Innovative Energy Technologies Program
Application 01-023
Taber S Mannville B
Alkaline-Surfactant-Polymer Flood
Warner ASP Flood

Annual Report
June 30, 2006

Summary of Project

Introduction

Husky Oil Operations Limited (Husky) implemented the first field-wide Alkaline-Surfactant-Polymer (ASP) Flood in Canada on May 17, 2006. Incremental oil production is expected to be 1 003 10^3m^3 (6 311 MBO) from the Taber S Mannville B pool (Mannville B Pool), an incremental oil recovery factor equal to 14.5% of the original-oil-in-place (OOIP).

Husky is a 100% working interest owner in the Mannville B Pool. Produced water is pumped from Warner 4-20-7-16W4 Oil Battery (Warner) through a 6" pipeline to Etzikom Creek 6-13-6-17W4 ASP Plant (Etzikom). The produced water is filtered using walnut shell filters and softened using a weak acid ion exchange unit. The ASP chemicals are blended in the required concentrations and pumped through an 8" pipeline from Etzikom to the Warner 11-16-7-16W4 Injection Satellite (Injection Satellite). The Mannville B pool is split into 4 regions of approximately equal pore volumes. Each region or group contains 3 to 6 injection wells. At the Injection Satellite there are 4 pumps, each dedicated to one region. Each pump has an injection capacity of $900m^3/d$ for total injection of 3600 m^3/d into the Mannville B Pool.

For this project, the ASP solution consists of:

- 0.75wt% sodium hydroxide (NaOH – alkali), + 0.15wt% ORS-97HF (surfactant) + 1200 ppm Flopaam 3630 (polymer) blended in softened water.

On May 3, 2006 produced water from Warner was sent to Etzikom. The ASP plant was commissioned by producing softened water and pumping it to the Injection Satellite. The goal was to prevent precipitate from forming at the wellbore perforations by creating a buffer between hard water and sodium hydroxide in the ASP solution. On May 10, AS injection began to pre-condition the wells for full ASP. ASP injection began on May 17 into the Mannville B Pool.

Samples are taken at various locations though-out the Etzikom ASP plant and at the ASP Transfer pumps as the mixture leaves the facility to ensure the correct volumes are being injected into the reservoir. Concentrations are checked at the injection wells located at the end of the pipeline in each group to confirm that there is not a decrease in the fluid quality while it is pumped first to the Injection Satellite and then boosted to the injection wells.

If the project was not implemented, total oil production was expected to be 42 m^3/d and fluid production would be 2600 m^3/d by June 2006. Current oil production is 59 m^3/d and fluid production is 3500 m^3/d. Target injection rate is 3600 m^3/d. Since ASP injection only began May 17, the incremental oil production to date is from reservoir development (drilling, injection conversions, and reactivations). Total production rates vary daily as oil wells are sped up or slowed down to achieve target placement of ASP solution.

Timeline
Table 1 outlines some of the major activities that were required as part of the Warner ASP project.

Table 1: *Chronology of major activities and operations*

Activity	Description	Start	End
ASP candidate selection	Based on an internal review and work Surtek performed for their own consulting purposes, Warner was determined to be the best candidate Husky owned for application of an ASP flood.		February 2004
Laboratory Testing	Lab testing to determine the final ASP system.	May 2004	May 2005
Geologic and Reservoir Engineering Study	Geological and reservoir review to model reservoir, develop preliminary production plan, and forecast incremental oil production.	June 2004	June 2005
Detailed Engineering Design	Design of facilities and pipeline system. In November 2005 a second engineering firm was contracted to assist in completing the design.	May 2005	February 2006
Etzikom Turnaround project	Clean and assess equipment to determine future serviceability.	July 2005	September 2005
Conservation and Reclamation Study	Review potential surface impacts of pipelines between Warner and Etzikom.	September 2005	November 2005
EUB Applications	Directive 51&65 injection approvals	September 2005	March 2006
Procure chemical suppliers	Solicit bids from chemical suppliers, award chemical contracts, and finalize logistics.	September 2005	March 2006
Implement plan of development	Alter reservoir from 29 producers & 11 injectors to 45 producers & 18 injectors by drilling 7, reactivating 11, and converting 6 wells.	October 2005	July 2006 (1 remaining well to drill)
Etzikom refurbishment, replacement and additions	Refurbish and modify facility to prepare ASP solution for EOR purposes.	November 2005	March 2006
Construction of ASP Transfer Pipelines	6” poly lined pipeline to transfer produced water & 8” poly lined pipeline to transfer ASP solution.	November 2005	March 2006
Construction of 11-16 Injection Satellite	Build satellite for ASP injection pumps	February 2006	April 2006
Construction of gathering and distribution pipelines	Test satellites and 25 km of injection and production pipelines for oil wells and injectors.	February 2006	May 2006
Warner Oil Battery Modifications	Modify facility to send higher quality produced water to Etzikom ASP facility	March 2006	April 2006
Existing Injection line Cleanouts	Clean existing injection pipelines to remove solids that could be released by surfactant injection.	March 2006	May 2006
Commissioning	Commission Warner Modifications, Etzikom, and 11-16 Injection Satellite.	April 2006	May 2006
ASP Injection	30% Pore Volume of ASP injection	May 2006	June 2008
Polymer only injection	30% Pore Volume of Polymer injection	July2008	September 2010

Pilot Data

Geological Map
The eastern pool in *Attachment #1 - Mannville B Pool Net Oil Isopach* is the Mannville B pool.

Laboratory Studies
The Warner ASP Laboratory report (Attachment #2) outlines the methodology to select the final ASP system. The system below, used in Run 11 and Run 13 (a repeat of Run 11) was selected as

the ASP system to use in the Mannville B pool:

- 0.75 wt% NaOH + 0.15 wt% ORS-97HF (surfactant) + 1200 ppm polymer

Reservoir Data

Reservoir and pressure data are located in the following attachments:

- PVT Data –Attachment #3.1 and #3.2
- Core Data from the new drilling locations – Attachments #4.1 and #4.2
- Reservoir Pressure Data (divided into sections) – Attachments #5-5.6

Characteristics that make the Mannville B pool a good ASP candidate are waterflood response, 35 ^{o}C reservoir temperature, oil viscosity of 40 cp, and reservoir quality presented in Table 2.

Table 2: Basic Reservoir Properties for the Taber S Mannville B pool

Formation:	Glauconite	Initial Pressure:	9950 kPa
Lithology:	Sandstone	Current Pressure:	9000 kPa
Mean Formation Depth:	985 m KB TVD	Bubble Point:	4606 kPa
Permeability:	> 1000 mD	API Gravity:	19.1 ^{o}
Porosity:	24%	Rsi:	16.7 m^3/m^3
Swi:	18%	FVF:	1.05 R m^3/Sm^3
Average Net Pay:	7.1m	Reservoir Drive – Primary:	Fluid Expansion
		Reservoir Drive – Current:	Waterflooding

Well information

Well Layout Map

The Mannville B pool consists of 45 oil production wells and 18 injection wells as shown in Figure 1. The 3/6-16-7-16W4 is expected to be drilled, completed and on production in July.

Plan of Development Review

The objective of the plan of development was to review and utilize existing well bores, focus on regions with higher target oil volumes and optimize the placement of ASP to achieve maximum incremental oil recovery as discussed in the following *Well operations, Spacing and Patterns*, and *Drilling* sections.

Well operations

The work required in development plans for the Mannville B pool consisted of pipeline cleanouts, injection well cleanouts, drilling, producer optimizations and reactivations, and injection conversions. 102/3-16 is incorrectly shown as an injector in Figure 1.

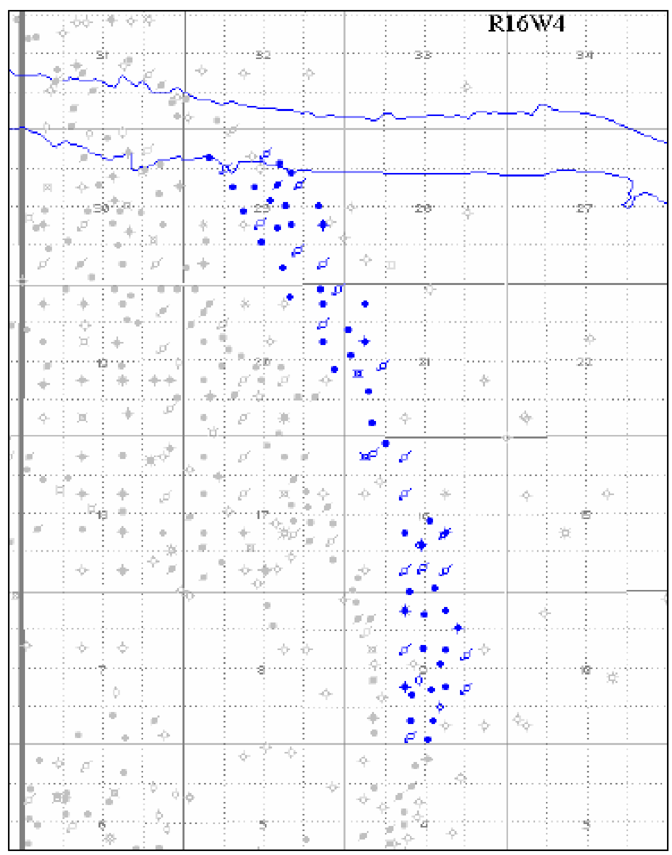

Figure 1 – Taber South Mannville B pool in 7-16W4

Solids built up on walls of existing injection pipelines were removed to eliminate plugging of injection wells. The solids would likely be released with the addition of surfactant. Approximately 9.55 km of pipeline was soaked for 24 hours with the following results:

Figure 2.1 and 2.2: Injection pipeline before (thick layer of hydrocarbons/solids around the entire pipe) and after chemical soak & water wash.

All existing injection wells had optimizations. Diesel was used for circulating out heavy oil and for multiple formation soaks. In one case, the tubing was perforated to circulate the heavy oil out and proceed with the program. These programs were done to improve injectivity of the existing wells that, during upset conditions, may have injected water with high oil concentration. All wells achieved improved injection rates after the cleanout programs. Coated tubing was installed to reduce the internal corrosion and fouling of the near wellbore region.

Wells identified in Table 3 were reactivated or converted based on the desired pattern.

Table 3: Wells in the Warner ASP flood with a status change

Well	Previous Status	Current Status	Well	Previous Status	Current Status
INJECTION WELLS			**PRODUCTION WELLS**		
2/03-09-7-16W4	Suspended	Injector	2/10-9-7-16W4	Suspended	Producer
0/11-09-7-16W4	Producer	Injector	2/14-9-7-16W4	Abandoned	Producer
0/03-16-7-16W4	Producer	Injector	2/15-9-7-16W4	Suspended	Producer
0/14-16-7-16W4	Suspended	Injector	2/3-16-7-16W4	Injector	Producer
3/16-20-7-16W4	Suspended	Injector	0/6-16-7-16W4	Suspended	Producer
2/05-21-7-16W4	Producer	Injector	0/11-16-7-16W4	Suspended	Producer
			0/4-21-7-16W4	Suspended	Producer
			0/12-21-7-16W4	Abandoned	Producer
			2/12-21-7-16W4	Suspended	Producer

Attachment #6 – Warner Well WO List is a working spreadsheet containing wells that were added for the Warner ASP project and results from operations of injectors that were cleaned out. It also includes generic programs for injectors and producers.

All existing producers were reviewed for target production and optimization through the addition of perforations, well fractures, tubing/pump sizes. VFDs were added for wells for improved flexibility in optimizing production rates. *Attachment #7 – Warner Oil Prod Rig Work*, contains existing production wells and recommendations (if required) to monitor or work over the wells.

The main operational difficulties were coordinating the timing and requirements for all of the workovers. Objectives included delaying work on injectors until filtered water was available from the ASP plant, not running oil pumps until the project was within a month of startup, waiting for pipeline crews, weather delays (especially Crown land), having lined tubing available to run into selected oil wells to reduce downhole failures, starting up wells as soon as pipeline was available, and the unknown downhole condition of wells that had been suspended for years.

Workover difficulties included typical problems, but the major challenge was older wells that had been injecting for a number of years that had heavy oil returns plugging up the tubing.

High risk pipelines were identified and replaced with new, coated pipelines to minimize corrosion and failures that could negatively effect production, safety or environment. New oil and injection pipelines along with highlighted wells in the Mannville B pool can be found on *Attachment #8 – Warner Oil Battery Systems Map.*

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

- Attachment #9.1 – Sample schematic for injection well 102/13-16-007-16W4
- Attachment #9.2 – Sample schematic for producing well 103/05-21-007-16W4

Spacing and patterns
The project boundaries are identified in *Attachment #10 – Pool Order – Taber S Mannville B.* The injection pattern is a combination of peripheral injection and a modified line drive. The flank/peripheral 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 will be reviewed regularly. Injection rates at the wells can not be controlled using chokes as pressure drop shears the polymer reducing solution viscosity in the reservoir and effectively wasting capital spent on the polymer. Injection wells will be shut-in temporarily (hours per day) or producing wells will be sped up or slowed down to ensure chemicals are placed in the reservoir for the most effective performance. Dividing injectors into groups has improved the ability of operations to meet injection targets on a pore volume basis into the 4 regions of the reservoir. The 4 groups are shown in Table 4.

Table 4 – Injection well groups.

Group A		Group B	Group C	Group D	
2/3-9	0/11-9	0/2-16	2/13-16	3/16-20	2/10-29
0/8-9	0/3-16	3/7-16	2/5-21	0/1-29	2/15-29
2/9-9		0/14-16	2/9-20	2/2-29	3/11-29
				4/6-29	

Section 4 is not included in the project because reservoir quality is poor (thin and shaly). Lower injectivity in this region would be further reduced with injection of polymer due to the high viscosity of ASP solution. Chemical retention in poor quality reservoir is often higher.

Drilling

Table 5: Drilled wells

Well	Bottom Hole Coordinates	Current Status
DRILLING		
3/06-16-7-16W4	473N, 745E	July 2006 Producer
2/07-16-7-16W4	590N, 614E	Producer
3/07-16-7-16W4	735N, 755W	Injector
2/13-16-7-16W4	179S, 285E	Injector
2/14-16-7-16W4	66S, 410E	Producer
3/05-21-7-16W4	480N, 238E	Producer
3/12-21-7-16W4	740S, 55E	Producer

In total there are 7 new wells. Two wells were drilled as injectors and five wells were drilled as producing wells. The focus for drilling was in Sections 16 and 21. This is the region with the best reservoir quality and highest OOIP but lowest drilling density. New drilling locations that were cored used a benign mud system to minimize the effect of drilling mud on the laboratory observed wettability of the core.

The last well required for the project is 103/6-16-7-16W4, expected to be drilled July 2006. The 2/6-16 well has 27 m of oil pay but only produced 343 m^3 of oil. Fifteen months after it was rig released, 2/6-16 was shut in at 0.2 m^3/d oil. It was abandoned after repairing a casing vent leak in 1995. Husky determined that a re-drill of 2/6-16 was justified based on the net pay and location of the well in the reservoir compared to the risk of re-entering an abandoned well that had repaired casing. 2/13-16-7-16W4 was drilled to replace 0/13-16 drilled in 1965.

A few positive surprises were encountered with infill drilling. Husky assumed 3/5-21-7-16W4 had been swept but there was a large un-swept portion at the top of the sand (Figure 3.1). 3/5-21 came on at 12 m^3/d, 67% oil cut, but has declined 3% oil cut. 2/13-16-7-16W4 was drilled offsetting the 0/13-16 well and encountered significantly more net oil pay than the 5m expected (Figure 3.2). The petrophysical interpretation of 6 new wells is included in Attachment #11.

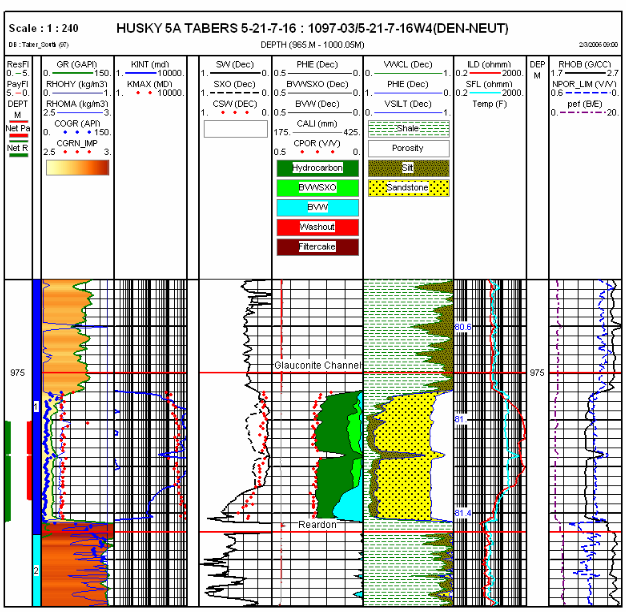

Figure 3.1: Interpretation of 3/5-21-7-16W4 log

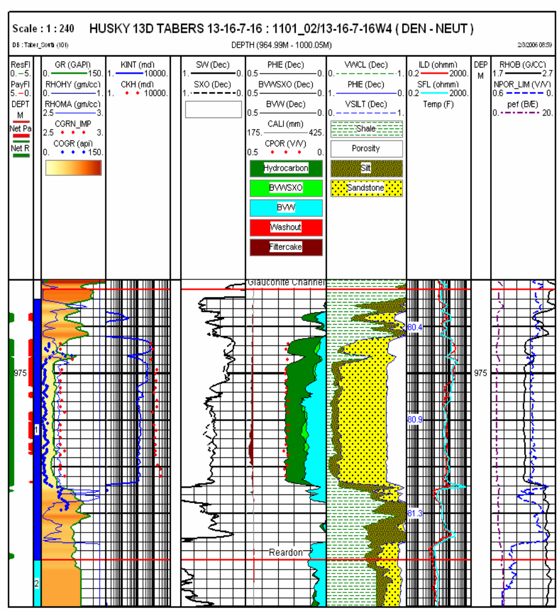

Figure 3.2: Interpretation of 2/13-16-7-16W4 log

Production Performance and Data

Incremental oil from ASP flooding is expected to be 1.0 $10^6 m^3$ (6.3 MMBO), an incremental recovery factor of 14.5% OOIP as summarized in Table 6.

Table 6: Reserve Summary for the Taber S Mannville B pool

Production Values as of May 2006	Oil Volume $10^3 m^3$ (MBO)	Remaining Recoverable Oil $10^3 m^3$ (MBO)	Percent of OOIP (%)
Original Oil in Place (OOIP)	6,992 (44.0)	-	-
Cumulative Production to date (CTD)	2700 (17.0)	-	38.6%
Waterflood Ultimate Oil Production	2763 (17.4)	63 (0.4)	39.5%
ASP Forecast Ultimate Oil Production	3766 (23.7)	1066 (6.7)	53.9%
Incremental Oil Production from ASP	-	1003 (6.3)	14.5%

Based on predictions from the model, oil production is expected to increase from a waterflood forecast of 42 m^3/d in June 2006 to a peak oil rate of 519 m^3/d approximately 4 years after ASP injection begins. Oil cuts are expected to increase from 2% to 14.5% (Figure 4). One drilling location (3/6-16) and one well reactivation (2/3-16) included in the prediction will be on production in July. Forecast production rates as well as the oil production profile required to achieve an incremental 10% recovery factor (4.4 MMBO) are also plotted.

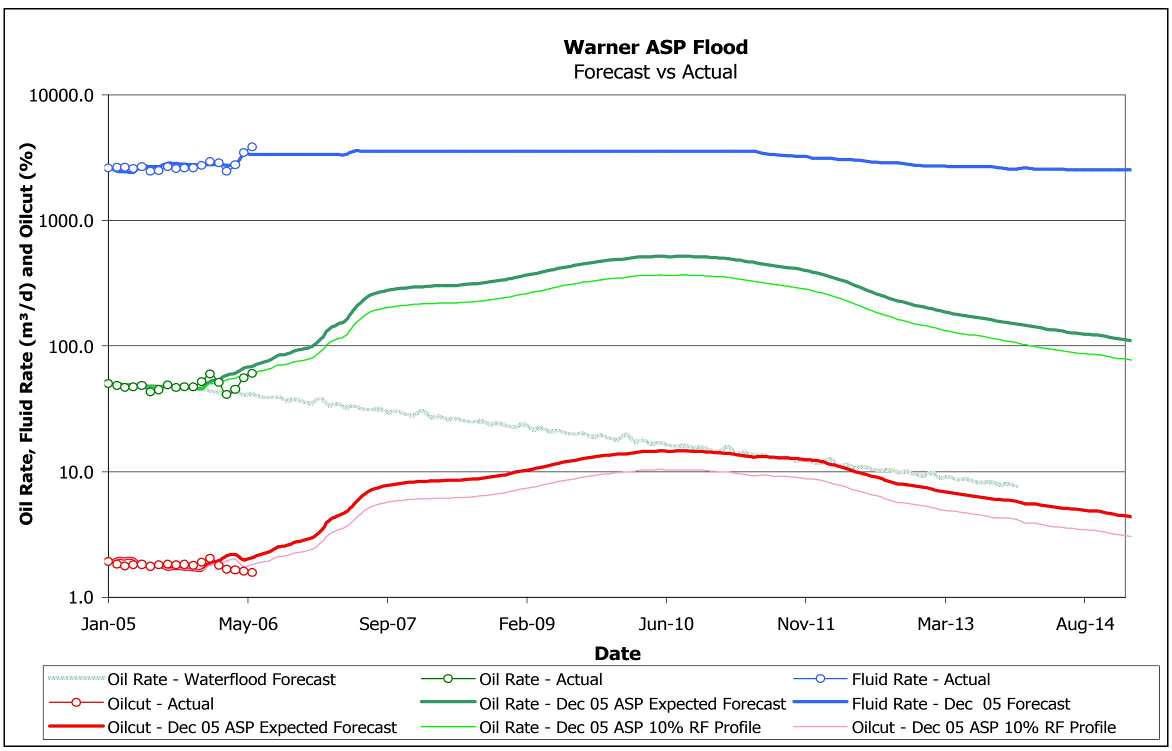

Figure 4: Comparision of production to waterflood and ASP predictions

The reservoir injection rate has increased from 2500 m^3/d in January 2006 to 3600 m^3/d. Average wellhead injection pressure decreased over this time from 14 to 9 MPa (Figure 5). The individual production and injection information are included in *Attachment # 12 – Warner Production Wells* and *Attachment #13 – Warner Injection Rates*.

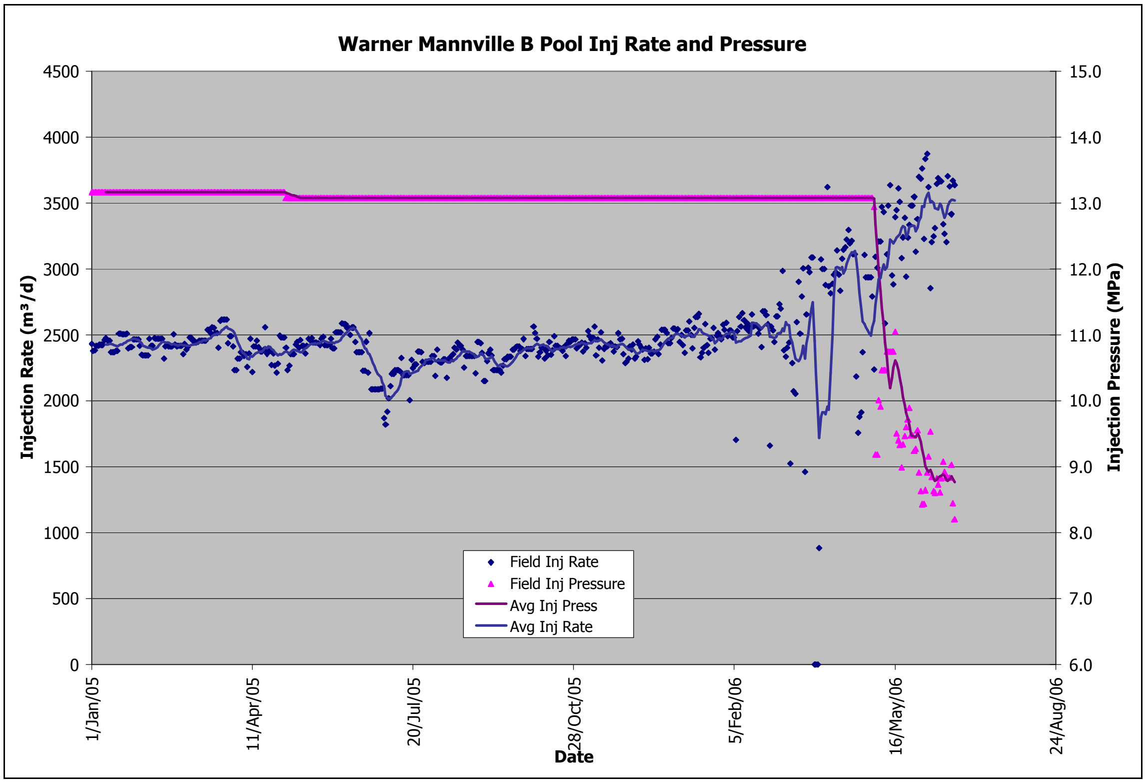

Figure 5: Taber South Mannville B pool injection rates and average wellhead pressure

Composition of Production Fluid

Each production well is sampled monthly and detailed analysis of the water is preformed by a laboratory and reviewed internally to monitor if there is a change in the properties of the produced fluid. The results for May and June have not been received. Husky also analyzes the produced water on from each well on site for surfactant and polymer and no chemicals have been observed in the produced fluid to date.

Composition of the Injection fluid.

The injection is monitored daily to ensure the correct concentration of ASP is injected in the reservoir. The fluid viscosity as measured at the injection wells ranges between 23-26 cP with screen factors equal to 55-65.

Pilot Economics to date

The project started May 2006, therefore production sales volumes are not available. The expected revenue, capital, operating costs, and royalties are included in *Attachment #14 – Forecast Project Economics* in the same format as the March 2005 IETP application. The final capital cost is expected to be $71 million as shown in Table 7.

Table 7: Comparison of original capital estimate to actual costs to date.

Description	IETP Estimate March 2005	Desription	LTD Actual	Estimated Total
Facility - Relocate& Install	$ 3,168,000	Etzikom evaluation and redesign	$ 1,812,657	$ 1,812,657
Facility Equipment - new	$ 2,336,000	ASP Transfer Pipelines	$ 3,698,418	$ 3,705,666
Facility Equipment - used	$ 5,772,000	Etzikom Plant Installation	$ 3,386,743	$ 3,437,940
		ASP injection pumps at 11-16W4	$ 2,735,881	$ 3,497,126
		Warner Facility Modifications	$ 1,613,206	$ 1,904,226
Total Facility Costs	**$ 11,276,000**	**Total Facility Costs**	**$ 13,246,905**	**$ 14,357,615**
Recompletions	$ 1,200,000	Recompletions	$ 2,806,030	$ 3,707,934
Pipelines	$ 1,000,000	Pipelines	$ 3,982,527	$ 4,017,900
		Test Satellites	$ 1,849,013	$ 1,977,563
		Drilling	$ 2,648,891	$ 3,137,922
Total Optimizations	**$ 2,200,000**	**Total Optimizations**	**$ 11,286,461**	**$ 12,841,319**
Design and Testing	**$ 537,000**	**Design and Testing**	**$ 549,219**	**$ 614,393**
Total Chemicals	**$ 35,483,000**	**Total Chemicals**	**$ 1,602,840**	**$ 43,300,000**
Total Project	**$ 49,496,000**	**Total Project**	**$ 26,685,425**	**$ 71,113,327**

The costs are $20 million dollars higher than the capital estimate submitted in the March 2005 IETP Application. The IEPT Application was submitted in the early design stages of the project before laboratory work, facility design, geologic reservoir modeling, and simulation were completed. The project cost is very close to the total AFE estimate of $70.5 million.

Differences between the IETP submission and forecasted final costs are due to the condition of the original AP plant, scope change of the facility design, under estimation of the reservoir development costs, and increase in chemical prices due to the increase in oil price.

The original plan was to re-locate the Etzikom AP plant 11 km north to the Warner ASP site. After an engineering study was completed, it was determined that it would be cost effective to keep the Etzikom AP plant in the same location and pipeline between the two facilities. The pipeline costswould be very close to the freight and labour costs of relocating the facility and Husky would have tangible pipeline assets after the project was finished. When the original AP plant was inspected, the plan was to spot check equipment where corrosion was expected but all equipment that was not internally coated had to be replaced or re-worked. In addition, the first engineering firm contracted to design the facility had a majority of the engineering work performed by another engineering firm due the first engineering firm's difficulty in finding qualified resources given industry activity. This was compounded by the lack of experience the oil and gas industry has with water treatment and ASP facilities. Increased facility costs were also required to bring the facility up to Husky specifications.

In the IETP estimate, 6 wells were expected for reactivation and 4 wells for injection conversion. After the reservoir simulation was completed, it was determined that sections 16 and 21 had the best reservoir quality and highest oil in place but the lowest well spacing. It was concluded that the highest incremental recovery would be achieved with 7 drilling locations, 17 reactivations and conversions, and 10 optimizations on existing injection wells. In addition to the increased costs, predicted incremental oil production also increased by 90 10^3m^3 (560 MBO). The pipeline system was reviewed as a part of the project and it was determined that some pipelines would have to be replaced. Approximately 3 test satellites and 25 km of pipelines were added resulting in costs significantly higher than estimated.

Chemical prices increased because the raw material in polymer, propylene in closely linked to the oil price. Surfactant raw materials, ethylene glycol monobutyl ether and jet kerosene, are also closely linked to the oil price. The oil price increased 30% from February 2005 to September 2005 when RFQs were submitted.

Facilities

The Process Flow Diagram is included as Attachment #15 and facility plot plans are included as Attachment #16.1 and #16.2. The route for the ASP Transfer pipelines is included as Attachment #17. A description of the main facilities is described below.

Etzikom Turnaround project
A turnaround at the Etzikom AP facility had not been performed for 5 years. One of the major findings after cleaning and inspection of the equipment indicated that equipment that was coated was in good condition but vessels, piping, and valves that were not coated had to be replaced. The policy for the Etzikom ASP Plant modifications was to replace and coat equipment. The higher costs are justified by future serviceability and increased salvage value.

All vessels, pumps, valves, were cleaned and inspected. Piping, electrical and instrumentation were also checked

Etzikom Plant Modifications
The following modifications to the plant for the Warner ASP project were implemented based on requirements for the Mannville B reservoir and previous operational experience from the Etzikom AP flood:

- Addition of Surfactant tanks and pump skids.
  - Key learning was that surfactant must be measured using a mass meter as surfactant has low conductivity.
- Replacement of High Pressure NaOH Pump with Low Pressure NaOH Pump
- Add Proximity Probe to Walnut Shell Filters to monitor the agitator
- Re-design Blanket Gas/Scrubbers on tanks for prevention of H_2S emissions
- Transfer pumps for Etzikom ASP fluid to 11-16-7-16W4 Injection Satellite.
- Add filter for Wetted Polymer to reduce plugging of injection wells
  - 25 micron filter to catch polymer that is not hydrated in the blending process.

The value of the existing equipment and new equipment required in the project can be found in *Attachment #18 – Equipment List – Etzikom&11-16.*

Warner Modifications
The Warner 4-20-7-16W4 Oil Battery was modified to supply higher quality produced water with lower oil concentrations to Etzikom and to prepare the facility for polymer that would be present in produced water from Mannville B pool oil production wells. Facility piping was

modified to dedicate one existing pump to supply water to Etzikom with the ability to draw from pumps dedicated to non-ASP pools if make up water was required. The water tank internals were modified to improve retention time and a new skim system was added. The skim pump was upsized and the system was automated for improved efficiency. To handle additional skim volumes, a small, unused treater on site was refurbished. The fire tube in the refurbished treater was coated, a new dump was added to the FWKO for additional level control, and a pressure wash system was installed on the fire tube of the treaters to wash any polymer that might collect in the tubes and cause a failure. A new inlet header was also added for the new group line from the Mannville B pool wells.

11-16-7-16W4ASP Injection Satellite
ASP fluid from Etzikom is pumped at low pressure to the Injection Satellite. Four Q-300 pumps boost the solution into the Mannville B pool at high pressure. Each pump is dedicated to one region of the reservoir. One change was to design the piping so that 0/14-16-7-16W4 could be placed in any group (Table 4) if required to balance injection rates into each region. If there are no difficulties meeting targets, the 0/14-16 well will remain in Group B. The pumps were designed so that they will be easily transferable to future ASP floods.

Capacity limitation:
The ASP facility is capable of blending ASP solution for approximately 4000 m^3/d but the capacity of the facility is limited at the 11-16 Injection Satellite. There are 4 Q-300 pumps, each with a capacity of 900 m^3/d. Current injection is at capacity, approximately 3600 m^3/d.

Operational Issues
The main operational issue is controlling the injection rates to each injection well without the use of chokes. Currently production wells are being slowed down and injection wells are being shut in for 2-3 hours per day to achieve target injection rates.

Environmental/Regulatory/Compliance

Regulatory
A Conservation and Reclamation Study was completed for the ASP Transfer Lines from Warner to Etzikom and from Etzikom to the Injection Satellite. A post-construction reclamation assessment will be conducted in the summer of 2006 to ensure construction practices were conducted accordingly. This will include monitoring for weed populations, evaluating slumping and erosion, topsoil depths, and subsoil salinity. In 2008, a Land Capability Assessment will be conducted to compare the land capability and vegetation success following pipeline reclamation along the pipeline ROW compared to off the ROW.

The injection wells were approved under Directive51 with a Maximum Wellhead Injection Pressure of 16 200 kPag. No injection wells have exceeded this pressure. Average injection pressure is currently 9 000 kPag. The project received Directive 65 Approval (Approval 10418B) to inject ASP into the Taber South Mannville B pool with the following requirements:

- The ASP solution will be 0.75wt% NaOH, 0.15wt% surfactant, and 0.12wt% polyacrylamide polymer

- The polymer solution will be polyacrylamide polymer between 0.06 and 0.12 wt%.
- ASP injection will be not less than 2480 10^3m^3 followed by not less than 2480 10^3m^3 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.

Environment and Safety
Husky has a management system that contains elements such as auditing, incident reporting, contacting residents, and site maintenance. Issues identified comprising of these elements will be managed and acted on appropriately.

Shut down and Environmental Clean Up
The facility will be in operation until at least 2010. 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.

Future Operating Plan

The injection of ASP began just over a month ago. One well is currently being equipped for production, and the final well is expected to be drilled and completed in July. 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 analysis are obtained.

Etzikom is expected to be in operation from May 2006 to the end of 2010. Knowledge from the facility operation will be utilized to optimize the next facility. Husky will also review extending the length of time the chase polymer solution is injected to determine if the cost of additional chemical will justify potential incremental reserves. In light of this, salvage value of the facility has not been determined.

Conclusions:

Although there were many challenges designing the plant due to the available human and capital resources in the industry, ASP start-up went smoothly and the facility is effectively treating and softening the produced water. Alkali, surfactant, and polymer are being blended in correct concentrations. Dedicating one pump to one region of the reservoir is proving to be a cost effective method of controlling injection rates without using well chokes that would shear polymer.

It is very early in the project to determine the effect on oil recovery but production is 17 m^3/d above expected oil production under waterflooding. This increase is from the addition of new wells through drilling, rig operations on suspended wells, and/or conformance changes from the addition of new injection wells and is close to expected results for this stage of the project.

The technical and economic viability looks promising but since the chemical injection only began in May, the overall effect on oil recovery can not be determined. Husky is expecting incremental production from ASP to be 4.4 to 6.4 MMBO.

ASP system design is a detailed process that takes approximately 1 year of laboratory analysis. Husky currently has 4 properties that are in various stages in the laboratory with the purpose of selecting an ASP system that will be ready to implement in other reservoirs if the forecasted oil production rates in the Warner ASP project can be achieved. The laboratory work on all the properties is expected to be completed by summer 2007

There are very few enhanced oil recovery methods for medium crude oil reservoirs after waterflooding despite the fact that a sizable target of oil remains trapped in the reservoir. The advantage with tertiary recovery, compared to exploration, is that the target is often known to a high degree of certainty. The challenge is to understand the technical risk of this tertiary recovery process. Husky and the Alberta Department of Energy have invested resources to increase understanding of ASP technology in anticipation of a successful project. Husky intends to technically and economically advance the process to justify additional ASP floods in suitable reservoirs in Alberta by increasing oil recovery and reducing costs through facility optimization and ASP chemical system improvements.