

Impact of Carbon Dioxide Sequestration on Reservoir Brine Composition at an Enhanced Oil Recovery Site in Fayette County, Illinois

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Open File Series 2010-1



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Institute of Natural Resource Sustainability
ILLINOIS STATE GEOLOGICAL SURVEY

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Introduction

The Intergovernmental Panel on Climate Change (2007) concluded that the global climate has warmed and that atmospheric concentrations of three greenhouse gases (carbon dioxide [CO₂], methane, and nitrous oxide) have increased markedly because of human activities since 1750. Further, most of the observed increase in global average temperatures since the mid-20th century is *very likely* due to increases in anthropogenic greenhouse gas concentrations. In response, governments around the world have sponsored research and demonstration projects to sequester greenhouse gases with an emphasis on CO₂. Sequestration has been evaluated for geologic, oceanic, and terrestrial sinks. Geologic carbon sequestration involves the injection of carbon dioxide into suitable reservoirs such as deep coal seams, depleted oil reservoirs, and deep saline reservoirs. While sequestration into coal seams and oil reservoirs offers the potential for hydrocarbon recovery, sequestration in saline reservoirs offers the largest potential sequestration sink.

The Illinois Basin encompasses Illinois, western Indiana, and western Kentucky (Fig. 1). Stationary sources such as power plants refineries and ethanol plants emit more than 304 million tonnes of CO₂ per year (USDOE, 2008). These emissions are an excellent target for geologic carbon sequestration because of the proximity to large saline reservoirs found throughout the basin. Some of the saline reservoirs available for injection of CO₂ are mature oil fields. Much of the infrastructure needed for sequestration at the oil-field sites, such as wells for injection and withdrawal, is already in place. Also, the injection of CO₂ can enhance oil recovery from these wells, which provides an economic incentive other sequestration options currently lack.

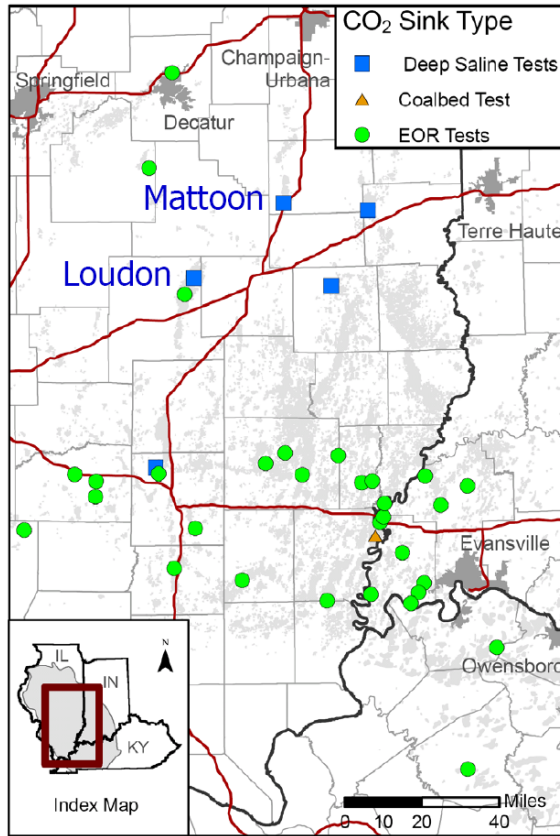


Figure 1. Location of the Loudon Oil Field.

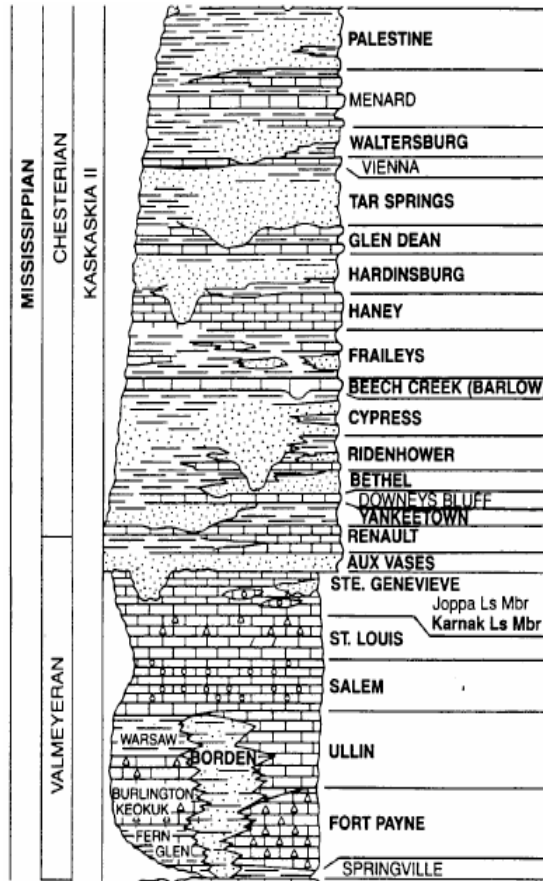


Figure 2. Geologic column for Mississippian age oil reservoirs in the Illinois Basin (Leetaru, 1996).

Project Description

The enhanced oil recovery (EOR) project outlined in this report was part of the Illinois State Geological Survey and the Midwest Geological Sequestration Consortium’s ongoing research into CO₂ sequestration. The goal was to demonstrate that mature Illinois oil reservoirs can provide a reservoir for the greenhouse gas, and to contribute to previous research that showed substantially increased oil recovery after CO₂ injection (Brock and Bryan, 1990). This project was the first of several field-scale demonstrations in the Illinois Basin funded by the U.S. Department of Energy (USDOE) to help develop the knowledge and experience needed for CO₂-based enhanced oil recovery and sequestration.

The EOR trial in the Illinois Basin was a “Huff”n’Puff” setup. A Huff’n’Puff involves an initial injection of CO₂, the huff, a soak-in period, and then opening the well, the puff, which allows some of the CO₂ to escape before pumping resumes (Klins, 1984). The soak-in period allows the CO₂ time to reduce the viscosity of the oil, and for the acidity of the gas to increase reservoir permeability by dissolving mineral grains. Some of the gas

escapes before pumping resumes if a large amount of gas near the well prevents fluid recovery.

The ISGS pumped 39 tonnes of CO₂ into the middle Mississippian Cypress Sandstone (Fig. 2) via the Owens 1 well over a period of 5 days, and the well was then shut in for 8 days. Once the shut-in period was complete, the well was reopened and produced 30 tonnes of the injected CO₂ (Frailey, 2007). The CO₂ should have remained immiscible given the temperature and pressure conditions measured in the formation. For the two months after the well resumed pumping, it produced 93 barrels of oil over the average production and peaked at 8 times that of normal production (MGSC-ICCI, 2007b).

The ISGS monitored the pressure, pumping rates, brine, and gas composition of the CO₂ injection well, brine reinjection well, several nearby oil producing wells, shallow groundwater monitoring wells, and a brine oil separator attached to the Owens 1 well. The well operator used anticorrosion chemicals weekly on all producing wells during the course of the test; however, the small amount of chemical was not expected to influence brine chemistry (Frailey, pers. comm., 2009). The purpose of creating this report was to compile all of the geochemical and some pumping data collected during the course of the EOR test, so that they can be used as convenient reference for future work.

Geologic Setting

The Loudon Oil Field is in an anticlinal structure and occupies 40 square miles in south central Illinois. Production from Loudon began in 1938 with waterflooding starting 13 years later. The waterflooding is ongoing with produced water from several wells mixing in a holding tank before reinjection. The field has produced 393 million barrels of oil to date (MGSC, 2006). Figure 3 shows the spacing and layout of the test site. Table 1 contains information about the four wells sampled (Owens 1, Owens 4, Coddington 2W and Coddington 4) in this project.

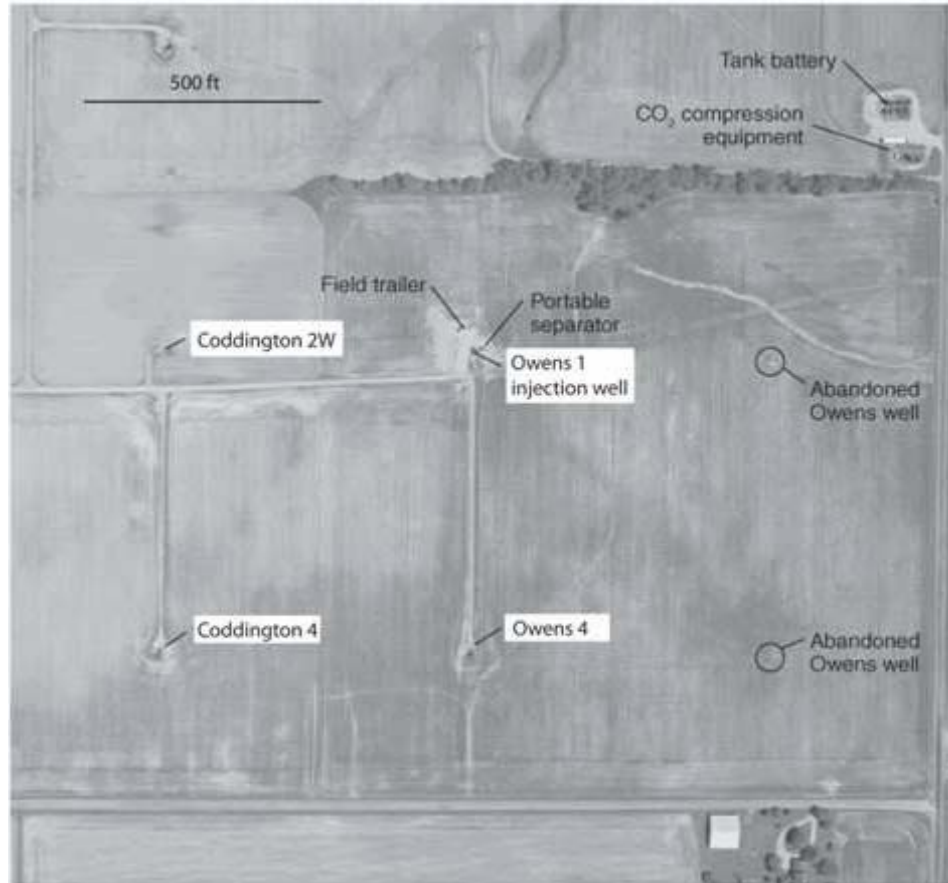


Figure 3. Aerial photo of the Huff'n'Puff field site.

The oil-producing units in the Cypress are sandstone units in cyclical Mississippian sandstone-limestone-shale deposits with the shales being a possible source rock. A prograding delta deposited the sand offshore where it was subsequently reworked by tidal forces (Cluff and Lasemi, 1980; Treworgy, 1990). At Loudon, the Cypress Sandstone is typically over 100 ft thick.

Cypress reservoirs in the Loudon Field are typically small, lenticular "pods" with an extent of less than 180 acres and up to 20 feet thick. According to geologic mapping, the injection well is near the southwestern extremity of one of these pods. Analysis of well logs from the Owens 1 well shows that the Cypress Sandstone at the site is made up of thin (6-10 feet) sands separated by thin, interbedded shales (Damico et al., 2009).

Demir and Seyler (1999) reported that the Cypress sandstone is predominately a quartz sandstone with small percentages of clay minerals, plagioclase, feldspar, and carbonates (Table 2). These results were based on other fields to the south of Loudon. However, a visual inspection of cuttings from the injection well showed it is predominately a quartz-rich sandstone with small amounts of iron oxides and other minerals.

Injection and Withdrawal

Neither CO₂ injection nor fluid production from Owens 1 (after the soak-in period) was constant. Occasional equipment problems interrupted or slowed the injection during the initial period of CO₂ injection. The total measured CO₂ injection was 39 tonnes over 5 days starting on March 20 (Table 3). Pumping following the soak-in period produced liquid intermittently until April 7 because of the large amounts of gas coming up the well. It is estimated that the well produced 3.6 to 4.1 tonnes of CO₂ over the first week of pumping (MGSC-ICCI, 2007a). From the date of CO₂ release to March 2009 the amount of CO₂ degassing from the well annulus noticeably decreased.

Samples and Analysis

We collected brine samples from the wells before CO₂ injection began and after the shut-in period ended. These samples were collected by plumbing a plastic tube into the exit port of the individual oil wells. This tube then transported the oil/brine/gas mixture into a 3-gallon separation carboy. The carboy included an input and waste connection on the lid, as well as a three-way sampling valve at the base. Three carboy volumes were purged for each sample to ensure fresh formation brine. As the oil collected at the top of the carboy, and exited through the waste tube to a waste carboy, the brine flowed from the three-way valve to a jar containing electrodes measuring pH, temperature, Eh, specific conductance, and dissolved oxygen. The brine then flowed from the exit port in the jar to the input port of a Hydrolab[®] MS5 Mini-Sonde, which measured the same parameters. The purpose of using both the mini-sonde and the electrodes was for quality assurance, and also because the mini-sonde did not read specific conductance above 100 mmohs, whereas the electrode could read to 200 mmohs. Once the parameters were stable, samples were collected by switching the three-way valve to the sampling tube at the base of the carboy directing flow into either a bottle or collapsible bag. Both filtered and unfiltered archive samples were collected in a 1 liter collapsible bag. The last brine samples were collected 732 days after the initial injection of CO₂. Ammonia, alkalinity, and CO₂ concentrations were determined in the laboratory. Alkalinity was measured three separate times for each well-sampling. Field alkalinity represents alkalinity measured in the field within 12 hours of collection. Bottle alkalinity was analyzed in the lab within 24 hours of collection and measures brine that was exposed to the atmosphere. Bag alkalinity was analyzed at the same time as bottle alkalinity, however this brine was not exposed to the atmosphere. Anion concentrations were determined by ion chromatography and cation concentrations by inductively coupled argon spectroscopy (Table 4). A complete summary of all the analytical results is provided in Table 5.

pH and HCO₃

While we collected samples from the wells, CO₂ visibly bubbled out of solution. Most of the collected anion and cation data should be unaffected by this degassing because there

was no visible mineral precipitation. However, the pH and obviously the CO₂ values measured for the samples and reported in Table 4 are in need of correction.

At the beginning of our geochemical modeling work (Berger et al., 2009), we corrected the HCO₃⁻ and pH values using React version 7.0.6 (Bethke and Yeakel, 2007). During the numerical modeling process, we started with measured concentrations and added CO₂ until the system was at equilibrium with calcite. This technique is viable if no solid phases precipitated during sampling, and the injection of the acidic gas did not dissolve all of the calcite in the injection formation. The results of this analysis for the injection-well data are listed in Table 6 under the heading Method 1.

An alternative assumption for correcting the data was also made. In Method 2, we assumed that the water in the reservoir was in equilibrium with CO₂ as a gas phase. Method 2 in Table 6 corrects the pH and HCO₃⁻ by adding CO₂ until it reaches the fugacity it would have as a separate phase under reservoir conditions (Duan et al., 1992). Other corrections are possible by varying the assumed phase the brine is at equilibrium with in the subsurface. The number of different correction methods is limited only by the number of possible phases in the reservoir.

Summary

The Huff'n'Puff test successfully demonstrated the potential for EOR-based carbon sequestration in the Illinois Basin. The flow of oil into the wells increased and there was no discernable CO₂ leakage into the shallow groundwater. This Open File Report was created to display all of the geochemical and some pumping data collected during the course of the EOR test so that they can be used as convenient reference for future work

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Table 1. Well information

Well	Well id (API)	Depth (ft)	Elevation (ft)	Type
Owens 1	120510266800	1,546	595	CO ₂ injection/withdrawal
Owens 4	120510267000	1,550	595	withdrawal
Coddington 2W	120510262802	1,529	595	brine injection
Coddington 4	120510263000	1,549	596	withdrawal

Table 2. Mineralogy of the Cypress Formation (Demir and Seyler, 1999)

	Total Clay	Illite	Illite/Smectite clays	Kaolinite	Chlorite
Average (wt %)	8.0	2.3	1.7	3.0	1.0
Std. Dev.	5.5	2.5	1.9	1.5	1.1
	K-feldspar	Plagioclase	Calcite	Dolomite	Quartz
Average (wt %)	0.5	3.1	1.9	0.2	86.4
Std. Dev.	0.9	1.8	3.1	0.4	5.9

Table 3. Volumes, pressures, and rates of CO₂ injection.

Date	Injection Period (hours)	Average Surface Casing Pressure (bar)	Average Bottom Hole Pressure (bar)	Average Injection Rate (L/min)	CO ₂ Injected (tonnes)	CO ₂ Density (kg/L)
3/20/2007	10.08	41.69	39.33	8.22	4.74	2.086
3/21/2007	17.83	47.91	45.84	6.38	7.47	1.621
3/22/2007	19.90	48.91	47.24	5.46	7.16	1.387
3/23/2007	23.94	49.43	48.13	5.39	7.37	1.370
3/24/2007	23.82	49.71	48.55	5.90	8.01	1.497
3/25/2007	7.85	49.75	49.22	8.06	3.73	2.047

The CO₂ injection period is the time during the day when the injection rate was greater than 0.01 gallon per minute.

Table 4. Summary of analytical methods.

Analyte group	Analytical method	Standard methods
pH	Electrode	US EPA 150.1
Redox potential (Eh)	Electrode	Standard Methods 2580
Electrical conductivity	Electrode	Standard Methods 2520B
Dissolved oxygen	Electrode	Standard Methods 4500OG
Ammonium	Electrode	Standard Methods 4500-NH ₃
Alkalinity	Titration	USGS 1-1030-85
CO ₂	Electrode	Thermo Electron Corp Manual
Anions	Ion chromatography	US EPA 300.0
Cations	Inductively Coupled Argon Plasma Spectrometer	US EPA 200.7

Table 5. Chemical composition of the brine samples.

Sample ID	Measuring method	Sampling Date	pH		EC Electrode mS/cm	Eh _z mV		DO mg/L		Temperature °C	
			Electrode	Sonde		Electrode	Sonde	Electrode	Sonde	Electrode	Sonde
OWENS 1		12/13/2006	6.39	6.68	137.1	191	NA	ND	3.17	19.0	NA
TEST SEPARATOR		3/20/2007	6.39	NA	133.1	-14.9	NA	0.20	N/A	15.8	NA
TEST SEPARATOR-1		5/3/2007	6.02	5.81	133.7	-16.3	-45.0	0.10	0.14	17.4	17.3
TEST SEPARATOR-2		6/19/2007	6.10	5.78	121.0	-21.5	-70.0	0.10	0.08	29.5	32.0
OWENS 1-1		9/19/2007	5.78	5.44	120.9	-18.0	82.0	0.10	1.42	19.7	25.3
OWENS 1-2		1/16/2008	5.83	5.33	135.7	127	-38.0	0.10	0.08	17.1	16.7
OWENS 1-3		7/29/2008	5.81	5.30	116.0	245	-52.0	0.10	0.00	21.0	21.7
OWENS 1-4		3/26/2009	5.65	NA	115.6	-62.2	NA	0.10	NA	18.2	NA
CODD 4		12/15/2006	6.12	NA	136.9	-58.0	NA	ND	NA	22.0	NA
CODD 4-1		1/17/2007	6.32	6.63	116.7	-102	NA	0.10	0.00	20.7	20.3
CODD 4-2		3/26/2007	6.28	6.23	123.6	-110	-92.0	0.20	0.23	22.9	24.4
CODD 4-3		5/3/2007	6.45	6.25	133.8	-113	-86.0	0.10	1.31	23.3	23.4
CODD 4-4		6/19/2007	6.54	6.03	122.8	-42.60	5.00	0.10	1.23	25.5	26.8
CODD 4-5		9/19/2007	6.37	6.01	129.4	-133	15.0	0.10	1.74	24.8	27.5
CODD 4-6		1/16/2008	6.42	5.98	121.3	57.7	-98.0	0.10	0.09	23.1	22.6
CODD 4-7		7/29/2008	6.47	6.19	123.9	342	-106	0.10	0.11	24.8	25.5
CODD 4-8		3/26/2009	6.07	NA	115.8	-72.8	NA	0.10	NA	24.4	NA
OWENS 4		12/15/2006	6.25	5.65	140.3	-75.4	NA	ND	0.64	19.2	18.8
OWENS 4-1		1/17/2007	6.33	6.47	125.6	-196	NA	0.10	0.00	17.3	16.7
OWENS 4-2		3/26/2007	6.33	6.24	119.3	-186	-118	0.10	0.11	21.4	21.8
OWENS 4-3		5/3/2007	6.38	6.17	130.9	-116	-86.0	0.10	1.40	21.5	21.3
OWENS 4-4		6/19/2007	6.45	6.24	112.1	-111	11.0	0.10	0.95	24.0	25.8
OWENS 4-5		9/19/2007									
OWENS 4-6		1/16/2008	6.39	5.87	117.7	150	-101	0.10	0.15	21.4	21.4
OWENS 4-7		7/29/2008	6.38	6.05	120.3	NA	-110	0.10	0.09	23.5	24.6
OWENS 4-8		3/26/2009	6.02	NA	115.6	-106	NA	0.10	NA	22.3	NA
CODD 2W		3/7/2007	6.49	6.16	128.3	-39.6	51.0	1.50	0.29	9.00	8.78
CODD 2W-2		5/3/2007	6.81	6.31	132.3	-67.3	-67.0	0.40	0.51	18.1	18.1
CODD 2W-3		6/19/2007	6.54	6.12	129.1	-13.3	44.0	0.10	1.41	25.8	26.7
CODD 2W-4		9/19/2007	6.54	6.00	135.7	-69.9	111	0.10	2.80	25.5	27.1
CODD 2W-5		1/16/2008	6.44	5.69	131.7	125	-14.0	0.20	0.14	10.8	9.98
CODD 2W-6		7/29/2008	6.60	6.30	128.1	188	-42.0	0.10	0.23	25.2	30.5
CODD 2W-7		3/26/2009	6.30	NA	111.5	-106	NA	0.10	NA	16.8	NA

No sample was collected

Sample ID	Alkalinity as CaCO ₃				CO ₂	Ammonia	F	Cl
	Field	Bag	Bottle	Ave.				
	mg/L							
Units					mg/L	mg/L	mg/L	mg/L
OWENS 1	264	253	250	256	281	22.7	<0.01	68,700
TEST SEPARATOR	255	245	246	249	325	20.4	<0.01	N/A
TEST SEPARATOR-1	1951	NA	1990	1970	2,620	14.5	<0.01	69,800
TEST SEPARATOR-2	1790	1730	1760	1760	2,190	21.7	<0.01	81,100
OWENS 1-1	1380	1300	1310	1330	1,670	17.2	<0.01	65,900
OWENS 1-2	892	892	868	884	1,390	12.4	59.9	70,000
OWENS 1-3	694	680	692	689	252	11.7	<0.01	68,600
OWENS 1-4	636	601	612	617	1,110	13.3	<0.01	64,800
CODD 4	281	274	273	276	307	23.2	<0.01	68,500
CODD 4-1	277	275	268	273	350	25.1	<0.01	64,800
CODD 4-2	295	294	294	294	385	25.8	<0.01	71,100
CODD 4-3	290	284	286	287	367	17.5	<0.01	74,500
CODD 4-4	281	280	283	281	347	24.8	<0.01	76,000
CODD 4-5	285	NA	289	286	336	17.6	<0.01	66,700
CODD 4-6	290	288	286	288	370	9.84	10.9	67,400
CODD 4-7	291	299	289	293	375	11.3	<0.01	68,800
CODD 4-8	324	310	308	314	359	13.2	<0.01	65,000
OWENS 4	350	338	342	343	374	23.0	<0.01	65,900
OWENS 4-1	348	347	343	346	386	24.7	<0.01	61,200
OWENS 4-2	312	310	307	310	395	25.0	<0.01	77,800
OWENS 4-3	346	346	350	347	454	17.0	<0.01	74,800
OWENS 4-4	368	360	363	364	427	24.3	<0.01	75,200
OWENS 4-5					No sample was collected			
OWENS 4-6	382	367	363	371	458	8.79	63.8	67,900
OWENS 4-7	372	383	377	377	466	9.91	>0.01	67,000
OWENS 4-8	412	386	390	396	443	13.8	<0.01	62,900
CODD 2W	195	NA	196	196	231	24.0	<0.01	80,000
CODD 2W-2	206	205	202	204	265	18.2	<0.01	73,800
CODD 2W-3	210	203	204	206	245	24.3	<0.01	73,200
CODD 2W-4	206	203	203	204	245	19.7	<0.01	66,600
CODD 2W-5	207	209	207	208	269	11.0	13.6	74,900
CODD 2W-6	247	213	205	222	223	11.7	<0.01	67,400
CODD 2W-7	228	214	214	219	275	14.0	<0.01	64,800

Sample ID	PO ₄ mg/L	SO ₄ mg/L	Al mg/L	As mg/L	B mg/L	Ba mg/L	Ca mg/L	Cd mg/L	Co mg/L
Detection limit	0.01	0.01	0.0022	0.1080	0.0230	0.0001	0.0120	0.0120	0.0130
Units	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L
OWENS 1	<0.01	<0.01	0.120	<0.108	3.33	391	2,760	<0.012	<0.013
TEST SEPARATOR	N/A	N/A	0.0958	<0.108	3.11	386	2,880	0.0130	0.0140
TEST SEPARATOR-1	8.04	<0.01	0.209	<0.108	6.20	340	3,320	0.0280	<0.013
TEST SEPARATOR-2	7.06	<0.01	0.186	<0.108	4.78	360	3,310	0.0260	<0.013
OWENS 1-1	6.50	<0.01	0.210	0.160	3.56	398	3,110	0.0100	<0.013
OWENS 1-2	7.69	1.08	0.167	<0.108	3.47	424	2,930	0.0200	<0.013
OWENS 1-3	6.97	1.28	0.119	0.173	3.39	362	2,850	0.0160	<0.013
OWENS 1-4	<0.01	4.74				No sample was collected			
CODD 4	ND	<0.01	0.108	0.126	3.12	539	2,490	<0.012	<0.013
CODD 4-1	ND	<0.01	0.124	<0.108	3.03	539	2,520	<0.012	<0.013
CODD 4-2	8.86	<0.01	0.094	<0.108	2.81	564	2,710	<0.012	0.0140
CODD 4-3	9.35	<0.01	0.162	<0.108	3.21	564	2,660	<0.012	0.0180
CODD 4-4	9.51	<0.01	0.143	0.112	2.97	532	2,710	<0.012	0.0150
CODD 4-5	5.09	<0.01	0.190	0.120	2.89	550	2,660	<0.012	0.0200
CODD 4-6	9.74	1.30	0.141	<0.108	2.84	624	2,550	<0.012	0.0150
CODD 4-7	0.430	>0.01	0.101	0.241	2.81	559	2,530	<0.012	<0.013
CODD 4-8	<0.01	7.67				No sample was collected			
OWENS 4	<0.01	<0.01	0.115	<0.108	3.52	536	2,620	<0.012	0.0230
OWENS 4-1	<0.01	<0.01	0.129	0.137	3.56	565	2,650	<0.012	<0.013
OWENS 4-2	8.43	<0.01	0.103	<0.108	3.30	513	2,710	<0.012	0.0140
OWENS 4-3	9.39	<0.01	0.156	0.134	3.74	568	2,627	<0.012	0.0140
OWENS 4-4	9.47	<0.01	0.145	0.112	3.44	545	2,620	<0.012	<0.013
OWENS 4-5						No sample was collected			
OWENS 4-6	8.91	1.10	0.131	<0.108	3.33	645	2,580	0.0130	0.0140
OWENS 4-7	7.71	>0.01	0.0994	<0.108	3.26	565	2,530	0.0110	<0.013
OWENS 4-8	<0.01	6.23				No sample was collected			
CODD 2W	8.53	<0.01	0.122	<0.108	2.96	307	2,670	<0.012	0.0200
CODD 2W-2	10.3	<0.01	0.152	0.1210	2.99	310	2,640	<0.012	0.0170
CODD 2W-3	6.34	<0.01	0.137	<0.108	2.78	295	2,660	0.0120	<0.013
CODD 2W-4	4.64	<0.01	0.180	0.150	2.77	338	2,650	<0.012	<0.013
CODD 2W-5	10.4	1.36	0.163	0.119	2.63	338	2,550	0.0140	<0.013
CODD 2W-6	4.41	<0.01	0.104	0.182	2.62	291	2,520	0.0170	<0.013
CODD 2W-7	<0.01	3.88				No sample was collected			

Sample ID	Fe mg/L 0.0059	K mg/L 0.0160	Li mg/L 0.0048	Mg mg/L 0.0025	Mn mg/L 0.0015	Na mg/L 0.0260	Ni mg/L 0.0140	P mg/L 0.0630	Pb mg/L 0.0410
OWENS 1	0.678	109	6.55	992	0.481	36,400	0.200	<0.063	0.0730
TEST SEPARATOR	0.491	147	10.9	1,050	0.418	35,200	0.158	<0.063	<0.041
TEST SEPARATOR-1	14.9	188	12.5	1,040	4.34	35,700	0.250	<0.063	0.109
TEST SEPARATOR-2	17.2	132	7.46	1,040	5.01	34,500	0.246	<0.063	0.0590
OWENS 1-1	17.2	143	9.57	1,070	4.24	35,200	0.250	0.120	0.0600
OWENS 1-2	8.57	112	5.96	989	2.54	36,000	0.220	0.138	0.0730
OWENS 1-3	5.11	122	10.6	1,050	1.76	35,100	0.185	0.121	0.0850
CODD 4	0.0633	104	7.57	1,010	0.207	35,300	0.153	<0.063	0.0800
CODD 4-1	0.0976	110	6.24	1,020	0.220	36,800	0.173	<0.063	0.132
CODD 4-2	0.859	140	9.70	1,030	0.257	34,000	0.178	<0.063	0.108
CODD 4-3	0.121	178	10.8	946	0.214	35,600	0.207	<0.063	0.103
CODD 4-4	0.119	135	7.64	1,050	0.211	35,000	0.222	<0.063	0.0730
CODD 4-5	0.100	136	8.98	1,010	0.220	35,300	0.240	<0.063	<0.041
CODD 4-6	0.0692	110	5.65	953	0.206	35,300	0.168	0.155	<0.041
CODD 4-7	0.0382	120	10.8	963	0.174	35,300	0.162	0.120	<0.041
OWENS 4	0.563	119	6.23	1,060	0.280	35,800	0.181	<0.063	0.103
OWENS 4-1	1.69	122	6.53	1,020	0.299	35,500	0.150	<0.063	0.0890
OWENS 4-2	2.46	145	9.52	1,030	0.349	33,500	0.186	<0.063	0.0810
OWENS 4-3	0.539	181	10.6	942	0.222	34,600	0.168	<0.063	0.147
OWENS 4-4	0.322	145	6.85	889	0.195	34,600	0.266	<0.063	0.0700
OWENS 4-5									
OWENS 4-6	0.348	117	5.30	948	0.196	35,100	0.185	0.0750	0.0940
OWENS 4-7	0.121	126	9.54	942	0.157	34,500	0.183	0.208	0.0830
CODD 2W	3.06	104	7.14	1,070	0.537	35,600	0.186	<0.063	0.0760
CODD 2W-2	2.42	180	11.3	946	0.484	35,300	0.195	<0.063	0.0580
CODD 2W-3	2.80	137	8.03	939	0.509	35,300	0.283	<0.063	<0.041
CODD 2W-4	2.31	136	9.53	1,020	0.500	34,900	0.230	<0.063	0.100
CODD 2W-5	2.96	105	5.67	987	0.500	34,700	0.204	0.211	0.142
CODD 2W-6	1.79	119	10.2	975	0.461	34,600	0.149	0.0770	0.145

No sample was collected

Sample ID	S mg/L	Sb mg/L	Se mg/L	Si mg/L	Sn mg/L	Sr mg/L	Ti mg/L	Zn mg/L
OWENS 1	18.4	<0.059	0.473	8.30	0.0860	222	0.128	0.0221
TEST SEPARATOR	94.6	<0.059	0.331	7.78	<0.070	213	0.0990	0.0163
TEST SEPARATOR-1	3.73	<0.059	0.586	21.0	0.189	223	0.109	0.0265
TEST SEPARATOR-2	15.1	0.103	0.388	16.8	<0.070	215	0.0620	0.0372
OWENS 1-1	19.2	<0.059	0.510	12.2	0.110	223	0.0900	0.0300
OWENS 1-2	24.5	<0.059	0.552	10.5	<0.086	210	0.0900	0.0203
OWENS 1-3	66.9	<0.059	0.607	10.3	0.131	204	0.0940	0.0478
CODD 4	37.0	<0.059	0.430	8.88	0.0810	211	0.111	0.0208
CODD 4-1	46.1	<0.059	0.352	8.26	0.0910	214	0.0790	0.0595
CODD 4-2	233	0.0630	0.173	7.55	<0.070	206	0.0750	0.0113
CODD 4-3	170	<0.059	0.472	9.02	0.109	212	0.134	0.0187
CODD 4-4	125	0.0980	0.444	8.05	0.0970	209	0.0900	0.0337
CODD 4-5	93.1	<0.059	0.520	7.92	<0.070	220	0.0600	0.0100
CODD 4-6	129	<0.059	0.483	8.27	0.0880	204	0.0800	0.0218
CODD 4-7	213	<0.059	0.597	8.67	0.103	201	0.124	0.0250
OWENS 4	48.2	<0.059	0.535	8.37	0.119	209	0.128	0.0143
OWENS 4-1	55.3	<0.059	0.517	8.81	<0.070	209	0.0930	<0.0073
OWENS 4-2	119	<0.059	0.304	8.01	<0.070	205	0.0850	0.0342
OWENS 4-3	214	<0.059	0.598	9.41	0.105	208	0.109	0.0186
OWENS 4-4	165	<0.059	0.366	8.34	<0.070	205	0.105	0.0111
OWENS 4-5					No sample was collected			
OWENS 4-6	163	<0.059	0.405	8.47	<0.086	199	0.0950	0.00760
OWENS 4-7	241	<0.059	0.430	8.84	<0.086	193	0.0590	0.0265
CODD 2W	6.64	<0.059	0.483	8.11	<0.070	202	0.0600	0.263
CODD 2W-2	8.54	<0.059	0.476	8.67	<0.070	199	0.101	0.0252
CODD 2W-3	4.24	0.0650	0.316	7.64	<0.070	196	0.100	0.1345
CODD 2W-4	5.77	<0.059	0.490	7.50	0.0800	205	0.0900	<0.0073
CODD 2W-5	8.83	0.0650	0.496	7.69	<0.086	188	0.0830	0.0294
CODD 2W-6	18.6	<0.059	0.600	8.04	0.117	185	0.0990	0.0462

Table 6. Corrections for pH and CO₂

Sample ID	Measured pH		Method 1		Method 2	
	Electrode	Sonde	Calculated pH	Calculated HCO ₃ ⁻ (mg/kg)	Calculated pH	Calculated HCO ₃ ⁻ (mg/kg)
TEST SEPARATOR-1	6.02	5.81	5.436	9,045	4.82	27,450
TEST SEPARATOR-2	6.10	5.78	5.48	7,166	4.73	27,330
OWENS 1-1	5.78	5.44	5.571	5,364	4.66	26,790
OWENS 1-2	5.83	5.33	5.745	2,882	4.47	25,910
OWENS 1-3	5.81	5.30			4.37	25,790

We did not calculate values for the “OWENS 1” and “TEST SEPARATOR” data points because we measured those values before injection. “OWENS 1-3” does not have a data point for Method 1 because it was initially undersaturated in calcite.

