EXECUTIVE SUMMARY

The United States Environmental Protection Agency (EPA) Region 9 requested a review and evaluation of the California Division of Oil and Gas and Geothermal Resources (CDOGGR, or the Division) Class II Underground Injection Control (UIC) Program for compliance with the CDOGGR Program Description and Memorandum of Agreement (Appendix A1) that were submitted in connection with the State of California application for primacy (the Primacy Application) that was approved by EPA in 1983. The review focuses on the following topics:

- Definitions of Underground Sources of Drinking Water (USDWs) and Base of Fresh Water (BFW);
- Area of Review (AOR)/Zone of Endangering Influence (ZEI) considerations, including corrective action requirements, well construction practices, and status of wells located within the AOR;
- CDOGGR annual project reviews;
- Monitoring program, including procedures for establishing Maximum Allowable Surface Pressures (MASPs);
- Inspections and compliance/enforcement procedures;
- Idle well planning and testing;
- Financial responsibility requirements;
- Plugging and abandonment requirements; and
- UIC staff qualifications.

The review was conducted as a third-party endeavor by the Horsley Witten Group, Inc. (HW) and Mr. James D. Walker, subcontractor to HW, and with initial guidance from EPA Region 9 on the process, format, and content of the review and of this final report. The conclusions, recommendations, and expressions of opinion provided in this report are solely those of HW and Mr. Walker.

The evaluation process of the CDOGGR Class II UIC Program started with a review of a number of critical documents and field data. A questionnaire was then developed (the EPA Questionnaire - available in Appendix A2) as a tool to gather critical information in the areas listed above from each of the six CDOGGR district offices. A district specific follow-up questionnaire was then submitted for clarification on certain district responses. Following these responses, Mr. Walker visited each district office to discuss any additional information, and collect information on representative samples of injection well projects and other data that would provide further insight into the areas of focus listed above.

A map of California showing the boundaries of each of the six districts, as well as district office locations is provided in Figure ES-1. In addition, a summary of injection well numbers by district is provided in Table ES-1. Well numbers are provided for both active and inactive wells of the following types: gas storage (GS), pressure maintenance (PM), cyclic steam (CS), steamflood (SF), waterflood (WF), air injection (AI), and water disposal (WD).

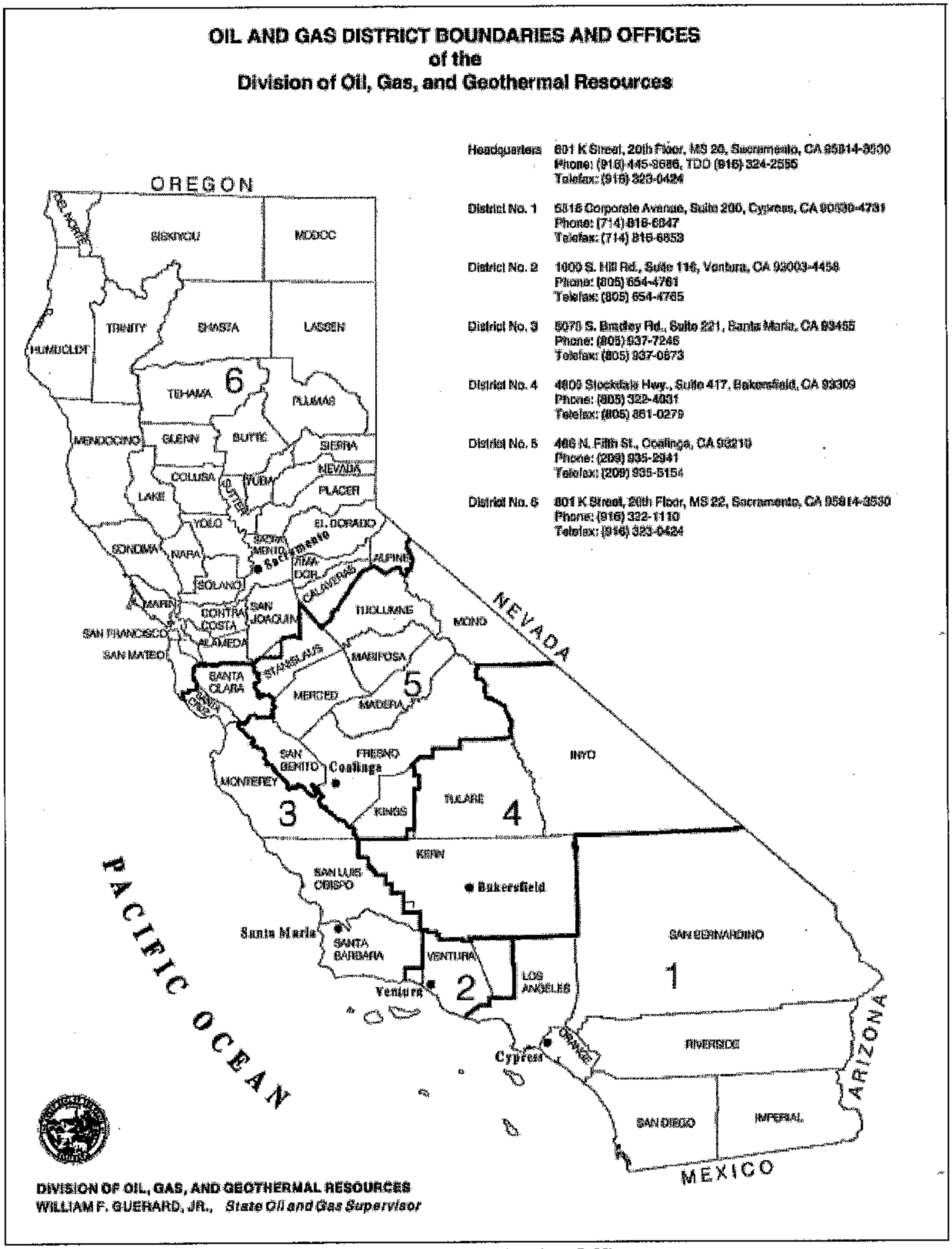

Figure ES-1. Map of CDOGGR Districts and District Offices

Table ES-1. Summary of Injection Well Numbers by District and Well Type

District	Injection Well Type	GS	PM	CS	SF	WF	AI	WD	Total	% of State Wells
1	Active	24	1	-	2	1,397	-	16	**1,440**	**6.14%**
	Inactive	53	1	-	9	411	2	26	**502**	
	Total	**77**	**2**	-	**11**	**1,808**	**2**	**42**	**1,942**	
2	Active	86	-	66	45	326	-	64	**587**	**3.19%**
	Inactive	48	1	-	31	278	-	65	**423**	
	Total	**134**	**1**	**66**	**76**	**604**	-	**129**	**1,010**	
3	Active	17	8	203	120	87	-	87	**522**	**2.83%**
	Inactive	4	8	-	124	142	4	90	**372**	
	Total	**21**	**16**	**203**	**244**	**229**	**4**	**177**	**894**	
4	Active	-	63	14,310	3,380	2,893	-	604	**21,250**	**80.8%**
	Inactive	-	16	-	3,064	851	12	377	**4,320**	
	Total	-	**79**	**14,310**	**6,444**	**3,744**	**12**	**981**	**25,570**	
5	Active	-	-	369	276	136	-	29	**810**	**6.45%**
	Inactive	1	-	-	694	501	-	36	**1,232**	
	Total	**1**	-	**369**	**970**	**637**	-	**65**	**2,042**	
6	Active	104	-	-	-	-	-	26	**130**	**0.57%**
	Inactive	41	-	-	-	-	-	10	**51**	
	Total	**145**	-	-	-	-	-	**36**	**181**	
State Totals	Active	231	72	14,948	3,823	4,839	-	826	**24,739**	**100%**
	Inactive	147	26	-	3,922	2,183	18	604	**6,900**	
	Total	**378**	**98**	**14,948**	**7,745**	**7,022**	**18**	**1,430**	**31,639**	

This report summarizes the results of the evaluation, and provides third-party conclusions and recommendations to EPA on potential improvements to the CDOGGR Class II UIC Program related to each of the topics identified above.

USDW DEFINITION AND PROTECTION

The CDOGGR Program Description submitted with the Primacy Application refers to protection of fresh water, and historically that term has been used to describe groundwater that contains 3,000 milligrams per liter (mg/L) or less total dissolved solids (TDS) in California. That is inconsistent with the federal definition of a USDW at 40 CFR §144.3, which defines USDWs as containing less than 10,000 mg/L TDS. In addition, there are apparently no provisions in California statutes or UIC regulations for exemption of an aquifer as an USDW containing between 3,000 and 10,000 mg/L TDS. The term commonly applied to identify the depth to which groundwater is protected is the BFW not the base of USDWs, and fresh water in California is defined as containing 3,000 mg/L or less TDS. Consequently, it would appear that USDWs containing more than 3,000 mg/L TDS are not fully protected under the California UIC regulations.

The Manual of Instructions (MOI) for the administration of the CDOGGR program, however, has a provision for the protection of USDWs containing 3,000 to 10,000 mg/L TDS. That provision clearly defines a USDW as containing fewer than 10,000 mg/L TDS, but that provision refers primarily to the aquifer exemption requirements, not to the more stringent protections in well construction and plugging abandonment requirements applied to fresh water zones. The description of the aquifer exemption process in the MOI includes requirements for an aquifer exemption in new injection projects if the proposed aquifer contains less than 10,000 mg/L TDS. Essentially all existing hydrocarbon bearing formations were exempted in the approval of the original Primacy Application in 1983, regardless of TDS concentrations. In addition, existing nonhydrocarbon bearing formations that were used for oil field wastewater disposal were identified and exempted at that time. There have been very few aquifer exemptions requested and approved since then.

Based on our review, the actual practices employed in UIC operations provide protection of fresh water from movement of fluids, but not necessarily for other USDWs. Annular cement is required at the BFW, but not at the base of other USDWs in injection wells. Zonal isolation of saline aquifers from USDWs by cement placement is not required and isolation from hydrocarbon bearing zones open to the uncemented wellbore is not assured without cement placement at the base of USDWs. That leaves those USDWs exposed to fluid movement due to improperly plugged wells and/or lack of cement in the casing/wellbore annulus, notwithstanding the presence of drilling mud that may restrict fluid flow. We believe that CDOGGR should address the lack of clarity regarding USDW protection and ensure that all USDWs are fully protected from fluid movement and resulting degradation. USDWs containing more than 3,000 mg/L TDS should be protected as much as fresh water aquifers are protected in the permitting, construction, operation, and abandonment of injection wells.

AREA OF REVIEW/ZONE OF ENDANGERING INFLUENCE

District staff indicated that the quarter-mile fixed radius AOR standard has been applied historically with very few exceptions. The ZEI calculation has rarely been applied to the AOR determination. The quarter-mile fixed radius for determination of the AOR applies to both water disposal wells and to multi-well projects in enhanced recovery projects.

The CDOGGR MOI states that, "(a)s a general rule, disposal into a nonhydrocarbon-producing zone should not be allowed to raise the zone pressure above that of hydrostatic pressure; however, exceptions may be made under certain conditions." District staff members indicated that surface shut-in pressures are monitored or fall-off tests are performed in wells of concern to ensure that the pressure falls to zero over a reasonable period of time. If the pressure does not fall to zero, the permit to inject into that zone is usually terminated or otherwise limited to avoid fluid movement in defective wells in the quarter-mile AOR.

District staff statements and a review of selected project files indicate most disposal wells inject into abandoned or producing zones, either in the field or at the flanks below the oil-water contact. Since the zone pressure is usually reduced well below hydrostatic pressure due to fluid withdrawals in those fields, it can be maintained at a pressure below hydrostatic as produced water is injected into the producing reservoir. Disposal of produced water into nonhydrocarbon bearing zones and normally pressured hydrocarbon bearing zones should be carefully monitored for reservoir pressure increases above hydrostatic, and the AOR should be determined by the ZEI calculation to ensure that corrective action requirements are fully addressed in all wells within the expanded AOR. Generally, the ZEI calculation is not necessary in Enhanced Oil Recovery (EOR) projects unless fluid volumes injected exceed the volumes withdrawn and static reservoir pressure exceeds hydrostatic pressure for an extended period of time, which is usually not the case.

Well construction practices and status of wells located within the AOR were reviewed in each district for consistency with the MOI, CDOGGR Program Description, UIC regulations, and adequate protection of USDWs. The review indicated that all defective wells in the AOR must meet those requirements for project approval, but that USDWs containing more than 3,000 mg/L TDS do not require as much protection as fresh water aquifers in terms of annular cement and plug placement in those wells. Sufficient volumes of cement in the annulus of unplugged wells are required at the BFW and above the injection/production zones to protect fresh water zones, but cement is not required at the base of USDWS in any well. Only "heavy" drilling mud between the injection zone and BFW annular cement is required for protection of USDWs from fluid movement in unplugged wells. Plugged wells require similar confinement in the annulus plus heavy mud inside the casing or open hole between cement plugs. The result of that practice is that fluid movement in the uncemented casing/wellbore annulus can occur, especially in older wells wherein the mud has likely deteriorated and may no longer be capable of preventing fluid movement.

Project approvals for recent applications generally satisfy corrective action requirements, but historical projects do not always meet current standards. In the May 2010 memorandum to the district offices (the Division Expectations Memorandum - available in Appendix A3), the Division provides directives (the Division directives) that require existing injection projects to comply with corrective action standards for wells within the AOR, in addition to new injection projects. The overriding mandate is that "injection fluid must be confined to the permitted zone of injection" whether or not a USDW is present.

The recent Division requirement that the ZEI be calculated for existing injection projects and all new Class II injection well project applications should result in a substantial improvement in the protection of USDWs when fully implemented at the district level. It will require a significant increase in the number of qualified staff members in the district offices, and we were informed that those increases have been authorized at the State level.

CDOGGR ANNUAL PROJECT REVIEW

Records of well activity, pressures, inactive well and non-compliance data and CDOGGR actions taken to correct non-compliance were reviewed in each district. All existing projects are required to have an annual review, in accordance with the MOI and the recent Division directives from the Division Expectations Memorandum to the district offices. The adherence to the annual project review standards varies from district to district. Most projects are reviewed at least on the basis of the CDOGGR Project Review Questionnaire (Appendix A4) responses, inspection reports, and other data in the monthly reports submitted by operators. Annual meetings with project operators are prioritized on the basis of the numbers of wells, activity, and levels of non-compliance associated with the operator. Actions taken to correct non-compliance include informal contacts, deficiency notices, shut-ins, notices of deficiency, civil orders, plugging and abandonment, and fines.

Comprehensive project reviews should be conducted annually for all active injection well projects, especially with those operators that are negligent in maintaining compliance with UIC regulations. Based on district responses, that may not be the case in the largest districts, due to the large number of injection wells and lack of manpower in those districts. That situation should improve with the hiring and training of several additional UIC personnel that was reportedly authorized by the Division. In addition, the requirement for monthly reports from the operators, mechanical integrity tests (MITs), periodic inspections, and other sources of project information provides data on wells that support the objectives of the annual project reviews.

MONITORING PROGRAM

Mechanical Integrity Testing surveys/reports were examined for compliance with UIC requirements and consistency with actual MIT results in each district. Radioactive tracer (RAT) surveys are required annually in water disposal wells, every two years in waterflood wells, and every five years in steamflood wells. Standard annulus pressure tests (SAPTs) are required in all Class II injection wells every five years. Our review of the well records indicates that schedule is followed with a few exceptions for variances approved by CDOGGR.

CDOGGR inspectors witness a large percentage of the SAPTs, but only a few of the RAT surveys. The percentages vary widely from district to district depending largely on the number of wells to test and the availability of inspectors to witness a test. Examination of MIT reports in district files indicates that they are generally consistent with historic UIC requirements as described above. Few of the RAT surveys are witnessed in the largest districts, but most of the SAPTS are witnessed in all districts. In our view, the percentage of RATs witnessed should be increased to at least 25 percent per year and the goal for SAPTs should be 100 percent, which would include witnessing MITs on all wells in a five-year cycle.

The requirement for pressure testing wells to at least 200 pounds per square inch (psi) for 15 minutes in the approved SAPT procedure is inconsistent with the standards applied to Class II injection wells in many of the other state and federal UIC programs. Those programs require testing to the maximum allowable surface injection pressure or at a minimum pressure higher than 200 psi, and for more than 15 minutes in some cases.

The Division directives modify the SAPT procedure to require testing at the approved MASP for a well where there is only a single string of cemented casing across a USDW (10,000 mg/L TDS). Comments received by the districts indicate that this standard is undergoing further review at the Division level and may be modified to allow for consideration of the age and condition of the casing in a well.

We support the Division directive to test the casing/tubing annulus to the maximum allowable surface injection pressure, if that will not expose the casing to a pressure that could cause a rupture, which can be a significant risk in older wells. The recently modified SAPT procedure described above is a substantial improvement, but we would recommend it be applied regardless of the number of cemented casing strings across USDWs.

Procedures for establishing MASPs and monitoring for compliance were reviewed in each district. Historically, MASPs were based largely on assumptions or estimates of the formation fracture gradient of the injection formation. Fracture gradients applied in the MASP determination vary from 0.6 to 1.0 psi/foot. In some wells, the fracture gradients were based on results of step-rate testing or calculations from other data. Estimates of fracture pressures based on generalized relationships between fracture pressure and depth to the formation or other means are not always a reliable method for that determination. Step-rate tests (SRTs) provide a more reliable and accurate measure of formation fracture pressures in the injection zone.

A review of selected SRT reports in each district indicated that the methodology and validity of the tests were generally in accordance with accepted industry standards, although most were based on surface pressure rather than bottom- hole pressure measurements. The estimation of friction losses would be avoided and the accuracy of the test results would therefore increase if the test analyses were based on bottom hole in addition to surface pressure measurements.

It is our view that the fracture pressure of the injection zone should be determined on the basis of an SRT unless SRTs have been performed on a sufficient number of wells in the area to ascertain the fracture gradient within acceptable confidence limits. Also, the SRT should include a pressure gauge to measure bottom-hole pressures directly rather than relying on calculation of friction losses from surface pressure measurements and injection rates.

In its Division directives, CDOGGR has recently initiated steps to ensure the accuracy of fracture gradients and MASP determinations in all districts. New and existing projects will require approved SRTs to determine the fracture gradient in injection wells, and that injection pressure will be maintained below fracture pressure as determined by approved SRTs. Implementation of that directive should improve the accuracy of the fracture pressure determination and reduce the potential for fracturing the injection zone. We support that directive to the fullest extent.

We also support the requirement for a wellhead inspection at least once every two years to ensure that the injection pressure is below the MASP and the requirement to immediately reduce the injection pressure if it exceeds the MASP. Annual inspections are required according to the MOI, but that may not be possible in the largest districts with current staffing levels. In our view, wells that inject at or near the MASP should be inspected annually. In addition, we endorse the requirement that a database or records must be maintained that lists the MASP for all injection wells and is easily accessible to field personnel to verify that the MASP is not being exceeded.

The databases used in each district office vary, but the districts are in the process of replacing those with the California Well Information Management System (CalWIMS) database statewide. CalWIMS is more user-friendly and more up-to-date in its applications than the existing systems at the district level

INSPECTIONS AND COMPLIANCE/ENFORCEMENT PRACTICES AND TOOLS

Injection wells are required to be inspected annually in accordance with the Division MOI guidelines. Injection pressures are compared with the MASP for a well to ensure that the MASP or 90 percent of the fracture gradient is not exceeded. If exceeded, the well is considered in violation of the project approval letter and the operator is required to reduce the pressure immediately. If USDWs are endangered, the violation is considered a significant non-compliance (SNC). An enforcement action may ensue at the district level if the operator fails to comply with the order to maintain the pressure below the MASP and/or correct other deficiencies

A MIT is described as either a RAT, temperature, or spinner survey. The initial MIT is usually witnessed and subsequent MITs may be witnessed depending on the availability of an inspector and the priority for witnessing the MIT. Water disposal wells are tested annually, waterflood wells are tested biennially, and steamflood wells are tested every five years. Less than five percent of RATs are witnessed in the largest districts and they are not a priority in most districts. However, essentially all tests are reviewed and documented by district personnel.

An SAPT is required for all water disposal wells and waterflood wells every five years. Most of the SAPTs are witnessed by district personnel. When a MIT is not witnessed, the results of the tests are reviewed in the office. Inspections are also carried out in cases of noncompliance and in response to citizen complaints. Plugging and abandonment operations are witnessed for plug depth and hardness, squeeze cementing operations, and surface plug location, but witnessing cement placement in a well is not a requirement. An SRT for the determination of the formation fracture gradient and pressure is usually witnessed, but is rarely required by CDOGGR. Most MASP limits are set on the basis of fracture pressures estimated from statistical data on fracture gradients in the oil producing basins of California. However, SRTs are required for establishment of the MASP in new and existing projects under the Division directives of May 20, 2010. We fully support that directive, and recommend that the fracture pressure be based on bottom-hole pressures rather than surface pressures corrected for estimated friction losses.

Compliance assurance and enforcement tools utilized are as follows: informal contact, well shut-in, notice of deficiency, notice of violations, rescission of approval to inject, project suspension, civil order and penalty. Orders can be issued to repair or plug and abandon wells and "undertake such action as is necessary to protect life, health, property, or natural resources." Generally, an order is issued only after a reasonable attempt to obtain voluntary compliance with requirements has failed. If an emergency exists, district deputies can obtain authorization from the Division headquarters to repair or plug wells or eliminate hazardous conditions without issuing a formal order or seeking bids. Civil penalty procedures are described in Section 137 of the MOI and are limited to $25,000 per violation.

Inspections are not necessarily prioritized for wells where fresh water is present, and residential areas are not a consideration for the many wells that are located in rural areas, which is the case in most districts. In our view, those areas should receive a higher priority for inspections than is apparently the case in some districts.

According to the MOI, annual inspections are required for all injection wells, but not all wells are inspected annually in all districts. However, the recent Division Expectations Memorandum to the districts states that inspections at least every two years are acceptable. Most plugging and abandonment (P&A) operations are witnessed, but witnessing cement placement is not required, and that is one of our concerns. We believe it is important to witness cement placement operations to ensure the correct volumes and quality of cement are pumped into a well.

In general, inspections and monitoring are conducted in accordance with the general outline in the CDOGGR Program Description, but not in rigid adherence to the CDOGGR UIC regulations and MOI guidelines in all districts. The Division Expectations Memorandum requires inspections of all injection wells at least every two years and annual project reviews, which is consistent with the CDOGGR Program Description, but not with the annual inspection standard in the MOI. Historically, the MOI standards have not always been met in most districts. The hiring of additional staff members that was recently authorized by the Division should alleviate the lack of personnel to meet the Division standards.

Violation of a formal enforcement action is a significant noncompliance. Most (13) of the civil penalties issued in the past ten years were initiated by District 4 with fines ranging from $250 to $25,000 for each violation. Most of these actions were related to unauthorized injection violations.

In general, the CDOGGR enforcement program is apparently conducted in accordance with the general outline in the CDOGGR Program Description. Most districts indicated that they do not have enough resources and personnel to initiate adequate numbers of compliance/enforcement actions. That is also our assessment from our review of the district level inspection activity and formal enforcement actions. The hiring of additional personnel that was recently authorized by the Division, however, should alleviate the lack of staff to initiate and carry out UIC compliance/enforcement actions when violations occur.

IDLE WELL PLANNING AND TESTING PROGRAM

The stated objective of the idle well program is to eliminate idle wells by requiring operators to return idle wells to production/injection, or to plug and abandon their idle wells. The description of the program is found in Section 138 of the MOI. The definition of an idle well is "any well that has not produced oil or natural gas or has not been used for injection for six consecutive months of continuous operation during the last five or more years." The definition of long-term idle is "any well that has not produced oil or natural gas or has not been used for injection for six consecutive months of continuous operation during the last ten or more years."

Idle wells must have the fluid level determined as prescribed in the Idle Well Planning and Testing Program. The tests are required to verify fresh water is protected and that reservoir damage is not occurring. The program states that if the fluid level of a well is above the BFW, a casing pressure test should be run. If the casing lacks mechanical integrity and fresh water is threatened, the program recommends that the operator be ordered to perform remedial work. If an injection well is inactive for two or more years, the program recommends that approval for injection be rescinded.

Idle injection wells are not subject to the normal MIT schedule, but are subject to the idle well testing guidelines. In areas with fresh water, a two-year test cycle applies after five years of inactivity. Testing procedures for wells in areas with no fresh water are identical to those in fresh water areas except the testing cycle is five years instead of two years and references to BFW are excluded.

Plans for future use of idle wells are required for wells idle for ten years or longer. An approved Idle Well Management Plan satisfies this requirement. Otherwise, the plan for future use must include what is planned for the well and when it will be done. Wells idle for 15 years or longer must have an engineering study prepared and submitted detailing the future plans for the well(s).

The idle well testing guidelines for District 4 vary significantly from the statewide program. Districts are allowed to modify the general guidelines to address specific district conditions. The emphasis of the District 4 Idle Well Program is testing ten-year and 15-year idle wells for mechanical integrity (MI). District 4 wells that are idle for longer than ten years in areas where fresh water is present must be tested every two years. If located in a non-fresh water area, ten and 15-year idle wells must be tested every five years." The MIT for idle wells consists of a fluid level survey, and/or a casing pressure test if the fluid level is found above the BFW.

This program is a comprehensive monitoring program except that remedial work or plugging is not required for wells that lack MI unless there is evidence of a threat to fresh water zones while in idle status. Also, idle wells with apparent casing integrity are not required to be reactivated or plugged and abandoned before 15 years in that status. Only a small fraction of long-term idle wells are plugged and abandoned on a yearly basis, resulting in long-term temporary abandonment of most idle wells. The option for an operator to submit an Idle Well Management Plan provides some assurance that idle wells will be reactivated or plugged and abandoned on a specific timetable after ten years in idle status. However, it is optional and the other options provide insufficient assurance that the operator will comply with the requirement to reactivate or P&A a long-term idle well. In our view, the idle well fee amounts imposed on operators are too small to incentivize operators to reactivate or plug their idle wells and idle well bond or escrow amounts are insufficient to cover P&A costs.

Monitoring the fluid levels in idle wells every two years in fresh water areas is not consistent with adequate protection of other USDWs penetrated by an idle well. A pressure test is required if the fluid level rises above the BFW, but not the base of USDWs. In non-fresh water areas, testing requirements are on a five-year cycle and are otherwise less rigorous. If USDWs containing more than 3,000 mg/L TDS are present, those USDWs are not protected as well as they would be in a fresh water area. A pressure test would be more definitive of a casing or bridge plug leak and the potential for fluid movement into USDWs as fluid levels rise in a well, especially where USDW heads are drawn down by pumping for drinking water, agricultural, and/or other uses. Well integrity should be maintained while a well is in idle status, as it is in active status, unless the permittee can satisfactorily demonstrate that fluid movement will not occur into or between USDWs. Consideration should be given to modification of the CDOGGR Program to strengthen the protection of all USDWs penetrated by a well.

Field rules for District 4 allow less rigorous monitoring and testing of idle wells, probably because of the large number of idle wells in that district. In our view, consideration should be given to strengthening the idle well requirements in District 4 to make them more consistent with the statewide program and more protective of USDWs.

FINANCIAL RESPONSIBILITY REQUIREMENTS

These are applied on a statewide basis. The districts are fairly consistent in their responses regarding financial responsibility requirements for operators, as noted in Section 4.

An operator may demonstrate financial responsibility by filing an individual indemnity or cash bond for each well drilled or a blanket bond covering all well operations. Individual bonds are normally released after a noncommercial injection well has injected fluids for a six-month continuous period if the Division is satisfied that a well is mechanically sound. Blanket bonds are normally not released until all of the operator's wells are abandoned or until the operator specifically requests the release of a well from bond coverage. After the release of a bond, the Division still has the authority to order an operator to perform remedial or corrective work on a well. The Division may also order the abandonment of any well that has been deserted whether or not any damage is occurring or threatening to occur.

The individual bond amount for a Class II commercial disposal well is $50,000 per well if not covered by a blanket bond. The bond must be retained until the well is plugged and abandoned to the satisfaction of the Division.

The CDOGGR Program Description states that "(a) special well abandonment allotment is also available in California for the purpose of abandoning deserted wells when the last known operator is deceased, defunct, or no longer in business in California and the present surface and mineral estate owners did not receive a substantial financial gain from the wells."

The current bond amount of $50,000 per well may not be adequate to cover the full cost to plug and abandon some commercial Class II injection wells. Bond amounts for non-commercial wells are much less and are based on well depth. Basing the bond amount on third-party estimates of P&A costs for individual wells and periodic review and adjustment of those amounts would increase the probability that adequate funds would be available to P&A a deserted well. The individual well bond amounts were increased in 1999, but have apparently not been updated since then and are probably not adequate to cover the full cost to plug and abandon a well when that becomes necessary.

PLUGGING AND ABANDONMENT REQUIREMENTS

Procedures for P&A are standardized at the state level, with special requirements at the field level as described in field rules issued for special circumstances (see the *Bentonite Plugging Guidelines* discussed below for an example of the field rules that apply in the Bakersfield and Coalinga Districts). In general, cement plugs are placed across specified intervals to protect oil and gas zones, to prevent degradation of "useable" waters, to protect surface conditions, and for public health and safety purposes. Cement may be mixed with or replaced by other substances with adequate physical properties, subject to approval by the supervisor and application to particular wells at the discretion of the district deputy.

Plugging an open hole requires a cement plug from at least 100 feet below the bottom to at least 100 feet above the top of each oil or gas zone. A minimum 200-foot cement plug must be placed across all fresh-saltwater interfaces or within a thick shale if the shale separates the fresh water sands from the brackish or saltwater sands. Plugging in a cased hole requires that all perforations be plugged with cement, and that the plug extend at least 100 feet above the top of the upper most perforations, a landed liner, the casing cementing point, the water shut-off holes, or the hydrocarbon zone, whichever is highest. If there is cement behind the casing across the fresh-saltwater interface, a 100-foot cement plug must be placed inside the casing across the interface. If the top of the cement behind the casing is below the top of the highest saltwater sands, squeeze-cementing is required through perforations to protect the fresh water aquifers. Surface plugs require at least a 25-foot cement plug placed in the casing and the annuli of all casing strings at the surface.

The regulations specify that some P&A operations **may** require witnessing by a Division employee, at the discretion of the district deputy, and that some operations require witnessing. Witnessing the placement of cement plugs is optional. Operations that require witnessing include the location and hardness of cement plugs, cementing through perforations, and environmental inspection after completion of plugging operations. The operator is required to submit a detailed P&A report to the district within 60 days of the completion of P&A operations.

Each district has special abandonment requirements, resulting from unique geology and/or operational practices in certain fields. Field rules or field practice guidelines are issued for those special requirements that vary from the regulations and general P&A requirements described in the regulations and MOI. For example, Field Rules in the Bakersfield and Coalinga Districts, allow the use of sodium bentonite in well plugging operations with certain conditions and restrictions. Use of bentonite plugs is contrary to the federal UIC regulations at 40 CFR 146.10(a) regarding the requirement for the use of cement in plugging Class II injection wells. Additional information on the basis for those field rules were requested, but has not yet been provided by CDOGGR (as of June 23,2011).

Procedures for P&A are intended to isolate fresh water zones from the injection zone and hydrocarbon bearing formations, poor quality surface waters, and water zones of varying quality. Those objectives are generally met in wells plugged in recent decades. They are not always met in older wells due to plugging practices that were not as rigorous or protective of fresh water aquifers and other USDWs. However, deficient wells located within the AOR must be re-plugged or otherwise eliminated as a pathway for fluid movement, as a condition of approval of an injection well project.

In addition, USDWs containing more than 3,000 mg/L TDS are not protected to the extent that fresh water aquifers are protected from inflow of lesser quality waters. Placement of cement plugs is required at the BFW, but not at the base of other USDWs unless those depths happen to be coincident in a well. Protection from fluid movement into and between USDWs below the BFW depends partially on the presence of "heavy mud" in the casing/wellbore annulus and between cement plugs in the open-hole or inside casing strings. However, USDWs must be isolated from fluid movement exiting the injection zone and hydrocarbon bearing zones, by placement of sufficient cement volumes in the annular space and cement plugs above those zones. The presence of drilling mud may not prevent fluid movement between zones in the uncemented annulus, especially in the older wells within the AOR since the mud will degrade over time and not retain the density and other properties necessary to suppress fluid movement.

The requirements for witnessing P&A operations are somewhat flexible in that the district deputy in each district has the discretion to require witnessing or not for some plugging operations. Placement of cement plugs does not require the presence of a CDOGGR inspector, for example. Witnessing the tagging of cement plugs for proper placement and hardness, and the final site inspection for environmental compliance are requirements, and those are high priorities in the districts. However, in our view, the mixing and pumping of cement for placement of plugs is a critical step in the plugging operation that warrants the presence and monitoring of a CDOGGR inspector and should be witnessed whenever possible.

The option to use bentonite as a replacement for cement in plugging some wells in Districts 4 and 5 is contrary to federal UIC regulations which specify the use of cement in plugging Class II injection wells. The basis for that option is not clear from a review of the CDOGGR regulations, MOI, EPA Questionnaire responses, and other references to P&A requirements. CDOGGR should provide the basis for the use of bentonite instead of cement in plugging operations in those districts. District 4 was requested to provide that information and the district deputy agreed to that request, but that had not been received as of June 23, 2011.

UIC STAFF QUALIFICATIONS

The district offices provided organization charts and position descriptions for district level staff positions, which are included in Section 4 and in the appendices to this report (Appendix A5 for the overall CDOGGR organization chart, Appendix B1 for District 4, and Appendix B2 for District 2). Based on a review of staff qualifications and responses to the EPA Questionnaire and questions raised during the on-site visits, most district personnel appear to possess the necessary qualifications for the positions they hold. A general assessment of staff qualifications was based primarily on discussions with district management and staff.

Additional UIC specific training for the less experienced staff members would be beneficial to the CDOGGR UIC Program. Some have not attended the EPA sponsored UIC Inspector Training Course offered in nine EPA regional offices annually on a rotational basis between EPA offices. Attendance at that training course by new hires and the less experienced staff members would enhance staff qualifications and should be a priority for the districts.

The overriding concern with regard to staff qualification is that the districts lack sufficient personnel to adequately manage and implement the Class II UIC Program, especially with regard to the standards set forth by Division management in the Division Expectations Memorandum. As a result of implementation of these new standards and expectations, completion of reviews for UIC project applications has been delayed, especially in the largest districts. However, some districts have not yet fully implemented those standards, and are awaiting further clarification and/or modification before acting on the new Division directives from that memorandum.

Comprehensive annual UIC project reviews have also been limited to the most critical projects in some districts. Additionally, more MITs and P&A operations could be witnessed and more annual inspections could be performed if there were sufficient numbers of qualified staff in the district offices. However, we were informed by district management that authorization has been given to hire several additional personnel for implementation of the UIC Program. That authorization should substantially improve the quality of the CDOGGR UIC program at the district level when the new positions are filled and the new hires complete the CDOGGR UIC training program.