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January 19, 2007

Mr. D.G. Davies
McCarthy Tétrault LLP
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Mr. Patrick J. McGovern
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#1900, 736 - 6th Avenue S.W.
Calgary, AB T2P 3T7

Mr. Gary D. Perkins
Alberta Energy and Utilities Board
8th Floor, Application Branch, EUB
640-5th Avenue SW
Calgary, Alberta T2P 3G4

Dear Mr. Davies:

Re: EUB Application Nos. 1394112, 1409180 and 1481725
Cold Lake Oil Sands Area - Clearwater Deposit

Attached are the responses of Husky Energy to the Information Requests of Board Staff. We are currently obtaining an electronic copy of the attachment, and will forward this attachment in electronic form when received.

Yours truly,

BORDEN LADNER GERVAIS LLP

RANDALL W. BLOCK

enclosure (hard drive)

cc: Ms. Susan Anderson, Husky Oil Operations Ltd.

::ODMA\PCDOCS\CAL01\262811\1

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Jan 19, 2007

Husky Response to Board Staff questions on Husky's January 8, 2007 submission (Jan 12, 2007)

1. With respect to Husky's geostatistical modeling:

a) Provide the details of Husky's geostatistical modeling, including a detailed discussion of how Husky 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).

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- Facies were simulated using General Mark Point Process conditioned to the four wells and biased to vertical and laterally mapped deterministic facies trends.

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- Water saturation was populated within the previously modeled facies using Sequential Gaussian Simulation co-simulated with the previously modeled porosity and by assigning deterministic values.
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- Vertical permeability was populated by applying the core horizontal permeability to Kv-Kh ratio transform to the previously populated horizontal permeability. The vertical permeability model was calculated by multiplying the Kv-Kh model by the horizontal permeability model.

D. Uncertainty analysis

- Due to time constraints only one realization was run and this was used in the numerical simulation study reported. It should be noted that all realizations generated in a geostatistical model are considered equiprobable. In this context, the model used in this study is representative of the uncertainties associated with characterizing the Clearwater formation. The numerical simulations conducted with the model is a fair representation of the analysis of the risk to the bitumen resource due to gas cap depletion.

Given the multivariate setting of the geostatistical model (as opposed to univariate setting), the exact positioning of each of the facies will be different in each realization. However, it should be noted that the size of the model is significantly larger than the size of the heterogeneities and, thus, it becomes reasonable to use just one realization³. The variability averages out over different locations and on average the composite effect on the thermal recovery process will be similar.

b) On page 5 Husky states that the area covered by the geostatistical model contains four wells. Comment on why four wells provide sufficient data to construct a geostatistical model.

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Our learnings from the over all field facies modeling based on all the existing wells in the area is incorporated into the model under consideration in this study as well. The structural surfaces for the facies used in the model were generated using the data over the entire 15 section Husky lease and were cropped for the area of interest. The resulting model captures the heterogeneity of the Clearwater formation in the Caribou area.

Consequently, we believe that a geostatistical model that is generated by honouring the available well data presents a more realistic representation of the field and will provide more accurate estimation of the effect of gas cap depletion on the bitumen recovery. This is especially true when contrasted with a deterministic model that assumes continuity over a long range and does not honour any well data in particular. If one wants to understand the risk to the bitumen resource, it is essential that an unbiased geological model is utilized in evaluation of the risks. A geostatistical model presents the best estimate of the details of geology through unbiased characterization of uncertainty having minimal variance of the error of estimation.

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c) Table 1 on page 14 indicates the spacing between the SAGD and HWCSS wells in the HSAGD model was about 100 m. In Husky's October 3, 2006 submission in response to question 4 of the EUB information request, Husky indicated the spacing between the SAGD and HWCSS wells would be 60 m. Why did Husky use a different well spacing in the model than was shown in its October 3, 2006 submission?

Husky's Response:

The optimization of HSAGD is an ongoing process. Our initial work considered a well spacing of 60 m. Other operators in the area (CNRL and Imperial) use a well spacing for CSS of up to 170 m. Consequently, as a compromise, we utilized a well spacing of 100 m in our recent submission.

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• If it is correct:

i. Explain how this arrangement of gas and bitumen would occur.

Husky's Response:

The models are generic test cases for evaluating the impact of gas cap depletion on HSAGD and CSS. The models are flat because in the area of interest the top and the bottom of the reservoir are reasonably flat. The inclusions of such refinements are unnecessary when looking at the size of the model used in this study. The gas-bitumen interface is slightly tilted but this has no impact on model results.

ii. Comment on whether this would prevent the gas zone from acting as a thief zone for the thermal operations since the

gas zone is not present above the thermal operations, and possibly result in the model underestimating the effect of gas zone depletion on thermal bitumen recovery.

Husky's Response:

There is a possibility that the top gas zone where present will act as a thief zone for steam. This is even more likely during the CSS operations where the steam injection pressures are above the formation fracture pressures. Consequently, we concur with the Board that our model presents a conservative estimate of the effect of gas cap depletion on the bitumen recovery. The models with the offset gas pool reveal that as a consequence of gas pool depressurization, solution gas removal from the bitumen throughout the reservoir has a large impact on the performance of the process. In the case where the gas pool sits above the wells, the impact of gas depletion on thermal process performance will be larger because not only is the solution gas effect present but also the steam chambers and top gas zone would interact and there would be direct steam losses. Simulation studies have shown that SAGD operated with a lower pressure top gas zone can lead to very large steam-to-oil ratios, in excess of 20 (Gates et al. 2006)⁸.

iii. Clarify whether the gas zone was modeled as a confined or unconfined gas zone and comment on the appropriateness of how the gas zone was modeled.

Husky's Response:

The gas zone is confined with a finite volume. The gas producer in the gas zone is used to deplete the gas pool pressure to the desired pressure in a time scale similar to the actual pools in the area. Therefore, we believe that the actual process of gas cap depletion is accurately simulated in the model.

It must be recalled that this model is a generic model meant to replicate the characteristics of the geology in the Caribou area. The reservoir model has been conditioned by geological inputs from the Caribou area but is meant to be a test model to determine the impact of gas pool depletion on HSAGD and CSS. Given that the volumes of the gas zone are finite, they are not unconfined. The model only contains a fraction of the gas cap gas and one method to include the extent of the gas beyond the model domain is by using grid blocks with altered volumes. For gas pool modelling, given that only depletion is occurring in the gas zone, this is a reasonable method to handle the gas pool beyond the model boundaries.

- If it is not correct, explain why by reference to the input data files.

⁸ Gates, I.D., Kenny, J., Hernandez-Hdez, I.L., Bunio, G.L., "Steam Injection Strategy and Energetics of Steam-Assisted Gravity Drainage", SPE 97742. Accepted for publication in SPE Reservoir Evaluation and Engineering Journal.

e) The input data files appear to indicate that there was no maximum production limit specified for the HWCSS wells in both the HWCSS and HSAGD models, and the output files appear to show that the predicted bitumen production rates at the beginning of the production cycles for the HWCSS wells were extremely high. Clarify if this is correct.

- If it is correct, explain why Husky did not include a maximum production limit and discuss what effect this has on the model predictions.

Husky's Response:

We did not include a maximum fluid rate because these peak rates are short lived and the rates decline to more realistic numbers for the majority of the production period. By limiting the maximum production rate, more of the reservoir energy is retained by preventing steam from flashing in the reservoir. This would have the effect of maintaining higher production rates for longer intervals. However, as mentioned before, the process is not optimized with respect to cycle length and volumes injected. Therefore, it was felt that putting a production limit would restrict the wells unnecessarily. The average numbers and differences between the cases run would remain the same in the case where production limits are imposed. Additional simulation runs with a rate constraint do not alter the conclusions that gas depletion significantly increases to the bitumen resource.

- If it is not correct, explain why by reference to the input and output data files.

f) Comment on why the simulations were terminated at a particular time rather than at an economic limit.

Husky's Response:

There is chance that an imposed economic limit may skew the results. The HSAGD process utilizes both SAGD and CSS wells. Since the injection and production profiles of both well types vary significantly between different process stages, a simple criterion such as economic limits may not be appropriate to use and risk shortening the operating life prematurely. Thus, it was decided to run the cases for a sufficiently long time to see the full reservoir response. We believe the ultimate economic assessment should best be performed by using an economic model. However, the cSOR's are a first order measure of the economics of the process and show a clear distinction between the depleted and undepleted cases over the time range of the simulations.

g) On page 18 Husky states that the predicted negative effect of adjacent gas cap depletion is expected to be more pronounced with larger well spacing.

Explain why Husky believes this would occur.

Husky's Response:

Initially in HSAGD, the SAGD wellpair and HWCSS well do not directly interact in that the steam chambers from each are not in direct contact. Later on, the steam chambers from both are large enough so that they become in direct contact with each other. A key benefit of the HSAGD process is the ability of the HWCSS well to become a producer-only well with steam being supplied to the combined chamber from the SAGD wellpair. This means that steam is injected through a single well and production occurs from two wells. Thus the economics of the overall HSAGD triplet pattern are improved over SAGD because only three wells are used instead of four. The larger the well spacing the longer it takes for the steam chambers to interact in the HSAGD process and thus the longer it takes to evolve to the single injector-dual producer operating state. If the well spacing is larger, then there is more reservoir between the SAGD wellpair and HWCSS well which under gas pool depressurization will become solution gas depleted. Thus, the oil in between the SAGD wellpair and HWCSS well becomes less "live" and its viscosity goes up. Consequently, the larger the well spacing, the larger the impact of gas pool pressure depletion on HSAGD given the energy and time required to stimulate this larger amount of less "live" oil. Simulation runs have been done which confirm this result.

3. Provide copies of the appropriate part of reference 4 and references 5, 6, and 7.

Husky's Response:

References are attached.

Jan 19, 2007

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Husky's Response:

The gas zone is confined with a finite volume. The gas producer in the gas zone is used to deplete the gas pool pressure to the desired pressure in a time scale similar to the actual pools in the area. Therefore, we believe that the actual process of gas cap depletion is accurately simulated in the model.

It must be recalled that this model is a generic model meant to replicate the characteristics of the geology in the Caribou area. The reservoir model has been conditioned by geological inputs from the Caribou area but is meant to be a test model to determine the impact of gas pool depletion on HSAGD and CSS. Given that the volumes of the gas zone are finite, they are not unconfined. The model only contains a fraction of the gas cap gas and one method to include the extent of the gas beyond the model domain is by using grid blocks with altered volumes. For gas pool modelling, given that only depletion is occurring in the gas zone, this is a reasonable method to handle the gas pool beyond the model boundaries.

- If it is not correct, explain why by reference to the input data files.

⁸ Gates, I.D., Kenny, J., Hernandez-Hdez, I.L., Bunio, G.L., "Steam Injection Strategy and Energetics of Steam-Assisted Gravity Drainage", SPE 97742. Accepted for publication in SPE Reservoir Evaluation and Engineering Journal.

e) The input data files appear to indicate that there was no maximum production limit specified for the HWCSS wells in both the HWCSS and HSAGD models, and the output files appear to show that the predicted bitumen production rates at the beginning of the production cycles for the HWCSS wells were extremely high. Clarify if this is correct.

- If it is correct, explain why Husky did not include a maximum production limit and discuss what effect this has on the model predictions.

Husky's Response:

We did not include a maximum fluid rate because these peak rates are short lived and the rates decline to more realistic numbers for the majority of the production period. By limiting the maximum production rate, more of the reservoir energy is retained by preventing steam from flashing in the reservoir. This would have the effect of maintaining higher production rates for longer intervals. However, as mentioned before, the process is not optimized with respect to cycle length and volumes injected. Therefore, it was felt that putting a production limit would restrict the wells unnecessarily. The average numbers and differences between the cases run would remain the same in the case where production limits are imposed. Additional simulation runs with a rate constraint do not alter the conclusions that gas depletion significantly increases to the bitumen resource.

- If it is not correct, explain why by reference to the input and output data files.

f) Comment on why the simulations were terminated at a particular time rather than at an economic limit.

Husky's Response:

There is chance that an imposed economic limit may skew the results. The HSAGD process utilizes both SAGD and CSS wells. Since the injection and production profiles of both well types vary significantly between different process stages, a simple criterion such as economic limits may not be appropriate to use and risk shortening the operating life prematurely. Thus, it was decided to run the cases for a sufficiently long time to see the full reservoir response. We believe the ultimate economic assessment should best be performed by using an economic model. However, the cSOR's are a first order measure of the economics of the process and show a clear distinction between the depleted and undepleted cases over the time range of the simulations.

g) On page 18 Husky states that the predicted negative effect of adjacent gas cap depletion is expected to be more pronounced with larger well spacing.

Explain why Husky believes this would occur.

Husky's Response:

Initially in HSAGD, the SAGD wellpair and HWCSS well do not directly interact in that the steam chambers from each are not in direct contact. Later on, the steam chambers from both are large enough so that they become in direct contact with each other. A key benefit of the HSAGD process is the ability of the HWCSS well to become a producer-only well with steam being supplied to the combined chamber from the SAGD wellpair. This means that steam is injected through a single well and production occurs from two wells. Thus the economics of the overall HSAGD triplet pattern are improved over SAGD because only three wells are used instead of four. The larger the well spacing the longer it takes for the steam chambers to interact in the HSAGD process and thus the longer it takes to evolve to the single injector-dual producer operating state. If the well spacing is larger, then there is more reservoir between the SAGD wellpair and HWCSS well which under gas pool depressurization will become solution gas depleted. Thus, the oil in between the SAGD wellpair and HWCSS well becomes less "live" and its viscosity goes up. Consequently, the larger the well spacing, the larger the impact of gas pool pressure depletion on HSAGD given the energy and time required to stimulate this larger amount of less "live" oil. Simulation runs have been done which confirm this result.

3. Provide copies of the appropriate part of reference 4 and references 5, 6, and 7.

Husky's Response:

References are attached.