Question

1. On page 7 of its January 29, 2007 submission, CNRL states that EnCana's model for CNRL's Primrose area does not have proper input parameters to simulate regional flow and pressures due to gas cap production. CNRL states that Figure 7 shows that the EnCana model predicts the bitumen zone to be close to original pressures of 2500 – 2800 kPa even after the gas cap is produced to about 1000 kPa. It appears that Figure 7 refers to EnCana's edge model. Discuss whether CNRL's concern is also applicable to EnCana's non-edge and flank models.

Response

EnCana's models do not have proper input parameters to simulate regional flow and thermal recovery processes. In addition to the comments in a previous reply (See CNRL's January 26, 2007 Reply Evidence), there are the following major deficiencies in EnCana's models:

- Zero mobile water saturation was assigned in its models for CNRL's Primrose area which artificially hinders the communication of the bitumen leg with the gas cap; the bitumen leg does not allow for pressure depletion with production from the gas cap. This problem was described in an example for EnCana's "Edge" model (page 7 of CNRL's January 26, 2007 submission). The similar pressure profiles from EnCana's "Flank" and "Non-Edge" model are attached in this reply (see Figues 1 and 2). Because there is no pressure depletion and degassing from the bitumen, it is not surprising that EnCana's model showed no effect on CSS recovery from the production of the gas cap.
- The model does not have any history match and is not grounded with actual field performance. The EnCana model for Husky's Caribou area predicted an unrealistic SOR of about 20 for CSS operations, whereas the typical CSS wells in the Clearwater Formation in the Primrose area have SORs from 3.0 to 6.0. Even CSS conducted in the lower grade McMurray Formation bitumen achieved better SORs than that predicted from EnCana's model. Figure 3 shows performance from a CSS test conducted by Petro-Canada in the McMurray Formation at Hangingstone. The cumulative SOR is 12.
- The model cuts the production cycle too short thereby minimizing the contribution of solution gas drive to the total production. During a CSS production cycle, the later stage of the production is dominated by solution gas drive. This results in a "long tail" of production in the actual field performance. In EnCana's model for CSS simulation, only two months of production is assigned in each cycle following steam injection and the "tail" production is thereby cut off. The "tail" production due to solution gas drive is cut off in this original simulation at rates ranging from 2 – 5 m^3/d (see Figure 4). In EnCana's subsequent modeling study for CNRL's Primrose area, the production is cut off at even higher rates (about 18 m^3/d oil – See Figure 5). Figure 5 shows a comparison of the first cycle production profile predicted from EnCana's "Edge" model with its short cycle (i.e. EnCana's Schedule) and the more realistic extended cycle (i.e. Modified Schedule). With stable gas production rate in the late cycle, it is clearly shown that the "tail production" is dominated by solution gas drive.

CNRL has used EnCana's models to evaluate the effect of initial solution gas GOR on CSS performance. The only modification is that the production cycle length is extended (Referred to as "Modified Schedule"), with all other model parameters kept the same as in the "EnCana Schedule". Because the model can not model depletion in the bitumen leg properly, two initial conditions are assumed in the models: (1.) original reservoir condition without gas production (solution GOR = 8) and (2.) reservoir pressure reduced to 500 kPa (solution GOR of 1.0 m^3/m^3). Figure 6 shows a comparison of the cumulative oil production between the two cases for EnCana's model for Husky Caribou area. The oil production in the low solution GOR case decreases by over 35% during the initial period and over 20% over the entire production period.

EnCana's Edge model for CNRL's Primrose area is also used to perform the evaluation on the effect of initial solution GOR on CSS performance. With this model, a larger difference in CSS production is predicted from the modeling results between the two different initial solution GOR cases. Figure 7 shows a comparison of cumulative oil production. Cumulative oil production is reduced by more than 40% with initial GOR reduced from 8 to 1.0 m^3/m^3. The conclusion from the above two examples is consistent with that from CNRL's modeling studies and laboratory studies reported in the literature. The input data and results files for those runs are attached to this reply.

In summary, with proper input parameters that better simulate actual field conditions simulations including EnCana's can show a significant effect of bitumen recovery and SOR from degassing in the bitumen due to the production of the gas cap.

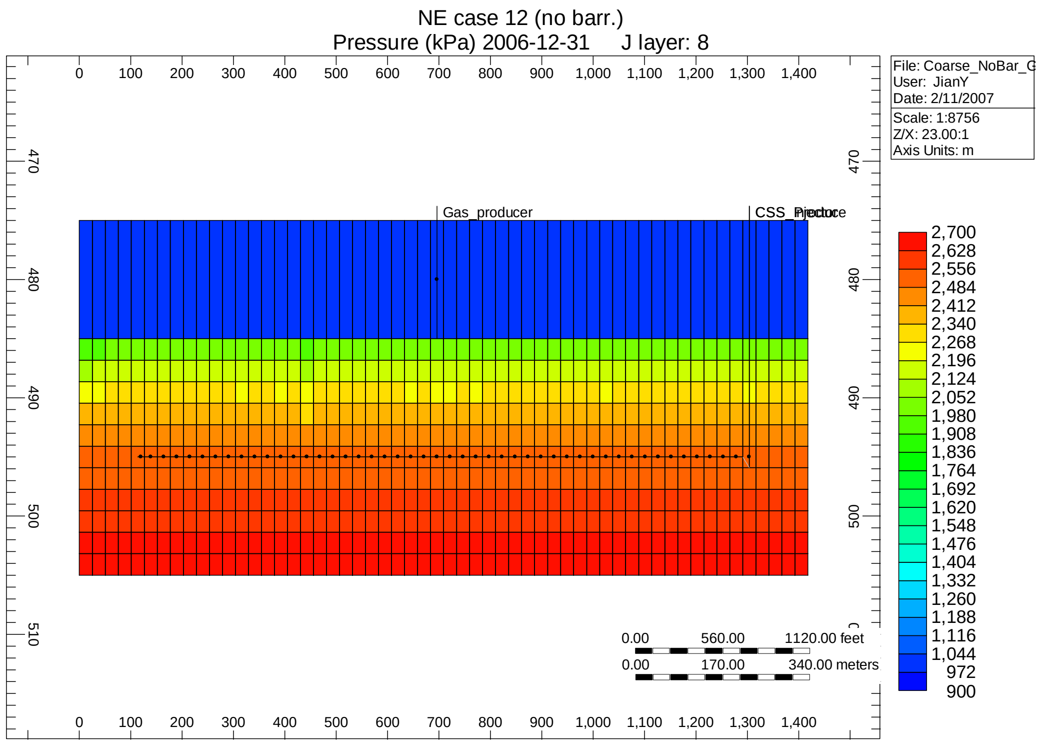

Figure 1 – NE case 12, there is no permeability barrier between the gas cap and the bitumen pay.

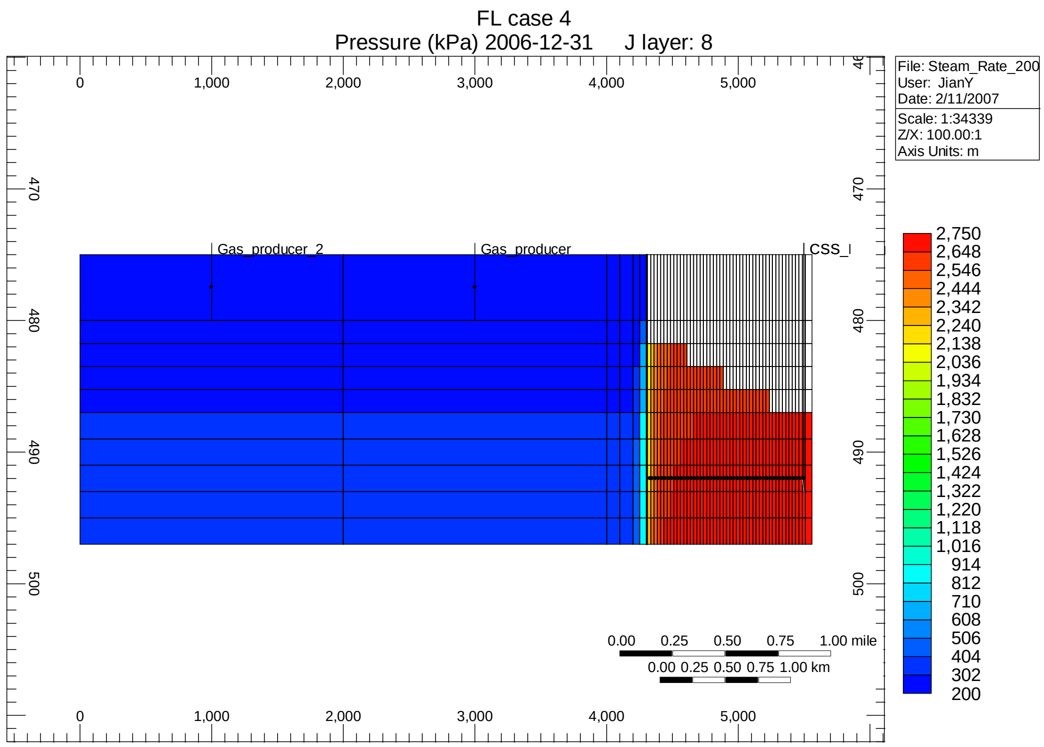

Figure 2 – FL case 4, there is no barrier between the gas cap and the bitumen pay zone.

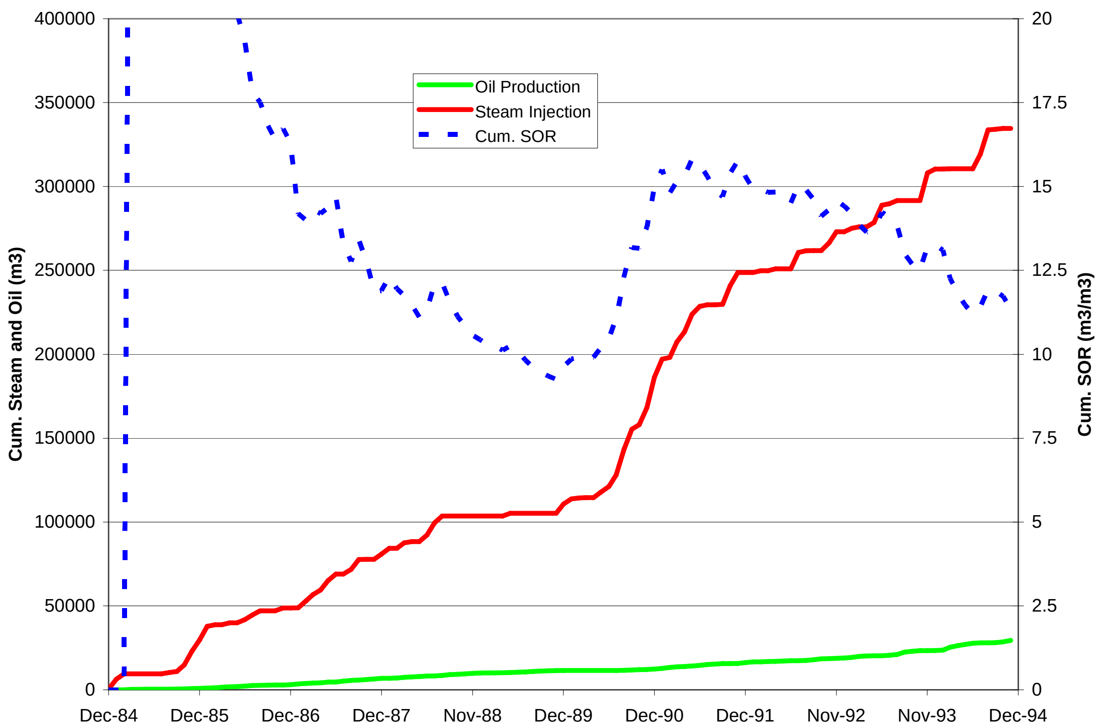

Figure 3 – CSS Performance in McMurray Formation at Hangingstone.

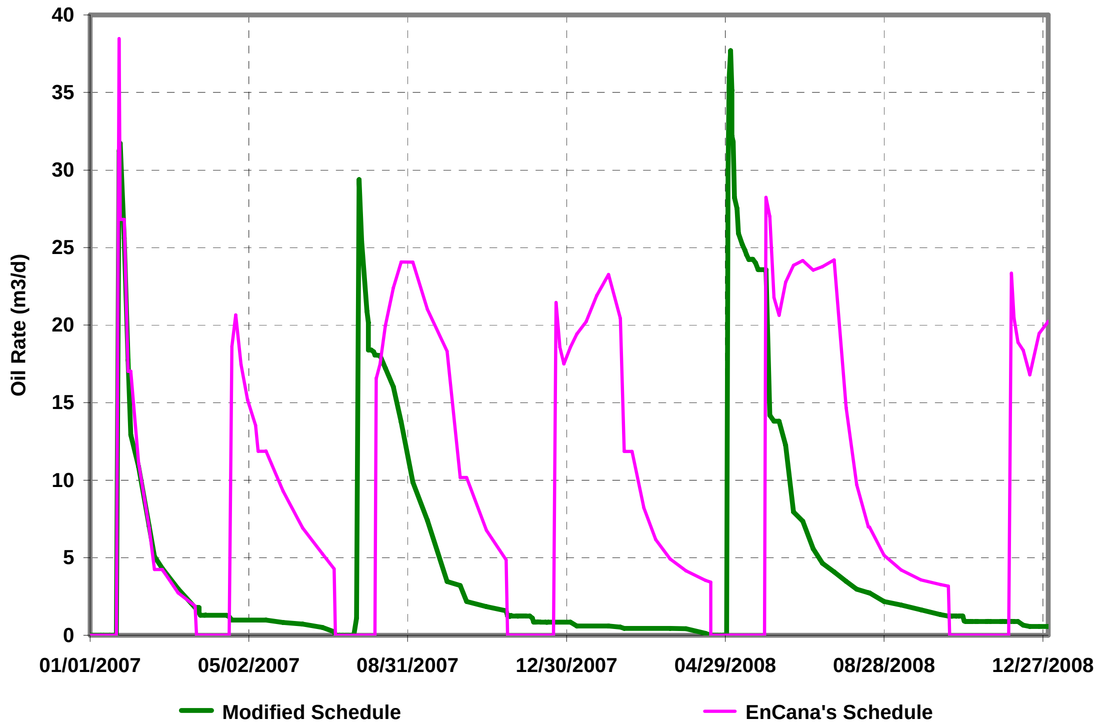

Figure 4 – Comparison of Oil Rate for CSS Production.

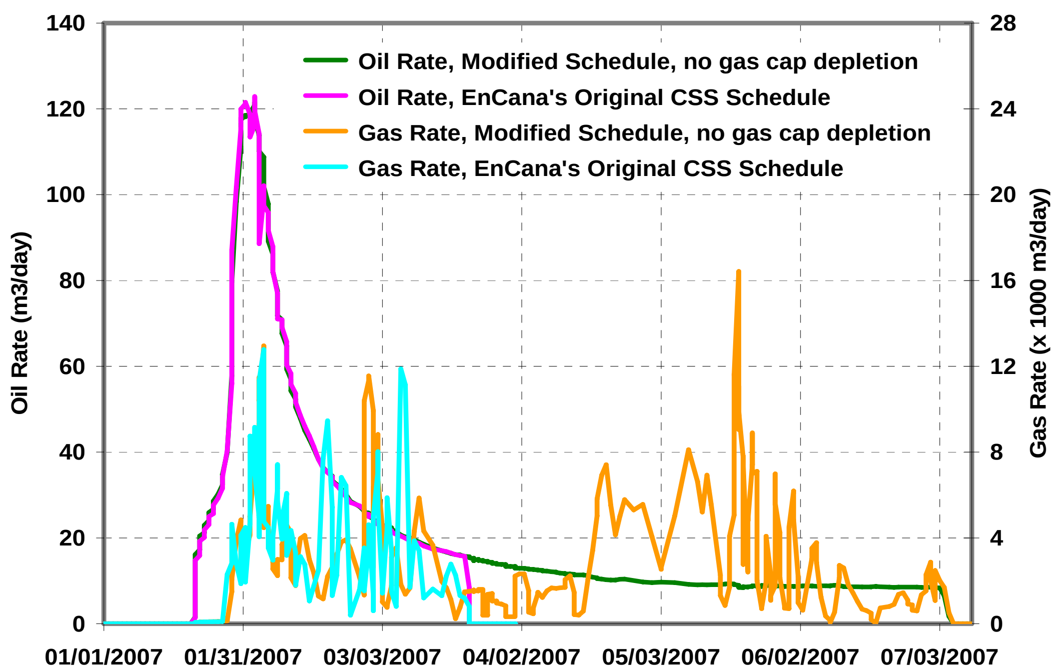

Figure 5 – Comparison of First Cycle CSS Production from EnCana's Edge Model for CNRL's Primrose Area, Tail Production due to Dominated Solution Gas Drive is Cut Off from EnCana's Original Modeling).

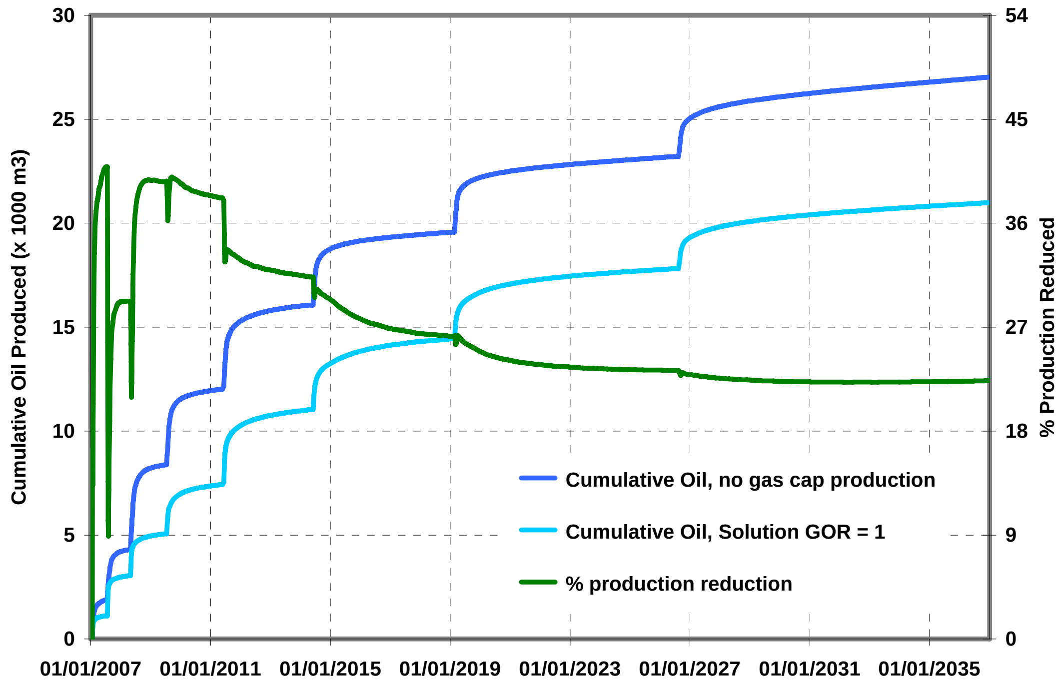

Figure 6 – Effect of Solution GOR on CSS Performance (Modified EnCana's Model for Husky's Caribou Area).

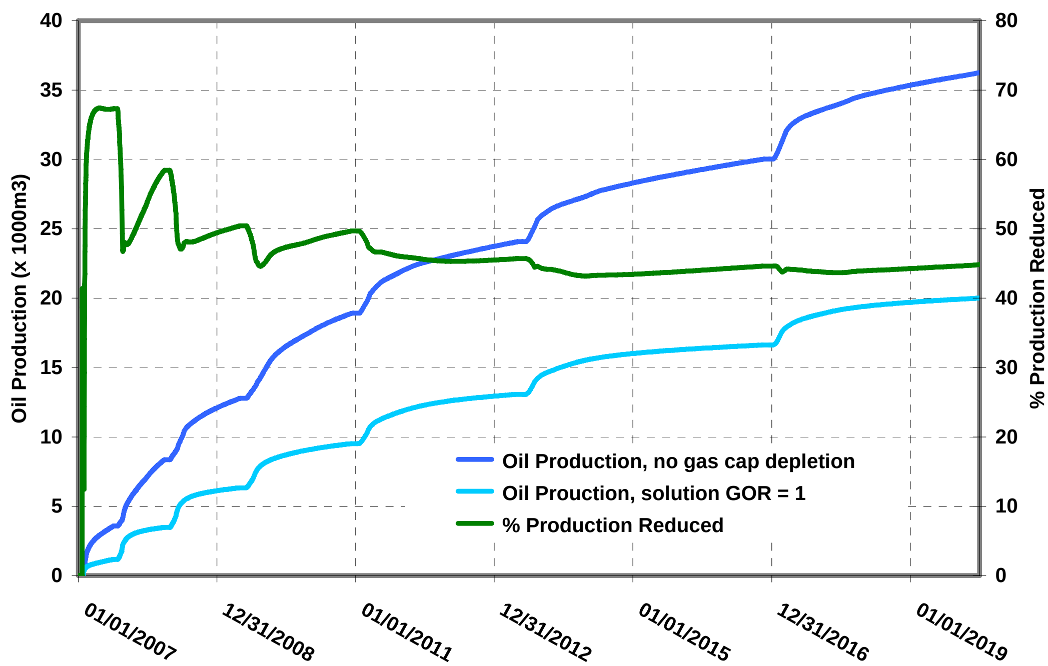

Figure 7 – Effect of Solution GOR on CSS Performance (Modified EnCana's "Edge Model" Model for CNRL's Primrose Area.

Question

2. On page 9 of its January 29, 2007 submission CNRL states that it used a 2D model to evaluate the effect of initial solution GOR in bitumen on HWCSS performance. The model was verified by matching the performance from a column "C" well of phase 17 from CNRL's Primrose south area.
   a. Provide the details of how the model was constructed, including how the porosities and permeabilities (both horizontal and vertical) for the grid blocks were determined. If geostatistical methods were used, provide a detailed discussion of how CNRL completed the five basic steps of a geostatistical reservoir characterization: exploratory-data analysis; spatial modeling; kriging; conditional simulation; and uncertainty analysis (reference: "Practical Geostatistics—An Armchair Overview for Petroleum Reservoir Engineers"; J. M. Yarus, R. L. Chambers; Journal of Petroleum Technology, November 2006).
   b. The input data files provided by CNRL indicate two wells were included in the model (wells are located at each end of the model). Clarify the statement on page 9 that the model was verified by matching the performance from a column "C" well. (i.e. Was the performance of one or two wells matched?)
   c. Identify the well or wells whose performance was matched.
   d. Explain why this well (or these wells) was used for the history match.
   e. Discuss the adjustments that were made to the model to obtain the history match.
   f. Discuss whether any pressure and/or temperature data were history matched and if they were, provide the results.
   g. Discuss the extent to which history matching the performance of one or two wells validates the model.
   h. Discuss why changing the solution GOR from 8 to 1 m3/m3 would be representative of what would occur in the bitumen zone if the gas zone was depleted to 500 kPa.

Response

2. Regarding CNRL's simulation model:
   a. The average porosity of the model is 32% and the average horizontal permeability of the model is 2.0 Darcies, with the horizontal correlation length of 15m and a log-norm distribution with the standard deviation of 0.1. Vertical permeability values were chosen to be 0.3 of the horizontal ones. Due to the lack of geological information at metre-scale, the standard methodology of geostatistics was not utilized to construct the model. Instead, a simpler statistical model (see F. J. Fayers and F. Jouaux, *An Improved Macroscopic Model for Viscous Fingering and its Validation for 2D and 3D Flows III. Inclusion of Effects of Heterogeneities*, In Situ 19[4], 393-425 [1995]), taking into account of the geostatistical characteristics of heterogeneities was used. The details of the model beyond the theoretical background described in the paper is proprietary to the AACI program which is based at Alberta Research Council, supported by Alberta Government and most of major heavy oil and oil sands producers in Alberta, except EnCana, and a few international heavy oil producers. This model has been used within the AACI program for more than 10 years in detailed studies of reservoir behaviours for both thermal and non-thermal recovery processes. The conclusion from this simulation study will not be changed even with a homogenous model of average properties (See Figure 8).
   b. The two-well configuration was for testing the validity of the statistical model purposes only. The average performance of two wells in the model was used to match the production history of the well 2C17.
   c. Canadian Natural's history matched simulation was conducted using data from 2C17 which is 102/03-10-067-04W400.

d. The well 2C17 was used for the history matched simulation because it is considered a fairly typical Primrose South well that shares the following important characteristics with the areas involved in the current GOB hearing:
   i. Located in the Blue Sand.
   ii. Located in thin pay.
e. During the history match, steam injection data were used as input; casing pressure data were used as a guideline for the primary constraint during production; secondary constraints are gross rate and occasionally oil rate as upper limits.
f. There was no down-hole temperature and pressure data measured for that CSS well. As mentioned in 2.e., casing pressures were monitored and the data were used as the guideline for the down-hole production pressure constraints.
g. Gas production rate is measured on pad level or on plant level. There is no gas rate measurement from individual CSS wells. However, the production GOR trend was generally matched. Water production rate is not measured during flow back for this well during early years. It was difficult to match the water production rate.

The initial solution GOR in our model is 8 m^3/m^3. Based on the K-values used in the model, the calculated solution GOR is 1.0 m^3/m^3 at 500 kPa (see CMG's STARS User's Guide). The model used by EnCana can not model the depletion in the bitumen region properly. A reservoir pressure of 500 kPa is assumed if a gas cap were depleted to 200kPa.

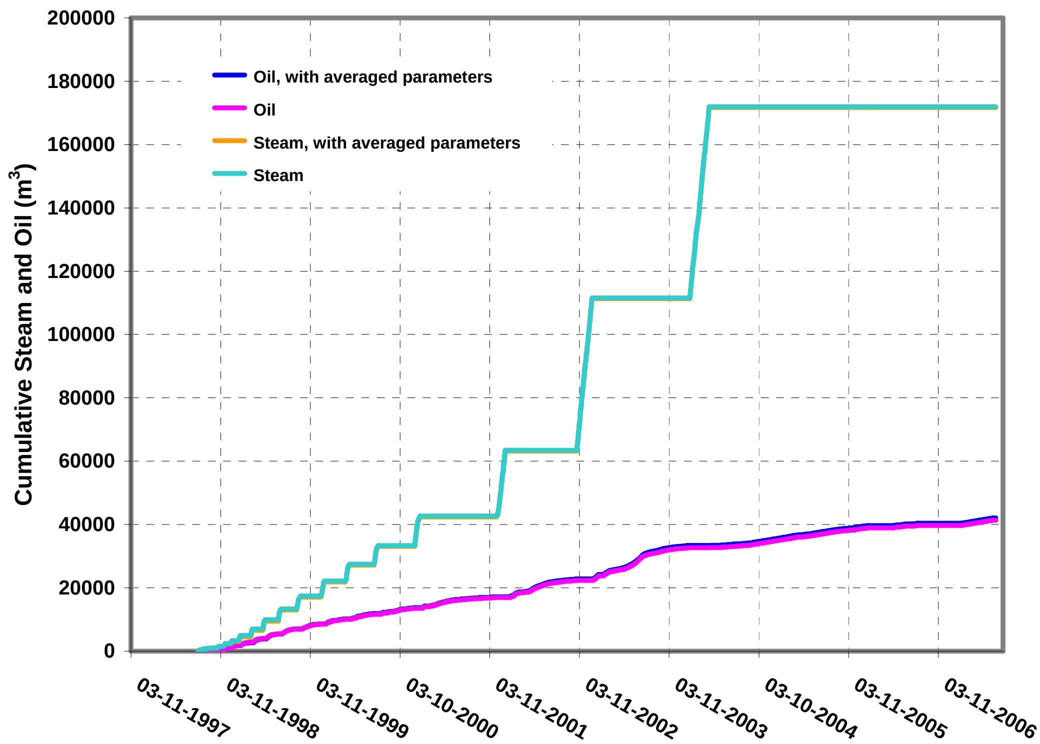

Figure 8 – Comparison of Model Production with Averaged Parameters vs. Constant Parameters.