ALBERTA ENERGY and UTILITIES BOARD

APPLICATION NO. 1481725

APPLICATION TO SHUT-IN GAS PRODUCTION

COLD LAKE OIL SANDS AREA – CLEARWATER FORMATION

Responses of EnCana Oil and Gas Partnership (EnCana) to

Board Staff Information Requests (January 12, 2007)

1. **On the Summary and Conclusions page, EnCana states that the pressure history match to the piezometer pressures in the overall area was reasonable. Explain the basis for this conclusion, considering the lack of agreement between the measured and predicted pressures shown on the plots for wells 4-9-69-4W4, 14-9-69-4W4, l6-7-69-4W4, 10-32-68-4W4, and 5-10-69-4W4.**

As indicated in the conclusions we considered the overall history match to pressures to be reasonable and the match in the area where we planned to place the producing wells was good. As indicated in the discussion the model predicted pressures in the bitumen to the north were lower than the field data and those to the south were higher. On average they were in line with the piezometer pressures and all were showing some response to the gas production. On the specific wells the Board staff has mentioned:

- 4-9-69-4W5. The match for the bottom piezometer in this well was about as good as it gets. The strange pressure response of the two upper piezometers (rising pressures in the bitumen zone) has been discussed in previous information requests and responses. Husky has indicated that they believe the recorders are taking longer to stabilize due to "initial partial saturation of the protective membrane". We find it very unlikely that the only two recorders with this problem are in the same well, partially failed in exactly the same manner and are reporting essentially the same pressures. We believe it is much more likely that the cement job in this well is not perfect and there is communication behind pipe that starts somewhere above the bottom piezometer and ends in the thin gas zone where the upper piezometer is located. The middle piezometer is located in the bitumen zone 4 m below the top piezometer and approximately 3 meters below the gas oil contact. If this is the case what we are actually seeing is an average flowing pressure as some combination of bitumen, water and gas move from the bitumen zone to the gas zone. The fact that these piezometer pressures started low, closer to the model predicted pressures than the bottom piezometer pressure, and seem to be climbing to a point between the two lends some support to this theory. In any event the model was predicting pressures for the piezometer in the gas cap in line with other gas cap pressures, the predicted pressure for the middle piezometer was in line with what we would expect for a bitumen zone 3 m below the gas, and we would not consider making changes to the model to history match what is obviously a problem unrelated to the reservoir.

- 14-9-69-4W4. This is one of the wells on the north where the model is predicting pressures generally lower than observed pressures however the match to the lowest piezometer pressures recorded is not bad and the match to the trend of that pressure is excellent. It is noted that after an initial rapidly declining “stabilization” period the two bottom–most recorders seem to be trending slightly upwards. It would likely be possible to obtain a better match to the bottom piezometers by introducing local vertical permeability barriers or making significant reductions in vertical permeability. Until the trend of the pressure change in the bottom piezometers has stabilized these changes would, in our opinion, be premature.

- 16-7-69-4W4. Another north end well with model predicted pressures about 15% below the piezometer pressures. A better match could have been obtained by increasing the effective pore volume in this area or changing the permeability profile between the B pool and this well. However this would have necessitated another set of local changes to lower pressures in the south and keep the average level of pressure depletion in line with what actually exists today.

- 10-32-68-4W4. As discussed in the report placing a permeability barrier between 10-33-68-4 and the gas wells to the north eliminated an apparent time lag in the pressures for the wells in the south west of the gas pool (this comment was actually meant to include 10-32 although it was not specifically identified and we are not sure if the piezometers in this well are located in a very shaley water zone or a shaley low bitumen saturation zone) As stated the permeability barrier was not added because the prediction runs had already been started

- 5-10-69-4W4. This is a gas well where the initial and final pressures did match but three pressures reported in 1998 were lower than the model prediction. The addition of the permeability barrier mentioned above helped this match too but would not explain the total difference. Reducing the permeability around this well could have given a better match but since the last pressure point was a good match to the model and also was consistent with the other gas pool pressures no change was made.

A more exact match could certainly be created for all the wells and pressures in the model (except the rising ones) however we did not do this for reasons both practical and philosophical. The practical reason was that we were running out of time and had to end the history matching to make sure there was time for the prediction runs to be completed. Even if we did have more time we probably would not have gone much further because the purpose of the model is not to achieve the best possible history match. The history match is the way we determine if the geological model, which will always be a simplification of the real world, is good enough input to the computer to match observed field data, If it does not match reasonably well then the geological model should be reexamined before any match is forced in the computer model.

In this model, changes, which are discussed in the report and which we believe to be within the range of what can reasonably be expected in this reservoir, have been made and in total we believe the pressure match was reasonable. Local changes to pore volume or permeability could certainly be made to produce a more cosmetically pleasing picture but since there are no unique solutions each local change actually increases the possibility that the prediction runs will be less reliable. Our next step, if additional work on this model was requested, would be to go back to the logs and core for areas where we wish to improve the match and see if there is any geological or engineering data to support local changes from any of the average parameters used in the model.

2. Under the heading "Geological Model" (pages are not numbered), EnCana states that the bitumen net to gross ratio maps were based on well net pays determined using a 50% oil saturation cut-off for cored intervals and a 12 to 16 ohm-m log cut-off for uncored intervals. What is the basis for the 12 to 16 ohm-m cutoff? Why wasn't a porosity cut-off also used?

The resistivity cutoff normally used if no core data was available for a well or nearby wells was 15 ohm-m. However, if core data indicated a higher or lower cutoff was more appropriate, to correspond to core bitumen saturations of 50%, then the higher or lower cutoff was used for un-cored intervals. No porosity cutoff was used because in core the few intervals with porosity less than 30% are usually mudstone or calcite layers that have very low or no oil saturation. We should have added that the calcite intervals, which have a very distinctive log signature and are seldom analyzed in core, were not counted as pay on logs. The thickness of the calcite zones not counted would correspond to a log density porosity cutoff of about 24%. It is noted that the calcite stringers are an excellent way to depth correlate logs to core, as the core gamma curves (like gamma on the well logs) are often very flat and non-descript.

M&A's core summary program that produced Tables 1 and 2 in the report can apply several different sets of cutoffs to any number of cores. We have examined what the effect would be of applying a 30% core porosity cutoff in addition to the 50% bitumen cutoff. In Twp 68 Rge 3 and 4W4, for 1759 m of core analyzed in 111 wells, total net pay would be reduced by 2% from the net pay determined using oil saturation alone. In Twp 69 Rge 3 to 6, for 883 m of core analyzed in 62 wells total net pay would be reduced by 7%.

3. Under the heading "Computer Model", EnCana indicates that the model was initialized with the geological data discussed previously and a list of assumptions about reservoir parameters. Explain how EnCana assigned porosity and permeability values to the grid blocks in the model.

Initially the porosity and permeability were assigned to the gridblock by layer using the "Specify Property" option in Builder and then the values were implemented by executing "Calculate Property" button. Later on during history matching some of the grid blocks values were modified by using "Edit Reservoir Property" for the grid blocks to be modified.

4. Under the heading "Prediction Runs", EnCana states that in the model the wells for HWCSS and SAGD were located as laterally close to the gas cap as possible in order to maximize any possible effects of pressure depletion and/or gas migration on predicted bitumen recovery. The west edge of the D pool gas cap was chosen as this area permits the ends of the thermal wells to be located under the mapped gas zone. Wouldn't the possible effects of pressure depletion and/or gas migration on predicted bitumen recovery be maximized if the HWCSS and SAGD wells were located directly under the gas cap?

A portion of the central well in the pattern was under the gas cap in the model. The only two places where Husky can drill wells on its lands in reasonable pay thickness directly under the gas caps are small areas on the west sides of the B or D pools. The D pool was chosen since the well control and thus the reservoir description is better in this area and this was the area of the pressure match in the model. Our wording in the report was poor because the well was oriented so that as much of the well as possible was directly under the gas cap before the toe of the well went under the C-D mudstone. We could have placed the well parallel to the gas cap and perhaps increased the chances of direct communication with the steam chamber but we did not feel that this would reflect the actions of a prudent operator. Previous generic model runs and the experience of some operators indicate that bitumen recovery under a gas cap will be lower no matter what the pressure. Given the relatively uniform permeability profile in the model it is unlikely that a change in well orientation or location would produce any significant change in the model results.

5. The input data files for EnCana's models of the CNRL area (September 5, 2006 submission) appear to indicate that the irreducible water saturation of the oil-water relative permeability curves for the bitumen zone was 0.45. The input data files for EnCana models of the Husky area (January 8, 2007 submission) appear to indicate that the irreducible water saturation of the oil-water relative permeability curves for the bitumen zone was 0.20. Clarify if this is correct.

- **If it is correct, explain why EnCana used different oil-water relative permeability curves for the two areas and comment on the effect this would have on the predicted results.**
- **If it is not correct, explain why by reference to the input data files.**

Yes, we used an irreducible water saturation of 0.45 in the generic model runs of the CNRL area (September 5, 2006) and 0.20 for the Husky Area (January 8, 2007). In the generic model we carried out sensitivity runs to assess the impact of mobile water saturation.

At the start of the simulation for the Husky Area, we used an irreducible water saturation of 0.45 and the same relative permeability curve that we applied for the CNRL Area generic model runs. We had to modify the relative permeability curve to reduce the irreducible water saturation gradually from 0.45 to 0.20 during history matching to allow adequate water to move and match water production levels reported in the field. The small amount of water movement reduced the pressure in the bitumen zone immediately adjacent to the gas zone and allowed gas to break out of the bitumen zone. Total water production at the end of the history match is similar to reported field values as per the Appendix of our January 8 submission (Appendix Figure entitled "History Match of Total Water Production").

6. With respect to Table 5, how was the original bitumen in-place determined to calculate the bitumen recovery factors for HWCSS and SAGD?

The original bitumen in place was determined by creating a sector in the model and assigning to the sector, grid blocks in the assigned Drainage Area for the horizontal wells. In the SAGD and CSS models this sector may be viewed in layers 4-12 by selecting "Reservoir", "Sectors", "Total_CSS_HW". The pattern area for the three CSS wells or the three SAGD well pairs in the model is 1260.4 m along the HW direction and 868.5 m in the direction perpendicular to the HWs.

7. Provide plots showing the predicted bitumen production rates, cumulative bitumen production, and cumulative steam-oil ratios versus time for the HWCSS and SAGD model runs. Discuss the criteria that were used to determine when to terminate the model runs.

Please find in the attached Excel spreadsheet (IR-7 EUB Jan 16 2007.xls) the predicted production rates, cumulative bitumen production and cumulative steam-oil ratios versus time for the HWCSS and SAGD model runs. The models prediction runs were just run for sufficient time to permit economic evaluation of the results. No cut-off criteria other than time were used.

8. Provide a more readable version of Drawing 2.

Drawings 1, 2 and 3 at their original size are attached. We apologize for the poor resolution that resulted from the PDF reduction to 8.5x11.