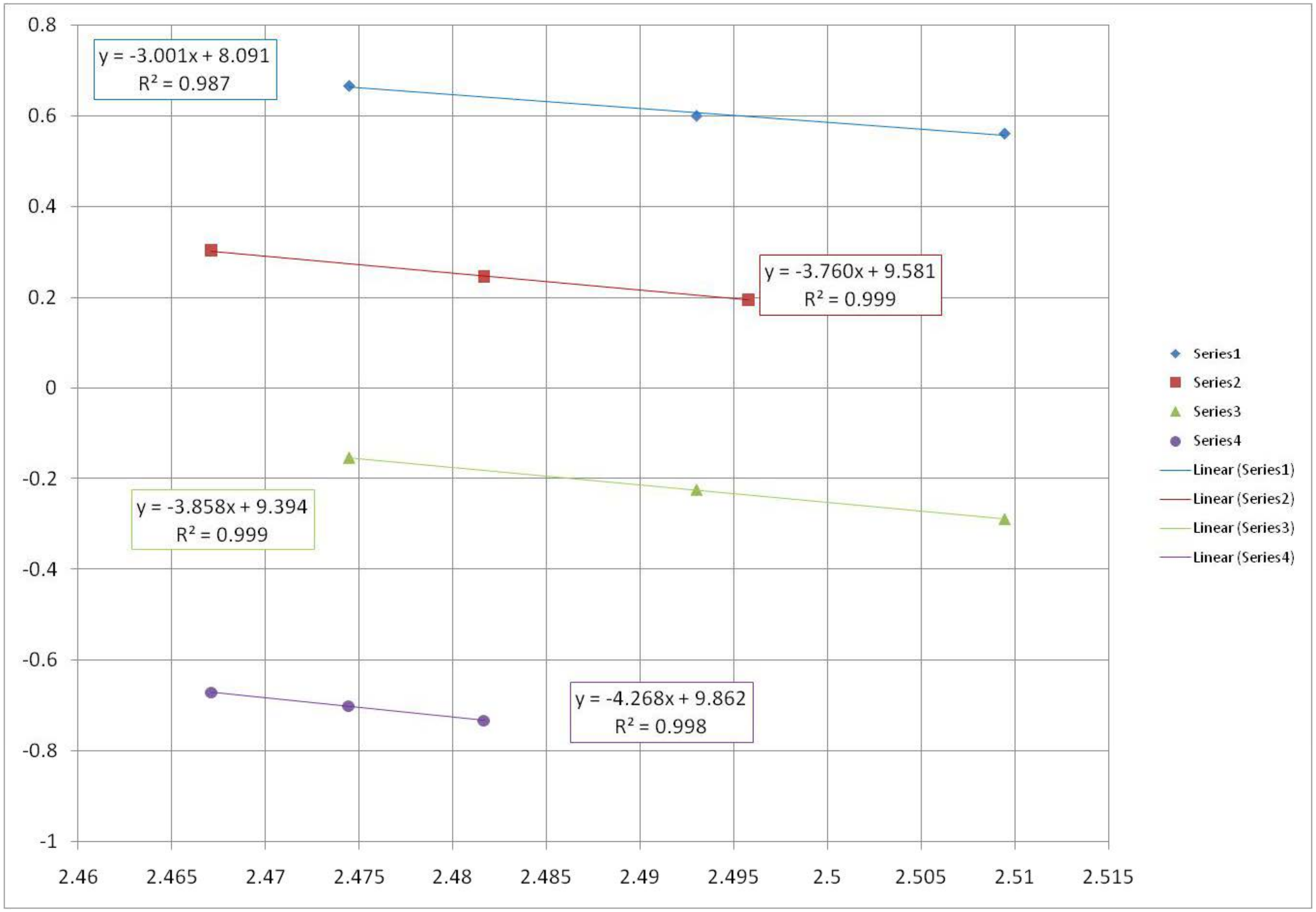
| Field and Pool | | Oil In Place | Recovery Factor | Initial Established Reserves | Cumulative Production | Reservoir Parameters | | | | | | | | | Other Pool Information | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Field | Pool | Pool | Primary | Primary Pool | | Area Pool | Average Pay Thickness | Porosity | Water Saturation | Shrinkage | Initial Solution GOR | Density | Temperature | Initial Pressure | Mean Formation Depth | Discovery Year |
| | | $10^3m^3$ | Fraction | $10^3m^3$ | $10^3m^3$ | ha | m | Fraction | Fraction | Fraction | $m^3m^3$ | $kg/m^3$ | $^oC$ | kPa | m KB | |
| LLOYDMINSTER | LLOYDMINSTER M | 17740.0 | 0.004 | 71.0 | 70.3 | 1042 | 6.57 | 0.310 | 0.17 | 0.99 | 10 | 983 | 27 | 4192 | 685.7 | 1977 |
| LLOYDMINSTER | COMMINGLED POOL 014 | 20620.0 | 0.100 | 2062.0 | 1329.0 | 1929 | 4.36 | 0.320 | 0.21 | 0.97 | 8 | 981 | 22 | 2985 | 478.4 | 1994 |
| PROVOST | BASAL QUARTZ C | 9937.0 | 0.430 | 4273.0 | 4113.2 | 648 | 7.02 | 0.280 | 0.17 | 0.94 | 25 | 921 | 33 | 6501 | 881.1 | 1975 |
| SUFFIELD | UPPER MANNVILLE TTT | 9234.0 | 0.030 | 277.0 | 185.7 | 659 | 9.10 | 0.260 | 0.37 | 0.94 | 26 | 956 | 34 | 9236 | 946.7 | 2002 |
| WILDMERE | SPARKY O | 9427.0 | 0.010 | 94.3 | 27.6 | 1836 | 2.45 | 0.290 | 0.27 | 0.99 | 10 | 973 | 28 | 4186 | 659.0 | 1982 |

## Table 114

### POOLS WITH POTENTIAL FOR THERMAL RECOVERY

| EOR TYPE | NUMBER OF POOLS | OOIP ($10^3$ $m^3$) | INITIAL ESTALISHED RESERVES ($10^3$ $m^3$) | REMAINING ESTABLISHED RESERVES ($10^3$ $m^3$) | RECOVERY FACTOR TO 2010 (%) |
|---|---|---|---|---|---|
| Cyclic Steam | 196 | 275185.3 | 29661 | 8655.7 | 7.63 |
| Steam Flood | 214 | 279257.8 | 29922.3 | 3621.3 | 9.42 |
| SAGD | 196 | 275185.3 | 29661 | 3423.5 | 9.53 |
| In-Situ Combustion | 1434 | 528507.6 | 97448.1 | 10485 | 16.45 |

Sproule

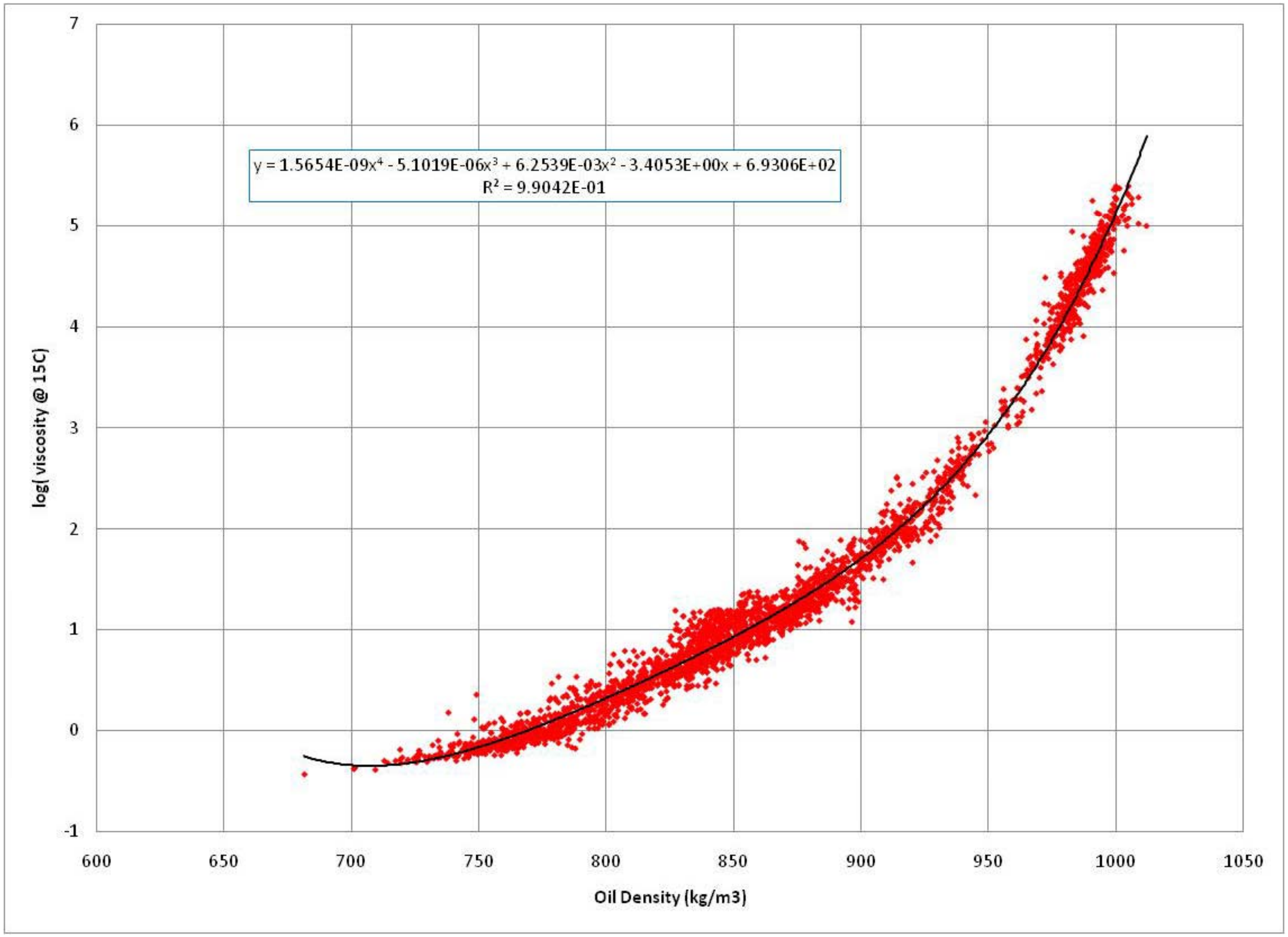



**ASTM Correlation for Four Alberta Oil Samples**

Figure 1



Sproule

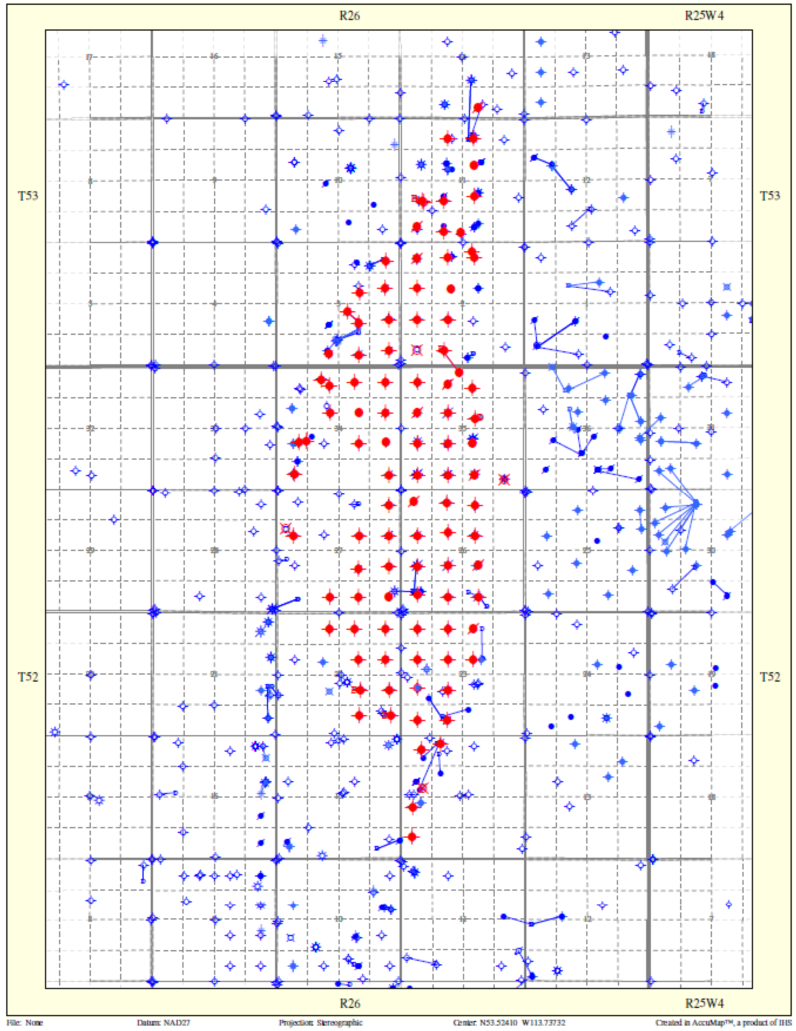



**Oil Viscosity at 15°C vs Oil Density**

Figure 2

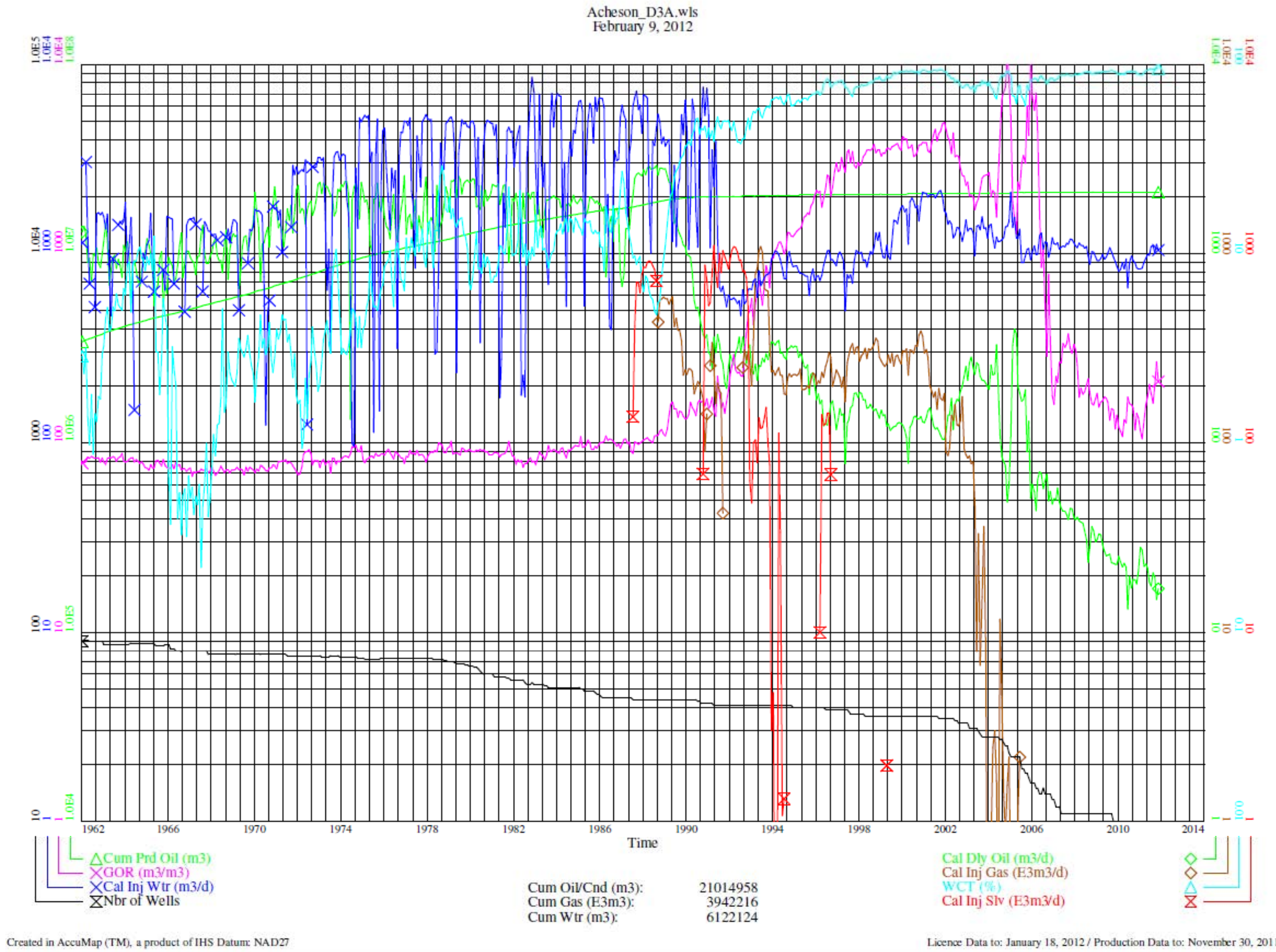


Sproule



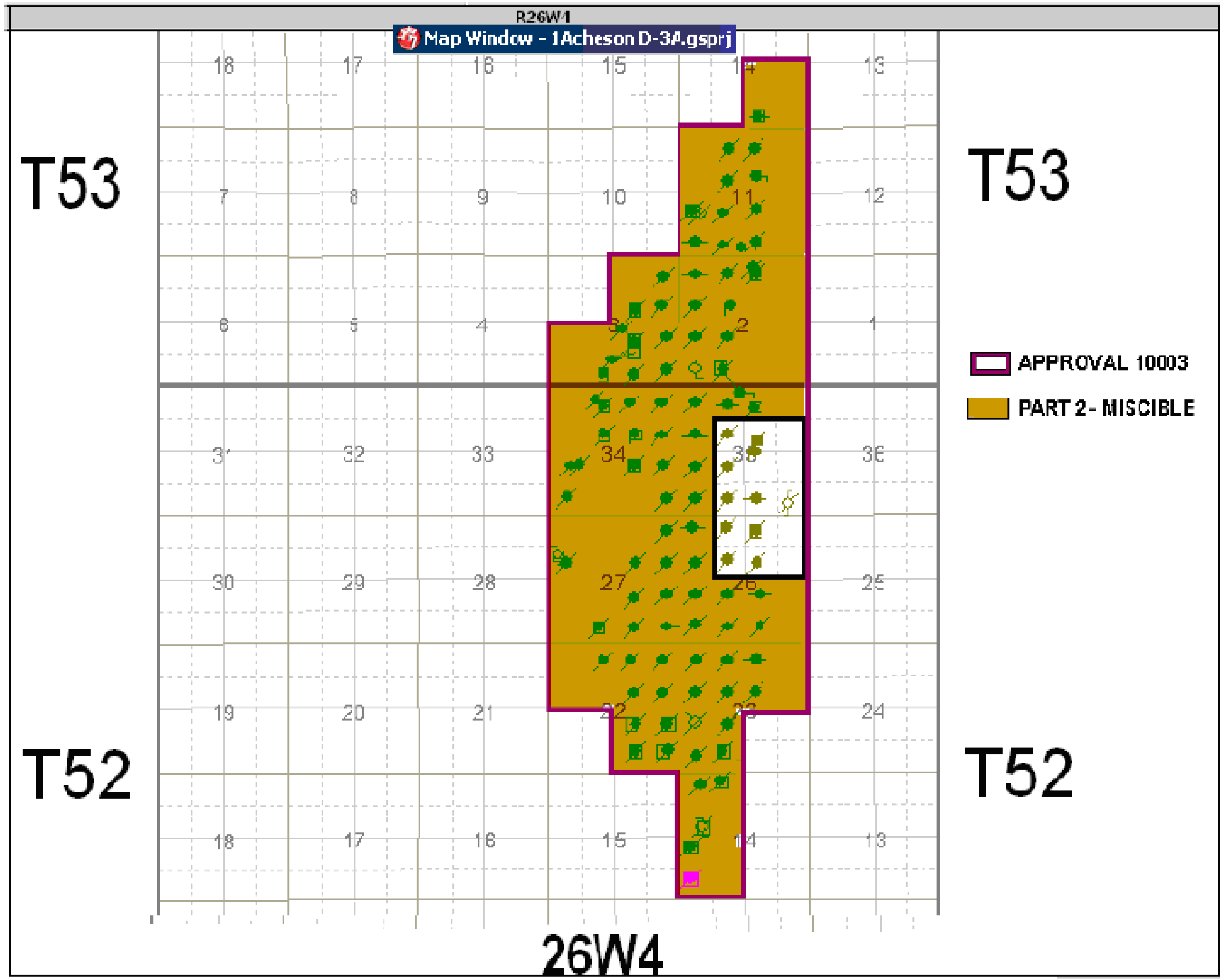

**Acheson D-3A - Well Locations**

Figure 3



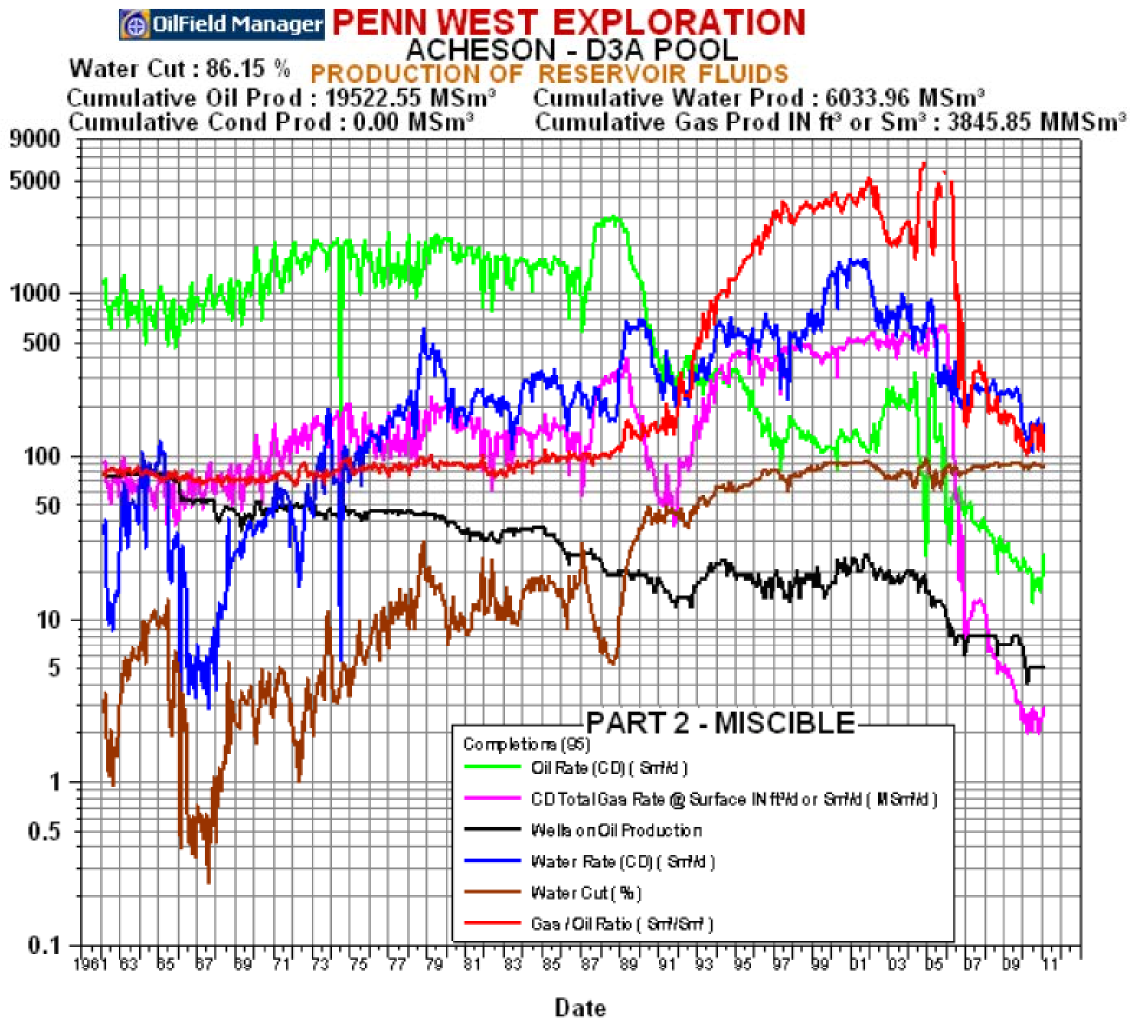

**Acheson D-3A - Production / Injection History**

Figure 4




**Acheson D-3A - Approval 10003 Area**

Figure 5

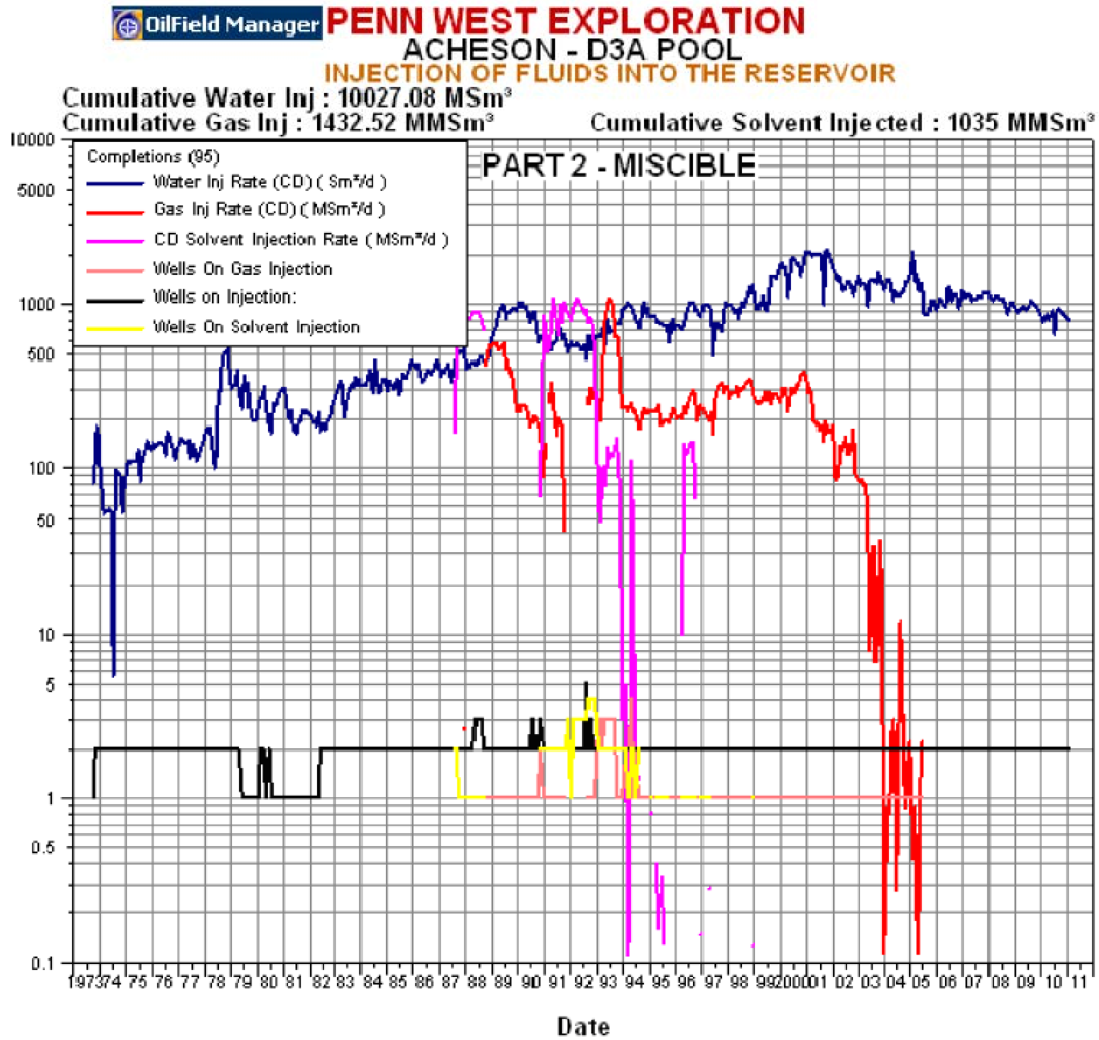



**Acheson D-3A – Area 2 Production History**

Figure 6

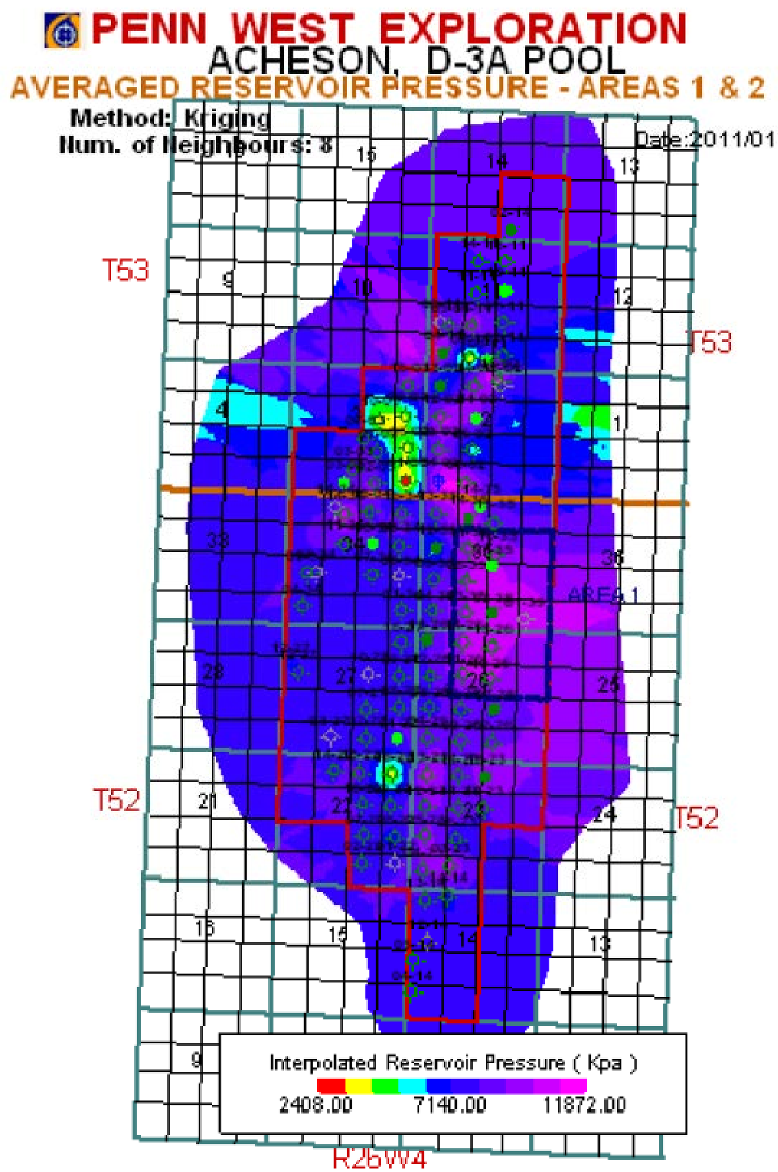


Sproule




**Acheson D-3A – Area 2 Injection History**

Figure 7




Acheson D-3A – Reservoir Pressure Map at January 2011

Figure 8

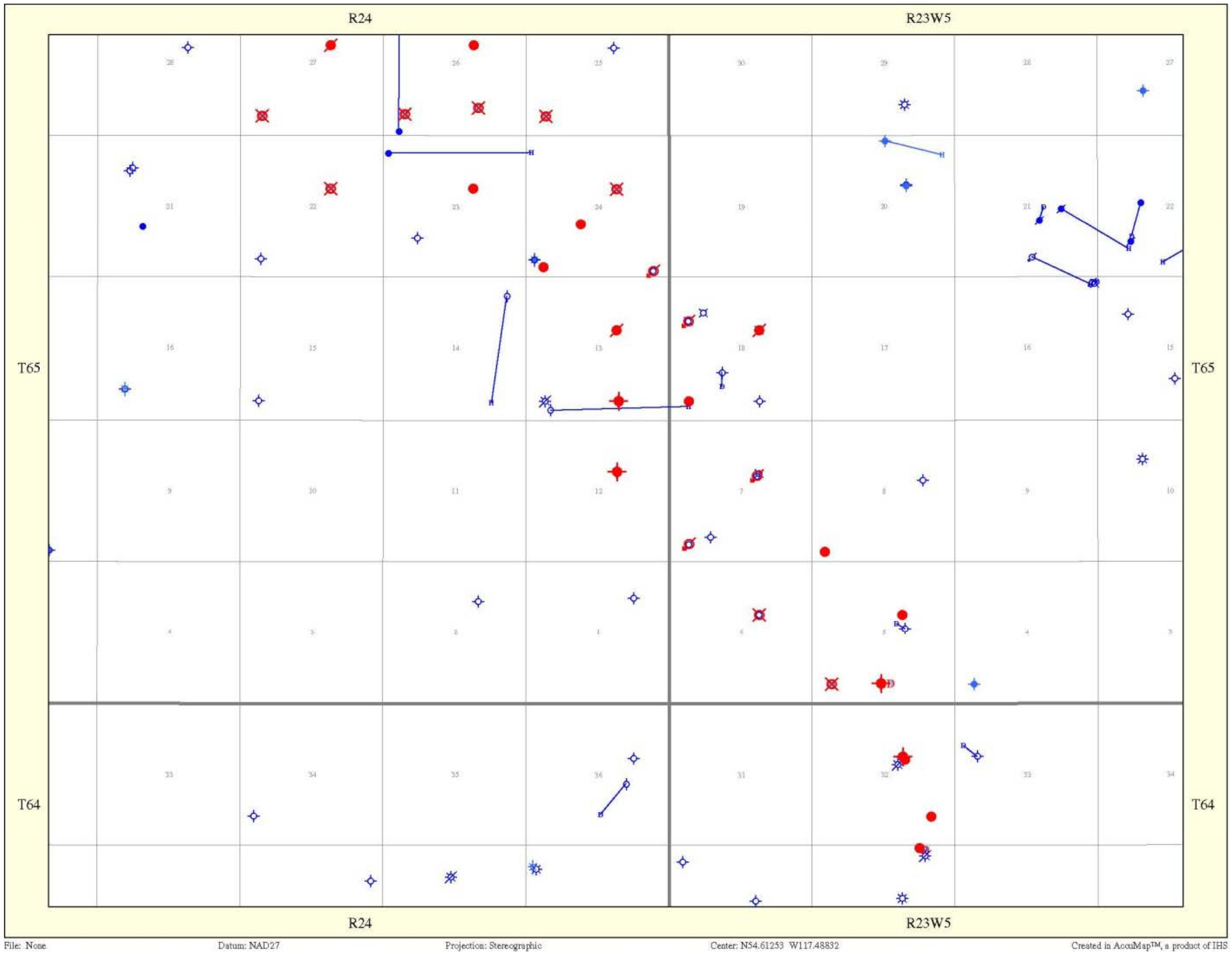
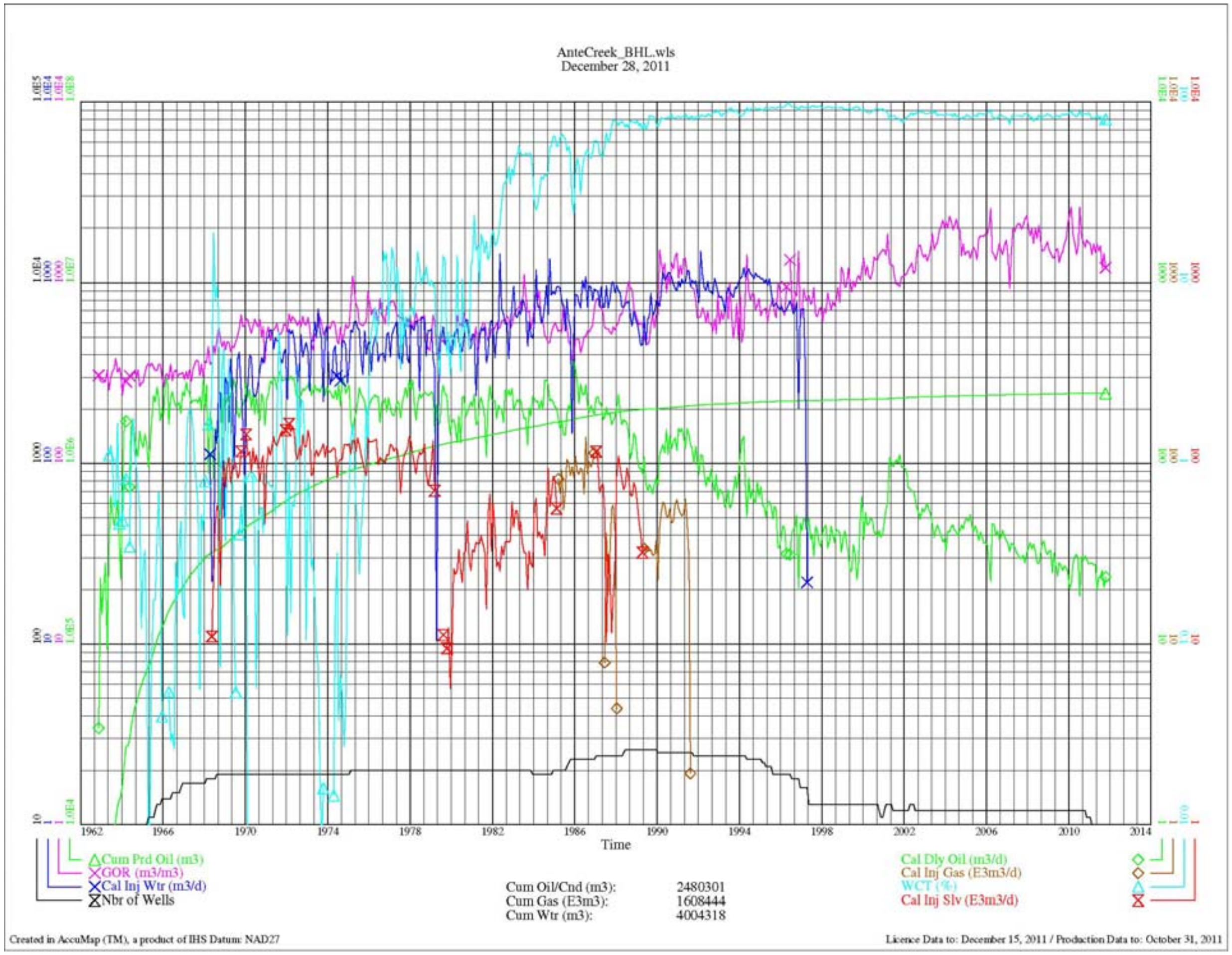



Figure 9

**Ante Creek Beaverhill Lake - Well Locations**

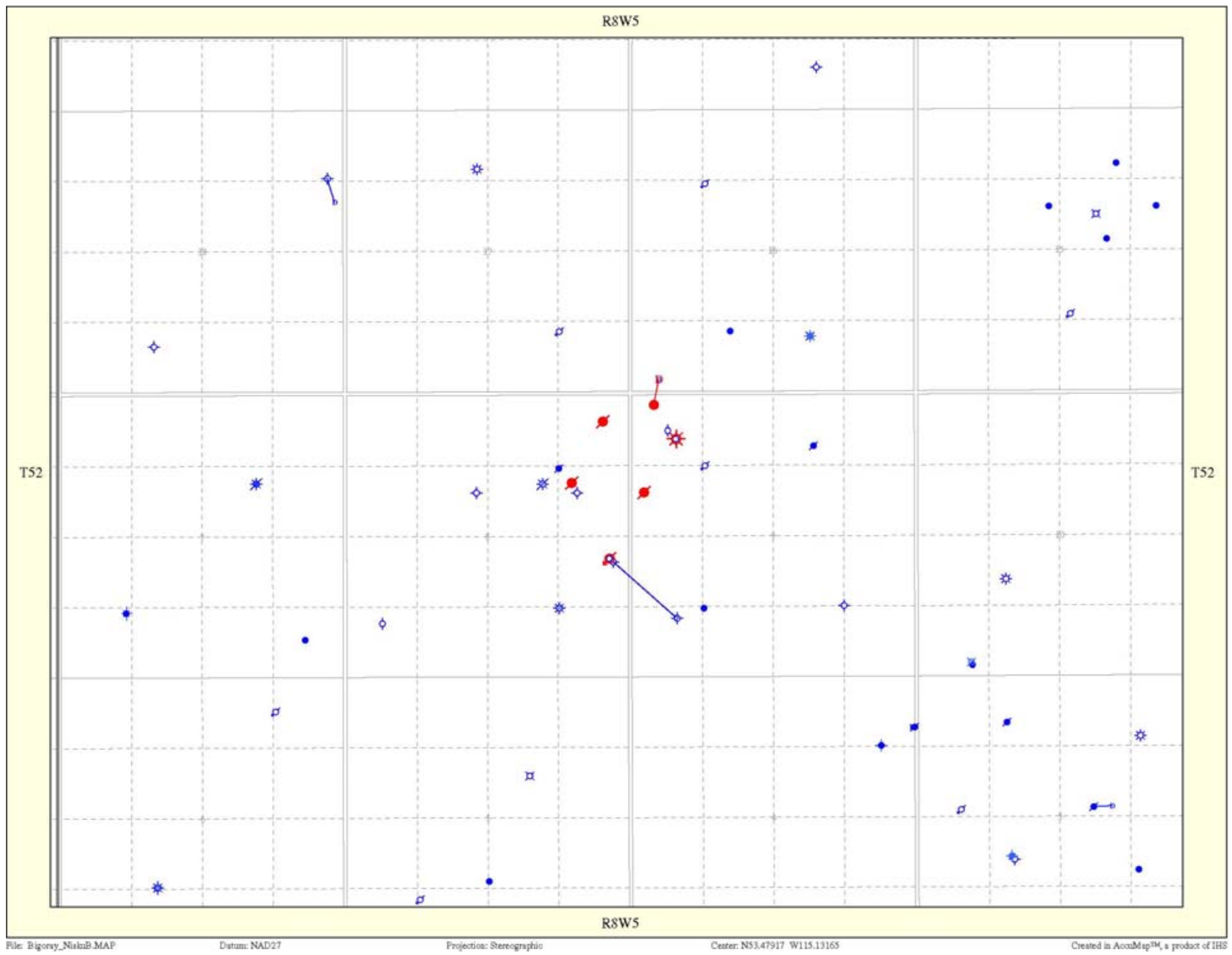



**Ante Creek Beaverhill Lake - Production / Injection History**

Figure 10

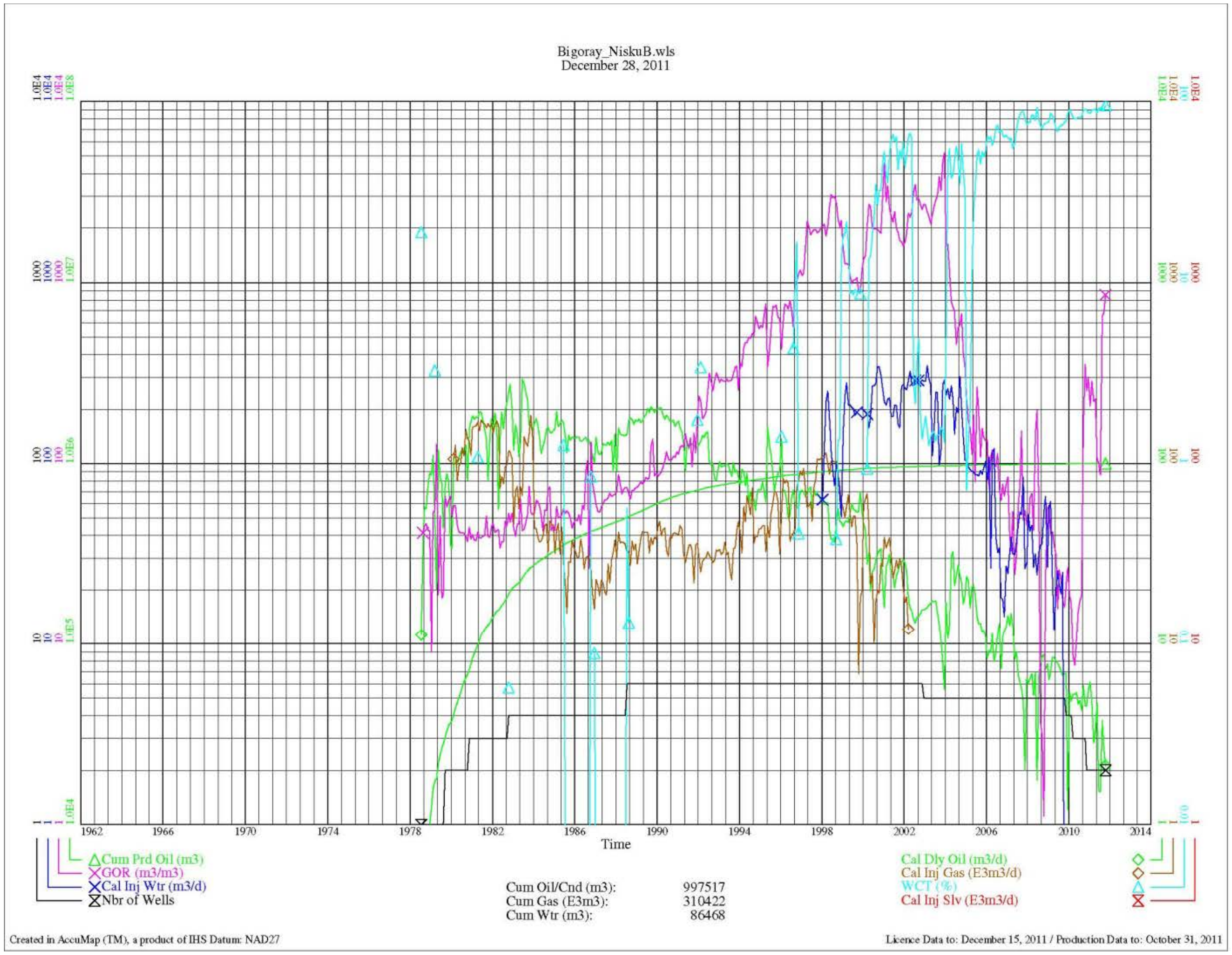


Sproule




**Bigoray Nisku B - Well Locations**

Figure 11

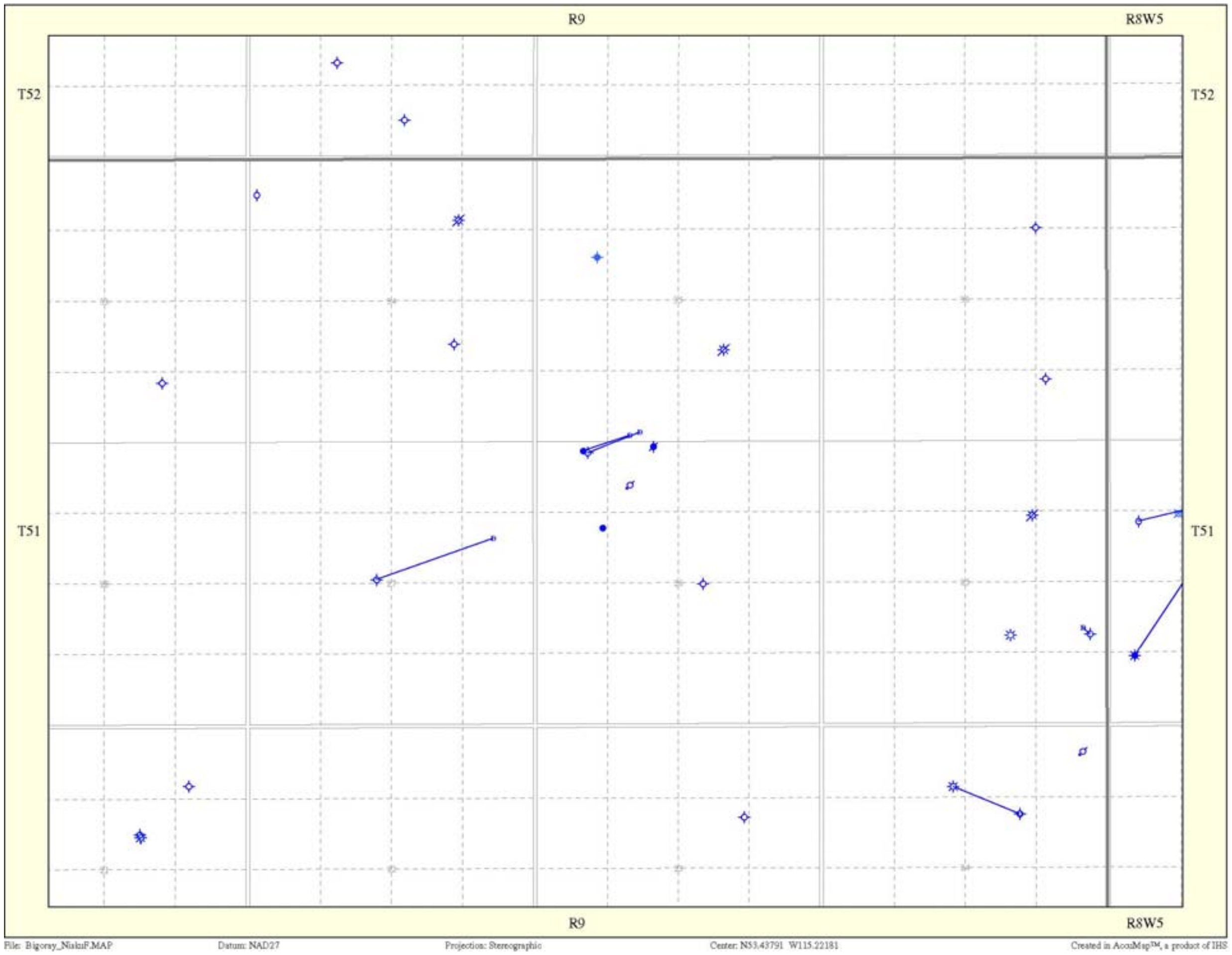



**Bigoray Nisku B - Production / Injection History**

Figure 12

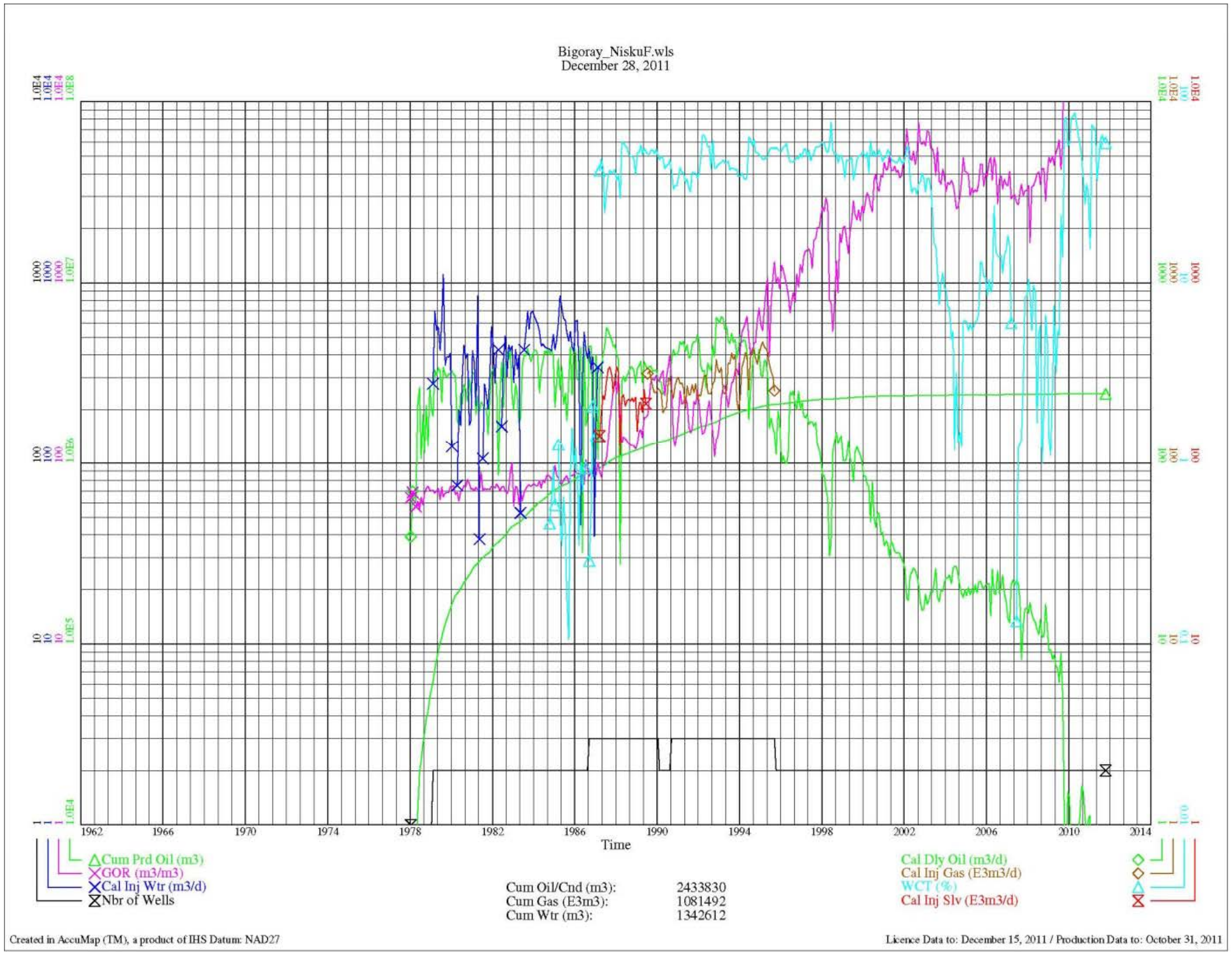


Sproule



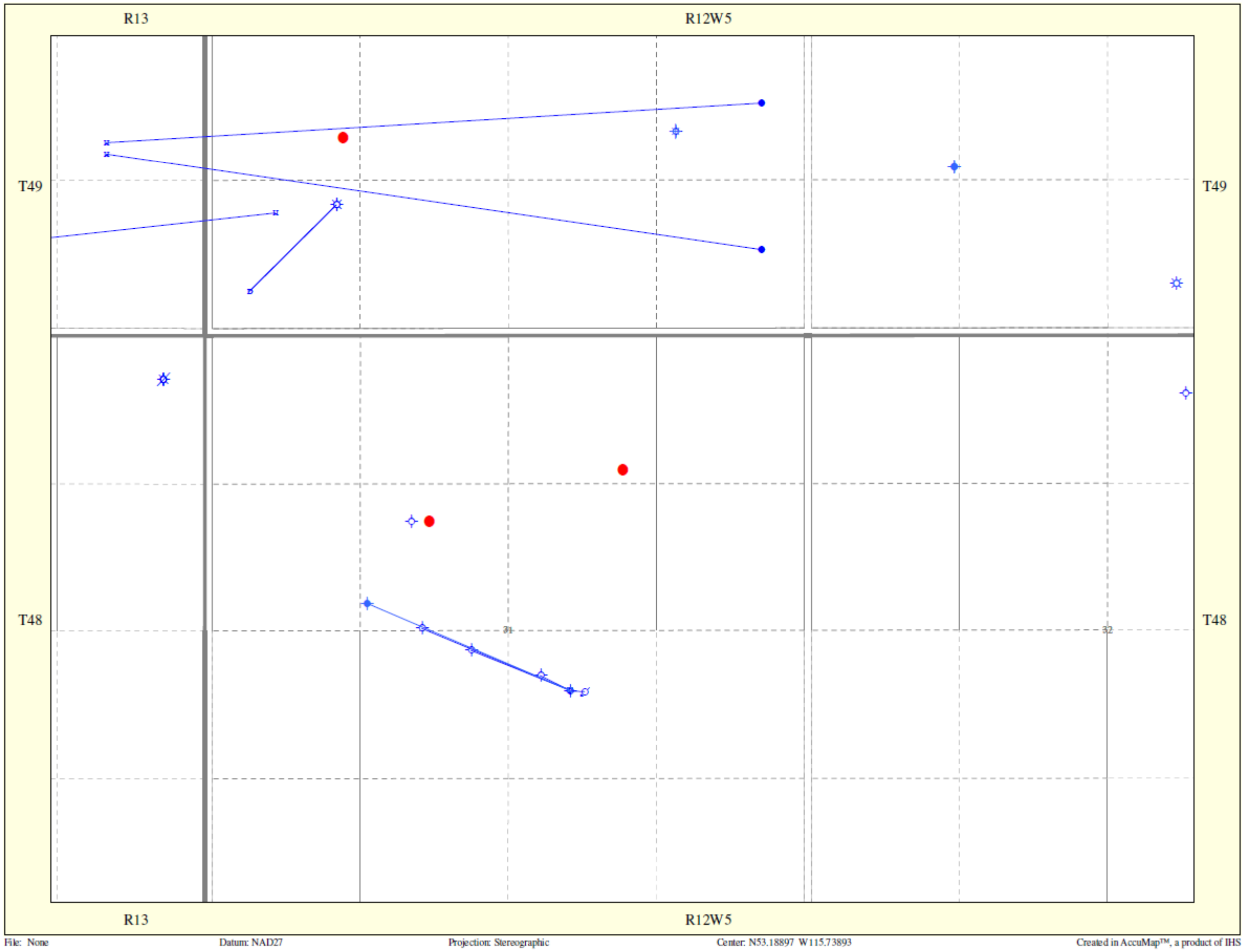

**Bigoray Nisku F - Well Locations**

Figure 13




**Bigoray Nisku F - Production / Injection History**

Figure 14

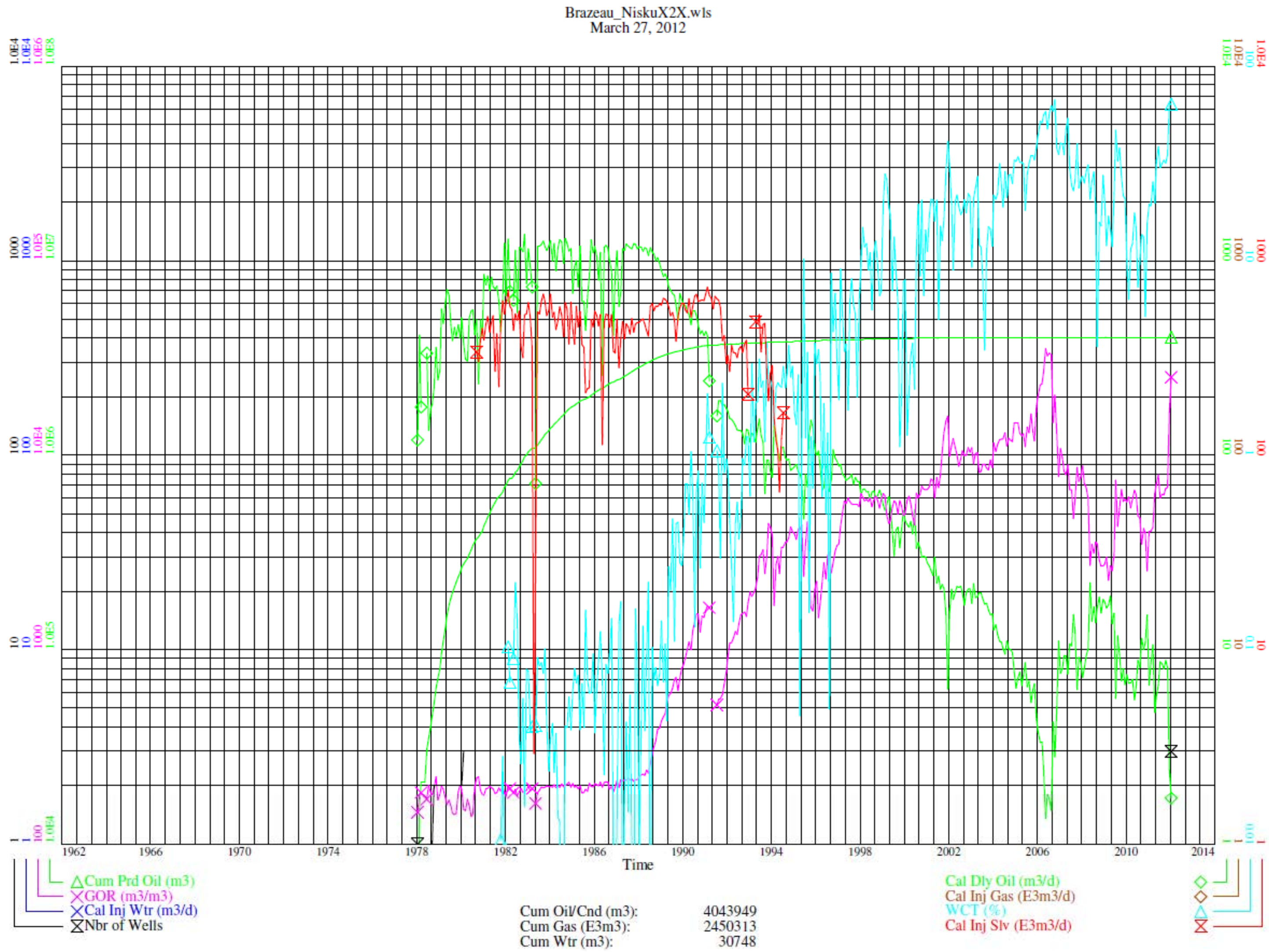



**Brazeau River Nisku A (aka Nisku X2X) – Well Locations**

Figure 15

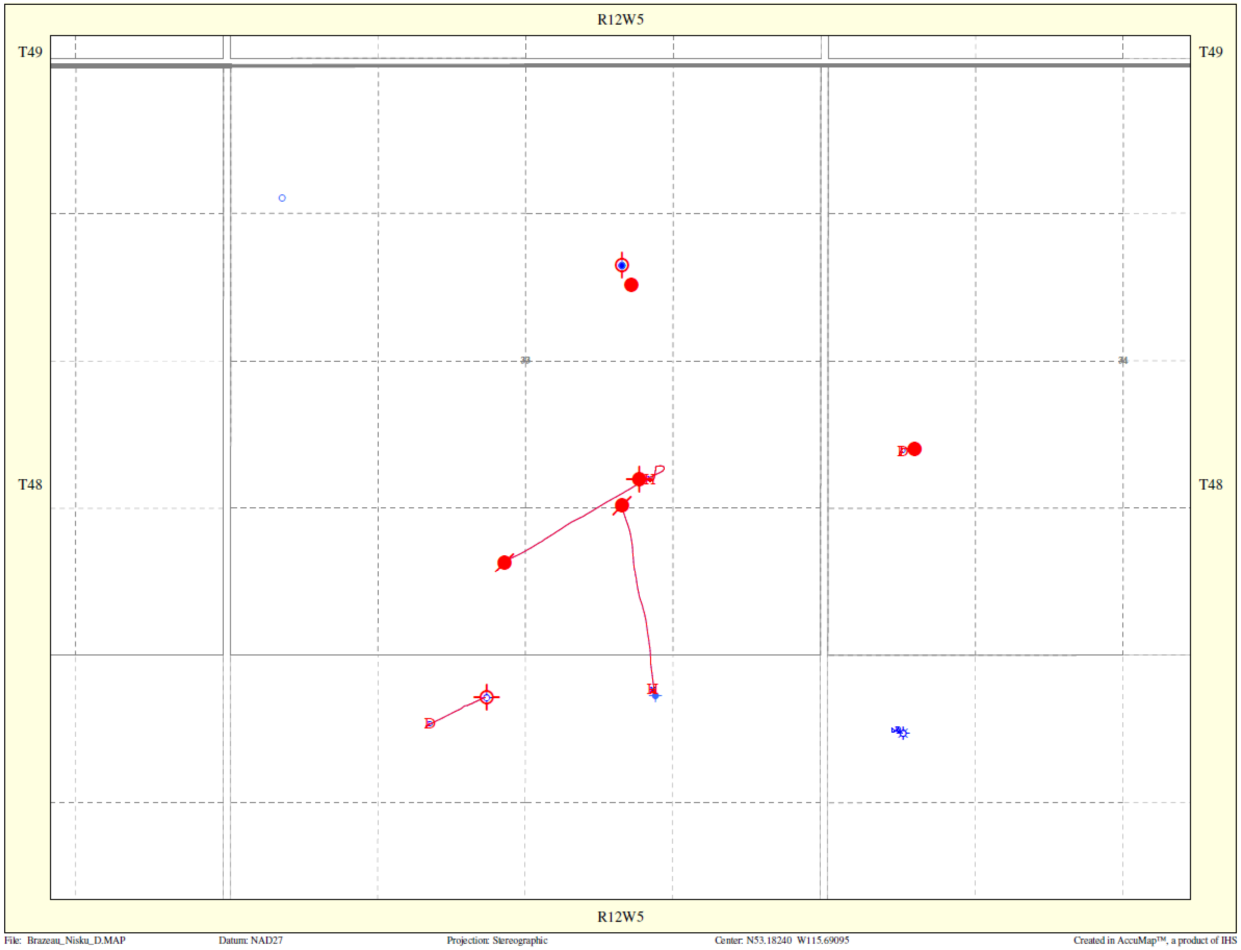


Sproule




**Brazeau River Nisku A (aka Nisku X2X) – Production / Injection History**

Figure 16




**Brazeau River Nisku D - Well Locations**

Figure 17

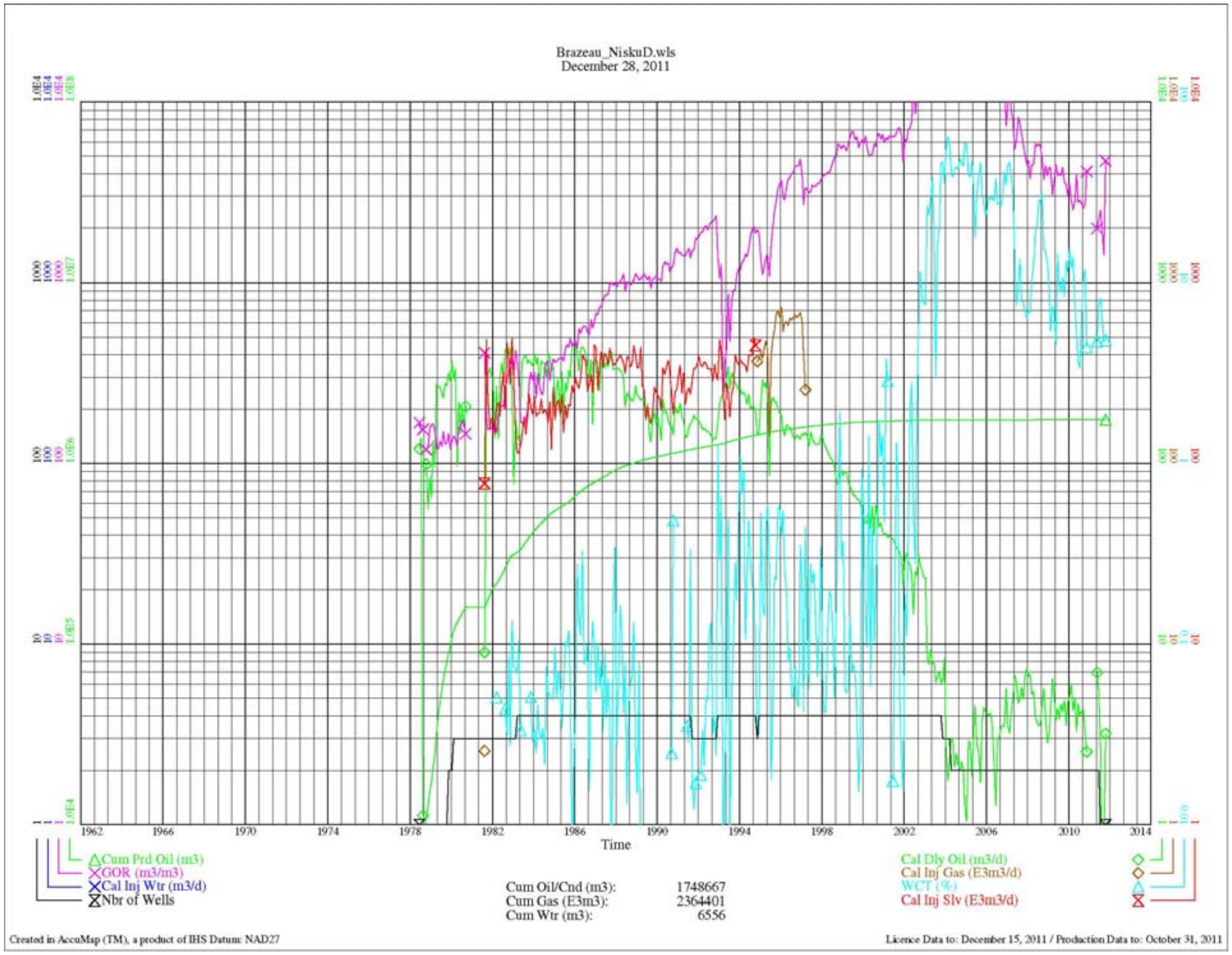
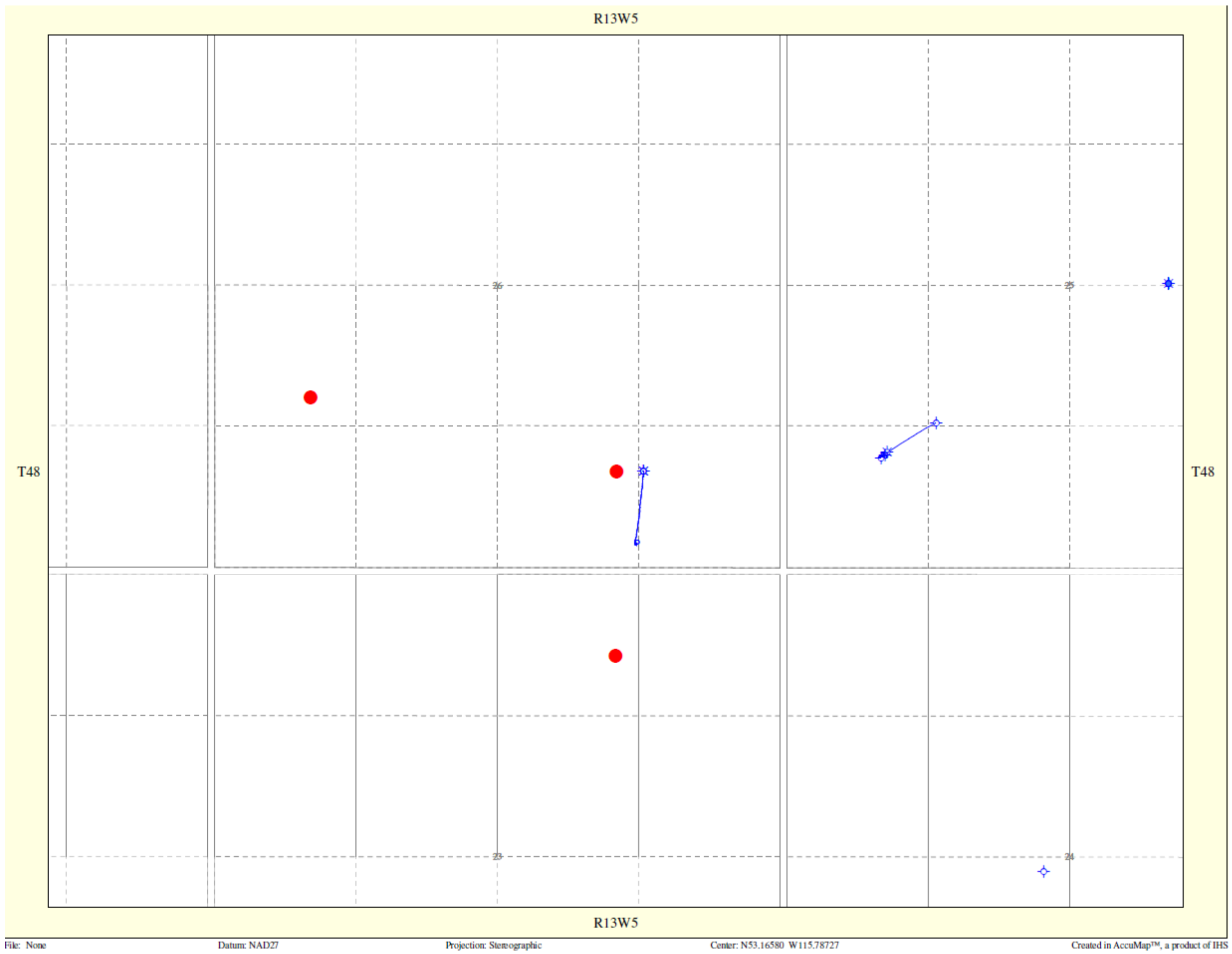



Figure 18

**Brazeau River Nisku D - Production / Injection History**




**Brazeau River Nisku E - Well Locations**

Figure 19

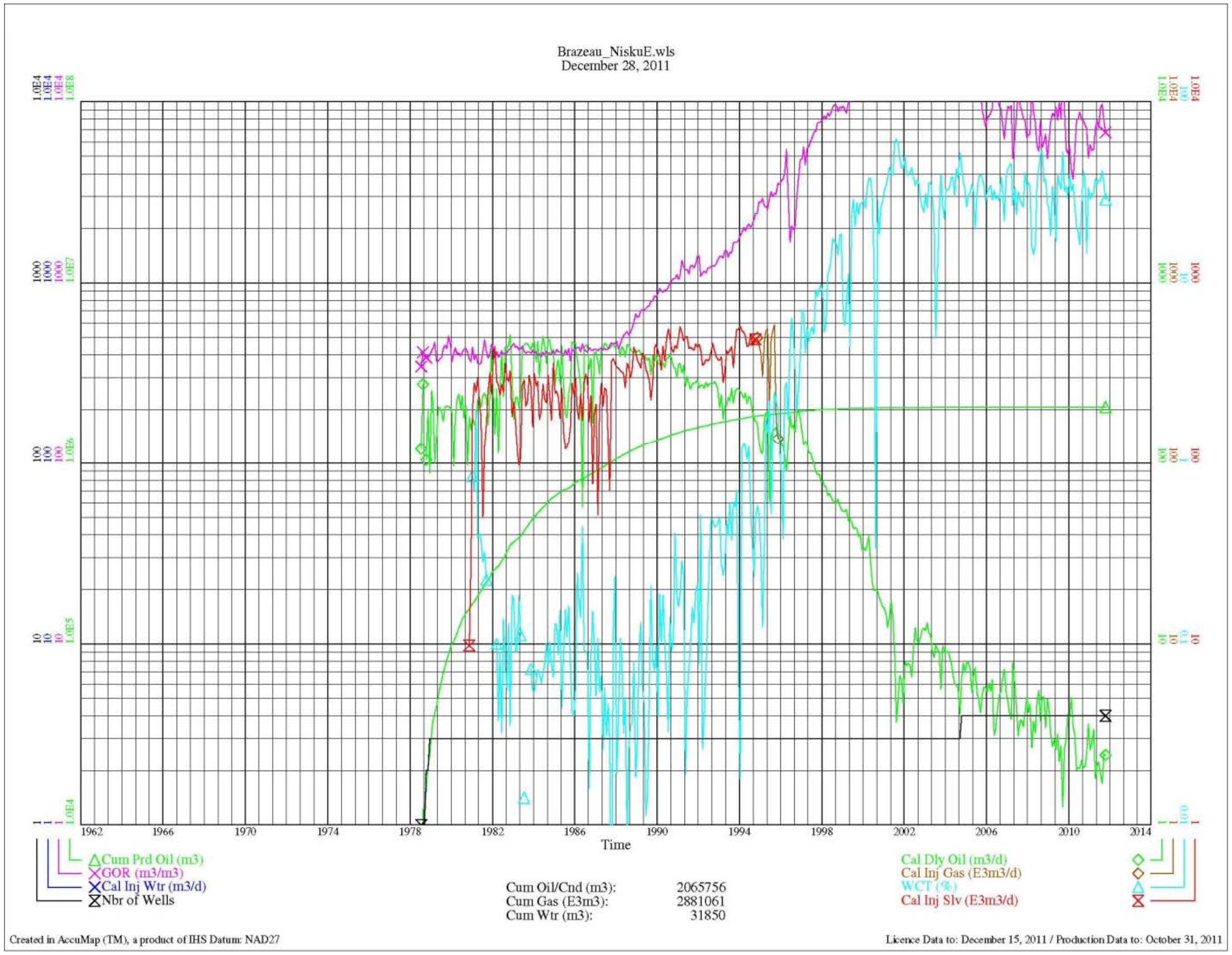
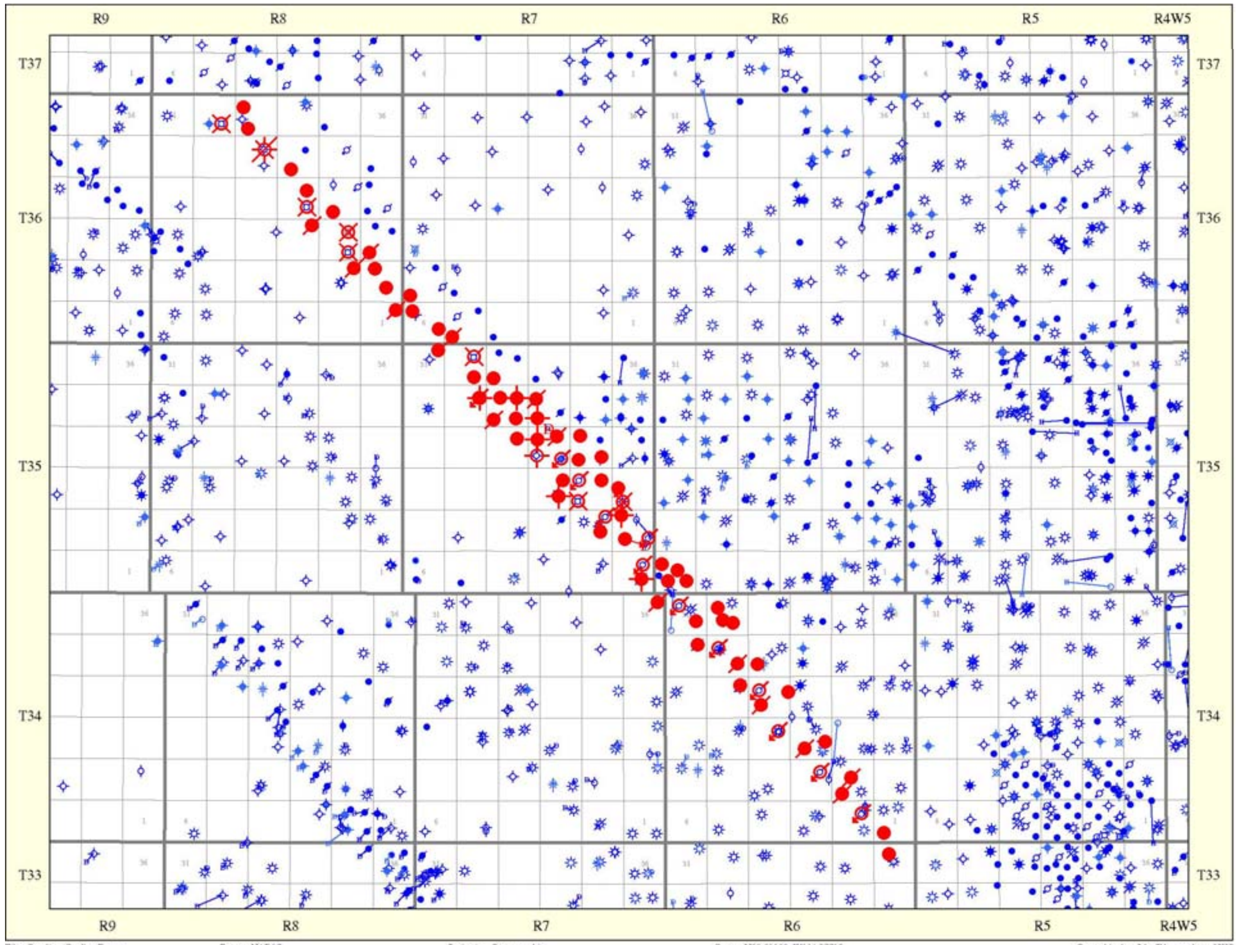


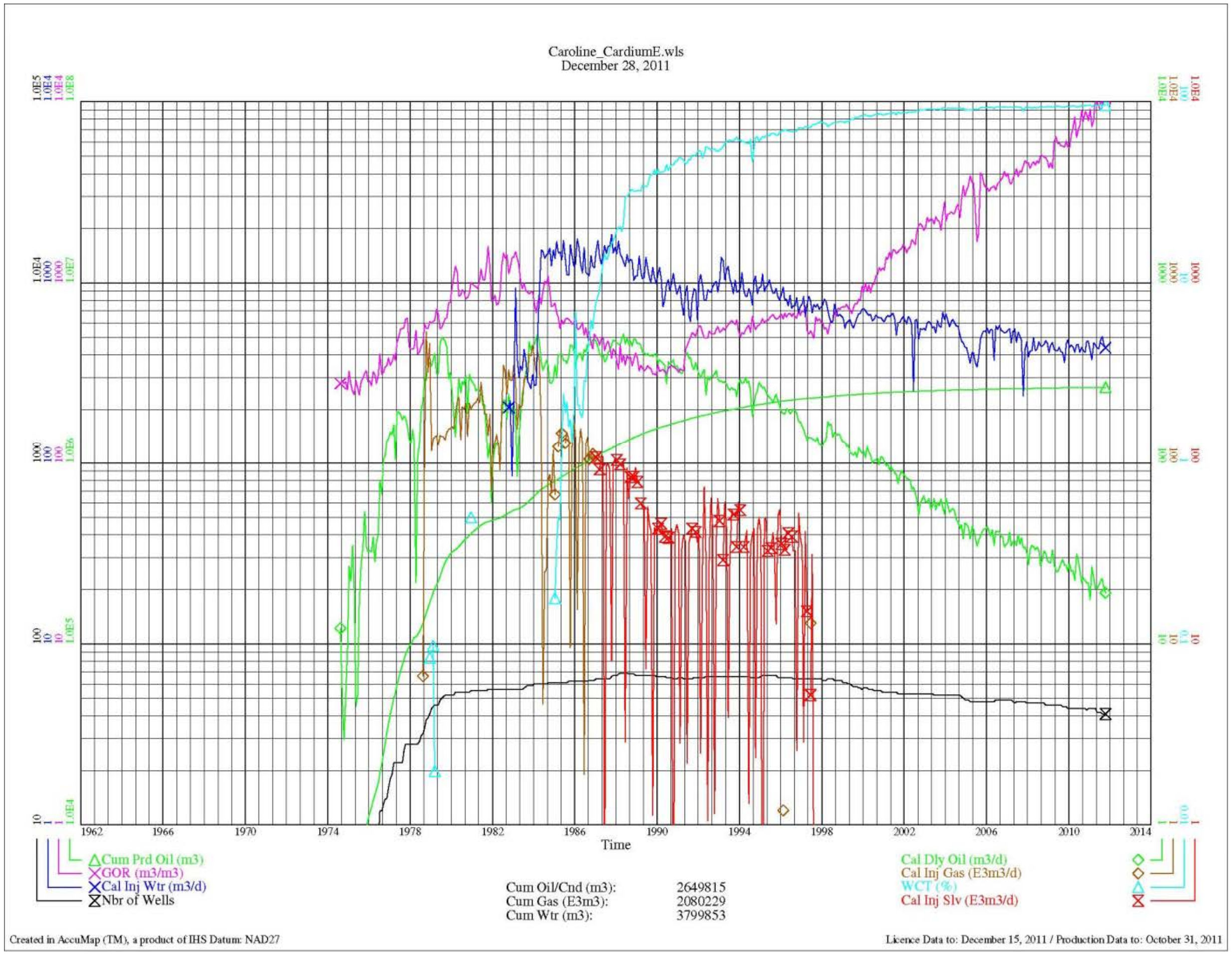

Figure 20

**Brazeau River Nisku E - Production / Injection History**




**Caroline Cardium E - Well Locations**

Figure 21




**Caroline Cardium E - Production / Injection History**

Figure 22

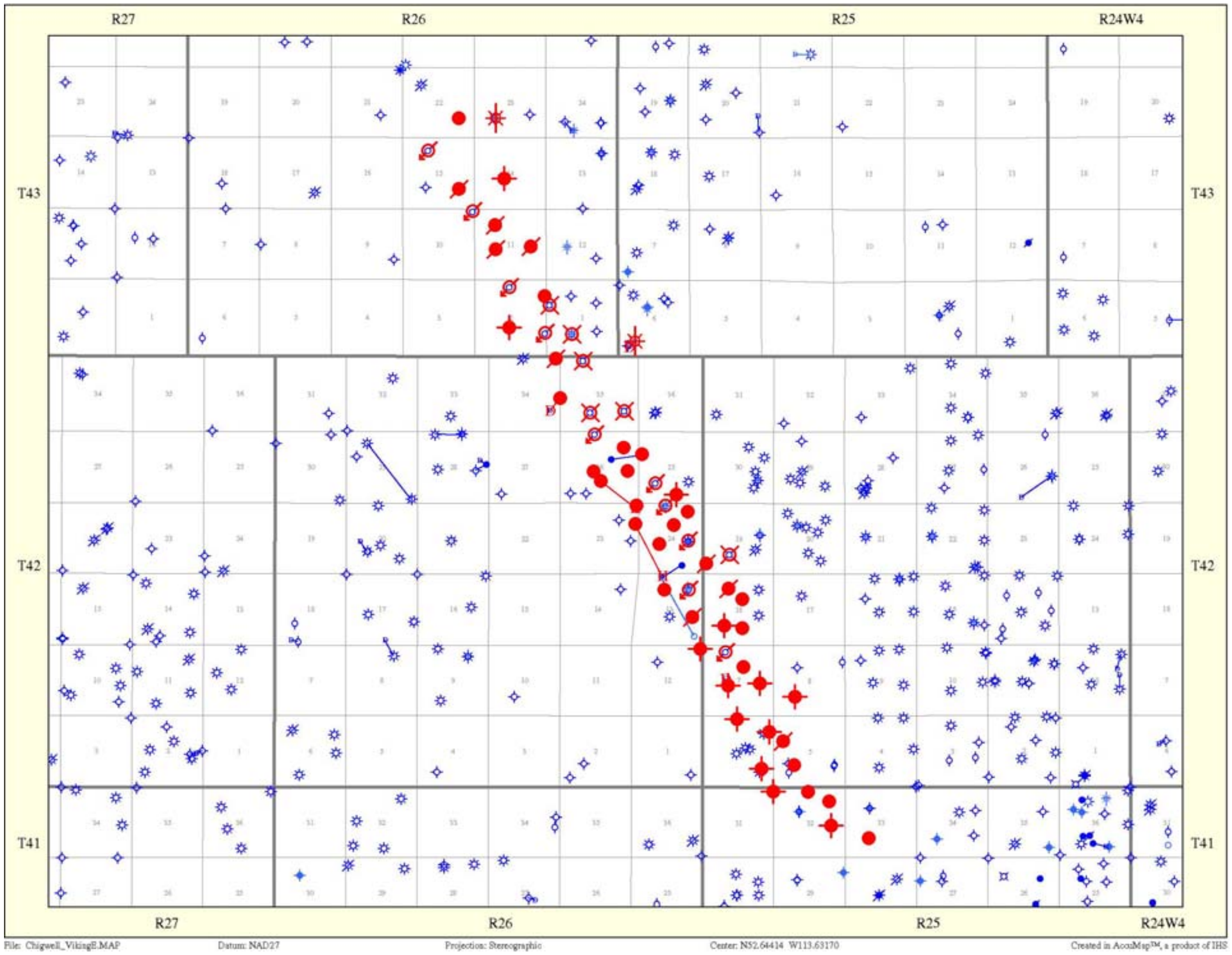



Figure 23

**Chigwell Viking E - Well Locations**

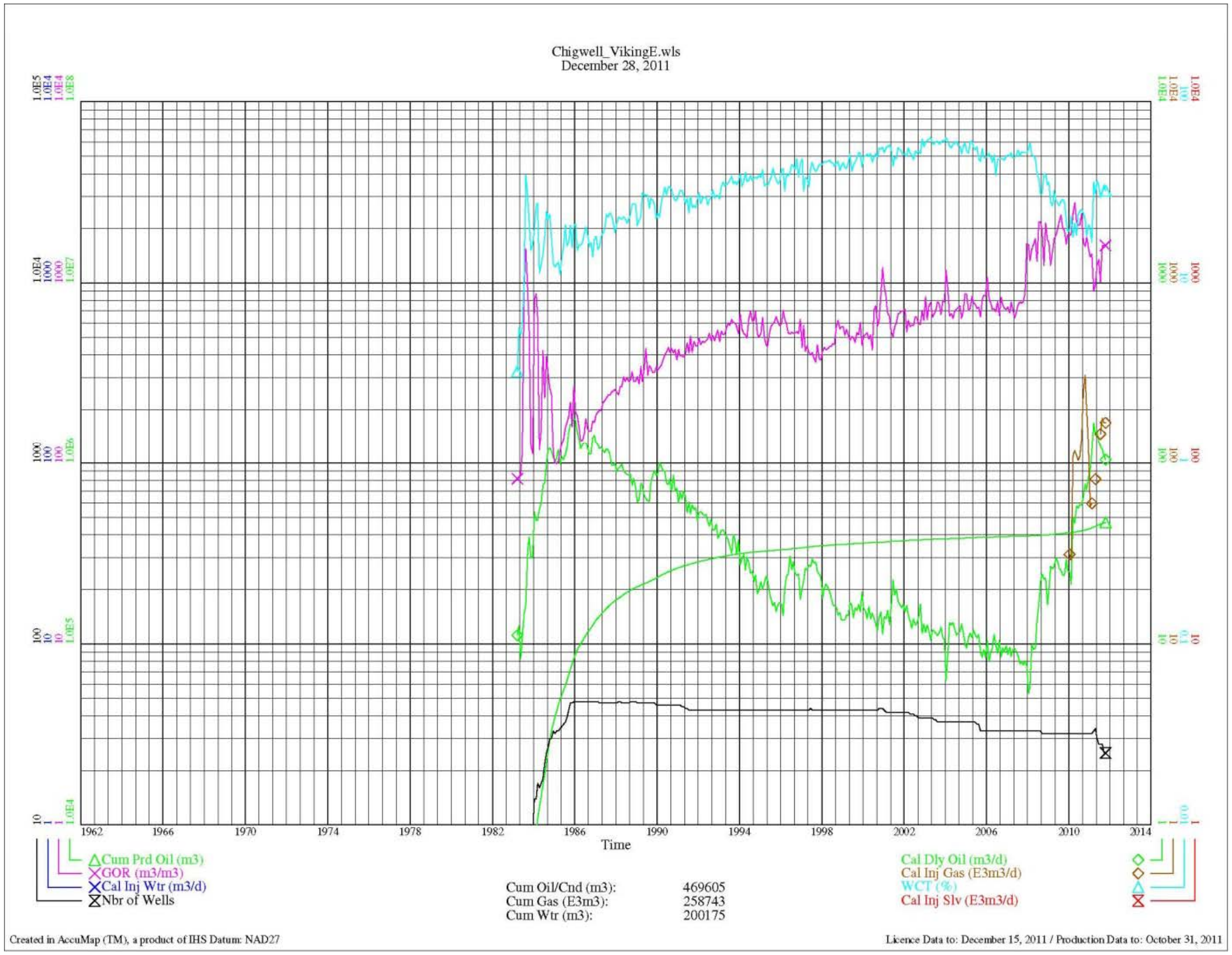
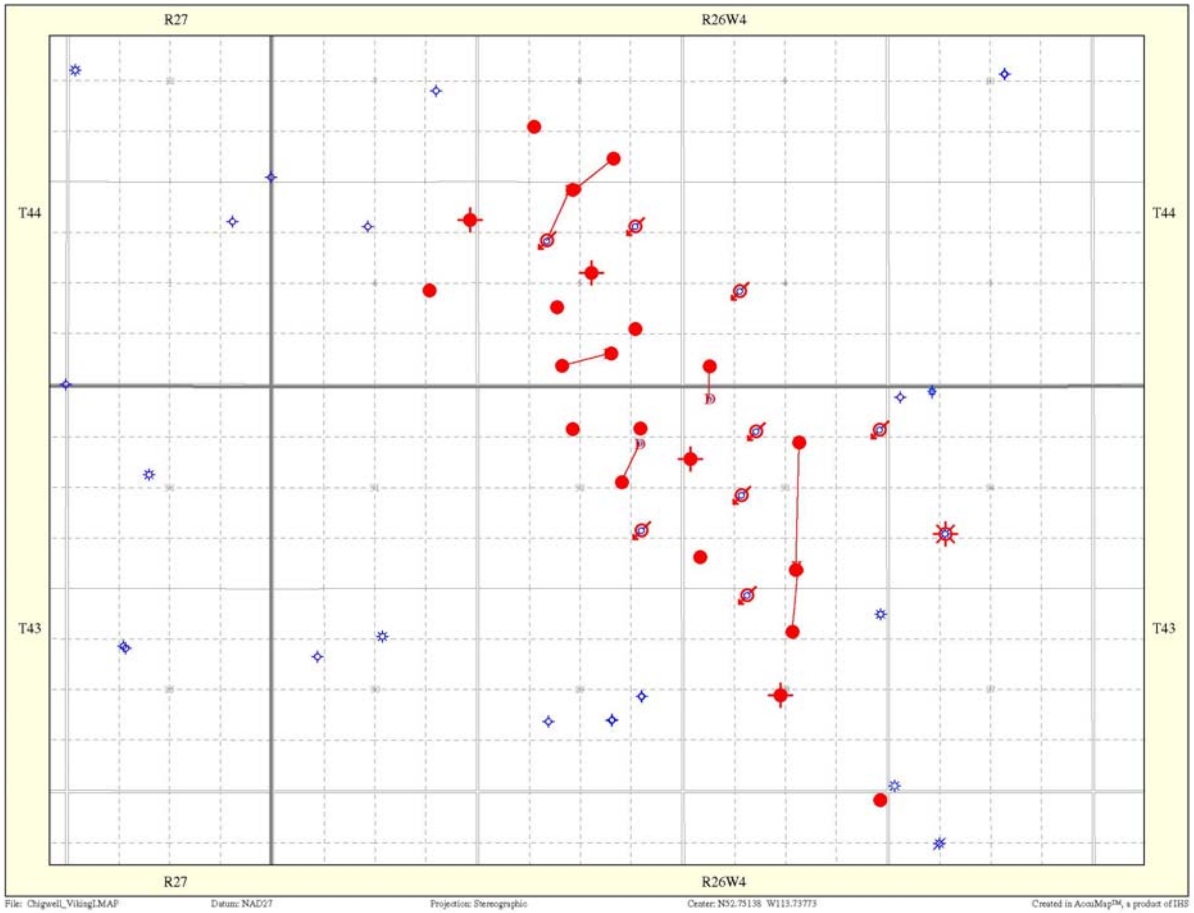



Figure 24

**Chigwell Viking E - Production / Injection History**



Sproule

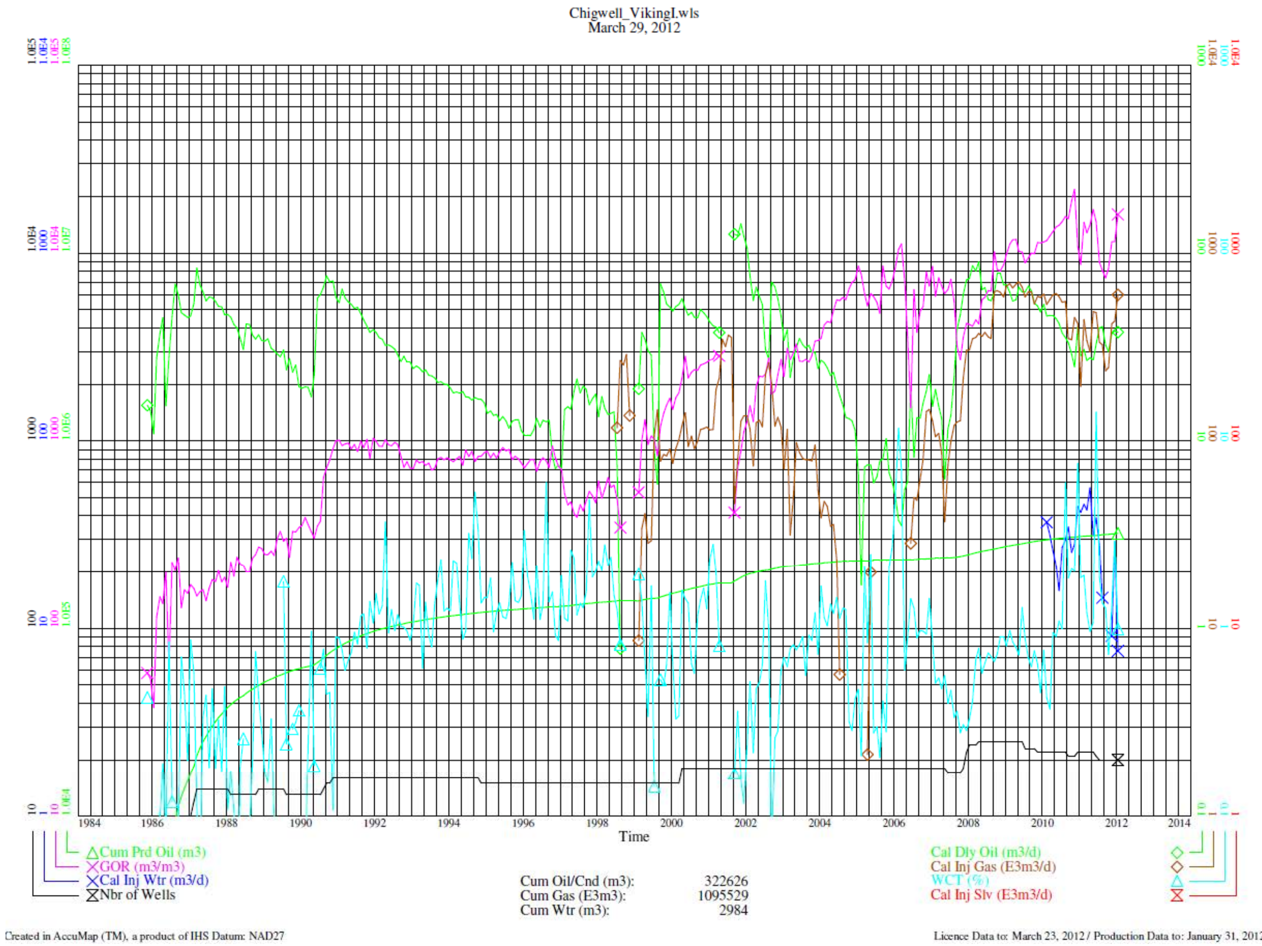



**Chigwell Viking I - Well Locations**

Figure 25



Sproule

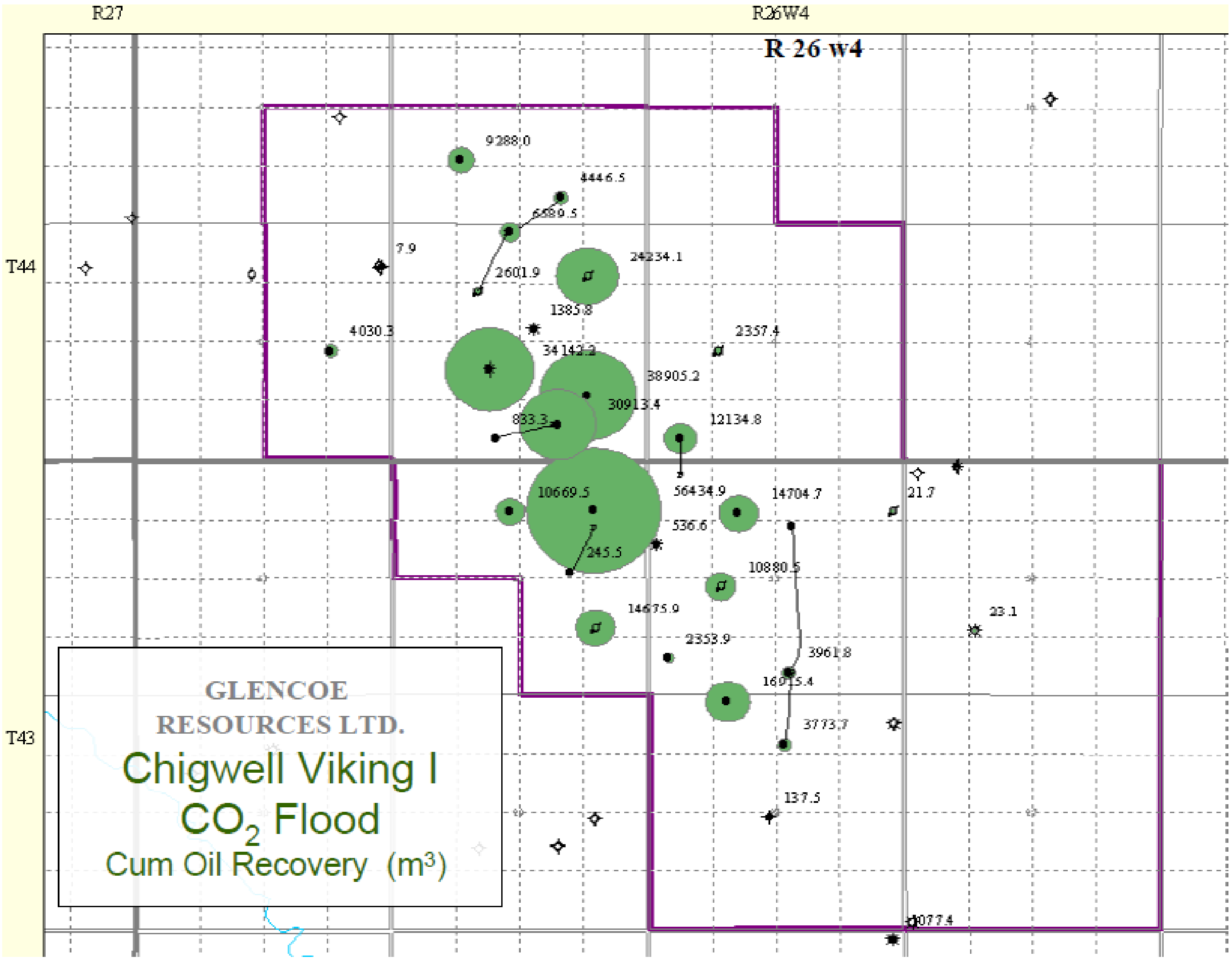



**Chigwell Viking I - Production / Injection History**

Figure 26



Sproule




**Chigwell Viking I $CO_2$ Flood Cumulative Oil Recovery ($m^3$)**

Figure 27

GLENCOE
RESOURCES LTD.

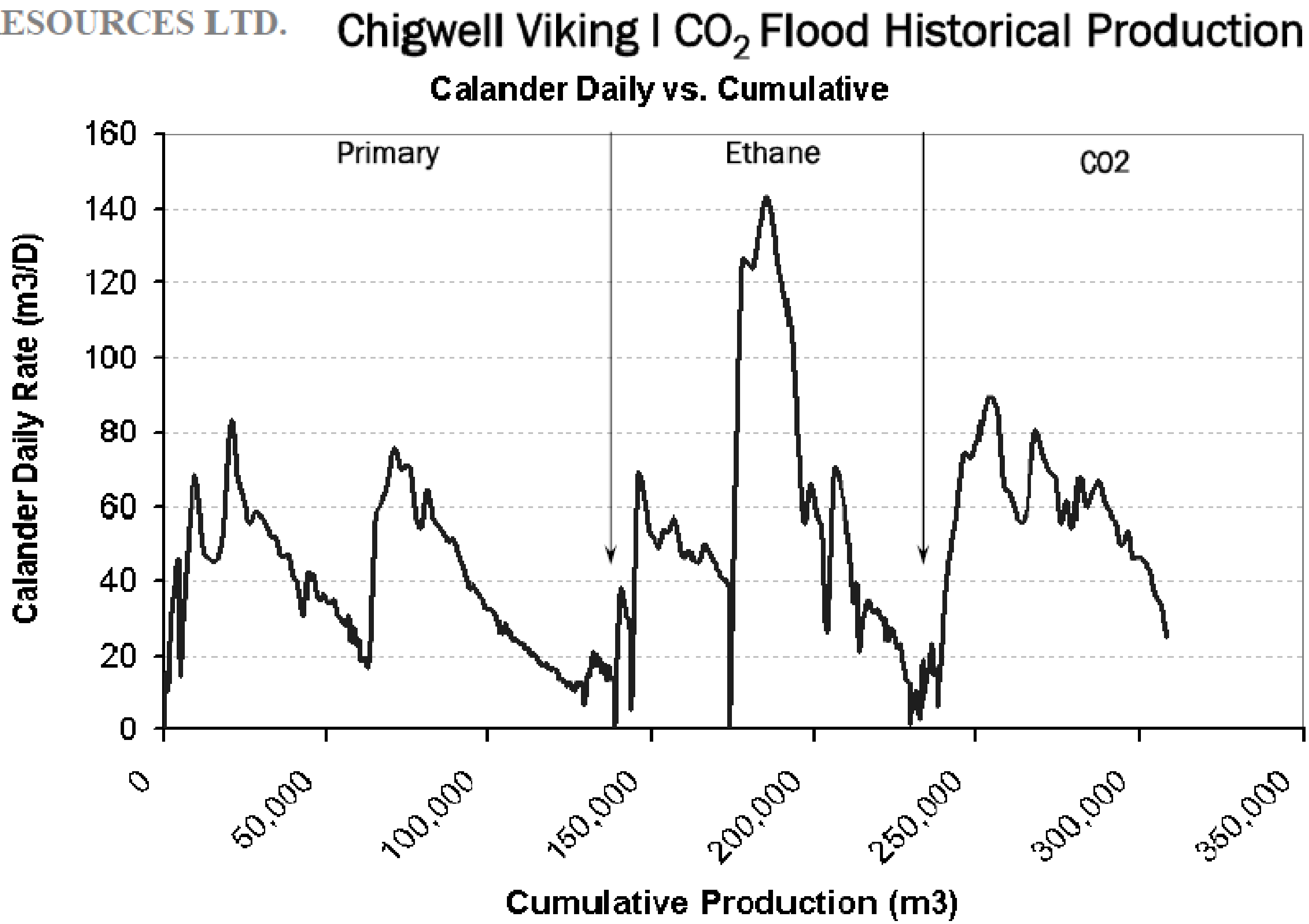



Figure 28



Sproule

GLENCOE
RESOURCES LTD.

# Chigwell Viking I ER Scheme Historical Production

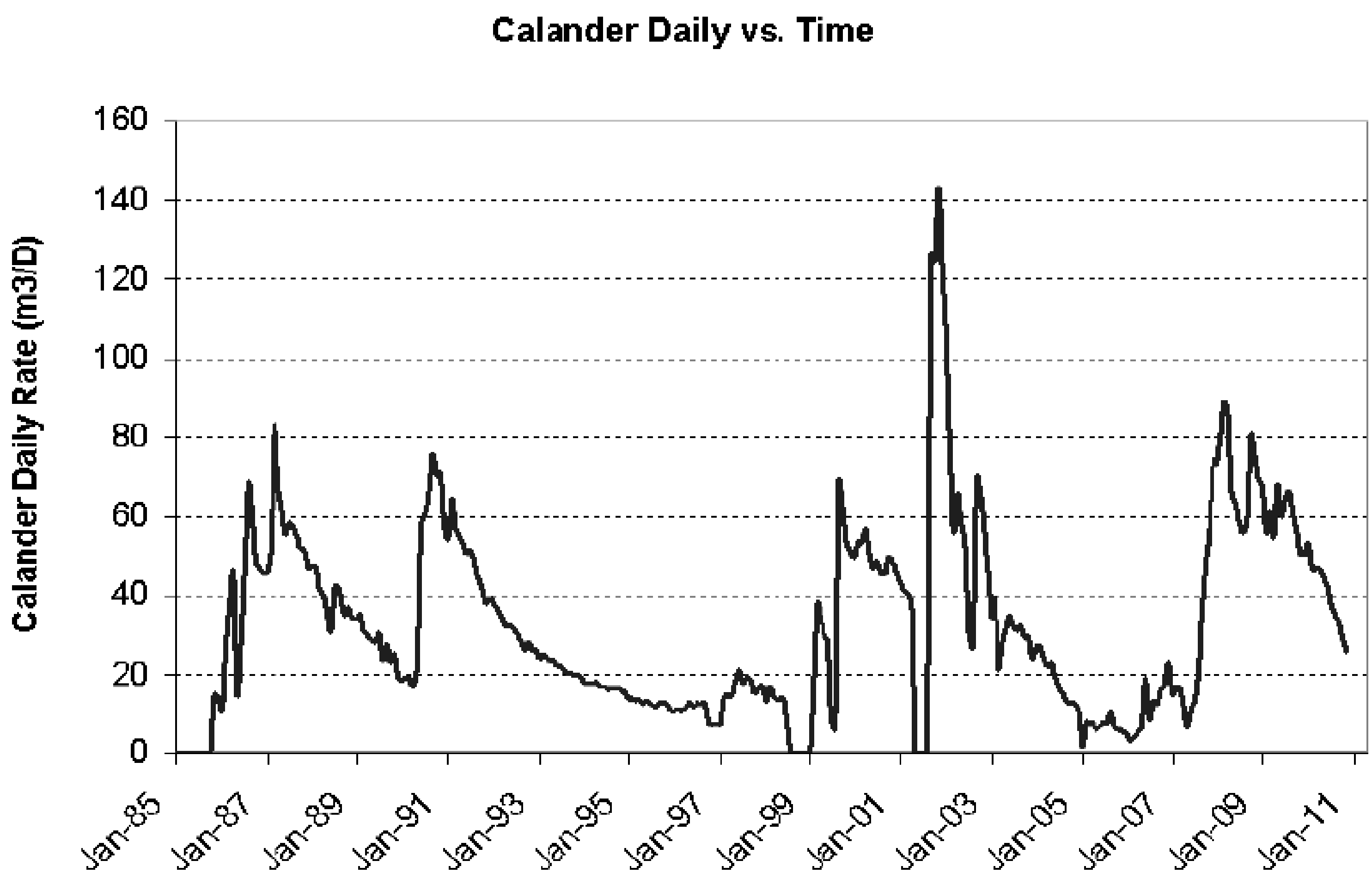



Figure 29

GLENCOE RESOURCES LTD.

## Chigwell Viking I
## Ethane and $CO_2$ Flood Pressure History

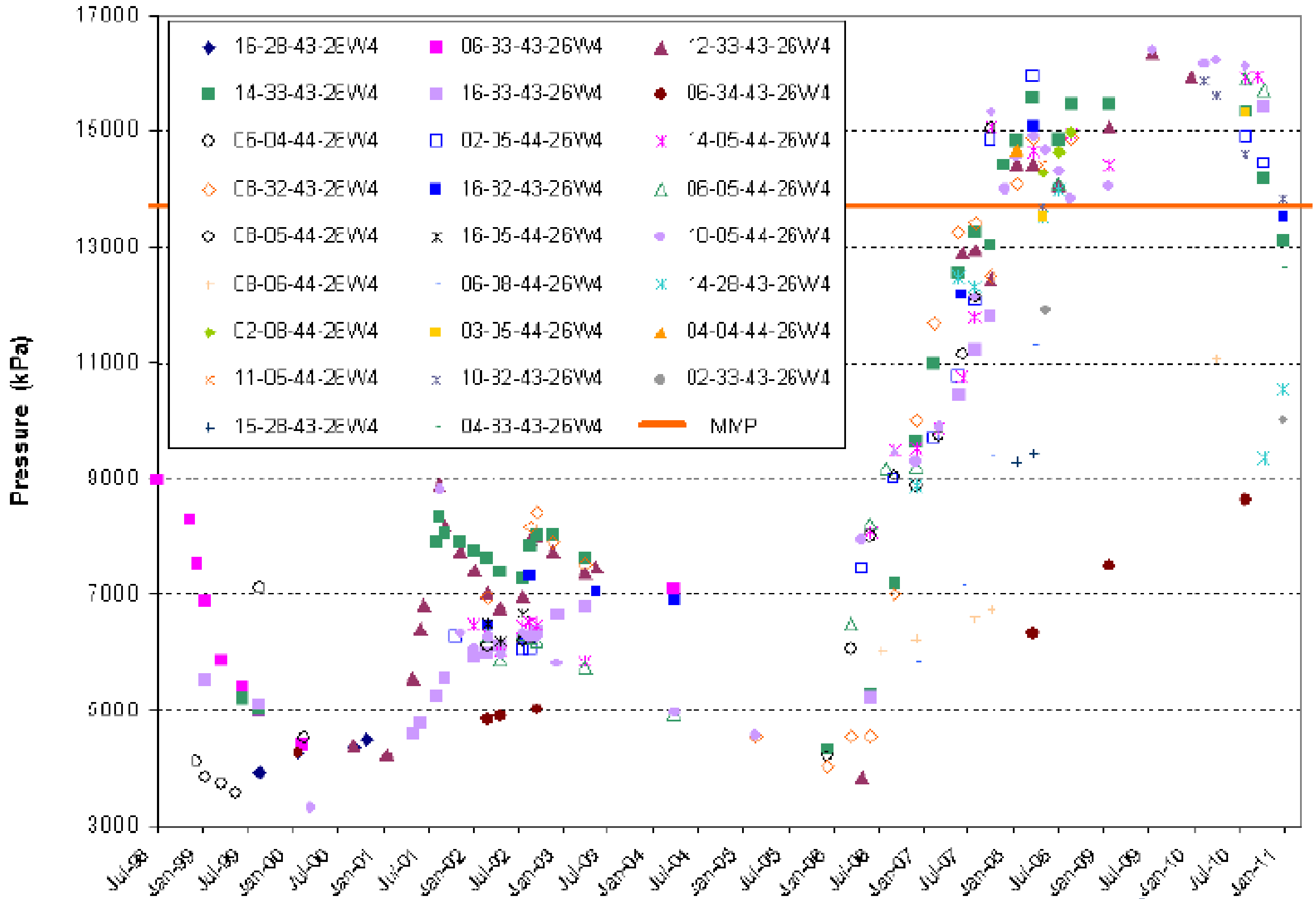



Figure 30



Sproule

GLENCOE
RESOURCES LTD.

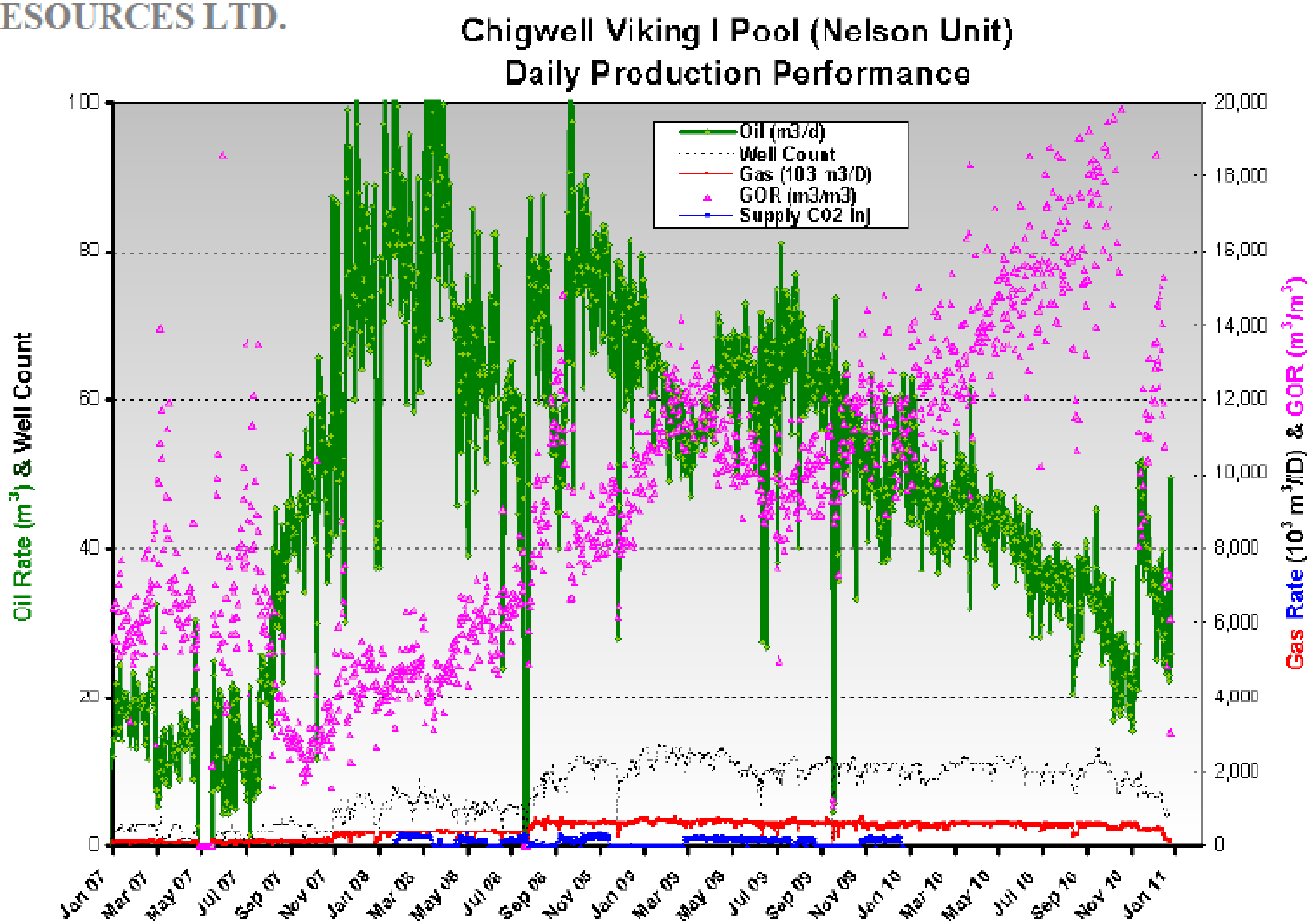



Figure 31



Sproule

GLENCOE
RESOURCES LTD.

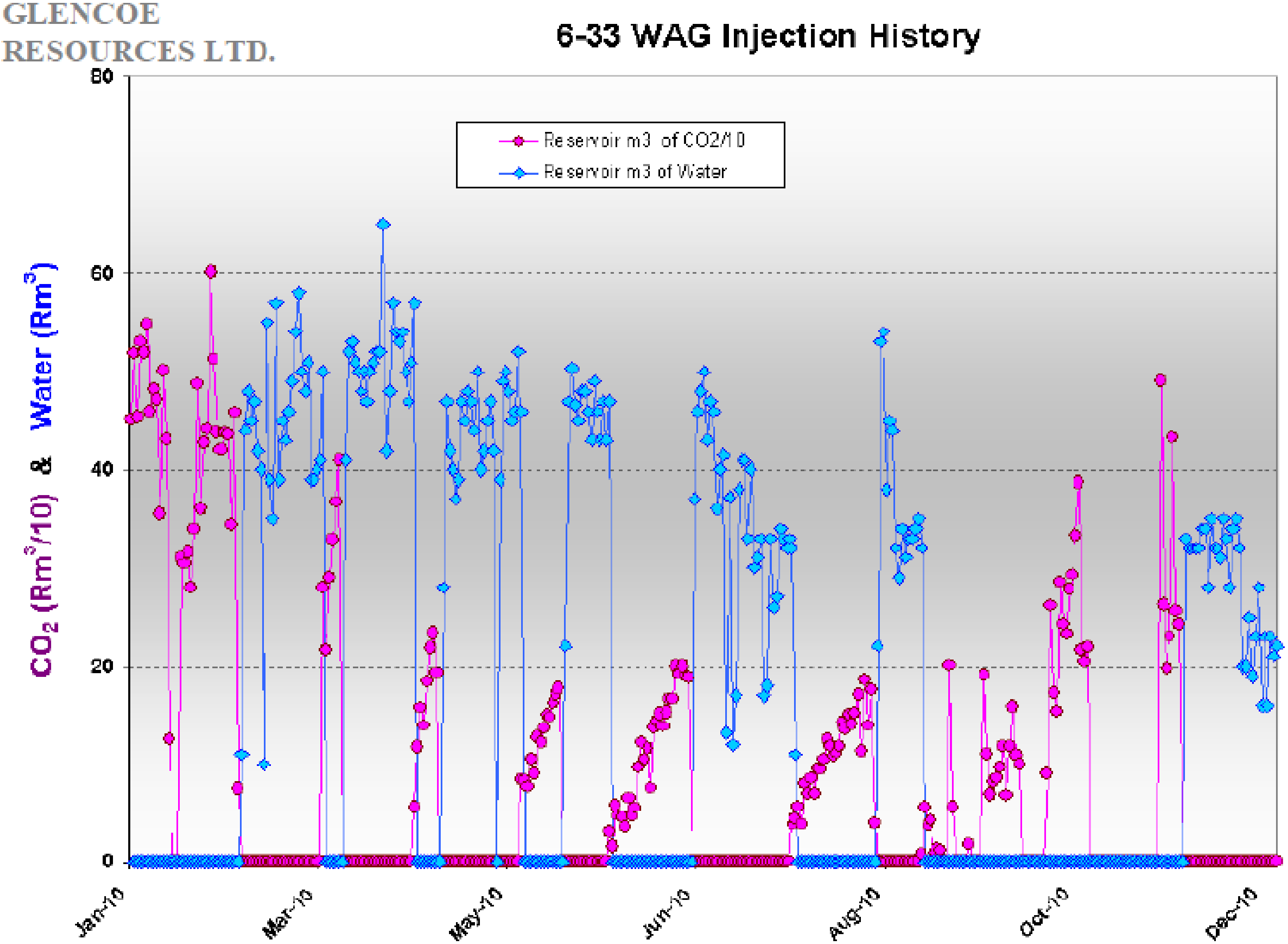



Figure 32

18158

Sproule

GLENCOE RESOURCES LTD.

## Chigwell Viking I Pool Net $CO_2$ Volumes Injected

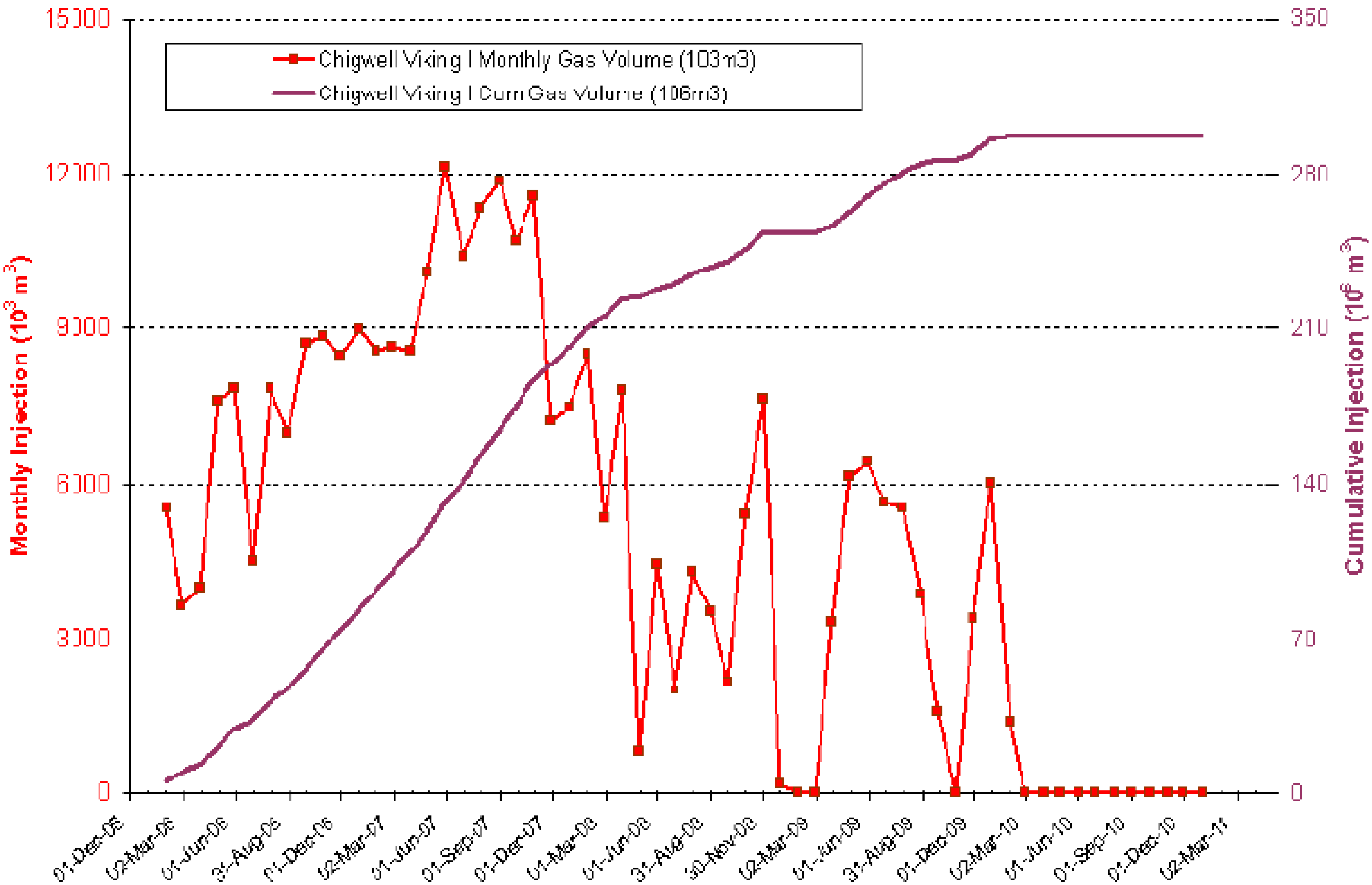
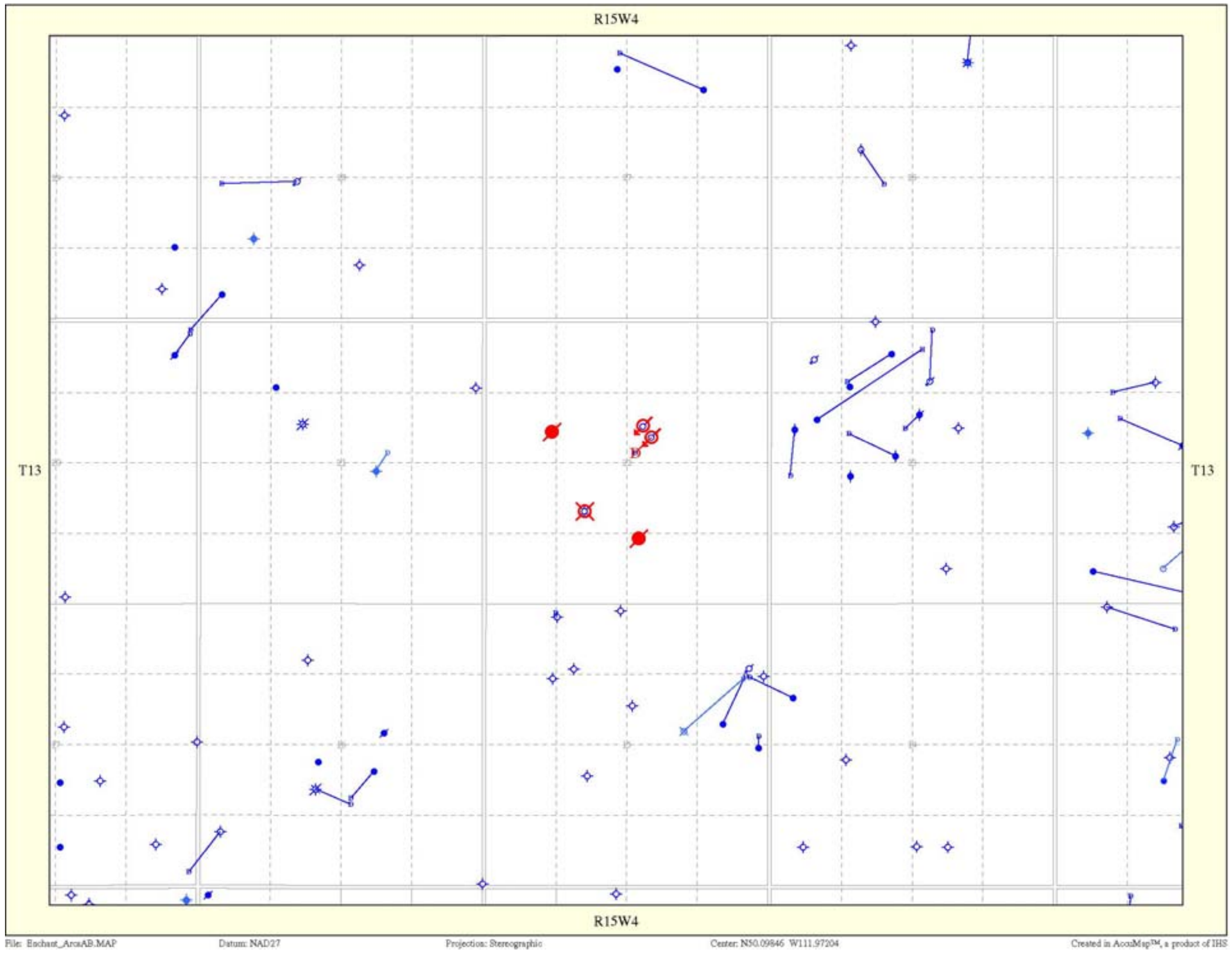



Figure 33

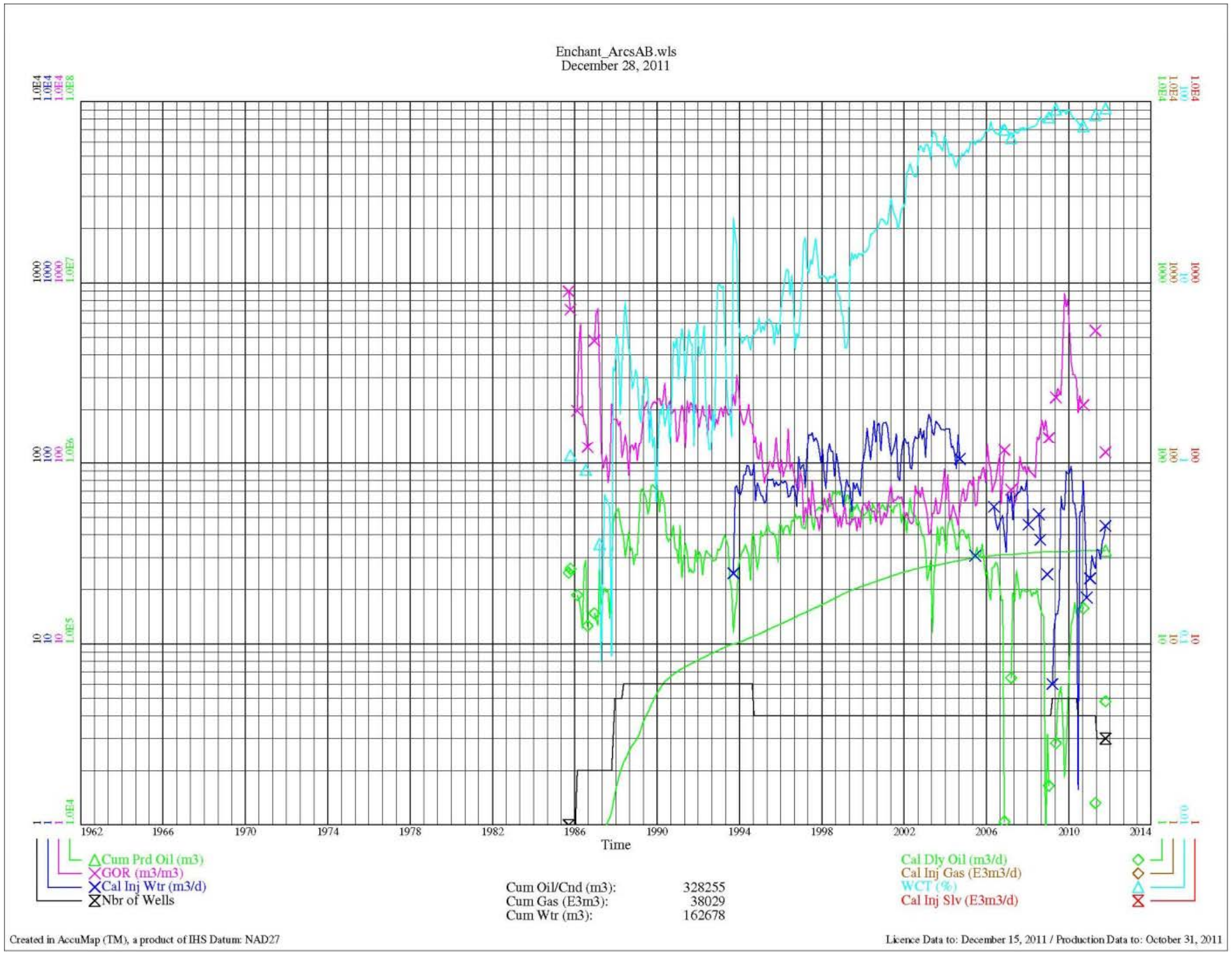
18156

Sproule



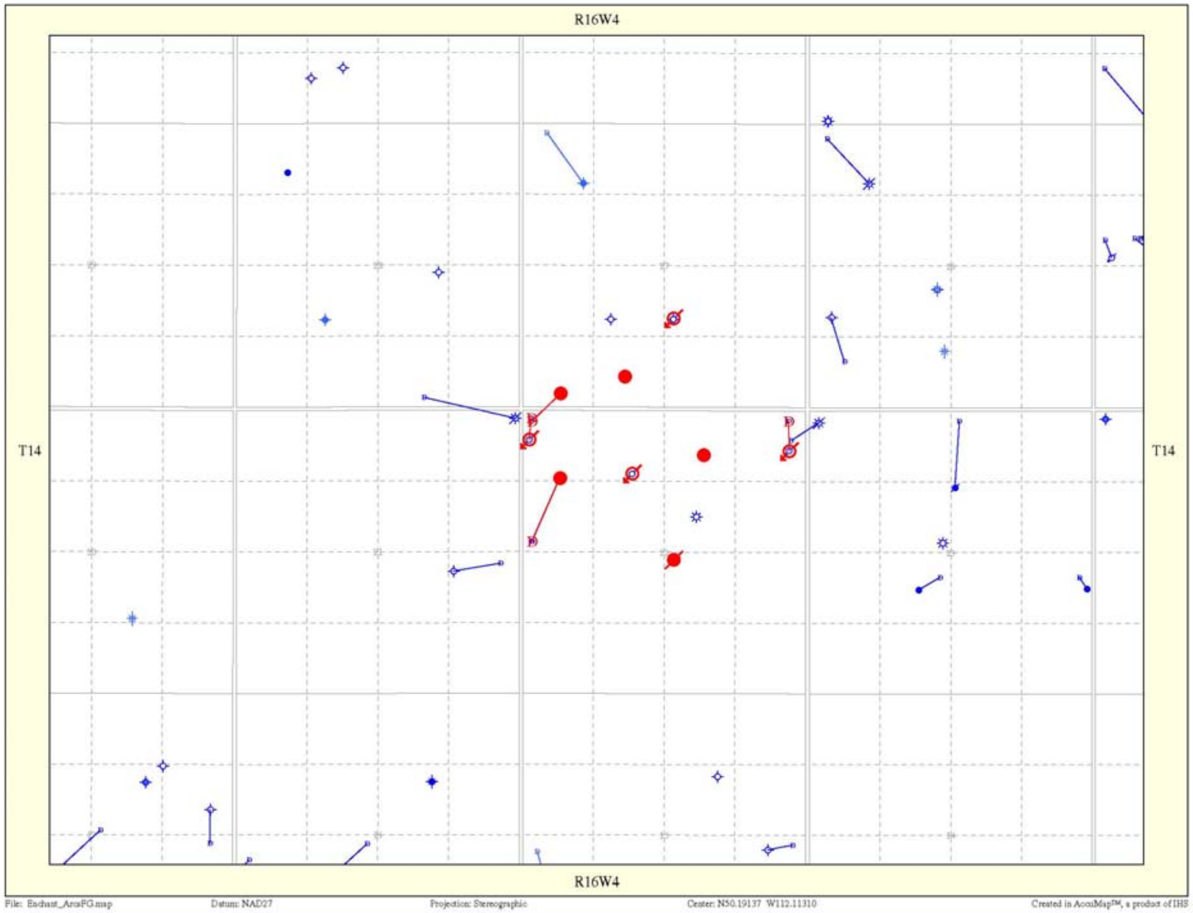

**Enchant Arcs A & B - Well Locations**

Figure 34



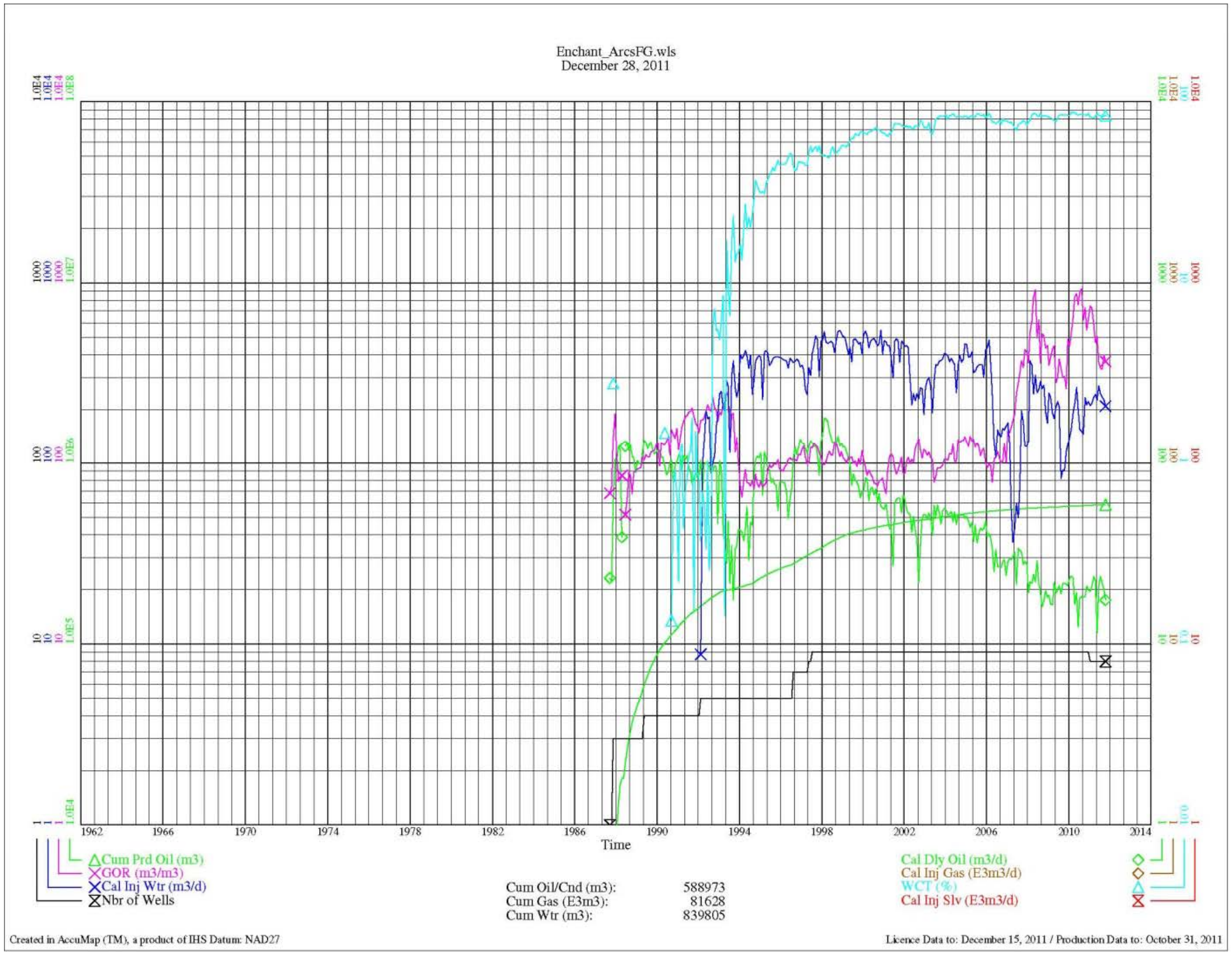

**Enchant Arcs A & B - Production / Injection History**

Figure 35



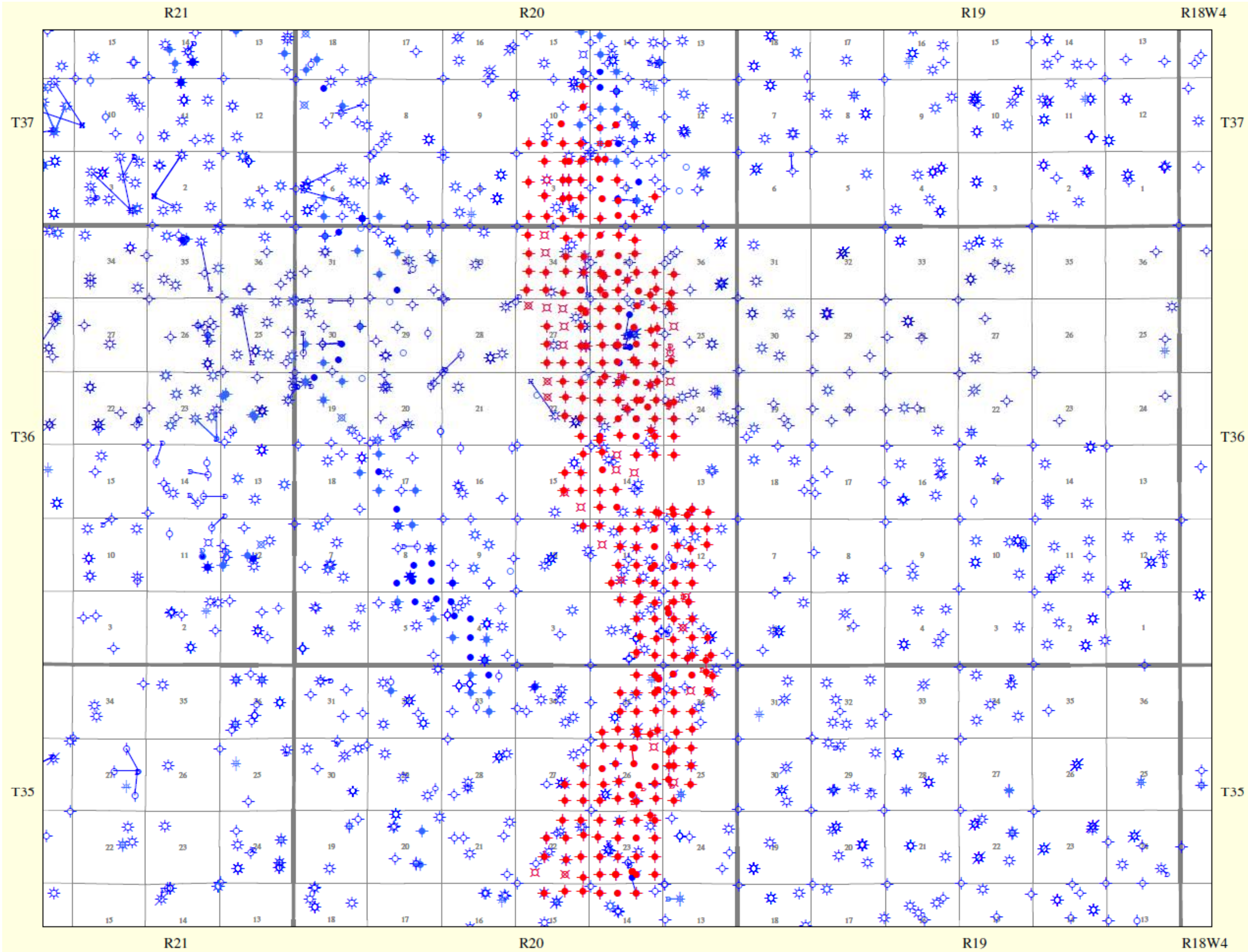

**Enchant Arcs F & G - Well Locations**

Figure 36




**Enchant Arcs F & G - Production / Injection History**

Figure 37

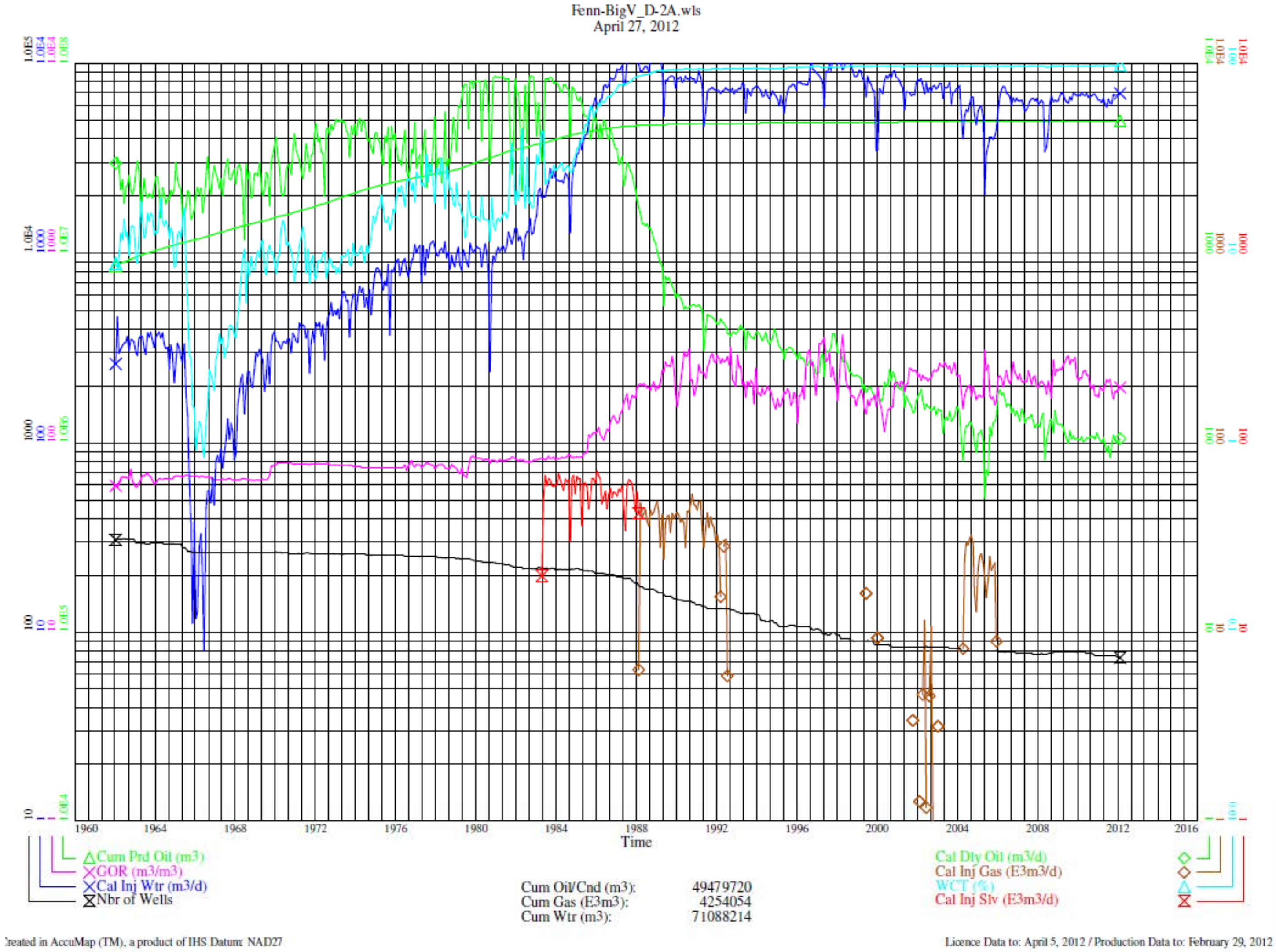



**Fenn-Big Valley Nisku A - Well Locations**

Figure 38

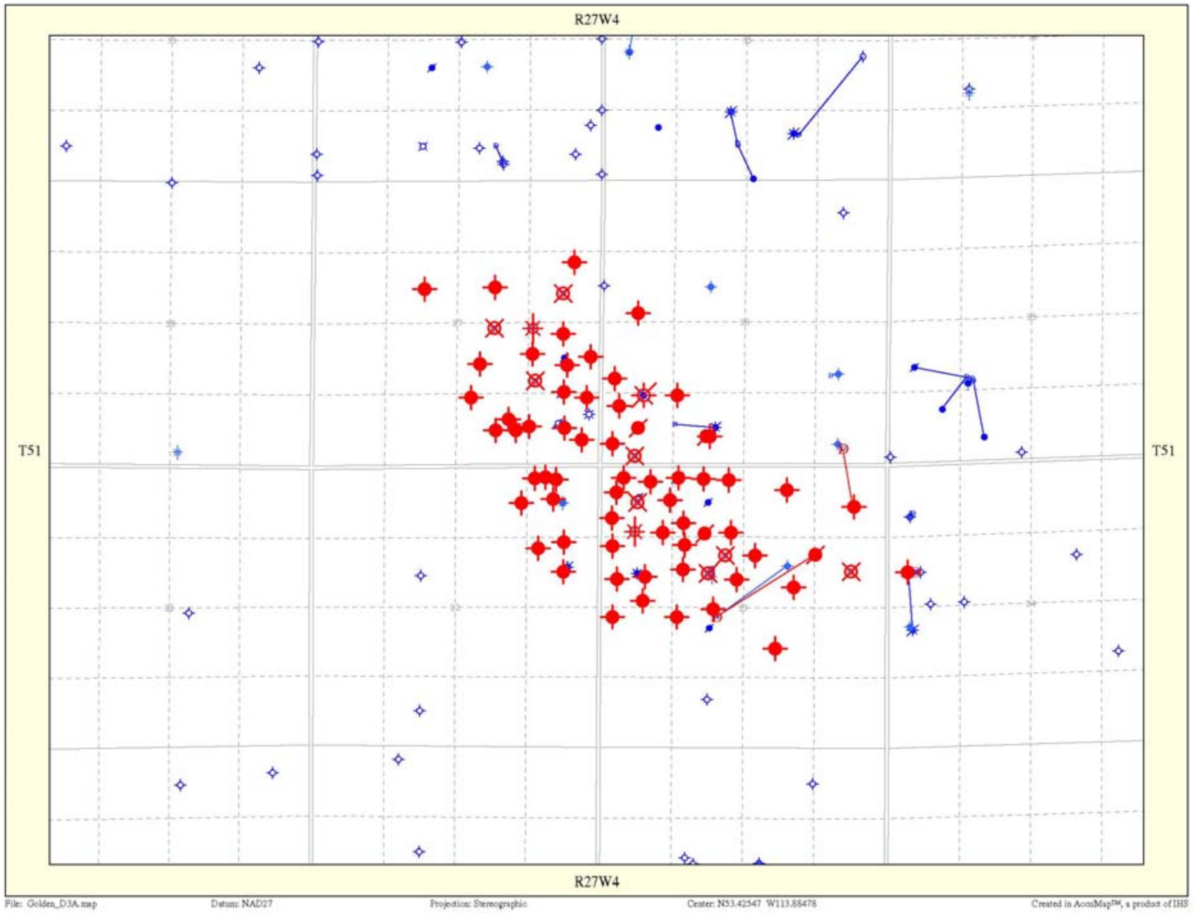


Sproule



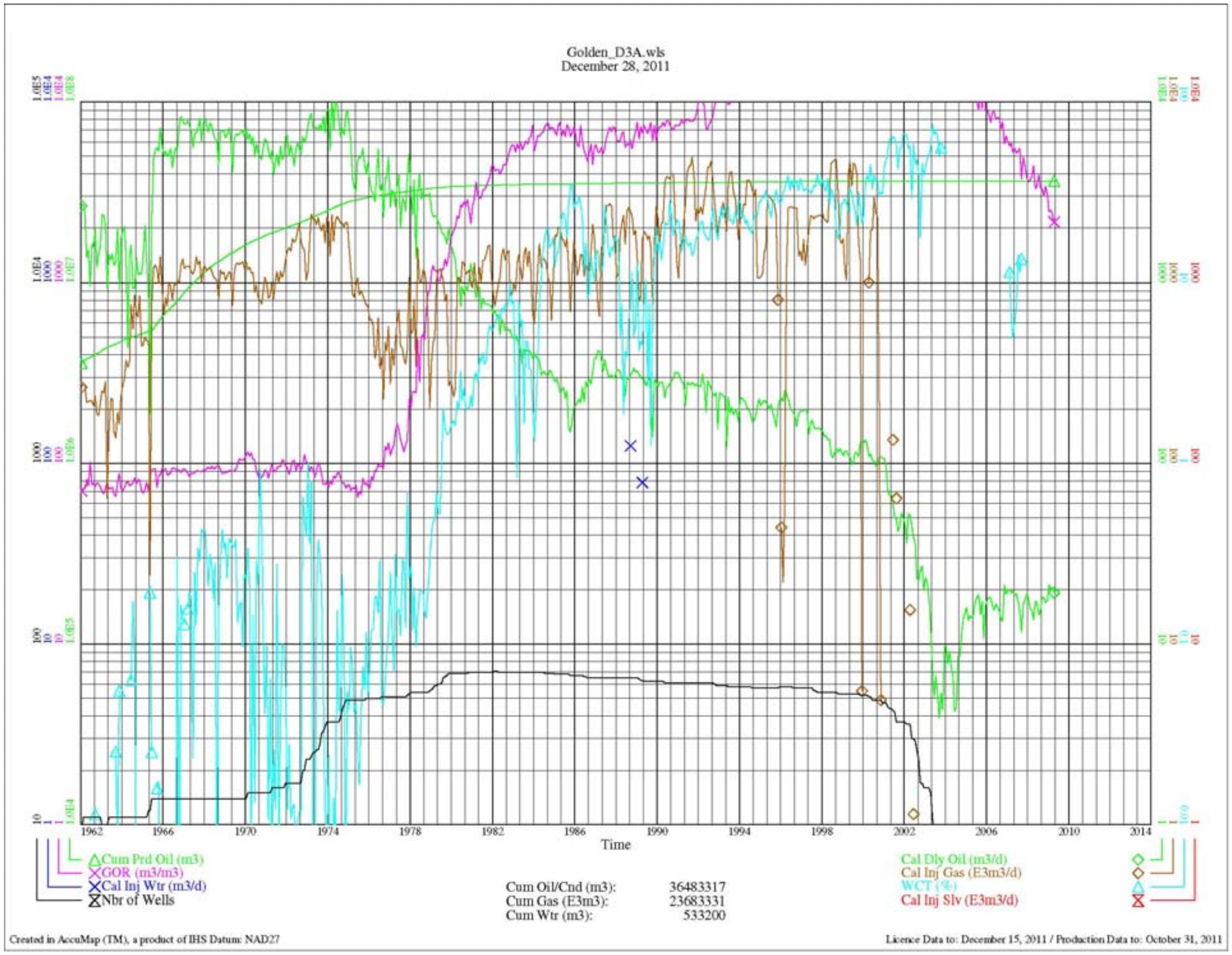

**Fenn-Big Valley Nisku A - Production / Injection History**

Figure 39



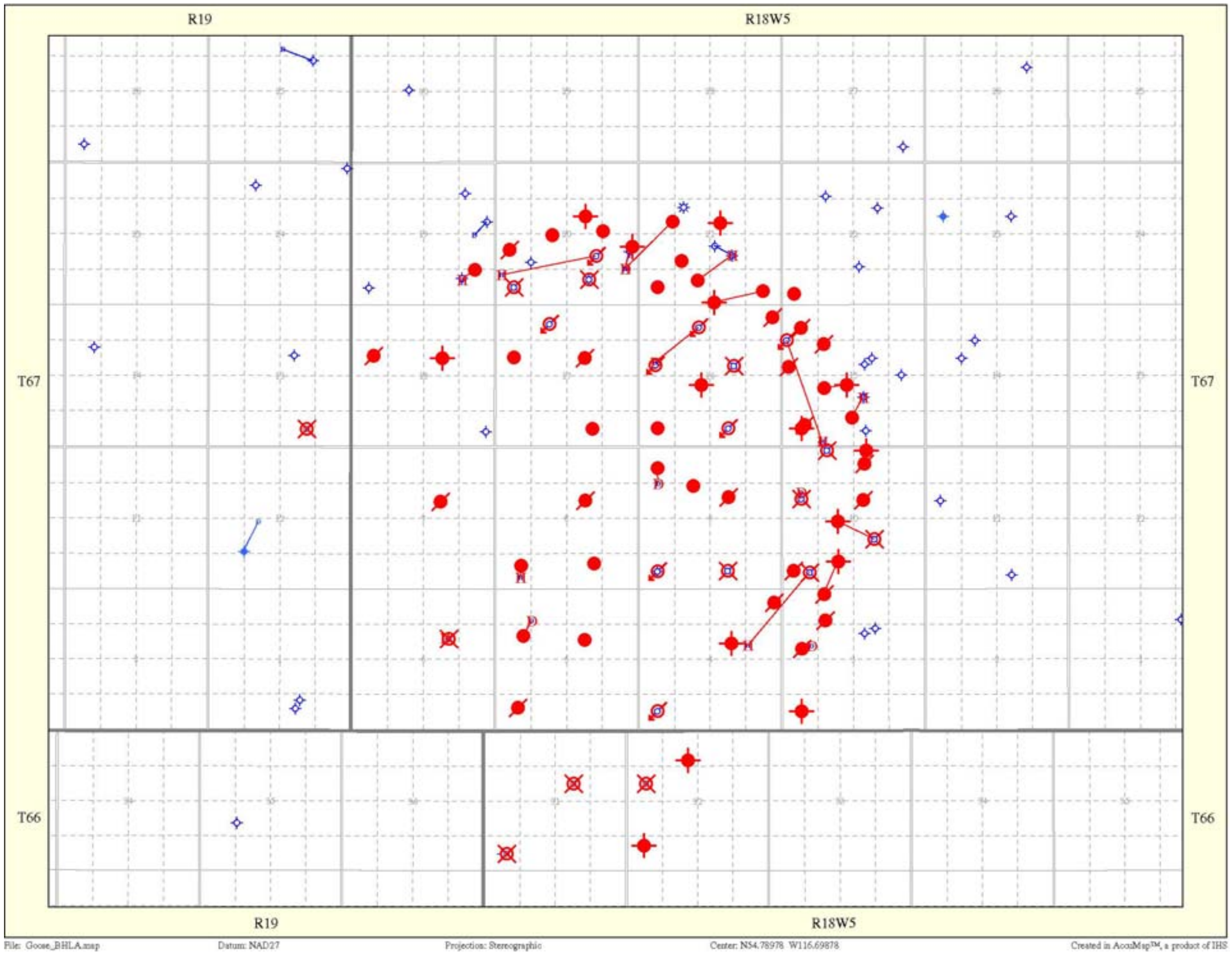

**Golden Spike D-3A - Well Locations**

Figure 40



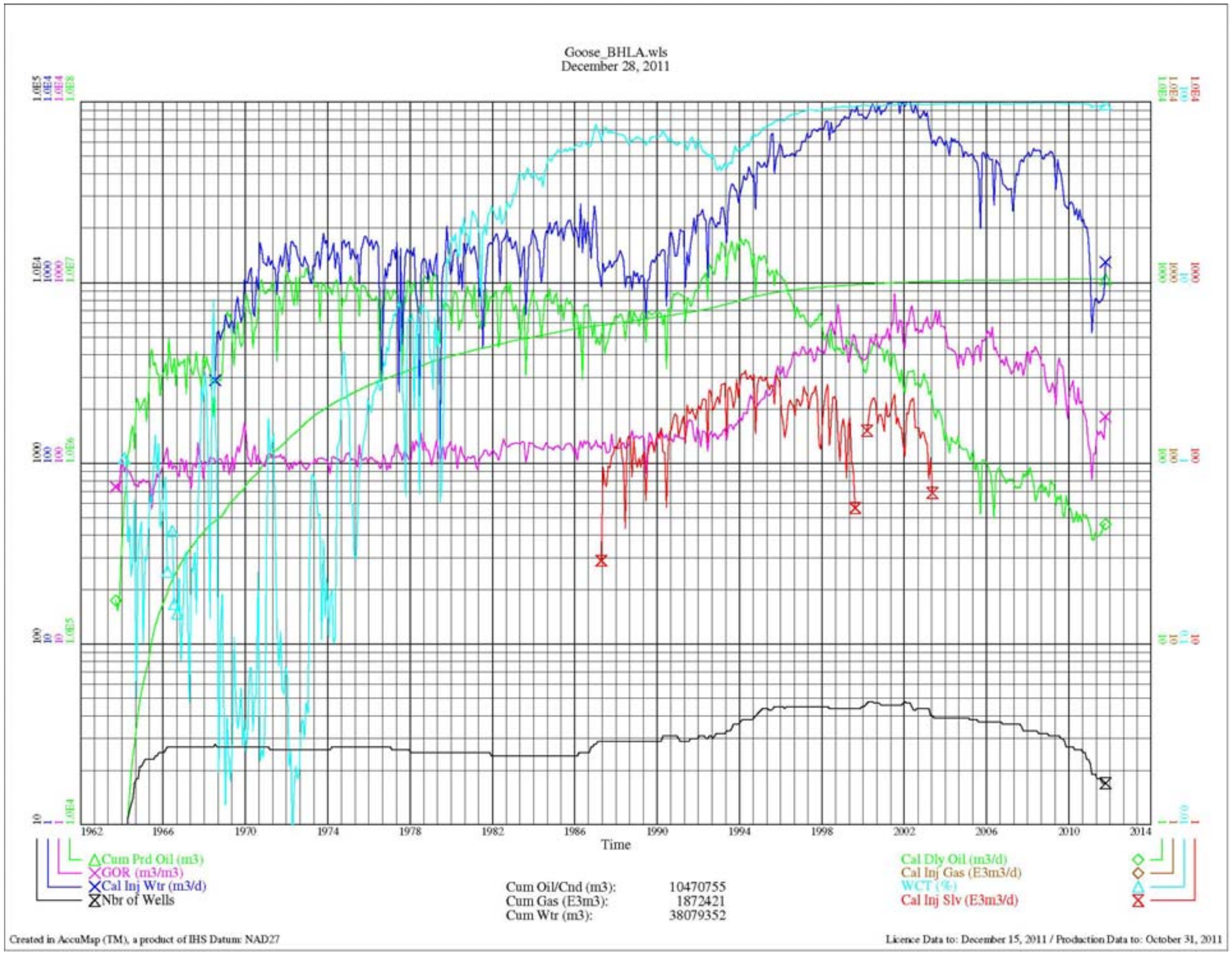

**Golden Spike D-3A - Production / Injection History**

Figure 41




**Goose River Beaverhill Lake A - Well Locations**

Figure 42

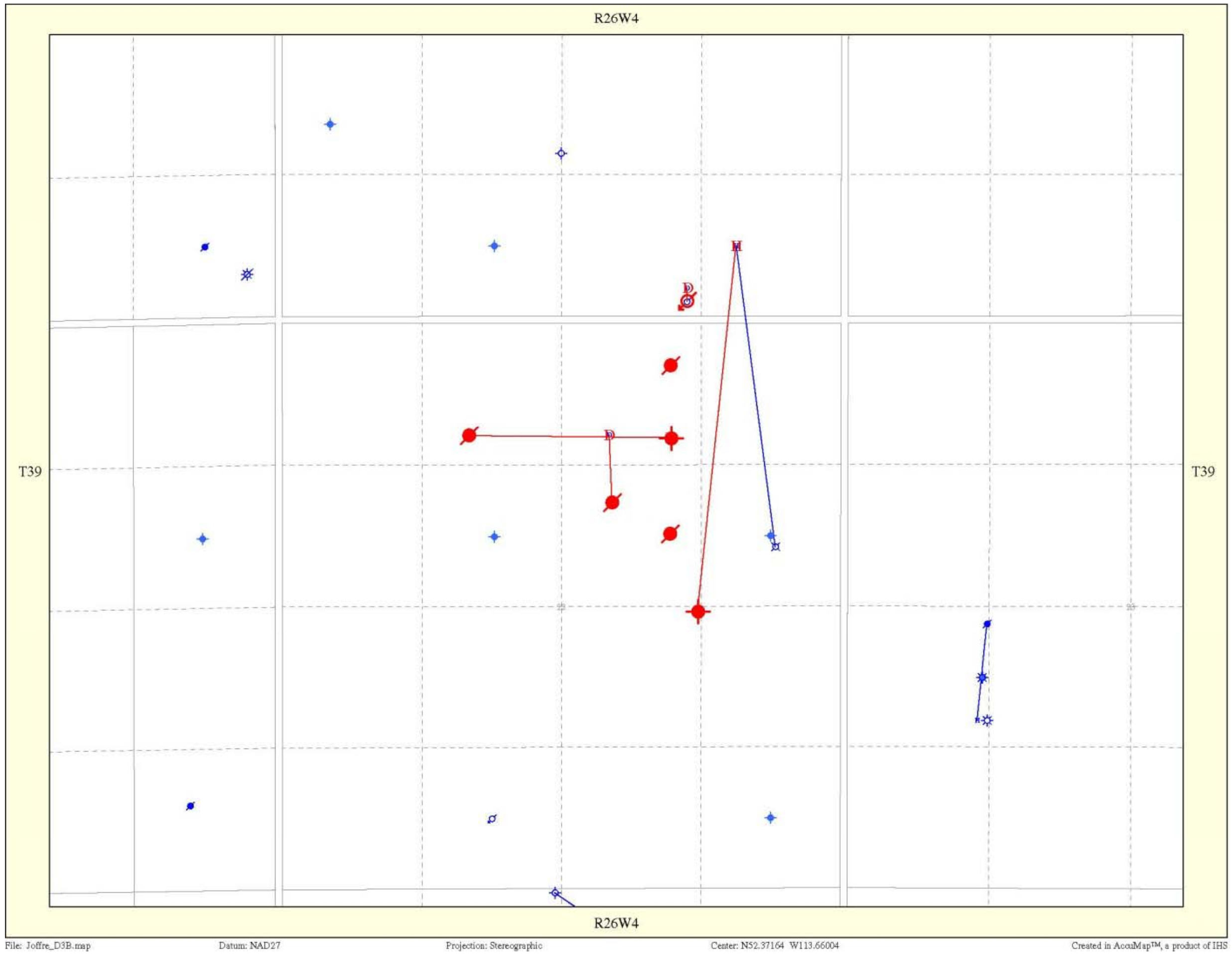



**Goose River Beaverhill Lake A - Production / Injection History**

Figure 43

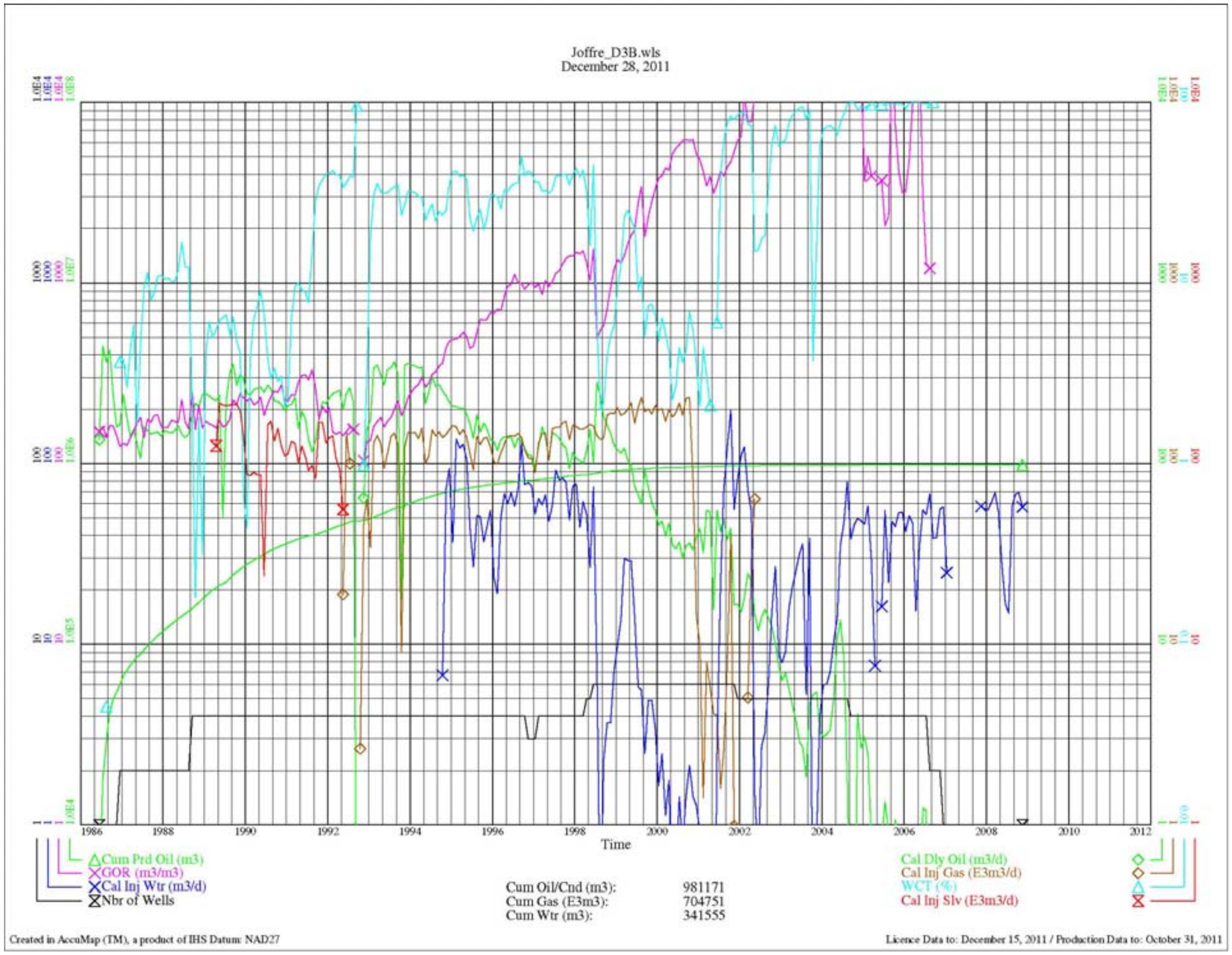


Sproule



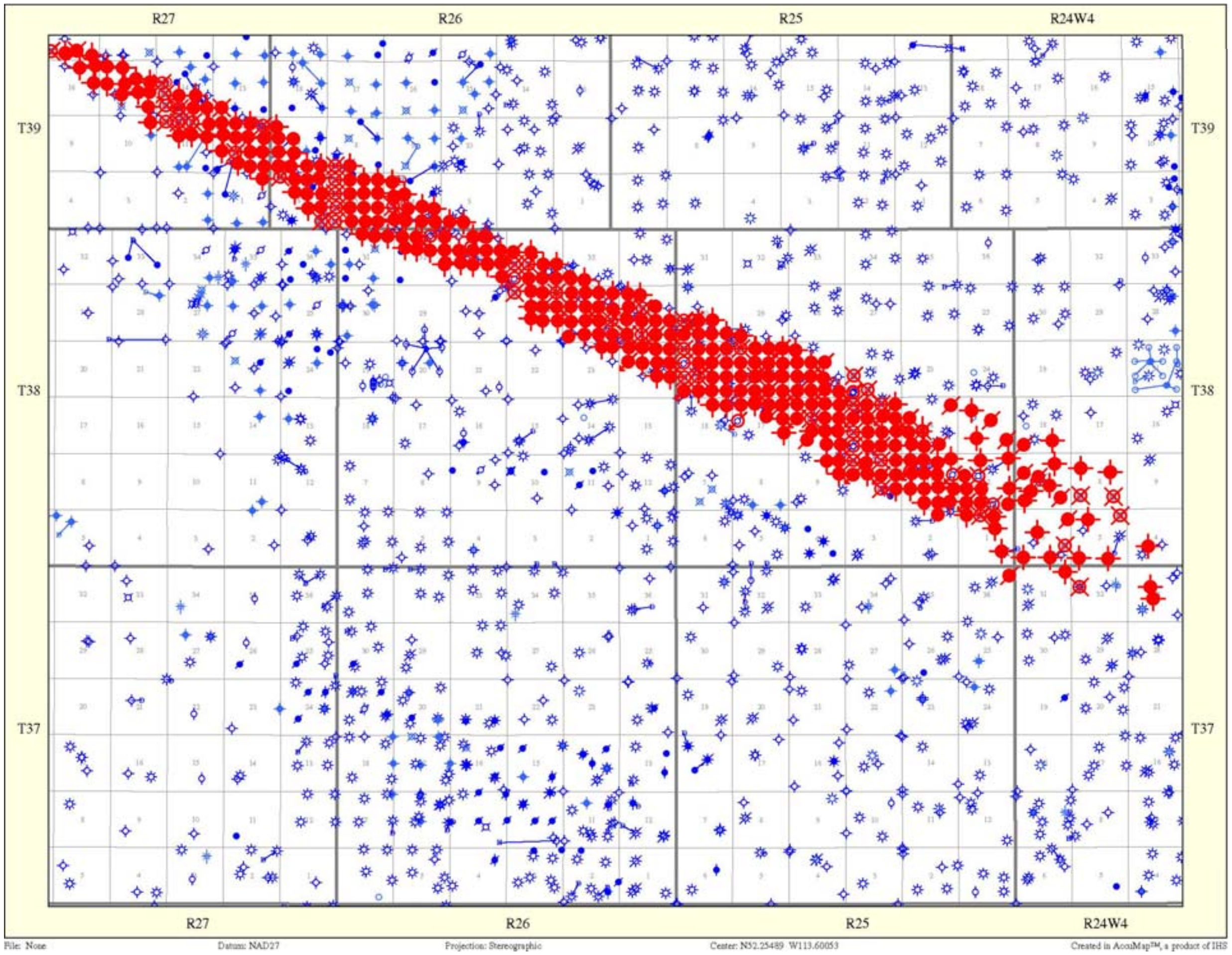

**Joffre D-3B - Well Locations**

Figure 44




**Joffre D-3B - Production / Injection History**

Figure 45




**Joffre Viking - Well Locations**

Figure 46

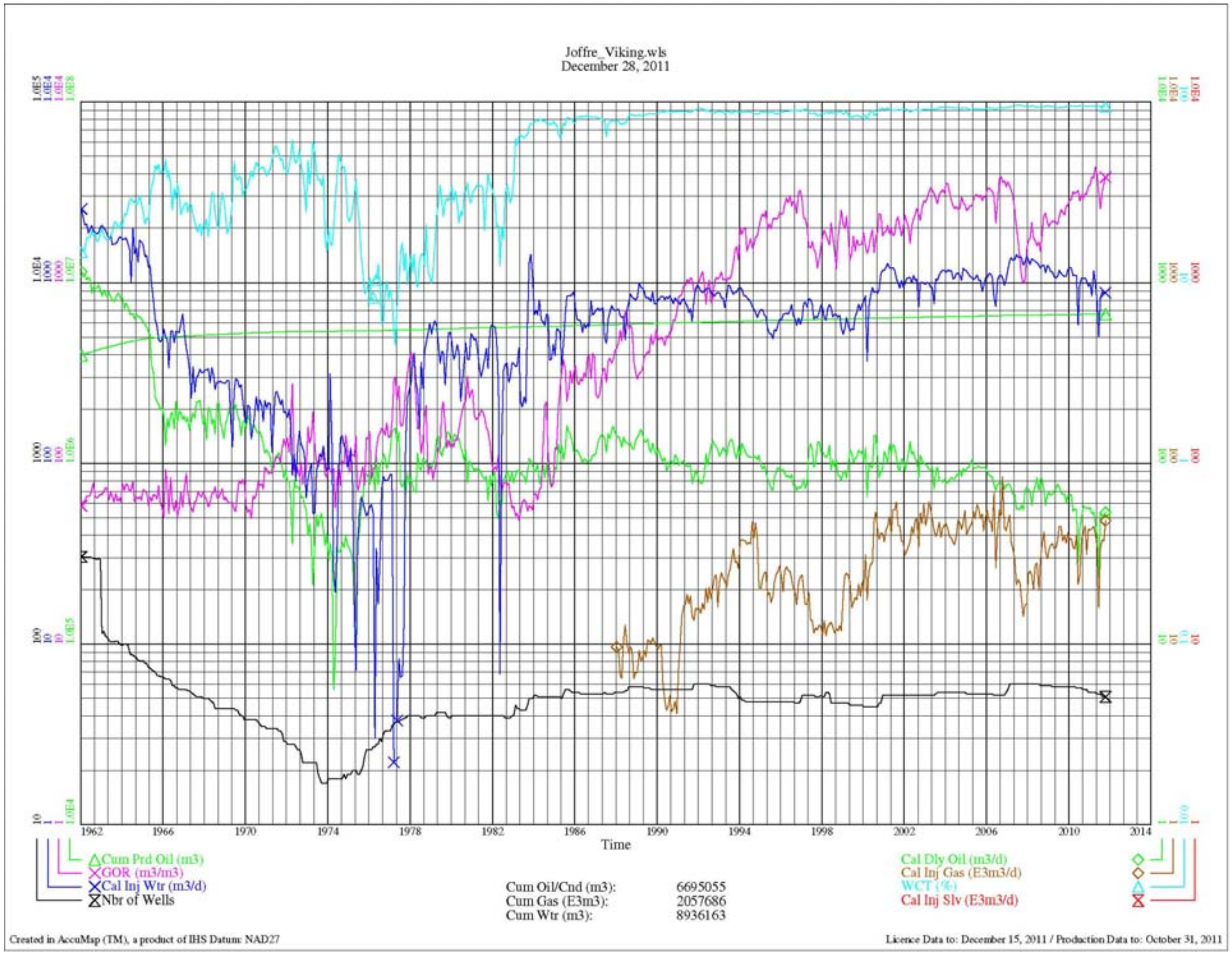
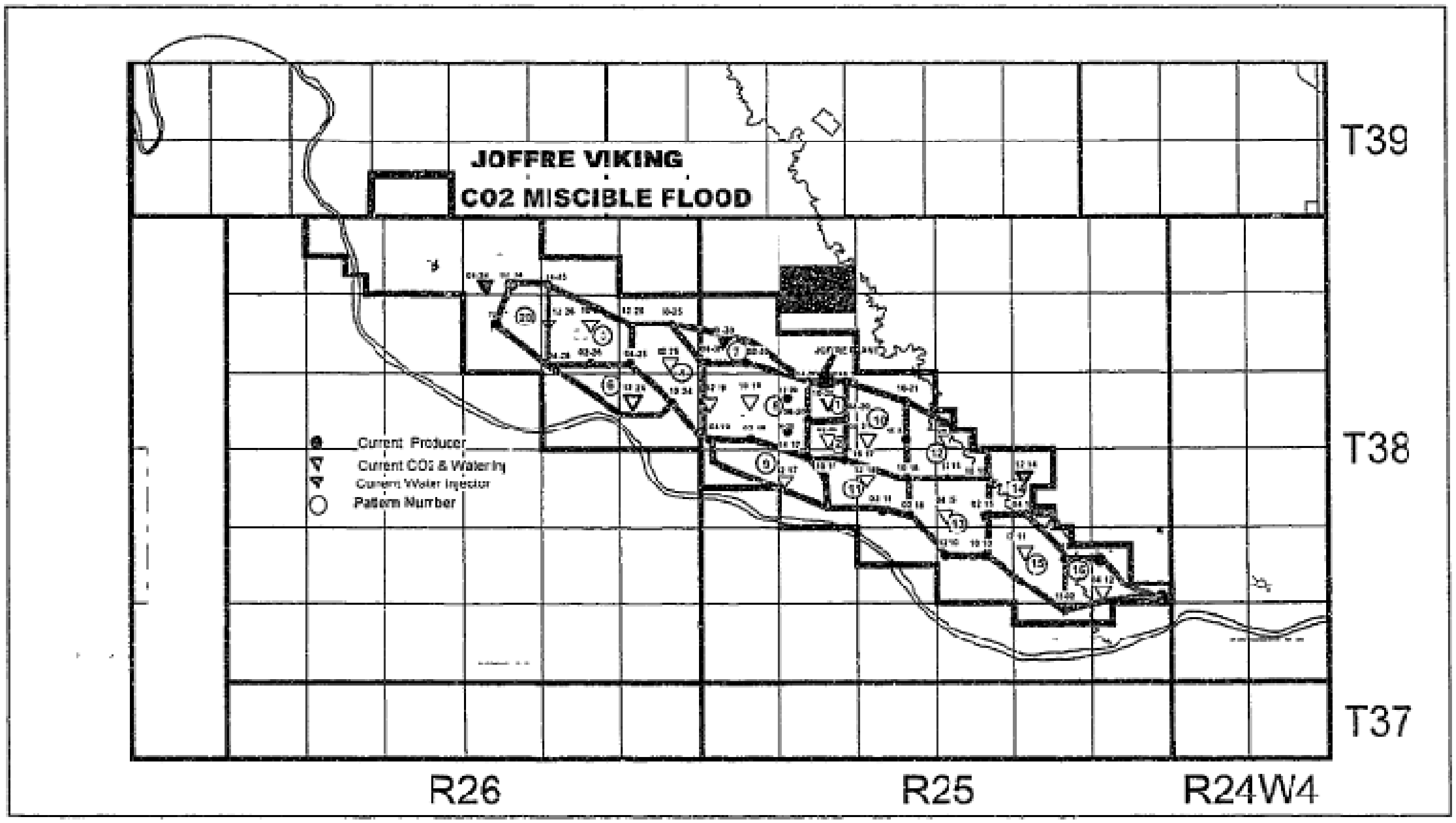


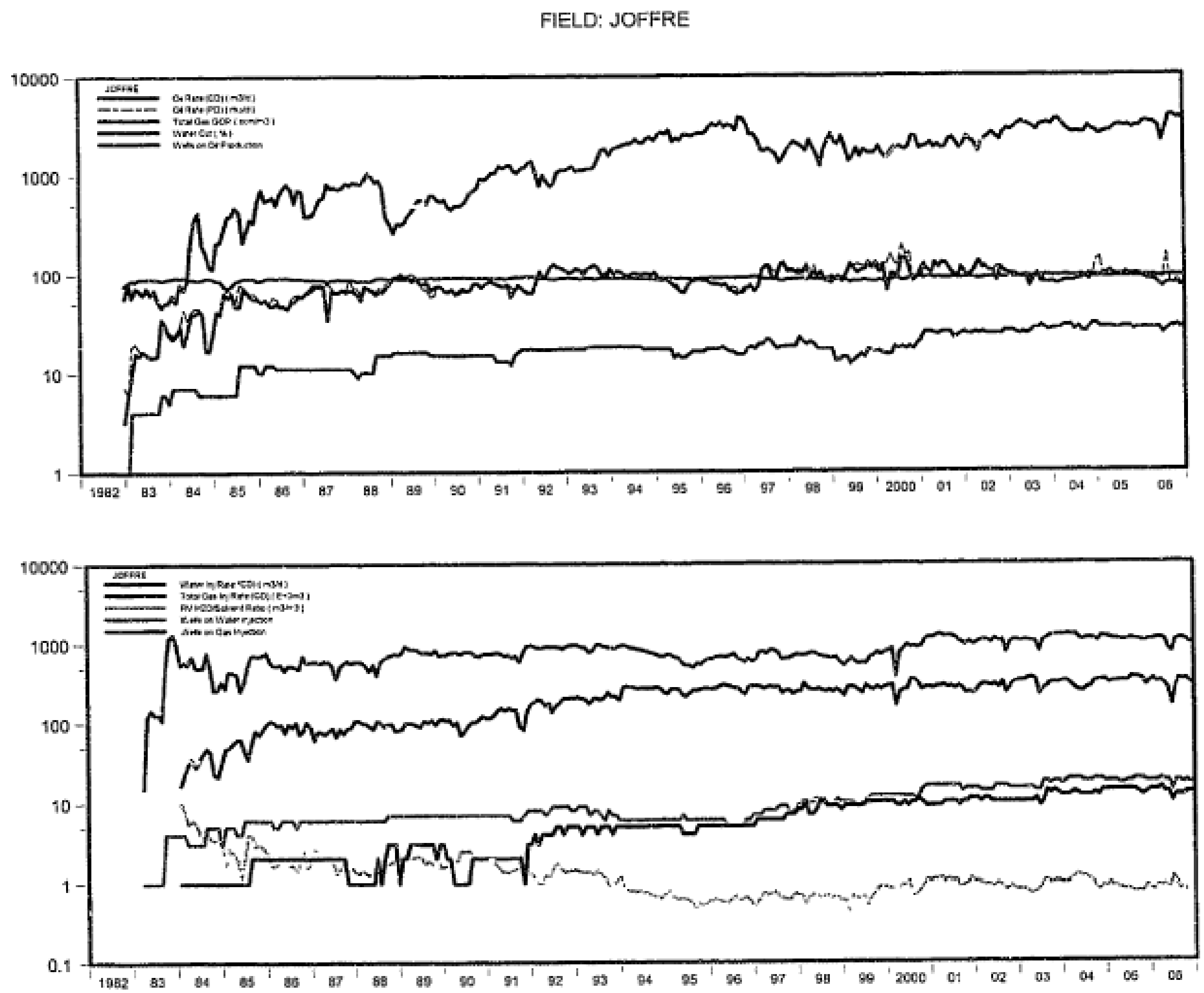

Figure 47

**Joffre Viking - Production / Injection History**




**Joffre Viking – $CO_2$ Miscible Area**

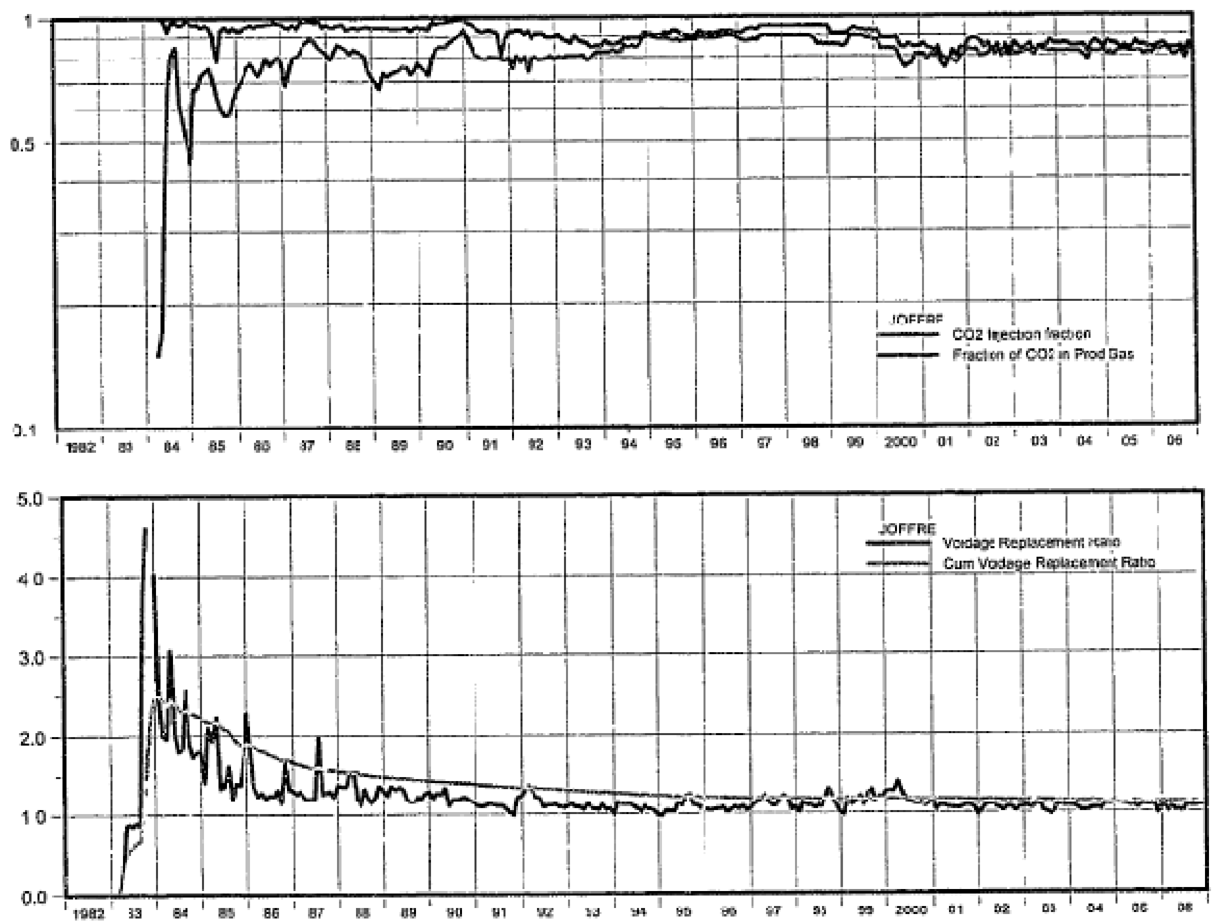
Figure 48




**Joffre Viking – $CO_2$ Miscible Area Production History**

Figure 49

FIELD: JOFFRE

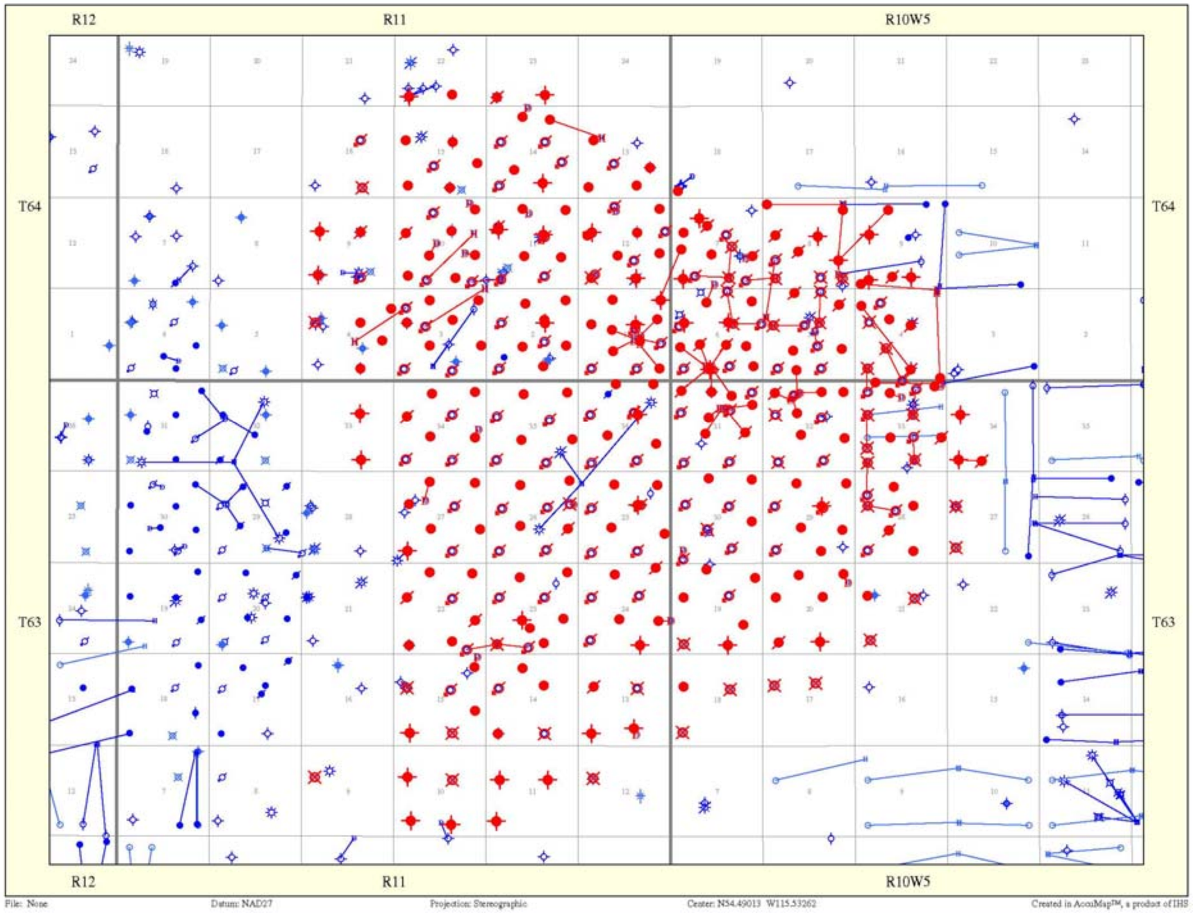



**Joffre Viking – CO2 Miscible Area Voidage Replacement Ratio**

Figure 50

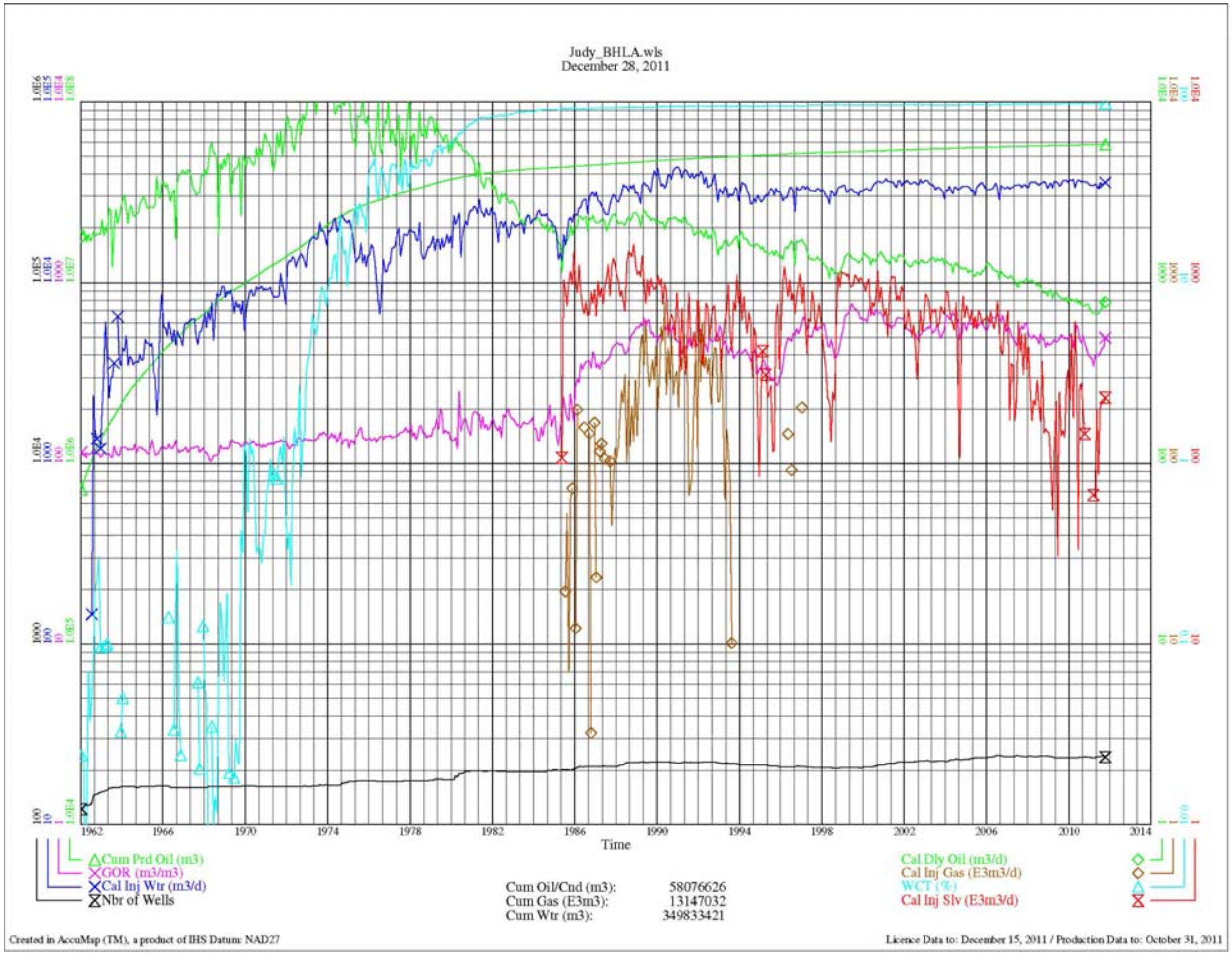


Sproule




Judy Creek Beaverhill Lake A - Well Locations

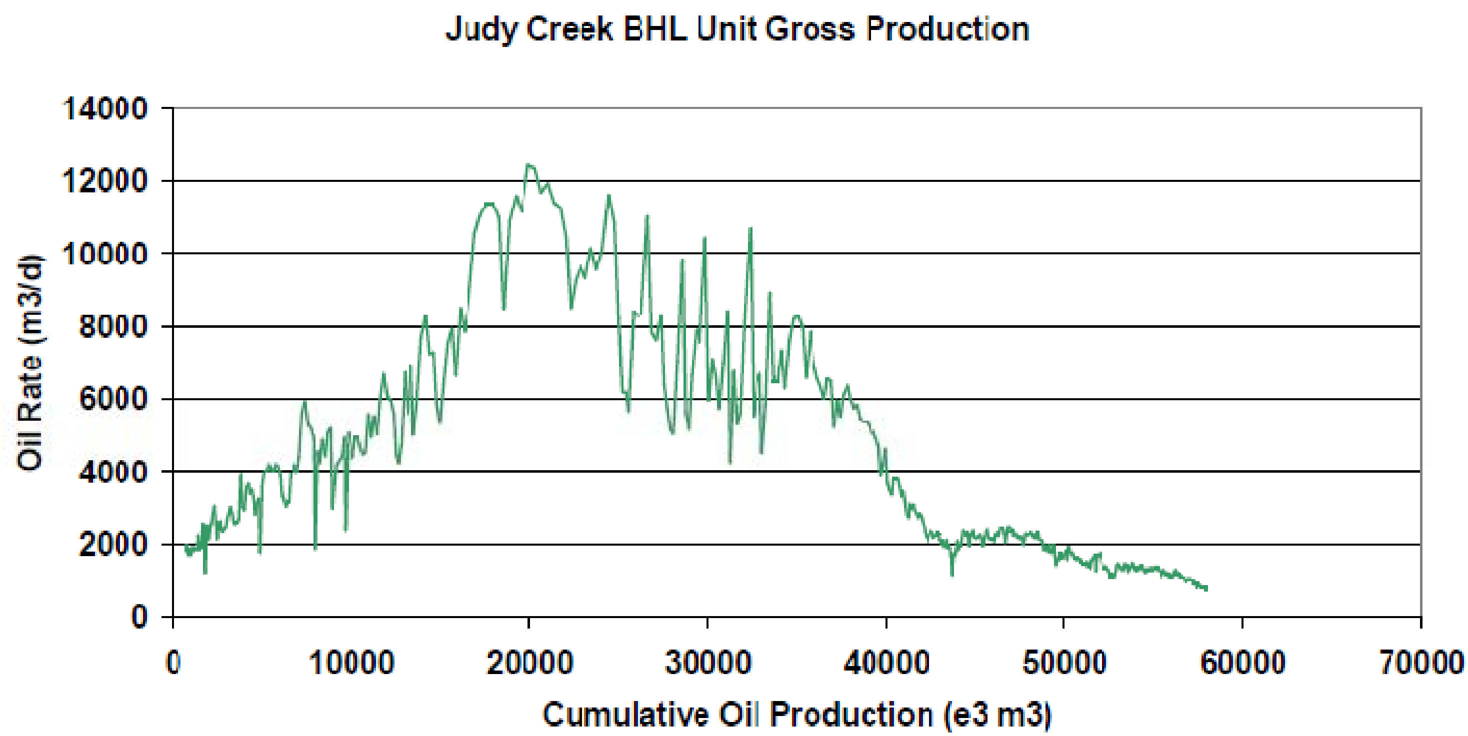
Figure 51




**Judy Creek Beaverhill Lake A - Production / Injection History**

Figure 52

# "A" Pool Rate Versus Cumulative Plot




- 2010 ERCB OOIP – 126,200 e3 m³ (unchanged from 2004)
- 2010 ERCB Recoverable Reserves – 58,710 e3 m³ (unchanged from 2004)
- Cumulative oil production of 57,921 e3 m³ (as of Dec 31, 2010)

Judy Creek 'A' Pool ERCB Presentation, January 27th 2011

Figure 53



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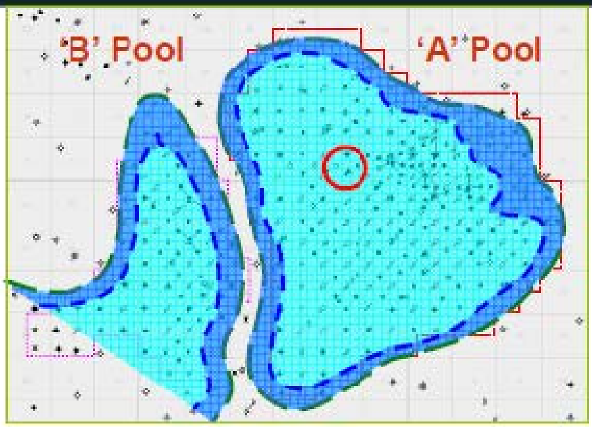
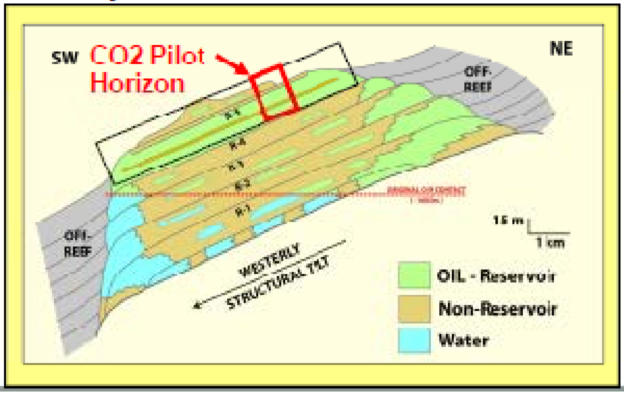
# Judy Creek "A" Pool $CO_2$ EOR Pilot



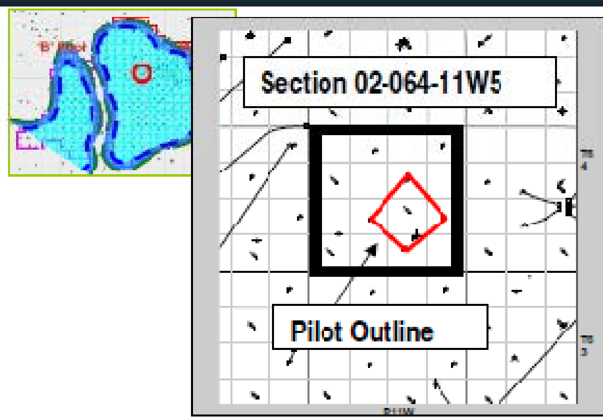

Judy Creek-Schematic Cross Section



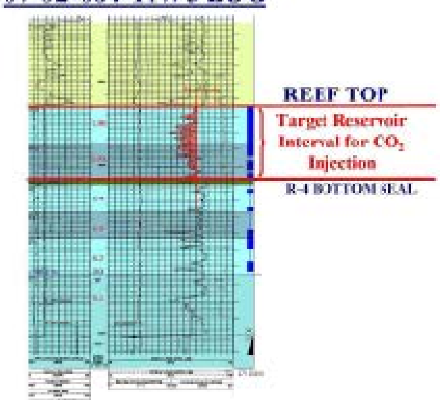

- Pilot centered on injector 07-02-064-11W5
- Pattern Area: 80 acres
  - Small pattern
  - Large banksize
  - Quick response
- Target R5A/B
  - R5: 42% of Judy Ck. OOIP
- Four producers
- All vertical wells
- 4 of 5 pattern wells 'Recent'
  - (02-02 is 1960's vintage)
- Historical HC Solvent injection:
  - Feb '02 - Aug '03

Figure 54

# Judy Creek $CO_2$ Pilot: Description




*07-02-064-11W5 LOG*




- Full R5A & B reef development
- Good bottom seal & near up-dip culmination
- 07-02 porosity
  - ~20m >3%Ø
  - Ave. ~8% Ø
  - Max ~15% Ø
- No 'hot streaks' (minimizes risk of early gas break through)
- Injection profiles
  - Solvent: 87% into R5A/B
  - Water: 82% into R5A/B
- HC flood response primarily to SW producers (02-02 and 06-02-064-11W5)

Figure 55



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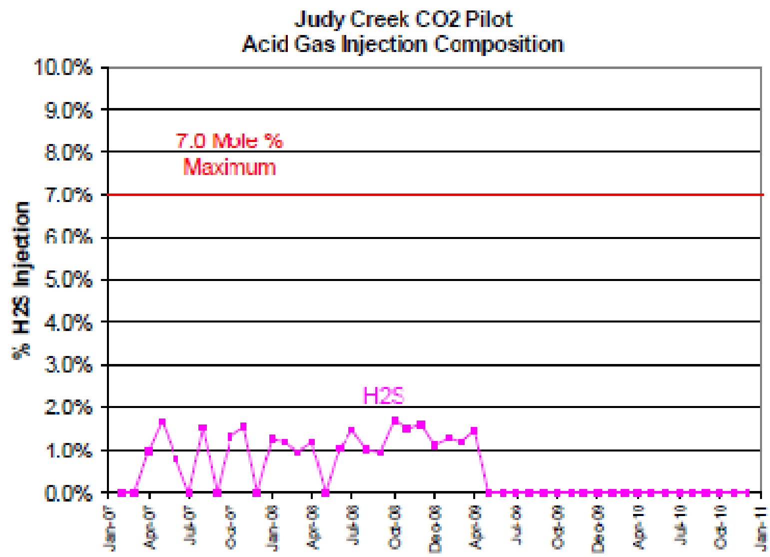
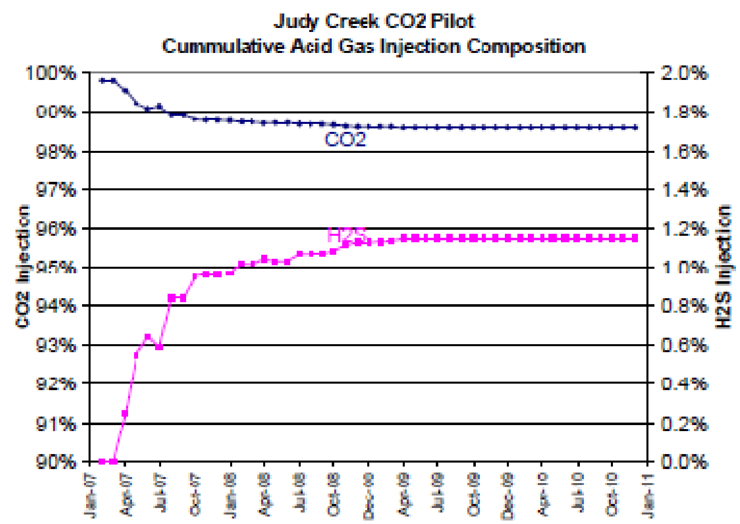
# Regulatory Compliance Highlights

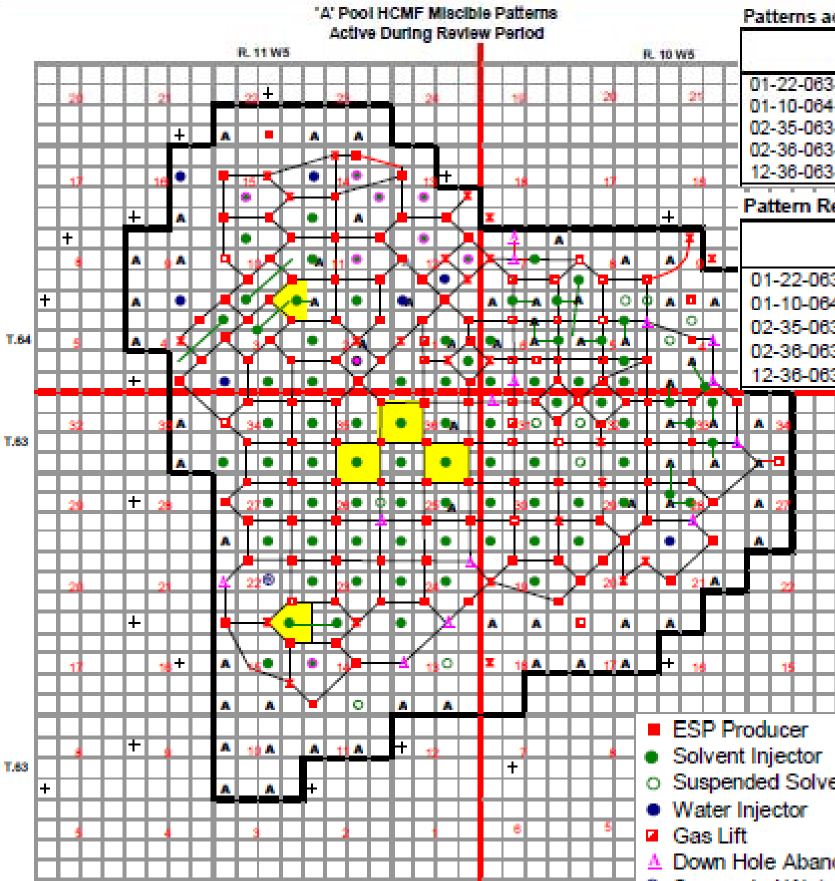



Did not exceed maximum $H_2S$ concentration of 7% at any time

Figure 56

# "A" Pool Solvent Banksize & Performance




Judy Creek 'A' Pool ERCB Presentation, January 27th 2011

**Patterns active during review period - "A" POOL**

| | Pattern # | start date | end date | Banksize (%FCHCPV) | Previous Banksize (%FCHCPV) | FCHCPV (e3m3) |
|---|---|---|---|---|---|---|
| 01-22-063-11 | 126 | 8-Aug-07 | active | 18.2% | N/A | 534 |
| 01-10-064-11 | 128 | 16-Sep-08 | 5-Sep-10 | 71.9% | N/A | 574 |
| 02-35-063-11 | 83 | 22-Dec-09 | 19-Oct-10 | 3.8% | 16.6% | 727 |
| 02-36-063-11 | 71 | 22-Dec-09 | active | 9.5% | 10.4% | 1100 |
| 12-36-063-11 | 86 | 22-Dec-09 | 19-Oct-10 | 7.6% | 19.3% | 942 |

**Pattern Recovery (to Dec-10)**

| | Pattern # | Tertiary Oil (E3m3) | %OOIP (%) | Solvent Reprd (% of inj) | Banksize (%FCHCPV) | FCHCPV (e3m3) |
|---|---|---|---|---|---|---|
| 01-22-063-11 | 126 | 11 | 2.9 | 43 | 18.2% | 534 |
| 01-10-064-11 | 128 | 36 | 8.7 | 59 | 71.9% | 574 |
| 02-35-063-11 | 83 | 1 | 0.1 | 12 | 3.8% | 727 |
| 02-36-063-11 | 71 | 4 | 0.6 | 35 | 9.5% | 1100 |
| 12-36-063-11 | 86 | 2 | 0.2 | 13 | 7.6% | 942 |

Figure 57



Sproule

# $CO_2$ Pilot Performance to Date (Dec. 31-10)

- $CO_2$ recovery 8,700 $e^3m^3$ (25% of injection)
- Hydrocarbon Solvent Recovery
  - Methane: 3,500 $e^3m^3$
  - Ethane: 2,800 $e^3m^3$

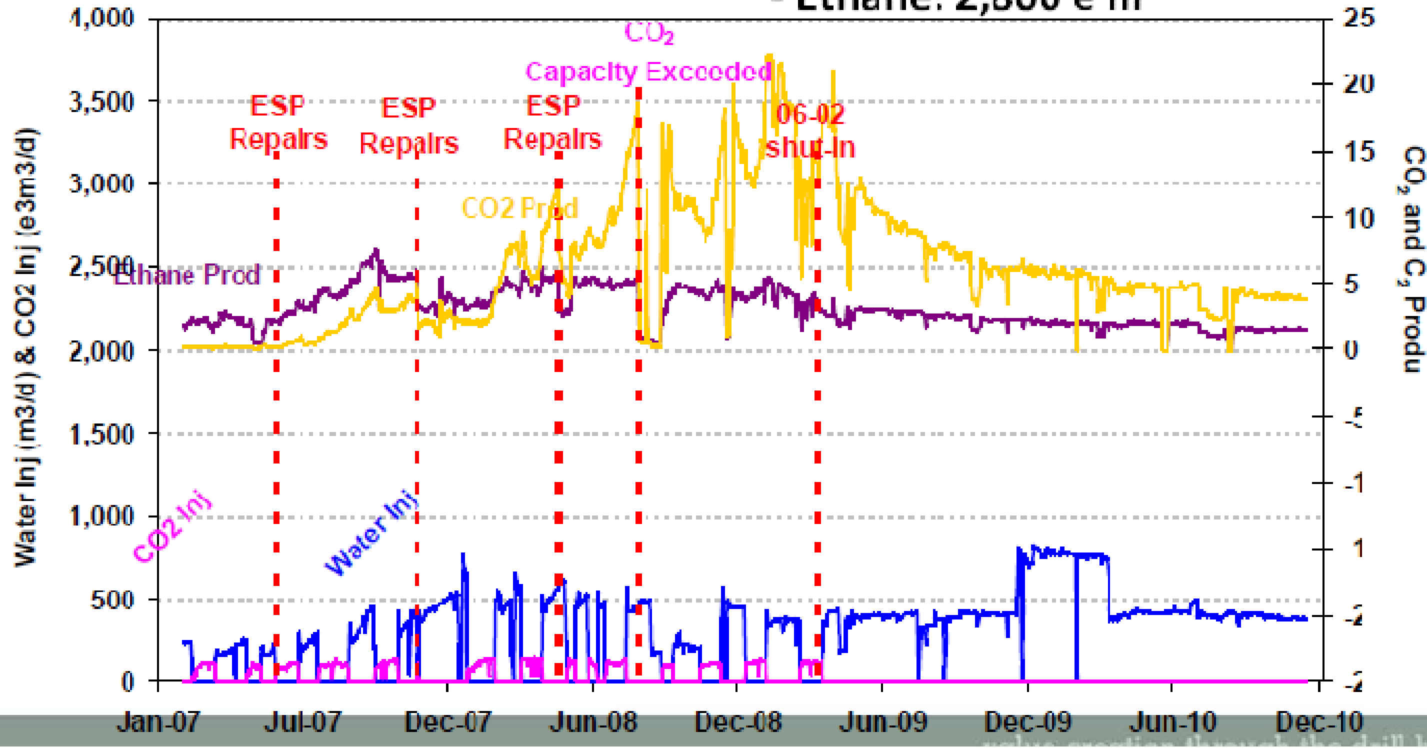
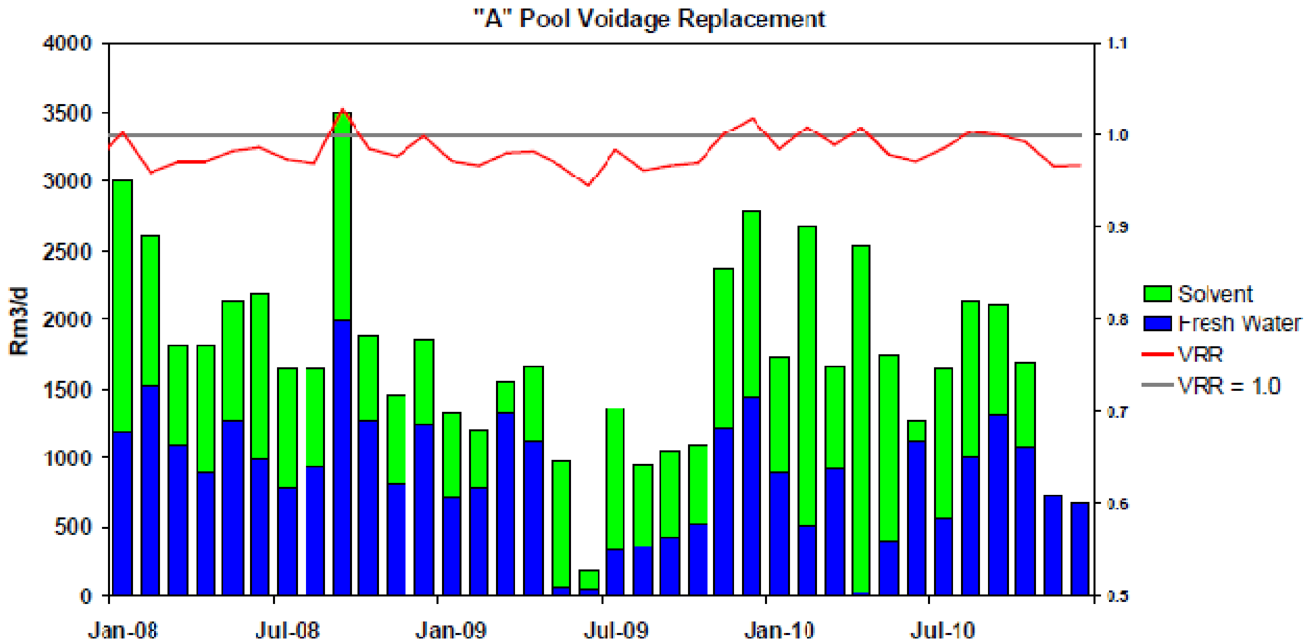



Figure 58



Sproule

# Voidage Replacement Ratio Averages 0.99




- 100% of the produced water is re-injected (no SWD)
- Freshwater makeup injection utilized to balance voidage
- Improved on 2009 VRR (0.98)

Judy Creek 'A' Pool ERCB Presentation, January 27th 2011

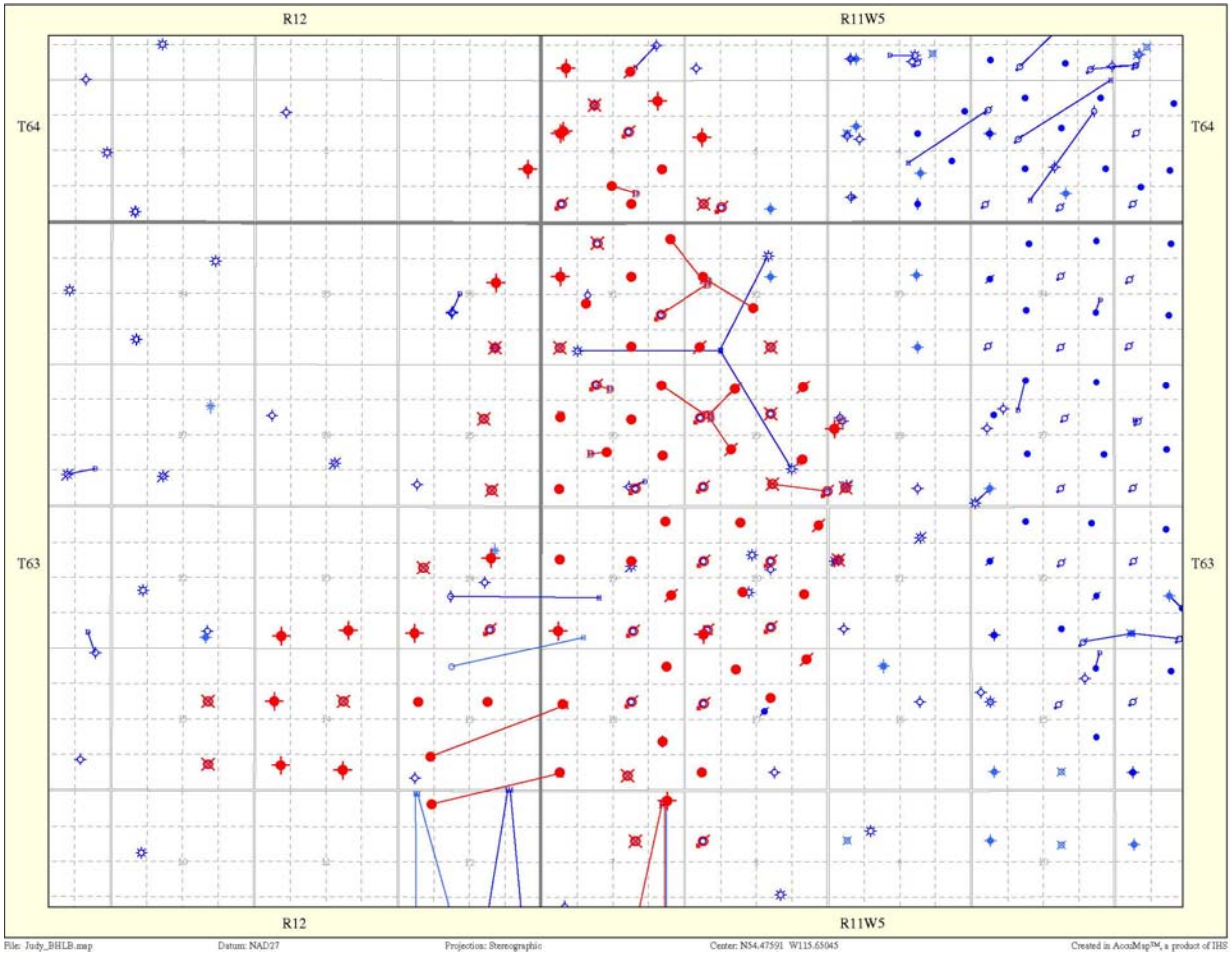
Figure 59

# Pattern Injection & Recovery Data


- Injected Banksize 26.2% HCPV
  - $CO_2$ 34,500e$^3$m$^3$ or 118,500Rm$^3$
- Oil recovery 9,450m$^3$ (2.95% OOIP)
  - 10-02-064-11 Acid Frac 5,300m$^3$
  - Target: 10,000m$^3$ (3.0% OOIP)
  - Outlook: 11,000m$^3$ (3.3%OOIP)
- Hydrocarbon Solvent Recovery
  - Methane recovery
    - 3,500e$^3$m$^3$ or 17,000Rm$^3$
  - Ethane recovery
    - 2,800e$^3$m$^3$ or 10,600 Rm$^3$

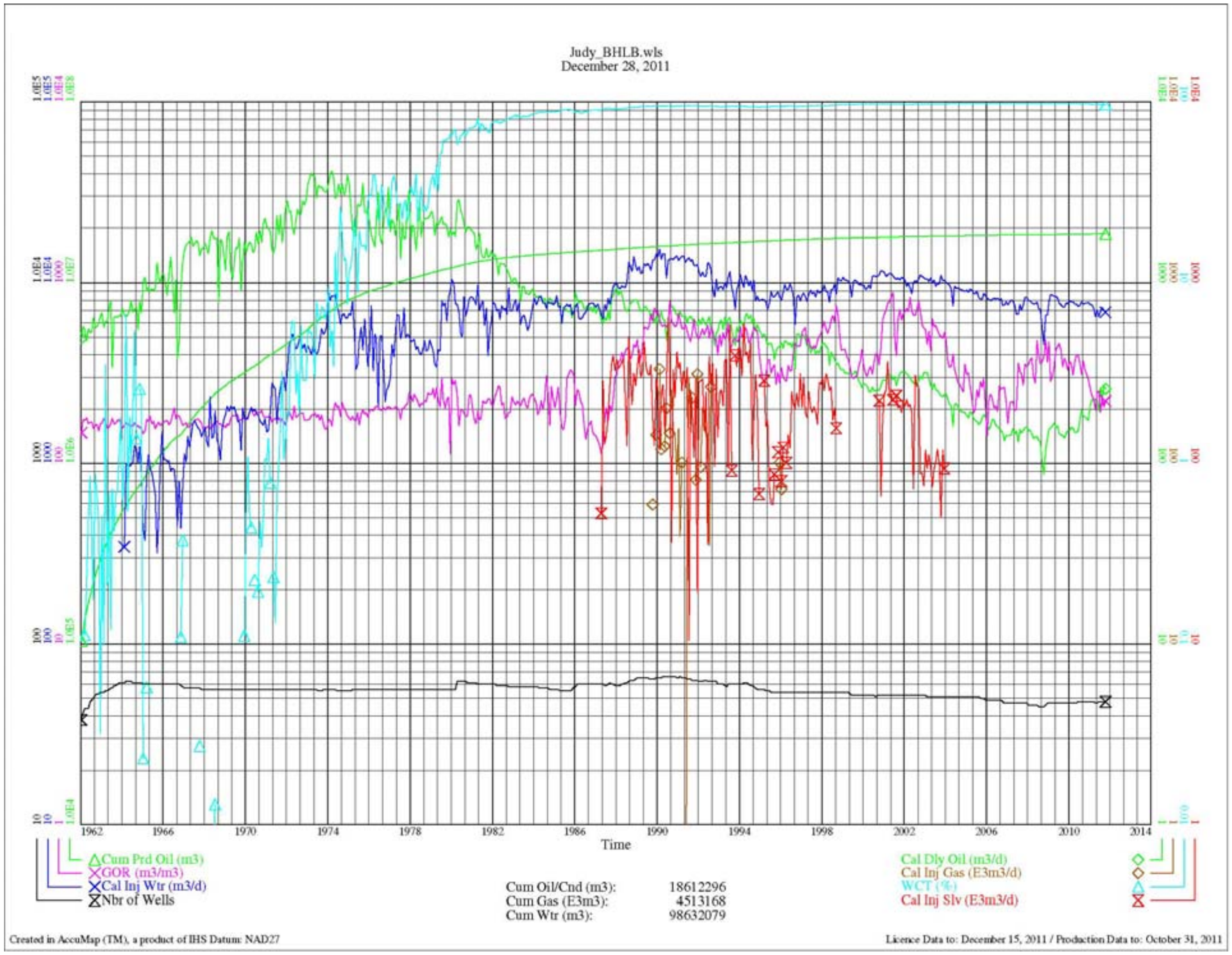
      (~20% of retained HC solvent)
- $CO_2$ recovery
  - 8,700e$^3$m$^3$ or 29,900Rm$^3$ (25.2% of injection)
- $CO_2$ sequestered / unrecovered
  - 25,800e$^3$m$^3$ or 88,600Rm$^3$ (79.2%)
- **Data from Feb 14th, 2007 to Dec 31st, 2010**

Figure 60



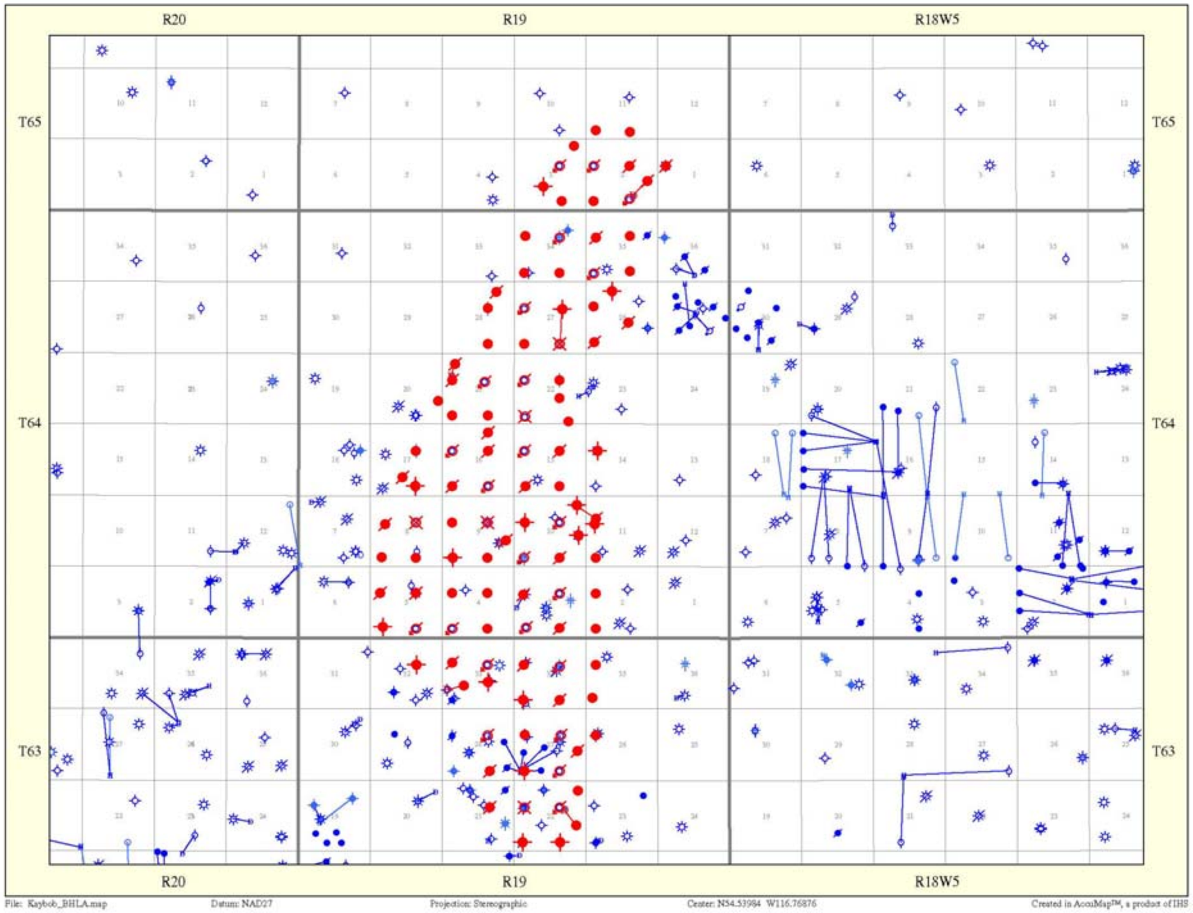

**Judy Creek Beaverhill Lake B - Well Locations**

Figure 61




**Judy Creek Beaverhill Lake B - Production / Injection History**

Figure 62




**Kaybob Beaverhill Lake A - Well Locations**

Figure 63



Sproule

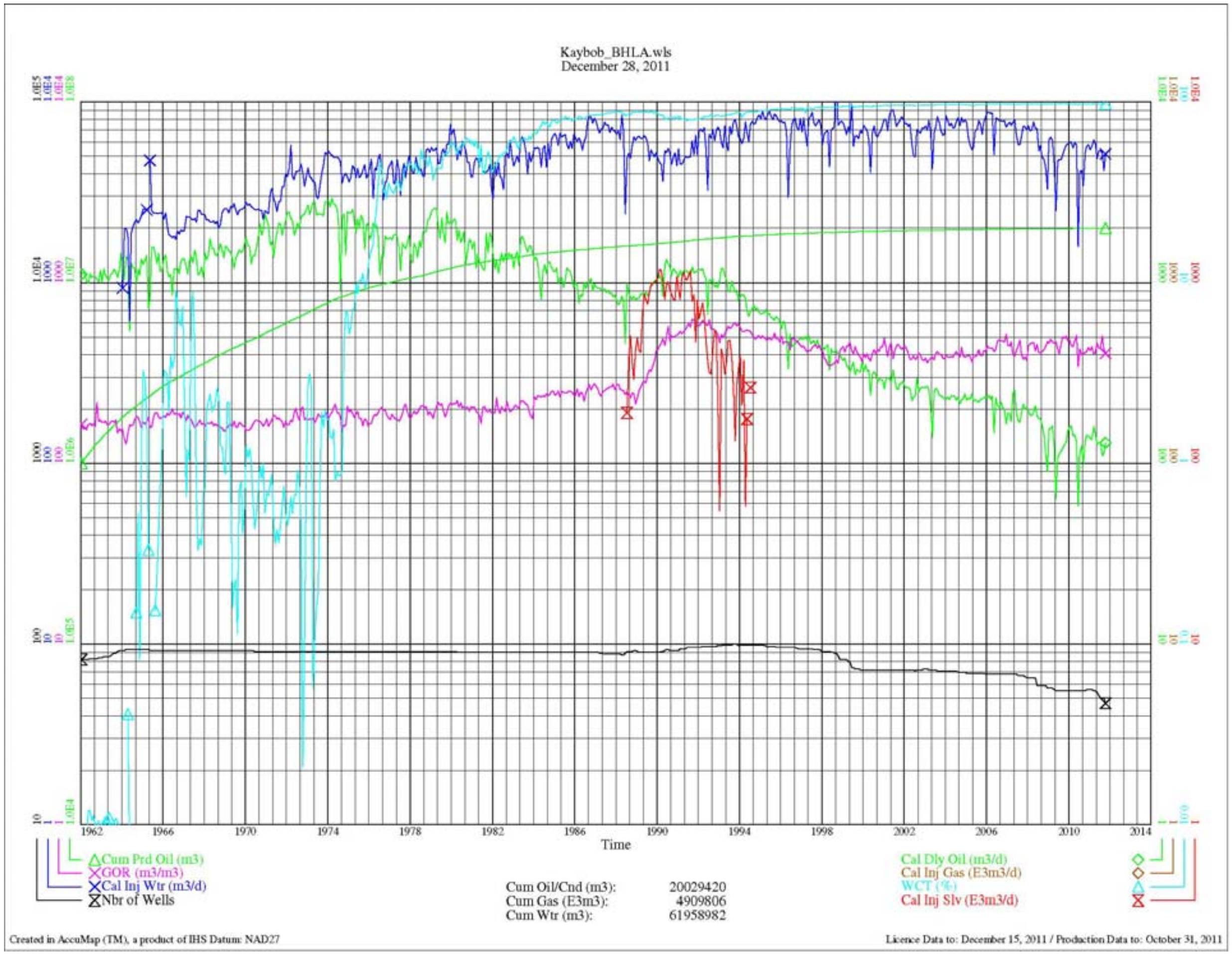
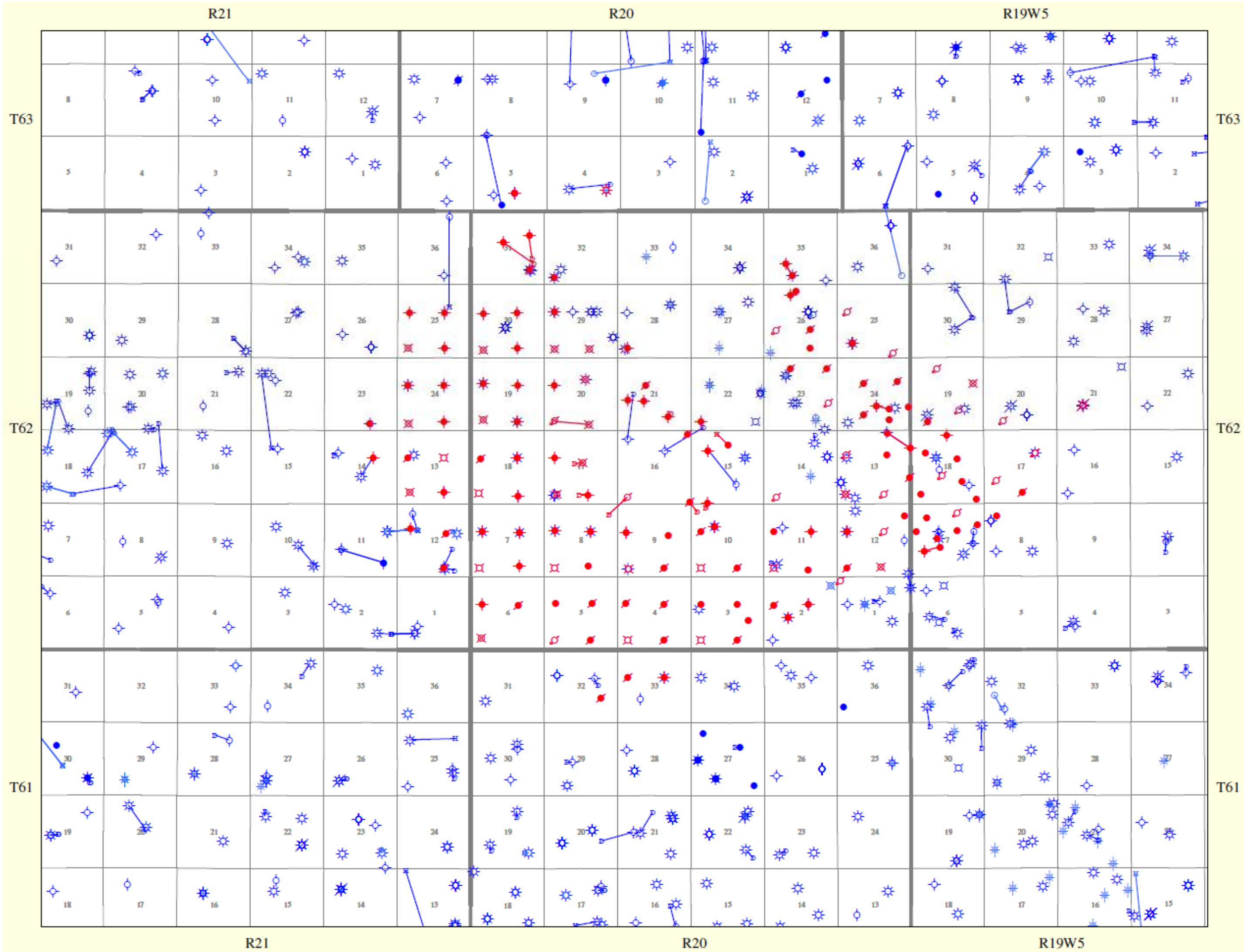



Figure 64

**Kaybob Beaverhill Lake A - Production / Injection History**

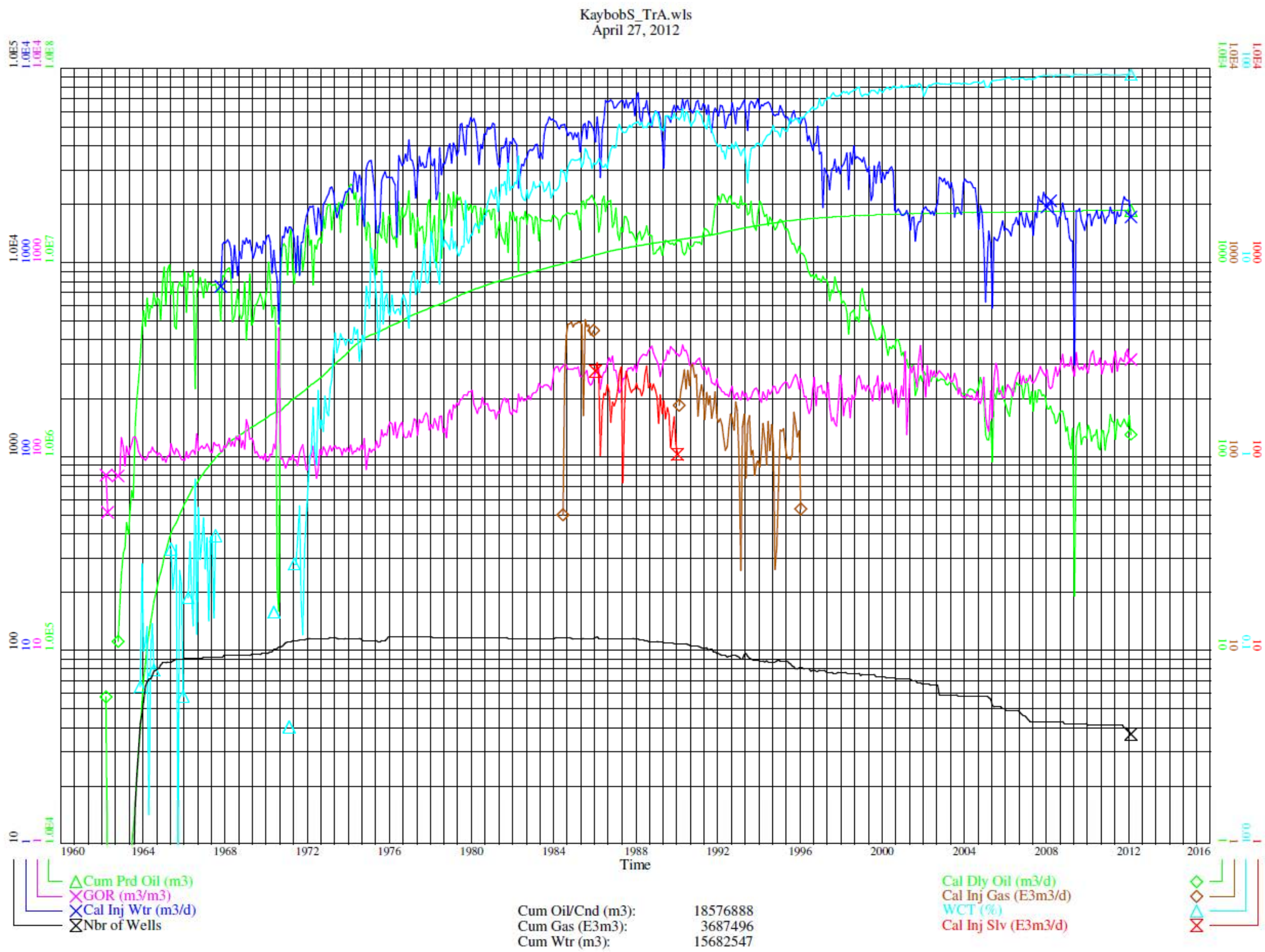



**Kaybob South Triassic A - Well Locations**

Figure 65

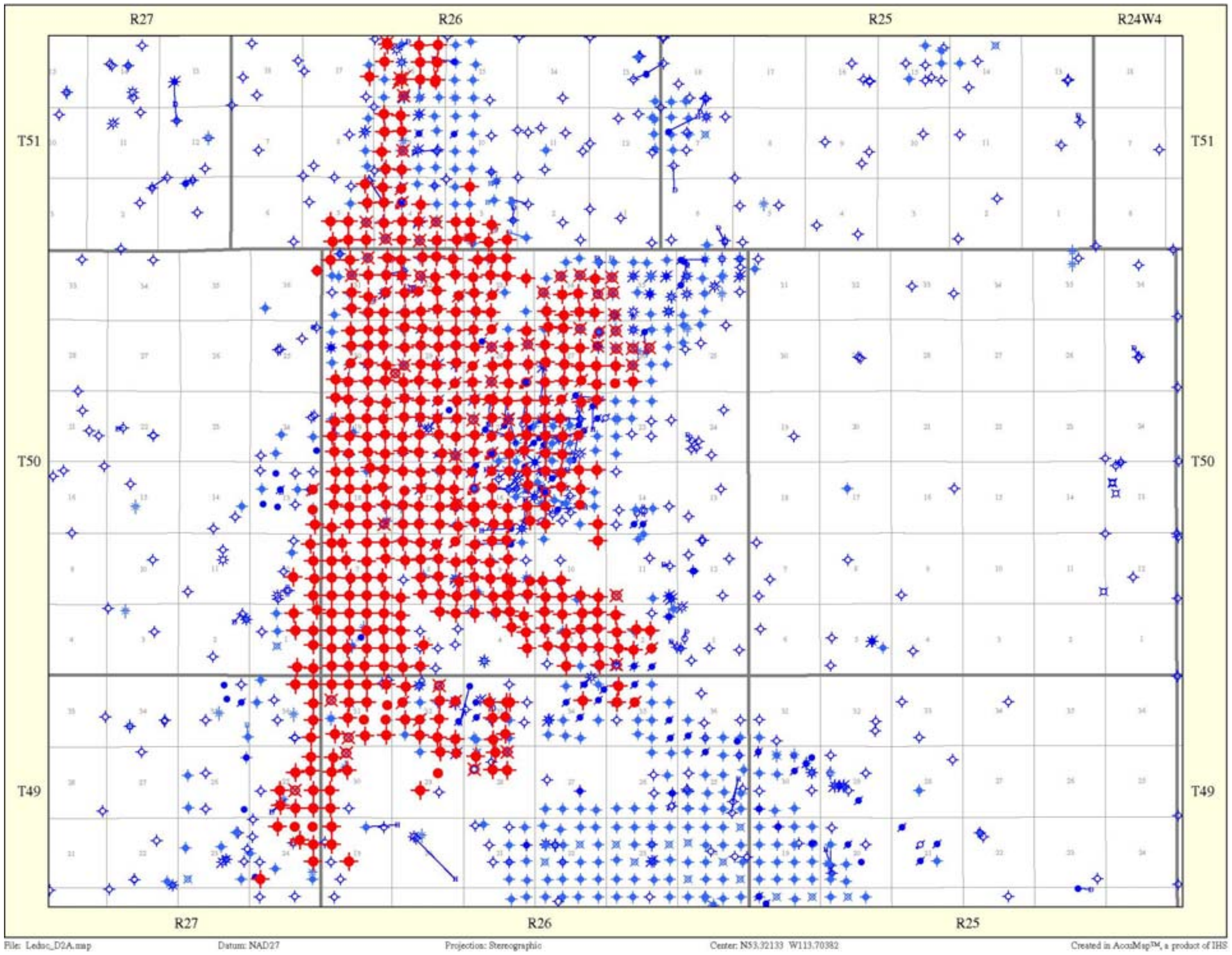


Sproule



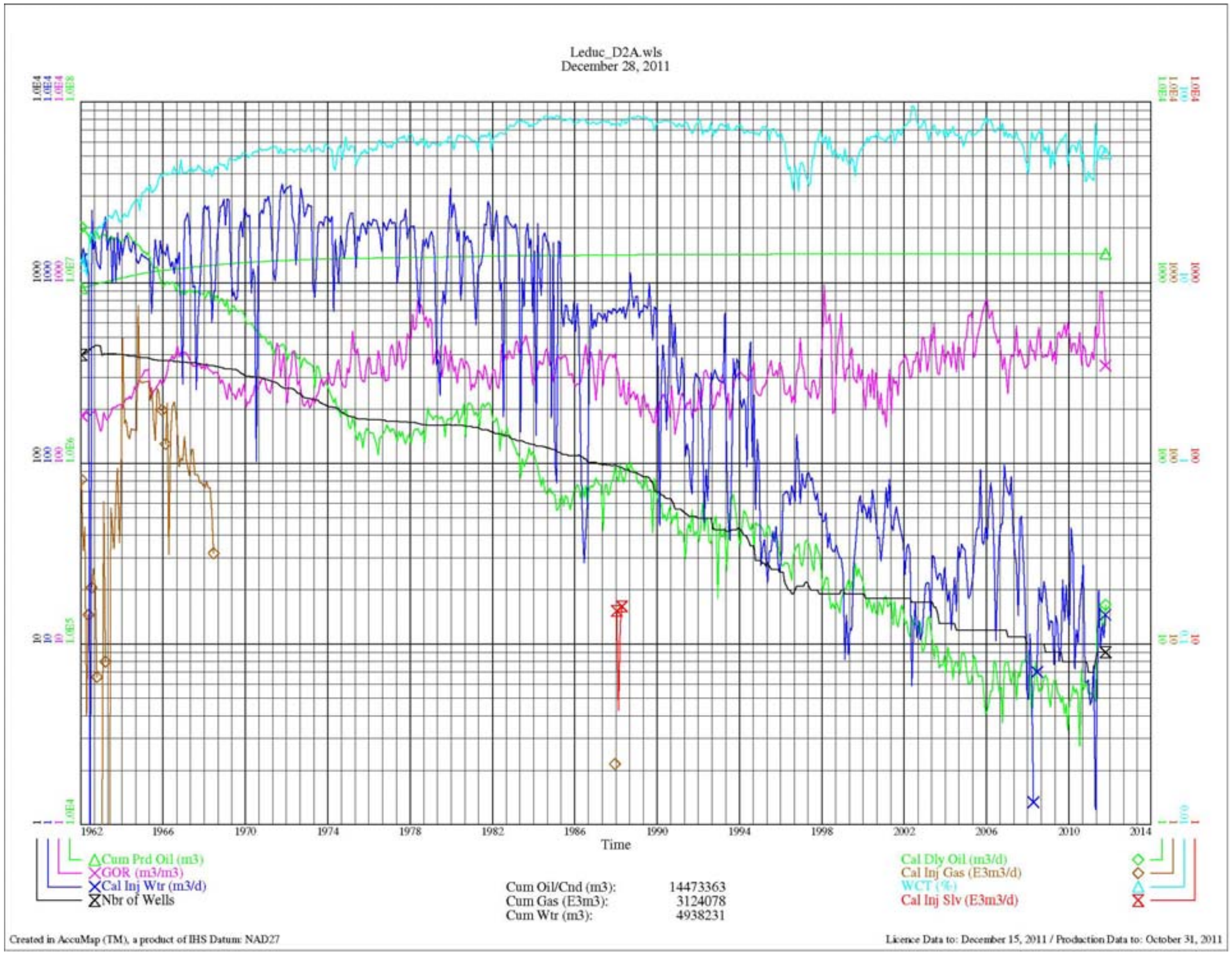

**Kaybob South Triassic A - Production / Injection History**

Figure 66




**Leduc D-2A - Well Locations**

Figure 67

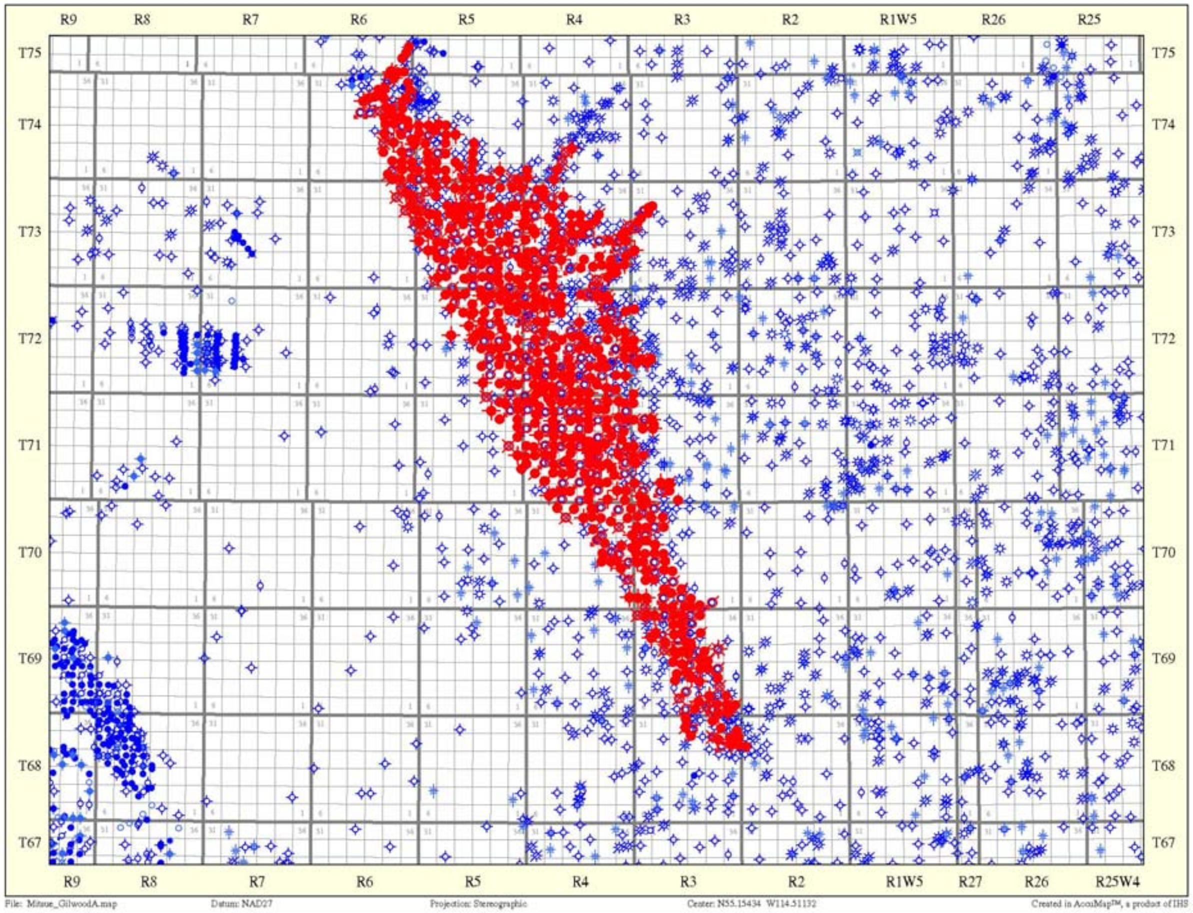



**Leduc D-2A - Production / Injection History**

Figure 68

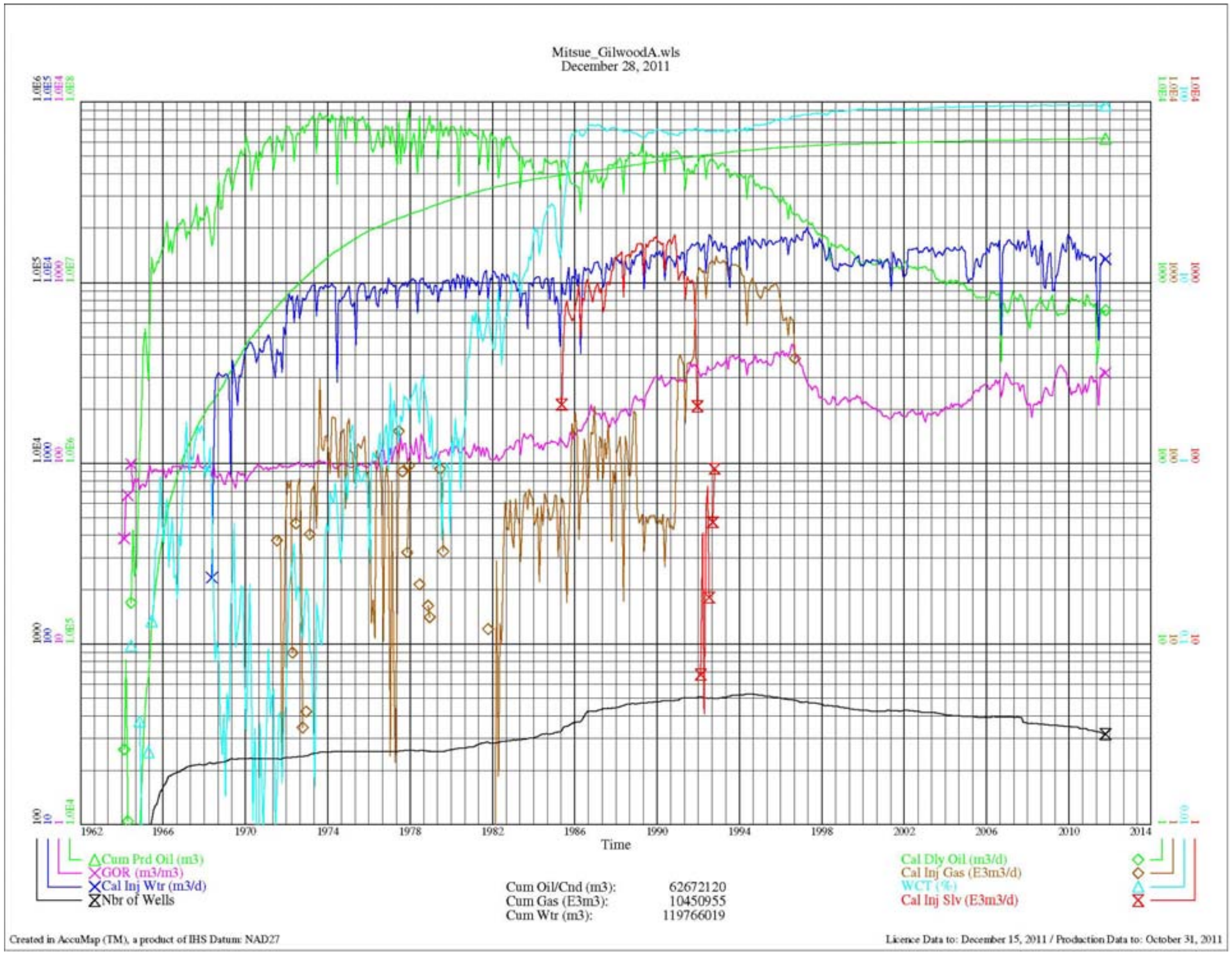


Sproule



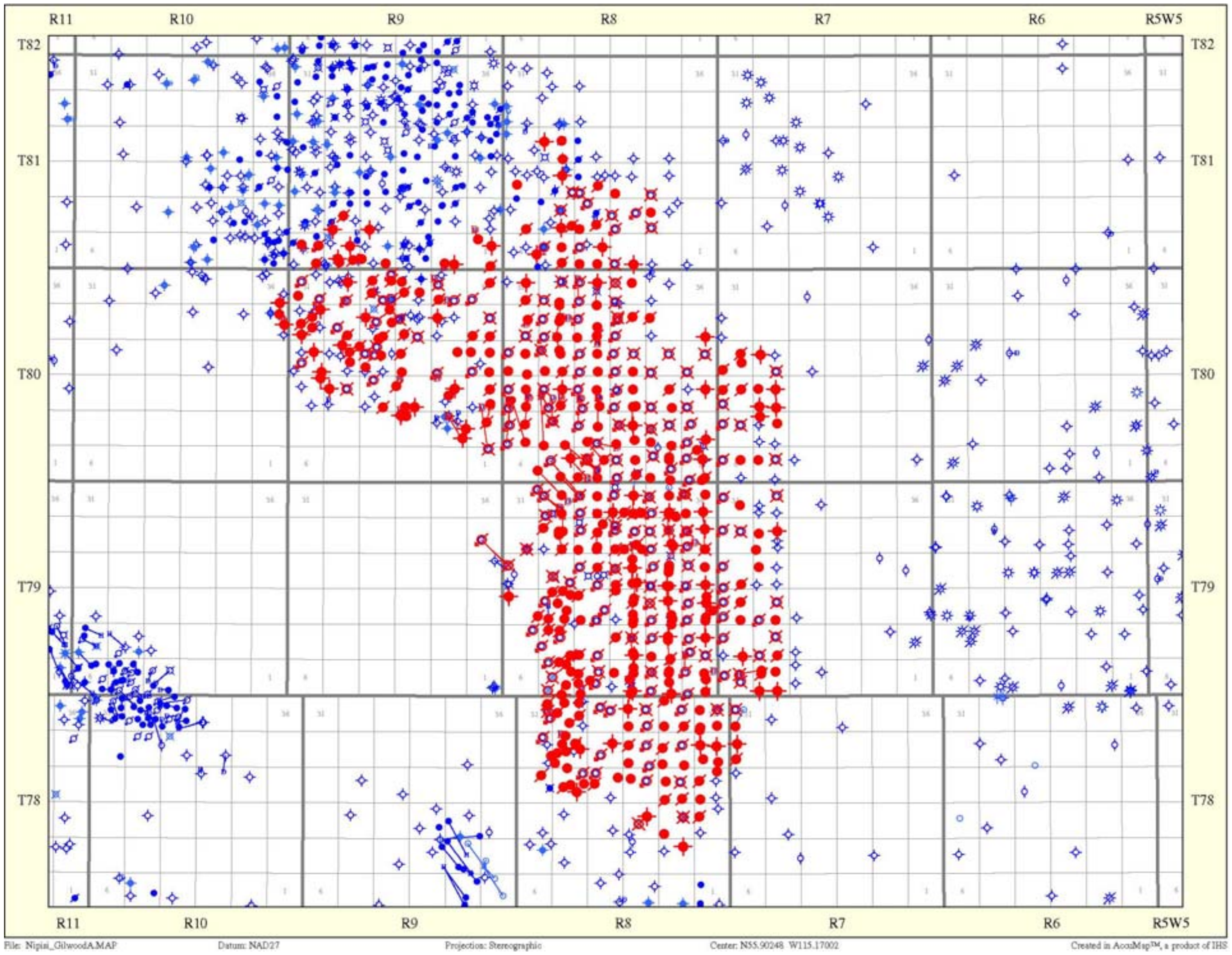

**Mitsue Gilwood A - Well Locations**

Figure 69




**Mitsue Gilwood A - Production / Injection History**

Figure 70




**Nipisi Gilwood A - Well Locations**

Figure 71

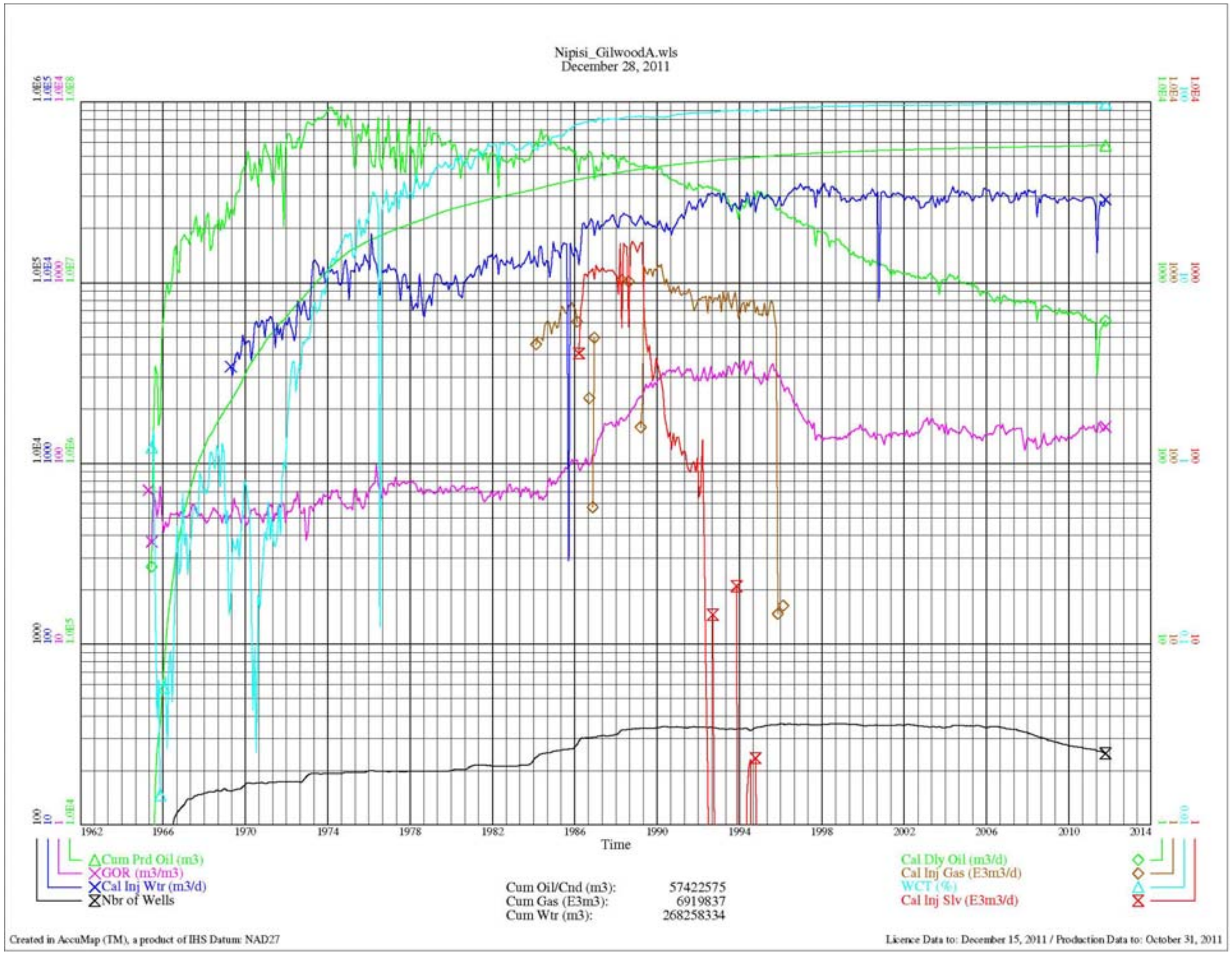
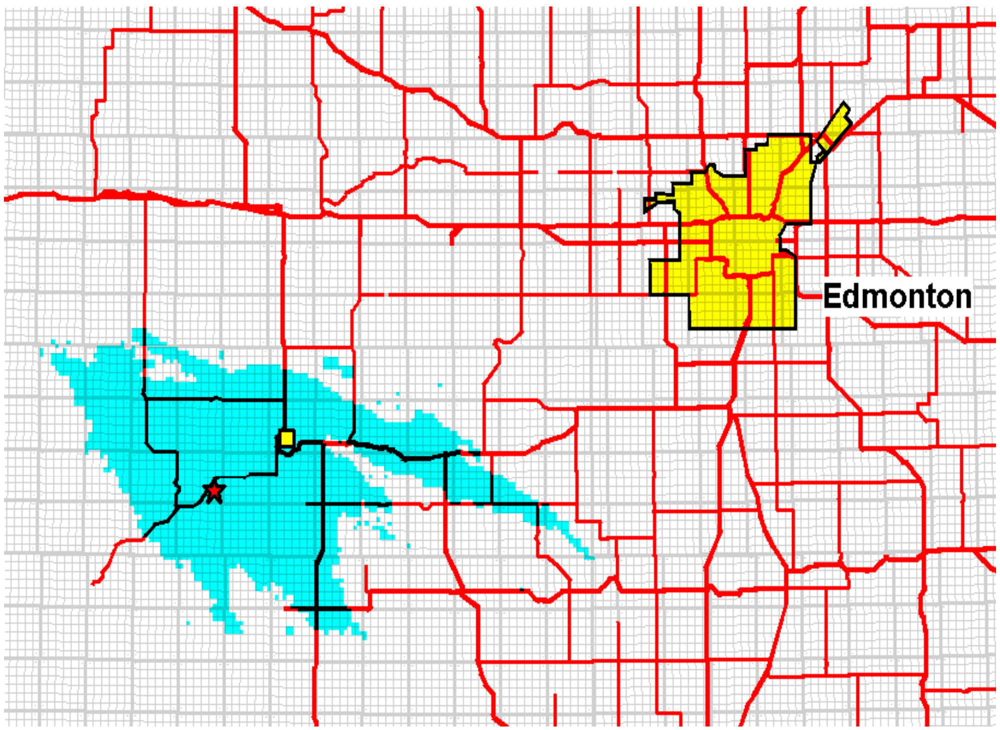



Figure 72

**Nipisi Gilwood A - Production / Injection History**

## Pembina Cardium A Pool - Location



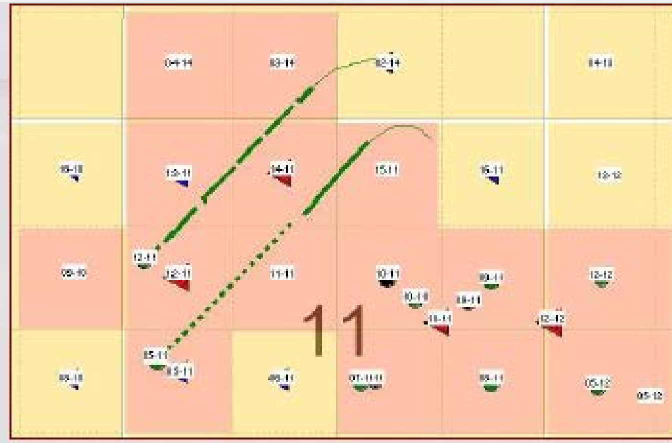

- Initially produced under primary depletion
- Waterflood initiated in 1960
- Some areas have experienced gas injection
- Good clean homogeneous sand
- Some areas have heterogeneous, highly permeable conglomerate on top of sand
- Reservoir pressure is well maintained in most areas

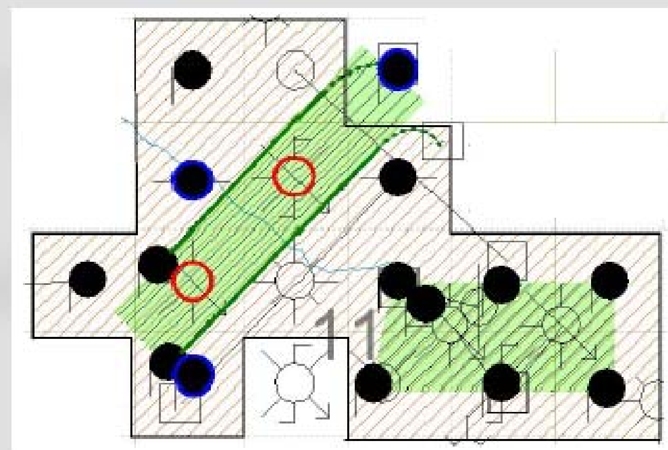
Figure 73

# Location

## Pembina 'A' Lease $CO_2$ Pilot

- Located adjacent to the Penn West's initial 'A' Lease vertical $CO_2$ pilot
- Targeting the residual oil in well flooded area (high watercut)
- $CO_2$ injection commenced on September, 2008



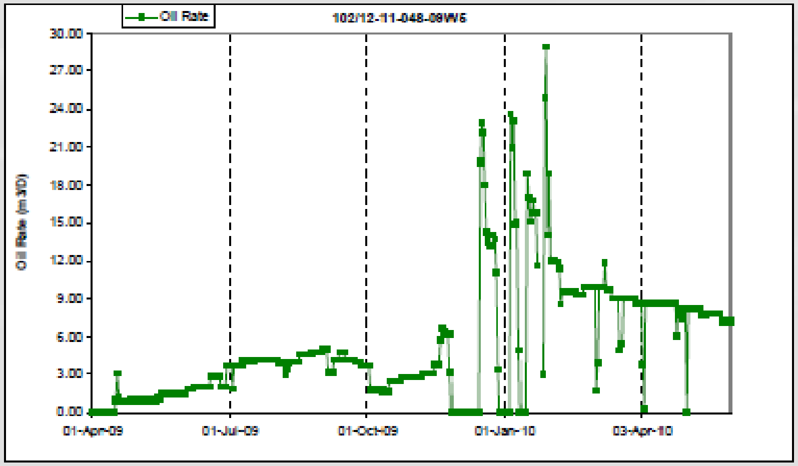



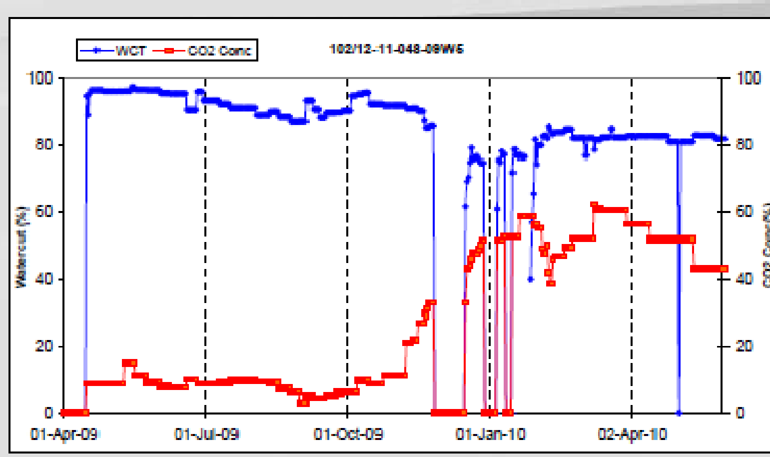

PennWest ENERGY

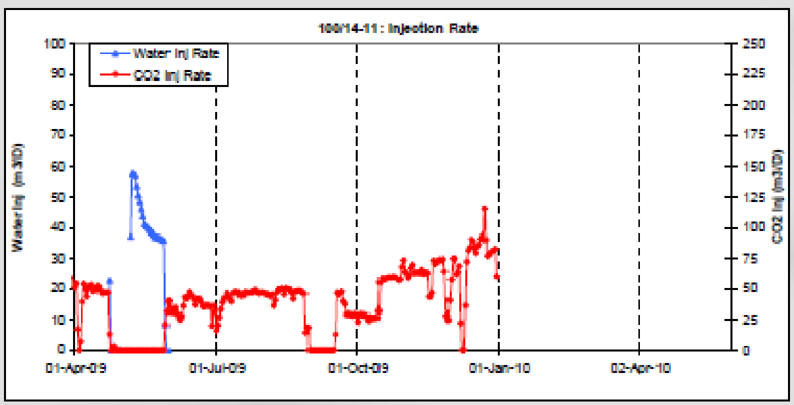
Figure 74

# Performance -02/12-11-048-09W5 2010 Response

Pembina 'A' Lease $CO_2$ Pilot



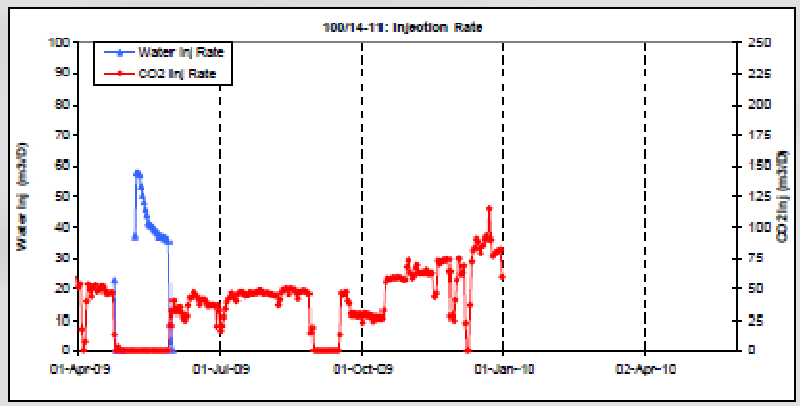




Figure 75

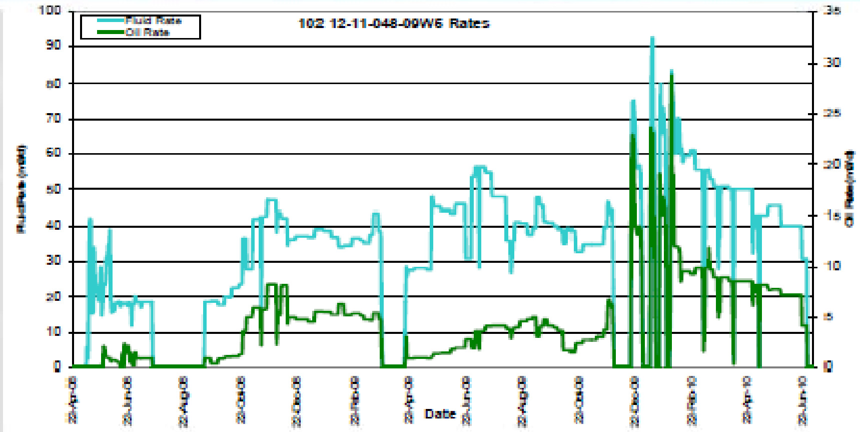
West
RGY

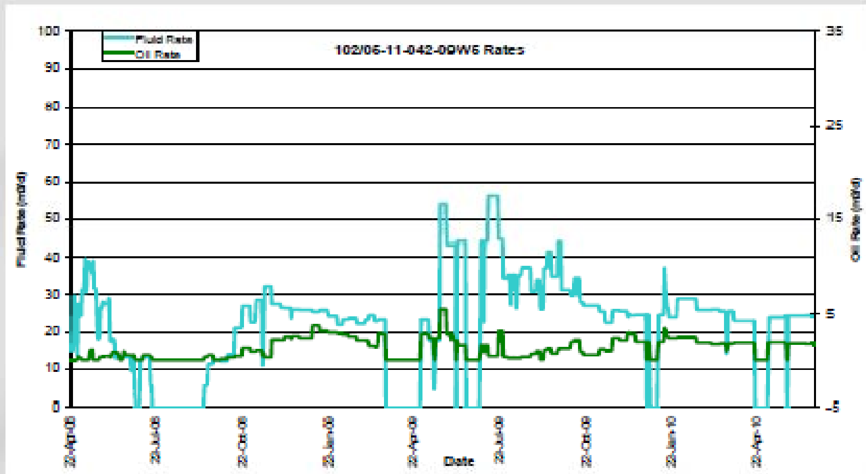
18158

Sproule

# Performance Comparison

## Pembina 'A' Lease $CO_2$ Pilot




PennWest ENERGY

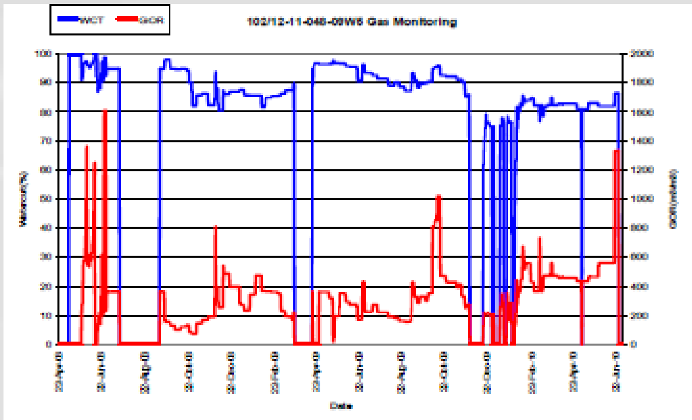
Figure 76

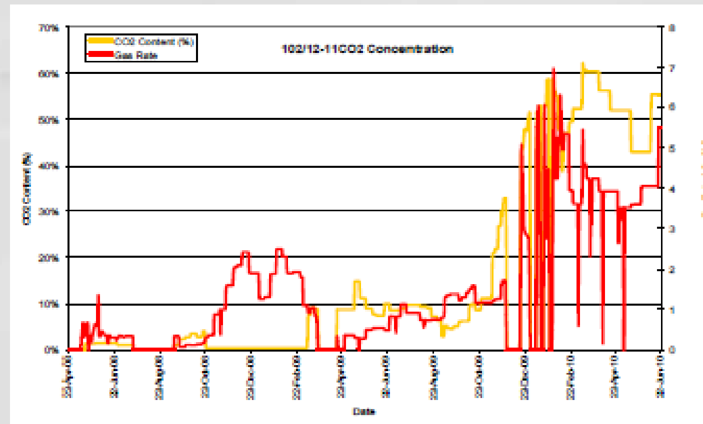


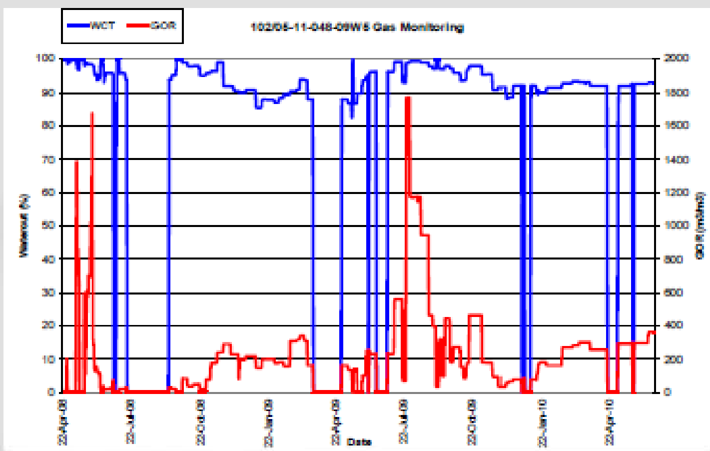
Sproule

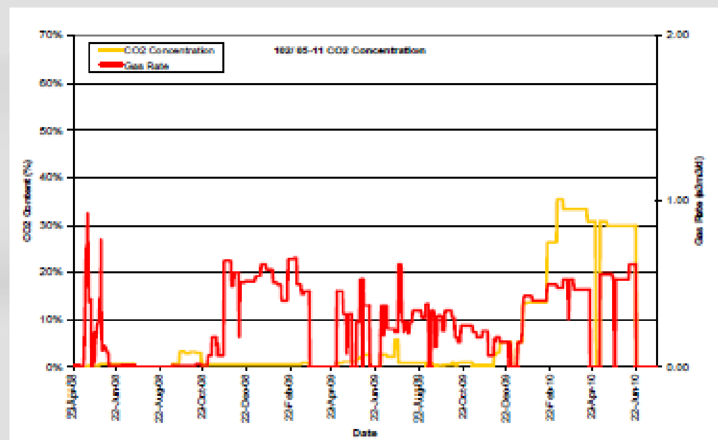
# Performance Comparison

## Pembina 'A' Lease $CO_2$ Pilot



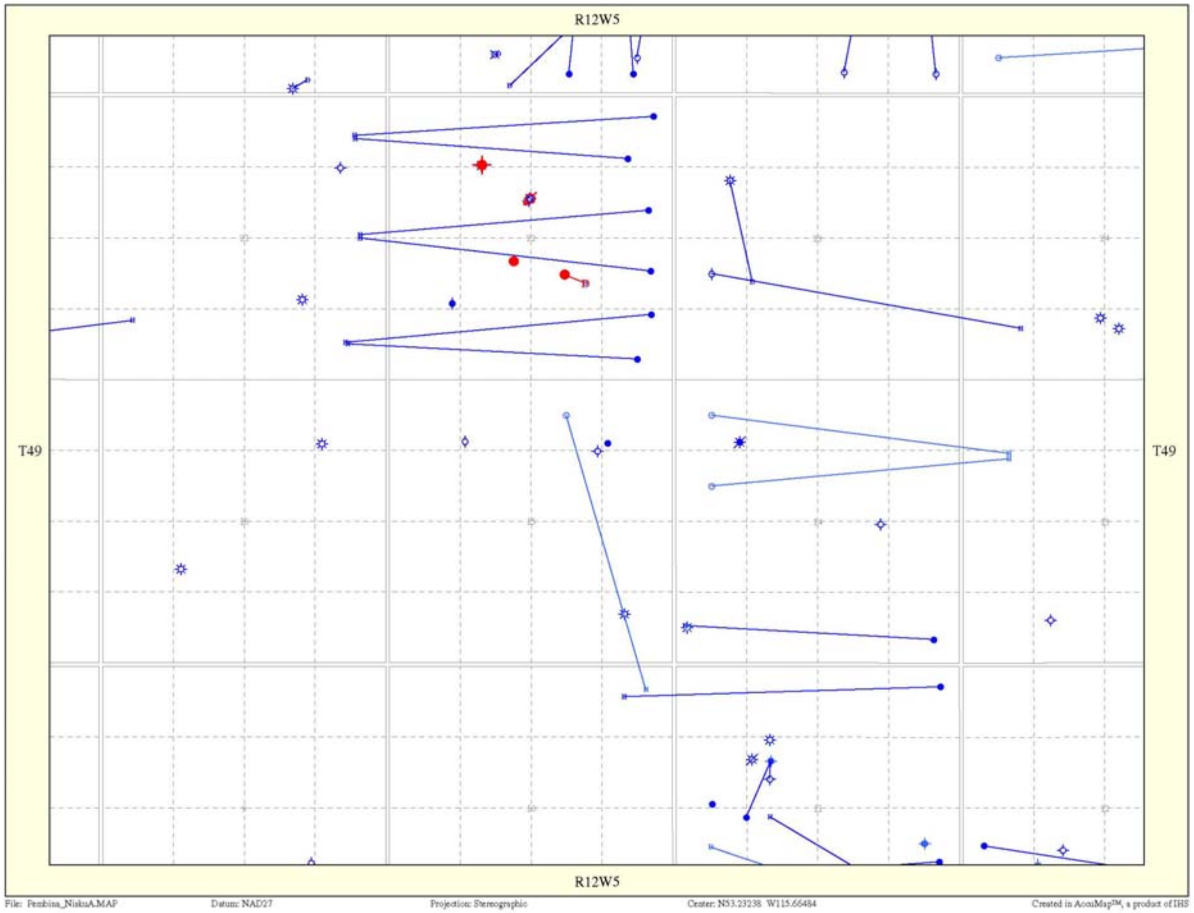




PennWest ENERGY

Figure 77

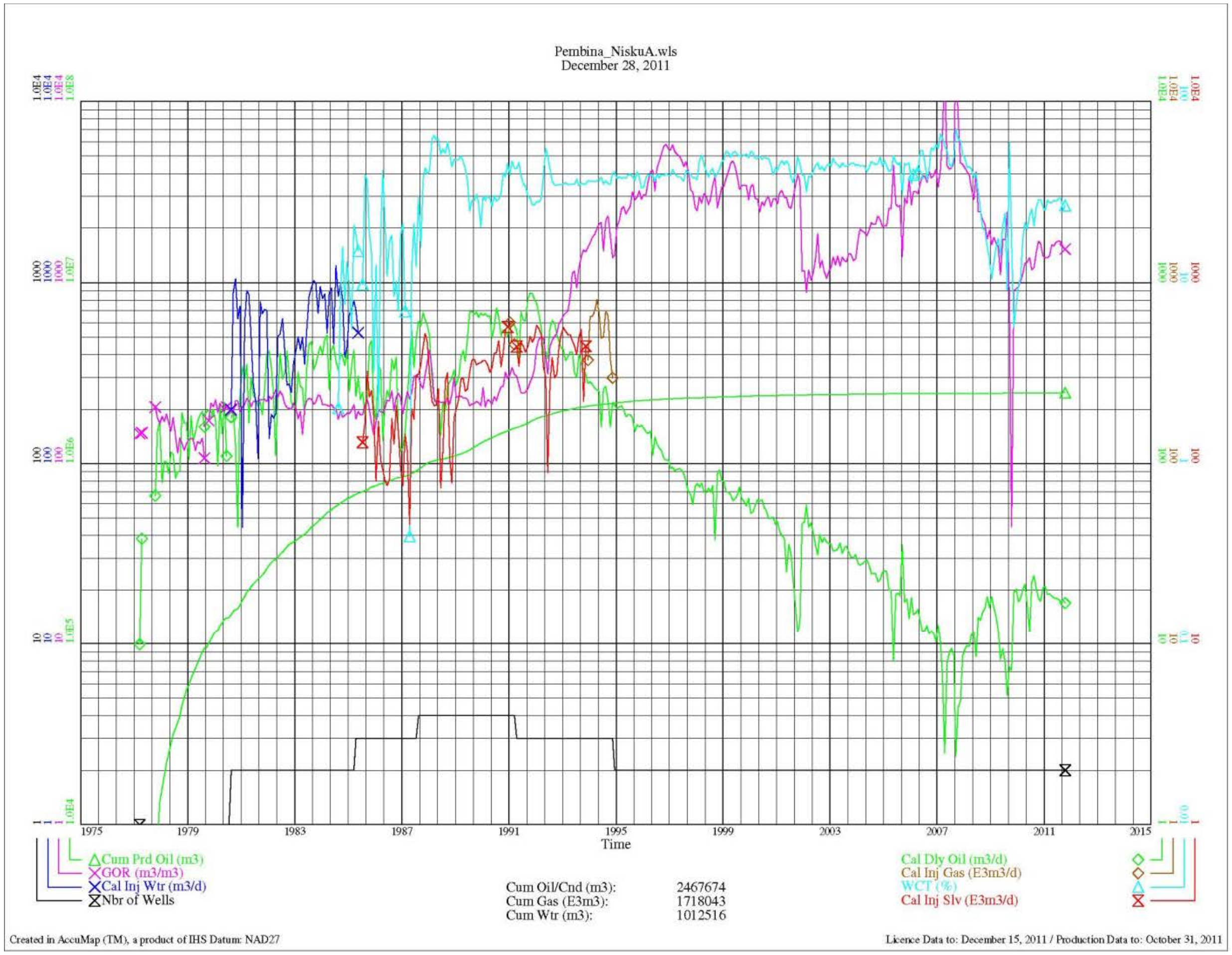


Sproule




**Pembina Nisku A - Well Locations**

Figure 78

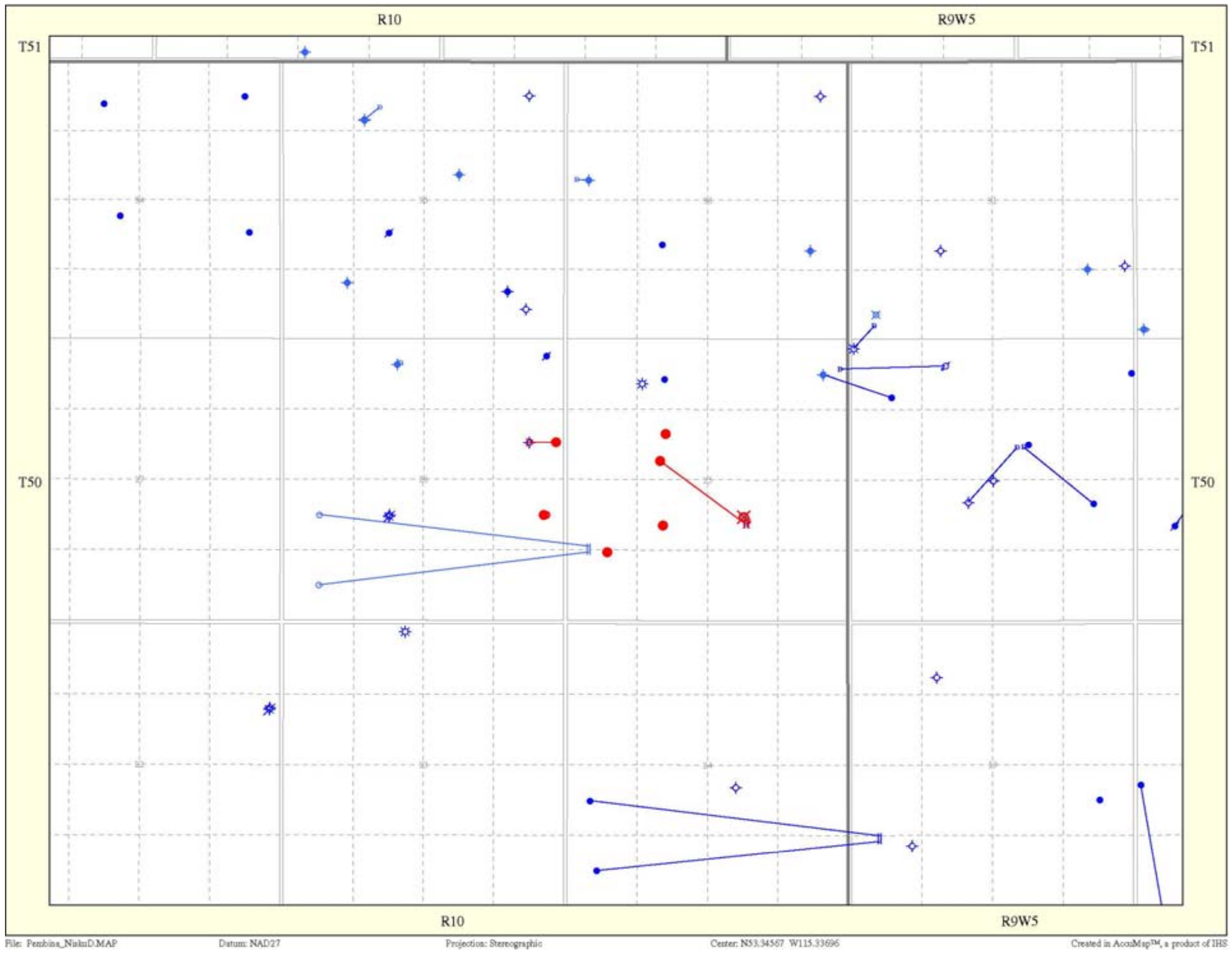



**Pembina Nisku A - Production / Injection History**

Figure 79

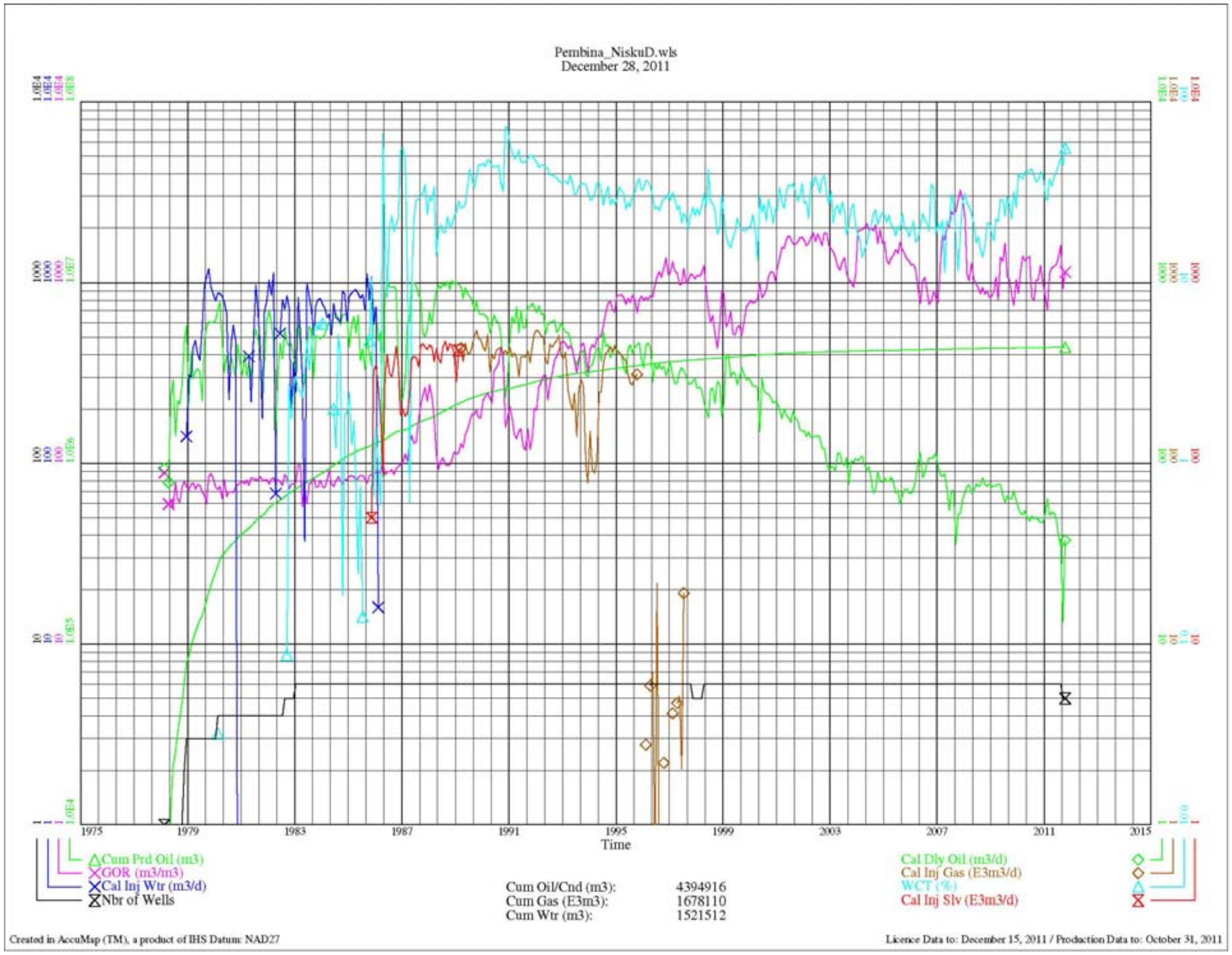


Sproule



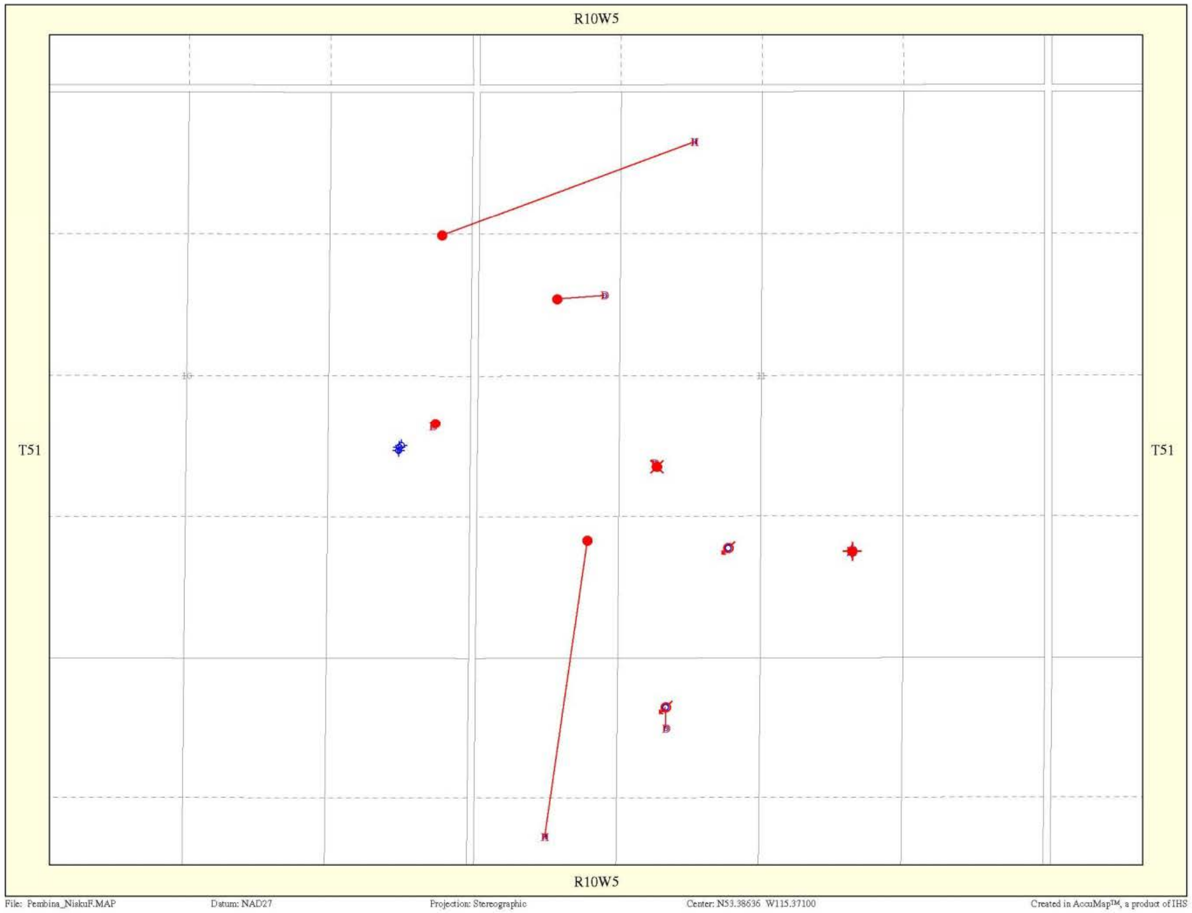

**Pembina Nisku D - Well Locations**

Figure 80



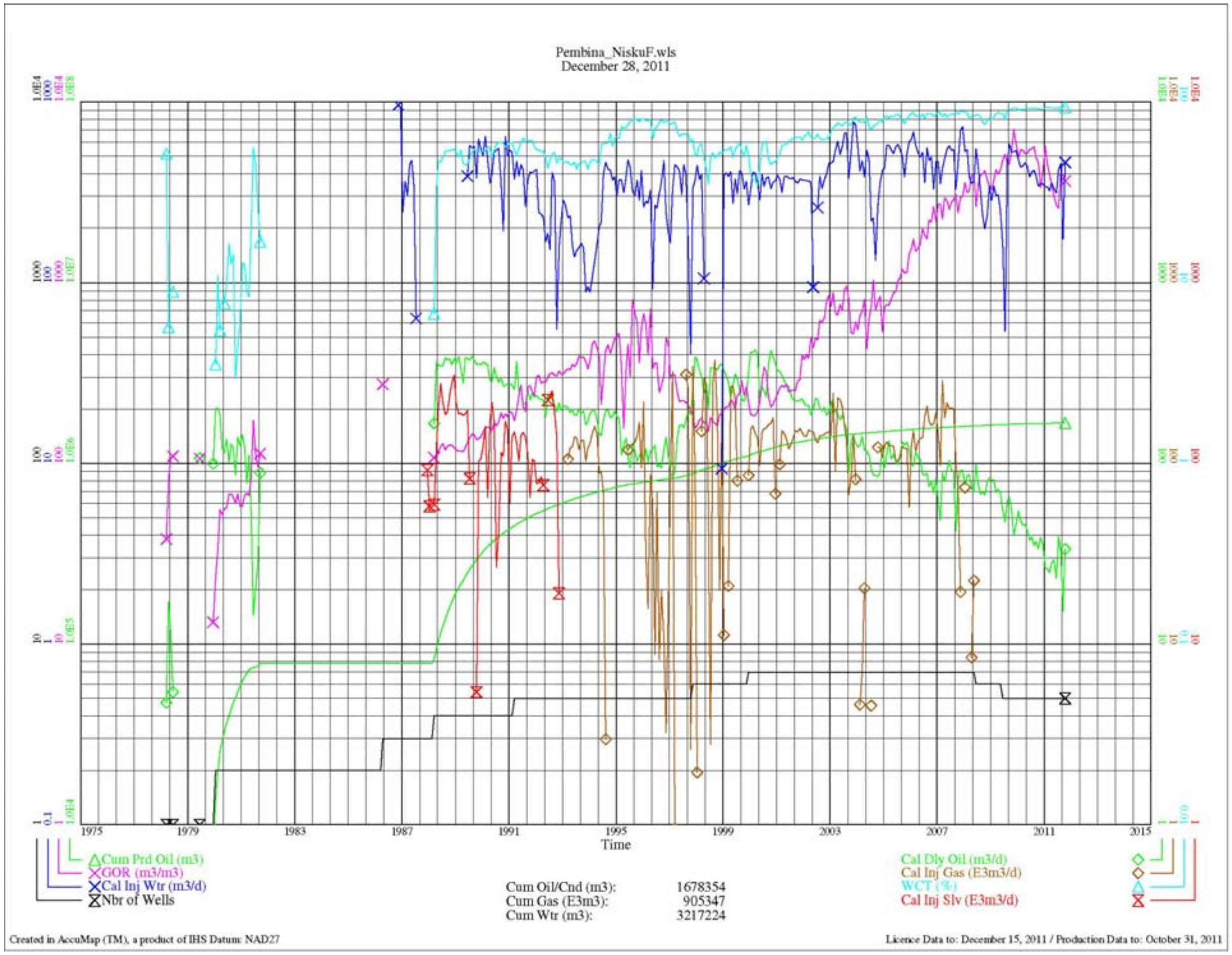

**Pembina Nisku D - Production / Injection History**

Figure 81




**Pembina Nisku F - Well Locations**

Figure 82




**Pembina Nisku F - Production / Injection History**

Figure 83

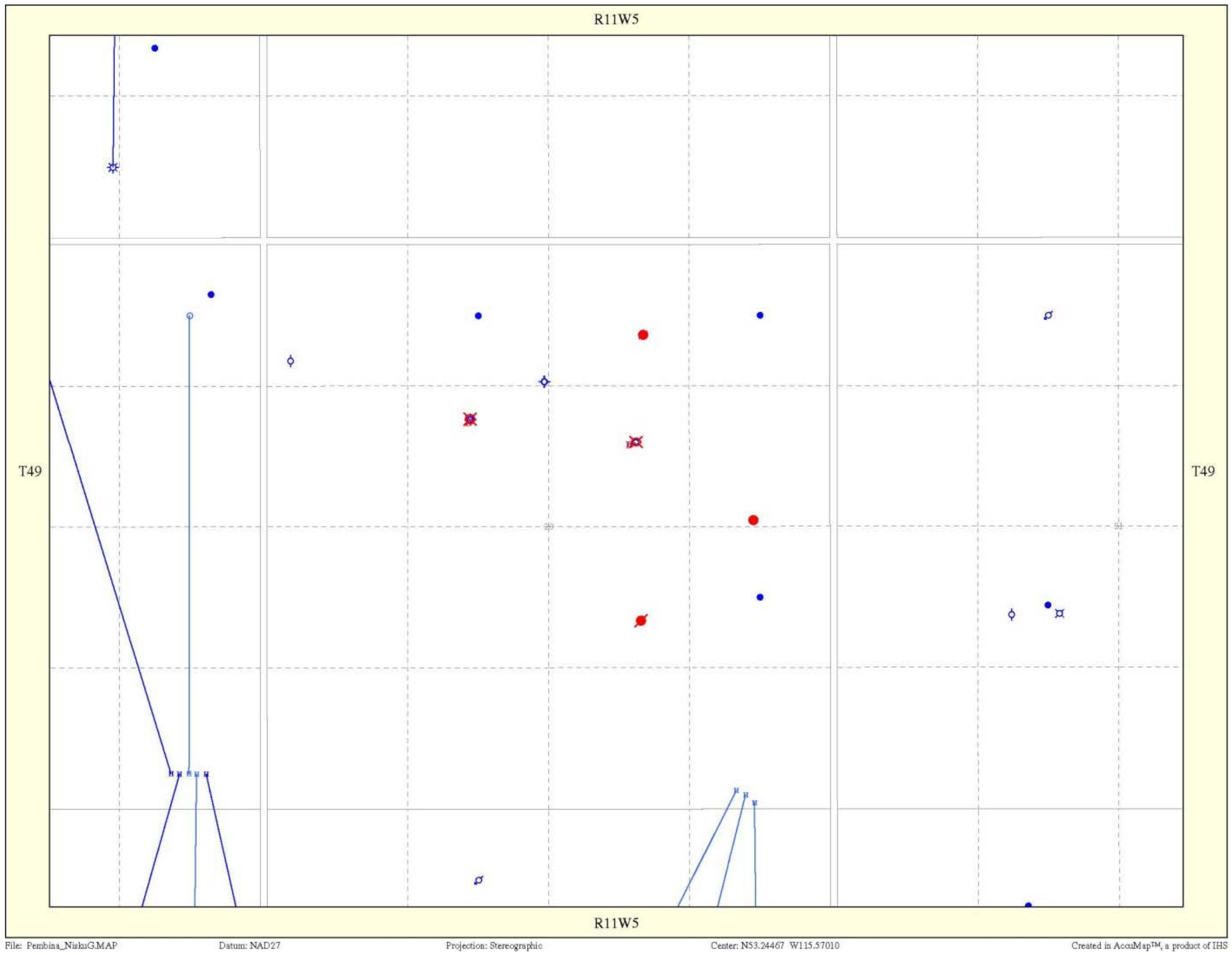
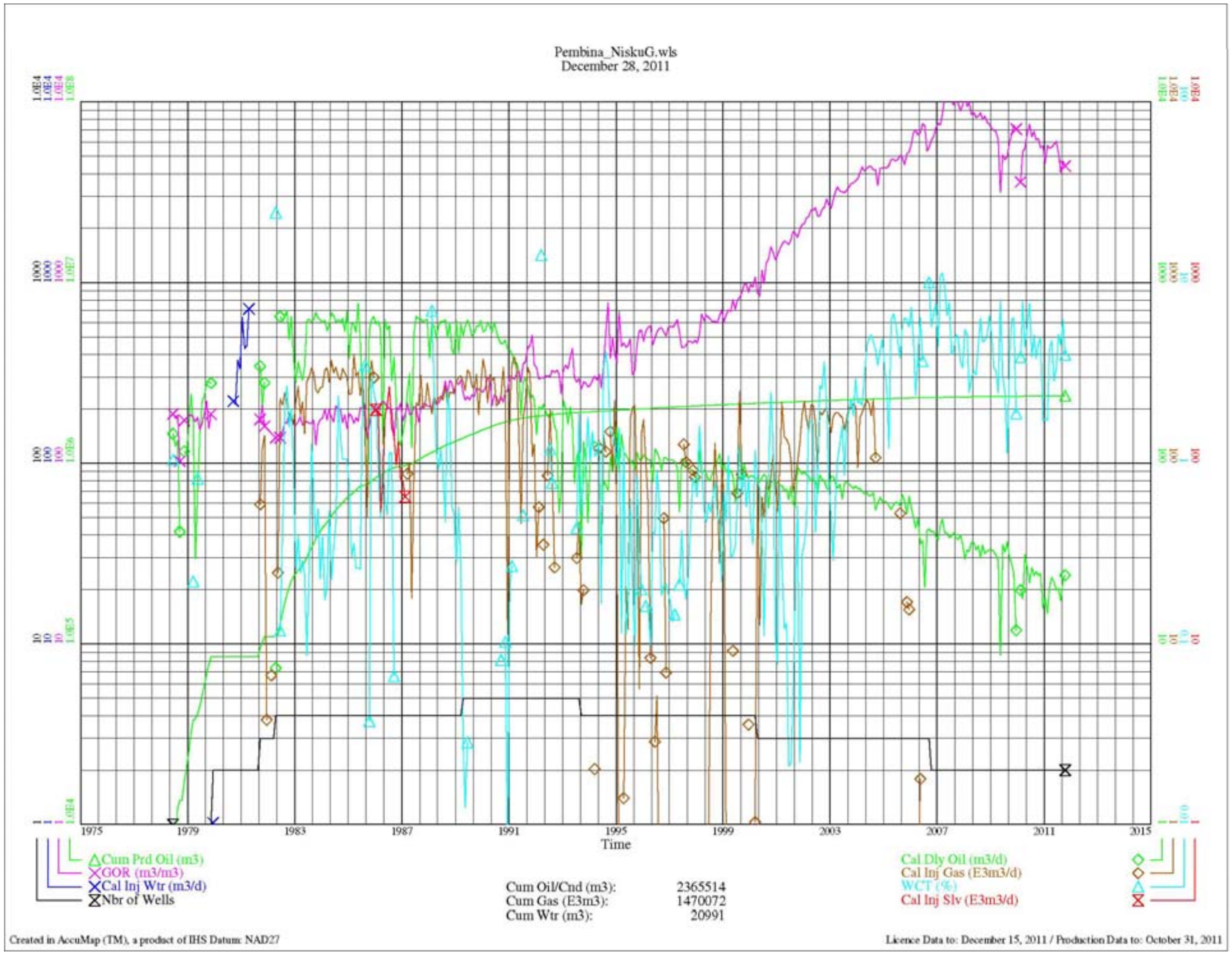



Figure 84

**Pembina Nisku G - Well Locations**

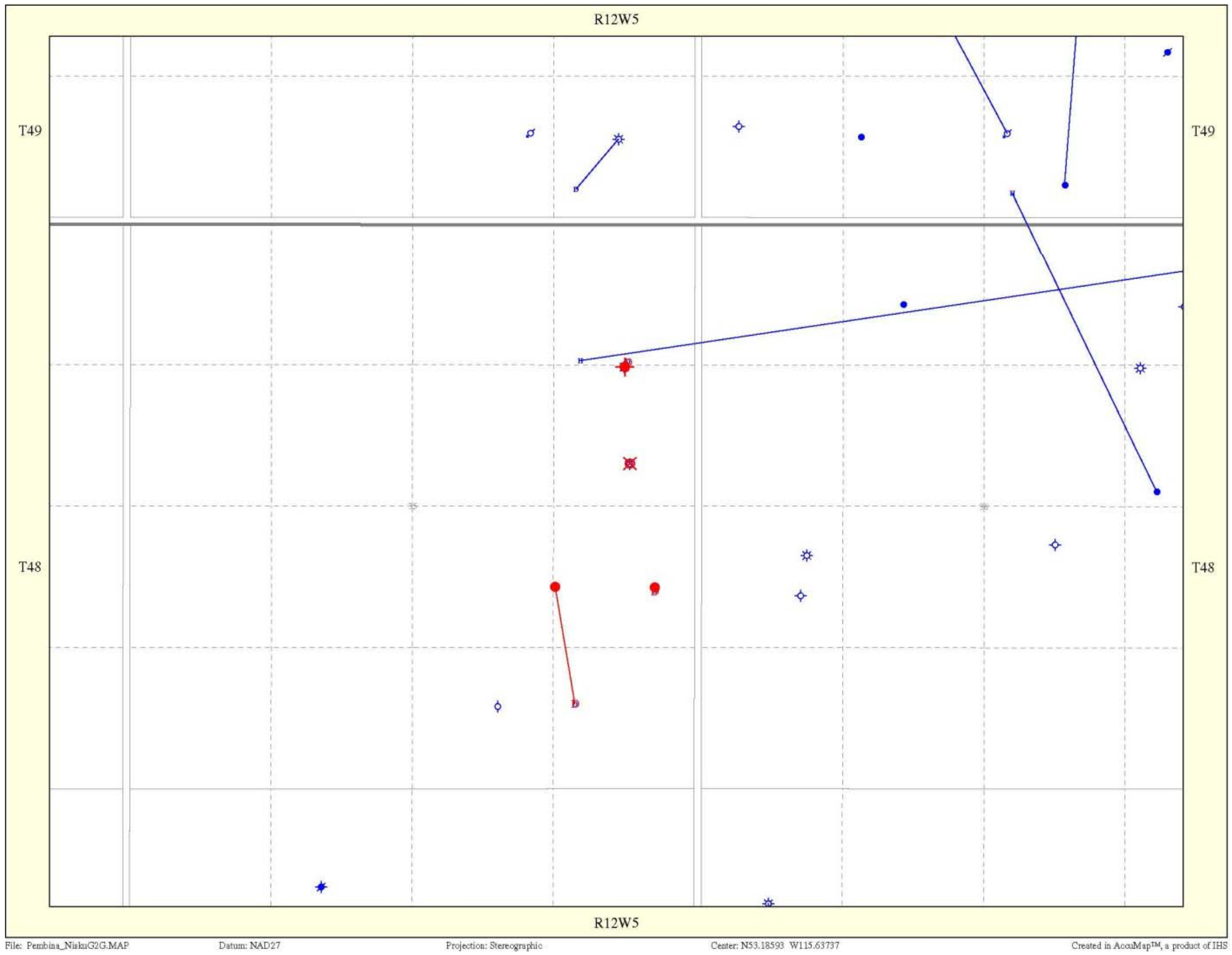



**Pembina Nisku G - Production / Injection History**

Figure 85



Sproule

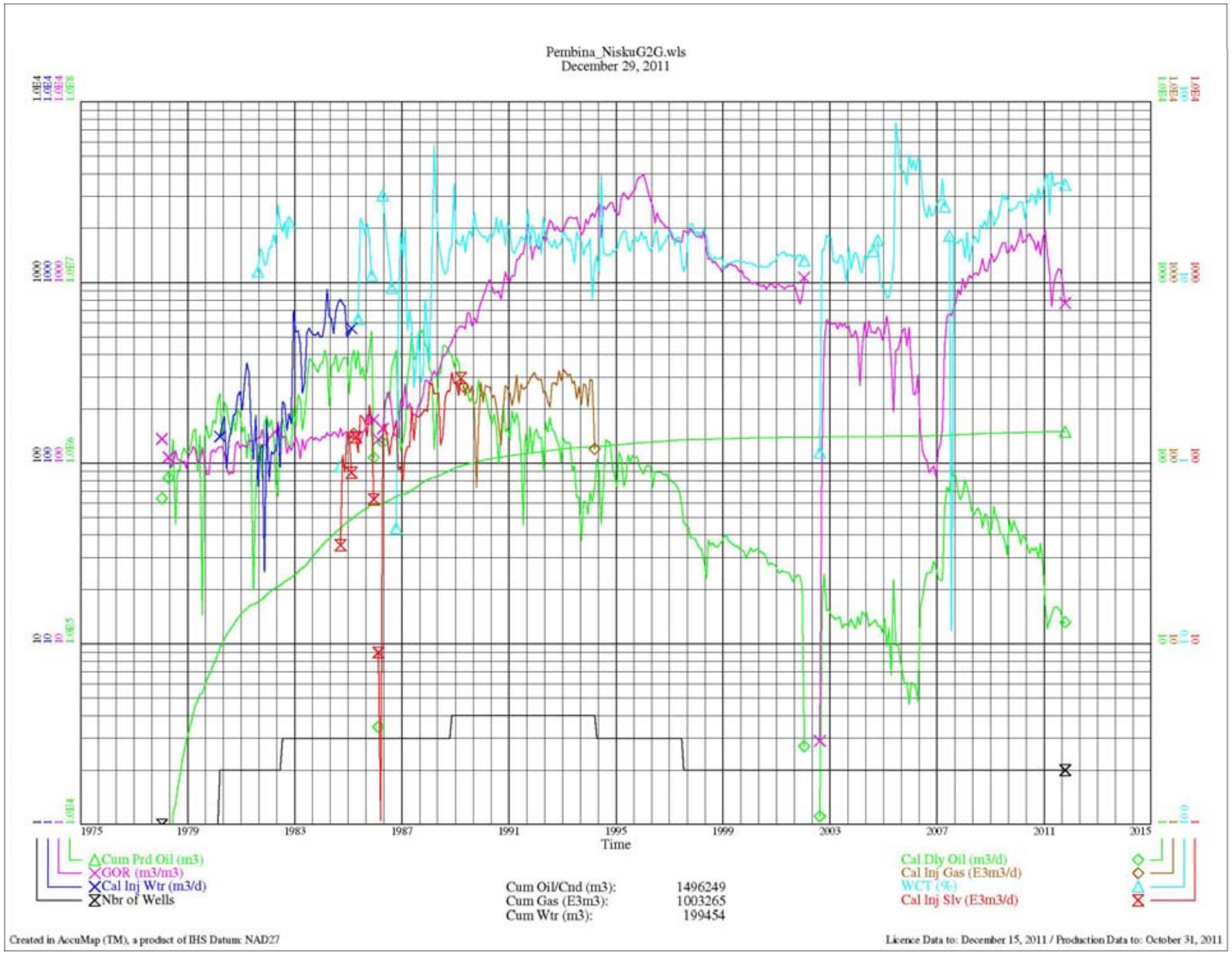



**Pembina Nisku G2G - Well Locations**

Figure 86

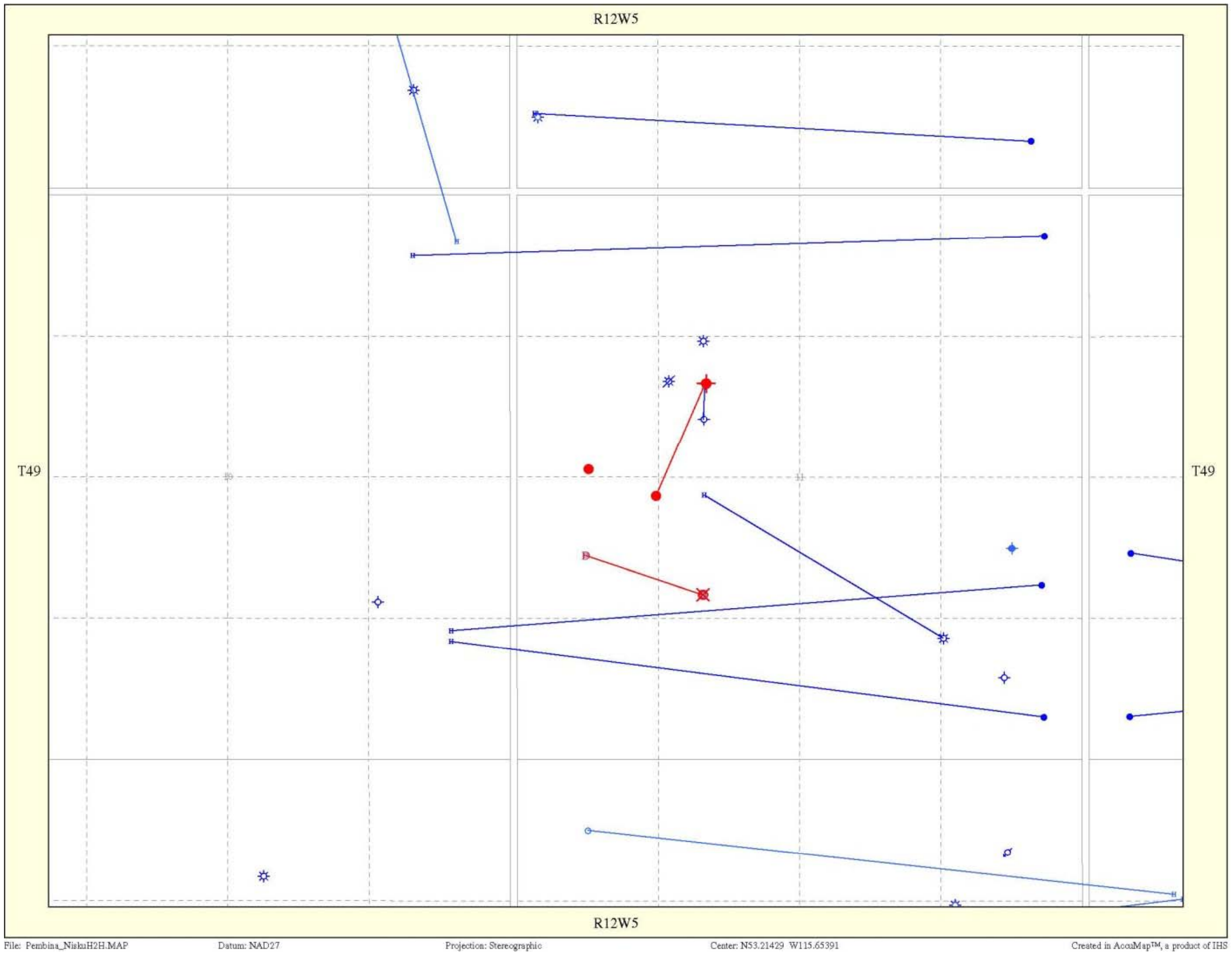


Sproule




**Pembina Nisku G2G - Production / Injection History**

Figure 87

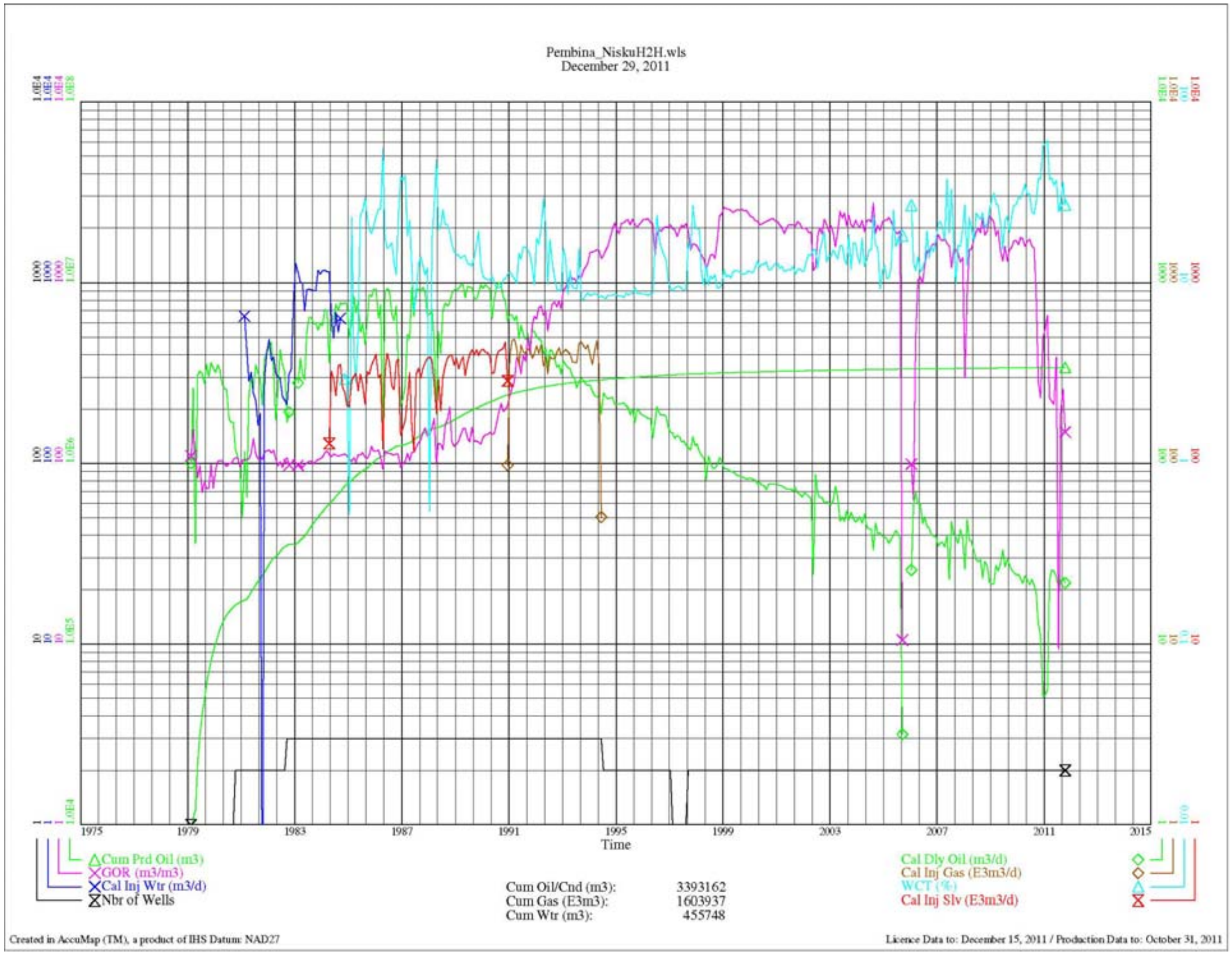



**Pembina Nisku H2H - Well Locations**

Figure 88

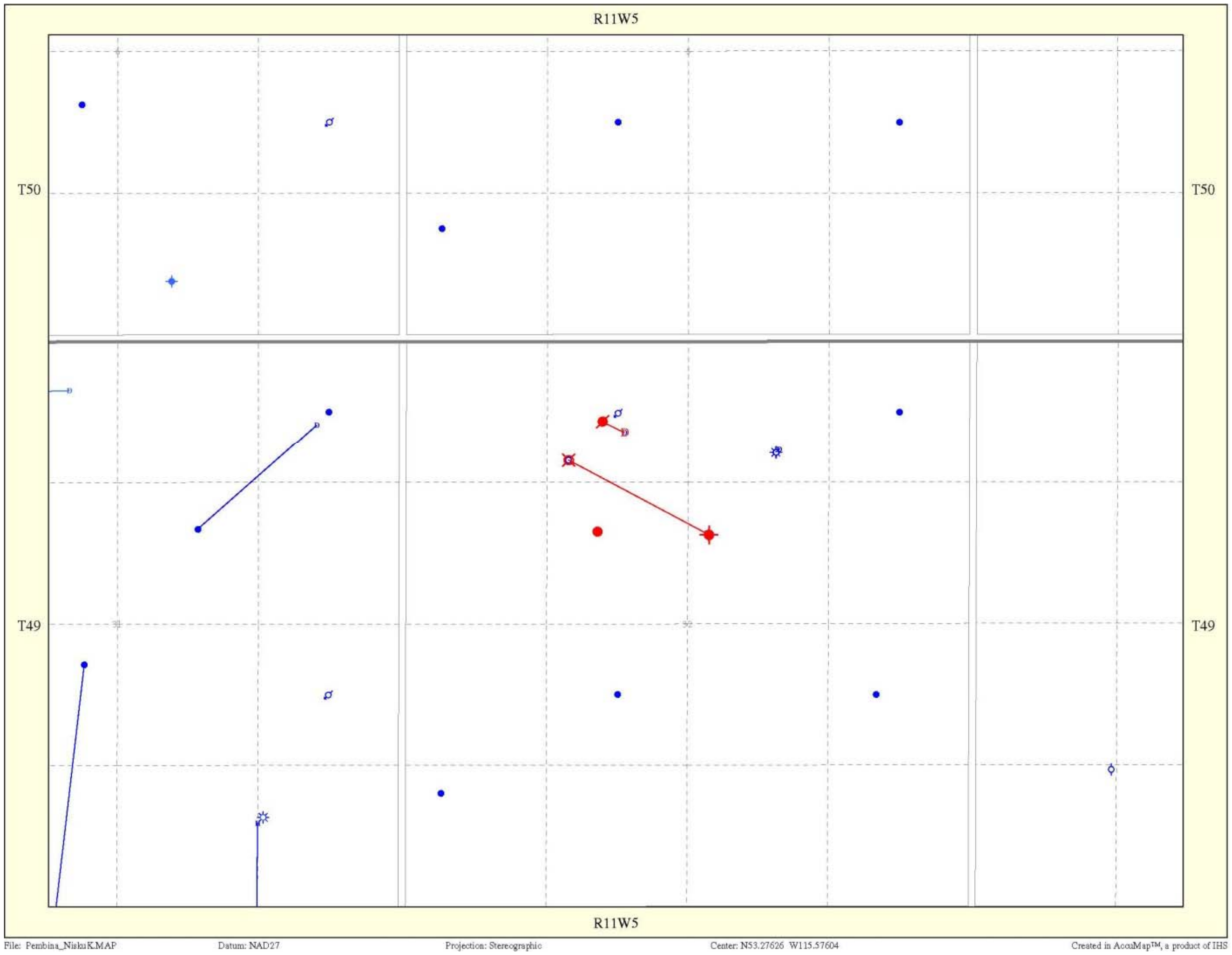


Sproule



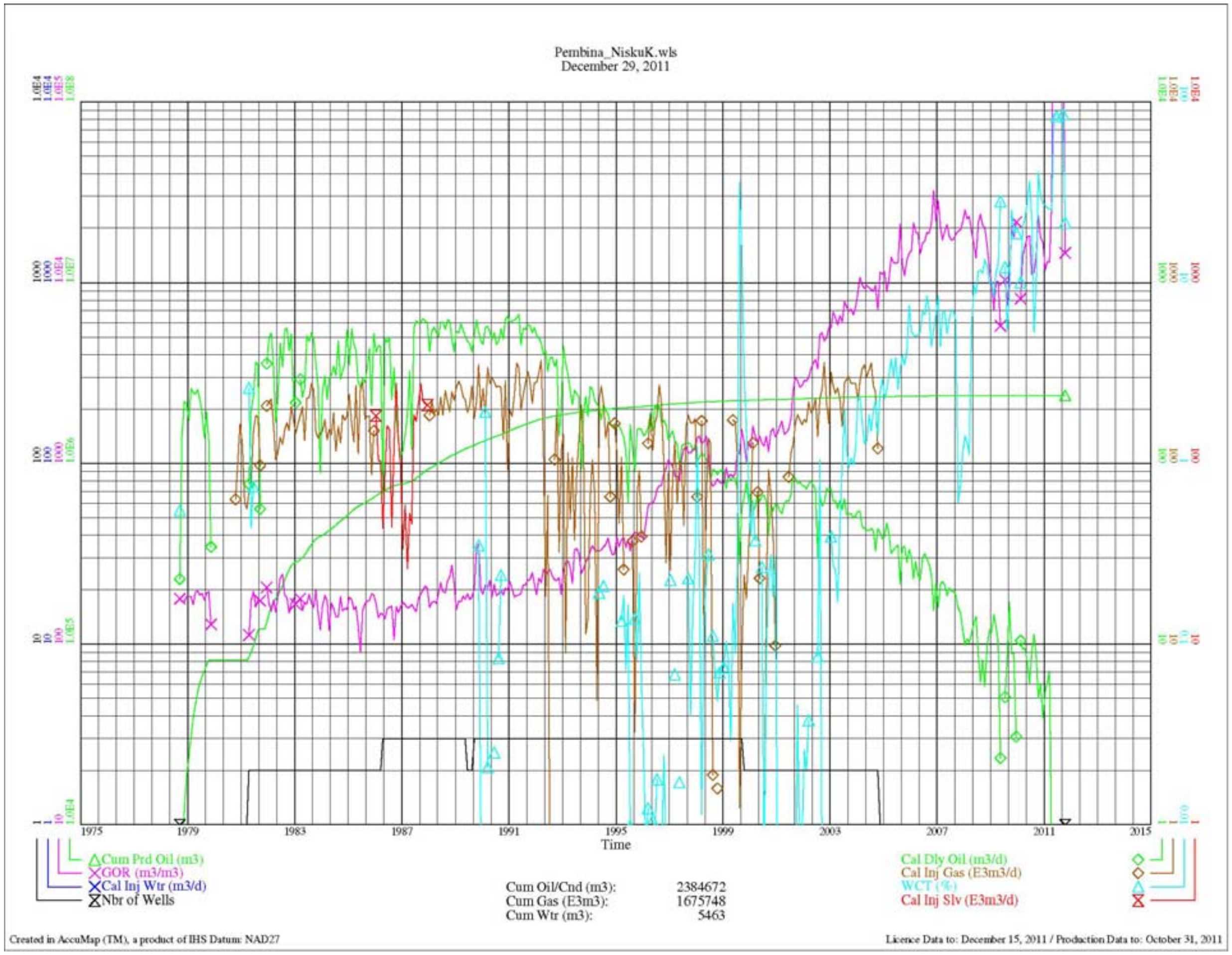

**Pembina Nisku H2H - Production / Injection History**

Figure 89



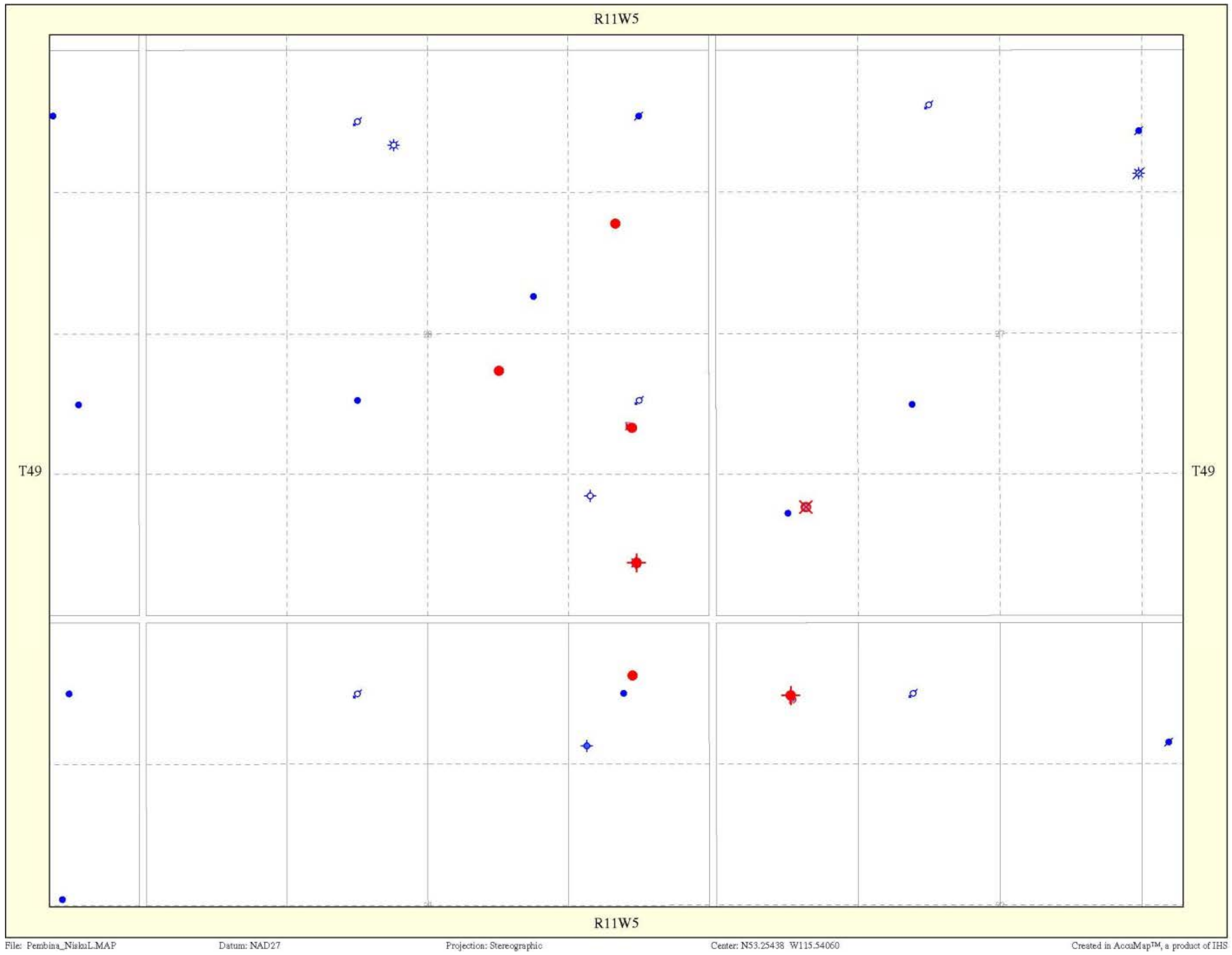

**Pembina Nisku K - Well Locations**

Figure 90



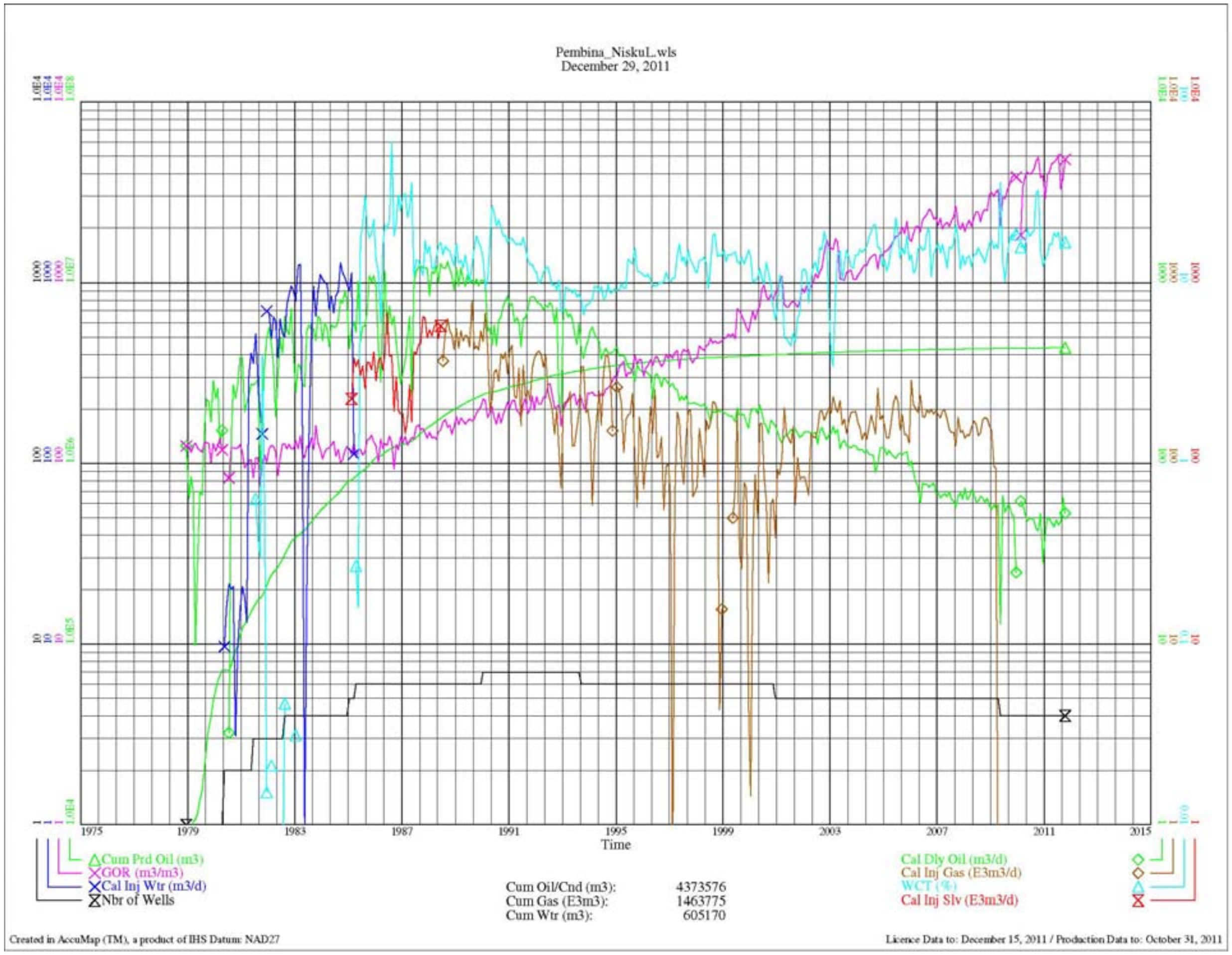

**Pembina Nisku K - Production / Injection History**

Figure 91




**Pembina Nisku L - Well Locations**

Figure 92




**Pembina Nisku L - Production / Injection History**

Figure 93



Sproule

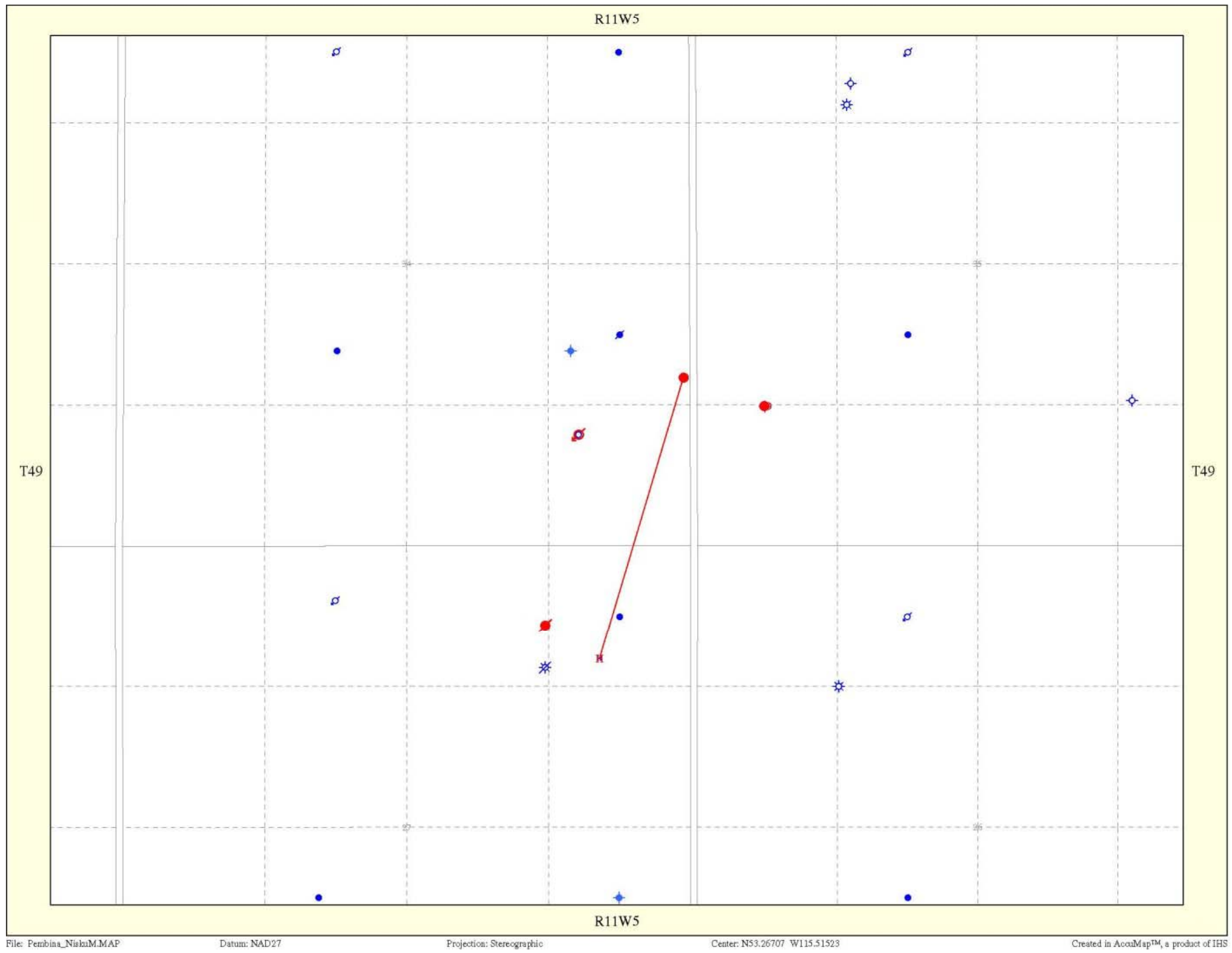
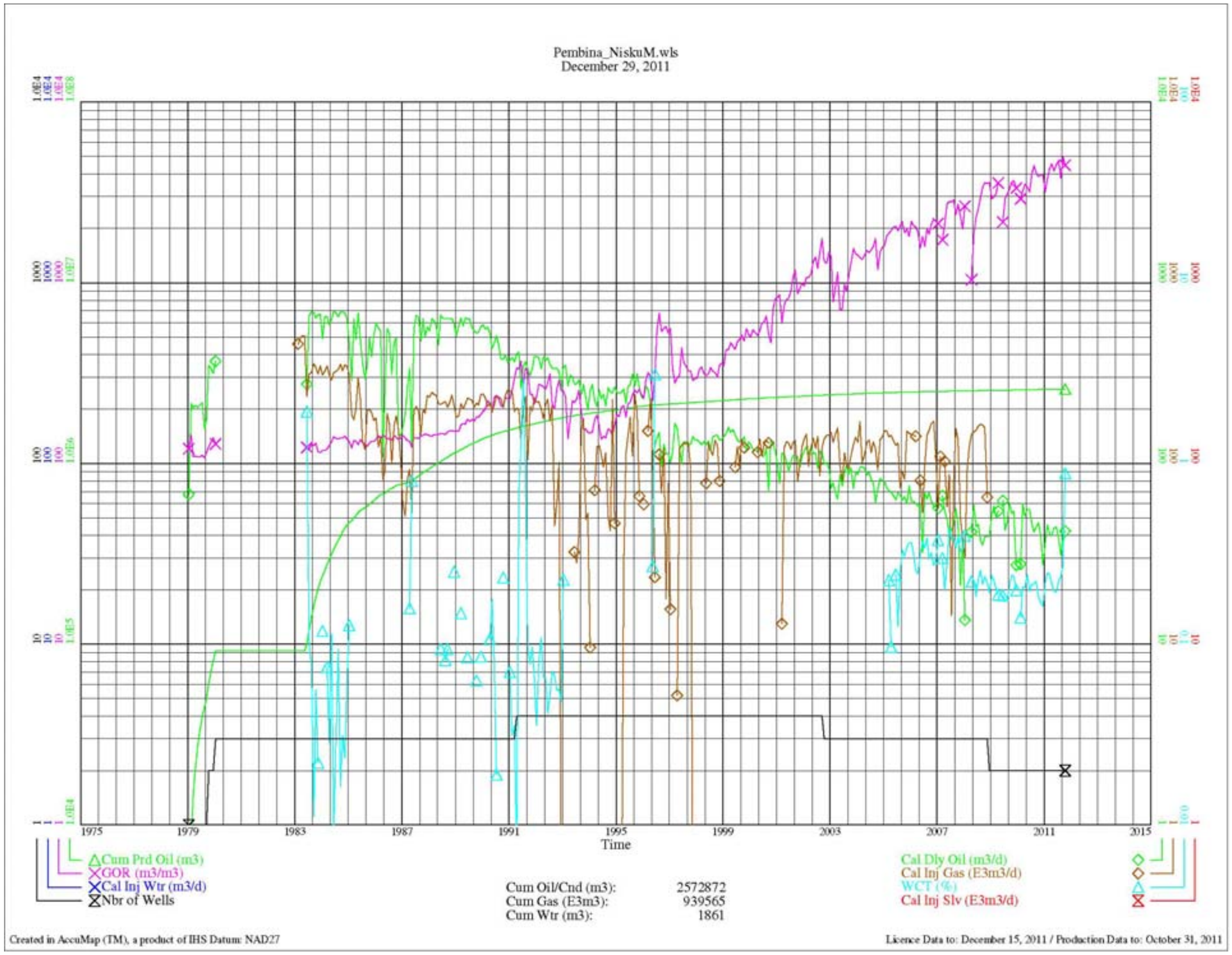


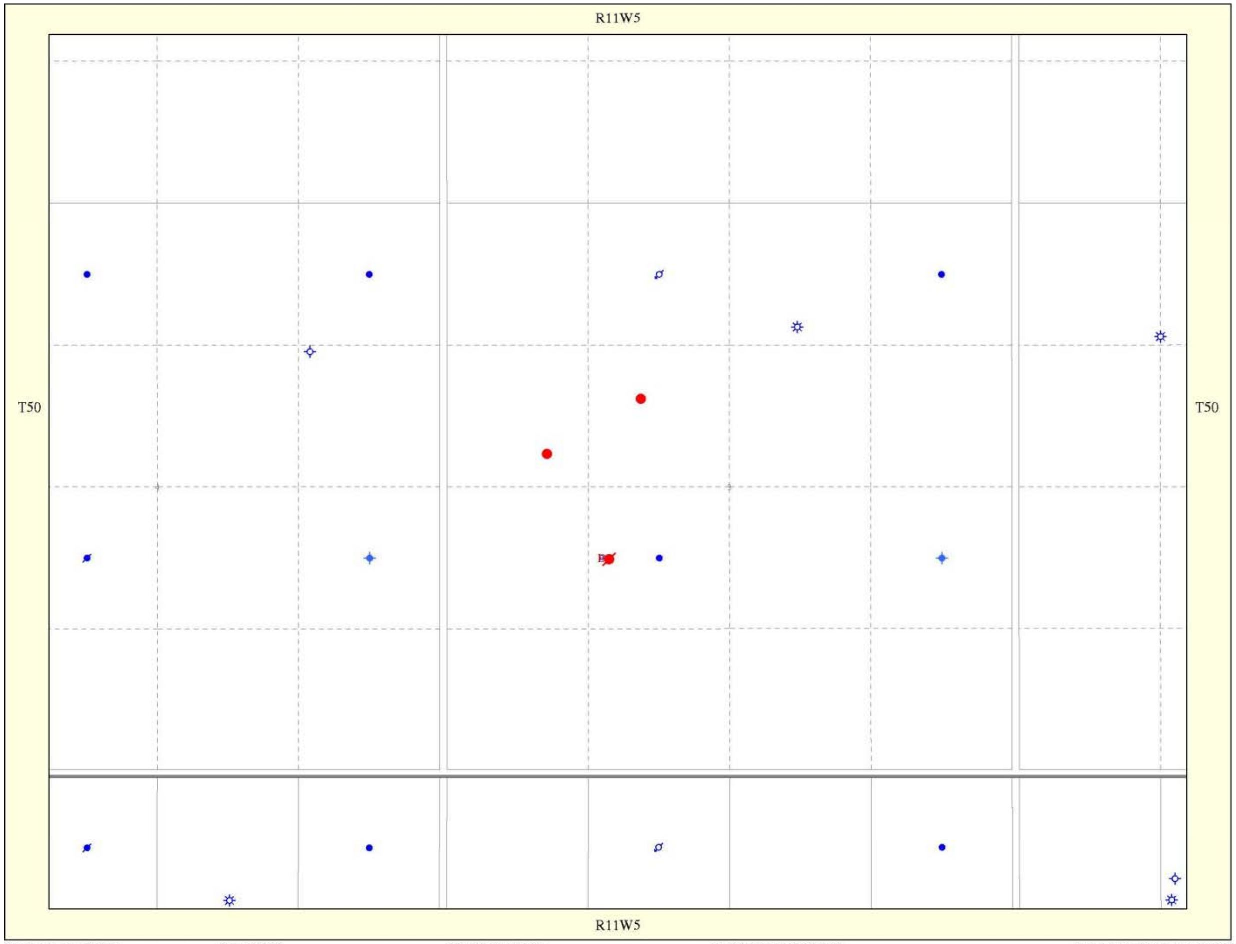

Figure 94

**Pembina Nisku M - Well Locations**




**Pembina Nisku M - Production / Injection History**

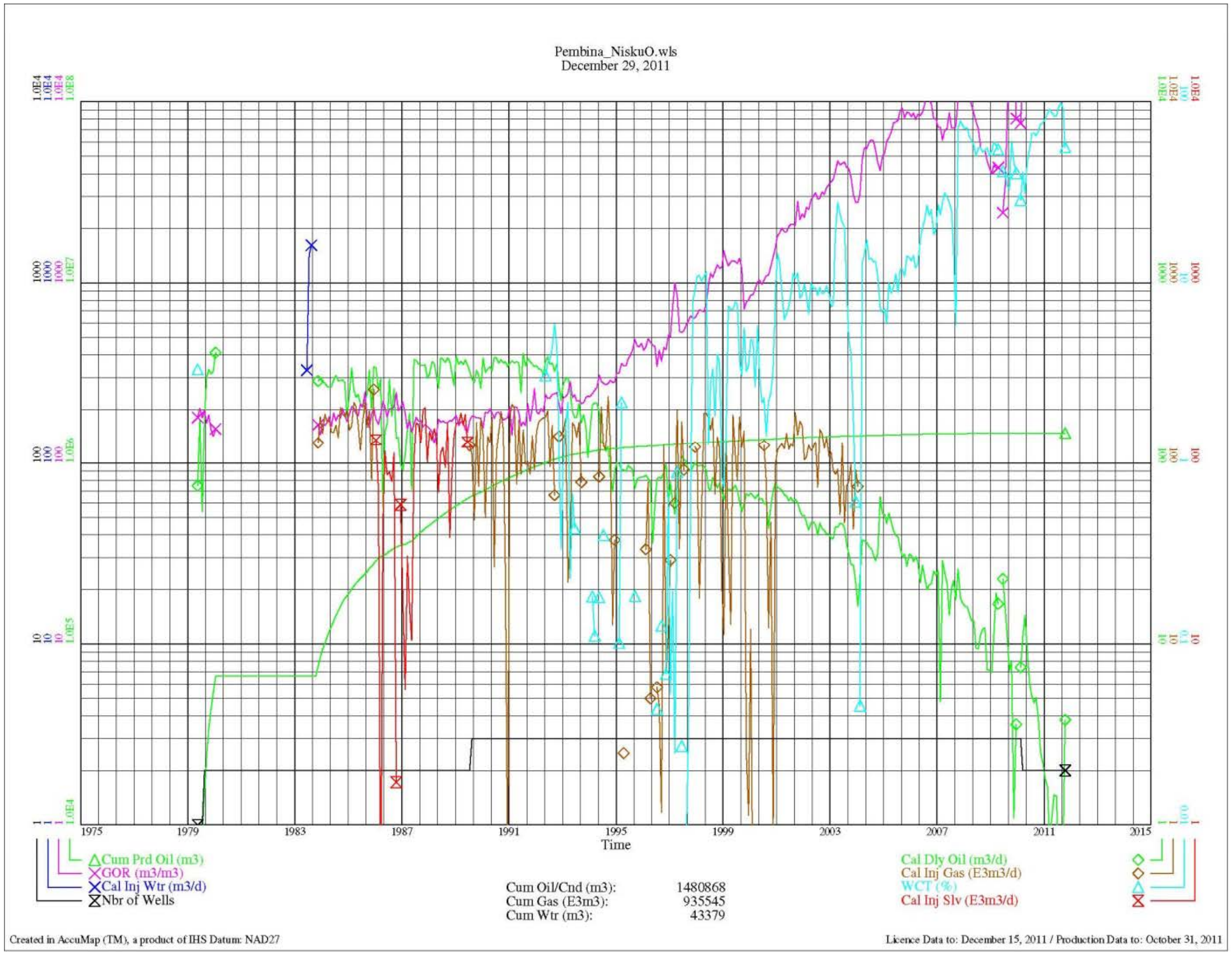
Figure 95




File: Pembina_NiskuO.MAP Datum: NAD27 Projection: Stereographic Center: N53.28738 W115.52897 Created in AccuMap™, a product of IHS

**Pembina Nisku O - Well Locations**

Figure 96

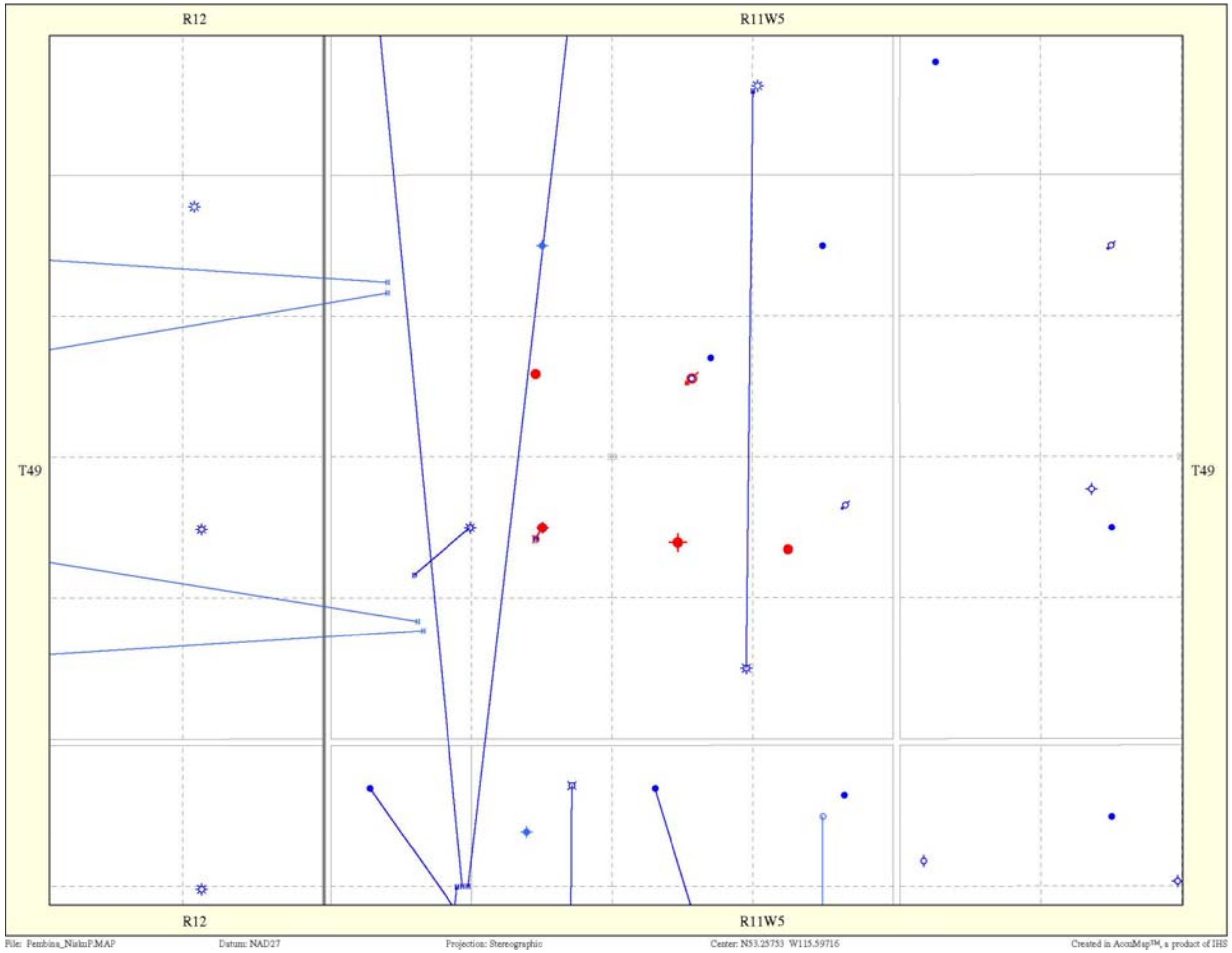



**Pembina Nisku O - Production / Injection History**

Figure 97

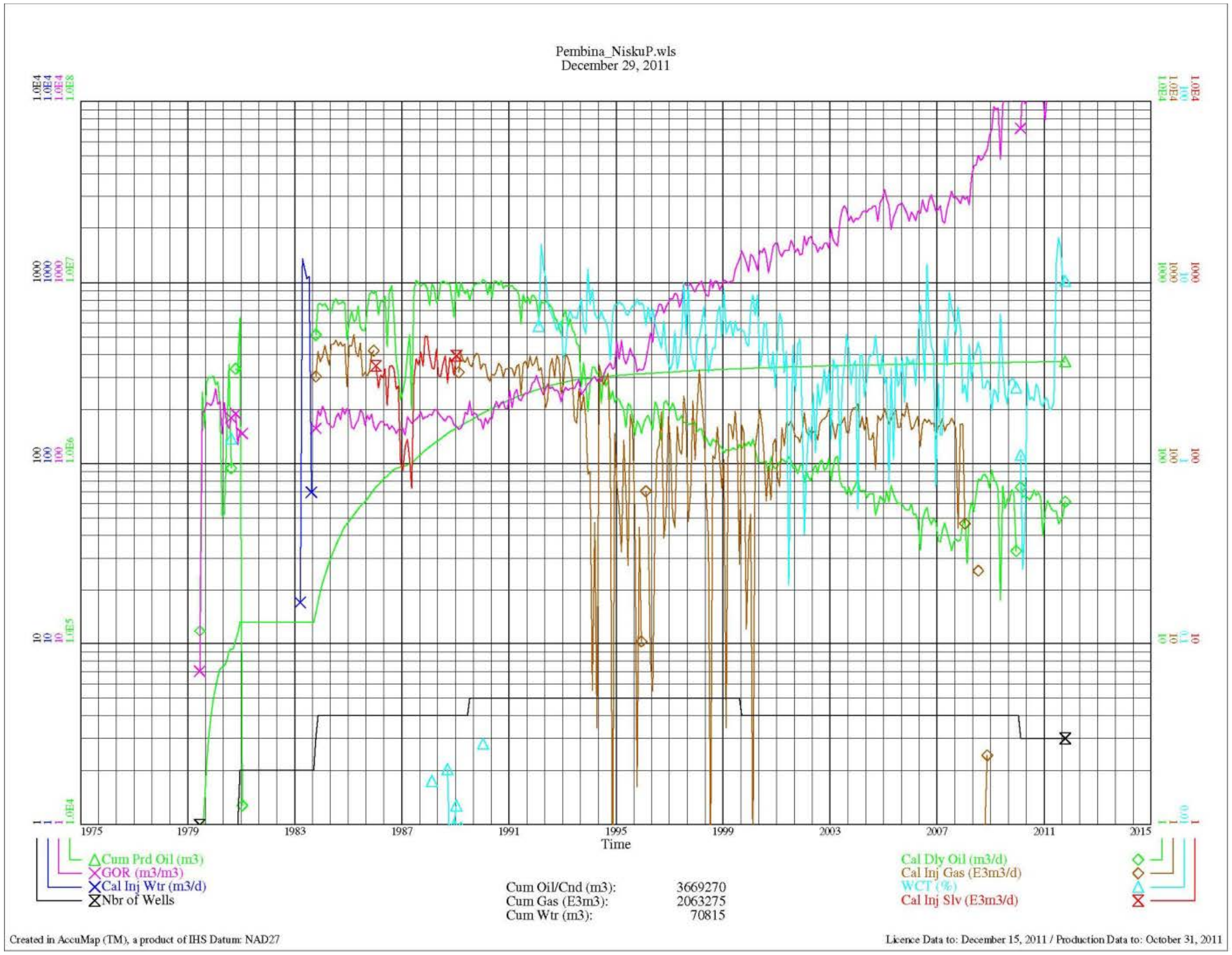


Sproule



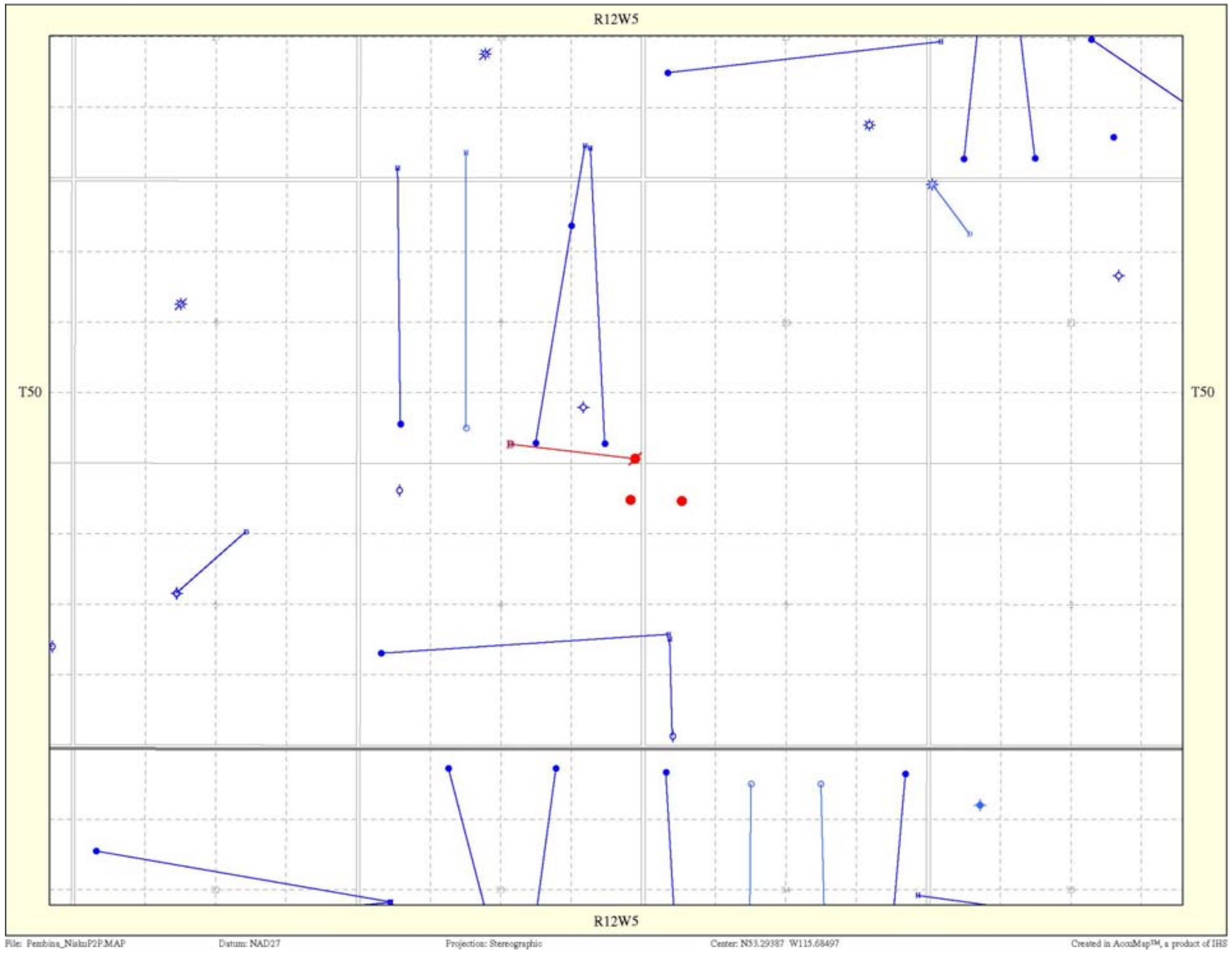

**Pembina Nisku P - Well Locations**

Figure 98



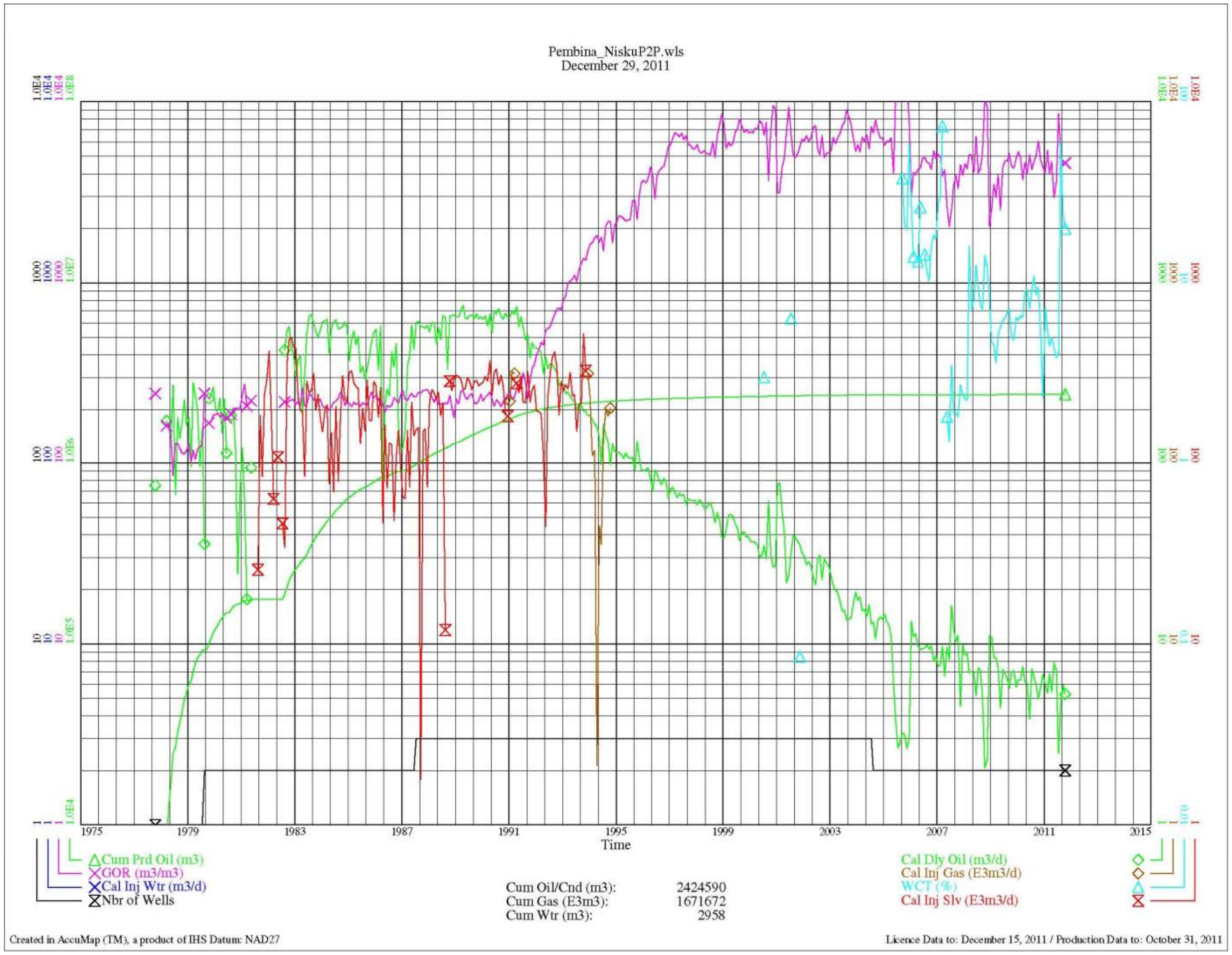

**Pembina Nisku P - Production / Injection History**

Figure 99




**Pembina Nisku P2P - Well Locations**

Figure 100




**Pembina Nisku P2P - Production / Injection History**

Figure 101

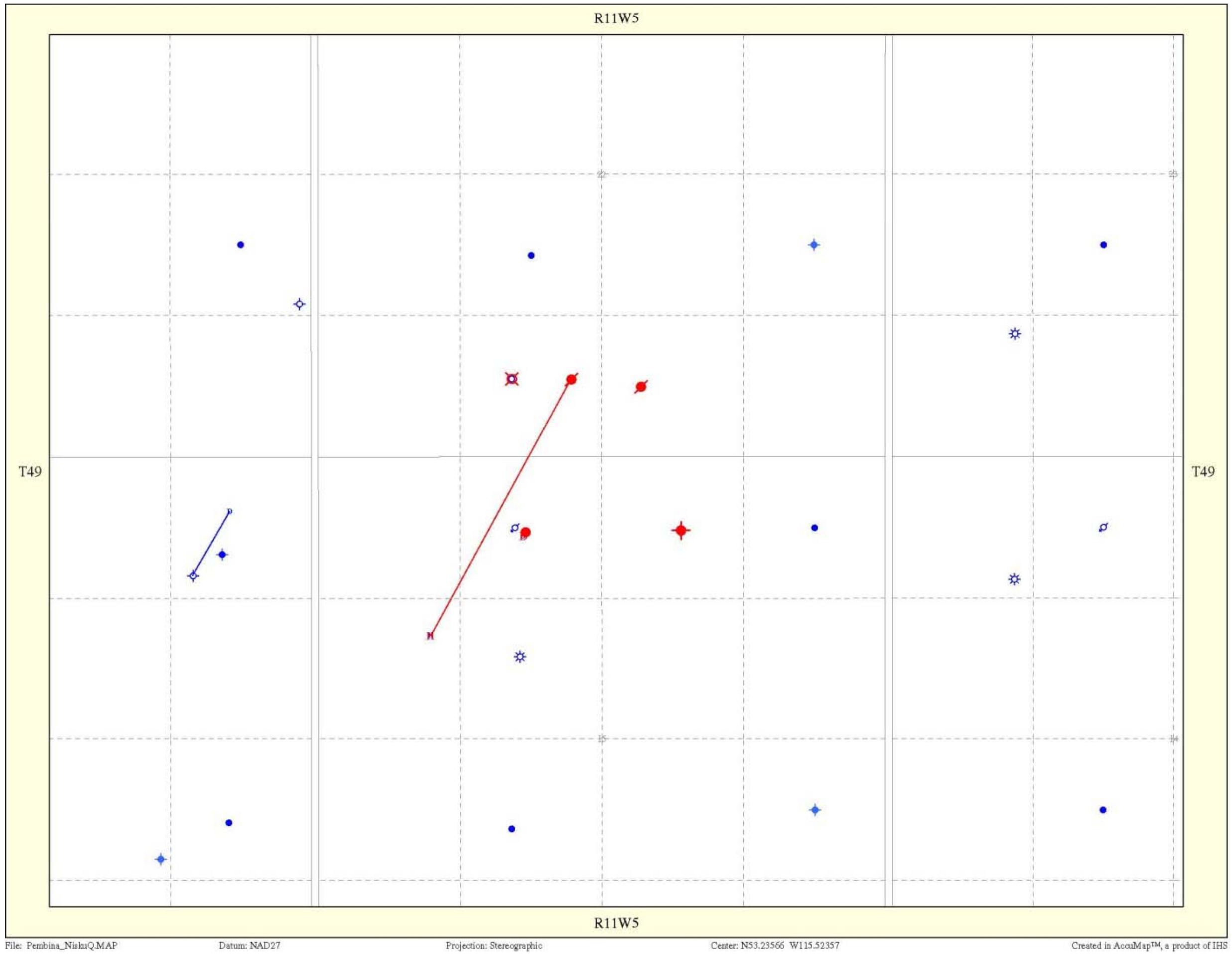
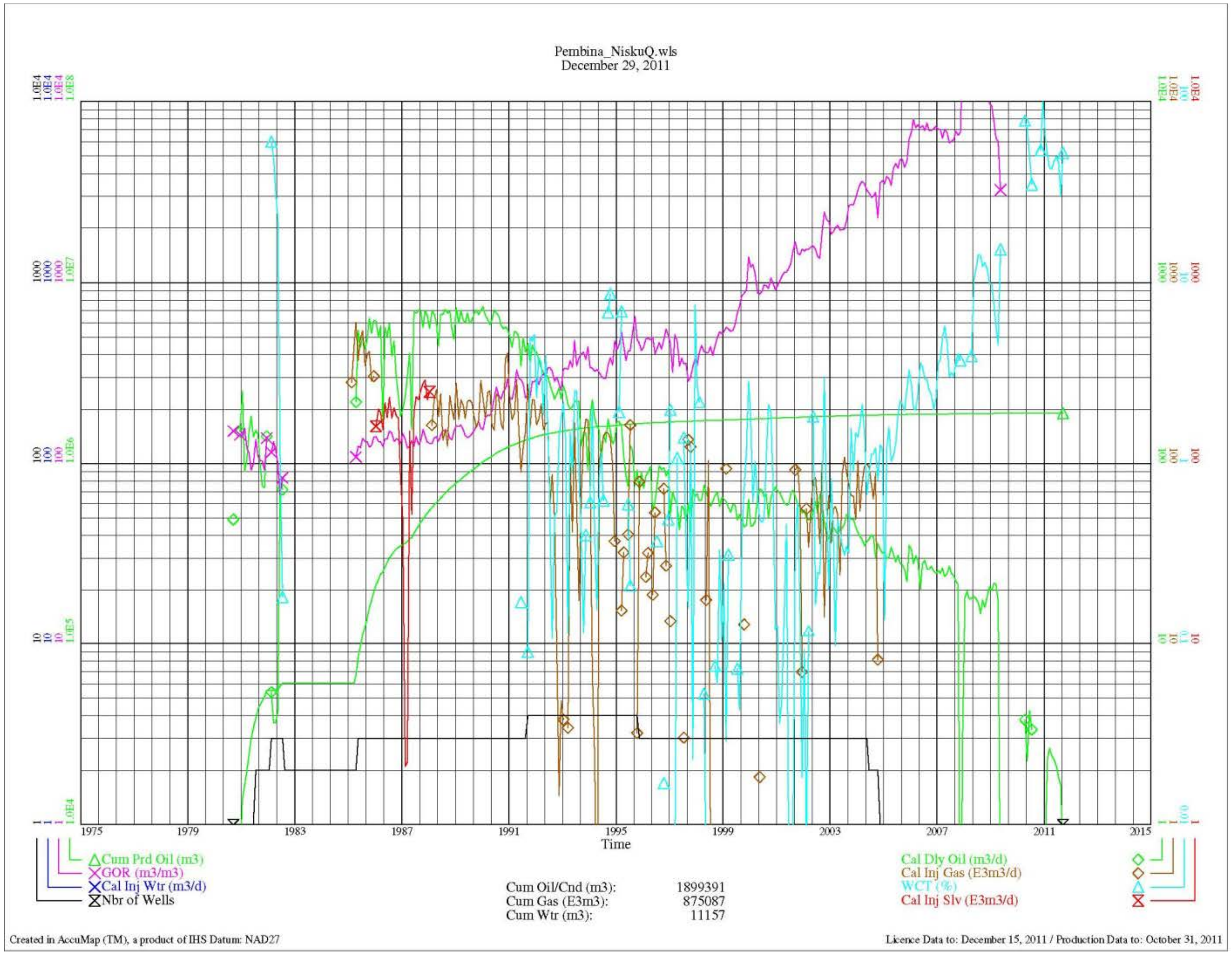


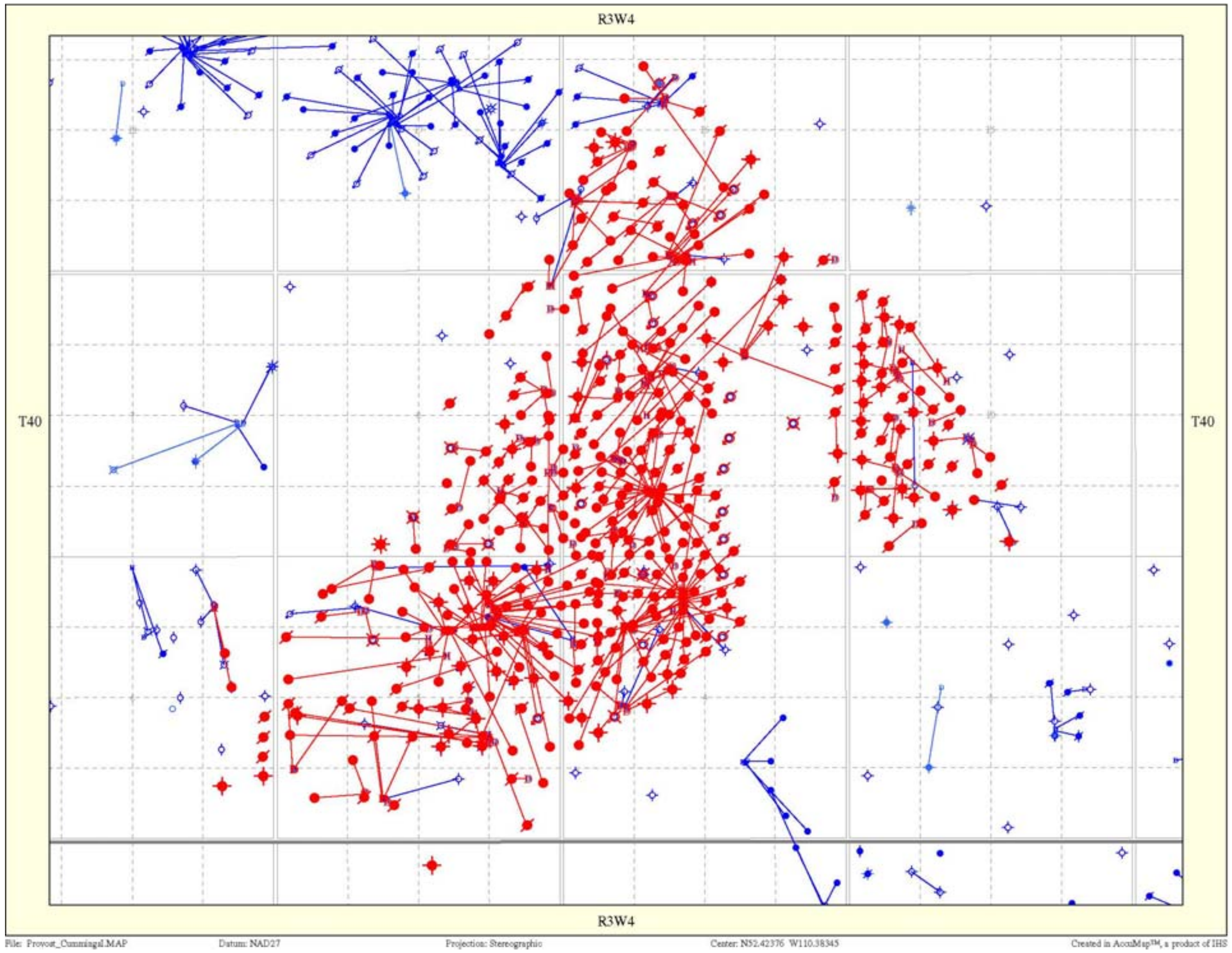

Figure 102

**Pembina Nisku Q - Well Locations**




**Pembina Nisku Q - Production / Injection History**

Figure 103

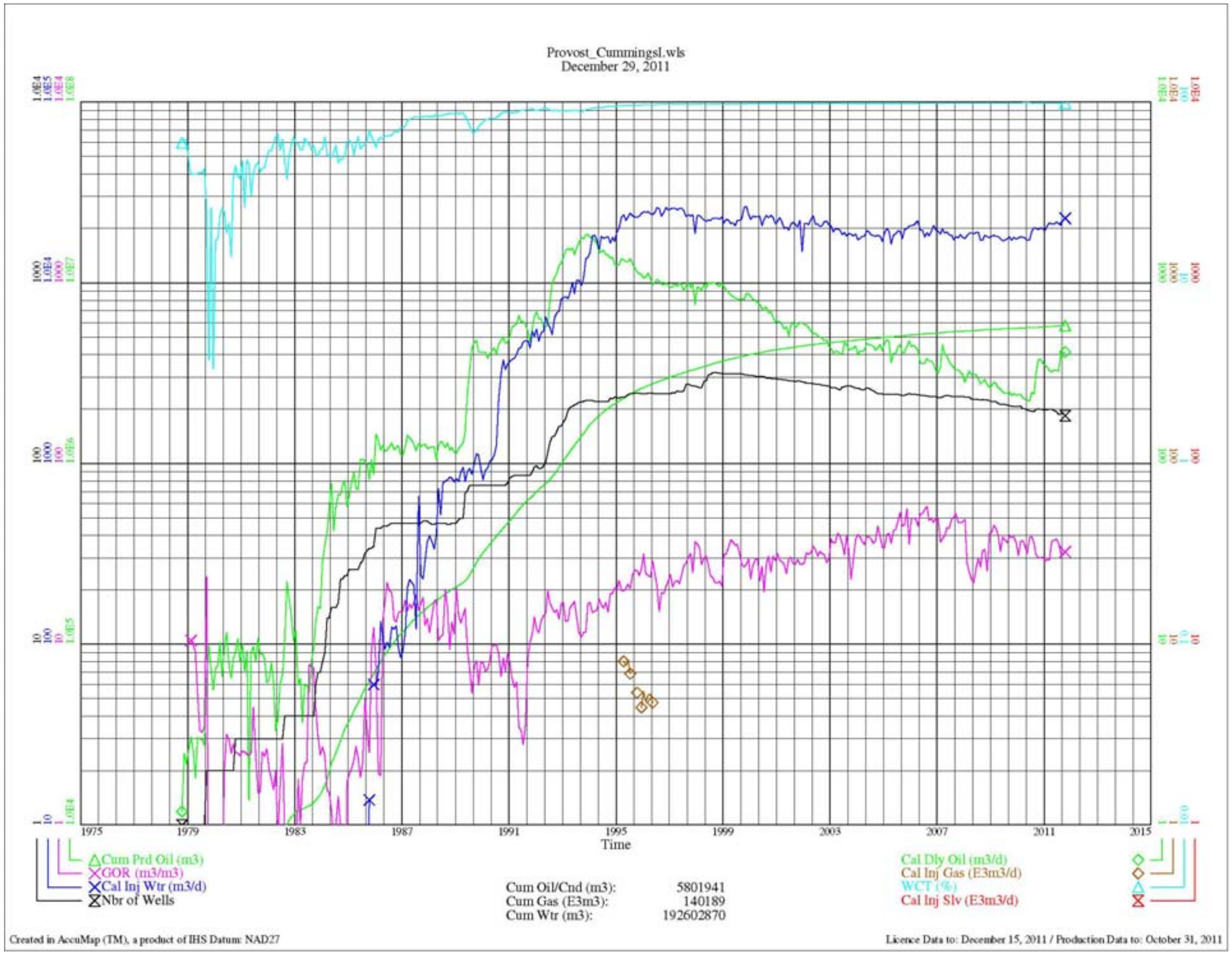



**Provost Cummings I - Well Locations**

Figure 104



Sproule

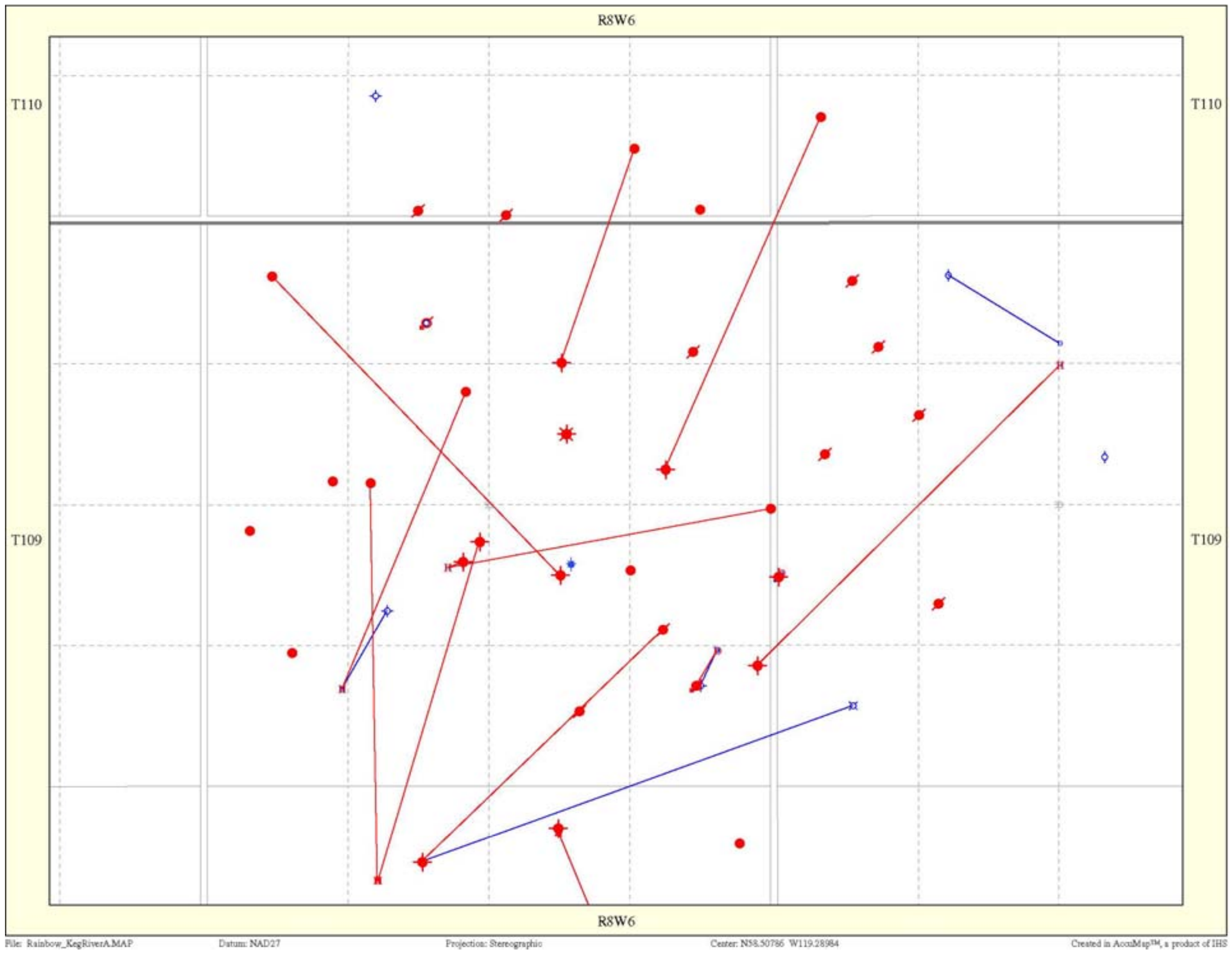



**Provost Cummings I - Production / Injection History**

Figure 105



Sproule




**Rainbow Keg River A – Well Locations**

Figure 106

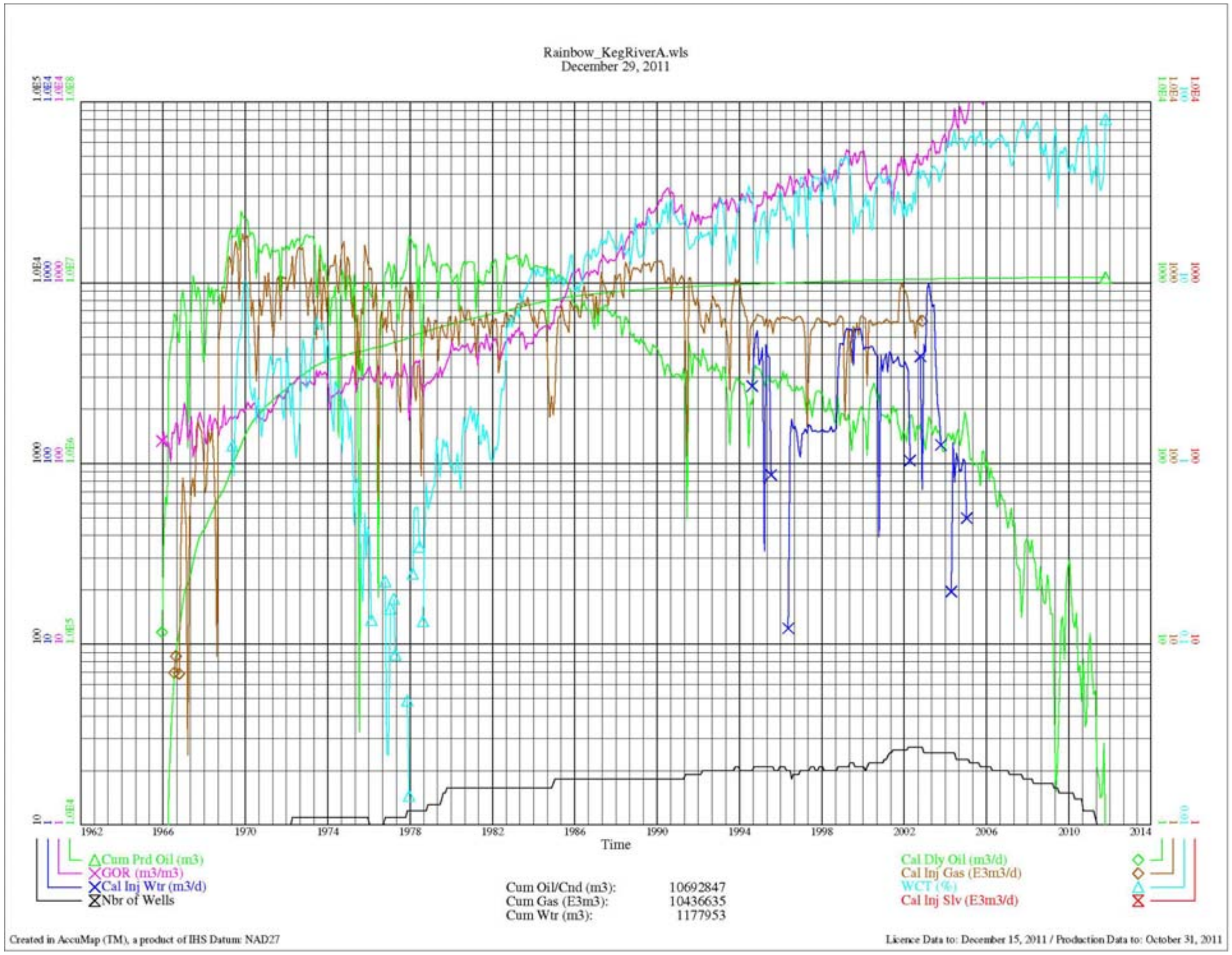
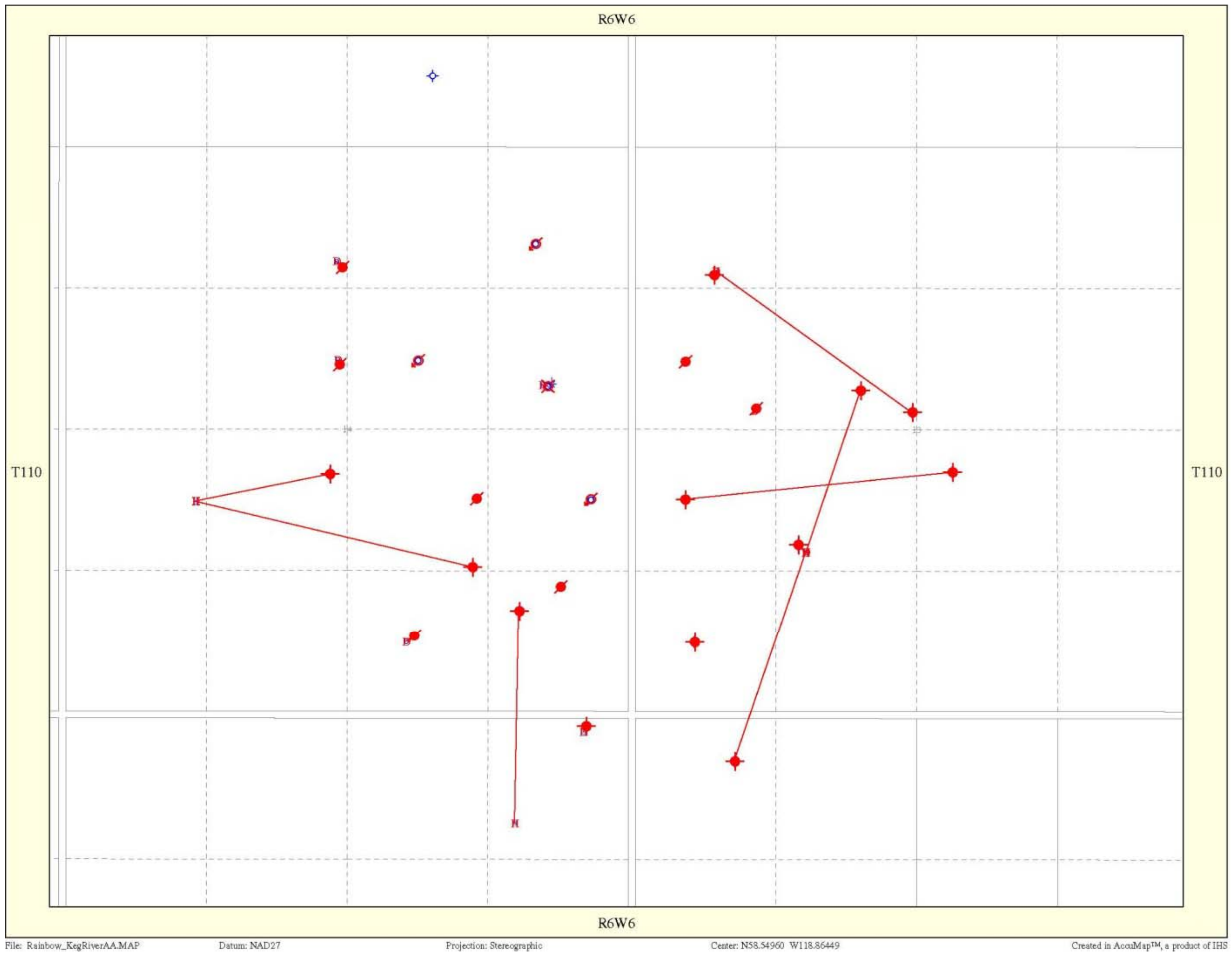



Figure 107

**Rainbow Keg River A – Production / Injection History**

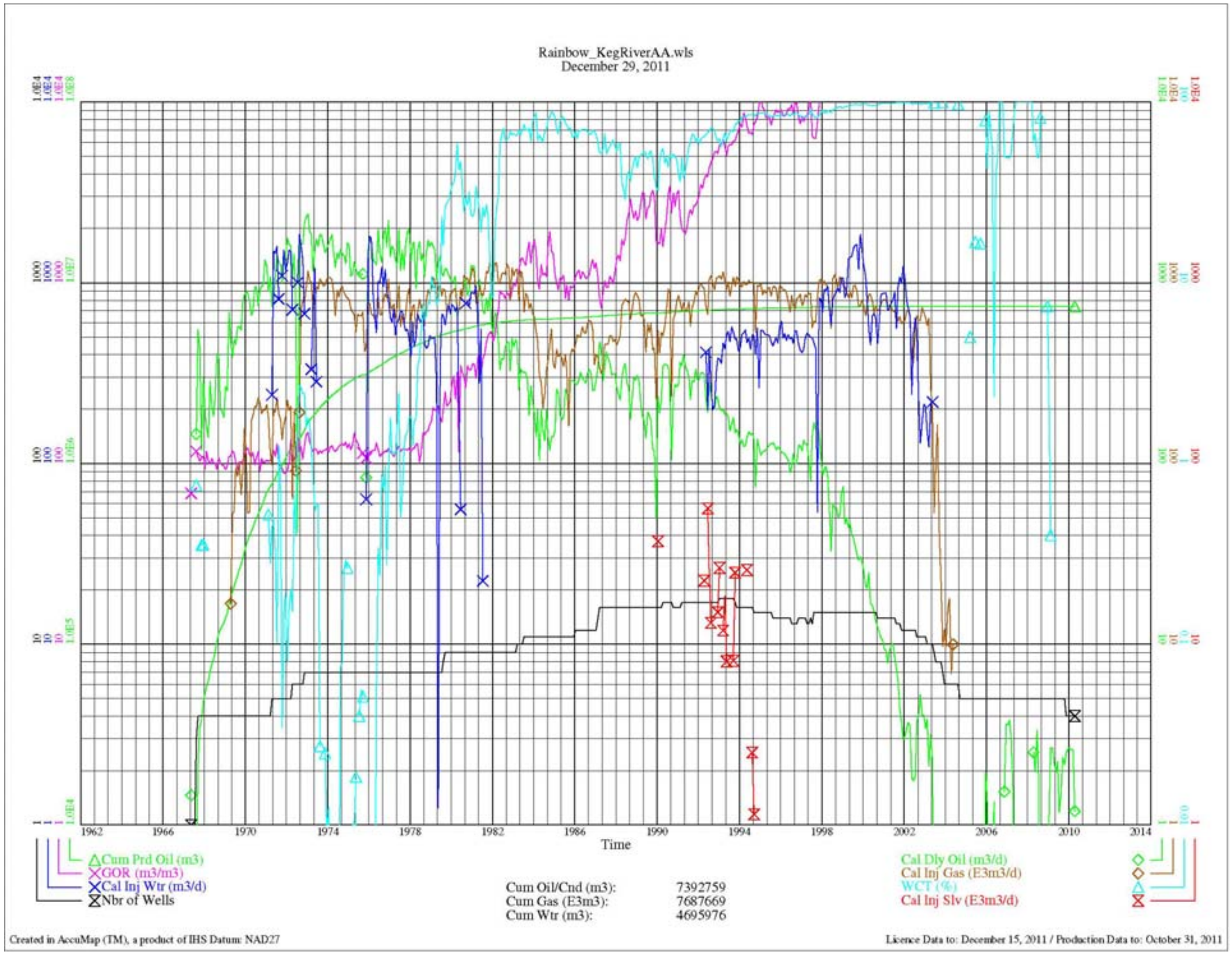



**Rainbow Keg River AA – Well Locations**

Figure 108



Sproule




**Rainbow Keg River AA – Production / Injection History**

Figure 109

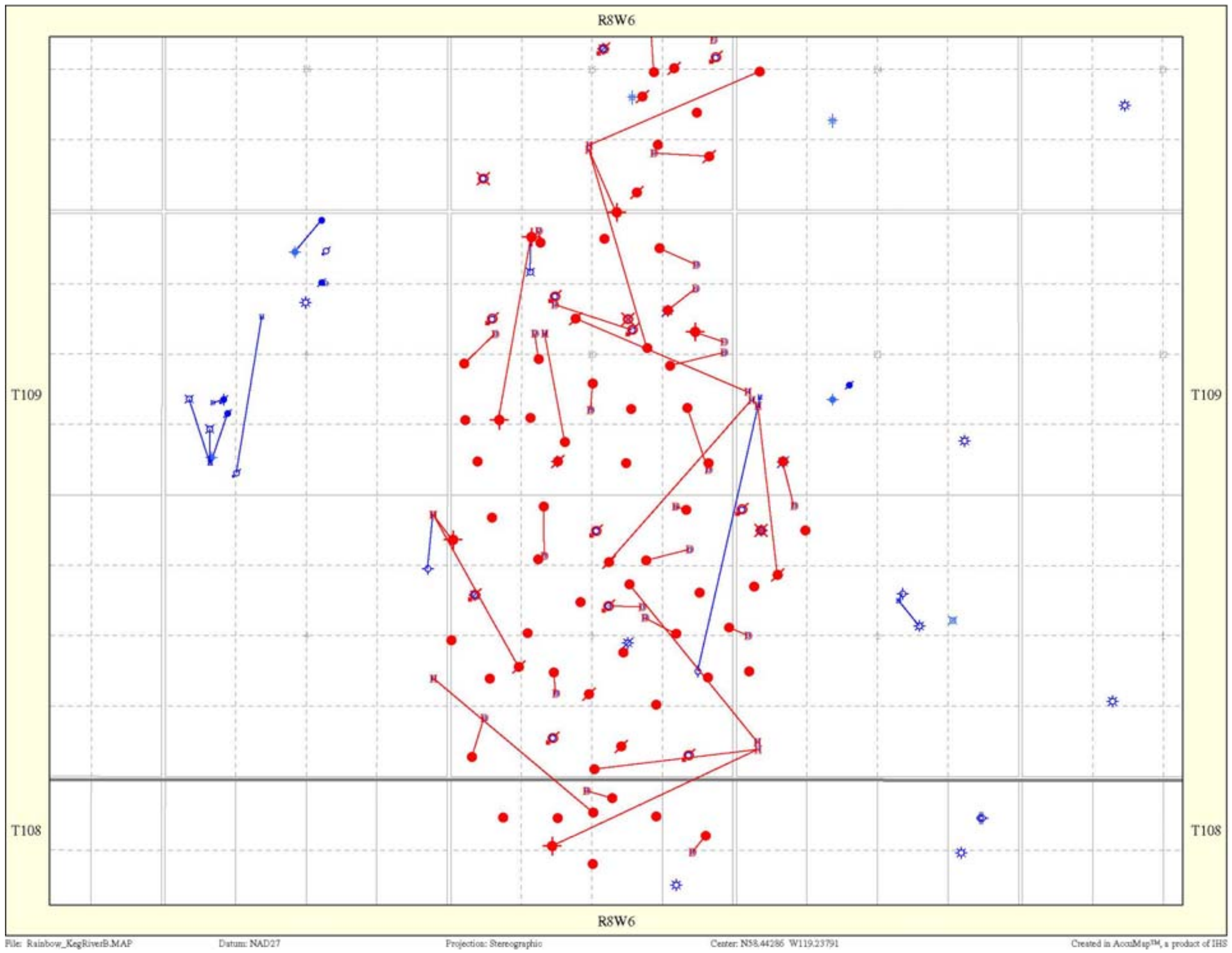
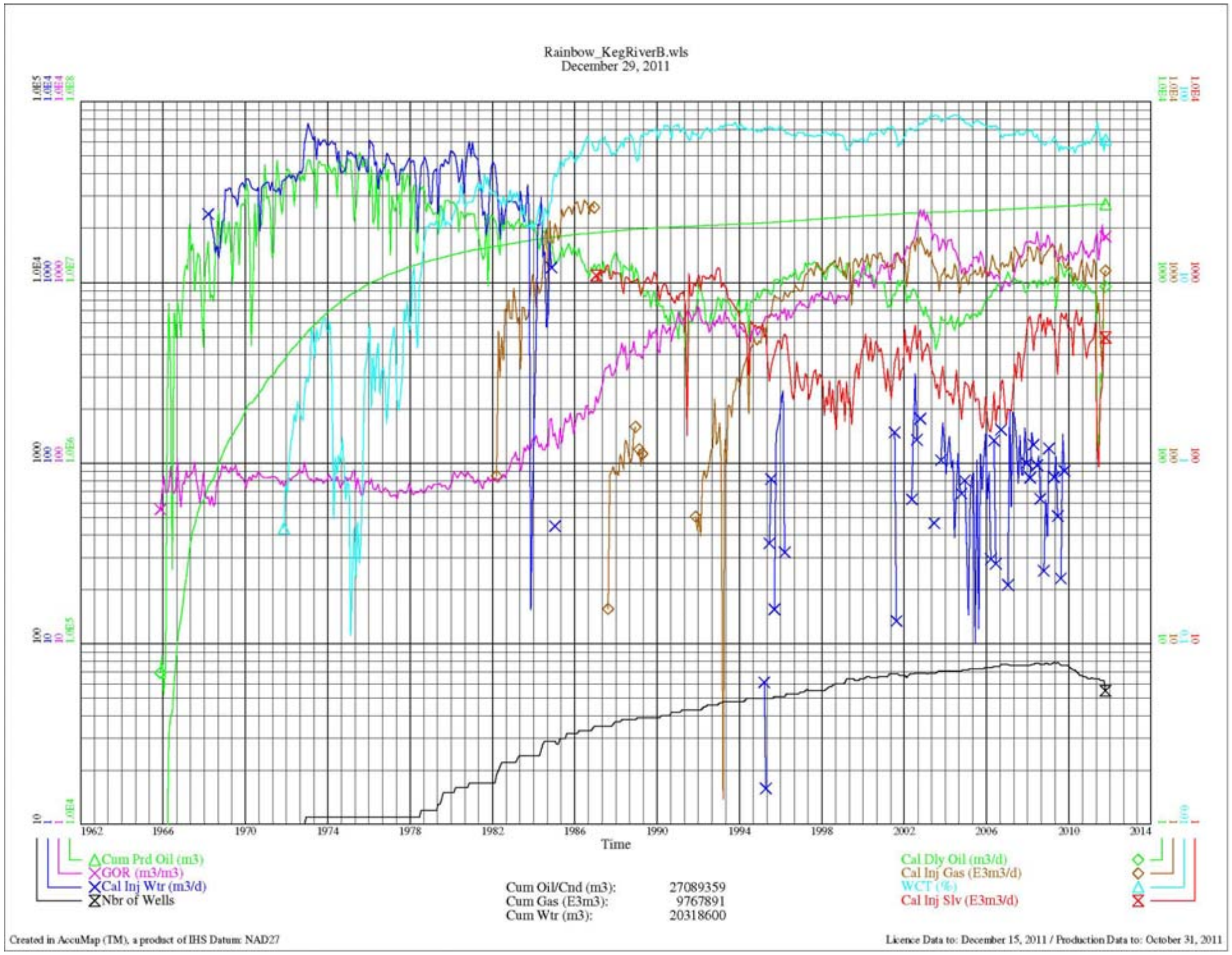



Figure 110

**Rainbow Keg River B – Well Locations**

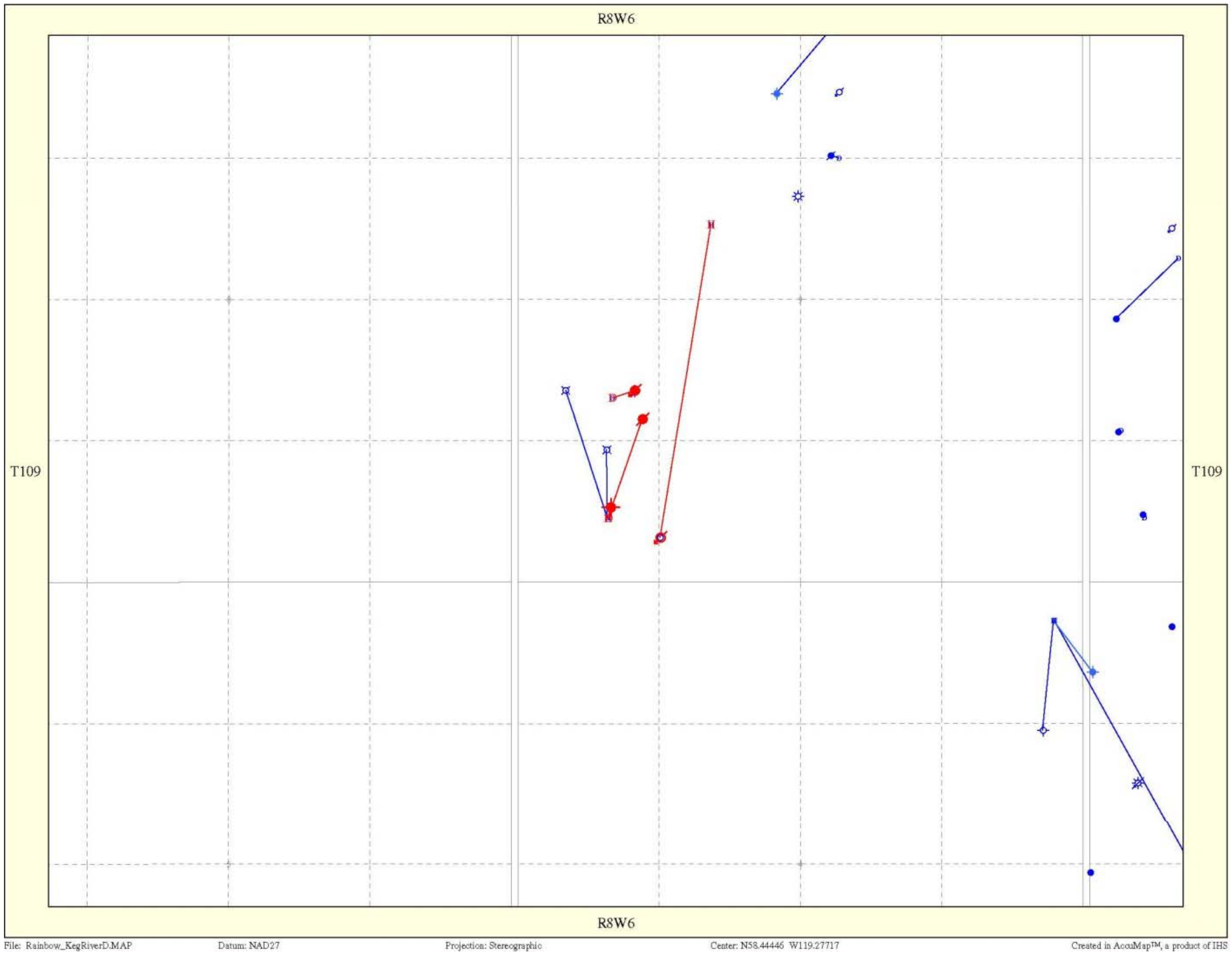



**Rainbow Keg River B – Production / Injection History**

Figure 111

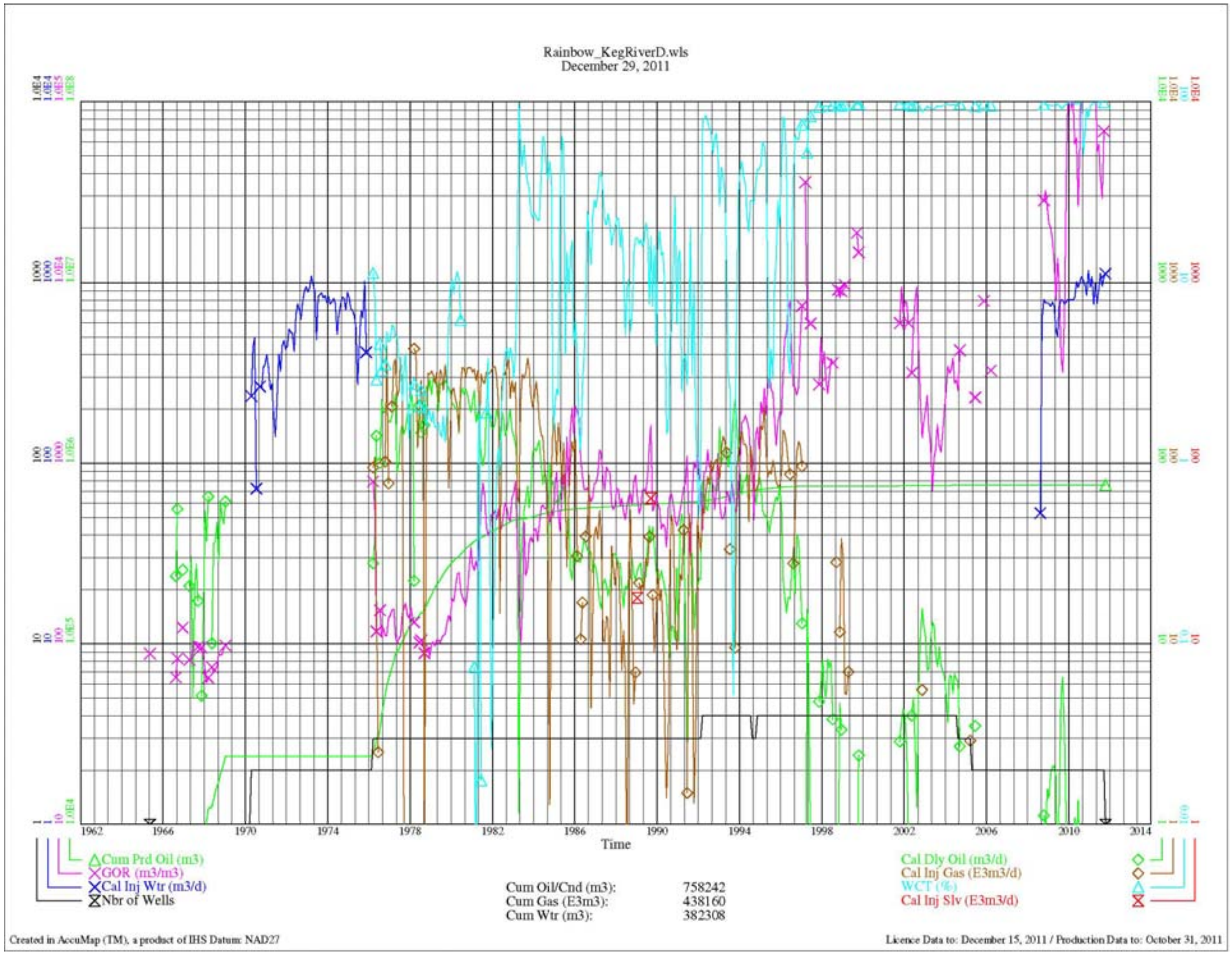


Sproule




**Rainbow Keg River D – Well Locations**

Figure 112




**Rainbow Keg River D – Production / Injection History**

Figure 113

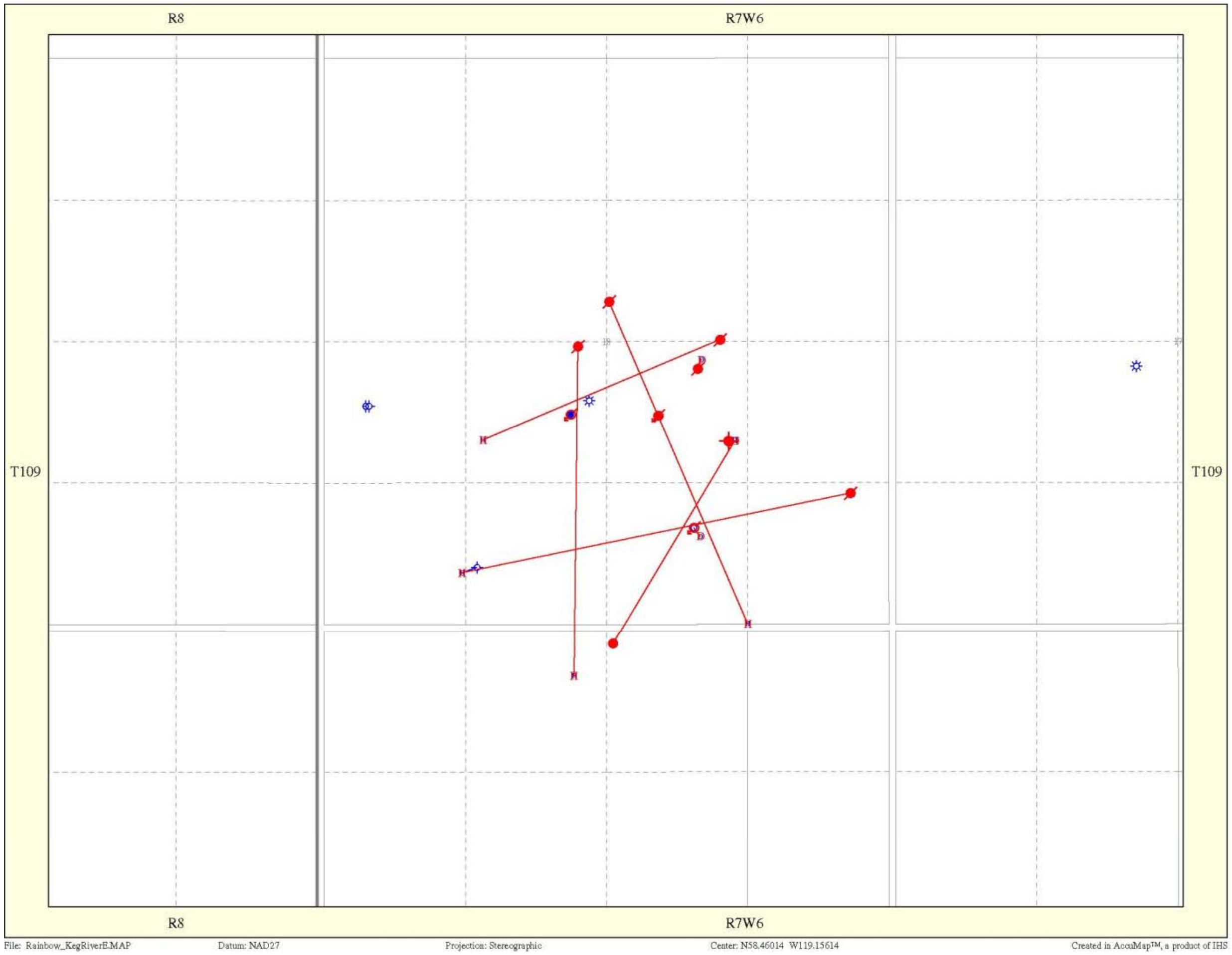
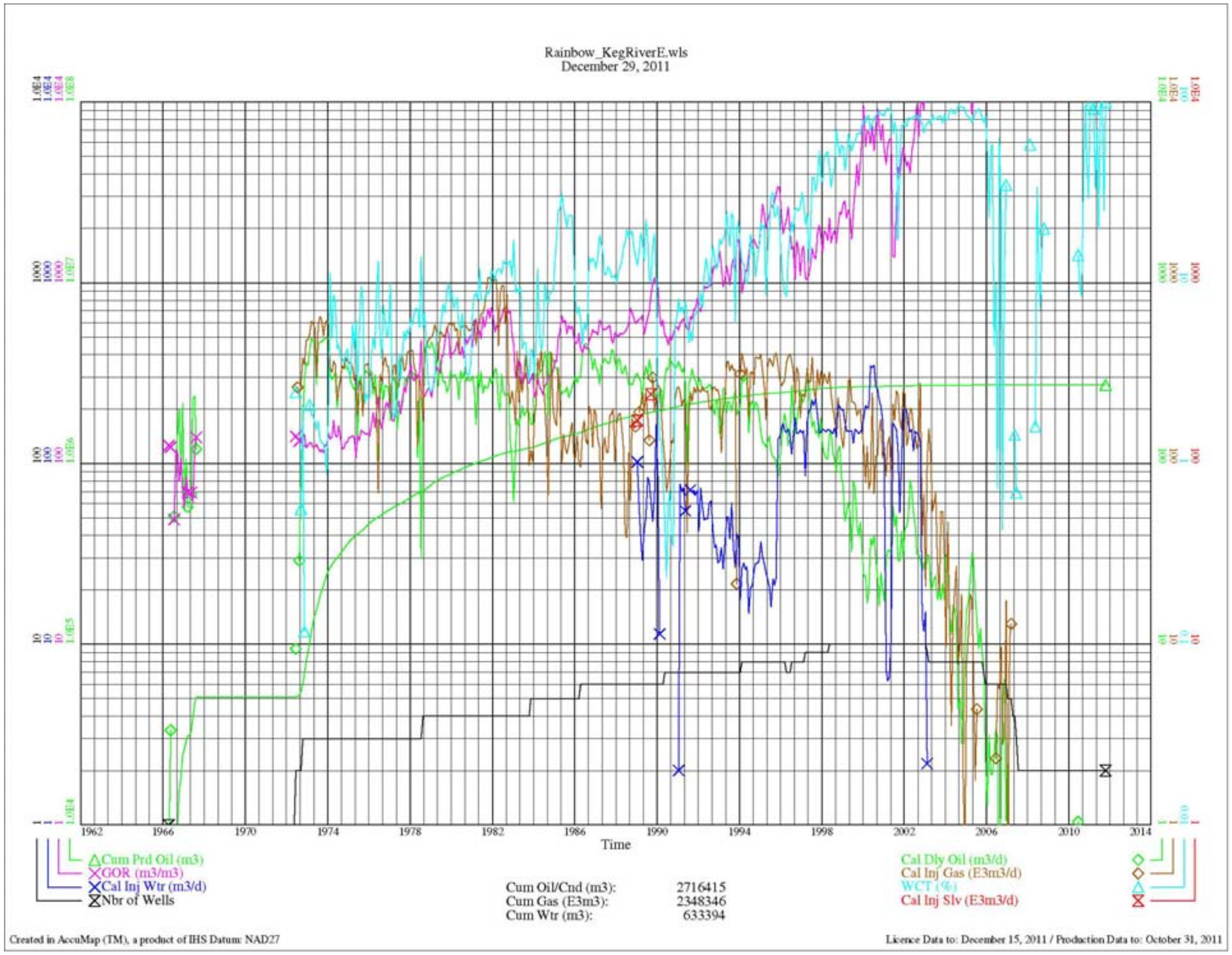



Figure 114

**Rainbow Keg River E – Well Locations**




**Rainbow Keg River E – Production / Injection History**

Figure 115



Sproule

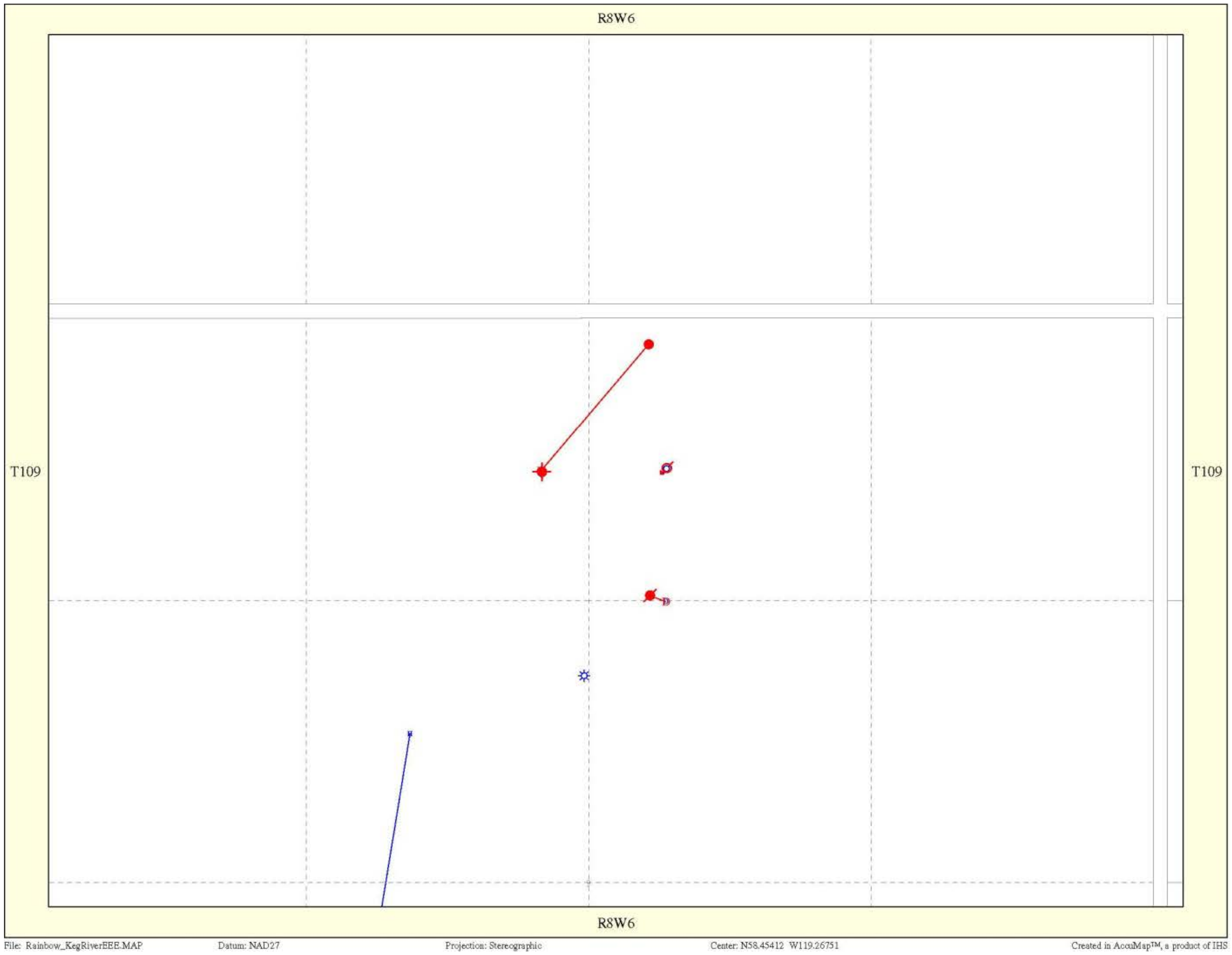
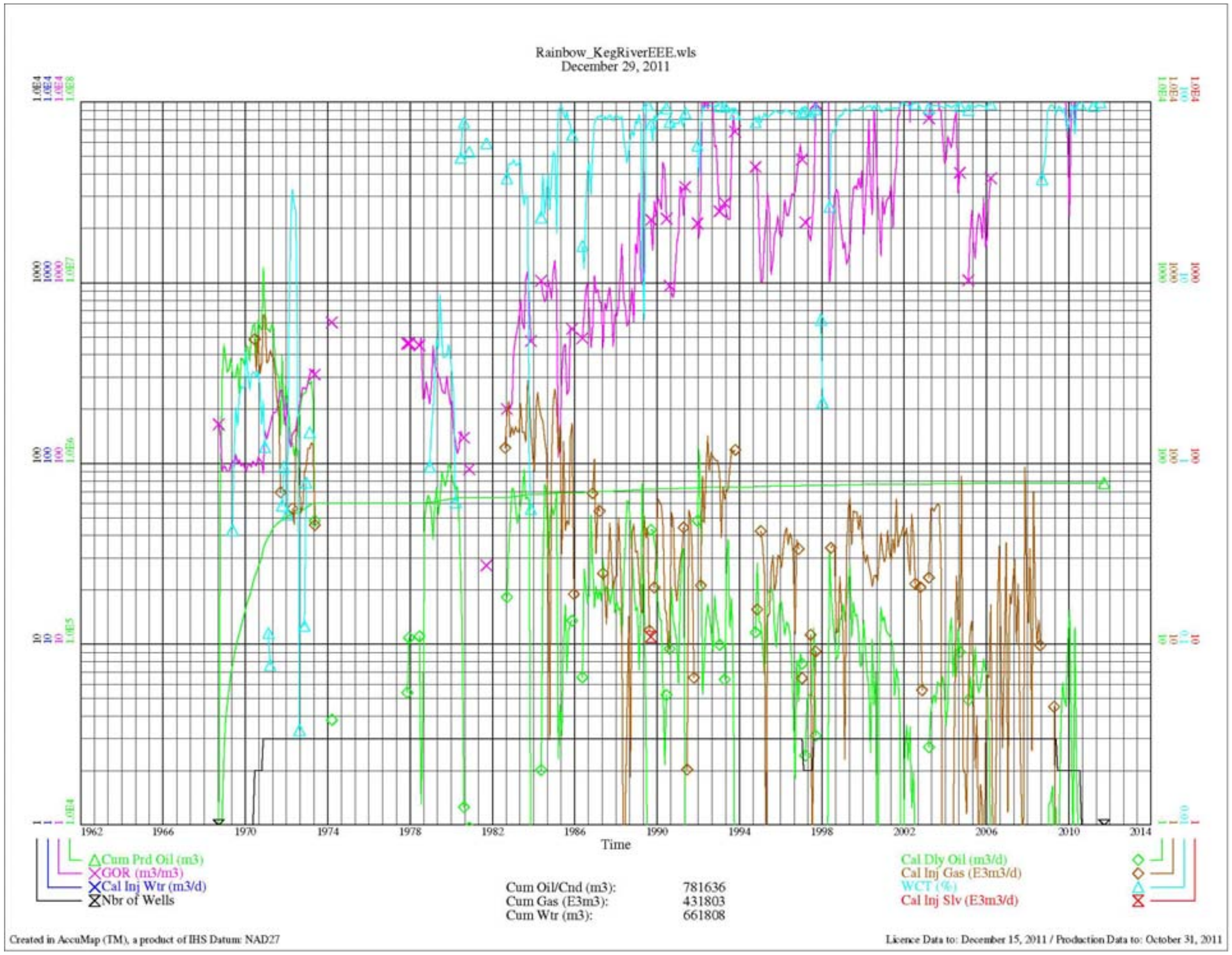


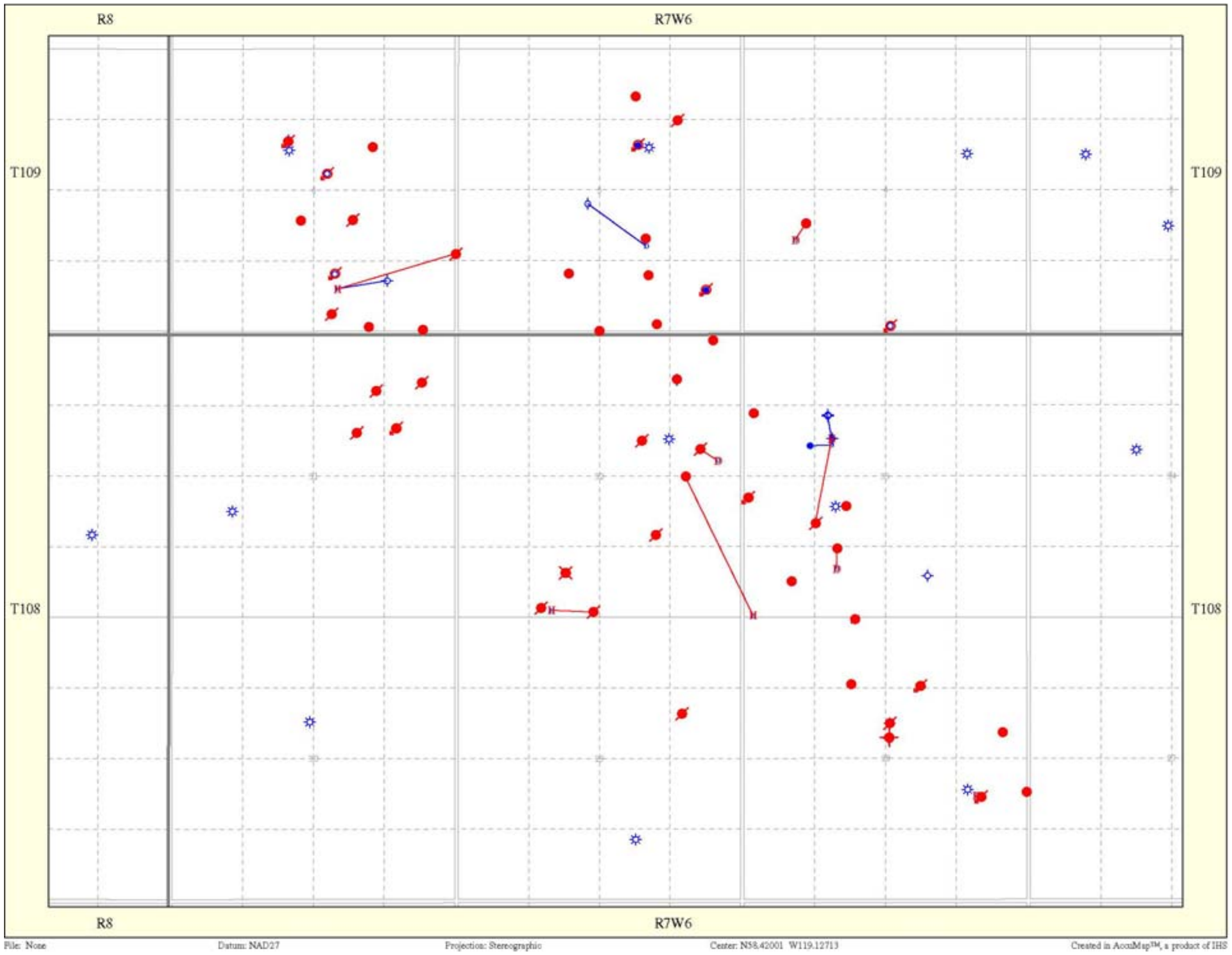

Figure 116

**Rainbow Keg River EEE – Well Locations**



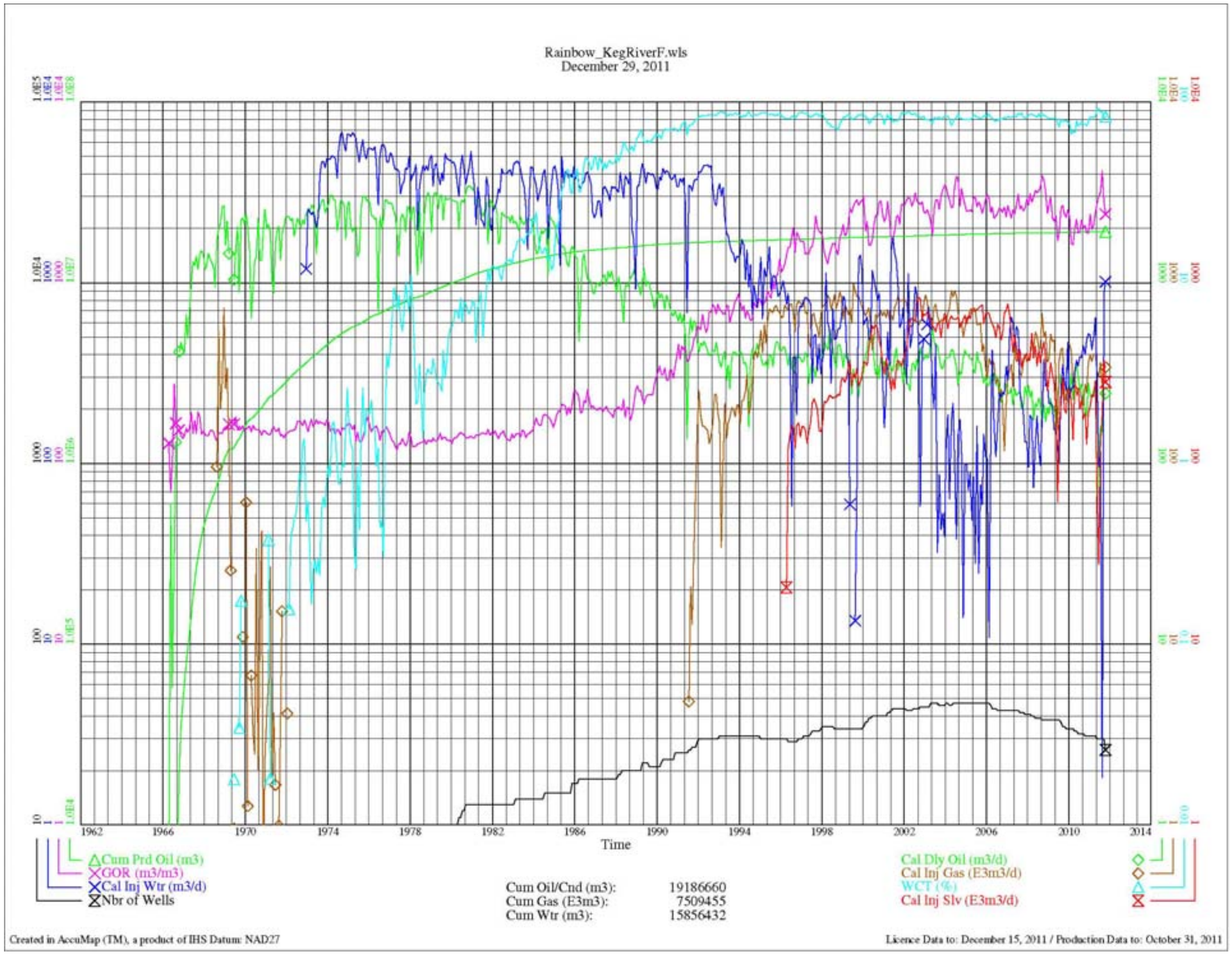

**Rainbow Keg River EEE – Production / Injection History**

Figure 117



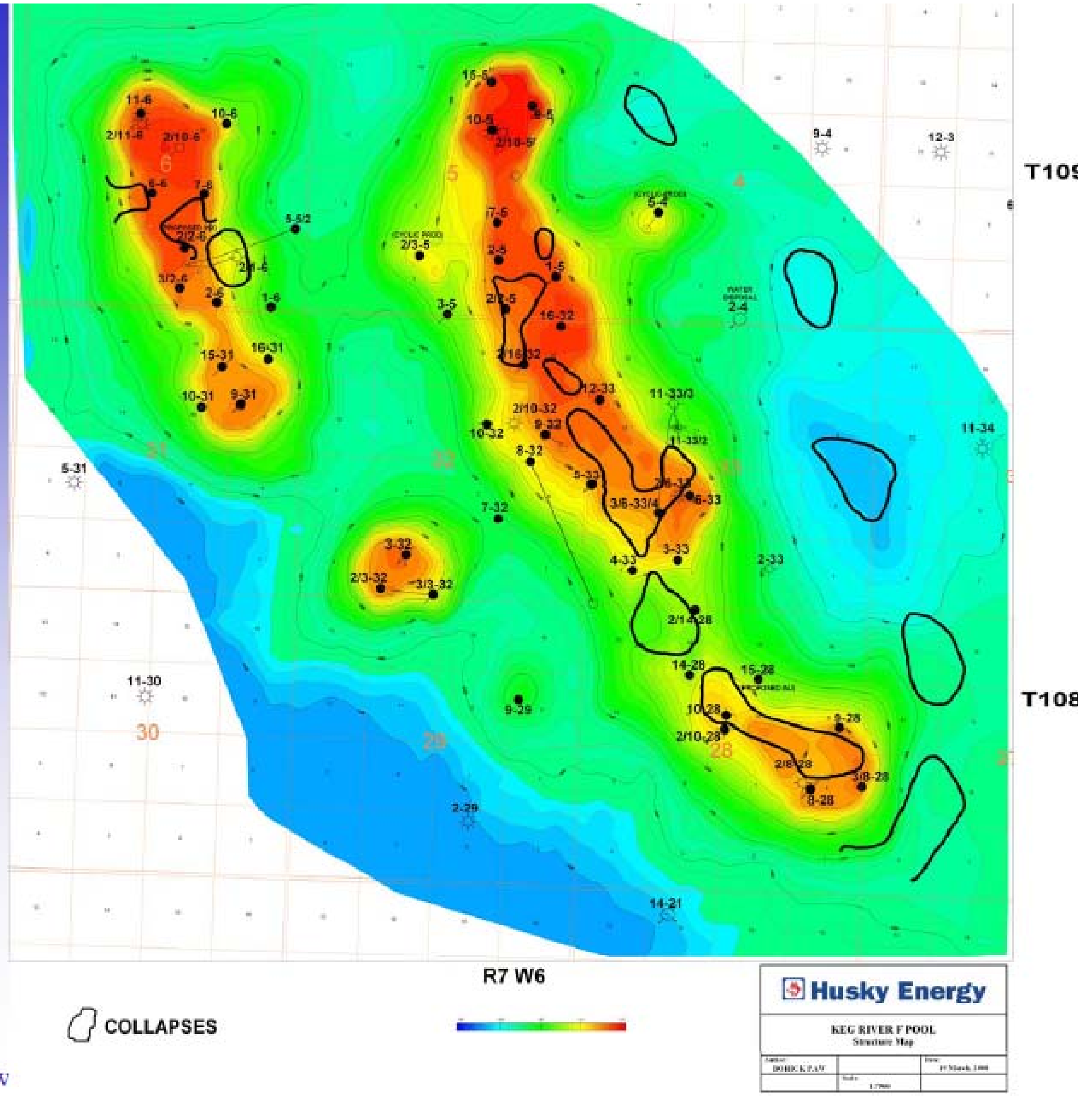

**Rainbow Keg River F – Well Locations**

Figure 118




**Rainbow Keg River F – Production / Injection History**

Figure 119



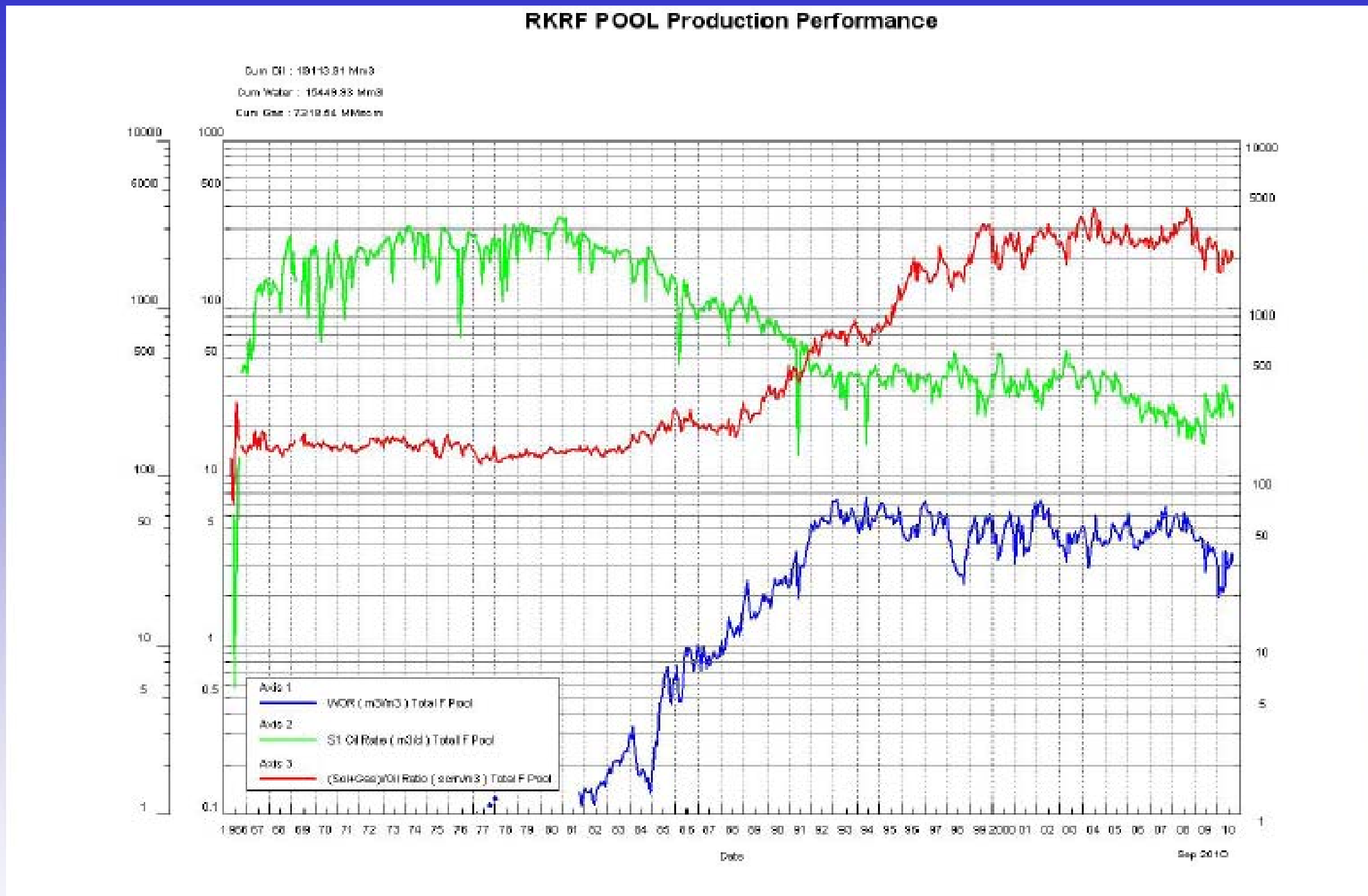

Rainbow Keg Riv mited

**Keg River F Pool – Structure Map**

Figure 120



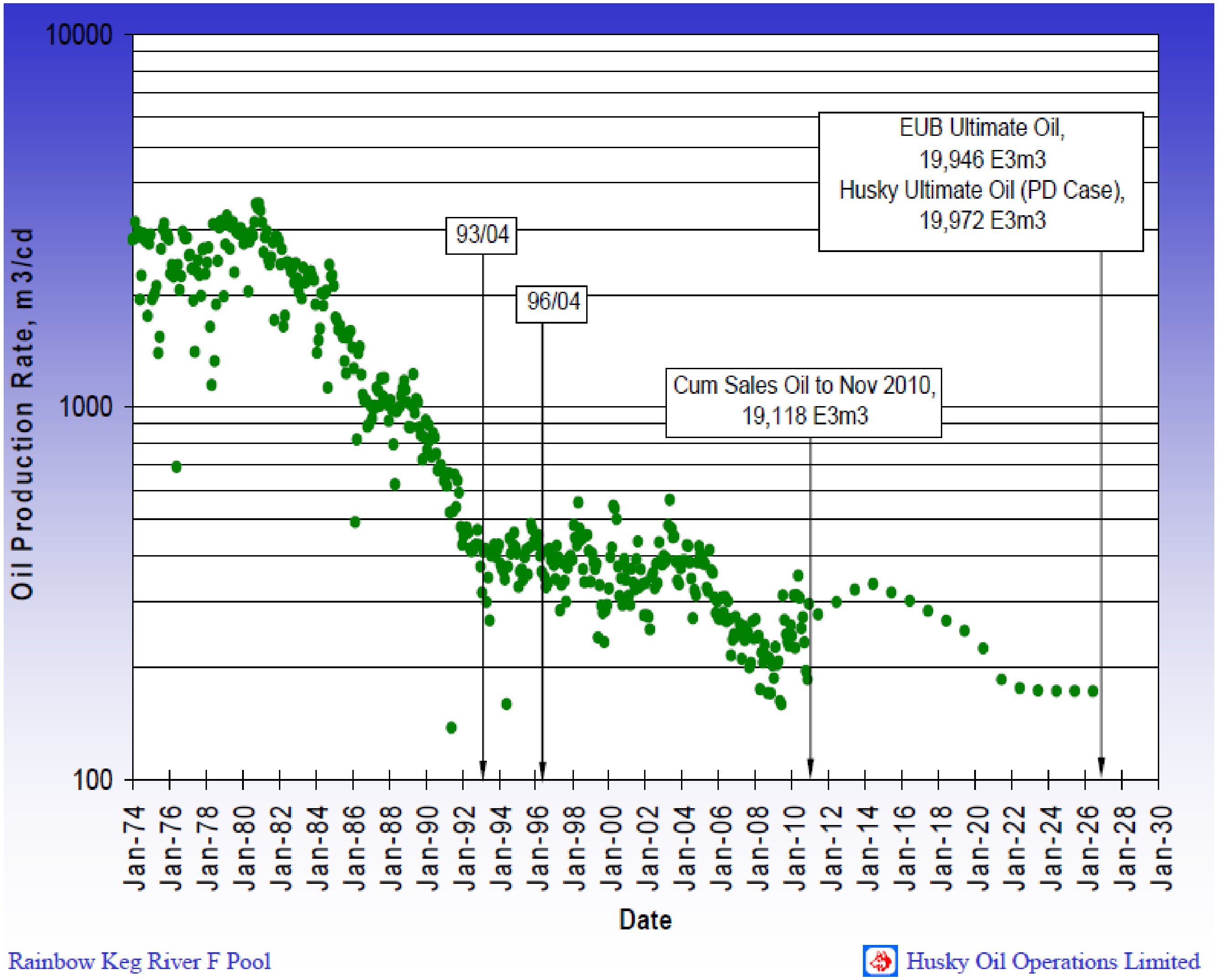
Sproule




- Total Wells: 49
- Total Producers: 39 (including 2 cyclic Inj/Pro wells)
- Total Injectors: 12 (including 1 water injector and 2 cyclic Inj/Pro wells)



Figure 121




**Rainbow Keg River F Pool – Ultimate Oil**

Figure 122

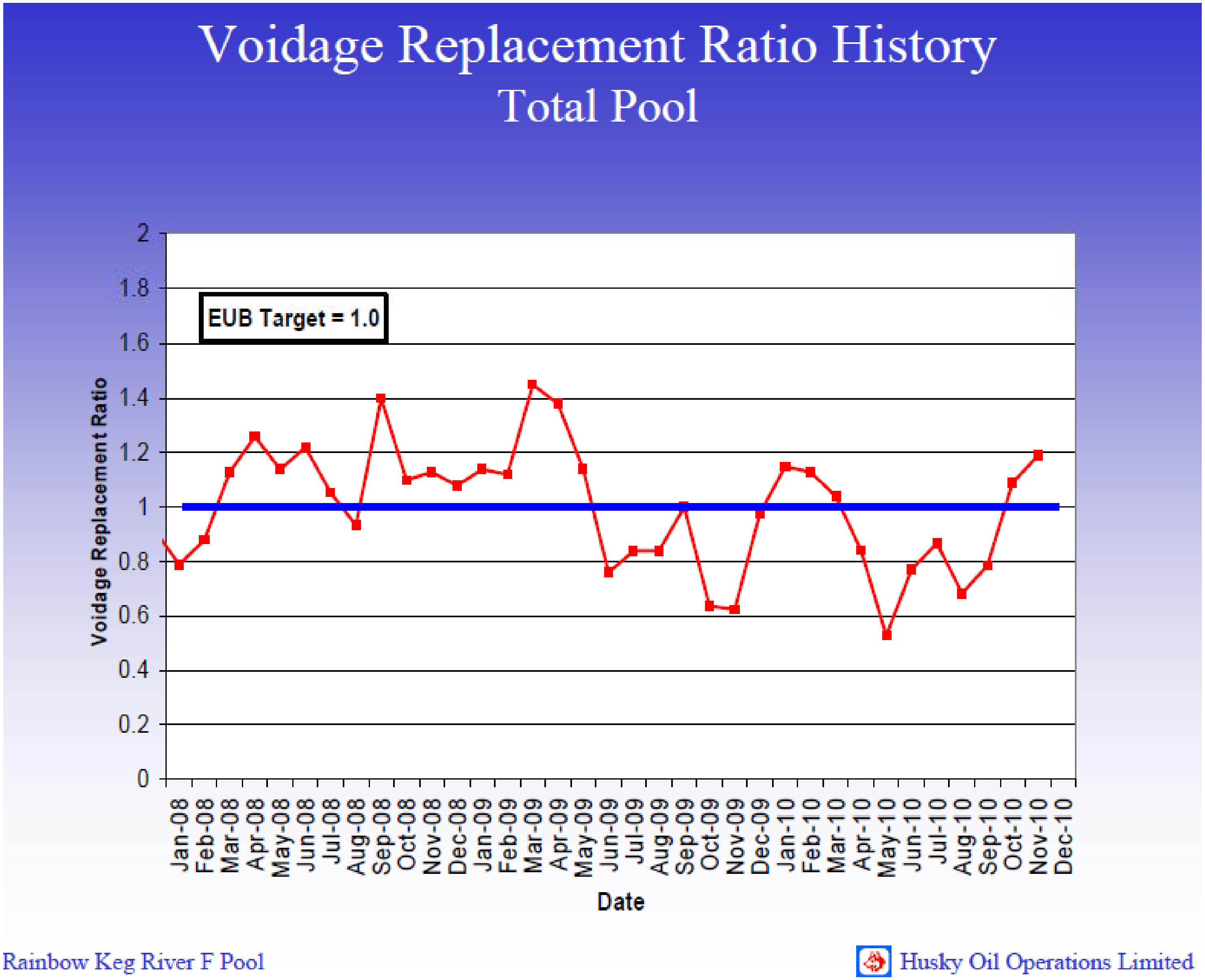
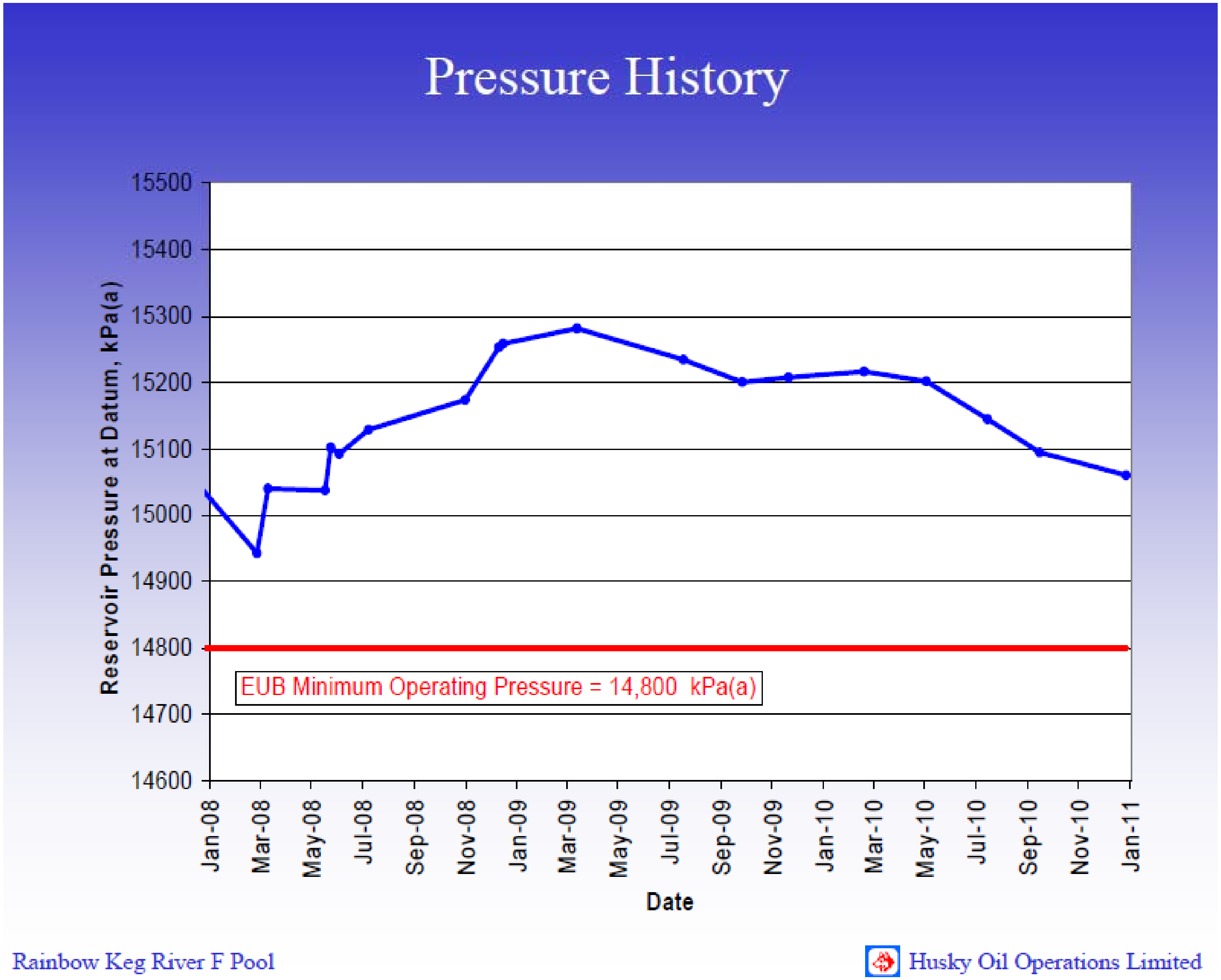

Voidage Replacement Ratio History
Total Pool
EUB Target = 1.0
Voidage Replacement Ratio
Date
2
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
Jan-08
Feb-08
Mar-08
Apr-08
May-08
Jun-08
Jul-08
Aug-08
Sep-08
Oct-08
Nov-08
Dec-08
Jan-09
Feb-09
Mar-09
Apr-09
May-09
Jun-09
Jul-09
Aug-09
Sep-09
Oct-09
Nov-09
Dec-09
Jan-10
Feb-10
Mar-10
Apr-10
May-10
Jun-10
Jul-10
Aug-10
Sep-10
Oct-10
Nov-10
Dec-10
Rainbow Keg River F Pool
Husky Oil Operations Limited

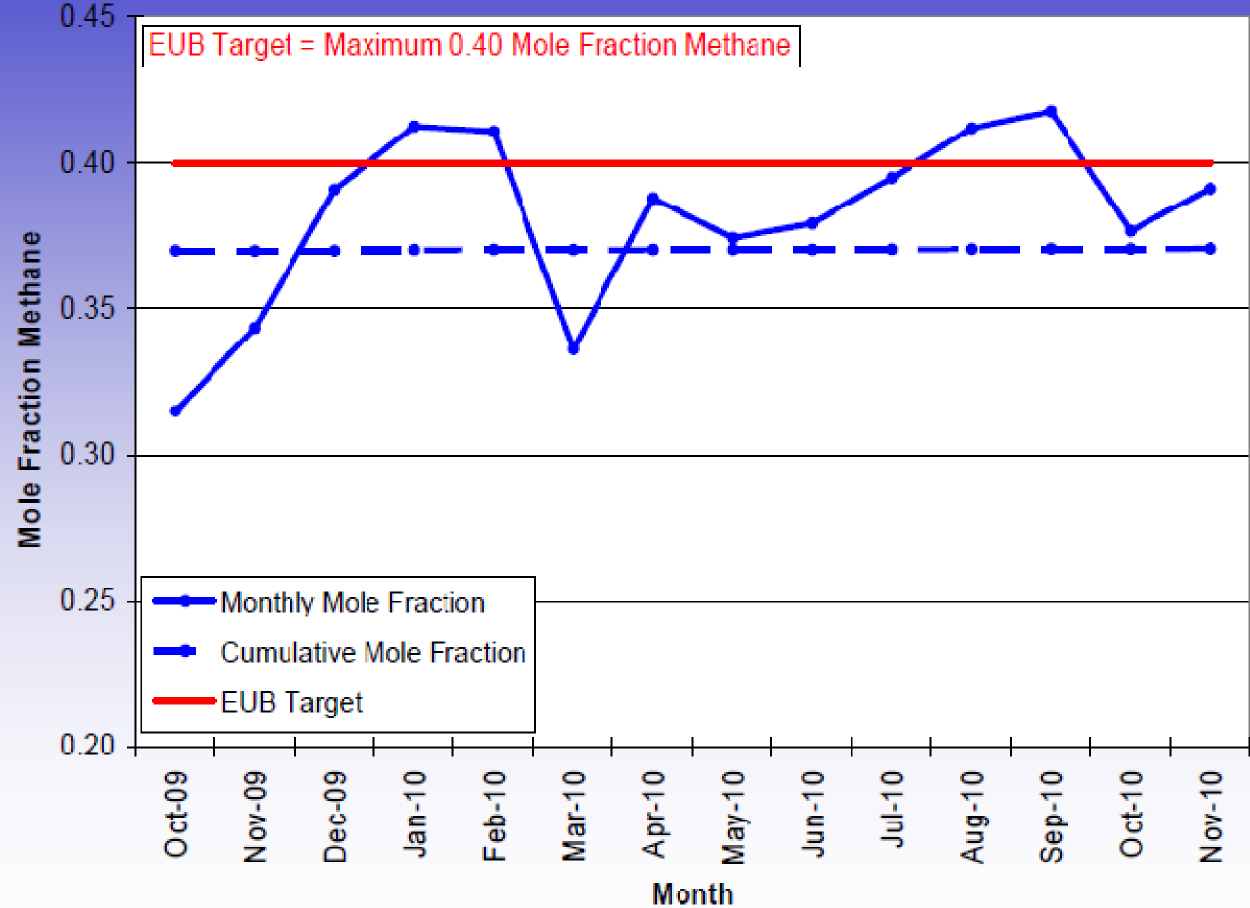
Figure 123



Pressure History
Reservoir Pressure at Datum, kPa(a)
15500
15400
15300
15200
15100
15000
14900
14800
14700
14600
EUB Minimum Operating Pressure = 14,800 kPa(a)
Jan-08
Mar-08
May-08
Jul-08
Sep-08
Nov-08
Jan-09
Mar-09
May-09
Jul-09
Sep-09
Nov-09
Jan-10
Mar-10
May-10
Jul-10
Sep-10
Nov-10
Jan-11
Date
Rainbow Keg River F Pool
Husky Oil Operations Limited


Figure 124

# Injected Solvent Composition




Rainbow Keg River F Pool

Husky Oil Operations Limited

Figure 125

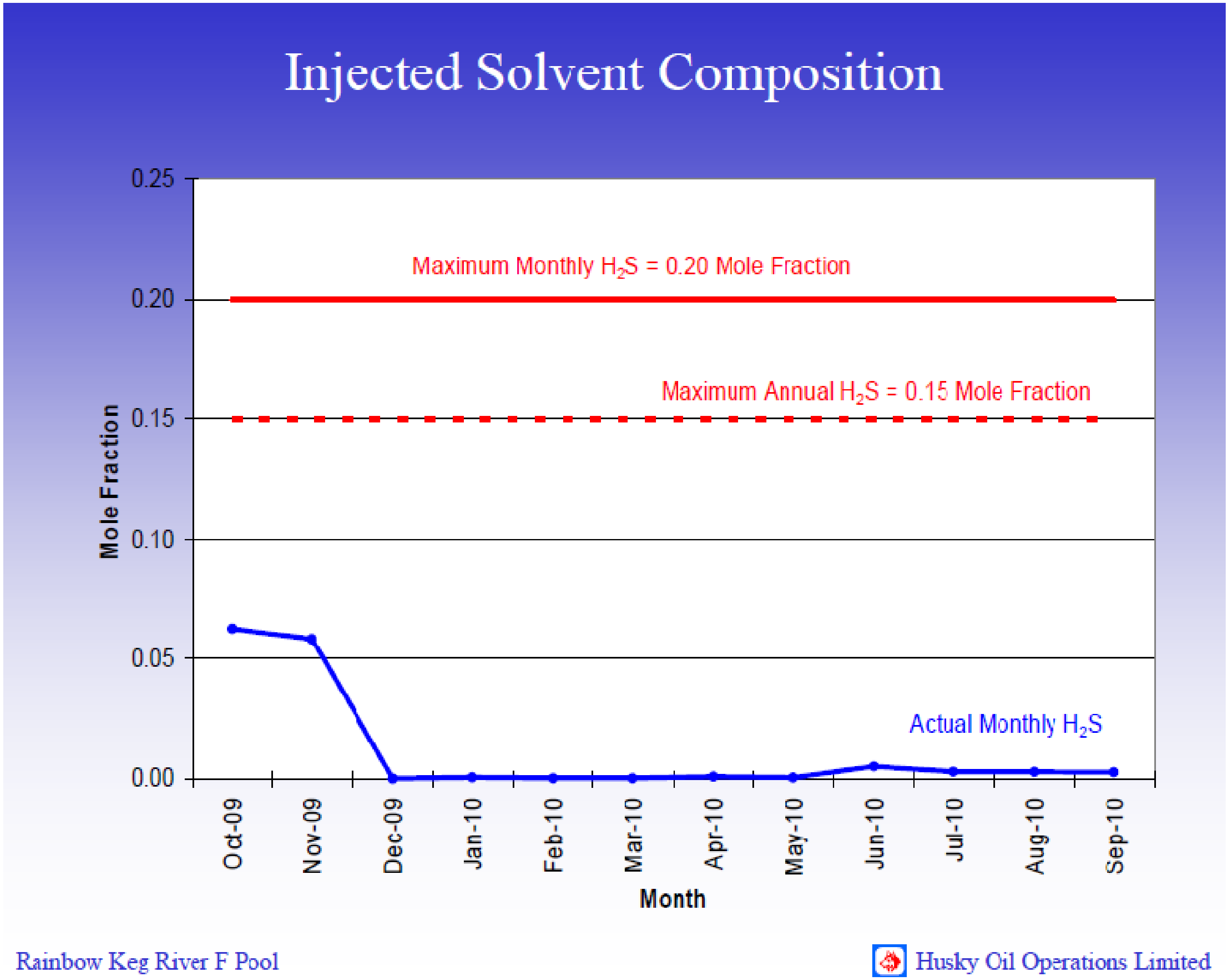
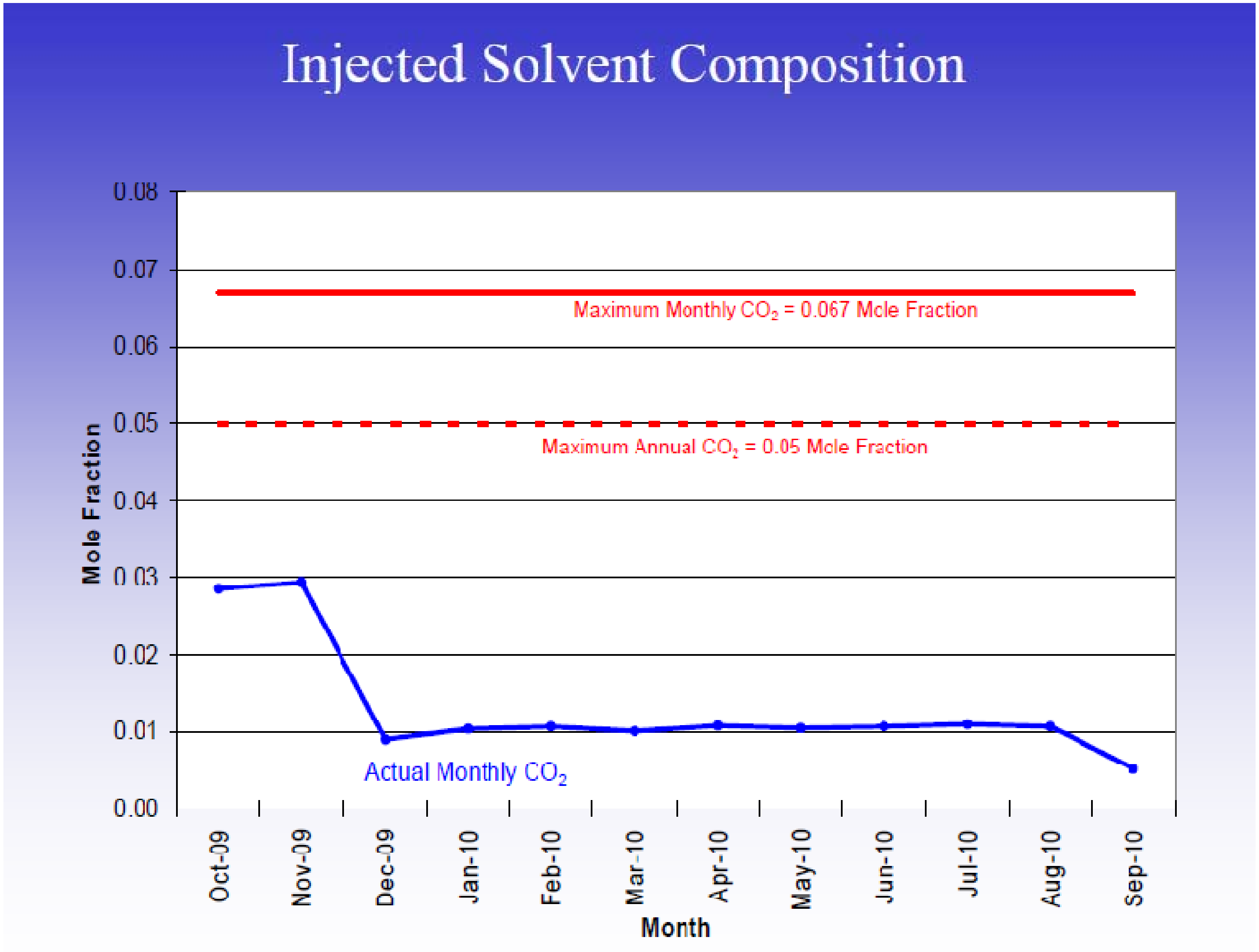

Injected Solvent Composition
Maximum Monthly H2S = 0.20 Mole Fraction
Maximum Annual H2S = 0.15 Mole Fraction
Actual Monthly H2S
Mole Fraction
0.25
0.20
0.15
0.10
0.05
0.00
Oct-09
Nov-09
Dec-09
Jan-10
Feb-10
Mar-10
Apr-10
May-10
Jun-10
Jul-10
Aug-10
Sep-10
Month
Rainbow Keg River F Pool
Husky Oil Operations Limited

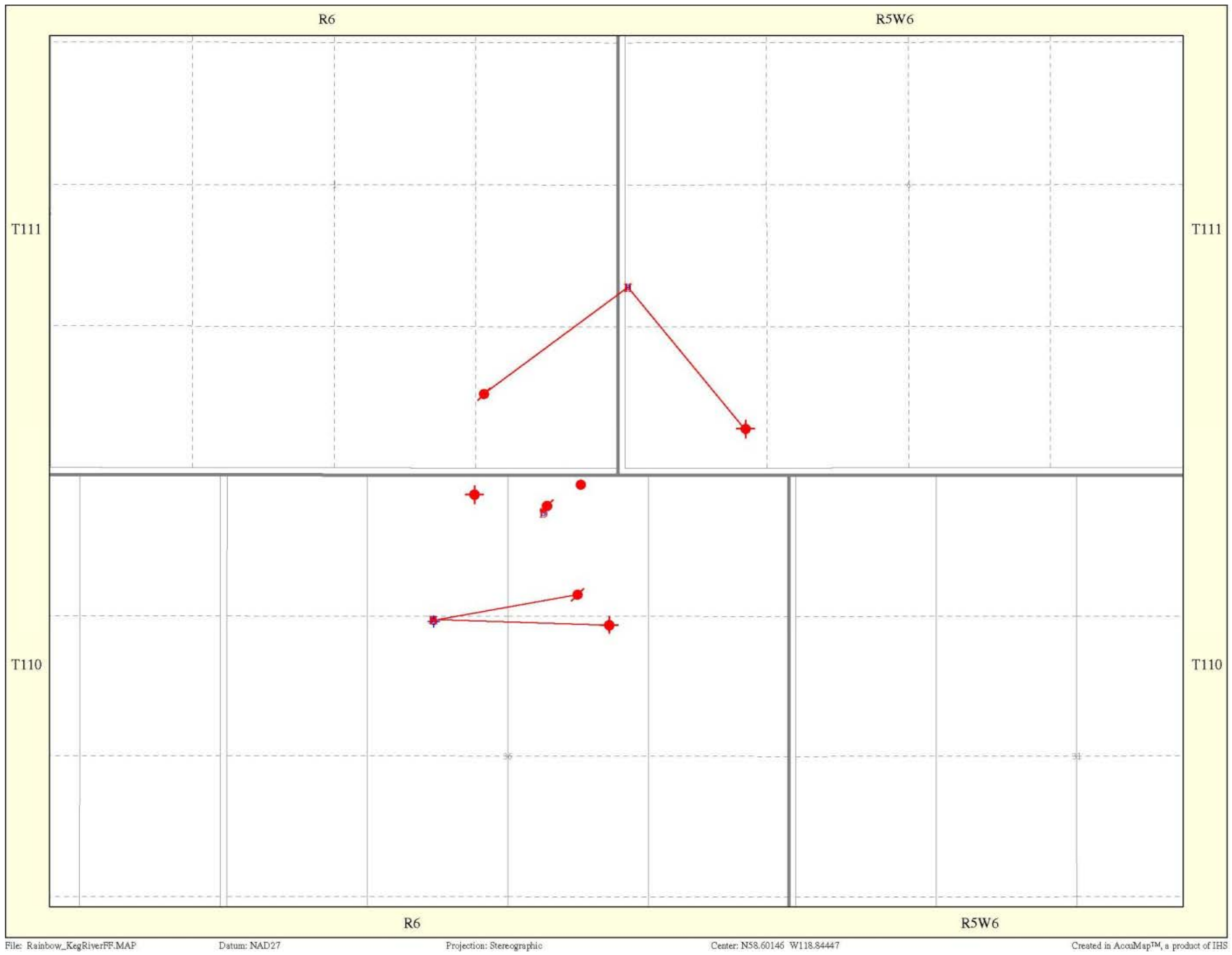
Figure 126




Rainbow Keg River F Pool

Husky Oil Operations Limited

Figure 127

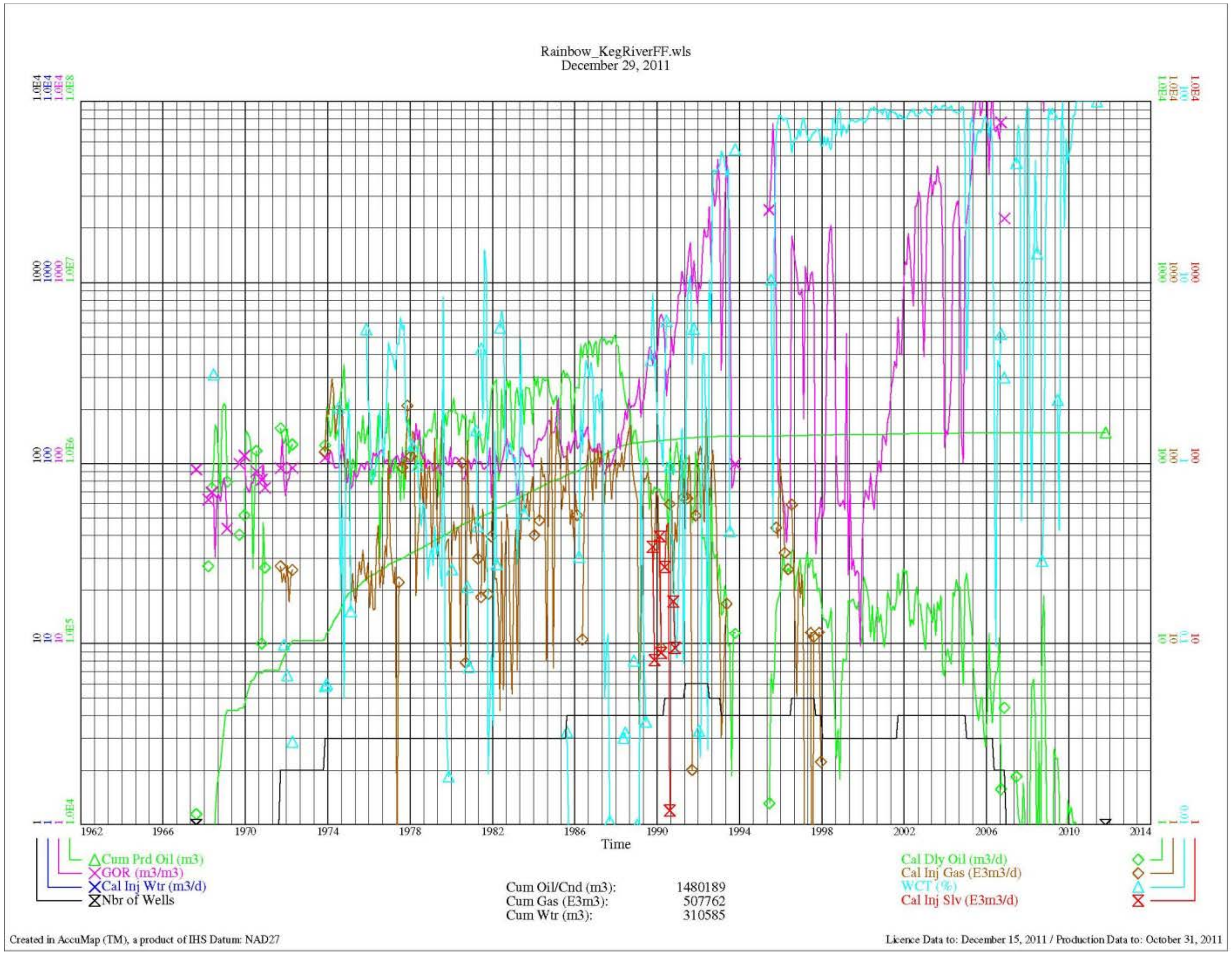



**Rainbow Keg River FF – Well Locations**

Figure 128



Sproule

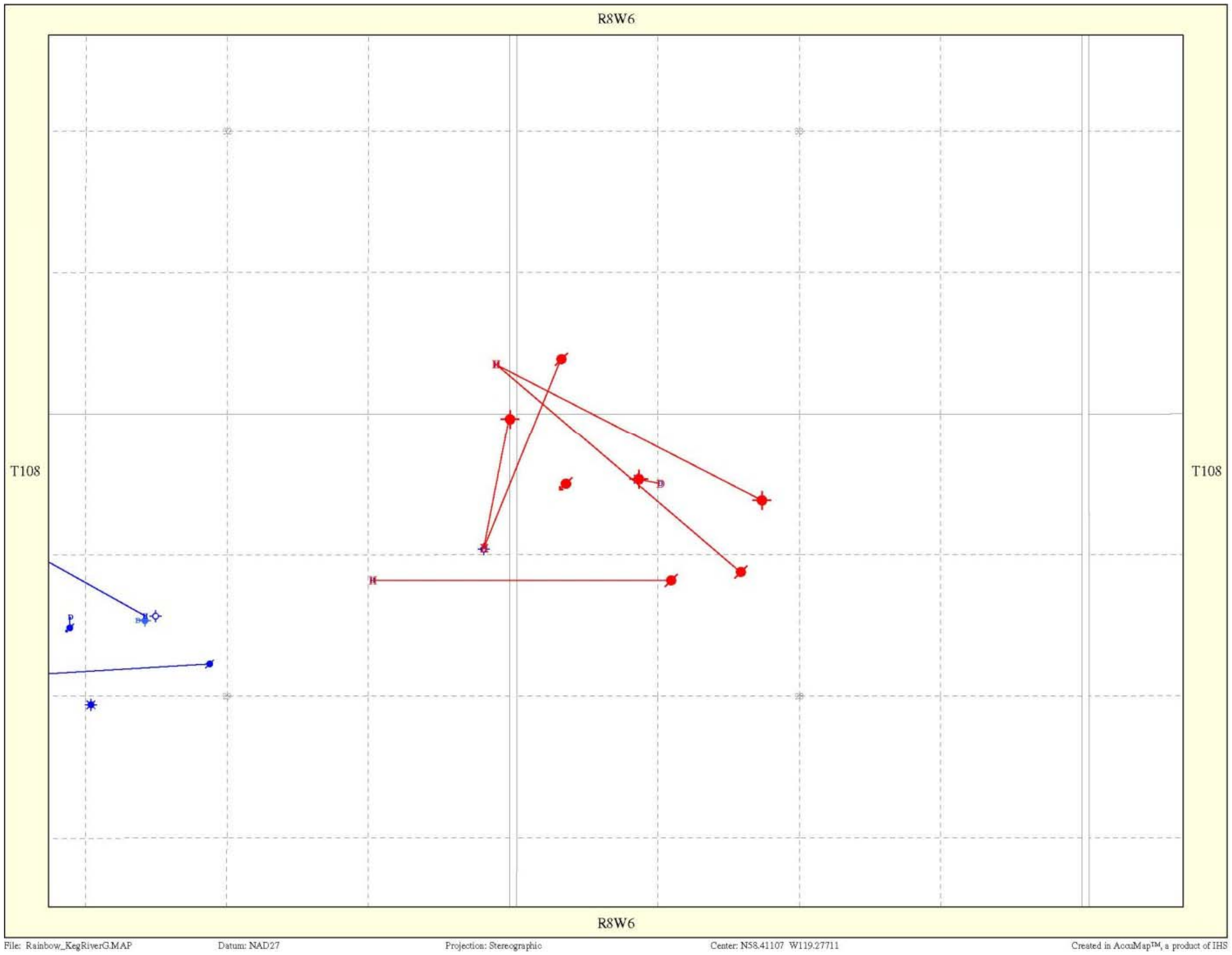



**Rainbow Keg River FF – Production / Injection History**

Figure 129

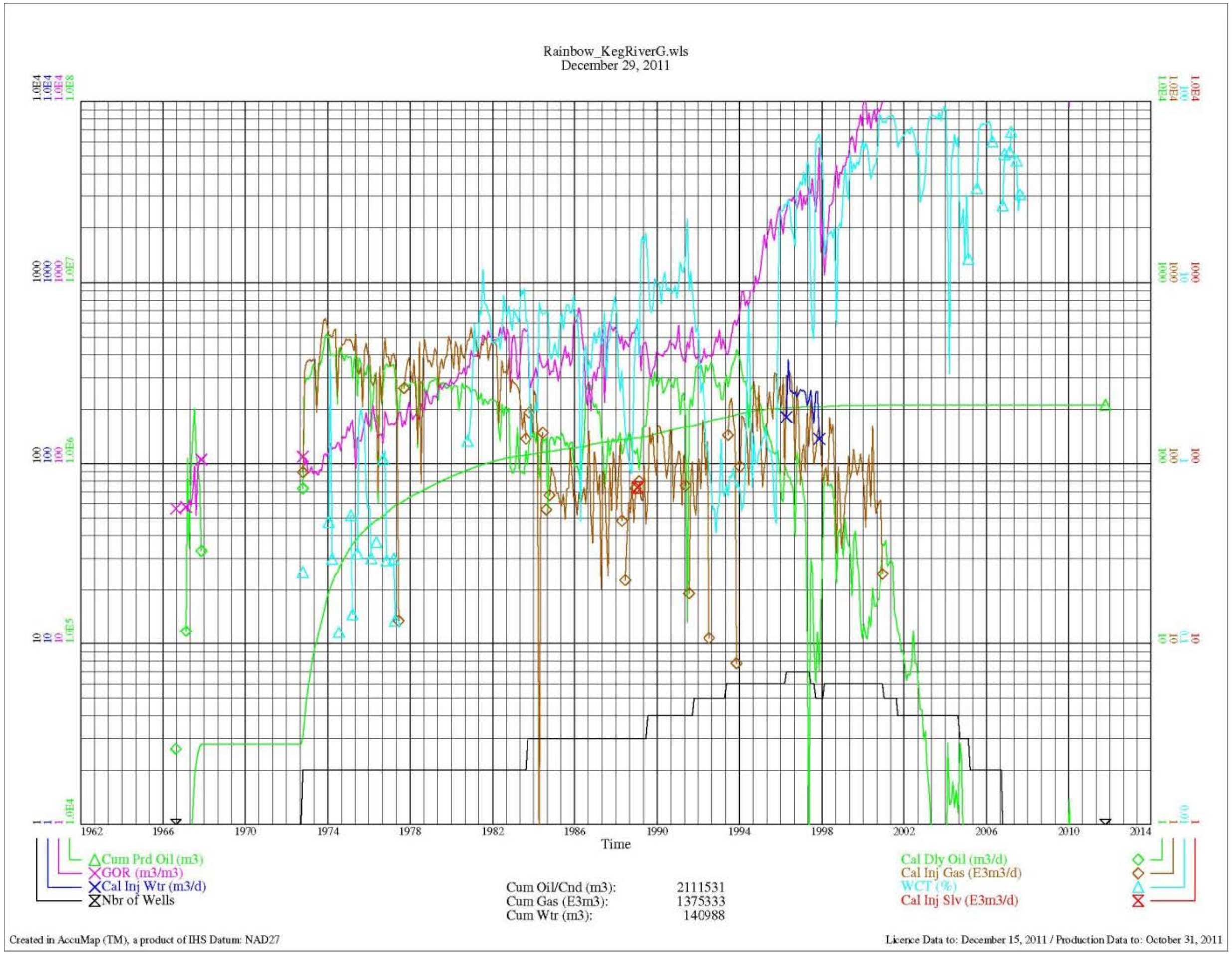


Sproule




**Rainbow Keg River G – Well Locations**

Figure 130




**Rainbow Keg River G – Production / Injection History**

Figure 131

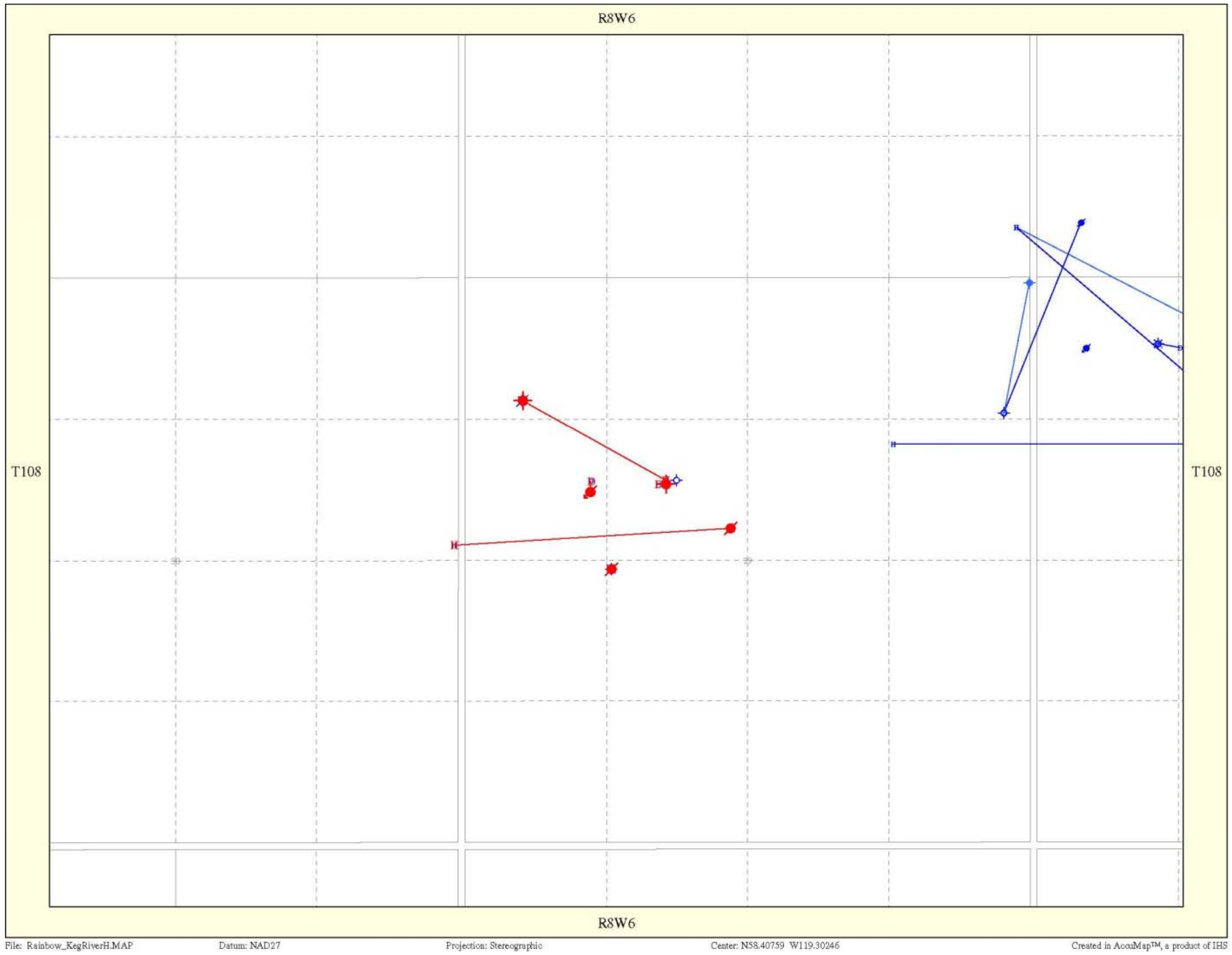
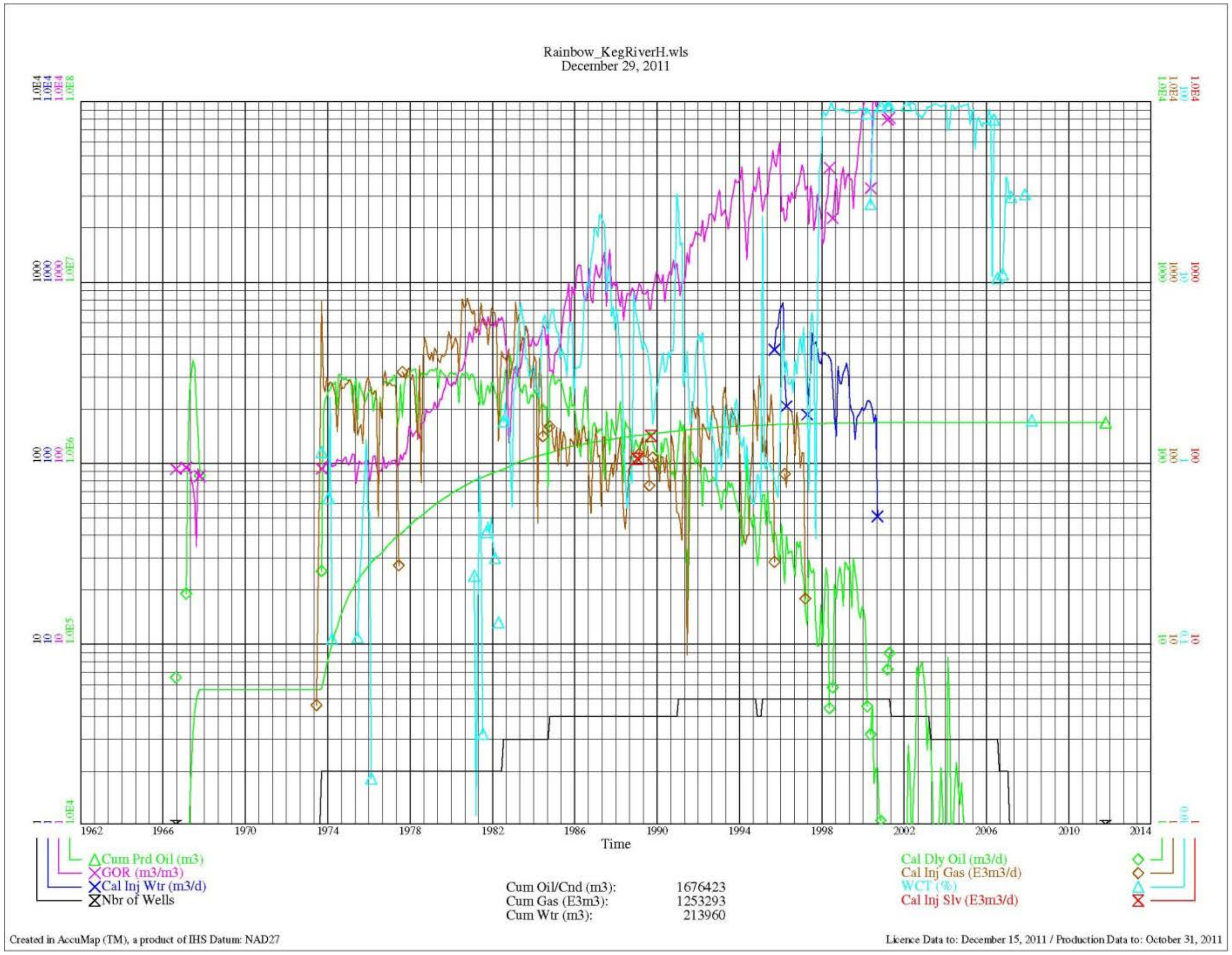


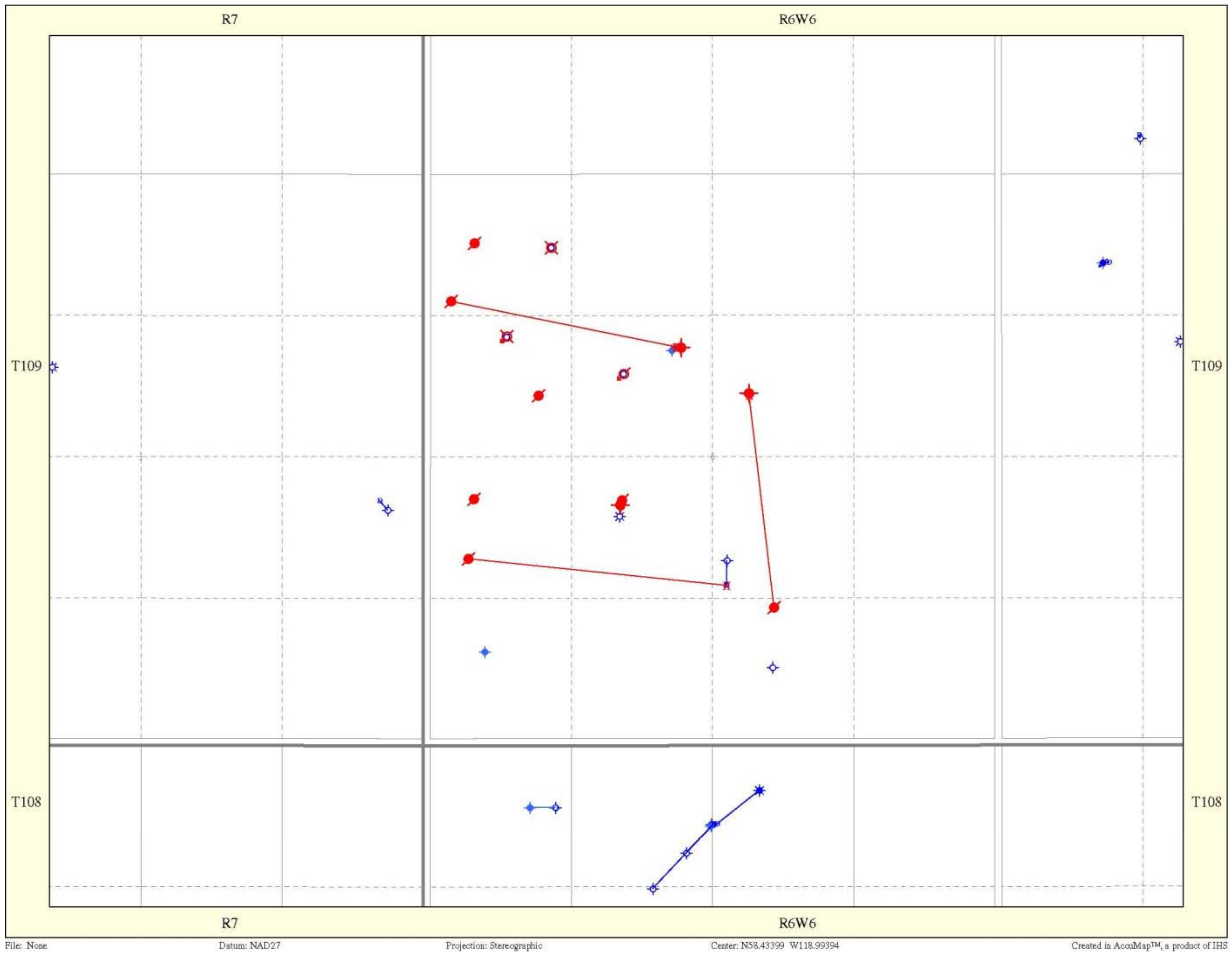

Figure 132

**Rainbow Keg River H – Well Locations**



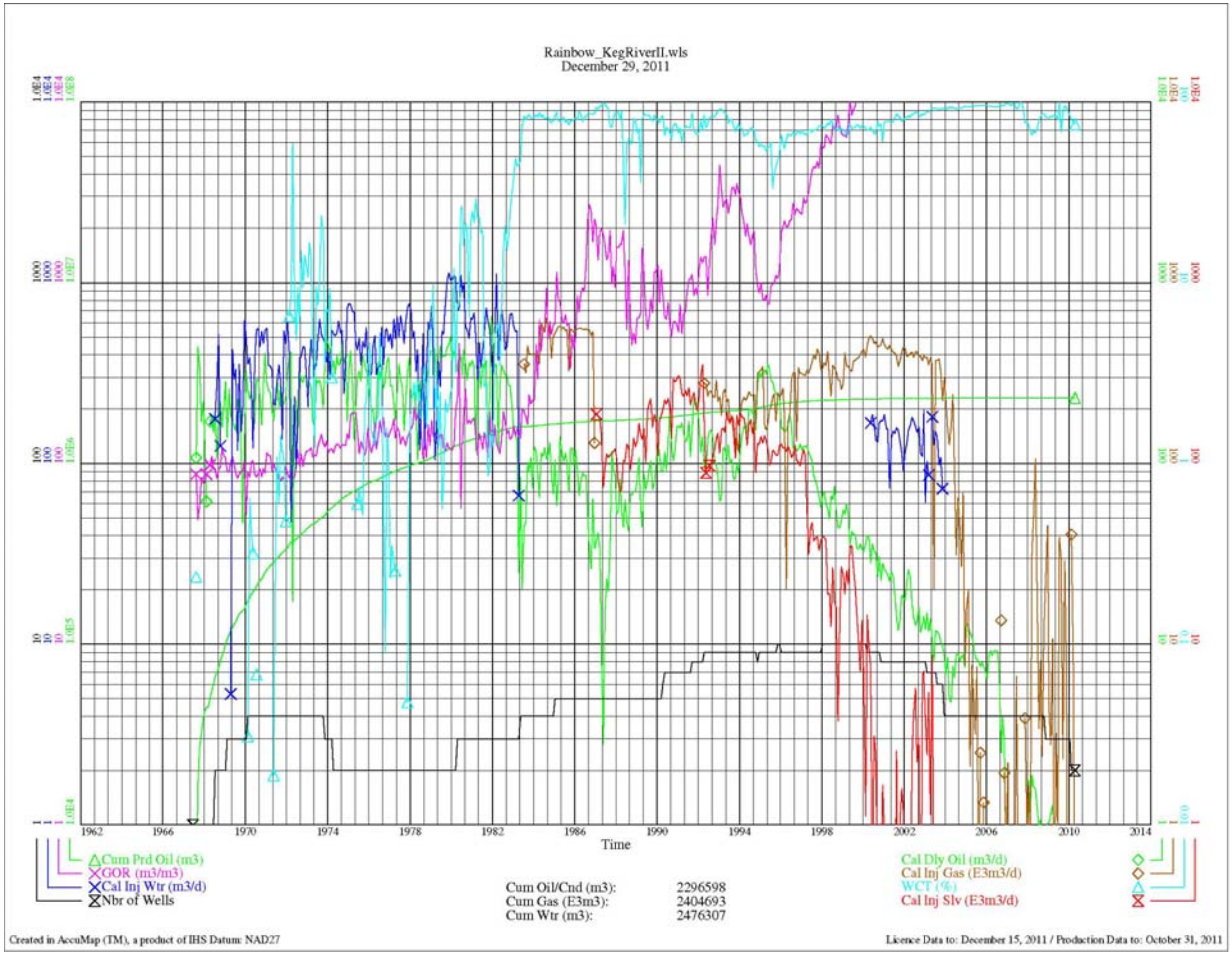

**Rainbow Keg River H – Production / Injection History**

Figure 133




**Rainbow Keg River II – Well Locations**

Figure 134




**Rainbow Keg River II – Production / Injection History**

Figure 135



Sproule

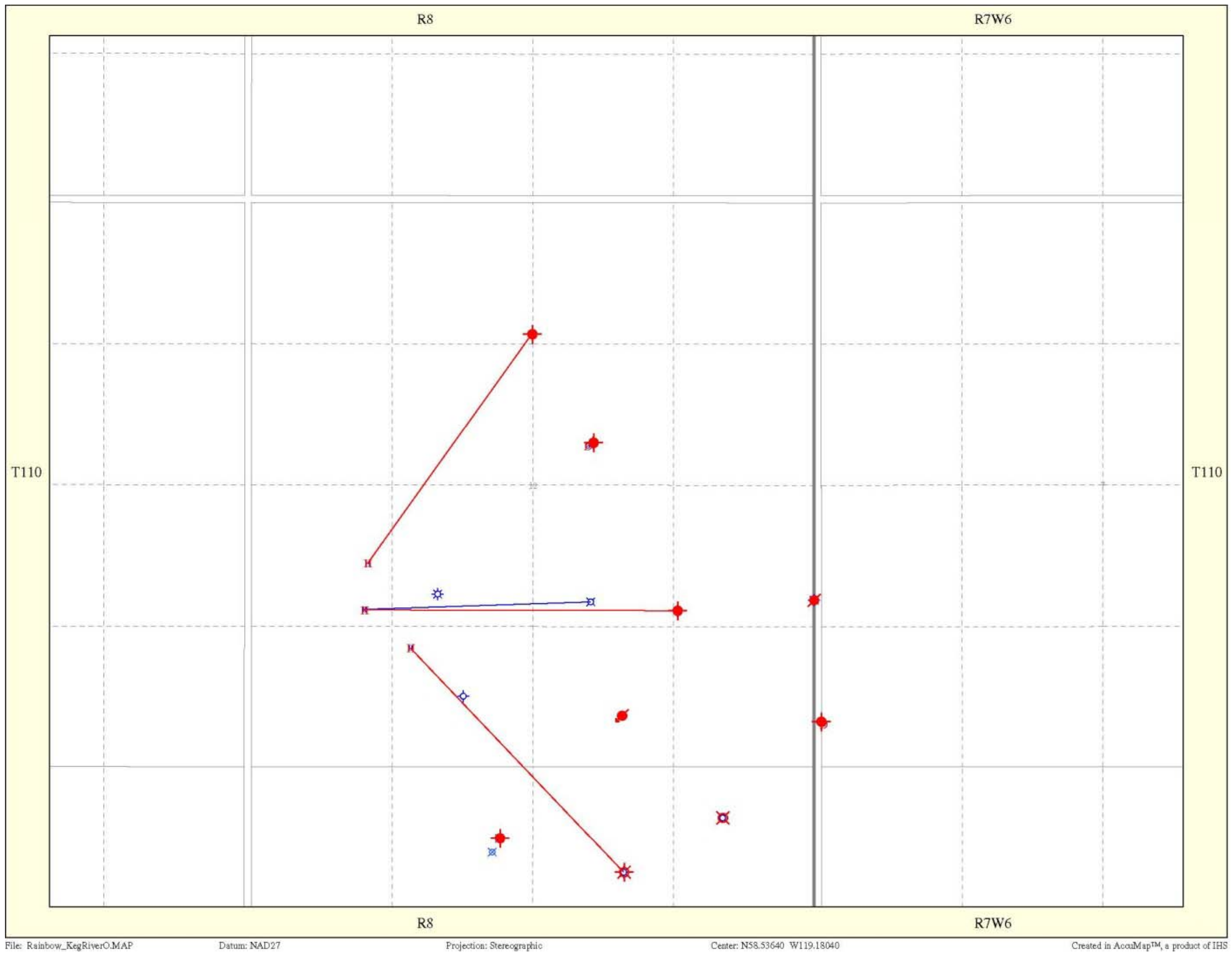
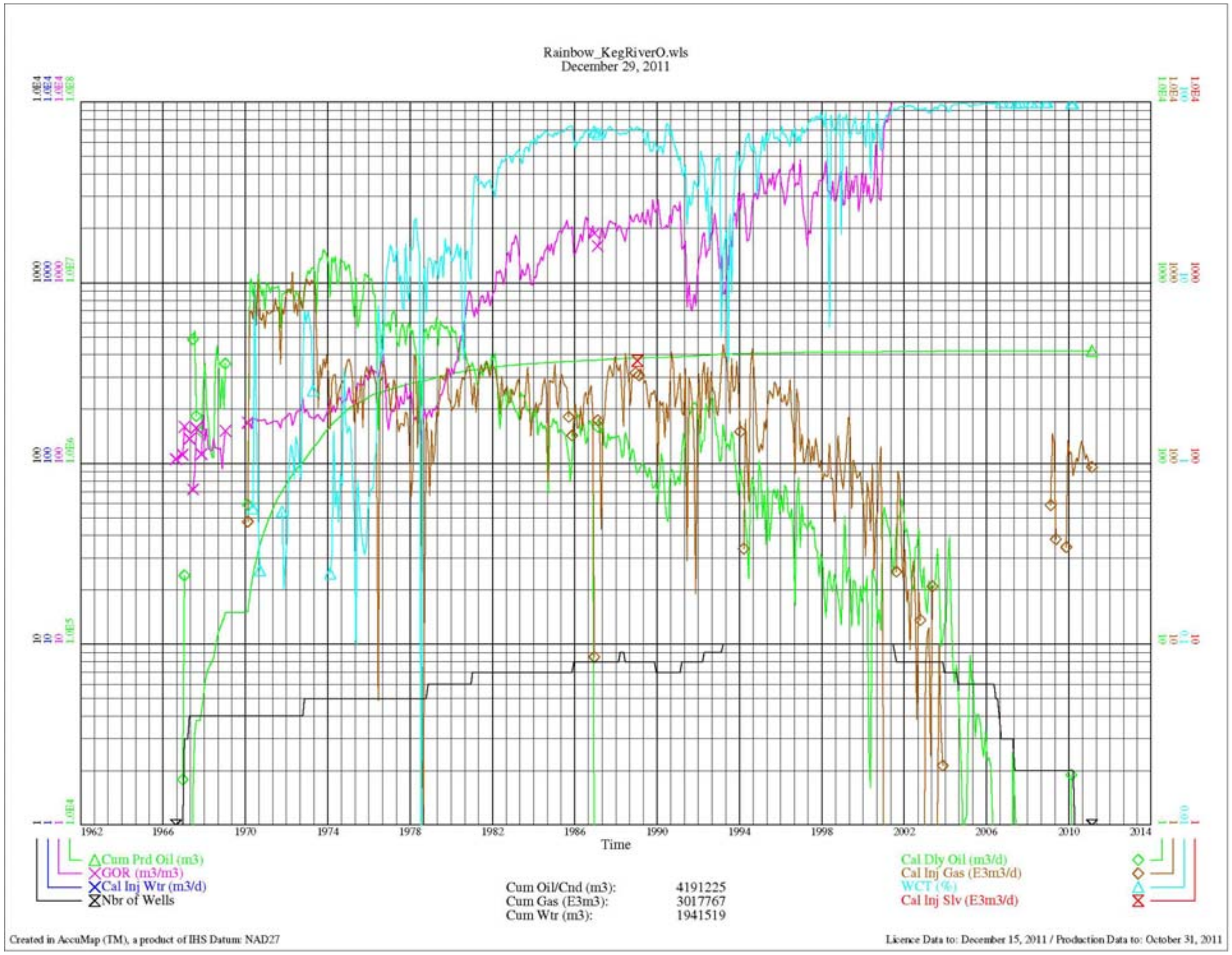


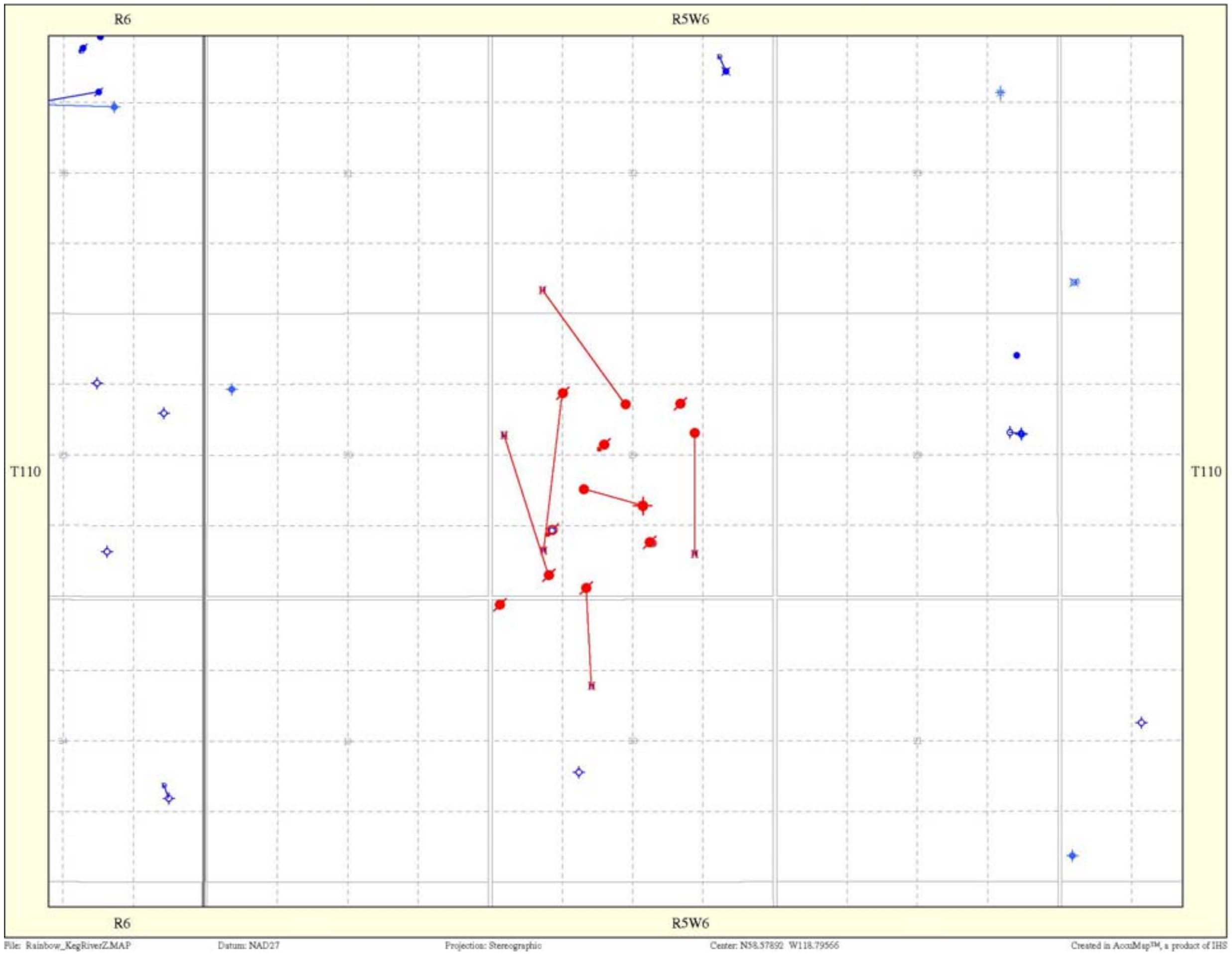

Figure 136

**Rainbow Keg River O – Well Locations**



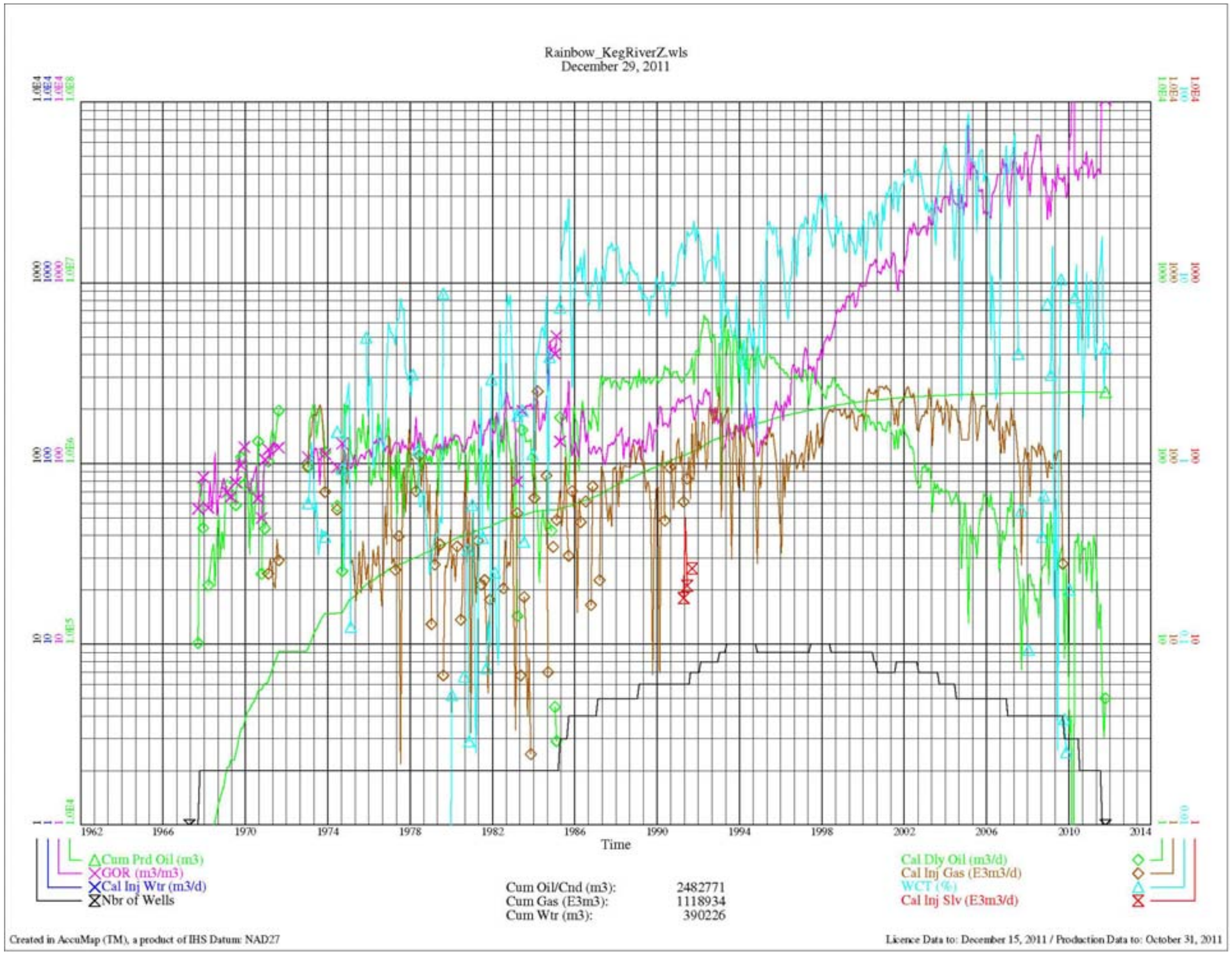

**Rainbow Keg River O – Production / Injection History**

Figure 137



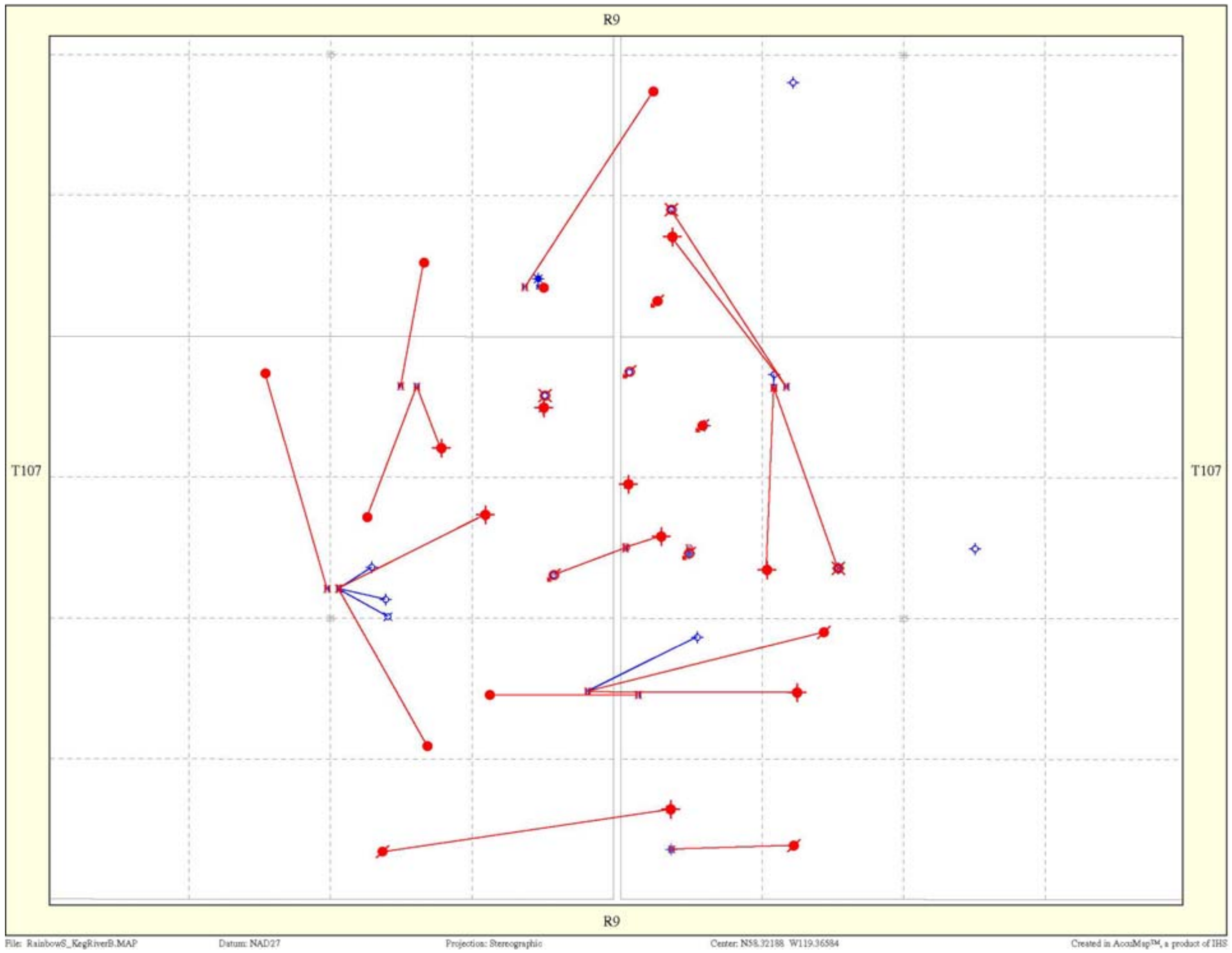

**Rainbow Keg River Z – Well Locations**

Figure 138




**Rainbow Keg River Z – Production / Injection History**

Figure 139




**Rainbow South Keg River B – Well Locations**

Figure 140

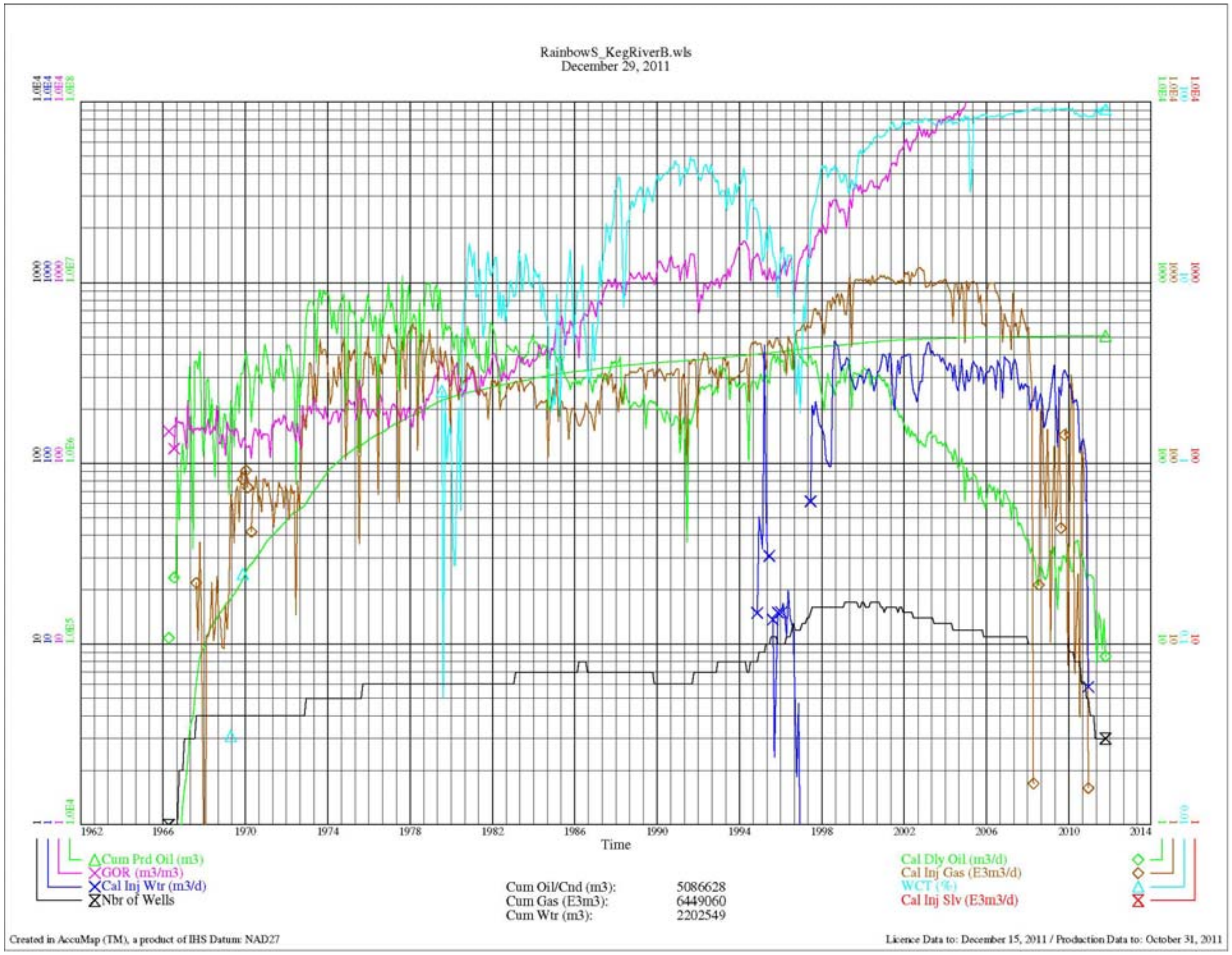
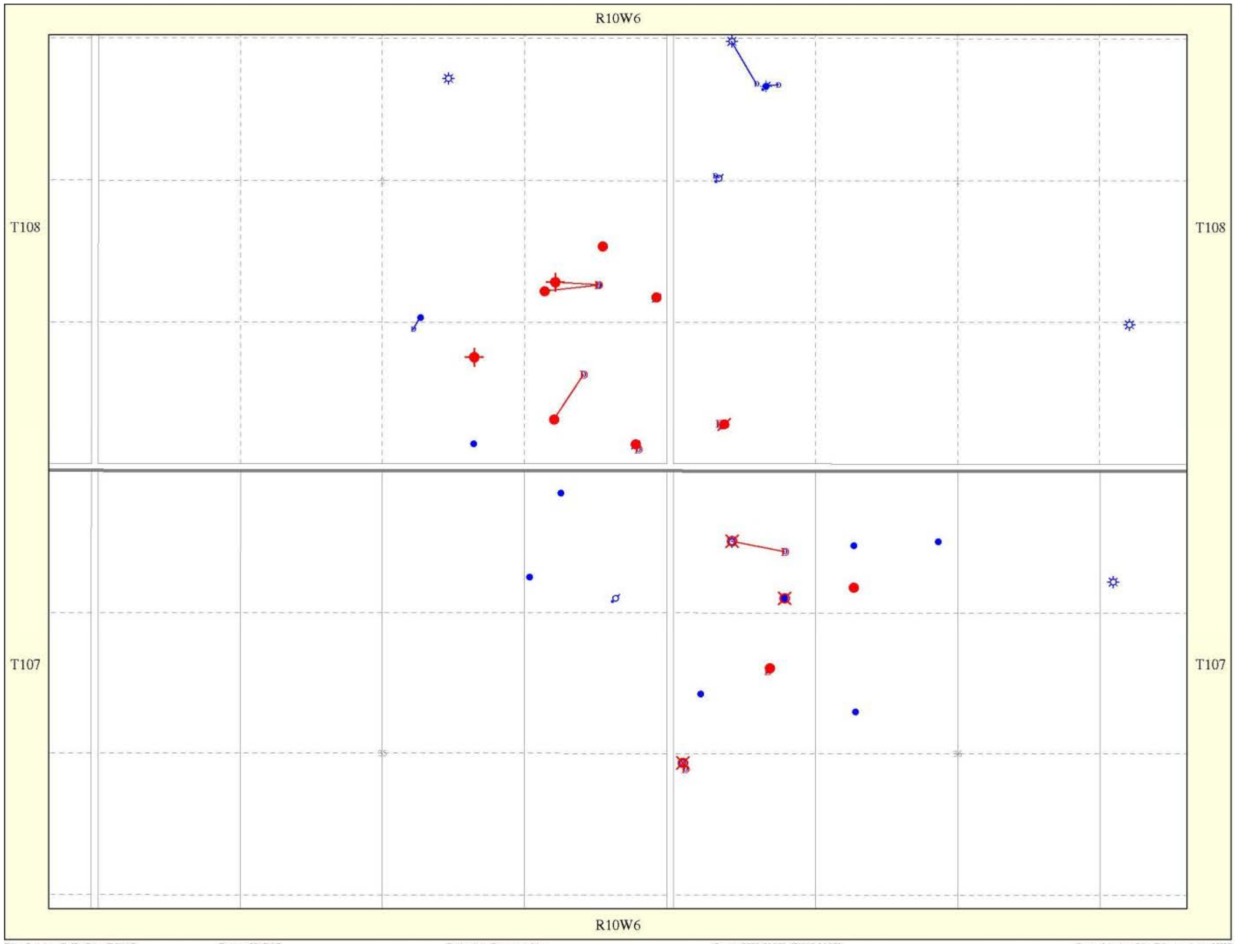



Figure 141

**Rainbow South Keg River B – Production / Injection History**



Sproule




File: RainbowS_KegRiverE.MAP Datum: NAD27 Projection: Stereographic Center: N58.33972 W119.53568 Created in AccuMap™, a product of IHS

Figure 142

**Rainbow South Keg River E – Well Locations**

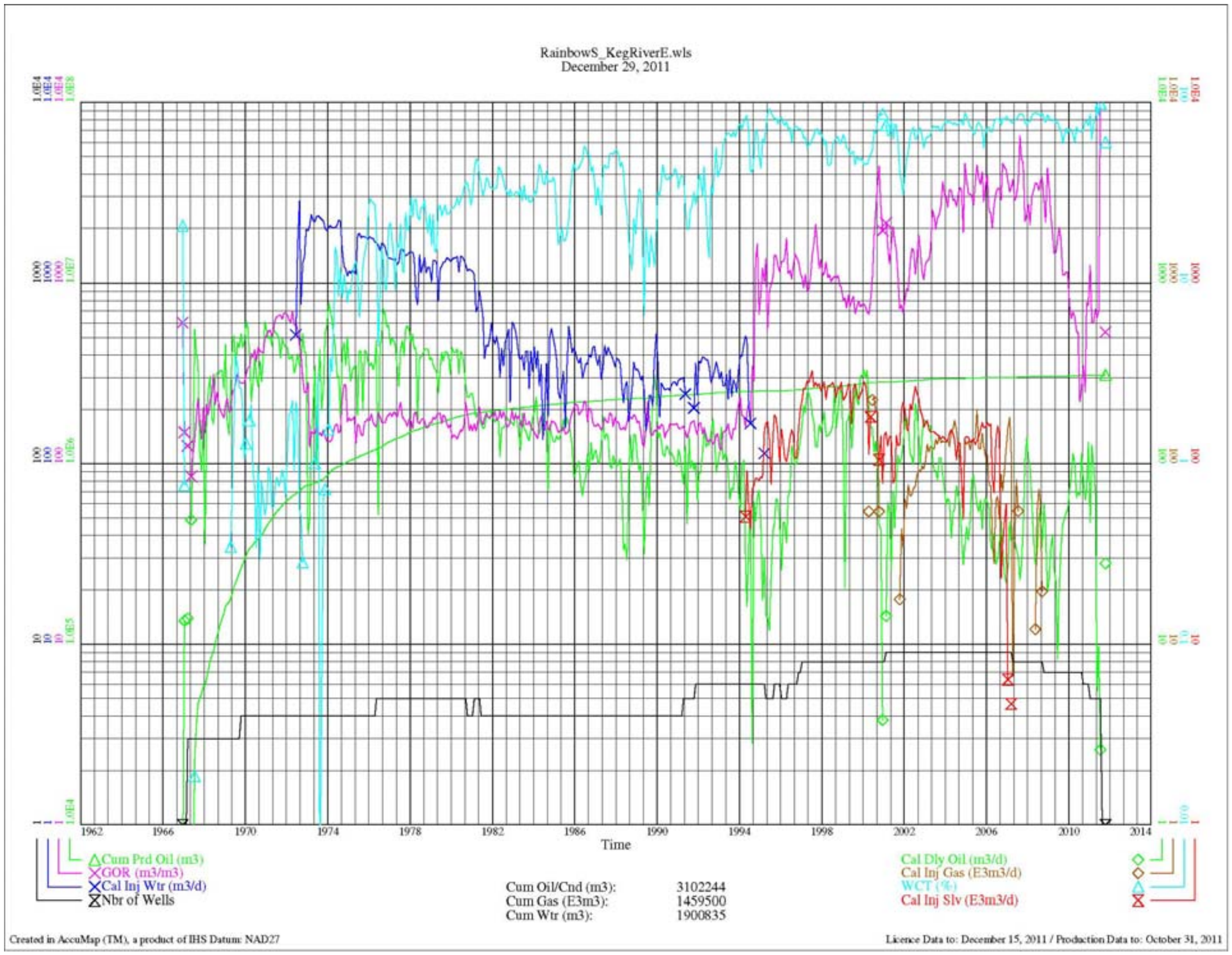



Figure 143

**Rainbow South Keg River E – Production / Injection History**



Sproule

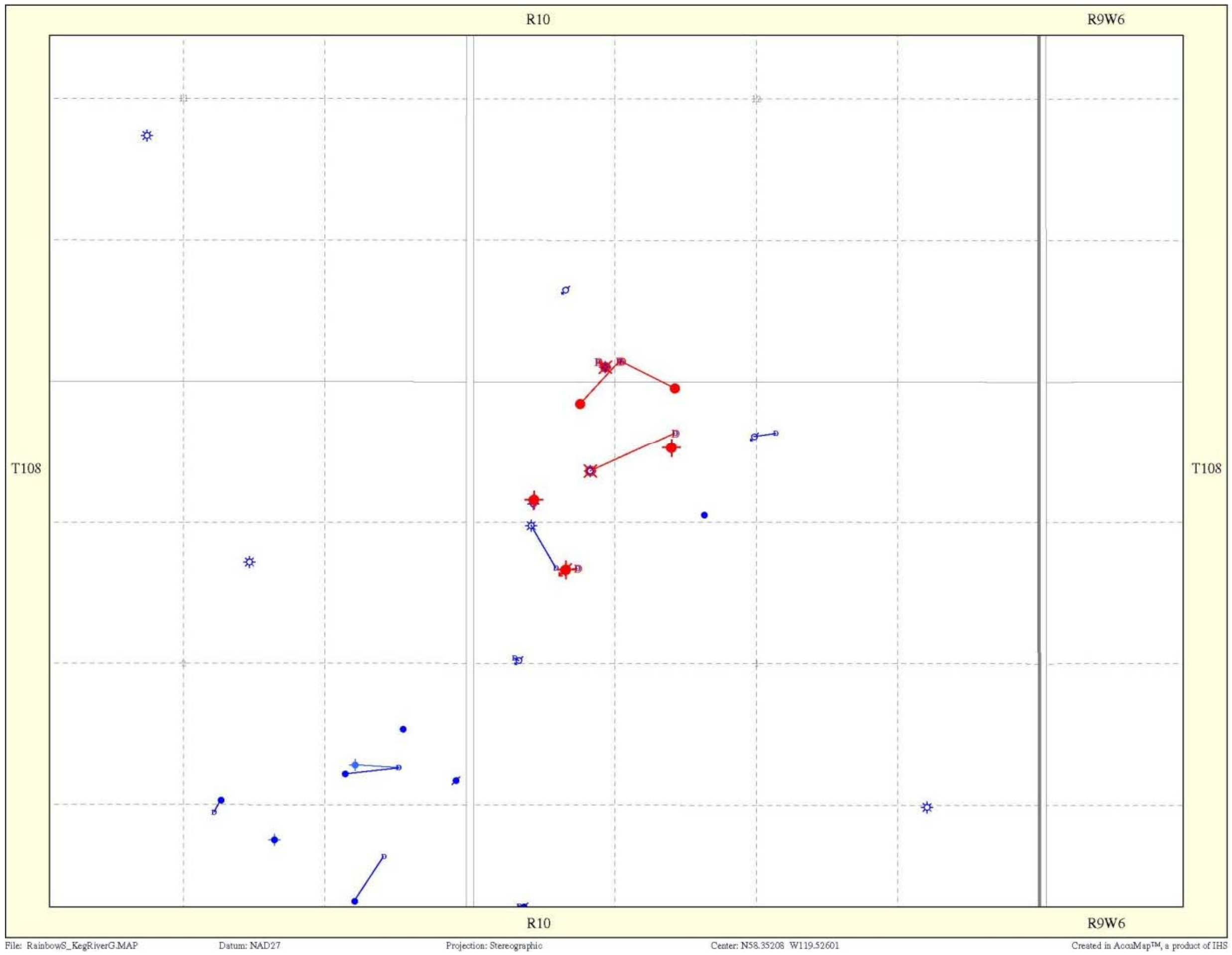
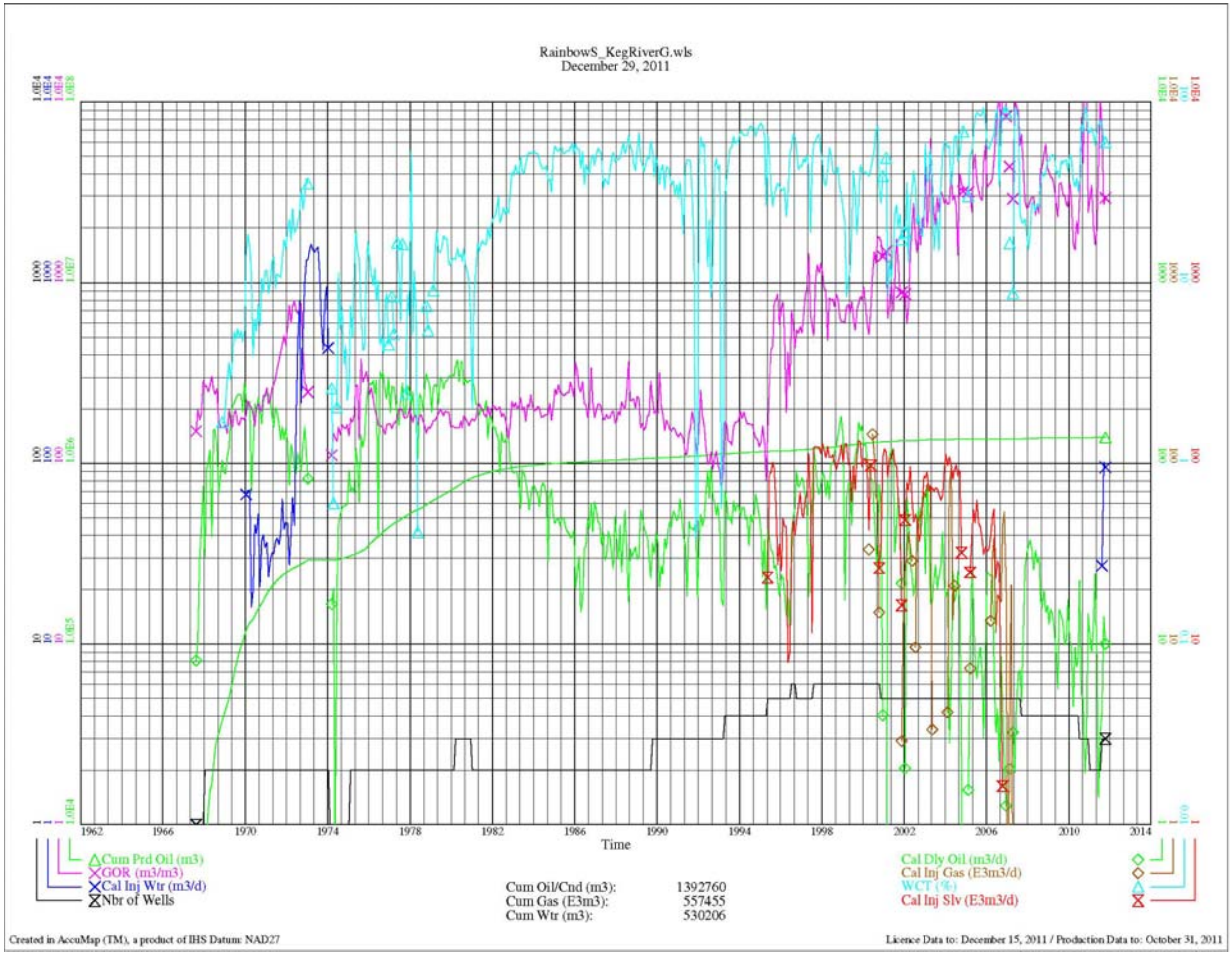


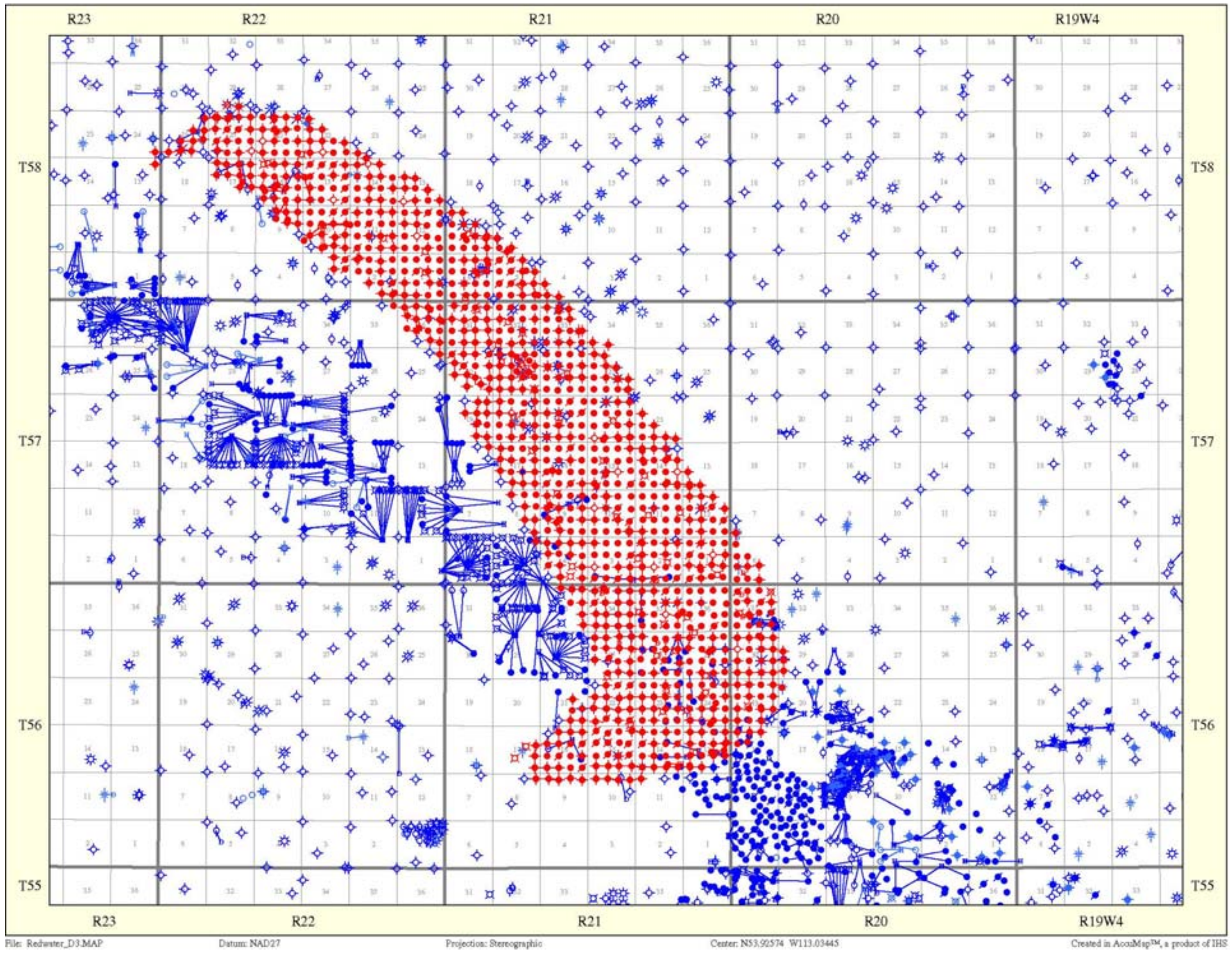

Figure 144

**Rainbow South Keg River G – Well Locations**




**Rainbow South Keg River G – Production / Injection History**

Figure 145

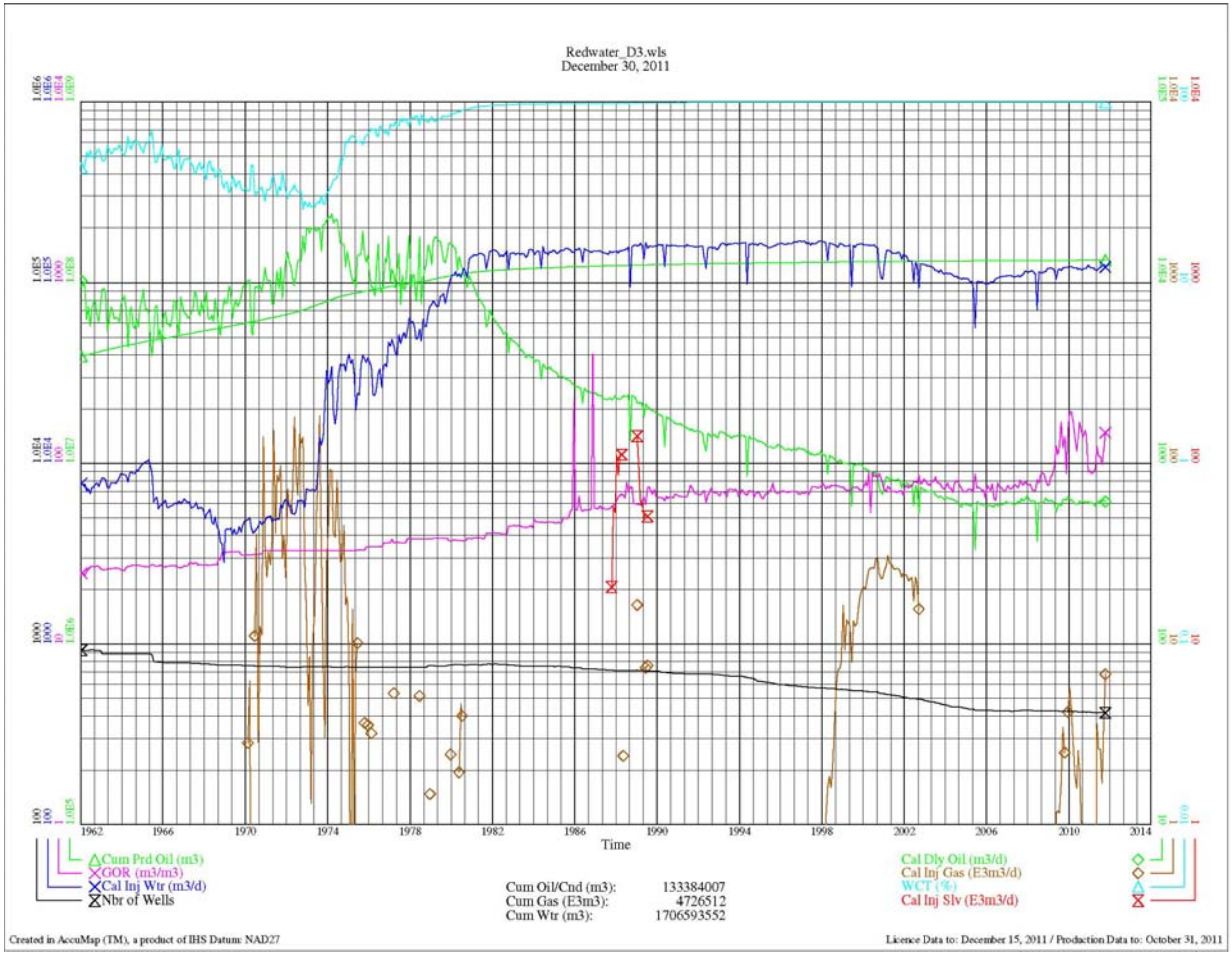



**Redwater D-3 – Well Locations**

Figure 146

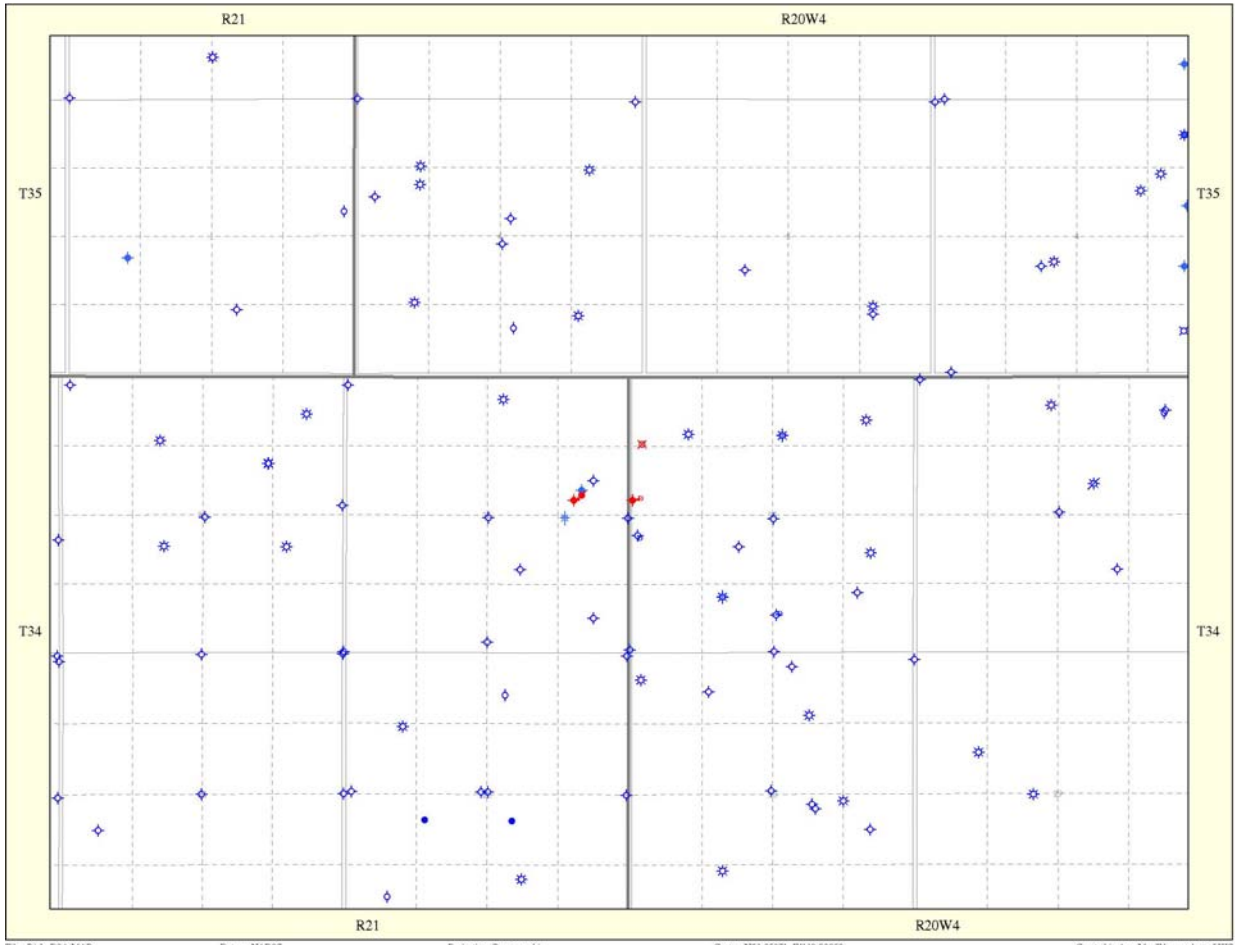


Sproule




**Redwater D-3 – Production / Injection History**

Figure 147




File: Rich_D3A.MAP Datum: NAD27 Projection: Stereographic Center: N51.96371 W112.83960 Created in AccuMap™, a product of IHS

Figure 148

**Rich D-3A – Well Locations**

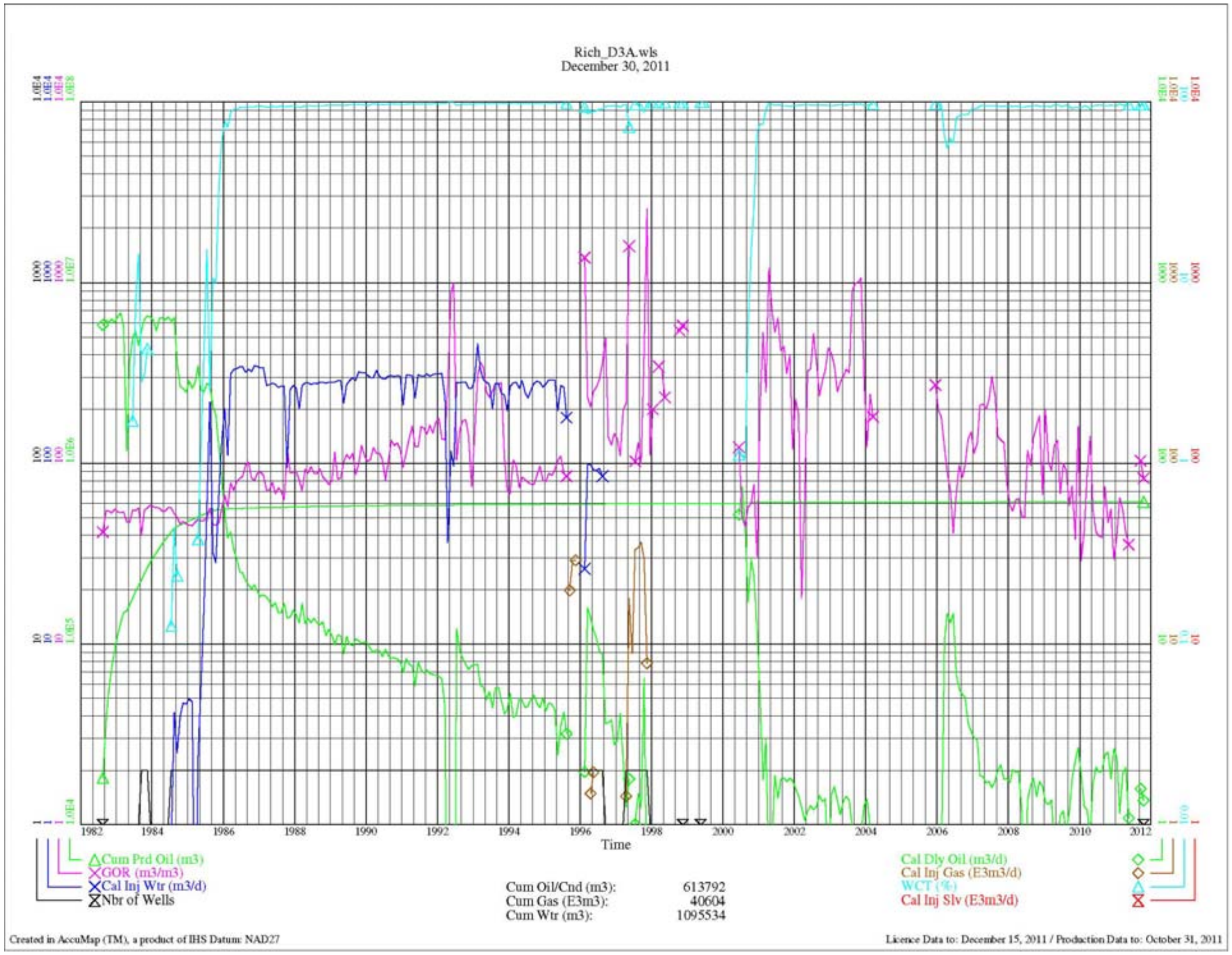
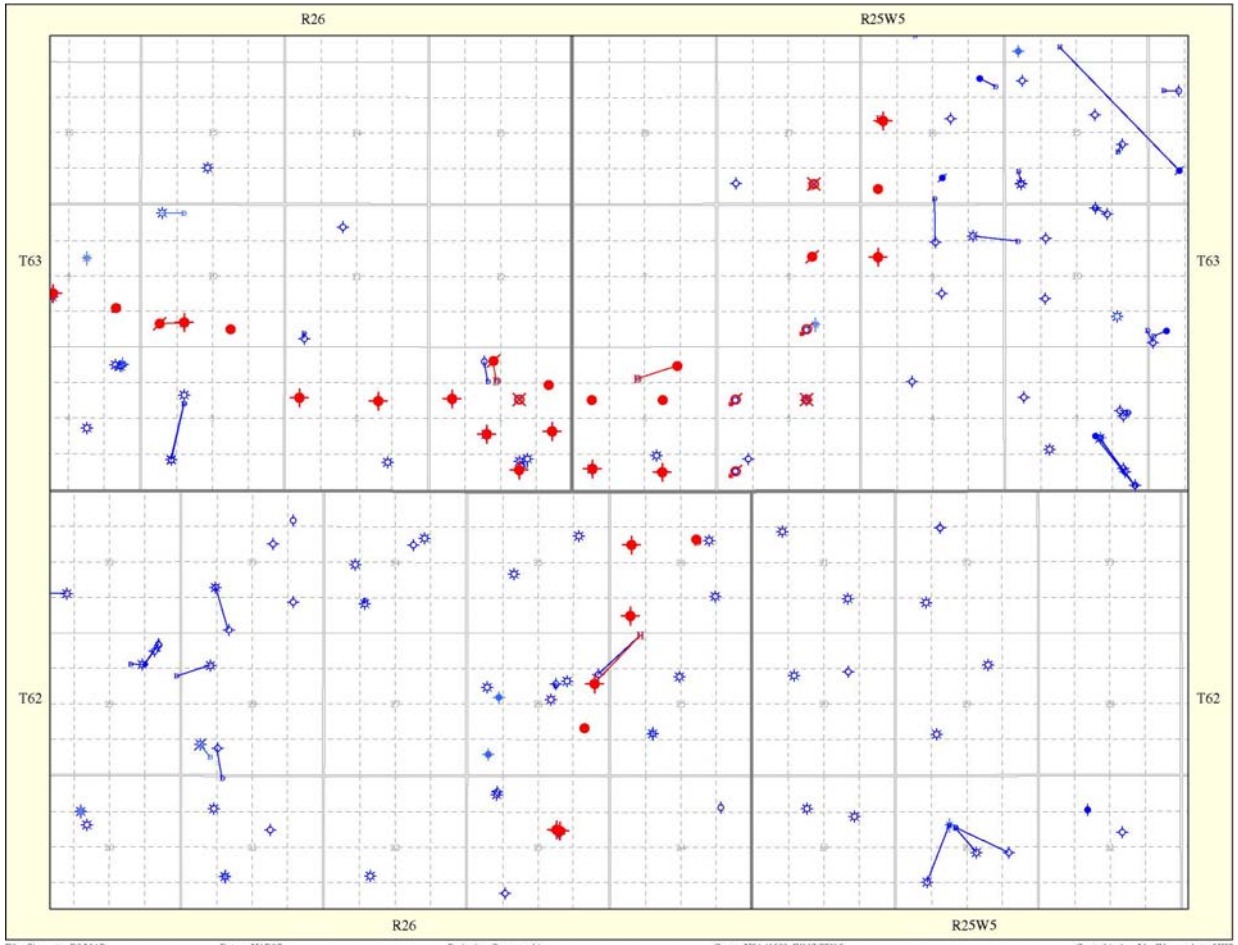


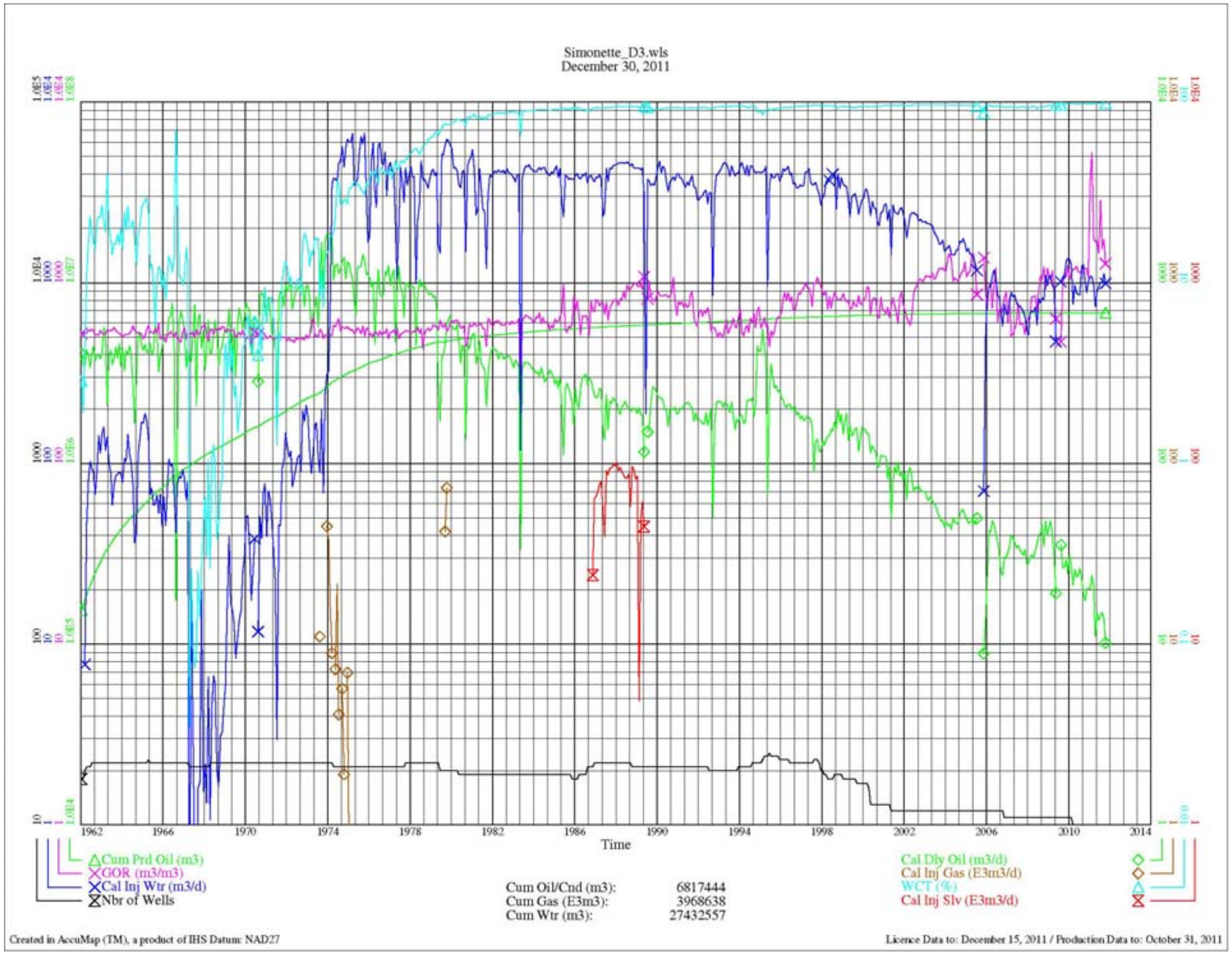

Figure 149

**Rich D-3A – Production / Injection History**



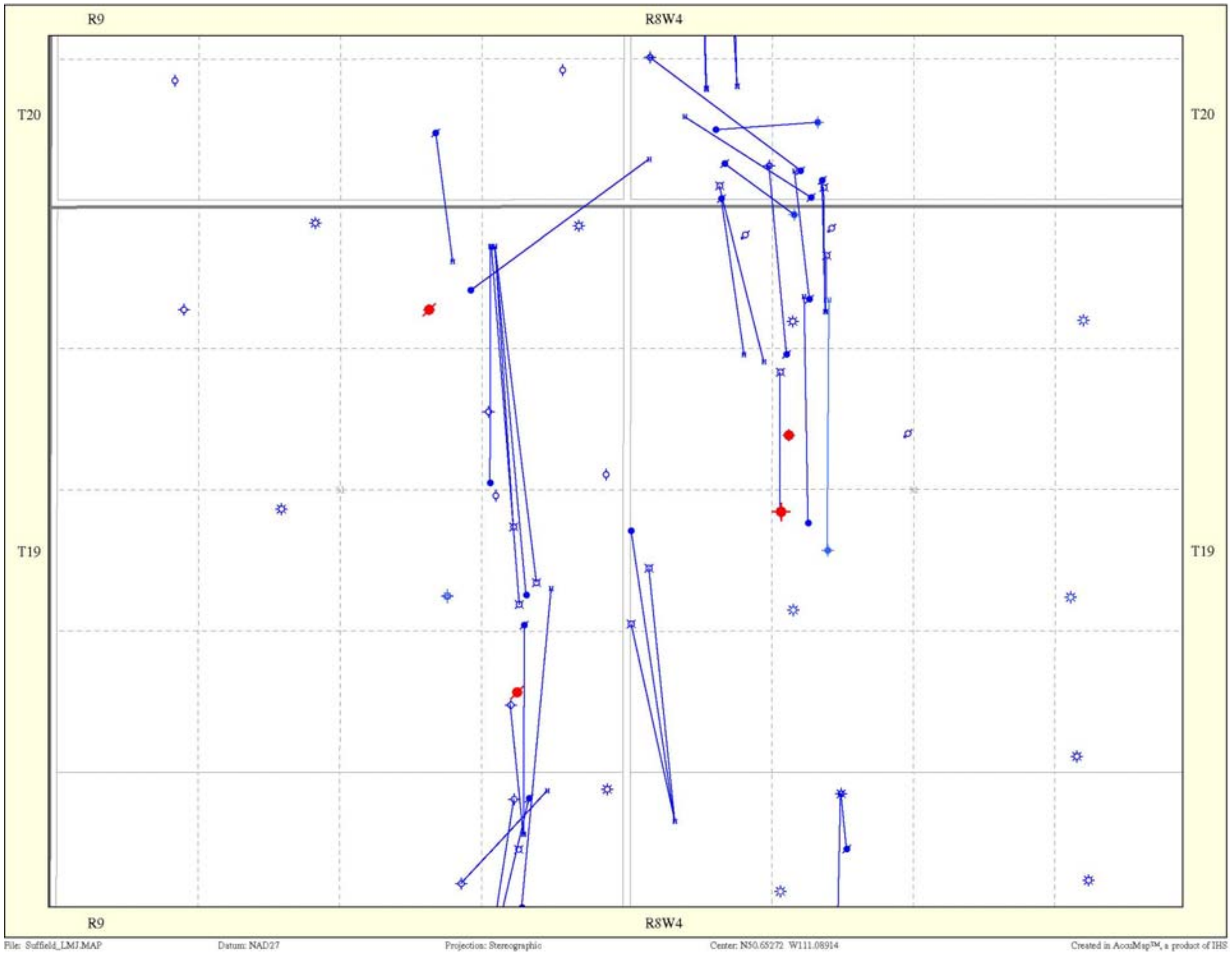

**Simonette D-3 - Well Locations**

Figure 150



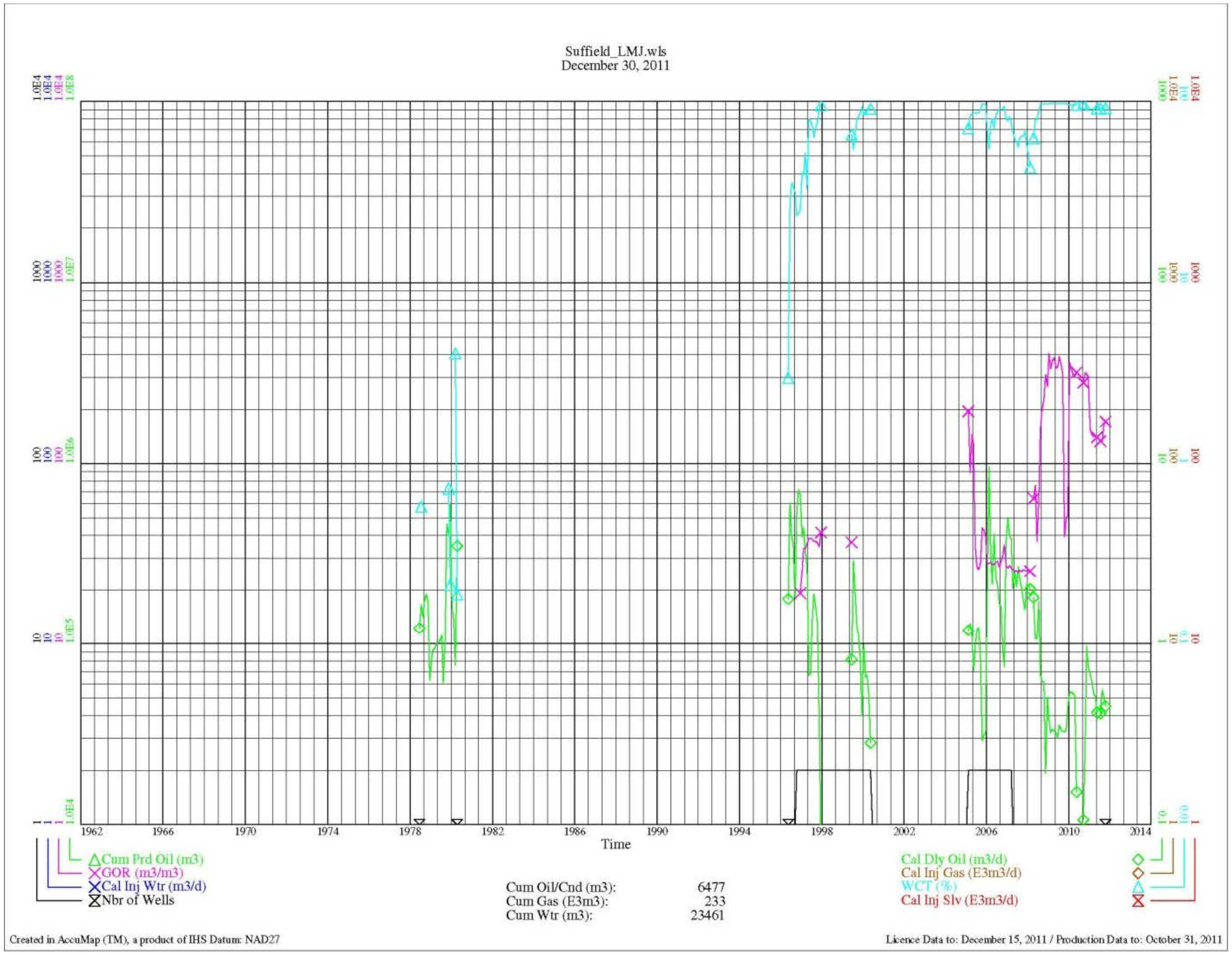

**Simonette D-3 – Production / Injection History**

Figure 151



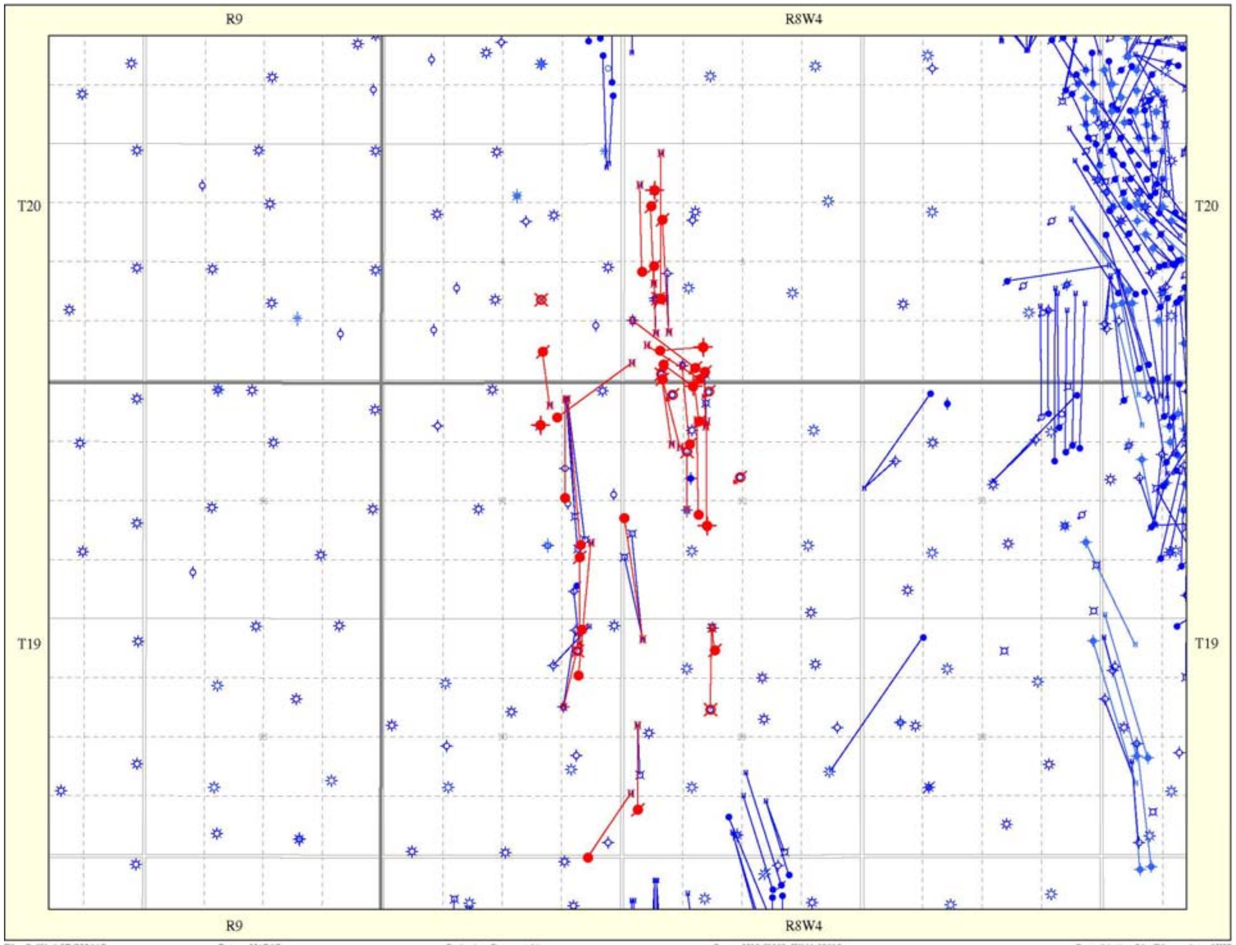

**Suffield Lower Mannville J – Well Locations**

Figure 152




**Suffield Lower Mannville J – Production / Injection History**

Figure 153

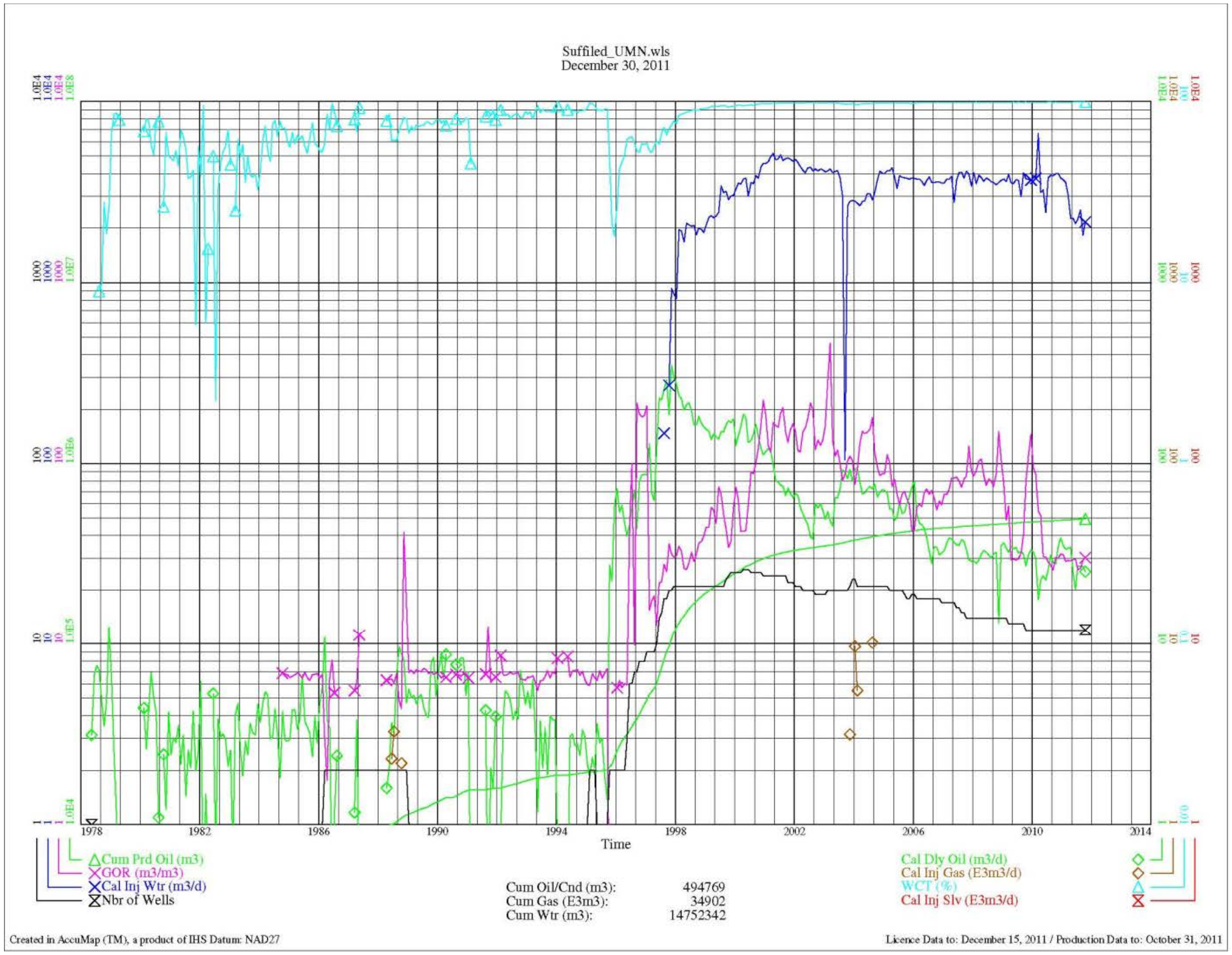



**Suffield Upper Mannville N – Well Locations**

Figure 154

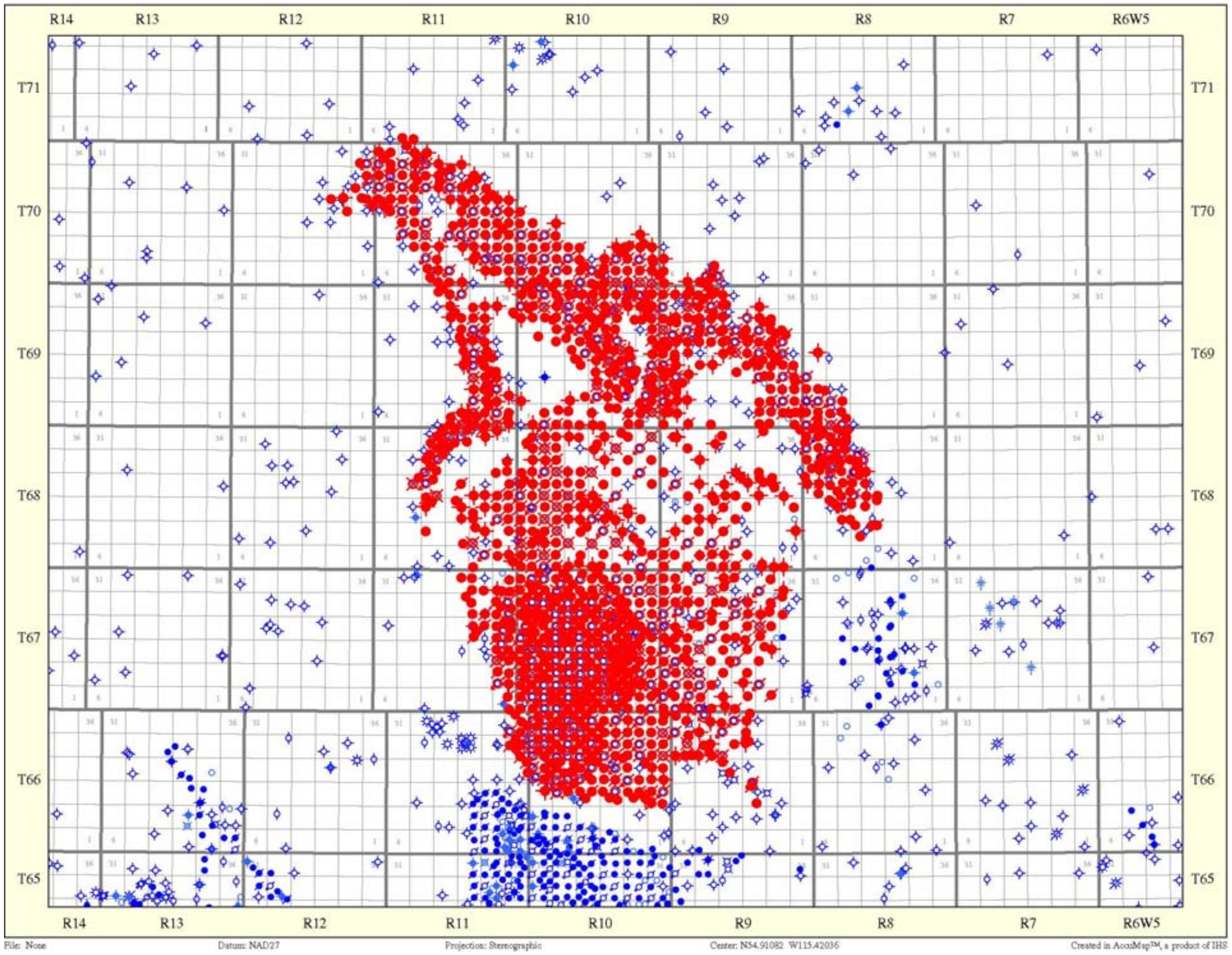


Sproule



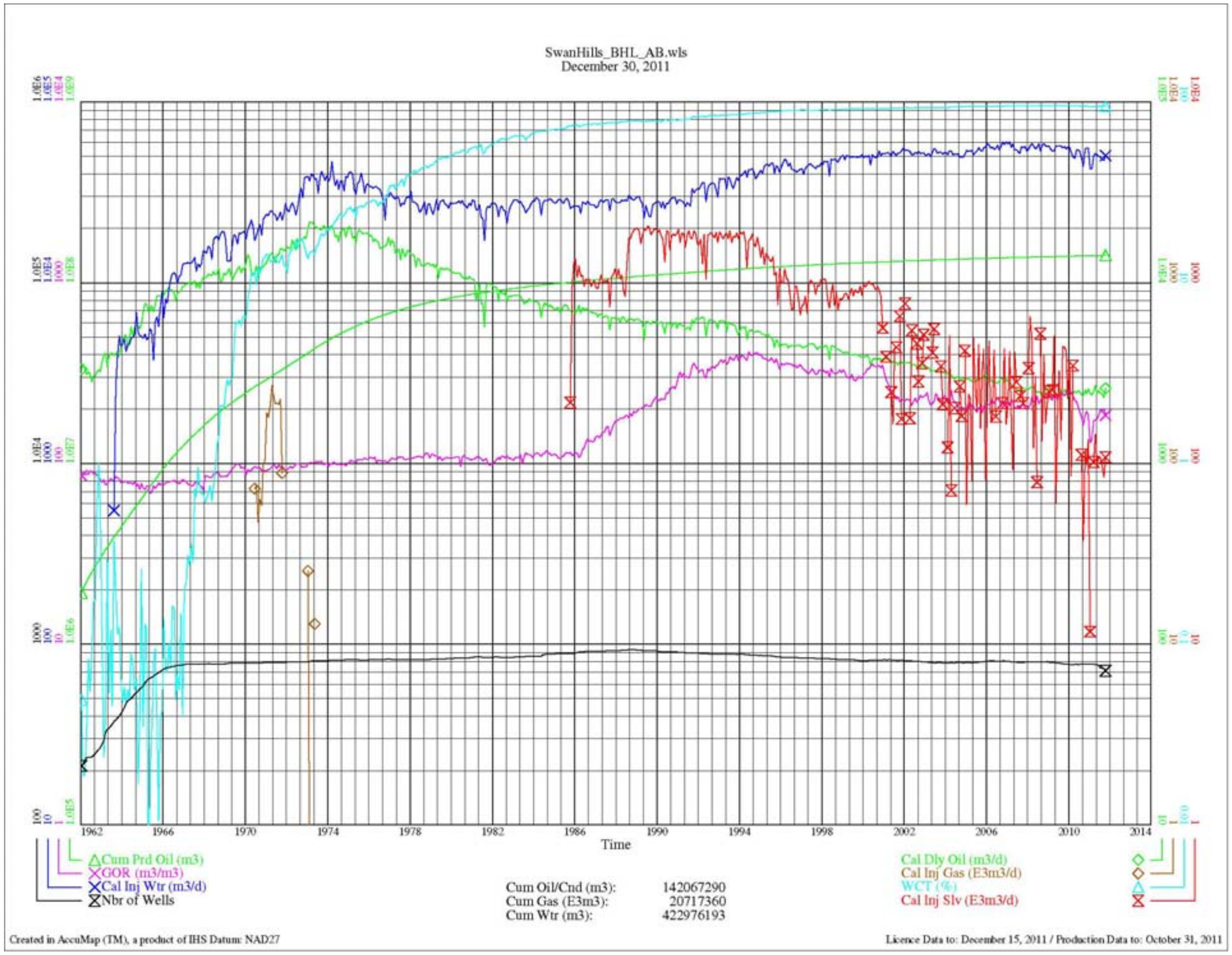

**Suffield Upper Mannville N – Production / Injection History**

Figure 155




**Swan Hills Beaverhill Lake A&B – Well Locations**

Figure 156




**Swan Hills Beaverhill Lake A&B – Production / Injection History**

Figure 157



Sproule

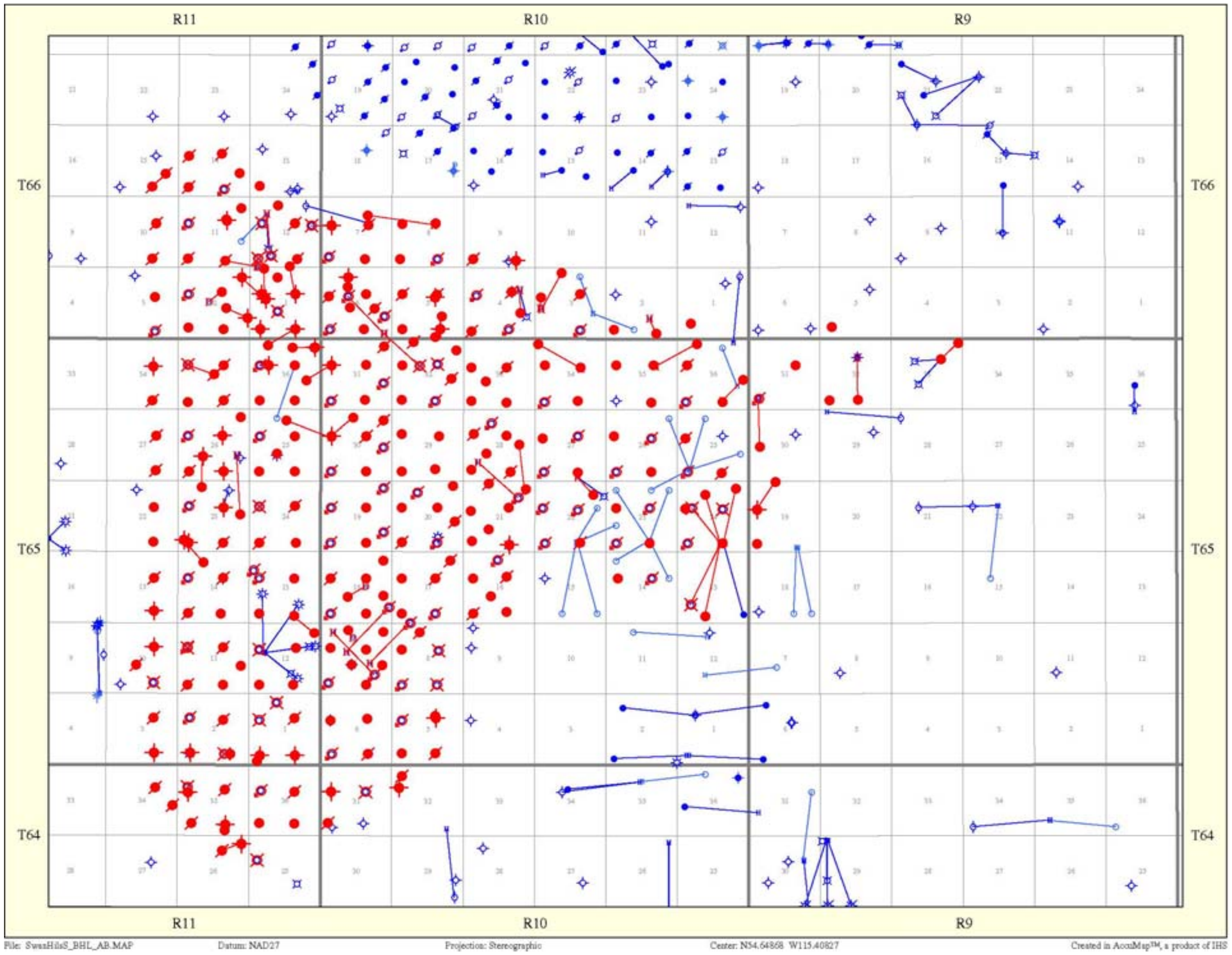
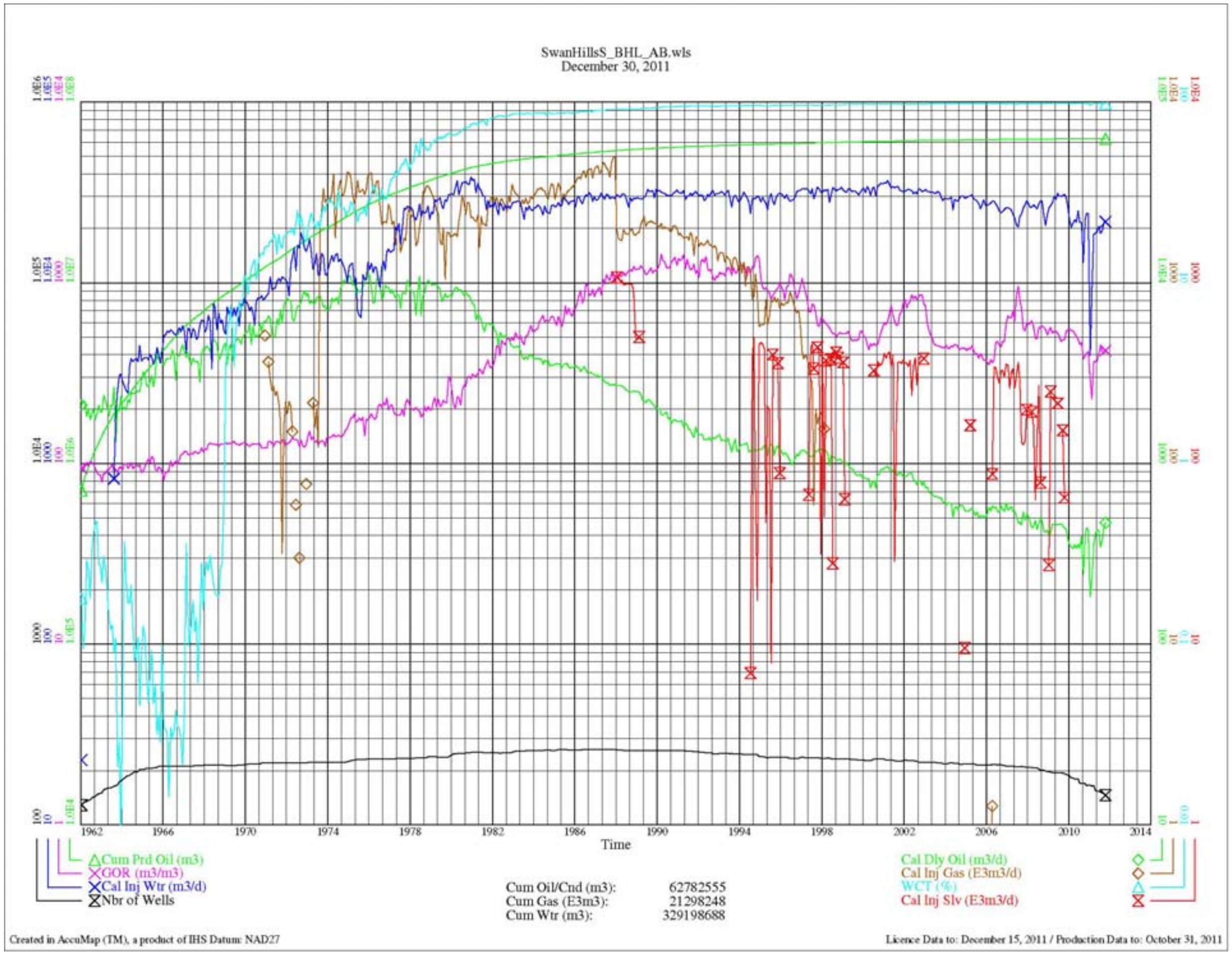



Figure 158

**Swan Hills South Beaverhill Lake A – Well Locations**




**Swan Hills South Beaverhill Lake A – Production / Injection History**

Figure 159

SSH CO2 Pilot Review

PennWest Exploration

## Pilot Location

- Located within the SSHU previously hydrocarbon miscibly flooded area
- Targeting the bypassed oil in the lower zones below Z1 shale
- $CO_2$ injection commenced on May 21, 2008
- $6.4 MM in IETP funding

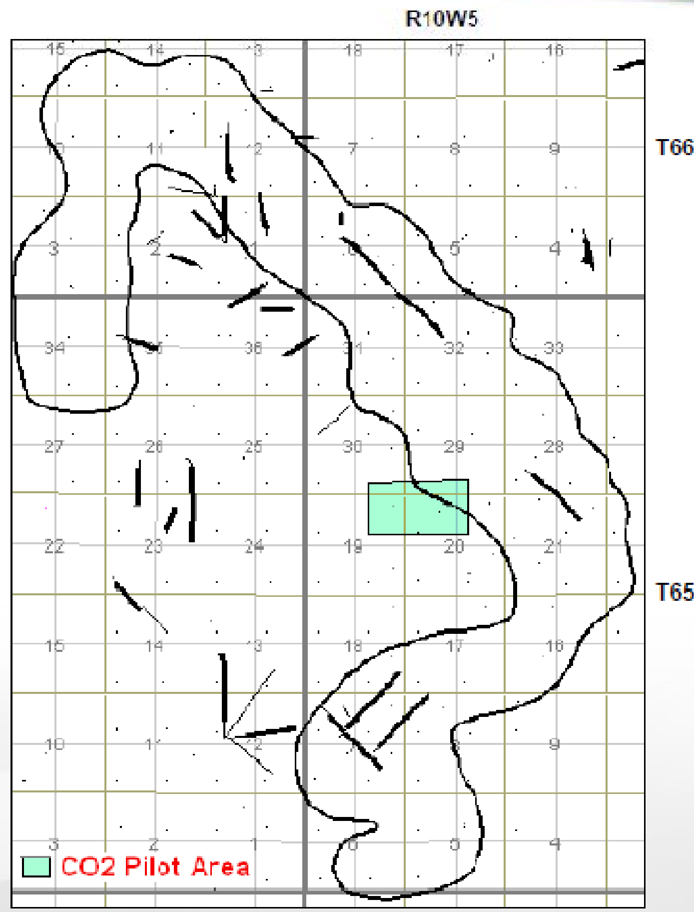
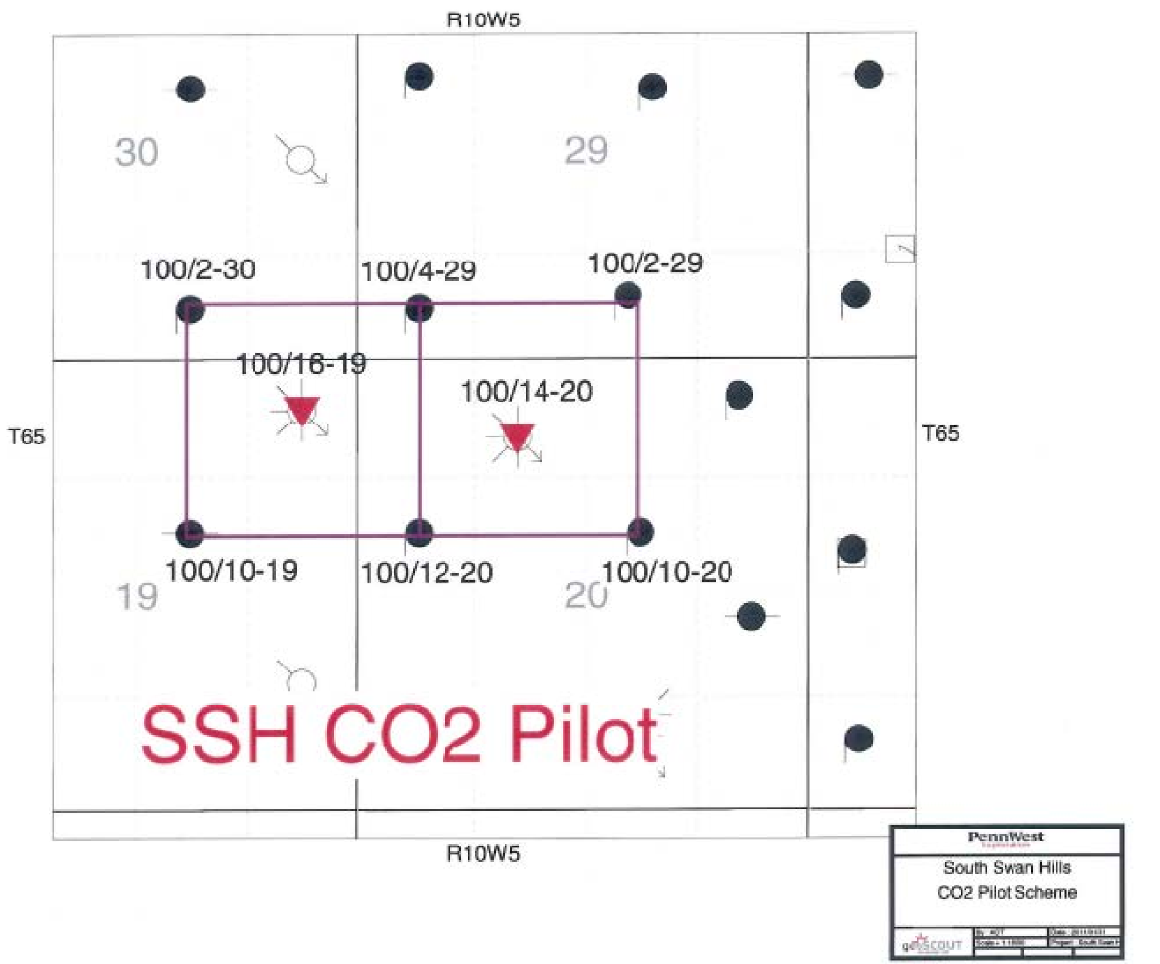



Figure 160




**South Swan Hills – $CO_2$ Pilot Scheme**

Figure 161

SSH CO2 Pilot Review

PennWest Exploration

## Performance - Injection

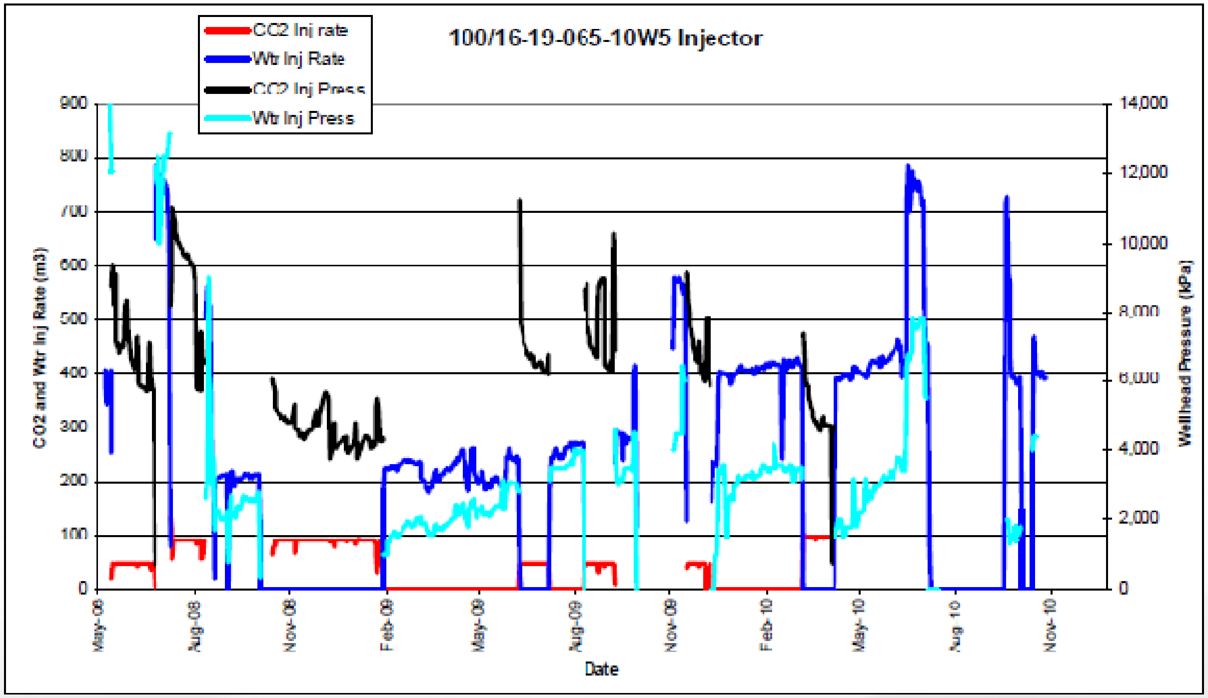



Figure 162

# SSH CO2 Pilot Review

PennWest Exploration

## Performance - Injection

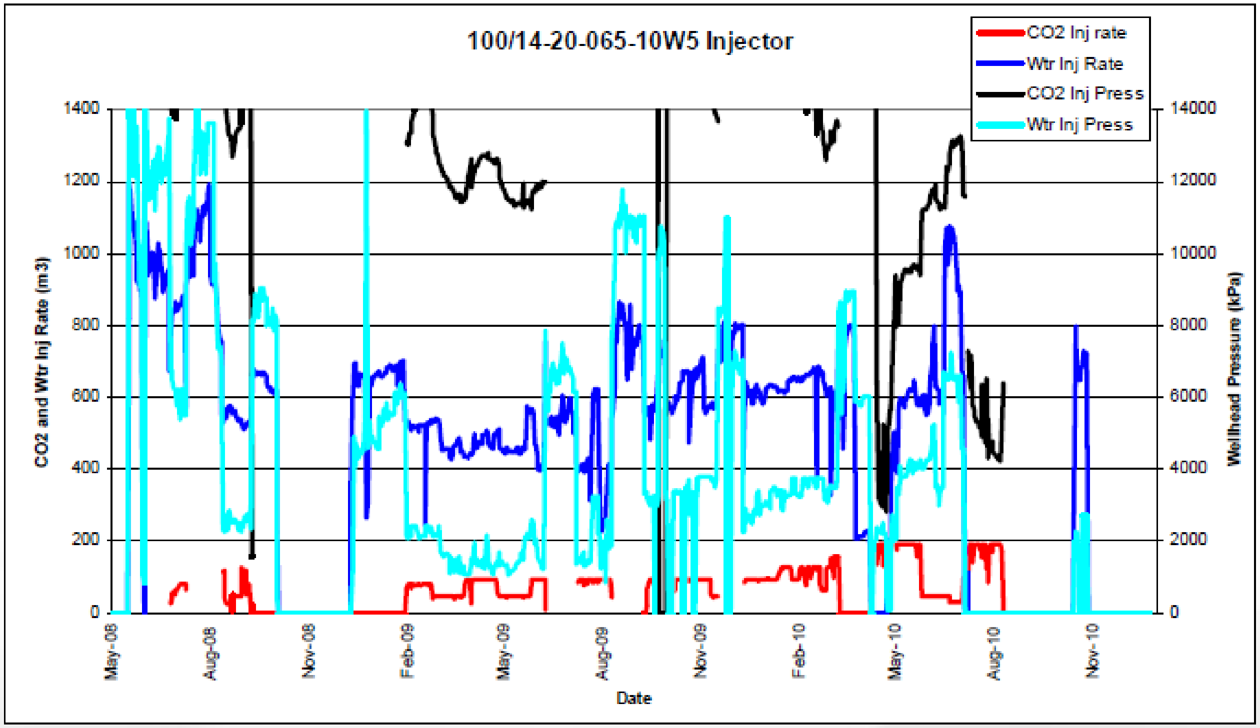


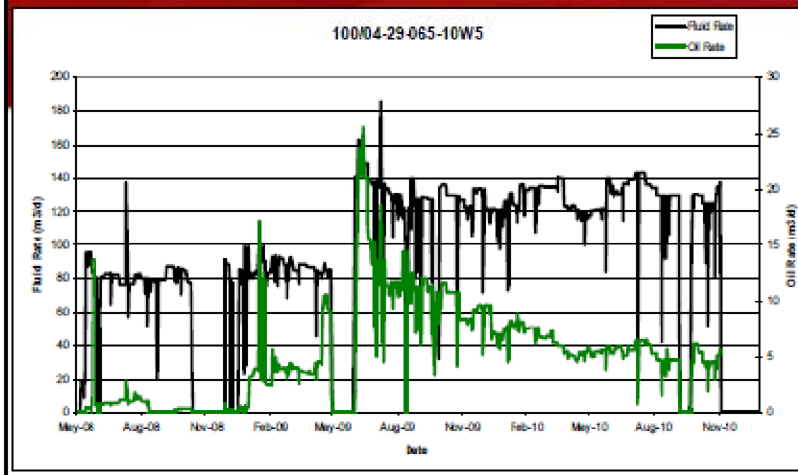

Figure 163

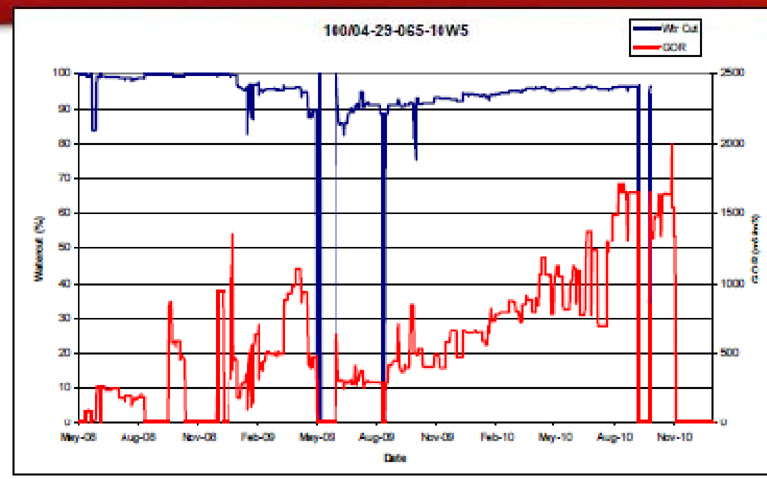


Sproule

# Performance: 04-29-065-10W5

PennWest Exploration




- First well to show $CO_2$ EOR response
- Accounts for majority of the gas produced from the pilot

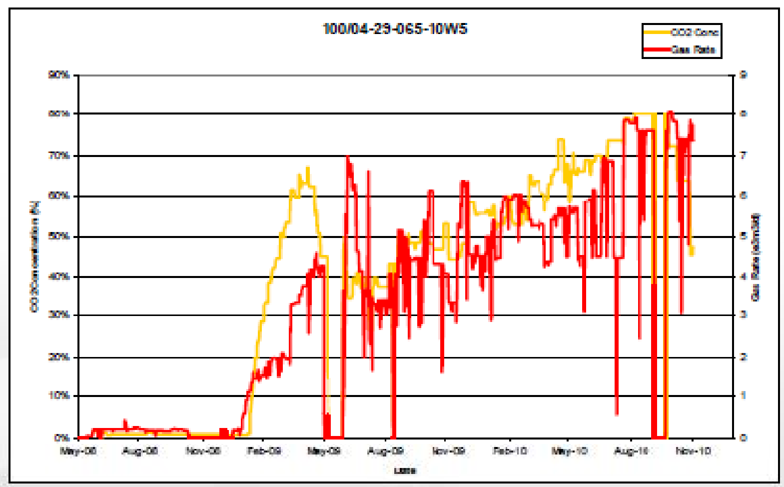


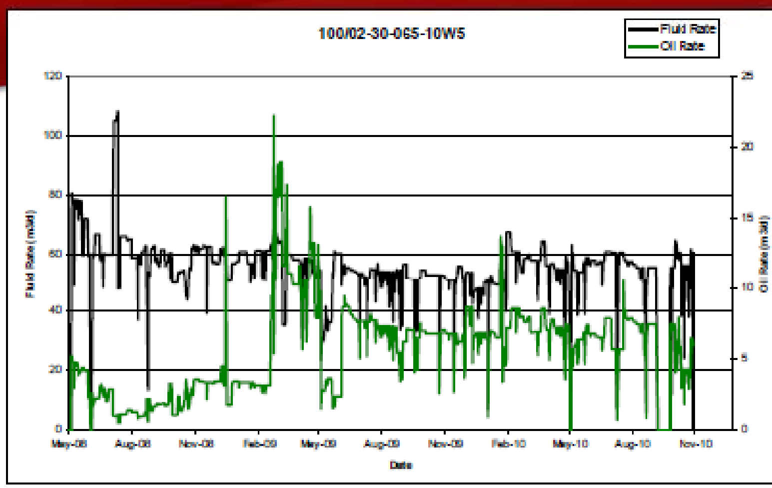

Figure 164

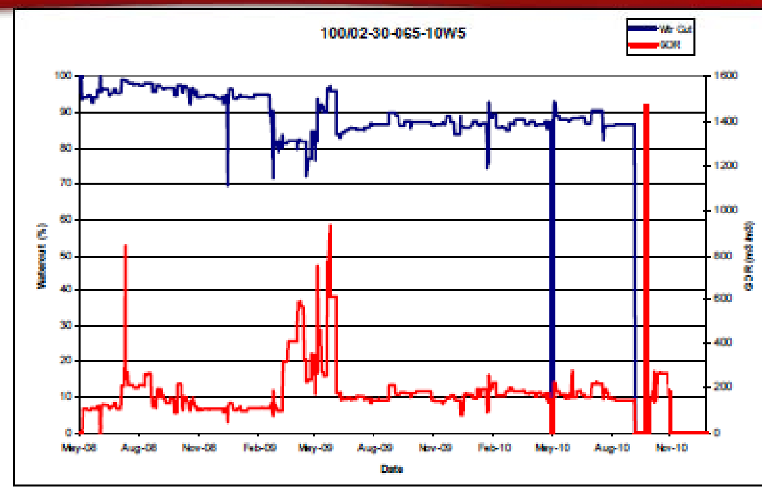


Sproule

# Performance: 02-30-065-10W5

PennWest Exploration




- $CO_2$ EOR response in late February 2009

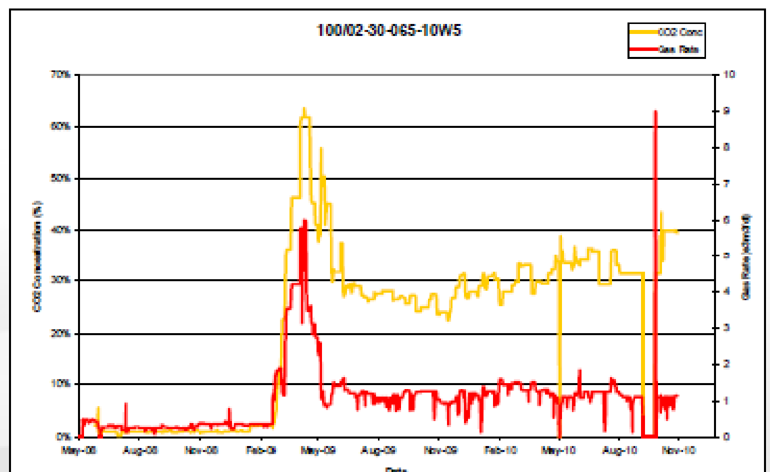



Figure 165



Sproule

# Pilot Performance: Forecast VS Actual

PennWest Exploration

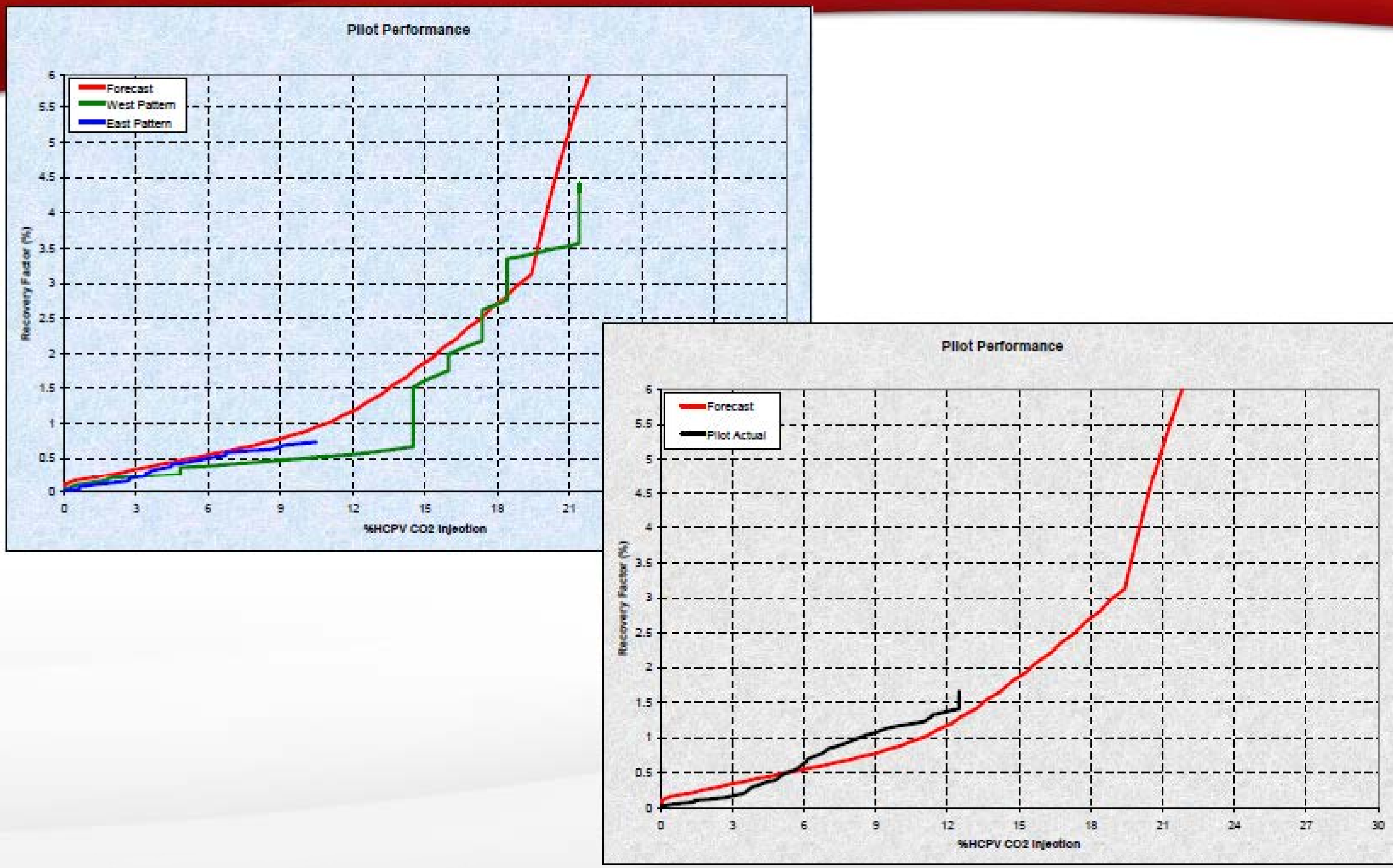
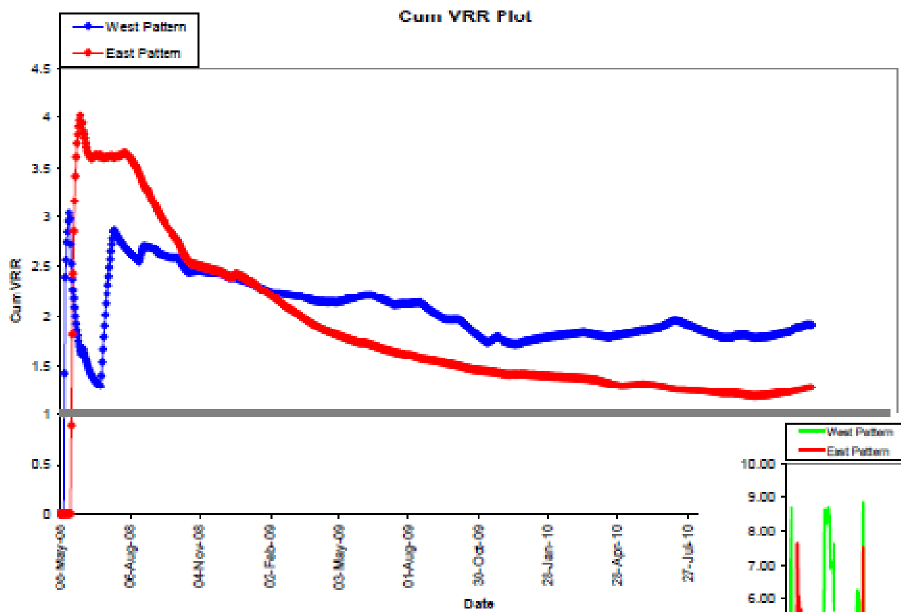



Figure 166

# Compliance: Voidage Replacement Ratio

PennWest Exploration



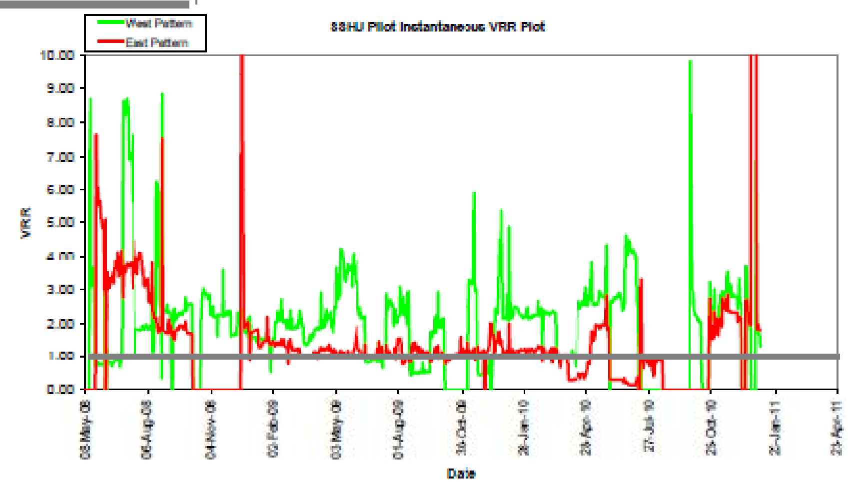




Figure 167



Sproule

## Compliance: Gas Analyses

PennWest Exploration

### July/August 2010 Gas Analyses

### ($CO_2$ Mole Fraction)

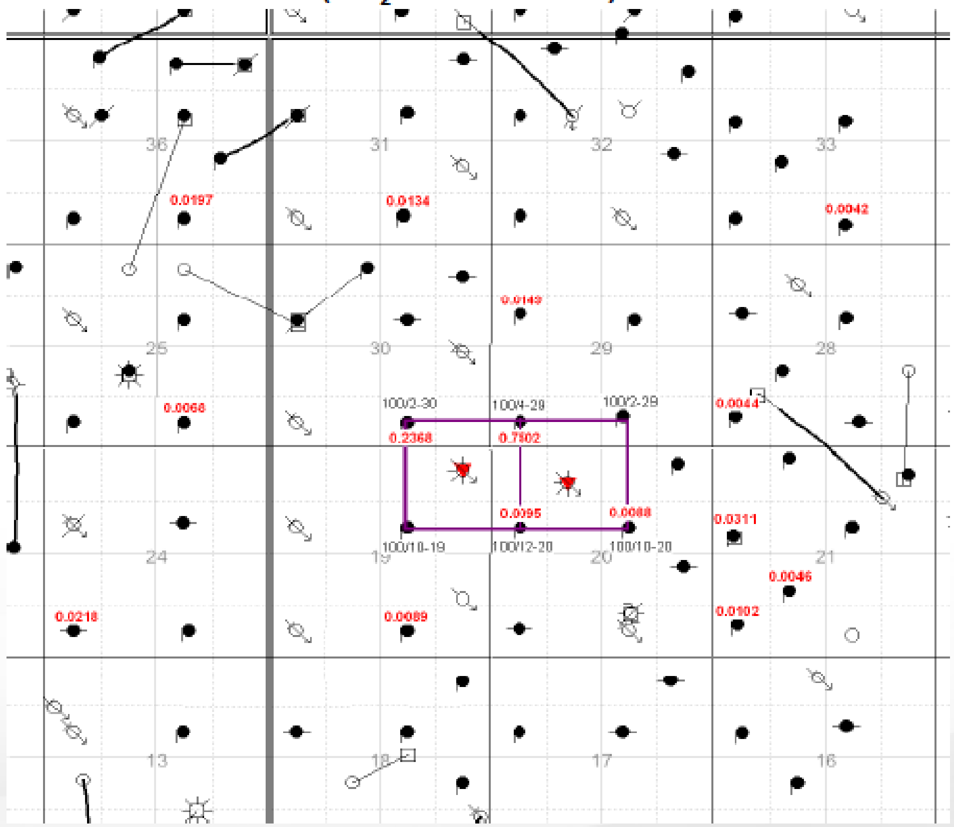



Figure 168



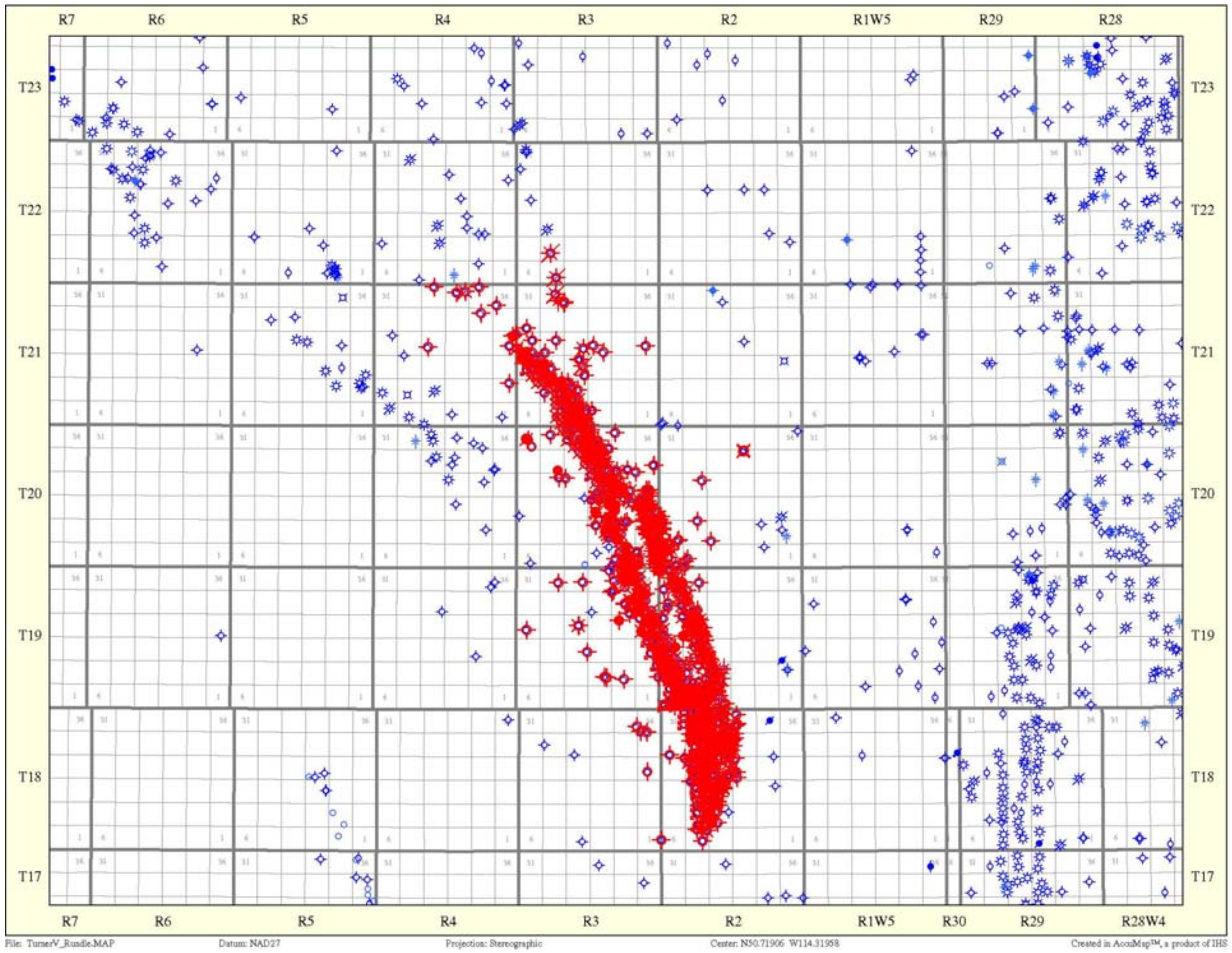
Sproule

## Performance - Oil Recovery & $CO_2$ Injection (Dec. 2010)

| | Parameters | CO2 Pilot Area | | Units |
|---|---|---|---|---|
| | | West Pattern | East Pattern | |
| | OOIP (Target Zones) | 2.14 | 4.28 | *MMStb* |
| | OOIP (OOIP - Actual Flood) | 0.78 | 3.45 | *MMStb* |
| | HCPV | 1.11 | 4.90 | |
| Actual Flood | | | | |
| Actual Flood | Cumulative CO2 Injected | 403.0 | 873.0 | *MMScf* |
| Actual Flood | Cumulative CO2 Injected | 237.8 | 515.1 | *E3 Rbbl* |
| Actual Flood | Cumulative CO2 Injected | 21.5 | 10.5 | *%HCPVI* |
| Actual Flood | | | | |
| Actual Flood | Cumulative CO2 Produced | 32.1 | 32.5 | *MMScf* |
| Actual Flood | | | | |
| Actual Flood | Cumulative Oil Produced | 39737.1 | 30653.0 | *STB* |
| Actual Flood | Iincremental Recovery | 5.1 | 0.9 | *% OOIP* |
| Actual Flood | | | | |

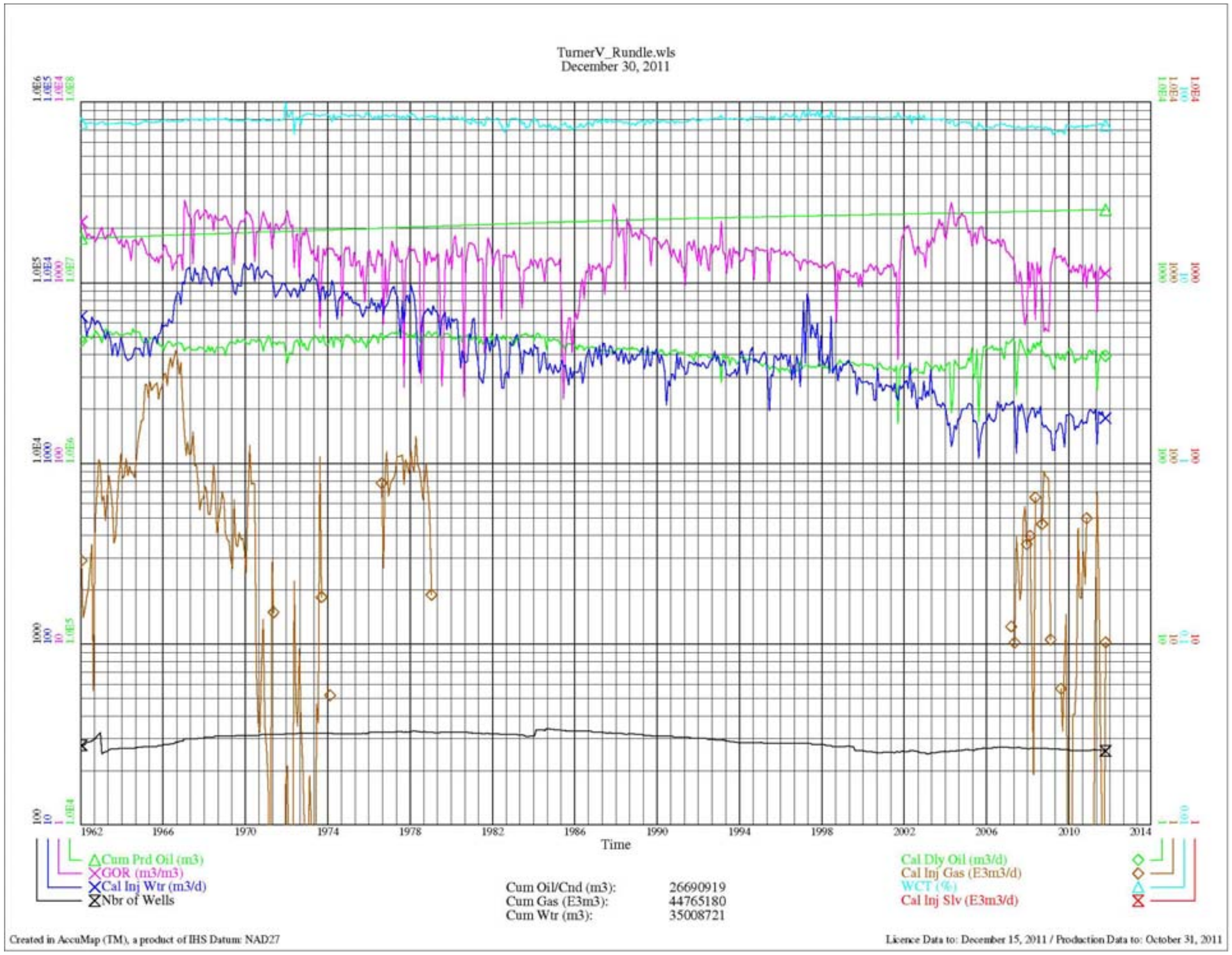
Production allocated

Figure 169



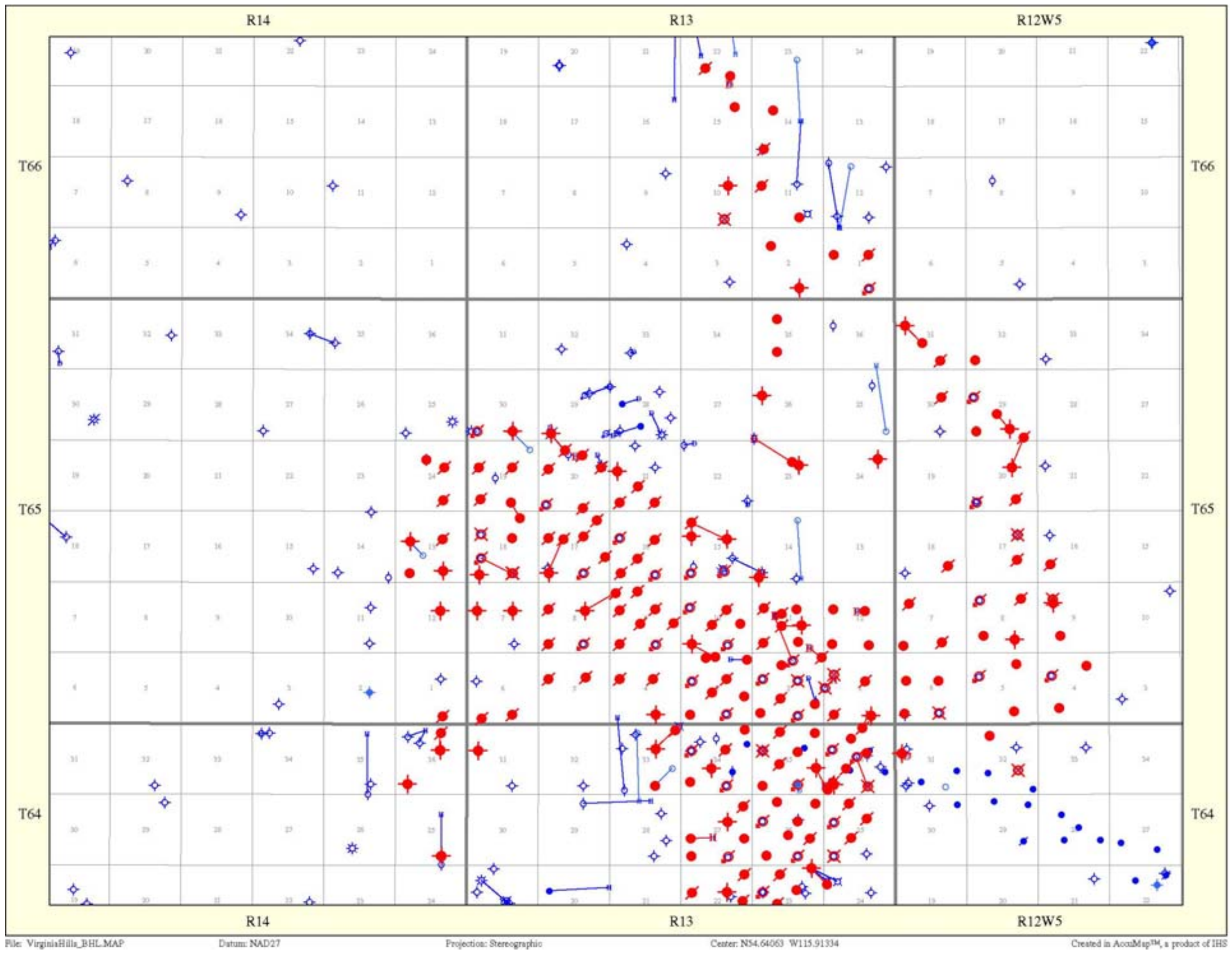

Turner Valley Rundle – Well Locations

Figure 170




**Turner Valley Rundle – Production / Injection History**

Figure 171




**Virginia Hills Beaverhill Lake – Well Locations**

Figure 172

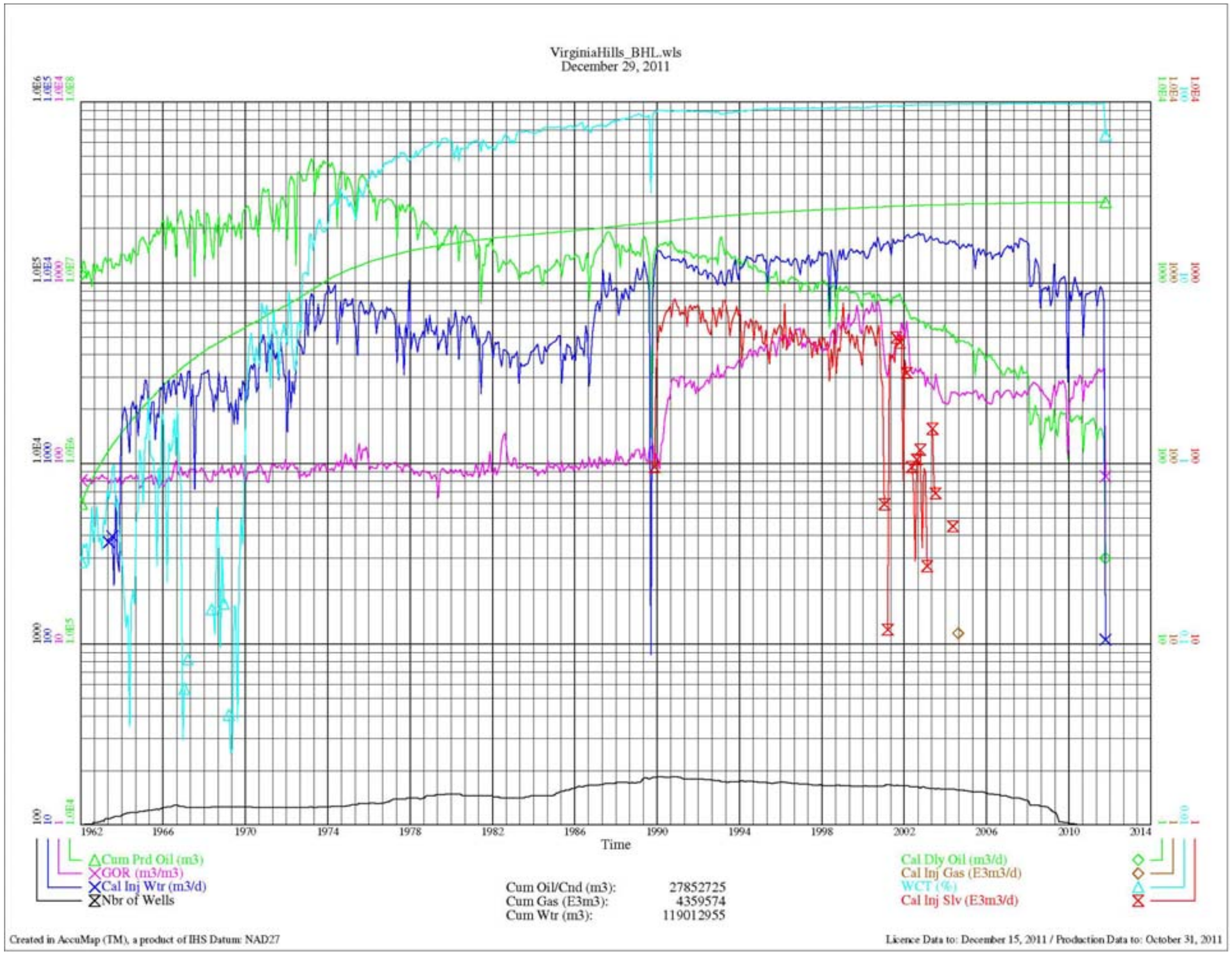
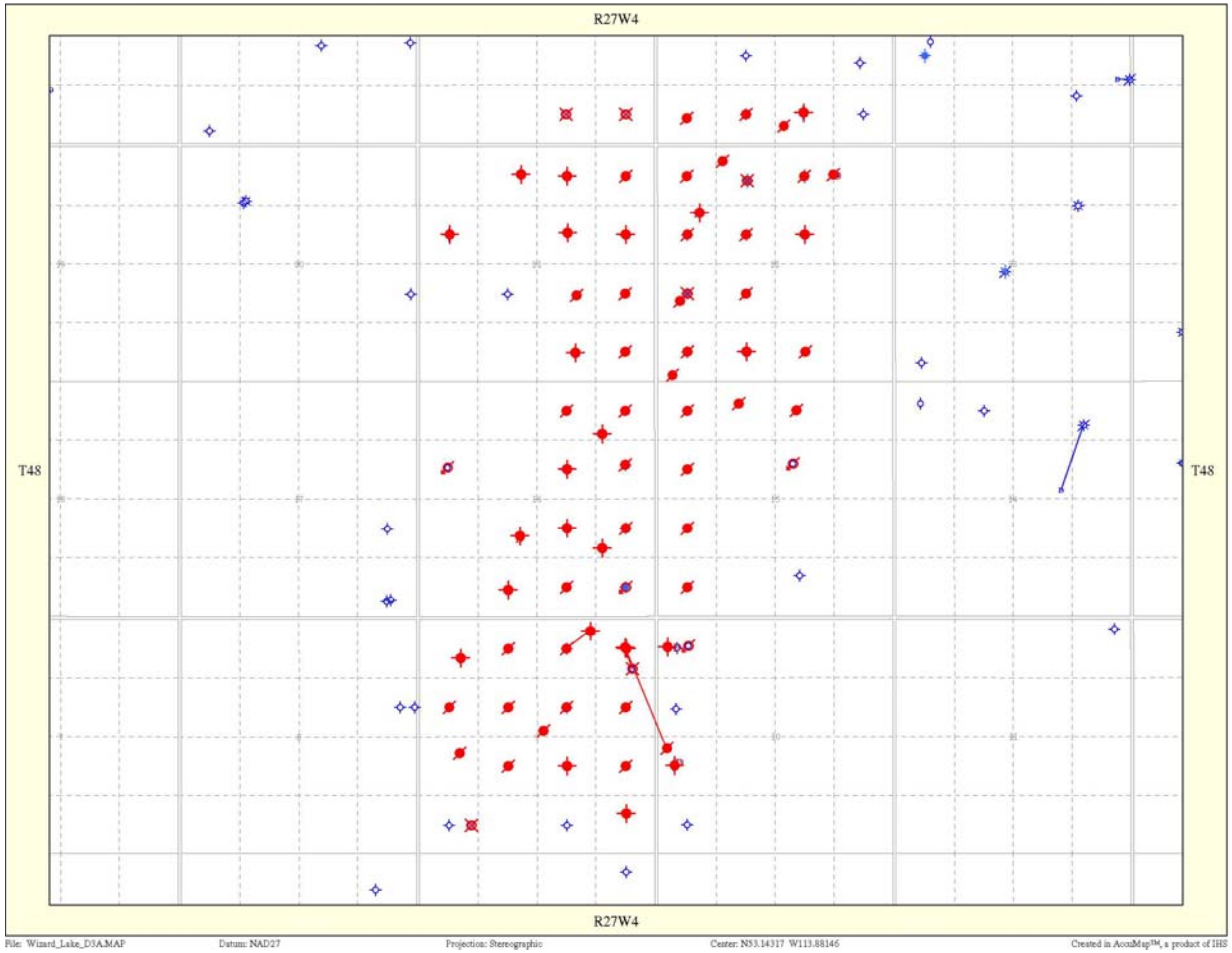
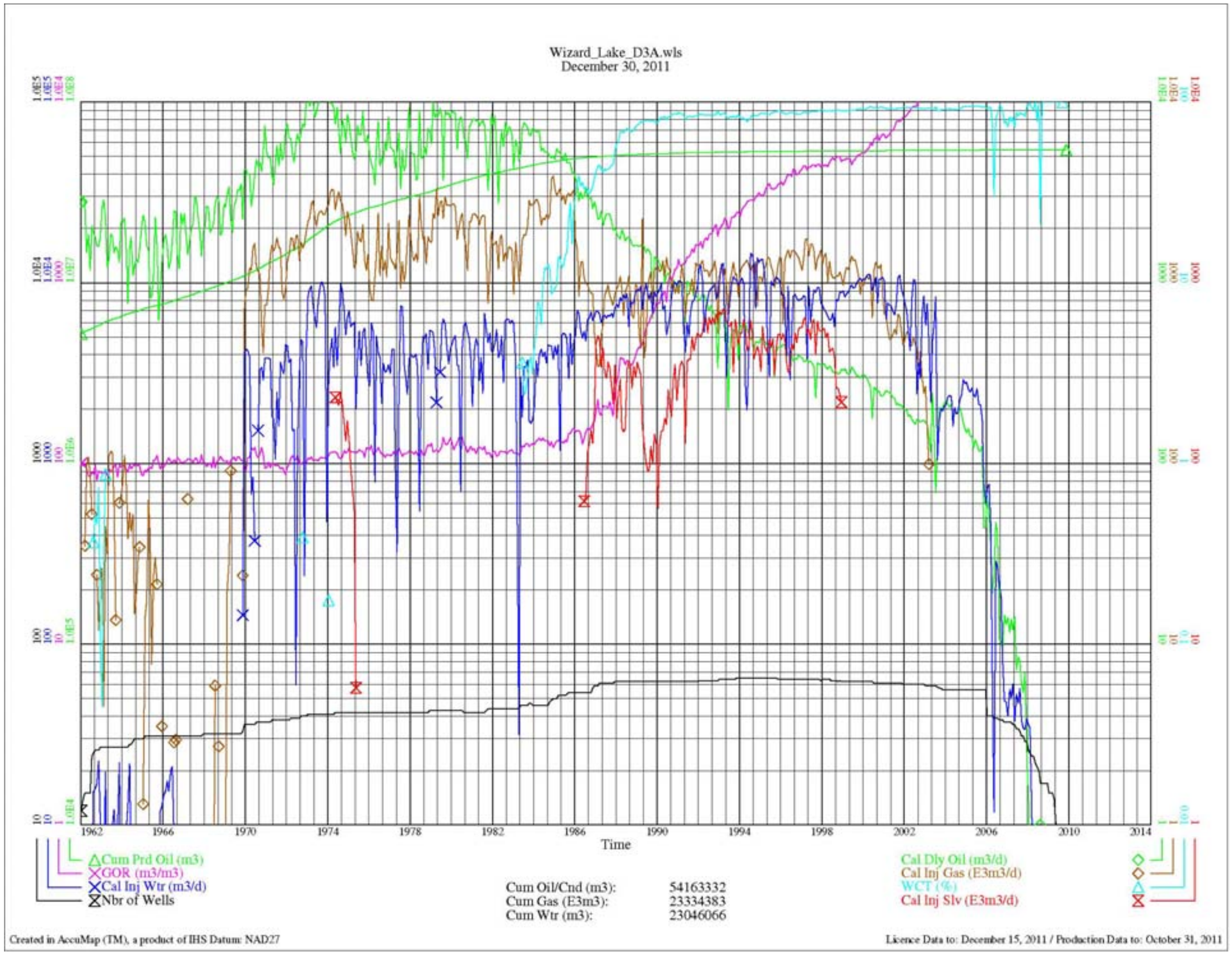



Figure 173

**Virginia Hills Beaverhill Lake – Production / Injection History**

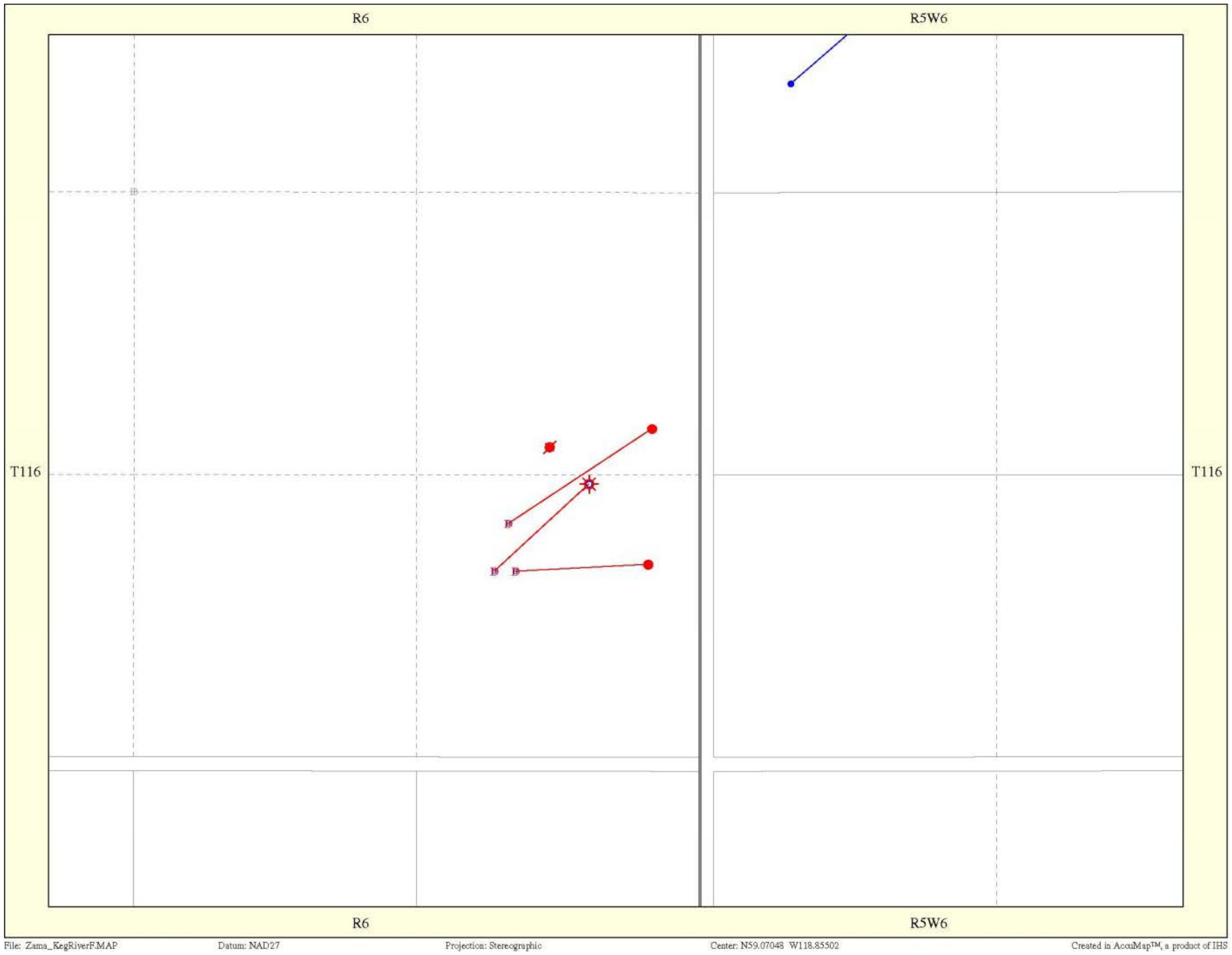



**Wizard Lake D-3A - Well Locations**




**Wizard Lake D-3A – Production / Injection History**

Figure 175




**Zama Keg River F - Well Locations**

Figure 176



Sproule

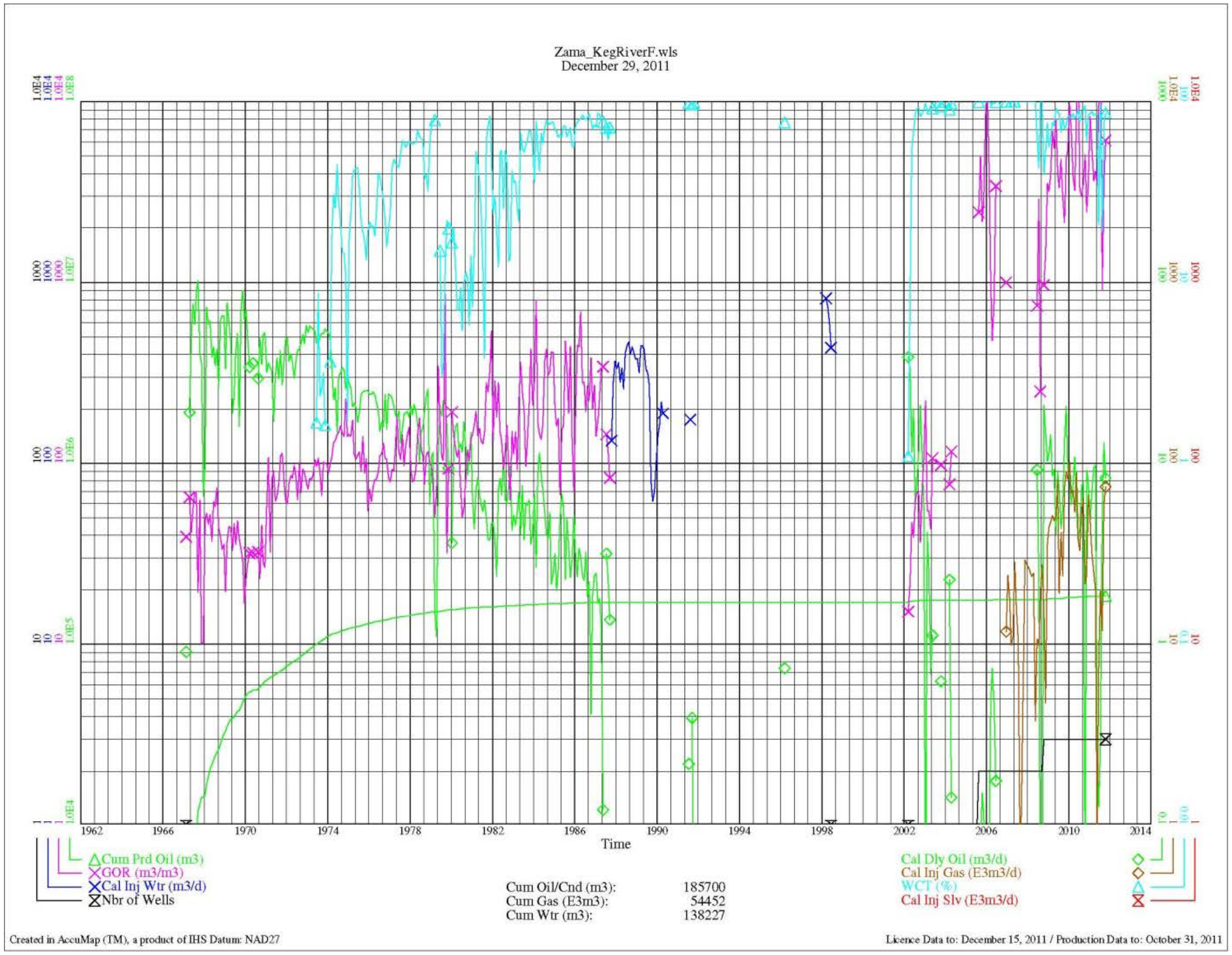
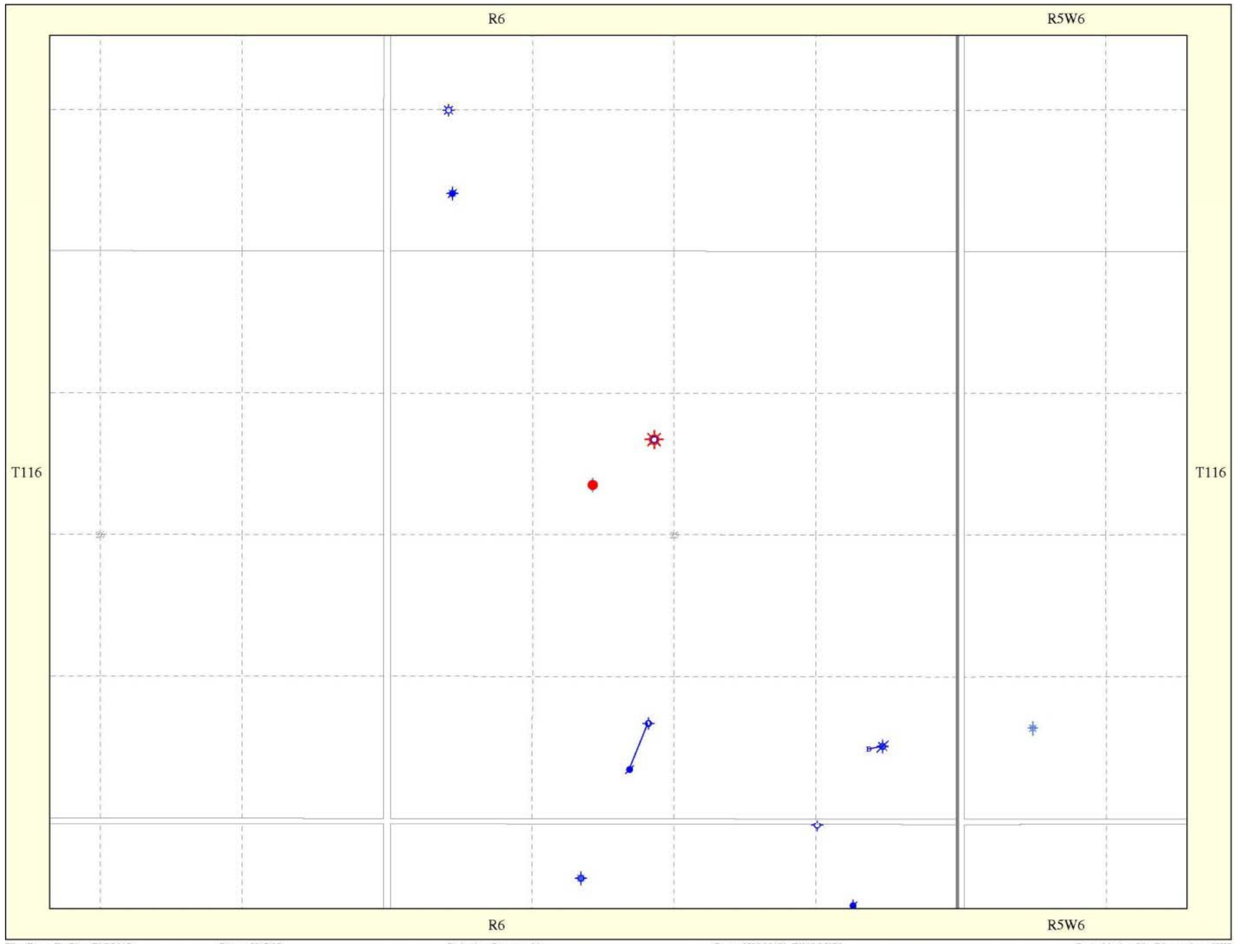


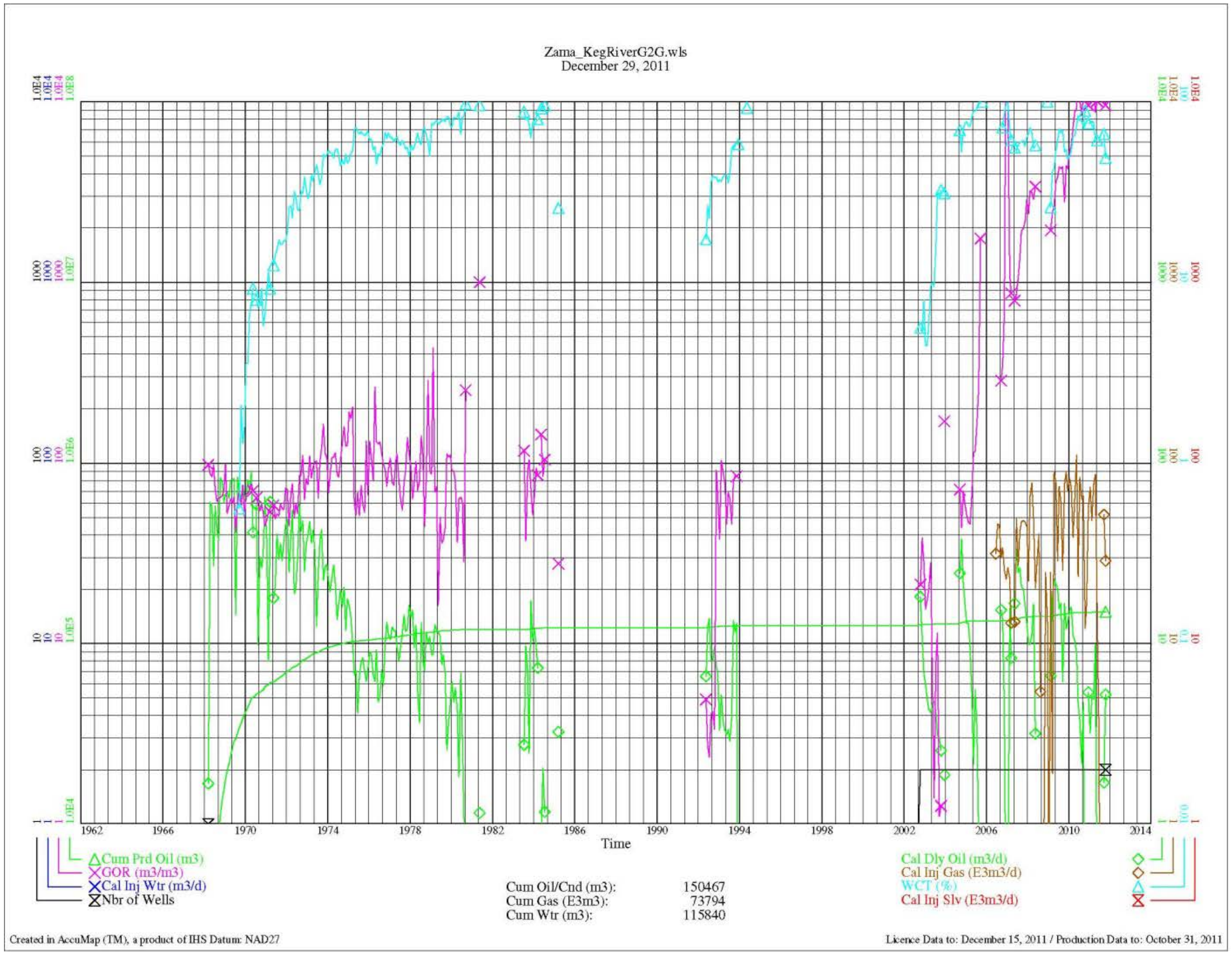

Figure 177

**Zama Keg River F – Production / Injection History**




**Zama Keg River G2G - Well Locations**

Figure 178

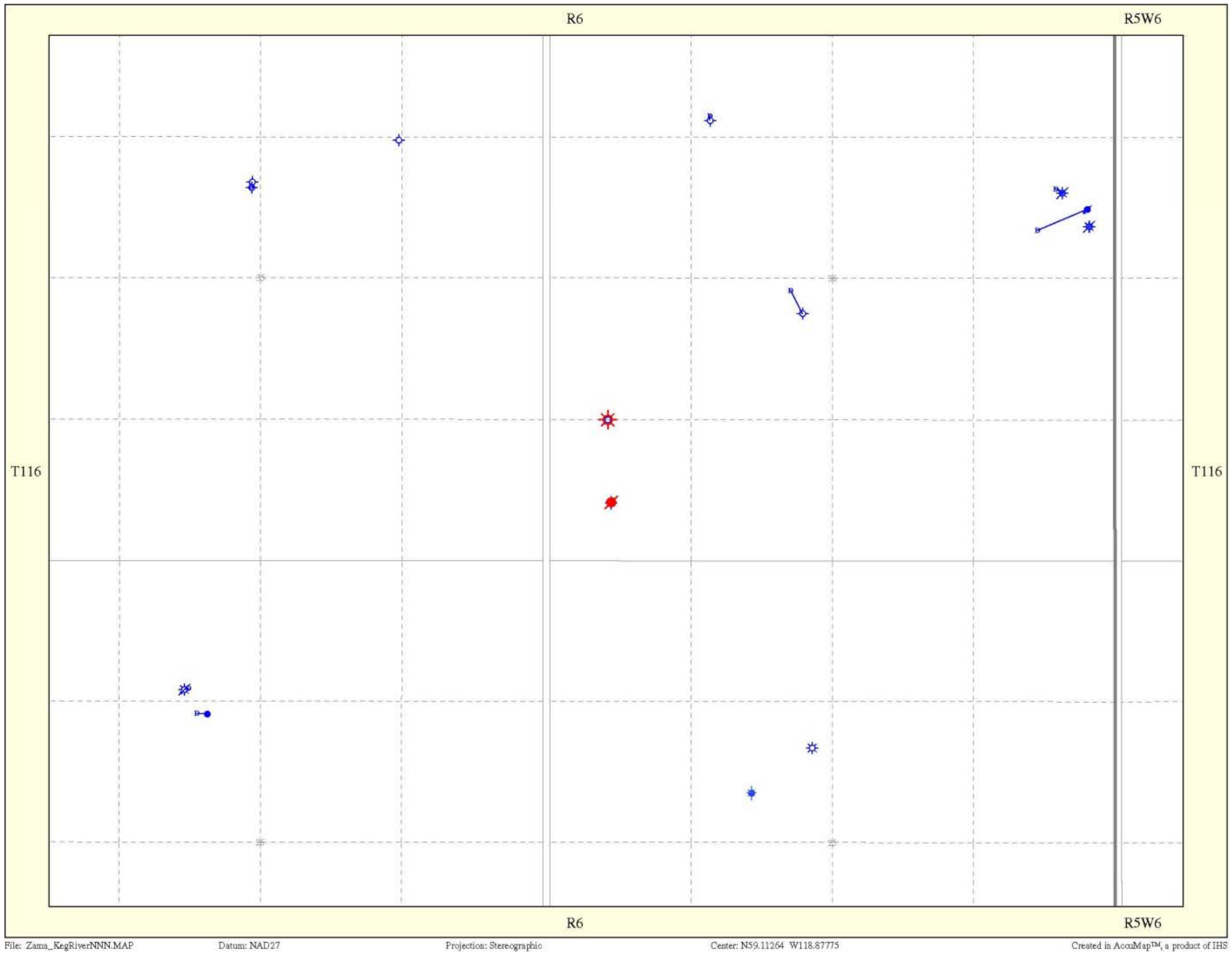



**Zama Keg River G2G – Production / Injection History**

Figure 179



Sproule

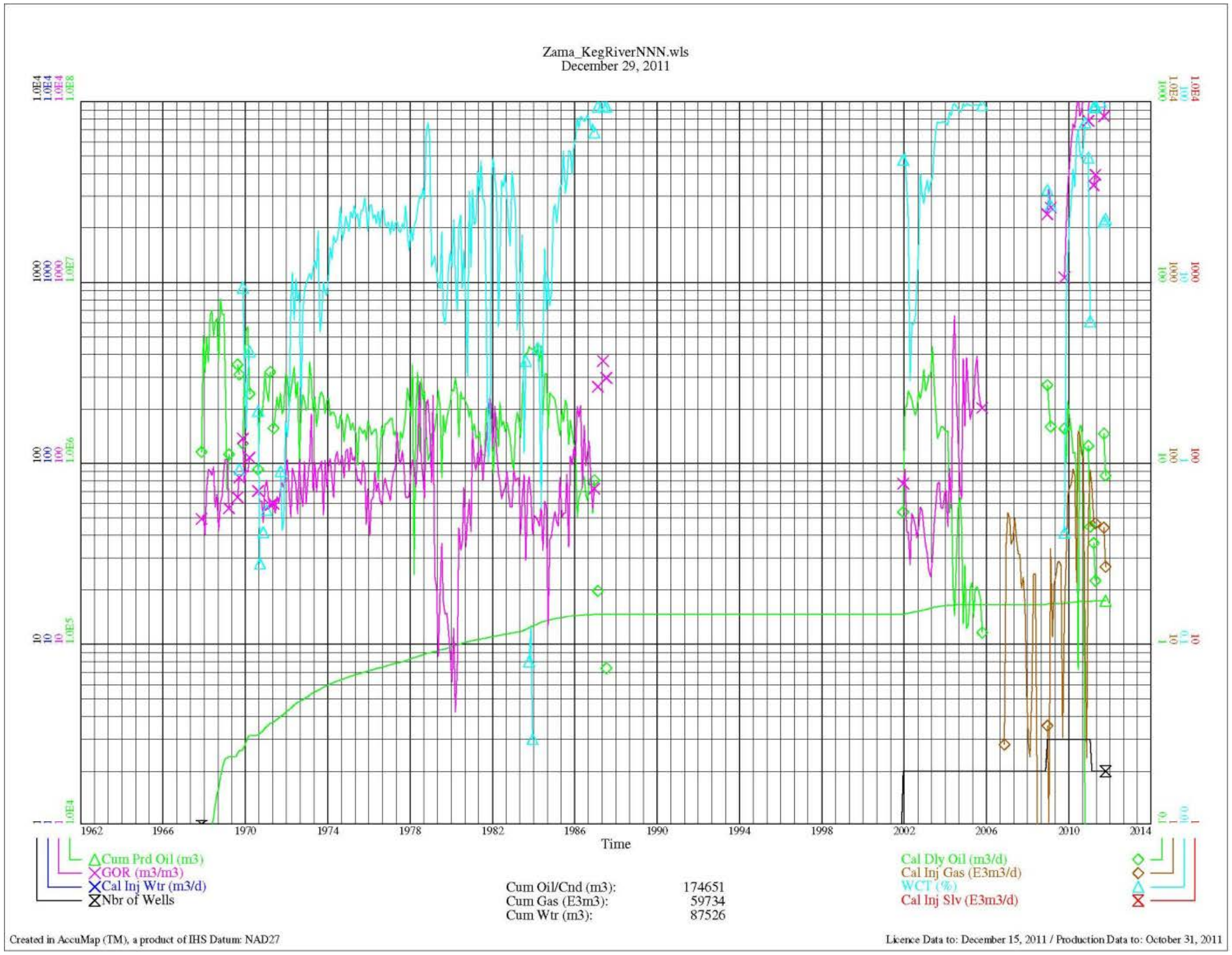



**Zama Keg River NNN - Well Locations**

Figure 180

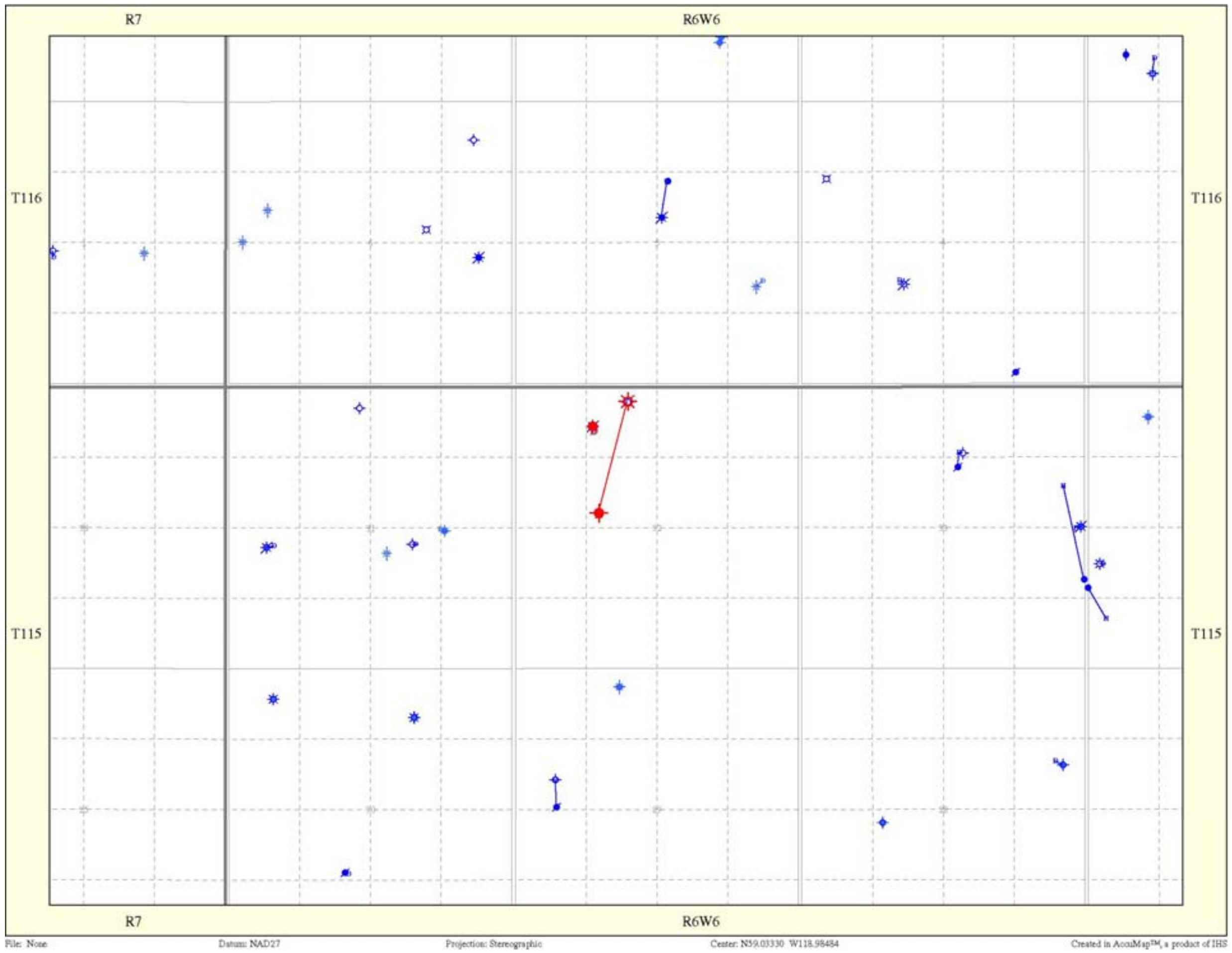


Sproule



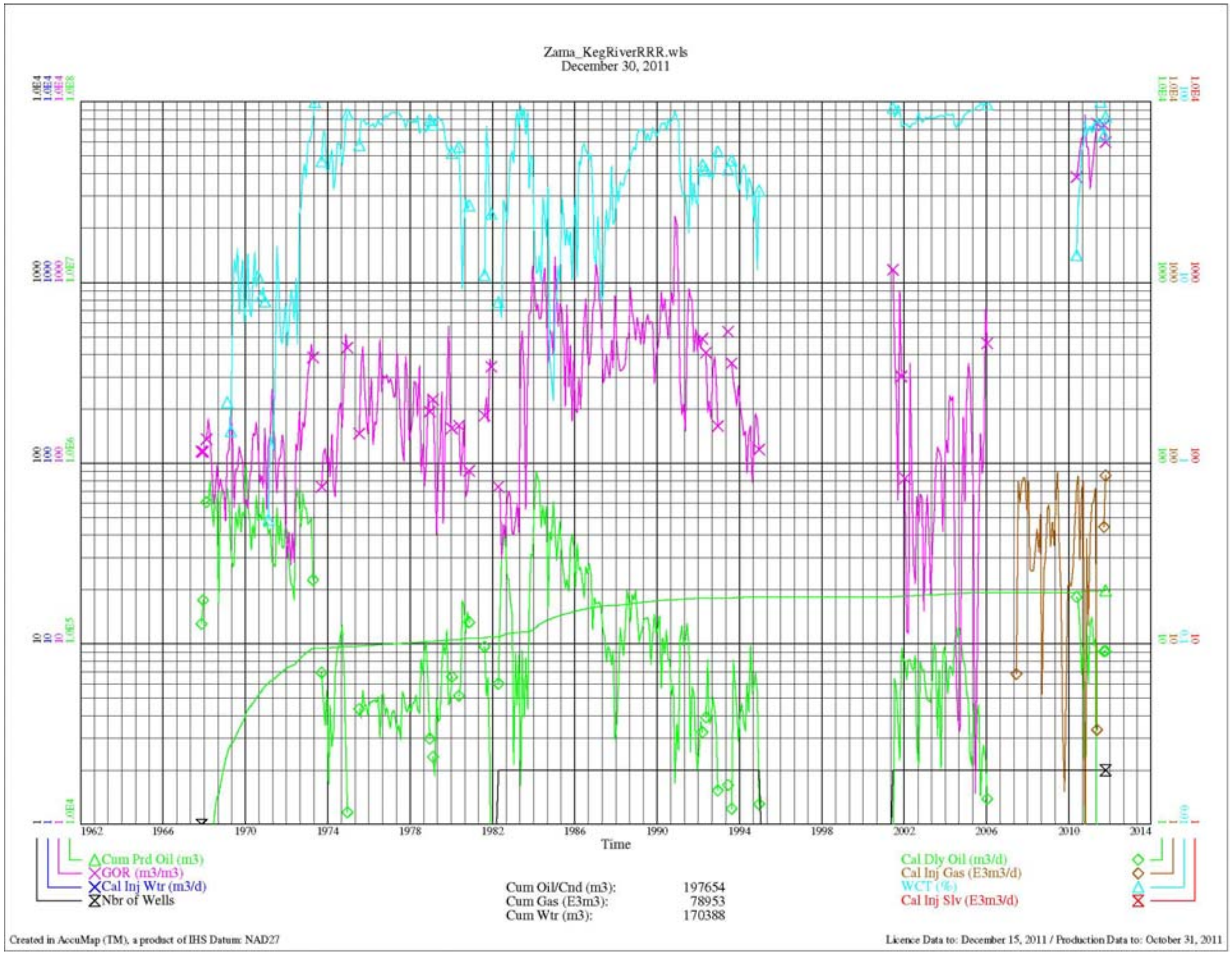

**Zama Keg River NNN – Production / Injection History**

Figure 181




**Zama Keg River RRR - Well Locations**

Figure 182

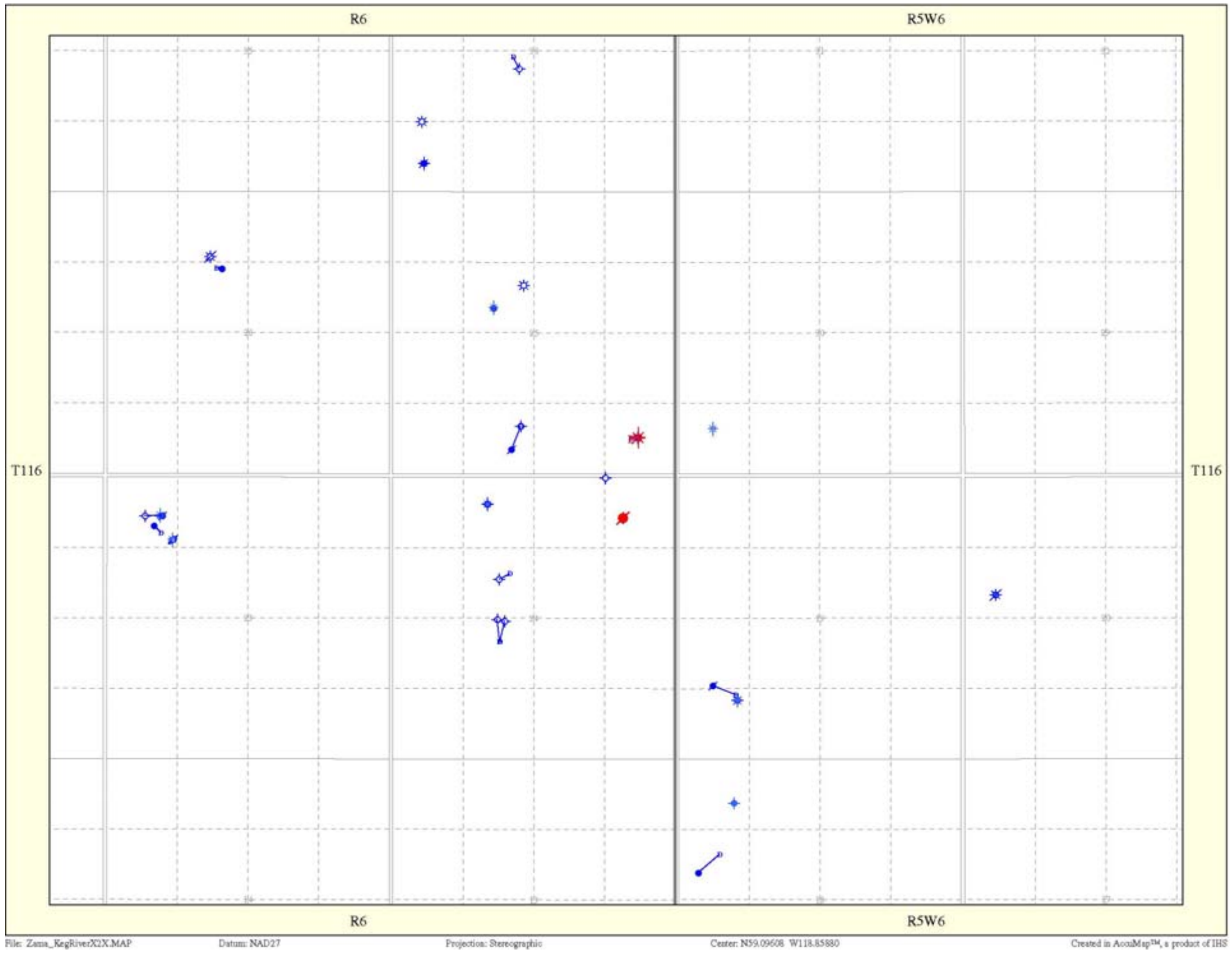



**Zama Keg River RRR – Production / Injection History**

Figure 183



Sproule

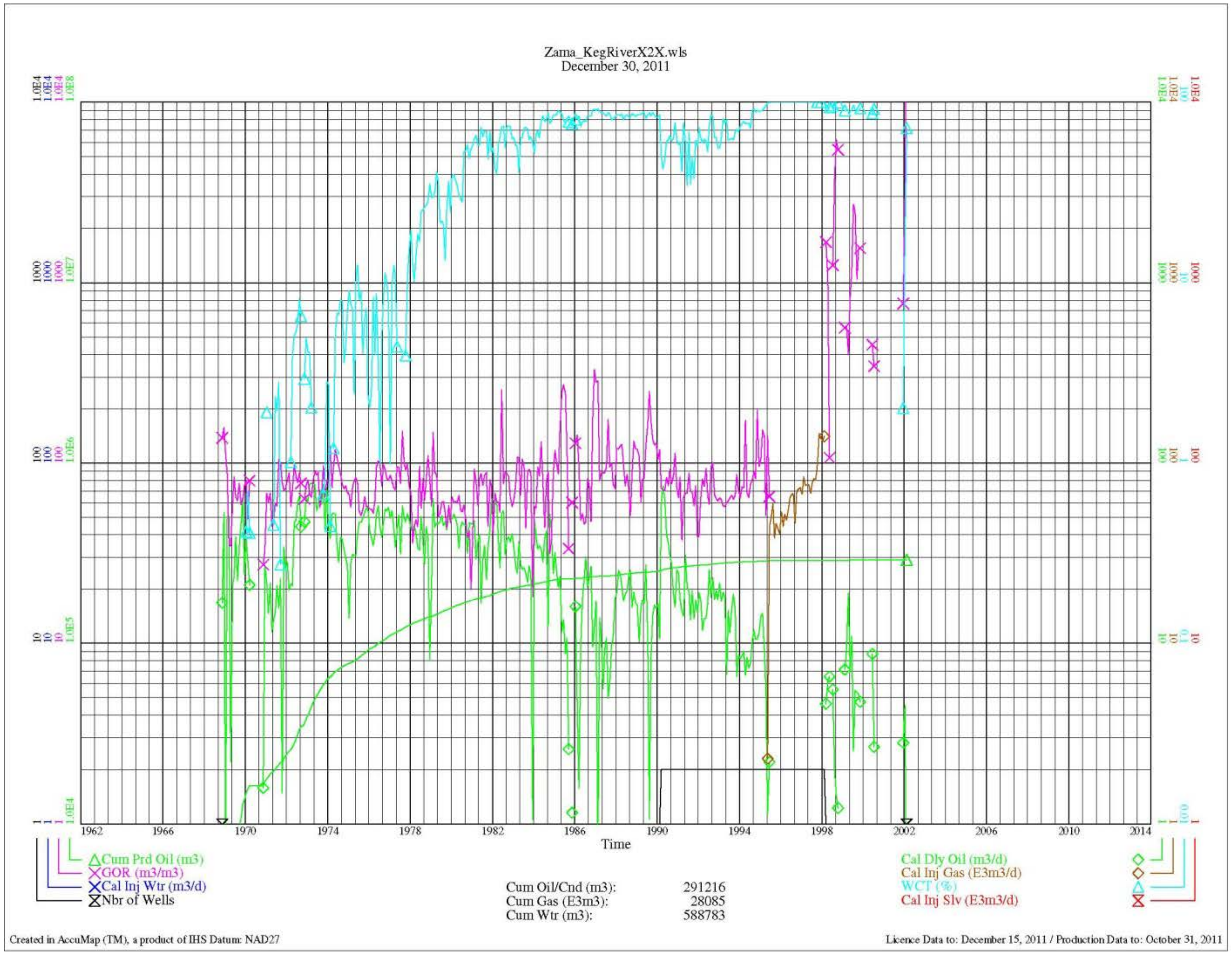



**Zama Keg River X2X – Well Locations**

Figure 184



Sproule

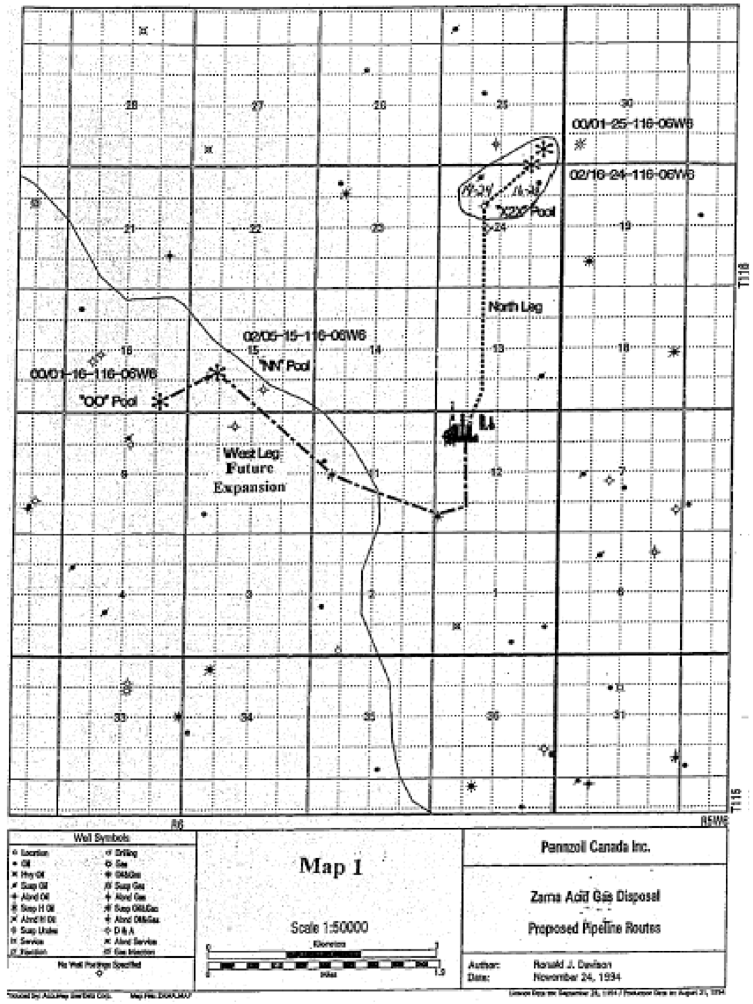



**Zama Keg River X2X – Production / Injection History**

Figure 185

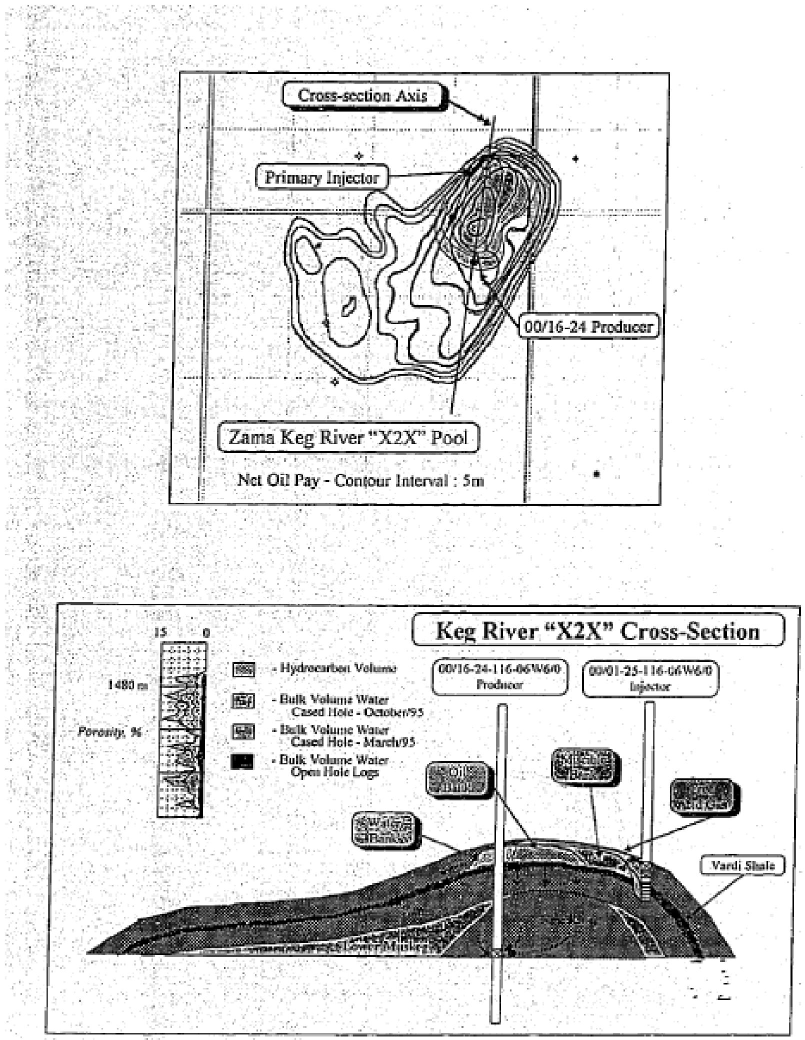


Sproule




**Zama Acid Gas Disposal – Proposed Pipeline Routes**

Figure 186




**Keg River "X2X" Cross-Section**

Figure 187

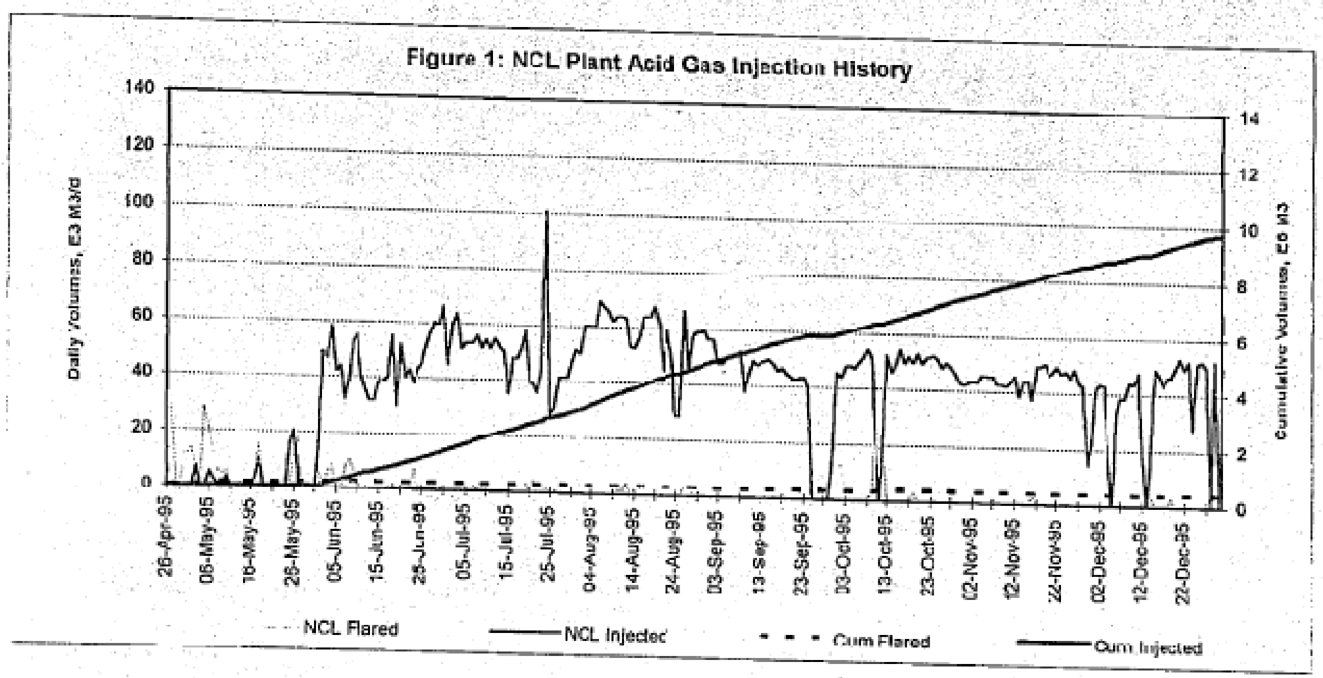
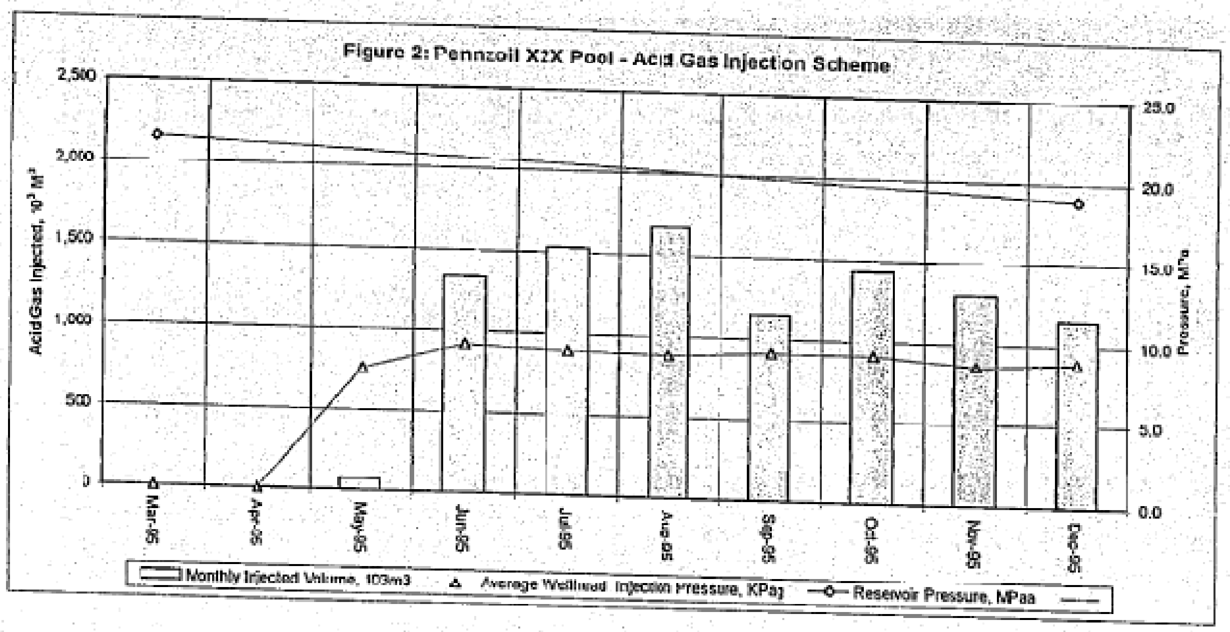


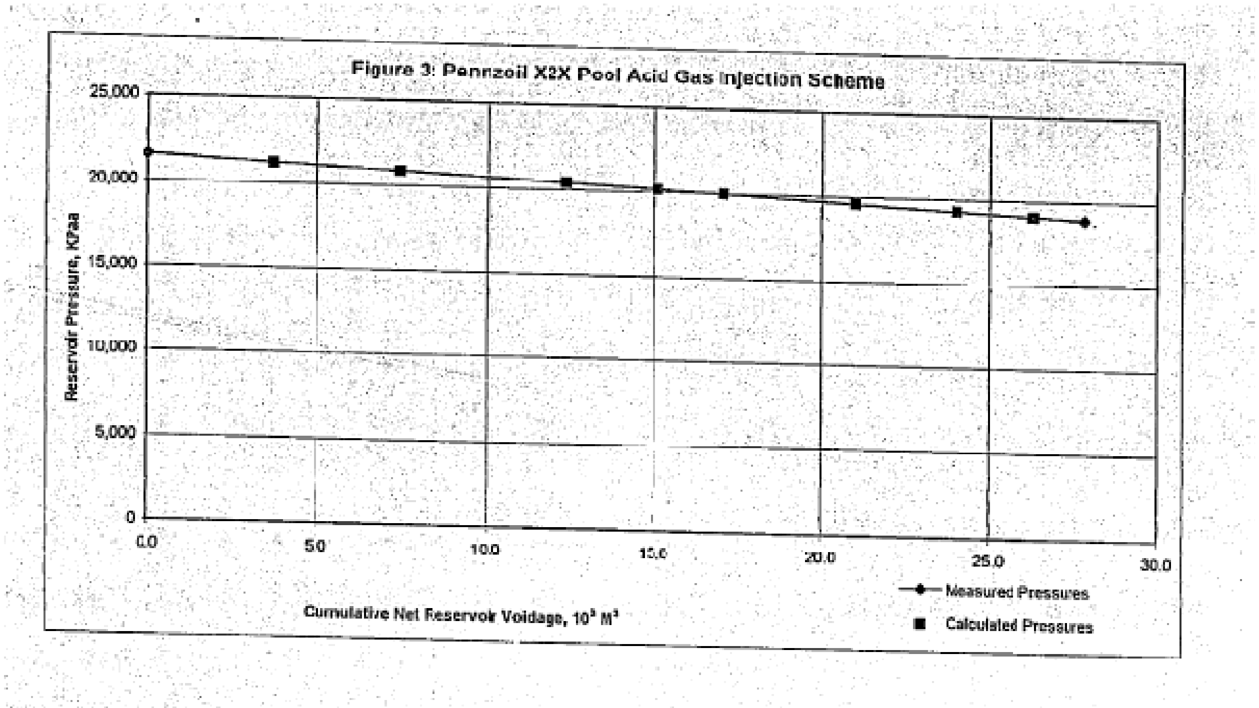

Figure 188

**NCL Plant Acid Gas Injection History**



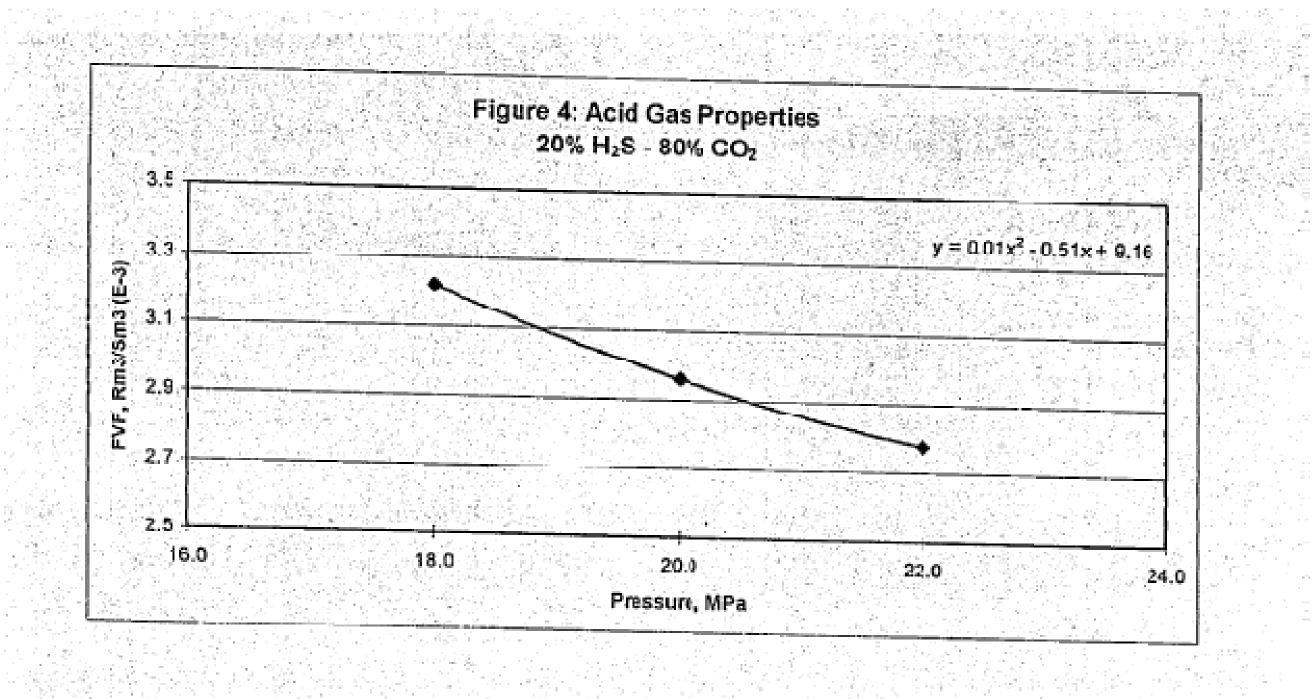

**Pennzoil X2X Pool – Acid Gas Injection Scheme**

Figure 189



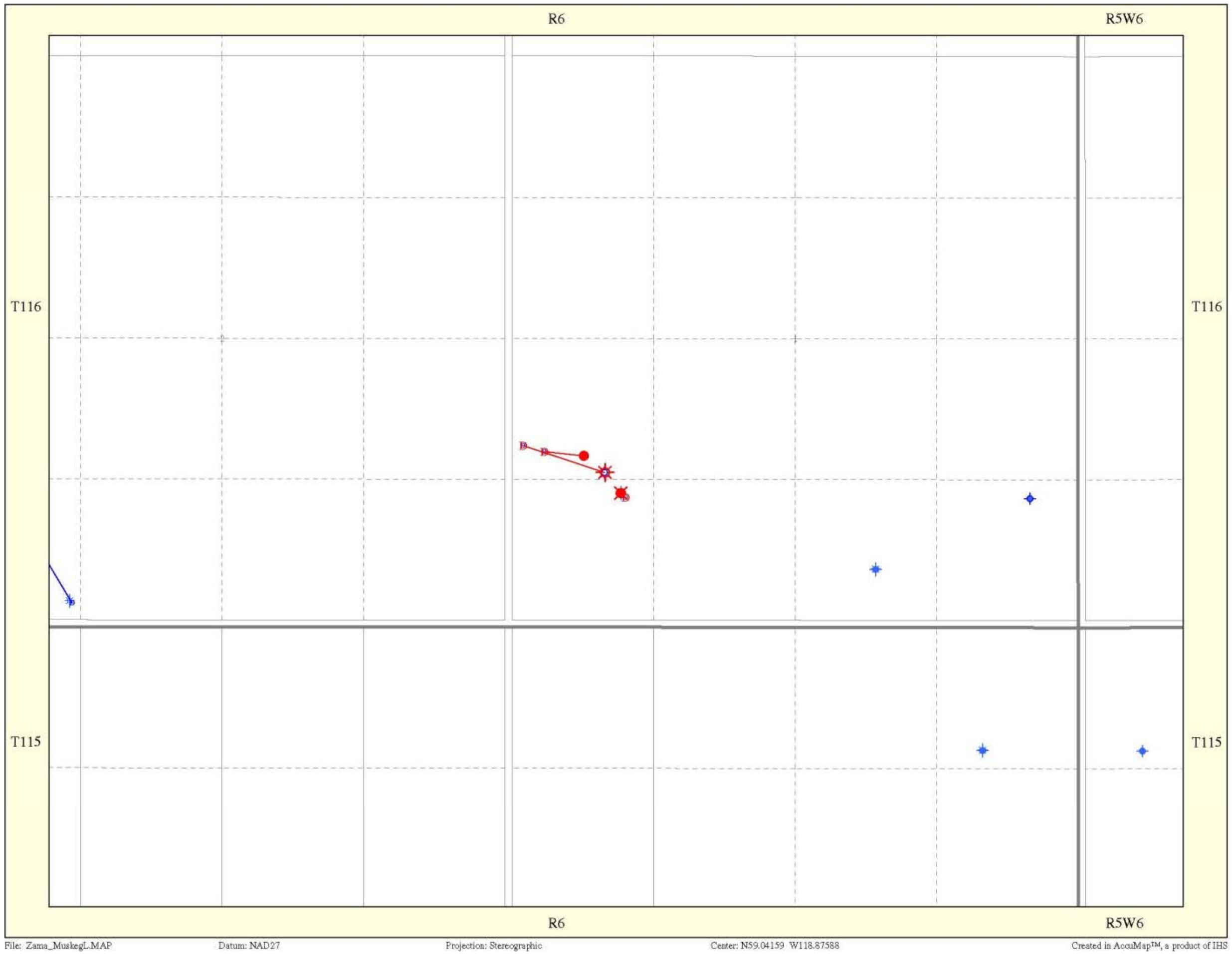

**Pennzoil X2X Pool – Acid Gas Injection Scheme**

Figure 190



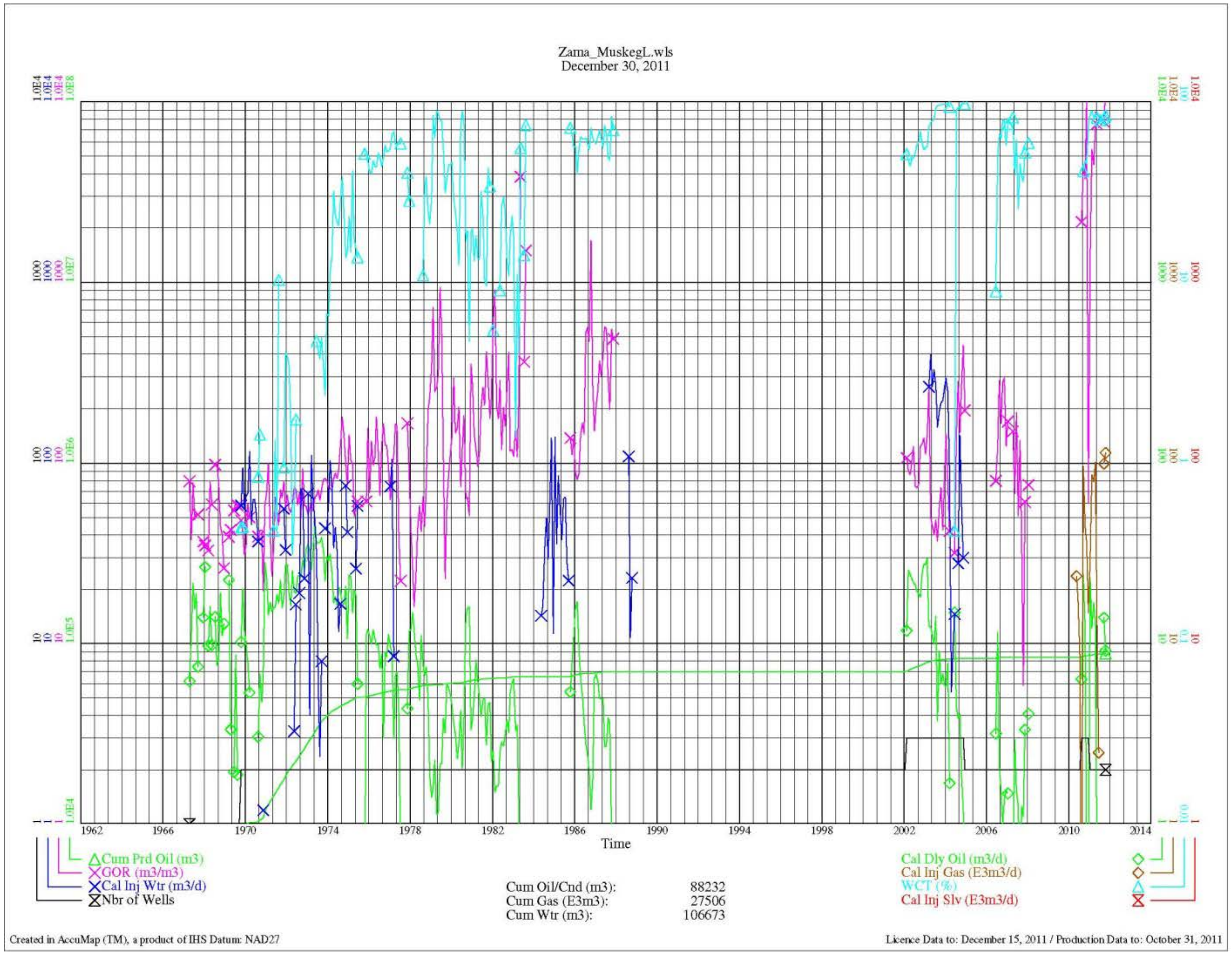

**Acid Gas Properties**

Figure 191



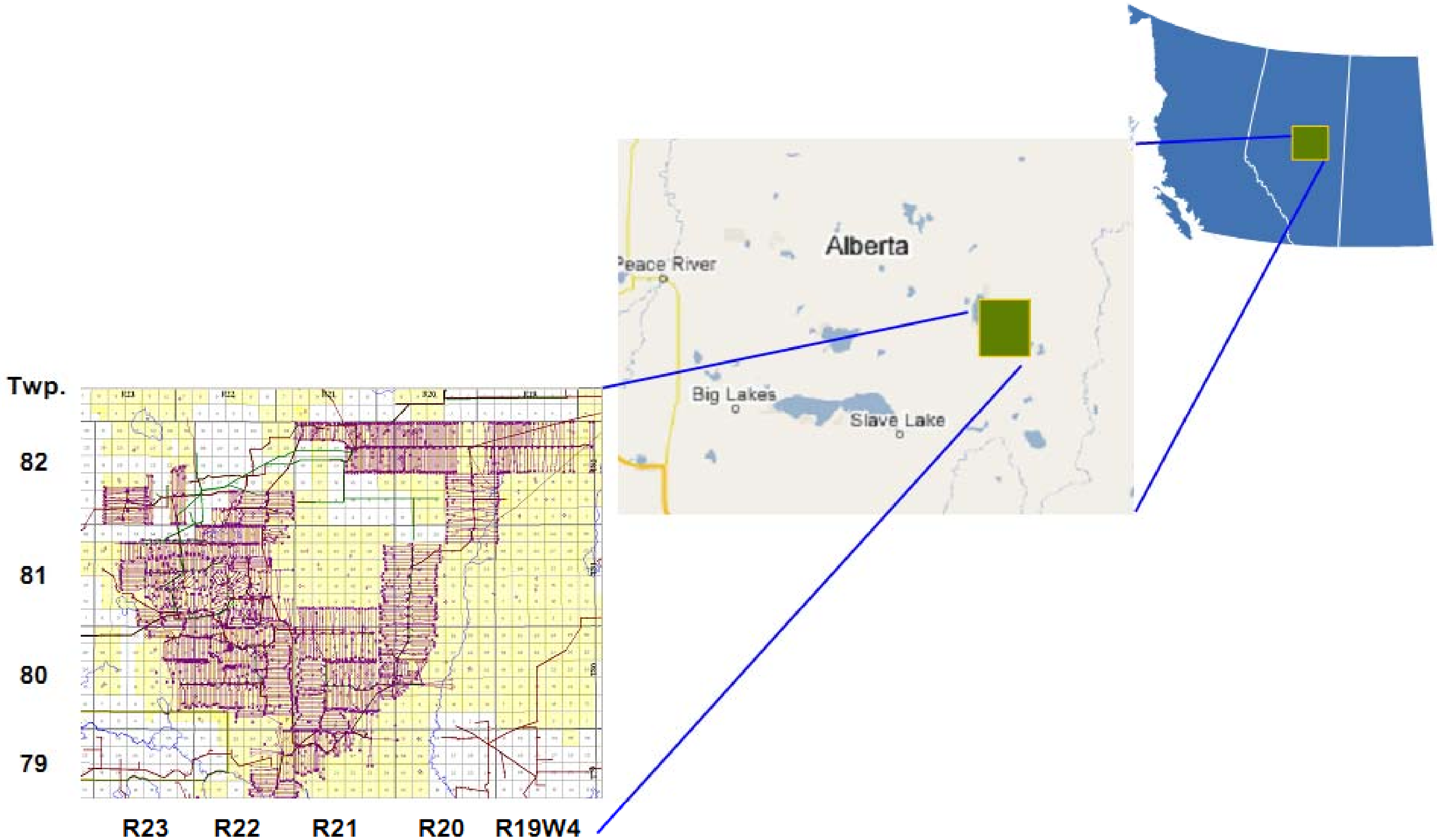

**Zama Muskeg L – Well Locations**

Figure 192




**Zama Muskeg L – Production / Injection History**

Figure 193

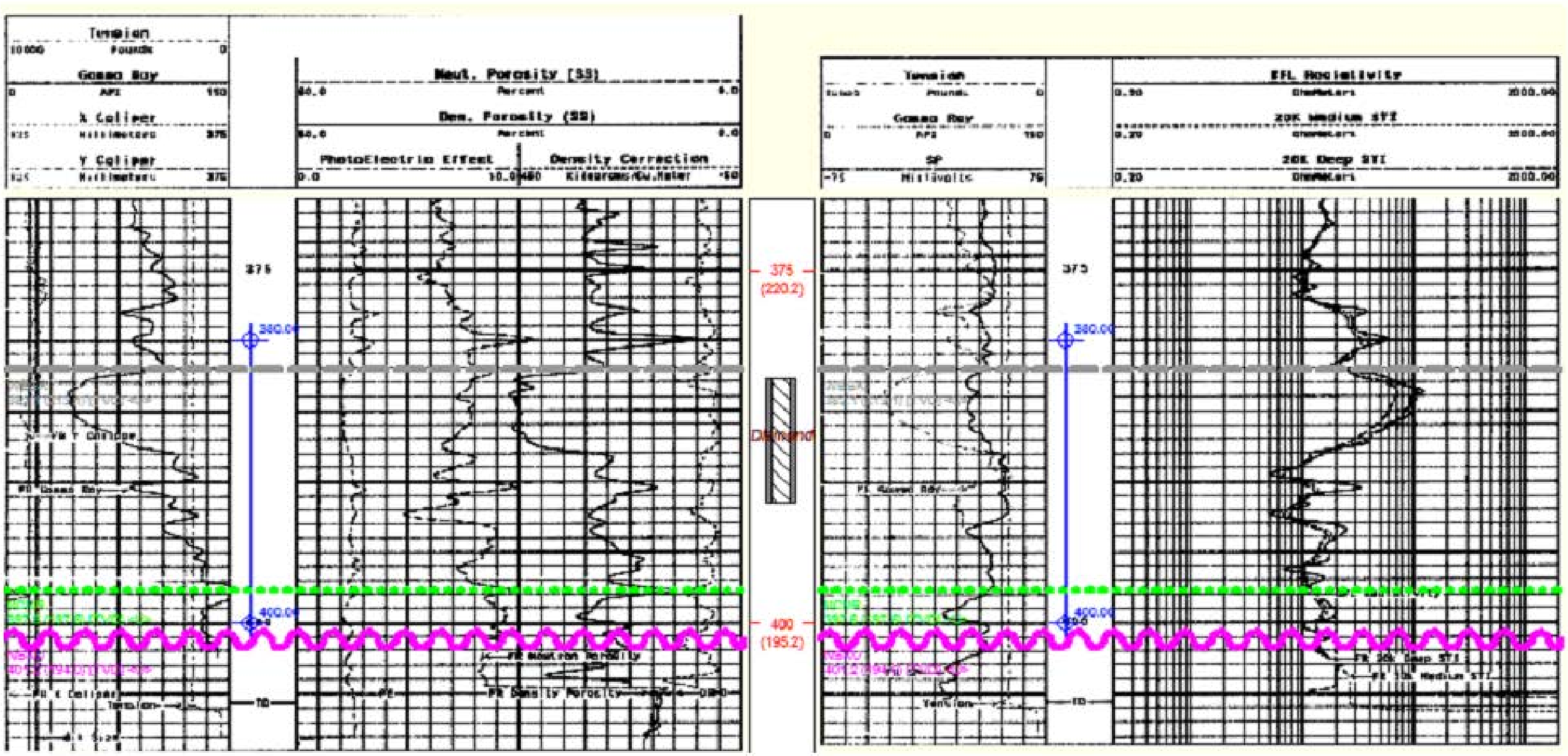



**Location of Brintnell Project**

Figure 194

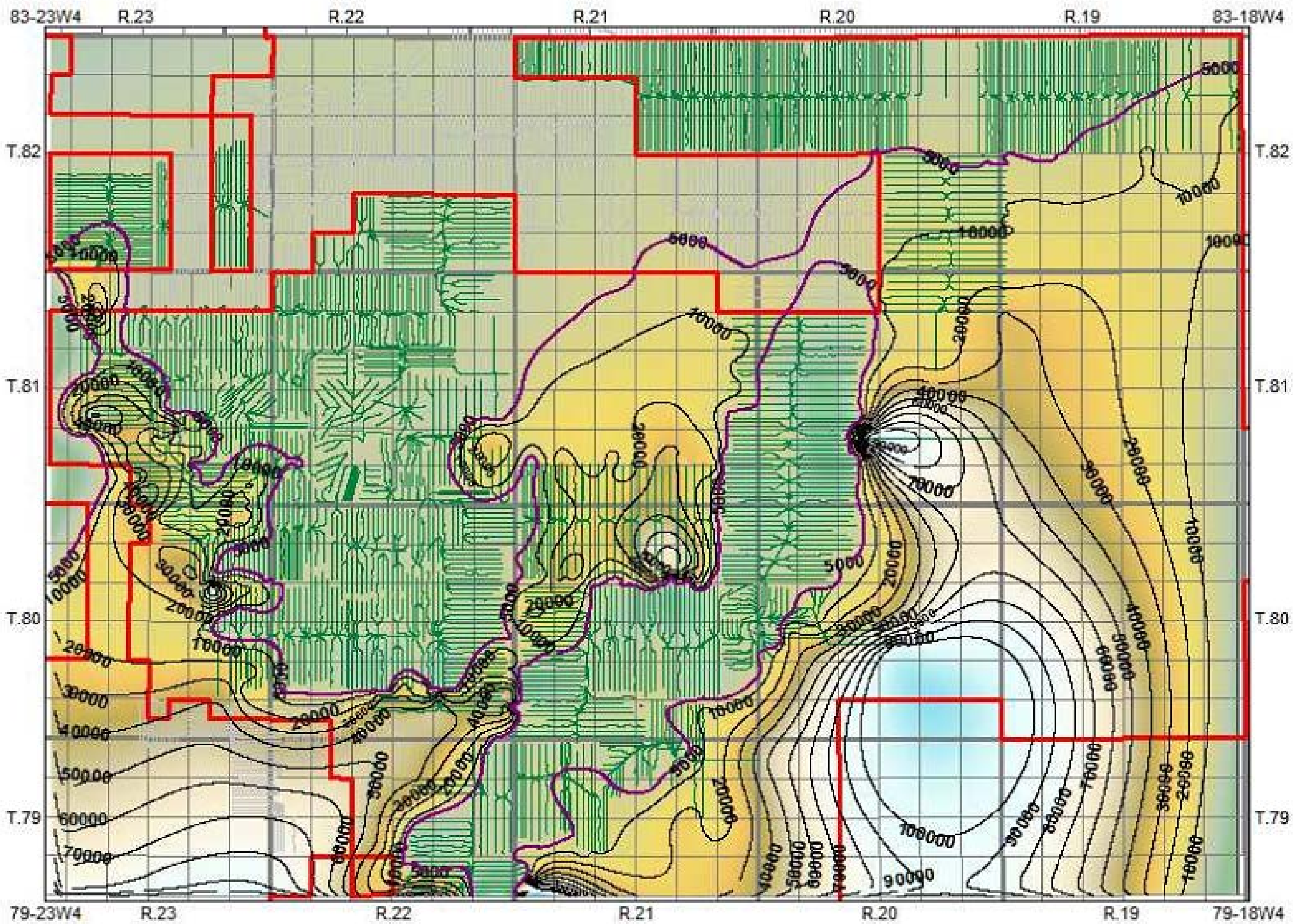


Sproule



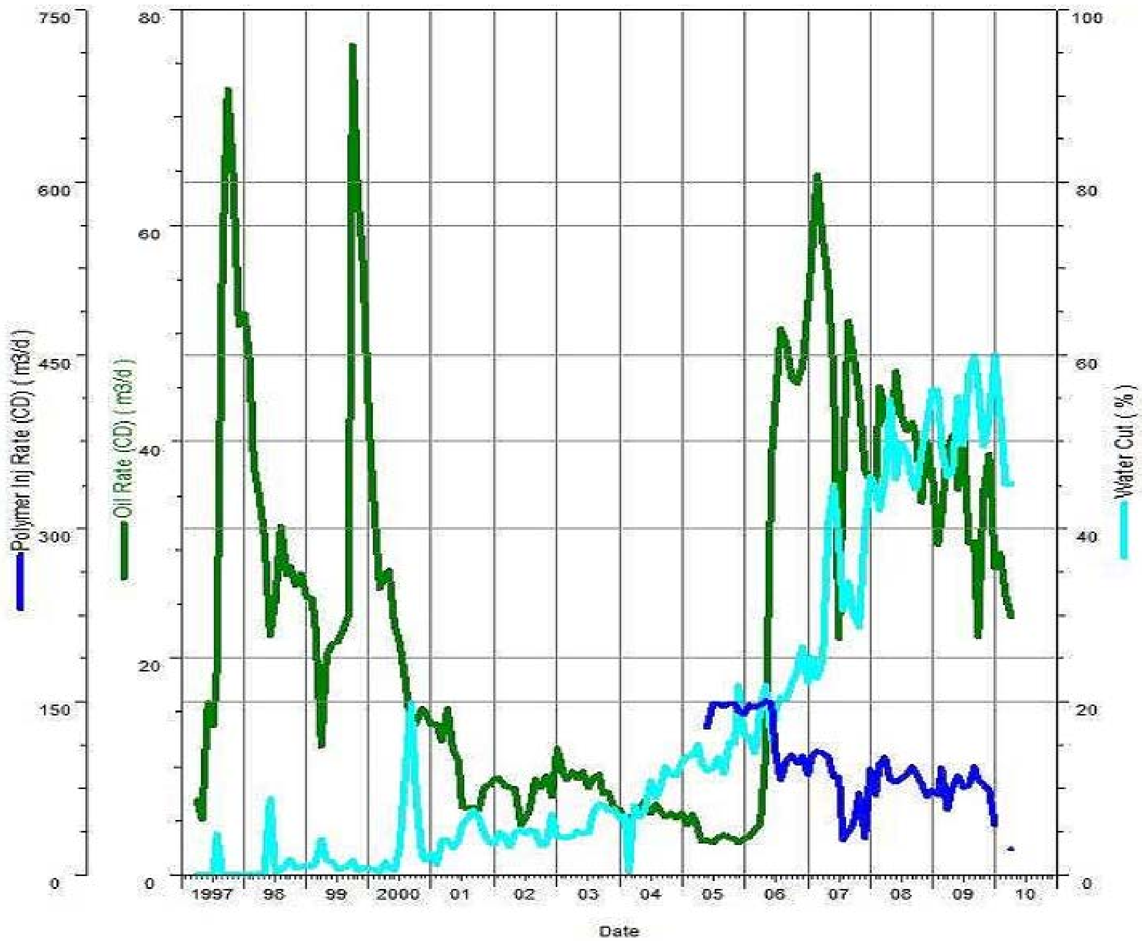
**CNRL Brint 6-14-81-21W4M Type Log**

Figure 195



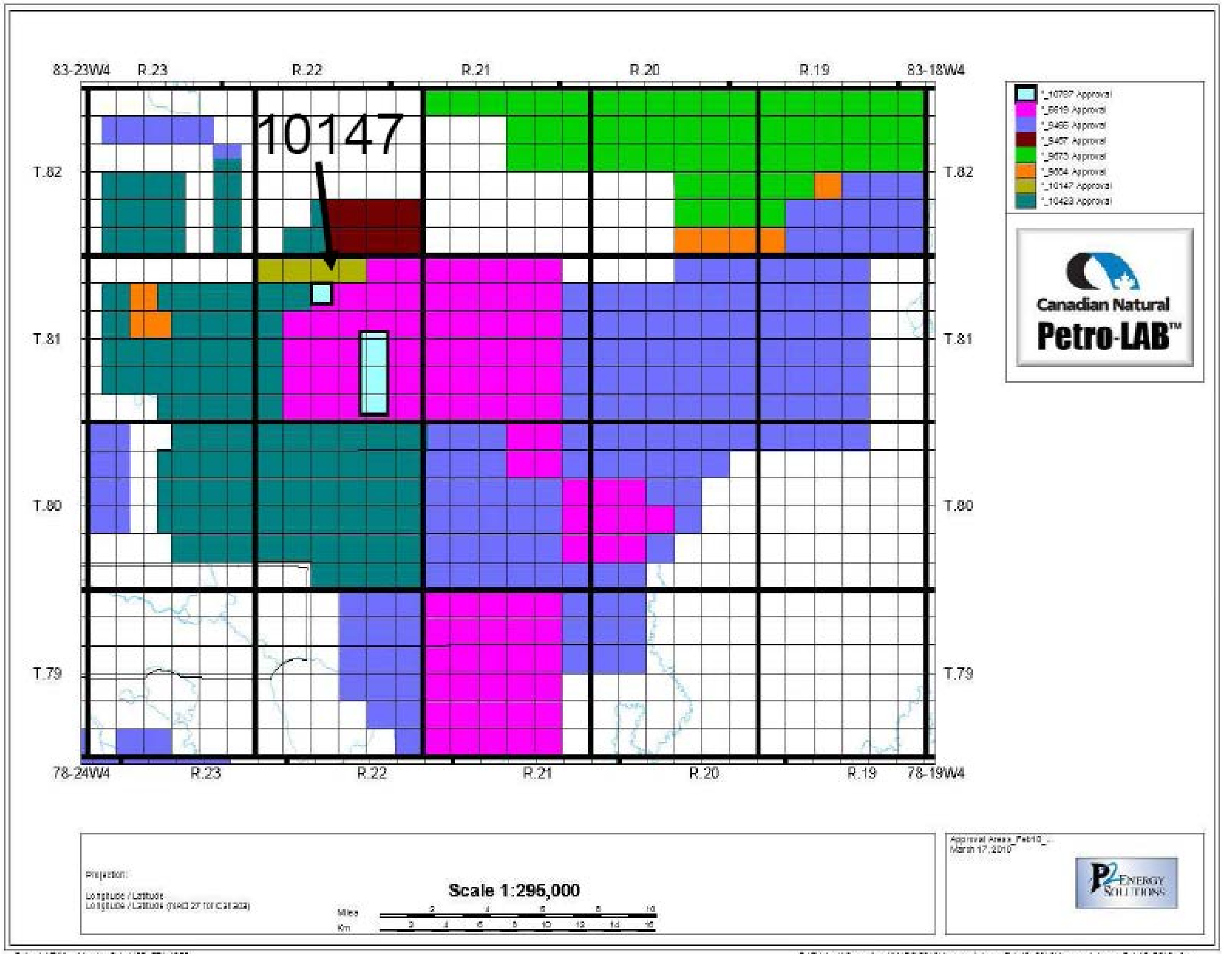

**Brintnell Produced Viscosity Map**

Figure 196




**Brintnell – Performance of Average Pattern under Polymer Flood**

Figure 197

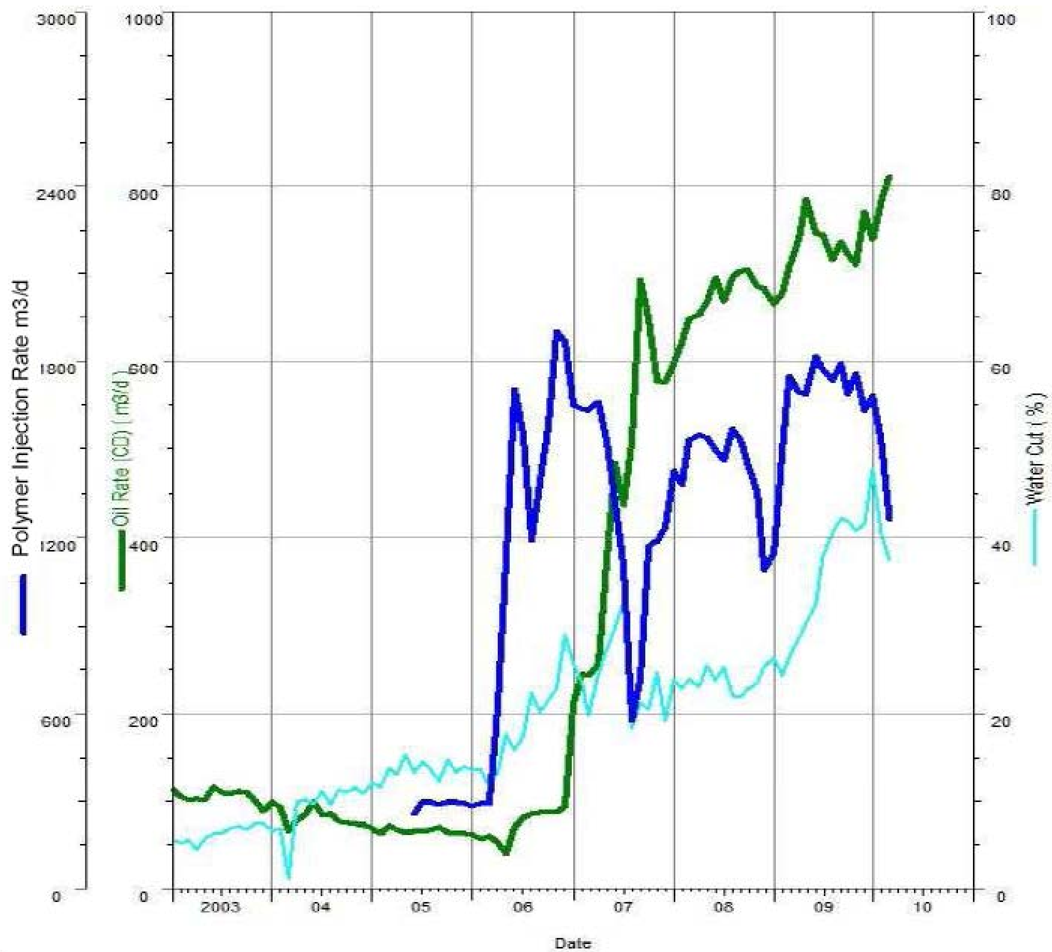



Brintnell – Approval 10147 – First Area Expanded After the Pilot

Figure 198

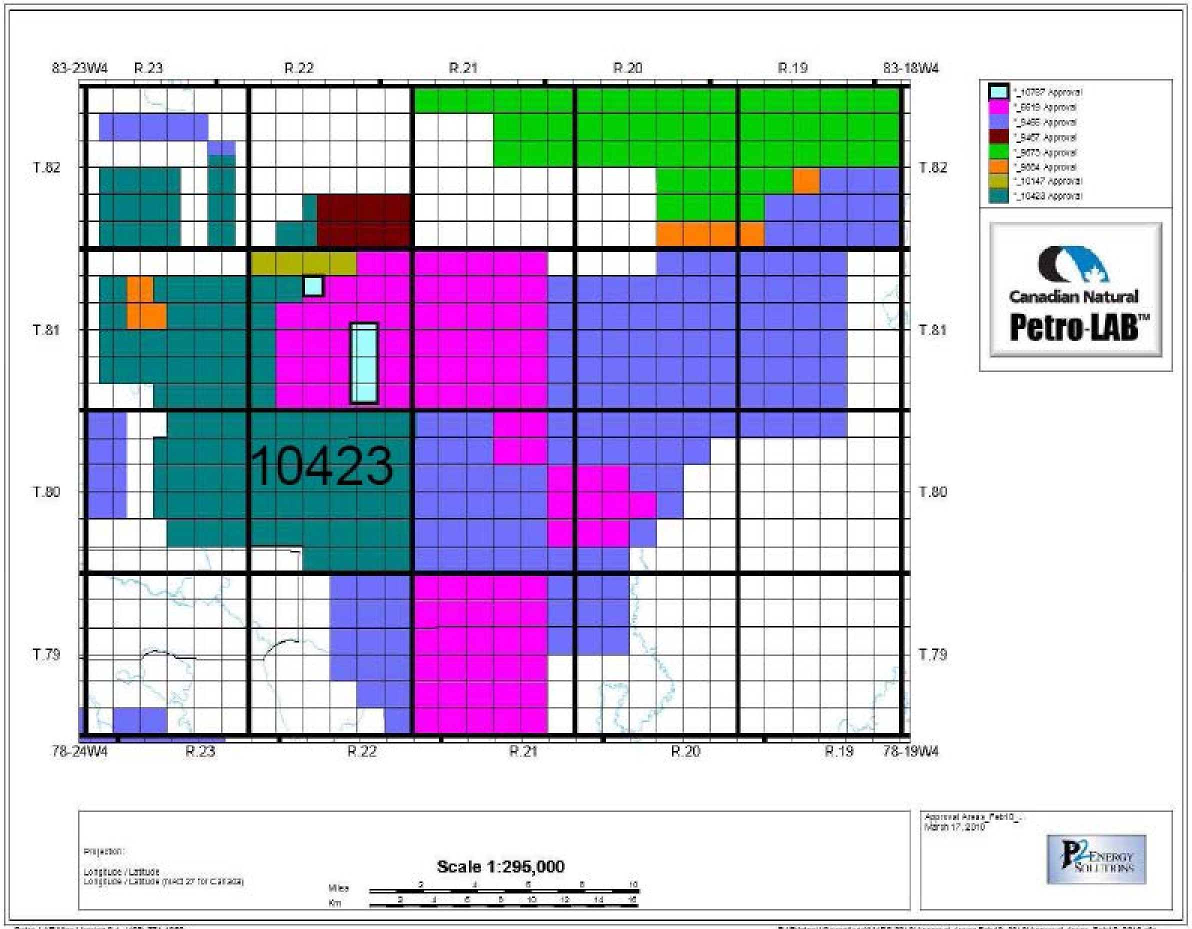


Sproule



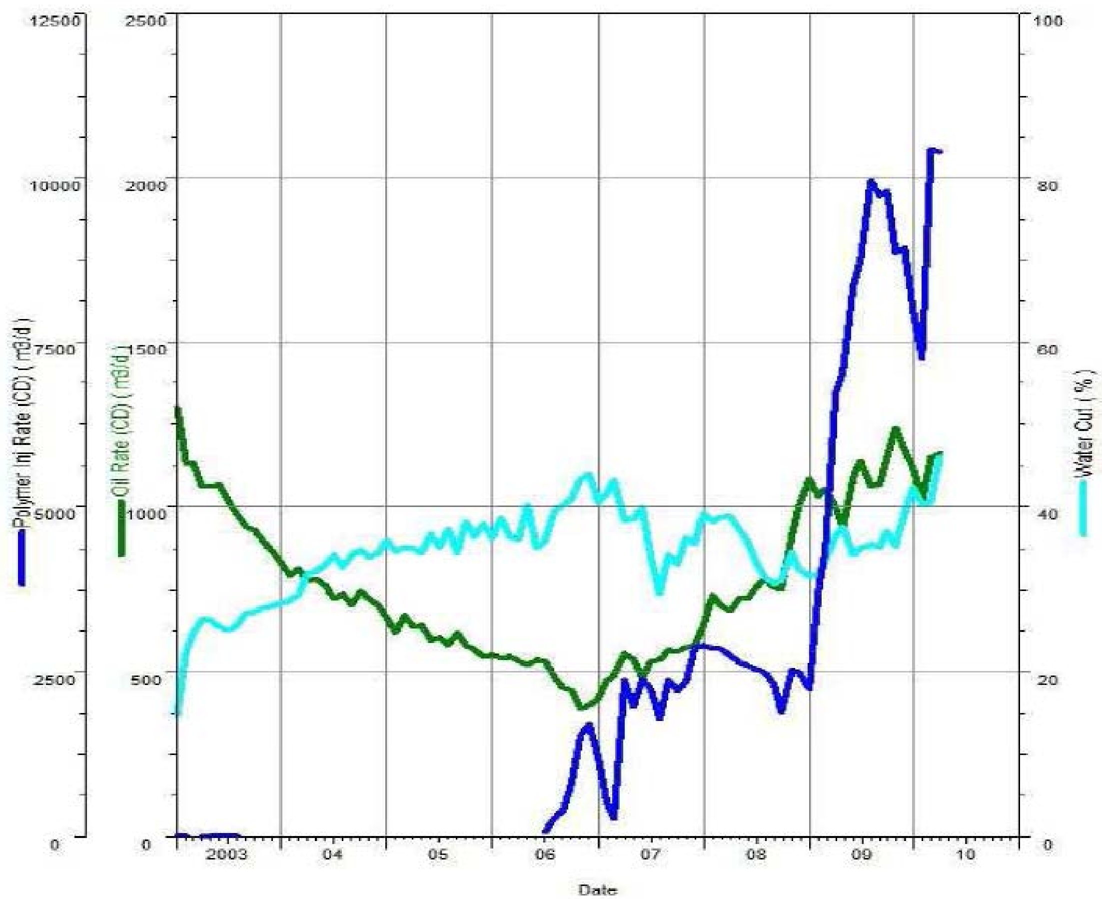

**Brintnell – Approval 10147 – Polymer Flood Performance**

Figure 199




**Brintnell – Approval 10423 – Polymer Flood**

Figure 200

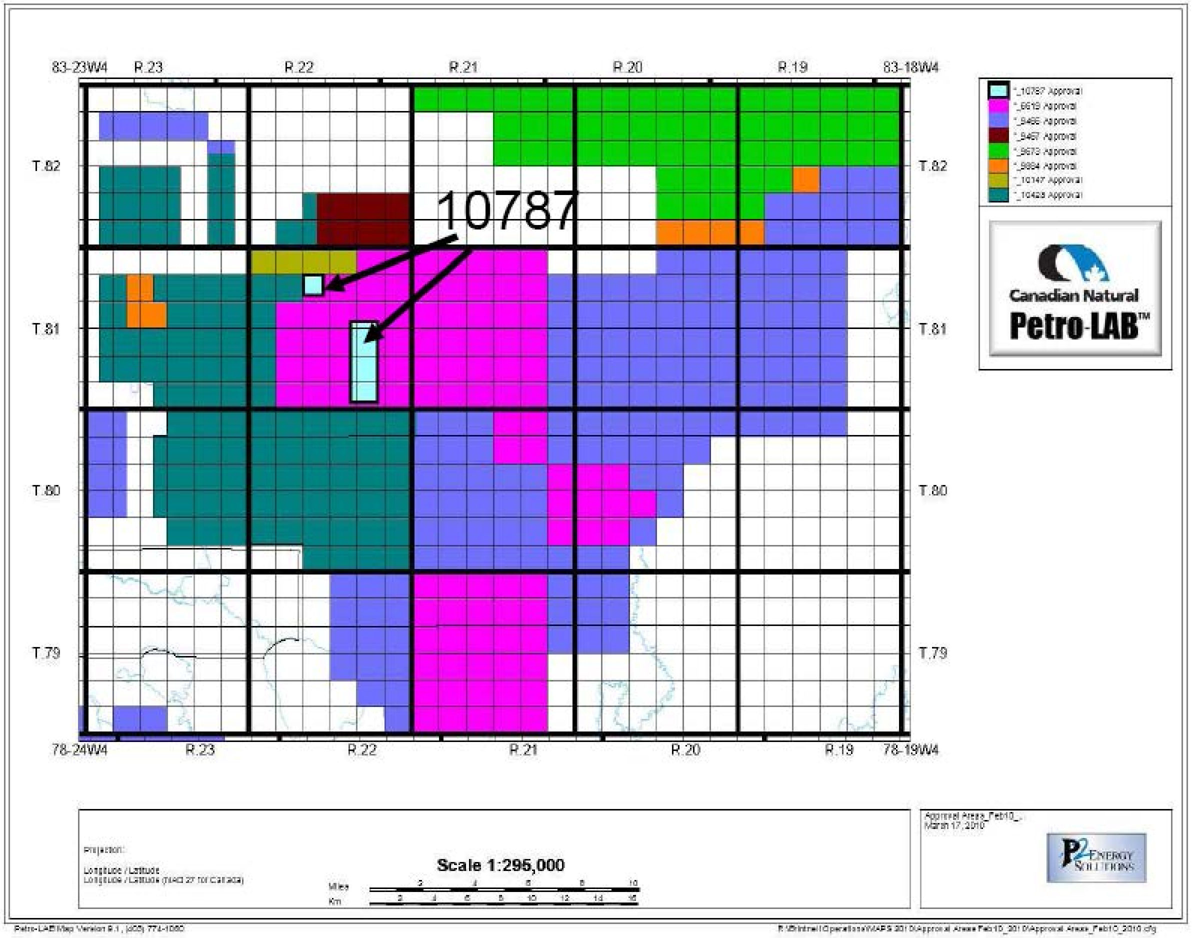



**Brintnell – Approval 10423 – Polymer Flood Performance**

Figure 201



Sproule

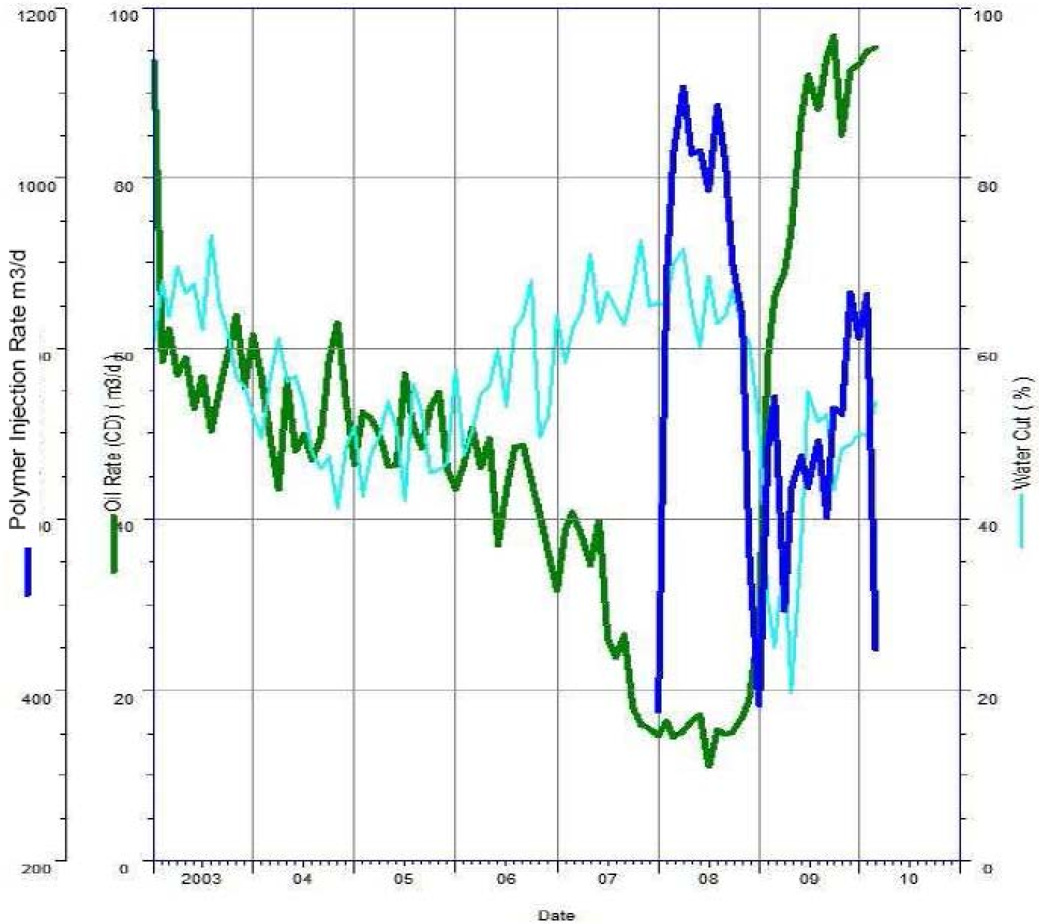



**Brintnell – Approval 10787 – Polymer Flood**

Figure 202



Sproule

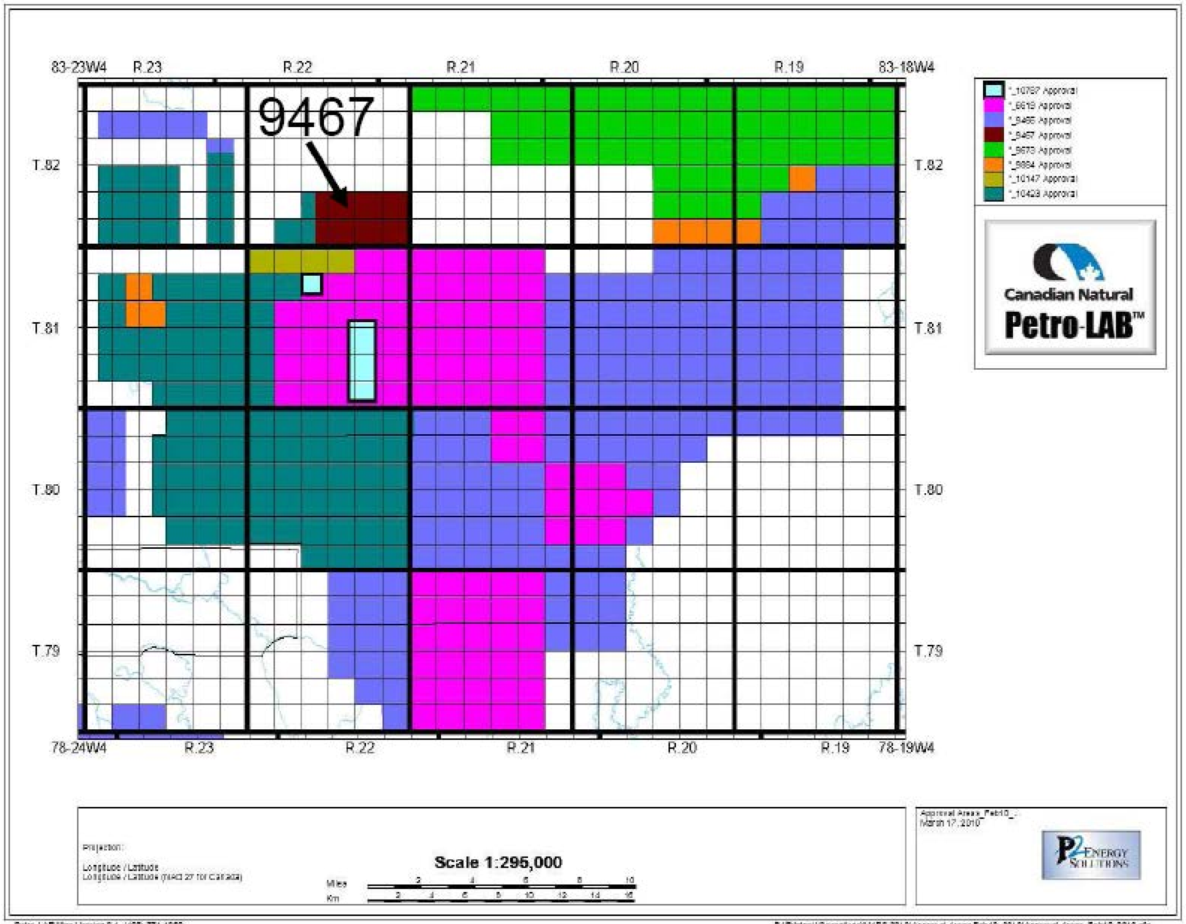



**Brintnell – Approval 10787 – Polymer Flood Performance**

Figure 203



Sproule

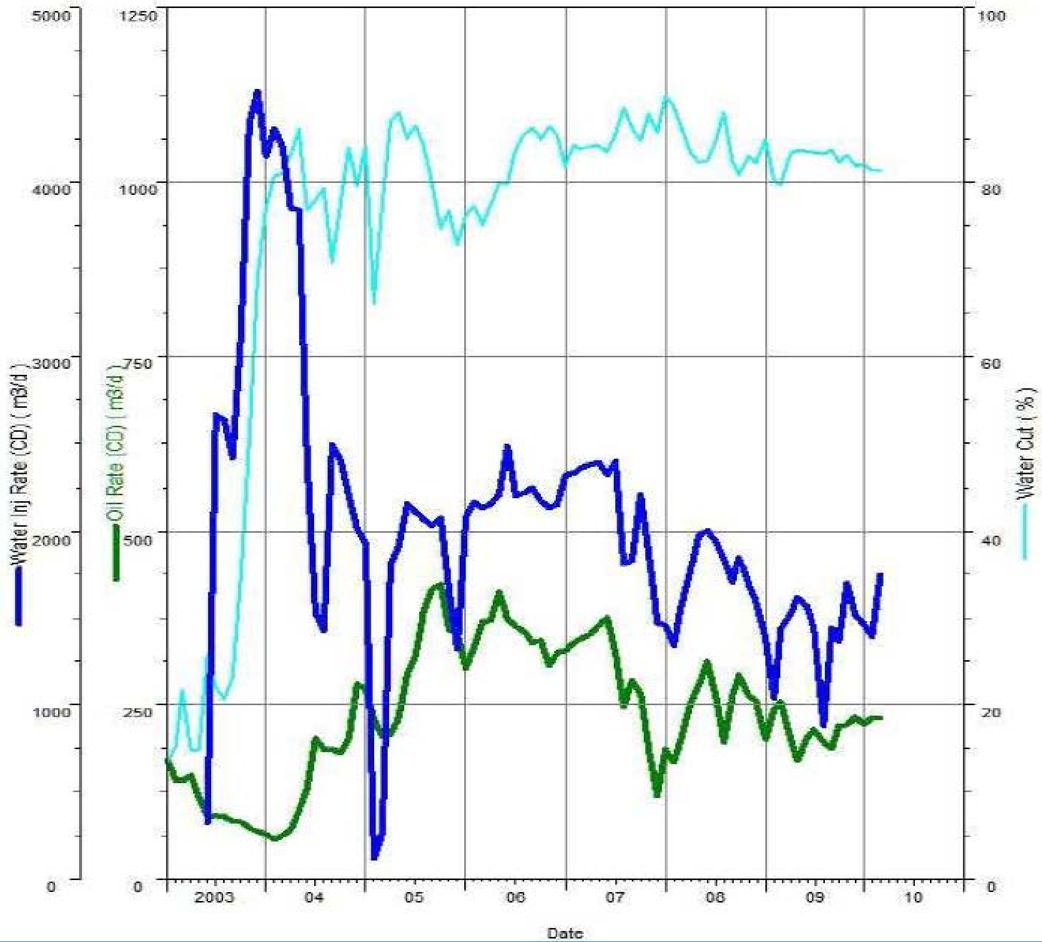



**Brintnell – Approval 9467 – Waterflood / Polymer Flood**

Figure 204

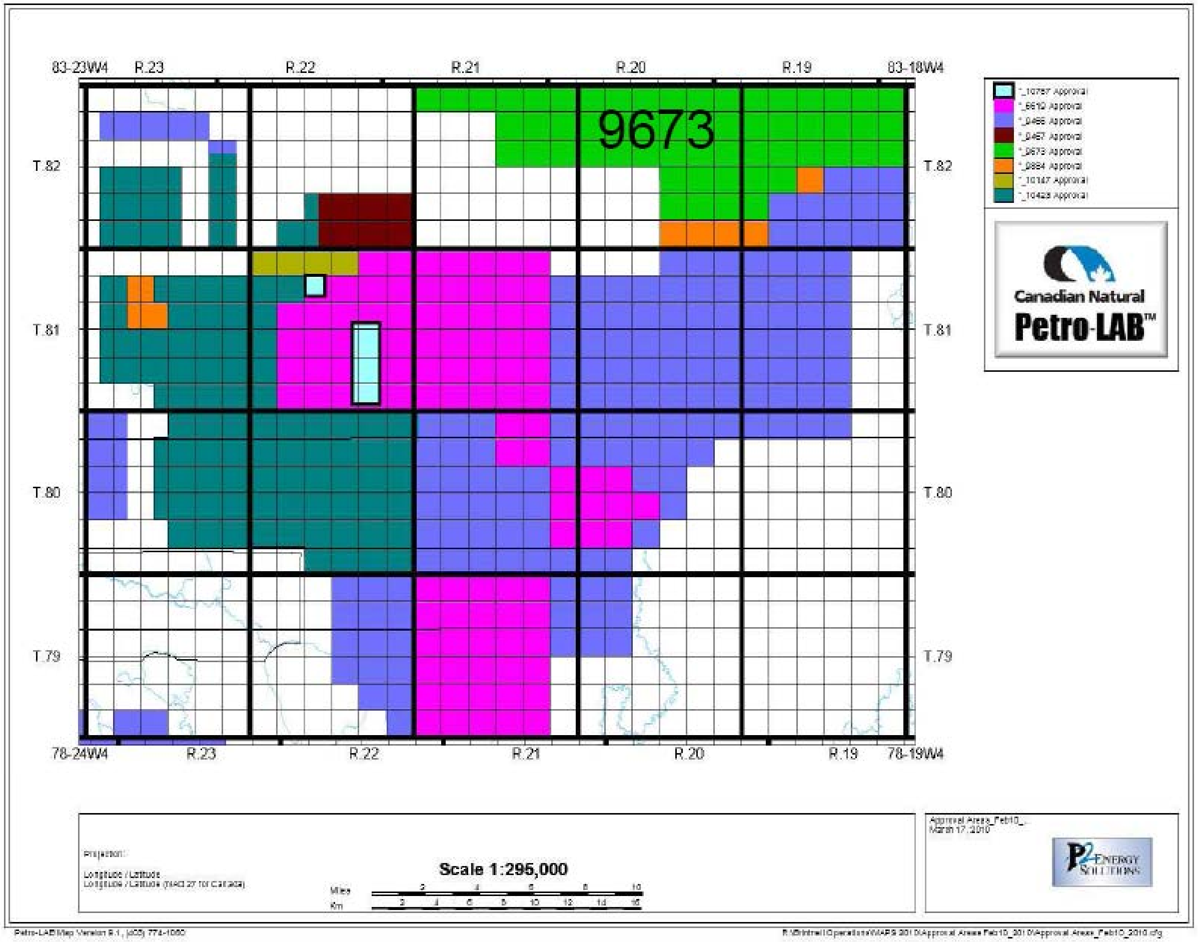


Sproule




**Brintnell – Approval 9467 – Polymer Flood Performance**

Figure 205

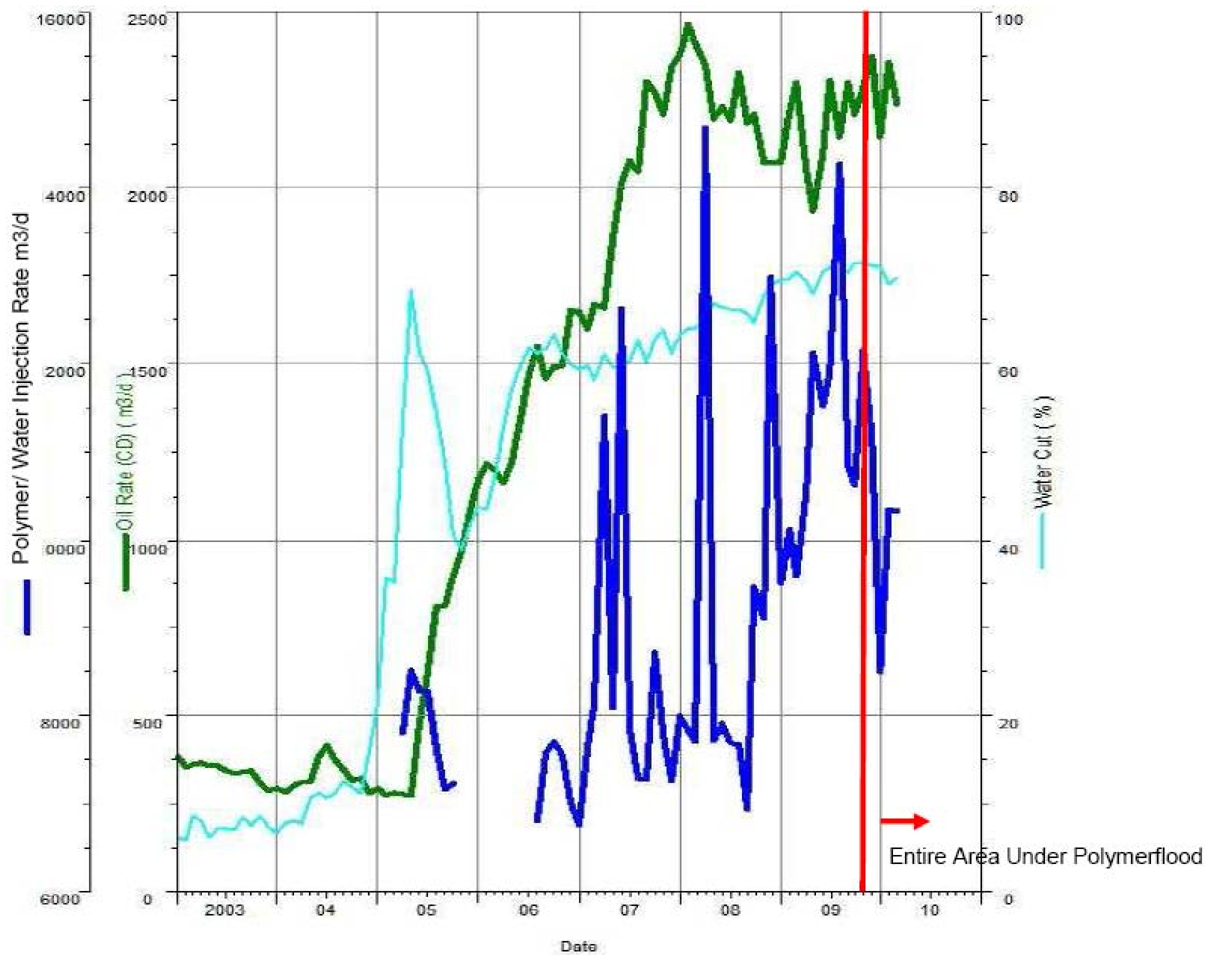



**Brintnell – Approval 9673 – Waterflood / Polymer Flood**

Figure 206



Sproule

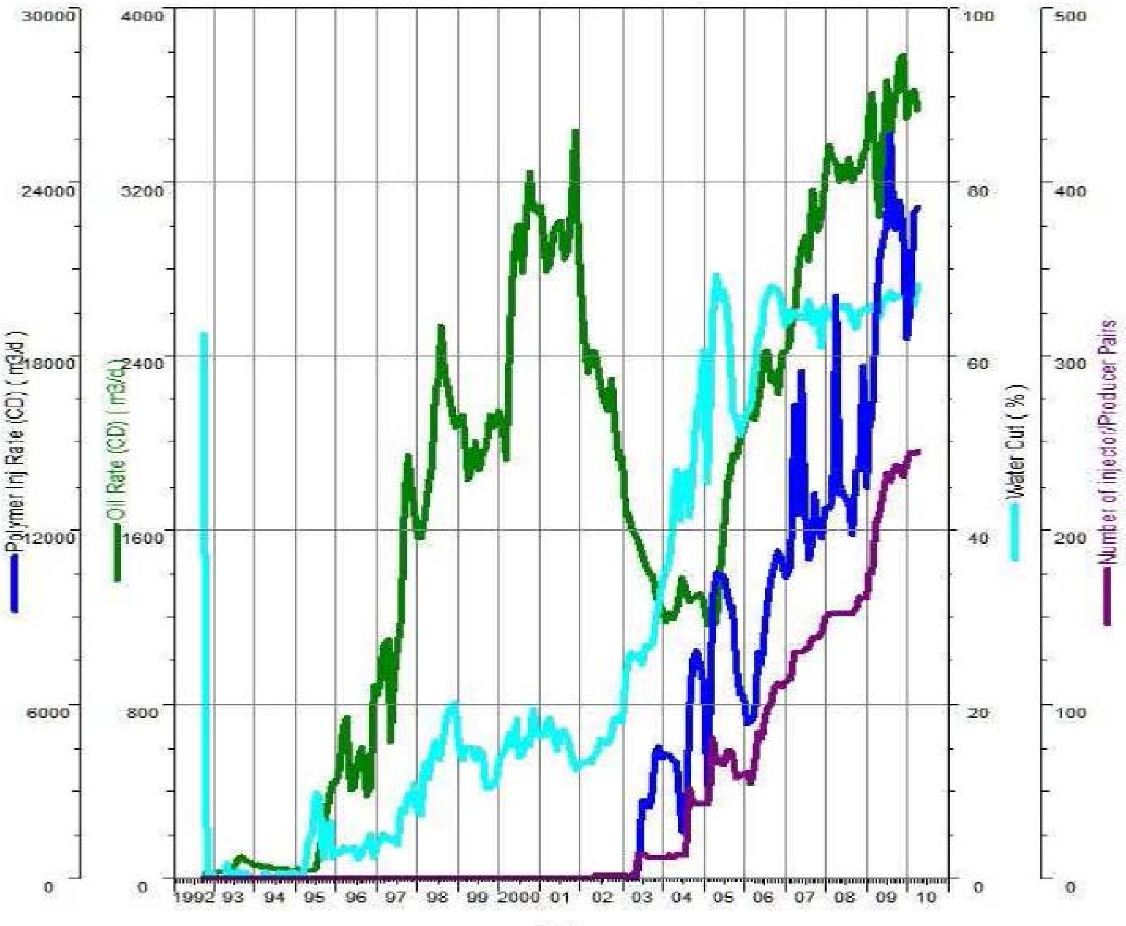



**Brintnell – Approval 9673 – Polymer Flood Performance**

Figure 207



Sproule

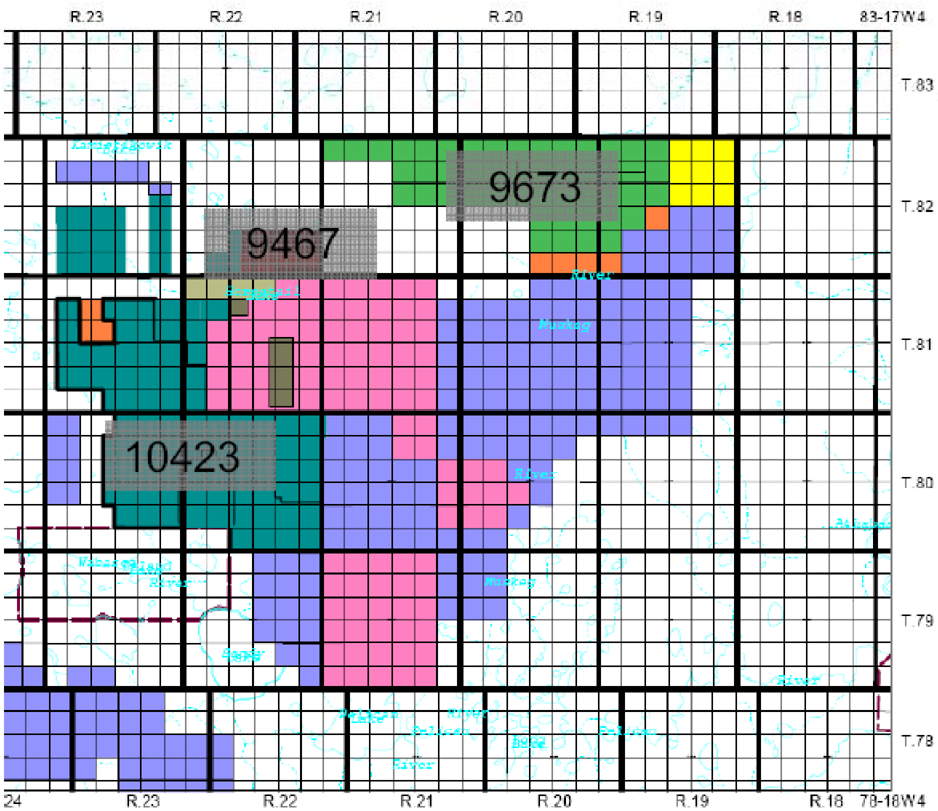



**Brintnell – Entire Flood Performance Results**

Figure 208



Sproule



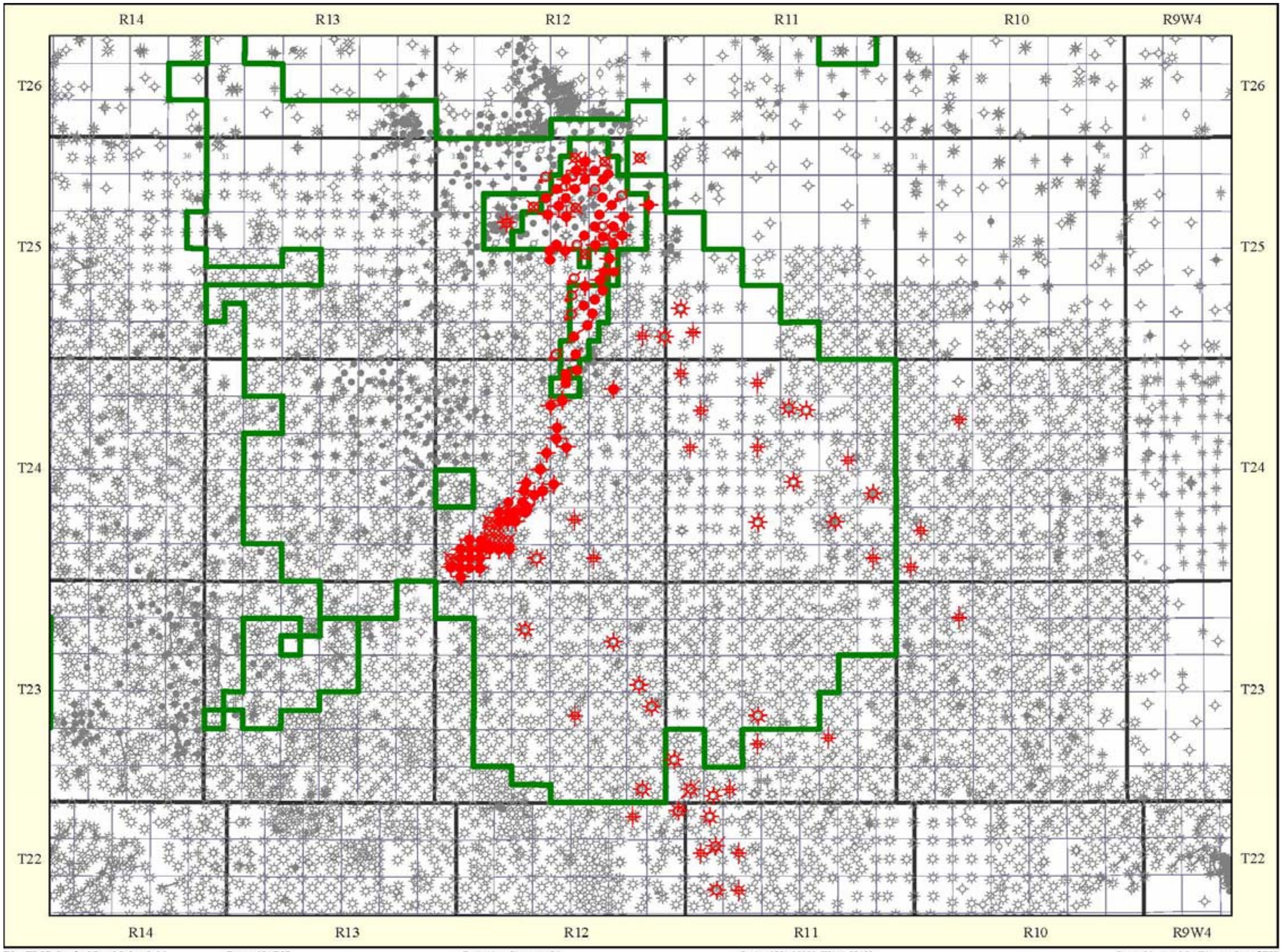

**Approval 9673**
**Total area OBIP 96,041,971 m3**
**Estimated developed area ultimate**
**Recovery factor ranges:**
**12 – 22%**

**Approval 9467**
**Total area OBIP 14,006,041 m3**
**Estimated developed area ultimate**
**Recovery factor ranges:**
**9 – 17%**

**Approval 10423**
**Total area OBIP 210,467,090 m3**
**Estimated developed area ultimate**
**Recovery factor ranges:**
**8 – 24%**

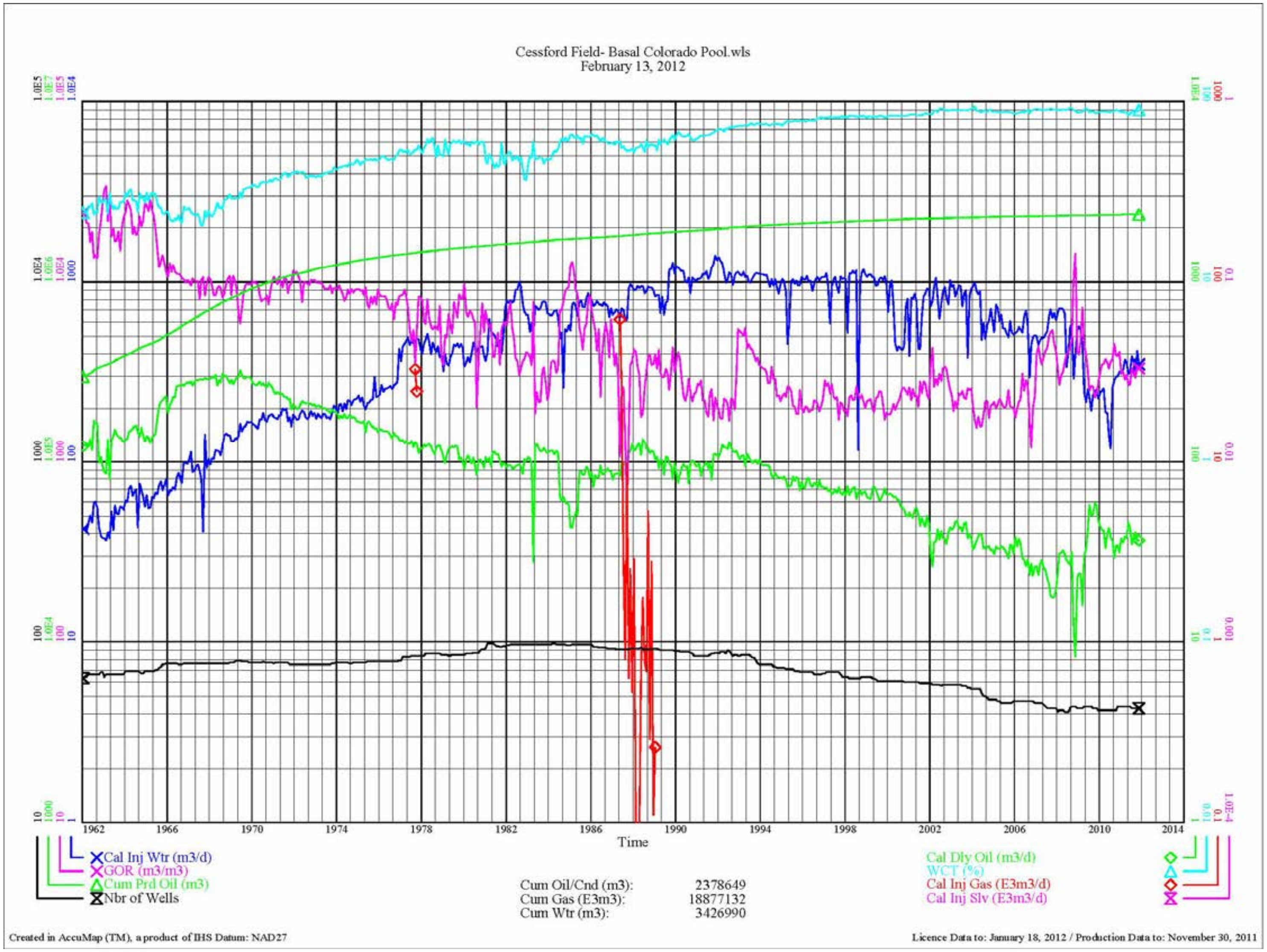
Figure 209

**Brintnell – Major Approval Area Recovery Factors**



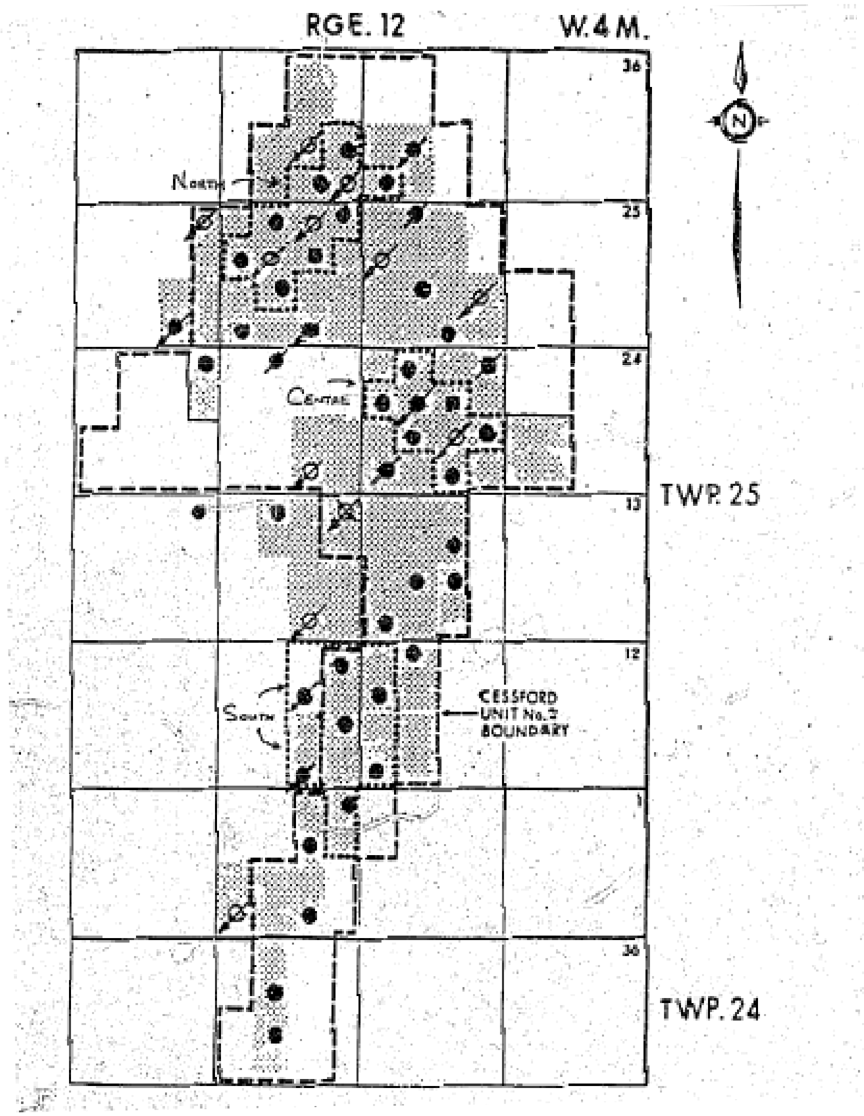

**Cessford Basal Colorado A – Well Locations**

Figure 210



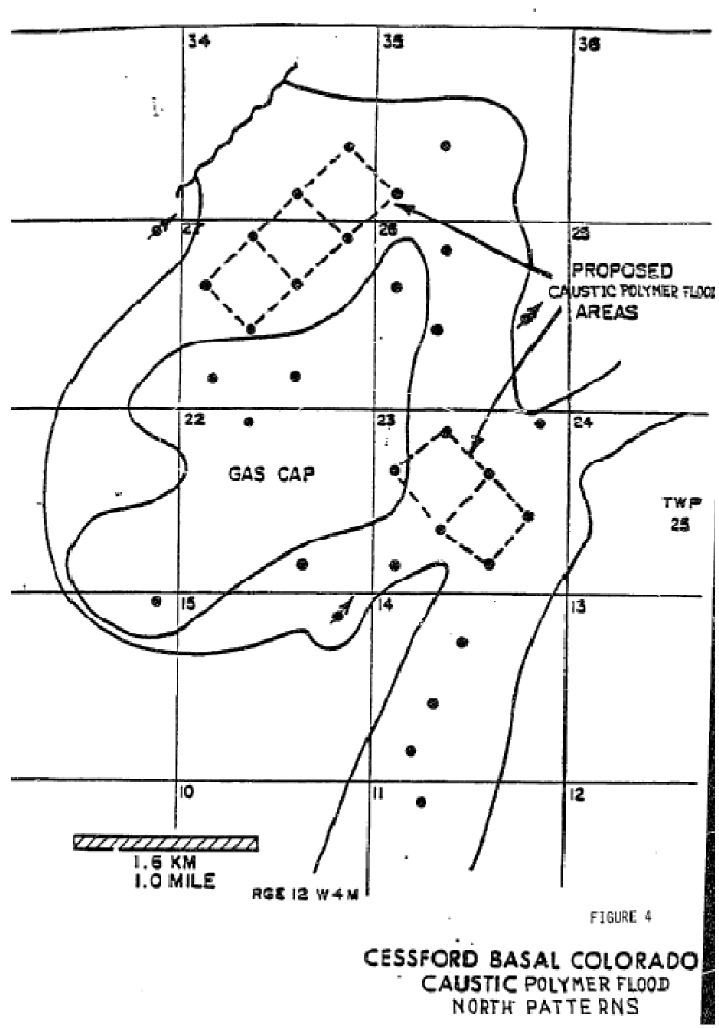

Cessford Basal Colorado A - Production / Injection History

Figure 211



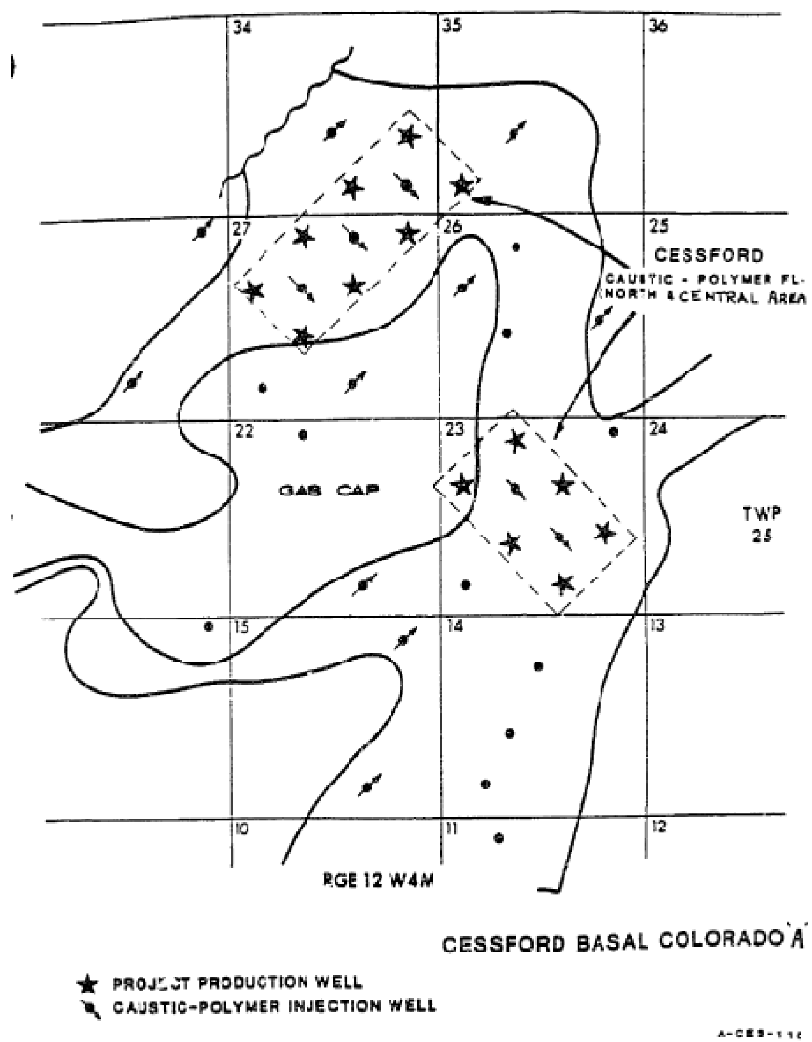

**Cessford Basal Colorado A Pool – North, Central and South Patterns**

Figure 212



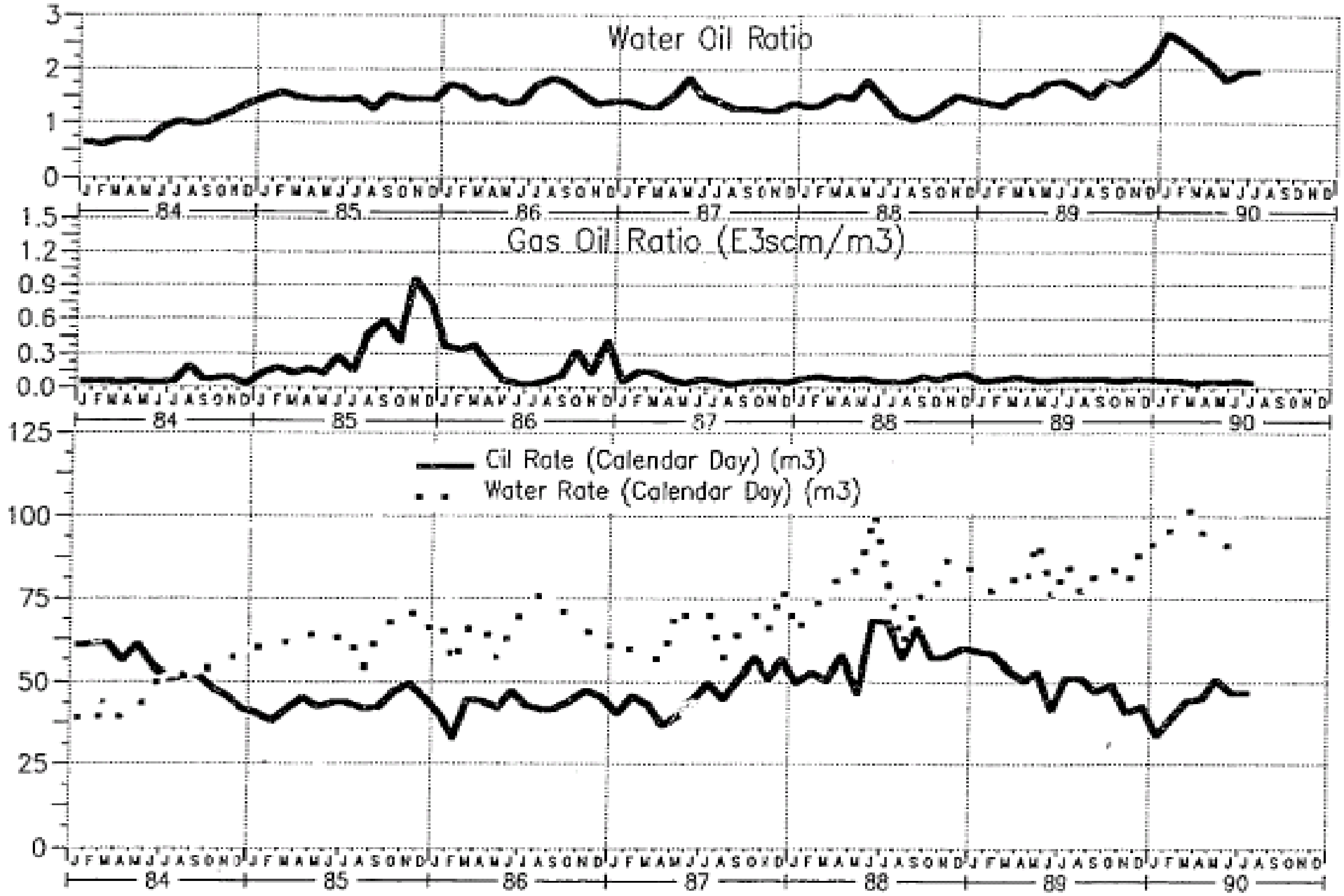

Cessford Basal Colorado A Pool – Gas Cap (North Patterns)

Figure 213




**Cessford Basal Colorado A Pool – Northern Patterns Caustic Polymer Flood**

Figure 214

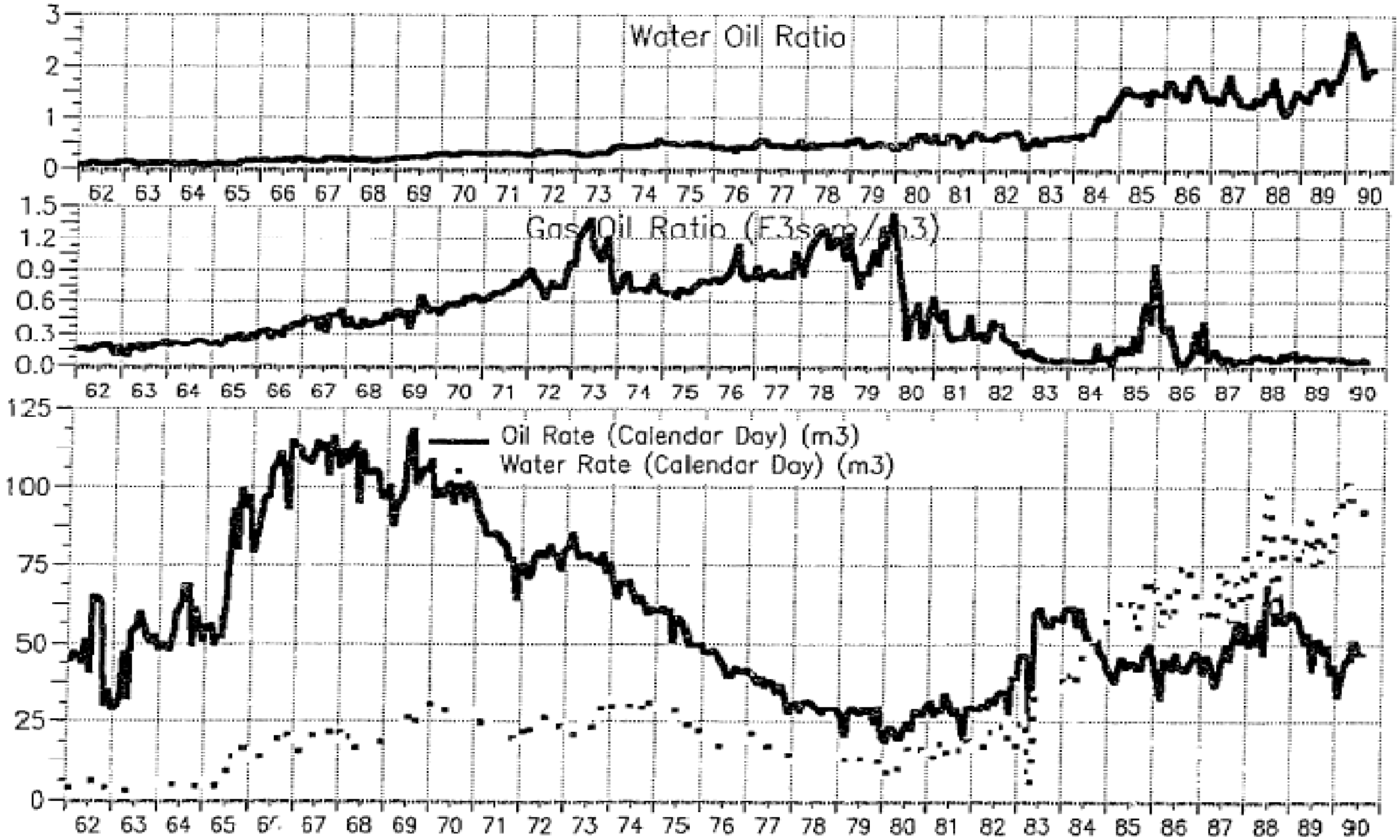



**Cessford Basal Colorado A Pool – All Wells Alkali Polymer Flood Performance (1984 – 1990)**

Figure 215

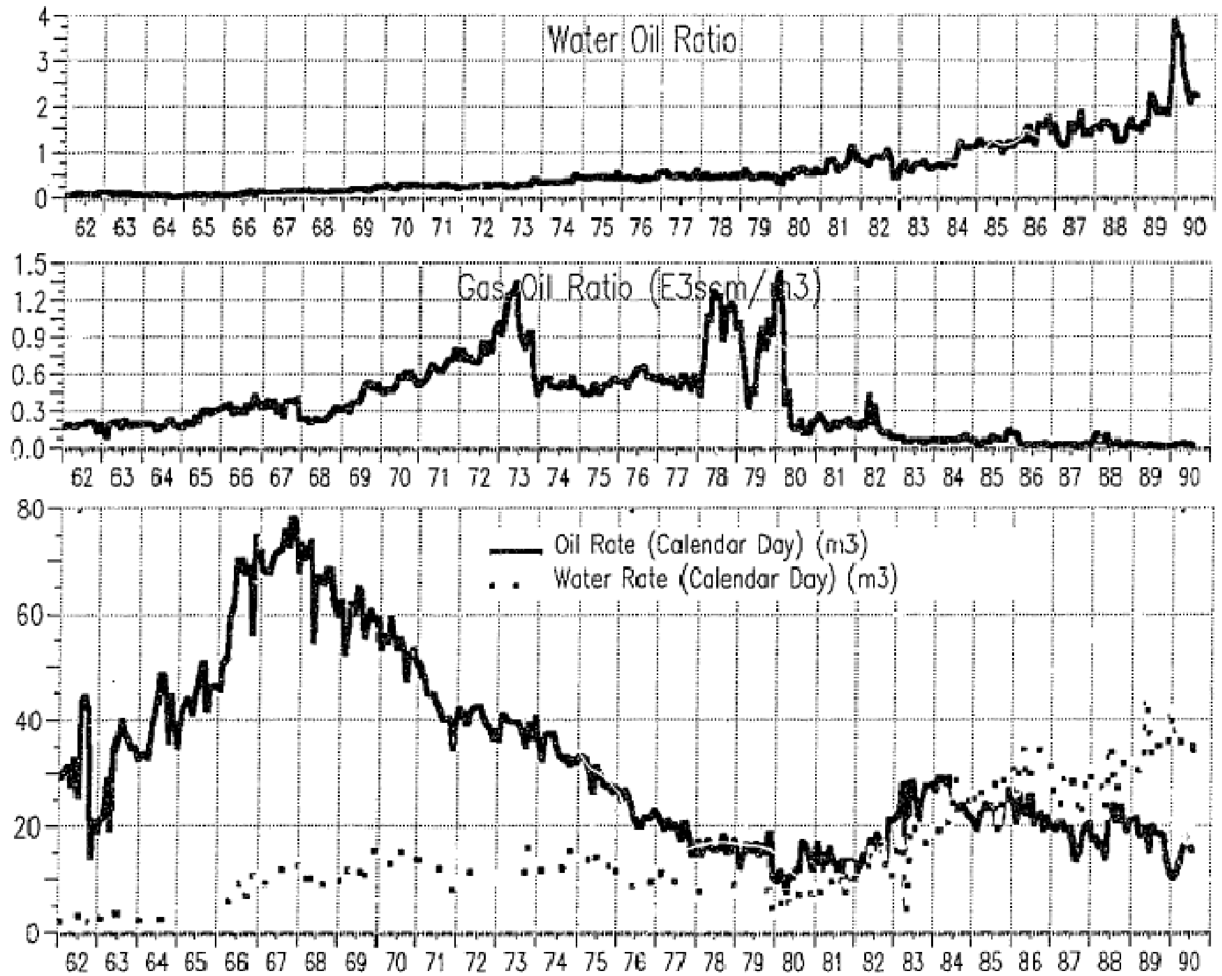


Sproule



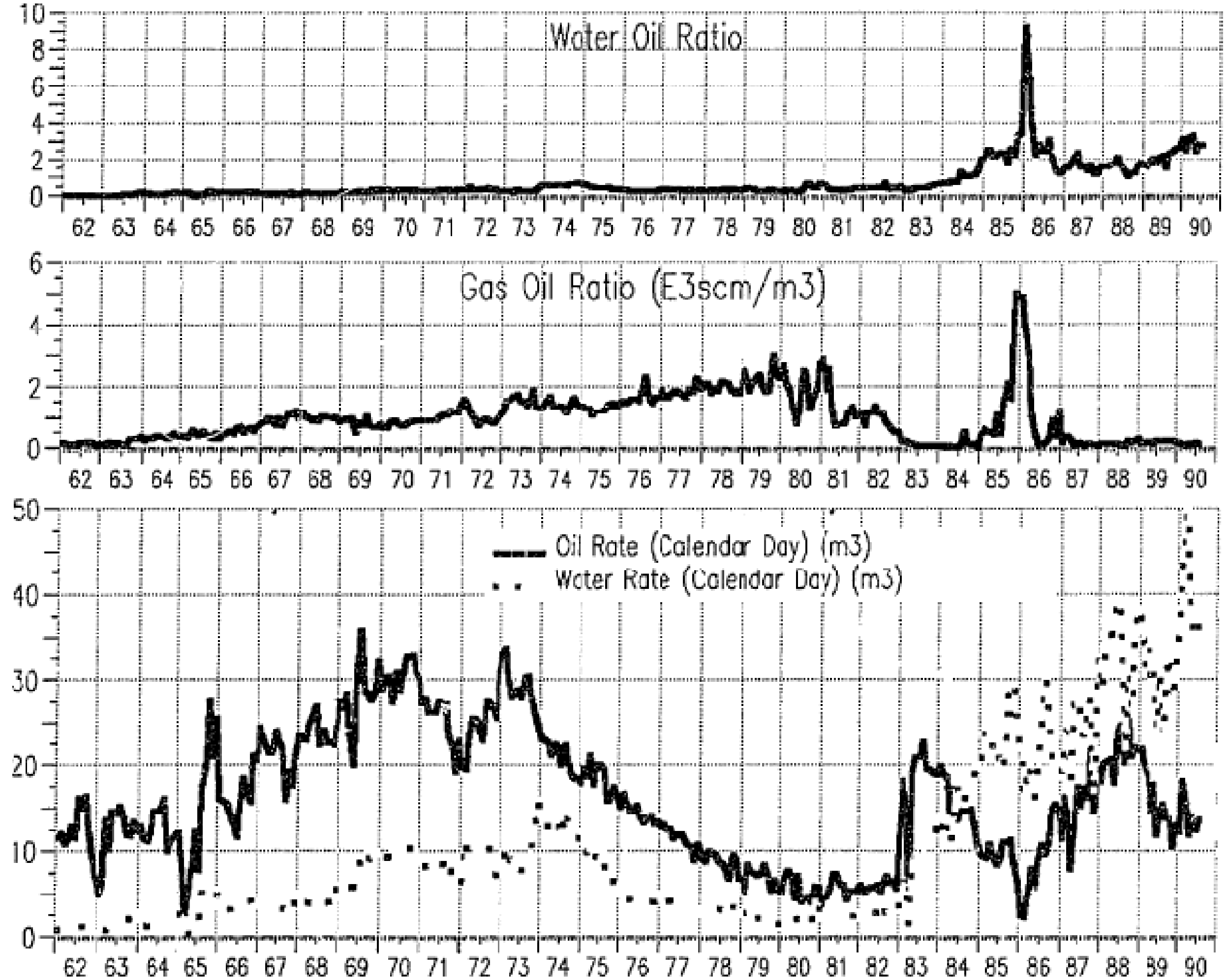

**Cessford Basal Colorado A Pool – All Wells Alkali Polymer Flood Performance (1961 – 1990)**

Figure 216




**Cessford Basal Colorado A Pool – North Pattern Performance (1961 – 1990)**

Figure 217

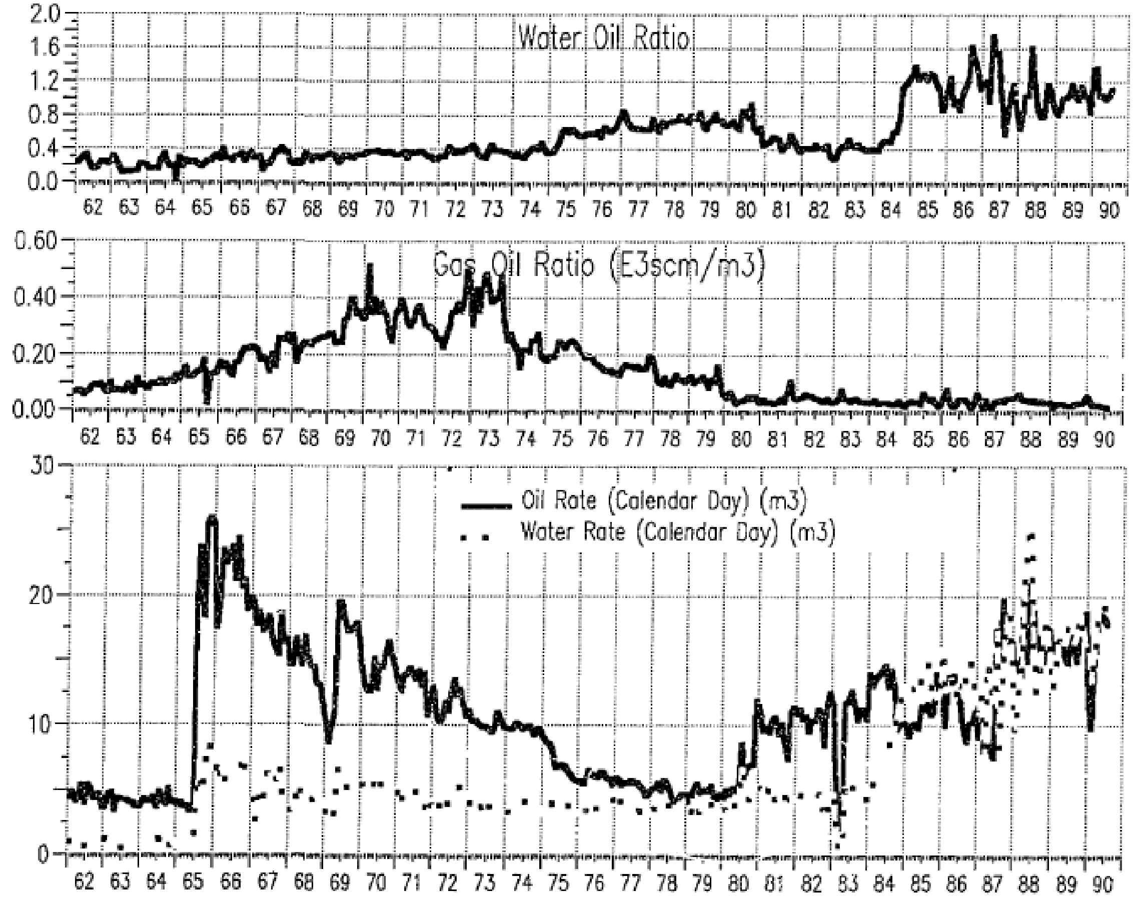



**Cessford Basal Colorado A Pool – Centre Pattern Performance (1962 – 1990)**

Figure 218

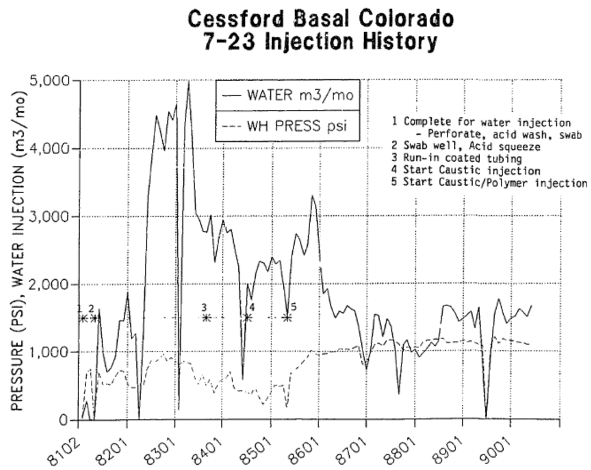


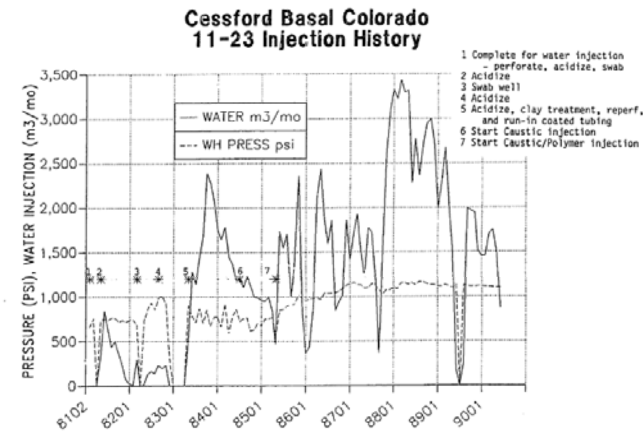
Sproule

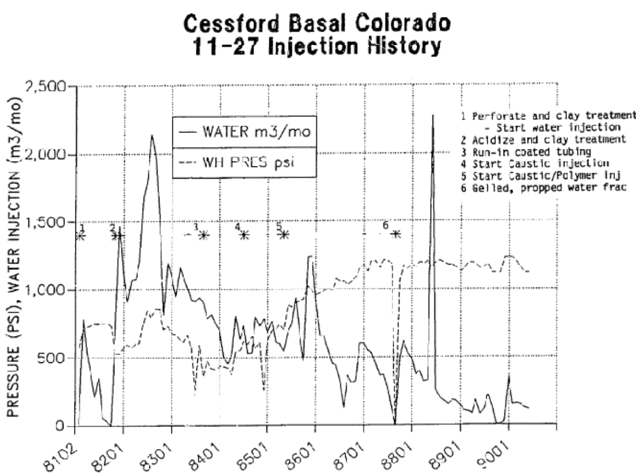


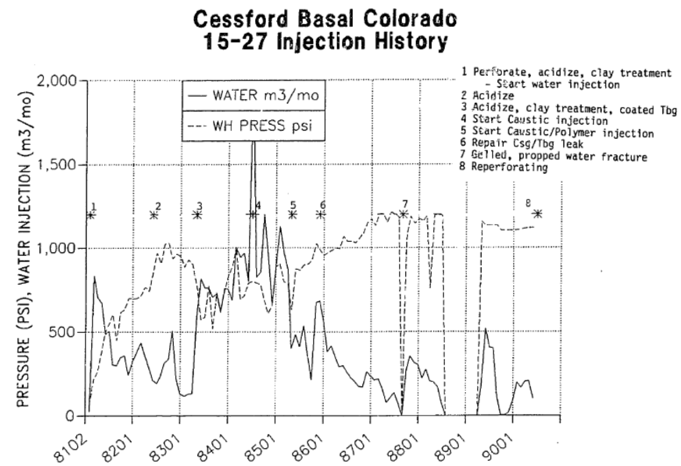

**Cessford Basal Colorado A Pool – South Pattern Performance (1962 – 1990)**

Figure 219



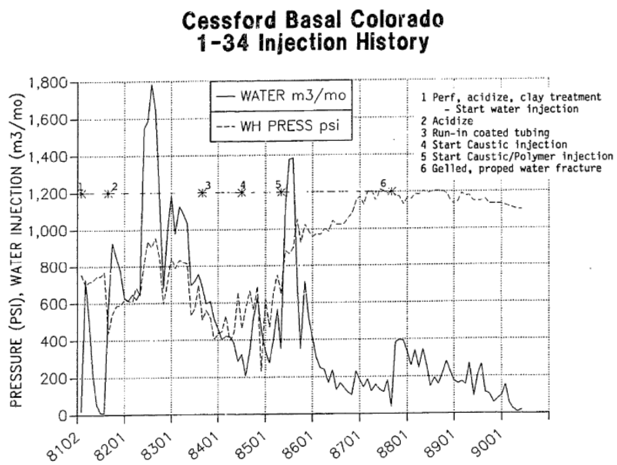



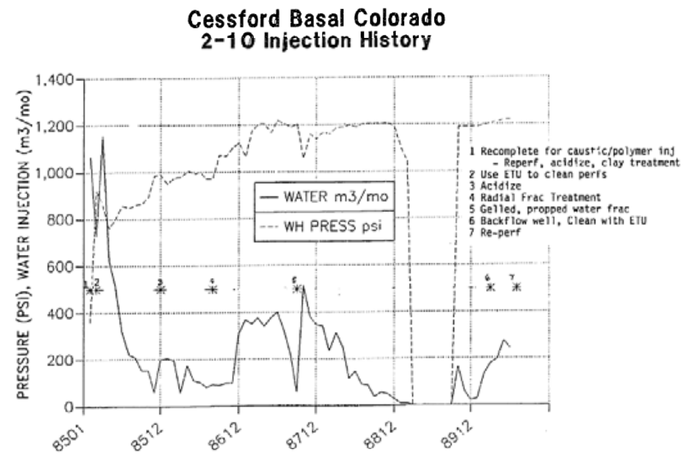

**Cessford Basal Colorado A Pool – Injection History (7 injectors)**
**(1962 – 1990)**

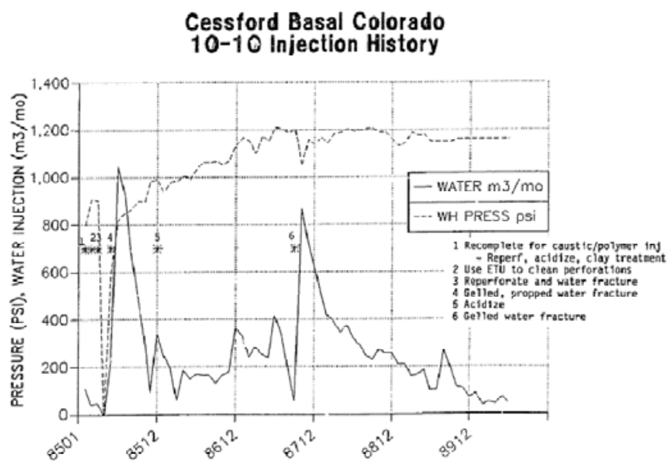
Figure 220



Sproule



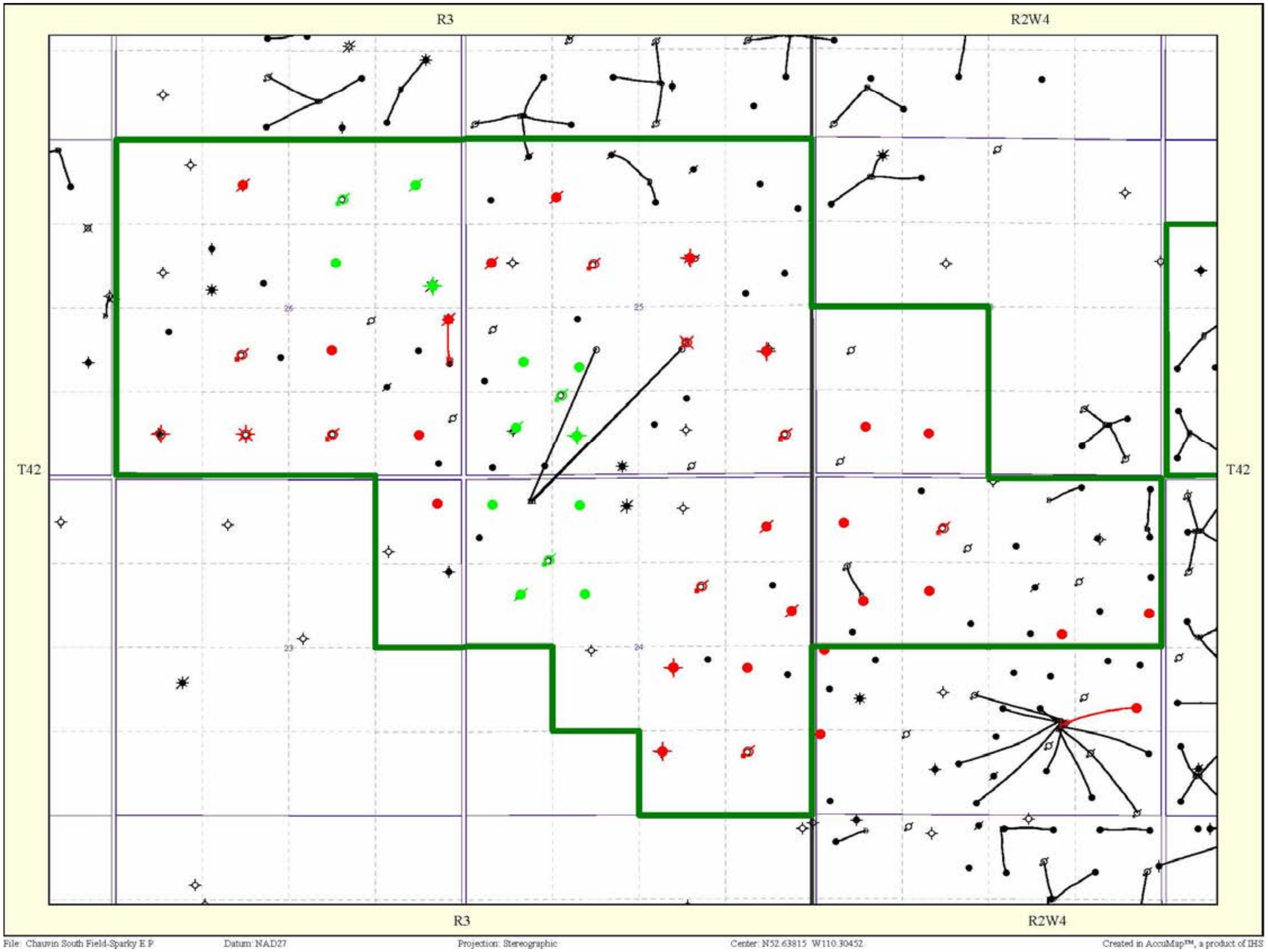




**Cessford Basal Colorado A Pool – Injection History (7 injectors)**
**(1962 – 1990)**

Figure 221

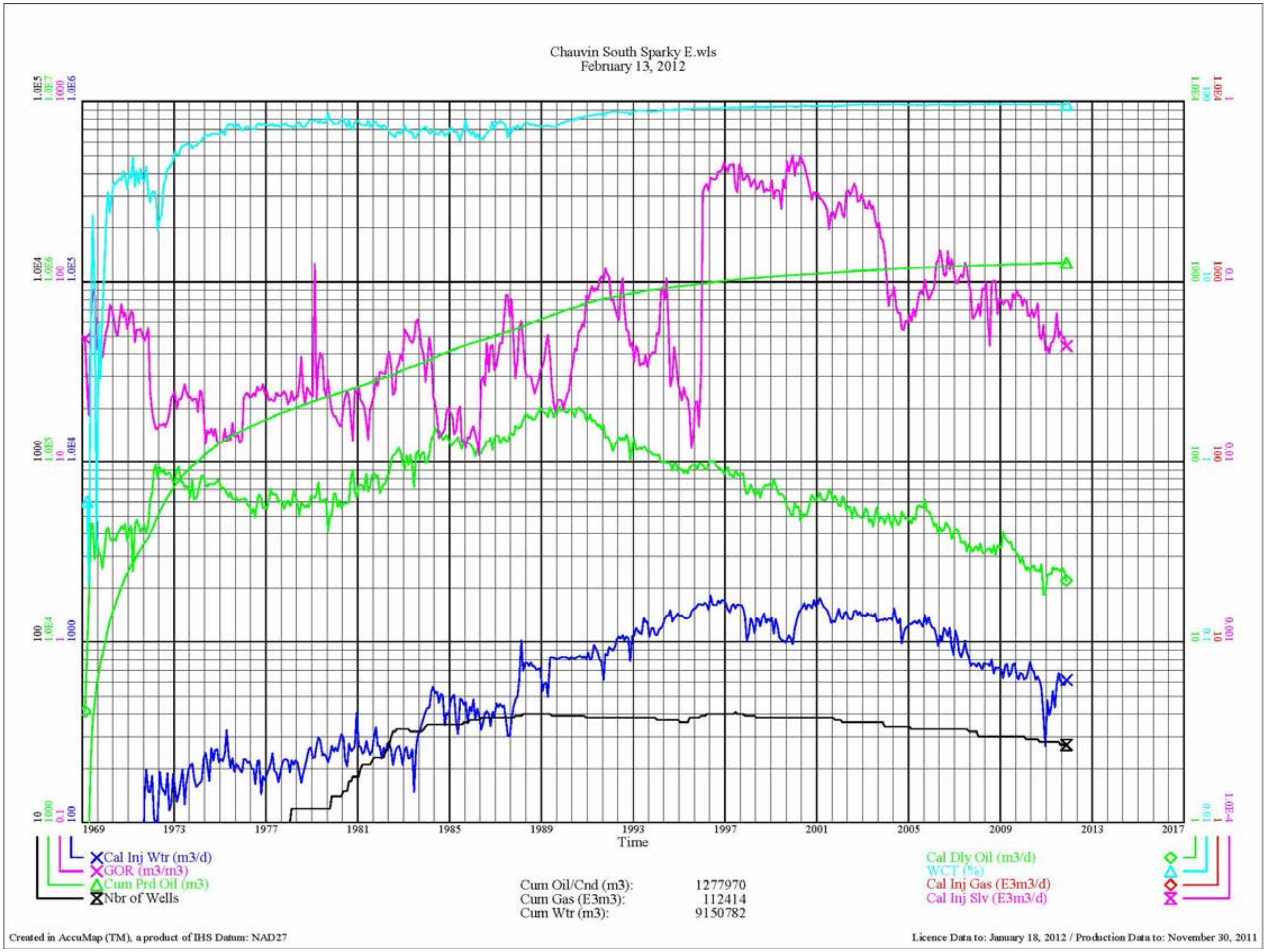


Sproule




**Chauvin South Sparky E – Well Locations**

Figure 222

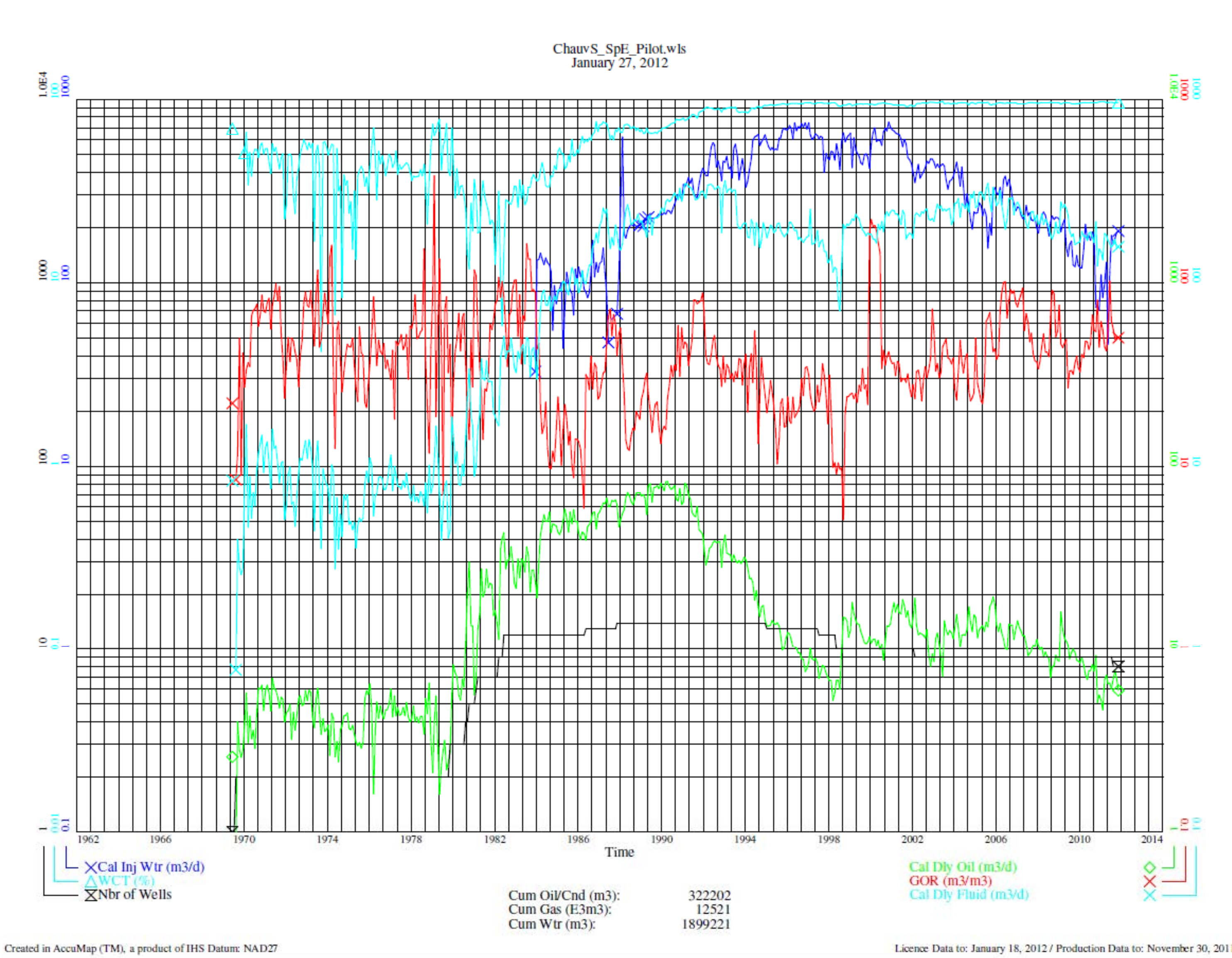



**Chauvin South Sparky E – Production / Injection History**

Figure 223

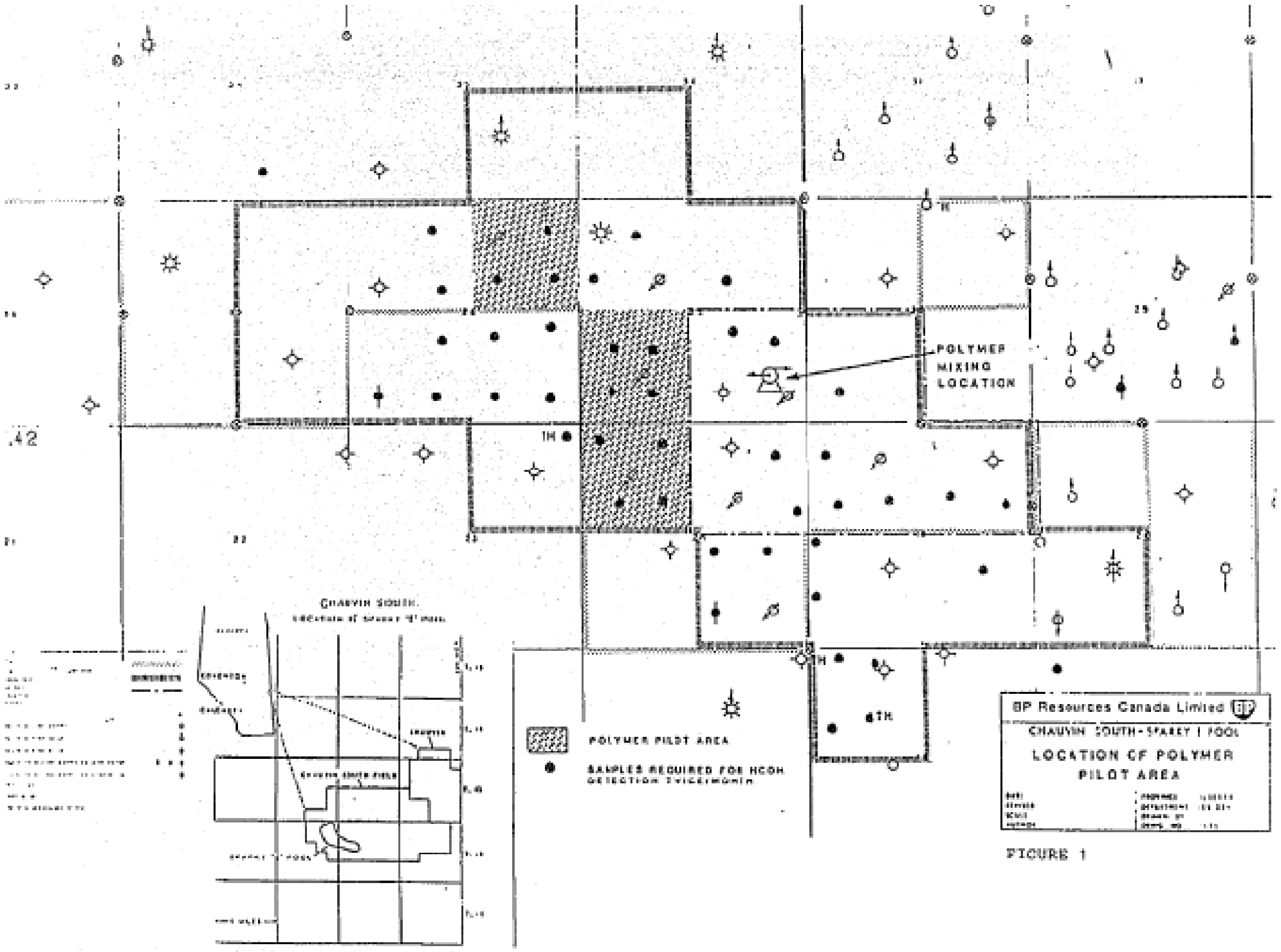


Sproule



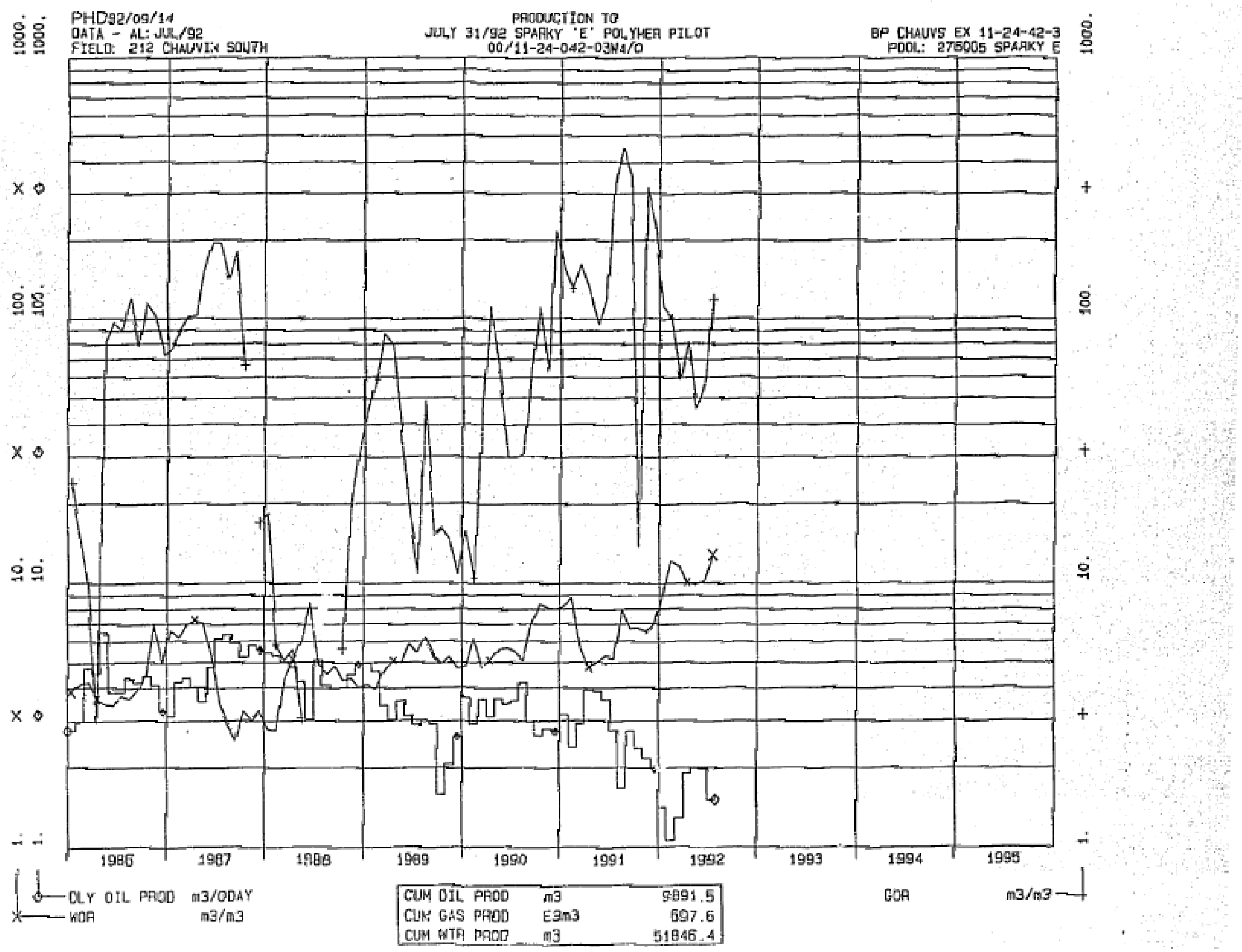

**Chauvin South Sparky E – Production / Injection Pool Polymer Pilot History**

Figure 224




**Chauvin South Sparky E Pool – Pilot Area**

Figure 225

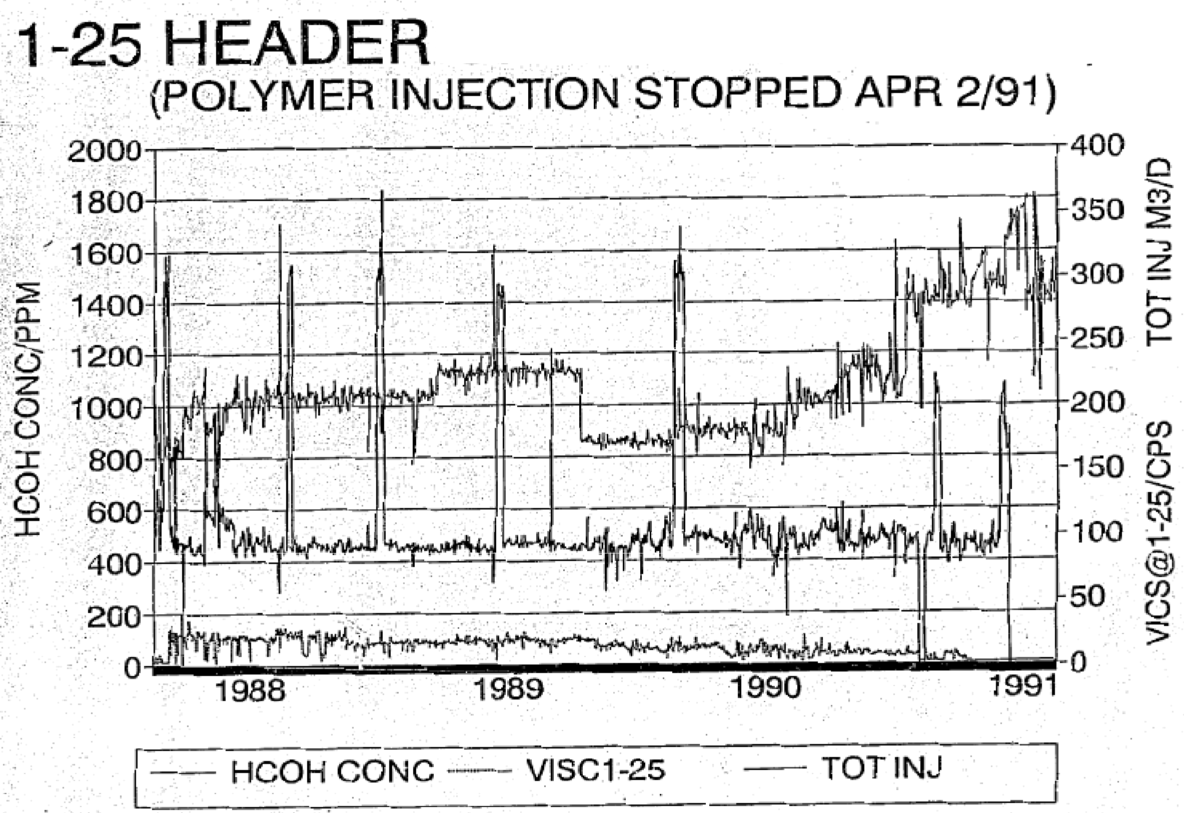



**Chauvin South Sparky E Pool – All Wells Production Performance (1986 – 1992)**

Figure 226

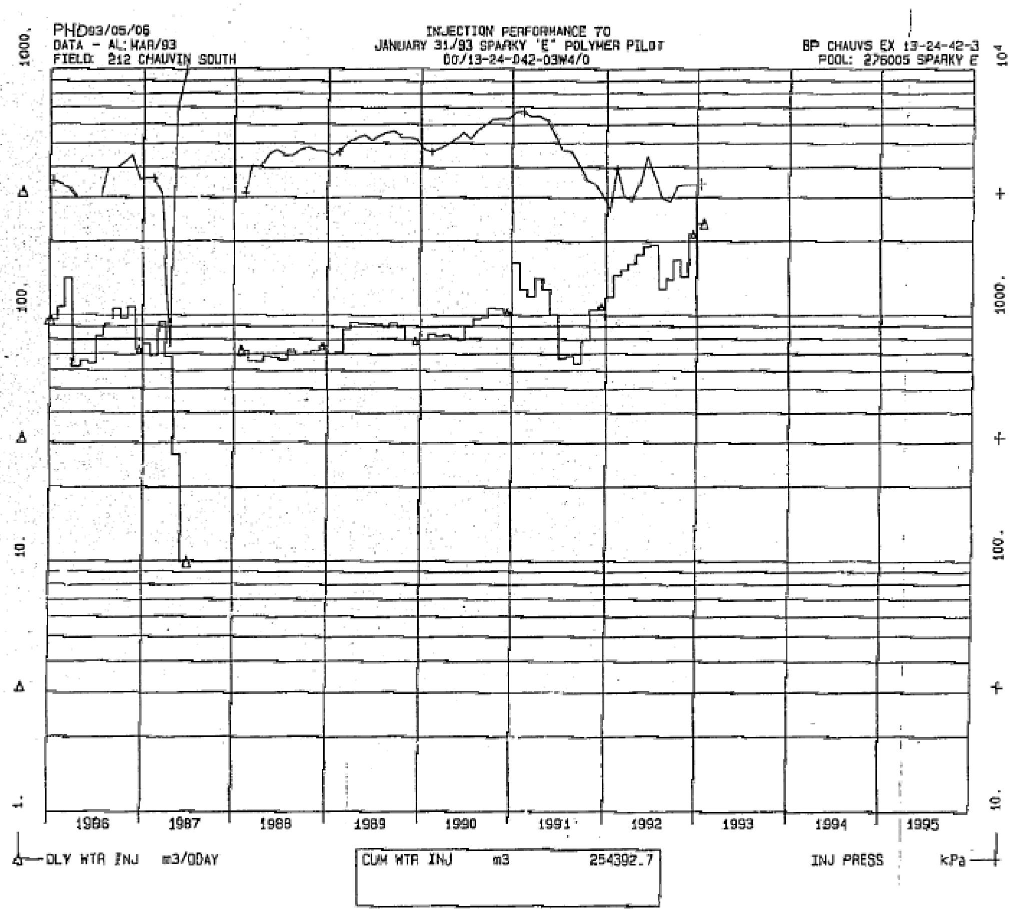


Sproule




**Chauvin South Sparky E Pool - Total Injection, Viscosity & HCOH Concentration (1988 - 1991)**

Figure 227

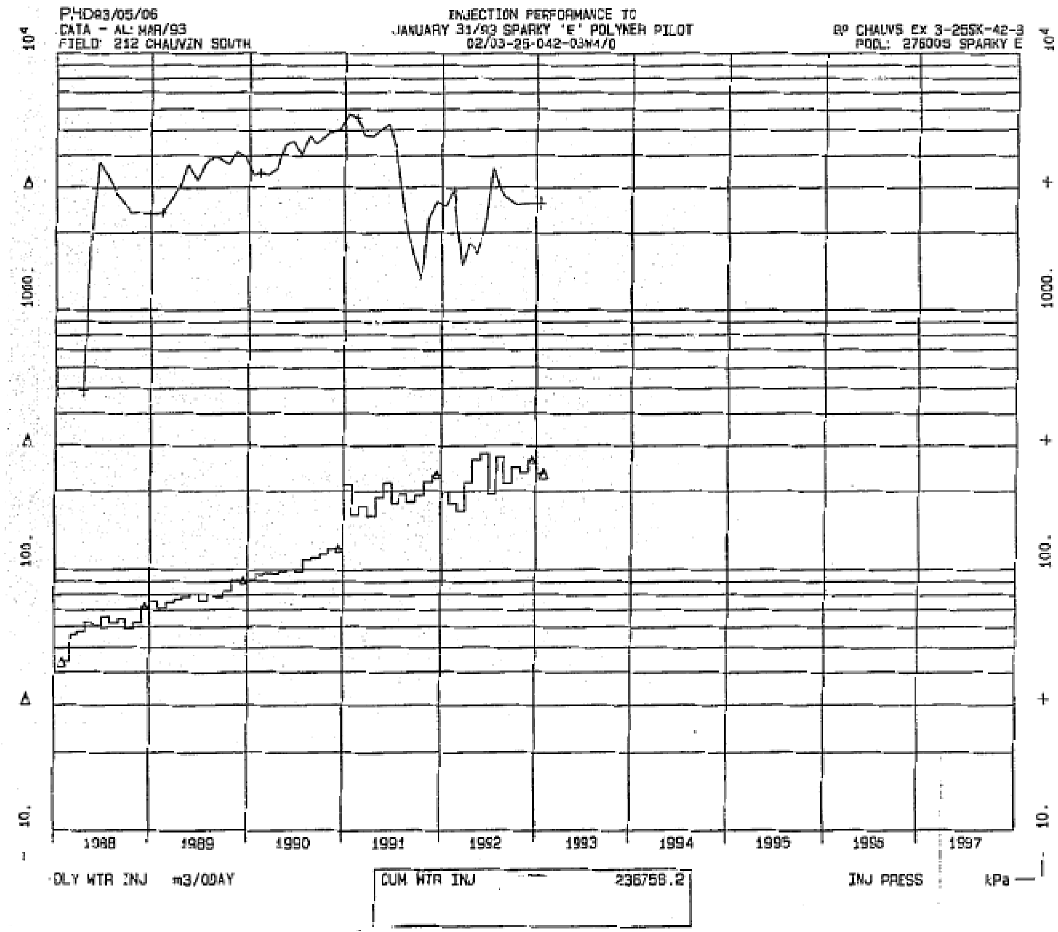



**Chauvin South Sparky E Pool - Injection Performance to Jan 31, 1993**
**00/13-24-042-03W4/0**

Figure 228

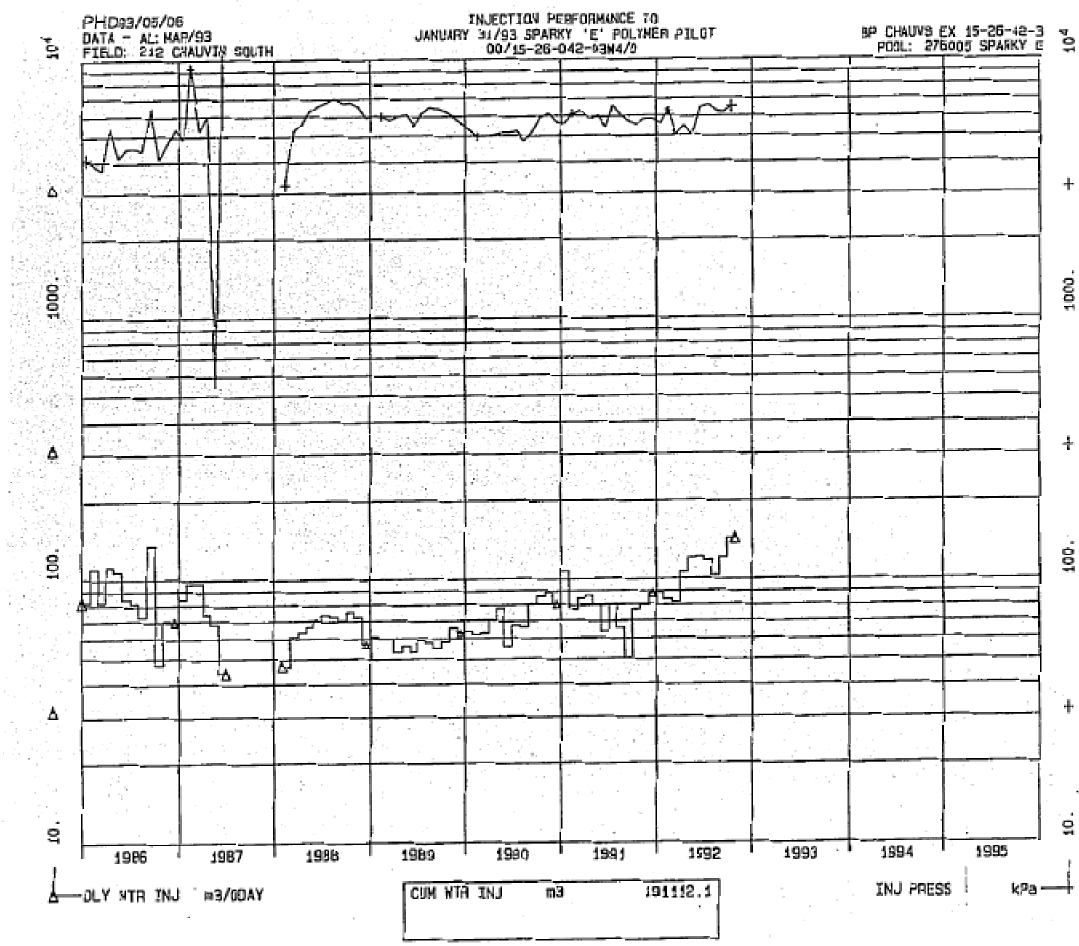


Sproule




**Chauvin South Sparky E Pool - Injection Performance to Jan 31, 1993**
**02/03-25-042-03W4/0**

Figure 229

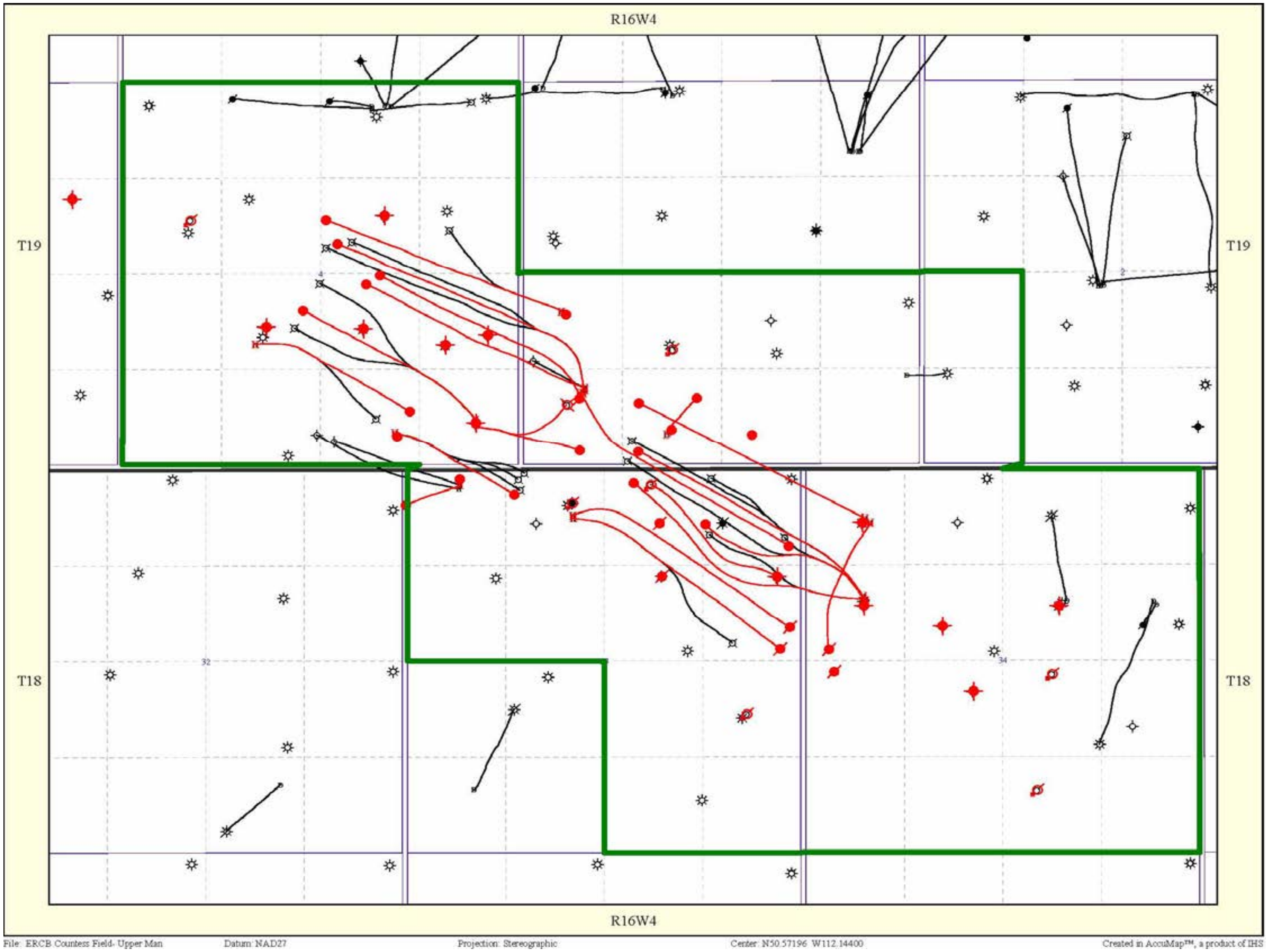



**Chauvin South Sparky E Pool - Injection Performance to Jan 31, 1993**
**00/15-26-042-03W4/0**

Figure 230

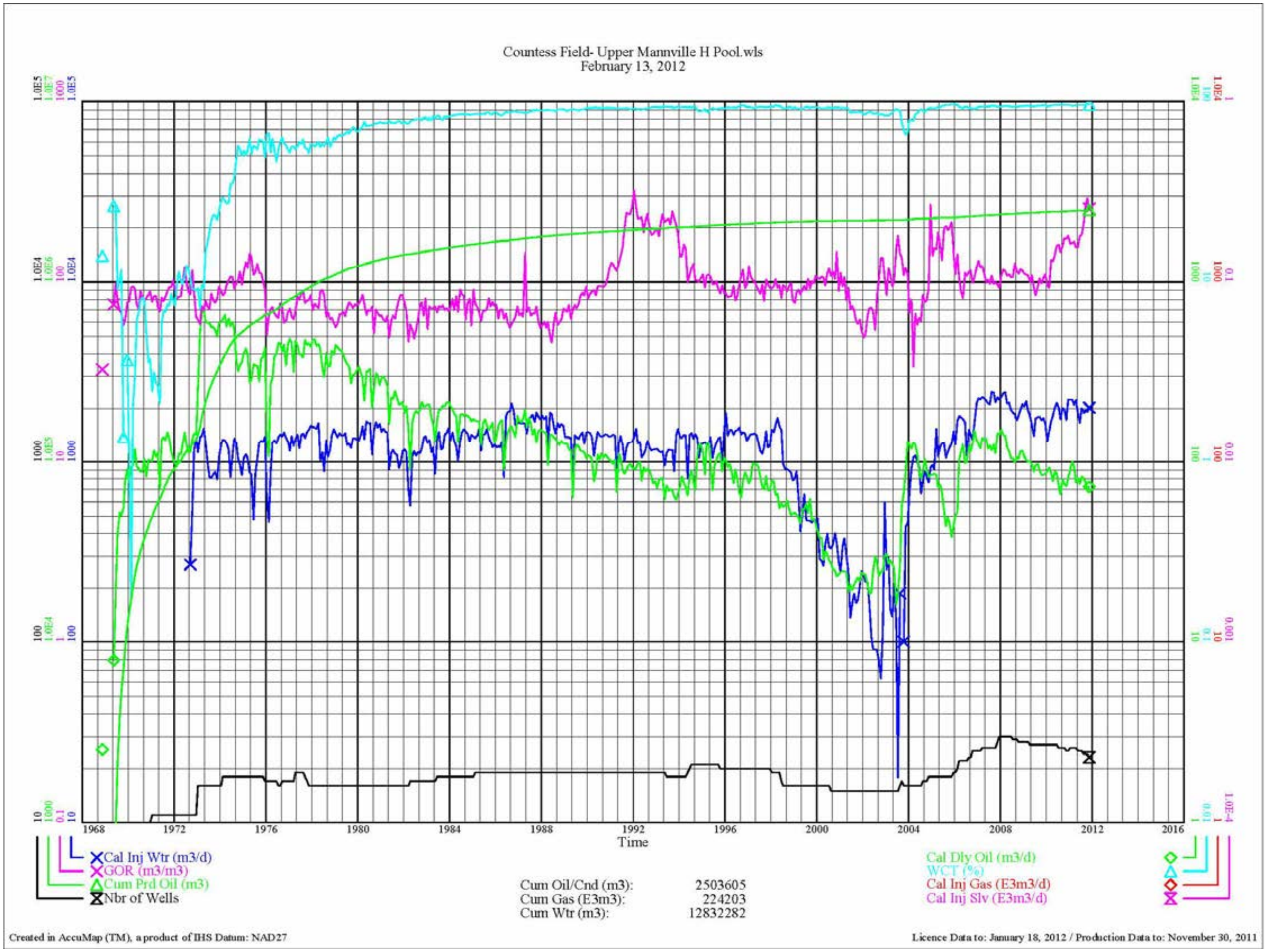


Sproule



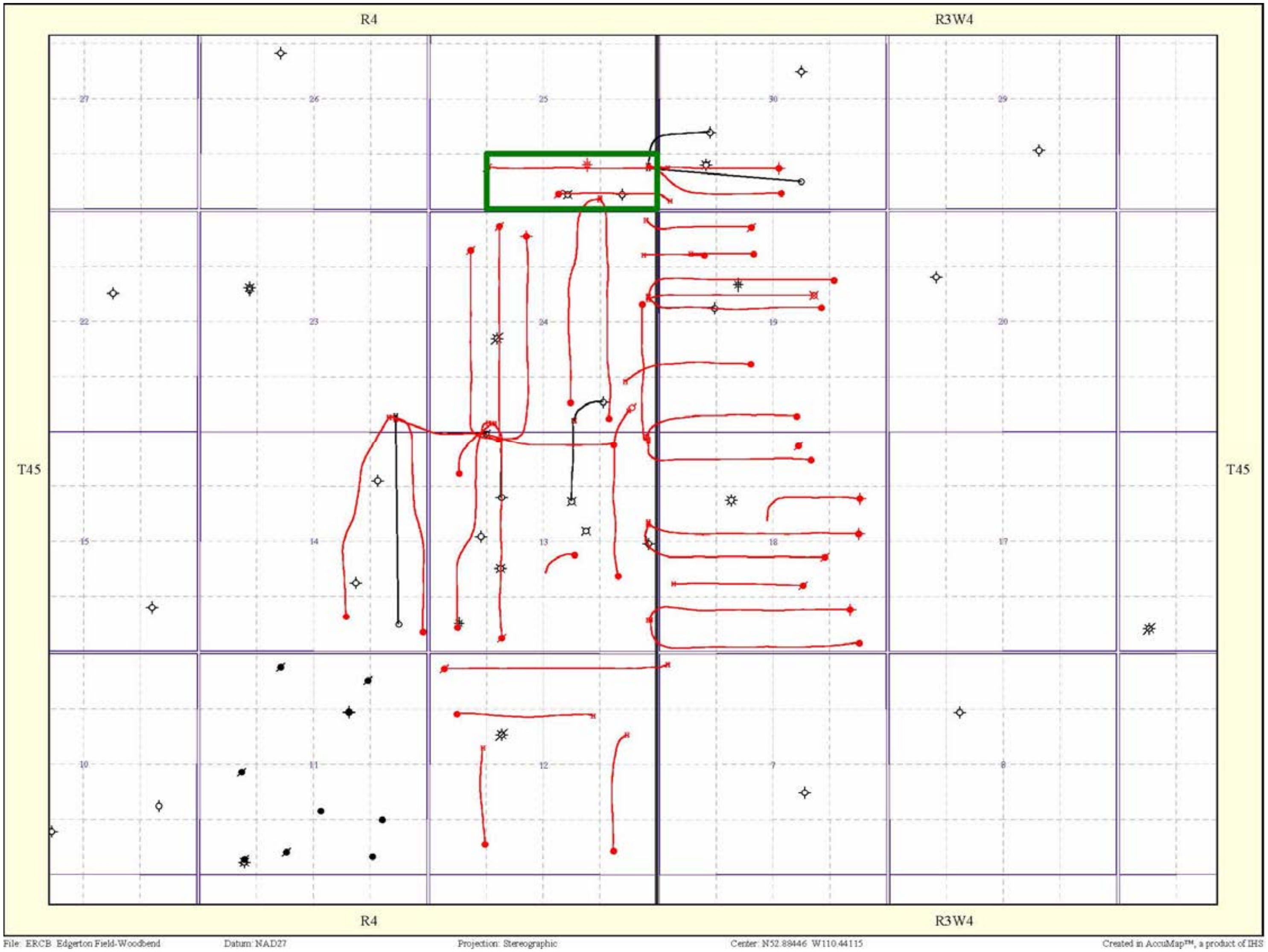

**Countess Upper Mannville H – Well Locations**

Figure 231




Countess Upper Mannville H - Production / Injection History

Figure 232

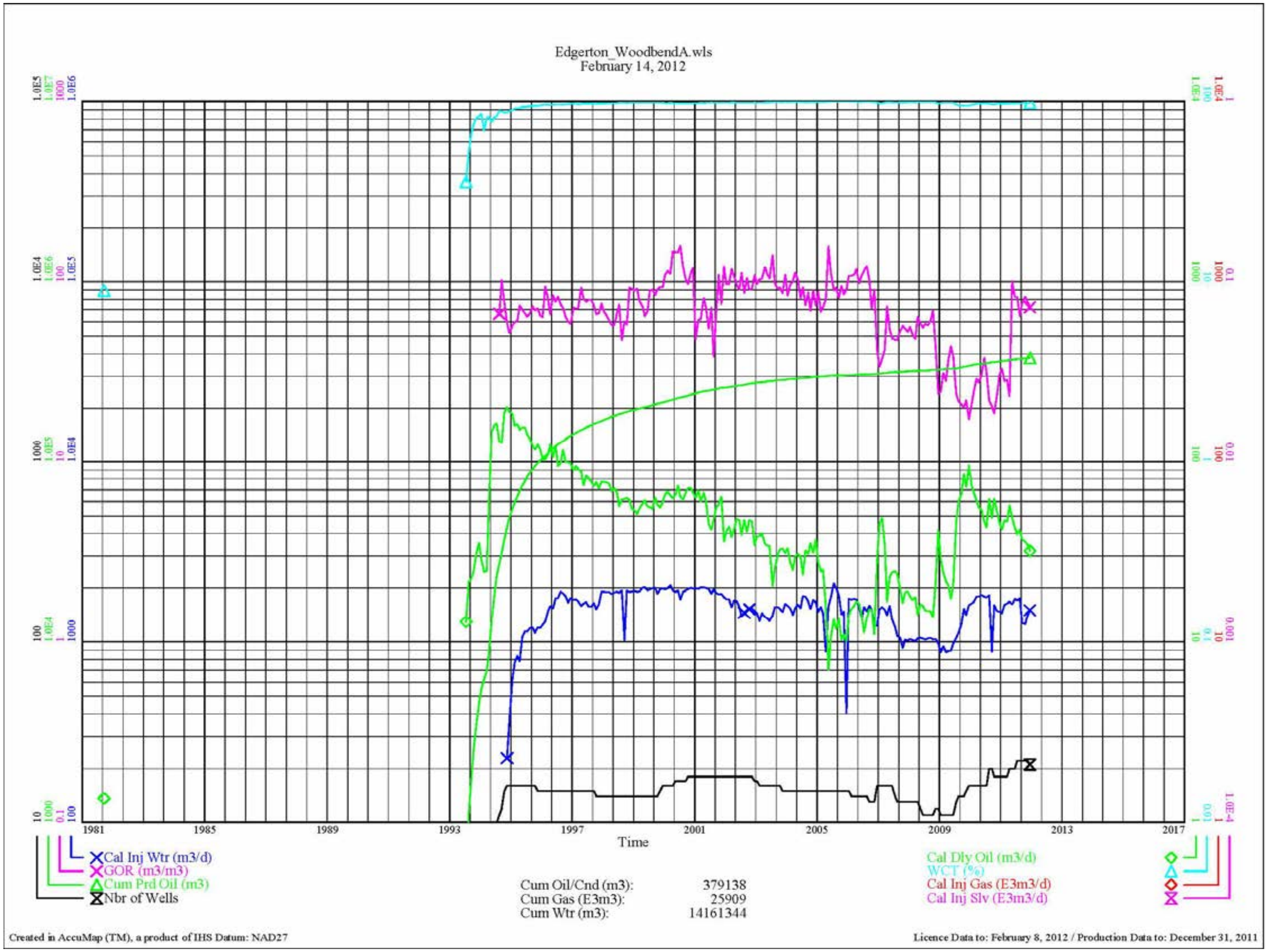



**Edgerton Woodbend A – Well Locations**

Figure 233



Sproule

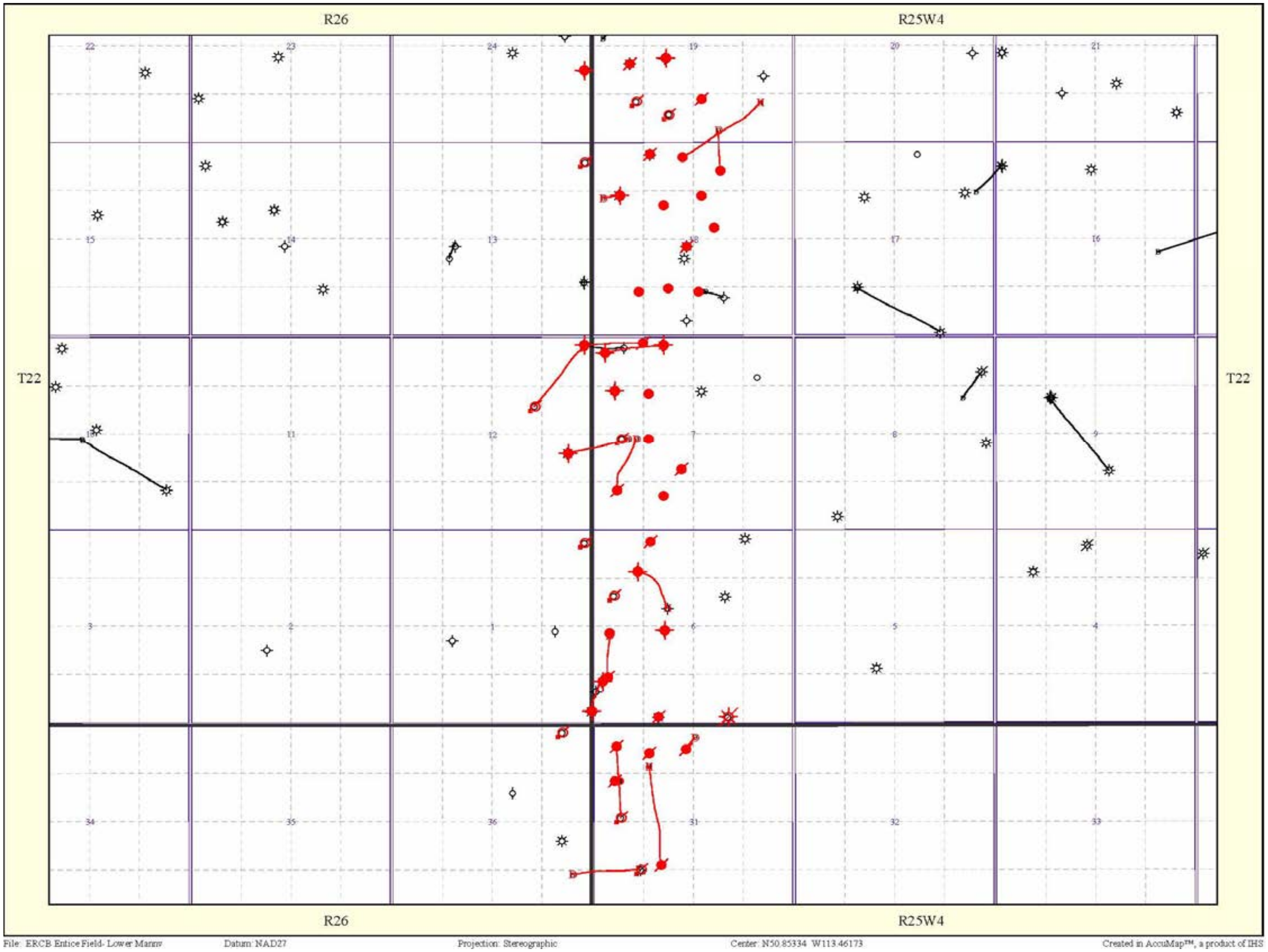



**Edgerton Woodbend A - Production / Injection History**

Figure 234

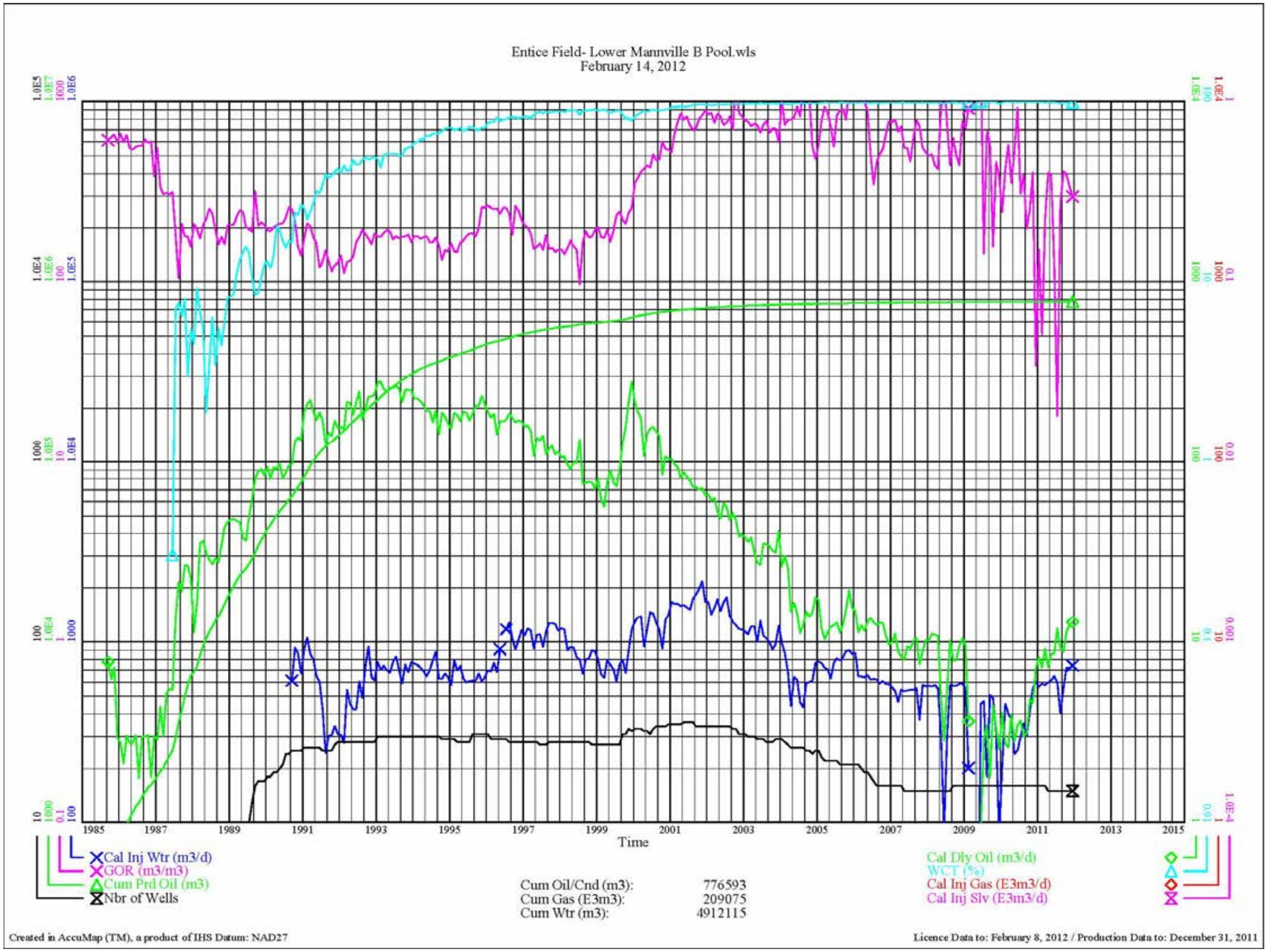


Sproule



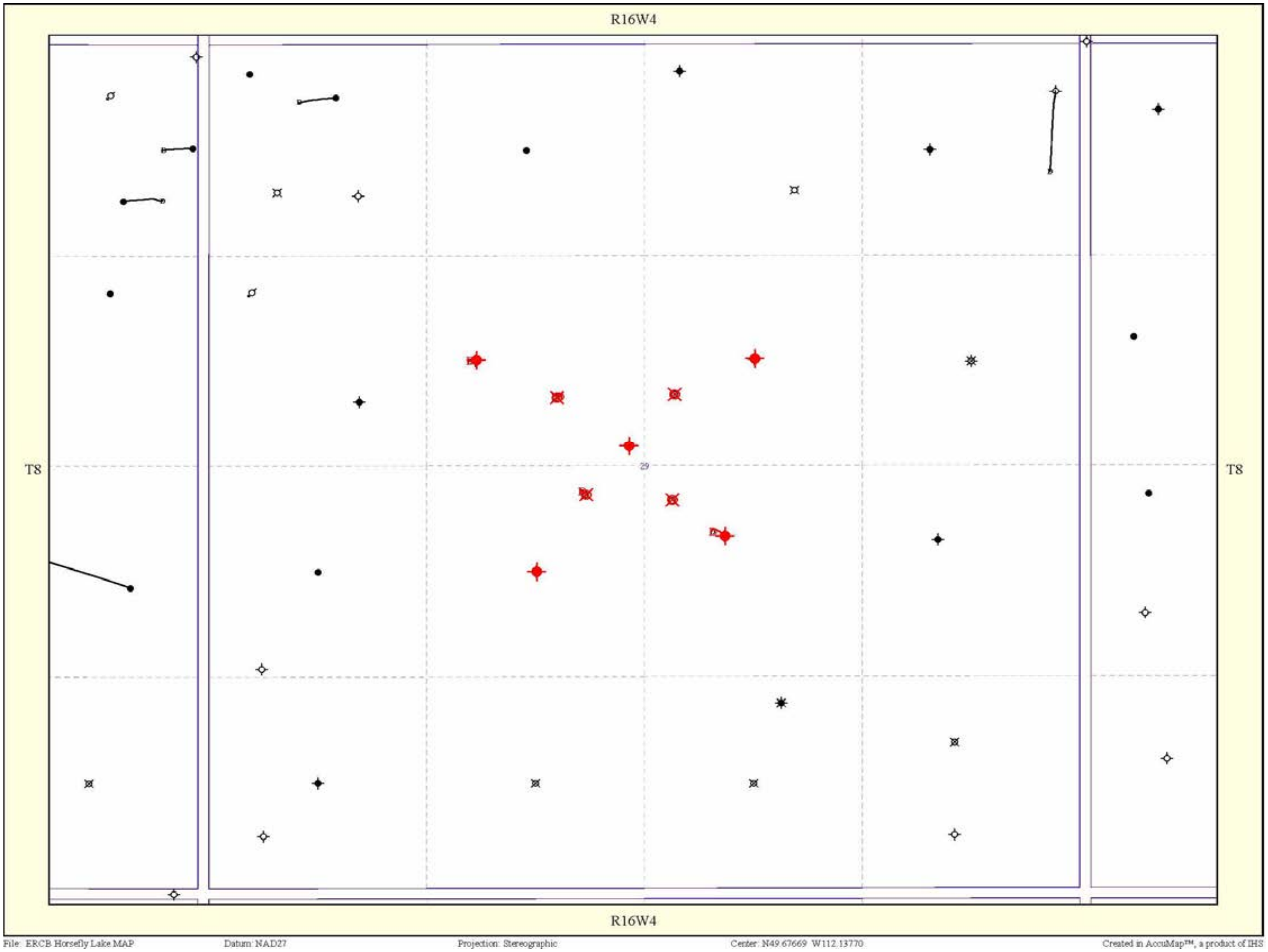

**Entice Lower Mannville B – Well Locations**

Figure 235




**Entice Lower Mannville B - Production / Injection History**

Figure 236




**Horsefly Lake Mannville – Well Locations**

Figure 237

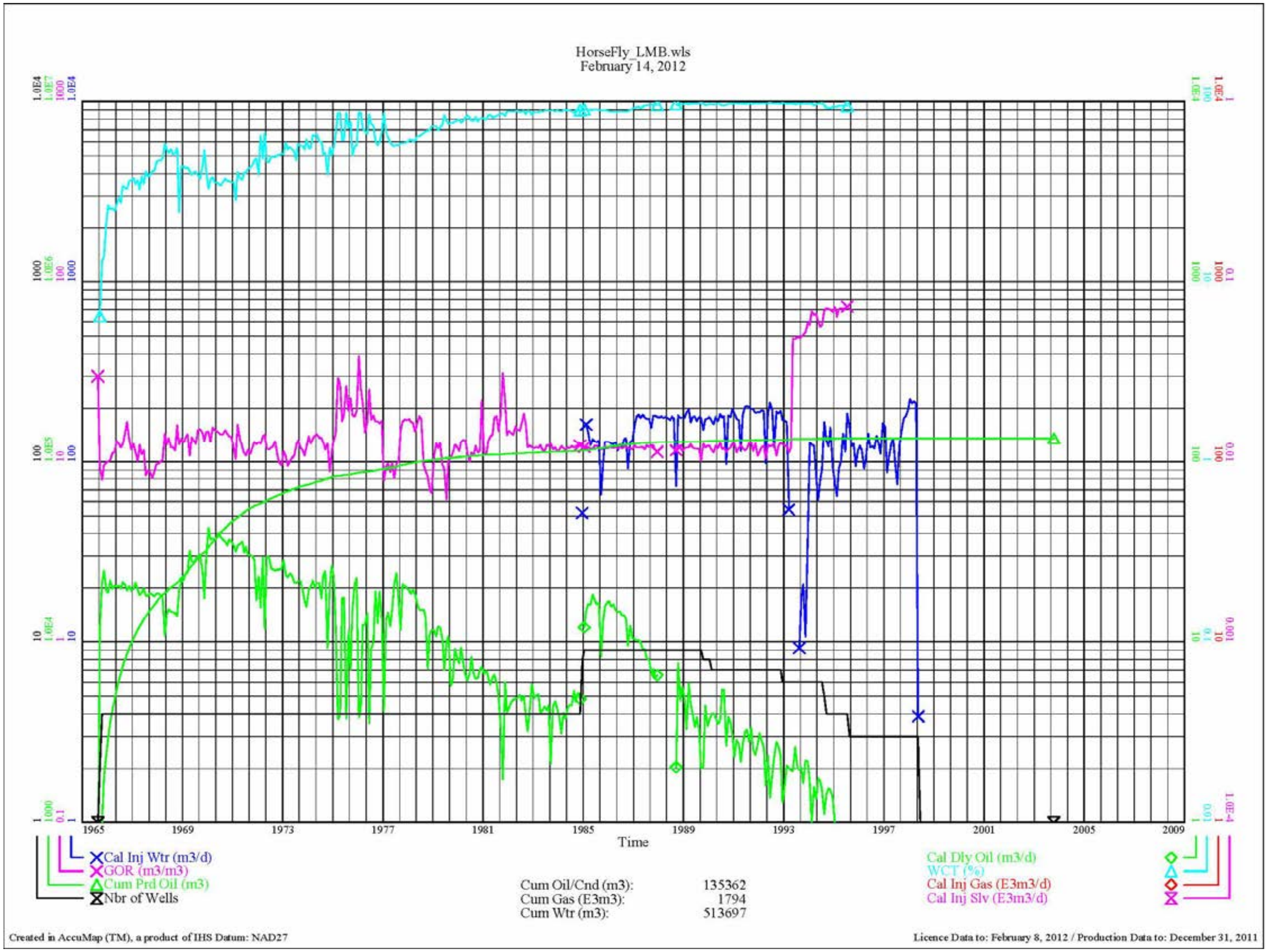
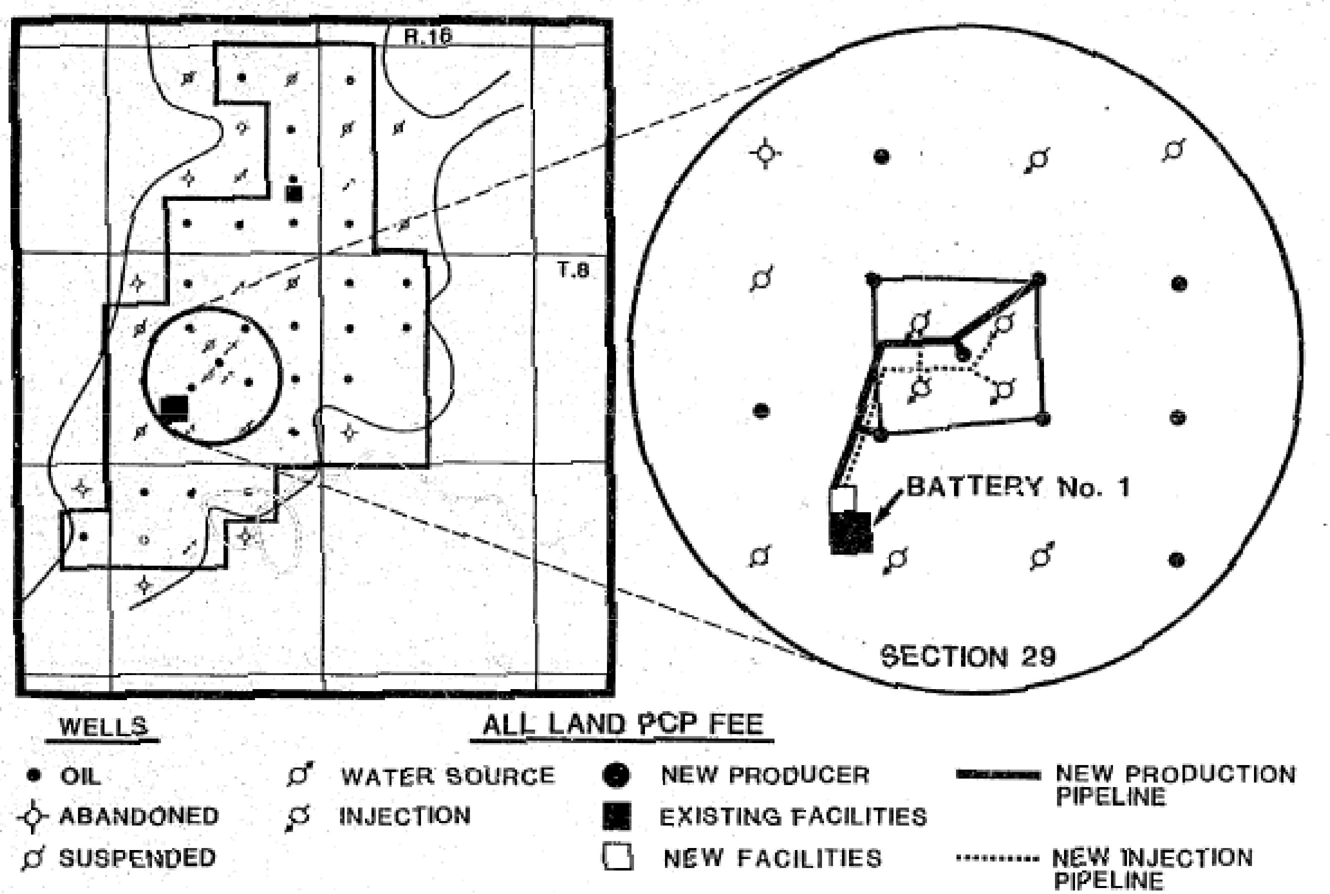


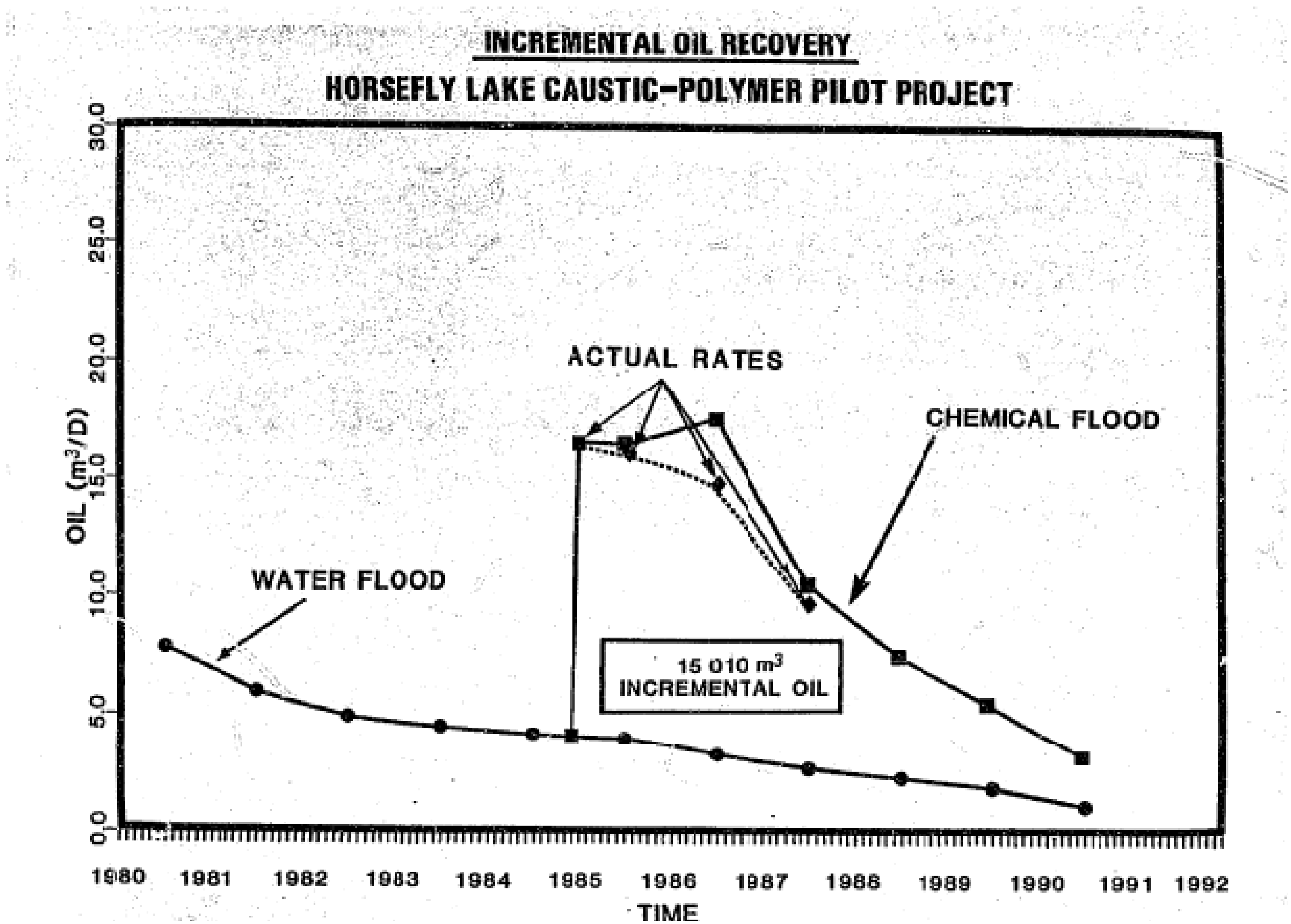

Figure 238

**Horsefly Lake Mannville - Production / Injection History**



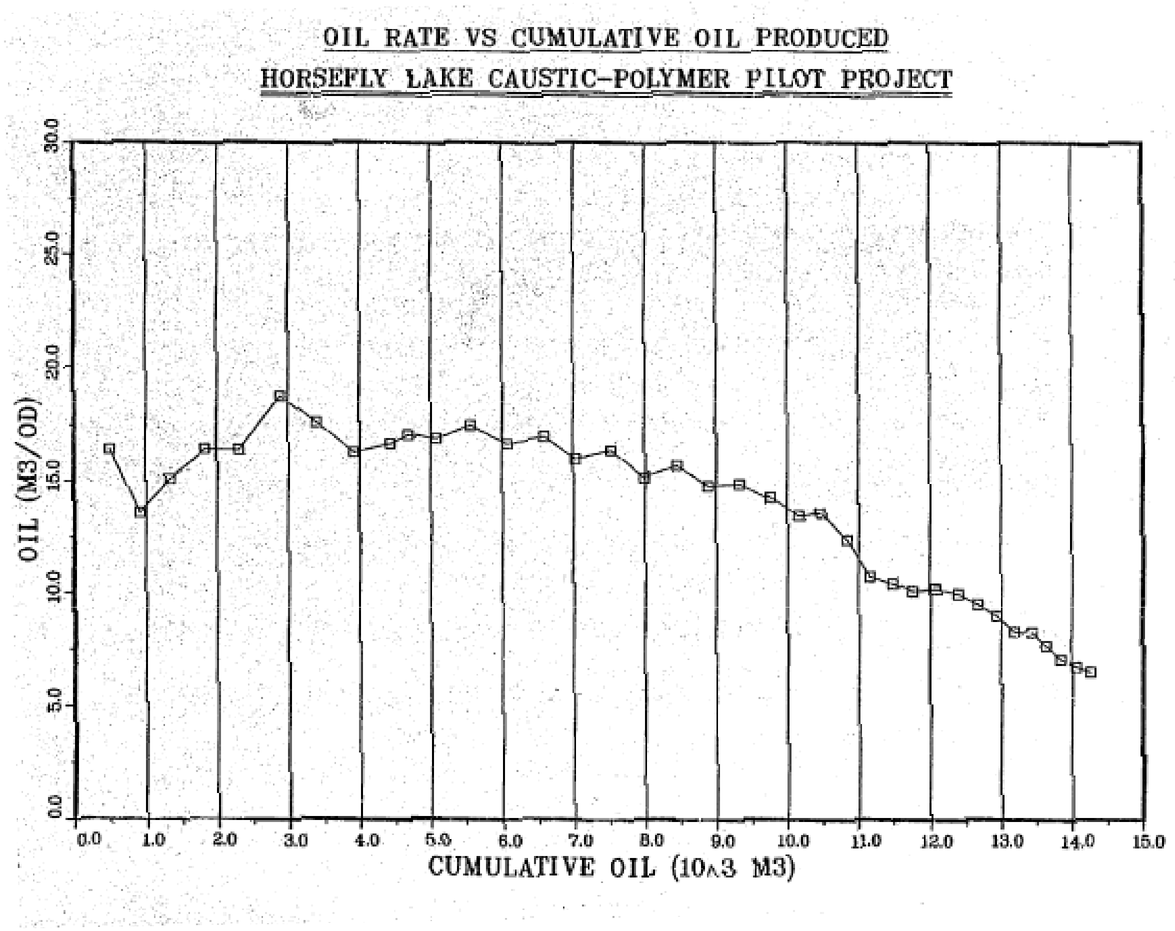

**Horsefly Lake - Mannville Pool – Pilot Area**

Figure 239




**Horsefly Lake - Mannville Pool – Incremental Oil Recovery**

Figure 240

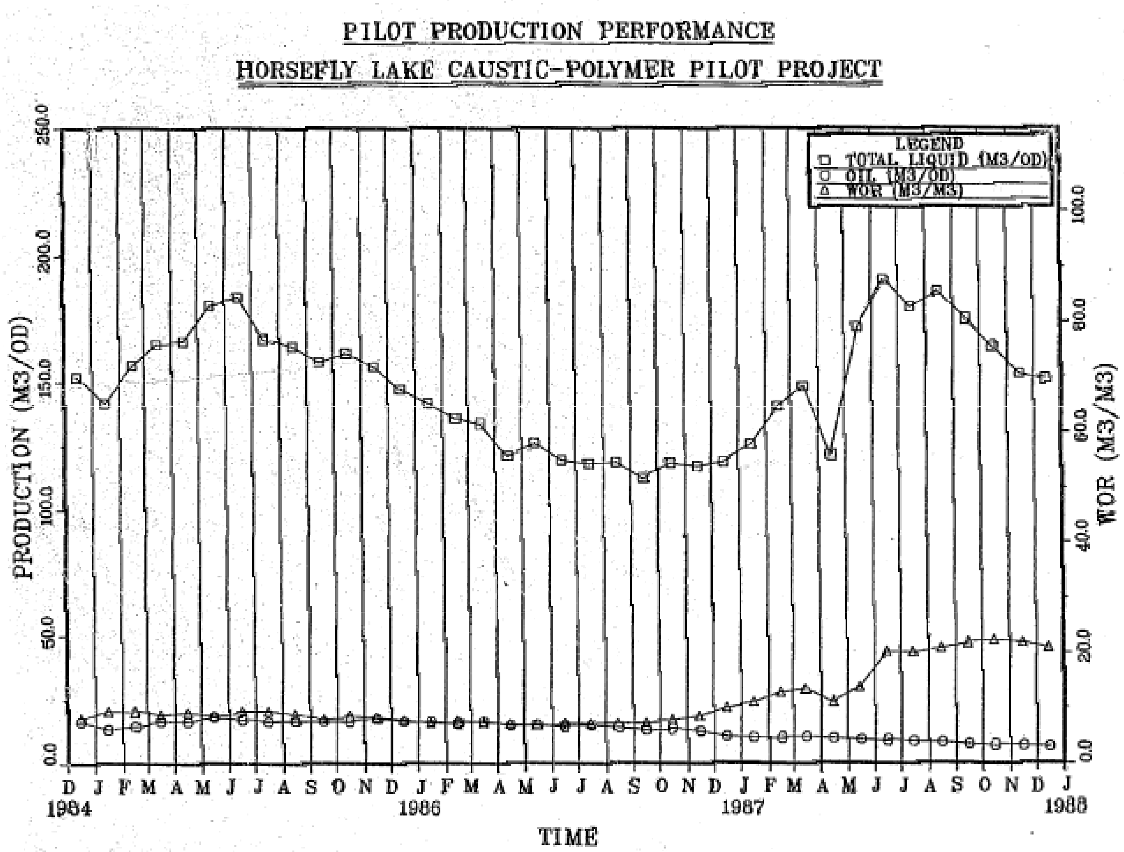



**Horsefly Lake - Mannville Pool – Production Performance**
**Oil Rate vs Cumulative Oil**

Figure 241



Sproule

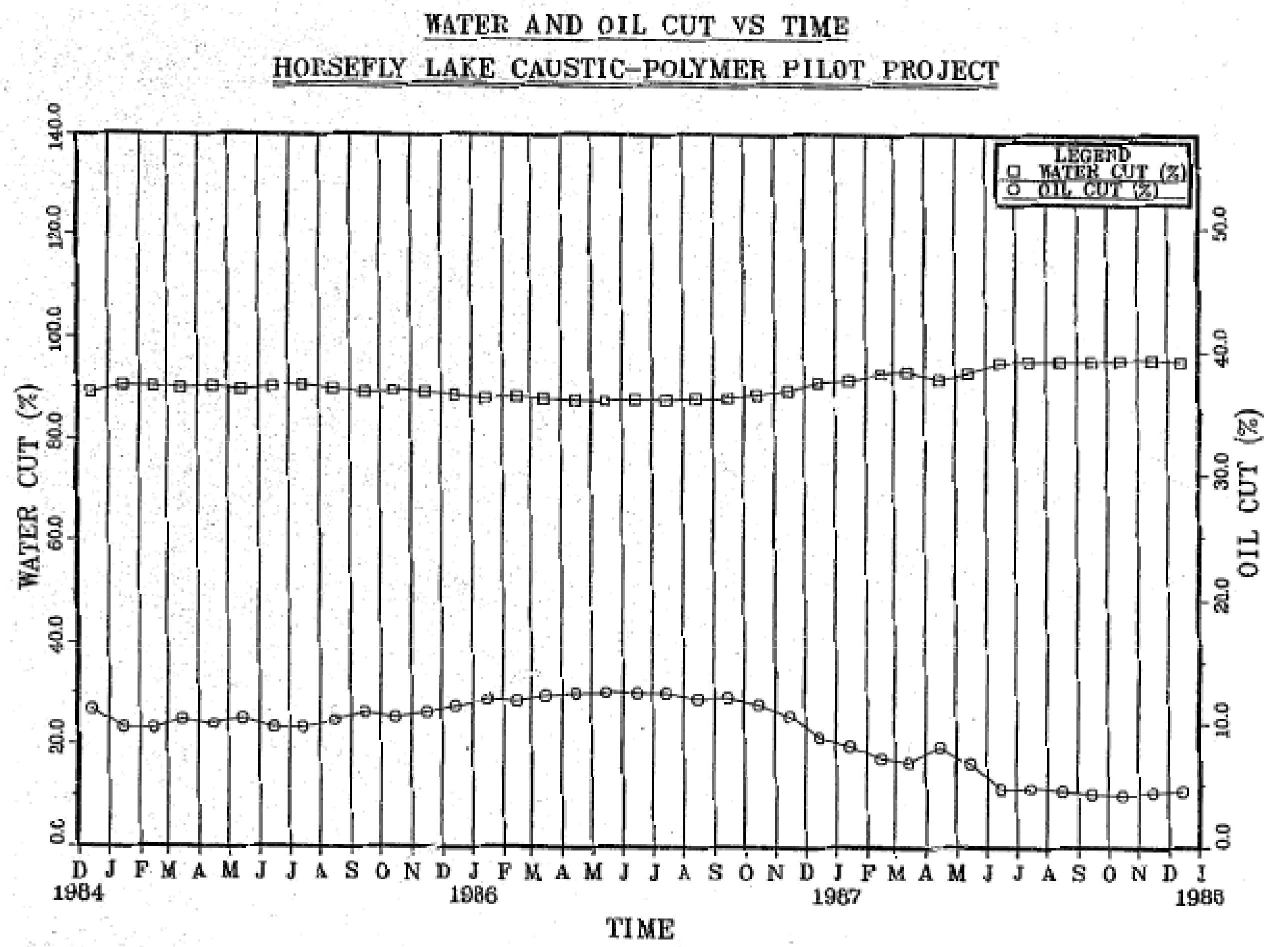



**Horsefly Lake - Mannville Pool – Production Performance (1984 – 1988)**
**Oil Rate vs Time**

Figure 242

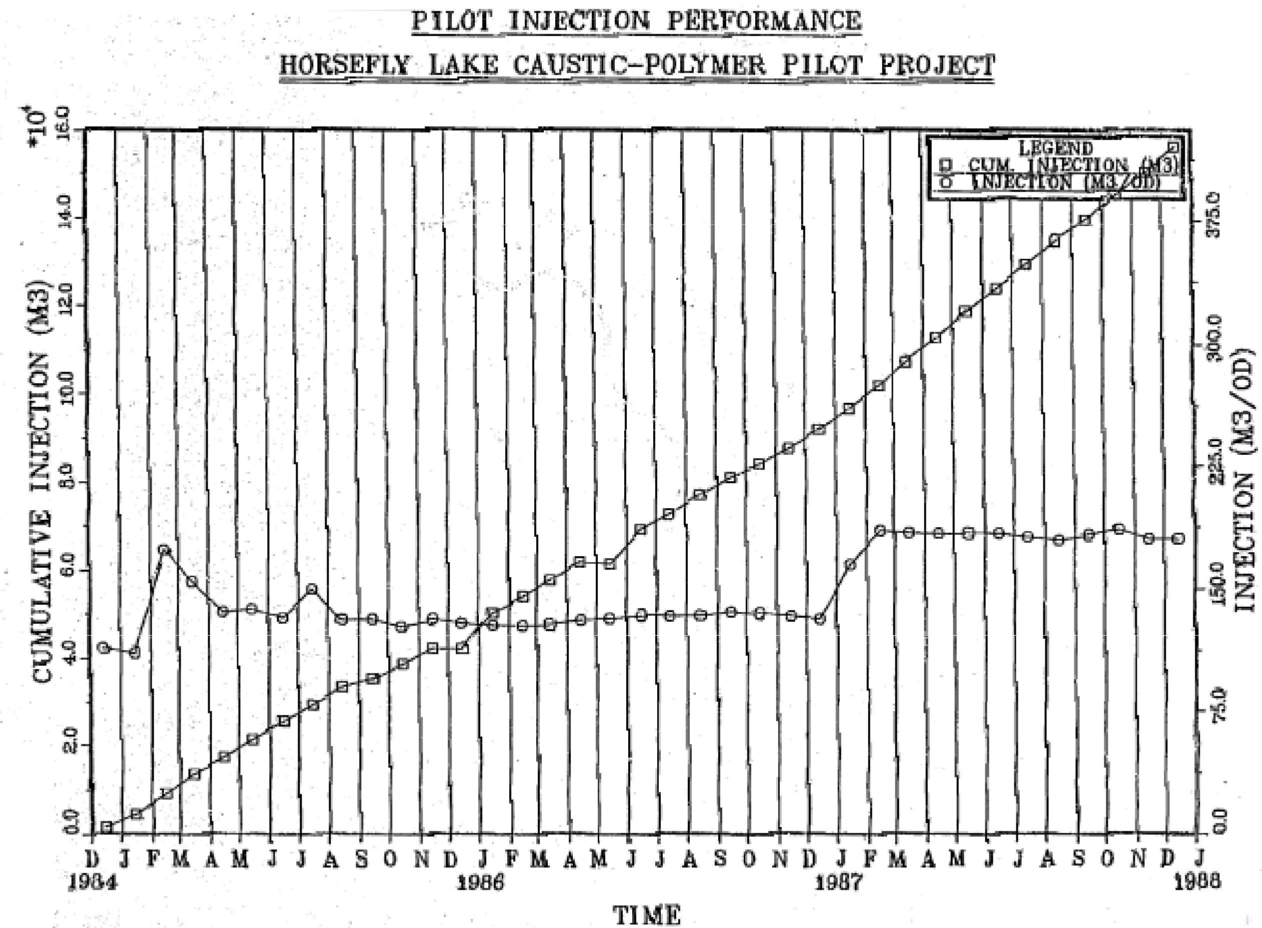


Sproule




**Horsefly Lake - Mannville Pool – Production Performance (1984 – 1988)**
**Water and Oil Cut vs Time**

Figure 243




**Horsefly Lake - Mannville Pool – Injection Performance**
**(1984 – 1988)**

Figure 244

SUMMARY OF TOTAL PILOT INCREMENTAL OIL

HORSEFLY LAKE CAUSTIC-POLYMER PILOT

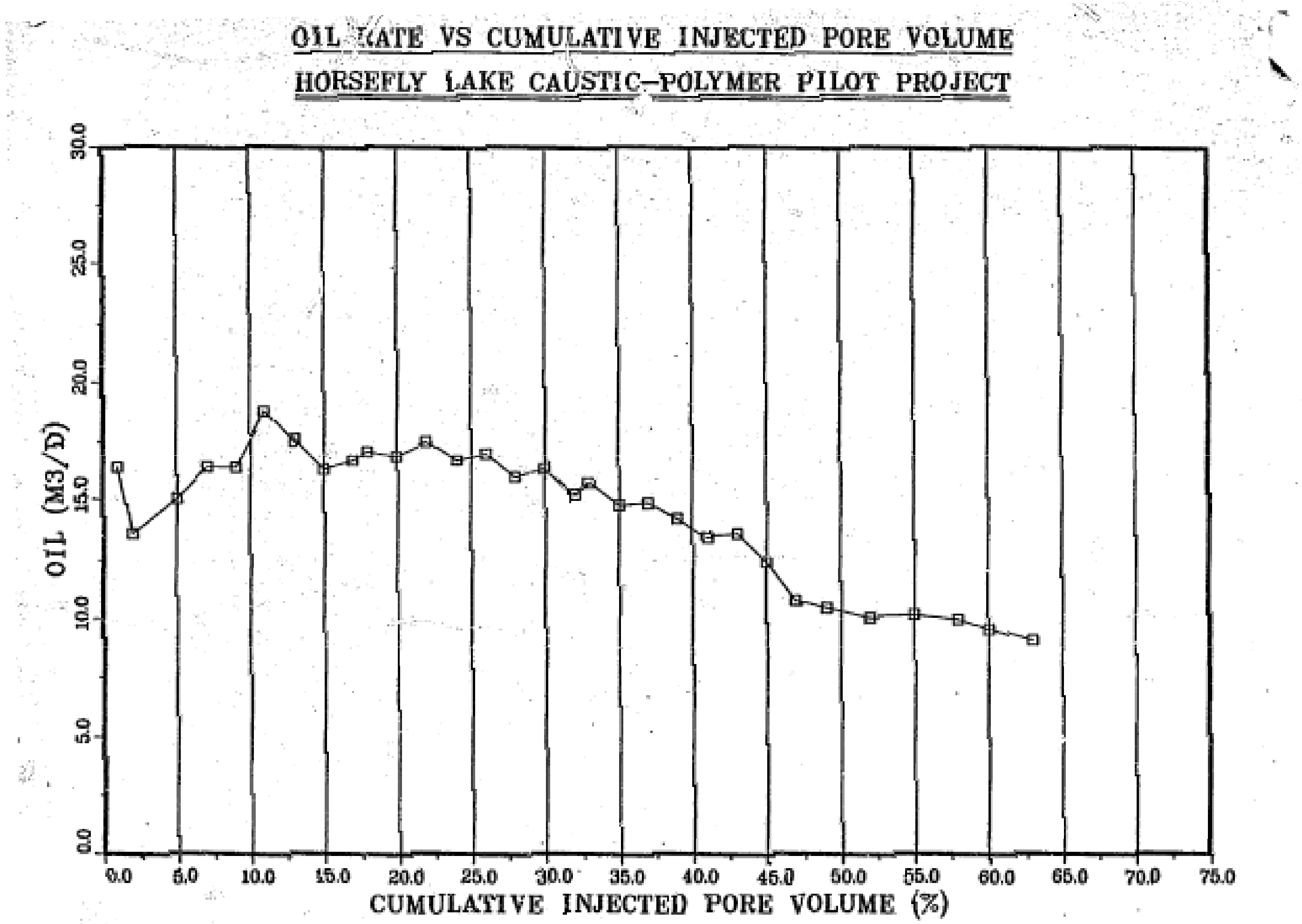
| Year | Waterflood Forecast | | Pilot Production | | Incremental Oil | | |
|---|---|---|---|---|---|---|---|
| | $m^3$ | $m^3/cd$ | $m^3$ | $m^3/cd$ | $m^3/cd$ | $m^3$ | Cum., $m^3$ |
| 1984-12 | 188 | 6.1 | 501.8 | 16.2 | 10.1 | 313.8 | 313.8 |
| 1985 | 1 632 | 4.5 | 5 572.6 | 15.3 | 10.8 | 3 940.6 | 4 254.4 |
| 1986 | 1 442 | 3.9 | 5 065.0 | 13.9 | 10.0 | 3 623.0 | 7 877.4 |
| 1987* | 927 | 2.5 | 3 091.4 | 8.5 | 6.0 | 2 164.4 | 10 041.8 |
| 1988** | 689 | 1.9 | 1 156.0 | 3.2 | 1.3 | 467.0 | 10 508.8 |
| 1989 | 372 | 1.0 | 512.0 | 1.4 | 0.4 | 140.0 | 10 648.8 |
| 1990 | 230 | 0.6 | 256.0 | 0.8 | 0.2 | 26.0 | 10 674.8 |
| | 5 480 | | 16 154.8 | | | 10 674.8 | |

* To end of 1987 pilot incremental recovery represents 94% of the expected ultimate incremental oil.

** Forecast.

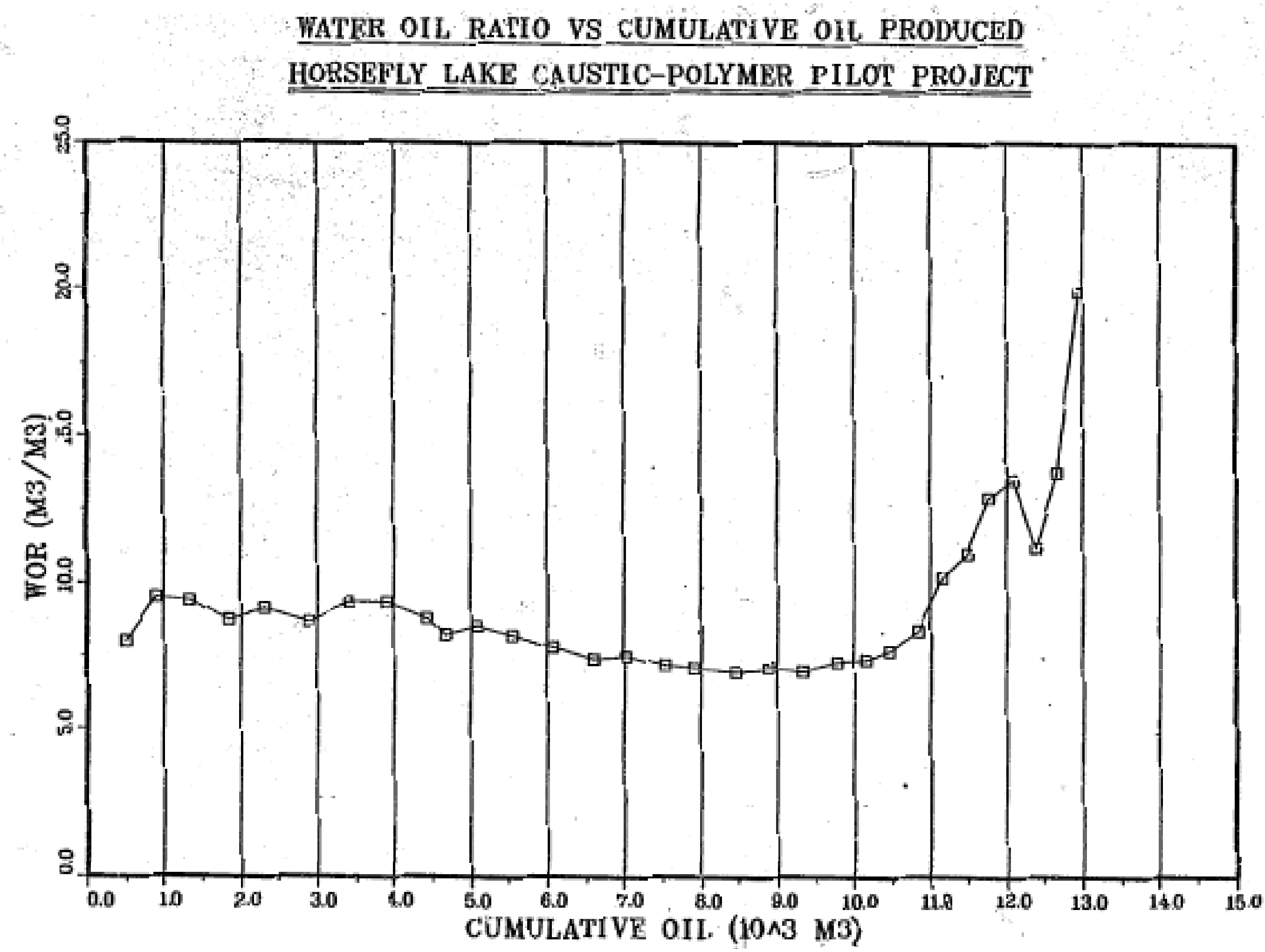
**Horsefly Lake - Mannville Pool – Incremental Oil (1984 – 1990)**

Figure 245



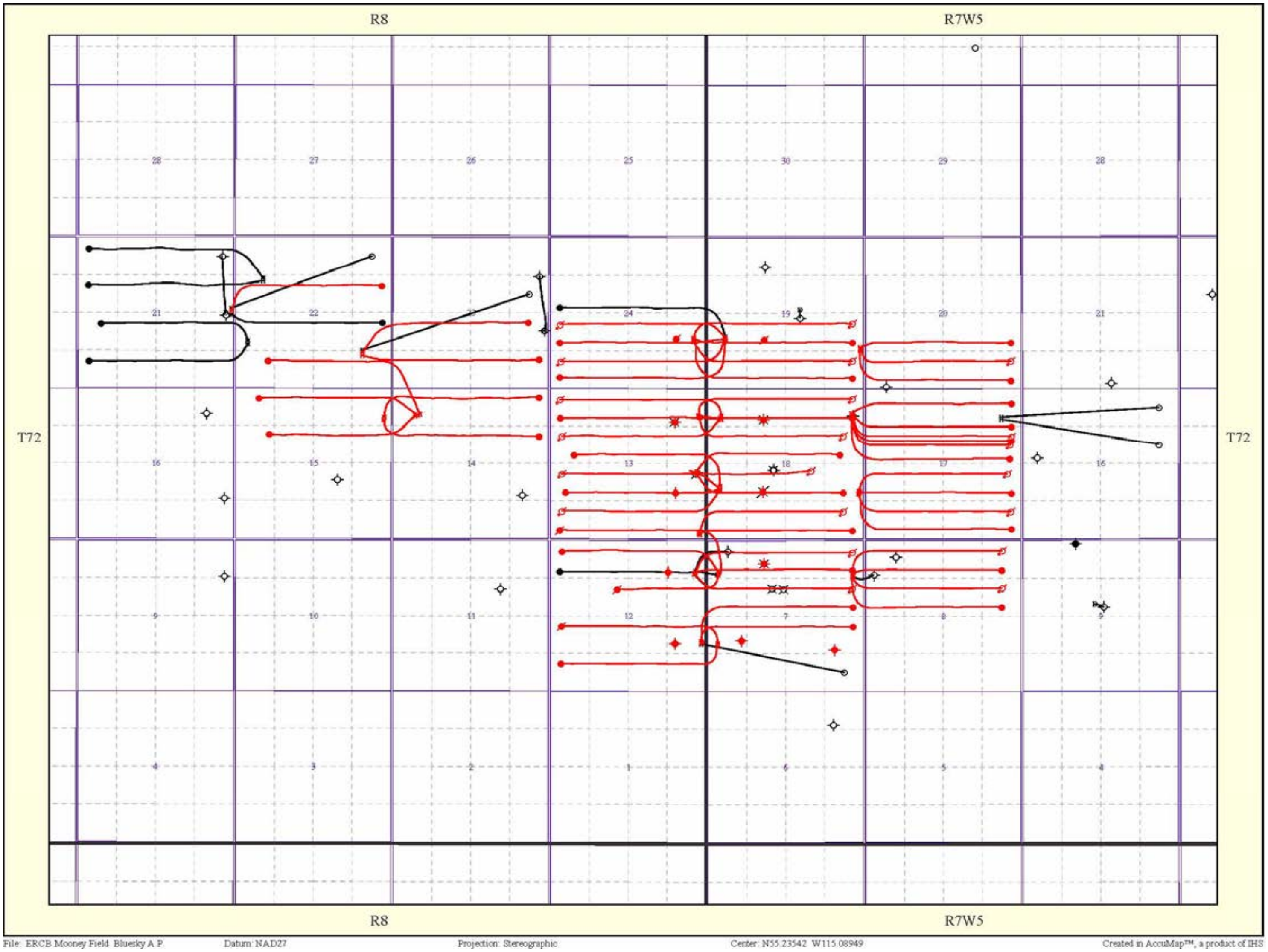

**Horsefly Lake - Mannville Pool**
**Oil Rate vs Cumulative Injected Pore Volume (%)**

Figure 246



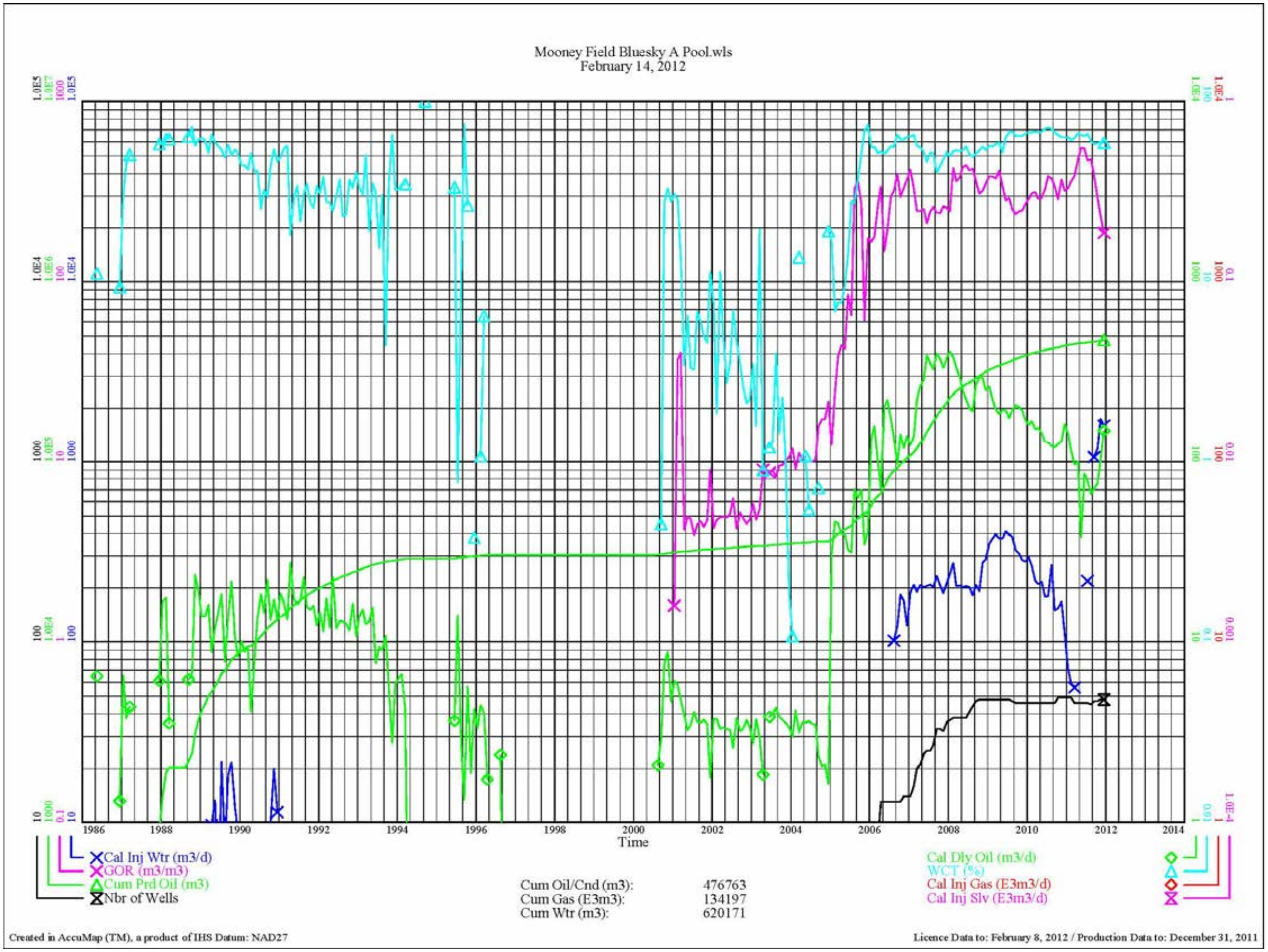

**Horsefly Lake - Mannville Pool – WOR vs Cumulative Oil Produced**

Figure 247




**Mooney Bluesky A – Well Locations**

Figure 248




**Mooney Bluesky A - Production / Injection History**

Figure 249



Sproule

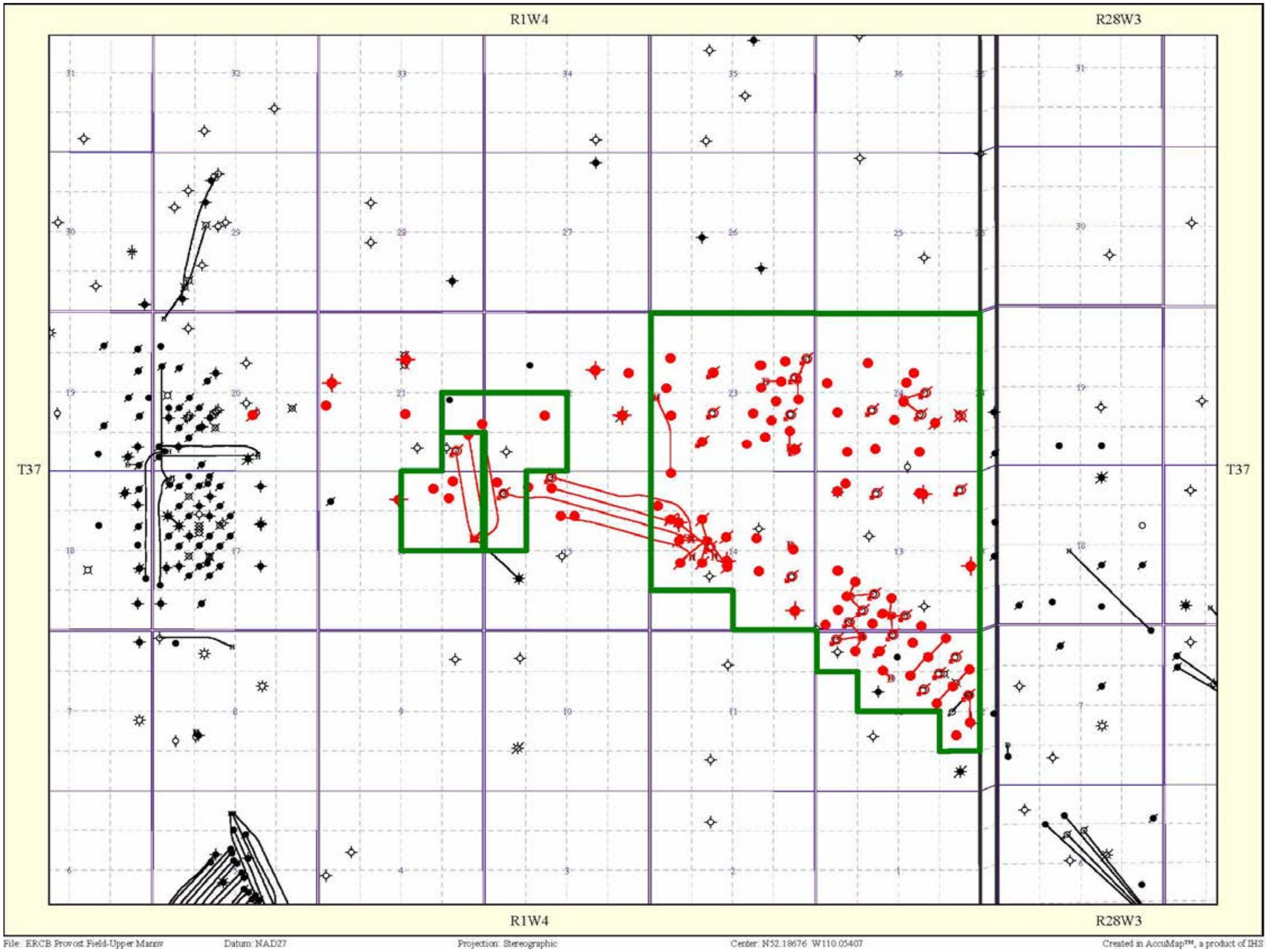
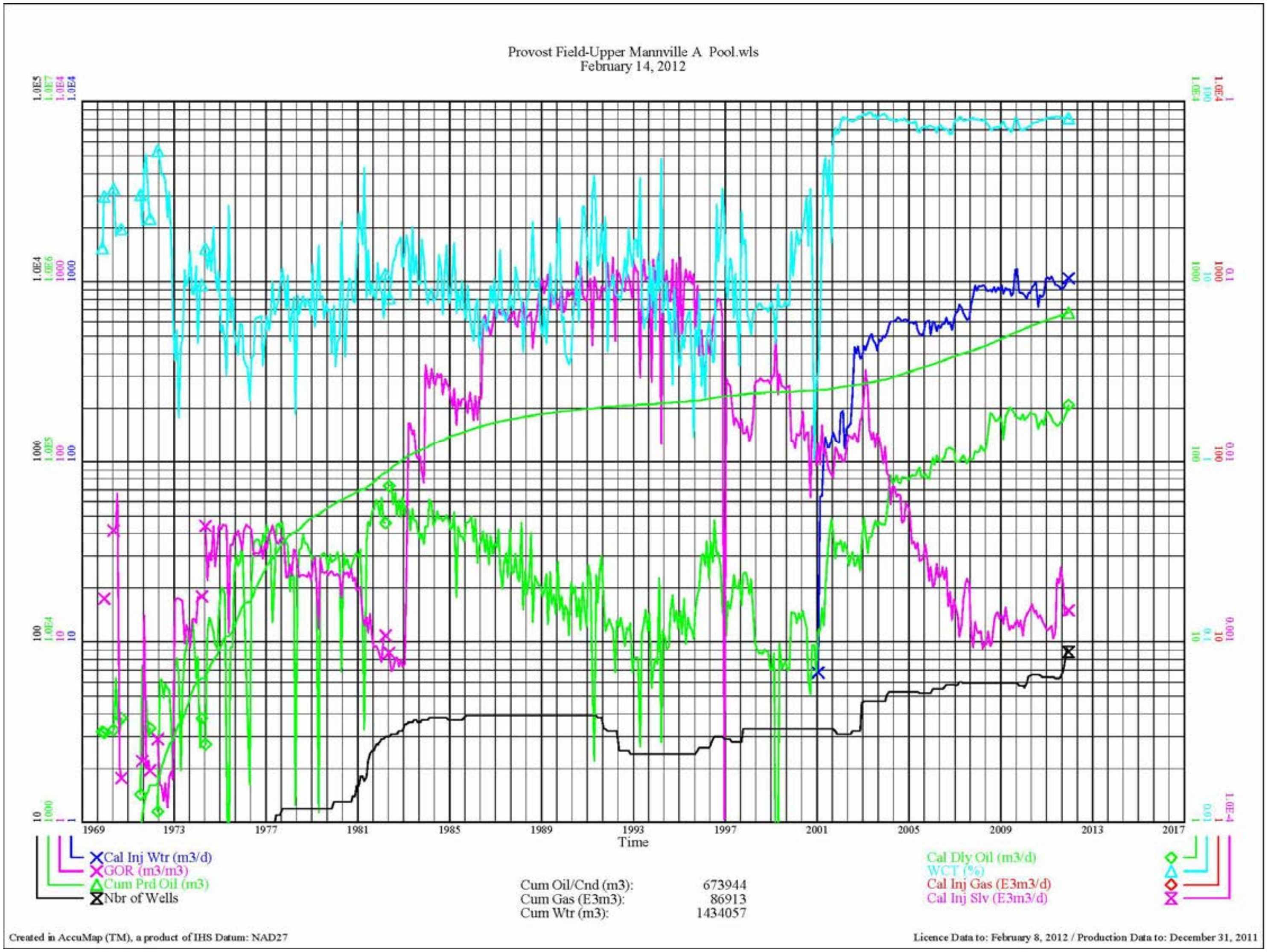



Figure 250

**Provost Upper Mannville A - Well Locations**

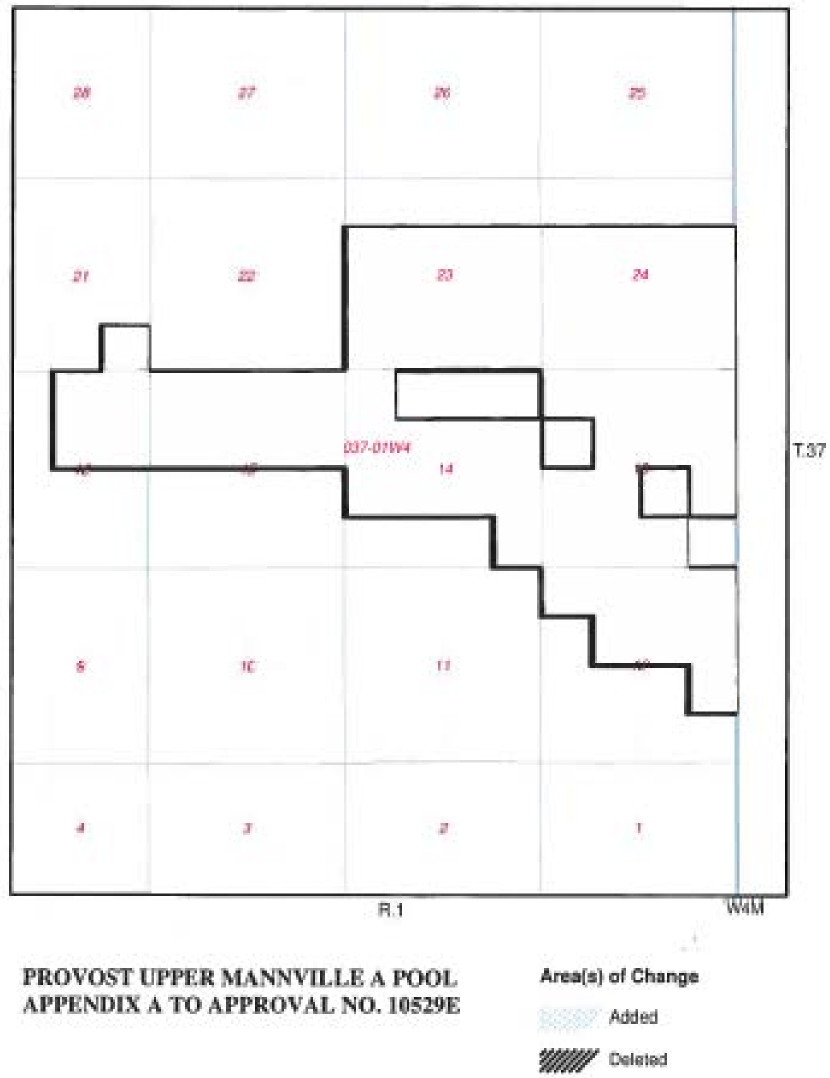



**Provost Upper Mannville A - Production / Injection History**

Figure 251



Sproule




**Provost - Upper Mannville A Pool – Pilot Area**

Figure 252

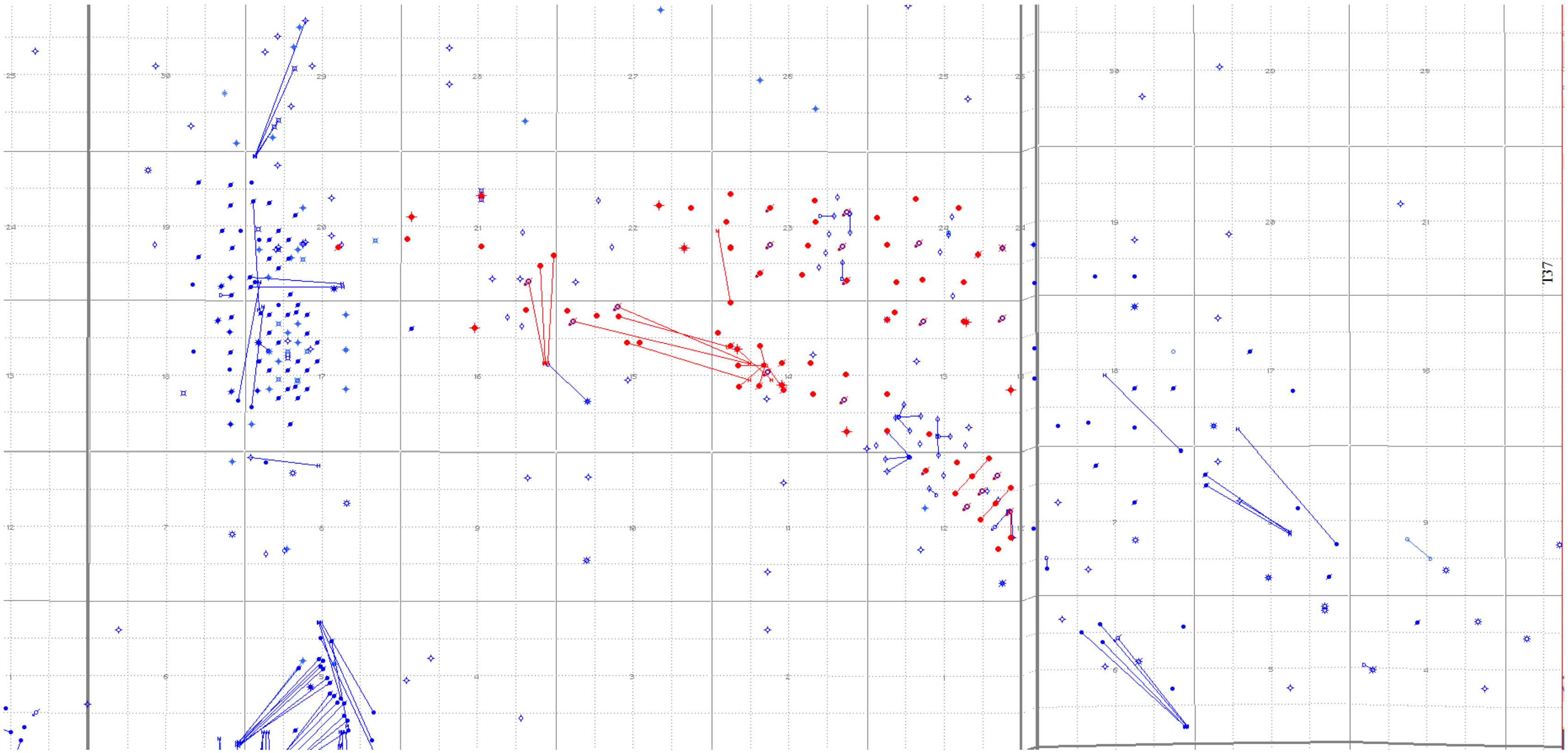
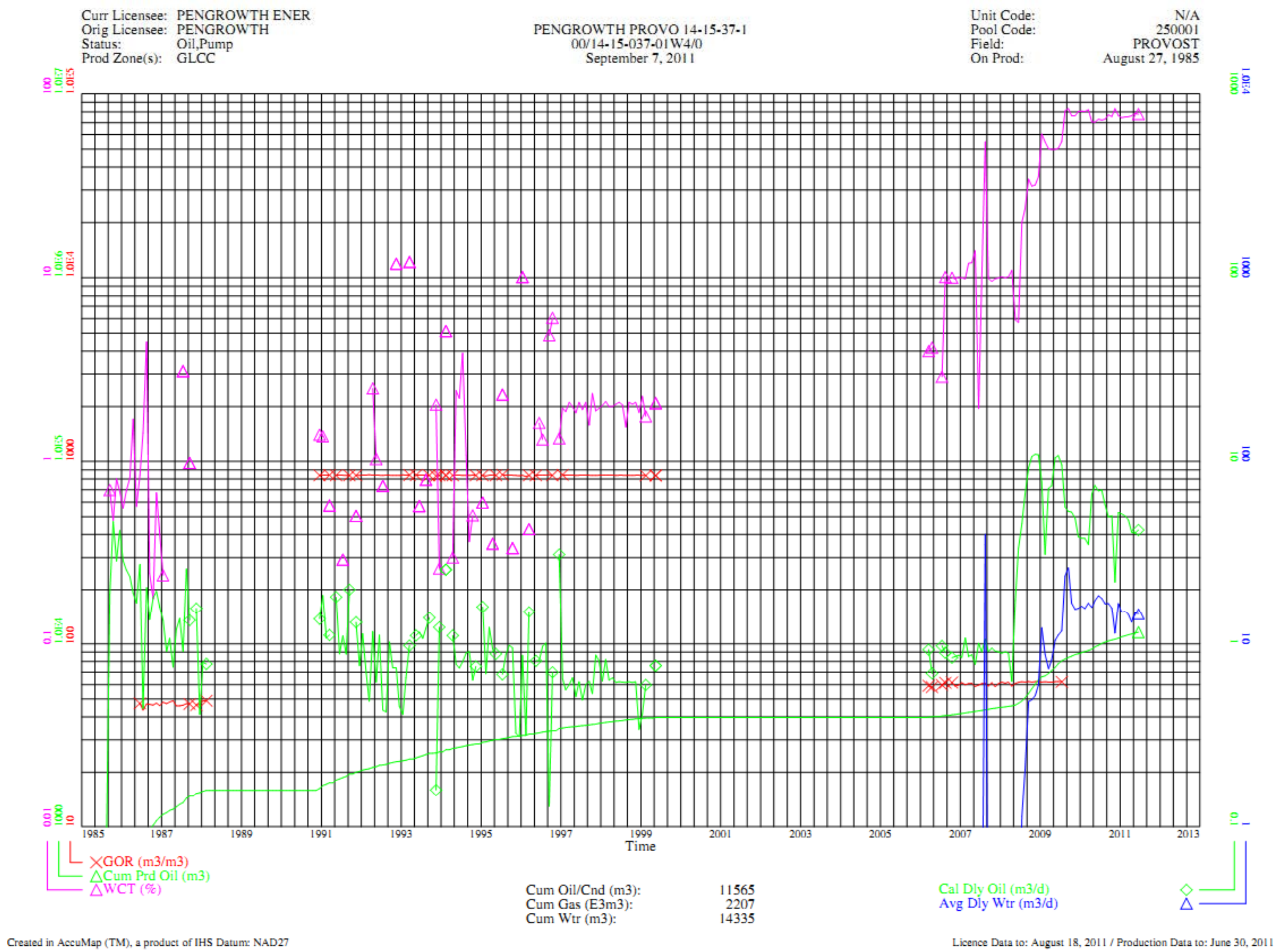


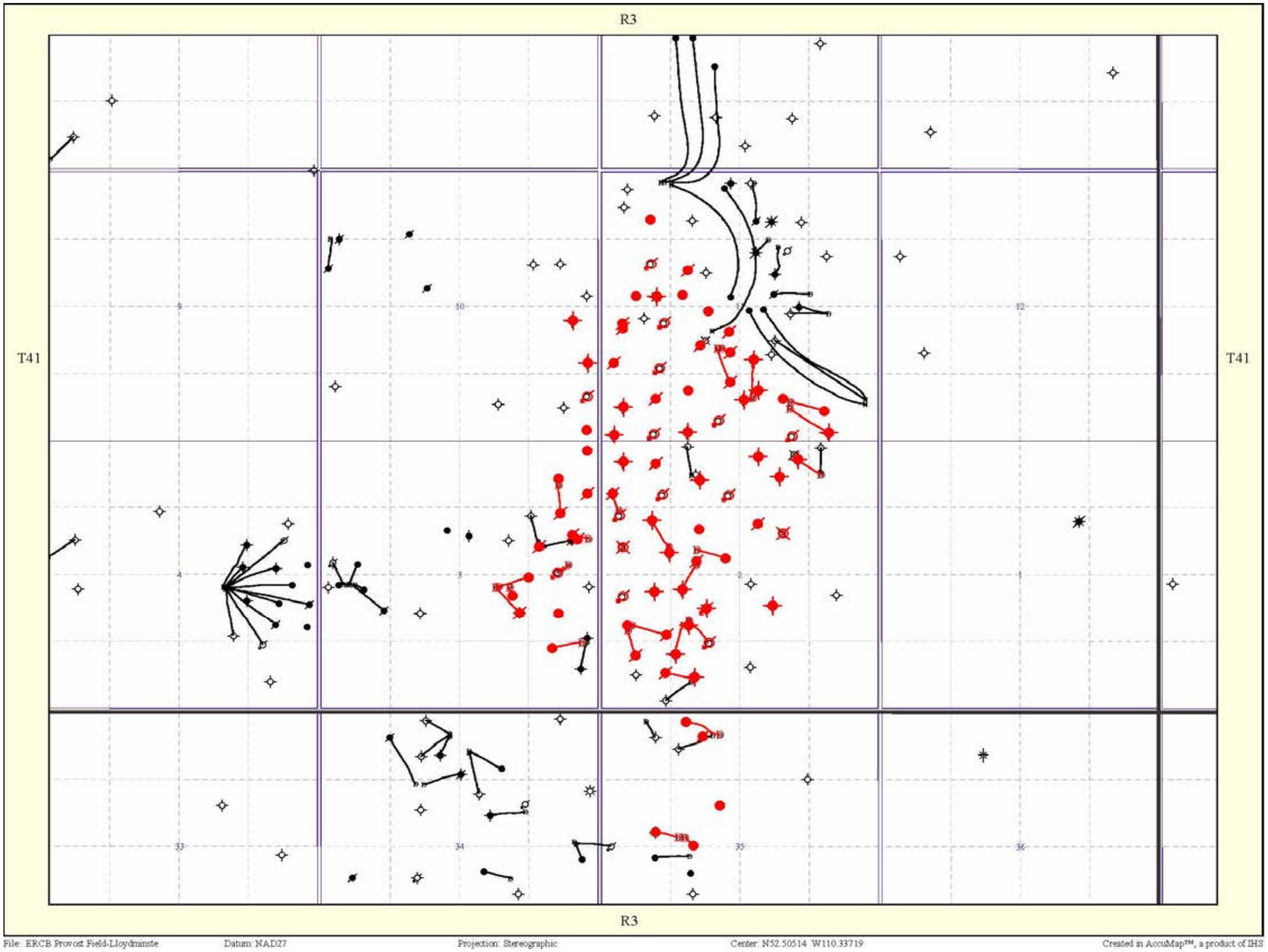

Figure 253

**Provost Upper Mannville A – Well Locations**



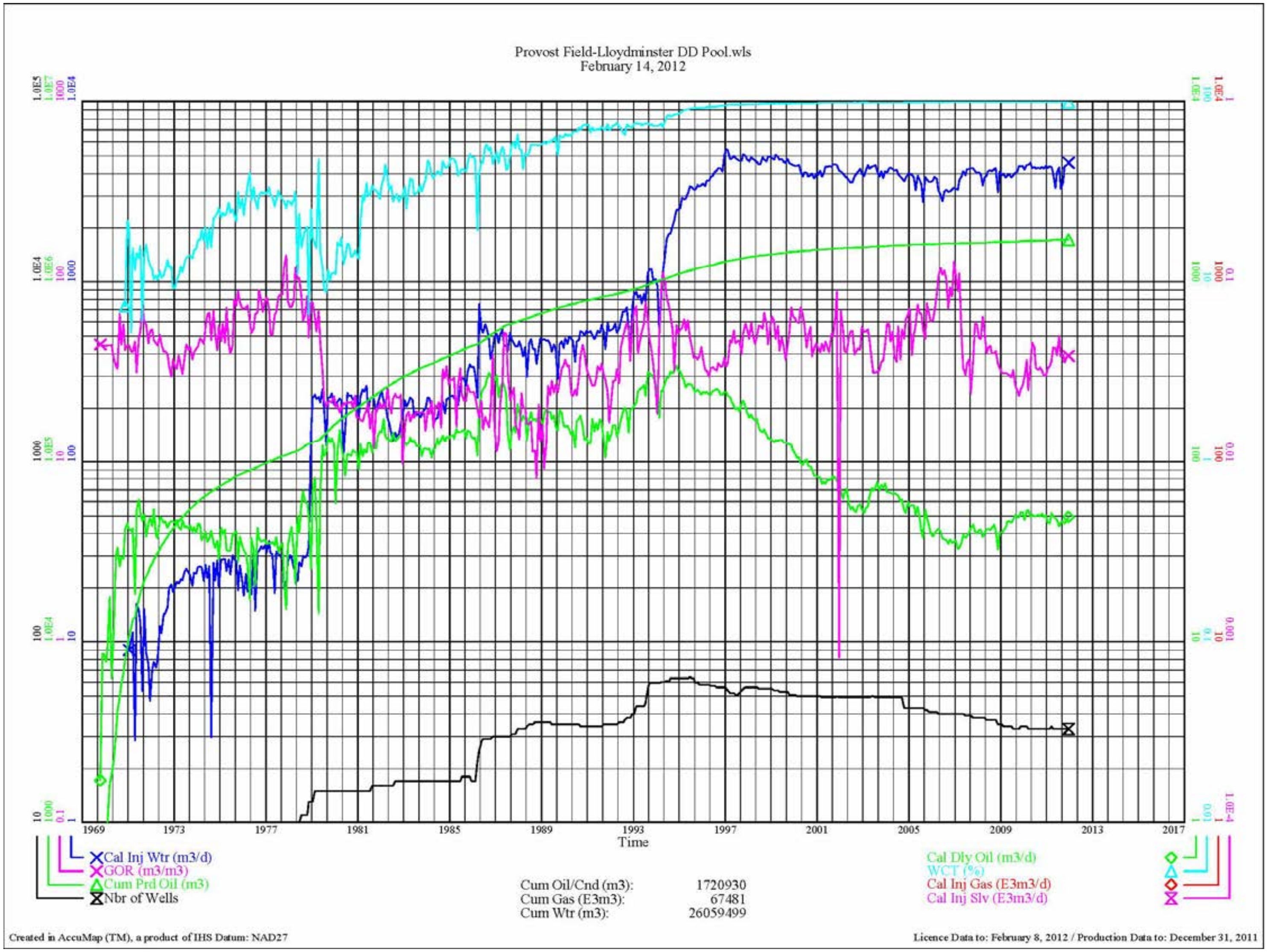

**Provost Upper Mannville A – Production Profile of 14-15-37-01W4M**

Figure 254



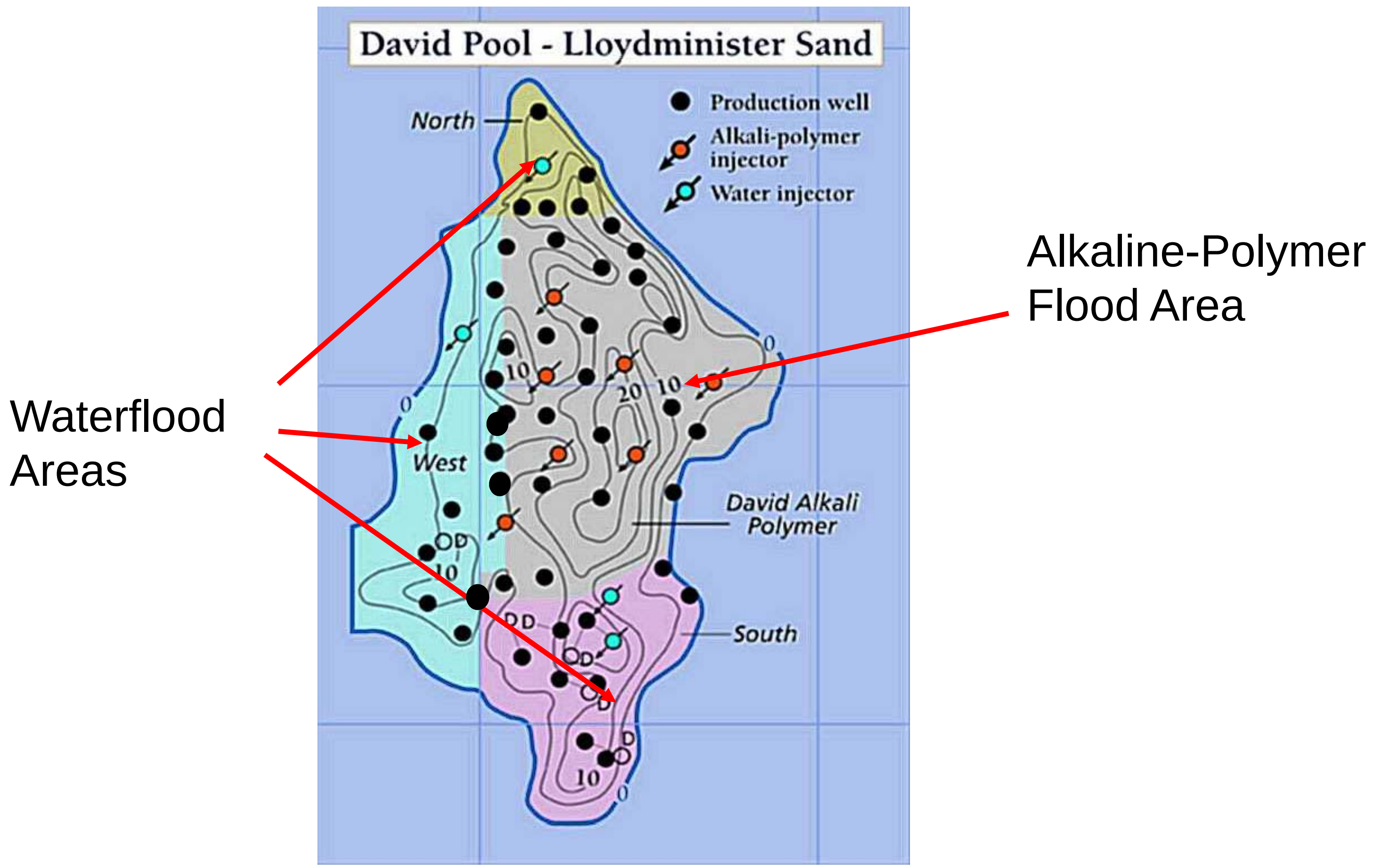

**Provost Lloydminster DD - Well Locations**

Figure 255




**Provost Lloydminster DD - Production / Injection History**

Figure 256

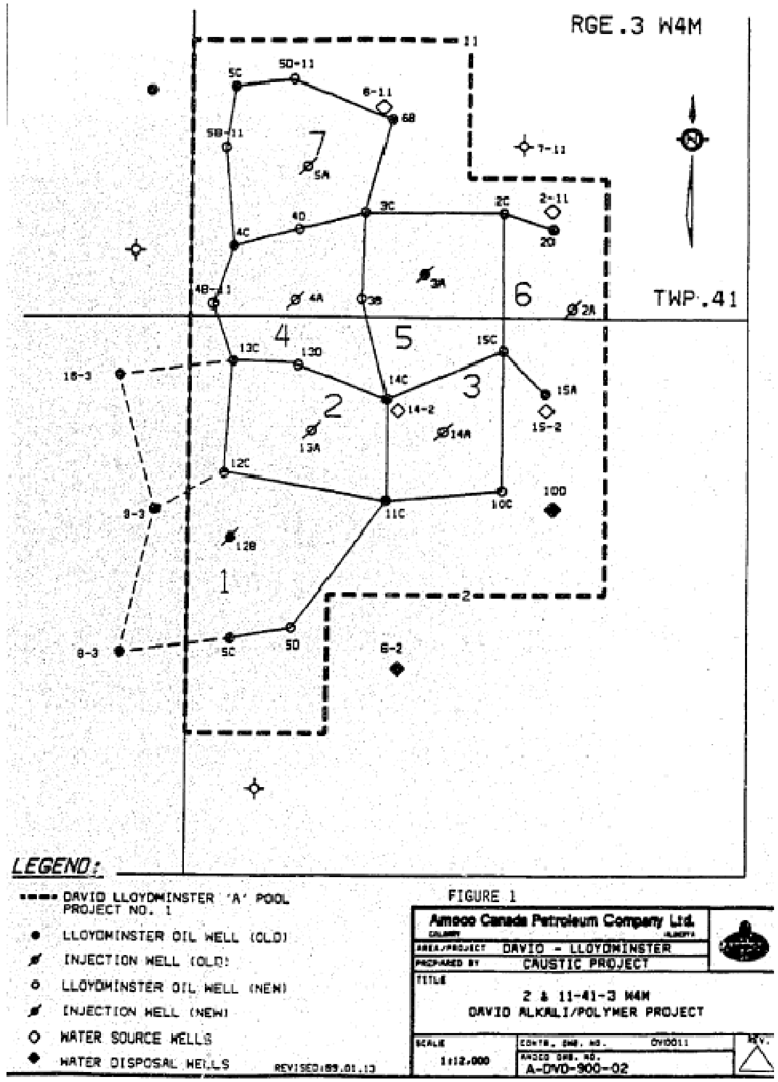



**Provost – (David) Lloydminster DD Pool Alkali/Polymer Project 2 & 11-41-3W4M Net Pay Isopach**

Figure 257



Sproule




**Provost – (David) Lloydminster DD Pool Alkali/Polymer Project 2 & 11-41-3W4M Pattern Configuration**

Figure 258

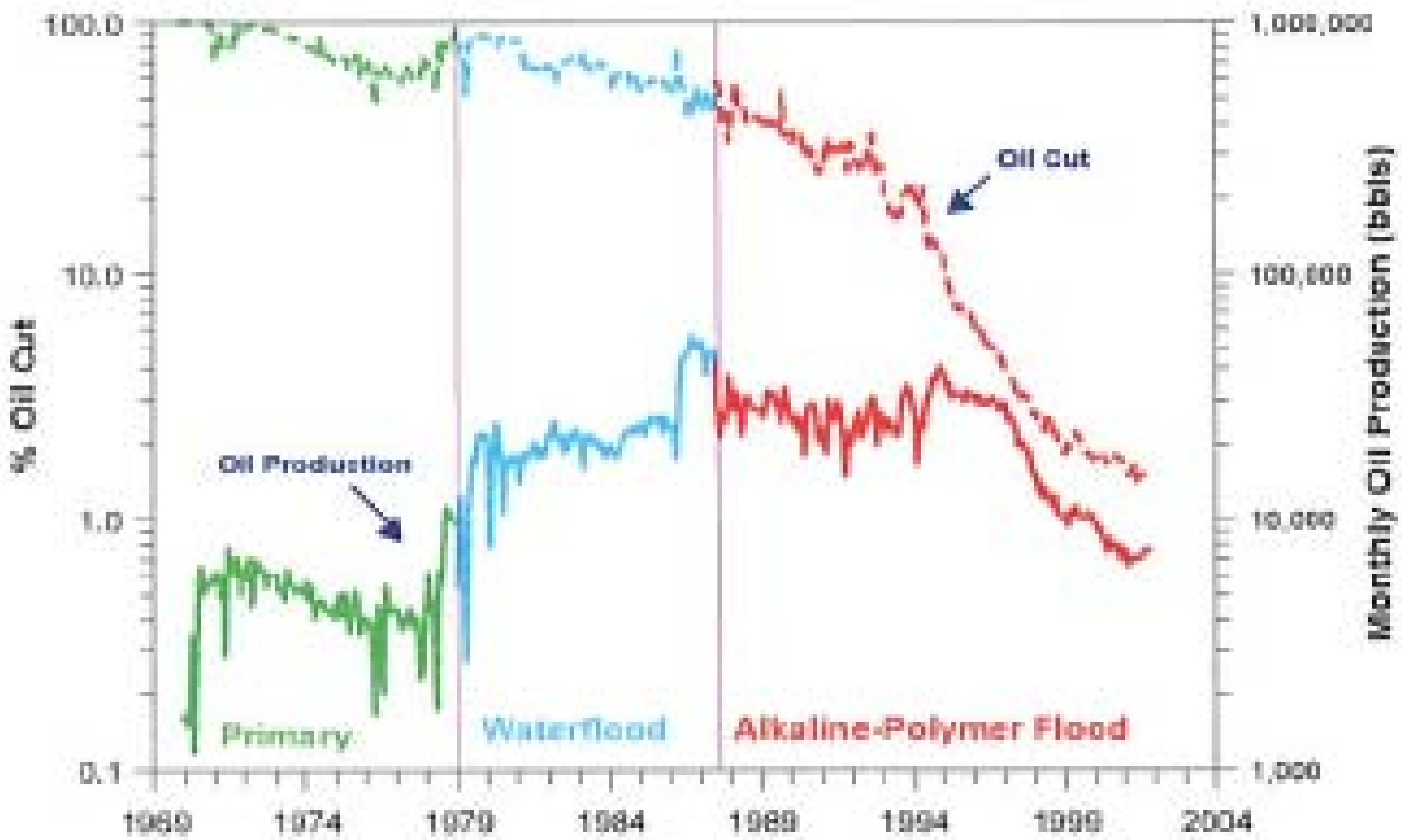
## Summary of Slug Size

David Project No. 1

| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|---|
| | | 12B-2 | 13A-2 | 14A-2 | 4A-11 | 3A-11 | 2A-11 | 5A-11 |
| Pre-Flush | m3 | 24261 | 33533 | 30194 | 31850 | 31548 | 25589 | 30335 |
| | % | 22 | 17 | 24 | 13 | 12 | 27 | 21 |
| Alkali-Polymer | m3 | 58623 | 55549 | 70883 | 62268 | 100816 | 40512 | 81220 |
| | % | 52 | 29 | 56 | 26 | 38 | 58 | 50 |
| Polymer | m3 | 10986 | 17796 | 22057 | 21610 | 42247 | 2219 | 24917 |
| | % | 10 | 9 | 17 | 9 | 16 | 3 | 17 |
| Post-Flush | m3 | 41767 | 40280 | 10997 | 56696 | 32690 | 21417 | 56854 |
| (to 92-07) | % | 38 | 20 | 9 | 23 | 12 | 31 | 39 |

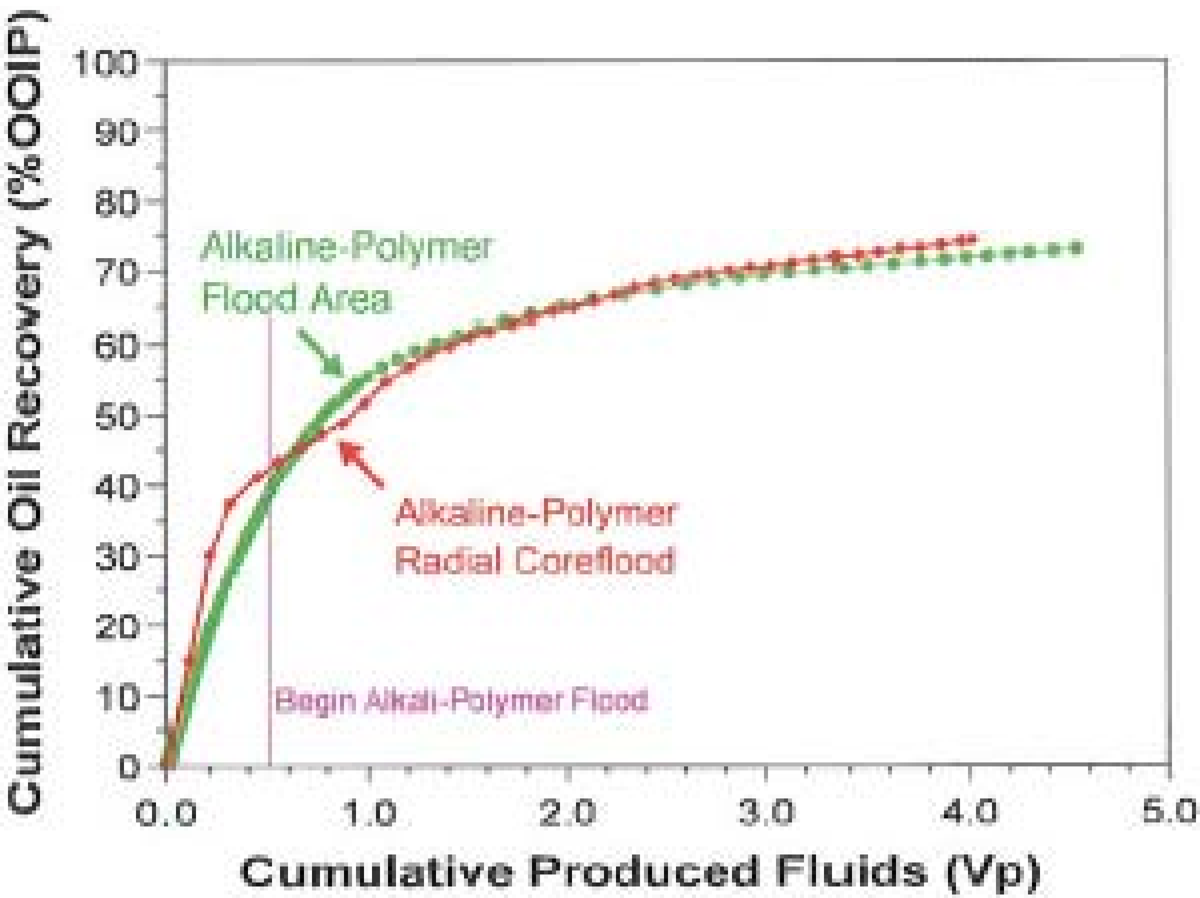
**Provost – (David) Lloydminster DD Pool Alkali/Polymer**
**Summary of Slug Size for the 7 Patterns**

Figure 259



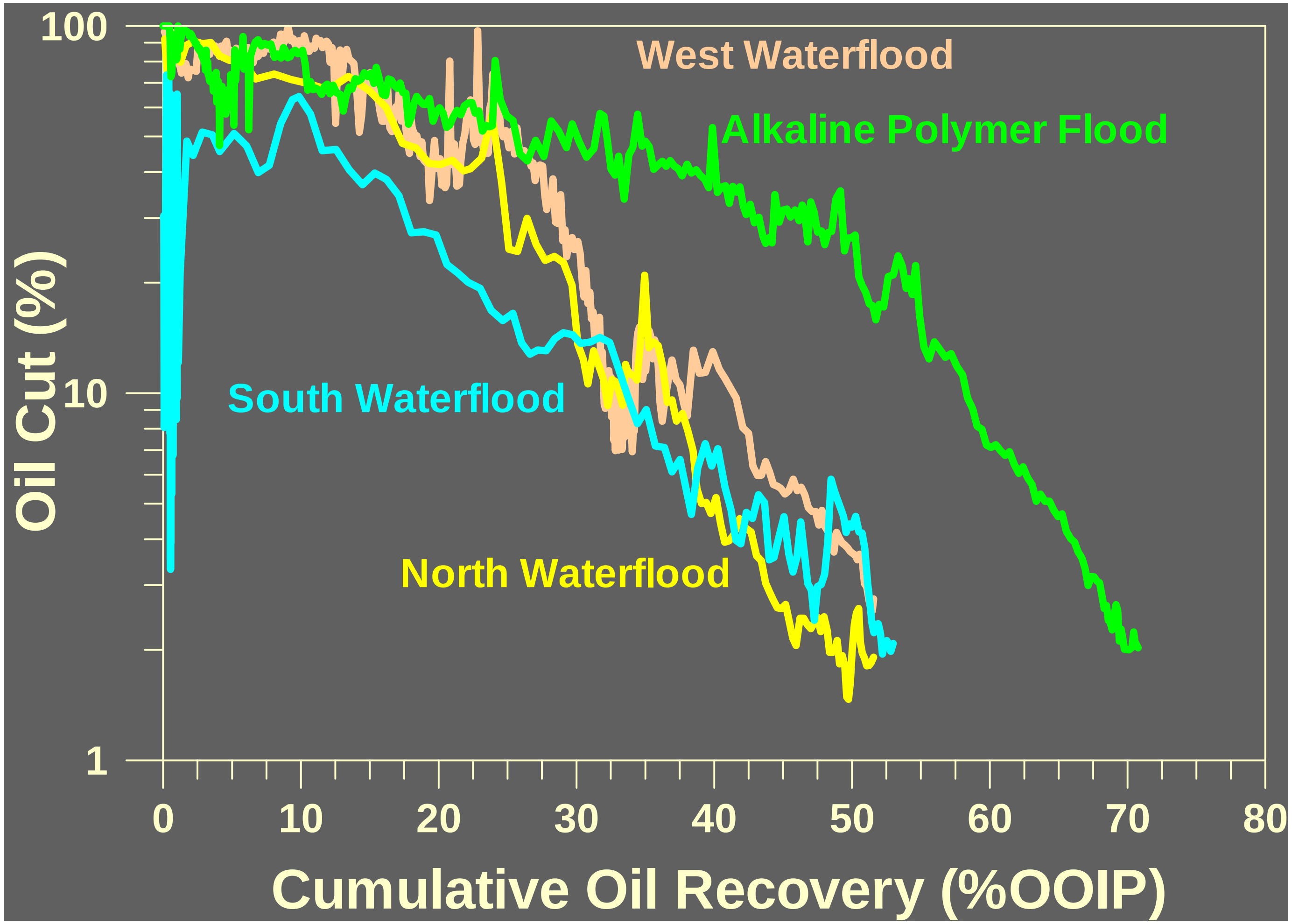

**Provost - (David) Lloydminster DD Pool Alkali/Polymer Project 2 & 11-41-3W4M**
**Oil Cut and Oil Production vs Time**
**Primary, Waterflood and Alkaline-Polymer Flood**

Figure 260




**Provost – (David) Lloydminster DD Pool Alkali/Polymer Project 2 & 11-41-3W4M**
**Core Flood vs Field Performance**
**% Cumulative Oil Recovery vs Cumulative Produced Fluids**

Figure 261




**Provost - (David) Lloydminster DD Pool Alkali/Polymer Project 2 & 11-41-3W4M**
**Oil Cut % vs Cumulative Oil Recovery (%)**

Figure 262

18158

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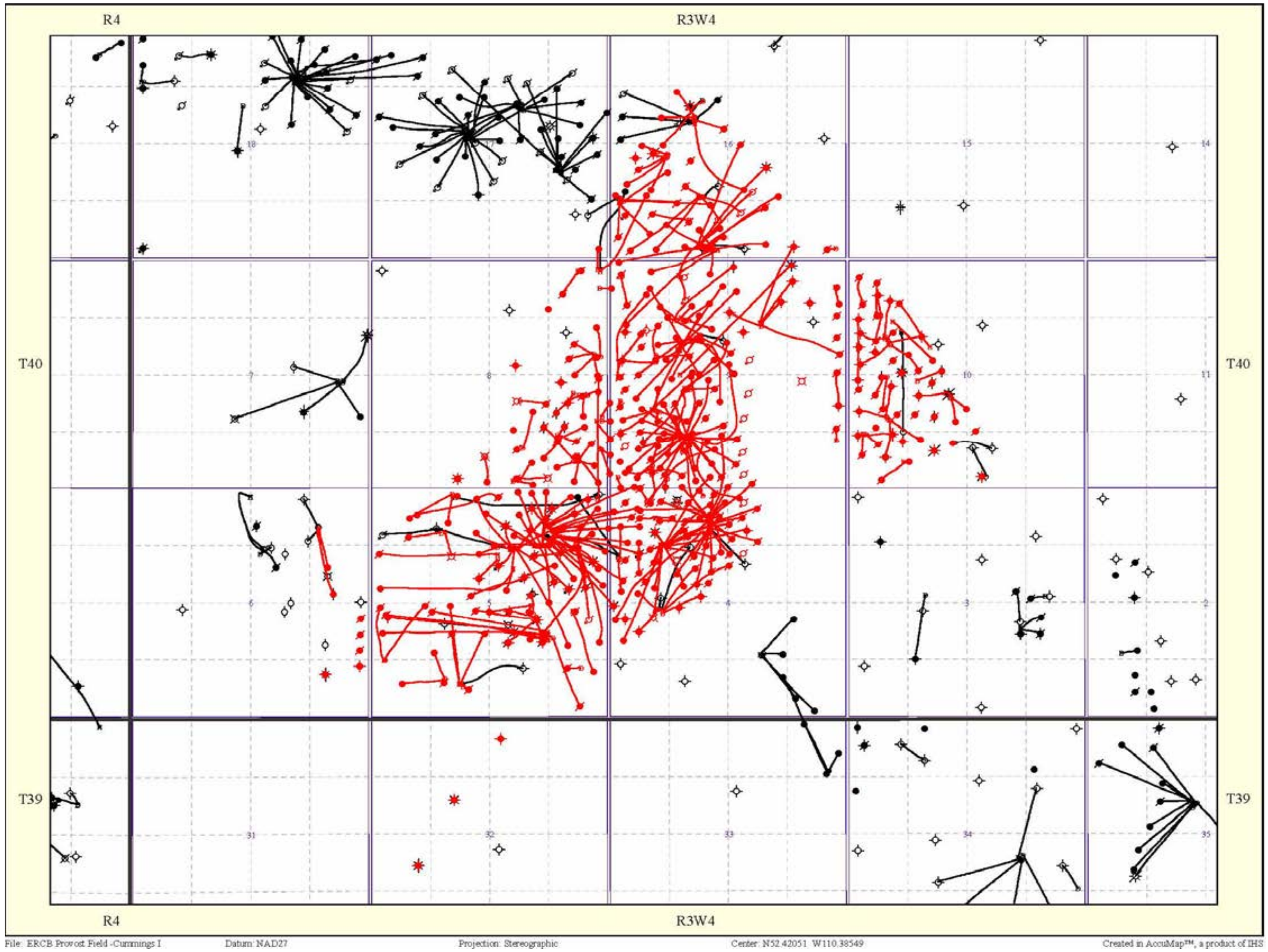
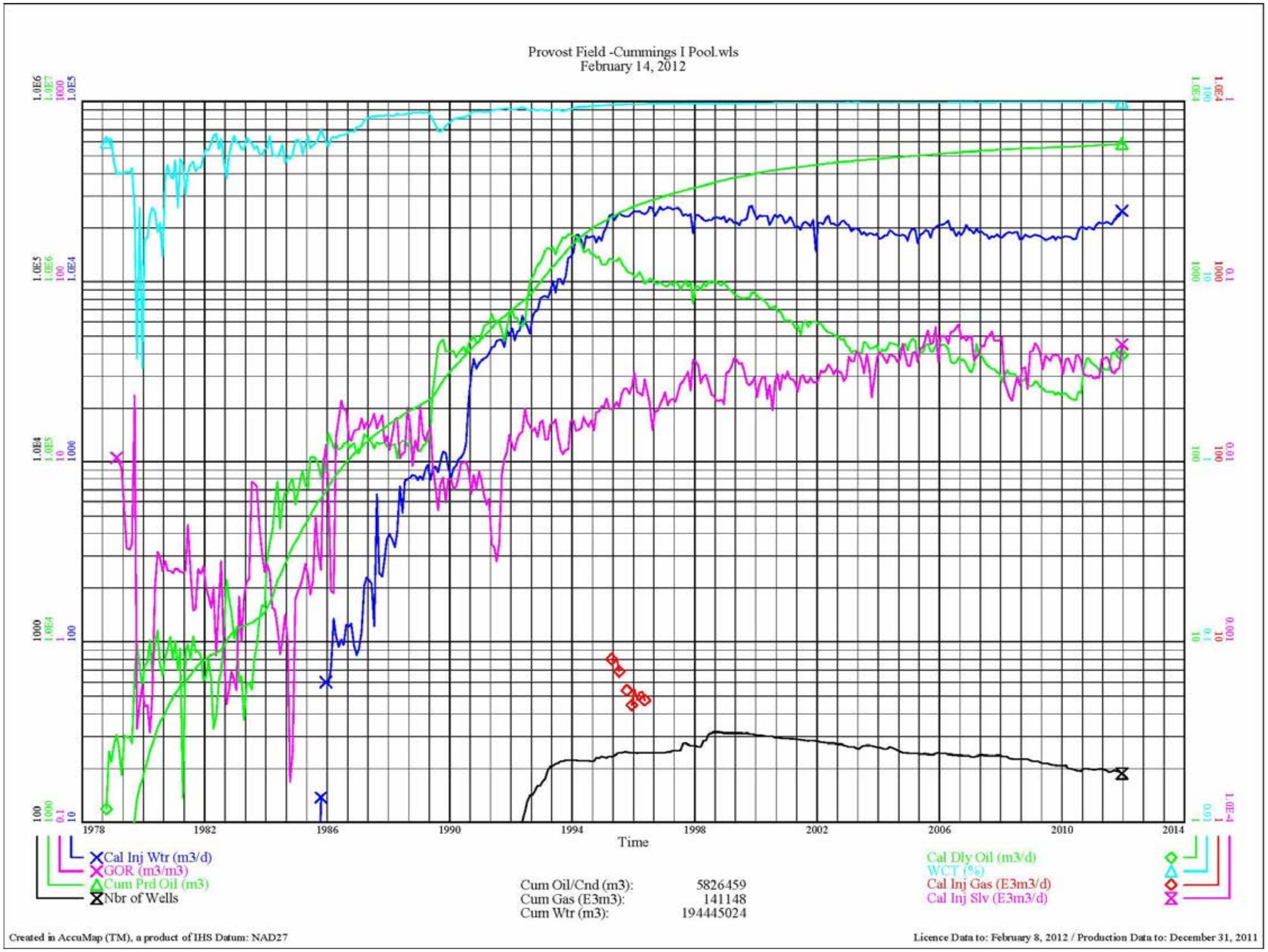


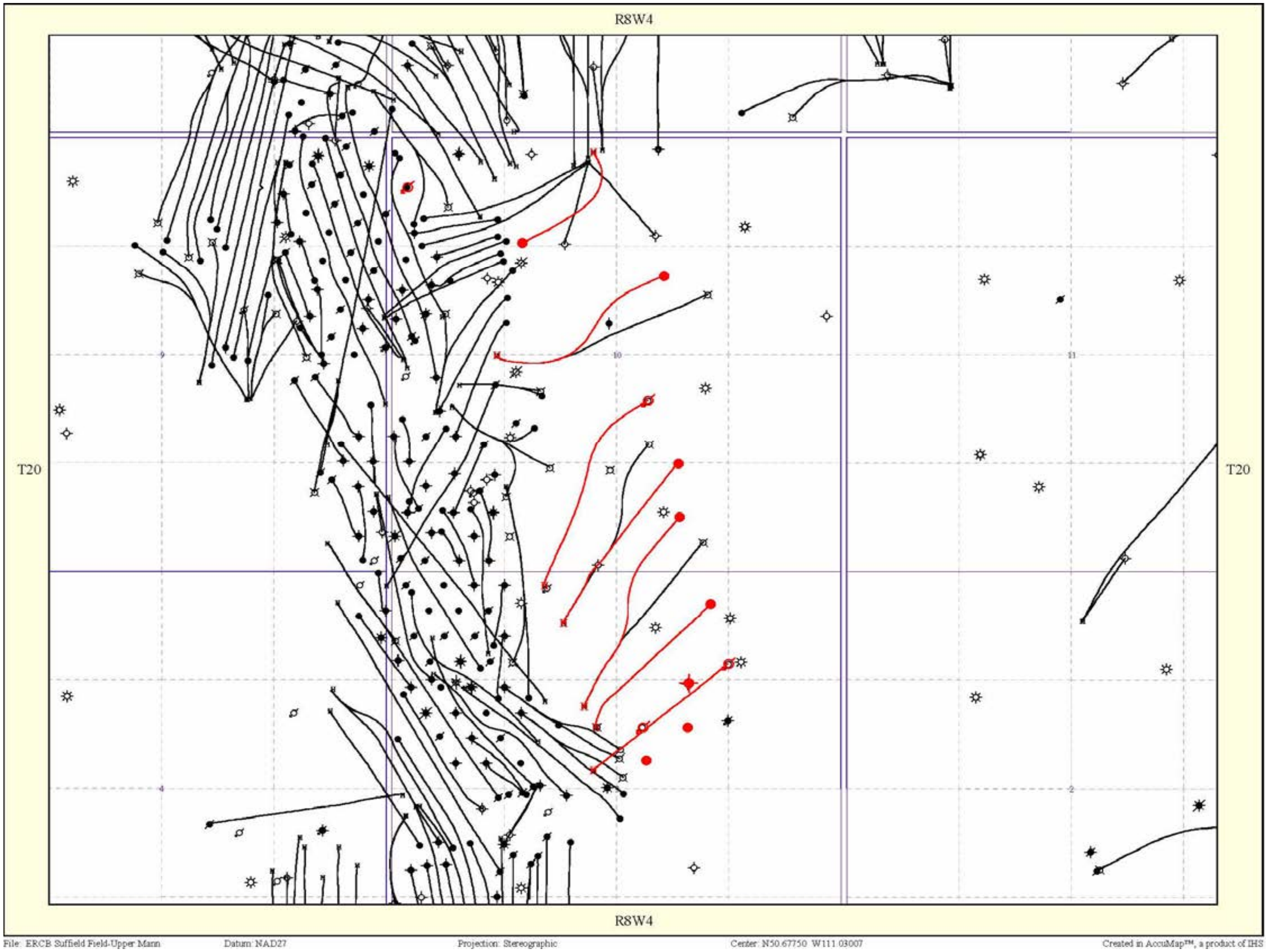

**Provost Cummings I – Well Locations**

Figure 263



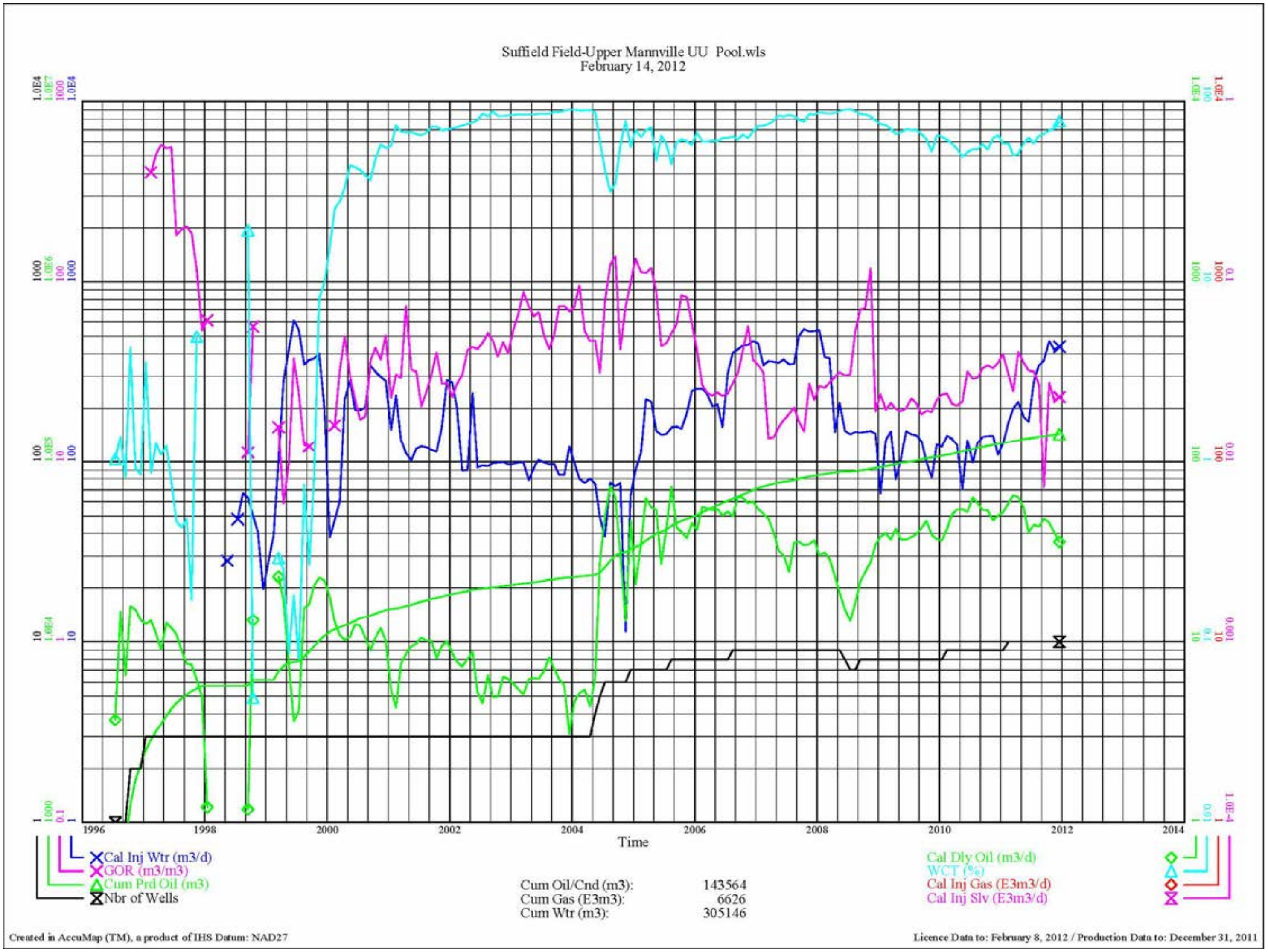

**Provost Cummings I - Production / Injection History**

Figure 264




**Suffield Upper Mannville UU - Well Locations**

Figure 265

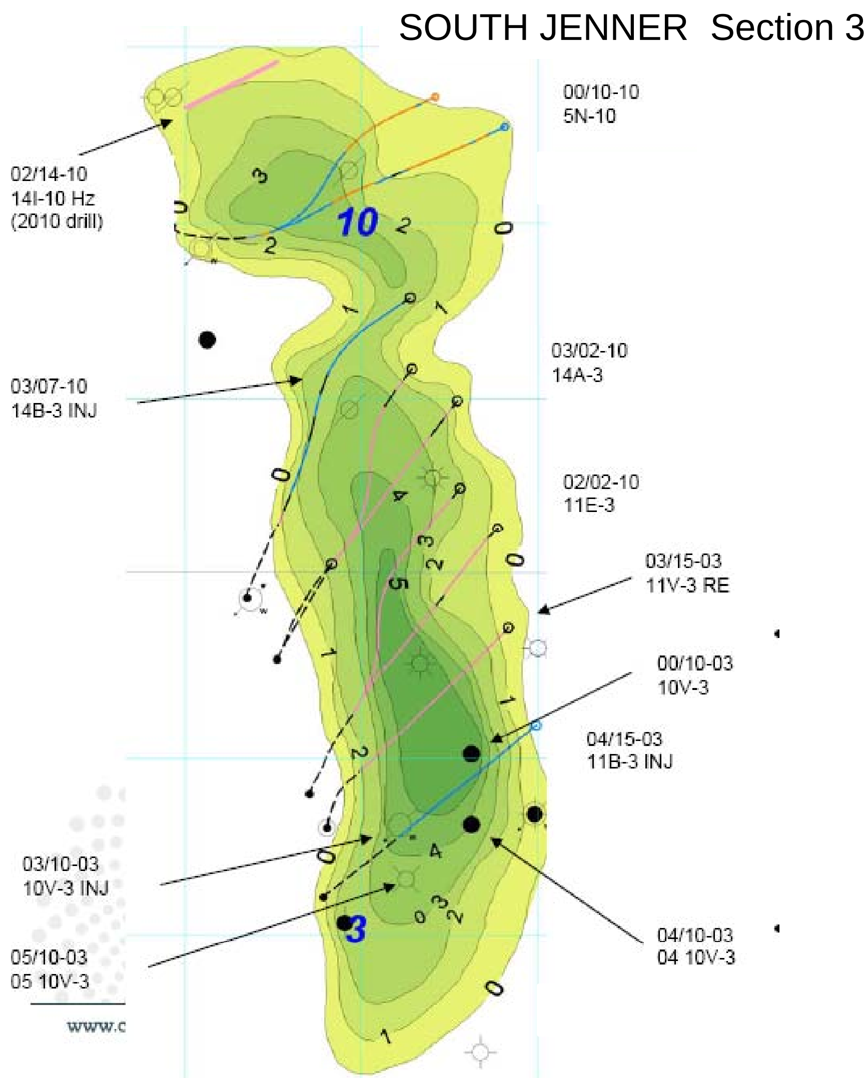



**Suffield Upper Mannville UU - Production / Injection History**

Figure 266



Sproule

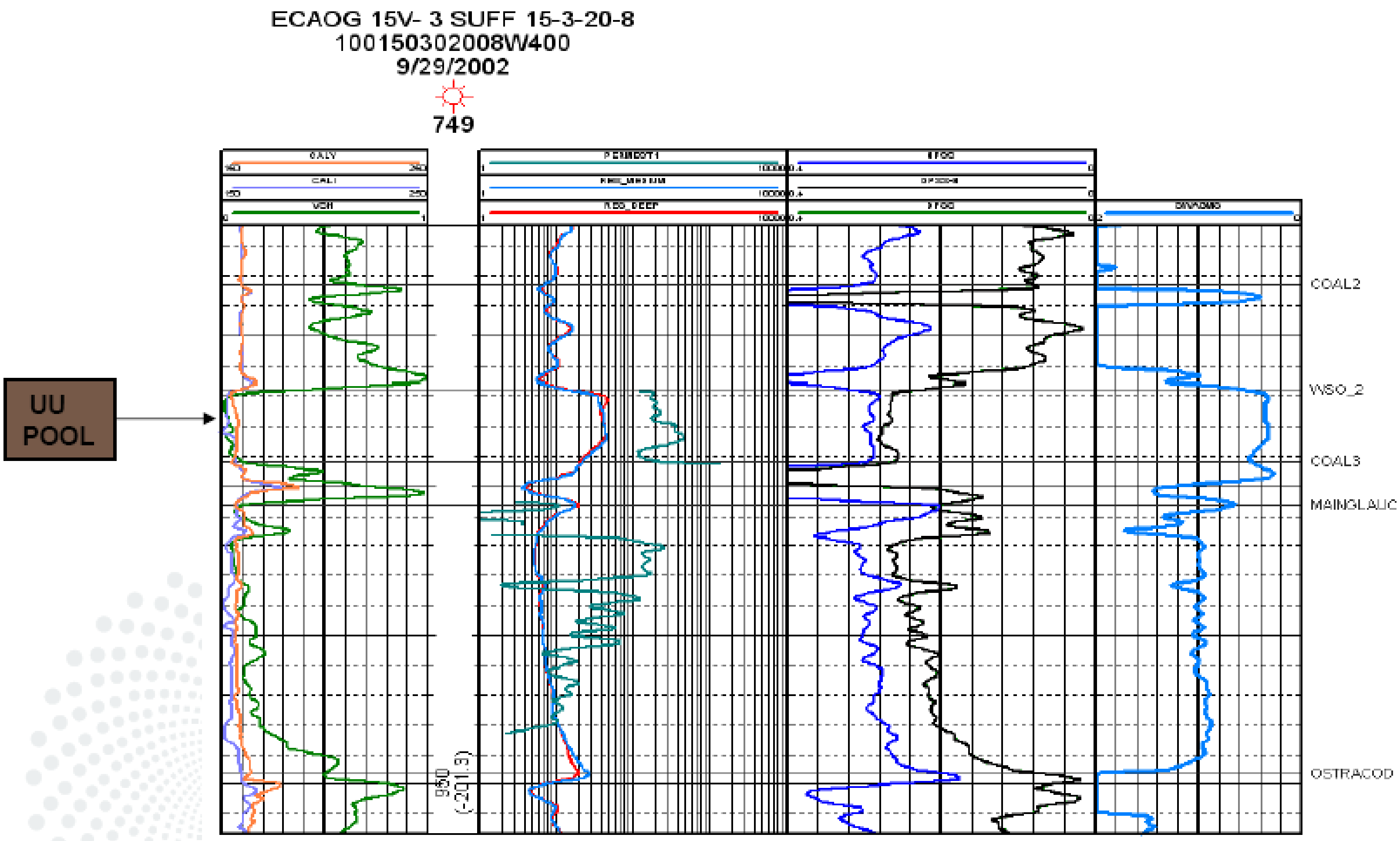



**Suffield Upper Mannville UU Pool Pilot**

Figure 267

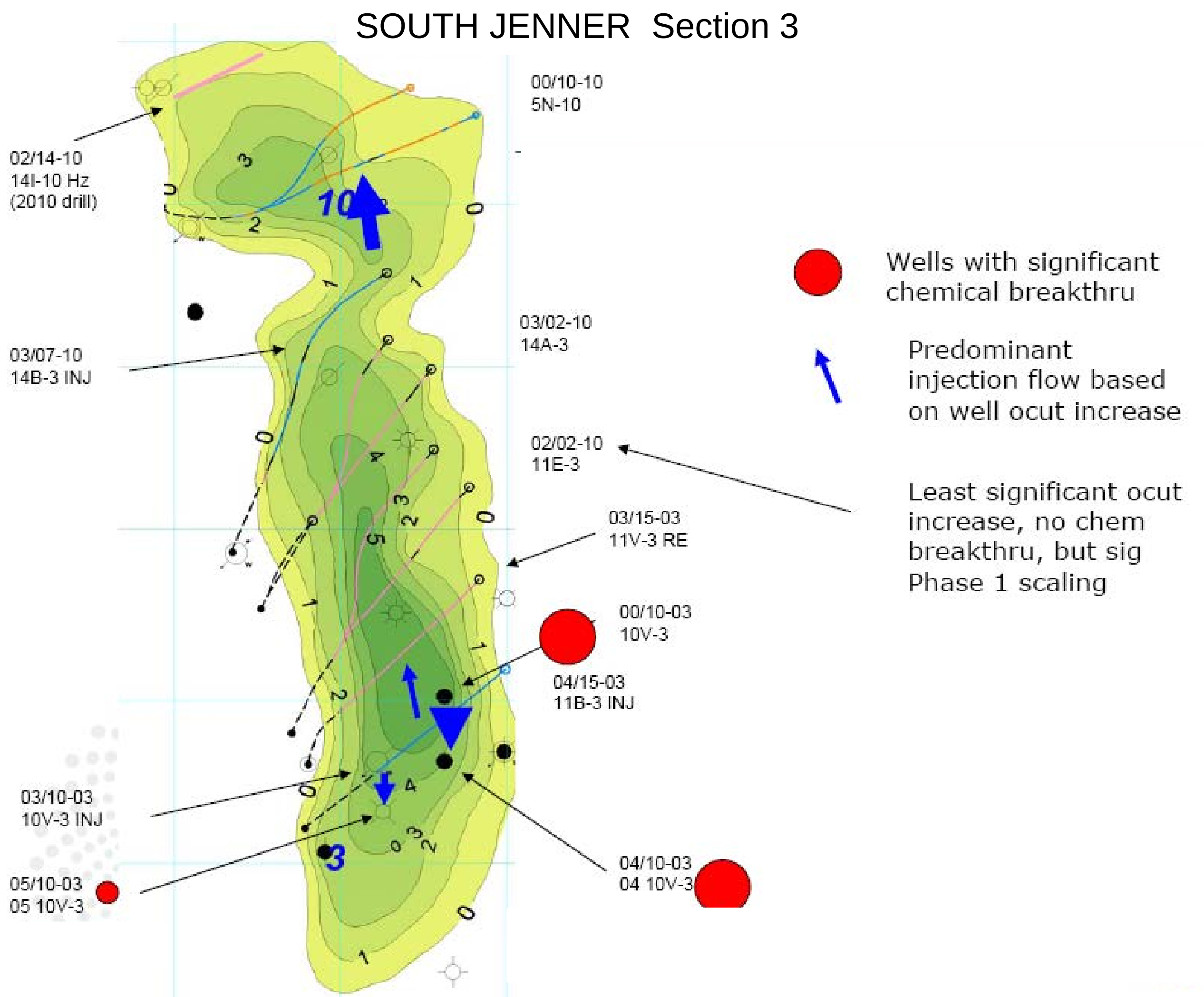


Sproule




**Suffield Upper Mannville UU Type Log**

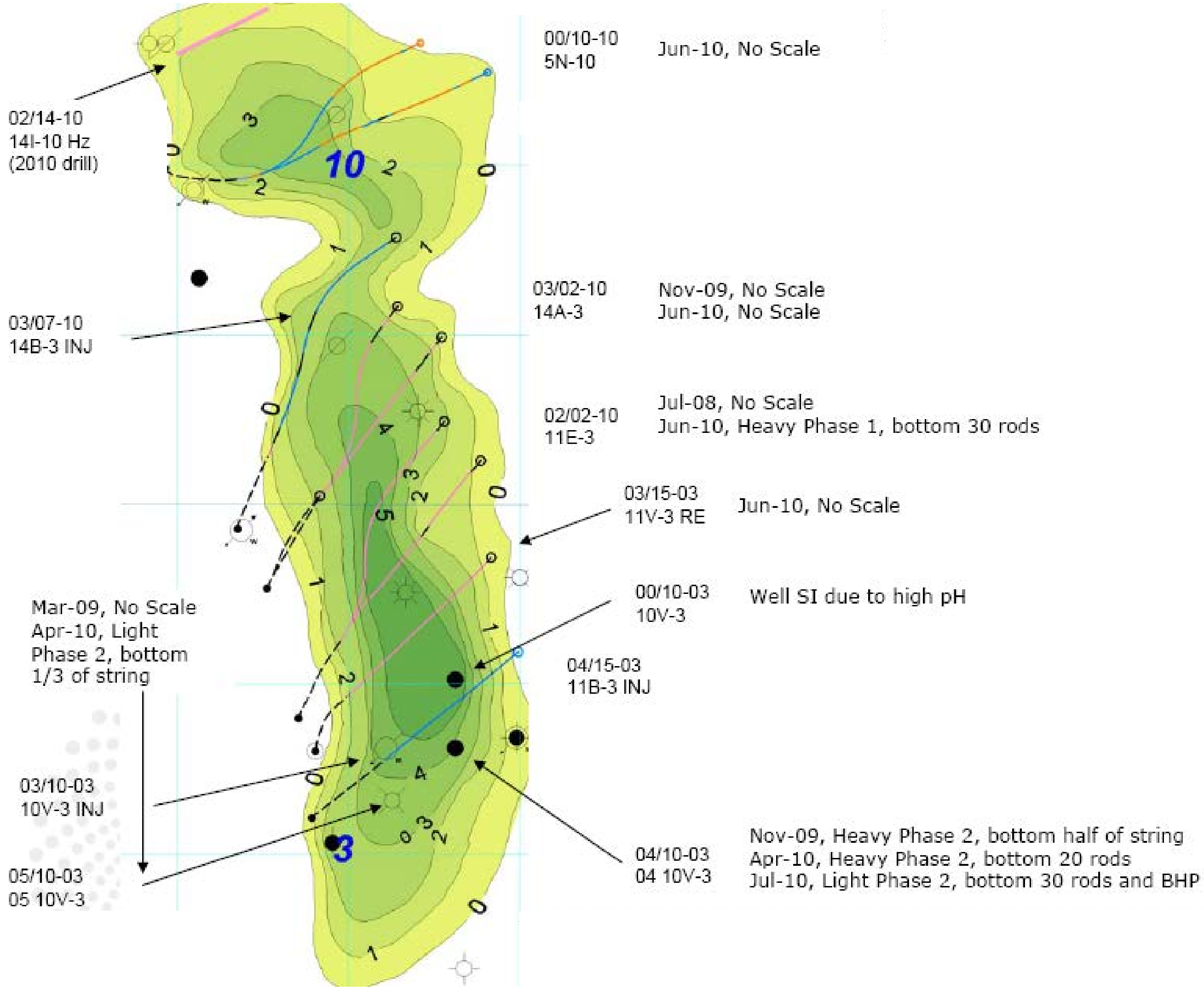
Figure 268




**Suffield Upper Mannville UU Produced Water Analysis**

Figure 269

SOUTH JENNER Section 3

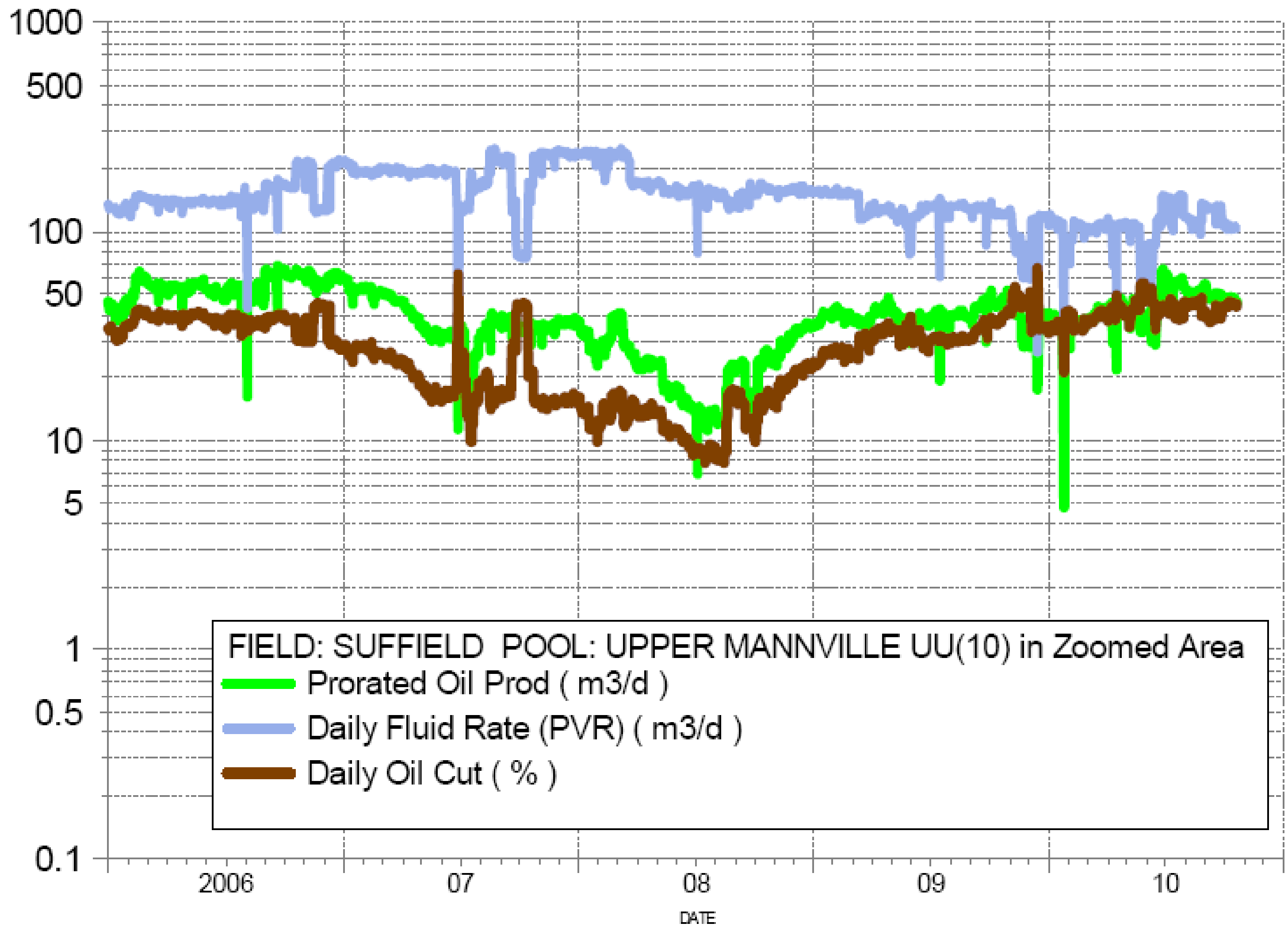



**Suffield Upper Mannville UU Scale Activity Map**

Figure 270



Sproule

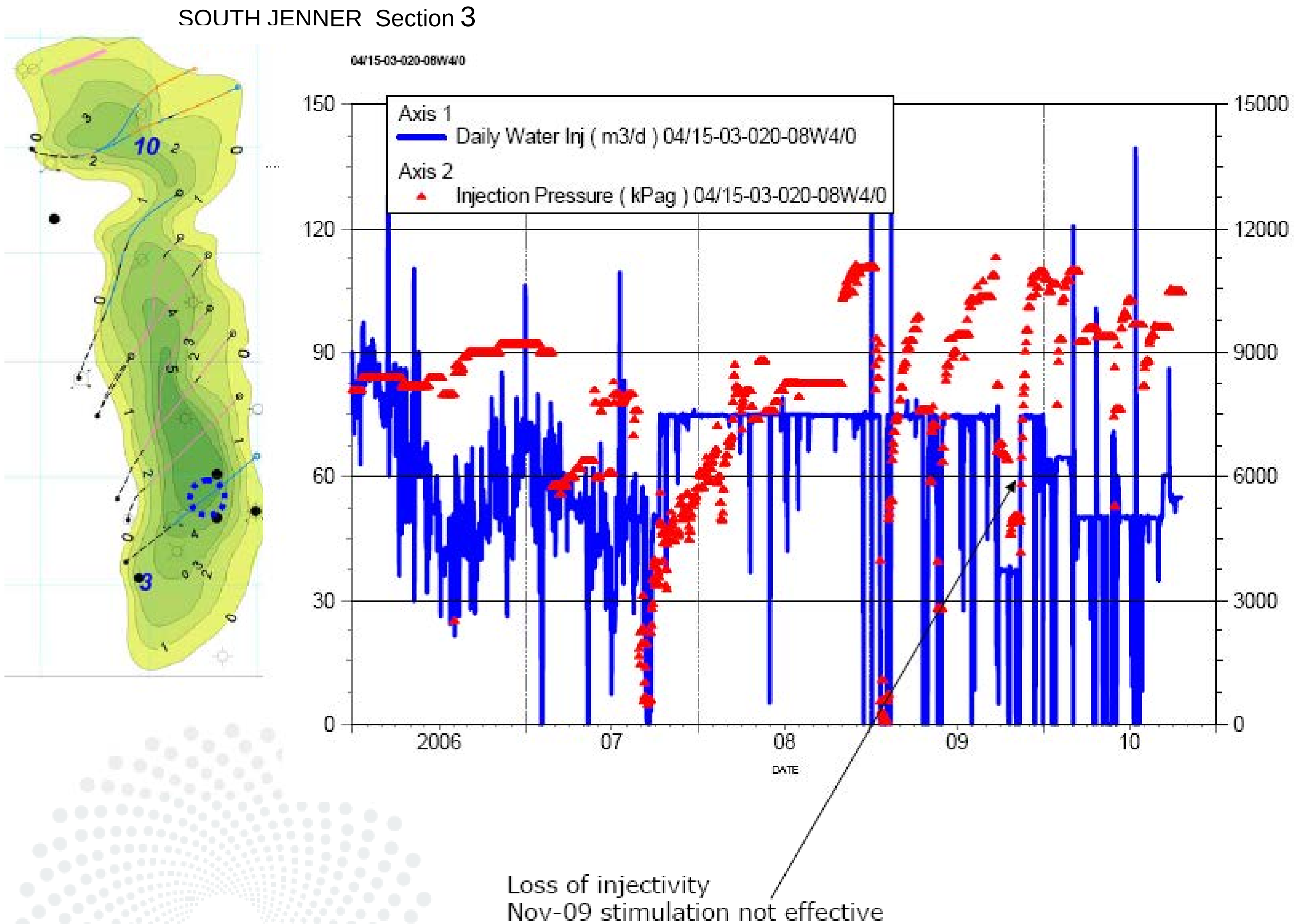



**Suffield Upper Mannville UU Group Performance Plot**
**Excluding 02/14-10 (2010 Horizontal Well)**

Figure 271



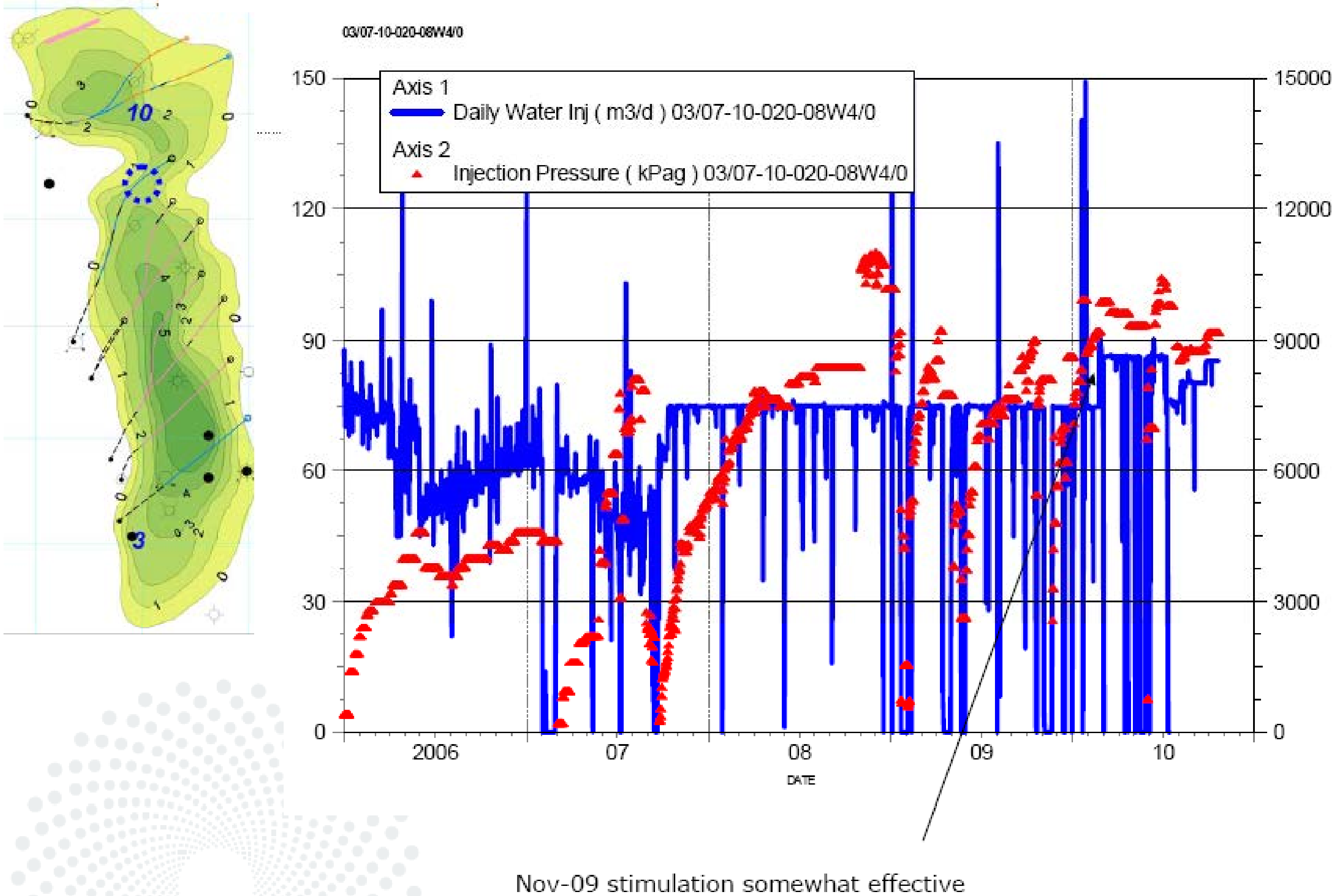
Sproule




**Suffield Upper Mannville UU Water and Injection Pressure**

Figure 272

SOUTH JENNER Section 3

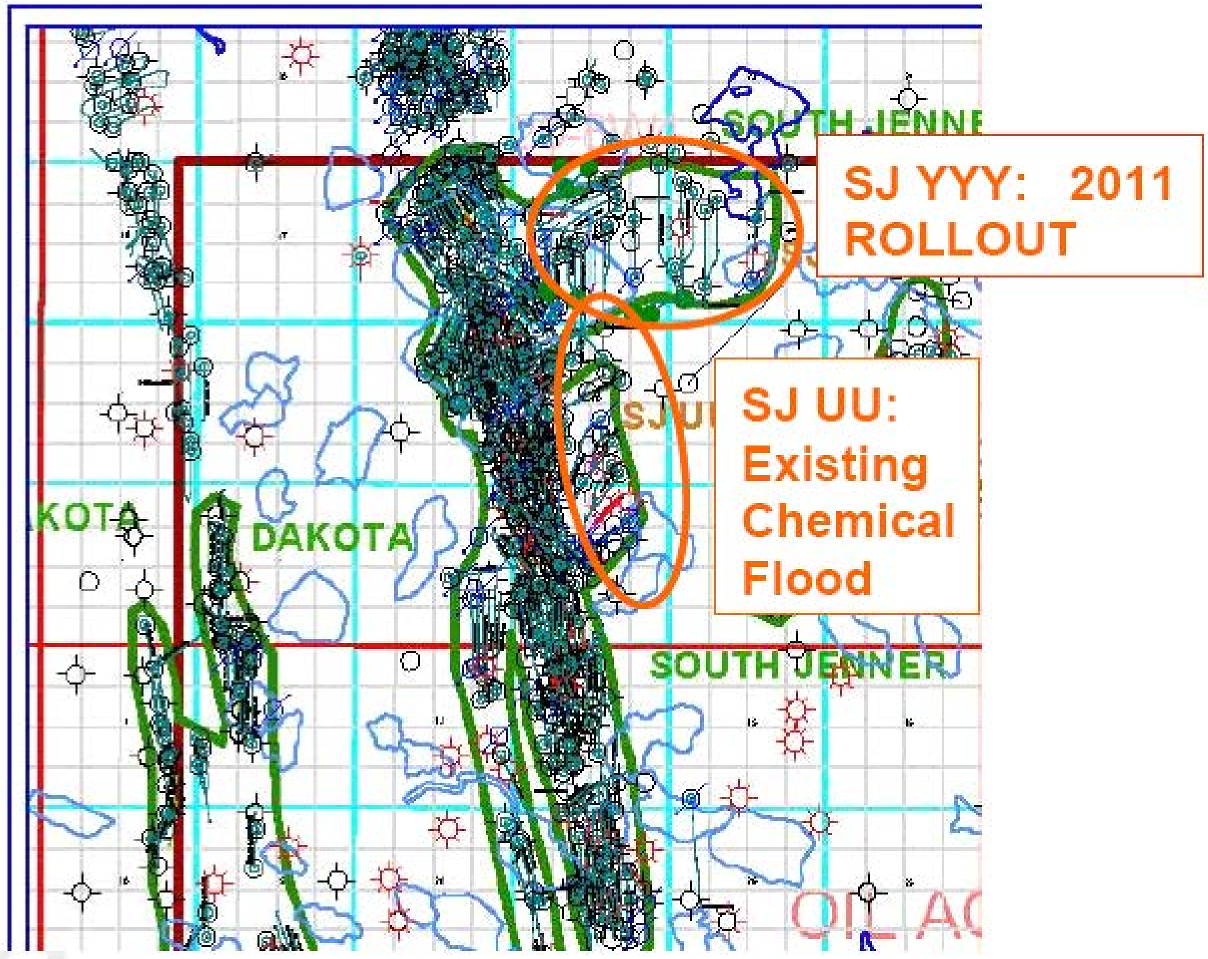



**Suffield Upper Mannville UU Water and Injection Pressure**

Figure 273

• Resource Application No. 1660236 submitted on Sept 7, 2010 for an ASP flood of the Suffield UM YYY pool.

• OOIP = 15 MMSTB, a true commercial sized ASP flood.

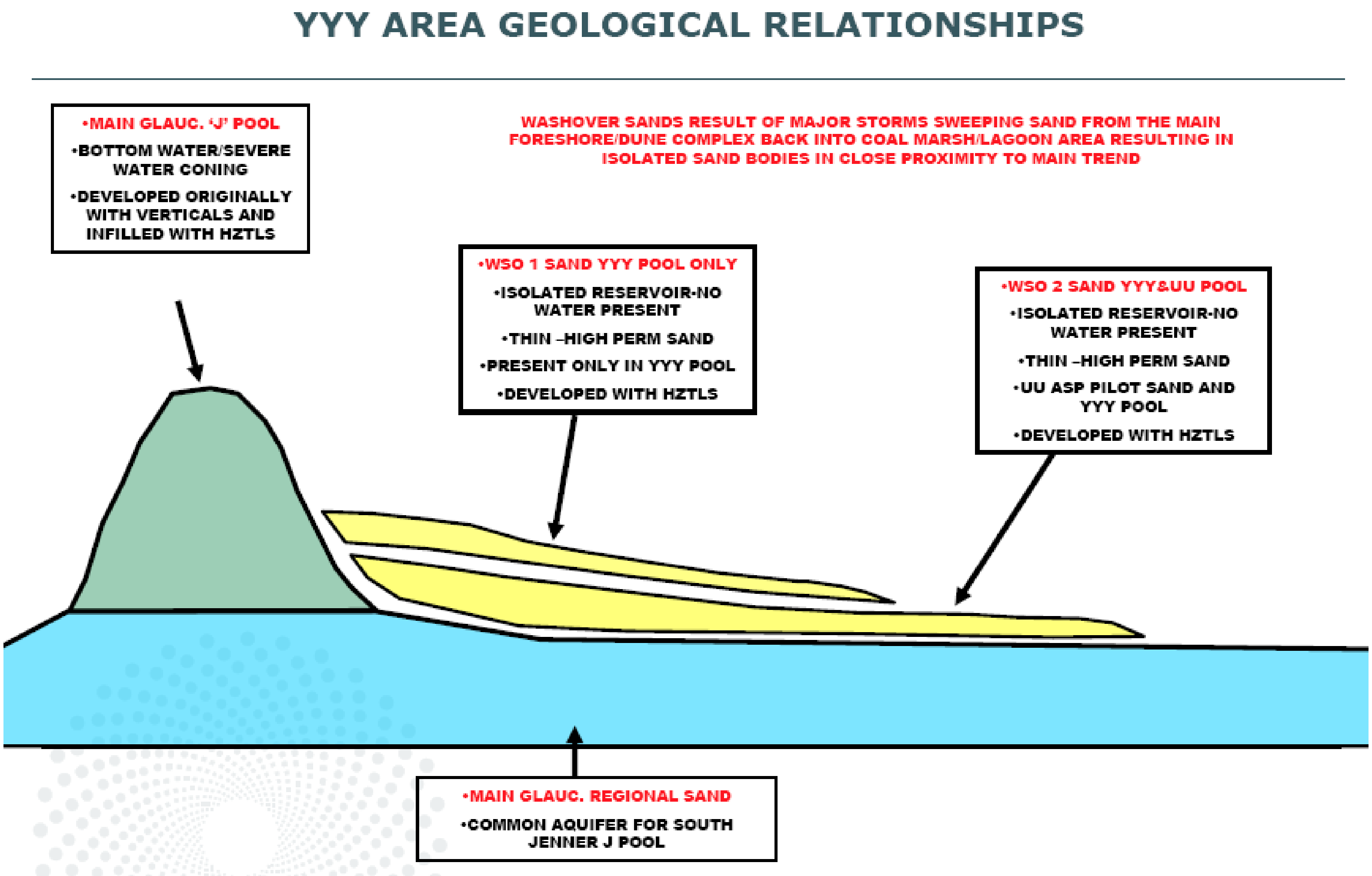



**Future Suffield Chemical Flooding – South Jenner Field – UM YYY Pool**

Figure 274

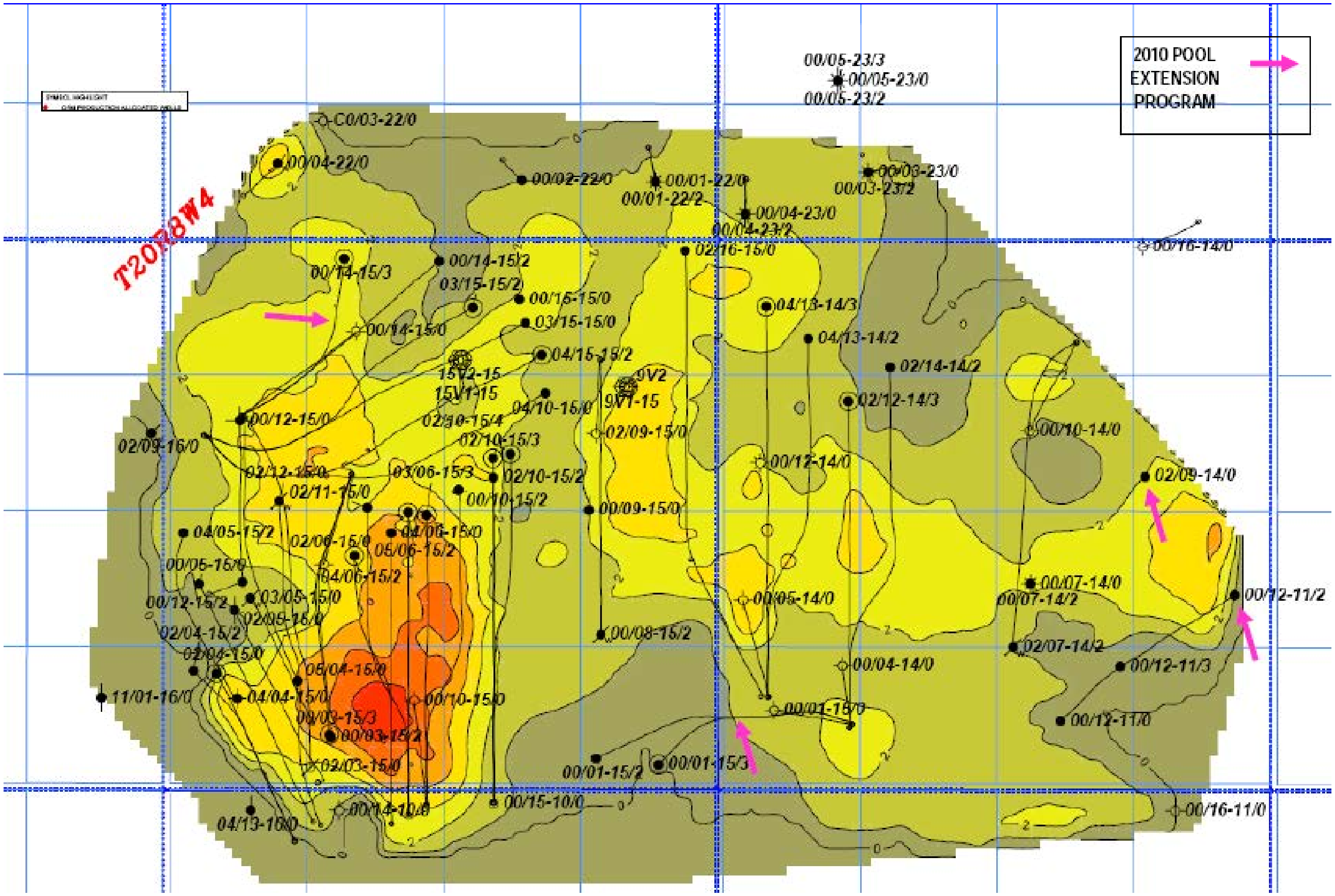


Sproule




**South Jenner Upper Mannville YYY Area Geological Relationships**

Figure 275

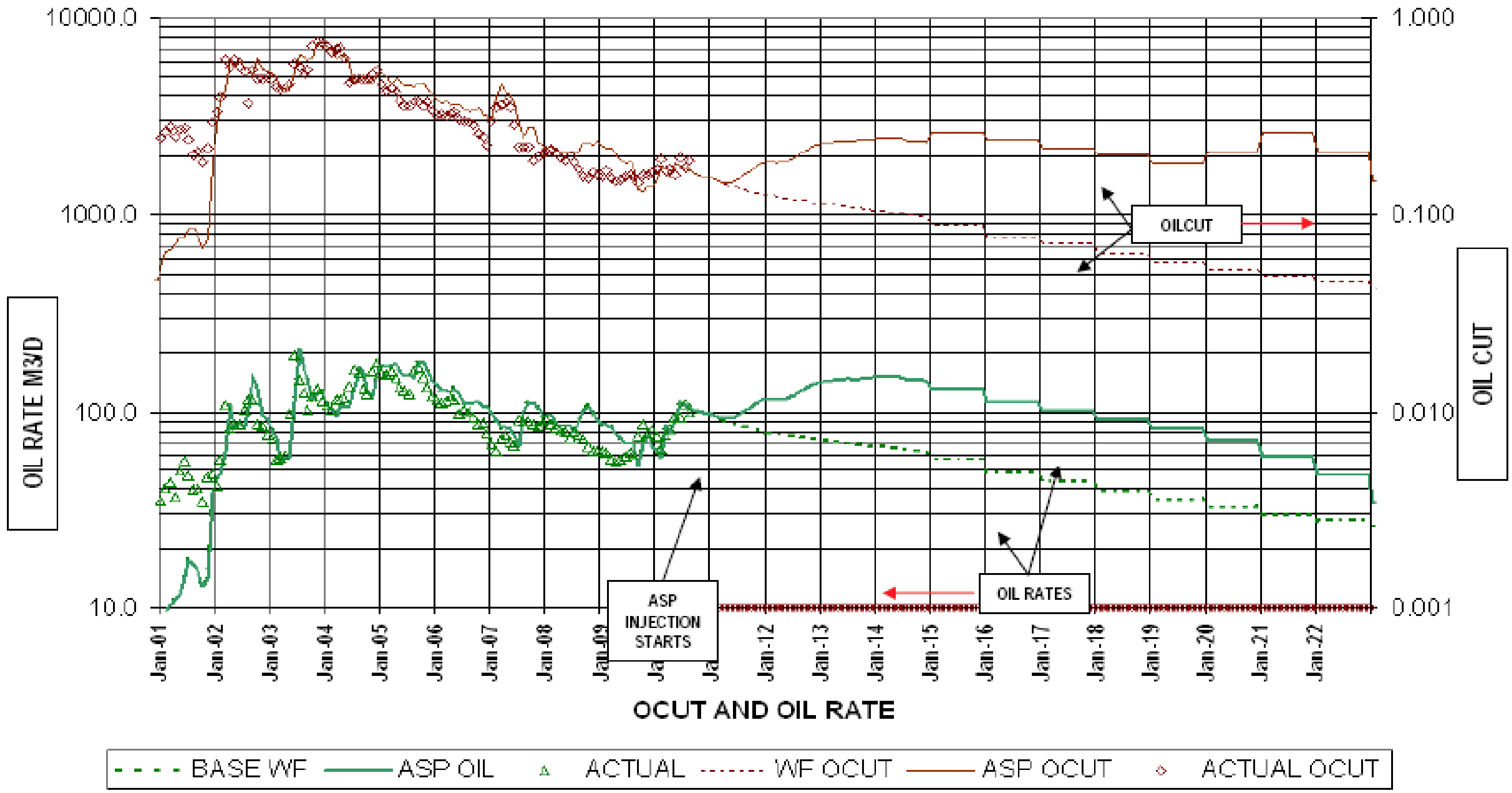



**South Jenner Upper Mannville YYY Pool WSO # 2 Gross Isopach**

Figure 276

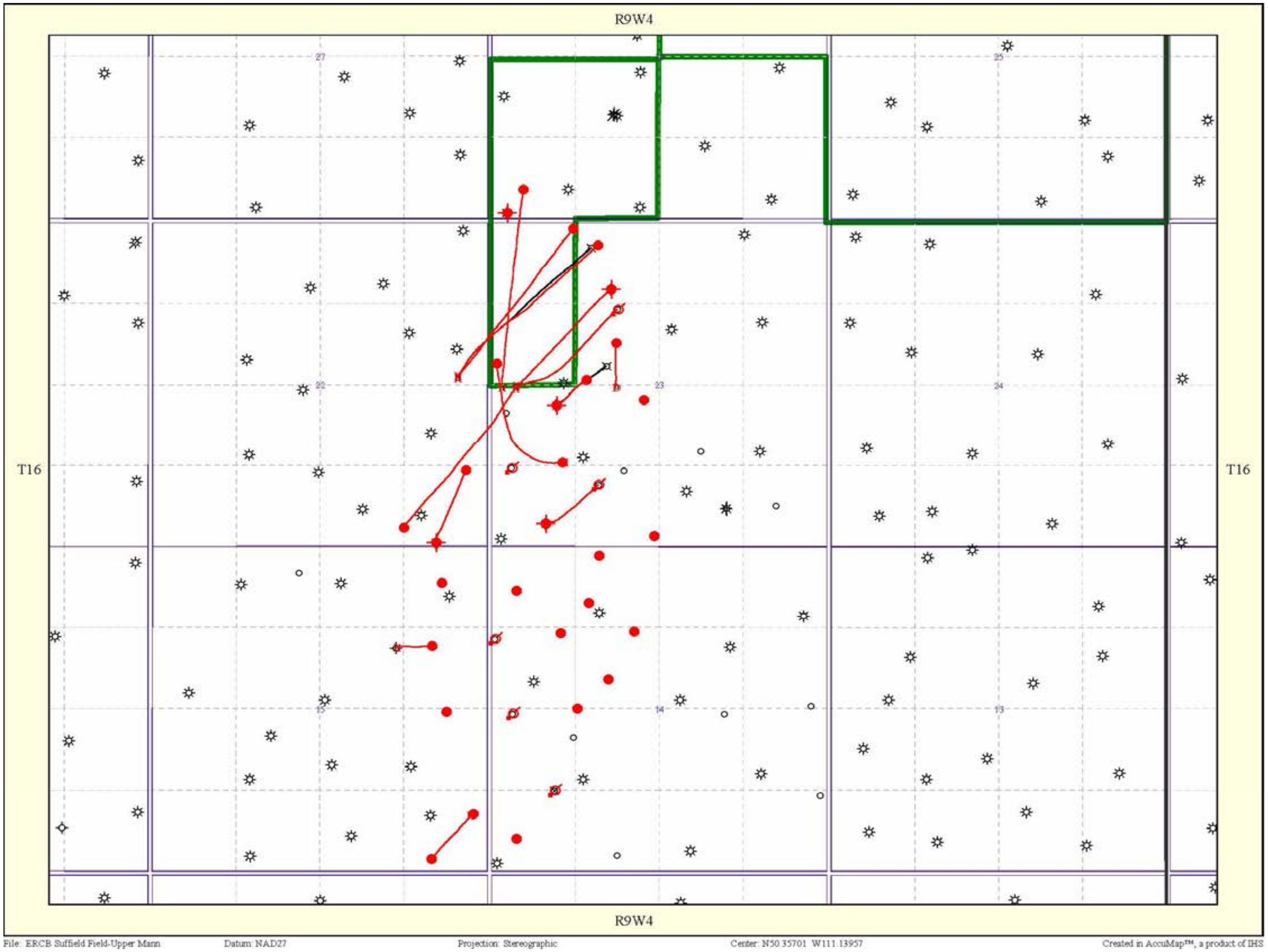


Sproule




**South Jenner Upper Mannville YYY Pool Waterflood vs ASP Prediction**

Figure 277




**Suffield Upper Mannville U - Well Locations**

Figure 278

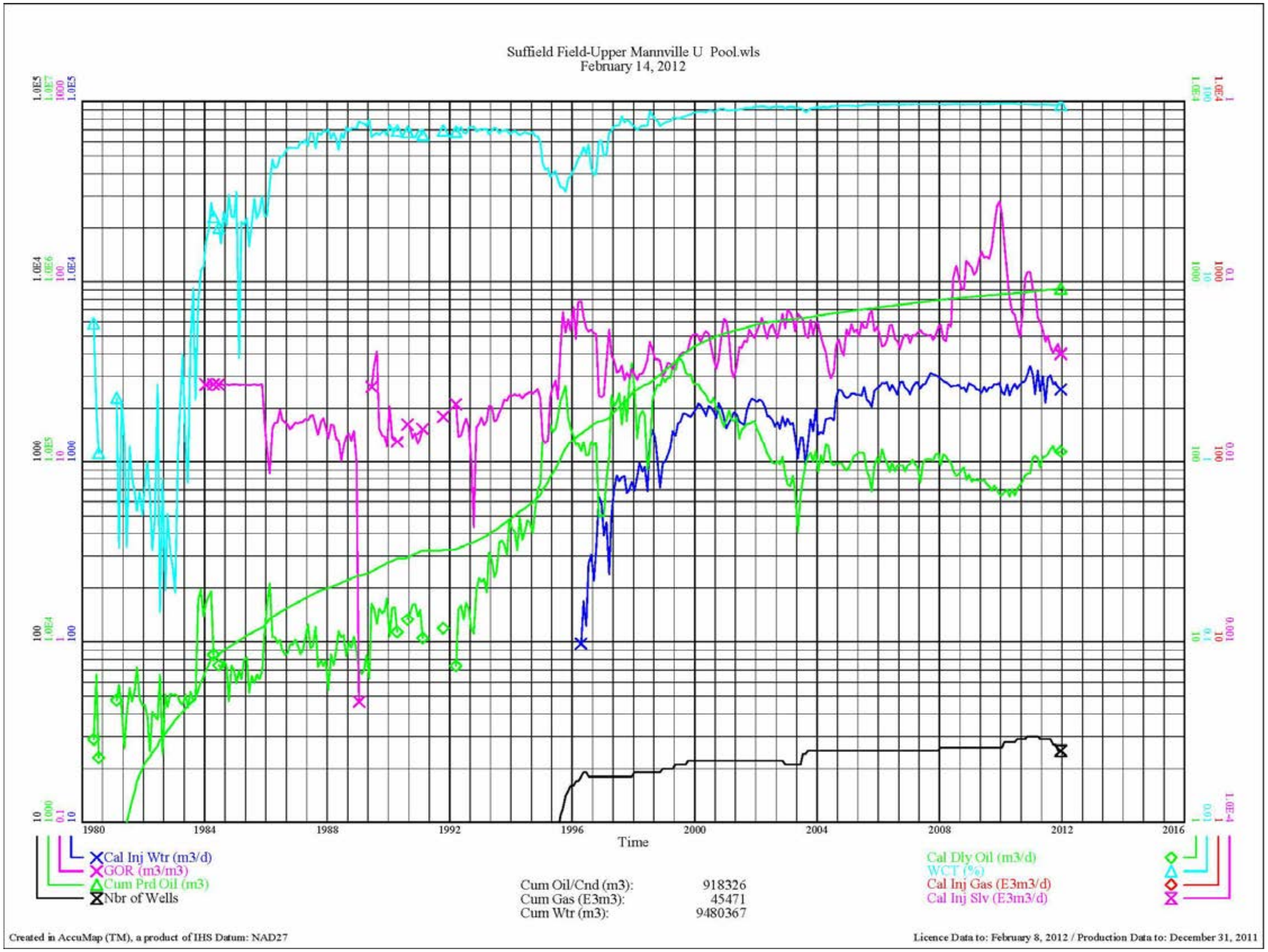
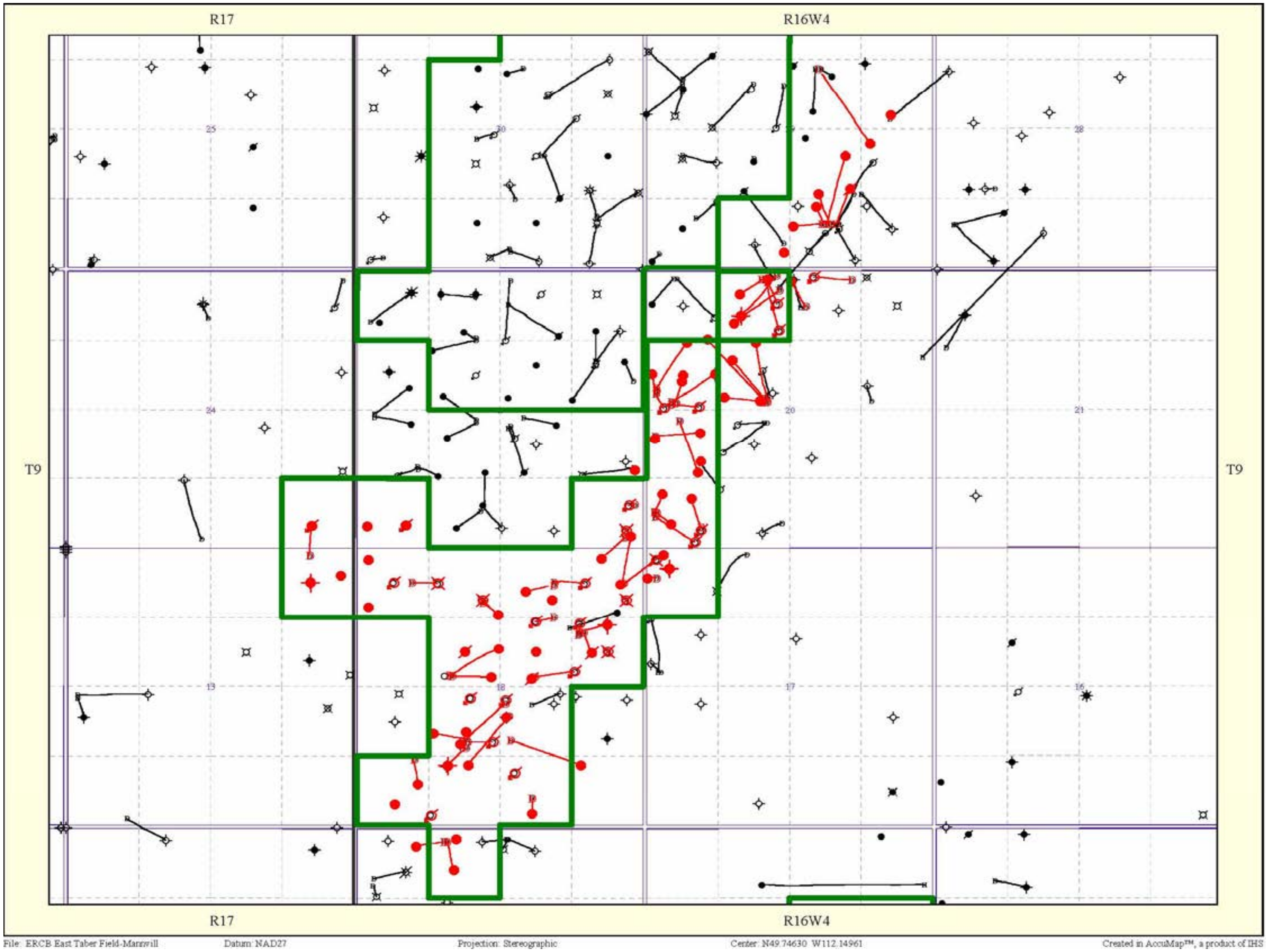


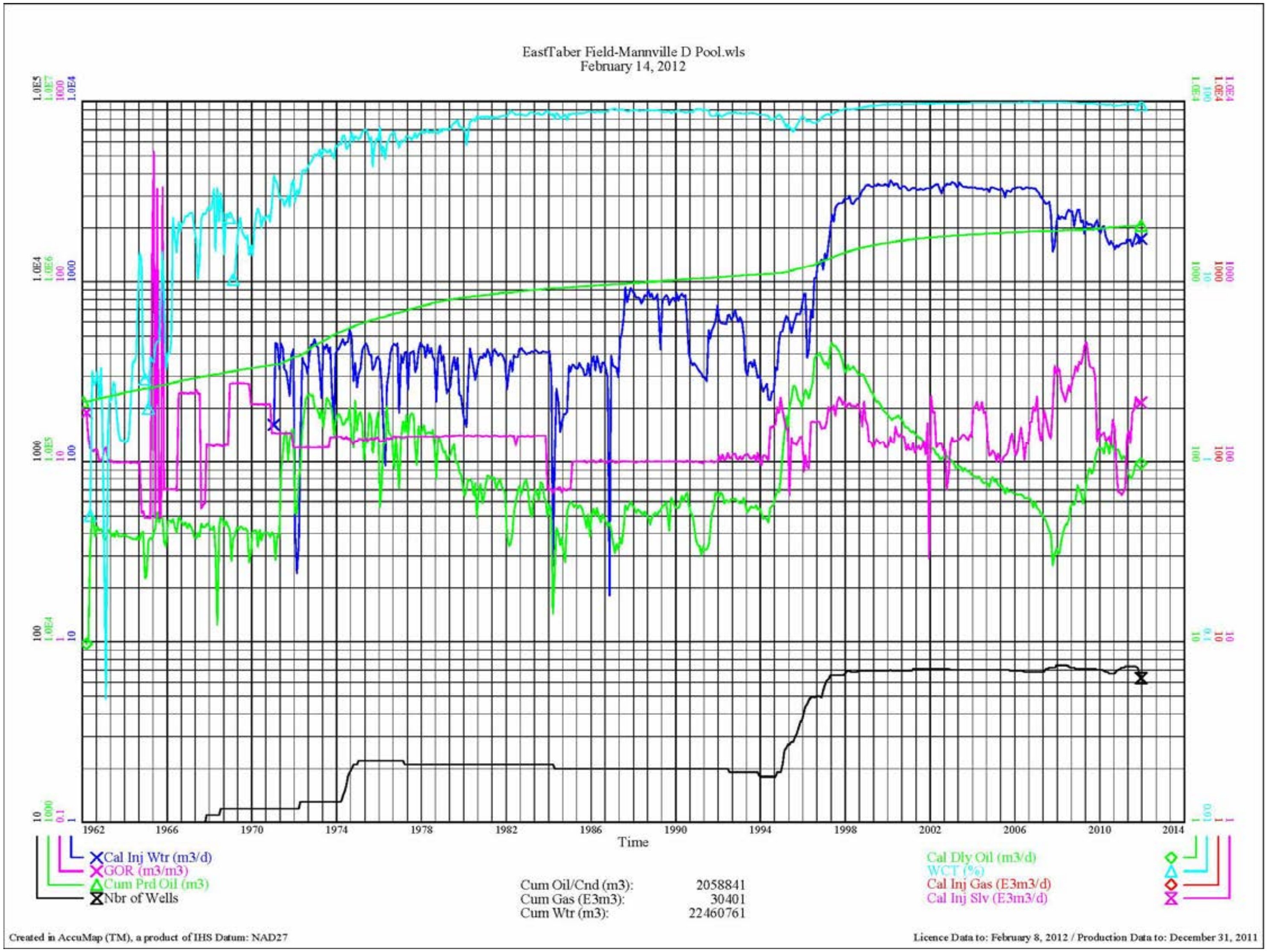

Figure 279

**Suffield Upper Mannville U - Production / Injection History**



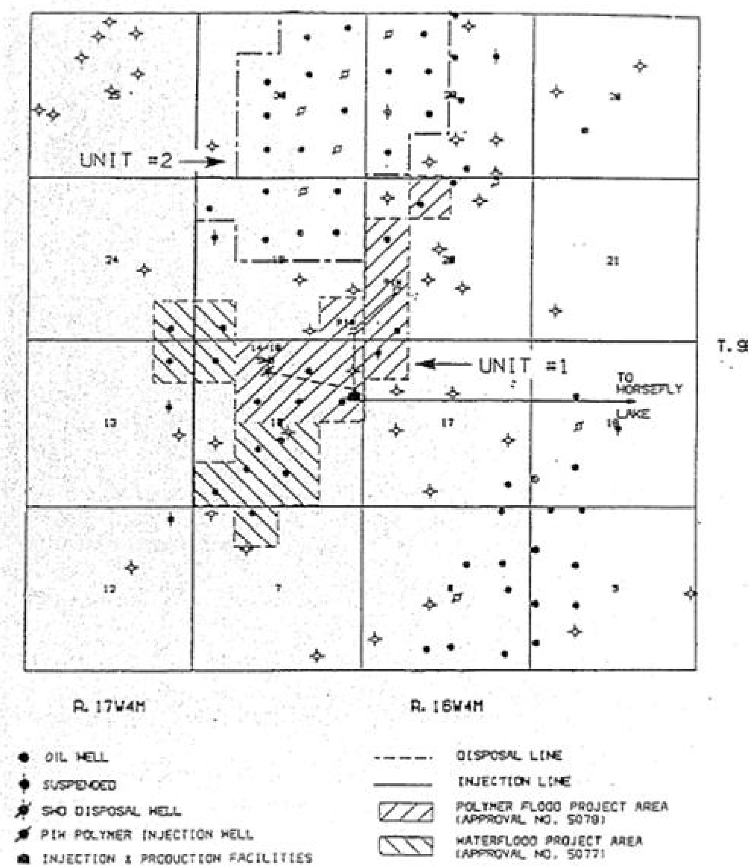

**Taber Mannville D – Well Locations**

Figure 280



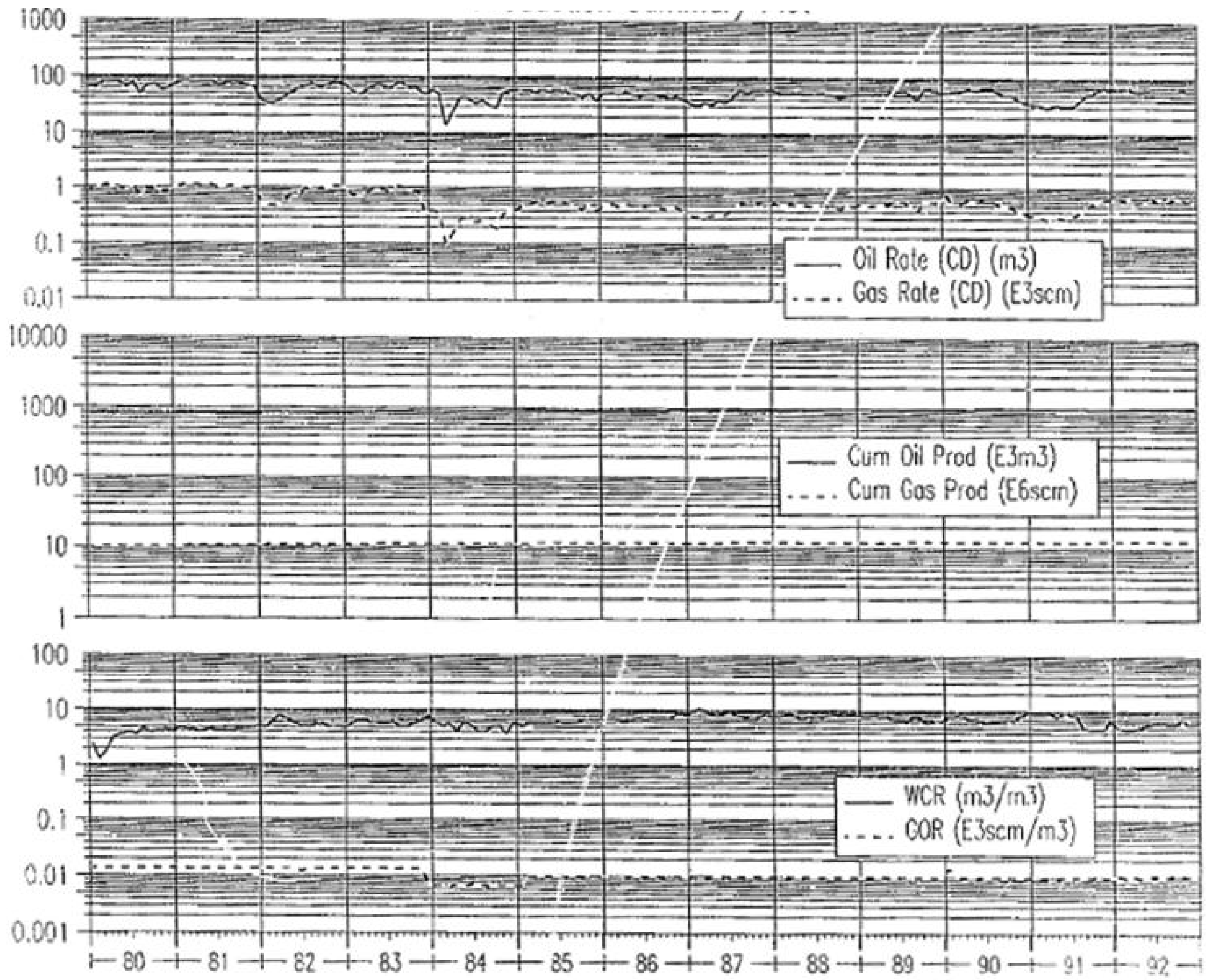

**Taber Mannville D - Production / Injection History**

Figure 281



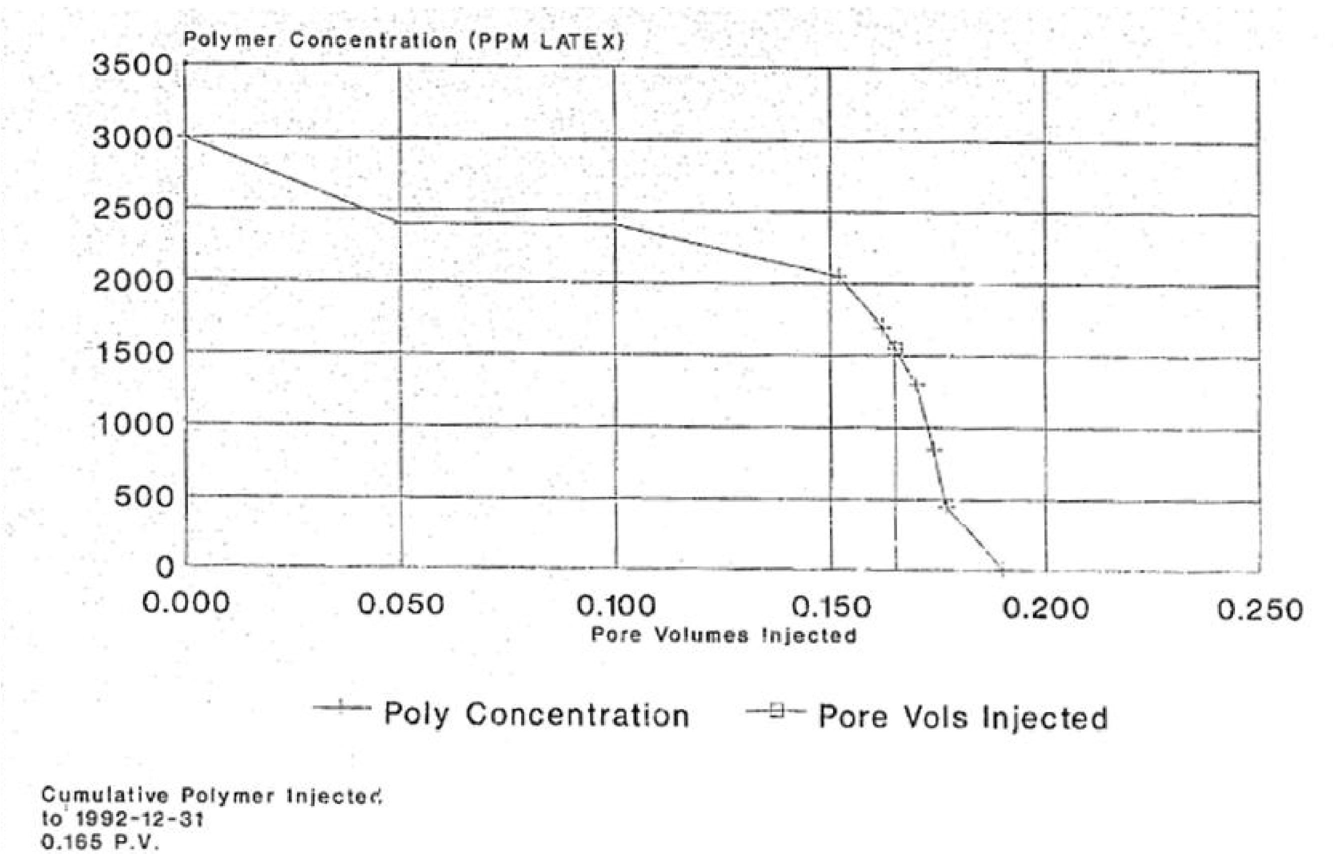

**Taber Mannville D Pool Unit No 1 Project Areas**

Figure 282




**Taber Mannville D Pool Unit 1 – Pilot Production Summary Plot**

Figure 283

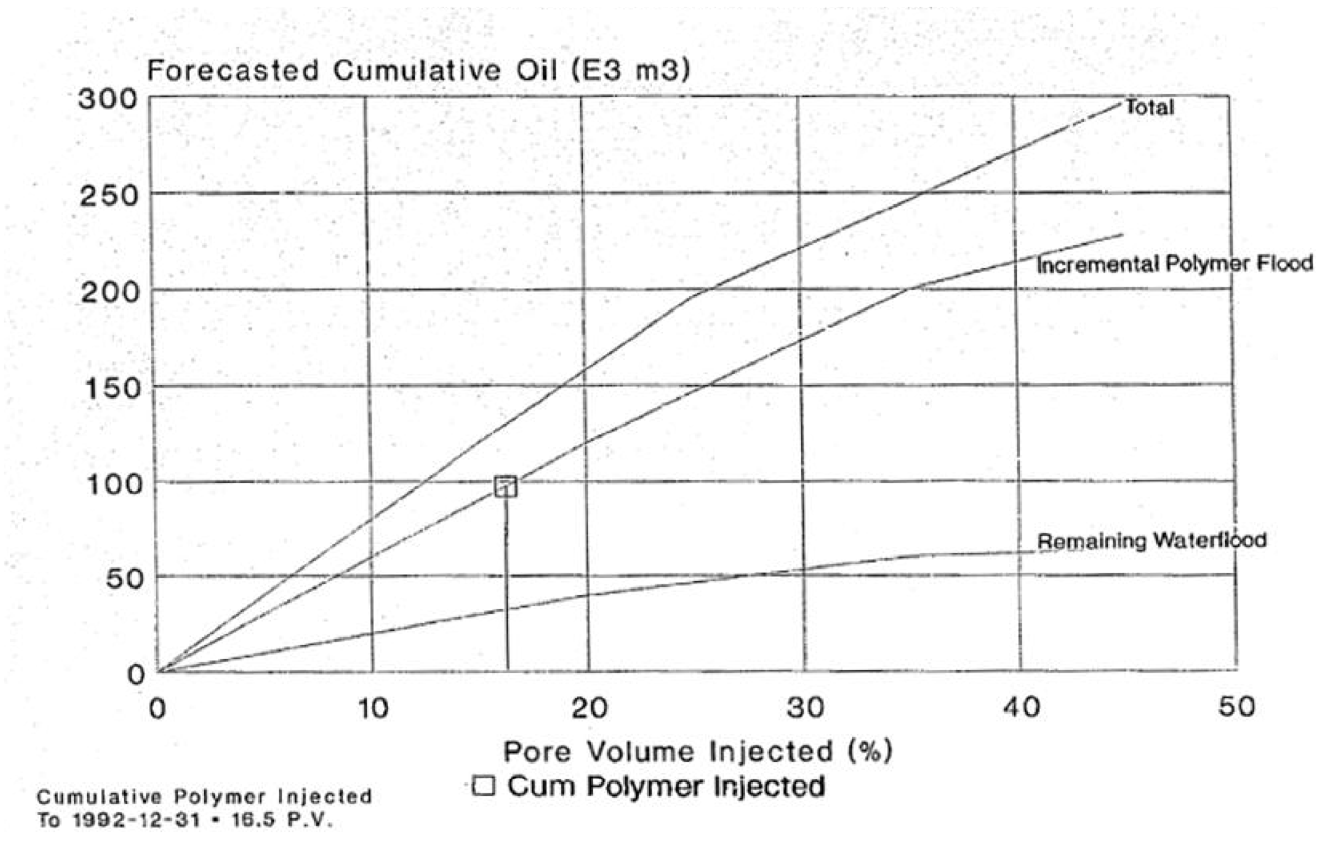



**Taber Mannville D Pool Unit 1 – Tapered Polymer Slug Design**

Figure 284



Sproule

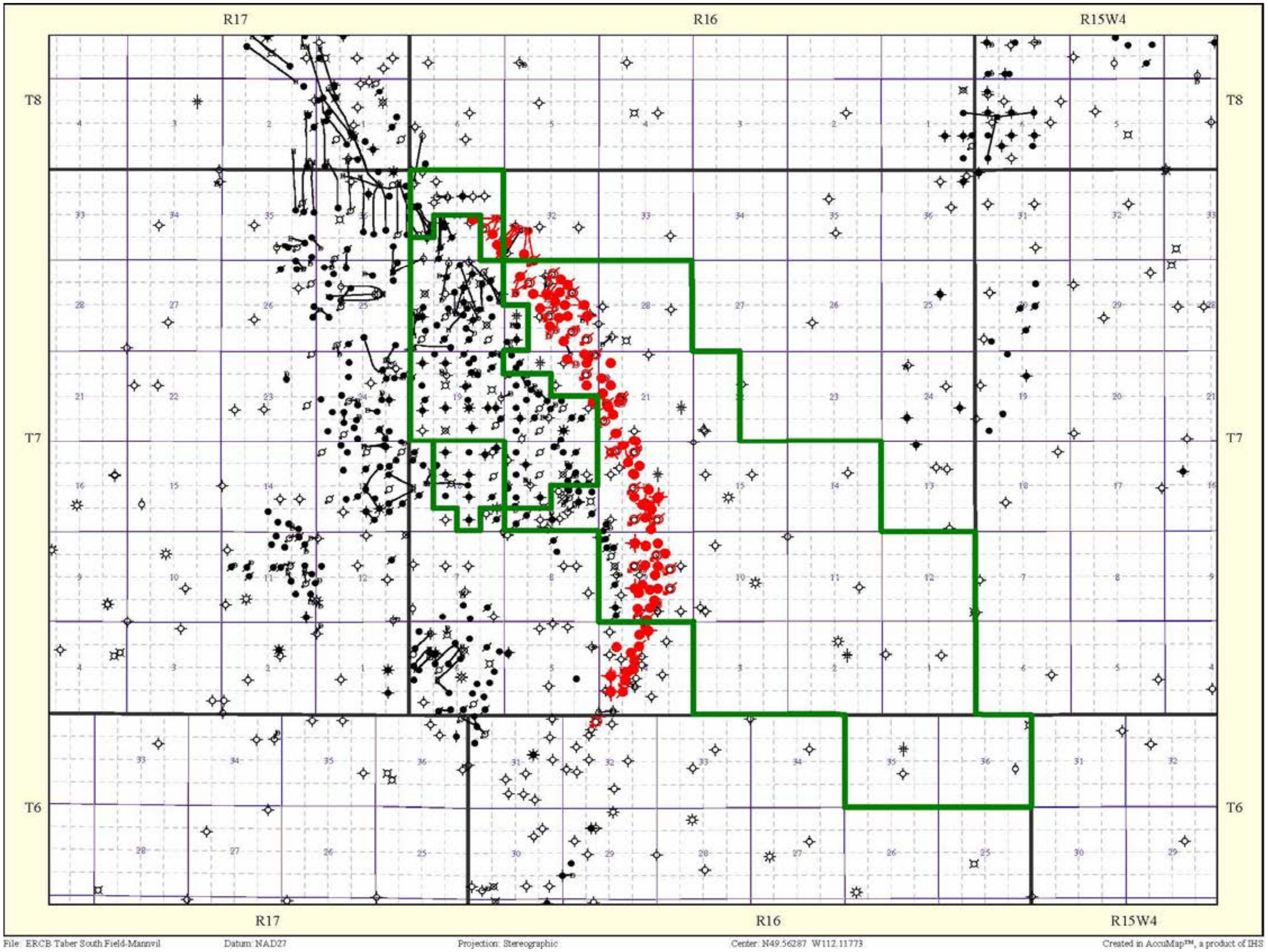



**Taber Mannville D Pool Unit 1 – Polymer Area Recovery Curves**
**Actual vs Predicted Performance**

Figure 285

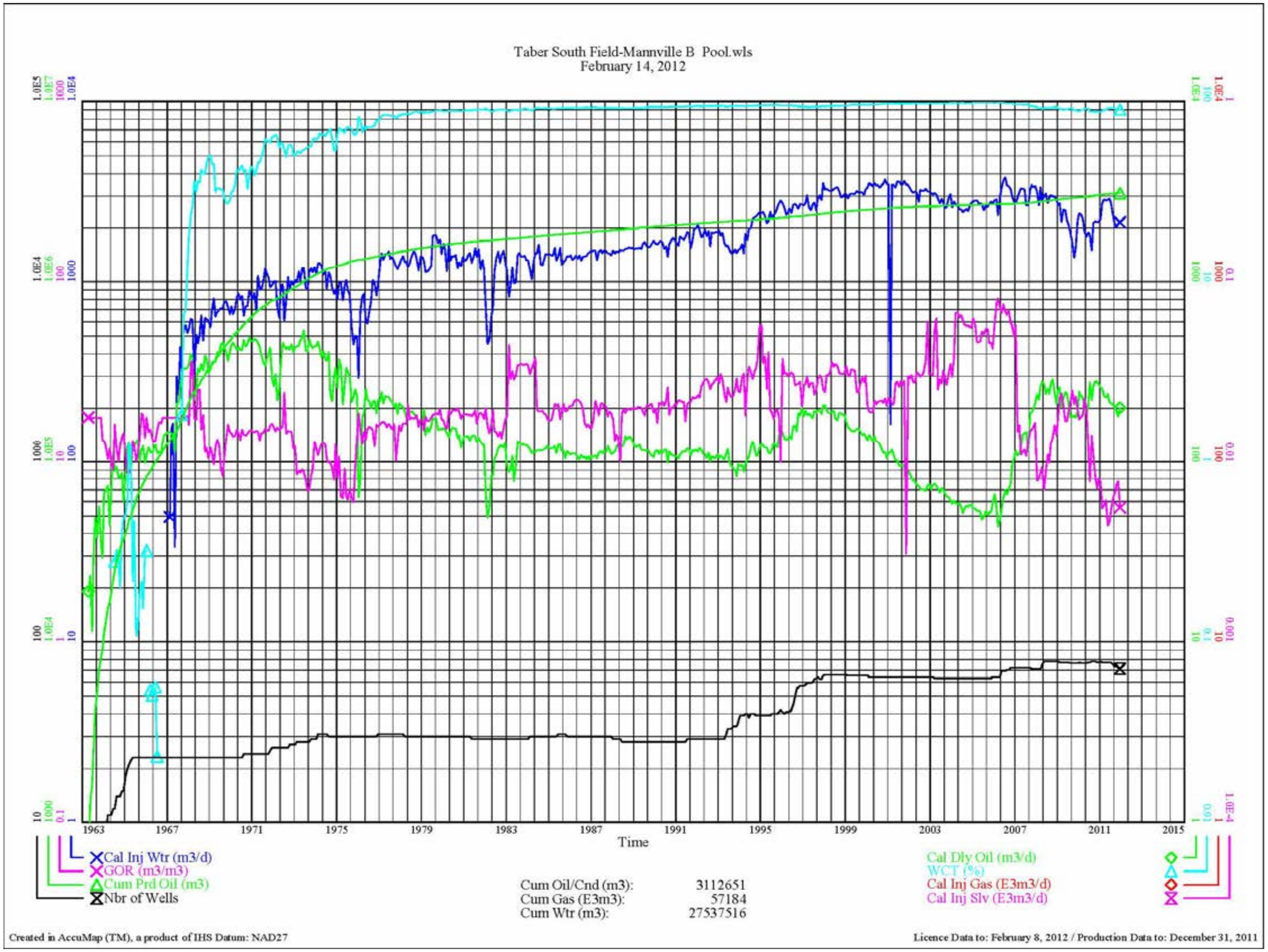


Sproule




**Taber South Mannville B - Well Locations**

Figure 286



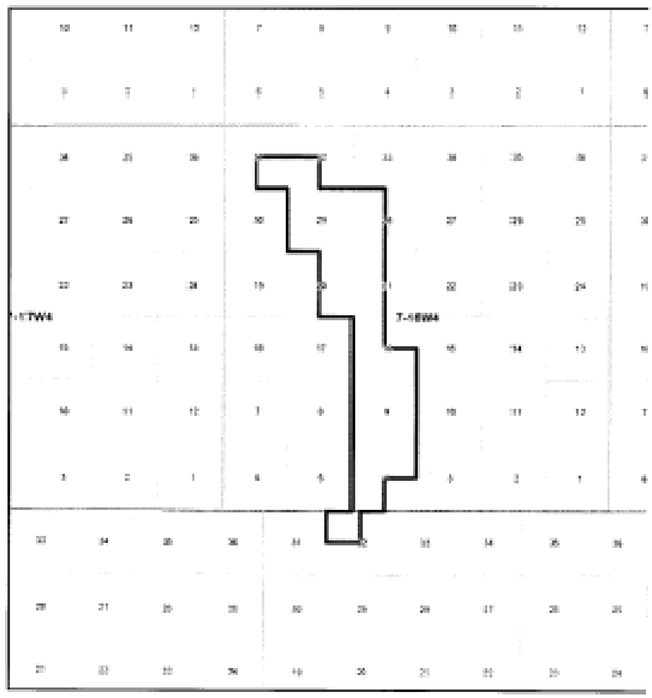

**Taber South Mannville B - Production / Injection History**

Figure 287



Sproule

**POOL ORDER: 895 248002 2001-02-01**




Field/Pool Code: 895 248002
Field Name: TABER SOUTH
Pool Name: MANNVILLE B
Reference Well: 00/02-29-007-16W4/0
Well Depth: 979.01 - 992.73 m
Area of Change:

Effective Date: 2001-02-01

EUB

## Taber South – Mannville B Pool – Pool Order

Figure 288



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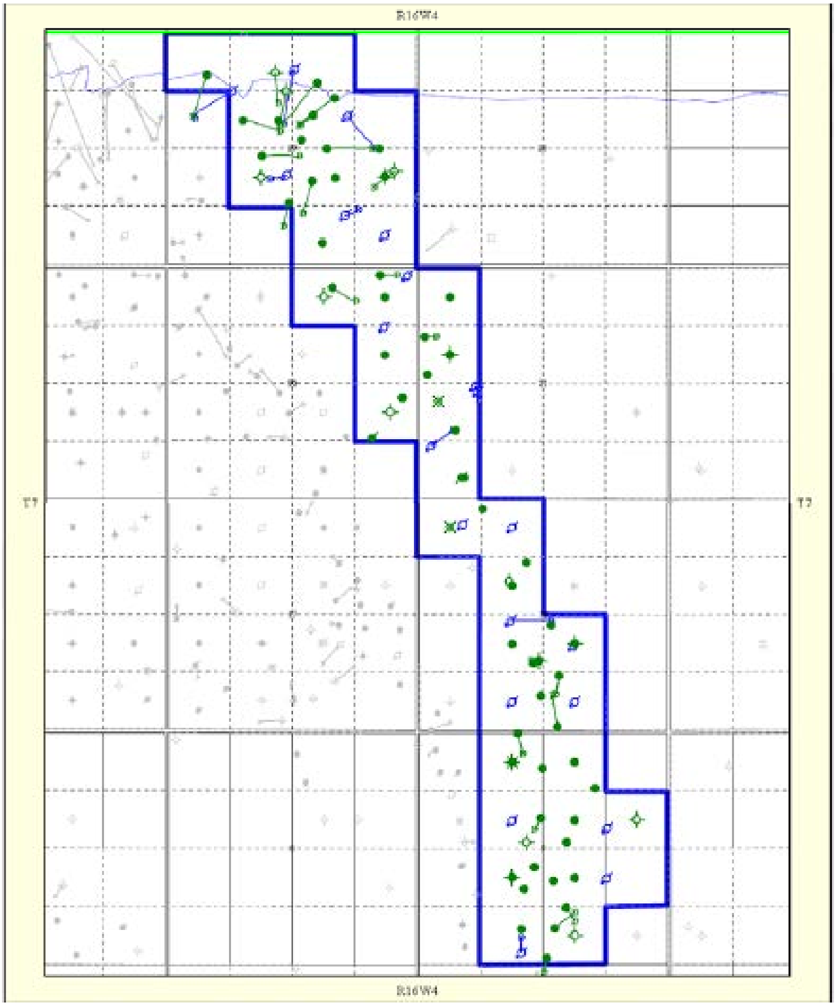
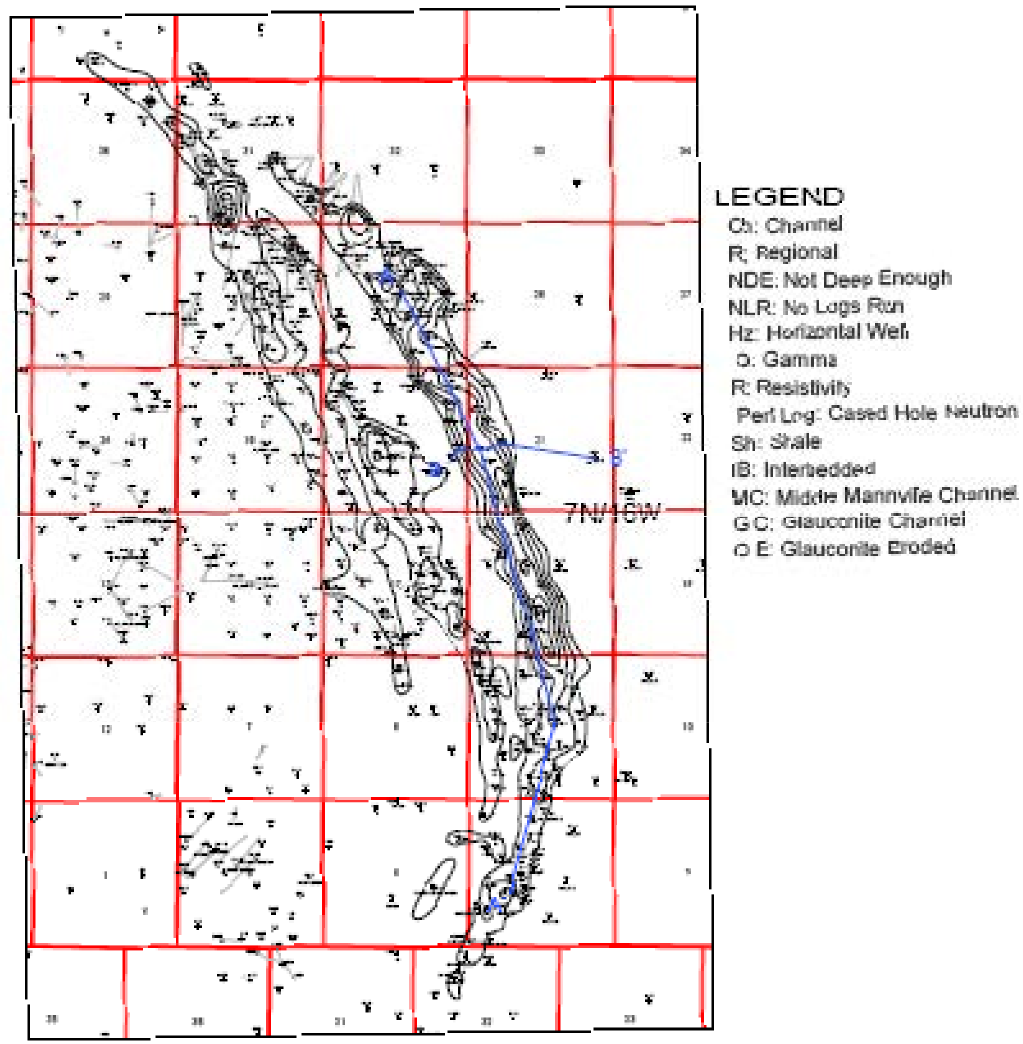



**Taber South – Mannville B Pool Pilot**

Figure 289




**Taber South – Mannville B Net Oil Isopach**

Figure 290

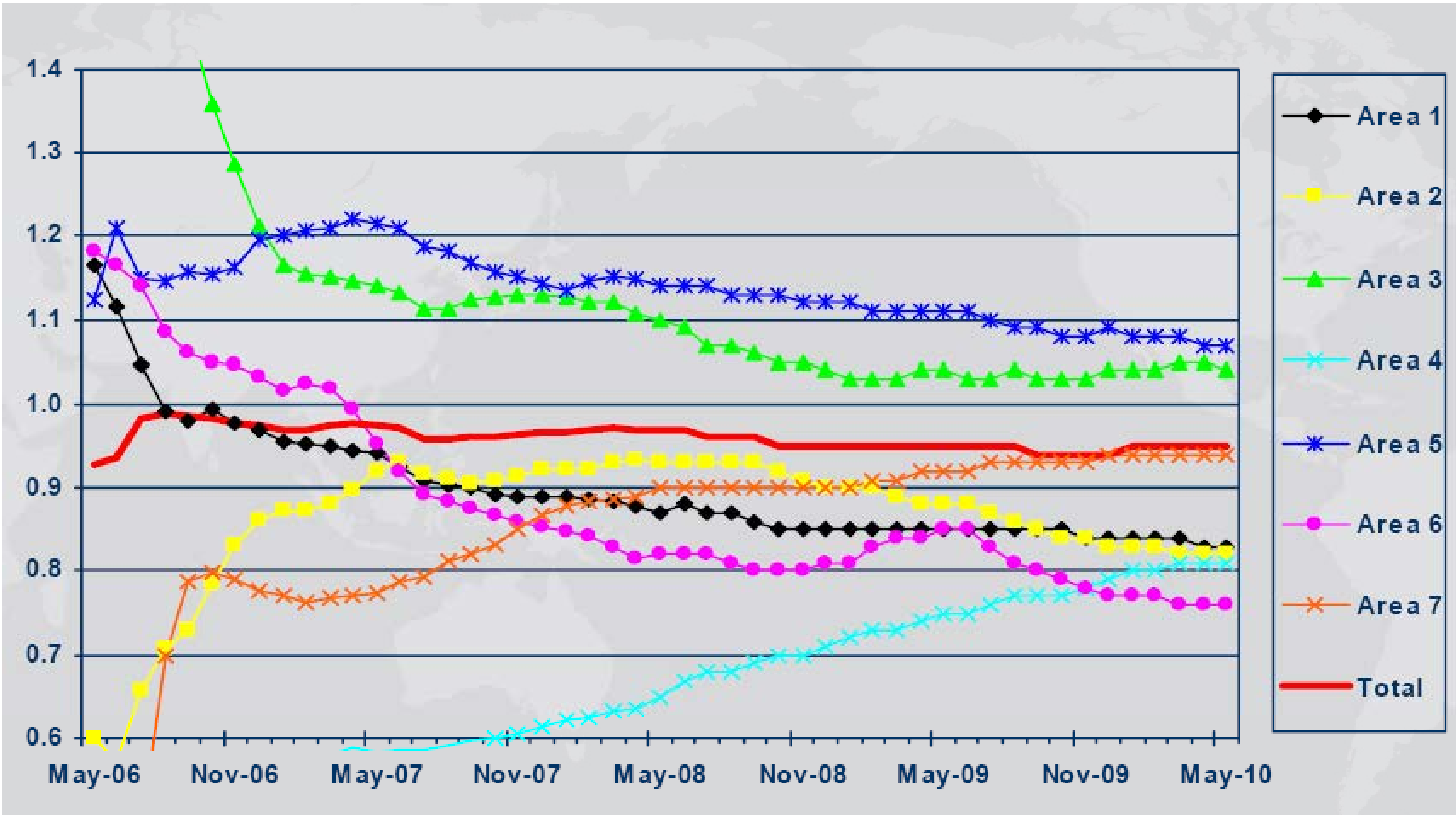
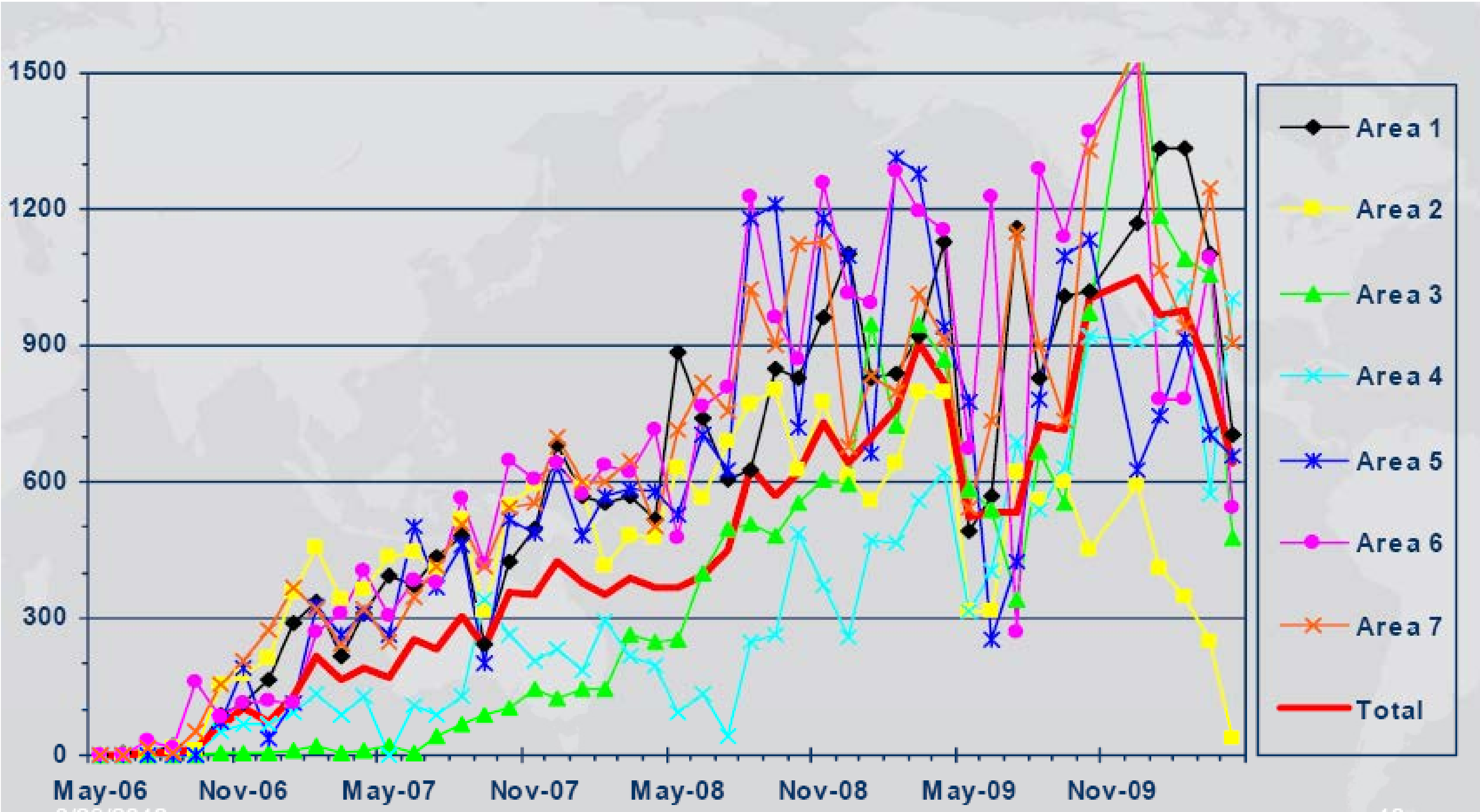



Figure 291

**Taber South – Mannville B Cumulative VRR**



Sproule




**Taber South – Mannville B Polymer Concentrations in ppm**
**(By Area & Total Approval Area)**

Figure 292



Sproule

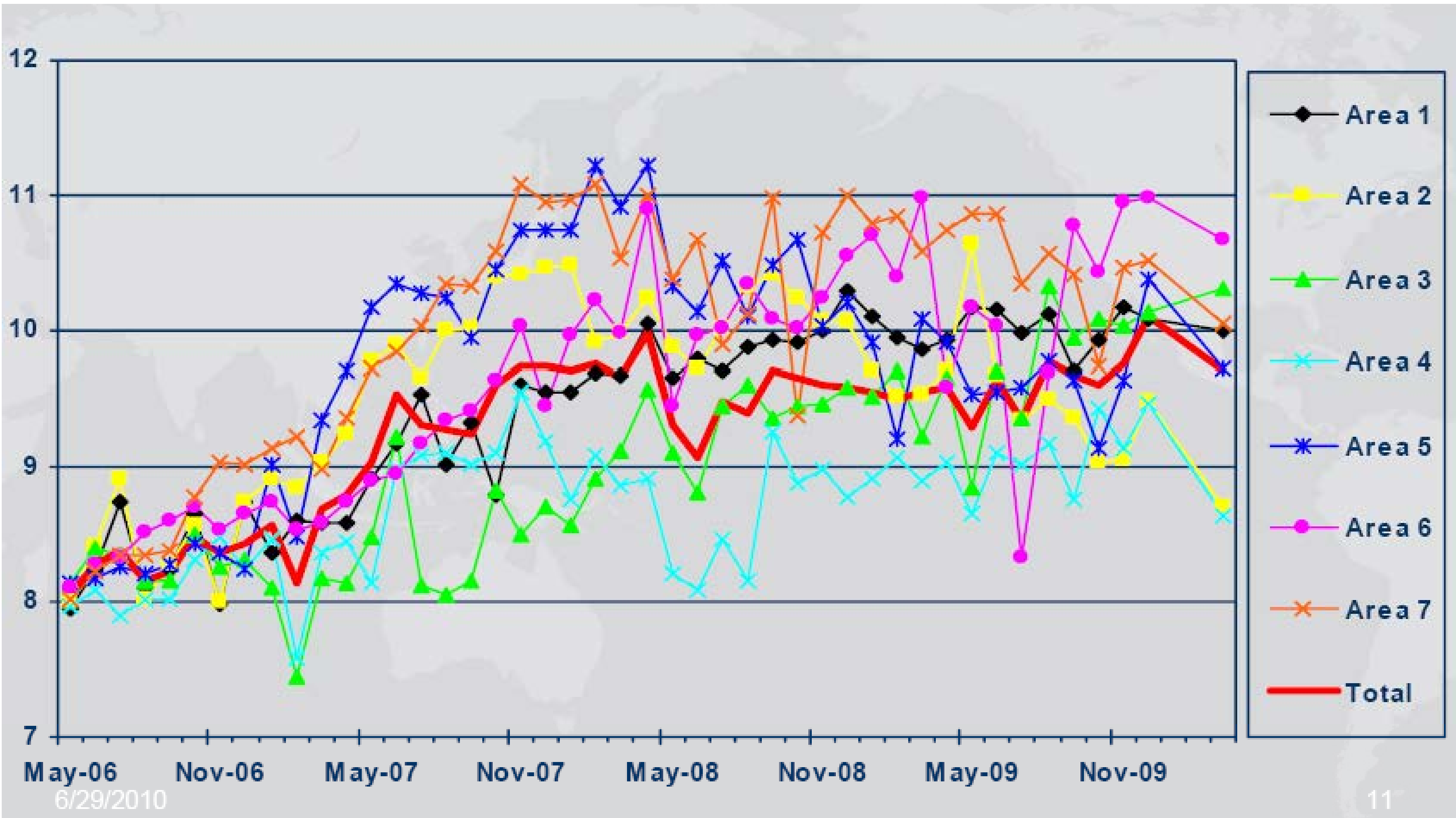
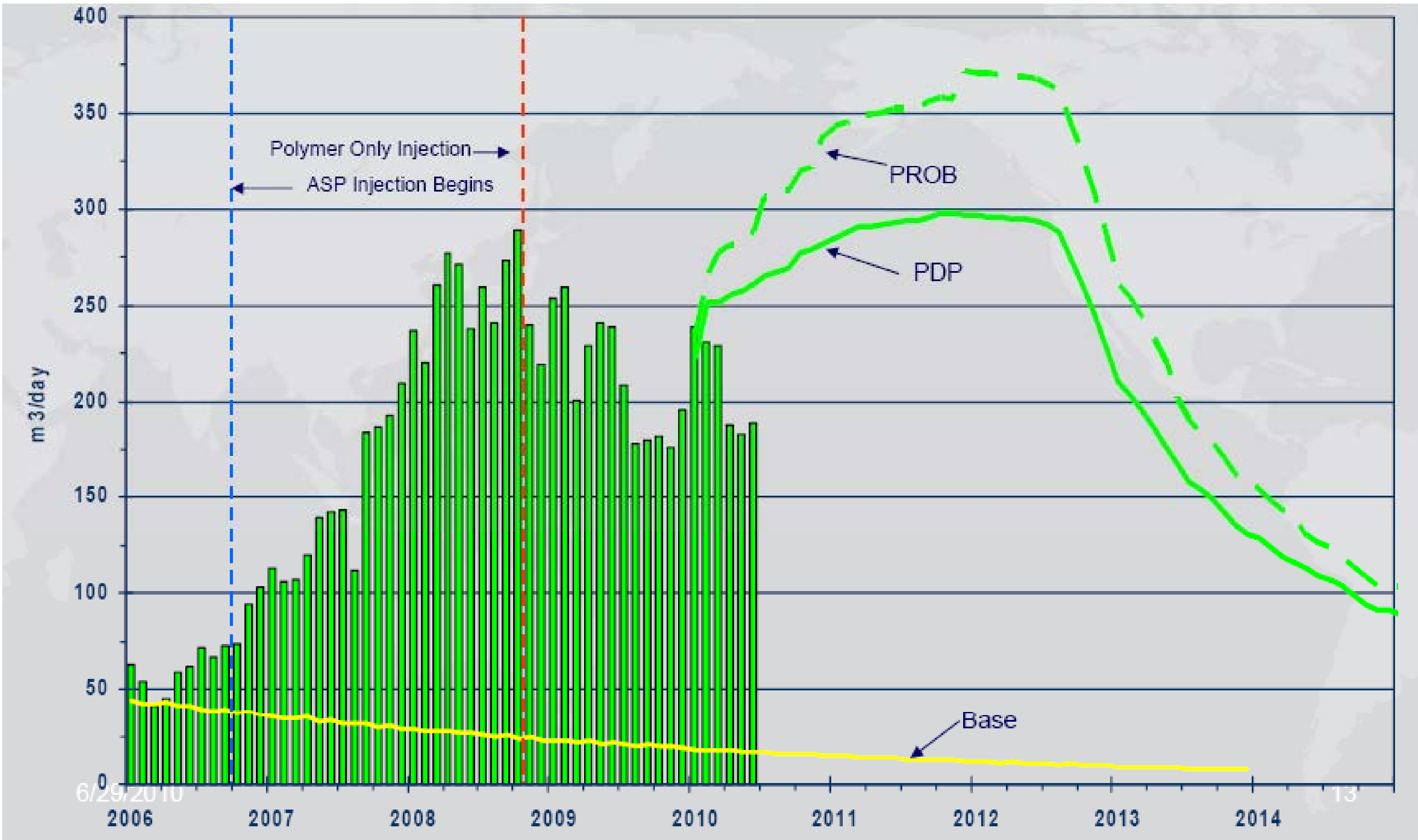



Figure 293

**Taber South – Mannville B pH of Produced Wells**
**(By Area & Total Approval Area)**




**Taber South – Mannville B Production & Forecast**

Figure 294

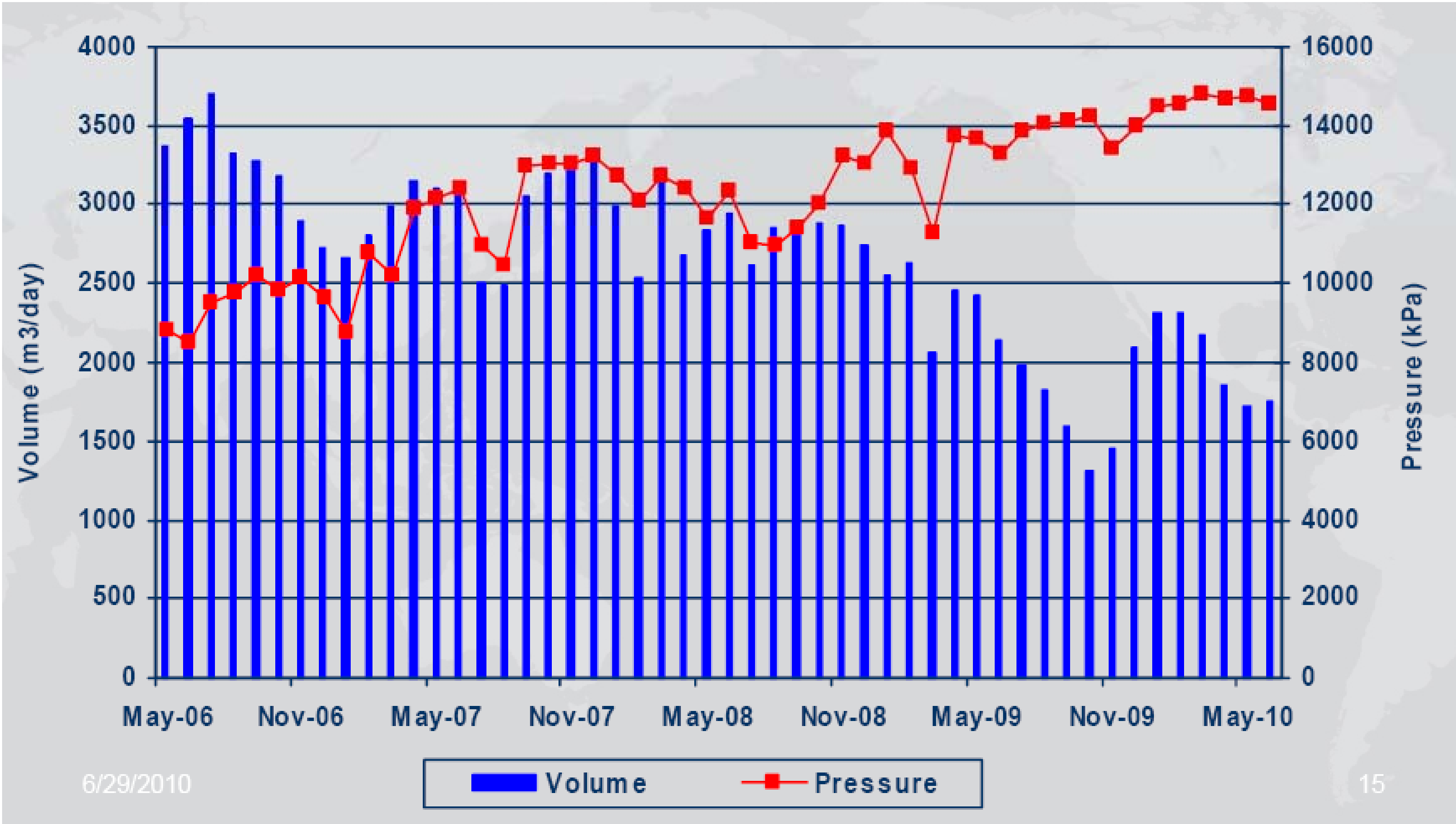
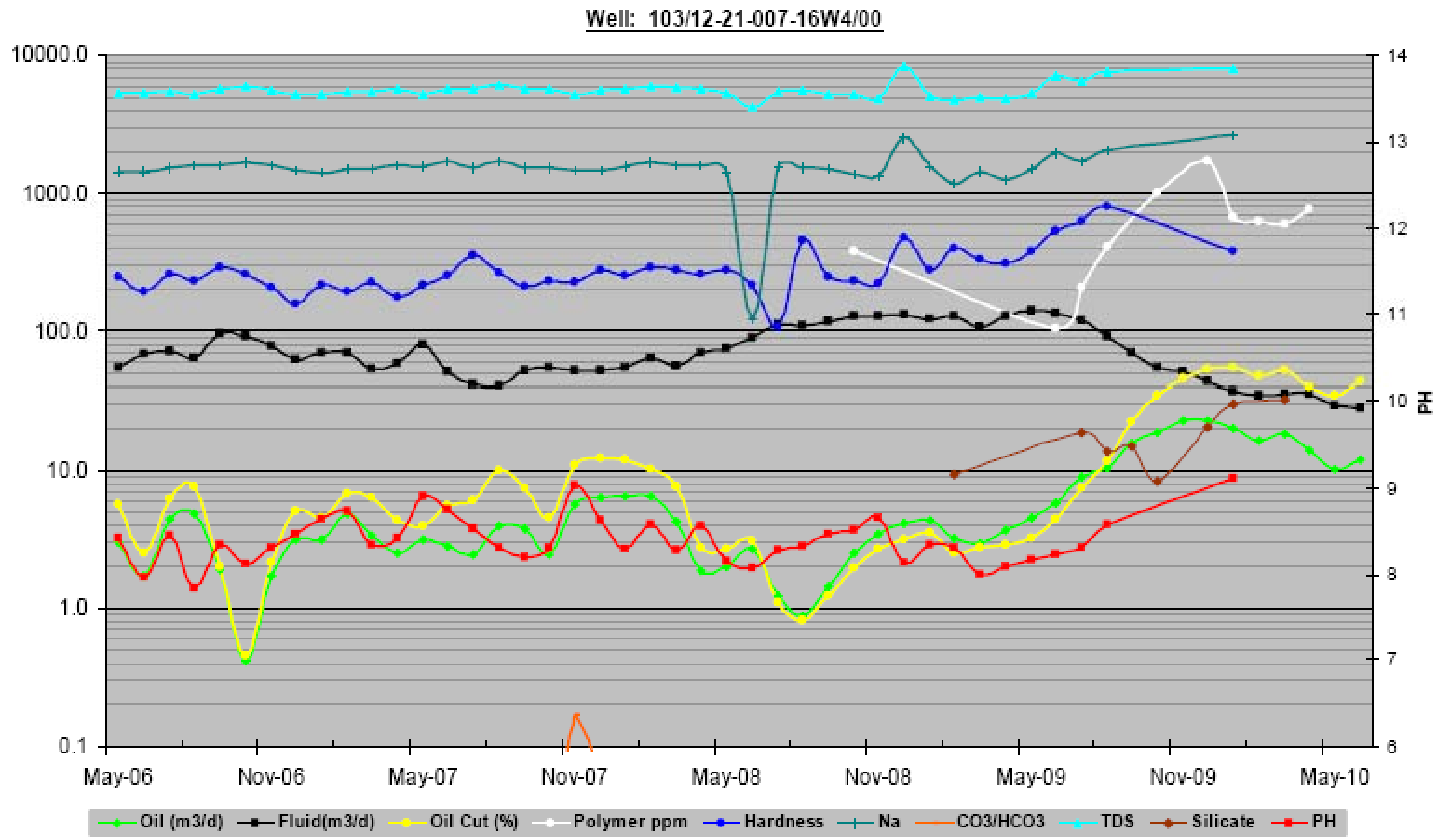



Figure 295

**Taber South – Mannville B Injection Volumes & Pressures**
**(Monthly Averages Including Downtime)**

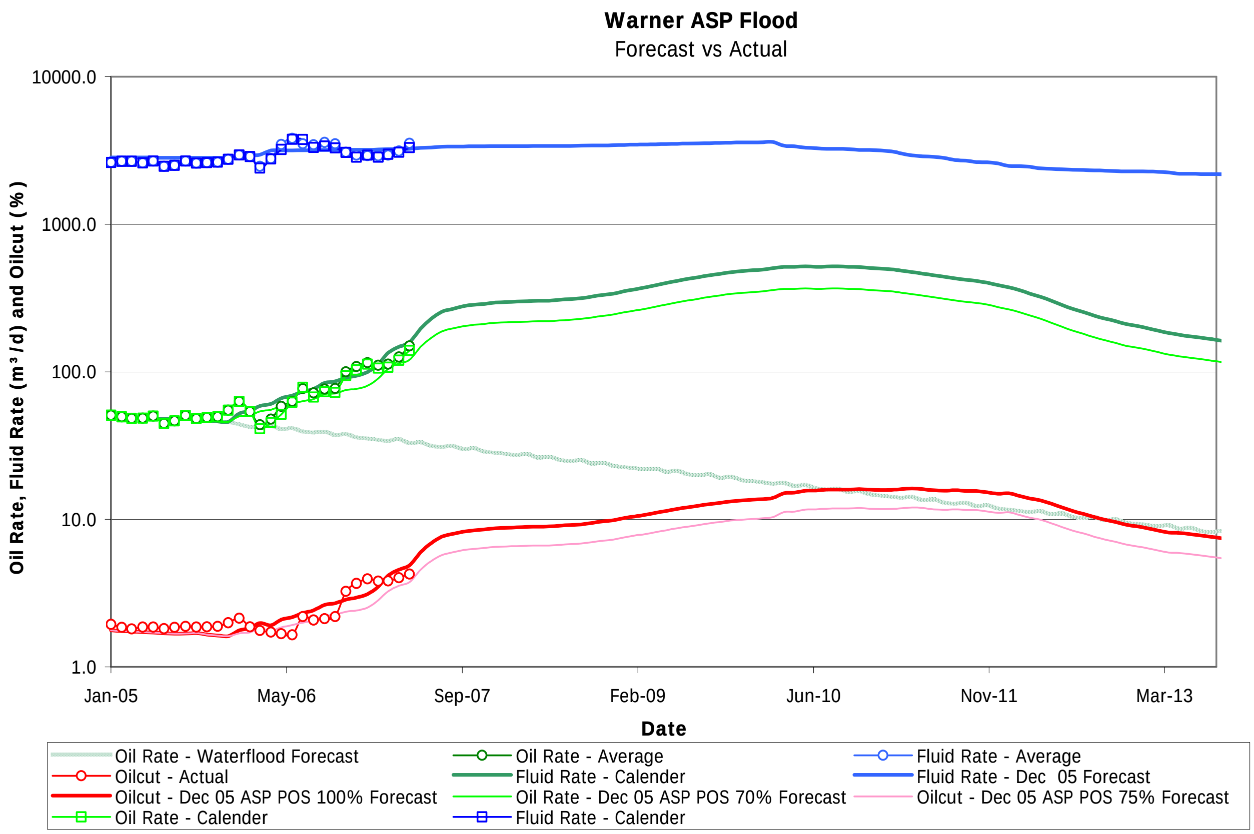


Sproule




**Taber South – Mannville B Well Graph**
**Some of the Key Indicators Used to Monitor Wells**

Figure 296




**Taber South – Mannville B Comparison of Production to Waterflood and ASP Production**

Figure 297

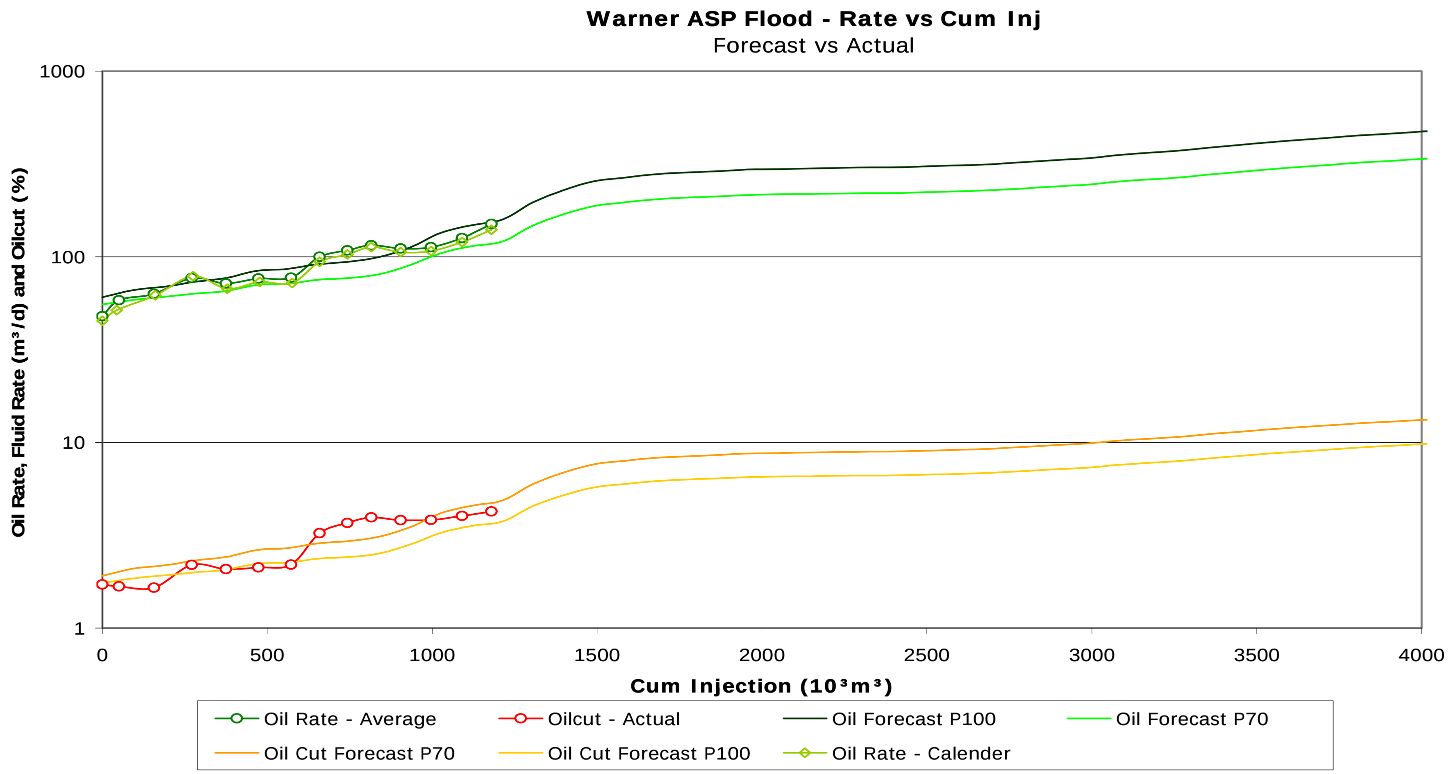



Figure 298

**Taber South – Mannville B Oil Production Based on ASP Volumes Injected**

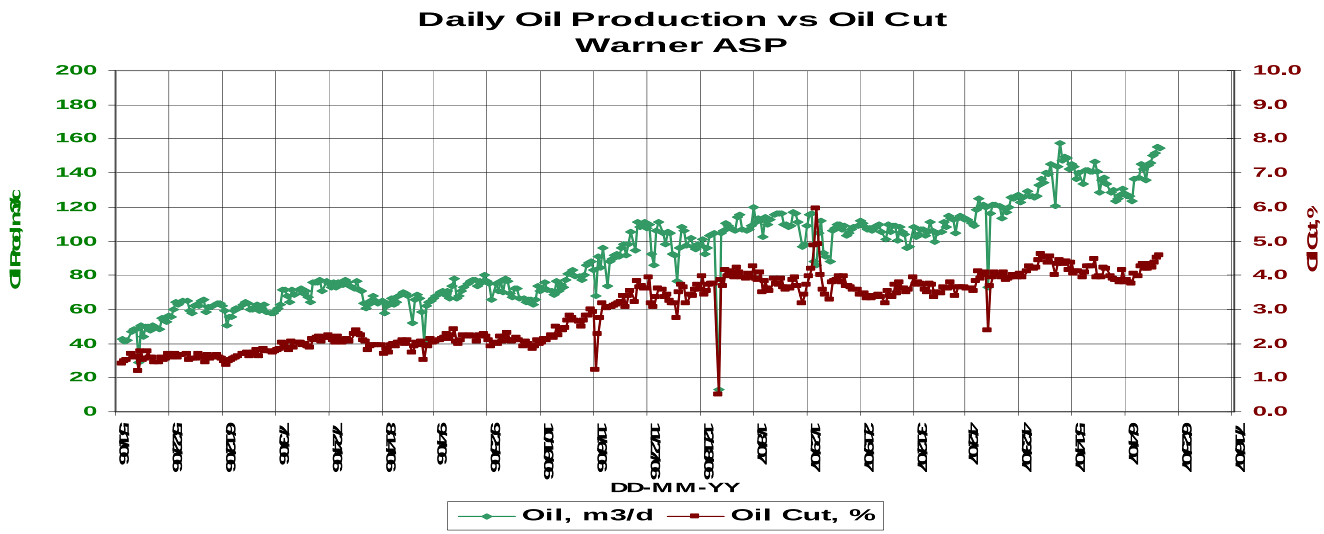
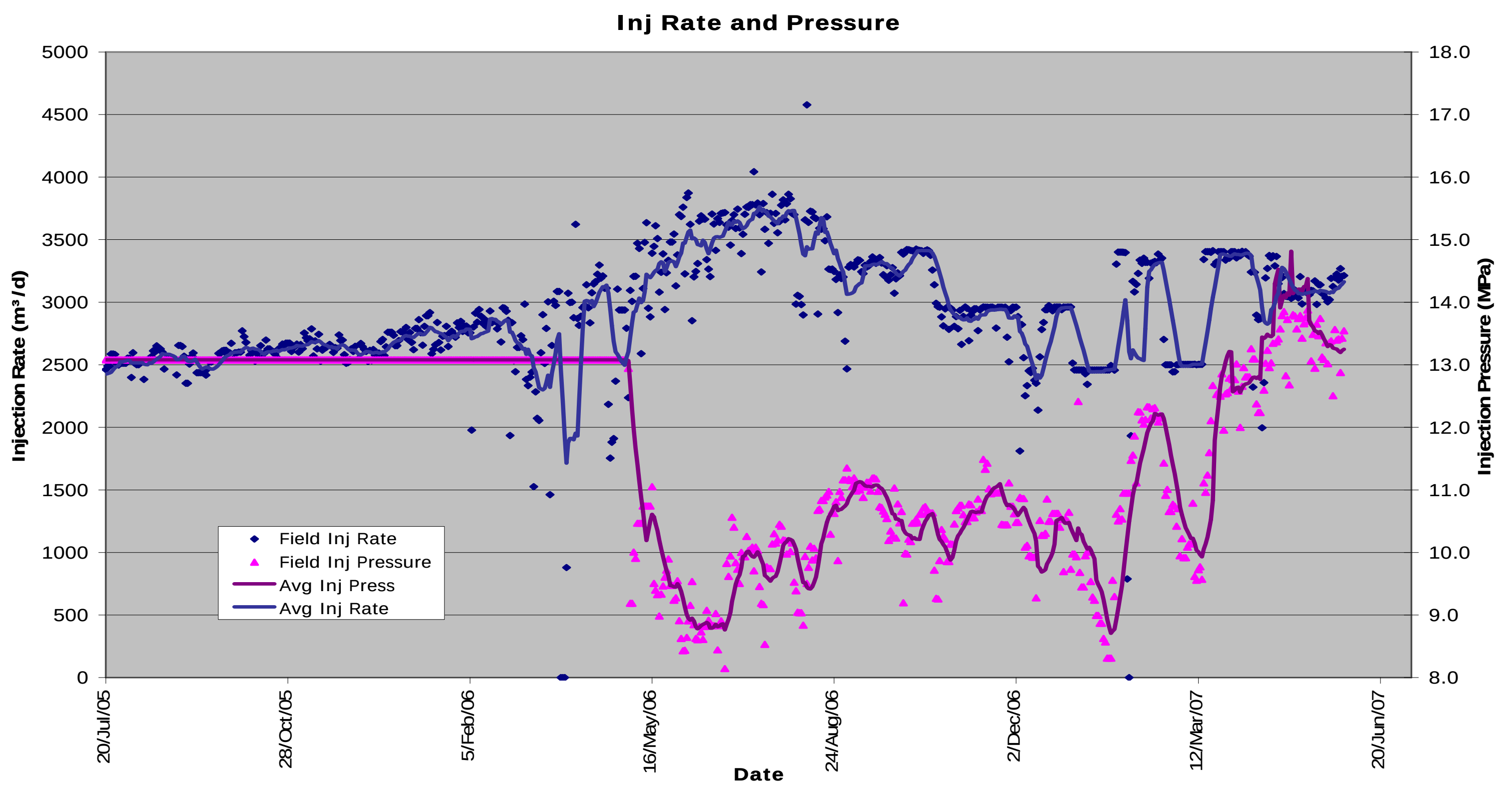


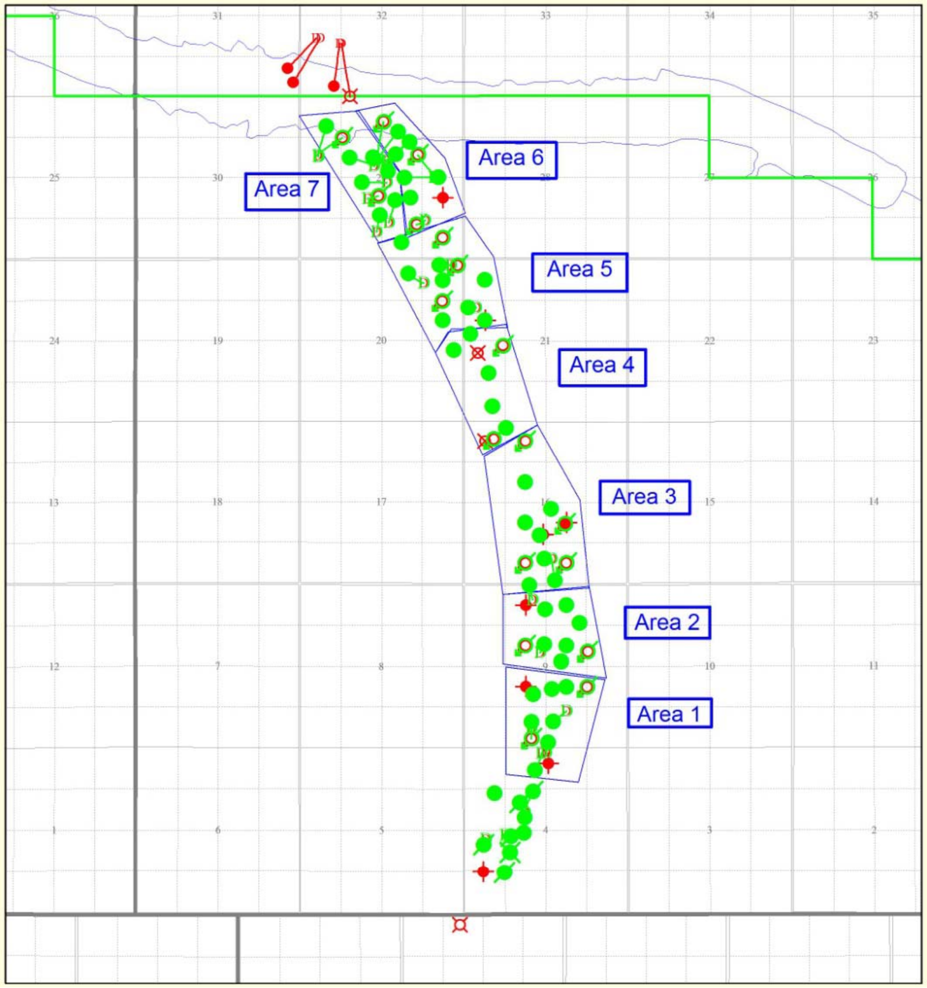

Figure 299

**Taber South – Mannville B Oil Production and Oil Cut**



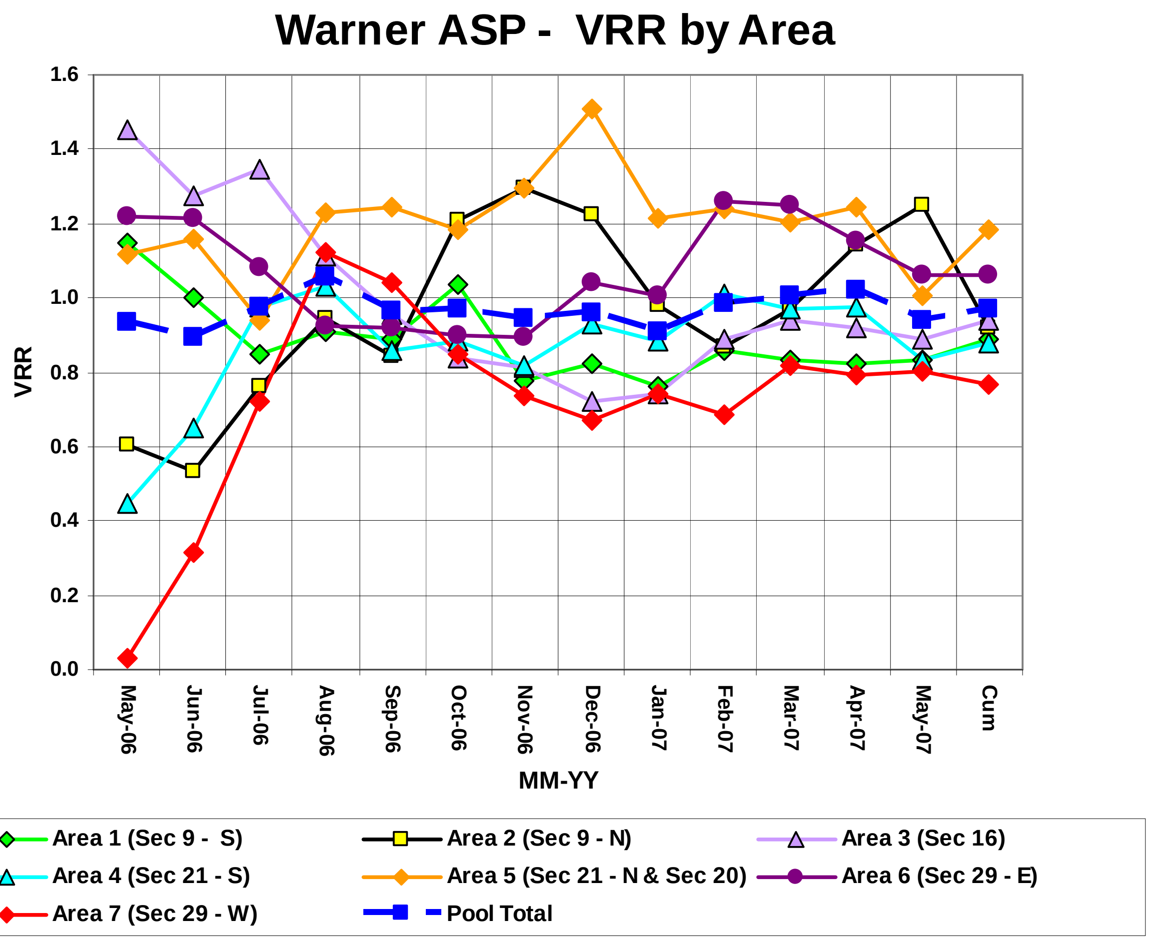

**Taber South – Mannville B Injection Rates and Average Wellhead Pressures**

Figure 300



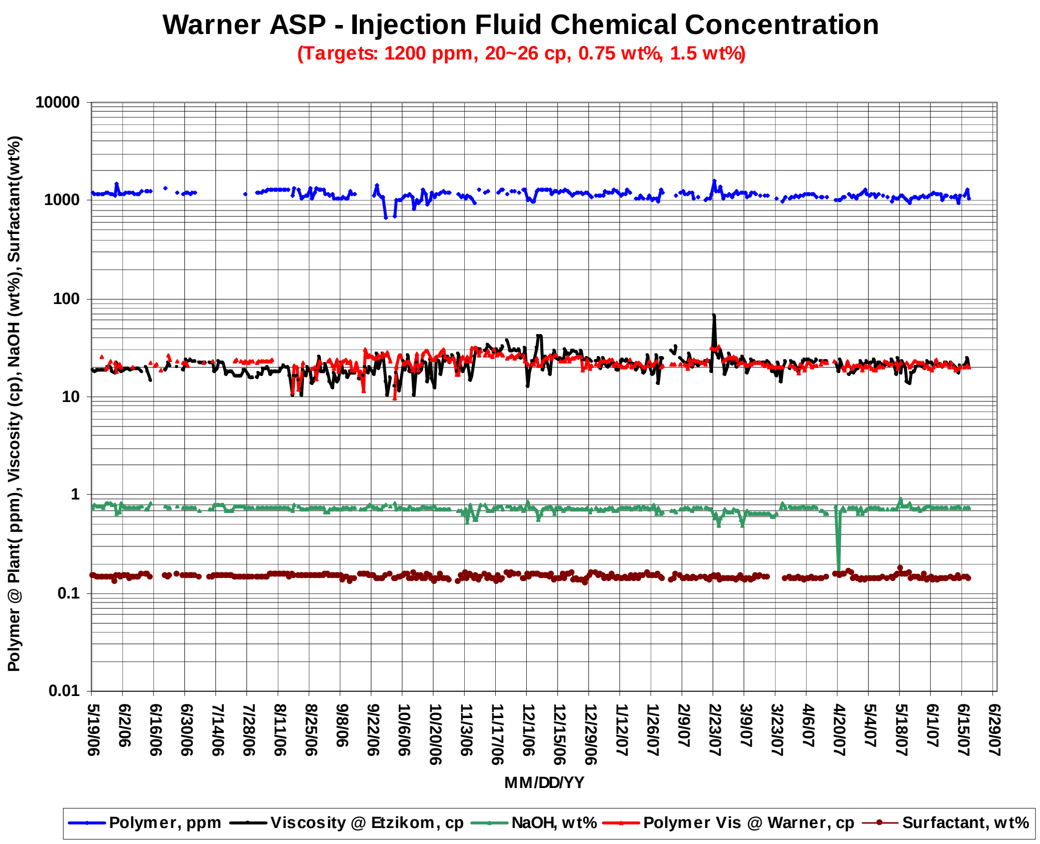

**Taber South – Mannville B (Warner) Region Map**

Figure 301



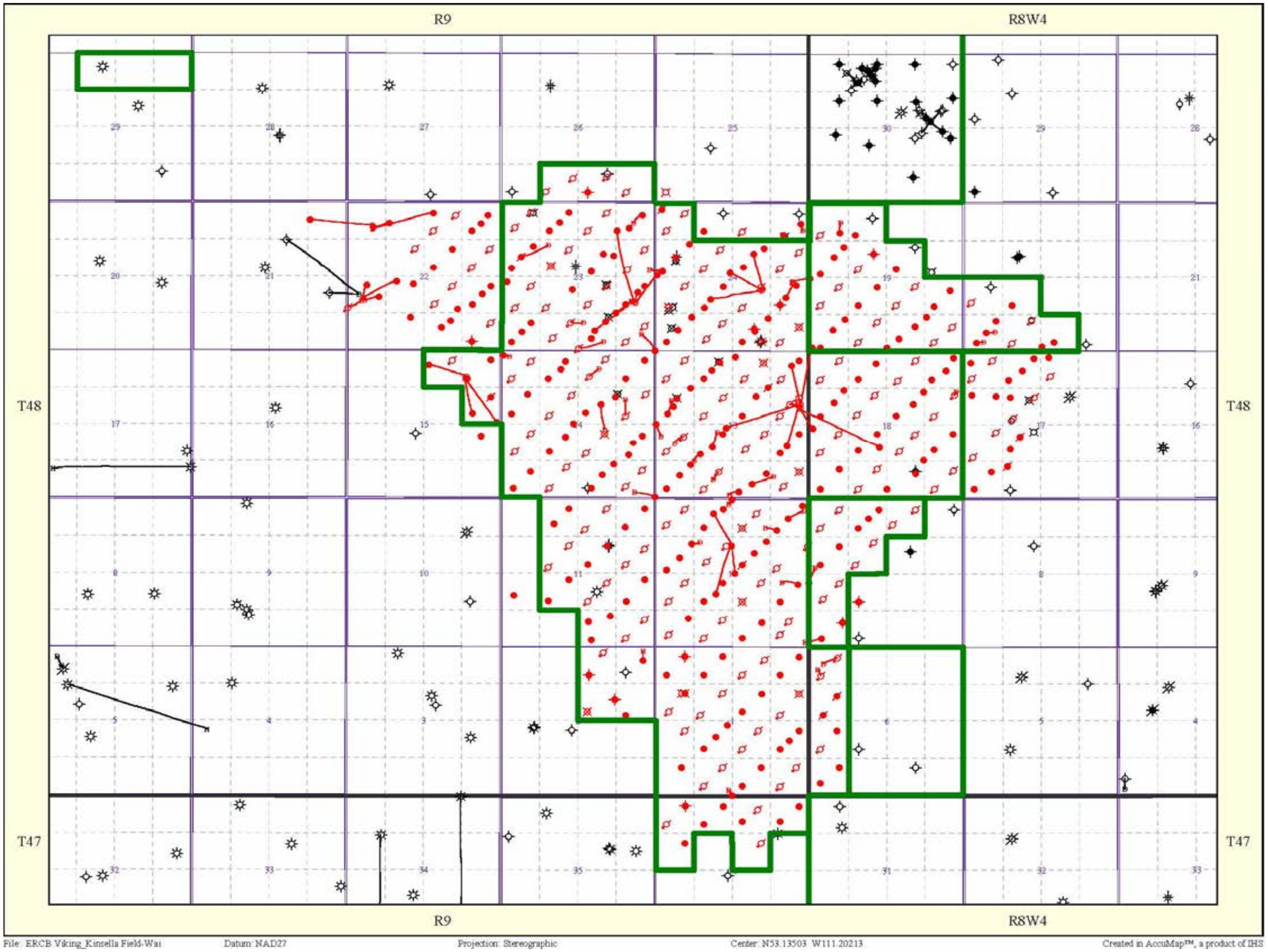

**Taber South – Mannville B (Warner) VRR by Area**

Figure 302




**Taber South – Mannville B (Warner) Injection Fluid Chemical Concentration**

Figure 303




Viking-Kinsella Wainwright B - Well Locations

Figure 304

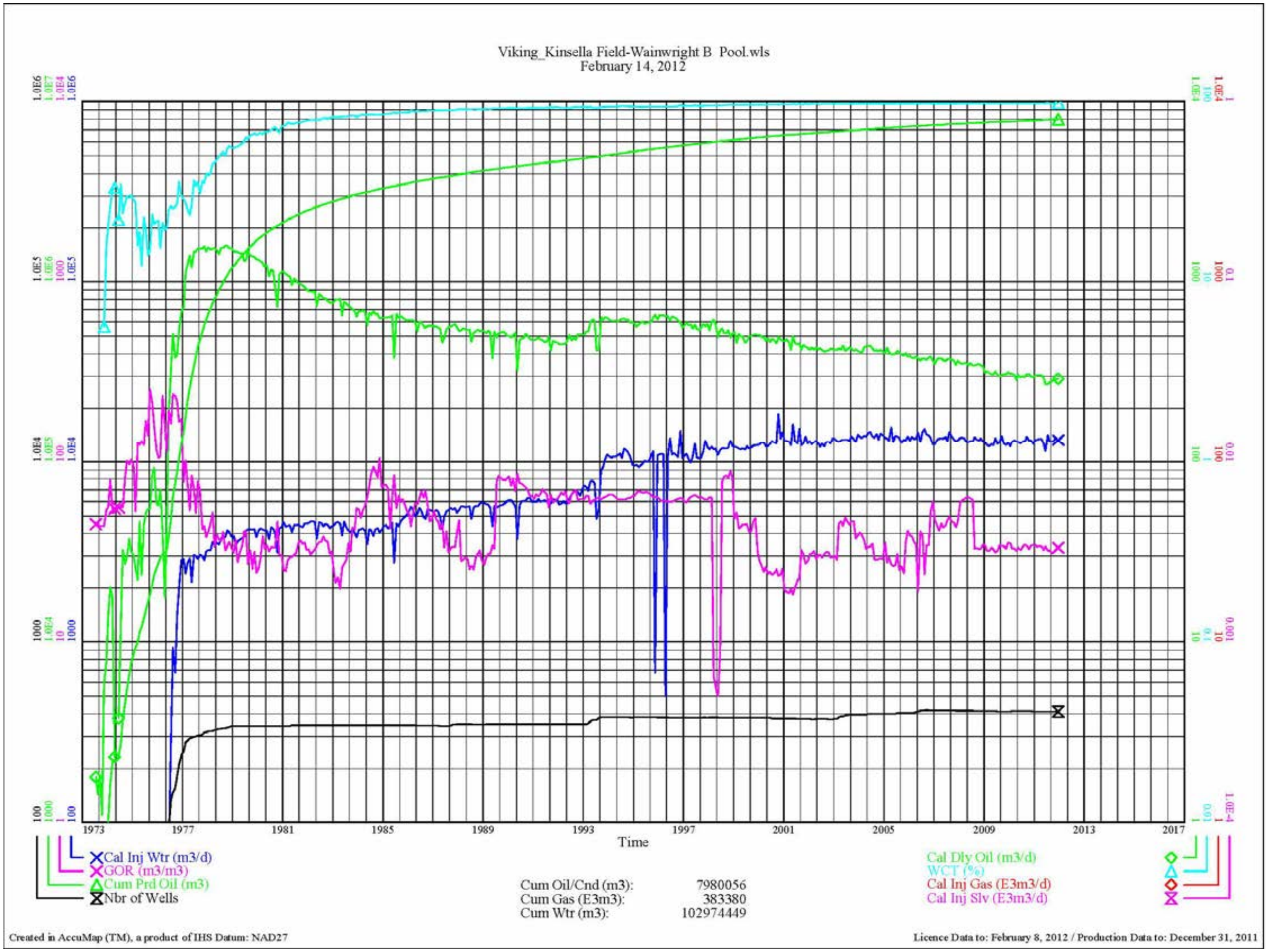


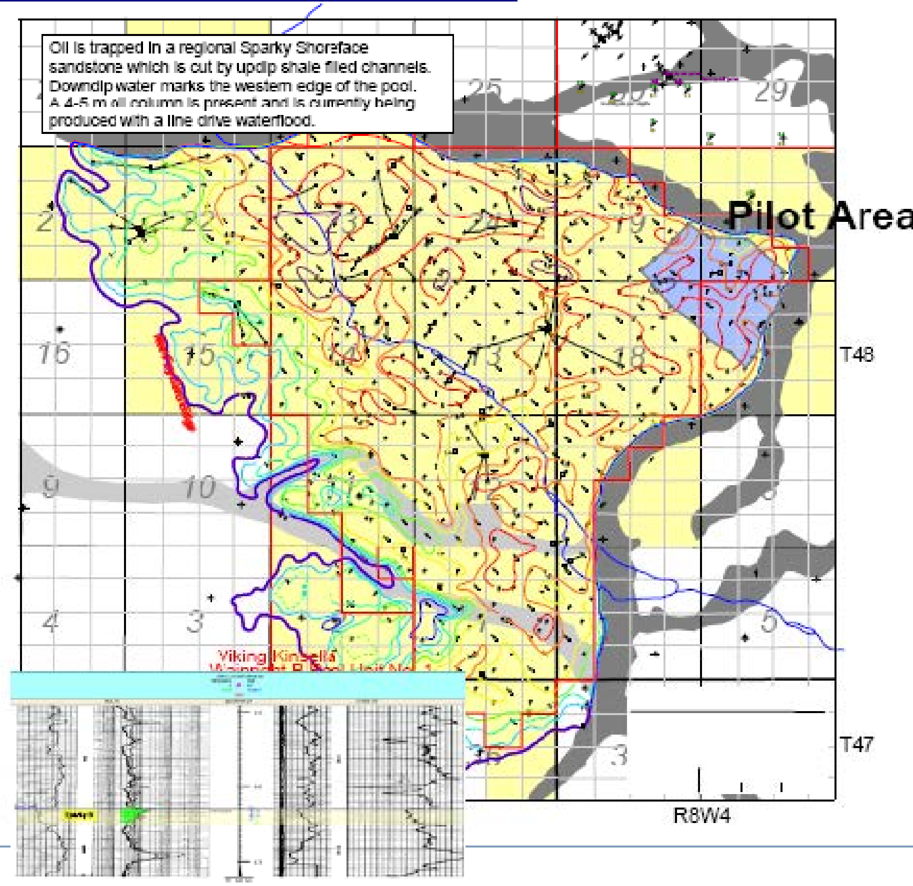

Figure 305

**Viking-Kinsella Wainwright B - Production / Injection History**



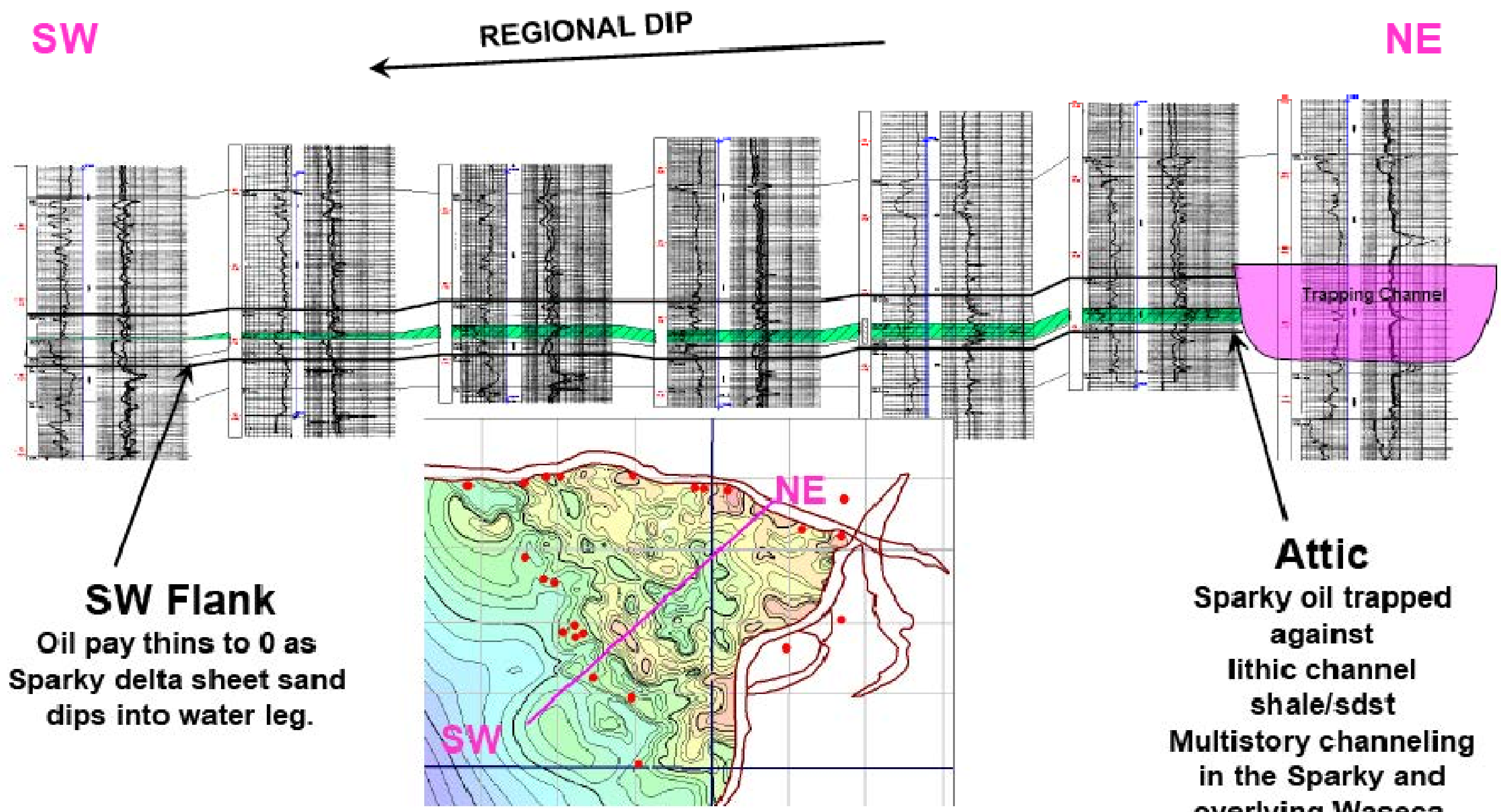
Sproule

## VIKING-KINSELLA WAIN B Pool




**Viking-Kinsella – Wainwright B Pool - Pool**

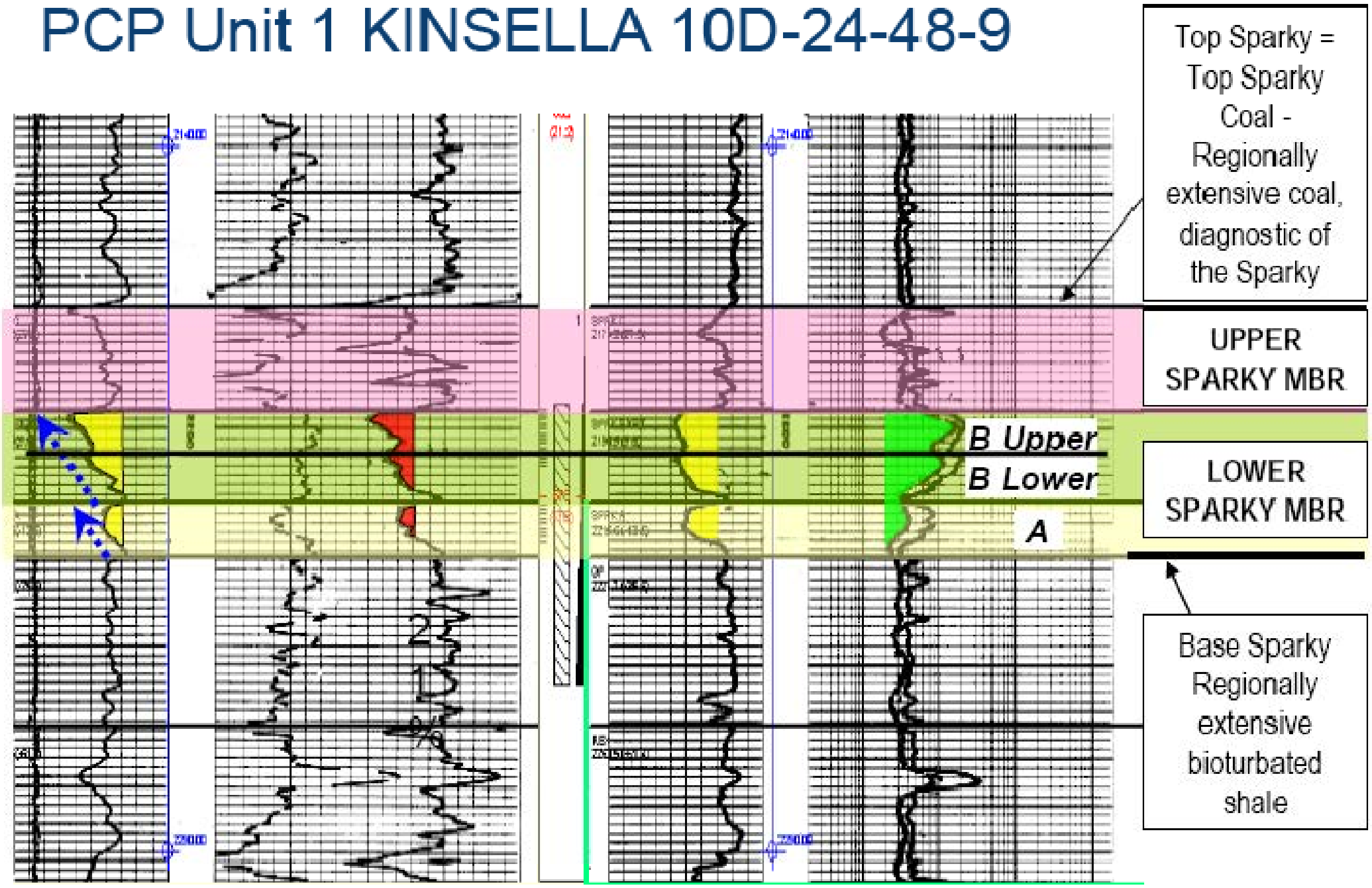
Figure 306




**Viking-Kinsella – Wainwright B Pool – Cross-Section**

Figure 307

# • PCP Unit 1 KINSELLA 10D-24-48-9

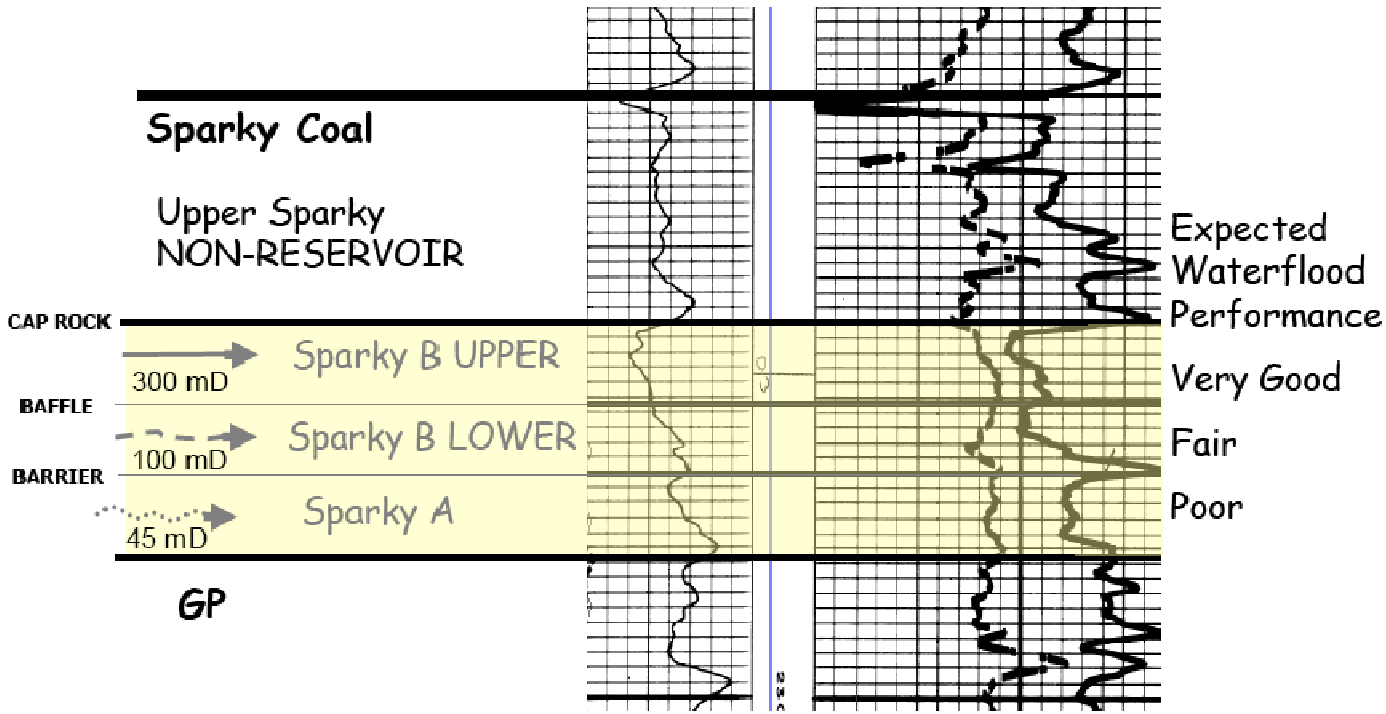



**Viking-Kinsella – Wainwright B Pool – Type Log**

Figure 308



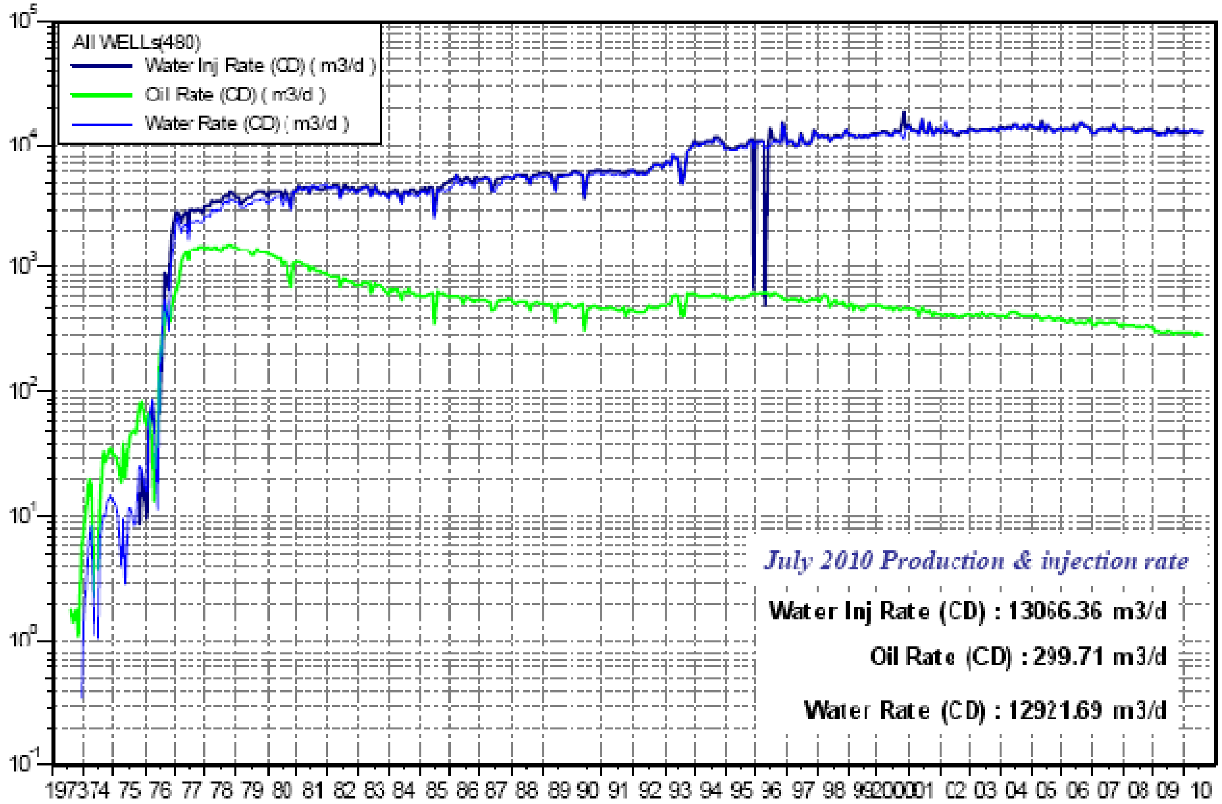
Sproule




Macroscopic-scale permeabilities will be significantly lower in Sparky A and B LOWER due to tortuosity of interbedded siltstone and shale, resulting in more rapid waterflood progress in the Sparky B UPPER.

**Viking-Kinsella – Wainwright B Pool – Flow Unit**

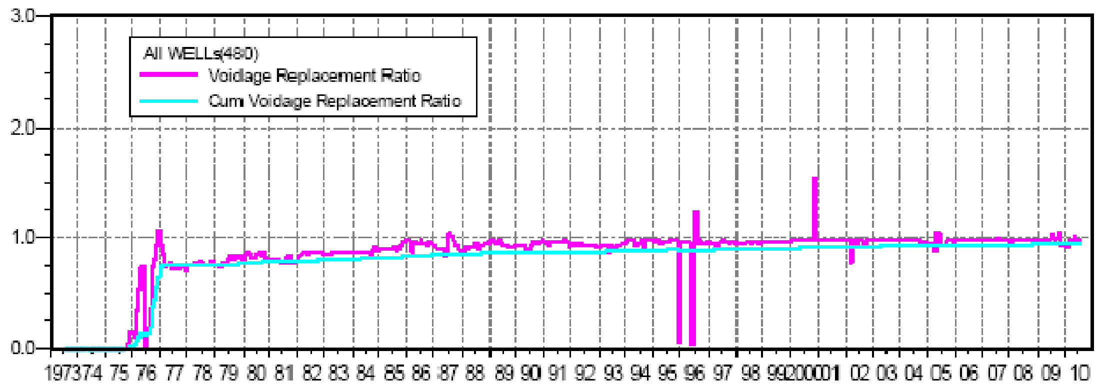
Figure 309




**Viking-Kinsella – Wainwright B Pool – Production & Injection Performance Full Field**

Figure 310

# Voidage Replacement Ratio – Full Field



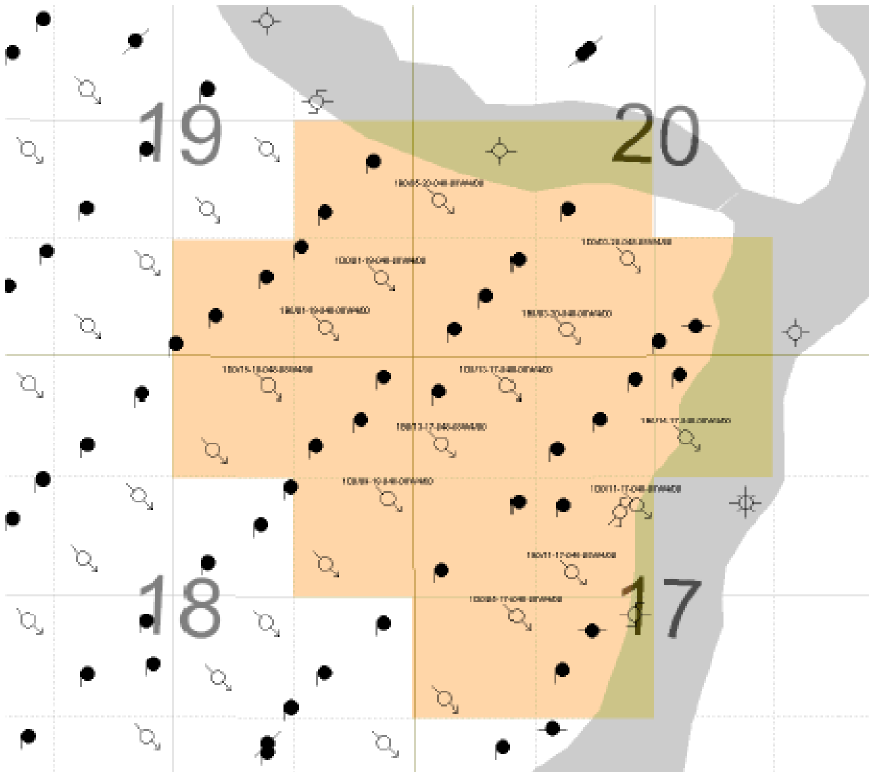

*July 2010*

| | |
|---|---|
| VRR | 0.99 |
| Cumulative VRR | 0.94 |

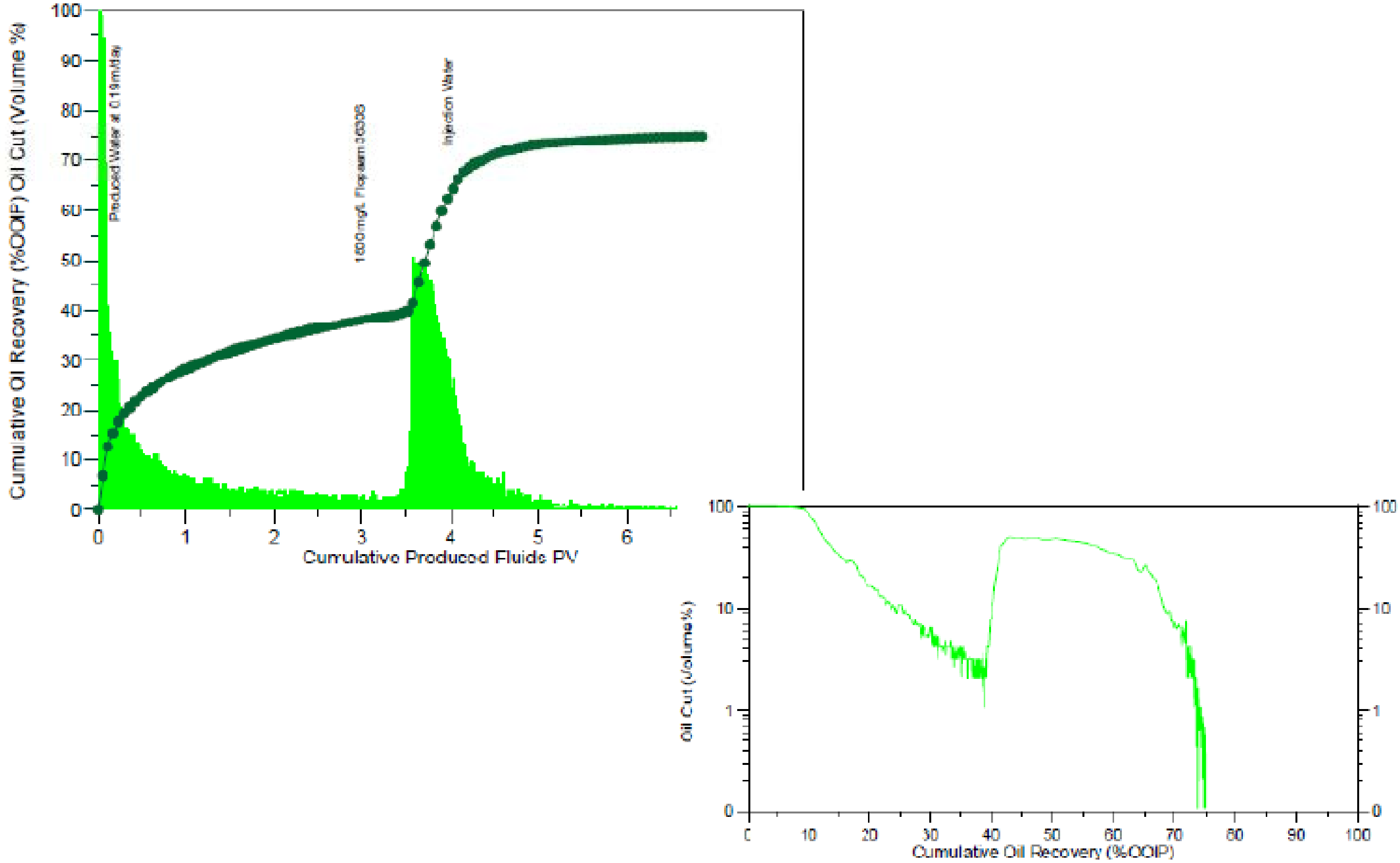
Figure 311

**Viking-Kinsella – Wainwright B Pool – Voidage Replacement Ratio Full Field**

- 13 injectors and 23 producers




**Viking-Kinsella – Wainwright B Pool – Polymer Pilot Area**

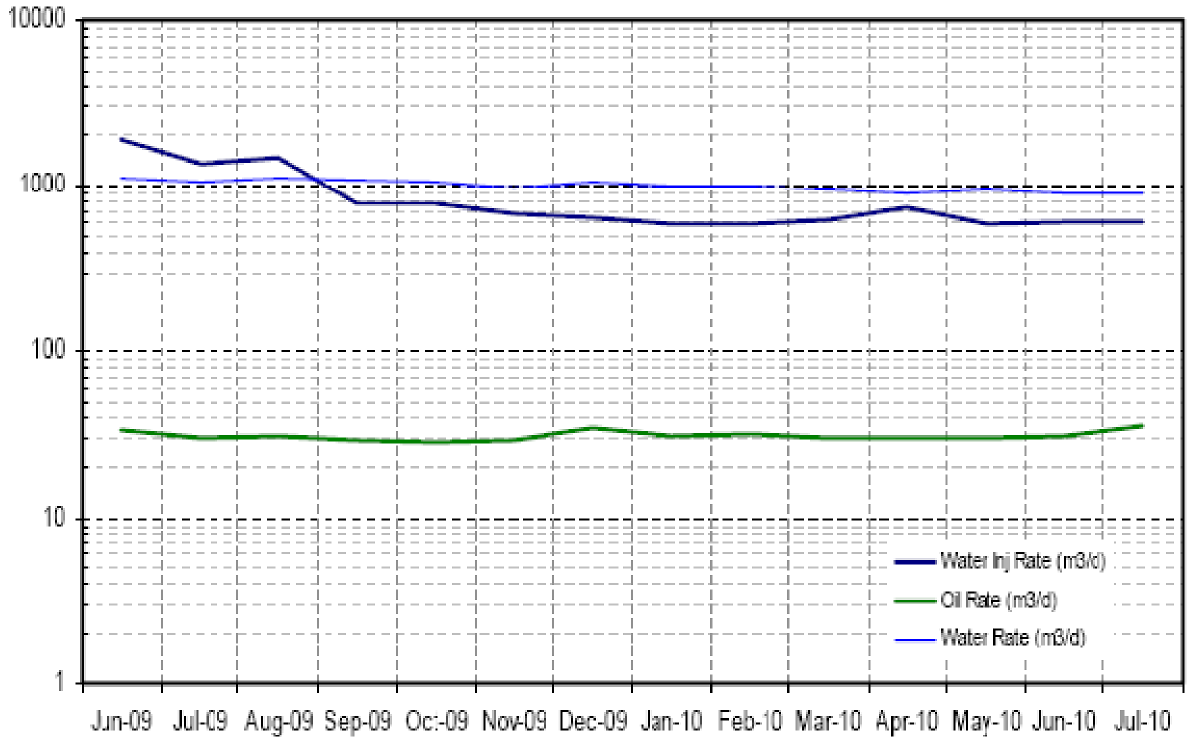



**Viking-Kinsella – Wainwright B Pool – Laboratory Test Results**

18158

Figure 313

*From the commencement of polymer injection*



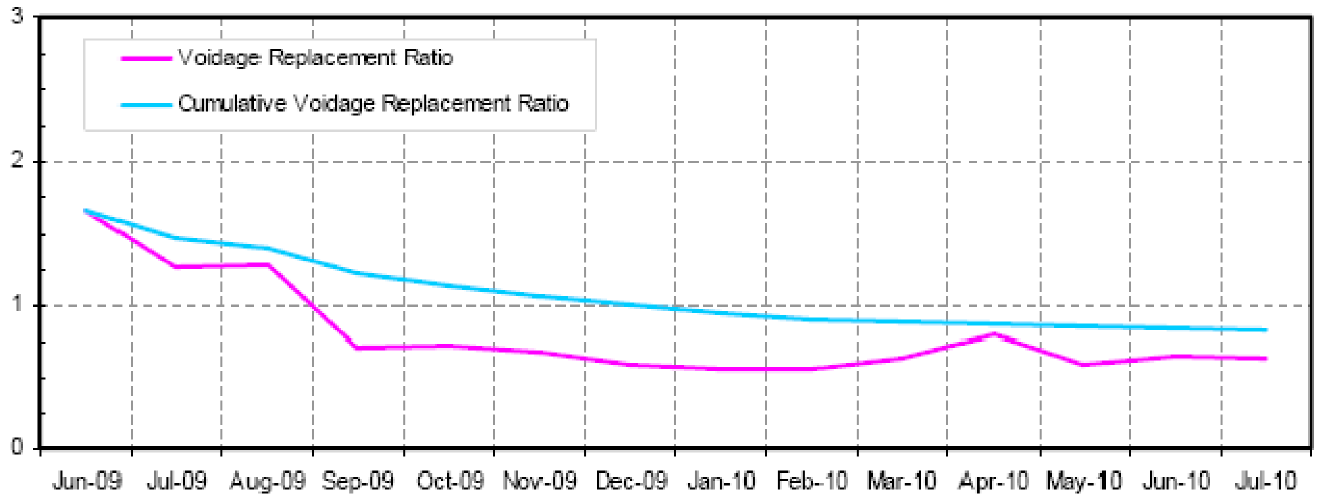

**Viking-Kinsella – Wainwright B Pool – Production & Injection Performance**
**Pilot Area**

Figure 314



Sproule

*From the commencement of polymer injection*




*July 2010*

| | |
|---|---|
| **Cumulative VRR** | **0.82** |

**Viking-Kinsella – Wainwright B Pool – Voidage Replacement Ratio**
**Pilot Area**

Figure 315

- Production performance

| | Timeline | Oil ($m^3/d$) | Total Fluid ($m^3/d$) | Water Cut (%) |
|---|---|---|---|---|
| | 24 months ago | 41 | 1562 | 97.4 |
| | 18 months ago | 38 | 1458 | 97.4 |
| *Polymer flooding* | 12 months ago | 36 | 1368 | 97.4 |
| | April - Jun 2010 | 39 | 1260 | 96.9 |
| | July 2010 | 43 | 1216 | 96.5 |
| | Aug 2010 | 39 | 1235 | 96.8 |

**Viking-Kinsella – Wainwright B Pool – Production Performance Pilot Area**

Figure 316

| Well | Gamma Clean Sand | Net Perfed Pay Upper Sparky | Max Porosity Upper Sparky | Additional Lower Perfs | Perf Type / SPM | Conversion and Prior Producer | Total Years of Inj. |
|---|---|---|---|---|---|---|---|
| B0/5-20* | 60-Dirty | 2.5 m | 26% | No | 6 SPM | Yes-1 Year | 10 |
| d0/1-19* | 47-Clean | 3.2 m | 30% | Yes | 12 SPM | Yes-16 year | 13 |
| b0/1-19 | 52-Mid | 3.0 m | 32% | Yes | 12 SPM | No Production | 15 |
| d0/15-18* | 30-V. Clean | 1.7 m | 30% | No | 6 SPM | Yes-18 Years | 15 |
| d0/9-18** | 45-Clean | 3.3 m | 33% | Yes | 12 SPM | Yes | 10 |
| b0/13-17 | 45-Clean | 3.6 m | 30% | Yes | 12 SPM | No Production | 33 |
| d0/13-17 | 60-Dirty | 3.6 m | 29% | No | 12 SPM | Yes-21 Years | 12 |
| b0/3-20 | 52-Mid | 3.6 m | 31% | No | 12 SPM | Yes 1 Year | 32 |
| d0/3-20 | 72-Dirty | 1.7 m | 27% | Yes | 6 SPM | Yes- 20 Years | 13 |
| d0/5-17 | 60-Dirty | 1.5 m | 30% | Yes | 6 SPM | No Production | 33 |
| bo/11-17 | 45-Clean | 3.2 m | 31% | Yes | 6 SPM | No Production | 33 |
| do/11-17 | 52-Mid | 3.6 m | 31% | Yes | 12 SPM | Yes- 19 Years | 12 |
| b0/15-17 | 80-Dirty | 1.0 m | 28% | Yes | 12 SPM | No Production | 20 |

Figure 317

**Viking-Kinsella – Wainwright B Pool – Polymer Injection Performance Factors**
**Pilot Area**

- Polymer concentrations were tested monthly to find trace amounts of Polymer through clay reaction testing for the first 10 months of the flood. ( Until April 2010)

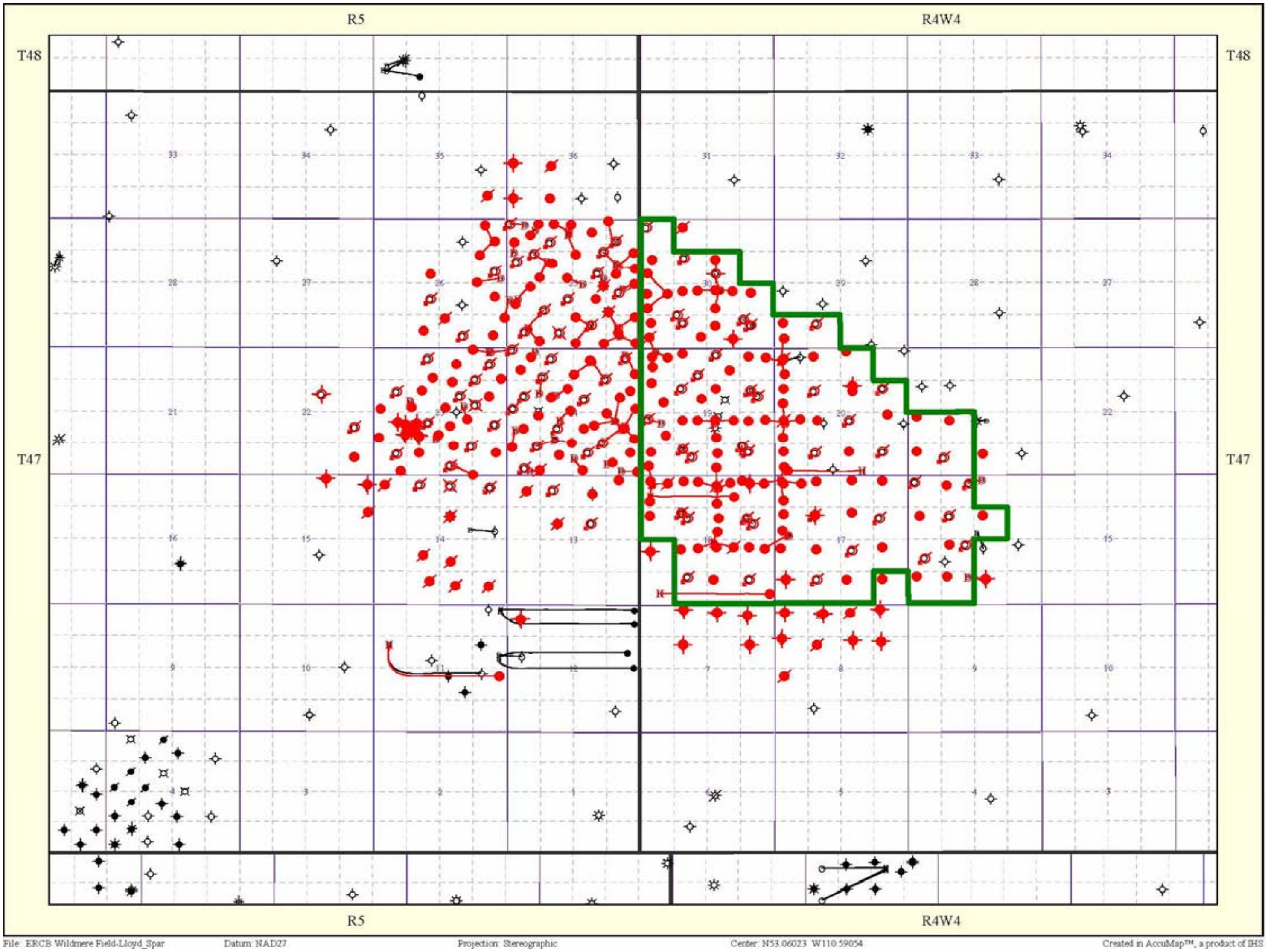
- Polymer – Produced fluids were lab tested on the wells which tested positive for Polymer residual through clay reaction. ( April 2010)

- Monthly lab testing on all producers is monthly (As of Aug 2010)

| | PPM POLYMER PPM | |
|---|---|---|
| | Apr-10 | Aug-10 |
| Well | PPM | PPM |
| 1C0/01-19-48-08 | 31 | 33 |
| 1B0/02-19-48-08 | 149 | n/a |
| 1D0/02-19-48-08 | 98 | n/a |
| 1A0/03-19-48-08 | n/a | 31 |
| 1B0/08-19-48-08 | 38 | 33 |
| 1D0/08-19-48-08 | n/a | 34 |
| 1D0/08-18-48-08 | n/a | 33 |
| 1D2/10-18-48-08 | n/a | n/a |
| 1A0/16-18-48-08 | n/a | 31 |
| 1B0/16-18-48-08 | n/a | 30 |
| 1D0/16-18-48-08 | n/a | 33 |
| 1B2/02-20-48-08 | n/a | 44 |
| 1B0/04-20-48-08 | n/a | 49 |
| 1D0/04-20-48-08 | n/a | 38 |
| 1D2/04-20-48-08 | n/a | 45 |
| 1B0/06-20-48-08 | n/a | 45 |
| 1B0/06-17-48-08 | n/a | 30 |
| 100/11-17-48-08 | 57 | 133 |
| 1B0/12-17-48-08 | n/a | 30 |
| 1D0/12-17-48-08 | n/a | 30 |
| 1C0/13-17-48-08 | n/a | 45 |
| 1A0/14-17-48-08 | n/a | 45 |
| 1B0/14-17-48-08 | n/a | 46 |
| 1D0/14-17-48-08 | n/a | 45 |
| 1C0/15-17-48-08 | n/a | 46 |

**Viking-Kinsella – Wainwright B Pool**
**Polymer Breakthrough Monitoring On Producers**

Figure 318




**Wildmere Lloyd / Sparky - Well Locations**

Figure 319

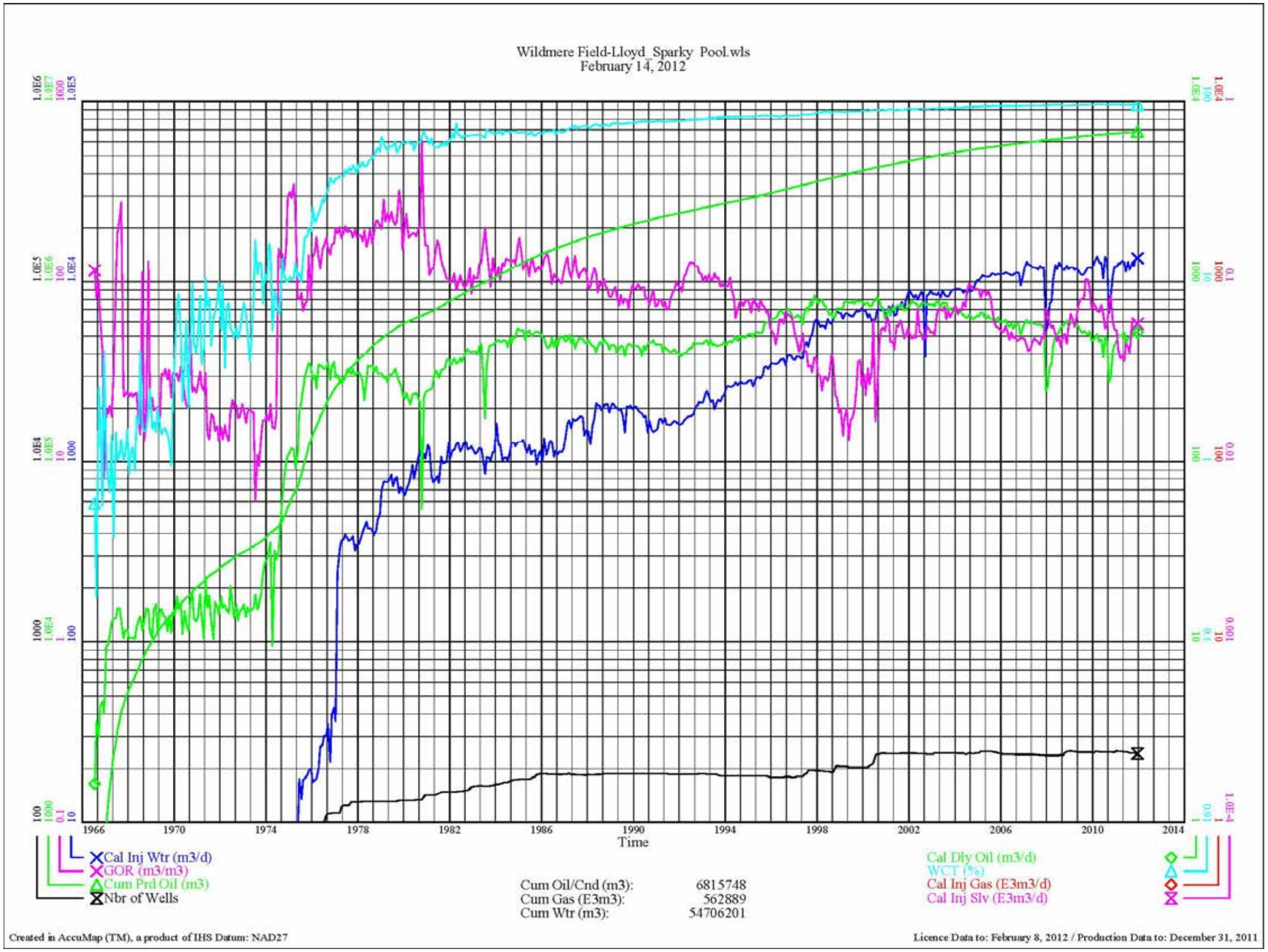
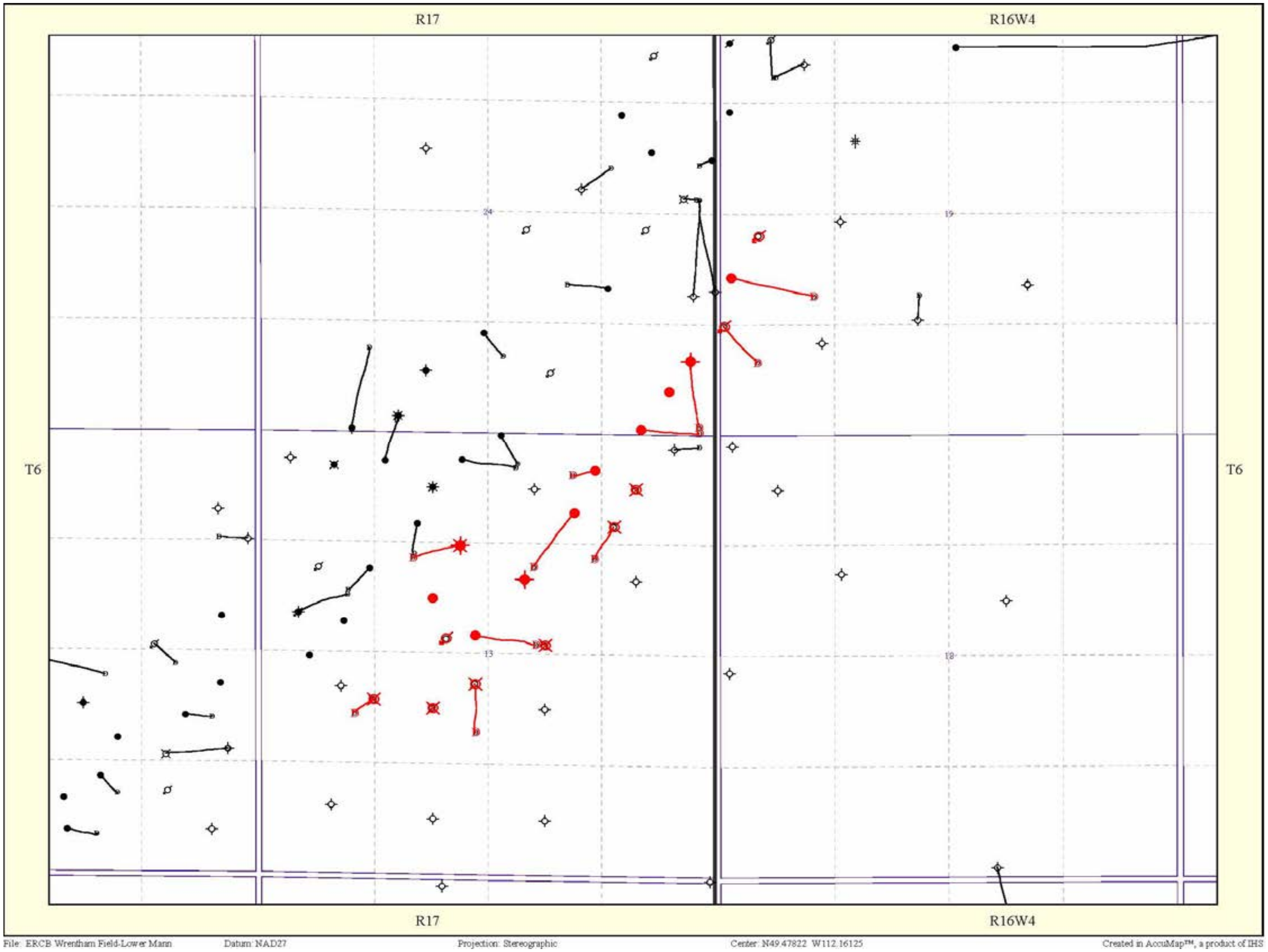


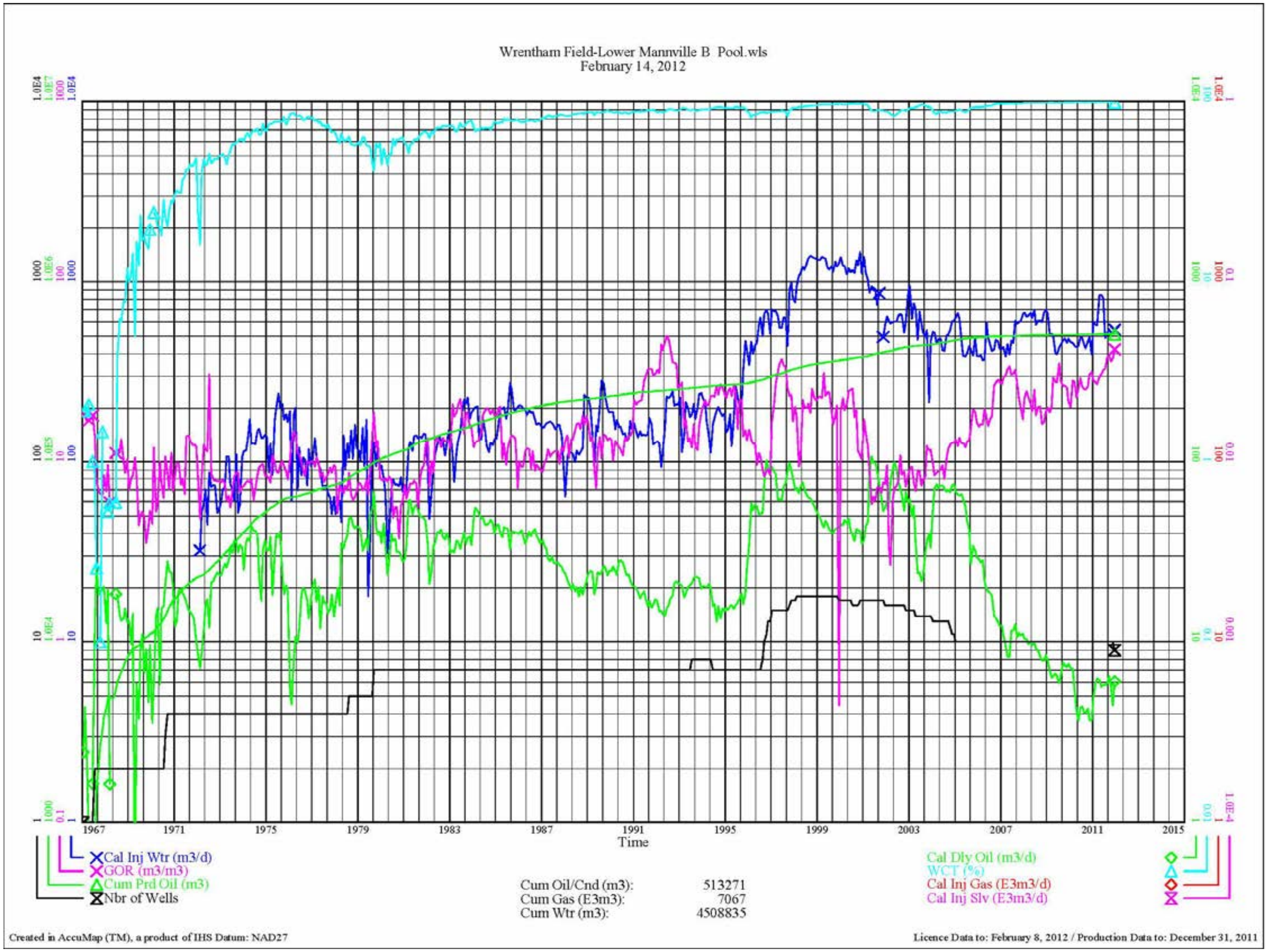

Figure 320

**Wildmere Lloyd / Sparky - Production / Injection History**



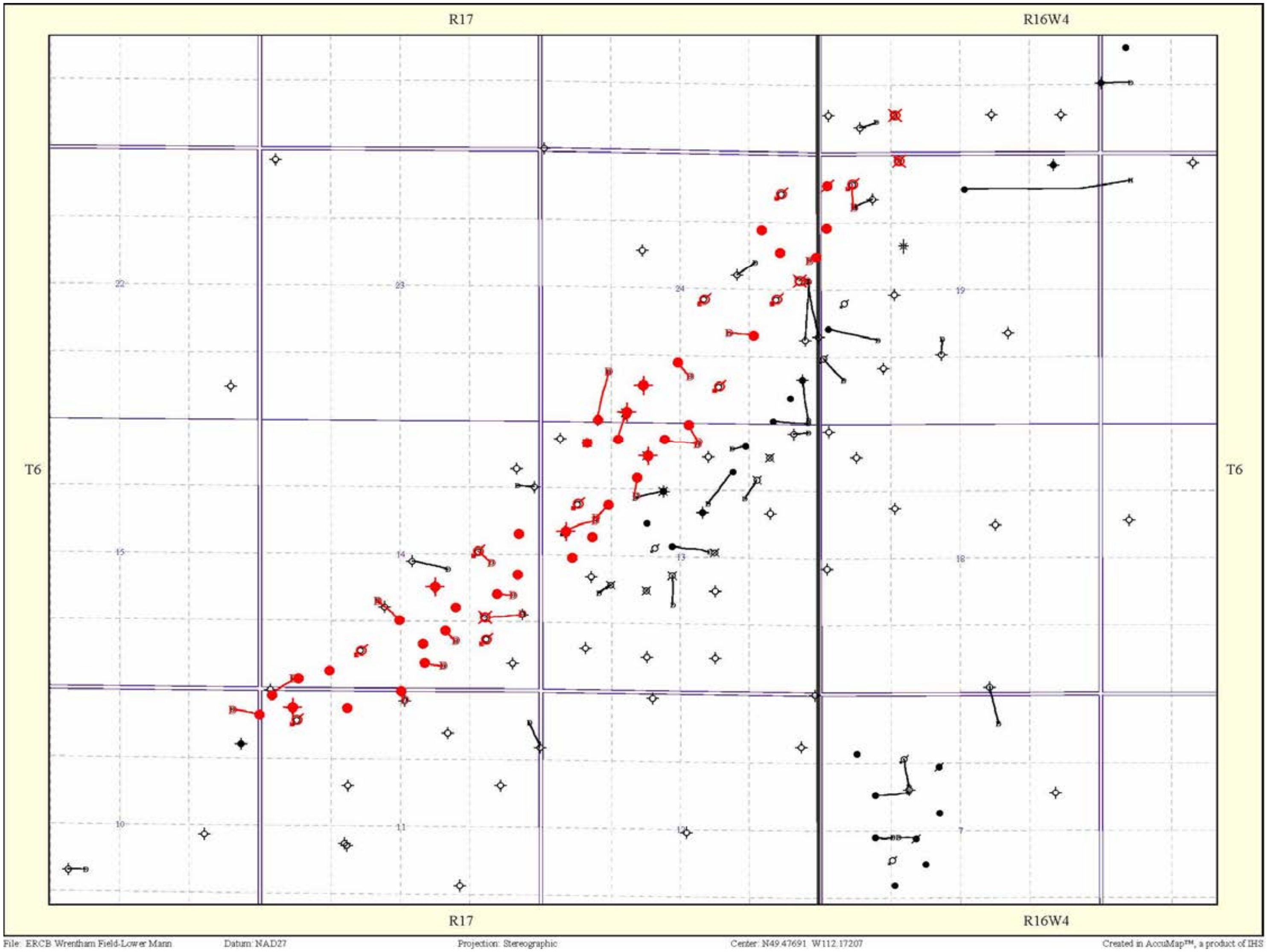

**Wrentham Lower Mannville B - Well Locations**

Figure 321




**Wrentham Lower Mannville B - Production / Injection History**

Figure 322




**Wrentham Lower Mannville C - Well Locations**

Figure 323

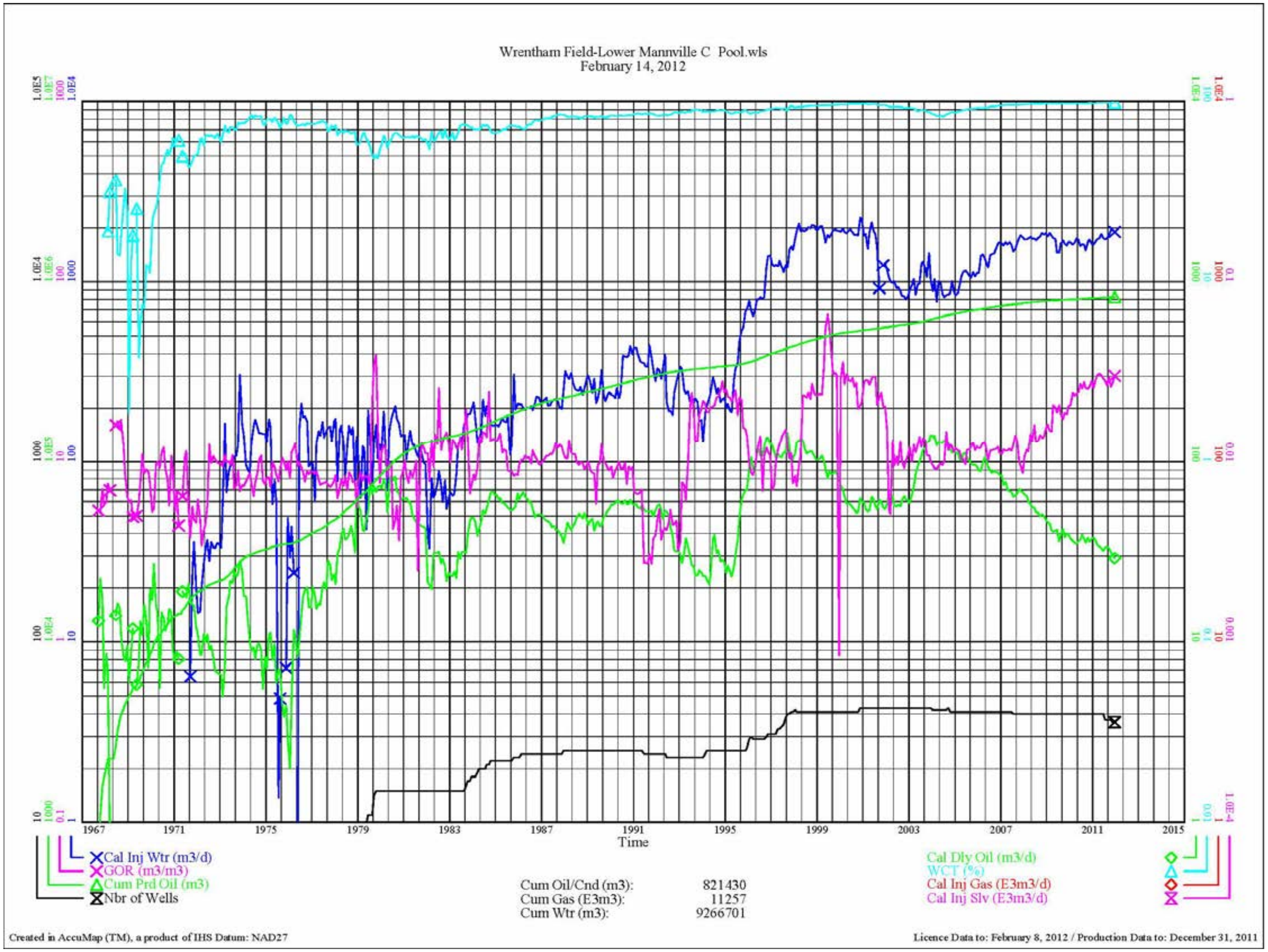
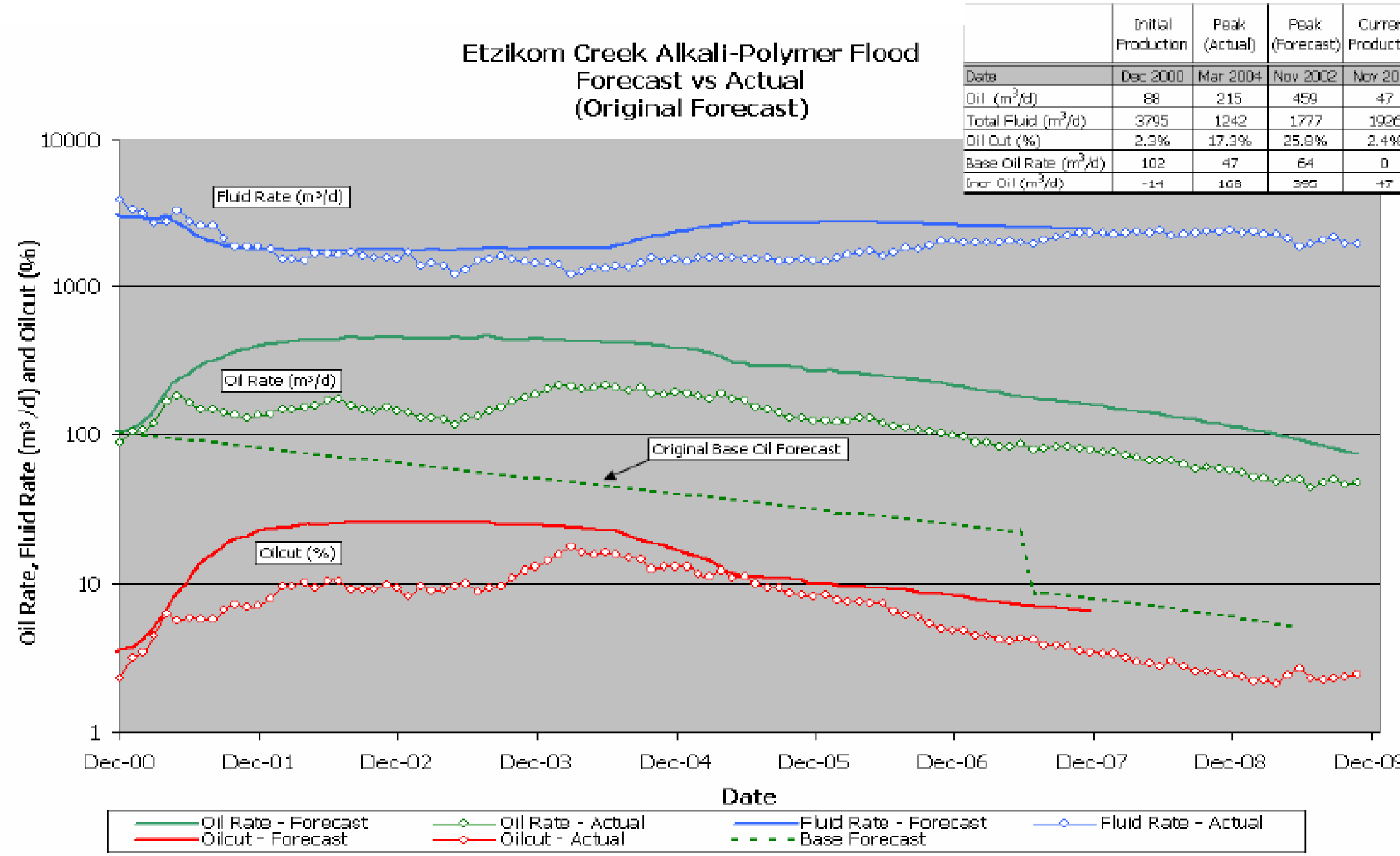



Figure 324

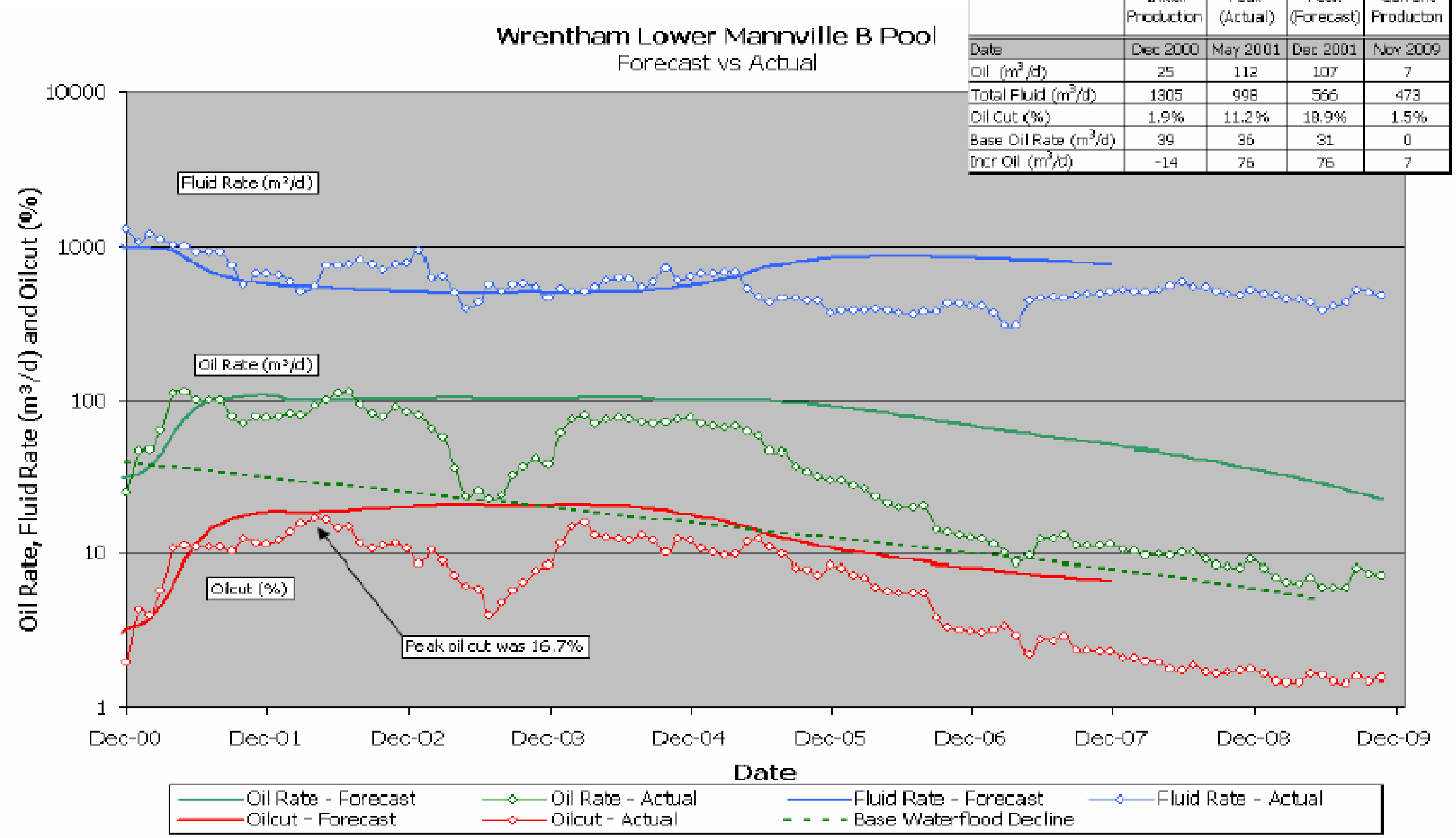
**Wrentham Lower Mannville C - Production / Injection History**




| | Initial Production | Peak (Actual) | Peak (Forecast) | Current Production |
|---|---|---|---|---|
| Date | Dec 2000 | Mar 2004 | Nov 2002 | Nov 2009 |
| Oil ($m^3$/d) | 88 | 215 | 459 | 47 |
| Total Fluid ($m^3$/d) | 3795 | 1242 | 1777 | 1926 |
| Oil Cut (%) | 2.3% | 17.3% | 25.8% | 2.4% |
| Base Oil Rate ($m^3$/d) | 102 | 47 | 64 | 0 |
| Incr Oil ($m^3$/d) | -14 | 168 | 395 | 47 |

Figure 325

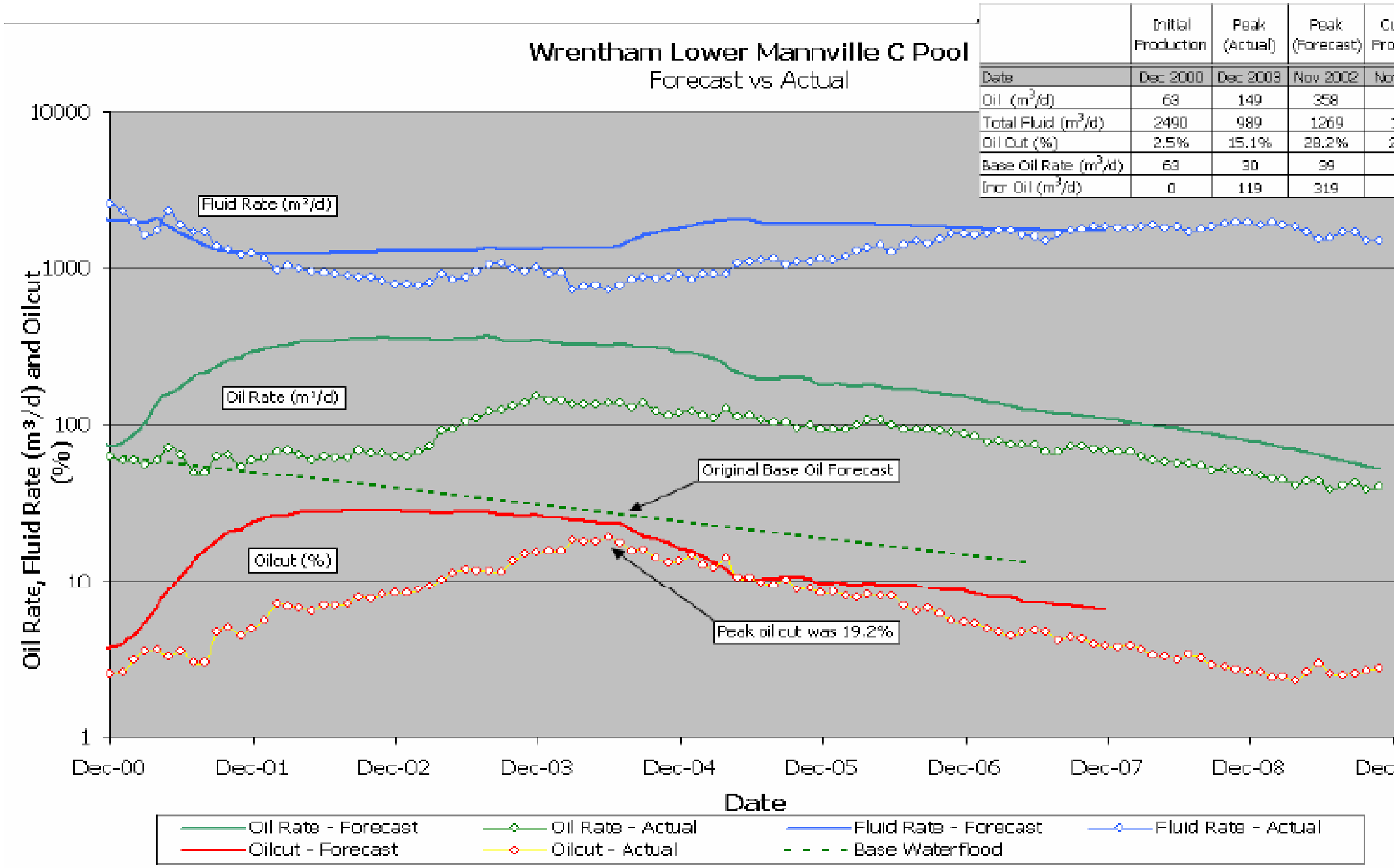
**Wrentham Lower Mannville B & C Pools – Etzikom Creek Facility Production**




| | Initial Production | Peak (Actual) | Peak (Forecast) | Current Producton |
|---|---|---|---|---|
| Date | Dec 2000 | May 2001 | Dec 2001 | Nov 2009 |
| Oil ($m^3/d$) | 25 | 112 | 107 | 7 |
| Total Fluid ($m^3/d$) | 1305 | 998 | 566 | 473 |
| Oil Cut (%) | 1.9% | 11.2% | 18.9% | 1.5% |
| Base Oil Rate ($m^3/d$) | 39 | 36 | 31 | 0 |
| Incr Oil ($m^3/d$) | -14 | 76 | 76 | 7 |

**Wrentham Lower Mannville B Pool – Etzikom Creek Facility Production**

Figure 326




| | Initial Production | Peak (Actual) | Peak (Forecast) | Current Producton |
|---|---|---|---|---|
| Date | Dec 2000 | Dec 2003 | Nov 2002 | Nov 2009 |
| Oil ($m^3$/d) | 63 | 149 | 358 | 40 |
| Total Fluid ($m^3$/d) | 2490 | 989 | 1269 | 1453 |
| Oil Cut (%) | 2.5% | 15.1% | 28.2% | 2.8% |
| Base Oil Rate ($m^3$/d) | 63 | 30 | 39 | 0 |
| Incr Oil ($m^3$/d) | 0 | 119 | 319 | 40 |

**Wrentham Lower Mannville C Pool – Etzikom Creek Facility Production**

Figure 327



Sproule

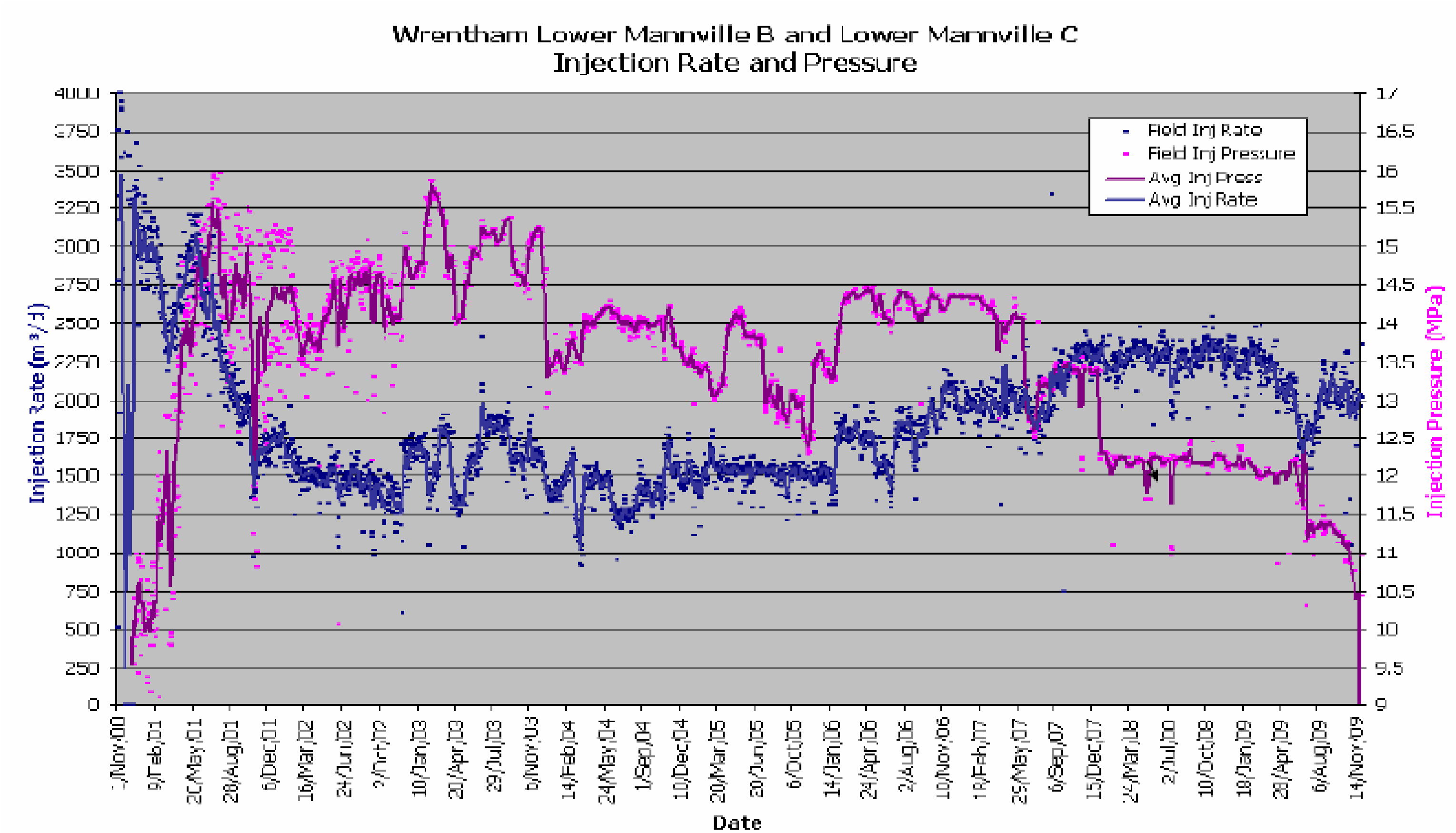
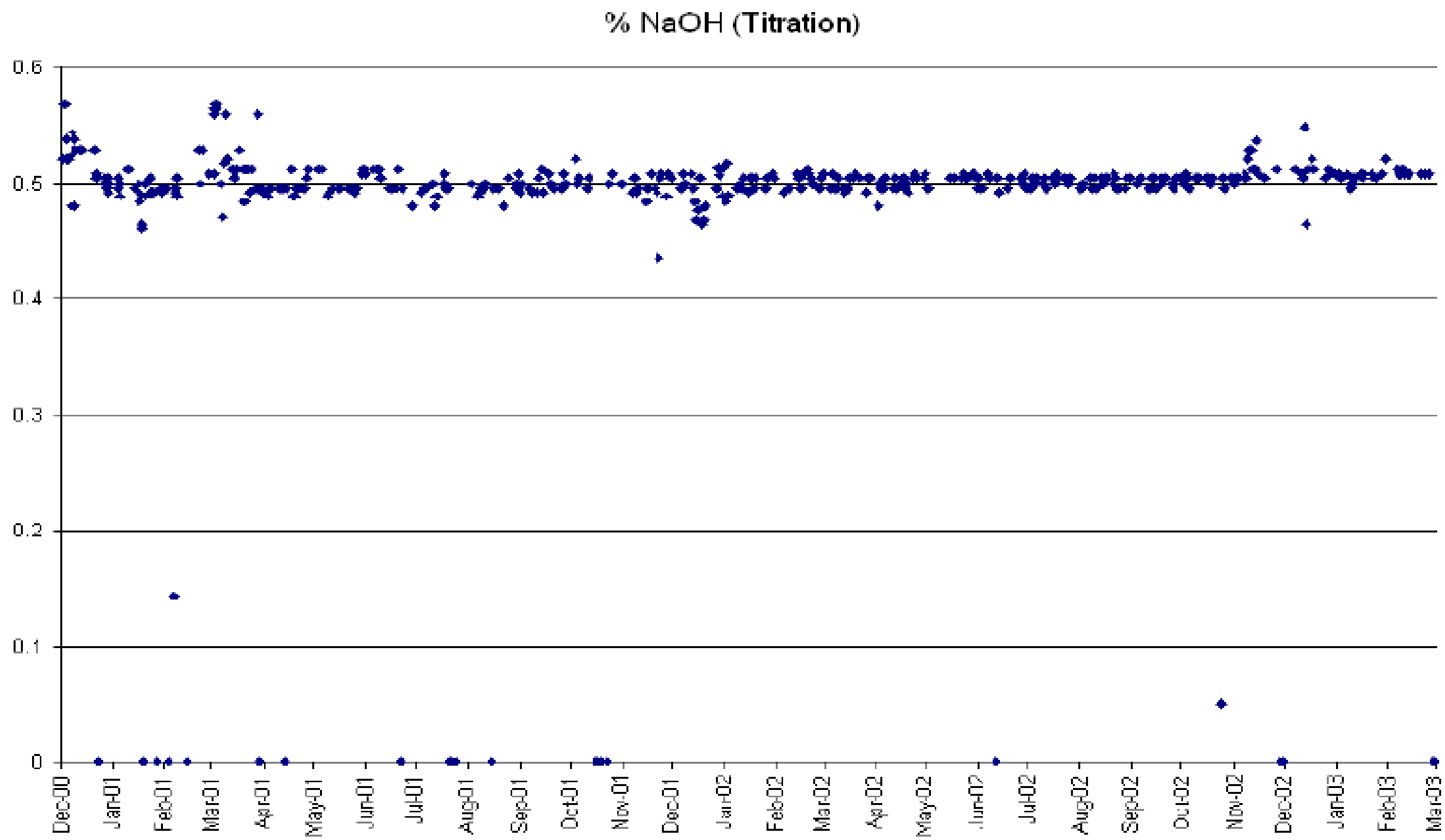


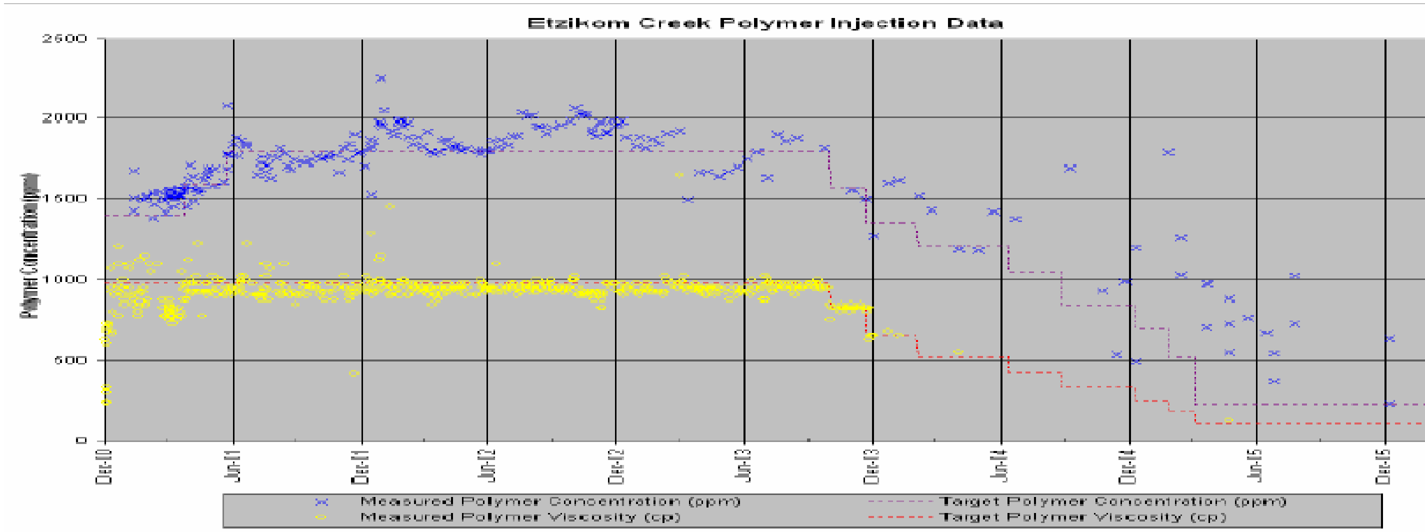

Figure 328

**Wrentham Lower Mannville B & C Pools – Etzikom Creek Facility Injection**




**Wrentham Lower Mannville B & C Pools – Etzikom Creek Facility Injection**

Figure 329

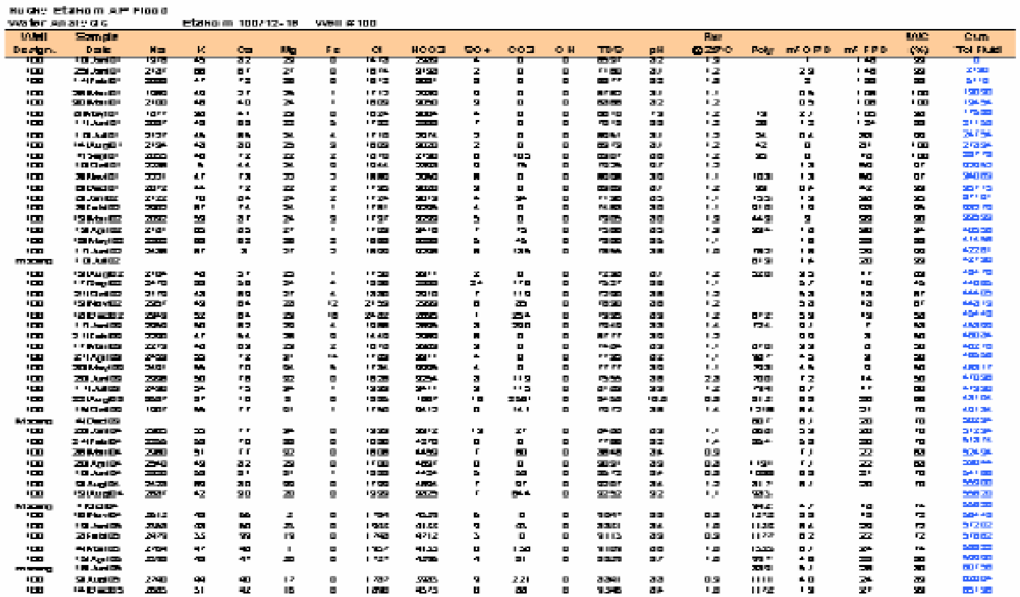


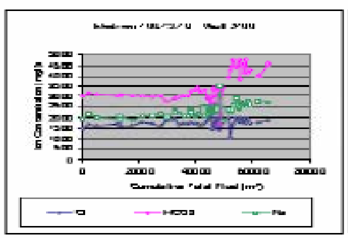

- AP injection until March 2003
- Polymer Taper began October 2003
- Polymer facility shut down March 2005

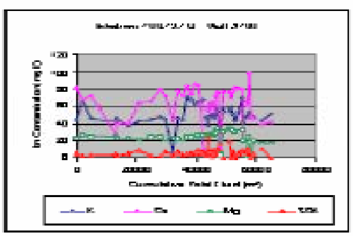
| Target Polymer Concentration (ppm) | Target Solution Viscosity (cp) | Start Date | Completion Date | Target Pore Volume | B Pool Actual Polymer PV injected | C Pool Actual Polymer PV injected |
|---|---|---|---|---|---|---|
| 1800 | 39 | Mar-03 | Oct-03 | 7% | 6% | 7% |
| 1575 | 33 | Oct-03 | Nov-03 | 9% | 7% | 9% |
| 1350 | 26 | Nov-03 | Feb-04 | 11% | 8% | 11% |
| 1200 | 21 | Feb-04 | Jun-04 | 13% | 11% | 14% |
| 1050 | 17 | Jun-04 | Aug-04 | 15% | 13% | 16% |
| 850 | 13 | Sep-04 | Dec-04 | 17% | 15% | 19% |
| 700 | 10 | Dec-04 | Jan-05 | 19% | 17% | 20% |
| 525 | 7 | Feb-05 | Mar-05 | 21% | 18% | 21% |
| 225 | 4 | Mar-05 | May-05 | 23% | 20% | 23% |

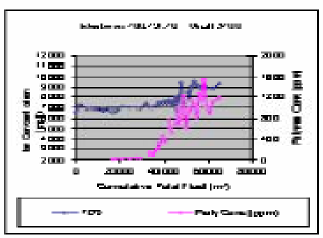
**Wrentham Lower Mannville B & C Pools – Etzikom Creek Facility Injection**

Figure 330









Sample breakthrough data.

Standard water analysis.

Polymer concentration measured by operators.

Monthly water analysis were submitted in the final report for the project.

**Wrentham Lower Mannville B & C Pools – Performance - Etzikom Creek Facility Breakthrough**

Figure 331

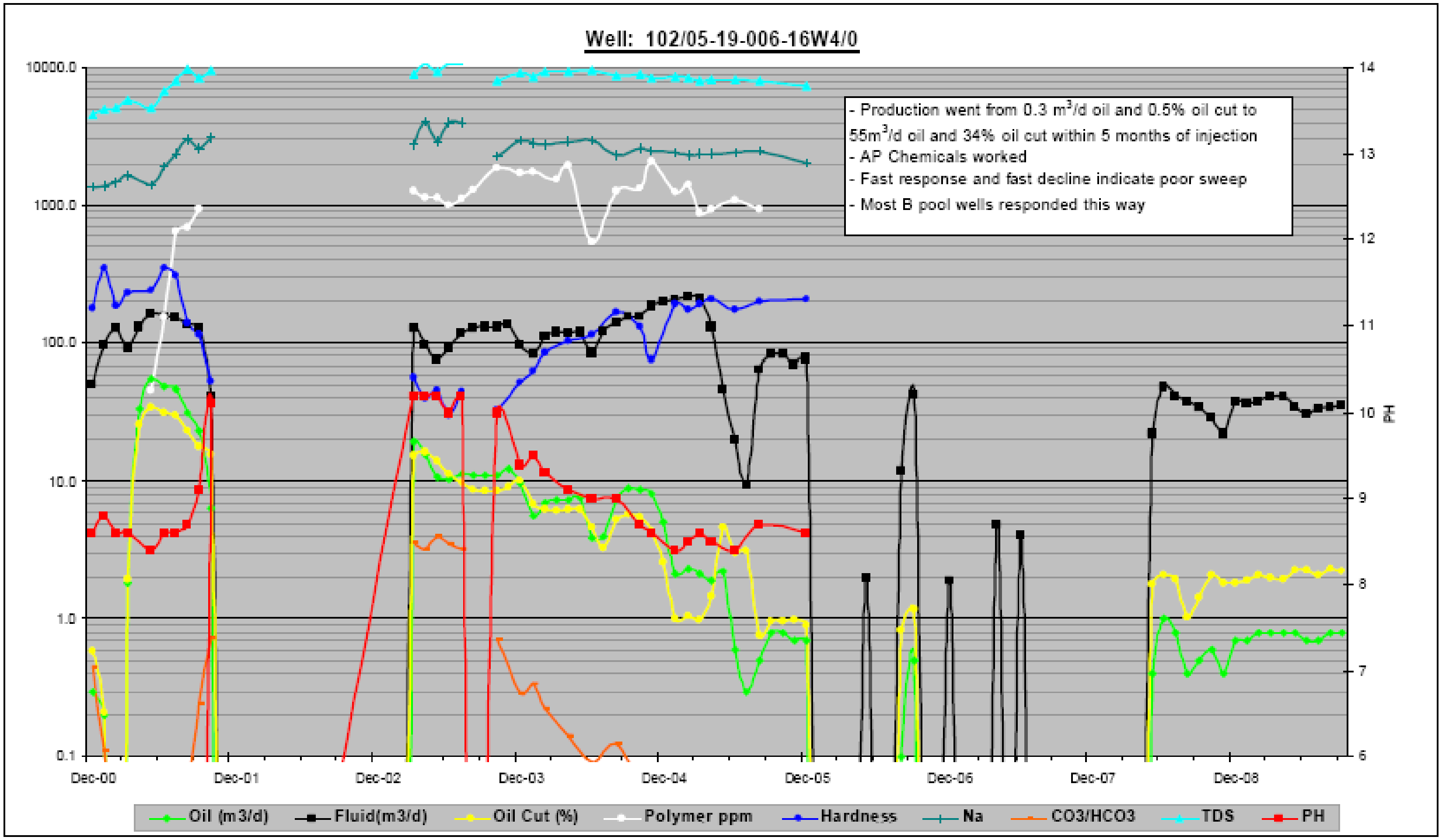



Figure 332

**Wrentham Lower Mannville B Pool – Performance**
**Well Response and Breakthrough**

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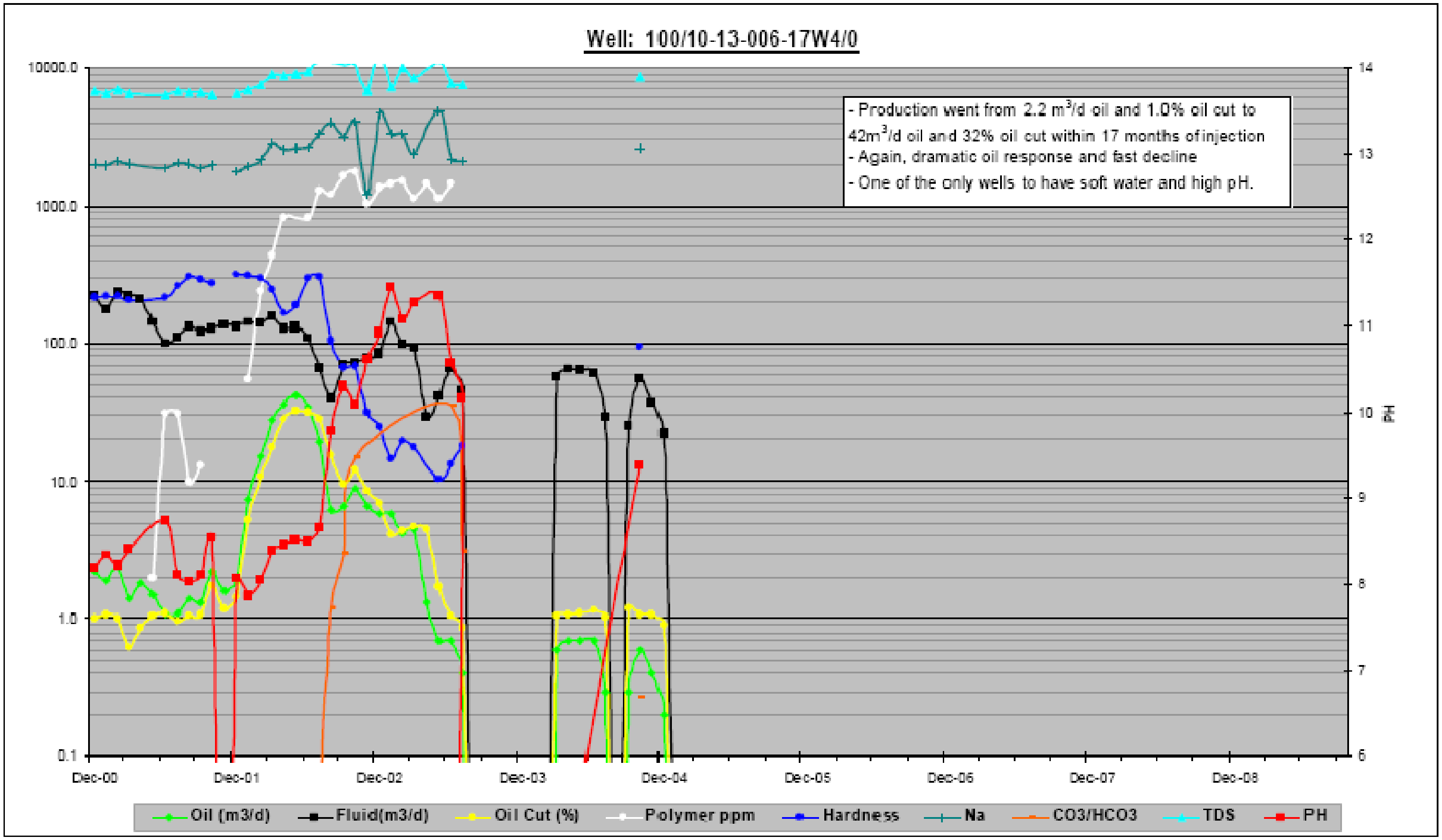



Figure 333

**Wrentham Lower Mannville B Pool – Performance**
**Well Response and Breakthrough**

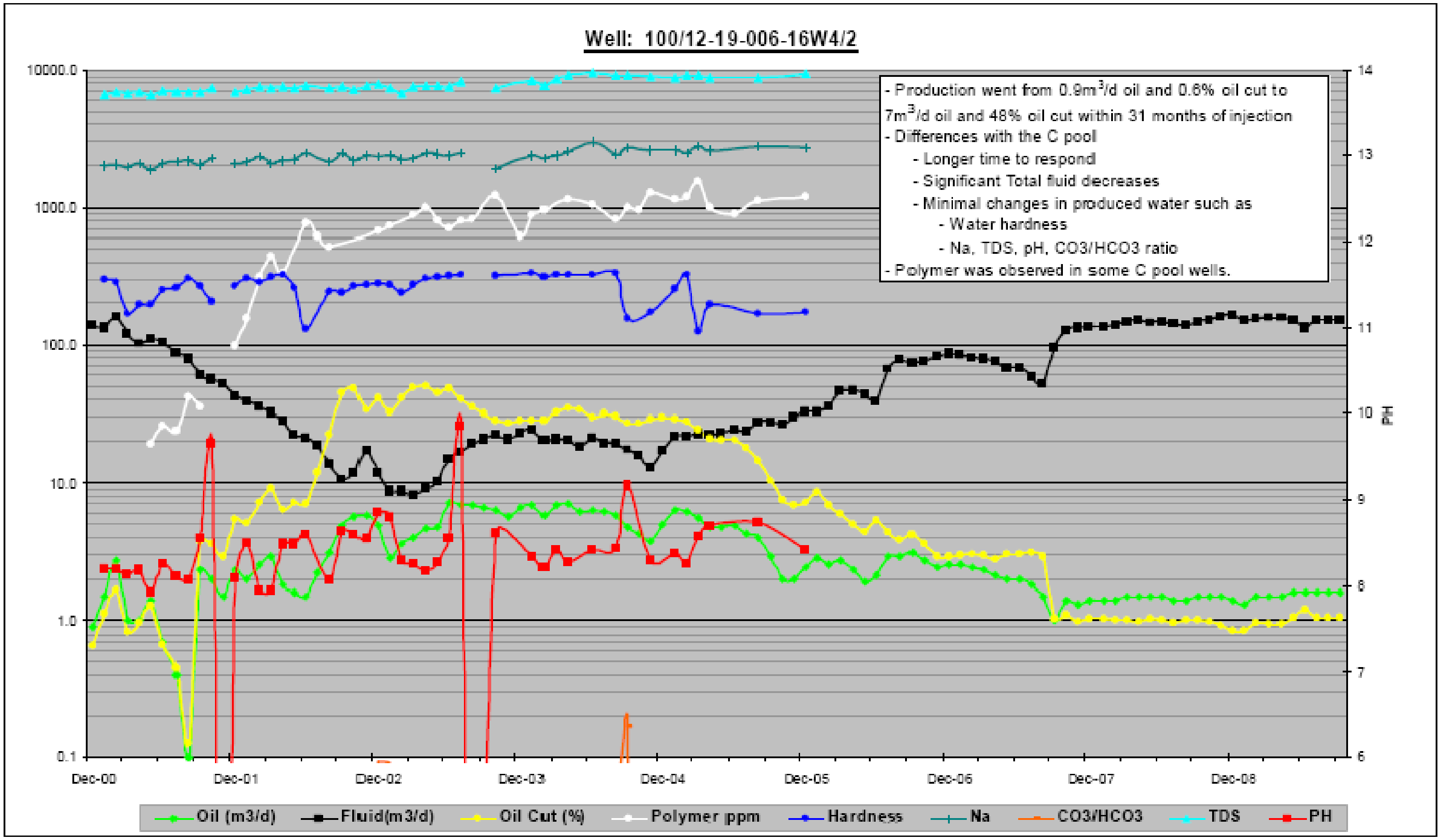



Figure 334

**Wrentham Lower Mannville C Pool – Performance**
**Well Response and Breakthrough**



Sproule

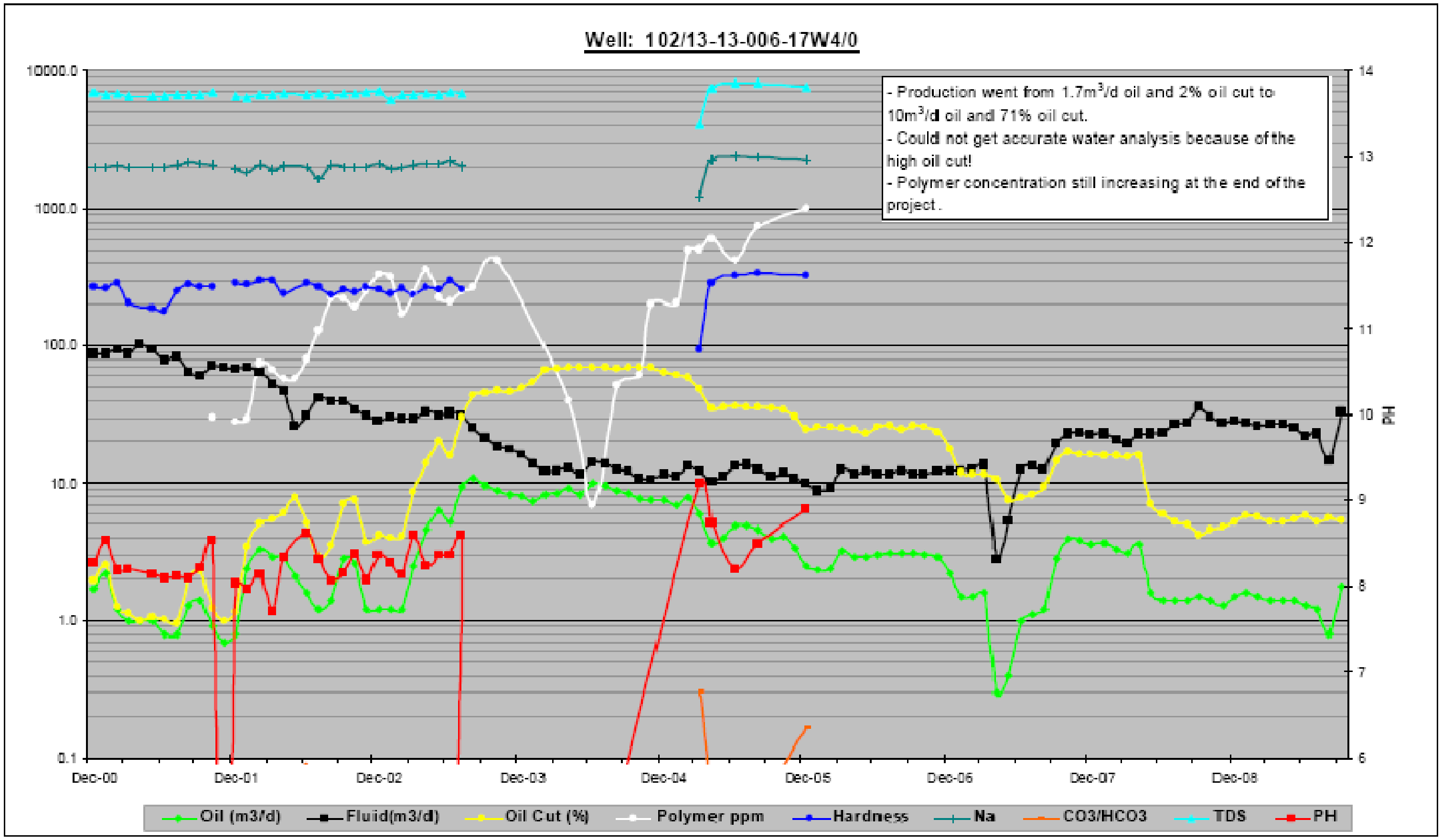



Figure 335

**Wrentham Lower Mannville C Pool – Performance**
**Well Response and Breakthrough**



Sproule

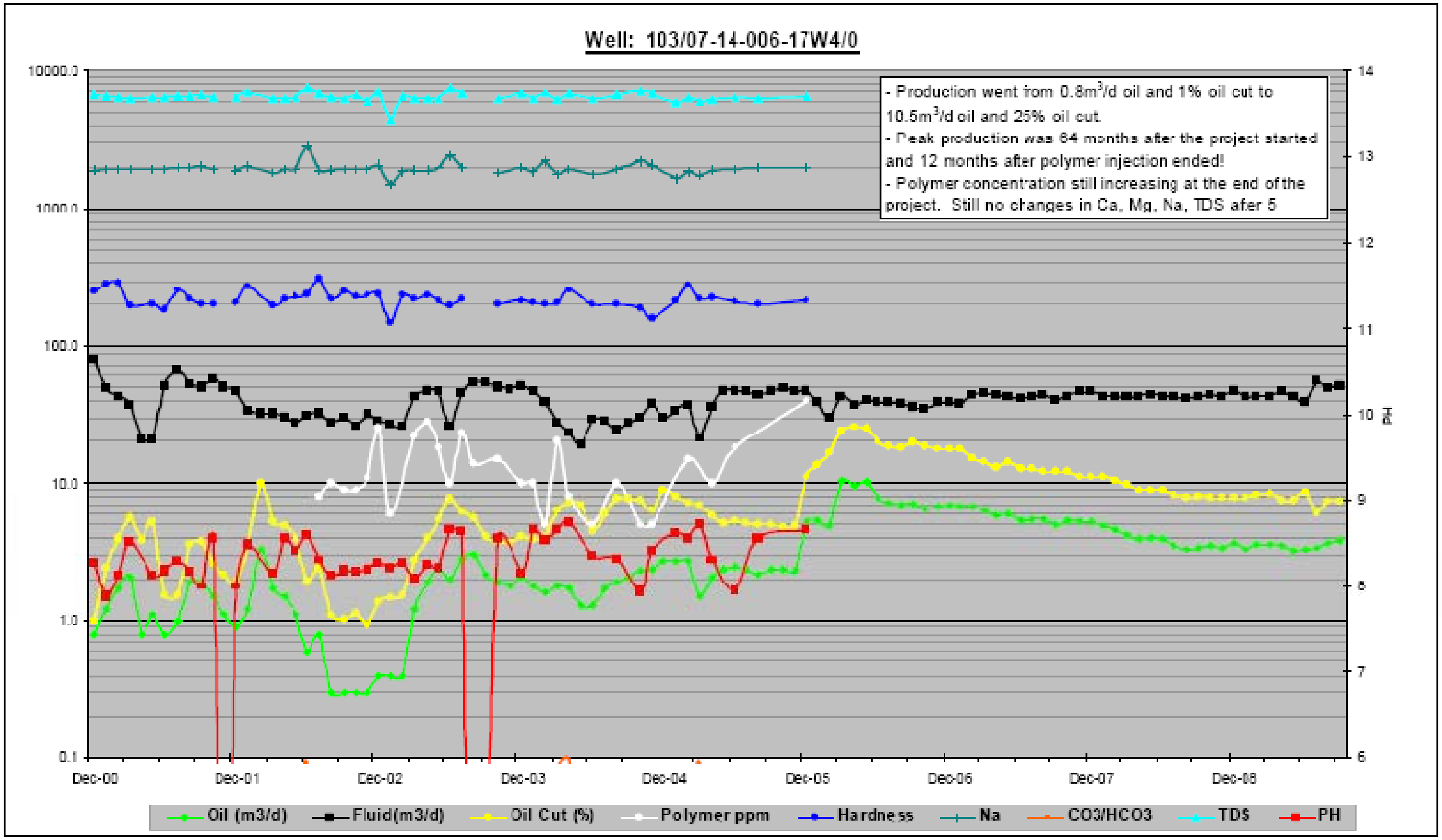



Figure 336

**Wrentham Lower Mannville C Pool – Performance**
**Well Response and Breakthrough**



Sproule

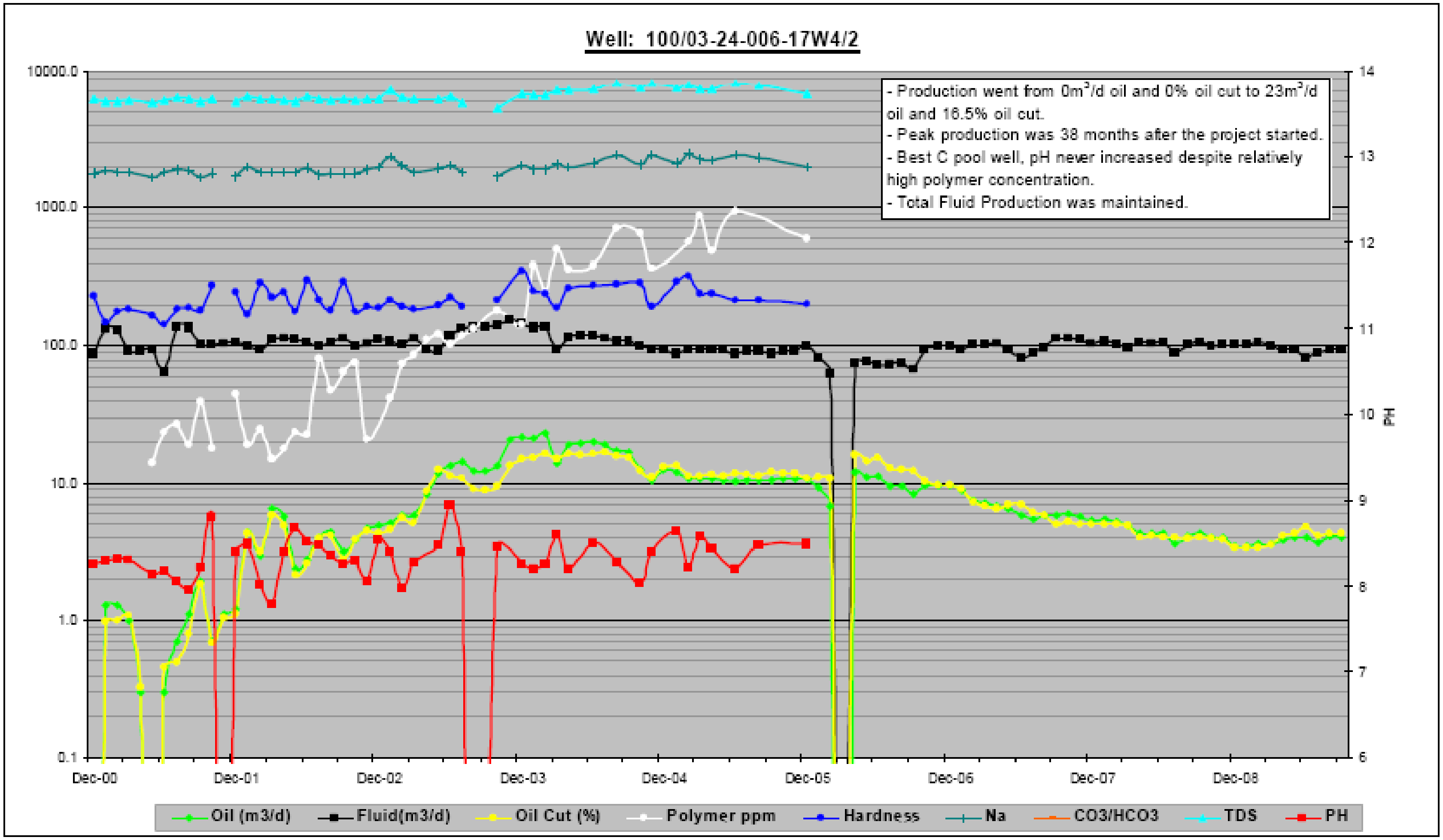



Figure 337

**Wrentham Lower Mannville C Pool – Performance**
**Well Response and Breakthrough**



Sproule

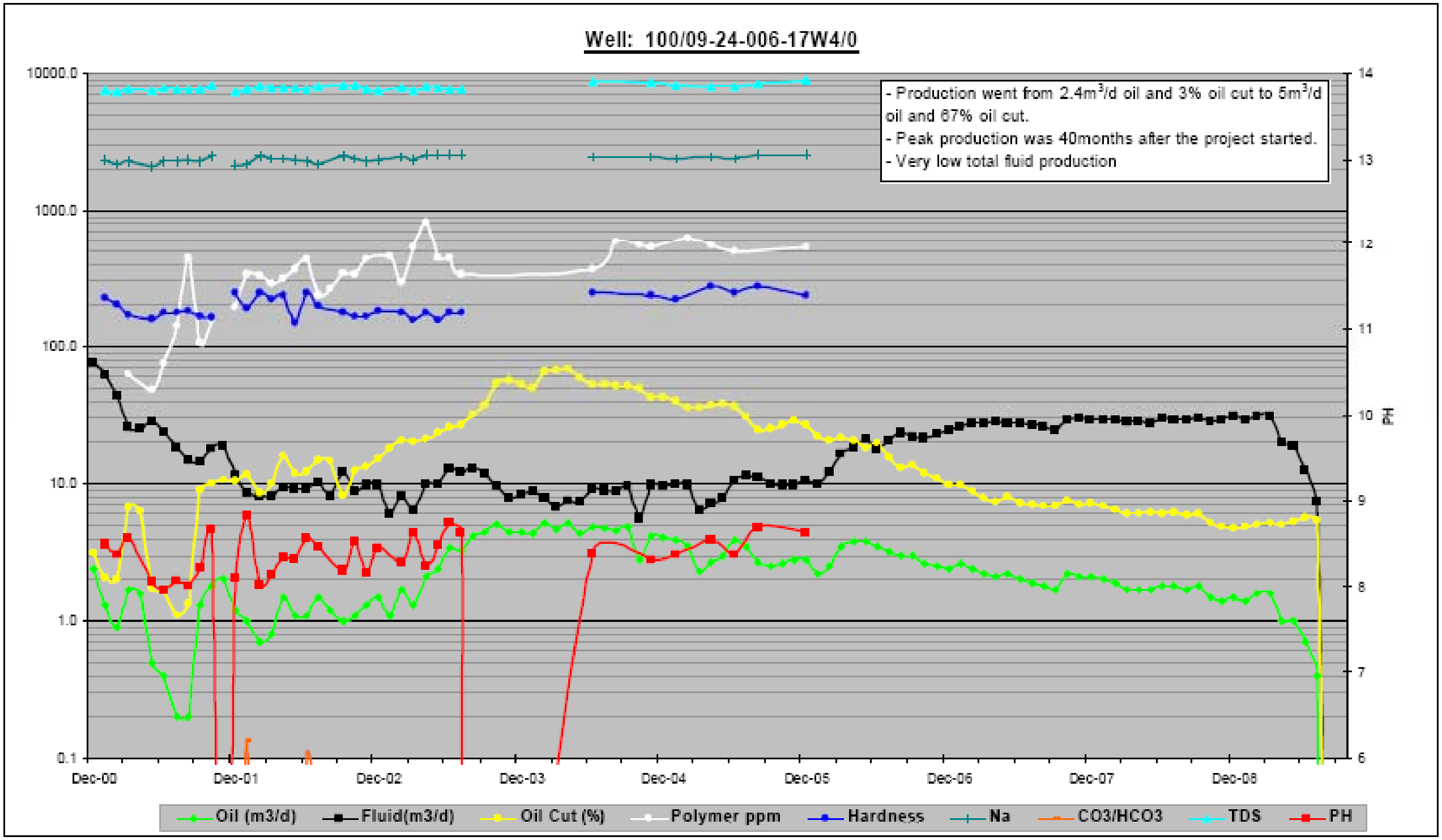



Figure 338

**Wrentham Lower Mannville C Pool – Performance**
**Well Response and Breakthrough**



Sproule

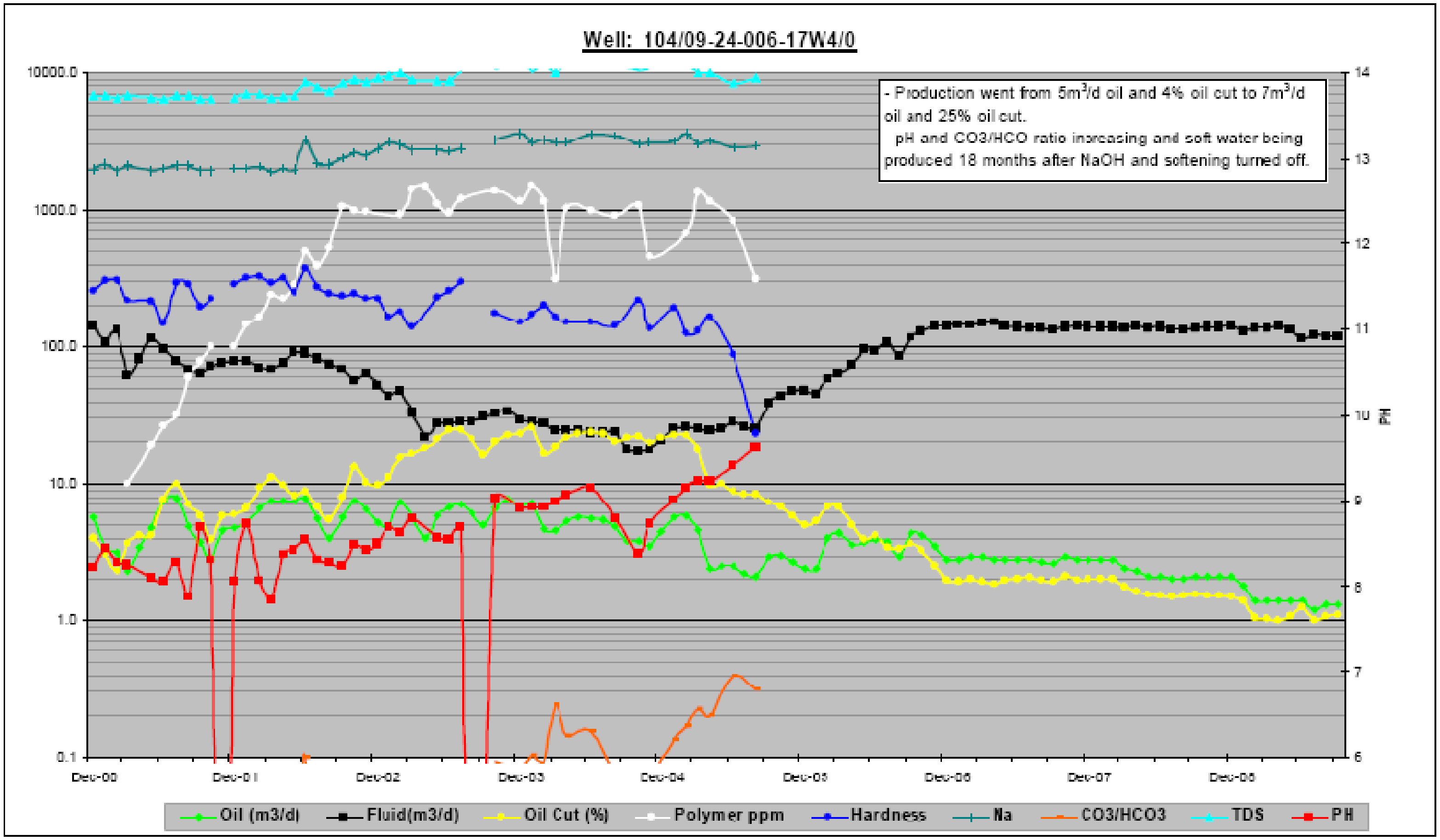
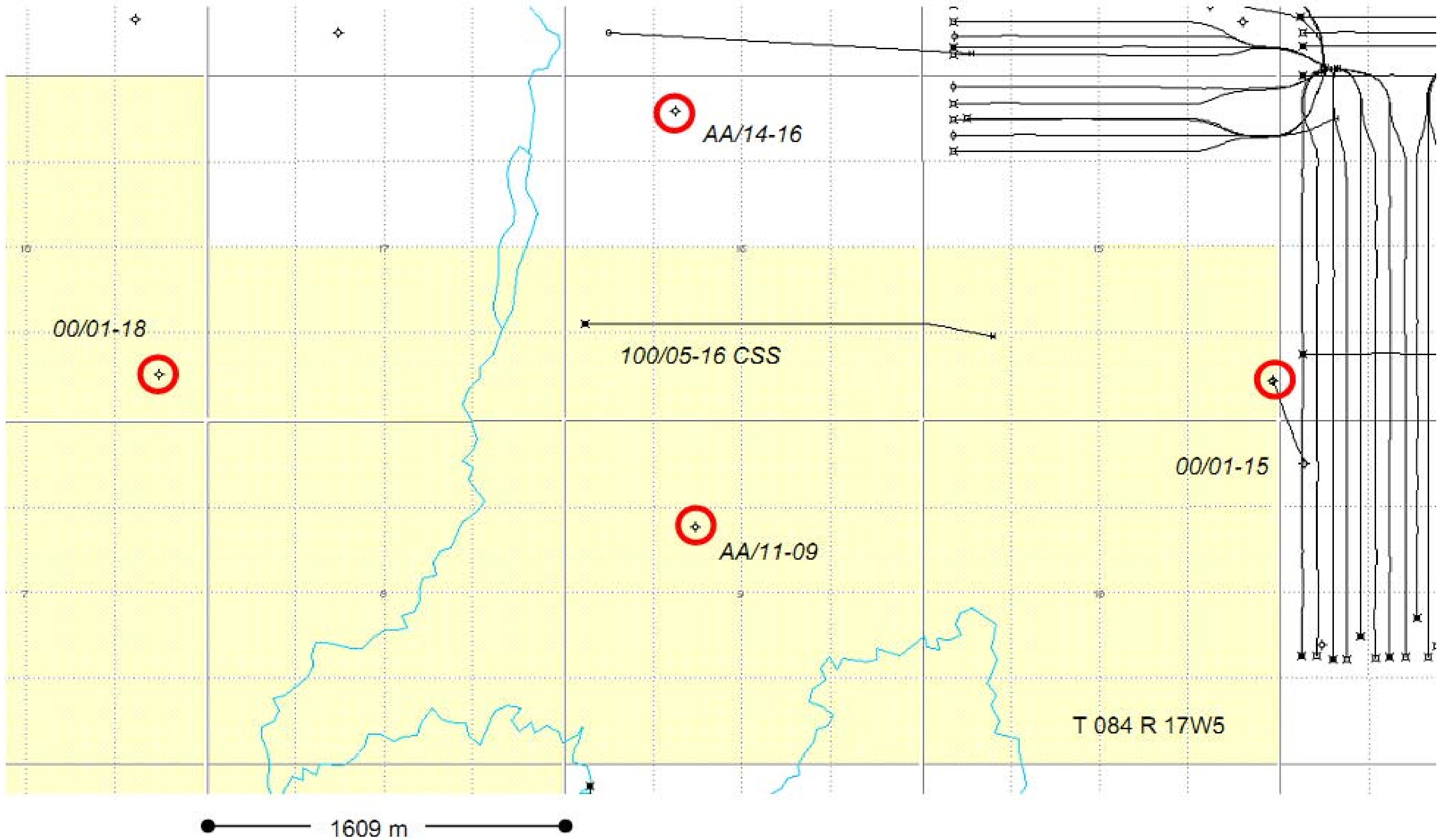


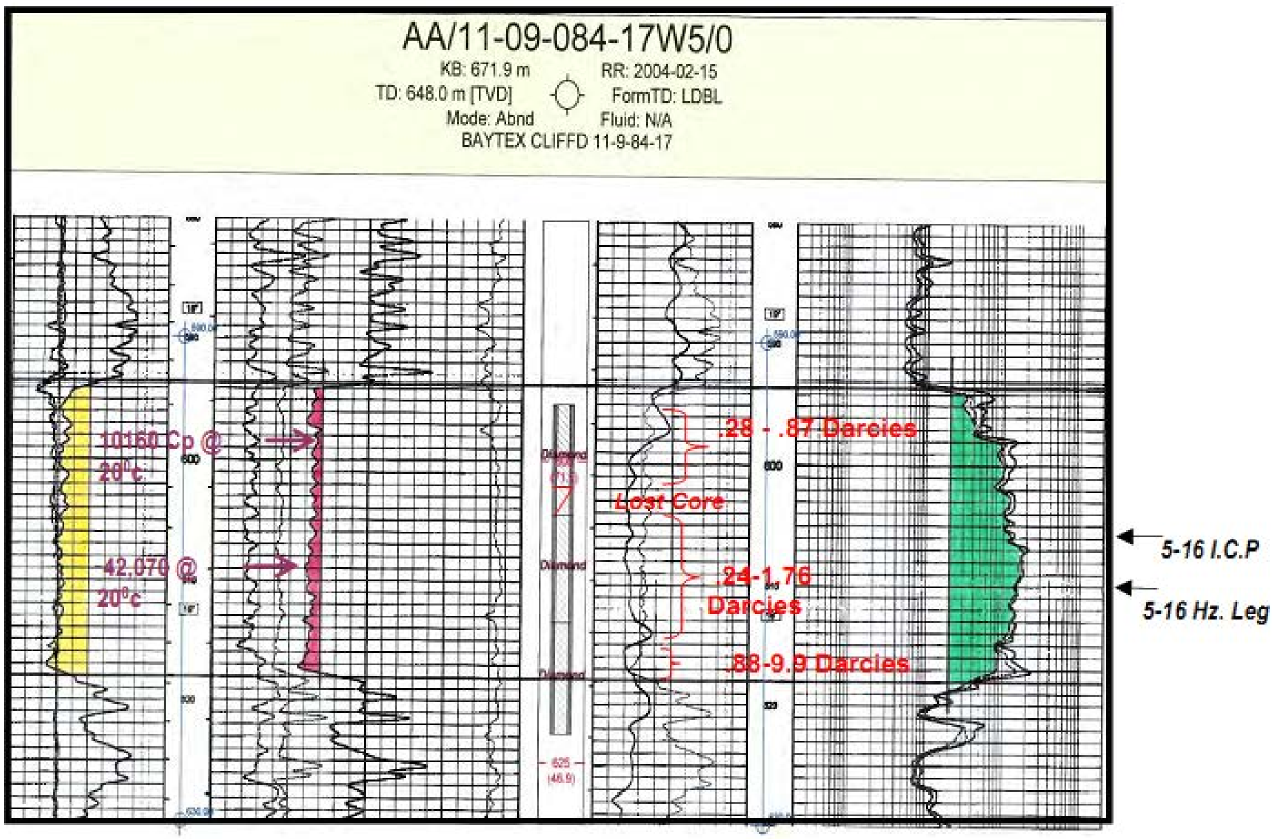

Figure 339

**Wrentham Lower Mannville C Pool – Performance**
**Well Response and Breakthrough**




**Location of Baytex Cliffdale CSS Project**

Figure 340



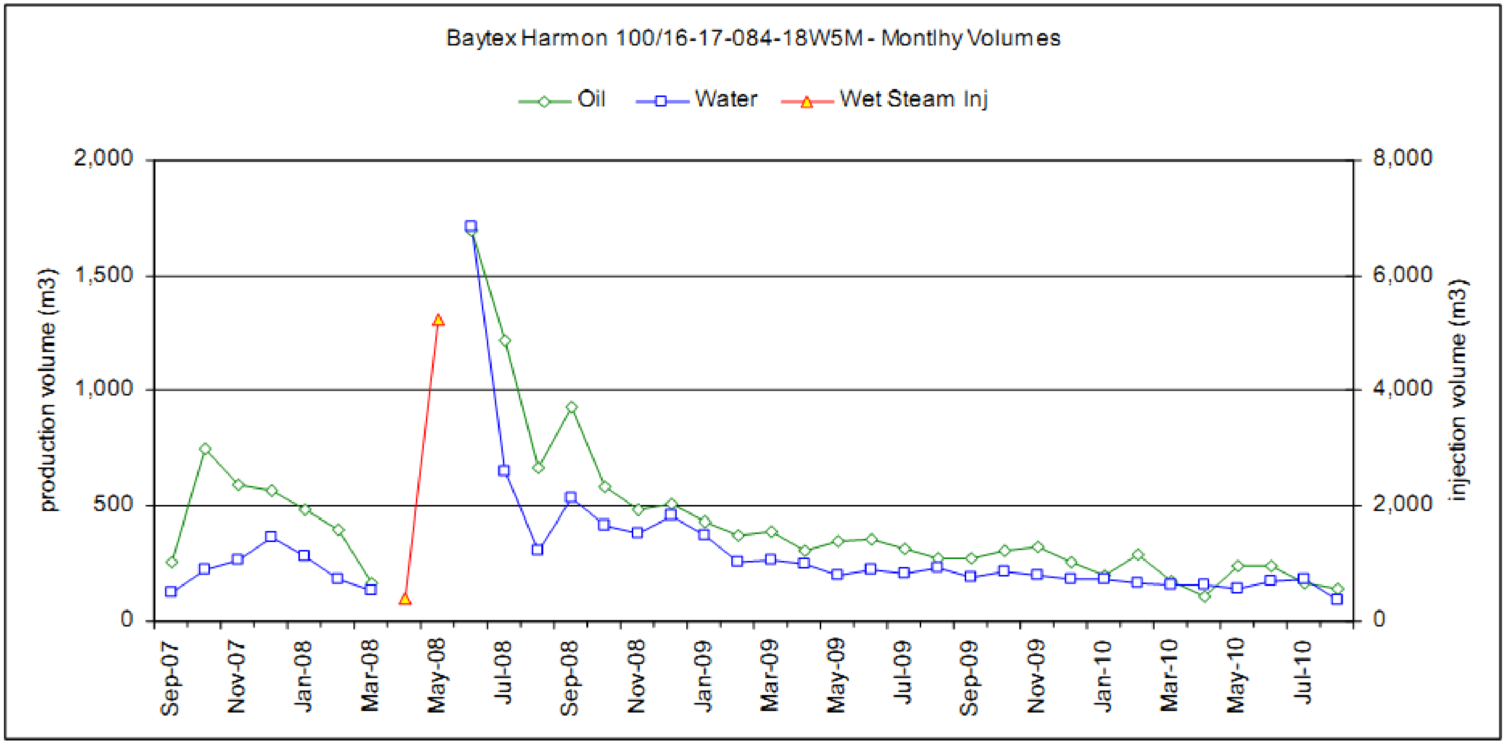

**Baytex Cliffdale Type Log**

Figure 341



Sproule

# Harmon 100/16-17-084-18W5M




using estimates for Aug-2010

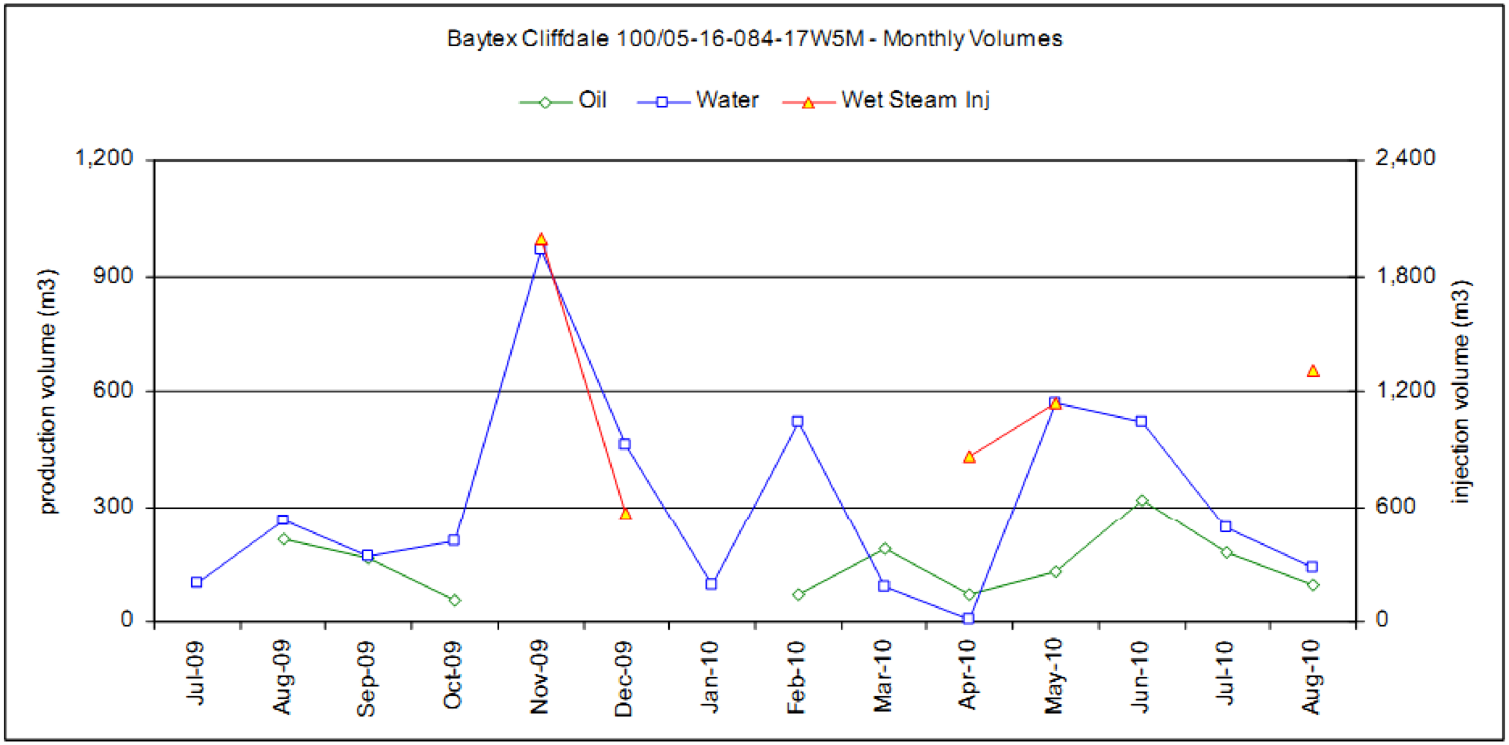
Figure 342

**Harmon Valley Cyclic Steam Performance**



Sproule

# Cliffdale 100/05-16-084-17W5M




using estimates for Aug-2010

Figure 343

**Cliffdale Cyclic Steam Performance**

# APPENDIX A

# ABBREVIATIONS, UNITS AND CONVERSION FACTORS

# Appendix A — Abbreviations, Units and Conversion Factors

This appendix contains a list of abbreviations found in Sproule reports, a table comparing Imperial and Metric units, and conversion tables used to prepare this report.

## Abbreviations

| | |
|---|---|
| AFE | authority for expenditure |
| AOF | absolute open flow |
| APO | after pay out |
| ASP | alkaline surfactant polymer |
| $B_g$ | gas formation volume factor |
| $B_o$ | oil formation volume factor |
| bopd | barrels of oil per day |
| bfpd | barrels of fluid per day |
| BPO | before pay out |
| BS&W | basic sediment and water |
| BTU | British thermal unit |
| bwpd | barrels of water per day |
| CF | casing flange |
| CGR | condensate gas ratio |
| CSS | cyclic steam stimulation |
| CTD | combination thermal drive |
| D&A | dry and abandoned |
| DCQ | daily contract quantity |
| DSU | drilling spacing unit |
| DST | drill stem test |
| EOR | enhanced oil recovery |
| EPSA | exploration and production sharing agreement |
| FVF | formation volume factor |
| GOR | gas-oil ratio |
| GORR | gross overriding royalty |
| GWC | gas-water-contact |
| HCPV | hydrocarbon pore volume |
| HPAI | high pressure air injection |
| ID | inside diameter |
| IOR | improved oil recovery |
| IPR | inflow performance relationship |
| IRF | incremental recovery factor |
| IRR | internal rate of return |

| | |
|---|---|
| ISC | in-situ combustion |
| k | permeability |
| KB | kelly bushing |
| LKH | lowest known hydrocarbons |
| LNG | liquefied natural gas |
| LPG | liquefied petroleum gas |
| md | millidarcies |
| MDT | modular formation dynamics tester |
| MEOR | microbial enhanced oil recovery |
| MPR | maximum permissive rate |
| MRL | maximum rate limitation |
| NGL | natural gas liquids |
| NORR | net overriding royalty |
| NPI | net profits interest |
| NPV | net present value |
| OD | outside diameter |
| OGIP | original gas in place |
| OOIP | original oil in place |
| ORRI | overriding royalty interest |
| OWC | oil-water-contact |
| P1 | proved |
| P2 | probable |
| P3 | possible |
| P&NG | petroleum and natural gas |
| PI | productivity index |
| ppm | parts per million |
| PSU | production spacing unit |
| PSA | production sharing agreement |
| PSC | production sharing contract |
| PVT | pressure-volume-temperature |
| Rf | recovery factor |
| RFT | repeat formation tester |
| RT | rotary table |
| SAGD | steam assisted gravity drainage |
| SCAL | special core analysis |
| SS | subsea |
| THAI | toe to heel air injection |
| TVD | true vertical depth |
| WGR | water gas ratio |
| WI | working interest |
| WOR | water oil ratio |

| | |
|---|---|
| 2D | two-dimensional |
| 3D | three-dimensional |
| 4D | four-dimensional |
| 1P | proved |
| 2P | proved plus probable |
| 3P | proved plus probable plus possible |
| $^{o}$API | degrees API (American Petroleum Institute) |

## Imperial and Metric Units

| Imperial Units | | | Metric Units | |
|---|---|---|---|---|
| M ($10^3$) | one thousand | **Prefixes** | k ($10^3$) | one thousand |
| MM ($10^6$) | Million | | M ($10^6$) | million |
| B ($10^9$) | one billion | | T ($10^{12}$) | one billion |
| T ($10^{12}$) | one trillion | | E ($10^{18}$) | one trillion |
| | | | G ($10^9$) | one milliard |
| in. | Inches | **Length** | cm | centimetres |
| ft | Feet | | m | metres |
| mi | Mile | | km | kilometres |
| $ft^2$ | square feet | **Area** | $m^2$ | square metres |
| ac | Acres | | ha | hectares |
| cf or $ft^3$ | cubic feet | **Volume** | $m^3$ | cubic metres |
| scf | Standard cubic feet | | | |
| gal | Gallons | | L | litres |
| Mcf | Thousand cubic feet | | | |
| Mcfpd | Thousand cubic feet per day | | | |
| MMcf | million cubic feet | | | |
| MMcfpd | million cubic feet per day | | | |
| Bcf | billion cubic feet ($10^9$) | | | |
| bbl | Barrels | | $m^3$ | cubic metre |
| Mbbl | Thousand barrels | | | |
| stb | stock tank barrel | | $stm^3$ | stock tank cubic metres |
| bbl/d | barrels per day | | $m^3/d$ | cubic metre per day |
| bbl/mo | barrels per month | | | |
| Btu | British thermal units | **Energy** | J | joules |
| | | | $MJ/m^3$ | megajoules per cubic metre ($10^6$) |
| | | | TJ/d | terajoule per day ($10^{12}$) |
| oz | ounce | **Mass** | g | gram |
| lb | pounds | | kg | kilograms |
| ton | ton | | t | tonne |
| lt | long tons | | | |

| | | | | |
|---|---|---|---|---|
| Mlt | thousand long tons | | | |
| psi<br><br>psia<br>psig | pounds per square inch<br><br>pounds per square inch absolute<br>pounds per square inch gauge | **Pressure** | Pa<br>kPa | pascals<br>kilopascals ($10^3$) |
| °F<br>°R | degrees Fahrenheit<br>degrees Rankine | **Temperature** | °C<br>K | degrees Celsius<br>Kelvin |
| M$ | thousand dollars | **Dollars** | k$ | thousand dollars |

## Imperial and Metric Units (Cont'd)

| Imperial Units | | | Metric Units | |
|---|---|---|---|---|
| sec | second | **Time** | s | second |
| min | minute | | min | minute |
| hr | hour | | h | hour |
| day | day | | d | day |
| wk | week | | | week |
| mo | month | | | month |
| yr | year | | a | annum |

## Conversion Tables

| Conversion Factors — Metric to Imperial | | |
|---|---|---|
| cubic metres ($m^3$) (@ 15°C) | x 6.29010 | = barrels (bbl) (@ 60°F), water |
| $m^3$ (@ 15°C) | x 6.3300 | = bbl (@ 60°F), Ethane |
| $m^3$ (@ 15°C) | x 6.30001 | = bbl (@ 60°F), Propane |
| $m^3$ (@ 15°C) | x 6.29683 | = bbl (@ 60°F), Butanes |
| $m^3$ (@ 15°C) | x 6.29287 | = bbl (@ 60°F), oil, Pentanes Plus |
| $m^3$ (@ 101.325 kPaa, 15°C) | x 0.0354937 | = thousands of cubic feet (Mcf) (@ 14.65 psia, 60°F) |
| 1,000 cubic metres ($10^3m^3$) (@ 101.325 kPaa, 15°C) | x 35.49373 | = Mcf (@ 14.65 psia, 60°F) |
| hectares (ha) | x 2.4710541 | = acres |
| 1,000 square metres ($10^3m^2$) | x 0.2471054 | = acres |
| 10,000 cubic metres (ha·m) | x 8.107133 | = acre feet (ac-ft) |
| $m^3/10^3m^3$ (@ 101.325 kPaa, 15° C) | x 0.0437809 | = Mcf/Ac.ft. (@ 14.65 psia, 60°F) |
| joules (j) | x 0.000948213 | = Btu |
| megajoules per cubic metre ($MJ/m^3$) (@ 101.325 kPaa, 15°C) | x 26.714952 | = British thermal units per standard cubic foot (Btu/scf) (@ 14.65 psia, 60°F) |
| dollars per gigajoule ($/GJ) | x 1.054615 | = $/Mcf (1,000 Btu gas) |
| metres (m) | x 3.28084 | = feet (ft) |
| kilometres (km) | x 0.6213712 | = miles (mi) |
| dollars per 1,000 cubic metres ($/$10^3m^3$) | x 0.0288951 | = dollars per thousand cubic feet ($/Mcf) (@ 15.025 psia) B.C. |
| ($/$10^3m^3$) | x 0.02817399 | = $/Mcf (@ 14.65 psia) Alta. |
| dollars per cubic metre ($/$m^3$) | x 0.158910 | = dollars per barrel ($/bbl) |
| gas/oil ratio (GOR) ($m^3/m^3$) | x 5.640309 | = GOR (scf/bbl) |
| kilowatts (kW) | x 1.341022 | = horsepower |
| kilopascals (kPa) | x 0.145038 | = psi |
| tonnes (t) | x 0.9842064 | = long tons (LT) |
| kilograms (kg) | x 2.204624 | = pounds (lb) |
| litres (L) | x 0.2199692 | = gallons (Imperial) |
| litres (L) | x 0.264172 | = gallons (U.S.) |
| cubic metres per million cubic metres ($m^3/10^6m^3$) ($C_3$) | x 0.177496 | = barrels per million cubic feet (bbl/MMcf) (@ 14.65 psia) |
| $m^3/10^6m^3$ ($C_4$) | x 0.1774069 | = bbl/MMcf (@ 14.65 psia) |
| $m^3/10^6m^3$ ($C_{5+}$) | x 0.1772953 | = bbl/MMcf (@ 14.65 psia) |
| tonnes per million cubic metres ($t/10^6m^3$) (sulphur) | x 0.0277290 | = LT/MMcf (@ 14.65 psia) |
| millilitres per cubic meter ($mL/m^3$) ($C_{5+}$) | x 0.0061974 | = gallons (Imperial) per thousand cubic feet (gal (Imp)/Mcf) |
| ($mL/m^3$) ($C_{5+}$) | x 0.0074428 | = gallons (U.S.) per thousand cubic feet (gal (U.S.)/Mcf) |

| | | |
|---|---|---|
| Kelvin (K) | x 1.8 | = degrees Rankine (°R) |
| millipascal seconds (mPa·s) | x 1.0 | = centipoise |
| | | |

# Conversion Tables (Cont'd)

**Conversion Factors — Imperial to Metric**

| | | |
|---|---|---|
| barrels (bbl) (@ 60°F) | x 0.15898 | = cubic metres ($m^3$) (@ 15°C), water |
| bbl (@ 60°F) | x 0.15798 | = $m^3$ (@ 15°C), Ethane |
| bbl (@ 60°F) | x 0.15873 | = $m^3$ (@ 15°C), Propane |
| bbl (@ 60°F) | x 0.15881 | = $m^3$ (@ 15°C), Butanes |
| bbl (@ 60°F) | x 0.15891 | = $m^3$ (@ 15°C), oil, Pentanes Plus |
| thousands of cubic feet (Mcf) (@ 14.65 psia, 60°F) | x 28.17399 | = $m^3$ (@ 101.325 kPaa, 15°C) |
| Mcf (@ 14.65 psia, 60°F) | x 0.02817399 | = 1,000 cubic metres ($10^3m^3$) (@ 101.325 kPaa, 15°C) |
| acres | x 0.4046856 | = hectares (ha) |
| acres | x 4.046856 | = 1,000 square metres ($10^3m^2$) |
| acre feet (ac-ft) | x 0.123348 | = 10,000 cubic metres ($10^4m^3$) (ha·m) |
| Mcf/ac-ft (@ 14.65 psia, 60°F) | x 22.841028 | = $10^3m^3/m^3$ (@ 101.325 kPaa, 15°C) |
| Btu | x 1054.615 | = joules (J) |
| British thermal units per standard cubic foot (Btu/Scf) (@ 14.65 psia, 60°F) | x 0.03743222 | = megajoules per cubic metre ($MJ/m^3$) (@ 101.325 kPaa, 15°C) |
| $/Mcf (1,000 Btu gas) | x 0.9482133 | = dollars per gigajoule ($/GJ) |
| $/Mcf (@ 14.65 psia, 60°F) Alta. | x 35.49373 | = $/$10^3m^3$ (@ 101.325 kPaa, 15°C) |
| $/Mcf (@ 15.025 psia, 60°F), B.C. | x 34.607860 | = $/$10^3m^3$ (@ 101.325 kPaa, 15°C) |
| feet (ft) | x 0.3048 | = metres (m) |
| miles (mi) | x 1.609344 | = kilometres (km) |
| $/bbl | x 6.29287 | = $/$m^3$ (average for 30°-50° API) |
| GOR (scf/bbl) | x 0.177295 | = gas/oil ratio (GOR) ($m^3/m^3$) |
| horsepower | x 0.7456999 | = kilowatts (kW) |
| psi | x 6.894757 | = kilopascals (kPa) |
| long tons (LT) | x 1.016047 | = tonnes (t) |
| pounds (lb) | x 0.453592 | = kilograms (kg) |
| gallons (Imperial) | x 4.54609 | = litres (L) (.001 $m^3$) |
| gallons (U.S.) | x 3.785412 | = litres (L) (.001 $m^3$) |
| barrels per million cubic feet (bbl/MMcf) (@ 14.65 psia) ($C_3$) | x 5.6339198 | = cubic metres per million cubic metres ($m^3/10^6m^3$) |
| bbl/MMcf ($C_4$) | x 5.6367593 | = ($m^3/10^6m^3$) |
| bbl/MMcf ($C_{5+}$) | x 5.6403087 | = ($m^3/10^6m^3$) |
| LT/MMcf (sulphur) | x 36.063298 | = tonnes per million cubic metres ($t/10^6m^3$) |
| gallons (Imperial) per thousand cubic feet (gal (Imp)/Mcf) ($C_{5+}$) | x 161.3577 | = millilitres per cubic meter ($mL/m^3$) |
| gallons (U.S.) per thousand cubic feet (gal (U.S.)/Mcf) ($C_{5+}$) | x 134.3584 | = ($mL/m^3$) |

| | | |
|---|---|---|
| degrees Rankine (°R) | x 0.555556 | = Kelvin (K) |
| centipoises | x 1.0 | = millipascal seconds (mPa•s) |