Oil & Natural Gas Technology

DOE Award No.: DE-NT0006553

Progress Report
Third Quarter 2009

ConocoPhillips Gas Hydrate Production Test

Submitted by:
ConocoPhillips
700 G Street
Anchorage, AK 99501
Principle Investigator: David Schoderbek

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

November 12, 2009

Office of Fossil Energy

Disclaimer

Executive Summary

Accomplishments

- Continued the process to gain working interest co-owner approval for the proposed production test sites.
- Completed laboratory experiments that evaluate the effect of carbon dioxide hydrate formation on reservoir permeability
- Completed initial, scoping reservoir simulation for the production test, providing critical design information
- Made significant strides to evaluate and identify drilling, logging, and completion options for the production test.

Current Status

- Well testing and completions options continue to be evaluated. Work has begun regarding completion metallurgy options.
- Broad engagement with other stakeholders to secure approvals to perform the test with a continued focus on possible synergies with BP Alaska's hydrate project.

Introduction

Work began on the ConocoPhillips Gas Hydrates Production Test (DE-NT0006553) on October 1, 2008. This report is the fourth quarterly report for the project and summarizes project activities from July 1, 2009 to September 30, 2009. Work during this quarter was focused on Phase 2, Field Test Planning while substantial efforts continued on Tasks 3 & 4 from Phase 1, Site Identification, to secure approvals for the sites selected and evaluate synergies with the DOE-BP hydrates project.

The report begins with a summary of current Site Identification activities. Following this summary is a detailed discussion of the experimental design and well design activities. Cost and milestone information is presented at the end of the report.

PHASE 1, SITE IDENTIFICAITON

Task 2 – Site Identification, Evaluation, and Selection

ConocoPhillips facilitated a videoconference on September 30 with DOE and USGS reps to provided updates regarding exchange field trial site ranking and project design. Scoping reservoir modeling results, which aided in project design, were also presented and discussed at this meeting.

Task 3 – Field Site Ownership Partner Negotiations

ConocoPhillips prepared a written proposal to perform the CO_2/CH_4 exchange field trial in the Prudhoe Bay Unit and submitted a draft to PBU working interest owners July 21. ConocoPhillips facilitated a follow-up meeting to thoroughly review site ranking, field experiment and well designs, and details on August 13. This meeting connected ConocoPhillips Houston Gas Hydrates management, ConocoPhillips Alaska-based Well Planning Team, and representatives of Prudhoe Bay Unit owners from BP, ExxonMobil, and Chevron. ConocoPhillips will continue to keep DOE informed of progress on working interest owner discussions through regular project communications and will inform DOE of any issues that could affect the intended content of the production test planned under this project.

Task 4 - Evaluation of Synergies with DOE-BP Arctic Field Project

ConocoPhillips personnel have facilitated several meetings with Anchorage-based BP hydrates representatives to identify and optimize synergies between the CO_2/CH_4 exchange field trial and BP's long-term depressurization test. Options from multiple operations in a single wellbore to twin wells on the same ice pad to twin wells drilled directionally from an existing gravel pad have been discussed. No options have been ruled out, but multiple operations in a single wellbore appear too operationally complex to be feasible. The "twin wellbores" configuration contemplates conversion of the CO_2/CH_4 exchange wellbore to a pressure observation well during the long-term depressurization test. Discussions between operational teams at BP and ConocoPhillips are continuing.

PHASE 2: FIELD TEST PLANNING

Field Test Planning is embodied by two closely related tasks: Task 5 (Detailed Well Planning / Engineering) and Task 6 (Pre-Drill Estimation of Reservoir Behavior). Two interdisciplinary teams (Experimental Design Team & Well Design Team) were chartered in the 2nd Quarter to begin work on this phase of the project. The work completed by each team is discussed below.

Experimental Design Team

The Experimental Design Team worked throughout the 3rd Quarter on the design of the CO_2/CH_4 exchange field trial. Three accomplishments are reported here: 1) results of laboratory experiments to measure effects on permeability of CO2-hydrate formation, 2) discussions of hydrate coring and core analysis, and 3) reservoir simulation and modeling of nitrogen injection, carbon dioxide injection, and methane flow back.

1) Laboratory Experiments: A set of experiments were designed to investigate the effect that liquid carbon dioxide injection has on the permeability of hydrate-bearing sediment that contains excess free water. Previous experiments that measured permeability in hydrate-saturated samples, both in this laboratory and in the literature, were run in systems with no free water (i.e. there was sufficient hydrate formers in the system to convert all available water to hydrate). Log analysis of hydrate bearing zones indicates that natural gas hydrate zones contain some free water in the pore system. Under these circumstances, the introduction of carbon dioxide to the system would convert any remaining free water to hydrate and could significantly reduce the permeability. On the contrary, these experiments demonstrated, that while the additional carbon dioxide combined with the free water to form additional hydrate, the remaining permeability was sufficient for gas transport.

1a) Experiment description

Two experiments to determine the role of excess water on the effectiveness of carbon dioxide injection were run. The results from the first test were discussed in the second quarter report. The second test results are discussed here.

This experiment was based upon a Bentheim sandstone core plug with approximately 1 Darcy permeability. The sample was partially saturated with a 0.1 weight percent NaCl solution (0.018M or 1000 ppm NaCl) by imbibition to a final saturation of approximately 70%. The imbibition process produced a fairly uniform distribution of water along the length of the core as monitored by MRI techniques. Methane gas at 1200 psi was introduced to the core at one end of the core plug to fill the remaining pore space. The sample was then cooled to $4^{o}C$, which initiated the formation of hydrate in the core as monitored by MRI. The amount of methane introduced to the system was limited so that approximately half of the available water was converted to hydrate. Permeability at that point was determined by the changes in the methane flow rate as the inlet and outlet pumps maintained a constant differential pressure.

Once the methane hydrate formation stabilized at approximately 35% free water saturation and 35% hydrate saturation, several permeability-to-nitrogen gas measurements were completed by measuring pressure differences across the core at several injection rates.

Liquid carbon dioxide (viscosity approximately 0.1 cP at $4^{o}C$ and 1200 psi) was injected at a rate of 0.1 to 0.2 cm^3/min for a period of 9 hours. The pressure difference across the core was maintained at 10 psi and the changes in injection rate were monitored as an indicator of permeability to liquid carbon dioxide. The injection rate values were smoothed with a 10-point moving average to reduce spikes. A series of MRI profiles along the length of the core were collected every twenty minutes to monitor hydrate formation.

Following the liquid carbon dioxide injection the system was stabilized for 12 hours before starting a series of depressurization steps. The pore pressure was dropped from 1200 psi to 570 psi and left to stabilize for 6 hours. This was followed by depressurization steps to 550 and 350 psi after each the system was shut-in for 6 hours. The final step was to 0 psi, which should result in complete dissociation of any hydrate in the core.

1b) Experiment Results

The initial water saturation of 70% was uniformly distributed along the length of the core as monitored with MRI profiles. The injection of calibrated amounts of methane at 4°C and 1200 psi formed hydrate throughout the core, with a greater amount at the outlet end (Figure 1). The free water saturation was estimated at 35% based on the changes in MRI intensity, which correlates to a hydrate saturation of 35%.

Permeability to nitrogen gas measured at this point in time was 4-18 mD. The injection of liquid carbon dioxide converted much of the available excess water into hydrate. The formation of this additional hydrate occurred along the length of the core rather than being localized at the inlet portion of the sample (Figure 1). After nine hours of liquid carbon dioxide injection some of the excess water remained unconverted to hydrate.

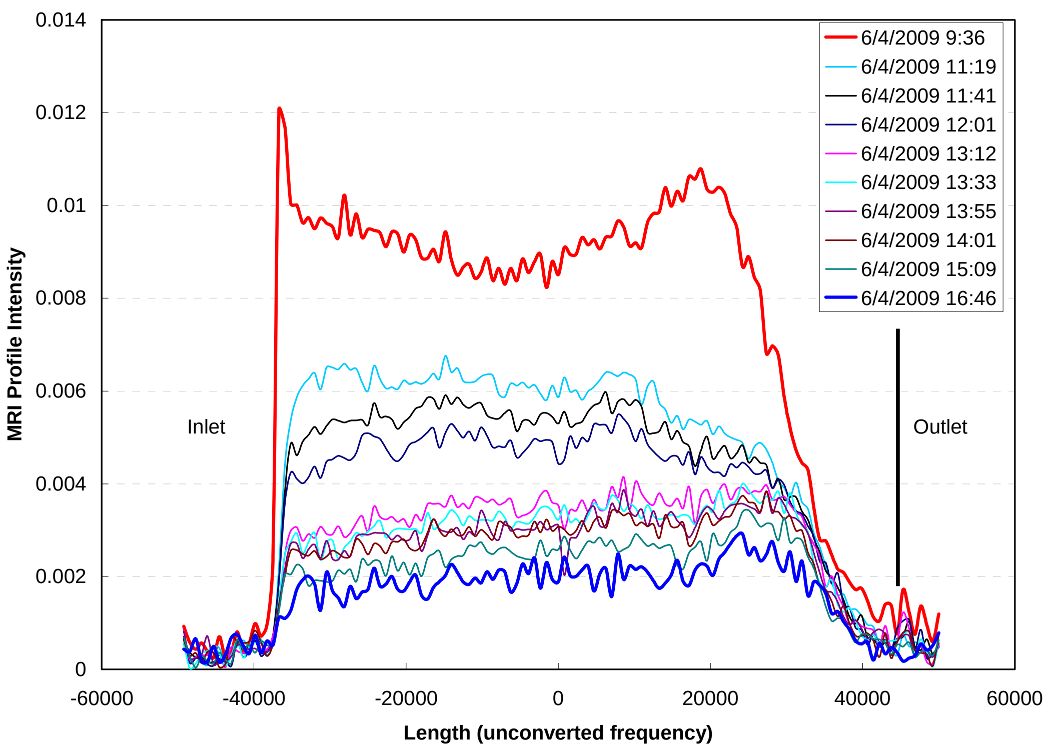

Figure 1: MRI Profiles collected during liquid carbon dioxide injection into a methane-hydrate saturated core plug that contained 35% excess water. The initial methane hydrate saturation was not uniform as more formed at the outlet end as evident in the loss of MRI intensity on the initial profile (red line). The final saturation of remaining excess water was uniformly distributed (blue line). The x-axis represents the length of the core plug (9.7 cm) in frequency space (Hz).

Permeability measurements collected during the injection of liquid carbon dioxide started at 0.9 mD and dropped quickly to 0.2 mD (Figure 2). After that point the permeability remained relatively constant even though additional water was being converted to hydrate. The average intensity of the profiles collected during the injection dropped from 0.007 to 0.0018, but did not reach 0.

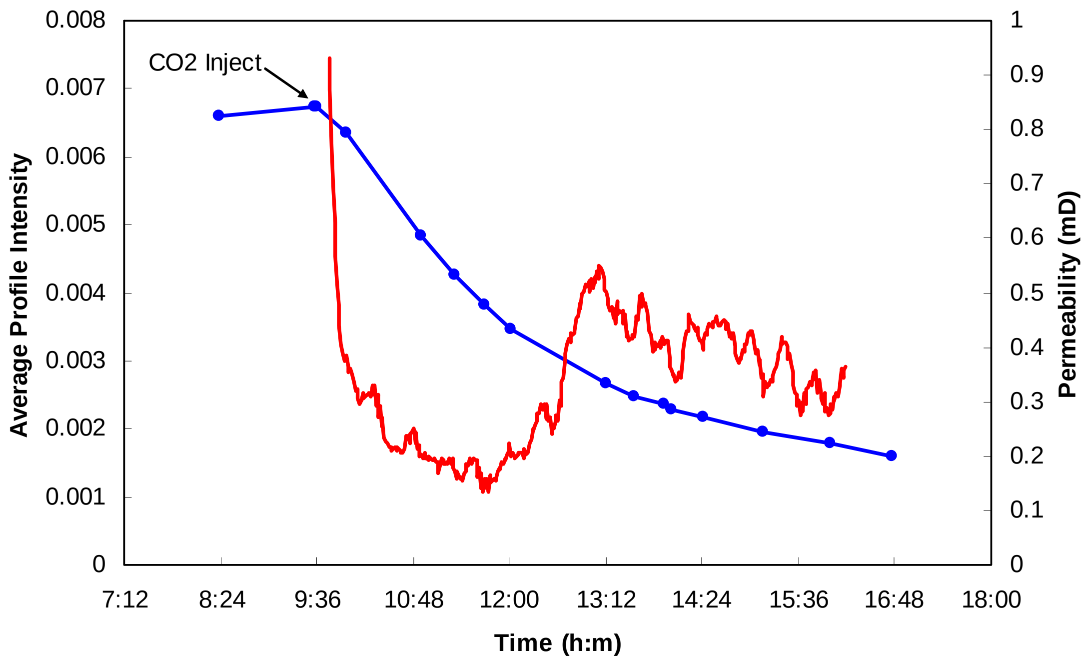

Figure 2: Changes in MRI profile intensity (red) as additional hydrate formed from excess water and liquid carbon dioxide injection that started at 9:36 hours. Hydrate formed during the 9 hour period of injection, but did not convert all of the available water. Permeability (blue) started at 0.9 mD and dropped to 0.2 mD.

The MRI profiles were used to estimate the amount of free water that was converted to hydrate (Figure 3). The profiles were normalized to the intensity of 70% water saturation at 1200 psi. The water volume added to the sample was 18.08 cm^3, which is roughly one mole of water. Since one half of the original water was converted to methane hydrate, there was approximately 0.5 moles of free water in the system prior to liquid carbon dioxide injection. These calculations indicate that much of the available free water was converted to hydrate. This curve mirrors the reduction in MRI profile intensity (Figure 2), but was converted to provide a quantitative estimate of changes in the moles of available water.

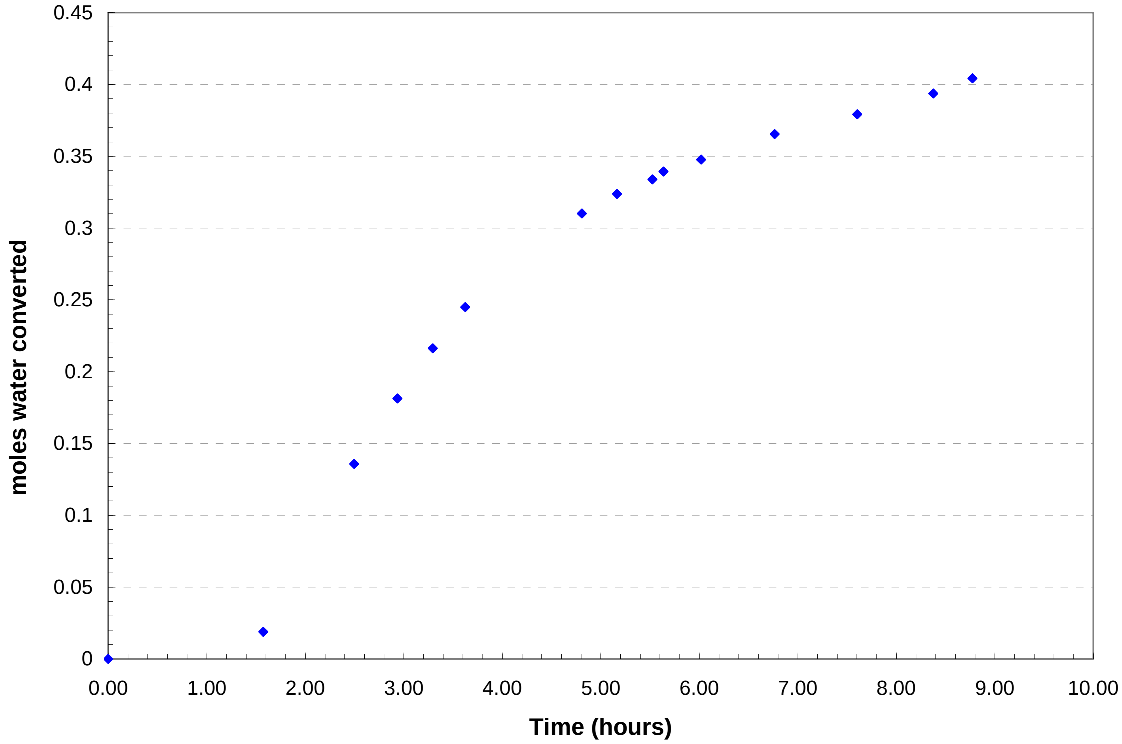

Figure 3: Conversion of available water in the core to hydrate as it occurred during carbon dioxide injection. There was approximately 1 mole of water in the core at the beginning of the experiment, half of which was converted to methane hydrate prior to carbon dioxide injection.

The depressurization steps at the conclusion of the liquid carbon dioxide injection produced changes in the MRI profiles as hydrate was preferentially dissociated at different stages. The initial pressure of 570 psi was close to the dissociation pressure for pure methane hydrate. The MRI profiles indicated little change in the hydrate saturation (or free water saturation) compared to the profile collected at the end of the carbon dioxide injection. In contrast, when the pressure was reduced to 350 psi the MRI intensity at the outlet end of the core increased significantly (Figure 4). This region is where there was significant methane hydrate formation at the beginning of the experiment. As the pressure fell below the stability pressure of the methane hydrate, there was the release of free water. Given the size of the pressure step between 570 and 350 psi, it is not possible to determine that the hydrate at the outlet end was a pure methane hydrate or whether that some of the carbon dioxide had exchanged with the methane. The hydrate completely dissociated when the pressure was reduced to 0 psi. Water was observed in the outlet line so it was not possible to quantify the MRI profiles at the beginning and the end of the experiments since there was clear evidence of water migration out of the system.

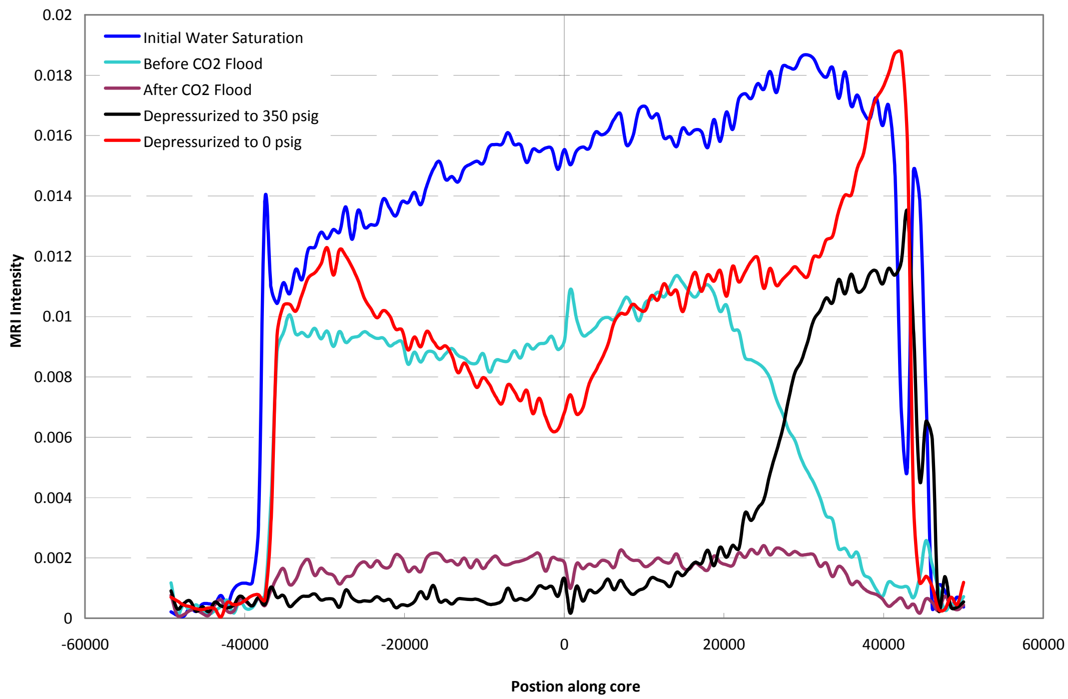

Figure 4: MRI profiles illustrate the distribution of water in the core at various stages of the experiment.

<u>2) Coring and Core Analysis:</u> The primary goal of coring in this project is to recover hydrate-bearing strata and quickly analyze them at the surface, before hydrate saturation degrades. Mike Dunn and his colleagues at Petrotechnical Resources Alaska (PRA), with assistance from Tim Collett (USGS), prepared and shared their three-volume "Coring Procedures Manual," which COP team reviewed. The PRA Coring Manual extensively discusses state-of-the-art wireline-retrieved coring (ReedHycalog's CorionExpress system) and documents on-site and off-site core analysis protocols. Dr Collett confirmed in conversation, based on his worldwide experience, that recovery of in-situ methane hydrate from non-pressurized core barrels has historically been quite low, even when utilizing wireline-retrieved coring. Tim estimates loss of "more than 70% of the in-situ gas hydrate during recovery" of cores from the Mt Elbert project.

Sealing cores downhole under in-situ conditions to capture samples at reservoir temperature and pressure is the goal of pressure coring. Pressure coring is the only way to capture in-situ hydrate saturation and concentrations for transport to the surface. Pressure coring conversations have been initiated with Aumann & Associates (Jim Aumann) and Diamond Oil Well Drilling Co (Wade McCutcheon) regarding state of the current technology and developments expected in the near future. Both Aumann & Associates and Diamond Oil Well Drilling Co are experienced in wireline retrieval of pressure cores, an approach that may be applicable to this project.

Technology for accurate determination of hydrate saturation in cores once they reach the surface is a prerequisite to a coring recommendation in this project. Conversations regarding magnetic-resonance imaging of freshly retrieved cores have been undertaken with Mike Walker, manager of Business Development at Weatherford Laboratories, now owners of both Omni Labs and Hycal Labs. Weatherford is researching technology for magnetic resonance imaging of hydrate-bearing cores in a cold, Arctic setting.

3) Reservoir Modeling and Simulation: Scoping simulation to design fieldtest parameters has been performed with the CMG Generalized Equation-of-state Model (GEM), because neither LBNL's TOUGH+Hydrate code nor PNNL's STOMP routine can model CO_2/CH_4 exchange. The GEM tool is a compositional reservoir simulator that uses the full Equation of State to calculate PVT (pressure-volume-temperature) properties of each fluid phase based on the compositions of each phase. GEM has been used to model N_2 and CO_2 injection and post-exchange CH_4 flowback. To model CH_4 flowback, the exchange of CO_2 & CH_4 was calculated externally. In an iterative, step-wise approach, post-exchange saturations of water, carbon dioxide, and methane were then fed back into the GEM simulator.

Input parameters for reservoir modeling and simulation are summarized in Figure 5. Initial reservoir pressure and temperature are estimated from regional databases of hydrostatic and geothermal gradients respectively. Formation breakdown pressure is estimated from integration of shear and compressional sonic log data with density log data. Hydrate stability pressure is estimated by CMG-STARS correlations based on depth, temperature, pressure, and gas and water composition. Sandstone porosity and hydrate and water saturation estimates are derived from recently published results at Mt Elbert #1. Three discrete permeabilities have been modeled: 0.15mD, 1mD, and 10mD.

Initial reservoir parameters

- Initial reservoir pressure: 1000 psi
  - Breakdown pressure = 2250 psi
  - Hydrate stability pressure = 680 psi
- Initial reservoir temperature: 42°F (5.5°C)
- Hydrate zone thickness: 30 ft (central 20 ft perf'd)
- Hydrate zone porosity: 40%
- Initial hydrate saturation: 70% (30% S_w)

Figure 5: Initial reservoir parameters for reservoir simulation

Nitrogen Injection: The exchange field trial has been conceptually designed with a pre-CO2-injection N2 injection-falloff test to determine initial reservoir permeability. Several constraints have been placed on the nitrogen injection-fall off modeling. First, a nitrogen volume has been selected, based on modeling, that does not exceed a threshold nitrogen concentration that would lead to methane-hydrate dissociation. Modeling indicates injection of approximately 700mcf of N_2 will result in less than 5% methane-hydrate dissociation, allowing for accurate estimation of permeability by injection-fall off analysis. Nitrogen injection volume and pressure have been maintained in reservoir simulation so as not to exceed formation breakdown pressure. Simulation results for N_2 injection are shown graphically in Figure 6. This simplified figure provides a comparison of high, medium, and low-permeability simulations, but should not be taken literally. Only in the low-perm case would a six-hour injection be undertaken. If the reservoir has medium and high permeability, then a shorter injection period would be designed (with volume not to exceed approx 700mcf) at a rate appropriate to drive injection pressure close to 2000psi, yielding a significant pressure falloff for permeability interpretation.

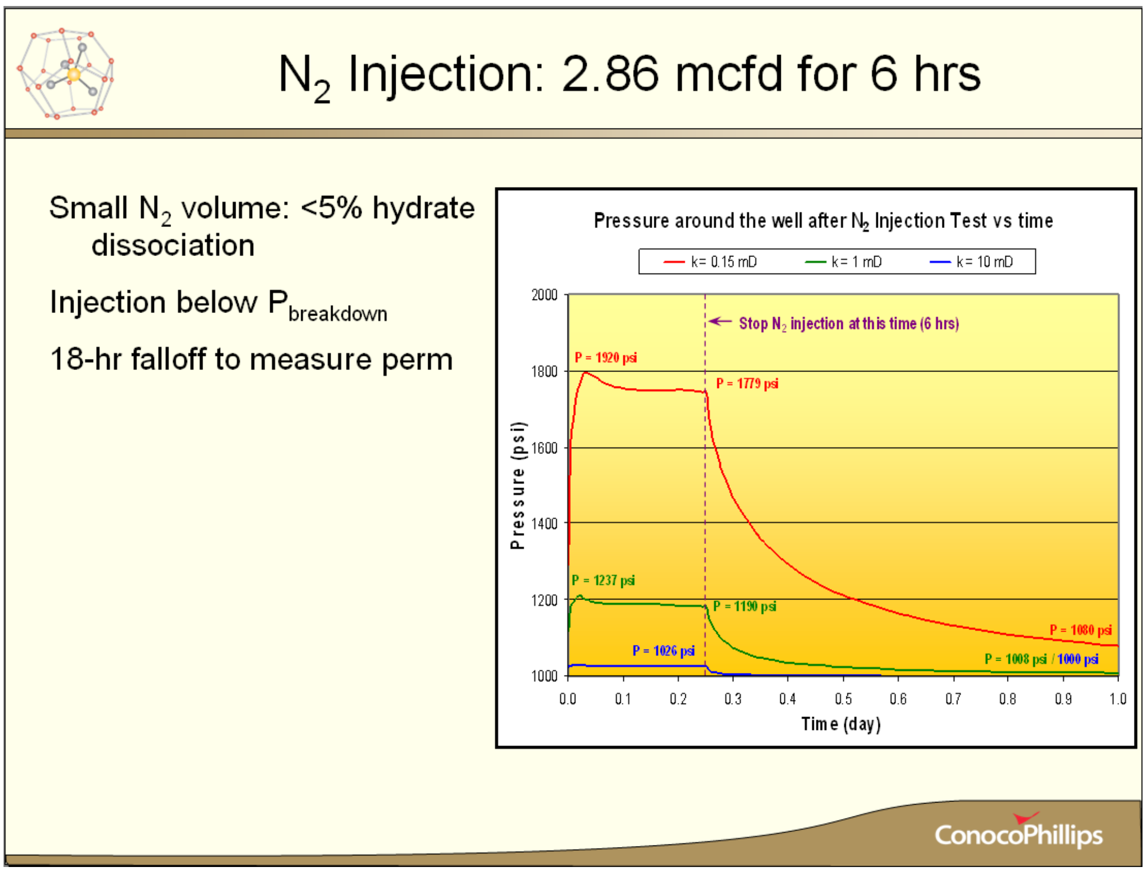

Figure 6: Scoping Reservoir Simulation of Nitrogen Injection

Carbon Dioxide Injection: As in the nitrogen injection simulation, carbon dioxide injection has been modeled at rates so as not to exceed the calculated reservoir breakdown pressure. Interpretation of magnetic resonance logs from BP's Mt Elbert #1 test and GSC's Mallik L-38 wells on the Canadian Mackenzie Delta Canada indicates that gas hydrate saturations (S_H) which average 70% exist in 25-75 foot-ft thick sandstone bodies. Magnetic resonance logs (also referred to as NMR or CMR logs) also indicate that the remainder of the pores in these reservoirs filled with "free water." For scoping reservoir simulation, it has been assumed that this water is all reactive and is free to combine with carbon dioxide upon injection to form additional CO_2-hydrate. Newly formed CO_2-hydrate will reduce reservoir permeability.

Modeling suggests approximately an order of magnitude reduction in permeability may be expected if all this free water (S_w=30%) reacts to form CO_2-hydrate. An immediate order-of-magnitude drop in permeability has been modeled in Figure 7. Scoping simulation shows that in the high perm case, approximately 40 tons of CO_2 can be injected over four days and the formation breakdown pressure will not be exceeded. If pore water is reactive and CO_2-hydrate forms, permeability immediately drops from 10mD to 0.8mD. In medium and low-permeability models, simulation indicates that CO_2-hydrate formation will render permeability so low as that sub-breakdown pressure injection period will be unreasonably long (refer to Figure 9.)

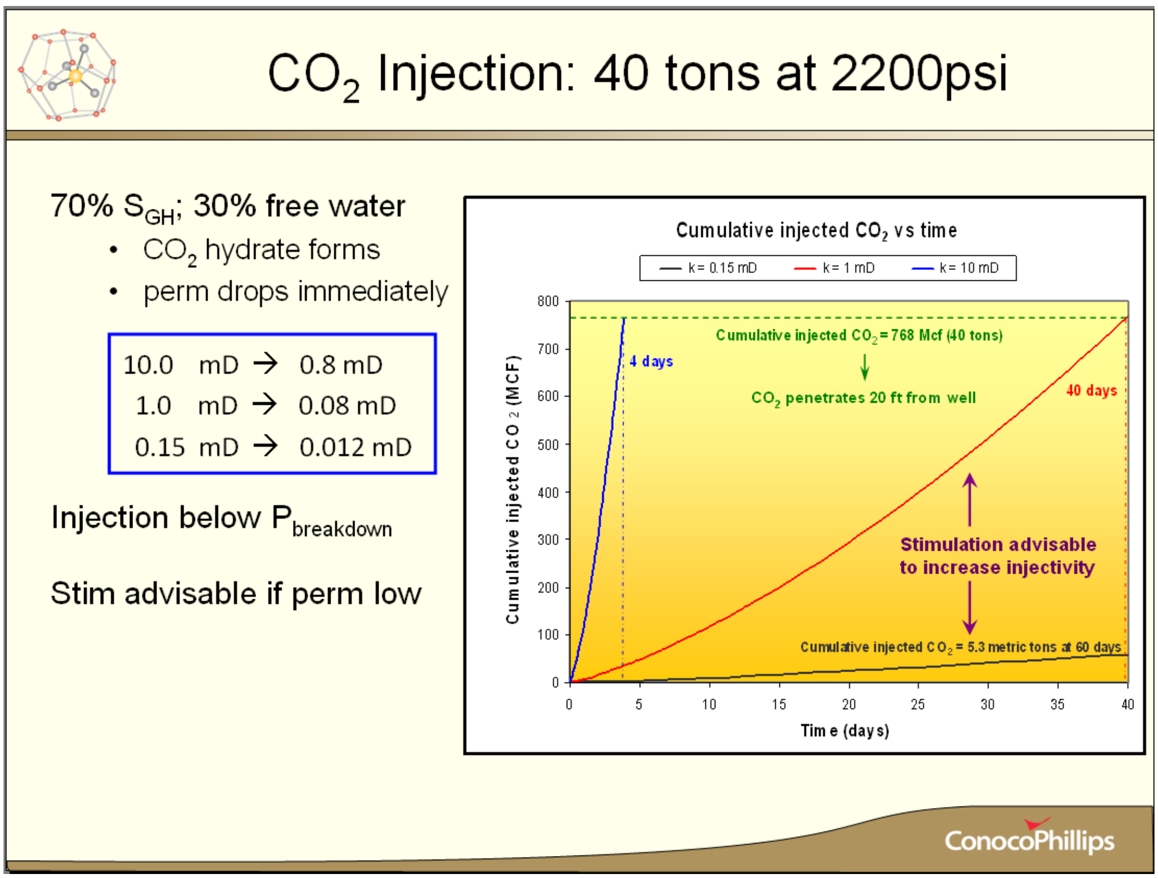

Figure 7: Scoping Reservoir Simulation of Carbon Dioxide Injection

Shut-In for Carbon Dioxide/Methane Exchange: Modeling of post-CO_2 injection shut-in period has just started. GEM simulator cannot model CO_2/CH_4 exchange, so a five-day shut-in for CO2/CH4 exchange has been assumed for the models reported here. Kinetic data from laboratory exchange experiments is undergoing analysis to understand both diffusion effects and competition for CO_2 between two processes: exchange with methane in CH_4-hydrate and formation of CO_2-hydrate in the presence of reactive free water.

Methane Flowback: Methane flowback has been modeled with bottomhole pressure held at 700psi, just above calculated gas hydrate stability pressure. Depressurization below gas hydrate stability pressure will be simulated in the future with LBNL's TOUGH+Hydrate code and/or PNNL's STOMP program. Methane flowback is summarized in Figure 8. Flowback has only been simulated for the high (10mD) and medium (1mD) initial permeability cases, because the low (0.15mD) initial permeability results in too low a CO_2 injection volume (assuming order of magnitude perm drop due to CO_2-hydrate formation) for effective exchange. In the two realizations shown in Figure 10, approximately two-thirds of injected CO_2 is modeled to have been consumed by CO_2-hydrate growth. As a consequence of CO_2-hydrate formation, only ~250mcf of CO_2 is available for exchange to yield methane, and ~250mcf of methane is produced. In the high initial permeability case, all the methane is produced back in just 12 days, whereas the medium-perm case must flow back for 71 days before all the exchanged methane is recovered.

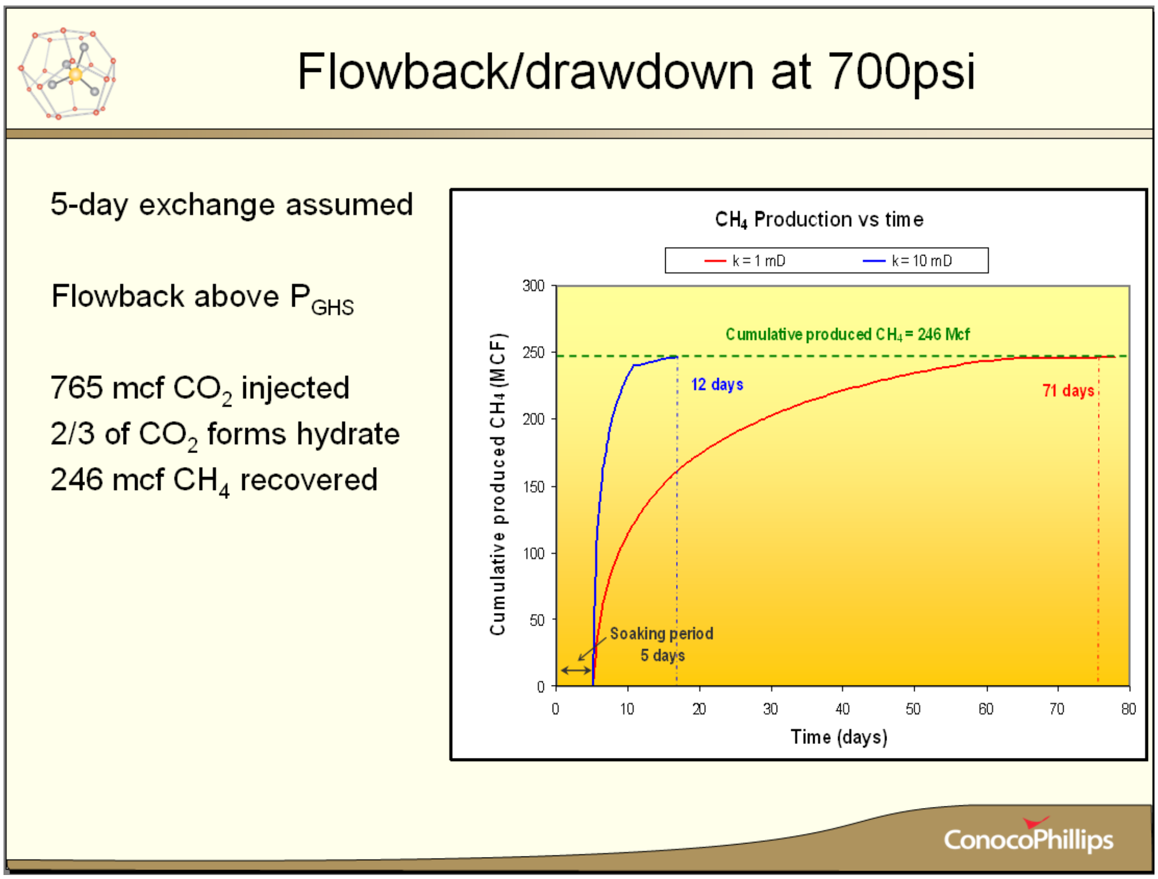

Figure 8: Scoping Reservoir Simulation of Methane Flowback

Well Design Team

The Well Design Team worked throughout Q3'09 to build a well plan around the field experiment designed by the Experimental Design Team. Reported herein are accomplishments regarding 1) drilling design, 2) openhole and cased-hole logging, 3) completion design, and 4) well testing and stimulation scoping.

1) Drilling Design: Scoping drilling design of a "built-for-purpose" gas hydrate exchange well is summarized in Figure 9. A hole 36 inches in diameter will be drilled to a depth of 80 feet. Conductor casing, 30 inches in diameter, will be run and cemented back to surface. Surface hole 12¼ inches in diameter will be drilled to a depth of 1800 feet. Openhole logs may be run before setting surface casing, or this wellbore segment may be evaluated with logging-while–drilling (LWD) tools. Surface casing, 9⅝ inches in diameter, will be run and cemented back to surface. Production hole 8¾ inches in diameter will be drilled to a depth of 3000 feet with chilled oil-based mud. Openhole logs (described in detail below) will be run before production casing, 7 inches in diameter, will be run and cemented back into the surface casing. Low heat-of-hydration specialty cementing agents will be employed to minimize hydrate dissociation adjacent to the wellbore annulus, which could create micro-annulus effects that could make zonal isolation difficult. External casing packers may also be employed to ensure isolation of zones destined for completion and CO_2/CH_4 testing.

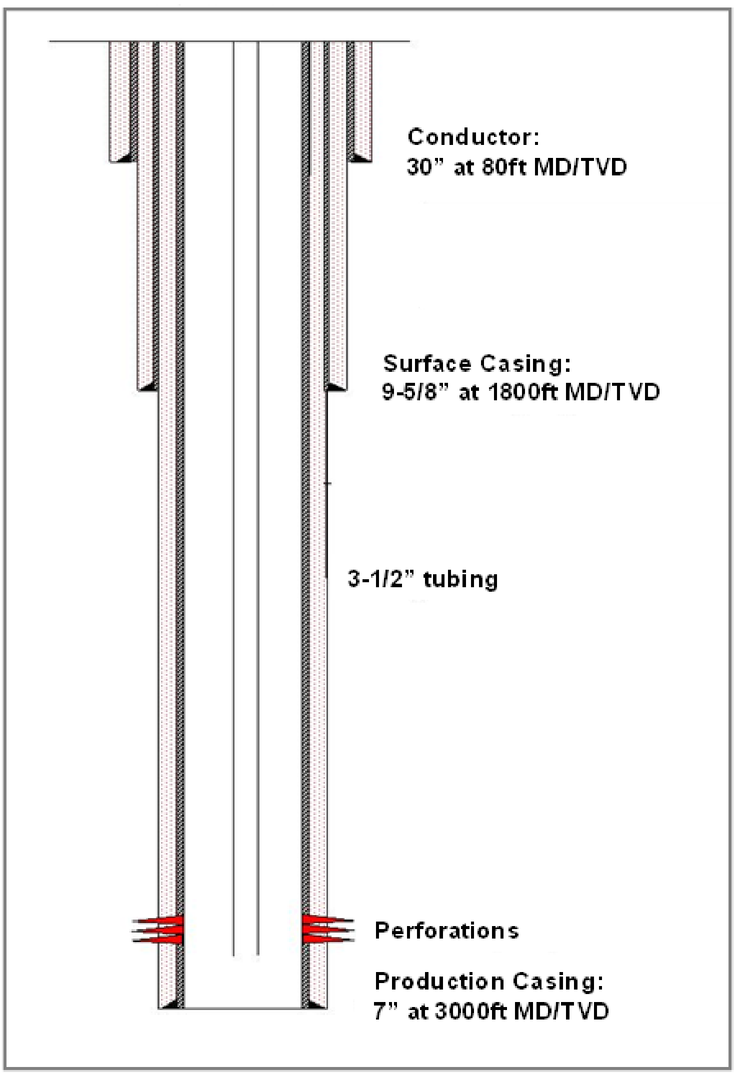

Figure 9: Draft Drilling Schematic

2) Openhole and Cased-Hole Logging: A thorough openhole logging program has been developed to address formation evaluation objectives. The full openhole logging suite anticipated consists of Gamma-Ray, Array Resistivity, Density/Neutron, Dipole Sonic, Magnetic Resonance, Formation Testing (MDT or similar tool) and wellsite geology/mudlogging. This openhole suite provides independent multiple methods for hydrate saturation calculation, as well as providing input data (compressional velocity, shear velocity and bulk density) for computation of geomechanical rock properties. Formation testing tools, like Schulmberger's Modular Dynamic Tool, will provide accurate measurements of in-situ reservoir conditions (pressure and temperature) as well as initial estimates of reservoir permeability.

Cased-hole logging objectives are to evaluate cement quality/zonal isolation and provide reservoir monitoring. Circumferential cement bond logs are anticipated to ensure a high quality cement sheath and isolation of zones for proposed injection testing. Cased-hole neutron porosity and resistivity measurements are planned be recorded at initial reservoir conditions (before N_2 or CO_2 injection), after CO2 injection, and after methane flowback. The primary goal of these multiple cased-hole logging runs is measure near-wellbore changes in free-gas saturation. Openhole and cased-hole logging programs are summarized in Figure 10.

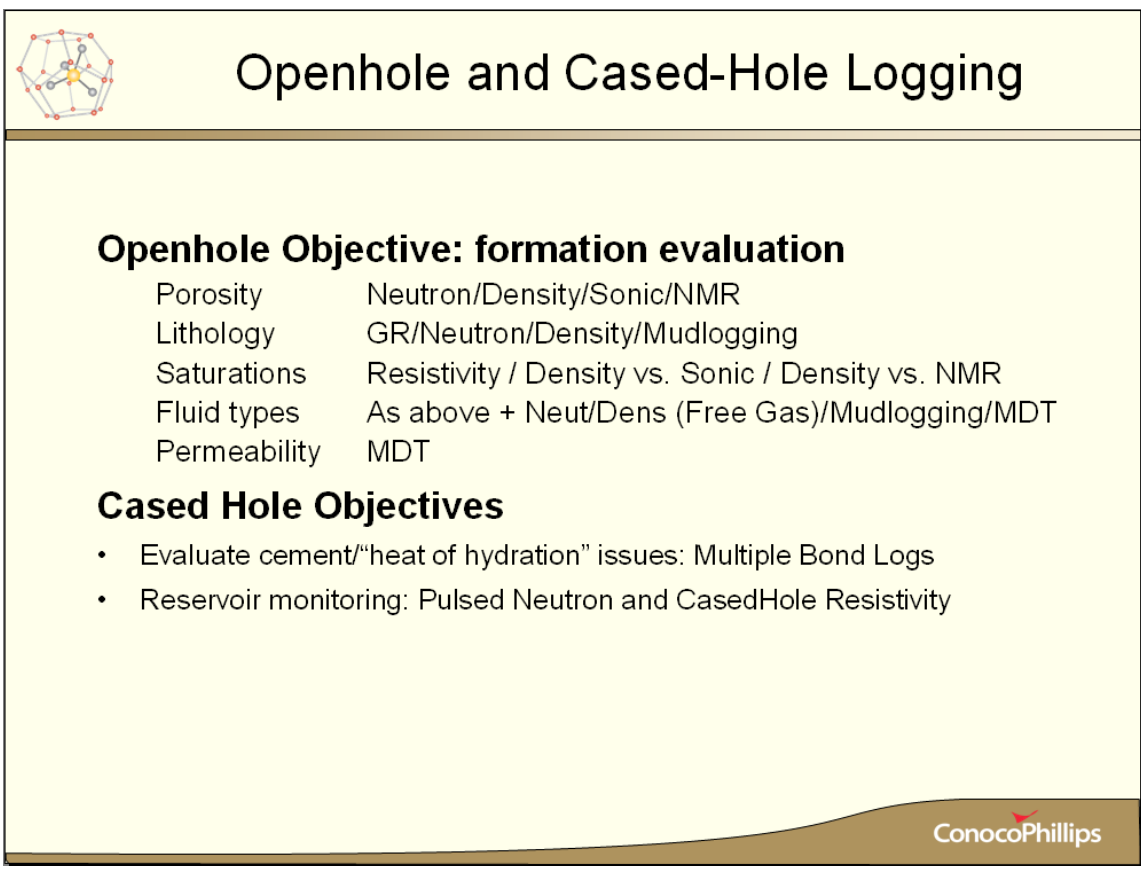

Figure 10: Well Logging Program

3) Completion Design: Draft completion design has been completed for CO_2/CH_4 exchange field trial wellbore as shown in Figure 11. Current design proposes 3½-inch tubing hung in a packer above hydrate perforations. Proposed tubing diameter is large enough to allow for passage of both perforating guns and cased-hole logging tools. Pressure and temperature gauges mounted outside the tubing will allow real-time measurement of ambient downhole conditions. These gauges will provide surface readout before, during, and after N2 and CO2 injection. The 3½-inch tubing string will be heat-traced to inhibit the formation of ice and/or hydrate plugs.

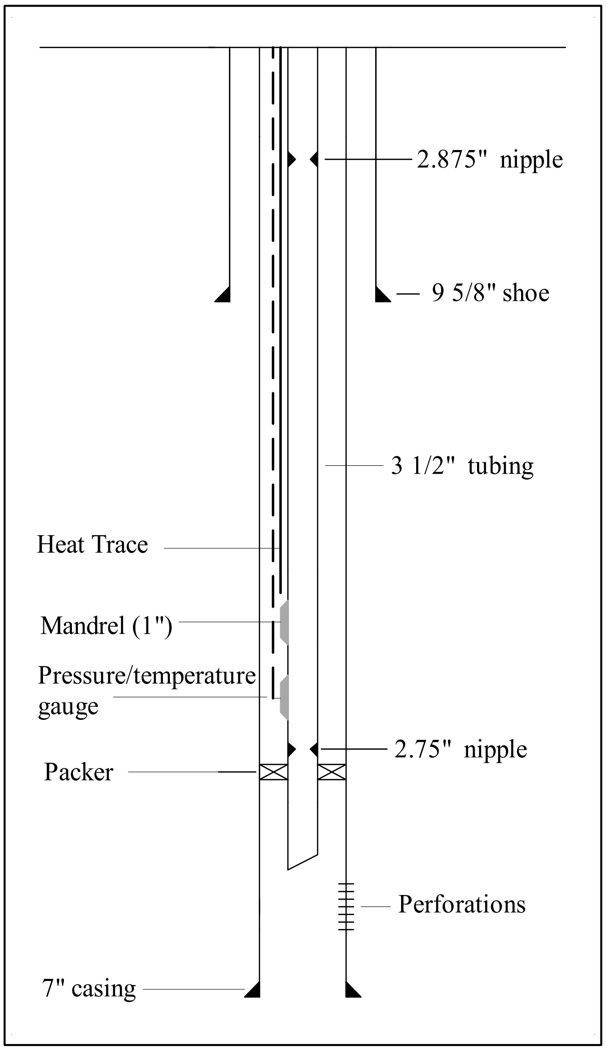

Figure 11: Draft Completion Schematic

4) Well Testing and Stimulation: Scoping well-test and stimulation design has begun. In addition to heat-traced 3½-inch tubing, a string of concentric coiled tubing (1-inch tubing inside of 2-inch tubing) will be onsite to safely clean-out any hydrate blockages that occur in the tubing. Concentric coiled tubing will also allow efficient clean-out of any

produced sand or water without pressuring-up the open perforations, which could, create an undesirable pressure surge in the formation.

As discussed previously, combination of injected CO_2 and free water, resulting in the formation of CO_2-hydrate, may reduce permeability. If in-situ permeability is reduced below 0.1mD, injection of CO_2 at "matrix injection rates" will be too slow for an effective exchange experiment. Design of a small hydraulic stimulation has begun, starting with prediction of geomechanical properties from publicly available well logs. Integration of log-derived predicted mechanical properties with a fracture stimulation program (StimPlan) will allow for scoping stimulation design.

Cost Status

Expenses incurred during this quarter were below the Baseline Cost Plan as shown in Exhibit 1. The Baseline Cost Plan forecasted Federal expenses of $1,450,000 in the 3rd Quarter for procurement of long-lead items for the test. The test is now scheduled for 2011 and as such, these expenditures were not necessary. The Non-Federal Incurred Cost for the 3rd Quarter was slightly above forecast. However, cumulative Non-Federal Incurred Cost continues below Baseline Cost Plan due to fewer hours required by our Alaska and Technology staff to progress the project.

Exhibit 1 - Cost Plan/Status

COST PLAN/STATUS									
Project Phase ==>	Phase 1, Site Ident.		Phase 2, Field Test Planning			Phase 3, Field Test			
Baseline Reporting Quarter ==>	Q408	Q109	Q209	Q309	Q409	Q110	Q210	Q310	Q410
BASELINE COST PLAN									
Federal Share	0	0	60000	1450000	0	8315000	1300000	630000	0
Non-Federal Share	325100	499172	390875	333875	170699	361135	353410	348523	151351
Total Planned	325100	499172	450875	1783875	170699	8676135	1653410	978523	151351
Cumulative Baseline Cost	325100	824272	1275147	3059022	3229721	11905856	13559266	14537789	14689140
ACTUAL INCURRED COSTS									
Federal Share	0	0	0	0					
Non-Federal Share	121012	186099	275348	354447					
Total Incurred Cost	121012	186099	275348	354447					
Cumulative Incurred Cost	121012	307111	582459	936906					
VARIANCE									
Federal Share	0	0	-60000	-1450000					
Non-Federal Share	-204088	-313073	-115527	20572					
Total Variance	-204088	-313073	-175527	-1429428					
Cumulative Variance	-204088	-517161	-692688	-2122116					

Milestone Status

The Milestone Status Report is shown in Exhibit 2 below. Well test design and planning is well underway. Initial estimates of reservoir behavior have been completed.

Exhibit 2 – Milestone Status Report

MILESTONE STATUS REPORT						
#	Task/Subtask Description	Planned Start Date	Planned End Date	Actual Start Date	Actual End Date	Comments
	Field trial site selected	1-Oct-08	31-Mar-09	1-Oct-08	3-Apr-09	Top sites identified
	Partner negotiations completed	15-Feb-09	31-Mar-09	17-Mar-09		Ongoing
	Synergies with DOE-BP project identified	1-Mar-09	31-Mar-09	30-Mar-09		Ongoing
	Well test designed and planned	1-Apr-09	30-Sep-09	10-Mar-09		Progressing
	Well and reservoir performance predicted	1-Jul-09	31-Dec-09	22-Jun-09		Initial scoping complete
	Field testing completed	1-Jan-10	31-Dec-10			
	Injection and production monitoring completed	1-Apr-10	30-Apr-10			
	Well abandonment complete	1-May-10	31-Dec-10			

National Energy Technology Laboratory

626 Cochrans Mill Road
P.O. Box 10940
Pittsburgh, PA 15236-0940

3610 Collins Ferry Road
P.O. Box 880
Morgantown, WV 26507-0880

One West Third Street, Suite 1400
Tulsa, OK 74103-3519

1450 Queen Avenue SW
Albany, OR 97321-2198

2175 University Ave. South
Suite 201
Fairbanks, AK 99709

Visit the NETL website at:
www.netl.doe.gov

Customer Service:
1-800-553-7681