

Peer Review
of the
Alaskas Class II
Underground Injection Control Program



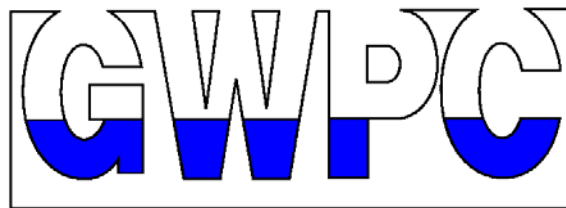
A Report of the



2002

PEER REVIEW REPORT ALASKA UIC CLASS II PROGRAM

Final 10/22/03



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CLASS II UIC PEER REVIEW

INTRODUCTION

The findings included in this report and any comments added subsequent to this report are the result of an ongoing effort to evaluate the effectiveness of state programs to protect Underground Sources of Drinking Water (USDW) from potential contamination resulting from the operation of injection wells related to the production of oil and gas (Class II injection wells). A USDW is defined as an aquifer or the portion of a geologic unit which supplies a Public Water Supply contains sufficient water to supply a public water system, and contains a concentration of less than 10,000 mg/l total dissolved solids (TDS) and which is not otherwise exempted as a USDW. Individual states may have definitions, either by statute or regulation for waters designated as fresh, potable, usable, etc. Such waters generally have maximum TDS concentrations, which are equal to or more stringent than the Federal maximum TDS concentration for USDWs. These definitions were historically carried over into the Underground Injection Control (UIC) regulatory program from preexisting statutes, regulations and /or policies. In this report, where other definitions of a USDW are part of the state program, they are highlighted in the General Program Comments and Observations portion of the report. Readers will need to exercise care when using this report to understand specific relationships between USDWs and those more restrictive definitions of water used by the state. The Review Team's conclusions are in every case based on the protection of USDWs.

The UIC program examined in this study covers wells which are used for the injection of fluids into oil reservoirs for the purpose of maintaining producing formation pressure, stimulating or furthering their production when natural (primary) production mechanisms decline or cease (enhanced oil recovery (EOR) and wells for the disposal of approved wastes generated during the drilling for oil and gas and waters produced in conjunction with the production of oil and gas (disposal wells). If improperly constructed, operated, maintained, or abandoned, such wells may allow contaminants to enter USDWs potentially depriving the public of current or future water supplies.

This program evaluation was conducted under the auspices of the Ground Water Protection Council (GWPC)¹. The program examined in this report is the Alaska Class II UIC program administered by the Alaska Oil and Gas Conservation Commission (AOGCC). Primary enforcement authority was delegated to Alaska in 1986 by the US Environmental Protection Agency (EPA) under provisions of Section 1425 the Safe Drinking Water Act (SDWA) and EPA regulations. (See following UIC Development Section of this report). The Alaska Class II UIC program was first evaluated in 1991 as a

¹ **The GWPC is an association of state and federal UIC officials, representatives of the regulated community, consultants, environmental groups, academia and other interested parties. The GWPC promotes and facilitates communication and exchange of information with regard to practices and regulation of injection wells. The organization also promotes the best practices for the protection of ground water and the principles of source water planning. The GWPC further promotes related research and the dissemination and exchange of technical data on injection well technologies and general protection of ground water through integrated and coordinated methodologies.**

part of a series of peer reviews, which GWPC, then the Underground Injection Practices Council, sponsored between 1989 and 1992.

The purposes of the State Class II reviews are as follows:

- (1) To determine the effectiveness of state UIC programs to protect USDWs
- (2) To increase the knowledge of the oil and gas producing states of the content and operation of the various Class II programs and to identify evolutionary program changes since UIC programs were first granted primacy by EPA or instituted as Direct Implementation by EPA.
- (3) To assist the states and GWPC in identifying potential problem areas in the Class II UIC program resulting from statutory and philosophical changes at either the Federal or State level or from economic cycles within the oil and gas producing industry.
- (4) To provide states an independent evaluation of their Class II UIC program and to provide non-binding recommendations for program improvements.

This Peer Review was conducted and completed in the following manner:

A Review Questionnaire Workbook was prepared containing numerous questions about the important aspects of a state's Class II UIC program, including:

- A) Permitting and file (compliance) review (the process by which new injection well applications are examined, technically reviewed and approved);
- B) Inspections (the process by which actual injection well operations are examined for compliance with rules and permit conditions by regulatory agency field personnel);
- C) Mechanical integrity testing (the process by which wells are tested to ensure that injected fluids are confined in the well bore and target formation and to certify no upward migration of fluids is occurring along the back side of the well casing);
- D) Compliance and enforcement (the process used to assure that compliance with all state UIC regulations and permitting requirements is achieved and, where appropriate, penalties are sought and enforced);
- E) Plugging and abandonment (the process by which assurance is made that when there is no longer any use for the well as an injection point, it can and will be plugged in a manner to prevent the movement of fluid into a USDW);
- F) Inventory and data management (the process by which important program data is organized into usable formats to demonstrate program compliance and evaluate risk of injection well use); and
- G) Public outreach (the process used by the agency to keep the public aware of developments and permitting activities in the UIC program).

The Peer Review Questionnaire Workbook was furnished to the AOGCC and the AOGCC staff responsible for managing the UIC Class II program completed the questionnaire. The State submitted whatever additional material they thought would be helpful to the reviewers in understanding the program

The Review Team was assembled and given copies of the completed Workbook prior to traveling to Alaska. The Review Team consisted of two state UIC program directors or their immediate subordinates, a GWPC contract employee (a former state oil and gas division director) and the GWPC Associate Director. The Review Team members for the Alaska Review are identified at the beginning of this report and resumes' for each are included in the Alaska report appendix. Representatives from EPA, both Region 10 and Headquarters Office of Water participated in the Peer Review as observers.

The Review Team traveled to Anchorage, Alaska and using the completed Workbook as a guide, questioned the UIC personnel and other persons designated by the State to participate in the Review extensively about the operation of the various program areas. Additionally, the Review Team was given a complete tour of the UIC offices and the area of operations where UIC data management activities were conducted. The Peer Review was conducted over a 5-day timeframe including the briefing period on the Sunday preceding the beginning of the actual review, and a tour of a North Slope injection facility mid-way through the review.

The Review Team reviewed the written Workbook responses to questions, the oral responses to questions given at the time of the visit, and the various documents supplied by the State and daily prepared a list of strengths, areas of concern and subjects which required additional discussion to understand the situation. These questions were discussed with AOGCC staff at appropriate times during the following days. An exit interview was conducted with the AOGCC Commissioners and UIC staff at the end of the review and which consisted of a summary of major points of concern to the Reviewers. The exit interview was also an opportunity for the Review Team to stress the strong program elements. A draft report was then prepared by the GWPC contractor and sent to the State and the Review Team for final comment. Where appropriate, corrections supplied by the State in the form of clarification or supplemental information were incorporated into the report.

The Review Team report and evaluations are generally arranged in the same order as the Workbook. Each section is followed by identified strengths and other considerations of the Review Team. Any such comments are followed by the Review Teams conclusions relative to the effectiveness of that portion of the State's UIC program in protecting USDWs. Where portions of the report, strengths, other considerations or conclusions did not fit within one of the major program areas identified in the Workbook, they were placed in a General Program Comments and Observations section of the Report. An Executive Summary precedes the specific technical subject sections. "Data Management" and "Program Changes since 1990" were included in the Workbook for each Section. In a sense, Data management is a crosscutting issue and a State response may apply to more

than one Section. These issues are included in the report at the most appropriate place for the discussion.

ALASKA CLASS II PEER REVIEW

EXECUTIVE SUMMARY

The peer review of the Class II UIC program administered by the AOGCC was conducted from July 14-18, 2002, at the AOGCC office in Anchorage, Alaska. On July 17, 2002, the Review Team toured a Prudhoe Bay (North Slope) injection facility. The review team consisted of one state oil and gas director from Montana – the state with one of the most recently approved UIC programs, one state UIC program director from Texas – the state with one of the first programs to receive primacy, one former state oil and gas division director from a state with 14,000 injection wells and a GWPC Associate Director. The EPA had three representatives: one UIC Class II Project Officer for Region X, a contractor to Region X who does UIC program work, and the Chief, Prevention Branch (UIC Program) from EPA Headquarters Office of Water.

The review was conducted using a comprehensive questionnaire completed by the state UIC personnel and on the basis of the response, asked in-depth questions of the AOGCC Commissioners and technical staff and other personnel made available for responding to specific areas of agency operations which have some effect on UIC activities. One of these presentations was on the data management system, which is a work in progress. The AOGCC staff also provided statutes and rules, and other administrative and technical documents and materials relating to agency procedures, interagency agreements and statistical information, which gave insight and understanding to program operation and state organizational matrix. The questionnaire originally completed by the AOGCC is included in the appendix of this report along with other materials on organizational structure of the Commission, UIC program and other associated activities. Principal forms used for UIC inspections, mechanical integrity tests (MITs), complaint investigations and required operator reporting forms are also included for reference.

A list of acronyms is included at the end of this document on page 52

PERMITTING/FILE REVIEW

The AOGCC office in Anchorage issues all UIC Class II well permits. The UIC application review process is well conceived and designed to provide the best possible technical and administrative judgment of proposed Class II wells. Most of the UIC applications reviewed by AOGCC are for wells located in environmentally sensitive areas, but where USDWs do not exist. Alaska is unique with only two producing petroleum regions and twelve operators. Alaska also differs from other states in their approval of large area permits (area injection orders). The AOGCC also approves applications for individual well permits. The low number of operators (currently 12) allows AOGCC to have pre-application filing conferences on many proposed area injection orders. This is a luxury Alaska currently has but may not have in future years if both the number of filings and operators increase. The pre-application conference allows

the UIC staff to concentrate on the technical issues and streamlines the application completeness process. The application requirements for permits to drill and operate UIC Class II wells are very detailed and require an experienced technical staff (petroleum engineers and geologists), which the AOGCC has, to properly review applications. File reviews² are still done, but are conducted more in the sense of compliance reviews. Casing and cementing requirements assure good protection to USDWs.

The Review Team originally had some concern that there did not seem to be an aquifer map of Alaska outlining areas of USDWs and their inherent quality. This concern, however, was lessened after the Team learned of the amount of information that the operator (applicant) had to provide and includes a review of the Alaskan aquifers. Much of the North Slope and offshore Cook Inlet are without USDWs; this allows the AOGCC to grant waivers to certain cementing, operating, and plugging requirements.

The Review Team believes that the AOGCC should review its financial assurance levels and methods in anticipation that smaller, independent operators may increase in number.

The Review Team also recommends that written correspondence regarding incomplete applications and the setting of time limits to complete applications would improve the permitting process.

The Review Team concluded that the permitting process implemented by AOGCC provides for the protection of USDWs.

INSPECTIONS

Five inspectors currently perform field inspections. This is an increase over the three inspectors employed by AOGCC in 1991. The Inspectors work throughout Alaska and are not specifically assigned to the North Slope or Cook Inlet. The schedule worked by the Inspectors is two weeks on the North Slope, one week off on call for Cook Inlet operations. The AOGCC shares living and office spaces with other state agencies on the North Slope. The sharing of the North Slope office in Deadhorse with the Department of Natural Resources (DNR) and Alaska Department of Environmental Conservation (ADEC) field inspectors has a potential for positive interagency communication. The inspectors are all trained people with field experience in oil field related activities. Class II wells require a MIT either on a two- year or four- year schedule. When the injection wells are required to have surface and/or subsurface safety valves, the valves are tested every six months. The testing program and in general, the high quality of operators allow for a good routine inspection program. Inspectors routinely witness a large percentage of

² File Review as used here is an effort by AOGCC staff to self-manage the accuracy of technical and administrative processes and to compliment the compliance efforts of industry. File reviews are triggered by actions such as administrative approvals, requests for waivers, sundry applications, drilling permits, etc.

the safety valve and mechanical integrity tests (80% MITs; 30% safety valve on an annual basis – 2002 statistics).

The Review Team had some concern over the fact that the Inspectors do not receive the same level of training in environmental activities normally associated with inspections of oil field facilities, such as sample collection, chain of custody and orderly documentation as they do for oil field operations and safety related activities. On this point the AOGCC does not have the same concern because inspections of such matters are performed by the ADEC.

The Review Team found that this portion of the program was providing a high level of protection to USDWs; however, some reassessment of program procedures may have to occur if a different mix of operator begins to operate in Alaska. The Review Team and the AOGCC staff discussed on several occasions as to what would happen if Alaska inherited a lot of independent operators with different financial structures and methods. The Review Team felt this was an important point when AOGCC prospectively reviews its regulations and procedures for future revisions.

MECHANICAL INTEGRITY

Alaska primarily uses the standard inner-annulus pressure test as the demonstration of Part I mechanical integrity and the cement records for the verification of Part II. Cement bond logs are required on all new injection wells. Other evaluation logs, including oxygen activation logs, temperature surveys and radioactive tracer surveys may be used supplemental to regular testing. Operators are expected to comply with the testing schedule; AOGCC does provide periodic reminders of upcoming MITs. Because of the uniqueness of the North Slope and Cook Inlet (arctic environment/weather, efficiency), operators prefer to test wells in the summer time. AOGCC is able to witness about 85% of the tests. All Class II-R and some Class II-D wells³ are tested every four years. The remaining Class II-D wells, including those receiving drill cuttings slurry, are tested every two years. Annulus pressure monitoring is considered an acceptable method to demonstrate continued mechanical integrity once the initial pressure test has been passed.

The Review Team was somewhat concerned over the fact that a well with a failed MIT can continue to be used. Wells failing an MIT are generally promptly repaired. The Decisions to allow a well to continue to operate after failing a test are rational from a technical standpoint because they are in areas lacking USDWs and require additional and more frequent monitoring to ensure fluids do not escape to the environment. MIT schedules are set by regulation with more frequent testing conducted as needed. The operator is provided some flexibility in the actual date an MIT is performed to account for logistics, well operating conditions, inspector availability, and efficiency issues. The Review Team believes that after the Risk Based Data Management System (RBDMS) is validated it should be used to track and schedule MITs.

³ II-D is UIC Class II Disposal; II-R is Class II Enhanced Recovery

The Review Team concluded that this portion of the UIC program was being conducted in a manner to provide good protection to USDWs.

COMPLIANCE/ENFORCEMENT

The Commission has a variety of enforcement tools available to ensure operator compliance. These range from calling in a bond to ordering corrective action. They can also suspend or revoke a permit and seek civil penalties under statutory authority. They also have the authority to withhold subsequent approvals and pursue legal action or injunctive relief in the courts. With the quality of current operators much of the compliance is accomplished voluntarily after verbal notification of a violation by the AOGCC inspector or engineer. No formal enforcement actions for Class II have ever been filed, nor has EPA found occasion to over file or initiate its own action against an Operator. Much of the Review Team's evaluation is in the subjunctive and expressed what AOGCC would do if confronted with a given enforcement situation. The AOGCC has a good complaint tracking system and adequate follow up procedures by field and administrative personnel.

Some members of the Review Team believe AOGCC' compliance program should be partially self-funding in the sense that fines and penalties should go back into the agency's budget allocation to pay for the cost of investigation. The Review Team also believed that verbal direction to Operators to correct a problem should be followed up with a written notice. The Review Team believes that standard procedures should be developed outlining the type of non-compliance events where written notification to the operator is appropriate (and adopted in this regard.)

The Review Team concluded that, with the present group of Operators, this program is being carried out in a manner, protective of USDWs and other environmental resources.

The changing operator base in Alaska as the primary producing regions become more mature is inevitable. Smaller operating companies with fewer economic and personnel resources may not be managed as effectively with a voluntary compliance emphasis as is now possible with fewer large companies.

PLUGGING AND ABANDONMENT

The plugging requirements contained in the Commission rules and administered by the AOGCC are very specific to what procedures an Operator must use when plugging and abandoning a well under different completion and casing scenarios. Approval must be obtained from AOGCC prior to plugging any well. Cement plugs are placed above and below or across all perforations, at the top of any liners, at the surface casing shoe and at the surface. All casing annuli must be sealed. Essentially, all plugs must be tagged and

the AOGCC inspectors must be given an opportunity to witness the tagging. Inspectors witness about 60% of all well pluggings and particularly those where USDWs exist. Injection wells that are placed on inactive (shut in) status require AOGCC approval (not the case in 1991). There is still no time limit for wells to remain on inactive status. Shut in wells are reviewed each year.

The Review Team initially expressed some concern that shut in wells are not subject to periodic mechanical integrity testing, however, AOGCC staff provided clarification that shut in wells in Cook Inlet region where USDWs are present are subject to periodic MITs; shut in wells on N. Slope where no USDWs are present do not require periodic MITs, but are periodically monitored for indications of integrity loss. The Team also believes the AOGCC may benefit from the separate tracking of wells that are, by their definition, on shut in, suspended or orphan status. The AOGCC should consider the future benefit of a dedicated well plugging fund.

The Review Team concluded that this part of the Alaska program is providing adequate protection to USDWs. The Inspector cannot change a plugging program unless the reviewing engineer grants approval. The AOGCC may want to give the Inspectors authority to make minor modifications to a plugging program if certain unforeseen down hole conditions exist and the wait for engineering approval provides no additional protection to the USDWs or has a high cost to benefit ratio.

PUBLIC OUTREACH

The AOGCC informs the public of oil and gas activities including the filing of UIC applications through a mailing list of over two hundred persons and entities, to which anyone can subscribe. The public is also informed of UIC applications by legal notices placed in the Anchorage newspaper, the Alaska Administrative Journal and a paper in the area of the proposed injection project. The technical staff is always available to meet with interested groups and stakeholders regarding UIC issues on request. The AOGCC is encouraged to finalize the memorandum of agreement (MOA) with the ADEC to delineate the responsibilities of each agency for spill response and reporting, information sharing, and cleanup of any oil field sites if such ever occur.

The Review Team concluded that Commission public outreach activities are appropriate and have improved since the 1991 Peer Review. The AOGCC is sensitive to the needs of the public to be better informed on UIC matters.

Overall Assessment

The Review Team performed a rigorous review of the Alaska UIC Class II program over a 5-day period. Information provided by the AOGCC prior to the Peer Review enabled the peer reviewers to make best use of their time while in Alaska; the comprehensive response to the review questions were complete and accurate, as was

confirmed by the verbal section of this review. The Review Team was generally impressed with the quality of staff, the attention to detail, and the work product created by AOGCC regarding the Class II UIC program.

Recommendations have been provided to the AOGCC and represent opportunities to further strengthen the UIC program. In all areas investigated as part of this Peer Review, the AOGCC managed program has been found to provide the necessary protection of USDWs.

PEER REVIEW OF THE ALASKA CLASS II UIC PROGRAM

ALASKA OIL AND GAS CONSERVATION COMMISSION

TEAM REPORT

REVIEW TEAM MEMBERS

Tom Richmond	Administrator/Petroleum Engineer Montana Board of Oil and Gas Conservation
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PART I: GENERAL: ADMINISTRATIVE OVERVIEW

A. Statutory Authorities and Regulatory Jurisdictions

Overall responsibility for the Alaska Class II UIC program is mandated to the AOGCC. The AOGCC is comprised of three commissioners and is a quasi-judicial agency within the executive branch of the State of Alaska. The AOGCC derives its authority from the Alaska Oil and Gas Conservation Act, Title 31 AS 31.05.005 through 31.05.170. AS 31.05.030(c) provides the AOGCC authority to promulgate regulations. The statute requires that two of the three commissioners must be technically qualified (one petroleum engineer and one geologist) while one must be a public member (with or without oilfield knowledge and experience). At the time of the 1991 review, each commissioner was assigned responsibility for a program area and carried out reviews and technical program evaluations similar to those routinely performed by technical staff. The commissioners have overriding approval and policy responsibility, including UIC authorizations, and still review much of the documentation generated by the regulatory program. Most of the technical review and coordination of field inspection activities, however, is now implemented through one of the Petroleum Engineers. The Commission staff is composed of three technical teams, one focused on North Slope activities, one for Cook Inlet activities, and one that provides technical support for the other teams. During the writing of the Review team report AOGCC advised that it has recently realigned staff into 2 decision teams and 1 team with UIC, inspection, and policy related functions. The 2 decision teams split the state geographically along a north-south line: West - Kuparuk/Cook Inlet West/Cook Inlet Offshore; East – Prudhoe/Cook Inlet Kenai. The major shift is to move inspections to the Policy & Inspection team that supports both decision teams.

B. Historical Perspective on Alaska Oil and Gas Production and Injection

The first commercial oil well was drilled on the Kenai Peninsula /Cook Inlet Area in 1957. The first North Slope commercial oil well was drilled near Prudhoe Bay in March 1968. It was the Prudhoe Bay State No. 1. In 2001, Alaska produced 381 million barrels of oil and condensate as compared with 680 million barrels in 1991 at the time of the first UIC Peer Review. The peak production year was in 1989 when 703 million barrels were produced. In 1991, 539 million barrels of water was produced, 827 million barrels of water was injected for enhanced recovery and nearly 126 million barrels of wastes was disposed of by injection. By contrast in 2001, nearly 820 million barrels of water was produced, 930 million barrels was injected for enhanced recovery and 102 million barrels of waste was disposed of by injection. Alaska production is currently from 2371 oil and 181 gas wells. Thus far, commercial gas production is not a major factor on the North

Slope of Alaska. In 2001, 250 new⁴ wells were drilled. In 1991, the AOGCC regulated 39 Class II-D wells and 578 Class II-R wells. In 2001 this figure had risen to 58 Class II-D wells and around 1000 Class II-R wells. The producing oil formations range in depth from about 4,000 feet to around 12,000 feet. Alaska also has 6 Class I disposal wells, all located on the North Slope, which are regulated by EPA under their Direct Implementation (DI) program.

C. Staffing and Funding

There are 27 budgeted positions in the AOGCC. Table 1 shows the 19 positions that are primarily involved in UIC activities. In 1991, the AOGCC had 20 total positions including the three Commissioners.

Table 1 - AOGCC Staff Involved in UIC

Position	Primary Responsibilities
Commissioners (3)	UIC authorizations, policy, oversight
Petroleum Engineers (3)	Well design and operation reviews; inspection oversight; MIT reviews; P&A reviews; program management ⁵ ; review Orders and recommend operating rules; investigations.
Geologists (2)	Geologic review for Permits to Drill; Orders; Aquifer Exemptions
Reservoir Engineers (2)	Provide review of reservoir issues; coordinate preparation of orders
Inspectors (5)	Inspection responsibilities; witnessing MITs and P&As
Statistical Technician (2)	Data management
Administrative (2)	Files management, reporting, project tracking, UIC grant application administration

The following tables were provided to the Review Team to show the amount of time and expenditure for UIC versus the total AOGCC budget. As shown in Table 2, the total budget for AOGCC has increased from 1.66 million in 1999 to approximately 4.15 million for Fiscal Year (FY) 2003 (the current fiscal year). The EPA grant was \$119,000 for Federal FY2002 with small prospect for an increase in Federal FY2003 (starting Oct. 1, 2002). In FY 2000, the federal UIC grant funded 53% of the allocated UIC costs. In FY2002, the federal share of the program had decreased to 48% of the allocated cost. The AOGCC indicated that the technical and administrative support is adequate to maintain the UIC program based on the assumption that the state is willing to fund an

⁴ There were 250 “grass roots” wells (new surface penetrations; there were 366 new wells including sidetracks.

⁵Program Management as referred to here includes public outreach, clarifying and interpreting regulation, recommending operating guidelines.

increasingly larger share and EPA finds the level of effort acceptable. One improvement over the findings in 1991 is that in FY2000, the Legislature authorized the AOGCC to receive program receipts determined by a formula based on volumes of production and fluids injected. The UIC grant money is directed specifically to AOGCC budget, not the general revenue funds. There is no person on the AOGCC staff whose time and responsibility is dedicated strictly to UIC. This division of responsibility is reflected in Table 3.

Table 2 - AOGCC Budget by State Fiscal Year

State FY	Total Budget (\$1000)	Budgeted Personnel
1999	\$1660	19
2000	\$2450	23
2001	\$2910	23
2002	\$3420	24
2003	\$4151	27 + 1 Seasonal Inspector

Table 3 – UIC Expenditures by State Fiscal Year

State FY ⁶	FTE (Total)	FTE (UIC)	UIC (\$1000)		% Total Work directed at UIC				
			Actual	Grant	Eng. ⁷	Geo.	Insp.	Admin	Mgt
2000	16.24	2.54	\$188.8	\$100	20	15	14	20	12
2001	16.30	2.88	\$224.5	\$119	19	11	24	28	7
2002	16.85	2.61	\$260.5	\$119	15	9	20	29	8

In gathering information for table 3, it has become evident to the Commission that some of the UIC work levels are under reported. Administrative staff time dedicated to UIC work is currently not tracked. The AOGCC plans to review the inspectors’ time allocated to UIC in reference to how MIT, as a core inspection activity, is reported on time sheets.

A sixth full-time inspector and one half-time inspector have been approved for FY 2003.

D. Inventory Maintenance and Data Management

The AOGCC uses several electronic data systems to assist management of the UIC program. These include Geoframe, the RBDMS and a document imaging technology. None of these systems were in use when the 1991 review occurred. At that time, all UIC documents were processed and managed manually as hard copy files. The agency goal is to integrate all the systems using a front-end Geographic Information System (GIS). The Staff is optimistic that eventually a system-wide data management program can be constructed that will significantly enhance data access and exchange with other agencies through incorporating GIS capabilities. Limited external access is currently provided to production and injection data maintained by AOGCC. AOGCC note: Public and other

⁶ State FY runs from July 1 through June 30.

⁷ Engineering includes past position labeled “Natural Resource Manager”

agency access to AOGCC production and injection data is currently available by a FTP site maintained by the AOGCC; production and injection data are updated monthly – address is <ftp://puboil@transfer.state.ak.us>; RBDMS access is not currently available to the public. The AOGCC and Alaska Department of Natural Resources (DNR) have jointly applied for a U.S. Department of Energy (DOE) grant to enhance the State’s overall data management system. The RBDMS system is currently intramural and cannot be accessed by other state agencies. The AOGCC continues to evaluate the effectiveness of RBDMS. Copies of mainframe files and well log digital data are available on the State FTP site for public download. In relation to the various UIC program elements, the following applies:

- (1) Permitting -- Hardcopy wells files, have been used since the agency’s inception. Pre-1981 mainframe applications existed since the early 1970’s. Mainframe programs and current record formats (include well permits, drilling production and injection data) were established in 1981-2. RBDMS installation began in November 2001. Upgrades during June 2002, have given the AOGCC a partial ability to use the database. Additional visits by the consultants involved with the RBDMS installation are necessary before full implementation of the system can be realized.
- (2) Inspections -- The Microsoft Access database used for Inspections was established in 1996 and is used primarily for MIT data. The Inspectors currently do not have full access to all information in the field. Cost effective, reliable communication between Anchorage and the North Slope is challenging. At the time of this review, the only external electronic information that inspectors can access is the Orders on the AOGCC website. Past inspection reports are on the computers in the North Slope Office. When the RBDMS is fully installed, a copy of all databases will be on the computers in the North Slope Office. The AOGCC staff indicated that even without enhanced data management tools; the communication between the Anchorage staff and Inspectors has overcome whatever shortcoming may exist. Direct access to information from other agencies has been limited to what they have posted on their website.
- (3) MITs --- Operators submit most MIT and safety valve test results by email. Production and injection data are also received electronically from the Operator. Internal datasets (Access and Excel) have been in use by the AOGCC staff since 1996. The RBDMS inspection module was not installed at the time of the 2002 review.
- (4) Plugging and Abandonment --- The AOGCC maintains an inventory of wells in Alaska and their last known status. These are on mainframe programs described above. Operators and inspectors can submit plugging reports and documentation by email. This file is intramural.

E. Interagency Coordination

There are 3 major state agencies involved with resource development in Alaska.

The Alaska DNR has 2 divisions dealing with oil and gas: Division of Oil and Gas and Division of Mining, Land, and Water Management (DMLWM). The Division of Oil and Gas is responsible for leasing and lease administration [approving post lease activities]. The DMLWM issues land and water use permits for exploration and development projects.

The ADEC has responsibility for pollution abatement (air, land and water) and all waste management functions with the exception of the Class II program. ADEC also coordinates spill planning and emergency response in the event of an incident.

The AOGCC is charged by statute to prevent waste, protect correlative rights and protect fresh water. AOGCC is responsible for permitting all wells within the state where the state has police power. Wells are classified as exploration/delineation, development (oil or gas) and service (Class I, II-R or II-D)⁸.

The AOGCC provided the Review Team with copies of the current MOA and Compliance Assurance Agreement with the EPA. The current MOA has been in effect since November 1991. The Compliance Assurance Agreement has been in effect since November 2, 1987.

The AOGCC, in cooperation with the DNR and the ADEC have leased a “camp” facility at Deadhorse on the North Slope. This facility provides office and sleeping quarters for the inspectors. In 1991, all AOGCC inspectors were stationed in Anchorage. The ADEC and AOGCC are trying to formalize an agreement to delineate jurisdiction and coordinate matters such as spill response coordination, waste management and quality assurance.

At the outset of a project in the coastal zone, the Division of Governmental Coordination (DGC) provides an opportunity for all resource agencies involved in a project to determine consistency with the State’s Coastal Zone Management (CZM) Act. DGC coordinates permits from several State resource agencies and provides a forum for public participation in the process. AOGCC permits are issued subsequent to CZMA reviews. Following CZM approval, ADEC is provided opportunity to comment via copies of notices for all applications for injection and aquifer exemption as they are considered. They also receive copies of all Permit To Drill (PTD) approval letters. Complaints and emergency response coordination between AOGCC and ADEC is currently handled by informal arrangements; these will be formalized in a MOA between AOGCC and ADEC.

F. Summary of UIC Program Changes since 1991 Review

The AOGCC was delegated program primacy from EPA on June 18, 1986. The first Peer Review for Alaska was carried out in September 1991. The current MOA for the UIC

⁸ II-D is UIC Class II Disposal; II-R is Class II Enhanced Recovery

Class II Section 1425 primacy program between the AOGCC and the EPA was signed on November 22, 1991. Class II UIC regulations were promulgated prior to the MOA signing date and provided for AOGCC's authority to regulate all oil and gas field related UIC activities. The EPA administers the program for Class I UIC in Alaska under Direction Implementation by Region X. Some injected waste related to North Slope oil field production fall under this category because, by EPA interpretation, they are not fluids brought to surface in connection with the production of oil or gas.

Since 1991, the AOGCC has effected enhancements and clarifications to their Class II UIC regulations, however, few changes to the intent of the rules have occurred. The AOGCC has enhanced its staff through the addition of personnel. No administrative or technical program changes have been made to accommodate more recent Federal mandates such as the passage of the Safe Drinking Water Act Reauthorization of 1996 (i.e., Source Water Protection or Watershed Quality Management). The SARA Title III program or the Emergency Planning and Community Right-To-Know Act (EPCRA) has not impacted the efficiency of the program as administered by the AOGCC.

Class II-D slurry injection wells are a new development since 1991. The frequency of MIT was established at every two years for these wells. An annual reporting requirement was also established for these wells.

New regulations pertaining to shut-in wells were incorporated into the AOGCC regulations in November 1999 (20 AAC 25.115).

G. North Slope Field Trip

The Review Team made a field trip to the North Slope during the review. The field trip involved both site visits and drive-by views of production facilities where produced water is separated from crude oil, injection wells, produced water disposal wells, oily waste disposal facilities, pit closure and reclamation operations and outdoor storage cells. The Review Team was able to visit with both production and environmental personnel from British Petroleum, Alaska, Inc, (BP) who gave a presentation on the total waste management program. The team also visited a Class I Injection Facility Plant and the Grind and Inject Plant (Class II). The tour took place in the Prudhoe Bay area.

Most of the 819.8 million barrels of water produced during 2001 along with the crude oil is reinjected into the producing reservoirs for secondary recovery purposes. The injection and disposal wells are equipped with gauges required for periodic testing of mechanical integrity. Observed pressures were within approved limits. The Grind and Inject facility, which injects a slurry of ground up real-time drilling waste plus materials reclaimed from efforts to close out waste pits on the North Slope, was idle at the time of the visit due to scheduled maintenance. At the time of the 1991 Review, a previous ball mill facility where cuttings were ground to a fine powder for disposal into a deep zone, was an experimental project. The reclamation of old drilling and reserve pit areas continues.

There are 6 Class I wells in Alaska that are regulated by EPA under Direct Implementation. In addition to non-hazardous industrial waste, produced water and other Class II wastes are disposed into these Class I wells. The Review Team visited BP's Pad 3 facility in the Prudhoe Bay field which has 3 of the Class I wells; the other wells are located at the Badami, Alpine, and Northstar fields.

Injection into Class I wells has accounted for just 1% of the total fluids injected to date. As of 5/28/2002, Class II wells in Alaska have received 1,649,803,933 barrels of fluid and Class I wells have received 15,227,528 barrels of liquid waste.

Identified Strengths

1. The Commissioners demonstrate a real interest in all phases of the regulatory program, as was shown by the daily participation of one or more of the Commissioners in the Review. This interest and level of hands-on knowledge of the regulatory subjects may be unique and does not generally occur in oil and gas regulatory programs with larger staffs. The Commission has a well-defined organizational pattern designed to ensure quality coverage of all regulatory areas.
2. The increase in the number of professional staff and field inspectors is commended. This will allow AOGCC to keep up with the demands of the regulatory program and the increased workload, which additional wells and new operators are expected to bring.

Comments and Recommendations

1. The AOGCC has devoted considerable time to improving its data management systems. The installation of the RBDMS is a work in progress and should be fully operational in the next two years. The Review Team compliments AOGCC for embracing RBDMS and urges it to develop compliance schedules for operators. RBDMS may also be useful for developing inspection schedules for AOGCC staff.
2. The AOGCC currently has primacy for over 1000 Class II wells and EPA has regulatory authority over 6 Class I wells on the North Slope under Direct Implementation. The AOGCC, however, has authority over well drilling, construction and sundry operations. This leaves operators dealing with two regulatory entities to satisfy. It is the understanding of the Review Team that the matter of sanitary wastewater being injected is the major distinction to cause the wells to be categorized as Class I. The Review Team recognizes this situation as inefficient regulation and suggests authority over the wells be fully delegated to the AOGCC. The Review Team recommends AOGCC and EPA Region 10 continue their discussions over what fluids are appropriate for Class II wells.

3. The AOGCC and the ADEC should adopt a MOA to address jurisdiction, coordination, and information exchange.

The administrative program conducted by AOGCC is very well organized and provides a close working relationship with the technical, field services and support staffs while maintaining a proper balance to guarantee efficiency. The AOGCC is currently making dynamic improvements to its data management system, which will benefit not only its own program goals but also transfer of information to other agencies and the public. Development of working relationships with other state agencies having cross cutting responsibilities continues to improve.

PART II: PERMITTING/FILE (COMPLIANCE) REVIEW

A. Permitting Flow and Processing Procedures

As was pointed out in the 1991 Peer Review, Alaska is unique among the major oil and gas producing states in the nation. There are only two producing areas in the state, the North Slope and the Cook Inlet. In 1991, there were only six operators, all of them major companies. Of the 12 active operators in Alaska, only 6 currently operate injection wells (90% of the injection wells are operated by BP, Conoco/Phillips, and Unocal). Essentially all the wells within the developed areas of the State have been drilled, completed and plugged in accordance with modern standards. Alaska has no commercial Class II facilities or wells. In the 1991 Report, the AOGCC staff indicated that all UIC well permits in existence when Alaska received Class II primacy from EPA in 1986 were re-permitted as a part of the newly acquired program. The AOGCC provided the Review Team with a flow diagram showing the typical progression of permits and applications through the AOGCC review process from the first operator contact with the Commission to the point of final action on an application where the permit is either granted or denied. AOGCC also provided a detailed flow diagram of the process for approving an Area Injection Order (AIO). The Disposal Injection Order (DIO) and Aquifer Exemption Order (AEO) process follow similar lines of review and approval process. The AOGCC also uses a Permit to Drill (PTD) and a Sundry Notice process that apply to the drilling and completion of UIC wells.

An AOGCC PTD is required for all wells in Alaska. When the EPA authorizes the construction of a Class I well, the operator will secure an AOGCC PTD to drill and equip the well to EPA requirements.

The AOGCC makes a distinction between PTD which means a “permit” and an “application” which includes an AIO, DIO or AEO. The AIO’s are essentially area permits that apply to a single operator and unit and define the geographical area and depth of the proposed injection project. The AIO’s outline the imposed general permit

conditions. Permits to Drill cover individual injection wells. This is a different approach than is used in most states where the operator is issued well-by-well UIC permits. The Operator, however, must have an approved PTD for each new well or an approved sundry notice for the conversion of an existing well.

The Operator initiates an application for AIOs by filing appropriate information as specified in 20 AAC 25.252 (Underground Disposal of Oil Field Wastes and Underground Storage of Hydrocarbons), or 20 AAC 25.402 (Enhanced Recovery Operations). Data submittal requirements are extensive and include a plat showing all existing and proposed well locations, any wells that penetrate the injection zone within one-quarter mile of each proposed injector, a list of operators and surface owners within one-quarter mile radius of each proposed injector, an affidavit confirming offset operator notification, names and descriptions of the reservoir (s) that will be affected, engineering and geological data on the injection zone and confining layer, well casing program, injection fluid description, estimated average and maximum injection pressure, fracture pressure data, formation water analysis, estimated incremental oil recovery, logs of the injection wells if not on file with the AOGCC and a description of the proposed method for demonstrating internal and external integrity.

The Operator may choose to meet with the technical staff in a pre-application process that provides a cooperative exchange that is non-binding and not a part of the administrative record, but is designed to share as much information as possible on the proposed project. Upon filing of an application, AOGCC administrative personnel log and date-stamp all applications when applications are received. Copies are distributed to all Commissioners and assigned to a Review Team consisting of a Geologist, Reservoir Engineer and a Petroleum Engineer. The Review Team is responsible for determining application completeness and if an application is found incomplete, a telephone call or e-mail is generally made to the Operator for additional information. No further action is taken on the application until the information is received. No time limitation is set for response since delay by the Operator is in a sense a penalty on him. If the Operator decides to withdraw the application, the Commission retains one copy for a record and returns the balance of the copies to the Operator. The request by the Operator for withdrawal must be submitted in writing.

All permit applications are logged as they are received. Administrative staff tracks the progress of Orders, PTDs, and Sundry Notices using Microsoft Excel, RBDMS and Microsoft Project. The Commissioners have weekly staff meetings to review timing on actions. A complete application is one that includes all requested information; it may or may not be technically accurate or acceptable. When the application is determined to be complete, the Commission provides public notice of receipt of the application in appropriate newspapers and state administrative journals. If requested by a member of the public, the Commission may conduct a public hearing. After hearing, or if no hearing is held, the Commission issues the AIO or DIO. The Commission indicated to the Review Team that they had experienced very little interest from the public in UIC applications. The same hearing process applies to amendments to existing applications, however, existing approvals (e.g. AIO, DIO), generally contain a provision that allows the

Commission to administratively waive or amend promulgated rules in an Order unless the action requires notice and hearing.

Official copies of all permits are retained as permanent hard copy at the AOGCC office. Microfilmed copies are stored both on and off-site. The Commission has recently initiated an effort to image all Commission records so that they will be accessible to the public on the web.

The AOGCC requires Petroleum Engineers and Geologists to review UIC applications as members of a Technical Review Team. The Petroleum Engineers must have a degree in engineering from an accredited university and at least 10 years of professional experience involved in drilling, development or production. Geologists must have a Masters Degree and at least 8 years of professional level experience in petroleum exploration and development geology or a Bachelor's degree and 10 years of experience. The current AOGCC technical staff has considerable professional experience in dealing with Alaska oil and gas production.

B. Current File and Compliance Review Processes

The AOGCC described the permitting process in 1986 as satisfying a dual purpose of a file and compliance review. In their current program, AOGCC staff initiates file reviews upon receipt of any proposed change in well activity or status in a given area. When an existing producing well is proposed for conversion to injection service, the available file information is reviewed to determine if the necessary construction requirements have been met. Compliance with all reporting requirements and a review of the applicable Orders is also performed as part of the file review. When deficiencies have been identified, the operator (applicant) is contacted to provide additional information even if this involves acquisition of new data or information.

In each case, the reviewer completes a summary of the file review, which includes recommended action that is forwarded to the Commissioners for approval or denial. A copy of the review summary becomes part of the administrative record file. File reviews are also performed as a part of the MIT (Part I or II). Between five and ten percent of the Class II wells (50-100) are reviewed annually as a part of the MIT Part II evaluation. The normal file review, without complications such as missing information or amended orders, takes about two hours to complete. The AOGCC does allow the operator to continue injecting where identified deficiencies are minor or of a "paper" nature. If the review discovers serious deficiencies such as safety or threat of fluid movement outside the wellbore or confining layer, the Commission would evaluate the appropriate type of enforcement action to be taken (20 AAC 25.535 and AS 31.05.150).

The reviews conducted by the engineers for AOGCC are basically file reviews with compliance aspects. A copy of the review summary goes to the Commissioners in conjunction with the action document since most reviews are linked to a current request

by the operator. When an MIT triggers the file review, accuracy of information and documentation is the responsibility of the engineer who performed the review.

C. Technical Review Process Related Aspects of Compliance Review

Casing and cementing requirements are essentially the same for all wells in Alaska and are governed by 20 AAC 25.030. Surface casing in all wells must be cemented to surface. Subsequent strings must be cemented a minimum of 500 feet above any hydrocarbon zone to prevent migration of formation fluids into different zones. Regulation 20 AAC 25.412 (b) requires the use of tubing and packer in all injection wells unless the Commission approves an alternate plan, which provides equivalent protection. Wells converted to use as injection wells must meet the same technical standards as newly constructed wells. A well converted to injection must demonstrate mechanical integrity before injection may commence.

The regulations also require isolation of the pressure to the injection interval and that the minimum pressure burst pressure of the tubing must exceed the maximum surface injection pressure by at least 25 percent. In 1991, the regulations had no restrictions placed on the type of tubing and packer to be used and no specific requirement for packer setting depth. Current 20 AAC 25.412 (b) requires the packer to be placed within 200 feet measured depth above the top of the perforations unless the Commission allows a different setting depth based on thickness and depth of the confining zone. Where an exception is allowed, the commission may impose additional requirements such as daily annulus pressure monitoring (APM), more frequent MITs, step rate test(s) and limitations on rate pressure, or volume. Where tubing is composed of materials other than the traditional metallurgy, the commission staff would have to review the operator's demonstration that it would provide at least an equivalent effective means of wellbore integrity. Through time, the AOGCC has approved dual injection where the purpose is to inject into multiple zones through one well bore. AOGCC staff indicated only one case where a well was dually completed for waste disposal into one zone while producing gas from another.

The North Slope oil fields contain no underground sources of drinking water. This is in contrast to the Cook Inlet where fresh water can exist at great depth (as deep as 7000' tvd). There are United States Geological Survey (USGS) aquifer maps available for Alaska. ADEC is in the process of mapping source water areas (part of the source water assessment program), however, due to security reasons, do not make the information available to the public. The Operator carries the burden of proving or disproving the existence of USDWs to the AOGCC and is required to run logs in areas of sparse information. The AOGCC relies on this site-specific data for each UIC application.

AOGCC is mandated by statute to protect fresh water. Due to the Alaska definition of fresh water, the AOGCC must assure that oil and gas activities do not threaten any identified underground water resources with total dissolved solids concentration of less than 10,000 mg/l. An important difference for Alaska is that deliverability is not

considered as is done in the Federal definition of a USDW (i.e., Alaska is actually more restrictive).

In the same sense, the Operator (applicant) is responsible for demonstrating the effectiveness of the confining layers throughout the area covered by the application. This requires evaluation of the lithology, thickness, areal extent of the confining layers and mechanical strength of the layers. Fracture growth and the potential to breach the confining zone must be analyzed using modeling technology. The AOGCC staff requires the Operator to perform step rate tests to determine formation fracture gradient and maximum injection pressure. This test must be done after the well is drilled and before it is approved as an injection well.

The operator's normal operating procedures include daily monitoring of the casing-tubing annulus. The annulus pressure, along with injection rates and pressures, must be reported monthly on the Monthly Injection Report (Form 10-406). The regulations specify the casing-tubing annulus pressure limitations. In the 1991 Review, the Team expressed a concern that "no specific injection pressure limit stated in order or individual well permits". The AOGCC believes that project reviews address injection pressures in the context of the geologic setting and proposed activity satisfies this concern. Commission establishes step rate tests to establish pressure limits; frac design validates rock properties; pressure limitation is set in the Order if sufficient information is available. Otherwise, the general standard establishes prohibition of pressures that would fracture through confining layer (with provision to establish injection pressure limits at a later date by administrative action, if appropriate); initial report within one month of initiating injection. It should be noted that the Operator is required to investigate worst-case scenarios with rates and volumes that are greater than the planned injection volumes for the project. Follow up tests may be required to validate the fracture analysis after the well is put initially into service. The AOGCC does not grant approvals prospectively contingent upon correcting an existing adverse condition.

D. Area of Review Considerations and Procedures

The Commission does a thorough review of wells within the fixed one-quarter mile radius⁹ of each proposed injection well location to assure that wells in the Area of Influence or Review (AOR) have been properly completed or plugged so that injected fluids are contained within the permitted zone of injection. The fixed radius applies to all Class II wells. In the case of area permits, the AOR extends ¼ mile beyond the project area. To the AOGCC staff's knowledge, no applications have been withdrawn because an applicant refused to take corrective action as a condition of permit approval.

20 AAC25.402 requires the Operator to demonstrate that the injection fluid will be confined to the approved injection zone. The Operator must ensure that all wells under his control are properly repaired, plugged or otherwise modified or the AOGCC will not

⁹ There are a few examples of a ½-mile AOR for injection projects in Alaska

issue the AIO or DIO. The UIC application requires an affidavit showing that the applicant has contacted operators and surface owners in the AOR. For wells that are under someone else's control, the Operator must present satisfactory evidence that the well(s) are properly plugged, repaired or otherwise modified or the Commission will not issue the Order. As was pointed out in the 1991 review, the task of identifying affected wells is relatively simple in Alaska because most wells have been completed or plugged and abandoned to modern-day specifications. A large number of "historical" wells do not exist. Recent trends toward development of uphole, marginal zones in fields like Prudhoe Bay does present a challenge in terms of demonstrating confinement where deeper zones were developed first.

E. Components of Administrative Permit Application Processing

A public notice of the opportunity for a hearing is published by the Commission prior to the issuance of an Area Injection Permit or Disposal Injection Permit. The Commission provides a minimum 30-day opportunity for public review and input when an application is received. The notice is published in an Anchorage newspaper, a paper in the area of the proposed Order and in the Alaska Administrative Journal. The AOGCC also notifies parties through its mailing list of over two hundred names (using email whenever possible to reduce the cost of postage).

A person may submit written protests or comments during the 30-day period by letter, fax or email. On rare occasion, participation by teleconference has been allowed. The Commission will decide if a hearing is warranted; all comments received in a timely manner will be considered in a decision to hold a hearing; all comments become part of the administrative record. A hearing is usually held on all UIC related applications. The AOGCC has no definition of "significant interest" which some states use to reduce frivolous protest where the protestor does not show for the hearing. Hearings are formal and are conducted in accordance with procedures established by 20 AAC 25.540. The Commissioners preside at the hearings. Protests received before the application is approved are addressed in the administrative process, which could include compiling documentation and holding a hearing. Complaints received after UIC orders have been issued are dealt with through the normal complaint resolution process. AOGCC provided the Team a flow diagram of the complaint process, which is included in the appendix.

AOGCC staff indicated that public comments on UIC-related applications are rare. The environmental community generally opposes oil and gas activities in Alaska but has in the past generally supported underground injection as an environmentally preferred disposal option for drilling and production wastes. The last significant comments on an UIC application was by a public interest law firm in 1989, but the permit terms were not significantly affected.

Bonding requirements in 20 AAC 25.025 direct that financial assurance be provided through a surety bond, or a personal bond of the operator accompanied by a security guaranteeing the operator's performance. The latter must be in the form of a certificate of

deposit or irrevocable letter of credit issued in the sole favor of the AOGCC by a bank authorized to do business in the state, or in another form that the commission determines to be adequate to ensure payment. Security is to ensure that each well is drilled, operated, maintained, repaired, abandoned and each location cleared in accordance with AOGCC standards. The bond or other financial assurance arrangement must be either for a single-well in the amount of not less than \$100,000 or blanket coverage of all wells in the amount of not less than \$200,000. The US Government Accounting Office (GAO) has recently recommended the bonding amounts be raised to accommodate current costs. The operator performance bond discussed above are designated as security to “ensure that each well is drilled, operated, maintained, repaired, and abandoned and each location is cleared” in accordance with AOGCC regulation – 20 AAC 25.025. The bond is not intended to be used for pollution clean up, however, according to the AOGCC, some flexibility exists in interpretation

F. Process for Aquifer Exemption

The regulatory aquifer exemption procedures are set forth in 20AAC 25.440. The process remains unchanged from the 1991 review and was established when the state received Class II primacy in 1986. Since 1986, the AOGCC has granted eight (8) exemptions, all of which they consider as “minor”. No requests for exemptions have been denied. Alaska does not have any hydrogeologic situations wherein a fresh water aquifer in one part of the state becomes eligible for exemption in another part of the state due to salinity increases or because it becomes an oil or gas-producing reservoir. Alaska aquifers are glacial deposits and are laterally discontinuous.

To apply for an exemption under 20AAC 25.440 (b), an operator must submit a letter to the Commission that includes sufficient data to justify the proposal and to substantiate that the aquifer does not currently serve as a source of drinking water, and it cannot and will not serve as a USDW in the future because it is hydrocarbon producing or can be demonstrated by the applicant to contain hydrocarbons that, considering their quantity and location, are expected to be commercially producible. Exemption may also be granted if the aquifer is at such a depth or location that makes recovery of water for drinking water purposes economically or technologically impractical or if the Total Dissolved Solids (TDS) concentration of the ground water is more than 3,000 and less than 10,000 mg/l and is not reasonably expected to supply a public water system. Under Alaska’s regulations, “fresh water” does not require a determination of deliverability. Alaska may be granting “aquifer exemptions” for areas that in fact have no USDW, but have strata that contain water that must be evaluated qualitatively before injection is permitted.

Prior to the granting of primacy to the state in 1986, EPA had established exemptions for some North Slope and Cook Inlets Fields. These exemptions have been incorporated into the state program by reference in 20AAC 25.440(c). A fresh water aquifer exemption designation by Commission order does not become effective with respect to any UIC or underground storage activity until the EPA has been provided the opportunity to review and concur with the order. The Commission may issue an order where the exemption is

based on the 3,000-10,000 mg/l TDS concentration range if EPA fails to act upon the Commission's decision prior to an agreed to expiration date. The MOA considers the latter type of exemption "minor". Additionally, the Commission also provides 15 days legal notice of the intent to hold a public hearing on any exemption in accordance with 20AAC25.540.

Identified Strengths

1. Both the AIO and individual well permit application review system are technically sound and the tracking of the applications assures that they are complete and acted upon by the Commission in a timely manner. The comment of the 1991 Review Team that the "review process has no check list or sign-off procedure and appears unstructured" has been improved. The structure is now outlined in a work flow diagram and the MS Project data system is under development to track milestones and divisions of responsibility.
2. The technical review and the criteria used for the determination of the confining zone adequacy is very good and appears to be more than sufficient to ensure that injected fluids are confined to the permitted injection zone.
3. As was true at the time of the 1991 review, Alaska still has two major producing areas, which have been developed with modern technology. The decrease in distance between wells on a pad is an example. This eliminates a lot of problems encountered in other states where considerable acreage is consumed by individual well locations that have to have well vicinities and access roads maintained. The low number (12) and high quality of operators continues to be a plus.
4. The AOGCC never grants an AIO or DIO that is provisional upon an action to correct an adverse condition.
5. The pre-application meetings with UIC applicants allow the applicant (Operator) to know shortcomings of a proposal before formally filing. This allows the AOGCC time to direct its focus toward technical issues rather than application completeness.
6. The AOGCC staff has a good balance of sound engineering and geologic expertise to provide log interpretation, technical judgment of casing and cementing materials proposed by operators and the evaluation of injection reservoirs and confining zones. The staff appears to have a thorough understanding of the problems encountered under Alaska's rigorous environment and is able to come up with viable solutions.
7. File reviews, although not specifically tracked as a UIC work measure, are an integral part of the program because they are performed whenever well activity or status changes and when an MIT is performed.

Comments and Recommendations

1. In the 1991 Report, the Team stated, “AOGCC should be aware of and develop a plan to protect the state in the event that a major operation sells its holdings to a company that may not have adequate financial resources to properly plug and abandon the wells and close the attendant facilities”. AOGCC stated it had no mechanism to determine solvency of operator and that the bond adequacy was the same as in 1991. The Review Team believes the 1991 comment to be more valid now than it was in 1991. The Commission is encouraged to review its bonding levels and other operator assurance instruments with an eye toward future needs.
2. Operators are contacted by telephone if an application is incomplete and are told what additional information is necessary. An incomplete application may pend indefinitely. The Review Team recommends that notice of an incomplete application and the requested information be documented in writing by e-mail or letter and those Operators be given a time limit to complete applications.
3. The review team was concerned that AOGCC did not have an administrative process in place for transferring permits on acreage where problems exist. AOGCC explained the current situation and why, unique to Alaska, perhaps, a permit transfer procedure was not needed. AOGCC states as follows: “We have had little experience with the transfer of leases and how such affect permit conditions, well abandonment, and decisions about unrepaired wells. The major realignment of Prudhoe Bay (with BP purchase of Arco) where BP assumed designated operator for the entire field occurred without revisions to injection orders, permit conditions and required well repairs (BP was operator of Western Operating Area; Arco was operator of Eastern Operating Area). Similarly, the Cross Timbers (now XTO Energy) acquisition of Shell assets in Cook Inlet did not trigger any permit changes. There have been alternate compliance measures approved in one case for demonstrating well integrity (e.g., temperature surveys in lieu of conventional MITs) but it was based on well-specific considerations rather than transfer of ownership. A new well operator is expected to comply with the requirements in an existing order or rule. The Commission-mandated monitoring, reporting, and periodic MITs provide the means to ensure an injection well is operating in a manner that protects freshwater, regardless of the well’s operator. The AOGCC considers the rules specified within an order to apply to the property (well).”

The permitting program conducted by AOGCC is very well organized and features both processing efficiency of UIC applications but a high quality technical review. The pre-application conferences are a good feature for letting the operator know what is expected. This part of the programs is generally protective of ground water and environmental resources.

PART III: INSPECTIONS

A. Description of the Conduct and Management of Field Operations by the Agency

All field inspections are performed by Commission employees, as was the case at the time of the 1991 Review. The AOGCC employs five petroleum inspectors who work on a rotating schedule. Schedules are staggered so that there is at least one inspector available for each area. The Inspectors report to the Senior Petroleum Engineer. At the time of the 1991 review, one Commissioner was assigned the task of coordinating field inspections with backup provided by the Senior Petroleum Engineer.

All Inspectors are qualified to conduct inspections on those items under the AOGCC jurisdiction; however, one Inspector has a “lead” role for certain types of inspections (well control, well safety valve systems, and meters). No one inspector is charged with the UIC lead. UIC inspections are generally conducted at the time wells are tested for mechanical integrity and safety valves, however, visual inspection for leaks from both production and injection wells is part of the ongoing program. The engineering staff only occasionally accompanies the inspectors on field visits. Alaska is unique in that air travel is necessary to access most well locations. Workload and staff availability add to the travel logistic difficulties for the staff from the Anchorage office. The AOGCC employs a Petroleum Inspector Manual that contains recommended procedures for conducting inspections and this document also is designed to create a common standard of inspection fairness for operators as well as a level of expected inspection quality. Each inspector is provided a copy of the Manual. Inspectors and the Senior Petroleum Engineer are in frequent contact both by phone and email. Inspectors also come into the Anchorage office between trips to the North Slope or the Cook Inlet.

Field inspectors are qualified by education and experience. The minimum education level is a high school degree and six years of hands-on experience in oil field operations, or an Associate Degree from an accredited vocational school majoring in oil field drilling and production. The AOGCC has no required training courses established for their inspectors, although individual inspectors can request training on an as-needed basis to address new technological developments or refresh certifications (e.g. safety valve systems, well control, metering). The Commission indicated they have had discussions with the Interstate Oil and Gas Compact Commission (IOGCC), the Bureau of Land Management (BLM) and the Mineral Management Service (MMS) about training for inspectors. Inspectors are furnished with cold weather gear, hard hats, and H₂S detectors and have access to either State owned or operator’s masks and breathing devices when needed. The inspectors on the North Slope have computers in their office and have had laptops since 1995. The RBDMS installation began in November 2001. This system, when completed, will be accessible to the field inspectors.

The Inspectors are responsible for identifying compliance issues and reporting violations and substandard conditions to the Operator and the appropriate Commission office staff. The Commission has not yet had to resort to hearing and judicial processes to assure

compliance. Operators have complied with verbal requests from inspectors, or from the Commission to correct deficiencies. Inspections are coordinated through the central AOGCC office in Anchorage where the compliance history of the lease and operator is used to determine inspection frequency. Inspectors rarely testify at Commission hearings on UIC matters but occasionally attend.

B. Description of Routine/Periodic Inspection Program

Most routine inspections of UIC wells in Alaska are conducted in conjunction with general inspections of producing wells, gravel pads and platforms and directional drilling activities. The AOGCC considers the MIT to be a routine inspection. Safety valve inspections and MITs provide the opportunity to inspect other wells on the pad or platform. This inspection protocol gives AOGCC inspectors frequent opportunity to check the performance and condition of injection wells between the scheduled MIT dates for each well. Inspection frequency for each well is determined by the availability of inspectors, inspection priorities, the frequency of test mandated by AOGCC Order, or the opportunity to witness multiple tests. Problem wells (waivers, integrity concerns, etc.) will also trigger inspections. Typically, inspection of newly completed UIC wells does not occur until shortly after the Operator has initiated injection, however, circumstances can dictate inspections at any time. In 1991, the AOGCC inspectors conducted about 40 general inspections and 14 MITs per month. The staff indicated they no longer keep UIC related inspections as a separate statistic, however, some of this information is documented in the Quarterly Reports and 7520-Forms submitted to EPA.

Routine inspections and MITs take about one hour of time once on the site. Because of the remote nature of Alaska oil and gas wells, operators are always given notice of inspections prior to site visits. Legally, the AOGCC inspectors have the right of access and to make unannounced well-related inspections at any time. Additionally, road access to North Slope production has been further limited by enhanced security measures at the Deadhorse check-point.

The AOGCC inspectors do not carry their own pressure gauges or flow meters nor do they gather samples. As was indicated in the 1991 Review, inspectors are not trained in “legal” quality sampling and “chain of custody” transfer procedures. The AOGCC relies on 20 AAC 25.200(c), which specifies that wellhead equipment must be equipped with gauges to monitor tubing and casing annuli. The AOGCC may request verification from the operator that a gauge has been calibrated but no standard of calibration has been adopted by the AOGCC. Operators are expected to comply with recognized industry standards.

Inspectors do have access to digital cameras and most inspectors carry them while conducting inspections. If unusual circumstances are noted, any photos taken are submitted as a part of the inspector’s report and become a part of the administrative record. No formal log is maintained of the photos taken. No written procedures have been developed by AOGCC to preserve photos as evidence. AOGCC does not have an updated

Quality Assurance/Quality Control (QA/QC) plan or a UIC EPA-approved Quality Assurance Project Plan (QAPP).

C. Emergency and Citizen Complaint Response Procedures and Processes

Regulation 20AAC 25.205(a) requires the Operator to notify the AOGCC immediately if there is an uncontrolled release of oil (>10 barrels) or gas (>1 million cubic feet), or any release that results in the shut down of operations at a facility. Notification of emergency situations regarding UIC well integrity must be reported to the AOGCC immediately upon discovery, regardless of volume. All Operators are provided contact numbers for inspectors and the Sr. Petroleum Engineer. Standard procedures for after hour contact with AOGCC staff have been established. The ADEC also has a 24-hour emergency number, which can be accessed by Operators and citizens.

The Operator has the responsibility to notify all appropriate agencies when an emergency occurs. The ADEC has been designated as the lead agency for emergency response actions. State Emergency and Disaster Plans use the Incident Command System that is designed to coordinate response and necessary record keeping activities, which will allow both complete investigation and documentation of the event. If the original notification of a complaint or incident came to an Inspector, he or she would notify the Sr. Petroleum Engineer for further instructions. If the event occurred on the North Slope, the Inspector would receive the reports of the ongoing response at an incident command site set up for that purpose.

In 1991, the AOGCC indicated the Operators are the parties who report all emergencies and spills. To date, no significant citizen complaints have been received. The only emergency situation involving an UIC permitted well was a surface breach of Class II-D well Drill site 04-19 in the Prudhoe Bay East Operating Area. This event occurred in March 1997. The AOGCC has developed rather detailed flow diagram that outlines the steps used by their staff to process a complaint. Complainants are contacted to gather additional information and they are notified of the results of the investigation. Usually the notification is in writing. The Operator is also notified if additional information is necessary to substantiate the nature of the complaint. The Operator would always be notified if enforcement action were necessary to resolve the subject of the complaint.

All complaints are handled in a timely manner; however, the time to respond depends upon the nature of the complaint and the level of investigation required. No statutory or regulatory timeline has been established which obligates the Inspector to contact the complainant or investigate the source of the complaint. The Operator has the burden to notify the AOGCC when an emergency occurs. AOGCC is required to notify EPA immediately when it learns of any hazard to public health resulting from USDW contamination by fluids injected into a Class II well. The ADEC would also be notified if

such an event occurred. This scenario has never occurred, however, the Cook Inlet does include USDWs and the potential for complaints about UIC practices does exist.

D. Reporting and Follow-up Procedures Used in the Inspection Program

Routine inspections are documented on a variety of standard inspection forms such as the MIT report, Surface Abandonment Report and Plug and Abandonment Report. The AOGCC has no special forms for complaints or emergency situations. Inspectors generally take field notes. One inspector uses a pocket PC to document inspection findings. Inspectors generally transcribe whatever pertinent information into a formal document, which is subsequently transmitted to the Senior Petroleum Engineer for further handling. MIT inspections are recorded in a mainframe database and the hard copy is retained in the individual well file. Individual MIT inspections are not cross-referenced to the Order that governs their operation.

The state uses regulation 20 AAC 25.070 to require the operator to keep records of all activities pertaining to a well for five years after the abandonment of the well. The AOGCC is required to retain any document developed in conjunction with the conduct of official business. The Alaska state archives and record management program reviews and approves agency record retention schedules. The Commissioners are responsible for judging how long a record must be retained.

Since the 1991 review, the lag time between inspection and submission of the report by the inspector has shortened from up to two weeks to a week or less. Inspectors on North Slope assignment generally submit a week's worth of reports when his tour is finished. With few exceptions, all MIT inspections are submitted by email by operators. Inspection results are tracked in the Anchorage office. AOGCC staff indicated that RBDMS would eventually be used to track compliance deadlines and the need for follow up review. Any photos taken are attached to the manual file. Any chain of custody, photograph negatives, and analysis documents generated through the inspection program would be come part of the official well file, or a dedicated incident file. The Senior Petroleum Engineer reviews all reports for completeness and forwards them to the Commissioners for final review. A Statistical Technician also reviews the reports for administrative accuracy and inputs the information into a database. No restrictions are placed on Inspectors providing information or cooperating with other agency personnel except where confidentiality rules apply under AS 31.05.035: Confidential Reports. Most UIC application information is not eligible for confidentiality claim (AS 31.05.035 (e)).

All inspection forms are reviewed and approved by the Commission before being put into use by inspectors. None of the forms or inspection procedures has been reviewed by the Alaska Department of Law. None of the forms relating to UIC inspections have been sent to EPA for comment; however, some forms in use at the time of primacy application (1986) for the Class II UIC programs were reviewed by EPA.

Identified Strengths

1. Inspection activities are well supervised and coordinated between the Inspectors and the Anchorage Office. Having the Senior Engineer, instead of one of the Commissioners directly in charge of field operations assures technical continuity for UIC inspections. In 1991, one commissioner was in charge of inspections and while this was considered a strong point at that time by that Review Team, this Review Team believes having the Senior Petroleum Engineer directly responsible for field coordination and report review may enhance technical communication.
2. The agency continues to implement an excellent inspection program and has inspectors on site at remote locations under very inclement conditions. The establishment of the field facility “camp” on the North Slope at Deadhorse provides for prompt inspection of well activities and UIC problems or malfunctions on very short notice. The sharing of the North Slope office with DNR and ADEC inspectors should enhance interagency communication and an appreciation of other agency’s objectives and responsibilities.
3. AOGCC Inspectors work to achieve voluntary compliance by giving operators a timeline to correct a violation or substandard situation. Inspectors prepare field reports that document both instructions and results.
4. The scheduling and witnessing of MITs form the cornerstone of inspections of injection well facilities. UIC facilities also receive inspections during the conduct of safety valve tests. This allows for a high level of inspection and monitoring.
5. The 1991 Review stated, “except for MIT, there are no clearly defined UIC inspection goals priorities or checklists”. The AOGCC responded by stating that the “inspection program was driven by MITs.” This Review Team believes that using MIT occurrences and safety valve checks as an opportunity to make UIC inspections is a strength rather than a weakness of the program, because of the climate and difficulty in travel to well locations and the fact that many wells are drilled off the same location, Alaska’s inspection program should be viewed differently than that in other states.

Comments and Recommendations

1. The 1991 Review stated, “even though there are several specific inspection forms which pertain to individual UIC well, there is no general UIC inspection form or checklist.” AOGCC indicated it currently has no inspection forms or checklists. AOGCC will be participating in a pilot program testing handheld computers for documenting inspections. This Review Team believes a form similar to the MIT form where the inspector could list several inspections on one sheet might be of benefit in documenting “presence on a lease or at a well”. Such documentation would also supplement the number of inspections reported on Form 7520 to EPA.

2. The Review Team is concerned that the AOGCC inspectors appear to have not received ongoing training in such environmental activities as QA/QC, sample collection, and proper documentation for use in compliance and enforcement. An up-to-date QA/QC program and applicable QAPPs will support any future legal enforcement cases. Some inspectors have received training through IOGCC, and some have not. Because the Alaska oil company mix is unique in that many of the dozen companies have environmental departments on-site, the AOGCC may have developed a dependency on a level of business conduct that may not exist with future companies. Ongoing training helps inspectors deal with “surprises”.
3. Inspectors should have their own gauges, which are properly calibrated for witnessing pressures. The inspector can always ask company personnel to install the Inspector’s gauge to alleviate liability concerns over the potential for an inspector to cause damage to the operator’s equipment while installing the gauge.
4. The Review Team had some difficulty discerning the quality of field notes taken by inspectors. Additionally, there did not seem to be any requirement to keep notes of findings nor maintain log books of inspections. Which such matters are left to the inspector’s discretion. This includes documentation of follow up inspections of complaints and violations.

The inspection program conducted by AOGCC is very well organized and is geared toward the early detection of problems; therefore it is generally protective of ground water and environmental resources.

PART IV: MECHANICAL INTEGRITY TESTING

A. Types of Mechanical Integrity Tests Allowed for Different UIC Well Completion Programs

Alaska primarily uses the standard inner-annulus pressure test (MITIA) as the demonstration of Part I integrity. When a casing or tubing leak has been identified, pressure integrity may be demonstrated through modified pressure testing. A mechanical plug is set in the tubing string and the tubing (MITT), or combination tubing and annulus (CMITIA) are pressure tested. In some cases, alternative testing methods have been used including water flow log, tracer logs and temperature surveys (see 20 AAC 25. 450). A few offshore wells in the Cook Inlet, which do not have packers, have to be successfully pressure tested during a workover. Regulation 20AAC 25.412 (c) specifies that the annular space must be pressured to a minimum of 1500 psi or 0.25 psi/ft multiplied by the true vertical depth at the packer, whichever is greater. The surface pressure is limited not to exceed the 70% of the minimum yield strength of the casing. The applied pressure must show a stabilizing trend and not decline more than 10% in 30 minutes. Pressure readings are taken when the annulus is initially pressured, at 15 minutes and at 30 minutes. If the pressure readings are inconclusive, the Inspector has the discretion to extend the observation period. The volume of fluid pumped, *per se*, is not a determinant

of MIT passage or failure. The same testing criteria are applied to all Class I and II UIC wells in Alaska.

Between scheduled MITs, Annulus Pressure Monitoring (APM) is the method used to demonstrate continued mechanical integrity. A minimum differential pressure between the tubing and tubing-casing annulus of 500 psi is required. In addition, AOGCC regulation (20 AAC 25.252(e) and .402(f) require notification and corrective action or increased surveillance (AOGCC determination) “if an injection rate, operation pressure observation, or pressure test indicates pressure communication or leakage in any casing, tubing, or packer.” Data acquisition systems are not routinely used for monitoring annular pressures on injection wells and operator personnel check the wells daily for pressures. APM information is submitted monthly as a part of normal surveillance requirements, (Monthly Injection Report Form). The average daily information, which includes injection rate, tubing and annuli pressures, is submitted monthly. When an Operator is required to conduct APM as a condition of an integrity waiver, daily values are submitted on a monthly basis. AOGCC staff indicated that 75 UIC wells were currently on a waiver program subject to additional monitoring requirements because they had demonstrated less than complete integrity (i.e., one barrier in the well – tubing, packer, wellhead seals, or production casing - does not pass an MIT). No waivers are granted for wells located in areas where USDWs would be threatened. In most cases, the monitoring information is submitted electronically and presents three months worth of data in chart form. The Senior Petroleum Engineer presently reviews all information for indications of mechanical integrity failure. No other monitoring records or methods are used to detect failures.

MIT Part II (external-fluid migration) as it was in 1991, is determined by reviewing the cementing records for a given string of casing and /or liner. Regulation, 20 AAC 25.412 (d) requires an Operator to provide a Cement Quality Log (CQL) to demonstrate isolation. The AOGCC does have authority to require other surveys such as temperature logs, water flow logs or Radioactive Tracer Surveys (RATS) if the CQL cannot, on its own, demonstrate isolation. Cementing records are reviewed to determine if sufficient volumes were pumped to satisfactorily cement the string in place. AOGCC staff uses actual reported cement volumes and an Excel spreadsheet to calculate the likely cement height. AOGCC staff has extensive experience designing and executing cementing operations specific to Alaska situations. The staff uses experience rather than a written protocol for determining failure potentials. Log anomalies are used to identify potential communication and fluid migration. Both the engineers and the geologists examine logs to determine if additional runs are necessary to resolve an anomaly.

Common remedial actions used by the AOGCC to address failures and restore integrity include squeezing cement, resetting packers, tubing replacement, tubing or casing patches or the installation of “scab” liners. Polyethylene liners are an emerging technology for injection wells but have not been proposed for use to date in Alaska. The Operators are required to address any failures, however, if an insolvency occurs and leads to an “orphaned” well situation, the Commission would take action to seize the Operator’s

bond and solicit proposals to P&A the well(s) including any necessary remedial action prior to plugging.

B. Manner of MIT Program Implementation

The AOGCC has established a schedule for the Operator to run MITs on Enhanced Recovery wells (Class II-R) every four years and every two years on slurry disposal wells (Class II-D). The Commission has developed a matrix to address the increased frequency for MITs and more restrictive operating conditions when a well is granted a waiver status. The Operator generally schedules the tests, however, the availability of the inspector is taken into account so that as many tests as possible are witnessed. To the extent practical, the AOGCC will accommodate the Operator by allowing scheduling of MITs for a larger number of wells in the same area. The operator has the responsibility for notifying the Commission of plans to conduct the MIT at least 24 hours in advance to allow the inspector to witness the test. The Operators are generally not notified by the AOGCC of a pending MIT. AOGCC staff indicated most MITs are done in the summer months; however, the overall annual inspection workload has remained the same for the last three years.

An MIT must be completed prior to initiating injection and occasionally the test will be performed prior to the Commission's approval of an injection order. The result of this test must be forwarded to the AOGCC for review because the inspector may have not been able to witness the test. In these cases, the inspector will schedule an opportunity to witness the MIT once the well has been placed in service and thermal equilibrium has been established.

The AOGCC has a goal to enter all MIT information into RBDMS for easy information access, tracking and trend analysis. This system will allow for easier matching up of the initial test with the fluid migration log tests that come into the agency at a later date. Copies of all reports are placed into the well file. The Statistical Technician is responsible for entering all appropriate information into the database. The Commission engineering staff reviews MIT reports to determine any necessary follow up action. Operators are required to report MIT failures to the AOGCC. The Operator notifies the Sr. Petroleum Engineer of a loss of UIC well integrity, usually by email. The Operator will describe the nature of failure and proposed corrective action needed and the time frame necessary to accomplish the work.

C. Agency Procedures for Witnessing a MI Test

Based on recent trends, about 85% of all MITs are witnessed by the five Petroleum Inspectors employed by the AOGCC. Nearly 100% of Cook Inlet MITs have been witnessed. The apparent disparity is based on fact that there are USDWs present in onshore areas of Cook Inlet; there are no USDWs within the oil producing areas on the North Slope. At the time of the 1991 Review, the AOGCC indicated that inspectors witnessed 72% of the MITs; however, only 25% of the North Slope tests were witnessed.

Since 1998, the cumulative percentage of MIT failures is approximately 3.5% of the tests performed. This is slightly less than the 4.5% failure rate shown at the time of the 1991 review. AOGCC staff indicated the failure rate does not seem to be changing during successive test cycles. AOGCC policy has been to witness the initial integrity tests for all new, converted, and worked over wells. At least 25% of all other MITs are also witnessed. Each MIT takes about one hour to perform, however, travel time to the well may vary widely between 15 minutes to a day and a half depending upon weather, distance from site, etc. It is rare for the Operator not to have a scheduled injection well prepped and ready for test.

The Inspector will check for stabilized tubing and annulus pressures before the operator initiates the test and will record the changes in those pressures over a 30-minute monitoring period. As previously indicated, inspections of other equipment may occur in conjunction with the MIT. All MITs are documented by submitting a standardized report of the witnessed test to the Sr. Petroleum Engineer. Where an AOGCC inspector does not witness the test, the Operator is required to complete and sign the same form and submit it to the AOGCC. The Review Team was furnished a copy of the MIT report form that allows the operator to report the results of up to five tests on the same form.

An Operator is required to file a sundry application (Form 10-403) and receive approval from the Commission prior to performing work on an injection well. When the work is completed, the Operator files a Report of Sundry Well Operations (Form 10-404). An Operator may run an MIT at any time and often “pre-tests” a well during preparation for an AOGCC-witnessed MIT. A failure during the pre-test is required to be reported to the AOGCC. Repairs resulting from a loss of well integrity require a new AOGCC-witnessed MIT.

D. Procedures Used for Follow-up on Failed MI Tests

The Operator is verbally notified if it is necessary to shut down a well due to a MIT failure. Notification may come from the Inspector in the field or by the Senior Petroleum Engineer in the AOGCC office in Anchorage. An MIT failure does not always result in a decision to shut in the well. The AOGCC is currently tracking 75 wells, which are operating on an alternative demonstration of integrity and APM. Regulation 20 AAC 25.450 allows the Commission to grant a waiver to the stricter UIC regulations for Class II wells if the nature of the loss in mechanical integrity will not threaten USDWs. The AOGCC has a rather detailed flow chart showing the decision tree used to determine if a waiver should be granted. The Operator must institute corrective action or secure the well if a waiver is not granted.

Wells repairs are not generally witnessed by AOGCC Inspectors, however, arrangements are made for an Inspector to witness a pressure MIT following repairs. A workover, or other work done on an injection well requires prior approval by the Commission. If an Operator elects to plug and abandon an injection wells rather than repair the well, the plugging program must isolate the wellbore and its contents. The decision to witness the placement of abandonment plugs in a well is based on factors such as work priorities and

logistics; abandonment of an injection well that failed an MIT would likely be witnessed, particularly if the well were located near a USDW.

Identified Strengths

1. The frequency of mechanical integrity testing is more stringent than the five-year minimum frequency established by UIC program requirements under SDWA 1425. Part of this reflects an inherent sensitive environment of the North Slope and Cook Inlet and the awareness of both the AOGCC and the regulated community of their obligation to keep MIT failures at a low percentage. This is also done to ensure compliance with the EPA-mandated 5-year test frequency since logistics in Alaska can be challenging. Slurry Fracture Injection wells are MIT'ed on a biennial basis. Fracture injection of drilling waste slurry was in an experimental period during the 1991 Review
2. The AOGCC has continued to improve on the percentage of tests witnessed. The percentage of witnessed tests exceeds the 1991 benchmark, which was already high in total percentage but on occasion, much lower on the North Slope. A high level of MITs continues to be witnessed by Commission inspectors (85%). In 1991, Inspectors witnessed 72%.
3. The AOGCC inspection program for UIC wells is driven by regularly scheduled MITs and required safety valve tests. This allows for a great amount of routine inspection and surveillance to be accomplished throughout the field which otherwise might not be cost effective to do so (e.g., housekeeping, maintenance practices, pressure monitoring, other visual inspections).
4. All MIT documents, tests and logs receive careful examination by the Sr. Petroleum Engineer to insure program consistency.

Comments and Recommendations

1. The 1991 Review felt the MIT program could be enhanced by development of a computer tracking system. AOGCC indicated that RBDMS has been installed. Data validation an ongoing effort with the transition from mainframe applications to RBDMS. They are currently using Microsoft Excel to track MIT data on a well-by-well basis.
2. The Review Team agrees with the 1991 Review Team, “more clear cut time frames for repair of wells failing MI should be established”. The Team is cognizant of the fact that on the North Slope there are no USDWs to be protected and many mechanical integrity failures are internal. In most states, a mechanical integrity failure results in the well being shut down until repairs are made and a retest passes. The Team encourages the AOGCC to expedite the guidance document for operators that outlines the waiver process for wells failing an MIT

and the conditions for continued operation of the well. According to AOGCC staff, the matrix is currently in use, which was developed to address those situations when a well can continue to receive injected fluids after failure has been discovered.

3. As the number of Operators increase, AOGCC may want to change the MIT program to the extent that they (AOGCC) are taking even a stronger initiative setting the MIT schedule for the Operator. The Operators currently have great flexibility in scheduling based on climate and logistic considerations. The regulatory agency usually does not want to get into positions where industry is setting the program and not adhering to the test frequency.
4. Wells failing MIT are not, as a rule, promptly repaired. A proposal to repair is generally received in 2 to 3 weeks. The Review Team did not get a good appreciation of how soon the AOGCC expected failure conditions to be repaired. The AOGCC did provide information that the operator has several options available, including the securing of a waiver, “safeing” out the well or repairing the well. This latitude is given primarily in Alaskan oilfields where no USDWs exist.

The Review Team concluded that AOGCC administers an MIT program, which is protective of USDWs and other environmental resources. The frequency for mechanical integrity testing is the same for wells in areas of no USDW as it is for wells where USDWs are a consideration. Testing is also tailored to the type of injection service (slurry versus “clean” fluid) and actual mechanical integrity of the well. The selection of the type of tests or monitoring programs for continued well integrity are well thought out and follow a decision matrix.

PART V: COMPLIANCE/ ENFORCEMENT

A. Description of Enforcement Tools Available to the Agency

The Commission has a variety of enforcement tools available to ensure operator compliance. The AOGCC may, by direct enforcement action order (1) corrective action or remedial work; (2) revocation or suspension of a permit or other approved activity; (3) payment under a bond; or the (4) imposition of civil penalties under 20AAC 25.535. Under Alaska statutory law, the AOGCC may withhold subsequent permit approvals if an operator has unresolved enforcement matters. Injunctive relief may also be sought by suit in superior court.

The AOGCC indicated to the Review Team that they have received 100 % voluntary compliance from operators and no formal enforcement actions for Class II have ever been initiated. In 1999, the AOGCC did promulgate 20 AAC 25.535 which sets forth a formal process for taking enforcement action which includes an orderly process for notifying the

operator of the action, opportunity for informal review and /or hearing and final order from the Commission outlining required corrective action, actions against the permit (revocation, suspension, etc.), payment under the bond or the imposition of penalties under statutory law. Also in 1999, the AOGCC promulgated 20 AAC 25.539 which outlines the procedure for the AOGCC to use should a temporary emergency order be issued without hearing to protect against immediate harm to public health and safety. If a hearing on an appealed violation or non-compliance relates to an UIC issue, a person with an interest and who is adversely affected may intervene in the enforcement proceedings. Any person may make an oral statement at a hearing of the Commission.

A person affected by an order or decision of the Commission may file an application for a rehearing within 20 days of the decision. The Commission must act on the request within 10 days. Any further appeal is to the Superior Court. UIC staff only becomes involved to the extent when the dispute is technical. The senior staff and commissioners evaluate reports for violations and enforcement actions and would eventually develop the cases. The AOGCC has an attorney assigned to them by the State Department of Law who also assists in drafting enforcement documents.

B. Nature and Disposition of “Paper” Violations versus Technical Violations

The AOGCC has no provisions for automatic fines or penalties. If a situation arises where it is necessary to protect against immediate harm to public health and safety, the Commission may issue a temporary emergency order without a hearing. This Order expires after 14 days unless the Operator asks for a hearing or the AOGCC grants an extension (20 AAC 25.539 (c)). Normally, Emergency Orders would not be issues for “paper violations”. If the Commission proposes to take enforcement action for a violation, it would provide written notice of the proposed action (revocation of permit, penalties, or corrective action). The Operator has the option of concurring with the Order, requesting an informal review or requesting a formal hearing. Any follow up inspection reports made by AOGCC staff become part of the administrative record after review by the Commissioners.

C. Time Allowance for Corrective Action/ Return to Compliance

The AOGCC requires prompt action for any violation including “paper violations (tardy or failure to submit reports, monitoring summaries, etc.)” Most requests for compliance are verbal and not in the form of Notice of Violation or “Traffic Tickets” used by some state oil and gas regulatory programs. Inspectors provide follow up inspections as dictated by the seriousness of the violation. Threatened USDWs would require immediate action by the Operator. No timelines for corrective actions for various violations have been established and no written procedures have been established. To date, there are few examples of injection swells near USDWs in the Cook Inlet region and none on the North Slope; consequently, AOGCC has not visualized the need for written protocols.

D. Procedures for Escalation from Non-Compliance Discovery to Formal Enforcement Action

Almost all field violations by Alaska Operators are resolved informally before they reach the enforcement stage. Voluntary compliance is sought on an informal basis. A violation would be elevated to an enforcement action where a threat to a USDW is perceived and immediate action is necessary. In the past, the AOGCC has ordered payment under a bond when the operator failed to plug and abandon a well upon lease expiration. Generally, bonds can be called in or used to plug abandoned wells and possibly for limited corrective action to prevent USDW contamination, however, they are not often reviewed as a part of initial enforcement action. Enforcement actions by AOGCC could, but not necessarily have to involve other state agencies such as the DNR or ADEC. The MOU currently being developed with the ADEC may have some provision about when cooperation on enforcement actions would be appropriate.

The AOGCC stressed to the Review Team that when threatened with enforcement action, the Operator has come into compliance without further action. No penalties have been assessed for UIC violations. The one major Class II well failure event to date was in an area without a USDW. As the Operator cooperated fully and spent a large amount of money fixing the problem, both the AOGCC and EPA believed penalties were inappropriate.

The AOGCC senior staff determines when the Operator has returned to compliance after a violation and would make a recommendation to the Commissioners. Approval to reactivate a well would likely be given through approval of a Sundry Application. MIT failures are the usual failures encountered. Options available to operators include repair or operation under waiver stipulations. The operator could also shut-in and secure the well.

E. State/ Federal Enforcement Action Interface

The cooperation level between the AOGCC and the EPA on enforcement issues, according to participants from both parties who were in attendance during the review, has been very good. The MOA and Compliance Assurance Agreement documents articulate the responsibilities of each party and the manner of communication needed when non-compliance events and violations occur. The AOGCC has never requested that EPA take over an enforcement case, nor has the EPA ever overfiled on a case.

F. Contamination/ Alleged Contamination Resulting from Injection Well Practices or Associated Activities During the Past Ten Years.

There have been no Class II UIC related contamination cases reported to the AOGCC or other state agency during the past ten years. The commission staff indicated that if a report were ever received, response and investigation of the allegation would begin

immediately. The absence of contamination cases can be directly related to the fact that many of the injection wells were drilled, operated, monitored and regularly tested under the Class II Primacy program. Alaska does not have the heritage of a large number of pre-program wells common to most oil producing states.

Identified Strengths

1. As was indicated in the 1991 review, the Commission continues to have a wide array of enforcement tools, which can be implemented to ensure compliance.
2. The promulgation of regulations in 1999 for enforcement action and emergency action procedures by the Commission is now in place in case it is needed for the wider range and number of operator types which Alaska is expected to have in future years.
3. The timely review of field inspection reports and reports of required tests by the Sr. Petroleum Engineer ensures that violations are rechecked in a timely manner for compliance. With the current operator set, the voluntary compliance program has worked very well.

Comments and Recommendations

1. Even though AOGCC has not received any complaints and have not issued fines and penalties to date, they should consider seeking revisions to statutory structure or regulatory mandate to allow fines and penalties to go back into the agency's operating fund. The primary reason would be to recoup the cost of complaint and violation investigation. Some states have received the authority to issue "traffic ticket" fines for lesser violations. The Legislature can always place a ceiling on the amount collected if they are worried AOGCC would use fining as a "funding log" or revenue enhancement.
2. The Review Team had some concern that more verbal notifications of violations should be followed up with correspondence from either the Inspector or the Sr. Petroleum Engineer detailing the non-compliance and providing time frames for expected resolution of the violating condition. The Review Team believes that standard procedures should be adopted and included in the Inspector's Manual.
3. During the Compliance discussion, the AOGCC expressed some concern that EPA, in the course of their Class I regulatory duties, does not always give a notice of violation to Operators. The Review Team recommends the AOGCC and EPA revisit their MOA to determine if there is an easy method to improve communication. This prevents the potential of one entity from permitting an operator to do an activity while another has the operator in a state of violation for a related activity.

The AOGCC compliance and enforcement program has array of tools to deal effectively with violations when they occur. The fact that penalties and fines have not been assessed is reflective of the diligence of the Operators in resolving non-compliance problems as soon as they are discovered. AOGCC's program will adequately protect water resources.

PART VI: PLUGGING AND ABANDONMENT

A. Description of the Technical Aspects of P&A; Documentation

Three regulations apply to the abandonment and plugging of all wells, including injection wells: 20AAC 25.105 (Abandonment of Wells), 20AAC 25.107 (Plugging Well Branches) and 20AAC 25.112 (Well Plugging Requirements). The AOGCC does not use special geological standards, tables, or other technically based policy documents to assist field staff in determining where plugs should be set. The latter regulation is quite detailed and covers both cased and uncased sections of the borehole. Section (c) of 25.112 provides five options for plugging the perforated interval of cased borehole. Injection wells would typically be plugged using the displacement method by placing a cement plug from 100 feet below to 50 feet above the base of the perforated interval and from 50 feet below the top to 100 feet above the top of the perforated interval or by placing a cement plug from the well's total depth to 100 feet above the top of the perforated interval. Occasionally wells are plugged with the casing and tubing left in the hole due to uneconomic recovery. Fluid of sufficient density to exert a hydrostatic pressure exceeding the formation pressure must be placed between plugs. The provisions 20 AAC 25.105 require the plugging of all oil field related wells in such a manner as to contain fluids within the interval in which they were found.

There are no wells in Alaska without surface casing, however, there are wells in Kuparuk West, West Sak, and Milne Point where the surface casing is also the production casing. The casing is cemented to surface in these wells. Several parts of 20 AAC 25.112 applies to specific plugging problems. Subsection (c) (2) provides three options for plugging a well when "casing stubs" exist with outer casing. One of these, the displacement method, results in 100 feet below and 100 feet of cement above the stub. The other methods intend to achieve similar results. Subsection (c) (3) outlines the plugging requirements if fresh water is present.

Section (g) requires the Operator to record ("tag") the actual downhole location of any cement and plugging devices by allowing the plug to be weight tested or by pressure testing to 1500 psig or 0.25 psi/ft multiplied by the vertical depth of the casing shoe whichever is greater, and tagging the plug to confirm the location. Prior notice of 24 hours must be given to the AOGCC to allow them an opportunity to witness the test. AOGCC indicated they try to witness all critical plugs (across hydrocarbon zones, across from the surface casing shoe and at the surface on exploratory wells. The tagging and witnessing of any "off bottom" plug is seldom waived. If the plug is "bottom founded",

the tagging is sometimes waived particularly in areas of no USDW. AOGCC inspectors witness about 50% of all pluggings with priority given to the areas where USDWs need to be protected.

If a radioactive source were lost in a well, Nuclear Regulatory Commission (NRC) guidelines would proscribe the abandonment steps necessary. The AOGCC would coordinate with other agencies (ADEC, NRC etc.) to assure that a nonrecoverable source is properly isolated. AOGCC Inspectors would likely be on-site to witness the placement and confirm the integrity of any cement plugs.

B. Non-Technical Aspects of P&A: Relation to Rest of O&G Program

All plugging and well abandonment records are maintained in the AOGCC office in Anchorage. They are used by the staff in performing file and compliance reviews and to verify accuracy of the Operator's information on Area of Review. The regulations require prior approval of the Commission before plugging may begin. Well plugging and abandonment operations require sundry approval – Form 10-403; AOGCC considers this a permit rather than an application. The Operator is required to submit a Sundry Notice (Form 10-403) indicating an intention to plug and providing a plugging plan. Once the plan is reviewed and approved by the AOGCC engineering and geological staff, the Inspector cannot change the plan unless the AOGCC Anchorage staff approves. Once plugging is completed, the information provided on the plugging completion report (Form 10-407) is compared with the approved plan. Penalties could result from deviating from the approved plan without prior approval from AOGCC.

The Statistical Technician updates the status of all wells. The Commission publishes a weekly report of all new information, which is available on the AOGCC website. Deserted wells that are not properly plugged and abandoned are considered "orphan wells". AOGCC attempts to determine the owner or leaseholder of record. AOGCC has identified 17 wells that meet the orphan definition. The condition and ownership of 56 additional wells is currently unknown. A number of other wells are the subject of disputed ownership; nearly all were drilled for or by the Federal government during early exploration in the National Petroleum Reserve Alaska. The search for responsible parties is a current AOGCC effort. If no responsible party can be found, AOGCC must identify potential funding sources to plug the orphan well, particularly if a threat to USDW exists. This applies to all wells, not just UIC wells. Alaska does not have a dedicated well plugging fund as has been established in many major oil-producing states. At present, the AOGCC would have to seek an appropriation from the Alaska Legislature for special funds.

C. Disposition of Temporarily Abandoned Wells

The AOGCC recognizes three well status situations that apply to either producers or injectors: active, shut-in or suspended (nearly equivalent to P&A). Any injector on suspended or shut-in status must successfully pass an MIT before returning to service. New regulations pertaining to shut-in wells were promulgated in 1999. Alaska

regulations and the AOGCC do not recognize the term “Temporary Abandonment” to describe a well that is inactive but not plugged. 20AAC 25.110 provides regulations for suspended wells and 20 AAC 25.115 provides regulations for shut-in wells. The Operator is required to provide the Commission a report on a suspended well every five years and an annual report on wells that have been shut-in for 365 days or more (20 AAC 25.110(e)).

Identified Strengths

1. The technical plugging requirements for injection wells are quite detailed and continue to provide for several technically sound and accepted options to cover different cased hole scenarios. As was the case in 1991, the technical requirements are sufficient to properly plug downhole intervals below the base of the surface casing and above and below the perforated interval.
2. The tagging of all plugs and the witnessing of the tagging assures that plugs have been set at depths required in the plugging program.
3. 20 AAC 25.112 was amended in 1999 and now addresses in more specificity the concern the 1991 Review Team had about the regulations not requiring a solid cement plug both inside and outside casing opposite the surface casing shoe. The 2002 Review Team believes the plugging and abandonment regulations are protective of USDWs.
4. The priorities are given to witnessing of pluggings in areas where there are USDWs and gives assurances that groundwater is protected, even given the available personnel and logistic problems.

Comments and Recommendations

1. The 1991 report stated “There appears to be no technical reason why inactive injection wells should not be continued to be subject to testing for mechanical integrity”. The state responded that “a traditional MIT may not be appropriate given the shut in status (and would not replicate risk of well to integrity loss); operator must justify continued shut in status of well to AOGCC”. This Review Team believes that for “suspended wells”, the temporary plugging requirements of 20AAC 25.110 are sufficient to protect USDWs without periodic MIT since the wells have a plug to be drilled out. Wells that receive Shut-In status under 20AAC 25.115 only requires an annual report from the Operator that the known mechanical condition of the well is satisfactory. These wells should have a MIT conducted on the same frequency as active wells.
2. The AOGCC would benefit from having a dedicated, self-sustaining fund for plugging abandoned and orphan wells. The fund can have a ceiling amount, which cannot be exceed without legislative approval. To date, Alaska has been fortunate in that its operators are completely sensitive to the potential ramifications of

abandoned wells and have the \$50,000 to \$100,000 it takes to plug a well in accordance with current regulations.

3. Should the nature of Alaska production gravitate down the evolutionary scale from major oil companies and major independents (mini-majors) to Operators with less financial resources (the bond notwithstanding), the state might have to deal with additional abandoned wells. The chosen data management system should be designed to track both shut in and abandoned wells as a separate category as a routine procedure. During times of economic depression in the industry, the evolution of well from active status to temporarily abandoned and then to orphan status is sometimes very short.

The AOGCC administers and implements a very comprehensive and technical set of plugging rules that are protective of USDWs. AOGCC needs to plan to the future when Alaska has a less diligent level of Operator and the threat for leaving wells improperly abandoned increases.

PART VII: PUBLIC OUTREACH

A. Description of Public Outreach Program for UIC Activities

The general public is informed about UIC program activities through the public notice and hearing process where individuals are provided the opportunity to review and comment on area enhanced recovery, aquifer exemption, produced water injection for disposal, storage injection and conservation order applications. In addition to publishing on the state wide web site, notice is published in the Anchorage newspapers, the Alaska Administrative Journal and the newspaper in the borough in which the subject of the application is located. Notices are published in the Peninsula Clarion for UIC applications in the Kenai/Cook Inlet area. Applicants are required to provide a copy of the application to operators and surface owners within one-quarter mile radius of the proposed well or Area Injection Order.

The state Administrative Procedures Act sets forth the process to be used by the AOGCC when noticing the proposal of new regulations or amendments to existing regulations. In addition to publication of notice of proposals on the state and Commission web sites, notice is published in the newspaper and mailed to all persons on the AOGCC mailing list. The mailing list contains over two hundred entities and persons and also includes all of the Alaska oil and gas regulated community as well as environmental groups, other state agencies and interested members of the public. This list is issued and updated annually to provide copies of all Commission notices and orders. Mailings occur every three to four months but may vary according to the level of regulatory activity. (The Review Team was provided a copy of the current mailing list). The AOGCC does involve the regulated community, the Alaska Oil and Gas Association and other interested parties in development of new regulations through the periodic formation of “working groups”.

The AOGCC does not have an established Technical Advisory Group, which consistently involves either the industry or other stakeholder interests.

The 12 operators currently operating oil and gas wells in Alaska are very familiar with the existing regulations. They, along with the public, receive notices of proposed changes to regulations. New operators generally meet informally with the Commission staff and are provided with copies of regulations and Commission forms. The regulations are also available on the AOGCC web site.

The mailing list includes Trustees for Alaska (a public interest litigation firm), Greenpeace, the Cook Inlet Keeper, Native Corporations and the National Resource Defense Council. Several of these groups have expressed interest in UIC issues, primarily in proposed regulatory changes. AOGCC staff indicated no group has expressed concern over UIC well completion practices or hydraulic fracturing. In Alaska, both the regulated community and the environmental interest groups have expressed a preference for underground injection of oil field waste over surface disposal options.

B. State of Alaska Hearing Opportunity Process

Formal hearings are conducted according to procedures in 20 AAC 25.540 (c) which have been adopted in accordance with the provisions of the Alaska Administrative Act. On UIC applications, the hearing opportunity is offered at the draft permit stage. The applicant presents testimony first and all others wishing to present testimony are heard next. Upon request, the Commission will, in its discretion, allow cross-examination of witnesses. Persons are prohibited from asking questions directly of witnesses, but may submit questions to the Commission to consider posing to a witness. The Commission is not obligated to ask all the submitted questions but will generally ask questions, which are helpful in eliciting information to make a decision. The AOGCC believes the hearing process does provide an opportunity for an interested person to learn about proposed UIC projects, however there has been little interest in UIC hearings beyond the parties involved in the application and oil and gas reporters.

The EPA has not appeared at any recent hearings, but they have occasionally provided comments on UIC applications. EPA is provided notices of all proposed changes in regulations at the beginning of the promulgation process and again when the regulation is in final form. There were no regulatory changes to the UIC regulations between 1986 and 1996. Regulatory changes occurred in 1996 and in 1999.

C. Identification of Coordination with State and Local Water Planning Efforts

None of AOGCC's coordination activities with other state agencies could be termed as "public outreach" in the general sense of the definition. When multiple resource agency permits are needed for a project, the permitting reviews are coordinated through the DGC, which is housed in the Governor's office. The DGC is charged with the CZM program, and provides coordination between resource agencies and serves as a forum for

public comment. The AOGCC is currently working on a MOA with the ADEC to formalize coordination between agencies, primarily for coordination of spill events and remediation activities.

Identified Strengths

1. The mailing list to over 200 addressees includes most persons and environmental groups who may have concerns or comments on UIC applications and regulatory changes. This mailing list plus the AOGCC web site provides very good access for both the regulated operators and the public to keep abreast of UIC matters before the Commission.
2. The AOGCC hearing process does avail anyone the opportunity to comment on UIC applications while under the technical review and permitting process. Interested persons may submit written comments, which become part of the administrative record.
3. The AOGCC is conscientious in keep the Alaska environmental community aware of the permitting of oil and gas activities as they arise. The AOGCC public outreach activities are satisfactory with the mailing list, on which anyone can request to be added.

Comments and Recommendations

1. The 1991 Peer Review suggested public outreach could be enhanced by providing additional detail in the legal notice of applications, such as the depth of the injection interval, the nature of the injected fluid and the geographical location of the well. This Review team believes the more formalized hearing process and the AOGCC web site, which was not available in 1991, allows interested parties access to information on any given UIC matter before the Commission.
2. The fact that AOGCC, ADEC and DNR share a field office on the North Slope at Deadhorse should improve inter-agency communication particularly if the AOGCC and ADEC complete the MOA under current negotiation.
3. The 1991 Review Team suggested the AOGCC consider developing an informational brochure to provide an overview of their UIC program. In response to this Review, the Commission felt the current Peer Review documentation would serve as a good basis for public education of Alaska's Class II UIC Program. They believe that the protection of fresh water was embodied in both the Alaska statutes and regulations. The Commission still may want to develop a brochure that articulates the high points of its ground water protection program and assurances to the public.

AOGCC administers a very good public outreach program in that Commission activities concerning the filing of Class II UIC well applications is very open and accessible to the

public. This allows the public and concerned citizens to be appraised of actions to be taken by the AOGCC as well as educated on rules and regulations designed to protect USDWs.

PART VIII: REVIEW OF WATER REUSE POLICIES FOR OIL AND GAS ACTIVITIES

The AOGCC Staff was asked several questions related to the reuse of water produced in connection with oil and gas activities. Alaska currently has no mandate or policies relating to the reuse of produced water. Reuse of produced water by means other than by injection into Class II-R wells is outside the mandated authority of the AOGCC. At the present time, there is no active coal bed methane (CBM) being produced in Alaska, although seven potential production wells and one Class II –D well have been drilled. Another Operator is planning to drill eight production wells beginning in the fall of 2002, however, the operator plans to truck produced water to the disposal well rather than reuse it. In the absence of specific regulations, AOGCC would use their authority to require public noticed development of individual pool rules and injection orders to accommodate CBM production, should it occur. How AOGCC chooses to administrate the development of CBM is outside the scope of this review. All Class II injection wells associated with CBM production would be covered under the currently administered UIC program regulations.

Appendix A

UNDERGROUND INJECTION CONTROL PROGRAM DEVELOPMENT

The Underground Injection Control programs have been developed and implemented as a result of the federal SDWA of 1974. Under Part C of the SDWA (Public Law 93-523), as amended by Public Law 96-502; 42 US Code 300f et seq. Congress directed the EPA to develop regulations for a nationwide UIC program that would control the permitting and operation of injection wells to protect the USDWs. EPA was given the responsibility for developing minimum requirements for state UIC programs. States had the option of developing regulations that were more stringent than the federal regulations, however, the states could not adopt regulations, which were less strict than the minimum federal requirements.

The EPA promulgated the current regulations, which they use to implement UIC programs in 1980 under authorities of Section 1422 of SDWA. The Congressional intent was for individual states to assume administration of the UIC program. States could receive grant money from EPA to develop a UIC program and apply to EPA for primary enforcement responsibility (“primacy”) for that program. In states, which have not sought or have not received primacy, the EPA administers the program directly (“direct implementation” programs). States have the option of applying for primacy for all or only a portion of the injection wells classes with some restriction by EPA. For example, in Alaska, the EPA administers the UIC program for Class I, III, IV and V (although there are no Class III or IV wells in Alaska); while the state administers the program for Class II injection wells. Although there has been some subsequent modification to these regulations since 1980, the only real changes have been interpretations of the various concepts as the UIC program has matured.

EPA regulations established five classes of injection wells, which were defined and delineated, in part, by the source of the injected fluids and the physical relationship of the injection zone to a USDW. Class I wells are those that inject hazardous and non-hazardous industrial waste fluids and also municipal liquid wastes into formations located stratigraphically beneath the lowermost USDW. Class II wells are those used for injection related to oil and gas activities or some types of hydrocarbon storage. Class III wells are those that inject fluids for the extraction of minerals as in solution mining operations. Class IV wells, those directly injecting into a USDW, were banned nationwide on May 13, 1980 (40 CFR Part 122.36) and all other Class IV wells were banned on and after May 11, 1984 (40 CFR Part 144.13). Class IV is now restricted to those injection wells, which are part of contamination remediation operations at Federal Superfund sites. Class V wells are injection wells not covered by the other classes and generally include wells injecting fluids into formations above USDWs.

In 1980, Congress amended the SDWA to include Section 1425, which established a method for a state to obtain primary enforcement authority for its Class II program by substituting the existing state regulatory program for the prescribed EPA program. This alternative program could be approved by the EPA if the state demonstrated a level of

equivalent effectiveness for USDW protection as defined by the SDWA, specifically subparagraphs (A) through (D) of Section 1421 b)(1), and that such program represented an effective program to prevent injection operations which endanger USDWs. The state review process, such as the one conducted in Alaska, is one of the assurances available to EPA that state Class II primacy programs are being administered in accordance with the best principles of protection to USDWs.

Acronyms (in order of use)

Page		
1	USDW	Underground Source of Drinking Water
1	mg/l	milligrams per liter
1	TDS	Total Dissolved Solids
1	UIC	Underground Injection Control
1	EOR	Enhanced Oil Recovery
1	GWPC	Ground Water Protection Council
1	AOGCC	Alaska Oil and Gas Conservation Commission
1	EPA	Environmental Protection Agency
1	SDWA	Safe Drinking Water Act
6	MIT	Mechanical Integrity Test
7	DNR	Department of Natural Resources
7	ADEC	Alaska Department of Environmental Conservation
8	II-R	Class II UIC Enhanced Recovery
8	II-D	Class II UIC Disposal
8	RBDMS	Risk Based Data Management System
10	MOA	Memorandum of Agreement
13	AS	Alaska Statute
14	P&A	Plug and Abandonment
14	FY	Fiscal Year
15	GIS	Geographic Information System
17	DOE	Department of Energy
17	DGC	Department of Governmental Coordination
17	CZM	Coastal Zone Management
17	PTD	Permit to Drill
17	DMLWM	Division of Mining, Land, and Water Management
18	AAC	Alaska Administrative Code
18	BP	British Petroleum, Alaska Inc.
18	EPCRA	Emergency Planning and Community Right-To-Know Act
20	AIO	Area Injection Order
20	DIO	Disposal Injection Order
20	AEO	Aquifer Exemption Order
23	APM	Annulus Pressure Monitoring
23	USGS	United States Geological Survey
24	AOR	Area of Review
26	GAO	Government Accounting Office
29	IOGCC	Interstate Oil and Gas Compact Commission
29	BLM	Bureau of Land Management
29	MMS	Minerals Management Service
31	QA/QC	Quality Assurance/Quality Control
31	QAPP	Quality Assurance Project Plan
34	MITIA	Mechanical Integrity Test of Inner Annulus
34	MITT	Mechanical Integrity Test of Tubing
34	CMITIA	Combination Mechanical Integrity Test of Inner Annulus
35	CQL	Cement Quality Log
35	APM	Annual Pressure Monitoring
35	RATS	Radioactive Tracer Survey
44	NRC	Nuclear Regulatory Commission
49	CBM	Coal Bed Methane
50	CFR	Code of Federal Regulations

Our Mission

The Ground Water Protection Council is a national association of state ground water and underground injection control agencies whose mission is to promote the protection and conservation of ground water resources for all beneficial uses, recognizing ground water as a critical component of the ecosystem.

The Ground Water Protection Council provides a forum for stakeholder communication and research in order to improve governments' role in the protection and conservation of ground water.



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