Barristers & Solicitors
Patent & Trade-mark Agents

McCarthy Tétrault

McCarthy Tétrault LLP
Suite 3300, 421-7th Avenue S.W.
Calgary AB T2P 4K9
Canada
Telephone: 403 260-3500
Facsimile: 403 260-3501
mccarthy.ca

D. G. Davies
Direct Line: 403 260-3681
Direct Fax: 403-260-3501
E-Mail: ddavies@mccarthy.ca

Assistant: Penny Goebel
Direct Line: 403-260-3662
E-Mail: pgoebel@mccarthy.ca

October 3, 2006

Electronic Notification

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

Attention: Ms. Giuseppa Bentivegna

Dear Madam:

Re: Application No. 1409180
Cold Lake Oil Sands Area - Clearwater Deposit

Attached please find the responses of EnCana Oil and Gas Partnership to the information requests of the Board Staff.

Yours very truly,

McCarthy Tétrault LLP

Original signed by

D. G. DAVIES

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

CAL_DOCS #1543752 v. 1

ALBERTA ENERGY and UTILITIES BOARD

APPLICATION NO. 1409180

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 (September 19, 2006)

1. On page 2 of its submission EnCana states that the study by Kade Technologies Inc. demonstrates how erroneous conclusions can be reached by endeavouring to transfer inapplicable learnings from SAGD or vertical wellbore CSS to a development using horizontal wellbore CSS. In EnCana's view, what are the inapplicable learnings from vertical wellbore CSS that are being transferred to horizontal wellbore CSS?

With respect to the effect that de-pressuring a gas cap might have on CSS performance, why would there be a difference between horizontal wellbore CSS and vertical wellbore CSS?

The learnings that have been inferred by CNRL from vertical CSS theory that are inapplicable to horizontal CSS are:

a) Successful bitumen recovery from the Clearwater Formation in the Primrose area depends on having an active solution gas drive mechanism.

b) The production of the solution gas from these progressively migrating regions of influence will defeat the gas drive mechanism and thereby prevent the recovery of the bitumen.

These two inferred learnings are stated as conclusions in the CNRL July 4, 2006 application.

CNRL has not considered other oil recovery mechanisms at play in CSS and any beneficial effects that reducing reservoir pressure might have on these mechanisms in horizontal wells.

These recovery mechanisms are described in detail by Denbina et al: "Evaluation of Key Reservoir Drive Mechanisms in the Early Cycles of Steam Stimulation at Cold Lake", SPE 16737, May 1991. The extent of reservoir area accessible to a vertical CSS well compared to a horizontal CSS well will affect the relative importance and impact of these principal mechanisms to the CSS recovery process including; compaction, solution gas drive, fluid expansion, gravity drainage. To date no study has been published to demonstrate how these observations will influence horizontal CSS well applications.

A comparison was made between the model performance of the first 15 cycles of vertical well (VW) CSS in the bitumen zone in a case in which the gas cap was depleted to an abandonment pressure of 201 kPaa (FL 23) with that in which the gas cap was undepleted (FL 24).

A second comparison was made between the model performance of the first 15 cycles of horizontal well (HW) CSS in the bitumen zone in a case in which the gas cap was depleted to an abandonment pressure of 209 kPaa (FL 21RE) with that in which the gas cap was undepleted (FL 22RE). Summary of cases FL 23, FL 24, FL 21RE and FL 22RE are presented in the revised Table E.4.

The following parameters are compared for the depleted gas cap and the undepleted gas cap cases - bitumen production rate, average reservoir pressure in the bitumen zone and cumulative bitumen production. The following are the key observations in the comparison of FL 23, FL 24, FL 21RE and FL 22RE

- The average reservoir pressure in the bitumen zone between the depleted and the undepleted gas cap cases for both the VW and the HW CSS remained higher in the undepleted gas cap case for the entire 15 cycles.

- The difference in the oil production rate between the undepleted and the depleted gas cap is significantly much higher for the VW CSS during the first 15 cycles of operations.

- Note that for the HW CSS, the oil production rate for the depleted gas cap gas is approximately equal to that of the undepleted gas cap and in some cycles exceeds that of the undepleted gas cap case. This was not the cases for the VW CSS in which the oil production rate for the undepleted gas cap case consistently exceeds that of the depleted gas cap. This observation suggests that gravity drainage is likely the more dominant key performance driver for the depleted HW CSS case.

- At the end of 15 CSS production cycles and using the same assigned drainage volume for FL 23 and FL 24, VW CSS achieved a bitumen recovery factor of 14.8 and 9.6 % OBIP respectively for the undepleted and the depleted gas cap cases. This difference in VW CSS bitumen recovery factor of 5.2% is significant.

- At the end of 15 CSS production cycles and using the same assigned drainage volume for FL 21 RE and FL 22RE, HW CSS achieved similar bitumen recovery factors of 18.5 and 17.9 % OBIP respectively for the undepleted and the depleted gas cap cases. This difference in HW CSS bitumen recovery factor of 0.6% of OBIP achieved between the depleted and the undepleted gas cap cases is within the tolerance of model predictions. Consequently, the model prediction for both case is essentially the same.

Key conclusions from these observations include the following:

1. *Solution gas drive was likely a more dominant key performance driver involved in the vertical well CSS.*

2. *Gravity drainage was likely the most dominant key performance driver for the horizontal well CSS especially for the depleted HW CSS case and more likely compensated for any mechanisms due to solution gas effects.*

2. **With respect to the study by Kade Technologies Inc.:**

(a) **On page 1 it is stated that the Computer Modeling Group's (CMG) thermal reservoir simulator STARS was applied in the study. What version of STARS was used?**

The version of STARS used was 2005.13

(b) **Provide electronic copies of the input files for each of the simulation cases that were run. Also, provide the results files (*.irf and *.mrf) for cases FL2, FL3, FL8, FL13, FL14, NE6, and NE8.**

A DVD is being submitted containing all the input files for each of the simulation cases run. Results files *.irf and *.mrf files are provided for the following cases as requested, FL 2, FL 3, FL 8, FL 13, FL 14, NE 6, and NE 8.

Please note that in the Non Edge and the Edge cases only, an error was noted in the dataset. The maximum injection pressure constraint and the dilation pressure were both set to 108,000 kPaa instead of 12,000 kPaa and 9,800 kPaa respectively. Therefore, the high injection pressure caused the specified steam injection volume to be injected prior to the well gridblocks reaching the dilation pressure. However, because the injection rate of 250 to 400 m^3/d applied in the Non Edge and the Edge cases were relatively low, we do not expect the results to change significantly from those presented in Table E.2 and E.3 if the errors were corrected. Nevertheless, all the Non Edge and the Edge cases will be rerun.

This error has been corrected in cases NE 6 and NE 8 requested by the EUB and the maximum steam injection pressure and dilation pressure were set to 12,000 and 9,800 kPaa respectively. Results of these two cases are essentially identical to those presented previously in Table E.2 (EnCana's September 5, 2006 submission). Results show that there is no adverse impact of gas cap depletion on HW CSS bitumen recovery factors. The results of the revised runs for cases NE 6 and NE 8 are presented in the revised Table E.2. A summary of the remaining cases will be submitted to the EUB when the runs are completed. It should be noted that each run takes about 13 hours to complete.

The error has been corrected for all the Non Edge and Edge input datasets in the DVD.

(c) Page 1 refers to Figure E.2 which is a schematic diagram outlining the structural position of the hydrocarbons and barrier relative to the position of the model runs. It is stated that the bitumen intervals in the model are approximately correlative to the Blue valley sands and the Yellow valley sands to the east shown on CNRL's schematic cross-section (Figure E.1). Does this mean that EnCana agrees with CNRL's geological model? If no, why not? Why does the model not include the Orange valley sands to the west as illustrated in Figure E.1?

CNRL states "The Clearwater formation in the area of interest consists of a number of stacked, locally incised paleovalleys each of which consists of sediments that were deposited in a southerly to northerly prograding system." This viewpoint cited work done by McCrimmond and Arnott(2002) and presented a schematic cross section of valley incision (Fig 2.2).

Conceptually this is not an unreasonable interpretation. There is a northerly prograding deposition in play and evidence of incised valley fill sediments. However deposition in the area of interest is north of the work done by McCrimmond and Arnott. McCrimmond and Arnott also state "Clearwater deposition is a complex assemblage of non marine, marginal marine and shallow marine strata".

CNRL also states "Interpretation of valley sediment fill is not critical to the impact of gas production on bitumen". However the truncation of the "barrier" muds to the east requires later downcutting in just such a depositional setting. CNRL facies assemblages C and D are a "mud rich non reservoir unit which effectively provide local vertical seals". This "local" vertical seal(barrier) as mapped by CNRL (fig 2.7) exists under the three western EnCana gas pools and provides a continuous, thick, effective barrier to vertical permeability, from section 5-68-5W4 in the west to central section 6-68-3W4 in the east. Core from wells on the western edge of the Yellow sand contain interbedded mudstone and sandstone. These muds can not be differentiated from the Facies C and D "barrier" sediments. This indicates both the heterogeneity of the Yellow sand package and extends the "barrier" muds much further to the east than currently mapped by CNRL. These Yellow Sand muds are identifiable to the eastern ROI, and isolate less than 10m net bitumen pay above.

CNRL facies E of the Blue valley sands were not described in any detail other than a generic description that was eventually included based on an EUB IR. CNRL has assigned 17.0E6m3 OBIP to the E facies (Table 6.2) with 1.7 e6m3 recoverable bitumen by way of thermally induced primary production. Core examination and log analysis of this interval indicates lower quality reservoir sands disrupted by calcite stingers, mud stringers and intervals of bitumen saturation < 50%. Mapping by CNRL does not identify any regions of net pay greater than 10meters.

The orange valley sands are not included in the model because they are beyond the region of influence(ROI) surrounding EnCana Gas pools. The Orange valley sands are limited to the south and extreme west of the area of interest. Introduction of the orange sands in to the model would not change the conclusion that horizontal CSS production is unaffected by gas cap production.

(d) Was the gas cap modeled as a confined or unconfined gas cap? If confined, why is it appropriate to use a confined model?

The gas cap was modeled as confined. The following are the reasons for using a confined gas cap option in the model:

- It is appropriate to use a confined gas cap model because the bitumen reservoir is under a finite gas cap. In addition, the extent of the bitumen deposits is well beyond the edge of the gas cap.
- Pressure surveys of the gas cap in the field have shown decline with gas cap depletion from an initial pressure of approximately 2585 kPaa at the original conditions to a current average pressure of between 700 to 1200 kPaa. This decline in the gas cap pressure surveys confirms that the gas cap is well confined.
- An unconfined gas cap model is inappropriate since it infers that the gas cap size is huge compared to the size of the bitumen deposits in the Primrose area.

(e) On page 2 it is stated that the deformation model and imbibition and drainage relative permeability hysteresis techniques applied in the study are similar to those successfully applied to model CSS operations in Cold Lake by Imperial Oil Limited. Discuss any differences between the techniques used in the study and those that have been applied to model CSS operations in Cold Lake by Imperial Oil Limited.

There is no difference in the deformation model and imbibition and drainage relative permeability hysteresis technique applied in this model and that applied to model CSS operations in Cold Lake by Imperial Oil Limited (SPE 20743, SPE 18752, SPERE, May 1991, p 207-211, STARS User’s Guide, v2005.13, page 371).

(f) On page 2 it is also stated that sensitivity studies cover possible scenarios of reservoir configurations and operational parameters that include changes to nine parameters. Explain what is meant by “changes in the fluid flow physics in the bitumen zone”.

“changes in the fluid flow physics in the bitumen zone” refers to sensitivity cases conducted relating to changes in mobile water saturation in the Flank Pool cases and hydraulic diffusivity in the Flank Pool cases FL 19 and FL 20.

(g) On page 5 it is stated that reasons for achieving relatively similar HW CSS bitumen recovery factors in cases involving depletion of the gas cap gas when compared to similar reservoir cases without gas cap production are currently being investigated. However, early analysis results indicate that lower bitumen reservoir pressure below the gas cap, resulting from gas cap gas depletion, allows the steam vapors to rise higher and have better penetration into the upper regions of the reservoir. Why should the Board place any reliance on an explanation that is still being investigated?

We have now conducted further analysis to understand the reasons for achieving relatively similar recovery factors in cases involving depletion of the gas cap when compared to similar cases without gas cap production. To facilitate analysis of results we have further refined the reservoir gridblocks in the region of the horizontal well closer to the gas cap edge in the Flank cases FL 6 and FL 7. The refined grids cases FL 21RE and FL 22RE were created from FL 6 and FL 7 cases respectively. The dilation gridblock treatment multiplier factor was applied to the well layer gridblocks only in FL 21RE and FL 22RE. The conclusions of our analysis are the following:

- The higher pressure gradient between a depleted gas cap and the bitumen reservoir during steam injection causes injected steam vapor to rise up more quickly into the upper regions of the reservoir closest to the gas cap edge where the pressure gradient is the highest.
- The more rapid rise of injected steam observed in the depleted gas cap case resulted in much higher temperature in the upper regions of the pool, particularly those closest to the gas cap region.
- Gravity drainage is likely the most dominant mechanism enhancing drainage of oil to the horizontal well, particularly in the depleted gas cap case.

Figure 2g.1 shows the vertical cross-section through the model (FL 21RE/FL 22RE) from the areal cross-section centre row grids. It shows the zero reference point taken from where the grids are well refined close to the edge of the gas cap. Distances are taken from the zero reference towards the edge of the reservoir. It also shows the model layer numbers. The following Figures demonstrate the following:

- Figure 2g.2 shows the initial pressure of the reservoir across layers 3, 4, and 5 on 2006-12-31 for the FL 21RE (depleted gas cap) and FL 22RE (no gas depletion) prior to commencing HW CSS in the bitumen zone on 2007-01-01. The Figure shows a constant initial reservoir pressure of 2585 kPaa across the layers for FL 22RE. For FL 21RE, it shows a steep pressure gradient. It shows for FL 21RE a pressure of about 200 kPaa at the zero edge increasing steeply to 2585 kPaa towards the reservoir edge.

- Figure 2g.3, 2g.4 and 2g.5 compare the temperature profiles across top layers 3, 4, and 5 respectively after 5, 10, and 15 injection cycles for both cases. The Figures show significantly higher block temperatures for FL 21RE, the depleted gas cap case.

Cases FL21RE and FL22RE

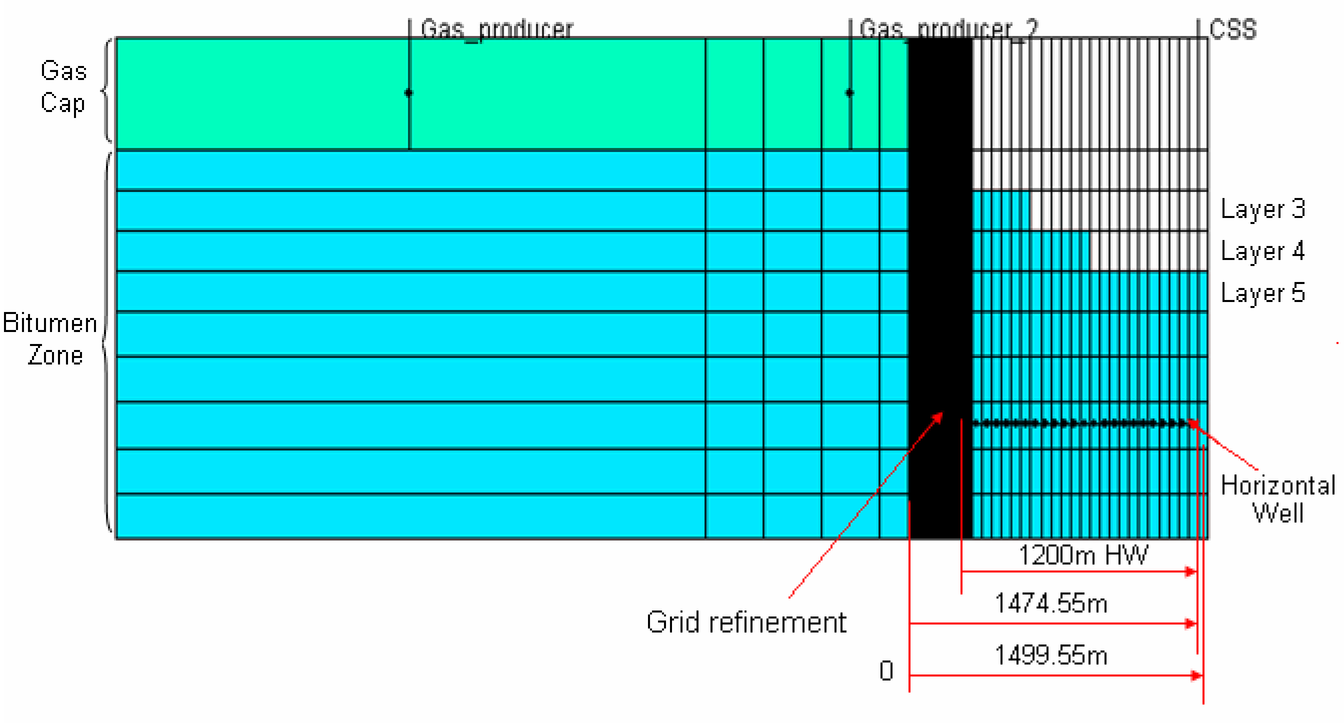

Figure 2g.1: Vertical cross-section through model for cases FL21RE and FL22RE sliced from the areal cross-section centre row grids

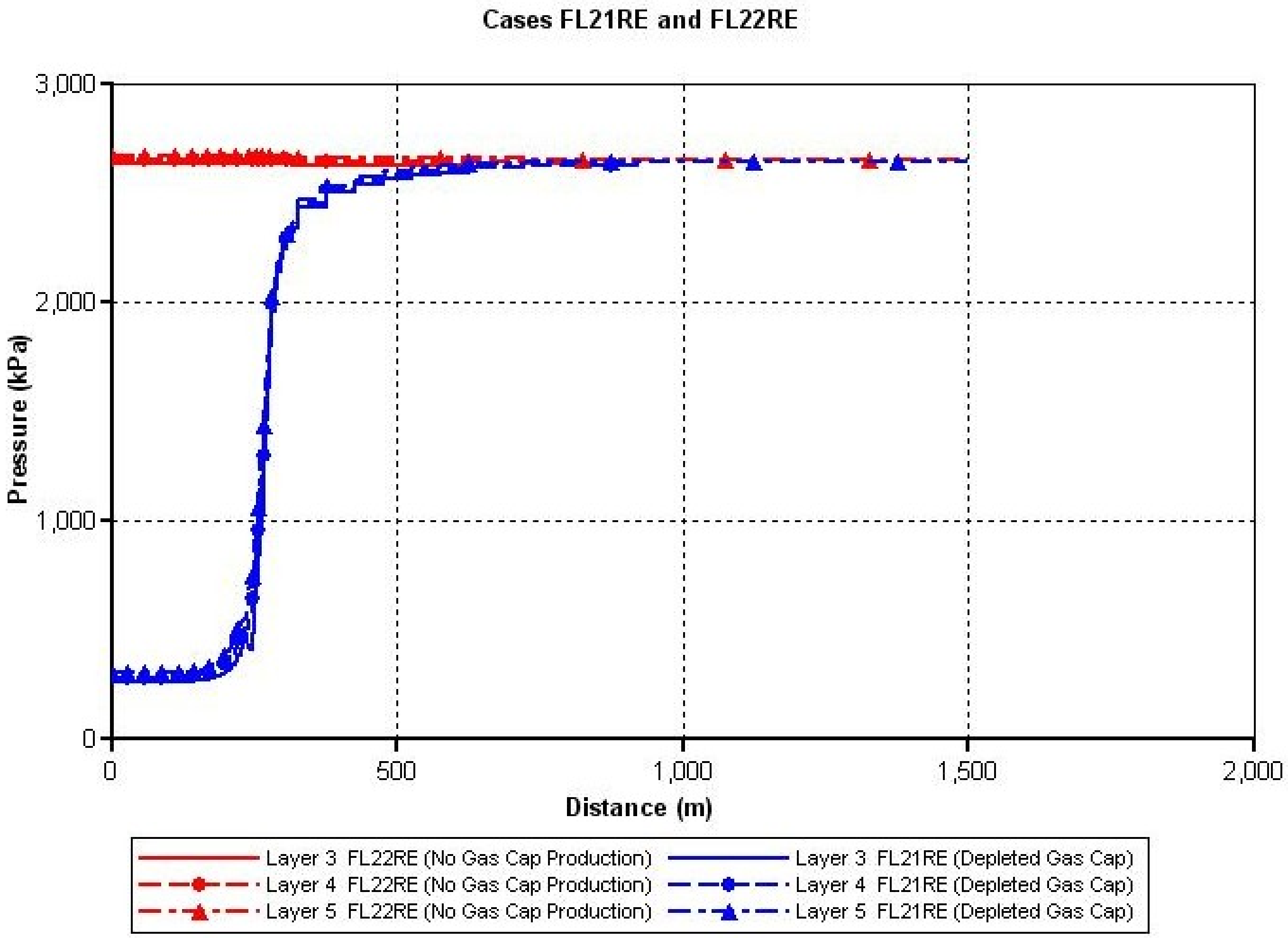

Figure 2g.2: Pressure profile after gas depletion on 2006-12-31 prior to commencing HW CSS in the bitumen zone

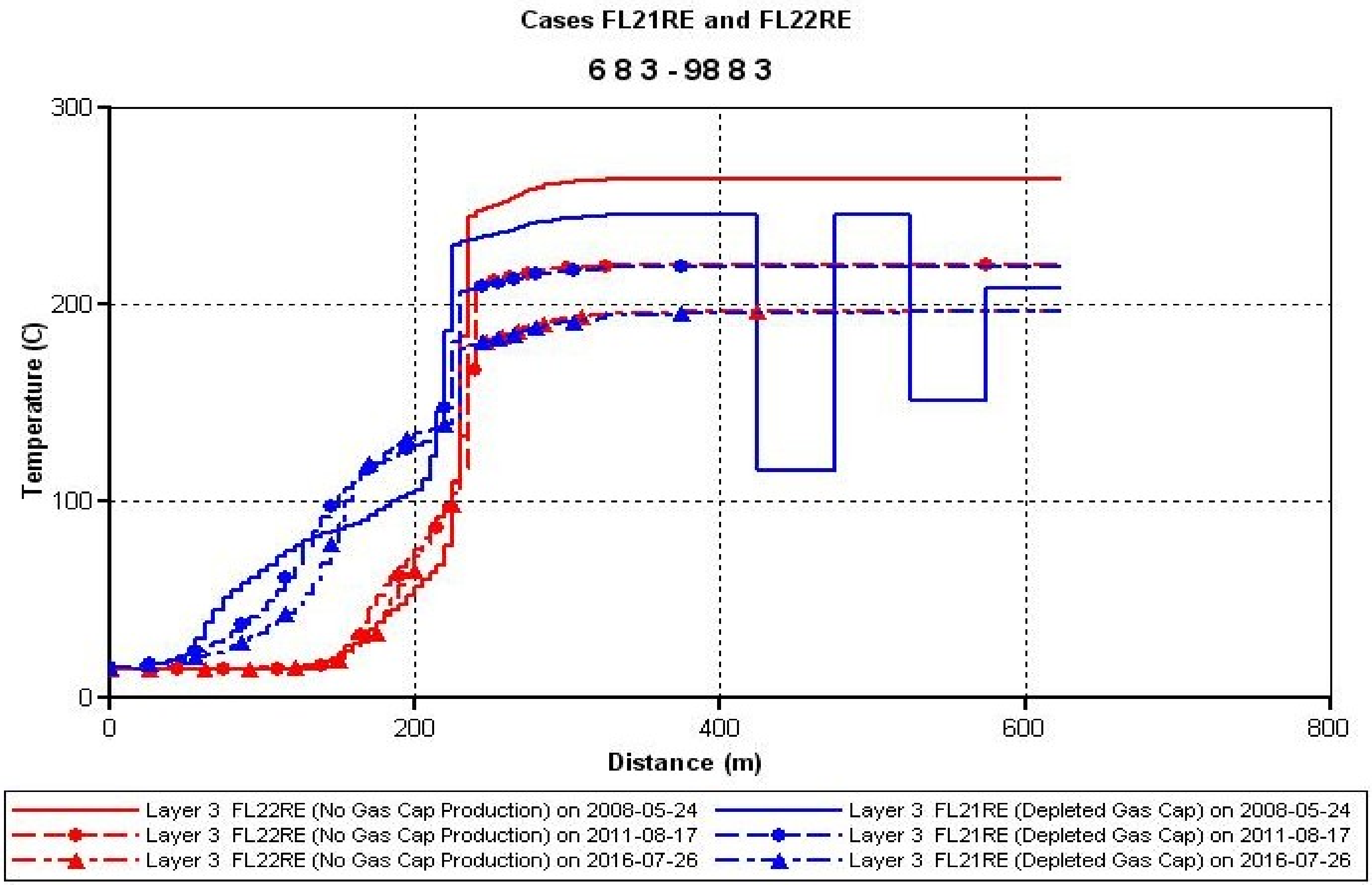

Figure 2g.3: Showing block temperatures in model Layer 3 after 5, 10 and 15 steam injection cycles

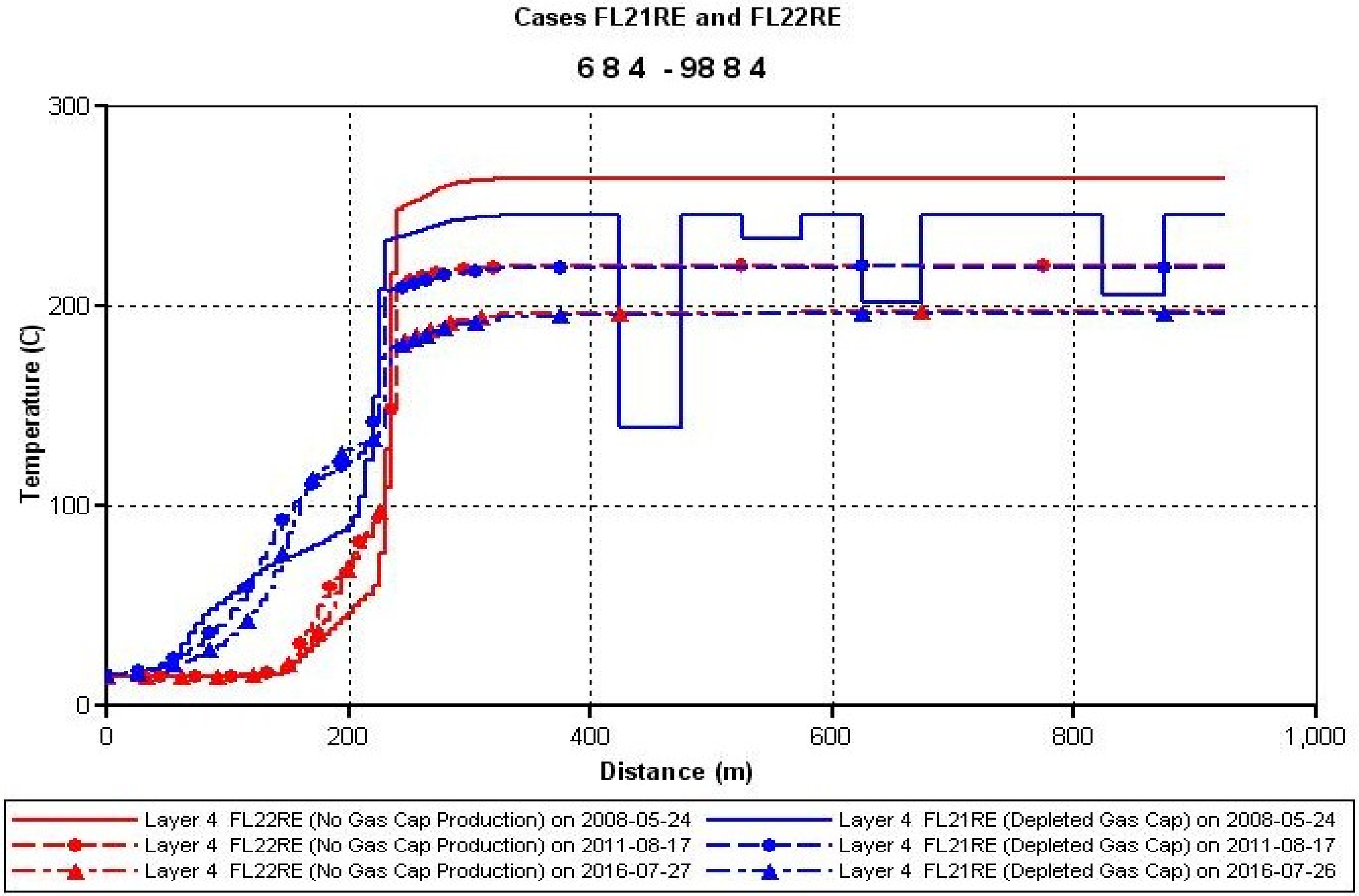

Figure 2g.4: Showing block temperatures in model Layer 4 after 5, 10 and 15 steam injection cycles

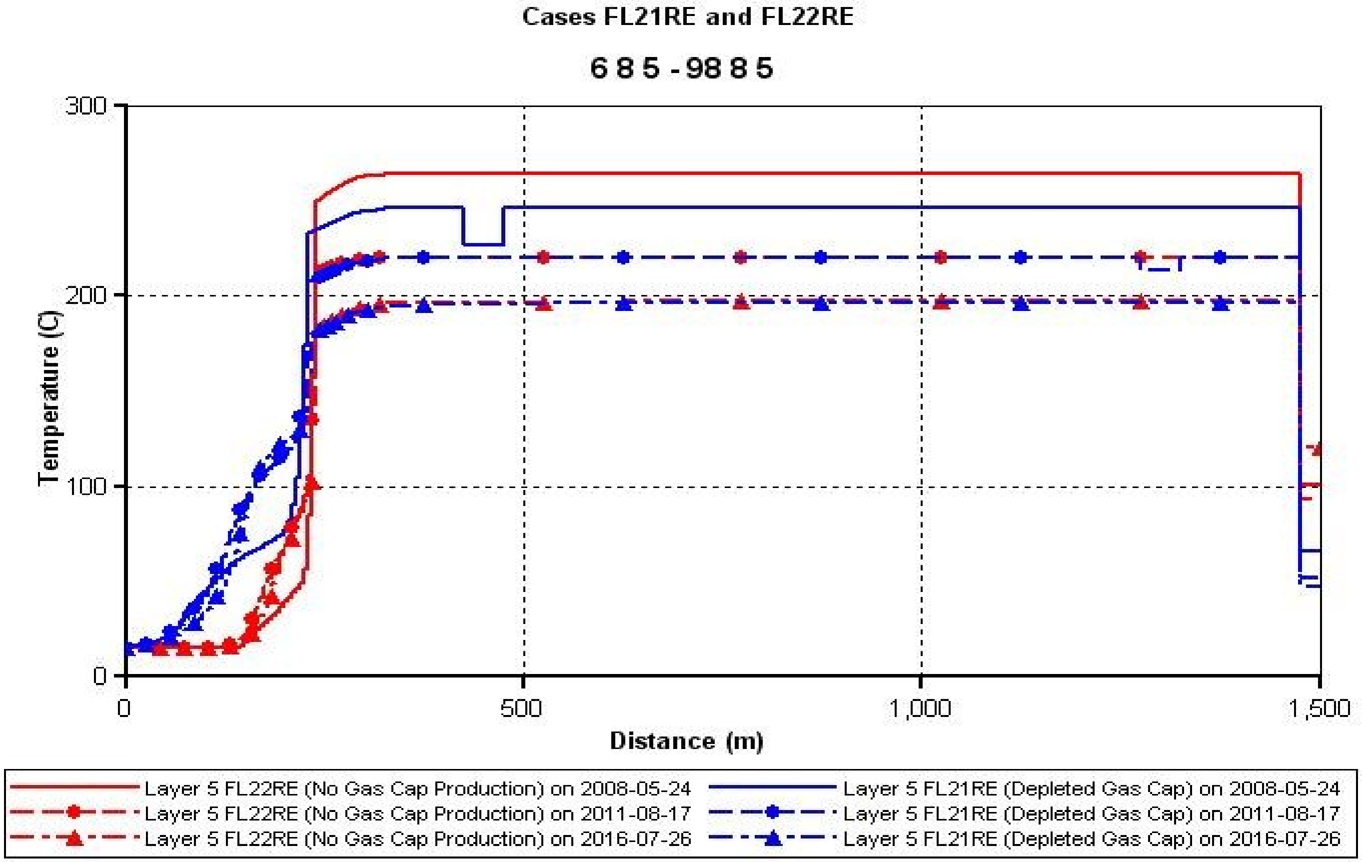

Figure 2g.5: Showing block temperatures in model Layer 5 after 5, 10 and 15 steam injection cycles

(h) **On page 6 it is stated that HW CSS bitumen recovery factors of approximately 36 and 33 % were achieved for case FL 13 (gas cap at 201 kPaa) and case FL 14 (gas cap at 2585 kPaa) respectively, and that this suggests there is no impact of gas cap gas depletion on HW CSS bitumen recovery. However, Table E.4 indicates that in case FL 13 the permeabilities of all layers were multiplied by 60 while in case FL 14 only the permeability of the well layer was multiplied by 10. Why is it appropriate to compare the recoveries of these two cases with respect to the impact of gas cap production on bitumen recovery considering the large difference in the changes to the permeabilities between the two cases?**

There was an error in reporting the maximum dilation grid block permeability multiplier constraint in Table E.4. Both cases FL 13 and FL 14 applied a maximum dilation permeability multiplier of 60 for grid blocks within the assigned horizontal well drainage volume in the bitumen zone. This error has been corrected and a revised Table E.4 is attached.

Yes, on Page 4, the two cases refer to NE 6 and NE 8. The dilation grid block treatment was the same in the models for the two cases. A maximum dilation permeability multiplier of 10 was specified within the assigned drainage volume of the horizontal well for both cases. A revised Table E.2 is attached and now shows correctly the dilation permeability multiplier used for both cases.

On page 4, the Flank reservoir (Max) having no barrier and HW CSS operations utilizing a steam injection rate of 400 m^3/d referred to cases FL 2 and FL 3 reported in Table E.4. Yes, both cases are the same except that FL 2 involved gas cap gas depletion and FL 3 had no gas cap gas depletion.

(i) **On page 7 under Fluid Properties, it is stated that published data for component properties from oil characterization for the Wolf Lake bitumen3 (where superscript 3 refers to paper SPE/DOE 17393) was used in the model. The reference does not appear to provide this information. Clarify where this information is found in the reference.**

What initial solution gas oil ratio and saturation pressure were used for the bitumen in the model?

The component properties applied in the model were same as provided in the STARS, v2005.13, dataset stflu024.dat and referenced for Wolf Lake steam injection phase (SPE/DOE 17393). This file can be located in the following STARS folder - Samples for STARS 2005.13-TPL-flu-stflu024.dat.

The initial solution gas oil ratio in the model was 5.93 m^3/m^3. The saturation pressure used for the bitumen in the model was 2585 kPaa.

(j) Tables E.2 and E.3 do not show results for the abandonment pressure (201 kPaa) case or the high steam injection rate (1000 m3/d) case for the Non-Edge and Edge models. Why is this?

One of the objectives at the start of our study was to first assess whether commencing HW CSS in a bitumen zone in direct contact with a depleted gas cap at pressure levels corresponding to current field levels of between 700 to 1200 kPaa will show significant changes in bitumen recovery compared to a similar case with no gas cap deletion. We wanted to assess this case of gas cap depletion to current pressure levels first prior to investigating cases of gas cap depletion to abandonment pressure levels of roughly 200 kPaa. Cases presented in Tables E.2 and E.3 (Edge and Non Edge cases) show the results of these initial cases. Cases presented in Table E.4 (Flank cases) were conducted later in time and included those in which gas cap depletion to abandonment pressure of approximately 200 kPaa was investigated. Results of the Flank cases involving depletion of the gas cap to 200 kPaa indicated that there is no adverse effects of gas cap depletion on HW CSS bitumen recovery factor. Due to time limitations we did not conduct cases with gas cap depletion to abandonment pressure levels of 200 kPaa for the Non Edge and the Edge cases.

It is our belief that the results of the Non Edge and the Edge cases in Table E.2 and E.3 to abandonment pressure will be consistent with those reported in Table E.4 for the Flank cases and will show no impact of gas cap depletion to abandonment pressure on HW CSS bitumen recovery. Some cases are currently being run to confirm this. We will provide the results of these cases when they are completed

(k) On Table E.3, cases ED 1, 2, 3 and 4 have the same gas pay and initial water saturation but cases ED 1 and 2 have a different gas cap OGIP than cases ED 3 and 4. Explain why the OGIP is different.

Also on Table E.3, although cases ED 5 and 6 have the same bitumen pay as cases ED 1, 2, 3 and 4 the initial water saturations are different but the OBIP is the same for all six cases. Why isn't the OBIP for cases ED 5 and 6 lower since these cases have higher initial water saturations?

In cases ED 3 and 4 reported in Table E.3 we modified the volume of the gas cap by applying a pore volume multiplier of 3.2 to make the OGIP/OBIP ratio of ED 3 and ED 4 identical to that of cases NE 9, NE 10, NE 11, and NE 12 (Table E.2). ED 3 and ED 4 were sensitivity cases to assess any impact of an increased gas cap size to that in cases ED 1 and ED 2. Results presented in Table E.3 shows no impact of OGIP/OBIP ratio on HW CSS bitumen recovery factor regardless of gas cap depletion.

There were errors in the OBIP reported for cases ED 5 and ED 6 in Table E.3. The OBIP of these cases in the model was 1.26 E+06 m^3. A revised Table E.3 is attached.

(l) **With respect to Tables E.3 and E.4 there is a column titled "Cumulative Gas Produced from GasCap in CSS" that contains both positive and negative values. What do the negative values for the cumulative gas produced from the gas cap in CSS mean? Also with respect to Table E.4, provide the results for case FL 5 (only the description is provided).**

To clarify Tables E.2, E.3 and E.4 the column title "Cumulative Gas Produced from GasCap in CSS" is now changed to "Cumulative Gas into Bitumen Zone from Gas Cap during CSS". The negative values in this column represent cumulative gas transferred from the bitumen zone into the gas cap during the CSS operations.

Case FL 5 was not completed due to time limitation. This case is now being completed and results will be provided when it is available.

(m) **Tables 2.1 to 2.3 provide the reservoir description parameters, which include the horizontal permeability and kv/kh values for the gas, bitumen, and shale zones in the model. Provide the data source for these values.**

Explain why it is appropriate to use homogenous descriptions of the gas and bitumen zones.

The cases described in the study show permeability multipliers of up to 60 times the initial values used in the study. Considering the high initial permeabilities for the gas and bitumen zones, why is it appropriate to use permeability multipliers of up to 60?

The source of data in Tables 2.1 to 2.3 is the following:

A porosity of 0.33 and an initial gas saturation of 0.75 are in the ballpark of data provided by CNRL for gas pools in its July 4, 2006 submission to the EUB. A critical water saturation of 0.20 applied in the gas cap was assumed.

A porosity of 0.1 and permeability of 0.01 applied in the shale barrier were assumed. Please note that a k-direction transmissibility multiplier of zero was applied between the gas cap and shale barrier and between shale barrier and the bitumen zone. Therefore, there was no fluid and pressure communication in the vertical direction between the shale barrier, the gas cap and the bitumen zone over the extent of the shale barrier.

A porosity of 0.33 was applied in the bitumen zone.
Source for this data is:

- Page B2-1 Section B2.1.2 of "Canadian Natural Resources Limited Primrose and Wolf Lake, Expansion 2000, Volume I, Section A, Project Description, October 2000."

A permeability of 3000 mD and Kv/Kh ratio of 0.2 applied in the bitumen zone.

Source for these data is:

- Page B2-1 Section B2.1.2 of "Canadian Natural Resources Limited Primrose and Wolf Lake, Expansion 2000, Volume I, Section A, Project Description, October 2000."

The original gas cap permeability was assumed at 1500 mD. However, for sensitivity purposes, the permeability values applied in the gas cap range from 1500 to 7500 mD depending on the case. Tables E.2 to E.4 now list the gas cap permeability inputs into the model for each of the cases. Please note that these variations in the gas cap permeability readily provide a sensitivity of the impact of the gas cap permeability on HW CSS bitumen recovery factor. No adverse effects of gas cap permeability on bitumen recovery factor were observed in all the cases investigated.

An initial oil saturation of 0.55 was applied. This value was assumed to represent the range of initial oil saturation presented for Clearwater bitumen in this area.

An initial mobile water saturation of 0.01 (Table 2.3 initial oil saturation of 0.539, initial water saturation of 0.461, and critical water saturation of 0.45) was input for sensitivity purposes to assess the impact of mobile water saturation on HW CSS bitumen recovery factor. These data were assumed.

In our investigation of the impact of gas cap depletion on HW CSS bitumen recovery factor we applied a simple model using homogeneous reservoir description because it allows us to gain a better understanding of the key performance drivers of the process in the model more easily and more quickly than the application of heterogeneous models. Use of heterogeneous reservoir descriptions will likely make analysis and understanding of the results from the model more complex. An increase in heterogeneity will most likely reduce bitumen recovery factor in all cases conducted but will not have any significant impact on the relative results between depleted and undepleted gas cap cases. We believe that the overall conclusion of this study that depletion of gas cap does not adversely impact HW CSS bitumen recovery factors will likely remain valid with use of appropriate heterogeneous reservoir descriptions in the model.

Contrary to what is stated in the question, a permeability multiplier factor was not used to scale up directly the permeability of the grid blocks. Please note that the Table column referred to in the question had a heading "Dilation Grid Block Treatment" and as such the permeability multiplier factor reported in Tables E.2 to E.4 are porosity dependent as per equations 1 and 2 in the deformation or dilation model applied (SPE 18752, STARS User's Guide, "Dilation/Recompaction Model", STARS User's Guide, v2005.13, page 252).

Imperial Oil Limited applied the deformation model permeability multiplier factor to include the effects of tensile fracturing caused in the reservoir during steam injection in the Cold Lake reservoir. A dilation permeability multiplier factor of up to 60 was applied in the fracture gridblocks to history match multiwell CSS process in Cold Lake (SPE 20743). Strictly, the permeability multiplier factor is general derived from history matching and applied in the tensile fracture region caused by steam injection. In general, the induced fracture regions in the field are not known to a high degree of accuracy and it is determined in the model by matching historical data including fluid production, pressure, temperature and energy production. The multiplier factor and the assigned fracture regions (gridblocks) in the model serve primarily to allow steam injection and appropriate spreading of the injected steam in the reservoir.

In this study, sensitivity runs were carried out to test the impact of permeability multiplier factor and the location of the gridblocks where the permeability enhancement (dilation model) at the steam injection pressure was applied. Sensitivity cases include multiplier factors of 10, 30 and 60 in the well layer gridblocks and 10, 30 and 60 in the assigned horizontal well drainage volume in the bitumen zone. The wide range of dilation permeability multiplier factor and assigned fracture gridblocks allow us to scope the impact of these dilation variables. Note that assigned fracture gridblocks and dilation permeability multiplier factors were the same for cases that are being compared (i.e., undepleted gas cap versus depleted gas cap).

Figure 2m.1 and 2m.2 show the injection pressure and the permeability in assigned fracture well gridblocks as a result of the specified dilation permeability multiplier factor of 60 for FL 21RE and FL 22RE cases.

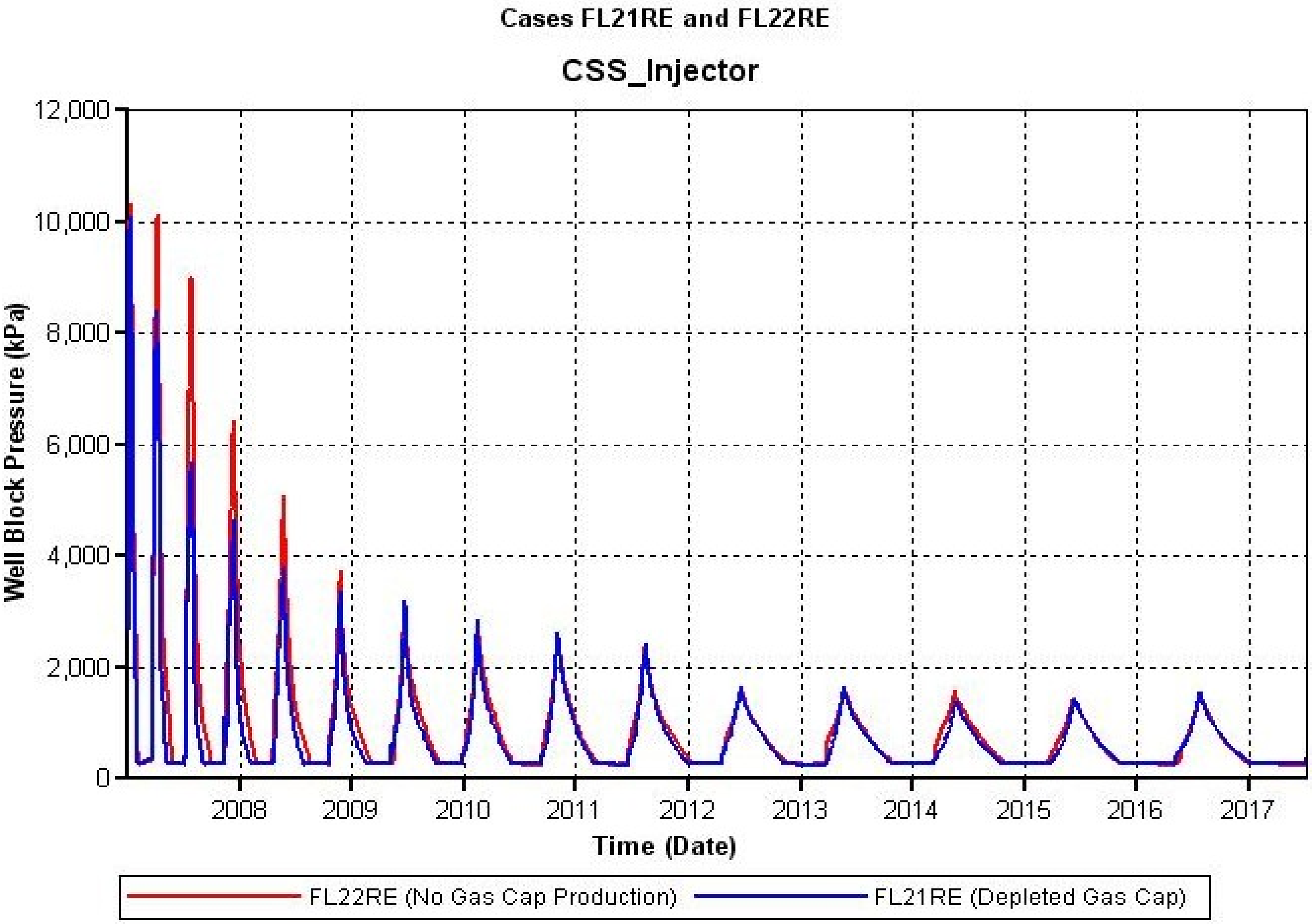

Figure 2m.1: Showing well block pressure for cases FL2RE and FL22RE using a dilation permeability multiplier factor of 60

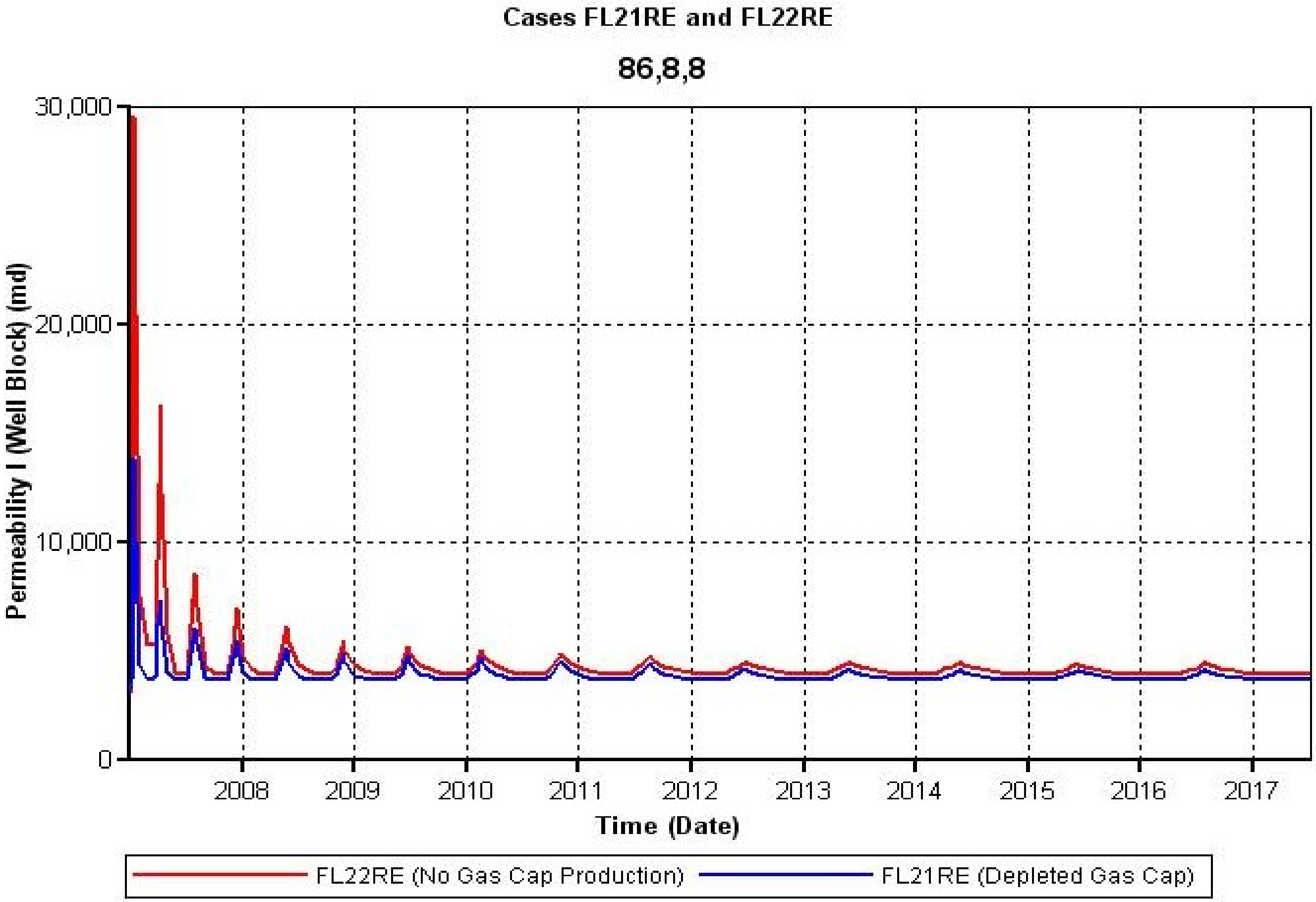

Figure 2m.2: Showing well block permeability for cases FL21RE and FL22RE using a dilation permeability multiplier factor of 60

(n) **On page 2 it is stated that the CSS operations were conducted in a total of 26 injection and production cycles covering a total of 26 years. Discuss why a limit of 26 cycles was used rather than an economic limit.**

With respect to Table 2.6, clarify the steam volume for injector cycle 1. Why is the cumulative steam (3750 m3) less than the cycle size (15000 m3)?

I would like to make a correction to the items on page 2 stating "The CSS operations were conducted in a total of 26 injection and production cycles covering a total of 26 years."

The 26 injection and production cycle covered a total of 30 years as per the cycle schedule provided in Table 2.6 of EnCana's September 5 submission.

We did not apply an economic cut-off because CNRL has not provided any economic data. Also, since the models are single well based, economic cut-off could be manually applied on the performance results.

The cumulative steam injection data reported in Table 2.6 were incorrect. We have attached a revised Table 2.6.

(o) **Provide copies of references 2, 3, and 5.**

Copies of all references are attached.