

Question

1. Please provide the DLS location of the well that was history matched in the model. Please provide the historical (field measured data) gas-oil-ratio or the historical gas production rate of this well and indicate whether gas/oil ratio was one of the history match parameters.

Response

The 2C17 well is located at 102/03-10-067-04W400. Gas production was not one of the parameters that were specifically matched during the history matching process. The production rates from the model are generally consistent with producing GORs observed in Clearwater CSS considering that the production rates from the model should be lower than that from the field where produced gas contains CO₂ and other non-hydrocarbon gases.

Question

2. Please explain why CNRL did not deplete the reservoir to 500 kPa by incorporating, into the history match model, a flank gas cap and production of this gas cap to 500 kPa.

Response

Canadian Natural believes that it is extremely difficult to simulate both gas cap depletion and the CSS process in one model. The gridblock definition needed to adequately simulate these processes together is prohibitive based on the time required to run the simulation. The use of a reservoir model initialized at a lower pressure allows multiple simulation runs that can practically model a system where solution gas has been produced and reservoir pressure is depleted at the beginning of the CSS process. Canadian Natural would like to draw further attention to the fact that areas of the Clearwater Formation being monitored by CNRL piezometers already exhibit pressure in the 1000 kPa range (See CNRL July 4th, 2006 evidence submission) and will have pressure much lower when CSS operations commence.

Question

3. Please confirm the following observations in the models and please provide the source of the following data input into the model.
 - a. Initial water saturation in the grid blocks containing wells. (inj_left, pro_left, inj_right and pro_right) is 0.99.
 - b. Initial mobile water saturation in the grid blocks containing wells. (inj_left, pro_left, inj_right and pro_right) is 0.65 and elsewhere is 0.01.
 - c. Initial porosity in the grid blocks containing wells. (inj_left, pro_left, inj_right and pro_right) is 0.45.
 - d. There is no gas cap represented in the model.
 - e. Porosity, particularly of greater than 36% in non well grid blocks.
 - f. Permeability (vertical and horizontal).
 - g. Initial solution gas-oil ratio.
 - h. Initial mobile water saturation in the gridblocks and its variation between gridblocks.

Response

- a. Yes, the initial water saturation in the grid blocks containing wells is 0.99. This is one of the simulation techniques to avoid unnecessary run time by changing the initial water saturation in wellbore blocks. This will affect the overall results due to the small volume of the wellbore blocks with comparing to the volume of the entire model.
- b. Yes, the initial mobile water saturation in the grid blocks containing wells is 0.65. Not every block elsewhere is 0.01, depending on the initial water saturation assigned to those grids.

The distribution of fluid saturation in these blocks was generated using a random number generator of MS Excel. The average oil saturation (about 60% of pore volume) is very representative in the model area. The same reason to answer (a), there is no effect on the overall simulation results by assigning a higher mobile water saturation in wellbore blocks.

- c. Initial porosity in the grid blocks containing wells is 0.45. This is again one of the simulation techniques applied to the blocks containing wells. This will not affect the simulation results.
- d. There is no gas cap for the modeled well (2C17);
- e. The average porosity is 32%, which is very representative in this area. There are some blocks with higher porosity assigned from a statistical model, see below.
- f. Horizontal permeability distribution were generated randomly with a log-norm distribution, details of which is described in Reply to Board's IR;
- g. Initial solution GOR is set to 8 which is a typical value for the area of interests
- h. See 3.b

Question

4. With respect to the oil-water and gas-liquid relative permeability applied in the model:
 - a. Please explain the three relative permeability regions applied in the model (Rel Perm Set Number) and any geological facies are they meant to represent.
 - b. What was the source of the relative permeability data for each region?
 - c. If the source was laboratory data please provide the full laboratory reports.
 - d. No hysteresis relative permeability was used. Please explain.
 - e. The oil-water relative permeability has a sharp drop in value from a water saturation of 0.60 to 0.70. Please explain.

Response

Regarding relative permeability curves

- a. Three relative permeability regions are used in the model: type 1 "rpt1" is for the blocks with mobile water, type 2 "rpt2" is for the blocks containing wells and type 3 "rpt3" is for the blocks without mobile water.
- b. CNRL does not have measured relative permeability curves. The relative permeability data used in the model are representative from our previous modeling studies in this area.
- c. see 4.b.
- d. CNRL does not believe the hysteresis behavior in relative permeability is crucial to the gas drive in CSS process; and we don't believe there are any reliable measurement .
- e. there is no sharp drop in the oil-water relative permeability curves

Question

5. On page 10, CNRL states that "It was determined that at 500 kPa the solution GOR is about 1.0
 - a. How was the 500 kPa pressure arrived at?
 - b. How was the GOR determined to be 1 at 500 kPa?

Response

Pressure at the depleted state:

- a. The model used by EnCana can not model the depletion in the bitumen region properly. A reservoir pressure of 500 kPa is assumed in the model to conduct sensitivity studies on the effect of reduced reservoir pressure on the CSS performance. The case is based on assumption that reservoir pressure will eventually reduced to 500 kPa with continued depletion of gas cap pressure to 200 kPa.

- b. This is determined by the equilibrium values (kvs) in the model. The typical initial solution GOR is about $8 \text{ m}^3/\text{m}^3$, which is equivalent to 15% mole fraction in the oil phase. The mole fraction of gas in the oil phase reduces to 2% at 500 kPa. This gives a solution GOR of about 1.0.

Question

6. Please confirm that the initial reservoir pressure for all gridblocks in the models was set to 3500 kPaa regardless of grid block depths. If true, please explain why gravity effects were ignored.

Response

There are two ways to assign initial saturation values in CMG's STARS, one uses *VERTICAL *DEPTH_AVE which performs depth-averaged capillary-gravity vertical equilibrium calculation in conjunction with *DWOC and *DGOC; the other uses *VERTICAL *OFF option which do not perform gravity equilibrium calculation for the initial saturation values. The gravity effects were not ignored in the calculation. Please refer to STARS User's Guide.

Question

7. Were any measured field reservoir pressure or reservoir temperatures used to assess the model's ability to match field performance? Please provide the results of any pressure or temperature history matches and the field data.

Response

There are no measured down-hole temperature and pressure data in horizontal CSS wells. Casing pressure was monitored during CSS production and used as the guidelines for downhole pressure constraint in the simulation. The casing pressure for the model well is given in the attached graph (Figure 3).

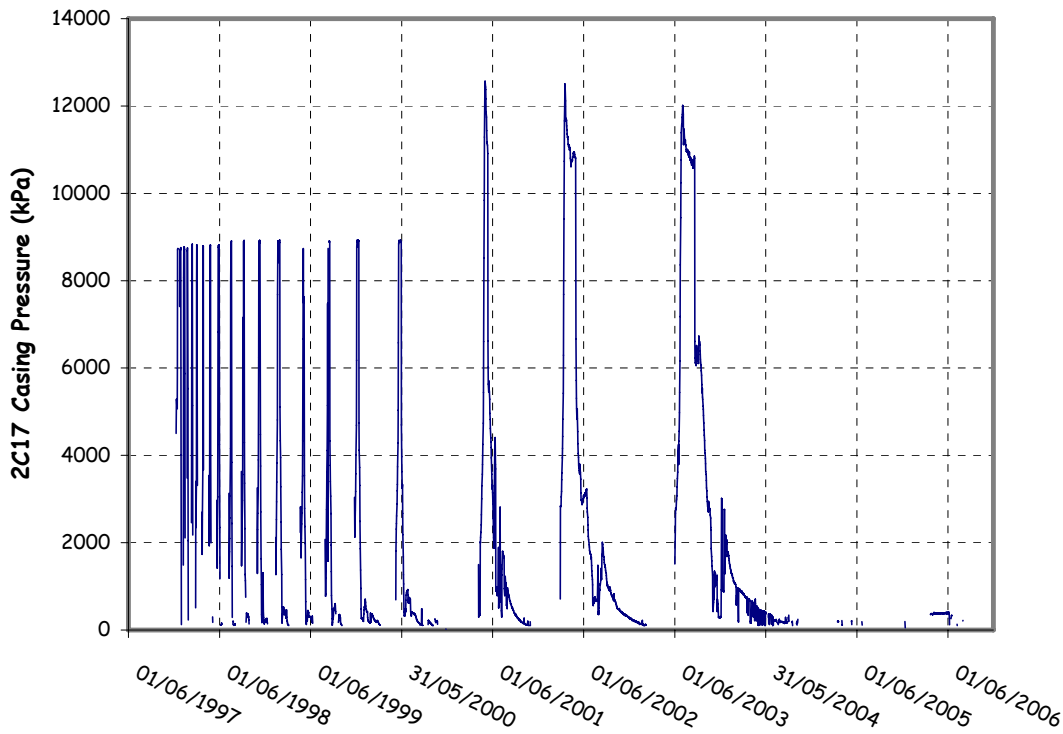


Figure 3 – Casing Pressure for Well 2C17

Question

8. It is observed in the model that the production wells were constrained by bottomhole producing pressure of between 100 and 6,600 kPaa. Please provide field data to support for the production well pressure constraints used in the history match.

Response

See response #7.

Question

9. Please confirm that the following three constraints were applied together at the same time to match historical performance of the well in the model:
 - Maximum liquid production rate,
 - Maximum oil production rate, and
 - Minimum bottomhole pressure.

Response

The primary is minimum BHP; secondary is maximum STL; occasionally, additional secondary constraint of maximum STO is used.

Question

10. EnCana does not believe that wells in Wolf Lake are relevant to the bitumen area in and around the gas pools subject to CNRL’s shut-in request, however, if CNRL believes they

are valid analogs please provide the following data for each individual well that has been included in CNRL's group graphs:

- a. Length of well bore open in the Clearwater.
- b. Estimated drainage area.
- c. Average net pay, porosity, and water saturation in the estimated drainage area of the well.
- d. Average, maximum, and minimum vertical permeability in the drainage area of the well.
- e. A plot of cumulative bitumen recovery and cumulative steam oil ratio.
- f. A plot of oil rate, water cut, gas oil ratio and steam injection rate.

Response

EnCana has stated that HW and VW CSS behave differently and therefore the learnings from one are not applicable to the other. EnCana appears to misunderstand Canadian Natural's rationale in using a field analog to demonstrate behaviours that are independent of well architecture and therefore reflect common mechanisms of recovery.

For example the physics involved in HW vs. VW CSS can best be inferred from long term field operations in the same Clearwater reservoir over years and perhaps decades and be used to test the working hypothesis that the thermodynamics, fluid mechanics, and geomechanics, would (using reservoir engineering principles) be independent of wellbore architecture; wellbore architecture affecting only individual well rates. Furthermore this working hypothesis implies that CSS drive mechanisms such as dilation/recompaction and solution gas drive would also be independent of wellbore architecture as long as the operating pressure range is similar (i.e. 10MPa – 500kPa). If, as Canadian Natural contends, the field response over years to decades of operating history including recoveries, thermal efficiencies (SOR's), and GOR behaviour are similar for HW and VW CSS, then the working hypothesis is validated and supports conclusions pertaining to drive mechanisms.

Furthermore, Canadian Natural believes that it is crucial to use field observations to calibrate, or ground truth, one's findings or conclusions derived from simulations and lab models. These latter investigative techniques can be used to further test a working hypothesis of recovery behaviour, but are at best directional in nature since they cannot replicate all of the actual field conditions, and therefore must be grounded to physical responses observed in the field. Accordingly, Canadian Natural's contention that bitumen recovery is dependent on an active solution gas drive mechanism, can be interpreted with a reservoir engineering mechanistic perspective from field data, production, and direct observation of bitumen behaviour, and further supported by lab work and simulation that have been properly ground truthed with real field data.

Conversely, simulations that have not been calibrated with field data can be, at the least, misleading or at worst, lead to incorrect conclusions.

The first simulation study EnCana submitted as evidence, for example, showed that producing gas caps made no difference to CSS recoveries. However, gas cap depressuring didn't result in bitumen leg depressuring due to the absence of mobile water within the model (See Figure 4). Consequently, the bitumen was at initial pressures whether the gas cap was produced or not, the bitumen had the same initial GOR, and thus, not surprisingly, the predicted bitumen CSS recoveries were independent of gas cap production. However, using field data to ground truth this model, it is clearly invalid, since gas cap depressuring shows a large pressure transient in the bitumen, and gas caps have produced more than the mappable OGIP (as demonstrated in CNRL's July 4th, 2006 evidence submission). This clearly implies that the bitumen is being degassed but the model is unable to simulate this and the ultimately degassed condition of the bitumen. Conclusions based only on this simulation, without the requisite grounding in field data, are therefore incorrect.

EnCana’s second simulation study has similar inadequacies, and yet it too is used to conclude that producing the gas cap does not have any impact on bitumen recoveries. This study attempted to model a large area including the gas cap and the bitumen wells. In this instance, though depressuring the gas cap is transmitting into the bitumen column, CSS recovery was started at pressures very close to initial values and thus initial GOR in a depleted gas cap case is very near to initial GOR in an undepleted case (See Figure 5). As a result CSS performance appeared to be the same whether the gas cap was produced or not. However, were the model to be calibrated to field data, the bitumen pressures would be much lower (500 kPa) at commencement of the bitumen project.

In addition predicted SOR’s were quite high at around 20. These are unrealistic if compared to actual field data. CSS conducted in the lower grade McMurray bitumen has lower SOR’s than realized with this model (See Figure 6). Also the steam schedule is modeled with unrealistically short production times (EnCana’s Schedule) with subsequent injection phases being started before the reservoir can be drawn down to activate solution gas drive (See Figures 7 & 8, comparing EnCana’s Schedule to a more realistic extended Modified Schedule). Ground truthing this EnCana model by commencing the bitumen recovery project when the reservoir pressure is 500 kPa, the initial GOR is about 1, and with a steam schedule that more accurately represents reality (“Modified Schedule”), shows a 20-45% decrease in bitumen production if the bitumen is degassed (See Figures 9 & 10).

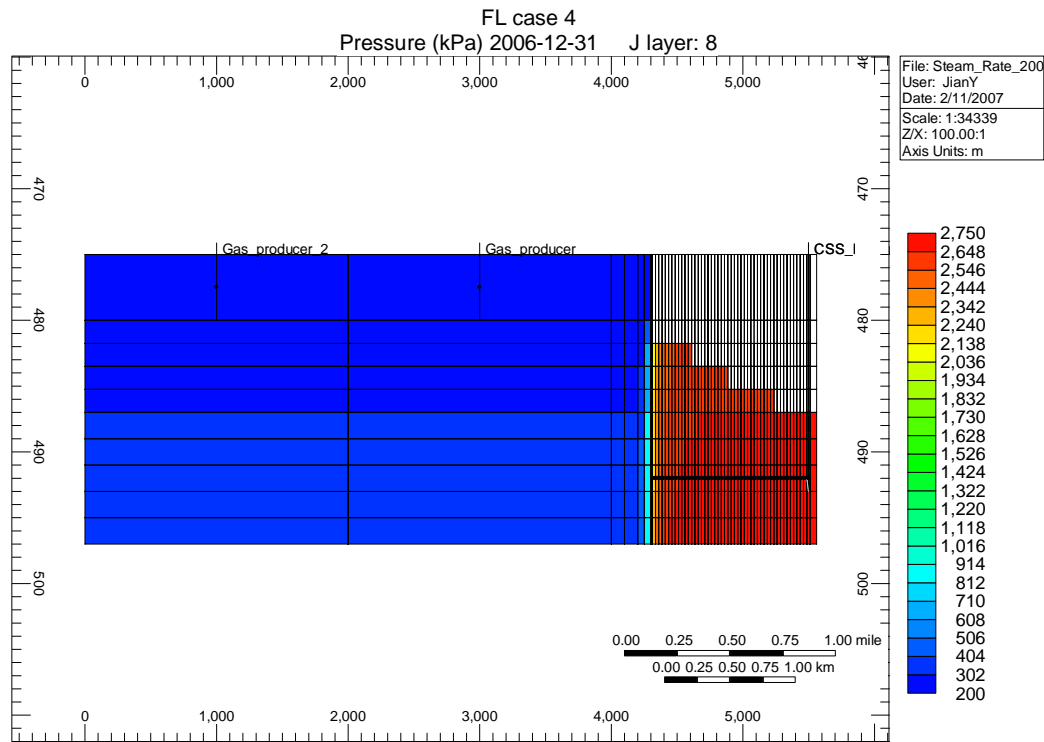


Figure 4 – FL case 4, there is no barrier between the gas cap and the bitumen pay zone.

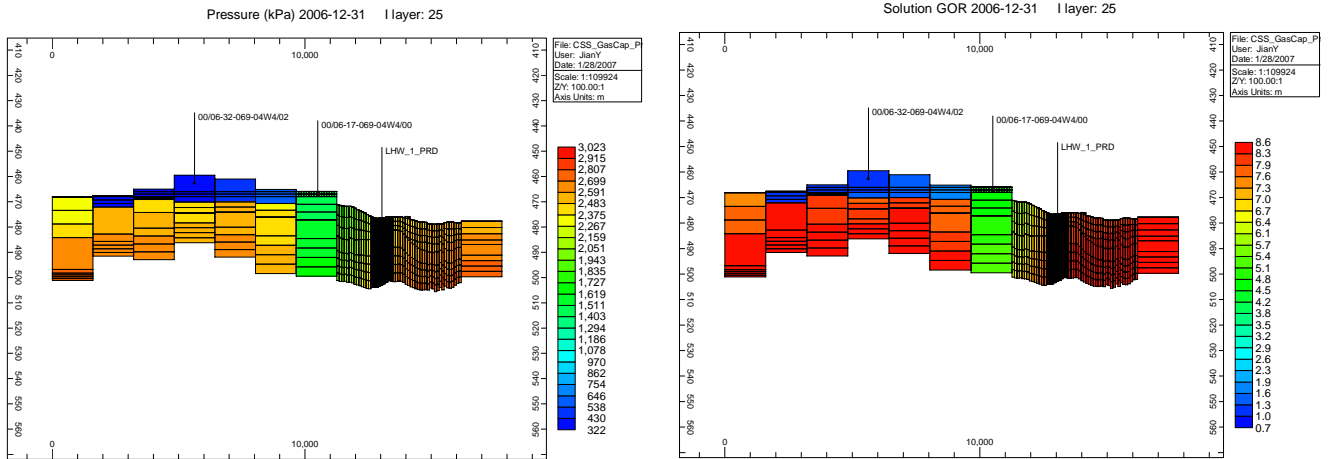


Figure 5 – Pressure and Solution GOR distribution in EnCana model of Husky’s Caribou area after gas cap depletion and before start of CSS process.

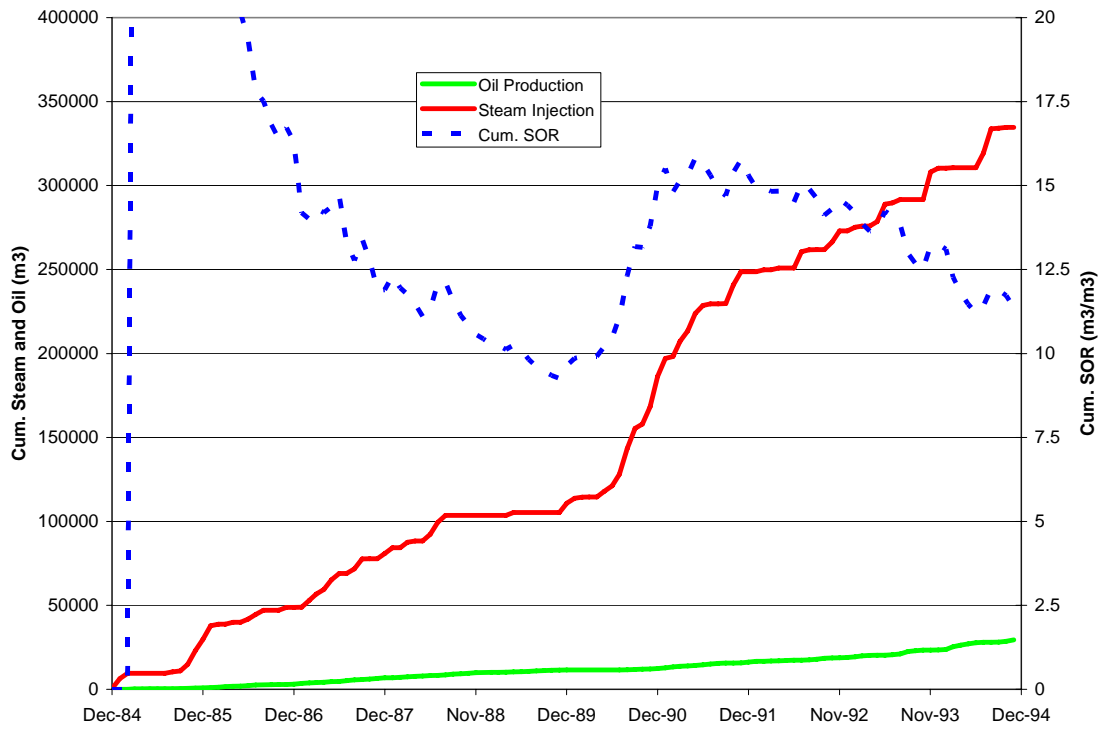


Figure 6 – CSS Performance in McMurray Formation at Hangingstone.

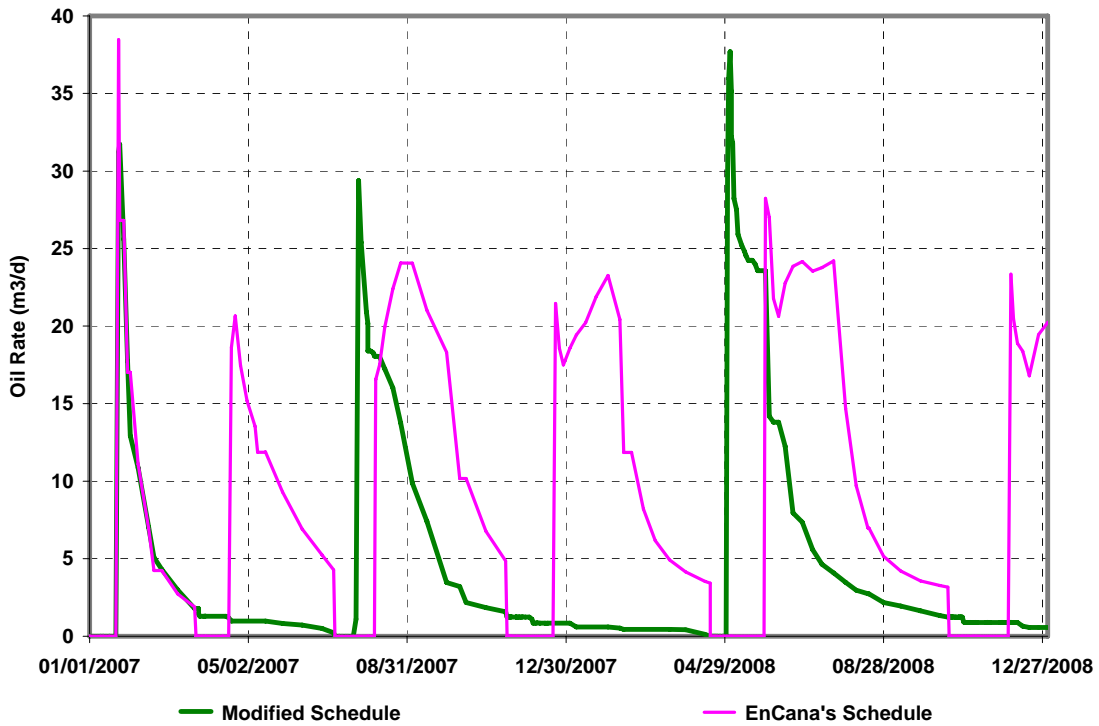


Figure 7 – Comparison of Oil Rate for CSS Production.

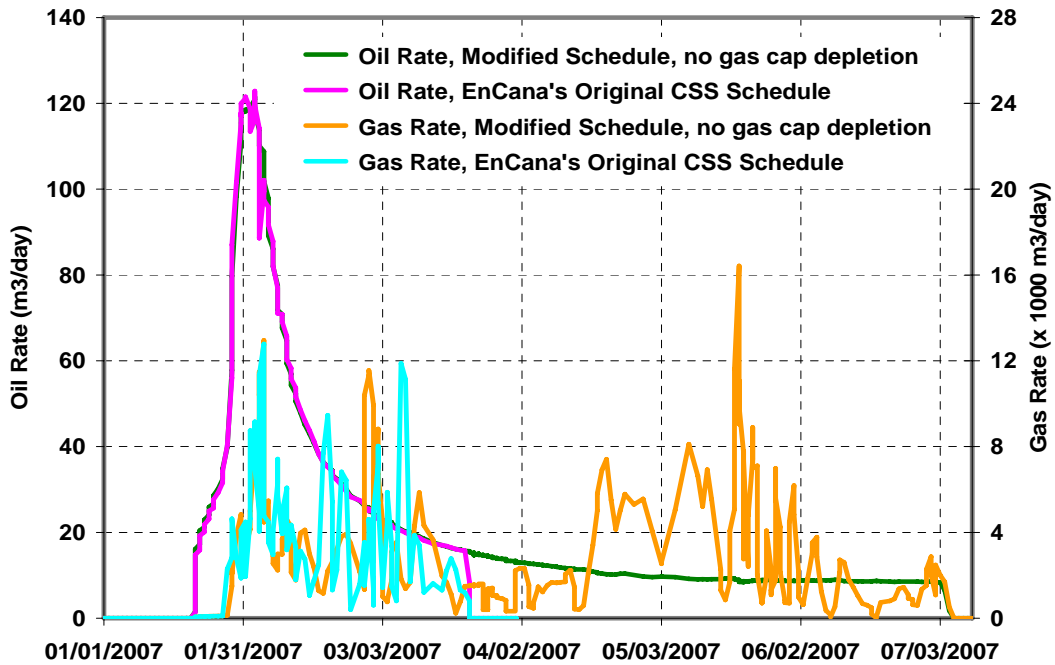


Figure 8 – Comparison of First Cycle CSS Production from EnCana's Edge Model for CNRL's Primrose Area, Tail Production due to Dominated Solution Gas Drive is Cut Off from EnCana's Original Modeling).

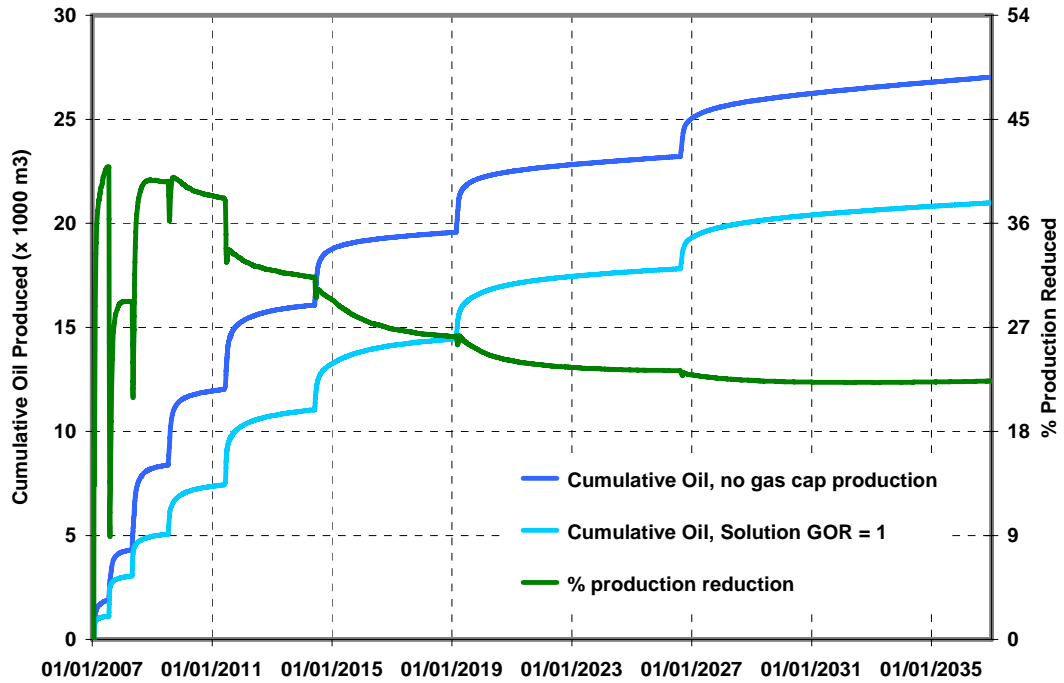


Figure 9 – Effect of Solution GOR on CSS Performance (Modified EnCana's Model for Husky's Caribou Area).

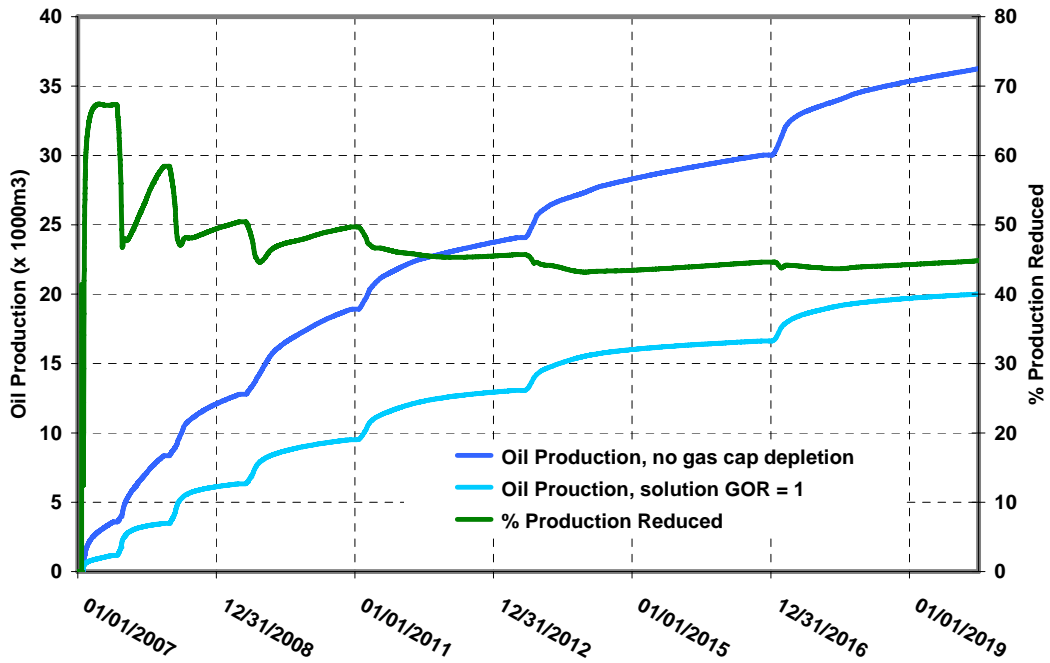


Figure 10 – Effect of Solution GOR on CSS Performance (Modified EnCana's "Edge Model" Model for CNRL's Primrose Area).