Innovative Energy Technologies Program
Approval 03-055
Taber Glauconitic K Pool

Alkaline-Surfactant-Polymer Flood Using Surfactants Derived from Renewable Resources

Crowsnest ASP Flood

2008 Annual Report
July 22, 2009

Table of Contents

1. Executive Summary

Husky Oil Operations Limited implemented the first field-wide Alkaline-Surfactant-Polymer (ASP) Flood using surfactants derived from renewable resources on January 23, 2008.

The co-surfactants are a blend of sodium lignosulfonate (lignin) and alkyl polyglycosides (APG). Lignin is a natural polymer that binds a tree together. Lignosulfonates can act as both a binder and a dispersant and these qualities can enhance the efficiency of ASP systems. APGs are an agricultural crop based combination of fatty alcohols and glucose, mostly used in personal care formulations, cleaners, and agricultural formulations, and are readily biodegradable.

Incremental oil production is expected to be 792 10^3m^3 from the Taber Glauconitic K pool, an incremental oil recovery factor equal to 15.5% of the original-oil-in-place (OOIP). Ultimate production is estimated to be 10% higher using green chemistry based surfactants than the ASP system using conventional surfactants.

Pool production was 26 m^3/d oil and with an oil cut of 0.9% when ASP injection began in January 2008 and production as of June 2009 was 85m^3/d oil and 3.3% oil cut.

2. Summary Project Status Report

Key Team Members

Key team members are shown in Table 1. Gilbert Chen was added to the team based on his involvement with ASP floods in China. His expertise is ASP chemicals and their interactions with the reservoir. Lee McInnis has over 10 years experience in various oil properties in Western Canada and Krystle Drover is an E.I.T. that was operating on site during facility construction and trained operators on laboratory quality control procedures. She is now added to the team as a production engineer.

Table 1: *Key Team Members*

Name	Title	Expertise Added
Ran Lin	Reservoir Engineering Specialist	Reservoir Engineering Ph.D., Mech. Engineering
Lee McInnis	Staff Reservoir Engineer	Reservoir Engineering B.Sc., Mech. Engineering,
Tyler Ellis-Toddington	Engineering Specialist	Project Manager, B. Sc., Chemical Engineering
David Grawbarger	Geological Specialist	Geology M. Sc., Geology M. Sc., Hydrogeology
Gilbert Chen	Staff Geologist	Facilities Engineering, Ph.D., Development Geology
Krystle Drover	Production Engineer	Production Engineering B.Sc., Mech. Engineering
Rick Reti	Field Foreman	9 years of operational experience in chemical flooding

Timeline

Tables 2 and 3 outline major activities conducted as part of the Crowsnest ASP project.

2008 Production

Oil production from the ASP project is lower than forecast due to project start-up delays and operational issues which will be discussed in Section 7. Originally, ASP injection was expected to begin in September 2007. In addition, production began at rates lower than predicted and in January 2008 oil production was 29 m^3/d below the base waterflood decline further discussed in Sections 4 and 5. Table 4 compares 2008 production to estimated production from the May 2007 IETP application.

Table 2: *Chronology of major activities and operations*

Activity	Description	Start	End
ASP system selected	Conventional ASP system selected	2000	2001
Identify and evaluate ASP Alternatives	Began investigating "waste" chemicals from various industries. Came across pulp and paper by-product and research about APGs. Determined that they could be combined to improve oil recovery.	2005	January 2007
Facility Design	ASP facility design and battery modifications, long lead equipment AFE approval	August 2006	
Implement plan of development	Injection conversions, reactivations, drilling, and pipelines	November 2006	December 2007
Procure chemical suppliers	Solicit bids from chemical suppliers, award chemical contracts, and finalize logistics. Needed to get bids from conventional and "green chemistry" suppliers to compare economics.	December 2006	May 2007
Final Lab results and economics evaluation.	Performed economic evaluation comparing laboratory results, reservoir simulation, and chemical bids.	January 2007	March 2007
Management Approval	Experimental ASP system approved based on higher predicted ultimate recovery at lower costs.	March 2007	April 2007
Design scope changes for second surfactant.	Second tank, pump and different surfactant fluid properties needed to be accounted for.	March 2007	
Construction of ASP facility		April 2007	September 2007
Commissioning		October 2007	December 2007
Chemical injection beings	Staged process of soft water, A-S, then full ASP	December 2007	January 2008
ASP injection	Began January 23, 2008 – 30% PV target	January 2008	December 2009
Polymer injection	40% PV of polymer only injection chases ASP	December 2009	December 2012

Table 3: *Chronology of major activities in 2008*

Activity	Description	Start	End
ASP Injection began	A-S injection started in December 2007. Polymer deliveries delayed and full ASP injection began on January 23, 2008.	January	Present
Heater on Lignin tank	Heater failed due to coking of lignosulfonate on sheath. Decided not to repair heater.	January	March
Water quality Issues	Oil concentration in injection water increasing. Attempted new cationic clarifier which reduced oil concentrations in injected water to 10 ppm but caused 3 fire tube failures and treatment issues of the floc at multiple third party disposal facilities.	September	November
Price Issues	NaOH supplier changed and polymer contract modified due to volatility in raw materials.	June	September
Scale	Scale observed on rods at some oil wells.	November	December
WAC Coating application.	Rubber lining from WAC vessels started showing up in pump screens throughout ASP facility. Eventually applied coating to the vessels.	July	November
ASP Production Response	Two wells have shown noticeable ASP response: 2/14-20 increasing from 0% oil cut to 6 m^3/d oil at 12% oil cut and 3/15-20 increasing from 0.6 m^3/d oil, 1% oil cut to 5.5 m^3/d, 8% oil cut	October	December

Table 4: *2008 Crowsnest ASP Flood Oil Production*

	Base Waterflood	IETP Application Forecast - Unrisked			Actual		
Month	Oil Rate (m^3/d)	% PV injected	Oil Rate (m^3/d)	Oil Cut (%)	% PV injected	Oil Rate (m^3/d)	Oil Rate (m^3/d)
January	49	5.9%	60	2.1%	0.4%	20	0.8%
February	49	7.3%	60	2.1%	1.6%	26	1.0%
March	48	8.8%	63	2.2%	3.0%	31	1.2%
April	48	10.2%	74	2.6%	4.3%	35	1.3%
May	48	11.7%	74	2.6%	5.6%	39	1.4%
June	47	13.1%	75	2.6%	7.0%	39	1.3%
July	47	14.6%	84	3.0%	8.6%	42	1.3%
August	46	16.0%	90	3.2%	10.2%	48	1.5%
September	46	17.5%	97	3.4%	11.7%	51	1.6%
October	45	18.9%	107	3.8%	13.0%	53	1.9%
November	45	20.3%	118	4.2%	14.2%	57	2.0%
December	45	21.8%	129	4.6%	15.6%	69	2.4%

In the May 2007 forecast, January 2008 ASP pore volumes injected were supposed to be 5.9% and oil production was forecast to be 60 m^3/d. ASP injection did not start until January 23, 2008 and initial production was lower than originally forecast. In the original prediction, the oil rate was expected increase 30 m^3/d from 5.9% PV injection to 16.0% PV injection resulting in an oil rate of 90 m^3/d at this point in the project. In 2008, production actually increased 30 m^3/d oil from 5.6% PV injected (May 2008) to December 2008 ending the year at 69 m^3/d. The trend and magnitude of the oil rate increase is similar to forecast but actual production is 75% of the forecast which is also the probability of success that is put on the project.

Reserves

Reserves have been modified slightly based on a simulation update and actual production results to date. Expected incremental oil recovery has dropped from 16.6% in the application to 15.5% (Table 5) due to lower than expected production at this time. At the time of the application, it was stated that the green ASP system is expected to have incremental recovery that is 10% higher than that of a conventional ASP system. This remains the expectation as incremental production forecast for the Warner ASP project using a conventional surfactant has been reduced to 14.0%.

Table 5: *Reserve Summary for the Taber Glauconitic K pool*

Production Values as of June 2009	Oil Volume 10^3m^3 (MMBO)	Percent of OOIP (%)
Original Oil in Place (OOIP)	5,100 (32.1)	-
Cumulative Production to date (CTD)	1985 (12.5)	38.9%
Waterflood Ultimate Oil Production	2055 (12.9)	40.3%
ASP Forecast Ultimate Oil Production	2847 (17.9)	55.8%
Incremental Production (CTD)	3.4 (0.02)	0.07%
Remaining Incremental Production	789 (4.96)	15.4%
Total Incremental Oil Production from ASP	792 (4.98)	15.5%

The incremental production forecast in the original IETP application due to ASP injection has been reduced from 5.3 to 5.0 MMBO based on lower oil production to date.

3. Well information

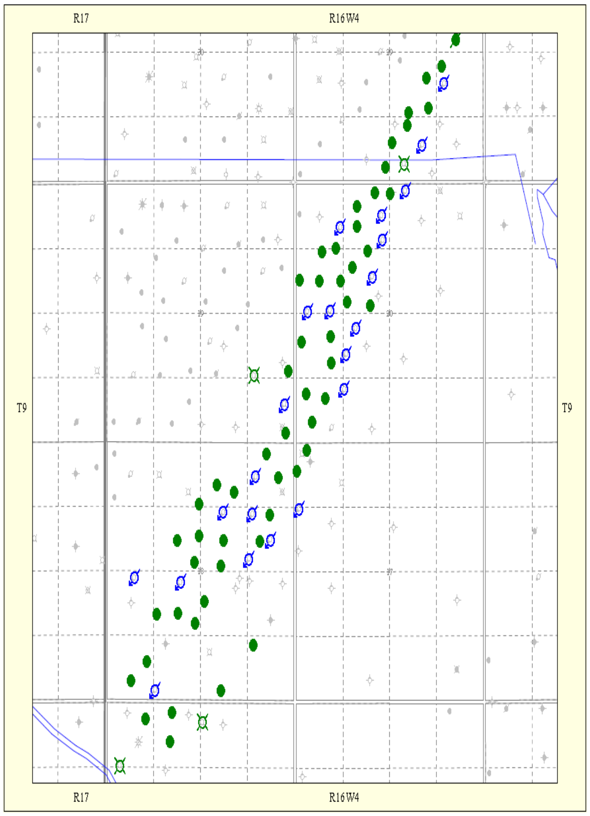

Figure 1 – Taber Glauconitic K pool in 9-16W4

Well Layout Map

Husky is a 100% working interest owner in the Crowsnest ASP flood. The Glauc K pool consists of 54 oil production wells, 21 injection wells, and 4 observation wells as shown in Figure 1. Producers and injectors may be shut-in for periods of time to achieve and balance target pore volumes injected throughout the reservoir and to maintain target voidage replacement ratios.

The 02/9-29-9-16W4 well was pipelined and reactivated May 2009. All wells in the pool are identified in *Attachment #1 - Well List and Status.*

Well operations

The objective of the plan of development was to review and utilize existing well bores, drill wells to extend the pool boundary or replace old well bores, and optimize the placement of ASP to achieve maximum incremental oil recovery.

Twenty three production wells were reactivated and one injector was converted to a producer. Nine shut-in wells and 3 producers were converted to injectors increasing the total from 12 to 22 to ensure optimum sweep efficiency and maintain injectivity until the end of chemical injection. All existing producers and injectors were reviewed for target production and optimization through the addition of perforations or well fractures treatments. To the end of June, 9 out of 27 recommendations have been carried out on production wells that were active under the base conditions in 2006. The remaining recommendations are continually re-evaluated based on production and injection results and will be preformed as required. Diesel washes were performed on 7 of 9 existing injection wells before ASP injection was started. Diesel was used for circulating out heavy oil and for multiple formation soaks. These programs were done to improve injectivity of the existing wells that, during various facility upset conditions over the history of the injector, may have injected water with higher oil concentrations. Coated tubing was installed on all existing and new injectors to reduce the internal corrosion and fouling of the near well bore region and lined tubing was ran in all producers. The results of all operations can be found in two tables in *Attachment #2 – Crowsnest Well Operations*.

Workover difficulties included typical problems, but the major issue was 100/4-20-9-16W4 which had casing that was in poor condition and had to be abandoned. The other main issue was very few Glauc K producing wells are fractured and fracture stimulations were not budgeted. While it is rare for a producer to be fractured, almost every Glauc K injector needed a fracture during injection conversion to meet targeted injection rates.

Drilling

In total there are 5 new wells. One well was drilled as an injector and four wells were drilled as producing wells. Three new drills were in the center of the reservoir and were drilled to replace 1940 vintage wells. This is the region with the best reservoir quality and highest OOIP. All these producing wells came in as expected. The fourth well was a step out well to test a seismic feature. The well only discovered 1.3 m of pay and only produces at a rate 2 m^3/d fluid. Completion results from drilled wells are listed in Attachment #2. The injection well is also a step out well and although achieved 8m of pay as expected, is injecting less than 10 m^3/d, even after the well was fractured on completion. New drilling locations were cored used a benign mud system to minimize the effect of drilling mud on the laboratory observed wettability of the core.

Wellbore schematics

Wells in the Glauc K pool are conventional medium oil wells. The well equipment is very similar and representative schematics are provided for an injector and producer:

- *Attachment #3.1 – Sample schematic for injection well 102/6-18-009-16W4*
- *Attachment #3.2 – Sample schematic for producing well 103/4-20-009-16W4*

Spacing and patterns

The project boundaries are identified in ERCB approval 10860A found in Attachment #4. The pool on average has approximately 15 acre well spacing. The injection scheme does not have a regular pattern but is a combination of peripheral injection and a modified line drive. The injectors were located to flank the structural highs that are evident throughout the pool. This injection strategy is advantageous in this reservoir as the Kv/Kh ratio is high. In order to take advantage of gravity effects, previous water injectors located in the structurally high positions were converted to producing wells.

In addition to polymer for mobility control, additional injectors were added to prevent channeling and maximize sweep efficiencies. ASP injection and production volumes will be closely monitored and will be adjusted to meet targets that are reviewed regularly. Injection rates at the wells are controlled by the used of actuated valves that have been installed at each injector that fully open or fully close the valve on the well. A daily volume target is entered at the facility and when the target volume for that injector was achieved, the well would shut-in. Most of the wells are open 24 hours a day; it is just a few of the wells with higher injectivity that are closed for a period of time throughout the day. This advancement is worth the cost and was done to ensure chemicals are placed in the reservoir for the most effective performance. The cost of chemicals is a substantial component of ASP projects.

4. Production Performance

Production History

Full ASP injection began on January 23, 2008. To the end of June 2009, the project produced 27 10^3m^3 of oil and 1,449 10^3m^3 of water. During this period, the daily oil production increased from $26m^3/d$ at 0.9% oil cut to $85m^3/d$ at 3.3% oil cut. Daily production and injection information are provided in electronically in Attachments #5 and 6.

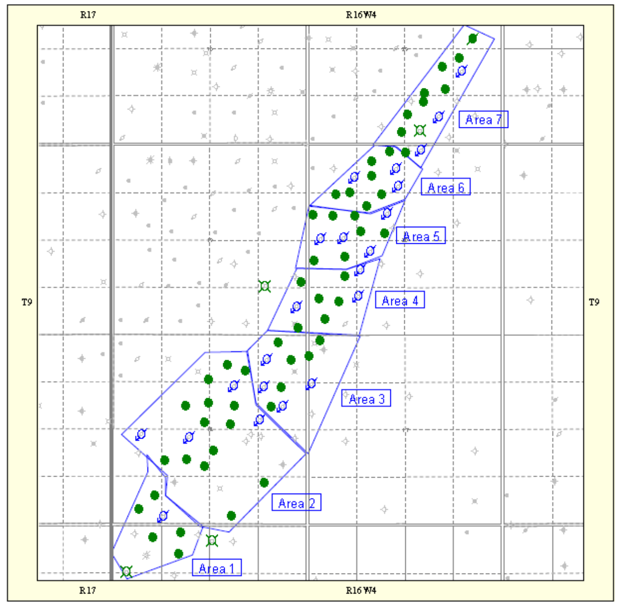

Figure 2: Crowsnest ASP Area map

The pool was divided into 7 areas (Figure 2) for monitoring purposes and efforts are continuously made to ensure both production and injection rates are optimized as much as possible in each area. Actual pool production is compared to the un-risked forecast submitted in the original IETP application in Figure 3. The oil production trend is similar, but lower, for a number of reasons:

- ASP injection began 4 months later than predicted due to facility delays.
- The forecast assumes all rig work occurred in one month. In reality 46 rig operations took over a year.
- The forecast assumes 100% run-time and is un-risked.
- When ASP injection began the oil rate was 26 m^3/d compared to $37m^3/d$ expected. In January 2008 there were 23 wells that had 100% water cut.

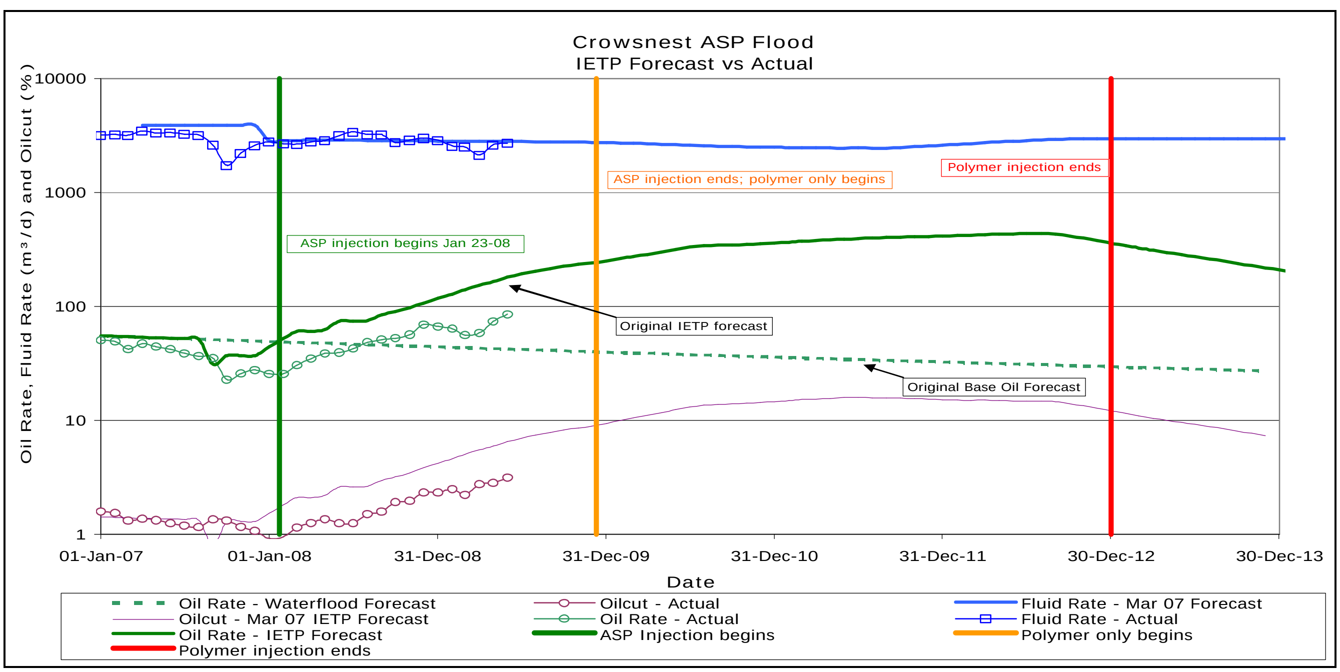

Figure 3: Comparison of production to base waterflood and May 2007 IETP ASP predictions

The best method of evaluating the performance of an ASP flood is to compare production on a basis of ASP fluid volume injected. This reduces the impact of facility delays, reduced injection rates, and other operational issues so that the affect of chemical on improved recovery can be independently evaluated. Figure 4 compares actual production to the forecast submitted in the IETP application based on reservoir pore volumes (PV) injected including a forecast assuming a 70% probability of success. Although lower than the simulation, oil production has generally been within the range expected when the project was designed. In March and April 2009, production was outside the range due to lower total fluid production but the oil cut continued to increase demonstrating the EOR process is working. To the end of June 2009 approximately 23% PV of ASP solution has been injected out of a target 30% PV. Final ASP injection is expected to be completed in December 2009 and will be followed by 40% PV of polymer solution. Based on predictions from the model, oil production is expected to increase from 49m^3/d in June 2006 under waterflood to a peak oil rate over 400 m^3/d approximately 4.5 years after ASP injection begins. Oil cuts are expected to increase from 1.5% to 15.1%.

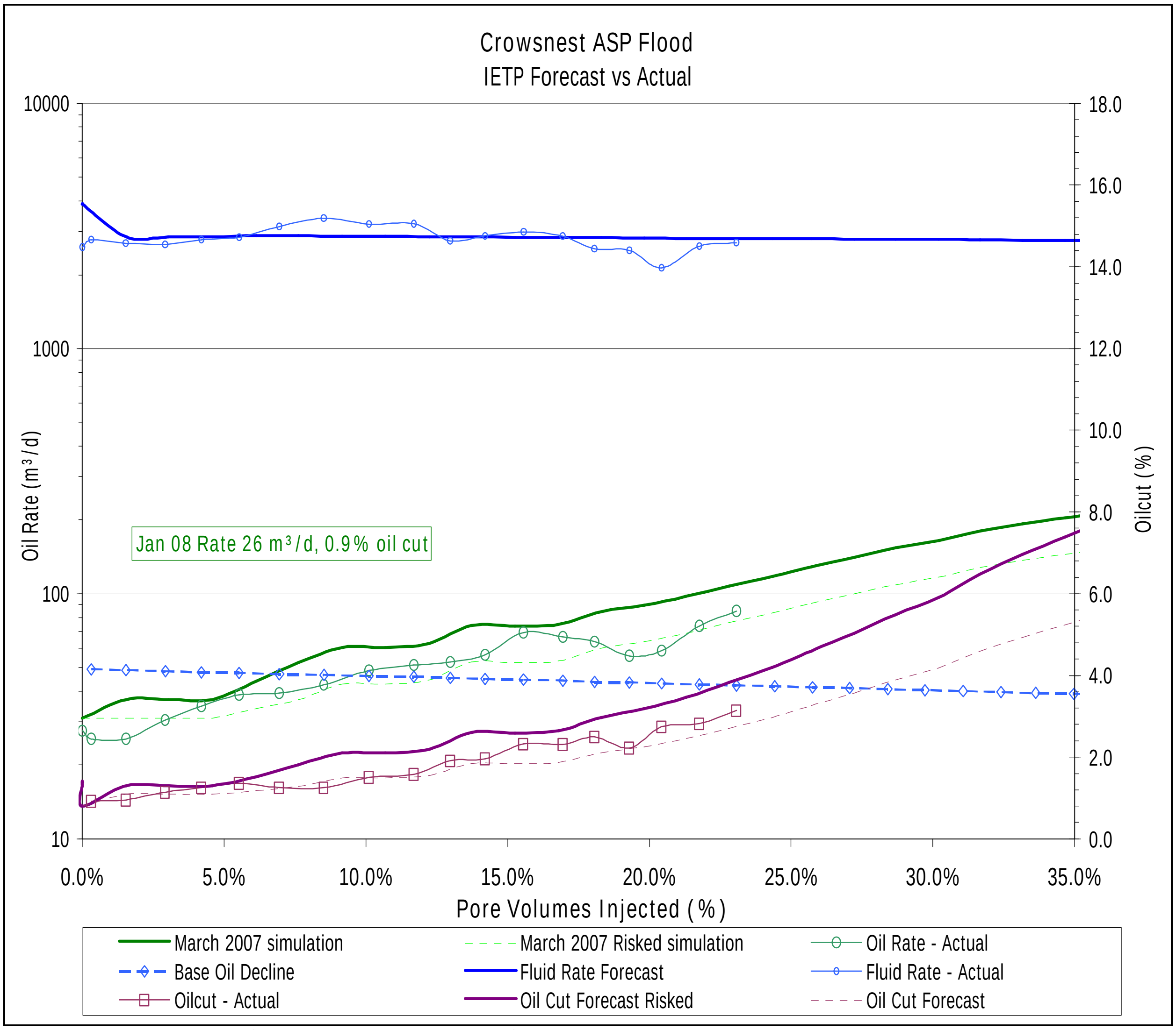

Figure 4: Comparison of production to base waterflood and IETP ASP predictions based on pore volumes injected

Injection Performance and Data

The target injection rate for the Glauc K pool is 2900 m^3/d but the average injection rate since the project began is approximately 2800 m^3/d (Figure 5). This is due to facility downtime, non-technical reasons such as a revised 2009 budget due to lower oil prices, and limits of injectors in the south part of the pool. As a higher viscosity fluid is injected further into the reservoir, the average injection pressure has steadily increased from 4 MPa when the project began to the current average injection pressure of 10.7 MPa in June 2009.

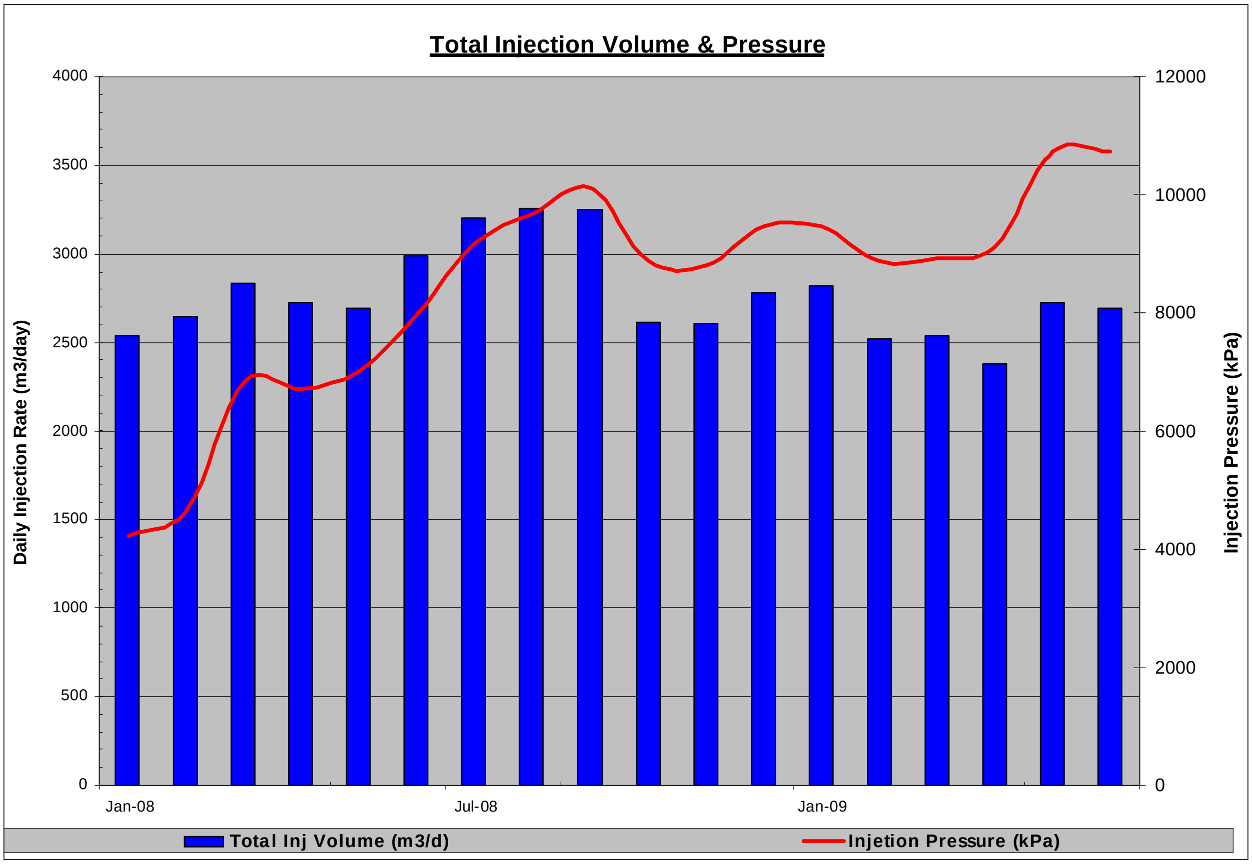

Figure 5: Taber Glauc K pool injection rates and average wellhead pressure

The oil concentration in the injected water is poor, decreasing from approximately 35 ppm oil in the water to an average of 1300 ppm in May 2009 which is almost double the average concentration of 650 ppm in Q4 2008. In the reservoir, one of the mechanisms used to produce more oil is the use of surfactant to emulsify oil into water. On surface, there have been issues related to reversing this process and treating the produced water. Clarifiers that worked in March 2008 did not work as well in November 2008 and were underperforming in May 2009. These unexpectedly poor injection water qualities may be the result of using green chemistry based surfactants because the oil concentration in the injection water in the Warner ASP flood peaked at 400 ppm after ASP injection was complete. The chemical company that treats facility water is currently trying to identify new clarifier products that could work with the emulsified oil created using the unique co-surfactant system used in this project.

Voidage Replacement Ratio

Cumulative VRR by area ranges between 0.88 and 1.09 with a cumulative VRR for the pool equal to 0.99 (Figure 6). Improved VRR control on an area basis has been achieved through the use of actuated valves at the injection well (Section 7 – *Injection wellhead*).

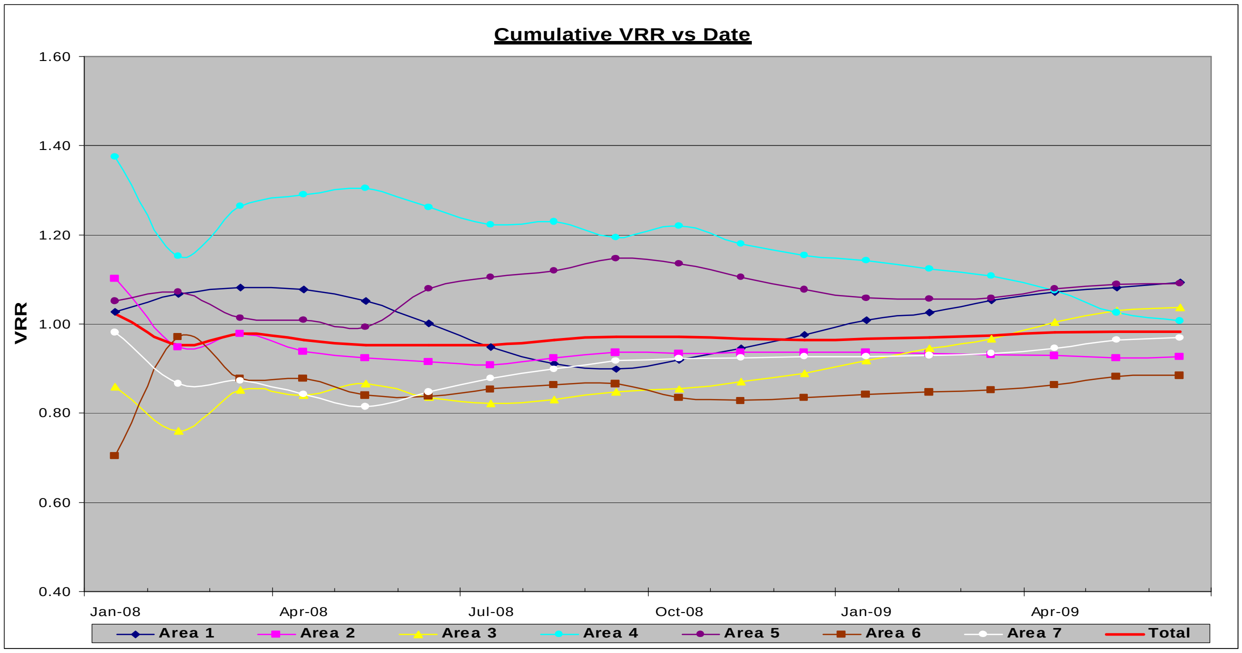

Figure 6: Crowsnest Voidage Replacement Ratio by Area

Composition of Production Fluid

A detailed laboratory water analysis from each producer is reviewed each month to monitor changes in produced fluid properties. This information is essential to understanding the movement of fluid through the reservoir and the effectiveness of the ASP flood. Produced water analyses from are provided in electronically in Attachment #7.

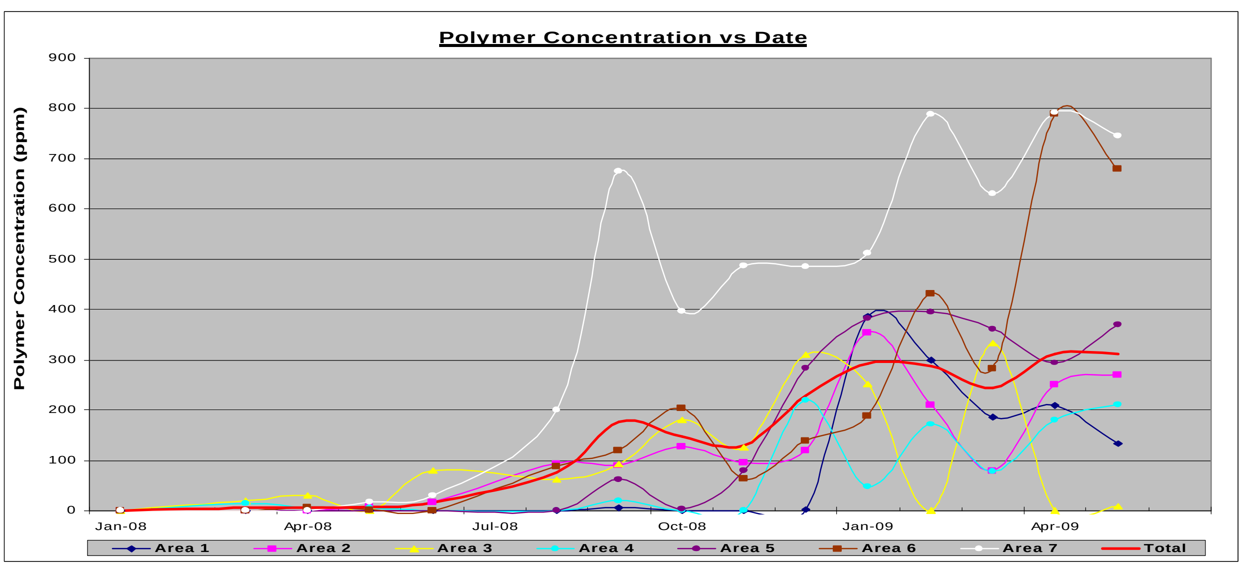

Figure 7: Average produced polymer concentration by pool and by area

A number of parameters are tracked when monitoring ASP floods. The weighted average polymer concentration is calculated for the pool and for each area shown in Figure 7. Since it is a weighted average, it depends on if the well is producing or not and can be volatile on a month to month basis for individual regions. On a pool basis, the average produced polymer concentration is 312 ppm. For comparison, after 22.2% PV had been injected in the Warner ASP project, the pool weighted average produced polymer concentration was 353 ppm. The polymer injection concentration at Crowsnest is 1100 ppm compared to Warner which is 1200ppm.

Production well 104/14-20-9-16W4 shown in Figure 8 is one of the wells that have recently responded to ASP injection. Future oil production and oil cut response can often be predicted by key produced fluid parameters. 104/14-20 was producing approximately 1 m^3/d at 1% oil cut. The first indication that an ASP flood is starting to work occurs when the water hardness starts to increase. The Glauc K pool water hardness (a mathematical combination of Ca^{2+} and Mg^{2+}) often increases as previously by-passes areas of the pool are produced since the formation water is harder than the makeup water. The second indication of ASP response is the detection of polymer in produced water. This is quickly followed by increases in pH, TDS, Na, a change in the carbonate to bicarbonate ratio and a decrease in the water hardness as softened injection water is diluted through the reservoir. In earliest wells, polymer was observed within 2 months. Finally, the front of the oil bank that has been established begins to be produced increase the oil cut for 104/14-20 to 11.5%. Generally, the longer it takes for oil production increases, the greater the increase in oil production when the oil bank reaches the well.

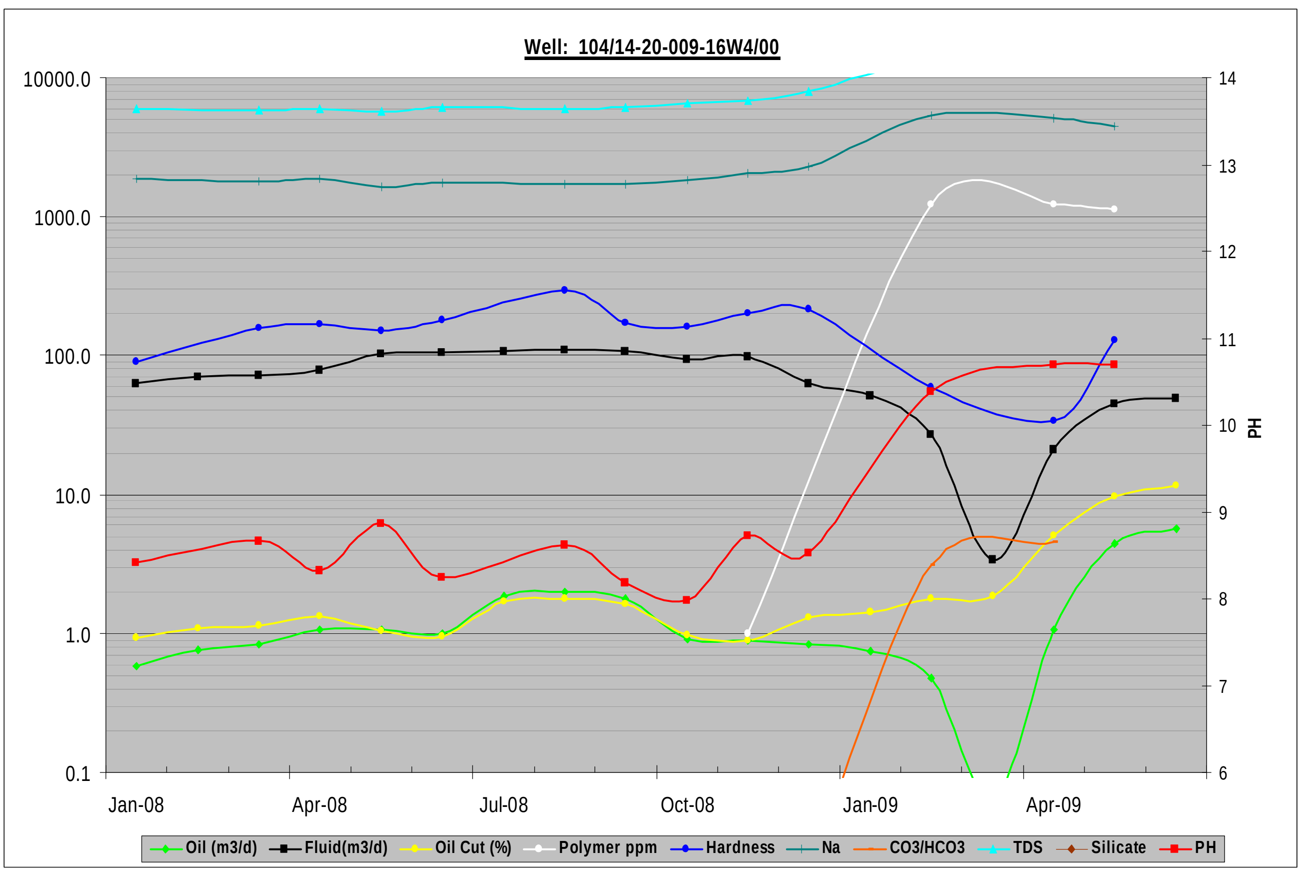

Figure 8: Produced water analysis of 104/14-20-9-16W4

Composition of the Injection fluid

Injection is monitored daily to ensure the correct concentration of ASP is injected in the reservoir. The fluid viscosity as measured at the plant and at one injection well at each of the north and south ends of the pipeline system. The fluid needs to have the correct concentration of the 4 ASP chemicals which is also confirmed by a material balance. ASP injection fluid properties are also measured to ensure the solution is within a viscosity range between 20-26 cp, a screen factor of 52-68, and conductivity between 32.5-39.5 mS/cm. There is very little difference between the values at the plant and at the injection wells.

Pressure

Static gradients taken over the last two years are provided in Table 6. Historical reservoir pressure data is provided in Attachment #8.

Table 6: *2007-08 Static Gradients in the Table Glauconitic K Reservoir*

Well	Year	Last recorded pressure at MPP
103/13-7-9-16W4	2007 2008	9220 kPa 9274 kPa
102/15-17-9-16W4	2007 2008	9410 kPa 9531 kPa
100/15-18-9-16W4	2007 2008	8146 kPa 8905 kPa
102/08-19-9-16W4	2008	8322 kPa
102/2-29-9-16W4	2007 2008	10071 kPa 12341 kPa
102/9-29-9-16W4	2007 2008	9414 kPa 6282 kPa

5. Pilot Data

Geology and Geophysical Data

The Taber Glauconitic K pool is a good reservoir for ASP flooding. The reservoir quality is excellent with large intergranular pores and contains 97% quartz. Of the 3% clays, approximately 75% is Kaolinite, 20% Illite, and 5% Smectite, indicating the effects of clay swelling or fines migration will be minimal. The geological study of the reservoir is provided in Attachment #9. The thickest wells have 15-17m of net pay (3/11-18, 103/4-20, 104/14-20, and 104/7-29) shown in Figure 9. In addition, net pay, structure, porosity and cross-section maps are included in *Attachment #10 – Geological Maps and Cross Sections.*

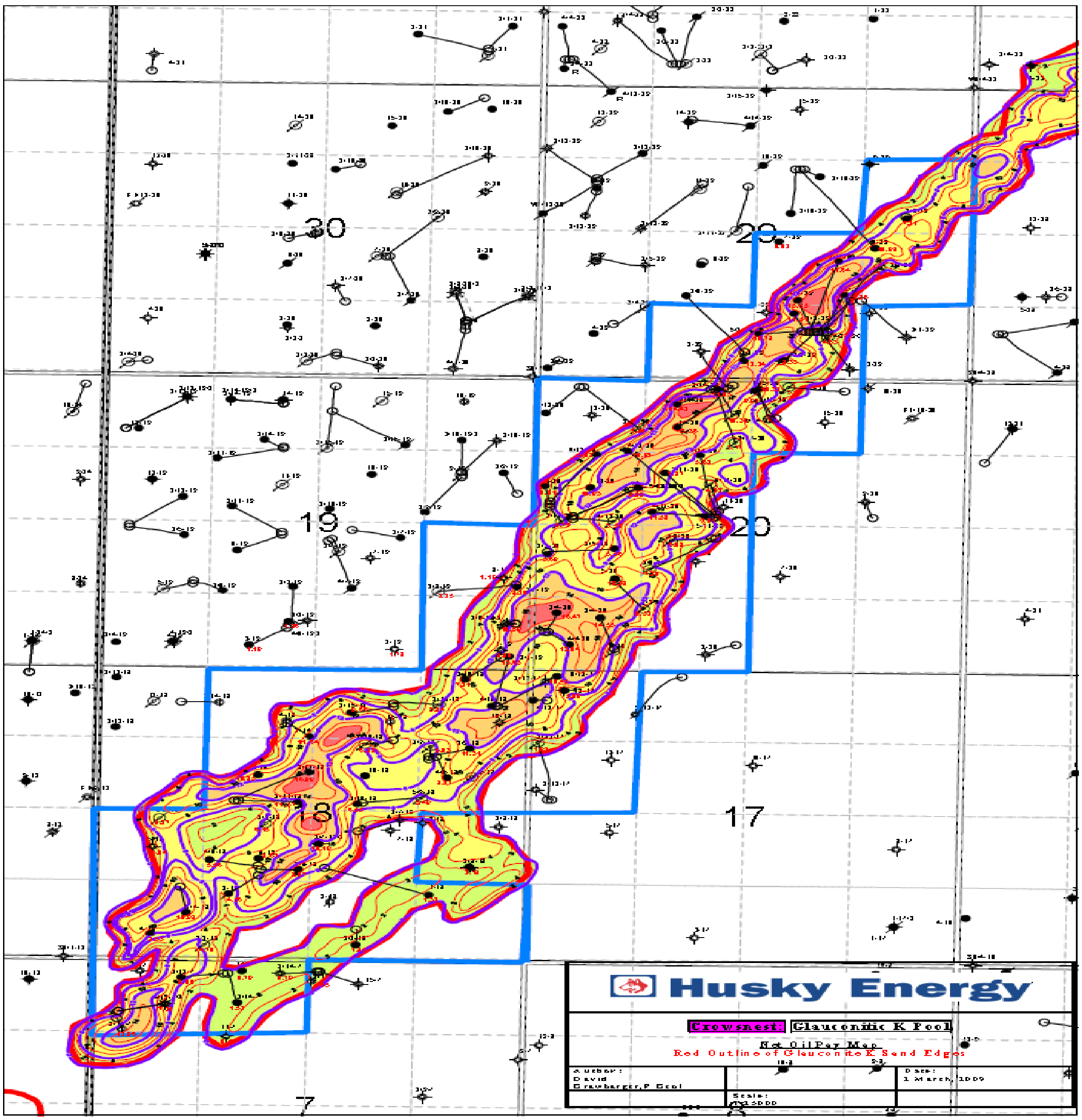

Figure 9: Glauc K Pool Net Pay Map

The reservoir is definable with seismic interpretations observed on the 3D profiles at 8-19-9-16W4 and 13-20-9-16W4 (Attachment 11) and synthetic log of 100/14-20-9-16W4 (Figure 10).

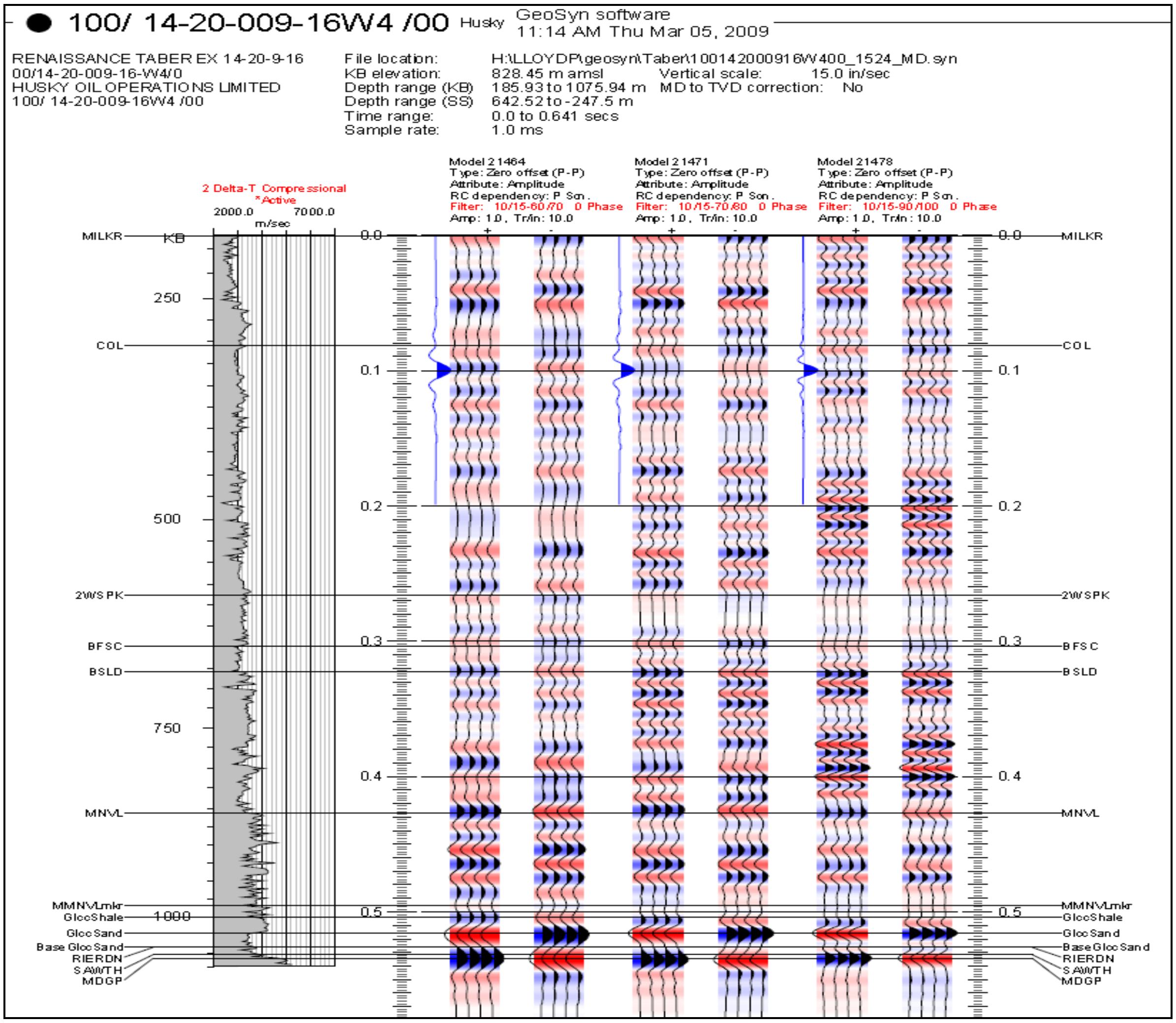

Figure 10: Synthetic log of 100/14-20-9-16W4

Laboratory Studies

Based on Husky's laboratory tests, ASP chemical systems with lignin or APG as a sole surfactant failed to match the IFT achieved between oil and water using ASP systems with petroleum based surfactants. When the two green chemistry based surfactants are combined at an optimized ratio, the synergies between the two products significantly reduced the IFT.

A comparative laboratory core displacement study of this new co-surfactant system to the conventional surfactant system previously selected indicated that the new system is as effective in mobilizing waterflood residual oil and is also superior in its ability to control mobility compared to a conventional ASP chemical system. Husky considers the improved mobility control to be a significant technical breakthrough and attributes it to a significantly higher residual resistance factor resulting in increased incremental ASP oil at a lower cost when compared to conventional systems. It was also noted that the chemical retention of this new surfactant is substantially lower that that of the conventional counterpart, and, in its presence, the retention of polymer is also lower.

The Crowsnest ASP Fresh Coreflood Evaluation (Electronic Attachment #12) outlines the methodology to select the final ASP system. The final ASP system selected was:

- *0.75wt% NaOH + 0.15 wt% lignosulfonate + 0.05wt% APG + 1100 ppm polymer*
- *Followed by 1500 ppm polymer injection*

Reservoir Data

PVT data is provided in Attachment #13 and historical pressures are in Attachment #8.

Characteristics making the Glauc K pool an ASP candidate are excellent waterflood response, 34^{o}C reservoir temperature, oil viscosity of 85 cp, and reservoir quality presented in Table 7.

Table 7: Basic Reservoir Properties for the Taber Glauconitic K pool

Formation:	Glauconite	Initial Pressure:	10 162 kPa
Lithology:	Sandstone	Current Pressure:	9 600 kPa
Mean Formation Depth:	960 m KB TVD	Bubble Point:	4 306 kPa
Permeability:	1517 mD	API Gravity:	18.5 ^{o}
Porosity:	23%	Rsi:	12.4 m^3/m^3
Swi:	16%	FVF:	1.05 R m^3/Sm^3
Average Net Pay:	6.5m	Reservoir Drive – Primary:	Fluid Expansion
		Reservoir Drive – Current:	Waterflooding

The petrophysical interpretation of 60 Glauc K logs was performed to provide data for reservoir predictions and well optimizations. Logs of analyzed wells shown in Figure 11.1 and 11.2 depict partially swept and un-swept wells that were both drilled in the mid 1990's. Well 2/14-20 was one of the first wells to respond to ASP injection. All log analysis can be viewed in Attachment #14.

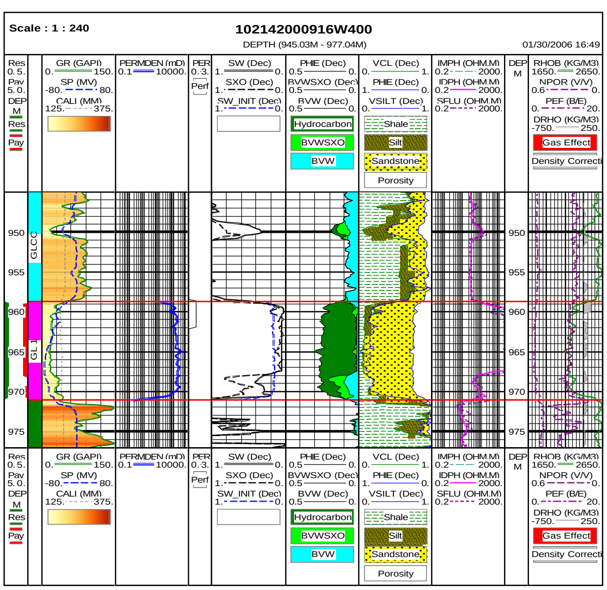

Figure 11.1: Interpretation of 2/14-20-9-16W4 log

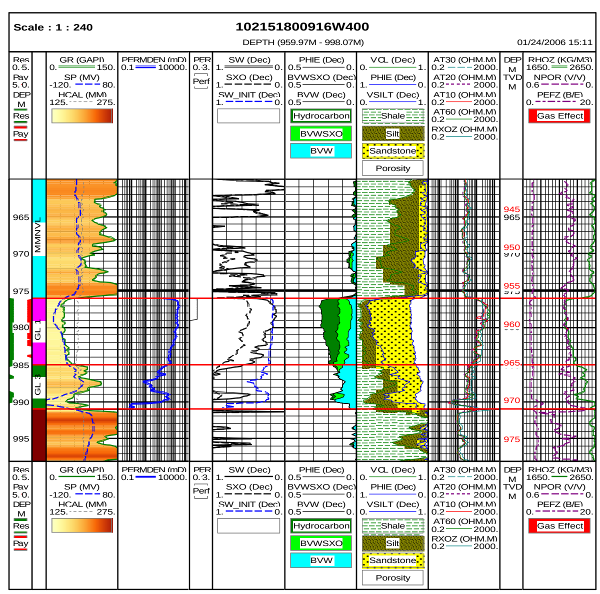

Figure 11.2: Interpretation of 2/15-18-9-16W4 log

Interpretation of Pilot Data

There have been many facility problems that have delayed production results and increased costs. Some have been due to poor facility design while other issues are related to unexpectedly poor water quality that could be the result of injecting non-conventional surfactants. These issues are discussed in detail in Section 10 but have increased the complexity of successfully implementing this project. Other operation issues include increased well failures and difficulties getting rigs to wells due to wet lease conditions. Despite these challenges, oil production is responding satisfactorily. Oil production and oil cuts are within the expected range (Figure 4). There has been good oil production response in individual wells and the pool oil cut has increased from 0.9% to 3.3% as shown in Figure 12. A number of wells were just beginning to respond to ASP injection at the end of June 2009.

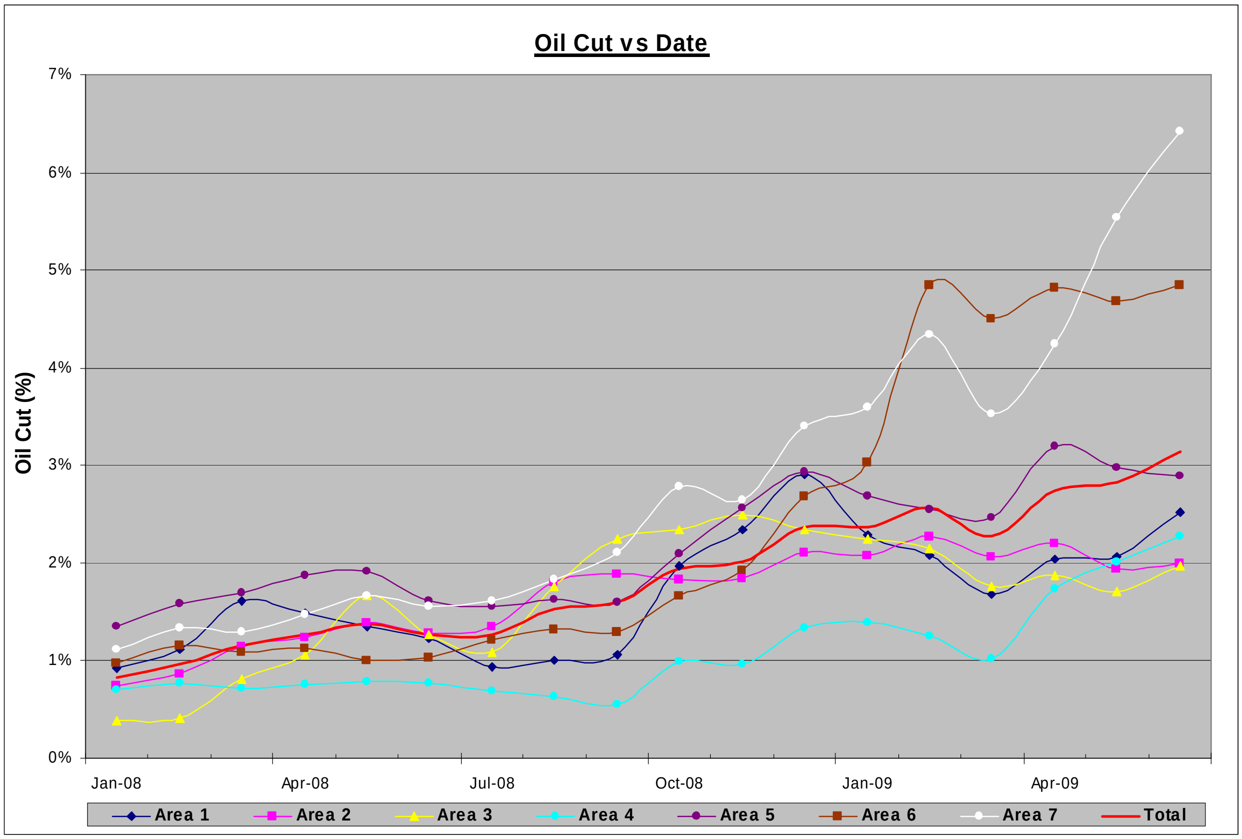

Figure 12: Oil cut in each area of the pool.

Note that 25% PV of ASP fluid has been injected into Areas 5 to 7 compared to only 21% PV into Areas 1 to 4. This corresponds to an average oil cut equal to 4.8% in Areas 5-7 compared to a 2.1% oil cut in Areas 1-4. It is expected that the oil cut in the south portion of the pool will increase in the next few months as the pore volume injected in those areas nears 25%.

Incremental Production

Incremental oil from ASP flooding is below target and is only 3.4 10^3m^3 as of June 2009. Production is low because ASP production was lower than the base waterflood decline for a longer period of time than forecast due to facility delays. In mid 2006 the pool was producing $59m^3/d$ oil and 4000 m^3/d total fluid (1.5% oil cut) from 30 producing wells. For the ASP project, the reservoir simulation indicated the highest ultimate recovery would be achieved by targeting 2900 m^3/d injection. At the same time 27 wells were reactivated and or drilled so that many existing wells were slowed down to reduce total fluid production by 1100 m^3/d and oil cuts decreased in some of these wells at higher fluid levels. The result was that at the start of the project 23 out of 52 wells were making 100% water cut. In addition, injection rates were reduced in January 2009 to save 2009 chemical costs in a corporate budget revised due to lower oil prices. Injection rates increased again in May 2009 when it was confirmed IETP funding would be received. As of June 2009 the pool was producing 42.5 m^3/d (267 bopd) above the base water flood decline (Figure 13). It is difficult to determine the effectiveness of the green co-surfactant ASP system at this time because production response using this green chemistry based ASP system is slower but achieves a higher peak production when compared to predictions using conventional surfactant ASP systems. Total expected incremental oil production is expected to be 792 10^3m^3.

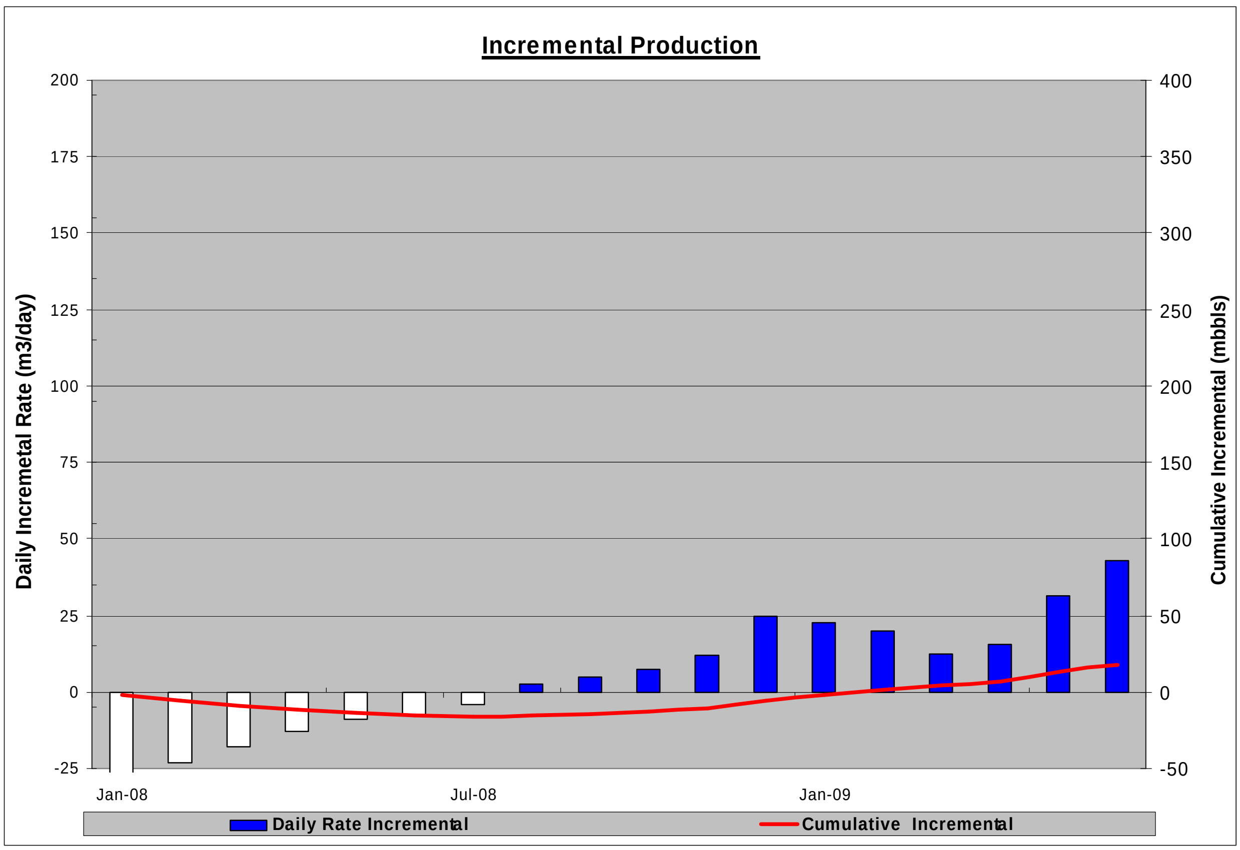

Figure 13: Incremental oil production.

6. Pilot Economics to date

Tables for expected revenue, capital, operating costs, and royalties are included in Attachment #15 in the same format as what was submitted in the May 29, 2007 IETP application.

Capital
Economics of the project have been decreased by a combination of facility cost over-runs, extreme volatility in commodities resulting in chemical cost increases, slower than expected production, and royalty increases. Table 8 compares estimates submitted in the IETP application compared to capital spent at the end of 2008 and expected final costs.

Table 8: *Comparison of actual costs to original estimates*

Description	IETP Estimate May 2007		Desription	LTD Actual Q1 2009	Estimated Total
Total Facility Costs*	**$ 27,000,000**		**Total Facility Costs***	**$ 31,827,901**	**$ 31,827,901**
			New construction	$ 5,193,595	$ 5,193,595
			Liners in existing lines	$ 857,769	$ 857,769
			Injector coating, measurement and control	$ 629,737	$ 629,737
Total Pipelines	**$ 5,320,000**		**Pipelines**	**$ 6,681,101**	**$ 6,681,101**
			Drilling	$ 2,647,000	$ 2,647,000
			Conversions	$ 3,419,978	$ 3,419,978
			Optimizations	$ 2,382,903	$ 3,383,000
			Reactivations	$ 2,972,508	$ 2,549,495
Total Reservoir Costs	**$ 9,000,000**		**Total Reservoir Costs**	**$ 11,422,389**	**$ 11,999,473**
			ASP System Design	$ 177,148	$ 177,148
			Monitoring	$ 204,757	$ 350,000
Total Laboratory	**$ 250,000**		**Design and Testing**	**$ 381,905**	**$ 527,148**
Total Chemicals	**$ 28,969,000**		**Total Chemicals**	**$ 17,411,867**	**$ 38,027,000**
Total Project	**$ 70,539,000**		**Total Project**	**$ 67,725,163**	**$ 89,062,623**
* Does not include salvage value					

The project is expected to be over the original estimates. Year 2007 and 2008 were periods of extreme volatility in commodities prices and unprecedented activity in oil and gas resulting in higher than expected costs. Increased costs are due to the following:

- Facility scope changes
- Capital cost inflation
- Chemical cost increases
- Increased workovers

Facility Scope changes
The original facility estimate was expected to be $27 MM. The final facility costs were $31.7MM. There were many scope changes but the most significant change was to accommodate the additional surfactant tank. It was estimated that it would cost approximately $300,000 to install another tank, small pump, piping changes, engineering, and installation but it ended up costing $1.3MM. Equipment costs were only $200,000 including instrumentation,

heaters, and mixers with engineering and construction splitting the remaining costs. Some of the other scope changes are included in Table 9:

Table 9 – Facility scope changes:

Item	Approximate cost	Comment
Structural Steel	$20,000	
Acid line replacement	$139,000	Changed to coated steel lines requested in DBM from plastic lines for HCl.
Building modifications/insulation	$296,000	Buildings either not included for some vessels or enlarged to load chemical.
Tank nozzles	$63,000	Nozzles set too low – raised for full use of tank.
Additional hydrovac	$300,000	
Additional piping	$28,000	
Additional pumps	$45,000	
Additional electrical	$28,000	
Chemical unloading road	$21,000	Road was too narrow for chemical trucks.
Additional drawings	$32,000	
Forklift for loading polymer	$31,000	Required to load 750 kg bags of polymer.
Critical Oil Battery upgrades	$371,000	Add coating to critical piping and valves
WAC coating change	$707,000	Discussed in **Section 7**
Air Conditioning	$30,000	MCC building overheating; in DBM, not added.
Repairs on injection pumps	$236,000	Failed on commissioning due to programming.
Treater Burner wash systems	$125,000	Installed due to repeated tube collapse
Software	$74,000	Software upgrade and high speed internet access.
External Engineering	$600,000	
External Supervision	$400,000	

Chemical Injectants

There are two main reasons for increased chemicals costs. The first is that the estimated reservoir pore volumes increased for the project. The project called for 30% PV injected of ASP followed by 40% PV of polymer only. When the pore volume estimate increased, so did the volume of chemical required. In addition, 2008 was a very volatile year for raw materials resulting in increased prices for ASP chemicals.

The caustic contract had a fixed, delivered price for the term of the project. The supplier that signed the original contract with Husky produced NaOH in Alberta. They sold the NaOH business and terminal to another company and stopped manufacturing NaOH. The new supplier purchased caustic for Husky's project from Asia. In the middle of 2008, the Asia spot price was higher than the negotiated Husky delivered price and the product still had to be shipped to Vancouver, railed to Edmonton, and trucked to Southern Alberta. It was uneconomical to supply the product and the vendor exercised an "excused performance" clause in the contract. The caustic price immediately increased by 70% in July 2008. After 2 months Husky negotiated with a Western Canada manufacturer a fixed price for the remainder of the project that was still 40% higher than the original budgeted price.

A similar situation occurred with the polymer manufacturer. The original contract included a fixed component and a variable component based on a published commodity price. The polymer price was adjusted every 6 months. Commodities were so volatile in 2008 that Husky's negotiated, 6 month adjustment price, was lower than the price of the polymer produced under rapidly increasing raw material markets. Husky knew there would be 4-5 more years of polymer provided from this supplier so natural gas, ammonia, and freight surcharges were added to the formula and the price is now adjustment monthly. Currently polymer is at the floor price as all surcharges are zero because the commodity is below the price where the surcharge is activated.

The green chemistry based surfactants are derived from natural, renewable resources and the price is less volatile. There was no reason to modify the contract price. Lignosulphonate prices have been stable for many years and could possibly decrease for larger projects. There were many requests to modify the surfactant contract for the Warner ASP project due to the volatility of petroleum based raw materials but none for the Crowsnest project.

Two other reasons for higher costs are that when the ASP system is designed, soft water is used through out the laboratory corefloods, even for the polymer only phase. If hard water is used in the polymer only phase, polymer solution viscosity is reduced. Extra polymer is required in hard water to maintain the same polymer viscosity as in soft water. The costs of softening are 5-6 times the costs of additional polymer so the decision was made to add more polymer instead of continuing to soften. In addition, water quality has decreased resulting in more regenerations and higher chemical rates to regenerate the resin in the water softeners.

In summary chemical costs increases were a result of:

- Chemical price (raw materials) increase $3.1MM
- Canadian/US Dollar Exchange rate $1.0MM
- Pore Volume increase $3.1MM
- Increased polymer in hard water $1.3MM
- Additional regenerations $0.2MM
- Freight fuel surcharge increases $0.3MM

Pipelines

Pipelines are overspent by $1.4MM. A liner was added to critical existing pipelines at a cost of $850,000. Injection wells had to be modified to add ultrasonic flow meters (for polymer measurement), add coatings, and modify piping to fit flow meters and actuated values at a cost of $630,000.

7. Facilities

Major Capital Items
A Process Flow Diagram and an isometric drawing of the ASP facility are included Figure #14 and Figure #15. A description of the main facilities is described below.

General
There are two pools that produce to the Crowsnest oil battery, the Glauc K pool and a "non-ASP" pool. Produced emulsion is pipelined to the oil battery and the oil, water and gas are separated. Produced water is pumped out of the produced water tank by one of three Bingham pumps. The first pumps water to the non-ASP injectors, the second pumps water to the ASP plant, and the third pumps softened water, surfactants, and sodium hydroxide (NaOH) to the Glauc K injectors. Water is pumped to the ASP plant using the Bingham boost pump only until such time that the polymer concentration in the produced water gets to high. When this occurs, the fluid is too viscous to flow through the water softeners in the ASP plant and the fluid must be sheared to destroy the polymer chains, reducing the fluid viscosity. The Bingham pump is turned on to shear the polymer and pump the fluid to the ASP plant. A fourth Bingham can be used as a spare for all three services.

ASP Plant
A key component of an ASP project is a facility that can blend designed ASP chemicals in good quality filtered and softened produced water. Produced water from the oil battery is pumped to a storage tank at the ASP plant. This water is then pumped through the walnut shell filter (WSF) is softened by a weak acid ion exchange water softener (WAC), and the resulting soft water is stored in a tank. A portion of the soft water is pumped back to the oil battery along with surfactants and caustic and pumped by the A-S Bingham. The remaining soft water is used for the polymer blending. The required volume of soft water is pumped to the polymer slicing unit and a 15,000ppm polymer solution is created. This is diluted with more soft water and pumped through a positive displacement pump (so the polymer is not sheared) and mixes with the high pressure A-S solution coming from the oil battery for injection into the Glauc K pool to meet the targeted final polymer concentration of 1100ppm.

A few modifications were made to the Etzikom/Warner ASP plant when designing the Crowsnest ASP plant. The first improvement was removal of the 20% NaOH tank. NaOH is trucked in at a 50% concentration. The freezing point of this solution is approximately 10^{o}C. At Etzikom, trucked in caustic was diluted to 20% as the freezing point of this solution is approximately -20^{o}C. In addition, diluting caustic is an exothermic reaction that warms the fluid so there is no chance of freezing. The 20% caustic tank and associated diluting pumps and piping were eliminated by insulating and heat tracing the 50% caustic system.

Etzikom had two walnut shell filters (100% spare) to eliminate oil and grease from the process water. They were relatively problem free so one was eliminated from the design for the Crowsnest project.

Another modification is that Etzikom was designed with a tank and pump for each service. Crowsnest was designed with a soft water header. This eliminated some tanks and pumps. One problem with this design is that some services require high pressure soft water and others require low pressure water. A future design could consider a high and low pressure pump/header system for different services instead of choking back pressure to meet low pressure service requirements.

The polymer blending system is new. Etzikom used a wetted jet method while Crowsnest uses a polymer slicing unit. At Etzikom a blower was used to send the polymer to the top of a tank and was wetted with a specially designed nozzle. Polymer was stored at a viscosity equal to 5000 cp and diluted to ASP injection requirements. At Crowsnest, polymer is sliced into very thin wafers which can be hydrated more efficiently and the viscosity in the storage tank is increased to 15,000 cp reducing the size of the polymer storage tanks.

Since the Crowsnest ASP system is using a co-surfactant system, a second surfactant storage tank was required. The main challenge with the green chemistry based surfactants compared to the conventional surfactant originally chosen for the project, which the facility was actually designed for, was that some of the fluid properties were different. Lignosulphonate is a difficult product to handle as the viscosity of a 50% active solution ranges from 2000cp at 20^{o}C to a viscosity of 13000cp at 10^{o}C. The product polymerizes and corrosion can be rapid at temperatures above 60^{o}C. The delivered APG viscosity was 3200cp at 20^{o}C. This viscosity is substantially higher than 200cp for conventional surfactants. It was concluded that the best method to deal with these products without affecting the project schedule and cost was to dilute the surfactants. Heat was also considered but the heat required to decrease the viscosity approached product maximum temperature specification in localized areas of the storage tank. Purchasing new pumps could delay project implementation and increase costs. Lignosulfonate viscosity at 45% active concentration and 20^{o}C is 200cp and the dilute APG at 20^{o}C decreased to 600cp.

Crowsnest Oil Battery modifications

Injection water quality gets progressively worse as more emulsions containing ASP components and their reaction by-products are produced. Therefore it was known that additional water treating processes were required. At Etzikom, hydrocyclones were originally installed but they stopped working within 3 months once polymer was observed in the produced water at the oil battery. A horizontal Induced Gas Floatation (IGF) vessel was installed at Crowsnest. Gas bubbles are introduced to the bottom of the vessel in four different compartments and oil collects at the top of the vessel as the bubbles float to the surface. Wiper blades skim the oil into troughs that run along the sides of the vessel.

Similar to Etzikom and Warner, a treater to handle all the waste streams from the IGF, walnut shells, and tank skim fluid was added. A waste treater is critical to ASP facilities otherwise it would be impossible to produce spec oil and good injection water quality if all other intermittent processes (WAC regeneration, WSF backwash, IGF skim, and water tank skim) had to be processed by the FWKO and main treater.

Fire tube wash systems were also added to the FWKO and both treaters to remove polymer that builds up on the fire tube walls when the polymer in the produced water comes into contact with heat. Multiple fire tube failures occur if the wash systems are not added.

Pipes and valves were coated. This was a major finding from the first project. Coated valves could be re-used after 5 years and uncoated valves had too much scale and were junk.

Injection wellhead
One of the biggest issues that a polymer injection flood has to deal with is control to each injector. When polymer goes through a severe pressure drop, such as a wellhead choke, the polymer gets sheared and loses fluid viscosity. A common way to handle this issue is to have a central injection facility that contains an injection pump for each well. A flow line runs from the injection facility to each individual injector. This option gets expensive for fields with established injection pipeline systems. The idea Husky used for this project is that actuated valves and SCADA were installed at each injector. The operators would enter the daily injection target at the facility for each individual injector and the actuator would close the valve when the daily target was met at that well.

Capacity limitation:
The ASP facility is capable of blending ASP solution for approximately 4000 m^3/d injection.
The actual volume depends on the volume of water that can be softened by the water softening units. It is partially a function of cost as regenerations are performed every 18-48 hours depending on injection rates and water quality.

The other major limitation is the injectivity of injection wells decreases as more of the viscous ASP solution is injected. At Etzikom total injection rates decreased from 4000m^3/d to 1400m^3/d by the end of polymer injection. For the Crowsnest project, the injection rate target was decreased from 4000m^3/d to 2900m^3/d before the project began and the number of injectors was increased from 12 to 22 to maintain a constant injection rate throughout the project.

Operational Issues – Facilities
There were a surprising high amount of operational issues. Some issues were directly or indirectly related to the use of green surfactants.

One month into the project, heaters in the lignosulphonate tank failed. Upon inspection, there was a heavy coating of coked surfactant on the heater sheath. The probable cause of the failure was rupture of the sheath from over-heating. It was determined that the tank heater design would have to be modified to handle this product. The facility in Lethbridge that is used to unload the product from railcars has a different tank heater design. The tank heating system at Crowsnest was designed for a conventional surfactant. Since there were so many delays to start the project, cost over-runs, turnover in the tank was on average about 5 days, and the viscosity of the dilute product was significantly less sensitive to temperature, it was decided not to install a new heating design. Product temperature was maintained by heating lignosulfonate at the rail unloading terminal before it was trucked to site. There were no issues with the APG tank heater.

The largest operational issue experienced involved the water softeners. Water softeners are essential to the entire ASP project and if they fail, alkali can not be added to the injected solution rending the surfactant ineffective. Alkali-Surfactant injection must be stopped.

After 6 months of operation, rubber lining was found throughout the plant in pump screens at the T708 forwarding and skim pumps and T795 waste disposal pumps (Figure 16.1 and 16.2). At times a pump would run for only 10 minutes before the screen was full of rubber. The lining collected was in thin strips and felt soft and "squishy" compared the original installation which felt hard.

Figure 16.1: Lining in 24 hours from T-708 skim pump screen

Figure 16.2: Lining discovered in Sheared water P-515

Based on experience at two other chemical projects, this was a completely unexpected problem. For the original Etzikom AP project, the WAC units were lined with 3/16" rubber. They operated from 2000-2003 with no problems. For the Warner ASP project, the bottom third of the vessels were re-lined as there was damage caused when the vessels were being cleaned out for used in the second project. These vessels operated from 2006-2008 with no issues.

The design for the Crowsnest project was to also use 3/16" rubber. The exact same description was on both the Etzikom and Crowsnest vessel data sheets. After the rubber lining was observed throughout the Crowsnest ASP facility it was revealed that Etzikom vessels were lined with 1048 semi-hard natural rubber and this was also used to re-line the vessels for the Warner project. The Crowsnest vessels were lined with 1055 cholorbutyl polymer synthetic rubber. It was discovered that the most common oil field applications for WAC vessels are SAGD oil sands projects which require higher temperature tolerance and a need for synthetic rubber. It was assumed by the vendor that our oil field application required a synthetic rubber but this is not an issue for our project since the maximum operating temperature is ~30^{o}C. Husky assumed the same rubber as previous projects would be used. Neither rubber is compatible with hydrocarbons. When the lining started to fail at Crowsnest, the average oil concentration in the water going through the water softeners was approximately 250 ppm but Etzikom and Warner peaked at oil concentrations in the softeners of approximately 600ppm. Oil sand operations generally have 5ppm oil in the water to meet boiler specifications.

The lining and coating experts contacted could not believe that there were no issues at Etzikom or Warner despite the very high oil concentration in the water going through the softeners. Natural rubber is used commonly in HCl storage tanks (35% concentrations) because over time, HCl reacts with natural rubber to form a crystalline layer which protects the rubber lining. This lining can last for 20-30 years in this type of application. During the regeneration of resin in the WACs, a 5% HCl solution is used for 30 minutes. Chemists suggest that this is to low a concentration for too short a period of time to form the protective crystalline layer and the hydrocarbons present should have destroyed the natural rubber lining. Reasons for the failure at Crowsnest are unknown but possible reasons include:

- Synthetic rubber is more incompatible with hydrocarbons compared to natural rubber.
- Lignosulfonate in the produced water accelerated the disintegration of the lining.
  - Surfactant concentrations estimated between 50-150 ppm at the time.
- The protective crystalline layer using natural rubber did form at Warner and Etzikom.
- Slightly different designs between the vessels at each project.
  - There was room at the top of the vessel for oil to collect in the Crowsnest vessels. Most of the damaged lining was at the top but damage was observed throughout.

When the lining started to fail, the changes were rapid as observed in WAC vessels V-150 and V-160 stated in the timeline below (all events in 2008). Options considered at Crowsnest included relining the WACs with the same natural rubber as Warner, using an alternative rubber such as neoprene or nitrile rubber, or finding an alternative solution. Water softeners have traditionally been used in water treating facilities for over 50 years and various types of rubber materials are the linings of choice as there are no hydrocarbon issues. The vendor would not recommend a product without compatibility testing and suggested that at least 3-6 months would be required to test the effect of the hydrocarbons and surfactants on common linings. Material delivery, application, and shipping would be another 6-9 months. The ASP vessels and project could have been in jeopardy due to the strong acid and base used in regenerations. After some investigation, DSI Dalco Service Inc. based in Red Deer, Alberta was contacted. A coating was recommended that was resistant to acid, caustic, and hydrocarbons. All WAC vendors contacted were not aware of any vessels that had been coated and knew it would be difficult due to 105 nozzles present in the design of the vessel. The coating was experimental both in application and effectiveness. DSI was prepared to stand behind the coating and it was installed by the end of the year. The history of this issue is shown below:

- July 20 – first large pieces of rubber were observed, some sank and some floated.
- July 24 – sent rubber to manufacturer to confirm the material.
- July 25 – the operators looked in the man-way of V-150, the lining looked okay.
- August 20 – looked in the man-way of V-160, rubber observed hanging off the sides of the vessel but the throat looked okay
- August 27 – blistering of the lining in V-150 observed
- September 2 – blistering in the throat of V-160 observed
- September 3 – Cleaned and inspected V-160, removed large strips or rubber from the vessel with the largest strips found at the top.
- September 4 – Cleaned and inspected V-150, similar condition as V-160
- October 12-24 – Applied coating to vessels an let cure.
- October 27-30 – Installed newly coated vessels.
- February 9-09 – Inspected coating on V-150 – looked good
- February 18-09 – Inspected coating on V-160 – looked good

The coating on both vessels will be inspected in Q2 2010 after water softening is complete.
ASP injection water quality is also an issue which has caused a few problems. It is known that one of the mechanisms for enhanced oil recovery is that surfactant emulsifies oil in the reservoir water. Incremental oil is produced but this creates problems trying to reverse this process at the oil battery. Warner is not having the same problems as at Crowsnest. It is possible that this green chemistry based co-surfactant system is efficient at emulsifying oil resulting in treating issues that have not been observed in the other projects. Alternatively, one of the properties of these products observed in laboratory testing is that absorption is less. At the time this was thought to be an advantage but possibly more surfactant is produced and treating is more difficult. Both projects had similar oil concentrations of approximately 10-50ppm in the injected water after the oil battery modified, the ASP facility was constructed, and before injection chemicals were observed at the oil battery. Currently Warner is able to get 1000 ppm oil concentrations in water from FWKO and the injection water contains 200-400 ppm oil after 45% PV chemical injected has been injected. Crowsnest can only get down to 3000 ppm oil in water from FWKO and 800-2000 ppm in the injection water after only 20% PV injected. These high oil concentrations are a concern at this stage in the project as water treating gets more difficult as more chemical is injected into the reservoir. Poor water quality directly and indirectly resulted in numerous operational requirements and issues:

1. WAC Resin Wash
    - The design parameters for WAC units are a maximum of 10 ppm hydrocarbons in the produced water. Up to 2000 ppm has been processed through the softeners and soft water is still produced. The resin from both vessels was so coated that it had to be emptied and washed with detergent to restore its effectiveness.
2. Additional chemical required for resin regenerations
3. Higher than expected injection pressures.
4. Ineffective IGF and Walnut shell filters.
    - Little/no change in oil concentration comparing the inlet to outlet streams.
5. FWKO modifications April 14-18, 2009
    - Vessel internals and externals were modified to improve retention time
    - Changed to operate from a 3-phase vessel to a 2-phase vessel.
    - Oil concentrations in the injected water after the modifications decreased from 1000 to 600 ppm until facility fluid through put was increased and water returned to 2000ppm.
6. Creation of a floc using a new clarifier.
    - A new water clarifier was used from September 11 - November 6, 2008.
    - Oil concentration in injected water decreased from 500 ppm to 10 ppm oil in the water after optimization of the application and volumes in 3 weeks.
        - It was a cationic product and the surfactants and polymer in the produced water are either anionic or non-ionic.
    - Injection water was great a floc that was created that caused many problems:
        - The treater fire-tube collapsed twice in two weeks. The jelly-like floc that was created could not dissipate the heat from the fire-tube.
        - The treater grid was coated and treater effectiveness was reduced.
        - The waste treater couldn't handle the material and it had to be trucked out to third parties for disposal. A few third party disposal facilities in Southern

Alberta stopped taking the floc because it was too difficult to treat with heat, time, and chemicals.

- When the clarifier was turned off, water qualities returned to 600ppm. Since November the water treating company has been testing commercial and experimental clarifiers in the lab without success.

Pipelines

Higher risk pipelines were identified and either internally lined or abandoned and replaced with flex pipe pipelines to minimize corrosion and failures that could negatively effect production, safety or environment. New oil and injection pipelines along with new or reactivated wells in the Glauc K pool can be found on *Attachment #16 – Crowsnest Oil Battery Systems Map.*

Operational Issues – Wells/Pipelines

Scale is an unresolved issue with some ASP floods. Scale has been observed in 7 of 50 wells with average run-time decreasing from 1140 days to 285 days on those wells. The challenge with this scale is that a chemical has not been found which can break it. The scale is a combination of calcite, silicate, and polymer and changes composition throughout the life of the project. The current strategy is to apply continuous scale inhibitor slip-streamed down the casing once the measured produced water reaches a pH greater than 8.5. Identification of more effective inhibitors is continuing.

Chromium coating was stripped off some rotors when pulled out of the hole. A nickel-based coating was applied on rotors beginning March 2009 to see if run-times could be increased. The hardness of this coating is 58 compared to 40 for Chromium based coatings. Coated, slotted tag bars and coated NTT were replaced on five wells in May 2009 to determine if coating additional down-hole equipment would further improve well run time.

The scale changes from predominately calcite to predominately silicate scale. Calcite inhibitors are currently being used but inhibitor efficiency is significantly reduced above a Si concentration of 75ppm or with low magnesium concentrations. In some wells the Si concentration has increased from 0 to as much as 1500 ppm and the magnesium is down to 1 or 2 ppm as it is removed in the softening process. A silicate scale inhibitor has not been found to date that will prevent scale from forming. Husky is currently testing a new calcite scale inhibitor that is supposed to work in higher pH environments to prevent the site for silicate scale to form but this work is continuing.

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8. Environmental/Regulatory/Compliance

Environment and Safety
In 2008 Husky implemented the Husky Operational Integrity Management System (HOIMS) to improve Husky's health, safety, asset integrity and environmental performance. HOIMS integrates both occupational and process safety into one comprehensive management system. HOIMS in comprised of 14 fundamental elements, including Safe Operations, Risk Assessment and Management, Personnel Training, Environmental Stewardship, Compliance Assurance and Information Documentation. All levels of management at Husky are committed to the principles of HOIMS and are dedicated to having a safe working environment at Husky.

There are four main environmental advantages to the new ASP system proposed by Husky:

1. Using surfactants derived from renewable raw materials to produce incremental oil

2. Lignin is a waste product of the pulping process that is used to produce sodium lignosulfonates, a by-product of the pulp and paper industry.

3. An ASP system that would be less damaging to the environment. Conventional surfactants are considered to have a mild toxicity but lignosulfonates are non toxic. The most common use of lignosulfonates is as a dust suppressant for roads and it is already been established in Alberta for use on gravel roads. If there was a spill, the product is completely biodegradable.

   APGs are an agricultural-crop-based combination of fatty alcohols (coconut and palm oils) and glucose (corn, wheat, potato) and are mostly used in personal care formulations, cleaners, and agricultural formulations. APGs are made from renewable and natural raw materials and are readily biodegradable. In fact, the APG chosen for this project has been approved for use in eco-labeled "Good Environmental Choice" by Swedish Society for Nature Conservation[1] which is the largest environmental organization in Sweden. The ecotoxicity[2] profiles of APGs are very low[3] and they release no undesirable by-products such as nitrogen, ethylene oxide and preservatives[4] upon decomposition.

4. Reducing the use of petroleum based products in the ASP system. There is a complete reduction in the use of petroleum sulfonates and polymer (propylene based) use is reduced.

Regulatory
The injection wells were approved under Directive 51 with a Maximum Wellhead Injection Pressure of 15 300 kPag. No injection wells have exceeded this pressure. Average injection pressure is currently 10 700 kPag.

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[1] Cognis Presentation to Husky March 2007 *"APG's for EOR"*
[2] The study of how chemicals affect the environment and the organisms living in it.
[3] United States Environmental Protection Agency, *"The Presidential Green Chemistry Challenge Awards Program, Summary of 1996 Award Entries and Recipients"* http://www.p2pays.org/ref/13/12041.htm (May 28, 2007)
[4] Cognis website. *Add APG® surfactants – Power to your formulations,* http://cognis.com (May 28, 2007)

The project received Directive 65 Approval (Approval 10860A) to inject ASP into the Taber Glauconitic K pool with the following requirements:

- The ASP solution will not less than 0.5wt% NaOH, 0.10wt% surfactant, and 0.11wt% polyacrylamide polymer
- The polymer solution will be polyacrylamide polymer between 0.06 and 0.11 wt%.
- ASP injection will be not less than 30% PV followed by not less than 30%PV polymer solution
- Must maintain a VRR = 1.0 on a project basis
- Shall target a VRR = 1.0 on a monthly basis
- Monthly sampling of produced water to determine ASP breakthrough
- Presentation to the EUB required annually with the first to occur before June 30, 2007.

Husky is satisfying the requirements of Directive 65.

Shut down and Environmental Clean Up

The facility will be in operation until at least 2012. Reclamation of the ASP Plant and injection site will meet all Alberta Environment requirements. At the time of abandonment a Phase I Environmental Assessment will be completed. If any issues are identified following this, a Phase II Environmental Assessment will be completed. Remediation will be conducted if necessary. The site will be reclaimed and a Reclamation Certificate will be applied for.

Once wells and facilities have reached the end of their operational life, Husky has a corporate asset retirement obligation to reclaim the sites to a productive state. This consists of plugging and abandoning wells, removing and disposing of surface and subsurface equipment and facilities, and restoring the land to the state required by ERCB regulation. Although this will be 25+ years into the future for the Glauc K pool, Husky has considerable expertise in this area and is committed to meet all provincial and federal environmental regulations now and in the future.

9. Future Operating Plan

Project Schedule
Full ASP injection began January 23, 2008 and is expected to continue until December 2009. 40% PV polymer only injection is expected to continue following ASP injection until December 2012. Peak production is also expected to occur in Q1 2013. At this time it will be possible to compare the incremental oil recovery performance of surfactants derived from renewable natural resources to expected recovery factors from ASP floods using conventional surfactants.

Changes in pilot
Injection and production rates are continually being monitored and adjusted to meet targets. Targets will be review regularly as additional production results and produced water analyses are obtained so that ASP chemical is placed efficiently and cost effectively throughout the reservoir.

Husky will also review extending the length of time the chase polymer solution to 60% PV injected. This decision will be made in 2012 depending on updated simulation results, the oil price, and the price of polymer at that time. In light of this time frame, the salvage value of the facility has not been determined.

Lignosulfonates and Alkyl-poly glycosides are not molecules that were designed for enhanced oil recovery. Chemical manufacturers of conventional surfactants normally used for EOR have been working on products since the 1980's. Representatives from both Tembec and Cognis (suppliers of the green chemistry based surfactants) have met with Surtek individually to try to understand their molecules better. They are trying to understand what component of the molecule is contributing to oil recovery and if that component could be modified to improve results further. Representatives from Tembec and Cognis have also met to determine if a business arrangement could be made so that a combined product can be marketed for EOR as it is easier logistically for implementation in an ASP system to only blend 3 products instead of 4.

Since the new WAC coating has not been used in this application before, Husky also plans on inspecting the WAC coating in Q2 2010 after softening is completed. The performance of the coating will be evaluated after and will provide Husky the information required to including this coating as a specification for future projects.

Cost optimization strategies
Currently the largest areas for operating cost optimization are in the areas of water quality and scale. Husky is continuing to work with chemical companies to identify new clarifiers and scale inhibitors. If an effective clarifier can be found, treating costs could be reduced through lower chemical use. Also better water quality reduces the number of WAC regenerations. It costs $4100 or more per regeneration depending on chemical volumes used. If the cycle is extended from 24 to 48 hrs, it equates to annualized savings of more than $750,000.

Improved injectivity for both ASP and non-ASP injection wells is also a result of improved clarifier performance. Finding a new clarifier is a key objective in 2009. There is also no chemical found that can break down and/or inhibit the scale. If there was, cost savings could be realized with reduced well servicing costs and increased pump efficiencies.

10. Interpretations and Conclusions

This has been a very challenging project due to many operational, contractual, and technical issues. There are some valuable lessons learned but it is still early in the project to understand all the implications of the decision to use green chemistry based surfactants. More time is required to resolve some of the outstanding issues and to evaluate if this innovative co-surfactant system results in a more effective ASP system at a lower cost as production response is expected to be slower but the peak rate and ultimate production would be higher. Results to date have prompted companies to work together to develop other green based surfactants for use in EOR. Despite these challenges, Husky is making progress on addressing many of the complex issues related to implementing a successful ASP flood.

Some of the key lessons from the project are:

- Understanding of the geology is very important.
- Effective control of ASP fluid at the injectors is worth the relatively small expense.
- Eliminate butterfly valves - they plug up when used in difficult emulsions. Should be full port or at least full opening ball valves.
- It is difficult to modify existing surfactant facilities to accommodate the green based surfactants used in this project due to the higher viscosity. These surfactants would not be a problem to handle if the equipment is designed for product specifications.
- Clarifier needs to be anionic or non-ionic to avoid formation of emulsion or floc.
- Additional retention time is required at the facility to deal with water quality issues.
- Diaphragm caustic pumps are the best pumps to use for NaOH.
- Used coated steel for HCl lines.
- Compatibilities are important. Incompatibilities include: HCl with steel; caustic with glass based materials; and some surfactants with carbon steel.
- Produced water changes throughout the project resulting in scale and water clarity issues. Sufficient water analysis from each producer is vital before ASP injection begins. Additional work and testing should be performed before the project begins to address the potential for some of these issues.

Technical and economic viability can not be determined at this time. Results are still promising but incremental recovery at this time has just begun (less than 0.4% of the final expected value). Project costs are higher than expected but this could be offset by higher than forecast oil prices. Based on current economic evaluations, the expected after tax rate of return is 18%. Facility costs can be reduced if some of the lessons Husky has learned can be corrected in future projects. The other challenge with this pool is that it was over-developed and production rates had to be slowed down to achieve maximum recovery. Production was below base production for a period of time. Most reservoirs are under-developed so that when new wells are drilled or injectors are converted, even though these activities work likely would have been uneconomic if an ASP flood was not implemented, production is above the base decline immediately and results in improved economics. At Crowsnest, ASP production is now 42 m^3/d (265 bopd) above the base decline and 59 m^3/d (370 bopd) above the oil rate when the project was started.

It is too early to determine, but expected incremental oil recovery is expected to be 5.0 MMBO, or 15.5% OOIP which is 10% higher recovery factor than what is expected at the Warner ASP project using a conventional surfactant. There are still uncertainties about the affect of unconventional surfactants used in this project on the reservoir and water qualities and the influence on ultimate recovery. Husky isn't using green based surfactant in other projects until some of these uncertainties are resolved and it can proved that surfactants derived from renewable raw materials are as equally effective, or as expected, more effective than conventional surfactants.

Based on early results on the project, incremental production can be achieved - it is simply a matter of determining how much and at what cost. Husky is dedicated to technically and economically advancing the process to justify additional ASP floods in suitable reservoirs in Alberta. Husky and the Alberta Department of Energy have invested resources to improve understanding of how to increase oil recovery and reduce costs through facility optimization and ASP chemical system advancement. Husky would like to proactively justify more green chemistry based ASP projects to demonstrate environmental performance can be improved while still achieving economic goals.