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VIA E-MAIL

January 30, 2007

Alberta Energy and Utilities Board
640 - 5 Avenue S.W.
Calgary Alberta T2P 3G4

Attention: Mr. Gary D. Perkins

Dear Mr. Perkins:

**Re: EnCana Oil and Gas Partnership (EnCana) Application No. 1394112
Canadian Natural Resources Limited (CNRL) Application No. 1409180
Husky Oil Operations Limited (Husky) Application No. 1481725
Cold Lake Oil Sands Area – Clearwater Deposit**

Attached please find the reply evidence of EnCana.

Yours very truly,

McCarthy Tétrault LLP

ORIGINAL SIGNED BY D. G. DAVIES

D. G. DAVIES

DGD/dw
Enclosure

cc: Alberta Energy and Utilities Board
Attention: Mr. Ernie Smith

Canadian Natural Resources Limited
Attention: Mr. Jared Paddock

Thackray Burgess
Attention: Mr. Patrick J. McGovern

Husky Oil Operations Ltd.
Attention: Ms. Susan Anderson

Borden Ladner Gervais LLP
Attention: Mr. Randall W. Block

Imperial Oil Resources
Attention: Ms. Susan C. Stark

ALBERTA ENERGY AND UTILITIES BOARD

ENCANA OIL AND GAS PARTNERSHIP (ENCANA) APPLICATION NO. 1394112 CANADIAN NATURAL RESOURCES LIMITED (CNRL) APPLICATION NO. 1409180 HUSKY OIL OPERATIONS LIMITED (HUSKY) APPLICATION NO. 1481725 COLD LAKE OIL SANDS AREA – CLEARWATER DEPOSIT

REPLY EVIDENCE OF ENCANA

14-31-68-4W4

EnCana's original application to produce the well 14-31-68-4W4 was just one of many that had been routinely submitted over the years and as such had minimal technical input. This current proceeding has resulted in a major technical review of the entire Hearing area. EnCana now believes that this well is located in a small structural accumulation with an average net pay of 0.5 m, an area of 157 ha and a gas in place of approximately $5 \text{ E}^6 \text{ m}^3$.

The bitumen net pay under the gas at a 50% bitumen cutoff ranges from 9 m to 17.6 m.

This is one of very few areas in the Hearing area (outside EnCana lands) where gas is directly over potentially commercial bitumen. Therefore some of the concerns of the Athabaska hearings regarding SAGD steam losses to a gas cap may be relevant. EnCana however requests that this well be allowed to produce for the following reasons:

1. The gas overlies a proposed CNRL expansion area for CSS and nothing we have seen leads us to believe that gas cap production has any impact on CSS recovery in the Clearwater zone in this area.
2. Even if there is communication of the steam chamber with the gas cap, the gas cap is so small that steam "losses" could actually improve recovery by heating an area at the top of the bitumen reservoir that would not normally be contacted by steam.

Technical Papers

Husky and CNRL have referenced a number of technical papers in their submissions in an attempt to support general arguments for which they have no supporting data.

EnCana has reviewed all of the papers and a number of others and has yet to find any reference to the effect producing gas caps might have on bitumen production. Therefore a brief review of what some of these papers say is in order.

September 1987 SPE 16737

Evaluation of Key Reservoir Drive Mechanisms in the Early Cycles of Steam Stimulation at Cold Lake.

By E.S. Denbina, Esso Resources Canada Ltd., and T.C. Boberg and M.B. Rotter, Exxon Production Research Co.

This paper has been referenced numerous times by the hearing participants.

Its conclusions are:

Over the first five cycles of steam stimulation at Cold Lake:

1. Formation compaction is by far the dominant mechanism supplying drive energy to the CSS process.
2. Solution gas drive accounts for a smaller fraction of oil production, but is the most important mechanism after formation compaction.
3. Fluid expansion provides a relatively minor amount of drive energy.
4. Gravity drainage contributes very little to oil recovery in the first two or three cycles, but its role appears to increase in significance in subsequent cycles.

Another important statement by the authors is the following:

“Neither of these approaches” (to determining the individual contribution of each mechanism) “provides an exact measure of the contribution of a given mechanism because there are complex interactions between the various mechanisms. That is, eliminating one mechanism impacts the perceived performance of the remaining mechanisms as well as the character of the model itself. These interactions can be positive or negative (increasing or decreasing the apparent contribution to oil production), and undoubtedly vary in magnitude and/or sign with time. However, by examining the impact of both the removal of a given mechanism as well as the inclusion of that mechanism alone, we can obtain a range indicating the relative magnitude of its contribution to CSS oil recovery.”

There is no doubt this was an important paper in the understanding of CSS operations. It described in detail, the reservoir parameters, model input, history matching effects, and changes that were made to the model. It clearly stated the results, including many of the authors concerns.

It was a single well model describing the average performance of one 20 well pad at Cold Lake. The effect of solution gas drive was determined by not allowing the solution gas to break out of the oil. The authors note, “This introduces an error in the model oil viscosity at elevated temperatures when gas would normally be stripped out. However, the oil viscosities at elevated

temperatures in the producing region are sufficiently low that a slightly further reduced oil viscosity should have a negligible impact on the stimulation results.”

The well simulated in the model was a vertical well with a completion interval of 8 m in a four-layer sand with a total thickness of 44.3 m (from Figure 3 in the paper published in SPE Reservoir Engineering, May 1991)

Several issues are important to assessing the results of this work:

1. The authors referred to solution gas as a “minor mechanism” in comparison to compaction.
2. Compaction drive was indicated to include rock compressibility and the cyclical increase and decrease in porosity (reservoir size) created by steam injection. Presumably, since solution gas, fluid expansion, and gravity were specifically described, compaction would also include by default:
 - Thermal expansion
 - Subsidence of the overburden
 - Steam flashing
 - Steam distillation
 - Dynamic vacuum effect due to steam condensation at the steam front
 - CO₂ generation

Perhaps if all the mechanisms had been studied in more detail the perceived role of solution gas drive would have changed.

3. The model prediction only went for five cycles.
4. The four cycles history matched lasted for a total of 850 days with approximately 690 days of production. The time of production cycles was not given but a total of 87,700 bbls of oil was produced compared to approximately 60,000 bbls during the history match. By ratioing the production volumes it can be assumed that the total time of the predictions was approximately 3.4 years with production time of 2.7 years.

Our understanding of the authors’ conclusion regarding solution gas was, for a vertical well in the reservoir described in the paper, for the first 2.7 years of production, solution gas drive accounted for 17% to 23% of the total recovery and its impact was decreasing. Since this was based on the impossible situation of no gas evolving from the oil this would be higher than the absolute maximum possible effect in the real world.

If one assumes that the average impact of solution gas drive indicated in Table 5 (in the paper published in SPE Reservoir Engineering, May 1991) continues to decrease at 0.5% per cycle until it reached 5% and then stayed constant to the end of 20 years the average impact over the 20 year life would be approximately 10%. Therefore, if we could create in the real world a situation where no gas evolved and total recovery of the vertical well project was 30%, then the

maximum possible contribution of solution gas to total recovery would be 3%. We currently have no way of knowing if there is an optimum level of solution gas to maximize recovery or what effect higher or lower solution gas levels have on the other recovery mechanisms in a thermal recovery project.

February 1997 SPE 37550

A Mechanistic Model of Cyclic Steam Stimulation.

By J.P. Batycky, SPE; R.P. Leaute, SPE; and B.A. Dawe, SPE, Imperial Oil Resources Limited.

The conclusions of this paper were as follows:

1. A mechanistic framework has been advanced for interpreting the performance and the factors which control Cold Lake cyclic steam stimulation. Key, was the identification of three zones, a hot, a cold and an impedance zone, each of which plays a complementary role during mid- to late-cycle CSS. The essential features include:
 - Zone 1 – Heated reservoir acts as a stimulated reservoir access.
 - Zone 2 – Impedance zone harnesses solution gas drive, emanating from cold reservoir and couples bitumen and gas flow.
 - Zone 3 – Cold reservoir supplies solution gas drive over the life of CSS.
2. Related was the development of a new understanding of relative permeability hysteresis, which is required to match field performance. The revised interpretation recognizes that the most important fluid flow characteristics, perhaps now represented by relative permeability hysteresis, are more correctly represented by impedance within a very narrow region during production when compared with the same region during injection. The source of the impedance is believed to be a combination of a bitumen phase viscosity increase (due to foam and emulsions) and a gas mobility reduction. Gas mobility reduction is due to the foaming itself and associated interference with viscous fingering by gas and water originating from cold reservoir. The continuous influx of gas and water contribute, in turn, to additional foaming and potential emulsification. In summary, following the early cycles when compaction drive plays a major role, cyclic steam stimulation can be simplistically depicted as a thermally stimulated cold flow (foamy oil, solution gas drive) process.
3. The framework that was developed to explain Cold Lake cyclic steam stimulation can be extended to explain other primary operations with very unfavorable mobility ratios, such as the solution gas drive, cold flow of heavy oils.

This paper presents a set of theories that were developed to help explain why existing models were not matching intracycle gas production profiles and why stable WOR and GOR patterns were observed in the field.

Many of these theories have merit and are the subject of many subsequent papers and lab studies.

The paper does not discuss or contradict the previous Denbina paper that it references, so the statement in the Abstract of the paper "It is concluded that Cold Lake CSS is a surprisingly effective solution gas drive process" seems to be unsupported. Perhaps, since the authors focused on gas foams and water oil emulsions in trying to explain the production behavior of CSS operations, it was assumed that the importance of solution gas in explaining production behavior translated into an importance to total recovery. Or perhaps since several references to primary production were made in the paper it was a reference to the fact that solution gas drive appears to be less of a negative factor to recovery in CSS than it can be in high permeability conventional reservoirs without pressure support.

One important aspect of the work is that it does seem to confirm that the steam chamber concept of SAGD has an analog in the hot region of the CSS reservoir. The active reservoir is the hot region that is bounded in terms of pressure and fluid movement by the cold region. Production is maintained by gradually increasing the size of the hot region where bitumen will flow.

March 1988 Journal of Petroleum Technology

Effect of an Initial Gas Content on Thermal EOR as Applied to Oil Sands

By T.W.J. Frauenfeld, SPE, Alberta Research Council, R.K. Ridley, SPE, Alberta Research Council, D.M. Nguyen, Alberta Research Council.

The conclusions of this study were as follows:

The results from a series of experiments conducted in a 2D unscaled physical model indicated the following:

1. A live oil, such as that found in some heavy-oil reservoirs, will respond differently to a thermal EOR process than will a similar dead-oil. Live-oil experiments produced significantly more oil than did dead-oil experiments. This was in spite of a gas content in the live-oil that was much lower than that found in many conventional oils.
2. The steam/CO₂ coinjection process used in these experiments was not effective in improving the oil recovery when applied to a live-oil situation. Although steam/CO₂ coinjection was effective when applied to a dead-oil experiment, it appeared to inhibit oil production in a live-oil test. Possible reasons for this effect are reduction in oil phase permeability as a result of formation of a free-gas phase and reduction of the effect of CO₂, namely oil swelling and viscosity reduction, because of the presence of CH₄.
3. Slugs of CH₄ injected with steam were capable of sustaining incremental oil production in live-oil tests. Processes using slug injection of CH₄ with steam have the potential of improving oil production while using relatively small amounts of a gaseous additive.

EnCana has no argument with these findings that apply to laboratory experiments conducted in 80x80x10 cm simulated reservoirs. The experiment dealt with the effects of injection of CO₂ and CH₄ with steam on oil recovery. It is noted that it would be impossible to create “dead-oil” in an actual Clearwater reservoir even if one were to produce for thousands of years.

Other Papers

EnCana would like to draw to the Board’s attention to several more recent papers that may assist it in reaching a decision in this matter (copies are attached).

1. December 2001 Journal of Canadian Petroleum Technology
Economic Optimum Operating Pressure for SAGD Projects in Alberta
By N. Edmunds and H. Chhina, AEC Oil & Gas

This paper, which discusses U.S. and Athabaska reservoirs, has general applicability in the Cold Lake area.

2. November 2002 SPE/Petroleum Society of CIM/CHOA 79020
Comparison of CSS and SAGD Performance in the Clearwater Formation at Cold Lake.
By George R. Scott, Imperial Oil Resources.

This paper presents a review of six thermal projects in the Clearwater and addresses some of the difficulties in comparing projects.

3. January 2003 SPE/Petroleum Society of CIM/CHOA 2001-086
Impacts of Initial Gas-to-Oil Ratio (GOR) on SAGD Operations.
By J.-Y. Yuan, T.N. Nasr, D.H.-S. Law, Alberta Research Council.
4. January 2007 Journal of Canadian Petroleum Technology
Effect of Solution Gas on ID Steam Rise in Oil Sands.
By N. Edmunds, Laricina Energy Ltd. (Formerly with EnCana Corp.)

These last two papers both deal with the effects of solution gas evolution and migration in the steam chamber in SAGD operations. Both suggest that the best recovery and rates could be obtained with the lowest possible solution gas oil ratios.

EnCana does not contend that the mechanisms discussed in these two papers are dominant factors in SAGD recovery but they do illustrate that one must consider all the possible affects of solution gas drive both positive and negative, when assessing the impact of solution gas on total recovery. One can not assume that solution gas drive in a bitumen reservoir is the same as solution gas drive in a conventional oil reservoir because of the immobility of the bitumen until it is heated and the behavior of the liberated gas in the steam chamber.

Other Models

Encana would also suggest that the Board may wish to review the Clearwater models outlined in the March 1998 report EUB Inquiry Gas/Bitumen Production in the Oil Sands. We are not sure if they are directly applicable to the specific geology of this area, but they are the only model studies that we have encountered in our literature search, specific to the Clearwater formation, relevant to the issues at hand, and performed by an objective organization.