Oil & Natural Gas Technology

DOE Award No.: DE-FC26-06NT15569

Quarterly Progress Report
With Summaries of Center-sponsored Research
(October – December, 2008)

UTAH HEAVY OIL PROGRAM

Submitted by:
University OF Utah
Salt Lake City, UT

Prepared for:
United States Department of Energy
National Energy Technology Laboratory

January 31, 2009

Office of Fossil Energy

Utah Heavy Oil Program

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Quarterly Progress Report

October 2008 to December 2008

Submitted by:
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Project Period: June 21, 2006 to October 21, 2009

Prepared for:
U.S. Department of Energy
National Energy Technology Laboratory

EXECUTIVE SUMMARY

The Utah Heavy Oil Program (UHOP) recently received a contract extension so that milestones for the five UHOP-sponsored projects and the on-line repository could be completed. Project delays resulted from the loss of key individuals, but UHOP is again fully staffed and rapid progress is anticipated between now and the new end date of the contract, October 20, 2009. Both isothermal and non-isothermal experiments were performed for the detailed study of shale pyrolysis. Most of the oils produced had good distillate fractions; maximum oil recovery was achieved at low heating rates (1°C/min). The water management team finished the acquisition of GIS data related to water resources in the Uinta Basin and will upload all materials collected to the UHOP repository to complete the project. Researchers working on treatment of produced water tested electrolytic degradation of BTEX and naphthalene under varying pH and current densities. To test biological degradation, they are growing bacteria communities capable of degrading BTEX, naphthalene and MTBE. The team applying a thermal simulator to in situ production of Utah oil sands examined the steam-assisted gravity drainage (SAGD) process in partitioned reservoirs. Their results show that high vertical communication in the reservoir is the key to the success of SAGD. Researchers studying depositional heterogeneity and fluid flow modeling in an oil shale interval in the Uinta Basin used a well geometry for their simulations that was based on the pilot scale in-situ conversion process (ICP) used by Shell Oil. The kerogen content in the oil shale interval was estimated using gamma log data from the Utah Geological Survey. Results from the simulation base case show about 50% reservoir heating efficiency at the end of 4 years. Assuming 36% electricity generation efficiency for the down hole heaters, the approximate net energy gain is 3:1. The legal team analyzing the issues surrounding a commercial oil shale leasing program hired an additional attorney and an economist to help complete the analysis. The repository was also fully staffed in this reporting period with the hiring of a librarian and a computer professional.

PROJECT MILESTONES/PROGRESS PERFORMANCE

A. Progress in Program-Sponsored Projects

UHOP received a no-cost extension to their contract during this reporting period. As such, final deliverables are now due on October 20, 2009. Brief summaries are provided below for ongoing work in the five UHOP-sponsored projects.

1. **Detailed Study of Shale Pyrolysis for Oil Production**

Experimental Results: The pyrolysis (N_2 environment, 55 ml/min flow rate) of cylindrical oil shale core samples (3/4” diameter and 9” long) was performed under isothermal conditions (300-400°C, with 100°C/min ramp rate) in an autoclave reactor (Figure 1). Most of the experiments were conducted over a period of 24 hours. The amount of the condensate vapor (yield of shale oil) in the condensers (two condensers in series at an average temperature of -6°C), and total weight loss were recorded and are shown in Table 1. One experiment at 200°C was carried out for 7 days; no sign of shale oil was observed in the condensers. A non-isothermal experiment was performed at a low heating rate(1°C/min) to 400°C for 24 hours. It was observed that the maximum oil recovery occurs at low heating rate (11.91% of total oil shale @ 1°C/min).

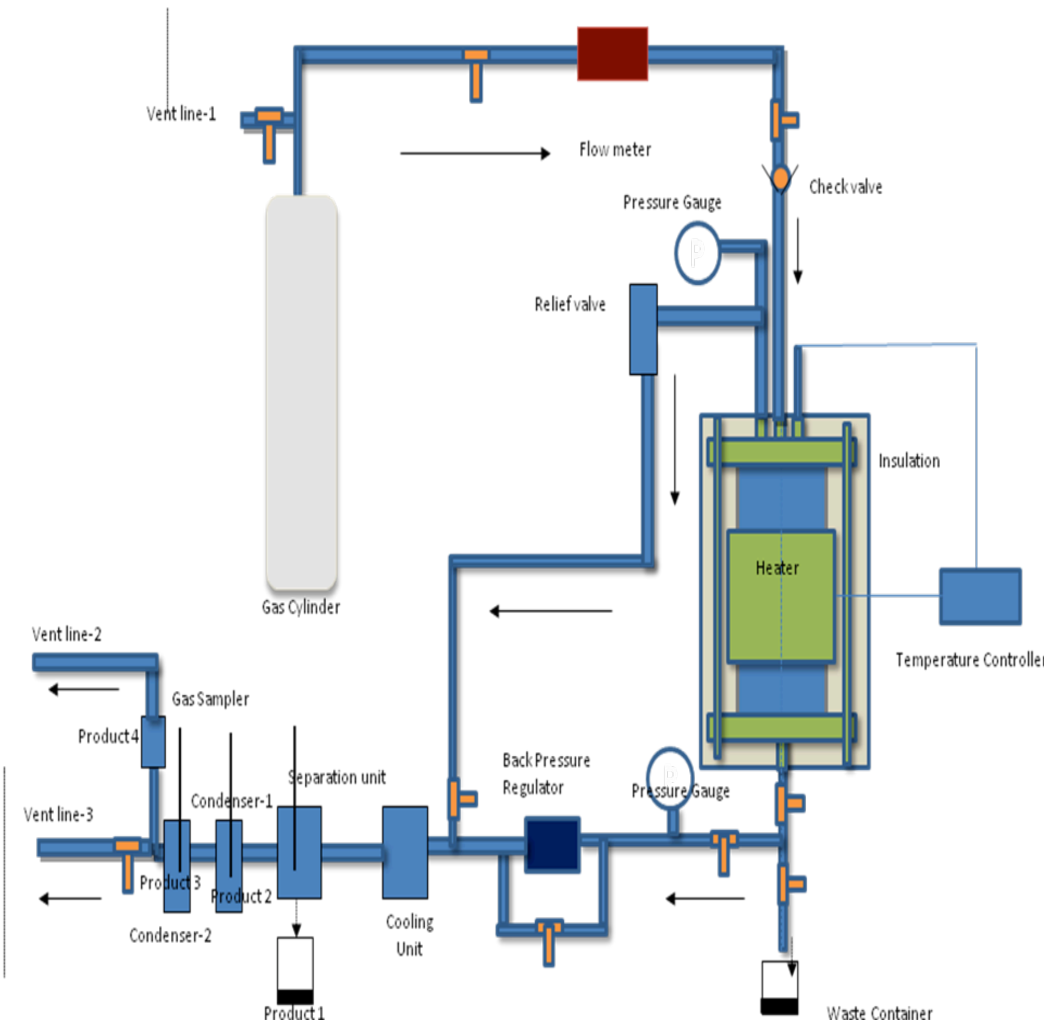


Figure 1. Schematic diagram of experimental setup.

Table 1. Yields at different temperatures using ¾-inch cores and a tubular reactor with shale chunks.

ID	Temp, ºC	Oil Shale wt, gm	Spent shale wt	% Weight loss	% Shale oil
Experiment with Swagelok Reactor					
Run 1	300	51.36	46.17	10.11	6.56
Run 2	350	47.44	40.8	14.00	6.74
Run 3	400	58.12	45.38	21.92	10.28
Run 4	300	57.76	53.65	7.12	5.67
Run 5	350	55.41	48.42	12.62	4.83
Run 6	400C	52.47	44.71	14.79	6.97
Run 7	400	31.5322	26.04	17.42	11.91
NI-Run8	Equil - 130C	1C/min	400C	24 hr at 400C temperature	
Run 9	200C	33.57	33.6	No oil generation (7 days)	
Experiment with Tube Reactor					
Tube-Run1	450C	250.08	205	18.02	8.31
	4th Expt	Pieces of rock			

For all experiments, the collected shale oil, without further treatment, was analyzed in GC 6890 (Agilent) to quantify the hydrocarbon compositions. The ASTM-5307 standard was followed and the operating conditions of the GC (Cool on Column) were: temperature programmed oven (initial 40°C, ramp rate 10°C/min, final 410°C and hold time 10 min), capillary column (helium-carrier gas with 1 ml/min flow rate, inlet temperature with tracked oven condition, 3°C higher than oven) and FID detector (350°C, 40 ml/min H_2 and 450 ml/min zero grade air flow rate). Some of the chromatograms are shown in Figure 2. Most of the oils have good distillate fractions (gasoline, diesel and kerosene) and the residual fraction boiling above 1000°F is about 15 wt%.

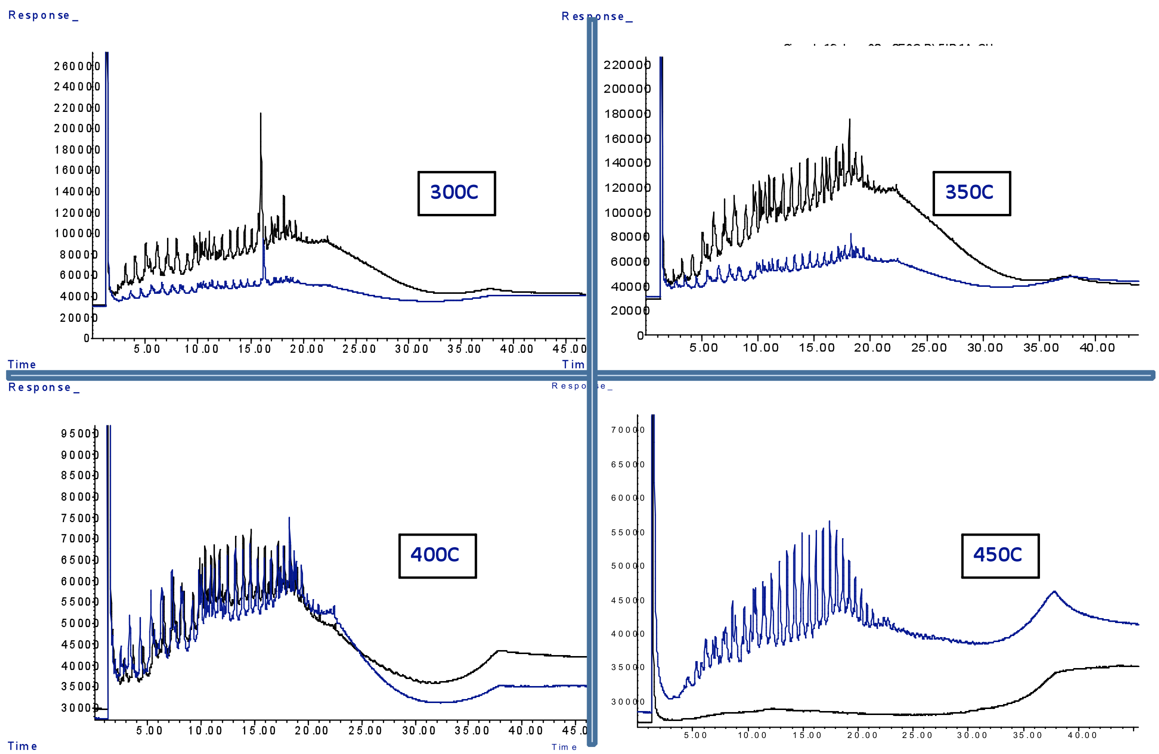


Figure 2. Selected chromatograms of the oil shale samples generated at different conditions.

In situ Oil Shale Recovery Modeling: The project team has been working on the numerical stability of their multi-physics, in situ oil shale recovery model. The 2-D model created for the simulation is in the form of a 60°-30° right triangle. At one apex is the the heating well, at the second is the production well and at the third apex, the right angle, is the point where two symmetry boundaries come together. The 2-D model combines heating from a single well with gas and liquid flows (using d'Arcy's Law) to a production well in a triangular drill pattern which alternates the heating and production wells in each row. In addition, there are reaction kinetics for kerogen conversion to bitumen followed by conversion to oil and gas which are accounted for as source terms in the two mass balance equations calculated by the model (one for oil and one for gas). The goal of the project is to run the model for a simulation period of one year in order to see significant production. As formulated, the model runs for a simulation period of one month and then becomes numerically unstable. The research team has investigated different solvers, different mesh densities and various mesh distributions with no substantial success. Recent work has shown that the cell Peclet number (ratio of local convective to diffusion terms scaled by the cell size) is a critical indicator for the numerical instability; numerical instability occurs when the cell Peclet number is larger than 2. For most operating conditions, the numerical instability comes from one or both of the mass balance equations but most often from the gas mass balance equation. Researchers are examining the computational field to determine where the cell Peclet number is greater than 2; they will then decrease the grid size at that point. In addition, the next version of the software being used, Comsol, has been ordered.

2. New Approaches to Treat Produced Water and to Perform Water Availability Impact Assessments for Oil Shale Development

Water Resources Sustainability: The water management team finished the acquisition of GIS data related to water resources in the Uinta Basin. The data was compiled into a data catalogue and is being transferred to the UHOP repository. A final collection of reports and documents related to oil shale development and water resources was made, and those documents are also being organized for upload to the UHOP repository.

Biological and Chemical Treatment of Produced Water: Electrolytic degradation of BTEX and naphthalene was tested under varying pH and current densities. Specific bacteria responsible for biological degradation were also enriched for BTEX, naphthalene and MTBE. Bacteria for BTEX and naphthalene degradation were relatively easy to enrich. As the literature suggest, the bacteria community which can degrade MTBE is very slow growing and is difficult to maintain. After negotiation with GE (Zenon), the team was finally able to obtain membrane modules to be installed for membrane bioreactors. However, the design parameters for the membrane reactor are confidential, and the researchers are still trying to get the design parameters for the membrane modules from GE to set the membrane bioreactor.

Ozonation of Produced Water: The ozonation team analyzed the results from pressure cycles-assisted ozonation for the treatment of produced waters. The new method is superior to best available technologies in addressing oil removal and water quality issues. A full manuscript describing the process will be completed and sent for review and publication. The PI is presently seeking funding for optimization, pilot testing, and site implementation on the new technology for produced water treatment and reuse.

3. In Situ Production of Utah Oil Sands

In previous quarterly reports, the development of a thermal simulator suitable for many process applications was described. This report discusses the application of the thermal simulator to partitioned reservoirs in the examination of the steam-assisted gravity drainage process (SAGD).

Steam-assisted Gravity Drainage: Many factors determine whether the SAGD process can be successful. These factors include the temperature of the steam and of the reservoir, the oil properties, well locations, the existence of bottom water, reservoir heterogeneities, and the formation of water/oil emulsions within the reservoir (Butler, 1990). In this study, researchers have focused on the influence of the low permeability layers and of the vertical/horizontal permeability ratio on SAGD performance. A hypothesized three-dimensional domain is created where the horizontal wells are deployed in the y-direction. Further, all the geological features are assumed to be repeatable along the trajectory of the wells. Thus, only a vertical slice (600 feet X 100 feet X 600 feet) of the entire domain needs to be simulated.

Four simulation were run with fixed fluid properties, well locations, and operation strategies for a production time of 8000 days. In the first run, the reservoir was assumed to be homogeneous sandstone with uniform isotropic permeability; the second run was identical to the first except two low permeability layers (shale barriers) were added to the formation; the third and fourth runs were modified from the first and second runs, respectively, with the vertical permeability being reduced to 1/10 of the horizontal permeability. The sketch of the domain used in the second and the fourth runs is shown in Figure 3. The essential data for this study is summarized in Table 2. The producer is 76 feet above the bottom of the reservoir and two horizontal wells are 38 feet apart vertically. The perforations are completed at the end points of each well segment.

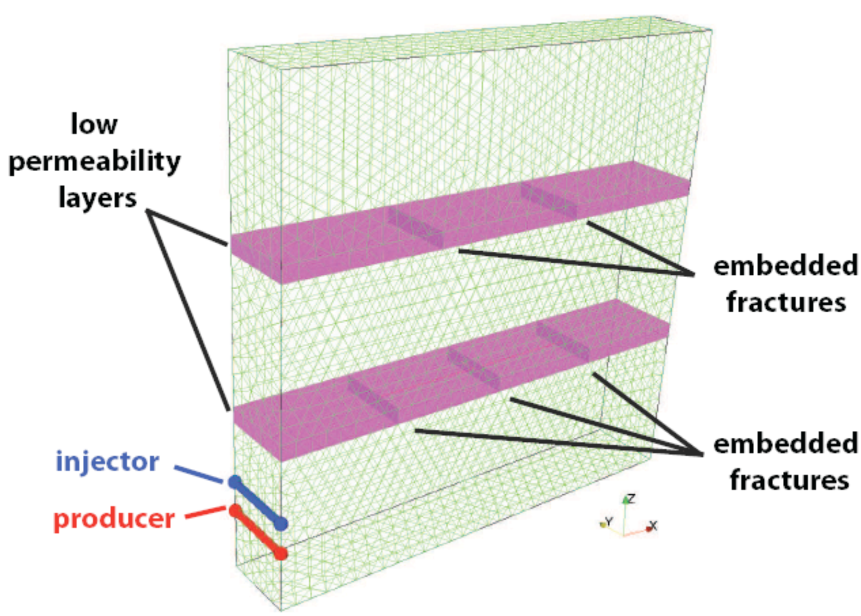


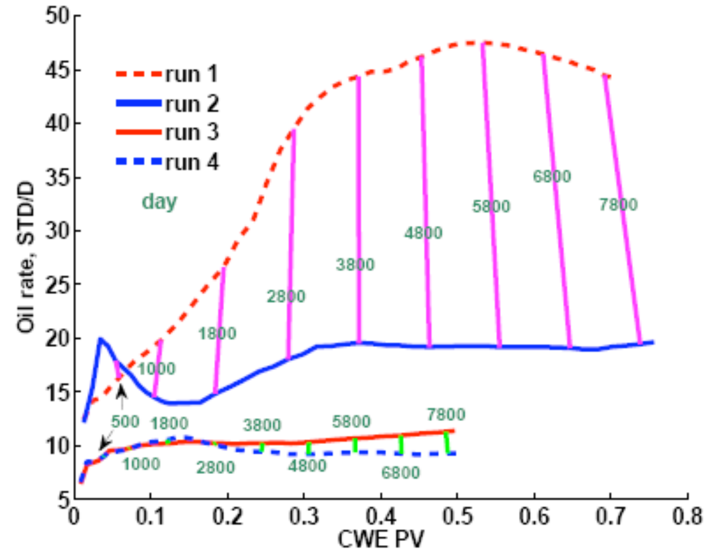
Figure 3. The domain used in the SAGD simulations with embedded fractures.

Table 2: Properties used in the simulation.

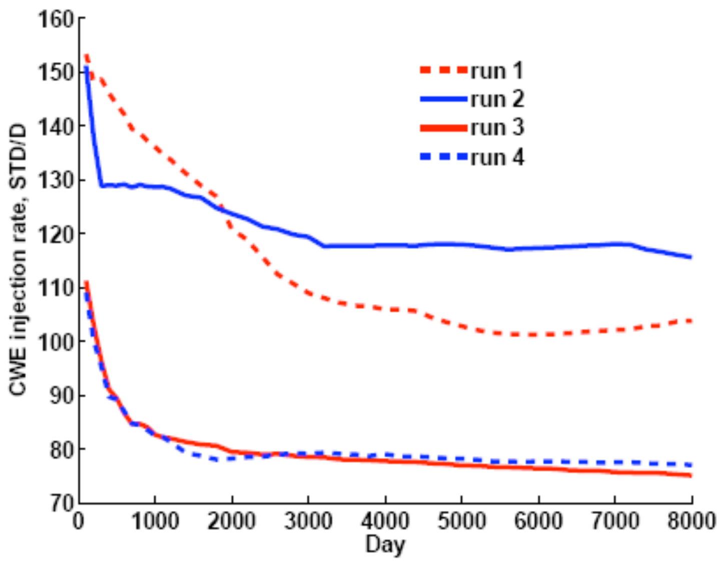
Simulator	CVFEMF2CKT
Grid information	
domain size, (ft)	$600.0ft \times 100.0ft \times 600.0ft$
N_I	8102
No. of tetrahedrons	40309
No. of triangles	51
Fluid property	see SPE4 problem
Rock property	
ϕ	0.20
$k_{m,h}\,(mD)$	1000.0, 0.1[a]
$k_{m,v}\,(mD)$	1000.0[b], 100.0[c], 0.1[a]
$k_f\,(mD-ft)$	10000.0
$K_{c,m}\,\left(\frac{Btu}{ft-R-day}\right)$	45.0, 50.0[a]
$K_{c,f}\,\left(\frac{Btu}{ft-R-day}\right)$	30.0[d]
$\bar{C}_{p_r}\left(\frac{Btu}{ft^3-R}\right)$	35.0
Rock-fluid data	
fracture	
$Pc_{wo}\,(psi)$	0.0
$Pc_{go}\,(psi)$	0.0
kr_{wro}, kr_{oiw}, kr_{gro}	0.1, 0.4, 0.2
n_g, n_{ow}, n_{og}, n_w	1.0, 1.0, 1.0, 1.0
S_{org}, S_{orw}, S_{wir}, S_{gr}	0.1, 0.15, 0.45, 0.06
matrix	
$Pc_{wo}\,(psi)$[e]	0.75, -1.5, 0.0, 0.0
$Pc_{go}\,(psi)$[e]	-3.00, 8.45, 0.0, 0.0
kr_{wro}, kr_{oiw}, kr_{gro}	0.1, 0.4, 0.2
n_g, n_{ow}, n_{og}, n_w	1.5, 2.0, 2.0, 2.5
S_{org}, S_{orw}, S_{wir}, S_{gr}	0.1, 0.15, 0.45, 0.06

Initial conditions		
$T\,(R)$	670.0	
$P\,(psi)$	200.0	
S_o	0.55	
S_w	0.45	
Well conditions		
WI(ft^3)	1000.0	
Injection	max. CWE rate$\left(\frac{STB}{day}\right)$	1000.0
	$T\,(R)$	910.0
	steam quality	0.7
	max. BHP (psi)	400.0
Production	BHP(psi)	300.0

The results of oil production rate, steam/oil ratio (SOR), steam injection rate and water cut are shown in Figures 4 and 5. The formations which have high, isotropic permeability show higher oil production rates (run 1 and 2). In such formations, the introduction of the barrier layers dramatically decreases the oil production rate. However, this effect becomes less significant in the formations where the vertical permeability is as low as 1/10 of the horizontal permeability (runs 3 and 4). The introduction of the barrier layers affects the injection rate differently. In isotropic formations (runs 1 and 2), a higher steam injection rate was observed if the formation does not contain the barrier layers (run 1) at the initial stage of the process where the pressure field is being developed.

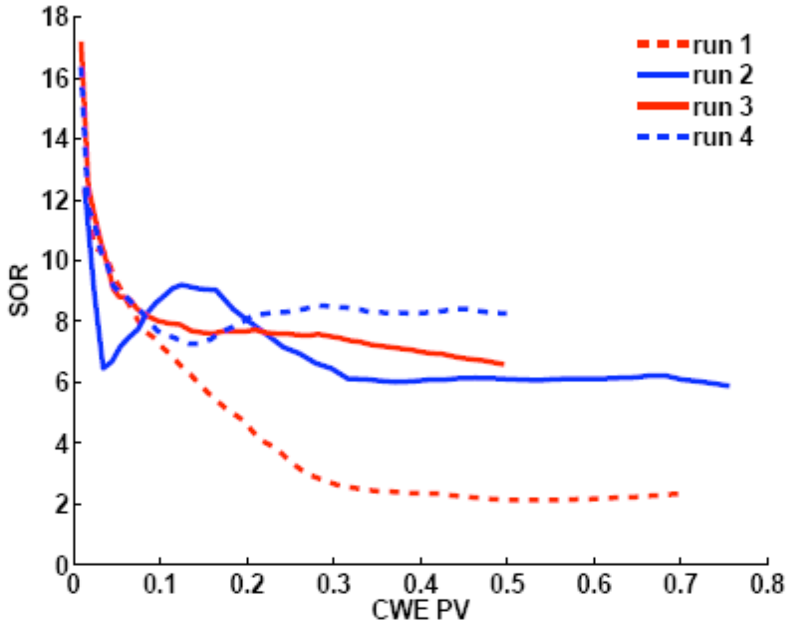


(a) Oil production rate

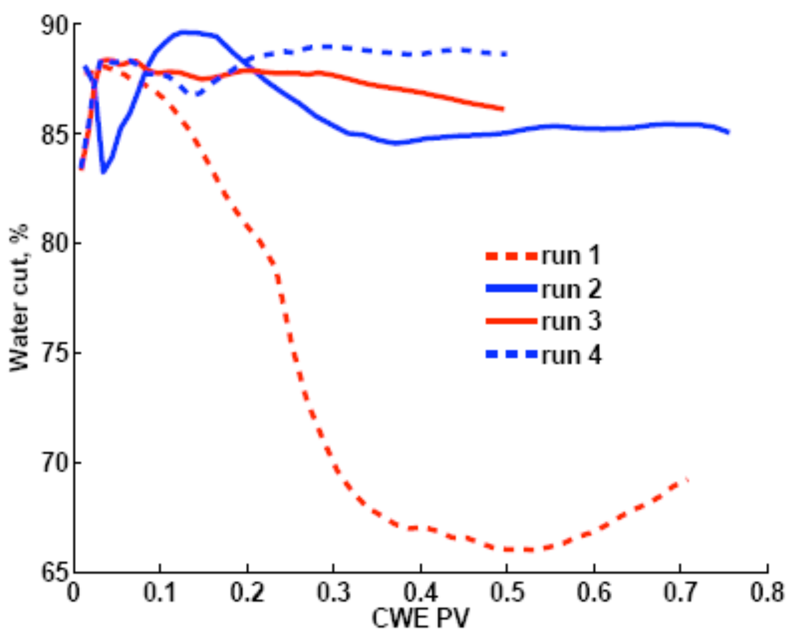


(b) CWE injection rate

Figure 4. Oil production rate and cold-water equivalent (CWE) steam injection rate in the different runs.



(a) SOR



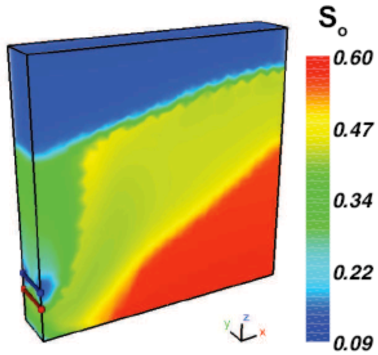
(b) Water cut

Figure 5. Steam oil ratio (SOR) and water cuts.

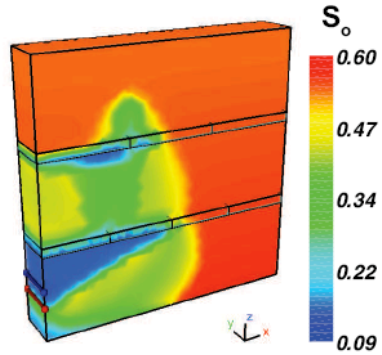
As this pressure field developed, the injection rate decreased until it reached the "pseudo steady state". The rate dropped faster in the formation without the existence of the barrier layers (run 1). Thus, during the "pseudo steady state" period, the injection rate is lower if the barriers are absent. Barrier layers not only slow vertical flow, they also disconnect the pressure field. They partition the reservoir and partially isolate the section of the reservoir between layers. Therefore, the formations containing barrier layers (runs 2 and 4) appear to have lower average formation pressure (see Figure 6), which helps to increase the injection rate at the constant bottom hole pressure condition.

SOR is one of the economic indices for evaluating the SAGD process. An SOR of about 3 is considered economical. In this study, the process with the formation that has isotropic permeability without barriers is most economic. This process also has an attractive water cut curve compared to the other processes. However, as mentioned earlier, many parameters in SAGD need to be optimized to make the process successful. These include reservoir characteristics, thermal efficiency, geomechanics, and a number of process considerations.

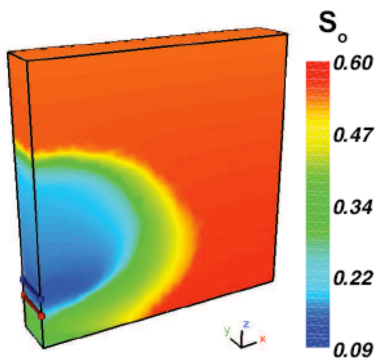
The oil saturation distribution is shown in Figure 6 for runs 1-4. The process with the highest efficiency can be easily identified in the comparison of the size of the oil drainage area at about 0.5 pore volume (PV) injection. The steam chamber grows vertically, and its growth is fastest when uninhibited by the barriers. This phenomenon results in the homogeneous/isotropic formation having a late breakthrough. The temperature distributions are uniform, confirming the conductive control of the process.



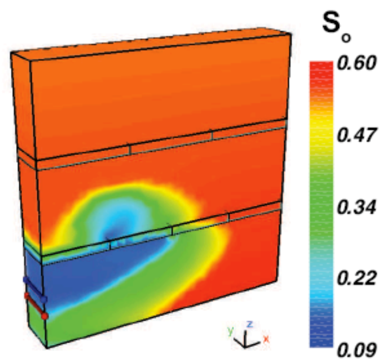
(a) $k_v/k_h = 1.0$, PV = 0.4968



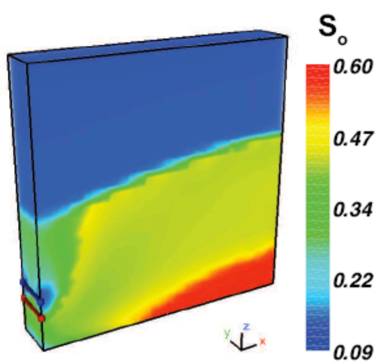
(b) $k_v/k_h = 1.0$, PV = 0.4998



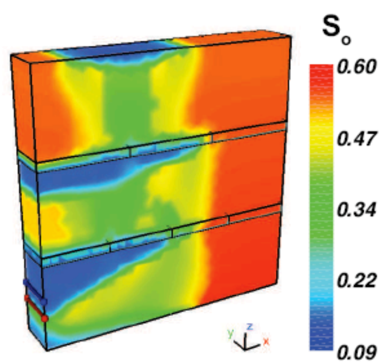
(c) $k_v/k_h = 0.1$, PV = 0.5013



(d) $k_v/k_h = 0.1$, PV = 0.5005



(e) $k_v/k_h = 1.0$, PV = 0.7083



(f) $k_v/k_h = 1.0$, PV = 0.7566

Figure 6. Temperature distributions in SAGD runs 1-4 at different pore volumes (PV) of cold water equivalent (CWE) injection.

These results show that vertical communication in the reservoir is the key to the success of SAGD. Low vertical communication can be caused by vertical permeability or shale sand impurities. The shale layer can be a significant production inhibitor in an isotropic formation. However, its effect becomes limited if the effective vertical permeability is low enough.

4. **Depositional Heterogeneity and Fluid Flow Modeling of the Oil Shale Interval of the Upper Green River Formation, Eastern Uinta Basin, Utah**

In this quarter, the project team explored the use of a better kinetic representation of kerogen transformation to oil than was used previously. The geologic information included as part of the model was identical to that detailed in previous quarterly reports.

Kinetics and Mechanism: Kerogen, the hydrocarbon material in oil shale rock, can be pyrolyzed to produce oil, gas, and residue. The following reaction mechanism, adapted from a previous study (Braun et al., 1992), was used in these simulations.

1	Kerogen	$\longrightarrow$	Heavy Oil + Light Oil + Gas + CH_4 + Char
2	Heavy Oil	$\longrightarrow$	Light Oil + Gas + CH_4 +Char
3	Light Oil	$\longrightarrow$	Gas + CH_4 + Char
4	Gas	$\longrightarrow$	CH_4 + Char
5	Char	$\longrightarrow$	CH_4 + Gas + Coke

All the reactions were assumed to be first order, and kinetic parameters from Braun et al. (1992), with the exception of heats of reaction, were used. For each reaction, the heat of reaction was assumed to be 46.5 kJ/gmole. Stoichiometry was approximated based on the molecular weights and the hydrogen to carbon ratios chosen for each component to force a mass balance. These values are shown in Table 3.

Additional simulations, including a more realistic hydrogen/carbon ratio of 1.50 for kerogen and more rigorous mass and elemental balances, were run and showed comparable results and trends. It should be noted that stoichiometric coefficients used in this reaction scheme are not unique. They are simply estimated to force mass and elemental balances based on approximated molecular weights and hydrogen/carbon ratios of each component.

Table 3. Molecular weights and hydrogen/carbon ratios used in kerogen reaction mechanism.

Component	Molecular Weight	Hydrogen/Carbon Ratio	Hydrogen/Carbon Ratio (rigorous)
Kerogen	670	1.05	1.5
Heavy Oil	441	1.64	1.52
Light Oil	152	2.27	1.52
Gas	54	2.5	1.62
Methane	16	4	4
Char	12.4	0.6	0.39
Coke	12.5	0.45	0.34

Geometry: The well geometry used in the simulations was based on the pilot scale in-situ conversion process (ICP) used by Shell Oil. Six heating wells surround one production well (Figure 7a). This arrangement translates to a simulation heater spacing of 53 feet. The thickness of the simulated reservoir was 50 feet. Due to symmetry, only a triangular wedge was simulated (see Figure 7b). The results from this simulated section can be repeated to represent the field. Using CMG Builder, the wedge was discretized into 21 blocks in the vertical direction, 19 blocks in the horizontal direction, and 1-10 blocks in the height direction of the triangle (10 blocks being the height of the triangle from an aerial view).

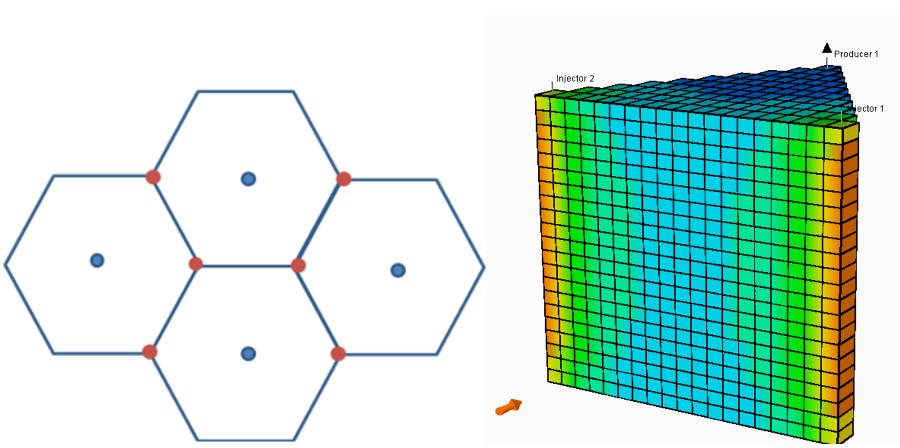


Figure 7: (a) Geometric arrangement of heating and production wells for Shell ICP. (b) Triangular wedge representing computational mesh used for simulations.

Initial Conditions: Gamma log data from the Utah Geological Survey for the U059 well in the Uinta Basin was used to estimate the weight percent of hydrocarbons (kerogen). The kerogen-rich section of the well is from 665 feet to 715 feet deep, and the weight percent kerogen varies from 12.5 wt% to 25 wt%. Table 4 shows the weight percent of kerogen at different depths in the well. This information was used to calculate the initial kerogen volume at each depth. The remaining volume was assumed to be inorganic rock.

Table 4. Hydrocarbon content of oil shale interval in U059 as a function of depth.

Depth (ft)	Wt% Hydrocar-bons
665-670	12.5
671-680	12.5
681-690	14
691-694	15
695-700	16
700-710	25
710-715	16

The initial porosity of the rock was calculated for each layer with the assumption that kerogen completely filled the pore space in the rock. The initial pressure and temperature assigned to the reservoir were a constant 1000 psi and 80°F.

Production Strategy: The reservoir was directly heated with two vertical injection wells to simulate resistive or burner heaters. These heaters heated uniformly from the top to the bottom of the well. The heaters each supplied 50,000 BTU to the reservoir for a four-year time period. The production was pressure controlled by the producer. The base case scenario used a bottom-hole pressure (BHP) of 100 psi, but many simulations were run at different back pressures to estimate pressure sensitivity and numerical stability.

Results: The production results of the simulation are shown in Figures 8 and 9. Figure 8 shows that in addition to oil, significant quantities of gas are produced in the process. The oil and gas rate dynamics depend on the complex interactions among increasing temperature, the kinetics and stoichiometry of the conversion, porosity and permeability creation and on the complex aspects of multiphase flow.

The net energy gain/loss was estimated for this type of process. This preliminary estimate assumed that the kerogen content in the oil shale source rock was 15 wt%, all kerogen was converted to recoverable oil, the source rock was heated from 25°C to a retort temperature of 350°C, and the heat of reaction for kerogen conversion was 370 kJ/kg. Given these assumptions, the idealized estimate for net energy gain/loss was 17 units of energy produced per unit of energy required. Results from the simulation base case show about 50% reservoir heating efficiency at the end of 4 years. Assuming 36% electricity generation efficiency and 50% reservoir heating efficiency, the approximate net energy gain is 3:1. By including both gas and oil as products, the net energy gain from the simulation base case was 3.06 units energy produced per unit energy required. In pilot tests of ICP, Shell Oil estimated a net energy gain of 3 units out per unit required with resistive heating supplied.

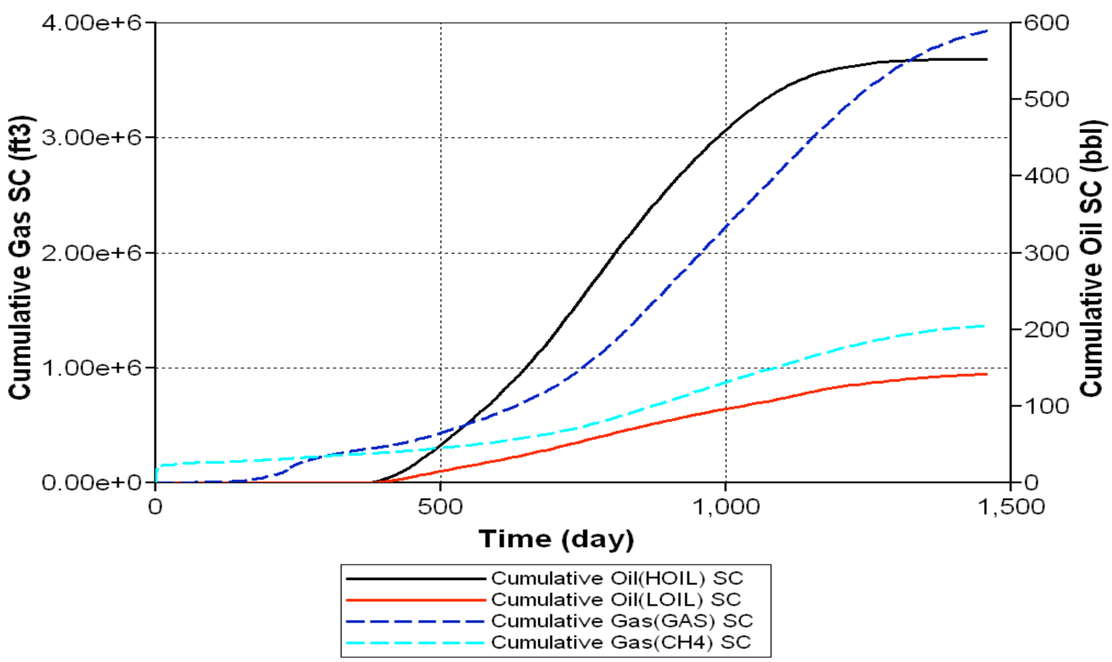


Figure 8. Cumulative production of the different oil and gas components from the reservoir.

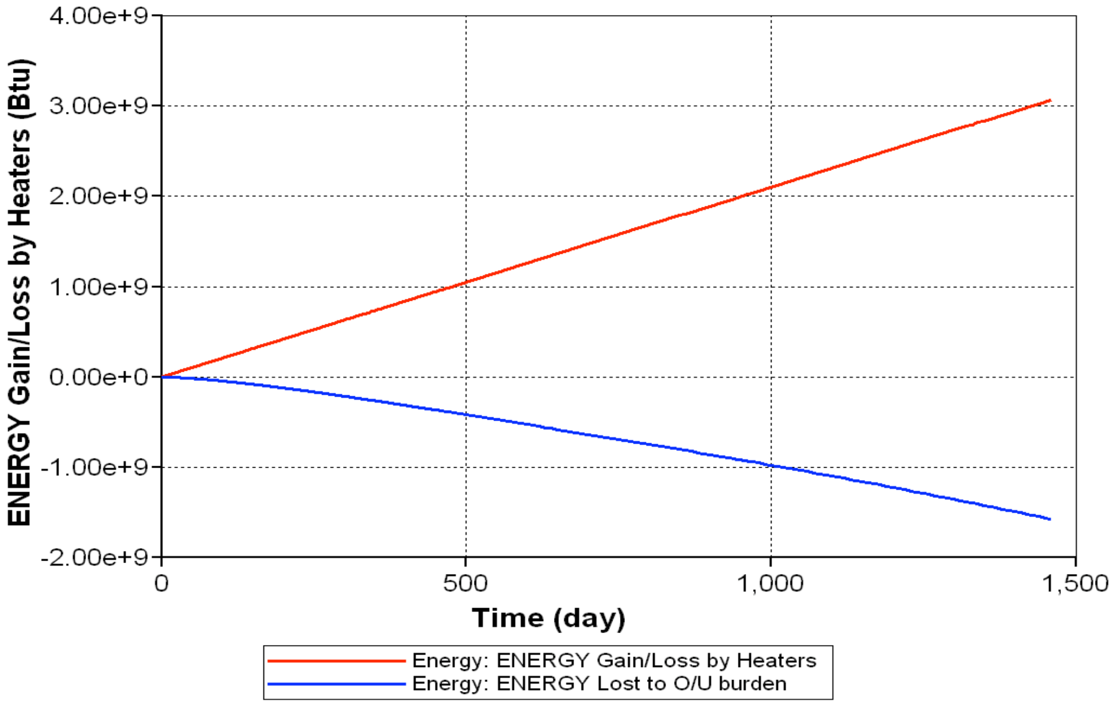


Figure 9. The energy input (through heaters) and loss (to the over-burden and underburden) in the model.

5. **Analysis of Environmental, Legal, Socioeconomic and Policy Issues Critical to the Development of Commercial Oil Shale Leasing on the Public Lands in Colorado, Utah, and Wyoming under the Mandates of the Energy Policy Act of 2005; Economic Evaluation of Bitumen Upgrading**

The legal team continued its research and drafting of sections addressing land use and impact issues and water quality and quantity issues. In addition, initial research and analysis of air and carbon issues was conducted. A new legal research associate, Jon Ruple, was hired during the reporting period. The team held several meetings to review project status with Jon and to revise the framework for sections addressing economics and socioeconomic issues in anticipation of hiring an economic analyst. The analyst selected, Michael Hogue, joined the Bureau of Economic and Business Research (BEBR) at the University of Utah in late December 2008 working with ICSE. His responsibilities include completing this project and working on economics issues in the new Clean and Secure Energy tasks.

B. On-line Repository

Since early summer, an undergraduate student has been working on uploading the 1400 documents received from UGS in 2006 with an improved workflow that includes copyright verification. However, most of these documents still wait approval by the recently-hired Institute librarian before being fully available to the public through DSpace. The librarian is working diligently to determine copyright and approve documents. Once all 1400 of these original documents are available through the repository, this task will be considered finished.

CONCLUSIONS

With the no-cost extension, researchers were able to continue working on their deliverables during the last quarter of 2008. Several projects have now spent their budgets, so final reports for those projects will be available in the next quarter.

COST STATUS

Baseline Reporting Quarter	Year 1							
	Q1		Q2		Q3		Q4	
	6/21/06 - 9/30/06		10/1/06 - 12/31/06		1/1/07 - 3/31/07		4/1/07 - 6/30/07	
	Q1	**Total**	Q2	**Total**	Q3	**Total**	Q4	**Total**
Baseline Cost Plan								
Federal Share	126,295	**126,295**	239,349	**365,644**	41,357	**407,001**	147,911	**554,912**
Non-Federal Share	31,574	**31,574**	34,342	**65,916**	25,969	**91,885**	38,387	**130,272**
Total Planned	157,869	**157,869**	273,691	**431,560**	67,326	**498,886**	186,298	**685,184**
Actual Incurred Cost								
Federal Share	126,295	**126,295**	239,349	**365,644**	41,357	**407,001**	164,491	**571,492**
Non-Federal Share	31,574	**31,574**	34,342	**65,916**	25,969	**91,885**	30,841	**122,726**
Total Incurred Costs	157,869	**157,869**	273,691	**431,560**	67,326	**498,886**	195,332	**694,218**
Variance								
Federal Share	0	**0**	0	**0**	0	**0**	16,580	**16,580**
Non-Federal Share	0	**0**	0	**0**	0	**0**	(7,546)	**(7,546)**
Total Variance	0	**0**	0	**0**	0	**0**	9,034	**9,034**

Baseline Reporting Quarter	Year 2							
	Q5		Q6		Q7		Q8	
	7/1/07 - 9/30/07		10/1/07 - 12/31/07		1/1/08 - 3/31/08		4/1/08 - 6/30/08	
	Q5	**Total**	Q6	**Total**	Q7	Total	Q8	Total
Baseline Cost Plan								
Federal Share	147,911	**702,823**	147,911	**850,734**	147,911	**998,645**	147,911	**1,146,556**
Non-Federal Share	38,620	**168,892**	38,620	**207,512**	38,620	**246,132**	38,620	**284,752**
Total Planned	186,531	**871,715**	186,531	**1,058,246**	186,531	**1,244,777**	186,531	**1,431,308**
Actual Incurred Cost								
Federal Share	161,343	**732,835**	178,570	**911,405**	165,243	**1,076,648**	114,429	**1,191,077**
Non-Federal Share	29,299	**152,025**	10,038	**162,063**	36,285	**198,348**	19,020	**217,368**
Total Incurred Costs	190,642	**884,860**	188,608	**1,073,468**	201,528	**1,274,996**	133,449	**1,408,445**
Variance								
Federal Share	13,432	**30,012**	30,659	**60,671**	17,332	**78,003**	(33,482)	**44,521**
Non-Federal Share	(9,321)	**(16,867)**	(28,582)	**(45,449)**	(2,335)	**(47,784)**	(19,600)	**(67,384)**
Total Variance	4,111	**13,145**	2,077	**15,222**	14,997	**30,219**	(53,082)	**(22,863)**

Baseline Reporting Quarter	Year 3							
	Q9		Q10		Q11		Q12	
	7/1/08 - 9/30/08		10/1/08 - 12/31/08		1/1/2009 - 3/31/09		4/1/09 - 6/30/09	
	Q9	Total	Q10	Total				
Baseline Cost Plan								
Federal Share	147,911	**1,294,467**	34,802	**1,329,269**	34,802	**1,364,071**	34,802	**1,398,873**
Non-Federal Share	38,620	**323,372**	8,758	**332,130**	8,758	**340,888**	8,758	**349,646**
Total Planned	186,531	**1,617,839**	43,560	**1,661,399**	43,560	**1,704,959**	43,560	**1,748,520**
Actual Incurred Cost								
Federal Share	144,808	**1,342,302**	31,909	**1,374,211**				
Non-Federal Share	37,868	**255,236**	4,266	**259,502**				
Total Incurred Costs	182,676	**1,597,538**	36,175	**1,633,713**				
Variance								
Federal Share	(3,103)	**47,835**	(2,893)	**44,942**				
Non-Federal Share	(752)	**(68,136)**	(4,492)	**(72,628)**				
Total Variance	(3,855)	**(20,301)**	(7,385)	**(27,686)**	0	**0**	0	**0**

Baseline Reporting Quarter	Year 3							
	Q13		Q14					
	7/1/09 - 09/30/09		10/01/09 - 10/20/09					
	Q9	Total	Q10	Total				
Baseline Cost Plan								
Federal Share	34,802	**1,433,675**	8,701	**1,442,376**				
Non-Federal Share	8,758	**358,404**	2,190	**360,594**				
Total Planned	43,560	**1,792,080**	10,890	**1,802,970**				
Actual Incurred Cost								
Federal Share								
Non-Federal Share								
Total Incurred Costs	0	**0**	0	**0**				
Variance								
Federal Share								
Non-Federal Share								
Total Variance	0	**0**	0	**0**				

Note: The Cost Plan has been revised to reflect the agreement's extension through 10/20/2009.

MILESTONE STATUS

Three project milestones have not been completed: Task 1.5, Develop on-line repository for all types of material pertaining to unconventional resources in North America; Task 1.8, Refine repository, incorporating information provided by user community; and Task 2.4, Complete technical report for Center-based research projects. With the recent hiring of a computer professional and a librarian to provide support for the repository, we anticipate that Tasks 1.5 and 1.8 will be completed by May 2009. Some Center-based projects have now spent their budgets and will be preparing final reports in the first quarter of 2009. Those reports will be available in March 2009. As budgets for the remaining projects are spent, final reports will be written. A completion date for technical reports from all the projects is October 20, 2009.

PROBLEMS OR DELAYS

As indicated in the report for the quarter ending September 30, 2008, several UHOP projects were behind schedule due to the loss of key personnel. Personnel issues on all projects were resolved in this reporting period, and it is anticipated that several projects will be finished in the next quarter.

RECENT AND UPCOMING PRESENTATIONS/PUBLICATIONS

Pankaj Tiwari, Kyeongseok Oh, and Milind Deo, "Isothermal and Non-isothermal Kinetic Analyses of Mahogany Oil Shale with TGA," Paper 17.4, 28th Oil Shale Symposium, October 13-17, 2008, Golden, CO.

William Gallin, Royhan Gani, Chung-Kan Huang, and Milind Deo, "Resource Characterization and Reservoir Modeling of Oil Shale Deposits in Uinta Basin, Utah," Paper 5.4, 28th Oil Shale Symposium, October 13-17, 2008, Golden, CO.

Milind Deo, participant in the Natural Resources Law Forum, " What exactly is oil shale? What does it mean for Utah? What are its environmental impacts? How will it help our energy crisis?" Held at the S.J. Quinney College of Law, October 27, 2008.

Milind Deo, "Technical Aspects of Producing Oil from Oil Shale," USTAR/SPE Update on Oil Shale in Utah, November 13, 2008.

Milind Deo and Pankaj Tiwari, "Kinetics of Oil Shale Pyrolysis and Oil Composition," Paper 172a, AICHE Annual Meeting, November 16-21, 2008, Philadelphia, PA.

Milind Deo and Chung-Kan Huang, "Modeling In Situ Production of Oil from Oil Shale," Paper 172d, AICHE Annual Meeting, November 16-21, 2008, Philadelphia, PA.

Liang Li, "Biodegradation of Naphthalene by Bacteria from Municipal Wastewater Treatment Plant," Water Environment Association of Utah, November 20, 2008, West Valley City, UT.

Milind Deo, "In Situ Production of Utah Oil Sands," 2009 Western U.S. Oil Sands Conference, February 27, 2009, Salt Lake City, UT.

Steve Burian and Eric Jones, "Water Availability Impact Assessments for Uinta Basin Oil Sands and Oil Shale Development," 2009 Western U.S. Oil Sands Conference, February 27, 2009, Salt Lake City, UT.

Andy Hong, Zhixiong Cha, Cheng-Fang Lin, and Angela Lin, "Pressure-Assisted Ozonation for Rehabilitation of Produced Water," 19th Annual AEHS Meeting & West Coast Conference on Soils, Sediments, and Water, March 9-12, 2009, San Diego, California.

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R. L. Braun, A. K. Burnham, and J. G. Reynolds, "Oil and Gas Evolution Kinetics for Oil Shale and Petroleum Source Rocks Determined from Pyrolysis-TQMS Data at Two Heating Rates," *Energy and Fuels*, **6**, 468-474 (1992).

S. Butler, R.M., 1991, Thermal Recovery of Oil and Bitumen, Prentice Hall, NJ.

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