February 14, 2007

Husky's Response to February 7, 2007 Board staff information requests

1. In its January 30, 2007 submission, Husky provided the input and output files for the runs using its 2D HWCSS and HSAGD models with a maximum liquid production constraint.

a) The input files indicate that Husky used a maximum liquid production constraint of 750 m^3/d for the depleted and undepleted HSAGD cases and the undepleted HWCSS case, but it used a constraint of 1500 m^3/d for the depleted HWCSS case. Why did Husky use a different constraint for the depleted HWCSS case? Provide input and output files for the depleted HWCSS case with a liquid production constraint of 750 m^3/d.

Husky's Response:

Using a different liquid constraint for the depleted HWCSS case was an oversight. The depleted HWCSS case was rerun with 750 m3/d liquid constraint, input and output files are attached. Despite the smaller difference in the performances between the two cases, the results indicate a similar trend that the depleted reservoir has risk on the process performance.

The consequence of the total liquid rate constraint has to be commented on. If the total liquid constraint is used and the CSS CDSR (calendar day steam rate) string is chosen incorrectly, then one consequence of the process performance is that the impact of solution gas drive on the process is suppressed. This means that the delta between depleted and non-depleted cases is reduced but this is a total consequence of the chosen operating strategy where the delivery of oil to the wellbore by solution gas is suppressed. However, in the field, it has been well established that solution gas drive is a major production mechanism for CSS and that viable commercial operating strategies must include oil delivery by this mechanism.

Earlier simulation runs, without the liquid constraint, reflect the unconstrained case where the reservoir deliverability is the key constraint on the process. This means that the physics of the process in the reservoir is controlling the oil delivery to the wellbore and the true effect of reduction of solution gas, both its viscosity impact and as a drive mechanism, is reflected when the performances of the processes are compared. With the liquid constraint in place, the reservoir deliverability no longer controls but now the well constraint does. Given alternate operating strategies that can be used, including ones similar to how CNRL practices CSS in the same reservoir in the field, the risk to the resource from solution gas removal is still demonstrated by the earlier runs and the ones presented here.

b) The input files indicate that the convergence criteria used by Husky were different than STAR's default convergence criteria. Provide input and output files for all four cases using STAR's default convergence criteria and a maximum liquid production constraint of 750 m^3/d. Also provide comparison plots of the predicted bitumen recoveries versus time for the January 30, 2007 runs and the new runs.

Husky's Response:

The input and output files for the new runs with the same liquid constraint and default convergence criteria are attached. Also included are the bitumen recovery and cSOR plots for these runs. As in Question 1a, the results still demonstrate that the process performance is impacted by solution gas depletion. The total liquid flow rate well constraint controls the oil delivery from the reservoir and to some extent suppresses the impact of solution gas drive on the process. With this operating constraint, together with the operating strategy that was employed, the simulation results do not reflect the total impact of solution gas depletion on process performance. As suggested above, the runs done earlier without the liquid constraint indicate the reservoir-limited process performance and the impact of solution gas depletion both through the viscosity difference and the reduction of the solution gas drive mechanism.

It should be noted that these runs have not been fully optimized at present. The current runs with the liquid constraint still suggest that the removal of solution gas impacts the process performance but because the impact of solution gas depletion is suppressed, the delta between the results is smaller than before. A commercial HSAGD and HWCSS process would be designed and operated to take full advantage of solution gas drive and therefore the delta between the depleted and non-depleted results strongly suggest that the performance directionally suffers with solution gas depletion and that the risk is significant enough that gas production must be stopped before more solution gas is removed from the bitumen resource.

2. Provide copies of references 1, 8, 9, 10, and 12 listed on page 27 of Husky's January 30, 2007 submission.

Husky's Response:

References are attached. Reference 10 will be provided shortly.