UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

RECEIVED
MAR 23 2009
CHOLLA POWER PLANT

Mr. Conrad Spencer, Plant Manager
Cholla Power Plant
P.O. Box 188, MS 7668
Joseph City, Arizona 86032

Re: Class V Experimental Injection Well Permit No. AZ50800004
Arizona Public Service Company, Cholla Power Plant

Dear Mr. Spencer:

This letter is to inform you that the enclosed permit was issued by the United States Environmental Protection Agency, Region IX (EPA) for a period of one (1) year beginning on March 19, 2009. The comment period for the subject permit closed on March 13, 2009. EPA's Ground Water Office received no comments on the draft permit during the public comment period and, accordingly, no changes to the draft permit were made.

Any underground injection activities at Arizona Public Service Company, Cholla Power Plant must adhere to all permit conditions. Please note that there are several permit conditions that must be addressed before authorization to construct or operate is granted. Please call Nancy Rumrill at (415) 972-3293 if you have any questions regarding this letter, the permit, or any other Underground Injection Control Program issue.

Sincerely,

David Albright
Manager, Ground Water Office
Date March 19, 2009

Enclosure

Cc w/enc: Michele Robertson, Arizona Department of Environmental Quality
John Beyer, Lawrence Berkeley National Laboratory

United States Environmental Protection Agency
Underground Injection Control Program

FINAL PERMIT

Class V Experimental Injection Well

Permit No. AZ50800004

Arizona Utilities CO_2 Storage Pilot Test

Cholla Power Plant

Navajo County, Arizona

Issued to:

Arizona Public Service Company
4801 Frontage Road
Joseph City, AZ 86032

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Part I. AUTHORIZATION TO OPERATE AND INJECT

Pursuant to the Underground Injection Control (UIC) regulations of the U.S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (CFR), §§124, 144, 145, 146, 147, and 148,

Arizona Public Service Company
4801 Frontage Road
Joseph City, AZ 86032

is hereby authorized, contingent upon Permit conditions, to construct and operate a Class V Experimental injection well. The proposed well is to be located in Section 30, Township 18N, Range 20E. Exact location of the proposed well will be established and approved as outlined within this permit.

EPA will grant authorization to inject after the requirements of Part II Sections A-C of this permit have been met. Operation of the well will be limited to maximum volume and pressure as stated in this permit. Total amounts must not exceed specified limits.

If approved, injection will be authorized into either the Martin Formation (in the Mississippian and Devonian carbonates) or the Naco Formation beneath the confining Supai Formation, whichever demonstrates that it meets permit requirements. This well is to be completed for the purpose of injecting approximately 2,000 metric tons of food-grade CO_2 over an expected duration of 14-20 days to allow the West Coast Regional Carbon Sequestration Partnership to gather information on the geology and suitability of the location for sequestration of CO_2.

All conditions set forth herein are based on Title 40 §§124, 144, 145, 146, 147 and 148 of the Code of Federal Regulations.

This permit consists of **twenty-five (25) pages** plus the appendices, and includes all items listed in the Table of Contents. Further, it is based upon representations made by Arizona Public Services Company (Permittee) and on other information contained in the administrative record. It is the responsibility of the Permittee to read, understand, and comply with all terms and conditions of this permit.

This permit and the authorization to construct, test, and inject are issued for a period of one (1) year unless terminated under the conditions set forth in Part III, Section B.1 of this permit.

This permit is issued and becomes effective on 19 March 2009

Alexis Strauss

Alexis Strauss, Director
Water Division, EPA Region IX

Part II. SPECIFIC PERMIT CONDITIONS

Prior to each demonstration required in the following sections A through C, the Permittee shall submit plans for procedures and specifications to the U.S. Environmental Protection Agency Region IX Ground Water Office ("EPA") for discussion and approval. The submittal address is provided in Section D, paragraph 5. No demonstration in these sections may proceed without prior written approval from EPA. The Permittee shall submit results of each demonstration required in this section to EPA within sixty (60) days of completion.

A. WELL CONSTRUCTION

1. Requirement for Prior Written Permission to Drill, Test, Construct, or Operate

   (a) Financial Assurance

   The Permittee has supplied evidence of financial assurance prior to commencing Injection Well Drilling and Construction, a requirement of the UIC program regulations. See Section F of this part.

   (b) Pre-notification

   After approval for any of the approved field demonstrations is provided, notification to EPA at least 30 days prior to performing the demonstration is required, to allow EPA to arrange to witness if so elected.

2. Location of Injection Well

   The injection well authorized under this permit will be located on the Arizona Public Service Company Cholla Power Plant property east of the fly ash pond, near Joseph City, Arizona. The proposed location for the well is found in Appendix A.

   (a) Prior to drilling the well, the Permittee must submit proposed field coordinates (Section, Township, Range, with latitude/longitude in decimal format) for the well.

   (b) After drilling is completed, the Permittee must submit final field coordinates (Section, Township, Range, with latitude/longitude) of the well constructed under this permit with the Final Well Construction Report required under paragraph 11 of this section. If final well coordinates differ from the proposed coordinates submitted under paragraph (a), justification and documentation of any communication with and approval by EPA shall be included.

3. Information and Data Collection during Drilling and Construction

Two injection zones were identified in the permit application as possible targets, a primary target and a secondary target in the case where the primary target does not meet project objectives. The deeper Martin formation will be tested first, and if the zone meets regulatory and operational requirements, the well will be completed at that depth. Alternatively, the Naco formation overlying the Martin formation is the secondary target. As the secondary target, the Naco formation will be tested if the primary target does not meet requirements. If the Naco formation meets regulatory and operational requirements, the well will be completed at the shallower depth. The Proposed Well Schematic submitted with the application is hereby incorporated by reference into this permit as Appendix B.

Logs and other tests conducted during drilling and construction shall include, at a minimum, deviation checks, cased hole logs, and injection formation tests as outlined in 40 CFR §146.12(d). An outline of the permittee's proposed testing program submitted with the application is provided in Appendix C of this permit. Open Hole logs, including mud cuttings logs, shall be conducted over the entire open hole sequence.

4. Injection Formation Testing

Injection formation information for the well, as described in 40 CFR 146.12 (e), shall be determined through well logs and tests and shall include porosity, permeability, static formation pressure, and effective thickness of the injection zone. A summary of results shall be submitted to EPA with the Final Construction Report required in paragraph 11 of this section.

(a) Ground Water Testing and Information Gathering

During construction of the well, information relating to ground water at the site shall be obtained and submitted to EPA. This information shall include direct Total Dissolved Solids ("TDS") analysis of target injection formation water to demonstrate either the presence and characteristics of, or the lack of, any Underground Sources of Drinking Water ("USDW" as defined in 40 CFR §§144.3, 146.3). Permittee shall also analyze water samples from the Coconino Aquifer obtained from offset Well 125.

(b) The Permittee shall provide well logs and representative ground water sample analyses from the targeted injection aquifer using method(s) approved in advance by EPA as evidence. These analyses shall be sufficient to confirm compatibility of the injectate with the injection formation.

(i) EPA may require minor alterations to the construction requirements based upon the information obtained during well drilling and related operations if the proposed casing setting depths will not completely cover the base of the USDWs and the confining formation located immediately above the injection zone.

(ii) The Permittee may produce water from the saline injection interval, filter it, and then use it for the step-rate injectivity test. Rhodamine dye may be added to the reinjected water.

(c) Step-Rate Test ("SRT")

The SRT will be conducted on the well before injection is authorized, to establish maximum injection pressure. Refer to Society of Petroleum Engineering ("SPE") paper #16798 for test design and analysis. The SRT will be used to establish the injection pressure limitation, in accordance with section C, paragraph 3 of this part. Permittee must submit detailed plans for conducting the SRT allowing sufficient time for EPA review and approval before the SRT will be allowed to be conducted.

(i) Prior to testing, shut in the well long enough so that the bottom-hole pressure approximates shut-in formation pressure.

(ii) Measure pressures with a down-hole pressure transducer to measure bottom hole injection pressure and synchronize with data from a surface injection pressure recorder. Data sampling rate must be sufficient to allow observation and analysis of the pressure transient behavior during each stepped rate as well as the final pressure falloff (see item (v)).

(iii) Use equal-length time step intervals throughout the test; these should be sufficiently long to overcome well bore storage and to achieve radial flow. Typically, use at least thirty (30) minute intervals.

(iv) Record at least five (5) time steps (data points on pressure vs. flow plot) before reaching the anticipated maximum pressure.

(v) At the end of the test, shut down pumps and record the instantaneous shut in pressure and the falloff.

(vi) Permittee shall report the results to EPA within 45 days of conducting the SRT. The results shall include analyses of the pressures versus rate and the transmissivity for the stepped rates throughout the SRT by analyzing the pressure transient data.

5. Drilling, Work-over, and Plugging Procedures

Drilling, work-over, and plugging procedures must comply with the Arizona Oil and Gas Conservation Commission of the Arizona Administrative Code, found in Title 12, Natural Resources, Chapter 7, Article I, R12-7-108 to R12-7-127. The proposed drilling procedures submitted with the permit application are hereby incorporated into this permit as Appendix C, and shall be binding on the permittee to the extent that the basic construction scheme is accurate pending the exact depths of the targeted geology encountered during the drilling process. Changes to the construction plans during construction are considered minor modifications provided that the permittee notifies and receives approval from EPA, and that the changes comply with the requirements of 40 CFR §§144 and 146 (40 CFR §144.41(f)). Drilling procedures shall also include the following:

(a) During drilling through the Regional C-Aquifer, the permittee will add a small quantity of Optitrak 600 blue dye to the drilling mud so that when water samples are obtained, the amount of mud filtrate in the samples can be determined.

(b) During drilling through the primary injection interval, the permittee will add fluorescein fluorescent dye to the drilling mud.

6. Casing and Cementing Specifications

Notwithstanding any other provisions of this permit, the Permittee shall case and cement the well to prevent the movement of fluids into or between USDWs. Cement evaluation analyses shall be performed as described in Section C paragraph 2(a)(iv) of this part. Casings shall be maintained throughout the operating life of the well. The following approximate specifications from the permit application apply to the proposed well:

(a) Conductor casing: 13-3/8 inch outside diameter ("OD") (48 lb/ft, Grade H-40) from ground surface to approximately 25 feet below ground surface ("bgs"), cemented to surface.

(b) Surface casing: 9-5/8 inch OD (36 lb/ft, Grade J-55) from ground surface to approximately 950 feet bgs, cemented to surface.

(c) Long String Casing: 5-1/2 inch OD (15.5 lb/ft, Grade J-55) from ground surface to approximately 3985 feet bgs, cemented to surface.

7. Tubing and Packer Specification

Injection will take place through tubing strings and packer, subject to the following approximate specifications from the permit application:

(a) Tubing: 2-3/8 inch OD (4.7 lb/ft, Grade J-55) from ground surface to approximately 3,645 feet bgs.

(b) Packer: Proposed 5-1/2 inch by 2-3/8 inch inflatable packer or equivalent set at approximately 3,445 feet (approximately 10 ft above the uppermost perforations in the Martin Formation). If the secondary target formation is used, the perforations in the Martin Formation will be cemented shut, and the packer set at a shallower depth in the Naco formation.

8. Injection Intervals

Injection shall be permitted for either the Martin formation, expected to occur at depths estimated from about 3,445 feet bgs to about 3,645 feet (200 feet) or, alternatively, for the Naco formation, at depths estimated from about 2,945 feet bgs to about 3,445 feet bgs (500 feet). Minor alterations of the depths of injection zone intervals and therefore, the casing setting depths are expected to be realized upon drilling. These alterations and other rework operations that may occur later in the course of operation of the well are considered minor for this permit and must be properly reported (use EPA Form 7520-12 in Appendix D), and the Permittee must demonstrate that the well has mechanical integrity, in accordance with Section C paragraphs 1 and 2 of this part, before any initial injection or recommencing after repair.

9. Confining Layer

Field information on the confining layer (the Supai formation), such as its characteristics, its thickness and its local structure will be obtained during drilling of the injection well and shall be included in the Final Well Construction Report required in paragraph 11 of this section.

10. Monitoring Devices

The Permittee shall install and maintain in good operating condition devices to continuously measure and record injection pressure, annulus pressure, flow rate, and injection volumes, subject to the following:

(a) Pressure gauges shall be of a design to provide:

(i) A full pressure range of 50 percent greater than the anticipated operating pressure; and

(ii) A certified deviation accuracy of five (5) percent or less throughout the operating pressure range.

(b) Flow meters shall measure cumulative volumes and be certified for a deviation accuracy of five (5) percent or less throughout the range of injection rates allowed by the permit.

11. Final Well Construction Report and Completion of Construction Notice

(a) The Permittee must submit a final well construction report, including logging, coring, and other results, with a schematic diagram and detailed description of construction, including driller's log, materials used (i.e., tubing and casing tallies), and cement (and other) volumes, to EPA within sixty (60) days after completion of Injection Well.

(b) The Permittee must also submit a notice of completion of construction to EPA (see EPA Form 7520-9 in Appendix D). Injection operations may not commence until EPA has inspected or otherwise reviewed the injection well and notified the Permittee that it is in compliance with the conditions of the permit.

12. Proposed Changes and Workovers

The Permittee shall give advance notice to EPA, as soon as possible, of any planned physical alterations or additions to the permitted injection well. Any changes in well construction require prior approval of EPA and may require a permit modification under the requirements of 40 CFR §§144.39 and 144.41. In addition, the Permittee shall provide all records of well workovers, logging, or other subsequent test data, including required mechanical integrity testing, to EPA within sixty (60) days of completion of the activity. Appendix D contains samples of the appropriate reporting forms. Demonstration of mechanical integrity shall be performed within thirty (30) days of completion of workovers or alterations and prior to resuming injection activities, in accordance with Section C paragraphs 1 and 2 of this part.

B. CORRECTIVE ACTION

Corrective action in accordance with 40 CFR §§144.55 and 146.7 may be necessary for existing wells in the Area of Review ("AOR", defined in 40 CFR §146.6) that penetrate the injection zone, or which may otherwise cause movement of fluids into USDWs. No corrective action plan is currently required, since no known wells located within the AOR penetrate the proposed zones of injection.

C. WELL OPERATION

1. <u>Demonstrations Required Prior to Injection</u>

   Injection operations may not commence until construction is complete and the Permittee has complied with paragraphs (2) through (5) below.

2. <u>Mechanical Integrity Tests ("MITs")</u>

   (a) Mechanical integrity testing shall conform to the following requirements throughout the life of the injection well:

   (i) Casing/tubing annular pressure (internal MIT)

   A demonstration of the absence of significant leaks in the casing, tubing and/or packer shall be made by performing a pressure test on the annular space between the tubing and long string casing. This test shall be for a minimum of thirty (30) minutes at a pressure equal to or greater than the maximum allowable injection pressure. In the submittal of plans (see paragraph at Part II) to conduct this demonstration, the Permittee may propose a pressure less than the maximum allowable injection pressure with a justification for EPA's consideration. This demonstration may be satisfied at a lesser pressure if EPA provides prior written approval. A well passes the MIT if there is less than a five (5) percent change in pressure over the thirty (30) minute period. A well also passes the MIT if there is a five (5) to ten (10) percent change in pressure over the thirty (30) minute period and EPA provides concurrence.

(ii) Continuous pressure monitoring

The tubing/casing annulus pressure and injection pressure shall be monitored and recorded continuously to an accuracy of 0.1% of full gauge pressure, or +/-5 psi for 5,000 psi gauges. The average, maximum, and minimum results shall be included in the quarterly report to EPA unless more detailed records are requested by EPA.

(iii) Injection profile survey (external MIT)

A demonstration that the injectate is confined to the proper zone shall be conducted and presented by the Permittee and subsequently approved by EPA. This demonstration shall consist of a radioactive tracer and a temperature log (as specified in Appendix E), or other diagnostic tool or procedure as approved by EPA. Permittee must submit detailed plans for conducting the external MIT allowing sufficient time for EPA review and approval prior to conducting the demonstration.

(iv) Cement Evaluation Analysis

After casing is installed, the Permittee shall submit cementing records and cement evaluation logs that demonstrate the isolation of the injection interval and other formations from underground sources of drinking water by means of cementing the surface casing and the long string casing well bore annuli to surface. The analysis shall include a spherically-focused tool, run after the long-string protection casing is set and cemented, which enables the evaluation of the bond between cement and casing as well as of the bond between cement and formation. The Permittee may not commence injection until it has received written notice from EPA that such a demonstration is satisfactory.

(b) Subsequent MITs

It is the Permittee's responsibility to arrange and conduct MITs. An MIT shall be conducted following completion of any work-over, if the packer is unseated, if the seal is broken in the tubing-casing annulus, if the seal is broken at the wellhead assembly, if a modification of the well compromises integrity, or when any loss of mechanical integrity becomes evident during operation. In addition, EPA may require that a MIT be conducted at any time during the permitted life of the well.

(c) Loss of Mechanical Integrity

The Permittee shall notify EPA, in accordance with Part III, Section E paragraph 10 of this permit, under any of the following circumstances:

(i) The well fails to demonstrate mechanical integrity during a test, or

(ii) A loss of mechanical integrity becomes evident during operation, or

(iii) A significant unexpected change in the annulus or injection pressure occurs during normal operating conditions.

Furthermore, in the event of (i), (ii), or (iii), injection activities shall be terminated immediately and operation shall not be resumed until the Permittee has taken necessary actions to restore mechanical integrity to the well and EPA gives approval to recommence injection.

(d) Prohibition without Demonstration

After the permit effective date, injection into the well may continue only if:

(i) The well has passed an internal pressure MIT in accordance with paragraph 2(a) of this section; and

(ii) The Permittee has received written notice from EPA that the internal pressure MIT demonstration is satisfactory.

3. Injection Pressure Limitation

Maximum allowable injection pressure measured at the bottom-hole shall be based on the results and analysis of the Step-Rate Test conducted under this part. As a backup to the bottom-hole gauge, the injection pressure may be calculated with a surface gauge. The Permittee shall provide calculations to support the maximum injection pressure determination for the CO_2 injectate as measured at the bottom-hole or at the surface. EPA will provide the Permittee written notification of the maximum allowable injection pressure for the injection well constructed and operated under this permit, along with a minor modification of the permit under 40 CFR

§144.41(e). In no case shall pressure in the injection zone during injection initiate new fractures or propagate existing fractures in the injection zone or the confining zone. In no case shall injection pressure cause the movement of injection or formation fluids into or between underground sources of drinking water.

4. Injection Volume Rate Limitation

The injection rate which is directly related to the injection pressure limitation shall not exceed the volume determined appropriate through the demonstrations conducted in this section and justified by the measured friction factors. EPA will provide written notification of the maximum daily injection rate allowed under this permit prior to any injection activities, after the SRT.

5. Injection Fluid Limitation

(a) The Permittee shall not inject any hazardous waste, as defined by 40 CFR Part 261, at any time.

(b) Injection fluids authorized by this permit shall be limited to only food-grade Carbon Dioxide (CO_2) of at least 99.5% CO_2 by volume with small amounts of other gases. Small quantities of krypton, xenon, and sulfur hexafluoride may be added to the injected CO_2 as tracers.

(c) Any well stimulation, such as treating formation damage from drilling mud or other shall be performed at the discretion of the operator, shall be proposed and submitted for approval from EPA prior to implementation.

6. Tubing/Casing Annulus Requirements

Corrosion inhibiting annular fluid shall be used and maintained during well operation. A complete description and characterization shall be submitted to EPA. A minimum pressure of 100 psi at shut-in conditions shall be maintained on the tubing/casing annulus.

7. Experimental Objectives - Monitoring, Analysis and Application

This Class V Experimental Project will provide a sophisticated level of investigation and analyses of complex mechanical operations and in situ processes that are expected to evaluate and verify theoretical projections related to the injection of carbon dioxide (CO_2) at supercritical conditions. Progress is likewise expected throughout this project regarding theoretical predictive analysis and application techniques as new data are acquired and various reservoir and geological characteristics and properties are obtained and confirmed. Reports addressing these objectives shall be made as outlined in Part II. Section D. 4.

D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Injection Well Monitoring Program

Samples and measurements shall be representative of the monitored activity. The Permittee shall utilize applicable analytical methods described in Table I of 40 CFR §136.3, or in EPA Publication SW-846, "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," unless other methods have been approved by EPA.

2. Monitoring Devices

(a) Continuous monitoring devices

Temperature and annular pressure shall be measured at the wellhead using equipment of sufficient sensitivity and accuracy. Injection pressure shall be measured at bottom-hole or the surface using equipment of sufficient sensitivity and accuracy. Injection rate shall be measured in the supply line immediately before the wellhead. The Permittee shall continuously monitor and record the following parameters:

Monitoring Parameter	Frequency	Instrument
Injection rate (gallons per minute)	Continuous	digital recorder
Daily Injection Volume (reservoir conditions) Cumulative total volume (gallons)	Continuous	digital totalizer
Injection pressure (psig)	Continuous	digital recorder
Annular pressure (psig)	Continuous	digital recorder
Injection fluid temperature (degrees Fahrenheit)	Continuous	digital recorder

(b) Calibration and Maintenance of Equipment

All monitoring and recording equipment shall be calibrated and maintained on a regular basis to ensure proper working order of all equipment.

3. Recordkeeping

The Permittee shall retain the following records and have them available at all times for examination by an EPA inspector:

(a) All monitoring information, including required observations, calibration and maintenance records, recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the permit application; and

(b) Information on the nature and composition of all injected fluids;

(c) Records and results of MITs, any other tests required by EPA, and any well workovers completed.

(d) The Permittee shall maintain copies (or originals) of all records described in paragraphs (a) through (c) above during the operating life of the well and shall make such records available at all times for inspection at the facility.

(e) The Permittee shall only discard the records described in paragraphs (a) through (c) if:

(i) the records are delivered to the Regional Administrator, or

(ii) written approval from the Regional Administrator to discard the records is obtained.

4. Reporting of Results

Quarterly for the life of the well, the Permittee shall submit accurate reports to EPA containing, at minimum, the following information:

(a) Daily average, maximum, and minimum values for the continuously monitored parameters specified in paragraph 2(a) of this section, unless more detailed records are requested by EPA;

(b) Cumulative total volume for the monitored parameter specified in paragraph 2(a) of this section, report in gallons and metric tons;

(c) To be included with the next quarterly report immediately following completion, results of any additional MITs or other tests required by EPA, and any well workovers completed;

(d) A narrative description of all non-compliance that occurred during the reporting period; and

(e) Progress is expected throughout this project regarding theoretical predictive analysis and application techniques as new data are acquired and various reservoir and geological characteristics and properties are obtained and confirmed. Include in the quarterly report updates comparing this experiment's results to the predictive models.

(f) Quarterly report forms as specified in Appendix D shall be submitted for the reporting periods by the respective due dates as listed below:

Reporting Period	Report Due
Jan, Feb, Mar	Apr 28
Apr, May, June	July 28
July, Aug, Sept	Oct 28
Oct, Nov, Dec	Jan 28

Monitoring results and all other reports required by this permit shall be submitted to the following address:

United States Environmental Protection Agency, Region IX
Water Division
Ground Water Office (Mail Code WTR-9)
75 Hawthorne Street
San Francisco, CA 94105-3901

E. PLUGGING AND ABANDONMENT

1. Notice of Plugging and Abandonment

The Permittee shall notify EPA no less than sixty (60) days before conversion, workover, or abandonment of the well. EPA may require that the plugging and abandonment be witnessed by an EPA representative.

2. Plugging and Abandonment Plans

The Permittee shall plug and abandon the well(s) as provided in Appendix F, the general Plugging and Abandonment Program submitted as Attachment Q to the application, and consistent with Arizona Oil and Gas Conservation Commission requirements and 40 CFR §146.10. EPA reserves the right to change the manner in which a well will be plugged if the well is modified during its permitted life or if the well is not consistent with EPA requirements for construction or mechanical integrity. EPA may require the Permittee to estimate and to update the estimated plugging cost periodically. Such estimates shall be based upon costs which a third party would incur to plug the well, including mud and disposal costs, with appropriate contingencies.

3. Cessation of Injection Activities

After a cessation of injection operations for more than six (6) months, the Permittee shall plug and abandon the inactive well in accordance with the Plugging and Abandonment Plans, unless it:

(a) Provides notice to EPA;

(b) Has demonstrated that the well(s) will be used in the future; and

(c) Has described actions or procedures, satisfactory to EPA, that will be taken to ensure that the well(s) will not endanger underground sources of drinking water during the period of temporary abandonment.

4. Plugging and Abandonment Report

Within sixty (60) days after plugging any well, the Permittee shall submit a report on Form 7520-13, provided in Appendix D, to EPA. The report shall be certified as accurate by the person who performed the plugging operation and shall consist of either:

(a) A statement that the well was plugged in accordance with the Plugging and Abandonment Plans, or

(b) Where actual plugging differed from the Plugging and Abandonment Plans, a statement specifying the different procedures followed.

F. FINANCIAL RESPONSIBILITY

1. Demonstration of Financial Responsibility

The Permittee is required to demonstrate and maintain financial responsibility and resources sufficient to close, plug, and abandon the underground injection operation as provided in the Plugging and Abandonment Plans and consistent with 40 CFR §144 Subpart D, which the Director has chosen to apply.

EPA has verified and determined that the requirements for Financial Responsibility for the Arizona Department of Environmental Quality have been met by the Permittee and that in so doing, they also meet the requirements for the US EPA Region IX. A separate or duplicate submission of Financial Responsibility for the US EPA is not required at this time.

2. Insolvency of Owner or Operator

An owner or operator must notify EPA by certified mail of the commencement of voluntary or involuntary proceedings under U.S. Code Title 11 (Bankruptcy), naming the owner or operator as debtor, within ten (10) business days. A guarantor of a corporate guarantee must make such a notification if he/she is named as debtor, as required under the terms of the guarantee.

G. DURATION OF PERMIT

This permit and the authorization to inject are issued for a period of up to one (1) year unless terminated under the conditions set forth in Part III, Section B.1 of this permit.

Part III. GENERAL PERMIT CONDITIONS

A. EFFECT OF PERMIT

The Permittee is allowed to engage in underground injection well construction and operation in accordance with the conditions of this permit. The Permittee shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of fluid containing any contaminant (as defined by 40 CFR §144.3) into USDWs , if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR Part 141 or may otherwise adversely affect the health of persons.

Furthermore, any underground injection activity not specifically authorized in this permit is prohibited. The Permittee must comply with all applicable provisions of the Safe Drinking Water Act ("SDWA") and 40 CFR Parts 144, 145, 146, and 124. Such compliance does not constitute a defense to any action brought under Section 1431 of the SDWA, 42 U.S.C. § 300(i), or any other common law, statute, or regulation other than Part C of the SDWA. Issuance of this permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local law or regulations. Nothing in this permit shall be construed to relieve the Permittee of any duties under all applicable laws or regulations.

B. PERMIT ACTIONS

1. <u>Modification, Revocation and Reissuance, or Termination</u>

   EPA may, for cause or upon request from the Permittee, modify, revoke and reissue, or terminate this permit in accordance with 40 CFR §§124.5, 144.12, 144.39, and 144.40. The permit is also subject to minor modifications for cause as specified in 40 CFR §144.41. The filing of a request for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance by the Permittee, does not stay the applicability or enforceability of any permit condition. EPA may also modify, revoke and reissue, or terminate this permit in accordance with any amendments to the SDWA if the amendments have applicability to this permit.

2. <u>Transfers</u>

   This permit is not transferable.

C. SEVERABILITY

The provisions of this permit are severable, and if any provision of this permit or the application of any provision of this permit to any circumstance is held invalid, the application of such provision to other circumstances and the remainder of this permit shall not be affected thereby.

D. CONFIDENTIALITY

In accordance with 40 CFR §§2 and 144.5, any information submitted to EPA pursuant to this permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures contained in 40 CFR §2 (Public Information). Claims of confidentiality for the following information will be denied:

1. Name and address of the Permittee, or

2. Information dealing with the existence, absence, or level of contaminants in drinking water.

E. GENERAL DUTIES AND REQUIREMENTS

1. Duty to Comply

   The Permittee shall comply with all applicable UIC Program regulations and all conditions of this permit, except to the extent and for the duration such noncompliance is authorized by an emergency permit issued in accordance with 40 CFR §144.34. Any permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action; permit termination, revocation and reissuance, or modification; or denial of a permit renewal application. Such noncompliance may also be grounds for enforcement action under the Resource Conservation and Recovery Act ("RCRA").

2. Penalties for Violations of Permit Conditions

   Any person who violates a permit requirement is subject to civil penalties, fines, and other enforcement action under the SDWA and may be subject to enforcement actions pursuant to RCRA. Any person who willfully violates a permit condition may be subject to criminal prosecution.

3. Need to Halt or Reduce Activity Not a Defense

It shall not be a defense, for the Permittee in an enforcement action, that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

4. Duty to Mitigate

The Permittee shall take all reasonable steps to minimize and correct any adverse impact on the environment resulting from noncompliance with this permit.

5. Proper Operation and Maintenance

The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the Permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this permit.

6. Property Rights

This permit does not convey any property rights of any sort, or any exclusive privilege.

7. Duty to Provide Information

The Permittee shall furnish to EPA, within a time specified, any information which EPA may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The Permittee shall also furnish to EPA, upon request, copies of records required to be kept by this permit.

8. Inspection and Entry

The Permittee shall allow EPA, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

(a) Enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records are kept under the conditions of this permit;

(b) Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit;

(c) Inspect and photograph at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and

(d) Sample or monitor at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location.

9. <u>Signatory Requirements</u>

All applications, reports, or other information submitted to EPA shall be signed and certified by a responsible corporate officer or duly authorized representative according to 40 CFR §§122.22 and 144.32.

10. <u>Additional Reporting</u>

(a) Planned Changes - The Permittee shall give notice to EPA as soon as possible of any planned physical alterations or additions to the permitted facility.

(b) Anticipated Noncompliance - The Permittee shall give advance notice to EPA of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

(c) Compliance Schedules - Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted to EPA no later than thirty (30) days following each schedule date.

(d) Twenty-four Hour Reporting

(i) The Permittee shall report to EPA any noncompliance which may endanger health or the environment. Information shall be provided orally within twenty-four (24) hours from the time the Permittee becomes aware of the circumstances. The following information must be reported orally within twenty-four (24) hours:

(1) Any monitoring or other information which indicates that any contaminant may cause an

endangerment to an underground source of drinking water; and

(2) Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between underground sources of drinking water.

(ii) A written submission of all noncompliance as described in paragraph (c)(i) shall also be provided to EPA within five (5) days of the time the Permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times; if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

(e) Other Noncompliance - At the time monitoring reports are submitted, the Permittee shall report in writing all other instances of noncompliance not otherwise reported. The Permittee shall submit the information listed in Part III, Section E.10(c) of this permit.

(f) Other Information - If the Permittee becomes aware that it failed to submit all relevant facts in the permit application, or submitted incorrect information in the permit application or in any report to EPA, the Permittee shall submit such facts or information within two (2) weeks of the time such facts or information becomes known.

11. Continuation of Expiring Permit

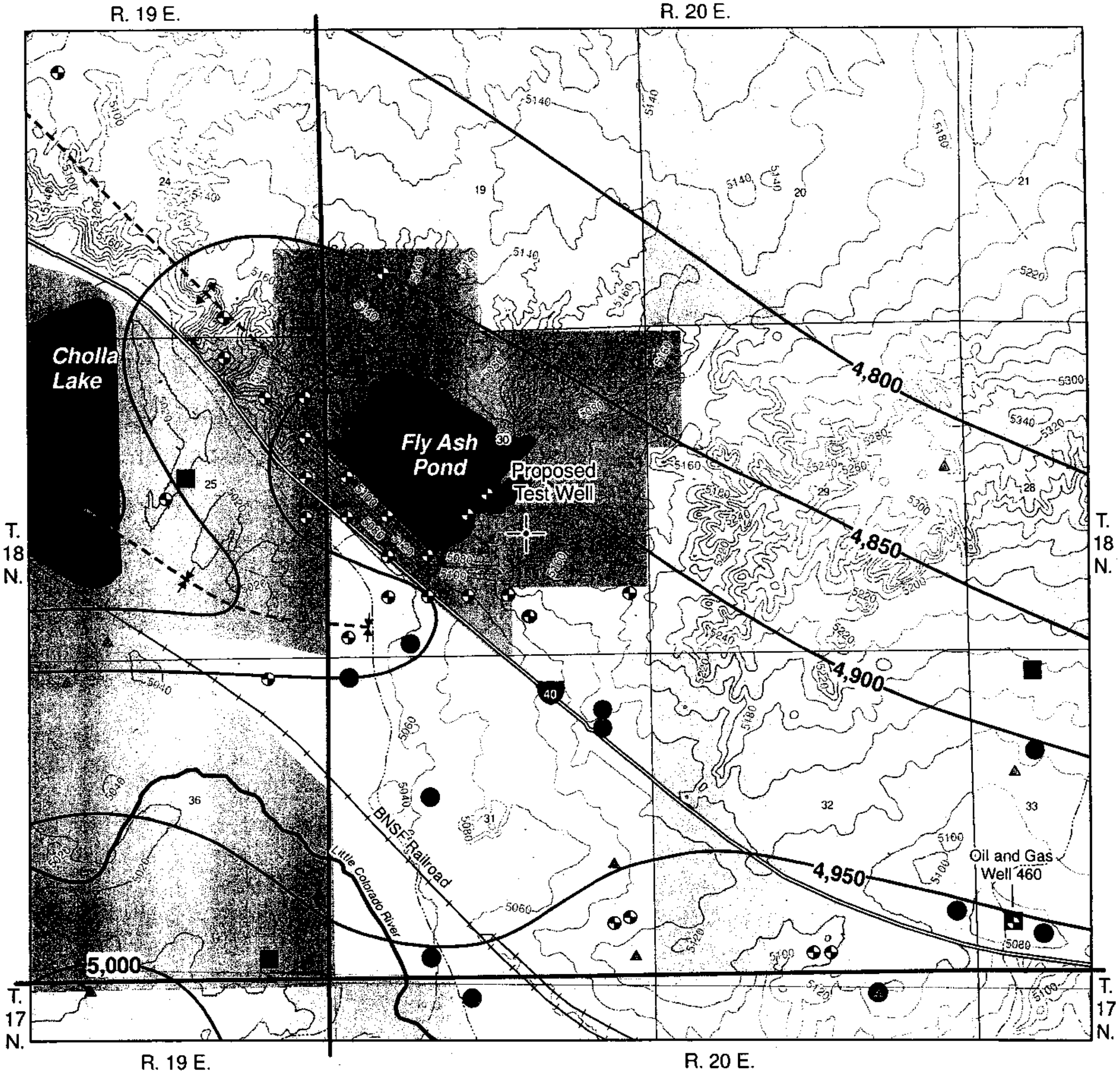
(a) Duty to Reapply - If the Permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the Permittee must submit a complete application for a new permit at least 180 days before this permit expires.

(b) Permit Extensions - The conditions and requirements of an expired permit continue in force and effect in accordance with 5 U.S.C. §558(c) until the effective date of a new permit, if:

(i) The Permittee has submitted a timely and complete application for a new permit; and

(ii) EPA, through no fault of the Permittee, does not issue a new permit with an effective date on or before the expiration date of the previous permit.

Appendix A – Proposed Well Location



EXPLANATION

Topographic Contour (feet, msl; CI = 20 feet)

Proposed Test Well

Wells of Record

- Industrial, Irrigation
- Exploration, Monitor
- Stock, Domestic *Coconino Sandstone*
- Stock, Domestic *Undetermined Formation*
- Domestic, Miss-Located

Land Ownership

- APS
- Aztec
- BLM
- Private
- State Trust

Coconino Structure

- Structure Contour (feet, msl)
- Syncline
- Anticline

N

0 2,000 Feet

CO$_2$ Sequestration Pilot Project
APS Corporation

PROPOSED PILOT SITE LOCATION MAP

ERROL L. MONTGOMERY & ASSOCIATES, INC. 2008
WATER RESOURCE CONSULTANTS
SCOTTSDALE, ARIZONA

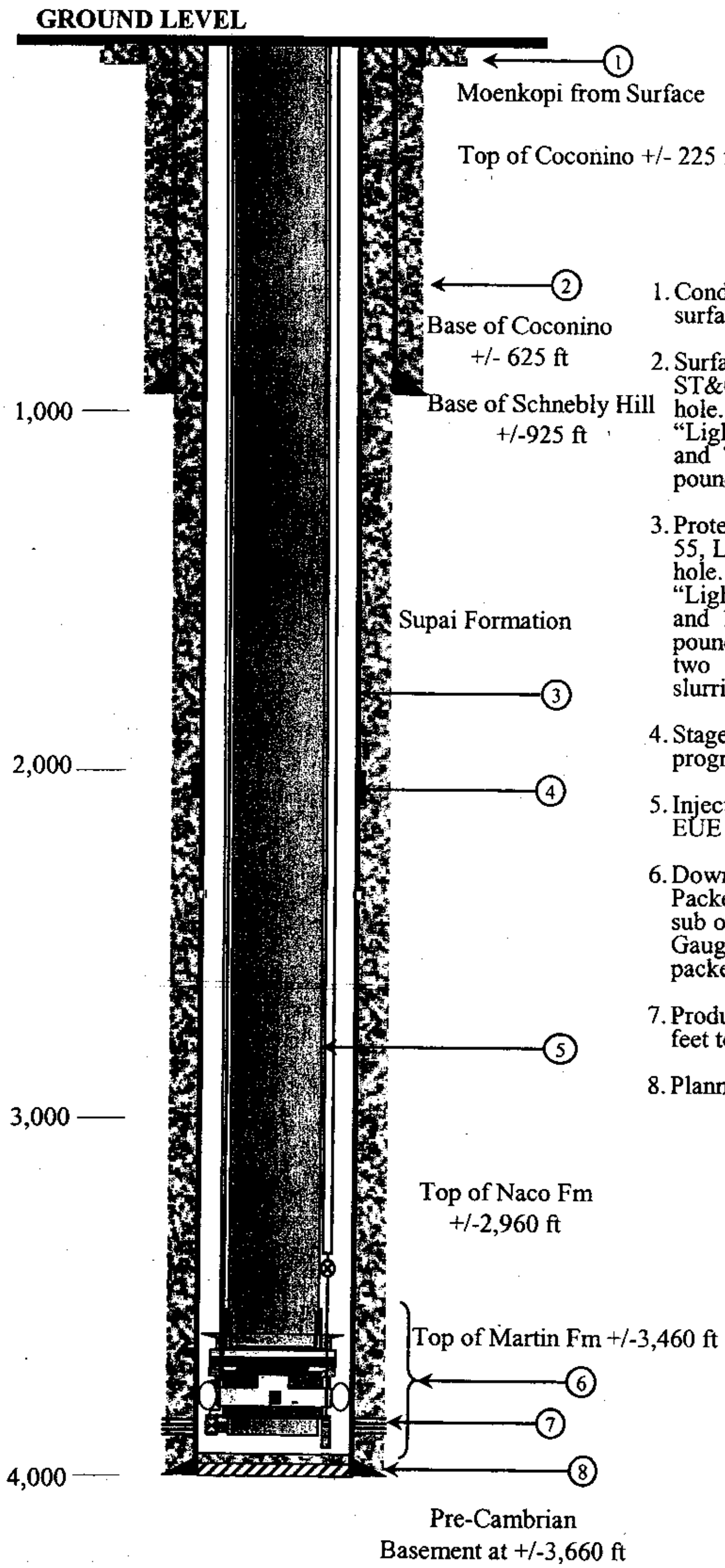
FIGURE 4

1263/03/Fig4 EPRI Test Site.mxd 21May08

Appendix B — Proposed Well Schematic

Arizona Utilities CO_2 Storage Pilot Injection Well

Proposed Completion Well Schematic



All depths reference Rig Kelly Bushing

Rig Kelly Bushing = 15' above Ground Level

Ground Level ~ 5,120'

COMPLETION DETAILS

1. Conductor Casing: 13-3/8-inch, 48 pounds per foot, surface to +/-40 feet, grouted to surface
2. Surface Casing: 9-5/8-inch, 36-pounds per foot. J-55, ST&C, Set from surface to +/-965 feet in a 12-1/4-inch hole. Cemented with Lead Slurry of 300 sacks of "Lightweight" cement mixed at ~12.3 pounds per gallon and Tail Slurry of Class "G" cement mixed at ~15.6 pounds per gallon.
3. Protection Casing: 5-1/2-inch 15.50 pounds per foot, J-55, LT&C. Set from surface to 4,000 feet in a 8-1/2-inch hole. Cemented with Lead Slurry of 380 sacks of "Lightweight" Cement mixed at ~11.5 pounds per gallon and 120 sacks of 50-50 Pozmix cement mixed at 13.5 pounds per gallon. Note: The final design may include a two stage cementing program and different cement slurries.
4. Stage Tool. Will only be used if a two-stage cementing program is required.
5. Injection Tubing: 2-3/8-inch, 4.7 pounds per foot, J-55, EUE 8rd. Surface to +/- 3,325 feet
6. Downhole completion consisting of: TAM Inflatable Packer (set at 3,460 feet) and inflate line, w/pass through sub on top of packer; Downhole Pressure & Temperature Gauge and LBL Stainless Steel U-Tube Sampler below packer.
7. Production Perforations: Martin Fm Test Interval: 3,460 feet to 3,660 feet w/ 4 shots per foot, 90 degree phasing.
8. Planned Total Depth; +/-4,000 feet

Notes

The Martin Formation is the Primary Target and the Naco is the Secondary Target

The Supai is expected to contain halite beds below +/-1,200 feet below ground

Sandia Technologies, LLC

6731 Theall Road, Houston, TX 77066

Tel: (832) 286-0471 Fax: (832) 286-0477

Drawn by: djc Date: May 2008 *Drawing not to scale*

Appendix C — Proposed Drilling Procedures and Testing Program

Table L1. Proposed CO_2 Injection Well – Casing Specifications

TUBULAR	Depth (ft)	Size (in)	Weight (lb./ft)	Grade	Thread	Collapse/ Burst (psi)	Tensile Body/Joint (X 1000 lbs.)
Conductor	0 - 40	13-3/8	48	H-40	ST&C	770/1,730	541/322
Surface Casing	0 – 965	9-5/8	36	J-55	ST&C	2,020/3,520	564/394
Protection Casing	0 – 4,000	5-1/2	15.5	J-55	LT&C	4,040/4,810	248/217

Well Drilling Program
The following sections contain the proposed step-by-step program for drilling and completing the proposed CO_2 Injection Well. The CO_2 Injection Well will be used for baseline monitoring and characterization, injection of the CO_2 fluid during the active experiment, and post-injection monitoring of the intervals of interest.

DRILLING PROCEDURE

CONDUCTOR HOLE

1. Prepare surface pad location and install well cellar.
2. Mobilize drilling rig. Perform safety audit during rig-up to ensure that equipment setup complies with project requirements.
3. Notify Arizona Oil and Gas Conservation Commission at least 48 hours prior to spudding the well.
4. Drill mouse and rat holes.
5. Drill 17-1/2" conductor hole to +/-40 feet. Install 13-3/8" casing and grout annular space from set depth to surface with concrete.
6. Wait on concrete to cure for 12 hours.

SURFACE HOLE

7. Rig up mud logging unit and test equipment. Collect and save 10-foot samples from 40 feet to total depth. A set of samples is required to be submitted to the Oil and Gas Administrator, Arizona Geological Survey, within 30 days of completion of the well. Samples should be: 1) washed and dried, 2) place approximately 3 tablespoons of sample in an envelope identifying the well, the well location, the Arizona Oil and Gas Conservation Commission's Permit Number, and the depth of the sample. Samples to be shipped to:

   Oil and Gas Administrator
   Arizona Geological Survey
   416 West Congress, Suite 100
   Tucson, AZ 85701

8. Pick up 12-1/4 inch bit and the bottomhole assembly (BHA). Drill a 12-1/4 inch surface hole to +/-965 feet (below base of Schnebly Hill) using freshwater spud mud, as detailed in the Drilling Fluids Program section below. Take deviation surveys every 500 feet and at total depth. The recommended maximum allowable deviation from vertical is 3 degrees with a maximum recommended deviation of no more that 2 degrees per 100 feet (to minimize dogleg severity) at any point in the borehole. If the maximum recommended deviation is exceeded, an evaluation will be made to determine whether remedial action is necessary. After reaching surface casing setting depth, the drilling fluid will be circulated and conditioned to ensure correct fluid properties for the open hole logging and testing.

9. Run open-hole formation evaluation logs per the requirements of the Well Logging, Coring, and Testing Program (See Attachment I above).

   If the logging procedure is extended and/or hole becomes sticky or unstable during logging, a conditioning/cleanup trip will be made with the drill string to circulate and condition the drilling fluid. The drilling string will be removed from the well and the logging program will be completed as planned.

10. Notify Arizona Oil and Gas Conservation Commission at least 48 hours prior to setting and cementing the surface casing.

11. Lower the 12-1/4" drilling assembly in the well to the total depth. The drilling fluid will be circulated and conditioned to ensure correct fluid properties for the casing installation and cementing. Remove the drilling assembly from the well.

12. Run 9-5/8 inch surface casing to +/-965 feet. See the Well Casing Specifications section above for a detailed description of the casing and casing equipment.

    Reduce mud levels in surface circulating system and have additional tanks on hand to recover any excess mud or cement that may be circulated to the surface.

    Designate a qualified person to observe the circulating system and monitor drilling fluid at all times during the cementing procedure. An accurate accounting of volumes will be critical information in the event that circulation is lost.

13. Rig up circulating equipment and perform a pressure test on the lines. Circulate and condition the drilling fluid to ensure correct fluid properties for the cementing procedure. Reciprocate the casing continuously during the circulation of the drilling fluid.

14. Cement the casing in place. Details of the cement blends proposed are located in the Well Construction Cementing Program section below.

    Be prepared to divert cement and cement-contaminated drilling fluid returns away from circulating system and into appropriate containment. Use sugar to retard the premature setting of the cement, if necessary.

15. If no cement returns are observed at surface, contact wireline service provider and schedule a temperature survey to determine the top of the cement.

16. Center the casing in the rotary table of the drilling rig after completing the cementing procedure and before the cement hardens.

17. Cement the annular space that does not contain cement, if required. Fill the annulus space by pumping cement through small tubing that has been run into the annulus to the top of cement.

18. After waiting on cement to harden for a minimum of 12 hours, cut off the surface and conductor pipe and install a 9-5/8 inch SOW (slip-on for welding) x 11-inch 3,000-psi casing head flange. Perform a pressure test on the casing head after installation. Digitally record the test and maintain a copy of the test results on location. Transfer the original test data to the Sandia Office for inclusion in the CO_2 Injection Well Report.

PROTECTION HOLE

19. Install 11-inch 3,000 psi double ram blow out preventer, 11-inch 3,000 psi annular preventer, and auxiliary well control equipment on the 11-inch, 3,000 psi casing head flange. Perform a pressure test on the equipment to the lesser of the manufacturer's full working pressure rating of the system, 70 percent of the minimum internal yield pressure of any casing subject to test, or one psi per foot of the last casing string depth. Annular or bag-type preventers shall be tested to the lesser of 1,000 psi or 50 percent of the full working pressure on installation. The blowout preventer and related equipment will be tested, as follows: a) after each string of casing is set in the well, b) not less than once every 14 days, and c) following any repairs that required the disconnection of any pressure seal assembly (note, only the repaired or replaced component need be tested unless alteration or repair occurs at a normal full blowout preventer test period).

20. Pick up an 8-1/2 inch bit, BHA, and trip in the hole to the top of cement with the drill pipe. Include drilling stabilizers above the second and third drill collars. Close pipe rams and perform a pressure test on the surface casing for at least 30 minutes. The surface casing will be pressure tested for at least 30 minutes to 70 percent of the internal yield pressure of the casing or one pound per square inch (psi) per foot of setting depth (whichever is less). A successful test is a drop of no more than 10 percent of the test pressure over the 30-minute time period. Digitally record the test and maintain a copy of the test results on location. Transfer the original test data to the Sandia Office for inclusion in the CO_2 Injection Well Report.

21. Convert the drilling fluid in the well to a salt-based drilling fluid. Details of the drilling fluid characteristics are located in the Drilling Fluids Program section below.

22. Drill out casing float equipment and 10 feet of new hole.

23. Perform a pressure test on the casing seat and formation to pressure leak-off point or to an 11.0 pounds per gallon equivalent drilling fluid density.

24. Drill an 8-1/2 inch hole from surface casing point to the core point in the Martin Formation. Alternatively, sidewall coring may be done as part of the wireline activities in Item #26. Take deviation surveys every 500 feet and at core point. The recommended maximum allowable deviation from vertical is 3 degrees with a maximum recommended deviation of no more that 2 degrees per 100 feet (to

minimize dogleg severity) at any point in the borehole. If the maximum recommended deviation is exceeded, an evaluation will be made to determine whether remedial action is necessary. Details of the coring program are described above in Appendix I. Monitor the well path as drilling proceeds.

25. Drill and retrieve the core (Martin proposed injection interval), unless sidewall coring is done instead.

26. Pick up the drilling assembly and lower into the well. Drill the cored interval (if taken) and continue drilling to the proposed total depth (+/-4,000 feet true vertical depth) into the Pre-Cambrian basement. Take deviation surveys every 500 feet and at total depth. The recommended maximum allowable deviation from vertical is 3 degrees with a maximum recommended deviation of no more that 2 degrees per 100 feet (to minimize dogleg severity) at any point in the borehole. If the maximum recommended deviation is exceeded, an evaluation will be made to determine whether remedial action is necessary.

27. After reaching total depth, circulate and condition the drilling fluid to ensure correct fluid properties for the wireline logging procedure. Make a short trip by pulling up into the 9-5/8-inch surface casing with the drill bit and BHA. Lower the drilling assembly back to bottom and check for solids fill. Resume circulating and conditioning drilling fluid and wellbore for open hole logging. Remove drilling assembly from well for open hole logging.

    Measure the drill string on the trip out to confirm well depth.

28. Rig up wireline equipment and run the open-hole logging and sampling suite. See Appendix I for Well Logging, Coring and Testing details.

    If the logging procedure is extended and/or hole becomes sticky or unstable during logging, a conditioning/cleanup trip will be made with the drill string to circulate and condition the drilling fluid. The drilling string will be removed from the well and the logging program will be completed as planned.

29. After completing all wireline logging and sampling, go into the hole with bit, drill collars, and drill pipe to bottom. Check and note presence of any fill at the bottom of the hole. Circulate hole clean, condition the drilling fluid for running of the protection casing. Note, a high viscosity pill may be required to keep the bottom portion of the hole open.

30. Pull out of the hole with the drilling assembly. Lay down drill pipe and drilling assembly.

    Notify Arizona Oil and Gas Conservation Commission and USEPA of upcoming cement job at least 48 hours ahead of anticipated activities.

31. Rig up casing handling and make-up equipment. Run the 5-1/2 inch protection casing. Details of the casing program are described in the Well Casing Specifications section above. Set a differential shoe and a differential collar between the second and third joint.

    Ensure that all dimensions of cementing equipment and casing are visually inspected, measured, and drifted before running in the hole.

API Modified thread lubricant or equivalent will be used unless premium threads and/or corrosion resistant casing are used.

Have a casing swedge available, on the rig floor, with circulating hoses ready, in the event the casing must be washed to bottom or in the event that well control procedures are required.

32. Once the casing is on bottom, rig up and circulate the hole for a minimum of 150% of the open hole volume to clear the floats and cool the formation sufficiently for cementing. Add water and chemicals to the drilling fluid to adjust the characteristics of the fluid to improve drilling mud removal from the annulus during the cementing procedure.

    Reciprocate the pipe slowly, but continuously, in ±20-foot strokes during the circulating and cementing operations. If the movement of the pipe begins to indicate that sticking is occurring, lower the pipe to planned setting depth and discontinue pipe movement.

    Reduce mud levels in surface circulating system and have additional tanks on hand to recover any excess mud or cement that may be circulated to the surface.

    Designate a qualified person to observe the circulating system and monitor drilling fluid at all times during the cementing procedure. An accurate accounting of volumes will be critical information in the event that circulation is lost.

33. Mix and pump the cement. Details of the cementing program are described in the Well Construction Cementing Program section below. Displace the cement with drilling mud, 2% KCl, or fresh water.

34. Lift the BOP stack and hang off the 5-1/2" casing in tension (same hook load as when originally cemented in place). Nipple up the 7-1/16-inch 3,000 psi x 11-inch 3,000 psi tubing spool and perform a pressure test on the seals to the manufacturer's specifications. Isolate the well by installing a 7-1/16-inch 3,000 psi tapped flange with valve on the tubing spool.

35. Rig down the drilling rig and release rig from location. Remove and clean location of all drilling equipment.

COMPLETION PROCEDURE

PROTECTION CASING AND CEMENT EVALUATION

1. Mobilize a workover rig to location and rig up the equipment (note that the drilling rig may be used for completion operations, depending on availability and scheduling). Perform safety audit during rig-up to ensure that equipment setup complies with project requirements.
2. Install 7-1/16" 3,000 psi dual blow out preventer on well and pressure test.
3. Pick up a 4-3/4-inch cement bit and two casing scrapers, trip into the hole with a workstring to tag the top of cement in the casing.

4. Verify tagged depth and dress off cement as needed. Circulate the fluid in the wellbore to remove any solids. Displace the wellbore with filtered 2% KCl or other suitable completion fluid. Pull the workstring, scrapers, and bit.

5. Rig up wireline equipment and lubricator to the top of the annular BOP. Perform a 2,000-psig pressure test on the lubricator. Run cement evaluation/casing inspection/caliper logs, differential temperature survey, and gyroscopic survey as detailed in Attachment I, Well Logging, Coring and Testing. Run cement bond log initially under zero pressure. A repeat run at elevated pressure may be necessary to remove effects from potential micro-annulus. Run cement evaluation/casing inspection logs to surface or approximately 500 feet above the top of calculated annular cement. Rig down wireline equipment.

6. Perform a pressure test on the casing to 70 percent of the manufacturer's rated internal yield pressure or one psi per foot of casing depth, which ever is less, for at least 30 minutes. Note: Arizona Oil and Gas Conservation Commission and/or USEPA may witness casing pressure test. A successful test is a drop of no more than 10 percent of the test pressure over the 30-minute time period. Digitally record the test and maintain a copy of the test results on location. The original copy of the pressure test record **MUST** be sent in to the Sandia Office and made part of the CO_2 Injection Well report. Keep a copy of the pressure test record at the CO_2 Injection Well site with other important records.

WELL COMPLETION – CO_2 INJECTION PILOT

7. Run any pre-experiment baseline testing that requires the well to be clear of completion equipment (such as the baseline VSP).

8. Rig up wireline unit and set up perforating charges. Run in hole and correlate perforation gun(s) on depth. Perforate the Martin Formation (or alternate Naco Formation) injection interval as determined from the open-hole logs. It is recommended that the well be perforated **underbalanced**, to aid in perforation tunnel clean up.

9. Produce formation fluid from the Martin Formation by swabbing or backlift. This will also aid in developing the well. Monitor formation fluid properties at surface (chlorides, pH, temperature, specific gravity, etc.). Continue flowing the well until parameters stabilize, indicating that formation fluids are being recovered. Collect samples periodically for laboratory analysis. Once clean and stable formation brine is established, divert returns to a "fresh" frac tank(s). The stored formation fluids will be used for injection testing of the injection interval.

10. Pick up completion packer and tubing. Attach any downhole monitoring equipment and control lines. Run the completion assembly into the well. Once on bottom, circulate the well with clean formation brine.

11. Space out tubing string and set the packer +/-10 feet above the uppermost perforation in the Martin Formation injection interval.

12. Land the tubing into the wellhead.

13. Install wellhead equipment and control lines.

14. Allow well to equilibrate and perform annulus pressure test. The pressure test will be run at equal to the lesser of the maximum authorized injection pressure or 1,000 psi (no testing pressure will be less than 300 psi). A successful test is a drop of no more than 10 percent of the test pressure over the 30-minute time period. Digitally record the test and maintain a copy of the test results on location. *Note: Arizona Oil and Gas Conservation Commission & USEPA may witness annulus pressure test.* The original copy of the pressure test record **MUST** be sent in to the Sandia Office and made part of the well report. Keep a copy of the pressure test record at the well site with other important records.
15. Rig down the workover rig and move out associated equipment.

GENERAL NOTES

All depths referenced are approximate and are based on the expected log depth from rig Kelly bushing of 15 feet above ground level.

Actual depths may vary based on lithology and evaluation of local formations.

DRILLING FLUIDS PROGRAM

Surface Hole

Depth (Feet)	Mud Type	Weight (Lb./gal)	Viscosity (Funnel-sec.)	Fluid Loss (cc/30 min)
40-300	Freshwater Gel	8.4 – 9.0	40 - 60	control
300-965	Freshwater Gel	8.4 – 9.0	50 - 60	<10

Notes:

1. Should lost circulation and excessive drilling mud losses occur, materials designed for that problem will be used to remedy the problem on an "as needed" basis.
2. High-viscosity sweeps will be used as needed to assist in hole cleaning.

Protection Hole

Depth (Feet)	Mud Type	Weight (Lb./gal)	Viscosity (Funnel-sec.)	Fluid Loss (cc/30 min)
965-2,300	Saltwater Gel	9.5 - 10.5	35-42	<10
2,300-4,000	Saltwater Gel	9.5 - 10.5	35-42	≤5

Notes:

1. Should lost circulation and/or excessive drilling mud losses occur, materials designed for that problem will be used to remedy the problem on an "as needed" basis.
2. High-viscosity sweeps will be used as needed to assist in hole cleaning.

I. **FORMATION TESTING PROGRAM** - Describe the proposed formation testing program. For Class I wells the program must be designed to obtain data on fluid pressure, temperature, fracture pressure, other physical, chemical, and radiological characteristics of the injection matrix and physical and chemical characteristics of the formation fluids.

For Class II wells the testing program must be designed to obtain data on fluid pressure, estimated fracture pressure, physical and chemical characteristics of the injection zone. (Does not apply to existing Class II wells or projects.)

For Class III wells the testing must be designed to obtain data on fluid pressure, fracture pressure, and physical and chemical characteristics of the formation fluids if the formation is naturally water bearing. Only fracture pressure is required if the program formation is not water bearing. (Does not apply to existing Class III wells or projects.)

WELL LOGGING, CORING, AND TESTING PROGRAM

Proposed Well Logging Program
The following geophysical well logs will be run in the open-hole section of the surface casing hole of the CO_2 Injection Well:

- Platform Express (AITH Induction/Spontaneous Potential/Gamma Ray/ Compensated Neutron/Triple Litho Density/Borehole Caliper)
- Modular Formation Dynamics Tester (MDT)

The following geophysical well logs will be run in the open-hole section of the protection casing (long string) hole of the CO_2 Injection Well:

- Platform Express (AITH Induction (or laterolog)/Spontaneous Potential/Gamma Ray/Compensated Neutron/Triple Litho Density/Borehole Caliper)
- Combinable Magnetic Resonance (Naco and Martin Formations from 2,960 to 3,660 feet or minimum run)
- Formation Micro-Imager survey (lower Supai to base of Martin Formations from 1,800 to 3,660 feet)
- Dipole Shear Imager

Additional diagnostic logs and/or formation cores (whole core or sidewall cores) may be run at the discretion of the Arizona Utilities Project Team.

The following cased hole geophysical well logs will be run after cementing the protection casing in place:

- Cement evaluation and casing inspection log
- Gyroscopic survey

- Differential temperature survey

  Additional diagnostic logs (such as a video log) may be run at the discretion of the Arizona Utilities Project Team.

INJECTION ZONE AND CONFINING ZONE TESTING

A whole core is proposed for the CO_2 Injection Well in the Martin Formation, based on anticipated funding. The core depth will be picked based on correlation from the offset wells and the mud log. The proposed conventional core may be supplemented or replaced with sidewall cores or horizontal rotary cores.

Conventional Coring

Core Size	Depth	Formation/Lithology
7-7/8" x 4" x 30 feet	+/-3,600 feet	Martin Formation

Supplemental conventional coring in the injection zone may be conducted to obtain additional reservoir data. The Arizona Utilities Project Team will select the actual core point during the drilling of the CO_2 Injection Well, in consultation with the mud logger's correlation to offset wells. If insufficient formation core is recovered in any core run, the core run may be repeated at the discretion of the team, or sidewall coring may be conducted in the interval. The core depth will be adjusted relative to actual drilling depths encountered.

Sidewall Coring/Horizontal Rotary Coring

Sidewall coring or horizontal rotary coring may be taken in the injection zone or the confining zone during the open-hole logging of the protection hole to supplement the conventional core data. The Arizona Utilities Project Team, based on the evaluation and percent recovery of the conventional core, will determine if sidewall coring is necessary and select actual core depths. If sufficient whole core is recovered, sidewall cores may not be taken in the CO_2 Injection Well.

Formation Fluid Sampling

The CO_2 Injection Well will be back flowed (pumping or via nitrogen) to obtain background native formation fluids from the Martin Formation. The decision to collect fluid samples in other intervals, via either wireline or drillstem testing, will be made based on open-hole logging and the condition of the borehole at the time of logging operations. Any fluid samples collected will be transported to a selected laboratory for detailed analysis.

Step Rate Injection Test

A step rate injection test using formation brine (recovered during well development operations) will be performed on the injection interval. An initial low rate, low injection pressure injectivity test will be performed to assess receptivity of the injection interval.

From these data, a detailed step rate test will be designed and performed, so that test injection pressures span the range from the measured initial shut-in pressure to a maximum pressure determined by multiplying the top of the completed injection interval depth by a value of 0.622 psi/foot of depth. It is expected that the 0.622 psi/foot of depth pressure gradient is below the parting pressure of the injection interval. For example, assuming a native background initial pressure equal to a freshwater gradient (0.433 psi/foot of depth) and a below ground depth of 3,445 feet to the top of the Martin Formation, the step rate test would be planned to span the pressure range of 1,492 psi (initial pressure) to 2,143 psi (maximum test pressure) at 3,445 feet below ground surface, or 651 psi above the native background pressure.

The step rate test will be initiated following pressure recovery from the low rate, low pressure initial injectivity test. Injection will be initiated and stepped up in equal rate increments using equal time intervals (one or two hours). The equal time increments should be sufficient to allow for proper rate stabilization of the injection pump(s) and allow sufficient time to overcome wellbore storage effects between each rate change (especially at the low rates when the well may be on a vacuum). General test procedure is as follows:

STEP-RATE TEST PROCEDURE:

1. The well will be shut in long enough prior to testing such that the bottom hole pressures approximate the initial shut-in formation pressure. Pressure gauges will be installed on the wellhead and downhole near the top of the perforated completion. The downhole gauge will include surface read-out, so that the test may be monitored.
2. A series of successively higher injection rates will be used. Both surface and downhole pressures will be read and recorded at the end of each rate and time step. Each rate step will last as long as the preceding rate (i.e., equal duration steps).
3. Injection rates will be controlled with a constant flow regulator that has been tested prior to use. Flow rates will be measured with a calibrated turbine flowmeter. Injection rates and surface and downhole pressures will be digitally recorded. Injection pressures will be measured and recorded for immediate evaluation and interpretation by recording and plotting each time step and corresponding pressure.
4. A plot of injection rates and the corresponding stabilized pressure values at the end of each step are expected to follow a constant slope straight line. If the slope reaches a point at which the formation fractures (i.e., "breakdown" pressure is exceeded), the slope of this plotted line will be observed to decrease. The injection pump(s) will be immediately stopped and the flow line valve will be quickly closed. Pressure will be allowed to bleed off into the injection interval.

The step rate test will be designed for either 5 steps (20 percent rate increase increments to 100 percent maximum rate) or 8 steps (15 percent rate increase increments to 100 percent maximum rate) to gather a sufficient number of points for valid test analysis. The step rate test results will be used to limit the maximum bottomhole injection pressure and surface injection pressure so that the reservoir and seal formations are not fractured.

Constant Rate Injection Test

After the step rate injection test, a constant rate hydraulic test may be performed to further define aquifer properties. This may directly follow the last step of the step rate test. Pressure will be adjusted to maintain a steady injection rate for 8-12 hours, or until the remaining stored formation water is injected. Then the well will be shut in. Bottom hole pressure will be measured throughout the injection and recovery periods.

WELL TESTING PROGRAM

Mechanical integrity tests will be performed during completion of the CO_2 Injection Well. The following tests will be performed:

- Pressure testing of the surface and protection casing to 70 percent of the manufacturer's rated internal yield pressure or one psi per foot of casing depth, which ever is less, for at least 30 minutes. A successful test is a drop of no more than 10 percent of the test pressure over the 30-minute time period. Test data will be digitally recorded and a copy of the test results will be maintained on location. The original copy of the pressure test record **MUST** be sent in to the Sandia Office and made part of the CO_2 Injection Well report.
- Pressure testing of the 5-1/2-inch protection casing by tubing annulus to confirm the mechanical integrity of the completion. The pressure test will be run at equal to the lesser of the maximum authorized injection pressure or 1,000 psi, provided that no testing pressure will be less than 300 psi. A successful test is a drop of no more than 10 percent of the test pressure over the 30-minute time period. Test data will be digitally recorded and a copy of the test results will be maintained on location. The original copy of the pressure test record **MUST** be sent in to the Sandia Office and made part of the CO_2 Injection Well report.
- Casing inspection and cement bond evaluation of the 5-1/2-inch protection casing from total depth to surface. Interpretation report to be prepared by the vendor.
- Radioactive tracer survey of the completed CO_2 Injection Well following perforation to show the absence of fluid movement in vertical channels adjacent to the well.
- Baseline and repeat reservoir saturation logging (RST log) to show the distribution of CO_2 adjacent to the well.

Appendix D — EPA Reporting Forms

Form 7520-9: **Completion of Construction**

Form 7520-11: **Annual Well Monitoring Report**

Form 7520-12: **Well Rework Record**

Form 7520-14: **Plugging and Abandonment Plan**

OMB No. 2040-0042 Approval Expires 4/30/07

EPA

United States Environmental Protection Agency
Washington, DC 20460

Completion Form For Injection Wells

Administrative Information

1. Permittee

Address (Permanent Mailing Address) (Street, City, and ZIP Code)

2. Operator

Address (Street, City, State and ZIP Code)

3. Facility Name

Telephone Number

Address (Street, City, State and ZIP Code)

4. Surface Location Description of Injection Well(s)

State

County

Surface Location Description

1/4 of 1/4 of 1/4 of 1/4 of Section Township Range

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface
Location ft. frm (N/S) Line of quarter section
and ft. from (E/W) Line of quarter section.

Well Activity

- Class I
- Class II
  - Brine Disposal
  - Enhanced Recovery
  - Hydrocarbon Storage
- Class III
- Other

Well Status

- Operating
- Modification/Conversion
- Proposed

Type of Permit

- Individual
- Area : Number of Wells

Lease Number

Well Number

Submit with this Completion Form the attachments listed in Attachments for Completion Form.

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*

Signature

Date Signed

PAPERWORK REDUCTION ACT

The public reporting and record keeping burden for this collection of information is estimated to average 49 hours per response for a Class I hazardous facility, and 47 hours per response for a Class I non-hazardous facility. Burden means the total time, effort, or financial resource expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal Agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822), 1200 Pennsylvania Ave., NW., Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed forms to this address.

Attachments to be submitted with the Completion report:

I. Geologic Information

1. Lithology and Stratigraphy

A. Provide a geologic description of the rock units penetrated by name, age, depth, thickness, and lithology of each rock unit penetrated.

B. Provide a description of the injection unit.

(1) Name
(2) Depth (drilled)
(3) Thickness
(4) Formation fluid pressure
(5) Age of unit
(6) Porosity (avg.)
(7) Permeability
(8) Bottom hole temperature
(9) Lithology
(10) Bottom hold pressure
(11) Fracture pressure

C. Provide chemical characteristics of formation fluid (attach chemical analysis).

D. Provide a description of freshwater aquifers.

(1) Depth to base of fresh water (less than 10,000 mg/l TDS).
(2) Provide a geologic description of aquifer units with name, age, depth, thickness, lithology, and average total dissolved solids.

II. Well Design and Construction

1. Provide data on surface, intermediate, and long string casing and tubing. Data must include material, size, weight, grade, and depth set.

2. Provide data on the well cement, such as type/class, additives, amount, and method of emplacement.

3. Provide packer data on the packer (if used) such as type, name and model, setting depth, and type of annular fluid used.

4. Provide data on centralizers to include number, type and depth.

5. Provide data on bottom hole completions.

6. Provide data on well stimulation used.

III. Description of Surface Equipment

1. Provide data and a sketch of holding tanks, flow lines, filters, and injection pump.

IV. Monitoring Systems

1. Provide data on recording and nonrecording injection pressure gauges, casing-tubing annulus pressure gauges, injection rate meters, temperature meters, and other meters or gauges.

2. Provide data on constructed monitor wells such as location, depth, casing diameter, method of cementing, etc.

V. Logging and Testing Results

Provide a descriptive report interpreting the results of geophysical logs and other tests. Include a description and data on deviation checks run during drilling.

VI. Provide an as-built diagrammatic sketch of the injection well(s) showing casing, cement, tubing, packer, etc., with proper setting depths. The sketch should include well head and gauges.

VII. Provide data demonstrating mechanical integrity pursuant to 40 CFR 146.08.

VIII. Report on the compatibility of injected wastes with fluids and minerals in both the injection zone and the confining zone.

IX. Report the status of corrective action on defective wells in the area of review.

X. Include the anticipated maximum pressure and flow rate at which injection will operate.

OMB No. 2040-0042 Approval Expires 4/30/07

EPA

United States Environmental Protection Agency
Washington, DC 20460

ANNUAL DISPOSAL/INJECTION WELL MONITORING REPORT

Name and Address of Existing Permittee

Name and Address of Surface Owner

Locate Well and Outline Unit on
Section Plat - 640 Acres

N

W E

S

State

County

Permit Number

Surface Location Description

___ 1/4 of ___ 1/4 of ___ 1/4 of ___ 1/4 of Section ___ Township ___ Range ___

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface
Location ___ ft. frm (N/S) ___ Line of quarter section
and ___ ft. from (E/W) ___ Line of quarter section.

WELL ACTIVITY

- [ ] Brine Disposal
- [ ] Enhanced Recovery
- [ ] Hydrocarbon Storage

TYPE OF PERMIT

- [ ] Individual
- [ ] Area

Number of Wells ___

Lease Name ___ Well Number ___

		INJECTION PRESSURE		TOTAL VOLUME INJECTED		TUBING -- CASING ANNULUS PRESSURE (OPTIONAL MONITORING)	
MONTH	YEAR	AVERAGE PSIG	MAXIMUM PSIG	BBL	MCF	MINIMUM PSIG	MAXIMUM PSIG

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed

EPA Form 7520-11 (Rev. 8-01)

PAPERWORK REDUCTION ACT

The public reporting and record keeping burden for this collection of information is estimated to average 25 hours annually for operators of Class I wells and 5 hours annually for operators of Class II wells. Burden means the total time, effort, or financial resource expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal Agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822), 1200 Pennsylvania Ave., NW, Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed forms to this address.

OMB No. 2040-0042 Approval Expires 4/30/07

EPA

United States Environmental Protection Agency
Washington, DC 20460

WELL REWORK RECORD

Name and Address of Permittee

Name and Address of Contractor

Locate Well and Outline Unit on Section Plat - 640 Acres

N

W E

S

State

County

Permit Number

Surface Location Description

1/4 of 1/4 of 1/4 of 1/4 of Section Township Range

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface
Location ft. frm (N/S) Line of quarter section
and ft. from (E/W) Line of quarter section.

WELL ACTIVITY

- Brine Disposal
- Enhanced Recovery
- Hydrocarbon Storage

Lease Name

Total Depth Before Rework

Total Depth After Rework

Date Rework Commenced

Date Rework Completed

TYPE OF PERMIT

- Individual
- Area

Number of Wells

Well Number

WELL CASING RECORD -- BEFORE REWORK

Casing		Cement		Perforations		Acid or Fracture Treatment Record
Size	Depth	Sacks	Type	From	To	

WELL CASING RECORD -- AFTER REWORK *(Indicate Additions and Changes Only)*

Casing		Cement		Perforations		Acid or Fracture Treatment Record
Size	Depth	Sacks	Type	From	To	

DESCRIBE REWORK OPERATIONS IN DETAIL USE ADDITIONAL SHEETS IF NECESSARY	WIRE LINE LOGS, LIST EACH TYPE	
	Log Types	Logged Intervals

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*

Signature

Date Signed

PAPERWORK REDUCTION ACT

The public reporting and record keeping burden for this collection of information is estimated to average 4 hours per response annually. Burden means the total time, effort, or financial resource expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal Agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822), 1200 Pennsylvania Ave., NW., Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed forms to this address.

OMB No. 2040-0042 Approval Expires 4/30/07

EPA

United States Environmental Protection Agency
Washington, DC 20460

PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility	Name and Address of Owner/Operator

Locate Well and Outline Unit on
Section Plat - 640 Acres

N

W E

S

State	County	Permit Number

Surface Location Description

☐ 1/4 of ☐ 1/4 of ☐ 1/4 of ☐ 1/4 of Section ☐ Township ☐ Range ☐

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface
Location ☐ ft. frm (N/S) ☐ Line of quarter section
and ☐ ft. from (E/W) ☐ Line of quarter section.

TYPE OF AUTHORIZATION

☐ Individual Permit
☐ Area Permit
☐ Rule

Number of Wells ☐

Lease Name

WELL ACTIVITY

☐ CLASS I
☐ CLASS II
☐ Brine Disposal
☐ Enhanced Recovery
☐ Hydrocarbon Storage
☐ CLASS III

Well Number

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE

METHOD OF EMPLACEMENT OF CEMENT PLUGS

☐ The Balance Method
☐ The Dump Bailer Method
☐ The Two-Plug Method
☐ Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inche							
Depth to Bottom of Tubing or Drill Pipe (ft							
Sacks of Cement To Be Used (each plug)							
Slurry Volume To Be Pumped (cu. ft.)							
Calculated Top of Plug (ft.)							
Measured Top of Plug (if tagged ft.)							
Slurry Wt. (Lb./Gal.)							
Type Cement or Other Material (Class III)							

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

From	To	From	To

Estimated Cost to Plug Wells

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed

Paperwork Reduction Act Notice

The public reporting and record keeping burden for this collection of information is estimated to average 19.5 hours annually for operators of Class I wells, 6 hours annually for operators of Class II wells, and 8 hours annually for operators of Class III wells. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR Part 9 and 48 CFR Chapter 15.

Please send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Office of Environmental Information, Collection Strategies Division, U.S. Environmental Protection Agency (2822), Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Officer for EPA. Please include the EPA ICR number and OMB control number in any correspondence.

Appendix E — Temperature Logging Requirements

APPENDIX E – TEMPERATURE LOGGING PROCEDURES
U.S.E.P.A. REGION IX

A Temperature "Decay" Log (two separate temperature logging passes) must satisfy the following criteria to be considered a valid Mechanical Integrity Test ("MIT") as specified by 40 CFR §146.8(c)(1). Variances to these requirements are expected for certain circumstances, but they must be approved prior to running the log.

1. With the printed log, provide also raw data for both logging runs (one data reading per foot depth) unless the logging truck is equipped with an analog panel as the processing device.
2. The heading on the log must be complete and include all the pertinent information, such as correct well name, location, elevations, etc.
3. The total shut-in times must be clearly shown in the heading. Minimum shut-in time for active injectors is 12 hours for running the initial temperature log, followed by a second log, a minimum of 4 hours later. These two log runs will be superimposed on the same track for final presentation.
4. The logging speed must be kept between 20 and 50 ft. per minute (30 ft/min optimum) for both logs. The temperature sensor should be located as close to the bottom of the tool string as possible (logging downhole).
5. The vertical depth scale of the log should be 1 or 2 in. per 100 ft. to match lithology logs (see 7(b)). The horizontal temperature scale should be no more than one Fahrenheit degree per inch spacing.
6. The right hand tracks must contain the "absolute" temperature and the "differential" temperature curves with both log runs identified and clearly superimposed for comparison and interpretation purposes.
7. The left hand tracks must contain (unless impractical, but EPA must pre-approve any deviations):
   (a) a collar locator log,
   (b) a lithology log:
      i. an historic Gamma Ray that is "readable", i.e. one that demonstrates lithologic changes without either excessive activity by the needle or severely dampened responses; or
      ii. a copy of an original SP curve from either the subject well or from a representative, nearby well.
   (c) A clear identification on the log showing the base of the lowermost Underground Source of Drinking Water ("USDW"). A USDW is basically a formation that contains less than 10,000 ppm Total Dissolved Solids ("TDS") and is further defined in 40 CFR §144.3.

Appendix F — Plugging and Abandonment Program

Upon completion of injection activities, the well shall be abandoned according to State and Federal regulations to ensure protection of Underground Sources of Drinking Water.

Q. PLUGGING AND ABANDONMENT PLAN -Submit a plan for plugging and abandonment of the well including: (1) describe the type, number, and placement (including the elevation of the top and bottom) of plugs to be used; (2) describe the type, grade, and quantity of cement to be used; and (3) describe the method to be used to place plugs, including the method used to place the well in a state of static equilibrium prior to placement of the plugs. Also for a Class III well that underlies or is in an exempted aquifer, demonstrate adequate protection of USDWs. Submit this information on EPA Form 7520-14, Plugging and Abandonment Plan.

WELL PLUGGING AND ABANDONMENT PLANS

General well closure procedures and any post-closure care plans are detailed in the following subsections. These procedures follow Arizona Oil and Gas Conservation Commission requirements for proper well abandonment (*R12-7-127*). An exact plugging and abandonment program will be developed prior to actual well abandonment. This detailed plugging and abandonment plan will be based on final as-built well construction and the specific zones perforated and used for the experiments/monitoring in the well. This well-specific plan will include: 1) information on type, number and placement of the proposed plugs; 2) type, grade, and quality of the cement(s) to be used; and, the method that will be used to place the plugs. The plan will be submitted a minimum 30 days in advance of well plugging for review and approval.

General Well Closure Procedures

The closure procedures for the CO_2 Injection Well are designed to be implemented following completion of monitoring activities for the pilot test. The general procedures for well closure are described below and may be modified prior to performing field operations according to the direction of the Arizona Oil and Gas Conservation Commission and/or
EPA:

A. Notice of intent to plug will be made at least 30 days prior to planned closure. Notification of the start of closure will be made to the Arizona Oil and Gas Conservation Commission at least 48 hours ahead of start of field operations.

B. The following detailed information will be provided with the formal notice of intent to plug:

1. Type and number of plugs to be set.
2. Placement of each plug including the approximate elevation of both the top and bottom of the plug.
3. Type, grade, and quantity of the plugging material and additives to be used.
4. Method used to place plugs in hole.
5. Procedure used to plug and abandon the well.
6. Any information on newly constructed or discovered wells, or additional well data, within the Area of Review.

C. Plugging operations for the CO_2 Injection Well will generally be conducted as follows:

1. Prepare location for workover rig.
2. Move workover rig onto location.
3. Record any shut-in tubing and/or casing pressures. Kill well with brine fluid. Remove wellhead and nipple up blow out preventers.
4. Pull injection tubing, injection packer(s), and downhole instrumentation from the well. Perform any end of experiment monitoring activities
5. Run in the well open-ended and displace the well with mud. Plugging mud, at a minimum, will have 15 pounds per barrel of sodium bentonite and a nonfermenting polymer, have a minimum consistency of 9 pounds per gallon, a minimum viscosity of 50 seconds per quart, and mixed with fresh water.
6. Trip in the well with a 5-1/2" cement retainer and set the retainer approximately 50 feet above the upper perforation in the CO_2 Injection Well. Squeeze approximately 100 feet cement below the retainer. Shear out of the cement retainer and spot approximately 100 feet of cement above the retainer in the 5-1/2" casing.
7. Pressure up on the 5-1/2" casing and plug to 1,000 psi for at least 30 minutes in order to verify integrity of the protection casing and the cement plug. Record the pressure test on a strip chart, circular chart, or digital recording devise. Note Arizona Oil and Gas Conservation Commission and/or EPA may witness the casing/cement pressure test.
8. Place a cement plug opposite the base of the surface casing, located at +/-965 feet. Plug will extend a minimum of 50 feet above and below the surface casing shoe depth (at a minimum top of plug at approximately 915 feet and bottom of plug at 1,015 feet). Displace cement out of tubing and pull up work string. Reverse circulate the hole clean. Allow cement to set and tag top of plug to verify depth. [Note, if the annular cement behind the 5-1/2-inch protection casing by 9-5/8-inch surface casing does not come up to the surface casing shoe, the 5-1/2-inch casing will be perforated at the depth of the surface casing shoe and cement squeezed outside the casing.]
9. A cement surface plug of at least 50 feet will be set from the anticipated casing cut-off point in the protection casing (at a minimum top of plug at surface or cut-off depth and bottom of plug at 50 feet or 50 feet plus cut-off depth). All open annular spaces that extend to surface in any of the other casing strings will also be cemented (minimum 100 feet of cement).
10. Cut off casing three to five feet below ground surface (or depth as designated by the Arizona Public Service Company (surface owner)) and fill any remaining open annular spaces with cement. The well will be marked by a piece of metal pipe, not less than 4 inches in diameter, that is securely set in cement and extends at least 4 feet above general ground level. The well location and identity will be permanently inscribed on the marker.

D. A plugging report will be filed with the Arizona Oil and Gas Conservation Commission and EPA within 15 days after completion of closure operations. The report will include: 1) the method used in plugging the well; 2) casing record details; 3) the size, kind, and depth of plugs used; and 4) the name and depth interval of each formation containing fresh water, oil or gas, or geothermal resources.

POST CLOSURE PLANS

Post-closure monitoring is not anticipated for the CO_2 Injection Well.