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Evaluation of Recovery Technologies for the Grosmont Carbonate Reservoirs

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Abstract

The Upper Devonian Grosmont Formation is a bitumen-saturated, carbonate unit located in northern Alberta. It is considered to be one of the world's next largest unconventional oil resource plays. Since early 2006, there has been an increased interest in Grosmont resources exhibited by a range of companies including super-majors.

Several in-situ pilot tests were conducted in the central portion of this area in the 1970s and 1980s utilizing steam and in-situ combustion processes. Similar to field tests in the McMurray Formation oil sands prior to invention of the steam assisted gravity drainage (SAGD) process, none of the early recovery technologies tested were proven to be economic. As the "gravity" drainage process has been proven successful in commercial development of the McMurray Formation oil sands since mid to late 1990s, the recovery potential for the Grosmont Formation should be re-evaluated based on improved recovery techniques.

Results from cyclic steam stimulation (CSS) field tests are compared and analyzed to understand the similarity and fundamental differences in reservoir properties between the McMurray Formation oil sands and the Grosmont Formation carbonate rocks. A preliminary interpretation is provided for laboratory test results for solvent processes applied to Grosmont carbonate cores. The scaling considerations from the laboratory results to field expectations are discussed. The paper also provides a direction for future studies and optimization opportunities for reservoir recovery leading to the commercial development of Grosmont carbonate reservoirs.

Introduction

The estimated original bitumen in place (OBIP) in the Grosmont carbonate reservoir is 51 billion m^3 or 320 billion bbl [1]. It is by far the largest heavy oil carbonate reservoir in the world. In comparison with the McMurray Formation in the Athabasca oil sands area, the carbonates of the Grosmont Formation have a very complex porosity and fluid mobility system as well as a highly heterogeneous oil saturation, a more hydrophobic rock matrix, and a poorly understood geomechanical property. The platform carbonates of the Grosmont Formation that form the best potential reservoirs have predictable and mappable lithology over several hundred square kilometers whereas the vertically homogeneous channel sand deposits that comprise the best-performing McMurray Formation reservoirs are limited in areal extent and require significant delineation in order to map accurately. While the Grosmont reservoir is very attractive from the resource point of view, the differences in reservoir characteristics pose significant challenges to reservoir development.

The first field operation attempt in the Grosmont Formation started in December 1974 by Union Oil in the Chipewyan River area, Section 21 of T89-R21-W4. The objective of the pilot was to test reservoir injectivity, well completion techniques and to recover bitumen samples for characterization. One cycle of CSS steam injection and production was conducted in two vertical wells, 14B-21 and 11E-21. The operation ended in April 1975. Although results achieved were not that spectacular, it marked the first operational encounter of the complexity of the Grosmont reservoir. Several more projects followed in partnership with Canadian Superior and AOSTRA and these were further extended into the Buffalo Creek (T88-R19-W4) and McLean (T87-R19-W4) areas, with significantly improved productivity and steam-to-oil ratios. In the winter of 1976-77, Chevron also conducted a CSS test in the Algar area, T81-R17-W4. Wet combustion was first tried in the second half of 1978 in the Buffalo Creek area following steam stimulation. Besides vertical well CSS and wet combustion, some tests involved steam drive, multiple well steam stimulation and co-injection of surfactants for formation of foam, with mixed results. Activities in Grosmont carbonate reservoirs slowed in the late 80's as the industrial attention shifted to development of the in situ production of the oil sands.

In the winter of 2007-08, Laricina Energy Ltd. in partnership with Osum Oil Sands Corp. conducted a cold solvent injection/production test in a single vertical well in section 26 of T85-R19-W4 [2]. The test, which resumed in the winter of 2008-09, has demonstrated the feasibility of the cold solvent process. This marked the beginning of a second wave of attempts to turn the Grosmont challenges into prospective opportunities.

During a similar time span, new in situ recovery processes as well as drilling and completion technologies have been rapidly evolving in Alberta's bituminous sands areas, namely, the Peace River, Athabasca, and Cold Lake regions. Some pilot tests utilizing horizontal, vertical and directional wells, thermal and non-thermal processes have been developed into large commercial projects. The most robust recovery processes are cyclic steam stimulation (CSS) and steam assisted gravity drainage (SAGD). There are also some hybrid variations of these two processes that include solvent injection. Can these technologies be borrowed, modified and then applied to Grosmont reservoirs? Are there other recovery technologies, such as in situ combustion, suitable for the complexity of carbonates? We believe that detailed analysis of past pilot and laboratory tests will provide valuable insights and that new pilot and laboratory tests will be needed for identification of the most feasible processes that may further develop into commercially viable recovery methods for Grosmont carbonate reservoirs.

Geological Description

The Upper Devonian Grosmont Formation carbonate rocks are richly saturated with bitumen in the Saleski/Liege area of northern Alberta (Figure 1.A). The shallow marine carbonate strata dip to the southwest and are eroded at the angular unconformity with the overlying clastic sediments of the Clearwater and McMurray Formations (Figure 1.B, Figure 2). The Grosmont Formation has been divided into four informal members; the Grosmont A, B, C, and D in order of decreasing stratigraphic age (Figure 3). The lithofacies of the Grosmont Formation at Saleski/Liege represent open marine to restricted marine deposits and record an overall shallowing-upward succession (Figure 2). The lithofacies were deposited in a wide carbonate platform setting and subjected to regional diagenetic processes. The lithofacies are correlatable over hundreds of square kilometers [3]. The Grosmont C and D units experienced early matrix dolomitization and as a result were more susceptible to late-stage solution enhancement by meteoric waters when the carbonate units were uplifted and exposed during the Late Jurassic to Early Cretaceous [4]. This diagenetic history resulted in the Grosmont C and D units having a complicated porosity network of matrix porosity, vuggy porosity, solution-enhanced fractures, and breccias related to karstification[5]. The solution-enhanced porosity zones are dominantly found close to the subcrop edge (Figure 2). Permeability measurements from whole diameter cores of the reservoir intervals are assumed to under-represent the bulk effective permeability in the subsurface.

Evaluation of Gravity Drainage Potential from CSS Pilot Tests

Several thermal recovery processes were tested in the Grosmont reservoirs from the mid -1970s to early 1980s. The processes tested include in-situ combustion, steamflood and cyclic steam stimulation. The cyclic steam stimulation test at the well 10A-5-88-19W4 at Unocal's Buffalo Creek pilot site was encouraging, with a cumulative oil production of more than 100,000 bbls and a cumulative SOR of 6.0 over 10 cycles. The best cycle achieved a SOR of less than 4.0. The production performance is plotted in Figures 4 and 5. The pilot exhibited the following characteristics:

- High injectivity for steam at a pressure much below the fracturing pressure of the formation (steam injection rate >100 m^3/d CWE at bottom hole injection pressure <4 MPa);
- High productivity of bitumen (peak rate in excess of 70 m^3/d);
- Low produced water to injected steam ratio (<70%).

The design and operation for the early field tests were limited to the concept of drive mechanisms. It was realized later that any processes requiring substantial pressure differential to produce bitumen would not work effectively in the Grosmont carbonate and Cretaceous oil sand reservoirs due to the following factors:

1. Immobile bitumen at the initial reservoir conditions due to high viscosity of bitumen;
2. Lack of solution gas drive due to low solution GOR in the bitumen;
3. Most of the Grosmont and McMurray reservoirs are buried in shallow formations and are partially pressure depleted.

Reservoirs with the above characteristics will have difficulty in establishing the initial communication between the injector and producer for any drive processes such as steam drive and in-situ combustion. The high viscosity of bitumen and lack of solution gas drive in such reservoirs also makes the CSS process inefficient, with the production cycles being terminated too early.

Fluids are difficult to produce back as the result of increased bitumen viscosity as the temperature falls. The success of the CSS process in the Clearwater Formation in the Cold Lake area is due to superior fluid properties and generally higher initial reservoir pressures.

To assist in the evaluation of the gravity drainage potential for the Grosmont carbonate reservoir, the development history of the oil sands in the McMurray Formation was assessed. With over two decades of pilot testing of various processes, no commercial recovery process was identified for McMurray development until the successful testing of the SAGD process. Although the direct analog may not be justified completely due to differences in pore structures and fluid distributions, it was the switching of recovery mechanisms from drive to gravity drainage that made the step change in recovery efficiency in the McMurray Formation. Considering the similar bitumen viscosity and low solution GOR in the Grosmont and McMurray Formations, gravity drainage should be a promising focus for the future development of recovery technologies applicable to carbonate reservoirs.

A side by side comparison of early CSS test results and later SAGD performance is provided for the McMurray Formation in Japan Canada Oil Sands' (JACOS) Hangingstone project area. The location of the CSS test pad is marked in red in Figure 6 and this site is adjacent to the current SAGD operation area. The CSS pilot was conducted by PetroCanada utilizing vertical wells in the Hangingstone area (sections 27 to 34-084-11W4) from 1990 to 1995. The performance from the test is plotted in Figures 7 and 8 based on the data available in the public database. The average daily oil production rate was less than 5.0 m^3/d per well at a cumulative SOR of 11.7 over multiple cycles. The peak oil rate from a single well was less than 20 m^3/d.

The SAGD test was conducted by JACOS in the same reservoir adjacent to the early CSS pilot site. The performance from the first two SAGD well pairs is plotted in Figures 9 and 10. For the same McMurray reservoir, SAGD produced a peak oil rate of 150 m^3/d per well pair and a cumulative SOR of 3.5. The daily oil rate per producer from SAGD was increased by more than 30 times and the cumulative SOR decreased by more than 3 times in comparison to the early CSS test.

The Buffalo Creek CSS Pilot test at 10A-5-88-19W produced about 20 m^3/d bitumen on average and the peak bitumen rate was over 70 m^3/d. The average productivity from the CSS test at the Buffalo Creek pilot was about 4 times that that found in JACOS Hangingstone. With a similar bitumen viscosity (in the order of 1 million mPa.s) at initial reservoir conditions and similar depths, it is natural to assume that the Grosmont carbonate has a much higher bulk permeability than the McMurray Formation. To match the CSS production history of the well 10A-5-88-19W, the bulk permeability in the Grosmont Formation would have to be in the order of 10 to 100 Darcies [5].

The theoretical methods described by Butler [6] are applied to compare the SAGD productivities between the Grosmont and McMurray Formations based on their typical reservoir properties listed in Table 1. The peak bitumen rate from the SAGD process can be estimated from the following " Lindrain" equation :

$$q = 2L\sqrt{\frac{1.3kg\alpha\phi\Delta S_o h}{m\upsilon_s}} \qquad (1.)$$

If the bitumen viscosity and thermal diffusivity are assumed to be the same under the same operating conditions, then the production rate is proportional to the square root of (ϕ k Δ S_o h). The Grosmont Formation would produce at a higher rate than, or equivalent to, the McMurray Formation for the SAGD process, based on the parameters given in Table 1.

Table 1, Typical Reservoir Properties in the McMurray and Grosmont Formations

Parameters	McMurray	Grosmont
Φ (fraction)	0.33	0.22
k_v (Darcies)	5	10
ΔS_o	0.7	0.7
h (m)	20	30
Productivity ratio	1.0	1.4

The above comparison assumes the same mobile oil saturation (ΔS_o) for the Grosmont and McMurray Formations. Without knowing the representative residual oil saturation in the steam chamber in the Gromont Formation, the estimation of the mobile oil saturation presents some uncertainty. However, the higher residual oil saturation for the Grosmont Formation is already 'buried' in the assumption due to the higher initial oil saturation in the Grosmont (85-95%) in comparison to the McMurray (75-85%).

Laboratory Test

The results from a cold solvent soak test for an 80 cm long full diameter Grosmont core have been previously reported [2]. The core sample was taken from a well located in the Laricina-Osum JV land. The propane and CO_2 mixture was injected as the solvent, which was at a temperature close to the original reservoir temperature. The injection pressure was determined based on the vapor pressure of the solvent mixture. The production curve for the cold solvent is shown in Figure 12. The overall oil recovery for this test exceeded 60% of OOIP.

To evaluate the effect of temperature and pressure on the efficiency of the solvent process, a warm solvent soak test was conducted at the University of Calgary's Tomographic Imaging and Porous Media (TIPM) laboratory. A 94 cm full diameter core was taken from the Grosmont Formation in Osum's Saleski area. The core was sealed by metal screens and held inside a larger diameter core holder. The solvent was injected and vaporized in the annulus of the core holder to achieve the conditions required for the vapor extraction (Vapex) process. The injection pressure was set at, or slightly lower than, the vapor pressure of the injected solvent at the test temperature. In this experiment, butane was injected at 50^{o}C and 400 kPa. In comparison to the cold solvent process, the heated solvent process has the following advantages:

1. Does not require the co-injection of non-condensible gas to assist the vaporization of solvent so that the solvent concentration in the gas phase and at the interface is maximized;
2. Enhances the diffusivity of solvent in the bitumen due to the reduced viscosity of bitumen;
3. Improves the process rate.

In field applications, the injection of heat into the reservoir with solvent can also accelerate the initial communication between the injector and producer, which is the key for a gravity drainage process. The disadvantages with the heated solvent could be the reduced solubility of solvent in the bitumen and the additional energy required to heat the solvent. Depending on the temperature, the operating pressure with pure solvent injection is usually low to match the vapor pressure of pure solvent. Further studies are underway on the effects of temperature, pressure and solvent composition on the efficiency of a solvent recovery process. Results will be reported in future papers. There are opportunities to optimize the solvent type, composition, temperature and pressure for the solvent process.

The production curve from the warm solvent soak test is shown in Figure 13. The overall recovery from this test was 50% of OIP. The process rate was faster initially and became slower with production time. The cumulative production curve appears to have three distinct slopes at different stages. The rate change in each stage would be an indication of fluid drainage from different porosity regions in the core.

Figure 14 is a comparison of the oil production rates between the reported cold solvent test [2] and the warm solvent test. The core samples used for the cold and warm solvent tests were taken from the same Grosmont "C" Formation from wells located in Saleski area. It can be seen that the initial oil rates from the warm solvent test were much higher than those from the cold solvent test. However, the difference in drainage rates between the cold solvent and warm solvent tests was not only due to the effect of temperature. There were differences in solvent types, composition and operating pressures. Generally, reduced pressure and increased temperature will improve the diffusivity of solvent in the bitumen [7].

The recovery would have been higher for the warm solvent test if the core held the original bitumen saturation from the formation. There was strong evidence that the core might have lost some bitumen prior to the solvent test. The NMR measurements before the test indicted that the core contained about 14% initial gas saturation. The introduction of gas (air) into the core was due to the lost fluids from the core. The initial water saturation is generally low (5 to 10%) in the Grosmont Formation and is considered to be bonded by the shale or mud within the formation. The fluids lost from the core were most likely bitumen. The seepage of bitumen to the surface of the core was observed visually.

The porosity measurements shown in Figure 15 indicated that about 10 to 15 cm of the core sample has low porosity (<10%). This would also affect the overall bitumen recovery due to possible lower recovery in the low porosity section. It is interesting to note that the drainage of bitumen from the low porosity section was confirmed by Dean Stark analysis and measurement of gas saturation before and after the solvent test.

Discussion

1. Drainage Efficiency and Residual Oil Saturation in Vapor Chamber

The recovery factor for the cold and warm solvent tests was in the range of 50 to 60%. However, there is still a high residual oil saturation in the core (>30%). This high residual oil saturation is due to the fact that the process mechanism at the experimental conditions was not scaled to the actual reservoir conditions. The residual oil saturation in the core was affected by the following factors:

- Less drainage head (0.9 m) in the core than in the field (20 to 60 meters)
- Less drainage time (days) in the core than in the field (years)
- Higher percentage of the liquid hold-up by capillary pressure in the core than in the field

As the result, the residual oil saturation in the core is higher than that in the vapor chamber in the actual reservoir. This can be explained from the following analysis.

The scaling factors (dimensionless parameters) described by Butler [8] for the SAGD and Vapex processes are provided in the Appendix. In order to meet the scaling criteria, a medium with much higher permeability should be employed in the model if the model height is less than the actual reservoir. Given the same solvent, fluid and other properties, the model permeability should be 30 times that of the actual reservoir permeability if the reservoir height is 27 meters and model height is only 0.9 meters according to the equation (a.3).

$$\frac{K_m}{K_f} = \frac{(h)_{field}}{(h)_{model}} = \frac{27}{0.9} = 30 \qquad (2)$$

Without proper scaling between the model and reservoir permeability, the time scale described in equation (a.4) is also not valid. The laboratory test using the actual core will not achieve the same recovery efficiency as in the field unless the drainage time in the laboratory is the same as in the field. The much shorter period for the oil drainage experiment using the actual core will result in a higher residual oil saturation in the core than in the field.

Although there is no theoretical equation available to analyze the change of residual oil saturation with drainage time in the solvent vapor chamber, the following equation to estimate the average oil saturation in the steam chamber [8] can be used for illustrative purposes.

$$S_{or} = \frac{(b-1)}{b}\left(\frac{\nu_s \phi h}{kgt}\right)^{1/(b-1)} \qquad (3)$$

Where S_{or} is the average residual oil saturation after time t; h is the drainage height; Φ is porosity; υ_s is the kinematic viscosity of oil at the temperature of steam; k is the permeability and b is exponent in Cardwell and Parson's equation for relative permeability, $k^r = S^b$.

Figure 15 is the predicted residual oil saturation based on the assumptions of Φ =0.15, h=30 m, k=500 md and b=3.5. It can be seen that the residual oil decreases with drainage time. The parameters in Figure 15 are bitumen viscosities at steam temperature. In the matrix portion of the Grosmont Formation where the permeability is low, the effect of drainage time on the residual oil saturation would be even greater.

When a solvent vapour (non-wetting phase) is in contact with liquid bitumen (wetting phase) during the solvent extraction process, a capillary pressure exists due to the interfacial tension between the gas and liquid phases. This has a tendency to keep the diluted bitumen from leaving the interface. The height of the liquid column held by capillary pressure is called the capillary rise height [9], which is the function of the saturation distribution as well as the porosity and permeability:

$$H = \frac{\sigma \Delta J}{\Delta \rho g}\sqrt{\frac{\phi}{k}} \quad (4)$$

Where σ is the interfacial tension, Δ ρ is the density difference between the solvent vapour and liquid bitumen and J is the Leverett's "J" function, ϕ is the porosity and k is the permeability.

The liquid hold-up from the capillary pressure near the interface will increase the residual oil saturation. According to equation (4), the capillary rise height is larger in the less permeable medium. Given the same properties for other parameters, the test using the actual core will have the same capillary rise height as in the field due to the same porosity and permeability. However, the core height is much less (0.9 m) than that in the field (20-60 m). Therefore, the percentage of the capillary rise height over the total height is much higher in the core than that in the field. For example, a capillary rise height of 4.0 cm is 4.4% of a 90 cm core and only 0.12% of a 30 m reservoir. This implies that the effect of capillary pressure will be larger in the core than in the field. This will further increase the residual oil saturation in the core test. To scale down the effect of capillary pressure in the model, a much higher permeable medium is necessary in the laboratory test model.

2. Impact of Temperature

The diffusivity of solvent in the bitumen is one of the most important parameters affecting the process rate for the solvent recovery process. With a least square fit for CO_2 , methane, ethane and propane in liquid hydrocarbons, a correlation was proposed by Renner [7] based on the laboratory measurement of diffusivity.

$$D_{ij} = 10^{-9}\,\mu_j^{-0.4562} M_i^{-0.6898} V_i^{-1.706} p^{-1.831} T^{4.524} \quad (5)$$

Where D is diffusivity in m^2/s; μ is viscosity in mPa.s; M is molecular weight in g/g.mol; V is molar volume in $cm^3/g.mol$; P is pressure in psia and T is temperature in Kelvin.

It can be seen from equation (5) that the favorable conditions for the solvent process should be the combination of low pressure and high temperature. Further optimization is required for the operating pressure and temperature in addition to the solvent type and composition.

Commercial Prospects for Grosmont Development

The commercialization process for the development of Grosmont resources will benefit from the technical path applied to the McMurray Formation reservoirs. The high productivity confirmed from the CSS test in the Buffalo Creek pilot and the high recovery factors achieved from the laboratory solvent tests are direct indications of high recovery potential for the Grosmont reservoir. To identify an economic commercial recovery process for the Grosmont Formation, the following challenges need to be overcome:

- To achieve high drainage efficiency (lower residual oil saturation) from all areas in the formation including low porosity and permeability regions ;
- To achieve high conformance for injected fluids in the reservoir.

The Grosmont Formation has a higher degree of heterogeneity in reservoir characteristics and fluid distribution in comparison to the McMurray Formation. The gravity dominated drainage process in combination with low pressure operations will probably be the primary choice of recovery technology to overcome the above challenges. The combination of high vertical permeability, abundance of natural fractures and a high oil saturation provides favorable conditions for a low pressure cold solvent or thermal solvent process.

Steam flood and cold/heated solvent tests with actual core samples are the first steps taken in order to prove the feasibility and recovery potential for the Grosmont reservoir. It is possible in the field to achieve lower residual oil saturation in the solvent vapour or steam chamber than that obtained from the core test. However, the actual recovery factor from the field is affected by reservoir conformance and operational challenges which can not be determined from the laboratory core test. Ongoing future field pilot tests in the Saleski area, operated by Laricina in partnership with Osum, will provide a better understanding of the commercial potential for the Grosmont development.

Conclusions

- A warm solvent soak test achieved 50% recovery from a Grosmont core. This again confirmed the high recovery potential for solvent processes in the Grosmont reservoir. Recovery would have been higher if the lost bitumen prior to the test was included.
- The drainage of oil from the low porosity (<10%) section of the Grosmont core was confirmed from the warm solvent soak test.
- In comparison to the cold solvent test, the warm solvent test achieved higher oil drainage rates especially during the initial production stage.
- The gravity drainage process in the field could be more efficient than that achieved from the unscaled core test due to: higher initial bitumen saturation, larger drainage head, and a longer drainage time within the vapor chamber and less of an effect from capillary pressure.
- Field pilot testing, scaled physical modeling and field-scale reservoir modeling are required to evaluate the commercial potential for future Grosmont development.
- The gravity drainage process applied to Grosmont reservoirs appears to hold great promise.
- The optimization of the recovery processes for the Grosmont reservoir should also be focused on a combination of solvent and thermal processes.

Acknowledgements

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Nomenclature

b=exponent for relative permeability function
B_3=dimensionless number defined in equation (a.1)
C=solvent concentration
D=molecular diffusivity of solvent
F_o=dimensionless number defined in equation (a.2)
h=reservoir or model height
J=Leverett's "J" function
k=permeability
k_V=vertical permeability
L=well length
m=viscosity coefficient
M=molecular weight
N=solvent parameter defined by (a.5)
P=pressure
q=oil rate
S_{oi}=initial oil saturation
S_{or}=residual oil saturation
t=time
T=temperature
V=molecular volume
α =thermal diffusivity
μ =dynamic viscosity
σ =interfacial tension
φ =porosity
Δ So=mobile oil saturation (Soi-Sor)
Δ ρ =density difference between oil and vapour
υ_s=kinematic viscosity at steam temperature
Subscript "e" refers to equilibrium state
Subscript "f" refers to field
Subscript "m" refers to model
Subscript "s" refers to solvent

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Appendix Scaling Factor

The extrapolation of the experimental results to field prediction is usually done through the application of scaling factors. For SAGD process, the following dimensionless numbers [8] are proposed：

$$B_3 = \sqrt{\frac{kgh}{\alpha \Delta S_o m \nu_s}} \tag{a.1}$$

And

$$F_o = \frac{\alpha t}{h^2} \tag{a.2}$$

The above dimensionless numbers should be the same for the model and for the field. Then the permeability and time between the model and the field can be derived as follows:

$$\frac{K_m}{K_f} = \frac{\left(\frac{h}{\alpha \Delta S_o m \nu_s}\right)_{field}}{\left(\frac{h}{\alpha \Delta S_o m \nu_s}\right)_{model}} \tag{a.3}$$

and

$$\frac{t_m}{t_f} = \frac{\left(\frac{\alpha}{h^2}\right)_f}{\left(\frac{\alpha}{h^2}\right)_m} \tag{a.4}$$

The above scaling factors applied to the SAGD process. For solvent process, the diffusivity and viscosity are the function of solvent concentration. The combined term (α m υ_s) in equation (a.1) can be replaced by

$$N = \int_{\partial C}^{C_e} \frac{(1-C)\Delta\rho}{D_s \mu} \frac{dC}{C} \tag{a.5}$$

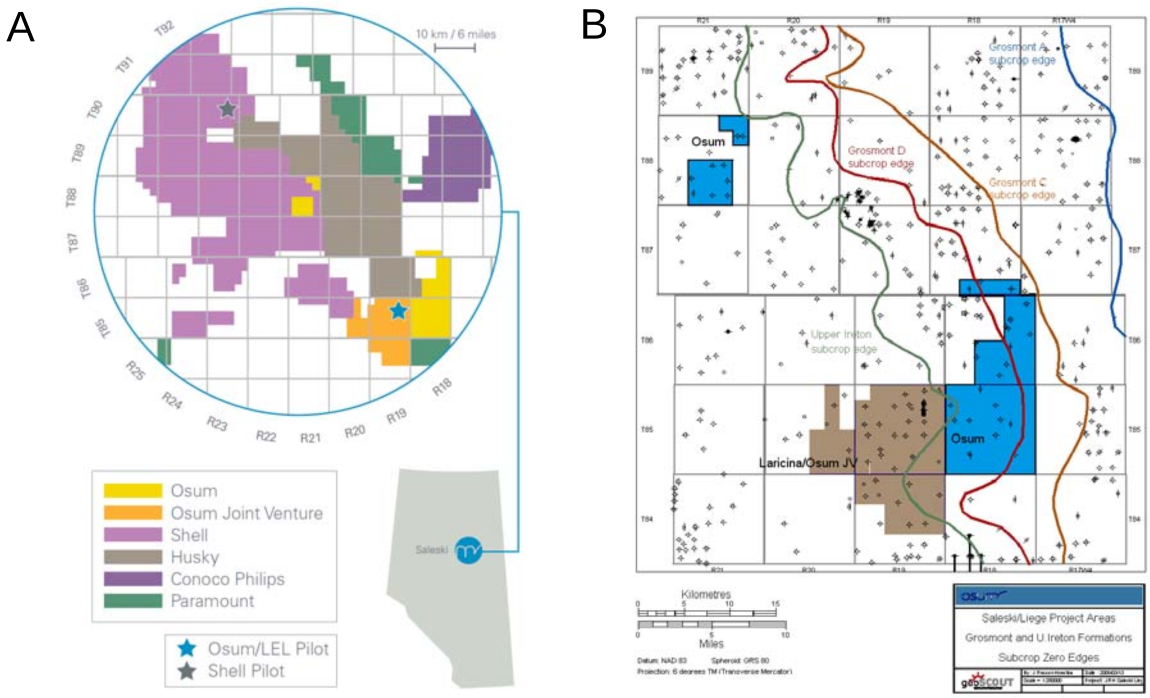

Figure 1, A) Location map of Osum Saleski/Liege project area and surrounding leases. B) Saleski/Liege Osum leases with the mapped Grosmont and Upper Ireton subcrop edges Highlighted.

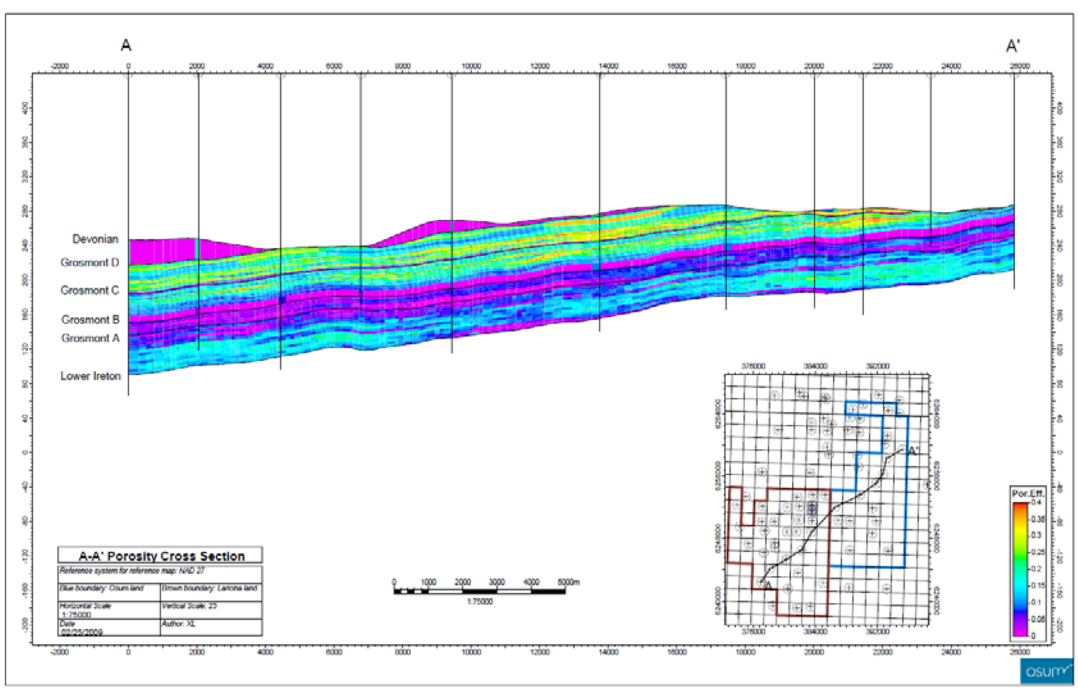

Figure 2. Southwest to northeast cross section through the Saleski Project Area. Grosmont stratigraphy (top layers identified) and porosity displayed from the static model.

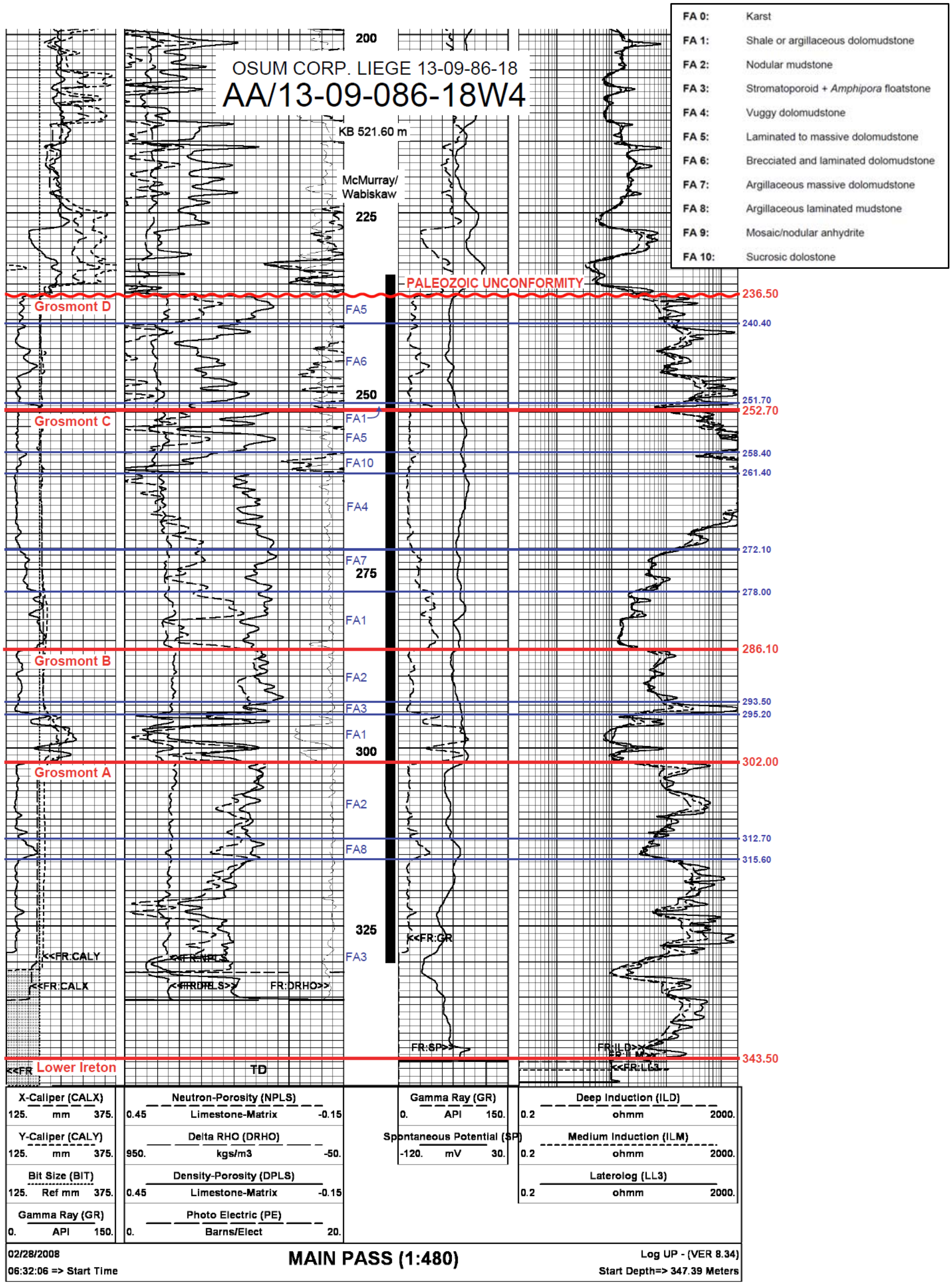

Figure 3, Saleski type log from well 1AA/13-09-86-18W4 with annotation of facies

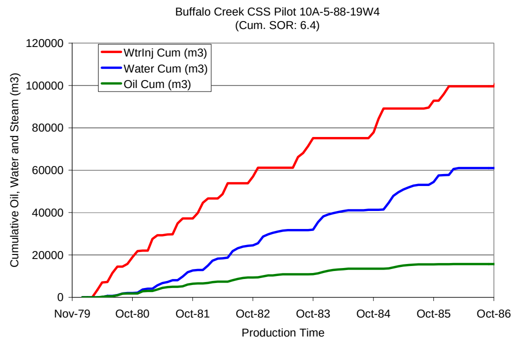

Figure 4, Cumulative production and Injection from Buffalo Creek CSS Pilot

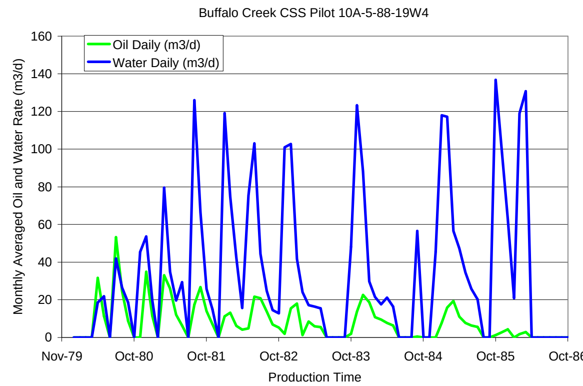

Figure 5 Daily production from Buffalo Creek CSS Pilot

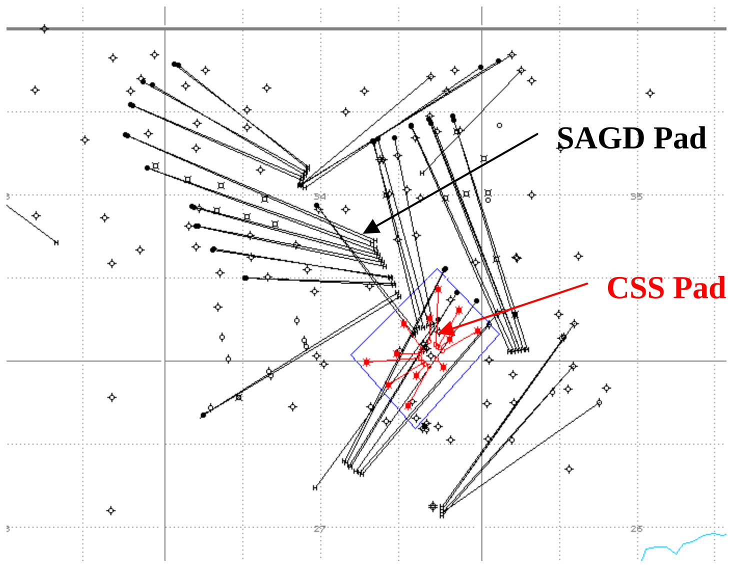

Figure 6, Location of CSS Pad (in Red) at the Hangingstone

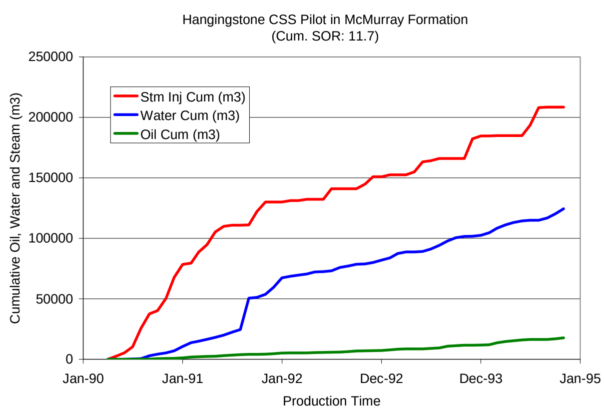

Figure 7, , Cumulative Production and Injection from Hangingstone CSS Pilot in McMurray Formation

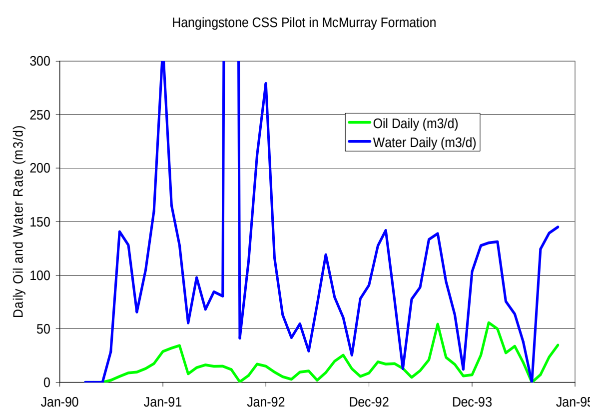

Figure 8, Daily Production Rates from the Hangingstone CSS Pilot in the McMurray Formation

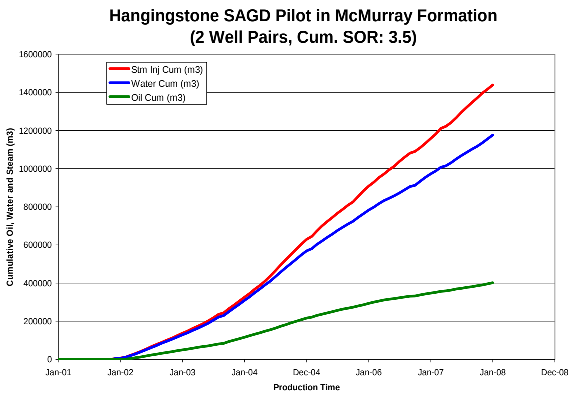

Figure 9, , Cumulative Production and Injection from the Hangingstone SAGD Pilot in the McMurray Formation

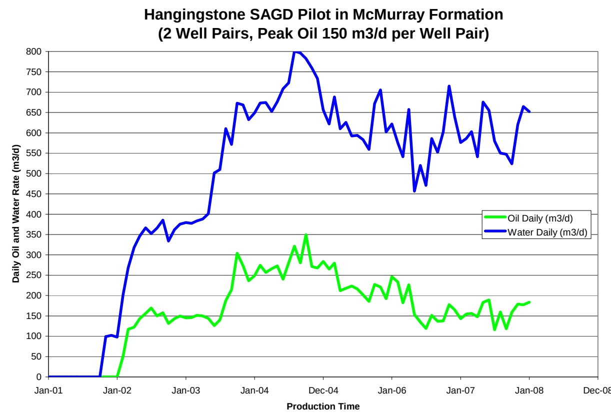

Figure 10, Daily Production Rates from the Hangingstone SAGD Pilot in the McMurray Formation

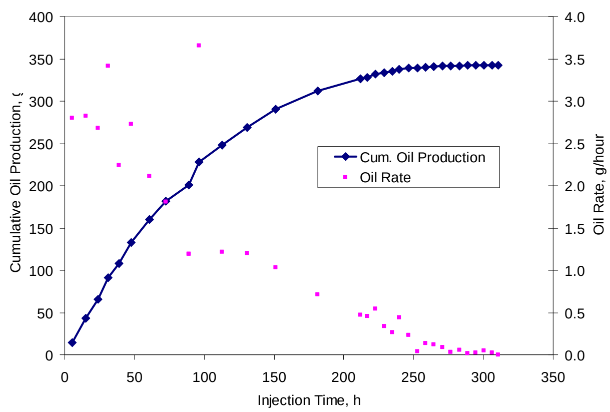

Figure 11, Cumulative Oil Recovery and Oil Rate During Cold Solvent Soaking Test

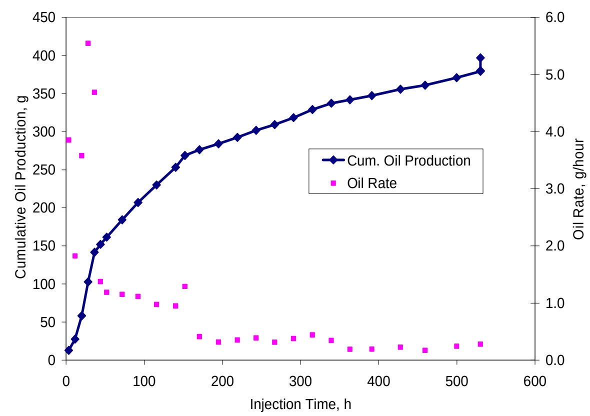

Figure 12, Cumulative Oil Recovery and Oil Rate During Warm Solvent Soaking Test

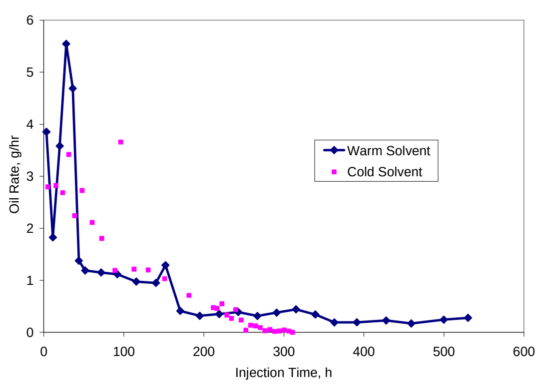

Figure 13, Comparison of Oil Rates between Cold and Warm Solvent Test

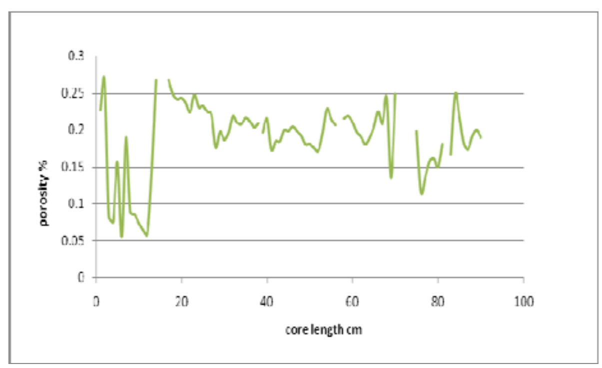

Figure 14, Porosity Measured along the Core Sample

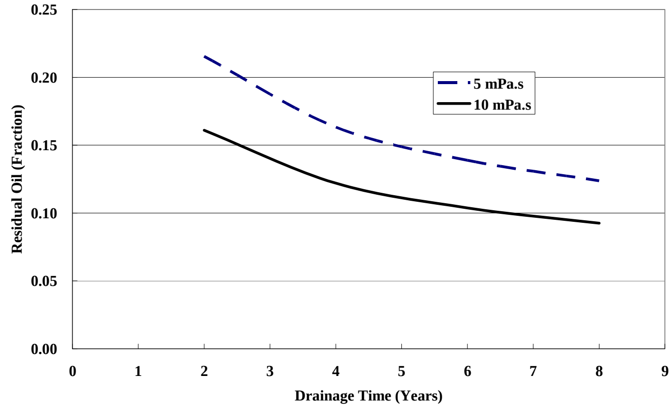

Figure 15, Predicted Residual Oil Saturation in the Steam Chamber