Oil & Natural Gas Technology

ConocoPhillips Gas Hydrate Production Test
Final Technical Report

October 1, 2008–June 30, 2013

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Submitted on: **July 20, 2013**
DOE Award No.: **DE-NT0006553**

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

Disclaimer

Acknowledgements

ConocoPhillips would like to thank the Department of Energy (DOE) and Japan Oil, Gas and Metals National Corporation (JOGMEC) for financial and technical support for this project. In addition, the project team is grateful for the input of individuals from the following organizations: United Stated Geological Survey (USGS), the University of West Virginia, ConocoPhillips Alaska, the State of Alaska, and the Prudhoe Bay working interest owners. ConocoPhillips also would like to acknowledge the input of the University of Bergen, who advanced the concept of CO_2 exchange as a production mechanism.

Abstract

Work began on the ConocoPhillips Gas Hydrates Production Test (DOE award number DE-NT0006553) on October 1, 2008. This final report summarizes the entire project from January 1, 2011 to June 30, 2013.

Contents

Executive Summary

The objective of the study was to perform field trial on the North Slope of Alaska to evaluate CO_2/CH_4 exchange, a methane hydrate production methodology whereby carbon dioxide is exchanged *in situ* with methane molecules within a methane hydrate structure, releasing the methane for production. In addition, production by depressurization was also evaluated. This was a short term test using a “huff and puff” injection/production cycle from a single well to demonstrate the CO_2/CH_4 exchange concept at larger-than-lab scale.

From 2008 to 2011 a suitable test site was identified and access permissions were obtained for the field trial. The test well, Iġnik Sikumi #1, was drilled from a temporary ice pad in early 2011 and the injection/production test was performed in early 2012. Production operations began in January 2012 and ended in May 2012, when the well was plugged and abandoned.

During the injection phase of the field trial, the total injected volume of gas was 215.9 Mscf, which consisted of 167.3 Mscf N_2 and 48.6 Mscf CO_2. Composition was tightly controlled during this period with an average molar injection ratio of 77.5/22.5 N_2/CO_2.

After injection, production proceeded in these phases:

1. jet pumping above methane hydrate-stability pressure
2. jet pumping near methane hydrate-stability pressure
3. jet pumping below methane hydrate-stability pressure

During production testing, approximately 70% of 167.3 Mscf of injected nitrogen was recovered. In contrast, only 40% of the 48.6 Mscf injected carbon dioxide was recovered during the production period. A total of 855 Mscf of methane was produced over the total production period. Along with the various gases, water and sand were also produced. A total of 1136.5 bbl of formation water was produced.

Conclusions presented in this final report are preliminary. They represent a current understanding, based on limited analysis performed with rudimentary tools. More definitive conclusions are expected as knowledge of mixed hydrate systems mature; however, here are the conclusions included in this report:

- A 23 mol% CO_2 – N_2 mixture was injected into a hydrate-bearing zone in which free water was present, and these gases did interact with native hydrate
- Test data indicated that solid-state CO_2 – methane hydrate exchange did occur
- A simple adiabatic homogeneous instantaneous equilibrium model cannot predict the observed production behavior
- During depressurization, bottomhole pressures below 400 psia are achievable during active hydrate dissociation; this sand face pressure is below that pressure at which equilibrium models predict that icing should occur.
- Wellbore conditions must be managed effectively for efficient production of hydrates (the wellbore conditions to manage include: solids control; temperature control; and water levels)

After completing the field trial, final abandonment of Iġnik Sikumi #1 wellsite was completed May 5, 2012. Tubing, casing-tubing annulus, and FLATPak™ tubes were filled with cement, which complies with the abandonment procedure approved by the Alaska Oil and Gas Conservation Commission. The wellhead area was refilled and graded to ensure it would return to its original grade following the spring melt-back of the ice pad. The final inspection of the wellsite was conducted by the Alaska Department of Natural Resources September 5, 2012, by helicopter.

Field Trial Goals

The objective of the field trial was to evaluate CO_2/CH_4 exchange. This is a methane hydrate production methodology where carbon dioxide is exchanged *in situ* with methane molecules within a methane hydrate structure, which then releases the methane for production. Production by depressurization was also evaluated during this field trial. This was a short term test using a “huff and puff” injection and production cycle from a single well to demonstrate the CO_2/CH_4 exchange concept at “larger-than-lab” scale.

Specifically the field trial aimed to:

- validate exchange mechanism results from laboratory work
- confirm injectivity into naturally occurring methane hydrates
- confirm methane release without production of water or sand
- obtain data to calibrate reservoir-scale modeling
- demonstrate stable production of natural gas hydrates by depressurization

Test Chronology

This section provides a brief timeline of events that took place during the field trial.

- 2008 – 2010
  - Identify and gain access to the test site
- 2011
  - Drill, log, complete and suspend Iġnik Sikumi #1
  - Design field test
- 2012
  - Re-enter well and perforate
  - Perform exchange test
  - Perform depressurization test
  - P&A well and remediate site

Test Site Characterization

This section of the report provides information about test site characterization, including details about how the site was selected and site selection criteria.

Site Selection

The test site selection was based upon accessibility, proximity to North Slope infrastructure, and confidence in the presence of gas hydrate-bearing sandstone reservoirs with multiple reservoir targets. The target for this field trial were reservoirs in high porosity, high permeability clastic sandstones of the Sagavanirktok Formation. Gas hydrate reservoirs occur within and below the ice-bearing permafrost on Alaska's North Slope, because the gas hydrate stability zone includes temperatures that are below and above the freezing point of water. For the field trial, reservoirs below the permafrost were targeted for two reasons. First, it is difficult to differentiate ice-bearing sandstones in the permafrost from hydrate-bearing intervals from well logs. Second, the CO_2/CH_4 exchange experimental work was conducted at 4°C. This temperature corresponds to a depth approximately 350ft below the base of permafrost.

Selection Criteria

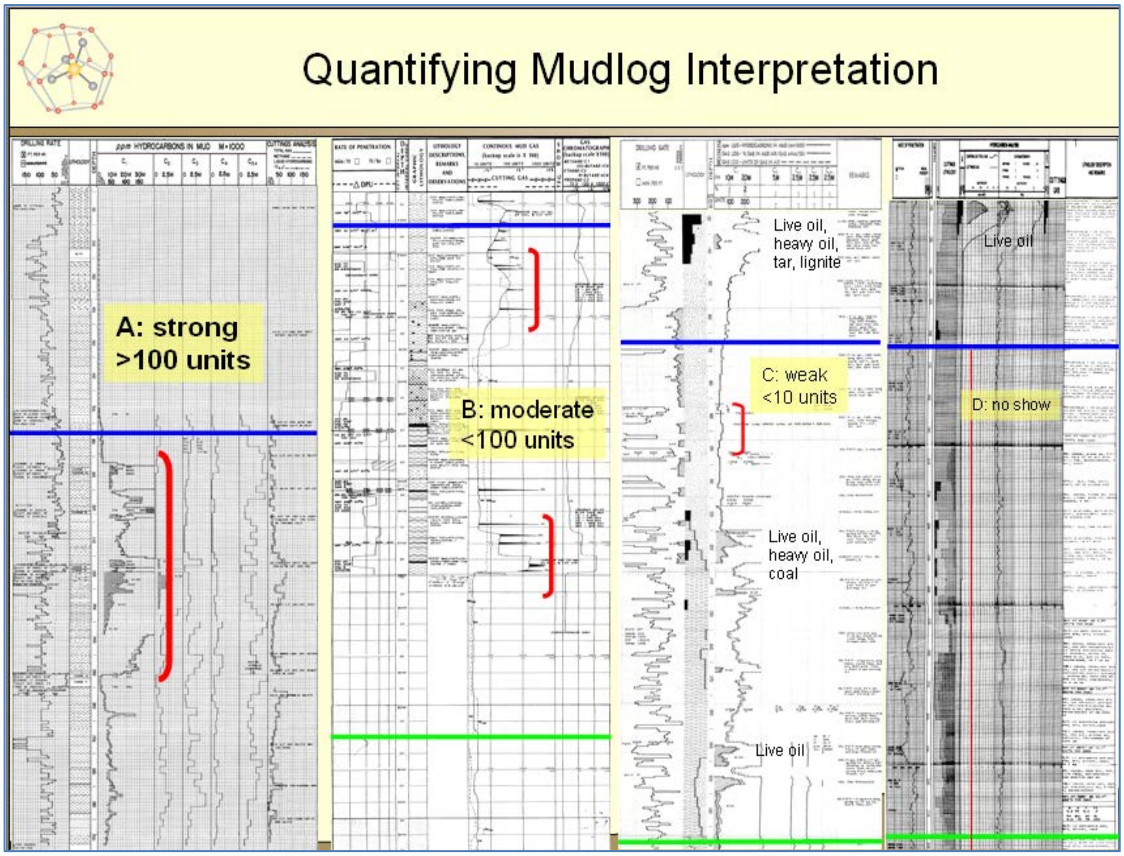
Wireline logs are the primary dataset used to evaluate *in situ* gas hydrates from existing wells. All wells drilled on the North Slope have penetrated the gas hydrate stability zone; although less than one-sixth of these wells have been logged between base permafrost and base gas hydrate stability zones. Sandstones with gas hydrate in their pores exhibit high resistivity and high velocity (low transit time), like their ice-bearing counterparts. Collett (1993) summarized sonic and resistivity log criteria to identify gas hydrate-bearing sandstones: resistivity 50 times greater than associated water-bearing sandstones and sonic transit time 40 microseconds per foot faster than adjacent wet sandstones. Sandstone with pore-filling gas hydrate is identified by gamma ray log response less than 55 API units; a sonic transit time of less than 140 microseconds/ft; and resistivity greater than 30 ohm-m (see Table 1).

Table 1: Log interpretation cutoff parameters for hydrate identification

Measurement	Cutoff Value
Gamma Ray (GR)	< 55 API
Deep Resistivity (Rt)	> 30 Ohm-m
Sonic Slowness (dT)	< 140 sec/ft

Many wells that fit the gamma ray and resistivity criteria for the presence of gas hydrates have ambiguous sonic log response due to poor hole conditions and incomplete log overlaps. In addition, partial post-drilling dissociation of gas-hydrate bearing sandstones during subsequent deeper drilling may have occurred before logging, which further complicates wireline log responses. Therefore, to improve confidence in hydrate identification, mud log records were also reviewed. A mud log is a compilation of penetration rate, cuttings description, and measurements of hydrocarbon gases in the drilling fluid. Mud logs are compiled while drilling, before any wireline logs are run. Interpretation of gas hydrates involves recognizing a gas signature on the mud logger's gas chromatograph over the interval identified as a hydrate bearing sand from the well logs. Where this gas response was over 100 units it was considered to be a "strong" indicator of gas (see Figure 1).

Figure 1: Mud log characterization



The selected field test site was adjacent to L-pad in the Prudhoe Bay unit (see Figure 2, and Figure 4) and was selected based on high quality hydrate indicators on logs and mud logs in 4 stacked reservoirs.

Figure 2: Location of L-Pad within the Prudhoe Bay Unit

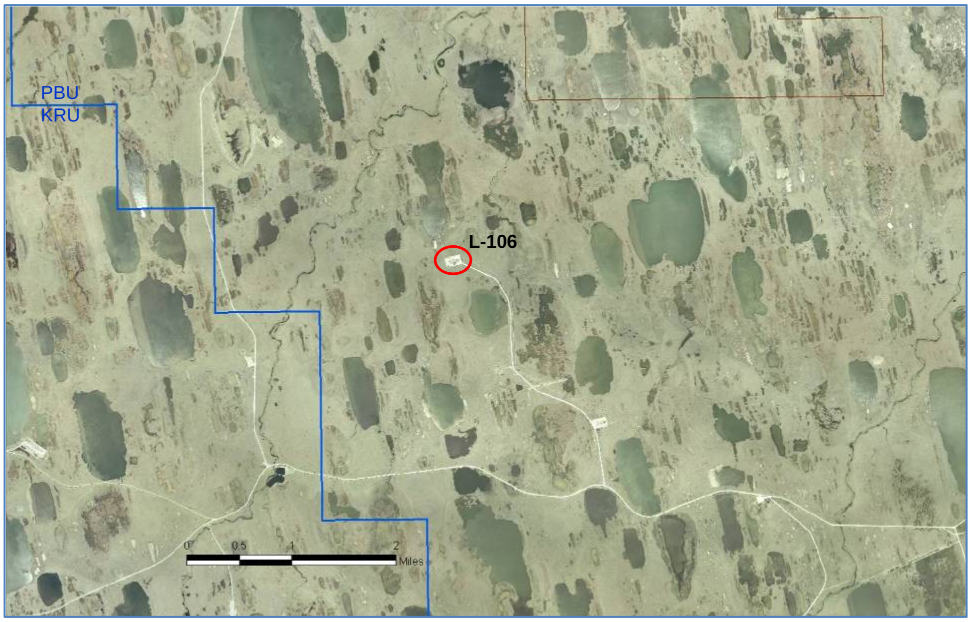


Figure 3: Log characteristics of the L-pad area showing a gross reservoir interval of 125 ft in four stacked hydrate bearing sandstones, C (2), D and E. F sand is within the permafrost and is ice bearing. Mud log gas response is highlighted in red.

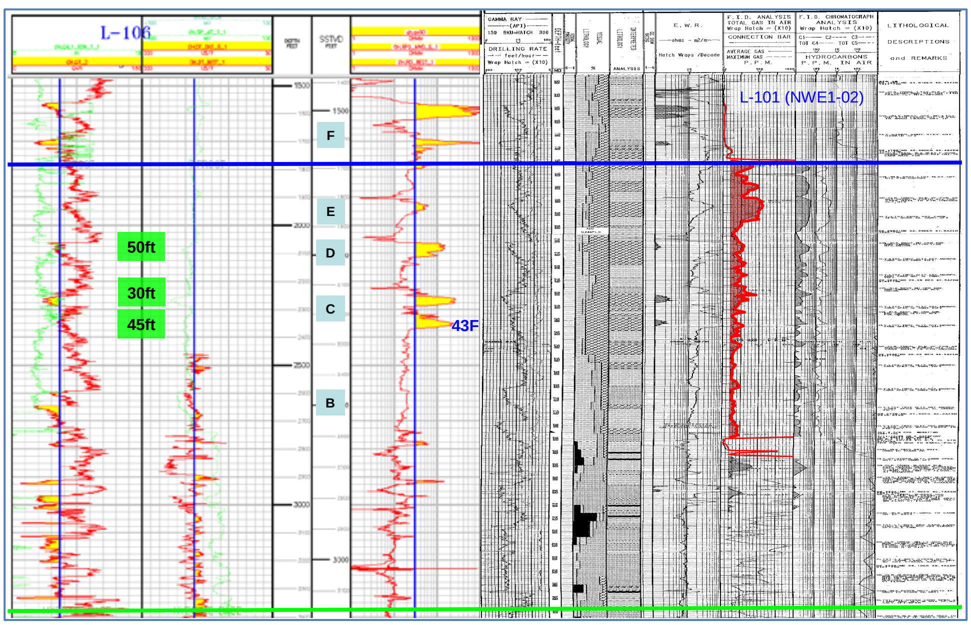
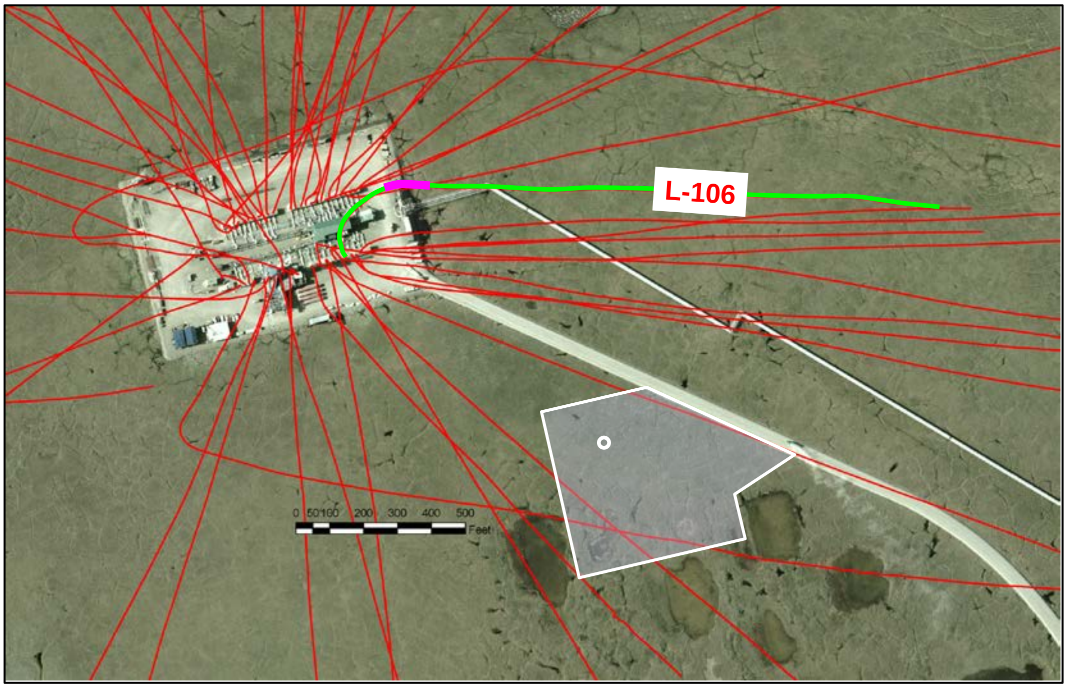


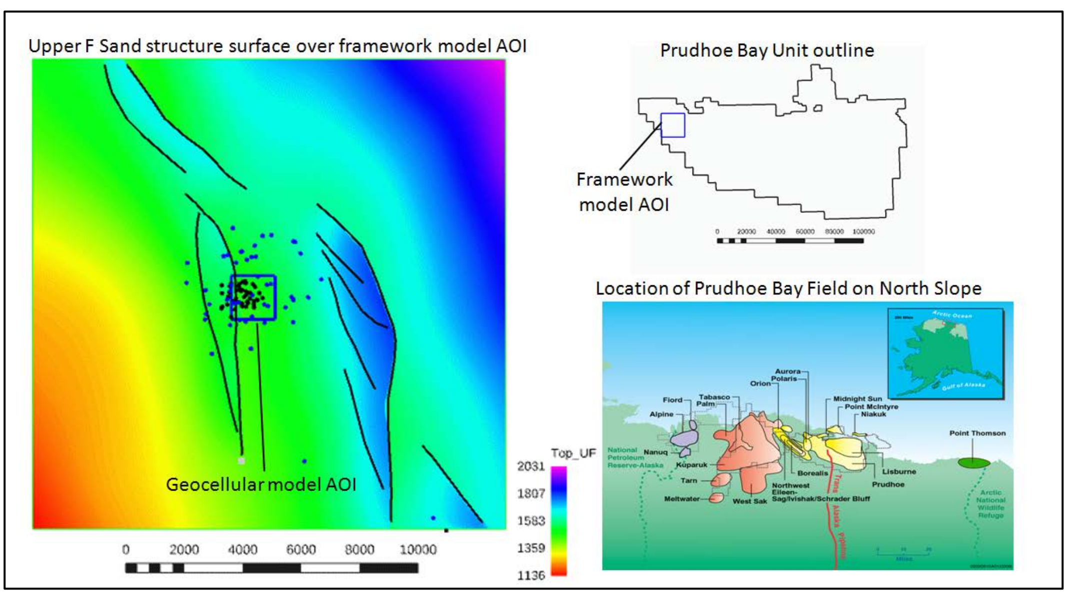
Figure 4: Photograph of the test site area that shows the approximate location of the ice pad. Well paths to underlying producing intervals are shown in red; L-106 (green) is the well with a full suite of logs, and it passes through the C sand at the pink location.



Reservoir Mapping

A geocellular model was built to support reservoir simulation of gas hydrate-bearing sandstones in the Sagavanirktok Formation (see Figure 5). All wells on this pad have gamma ray logs, which may be used to correlate sands. From those correlations, a structure may be built. All sands could be correlated across all wells in this area.

Figure 5: Model AOI and well control shown on the Upper F sandstone structure surface. Black points are well intersections at the top of the Upper F sandstone; blue points at the top of the B sandstone.



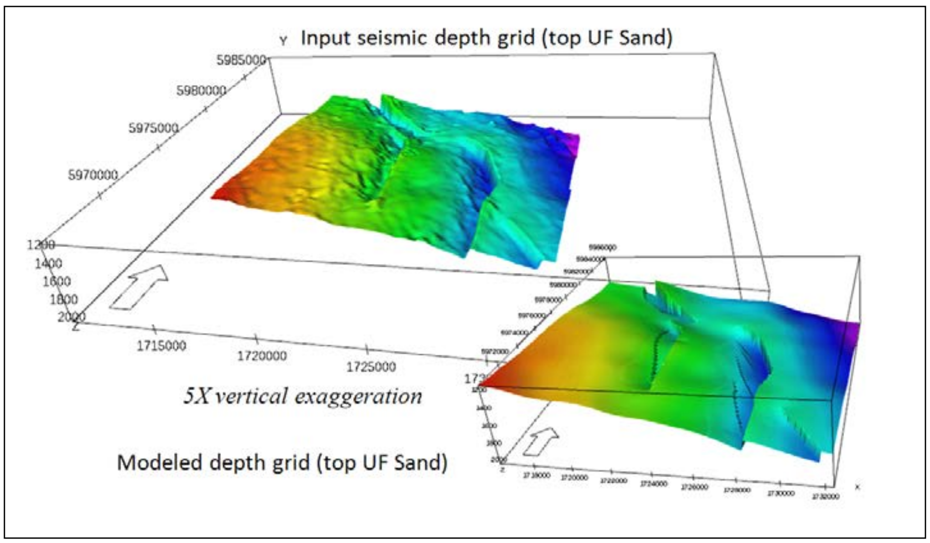
A structural and stratigraphic framework model was built across the Prudhoe Bay Unit L-pad area, delineating the informally named B through F sandstones. A 3-D geocellular model was then constructed over the central part of this framework model, encompassing the B through D sandstones. This model was rescaled to the 3-D gridding requirements of the reservoir simulator and exported for use in gas hydrate process modeling. The model was constructed in Roxar's RMS version 2010.01.

Structural and Stratigraphic Modeling

A seismically-defined structure grid of the top-most sandstone considered in this study, the Upper F sandstone, was used as the basis for the 3-D structural model. This grid, together with 10 fault surfaces, was interpreted and depth-converted. Structural surfaces on deeper horizons were also interpreted and depth-converted, but the top Upper F sandstone is regarded as the most reliable for use in 3-D structural modeling.

The original structure grid was conditioned to a subset of the well control in the L-pad area. The top of the Upper F sandstone was picked in a total of 54 wells for which gamma ray logs are available. The original depth grid was conditioned to all wells with valid well picks and re-gridded with a smoothing filter and the fault surfaces to create a smoother structure grid with better defined fault scarps (see Figure 6).

Figure 6: Input vs. modeled top Upper F sandstone structure grid



A flow unit-scale reservoir zonation was established in this region, breaking out sand-rich and sand-poor intervals. Figure 7 and Figure 8 show this stratigraphy on north-south and east-west-oriented sections, respectively, through the approximate center of the framework model AOI. Gross interval thicknesses are fairly consistent across the AOI. The reservoir stratigraphy attempts to constrain the sand- and siltstone-rich portions of upward-coarsening and fining sequences. A total of 12 zones are delineated; six of them are sand-rich. Strata are labeled to conform to Sagavanirktok stratigraphic nomenclature proposed by Collett (1993). Of these, the E, D and Upper and Lower C sandstones are gas hydrate-bearing. The B and Upper and Lower F sandstones are fully water saturated.

Figure 7: North-south stratigraphic cross-section (Datum is top Upper F sandstone)

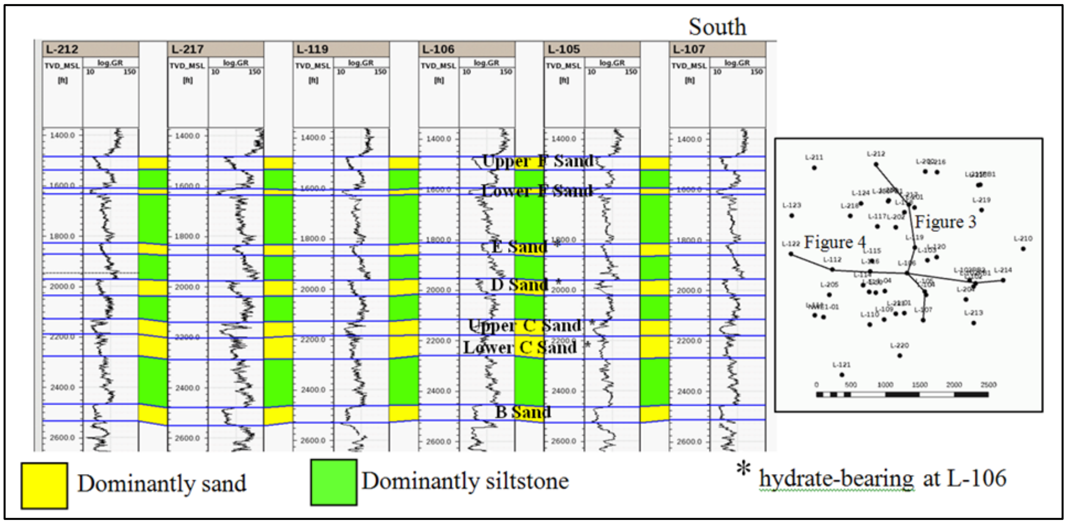
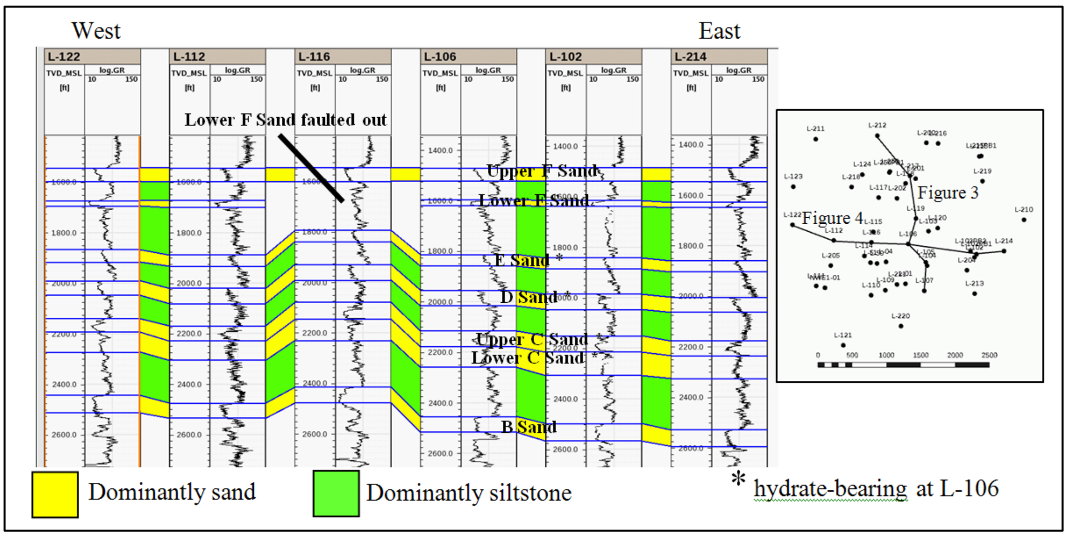


Figure 8: East-West stratigraphic cross-section (datum is top Upper F sandstone)



The detailed zonation revealed the existence of faulted sections within a number of the wells (see Figure 8 for an example). Point sets of fault cuts in wells (called "HardPoints") were generated and used together with the seismically interpreted fault surfaces (converted to fault sticks) in fault modeling. Some "pseudo-fault picks" were also added to the HardPoints set to help keep wells on the correct side of the faults.

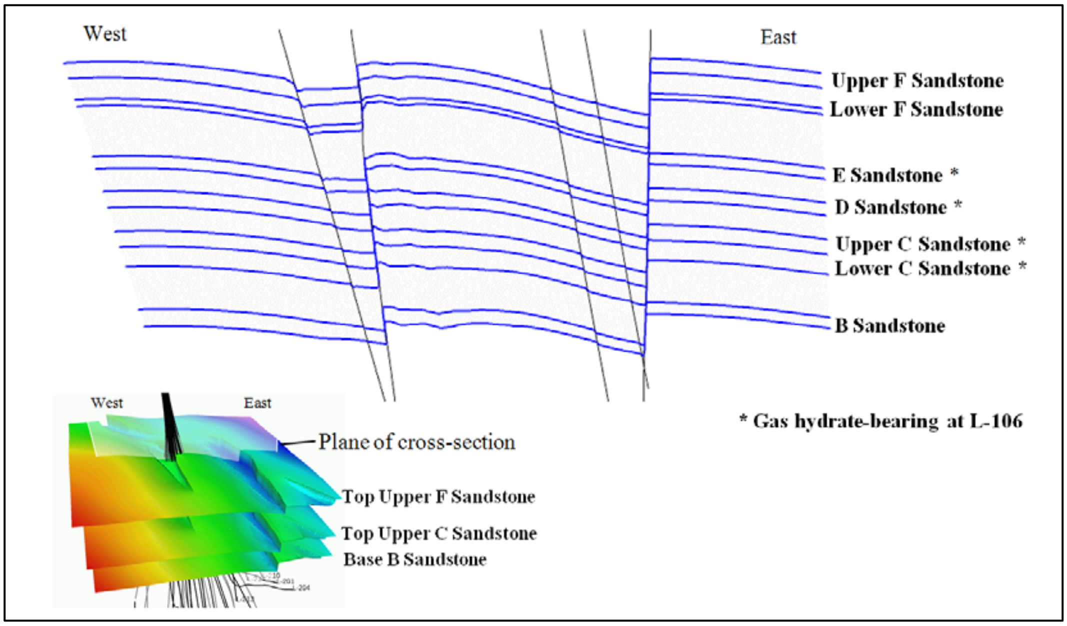
Isochore thickness well picks were used to generate gross thickness isochore grids. Only wells with complete intervals (that is, not faulted) were used to generate the gross thickness isochore grids to avoid thickness anomalies associated with faults. The isochore grids were used, together with depth well picks, the Upper F sandstone structure surface and modeled fault surfaces, to create the other stratigraphic horizons using the Horizon Modeling functionality in RMS 2010.01.Table 2 is a summary of the input data used in horizon modeling to generate the framework model. In effect, horizon modeling involves adding gross thickness isochore grids from the top Upper F seismically defined structure surface downward while honoring the zone tops and fault model.

Table 2: Input data used in horizon modeling

Element Modeled	Input Data			
	Well picks	Filtered structure surface	Fault model	Isochores
Horizons	Hard[1]	Soft[2]	Soft	0.9 confidence[3]

A representative east-west structural cross-section is shown in Figure 9. The framework model is about 16,000 x 16,000 feet aerially and about 1,045 feet thick from the top of the Upper F sandstone to the base of the B sandstone. Minimum depth in the model is 1136 feet and maximum depth is 3025 feet SSTVD.

Figure 9: East-west-oriented structural cross-section across the framework model



This framework model demonstrated that the test location is a structural trap with three-way dip closure to the north, east and south; and a fault closure with sands juxtaposed against silts and shales to the west. The test location was mapped to be above the lowest-known hydrate in the L-106 well for the E, D and Upper C sands. The Lower C sands extend below the lowest-known hydrate in L-106 and carried a risk that it could contain a gas hydrate/water contact.

Petrophysics

A complete suite of formation data was collected by a sequence of mud logging; logging-while-drilling (LWD) of 13½" hole and 9⅞"hole; and a full wireline logging

1 Hard means that input data is exactly preserved.

2 Soft means that data is not necessarily exactly preserved.

3 A value of 0.9 indicates a high degree of conformance with the input gross thickness isochore grids.

suite in 9⅞"hole during the 2011 winter season. Mud log data were collected under the supervision of ConocoPhillips wellsite geologist from the bottom of the conductor casing (110ft MD) to total depth of 2597ft. Mud loggers caught samples for real-time geologist review, archival storage, and to fulfill USGS geochemical sampling protocol. Preserved wet cuttings were canned every 60ft above surface casing point (1482ft MD) and every 30ft from surface casing point to TD (2597ft MD). Samples were treated with biocide, frozen and sent to the USGS for headspace gas analysis. In addition, canisters of gas agitated from the mud stream (Isotubes) were recovered with the same frequency and shipped to IsoTech Laboratories for compositional and isotopic analysis, per USGS sampling protocol. Figure 10 depicts the mud log over the hydrate-bearing interval of Sagavanirktok sandstones; shown are the rate of penetration, interpreted lithology, quantitative gas-show measurements, and the sample description.

Figure 10: Mud log through hydrate-bearing Sagavanirktok sandstones

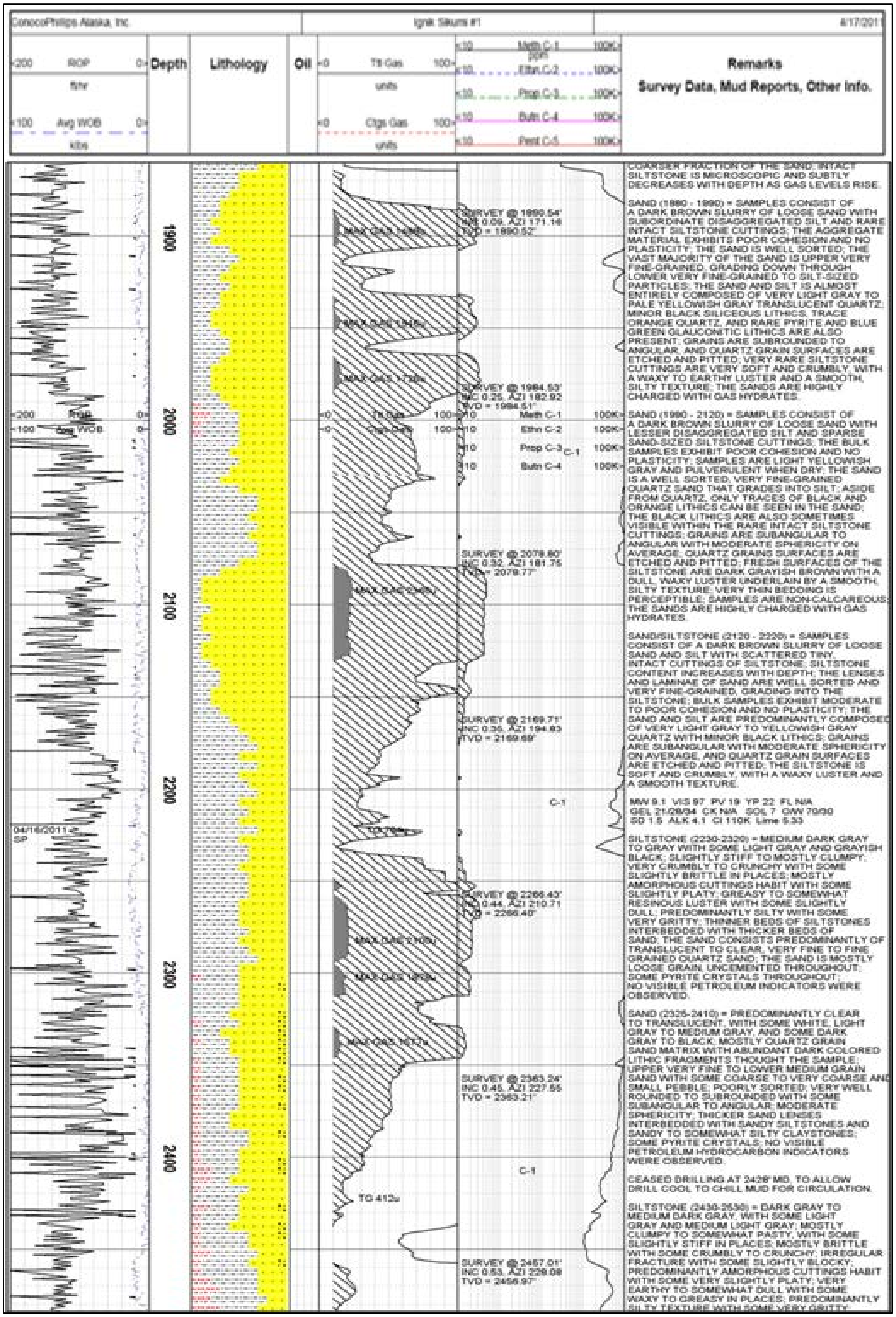


Table 3 contains a summary of the Schlumberger wireline logging tools that were run, with slight revisions to depths: Platform Express (PEX), Combinable Magnetic Resonance (CMR), Pressure Express (XPT) and Modular Dynamic Tool (MDT).

Table 3: Iġnik Sikumi #1 Openhole Data Collection

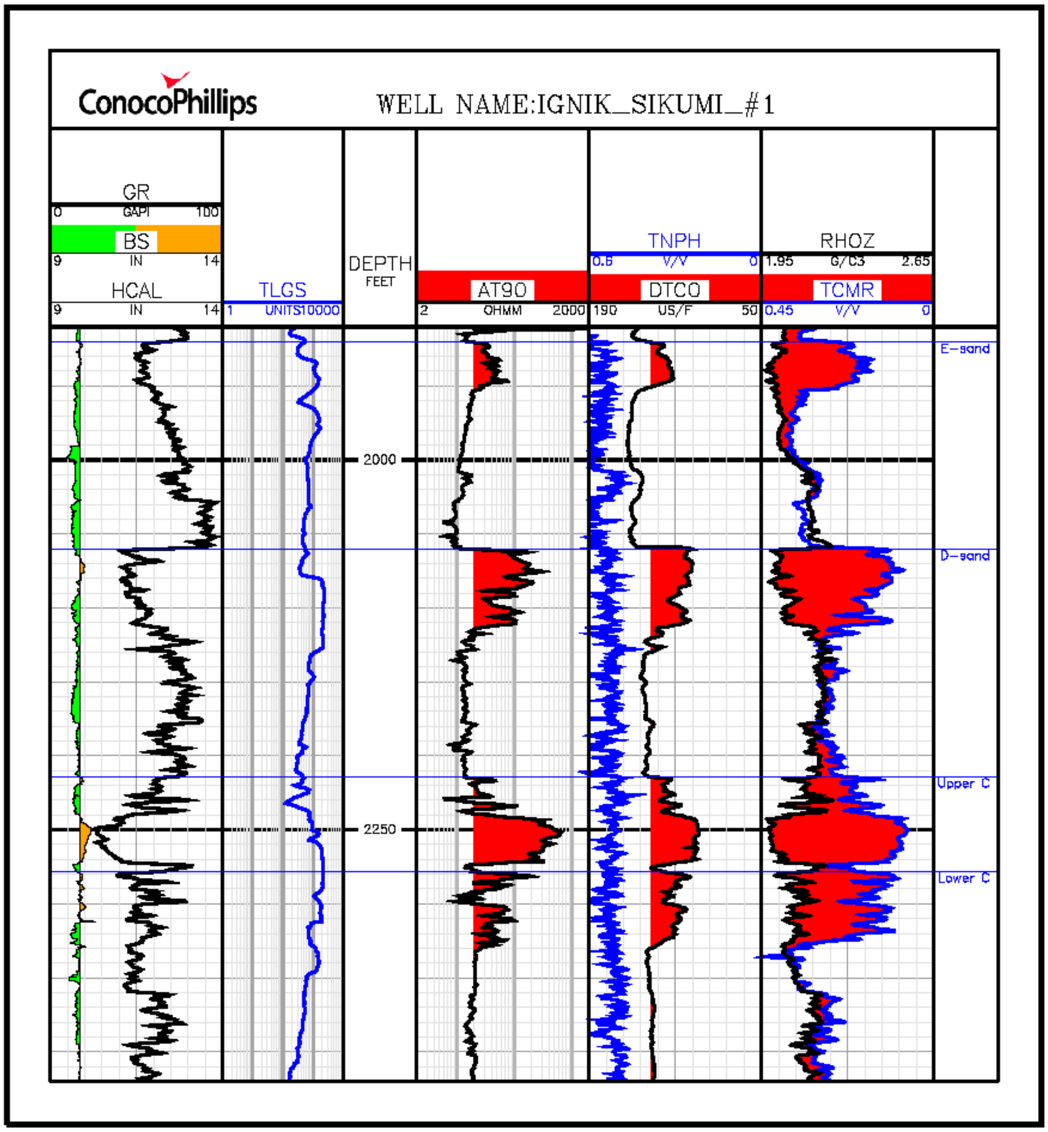
Logging Run	Vendor	Hole Size	Tool	Measurement	Interval
Mud log Mud logging	CanRig/Epoch	13½" & 9⅞"	Mud logger	ROP, mud gas, sample descriptions	110ft-2597ft
LWD Run 1	Sperry (Halliburton)	13½"	Gamma Ray	GR	110ft-1482ft
			Resistivity	pre-invasion Rt	110ft-1482ft
			Density-Neutron	ΦD, ΦN	110ft-1482ft
LWD Run 2	Sperry (Halliburton)	9⅞"	Gamma Ray	GR	1473ft-2597ft
			Resistivity	pre-invasion Rt	1473ft-2597ft
Wireline Run 1	Schlumberger	9⅞"	Gamma Ray	GR	1473ft-2597ft
			Sonic Scanner	ΔtC, ΔtS	1473ft-2597ft
			OBMI (+ GPIT)	Hi-Res image	1473ft-2597ft
			Rt Scanner	Vertical & horizontal resistivity	1473ft-2597ft
Wireline Run 2	Schlumberger	9⅞"	PEX	ΦD, ΦN	1473ft-2597ft
			HNGS	natural gamma spectroscopy	1473ft-2597ft
			CMR	distribution of relaxation times	1473ft-2597ft
			XPT	P, T, fluid mobility	selected points
Drill pipe	Schlumberger	9⅞"	TLC	Drill pipe conveyance	
			Gamma Ray	GR	
		Run 3A	MDT mini-Frac	P, T, fluid sampling	selected points
		Run 3B	MDT mini-DST	frac/breakdown pressures	selected points

Petrophysical Analysis

Figure 11 shows the basic log responses for the reservoir interval. The gamma ray (Track 1) is the standard sand – shale discrimination tool, where the hydrate-bearing sand intervals are recognized by the lower GR signal. The caliper log (Track 1 HCAL), when compared to the bit-size curve (Track 1 BS) indicates a good quality borehole throughout the hydrate-bearing intervals with minimal washout. The hydrate-bearing intervals are identified by high resistivity (Track 4 AT90), low compressional slowness values (Track 5, DTCO) and separation between the conventional density and NMR porosity curves (Track 6). The deepest reading resistivity curve, AT90, was collected with the RtScanner and processed with a standard two-foot vertical resolution. A threshold value of 2 ohm-m was chosen to identify the hydrate-bearing intervals (shaded red). Lower slowness values correspond to faster velocities and indicate the presence of a porosity-reducing hydrate that also strengthens the sand. A threshold value of 140 µsec/ft was used to discriminate the hydrate-bearing intervals. The bulk density measurement (RHOZ) is not affected when water is transformed into hydrate because the density of the liquid and solid are virtually the same. For this reason, the standard density log is the best option for determining the total pore volume filled with liquid and hydrate. In contrast, the fluid-sensitive NMR log does not detect the hydrate because the fast relaxation times associated with hydrate are not detectable by the conventional logging tools. The combination of the two provides a useful way to distinguish water-filled pores from hydrate-filled pores.

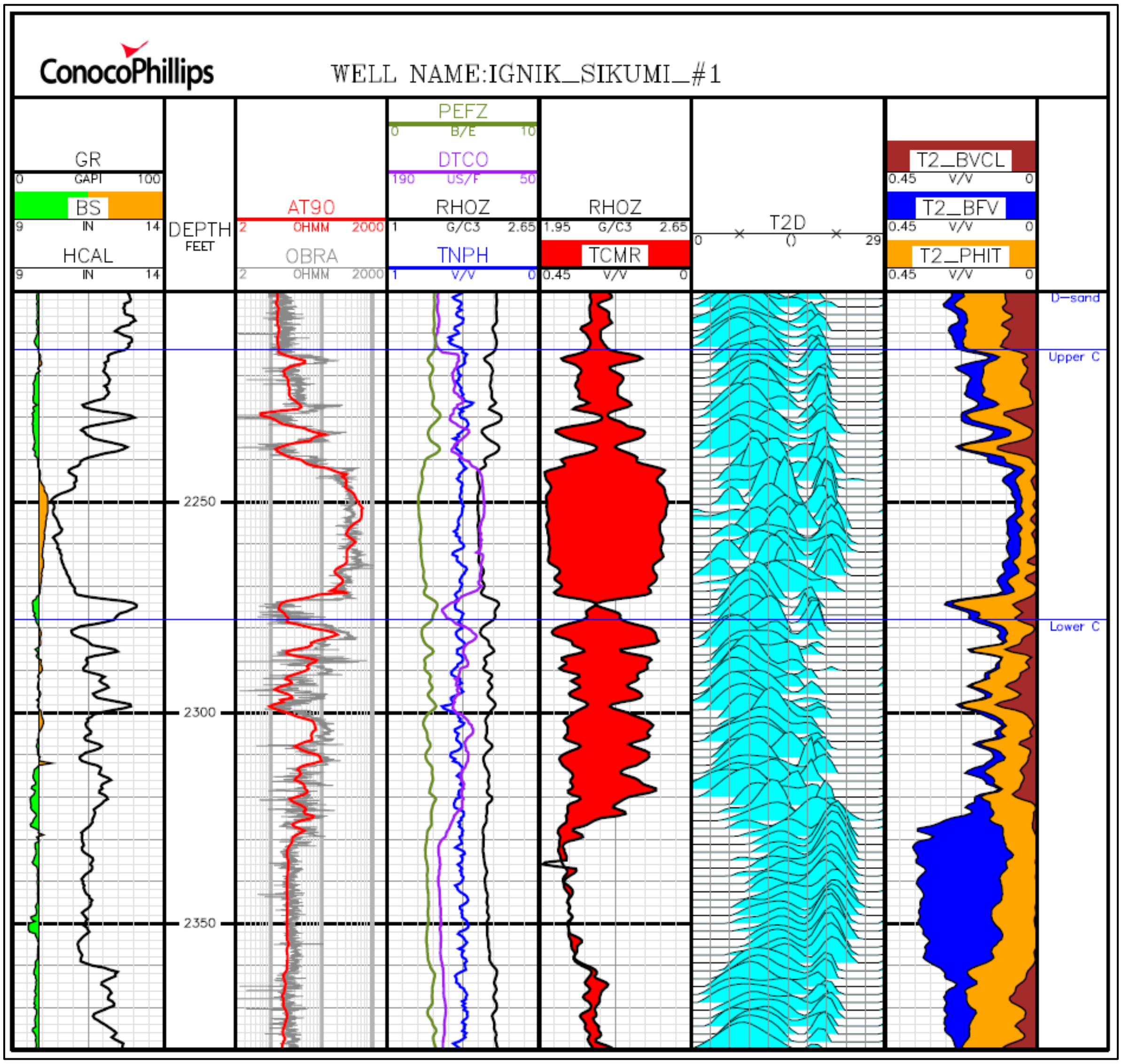
In Figure 11, hydrates are identified by high RT values, low compressional slowness (DTCO), (i.e. high velocity), a subdued NPHI response, and the relationship between low RHOB/high DPHI and low NMR porosity (TCMR) that results from fast T2 decay.

Figure 11: Iġnik Sikumi Log response with hydrate-bearing intervals (shaded)



The logs were analyzed to determine reservoir quality and calculate fluid saturations (Figure 12). The Upper C sandstone was selected for the test because it is thick, homogenous, and clean with uniform hydrate saturation. The interval has high resistivity values and reduced slowness, both of which indicate hydrates in this particular environment. The NMR relaxation time distributions (Track 6, T2D) in the hydrate-bearing interval are broad, with strong bimodal behavior at some depths. The faster relaxation times correspond to water in smaller or drained pores. In contrast, the slower, more intense distribution in the Lower C sand (2330 and below) indicates a water-filled sand without hydrate. This interval provides a baseline for any interpretation of the NMR log.

Figure 12: Log characteristics of the Iġnik Sikumi Upper C sands showing homogeneous character and well-defined bounding shales, and low moveable water



Tracks from left-to-right are: gamma ray, resistivity, sonic, neutron density, CMR T2 echo train and CMR calculated saturation (blue = free water, orange = capillary bound water, brown = clay bound water).

Hydrate saturation was calculated using four methods:

1. Archie's equation (Archie, 1942);
2. Schlumberger's Density-NMR method based on a conventional gas analysis approach (Kleinberg et al, 2005);
3. Multiple Mineral solution by linear regression, AIM (Klein et al., 2012); and
4. Sonic (Xu and White, 1995).

The assignment of parameters in the conventional Archie's method was based upon the similarity in resistivity between hydrates and hydrocarbons (i.e., high resistivity phases). The water resistivity (Rw) has a great deal of uncertainty associated with its value in hydrate-bearing reservoirs, and was determined by conventional well log analysis techniques in the water-wet sand at the base of the C sand interval. Standard values for the Archie parameters "a", "n" and "m" (i.e. 1, 2 and 2) were used given the absence of independently determined results. Saturations were calculated using a modified Archie expression where hydrate saturation is 1.0 minus water saturation.

Equation 1: Modified Archie's equation

$$Sh = 1 - \left(\frac{Rw}{\phi^m Rt} \right)^{1/n}$$

Where:

S_h = hydrocarbon saturation
$\O$ = porosity
Rw = formation water resistivity
Rt = observed bulk resistivity
n = saturation exponent (generally 2)

The NMR log-based interpretation model calculated hydrate saturation as the difference between NMR porosity and density porosity (Kleinberg et al., 2005). This approach was similar to conventional gas analysis methods where the density porosity approach measures the total pore volume while the NMR responds only to the liquid filled pores (gas density being so low that it approaches a value of zero). The NMR-based interpretation model is driven by the observation that while liquid water has relaxation properties that are easily detected by the logging tool, once that water is transformed into a solid state, either as ice or hydrate, the relaxation processes are too fast for detection by a conventional logging tool. The separation between a density-based porosity and the NMR-based value in a hydrate-bearing interval reflects the amount of hydrate (or ice) in the zone.

Equation 2: Hydrate Saturation model for NMR and Density logs

$$S_h = \frac{DPHI - TCMR}{DPHI + \lambda \cdot TCMR} \quad \text{where} \quad \lambda = \frac{\rho_{fluid} - \rho_{hydrate}}{\rho_{matrix} - \rho_{fluid}}$$

Where:

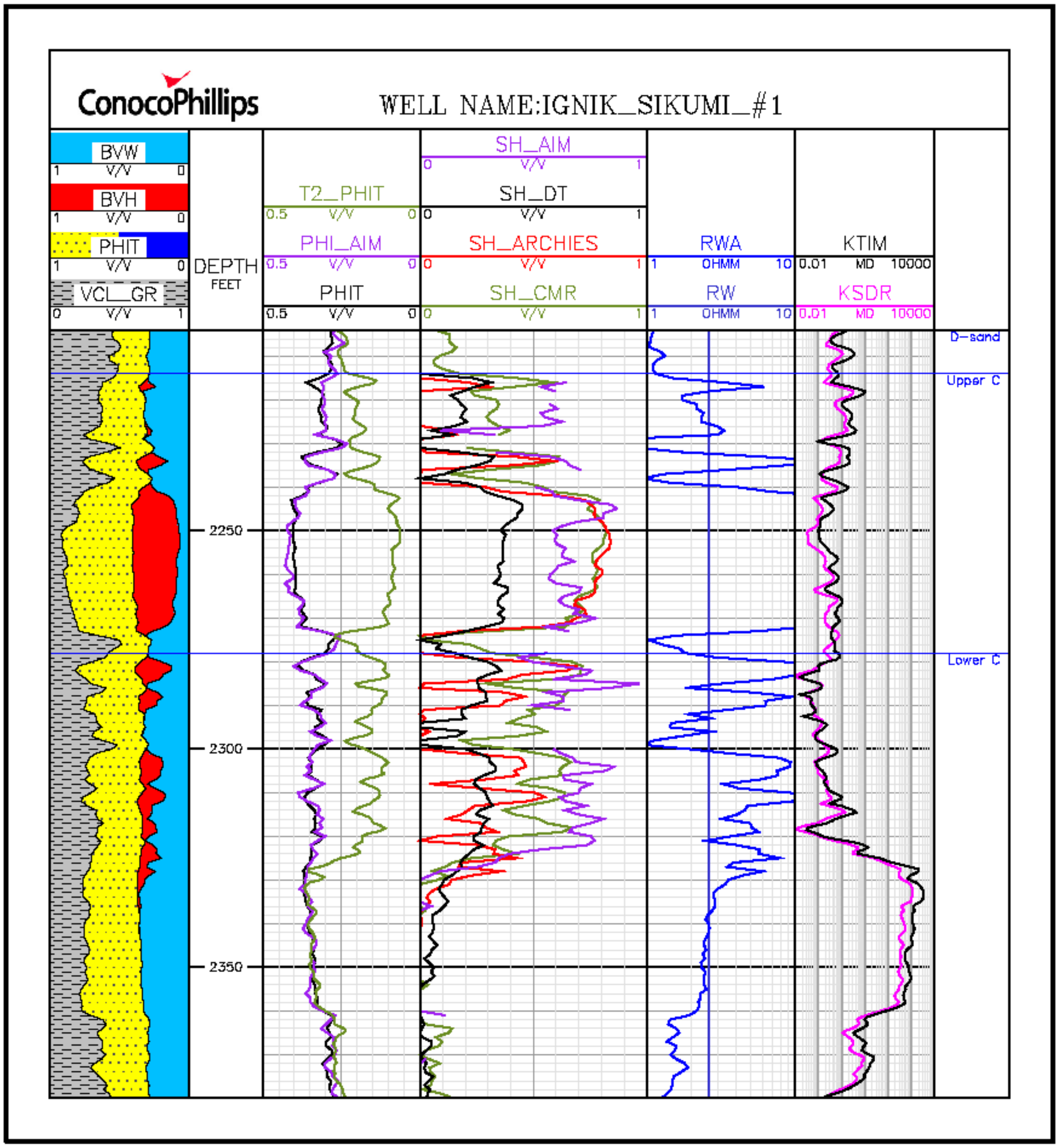
S_h = hydrocarbon saturation
DPHI = density porosity
TCMR = NMR total porosity
ρ = density of fluid, hydrate or bulk matrix

The multiple mineral solution used a simultaneous equation solver with GR, PHOB, DT and HPHI as inputs. The linear regression model generated outputs of sand, clay, hydrate and water volumes. This solution was independent of resistivity.

The sonic method calculated hydrate saturation as the difference between sonic porosity and density porosity, in a manner like the NMR-based interpretation model.

The results of these methods for hydrate saturation are shown in Figure 13. The Archie's and NMR methods provided a similar solution with average hydrate saturation in the Upper C sand being 75%. None of these methods were calibrated to core, so there was significant uncertainty in the actual saturations values. All methods indicated that the hydrate saturation was high and relatively uniform in the Upper C sand.

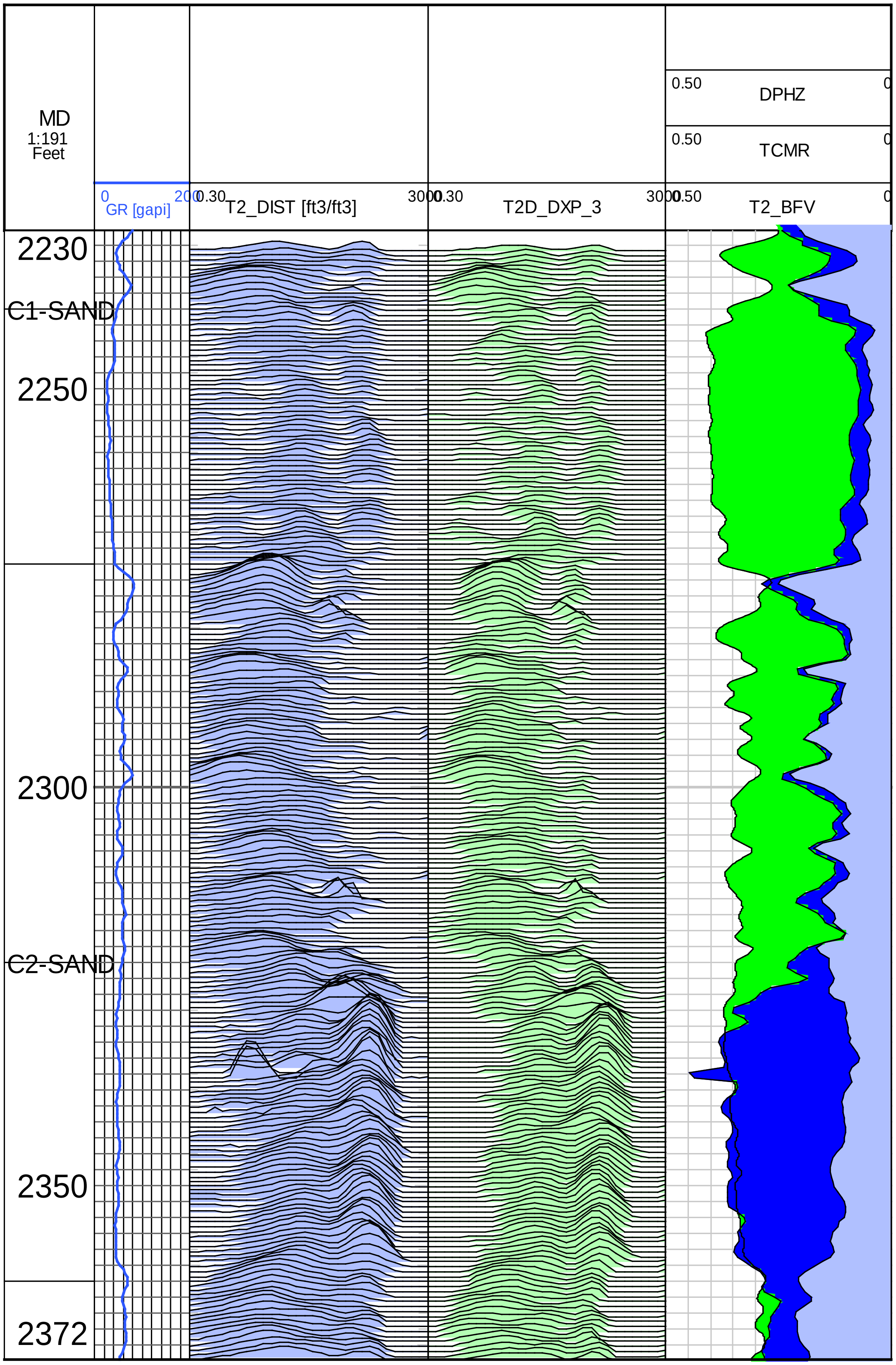
Figure 13: Calculated hydrate saturations in Iġnik Sikumi using four different methods (Red = Archie's equation; Green = NMR method; Purple = multiple mineral solution; Black = sonic)



NMR data from the CMR tool was reprocessed to improve time and depth resolution of the calculated relaxation time distributions. The original relaxation time distributions were broad, with weak discrimination between fast and slow relaxation components (Figure 14). Reprocessing with a similar T2 time basis (30 points between 0.3 to 3000 msec) and a fixed regularization parameter generated distributions with a more distinct bimodal nature. The fast relaxation component represented capillary-bound water, the majority of the free water in the hydrate-bearing intervals, while the slower component was associated with free water in larger pores. Volumetrically this mobile water was less than the faster capillary-bound water. The distributions were scaled to total NMR porosity, which was significantly reduced in the hydrate-bearing zones. The water-saturated interval at the base of the C sand was identified by high NMR porosity and a relaxation time distribution dominated by slower times (i.e., large water-filled pores).

Volumetric calculations from the NMR-Density model (Track 4, Figure 14), indicate that there are large volumes of hydrate (green) in the Upper C sand with smaller amounts of “free” water (dark blue) and capillary bound water (light blue). The Lower C sand interval at 2350 ft. does not contain hydrate as shown by the large volume of free water.

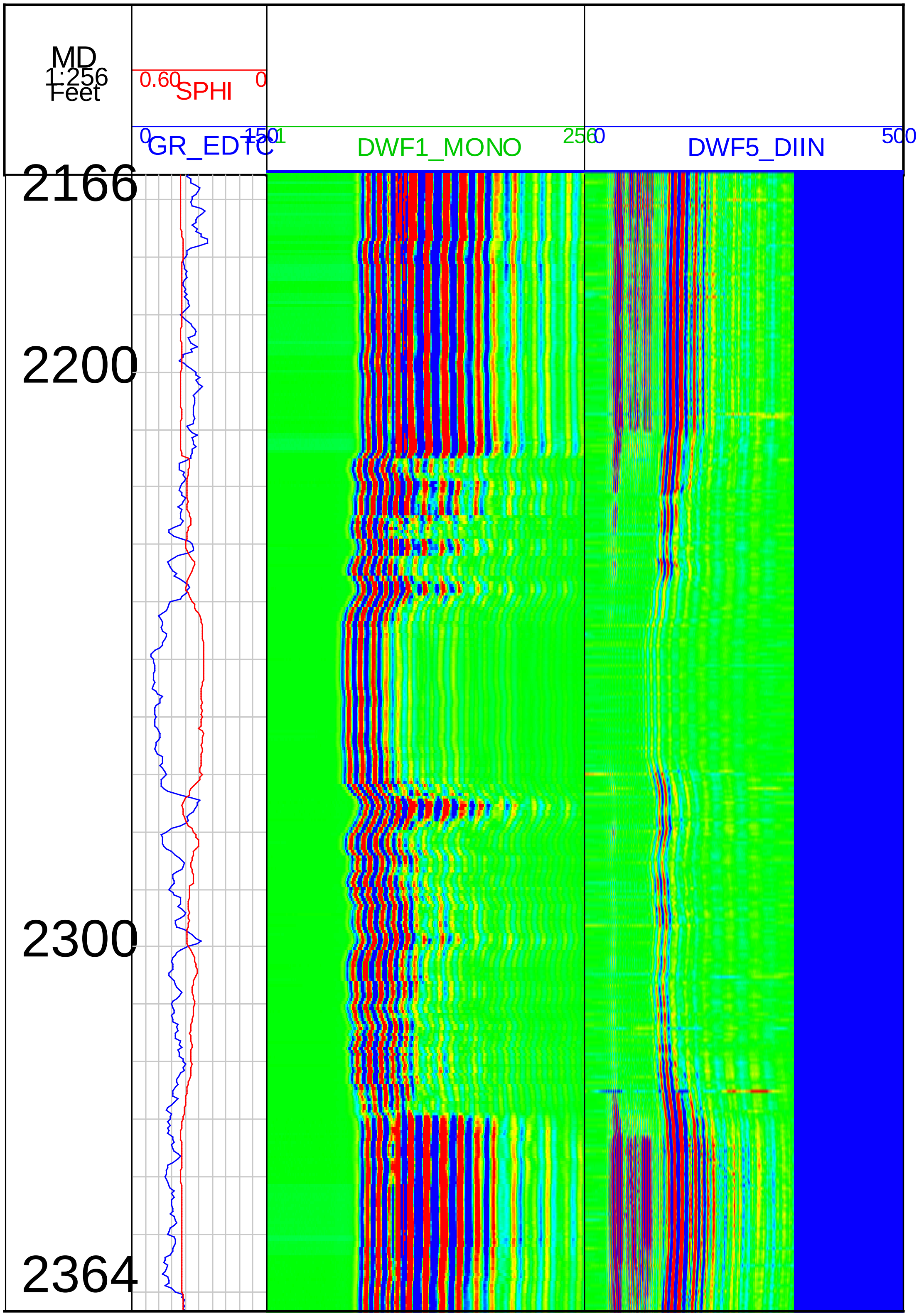
Figure 14: **Original (Track 2) and reprocessed (Track 3) NMR T2 relaxation time distributions for the C sand intervals**



Estimates of permeability based on NMR-measured properties were calculated with both the TIMUR and SDR conventional models. Both approaches generated permeability values greater than 1 Darcy in the water-bearing C sand (Lower C). The permeability was calculated to be less than 1 mD in the hydrate-bearing Upper C sand. These values are not actually measurements of permeability; instead, the models are based on pore geometry models of porosity and estimates of pore size, and should be used with caution.

Acoustic velocities were calculated from the first arrivals of Monopole and In-line Dipole of the Dipole Sonic Tool. The waveforms were well behaved with clearly resolvable first-arrivals (see Figure 15). The hydrate-bearing intervals stood out on the waveform plots by the increased attenuation (loss of signal amplitude). The Vp velocities ranged between 2500 and 3000 msec, comparable to the values obtained on the nearby L-106 and Mt. Elbert wells (Collett and Lee, 2012), and laboratory-based measurements (Howard et al., 2011). The Vp/Vs ratio was around 2.5.

Figure 15: **Wave form displays of the monopole array (Track 2) and in-line dipole array (Track 3) across the hydrate-bearing C sand interval**



The velocities and calculated saturations were compared to the general Effective Medium model used to determine hydrate distribution in pores (see Howard et al., 2011 for details of earlier work). The velocities compared favorably with the model-predicted values for hydrate enveloping discrete sand grains, but not for grain-contact hydrate cement or pore-filling hydrate (Figure 16). These results were similar to those collected on high-hydrate saturation sand packs.

Figure 16: Plot of hydrate saturation and velocity. When compared to the Effective Medium model, the velocities compare favorably with the model-predicted values for hydrate-enveloping discrete sand grains, but not for grain-contact hydrate cement or pore-filling

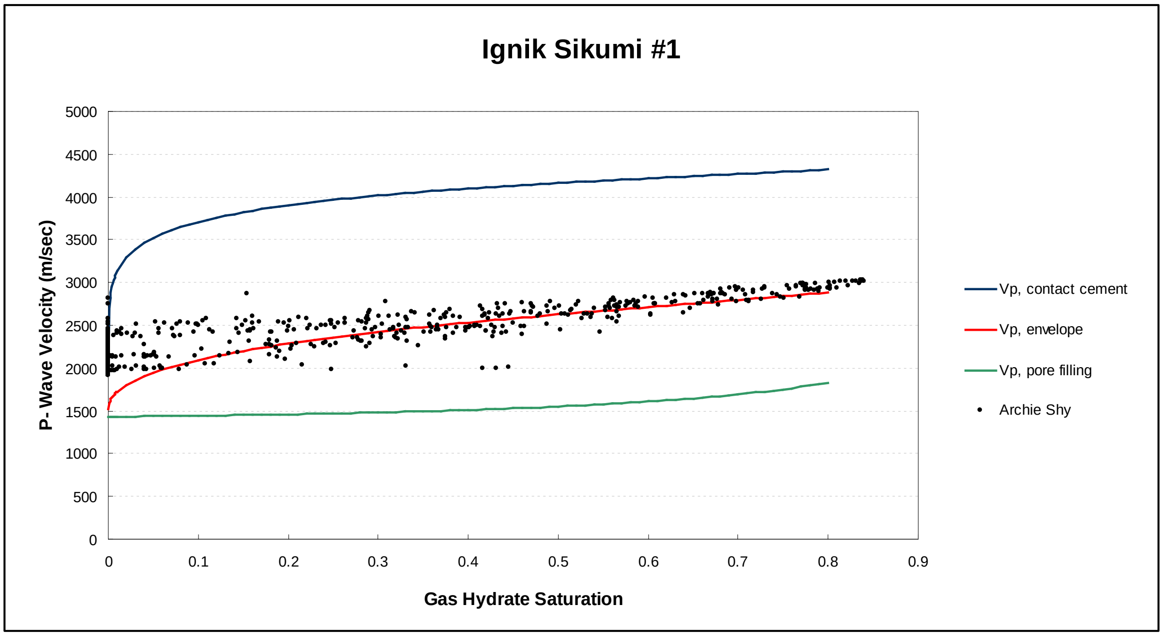


Table 4: Petrophysical reservoir characterization

PERFS	DEPTH FEET	Log Derived Reservoir Properties, per Jim Klein: total porosity PHIT_2 V/V	hydrate saturation from CMR SH_CMR_1 V/V	water saturation from CMR SW_CMR_1 V/V	Clay Volume VCL_GR_2 V/V	GammaRay GR_1 GAPI	Temperature: last DTS trace, 5/30 °F	Temperature: AVG of 5/30 readings °F	Temperature: last DTS trace, 9/08 °F	Temperature: AVG of 9/08 readings °F	Fracture Closure Pressure per Dave Cramer, 6/3: "reservoir" psi	Fracture Closure Pressure per Dave Cramer, 6/3: "seal" psi	Reservoir Pressure: Avg gradient psi	Reservoir Pressure from XPT (per Ahmad Latifzai/SLB): C Sd gradient psi	Actual XPT measurment psi	CMR Saturations (Howard/Klein): "capillary + clay-bound water" BFV_1 V/V	"clay-bound water" CBF2_1 V/V	"movable water" CMFF_1 V/V	"total water-filled porosity" TCMR_1 F3/F3	"Water-filled porosity" fraction DAS: clay-bound water %	capillary-bound water %	movable water %
	2234	0.377061	0.613156	0.386844	0.237248	45.501	40.59	40.59	40.39	40.25	1412	1542	1034	1072		0.0781137	0.0212058	0.0608266	0.13894			
	2235	0.36643	0.608362	0.391638	0.261158	48.5958	40.6	40.59	40.26	40.26	1413	1542	1035	1072		0.104868	0.0340508	0.0518991	0.156766			
	2236	0.340358	0.526221	0.473779	0.299577	53.5686	40.61	40.60	40.29	40.28	1414	1543	1035	1073		0.177083	0.0765328	0.0242302	0.201313			
	2237	0.294642	0.305374	0.694626	0.396601	66.1271	40.61	40.61	40.47	40.29	1414	1544	1036	1073		0.210874	0.100432	0.0141487	0.225022			
	2238	0.263994	0.140836	0.859164	0.471055	75.7642	40.56	40.64	40.37	40.31	1415	1544	1036	1074		0.17576	0.0831418	0.0233187	0.199079			
	2239	0.27503	0.26572	0.73428	0.419223	69.0552	40.55	40.66	40.30	40.32	1416	1545	1037	1074		0.127178	0.0531521	0.0408565	0.168035	0.32	0.44	0.24
	2240	0.322915	0.46622	0.53378	0.316374	55.7428	40.64	40.68	40.37	40.33	1416	1546	1037	1075		0.10477	0.0317679	0.0563572	0.161128	0.20	0.45	0.35
	2241	0.362891	0.542835	0.457165	0.246237	46.6645	40.67	40.70	40.42	40.35	1417	1547	1038	1075		0.0957086	0.0289622	0.0475758	0.143285	0.20	0.47	0.33
	2242	0.352673	0.581074	0.418926	0.231595	44.7692	40.66	40.72	40.45	40.38	1418	1547	1038	1076		0.0596246	0.0158921	0.0322984	0.091923	0.17	0.48	0.35
perf	2243	0.3752	0.744824	0.255176	0.189487	39.3189	40.67	40.75	40.42	40.39	1418	1548	1039	1076	1077	0.0496859	0.0122132	0.0319334	0.0816193	0.15	0.46	0.39
perf	2244	0.409261	0.791653	0.208347	0.173443	37.2422	40.66	40.77	40.41	40.40	1419	1549	1039	1077		0.0584877	0.0162107	0.0368581	0.0953457	0.17	0.44	0.39
perf	2245	0.406564	0.755788	0.244212	0.209842	41.9536	40.68	40.79	40.46	40.42	1419	1549	1039	1077		0.0607997	0.0166005	0.0400886	0.100888	0.16	0.44	0.40
perf	2246	0.40223	0.739011	0.260989	0.213226	42.3916	40.73	40.81	40.53	40.43	1420	1550	1040	1078		0.0500946	0.0107282	0.0372062	0.0873008	0.12	0.45	0.43
perf	2247	0.3932	0.768643	0.231357	0.203428	41.1234	40.79	40.83	40.63	40.45	1421	1551	1040	1078		0.0478018	0.0063433	0.030482	0.0782839	0.08	0.53	0.39
perf	2248	0.392448	0.791851	0.208149	0.191194	39.5398	40.8	40.84	40.62	40.45	1421	1551	1041	1078		0.0479679	0.00349079	0.0286886	0.0766564	0.05	0.58	0.37
perf	2249	0.40003	0.799916	0.200084	0.135598	32.3437	40.75	40.84	40.60	40.46	1422	1552	1041	1079		0.0430961	0.00699578	0.0288934	0.0719894	0.10	0.50	0.40
perf	2250	0.405236	0.814487	0.185513	0.0967856	27.3199	40.73	40.84	40.56	40.47	1423	1553	1042	1079		0.0401702	0.0137494	0.0274972	0.0676673	0.20	0.39	0.41
perf	2251	0.402424	0.824383	0.175617	0.0834363	25.592	40.76	40.86	40.55	40.49	1423	1553	1042	1080		0.0426361	0.0140413	0.0281119	0.070748	0.20	0.40	0.40
perf	2252	0.403509	0.816872	0.183128	0.100362	27.7828	40.78	40.90	40.57	40.53	1424	1554	1043	1080		0.0458755	0.014851	0.0283021	0.0741777	0.20	0.42	0.38
perf	2253	0.403206	0.807867	0.192133	0.0931144	26.8447	40.88	40.91	40.64	40.54	1424	1555	1043	1081		0.0431567	0.0141312	0.0312754	0.0744321	0.19	0.39	0.42
perf	2254	0.401042	0.806226	0.193774	0.0963507	27.2636	40.96	40.92	40.70	40.55	1425	1555	1044	1081		0.0463946	0.0145269	0.0344967	0.0808913	0.18	0.39	0.43
perf	2255	0.39703	0.787499	0.212501	0.11142	29.2141	40.95	40.94	40.66	40.57	1426	1556	1044	1082		0.053341	0.0150028	0.0376048	0.0909458	0.16	0.42	0.41
perf	2256	0.401873	0.7642	0.2358	0.121131	30.4711	40.95	40.95	40.63	40.58	1426	1557	1045	1082		0.0487623	0.0146244	0.0443903	0.0931526	0.16	0.37	0.48
perf	2257	0.403533	0.759571	0.240429	0.128729	31.4545	40.91	40.96	40.61	40.57	1427	1558	1045	1083		0.0475363	0.0162231	0.0441136	0.0916498	0.18	0.34	0.48
perf	2258	0.400327	0.761612	0.238388	0.135451	32.3246	40.93	40.97	40.65	40.60	1428	1558	1045	1083		0.0490216	0.014455	0.0377671	0.0867888	0.17	0.40	0.44
perf	2259	0.398109	0.772852	0.227148	0.105252	28.4158	40.97	40.98	40.69	40.62	1428	1559	1046	1084		0.0447164	0.00642813	0.0379777	0.0826941	0.08	0.46	0.46
perf	2260	0.397012	0.782811	0.217189	0.10351	28.1903	41.03	40.99	40.75	40.62	1429	1560	1046	1084		0.0418772	0.00356211	0.0442301	0.0861074	0.04	0.44	0.51
perf	2261	0.397733	0.774404	0.225596	0.117604	30.0146	41.07	41.01	40.73	40.63	1430	1560	1047	1085		0.0436701	0.00570766	0.0462096	0.0898797	0.06	0.42	0.51
perf	2262	0.3944	0.762645	0.237355	0.11663	29.8885	41.05	41.01	40.63	40.65	1430	1561	1047	1085	1092	0.0452442	0.00363129	0.0414258	0.0866699	0.04	0.48	0.48
perf	2263	0.396321	0.77204	0.22796	0.127144	31.2494	41.05	41.02	40.70	40.66	1431	1562	1048	1086		0.049414	0.0092803	0.0329891	0.0824032	0.11	0.49	0.40
perf	2264	0.396939	0.783584	0.216416	0.135567	32.3397	41.06	41.03	40.78	40.68	1431	1562	1048	1086		0.0622468	0.0232247	0.0337752	0.0960217	0.24	0.41	0.35
perf	2265	0.399752	0.749924	0.250076	0.138681	32.7427	41.06	41.04	40.85	40.70	1432	1563	1049	1087		0.0661496	0.0159439	0.045421	0.111571	0.14	0.45	0.41
perf	2266	0.386333	0.699909	0.300091	0.14671	33.7819	41.06	41.05	40.91	40.71	1433	1564	1049	1087		0.061911	0.0147614	0.0505238	0.112435	0.13	0.42	0.45
perf	2267	0.368515	0.683428	0.316572	0.155487	34.918	41.07	41.06	40.87	40.70	1433	1564	1050	1088	1082	0.0569285	0.0217814	0.0485922	0.105521	0.21	0.33	0.46
perf	2268	0.369048	0.703035	0.296965	0.162518	35.8281	41.09	41.08	40.88	40.73	1434	1565	1050	1088		0.0560756	0.0174721	0.0449302	0.101006	0.17	0.38	0.44
perf	2269	0.380909	0.724266	0.275734	0.176271	37.6082	41.12	41.10	40.92	40.77	1435	1566	1051	1089		0.0673501	0.0136647	0.0410437	0.108393	0.13	0.50	0.38
perf	2270	0.371648	0.697154	0.302846	0.179191	37.9862	41.11	41.11	40.91	40.77	1435	1567	1051	1089		0.0808854	0.023331	0.0443812	0.125267	0.19	0.46	0.35
perf	2271	0.361248	0.640941	0.359059	0.195886	40.1472	41.07	41.12	40.89	40.78	1436	1567	1051	1090		0.0760181	0.0230715	0.0442642	0.120282	0.19	0.44	0.37
perf	2272	0.375485	0.668104	0.331896	0.202259	40.9721	41.02	41.13	40.89	40.79	1436	1568	1052	1090	1088	0.0952361	0.0143062	0.0364327	0.131669	0.11	0.61	0.28
perf	2273	0.376218	0.637938	0.362062	0.216212	42.7781	40.97	41.15	40.97	40.81	1437	1569	1052	1090		0.18998	0.0406186	0.0253147	0.215295	0.19	0.69	0.12
	2274	0.313576	0.301934	0.698066	0.349246	59.9976	40.95	41.15	41.04	40.83	1438	1569	1053	1091		0.259009	0.0808297	0.0195688	0.278579	0.29	0.64	0.07
	2275	0.267139	0	1	0.502193	79.7947	40.9	41.16	40.98	40.84	1438	1570	1053			0.244544	0.0904397	0.022492	0.267035	0.34	0.58	0.08
	2276	0.276406	0.0325745	0.967426	0.517048	81.7174	40.94	41.17	40.93	40.85	1439	1571	1054			0.199134	0.0744931	0.0275285	0.226663	0.33	0.55	0.12
	2277	0.293352	0.218226	0.781774	0.468851	75.479	41.2	41.21	40.93	40.87	1440	1571	1054			0.179629	0.0747257	0.029471	0.209099	0.36	0.50	0.14
	2278	0.289588	0.267741	0.732259	0.420346	69.2006	41.26	41.22	40.97	40.90	1440	1572	1055			0.170225	0.0765782	0.0343493	0.204575	0.37	0.46	0.17
	2279	0.303109	0.313807	0.686193	0.40308	66.9658	41.19	41.23	41.04	40.92	1441	1573	1055			0.128809	0.041218	0.0401644	0.168973			
	2280	0.344739	0.4966	0.5034	0.306486	54.4629	41.2	41.25	41.10	40.95	1442	1573	1056			0.0910881	0.0083496	0.0302713	0.121359			
	2281	0.378436	0.667946	0.332054	0.210762	42.0727	41.2	41.26	41.10	40.96	1442	1574	1056			0.0831081	0.00925375	0.0231706	0.106278			
	2282	0.388473	0.715869	0.284131	0.188517	39.1933	41.18	41.25	41.02	40.98	1443	1575	1057			0.0791429	0.0200834	0.0239418	0.103085			
	2283	0.370042	0.71067	0.28933	0.219065	43.1474	41.22	41.26	40.99	40.98	1443	1575	1057			0.0824107	0.0374331	0.0134943	0.0959051			
	2284	0.334406	0.702505	0.297495	0.268678	49.5692	41.29	41.28	41.00	40.98	1444	1576	1057			0.119248	0.0600407	0.0108274	0.130075			

XPT Testing

The Pressure Express, XPT tool was used to measure formation pressure and estimate fluid mobility in the D and C sands. Each formation was expected to have low permeability resulting from the high hydrate saturations. The XPT has a pad and probe that permits fluid withdrawal/pressure build up testing with very low fluid flow rate for tight formations. The tool used a large area packer that increased the formation area exposed to the probe barrel. Both a lower flow rate and a larger area allowed for smaller draw-down pressure as shown by Darcy's equation.

Equation 3: Darcy's equation

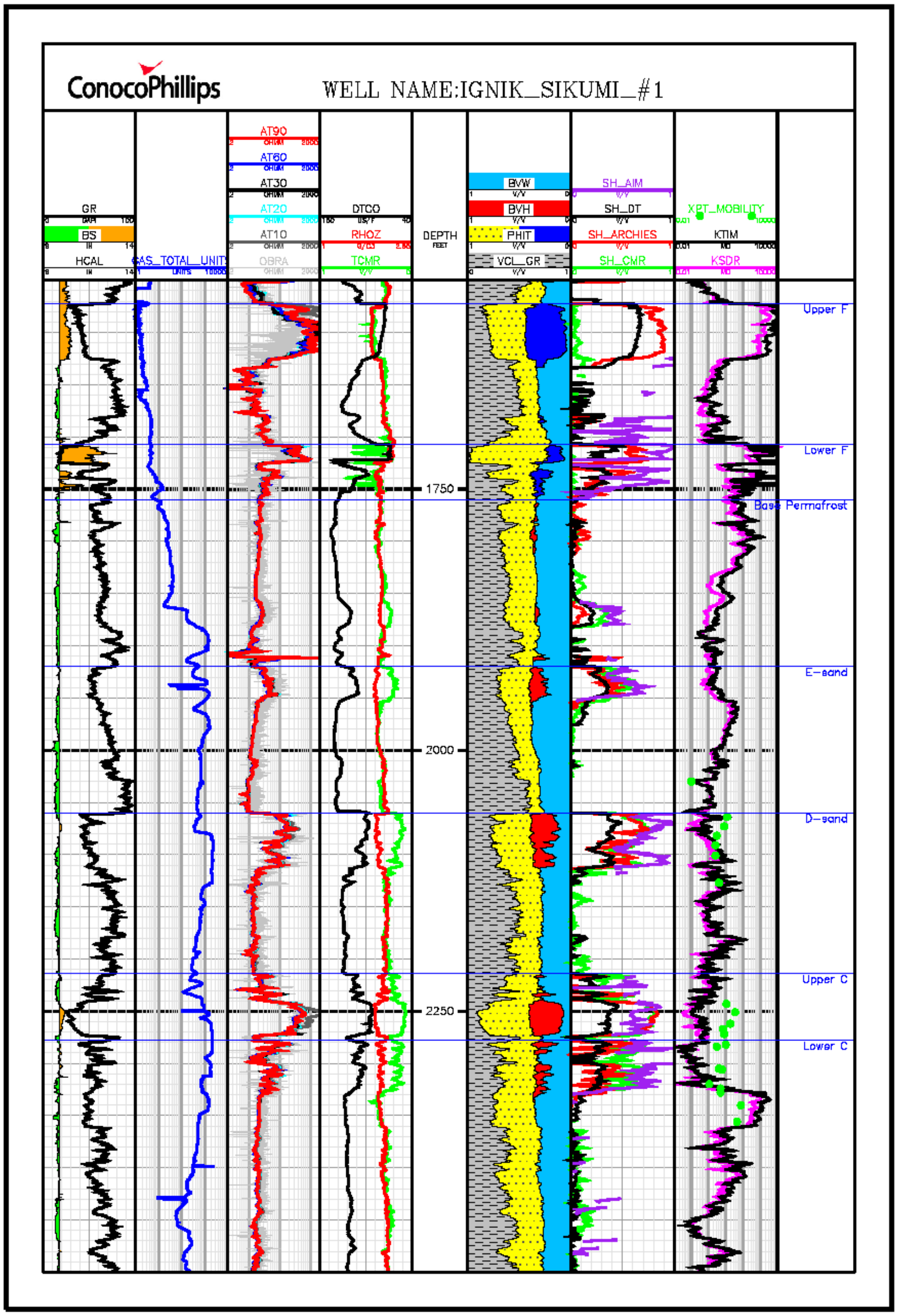
$$\Delta P = \frac{Q * \mu}{A * k}$$

Where:

ΔP = pressure drawdown
Q = flow rate
μ = fluid viscosity
A = area
k = formation permeability

Mobility calculations shown as green dots on Figure 17, while requiring an assumption on fluid viscosity, indicated that mobility is consistent with the permeability calculated from NMR. Estimated permeabilities are tight (< 0.1 md) and of a similar magnitude in the D and C sands.

Figure 17: Log panel showing raw and calculated curves. Track from left to right: Gamma ray and caliper; total gas from mud log; resistivity; neutron density and CMR; lithology; hydrate saturation and permeability with XPT mobility.



MDT Testing

Micro-fracturing tests were carried out using an MDT tool to measure the minimum horizontal stress. Fractures were generated by pressurizing an interval approximately 3 ft in length isolated between the dual packers of the MDT tool. The nominal diameter of the borehole was 9.88 in. Micro-fracturing tests were carried out at two stations located at 2071.95 and 2202.58 ft RKB. The formation at the first test station was a gas hydrate bearing D sand, and this test was performed to determine the formation breakdown pressure in sand similar to the test sand, without damaging the test sand. The second test was in the siltstone overlying the test sand to understand injection pressure limits. At times during testing, the pumps only completed half-strokes, which caused irregular flow. This problem was probably caused by interaction of solids in the mud with pump-check valves. Half-stroking complicated the interpretation of corroborative parameters such as the leak-off pressure. However this problem did not affect the inference of the most crucial parameter, i.e., the closure stress. Therefore the main objective of these tests was satisfied. The tests yielded minimum horizontal stress estimates of 1364 psi (12.7 ppg, 0.66 psi/ft) and 1625 psi (14.2 ppg, 0.74 psi/ft) in the sand and confining bed respectively.

Detailed reports on the XPT and MDT testing can be found in the appendices of the Q2 2011 progress report for this project.

Basis of Test Design

The testing equipment was designed to accommodate a range of operating conditions. The parameters are described in this section. Equipment was sourced to handle the following injection and flow back rates (Table 5):

Table 5: Pressure and rate condition ranges for each phase of the test

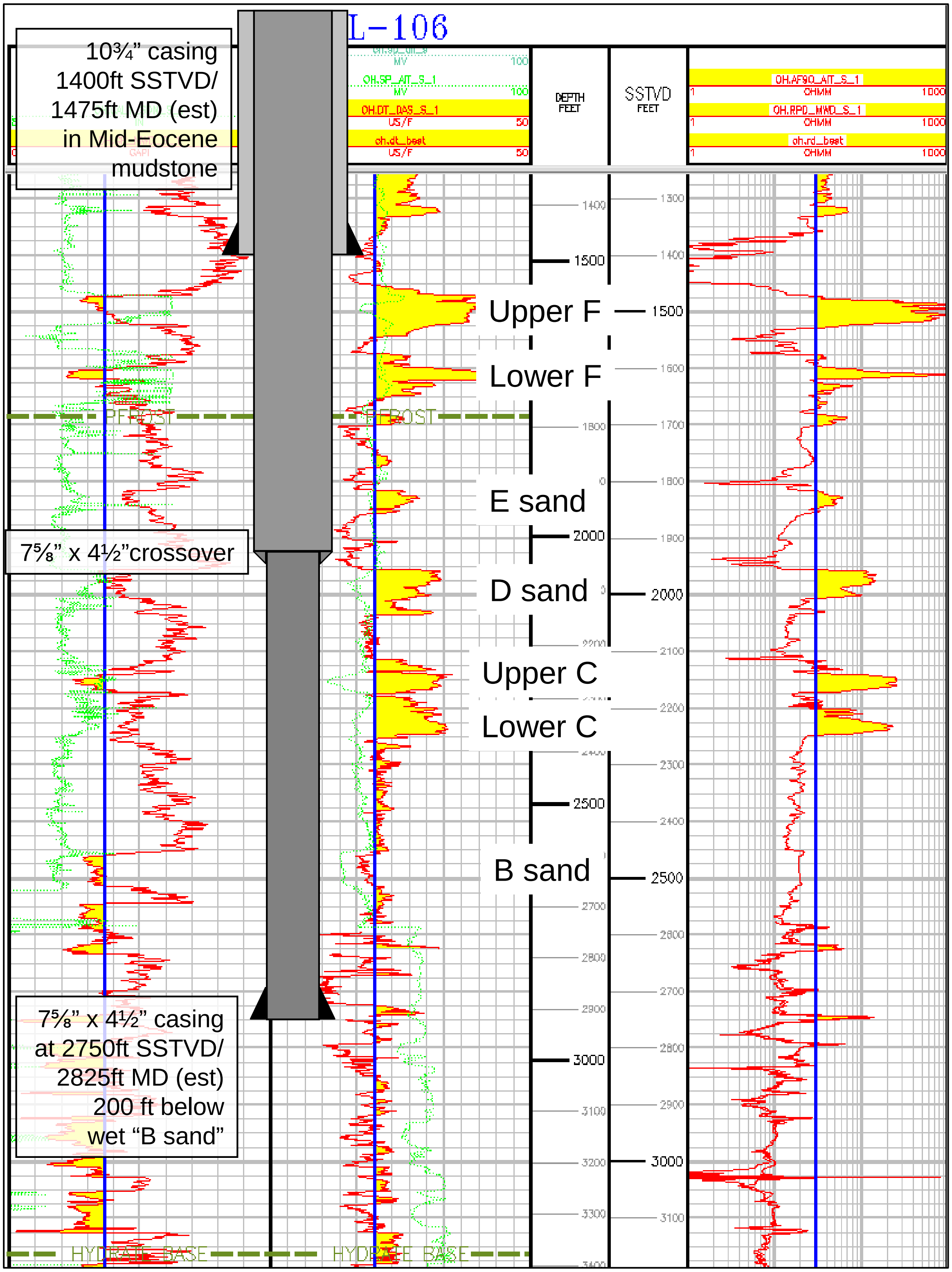
	Pre-Injection Drawdown		**N_2 injection**		**CO_2+N_2 injection**		**Exchange Test Drawdown above PGHS**		**Dissociation Test Drawdown below PGHS**	
	min	max	min	max	min	max	min	max	min	max
BHP (psi)	750	1000	1000	1400	1000	1400	750	1000	0	750
BHT (°F)	42	42	35	45	35	45	35	45	35	45
Qinj (gpm)	NA	NA	0.25*	2	0.25	2**	NA	NA	NA	NA
Qg (MCF/D)	0	0	NA	NA	NA	NA	7.5	100	50	150
Qw (Bbl/D)	0	75	NA	NA	NA	NA	0	50	50	400

BHP => Bottomhole pressure (psi)
BHT => Bottomhole temperature (F)
Qinj => Injection rate (gallons per minute of liquid N_2 or CO_2)
Qg => Gas production (MCF/D)
Qw => Water production (Bbl/D)
*0.25 gpm N_2 ≈ 22 SCF/min; **2 gpm CO_2+ N_2≈ 160 SCF/min
Pres => Reservoir pressure (1075-1090 psi)
Pbd => Breakdown pressure (1420-1440 psi)
Tres => Reservoir temperature (40.4-40.8°F)

Wellbore Design

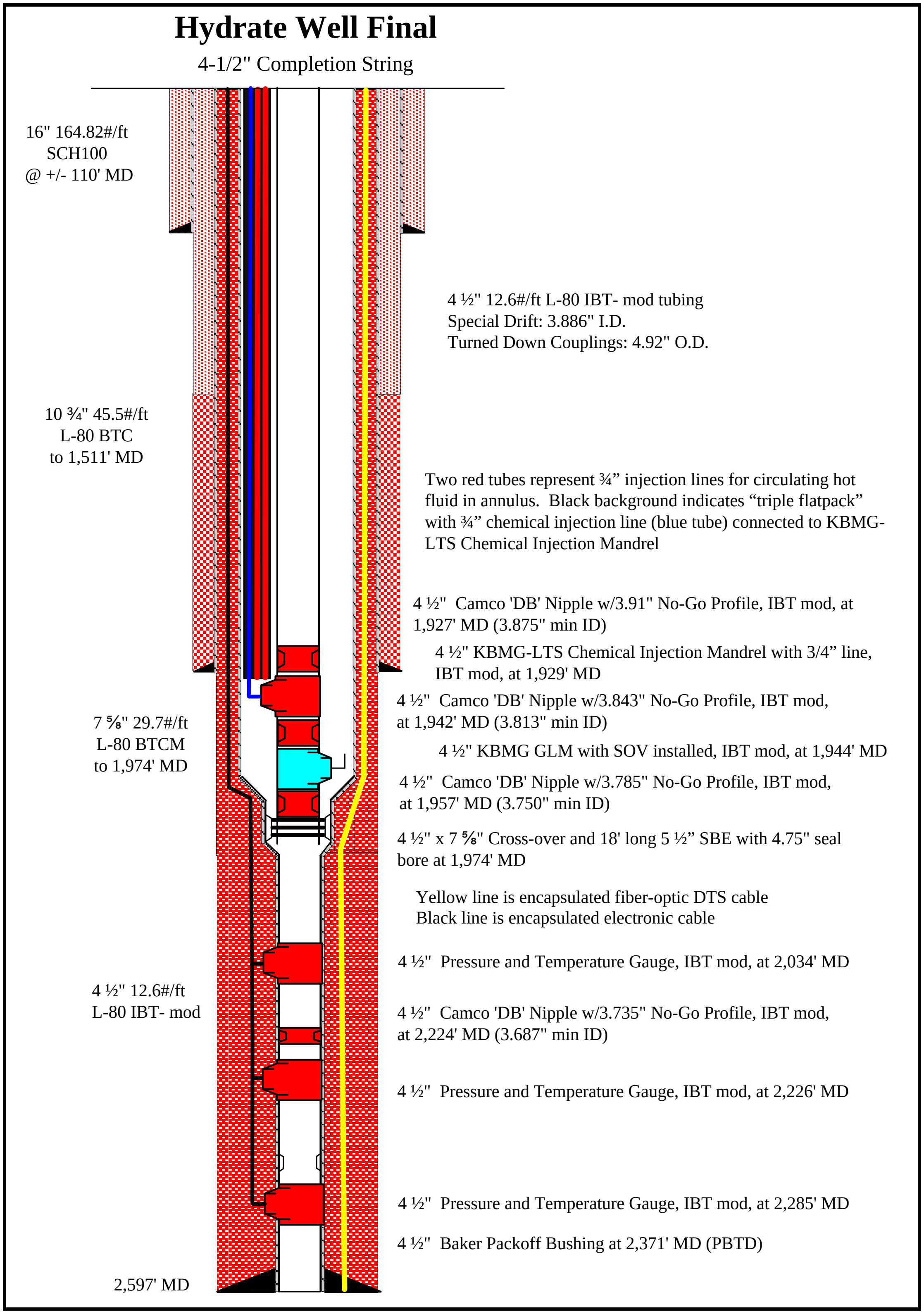
Drilling and casing design, including approximate proposed setting depths, is summarized in Figure 18. Surface casing was set in the 13½” hole, which was drilled to 1475 feet. The production hole was drilled with a 9⅞” bit and chilled, oil-based drilling mud to a depth of 2597ft. The production hole casing design consisted of two main elements: a tapered casing string that was instrumented and then cemented in place and an upper heated casing string that converted the wellbore to a 4½” monobore.

Figure 18: Subsurface stratigraphy and casing location



Completion design is summarized graphically in Figure 19.

Figure 19: Completion design



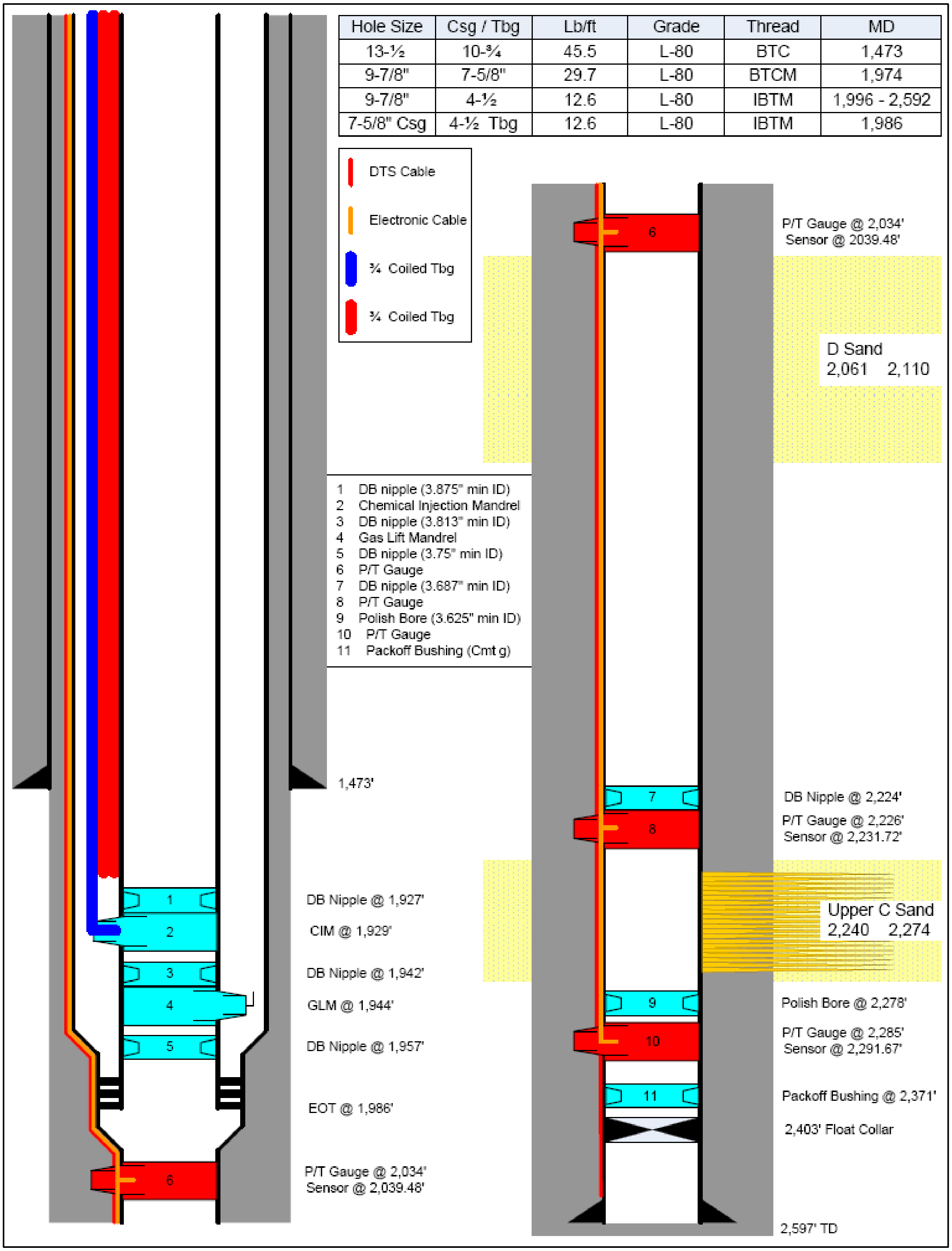
10¾” casing was cemented in the 13½” surface hole, and a 7⅝” x 4½” tapered casing was cemented to surface with low heat-of-hydration cement to minimize hydrate dissociation.

In Figure 19, a fiber-optic Distributed Temperature Sensor (DTS) string (shown in yellow) was clamped outside the tapered casing and run to TD. Three surface-readout pressure/temperature gauges (shown in red) were also run on the 4½” casing. Electronic lines for these (shown in black) were clamped to the outside of the tapered string adjacent to the DTS cable. The bottom gauge permitted monitoring fluid fill-up during completion operations. Both the upper and central gauges were run above the perforation interval in Sagavanirktok Upper C sand. A central gauge was placed between the nipple and the seal-bore receptacle, which reflect the top and bottom of a sand-control screen installed immediately after the perforation step.

After cementing the 7⅝” x 4½” tapered casing, the upper completion was installed on 4½” tubing. This tubing string was strung into a polish-bore receptacle seal assembly (at the 7⅝” x 4½” crossover) and converted the wellbore to a 4½” monobore which simplified perforation, injection, and flowback testing. Three, ¾” tubing strings were clamped to the outside of the tubing, and bound together in a triple flat pack. Two ¾” strings (shown in red on Figure 19) were run open-ended to facilitate fluid circulation and heating of the upper well annulus. This “heater string” was used to make the 7⅝” x 4½” annulus a heat exchanger, which facilitated the delivery of injected fluids at the desired temperature and prevented freezing of fluids in the permafrost. A chemical injection mandrel was connected to the third ¾” tubing string (shown in blue). The gas-lift mandrel (shown in blue) serves four functions: evacuation of fluid from the annulus; artificial lift of fluid in the 4½” tubing; installation of an additional pressure-temperature gauge; and as a circulation port for cementing during plug and abandonment (P&A) operations.

A more detailed wellbore schematic that shows equipment locations relative to the reservoir sands is provided in Figure 20.

Figure 20: Large scale wellbore schematic showing equipment position relative to reservoir sands



Well Information

Other elements in the wellbore design include: sand screen; heater/chemical injection; and artificial lift. These elements are described in detail.

Sand Screen

Delta Elite 200 micron screens for downhole sand control were built and shipped to Unique Machine in Anchorage, where an assembly including seals and a DB-6 lock was built for space-out across the Sagavanirktok Upper C sand. The screen was configured for running and setting inside the 4½"monobore.

Table 6: Sand screen assembly detail

OAL	Top Depth	Length	Description	Item	Est. Lbs
1.17	2,224.46	1.17	DB-6 Lock, 3.687" min ID DB Nipple	1	20
1.98	2,225.63	0.81	Upper Cross-Over	2	10
12.06	2,226.44	10.08	Upper Space-out pup	3	70
14.31	2,236.52	2.25	2-7/8" D Nipple (2.188" ID) + X/over	4	10
52.64	2,238.77	38.33	Screen sections (coupled length)	5	391
55.24	2,277.10	2.60	Lower X-over & space-out pup	6	20
56.66	2,279.70	1.42	Baker Seal assembly	7	20
		56.66			541

Heater/Chemical Injection String

The heater/chemical injection string consisted of three identical ¾ inch tubes made up into a FLATPak. Two of the tubes were open-ended at a depth of approximately 1,927 ft. and were glycol and warmed water circulation. The third tube was connected to a chemical injection mandrel and was intended to be used to power a small hydraulic pump.

FLATPak Tube Specifications, 3 each ¾" Tubes:

- 2 each, Glycol/water Heat Circulation Tubes (open-ended at bottom ~1,927' MD)
- 1 each, Chemical Injection Tube connected to Chemical Injection Mandrel

Table 7: FLATPak Tube specifications for chemical injection string

OD (inches)	ID (in.)	Drift (in.)	Wt #/ft	Grade	Tensile Conn. (1000 lbs)	Burst (psi)	Collapse (psi)	Thread Connection	Tensile Body (1000 lbs)
¾”	.576	NA	.618	HS-70	Coiled Tubing	15,000	14,356	12.7	NA

Chemical Injection Valve

A chemical injection valve with 1,500 psi set pressure, for placement in the chemical injection mandrel, was ordered and transported to the North Slope. The chemical injection tube was not used during 2012 operations, because it was in pressure communication with the 7⅝” x 4½” annulus. It is suspected that the tube failed as a consequence of sub-freezing temperatures in the wellbore due to incomplete removal of water from the tube before temporary well suspension in 2011. Below freezing temperatures for water existed in the wellbore between April 2011 and February 2012.

Artificial Lift

Options to provide pressure drawdown and to lift produced fluids included a hydraulic-drive mechanical pump and a reverse jet pump. The hydraulic-drive mechanical pump was designed to use the ¾”chemical injection line to supply power fluid and the lower end of a conventional sucker-rod pump. One advantage of hydraulic-drive pump, which has a maximum capacity estimated at 75 BWPD (with limited gas capacity), is the ability to pump fluid without contact between and mixing of power fluid and pumped fluid. This pump was not used in the test because the failed chemical injection line prevented the correct powering of the unit with hydraulic fluid.

Two reverse jet pumps of different capacities were used during the test and were installed to straddle the gas lift mandrel. They were able accommodate the entire range of produced water and gas volumes. Power fluid for the reverse jet pump was recycled, warmed, produced water that was pumped down the annulus and into the gas-lift mandrel.

Test Design

The objective of the field trial was to evaluate CO_2/CH_4 exchange, a methane hydrate production methodology whereby carbon dioxide is exchanged *in situ* with the methane molecules within a methane hydrate structure, releasing the methane for production. In addition, production by depressurization was also evaluated. This was a short term test using a “huff and puff” injection and production cycle from a single well to demonstrate the CO_2/CH_4 exchange concept at larger-than-lab scale.

Specifically the field trial aimed to:

- Validate exchange mechanism results from laboratory work
- Confirm injectivity into naturally occurring methane hydrates
- Confirm methane release without production of water or sand
- Obtain data to facilitate reservoir-scale modeling
- Demonstrate stable production of natural gas hydrates by depressurization

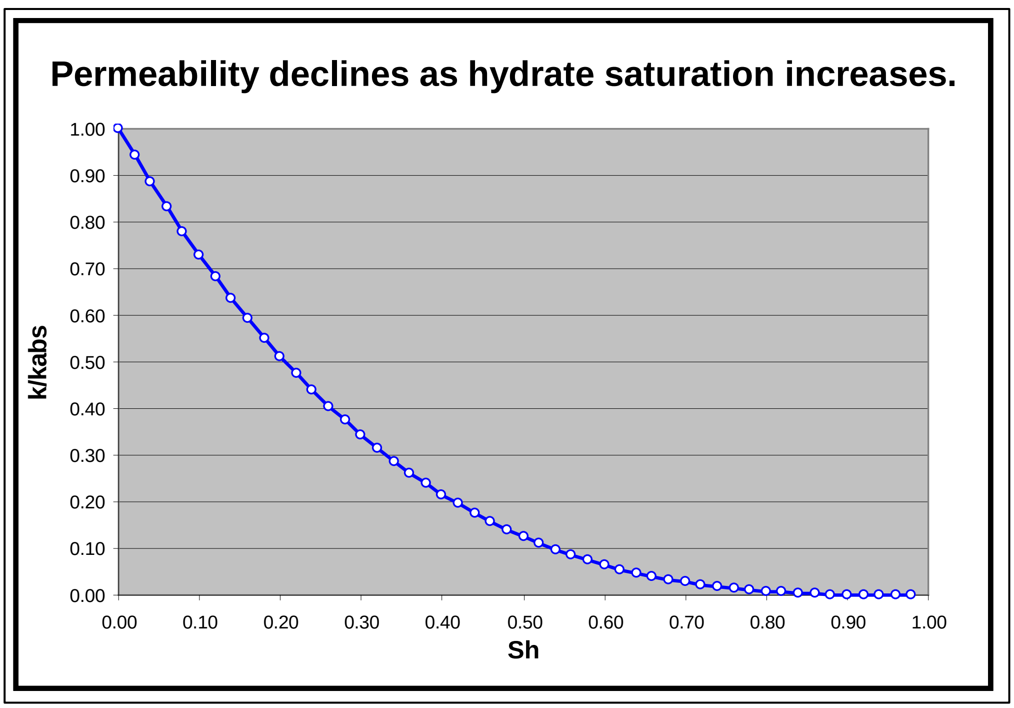
The initial reservoir conditions established from the 2011 reservoir characterization work were:

- Reservoir Pressure = 1000 psi, @ 2,250 ft MD
- Reservoir Temperature = 41°F @ 2,250 ft MD
- Average Saturation = 72% Hydrate + 28% water
- Thickness = 30 ft
- Reservoir = Unconsolidated sand
- Formation Breakdown pressure » 1450 psi

The field trial was designed to accommodate the following conditions and process constraints:

- Native hydrate exists in equilibrium with excess water;
- Free water can be converted to CO_2 hydrate;
- New hydrate formation can dramatically reduce permeability (Figure 21); and,
- N_2 can be used to displace water but may dissociate hydrate.

Figure 21: Showing permeability decrease with increasing hydrate saturation (source Tough+Hydrate)



Model Development

As originally conceived, the field demonstration of "solid state" CO_2 exchange with methane hydrate was predicated on injecting pure carbon dioxide into a methane hydrate bearing sand interval. The original concept, however, did not fully consider the practical ramifications of injecting liquid CO_2 at reservoir conditions into a hydrate zone that contains excess water. Primary concerns are the management of bottomhole pressure because gaseous CO_2 at surface conditions condenses to liquid at reservoir depth and temperature; and the maintenance of injectivity as excess CO_2 interacts with excess formation water to form additional hydrate saturation thereby reducing permeability.

Of the potential remedies to these problems the most promising employ the inclusion of nitrogen in the test design either as a pre-flush or as a CO_2 diluent. The inclusion of nitrogen in the design, however, presents a challenge in that existing hydrate simulators do not include nitrogen as a component, much less a third component, for compositional simulations. Because a functional simulator is deemed necessary for the proper design and interpretation of the field exchange test, the task was undertaken to construct a serviceable multi-component hydrate model.

Developing a thermodynamically rigorous simulator that strictly solves the governing equations for heat and fluid flow and energy and mass conservation is beyond the scope of this project, so a simplified approach was adopted employing a multi-cell equilibrium separation concept. Isothermal and adiabatic model versions were developed to bracket the anticipated extremes of thermal effects on hydrate exchange; the former implying instantaneous thermal equilibrium with the surrounding strata while the latter suggesting that there is no heat exchange at all.

In its isothermal manifestation, the system is divided into cells of equal volume at constant temperature, which are linked in series. All cells initially are identical containing the same global composition at the same temperature and pressure. Upon injection, a fractional cell volume of injectant is passed to the first cell at the specified injection pressure and composition. Simultaneously an equivalent volume is removed from the first cell at its resident condition and passed to the next downstream cell. The volume removed may under some conditions be subject to a global pressure constraint and/or a local pressure constraint between cells. The composition of the removed volume is solely dictated by the mobile phases present within the upstream cell. If both liquid and gas are present, the ratio of each phase removed is based upon their relative mobility given by the following equation.

Equation 4 Use this equation to determine the ratio of the liquid and gas phase removed based upon relative mobility

$$Q_g / Q_w = \frac{(k_{rg} / \mu_g)}{(k_{rw} / \mu_w)}$$

Where:

k_{rg} = the relative permeability of the gas phase

μ_g = viscosity of the gas phase

Relative permeability is determined in the standard manner and is solely a function of mobile phase saturations within the upstream cell. The entire remaining contents of the upstream cell are then flashed at constant volume and temperature. Multiphase equilibrium calculations are executed via Multiflash™, a commercial software package capable of dealing with mixed hydrates of nitrogen, carbon dioxide and methane. The algorithm is repeated sequentially for downstream cells until new pressure, phase saturations and compositions are determined for each cell in the model. The process is then repeated for the model until the full complement of injectant has been passed to the first cell. Under a production scenario the process is reversed and the global pressure constraint is amended to reflect the producing bottomhole pressure rather than the bottom hole injection pressure.

In the adiabatic version of the model the model process logic and cell to cell algorithms remain largely unchanged. However, in addition to mass transfer between cells energy transfer is allowed. Energy transfer between cells is mediated solely through the enthalpy change due to mass transfer. (Heat transfer between cells and the surrounding strata is not allowed.) The governing equation for energy is:

Equation 5: Governing equation for energy

$$m_{f1} \cdot U_{f1} - m_{f2} \cdot U_{f2} + m_{rock} \cdot c_{p\_rock} \cdot \Delta T = m_{f\_in} \cdot H_{f\_in} - m_{f\_out} \cdot H_{f\_out}$$

Where:

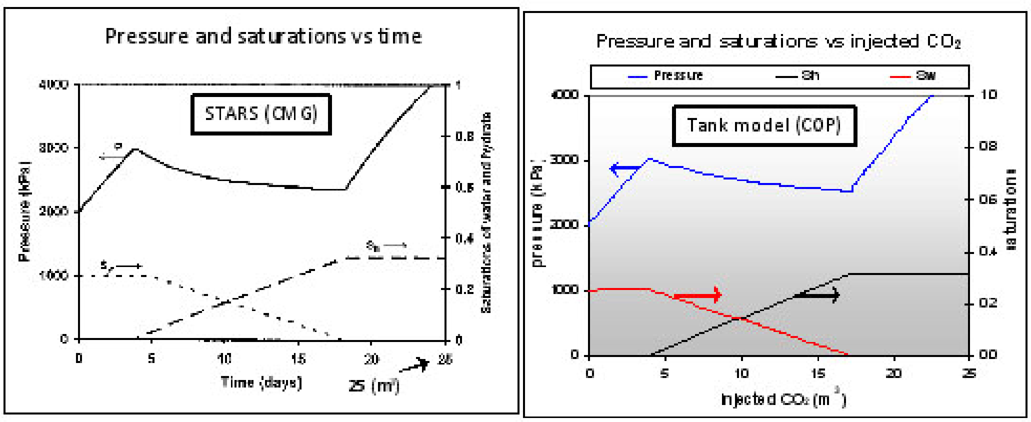
m_{f1} = Total mole of fluids at previous calculation step
m_{f2} = Total mole of fluids at current calculation step
U_{f1} = Molar internal energy at previous calculation step
U_{f2} = Molar internal energy at current calculation step
m_{f_in} = Total mole of fluids flowing into the tank
m_{f_out} = Total mole of fluids flowing out of the tank
H_{f_in} = Molar enthalpy of inlet fluid
H_{f_in} = Molar enthalpy of outlet fluid
m_{rock} = Total mass of porous rock
c_{p_rock} = Specific heat of porous rock
ΔT = Temperature change.

An iterative solution technique is employed wherein the temperature change is estimated, U_{f2} is calculated and a flash of the cell contents is conducted at constant volume and internal energy using Multiflash™. The resultant temperature of the flash calculation is compared to the original temperature guess and the process is repeated until convergence is attained.

The Cell-to-Cell model was benchmarked against Computer Modeling Group's STARS™ hydrate simulator. STARS™ is commercially available simulation code that is capable of modeling mixed hydrates of CO_2 and methane. The benchmarked case is documented in SPE 137313. It involves constant rate isothermal CO_2 injection into a single grid block or cell initially containing water and methane below the hydrate stability pressure. The reported results predict a unique pressure and saturation response.

Figure 22 shows a comparison between models for pressure, hydrate saturation and water saturation. The STARS™ results are expressed against time whereas the Cell-to-Cell Model results are expressed against volume injected. At the conclusion of injection the same volume of CO_2 has been injected into both models. From the comparison it is clear that the Cell-to-Cell model compares favorably to STARS™ for this simple example.

Figure 22: Comparison between Cell-to-Cell Model and STARS™



Injection Design

The objective of this study was to determine an appropriate injected fluid composition for a methane hydrate exchange field trial using carbon dioxide as the principal exchange constituent in the injected fluid. The design predicates the use of nitrogen in the injectant as a pre-flush and/or as a diluent to desaturate the near-well region of excess free water. The principal purpose being to:

1. maintain reservoir temperature above the freezing point for water, 32°F, given that prolonged contact of nitrogen with native methane hydrate could initiate hydrate disassociation thereby causing the reservoir interval to cool substantially and possibly freeze; and
2. In this study, isothermal and adiabatic cell-to-cell models were used to study the injection and production responses for the sequenced injection of nitrogen and carbon dioxide, and as constant composition mixtures of said gases.

Nitrogen Pre-flush

The use of nitrogen as a pre-flush could lead to hydrate dissociation and cooling, so the adiabatic model was deemed most suitable to study temperature effects due to injection. Because heat transfer between the reservoir and its surroundings is not allowed, the adiabatic model should reflect an extreme prediction for temperature changes associated with hydrate dissociation, formation, or exchange. Initial reservoir pressure, temperature and hydrate saturation were fixed at 1000 psia, 41°F, and 70% respectively. The remaining pore space not occupied by hydrate was assumed to be water filled. For injection, bottomhole conditions were maintained at 1400 psia and 41°F. Note that fluid temperature at bottomhole was assumed to be equal to initial reservoir temperature based on wellbore model predictions. Injected volumes are expressed as multiples of a single cell volume in the cell-to-cell model. The first cell volume equates to the reservoir annular volume associated with a radial distance of 1 foot from the wellbore wall, assuming a reservoir height of 30 feet.

Figure 23 shows the temperature profiles with radial distance from the well for a four cell volume (CV) N_2-pre-flush, which is followed by an 8 CV CO_2/N_2 mixture. At the end of the N_2 pre-flush (4 CV, amber curve), the near-well (cell one) temperature is near the freezing point of water (32°F). Based upon water displacement simulations, it is believed that the volume required to dewater the near-well region via nitrogen injection is much greater than four cell volumes. Therefore, it is unlikely that a nitrogen pre-flush would be effective in displacing free water from this region while avoiding the potential for water to freeze.

Figure 24 shows the same case but without the N_2-pre-flush. In this instance, the model predicted cell one temperature remains within a few degrees of the initial reservoir temperature. Hence, an icing problem is not expected in this injection scenario. It is, therefore, concluded that a N_2 pre-flush cannot be employed in the field test design; but rather a N_2/CO_2 mixture must be used to manage injectivity while promoting hydrate exchange. Mixture design is the subject matter of the following section.

Figure 23: Temperature profiles for 4-CV N_2-pre-flush & 8-CV CO_2/N_2 injection

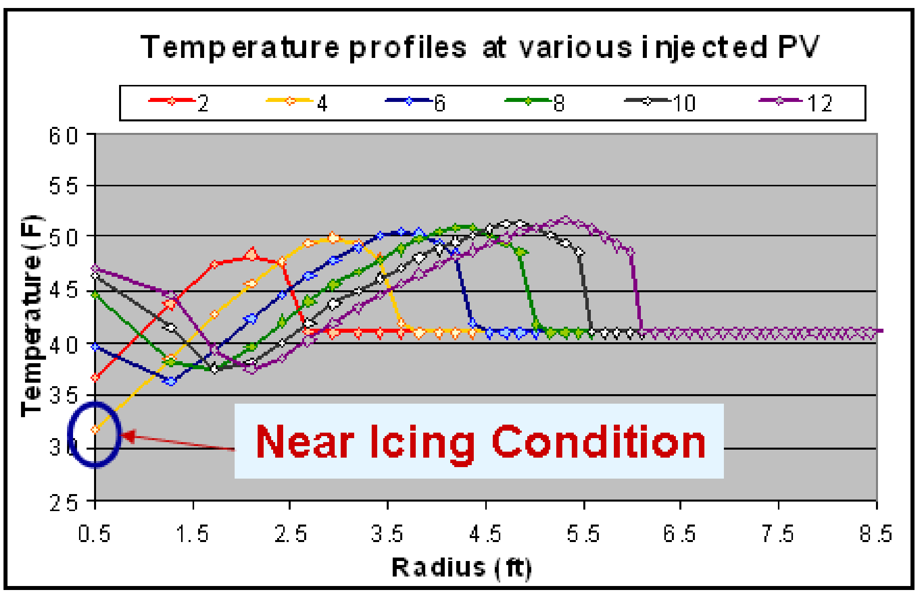
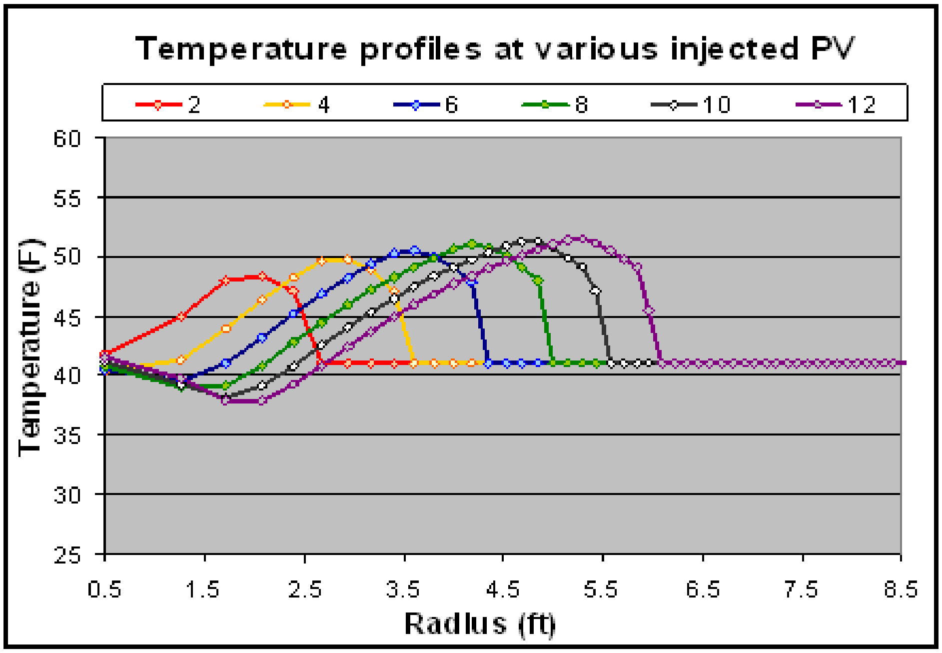


Figure 24: Temperature profiles for 12-CV N_2/CO_2 injection (no N_2 pre-flush)

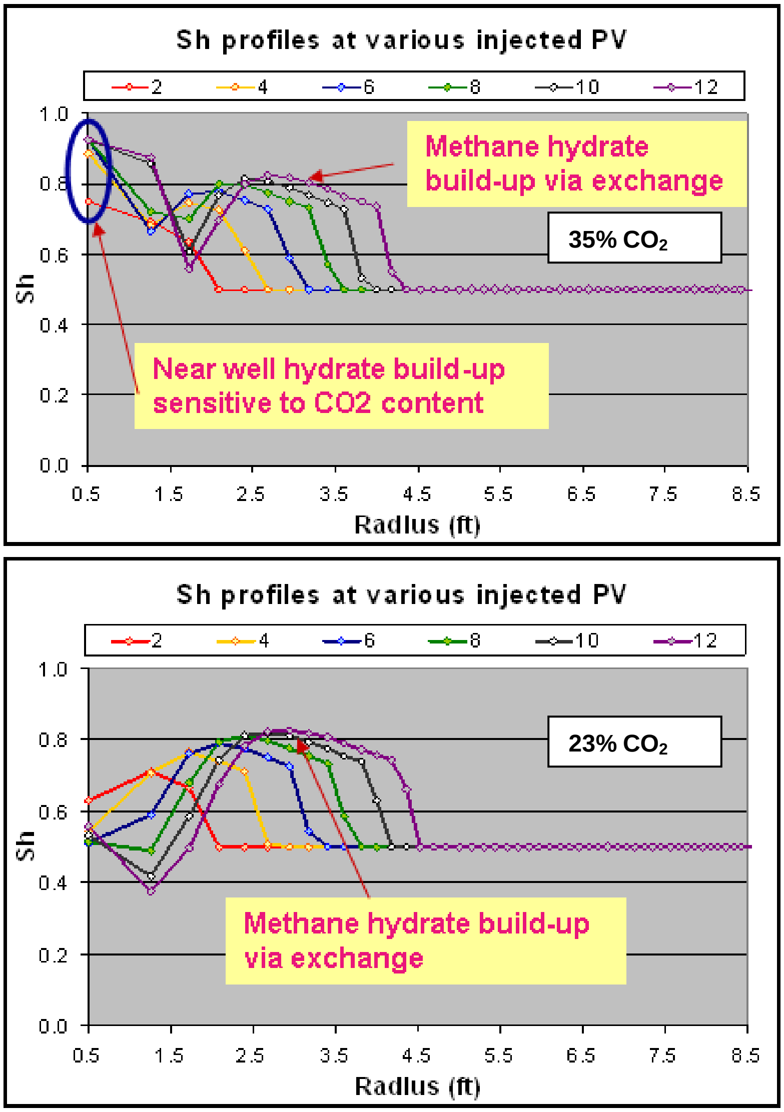


CO_2/N_2 Mixture Design

The injectant mixture design sought a CO_2/N_2 composition that preserved injectivity and promoted CO_2 exchange with methane hydrate. To preserve injectivity, it was critical to avoid excessive hydrate saturation build-up in the near-well region. The isothermal cell-to-cell model was used for this analysis. The imposition of isothermal conditions thermodynamically favored hydrate formation and represented the worst case scenario for hydrate build-up. CO_2/N_2 mixtures were varied from approximately 60 mol% CO_2 to 20 mol% CO_2. The upper limit was slightly below the composition at which the injectant will remain in the gaseous state from surface to bottomhole conditions. At higher CO_2 contents, the injectant transitions from a gas to a liquid. Plans were to operate the well under tight bottomhole pressure control, so it was judged important to avoid phase transitions that might complicate well control.

Figure 25 compares hydrate-saturation profiles during 12-CV N_2/CO_2 injection with two different mixture compositions (35 mol% CO_2 vs. 23 mol% CO_2). The initial hydrate saturation in both cases is 50%; initial reservoir pressure, temperature and bottomhole injection conditions are as stated above.

Figure 25: Hydrate saturation profiles for two different injected compositions



In the 35 mol% CO_2 case, hydrate saturation significantly increases in the near-wellbore region. After 12-CV of mixed gas injection, the hydrate saturation increases from 50% to about 93% by volume. In contrast, hydrate saturation build-up in the near well region is significantly less (50% to 63%) for the 23 mol% CO_2 case. Given that the initial effective permeability to gas is already quite low (1 md @ S_h = 50%), injectant mixture compositions below 25 mol% CO_2 are preferred.

Notably, both cases show hydrate build-up deeper into the formation. This hydrate build-up is associated with exchange-driven methane enrichment of the gas phase at the displacement front, where free water is available to form additional hydrate. With continued injection, the high hydrate saturation front progressively moves outward from the well. The maximum hydrate saturation appears to stabilize at about 80%. These results were replicated at other injectant compositions over the range of interest.

Model results indicated that within the tested composition range, some impairment of injectivity should be anticipated due to in-depth hydrate formation, which was generally insensitive to injectant composition and largely driven by exchange. In the near well region, however, excessive hydrate build-up (S_h > 90%) could be mitigated by adjusting injected fluid composition. A sensitivity study determined that the appropriate injectant composition for the field trial was 23 mol% CO_2 + 77 mol% N_2.

Injection Slug Size

A sensitivity study was conducted to determine whether the production response trends (i.e., produced gas composition trends) are affected by injection slug size. Both isothermal and adiabatic cell-to-cell models were used. . As in the previous cases, initial reservoir pressure, temperature and hydrate saturation were fixed at 1000 psia, 41°F, and 70% respectively. The producing bottomhole pressure was 650 psia. The 23 mol% CO_2 injectant slug size was stepwise varied from one to eight to thirty two cell volumes.

Figure 26 illustrates the change of gas compositions in the near-wellbore region (Cell 1) for each injection slug size. Results are for the isothermal cell-to-cell model. The plots show the change of gas composition from the start of injection until the end of production on a cumulative injection and production volume basis. In all cases, the first free-gas appears with a relatively high methane (about 55 mol%) composition, indicating the preference for CO_2 to exchange with methane into the hydrate phase. As injection continues, methane composition declines in the near-wellbore region while CO_2 and N_2 compositions in the gas phase increase, reflecting the gradual depletion of methane from the hydrate phase. The degree of methane depletion in cell one is a function of the slug size injected. After approximately 30 CV was injected, the hydrate phase in cell one was devoid of methane and the hydrate was in equilibrium with the injected gas composition. Upon production, the declining CH_4 composition trend reversed, although some lag was observed in the event that methane was completely swept from the near well region. The production composition profiles for the 1-CV, 8-CV and 32-CV injection cases adequately represented the range of responses expected for the field trial to the extent that isothermal equilibrium applies.

Figure 26: Production responses at different injection slug sizes (isothermal)

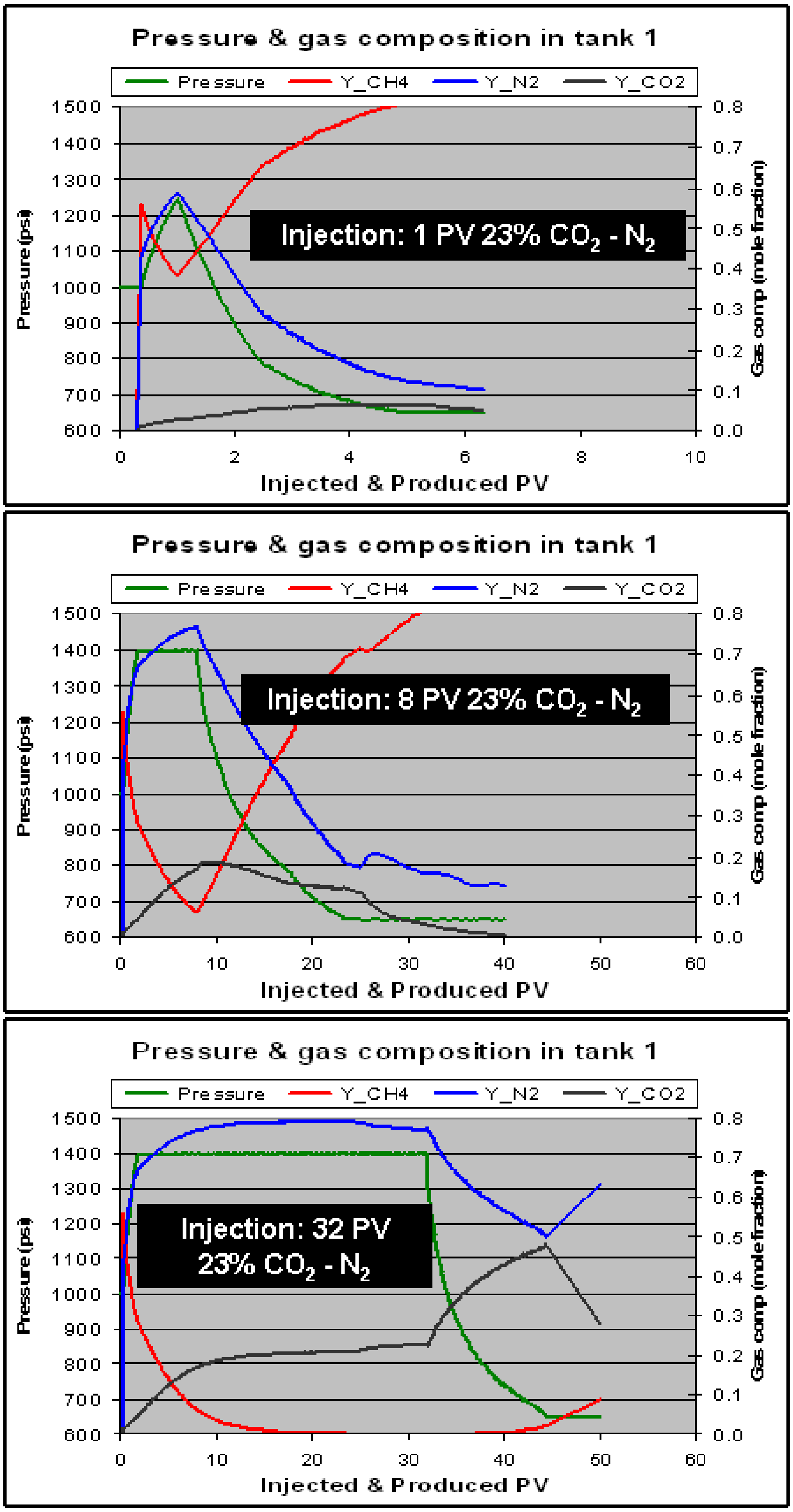


Figure 26 compares the change of gas compositions in model cell one for different injection slug sizes using the adiabatic cell-to-cell model. All model inputs are identical to isothermal cases shown in Figure 26. For the most part, the gas composition profiles from the isothermal and adiabatic cell-to-cell models appear similar. Model differences are reflected primarily as differences in magnitude and timing.

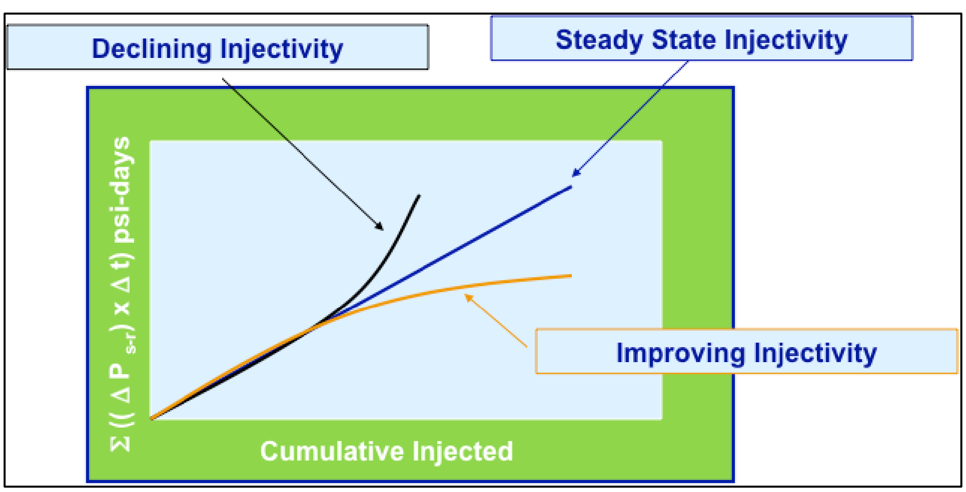
In conclusion, production trends may vary with injection slug size. However, these trends appear to be predictable and invariant with respect to the equilibrium model assumptions. Consequently, the design basis for the field trial was predicated on maximizing the injected volume in the allotted time for injection, 17 days. Given average field properties, the modeled estimated injection volume is 200,000 scf.

Recommended Test Design – Injection Phase

For the injection phase, all injection was performed below 1400 psia to ensure the injection occurred below parting pressure of the formation. Simple models indicated that 200 Mscf of gas could be injected into a formation with a permeability of 1md over a period of 13 days. Thus the recommended injection procedure was:

1. Inject 23% CO_2/ 77 molar % N_2 gas mixture (SF_6 tracer) for half of the allotted injection period or 6.5 days.
2. Inject 23% CO_2/ 77 molar % N_2 gas mixture (HFC 114 tracer) for half of the allotted injection period or 6.5 days.
3. Monitor the injection temperature profile at the wellbore on the DTS system to identify the thermal signature of hydrate formation or dissociation and to assess injection conformance
4. Monitor changes in injectivity using a Hall plot. The trend of this plot, which plots cumulative pressure-days versus cumulative volume injected, indicates whether formation permeability is increasing or decreasing over the injection period (Figure 27). The Hall plot is a standard graphical method to represent injection performance clearly and easily under steady-flow conditions (Hall, 1963).

Figure 27: Hall plot example



Recommended Test Design – Production Phase

Primary design considerations for the production phase of the test were:

- Avoid freezing in or near the wellbore; and
- Maximize returns of tracers, CO_2, N_2 and CH_4

The production phase was divided into two production periods. In the first period, targeted bottomhole pressures were at or above 650 psia. This is above the pure methane hydrate stability pressure at reservoir temperature. In the second period, the targeted bottomhole pressure was conditionally the minimum operating limit, which maintained borehole temperatures above 32°F. Pre-test, the production phase execution was planned as follows:

1. Stepwise reduce BHP to 650 psia
2. Maintain downhole temperature above 32°F
3. Measure borehole temperature
4. Measure produced fluid rates and compositions
5. Stepwise reduce BHP to minimum operating limit
6. Maintain downhole temperature above 32°F
7. Measure borehole temperature
8. Measure produced fluid rates and compositions

Success Criteria

Given our understanding of the test and its parameters, the operational success criteria were considered to be:

- Injection of > 200,000 scf
- Diminishing injectivity with time
- Avoid freezing during injection
- Significant production above CH_4 hydrate stability pressure
- Methane absent or diminished in initial produced gas
- Avoid freezing during production
- Stable bottomhole pressure
- Diminishing temperature
- >50% tracer recovery

Summary of Field Results and Observations

Field activities ran from January 2012 until the well was plugged and abandoned in May 2012. This section summarizes the results and observations of the production test from perforation on February 15, 2012, through well shut-in at the end of production on April 11, 2012.

During the injection phase, the total injected volume of gas was 215.9 Mscf, which consisted of 167.3 Mscf N_2 and 48.6 Mscf CO_2. Composition was tightly controlled during this period with an average injection ratio of 77.5/22.5 N_2/ CO_2. Injectivity decreased from an estimated average *in situ* permeability of 5.5 mD to 0.6 mD in the early stages of the injection. The calculated *in situ* permeability then increased gradually to 1.2 mD by the end of the injection period. These changes in permeability cannot be attributed solely to relative permeability changes and may reflect changes in the hydrate saturations in the formation.

Following injection, production proceeded in four phases:

1. Unassisted flowback
2. Jet pumping above methane-hydrate stability pressure
3. Jet pumping near methane-hydrate stability pressure
4. Jet pumping below methane-hydrate stability pressure

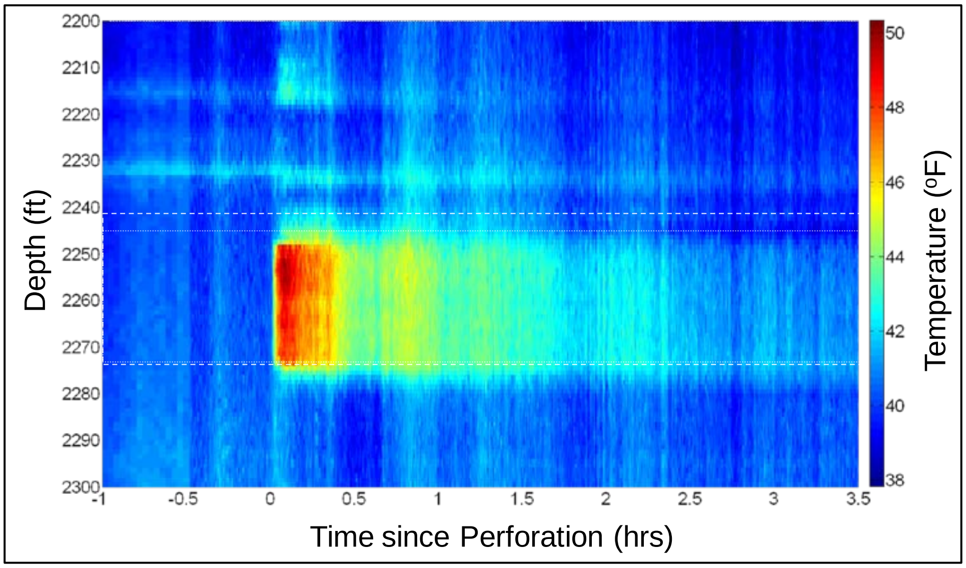
Over the course of the production test, approximately 70% of 167.3 Mscf of injected nitrogen was recovered. In contrast, only 40% of the 48.6 Mscf injected carbon dioxide was recovered. A total of 855 Mscf of methane was produced over the total production period.

Water and sand were produced along with the various gases. The test produced a total of 1136.5 bbl of formation water. Produced water-to-gas ratios varied between 10 and 50 on a molar basis during the first jet-pumping phase. However, the water rate stabilized during the following two jet-pumping phases when compared with gas production. The water rate followed the gas rate with a water-to-gas ratio of 8-9 on a molar basis. This compares to the stoichiometric ratio for structure one sI hydrate of 1 mole gas per 5.75 moles of water. During the final steady depressurization below methane hydrate-stability pressure, the produced water rate varied from 22-42 bbl/day with gas rates of 13-38 Mscf/day. Sand production continued until Phase 4 (jet pumping below methane hydrate-stability pressure), at which point sand production ceased. In total, an estimated 67 bbl of sand was produced during the test.

Perforation

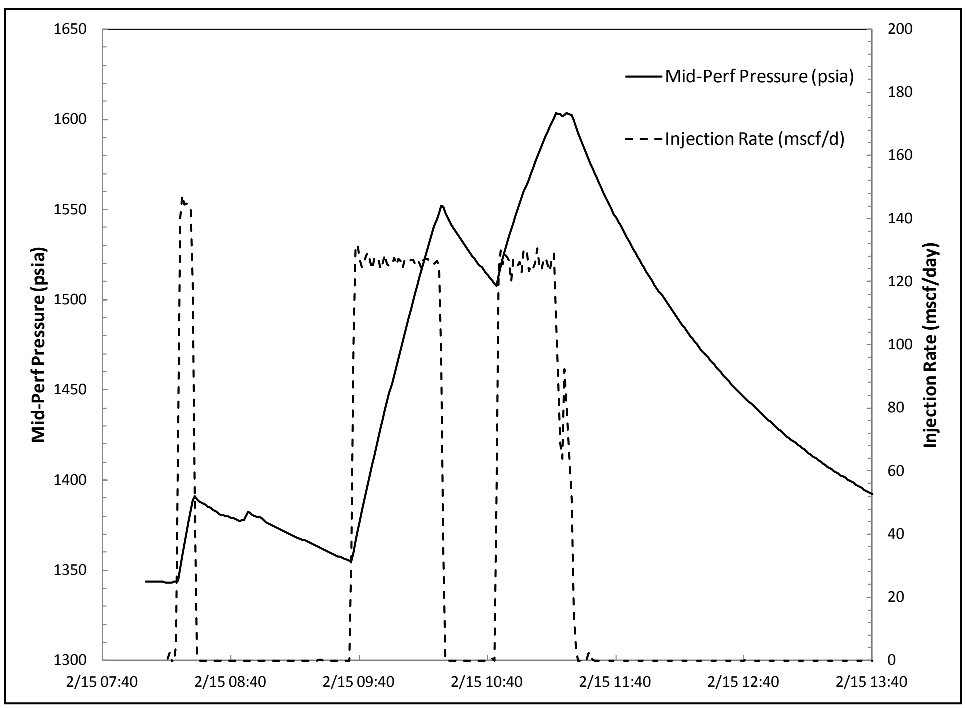
On February 15, 2012, at 08:15, a 30-foot interval (2243-2273ft. KB) in the Sagavanirktok C sandstone was perforated on six-inch spacing. The perforated interval included nearly all of the hydrate-saturated C sandstone, leaving the top 2 feet of the massive sand un-perforated. The tool was oriented so the shots would avoid the pressure-temperature cables and gauges, and the fiber-optic cables installed outside the casing. Perforation caused a temperature increase of more than 10°F across the entire perforated zone. The increase dissipated to reservoir temperature within a few hours (Figure 28). Continuous pumping of the CO_2/N_2 mixture controlled wellbore pressure during perforation, maintaining a pressure of ~1350 psia.

Figure 28: Temperature of the hydrate-bearing interval during the perforation procedure as recorded by the Distributed Temperature Sensor (DTS). The thick horizontal dashed lines indicate the targeted formation depth and the small dashed lines indicate the perforated zone.



Following perforation, the CO_2/N_2 gas mixture was injected at a high rate of ~120 Mscf/day over two short durations of approximately 45 minutes each. The chosen rate was necessary to overcome any near-wellbore obstructions and to establish good communication between the borehole and reservoir (Figure 29). Pressure was monitored with the pressure gauge just above the perforated interval (at 2226 ft). The measured injection pressure was significantly higher than planned for the actual test.

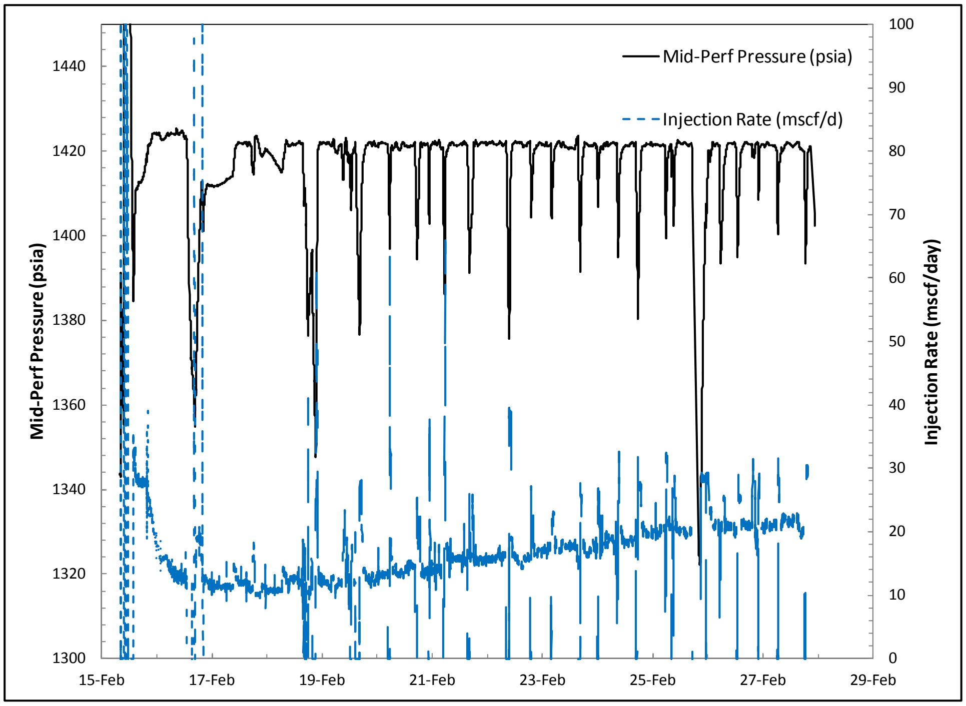
Figure 29: Mid-perforation pressure and injection rate during and immediately after perforation.



Injection Phase

After establishing injectivity into the formation, the injection phase of the field trial began and continued for ~14 days (13:45 February 15, 2012, through 07:45 February 28, 2012). The mid-perforation pressure remained constant throughout the injection stage while the injection rate varied (Figure 30). A constant downhole pressure controlled the injection rate. Injection pressure of 1420 psia was chosen as it was above original reservoir pressure (1055 psia) and below the minimum measured fracture closure pressure of the formation (1435 psia).

Figure 30: Mid-perforation pressure and injection rate during the injection phase.



Injection gas temperature at the surface after mixing typically ranged between 90°-100°F. The injectant gas cooled in the wellbore during low-rate injection and measurements show that it was within 0.2°F of formation temperature before injection (Figure 31). Downhole gauges positioned on the tubular assembly inside the wellbore responded directly to the pressure and temperature properties of the fluids in the well. The DTS assembly was attached to the outer wall of the casing in direct contact with the formation. The small temperature difference between the two instruments before injection reflected the non-equilibration of the fluids with the wellbore possibly due to natural convection. Dynamic flow of the injected gas into the reservoir eliminated this difference and resulted in similar temperatures between the downhole gauge and the DTS measurement (Figure 31). Note that temperature data during perforation was excluded from Figure 31 for clarity. The slight temperature decrease before February 17 was attributed to the residual temperature fall-off following heating due to perforation. The downhole temperature gauge showed more variability in temperature during the injection period while the DTS temperature increased by about 1°F within the perforated zone (Figure 32). Much of the DTS data in this report is shown as a temperature difference relative to an initial temperature distribution over the interval measured before the start of the production test. This technique removes the contribution of the constant geothermal gradient signal that could mask small differences in temperature changes at different points in the perforated interval. 0 describes this methodology. Warming during injection could signal an exothermic reaction that accompanied hydrate formation or exchange with native methane hydrate. A cooling event also existed above the perforated interval (2230-2245 ft) and continued in this restricted interval for some time following perforation (Figure 32).

Figure 31: Temperature from the middle downhole gauge and DTS @ 2230.9' at the pre-injection test and during the complete injection.

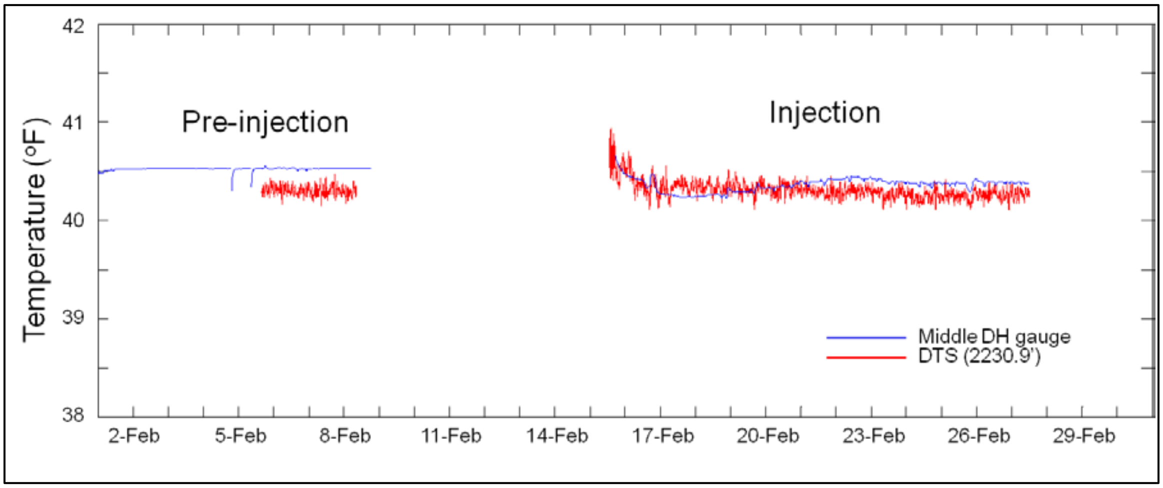
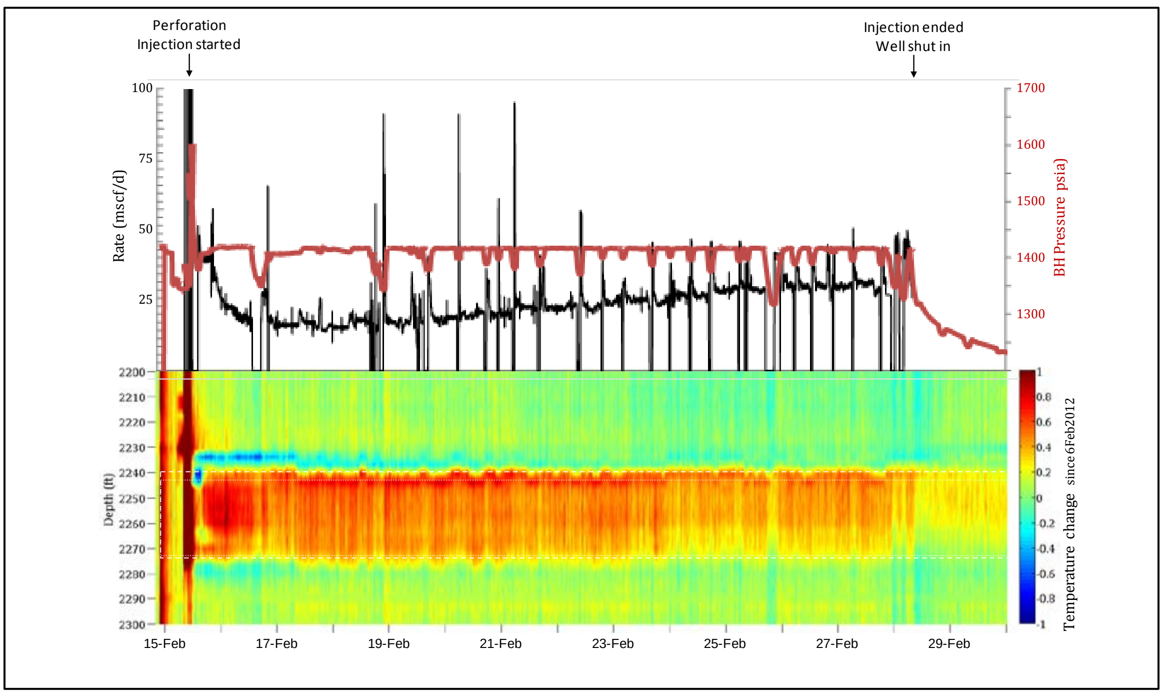


Figure 32: Pressure, gas injection rate, and temperature (DTS) during injection. The thick dashed lines indicate the targeted formation and the small dashed lines indicate the perforated zone.



During injection, operational constraints required idling the liquid N_2 and CO_2 tanks for short periods in order to control injection effectively. At low injection rates, the majority of the pumped cryogenic fluids were recycled. The heat transferred to the tanks during recycling caused the fluids to boil, which disrupted smooth operation of the injection pumps. During these idle periods, pressure in the wellbore decreased 20-50 psi (Figure 30). The pressure and temperature of the middle downhole gauge above the perforated zone, as well the pressures and temperatures at the top, middle, and bottom of the perforations taken from DTS, were compared with the flash-calculated hydrate stability zone for the injected gas mixture of 77/23 mol% N_2/CO_2 (Figure 33). Even with these decreases in pressure, the injection zone was always maintained at conditions above the predicted incipient hydrate stability for the injected composition. Hence, the small observed pressure excursions are not expected to have a significant impact on the process of exchange.

Other than these idle periods, injection was maintained very close to the desired pressure of 1420 psia. Composition monitored with the on-line gas chromatograph (GC) showed the injectant consistently held close to the target composition of 23 mol% CO_2 and 77 mol% N_2 (Figure 34).

Figure 33: Pressure-temperature diagram showing the hydrate phase line for the 77/23 mol% N_2/CO_2 mixture (red). Operational conditions during the injection phase are superimposed in this diagram.

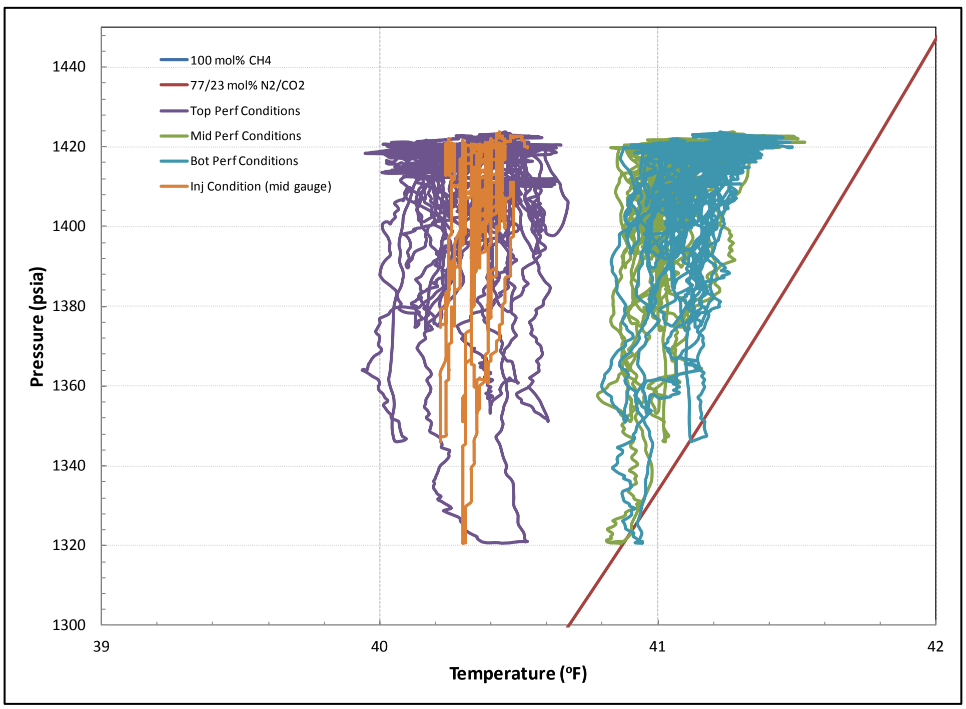
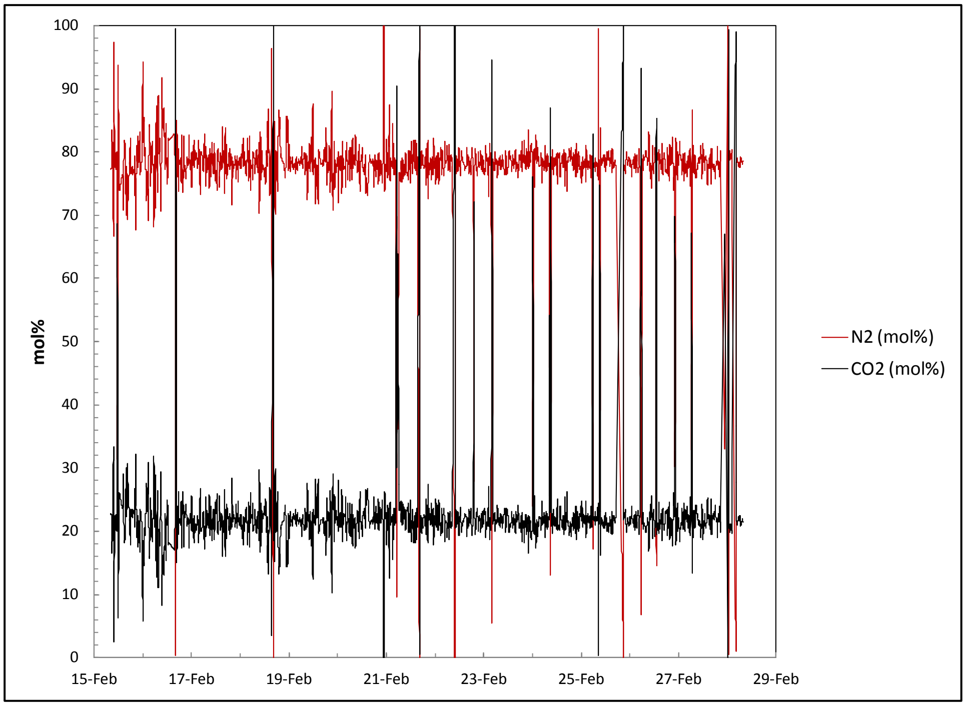


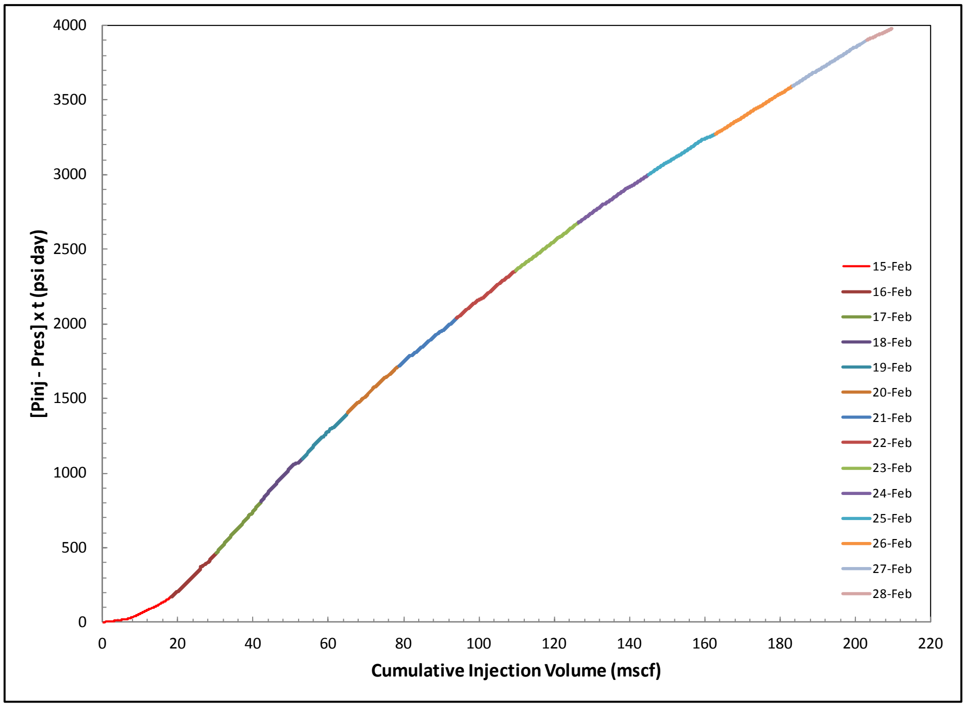
Figure 34: Composition of the injection gas recorded by the on-line GC.



Clear changes in the injection rate occurred as injection proceeded. Even while maintaining a constant 1420 psia downhole pressure, the injection rate began to decrease during the first days of injection (Figure 30). However, around February 17, the injection rate leveled off and began to increase steadily through the remainder of the injection phase.

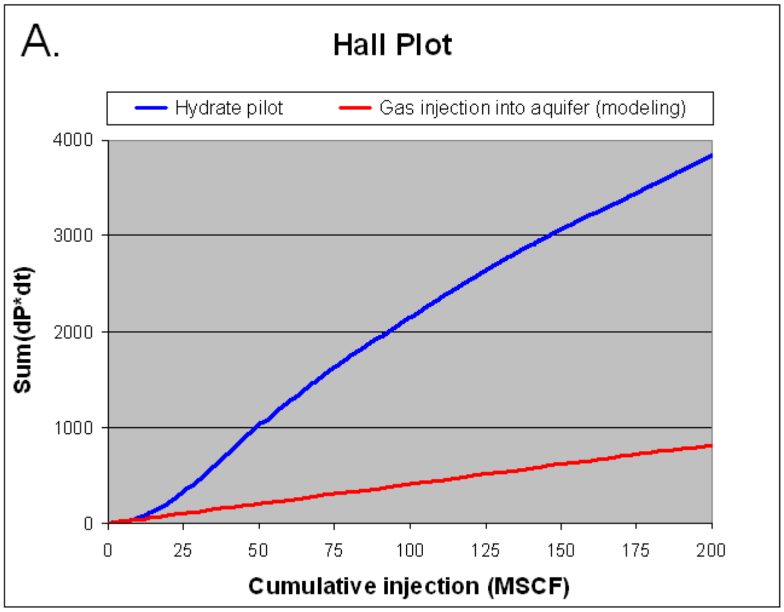
A Hall plot compared changing injectivity throughout the test (Figure 35). The Hall plot is a standard graphical method to represent injection performance clearly and easily under steady-flow conditions (Hall, 1963). A straight line on the plot of pressure difference per day against cumulative injection volume indicates constant injectivity. Upward curvature of the line indicates loss of injectivity, while downward curvature occurs when injectivity increases. The observations from the rate data agree with the conclusions from the Hall plot. Both indicate that the initial days of injection showed a decrease in injectivity (Figure 35) followed by a progressively increasing injection rate.

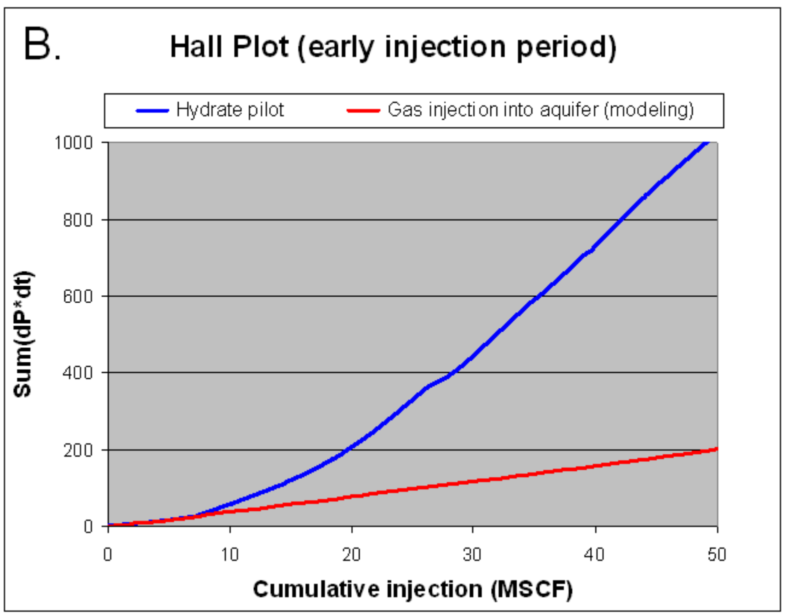
Figure 35: Hall plot showing injectivity changes during injection.



The change in injectivity could have resulted from a number of effects, including formation or dissociation of hydrate, and changes in relative permeability as gas saturation increased. A simulation of gas injection into a water aquifer was run in the compositional reservoir simulation modeling program GEM™ (CMG, LTD) to investigate these effects in more detail. To simplify the model, the reservoir was assumed to be homogeneous and isothermal. The model compared the gas injectivity observed during the pilot with the simulation results of gas injection into an aquifer (Figure 36). Figure 36B shows the early injection period in more detail. The model's *in situ* permeability of 5 mD was calibrated to match the initial injectivity of the field trial. The comparison indicated that injectivity during the pilot declined much faster than the modeled aquifer case. Adjusting the relative permeability curve to improve the match had no effect.

Figure 36: A) Comparison of the Hall plot from the injection and the calculated Hall plot matching the early injection data using a constant permeability aquifer model. B) A closer view of the early injection data and the calculated fit using the aquifer model.





Still assuming constant permeability, the *in situ* permeability was adjusted to obtain the best match possible for the entire pilot. A good history match could not be generated for the constant permeability case (Figure 37). The plot suggests that in addition to relative permeability, the reduction in injectivity was likely caused by hydrate formation, which reduced the effective permeability of the formation.

Figure 37: Hall plot comparison of cumulative injection performance from the pilot against the best fit from the gas injection aquifer model, assuming a constant permeability throughout the test.

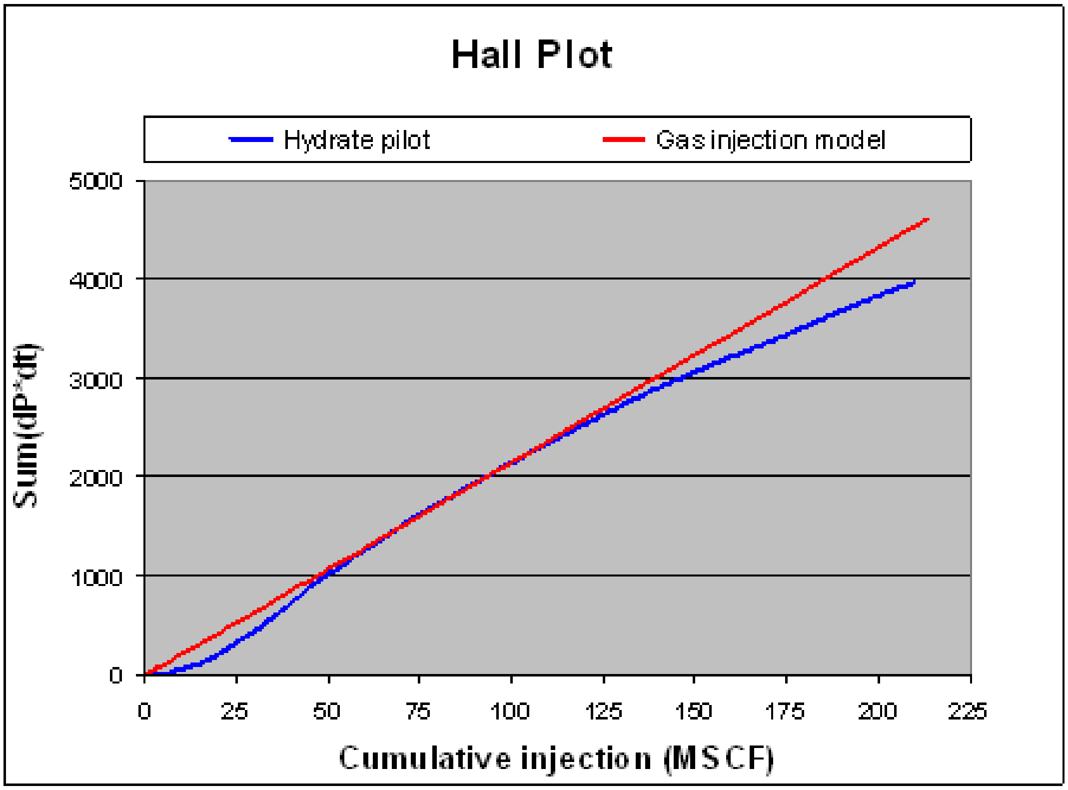
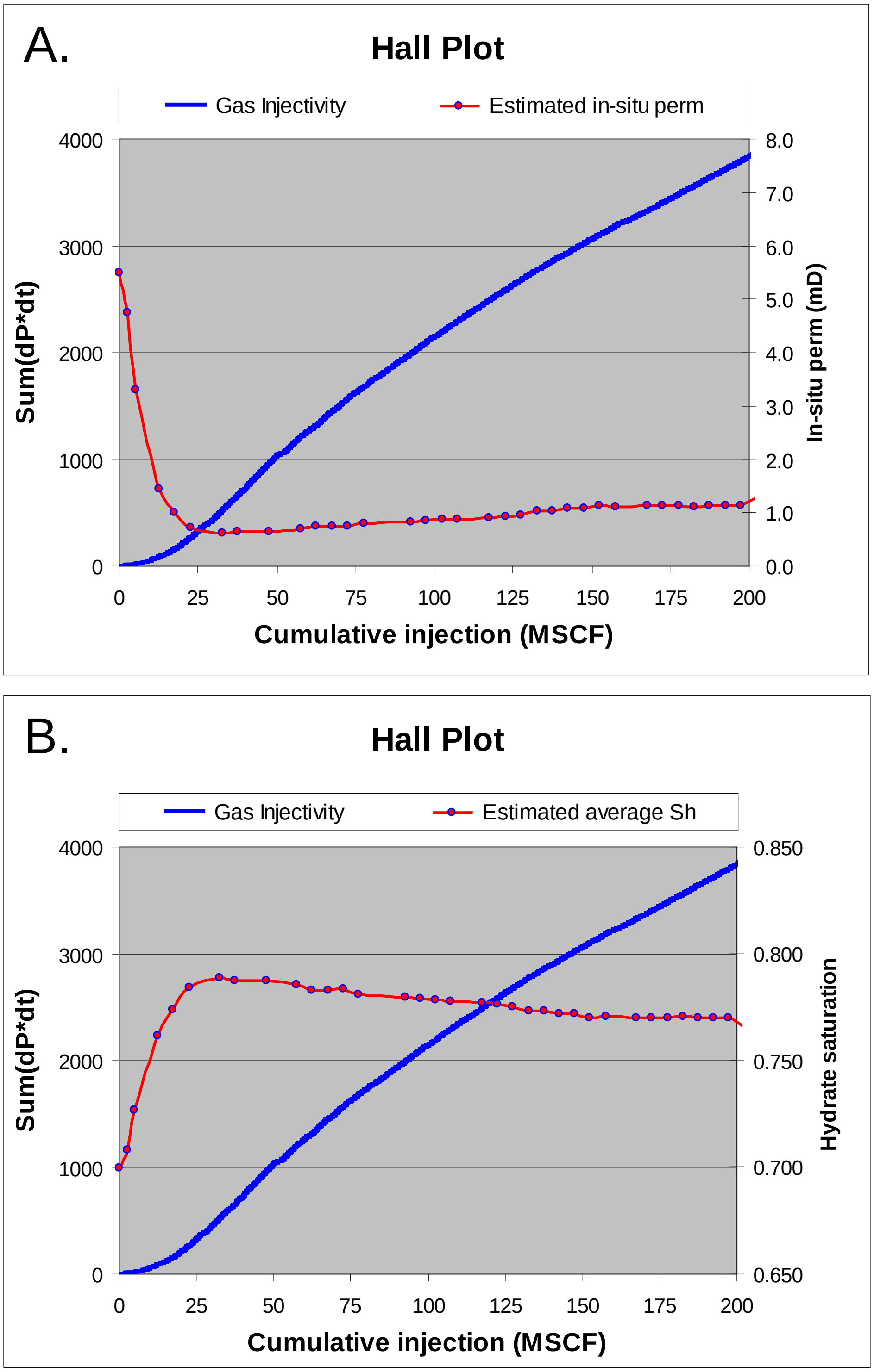


Figure 38: Hall plot of the injection performance compared with aquifer models that assumed: A) estimated *in situ* permeability during the injection phase and B) Calculated hydrate saturation based on the estimate permeability.



The aquifer model was modified to calculate an estimated average *in situ* permeability from the injection data (Figure 38A). The estimated permeability was calculated from the slope change of the Hall plot and based on an initial *in situ* permeability of 5.5 mD.

This approach assumed that the slope change was caused only by the change of *in situ* permeability. It was more likely that the injectivity was controlled by a combination of *in situ* permeability and relative permeability to gas phase effects. However, the straight line behavior for gas injection observed in the field test was comparable to the results expected from a conventional interpretation of cumulative injection into an aquifer where the linear response indicated constant injectivity after accounting for relative permeability effects (Figure 37). This implied that the gas injection rate was predicted to be more or less constant even though gas saturation around the well increased significantly during the injection, minimizing the impact of relative permeability.

The estimates of permeability change that were generated by matching the cumulative injection data showed that average *in situ* permeability decreased from 5.5 mD to 0.6 mD in the early stages of the injection. The calculated *in situ* permeability then gradually increased to 1.2 mD by the end of the injection period.

Average hydrate saturation was estimated from the calculated average *in situ* permeability using the method shown in Equation 6 (Moridis et al, 2008). The calculated average hydrate saturation changed slightly during the injection process (Figure 38B).

Equation 6: Average hydrate saturation estimation is calculated from the average *in situ* permeability

$$\frac{k_2}{k_1} = \left[\frac{\phi \cdot (1 - Sh_2) - \phi_c}{\phi \cdot (1 - Sh_1) - \phi_c}\right]^n$$

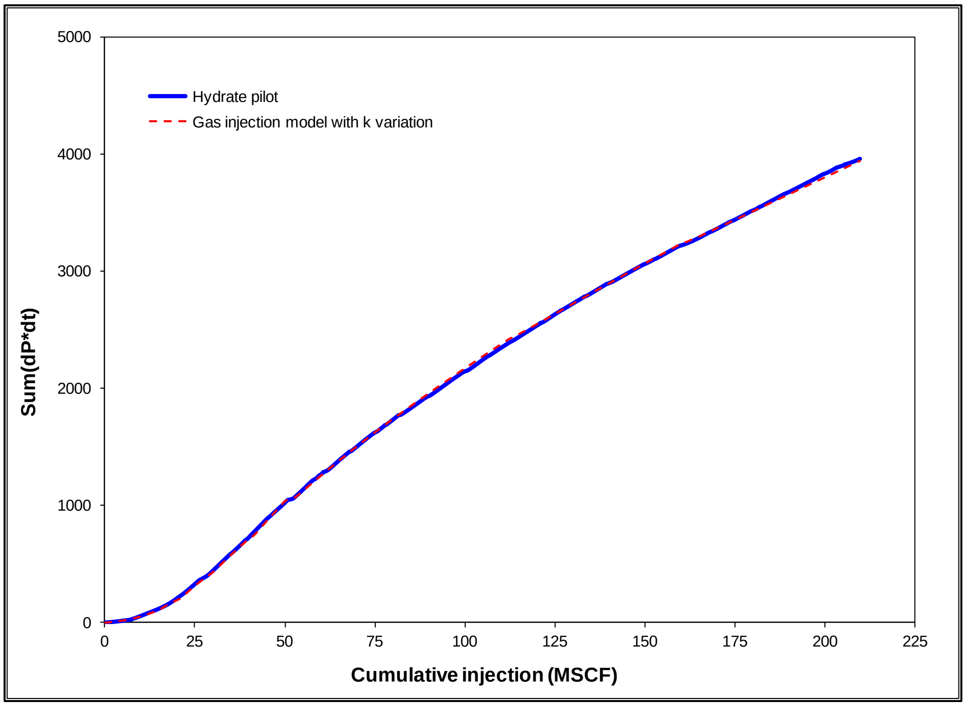
Where:

k_1 = initial *in situ* permeability (5.5 md)
k_2 = *in situ* permeability during injection
Sh_1 = initial hydrate saturation (0.7)
Sh_2 = average hydrate saturation during injection
ϕ_c = critical porosity (porosity that permeability become zero, 0.05)
n = exponential constant (3)

The model accounted for the changes in *in situ* permeability determined from the original Hall plot and calculated a new hydrate saturation at each point along the injection curve. The average hydrate saturation increased from 0.70 to about 0.79, then gradually decreased to 0.77 throughout the injection period.

To investigate whether permeability changes due to hydrate formation and dissociation could account for the observed injectivity, *in situ* permeabilities of near-wellbore grid blocks were adjusted manually every 3 hours throughout the injection period. By adjusting *in situ* permeability qualitatively according to the hydrate saturation profile predicted by the cell-to-cell model, a good history match was obtained during injection (Figure 39). As before, *in situ* permeability changes were used to recalculate the hydrate saturation at each time step using Equation 6. The high quality of the match between the actual injection results in the Hall plot and the modeled cumulative injection curve based on variable *in situ* permeability and hydrate saturation changes strongly suggested that hydrate formation and dissociation could account for the observed changes in injectivity during the injection period.

Figure 39: Hall plot based on field trial injection data compared with a calculated injection curve generated by manually adjusting permeability at 3-hour simulation time intervals.

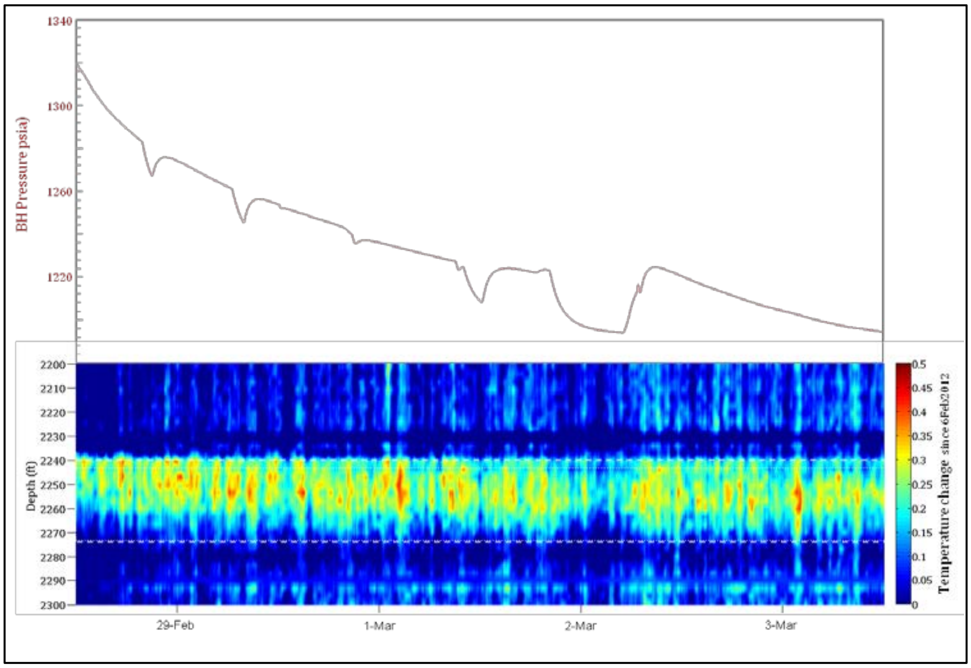


Total cumulative injection volume was calculated, including changes in wellbore storage, which consisted of the pressure increase at the beginning of production and the pressure falloff following shut-in at the end of injection pre-production period. The total injection volume of 215.9 Mscf comprised 167.3 Mscf N_2 and 48.6 Mscf CO_2.

Pre-Production Period

After the two-week injection period, the well was shut in and operations transitioned to production mode. The shut-in period lasted February 28 to March 4, 2012. As expected, the bottomhole pressure (BHP) began to fall off after injection ceased (Figure 40). Over the post-production period, downhole pressure dropped from an initial pressure of 1420 psi to 1200 psi. Short-term spikes and drops in the pressure data were followed by build-up to the main pressure decline trend (Figure 48). These changes appeared to be natural as opposed to instrument fluctuations or noise. These short-term events of less than one hour may have been caused by hydrate reformation taking place near the well. These events could not be localized because the pressure drops were detected by the bottom-hole gauge. The thermal information from the DTS, however, sheds additional light on these possible interactions. Each of the short-term pressure drops was associated with slight cooling of the hydrate-bearing reservoir interval. This was most notable with the longest-duration pressure drop on March 2, where a concomitant drop in temperature of several tenths of a degree was recorded (Figure 40). Endothermic hydrate reformation near or at the casing-formation interface could explain the combination of small pressure drops and temperature decreases.

Figure 40: Downhole pressure and temperature response during shut-in period following injection. The thick dashed lines on the DTS indicate the targeted formation and the small dashed lines indicate the perforated zone.



Production Period

The production stage of the field trial proceeded in two major phases: unassisted flow and lift-assisted flow using reverse jet pumping. The jet-pumping phase was divided further into an initial low-flow period (~7 days), a high-flow period (~2.5 days), and an extended increasing flow period (~19 days). Figure 41 illustrates downhole pressure and cumulative gas and water production in the different stages. Methane hydrate phase equilibrium pressure was also calculated with the downhole temperature for comparison with the actual reservoir pressure (Figure 41). The calculated mixed-hydrate phase equilibrium pressure from the downhole temperature and the produced gas composition is included in Figure 42. Pressures above methane hydrate equilibrium were maintained during the unassisted production and the first jet-pumping periods. This suggests that produced gas in these periods was not caused by dissociation of in-place natural hydrate. During the high-flow second jet-pumping production period, production pressure remained very close to the methane hydrate stability pressure. During the third and final jet-pumping period, downhole pressure dropped well below methane hydrate stability, likely resulting in the stimulation of in-place hydrate dissociation.

The short unassisted-flowback period at the beginning of the production test showed gas-only production to surface. However, water began to flow and fill the wellbore during the latter stages of the unassisted flowback. During the early stages of Production Phase 2, jet-pump flowback began and cumulative gas and water production rates were high. Water and gas production fell during the end of the second period of jet-pump flowback (Production Phase 3) as the well underwent maintenance. The onset of the third period of jet-pump flowback (Production Phase 4) coincided with the well pressure drop below the methane hydrate equilibrium pressure. These factors resulted in near constant rate production of both gas and water during the last stage of the production period (Figure 41).

Figure 41: Total volumetric production rate, downhole pressure, and cumulative water and gas during the production phase. Also included is the calculated CH_4 hydrate stability pressure based on the downhole pressure.

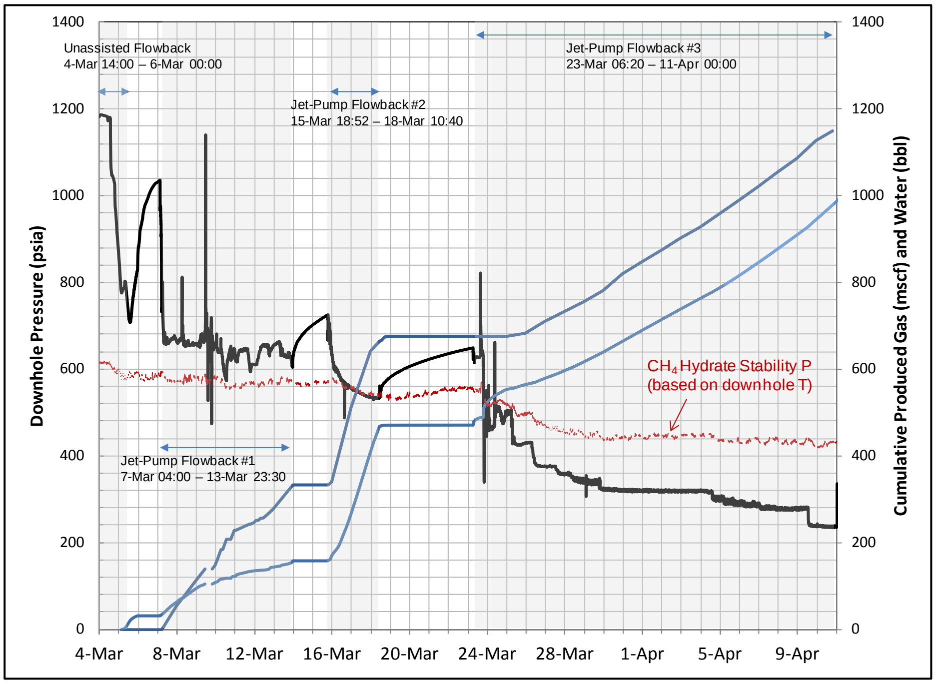


Figure 42: Total volumetric production rate, downhole pressure, and cumulative water and gas during the production phase.

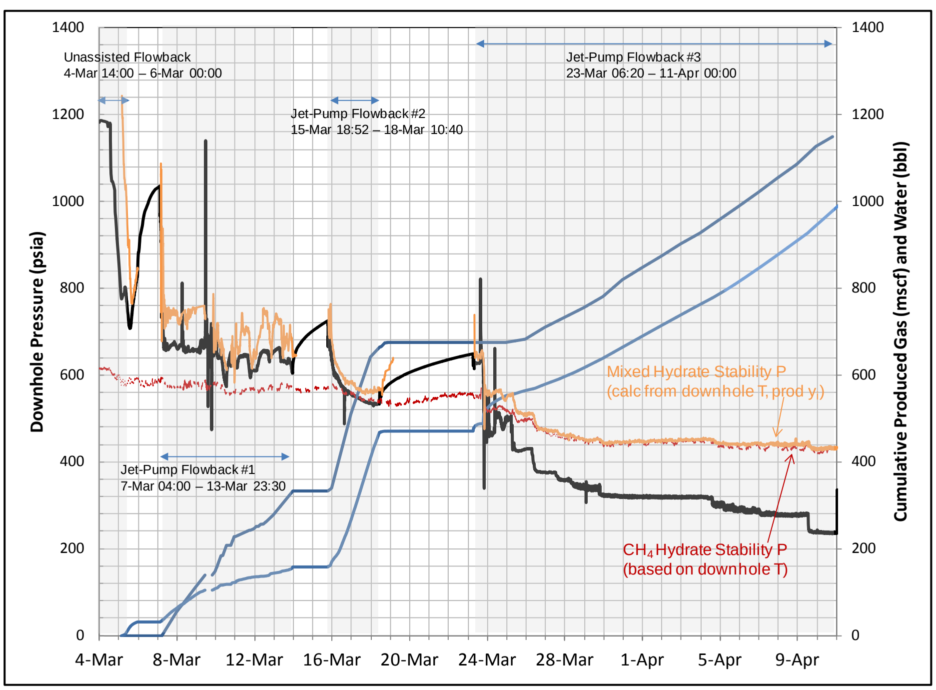
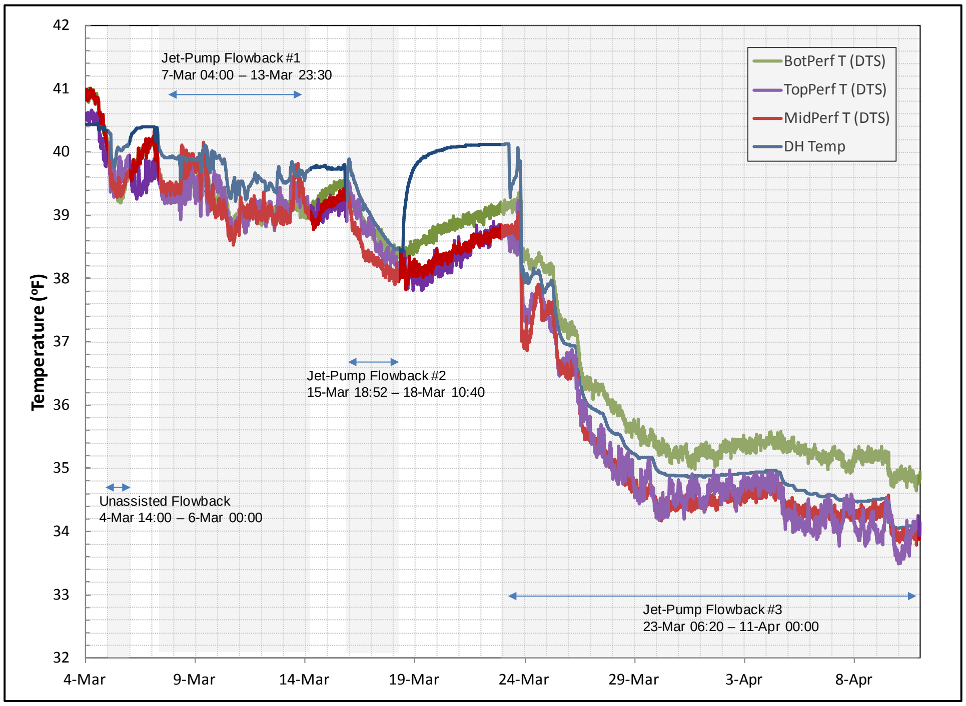


Figure 42 also includes the calculated CH_4 hydrate stability pressure based on the downhole pressure and the mixed gas-hydrate stability pressure based on the downhole pressure and the composition of the produced gas stream.

Temperature sensors active during the production period monitored temperature fluctuations at various points in the reservoir interval (Figure 43). The DTS temperature array was sampled at three points corresponding to the top, middle, and bottom of the perforated zone. Since the DTS array was attached to the outside of the casing string, it was more responsive to temperature fluctuations in the formation. In contrast, the bottomhole temperature gauge (middle gauge) was ported to the borehole and was responsive to the average temperature of the borehole fluids. The early stages of the production through the end of the second jet-pump flowback sequence saw a uniform temperature drop. When the jet pump was shut in for maintenance, the borehole temperature increased rapidly to 40°F as the fluids equilibrated with the surrounding formation. Formation temperatures as indicated by the three DTS curves showed a more gradual and less complete temperature increase during this shut-in period. During the early stages, the borehole temperature generally showed greater variability and faster response to changing conditions than the DTS temperatures. Once jet-pump flowback #3 (Production Phase 4) began, all of the temperature sensors showed a significant rapid drop from 38.5°F to 34-35°F. After this rapid drop in the borehole and along the casing-formation interface, the temperatures stabilized in the 34-35°F range with fluctuations of approximately 0.1°F. The final stages of depressurization during jet-pump flowback #3 period show a significant divergence in the DTS temperatures from each other, with the lowest perforation 1.0°F warmer than the middle and top perforations.

Figure 43: Temperature during production. Note that the DTS temperature represents temperature measured by a fiber cemented in the casing and the downhole temperature is a gauge in contact with wellbore fluid.



Interesting correlations appeared in the combined results from the downhole pressure, downhole temperature (DTS), and volumetric production rates for the early stages of the production period (Figure 44). The complete DTS array has a visual aspect that was not captured by the extraction of temperature curves for individual points along its length. Small perturbations in temperature and the spatial distribution of those temperature changes are associated with specific events during this production period. In the early stages the hydrate-bearing zone showed a small amount of cooling that was restricted to the perforated interval. Only during the second jet-pump flowback period (Production Phase 3), when there was a very high rate of gas production, did the temperature changes affect the reservoir interval above the perforated interval. During this time the produced interval had a significant reduction in temperature.

The continued reduction in temperature in the perforated interval and in the surrounding reservoir above the perforated interval characterized the period of depressurization below methane hydrate stability during the third jet-pump flowback (Figure 45). The temperature in the perforated zone shows marked cooling that was most noticeable after the BHP dropped below the pure methane hydrate equilibrium value. This temperature drop was consistent with the endothermic reaction of hydrate dissociation. The spatial heterogeneity in the thermal response from top to bottom of the perforated intervals provides potential clues on how to evaluate the relative flow of gas and water into the wellbore from the formation.

The gas composition was monitored during the entire production period with an on-line GC. The three dominant gases comprised nitrogen, carbon dioxide, and methane, so the produced volumes were normalized to a relative proportion in mole percent, mol%,

(Figure 46). Even during the unassisted production interval during the first two days, methane was the dominant gas produced from the well. After the initial jet-pump stages were under way, methane increased in the total gas stream, reaching almost 80 mol% of the total by the end of the first jet-pumping flowback period (Production Phase 2). During that time, nitrogen and carbon dioxide decreased their contribution to the gas stream. When the depressurization stage started during third and final jet-pump flowback stage, the methane contribution rose to more than 95 mol%. Nitrogen and carbon dioxide contributions fell to very low levels, with carbon dioxide never exceeding 2.0 mol% of the total stream. The produced gas volumes were converted to cumulative volumetric amounts of the individual produced gases (Figure 47). Significant increases in produced methane during the production test corresponded to the initial jet-pump flowback and a very large increase at the beginning of the second flowback stage. When the third flowback period began on March 23, the methane production rate was fairly uniform for the final 18 days. Nitrogen showed early production during the first two flowback stages, but once pressures fell below the methane hydrate stability pressure the amount of produced nitrogen fell to very low levels. Carbon dioxide behavior was very similar. After an initial burst of production during the initial flowback period, the amount of produced carbon dioxide remained almost constant.

The recovery percentage of the injected gases was calculated based on the cumulative injected volumes (Figure 48). The test produced 855 Mscf of methane over the total production period. Of the initial 215.9 Mscf of injected gas, 167.3 Mscf was nitrogen. Over the course of the production test approximately, 70% of that nitrogen was recovered. In contrast, only 40% of the 48.6 Mscf of injected carbon dioxide was recovered. During the early stages of the production test, excluding the first period where gas from the wellbore was produced on initial depressurization, more nitrogen was produced compared to the amount of carbon dioxide that was injected. This is shown by the CH_4-free mol% CO_2 relative to nitrogen (Figure 49). Only in the final jet-pumping stage, in which the pressure was lowered below CH_4-hydrate stability, did we see an increase in the amount of CO_2 relative to N_2. This could indicate that pressures were finally being reached that led to the destabilization of CO_2-enriched hydrate. Note that because the separator normally operated above ambient pressure and jet-pumping water was mixed with produced fluids in the wellbore, gas loss occurred when the water containing dissolved gas moved from the separator into the atmospheric upright-tanks. It was necessary to correct for the lost gas in the data reported because CO_2 is much more soluble that N_2 or CH_4. To account for this, a procedure was developed to calculate the amount of dissolved gas leaving the separator over the production phase. This lost gas was added to the gas production amounts metered through the gas leg of the separator. Appendix C provides details for this calculation.

Figure 44: Thermal effects (along with gas production rate and downhole pressure) during the unassisted and the first two jet-pumping phases of production. The thick dashed lines indicate the targeted formation and the small dashed lines indicate the perforated zone.

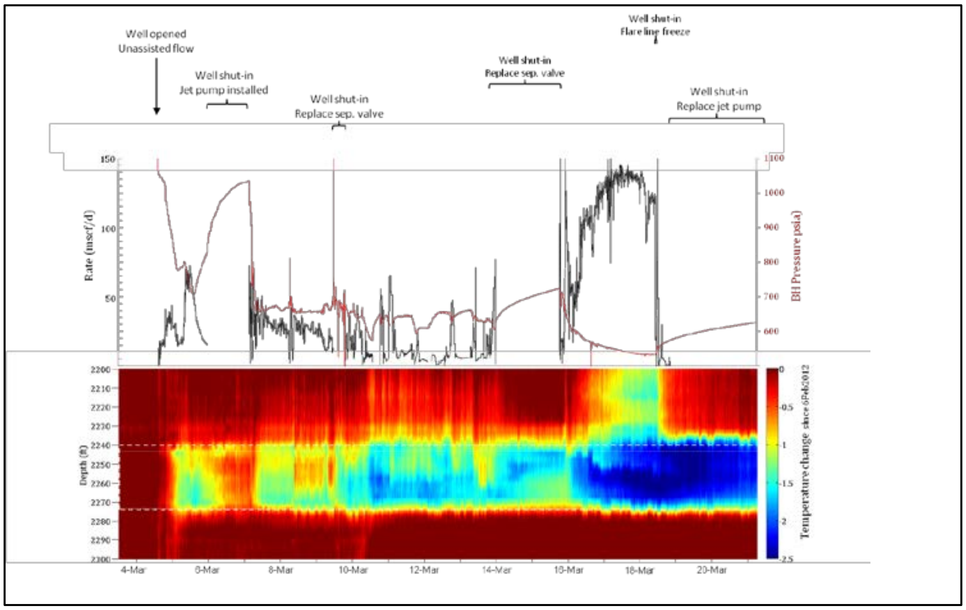


Figure 45: Thermal effects (along with gas production rate and downhole pressure) during the third jet-pumping phase of production. Note that A and B have different temperature threshold limits. The thick dashed lines indicate the targeted formation and the small dashed lines indicate the perforated zone.

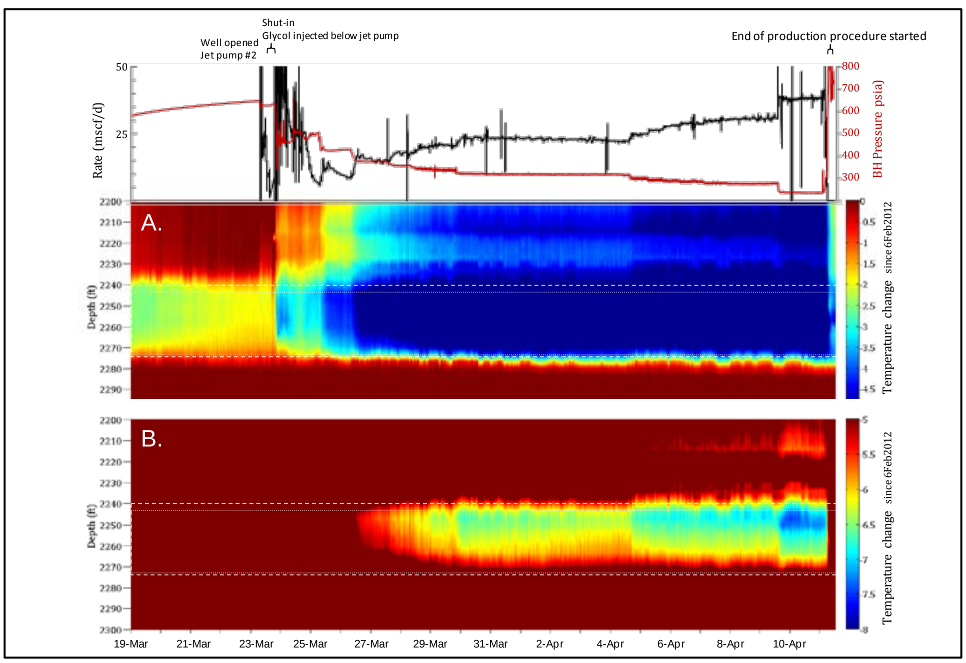


Figure 46: Produced gas composition during production measured with the on-line gas chromatograph.

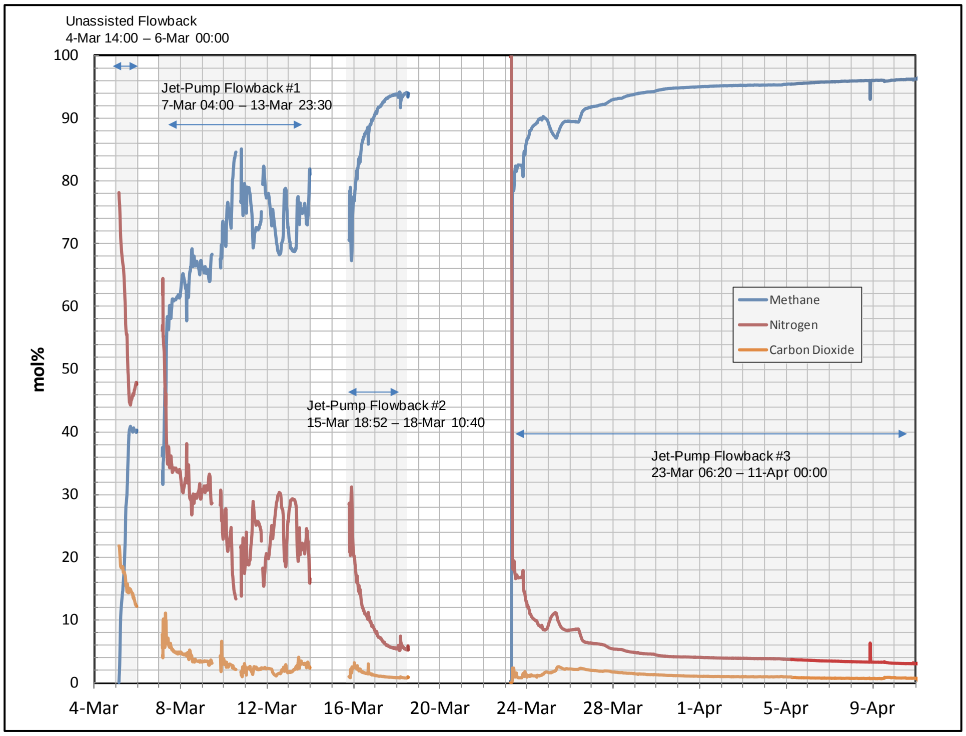


Figure 47: Cumulative volumes of gas during the production period.

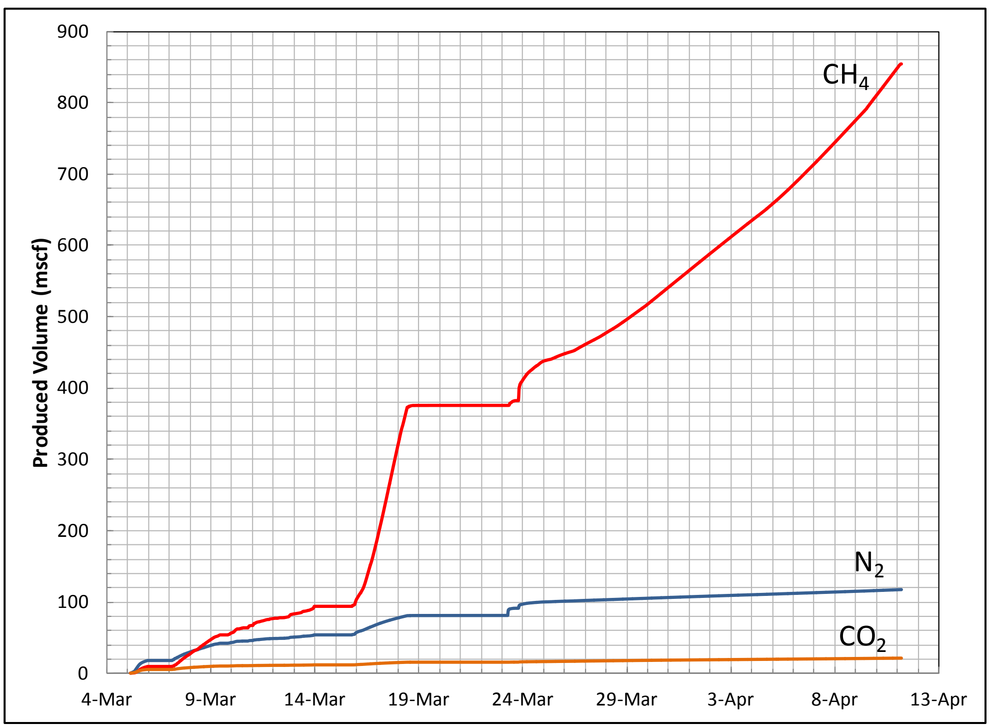


Figure 48: Percentage of injected gas recovered during production based on the total amount injected.

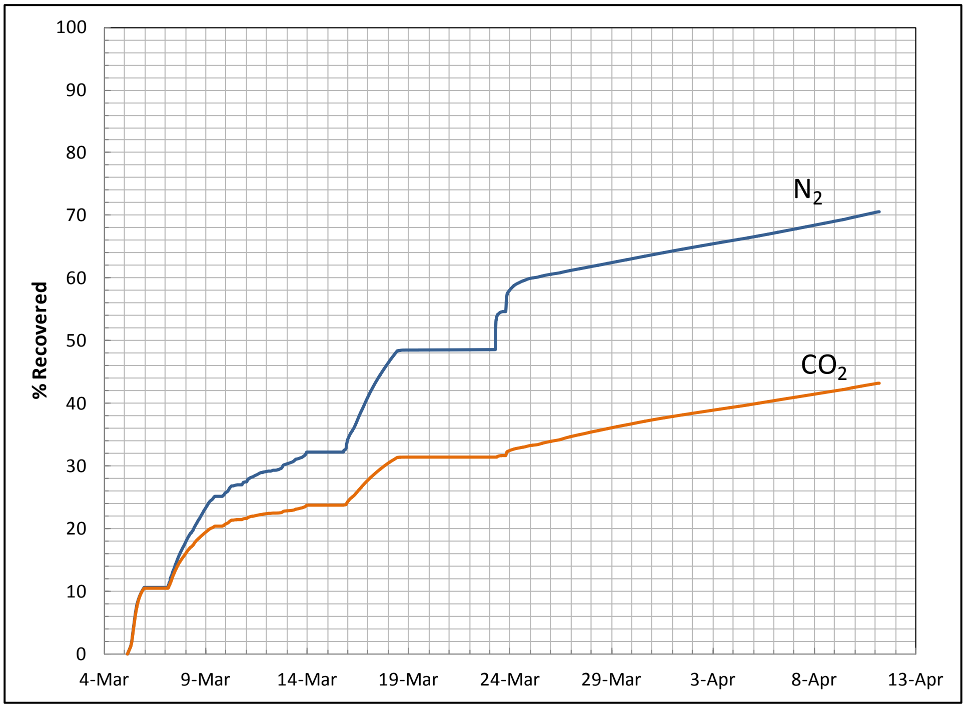
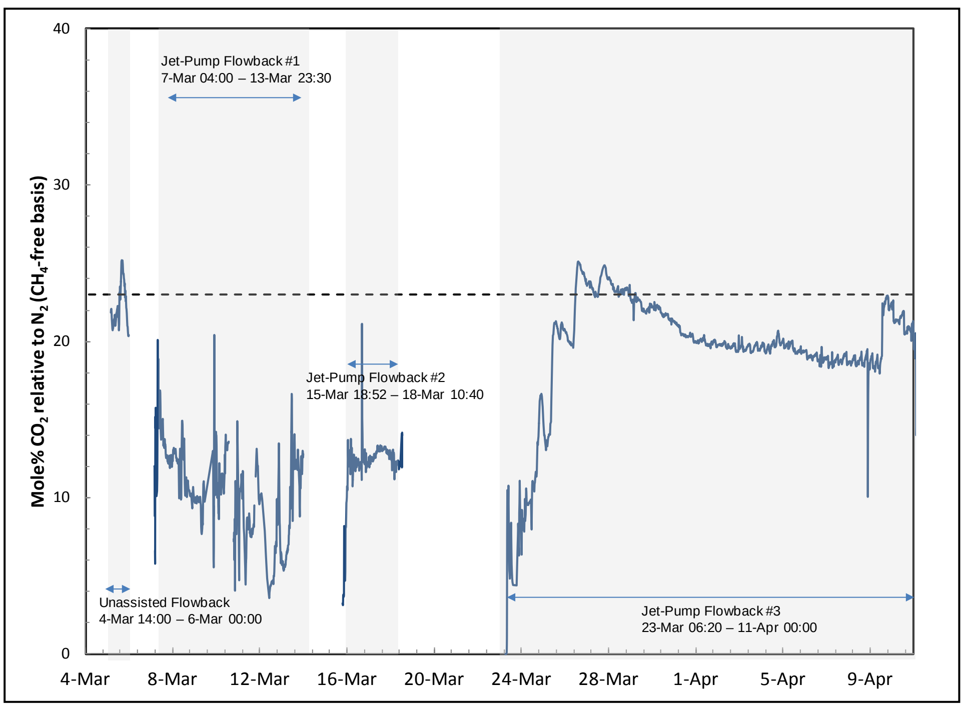


Figure 49: Mole % CO_2 relative to N_2 on a CH_4-free basis.



A total of 1136.5 bbl of formation water was produced with varying daily production rates during the jet-pumping phases (Figure 50) Appendix C describes the methodology for calculating the daily water rate. Figure 51 shows the molar ratio of produced water to produced gas over the jet-pumping production periods. Produced water:gas ratios were erratic during the first jet-pumping phase and varied from 10-50 on a molar basis.

However, the next two jet-pumping phases showed a steadier water rate compared with gas production. The water rate followed the gas rate with a water:gas ratio varying from 4-12 on a molar basis. The expected ratio from hydrate dissociation alone would be approximately 6. Therefore, for almost all of the production, the amount of water produced was greater than can be attributed to the release of water by hydrate dissociation. (Assuming a 5.75:1 molar ratio of water to methane, approximately 40% of the produced water was sourced from something other than native hydrate.) During the final steady depressurization below the methane hydrate stability pressure, water rate varied from 22-42 bbl/day with gas rates of 13-38 Mscf/day. The ratio of water to gas is comparable to that observed at the 2007/2008 Mallik hydrate production test. During a smooth production period, the Mallik test recorded rates of 63-125 bbl/day of water with 70-106 Mscf gas, resulting in molar water:gas ratios of 6.6-8.8 (Kurihara et al, 2011).

Figure 50: Estimated daily water production rate (bbl/day).

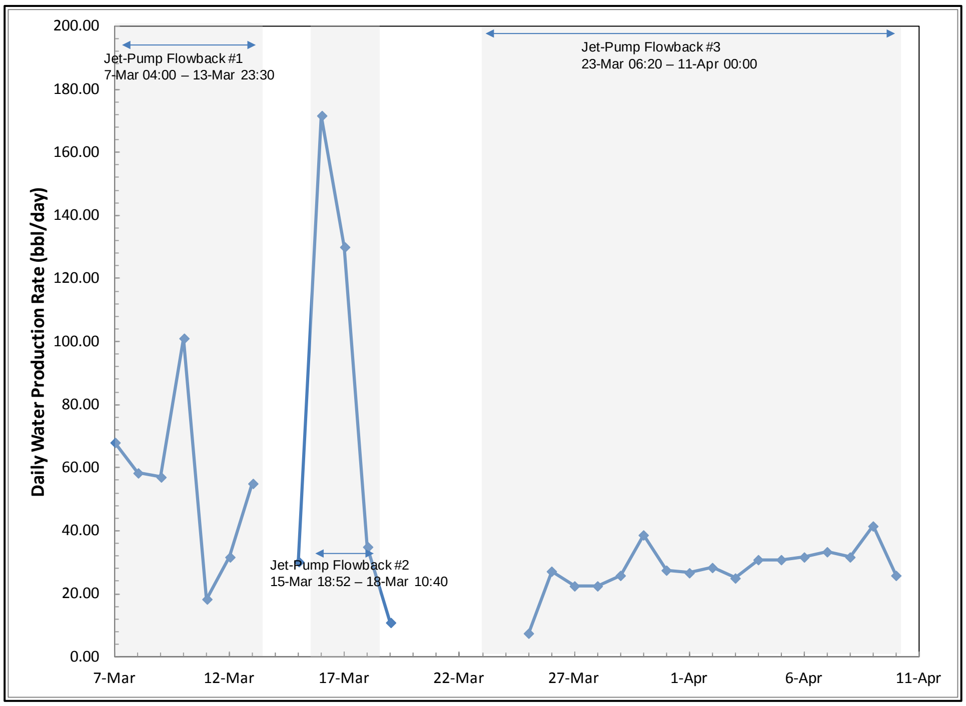
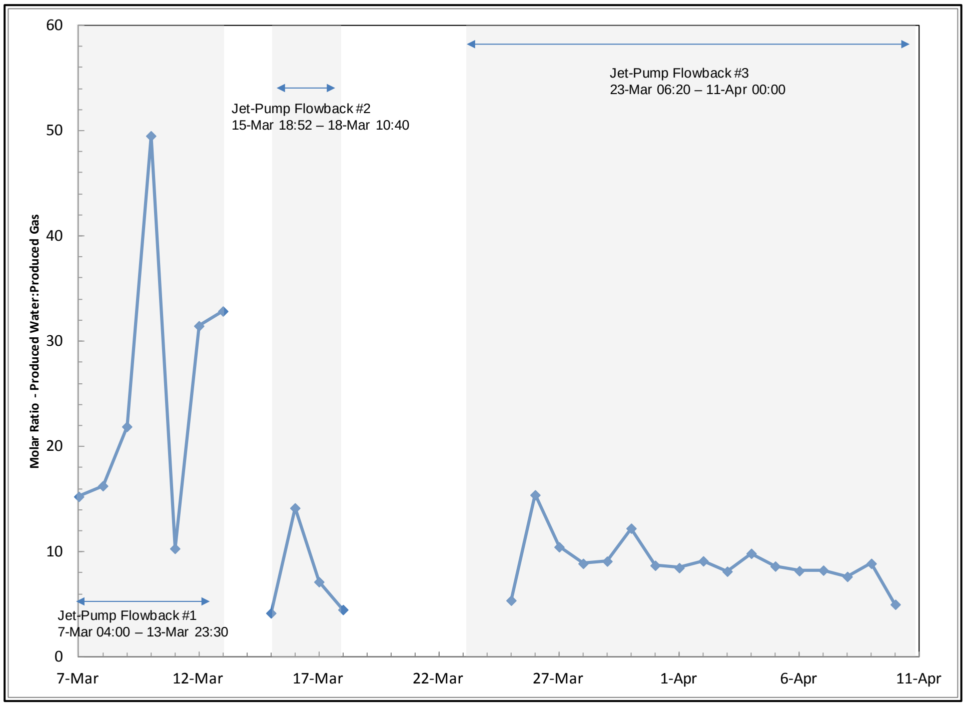


Figure 51: Molar ratio of produced water to produced gas based on daily cumulative values.



In addition to gas and water, sand was also produced. During the first two jet-pumping phases, sand was produced steadily with occasional large spikes (Figure 52). In Phase 4 (jet-pump flowback #3), however, sand production virtually stopped. Sand sampled on March 7, 2012, was analyzed by the ConocoPhillips Kuparuk laboratories and found to have a mean particle size of 148 µm. Although the well used a 200 µm sand screen, the continual pressure fluctuations (especially in Production Phase 2) could account partially for the continuous production of sand, as the sand could not form an effective bed around the sand screen. This produced sand ultimately damaged two valves in the separator during Production Phase 2.

On April 10, 2012, the tank strap on empty upright tank #1 measured 38.1 cm (1 foot, 3 inches), indicating that the bottom of the tank held sand at a height equivalent to ~25 bbl. At the conclusion of the test, the tanks were drained, leaving behind sand in the upright tanks (Figure 53). Both tanks were full to the lowest off-load point at 30.48 cm (1 foot). This represented ~20 bbl in each tank. At some points the tanks may have contained more sand, but some sand could have been removed as water was off-loaded from the tanks. The separator also was known to contain a significant amount of sand. The amount of sand removed at the end of the field trial was unavailable.

Total produced sand was estimated using the average daily sand volume percent in the produced water and the daily water production (sum of jet-pumping rate and estimated formation water production). As shown in Figure 54, more than 67 bbl of sand could have been generated over the course of production.

Figure 52: Bottom sediment and water measurements of the percentage sand in the produced water stream.

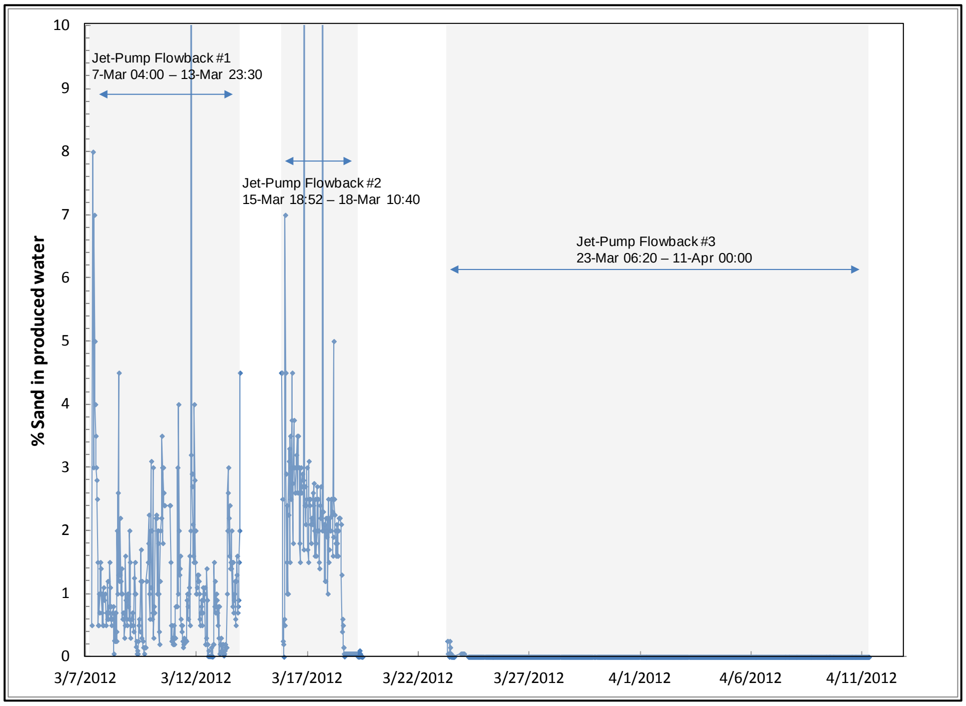


Figure 53: Sand in upright tank at the conclusion of the pilot.

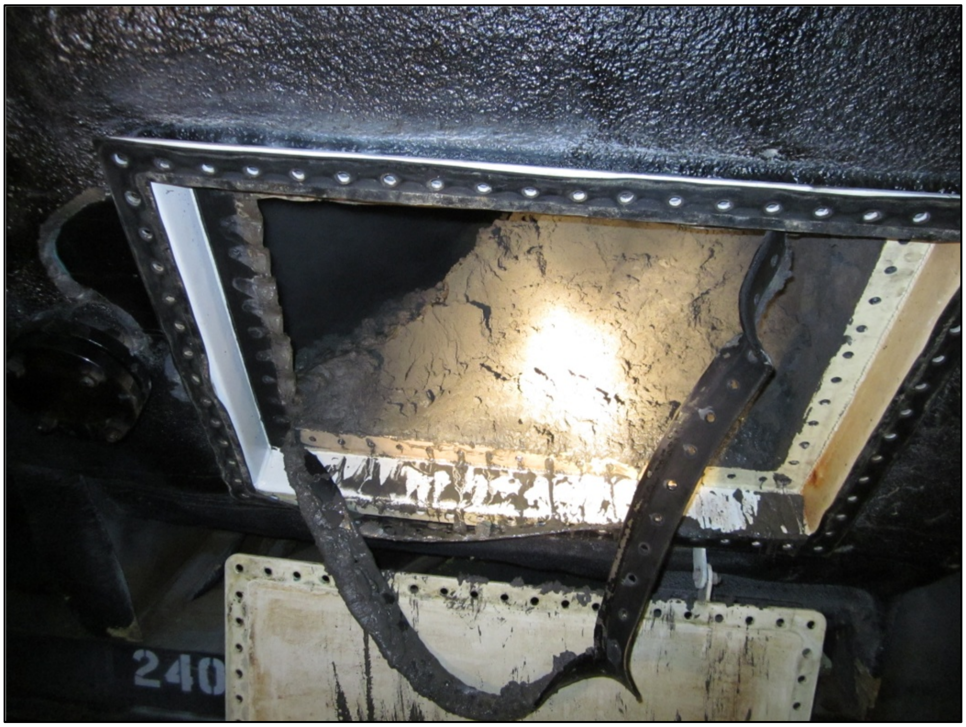
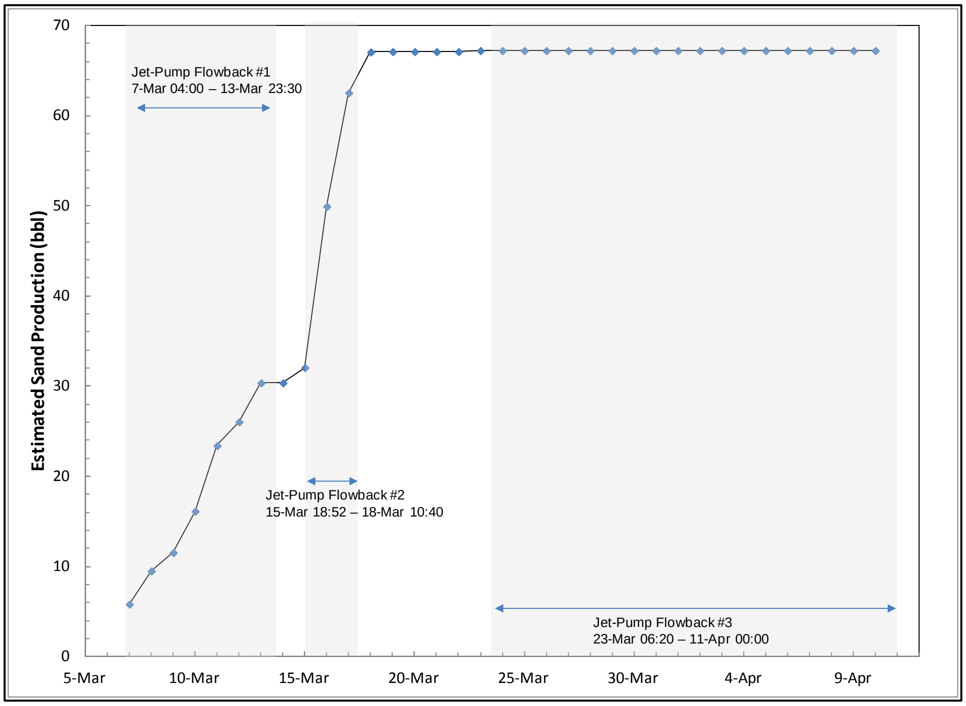


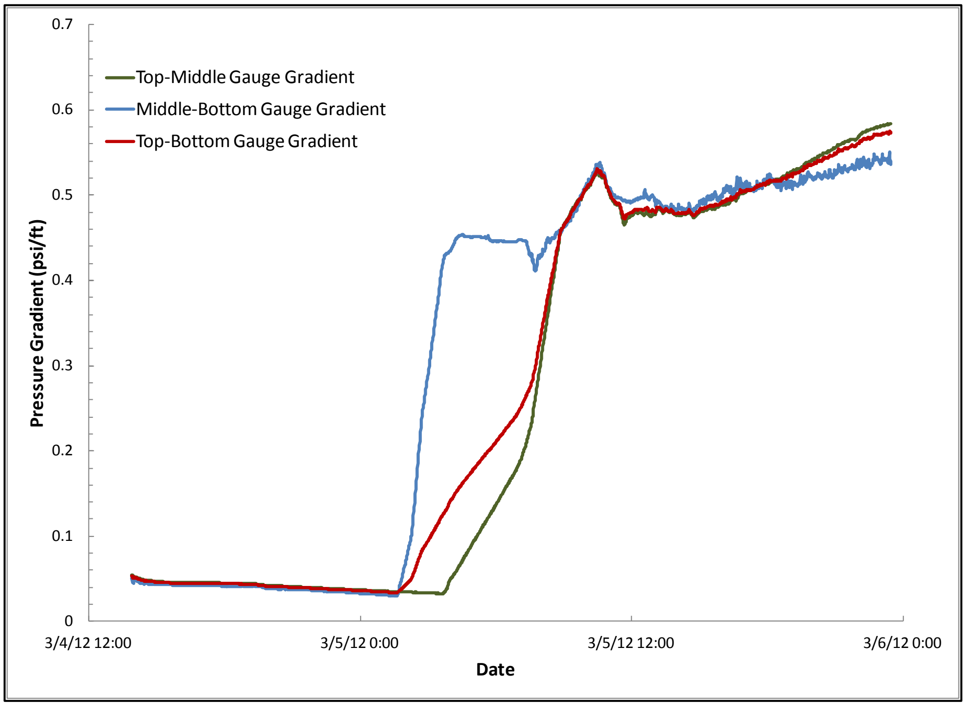
Figure 54: Estimated cumulative sand production based on bottom sediment and water measurements and water production.



Phase 1: Unassisted Production

Unassisted production ran March 4-6, 2012. The methane concentration in the produced gas rapidly rose to more than 40 mol% (Figure 46). After the first day of production, the pressure gradient calculated from the downhole gauges began to increase (Figure 55). This increase was attributed to water flowing into and filling the wellbore. Based on the density of water, a pressure gradient of 0.43 psi/ft was anticipated. This was indeed the case for the gradient between the bottom and middle gauges for a short period. This gradient then increased (for all gauges) indicating that solids (sand) were likely mixed with the produced water. As the water continued to fill the wellbore, the downhole pressure began to rise (see Figure 44), which corresponded with a marked decrease in production rate. On March 6, the test transitioned to an artificial lift system, the well was shut in, and the first jet pump (Oilmaster 5C) was installed.

Figure 55: Pressure gradients among the three downhole gauges during the unassisted production period.



Phase 2: Jet pumping above methane stability pressure, jet-pump flowback #1

Reverse-flow jet pumping above the in-place hydrate stability pressure began March 7, 2012, and proceeded for seven days. As suspected from the downhole pressure gradients, the first produced water to the surface separator showed entrained sand. The downhole pressure during this period was maintained at a higher pressure than the calculated methane hydrate phase stability pressure (Figure 41). While pressure was maintained to avoid dissociating the in-place hydrate, the composition of the produced gas quickly rose to greater than 70 mol% CH_4 (Figure 46).

The rate of gas production during this period was erratic and prone to periods of no flow. In addition, downhole pressure displayed periods of “saw tooth” behavior with periods of pressure buildup and rapid fall-off under stable and constant wellhead pressure operations (Figure 56). This could indicate hydrate formation or dissociation in the reservoir or the wellbore. Marked heterogeneity in the thermal response of the perforated zone also occurred during this phase of production (Figure 44). As shown in Figure 57, pressure gradients between the downhole gauges varied greatly during this production period. The gradient was often greater than expected for water (0.43 psi/ft), indicating the possible presence of dense solids (sand) in the water column. Sand production was observed on the surface during this period. The test also exhibited periods in which the gradient dropped well below 0.43 psi/ft, even into negative numbers. This was especially true for gradients calculated from the bottom gauge. This might be explained by the formation of hydrates in the wellbore tubing, creating temporary blockages that isolated the lower gauge and prevented effective communication of the true fluid head pressure in the well.

Figure 56: Example of downhole pressure behavior during the Phase 2 production with characteristic "saw tooth" behavior.

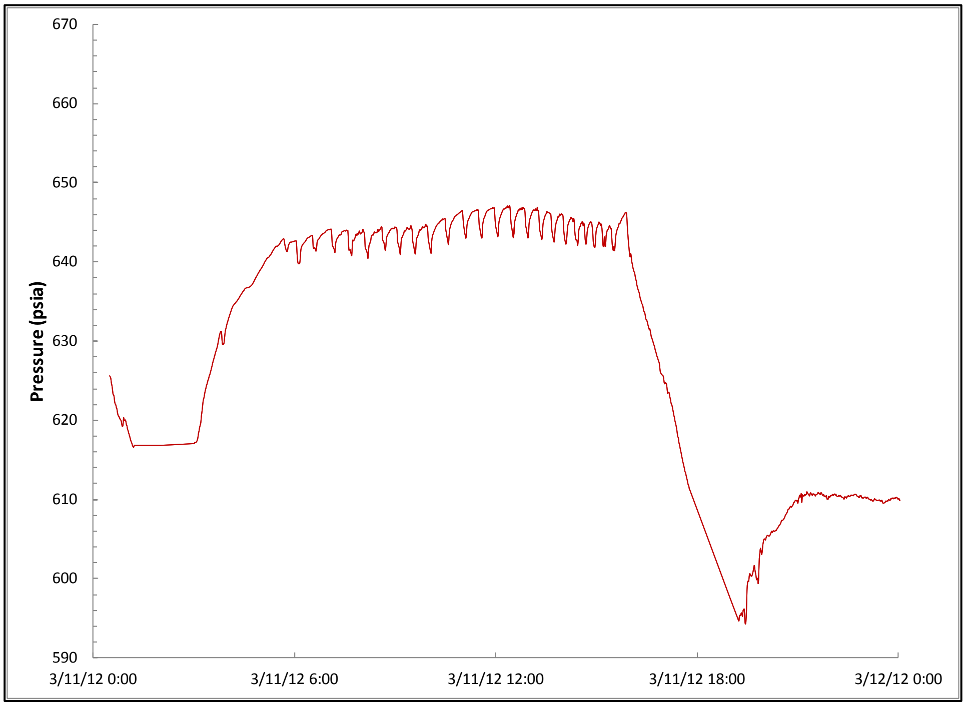
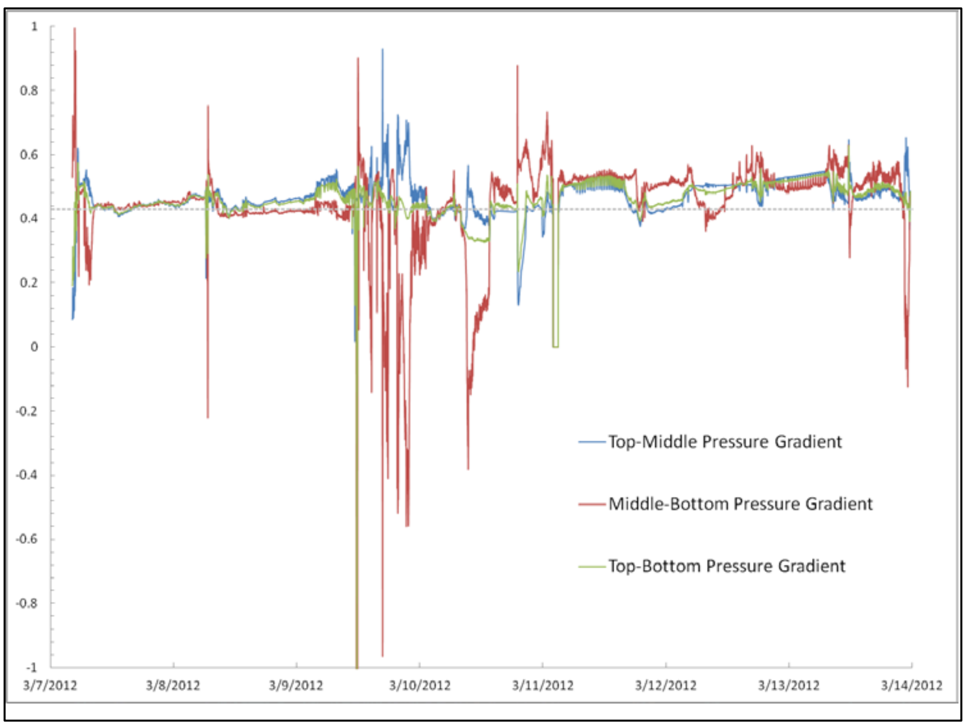
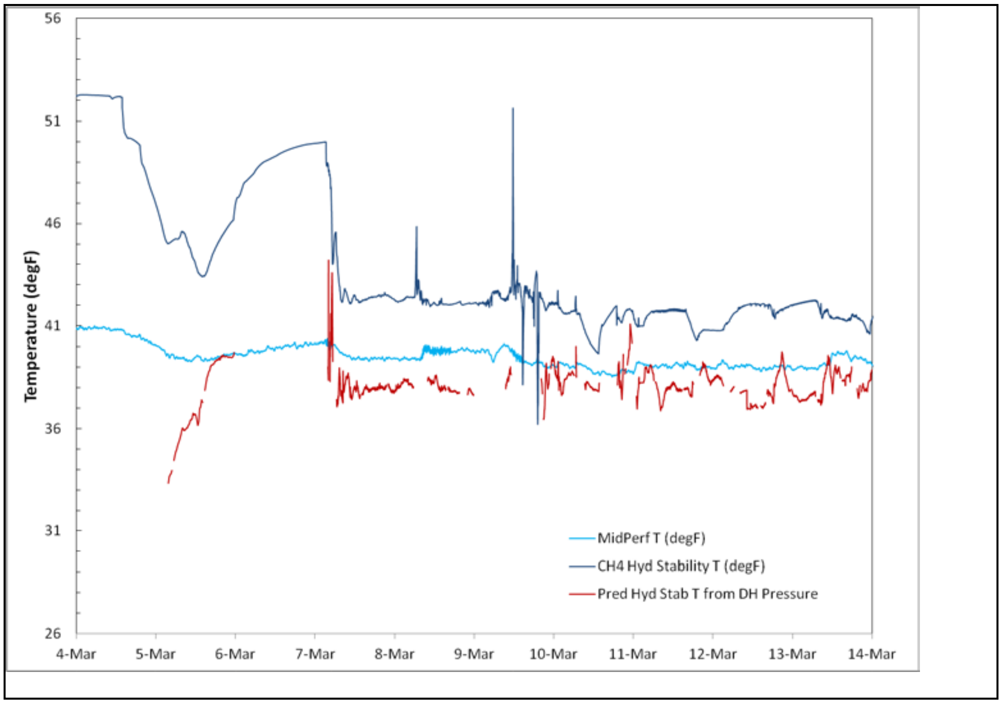


Figure 57: Pressure gradients between the three downhole gauges during Phase 2 of production. Gray dashed line indicates the expected gradient for a column of water (0.43 psi/ft).



Using downhole pressure to calculate the hydrate stability temperature, the potential for hydrate formation during this phase of production can be evaluated. Figure 58 shows the unassisted flow (Phase 1) and first jet-pumping periods (Phase 2). The plot shows that the mid-perforation temperature stayed below the pure methane hydrate stability temperature, indicating in-situ methane hydrate was stable. However, using the composition of the produced gas to predict a stable hydrate temperature, the predicted equilibrium temperature for the mixed hydrate is, in general, lower than the measured temperature. Therefore, mixed hydrates of this composition would have been unstable. Based on the produced composition, this could indicate dissociation of a mixed hydrate.

Figure 58: Mid-perforation temperature (from DTS) along with the predicted hydrate stability temperature for pure methane and based on the real-time produced gas composition.



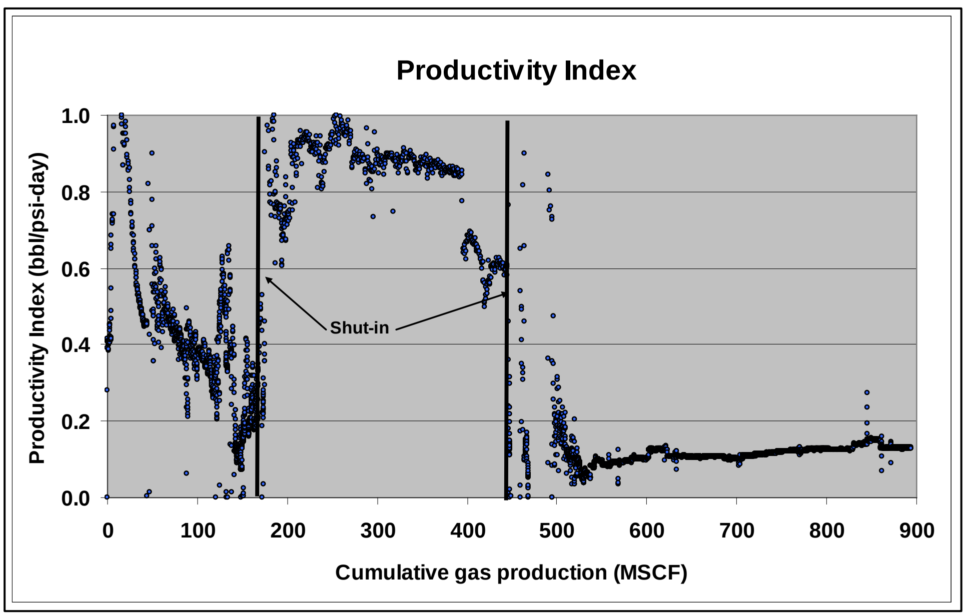
As annotated in Figure 44, production was halted twice during Phase 2 production to replace dump valves on the separator. The valves were damaged largely due to wear from sand production. Replacement of the first valve required several hours of down time. When the second separator valve was damaged near midnight on March 13, a different replacement valve with a design less prone to sand damage was ordered. The delay due to shipping halted production for ~1.5 days.

Phase 3: Jet pumping ≈ CH_4-stability pressure, jet-pump flowback #2

Following the replacement of the separator valve, production restarted at 18:52 on March 15, 2012. The downhole pressure was continually reduced to pressures that approached and eventually reached the methane hydrate stability (Figure 41, red line). This phase of production saw the highest gas production rates (approaching 150 Mscf/day, Figure 44). The increase in gas rate was accompanied by increasing amounts of produced water (Figure 41). During this period, methane concentration also increased to more than 90% in the total gas production stream (Figure 46). A marked cooling was observed in the perforated zone, as seen in Figure 44. Sand continued to be produced during this phase with an average of 2.6 vol% sand (Figure 52). Compared to the Phase 2 production, downhole pressure in Phase 3 did not show the “saw tooth” behavior or marked periods of episodic flow and downhole pressure build-up. In short, a deliberate reduction in the downhole pressure below previous levels resulted in relatively high flow rates that appeared to be consistent with hydrate dissociation.

Figure 59 displays a plot of productivity index versus time. Productivity index (PI) is expressed as reservoir barrels per psi drawdown and therefore provides a relative indicator of flow potential. As the figure indicates, productivity increased dramatically during the aforementioned production period (period between the vertical lines), well beyond what would have been attributed to the absolute pressure drawdown alone given the prior production period. This dramatic increase in flow potential must be associated with a dramatic increase in permeability, which is presumed to be a consequence of hydrate dissociation. Notably, the period of high PI ended when the well was shut in. After shut-in, PIs returned to a relatively low value that gradually improved over time. During the shut-in period, either a stable hydrate reformed in the near-well region or solids rearrangement led to additional mechanical damage or skin. Finally, in the later extended production period, some concern for icing existed in that sandface pressures would require subfreezing temperatures for methane hydrate stability. An improving PI would suggest that hydrate dissociation was sustained and was moving outward with time with no impairment associated with icing.

Figure 59: Plot of productivity index versus time.



Pressure gradients were calculated between the downhole gauges during Production Phase 3 (Figure 60). During Phase 2 shut-in and before reinitiating flow, all gradients had dropped to slightly less than 0.43 psi/ft. This may have resulted from hydrate forming in the wellbore during the shut-in period, which reduced average density in the well. Upon reopening the well, pressure drawdown appeared to be sufficient to promote hydrate dissociation. Evidence for gas and solids separation in the wellbore is noted from relative gradient values between gauge positions. The gradient above the producing interval is gassier while gradient below appears solid laden.

Production during Phase 3 ended abruptly when an ice blockage developed in the flare line. The well was shut in while the blockage in the line was remedied. Upon restart, reestablishing flow proved impossible. As shown in Figure 61, downhole pressure was unresponsive upon restart of jet-pump operations after the 2-hour shut-in. Numerous attempts to return the well to flowing condition by increasing the jet-pumping rate to reduce pump suction pressure were unsuccessful. Hydrate blockages may have occurred relatively high in the tubing at relatively low temperatures such that the jet-pump was ineffective at reducing the downhole pressure to initiate dissociation. A remediation of possible hydrate blockages below the jet-pump was impossible because of the standing valve (check valve) installed below the jet-pump. After a day of trying to return to flow, a new jet-pump was installed and the standing valve was removed to allow for hydrate remediation by injection of a hydrate inhibitor if needed.

Figure 60: Pressure gradients for the three downhole gauges during Phase 3 of production. Gray dashed line indicates the expected gradient for a column of water.

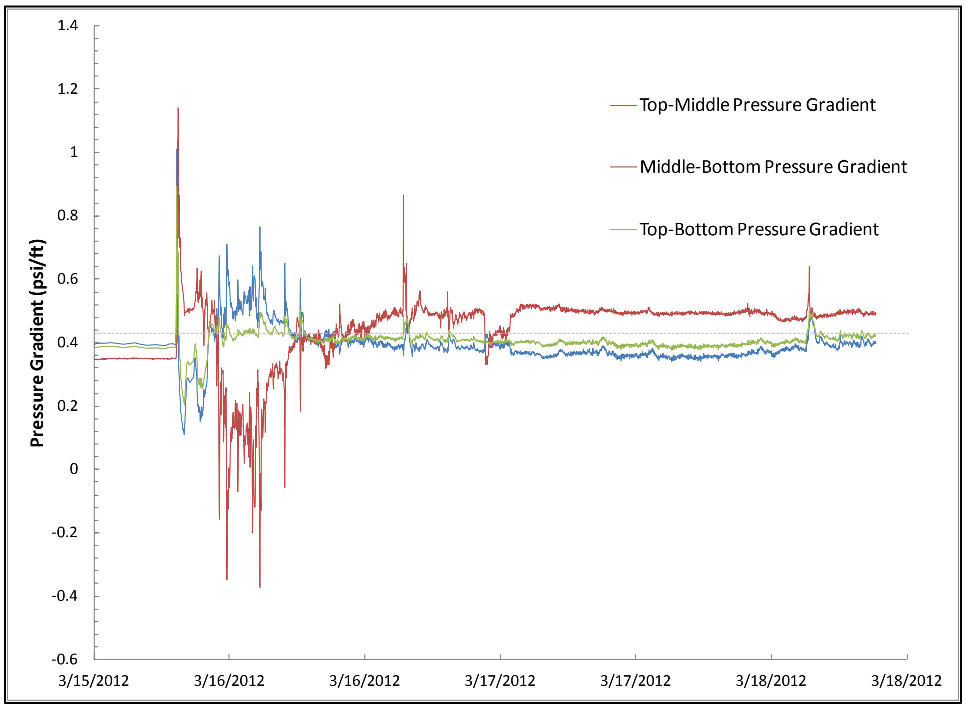
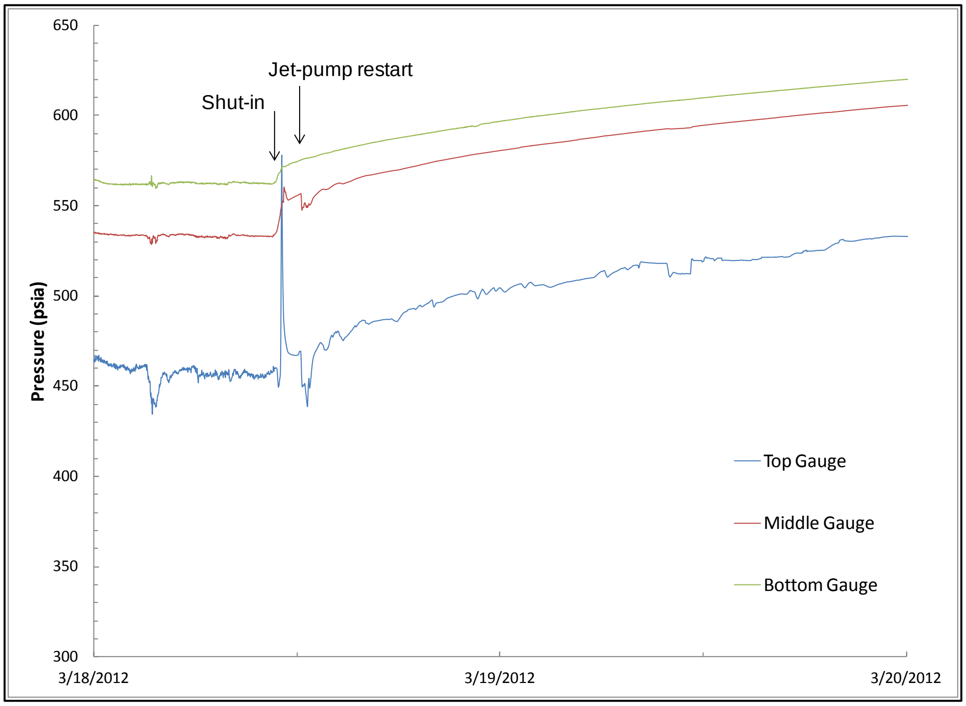


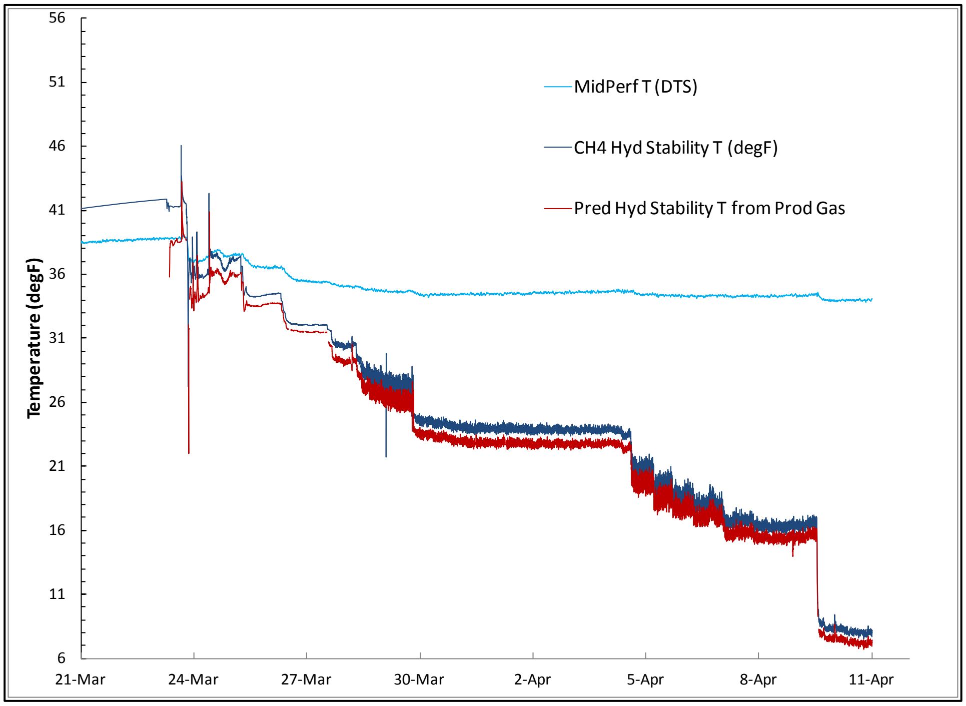
Figure 61: Downhole pressure gauges showing pressure response during shut-in to unfreeze the flare line and subsequent restart.



Phase 4: Jet pumping below CH_4-stability pressure, jet-pump flowback #3

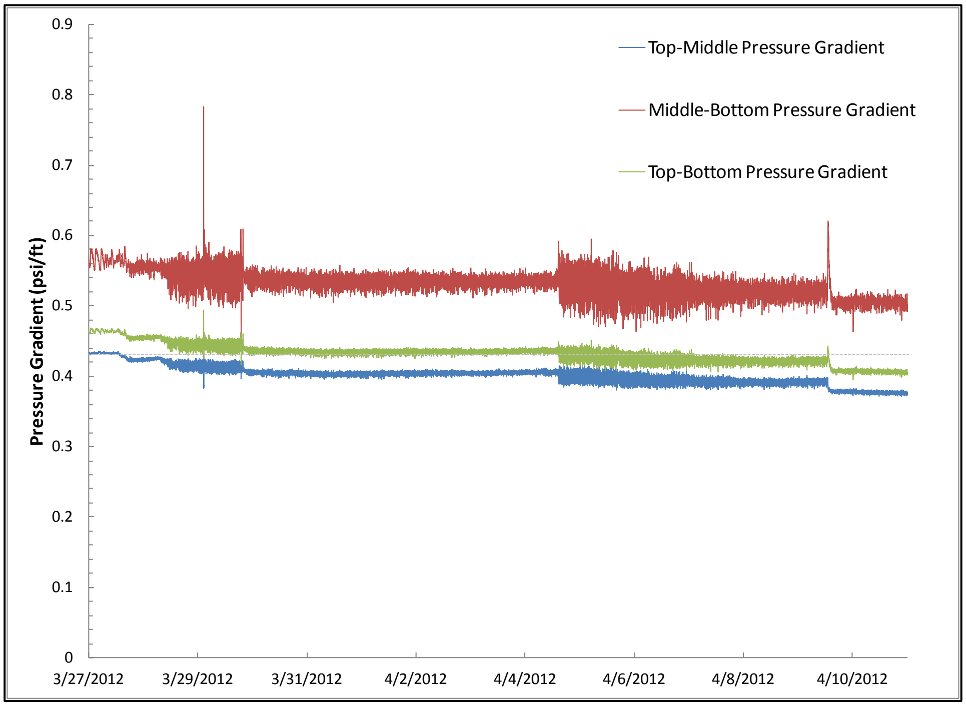
With a new jet-pump installed (Oilmaster 6C) and the standing valve removed, jet-pumping Production Phase 4 began on March 23, 2012. However, initial attempts to restart the well were unsuccessful as before. A limited volume of heated glycol was injected below the jet-pump to remediate any hydrate blockages. This successfully reestablished pressure communication with the formation and the fourth and final production phase began. The goal of this phase was to step down the pressure slowly to conditions that would destabilize the native methane hydrate. During this 19-day production phase, downhole pressure was lowered in steps from 648 psia to 266 psia. The reduction of downhole pressure led to a corresponding increase in gas production rate and a cooling at the perforations (Figure 45). Gas rate increased from approximately 5 Mscf/day to more than 30 Mscf/day. During this period, the methane concentration was greater than 90 mol% in the gas stream (Figure 46). Temperature dropped to about 33-34°F at the lowest flowing downhole pressures. A temperature drop corresponding to decreased pressure is expected for gas production from hydrates due to endothermic reactions associated with hydrate dissociation and Joule-Thompson cooling. As illustrated in Figure 41, the downhole pressure continued to drop below the predicted stability pressure for methane hydrate as monitored by the temperature at the perforations. While temperature decreased with lowering of the downhole pressure, the decrease was much smaller than predicted from the position of the hydrate stability line at the measured BHP. While the temperature at the perforations reached 33-34°F, the predicted hydrate dissociation temperature for both pure methane hydrate and a hydrate based on produced gas composition was far below the freezing point of water (Figure 62). This difference could be due to an incorrect prediction of the hydrate phase behavior. However, as the pressure-temperature behavior for methane hydrate is well known, an alternative explanation is likely. It is probable that the hydrate dissociation front has moved an appreciable distance from the wellbore. To sustain flow, the pressure at the front must be measurably higher than the wellbore and given the pressure-temperature dependency for dissociation, the front temperature must also be higher. The exact temperature at the front is difficult to estimate without using a fully coupled flow model that incorporates heat transport. Nonetheless, as shown in both Figure 45 and Figure 50, gas and water rates slowly increased over time, indicating that if ice formation occurred, it had no immediate detrimental impact on production.

Figure 62: Temperature at the perforations compared with the predicted hydrate stability temperature (based on the pressure reduction) for pure methane hydrate and a hydrate with the produced gas composition.



The pressure gradients between downhole gauges showed uniform behavior during Production Phase 4 (Figure 63). As discussed for the previous production phases, the higher gradient between the bottom and middle gauges could be due to gas-solids separation in the water column. The uniform nature of the middle-bottom gauge difference indicated that the sand content in the well probably remained constant during this time. Recall that surface-measured sand content in the produced water during this period approached zero. Hence, elevated gradients above the water reference probably reflect sand trapped in the rat hole below the screen. As Figure 63 shows, all Production Phase 4 gradients declined with time. This reflects the increase of gas rates while the water:gas (Figure 51) ratio was declining.

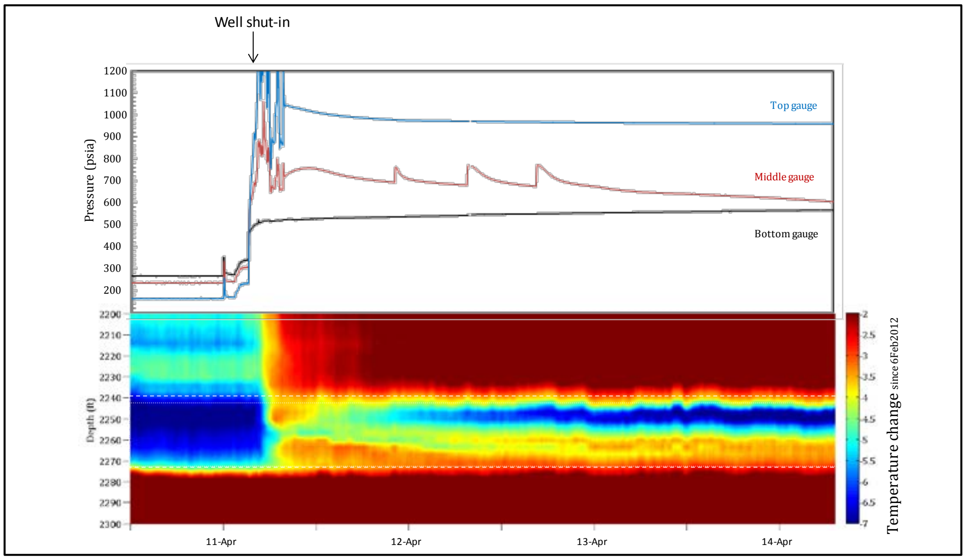
Figure 63: Pressure gradients between the three downhole gauges during Phase 3 of production. Gray dashed line indicates the expected gradient for a column of water.



Post-Production Period

Right after midnight April 5, 2012, the jet-pumping power fluid was replaced with glycol. The jet-pumping rate then was significantly reduced to stall-out the jet-pump. At that point, the well was shut in to conclude the field test. Almost immediately after shut-in, the temperature profiles showed warming in the perforated zone (Figure 64); likely because fluid flow ceased and no cool fluid was leaving the perforations to cool the wellbore. The temperature profile in the perforated zone behaved in a manner that provides information about the heterogeneity of the reservoir and flow paths during injection and production. After a period of immediate warming following shut-in, the middle of the perforated interval showed cooling; this gradually moved to the upper portion of the perforated interval. By April 12, the top of the interval had cooled significantly while the lower portion of the interval remained relatively warmer (although still cool compared to the initial reference temperature). Notably, the vertical location of the cooling event is coincident with cooling in the zone of persistence of post-injection warming (Figure 32). In conjunction, this may provide evidence for vertically localized hydrate formation upon injection and dissociation upon production. While this temperature segregation may reflect the effects imposed by reservoir and hydrate saturation heterogeneity, it also may reflect the effects of gravity segregation or the tendency for injection gas to override water.

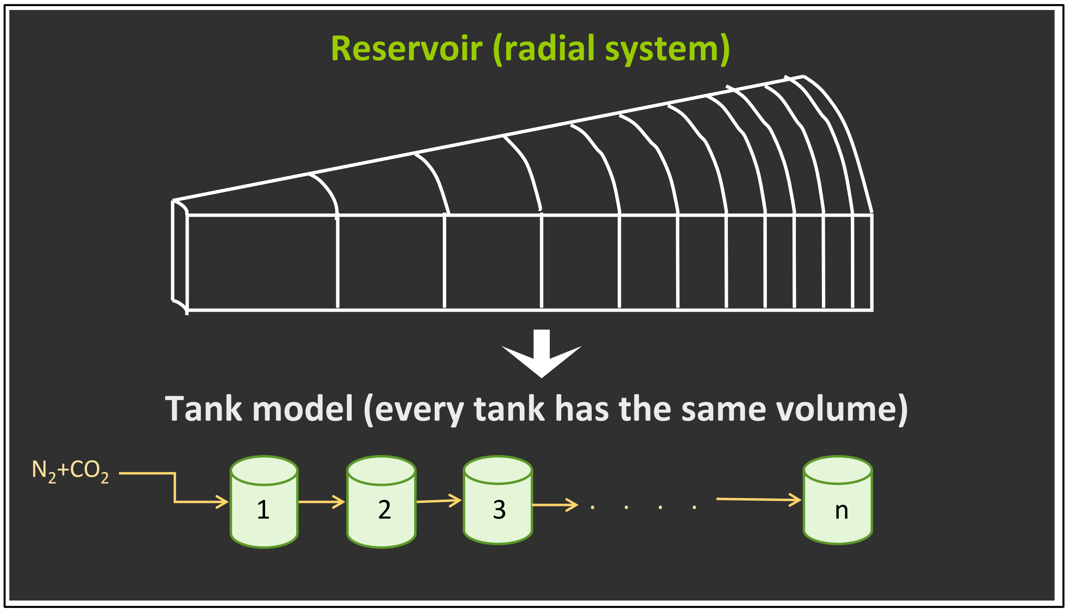
Figure 64: Thermal effects along with downhole pressures after shut-in following production. The thick horizontal dashed lines indicate the targeted formation depth and the small dashed lines indicate the perforated zone.



Comparison with Model Predictions

At this moment, currently available hydrate flow simulators cannot model either N_2/CO_2 mixture injection into a methane hydrate-bearing reservoir or the subsequent production from said reservoir. For this reason, the internally developed cell-to-cell model (or tank model) helped guide planning for the field trial. Details of this model were given earlier and in a previous report (DOE Award No.: DE-NT0006553, Progress Report Second Half 2011). While this model is limited in its ability to capture the physics and chemistry that occurred in the formation during the field trial, a history-match between the field data and this model could provide insights into where the assumption of a well-mixed instantaneous equilibrium system succeeds and where it fails. The adiabatic cell-to-cell model was used in the history-matching attempt. It was assumed that the reservoir was homogenous and was represented by a series of cells as shown in Figure 65.

Figure 65: Cell-to-cell model configuration used to history-match the field trial.



The following example details the model protocol and results. The model was initialized with a homogeneous hydrate saturation of 65% and a water saturation of 35% in the formation. The initialized hydrate saturation is approximately the midpoint of the range determined from multiple log analysis methods. Reservoir pressure and temperature were set at 1000 psi and 40.5°F, respectively. The volume of the first tank was equivalent to the volume of the first 3.5 ft around the well assuming a 30-ft reservoir height. Note that the volume of every cell is the same except for the last cell, which is 100 times that of the basic cell volume. The number of cells in the model is 25. At the end of injection, the injected gas had only reached cell 8.

The model simulated injection of 230 Mscf of mixed gas (23 mol% CO_2 and 77 mol% N_2) followed by stepwise depressurization. The model injection pressure was fixed at the average injection pressure for the field trial, 1420 psia. The production BHP history was approximated with a series of stepwise values. As the cell-to-cell model is a volume-based model, all the simulation results are referenced to volume injected or produced. Therefore, BHP control was predicated on injected or produced volumes, which ensured at a minimum an exact volume balance agreement between the model and the actual data. All of the comparison plots with the field trial will be based on cumulative volumes instead of time. Composition is expressed on a molar basis. The first cell in the model provides the closest prediction of near-wellbore conditions. Measured sandface temperatures will be compared to cell one.

Figure 66 and Figure 67 show the predicted mole fraction of methane, nitrogen, and carbon dioxide in the hydrate phase and the vapor phase in the first cell during the injection of 230 Mscf of the CO_2 mixture. The simulated mole fraction of methane in the hydrate immediately began to decrease as nitrogen and carbon dioxide entered the hydrate phase. However, a vapor phase was not predicted during the initial stage of injection (Figure 68). Instead, the thermodynamic flash initially predicted a two-phase aqueous (liquid water) + hydrate (Lw-H) phase region equilibrium based on the total moles of all of the species in the tank. After approximately 12 Mscf of injection, the model predicted that the cell entered a three-phase aqueous + Hydrate + free gas (Lw-H-V) region equilibrium, which persists through injection (Figure 68). The model predicted a relatively rapid initial increase in hydrate saturation at the start of injection followed by a gradual decrease. Vapor saturations continually increased over the course of injection (Figure 68).

From the compositional behavior of hydrate in the first cell (Figure 66), nitrogen uptake is rapid, more than 30% at roughly half the total injection volume. With further injection, however, predicted nitrogen in the hydrate appears to approach an asymptote. Carbon dioxide uptake is steady throughout the injection period and finally surpasses nitrogen at around 150 Mscf of injection. In the later stage of the injection, the slope of the increase in carbon dioxide in the hydrate is similar in magnitude to the decrease of methane. If injection continued, the methane eventually would be removed from the hydrate phase in cell one with only nitrogen and carbon dioxide remaining in a molar ratio of ~35% N_2 to 65% CO_2. As expected, the CO_2 is preferred over N_2 and it is concentrated in the hydrate phase relative to the injected gas phase composition (77% N_2 and 23% CO_2). Note, however, that while carbon dioxide is preferred in the hydrate phase, the model still predicted a relatively high concentration of N_2 participating in the hydrate.

Figure 66: Predicted mole fraction of methane, nitrogen, and carbon dioxide in the hydrate phase during injection using the cell-to-cell model (first tank). This is on a water-free basis.

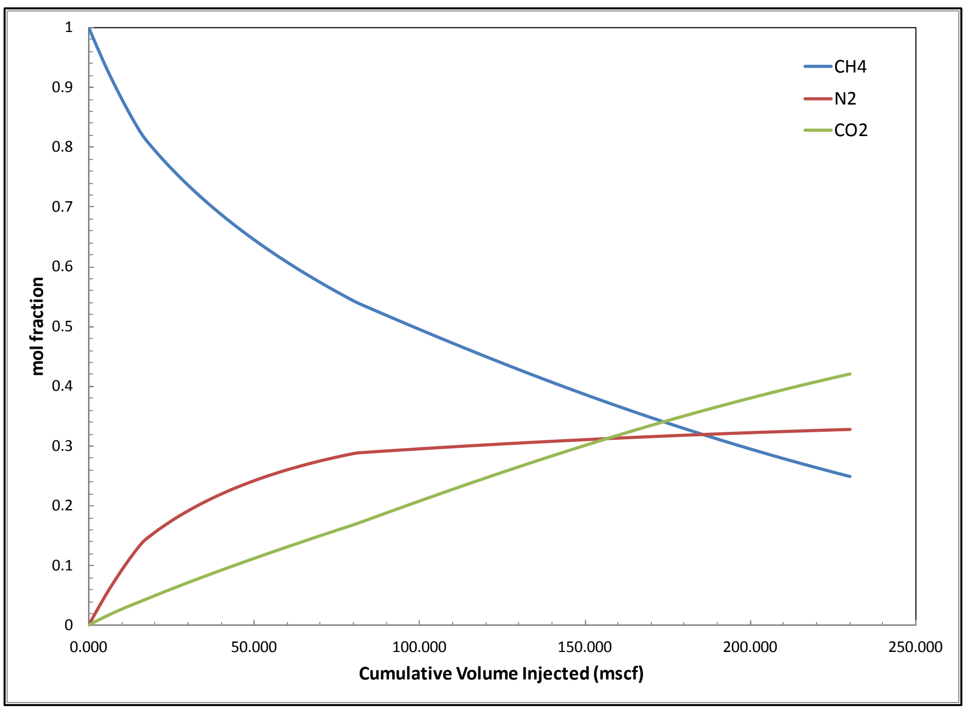


Figure 67: Predicted mole fraction of methane, nitrogen, and carbon dioxide in the vapor phase during injection using the cell-to-cell model (first tank). This is on a water-free basis.

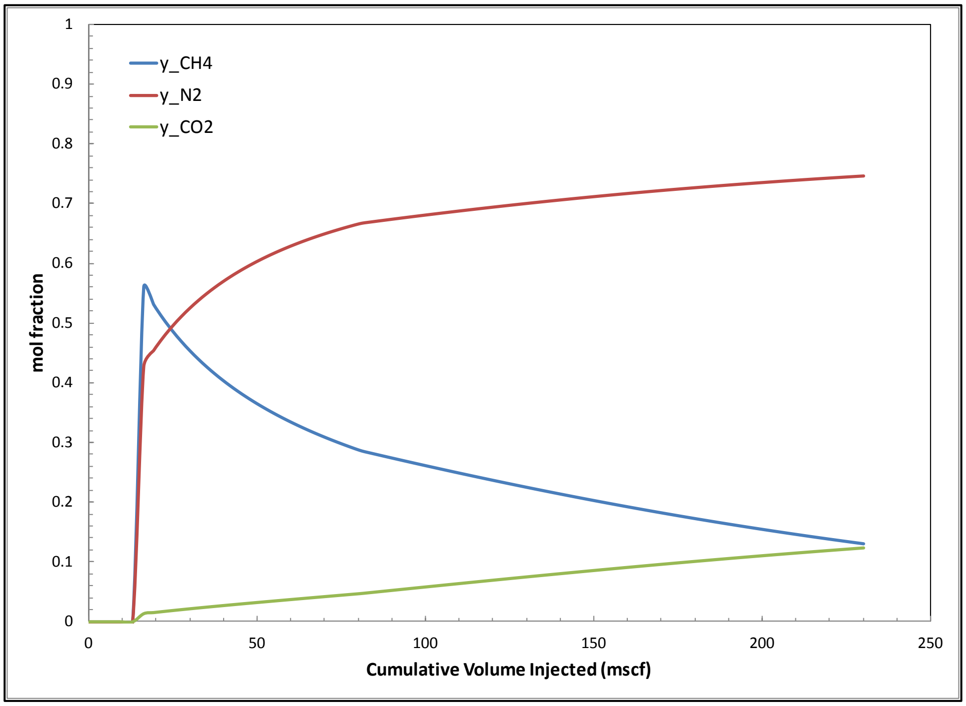
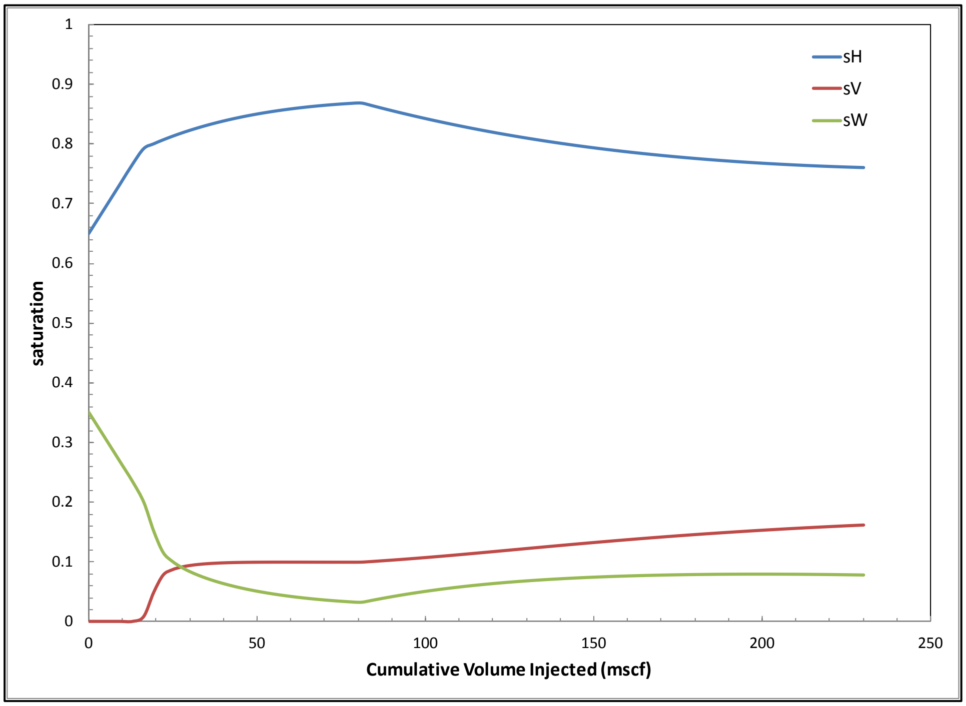


Figure 68: Phase saturation predicted by the cell-to-cell model in the first tank during injection.



The injection phase is followed by the production phase, which replicates the BHP versus cumulative volume withdrawal. Figure 69 compares BHP during the production period with the BHP used in the simulation. Using the BHP history in the production simulation and adjusting the formation's specific heat, Figure 70 shows the measured bottomhole temperature versus the best match obtained in the first tank temperature from the cell-to-cell model. Even with artificially high specific heat for the formation, the model could not obtain a good fit to the test data. In addition, after about 250 Mscf of production, all of the hydrate was dissociated from the first tank, and correspondingly, the predicted temperature became almost constant. This is far different from the field observation.

One possible explanation for this difference is that conductive heat transfer between the formation and its surroundings during the actual test helped reduce the degree of the temperature drop during the flowback. This confirms the need for a simulator with fully coupled mass flow and heat transfer.

Figure 69: BHP as a function of cumulative gas production from the field and BHP used in the model.

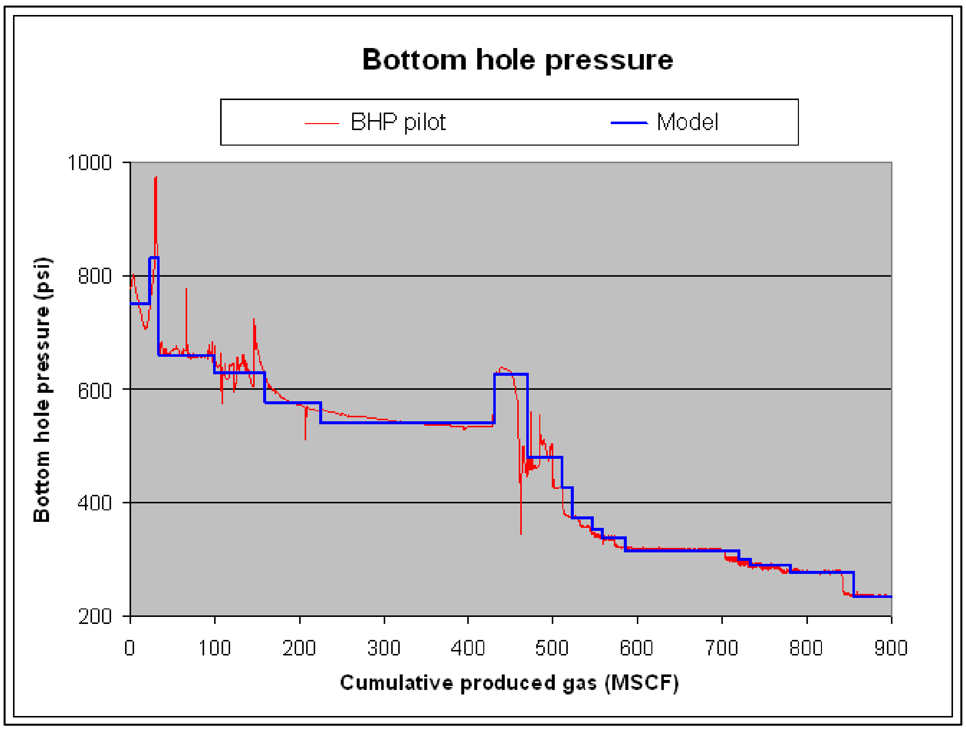
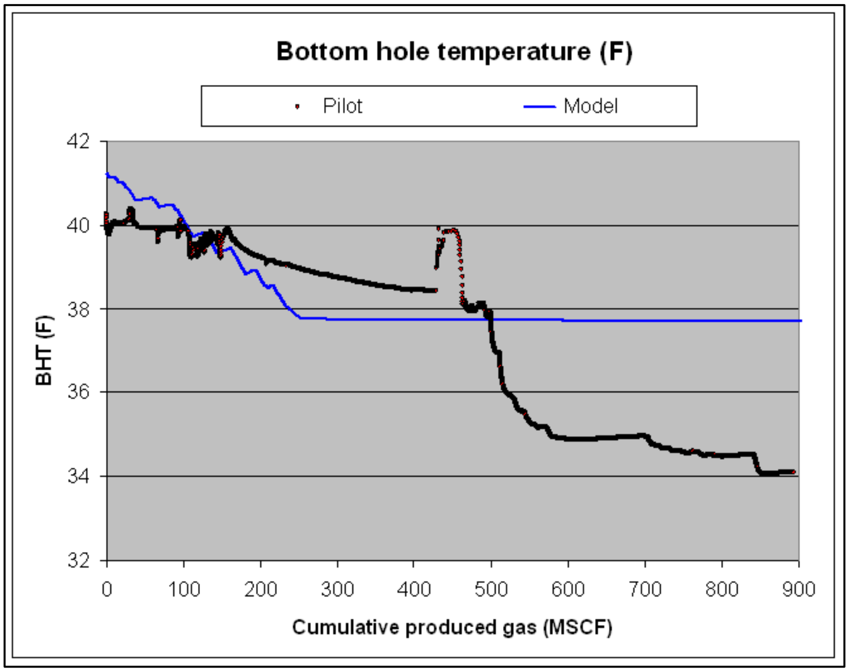


Figure 70: Measured versus predicted bottomhole temperature of the first tank during production.



As shown in Figure 71 and Figure 72, the model also could not reproduce the produced gas composition observed in the field. Namely, the model fails to replicate the early and rapid increase in methane concentration as well as its long-term trend. In addition, the model over-predicts the nitrogen concentration with cumulative production and under-predicts the initial carbon dioxide concentration. Cumulative water production is under-predicted as well (Figure 73). Given the large proportion of non-associated hydrate water produced (40%); it is likely that free water was displaced ineffectively from the near-well region, possibly as a consequence of gravity override during gas injection. Additional simulations wherein initial hydrate saturation was varied from 50-85% did not alter these conclusions. Likewise, varying the assumed model cell volume from an effective radius of 1 foot to 14 feet did not improve the match.

Figure 71: Methane composition of the produced gas during the pilot and predicted from the cell-to-cell model

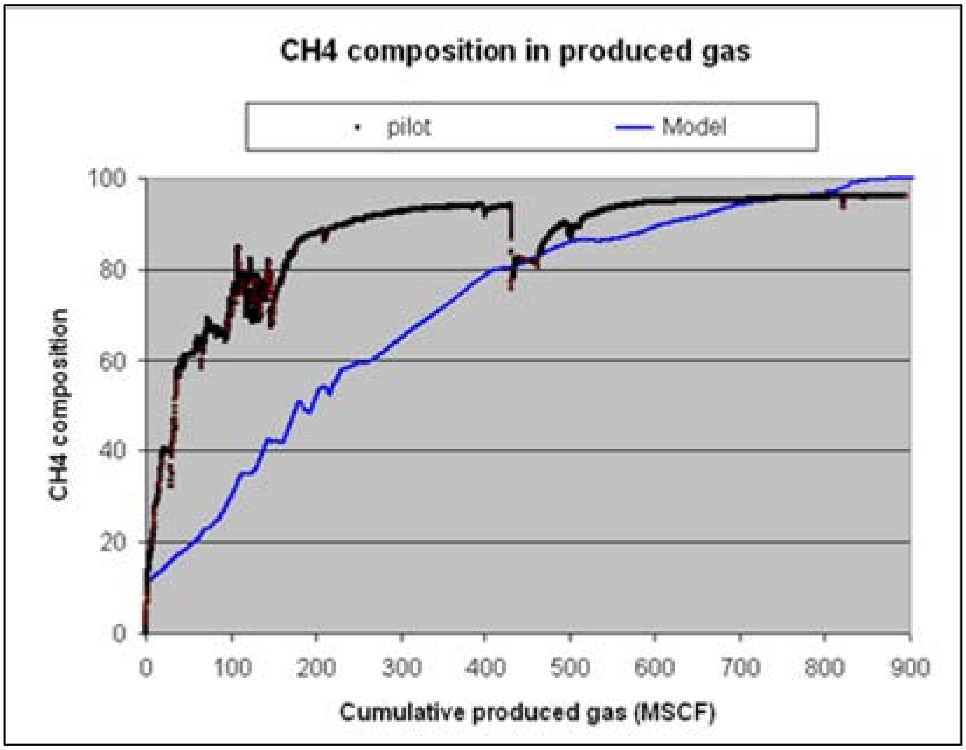


Figure 72: Nitrogen and carbon dioxide composition of the produced gas during the pilot and predicted from the cell-to-cell model.

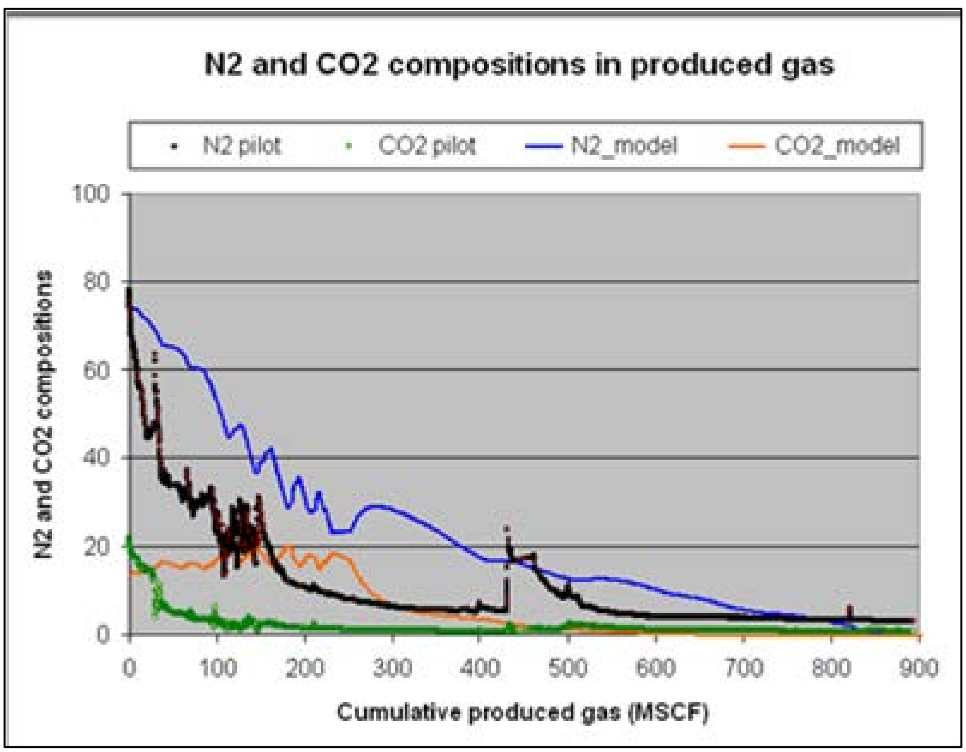
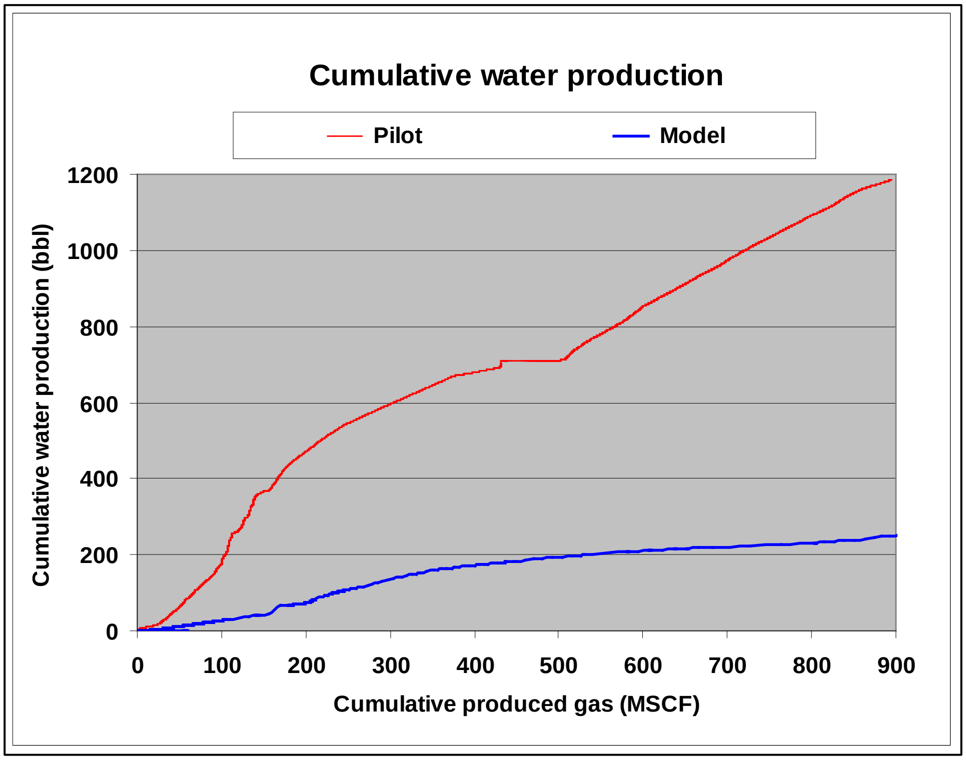


Figure 73: Plot of cumulative water produced and predicted from the cell-to-cell model.



The inability of the cell-to-cell model to match most aspects of the production data indicates that the major assumptions of the model may be incorrect. These assumptions include:

- The system is adiabatic and heat transfer to and from confining strata is unimportant.
- The system reaches local instantaneous equilibrium. Mixing among all constituents within the defined volume is complete and exchange kinetics are rapid and therefore do not control the observed dynamic behavior.
- The reservoir is homogeneous and uniform throughout.
- Gravity can be ignored.
- Transport of mass is limited to only liquid and gas. Solids cannot flow.

The assumption of an adiabatic system is invalid given the ample evidence for heat transfer above and below the reservoir interval as indicated from the DTS field data. With respect to equilibrium, it has been shown that local equilibrium is a poor assumption for bench-scale experiments involving "solid-state" hydrate exchange. This observation may be equally applicable to an injection or flowback field experiment in which fluid residence times are arguably closer to the bench scale than those for an actual field displacement process on a commercial scale. Nonetheless, a full accounting of heat transfer and kinetic effects must await future modeling efforts.

As regards the remaining bullet points, limited testing of the validity of these assumptions can be undertaken with the cell-to-cell model. Specifically, the potential for flow heterogeneity and solid hydrate production to improve the field history match can be explored through a series of model recombinations. The remainder of this section describes these efforts.

Model Recombinations

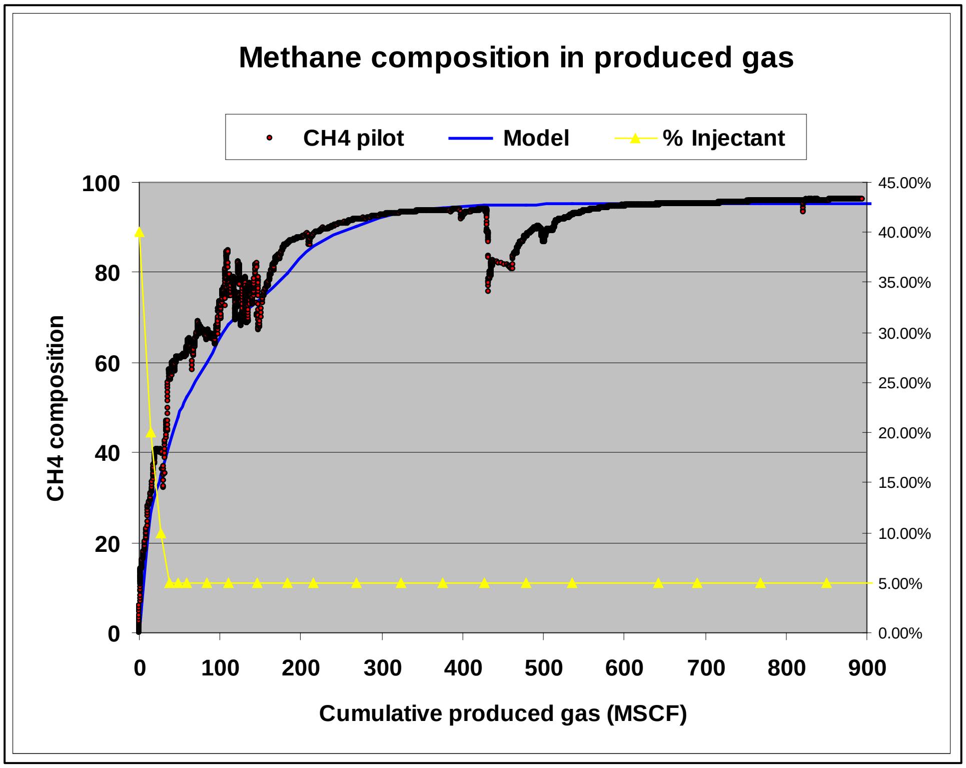
The process of model recombination was quite simple. Produced streams from two model simulations were recombined in a stepwise manner that replicated the field methane composition history while honoring the total produced gas volume. The quality of the history match was then assessed by its ability to reproduce both the nitrogen and carbon dioxide composition versus cumulative gas production. Three recombination cases were specifically addressed: Case One considers partial injection/production out-of-zone; Case Two regards injection into and production from zones of differing initial hydrate saturation; and Case Three speculates on the potential for the coproduction of solid methane hydrate. In the cases of solid hydrate and out-of-zone production, pure methane hydrate or injectant gas were recombined with a single model production stream, again explicitly matching the gas phase methane composition while honoring the imposed total gas production constraint. In attempting to model heterogeneous production, the act of recombining produced streams assumes that hydrate exchange occurs independently in each interval and therefore can be represented by separate models. The composition-volume response of each interval is a function of the initial hydrate saturation, the volume of injectant, and the volume of produced gas. Given that injection and production pressures are fixed, the latter are controlled implicitly by permeability-height. Permeability is not considered here, hence the reliance on mathematical mixing.

Three cases for heterogeneous mixing will be illustrated.

Case 1: Partial Injection Out of Zone

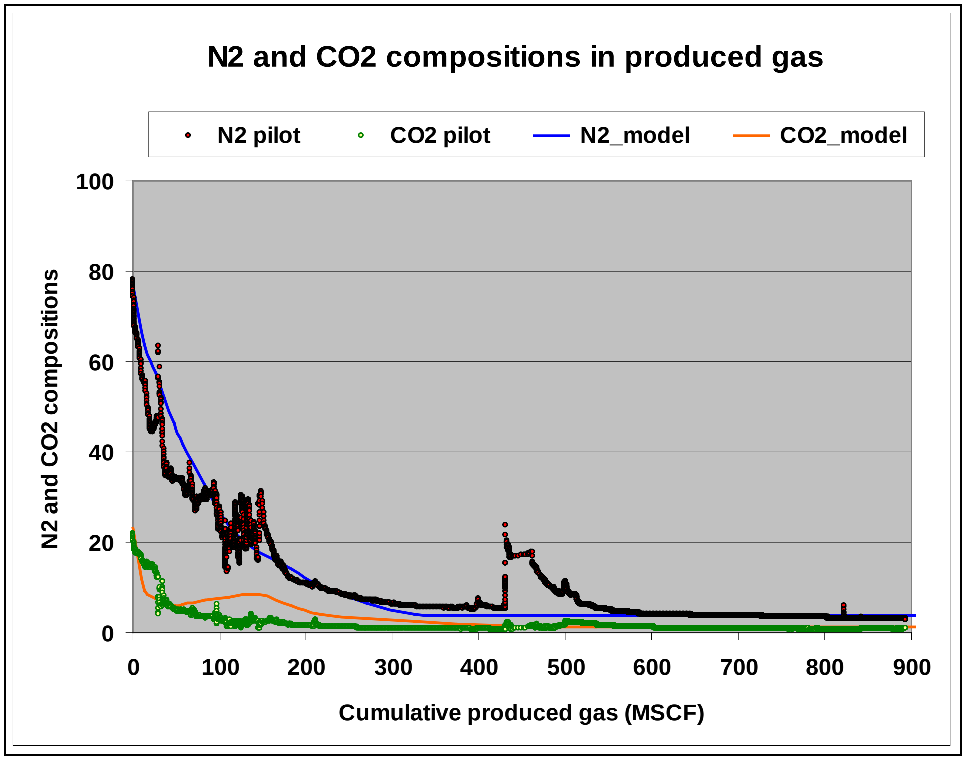
A model with initial hydrate saturation of 75% is recombined with the 23% CO_2 injectant. This would simulate the possibility that only a portion of the injected gas was delivered to the hydrate-bearing interval while the remaining portion was injected out of zone and did not react within the thief zone to form additional hydrate. Notably, the cell-to-cell model predicts that only about 60 Mscf of the injectant can be placed into the 75% hydrate saturation interval before injection ceases due to *in situ* hydrate saturations approaching 100% in the first cell. Consequently, the hydrate composition in the first cell is comparatively enriched with nitrogen at the point that injection into hydrate terminates as discussed earlier. Upon depressurization, this hydrate becomes unstable immediately and is available to mix with the gas stream injected out of zone. Figure 74 shows the produced methane composition match and the percentage of injectant required to achieve the produced methane match.

Figure 74: Plot showing produced methane composition match and the percentage of injectant required to achieve the match in Case 1.



Except for the early production period, the recombination indicates that the majority of produced gas originated from the hydrate interval. Figure 75 compares the predicted nitrogen and carbon dioxide composition in the produced gas to the actual field data. The recombined prediction of produced gas compositions shows the correct trends and is dramatically improved with respect to the previously described model (Figure 72).

Figure 75: Comparison of the predicted nitrogen and carbon dioxide composition in the produced gas to the actual field data for Case 1.



Case 2: Heterogeneous Mixing

Case 2, which illustrates heterogeneous mixing, recombines produced streams from a 30-ft cell model with an initial hydrate saturation of 75%, and a 5-ft cell model with an initial hydrate saturation of 50%. Injection was restricted to 60 Mscf in the higher hydrate saturation model for reasons already stated in Case 1. The remainder of the total volume of injectant (160 Mscf) was placed in the 5-ft low-saturation model. This recombined case represents a realistic scenario for the field wherein the majority of the C sandstone, except for the extreme upper portion, has a uniform, log-indicated hydrate saturation of 75% (by AIM analysis). The upper interval saturation is significantly less. Figure 76 shows the recombined methane composition history match and the percent volume contribution from the low-saturation model. The percent contribution generally increases with total produced gas volume but is noticeably erratic over the simulated production interval. The case for heterogeneous production is appealing from several aspects. The first concerns tracer production. It was observed in that the first tracer injected, SF_6, was produced coincidentally with R114 (Figure 108). While acknowledging some partitioning of tracer to the hydrate phase, this outcome suggests that SF_6 was trapped near the well, potentially in intervals of high initial hydrate saturation that received limited injection due to early and rapid build-up of mixed hydrate. In effect, these zones could receive injectant and tracer until the effective permeability to gas, as a function of hydrate saturation, approached zero. The equilibrium cell-to-cell model suggests that as much as one half the SF_6 would be sequestered in the near-well area if the initial hydrate saturation was about 75%. Furthermore, the same model predicts that depressurization would readily destabilize the in-place mixed hydrate, resulting in a rapid desaturation of hydrate, presumably promoting much-improved permeability and early production of SF_6 coincident with a nitrogen-enriched gas phase. As Figure 48, Figure 49, and Figure 78 indicate, these predictions agree with observed produced gas trends from the field test. Field temperature data also supports heterogeneous injection and production in that during both operations, non-uniform temperature profiles were observed both within and without the perforated reservoir interval as shown in Figure 40 and Figure 64. However, cursory circumstantial evidence does not fully validate this interpretation; a more rigorous simulation approach is required. Figure 77 depicts the predicted compositions for nitrogen and carbon dioxide. Again, the trend of the prediction for each is in keeping with actual production.

Figure 76: Methane match for Case 2.

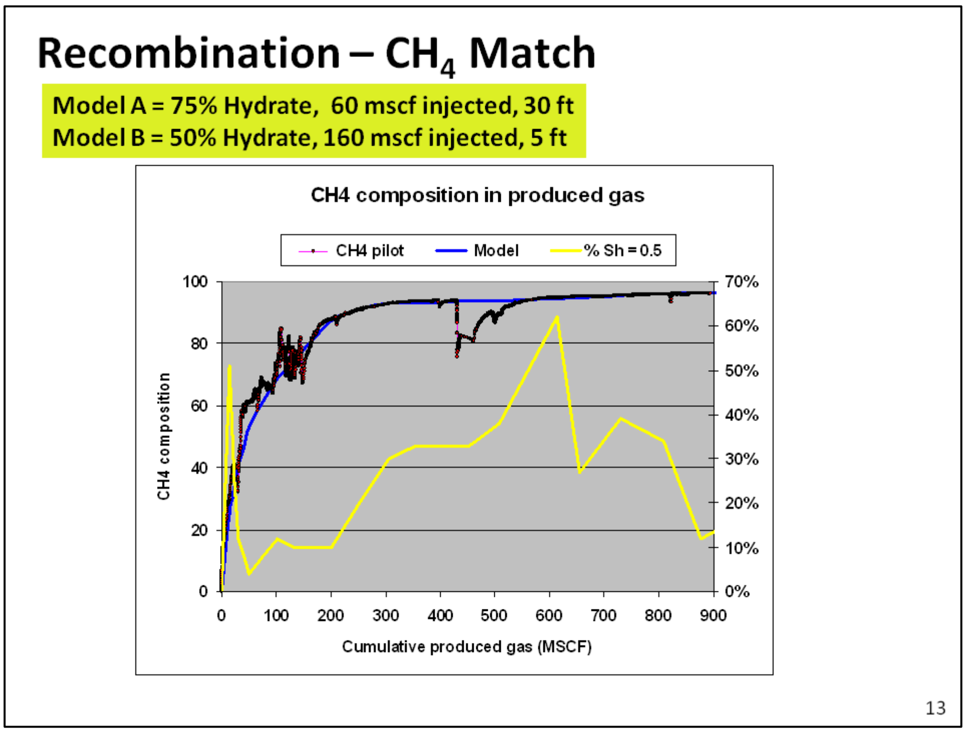
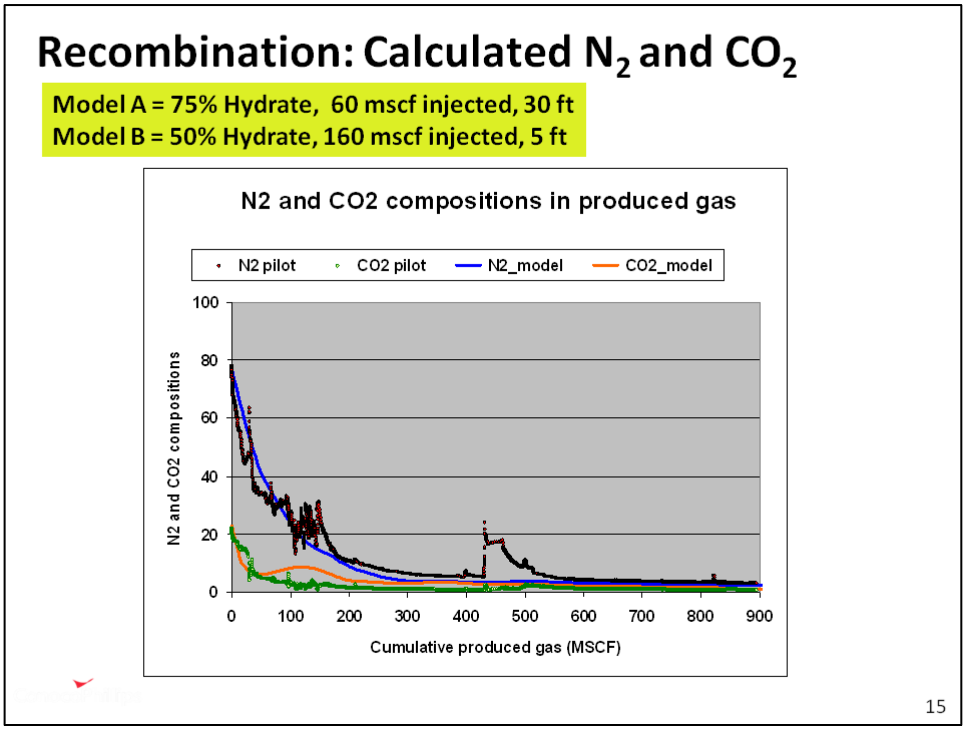


Figure 77: Calculated N_2 and CO_2 for Case 2.



Case 3: Solid Hydrate Production

The final recombination exercise addresses the potential for producing solid methane hydrate based on the observation that solids were produced readily throughout much of the production phase of the test. The production of solid hydrate could promote early methane production as well as additional water production, which the prior cases approximate poorly (Figure 73). As before, the recombination process matched the produced gas methane composition by mixing the cell-to-cell model output for a 5-ft model with initial hydrate saturation of 50% into which 220 Mscf of 23% CO_2-nitrogen was injected, with pure methane hydrate that has a water-to-gas molar ratio of six. Figure 78 represents the percentage of pure hydrate mixed to achieve the shown methane composition history match while maintaining the produced gas volumetric balance. Figure 79 details the actual composition trends for N_2 and CO_2 versus the recombined model predicted trends.

Figure 78: Plot showing the percentage of pure hydrate mixed to achieve the shown methane composition history match shown in Figure 79.

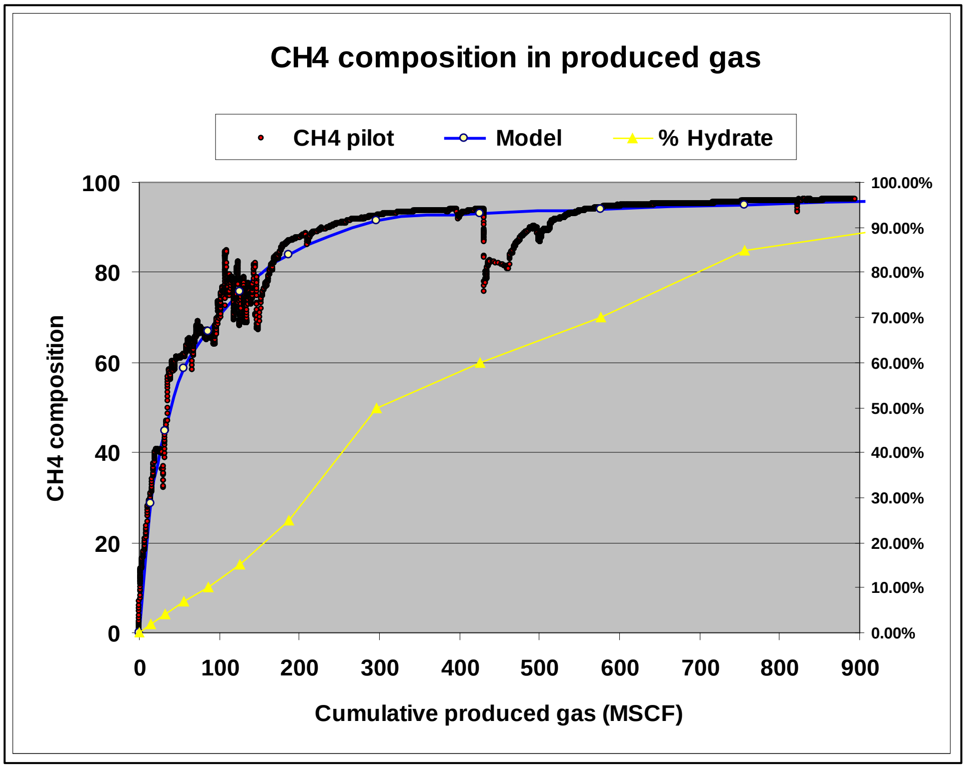
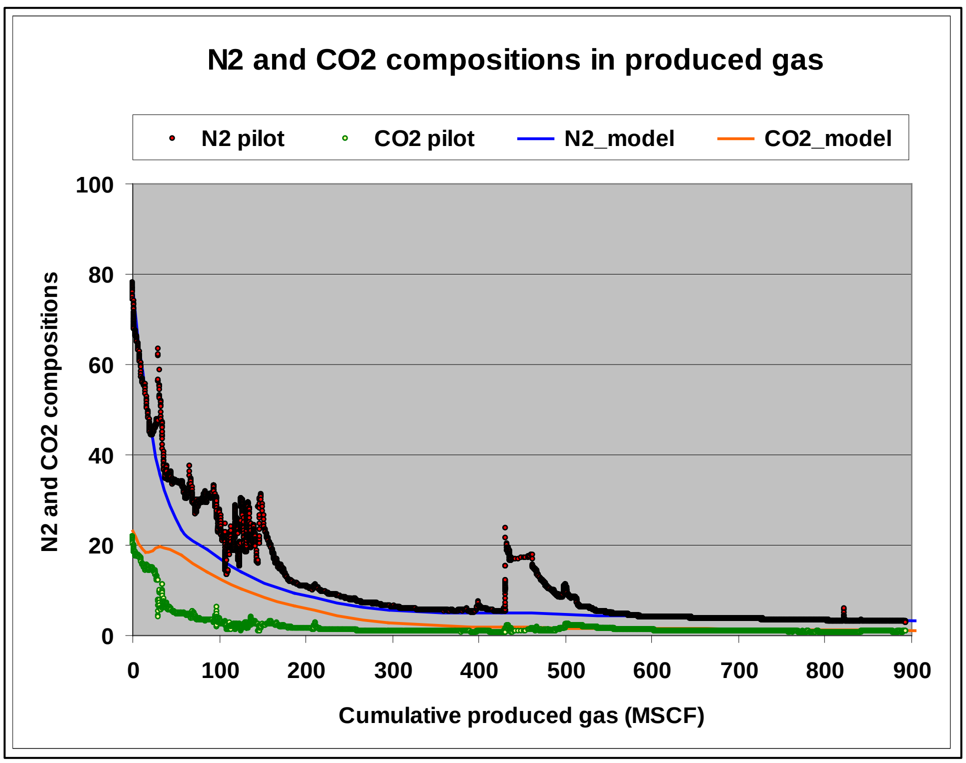


Figure 79: Plot showing details the actual composition trends for N_2 and CO_2 versus the recombined model predicted trends for Case 3.



As indicated, the amount of solid methane hydrate in the recombined produced gas stream increases almost linearly with cumulative produced gas volume in order to replicate the observed methane composition. The recombined model predicts that at the end of the field trial, nearly 90% of the produced methane is derived from solid methane hydrate. Predictions of nitrogen and carbon dioxide are somewhat in keeping with observed trends but of lower quality than those reported earlier for the heterogeneous recombination cases. Although not shown, the prediction of produced water is marginally improved. Solid methane hydrate recombination with models of variable initial hydrate saturation and reservoir thickness (0-85% hydrate saturation) did not improve upon the quality of the gas composition match.

Post Test Operations

Final abandonment of Iġnik Sikumi #1 wellsite was completed May 5, 2012. Tubing, casing-tubing annulus, and FlatPak tubes were filled with cement following the abandonment procedure approved by the Alaska Oil and Gas Conservation Commission. To minimize effects on the landscape and leave as little trace of the operations as possible, a small area around the wellhead was excavated to expose well casing to six feet below tundra surface. Casing and tubing were cutoff three feet below ground level. Cement fill-up was verified, and a cap was welded on top. The excavation was refilled and graded appropriately to ensure return to original grade following spring melt back of the ice pad. The top surface of the ice pad was scraped, with residue hauled-off for disposal. Barriers to the pad entrance were erected and periodic monitoring continued during spring melt. Inspection was conducted with AOGCC representatives August 21, 2012, followed by hand-grooming of the P&A "mound" to mitigate slight (1ft wide by 3ft long) ponding. Crowned areas were shoveled into the center of the ponded area to encourage drainage, and the entire area of the ice pad was re-inspected for trash and debris. Helicopter inspection with North Slope Borough officials was conducted September 3, 2012. The final inspection was conducted by Alaska Department of Natural Resources September 5, 2012, by helicopter to minimize surface disturbance. This inspection concluded that the ice pad had "no impact on the tundra, even in the areas of variable terrain.'

Conclusions

The stated conclusions are preliminary in nature. They represent a current understanding based on limited analysis with rudimentary tools. More definitive conclusions are expected as knowledge of mixed hydrate systems mature.

- A 23mol% CO_2 – N_2 mixture was successfully injected into a hydrate bearing zone in which free water was present. Although the possibility for injection out of zone cannot be eliminated, it is clear that a sizeable portion of the injectant interacted with the intended target.
- Evidence for solid state CO_2 – methane hydrate exchange exists.
- Methane was produced above the methane hydrate stability pressure and temperature. This methane was produced coincident with CO_2 and N_2, whose molar ratios were different from the injected gas. The relative abundance of each gaseous component was consistent with the dissociation of a three species mixed hydrate

whose stability requirements for pressure and temperature were not met at the producing bottomhole conditions.

- Injectivity declined over time. This is consistent with simple model predictions, which indicate that total hydrate saturation generally increases with injection of this mixture at the observed in-situ conditions. It is expected that any significant dissociation of bulk hydrate would have been noted as improved injectivity.
- The formation temperature increased during injection consistent with exchange or new hydrate formation.
- A simple adiabatic homogeneous instantaneous equilibrium model cannot predict the observed production behavior.
- The observed differences between the actual data and the model may be attributable to the following: the process is kinetically dominated; heat transfer is inadequately modeled; or reservoir heterogeneity controls the observed response. Although other mechanisms may be operative, these are believed to be the most important.
- Bottomhole pressures below 400 psia are achievable during active hydrate dissociation, even though models indicate that this sandface pressure would cause icing. No evidence for icing via measured temperature or impaired productivity was observed. This likely suggests that the pressure increase between the well and the dissociation front to sustain flow is sufficiently large to avoid icing conditions at the observed sandface pressure.
- As large as eight-fold variations in productivity index were observed during production. Understanding the root cause for these changes may be crucial in maintaining commercially viable rates from hydrate production wells.
- Sufficient evidence for heterogeneous injection and production exists within the distributed temperature sensing record.
- The temperature record, furthermore, supports hydrate formation and dissociation given that the observed sandface temperature changes were in accord with those expected at the existent bottomhole pressure and in-situ composition conditions.
- Wellbore conditions must be effectively managed for efficient production of hydrates. Wellbore conditions to be managed include solids control, temperature control, pressure control and wellbore fluid levels. Operational difficulties during production were usually associated with shut-in events wherein well pressures rose and hydrates formed within the well. Many of these events were precipitated by solids production; effective application of downhole heating and water level management may have mitigated these.

Graphical List of Materials

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List of Acronyms and Abbreviations

Acronym or Abbreviation	Acronym, Abbreviation, or Term Explained
µm	Micron
µsec	microsecond
3-D	Three-dimensional
AIM	Advanced Interpretation Model
AOGCC	Alaska Oil and Gas Conservation Commission
API	American Petroleum Institute
bbl	Barrel
Bbl/D	Barrels per day
BHP	Bottomhole pressure
BHT	Bottomhole temperature
BWPD	Barrels of water per day
CH_4	Methane
CMR	Combinable Magnetic Resistance
CO_2	Carbon Dioxide
CSV	Comma Separated Value (file format)
CV	Cell volume
DOE	Department of Energy
DPHI	Density porosity
DT	Delta T (Time)
dT	Transit time
DTCO	Compressional wave transit time (well log measured in µsec/ft)
DTS	Distributed temperature sensing
Ft.	Feet
GC	Gas chromatograph
gpm	Gallons per minute
GR	Gamma ray
He	Helium
Hi-Res	High-resolution
in.	Inch
JOGMEC	Japan Oil, Gas and Metals National Corporation
Lbs.	Pounds
LWD	Logging-while-drilling
Lw-H	Water and hydrate
Lw-H-V	Water, hydrate and gas
MCF/D	1000 cubic feet per day
mD	millidarcy
MDT™	Modular Dynamic Tester™
mol%	Molecular percentage
MRI	Magnetic Resonance Imaging
Mscf	Million standard cubic feet
N_2	Nitrogen gas
NaCl	Sodium Chloride
Ne	Neon
NETL	National Energy Technology Laboratory
NMR	Nuclear Magnetic Resonance
P&A	Plug & Abandon

Acronym or Abbreviation	Acronym, Abbreviation, or Term Explained
P&IDs	Piping & Instrumentation Diagrams
Pbd	Breakdown Pressure
PEX™	Platform Express™
PGHS	Methane hydrate stability pressure
PI	Productivity Index
ppg	Pounds per gallon
ppm	Parts per million
Pres	Reservoir Pressure
psi	Pounds per square inch
psia	Pounds per square inch absolute
PV	Pressure x Velocity
RHOB	Bulk Density (log file measured in g/cm^3)
RHOZ	HRDD Standard Resolution Formation Density (log file)
RKB	Rotary Kelly Bushing
Rt	Observed bulk Resistivity
Rt	Resistivity
Rw	Water Resistivity
scf	Standard cubic foot
SF_6	Sulfur hexafluoride
S_h	Hydrate saturation
sI	Structure I (structure I hydrate formation)
sII	Structure II (structure II hydrate formation)
SLB	Schlumberger
SPE	Society of Petroleum Engineers
SSTVD	Subsurface True Vertical Depth
TCMR	Total CMR Porosity
TD	Total Depth
Tres	Reservoir Temperature
USGS	United States Geological Survey
Vol%	Volume percentage
Vp	P-wave velocity
Vs	S-wave velocity
X-over	Crossover
XPT™	Pressure Express™

Appendix A Experimental Basis for CO2 Exchange

A series of laboratory experiments between 2003 and 2009 demonstrated the viability of exchanging CO_2 with CH_4 in hydrate structure as a potential production strategy for natural gas hydrate reservoirs (Stevens et al., 2008; Graue et al., 2006). This work was used as the basis to design a field test that evaluated the exchange mechanism at a larger scale.

The early experiments were designed around a simplified scenario of hydrates forming in a gas-rich, partial water saturation environment in a consolidated rock pore system. This low initial water saturation condition contrasted with higher water saturations that are believed to be present in many hydrate-bearing settings. The advantages of these initial conditions were that hydrate formation was faster in a gas-rich system, with nearly complete conversion of all the available water into hydrate. Permeability to gas was also optimized in this system because of the connected gas phase in the pore system.

The early planning stages of the field trial identified several themes that needed further investigation. A new series of laboratory tests were run to generate critical information for the field-trial design. The major concerns were:

1. what happens in a hydrate-bearing system with excess water,
2. how is CO_2 delivered to the proper reservoir interval, and
3. what is the impact of a fine-grain, unconsolidated sediment on the effectiveness of the exchange process?

The first concern was that hydrate-bearing sands in the Arctic regions have high hydrate saturations along with water in the pores. Wireline log interpretation at Milne Point and Mallik used a combination of conventional resistivity and porosity measurements along with the nuclear magnetic resonance (NMR) logging tool to estimate fluid and hydrate saturations in the reservoir intervals. These interpretations also indicated the presence of “free” water in the hydrate-bearing sands (Collett and Lee, 2011). Free water, whether a near-wellbore effect or a reservoir characteristic, would be available to interact with injected $CO_{2,}$ and form new hydrate and thus reduce injectivity.

The second concern was how to deliver a pure, liquid CO_2 stream to the face of the reservoir layer 2000 ft. below the surface. The liquid CO_2 column weight at that depth would exceed the parting pressure of the hydrate-cemented sediments. A potential solution was to transform the CO_2 into a mixed gas phase by adding nitrogen. The impact of mixed-gas on exchange was investigated experimentally.

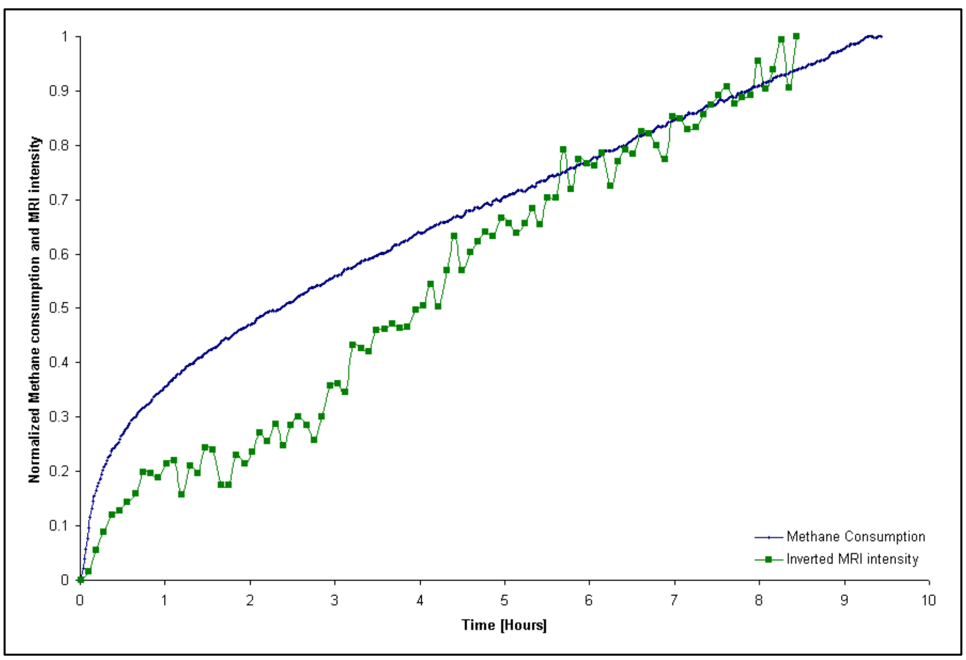
The third major concern was whether the hydrate cements, which control the strength of the reservoir, would be affected by exchange and whether formation integrity would be maintained.

Excess Water Saturation

These experiments were designed to evaluate the impact of free water in the hydrate pore system and to quantify permeability reduction from hydrate formation as a result of injecting CO_2 into a water-filled pore system.

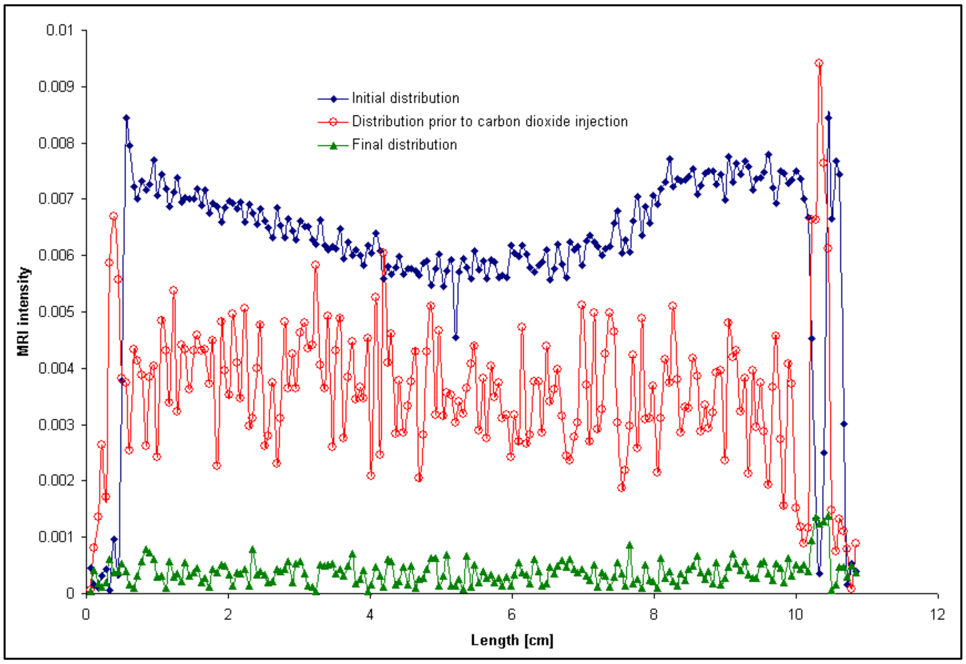
In this experiment, a Bentheim sandstone core plug was partially saturated with 0.1N NaCl by imbibition to a final water saturation of approximately 50%. The imbibition process generally led to a uniform distribution of water along the core length as monitored by magnetic resonance imaging (MRI) techniques. 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 (Figure 80). In this experiment, the methane volume was constrained so that roughly half of the available water was converted into hydrate and free water remained in the pore system. Water and hydrate saturations were each approximately 25% and the remaining pore volume was gas. The comparison of methane consumption with the loss of MRI intensity as hydrate forms showed a general agreement (Figure 80). A series of rapid permeability measurements were made using small volumes of nitrogen. Permeabilities of 2 to 3 mD were determined on this sample in the presence of excess water.

Figure 80: Methane consumption as measured in volume of gas during the formation of hydrate (blue) compared to the loss of MRI signal intensity during hydrate formation (green)



Liquid carbon dioxide was then injected into the hydrate-bearing core with excess water. As expected, the carbon dioxide converted all of the available free water into a hydrate as monitored by the MRI (Figure 81). The saturation profile along the core length showed the somewhat uneven distribution of the initial water saturation (blue) and then the water saturation after methane hydrate formation and partial dissociation with the large volumes of injected nitrogen (red). The noise in this intermediate curve results from greatly reduced scan time. The final profile following the introduction of carbon dioxide showed the conversion of the remaining free water into hydrate (green). Permeability measured on the core after carbon dioxide injection and returned values of 0.045 mD, almost two orders of magnitude smaller than the pre-CO_2 injection measurement.

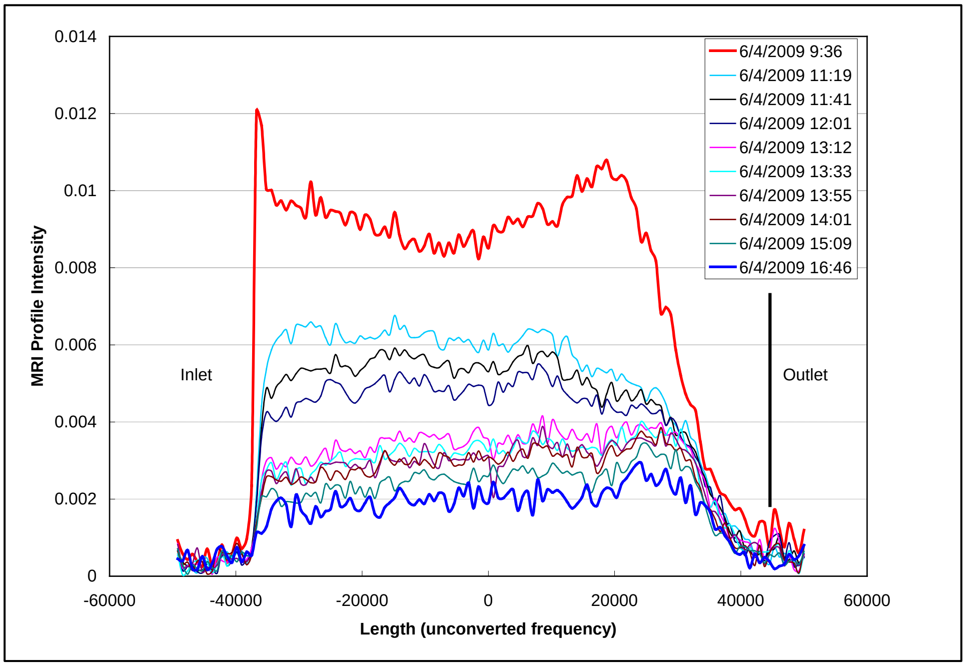
Figure 81: MRI-generated profiles of water saturation along the core length at initial state (blue), following methane hydrate formation and before carbon dioxide injection (red) and following the formation of carbon dioxide hydrate (green).



This test was repeated with a higher starting water saturation of 70%. The initial water saturation was uniformly distributed along the core length as monitored with MRI profiles. Injection of methane, cooling and pressurization resulted in final saturations of approximately 35% free water and 43% hydrate, due to the expansion as hydrate formed (Figure 82, red curve). Hydrate saturations were slightly higher at the outlet end (Figure 82).

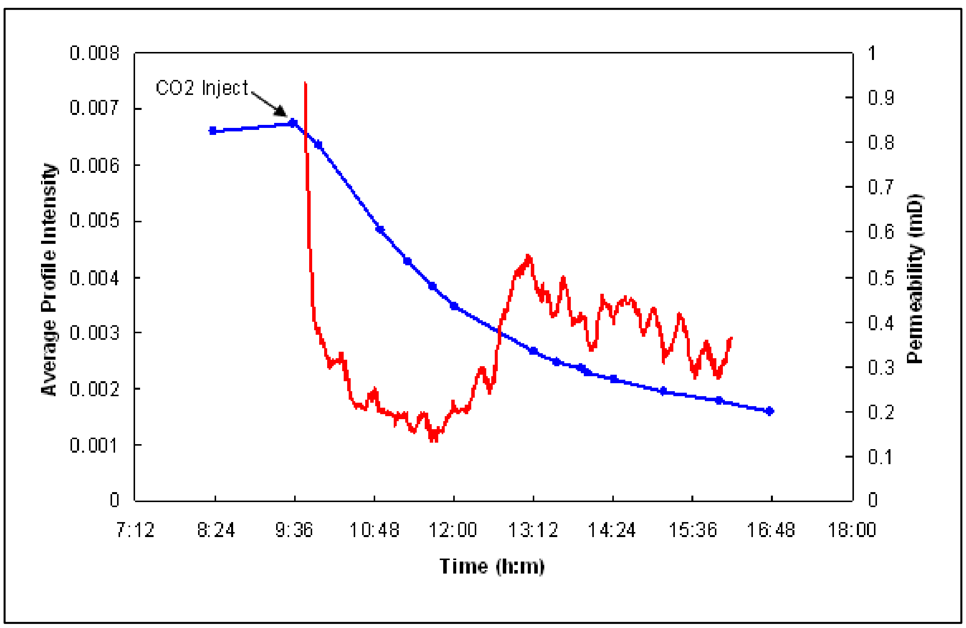
Permeability to nitrogen gas measured at this point in time was 4-18 mD. Again, the injection of liquid carbon dioxide converted much, but not all of the available excess water into a hydrate (Figure 82, lowermost blue curve).

Figure 82: MRI Profiles collected during liquid carbon dioxide injection into a methane-hydrate saturated core plug that contained 35% excess water.



Permeability measurements collected during the injection of liquid carbon dioxide started at 0.9 mD and dropped quickly to 0.2 mD (Figure 83). 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 zero.

Figure 83: Changes in MRI profile intensity as additional hydrate formed from excess water and liquid carbon dioxide injection that started at 9:36 hours.



From these tests it was concluded that CO_2 injection into a hydrate saturated pore system containing free water and gas would result in reduction in permeability, but that the permeability would not be reduced to zero. Permeability reduction in a system with no gas in the pores could not be tested experimentally and remained a concern that was addressed through phase modeling.

CO_2 Delivery Mechanism

Experiments were performed to validate the efficiency of exchange with mixed N_2/CH_4 gas. The first experiment (May_2011_B) had an initial hydrate saturation of 58% and gas-filled pore space. Injection of a 60/40 mol% CO_2/N_2 gas mixture did not alter the water and hydrate saturation in any appreciable manner (Figure 84).

Figure 84: Progress of May_2011_B experiment as monitored with MRI.

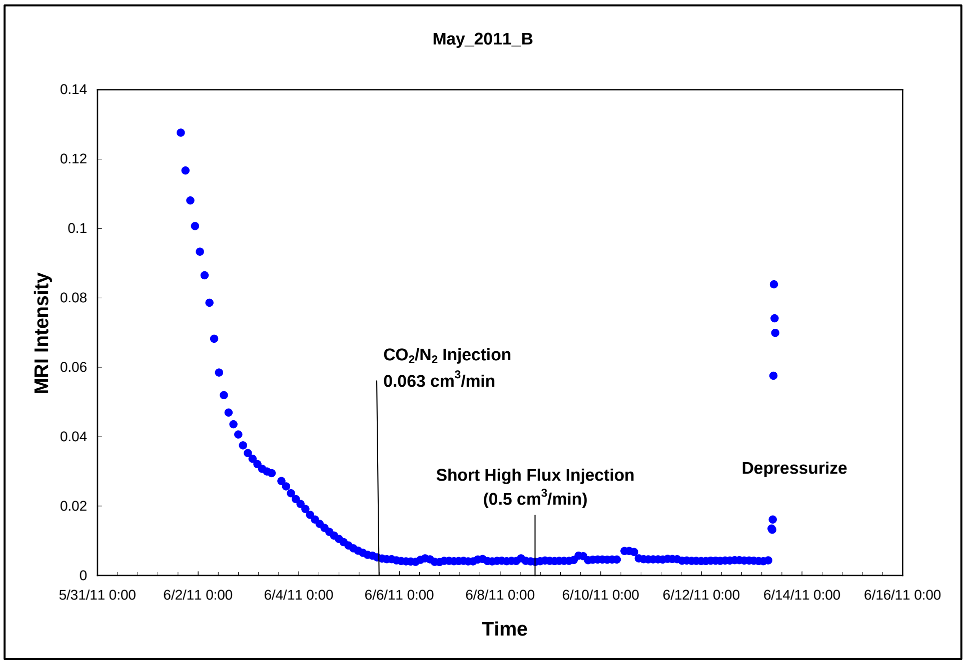


Figure 85: MRI intensity in May_2011_2 sand pack after hydrate formation and during the initial stages of CO_2/N_2 injection around 6/8/2011.

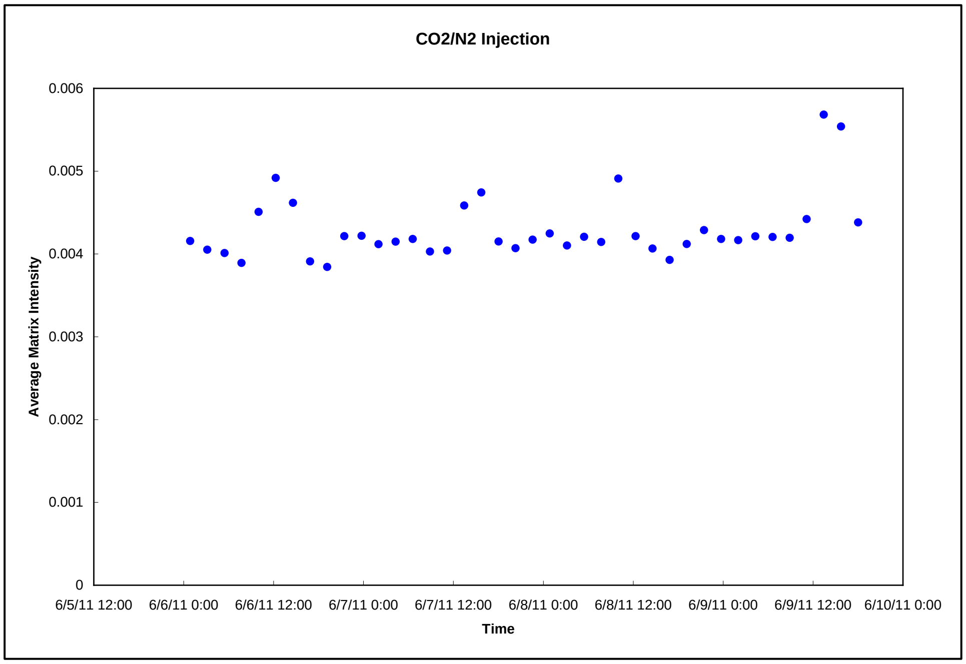
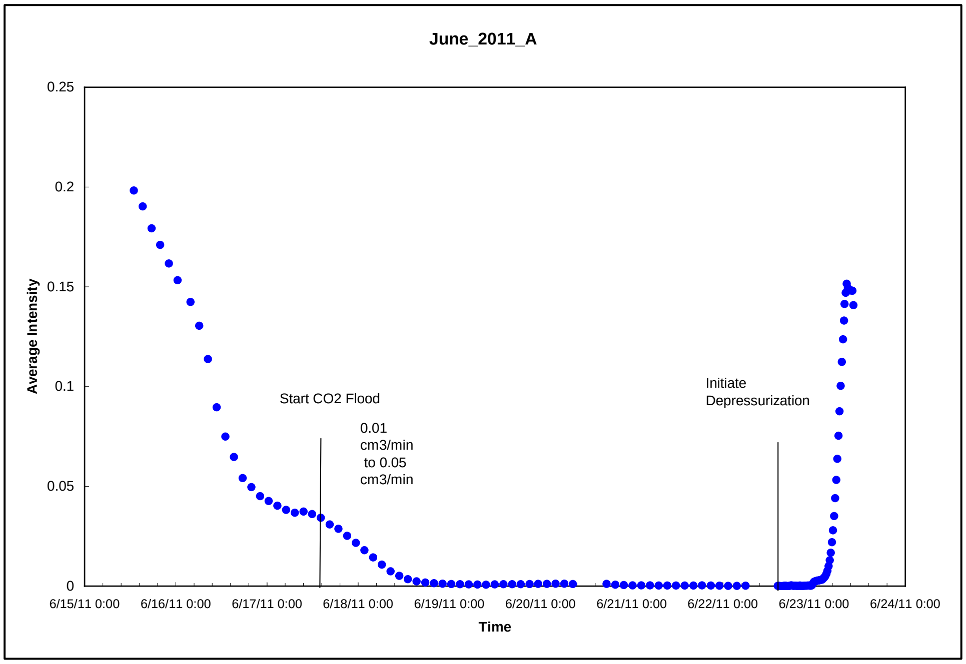


Figure 85 shows no change in intensity, which indicates that there was no additional hydrate formation when the mixed N_2/CO_2 gas was introduced.

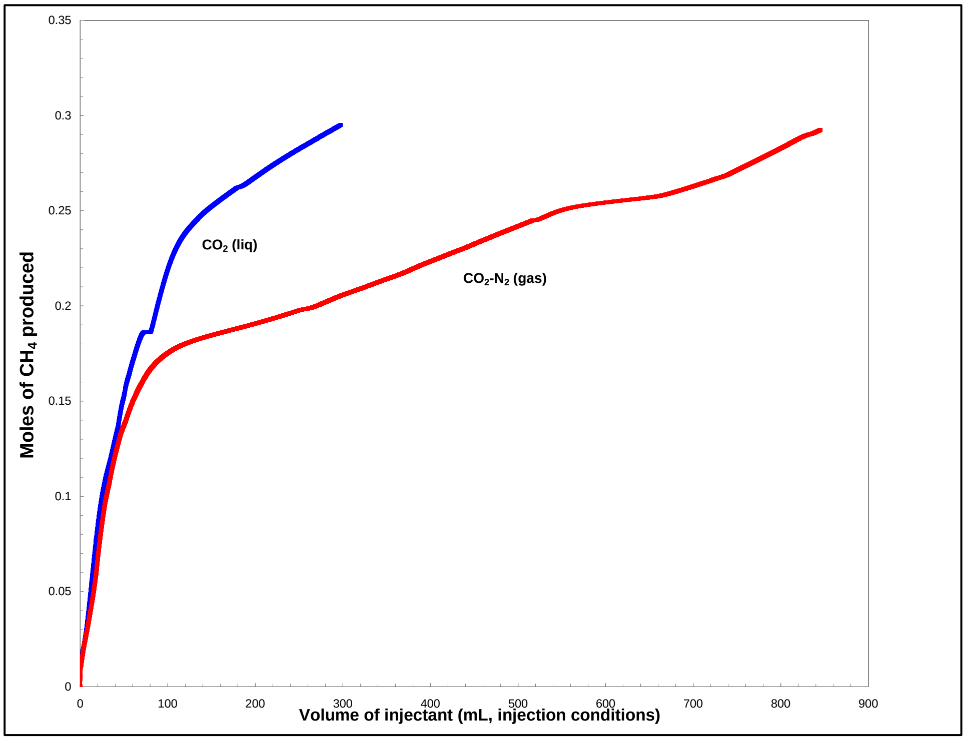
A second experiment (June_2011_A) continued evaluating the effectiveness of the gas versus liquid sourcing of the CO_2 for exchange. The initial parameters were similar to those used in the May_2011_B test, but in this case liquid CO_2 was used. After initial hydrate formation, liquid CO_2 was injected at a rate of 0.01 cm^3/min to 0.05 cm^3/min. The introduction of CO_2 converted trace amounts of water in the system to a hydrate as shown by an additional loss of MRI intensity (Figure 86).

Figure 86: Progress of June_2011_A experiment as monitored by MRI intensity.



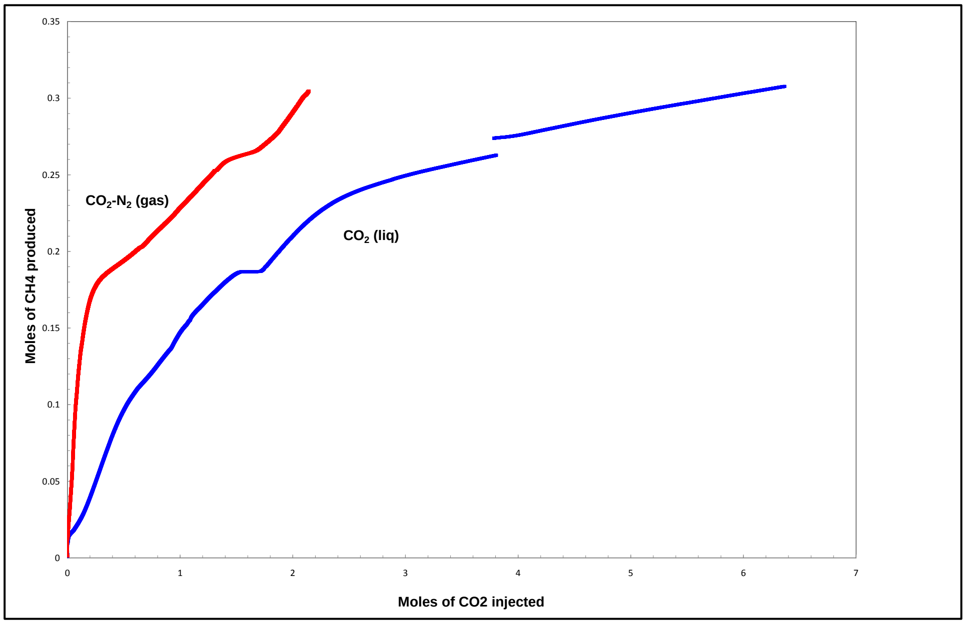
A comparison of the produced methane from the two experiments indicated that the CO_2/N_2 60-40 mixture was as efficient in the rate and extent of exchange with the methane hydrate as was liquid CO_2 (Figure 87). The initial production of methane from the pores was independent of the volume of injectant, corrected for experimental conditions. After that initial stage, the liquid CO_2 produced the same molar volume of CH_4 as the CO_2/N_2 mixture, but only used one-quarter of the injected volume.

Figure 87: Comparison of methane production from experiments that injected liquid CO_2 and a gas mixture of CO_2/N_2.



When the injected volumes of the liquid and gas mixture were converted into moles of CO_2, the gas mixture proved to be more efficient in terms of total moles of available CO_2 in the production of the CH_4 (Figure 88). In this instance, the efficiency of the exchange was greater with the gas mixture. The liquid CO_2 system likely was inefficient in the exchange because much of it was forced through the system before it had time to interact with CH_4-hydrate sites. The exchange process was less affected by the driving force, as represented by the moles of available CO_2, as by the reactivity. Note that surface area and abundance of interfaces, as determined by the initial water saturation, were the same for these two tests.

Figure 88: Comparison of methane production from experiments that injected liquid CO_2 and a gas mixture of CO_2/N_2.



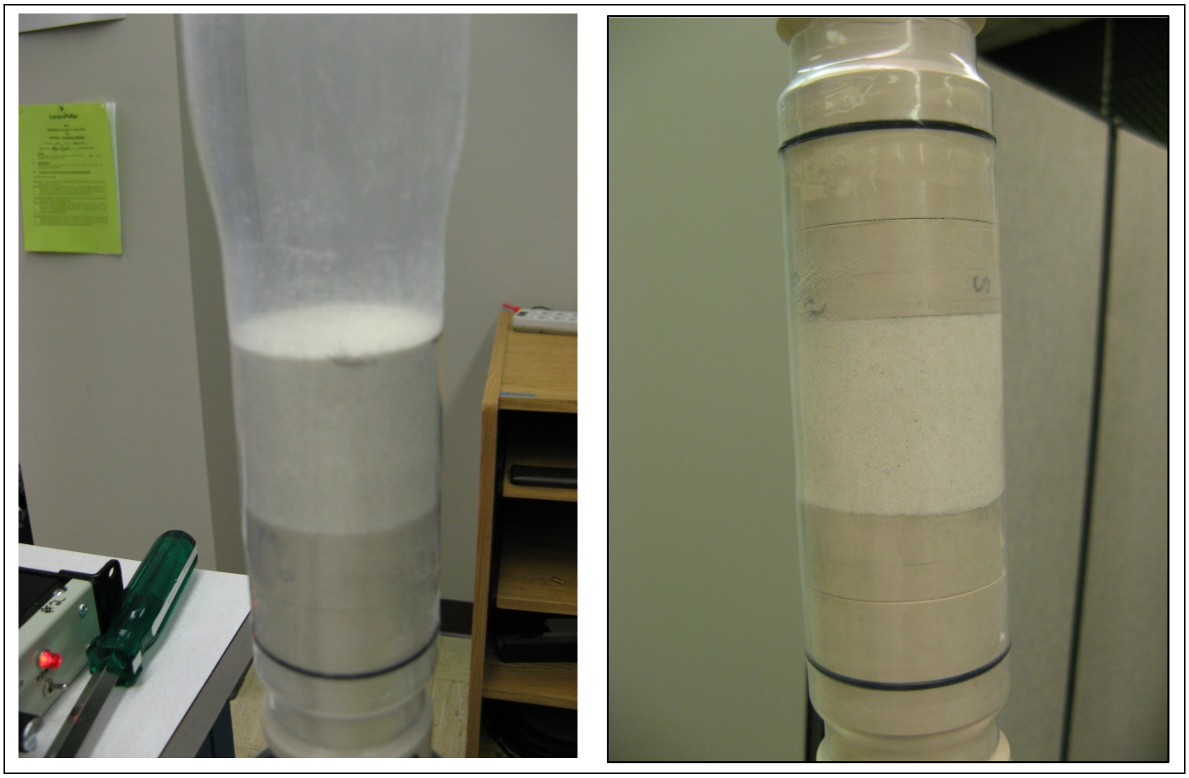
Strength of Unconsolidated Sand

The hydrate-bearing sand reservoirs in the Arctic are composed of poorly consolidated, fine-grained sands that are cemented primarily by hydrate. Loss of sediment strength caused by large-scale dissociation of the load-bearing hydrate cement during CO_2 exchange process was a concern. To assess this risk several exchange tests were run in a core holder that included ultrasonic transducers, which measured compressional and shear wave velocities on the hydrate-saturated sand. Analysis of the velocities is a standard technique to provide information on the elastic moduli of the hydrate-bearing sands (Waite et al., 2009)

The experimental setup for measuring ultrasonic velocity properties in samples while simultaneously monitoring reaction progress was developed at ConocoPhillips in 2010. A key step in this procedure was the design and construction of PEEK end pieces to house the piezoelectric P- and S-transducers (500 kHz). Wave speeds were measured with a conventional pulsed-transmission method. Waveforms were collected at regular intervals and evaluated, initially by hand. Eventually, these data were evaluated by a waveform sonic analysis tool LogIC, a commercial petrophysics software package that was modified to accept the laboratory data format, and with a MATLAB signal processing module developed in this lab.

A series of sand packs were formed with Ottawa F-110 sand that was being used by hydrates researchers as an inter-laboratory standard. A mold was formed by using shrink-wrap Teflon tubing around one of the PEEK end pieces (Figure 89, left). Dry or wet sand was then added to the mold, followed by compaction to a pre-determined volume that resulted in an initial porosity of ~40% (Figure 89, right). Initial water saturation was determined by the amount of water mixed with the sand before placing it in the mold.

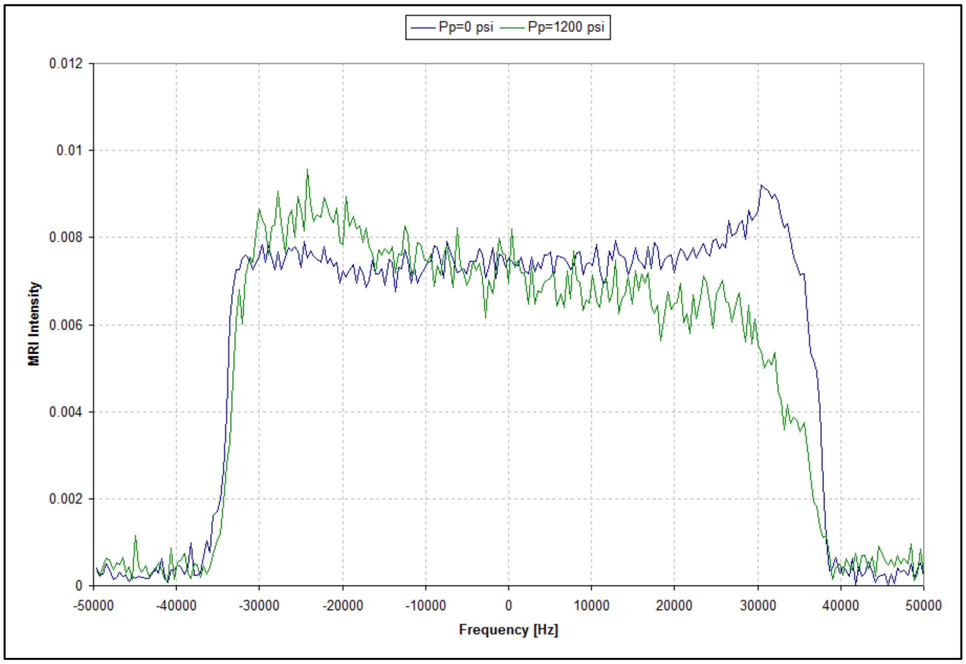
Figure 89: Shrink-wrap tubing was used as mold for forming sand pack (left). Dry and wetted sand is compacted to a pre-determined volume (length) before adding the second transducer end piece (right) and completing the seal.



For samples with higher initial water saturation than the wet sand mixture could establish additional water was added. The distribution of water in these sand packs was determined by MRI profiles. Hydrate saturation was determined by monitoring the changes in the MRI images as signal intensity decreased when water and methane combined to form hydrate. Previous tests established a strong correlation between MRI image intensity and moles of consumed methane during hydrate formation, which made the MRI approach a valid means to estimate hydrate saturation while gaining additional spatial information.

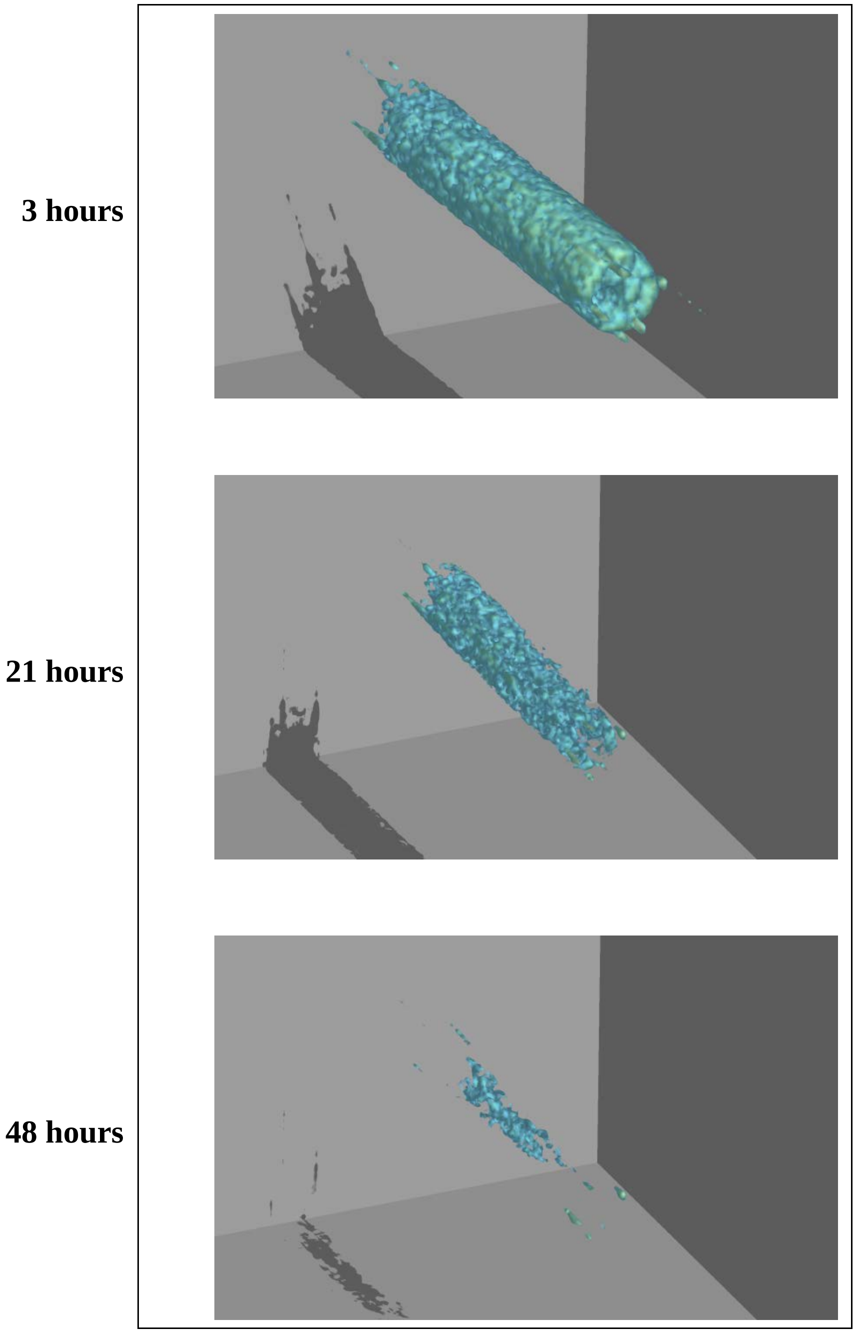
Initial tests were run with a Bentheim sandstone sample, which was the standard medium used in ConocoPhillips' earlier tests on hydrate formation and CO_2 exchange. This test had an initial water saturation of 70%, which was uniformly distributed along the core length (Figure 90). The sample was pressurized with methane at 1200 psi and then cooled to 4°C. Hydrate formation was monitored with a series of 3-D MRI images (Figure 91).

Figure 90: MRI profile along the longitudinal axis of the Bentheim sandstone core shows a uniform initial water saturation of 70% before hydrate formation.



In Figure 90, note that there was some redistribution of water when the sample was pressurized with 1200 psi of methane.

Figure 91: 3-D MRI images of water-saturated Bentheim sandstone sample showed a loss of signal as hydrate formed at different test stages.



In Figure 91, the MRI was sensitive to the presence of water and methane, but the MRI did not detect hydrate because of its very fast relaxation properties.

Ultrasonic waveforms were collected every minute during the hydrate formation. Selected waveforms during the test were evaluated for first arrival times (Figure 92). The arrival times were converted into velocities by assuming a constant sample length and corrected for the offset from the PEEK transducers (Figure 93).

The complete test included a stage of hydrate formation where P- and S-wave velocity increased to 4300 msec and 2200 msec respectfully. After most of the water was converted to hydrate, the methane pore pressure was dropped below dissociation pressure. This released free water and methane, causing an increase in MRI signal intensity. There was a concomitant decrease in velocity to 3300 msec and 2000 msec for the P- and S-waves. The system was then re-pressurized to 1200 psi and the remaining water was reconverted to hydrate with Vp and Vs approaching the original values.

Figure 92: P and S-waveforms collected during hydrate formation. First arrivals were identified by hand.

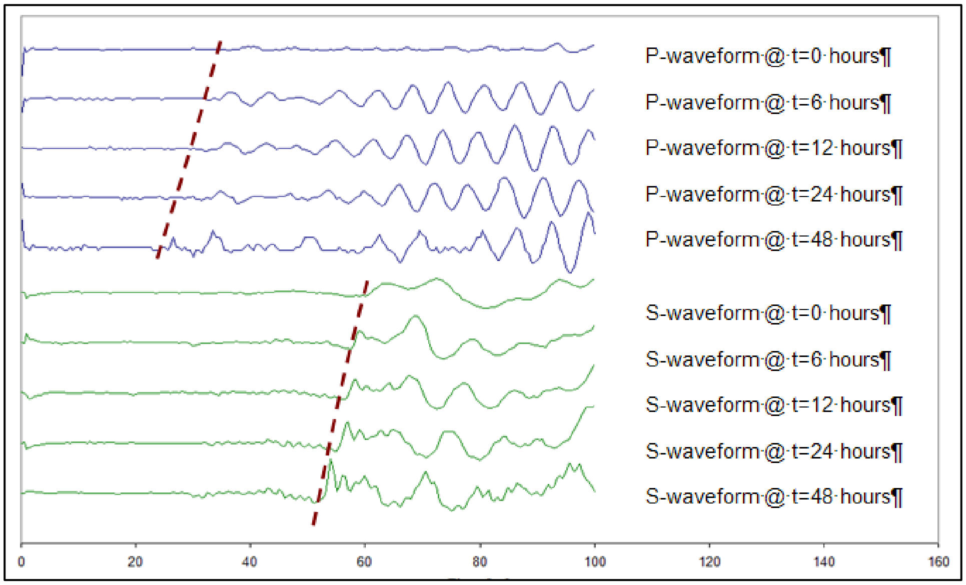


Figure 93: Summary of Bentheim sandstone test showing hydrate formation.

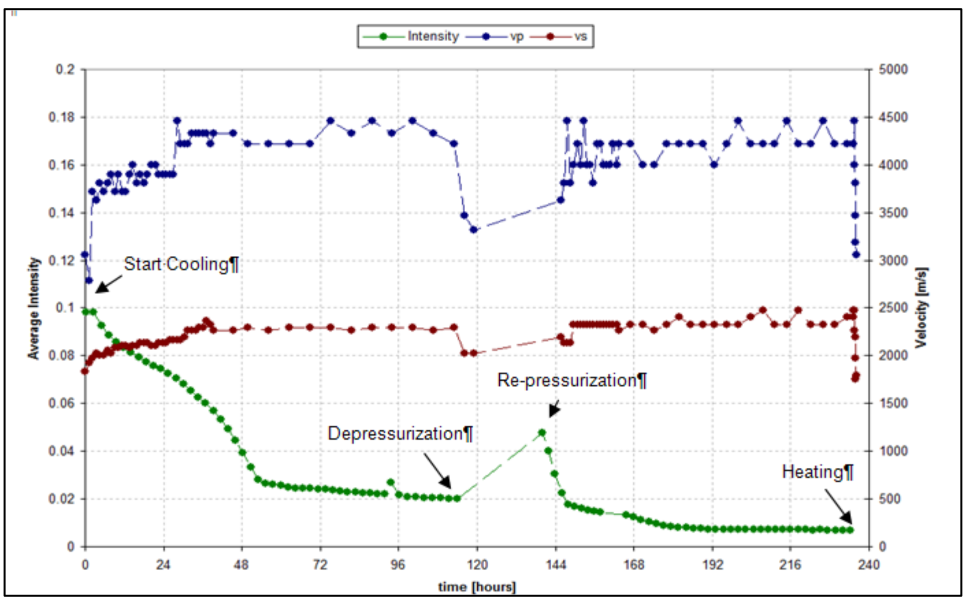
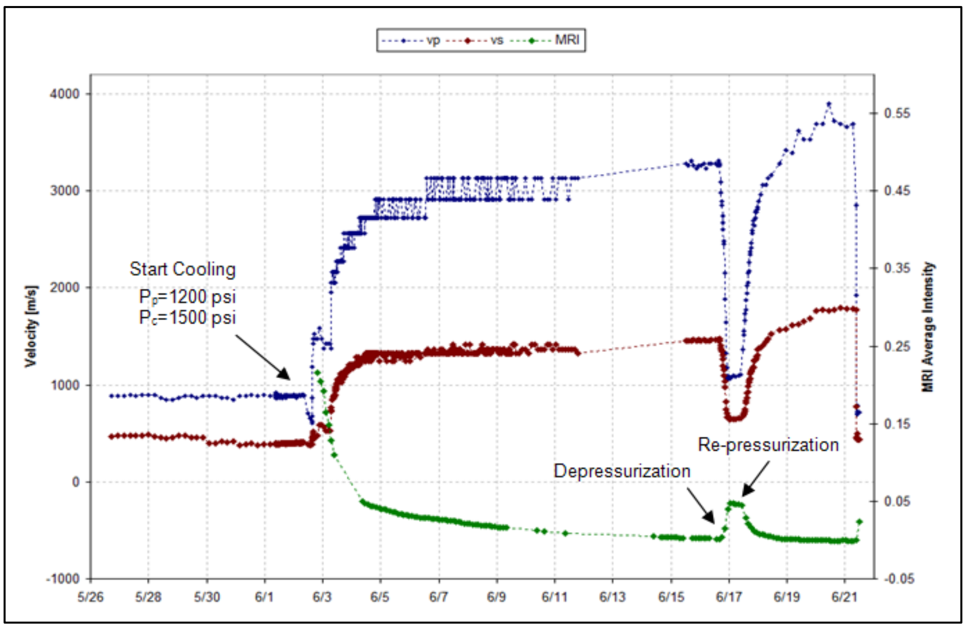


Figure 93 charts the Bentheim sandstone test hydrate formation. Hydrate formation is shown, followed by depressurization below dissociation pressure.

Then, Figure 93 shows re-pressurization to 1200 psi and finally, CO_2 injection. The MRI intensity is a reflection of hydrate saturation (water saturation). P- and S-wave velocities were determined manually (Figure 92).

Additional tests with a sand pack were run with initial low and high water saturations. The first test had an initial water saturation of 80%. Hydrate formation caused the velocities to increase to 2800 – 3000 msec for Vp and 1200-1300 msec for Vs (Figure 94). On approximately June 16th, the pore pressure was dropped below the hydrate dissociation pressure. The increase in MRI signal intensity did not approach the levels associated with the initial water saturation. This fact, along with the observation of water in the outlet lines, indicated that much of the water was lost from the sand pack during depressurization. Re-pressurization of the system converted the remaining water, now in a low water saturation state of approximately 20%, to hydrate. Note that even with the lower initial water saturation that converted to hydrate, the velocities were slightly greater than when the hydrate formed at the higher initial water saturation (Figure 94).

Figure 94: Hydrate formation and CO_2 injection test for high initial water sand pack is illustrated by changes in MRI intensity. P- and S-wave velocity values were determined by the manual first arrival picking method.



The MRI results allowed for periodic estimates of gas hydrate saturation during the hydrate formation process and CO_2 exchange tests. The relationship between hydrate saturation and velocity followed two distinct trends, depending on whether there were high or low initial water saturation levels (Figure 95). The trends from the two initial water saturation levels did not overlay at the same gas hydrate saturation (5% to 20%). The thought was that the initial water saturation played a significant role in how the hydrate was distributed within the pore space, even when the absolute hydrate saturations were the same. The interpretation of where this hydrate was distributed within the pore space remained unclear. The P-wave velocity results for the initial high water saturation test fell between the enveloping and pore-fill models (Figure 96).

Figure 95: Changes in P- and S-wave velocity at different gas hydrate saturation follow distinctly different trends, depending upon initial water saturation levels. Gas hydrate saturation was determined from the MRI intensity.

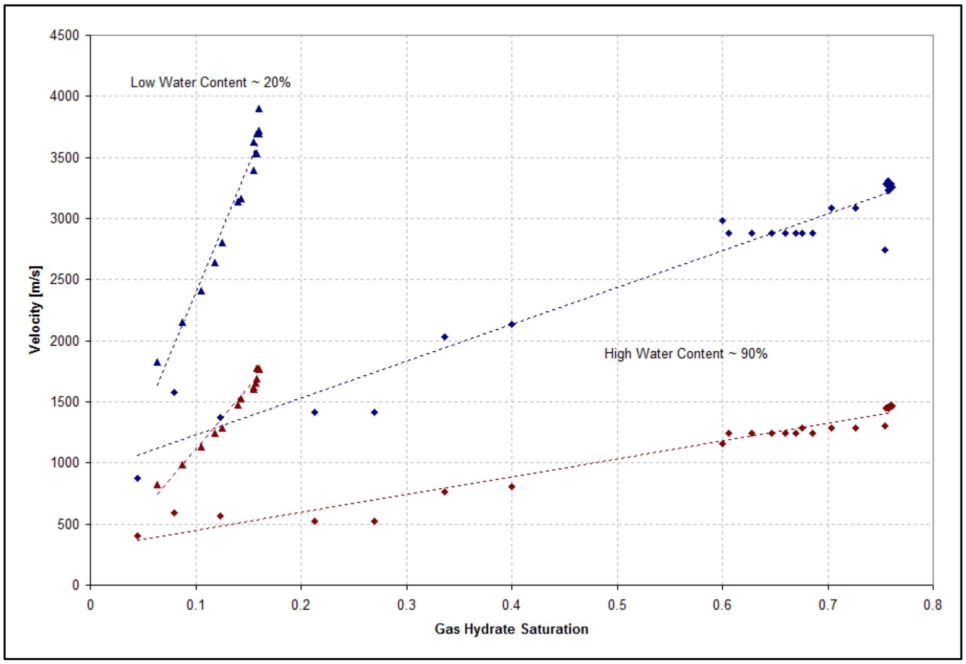
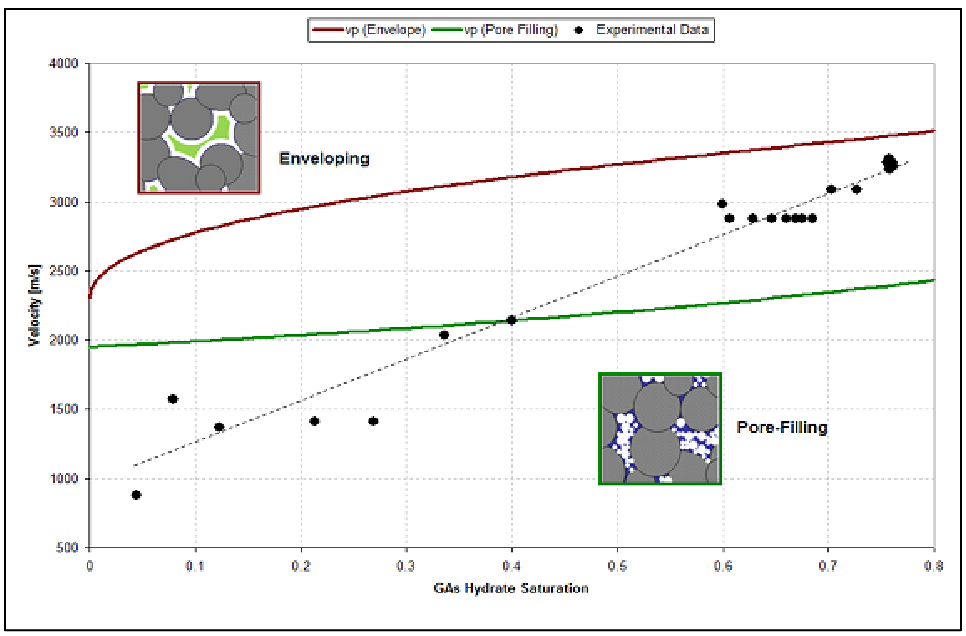
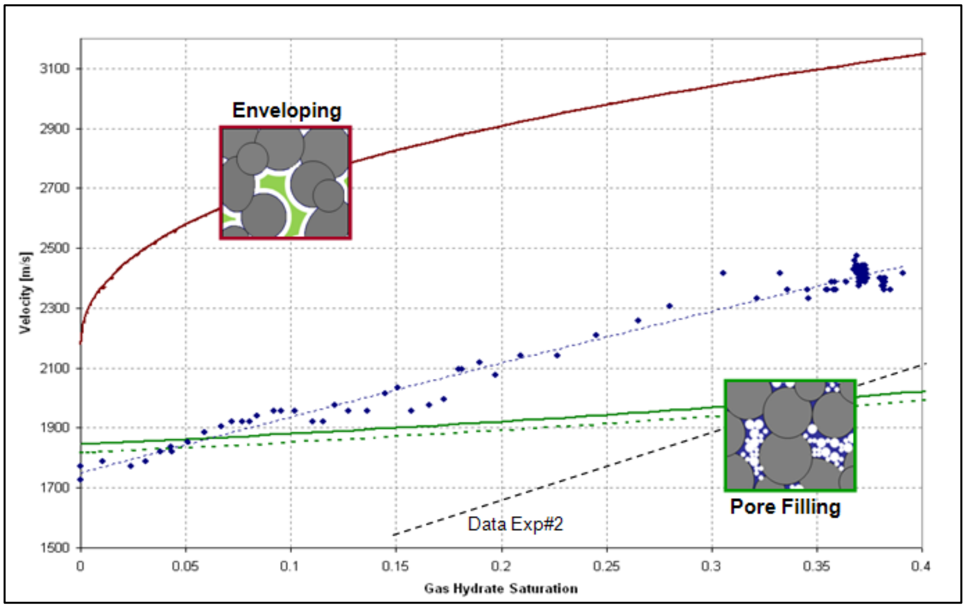


Figure 96: P-wave velocity at different gas hydrate saturation levels fall between the theoretical values for enveloping and pore-filling models for the test with initial high water saturation.



A second hydrate formation test with high initial water saturation levels (80%) was characterized by a similar trend in P-wave velocity at different gas hydrate saturations (Figure 97). The second trend had a similar slope to the original experiment (Experiment #2); however, the velocity values were offset by approximately 400 msec. This offset was linked to differences in the sand packs used in the two tests. The overall trend of the second test was closer to the pore-filling model trend, especially at lower hydrate saturations.

Figure 97: P-wave velocity trend as a function of hydrate saturation for a second, high initial water saturation test in a sand pack shows a trend similar to the first test (Experiment #2), though offset to higher velocities.



In Figure 33, there is greater data density, especially at low hydrate saturation, where hydrate formation began.

Two tests that were run at low initial water saturations (20%) showed an increase in P-wave velocity that approached the contact-cement model of hydrate distribution (Figure 34). The second test was marred by the absence of MRI data to estimate intermediate hydrate saturation during formation. Almost 100% of the free water was converted to hydrate during the collection of one 3-D MRI image. Therefore, the only measured values were the endpoint saturations. CO_2 was flooded into the core following conversion of the water to methane hydrate. Figure 99 shows that both the P- and S-wave velocities decreased during the CO_2 flood and exchange process. In Figure 98, the first test (black scatter diagram) shows a trend of increasing velocity that passes from enveloping to contact-cement distribution. The second test (orange scatter diagram) shows velocities centered near the enveloping model.

Figure 98: P-wave velocity trends for two tests at low initial water saturations (20%).

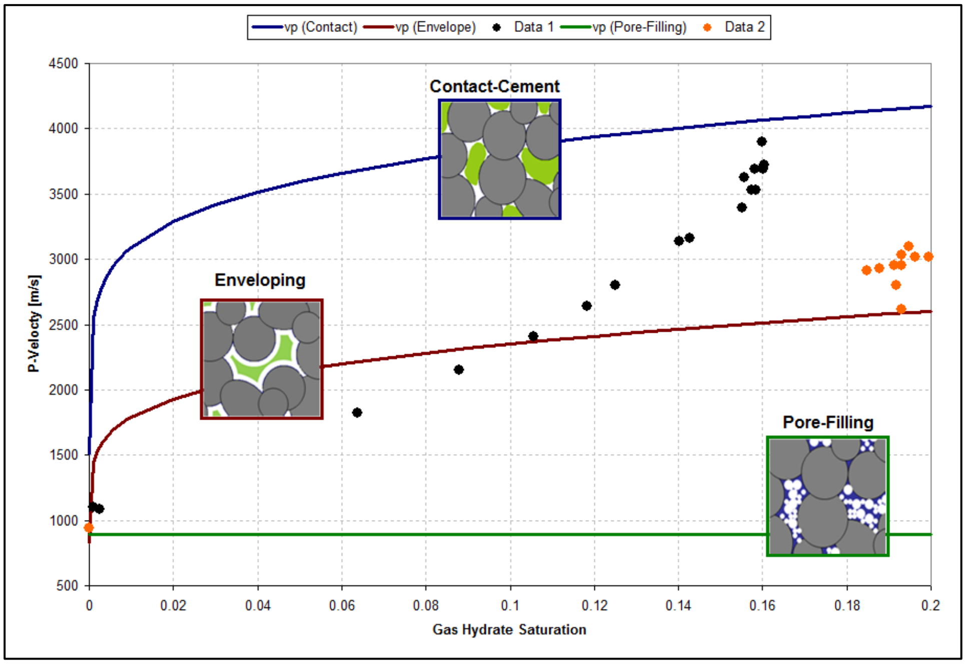
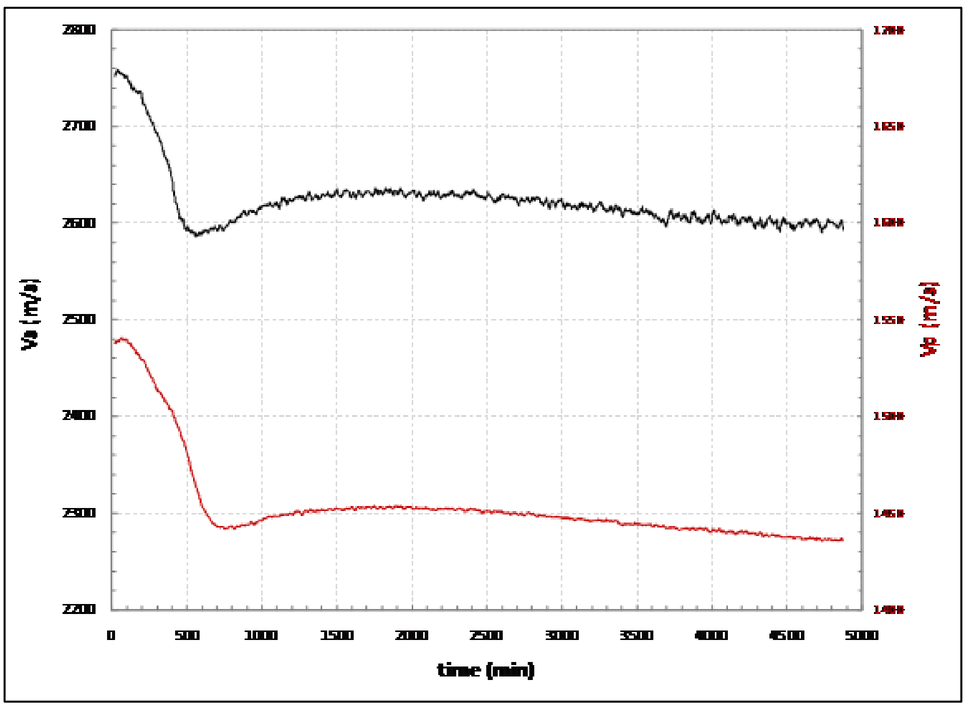


Figure 99: Changes in P- and S-wave velocity during a CO_2 flood of a low saturation core (SH=20%).



Ultrasonic measurements from hydrate-bearing samples formed by methane injected into partially-saturated sand showed that P- and S-wave velocities increased when hydrate was present. The increase in velocity depended upon the amount of water initially present and the location of gas and water in the pore space. At low saturations, the hydrate in the sediment acted as a “cementing,” element, and increased the ultrasonic velocities dramatically. However, the final velocities decreased with initial water saturation. At high initial water saturations (about 80 percent), the gas hydrate acted as a “load bearing,” element, even at low gas hydrate saturations.

This work led to the conclusion that the formation was unlikely to fail during exchange. However, loss of competency during dissociation is likely as demonstrated by the Mallik field test.

Appendix B Distributed Temperature Sensing Data Processing

Distributed Temperature Sensing (DTS) data was collected from surface to a depth of 2575.4 ft. Based on standard practice by the vendor, the DTS data was normalized to a "known" temperature to account for shifts in the data. The two normalization approaches were: normalizing to the top and bottom downhole gauges and normalizing to an interval in the rathole (2449-2562 ft). Based on the DTS processing software, the spatial resolution of the data was 3.28 ft. Following normalization, the DTS temperature was compared to the middle downhole gauge temperature. As shown in Figure 100, the normalization to the downhole gauges produced a result in better agreement with the static middle gauge temperature. The discrepancies seen at later times could result from the DTS being cased in cement while the middle gauge measured wellbore fluid temperatures directly during flowing operations. Based on this result, much of the DTS data in this report was normalized to the downhole gauges (the raw and rathole normalized data are available in the project database). A second processing step, a 13-point Savitzky-Golay smoothing routine, was applied to smooth the data and remove noise in the measurement (Figure 101). Finally, changes in temperature during the pilot test are reported with respect to the baseline geothermal gradient. The baseline thermal gradient of the reservoir was calculated by averaging the calibrated DTS data collected on February 6, 2012, before the well was opened for the 2012 testing (Figure 102). This created a reference temperature curve for each depth point used to calculate changes in temperature in the interval during the field trial. While a nearly 2.0°F difference in temperature existed between the top and bottom of the hydrate-bearing interval, the temperatures at any given depth were stable within 0.1°F during the entire reference day. The calculated average geothermal gradient in the perforated zone was ~1.8°F/100ft.

Figure 100: Plot showing, DTS normalization to the downhole gauges.

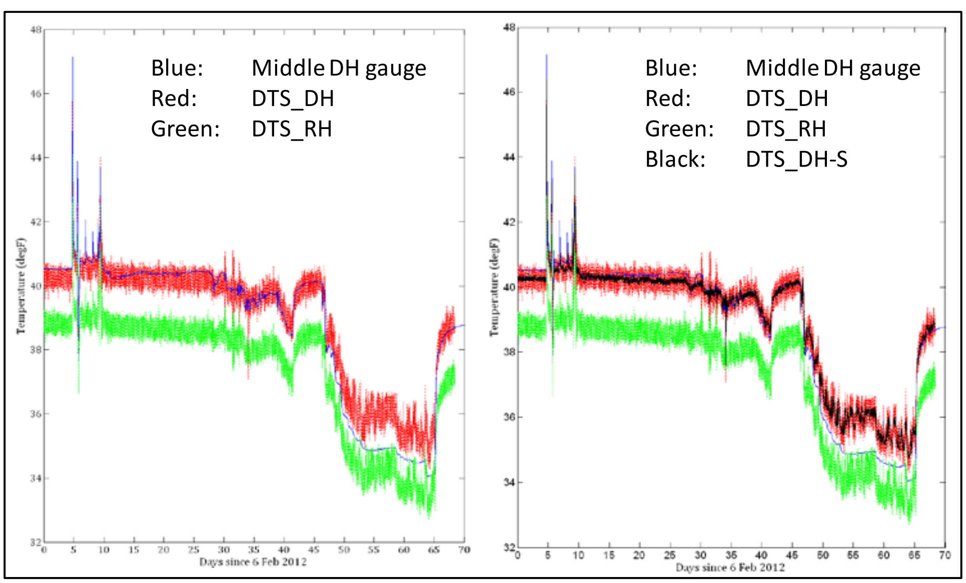
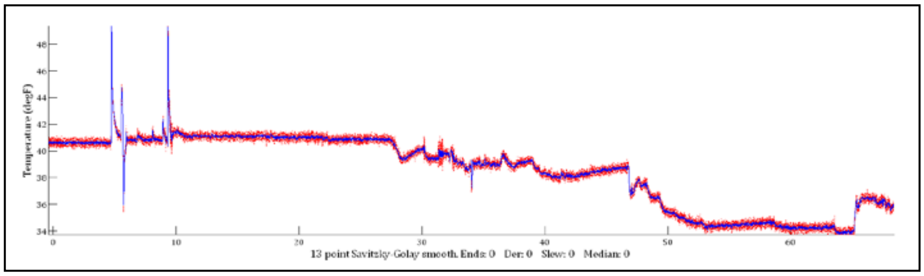
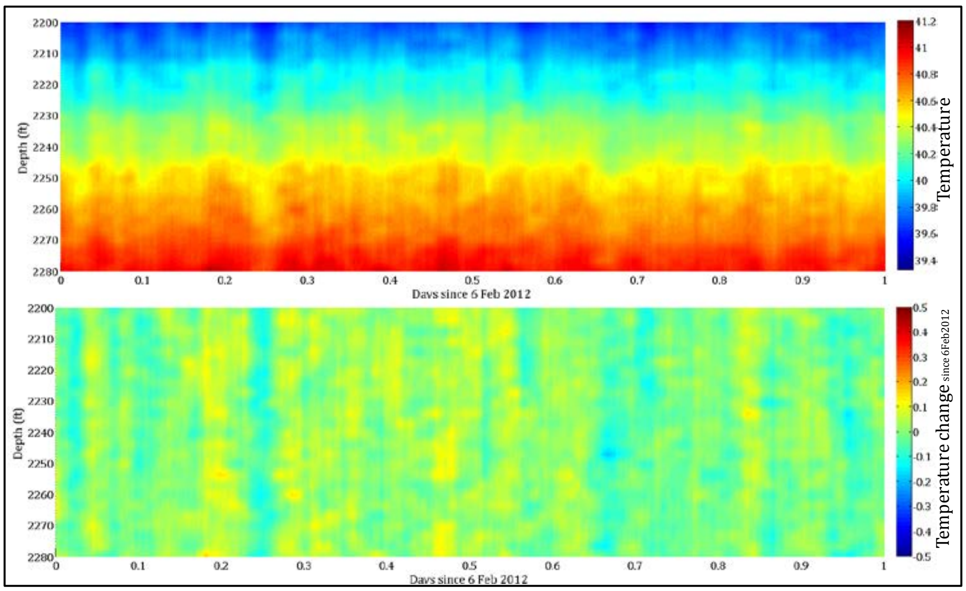


Figure 101: DTS data with a 13-point Savitzky-Golay smoothing routine applied to the data.



Time in days since Feb 6, 2012

Figure 102: DTS data. Top: absolute measured temperature. Bottom: temperature differences relative to an average temperature collected in the zone of interest on February 6, 2012. Measurements were taken before well work. The near-homogeneity of the temperature difference curve throughout the reference day helped evaluate temperature changes during the test.



Appendix C Lost Gas Correction due to Dissolved Gas

Measurements were taken of the gas flow rate and produced gas composition during the flowback stage. However, no measurements were made of the dissolved gas composition of aqueous phase from the separator. Ignoring the amount of gas dissolved in the aqueous phase could affect instantaneous gas rates, total gas, and recovery factor for each component. Due to the expected significance of CO_2 dissolved in the aqueous phase, the amounts of gases dissolved in produced water were estimated and were treated as production corrections.

Water Production Rate

Water production data required for gas loss calculation are unavailable because the flow meter broke during the early production period (damaged by sands in the production stream). Estimations of the water production rate were based on changes of water volume in each water tank and calculated using Equation 7.

Equation 7: Estimated water production rate calculations

$$\text{Volume change} = A_{\tan k} \times \left(H(t_2) - H(t_1)\right) + \text{volume removed by vac truck}$$

Where:

$H(t_2)$ = represents water levels at t_2
$H(t_1)$ = represents water levels at t_1

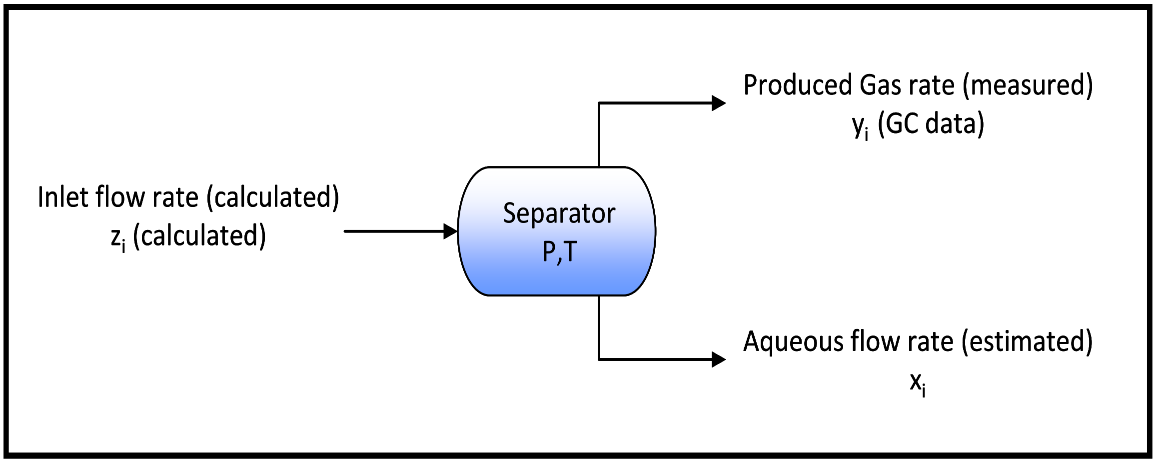
Daily water production was calculated from tank water levels taken every 30 minutes plus the total volume change during each 24-hour period.

As water leaving the tanks (recycle water) was sometimes higher than water entering the tanks during some short periods, the calculated water productions were often less than zero in those periods. Total water production during longer periods did not display this issue. Therefore, the average water production rate was calculated from the daily water production values.

Dissolved gas calculation (aqueous phase composition)

Material balance and flash calculations provided the basis for determining the composition of the aqueous phase from the separator. Figure 103 illustrates the flow diagram at the separator.

Figure 103: Flow diagram at the separator.



Gas rate and its composition were measured, whereas water rate from the separator was set to be equal to the summation of the water production rate (in the previous section) and the water recycle rate (measured).

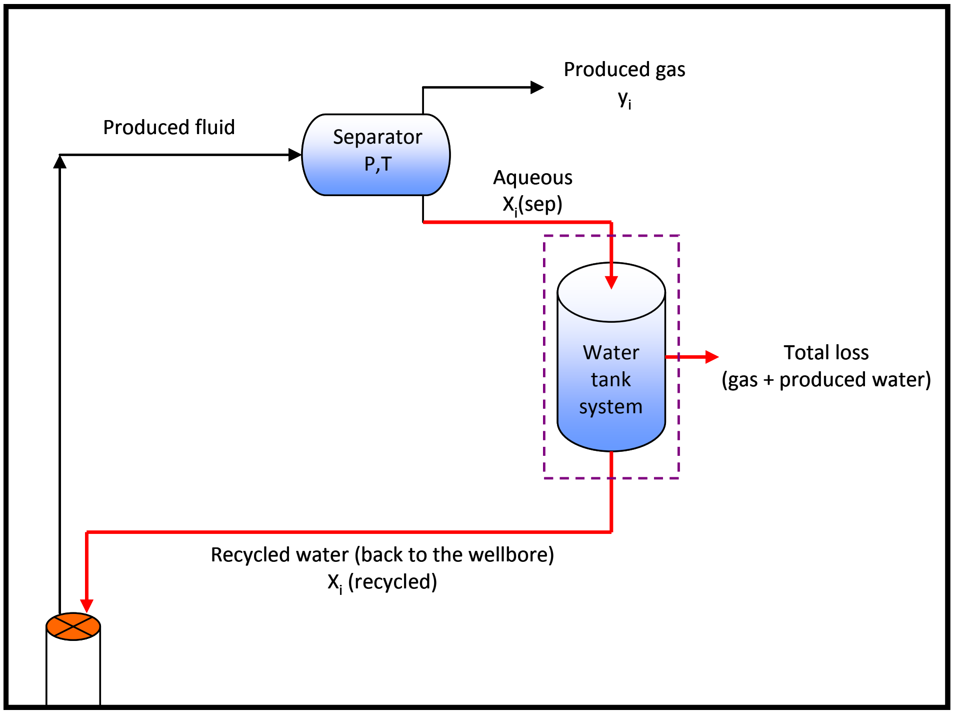
Equation 8: The total amount (mole) of each component in the inlet stream was determined from the material balance at the separator

$$\left(Component\, i^{th}\right)_{inlet\ stream} = \left(Gas\, rate \times y_i\right) + \left(Aqueous\, rate \times x_i\right)$$

The aqueous phase composition (x_i) was estimated from Henry's law, and the total mole of each component in the inlet stream was calculated using equation B2. At that point, a flash calculation obtained gas and aqueous phase compositions (y_i, x_i). The entire calculation process is repeated (with different x_i) if the calculated gas compositions (y_i) are very different from the measured gas compositions. However, the estimation of aqueous phase composition using Henry's law was adequate after adjusting the constant for each component. The maximum difference of the calculated and measured gas compositions was less than 1%.

The next step used the calculated aqueous phase compositions for the loss calculation. Figure 104 illustrates the simplified process flow diagram used for the gas loss calculation.

Figure 104: Simplified flow diagram for gas loss calculation.



Equation 9: Material balance at the water tank system

$$\left(component\ i^{th}\right)_{loss} = \left(Aqueous\ rate \times x_i\right)_{separator} - \left(Aqueous\ rate \times x_i\right)_{recycle}$$

Compositions of the aqueous phase from the separator were calculated in the previous step. The recycling water compositions were determined from flash calculation at the water tank conditions. Temperature at the water tank was measured, whereas water tank pressure was set to 14.7 psi (open tank).

The loss from Equation 9 includes the loss with vented gas at the water tank and the loss with produced water. This calculation assumes that the CO_2 concentration in the aqueous phase is in equilibrium with the CO_2 concentration in the produced gas phase at the separator. This assumption should be valid unless the flow to the separator is too high, meaning the fluid does not have enough time to reach equilibrium at the separator conditions.

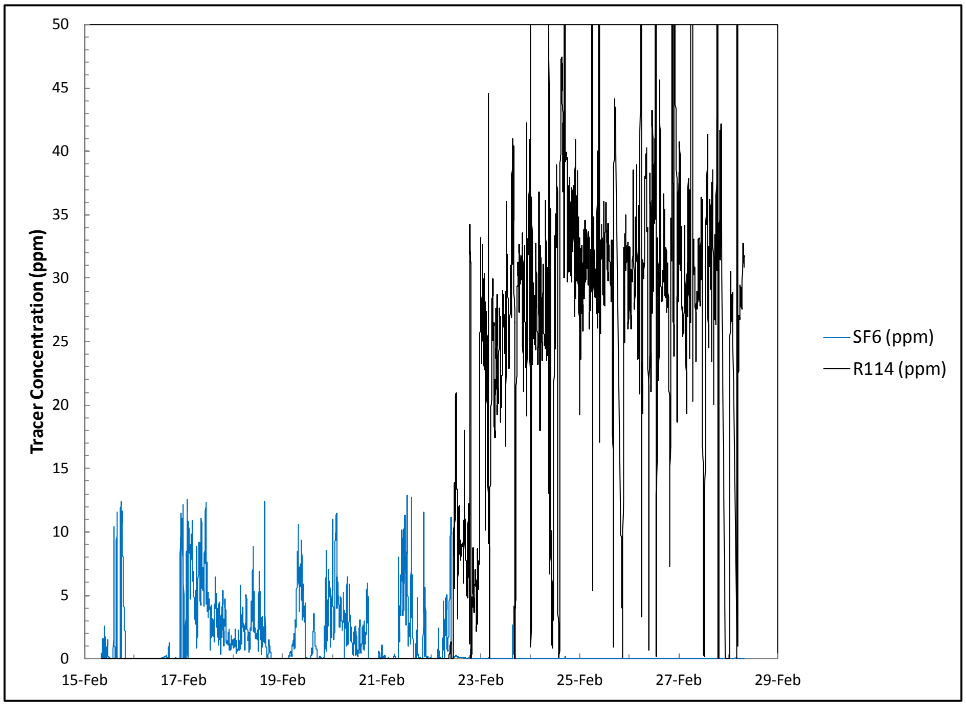
Appendix D Tracer Gases

The field trial design included "non-interacting" conservative chemical tracers to the CO_2/N_2 injection mixture as a way to reconcile mass balance issues associated with the trial. This decision was based on the premise that a proper selection of tracers would allow monitoring of the production stream to determine how much of the original injected gas mixture was recovered with respect to a non-interacting component. The selection criteria included identification of a tracer that would stay in solution with the injection gas and would not participate in the hydrate phase. Two classes of molecules were considered: very small chemical species (for example, He, Ne) and larger species that do not fit in the cages of the sI hydrate. The very small chemical species form hydrates on their own but only at high pressure. While these small molecules could enter into empty cages of existing hydrate, their partitioning into the hydrate phase is relatively low (Strobel et al, 2006, DOI:10.1021/jp062139n). However, some finite partitioning of these small species would have to be accounted. The second class included larger molecules too large to fit in the sI hydrate, the expected crystal structure for natural CH_4 hydrate and CO_2 hydrate. Although these molecules form sII hydrate on their own, sufficiently low concentrations will exclude them from the hydrate phase. Low concentrations cannot produce a driving force sufficient to cause a hydrate crystal structural transition.

The two selected molecules, SF_6 and R114, are too large for sI structures. They were used in the gas injection mixture at a sufficiently low concentration to avoid sII hydrate formation. SF_6 is a commonly used tracer for subsurface studies (Wilson & Mackay, 2005, DOI: 10.1111/j.1745-6584.1993.tb00842.x). R114 was selected based on its size and low water solubility. The desired injection concentration was based on the GC detector sensitivity. The desired concentration came to 1 ppm/v for SF_6 and 30 ppm/v for R114. Using Multiflash (Infochem), SF_6 was predicted to be excluded from the hydrate at the desired injection concentration. Experimental conditions predicted the need for at least 600 ppm/v SF_6 to create a stable sII hydrate-trapping SF_6. Below those concentrations, SF_6 should remain in the gas phase. R114 was unavailable in the program for prediction.

Two tracers added detail to the characteristics of the flowback. SF_6 was the first tracer injected (for roughly half of the desired injection volume) and R114 followed for the remainder of the injection. The tracers were delivered using a positive displacement pump and metered into the injection stream through a check valve. Figure 105 shows the tracer concentrations during the injection phase. A number of operational challenges affected the injection of the first tracer, SF_6. These included inefficient filling of the pump due to gas instead of liquid flowing into the system, leaks, and tubing configuration issues. A check valve positioned downstream of the analog valve V-127 generated the main configuration issue. The check valve was repositioned upstream of V-127 before the R114 injection, which allowed injection at a more controlled and steady concentration. Based on the integrated signal from the GC composition and flow rate data, the total injected SF_6 was 0.1988 scf and 2.9169 scf for R114.

Figure 105: Tracer concentrations during the injection phase measured with the on-line gas chromatograph.



Unexpectedly, both tracers were present immediately in the production stream upon flowback. Figure 106 shows the tracer concentration during the production phases along with the cumulative volumes in Figure 107. The first conservative tracer in a “huff-and-puff” style test should not be present until later times, as it would have been displaced into the formation during the R114-traced phase of injection. In addition to being present immediately on flowback, the estimated recovery factor for SF_6 was greater than R114 (Figure 108).

To investigate whether these tracers actually were non-interacting, follow-up laboratory tests were performed using two gas mixtures: 1) 77/23 mol% N_2/CO_2 with 1ppm/v SF_6 and 2) 77/23 mol% N_2/CO_2 with 10ppm/v SF_6 and 50ppm/v R114. Hydrate was formed at ~34°F and 1420 psi from a water-filled sand pack under constant pressure conditions. Following hydrate formation, the head space gas was sampled and the cell was vented rapidly. After venting, the hydrate was allowed to dissociate and the hydrate gas was collected and analyzed. In both cases, the hydrate gas was enriched on CO_2 relative to N_2, as expected. The R114 was depleted in the hydrate case, indicating that it would act on a non-partitioning tracer. However, in both cases, the SF_6 was enriched in the hydrate gas. This indicates that, at least for the case on new hydrate formation, the SF_6 was not acting as a non-interacting tracer. While this was not the result desired from SF_6, it may explain the tracer’s anomalous behavior during flowback (Figure 108). More work is needed to explain the behavior of the tracers and to determine how to interpret them in relation to the field trial.

Figure 106: Tracer concentration during the production phases.

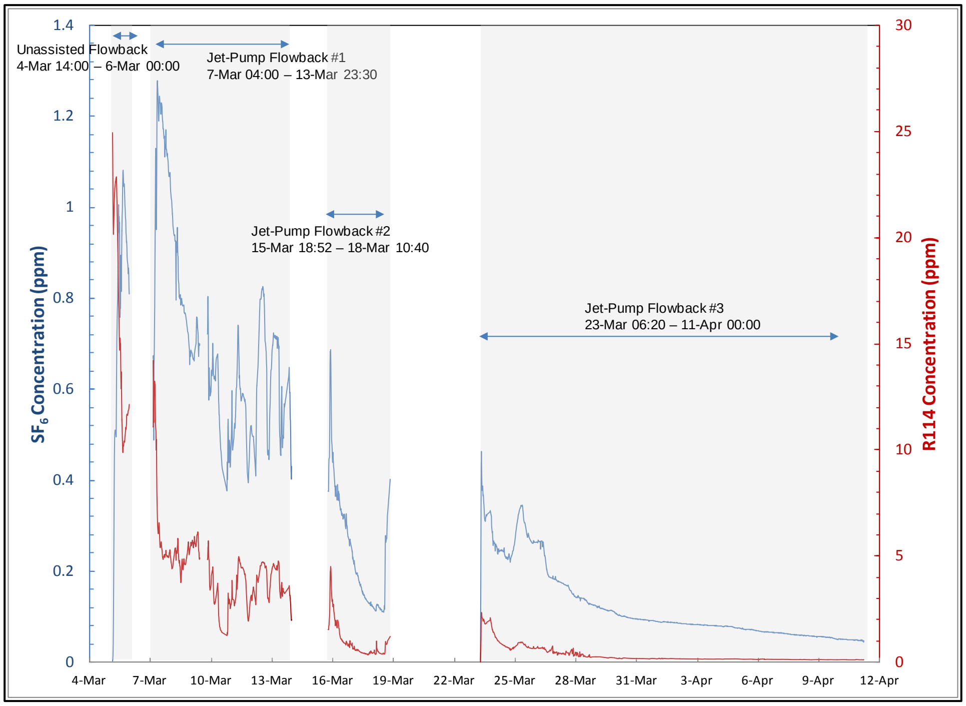


Figure 107: Tracer cumulative produced volume during the production phases.

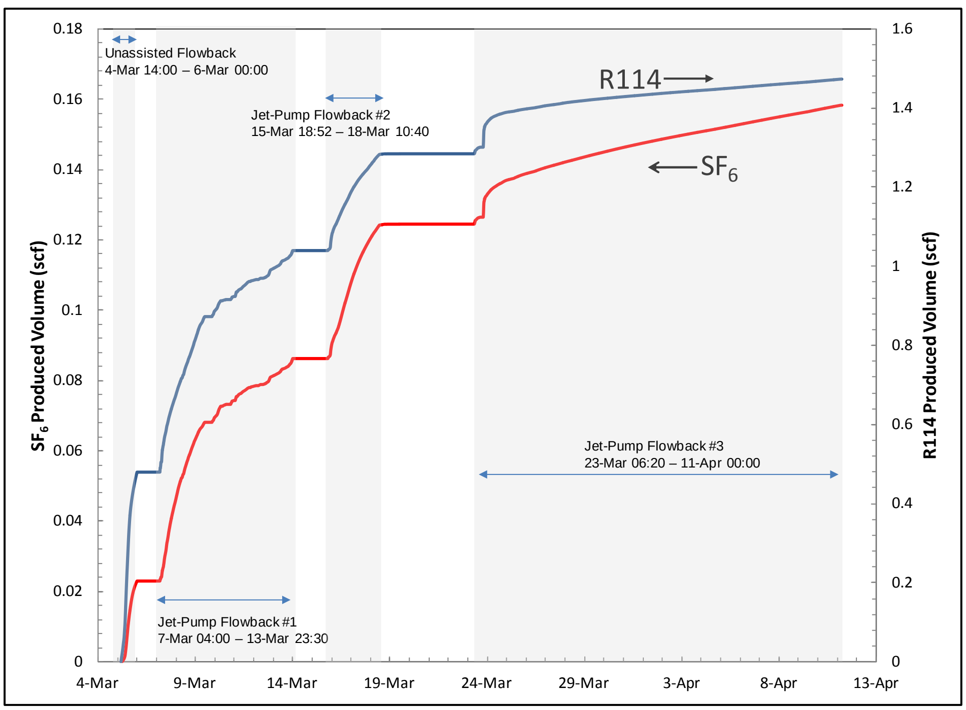
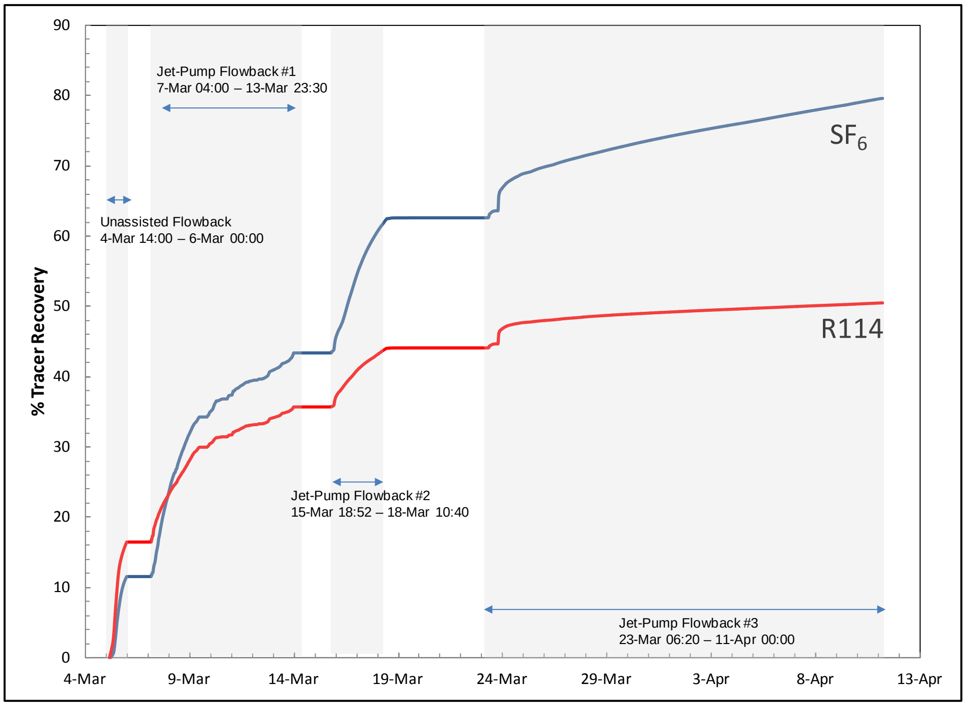


Figure 108: Tracer percentage recovery during the production phases.



Appendix E Isotopic Gas Analysis

www.isotechlabs.com

Isotech Gas Data

Job 18298

Isotech Lab No.	Sample Name	Sample Date	Sample Time	Field Name	GC Date	H_2S %	He %	H_2 %	Ar %	O_2 %	CO_2 %	N_2 %	CO %	C_1 %	C_2 %	C_2H_4 %	C_3 %	C_3H_6 %	iC_4 %	nC_4 %	iC_5 %	nC_5 %	C_6+ %	MS Date	$\delta^{13}CO_2$ ‰	$\delta^{13}C_1$ ‰	δDC_1 ‰	$\delta^{15}N$ ‰	Specific Gravity	BTU	Comments
249090	78/0/20/0.004/?	2/15/2012	8:14	COP Ignik Sikumi #1	5/29/2012	na	0.0027	nd	nd	0.057	26.33	73.61	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd	6/22/2012	-39.40			0.1	1.113	0	
249091	77/0/21/4.479/0.001	2/17/2012	20:15	COP Ignik Sikumi #1	5/30/2012	na	0.0034	nd	0.107	2.50	19.56	77.83	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd	6/22/2012	-39.87			-0.3	1.079	0	
249092	73/0/25/0/0.003	2/20/2012	20:07	COP Ignik Sikumi #1	5/29/2012	na	0.0053	nd	nd	0.071	23.23	76.69	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd	6/22/2012	-40.05			-1.4	1.096	0	
249093	78/0/22/0/0.908	2/24/2012	10:50	COP Ignik Sikumi #1	5/29/2012	na	0.0044	nd	nd	0.050	21.00	78.95	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd	6/22/2012	-38.72			-1.2	1.083	0	
249094	78/0/21/0/28	2/28/2012	1:40	COP Ignik Sikumi #1	5/29/2012	na	0.0031	nd	0.0056	0.11	21.08	78.80	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd	6/22/2012	-38.79			-1.1	1.084	0	
249095	66/15/17/0.5/24.4	3/5/2012	8:15	COP Ignik Sikumi #1	5/30/2012	na	0.0053	nd	0.0151	0.21	17.57	67.66	nd	14.54	0.0005	nd	nd	nd	nd	nd	nd	nd	nd	6/22/2012	-39.11	-48.42	-239.1	-0.7	1.004	147	
249096	55/28/15/0.977/15.75	3/5/2012	12:00	COP Ignik Sikumi #1	6/1/2012	na	0.0046	0.0017	0.0136	0.091	15.09	56.72	nd	28.08	0.0012	nd	nd	nd	nd	nd	nd	nd	nd	6/22/2012	-39.09	-48.87	-242.9		0.935	284	
249097	43/39/14/1/11	3/5/2012	15:53	COP Ignik Sikumi #1	6/1/2012	na	0.0070	0.0022	0.0157	0.084	14.42	45.29	nd	40.18	0.0019	0.0001	nd	nd	nd	nd	nd	nd	nd	8/1/2012	-38.93	-48.62	-241.4	-0.9	0.881	407	*
249098	41/51/8/1.162/8.6	3/7/2012	8:08	COP Ignik Sikumi #1	6/1/2012	na	0.0087	0.0021	0.0196	0.12	7.78	41.07	nd	51.00	0.0021	nd	nd	nd	nd	nd	nd	nd	nd	8/1/2012	-38.02	-48.53	-237.9	-0.8	0.800	517	*
249099	34/60/5/1.177/5.348	3/7/2012	16:07	COP Ignik Sikumi #1	6/1/2012	na	0.0113	0.0019	0.0237	0.22	4.75	34.60	nd	60.39	0.0025	nd	nd	nd	nd	nd	nd	nd	nd	6/23/2012	-38.09	-48.39	-238.4		0.744	612	
249100	34/62/5/1.078/5.591	3/8/2012		COP Ignik Sikumi #1	6/1/2012	na	0.0095	0.0016	0.0191	0.045	4.63	33.01	nd	62.28	0.0025	nd	nd	nd	nd	nd	nd	nd	nd	6/23/2012	-38.20	-48.58	-241.1		0.735	631	
249101	58/38/5.208/0.681/16	3/8/2012	3:52	COP Ignik Sikumi #1	6/1/2012	nd	0.0042	0.0058	0.0156	0.045	4.98	58.04	nd	36.91	0.0018	nd	nd	nd	nd	nd	nd	nd	nd	7/25/2012	-39.34	-48.85	-239.4	-0.9	0.842	374	
249102	32/62/5/0.943/5.615	3/8/2012	8:00	COP Ignik Sikumi #1	6/1/2012	na	0.0095	0.0031	0.0205	0.12	4.41	32.84	nd	62.59	0.0026	nd	nd	nd	nd	nd	nd	nd	nd	6/23/2012	-38.07	-48.54	-239.8		0.733	634	
249103	29/65/4/0.777/5.116	3/8/2012	16:00	COP Ignik Sikumi #1	6/1/2012	na	0.0110	0.0018	0.0206	0.072	3.54	29.95	nd	66.40	0.0027	nd	nd	nd	nd	nd	nd	nd	nd	6/23/2012	-37.24	-48.49	-241.5		0.712	673	
249104	30/64/3/0.688/5.863	3/8/2012	22:00	COP Ignik Sikumi #1	6/1/2012	na	0.0105	0.0021	0.0188	0.047	3.13	30.66	nd	66.13	0.0027	nd	nd	nd	nd	nd	nd	nd	nd	6/23/2012	-37.12	-48.51	-241.9		0.711	670	
249105	32/62/2/0.743/6.530	3/9/2012	8:00	COP Ignik Sikumi #1	6/1/2012	na	0.0103	0.0035	0.0191	0.047	2.79	33.14	nd	63.99	0.0027	nd	nd	nd	nd	nd	nd	nd	nd	6/23/2012	-37.23	-48.56	-242.7		0.718	648	
249106	23/72/4/0.586/3.751	3/9/2012	23:48	COP Ignik Sikumi #1	6/4/2012	na	0.0124	0.0016	0.0229	0.086	3.59	23.46	nd	72.82	0.0028	nd	nd	nd	nd	nd	nd	nd	nd	6/23/2012	-37.04	-48.38	-239.0		0.686	738	
249107	19/77/3/0.579/2.359	3/10/2012	9:08	COP Ignik Sikumi #1	5/30/2012	na	0.0101	nd	0.0225	0.084	2.56	18.40	nd	78.92	0.0029	nd	nd	nd	nd	nd	nd	nd	nd	6/23/2012	-37.50	-48.37	-240.3	-1.1	0.655	800	
249108	24/74/1.2/0.603/4.14	3/11/2012	1:14	COP Ignik Sikumi #1	6/4/2012	na	0.0089	nd	0.0216	0.060	2.25	20.76	nd	76.90	0.0032	nd	nd	nd	nd	nd	nd	nd	nd	6/23/2012	-37.85	-48.44	-241.9		0.662	779	
249109	29/68/2/.747/5.247	3/11/2012	8:37	COP Ignik Sikumi #1	6/4/2012	na	0.0103	0.0026	0.0244	0.060	1.75	28.77	nd	69.38	0.0032	nd	nd	nd	nd	nd	nd	nd	nd	6/23/2012	-37.06	-48.55	-241.4		0.690	703	
249110	25/71/2/0.579/4.423	3/11/2012	16:02	COP Ignik Sikumi #1	6/4/2012	na	0.0083	0.0024	0.0231	0.10	1.99	24.75	nd	73.12	0.0030	nd	nd	nd	nd	nd	nd	nd	nd	6/23/2012	-37.25	-48.49	-243.0		0.676	741	
249111	20/75/2.13/0.525/3.298	3/11/2012	23:54	COP Ignik Sikumi #1	6/4/2012	na	0.0119	0.0020	0.0216	0.079	2.14	20.20	nd	77.54	0.0031	nd	nd	nd	nd	nd	nd	nd	nd	6/23/2012	-36.76	-48.41	-244.3		0.659	786	
249112	28/69/2/0.714/4.766	3/12/2012	16:00	COP Ignik Sikumi #1	6/4/2012	na	0.0092	0.0045	0.0223	0.081	1.80	28.05	nd	70.03	0.0034	nd	nd	nd	nd	nd	nd	nd	nd	6/23/2012	-36.92	-48.56	-245.7		0.688	710	
249113	26/72/1.7/0.655/4.532	3/12/2012	23:53	COP Ignik Sikumi #1	6/4/2012	na	0.0080	0.0044	0.0215	0.066	1.63	26.41	nd	71.86	0.0032	nd	nd	nd	nd	nd	nd	nd	nd	6/23/2012	-36.45	-48.51	-242.0		0.679	728	
249114	29/69/3/0.7/5.036	3/13/2012	8:00	COP Ignik Sikumi #1	6/4/2012	na	0.0092	0.0054	0.0213	0.053	2.47	28.25	nd	69.19	0.0033	nd	nd	nd	nd	nd	nd	nd	nd	6/24/2012	-37.10	-48.55	-244.1		0.695	701	
249115	30/103/4/1.16/6.844	3/13/2012	16:00	COP Ignik Sikumi #1	6/4/2012	na	0.0109	0.0019	0.0226	0.062	2.83	21.60	nd	75.47	0.0031	nd	nd	nd	nd	nd	nd	nd	nd	8/1/2012	-36.63	-48.42	-242.9	-0.6	0.671	765	*
249116	28/70/0.9/0.373/1.571	3/15/2012	19:26	COP Ignik Sikumi #1	6/4/2012	na	0.0109	0.0025	0.0207	0.052	0.87	22.94	nd	76.10	0.0028	nd	nd	nd	nd	nd	nd	nd	nd	6/24/2012	-38.12	-47.85	-242.7		0.658	771	
249117	20/77/2.4/0.442/2.761	3/16/2012	0:29	COP Ignik Sikumi #1	5/30/2012	na	0.0104	0.0011	0.0224	0.045	2.57	20.06	nd	77.29	0.0030	nd	nd	nd	nd	nd	nd	nd	nd	6/25/2012	-36.79	-48.45	-233.9	-1.0	0.662	783	
249118	10/87/1/0.296/0.916	3/16/2012	15:19	COP Ignik Sikumi #1	6/4/2012	na	0.0099	nd	0.0215	0.072	1.36	10.23	nd	88.30	0.0037	nd	nd	nd	nd	nd	nd	nd	nd	6/25/2012	-36.21	-48.40	-242.2		0.610	895	
249119	7/91/1.054/0.209/0.594	3/17/2012	3:04	COP Ignik Sikumi #1	6/4/2012	na	0.0088	nd	0.0199	0.048	1.02	7.23	nd	91.67	0.0038	nd	nd	nd	nd	nd	nd	nd	nd	6/25/2012	-36.09	-48.40	-242.1		0.594	929	
249120	6/92/0.871/0.143/0.430	3/17/2012	15:09	COP Ignik Sikumi #1	6/4/2012	na	0.0074	nd	0.0208	0.081	0.83	5.74	nd	93.32	0.0039	nd	nd	nd	nd	nd	nd	nd	nd	8/1/2012	-35.54	-48.30	-242.8	-1.4	0.586	946	*
249121	5/93/0.766/0.113/.408	3/18/2012	2:59	COP Ignik Sikumi #1		na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na						0	0	
249122	18/80/2/0.37/2.087	3/23/2012	9:01	COP Ignik Sikumi #1	5/30/2012	na	0.0074	nd	0.0252	0.075	1.73	18.00	nd	80.16	0.0031	nd	nd	nd	nd	nd	nd	nd	nd	6/24/2012	-37.31	-48.46	-242.5	-1.1	0.646	812	
249123	14/86/1.1/0.287/1.6	3/23/2012	21:00	COP Ignik Sikumi #1		na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na						0	0	
249124	10/88/1.1/0.294/1.815	3/24/2012	9:04	COP Ignik Sikumi #1	6/4/2012	na	0.0092	nd	0.0227	0.044	1.04	9.86	nd	89.02	0.0036	nd	nd	nd	nd	nd	nd	nd	nd	6/24/2012	-36.54	-48.36	-241.9		0.605	902	
249125	10/86/1.666/0.318/0.961	3/25/2012	3:15	COP Ignik Sikumi #1	5/30/2012	na	0.0058	0.0028	0.0228	0.053	1.53	10.37	nd	88.01	0.0037	nd	nd	nd	nd	nd	nd	nd	nd	6/24/2012	-36.53	-48.37	-242.8	-1.0	0.612	892	
249126	8/87/3/0.2/0.7	3/26/2012	9:07	COP Ignik Sikumi #1	6/4/2012	na	0.0069	0.0147	0.0215	0.048	1.98	8.45	nd	89.48	0.0037	nd	nd	nd	nd	nd	nd	nd	nd	6/24/2012	-36.92	-48.33	-242.2		0.608	907	
249127	6/90/2/0.173/0.396	3/27/2012	9:54	COP Ignik Sikumi #1	5/30/2012	na	0.0070	0.0065	0.0202	0.041	1.73	6.00	nd	92.19	0.0039	nd	nd	nd	nd	nd	nd	nd	nd	6/24/2012	-37.18	-48.35	-243.4	-1.5	0.596	935	
249128	5/95/1.7/0.15/0.302	3/28/2012	2:34	COP Ignik Sikumi #1	6/4/2012	na	0.0049	0.0042	0.0218	0.087	1.58	5.32	nd	92.98	0.0040	nd	nd	nd	nd	nd	nd	nd	nd	6/24/2012	-37.27	-48.35	-242.4		0.592	943	
249129	4.7/95/1.4/0.119/0.28	3/29/2012	2:42	COP Ignik Sikumi #1	6/4/2012	na	0.0048	0.0043	0.0225	0.085	1.32	4.70	nd	93.86	0.0041	nd	nd	nd	nd	nd	nd	nd	nd	6/24/2012	-37.27	-48.34	-240.6		0.587	952	
249130	4/93/1.2/0.103/0.206	3/30/2012	2:56	COP Ignik Sikumi #1	5/30/2012	na	0.0037	0.0053	0.0214	0.054	1.16	4.25	nd	94.50	0.0043	nd	0.0001	nd	nd	nd	nd	nd	nd	6/25/2012	-36.79	-48.39	-243.1	-1.7	0.583	958	
249131	4/94/1/0.092/0.183	3/31/2012	8:00	COP Ignik Sikumi #1	6/4/2012	na	0.0047	0.0077	0.0213	0.076	1.01	4.04	nd	94.84	0.0041	nd	nd	nd	nd	nd	nd	nd	nd	6/25/2012	-36.34	-48.37	-243.4		0.581	962	
249132	4/96/1/0.09/.193	4/1/2012	8:11	COP Ignik Sikumi #1	5/30/2012	na	0.0034	0.0099	0.0216	0.041	0.95	3.91	nd	95.06	0.0041	nd	nd	nd	nd	nd	nd	nd	nd	6/26/2012	-35.59	-48.38	-245.1	-1.5	0.580	964	
249133	4/96/1/.084/.121	4/2/2012	8:00	COP Ignik Sikumi #1	6/5/2012	na	0.0063	0.0149	0.0217	0.054	0.92	3.82	nd	95.16	0.0040	nd	nd	nd	nd	nd	nd	nd	nd	6/26/2012	-34.87	-48.35	-242.9		0.579	965	
249134	3.8/94/.974/.08/.162	4/3/2012	2:48	COP Ignik Sikumi #1	5/30/2012	na	0.0042	0.0175	0.0268	0.20	0.91	4.21	nd	94.63	0.0041	nd	nd	nd	nd	nd	nd	nd	nd	6/26/2012	-33.72	-47.67	-241.8	-2.7	0.581	960	
249135	0/97/.946/.079/.16	4/4/2012	2:29	COP Ignik Sikumi #1	6/5/2012	na	0.0057	0.0195	0.0222	0.058	0.90	3.76	nd	95.23	0.0040	nd	nd	nd	nd	nd	nd	nd	nd	6/26/2012	-33.25	-48.36	-243.1		0.579	966	
249136	0/100/1/.072/.143	4/5/2012	8:15	COP Ignik Sikumi #1	6/5/2012	na	0.0070	0.0158	0.0215	0.053	0.86	3.57	nd	95.47	0.0041	nd	nd	nd	nd	nd	nd	nd	nd	6/26/2012	-32.48	-48.35	-243.1		0.577	968	
249137	3/94/1/0.07/0.129	4/6/2012	8:04	COP Ignik Sikumi #1	6/5/2012	na	0.0052	0.0161	0.0214	0.046	0.77	3.42	nd	95.72	0.0042	nd	nd	nd	nd	nd	nd	nd	nd	6/26/2012	-31.96	-48.36	-242.8		0.576	971	
249138	3/97/1/.063/.0133	4/7/2012	8:14	COP Ignik Sikumi #1	5/30/2012	na	0.0067	0.0203	0.0215	0.058	0.78	3.32	nd	95.79	0.0042	nd	nd	nd	nd	nd	nd	nd	nd	6/26/2012	-31.56	-48.35	-244.2	-1.8	0.576	971	
249139	3/96/1/0.059/.121	4/8/2012	0:14	COP Ignik Sikumi #1	6/5/2012	na	0.0062	0.0254	0.0220	0.058	0.71	3.24	nd	95.93	0.0042	nd	nd	nd	nd	nd	nd	nd	nd	6/26/2012	-30.78	-48.33	-244.6		0.575	973	
249140	3/96/1/.057/.113	4/8/2012	16:07	COP Ignik Sikumi #1	6/5/2012	na	0.0063	0.0274	0.0218	0.064	0.70	3.19	nd	95.99	0.0042	nd	nd	nd	nd	nd	nd	nd	nd	6/26/2012	-30.00	-48.40	-243.1		0.574	973	
249141	3/97/1/.051/.111	4/9/2012	23:57	COP Ignik Sikumi #1	5/30/2012	na	0.0072	0.0296	0.0211	0.032	0.85	2.99	nd	96.07	0.0043	nd	nd	nd	nd	nd	nd	nd	nd	6/26/2012	-28.45	-48.38	-240.3	-1.9	0.575	974	
249142	3/96/1/.048/.11	4/10/2012	23:46	COP Ignik Sikumi #1	6/5/2012	na	0.0063	0.0290	0.0213	0.049	0.68	2.92	nd	96.29	0.0042	nd	nd	nd	nd	nd	nd	nd	nd	6/26/2012	-27.98	-48.34	-239.6		0.573	976	

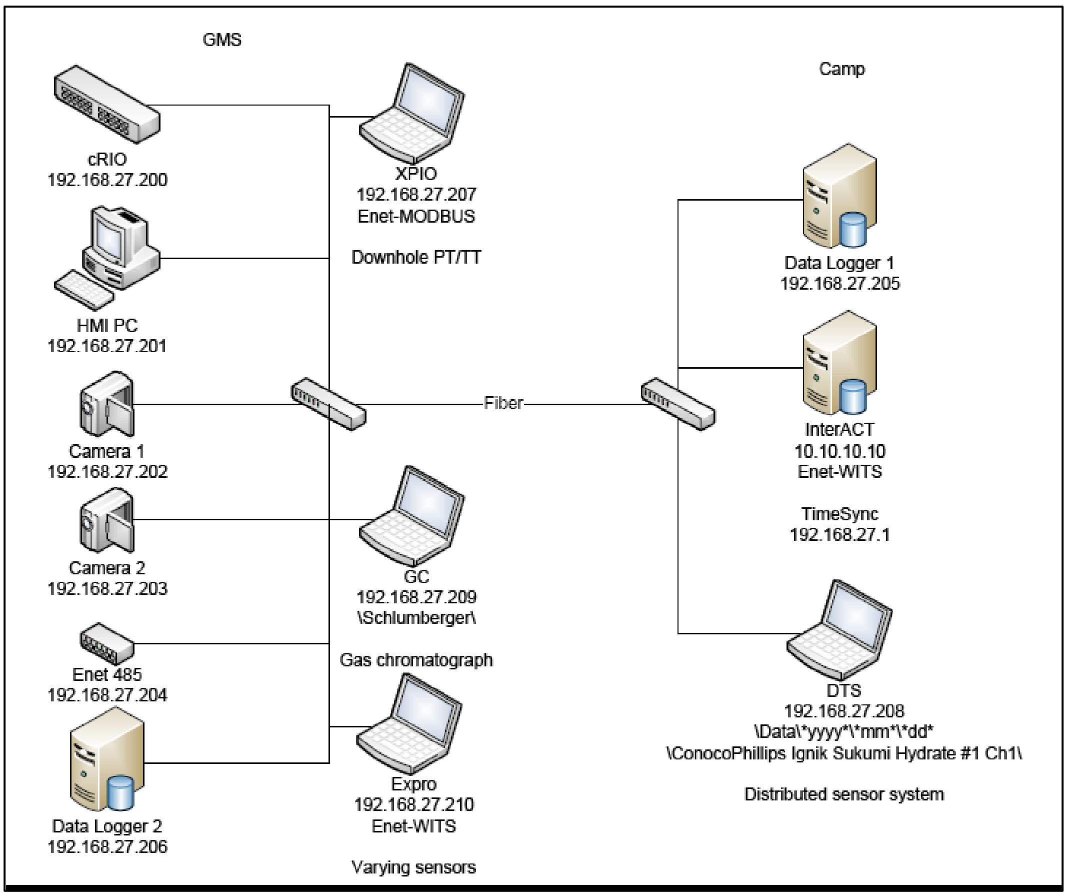
nd = not detected, na = not analyzed

* Nitrogen isotope analyses added on 8/02/2012

Appendix F Database

The Iġnik Sikumi #1 2012 database contains all of the information recorded during the field trial along with corrections and calculations performed. Data sources include an on-line gas chromatograph (GC), three downhole gauges, flow meters, pumps, temperature and pressure sensors, DTS, and water production rates. Schlumberger (SLB) provided data logging for the entire test with data fed from other vendors, including Halliburton (DTS) and Expro (production, separation). All data were fed to a main data logger from the various sources (Figure 109) and recorded in a MySQL database with daily tables. Eight table types were used with variables categorized based on their function (for example, flow, temperature, pressure). The original raw data is provided in the *Raw_Database* folder.

Figure 109: Data streams and data logger used during the field trial.



Supporting documents are included to help future interpretations of the field trial. Additional documentation includes the P&IDs from EXPRO and SLB for all surface facilities. The database includes volumes for all surface lines and equipment in the injection and production streams as well as the wellbore volumes. An operations log contains notes from the well supervisor, SLB, EXPRO, well work, and the production engineers during the pilot. A master variable list identifies each data stream, including all available supplementary information (sensor type, model, calibration parameters, scaling parameters, and so on). In addition, a supporting data document highlights known issues, lists corrections made to the raw dataset, and details how various calculations were performed.

The “clean” dataset was formed using the original data streams from each vendor. Corrections to the dataset included correcting for time-stamping errors, reprocessing all of the GC data, correcting data spikes and noise (especially from the downhole gauges), and renormalizing the DTS data. Because of the large number of data points, one-minute and five-minute time-averaged datasets were created. The one-minute time-averaged data fed all injection and production calculations, which are provided with the database.

The final database is in MS SQL 2008 R2 format and includes an installer. Following installation of the database, the clean datasets and the time-averaged datasets must be restored into the database. A data extraction tool allows users to extract CSV format files of select data. In addition to using the database, all data are already available and included in both CSV and Matlab formatted files. DTS playbacks in mp4 format have been provided for the entire test at three ranges: full wellbore, 2150-2350 ft, and 2230-2280 ft.

Appendix G Operations Report

This section of the report contains a copy of the Time Log and Summary Report file that was generated for the Iġnik Sikumi Well #1 during the test phase of this project.

Time Log & Summary Report

ConocoPhillips Wellview Web Reporting

Well Name: IGNIK SIKUMI 1
Job Type: TEST-LOG-PROFILE

Rig Name: CPAI IGNIK WELL TEST
Rig Accept: 1/12/2012 12:00:00 AM
Rig Release: 5/4/2012 10:00:00 PM

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
01/12/2012	**24 hr Summary** Attended morning PJSM at Ignik Camp with camp personell and Prec. Power Electrician, Simplex Grannell. Spot Precision Power equipment (2 gen sets, 2 fuel tanks, switch shack, equip. shed) in containment area. Applied heat to warm up equip. Set Wellhouse and applied heat to warm up tree. Continued working on camp. Wiring up alarm system (smoke detectors), telephones and computers. Bullcooks continue to prep rooms and kitchen. Super - chlorinated water has been circulated thru water system, waiting 24 hrs before flushing and testing. Lined up 3rd party services for potable water and waste water. Held pre-planning Gen-set installation duct work meeting.									
	00:00	00:00	24.00			SURPRI	FLOWT	RURD	P	Attended morning PJSM at Ignik Camp with camp personell and Prec. Power Electrician, Simplex Grannell. Spot Precision Power equipment (2 gen sets, 2 fuel tanks, switch shack, equip. shed) in containment area. Applied heat to warm up equip. Set Wellhouse and applied heat to warm up tree. Continued working on camp. Wiring up alarm system (smoke detectors), telephones and computers. Bullcooks continue to prep rooms and kitchen. Super - chlorinated water has been circulated thru water system, waiting 24 hrs before flushing and testing. Lined up 3rd party services for potable water and waste water. Held pre-planning Gen-set installation duct work meeting.
	00:00	00:00	0.00			SURPRI	RPEQPT	PULL	P	1-4-12 Pulled BPV and confirmed no VR plugs in annulus valves. Installed integral flanges and associated jewelry.
01/13/2012	Spot PP GenSets, Fuel Tanks, Switch Shack & apply heaters to warm up. Continue prepping camp.									
	00:00	00:00	24.00			SURPRI	FLOWT	RURD	T	All outside work ceased due to Phase weather conditions. Continued on inside camp work (fire detection system and water). Sent water samples to Lab for potable water. Install fire detection control panel.
01/14/2012	Weather hold Phase II. Continue on camp inside work.									
	00:00	00:00	24.00			SURPRI	FLOWT	RURD	T	Weather day, all outside work on hold for high winds and cold temps.
01/15/2012	Prep WH for Skimpy Panels, Spot rig mats for CO2 tanks. Move snow									

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Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	00:00	00:00	24.00			SURPRI	FLOWT	RURD	T	Clear snow after blizzard. Set rig mats & cribbing prepping for floats. Start installing duct work on Gen Sets. Precision Power connected fuel tanks to Gen Sets, preped Gen Set and Swich Gear Shear for start up. Continued prepping camp for move in.
01/16/2012	Clear snow from pad from blow. Spot two floats and rig mats for setting CO2 & N2 tanks. Install platform inside wellhouse and install Skimpy Panels for both SSV's. Continued hookups for Prec. Power GenSets. Shut down all outside work because of Phase II weather.									
	00:00	00:00	24.00			SURPRI	FLOWT	RURD	T	Clear snow from pad from blow. Spot two floats and rig mats for setting CO2 & N2 tanks. Install platform inside wellhouse and install Skimpy Panels for both SSV's. Continued hookups for Prec. Power GenSets. Shut down all outside work because of Phase II weather.
01/17/2012	Weather hold, 25-35 MPH winds / Phase I/II. Continued working on Hook ups to Gen sets until weather hold. Civil crew worked on permanent well head platform and hung one Skimpy pannel. Spotted rig mats and floats for cryo tanks.									
	00:00	00:00	24.00			SURPRI	FLOWT	RURD	T	On weather hold, Phase conditions. Plan to perform camp safety inspection pending weather.
01/18/2012	Attempted to reach camp mid day for safety inspection convoy turned around at 1D pad due to poor driving conditions. Winds reduced during the night DTH able to remove snow with dozer and loader.									
	00:00	00:00	24.00			SURPRI	FLOWT	RURD	T	All outside work shut down due to Phase II weather. Camp alarm installation completed and tested.
01/19/2012	CPAI Safety performed camp safety inspection. Camp is approved for occupancy. Civil crew Installed second surface safety valve panel and continued work on permanent well head platform. Spotted SLB N2 tanks, CO2 tank, GMS, Line Heater, and SLB tool house									

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	00:00	00:00	24.00			SURPRI	FLOWT	SFTY	P	Performed camp safety inspection mid morning with Al Bergh - Gary Gauthier CPAI safety and Keith Dukowitz Nordic camp manager. Camp is approved for occupancy. Precision power back up genset (power to block heaters on mains) went down during the blow. Back up has been taken in for servicing. Construction need to build stairs and a cat walk to fuel the Precision power tanks. Ordered out additional snow removal around precision power equipment and SLB staging sites. Two light plants and one heater down, requested service. Lynden delivered SLB equipment standing by for Peak crane. Civil crew continues to work on permanent well head platform. Second skimpy panel mounted. 3:50 pm spot crane to pic N2 tanks, CO2 tank, GMS, Line Heater, and SLB tool house.
01/20/2012	Off loaded remaining palletized SLB equipment from trailers. Installed temporary power the GMS unit for lights and heat. Unloaded GC, GMS computers, and Well Site Data Hub. Installed exhaust louver on Well site Gen set #1.									
	00:00	00:00	24.00			SURPRI	FLOWT	RURD	P	Phase 1 Level 1. Contacted SimOps for scaffolding crew to build stairs and catwalk to access fuel hatch during fueling of well site generators. 9:00 Held prejob safety meeting with Al Bergh CPAI safety, loader operator, SLB crews. Discussed off loading of remaining pallets from Lynden trailers, installation of well site gen set louvers. John Brooks Precision power to investigate temp power to GMS unit and SLB skid until main gen sets can be fueled. SLB crews pulled shipping plywood from GMS and removed snow from revetments around the 400 bbl upright tanks and 125 bbl Glycol tank and begin rigging up fittings. Precision power was able to run a temp power line to the GMS. The lights are on and the unit is warming up. One exhaust louver was successfully installed on Gen set #2. SLB transported the Gas Chromatograph, GMS computers, and the Well Site Data Hub to location. Phase 1 canceled at 5:30 pm Scaffold crew scheduled to walk down job site at 7:00 am.

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Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
01/21/2012	**24 hr Summary** Held pre job safety meeting. Unloaded and staged construction material. Installed exhaust louver on well site generator #2. Scaffold crew walked down job will return to construct stairs to access fuel tanks. Crews installed SLB treating line revetments. GMS unit is warm. Well head platform work ongoing.									
	00:00	00:00	24.00			SURPRI	FLOWT	RURD	P	06:00, held pre job safety meeting in conference room. DTH loader operator stuck behind rig move showed up after 9:00 with trailer of construction material. Unloaded and staged construction material. Installed exhaust louver on well site generator #2 and fuel lines to both generators. Civil crew also stuck behind rig move showed up after 9:00 begin working on permanent well head platform. Platform required extensive modification due to tree design with double SSVs above the deck. Scaffold crew showed up ~10:00 to walk down job and left. Hand-Y-Berm & SLB crews laid out treating line revetment for all SLB lines. Temporary gen set on GMS and Precision Power main generator block heaters failed. Gen set rigged down, removed and replaced. Temp Power to GMS back on entire unit is warm. Civil crew rigged down for the day, platform work ongoing. Held post job safety / planning meeting 19:00.
01/22/2012	Held prejob safety meeting. On weather hold, ambient temp below -35. DTH loader operated under variance to assist in trenching. installed SLB and HES fiber optic leads from camp to well house and GMS. Terminated SLB leads in camp and at GMS. Terminated HES leads at camp.									

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Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	00:00	00:00	24.00			SURPR	FLOWT	RURD	P	0600 pre job safety meeting. Wind chills -50 - conducted safety assessment. 0700 HES crew on location prepping to lay fiber optic cable. 0730 ambient temp dropped to -36 all hydraulic equipment idled, per support groups cold weather operating policy. Canceled trenching operations regrouped and held ops meting. 0800 SLB mechanic and Precision power electrician on site moving forward with burner installation. 0900 cold weather variance signed with DTH allowing loader operations below -35F ambient. DTH dispatched with materials for insulated containment and loader mounted trenching device. 1030 -38 F ambient. HES setting up DAS DTS equipment. 1515 making up 1" jointed conduit to burry SLB and HES lines. Gouged out a 4" trench from camp to the well house. Made up 1" rigid conduit, snaked HES and SLB lines through conduit to well head and GMS unit, lay conduit in trench and packed ice back in the trench. Terminated SLB leads in the GMS and camp. Terminated the HES leads in camp. -42 F.
01/23/2012	Held pre job safety meeting. Wind chills -80, -51F ambient. Found ATF leak on pad after truck backed away from containment. Vehicle secured, Security notified and PIR e-mailed. Scaffold crew installed stairs to fuel tanks. Watered in the trench containing the fiber optic lines to the well. Crews laid out blue board insulation for all SLB surface lines and installed the 1502 high pressure treating iron gas line from the GMS to the well. SLB lost connectivity between their fiber optic line some time between 1100 and 1200. SLB mechanic installed the line heater burner assembly and Peak precision power hooked up temporary power. Attempted to test fire the burner but had issues with the controller.									

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	00:00	00:00	24.00			SURPRI	FLOWT	RURD	P	0600 pre job safety meeting. Wind chills -80, -51F ambient - conducted safety assessment 0844 found ATF leak on pad in front of camp. Found Peak truck # K307 with transmission leak. Truck turned off, containment pool placed under transmission and tow truck called. Security notified and PIR e-mailed out. 0945 scaffolding crew on location setting stairs to fuel tank. 0952 watering in the trench containing the fiber optic runs to the well. SLB crew drove to DTH to cut support blocks for treating iron. 1200 scaffold crew finished stairs and catwalk to fuel tanks. Bulk fuel truck ordered, ETA 0800 1-24 Crews laid out blue board insulation for all SLB surface lines and installed the 1502 high pressure treating iron gas line from the GMS to the well. SLB lost connectivity between their fiber optic line some time between 1100 and 1200. Efforts were made to reestablish connectivity through all 6 pairs but failed. HES aided by measuring the distance of the continuous fiber optic line. It appears as if the break is near the well head. . SLB mechanic installed the line heater burner assembly and Peak precision power hooked up temporary power. Attempted to test fire the burner but had issues with the controller. SLB is scheduled to call burner manufacturer in the am. Temperatures continue to be very cold all outside work is very slow with warm ups.
01/24/2012	Held pre job safety meeting. Wind chills -80, -51F ambient. Discussed continued cold weather and plan forward. All outside labor shut down unless work can be carried out with an enclosure and use of direct fired heaters to provide protection from the elements. SLB safety presented COP cutting policy, foul weather policy, traction policy, impact gloves, and when to go to the medic to the crew. Burner on the line heater fired successfully. No success reestablishing connectivity in the SLB fiber optic lines.									

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	00:00	00:00	24.00			SURPR	FLOWT	RURD	T	0600 safety / ops meeting. Discussed continued cold weather and plan forward. Well site fuel tank prepped for fuel delivery, wind break set up and nut plug down. 0800 call from town to discuss cold weather operations. All outside labor shut down unless work can be carried out with an enclosure and use of direct fired heaters to provide protection from the elements. Walking traffic allowed between the camp and GMS, work allowed in the GMS, well house, equipment connex, and line heater hooch, with hand tools, no power tools, large hammers or saws. On weather hold. Called CH2Mhill dispatch and canceled bulk fuel delivery until the weather breaks. Non mobile fuel continues as well as trucking of potable and waste water. 1328 SLB established connectivity to the Well Site Data Hub through the COP network. 1517 Peak wrecker leaving location with peak box van # K307. 1530 SLB safety held safety presentation covering COP cutting policy, foul weather policy, traction policy, impact gloves, and when to go to the medic. Burner on the line heater fired successfully. No success reestablishing connectivity in the SLB fiber optic lines. Water found in the conduit may have expanded and damaged the cable.
01/25/2012	Held pre job safety meeting. Wind chills -80, -51F ambient. Found ice free conduit 70' back from the well head but unable to move cable. Mounted Isco syringe pump in GMS. Crew change. Extreme cold weather hold.									
	00:00	00:00	24.00			SURPR	FLOWT	RURD	P	Held pre job safety meeting. Wind chills -80, -51F ambient. 0729 found ice free conduit pipe 70' back from the well head attempting to move wire. It wiggles freely but will not pull by hand. Took 100' of 3" soft hose to KIC to warm it up in the shop. Mounted Isco syringe pump in GMS. Precision Power electrician checked fluids on the temp power gen set. Crew change.
01/26/2012	Continue to wait on weather. Reviewed site control/safe work area with crews. Fiber optic line pulled free in conduit. Held pre job meeting to discuss reinstalling cable then pulled additional cable to well head through new conduit. Reestablished connectivity to the GMS skid though the SLB fiber optic line. Established connectivity with XPIO, Gauge #1 937.602 psi Temp 41.004F, Gauge #2 909.061 psi Temp 40.236F, Gauge #3 816.561 psi Temp 36.557F While fueling temp generator riser burped spilling1/2 gal diesel into secondary containment. Diesel cleaned from containment with adsorbent and bagged for disposal.									

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	00:00	00:00	24.00			SURPRI	FLOWT	RURD	P	0600 ops / safety meeting, new crew orientation. 0630 engineering ops call in. 0700 site control/safe work are review with crews. 0824 GMS temp gen set went down ½ tank of fuel, GMS still warm. 0900 lost three heaters. 0930 water truck attempting delivery frozen off, returning to shop to thaw. Fill in camp manager and staff alerted. Comm with crews to conserve water. 1100 attached cable clamp and com along to SLB fiber optic bundle. Applied a small amount of tension and cable popped loose, entire string is moving freely. Crews in for lunch and warm up. 1247 pre job meeting to discuss reinstalling cable. replacement heaters on location. Performed Visible fault locator (VFL) check of SLB cable, checked ok. Cleared trough of drifted snow and residual ice. Lay out replacement conduit. 1500 temp gen set back online. water delivered to camp. 1530 pulled additional cable to well head trough new conduit. 1545 new fiber pulled to GMS and well house. Checked SLB with VFL, checked ok. Pulled HES line into well house and SLB cable into GMS break for warm up. Spliced connectors onto the end of SLB fiber. 1900 connectivity to the GMS skid though the SLB fiber optic line. Temp gen set to GMS back down. Called electrician to replace GMS generator. No spare gen set at this time. Bringing new alternator. Established connectivity with XPIO, Gauge #1 937.602 psi Temp 41.004F, Gauge #2 909.061 psi Temp 40.236F, Gauge #3 816.561 psi Temp 36.557F. 2100 electrician on site fueler on site. While fueling temp generator riser burped spilling1/2 gal diesel into secondary containment. Diesel cleaned from containment with adsorbent and bagged for disposal. Well Supt, notified, security notified, PIR emailed.
01/27/2012	HES acquiring data with DTS and DAS. Optimation established conection from GMS through Well Site data Hub to Interact server and transferred data. Modified Precision power temp gen set fuel fill riser. Had safety / ops meeting with CH2M Hill fuelers Filled temp gen set with no issues.									

Time Logs

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	00:00	00:00	24.00			SURPRI	FLOWT	RURD	P	0600 ops / safety meeting, new crew orientation. 0630 engineering ops call in. Water truck and fuel truck on location. Filling camp and non mobile equipment then bulk generator fuel tank. Additional safety/ spill discussion outlining fill procedure and spill mitigations regarding temp generator and bulk well site fuel tank. 0900 HES at well head terminating DTS and DAS lines. Optimation established connectivity from GMS through Well Site Data Hub (WSDH) to SLB interact server in Sedalia. Precision power on location, installed shorter fuel riser ~ 4", stood by for fueling procedure, flagged and attached long fuel riser to generator for reinstallation before temp gen set is moved. Gen set fueled with no issues, elevated the front end, installed 4" riser. Discussed fueling the generator bulk tank. This is not the bulk hose, they have no connection to dry lock. Abort attempt until proper hose with dry lock can be used. Held safety ops meeting with CH2M Hill fuelers regarding 5000 gal bulk tanks fill procedure. 2" dry lock male to be installed on ULSD generator tank. 3" male dry lock to be installed on LEPD tank for line heater. Small fuel truck to be used for filling camp, non mobile equipment, and well site generators. Large bulk truck will be used to fill SLB line heater. 1425 HES terminating their fiber optic cable at the camp. 1500 acquiring DAS data. 1600 acquiring DTS data. 1800 SLB crew performed walk around. Temp GMS gen set still operating.
01/28/2012	Valve crew serviced tree valves and filled flow back SSV with hydraulic fluid. Rigged iron from GMS to edge of well house on fluid side and from well house to 125 bbl tank on flow back side. Hooched and heated main power spools									

Time Logs

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	00:00	00:00	24.00			SURPRI	FLOWT	RURD	P	0600 ops / safety meeting. 0630 engineering ops call in. Phase 1 driving conditions due to slick roads, drifting snow, and lack of maintenance. Scheduled Down Hole Diagnostics (DHD) crew to perform MITT / MITIA on 1/22/12. Contacted valve shop re service tree valves. Discussion over wind chill as it relates to equipment. Scheduled to service tree as soon as reasonably possible. Lost 3 heaters during the night. 0900 day mechanic on location to start loader. Requested Peak Precision power bring grinder and ground plates for bonding. 1320 loader up and running waiting on DTH operator. 1400 valve crew on location to service tree. 1420 loader operator on location spotting power cables. 1530 valve crew serviced tree valves and filled flow back SSV with hydraulic fluid. Attempted to fill injection side SSV with hydraulic fluid, exterior mounted dump valve failed and was leaking by to dump reservoir. Rigged iron from GMS to edge of well house on fluid side and from well house to 125 bbl tank on flow back side. Hooched and heated main power spools. Loader operator smelling fumes in cab suspects heater core leak. No drips apparent. Stopped loader, attached drip pan to loader with sash cord and returned the loader to KOC shop for PM / repair.
01/29/2012	Pulled wire to all SLB equipment, ongoing. Lay out and rigged up hard hose, ongoing. Performed MIT-T - Passed, MIT-IA, passed. IA shows communication with the chemical injection line. Drift well to 3.58" to 2350'									

Time Logs

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	00:00	00:00	24.00			SURPRI	FLOWT	RURD		0600 ops / safety meeting. 0630 engineering ops call in. 0800 DHD on location, held pre job, issues with wellbore sync, reviewed well bore schematic and procedure with crew.0926 DTH on location delivering cut plywood for revetment base. Peak Precision power on location running small gauge wire. 0930 DTH update on loader approximately 1 hr out. 1030 DHD on location to perform MITT / MITIA. Fluid levels at surface, T/I/O = 0/0/40 CI=0 Heater =0 Pumped IA to 400 and tubing to 3000 psi. Start T/I/O = 3000/440/40 CI = 420, Heater 510. 15 min T/I/O=2900/400/40 CI =445 Heater 500. 30 min T/I/O = 2850/400/40 CI=440 Heater 400. 45 min T/I/O = 2850/400/40 CI=325 Heater = 390. Tubing passed. Bleed CI line, IA tracked. Bleed Tubing. MITIA initial T/I/O = 600/75/40/ CI = 0 Heater = 50. Start T/I/O = 100/3000/40 CI 2950 Heater = 2950. 15 min T/I/O = 1050/2800/40 CI=2800 Heater= 2810. Bumped pressure, T/I/O = 1100/3000/40 CI=3000 Heater= 3000. 15 min T/I/O= 1100/2960/40 CI=2960 Heater = 2950. 30 min T/I/O = 1100/2950/40 CI=2940 Heater = 2950 Passes IA to T but CI in communication with the IA. Bleed CI line, T/I/O 1080/2525/40 CI=2500 Heater =2500. Bleed CI line second time T/I/O 980/1950/40 CI=1925 Heater 1960. Shut down stung into test port with test tool, void at 0 psi, clean test fluid. Tried to bleed CI again will not bleed down, frozen line at bleed tank. Thaw lines and pump 10 gal diesel down CI line. Rig down DHD. Run power lines to all electrical. SLB equipment and begin to terminate lines. Lay hard hose from 125 bbl tank to GMS continue to build insulated boxes. Slick line on location, RU, drift W 3.58" to 2350' RDMO
01/30/2012	Temps dropped to -40 F. Filled well site generator tank. Installed discharge hoses from GMS to SLB line heater and GMS to 125 bbl tank. Staged tree iron in well house. Terminated GMS power lead at switch shack and both leads of SLB connex.									

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Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	00:00	00:00	24.00			SURPR	FLOWT	RURD	P	0600 ops / safety meeting. 0630 engineering ops call in. 0700 walked through possible wellview reporting issues with support. Can't find a problem. Note, some time log entries on second page of report because they are too long and not broken out. 0745 -35F winds calm. 0859 cold weather alert -36F all hydraulic driven equipment need Supt variance to operate. 0915 alerted that the camp has no water service. Water back up, then down, then up again. Fueled the well site generator main tank 3700gal. Constructed and installed all discharge hose from SLB line heater to GMS and GMS to 125 bbl open top tank. Valves and T's placed to tie into Expro treating lines once on location. Heated all high pressure valves on SLB heater, shut in bypass, opened suction and discharge valves. Staged tree iron in well house. 1245 -40 F ambient crews traveled to KOC for CPA Supt orientation meeting and to construct hard hoses in KOC shop. Precision power terminated GMS power leads at switch shack and both leads of SLB connex.
01/31/2012	Unloaded 3700 gals. USLD fuel for Glycol Heater. Continue building blue board boxes for hoses. Accepted dilivery of 4000 gals N2 and loaded into N2 tanks. . Hardwire CO2 tank electrical plug. Optimation worked on Inter-Act channels for data transfer.									
	00:00	12:00	12.00			SURPR	FLOWT	OTHR	T	Cold weather alert -36F all hydraulic driven equipment need Supt variance to operate.Current conditions -44F Winds SW 6 mph. Unloaded 3700 gals. USLD fuel for Glycol Heater. Continue building blue board boxes for hoses.
	12:00	00:00	12.00			SURPR	FLOWT	RURD	P	Accepted dilivery of 4000 gals N2 and loaded into N2 tanks. Discovered that CO2 tank plug is incorrect. Made dicission to hardwire CO2 tank (original plan). Optimazation worked on Inter-Act straightening out channels.
02/01/2012	Attend morning PJSM. Continue SLB hookup as much as possible under weather conditions. Peak ordered disconnects for transfer house.									
	00:00	12:00	12.00			SURPR	FLOWT	OTHR	T	Cold weather alert -36F all hydraulic driven equipment need Supt variance to operate.Current conditions @ 0600 hrs -46F Winds SW 6 mph, temps dropped to -51 F.

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Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	12:00	00:00	12.00			SURPRI	FLOWT	OTHR	P	Continued blue board construction. Change out day for SLB. Built blanking caps for PT lines w/N2. Hang fall retractable harness on line heater. Put double thread 206 on suction and discharge of 125 bbl tank for Expro hookup. Worked on connex. Work on N2 guages. Made supply and return hoses for N2 and CO2. Peak ordered disconnects for transfer house. Waiting on parts for finishing electrical.
02/02/2012	Electricians pulled wire, relocate and reconnect transformer. Ground all equipment present on location . SLB continued blue board boxes. Pressure test all lines. Pressure test all lines and work on blue board.									
	00:00	12:00	12.00			SURPRI	FLOWT	RURD	P	Temps warmed up this morning -29 F. Resumed work. Electricians pulled out 500 MCM cable from GMS skid. Relocaated 50 amp fuse disconnect. C/O transformer to SLB tool house. Reconnect heaters to 50 amp disconnect to SLB tool house power feeder. Everything on site except Expro equipment (not arrived) has been grounded. Mounted 100 amp disconnect to CO2 tank. Parts have been Goldstreeked today. ETA = Friday.
	12:00	00:00	12.00			SURPRI	FLOWT	RURD	P	SLB, pressure test hoses & secure to hard line. Work on blue board. Expro crew arrived, set in on Kuparuk Orientation and issued badges.
02/03/2012	Filled line heater w/Tritherm 42 bbls. Tested chem. inj. line to 1100 psi (ice plug?). Performed PPOPT test on uper seal seal of W.H. Pressure test hoses with air. Installed knife for connex heat and CO2 tank.									

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	00:00	12:00	12.00			SURPRI	FLOWT	RURD	P	PJSM & opts meeting w/ SLB & Expro & Pinnacle. Covered all orientations, site control, Kuparuk and the 2012 Denali Ascent. Load SLB line heater w/42 bbls TriTherm. Performed PPPOT Test on top seal of wellhead. Set rack of N2 bottles near wellhouse. Installed a high pressure hose from the IA to the open top tank w/needle valves to control bleed to the bleed tank. Install high pressure hose from the N2 bottles to the Chemical injection valve on the wellhead. Opened N2 bottles to the needle valve on the chem. inj. line (1100 psi bottle pressure) Open needle valve to the chem inj. line and it pressured up immediately to 1100 psi. Held pressure for 10 min. No movement. Closed needle valve, bled press from hoses and disconneted. Bled pressure down from chem. inj. line from 1100 psi to 0. Closed needle valves. RD.
	12:00	00:00	12.00			SURPRI	FLOWT	OTHR	P	Pressure test discharge hoses. Attempt to run line heater and adjust burners but unable to get fuel from Precision fuel tanks. Applied heater to suction lines. Hooked up pressure sensor cords from GMS to tanks. Pressure test hoses from N2 & CO2 tanks. Knife swithch installed for the CO2 tank. Knife switch for the connex heat installed.
02/04/2012	Finish Blue board, work on Fuel Tanks, dial in Heater, install SSV Control in GMS, mounted all disconnet & wired, terminate to GMS & bring Gen on line.									
	00:00	12:00	12.00			SURPRI	FLOWT	RURD	P	PJSM w/ both crews (SLB & Expro). SLB clear fuel lines and get fuel flowing from tank to line heater and generators. Start up line heater and adjust burner. Install SSV control in opts cab of GMS. Installed battery covers on valves on N2 & CO2 tanks & electric cords. Finished blue board boxes.
	12:00	00:00	12.00			SURPRI	FLOWT	RURD	P	Mounted and wired 4 disconnects. Terminate to GMS and bring Generators on line. Expro cleaning out tank farm containment removing snow and prepping for arrival of equipment.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
02/05/2012	**24 hr Summary** Received and unloaded Atigun House and two other loads for Expro. Rig up to well for warming ops. Double check that we are able to pump down the flatpack, or the annulus. Also verified we can circulate as planned. PT Hardline for Glycol system Wire in AC to CO2 Tank, Test¿ Peak CO2 Tank Power Umbilical for CO2 Transport Pressure test HP Glycol lines. Ensure we have valves to circulate through the heating coils. Displace Diesel into 125 BBL Tank									
	00:00	12:00	12.00			SURPR	FLOWT	OTHR	P	Received and unloaded Atigun House and two other loads for Expro. Rig up to well for warming ops. Double check that we are able to pump down the flatpack, or the annulus. Also verified we can circulate as planned. PT Hardline for Glycol system Wire in AC to CO2 Tank, Test¿ Peak CO2 Tank Power Umbilical for CO2 Transport
	12:00	00:00	12.00			SURPR	FLOWT	OTHR	P	Pressure test HP Glycol lines. Ensure we have valves to circulate through the heating coils. Displace Diesel into 125 BBL Tank
02/06/2012	Transfer load of CO2 to tank. Continue to circulate warming wellbore. Trouble shoot main generator, and connect up Expro. Expro continue to rig up.									
	00:00	12:00	12.00			SURPR	FLOWT	OTHR	P	Continue circulating Glycol/water adjusting the circulation temps & rate through the line heater to manage the wellbore temperature. Brought temps up at 60' to 32 F, 61F at the turn around 1968'.
	12:00	19:00	7.00			SURPR	FLOWT	OTHR	P	Expro continue rig up and waiting delivery of last two loads of equip. CO2 arrived, purged tank and loaded 22 tons into our tank. PP electrician trouble shoot generator and hard wire power from the gen-set to the heater for the CO2.
	19:00	00:00	5.00			SURPR	FLOWT	OTHR	T	Ceased operations to work on CO2 tank. Wait on CO2 transport to return and empty tank. Contacted BP L&V Pad Operator and advised of small CO2 leak and will keep him advised.
02/07/2012	Install guard rails around CO2 tank upwind. Wait on Air Liq. CO2 transport to come back and empty CO2 tank.									
	00:00	00:00	24.00			SURPR	FLOWT	OTHR	T	Install guard rails around CO2 tank upwind. Wait on Air Liq. CO2 transport to come back and empty CO2 tank. Monitor and keep pressure on CO2 tank above 200 psi. All work on pad on hold until problem is remedied.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
02/08/2012	**24 hr Summary** Offloaded CO2 onto truck. Depressurized tank. Repaired tank. Started filling CO2 tankw/N2 for PT Built Hootch over CO2 tank to keep warm. Expro cont'd rig up. Electrician trouble shooting generator.									
	00:00	12:00	12.00			SURPRI	FLOWT	OTHR	P	0300 Air Liquide CO2 truck arrived on location. Off load CO2 from tank to truck. Depressurize CO2 storage tank. Inspected tank in area of leak and found 1 1/2" nipple not screwed into coupling tight enough and nipple was broken in the thread section. Chased threads on collar, replaced 1 1/2' nipple, secured all fittings with proper torque.
	12:00	00:00	12.00			SURPRI	FLOWT	RURD	P	Re-start circulating Glycol, warming up wellbore. Start filling CO2 tank with N2 for pressure test. Sent CO2 truck to KIC shop to warm up. Built a hootch over the CO2 tank and applied heat to keep tank temp above 0 °F. Expro continued rig up. Electrician trouble shooting generator problem. Rig up prep for Coil Tubing.
02/09/2012	Continue warming well bore. Plumb GC unit. Terminate the electrical on the GC unit. Continue to trouble shoot the Primary Generator.									
	00:00	12:00	12.00			SURPRI	FLOWT	OTHR	P	Continue pumping glycol warm the well bore. Plumb in the GC unit and terminate the electrical.
	12:00	00:00	12.00			SURPRI	FLOWT	OTHR	P	Precision Power (Peak) continue to trouble shoot the Primary Generator. Expro continue rigging up for flowback. 12:00 Reversed Glycol flow to down the annulus and return up the Flat pack. Shut down heating of well bore, temps were over 40°F thru-out the annulus.
02/10/2012	Inspect CO2 Tank. Trouble shoot Generator. CT clean out of well bore. CT lost gear box. Start repair.									
	00:00	07:00	7.00			SURPRI	FLOWT	RURD	P	MIRU, PJSM WITH SLB N2 PUMPERS, LRS, CTS, WELL ENGINEER, WELL SITE SUPERVISOR. COMPLETE RIGGING UP CT, LRS, N2 UNIT AND GMS SKID. PRE- JOB ON PT. PT HARDLINE AND LUBRICATOR WITH LRS TO 350/4000 PSI. PT N2 LINES AND GMS UNIT WITH N2 TO 500/3800 PSI.
	07:00	09:00	2.00			SURPRI	FLOWT	OTHR	P	DISPLACE CT WITH 30 BBLS, 104 DEGREE SEAWATER. MU SOL ONLINE FOR 8 BBLS 1.1 BPM CIRC PRESS = 3000 PSI.
	09:00	09:30	0.50			SURPRI	FLOWT	OTHR	P	OPEN WELL. ZERO AT TBG HANGER, PUH TO BUMP AT STRIPPER. RIH PUMPING AT 1 BPM. CIRC PRESS = 2750 PSI. MU-SOL AT NOZZLE AT 2000 FEET.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	09:30	10:15	0.75			SURPRI	FLOWT	OTHR	P	INCREASE RATE TO 1.2 BPM PUH AT 60 FT/MIN TAG STRIPPER.
	10:15	11:00	0.75			SURPRI	FLOWT	OTHR	P	ONLINE WITH SEA WATER RIH TO 2039' CTMD COLD WATER ONLINE AT 140.7 MM TOT. CIRC PRESS = 3850 PSI. WAIT AT 2039' FOR COLD WATER TO EXIT NOZZLE.
	11:00	11:30	0.50			SURPRI	FLOWT	OTHR	P	RIH TO 2139' AT 30 FPM PER K.L.M. WAIT AND MONITOR TEMPERATURES.
	11:30	11:45	0.25			SURPRI	FLOWT	OTHR	P	DECREASE RATE TO .8 BPM CIRC PRESS = 2037 PSI. DECREASE RATE TO .5 BPM. CIRC PRESS = 1116 PSI.
	11:45	12:45	1.00			SURPRI	FLOWT	OTHR	P	LINE UP SLB N2 DOWN THE CT TAKING RETURNS UP THE CT ANN. AT 350 SCF. RIH AT 30 FPM. TAG AT 2353.6' PUH 10 FEET AND WAIT ON N2 TO EXIT NOZZLE. PUH DISPLACING H2O FROM TBG AT 35 FPM.
	12:45	14:15	1.50			SURPRI	FLOWT	OTHR	T	LOST ALL HYDRAULIC PRESSURE TO UNIT.CLOSED PIPE RAMS. AND MANUALLY LOCKED. INCREASED N2 TO 1500 SCF BLOW DOWN CT AND CT ANNULUS.MECHANIC ON LOCATION. DIANOSED PROBLEM UNIT SHUT DOWN PENDING REPAIRS.
	14:15	00:00	9.75			SURPRI	FLOWT	OTHR	T	Expro continue rig up 90% complete. SLB work on GC w/Keith. Prec. Power trouble shoot Generator. Alaska State Boiler & Vessel Inspector on location and inspected SLB's CO2 Tank with no problems.
02/11/2012	Finished repairs on gearbox of Coil Tubing Unit. Completed wellbore clean out. Purge coil tubing with Nitrogen. Displace 4 1/2" tubing w/traced N2: CO2 blend.									
	00:00	05:00	5.00			SURPRI	FLOWT	RURD	T	Precision Power Electrician waiting on Cummins Technician and parts to repair Primary Generator. SLB repair software delay. Practice, set up for testing. flowed mixed gas out Bruce valve w/tracer, tested with GC. Opened CO2 tank to make sure lines are clear. Expro and Scaffolding crew constructed Hootch over end of Atigun Building. Waiting on crane for setting up flare and adjusting upright tanks. Will share crane with perforators.
	05:00	08:30	3.50			SURPRI	FLOWT	OTHR	T	WAIT FOR MECHANICS TO COMPLETE REPAIRS TO UNIT.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	08:30	09:00	0.50			SURPRI	FLOWT	OTHR	P	PJSM AND OPS MEETING, FUNCTION OPEN BOPE, OPEN CHOKE. PUH , RIH ADJUSTING RIH SPEEDS TO FUNCTION CHECK HYDRAULICS. N2 PUMP COOLING DOWN. RIH TAG PO BUSHING CORRECT DEPTH TO 2371'. PUH TO 2361'
	09:00	09:45	0.75			SURPRI	FLOWT	OTHR	P	PT N2 PUMP TO 500/4000 POUNDS. ONLINE N2 DOWN CT AT 500 SCF. INCREASE RATE TO 1500 SCF.
	09:45	10:45	1.00			SURPRI	FLOWT	OTHR	P	WHP = 150 PSI PUH AT 15 FT/MIN. CIRC PRESS = 1475 PSI. PARK CT AT 1994' CIRCULATE N2 DOWN THE CT AND UP THE CT ANN.
	10:45	12:00	1.25			SURPRI	FLOWT	OTHR	P	SHUT DOWN N2, LINE UP TO REVERSE CIRC DOWN THE CT ANN AND UP THE CT. RIH TAG AT 2371' REVERSE CIRCULATE. WATER AT SURFACE H/L AT TANKS FREEZING HOOKED UP HEATERS HAD METH. DELIVERED. SLIPSTREAM DOWN STREAM OF CHOKE .
	12:00	14:30	2.50			SURPRI	FLOWT	OTHR	P	POOH TO SURFACE BLEEDING DOWN WELLHEAD AND CT. H/L CONTINUING TO FREEZE OFF. WORK TO BLEED DOWN. CT FROZEN.
	14:30	16:30	2.00			SURPRI	FLOWT	OTHR	P	PUMP 1 BBL MEOH TO CT. COOL DOWN N2 PUMPERS ONLINE WITH N2 CIRC PRESS = 200 PSI INITIAL. PRESS INCREASED TO 2200 PSI. PRESS BROKE OVER TO 1000 PSI. PRESS. INCREASED TO 2100 PSI BROKE OVER TO 1400 PSI. PRESSURE INCREASED TO 2400 PSI.
	16:30	17:45	1.25			SURPRI	FLOWT	OTHR	P	PRESS. BROKE OVER. GETTING N2 BACK AT TANKS.
	17:45	18:15	0.50			SURPRI	FLOWT	OTHR	P	PURGE CT. 750 SCF INCREASE RATE TO 1000 SCF
	18:15	19:00	0.75			SURPRI	FLOWT	OTHR	P	CONTINUE PURGING CT CIRC = 1230 PSI. SHUT DOWN N2 FOR PRE JOB
	19:00	19:45	0.75			SURPRI	FLOWT	SFTY	P	PJSM TO PUMP N2/CO2 BLEND. ON LINE N2 DOWN THE CT AT MIN RATE RIH TAG AT 2364' PU TO 2360'
	19:45	20:15	0.50			SURPRI	FLOWT	OTHR	P	ONLINE WITH N2/CO2 DOWN THE COIL WHP = 500 PSI. DHP AT 2292' MD = 555 PSI. RATE = 220 KG/HR
	20:15	20:45	0.50			SURPRI	FLOWT	OTHR	P	WHP = 540 PSI, DHP = 560 PSI, RATE = 220 KG/HR TRACER GAS STILL MONITORING LOW.

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Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	20:45	21:15	0.50			SURPRI	FLOWT	PULL	P	POOH AT 75 FPM RATE = 220 KG/HR, BHP = 565 PSI, WHP = 540 PSI.
	21:15	22:15	1.00			SURPRI	FLOWT	OTHR	P	ON SURFACE CLOSE IN CHOKE. INCREASE WHP TO 600 PSI. SHUT IN SWAB. ONLINE WITH N2 DOWN THE CT.
	22:15	00:00	1.75			SURPRI	FLOWT	RURD	P	RDMO LOCATION STAGE ON PAD
02/12/2012	MIRU E-line and crane. Run tie-in Log & Map cables. Adjust BHP. MU Perforating assy. RIH and Tie-in Perforate.									
	00:00	04:00	4.00			SURPRI	FLOWT	RURD	P	SLB. Bled down CO2 and N2 tanks. Found and repaired leak in the Tracer line. Continued rig up of hoses for Heater string for the upright tanks. BHP = 625 psi.
	04:00	08:30	4.50			SURPRI	FLOWT	SFTY	P	Depart Deadhorse WL shop to Gun Shop and secure 2 ea. 30' guns.Travel to Ignik Sikumi.Arrive on location and obtain clearance to access Ignik Sikumi Pad. Meet SPOC. Tailgate PJSMN and wait on final ramoval of coil tubing set-up equipment. Spot up e-line unit and spot-up third party crane.
	08:30	13:30	5.00			SURPRI	FLOWT	PULD	P	Make up lubricator; test lift to confirm crane and grease hoses will reach. Finish picking up pressure equipment. Make up tools (completion mapper, WPPT and Gyrodata gyro tool) and perform tool checks. Move to well. Stab on well and line up for pressure testing using field triplex and diesel. PT 500-psi low; 1400-psi high.
	13:30	15:00	1.50			SURPRI	FLOWT		P	Bleed/blow down. Break off stack at quick connect. Stab off at quick connect and pump out all excess PT fluid below pump in sub and above swab valve.
	15:00	22:30	7.50			SURPRI	FLOWT		P	Open well and RIH WPPT with gyro. Performed completion mapping to 2350' using completion mapper with WPPT and Gyrodata tools. Determined clockwise tool spin (both RIH & PUH) at one full rotation per approximately 210' travelled or 1.7-deg/ft. Confirmed good signature from metal blast protectors on cable outside tubing, but rotation change from centralizer drift requires additional interpretation/investigation.
	22:30	00:00	1.50			SURPRI	FLOWT		P	POOH and rig back for night.
02/13/2012	Continued completion mapping logging to confirm toolface orientation for Perforating.									

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	00:00	12:00	12.00			SURPRI	EVALWE	ELOG	P	Continue completion mapping logging to confirm toolface orientation for perforating.
	12:00	00:00	12.00			SURPRI	FLOWT	PULD	P	Change out AES crane and replaced w/Peak crane for possible 24 hr coverage. Used AES crane for setting up flare stack and putting steps on upright tanks. Set up containment around truck loading area.
02/14/2012	Added 30' section to crane to lubricate long perforating tool string. Replaced primary well site generator control module and started same. Pressure tested SLB GMS to 2000 psi and loaded tubing with traced 77% N2 : 23%CO2 to 1400 psi.									
	00:00	12:00	12.00			SURPRI	FLOWT	OTHR	P	Changed out at F-wing and drove to location. Peak crane crew added a 30' extension section of lattice.
	12:00	00:00	12.00			SURPRI	FLOWT	OTHR	T	Peak Precision Power on site with Cummins mechanic to change out the engine control module of the primary well site generator. Generator successfully started and allowed to run. 20:40 SLB E-line arrived on location, performed safety / SimOps meeting. E-line crew MIRU and surface tested tools. 21:00 performed pre job safety and SimOps meeting with SLB wells services crew. Pressure tested SLB GMS and treating iron to the wing valve to 2020 psi. Walked pressure up to 1100 psi shut down and walked treating lines. Pressured up GMS and treating iron to wing valve to 2020 psi and shut in. Test good. Bled tubing to 1000 psi. 21:30 lined up to the tubing and began to load well with mixture of traced 77% N2 : 23%CO2. 22:37 slowed rate to 200 kg/ hr @ 1403 psi. 22:45 down on the pump T = 1425 psi.
02/15/2012	Perforated 2243'-2273' with 2.88" PJ Omega gun loaded 2 SPF 0/180 phased. Shots oriented 90 deg from blast protectors. Established injection of SF6 traced gas mixture 77% N2:23%CO2 into zone.									
	00:00	00:30	0.50			SURPRI	PERF	PERF	P	E-line PT'd lubricator to 3000 psi
	00:30	02:30	2.00			SURPRI	PERF	PERF	P	Bled and drained lubricator. Re shot through tools to confirm communication. Pick up perf guns. Perforating charges 2- 7/8" OD Power Jet Omega, 2906, 0&180 phase, 2 spf.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	02:30	05:00	2.50			SURPRI	PERF	PERF	P	RIH tied in and oriented guns in preparation to fire. Encountered electrical issue with GMS unit. N2 soft start relay is tripping. Replacement parts located and Peak electrician dispatched from Deadhorse.
	05:00	08:00	3.00			SURPRI	PERF	PERF	T	Wait on electrician. 0700 electrician on pad with replacement parts. 0755 Soft start repaired pumps back on line.
	08:00	08:30	0.50			SURPRI	PERF	PERF	P	0803 Come on line with SF6 traced N2:CO2 blend venting out the Bruce valve 2" valve closed to well. Tubing pressure 1342 psi at the second gauge. 0815 fired guns, indication of fire noted. CCL to top shot 25.8' CCL stop depth 2217.2' Shot 2243-2273' with 2.88" PJ Omega gun loaded 2 SPF 0/180 phased. Shots oriented 90 deg from blast protectors. Open 2" to well close Bruce valve. E-Line pulling out of hole.
	08:30	08:45	0.25			SURPRI	CHEMTI	OTHR	P	Down on pumps. Shut in pressure 1390 psi. 2" valved closed.
	08:45	09:45	1.00			SURPRI	CHEMTI	OPNW	P	Observe pressure fall off to 1351 adn 43 F at gauge #2. WHP 1110 psi. SLB E-line rigged off the well. All shots fired. Released crew.
	09:45	10:45	1.00			SURPRI	CHEMTI	OPNW	P	Start pumping 1354 psi and 43 F, mass flow 200 Kg/Hr (1 Kg/hr is approx 710 SCF/day). Shut down pumps at 1552 psi and 43 F at second gauge. Monitor pressure and temp @ 10:45 1507 psi and 42F.
	10:45	11:15	0.50			SURPRI	CHEMTI	OTHR	P	Start pumping at 200 kg/hr with 2" open. At 1598 psi stop pumping 2" closed.
	11:15	14:00	2.75			SURPRI	CHEMTI	OTHR	P	Monitor pressure fall off to 1391 psi
	14:00	16:00	2.00			SURPRI	CHEMTI	OTHR	P	start pumping at 50 Kg/hr 1383 psi at gauge # 2. Gauge #2 pressure slowly increasing to 1417 psi. at 20:00
	16:00	00:00	8.00			SURPRI	CHEMTI	OTHR	P	Continue to inject mixed traced gas reducing rate to maintain 1420 psi at gauge #2
02/16/2012	Set sand screen and loaded Nitrogen storage tank # 2 with 1900 gal product. Started primary wellsite generator and switched to same.									
	00:00	05:30	5.50			SURPRI	CHEMTI	OTHR	P	Pumping traced, mixed N2:CO2 into formation.
	05:30	07:00	1.50			SURPRI	CHEMTI	OTHR	P	SLB / Expro morning Safety / Ops meeting and Morning call in

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	07:00	10:30	3.50			SURPRI	CHEMTI	OTHR	P	Slickline on location with sand screen assembly. Hold pre job with crew and third party crane operator. Walk down well head, SLB & Expro equipment with HES slickline crew. Valve crew on location, service swab and injection side wing. Slickline assembling lubricator and screen.
	10:30	11:30	1.00			SURPRI	CHEMTI	OTHR	P	Problem Wells Supervisor on location to inspect location and prep for Alaska Oil and Gas Commission witnessed Mechanical integrity test of the Inner annulus. Walked down side and discussed procedure.
	11:30	13:30	2.00			SURPRI	CHEMTI	OTHR	P	Continue to pump traced, mixed N2:CO2 into formation. Start to lift lubricator. Shut down pick due to excessive flex in lubricator. Discuss plan forward. SL crew to source additional 5.5" lubricator.
	13:30	15:30	2.00			SURPRI	CHEMTI	OTHR	P	Shut down GMS @ 13:16 to swap to primary well site generator and install updated GMS software.
	15:30	16:30	1.00			SURPRI	CHEMTI	OTHR	P	Primary well site generator on line. GMS well bore heater string circulation back on line 15:01. GMS cryogenic pumps cooled down, pressure up, and operating 15:15. HES Nitrogen tanker on location 16:00. Off loaded 1900 gal liquid N2 into Nitrogen tank # 2.
	16:30	17:30	1.00			SURPRI	CHEMTI	OTHR	P	Picked up SL lubricator and rigged up to the well. Shut in upper master and opened the swab. Pressure tested the lubricator with traced mixed N2:CO2 to 1400 psi. Bled lubricator to 1240 and opened up to well. Drift and tag with 3.60" gauge ring. Tagged at 2371' POOH. Shut swab and bled off lubricator to bleed tank. Lubricator plus surface equipment is 22' of 41/2 (ID 3.958") and 60' of 5 1/2 (ID 5.00"). Pumping traced mixed N2:CO2 to formation at 20 kg/hr.
	17:30	19:30	2.00			SURPRI	CHEMTI	OTHR	P	Out of hole, lay down lubricator, make up sand screen, OL 56' 8.5", load in lubricator. Third party crane crew changed out from day to night operator.
	19:30	21:30	2.00			SURPRI	CHEMTI	OTHR	P	19:15 picking lubricator with sand screen. Pressure tested lubricator to 1310 psi with traced, mixed N2:CO2. 20:06 RIH, set down, hand spang sand screen into seal assembly, pull to establish latch, sheared off 20:38. POOH. 21:07 slickline off the well and rigging down surface equipment.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	21:30	02:30	5.00			SURPRI	CHEMTI	OTHR	P	Continue pumping traced, mixed N2:CO2 into formation @ 1410 psi middle down hole gauge and 20 Kg/ hr.
02/17/2012	Continued pumping traced mixed gas (77% N2:23%CO2) at 17-24 kg/hr to maintain 1420 psi on XPIO gauge @ 2226' MD. Performed Mechanical Integrity Test of the Inner Annulus (MITIA) - failed. Suspect thermal contraction of fluid not a leak. - ongoing									
	00:00	02:30	2.50			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 18 Kg/hr 1410 psi on XPIO gauge @ 2226' MD
	02:30	06:00	3.50			SURPRI	CHEMTI	OTHR	P	Bled gas from top of N2 pump. Pumping traced mixed gas (77% N2:23%CO2) at 18 Kg/hr 1411 psi on XPIO gauge @ 2226' MD.
	06:00	09:00	3.00			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 18 Kg/hr 1412 psi on XPIO gauge @ 2226' MD. Increased pump rate to 21 KG/hr to hit target bottom hole pressure of 1420 psi at 0900.
	09:00	09:30	0.50			SURPRI	CHEMTI	OTHR	P	Walking up pressure to 1420 psi max. Pumping traced mixed gas (77% N2:23%CO2) at 23 Kg/hr 1415 psi on XPIO gauge @ 2226' MD.
	09:30	10:00	0.50			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 23 Kg/hr 1418 psi on XPIO gauge @ 2226' MD.
	10:00	10:30	0.50			SURPRI	CHEMTI	OTHR	P	Slow rate to 22 Kg/hr. Pumping traced mixed gas (77% N2:23%CO2) at 22 Kg/hr 1420 psi on XPIO gauge @ 2226' MD.
	10:30	11:30	1.00			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 20 Kg/hr 1421 psi on XPIO gauge @ 2226' MD. Reduce rate to 19 Kg/hr to maintain pressure at 1420.
	11:30	14:30	3.00			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 19 Kg/hr 1420 psi on XPIO gauge @ 2226' MD. 1421 psi @ 14:45. Reduce rate to 18 Kg/hr to maintain pressure at 1420.
	14:30	17:30	3.00			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 17 Kg/hr 1420 psi on XPIO gauge @ 2226' MD. 1421 psi @ 14:45. Pre job for MITIA at 17:10. Open swab to monitor Tubing pressure for MITIA. Tubing pressure at middle gauge dropped to 1418 then 1415 psi. Increased rate to 24 kg/hr to raise tubing pressure.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	17:30	18:30	1.00			SURPRI	CHEMTI	OTHR	P	Performed pre witnessed MITIA - failed. Shut down glycol circulating pump. Double blocked returns to the 125 bbl glycol open top tank at the wellhead. Begin o pressure up IA. Mechanical gauge on IA companion valve not reading correctly. Decision made to continue test with GMS pressure gauge. Pressured the IA up to 1919 psi and blocked in at the pump. Pressure dropped 145 psi in the first 15 minutes and 98 psi in the second 15 minutes for a total of 243 psi. Max pressure loss may not exceed 10% in 30 minutes or 5% in the first 15 minutes. Will reatempt the test in the morning with new gauges.
	18:30	00:00	5.50			SURPRI	CHEMTI	OTHR	P	Continue pumping traced mixed gas (77% N2:23%CO2) at 16 Kg/hr 1420 psi on XPIO gauge @ 2226' MD.
02/18/2012	Continued pumping traced mixed gas (77% N2:23%CO2) at approx 20 kg/hr to maintain 1420 psi on XPIO gauge @ 2226' MD. Performed Mechanical Integrity Test of the Inner Annulus (MITIA) - Passed. Had to shut down GMS du to poor pump control. Adjusted the proportion portion of the Proportion, Integral, Derivative (PID) controller. Gas mixing / pumping issues solved.									
	00:00	05:00	5.00			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 17 kg/hr and 1415 psi on XPIO gauge @ 2226' MD.
	05:00	10:00	5.00			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 20 kg/hr and 1419 psi on XPIO gauge @ 2226' MD.
	10:00	15:30	5.50			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 19 kg/hr and 1420 psi on XPIO gauge @ 2226' MD. Starting to pump rougher.
	15:30	16:00	0.50			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 19 kg/hr and 1420 psi on XPIO gauge @ 2226' MD. Discussing shutting down to condition tanks when well site generator accidentally taken off line. Down on the cryogenic pumps. Secondary generator started in 2 minutes and transferred power. Conditioned tanks (N2 and CO2) Transferred liquid N2 from storage tank to working tank and ordered out N2.
	16:00	16:30	0.50			SURPRI	CHEMTI	OTHR	P	Start pumping mixed gas. Fighting the pumps unable to mix the product on spec. Shut down cryogenic pumps.

Time Logs										
Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	16:30	18:00	1.50			SURPRI	CHEMTI	OTHR	P	Conditioning tanks and priming pumps in attempt to bring pumps back on line with in spec blend.Started heating well and started pumping traced mixed gas (77% N2:23%CO2) at 15 kg/hr and 1379 psi on XPIO gauge @ 2226' MD.
	18:00	19:30	1.50			SURPRI	CHEMTI	OTHR	P	Increased rate to 25 kg/hr pressure 1391 at on XPIO gauge @ 2226' MD. Nitrogen transport arrived on location. Need to fill both tanks. Shut down N2 pumping and closed 2" to well. stopped circulation of the IA in preparation for MITIA.
	19:30	20:30	1.00			SURPRI	CHEMTI	OTHR	P	While transferring N2, perform MITIA - Passed. Pre T/I/O=1200/0/NA. Pumped up IA to 1900 lbs and double blocked in at well head. Initial T/I/O = 1200/1900/NA, 15 min 1200/1800/NA, aborted test. Repressure to 1900 psi. Initial T/I/O = 1200/1950/NA, 15 minute T/I/O = 1200/1870/NA, 30 minute T/I/O = 1200/1795/NA. Total loss of 155 psi
	20:30	21:30	1.00			SURPRI	CHEMTI	OTHR	P	Restart circulating heated glycol through the inner annulus and restart injecting traced mixed gas (77% N2:23%CO2) at 100- 75 kg/hr and 1347 psi on XPIO gauge @ 2226' MD.
	21:30	00:00	2.50			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 30-20 kg/hr and 1420 psi on XPIO gauge @ 2226' MD. Starting to pump very rough again. Large spikes in the N2 and CO2 rates. GC samples indicate N2 concentrations are high at ~81%.
	00:00	00:30	0.50			SURPRI	CHEMTI	OTHR	P	Adjust GMS blend setting to 72% N2 : 28% CO to achieve 77% : 23% respectively on GC results.
	00:30	01:00	0.50			SURPRI	CHEMTI	OTHR	P	Continue to fight blending issues. Discuss options. Investigation of pump rate charts suggest that the N2 pump is leading the CO2 pump. As the CO2 pump falls behind the N2 pump drops off to zero output followed by the CO2 dropping to zero creating a saw tooth pattern. Wake up Optimation operator and discuss problem. P in PID changed from 0.25 to 0.01. Rate instantly stabilizes.
	01:00	01:30	0.50			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 20 kg/hr and 1420 psi on XPIO gauge @ 2226' MD. Rate response is very smooth with the noise at approx +- 5kg/hr.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
02/19/2012	**24 hr Summary** Continued pumping traced mixed gas (77% N2:23%CO2) to maintain 1420 psi on XPIO gauge @ 2226' MD. Performed Mechanical Integrity Test of the Inner Annulus (MITIA) - inconclusive. Continue to pump. All Expro less three put on standby and left the slope. Scheduled to return Feb 29 th for initiation of flow back.									
	00:00	08:15	8.25			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 18-20 kg/hr and 1418-1420 psi on XPIO gauge @ 2226' MD.
	08:15	08:30	0.25			SURPRI	CHEMTI	OTHR	P	Shut down glycol pumping. Casing and 2" valves to 125 bbl tank shut in.
	08:30	09:00	0.50			SURPRI	CHEMTI	OTHR	P	Tubing pressure fell from 1420 to 1412 psi because of thermal contraction. Increased rate to maintain pressure.
	09:00	10:00	1.00			SURPRI	CHEMTI	OTHR	P	Increased rate to maintain pressure at 1420 psi on XPIO gauge @ 2226' MD.
	10:00	11:00	1.00			SURPRI	CHEMTI	OTHR	P	Perform AOGCC witnessed MITIA with Chuck Scheve. Passed with regard to total pressure loss but failed to stabilize. State man recorded a Fail Pre T/I/O=1268/0/NA. Pumped up IA to 1910 lbs and double blocked in at well head. Initial T/I/O = 1269/1910/NA, 15 min 1265/1828/NA, 30 min T/I/O = 1264/1770/NA, 45 minute T/I/O = 121264/1716/NA, Total loss of 140 psi in 30 minutes however pressure drop was nearly linear. Bled IA and resumed well bore heating.
	11:00	12:00	1.00			SURPRI	CHEMTI	OTHR	P	Reduced pump rate to 15 kg/hr. Tubing pressure rising because of thermal expansion. decreased rate to maintain pressure. Pumps erratic.
	12:00	13:00	1.00			SURPRI	CHEMTI	OTHR	P	S/D pumps, heat well bore, condition tanks.
	13:00	14:30	1.50			SURPRI	CHEMTI	OTHR	P	Bring pumps online at 28 kg/hr and 1409 psi. Adjust rate to achieve 1420 psi. Control screen turned full green. manually shutdown pumps. Screen reverted to normal.
	14:30	16:30	2.00			SURPRI	CHEMTI	OTHR	P	Transfer liquid N2 from storage tank to working tank. Cool down pumps. start pumping at 44 kg/hr and 1375 psi.
	16:30	18:30	2.00			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 44-22 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
	18:30	19:00	0.50			SURPRI	CHEMTI	OTHR	P	HES N2 transport on location.
	19:00	19:30	0.50			SURPRI	CHEMTI	OTHR	P	N2 transport contained 2040 gal. Off loaded and left with 7.5" or 534 gal on board. Off loaded 1506 gal into N2 storage tank.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	19:30	22:00	2.50			SURPR	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 20 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
	22:00	00:00	2.00			SURPR	CHEMTI	OTHR	P	Continue pumping traced mixed gas (77% N2:23%CO2) to maintain 1420 psi on XPIO gauge @ 2226' MD.
02/20/2012	Instituted proactive shut down to transfer fluids and condition tanks. Pumps running extremely well under new SOP. N2 pump appears to gas out and loose prime after approximately 8hrs continuous pumping. Initiation of event was anticipated today and successfully mitigated by bleeding gas from the top of the pump chamber. Pumped approx 10.2 MSCF product by 6 pm 77.2 MSCF total. Contacted Jim Regg - AOGCC regarding failed MITIA. Permission to continue injection granted. AOGCC requires a report of operations (pressures and rates) to confirm integrity of IA.									
	00:00	00:15	0.25			SURPR	CHEMTI	OTHR	P	Experienced a short upset while pumping. Bled the back side of the N2 pumps slowly nad let the GMS PID controlers pump through the upset.
	00:15	04:45	4.50			SURPR	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at ~21 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
	04:45	05:30	0.75			SURPR	CHEMTI	OTHR	P	Shut down pumping to condition N2 tanks & transfer N2. Greased N2 and CO2 pumps. Transfered 160 gal N2 from storage to working. 1730 gal remaining in storage.
	05:30	16:30	11.00			SURPR	CHEMTI	OTHR	P	Bring pumps back on line at 1395. Increase rate to 51 kg/hr to reach target of 1420 psi. Pumping traced mixed gas (77% N2:23%CO2) at ~20 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
	16:30	17:30	1.00			SURPR	CHEMTI	OTHR	P	Shut down pumping to condition N2 tanks & transfer N2. Transferred 101 gal N2 from storage to working. 1629 gal remaining in storage. Cool down pumps. Restart pumps
	17:30	00:00	6.50			SURPR	CHEMTI	OTHR	P	Bring pumps back on line at 1395. Increase rate to reach target of 1420 psi. Pumping traced mixed gas (77% N2:23%CO2) at ~20 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
02/21/2012	N2 pump still appears to gas out and loose prime after approximately 8hrs continuous pumping. Initiation of event was anticipated again today @ apporx 1330. Pumping continued for a few hrs after the event. Shut down and conditioned tanks to mitigate. Pumped approx 12.2 MSCF product by 7 pm for a total of 92 MSCF. Injection rate has increased slowly today from 22 kg/hr to 25 kg/hr									
	00:00	01:15	1.25			SURPR	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 22 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
	01:15	01:30	0.25			SURPR	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at ~22 kg/hr and 1420 psi on XPIO gauge @ 2226' MD. Forced to bleed off the back side of the pump, fighting the N2 pump.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	01:30	04:30	3.00			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 22-24 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
	04:30	05:00	0.50			SURPRI	CHEMTI	OTHR	P	Shut down pumping to condition N2 tanks & transfer N2. Transferred 238 gal N2 from storage to working. 1500 gal remaining in storage.
	05:00	06:15	1.25			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 1420 psi on XPIO gauge @ 2226' MD.
	06:15	07:00	0.75			SURPRI	CHEMTI	OTHR	P	GMS lost communication to the well site data hub. Optimation crew worked with SLB Interact support to reestablish communication.
	07:00	13:00	6.00			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 25 kg/hr and 1420 psi on XPIO gauge @ 2226' MD. Removed Tioga heater from CO2 tank @ 09:08
	13:00	14:00	1.00			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 1420 psi on XPIO gauge @ 2226' MD. Forced to bleed off the back side of the pump, fighting the N2 pump.
	14:00	15:30	1.50			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 25 kg/hr and 1420 psi on XPIO gauge @ 2226' MD. Removed Tioga heater from CO2 tank @ 09:08
	15:30	16:30	1.00			SURPRI	CHEMTI	OTHR	P	Shut down pumping to condition N2 tanks & transfer N2. Added 20 bbls of potable water to glycol tank to compensate for evaporation. 125 bbl tank level 70 bbls.
	16:30	00:00	7.50			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 28 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
02/22/2012	Pumping traced mixed gas (77% N2:23%CO2) at 24-26 kg/hr and 1420 psi on XPIO gauge @ 2226' MD. Replaced SF6 tracer with R-114 tracer. Received 20,000 lbs CO2, transferred on the fly while pumping down hole. Pumped approx 12.9 MSCF product by 20:30 for a total of 109 MSCF. Injection rate today was 24 kg/hr to 26 kg/hr.									
	00:00	05:30	5.50			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 24-26 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
	05:30	05:45	0.25			SURPRI	CHEMTI	OTHR	P	Forced to bleed off the back side of the pump, fighting the N2 pump.
	05:45	06:00	0.25			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 24-26 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
	06:00	06:15	0.25			SURPRI	CHEMTI	OTHR	P	Forced to bleed off the back side of the pump, fighting the N2 pump.
	06:15	08:30	2.25			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at ~ 25 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	08:30	09:15	0.75			SURPRI	CHEMTI	OTHR	P	Shut down pumping to condition N2 tanks & transfer N2. Purged ISCO tracer pump of SF6 Tracer. Replaced SF6 tracer bottle with R-114 tracer. Flushed ISCO pump with R-114 tracer. Loaded both colunms A and B to 103 ml each. Set pump rate at 0.01 ml/min.
	09:15	18:30	9.25			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at ~ 25 kg/hr and 1420 psi on XPIO gauge @ 2226' MD. Transport of CO2 on location, Pre job safety meeting, transfer from tanker to working tank on the fly, complete 13:00.
	18:30	19:15	0.75			SURPRI	CHEMTI	OTHR	P	Shut down pumping to condition N2 tanks & transfer N2.
	19:15	00:00	4.75			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 24-26 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
02/23/2012	Pumping traced mixed gas (77% N2:23%CO2) at 24-26 kg/hr and 1420 psi on XPIO gauge @ 2226' MD. Pumped approx 12.4 MSCF product by 19:00 for a total of 124.7 MSCF. Injection rate today was 24 kg/hr to 26 kg/hr.									
	00:00	03:30	3.50			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 27-28 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
	03:30	04:00	0.50			SURPRI	CHEMTI	OTHR	P	Shut down pumping to condition N2 tanks & transfer N2.
	04:00	15:30	11.50			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at ~26 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
	15:30	16:15	0.75			SURPRI	CHEMTI	OTHR	P	Shut down pumping to condition N2 tanks & transfer N2.
	16:15	00:00	7.75			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at ~26 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
02/24/2012	Pumping traced mixed gas (77% N2:23%CO2) at 29-30 kg/hr and 1420 psi on XPIO gauge @ 2226' MD. Pumped approx 14.5 MSCF product by 20:00 for a total of 143.9 MSCF.									
	00:00	00:30	0.50			SURPRI	CHEMTI	OTHR	P	Shut down pumping to condition N2 tanks & transfer N2.
	00:30	03:30	3.00			SURPRI	CHEMTI	OTHR	P	Pumps Acting Erratically. Pumping traced mixed gas (77% N2:23%CO2) at ~29-30 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
	03:30	08:00	4.50			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at ~29-30 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
	08:00	09:15	1.25			SURPRI	CHEMTI	OTHR	P	Shut down pumping to condition N2 tanks & transfer N2.

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Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	09:15	16:30	7.25			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at ~29-30 kg/hr and 1420 psi on XPIO gauge @ 2226' MD. Refilled ISCO Pump A with R-114.
	16:30	17:45	1.25			SURPRI	CHEMTI	OTHR	P	Shut down pumping to condition N2 tanks & transfer N2.
	17:45	00:00	6.25			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at ~29-30 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
02/25/2012	Pumping traced mixed gas (77% N2:23%CO2) at 31-33 kg/hr and 1420 psi on XPIO gauge @ 2226' MD. Shuttled power from primary well site generator to secondary and back for oil change. Attempted unsuccessfully to update GMS and InterAct software- ongoing. Pumped approx 13.7 MSCF product by 17:00 for a total of 161.3 MSCF.									
	00:00	05:15	5.25			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at ~31-32 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
	05:15	05:45	0.50			SURPRI	CHEMTI	OTHR	P	Shut down pumping to condition N2 tanks & transfer N2.
	05:45	08:00	2.25			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at ~31-32 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
	08:00	08:07	0.13			SURPRI	CHEMTI	OTHR	P	Shut down pumping briefly to swap power from primary generator to secondary well site generator for scheduled oil change.
	08:07	08:37	0.50			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at ~32-44 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
	08:37	08:52	0.25			SURPRI	CHEMTI	OTHR	P	Shut down pumping briefly to swap power from secondary generator to primary well site generator for scheduled oil change.
	08:52	16:59	8.12			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at ~32-44 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
	16:59	19:59	3.00			SURPRI	CHEMTI	OTHR	P	Shut down pumping to condition N2 tanks & transfer N2. Installed new software in GMS unit, coordinated changes with SLB Interact. Unable to effect change. Reloaded original software.
	19:59	20:29	0.50			SURPRI	CHEMTI	OTHR	P	Glycol pumps on line. Resume well bore heating. Cool down cryogenic pumps. Bring pumps online.
	20:29	23:02	2.55			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at 1420 psi on XPIO gauge @ 2226' MD.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	23:02	23:59	0.95			SURPRI	CHEMTI	OTHR	P	Surface Safety valve tripped inadvertenetly. Reset and resumed pumping traced mixed gas (77% N2:23%CO2) at 1420 psi on XPIO gauge @ 2226' MD.
02/26/2012	Pumping traced mixed gas (77% N2:23%CO2) at 31-33 kg/hr and 1420 psi on XPIO gauge @ 2226' MD. Swapped inlet/outlet on heater string with IA. Pumped approx 14.7 MSCF product by 21:00 for a total of 176.0 MSCF.									
	00:00	05:00	5.00			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at ~33 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
	05:00	05:30	0.50			SURPRI	CHEMTI	OTHR	P	Shut down pumping to condition N2 tanks & transfer N2.
	05:30	12:30	7.00			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at ~33 kg/hr and 1420 psi on XPIO gauge @ 2226' MD. Raised SLB line heater from 100 F to 120 F in 10 deg F increments over a 2 hour peroid from 06:45 to 08:45.
	12:30	13:00	0.50			SURPRI	CHEMTI	OTHR	P	Shut down pumping to condition N2 tanks & transfer N2.
	13:00	19:15	6.25			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at ~33 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
	19:15	19:45	0.50			SURPRI	CHEMTI	OTHR	P	Swapped inlet/outlet on heater strings while contining mixed gas injection.
	19:45	00:00	4.25			SURPRI	CHEMTI	OTHR	P	Pumping traced mixed gas (77% N2:23%CO2) at ~33 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
02/27/2012	Pumping traced mixed gas (77% N2:23%CO2) at 33-35 kg/hr and 1420 psi on XPIO gauge @ 2226' MD. Pumped approx 21 MSCF product by 23:00 for a total of 205 MSCF Hall Plot volume.									
	00:00	06:00	6.00			SURPRI			P	Pumping traced mixed gas (77% N2:23%CO2) at ~33 to 34 kg/hr and 1420 psi on XPIO gauge @ 2226' MD.
	06:00	06:30	0.50			SURPRI			P	Shut down pumping to condition N2 tanks & transfer N2.
	06:30	18:30	12.00			SURPRI			P	Pumping traced mixed gas (77% N2:23%CO2) at ~34 to 35 kg/hr and 1420 psi on XPIO gauge @ 2226' MD. Raised SLB line heater to 135 F at 08:00. Raised glycol circ rate to 15 gpm.
	18:30	19:00	0.50			SURPRI			P	Shut down pumping to condition N2 tanks & transfer N2.
	19:00	22:09	3.15			SURPRI	CHEMTI	OTHR		Pumping traced mixed gas (77% N2:23%CO2) at ~35 kg/hr and 1420 psi on XPIO gauge @ 2226' MD. Pumped up both SSV hydralic panels to 4000 psi at 20:00 hrs. Investigating an error that is creating a time delay in the data storge.
	22:09	22:45	0.60			SURPRI	CHEMTI	OTHR		Took the GMS offline and attempted to restart the computer to correct the data latency problem.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	22:45	00:00	1.25			SURPRI	CHEMTI	OTHR		Resumed pumping traced mixed gas (77% N2:23%CO2) at ~35 kg/hr and 1420 psi on XPIO gauge @ 2226' MD. The data latency problem has not been fixed
02/28/2012	Shut in injection, begin pressure fall off. Stand by for weather (currently -44)									
	00:00	02:00	2.00			SURPRI	CHEMTI	OTHR	P	Continued pumping traced mixed gas (77% N2:23%CO2) at ~35 kg/hr and 1420 psi on XPIO gauge @ 2226' MD. The data latency problem has not been fixed and is continuing to worsen
	02:00	04:00	2.00			SURPRI	CHEMTI	OTHR	T	HMI system crashed, injection offline. Optimation troubleshooting and attempt to restart.
	04:00	07:45	3.75			SURPRI	CHEMTI	OTHR	P	Continued pumping traced mixed gas (77% N2:23%CO2) at ~35 kg/hr and 1420 psi on XPIO gauge @ 2226' MD. The data latency problem continuing. Met with project team, decided to halt injection. Minimum injection volume has been met.
	07:45	00:00	16.25			SURPRI	CHEMTI	OTHR	T	Shut-in iinjection, begin pressure falloff. Stand-by for Weather - current temperature (-44 F, -75 F windchill) below minimum.
02/29/2012	Monitor data and standby for weather warming trend. Optimization working on computer/data issues.									
	00:00	05:27	5.45			SURPRI	CHEMTI	OTHR	T	Monitor data and standby during Cold Weather Shut Down (-42)
	05:27	05:57	0.50			SURPRI	CHEMTI	SFTY	P	Morning Pre-Job Safety Meeting with SLB and Expro.
	05:57	17:27	11.50			SURPRI	CHEMTI	OTHR	T	Monitor data and standby during Cold Weather Shut Down
	17:27	17:57	0.50			SURPRI	CHEMTI	SFTY	P	Evening Pre-Job Safety Meeting with SLB and Expro
	17:57	00:00	6.06			SURPRI	CHEMTI	OTHR	T	Monitor data and standby during Cold Weather Shut Down
03/01/2012	Data was monitored and on standby until Cold Weather Shut Down was lifted around 1300hrs.. Began completing Procedure #11 .									
	00:00	13:00	13.00			SURPRI	CHEMTI	OTHR	T	Monitor data and standby during Cold Weather Shut Down (-42). #1 glycol pump was shut down due to bad beaing and/or shaft. Parts on order.
	13:00	00:00	11.00			SURPRI	CHEMTI	PRTS	P	Cold Weather restrictions lifted (-31) and work commenced towrads completing Procedure 11. Expro's hardline and the GC lines were pressure tested successfully. 290 bbls of 140 dgree water was off loaded into uprights. Expro Stack Pac lines were connect3ed and PT'ed and glycol circulated.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
03/02/2012	**24 hr Summary** Finish Procedure #11, specifically validating the gas flow meters and GC as well as setting the back pressure valves on the Expro separator.									
	00:00	13:00	13.00			SURPRI	CHEMTI	PRTS	P	Continue making progress in completing Procedure #11. Finish pressure testing lines, setting the back flow valves on the Expro separator, validate the gas flow meters and GC. Increase glycol pump rate to warm wellbore back up.
	13:00	00:00	11.00			SURPRI	CHEMTI	PRTS	T	Lost Prime on pumps had to recondition Nitrogen tanks and transferr N2. Flow readings on small gas meter match GMS MicroMotion readings. Began testing larger gas meter wirth N2. Large gas meter showing difference of 10 to 7 % from GMS MicroMotion.
03/03/2012	Continue working gas metering issues. Moved meter FM 201 from GMS to gas outlet leg of Expro separator and tie in to automation system.									
	00:00	13:00	13.00			SURPRI	FLOWT	PRDT	T	Continue working gas metering issues.
	13:00	00:00	11.00			SURPRI	FLOWT	PRDT	T	Testing meters with CO2 and still finding offset between thermal conductivity and the MicroMotion in the GMS. While testing still, lost prime and basically emptied the CO2 tank. Had 3,000 gal of N2 delivered and offloaded. Moved MicroMotion meter FM 201 from the GMS to the gas outlet of the Expro separator and tied into the automation system. Began testing with N2 with the new meter in place.
03/04/2012	CompleteTesting of Micro Motion meter rigged up in the Atigun House and evaluate data. Started flowing well back.									
	00:00	06:00	6.00			SURPRI	FLOWT	PRDT	P	Start testing of Micro Motion meter rigged up in Expro Spearator skid. Testing with N2 at four different rates.
	06:00	09:30	3.50			SURPRI	FLOWT	PRDT	P	Finished testing of the four varying rates and added a fifth rate test which is actually a re-test of the lowest rate test performed previously in order to validate/compare data.
	09:30	13:24	3.90			SURPRI	FLOWT	PRDT	P	Finished the re-test of the lowest rate and determined this data was acceptable. Shut down testing and lined the Expro separator up for flow. Optimization person was requested to make several changes in software.
	13:24	13:54	0.50			SURPRI	FLOWT	SFTY	P	Hold Pre-Flow Back Safety Meeting with SLB, Expro, Halliburton hands in the Atigun House.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	13:54	00:00	10.10			SURPRI	FLOWT	PRDT		Open well to commence flow back As of 2005 hrs approximately 4,100 cf of gas has been flowed back.
03/05/2012	Continue with flowback operations and monitor data.									
	00:00	00:00	24.00			SURPRI				Continue with flow back operation. Have flowed back approximately 42mscf gas. BHP started at 1080psi and as of 2030 hrs is around 750psi. Well is loading up. Decision made to start prepping for Procedure #13 ("Jet Pump Running and Pulling) after 2300hrs. Pump truck and tanker with F/W ordered for after midnight. Slickline tentatively scheduled for am start setting jet pump.
03/06/2012	Continue implementing Procedure #13 (Jet Pump Running & Pulling). Flush glycol out of well with N2. After bleeding down N2, pump heated F/W down annulus. Slickline drift & tag, set standing valve, set catcher, pull dummy valve, pull catcher, and run jet pump.									
	00:00	12:00	12.00			SURPRI				Start implementing Procedure #13 (Jet Pump Running & Pulling) by displacing glycol from the IA with N2. Re-rig piping in wellhouse to facilitate this operation. Begin displacing the glycol by taking returns up the hearter string. Bleed down N2 after all gycol out of well.
	12:00	16:30	4.50			SURPRI				MIRU pump truck and tanker loaded with 200bbls F/W. Begin heating F/W to 175 degrees and pump down annulus in order to equlize pressure at the GLM.
	16:30	17:30	1.00			SURPRI				RDMO Pump Truck and tanker.
	17:30	19:00	1.50			SURPRI				MIRU Slickline.
	19:00	19:45	0.75			SURPRI				PJSM with Halliburton Slickline crew and SLB Night Supervisor.
	19:45	00:00	4.25			SURPRI				PT Lubricator to 500psi with N2. Bleed down to 250 psi, open well and RIH. Commence slickline operations as per Procedure #13.
03/07/2012	Finish Procedure #13 by setting jet pump and began Procedure #14 (Jet Pump Operations). Commence flow back to Upright #1 by starting the jet pump. Monitored BHP and took BS&W samples every 30min. BS&W samples started around 8% and as of 2100hrs samples were reading about .9% and at this time the total amount of produced fluids was 42bbls.									
	00:00	01:30	1.50			SURPRI				Finish Procedure #13 by setting the "5-C" Jet Pump @1919' SLM.
	01:30	02:00	0.50			SURPRI				RDMO location with the slickline unit.
	02:00	02:24	0.40			SURPRI				Line up well to flowback through Expro separator and into upright tank #1. Start up jet pump and begin taking returns.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	02:24	03:24	1.00			SURPRI				Begin taking samples for the GKBU Lab and the USGS. Samples were moderately "silty".
	03:24	06:24	3.00			SURPRI				Continue flowing back well and monitoring data. First slug of solids enter separator around 0530hrs. Heavy silt samples taken from separator.
	06:24	20:55	14.52			SURPRI				Continue flowing back into upright #1. Begin taking BS&W samples. First sample was about 8% solids. Subsequent solids were 7%, 5%, 3.5% 2.8%, 1.5%, .5% and eventually went back up around .9% by 2100hrs. Total bbls of fluid produced by 2100hrs is about 42bbls.
	20:55	23:59	3.08			SURPRI				Continue flowing back well, monitoring data, strapping flowback tank and take samples
03/08/2012	Continue Jet Pump operations, monitoring data, and taking BS&W samples.									
	00:00	06:27	6.46			SURPRI				Continue Jet Pump operations.
	06:27	06:46	0.33			SURPRI				Air line to air/hydraulic SSV froze off ca suing the SSV to slowly shut in. Clear air line, open SSV and resume flow back operations. Air line was eventually placed inside heated "blue board troughs" and a second air compressor was installed to allow for the compressors to be shut down and the Tanner Gas air dryer re-filled.
	06:46	07:01	0.25			SURPRI				Flow back was switched to upright #2.
	07:01	23:58	16.96			SURPRI				Continue Jet Pump operations. A snapshot of BS&W samples from midnight up to 2100 hhrs were from .8, 2..6, 1.3, 4.5, 1.2, 2.2, .6. Total bbls of produced fluids to uprights since startup is now at 96.07 as of 2100hrs as well as 98mscf gas. BHP at midnight was 663psi and at 2100 hrs was 659psi.
						SURPRI				
03/09/2012	Normal Jet Pump operations until 11:00am when separator pressure was lost. No gas in fluids. Implementing different options to maintain BHP and re-establish separator pressure.									
	00:00	11:00	11.00			SURPRI			P	Continue flowing back well and monitoring data.
	11:00	11:15	0.25			SURPRI			P	Pressure drops in separator and wellhead. Very little gas coming back with fluids causing the separator to lose charge. Close choke to allow for pressure bulid up.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	11:15	11:30	0.25			SURPRI			P	Open choke to minimum flows. No gas. Adjust Jet Pump rate to ensure Jet Pump operating.
	11:30	13:15	1.75			SURPRI			P	Pump N2 across wellhead to Expro separator to re-charge separator up to 125psi approximately. Switch to upright #1 to facilitate tank strapping (too much agitation causing plumb bob strap to give inaccurate readings).
	13:15	13:30	0.25			SURPRI			P	Shut down N2 pump. Continue flowing back well.
	13:30	14:37	1.12			SURPRI			P	Open choke further by two beans. Wellhead pressure dropped off from around 650psi to as low as 545psi and then started to climb towards 700psi resulting in choking back the well.
	14:37	15:22	0.75			SURPRI			P	Pressure slowly falls back. Continue making adjustments with pump and choke to maintain flow.
	15:22	17:31	2.15			SURPRI			P	Well essentially died and failed to produce fluids. Continue making adjustments to regain flow.
	17:31	18:31	1.00			SURPRI			P	Pump started behaving erratically. It was fluctuating between 4 & 18 gpm.
	18:31	19:01	0.50			SURPRI			P	Shut down pump. Flush lines and remove screen on suction line. Screen and line were clogged with sand. Re-route hoses on uprights tanks to facilitate suction from Tank #1 and flow into Tank #2 in order to allow "settling" of solids.
	19:01	23:59	4.98			SURPRI			P	Restart Jet Pump and establish flow. Continue to monitor data and make adjustments to help retain flow. Start removal of 302 fluid pump in GMS and replace with new pump. As of 2100hrs, well has produced 16mscf and 25bbls of fluid. Snapshot of BS&W samples were 2.0, 1.5, .05, .6, .4, 1.2, .25, .15
03/10/2012	Normal jet pump operations until about 1330hrs when well was shut in so a control valve on separator could be replaced. Resumed flow back operation after valve replacement.									
	00:00	00:45	0.75			SURPRI			P	Continue efforts to keep well flowing. Vac arrives and hauls off 110 bbls of returns for disposal.
	00:45	01:00	0.25			SURPRI			P	Shut down power fluid pump 301 in order to remove 302 pump and install new pump.
	01:00	06:00	5.00			SURPRI			P	Resume jet pump operations.
	06:00	06:15	0.25			SURPRI			P	Shut down pumping in order to re-configure pumps 301 & 302 piping. (This modification will facilitate a quicker pump installation next time)

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Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	06:15	13:30	7.25			SURPRI			P	Resume jet pump operations. Struggle to get well to previous performance level. Make adjustments to improve flow characteristics.
	13:30	18:36	5.10			SURPRI			P	Liquid level control valve on EXPRO separator washes out. Caught early when only a drip. Well shut in and flowline from wellhead to separator blown down with N2. Work commences on swapping out the washed out valve with a similiar valve already bolted in-line, but not being used. This location was blinded off.
	18:36	00:00	5.41			SURPRI			P	Open well and start Jet Pump operations. As of 2100hrs, in the previous 24hrs the well has produced 81bbls of fluid and 15.5 mscf of gas.
03/11/2012	Finally back to normal jet pump operations. Monitoring data and taking BS&W samples.									
	00:00	02:00	2.00			SURPRI			P	Continuing jet pump operations. Gas ceases to flow before midnight. Lower BHP and well begins to flow again with gas around 2:00am
	02:00	00:00	22.00			SURPRI			P	Continue Jet Pump Operations. The well has a tendency to flow for a period of time then lose gas and go to minimum flow or even cease to flow until pressure builds back. Monitor data and continue to flow well. Some of the BS&W samples ranged from .2%, .5%, 2.0%, 4.0%, 1.4%, .6%, .15%, 1.6%. As of 2100hrs, for the previous 24hr period the well produced 18 bbls of fluid and 12 mscf of gas.
03/12/2012	Continue to lower BHP, monitor data, and take BS&W samples. Troubleshoot GMS HPP issues.									
	00:00	00:00	24.00			SURPRI			P	Currently in Jet Pump operations and bringing down BHP. Haul off 175 bbls returns. Snow removal after blow. Shovel out around the buildings and piping. Troubleshoot pump issues. BS&W samples were running from .6, .22, 1.0, .5, 1.6, 3.2, 2.8, .2, .01, .15 as of 2100 hrs for the last 24 hrs, the gas flowed back is 7.2 mscf and the fluid produced are 25 bbls.
03/13/2012	Continue to lower BHP, monitor data, and take BS&W samples.									

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Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	00:00	23:30	23.50			SURPRI	FLOWT	PRDT	P	Currently in Jet Pump operations and bringing down BHP. Removed the small backpressure control valve in the Expro low rate metering skid. Controlling rate by holding surface separator pressure as low as possible. BS&W samples continue to range from 0.1 to 3.1% with a daily average of 0.9 and a spike of highest concentrations from 0930-1400 hrs. 10 mscf gas and 50 bbls H2O flowed back over the last 24 hrs as of 2030. Walked down location with CPAI environmental in preparation for ADEC visit tomorrow.
	23:30	00:00	0.50			SURPRI	FLOWT	PRDT	T	A dump valve in the flow back separator line cut out assumedly due to sand production. The well was shut in and efforts to blow down surface lines initiated.
03/14/2012	Washed out the water dump valve in the Expro test Separator. Shut in well, Displaced power fluid, (fresh water) from the inner annulus with 60/40 Tritherm (triethylene glycol) and initiated well bore heating by circulating down the heater string and taking returns from the Inner annulus casing valve. Waiting on replacement water dump valve.									
	00:00	04:00	4.00			SURPRI	FLOWT	PRDT	T	Blow down surface lines that contained power fluid (fresh water) One small section of riser found to be frozen at the well house door. Thawed same and cleared lines
	04:00	07:00	3.00			SURPRI	FLOWT	PRDT	T	Pre tower safety / ops meeting to discuss path forward. Drafted procedure to displace inner annulus to 60/40 tritherm (triethylene glycol). Took on 200 gal of liquid N2.
	07:00	11:00	4.00			SURPRI	FLOWT	PRDT	T	Walked lines and gathered necessary equipment. Broke glycol line at Expro stack pack bath. Added T with valves to facilitate blow down. Lined up lines to be able to take suction from the 125 bbl glycol tank deliver high pressure fluid to the heater string and returns from the IA to the 70 bbl sand jet tank. Returns truck on location. Shot tubing fluid level 703' @ 275 psi. Pressure up tubing with N2 to 700 psi IA at 60 psi. Re shot fluid level at 775' and 700 psi. After 10 minutes T=680 psi and IA = 260 psi.
	11:00	14:00	3.00			SURPRI	FLOWT	PRDT	T	Loaded IA with glycol 1585 psi and 15 gpm taking returns to the 70 bbl sand jet tank. Returns truck took load to 1R-18 for disposal.
	14:00	00:00	10.00			SURPRI	FLOWT	PRDT	T	Circulating the IA with heated glycol. 929 psi and 16 gpm inlet temp 105 F

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
03/15/2012	**24 hr Summary** Replaced washed out water dump valve with different style control valve. Displace glycol from inner annulus (IA) with N2. Load IA with power fluid (fresh water). Start jet pumping and flowing the well at 123 MSCF/D.									
	00:00	10:18	10.30			SURPRI	FLOWT	PRDT	T	Circulating the IA with heated glycol.
	10:18	10:30	0.20			SURPRI	FLOWT	PRDT	T	Start cooling down N2 pump in SLB GMS. Expro crew replacing washed out water dump valve.
	10:30	11:48	1.30			SURPRI	FLOWT	PRDT	T	Continue to cool down N2 pump. Shut in high pressure pump. S/I Heater and IA valves. Blow down soft hoses to 125 bbl glycol tank.
	11:48	14:48	3.00			SURPRI	FLOWT	PRDT	T	Pump N2 down the IA taking glycol returns up the heater string to the 125 bbl tank. Shut down trapping 1151 psi N2 on the IA.
	14:48	15:48	1.00			SURPRI	FLOWT	PRDT	T	Line up high pressure pump to load the IA with power fluid pumping down the heater string taking N2 returns to the sand jet tank.
	15:48	18:18	2.50			SURPRI	FLOWT	PRDT	T	load the IA with power fluid while bleeding N2 slowly as fluid rises in the IA to maintain 700 psi hydrostatic pressure at the jet pump / CAT standing valve.
	18:18	18:42	0.40			SURPRI	FLOWT	PRDT	T	Line up to pump power fluid from tank number 2. Expro flowing back through separator to tank #1.
	18:42	20:06	1.40			SURPRI	FLOWT	PRDT	P	Come on line with jet pump at 8 gpm. Gas returns to surface. well head pressure 494 psi. take Iso tube sample of gas (N2 29%, CH4 70%, C02 1%, SF6 0.373 ppm, R114 1.571 ppm). Fluid to surface at 20:00
	20:06	00:00	3.90			SURPRI	FLOWT	PRDT	P	Jet pumping at 11 gpm and 1800 psi at the IA. Well flowing 24 MSCF/D gas. Slowly working well head pressure down. Optimized rate 123 MSCF/D gas at 184 well head pressure.
03/16/2012	Normal jet pump operations with 5C pump in hole. Average rate 90 MSCFD gas and 180 BWD. Off loaded 280 bbls of produced fluid.									
	00:00	06:00	6.00			SURPRI	FLOWT	PRDT	P	Jet pumping at 11 gpm and 1900 psi at the IA. Well flowing 60 MSCFD gas. Slowly working well head pressure down.
	06:00	12:00	6.00			SURPRI	FLOWT	PRDT	P	Jet pumping at 11 gpm and 1890 psi at the IA. Well flowing 110 MSCFD gas. Slowly working well head pressure down.
	12:00	18:00	6.00			SURPRI	FLOWT	PRDT	P	Jet pumping at 11.5 gpm and 1990 psi at the IA. Well flowing 110 MSCFD gas. Slowly working well head pressure down.

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Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	18:00	00:00	6.00			SURPRI	FLOWT	PRDT	P	Jet pumping at 11-12 gpm and 1990 psi at the IA. Well flowing 110 MSCFD gas. Slowly working well head pressure down. Rig up vac truck to take returns from upright number 251. Found broken valve stem on upright. Had to empty tank to break connection. Encountered packed sand in the bottom of the 400 bbl upright. Estimate 20 bbls of sand remains in tank and 10 bbls of sand off loaded with produced fluid. Total volume trucked away 280 bbls.
03/17/2012	Normal jet pump operations with 5C pump in hole. Produced 142 MSCFD gas and 148 BWD from 9 pm to 9pm 3/16-17/12. Rebuilt High Pressure Pump (HPP) #1 HPP #2 has approx 50 hrs. Returns averaged 2.19 % sediment.									
	00:00	06:00	6.00			SURPRI	FLOWT	PRDT	P	Jet pumping at 11 gpm and 1990 psi at the IA. Well flowing ~ 137 MSCFD gas. Slowly working XPIO gauge #2 down from 555 psi.
	06:00	12:00	6.00			SURPRI	FLOWT	PRDT	P	Jet pumping at 11 gpm and 1960 psi at the IA. Well flowing ~140 MSCFD gas. XPIO gauge #2 550 - 543 psi.
	12:00	18:00	6.00			SURPRI	FLOWT	PRDT	P	Jet pumping at 11 gpm and 1640 psi at the IA. Well flowing ~148 MSCFD gas. XPIO gauge #2 543 - 537 psi.
	18:00	00:00	6.00			SURPRI	FLOWT	PRDT	P	Continue jet pumping at 11 gpm and 1740 psi at the IA. Well flowing ~148 MSCFD gas. Working XPIO gauge #2 down slowly from 537 psi. Rebuilt High Pressure Pump (HPP) #1. Expect 300-400 hrs with feed water of 0.05 % solids.
03/18/2012	Normal jet pump operations with 5C pump in hole. Produced 75 MSCFD gas and 57 BWD from 9 pm to 9pm 3/17-18/12. Ice blockage developed in flare line forcing well to be shut in 1 hr to clear the line. Jet pumping in attempt to restart the flowing.									
	00:00	03:00	3.00			SURPRI	FLOWT	PRDT	P	Jet pumping at 11 gpm and 1740 psi at the IA. Well flowing ~140 MSCFD gas. XPIO gauge #2 533 psi.
	03:00	06:00	3.00			SURPRI	FLOWT	PRDT	P	Jet pumping at 11 gpm and 1740 psi at the IA. Well flow decreasing to 100 MSCFD then climbing to 125 MSCFD gas. XPIO gauge #2 dipping some but averaging 533 psi.
	06:00	09:00	3.00			SURPRI	FLOWT	PRDT	P	Jet pumping at 11 gpm and 1740 psi at the IA. Well flowing ~127 MSCFD gas XPIO gauge #2 dipping some but averaging 533-534 psi.
	09:00	11:00	2.00			SURPRI	FLOWT	PRDT	P	Jet pumping at 11 gpm and 1740 psi at the IA. Well flowing ~125 MSCFD gas XPIO gauge #2 steady at 533 psi.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	11:00	12:00	1.00			SURPRI	FLOWT	PRDT	T	Ice blockage issue discovered in the flare line. Forced to come down on the jet pump at 11:00 and shut the well in. SLB S/I and blew down surface suction and discharge lines. SLB pushed air across the tree to blow down Expro lines by passing the separator to the returns tanks. BOth Expro and SLB cleared the blockage, ice, in the flare line.
	12:00	20:00	8.00			SURPRI	FLOWT	PRDT	P	Flood GMS HPP lines and initiate et pumping at ~ 8 gpm. Walk jet pump rate up until a pressure of 1950 at the IA ~11 gpm. Well NOT flowing gas. XPIO gauge #2 climbing slowly from 550 to 570 psi. Spotted Tank O 400 bbl upright tank in secondary containment.
	20:00	00:00	4.00			SURPRI	FLOWT	PRDT	P	Coontinue to pump at ~11 gpm and 1950psi. Well NOT flowing gas. XPIO gauge #2 climbing slowly.
03/19/2012	Unable to restart production by jet pumping. Attempted to pull jet pump. Ongoing.									
	00:00	07:24	7.40			SURPRI	FLOWT	PRDT	P	Continue to pump at ~11 gpm and 1950 psi. Well NOT flowing gas. XPIO gauge #2 climbing slowly.
	07:24	08:09	0.75			SURPRI	FLOWT	PRDT	P	Lower rate from ~ 11 gpm to ~8 gpm and. Well NOT flowing gas. XPIO gauge #2 climbing slowly. Monitor pressure and raise rate back to ~11 gpm.
	08:09	11:09	3.00			SURPRI	FLOWT	PRDT	P	Continue to pump at ~11 gpm and 1950 psi. Well NOT flowing gas. XPIO gauge #2 climbing slowly. Heating well bore while preparing for slick line intervention.
	11:09	12:27	1.30			SURPRI	FLOWT	PRDT	P	Cool down N2 pumps. Shut down High Pressure Pump and S/I well. Blow down surface lines from well head through Expro, by passing the separator to return tanks with N2. Block in Expro. Blow down suction and hard line to 70 bbl sand jet tank with air. Come online with N2 to the tubing taking returns to the 70 bbl sand Jet tank. Slick line on location and spotting up to well.
	12:27	15:03	2.60			SURPRI	FLOWT	PRDT	P	Pump 11932 SCF N2 at 1600 psi to tubing. Shut down with 1600 trapped on the tubing and 400 trapped on the IA. Bleed the tubing to 600 and the IA to zero.
	15:03	16:33	1.50			SURPRI	FLOWT	PRDT	P	Slick line RIH with 3.5 dump bailer. Tag top of pump at 1919' POH and make up fishing tool string.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	16:33	20:03	3.50			SURPRI	FLOWT	PRDT	P	RIH with jet pump fishing tool string and attempt to latch up. After ~10 tries able to latch up and started hitting oil jar licks. Unable to move pump up hole. Attempt to sheer off the jet pump for 60 minutes. Slow oil jar action, spang action not visible. Pumped 155 gal of thritherm down the heater string, taking returns to the tubing. Able to break free, sand and silt found on tools at surface.
	20:03	22:03	2.00			SURPRI	FLOWT	PRDT	P	On surface with tools. Add lubricator and lengthen tool string with longer spangs and more weight bar.
	22:03	00:00	1.95			SURPRI	FLOWT	PRDT	P	Make up tool string with long spangs and thin the oil in the oil jars. RIH. Hard time latching up again, once latched working wire with indication of good hits. Start attempting to sheer off at 23:00. Free at 23:48. POOH and RD for night.
03/20/2012	Pulled 4 1/2" jet pump assy from 1919'. Attempted to shear knockout in standing valve. Pressure response from well indicated a possible shear however tattle tail on prong was not sheared. Continue to circulate hot glycol down the heater string taking returns from the inner annulus.									
	00:00	07:36	7.60			SURPRI	FLOWT	PRDT	P	Returns truck on location to suck down 70 bbl sand jet tank. Vacuum 30 bbls returned power fluid from 70 BBLs sand jet tank. Line up Inner Annulus (IA) to take returns to the sand jet tank. Come online with the GMS High Pressure Pump (HPP) down the heater string with heated glycol. Pumped 50 glycol to IA, shut in returns to the Sand jet tank and initiated circulation of heated glycol through t SLB line heater.
	07:36	08:00	0.40			SURPRI	FLOWT	PRDT	P	Cold weather advisory for Kuparuk notification. Called CPA Wells Supt to discuss. -36 F on location. Called out Slick Line (SL) unit.
	08:00	09:30	1.50			SURPRI	FLOWT	PRDT	P	Continue to circulate IA with heated glycol. Organized resources for potential Coiled Tubing (CT) intervention in case SL intervention failed to retrieve jet pump. SL on location. Pre Job safety discussion. CPAI Cold Weather Equipment Operating Variance reviewed, safety discussion held and document signed. SL crew released to rig up. Expro constructing 20'x20' revetment for sand trap. Sand trap and iron on location.
	09:30	12:30	3.00			SURPRI	FLOWT	PRDT	P	SL R/U, Cut back 200' of wire, 16' 2 5/8" stem, OJ, LSS, and stand by for 2 1/8 jars.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	12:30	13:30	1.00			SURPRI	FLOWT	PRDT	P	Cold weather advisory lifted -34 F. HES delivered 3000 gal N2. 55' lubricator, 33' tool string. PT w N2 to 700 psi RIH to pull jet pump W 4 1/2 PRS, S/D Latch @ 1919' SLM. Jar 1500-1800 for 45 minutes untill pump assy came free. Drilling Tool House delivered timbers and herculite for sand trap revetment.
	13:30	15:00	1.50			SURPRI	FLOWT	PRDT	P	OOH W/ jet pump assy. Lock missing small piece of packing. Lay down assy and cut 200' of wire. Drop 8' of 2 5/8" stem.
	15:00	16:30	1.50			SURPRI	FLOWT	PRDT	P	Pump 42 gal of Glycol from the IA to the tubing (T) Glycol tank has 37-38 bbls. RIH W/ 5'x3" pump bailer W/ Mule shoe ball. S/D @ 1932' SLM stroke bailer a few times. POOH w metal marks on bailer bottom, recovered piece of packing from lock on jet pump assy. No other solids in bailer. Stand by SLU and deliver pump to Y-Pad shop for disassembly. Found 1/2" x 3/8" piece of metal (appears to be shear stock) lodged in the throat of the jet pump.
	16:30	18:30	2.00			SURPRI	FLOWT	PRDT	P	RIH W 3.50 cent, 2' stem, 3.25 cent, 47' x 1" prong. Stop at 1850'. Bleed T to 600 psi. S/D @ 1932' SLM, attempt to tap past but unable to. POOH to inspect tools. OOH small amount of sand on tools and marks on prong.
	18:30	19:30	1.00			SURPRI	FLOWT	PRDT	P	RIH W/ 3.25 cent, 2' stem, 3.50 cent, XO,XO, 37" prong, distance from bottom centralizer to bottom of prong = 44", S/D @ 1933' SLM, jar down attempt to bounce past. Pressure indication on T and down hole XPIO P1 that knockout had sheared. POOH. OOH tattle tail not sheared.
	19:30	20:30	1.00			SURPRI	FLOWT	PRDT	P	RIH W/ 4 1/2" PRS, S/D @ 1932' SLM Tap down lightly. Unable to latch up. One friction bite after hand spanging held to ~ 500 lbs. POOH. OOH tool has silt on it.
	20:30	21:00	0.50			SURPRI	FLOWT	PRDT	P	RIH W/ 3.25" cent, 2' stem, 3.50" LIB, S/D @ 1933' SLM, Tap down POOH. Tool has silt on it and no impression.
	21:00	21:30	0.50			SURPRI	FLOWT	PRDT	P	R/D SL unit
	21:30	00:00	2.50			SURPRI	FLOWT	PRDT	P	Continue to circulate the IA with heated glycol.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
03/21/2012	**24 hr Summary**									
	Spotted sand trap in containment, rigged up same. Bailed down to to lock, seal bore assembly, and sanding valve hung at 1957'. Knocked out KOBE saw XPIO #3 rise from 562 psi to 971 psi									
	00:00	08:00	8.00			SURPRI	FLOWT	PRDT	P	Continue to circulate the IA with heated glycol.
	08:00	08:15	0.25			SURPRI	FLOWT	PRDT	P	Pressure up Tubing with N2 to 700 psi. 40 bbls in glycol tank, S.G. = 1.087 corrected to 60 F
	08:15	09:45	1.50			SURPRI	FLOWT	PRDT	P	Slick line on location, perform prejob, rig up (0.125 wire), 2.125" stem, TS = RS,QC,6',QC,KJ,5',QC,LSS,QC. (OAL 280")
	09:45	10:45	1.00			SURPRI	FLOWT	PRDT	P	PT W N2 to 700 lbs, RIH W/3" x 5' pump bailer, sit down @ 1932' SLM tap down work pump bailer. Work down to 1933' SLM stick bailer tap up to free tools POOH. OOH no marks, recover 1 quart of sand.
	10:45	11:15	0.50			SURPRI	FLOWT	PRDT	P	PT W N2 to 850 psi
	11:15	12:30	1.25			SURPRI	FLOWT	PRDT	P	RIH W 3" x 5' pump bailer, sit down @ 1932 slm. Hit down 5 times work pump bailer for 30 min. Hit down 8 more times POOH. OOH recover 1 quart of sand. Good metal marks from the top of the lock.
	12:30	12:45	0.25			SURPRI	FLOWT	PRDT	P	PT W N2 to 850 psi
	12:45	13:30	0.75			SURPRI	FLOWT	PRDT	P	RIH W 3.48" CEN 3" X 1.875" stem 3.61" cen barbell and 1 3/4" sample bailer (17"), Zero @ bottom of cen, sit down @ 1931' SLM. Beat down very hard. Unable to make hole. Work tools by hand. POOH, OOH sample bailer full no metal marks.
	13:30	13:45	0.25			SURPRI	FLOWT	PRDT	P	PT W N2 to 800 psi
	13:45	14:45	1.00			SURPRI	FLOWT	PRDT	P	RIH W 3.48" CEN 3" X 1.875" stem 3.61" cen barbell and 1 3/4" sample bailer (28"), Zero @ bottom of cen, sit down @ 1931' SLM. Work tools by hand. Make 1' depth. Pull out of lock, sit back down . Work tools. Unable to make hole. POOH, OOH no metal marks very little in bailer.
	14:45	15:00	0.25			SURPRI	FLOWT	PRDT	P	PT W N2 to 800 psi
	15:00	16:00	1.00			SURPRI	FLOWT	PRDT	P	RIH W 3.48" CEN 3" X 1.875" stem 3.61" cen barbell and 1 3/4" sample bailer (17"), Zero @ bottom of cen, sit down @ 1932' SLM. Work tools by hand. Worked tools down 1'. Pulled 400 over to pull free. Set down, tap down, make 1 foot, pull free. POOH, OOH no metal marks. Bailer full.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	16:00	17:00	1.00			SURPRI	FLOWT	PRDT	P	Add 8' 2.125" stem and PT to 800 psi W N2. RIH W 3.48" CEN 3" X 1.875" stem 3.61" cen barbell and 1 3/4" sample bailer (28"), Zero @ bottom of cen, sit down @ 1931' SLM. Work tools by hand to 1932.5' SLM. Tap up to free tools. sit back down at 1931' SLM. Tap down on tools to 1932.5'. POOH, OOH no metal marks. Bailer full.
	17:00	18:15	1.25			SURPRI	FLOWT	PRDT	P	PT to 800 psi W N2. RIH W 3.48" CEN 3" X 1.875" stem 3.61" cen barbell and 1 3/4" sample bailer (28"), Zero @ bottom of cen, sit down @ 1931' SLM. Work tools to 1933' SLM. Tap up to free tools. sit back down at 1931' SLM. Tap down on tools to 1932'. POOH, OOH good metal marks. Bailer full.
	18:15	19:30	1.25			SURPRI	FLOWT	PRDT	P	PT to 800 psi W N2. RIH W 3.48" CEN 3" X 1.875" stem 3.61" cen barbell and 1 3/4" sample bailer (28"), Zero @ bottom of cen, sit down @ 1931' SLM. Work tools by hand to 1933' SLM. Tap up to free tools. POOH, OOH good metal marks. Bailer full.
	19:30	20:45	1.25			SURPRI	FLOWT	PRDT	P	PT to 800 psi W N2. RIH W 5' x 3/4" pump bailer. Sit down at 1931' SLM. Tap down and skip past lock. Sit down@ 1934' SLM tap down and work pump. POOH. OOH with pump blue fluid and 1 quart sand.
	20:45	22:00	1.25			SURPRI	FLOWT	PRDT	P	PT to 800 psi W N2. RIH W 3.48 cent 3' x 1875" stem 3.61" cent and equalizing prong. Sit down @ 1931' SLM. Work to 1934 no pressure change until prong removed from lock and KOBE. See XPIO gauge # 2 clime 200 psi. POOH. OOH with good metal marks on prong centralizer.
	22:00	22:45	0.75			SURPRI	FLOWT	PRDT	P	Watch well, little change in tubing pressure ~800 psi. 965 psi on XPIO gauge # 3. Shut down SLB HPP and shut in IA returns line at 125 bbl glycol tank. Shut down surface glycol circulation. Open IA to open top tank, 48 bbls, check for flow. No flow. Step up to 11 gpm circulating hot glycol down the eater string taking returns up the Ia to the 125 bbl tank. SLU rigged down for the night.
	22:45	00:00	1.25			SURPRI	FLOWT	PRDT	P	Continue to circulate the IA with heated glycol.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
03/22/2012	**24 hr Summary** Pulled Weatherford standing valve with polished bore @ 1957' RKB. Removed ball and both KOBE knockouts, reset at same. Set 3" RC jet pump (S/N: PH-1108) with spacer pipe and stinger assembly on 3.812 DB lock (OAL 200 ") @ 1942' RKB. Pushed 43 bbls glycol back to Expro stack pack. Displaced 50 bbls glycol from inner annulus to 125 bbl glycol tank. Loaded IA with power fluid, commence jet pumping activities pumping to the IA taking production from the tubing through the separator to return tanks.									
	00:00	06:45	6.75			SURPRI	FLOWT	PRDT	P	Continue to circulate the IA with heated glycol.
	06:45	08:45	2.00			SURPRI	FLOWT	PRDT	P	Slick line on location, perform prejob, rig up (0.125 wire), 2.625" TS = RS,8',QC,KJ,LSS,QC. (OAL 210") Cut 150' of wire.
	08:45	09:45	1.00			SURPRI	FLOWT	PRDT	P	PT to 800 psi W N2. RIH W 3.48" CEN 3" X 1.875" stem 3.61" cen barbell and 1 3/4" sample bailer (28"), sit down @ 1932' SLM. Work tools by hand, work down to 1932.5 POOH OOH good metal marks on bailer. Bailer empty.
	09:45	11:00	1.25			SURPRI	FLOWT	PRDT	P	PT to 875 psi W N2. Open up pressure dropped to 850 psi. RIH W 4.5" PRS sit down latch Weatherford SV @ 1931' SLM. Hit 10 OJ licks & 5 spang licks Pulled SV POOH W standing VLV.
	11:00	12:00	1.00			SURPRI	FLOWT	PRDT	P	PT to 860 psi W N2. RIH W 3" drive down bailer, sit down @ 2176' SLM / 2201' RKB tap down once POOH OOH bailer ful of fluid. Expro wrapped sand trap in rino hide (reinforced visqueen).
	12:00	13:15	1.25			SURPRI	FLOWT	PRDT	P	PT to 865 psi W N2. RIH W 4.5" Z-6 & 3.75 DB lock, Weatherford seal bore assembly, and standing valve W ball, seat, and both KOBE knockouts removed. Set lock in DB nipple @ 1913' SLM / 1957' RKB. POOH OOH W/ Z-6, tattle tail indicates good set.
	13:15	14:45	1.50			SURPRI	FLOWT	PRDT	P	PT to 860 psi W N2. RIH W 4.5" Z-6 & 3.812 DB lock & 3" RC jet pump S/N: PH-1108 ratio 6C (OAL 200") Stinger tip 1.73" ID. Sit down on stinger @ 1913' SLM tap down work past and set down at 1917' SLM set jet pump, good pull test, shear off POOH OOH tattle talil indicates lock NOT set.
	14:45	15:45	1.00			SURPRI	FLOWT	PRDT	P	PT to 860 psi W N2. RIH W 4.5" PRS sit down @ 1917' SLM. Hit 5 licks move jet pump up to 1910' SLM beat up on jet pump for 20 min. Pull jet pump free. POOH OOH. Jet pump looks good.
	15:45	16:15	0.50			SURPRI	FLOWT	PRDT	P	Redress lock, stinger looks good.

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Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	16:15	17:45	1.50			SURPR	FLOWT	PRDT	P	PT to 860 psi W N2. RIH W 4.5" Z-6 & 3.812 DB lock & 3" RC jet pump S/N: PH-1108 ratio 6C (OAL 200") Stinger tip 1.73" ID. Sit down on stinger @ 1913' SLM tap down work tools down and set down at 1919' SLM Beat down Z-6, good pull test, shear off, POOH OOH tattle tail indicates lock good set.
	17:45	19:15	1.50			SURPR	FLOWT	PRDT	P	SL Rig down.
	19:15	20:00	0.75			SURPR	FLOWT	PRDT	P	Pushed 33 bbls glycol to Expro stack pack tank to replentich Glycol used when loading the IA. 15 bbls glycol remain in the 125 bbl tank.
	20:00	23:24	3.40			SURPR	FLOWT	PRDT	P	Line up N2 pump to displace the inner annulus with N@ taking glycol returns to the 125 bbls tank. Returned 39 bbls of glycol to the 125 bbl tank. Estimate 11 bbls of glycol left in the tubing.
	23:24	00:00	0.60			SURPR	FLOWT	PRDT	P	Line up to pump N2 across the tree to Expro. Pressure test through sand trap to 1000 psi. Pressure test good.
03/23/2012	Unable to remove hydrate plug in production casing via dissociation. Bull head 250 gal140 F glycol down tubing via heater string and open pocket at 1944'. Bull head N2 down tubing to open pocket at 1944' taking returns to the 70 bbl sand jet tank. Bring well online under jet pump production.									
	00:00	03:45	3.75			SURPR	FLOWT	PRDT	P	Blow air through surface lines in direction of supply and back through suction to tanks. Attempt to flood suction lines to HPP. Troubleshoot blockage. Flood lines, prime pumps.
	03:45	05:45	2.00			SURPR	FLOWT	PRDT	P	Fill inner annulus with power fluid via the heater string while bleeding at IA to the 70 bbl sand jet tank. Start 795589 gal at 16 gpm. Raise rate to 22 gpm for 45 minutes. Reduce rate to 10 gpm, catch fluid at sand jet tank. Shut down pump 797513 gal - total 1924 gal.
	05:45	08:15	2.50			SURPR	FLOWT	PRDT	P	Line up HPP to IA, taking returns & production to Expro. Start HPP. Fluid to surface at 07:21. 28% N2, 70%CH4, 0%CO2,0.423 ppm SF6, 2.144 R114 @ 08:00. Slow HPP rate to 5 gpm for 5 min, increase rate to 10 gpm.
	08:15	14:15	6.00			SURPR	FLOWT	PRDT	P	Increase rate to 14 gpm 08:35, slow rate to 12 gpm 0846, slow rate to 10 gpm 08:56, increase rate to 12 gpm 09:07, increase rate to 14 gpm 09:28. Hold rate.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	14:15	16:09	1.90			SURPRI	FLOWT	PRDT	P	Start cool down of N2 pump. Come down on the HPP. Blow down all surface lines and line up to pump heated glycol to the tubing via the heater string. Pump 250 gal of heated glycol down the heater string while trapping pressure on the tubing and IA. 46 bbls of glycol in 125 bbl tank.
	16:09	18:09	2.00			SURPRI	FLOWT	PRDT	P	Lined up N2 pump to the tubing taking returns through the open pocket at 1944' to the 70 bbl bleed tank via the inner annulus. Pumped 11277 SCF, small amount of N2 returns observed at the returns tank. Shut down the pump.
	18:09	18:39	0.50			SURPRI	FLOWT	PRDT	P	Line up HHP to IA, taking returns & production to Expro. Start HPP at 13 gpm and 1500 psi. Open up the well to the separator.
	18:39	19:45	1.10			SURPRI	FLOWT	PRDT	P	Draw down well head through separator.
	19:45	20:21	0.60			SURPRI	FLOWT	PRDT	P	Draw well head to 100 psi, gas rate increased to 236 MSCFD, XPIO2 decreased to 350 psi. Shut in choke to build bottom hole pressure.
	20:21	00:00	3.65			SURPRI	FLOWT	PRDT	P	Attempt to stabilize rate at 490 psi. 0-150 MSCFD and slugging water.
03/24/2012	Normal jet pump operations gas flow trending down from 50 to 20 MSCFD. Water and solids production trending to zero. BHP @ XPIO 2 475-510.									
	00:00	03:00	3.00			SURPRI	FLOWT	PRDT	P	Well head 200-300 psi. Flow rates: ~ 50 MSCFD gas. Water consumed 8.3 bbls. BS&W 0.05% to 0.0%. Managing flow by target pressure of 490 psi on XPIO gauge #2, average 460 psi. Jet pumping at 11-12 gpm and 1000-1100 psi at the IA. Trace solids at the High Pressure Pump (HPP) inlet.
	03:00	06:00	3.00			SURPRI	FLOWT	PRDT	P	Well head 250-300 psi. Flow rates: ~ 40 MSCFD gas. Water produced 2.5 bbls. BS&W zero. Managing flow by target pressure of 490 psi on XPIO gauge #2, average 460 psi. Jet pumping at 11-12 gpm and 1000-1100 psi at the IA. Trace solids at the High Pressure Pump (HPP) inlet.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	06:00	09:00	3.00			SURPRI	FLOWT	PRDT	P	Well head 250-260 psi. Flow rates: declining from 35-25 MSCFD gas. Water consumed 1.7 bbl. BS&W zero. Managing flow by target pressure of 490 psi on XPIO gauge #2, increasing 460-477 psi. Jet pumping at 11-12 gpm and 1000-1100 psi at the IA. Trace solids at the High Pressure Pump (HPP) inlet.
	09:00	12:00	3.00			SURPRI	FLOWT	PRDT	P	Well head 175-250 psi. Flow rates: 35-25 MSCFD gas. Water consumed 2.5 bbls. BS&W zero. Managing flow by target pressure of 490 psi on XPIO gauge #2, increasing 450-525 psi. Jet pumping at 11-12 gpm and 1000-1100 psi at the IA. Trace solids after tank swap at the High Pressure Pump (HPP) inlet. Incident at 09:30 while swapping power fluid supply / return tanks the suction line to the HPP was frozen and jet pumping was temporarily down. Crews swapped back to the original configuration, diagnosed and rectified the issue.
	12:00	15:00	3.00			SURPRI	FLOWT	PRDT	P	Well head 250 psi. Flow rates:~25 MSCFD gas. Water produced 3 bbls. BS&W zero. Managing flow by target pressure of 490 psi on XPIO gauge #2, 502-511 psi. Jet pumping at 11-12 gpm and 1000-1100 psi at the IA. trace solids at the HPP suction.
	15:00	18:00	3.00			SURPRI	FLOWT	PRDT	P	Well head 250-225 psi. Flow rates: 20-25 MSCFD gas. Water produced 0 bbls. BS&W zero. Managing flow by target pressure of 490 psi on XPIO gauge #2, 510-485 psi. Jet pumping at 11-12 gpm and 1000-1050 psi at the IA. trace solids at the HPP suction.
	18:00	21:00	3.00			SURPRI	FLOWT	PRDT	P	Well head 225-200 psi. Flow rates: 27-20 MSCFD gas. Water produced 0. BS&W zero. Managing flow by target pressure of 490 psi on XPIO gauge #2, 485-475 psi. Jet pumping at 11-12 gpm and 1010-1000 psi at the IA. trace solids at the HPP suction.
	21:00	00:00	3.00			SURPRI	FLOWT	PRDT	P	Jet pumping at 11 gpm and 1000 psi at the IA. Slowly working BHP down.
03/25/2012	Normal jet pump operations gas flow trending down from 11 to 7.5 MSCFD. Jet pump rate increased to 13 gpm. Gas rates increased then trended lower ~14 -13 MSCFD Total gas produced from midnight to 20:00 9.3 MSCF. Water production 8.3 bbls as of 20:00. BHP @ XPIO 2 420 psi. Solids production zero.									

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	00:00	03:00	3.00			SURPRI	FLOWT	PRDT	P	Well head 175-160 psi. Flow rates: ~ 11-8 MSCFD gas. BS&W 0.0%. Managing flow by target pressure of 490 psi on XPIO gauge #2, average 500 psi. Jet pumping at 11-12 gpm and 1070 psi at the IA. Trace solids at the High Pressure Pump (HPP) inlet.
	03:00	06:00	3.00			SURPRI	FLOWT	PRDT	P	Well head 160-150 psi. Flow rates: ~8 - 7.5 MSCFD gas. BS&W 0.0%. Managing flow by target pressure of 490 psi on XPIO gauge #2, average 500 psi. Jet pumping at 11-12 gpm and 1070 psi at the IA. Trace solids at the High Pressure Pump (HPP) inlet.
	06:00	09:00	3.00			SURPRI	FLOWT	PRDT	P	Well head 150-250 psi. Flow rates: ~8 - 14 MSCFD gas. BS&W 0.0%. Managing flow by target pressure of 440 psi on XPIO gauge #2. Increased rate to drop bottom hole pressure 1300 psi at the IA. Trace solids at the High Pressure Pump (HPP) inlet.
	09:00	12:00	3.00			SURPRI	FLOWT	PRDT	P	Well head 250-220 psi. Flow rates: ~ 15 MSCFD gas. BS&W 0.0%. XPIO gauge #2, average 435 psi. Jet pumping at 1300 psi at the IA. Trace solids at the High Pressure Pump (HPP) inlet.
	12:00	15:00	3.00			SURPRI	FLOWT	PRDT	P	Well head 220 psi. Flow rates: ~ 15 MSCFD gas. BS&W 0.0%. XPIO gauge #2, average 425 psi. Jet pumping at 1317. Trace solids at the High Pressure Pump (HPP) inlet.
	15:00	18:00	3.00			SURPRI	FLOWT	PRDT	P	Well head 215 psi. Flow rates: ~ 13 MSCFD gas. BS&W 0.0%. XPIO gauge #2, average 425 psi. Jet pumping at 1315 psi at the IA. Trace solids at the High Pressure Pump (HPP) inlet.
	18:00	00:00	6.00			SURPRI	FLOWT	PRDT	P	Jet pumping at 1317 psi at the IA. Preassure at XPIO2 420 psi. 12 MSCF gas.
03/26/2012	Normal jet pump operations gas rates increased from ~10 to 17 MSCFD on increase of jet pump rate and lowering of BHP via the choke. Water production is 5 bbls as of 21:00. BHP @ XPIO 2 equals 375 psi. Solids production zero. Temp at the perforation is ~ 35 F at the coolest.									
	00:00	07:30	7.50			SURPRI	FLOWT	PRDT	P	Well head 200 psi. Flow rates: ~ 11-10 MSCFD gas. BS&W 0.0%. XPIO gauge #2 = 430 psi. Jet pumping at 11-12 gpm and 1317 psi at the IA. Trace solids at the High Pressure Pump (HPP) inlet.

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Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	07:30	08:36	1.10			SURPRI			P	Increased jet pumping rate to 54% ~13 gpm. Dropping well head with a target of no less then 34 F at the perforations. Well head ~ 200 psi. BS&W 0.0%. XPIO gauge #2 = 415 psi. Trace solids at the High Pressure Pump (HPP) inlet.
	08:36	12:24	3.80			SURPRI			P	Well head ~200 psi. Flow rates: increasing from 1-18 MSCFD gas. BS&W 0.0%. XPIO gauge #2 dropped gradually to 380 psi. Jet pumping at ~ 13 gpm and 1340 psi at the IA. Trace solids at the High Pressure Pump (HPP) inlet.
	12:24	13:18	0.90			SURPRI			P	Issue with Gaschromatograph supply line freezing off in the Gas Mixing Skid at the regulator. Diagnosed and fixed problem. GC back on line.
	13:18	20:18	7.00			SURPRI			P	Well head ~200 psi. Flow rates: ~ 17 MSCFD gas. BS&W 0.0%. XPIO gauge #2 ~ 376.5 psi. Jet pumping at 13 gpm and 1340 psi at the IA. Trace solids at the High Pressure Pump (HPP) inlet.
	20:18	00:00	3.70			SURPRI			P	Jet pumping at 1340 psi at the IA. Preassure at XPIO2 375-376 psi. 17 MSCF gas.
03/27/2012	Opened choke, gas rate went from 17 mscf/d to 19 mscf/d. WHP from 193 to 190 psig.									
	00:00	12:53	12.89			SURPRI				Well head ~200 psi. Flow rates: ~ 17-16 MSCFD gas. BS&W 0.0%. XPIO gauge #2 375-374 psi. Jet pumping at 13 gpm and 1340-1336 psi at the IA. Trace solids at the High Pressure Pump (HPP) inlet.
	12:53	15:38	2.75			SURPRI				Lowered backpressure enough to bring WHP down from 201 to 192 psig, choke from 16.5 to 16.75, rate didn't change much from 16 mscf/d, FBHP went from 376 to 366 psia.
	15:38	20:03	4.42			SURPRI				Opened choke to 17.25 to drop WHP rate went from 17 mscf/d to 19 mscf/d , WHP from 193 to 190 psig , FHBP at XPIO2 from 365 to 358 psia. Volume cumulatives Midnight: 517 mscf produced, 593 BW 18:38: 530 mscf produced, 610 BW From midnight to 18:40, 13 mscf and 17 bbls of water.
	20:03	00:00	3.95			SURPRI				GC data stopped being updated, stopped the Diablo software and restarted, first good sample completed at 21:01.

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Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
03/28/2012	**24 hr Summary** Normal jet pump operations gas rates increased from 19MSCFD to 21 MSCFD lowering of BHP via the choke. Water production is 18 bbls as of 19:00. BHP @ XPIO 2 equals 342 psi. Solids production zero. Temp at the perforation is ~ 34.4 F at the coolest. Gas 16 mscf.									
	00:00	04:19	4.32			SURPR	FLOWT	PRDT	P	Spike in water production associated with stoppage in gas flow lasted about 14 minutes. No obvious cause, gas rates rose and accumulated gas rate over the hour appeared normal, but the water volume rose by 4 bbls between tank straps.
	04:19	07:25	3.10			SURPR	FLOWT	PRDT	P	Opened choke from 17.25 to 17.75, BHP at XPIO2 dropped from 359 to 352 psia, gas rate rose from 19 mscf/d to 20 mscf/d, then over the next couple of hours fell back to 19. Coldest point on DTS trace-34.4°F.
	07:25	10:28	3.05			SURPR	FLOWT	PRDT	P	Opened choke from 17.75 to 18.25 , BHP at XPIO2 dropped from 351 to 344 psia, WHP dropped from 177 to 167 psig, gas rate rose from 19 mscf/d to 20.5 mscf/d. Coldest point on DTS trace-34.3°F
	10:28	00:00	13.54			SURPR	FLOWT	PRDT	P	Opened choke from 18.25 to 18.75. BHP at XPIO2 dropped from 345 to 342 psia, WHP dropped from 170 to 163 psig, gas rate initially rose from 22.5 to 23.5 mscf/d but then fell back to 21 mscf/d. Coldest point on DTS trace-34.4°F.
03/29/2012	Continued jet pumping operation and monitor data.									
	00:00	02:28	2.47			SURPR	FLOWT	PRDT	P	Opened choke from 18.75 to 19.25, BHP at XPIO2 dropped from 343 to 338 psia, WHP dropped from 164 to 156 psig, gas rate went from 22 mscf/d to 23.5 mscf/d for about 25 minute and then declined back to 22. Coldest point on DTS trace-34.2°F.
	02:28	03:29	1.02			SURPR	FLOWT	PRDT	P	Swapped from one HPP to the other. Temporary dip in BHP pressures of about 35 psi, resulted in a gas surge about 45 minutes later before everything returned to normal.
	03:29	00:00	20.52			SURPR	FLOWT	PRDT	P	Interval at top of perfs dropped below 34°F, during gas surge to 25 mscf/d. Midnight to 20:00hrs = 18,000 scf and 20 bbls wtr.
03/30/2012	Contilnue jet pumping operation and monitor data.									

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	00:00	00:00	24.00			SURPRI	FLOWT	PRDT	P	No events of note, choke remained at 19.25 all day. BHP stayed between 319 and 325 psia all day. BHT measured at XPIO2 dropped from 35°F to 34.89°F which it has read for the last 6 hours. Most of the day 6 to 10 feet of the DTS string read less than 34°F with occasional periods above 34°F interspersed throughout. Generally rising gas rate from 22 mscf/d to 24.5 mscf/d.
						SURPRI				Total Midnight to 8 pm. 20.6 mscf 20.8 bbls of water
03/31/2012										
	00:00	00:00	24.00			SURPRI	FLOWT	PRDT	P	No events of note, choke remained at 19.25 all day. BHP stayed between 317 and 322 psia all day. BHT measured at XPIO2 remained at 34.9°F all day. For the second day, 6 to 10 feet of the DTS string read less than 34°F with occasional periods above 34°F interspersed throughout. Generally steady gas rate between 24 mscf/d and 25 mscf/d with three short spikes above 26 mscf/d.
						SURPRI				Total Midnight to 8 pm. 20.5 mscf 24.1 bbls of water
04/01/2012	Normal jet pump operations. WHP remained between 153 and 165 psig, and BHP stayed between 316 and 322 psia all day.									
	00:00	00:00	24.00			SURPRI	FLOWT	PRDT	P	No events of note, choke remained at 19.25 all day. WHP remained between 153 and 165 psig, and BHP stayed between 316 and 322 psia all day. BHT measured at XPIO2 rose about 0.03°F during the day, remaining around 34.9°F. For the third day, 6 to 10 feet of the DTS string read less than 34°F with the periods above 34°F increasing in number throughout the day. Generally steady gas rate between 24 mscf/d and 25.5 mscf/d.
						SURPRI				Total Midnight to 8 pm. 20.6 mscf 23 bbls of water
04/02/2012	Choke remained at 19.25 all day.Generally steady gas rate between 23.8 mscf/d and 25.4 mscf/d.									

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	00:00	00:00	24.00			SURPRI				The number of variations in GC total measured percentage (e.g. CH4 swinging between 94 and 101%) continued to rise today, but calibrations continued to match the calibration gas. Higher inlet pressure may be the cause. This causes some error in the computed "corrected" gas rate presented in InterACT (about 2-3%). Gas mass flow rates continued to be very smooth. Choke remained at 19.25 all day. WHP remained between 151 and 164 psig, and BHP stayed between 316 and 321 psia all day. BHT measured at XPIO2 rose about 0.02°F during the day, remaining around 34.9°F. For the fourth day, 6 to 10 feet of the DTS string read less than 34°F in the evening with this interval being slightly above 34 most of the time from midnight to 10 am. Generally steady gas rate between 23.8 mscf/d and 25.4 mscf/d.
						SURPRI				Total Midnight to 8 pm. 20.3 mscf 24 bbls of water
04/03/2012	Choke remained at 19.25 all day. Generally steady gas rate between 23.6 mscf/d and 24.8 mscf/d. WHP remained between 151 and 165 psig, and BHP stayed between 316 and 320 psia all day									
	00:00	00:00	24.00			SURPRI	FLOWT	PRDT	P	Choke remained at 19.25 all day. Generally steady gas rate between 23.6 mscf/d and 24.8 mscf/d with larger variations between 4 am and 10 am with no obvious cause. WHP remained between 151 and 165 psig, and BHP stayed between 316 and 320 psia all day. BHT measured at XPIO2 rose about 0.02°F during the day ending at 34.94°F. For the fourth day, 6 to 10 feet of the DTS string near the top of the perfs read less than 34°F, now down to about once per hour, showing the very slight overall increase in temperature.
						SURPRI				Total Midnight to 8 pm. 20.1 mscf 22 bbls of water
04/04/2012	Opened choke from 19.25 to 19.75 beans, Raise power fluid from 55-56% of pump drive max. in effort to get temp. down to 33°.									
	00:00	08:33	8.55			SURPRI	FLOWT	PRDT	P	Opened choke from 19.25 to 19.75 beans, BHP at P2 dropped from 318 to 315 psia, temperature dropped 0.02°F/
	08:33	14:21	5.81			SURPRI	FLOWT	PRDT	P	Raise power fluid pump drive rate from 54 to 55%, BHP at XPIO2 dropped about 7 psi, but rate was very unstable

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	14:21	20:00	5.65			SURPR	FLOWT	PRDT	P	Raise power fluid from 55-56% of pump drive max. BHP dropped from 316 psia before the first power fluid rate increase at 14:20 to 300 psia. Temperature dropped from 34.94 to 34.80 in the first two hours. Power fluid flow rate rose from 450 BPD to about 465 BPD, but the rate variation went from +/- 5 BPD to +/- 60 BPD. Power fluid pressure rose from 1301 to 1452 psig.
	20:00	00:00	4.00			SURPR	FLOWT	PRDT	P	Temperature still declining after increase in jet pump rate and choke opening. Has dropped from about 34.2 to 33.75°F (measured by DTS at coldest point in perfs) since this morning at 8 am. Gas rate rose about 3 mscfd. Total Midnight to 8 pm. 20.2 Mscf 26 bbls of water
04/05/2012	Continued lowering bottom hole pressure to bring BHT down. BHT at XPIO2 dropped 0.2°F and coldest point in perfs now below 34.5°F according to DTS. Gas rate rose from 26 mscf/d to 29 mscf/d.									
	00:00	04:30	4.50			SURPR	FLOWT	PRDT	P	Raised Jet pump drive rate from 56 to 57%. BHP at XPIO2 dropped 9 psi. Power fluid rate went from 465 to 472 BPD.
	04:30	16:47	12.29			SURPR	FLOWT	PRDT	P	Raised Jet pump drive rate from 57 to 58%. BHP at XPIO2 dropped 8 psi. Power fluid rate rose from 472 to 479 BPD.
	16:47	23:59	7.21			SURPR			P	Continued lowering bottom hole pressure to bring BHT down. BHT at XPIO2 dropped 0.2°F and coldest point in perfs now below 34.5°F according to DTS. Gas rate rose from 26 mscf/d to 29 mscf/d.
						SURPR				Totals Midnight to 8 pm. 23.0 mscf 26 BW
04/06/2012	Continuing to lower the bottomhole pressure to bring BHP down. Gas rate has risen from 29 mscfd to nearly 30 mscfd.									
	00:00	06:06	6.10			SURPR	FLOWT	PRDT	P	Continuing to lower the bottomhole pressure to bring BHP down. Gas rate has risen from 29 mscfd to nearly 30 mscfd. Raised Jet pump drive rate from 58 to 59%. BHP at XPIO2 dropped 4 psi. Power fluid rate rose from 478 to 486 BPD.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	06:06	00:00	17.90			SURPRI	FLOWT	PRDT	P	Changed from pump number 1 to pump 2, stayed at 59%. PFP dropped from 1675 to 1650psig but the PFR only dropped from 486 to 483 BWPD. BHP at P2 rose from 285 to 287 psia.
						SURPRI				Total production midnight to 8 pm 27 BW 25 mscf
04/07/2012	Continuing to lower the bottomhole pressure to bring BHP down. Contilnue jet pumping operation and monitor data.									
	00:00	00:54	0.91			SURPRI	FLOWT	PRDT	P	Raised jet pump drive rate from 59 to 60%. Power fluid rate rose from 483 to 491 BWPD. BHP started at 286 psia and Power fluid pressure at 1690 psig
	00:54	02:01	1.13			SURPRI			P	Raised power fluid pump drive rate from 60 to 61%. Power fluid rate rose to 497 BWPD. BHP leveled off at 281 psia at a power fluid pressure of 1978 psig
	02:01	09:34	7.55			SURPRI			P	During electrical generator swap, measured power fluid pressure dropped by about 100 psi, but returned to normal over the next 10 minutes.
	09:34	23:58	14.41			SURPRI			P	Raised power fluid pump drive rate from 61 to 62%. Power fluid rate rose from 497 to 503 BWPD and pressure rose from 1796 to 1868 psig
						SURPRI			P	Produced from midnight to 8 pm 25.9 mscf 29 BW Gas chromatograph software performance in selecting Nitrogen separately from Methane improved today, so volumetric estimates were better than previous days.
04/08/2012	Continue jet pumping operation and monitor data. Remained at approximately 504 barrels of power fluid all day. The bottomhole pressure remained near 277 psia and the coolest interval measured by the DTS remained at approximately 34.5°F.									
	00:00	00:00	24.00			SURPRI	FLOWT	PRDT	P	Remained at approximately 504 barrels of power fluid all day. The bottomhole pressure remained near 277 psia and the coolest interval measured by the DTS remained at approximately 34.5°F.
						SURPRI				Midnight to 8 pm production volumes. 26605 scf 27 BW
04/09/2012	Opened choke to wide open, lowered back pressure on separator to 25 psig. Gas flow peaked at 140 mscf/d and dropped back to 40 mscf/d. DTS records temperature at 2446 to be below 33°F. XPIO ROC 2 temperature reading has dropped from 34.5 to 34.2°F.									
	00:00	06:30	6.50			SURPRI	FLOWT	PRDT	P	Objective, go for lowest possible pressure

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Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	06:30	08:40	2.18			SURPR	FLOWT	PRDT	P	EXPRO collected triplicate water samples from upstream of choke, water leg of separator and power fluid charge pump of GMS. Atmospheric air samples collected at each location.
	08:40	09:59	1.33			SURPR	FLOWT	PRDT	P	Delivered sand and ISOTUBE samples to Kuparuk shipping and receiving for distribution.
	09:59	12:50	2.86			SURPR	FLOWT	PRDT	P	Opened choke to wide open, lowered back pressure on separator to 25 psig. Gas flow peaked at 140 mscf/d and dropped back to 40 mscf/d.
	12:50	16:08	3.30			SURPR	FLOWT	PRDT	P	DTS records temperature at 2446 to be below 33°F. XPIO ROC 2 temperature reading has dropped from 34.5 to 34.2°F.
	16:08	19:58	3.84			SURPR	FLOWT	PRDT	P	temperature decrease has levelled off at about 34.1°F on XPIO ROC 2. BHP has dropped from 277 psia prior to choke opening (at 1250 hrs) to 237 psia. Wellhead pressure has dropped from 184 psig to 27 psig. Gas rate has risen from 32 to 39 mscf/d.
	19:58	23:58	4.00			SURPR	FLOWT	PRDT	P	Midnight to 8 pm production volumes. 29.5 mscf 35 BW
04/10/2012	Produced steadily at 40 MSCFD. Initiated removal of insulation on surface lines and stick build scaffold hooches in preparation for rig down and demob of well test equipment.									
	00:00	01:00	1.00			SURPR	FLOWT	PRDT	P	Raising outlet gas pressure enough to take ISOTUBE sample caused well flow rate to read zero, then spike as pressure dropped. This is not a formation/tubing change.
	01:00	07:45	6.75			SURPR	FLOWT	PRDT	P	Produced at 40 MSCFD with the well head pressure at ~31 psi while jet pumping at ~1875 psi.
	07:45	08:30	0.75			SURPR	FLOWT	PRDT	P	Raising outlet gas pressure enough to take ISOTUBE sample caused well flow rate to read zero, then spike as pressure dropped. This is not a formation/tubing change.
	08:30	13:30	5.00			SURPR	FLOWT	PRDT	P	Produced at 40 MSCFD with the well head pressure at ~31 psi while jet pumping at ~1875 psi.
	13:30	19:12	5.70			SURPR	FLOWT	PRDT	P	Started removing blue board insulation from surface lines. Continued to produce at 40 MSCFD with the well head pressure at ~31 psi while jet pumping at ~1875 psi.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	19:12	19:42	0.50			SURPRI	FLOWT	PRDT	P	Changed from using EXPRO heater as the surface storage volume for glycol circulation to the 125 bbl open top in order to heat glycol in open top in preparation for shutdown. Temperature in circulation pumps dropped to 6F, then rose back to 65°F in the first half hour. Scaffold crew on location. Walk down stick built hooches, fuel tank stairs, and well house. Discuss planned work and initiate removal of tank farm hooch, Expro Atigun house hooch and CO2 tank railing.
	19:42	00:00	4.30			SURPRI	FLOWT	PRDT	P	Truck off 290 bbls of returns to 1R-18 for disposal. Continued to produce at 40 MSCFD with the well head pressure at ~31 psi while jet pumping at ~1875 psi. BS&W has been zero for the past 24 hrs. Midnight to 8 pm production volumes. 33 mscf and 29 BW
04/11/2012	Freeze protect IA, tubing, chemical injection line, and heater string from jet pump to surface. Blow down surface lines and equipment. Dispose of returns and initiate rig down procedure.									
	00:00	04:00	4.00			SURPRI	FLOWT	PRDT	P	Swap from pumping produced water "power fluid" down the IA to 60/40 Tritherm glycol to freeze protect well. Displace IA to glycol taking returns up the tubing through the Expro stack pack separator. Drawing glycol from Expro serarator bath, 125 glycol tank, and SLB line heater.
	04:00	06:00	2.00			SURPRI	FLOWT	PRDT	P	Glycol at the jet pump. Increase choke setting to hold 700 psi back pressure in effort to stall jet pump and bull head glycol into tubing / perforations. No indication on DTS temperature trace that any glycol went below the jet pump. Attempt to pump glycol down the chemical injection line. Pressure up to 2200 psi instantly. Bleed line to 70 bbl sand jet tank. Pump 80 gal glycol down the heater string.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	06:00	07:30	1.50			SURPRI	FLOWT	PRDT	P	Reduce choke setting to circulate glycol up the tubing while keeping the jet pump stalled and well killed. Bleed off chemical injection line to 70 bbl sand jet tank while pumping glycol into the IA at 1100 psi . Returns from CI line at 30 gallons away are clear and appear to be water sample caught 07:45. Returns from the CI line at 40 gallons away down the IA appear to be 60/40 glycol. Sample pulled at 07:47. 18 bbls glycol left in the 125 bbl tank.
	07:30	08:18	0.80			SURPRI	FLOWT	PRDT	P	Lost HPP # 2, switch to #1 resume displacing well to glycol at 10 gpm and 1143 psi on the IA taking returns to the Expro separator. Start to cool down N2 pump.
	08:18	08:54	0.60			SURPRI	FLOWT	PRDT	P	Lost prime on pump while drawing down SLB line heater bath. Out of surface glycol. Shut in well. Line up to start blowing down surface lines with N2.
	08:54	11:00	2.10			SURPRI	FLOWT	PRDT	P	Blow down Expro lines, separator, and hoses to tanks. Blow down surface HPP lines. Down on N2. All valves on well head shut and flagged. Begin RD
	11:00	20:00	9.00			DEMOB	PLUG	DMOB	P	Start to rig down all Expro / SLB treating lines. Remove spill containment under all treating lines. Disconnect Gas chromatograph lines. Haul off all remaining returned surface fluid for disposal at 1R-18. Stage portable heaters on pad for release. Scaffolding crew removed large tank farm hooch. Palletize SLB treating iron for storage in connex. Rig down all SLB treating lines from well head.
	20:00	00:00	4.00			DEMOB	PLUG	DMOB	P	Continue to rig down all test equipment.
04/12/2012	Rigged down and inventoried all SLB treating lines and stored in connex. Rigged down and staged all Expro treating lines for shipment. Turned off well site power and removed all power leads. Staged and released non mobile equipment, heaters / light plants/ compressors.									
	00:00	06:00	6.00			DEMOB	PLUG	DMOB	P	Cut all long hoses to ~25' lengths and stack on pallets. Stage all SLB iron and hoses in front of storage connex. Rig down propane tank and prep for transport to Brooks Range.
	06:00	09:00	3.00			DEMOB	PLUG	DMOB	P	load SLB connex with treating lines. Truck propane tank to Brooks Range.

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	09:00	12:00	3.00			DEMOB	PLUG	DMOB	P	Drain and remove SSV pannels. return to CPF1. Staged all non mobile equipment for removal. Hand -y-berm removed all revetment supports. Shut off well site power unit. Cut all power leads to well site equipment.
	12:00	15:00	3.00			DEMOB	PLUG	DMOB	P	Rig down Expro treating Iron and stage for loading to back haul. Trucked off 4 heaters, 2 air compressors, one light plant. Spooled up well site electrical lines.
	15:00	18:00	3.00			DEMOB	PLUG	DMOB	P	Banded up lumber, insulation blue board, and returned to DTH. DTH removed Atigun house scaffolding.
	18:00	00:00	6.00			DEMOB	PLUG	DMOB	P	Continue to rig down all test equipment.
04/13/2012	Removed all Expro treating lines and ancillary equipment from location. Notified AOGCC of pending P&A. Crane on hold until tomorrow due to rig 27 broken down in road.									
	00:00	06:00	6.00			DEMOB	PLUG	DMOB	P	Drilling tool house crew removed the scaffolding in front of the Expro Atigun house and picked up all exposed revetment plus plywood. Rig 27 stuck at the kuparuk river west bridge blocking all dead horse traffic.
	06:00	12:00	6.00			DEMOB	PLUG	DMOB	P	Removed Cormorant WMD and choke skid from Atigun house.
	12:00	18:00	6.00			DEMOB	PLUG	DMOB	P	Rig moving and trailers allowed past however BP security unwilling to provide escort for 200 crane travel from dead horse to location. Rebook crane for tomorrow. Load all expro treating equipment on trailers. Notified AOGCC State inspectors of pending P&A activities (John Crisp)
	18:00	00:00	6.00			DEMOB	PLUG	DMOB	P	Lynden spotted 4 trailers on site for tomorrow picks. CH2 slowly removing released heaters from pad.
04/14/2012	Removed all major well test equipment from pad less well site generators. Built temporary well head scaffold for slickline and coiled tubing intervention.									
	00:00	06:00	6.00			DEMOB	PLUG	DMOB	P	sleep!
	06:00	08:00	2.00			DEMOB	PLUG	DMOB	P	Pre job to discuss lift plan. wait on crine and twin steer
	08:00	08:45	0.75			DEMOB	PLUG	DMOB	P	Crane and twin steer on location. Hold pre job and start spotting for fist pick.
	08:45	09:45	1.00			DEMOB	PLUG	DMOB	P	Rig up to well house. Cut DTS fiber optic lines 08:56. Remove well house. HES packed up DTS computers and hauled off.

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Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	09:45	10:45	1.00			DEMOB	PLUG	DMOB	P	Moved Atigun house with twin steer. Spotted same on trailer and trucked to peak yard for storage until the haul road weight restrictions are lifted. Lay down sand trap with crane. Loaded trap and trucked off. DTH removing 500 bbl tiger tanks and returning to Tanko yard.
	10:45	11:15	0.50			DEMOB	PLUG	DMOB	P	Rig CO2 tank. Pick and set on trailer for back haul to SLB deadhorse.
	11:15	12:15	1.00			DEMOB	PLUG	DMOB	P	Pick N2 tanks and spot on trailers for back haul. COlville fuel tanker and pump truck on location to drain and haul off excess fuel from well site tanks. Credit received for 4964 gal ULSD.
	12:15	13:15	1.00			DEMOB	PLUG	DMOB	P	Pick Schlumberger Gas mixing skid and spot on truck for back haul. Pick Expro stairs and lay down for demob.
	13:15	14:15	1.00			DEMOB	PLUG	DMOB	P	Lay down flare stack. Haul two 400 BBL uprights tanks to wash bay for cleaning. Load SLB work connex and storage connexes on trailers for transport to Deadhorse.
	14:15	15:00	0.75			DEMOB	PLUG	DMOB	P	Pick SLB line heater and spot on trailer for back haul. SLB crews left location.
	15:00	18:00	3.00			DEMOB	PLUG	DMOB	P	DTH removed well platform and SSV wing valves.
	18:00	00:00	6.00			DEMOB	PLUG	DMOB	P	DTH night crew cleaning up plywood and herculite from site. Hauling off all remaining equipment. Scaffold crew on location 20:47 to demo fuel tank stairs and build well platform. Updated BP planners with demob P&A schedule.
04/15/2012	Attempted to fish jet pump. Beat up for a total of two hrs and 30 minutes. Removed AZTAC and CPAI comms from camp. Staged well site generators for back haul. Return in the morning to try to retrieve jet pump assy.									
	00:00	06:00	6.00			DEMOB	PLUG	DMOB	P	no night operations

Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	06:00	12:00	6.00			DEMOB	PLUG	DMOB	P	SLick line unit arrived on location 07:00. Found departing crews had removed bleed fittings from sand jet tank. called out wells goup to instal new bleed port. Rig up SLU w/ 0.125 wire, 8' x 2.625" Stem, KJ, LSS. RIH w/QC, 2'x 1.875"STEM, 2.85" GAUGE RING, TAG @ 1919' SLM, POOH, set down in station# 1, bobble past, POOH. Added 5' x 2.625" stem, RIH w/ 4 1/2 PRS,(brass pin), to 1920' SLM, beat up for 50 min, sheer off POOH.; tool sheared. AZTAC and CPAI communications crews removing all comm systems from location.
	12:00	18:00	6.00			DEMOB	PLUG	DMOB	P	Cut 200' wire, had to rebuild PRS to repin and clean. RIH w/ QC, 4 1/2 PRS TO 1920' SLM, latch, beat up for 50 min. Shear off, POOH cut 100' wire. RIH w/ same. Beat for 46 min, POOH SIBD, cut wire. Picked up catcher RIH. Slips catching repeatedly setting down 800'. POOH RD for night. Return with rebuilt PRS (new collets) and catcher W/out slips. DTH assisting Peak Precision power to remove louvers from well site generators and stage same for back haul.
	18:00	00:00	6.00			DEMOB	PLUG	DMOB	P	ASRC Drilling Tool House Loader operating on pad suffered a hydraulic hose failure. Security called. PIR mailed. CPAI Wells SUPT notified.
04/16/2012	Pulled dummy valve @ 1928' RKB, pulled jet pump, S/N: PH-1108 ration 6C (OAL 200") from 1942' RKB, pulled Weatherford seal assembly and gutted CAT SV from 1956' RKB.									
	00:00	06:00	6.00			DEMOB	PLUG	FISH	P	no night operations
	06:00	12:00	6.00			DEMOB	PLUG	FISH	P	SL crew traveled to location, inspected equipment, performed pre-job safety meeting. RU SLU, .125 wire, TS=8' x 2.625" stem, KJ, LSS. RIH w/ 4 1/2"GS (3/16" Brass) 4 1/2 bait sub as catcher sub (12"OAL) set on 3.812 DB-6 lock @ 1918' SLM / 1942' RKB. RIH w/ 4 1/2 OM-K, 1.25"JD to STA# 1 @ locate @ 1908' SLM, latch @ 1910' SLM / 1928' RKB, pulled, POOH, OOH w/ 1"DV on BK latch. RIH w/ 4 1/2 GS, latch 4 1/2 bait sub @ 1942' RKB, POOH, OOH bait sub empty....

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Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	12:00	18:00	6.00			DEMOB	PLUG	FISH	P	RIH w/ 4 1/2 PRS to 1919' SLM, latch, beat up 1900#s for 1 hour, hit down 3 times, sheared, POOH, OOH w/ sheared PRS, cut 200' wire. RIH w/ 4 1/2 PRS to 3.812 DB lock & 3" RC jet pump (s/N: PH-1108 ratio 6C (OAL 200"), latch @ 1919' SLM, beat up for 1 hour, came free, pulled POOH slow, OOH, carbolite in lowest stinger. Brass marks around top of DB-6 lock mandrel. RIH w/ 4 1/2 PRS latch to 1934' SLM, / 1956' RKB, pulled 3.75" DB-6 lock mandrel w/ weatherford seal bore assembly and gutted CAT SV. RDMO.
	18:00	00:00	6.00			DEMOB	PLUG	FISH	P	DTH load up last remaining Delta Leasing heater and hauled to Kuparuk. Cleaned up oil from loader spill on 4-15-12, loaded into transport tank and trucked to Kuparuk for disposal. Dropped off envirovac for camp demob. Break down deluge system.
04/17/2012	Disconnected XPIO data acquisition box from well.									
	00:00	00:00	24.00			DEMOB	PLUG	OTHR	P	Disconnected the XPIO data collection box from the well. Camp continues to rig down for move.
05/01/2012	Perform Full-Bore Cement Job									
	15:30	16:00	0.50			DEMOB	PLUG	CMNT	P	MIRU Cement Pump unit and cement tankers
	00:30	00:45	0.25			DEMOB	PLUG	CMNT	P	Pre-Job Safety Meeting
	00:45	01:15	0.50			DEMOB	PLUG	CMNT	P	Pressure Test hardline.
	01:15	01:30	0.25			DEMOB	PLUG	CMNT	P	Line up well to pump down tubing and take returns up the IA. Pump approx. 7 bbls of Freshwater down the tubing to establish flow. Commence batching cement to job specs.
	01:30	02:15	0.75			DEMOB	PLUG	CMNT	P	Pump 81 bbls of cement down the tubing and take returns up the IA until at surface.
	02:15	02:30	0.25			DEMOB	PLUG	CMNT	P	Close IA and line tree up to take returns up the flat pack until cement is at surface.
	02:30	02:45	0.25			DEMOB	PLUG	CMNT	P	Close valve to flat pack and line up tree to take cement up the chemical injection line to surface.
	02:45	03:15	0.50			DEMOB	PLUG	CMNT	P	Shut in well and flush surface lines with 35 bbls of fresh water.
	03:15	04:15	1.00			DEMOB	PLUG	CMNT	P	RDMO. Secure Location.
05/03/2012	Begin Plug & Abandon Procedures. Excavate around cellar box and remove; begin excavation to get a minimum of 5' below tundra level.									

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Time Logs

Date	From	To	Dur	S. Depth	E. Depth	Phase	Code	Subcode	T	Comment
	06:00	07:00	1.00			DEMOB	PLUG	SFTY	P	Pre-Tower Meeting; PJSM.
	01:00	04:00	3.00			DEMOB	PLUG	MOB	P	Transport equipment to location and stage.
	04:00	05:00	1.00			DEMOB	PLUG	OTHR	P	Obtain Hot Work and Unit Work Permits.
	05:00	07:00	2.00			DEMOB	PLUG	OTHR	P	Begin to excavate around the cellar box to facilitate cutting and removal.
	07:00	11:00	4.00			DEMOB	PLUG	OTHR	P	After cellar box is removed, begin excavating around the wellhead to a depth of 5" below tundar level. Cut in a walking ramp to ease egress.
	11:00	12:00	1.00			DEMOB	PLUG	SISW	P	Set barricades and secure location for the night.
05/04/2012	Continue with Plug & Abandon Procedures. Cut off and remove wellhead, Have AOGCC Inspector sign off, weld on cap and backfill with spolis.									
	06:00	07:00	1.00			DEMOB	PLUG	SFTY	P	Pre-Tour Meeting and PJSM.
	01:00	02:30	1.50			DEMOB	PLUG	OTHR	X	Travel to location and clean up road entrance due to blowing snow. Free stuck vehicle in roadway.
	02:30	03:00	0.50			DEMOB	PLUG	OTHR	P	Obtain How Work and Unit Work Permits.
	03:00	03:30	0.50			DEMOB	PLUG	SFTY	P	Hold PJSM with welder and excavator operator.
	03:30	07:00	3.50			DEMOB	PLUG	RTWH	P	Begin window cutting procedures. Drill and cut windows in casings and tubing. Varify no gas or fluids and good cement to surface.
	07:00	07:30	0.50			DEMOB	PLUG	RTWH	P	Cut conductor until free and set off to the side.
	07:30	08:00	0.50			DEMOB	PLUG	OTHR	P	Verify good cement and obtain pictures with AOGCC Iinspector, John Crisp. Receive confirmation and weld cap to 16" conductor.
	08:00	08:30	0.50			DEMOB	PLUG	RURD	P	Release and rig down GBR Welder and close out Hot Work Permit.
	08:30	10:30	2.00			DEMOB	PLUG	OTHR	P	Backfill hole with existing spoils and observed that more fill was needed.
	10:30	15:00	4.50			DEMOB	PLUG	OTHR	X	Haul 3 loads (25 yds. each) of gravel and 2 loads (25 yds each) of overburden to location. Backfill to 4' above ice level to allow for settling. Total of 150 yards of extra backfill hauled and used on location.
	15:00	16:00	1.00			DEMOB	PLUG	RURD	P	Release equipment and secure location with barricades.

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